Definition of flexibility products for multilateral electricity markets

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Abstract of master's thesis

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Abstract

Power grids, electrical systems and liberalized zonal electricity markets are in due for major recasting as the ongoing energy transition impacts the electricity sector profoundly. This will mean new kinds of market behavior in liberalized and regulated electricity markets and increased challenges for TSOs to maintain power balance at system-level. Also, inadequacies in network capacity and flexible asset availability impact at local level. Congestions, voltage deviations and grid outages impact both TSOs and DSOs locally and the mitigation of these situations requires new types of multilateral coordination. In addition to more transmission and distribution grid capacity, future electrical systems need resilient flexible resources and intelligent control mechanisms. This thesis examines market-based control by using flexibility products. The envisioned flexibility products are expected to be implementable in the Baltic Sea area electricity markets during the regulatory period of Finnish electricity network companies beginning in 2024.

Thesis includes a literature review and a qualitative empirical research consisting of industry consultation. First, the literature study examines existing products traded on future European electricity markets and other mechanisms that control networks and network connected assets. Secondly, it examines emerging flexibility products that can provide local flexibility services which the existing product structure is not covering.

Industry consultation includes Finnish expert views regarding different aspects of flexibility needs, flexibility markets and opinions on the emerging flexibility products. Interviewees found the concepts of flexibility markets and products new and complex. Most of the interviewees had not experienced serious technical flexibility issues at local level in Finnish electrical networks but agreed that local flexibility challenges would be a reality in Finland within next five years. Majority of interviewees saw new enabling technologies and market-based trading of local flexibility worth considering. They had different local needs for flexibility products, if trading could be done cost-efficiently and market design would be supportive for both flexibility buyers and sellers. Outage management and voltage support with flexibility were identified as the most urgent local needs and congestion management was seen less important.

According to the findings, numerous although contradictory flexibility product alternatives can solve different flexibility needs. It was concluded that market design should go forward with the development of three options: locational intraday products, locational balancing products and competitive bilateral flexibility contracts. The results show, that these recommended products are modifications of existing products. All three preferred options should be enabled due to different reasons and these options are not mutually exclusive. The compatibility of flexibility products with existing products and operational processes must be ensured, especially considering reconciliation of flexibility markets and a reactive balancing model of TSOs. Development of flexibility products should start immediately with incremental experimentation with cooperation of all network users and operators.

Keywords flexibility product, electricity market, multilateral, congestion management, voltage and reactive power control, outage management

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Tiivistelmä

Meneillään oleva energiamurros aiheuttaa merkittäviä muutoksia sähköverkkoihin ja-markkinoihin. Tämä johtaa uudenlaiseen käyttäytymiseen vapautetuilla ja säännellyillä sähkömarkkinoilla sekä kantaverkkoyhtiöiden lisääntyviin haasteisiin ylläpitää järjestelmätason tehotasapainoa. Myös alueelliset haasteet lisääntyvät riittämättömän verkkokapasiteetin tai joustavien resurssien puuttuessa. Paikalliset ylikuormitukset, jännite- ja loistehopoikkeamat sekä käyttökatkot voivat vaikuttaa useisiin siirto- ja jakeluverkkoyhtiöihin, jolloin ratkaisut vaativat monenkeskistä koordinointia. Tulevaisuuden sähköjärjestelmät vaativat lisää siirto- ja jakeluverkkokapasiteettia, joustavia resursseja ja älykkäitä ohjausmekanismeja. Tässä diplomityössä tutkitaan markkinaehtoisiin joustotuotteisiin perustuvia ohjausmekanismeja. Suunniteltujen joustotuotteiden on tarkoitus olla käytettävissä 2024 alkavalla suomalaisten sähköverkkoyhtiöiden sääntelykaudella Itämeren alueen sähkömarkkinoilla.

Tämä diplomityö sisältää kirjallisuuskatsauksen ja empiirisen tutkimuksen, joka koostuu sähköalan asiantuntijoiden laadullisesta konsultaatiosta. Työssä tarkastellaan nykyisten sähkömarkkinoiden tuotteita, joilla verkkoja ja verkkoon kytkettyjä resursseja hallitaan. Lisäksi työ tutkii kehittyviä joustotuotteita, jotka voivat tarjota paikallisia joustopalveluita, joita nykyiset tuotteet eivät kata. Konsultaatio sisällyttää alan näkemyksiä jouston tarpeista, joustomarkkinoista ja kehittyvistä joustotuotteista tutkimukseen.

Haastateltavat kokivat joustomarkkinoiden ja -tuotteiden käsitteet uusiksi ja monimutkaisiksi. Suurin osa haastatelluista ei ollut todennut suomalaisissa sähköverkoissa alueellisesti vakavia haasteita, mutta arvioivat paikallisten joustavuushaasteiden yleistyvän seuraavan viiden vuoden aikana. Merkittävä osa asiantuntijoista arvioi uudet teknologiaratkaisut ja markkinalähtöisen joustokaupankäynnin harkinnan arvoiseksi, mikäli kaupankäynti on kustannustehokasta ja kannattavaa sekä joustavuuden ostajille että myyjille. Keskeyttämätön sähkönsyöttö ja loistehon hallinta tunnistettiin kiireellisiksi paikallisiksi tarpeiksi ja siirtojenhallintaa pidettiin vähemmän kiireellisenä tarpeena.

Työn mukaan lukuisat ja keskenään ristiriitaiset joustotuotevaihtoehdot voivat ratkaista erilaisia joustotarpeita. Ensisijaisesti tulisi keskittyä kolmen kategorian tuotteiden kehittämiseen: sijainnilliset päivänsisäisen markkinan tuotteet, sijainnilliset säätösähkömarkkinan tuotteet ja kilpailutetut kahdenväliset joustosopimukset. Tuloksista voidaan nähdä, että kaikki kolme vaihtoehtoa ovat olemassa olevien tuotteiden muunnoksia. Tuotteet ovat otettavissa käyttöön eri syistä, ja vaihtoehdot eivät ole toisiaan poissulkevia. Joustotuotteiden yhteensopivuus olemassa olevien tuotteiden ja toimintaprosessien kanssa on taattava, erityisesti yhteensovittaminen kantaverkkojen reaktiivisen säätötavan kanssa on varmistettava. Joustomarkkinoiden jatkokehittäminen tulisi aloittaa välittömästi kokeiluilla ja verkonhaltijoiden ja -käyttäjien yhteistyöllä.

Avainsanat joustotuote, sähkömarkkina, monenkeskinen, siirtojenhallinta, loistehon hallinta, keskeyttämätön sähkönsyöttö

Preface

This thesis has been commissioned by Fingrid Oyj and is a part of an EU project, INTERRFACE, which has received funding from the European Union's Horizon 2020 research and innovation programme. The topic is the result of currently missing or non-harmonized market-based services of electricity markets, such as congestion management, voltage support, and outage support. The goal of this thesis is to define flexibility products which when traded can provide innovative grid services for an efficient power system. Scope for these products is the next regulatory period of networks. I personally feel, that amid the energy transition, much of the content must be updated before 2024 and that energy and electrical experts will have the most interesting times ahead.

I want to thank Fingrid Oyj and everyone at the Market Solutions unit for the opportunity and for your support along the way. Especially, I need to mention my advisors Heidi Uimonen and Risto Lindroos, for without your kindness and brilliance there would be less intelligence in smart grids. During my research I felt motivating to talk with many industry professionals and would like to share my gratitude for the expertise of thesis steering group members, stakeholder interviewees, and INTERRFACE Baltic-Nordic regional team. I express my appreciation for Professor Sanna Syri for the supervision of my thesis and for your expertise during my studies. I thank Aalto University staff and my fellow students for the last five years, it truly has been a pleasure.

Thanks to my friends and family for support and company during these years.
Elina, thank you for making it all worthwhile.

Helsinki 22.11.2019

Taneli Leiskamo

Contents

Abstract
Abstract (in Finnish)
Preface
Contents 1
Abbreviations 3
1 Introduction 5
1.1 Background 5
1.2 Fingrid Oyj and EU INTERRFACE project 8
1.3 Objective and content of the thesis 9
2 Flexibility in electrical power systems 12
3 Existing products in European electricity markets 18
3.1 Day-ahead and intraday markets 19
3.2 Balancing mechanism 23
3.2.1 Balancing markets 23
3.2.2 Reserve markets 25
3.3 Transmission and distribution network management 26
3.3.1 Congestion management 26
3.3.2 Non-frequency ancillary and other networks services 29
3.4 Technical details and gap-analysis of existing electricity market products 31
4 Emerging flexibility products for electricity markets 36
4.1 Flexibility products for congestion management 36
4.1.1 Locational balancing products 36
4.1.2 Locational intraday market product 39
4.1.3 Competitive bilateral flexibility contract for congestion management 42
4.2 Flexibility products for voltage support 44
4.3 Dynamic network tariffs 45
4.4 Flexible network service agreement 46
4.5 Flexibility market development projects 47
5 Industry views on flexibility and flexibility products 49
5.1 Flexibility in the electricity system: present and future needs 49
5.2 Architecture and coordination of a flexibility market 53
5.3 Flexibility products and other steering mechanisms 59
5.4 General comments, development ideas and other feedback 62
5.5 Summary of industry consultation results 65
6 Flexibility products for multilateral power system management 67
6.1 Technical details of flexibility products 67
6.2 Utilization of flexibility products 71
6.3 Evaluation of flexibility products 73
7 Discussion 75
7.1 Market architecture and product reform 75
7.2 Operational changes 76
7.2.1 TSO-DSO coordination 77
7.2.2 Operational chain of flexibility 78
7.2.3 Flexibility delivery verification and settlement 79
7.2.4 Transparency 82
7.3 Locational market power 83
7.4 Regulatory and industry chances 84

8 Conclusions 87
References 89
Appendices 97
Appendix 1. Three possible models for market coordination
Appendix 2. Relation of flexibility products to grid and market needs
Appendix 3. List of the interviewees in industry consultation
Appendix 4. Interview framework
Appendix 5. Definition of product parameters
Appendix 6. DSO flexibility needs and products summary
Appendix 7. Industry guidelines for flexibility markets
Appendix 8. Next steps for flexibility markets

Abbreviations

AC	Alternative current
ACER	Agency for the cooperation of energy regulators
aFRR	Automatic frequency restoration reserve
AOF	Activation optimization function
ACE	Area control error
ASM	Active system management
BEGCT	Balancing energy gate closure time
BRP	Balance responsible party
BSP	Balancing service provider
BZ	Bidding zone
CACM GL	Capacity allocation and congestion management guideline
CCS	Carbon capture and storage
CDM	Central dispatch model
CEP	Clean energy for all Europeans package
CET	Central European time
CHP	Combined heat and power
CM	Congestion management
CMGCT	Congestion management gate closure time
CMOL	Common merit order list
CNE	Critical network element
CT	Countertrade
CZ	Cross-zonal
DAM	Day-ahead market
DC	Direct current
DCC	Network code on demand connection
DER	Distributed energy resources
DSO	Distribution system operator
D-	Days before delivery
D+	Days after delivery
EAN	European article numbering
EB GL	Electricity balancing guideline
EES	Electrical energy storages
ENTSO-E	European network of transmission system operators
EOM	Energy-only market
ERPR	Enhanced reactive power reserve
FAT	Full activation time
FCR	Frequency containment reserve
FCR-N	Frequency containment reserve for normal operation
FCR-D	Frequency containment reserve for disturbances
FFR	Fast frequency reserve
FSP	Flexibility service provider
FRR	Frequency restoration reserve
GCT	Gate closure time
GHG	Greenhouse gas
GO	Guarantees of origin
GOT	Gate opening time
HVDC	High-voltage direct current
H+min	Minutes after delivery

H-min	Minutes before delivery
IDCZCP	Methodology for pricing of intraday cross-zonal capacity
IDCZGOT	Intraday cross-zonal gate opening time
IDCZGCT	Intraday cross-zonal gate closure time
IDM	Intraday market
IEM	Internal energy market
INTERRFACE	TSO-DSO-Consumer INTERFACE aRchitecture to provide innovative grid services for an efficient power system
IZ	Intra-zonal
LFC	Load frequency control
mFRR	Manual frequency restoration reserve
mFRRda	Manual frequency restoration reserve, directly activated
mFRRsa	Manual frequency restoration reserve, scheduled activated
MGA	Metering grid area
MOL	Merit order list
MTU	Market time unit
NBM	Nordic balancing model
NC RfG	Network Code on Requirements for Grid Connection of Generators
NEMO	Nominated electricity market operator
NRA	National regulatory authorities
NWA	Non-wire alternative
LMOL	Local merit order list
LULUCF	Land use, land-use change and forestry
ORPR	Obligatory reactive power reserve
OTC	Over the counter
RD	Redispatch
REMIT	Regulation on Wholesale Energy Market Integrity and Transparency
RO	Regulating object
RR	Restoration reserve
SFP	Single flexibility platform
SDAC	Single day-ahead coupling
SDM	Self-dispatch model
SIDC	Single intraday coupling
SNG	Synthetic natural gas
SO GL	Electricity transmission system operation guideline
SO	System operator
TDCP	TSO-DSO coordination-platform
TSO	Transmission system operator
TOTEX	Total expenditure framework
VRES	Variable renewable energy sources
XBID	The Cross-Border Intraday initiative

1 Introduction

1.1 Background

Power grids, electrical systems and liberalized electricity markets are in due for major recasting as the on-going energy transition impacts the electricity sector profoundly. Fundamental structural changes in the energy sector result from a combination of technical development, political goals and guidelines, capital movements and other phenomena (Smil 2016). Here energy transition refers to a global trend, the most rapidly emerging in the 21st century, of governments, companies and public implementing policies and practices in place to mitigate climate change. The mitigation is done mainly by reducing greenhouse gas (GHG) emissions created from the use of fossil fuels. In Figure 1 is illustrated the trajectory of GHG reductions and GHG removal increases from land use, land-use change and forestry (LULUCF) based on European Commission vison to achieve carbon neutrality by 2050. For the power sector this target is particularly ambitious, as it means reducing fossil fuel-based power generation without carbon capture and storage (CCS) close to zero before 2035.

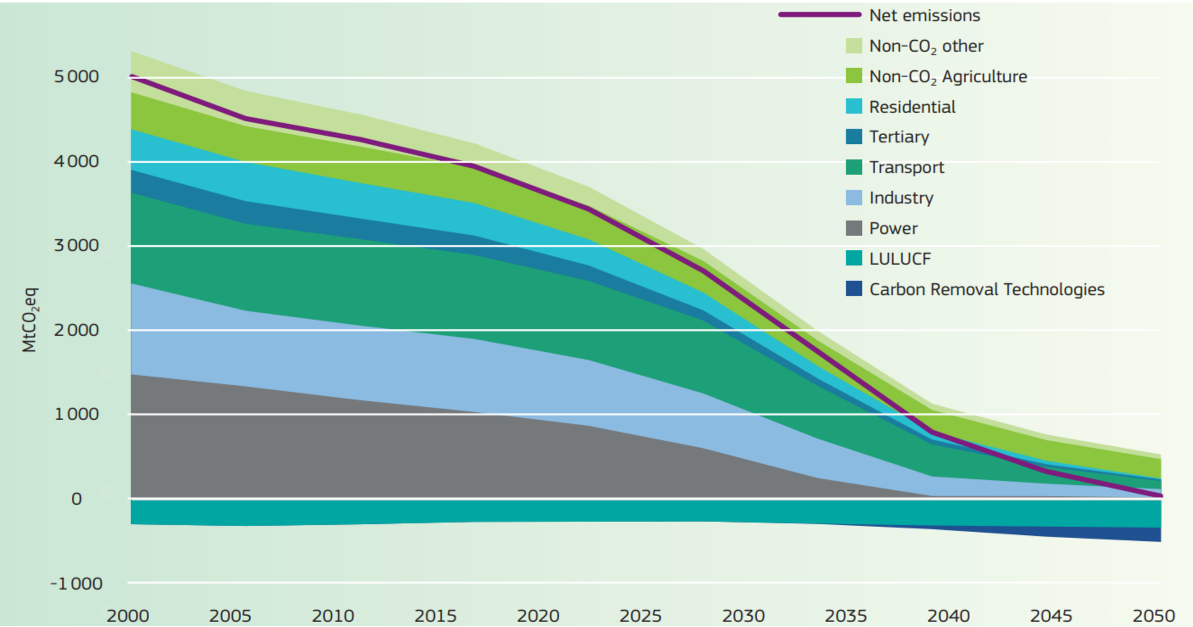

Figure 1: European emission trajectory in a 1.5°C scenario (European commission 2019).

