TAMPEREEN TEKNILLINEN YLIOPISTO
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AVOIDING UNDUE DISCRIMINATION IN TRANSMISSION CAPACITY CALCULATION AND ALLOCATION

Master of Science Thesis

Examiner: Professor Sami Repo
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ABSTRACT

NIKO KORHONEN: Avoiding undue discrimination in transmission capacity calculation and allocation
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European Union legislation on transmission capacity allocation and congestion management thrives to achieve fair and consistent treatment for European market participants. A lack of sufficient and coordinated methods to handle internal congestions in capacity calculation and allocation reduces given transmission capacity to the market. This leads to inefficient market and undue discrimination between market participants depending on location of internal congestions. Challenge is noticed in Finnish congestion management when production is shifting towards north whereas most of the consumption is located in south. Improved methods should consider socio-economic impacts and treat market participants without undue discrimination.

This master thesis discusses transmission capacity calculation between internal and cross-zonal trade including rules to avoid undue discrimination. Developed method improves currently used congestion management practices by estimating market impacts of capacity reduction during internal congestions in European market area. Congestion management during capacity calculation is realised either with redispatching or cross-border transmission capacity reduction. A decision between these methods is depending on which method shows lower socio-economic costs and higher market efficiency.

Socio-economic impacts of reduced transmission capacity were estimated based on market information gathered from years 2016–2017. Results show that socio-economic impact for reduced cross-zonal transmission capacity is averagely within 15–45 €/MWh during congestion while the majority of values are within 20–30 €/MWh indicating lower values than average Finnish day-ahead market price. Most of market impacts occur in Finnish bidding zone, respectively capacity changes influence Swedish and Baltic State bidding zones.

Highly volatile redispatching costs were estimated subject to balancing market prices due to relatively low quantity of historical redispatching measures. When comparing costs between capacity reduction and redispatching, results conclude socio-economic justification of redispatching especially below 100 MW congestions in all price ranges due to similar or even lower costs than capacity reduction. Above this, relieving congestions based on absolute costs of required actions and therefore, congestions within 100–200 MW are generally relieved with redispatching if reasonably priced resources are available. During even higher congestions, the availability of redispatch should be considered and capacity reduction is justified.

TIIVISTELMÄ

NIKO KORHONEN: Siirtokapasiteetin jakaminen markkinatoimijoille
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Euroopan unionin lainsäädäntö siirtokapasiteetin jakamisen ja ylikuormitusten hallintaan pyrkii varmistamaan markkinatoimijoiden tasapuolisen ja yhtenäisen kohtelun Euroopan sisäisessä sähkön siirrossa. Riittävän siirtokapasiteetin puute ja epäyhtenäiset siirtokapasiteetin jakamisen menetelmät ovat asettaneet eurooppalaiset markkinatoimijat eri asemaan riippuen alueellisista siirtorajoituksista. Haaste syntyy myös Suomen sisäisiin siirtoihin tuotannon siirtyessä pohjoisemmaksi kulutuksen ollessa etelässä. Kehitettävän menetelmän tulee huomioida tasapuolisesti eri markkinaosapuolet ja olla kansantaloudellisesti perusteltavissa.

Diplomityö käsittelee siirtokapasiteetin laskentaa ja sitä, miten siirtokapasiteetti jaetaan tarjousalueiden sisäisille ja välisille siirroille, ja siten eri markkinatoimijoille huomioiden lainsäädännön vaatimukset. Työssä kehitetään nykyistä syrjimättömyysperiaatteen varmistavaa menetelmää siten, että tarjousalueiden sisäisten rajoitusten tarjousalueiden rajoille siirtämisestä aiheutuvat markkinavaikutukset arvioidaan sähköpörssien kehittämän simulointiohjelmiston avulla. Käytännössä sisäiset rajoitukset tulisi hoitaa vastakauppaamalla rajakapasiteetin rajoittamisen sijaan, jos sen voidaan osoittaa olevan tehokkaampaa huomioiden markkinahyödyt ja vastakaupan kustannukset.

Työssä tutkittiin rajasiirtokapasiteetin muutosten vaikutusta kansantaloudelliseen hyötyyn simuloimalla vuosien 2016–2017 markkinatilanteita. Arvioitujen tulosten perusteella rajakapasiteetin alentamisen kustannus pullonkaulatilanteessa on keskimäärin 20–50 €/MWh, ja pääosa tarkastelluista viikoista on 20–30 €/MWh välillä. Suomen keskimääräiseen day-ahead aluehintaan suhteutettuna tämä on hieman alhaisempi ja kuvaa melko alhaista siirtojen hallinnan kustannusta verrattuna vastakauppaan. Rajakapasiteetin alentamisen vaikutukset ulottuivat Suomen hinta-alueen ulkopuolelle etenkin Ruotsin ja Baltian maiden tarjousalueisiin.

Vastakaupan kustannuksen suuruutta verrattiin säätösähköhintoihin vastakauppojen pienestä määrästä johtuen. Tulosten valossa vastakauppa on kansantaloudellisesti perusteltua alle 100 MW:n sisäisissä rajoituksissa kaikilla hintatasoilla, sillä sen kustannus on sama tai alhaisempi kuin rajakapasiteetin alentamisella. Suuremmat rajoitukset perustuvat arvioidun rajasiirtokapasiteetin alentamisen kustannukseen vastakaupan voimakkaan kasvun johdosta. Tämän perusteella noin 100–200 MW:n vastakaupat ovat kansantaloudellisesti perusteltuja, mikäli niitä on saatavilla kohtuullisesti hinnoiteltuna. Tätä suurempia vastakauppoja voi olla haastava toteuttaa, koska resursseja ei välttämättä ole saatavilla.

PREFACE

Master of Science thesis was written in Market Solution unit of Fingrid Oyj. I would like to thank my advisor Heini Ruohosenmaa for her guidance, effort and insightful views towards my work and my examiner Professor Sami Repo from Tampere University of Technology for his helpful comments and never-ending attention to details.

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Helsinki, 24.10.2018

Niko Korhonen

CONTENTS

LIST OF SYMBOLS AND ABBREVIATIONS

ACER	Agency for the Cooperation of Energy Regulators
ATC	Available Transmission Capacity
CACM	Capacity Allocation and Congestion Management
CNTC	Coordinated Net Transfer Capacity
EC	European Commission
ENTSO-E	European Network of Transmission System Operators for Electricity
EUPHEMIA	European Union Pan-European Hybrid Electricity Market Integration Algorithm
HVDC	High Voltage Direct Current
NEMO	Nominated Electricity Market Operator
NTC	Net Transfer Capacity
OTC-market	Over-The-Counter market
P1-cut	Internal transmission network intersection between South and North of Finland
RAC-cut	Cross-zonal border transmission network intersection in north between Sweden and Finland
TSO	Transmission System Operator

p_n	Unit price of n
q	Quantity of product

1. INTRODUCTION

Change towards cleaner energy system creates major changes in electricity market and power system. The latest Capacity Calculation and Congestion Management (CACM) guideline tries to assure low-carbon objectives broader in the energy market and target rules are made to utilise European interconnected transmission networks more efficiently in future low-carbon society. Intermittency related to renewable energy generation is apparent and the transmission network operation requires coordinated methods between TSOs. Increasing renewable energy adoption creates uncertainties related to power system operation and may lead to congestion in the transmission network.

Increasing internal congestion in future is due to significant transmission between North and South of Finland and resulting surplus and deficit area between North and South of Finland. Congestion is eventually noticeable in electricity prices and may discriminate if required methods are absent. Changes toward to renewable energy resources will primary change production location to Northern Finland and increasing risk for congestion in P1-cut transmission which is an internal transmission network intersection between South and North of Finland.

Internal congestion issues have been acknowledged by Agency for the Cooperation Energy Regulators (ACER) which states concerns due to a lack of common procedures to accommodate congestions in European transmission network. Generally, internal congestion issues has been shifted towards cross-zonal borders by decreasing cross-zonal capacities in order to avoid additional congestion related costs for Transmission System Operators (TSOs). Existing capacity calculation and allocation procedures have created situation where cross-zonal transmission capacities are reduced without clear transparency and creating a challenge for efficient electricity market. It leads to different treatment of market participants and may discriminate unjustly. Current practices are not providing incentives for TSOs to increase their cross-zonal capacities in order to avoid undue discrimination between internal and cross-zonal flows. (ACER 2016)

Current European regulation of undue discrimination and transmission capacity calculation and allocation notices the issue and represent principles to avoid undue discrimination. These principles shall be taken into account in the development and implementation of short-term congestion management methods developed by TSOs. Main task is to create market based implementation without affecting excessively to electricity market providing transparent and cost-reflective price signals for market participants. For this reason, rules to avoid undue discrimination should be further developed, tested and implemented in the current congestion management in Finnish transmission system.

1.1 Objective and structure of the thesis

This master thesis focuses on transmission capacity calculation and allocation between market participants without undue discrimination between internal and cross-border trade. Rules to avoid undue discrimination should follow current CACM guidelines which thrives to guarantee electricity market operational security and efficiency. In accordance to the regulation, target is to increase efficiency in electricity market focusing on the European point of view.

Thesis thrives to revise current method and rules avoiding undue discrimination applied by Fingrid in capacity calculation phase. This essentially means revising congestion management methods in order to ensure fair treatment for each market participants. Congestion management is revised for internal congestions within Finnish bidding zone by estimating market impacts of congested transmission situations with simulation tool. Market impacts are measured based on two different congestion management methods: relieving internal congestion by redispatching or reducing cross-zonal transmission capacity. Redispatching should be applied if market impacts of the capacity reduction is higher compared to redispatching costs indicating higher efficiency and lower market impacts. Analysed study results and estimated redispatching costs are foundation for revised Fingrid´s capacity allocation and congestion management policy.

The first two chapter represents background of the market environment and raises capacity allocation and congestion management objectives into attention. Power system and market represents common knowledge regarding supply and demand and European market coupling. Similarly, formation of day-ahead price and its impacts during congestion are represented and giving foundation for theoretical background of consumer and producer socio-economic welfare calculation in European electricity market. Then, transmission capacity calculation is represented and how cross-zonal border transmission capacity is determined. Technical aspects and calculation methods are represented to increase awareness of physical concerns of congestions.

Forth chapter represents undue discrimination rules based on European Commission (EC) regulation (No. 2009/714) and CACM guideline (2015/1222) in order to ensure accordance of current methods. Chapter gives detailed view on how congestion management should be realised and how ACER understands those requirements. Then, fifth chapter describes current congestion management methods applied by Fingrid in capacity calculation phase and describes reasons behind policies and made assumptions.

Market impacts are analysed in sixth chapter based on simulated market outcomes from historical market data. European socio-economic welfare change is calculated for consumers and producers representing market impact when congestion are relieved in P1-cut transmission. Then, redispatching costs are estimated and compared to transmission capacity reduction costs. Revised procedures are verified in accordance of regulations.

2. POWER SYSTEM AND MARKET

This chapter presents power system and electricity market showing common knowledge regarding to Nordic transmission system and European electricity market and gives foundation for understanding congestion management in internal and cross-border transmission. These subjects support understanding price formation in electricity market as represented along with producer and consumer surplus. Especially price formation and welfares for producers and consumers are essential to this thesis and giving background for further review to transmission capacity calculation and congestion management.

2.1 Nordic power system

Power system is understood as a whole supply chain from generation to consumption where in between transmission system enables electricity to consumers. Reliable power system utilisation requires control and balance between generation and consumption. These tasks require profound cooperation with Nordic TSOs in a common synchronous system.

Finnish transmission system is part of a synchronous area of the Nordic interconnected power system. It consists countries including Sweden, Norway and partially Denmark where Western Denmark is part of a synchronous area of Central Europe connecting to Nordic synchronous area with direct current transmission. The Nordic transmission system is utilised with alternative current and direct current depending on situations including as well Estonia, Latvia and Lithuania where these Baltic States are connected by HVDC (High Voltage Direct Current) with Finland and Sweden (Partanen et al. 2015)

Nordic TSOs have responsibility for reliable power system in order to sustain security of supply of the transmission system and have legal responsibility to manage the transmission system for the most beneficial manner from society´s standpoint. National TSOs has responsibility to maintain operation in nationwide with cooperation with other TSOs. TSOs actions are regulated by national and European Commission (EC) legislation enabling harmonised and fair electricity market rules. National and international authorities for instance energy authority in Finland and ACER approve methodologies proposed by TSOs and give recommendation based on legislation and monitor implementation progress. Common guidelines are established as well with ENTSO-E (European Network of Transmission System Operators for Electricity) which is an association of European TSOs founded according to EC regulation (No. 2009/714).

Finnish electricity production has been relatively diverse compared to European countries meaning that Finland does not have dependency on a single production method. Half of the Finnish electricity production is generated by nuclear and hydropower and fossil fuel based production is approximately one fifth of the yearly production. Other rapidly increasing resource is wind power with under one tenth of all productions (Finnish Energy 2017). Demand is normally supplied as well with imports from Sweden guaranteeing operational security and similarly harmonises electricity prices in Nordic area.

2.2 European electricity market

In a work of sustaining balance between supply and demand, electricity market is created to meet these requirements. Electricity market offers a platform for producers and consumers to trade efficiently electricity and sustaining balance between supply and demand. Efficiently working electricity market supports transmission system operation and making participation to the market easier. Efficiency requires highly integrated electricity market to create appropriate outcome.

Integration process has been continuous in the Nordic electricity market since 1991. It has improved efficiency and made possible to utilise various energy resources supporting renewable energy targets. Currently, the Nordic power system is a part of the European electricity market gathering large proportion market participants such as producers, consumers, TSOs and distribution system operators. Electricity market participants are for the most part producers and consumers. (Partanen et al. 2015)

European electricity market is divided to bidding zones where market participants set offers to buy or sell electricity in the corresponding bidding zone. The bidding zone itself represents a single pricing area where price is identical within bidding zone without a price spread. Bidding zones in European-wide trade are connected adjacently with cross-zonal transmission networks where transmissions are depending on transmission capacities between bidding zones. (Biggar & Hesamzadeh 2014)

Electricity market area is represented in figure 1 including bidding zones and hourly price for a one hour in Nordic and Baltic States. Most of the time electricity prices are similar in Finland, Sweden and Northern Norway bidding zones due to sufficient transmission capacity between zones. Prices are separated if transmission is congested such as demand for electricity is higher in certain bidding zone and creates individual pricing area. (Fingrid 2018a)

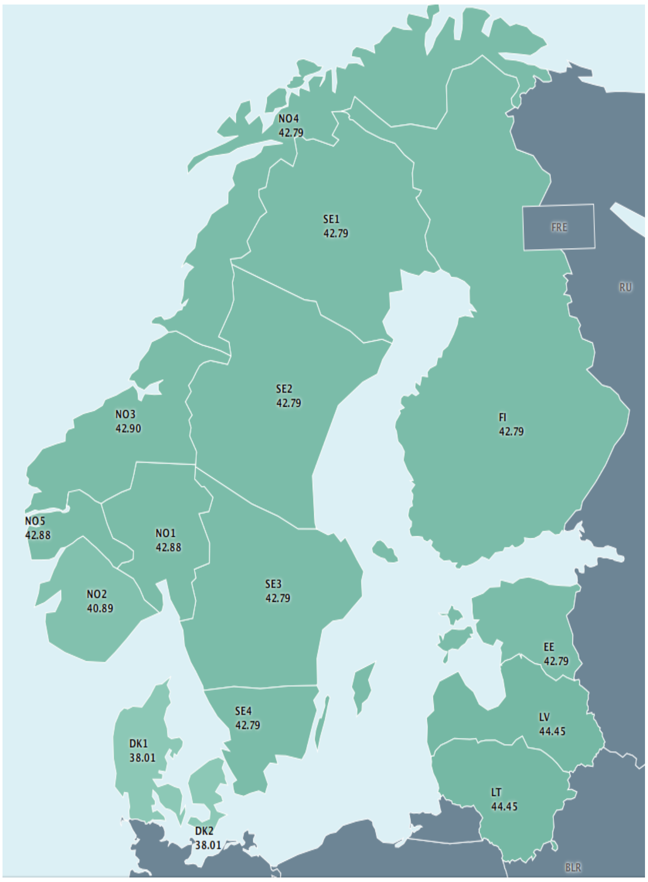

Figure 1. *Nordic and Baltic electricity market and bidding zones on 4th April 2018 (Nord Pool 2018a)*

Congestions are depending on hydrological situation between years and seasons and creates negative market impacts when transmission is restricted. Low availability of hydropower tends to increase electricity price due to large reliance of hydropower in the Nordic power system. Similarly, high hydrological reserve decreases the bidding zone price as significant amount of energy is produced by hydropower due to lower marginal costs compared to other production methods. High availability of hydropower in the Nordic electricity market guarantee similar prices in larger market area if transmission flow is adequate. However, power system could encounter congestions in Finland if large proportion of electricity is imported from Northern Sweden and Lapland and transferred to Southern Finland creating congested P1-cut transmission. These events are relevant especially during high demand in Southern Finland. Congested cross-zonal interconnections are discussed more profoundly in chapter 2.3.2. (Partanen et al. 2015)

Imports from Sweden have major role for electricity supply in Finland. Imported electricity guarantees lower electricity prices in the transmission system and improves security of supply due to larger market area. Larger market area is in a central role in developing European market coupling where two or more electricity markets are integrated in to one in order to implement cross-zonal transmission capacity allocation and utilisation of generation resources more efficiently. (Partanen et al. 2015)

2.2.1 Day-ahead and intraday market

Day-ahead market is a daily market for buyers and sellers where electricity is traded a day before the delivery day by an implicit auction. A large proportion of electricity is traded in the day-ahead market representing a primary market for market participants to buy or sell electricity and further the intraday market is utilised if supply and demand does not meet. Market participants submits their bids to the market on different hours and bidding zones before clearing process. Clearing process guarantees that electricity price is formatted efficiently accordingly to the physical need of electricity.

Day-ahead and intraday markets are administered by NEMOs which offer trading services and power market for market participants. It is based competition and currently Nord Pool is active in Nordic, Baltic States, Germany and other eight European countries in day-ahead and intraday markets (ACER 2018). In the day-ahead market, TSOs have to define transmission capacity for each day and hour and provide cross-zonal transmission capacities to the market for allocation before the implicit auction period. Based on calculated cross-zonal transmission capacities and given offers to the day-ahead market, NEMOs´ pricing algorithm allocate transmission capacity between market participants. The day-ahead auction is being held a day before the delivery day after left offers before 12:00 pm CET. These contain bid or ask offers for every hour on following day. (Nord Pool 2018b)

The intraday market is a continuous market which usually correct imbalances that are not able to forecast a day before the delivery day. Therefore, the intraday market volume is lower compared to the day-ahead market especially in Nordic countries due to sufficiently forecasted production and consumption. Sometimes forecasting congestions is not reliable and day-ahead capacity restrictions are made unnecessary which is also seen in intraday market capacity. These restricted transmission capacities from the day-ahead market could be offered to the intraday market when more accurate forecast are possible to make. This offers a tool avoiding unnecessary transmission capacity limitations. Still, transmission capacities are primary revaluated in the market where changes are firstly effecting. During unexpected network changes, the transmission capacity reduction is realised in the intraday market. (Fingrid 2016) However, this thesis estimate market impacts without scheduled outages and the intraday market is excluded from further review.