While electricity sector reduces emissions, the electricity consumption and peak loads can increase if other energy sectors such as industries, transport and heating can reduce their environmental impact trough electrification. For example, mobility electrification can decrease total energy consumption due to energy efficiency but increase electricity consumption and especially peak power utilization (Rautiainen 2015). According to Pinomaa (2019) the electrification of Finnish chemical industry will increase tenfold the current electricity consumption of 7 TWh (Pinomaa 2019). SSAB estimates, that cleaner steel manufacturing will require the equivalent of about 10 percent of Sweden's current electricity consumption, which was 145 TWh in 2018 (Dagens Nyheter 2019). In 2010 the EU28 building heat consumption was 13.1 exajoules, of which natural gas was 47 percent of this market. Replacing natural gas with synthetic natural gas (SNG) or other forms of electric heating, such as heat pumps, could reduce emissions of heating (Persson & Werner 2018). Previous examples put together require large amounts of affordable electricity production.

Reducing GHG emissions and increasing electricity consumption, implies that reductions in the emission content of electricity must be done. This can be achieved with increased non-fossil fuel-based power generation, such as nuclear, hydro, wind, solar and biomass power, together with different kinds of energy storages. This will result in increased shares of decentralized, variable and inflexible power production capacity in the electricity system. For example, a high-growth scenario from Wind Europe (2017) foresees the Nordic wind capacity increasing 2300 MW per year, exceeding 45 GW in 2030. This alone would significantly exceed the current minimum power demand of the area. Mid-term Adequacy Forecast 2018 of ENTSO-E sees the possibility of decommissioning or mothballing of tens of gigawatts of dispatchable capacity within the European area, such as nuclear and fossil-fuel thermal power plants, before the year 2025 (ENTSO-E 2018a).

Alongside with capacity adequacy and balance management, also local grid constraints pose major challenges due the foreseen changes. For example, in major European areas 2016 market facilitation with ancillary services, such as different capacity mechanisms, witnessed a 21.4% year-on-year capacity increase and congestion management costs rose 25% between 2015 and 2017 to 1.27 billion euros, although the distribution of these costs is highly concentrated in Germany and UK. The pressure on power grids described above is indicated by multi-billion grid infrastructure investment plants to all voltage levels. Changes in generation capacity together with the electrification of other energy sectors means that the current and future electrical system requires more transmission and distribution grid capacity, resilient flexible resources and intelligent control mechanisms. (ENTSO-E 2019a.)

Extension towards a larger and more liberalized European power system and markets has historically increased efficiency due to competition caused by the interconnectivity and market mechanisms (Elovaara & Haarla 2011). Existing market mechanisms must now be updated, so that market-based control can keep up with changes that physically impact networks. Current trends in the electricity sector mean that new types of distributed energy resources (DER) are connected and controlled by non-traditional parties in distribution and transmission systems. This happens sometimes in the grid segments with the lowest transmission capacity. System operators (SO) are responsible to continuously maintain both system level power balance and local level grid capacity adequacy to transfer electricity with reasonable cost. This also includes planning for future since infrastructure projects can take years to be completed, while new types of consumption and generation facilities can be completed at a much faster pace. A sizing approach of designing grids from centralized power plants down to low-voltage consumption to withstand almost all possible situations within a bidding-zone is also called a copper-plate-assumption (Elovaara & Haarla 2011). It is evident that this assumption is not working anymore or at least not fast enough in the rapidly changing market and technology environment. Together with insufficient existing network capacity this means that current zonal energy-only market models are not allocating resources according to spatial and temporal scarcity.

Moving from an integrated power system with centralized controllable generation mainly in transmission networks to a situation where both generation and consumption are distributed to all-voltage levels and new types of resources are controllable by many market parties is a challenge for transmission system operators (TSO) and distribution system operators (DSO) (Biggar et al. 2014). Therefore, previously proven market mechanisms, infrastructure planning principles and operational guidelines are not suitable for the type of multilateral coordination needed. For example, a common report from European industry: “An integrated approach to Active System Management”-report (ASM) encourages all market participants, market operators, resource owners and especially system operators to enhance current coordination measures to utilize the full potential of the power system (CEDEC et al. 2019).

Solely relying on grid reinforcements to handle every increase of load and connections of decentralized generation at the distribution grid level will be very expensive (Schittekatte & Meeus 2019). Similarly, solving all transmission grid congestions and balance management issues with grid investments or backup power plants will result in a power system that has oversized grids at all voltage levels, and has a socioeconomically non-optimal amount of generation capacity in the system. Thus, by over-investing, this hypothetical practice weakens the economic competitiveness of the entire electricity system in question, when compared to alternative energy sources or to electricity grids in other areas. The practice does not fully exploit new technology and advanced operating models and fails to utilize the full potential of the existing infrastructure. Moreover, in some cases the mentioned approach might not even be technically achievable, or its implementation may be too slow compared to the modern challenges. The provision of non-wire alternatives (NWAs) such as demand response, location specific generation, energy storage, and energy control devices can be an alternative for conventional investments, such as network reinforcements or centralized power generation facilities. An investment into a NWA or other market-based flexibility procurement can in specific cases reduce the total system costs if the network asset or a backup power plant alternative would be otherwise built to facilitate very limited operational hours or minor overcapacities. Similarly, flexibility can be a desirable temporary alternative if the option would be to curtail load or generation during the completion of infrastructure projects. In vertically disintegrated power systems, the selection of flexibility over or in conjunction with grid investments requires multilateral coordination between regulated and market actors. In addition, enabling network monopolies to procure NWAs from markets requires sufficient cost-efficient supply locally and a supportive regulatory environment. After investments or procurement from existing resources the utilization of NWAs for balancing, congestion management (CM) or to other ancillary services requires multilateral contracts and market-facilitated price signals. (Burger et al. 2019).

In Europe utilization of flexibility for market-based balance and transmission management and transparent grid development has a clear ruling within Clean energy for all Europeans package (CEP), which among many things contains recasts to the previous Electricity Directive (EUR-Lex. 2019b) and the Electricity Regulation (EUR-Lex. 2019b). CEP follows a series of European energy packages aiming to harmonize national markets to achieve an implementation of the internal energy market (IEM). The first package in 1996 started the deregulation process of the European electricity market. CEP continues this path to achieve a secure, competitive, customer-centered, flexible and non-discriminatory EU electricity markets with market-based supply prices while meeting with the requirements of EU's Paris Agreement for reducing greenhouse gas emissions (Nouicer & Meeus 2019). For example, Electricity Regulation and Directive will start to incentivize and oblige system operators, to systematically use market-based flexibility. The use of flexibility as a NWA has not happened on large scale either due to lack of need, complexity and uncertainties involved, technological costs, misaligned regulatory incentives or unfamiliarity related to the topic (Burger et al. 2019).

Regardless of the chosen strategy for tackling flexibility issues, major challenges for both balancing and network management can be foreseen. As power grids are physically struggling to keep up with the energy transition, the value of both system level and local flexibility is increasing. In future electricity demand and supply vary more and more temporally causing a need for new flexibility to balance system in different time windows. Flexibility is also required at multiple geographical locations to ease congestions and to solve power quality challenges at system-level and locally at all voltage levels. To use such market-mechanisms market parties, TSOs and DSOs face new challenges that will require greater coordination than previously. At the core of a liberalized electricity market model design is the market architecture, operational philosophy and the definitions of tradable products (Lin et al. 2017). Successful product design for electricity markets is such that it enables secure, sustainable and affordable electricity where realized prices reflect the true value of the service, allocates costs fairly to correct parties and enforce system-beneficial behavior. Flexibility products can be a desirable alternative to existing products or to traditional grid reinforcements, if such solutions produce better results in terms of cost-effectiveness. As technology and concepts advance and the use of new flexibility sources is becoming more mainstream, they provide a good opportunity to re-evaluate, define and harmonize existing and emerging flexibility product definitions. The energy transition makes this need for definitions urgent. Figure 2 shows the current situation where many European initiatives and pilots are working with flexibility market concepts.

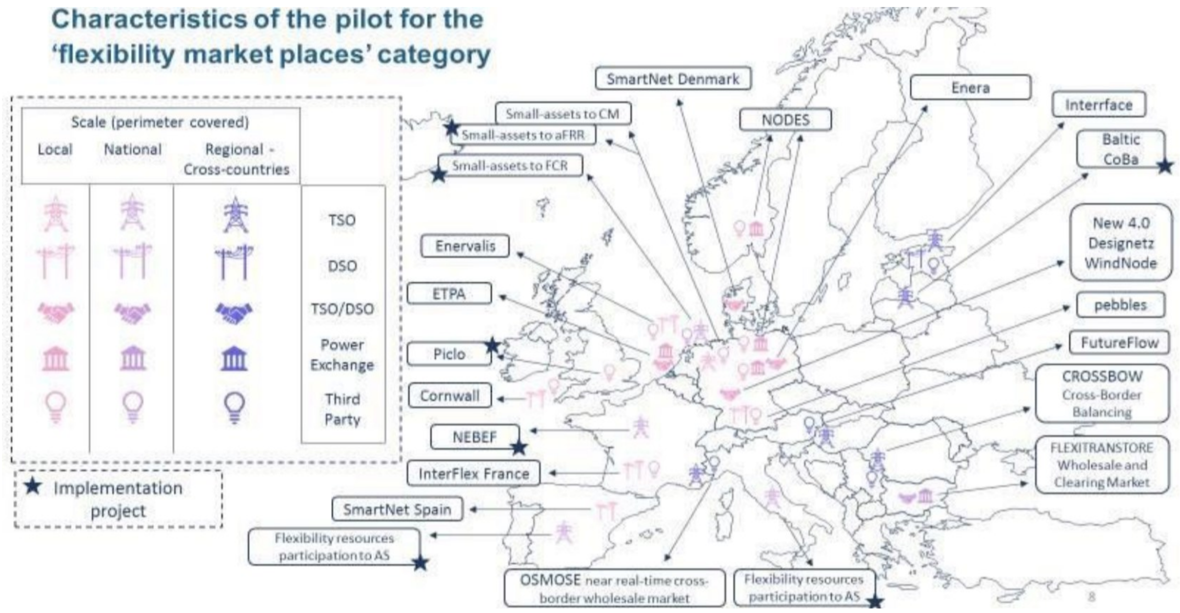

Figure 2: Flexibility pilot projects in EU (Nouicer & Meeus 2019).

1.2 Fingrid Oyj and EU INTERRFACE project

This thesis is commissioned by Fingrid Oyj. The findings are to be utilized for power system operation and market development purposes and as a part of the INTERRFACE-project. Fingrid is a Finnish TSO responsible for the electricity transmission in the high-voltage interconnectors and transmission system in mainland Finland. To enable continuous transmission in the power grid cost-efficiently, Fingrid utilizes flexibility procured from markets and from its own resources for balance management, non-frequency ancillary services and congestion management within the transmission system. Also, grid reinforcements and maintenance, market development and the sharing of electricity market information are necessary actions to increase efficiency of electricity markets together with stakeholders (Fingrid 2019a). Importance of increased collaboration between TSOs, DSOs and market parties and the development needs for market-based flexibility utilization are emphasized in the final report of the Finnish Smart Grid Working Group-report, in which work Fingrid participated (Pahkala et al. 2018).

This thesis is a part of an EU project, INTERRFACE, which has received funding from the European Union's Horizon 2020 research and innovation programme. INTERRFACE project (TSO-DSO-Consumer INTERFACE aRchitecture to provide innovative grid services for an efficient power system) is promoting cooperation and seeks to design, develop and test multilateral flexibility services to increase efficiency in European power system. The project will last 4 years from 2019. Fingrid participates in the piloting of a single flexibility platform (SFP) for different models of aggregation and network bottleneck management, coordination between the transmission system operator and distribution system operator, and the development of information exchange on distributed resources in the demonstration area of Finland, Estonia and Latvia. The use cases to be demonstrated in real-market conditions are: (a) congestion management (from TSO and/or DSO side); (b) frequency/ balance management in TSO side, including mFRR, aFRR, FCR products and demonstration in cross-border usage; (c) flexible grid connectors, where both contracts and technical feasibility will be demonstrated; (d) trading between interested market participants, like BRPs, prosumers. (INTERRFACE 2019).

1.3 Objective and content of the thesis

This thesis examines existing electricity market products, electricity market development and emerging flexibility product alternatives to complete gap-analysis of the foreseen future products and services. This is needed to define an optimal product structure for multilateral electricity markets. Examined products are to be used for balancing, congestion management and ancillary services in short-term electricity markets (Energinet et al. 2019). In this thesis, short-term electrical markets indicate the timeframe of current intraday and balancing energy markets, but the thesis considers also longer duration capacity-based products where the possible service happens within the day of physical delivery of electricity. Longer term financial contracts, day-ahead trading, electricity taxation and other structures that do not strictly enforce the utilization of flexibility within the delivery day are excluded from the scope, even though it is identified that these influence the attractiveness of flexibility markets, products and services significantly. Scope includes also the possibility of utilizing network products, such as grid tariffs or network service agreements, to enforce system beneficial behavior near delivery.

This thesis looks at all short-term products, both existing and emerging, to look for flexibility services that are not covered with the existing product structure. Focus is on short-term due to fact that longer-term markets have more commonly established products and procedures. Another reason to limit the scope to short-term products is the pressure of the energy transition pushing the system closer the operational timeframe and nearer the physical limits of equipment as established above. This will mean, that the current short-term products will be modified before 2024 and to avoid the development of overlapping flexibility products, the foreseen updated versions of existing products must be known. Parallel examination of emerging and existing short-term products is needed because of two reasons. Firstly, to investigate product possible synergies in linking offers between products or product integrations. Secondly, to understand will networks and network users see flexibility products as an attractive option instead of using existing products and mechanisms.

In this thesis multilaterality refers to utilization of flexibility for the needs of TSOs and DSOs as well both balance responsible parties (BRP) and third-party aggregators depending of the product or resource in question. It can be argued that historically all above-described parties have utilized flexibility, but not to full possibilities or in a coordinated manner as the term multilateral is here understood. In this thesis flexibility product definitions must be such that they are flexible, market-based whenever deemed societally beneficial, encouraging for new types of services and are compatible with existing products and other market mechanisms (Bischof et al. 2008). Product definitions will be subjected to state-of-the-art technical, economic and regulatory constraints and to upcoming changes that have been decided to be implemented. The analysis focuses on the power system, electricity market and regulatory characteristics of Finland, but seeks Baltic sea area power system and EU compliant solutions for the development of an internal electricity market. EU compliance is referred with the term European target model. Envisioned products are designed to be implementable in the Finnish regulatory period of electricity networks after 2023, if seen beneficial in further decisions.

The main research question of the thesis is:

- What kind of electricity market product structure would match the needs of the flexibility buyers and capabilities of the flexibility seller's best, while ensuring cost-efficient and secure delivery of electricity?

The main research question can be further separated into sub-questions:

- What changes are expected to existing electricity markets, products, rules and mechanisms in five years?
- What other changes could be done during next five years to existing tradable products on electricity markets or should completely new flexibility products be implemented?
- Which of the emerging flexibility product alternatives are compatible with the foreseen electricity market architecture and foreseen updated versions of existing products?
- Which of the emerging flexibility product alternatives are most promising for future development and testing?
- What kind of flexibility supply different resource owners and operators have now and in five years?
- What kind of flexibility needs different flexibility users have now and in five years?

The study in this thesis will consist of a literature study and an empirical part. Two different empirical research methods were considered: a quantitative cost comparison of flexibility product-based procurement against traditional alternatives, such as network reinforcements and capacity mechanisms or a qualitative industry consultation. The first method was not selected due to lack of suitable data and other reasons explained in more detail in Chapter 7. The later method was decided to be executed with half-structured expert interviews. The selection of a limited amount and discretionary expert sources for interviews is firstly due to time limitations and secondly since the concepts under research in this thesis are new or still non-existing and require comprehensive expertise from the field. Limited experience with flexibility products combined to current and foreseen flexibility challenges are the reason for real-life market-based demonstrations like the INTERRFACE-project, other industry wide collaboration and this thesis. The half-structured interviews will consult experts at Fingrid and with major stakeholders. Initial research hypothesis is that market participants, resource owners and network operators see barriers in further participation to markets or utilization of flexibility products for different services due to:

- restricting network codes, regulation and market rules,
- complexity of the operational demands of flexibility resources or networks,
- market and product fragmentation and non-existing markets and products,
- high transaction, availability and utilization costs of flexibility,
- commitment of a resource to a specific market or service provider for a long time.

The thesis starts by introducing the background of the research topic, Fingrid Oyj and INTERRFACE project and the thesis objective in the first chapter. The second chapter introduces the relevant concepts and terminology related to liberalized power markets and the use of flexibility for achieving stability in electrical grids. The premise for this is that the product design choices made in this thesis try to follow the market principles as closely as possible, while ensuring power system beneficial behavior physically. The third chapter elaborates the existing short-term market and product structures that will most likely be in place after 2023. The topics to be examined are intraday markets, balancing markets and transmission and distribution network management processes. The roles of day-ahead market, and system-level imbalance settlement are explained together with intraday markets when deemed necessary, though they are not the focus of this thesis. Main principles of product design are explained in the corresponding segments. Third chapter concludes with a gap-analysis of the foreseen updated versions of existing products. Fourth chapter introduces the currently emerging market-based concepts for flexibility management in future electrical markets. These concepts are categorized according to their capability to provide missing flexibility services for the power system. The fifth chapter summarizes industry consultation results from the interviews. Interviews contain topics regarding system and market development in general and the possible flexibility product alternatives described in chapter four. Chapter six proposes the most promising flexibility products for further development as a combination of results from chapters 3-5. Chapter 7 discusses the challenges related to proposed flexibility products and their implementation from the viewpoints of operational logic of electricity markets, network development planning and regulation. The last chapter summarizes the main conclusions of this thesis.

2 Flexibility in electrical power systems

This chapter examines the key concepts and terminology related to liberalized power markets and the use of flexibility for achieving stability in electrical grids. The chapter is written from the viewpoint what most parties agree on a European level and is compliant to major legislative frameworks such as the CEP of an interconnected electricity grid with liberalized electricity markets in Europe. Electrical power systems need flexibility to continuously and in the long term to adapt to demands that different physical conditions and users require from the system. The concept of flexibility in electrical power systems has many alternative versions depending on the party responsible for the definition, geographical area and the time when the definition was done. For example, in the pan-European market framework there are still major transactional differences in the existing market models, legal and contractual differences in responsibilities of different roles and physical differences in the actions regarding system operations (Schittekatte et al. 2019). Flexibility in electrical power systems is here defined according to CEER (2018):

> *"Flexibility could be defined as: the modification of generation injection and/or consumption patterns, in reaction to an external signal (price signal or activation) in order to provide a service within the energy system. The parameters used to characterize flexibility can include: the amount of power modulation, the duration, the rate of change, the response time, and the location. The delivered service should be reliable and contribute to the security of the system."*

An electrical power system consisting of a complexity of physical resources, can be classified into to the following subsystems: generating stations, transmission system, distribution system and consuming loads. With the emergence of electrical energy storages (EES) and other DERs such as photovoltaics, some bidirectional nodes of a network can inject or withdraw energy depending on the situation. The quality of power delivery from generation to load must be controlled locally and on the system level respecting different technical limits. This is achieved with assets of network operators and network users. The main parameters related to these technical limits of power networks are stability, voltage and thermal limitations. These refer to the grids capability to transmit power within the operational security limits, which must consider physical characteristics of the interlinked network elements and possible sudden malfunctions. Stability can be further divided into rotor angle stability, frequency stability and voltage stability. Frequency and voltage quality and the number and duration of interruptions are the main quality indicators for power delivery. Power quality is also measured and maintained based on voltage or frequency harmonics, phase asymmetry, transient voltages or frequencies and other metrics, which are not further examined in this thesis. (Kundur 1994).

Real-time operational frequency stability in alternating current (AC) power systems is achieved by balancing the generation and consumption of power at the power system level. This is done with markets described in chapters 3.1-3.2. At local level SOs are responsible to control voltage, mitigate congestions and solve outages to ensure safe and continuous delivery of power. In AC system voltage is controlled locally with the balance of reactive power consumption and generation. Network elements in AC power systems load the grid with resistive and reactive attributes. Reactive attributes of components can be either inductive, capacitive or nonlinear where this characteristic depends on the loading situation. Reactive power is an abstraction which represents the imaginary vector derived from the phase difference of voltage and current. SOs need reactive power control to continuously maintain voltage, minimize real-power losses and congestions and ensure adequate voltage stability in case of contingencies. To achieve voltage stability SOs use their own resources and include obligations in connection agreements and cost components in tariffs related to power angle control. This is currently challenged since many modern electrical devices are increasingly sensitive for voltage deviations and that many of the network connected devices have non-resistive characteristics. Also, the emergence of distributed and controllable resources and multilateral coordination required to use market-based flexibility can be new to SOs. All power system control is achieved with flexibility from different kinds of flexibility sources, categorized in Figure 3. It is important to add that long-term flexibility sources such as network reinforcements and network connected equipment are a mechanism which is a flexibility source with a lead-time in the investment. As the opposite of flexibility could be considered non-controlled demand and generation, but with evolving technology loads can be increasingly matched to generation or generation can be stored for later use. Utilization of flexibility needs preceding investments into the capability to do so. (Machowski et al. 1997).

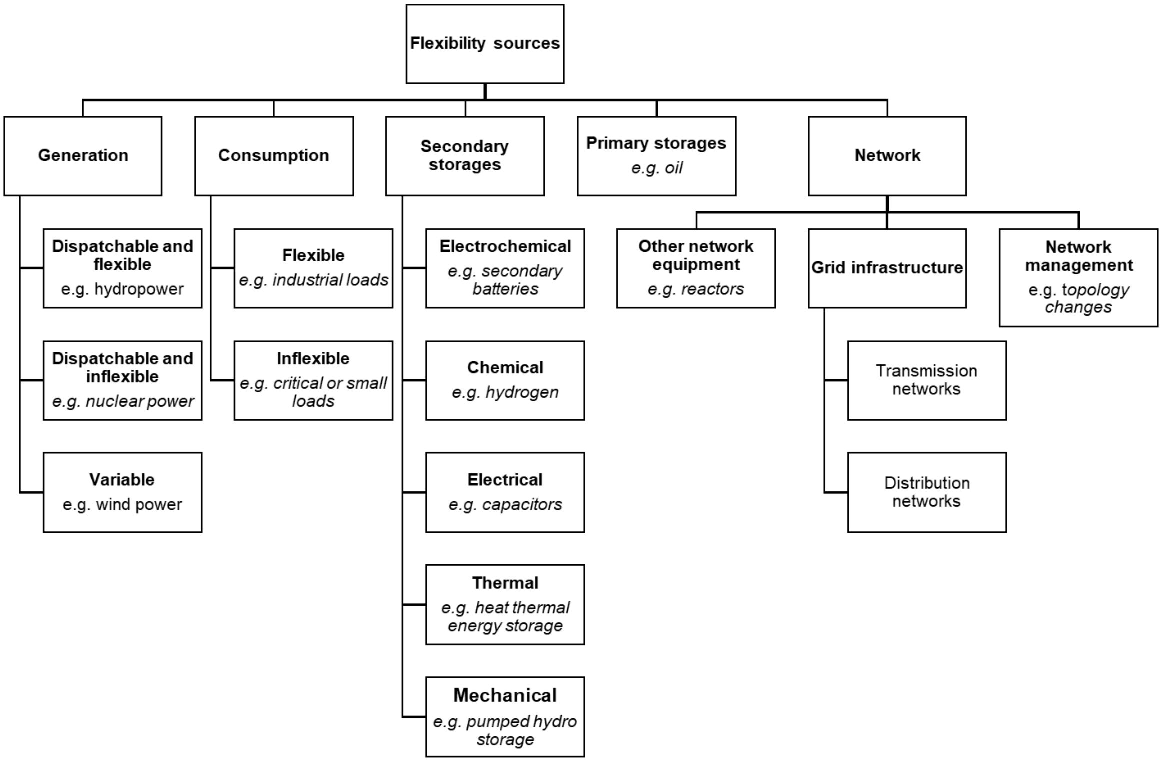

Figure 3: Categorization of network and network connected flexibility sources.

This thesis does not investigate flexibility capability and costs of different technologies in Figure 3, but here is highlighted that not all flexibility demand and supply is equal nor of equal importance. For example, some flexibility sources, such as certain types of power plants, can sell system-level balancing and black-start capabilities and local-level congestion management for long durations while other resources are able provide fast responses for short durations. Also, when operating power plants inherently provide system-level physical inertial response and local-level voltage support. Some technologies, like certain older types of inverter-connected photovoltaic and wind generators, have no or little inertial response or black-start capabilities, but still these can provide some active and reactive power and congestion management services under certain weather-related limitations. Currently certain types of demand response equipment react only to fixed rules, wholesale prices or weather. Energy storage can have limitations in the duration which the resource can deliver different kind of flexibility services. Some flexibility reacts instantaneously and for some resources an activation processes can take hours or days. All the differences above mean different capabilities and costs when different flexibility sources provide flexibility services. In cases of overlapping flexibility demands there might be reasons to prioritize needs. For example, in scarcity situations the severity of the situation and socioeconomical costs of a system-level black out are higher than a local outage and imbalance cost, and therefore TSO balancing should be prioritized over market party portfolio optimization or TSO-DSO congestion management (CEDEC et al. 2019). These system-level emergency situations are not part of this thesis. On the other hand, in the case there are flexibility needs in different activation directions for a resource and a portfolio optimization or balancing can be procured from another location without causing issues this should be preferred and local network operator given priority.

Equipment of power grids and network connected resources are controlled by complex set of directives, regulations, network codes, trading actions and various other measures that enforce system beneficial behavior to deliver electricity within the system. These can be categorized to rule, price and market-based signals and activations, explained in more detail in Chapter 3 together with corresponding products and mechanisms. Signal components that influence investment, operations and trading can be divided into four categories (Burger et al. 2019):

1. Energy price signal
2. Network use of system price signal
3. Ancillary services and capacity price signals
4. Subsidies and other policy and regulatory costs

Market signals and rules are a combination of these components. This thesis focuses on components one, two and three. Electricity markets are distinguishable from many other markets by three unique physical characteristics: time, location and flexibility (Biggar et al. 2014). These differences all relate to the fact that produced electricity is almost completely non-storable commodity and must continuously match system-level demand and local grid constraints. Previously market instruments have been mostly national or regional, but with the development of the internal electricity market international harmonization is taking place (Forsström et al. 2016). From the viewpoint of this thesis the most important European wide legislation, network codes and guidelines are (Nouicer & Meeus 2019; Schittekatte et al. 2019):

- Clean energy for all Europeans package (CEP),
- Capacity allocation and congestion management guideline (CACM GL),
- Electricity balancing guideline (EB GL),
- Electricity transmission system operation guideline (SO GL),
- Network Code on Demand Connection (DCC),
- Network Code on Requirements for Grid Connection of Generators (NC RfG).

Flexibility is a complex term which can be divided into technical, contractual and transactional aspects. Transactionally, flexibility means that there are sellers and buyers of flexibility in different types of markets or a party can acquire flexible assets to use them by itself. Physically users and buyers of flexibility are network operators which technically need flexibility for system level balance management or more locally for example voltage support or congestion management. Both physical operations and financial trading relationships require contracts to be in place to define roles and responsibilities.

In liberalized and deregulated power systems in Europe under the tasks of TSOs and DSOs include building, operating and maintaining transmission and distribution infrastructure for ensuring the long-term ability of the system with reasonable costs and as an integrated electricity undertaking manage and measure electricity flows on the system, while considering exchanges with other interconnected systems (EUR-Lex. 2019a). TSOs and DSOs must do this in close cooperation with neighboring SOs after results from electricity markets are available near delivery, but also in the longer term, ensuring the availability of all necessary ancillary services. IEM consists of different synchronous areas covered by synchronously interconnected TSO networks, which consist of one or more load-frequency control (LFC) areas operated by one or more TSOs fulfilling the obligations of balancing. LFC areas can be equal or consist of multiple scheduling areas. Scheduling areas link physical control areas to market based trading areas with bidding zones (BZ). To summarize each network component and network connected resource belongs to different kinds of system operation areas and a market area in which the trading of network use or allocation of network capacity takes place (Schittekatte et al. 2019). IEC 62325-451-3 standard distinguishes two alternatives for network capacity allocation: implicit and explicit allocation (IEC 2014). In explicit allocation capacity is not included and in implicit auctioning the available transmission capacity is included in market clearing of power exchange energy trading. Terms are later used also in other contexts to describe either integrated or separate processes in electrical markets. As a main rule in disintegrated electrical markets SOs do not participate to competitive markets, such as the production and sales of electricity. System operators utilizing generation or storage facilities as integrated network elements is limited in the CEP, therefore in this thesis is assumed that the use of NWAs is possible only via service contracts from market parties (EUR-Lex 2019a).

Market participant is a natural or legal person who buys, sells or generates electricity, who is engaged in aggregation or who is an operator of demand response or energy storage services (EUR-Lex 2019b). This is done through the placing of orders to trade, in one or more electricity markets. Balance responsible party (BRP) is a market participant or market participants chosen representative, responsible for its imbalances in the electricity market. Also, BRPs participate to the balance mechanism by utilizing and procuring flexibility to optimize their portfolios to minimize imbalance costs and by selling flexibility in different electricity markets. Such a market participant who provides either balancing energy or balancing capacity to TSOs is defined as balancing service provider (BSP) (EUR-Lex 2019a). Independent aggregator refers to an operator that combines flexible resources outside the conventional electricity delivery chain, in other words, an operator that is not the electricity supplier or balance responsible party related to these flexible resources (Pahkala et al. 2018). In more general terms, BRPs, BSPs and third-party aggregators can be together referred as flexibility service providers (FSP), which can offer a variety of flexibility services to different needs and users.

Among many other tasks national regulatory authorities (NRA) and Agency for the Cooperation of Energy Regulators (ACER) are responsible for the regulation of the natural monopolies of TSOs and DSOs and the monitoring of wholesale and retail electricity markets. Market operators or nominated electricity market operators (NEMO), certified by regulatory authority to organize cross-zonal electricity trade, provide a service whereby the offers to sell electricity are matched with offers to buy electricity. Market operators have a major role together with SOs, in the long-term and operational timeframe of power system management. Through the facilitation of competitive dispatching within and across bidding zone borders this service prices and balances generation and consumption, but also provides reference prices for financial and retail markets and price signals for example to install new generation or consumption assets. (EUR-Lex 2019b).

For in order to market results to be realized and networks operators to maintain the electricity system operational, many parties must do different market and remedial actions to provide ancillary services. Therefore, flexibility provides services to grids, system and markets (CEDEC et al. 2019). A set of remedial actions can consist of proactive and reactive actions. Preventive remedial actions in general are preventive operational planning processes that enable networks to cope with any possible single fault, so called N-1 criterion, based on forecasts or scheduled dispatches. Such actions can be topology changes, network capacity reallocation and redispatching or countertrading before network issues occur. Reactive actions are activated immediately or relatively soon after operational security limits are violated. Electricity Directive defines ancillary service as “a service necessary for the operation of a transmission or distribution system including balancing and non-frequency ancillary services but not congestion management”. Electricity Directive defines non-frequency ancillary service as “a service used by a transmission or distribution system operator for steady state voltage control, fast reactive current injections, inertia for local grid stability, short-circuit current, and black start capability and island operation capability. (EUR-Lex 2019a).

This thesis does not examine balancing as it is an established mechanism with already functional markets but examines balancing products and the balancing process to the extent it affects the use of flexibility products for the currently missing services. EB GL defines balancing as: “All actions and processes, on all timelines, through which TSOs ensure, in a continuous way, to maintain the system frequency within a predefined stability range” (EUR-Lex 2017). Two balancing approaches can be identified in the EU: reactive and proactive balancing. Håberg and Dooman (2016) summarize the differences between the two balance philosophies: “Reactive designs aim at providing strong incentives for market participants to reduce imbalances, thereby also reducing the need for balancing actions by the TSO. Proactive designs aim at efficiency through pooling of resources, early intervention, competition between products and centrally controlled price optimization through the TSO”. It can be said that reactive balancing attempts minimize balancing costs with lower balancing energy prices while reactive balancing attempts this by reducing the needed volume of balancing energy trades. Reactive balancing philosophy of TSOs relies strongly on the proactive participation of BRPs, BSPs and other FSPs to the maintenance of the system.

To balance electricity supply and demand at system-level and locally system operators must be able to manage electricity flows within the grid. This is known as dispatching (Elovaara & Haarla 2011). Power system dispatching can be based on self (SDM) or central-dispatching model (CDM). In Europe SDM is more common and is defined in EB GL as: “a scheduling and dispatching model where the generation schedules and consumption schedules as well as dispatching of power generating facilities and demand facilities are determined by the scheduling agents of those facilities” (EUR-Lex 2017). SDM can be further divided into unit based or portfolio-based dispatching. In portfolio-based self-dispatching the planning and dispatching of the entire resource portfolio is determined by the scheduling agents of those facilities, while in unit-based individual generation or demand facilities follow their own schedules. EB GL defines CDM as: “the generation schedules and consumption schedules as well as dispatching of power generating facilities and demand facilities, in reference to dispatchable facilities, are determined by a TSO within the integrated scheduling process” (EUR-Lex 2017). An integrated scheduling process means that balancing, reserve procurement and congestion management are done concurrently. This thesis refers to SDM as it is more in line with the European target model, unless explicitly stated otherwise. Resulting trade-offs between CDM and SDM and proactive and reactive designs are explained in the corresponding following chapters, when network operators and market parties must optimize scarce resources for portfolio-management, balancing, congestion management and non-frequency ancillary services.