A part of congestion management methods are realised in the day-ahead market. Transmission capacity reduction measures are realised in the day-ahead market by reducing day-ahead capacity of corresponding cross-zonal interconnections. Procedures decrease transmission in cross-zonal border and relieve internal bidding zone congestion. In this thesis, one of the limiting power transfer corridors are located between North and South of Finland in intersection of South of the Oulujoki. This P1-cut transmission is relieved by reducing transmission between FI-SE1 bidding zones. However, decision for capacity reduction should be planned and informed naturally before day-ahead auction and limits forecasting accuracy for the delivery day. This is represented more profoundly in chapter 5. Other congestion management methods are realised in balancing market. (Fingrid 2015)

2.2.2 Balancing market

Power system has to be operated in a way that balance is maintained between supply and demand. Normally, the day-ahead market is a regular market for trading commodities but forecasting demand and generation before following day is not necessarily precise and requires alternative solutions. While the day-ahead and intraday market doesn´t necessarily guarantee a balance between supply and demand, balancing market offers a tool for managing balance during operational hour and level supply and demand differences. The Nordic balancing brings larger market area available and greater disturbances are operated easier. (Borggrefe & Neuhoff 2011)

Balancing power fluctuations are enforced by Nordic TSOs in the Nordic balancing market. Balancing in the Nordic power system is carried mostly with TSOs in Sweden and Norway and their responsibility sustaining Nordic balance with cooperation of national TSOs. National TSO operates internal issues and cooperates sustaining balance in cross-border. Power system balance requires balancing power for operating hour by placing up-regulating or down-regulating bids depending on situation. Up-regulating bid increase production or decrease consumption and down-regulating bid decrease production or increase consumption. Different balancing products are utilised in normal network situation or disturbances typically depending on balancing response and duration.

Because of the nature of balancing markets, TSOs have agreements with each TSOs how power system should be balanced in same synchronous area. This is based on system operation agreement, which guides Nordic countries implementing similar balancing methods. (Borggrefe & Neuhoff 2011) Nowadays electricity balancing guidelines are being implemented creating European-wide balancing energy markets and common rules to guarantee harmonised balancing principles in the European power system. Balancing should be reasonable without having impact on market efficiency, consumers´ or producers´ surplus or discrimination between market participants. Exceptions are justified in unusual situations if operational security is compromised or balancing affects significantly on TSOs efficiency. (ACER 2017a)

The Nordic balancing market offers a platform for balancing generation and demand after the intraday market. For a congestion management, congestions are relieved in balancing market with countertrading and redispatching measures by increasing production or decreasing consumptions on areas where total bidding zone consumption is high, and decreasing production or increasing consumption on areas where consumption is low.

Therefore, the total balance between supply and demand is same while the transmission is lower. (Androcec & Wangensteen 2006) Countertrade and redispatching are similar procedures however, countertrades are utilised for cross-zonal trades and redispatching is utilised for internal bidding zone trades. For this thesis, main interest is to determine congestion management methods between redispatching and capacity reduction measures in order to improve internal congestion management method.

Countertrades and redispatching are usually carried out in the balancing market by special adjustments to relieve short-term transmission network congestions. Procedures are done due to other reasons than balancing management purposes and takes part in the special regulating market by Fingrid (2018c) which is a part of the balancing market. Actual countertrading and redispatching measures are partially made in OTC-market (Over-The-Counter) for longer congestion management needs. OTC-market is a bilateral agreement between two parties directly and enables exchange if suitable offers are unavailable in the special regulating market. (Androcec & Wangensteen 2006)

Special regulation utilises pay-as-bid pricing method compared to marginal pricing method utilised in the balancing market and therefore, share order books are separated from following markets. Pay-as-bid pricing method differs from a marginal pricing method in a way that each trade has individual price tied to the specific volume in bids. It denotes that actual bids are placed to the auction without creating clearing price subject to marginal cost compared to additional premium in pay-as-bid pricing. Therefore, bids are subject to average reference price rather than based on marginal costs. Pricing method is reasonable for special regulation as a result of lower liquidity compared such as to the day-ahead market when producer or consumer offers the actual amount of electricity to trade. (Tierney et al. 2008)

2.3 Price formation during congestion

2.3.1 Price formation

This chapter represents how price is fundamentally originated from meeting supply and demand in an competitive ideal market and further described in electricity market when decision are based on rational choices. It describes determination of each participants´ willingness to set offer and how it leads to certain accepted price and volume. Similarly, changes in prices are discussed and fundamental reasons behind it.

Demand is described subject to two factors: willingness to purchase and ability to purchase certain product. Willingness itself means desire to purchase the product whereas ability means liquidity to enable desires. Together it represents demand´s willingness to purchase certain product for the certain price. Fundamentally, the price becomes limiting factor as the desire to purchase product is high and leads to demand changes depending on the price level. Higher price indicates lower demand and lower price indicates higher demand. (Whelan & Msefer 1996)

The price setting behaviour is depending on demand changes of quantity and price. This relation between quantity and price is described with demand curve representing downward slope during increasing quantities. Generally, higher the volume, lower the price should be in order to realise trade due to fixed incomes and inability to purchase the same volume with similar costs compared to lower quantities. This creates a relation between lower and higher priced substitutes where increasing price of one or another will effect on another substitutes price similarly. Therefore, changing incomes or prices shifts demand curve accordingly. (Varian 2010)

Supply however, shows rather similar behaviour compared to demand. Similarly, supply is subject to two factors: willingness to sell and ability to supply certain product. Ability to supply represents ability to satisfy customers by offering quantities of product. This ability is guaranteed by inventories and production capacities and influencing to price of the product. High short-term demand increases production costs and influences to increasing price on higher quantities. This is generally represented with supply curve where upward slope illustrates increasing short-term price and higher quantities represents higher difficulty and costs to produce certain product. Higher need of the product shows higher costs of the product. (Whelan & Msefer 1996)

Now as described, supply responses to market changes is reversed compared to demand changes. While the price increase, demand´s willingness to purchase will decrease and supply´s willingness to sell will increase. At some point, demand exceeds supply and both supply and demand have intersection where price and quantity are identical. (Whelan & Msefer 1996) This is equilibrium point as illustrated in figure 2 where market clearing price represents equilibrium price.

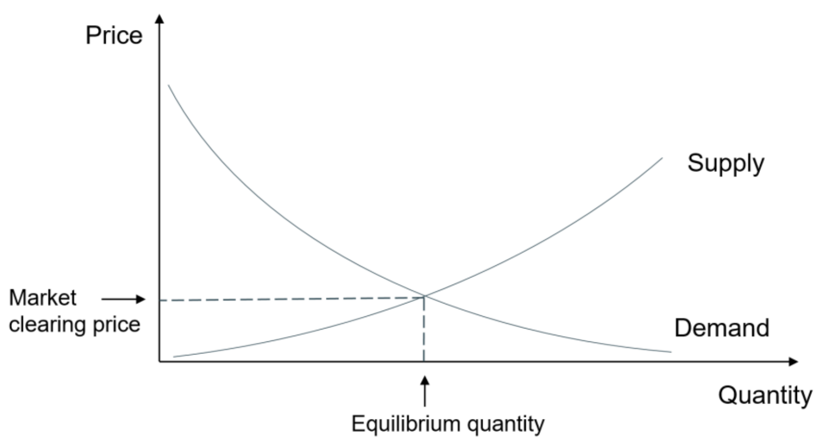

Figure 2. *Price formation from supply and demand curve in competitive market*

Now, the equilibrium point describes optimal price and volume where both participants have willingness to trade specific volumes and prices. Changes to demand or supply will change equilibrium point by shifting demand or supply curve accordingly. In electricity market, the need of electricity changes between day, night and seasons and illustrates volatile demand behaviour. However, supply behaviour and price formation is often understood as a marginal pricing principle in the day-ahead market favoured by marginal costs. Then, production dispatching is based on marginal costs of the production and creating supply curve accordingly and ensuring lower price risk for producers and competitive price for consumer. (Varian 2010)

Supply and demand responses differently to price changes depending on elasticity in electricity market. The price elasticity denotes changes in quantity relative to changes in price. High elasticity indicates changes in quantity without influencing widely to the price and representing responsiveness of supply and demand. (Varian 2010) Demand is not relatively elastic to changes due to the basic need of electricity and creates virtually vertical demand curve. This illustrates electricity markets where few close substitutes for electricity produce inelastic demand such as limited choices for heating, for example, decision between electricity and gas heating system. However, supply has more elasticity compared to demand caused by competitions and having a better response. Still, higher demand doesn´t necessarily change producer's behaviour to set higher offers but changes the equilibrium accordingly (Biggar & Hesamzadeh 2014; Varian 2010)

Particularly, short-term demand is inelastic as a result of consumers´ unwillingness to respond to real-time market changes if considering below 24 hour time period (Eirgrid 2018; Nagbe et. al. 2018). Still, long-term demand is able to respond in a limited degree. (ENTSO-E 2015) However, demand side management is increasingly drawing attention and indicating higher elasticity to the demand side management by shifting energy consumption to hours when electricity demand is lower.

Price elasticity is sometimes limited due to cross-zonal border or internal congestions. In this case, limited quantity of available offers create higher demand for electricity and inelasticity of demand is reflected to the bidding zone price. Higher changes in the bidding zone price compared to quantities indicates lower elasticity. The transmission limitation will cause price spread in cross-zonal interconnection or decreasing elasticity in internal bidding area. In practice, price spread appears between adjacent bidding zone prices. (Biggar & Hesamzadeh 2014; Varian 2010)

2.3.2 Price spread during congestion

Price formation guarantees fairly priced product by taking into account market participant´s willingness to sell or buy products. Now, trade between cross-zonal borders may be disrupted by physical transmission network constrains caused by congestions. Congestions are restrictions in the transmission network if transmission capacity is not sufficient to guarantee adequacy of transmission flow. It effects on uniform pricing areas and leads to spreading bidding zone prices.

Bidding zone prices are uniform between bidding zones if cross-zonal transmission capacity is not limiting transmission flow and therefore, supply and demand intersection are identical between adjacent bidding zones. If transmission between bidding zones is restricted, supply in adjacent bidding zone will not guarantee all sufficient transmission for consumers. As a result, producers in the same bidding zone as consumers should increase their production by the amount of limited transmission. (Varian 2010) As described in 2.3.1, higher requirement of production will increase the bidding zone electricity price due to increased short-term demand and creates spreading price between adjacent bidding zones. Similarly, decreasing short-term demand indicates lower price by the reason of restricted export to other bidding zone.

Transmission flow is still issued while the transmission capacity is restricted between adjacent bidding zones. Demand tends to buy electricity at lower price from adjacent price area and adjacent supply tends to sell electricity to higher price area. This indicates transmission flow from lower price area to higher price area in order to balance bidding zone prices. During a congestion, this is unavailable realise if transmission is restricted or demand´s willingness to buy decreases. After relieving congestion, prices will settle to similar equilibrium point. (Varian 2010; Frontier 2011)

Bidding zone prices are fundamentally created in electricity market in order to control congestion and represent physical locations of congestions and limitations of transmission network. (Frontier 2011) If producer sells electricity from lower priced bidding zone to higher priced bidding zone, producer receives only lower price regarding selling electricity to higher priced bidding zone during congestion. This price spread multiplied with transmission flow through bidding zones is received congestion income representing ownerless income of the market outcome. Incomes are received by NEMOs and further allocated to corresponding TSOs to relief congestions in long-term. (Nord Pool 2018c)

Congestion incomes essentially help to coordinate investments to areas where the actual need is located for the transmission capacity increase. Incomes are highly depending on restricted transmissions as a result of separated adjacent bidding zone prices. Due to these issues, rules and regulations for congestion management are represented in chapter 4. Part of the congestion issues could be handled with other methods than transmission capacity reduction e.g. countertrading and redispatching, which are discussed in chapter 3. (ACER 2016)

2.4 Socio-economic welfare in electricity markets

Socio-economic welfare in electricity market demonstrates generally all created common good among market participants indicating wellness of the European electricity market. It means maximisation of the welfare for producers and consumers leading to higher market value and higher market efficiency. Essentially, congestion management methods have a certain negative impact to socio-economic welfare by decreasing the welfare. In order to not violate operational security limits of the transmission system, relieving congestion in P1-cut transmission should be done regardless of negative welfare change. This chapter concentrates on socio-economic welfare change in European electricity market and how it impacts market participants.

Socio-economic welfare is measured for European-wide market coupling area and changes are depending on generation, demand and capacities on cross-zonal interconnections. (ENTSO-E 2015) Essentially, socio-economic welfare is depending on three factors: producer and consumer surplus and congestion income. Consumer and producer surplus indicates willingness to buy or sell specific price and volume compared to market clearing price representing created welfare for market participants. Figure 3 explains definition for consumer and producer surplus which is related to market price and created area between supply and demand curves. Socio-economic welfare is calculated for each bidding zone and different market outcomes change consumer and producer surplus accordingly. In theory, efficient market finds reasonable price for each situation thus maximising benefit for consumers and producers i.e. maximising the total socio-economic welfare in electricity market. (Varian 2010) Generally, demand curve´s lower slope increases demand´s surplus and similarly supply curve´s higher slope increases producer´s surplus.

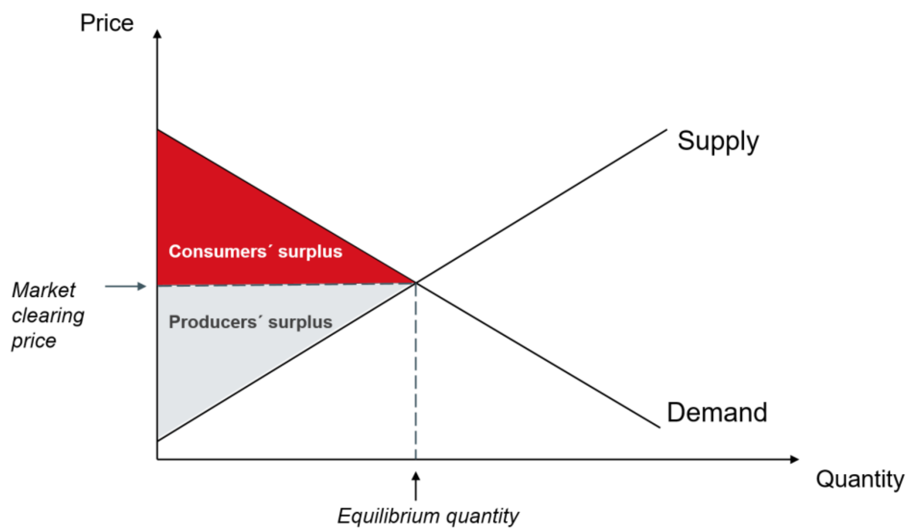

Figure 3. *Consumer and producer surplus formation.*

Welfare impacts in electricity market during congestions are generally subject to price difference between adjacent bidding zones as the optimal welfare is compromised. As described in chapter 2.3.2, separated bidding zone prices leads to lower price for other area and higher price for adjacent market area compared to initial congestion free situation. For consumer and producer surplus point of view, higher bidding zone price indicates higher market clearing price representing negative surplus change for consumer and positive surplus change for producer. (ENTSO-E 2015) It means that increasing price compared to initial situations benefit producers in bidding area at consumer´s expenses. Depending on the actual size of each surplus change, the total welfare change is either positive or negative however, increasing bidding zone price generally indicates lower total welfare in Finland.

In general, price spread between bidding zones is represented by surplus and deficit areas. Deficit area occurs if production is lower than consumption and residual energy is imported from other bidding zones with the aim of meeting the consumption. Due to this, bidding zone price increases if transmission flow is restricted from lower priced bidding zone. Similarly, surplus area means that production is higher than consumption within bidding zone indicating export from adjacent bidding zones and lower bidding zone price. (ENTSO-E 2015)

Figure 4 extends these conclusions where initial price p_1 and quantity Q_1 is represented without any congestions within internal bidding zone or between cross-zonal bidding zones. During congestion, producer and consumer welfare changes affect to changed price p_2 and quantity Q_2 and creates surplus and deficit areas. Fundamentally, bidding zone price in export region is lower compared to initial situation due to limited cross-zonal capacity and sufficient production guarantees lower prices comparing to initial situation. This is generally possible if marginal costs are lower than average marginal costs in the adjacent market area. Still, full utilisation of the transmission capacity contributes lower price spread between surplus and deficit areas, however, not necessarily make price difference non-existent. The idea is similar in import situation where bidding zone price is higher compared to adjacent bidding zone and leading importing electricity from bidding zone where price is lower. (ENTSO-E 2015) In other words, supply and demand will not create identical price between surplus and deficit area as a result of congestion. The equilibrium between bids and offers will move right or left accordingly until the balance is realised. This is based on TSO´s given commercial transmission capacity to cross-zonal interconnections.