Congestion is defined in the Electricity Regulation as: “a situation in which all requests from market participants to trade between network areas cannot be accommodated because they would significantly affect the physical flows on network elements which cannot accommodate those flows" (EUR-Lex 2019b). Congestions can exist on markets, physically or structurally (EUR-Lex 2019b). Market congestions are explained in Chapter 3.1. Physical congestions mean the breach thermal limits, voltage stability or the rotor angle stability as explained of network equipment as explained in Chapter 2. Physical congestions can happen due to market failures where there is insufficient capacity in relation to market nominations or due to outages and maintenance work. Because of the previous reasons and the in general due to the nature of electricity flows, physical congestions on grid elements can last only seconds or hours. In cases of continuous congestion situations, it can be discussed of structural congestions. Congestion management is tightly linked to energy markets, balance management and dispatching. In the short-term congestion management solves bottlenecks of scarce network capacity, which can be solved in the longer term with grid investments, bidding zone border reconfigurations or by other means (Fingrid 2019b).

Comparison of flexibility services for congestion management against reinforcements is obligated in CEP to DSOs serving more than 100 000 customers (EUR-Lex 2019a). In this thesis the management of congestion problems should provide correct economic signals to system operators and market participants and should be preferably based on open market mechanisms. Here congestion management is defined as any measure undertaken by system operators and regulatory authorities that aims at influencing power flows in accordance with operational security constraints within and across bidding zone borders in the operational and investment time scale. In this thesis countertrading (CT) is examined as a cross-zonal exchange where the locations of activated resources are not known within the bidding zone and redispatching (RD) as a cross-zonal exchange and all intra-zonal exchanges where the locations and parameters of the activated resources are known (EUR-Lex 2019b). In both countertrades and redispatching there should be another equally sized activation to the opposite direction within the bidding zone area, though this is assumed to be currently violated by many SOs. Figure 4 summarizes possible congestion management instruments.

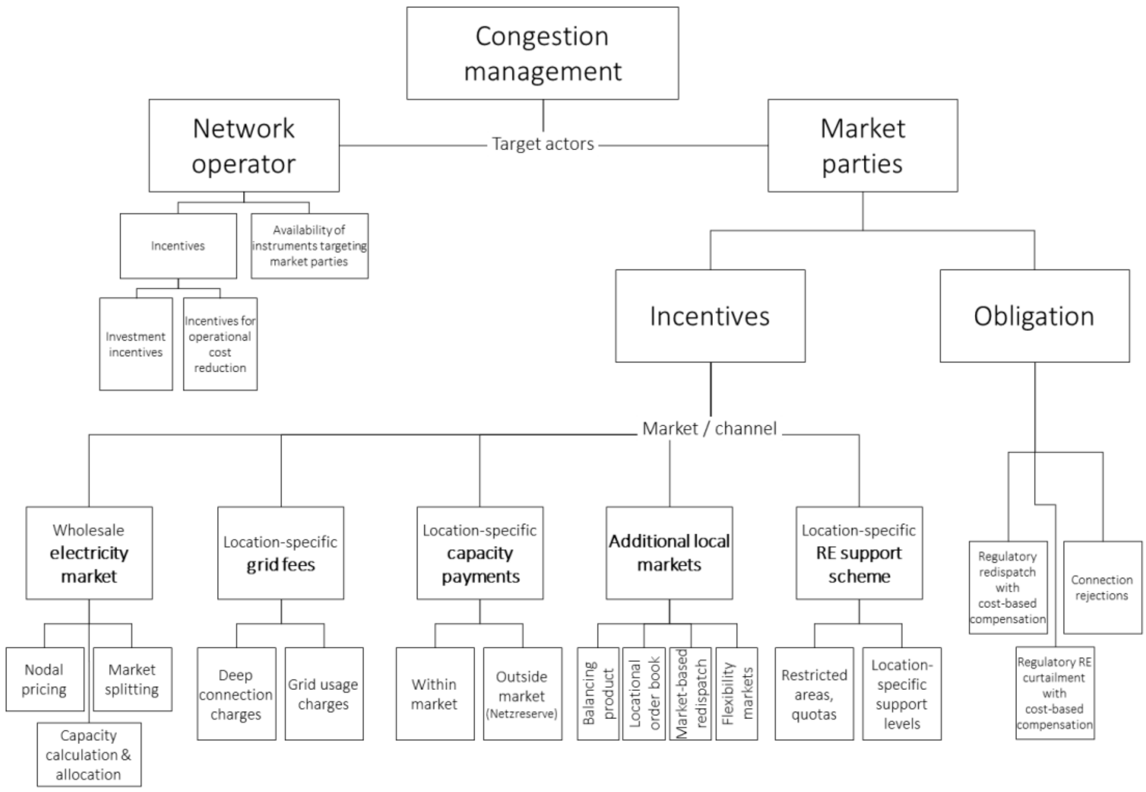

Figure 4: A structured list of congestion management instruments (Hirth & Glismann 2018).

3 Existing products in European electricity markets

This chapter elaborates the existing short-term product structures that will most likely be in place after 2023 in European electricity markets and their links to flexibility products. Subchapters 3.1-3.3 describe the existing short-term products and subchapter 3.4 summarizes the technical details related to these products and does a gap-analysis to identify missing products definitions. To limit the scope and provide concrete parameters, the examined products described here are currently or foreseen to be used in Finland, but whenever possible the described products are referenced to the corresponding European target model parameters or to the foreseen trends in the European electricity market area for year 2024 (Nouicer & Meeus 2019). It is assumed that all products parameters are subjected to be possibly updated before 2024.

There are thousands of different kinds of products and product-like concepts linked to European electricity markets. Definition of products and the differentiation of products, services, markets and other mechanisms related to liberalized power markets and electrical systems is complex. For example, Sys-Flex research identifies over 120 different kinds of products variations just in the current regulated electricity markets (Nolan et al. 2019). A product is an option that is purchased, delivered, settled and remunerated when called upon, and it is a central part of a specific market or mechanism (Nolan et al. 2019). Products are traded on markets to deliver services. Products are designed to incentivize regulated parties and market participants to invest, trade and control assets or commodities linked to the electricity system (Biggar et al. 2014). Here the entire electricity market and electricity system control is understood as the sum of different sub-markets and other non-market-based mechanisms, either related to the regulated or competitive domain. In terms of financial transactions, power balancing and energy flows, the majority of control in power systems is achieved with different kinds of electricity market mechanisms. These can be divided into liberalized and regulated markets. Liberalized markets, such as financial and wholesale markets, are much larger and allocate most of physical capacity in terms of energy delivered. Fine-tuning and other remaining control is achieved with regulated markets and mechanisms. Figure 5 illustrates these scales from a Nordic perspective.

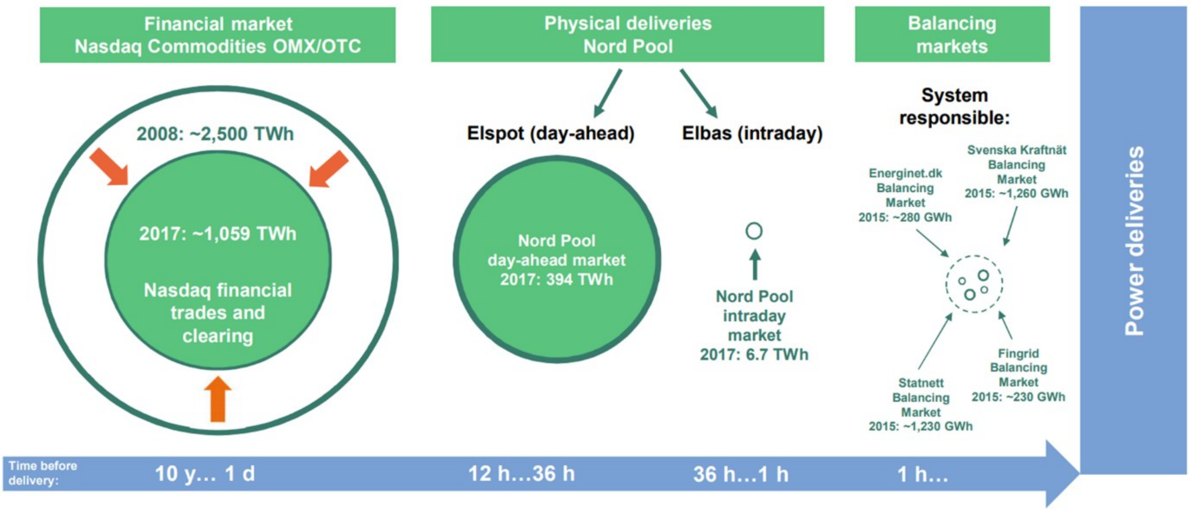

Figure 5: Electricity marketplaces in the Nordics 2017 (Aalto University 2019).

In liberalized markets market parties trade among selves whereas in regulated markets the counterparty is a regulated monopoly or monopolies. Other regulated control mechanisms can be further divided into price-based control, such as network tariffs, and to different rule-based mechanisms, such as network codes. Electrical system service is here defined as a physical action, which are needed to solve technical scarcities either at local or at system level as described in Chapter 2. Market service is here defined as a service that enables the functioning of markets, such as offer matching, that in turn enable electrical system services. To achieve market-based control, the market rules and tradable products must be functional, fair and harmonized. This compatibility applies to local and national markets, but due to international interconnectivity of networks, also larger scale market harmonization must be achieved to maintain control cost-efficiently.

Many existing products, such as products in day-ahead and intraday markets, have been extensively harmonized in Europe to achieve an internal energy market. In near future European compatibility of capacity and balancing products is expected to increase as, many cooperation -projects will be completed (ENTSO-E 2018b). Sufficiently standardized products and cross-process interoperability is addressed repeatedly in CEP and in many technical documents to avoid market-fragmentation, remove market entry-barriers and to increase competition in markets (CEDEC et al. 2019; Schittekatte et al. 2019). This must be remembered when defining flexibility products. Figure 6 illustrates the existing electricity market structures. This chapter focuses on products in short-term market groups 2-4 in Figure 6.

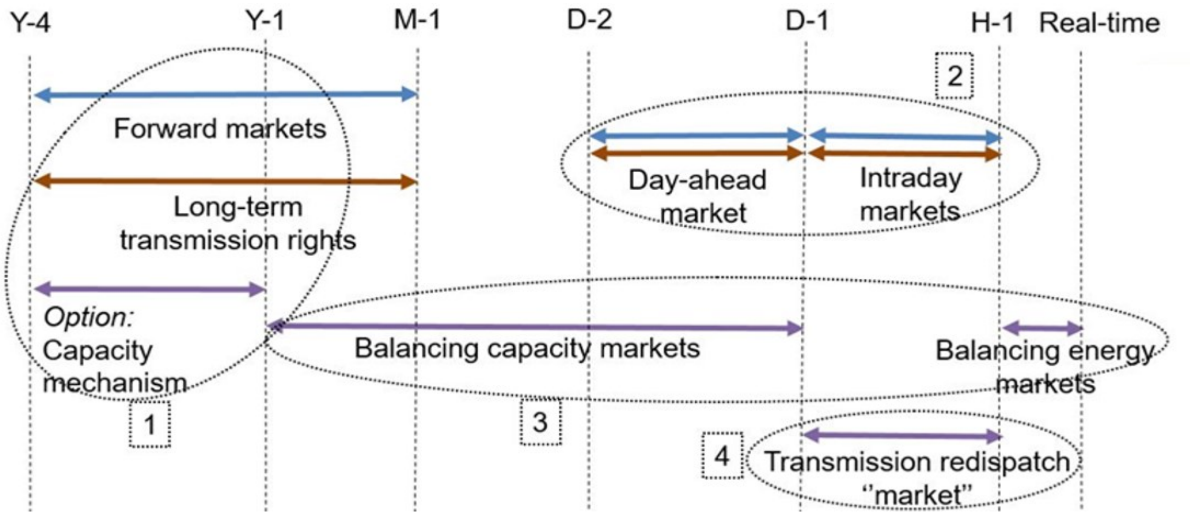

Figure 6: Electricity markets in EU (Nouicer & Meeus 2019).

3.1 Day-ahead and intraday markets

This subchapter explains the implications of the European target model regarding the wholesale electricity markets and the network capacity allocation process to flexibility markets. Day-ahead market (DAM) and Intraday market (IDM) are energy-only electricity markets (EOM). In energy-only markets market participants trade energy products in portions of megawatt hours (MWh) for delivered energy. EOM power trading takes place either on the power exchanges or in over the counter (OTC) trades based on bilateral commercial agreements. Due to single day-ahead coupling (SDAC) day-ahead markets is an integrated market within Europe where trading across bidding zone borders is possible. In intraday markets market participants can adjust their market position regarding foreseen changes in generation or consumption schedules. Single intraday coupling (SIDC) is less harmonized than SDAC, though this changed significantly in year 2018 when a joint initiative cross-border intraday market (XBID) was established. In some areas IDMs are designed with multiple intraday auctions, continuous trading or a hybrid combination of both (ACER 2019). In wholesale markets the offer formats and temporal resolutions, differ as this is highly depended of the imbalance settlement period (ISP), balancing and imbalance settlement mechanisms in place. Especially merchant market operators have the incentive to cooperate and develop trading products in close cooperation with the industry as they can recuperate costs from TSOs and because this increases trade volumes, which is a major income source of these platform owners (Schittekatte et al. 2019). Regarding new flexibility products, the most essential offer concepts of existing wholesale markets are explained next. A non-exhaustive list of currently SDAC (Nemo Committee 2019) and SDIC (Nord Pool 2018) compatible products types are:

- Day-ahead products (SDAC):
    - Aggregated Orders
    - Complex Orders
        - Minimum Income Condition (MIC) orders
        - Load Gradient orders
    - Block Orders
        - Linked Block Orders
        - Exclusive Groups of Block Orders
        - Flexible Hourly Orders
    - Merit Orders and PUN Orders.
- Intraday products (SIDC):
    - Regular predefined
    - Regular user defined block
    - Iceberg
    - Basket Orders

The simplest product type in auctions is aggregated orders where parties can offer to buy or to sell a certain amount of energy at a certain price. Different types of orders from market participants belonging to the same bidding zone will be aggregated into a single curve referred to as aggregated demand or supply curve. This is defined for each market time unit of the day. Demand orders are sorted from the highest price to the lowest and supply orders from the lowest price to the highest. The intersection of these two curves defines the market clearing price. Supply offers lower and demand offers higher than the clearing price are defined as in-the-money and are selected. Offers equal to the clearing price are defined as at-the-money and can be either rejected or accepted partially or fully. Remaining offers are defined as out-of-the-money and are fully rejected. (Nemo Committee 2019).

Block offers are more complex multiples of standard products. Block orders are defined by supply or demand sense, price limits, number of periods, volume that can be different for every period and with minimum acceptance ratio parameters. Acceptance ratio can be defined as how divisible each offer and the group of offers is. Market parties can create structures where, for instance, bid B is selectable if bid A is selected through linked block orders. With exclusive groups of block orders market parties can create bids where acceptance ratio limits of individual bids must be followed, and the sum of the selected offers accepted ratios will not exceed one (Nemo Committee 2019). This can mean that for example both bids A and B must be fully selected. Block bids can be used to create structures where non-convex costs of flexibility are included in the parent block and child blocks are then capable of bidding at marginal opportunity costs for a market time unit (MTU) or for the following MTUs. A buy offer (bid) and sell offer (ask) are cleared if another party is willing to trade for that price and quantity, either fully or partly. An ask is equivalent to the market party having a position where it would generate more electricity or consume less and a bid to an opposite position. The block and complex products described above must exist alongside simple sell and buy orders due to the different flexibility capabilities of different resources and technologies described in Chapter 2. These conditional parameters can include the different non-convex cost, such as start-up cost, ramp-rates and minimum run levels, of physical resources to the market processes. These conditional products must be in place in future electricity and flexibility markets to enable market-based dispatching of flexibility while respecting physical limitations of resources (Forsström et al. 2016).

In day-ahead and intraday markets market parties place bids according to pre-defined bidding zones and price convergence between areas is defined by the available transmission capacity between zones. From a market perspective, the physical network capacity within a bidding zone is considered as infinite, however this is not always the case, as discussed in Chapter 3.3. Due to these internal congestions and other historical reasons, both unit- and portfolio-based bidding and dispatch are in place in different European bidding zones, as seen in Figure 7.