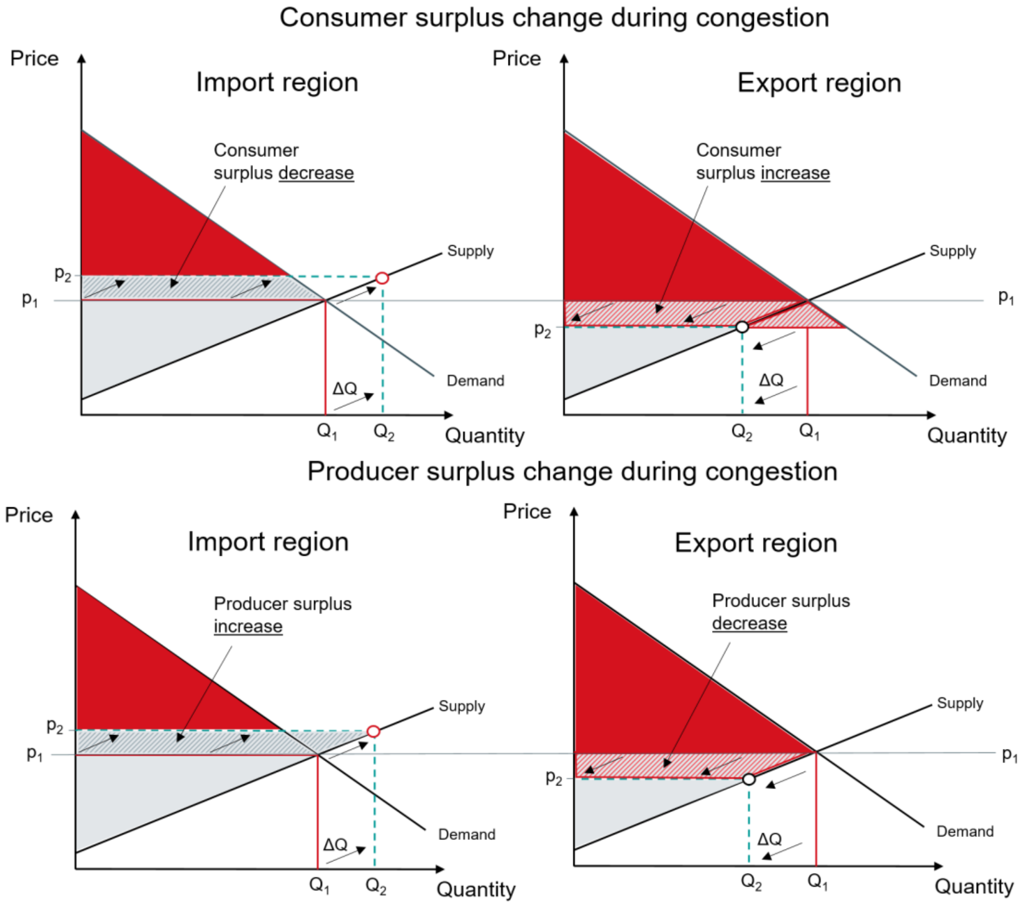

Figure 4. *Consumer and producer surplus change after congested adjacent bidding zones. (Adapted from ENTSO-E 2015)*

Congestions lead eventually to price spread between import and export region and creates congestion income representing ownerless income of the market outcome. These congestion incomes collected by NEMOs are further divided between cross-border transmission owners i.e. TSOs as described in chapter 2.3.2. However, congestion incomes regarding to socio-economic welfare tries to express bidding zone limitations and how much congestion limits possible consumer and producer welfare. In this case, consumers in import region witness welfare decrease and consumers in export region witness welfare increase. Similarly, producers in import region witness welfare increase and producers in export region witness welfare decrease. (Energinet et. al. 2014)

In addition to producer and consumer welfare, calculating congestion incomes guarantees that price coupling algorithm notices bidding zone congestion while seeking the most optimal solution. As a result, maximising the sum of consumer and producer surplus and congestion income guarantees efficiency and optimised solution noticing every market participants in each situation. (Energinet et. al. 2014)

Changing supply and demand caused by congestion is one of the key observations when calculating socio-economic welfare. Congestion in import region typically increases bidding zone price and implies consumer welfare loss and producer welfare increase.

This is subject to surplus area changes as represented in figure 4 and forces consumers to use internal bidding zone production offers and impacting to higher market clearing price. However, positive producer surplus change and negative consumer surplus change does not necessarily imply decrease into total socio-economic welfare change. In this case, the total welfare change is negative if absolute consumer surplus change is higher than producer surplus change indicating relatively higher change for consumer surplus compared to producer surplus. Therefore, the absolute value for socio-economic welfare in electricity market is not relevant, only the change of total welfare is relevant in different transmission network situations.

Taking into account different bidding zones in European-wide capacity allocation in future, main challenges are encountered how socio-economic welfare change is divided to the whole European market area. Different bidding zones may encounter situations where such as one bidding zone is encountering surplus increase for consumer but other bidding zone is encountering surplus decrease for consumer. Therefore, socio-economic welfare maximisation is a matter of European-wide optimisation in order to notice European market participants the most beneficial manner. Then, participants issue inevitably either positive or negative welfare change depending on transmission network situation compared to previous network situations such as situations during previous days. Although, fully maximised European welfare in electricity market is restricted due to political and national interests. (ENTSO-E 2015)

3. TRANSMISSION CAPACITY CALCULATION AND CONGESTION MANAGEMENT

Aim of the capacity calculation is to define maximum allowed transmission capacities that can be given to the market without exceeding operational security limits. Capacity calculation should be efficient and based on fair procedures without reducing transmission capacities unnecessarily. It means necessity to minimise market impacts and sustaining sufficient transmission system operation.

Limitations within bidding zones might cause a need to decrease cross-zonal capacities in order to relief internal congestion. In these cases, it is important to review the most efficient way to relieve congestion with different procedures and how decision might effect to market participants. Review gives a foundation to avoid undue discrimination between internal or cross-zonal flows which are more profoundly reviewed in chapter 4. Therefore, congestion management should be utilised without affecting cross-zonal transmission capacity excessively.

3.1 Congestion management in transmission network

Transmission flow limitations in internal or cross-zonal network elements create congestion situations if the transmission capacity is not sufficient as described in chapter 2.3.2. Therefore, open market principles are not guaranteed if transmission capacities are limited by TSOs. As a part of the thesis, transmission capacities limitations could be discriminatory for market participants and therefore, restricting potential socio-economic welfare requires appropriate congestion management procedures.

Congestion management in capacity calculation phase is fundamentally based on decision between cross-zonal capacity reduction and countertrading and redispatching measures depending on overloads and estimated congestion management costs in the transmission system. Congestion management procedures variates between European TSOs and capacity reduction procedures are commonly realised among Central European countries due to excessive congestions in internal and cross-zonal trade (ACER 2016).

Given capacity between FI-SE1 bidding zones i.e. RAC-cut transmission is an important driver for congestion management as a result of it supplies significant amount of electricity to Finland and guarantees relatively low energy prices by Swedish and Norwegian imports. High imports to the south though the P1-cut transmission may cause internal congestion management issues increasingly in future. (Fingrid 2015) Increasing internal transmission is based on the third interconnected transmission between FI-SE1 bidding zones, upcoming Hanhikivi 1 nuclear power plant and increasing wind power in Northern Finland and Sweden. At the same time, old combined heat and power plants and old nuclear power plants will be shut down in certain time frame which are largely located in Southern Finland. These issues result increasing surplus in Northern Finland and increasing deficit in Southern Finland and raises uncertainties to congestion management. Changes toward to renewable energy resources will be primary change production to Northern Finland hence surplus in the north will be greater in future. (Fingrid 2018a)

Excessive internal transmissions are realised by short-, medium- and long-term congestion management methods. Long-term congestion management fundamentally includes transmission network investments in order to physically increase transmission capacity. Reinforcing congested lines are primary solution in long-term while the bidding zone reconfiguration is another possible method. Reconfiguration is a medium-term congestion management method to coordinate bidding zone border locations where congestions typically occur. Both methods are realised within several years. (Frontier 2011)

This thesis concentrates on short-term congestion management due to need for improved methods for taking into account market impacts in capacity calculation phase. Short-term congestion management methods include countertrades and redispatching which relieve congestions directly after made transactions by shifting production closer to the demand as represented in chapter 2.2.2. However, use of countertrades or redispatching are relatively rare in special regulating market since intraday market offers may assist congestion management. In both markets TSOs can ask for up-regulating and down-regulating offers at their expenses to manage transmission congestions. Sometimes bilateral trades are utilised to redispatch within Finnish bidding zone if merely one redispatching offer is available. Still, countertrades and redispatching don´t eliminate physical long-term congestion and investments should be made to the transmission network in order to avoid future congestions. (Dijk & Willems 2009)

Alternatively, congestion are relieved with cross-zonal transmission capacity reduction measures instead of countertrades or redispatching. Transmission capacity reduction restricts given capacity to the market between bidding zones and restricts congested internal transmission. While the RAC-cut transmission is reduced, it forces demand to buy electricity from internal bidding zone area and relieves congestion occurred in P1-cut transmission and similarly in RAC-cut transmission. Naturally, this method has direct impacts to electricity market price and reduces overall socio-economic welfare in Finland subject to decreasing consumer surplus and increasing producer surplus. (ACER 2016). Still, this method could be inaccessible during high consumption and transmission in summers due to insufficient supply in Finnish bidding zone.

Redispatching may not be possible to realise during congestions in operational security point of view. Thermal limitations and power oscillation may occur especially during an outage such as in Fenno-Scan connection. In this situation, redispatching is inaccessible in Northern deficit area while power flow from south to north utilises all P1-cut transmission capacity. Situation is challenging to utilise without limiting cross-border transmission capacity. Still, scenario is not expected when P1-cut has been reinforced in recent years and wind power plants are installed in Northern Finland lowering the RAC-cut transmission need due to higher self-sufficiency of electricity. (Fingrid 2018a)

3.2 Determining the transmission capacity

While understanding the foundation of congestion in earlier chapters, transmission capacity calculation takes into account technical limitations of the power system in order to define maximum capacities that can be given for allocation. Reduction of cross-zonal transmission capacities may compromise market efficiency if alternative method shows lower market impacts. Therefore, foundation for determining transmission capacity is reviewed and causes of limited transmission capacity is represented during normal transmission states.

Transmission capacity is a maximum capacity that can be offered to the market without compromising operational security. Capacity limitations cause congestion situations occasionally as a result of dynamic stability, thermal limitation or system security policies. Often transmission capacity is understood as maximum transmission that withstand dimensioning fault i.e. N-1 criteria without violating operational security limits.

Determining transmission capacity is based on considering technical characteristics of the transmission system and operational security constrains. Measuring merely physical transmission capacity is not sufficient sustaining reliability of the transmission system. Operational security limit e.g. N-1 criteria is primary measured by determining stability during contingencies in Finland where higher operational security constrains limit physical capacity depending on transmission and fault situations. Therefore, given transmission capacity to the market is not a sum of lines´ physical capacities. (Fingrid 2015)

NTC (Net Transfer Capacity) is currently used calculation method in the electricity market in Nordic and Baltic States providing allocation of available transmission capacity on each bidding zone border. It is a maximum commercial capacity taking into account physical transmission grid and operational security constrains. This physical transmission capacity is reduced by reliability margin is a foundation for allowable commercial transmission capacity where reliability margin takes into account calculation uncertainties. After considering reliability margin, transmission capacity is a given maximum commercial exchange to the market. (Fingrid 2015)

Transmission capacity calculation requires coordination between TSOs to utilise network efficiently while noticing physical constrains. Optimisation requires essentially cooperation between TSOs if allocated interconnected lines are between adjacent TSOs. Neighbouring countries will coordinate NTC calculations for common border by TSOs where both TSOs calculate their NTC capacities and the lowest NTC will be selected to the allowed commercial transmission capacity. In the capacity calculation, grid topology with production and load forecasts and estimated exchanges are forecasted and utilised as a basis in the calculations aiming to maximise allowed commercial transmission capacity. These are coordinated with limited degree with other TSOs in Nordic. (Plancke et al. 2016)

During a normal transmission network circumstances, TSOs should allocate their maximum cross-zonal capacity to the market without primary choosing capacity reduction as a general measure compared to countertrading and redispatching. Still, TSOs have right to reduce transmission capacity during planned transmission outages in order to make maintenance in transmission system. Faults and other disturbances are threatening operational security where insurmountable issues could be resolved by reducing transmission capacity. (Fingrid 2015)

Maximum commercial capacities are illustrated in figure 5 as a result of transmission capacity calculation. Given transmission capacity to the market between Norway and Finland is merged to the RAC-cut transmission capacity since Norway transmission is excluded from commercial use while the physical maximum transmission capacity is 100 MW. This is due to fact that transmission between Norway and Finland has been historically low and exclusion from commercial use is agreed with corresponding TSOs. (Fingrid 2015; Fingrid 2018a) Maximum transmissions are depending on direction of the transmission where excessive export is hard to realise from smaller transmission system due to lower inertia (Kundur et al. 2004). However, it is important to notice that represented transmission capacities in figure 5 are not necessarily possible to realise together and therefore, one arrow shows maximum capacity between two points.

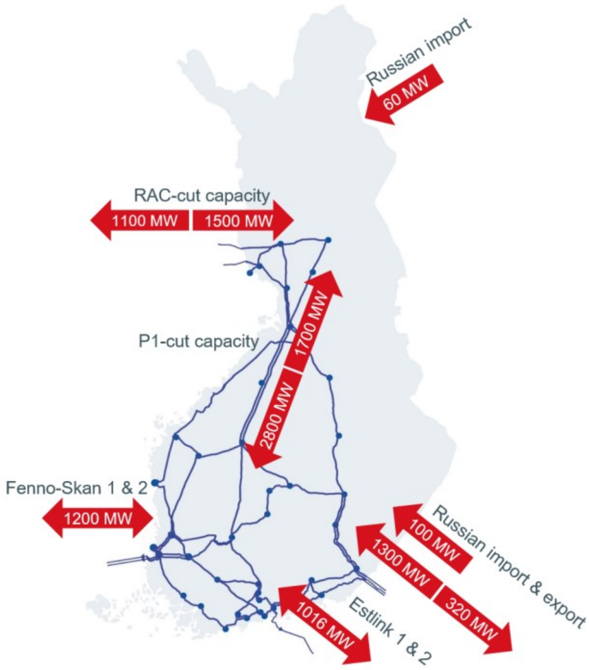

Figure 5. *Maximum commercial transmission capacities in Finland. (Adapted from Fingrid 2015; 2018c)*

Fenno-Skan import significancy arises for congestion management in Southern Finland: if P1-cut or RAC-cut transmission is limited, Fenno-Skan import is increased with normal balancing methods to decrease congestions in corresponding transmissions. Congestion issues are relieved also by countertrades with Estonian bidding zone while the importance of transmission between Finland and Estonia have been increased in several years. In some transmission network situations, countertrades between adjacent bidding zones are unavailable such as due to scheduled outage and therefore, redispatching within Finnish bidding zone is realised. (Fingrid 2018a)

3.3 Technical limitations of transmission capacity

Limitations in network elements and N-1 criteria creates starting point for sustaining transmission system reliability. As represented in chapter 3.2, technical transmission capacity is limited due to stability, voltage or thermal limitations and each constrain may limit transmission capacity in certain situations. Transmission capacity is calculated for cross-zonal interconnections and also for Fingrid´s internal purposes for internal cuts i.e. transmission between north and south.

Thermal limitations are subject to high load currents and physical constrains of the transmission system components. Constrains guarantee that high load currents will not damage components where limitations are primarily as a result of excessive temperatures and loading situations. Weather conditions e.g. temperatures and wind effect significantly estimating loading situations. Normally, nominal values for transmission system components are foundation for determining maximum transmission capacity. (Fingrid 2015)

Transmission system stability is another aspect to the restricted transmission capacity where oscillations between capacitive and inductive loads create instability. Synchronous machines does not necessarily sustain synchronisation in small disturbances or changes in rapid transmission network configuration and may create either unstable steady-state or transient oscillation. Issues occur especially in RAC- and P1-cut transmission where long lines with high loads and compensations may create stability concerns. High reactive power compensation in the transmission system create higher voltage to end of the line and supports sustaining voltage quality. Still, higher compensation has a higher risk for oscillation especially after contingencies. In Finland, rotor angle stability issues are more evident than thermal limitations due to long transmission distance and strong transmission system withstanding thermal limitations. (Fingrid 2015)

Voltage stability which is an ability to keep voltage within limits during normal transmission states and disturbances. It is highly associated with reactive power control and compensation due to reactive impedance of a line. High reactive power compensation may cause stability issues during disturbances especially if transmission flows are higher than usual. High voltage drop between start and end of the line could be an indication of voltage stability issue in the transmission system. In over compensated network, this is hard to validate when voltage is sustaining nominal levels without evident voltage drop. (Kundur et al. 2004)

Instead, transient stability is due to large and sudden changes in the transmission system. Changes cause fast output reduction and turbine has no time to adapt changes and derives faster rotor speed indicating rotor angle stability issue. If fault duration is sufficiently long, it may lead to loss of synchronisation. Naturally, active and reactive power oscillation creates variation also to frequency stability representing ability to keep frequency changes within deviation. Frequency below accepted limits will cause generators to disconnect from the system if sufficient balancing coordination is not realised. Frequency stability issues are encountered particularly in island operation when frequency oscillation is more evident compared to normal transmission state. Still, voltage oscillations are more common than frequency oscillation. (Kundur et al. 2004)

These constrains limit an operation of P1-cut and RAC-cut transmission which generally states operating range for the Finnish transmission system as represented in figure 6. As discussed in earlier chapters, electricity is imported from Sweden as a general measure and constrains are typically related to dynamic stability and voltage levels between FI-SE1 bidding zones. Limiting factors are depending primary on direction of power flow between Finland and Sweden and how much of this electricity is transferred to the south. This tends to follow Nordic hydrological situation. (Fingrid 2018a)

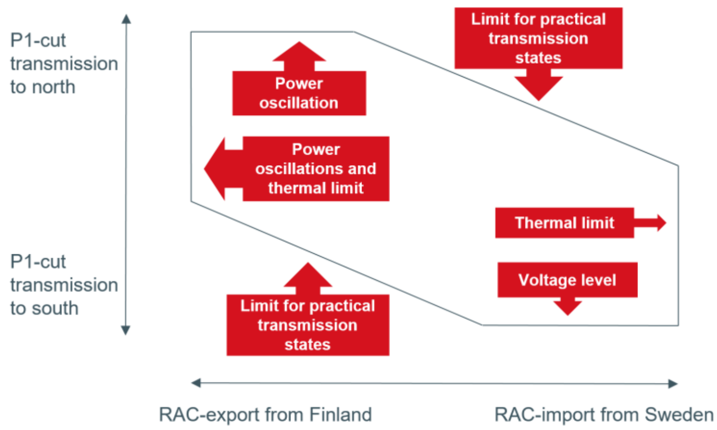

Figure 6. *Operating range diagram limiting transmission capacity*

The N-1 criteria is one of the key limiting factors for transmission capacity depending on scheduled or unintentional outages and switching situations to guarantee operational security during major outages. Transmission domain isn´t static and operating diagram changes shape based on e.g. temperatures, consumption and hydrological situations. Generally, higher consumption allows higher RAC-imports from Sweden but requires the P1-cut transmission lean more to the south in order to sustain operational security. (Fingrid 2018a)

Figure 6 illustrates relation between P1- and RAC-cut transmission and how excessive transmission leads to increasing transmission to one another. P1-cut and RAC-cut transmissions are essential study measurements whether relieving congestion in RAC-cut transmission has an effect on P1-cut transmission. Below figure 7 illustrates P1-cut and RAC-cut week average transmission in 2017 and concludes the relation between two transmissions. Week average values level high volatility between hours of a day and days of a week.