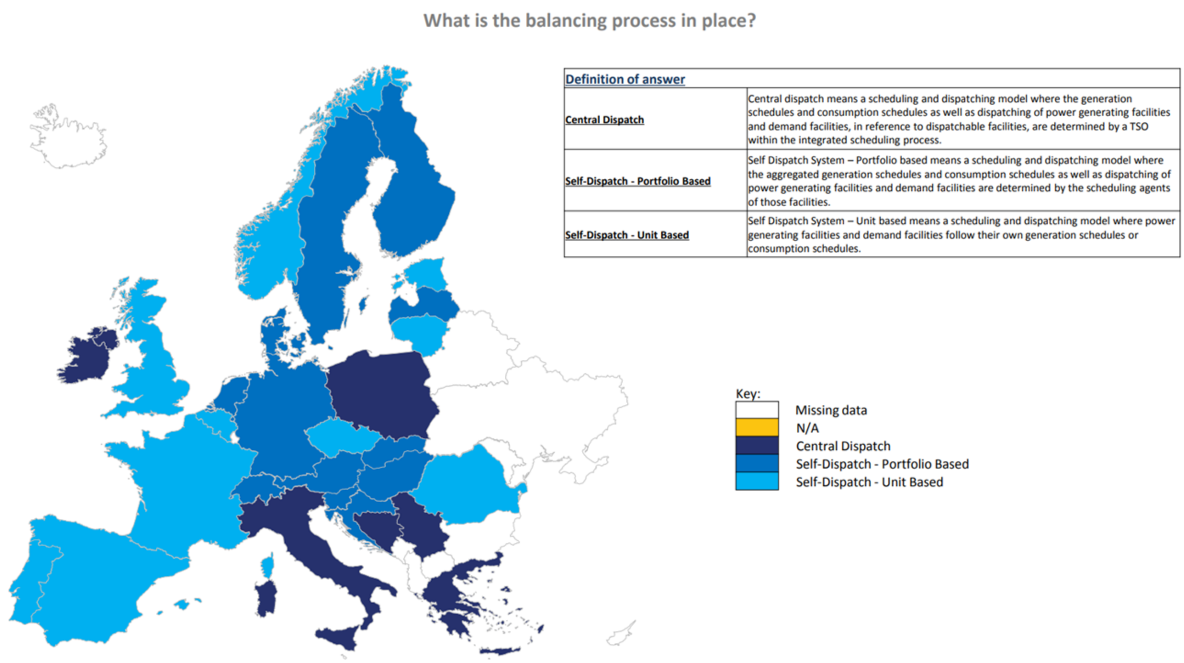

Figure 7: Balancing processes in European electricity systems 2017 (ENTSO-E 2018c).

Apart from to allow self-dispatch there is no clear European target model whether self-dispatch in the bidding process of wholesale markets or during dispatch should be unit- or portfolio-based (Nouicer & Meeus 2019). Majority of the European area is part of SDAC with implicit capacity allocation. In IDMs cross-border capacity allocation has both implicit and explicit types. Due to the need for a single methodology for pricing of intraday cross-zonal capacity (IDCZCP) ACER (2019) decided to move towards a combination of continuous intraday trading and three intraday auctions. This will impact flexibility market trading. Intraday capacity allocation is done after remaining capacity from DAM auctions is available and the remedial actions of system operators caused by infeasible market nominations or other network constraints are known. There is possibility to limit a maximum of 30% cross-border transmission capacity either due to TSO or DSO intra-zonal needs for cross-zonal balancing, intra-zonal congestion management or for other network management purposes (EUR-Lex 2019b). Such capacity reduction is here considered favorable if it is necessary due to the security of transmission or it can be shown to decrease the overall costs of balancing or congestion management more than the capacity limitation causes net societal costs from wholesale markets, here understood as an attempt to maximize social welfare based on European-wide market area (Korhonen 2018). If nominations in the zonal wholesale markets with implicit auctions cause market congestions, due to capacity limits, the two price zones split. This is different to continuous trading in IDM where the capacity is allocated explicitly or for free on first come first served basis (Schittekatte et al. 2019). The definition of price for each area is then based on the local nominations plus the maximum amount the region is capable to import or export when taking congestions into account. The price difference of areas times the commercial flow is defined as congestion rent and is allocated to the parties responsible for the transmission over the congested border (Fingrid 2019b). Here described cross-zonal practices and economic principles are applied in later described intra-zonal flexibility market areas, when network capacity allocation reductions and congestion management are discussed.

DAM has a gate opening time (GOT) latest at 11:00 central European time (CET) day before delivery (D-1) and a gate closure time (GCT) at noon D-1. DAM is based on double-side blind implicit auction where hourly supply and demand offers are traded. Both in DAM and IDM auctions marginal pricing is in place, but in continuous IDMs pay-as-bid pricing is in place. In continuous intraday trading trades are realized if a placed order is matched. In Europe the intraday gate opening time (IDGOT) and intraday gate closure time (IDGCT) are LFC area specific. When trading cross-market areas the intraday cross-zonal gate opening time (IDCZGOT) is often later than IDGOT and intraday cross-zonal gate closure time (IDCZGCT) is often earlier than IDGCT. To increase the possibility of wholesale trading, many areas will have IDGCT near the start of delivery. This can be later than foreseen balancing energy market gate closure time (BEGCT). Details above can be challenging for flexibility markets and mechanisms depending on preventive actions, as explained in later chapters (ENTSO-E 2018d).

To understand the implications of wholesale markets to flexibility markets also the European target model regarding balancing and imbalance settlement must be jointly examined. This is because near real-time markets described in chapters 3.2-3.3 affect the behavior of grid users in the wholesale and retail markets and vice versa. Also, behavior outside DAM and IDM trading can affect networks, if for example a market party decides to differ from the market position or unit schedule by reducing or increasing network use to minimize costs or gain revenue from imbalance settlement. This behavior is here defined as self-balancing, which is either explicit or implicit behavior of network users to intentionally change their consumption or generation regardless of market nominations and other plans (Håberg & Doorman 2016).

Imbalance settlement allocates occurred balancing costs to the parties responsible for the imbalance. Imbalances are calculated per imbalance settlement period in the imbalance area in question, as the difference between the final position and allocated volume of the balance responsible party. The position of BRPs is linked to nominations in financial markets, OTC trades, DAM and IDM as well possible imbalance adjustments from balancing markets. In the future also flexibility market trades must be considered as well. Allocated volume refers to the measured or estimated grid usage, which is delivered by system operators from each metering grid area (MGA) where the BRP is active. In the Nordic imbalance settlement model, this reporting window is 13 days after delivery day (eSett 2019). After intraday markets, market parties cannot anymore correct their position, excluding possible balancing, bilateral and flexibility market trades, unless there are aftermarkets for imbalance trading after the start of delivery.

Depending on operational agreement of the control area, BRPs can also be responsible to report either indicative or binding production and/or consumption plans per unit for the relevant system operator. Other changes described in CEP and EB GL oblige electrical markets move towards 15-minute wholesale products, 15-minute ISP, supports to abandon separate balances for generation and consumption and prefers to move to a single price model for imbalance settlement (Nouicer & Meeus 2019; EUR-Lex 2017). The above described changes are relevant to flexibility markets since these markets provide references and prices to monitor flexibility delivery in relation to some position. Also, to define a holistic product structure, the trading window and products of flexibility markets must be compatible with wholesale and regulated markets and vice versa.

3.2 Balancing mechanism

This part examines the relation of balancing mechanism products to other flexibility needs. Balancing mechanism ensures power supply matches demand at system-level in real-time. Balancing mechanism consists of balancing markets and reserve markets, but also of other mechanisms described in chapters 3.1 and 3.3. Figure 8 illustrates the balancing process where different reserves are activated for different purposes as ancillary service for frequency control.

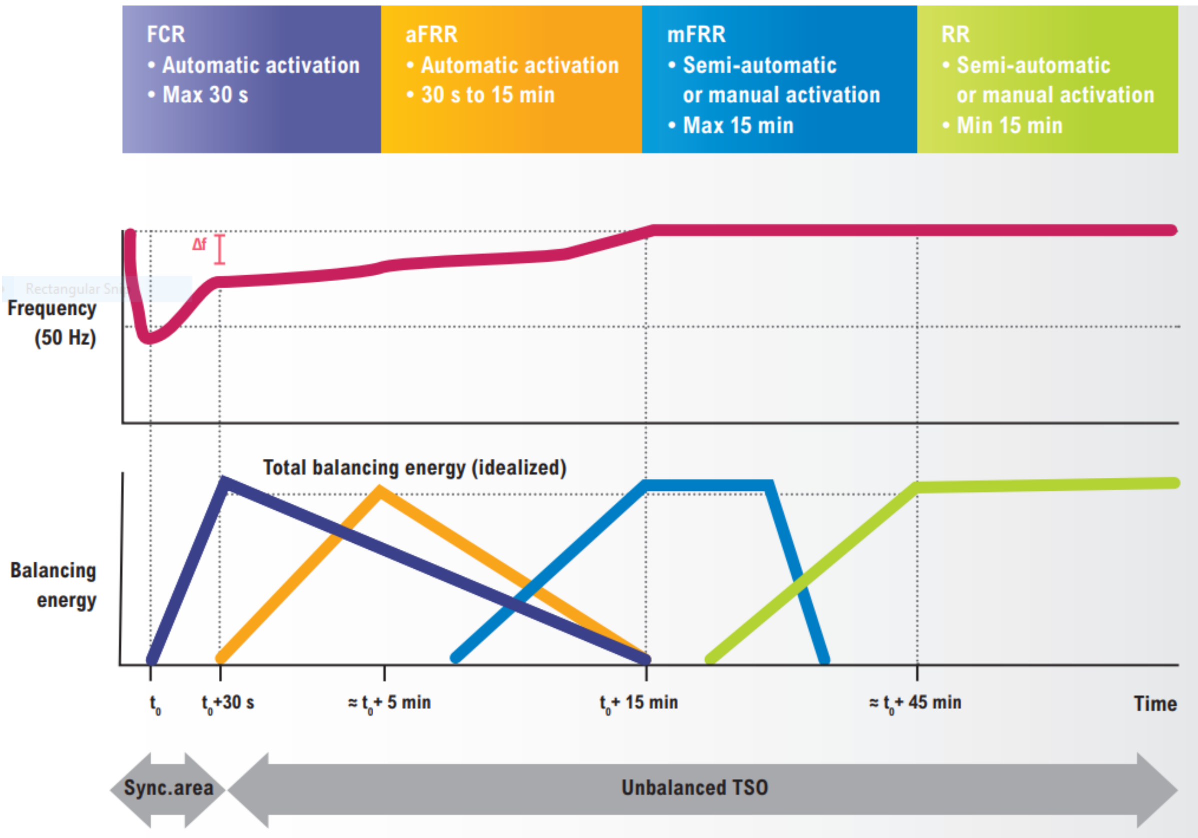

Figure 8: Balancing mechanism for frequency control (ENTSO-E 2018e).

3.2.1 Balancing markets

Balancing markets consist of balancing capacity and balancing energy markets. Balancing mechanism of the responsible TSO corrects the occurred imbalances during the operational time unit with self-balancing from market parties and reserve and balancing energy market offers from FSPs. Imbalances occur due to behavioral and weather-related forecasting errors of BRPs and due to disturbances, both in networks and in network connected equipment (Håberg & Doorman 2016).

Unlike the European common SDAC and SIDC, balancing markets are in most cases are nationally or regionally defined. Due to the energy transition examined in Chapter 1 and increasing interconnectivity of European electricity networks, also these markets are being harmonized (ENTSO-E 2018b, d). SO GL enforces the further harmonization of reserve categories, the sizing guidelines of reserves and the activation strategy for balancing energy in real-time. EB GL focuses on the product design of balancing markets and imbalance pricing (Schittekatte et al. 2019). Here the future balancing mechanism of the Baltic Sea area is studied from the viewpoint of the foreseen Nordic synchronous area control and European balancing markets after 2023. Future Nordic balancing model is referred here as modern area control error (ACE) control. ACE is derived by comparing measured flows on LFC area borders against planned flows corrected with activated primary reserves and balancing contracts. In modern ACE control balance is achieved for each LFC area, while allowing cross area balancing trading and imbalance netting. Bids to the balancing energy markets are first organized in local merit order list (LMOL) and then forwarded to combine the common merit order list (CMOL) (ENTSO-E 2018d). Activations of each LFC area are based on local control loops that are at system-level controlled by a common activation optimization function (AOF). AOF function results are realized with LFC controllers, which provide automatic setpoint or manual dispatch orders to activate resources accordingly. The setpoint or activation signal that the BSPs receive comes from TSOs, which results in activations corresponding to the need and the merit order of the usable bids. These balancing actions restore the system frequency and progressively return the activated primary reserves, while considering cross LFC area balancing and possible grid constraints. (ENTSO-E 2019b).

The possibility to reserve shares of transmission capacity from wholesale markets for balancing, congestion management or other purposes is not examined here further, but simply regarded as a possible option if it would create socioeconomical net benefits. If an offer activation itself would cause issues to power networks or if there is a need to reserve capacity for N-1-dimensioning, system operators have a chance to mark balancing bids unavailable during the formation of the MOL or during real-time. It is here assumed that in the future this unavailability marking is done by TSO as currently, but also by DSOs. The differences of TSO and DSO grid voltage levels, network connected resources and the capability of TSOs and DSOs to assess the need to red-flag bids differ between and within countries. Unnecessary unavailability marking and other discrimination is here assumed to be avoided at all costs, but the described actions require national and international multilateral coordination that does not exist in Europe at the moment (Håberg et al. 2019). Also, as discussed in later chapters, it is here assumed that in the future, SOs can have the possibility to manually activate contradictory bids from balancing energy markets differing from the price order or the balancing direction (Hadush & Meeus 2018). This can be done with the preconditions that firstly there is a local flexibility need and secondly that the costs are separated from balancing and allocated to correct parties. (ENTSO-E 2018d).

Responsible TSO organizes balancing markets and is the single buyer of the of services. Balancing energy market consists of three types of reserve products: automatic frequency restoration reserve (aFRR), manual frequency restoration reserve (mFRR) and restoration reserve (RR) (EUR-Lex 2017). Especially, product parameters of RR or mFRR with special products, such as long or fast activations, are interesting for local flexibility needs, as discussed in later chapters. Still, RR is not further examined here, since it's not foreseen to be implemented in the Nordic Balancing Model (NBM) and is interpreted here as an overlapping product with mFRR (ENTSO-E 2018f; ENTSO-E 2019b). The role of frequency restoration reserve (FRR) energy markets is to return the frequency to its normal range and to release activated frequency containment reserves (FCR). The role of balancing capacity markets is to be a premarket to ensure enough capacity in corresponding balancing energy markets. This thesis assumes that future balancing in the European area will be done with separate capacity and balancing energy markets consisting of aFRR and mFRR standard balancing products and possible other special products (ENTSO-E 2018g). Participation to regional balancing capacity markets or pan-European balancing energy markets will be done with offer submissions to the regional TSO, which then transfers the bids to the common markets. Here FCR refers to primary, aFRR to secondary and mFRR and RR to tertiary control of frequency. This order means that after aFRR has relieved activated FCR capacity, mFRR bids are used to release aFRR capacity.

The development project of the common aFRR-platform, called PICASSO, will enable a European platform for the exchange of aFRR balancing energy (ENTSO-E 2018b). The location of a aFRR bid resource or aggregated portfolio must be included in the bid in the level of the LFC area. Portfolio bidding per LFC area is allowed also in the foreseen aFRR and mFRR balancing capacity markets, meaning that local flexibility selections from capacity markets are challenging without modifications (ENTSO-E 2018g). This thesis assumes that due to the nature of the aFRR activation, this product will not be used for ancillary services other than balancing and is not assessed further as a flexibility product. The development project of the common mFRR-platform, called MARI, will enable a European platform for the exchange of mFRR balancing energy (ENTSO-E 2018d). The activation of mFRR products can be either direct (mFRRda) or scheduled activated (mFRRsa). Firstly, mFRRsa or mFRRda can be used for preventive balancing when a distinct and foreseen need occurs before delivery. This proactive balancing aims to keep the forecasted ACE within the limits that FCR and aFRR reserves are sized for. Secondly, when mFRR is used for reactive balancing the role of mFRR is here defined to provide tertiary frequency control. (ENTSO-E 2018e.)

Due to the nature of the mFRR standard product and the non-convexities of resources participating in the market, the design of the mFRR AOF must avoid technically or economically unfeasible selections. This means that the algorithm must be able to avoid linked bid activations where the underlying asset is not physically capable to deliver due to the maximum power feasible or the ramp-rate required. Economical linking means considering financial limitations, similar to block and complex bids in wholesale markets, described in Chapter 3.1 It should be noted, that the mFRR AOF does not perform optimization over multiple market time units. Therefore, according to current knowledge, economic linking with block offers forward in time will not be allowed, but it remains to be seen that will economic linking backward in time be allowed. This will mean that there is no certainty that manual balancing energy activations will be longer than a single market time unit of fifteen minutes. (ENTSO-E 2018d.)

Balancing energy markets result in product-specific marginal prices and thus the current imbalance pricing in Nordics, dependent on existing mFRR products, must be revisited (ENTSO-E 2018g). Also, the activation logic of FRR and some FCR resources can have a noticeable effect on the imbalance of the BRP in question. Currently in the Nordic system these reserve resources and aggregated bids are linked to a specific BRP and thus considered also in the imbalance settlement. Implementation of independent aggregator models where resources from different BRP balances are aggregated together to participate to reserve, balancing markets and or other flexibility markets, require rules, transactions, imbalance adjustment processing and information exchange between different parties that does not exist or are not harmonized (Pahkala et al. 2018). The relevance of aggregators, independent aggregators and other FSP roles is assumed to be increasing in future when smaller and smaller resources are participating to system level markets, such as balancing markets, and localized flexibility markets.