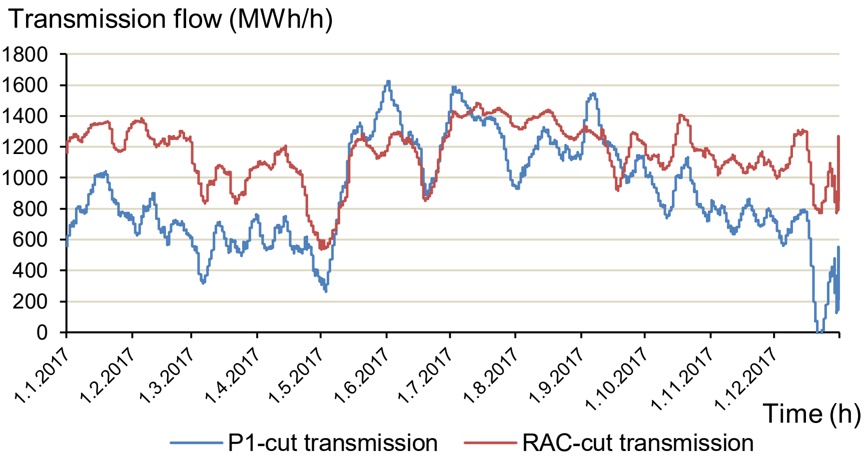

Figure 7. *Moving week average transmission in P1- and RAC-cut in 2017. (Adapted from Fingrid 2018c)*

Positive transmission flow indicate imports from RAC-cut transmission and P1-cut transmission to south. Both transmission shows a relation and changes generally impact on one another with moderately strong correlation coefficient of 0,66. Because of this, lower import in the RAC-cut transmission shows moderately strong positive correlation to lower transmission in the P1-cut and therefore, transmission capacity reduction indicate lower transmission in congested P1-cut. However, the highest P1-cut transmission is measured during May–August and indicates high imports from adjacent bidding zones and limitations in P1-cut during summer. Similar correlation of 0,61 in 2016 confirms presupposition of P1- and RAC-cut transmission similarities and high transmission in summers.

4. EUROPEAN REGULATION RELATED TO TRANSMISSION CAPACITY CALCULATION AND CONGESTION MANAGEMENT

Efficiency in European electricity market requires common guidelines. These guidelines are created to aim into “secure, sustainable and affordable energy supplies” (Mautino 2013). Because of this, target model for electricity markets defines harmonised rules for European electricity market where motivation is to provide common rules for TSOs, NEMOs and benefits for energy producers and consumers. Fully functioning electricity markets requires internal markets where efficiency and renewable energy resources are noticed. (EC 2015/1222) Chapter represents European regulation regarding to transmission capacity calculation of the day-ahead market and denotes foundation for congestion management without undue discrimination. In future, decision between countertrading, redispatching and transmission capacity reduction is verified from regulatory perspective and common methodologies shall take into account rules to avoid undue discrimination in capacity calculation and allocation. TSOs are obligated to show that the transmission capacity reduction on cross-zonal interconnections is justified compered to alternative measures in their transmission network area.

4.1 Capacity allocation and congestion management guideline

One of the biggest market codes are related to Commission regulation of CACM guideline (Capacity Allocation and Congestion Management) (EC 2015/1222). Regulation offers rules for cross-border capacity calculations and methods for countertrade and redispatching. These guidelines aim to harmonise European market “at least at regional level” however, utilising whole European electricity market for capacity allocation is common long-term target while the capacity calculation is coordinated regionally. This chapter presents regulation aims to effective competition and capacity optimisation issues. Related to thesis, harmonised rules are established based on three methods: capacity calculation, congestion management and trading of electricity.

Efficiency and optimisation is one of important themes in CACM guideline after noticing congestion situations especially in Central Europe. Despite of different perspectives in development of electricity market, Member States are required to fulfil requirements and TSOs are required to search reasonable solutions in order to acknowledge CACM regulation (ACER 2016). Common rules are believed to bring efficiency utilising the transmission system and offering a better platform for variable energy resources by lowering a threshold for joining to electricity market.

Countertrading and redispatching are part of the capacity allocation principles as represented in Articles 3, 25, 35 and 74 of CACM guideline. CACM guideline shows principles utilising countertrading and redispatching in order to control congestion without discriminating market participants. Primary, actions should be coordinated with the purpose of attempting efficiency and operational security. Coordination guarantees that each TSO should follow common methodologies for countertrading and redispatching actions.

Regulation gives rules determine how and when countertrading and redispatching can be utilised legitimately with reasonable costs. As Article 35 (EC 2015/1222) states, reasonable costs for countertrading and redispatching are based on either common price level in specific time frame or incurred transparent costs in electricity market. These are primary measures in congestion management stated by ACER if costs between countertrading and redispatching and capacity reduction measure costs are not distinctively different. Costs of countertrading and redispatching measures should be transparently calculated in accordance with common methodology. Costs are divided subject to such as “polluter-pays principle” which tends to prevent congestion issues in cross-border transmission as a result of potential penalties (ACER 2016).

Although, CACM guideline suggest that the transmission capacity reduction measures should work accordingly to operational security principles. Therefore, capacity reduction is justified in order to guarantee operational security which is a primary driver for congestion management. Transmission capacity reductions are generally chosen as a result of lower costs for TSOs compared to countertrading and redispatching while the impacts for electricity market are essentially created during congestions. (ACER 2016).

4.2 Undue discrimination rules for cross-zonal exchange

Setting undue discriminatory rules are part of the European Union´s third energy package achieving harmonisation and concluding regulations and directives related to energy and open market. Undue discrimination rules are set by European Parliament and the Council (EC 2009/714) where particularly rules for accessing and utilising the transmission system are represented and make possible transparency and new competitors in competitive electricity market. These guidelines thrive to improve overall competition, liquidity and welfare. For TSOs point of view, discrimination during limited transmission capacity should be studied.

The awareness of undue discrimination have been raised during the integration of European electricity market. Currently, common European interest should be favoured in part of national interests and therefore, not only national interests are treated, but European electricity market should be noticed. These issues are concluded in the Commission undue discrimination regulation where independence of market participants´ interests is one of the key assumption. Rules states that person should not use authority in order to influence producer, consumer or TSOs interest. Rules should guarantee independency for participant by removing interests between market participants, encouraging investments and guaranteeing access to the open market. Without vertical and horizontal influence by independent TSOs, part of an undue discrimination principles should be guaranteed. (EC 2009/714)

Internal congestion management is one of the key motives for existing regulation (EC 2009/714). Typically, the transmission capacity reduction is favoured in Central Europe in order to control internal bidding zone congestion with lower costs for TSOs. This will shift capacity limitation from inside of the bidding zone to cross-border causing limited transmission capacity between bidding zones. This have an effect on adjacent bidding zones and have an impact on spreading prices. (ACER 2016)

Discrimination between cross-border is matter of price spread of adjacent bidding zones. For consumers´ point of view, other consumers in adjacent bidding zone may witness lower electricity price during congested situation causing different position depending on which bidding zone consumers are situated. Fundamentally, the price discrimination exists if consumers have a decision between similar products with similar marginal costs but witness different prices among products. Therefore, consumers situated in lower priced bidding zone benefit situation since the identical product is sold at lower price. However, consumers in higher priced bidding zone found the situation discriminating after buying the product at higher price. (Armstrong 2006; Varian 2010)

Price spread occurs essentially due to physical restrictions and the price spread itself is not necessarily understood discriminative. It might be discriminative if dominant market participant has possibility to adverse free competition. In this case, restricting cross-zonal transmission capacities with no evident reasons might discriminate participants. (Armstrong 2006) Now, the main issue is to detect whether TSOs ability to restrict trade is found discriminating. Given transmission capacities between bidding zones have substantial influence on cross-zonal transmission flow impacting on the market settlement during congestion and further into total welfare as represented in chapter 2.4.

Due to this, ACER has made several statements complementing undue discrimination rules. Statements are discussed more profound by ACER (2016) which states rather strict recommendations to fulfil regulation. ACER recommendations are based on Article 16 and Annex I 1.7 of Regulation (EC 2009/714) where obligation to maximise cross-zonal transmission capacity is represented. ACER states that congestion should be primary assigned without reducing cross-zonal transmission capacity in order to limit undesired market impacts. This is considered by ACER the most reasonable in order to manage congestions without affecting to market participants and provide transparent and reasonable price signals based on competitiveness of market participant.

However, regulation (EC 2009/714) presents congestion management as a cost-reflective in the market and presents market-based mechanism for reasonable price formation. Part of an undue discrimination principles, TSOs cannot favour cross-zonal capacity reduction as a reason of congestions related costs. During a normal transmission network states, decision between countertrading and redispatching and transmission capacity reduction should reflect measured costs. Measured costs of transmission capacity reduction are matter of estimated socio-economic welfare changes.

Although, undue discrimination is not necessarily always fulfilled in insufficient liquidity or congestion situations if congestion management compromises operational security and causing inefficient utility of the transmission system. Regulation states that the transmission capacity reduction is justified if cost efficiency and socio-economic welfare is higher compared to countertrading and redispatching. Similarly, capacity reduction is justified if operational security is compromised in temporary situations such as scheduled and unintentional outages. Still, market based solution are required even if it increases TSOs congestion related costs in European-wide trade. (ACER 2016)

4.3 EU target model and monitoring in electricity market

The EU electricity target model provides common rules such as capacity calculation, day-ahead and intraday market capacity allocation. High-level guidelines attempts to harmonise market area and encourage market participants to invest and utilise the electricity market more efficiently based on marginal costs. Efficient operation of electricity market supports European Commission objectives in order to apply and increase renewable energy resources. These objectives are part of the renewable energy directive and open market principles. (Keay 2013)

Existing methods have concerned European regulatory authorities related to congestion management. Different treatments of cross-border and internal exchanges have led in situations where transmission capacities are reduced particularly between cross-zonal interconnections. This indicates congestion issues in several Member States causing limited market efficiency especially in Central Europe. This issue is particularly due to internal congestions within bidding zones and challenges to relief congestion otherwise than limiting cross-zonal transmission. Treatment of congestion management methods may discriminate market participants when some market participants may have unrestricted access to transmission capacities while others experience scarcity situations. Respectively, competition among market participants in scarcity situations is limited if market participants have different opportunities between internal and cross-border market. This should be organised in order to efficient functioning electricity market. (ACER 2016)

The current situation is partly due to the lack of having reasonable incentives for TSOs. Providing reasonable incentives may offer better signals for more efficient transmission system from European perspective. Minimising congestion-related costs by TSOs is usual and leads maximising national interest by decreasing cross-border capacities. Limiting electricity import or export between Denmark and Germany have raised concerns and may cause larger market impacts broader in market area. (ACER 2016) As a result, regulations are made to settle these issues in electricity market in order to harmonise non-discriminatory rules for capacity allocation and congestion management.

Regulation authorities monitor implementations of CACM guideline in accordance with non-discriminatory rules. Regulation authorities monitor that the day-ahead and intraday market coupling solutions are implemented in accordance of regulation. Authorities expect TSOs to comply and implement guidelines and creating consensus among TSOs. This means as well sharing "information on capacity calculation and redispatching and countertrading cost sharing" for authorities (ACER 2016). Authorities concentrate monitoring on expected and actual impacts and calculations of cross-zonal capacities and deviations in accordance with non-discriminatory rules. A part of implementation of CACM guideline, TSOs develop proposals to National regulatory authorities for approval. Methodologies are reviewed and approved by regulators.

5. CURRENT CONGESTION MANAGEMENT METHODS

Fingrid´s current capacity calculation and congestion management method considers decision based on available redispatching resources and costs and cross-border transmission capacity reduction costs. Transmission capacity reduction costs are measured based on estimated socio-economic welfare changes. Depending on costs of capacity reduction and redispatching, procedure with the lowest socio-economic costs is selected. This works in accordance of planned grid outages when estimating best procedure for different situations. The procedure relieving the P1-cut transmission should be scheduled one day in advance before the operational day due to fact that day-ahead cross-border transmission capacities should be given to the market before implicit auction period. Still, a part of congestion management methods are realised during implicit auction by allocating transmission capacities between bidding zones efficiently. Current method has been realised since published internal report in 2013.

As represented in chapter 2.2.2, countertrading is realised in cross-zonal trade and redispatching is realised within bidding zone. The main interest in this thesis are congestion issues due to P1-cut transmission insufficiency and therefore, congestion management method issues are represented only redispatching manner. This chapter represents currently used methods between redispatching and transmission capacity reduction in capacity calculation phase in Finnish internal bidding zone.

5.1 Realising redispatching

In order to redispatch, Fingrid purchases up-regulation power where the demand is higher and purchases down-regulation power where the demand is lower. This is based on two principles: either realising redispatching resources after intraday gate closure from special regulating market which is a part of a balancing market or determine the need for actions before the delivery day. Due to informing the capacities for a day before the delivery day, the decision depending on estimated costs between redispatching and capacity reduction before delivery day.

When comparing procedures a day before the delivery day, estimations are uncertain especially for up-regulation redispatching and during unusually high or low estimated redispatching costs. Costs are related especially to time before delivery hour where approaching closer to the delivering hour will increase costs accordingly. Represented procedures a day before the delivery day offer such as sufficient time for producers preparing for unexpected production changes meaning that e.g. thermal power plants require time for starting production and cannot be started in certain time frame. Necessity for faster starting leads such as utilising gas turbines as a replacement for thermal power plants and will have an impact on realised costs accordingly due to higher marginal costs. Therefore, sufficiently reliable forecasting for congestion management methods is essential in order to keep costs reasonable.

The redispatching cost unpredictability derives from uncertain electricity demand as described partially in chapter 2.3.1. While the estimation in the day-ahead market is relatively reliable based on earlier days, balancing market price estimation does not follow similar certainty due to rapidly changing realised volumes and market situation e.g. scheduled or unintentional outages. Similarly, production or consumption location effect increasingly to redispatching costs if merely few offers are possible realised.

Redispatching costs are calculated by multiplying volume and price for up- and down-regulation depending on received offers. Typically, redispatching prices and volumes follows balancing market price since offers are placed within a day to corresponding market. (Fingrid 2018c) In practice, transmission system operator ask different producers or consumers from the market or bilaterally to commit up- or down-regulating at a certain hours. Redispatching costs are defined

$$Total\ redispatching\ cost = p_{up} * V_{redispatch} + p_{down} * V_{redispatch}, \quad (1)$$

where p_{up} and p_{down} represents redispatching up- and down-regulating price (€/MWh) and $V_{redispatching}$ is required redispatching volume (MWh) which is identical for up- and down-regulation situations. It is important to notice that positive p_{down} price represents positive cash flow for TSOs. It is due to fact that such as producer is already sold electricity to the day-ahead market and producer has received a compensation to produce electricity to the market. When down-regulating situation occurs, producer should realise down-regulating bids if price exceeds above its marginal costs. Producer saves operational costs without realising production for certain hour and the profit from down-regulation is received by TSO. In this case, TSO´s total redispatching costs are calculated from up-regulating costs which are reduced by the amount of down-regulating costs. Similarly, up- and down-regulation could be realised with consumers´ bids instead of producers´ bids.

According to Fingrid´s (2013) former estimations, requirements below 300 MW offers sufficient availability for redispatching as represented in figure 8. Values are based on balancing market liquidity which changes accordingly in different transmission situations. The availability for redispatching means balancing power availability in certain location within bidding area. Occasionally, availability is not sufficient as a result of different locations of production units i.e. only limited amount of balancing power bids for redispatching are usable. Limited amount of available up-regulating balancing power is a challenge especially in Southern Finland and measures are replaced by transmission capacity reductions due to higher costs. Because of this, represented procedures works generally and decision in intersections shows uncertainty between redispatching and capacity reduction.

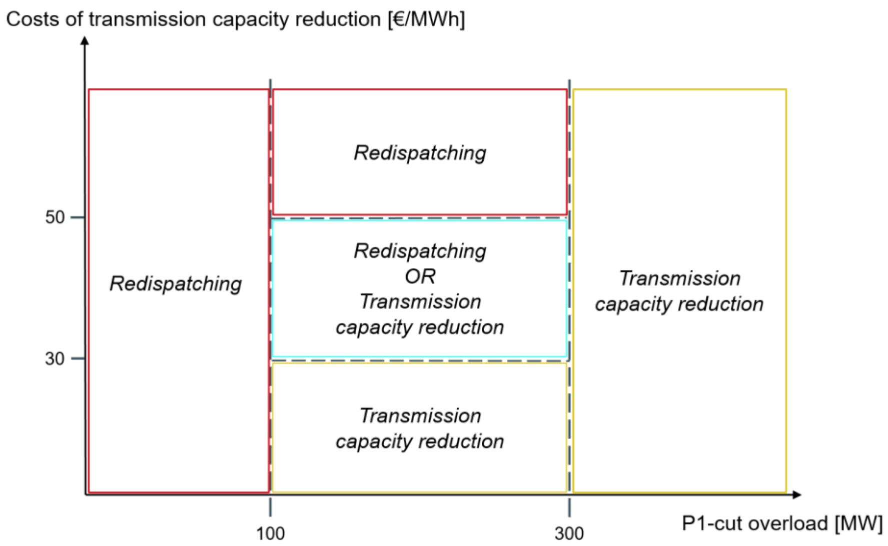

Figure 8. *Decision between redispatching and transmission capacity reduction (Adapted from Fingrid 2013a).*

Redispatching is firstly realised between 0–100 MW regardless of estimated transmission capacity reduction costs due to its lower impacts to the market. During 100–300 MW overload, higher unit price of capacity reduction will increase readiness to realise redispatching due to undesirable market impacts. Then, redispatching is realised if reasonably priced resources are available. (Fingrid 2016) Currently, 30–50 €/MWh represents the deviation between redispatching and capacity reduction costs and justification between actions is not explicit. Therefore, each action are valuated separately within 100–300 MW and 30–50 €/MWh which method shows lower market impacts.

Usable market bids are guaranteed sufficiently if overloading is below 100 MW. Above this, redispatching availability might be compromised occasionally when excessively high volume doesn´t necessarily guarantee resources availability to produce electricity at reasonable costs. Measures above 300 MW are not reliably available and therefore, redispatching is realised until 300 MW and remaining requirement is realised with transmission capacity reduction. (Fingrid 2016 & 2018c)

5.2 Cross-border transmission capacity reduction

Cross-border transmission capacities are maximised and offered to the market in normal transmission situations. During scheduled outages and congestions, cross-zonal transmission may compromise operational security and initiates capacity reduction. Capacity reduction impacts are non-existent to socio-economic welfare if capacity reduction measures are not restricting the actual transmission flow but increases a risk for congestion. If the transmission flow is restricted, TSOs should avoid unjustified impacts on electricity price difference between FI and SE1 bidding zones and effecting on socio-economic welfare unreasonably.

Congestion situations are justified by capacity reduction if redispatching measure shows higher costs and lower social welfare. The actual impact on social welfare is understood particularly for producers and consumers and estimation should be based on European-wide market area. For TSOs, capacity reduction does not increase congestion related costs for TSOs by informing lower capacities to the market but lowers generally socio-economic welfare for market participants as described in 2.4. Still, current method has been based on the Finnish bidding zone estimation without noticing European-wide impacts.

Decision for capacity reduction relies on price estimation and how much capacity reduction may cost on the next couple days since the capacity reduction procedure should be planned and informed before 10:30 am CET before operational day. It depends on price level and estimated price spread between Finnish and Swedish SE1 bidding zone where higher price spread indicates higher socio-economic impacts of reduced capacity. Price estimation is essentially subject to historical prices, load and production estimations highlighting possible congestion issues and made possible to determine the need for capacity reduction. Estimations and market impacts are hard to validate explicitly and therefore, overall principles are followed. (Fingrid 2013a) Still, estimation raises a risk that capacities are reduced unnecessary if operational situation changes. This situation tends to support redispatching since realisation during operation hours could be cancelled and market impacts are avoided or minimised.

Currently, overall principles are estimated in Fingrid´s internal (Fingrid 2013a) report based on estimated market impacts. Earlier, transmission capacity reduction impacts were measured by estimating price spread as represented above and estimating price between cross-zonal and multiplied with corresponding volume. Market impacts were essentially estimated based on FI and SE1 bidding zones but also with SE3 and EE bidding zones. Also, it were estimated that RAC-cut transmission capacity changes impacts to corresponding bidding zones. Based on these and historical values, report states that few euros per MWh change is expected depending on how extended reduction measures are realised. Higher reduction measures that limits cross-zonal flow will create higher price difference between adjacent bidding zones and creates generally higher market impacts during congested transmission states. Higher negative market impacts increase related capacity reduction costs. This clarifies that capacity reduction costs are greater if bidding zone prices are significantly separated.

Costs of capacity reductions are compared to redispatching costs if transmission capacity reduction costs are estimated within 30–50 €/MWh as represented in figure 8. Depending on costs between redispatching and capacity reduction, procedure with lowest costs will be applied within 30–50 €/MWh. Still, decision is depending on estimation accuracy in redispatching and capacity reduction costs. As described in chapter 5.1, redispatching has limited estimation accuracy compared to capacity reduction. It shows that liquidity in balancing market causes uncertainty between different procedures and redispatching could be chosen if socio-economic welfare is similar compared to capacity reduction (Fingrid 2013a).

Still, redispatching is reliably available within 0–300 MW requirement and congestions above 300 MW are relieved with cross-border capacity reduction if reasonably redispatching resources are unavailable. The importance of capacity reduction increases during extensive overloading situations and transmission capacity reduction is generally justified. Estimated capacity reduction costs could be also lower than 30 €/MWh representing generally limited congestion and relatively low impact to the market.

6. IMPROVED METHODS FOR CONGESTION MANAGEMENT

Undue discrimination in congestion management are represented distinctly by ACER (2016) while the issue has not resolved in other related publications. This study aims to conclude undue discrimination rules to congestion management methods and objective is to measure whether redispatching or transmission capacity reduction is justified relieving congested P1-cut transmission. Results are foundation to NTC capacity calculation principles where capacity reduction potentials are measured based on market impacts. Redispatching costs are estimated by taking into account uncertainties and redispatching price level before operating hour. The day-ahead market simulation allows capacity reduction costs to be measured more accurately compared to countertrading and redispatching costs due to higher market liquidity and simulated market outcomes. Results verify consumer and producer surplus change impacts in order to determine justified method for congestion management.

Due to the applied Simulation Facility market tool, market impacts are estimated more profoundly in European-wide trade compared to current congestion management method. Simulation Facility market tool simulates market outcomes based on actual day-ahead market algorithm. Earlier, method based on assumptions and general calculation without utilising any simulation tools and therefore, this study further develops the currently applied congestion management method as described in chapter 5.

6.1 Approach

The approach is divided into four main parts. First choosing comparable week periods to show similar market situations when congestions occurs. After that, Simulation Facility market tool is tested whether algorithm produces reliable market outcomes. Then, these week periods are analysed by utilising Simulation Facility market tool with different capacity reduction measures. This essentially brings into light the socio-economic costs of capacity reduction and shows how the socio-economic welfare changes during congested situations. Fourthly, Simulation Facility market tool results are compared with separately estimated redispatching costs and selected congestion management method is represented. Finally, reliability of results will be verified by analysing especially redispatching cost uncertainties and its effects on study results.

In order to evaluate a decision sufficiently reliably between capacity reduction and redispatching measures, firstly week periods are selected from years 2016–2017 based on

Fingrid´s Open Data and Nord Pool market data. Selected week periods indicate suitable situations for congested P1-cut and RAC-cut transmission and represents favourable situations for transmission capacity reduction or redispatching. In other words, congestion situations in P1-cut transmission and price separations between FI-SE1 bidding zones indicates favourable week periods for further analysis. Used data is further discussed in chapter 6.4.

After indicating suitable week periods for further study, simulation tool is tested whether algorithm produces identical market results compared to historical market outcomes. The simulation environment is based on historical supply and demand offers of selected week periods in the day-ahead market. These inputs are built-in in Simulation Facility which utilises Euphemia –algorithm (European Union Pan-European Hybrid Electricity Market Integration Algorithm) to simulate day-ahead market outcomes. Simulation Facility market tool makes possible to analyse market impacts of transmission capacity reductions. Simulation tool is further described in chapter 6.3 and reliability is tested in chapter 6.5.

Then, those periods are positioned to the simulation. In practice, algorithm calculates estimated transmission flows and bidding zone prices subject to historical offers and transmission capacity restrictions. Only transmission capacity restrictions can be set to the simulation. Reductions are set on every hundred megawatt until -600 MW is reached to show changing market outcomes on created price and welfare compared to initial situation. Analysis starts recognising market impacts from individual weeks and reoccurring impacts are represented to show how RAC-cut capacity restrictions generally impact to the market. The general view of congestions is estimated based on several week periods on each year. These are the foundation to understand the decision between redispatching and capacity reduction more accurately. These results introduce general representation on how capacity reduction impacts socio-economically to European-wide welfare.

Then, redispatching costs on every reduction measures are estimated subject to balancing market prices from years 2016–2017 due to low quantities of historical redispatching measures. Estimated up- and down-regulating prices for redispatching are created for every quarter of a year to show more accurately seasonal impacts to the capacity reduction. These estimations are noticed on hourly balancing market prices and expressing estimated redispatching costs. Finally, decision between capacity reduction and redispatching is evaluated based on which method shows lower costs in certain transmission situations. Then, results reliability is further reviewed.

6.2 Main assumptions measuring congestion management methods

Assumptions and reasons are shown in this chapter in order to generalise market conditions by simplifying study arrangements and focus on particular events related to redispatching during congestions without noticing outages in the transmission network. Therefore, data sets are selected to represent market and transmission system conditions and power flows essentially from recent years of 2016–2017 in order to produce relevant results in practice.

The following assumptions are made:

- Network outages are not involved into analysis
- Swedish electricity import generally occurs during congestion
- Redispatching is preferred if capacity reduction shows similar costs
- Demand is inelastic to production changes
- Producer´s and consumer´s bidding behaviour is static to transmission capacity changes
- Congestion incomes are allocated with 50:50 distribution in calculation area
- Russian welfare impacts are excluded from European market coupling area

The transmission system topology is represented from years 2016–2017 offering latest transmission network situations and guarantees relevance of study calculations and conclusions for upcoming years where only week periods are selected without any network outages involved. Hydrologically similar years guarantees similar export and import situations in Finnish bidding zones and makes it easier to analyse different years. During those years, electricity import is realised regularly from Sweden to Finland and being more general than export situations. For the most part, export situations typically occurs at night and exported electricity is under three percentage of normal exchange between FI and SE1 bidding zones (Nord Pool 2018a). Therefore, electricity import is a general measure between FI-SE1 bidding zones.

When redispatching and transmission capacity reduction shows similar impacts to the socio-economic welfare change depending on particular prices and volumes, redispatching is chosen for congestion management in this case. It is due to fact that capacity reduction is irreversible after informing capacities to the day-ahead market and decision for redispatching is changeable even before operational hour. Procedure lowers a risk for unnecessary capacity reduction if both methods shows no distinctive difference for socio-economic welfare change.

As described in chapter 2.3.1, demand is reasonably inelastic to production changes when consumers are unwillingness or does not witness benefits to respond particularly to short-term market changes and creates inelasticity to the day-ahead market. Therefore, demand consumes the electricity at almost any price without changing behaviour to short-term market changes. Similar effect occurs in long-term demand with limited indicated elasticity. Therefore, inelasticity is assumed to represent normal condition of the power system in 2016–2017. However, it has been acknowledged that demand side response is increasing in upcoming years and should be considered potential influence on electricity market. Demand side management offers are included to Euphemia if corresponding offers are placed to the day-ahead market.

Due to transmission capacity reduction measures between FI-SE1 bidding zones, bidding behaviour might change if measures are realised in reality. Fundamentally, bidding is subject to pay-as-bid pricing method in the special regulation market as described in chapter 2.2.2 and similarly transmission capacity changes might effect on bidding behaviour in the day-ahead market. The issue is not noticed in Simulation Facility since the simulation tool utilises historical market data and causes constant bidding behaviour regardless of how excessive changes are made i.e. historical offers shows constant bidding behaviour. Therefore in this thesis, market participants' bidding behaviour is assumed to be unchanged if transmission capacity is changed.

Simulation Facility calculates consumer and producer welfare results while congestion incomes should be calculated afterwards. As CACM regulation states, congestion incomes are distributed between adjacent bidding zones either with 50:50 distribution or based on ownership of cross-zonal transmission with surrounding TSOs. (ACER 2017b) Finnish congestion incomes are shared by 50:50 distribution with similar procedure among Nordic countries. However, Central European countries and Baltic States may allocate costs with the ownership of cross-zonal transmission while accurate ownership of each transmissions is not reliable available. For congestion income calculation assumption, allocation by 50:50 distribution is utilised for the whole European electricity market.

Nordic, Baltic States, Poland and Germany bidding zones are included to results and Central European countries are excluded from these results due to almost non-existing welfare impacts. However, market impacts are evaluated within European market coupling area to verify this assumption. Still, Russian welfare has been excluded from calculated data sets without being part of a European market coupling area. Russian welfare is essentially represented in Finnish and Baltic States welfares since Russian offers are sold to corresponding countries and distorts actual European coupling area welfare.

Because of this, the total welfare from each country is reduced by the sum of Russian welfare from total welfares of Finland and Baltic States if Russian import occurs. Respectively, electricity import from Russia is already calculated into Finnish and Baltic States welfare advancing their producer surplus. This is due to fact that Russian export increases total welfares of Finland and Baltic States when producers has willingness to sell more electricity to the day-ahead market and thus increasing producer surplus. Transmission flow with Russia is measured by calculating commercial transmission flow between Finland–Russia and Kaliningrad–Lithuania interconnection which represents interconnection from Baltic States to Russia. Transmission flow to Baltic State is divided evenly with corresponding countries (Fingrid Open Data 2018; Elering 2018; AST 2018; Litgrid 2018) and each interconnection flow is multiplied with actual areal price to notice included Russian welfare.

6.3 Simulation software and price coupling algorithm

Market impacts are measured with Simulation Facility –market tool that represents historical market data such as bid and ask prices, commercial transmission capacities and clearing constrains. It utilises real day-ahead Euphemia market algorithm to calculate European market coupling area prices and volumes for given time period. Trading algorithm calculates the market settlement where the historical market data should produce the same outcome even if calculation is made afterwards.

Simulation Facility provides historical market information in order to estimate market outcomes and impacts for the whole European electricity market area. Estimating reasonable measures between redispatching and capacity reduction requires changing market conditions and noticing recurring market impacts. This is done by changing commercial transmission capacity in the RAC-cut transmission with reasonable values that could be utilised in practice. Capacity reduction impacts can be evaluated simultaneously in interconnected countries in addition to Finnish bidding zone impacts. Still, market impacts are primary estimated to European bidding zones especially for Nordic countries, Baltic States, Poland and Germany. However, internal bidding zone capacities changes are unavailable in Simulation Facility and only cross-zonal border capacities are able to change.

For TSOs, accessing to Simulation Facility historical market data is preserved in order to avoid misuse of individual offers and locations within bidding zones. Therefore, specific information is concealed such as merit order lists while Euphemia algorithm calculates the outcome. Simulation Facility offers a possibility to change market conditions such as commercial transmission capacity and losses before running Euphemia algorithm. Changes reflects to the European electricity market prices and similarly to interconnected transmission flows.

Welfare maximisation problem is a primary issue when calculating the market outcome. First algorithm calculates different set of orders that maximises welfare without considering transmission network restrictions e.g. ramping limits, losses or tariffs. Restrictions are made after branching different solutions with the purpose of determining market clearing prices for each bidding zones. Those are determined similarly to fulfil conditions for accepting different set of orders. This could change welfare depending on different sets of orders such as block orders. Every settlement are revalidated in case of such as unrealised volumes. (Nord Pool 2016)

After calculating the market outcome for given time period, Simulation Facility offers results such as prices, cross-zonal flows and producer and consumer surpluses for every bidding zones. Iteration process maximises a sum of producer and consumer surpluses and congestion incomes creating calculated total welfare. However, simulation results doesn´t show congestion incomes although calculation process takes these into account. Therefore, congestion incomes are calculated afterwards based on calculation results.

6.4 Selecting suitable week periods for simulations

Week periods are selected for further study based on the day-ahead market data gathered from public sources by Nord Pool market data and Fingrid´s Open Data. The day-ahead market is the primary market trading electricity representing highest liquidity compared to other electricity markets where transmission capacity changes will be similarly reflected into the day-ahead market prices. Nord Pool market data represents cross-zonal transmissions and bidding zone prices and Fingrid´s Open Data represents P1-cut transmission.

Input data is utilised in order to find week periods where transmission capacity has the highest impact to the market and further select these weeks to the simulation. The data is gathered from Nord Pool and Fingrid Open Data instead of Simulation Facility since main values should represent historical market outcomes. The data is gathered based on P1- and RAC-cut transmission from years 2016 and 2017 to provide the most up-to-date market data as represented in table 1. Each data set is a seven day period in order to evaluate different years and seasons accordingly. Both Nord Pool and Fingrid Open Data does not represent individual offers as described in chapter 6.3.

Table 1. *Data sources for selecting suitable week periods to the simulation based on Fingrid (2018c) and Nord Pool (2018a).*

Data sources, years 2016–2017	**FI**
Day-ahead prices	Nord Pool
Realised redispatching measures	Fingrid´s unpublished data
Transmission flow (commercial)	
FI-SE1	Nord Pool / Fingrid Open data
P1-cut	Fingrid Open data
Transmission capacity	
FI-SE1	Nord Pool / Fingrid Open data
P1-cut	Fingrid Open data

Data is utilised with the purpose of finding situations when transmission capacity reductions have had impact on transmission flow in P1-cut. These situations represents uncertainty during a decision between redispatching and transmission capacity reduction. Therefore, main interests are historical congestion incomes, commercial transmission capacities and P1-cut transmission flows. Additionally, the day-ahead price data is utilised to identify price spread between FI-SE1 bidding zones showing limited transmission capacity.

Selected data should indicate two main issues in the transmission network. Firstly, the P1-cut transmission flow should be as high as possible in order to find real-world-cases utilising congestion management methods to relief P1-cut transmission to south. At the same time, price difference between FI-SE1 bidding zones should be noticeable illustrating congestion in FI-SE1 cross-border. These two factors show limited adequacy in transmission capacity in order to study further socio-economic welfare changes and re-dispatching costs.

Based on these factors, several data sets represented suitable week periods in years 2016 and 2017. Between those data sets, 13 weeks were selected from each year further into simulation as represented in appendix A including one fourth weeks of a year. Scheduled outages that limit transmission capacity in FI-SE1 cross-border were avoided. Selected week periods are compared in simulations with corresponding seasons firstly such as winters between different years to notice market impact changes.

6.5 Verifying reliability of the simulation tool output

First, Euphemia trading algorithm output data is verified whether algorithm produces similar market prices compared to real market prices confirming that Euphemia represents sufficiently reliable simulation results. All data sets were examined and the data set of August 2017 is shown in figure 9 representing difference between real market price and simulated market price. Given transmission capacities were identical in order to produce comparable results between real and simulated market price and to show algorithm´s functionality.

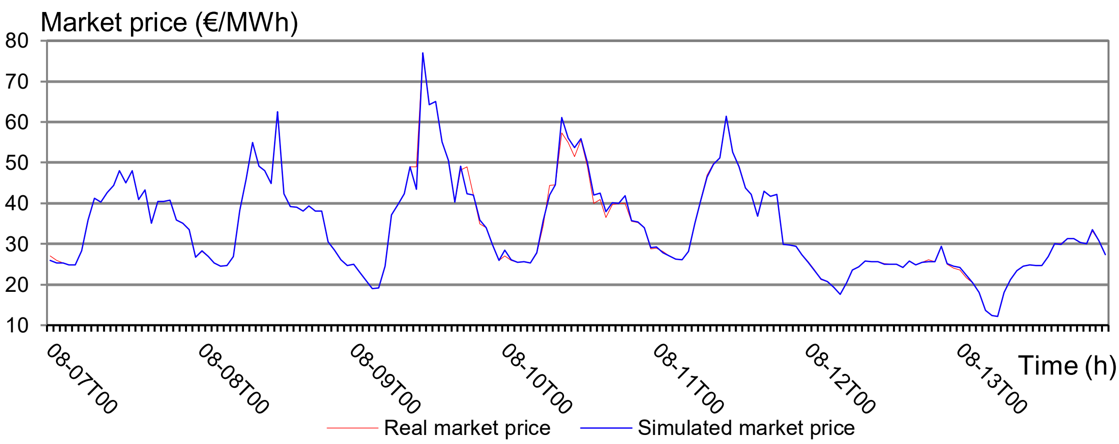

Figure 9. *A week data compering real market price to market price produced by Euphemia on 7–13th August 2017 in FI bidding zone.*

Figure 9 shows the correlation between real market price and simulated market price. Most of the time simulated market price correlates to real market price with little inconsistency when market conditions are identical and price coupling algorithm is the same. Price between Wednesday and Thursday verify possible price spread between real market price and simulated market price in high volatility situations and particularly in local maximum prices. Similar results were gathered from other data sets and were compared with SE1 market price. It seems that algorithm´s heuristic approach produces solutions that are not necessarily consistent due to combination of order activation such as block orders (Nord Pool 2016). Data sets suggest little inconsistency within few hours in a week period with similar differences occurring in SE1 bidding zone. The correlation between real and simulated market price is over 0,99 in data sets and represent sufficient reliability of algorithm´s functionality and reliably market outcomes.