3.2.2 Reserve markets

In this subchapter reserve markets of TSOs are examined from the viewpoint of Finland. Primary frequency control is achieved at the synchronous area level with physical inertial response of network connected resources, such as rotating masses of power-plants, reserve markets and SO resources. Reserve markets are designed to balance power deviations and maintain frequency to an acceptable limit. When the frequency of the synchronous area differs from 50Hz more than the dead band, the procured FCR or Fast Frequency Reserve (FFR) reserves activate with self-dispatch (Fingrid 2019c; Modig et al. 2019). Activation of FCR or FFR is done by the prequalified and selected resources, with a local measurement of frequency. FCR for normal operation (FCR-N) is a symmetrical product which is activated with a delay of a couple of minutes if frequency deviates within the normal frequency range of 49.9 - 50.1 Hz. Currently FCR for disturbance (FCR-D) is procured only for upward regulation to contain frequency above 49.5 Hz when FCR-N is not enough to contain frequency above 49.9 Hz. For FFR and FCR-D product there are different activation rules for different types of resources and how much the frequency has deviated. This thesis assumes that regardless of 15-minute imbalance settlement period and other market changes, the FCR and FFR markets will have a market time unit of one hour in 2024, but other parameters can be changed.

The maintenance of these reserves in the Nordic synchronous area is agreed together by Nordic TSOs. For example, the share of Fingrid of the Nordic FCR resources is procured in Finland from the domestic yearly and hourly markets, the Russian interconnector and Estonian High-voltage direct current (HVDC) links and other Nordic countries. FCR yearly markets ensure capacity and increase market liquidity, which is complemented with FCR hourly market offers. FFR will be a new market hourly market from 2020 onwards. It is established to maintain sufficient inertia in the Nordic synchronous area in case of an N-1 condition of critical network elements (CNE), such as large power plants or major interconnectors disconnecting. FFR is planned to be jointly procurable with FCR-D (Modig et al. 2019). The sizing and trading of these reserve products is not examined in further detail, as these are already established system-level products. Still, reserve products are relevant to be monitored in relation to flexibility products. Firstly, this is since FCR markets can provide an interesting market for flexible capacity and thus reduce the availability of these resources for local purposes on flexibility markets. Secondly, if in the future flexibility markets can or must be cross-process linked to reserve markets. Thirdly, if for example FCR capacity would not able to be activated due to a disturbance, voltage deviation or a congestion. (Fingrid 2019b)

3.3 Transmission and distribution network management

This subchapter describes the concepts related to electricity markets and power system management that chapters 3.1-3.2 did not dealt with. Terminology and definitions are related to Finland but can be applicable and valuable for other environments as well. Subchapter 3.3.1 defines the current service of congestion management and 3.3.2 explains non-frequency ancillary and other services, such as and local transmission management, grid maintenance and reinforcement planning.

3.3.1 Congestion management

Here is described how congestion management is done currently in TSO networks. As described in chapters 1 and 2, there are numerous alternatives how system operators manage congestions in the long and operational terms at the moment and that the need for commonly defined congestion management products and practices is growing due increasing technical difficulties and costs. As an example, currently many TSOs solve congestions by unit-based dispatching, redispatching or countertrading generation or loads with for example hourly balancing energy mFRR-bids or other bilateral trades (ENTSO-E 2018c). This practice must be revisited, as self-dispatching is promoted, and new common balancing energy markets are being established. Also, DSOs are not part of this process. For example, congestion management activations longer than fifteen minutes are challenging due to the short market time unit and bid linking details as described in Chapter 3.2.1. The possibility to do congestion management with other options are described in Chapter 4 as emerging solutions. Congestion management activations solve cross-border and intra-zonal violations of network capacity constraints which cross-border capacity allocation failed to solve (USEF 2018a).

Finland and TSO redispatching is now presented as an example of congestion management. In Finland BSPs currently indicate in their mFRR-bids the location of the underlying resources inside the "transmission area", although Finland is a single regulation area. Currently this means a division into north and south transmission areas, which are divided by the latitude 64º. These balancing bids are then sometimes used to solve congestions either on borders of the bidding zone or within the regulation area with redispatching and countertrades. If a balancing bid is used for congestion management, it is not considered in the balance or imbalance pricing and the system operator requesting the activations bears these costs. This cost-reflective allocation principle is the precondition of all congestion management and other flexibility solutions presented this thesis. Congestion management bids are settled at the balance price or as pay-as-bid if the offer is more expensive. (Fingrid 2019b.)

The process of congestion management mechanisms in general is described in Figure 9. As illustrated in the first phase, a product definition is needed for to network operators trade for congestion management services. Currently in the above described example model, the product definition and main motivation bid for congestion management is due to BSPs bidding for the balancing market instead of congestion management. The possibility of combining balancing and congestion management processes also combining DSO congestion management with TSO congestion management is being discussed among network operators (CEDEC et al. 2019). Historically DSO have solved congestions with bilateral contracts or there have been little congestions in DSO networks. According to phenomena presented in Chapter 1 the energy transition will impact all grid levels and DSOs must also procure flexibility for congestion management. Currently DSOs are not able to use TSO balancing energy market offers for congestion management and the foreseen 1 MW minimum bid size on the can be still too large for low-voltage networks (ENTSO-E 2018d). The motivation to combine TSO-DSO congestion management and balancing comes from possibility to avoid unnecessary market fragmentation (CEDEC et al. 2019). These combinations are listed in detail in Appendix 1, which shows three alternatives for balancing and congestion management markets and processes of grid operators:

- Option 1: Separated TSO and DSO congestion management.
- Option 2: Combined TSO and DSO congestion management, with separated balancing.
- Option 3: Combined balancing and congestion management, for all system operators.

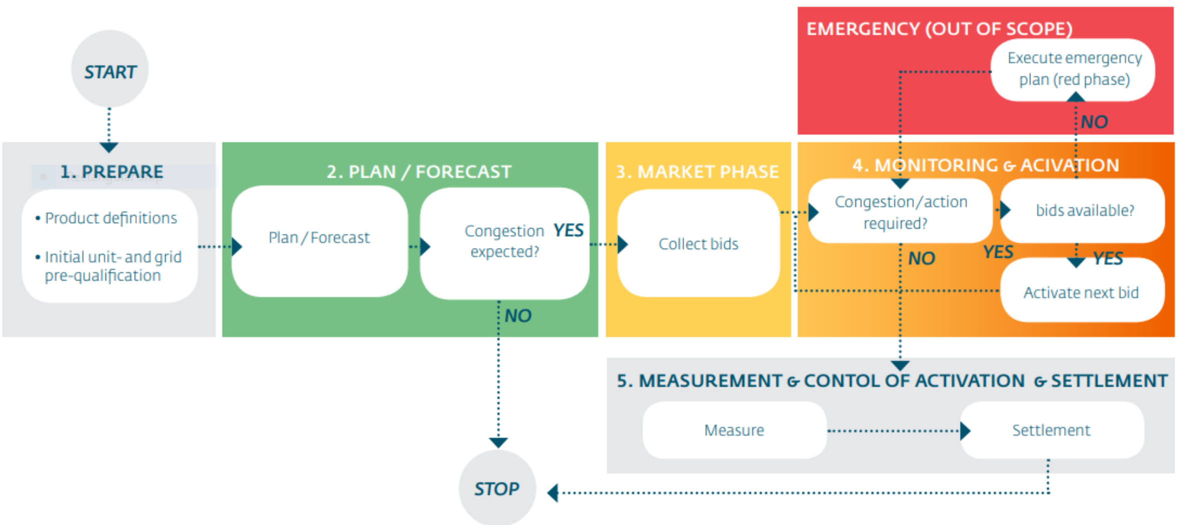

Figure 9: Congestion management processes (CEDEC et al. 2019).

Here preventive congestion management is defined as system operators activating congestion management bids based on a forecast, before the congestion has occurred. Reactive congestion management is here defined as system operators activating bids when the congestion is already active in a network element. Like preventive balancing with mFRRsa-product, preventive congestion management forecasting and settlement can be based on generation or consumption plans from market parties and other information such as weather data. It is important to notice that the availability and accuracy of these plans from network users might be questionable in the future, due to volatile loads or generation, near real-time trading, self-balancing and lack of motivation. Complementary to portfolio-based bidding and the possibility to aggregate imbalances over the portfolio, there can be an obligation for BRPs to deliver generation or consumption plans at unit-level. The motivation for BRPs to deliver accurate plans is dependent of the bidding-, dispatch and imbalance settlement model of different markets. It is here argued that if system operators allow portfolio-based self-balancing in a single price and single position imbalance model, the relevance and motivation to give accurate unit-based plans is reduced. This results from the situation, where BRPs are not financially responsible for the accuracy, as the imbalance settlement mechanism will not require schedules. The motivation of SOs to additionally incentivize market parties to forecast and deliver true private schedules at unit-level is here left open, though there are needs to use these plans during congestion management and other operational planning processes, as explained in following chapters.

SO GL considers that the operation of the mFRR energy market should avoid activations that itself cause congestions to DSO or TSO: "Each reserve-connecting DSO and each intermediate DSO, in cooperation with the TSO, shall have the right to set limits to or exclude the delivery of active power reserves located in the distribution system during the prequalification process. Each reserve-connecting DSO and each intermediate DSO can set temporary limits to the delivery of active power reserves before their activation. Procedures need to be agreed upon with the respective TSO" (EUR-Lex 2017). This right of TSOs and DSOs limiting certain offers partially or certain resources completely to participate, is here considered to be allowed when it is due to physical limitations in the network. Therefore, here described congestion management products and balancing in general should include a TSO-DSO coordination mechanism for enabling the marking of bids unavailable in the LMOL-process or during real-time from the CMOL. These assumptions are compatible with mFRR explanatory document, where it is stated, that TSOs can request to have a bid resource location defined for a LFC area or a more detailed geographical location. This location data is needed for the unavailability process described above (ENTSO-E 2018d). Here is also assumed, that if there is a SO need and it is societally beneficially to do redispatching or countertrades with location specific balancing offers this should be enabled. This is regardless of the fact, that this suitable offer might not be the cheapest in the MOL or in the wrong direction in relation to balancing need.

Reasonability of historical congestion management costs and technical suitability of the above described congestion management model of Fingrid is here simply assumed to have been sufficient, but not a precondition of future results. Congestion management activations from TSO balancing markets should be revisited because:

- the current locational signals are not sufficiently detailed and are static,
- standardization is lacking,
- common European balancing energy markets will be launched,
- DSOs are not able coordinate,
- the transparency is limited,
- the introduction of single price and single position imbalance model,
- to account for other challenges in the future.

3.3.2 Non-frequency ancillary and other networks services

This subchapter examines voltage and reactive power control, network maintenance and reinforcements that TSOs and DSOs are doing as a service to network users. Currently these services are procured and implemented either by the SO investing, procurement from market parties or via grid connection agreement and grid tariffs (Glismann & Nobel 2017). Remaining ancillary services and transmission management options such as grid topology reconfigurations, harmonics filtering, scarcity reserves and black start are not examined (EUR-Lex 2019b). As the services considered here are related to designated task of regulated networks, all services here should follow the main principles of sustainability, economic efficiency, non-discrimination or fairness, additivity, and transparency (Similä et al. 2011).

Cost related to grid connection contracts and utilization payments of TSOs and DSOs, vary significantly in Europe and within countries. Also, the definitions of cost components and cost allocation principles between parameters vary. Here is assumed that system operators have an obligation to connect all interested parties to a network, but they can impact on the conditions of the connection. When a new network user wants to connect to the network the corresponding system operator can define the timeline, location, costs and technical details of the connection while respecting the main principles. The cost components vary mainly due to the maximum size of the connection, voltage level in question and location in relation to the network. When a network operator takes care of the grid reinforcement costs related to the connection this is considered as a shallow connection cost. If on the other hand if the new network users must pay for the connection equipment and grid reinforcements this is considered as a deep connection cost. Due to the complexity of electrical networks and behavior of grid users it is impossible to allocate all or none of the reinforcement costs to a network user. Therefore, all connections vary in between deep and shallow costs (Similä et al. 2011). As stated in Chapter 1, reinforcement planning must be predictive and long-term since the lifetime of network components is often multiple decades and infrastructure projects can be slow to complete.

An important technical point related to connections and flexibility products, is the possibility of SOs limiting network use. Because of congestions and lack of supply due to high network use, maintenance work or outages, SOs can be interested to include the option of curtailment in connection contracts and network service agreements. This option can be obligatory or voluntary and paid or not remunerated by the SO in question. These practices vary significantly can vary even within a network area. For example, a successful connection agreement into weak network segment could have an option for the SO to curtail peak network usage until reinforcements are completed. The alternative of this is that connections are not completed, or delivery is curtailed anyway. Some customers can be more adjusted to be curtailed or completely cut out of supply than others. Reinforcing networks to account for all peak network use cases or to avoid outages in network areas with low consumption per line segment is expensive. NWAs, such as electrical storages, near the connection of the customer, can in specific cases deliver the necessary power during outages and peak use to reduce the need to invest or to curtail. These practices are either not in place or have not been harmonized. The motivation for network users is to be paid for these kinds of flexibility service directly or with reduced connection contract and grid tariff fees. (Similä et al. 2011; Schittekatte et al. 2018).

Reinforcement deferral is here defined as SOs purchasing a service from resource owner, rather than investing into grid reinforcements. The motivation is to avoid an investment into transmission capacity upgrades altogether or defer an investment into a future. The motivation for the former can be cheaper total costs, insufficient capability to complete a reinforcement in time or clarification of the need. For example, there might be significant uncertainty whether an area will have higher or lower network use in the future and therefore it might be best to wait for the forecasts to improve. If a SO could procure NWAs for to be available during peak hours, there might be reduced need to reinforce. The reference price for this service is lifetime costs related to the discounted investment costs, which can be calculated by the corresponding SO or the regulator. Figure 10 shows this graphically in years, but does not include physical and financial risks related to the decission to defer investments.

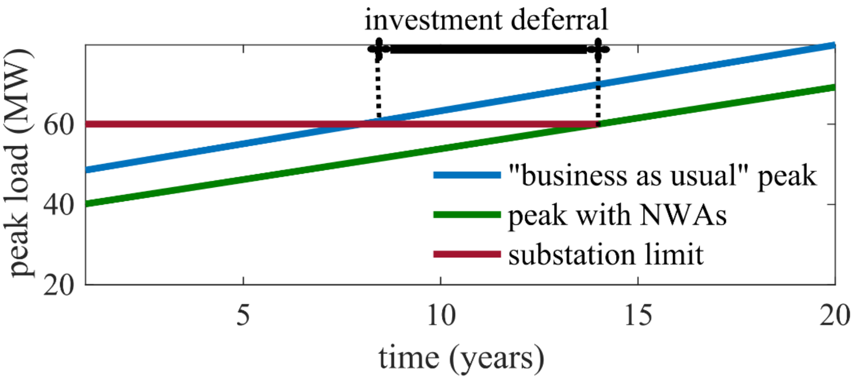

Figure 10: Reinforcement deferral (Contreras-Ocaña et al. 2018).

Grid tariffs are in place so that TSOs and DSOs can cover the operational expenses related to electricity transmission. Tariffs are often different for generation and consumption connections, but due to the emergence of energy storage and distributed generation this assumption is less valid anymore. Also, with the help of these new technologies, both energy and capacity measured network use can be changed and optimized by the network users. Grid tariffs can have cost components such as: volumetric energy (€/Wh), volumetric reactive energy (€/Varh), maximum size of the connection (€/W), power capacity (€/W), reactive capacity (€/kVAr) and other fixed fees (e.g. €/month) (Similä et al. 2011). These costs can vary periodically and are based on the network area of the connection. For similar connected users within a network area these costs parameters are equal, regardless of the location. Also, accuracy of SO invoicing varies significantly in Europe, since there is little European harmonization regarding metering and tariffs. Tariff design has a major impact on all other flexibility products and must be considered in the design process. By increasing cost-reflectiveness or price-responsiveness in tariffs, SOs can also procure explicit grid services from network users. The remuneration of these activations, such as congestion management, can be netted in the grid service invoicing or paid separately. These emerging concepts for SO grid services with flexible grid service agreements and dynamic tariffs are examined further in chapters 4.3-4.4.