After this, selected week periods are set to the simulation tool to test further reliability of algorithm functionality. For every seven day periods on each data set, RAC-cut commercial transmission capacity is reduced on every hundred megawatt to the -600 MW from the initial capacity which is typically 1400–1500 MW. More specific capacity reduction values such as values between 0-100 MW are not concluded since values could be aggregated accordingly from data points between 0-600 MW on every hundred megawatt. The highest capacity reduction value of -600 MW is based on practical transmission capacity reduction measures. In practice, even the -200 MW reduction on the RAC-cut transmission capacity is an excessive measure in a normal transmission network situation (Fingrid 2018a).

Now Euphemia -algorithm is tested whether the Finnish market price responds to transmission capacity changes properly. All data sets represent import situations to Finnish bidding zone and transmission capacity reductions between FI-SE1 bidding zones should therefore increase the market price. Export situations typically occurs at night and is under three percentage of the normal exchange between FI-SE1 bidding zones as described in chapter 6.2. Figure 10 represents data set of January 2017 and corresponding transmission capacity changes affecting to the simulated market price. Identical initial transmission capacities were applied in order to produce comparable prices and showing algorithm´s functionality between actual market outcome and simulated market outcome.

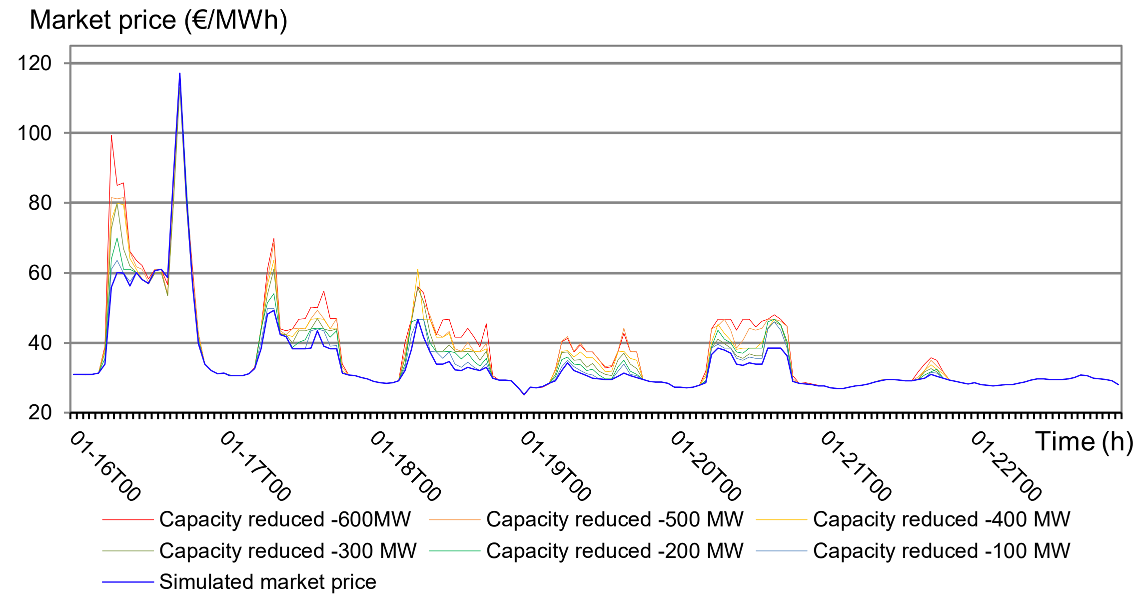

Figure 10. *Market price after the RAC-cut transmission capacity reduction from initial capacity on 16–22th January 2017 in FI bidding zone.*

As estimated, represented capacity reduction increases the Finnish market price and lowers import from SE1 bidding zone. Each transmission capacity reductions step shows higher market price increase indicating correctly functioning simulation environment. During nights, capacity changes are not influenced since reduced transmission capacities are adequate without restricting the transmission flow between FI-SE1 bidding zones.

Market price volatility represent different conditions between working days and weekend and between day and night affected by transmission capacity reductions. Market impacts generally occur during working week and especially during 07–20 hours. Similarly, transmission flow in RAC-cut and P1-cut is the most highest during those hours.

Essentially, reduced capacity measures should not lower market price below simulated market price during initial RAC-cut capacity whether algorithm functions correctly. However, optimised solution by algorithm appears to have inconsistency such as at Monday 16.1 hours 16–17 on figure 10. During those hours, market price after reduced capacity of 300–600 MW reveals to be lower than simulated market price suggesting optimisation uncertainty in market price settlement. Also during Monday´s peak price, the price did not increase while it decreased actual flow between FI-SE1 bidding zones. This may occur due to high price located in Swedish bidding zones. Similar results are shown at Wednesday 18.1 hours 8–9 when price after 400 MW capacity reduction shows higher market price than 500–600 MW capacity reduction. During these hours, Fenno-Skan and Estlink transmissions were reasonable without proving any significant changes. Dissimilarities are found from other week periods representing issue in larger perspective during working week.

It seems that inconsistency occurs during working week and individual issues represent 0,8 percent of hours of five day period. Therefore, its significance for study results is limited if measured data sets are sufficiently long periods and inconsistencies are limited to individual occasions in working week. Instead, measuring weekend doesn´t necessarily produce comparable study results if data set quantities are limited to few. Similarly, calculation results are volatile due to high volatility of RAC-cut and P1-cut transmission flow between different days of a week.

6.6 Results

6.6.1 Capacity reduction impacts on European socio-economic welfare

Selected week periods are represented in chapter 6.4 and those periods are set to Simulation Facility market tool. A sample week of 16–22th January 2017 is represented in figure 11 to notice welfare changes in European market coupling area. Similarities are noticeable compared to price changes in figure 10 where the most market impacts occur during working week and daytime between hours 07–20. The RAC-cut transmission capacity was originally 1520–1530 MW.

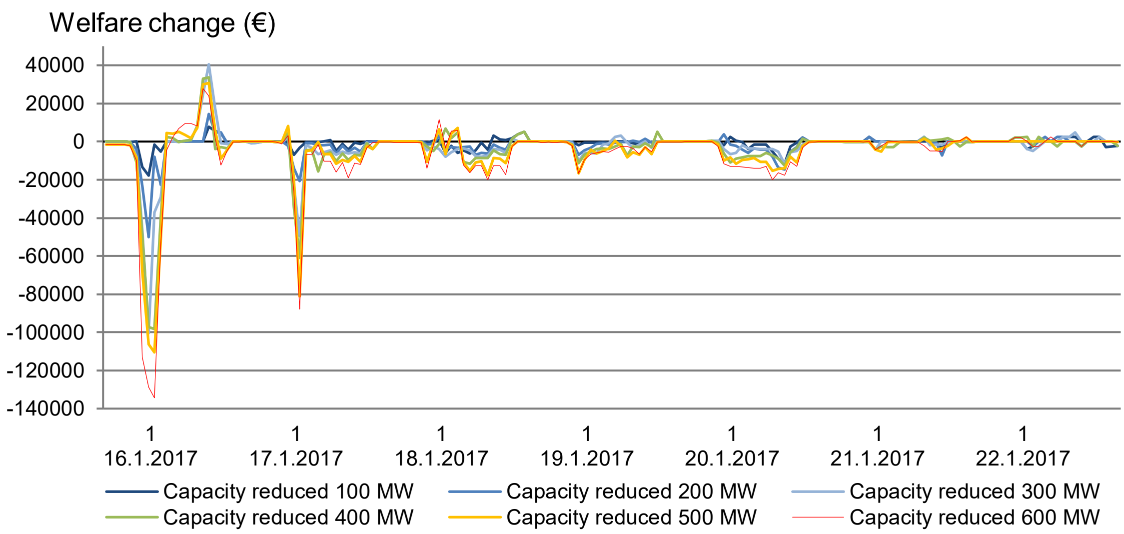

Figure 11. *A week welfare change on RAC-cut capacity reduction measures in European market coupling area.*

Fundamentally, every capacity reduction step generally represent decreasing welfare during high transmission and high net import during a day 16.1 shows the highest impacts to the market after reduced RAC-cut transmission. Changing net import in Finnish bidding zone seems to indicate negative correlation between welfare change and market price. If excessive import is restricted, it leads to increasing areal price and decreasing welfare. These changes are not affecting to night-time prices or welfare when the transmission capacity is adequate without restricting the transmission. Similar events occur at the weekend with limited noticeable welfare impacts.

Some of these hours represent positive welfare change even if capacity reductions are realised. In particular hours, such as during the day 16.1 evening, market price seems to be same without depending on reduction measures. This is due to fact that high congestion incomes in SE3 increase hourly total welfare excessively leading to positive total welfare in European market coupling area created by increasing price spread between FI-SE1 bidding zones.

The price spread between different bidding zones clarifies that increasing price spread leads to increasing or decreasing welfare depending on absolute price change. Decreasing price leads to higher total welfare for bidding zone and increasing price leads to lower total welfare for bidding zone if absolute consumer surplus is higher than producer surplus. Lower bidding zone price compared to initial situation represents either lower demand or higher transmission from adjacent Swedish bidding zones. Higher price e.g. in Finnish bidding zone represents either higher demand or lower import from adjacent bidding zone

Then, simulated capacity reduction impacts are measured in figure 11 for every bidding zone in Nordic countries, Baltic States, Poland and Germany to show individual changes between bidding zones. As figure shows, capacity reduction impacts are limited into few bidding zones and shows relatively high dependency of the RAC-cut transmission. Limited impacts are noticed in Poland (PL), Germany (DE), Denmark (DK 1–2) and Norwegian bidding zones (NO 1–4) with the exception of NO1 bidding zone. Welfare impacts on those bidding zones are generally absent compared to overall bidding zone welfare.

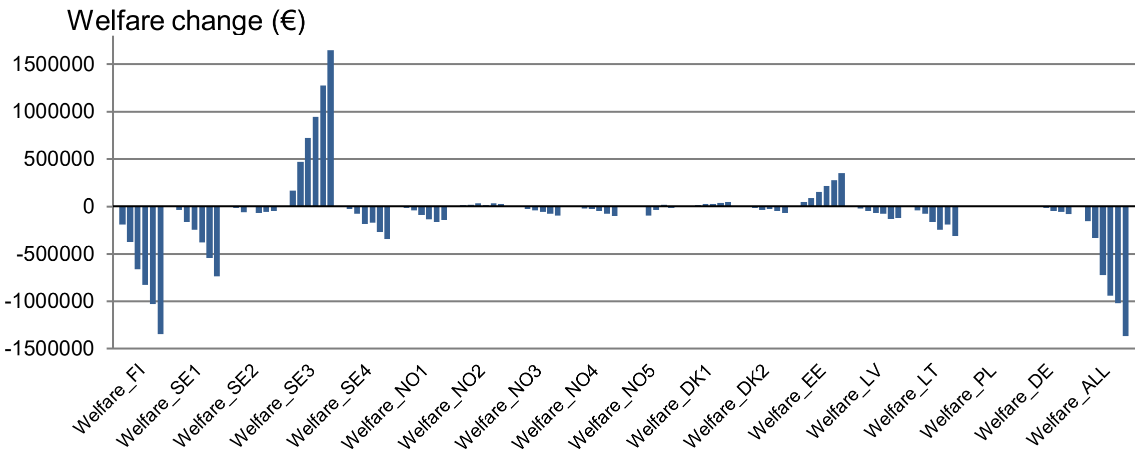

Figure 12. *Bidding zone socio-economic welfare week change after RAC-cut capacity reduction of 0–600 MW on 16–22th January 2017.*

Socio-economic welfare impacts are noticed in FI, SE1, SE3, SE4, Estonian (EE), Lithuanian (LT) and Latvian (LV) bidding zones indicating that Finnish adjacent bidding zones have higher impacts of reduced capacity compared to other bidding zones. Particularly, other data sets as represented in Appendix B show similar welfare changes in FI, SE1 and SE3 bidding zones and expresses high dependency of the RAC-cut transmission. Occasionally, SE2 bidding zone welfare impacts are high but not evident in every occasions. Welfare changes are generally negative whereas positive changes occur in SE3 and EE bidding zones. High positive welfare change in SE3 depends on excessive transmission from adjacent bidding zones with limited transmission capacity demonstrating high congestion incomes to SE3 bidding zone and high welfare change.

During a P1-cut congestion and RAC-cut capacity reduction, Fenno-Skan cross-border import increases from Swedish bidding zone. It relieves P1-cut transmission when electricity supply in Southern Finland is covered more by Fenno-Skan transmission. For example, 500 MW RAC-cut capacity reduction increases Fenno-Skan transmission averagely by 165 MW during day 16.1 and the actual capacity reduction impact is lower than initial capacity reduction measure. The similar occurrence in Estlink connection is depending on whether import or export situation occurs. While the export from Finnish bidding zone is more common, transmission flow increases averagely by 75 MW if 500 MW RAC-cut capacity reduction is realised. Instead, transmission shows 31 MW decrease during import situation from Estonia. This could be due to higher price in Latvia and Lithuania and electricity should be sold to corresponding bidding zones rather than to the Finnish bidding zone.

Occurring RAC-cut capacity reduction influences positively to Estonian bidding zone due to Estonian production capacity and Lithuanian and Latvian reliance to Estonian bidding zone changes. Estonia is self-reliant of its electricity and electricity is commonly exported to Lithuania and Latvia (Litgrid 2018). This is also noticeable with Finnish export (Elering 2018) and its impact on increasing producers´ welfare in Estonia. Lithuania and Latvia are not as self-reliant of electricity as Estonia and therefore, dependency of electricity export is evident explaining higher surplus in Estonia. Situation represents decreasing welfare in Lithuanian and Latvian welfares if transmission flow though Finland and Estonia is limited.

Then, welfare changes are measured for the 13 most congested weeks on each year in 2016–2017 in figure 13. Welfare changes caused by reduction measure are almost constant with a small increase into costs after higher reduction measures as similarly represented in figure 12 for year 2017. Comparable range of capacity reduction costs are represented in figure 6, however welfare impacts seems to have low estimated impacts per MWh even if selecting the most 13 congested weeks.

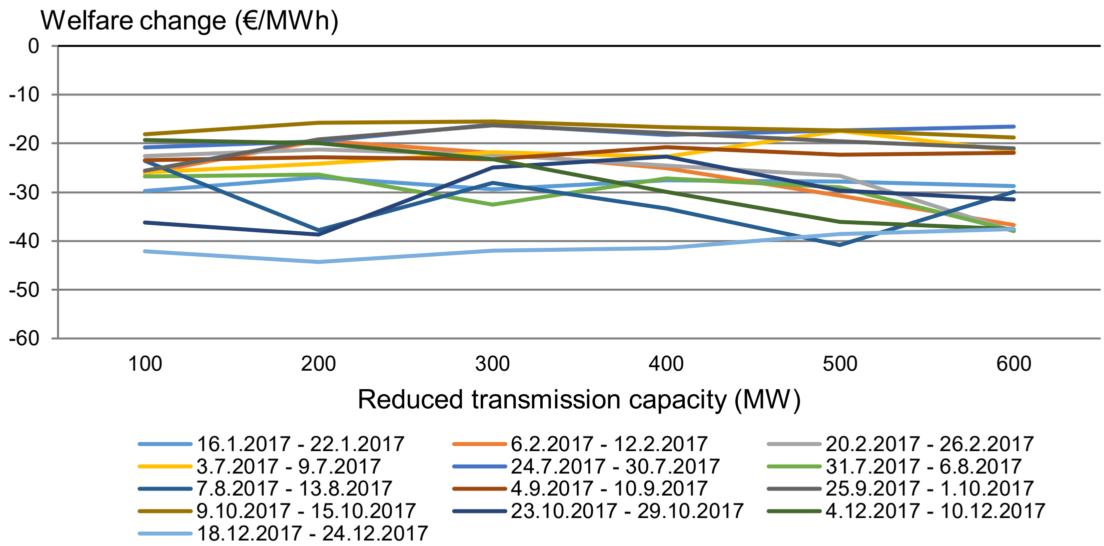

Figure 13. *European market coupling area average capacity reduction cost on congested hours in the 13 most congested weeks in 2017.*

On average, every 100 MW reduction step decreases European socio-economic welfare approximately 15–45 €/MWh as shown in figure 13 if only congested hours of a week are included. This is also the average hourly capacity reduction cost in a week if the RAC-cut transmission capacity is reduced. Higher capacity reduction measure increases average costs per MWh slightly although it is not consistent in particular weeks. Volatile costs are highly depending on an hour of the day and represents higher costs during the daytime and particularly in the morning and the evening. During year 2016, capacity reduction costs are almost identical changing 15–45 €/MWh compared to year 2017 however, two weeks in 8.–14.1.2016 and 15.–21.1.2016 showed average costs above 80 €/MWh. Those two weeks are due to very low temperatures in Finnish bidding zone with already congested RAC-cut transmission.

Volatile costs are also due to different seasons of years and especially late summer and early autumn weeks are represented in the 13 most congested weeks. Generally, those seasons in 1.7–30.9 shows the most welfare impacts subject to low electricity consumption and combined heat and power production. As a result, production proportion is generated more with hydropower indicating higher transmission in RAC-cut. This increases the average P1-cut transmission to 1270 MW in summer 2017. P1- and RAC-cut similarities are found as well during springtime when the least market impacts are measured as shown in figure 7.

Relatively constant capacity reduction costs are as a result of market outcome with historical data and made assumptions. Due to historical supply and demand orders, market participants´ bidding behaviour is static and willingness to offer does not change even after excessive changes in the market. In reality, producers might set higher offers after excessive capacity reductions and results higher bidding zone price and relatively higher welfare changes. Therefore, capacity reduction may indicate euros per MWh costs increase in reality which cannot be verified in simulated environment. This uncertainty is noticed to improved congestion management method.

6.6.2 Estimating costs and reasonable range for redispatching

Due to rare occurrence of redispatching for internal congestion management, redispatching costs are estimated based on up- and down-regulation balancing market prices due to low volume of historical redispatching costs. Balancing market price represents the most up-to-date data available of current market price estimation for redispatching. Historical redispatching costs are selected based on real situations during transmission congestions. Therefore, internal bidding zone and Fenno-Skan transmission interruptions and congestions are selected and compared with corresponding up- and down regulation bids as illustrated in figure 14. Up-regulation bids are represented with exponential regression and down-regulation bids with linear regression.

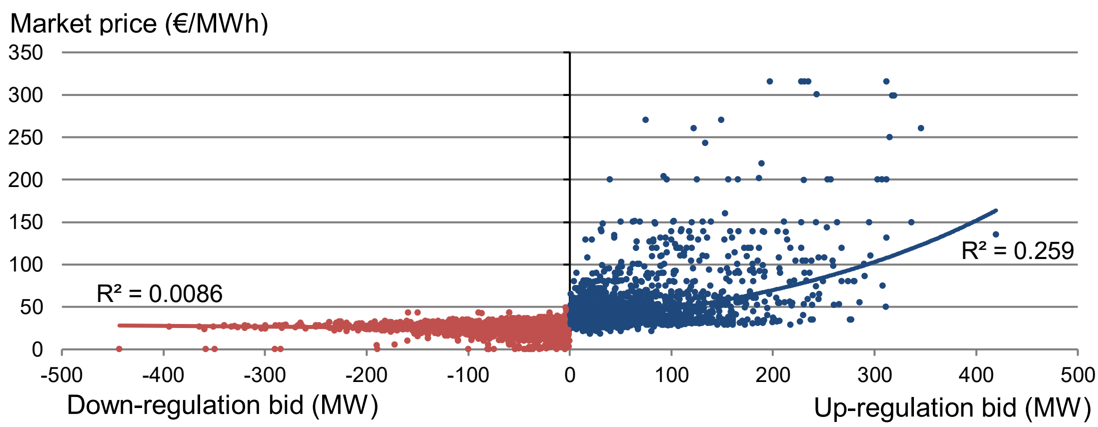

Figure 14. *Ordered up- and down-regulation bids from balancing market in 2017. (Adapted from Fingrid 2018c)*

Distinctive difference between up- and down-regulation offers are volatility and highly increasing price during increasing volumes in up-regulation bids, and setting uncertainties to estimate ordered up-regulation bids. Ordered up-regulating bids generally follow historical redispatching prices between 0–300 MW reasonably well though, over 300 MW requirement increases price uncertainty and estimated up-regulation prices due to unrealised up-regulating bids over 300 MW. Still, most of up-regulation bids are situated in a range of 20–100 €/MWh. However, ordered down-regulation bids follow historical redispatching costs with standard deviation of 26±6 €/MWh regardless of redispatching volume in 2017 and similarly 22±7 €/MWh in 2016 concluding relatively low price compared to the day-ahead price. Down-regulated bids follow historical redispatching values reasonably well in all reduction measures. Still, figure 14 confirms low predictability of regression curves due to low R-squared values. Additionally, zero values in down-regulation bids has a limited impact to the estimations since its impacts is 0,2 % of all down-regulation bids during that year.

Ordered up- and down-regulation were estimated in terms of whether values have a relation with the day-ahead and balancing market prices a day before the operating hour showing how well market prices could be estimated in advance. If up-regulation bids are compared to the day-ahead price, it implies moderately low relation due to correlation coefficient of 0,30 in 2017 and 0,24 in 2016. Higher relation were found from down-regulation bids indicating correlation coefficient of 0,43 in 2017 and 0,47 in 2016 representing moderately positive dependency to the day-ahead price. Similar characteristics occurs with real historical up- and down-regulation redispatching prices with low evident correlation to the day-ahead price.

Then, redispatching unpredictability is measured by estimating balancing market prices comparing balancing market price for up- and down-regulation instead of the day-ahead market price one and two days before delivering hour. Correlation coefficients are concluded in table 2 and representing no or moderate correlation to previous dates. This is similar correlation compared to the day-ahead market price.

Table 2. *Balancing market correlation coefficient comparing operation hour price and 1–2 days before balancing market price.*

D vs. D-1 correlation	Up-regulation bid	0.22
	Down-regulation bid	0.45
D vs. D-2 correlation	Up-regulation bid	0.12
	Down-regulation bid	0.29

Down-regulation bid correlation coefficient shows slightly higher correlation to prices of earlier days due to reluctance to increase bid prices compared to up-regulation bid prices. Therefore, moderately low correlation in down-regulation bids are slightly better predicted compared to up-regulation bids if balancing market prices are estimated a day before. Estimations before D-2 shows low predictability for up- and down-regulation estimation and does not provide reliable estimation. The issue confirms unpredictability of balancing market price with given volume especially in ordered up-regulation bids.

While the predictability is low with up- and down-regulation bids, average values follows reasonably well historical redispatching costs. This especially means redispatching measures below 200 MW volume follows balancing market price level. Therefore, average values are foundation for estimated down-regulation bids and volatility is noticed later in this chapter whether price changes impact on decision between different congestion management methods.

Then, those up- and down-regulation values from 2016–2017 were separated quarterly and estimated corresponding redispatching costs are created by calculating real week average balancing market price multiplied with estimated exponential function for up- and down-regulation. Exponential function illustrates highly increasing price when volume increases. Estimation coefficients are concluded in appendix C and following congestion management costs for 16–22th January 2017 are illustrated in figure 15. Only congested hours are included to produce comparable results with similar hours of capacity reduction costs.

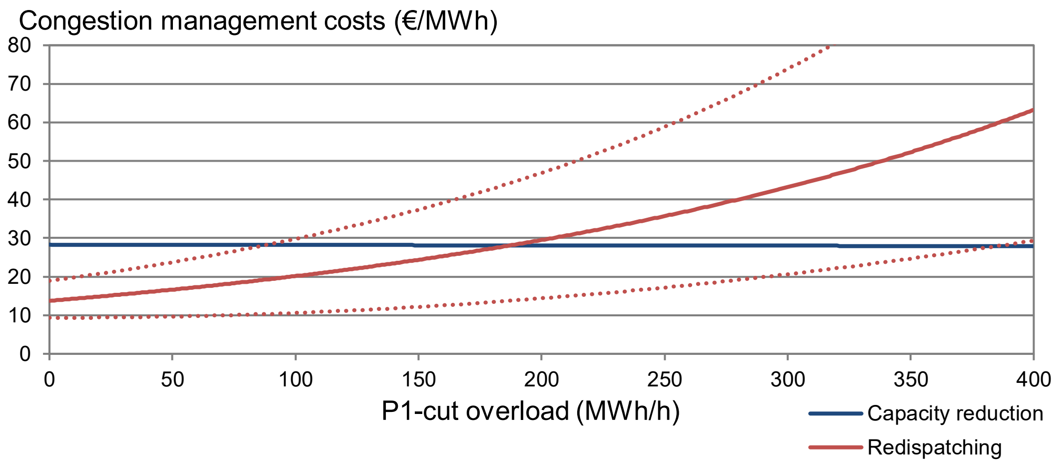

Figure 15. *Comparing congestion management costs with deviation on 16–22th January 2017 during congested hours.*

Congestion management shows increasing redispatching costs per MWh depending essentially on up-regulation balancing market price. Balancing market price increases exponentially and higher measures shows higher costs compared to capacity reduction costs. Capacity reduction measures show elasticity when increasing congestion in P1-cut represents no response into congestion management costs showing around 28 €/MWh for following week period. It is relatively inexpensive per MWh on higher congestions compared to redispatching or even average day-ahead market price of 34,44 €/MWh during the period (Nord Pool 2018a). Essentially, intersection of two functions shows that both methods are justified to relieve P1-cut congestion. In this case, estimated average up-regulating price during 200 MW required actions is 58,78 €/MWh and down-regulation price is 28,73 €/MWh. These are calculated from historical week average up- and down-regulation prices from Fingrid Open Data platform (Fingrid 2018c) multiplied with estimated balancing market regulating price coefficients in Appendix C.

High intersection point of 180 MW does not generally occur in other congested weeks in 2017 and 2016. Compering this data set to the higher congested situation such as the data set 7–13th August 2017 shows that the data set represents intersection between redispatching and capacity reduction to 25 €/MWh and 30 MWh/h. These are calculated similarly compared to the figure 15 values based on Fingrid Open Data historical balancing market regulating prices and Appendix C coefficients for redispatching and following week represented in figure 13 for capacity reduction values. This week illustrates congested situation that might justify capacity reduction even during below 100 MW required measures than current transmission congestion management method suggest. This is analysed further whether congestions effect on intersection between redispatching and capacity reduction.

Therefore, all intersections between redispatching and capacity reduction from the most 13 congested weeks in 2017 and 2016 are illustrated to figure 16. One week from 2016 and five weeks from 2017 were not represented due to unrealised intersections and couple values within 0–70 MW volumes are overlapping. Fundamentally, linear representation shows identical costs between redispatching and capacity reduction. If e.g. redispatching costs a day before the delivery hour shows higher costs compared to the linear representations, then capacity reduction is suggested. Similarly, if redispatching costs a day before the delivery hour shows lower costs compared to the linear representation, then redispatching is suggested. Deviations are shown on the following table 3.

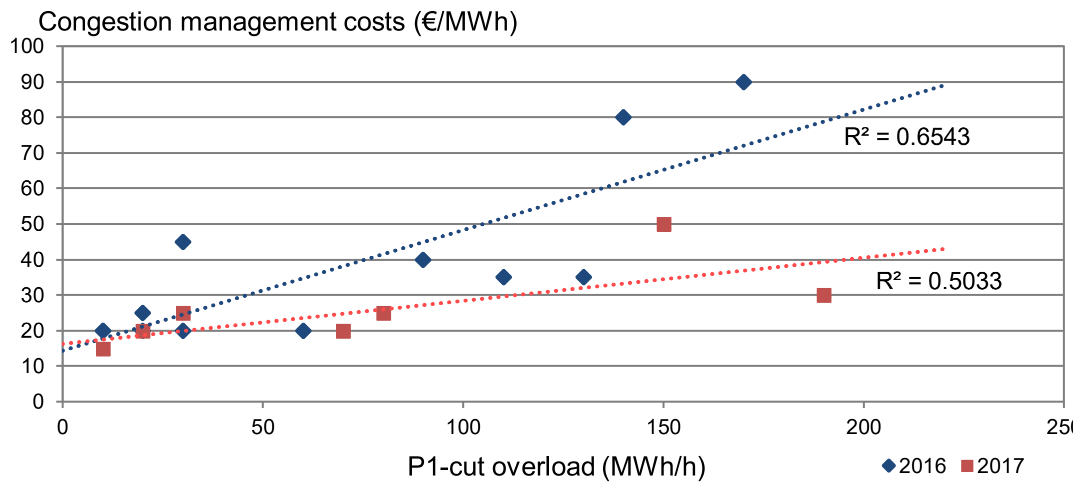

Figure 16. *Data points representing intersections between redispatching and capacity reduction curves in the most congested weeks only including congestion hours in 2016 and 2017.*

Intersection between redispatching and capacity reductions shows that even higher overloads indicate higher acceptability of congestion management costs and redispatching feasibility in 2016. Year 2016 represented more highly congested weeks compared to year 2017 especially due to cold temperatures during winter in 2016. While the deviation between data points is high, increment into costs clarifies presupposition: higher the need for resources, higher justification is for higher priced redispathing. It seems that minimum congestion management costs are at around 20 €/MWh within 0–50 MWh/h overloads either with redispatching or capacity reduction.

During a range of 50–100 MW as represented in table 3, average redispatching remains within average capacity reduction costs in 2016. Instead, higher redispatching volatility in 2017 year causes that the justification for both actions is under 50 MW. However, it is suggested that redispatching is realised within 50–100 MW measures as a result of high volatility in redispatching costs and an opportunity to cancel congestion management before delivering hour. This verifies justification of both actions within 50–100 MW volumes since capacity reduction costs show similar magnitude and accurate decision is not easily measured. Still, requirements approximately above 100 MW does not show low redispatching costs and the decision should be based on comparing different congestion management costs further a day before the delivery hour.

Table 3. *Average congestion management costs with standard deviation on the most 13 congested weeks in each year of 2016–2017.*

	2017		**2016**	
MW	Redispatch €/MWh	Capacity reduction €/MWh	Redispatch €/MWh	Capacity reduction €/MWh
50	30±16	27±8	34±15	43±24
75	34±17	27±8	38±17	43±24
100	39±19	27±8	44±20	43±25
150	52±25	27±9	63±26	39±23
200	71±33	26±11	82±33	36±21

Additionally, linear representation in figure 16 generally illustrates the decision between congestion management methods. After noticing both redispatching costs in a range of 100–200 MW, redispatching cost variation becomes more unpredictable due to higher variation of available redispatching resources without similar result noticed in capacity reduction costs. Therefore, redispatching is justified if its costs are similar or lower than average capacity reduction costs including the deviation. Then, capacity reduction is justified if redispatching costs are higher than average capacity reduction costs including the deviation. This general statement is justified since accurate measures between 100–200 MW are not possible due to uncertainties of available redispatching resources and prices a day before the delivery hour.

A notable observation is that extensive congestions above 150–200 MW indicate that redispatching becomes more expensive and capacity reduction measure is socio-economically justified. Although, bilateral trades are generally more inexpensive than balancing market bids and may lead realising bilateral redispatch if possible. Therefore, redispatching may be preferred above 200 MW if resources are reliably available and priced reasonably indicating a range of 20–50 €/MWh. This is generally the price range for capacity reduction costs during congestion.

However, redispatching and capacity reducition methods could be realised simultaneously. This is suggested if it lowers the total socio-economic costs. In this case, 200 MW overload could be realise by redispatching 100 MW and reducing RAC-cut capacity by 100 MW. The actual proportion between redispatching and capacity reduction volumes should be based on essentially measuring costs of the redispatching on different volumes. Then the cheapest offers are realised and remaining is reduced by transmission reduction.

Furthermore above 200 MW requirements, figure 16 does not provide data points above 200 MW and the decision between congestion management actions is not fully reliable. Therefore, available resources are analysed to clarify maximum reliable volume for redispatching. Resources are estimated based on up- and down-regulation offers after ordered regulating power in 2016–2017. These residual values are gathered in figure 17 expressing possible availability for redispatching. Still, all available bids are not possible to realise when redispatching depends on production location and duration curve is respectively lower. Duration curve shows reliability where every 0,03 step represents 11 days of a year. Due to nature of redispatching, both up- and down-regulation bids should be available reliably.

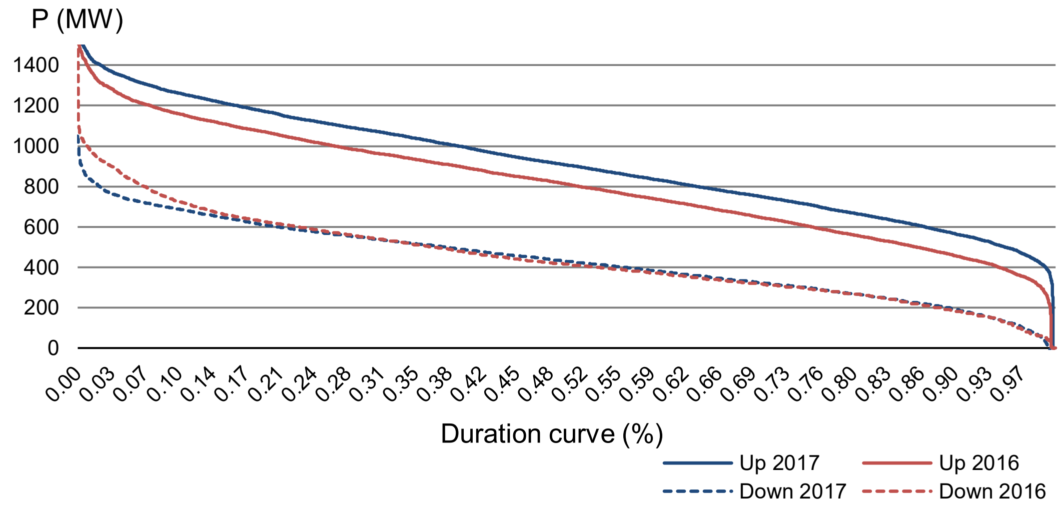

Figure 17. *Balancing market resources after ordered up- and down-regulation power in years 2016–2017. (Fingrid 2018c)*

Up- and down-regulation bids are clearly separated in terms of power and utilisation rate illustrating reliability challenge for redispatching resources in a few weeks of a year. Up-regulation bids have more deviation between years and comparing years 2016–2017 indicates that average up-regulation for redispatching with 0,97 reliability is 420 MW. The reliability issue is evident in down-regulation which clarifies lower reliability if required actions are similar than up-regulation of 420 MW. In this case, reliability is

0,50 and over 0,90 reliability is guaranteed below 200 MW measures. Availability for up-regulation bids are generally reliable however, reliability for down-regulation is not guaranteed generally over 100 MW if required reliability is 0,97. In practice, only a part of corresponding volumes are accepted to redispatching due to required production or consumption locations and sufficient reliability is generally compromised during a few weeks within a year.

Seasonal changes within a year are impacting on redispatching reliability and yearly average is not necessarily representing the issue reliably. Quarter measurements in 2016–2017 elevates differences between summers and winters which generally states 200 MW difference between seasons. Fundamentally, winters issue more generation power due to higher need of electricity and enables higher volumes during winters. While the most of congestions occurs during summers, this generally worsen possible redispatching realisations compared to figure 17 values. Alternatively, redispatching could be replaced in south by countertrading via DC-links if redispatching is unavailable.

Now, all following results from chapters 6.5.1 and 6.5.2 are concluded into figure 18 showing simplified decision between redispatching and capacity reduction measures in congested market situations. Capacity reduction costs in a range of 20–60 €/MWh shows the most challenges for decision between different actions. Challenges are especially within 100–200 MW range where increasing redispatching costs are still more justified than transmission capacity reduction and therefore, diagonal line represents the decision generally. Diagonal line is estimated based on figure 13, table 3, average linear representation of 2016–2017 in figure 16, 13 the most congested week data in 2016–2017 for redispatching and capacity reduction costs and due to assumptions to choose redispatching if capacity reduction shows similar costs.

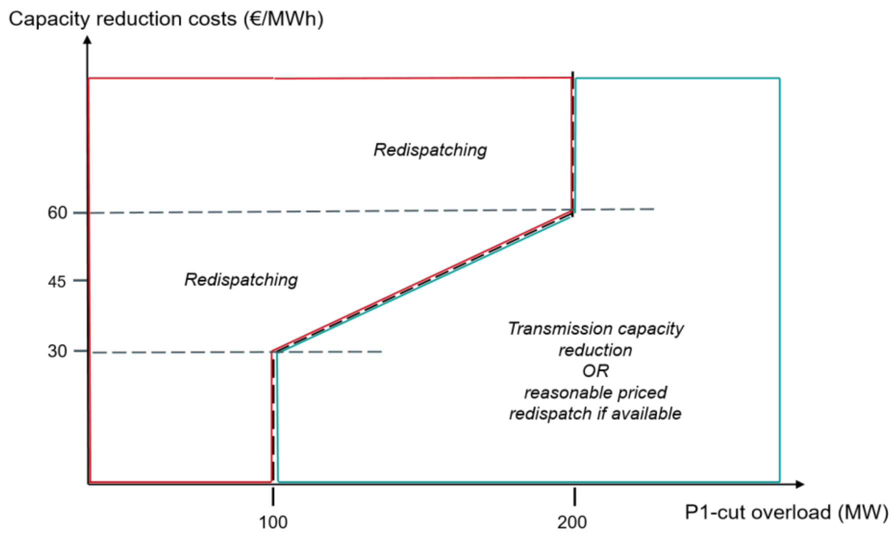

Figure 18. *Simplified decision between congestion management methods during congested P1-cut.*

Decision during 0–100 MW overloads did not indicate explicit difference between redispatching or capacity reduction costs and therefore, redispatching is preferred between 0–100 MW overloads as stated in assumptions. Above 200 MW volumes, redispatching resources are not necessarily available and redispatching is not recommended in higher volumes as partially due to highly increasing redispatching costs. Redispatching could be realised above 200 MW overloads if reasonable priced resources are available. This essentially means redispatching cost range of 30–60 €/MWh which is similar to capacity reduction costs.