Reactive power and voltage control is an important task of SOs as described in Chapter 2. Liberalization of energy markets and vertical disintegration of utilities means, that SOs must procure reactive power and voltage control from multiple resources. Firstly, SOs control the balance of reactive power and voltages with their own resources, such as reactors and capacitor banks and other controllable compensators. Secondly, they procure reactive power reserves from network users with rule and price-based mechanisms, such as network service agreements and reactive power tariffs. Network connected elements, can have an obligation in their grid connection agreement to do some degree of reactive power compensation according to the locally measured deviation from the needed terminal voltage or power factor or do this implicitly based on foreseen tariff cost. The quantity and quality of voltage support delivered is not equal among different types of resources. For example, some resources are procured to deliver continuous fixed compensation to an area while for example power plants can deliver dynamic control based on the momentary power factor.

In Finland there are reactive tariffs in place in TSO and DSO grids. With reactive power tariffs SOs pass on the costs of voltage and reactive power control to their customers. If a network user must partly pay for reactive power and energy transmitted through the network connection, there is an incentive to participate in the compensation of reactive power together with SOs. This kind of mandatory voltage is here defined as obligatory reactive power reserve (ORPR). The possibility to be remunerated for ORPR in the European area is shown in Figure 11.

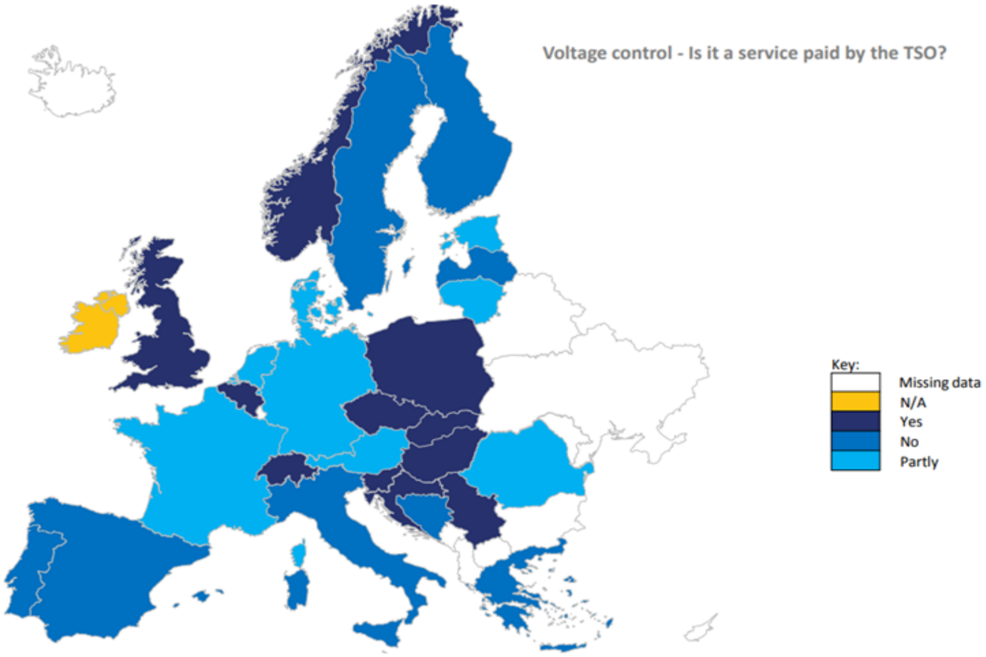

Figure 11: Remuneration of voltage control in Europe (ENTSO-E 2018c).

In addition to this SOs can procure voluntary enhanced reactive power reserve (ERPR) from network users that are either not obligated to deliver to ORPR or can provide voltage support services above the standards of ORPR and implicit control from grid tariffs. A method for this procurement is presented in Chapter 4.2. ERPR is not a commonly established product definition nor a harmonized market. This largely due to the locational and technical specificity required. Existing ERPR procurements are often based on bilateral contracts, for example in relation to a location with a large connection. (Takala 2018; UKPN 2019).

3.4 Technical details and gap-analysis of existing electricity market products

This subchapter lists the technical details related to products described in chapters 3.1-3.3 and summarizes with a gap-analysis of the existing product structure, including agreed changes before 2024. Here it is assumed that this foreseen product structure is due to two reasons. Firstly, the parameters of products have been defined as they are because they serve the different needs of buyers and sellers. Secondly, these match to the capabilities of the providers that operate these markets. Product structure should enable two main goals of electricity markets: trading of electrical energy and continuous and secure supply of power in electrical networks. The complex dependencies between markets, products and services is illustrated in Appendix 2. It should be noted that some of these connections are not primary purposes of the market or contract and that some lines do not apply to all electrical systems and markets in Europe. Also, some products and services, such as Guarantees of Origin (GO), are missing from Appendix 2. Interestingly many of the market mechanisms are designed for one service, but there is still significant overlap in some services, such as balancing and congestion management.

Product parameters are defined in Appendix 5. Parameters like minimum duration between deactivation period and the following activation and recovery period are not listed as these are assumed to be handled with bid linking, which is a market attribute not a product parameter. For example, conventional power plants might be interested to use linking so that they can be activated only if the activation is slow and long enough or in case of electrical storages use bid linking to ensure that the activation does not result into violations caused by the limited energy supply. Only the underlying standard products are described, while more complicated products are additionally in place. Examples of such are block product trades in wholesale markets or technical and financial linking in balancing energy market bids. Tables 1-3 list the technical details of existing products or the updated versions of existing products foreseen to be in place in 2024. This is done by using Appendix 5 as a template. Products in Tables 1 and 2 are common European products and products in Table 3 are Nordic regional products.

FRR capacity markets and FCR yearly markets are not listed due to similarities with FRR energy and FCR hourly markets. Both liberalized market and regulated market products are shown, but non-market-based products and mechanisms, such as existing grid tariffs and network service agreements, are not listed. Also, congestion management products, flexible service agreements, dynamic tariffs and enhanced reactive power reserve are not shown because these are listed in Chapter 4 as emerging products. Bilateral energy trading is not shown as a separate product, as it can be understood in the broader context of bilateral contracts which are used for many purposes.

Table 1: Wholesale and bilateral products.

Parameter	Bilateral contracts	Day-ahead market	Intraday market
Short description	Use-case specific bilateral contracts or trades for services that other products do not enable	Auction-based wholesale market for implicit trading of electrical energy.	Auction-based or continuous trading of electrical energy to modify previous nominations closer to real-time.
Market time unit/validity period	Many/continuous trading	15 min.	15 min.
Market opening	Many/continuous trading	D-1 10:00-12:00 (auction)	Uncertainties: Auction: D-1 15:00 Continuous: e.g. D-1 ~15:15
Market closure (Cross-zonal=CZ, Intra-zonal=IZ)	Many/continuous trading	D-1 12:00	CZ: varies e.g. H-60 min IZ: varies e.g. H-0 min
Minimum lead time	Contract specific	12 hours.	Varies depending on the closure time: e.g. 0 min
Full activation time	Contract specific	Not applicable since non-physically binding trade for the MTU. Also, results are known in advance.	
Duration of delivery period (minimum-maximum)	Contract specific	Equal to the validity period, 15 min.	Equal to the validity period, 15 min.
Minimum bid size [granularity]	Contract specific	0.1 MW [0.1 MW]	
Divisibility	Contract specific	Can be, depends on the product.	

Symmetric/asymmetric product	Contract specific	Asymmetric	
Mode of activation	Contract specific	Portfolio-based self-dispatch	
Locational information (order book, bid resources)	Contract specific	Order books organized based on portfolios in bidding zones. Underlying resources are not indicated (unless schedules, unit-based bidding or central dispatch used).	
Aggregation rules	Contract specific	Aggregation of own resources allowed.	
Link to primary service(s)	Many (e.g. portfolio optimization of BRPs, capacity mechanisms of SOs)	Wholesale market trading.	
Link to secondary or other services		Balance mechanism, imbalance pricing, cross-zonal network capacity cost allocation, retail markets, financial markets and many others.	
Market or other procurement channel	Many	Power exchanges	
Buyer(s)	Many: SO from FSP, BRP from FSP, BRP from BRP	BRPs trade with other BRPs.	
Seller(s)			
Remuneration and compliance monitoring	Contract specific	Remuneration is based on power exchange trades. Compliance monitoring and remuneration or sanctions for physical delivery via imbalance mechanism.	
Sources	-	(Nemo Committee 2019)	(Energinet et al. 2019; ACER 2019; Nord Pool 2018)

Table 2: Balancing products.

Parameter	**Replacement Reserve (RR)**	**Manual Frequency Restoration Reserves (mFRR)**	**Automatic Frequency Restoration Reserves (aFRR)**
Short description	Product to return frequency to its normal range and to release activated aFRR or mFRR back into use.	Product to return frequency to its normal range and to release activated aFRR back into use.	Product to return frequency to its normal range and to release activated FCR back into use.
Market time unit/validity period	30min	15 min.	15 min.
Market opening	Unknown	D-1 12:00	
Market closure	H-55 min	H-25 min	
Minimum lead time	25 min	17.5 min	25 min
Full activation time	30 min	12.5 min	5 min
Duration of delivery period (minimum-maximum)	15-60 min	5 min or longer (defined in Defined in terms and conditions for BSPs)	15 minutes (equal to the validity period)
Minimum bid size [granularity]	1 MW [0.1 MW]		
Divisibility	Yes (indivisible bids also allowed).		
Symmetric/asymmetric product	Asymmetric product		
Mode of activation	Manual SO signal	Manual SO signal	Automatic SO signal
Locational information (order book, bid resources)	Bids can include the detailed location of the underlying resources, but order books are organized according to LFC areas. This can be due to technical linking or SO rules, e.g. to do bid filtering to avoid or to solve congestions.		
Aggregation rules	Aggregation allowed.		
Link to primary service(s)	Balance mechanism. aFFR is for secondary and mFRR and RR are for tertiary frequency control.		

Link to secondary or other services	Can be used also for: N-1 fault dimensioning, congestion management and for other purposes.		-
Market or other procurement channel	TSO operated balancing energy market. Also balancing capacity markets (with availability remuneration) are used to ensure liquidity in balancing energy markets.		
Buyer(s)	TSOs (and DSOs in the future?)		
Seller(s)	BSPs (also resources of SOs or bilateral contracts can be used in scarcity situations)		BSP
Remuneration and compliance monitoring	Energy remuneration based on utilization with marginal pricing. Compliance based on monitored delivery.		
Sources	(ENTSO-E 2018f)	(ENTSO-E 2018d)	(ENTSO-E 2018b)

Table 3: Reserve products.

Parameter	Frequency Containment Reserve for Normal Operation (FCR-N)	Frequency Containment Reserve for Disturbances (FCR-D)	Fast Frequency Response (FFR)
Short description	Product to control frequency in normal operating conditions.	Product for frequency containment in the case of disturbances.	Product for frequency containment during low inertia conditions.
Market time unit/validity period	1 h		
Market opening	D-30		
Market closure	D-1 17.30		
Minimum lead time	6,5 h		
Full activation time	Depends on the frequency deviation, e.g. 3 min.	Depends on the frequency deviation, e.g. 1-30s.	Depends on the frequency deviation, e.g. <1s.
Duration of delivery period (minimum-maximum)	No minimum, maximum varies e.g. 30-60min.		No minimum, maximum varies e.g. 5-30s.
Minimum bid size [granularity]	0.1 MW [0.1 MW].	1 MW [0.1 MW].	
Divisibility	Yes (indivisible bids also allowed).		
Symmetric/asymmetric product	Symmetric	Asymmetric for upregulation only.	
Mode of activation	Automatic self-dispatch according to frequency.		
Locational information (order book, bid resources)	Order books are organized based on LFC area need, but underlying resources are indicated in bids.		
Aggregation rules	Aggregation allowed		
Link to primary service(s)	Balance mechanism. (FCR is for primary frequency control and FFR for primary frequency control in low inertia conditions).		
Link to secondary or other services	-	-	-
Market or other procurement channel	TSO (LFC block TSOs together) organized hourly reserve markets. Also, FCR yearly capacity markets are in place to ensure liquidity and adequate supply.		
Buyer(s)	TSOs		
Seller(s)	Reserve market participants		
Remuneration and compliance monitoring	Varies in Europe, e.g. remuneration with marginal pricing for availability and separate utilization compensation. Compliance monitored with measurements. Mostly capacity is remunerated.		
Sources	(Fingrid 2019c)		(Modig et al. 2019)

All electricity market participants and network operators use electricity market products very differently and value certain technical details from their own viewpoints. One of the most complex parts of trading are overlapping trading periods. This is shown in Figure 12 which shows different GOTs and GCTs regarding a hypothetical delivery period of 15 minutes in Finland after 2024. Asterix shows trading parameters where increased uncertainty about the future is involved.

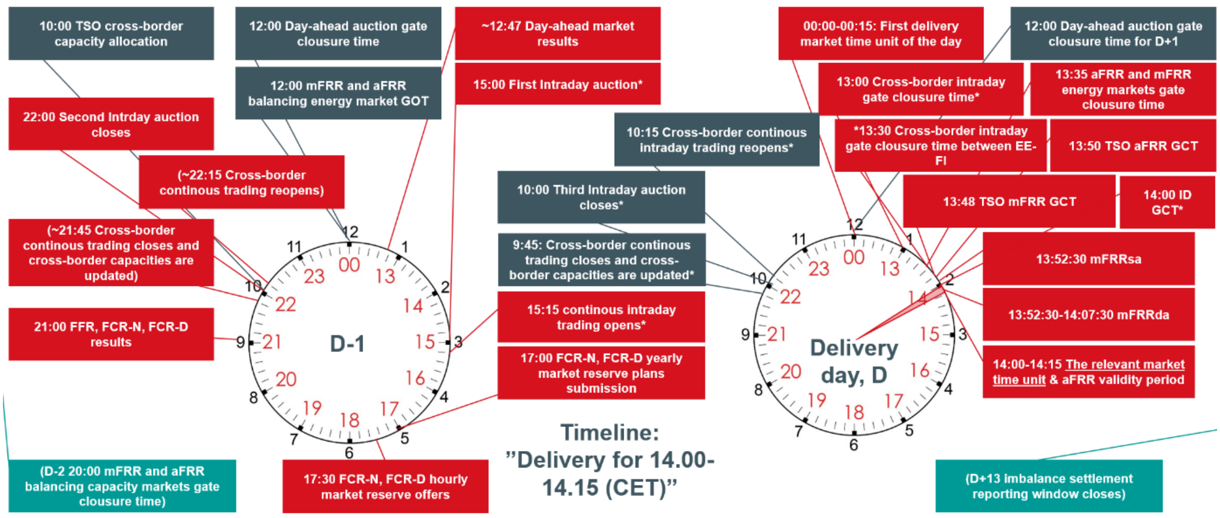

Figure 12: Scenario of market trading times related to a delivery period of 15-minutes. Adapted from: (Fingrid 2019c; ACER 2019; 2019; ENTSO-E 2018d; eSETT 2019).

The product parameters and market processes described in Chapter 3 have simultaneously unnecessary overlapping and missing details. Gaps of the current electricity market product structure in Tables 1-3 and other identified challenges in Chapter 3 are:

- Markets, products and other instruments are both fragmented and overlapping
- DSOs have no or limited access to current electricity or reserve markets.
- There are conflicting zonal- and nodal-market characteristics in most products.
- Many products result in binding obligations to deliver, which can reduce flexibility of the flexibility trading process. Cross-process linking of product offers is not difficult.
- Product parameters, market rules and settlement differ regionally and within regions.
- Role of SO actions in competitive and regulated markets differs:
    - Network tariff parameters are not harmonized, and these do not support the use of locational and system-level flexibility dynamically.
    - Balancing mechanism and reserve and balancing products are not harmonized.
    - SOs participation or other impacts to wholesale markets are not a harmonized.
- Missing locational based investment and dispatch incentives within bidding zones.
- Missing time-of-use and flexible capacity-based incentives.
- There are very limited harmonized, transparent or competitive processes and products for congestion management, outage support and voltage support.
- SOs do not always remunerate ancillary services.

Gap-analysis shows that there are many possible parameters that a product reform could tackle, regardless that major reforms and harmonization are foreseen already. For example, the implementation of near-real time GCTs, harmonized balancing products and updated settlement rules in of many products is here assumed to solve many of the identified gaps. Still, some common missing details are seen to remain, such as: the lack of locational information in energy-based products, dismissal of reactive power and voltage control products, outage support products and missing time-of-use and availability-based incentives in most products.

4 Emerging flexibility products for electricity markets

This chapter focuses on flexibility products traded on multilateral flexibility markets which either do not exist in current European electricity markets or of which the definitions are not fully established or harmonized. Although existing markets use flexibility, here the term flexibility market refers to markets where flexibility product trading or other mechanism is enabling services that existing products do not cover. The focus is on local flexibility services identified in Chapter 3.4. These include congestion management products, voltage and reactive power support products, dynamic network tariffs and flexible network service agreements. Practices and parameters used are those of emerging pioneer flexibility initiatives and thus the officiality of terminology and compatibility to the existing products described in the Chapter 3 is not ensured (Schittekatte & Meeus 2019; Villar et al. 2018). Locational or system level self-balancing concepts, rule-based control and network allocation reductions are not considered in this chapter, as these are not tradable products, although these can foster the use of flexibility.