Accurate decision in intersections at 30 €/MWh and 100 MW and similarly at 60 €/MWh and 200 MW are hard to validate due to uncertainty of estimated redispatching and capacity reduction costs. As stated in table 3, redispatching cost uncertainty increases in higher measures and e.g. 150 MW volume has a deviation of 25 €/MWh. However, diagonal line represents average justification between both methods which should be noticed along with deviation of redispatching costs. Transmission capacity reduction is generally justified in higher volumes due to increasing redispatching costs and uncertainty of available redispatching resources.

7. DISCUSSION

By definition, determining decision between congestion management methods is an optimisation issue where redispatching and capacity reduction cost uncertainty causes inability to conclude accurate methods. Decision is essentially depending how much cross-zonal transmission capacity restricts the actual flow between bidding zones. If all given transmission capacity for allocation is utilised, it indicates most impacts to adjacent bidding zones as a result of increasing price spread. Therefore, adequacy of transmission capacity is a foundation for minimal market impacts.

At first, most capacity reduction impacts were expected into adjacent bidding zones of FI-SE1 cross-border and Baltic States. It was unexpected that impacts are occurring not only in FI and SE1 bidding zones, but essentially in SE3 bidding zone which generally issues higher market impacts compared to SE1 bidding zone. It was presumed that SE3 market impacts could be high but actual results confirmed a clear correlation to the RAC-cut capacity reduction. This occurs subject to large internal market area, high transmission between FI-SE3 bidding zones and other SE3 cross-zonal interconnections and therefore, high congestion incomes advances SE3 positive socio-economic welfare. Welfare impacts to Baltic States were expected to be lower compared to Finnish bidding zone due to smaller market area and results clarified this presumption. Impacts generally occurred in Estonian and Lithuanian bidding zones as a result of Estonian self-reliance of electricity and Lithuanian reliance of Estonian electricity.

Capacity reduction clarifies connection to the RAC-cut transmission and further reflecting to the P1-cut transmission during congested hours. Capacity reduction did not show market impacts if transmission flow in FI-SE1 were not restricted. It was presumed that capacity reduction shows exponential cost increment on every reduction step due to higher marginal costs of Finnish electricity market resources compared Swedish and Norwegian resources marginal cost. Surprisingly, capacity reduction costs implied relatively linear decrease into costs representing almost constant costs per MWh on every reduction measure. One explanation is that Finnish supply merit order list is rather linear and the transmission capacity change issues linear price change and consequently, linear socio-economic welfare change. Other explanation is that market participants' bidding behaviour is static due to the use of historical offers in simulations and such as producers' ability to offer higher bids during foreseen congestion in reality could increase bidding zone price indicating higher negative welfare change. Additionally, studied years 2016–2017 may not represent results truthfully in future if markets witness major changes in production and consumption or in the transmission network.

Higher predictability of capacity reduction costs compared to redispatching costs were expected due to lower socio-economic welfare change deviation between weeks. Still, estimated redispatching costs based on balancing market prices did not remove uncertainty from realised prices and volumes. Essentially, redispatching unpredictability is due to available resources and how rapidly congestions occur. Approaching closer to operational hour will increases production costs due to faster need of electricity which is not necessarily foreseen a day before the delivery day. However, higher requirements of redispatching will generally increase deviation of corresponding costs and decreases predictability above 300 MW requirement due to absence of balancing market offers. This increased study result uncertainties during higher congestions.

Surprisingly, higher volumes indicated resources unavailability especially in down-regulating bids and shows 0,97 utilisation rate below 100 MW volumes. However, realising all available balancing market offers are not possible due to production location and its impropriety for redispatching explaining even lower reliability above 100 MW requirement. It clarifies that redispatching may not be socio-economically appropriate or reliably available for extended overload situations and economically may lead higher costs if resources are unavailable. Still, redispatching measures are desirable as long as congestions are foreseen due to generally lower costs.

Essentially, results between real and simulated market prices indicate occasionally dissimilarities during local maximum prices. Calculation iterations may take several iteration without finding optimal solution for the same situation in simulation environment. Euphemia –algorithm utilises some heuristics approaches that doesn´t necessarily guarantee optimal or identical solution always. Therefore, calculation results might change in few single hours depending on different iteration progress. Its impacts on study results are limited since small changes into prices in high volatility environment creates low impacts on average weekly socio-economic values. The issue could compromise results if time frames are defined only to couple days.

8. CONCLUSIONS

This thesis discusses internal bidding zone congestion management in capacity calculation phase and reflects concerns of undue discrimination in order to improve efficiency and handling of internal congestions in capacity calculation. Concern of socio-economic welfare changes in the European day-ahead market are encountered with measuring alternative method for relieving congestion in the P1-cut transmission. This essentially is depending on a decision between estimated redispatching or capacity reduction costs where the least impact to the market will indicate the most efficient and justified method for relieving congestions.

Congestion management methods are estimated based on market analysis from years 2016–2017 indicating European-wide market impacts during the RAC-cut transmission capacity reduction. Thesis improves current method by utilising simulation tool with European scope to determine market outcomes and socio-economic welfare changes relieving congested P1- and RAC-cut transmission. Simulation represents more accurate method compared to earlier method to estimate capacity reduction impacts regarding to the socio-economic welfare change. Redispatching costs were estimated based on balancing market prices due to low quantity of historical measures.

The actual range of simulated capacity reduction costs in the RAC-cut transmission during congestions are averagely within 15–45 €/MWh and especially within 20–30 €/MWh regardless of volume and represents lower costs compared to the average day-ahead market price. Capacity reduction does not indicate directly higher price in Finnish bidding zone or higher price spread between FI-SE1 bidding zones if transmission flow is adequate. If capacity is restricting the transmission flow, the majority of market impacts occur in Finnish bidding zone, but respectively capacity changes influence Swedish and Baltic State bidding zones. Simulations indicated that impacts are depending on seasons and the P1-cut congestion issues are subject to high RAC-cut imports and a lack of reasonable priced production resources in Southern Finland.

Estimated redispatching costs indicated increasingly higher costs and uncertainty depending on required volumes. Within 0–100 MW required volumes, redispatching costs showed similar or slightly lower costs compared to capacity reduction costs but did not show distinctive difference between one another. During higher volumes, redispatching costs become increasingly expensive supporting capacity reduction measures if redispatching costs exceed above 60 €/MWh. Similarly, unpredictability increases on required redispatching volume and such as 100 MW requirement shows averagely ±20€/MWh volatility. Higher volumes and especially volumes above 200 MW showed limitations on down-regulating power resources availability and clarifying uncertainty and limitations of redispatching on higher volumes. Despite of the fact that estimated redispatching costs are highly unpredictable, reasonable results are concluded especially around 100 MW required volumes.

Based on higher knowledge of congestion management method applied in capacity calculation enables reflecting earlier method in a new perspective. Earlier method realised undue discrimination rules generally well however, individual realised prices and volumes are occasionally higher than improved method would suggest. Before, capacity reduction costs in FI-SE1 border were estimated based on assumptions and general calculation without utilising simulation tools. In individual cases, earlier estimation undervalued capacity reduction impacts. This however, is due to calculating only Finnish cross-zonal border impacts without noticing broader impacts to the European electricity market.

Simulated market outcomes brought higher accuracy to estimate improved congestion management representing more detailed market impacts compared to earlier method. Redispatching estimation uncertainty lowers accuracy of improved method and reflects the difficulty to choose between congestion management methods. While the uncertainties are evident, improved method achieved its objectives and fulfilled avoiding undue discrimination rules on congestion management. Improved methods function also with upcoming capacity calculation e.g. CNTC and flow-based methods.

However, further review of other cross-zonal borders are suggested for congestion management purposes and especially Estlink capacity reduction could be used instead of the RAC-cut capacity reduction. As further work, it could be studied whether in some cases it would be more efficient to reduce the export capacity to Estonia instead of the RAC-cut import capacity in order to relieve the P1-cut congestion. Also, changes to congestion management method should be evaluated after Olkiluoto 3 power plant starts power production resulting 300 MW reduction to the RAC-cut transmission capacity. Its impacts on congestion management methods should be then reviewed further. Additionally, results of the method should be re-evaluated after any significant change in electricity market.

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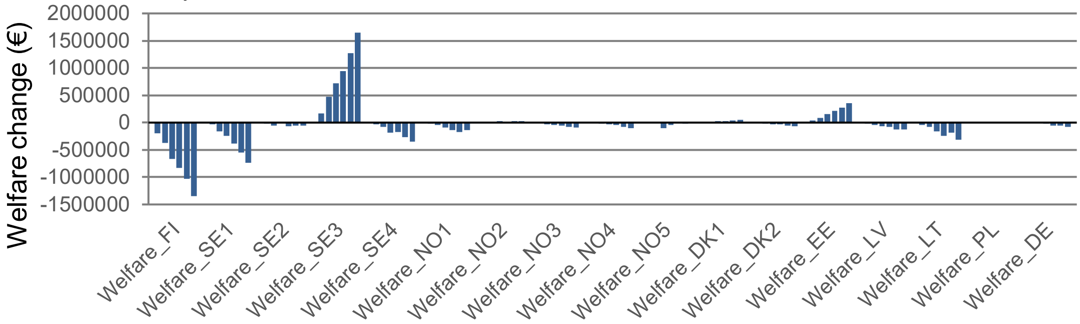
APPENDIX A: SIMULATED WEEK PERIODS

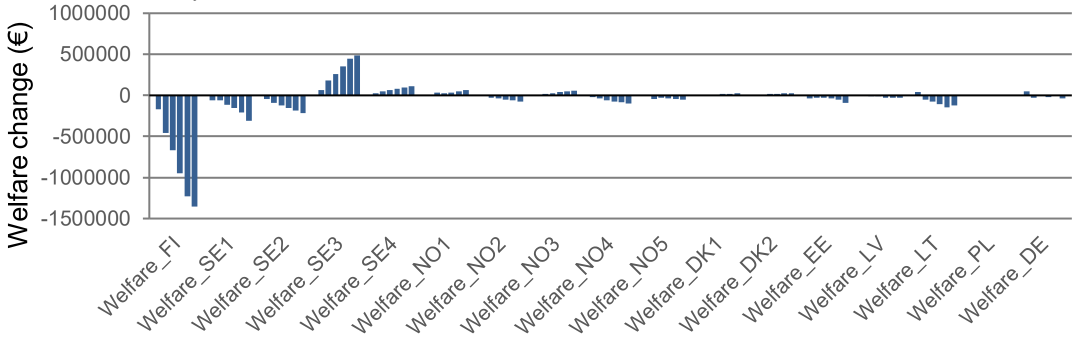
Time periods	Date (7 day period)	Average price difference and deviation in FI	Average P1-cut transmission and deviation
2017	16.1.2017 - 22.1.2017	34.49 ± 11.68 €/MWh	1008 ± 528 MW
	6.2.2017 - 12.2.2017	40.48 ± 10.53 €/MWh	749 ± 394 MW
	20.2.2017 - 26.2.2017	31.46 ± 6.44 €/MWh	702 ± 515 MW
	3.7.2017 - 9.7.2017	40.19 ± 10.15 €/MWh	1585 ± 247 MW
	24.7.2017 - 30.7.2017	33.38 ± 10.02 €/MWh	1323 ± 412 MW
	31.7.2017 - 6.8.2017	29.81 ± 7.95 €/MWh	951 ± 460 MW
	7.8.2017 - 13.8.2017	34.38 ± 11.47 €/MWh	1084 ± 532 MW
	4.9.2017 - 10.9.2017	39.00 ± 10.87 €/MWh	1495 ± 485 MW
	25.9.2017 - 1.10.2017	35.53 ± 7.33 €/MWh	1020 ± 492 MW
	9.10.2017 - 15.10.2017	35.87 ± 13.95 €/MWh	819 ± 708 MW
	23.10.2017 - 29.10.2017	33.74 ± 11.41 €/MWh	982 ± 601 MW
	4.12.2017 - 10.12.2017	32.00 ± 7.12 €/MWh	622 ± 718 MW
	18.12.2017 - 24.12.2017	32.25 ± 13.15 €/MWh	608 ± 776 MW
2016	1.1.2016 - 7.1.2016	30.86 ± 17.40 €/MWh	948 ± 313 MW
	8.1.2016 - 14.1.2016	40.92 ± 21.84 €/MWh	934 ± 349 MW
	15.1.2016 - 21.1.2016	54.11 ± 40.79 €/MWh	774 ± 284 MW
	22.1.2016 - 28.1.2016	32.58 ± 15.68 €/MWh	763 ± 448 MW
	29.1.2016 - 4.2.2016	26.10 ± 10.51 €/MWh	958 ± 373 MW
	12.2.2016 - 18.2.2016	26.20 ± 9.33 €/MWh	1088 ± 359 MW
	18.3.2016 - 24.3.2016	29.21 ± 10.72 €/MWh	1022 ± 409 MW
	1.4.2016 - 7.4.2016	26.01 ± 8.09 €/MWh	650 ± 500 MW
	20.5.2016 - 26.5.2016	29.75 ± 10.29 €/MWh	1337 ± 592 MW
	3.6.2016 - 9.6.2016	32.93 ± 11.92 €/MWh	1140 ± 519 MW
	2.9.2016 - 8.9.2016	32.61 ± 8.50 €/MWh	1028 ± 476 MW
	9.9.2016 - 15.9.2016	34.58 ± 10.71 €/MWh	1131 ± 330 MW
	30.9.2016 - 6.10.2016	34.80 ± 10.23 €/MWh	1433 ± 520 MW

APPENDIX B: EXAMPLE WEEKS OF SOCIO-ECONOMIC WELFARE CHANGE DURING REDUCED TRANSMISSION CAPACITY OF 0–600 MW

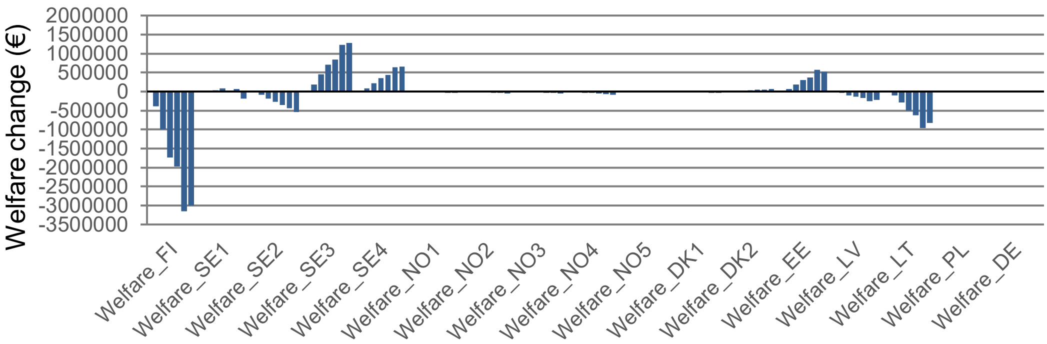
16–22th January 2017



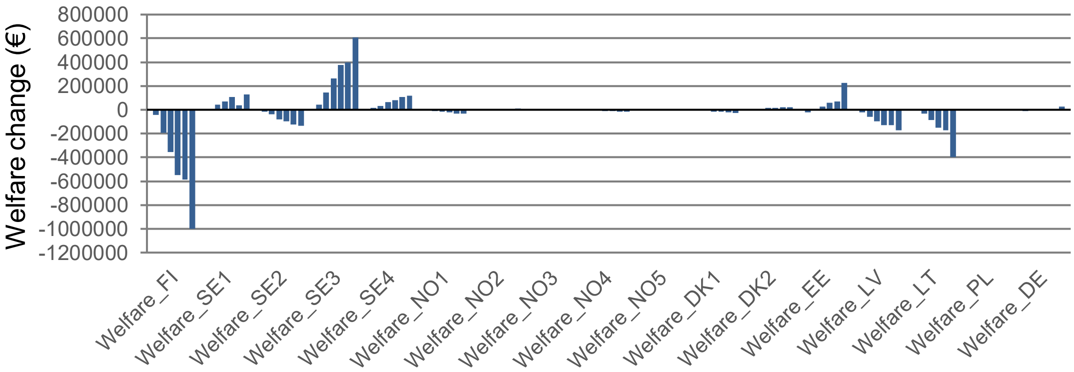
8–14th February 2016



7–13th August 2017



4–10th July 2016



APPENDIX C: ESTIMATED BALANCING MARKET REGULATING PRICE COEFFICIENTS

Up-regulation

	Quarter	0MW	100MW	200MW	300MW	400MW	500MW	600MW
2017	Q1	1	1.271249	1.616074	2.054433	2.611696	3.320117	4.230838
	Q2	1	1.506818	2.2705	3.42123	5.15517	7.767901	11.7529
	Q3	1	1.552707	2.4109	3.743421	5.812437	9.025013	14.075
	Q4	1	1.537258	2.363161	3.632787	5.584528	8.584858	13.25401
2016	Q1	1	1.682028	2.829217	4.758821	8.004469	13.46374	22.76445
	Q2	1	1.616074	2.611696	4.220696	6.820958	11.02318	17.89999
	Q3	1	1.537258	2.363161	3.632787	5.584528	8.584858	13.25401
	Q4	1	1.29693	1.682028	2.181472	2.829217	3.669297	4.77121

Down-regulation

	Quarter	0MW	100MW	200MW	300MW	400MW	500MW	600W
2017	Q1	1	0.99005	0.980199	0.970446	0.960789	0.951229	0.94167
	Q2	1	1.127497	1.271249	1.433329	1.616074	1.822119	2.0569
	Q3	1	1.116278	1.246077	1.390968	1.552707	1.733253	1.936922
	Q4	1	1.051271	1.105171	1.161834	1.221403	1.284025	1.350534
2016	Q1	1	0.995012	0.99005	0.985112	0.980199	0.97531	0.970397
	Q2	1	1.138828	1.29693	1.476981	1.682028	1.915541	2.18431
	Q3	1	0.970446	0.941765	0.913931	0.88692	0.860708	0.83502
	Q4	1	0.980199	0.960789	0.941765	0.923116	0.904837	0.886743