4.1 Flexibility products for congestion management

This part examines how SOs can procure resources for congestion management from flexibility markets with three options: locational balancing products, locational intraday and competitive bilateral contracts. The offers for these products can be placed on the same balancing or intraday platforms or to a separate platform with specialized products. Out of many possibilities, these alternatives are selected for further investigation because these product types are used by many SOs and flexibility initiatives in Europe (Esmat 2019; Schittekatte & Meeus 2019). There are no harmonized congestion management mechanisms and products in Europe and this is concluded in the ASM-report: "TSOs and DSOs are convinced that flexibility product design is not only important for the implementation and the extension of markets for congestion management but could in some cases trigger the establishment of such markets." (CEDEC et al. 2019). Following the recommendations of the ASM-report this thesis looks only into solutions that are compatible with EU level electricity markets and standardized regionally or at national level (CEDEC et al. 2019). Figure 13 shows the complex connections of existing and emerging markets and mechanism linked to congestion management in zonal electricity markets.

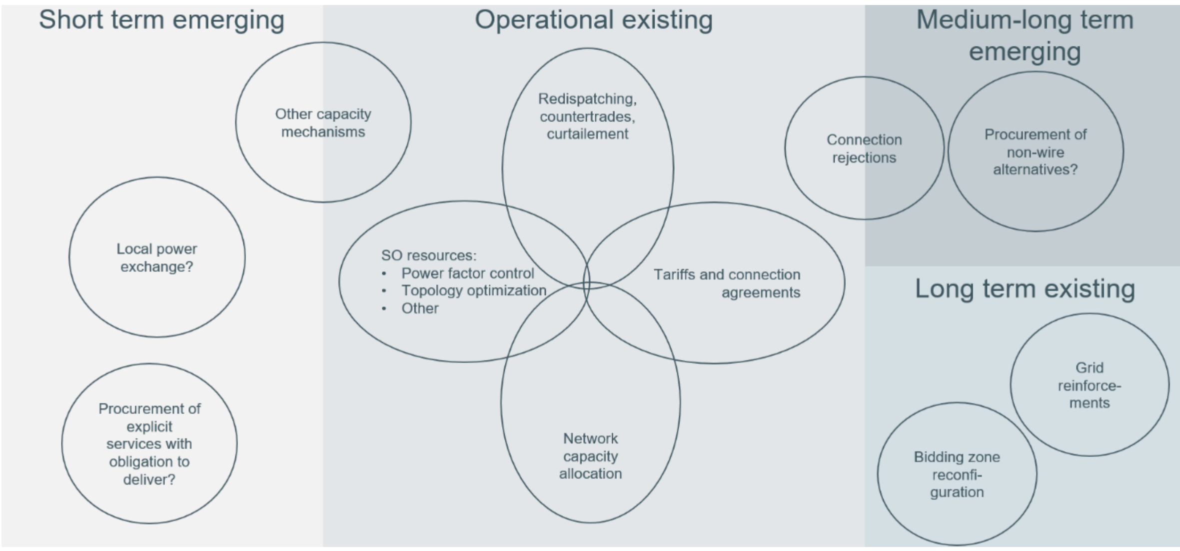

Figure 13: Congestion management mechanisms in zonal electricity markets.

4.1.1 Locational balancing products

Using locational balancing products for congestion management means activation of balancing energy offers or selection of balancing capacity offers for local needs. Local flexibility activations via balancing markets could be done also for other purposes, such as local voltage support in combination with ORPR, but here only active power congestion management is assessed. This process of congestion management with future European balancing platforms is like congestion management described in chapters 2 and 3.3.1, but only mFRRsa and mFRRda are considered out of the standard balancing energy products. Proposals presented here are not compatible with the foreseen common mFRR products and operational guidelines related to using these products, so therefore changes might have to be made.

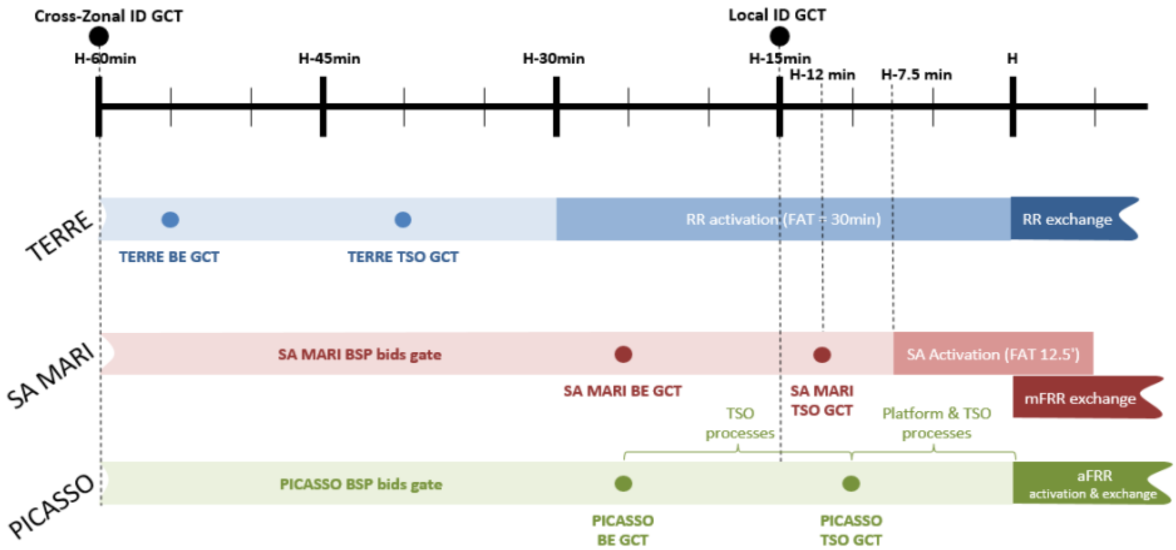

Figure 14: Interaction between trading for different balancing processes (ENTSO-E 2018d).

The possibility of having a separate mFRR congestion management interface is here excluded due market fragmentation. Still, a separate locational balancing energy market with the same interface with differing congestion management energy gate closure times (CMGCT) and special products could be organized. It is assumed that these complementary product offers should and could be linked to the balancing process by forwarding unused offers to the mFRR balancing market. In Figure 14 activations for mFRRsa take place 7.5 minutes before delivery and mFRRda can be ordered until 7.5 minutes after (H+) delivery. If there is a need for SOs to conduct congestion management with mFRR offers or similar offers how would this work:

a) from the common balancing platform preventively before real-time?
b) from the common balancing platform reactively in real-time?
c) from the common balancing platform with an earlier gate closure time?

In situation a, if a SO uses balancing offers for congestion management and predicts a congestion well in advance, it is assumed that the SO would order sufficiently cheap locational bids to be preventively activated. If an offer is placed to be available for balancing, it is not possible to activate it before H-7.5 min. SO could make sure that it would have the bid available by marking it unavailable during LMOL formation and then activating it directly for delivery before real-time. These markings are done also for N-1 dimensioning, so there is a working principle being studied: “to select most expensive bids” (ENTSO-E 2018d). It would be counterintuitive if an offer with a wanted location would be cheaper than the working principle requires. To add, these marked bids would be available for the direct activation process only.

As described in Chapter 3.2, preventive or long activations with mFRRsa or mFRRda with forward linking in time are not possible. A linked offer direct activated in a quarter hour (QH) can cause is issues, since for example a bid for QH-1 is not available in QH-0 for direct or scheduled activation. Thus, if there would be a need for a SO to use locational standard mFRR-bids preventively for congestion management it could do this securely for 15 minutes. If enough local supply is available, then a SO could order other bids with above described principles. These conditions are highly dependent on whether the balancing area uses unit- or portfolio-based bidding for balancing markets and how the linking is done. (ENTSO-E 2018d).

Here it is assumed that BSPs looking for increased flexibility trading revenue are interested to mark bids suitable for purposes other than the standard balancing product. The reason for this is, that the BSPs don't care about the underlying reason for activation. In addition to location, this marking could include the possibility to be activated for longer durations or with a faster ramp-rate. This means that a SO must identify suitable offers for congestion management and coordinate this with other SOs during the 13-minute time window for TSO processing time. In 13 minutes, it is impossible to calculate multilateral financial convexities of offers and technical constraints of underlying resources and networks with full accuracy. Therefore, near delivery GCT means extensive automation and approximations, especially at lower voltage levels. (ENTSO-E 2018d).

The BSPs could be allowed to add additional conditions into bids. If for example the balancing bid is selected with long or fast activations the price could be different. Pricing is here assumed as pay-as-bid, but at least the balancing energy price of the given market time unit. The offers selected for purposes other than balancing, are marked unavailable during the formation of LMOL so that these are not activated in the balancing process. It remains open whether this time is sufficiently long for this and if the SOs can trust the process. Option a is here recommended, since it assumes that BSPs are more likely to bid without locational premiums.

Option b with reactive congestion management with balancing bids is similar to option a. Reactive congestion management during operational market time unit with balancing offers can be done solely with the mFRRda product. Limitations of the common balancing energy platform can cause difficulties if there are linked bids in place and a long need for congestion management occurs suddenly, as described above. Here this is considered less significant since the whole process of congestion management is assumed to be preferably based on preventive operational and investment actions of SOs. If a non-forecasted congestion occurs, the relevant SOs can first activate mFRRda as reactive congestion management and if the situation is still present, then continue the activation with other methods to alleviate overloading.

Option c uses the same market interface as previous options but would have a congestion management gate closure time before the balancing energy gate closure time, which is at 25 minutes before delivery (H-). Since the BSPs would face two GCTs for similar mFRR-products it is argued here that they would be inclined to bid for the first market with a locational premium and then bid for the common balancing market without this margin. The assumption for this is that SOs value the risks and earning possibilities of location specific bids higher as these are earlier binding for physical delivery and that the geographically smaller market will be less liquid and competitive. This is not optimal as it incentivizes locational market power. However, SOs could be interested to apply for separated BEGCTs and CMGCTs if the congestion management coordination between SOs would require this. Possible separate CMGCT times are:

- earlier than IDCZGCT (before H-60min),
- IDCZGCT (at H-60 min) or IDCZGCT between Finland and Estonia (H-30 min),
- time of delivery of production plans (currently at H-45min in Finland).

If delivery is requested significantly earlier, the accuracy of congestion forecasts decreases and BSPs are less interested to trade or offer at higher prices. This is since risk margins due to physical responsibility to deliver increase relative to the length of the preparation period. The motivation to include locational information depends on the BSP in question and the location of the underlying asset. If, for example, bids from an area are rarely used for congestion management, there might be less motivation to bid for a such CM market. As said in Chapter 3.3, many TSO balancing markets, and NODES-platform post such a possibility to combine congestion management with mFRR balancing products (NODES 2019; ENTSO-E 2018c).

4.1.2 Locational intraday market product

This subchapter examines how SOs could procure resources for congestion management services using flexibility products based on intraday products. The possibility to use locational intraday bids for continuous trading for congestion management is here defined as preventive dispatch control. In preventive dispatch control SOs want to influence what consumption and generation is dispatched based on the market clearing. In self-dispatching-based markets this means that SOs affect with payments how market trades are cleared, instead of dictating multiple markets concurrently like in central dispatching models. To enable intra-zonal dispatch control, IDM bids must contain locational information more specific than the bidding zone where the underlying units belong to. This implies unit-based bidding and imbalance settlement to certain accuracy, regardless whether unit- or portfolio-based bidding is being used. Here only bidirectional dispatch control is examined, which means congestion management where a controlled dispatch to the opposite direction of the initially controlled dispatch is activated together. This is done to preventively solve either one or two forecasted congestions and maintain balance of the LFC area. The use of preventive dispatch control in DAM or IDM auction algorithms is here not examined, even though this could be possible.

Such dispatch control products linked to intraday market products are defined in development initiatives such as GOPACS and ENERA, which post similar products (BMWi 2018; GOPACS 2019a). Here the definition of the IDCONS-product in the GOPACS-platform combined to ETPA power exchange is further examined. GOPACS is currently in operational use in Netherlands by TSOs and DSOs. An IDCONS-product is a combination of two offers in opposite directions, an ask and a bid, with the same starting time and duration. Since these offers are available on the market, these must have non-matching offer prices, a bid-ask spread, meaning that the market has not cleared them already. This happens when the ask price is higher than bid price. For in order these bids to be cleared by the exchange the SO needing CM will select to pay the spread. GOPACS congestion management is shown in Figure 15. (GOPACS 2019a).

Currently, GOPACS supports only limit orders. These offers must contain locations which when cleared would result in dispatches that completely solve or alleviate a congestion. Parties indicate in their IDCONS offers which of the predefined European Article Numbering (EAN) electricity supply points are part of the offer. Asset owner must himself or give permission to a market party to trade with a specific EANs. In 2019 autumn GOPACS- developers are also testing whether the use of more broadly defined areas with virtual EANs area can achieve desired results in cross-zonal congestion situations. Offers with a locational information included can be activated also as a normal system level intraday trade. In case both locational up- and downregulation are needed in separate areas, an IDCONS-product can solve two congestions at once. (GOPACS 2019a).

Firstly, congestion management with GOPACS can happen only if the parties have indicated the location and to allow orders to be used for an IDCONS-product. Secondly, SOs estimate whether an IDCONS combination will achieve the desired results cost-efficiently. SOs have an interest to find the cheapest possible combinations that can achieve congestion management, while not causing other congestions, as they are paying for the spread. There is motivation for market parties to mark offers suitable for IDCONS and offer more aggressively. This is firstly because offers suitable for an IDCONS have higher risks due to physical delivery commitment. Secondly, offers are more likely to be activated in the case of congestions. Thirdly, the bid-ask spread is paid by a third party. This means that locational asks are submitted at higher price and bids at lower price, than for the system level IDM. Market parties can also submit two offers regarding an underlying asset, where one offer is marked for IDCONS and another more conservatively priced offer, for the system level intraday market. (GOPACS 2019a).

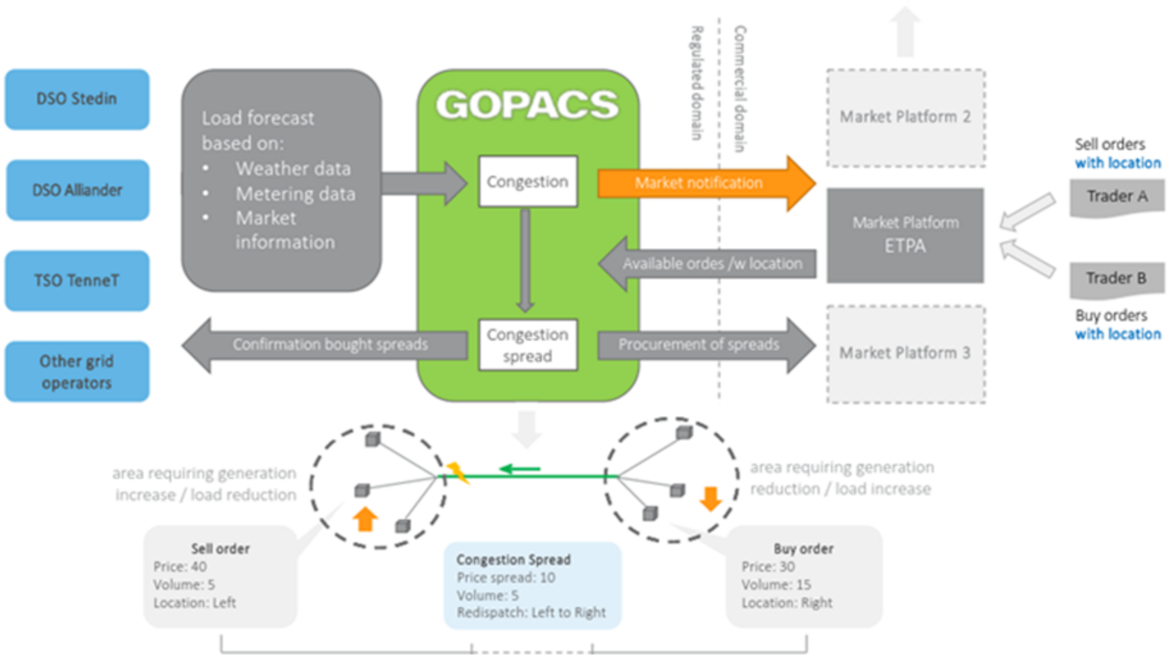

Figure 15: IDCONS product on GOPACS platform (GOPACS 2019a).

IDCONS-process can start by SOs first looking at locationally market bids and then selecting suitable ones. However, if there are no suitable bids available in the market, SOs submit notifications to ask for more offers in certain areas for a specific duration and regulation direction (GOPACS 2019b). Thus, IDCONS-products are case-specific. In case of similar and continuous needs there could be motivation for SOs to design standard IDCONS-product calls, for example announcements for weekday mornings from 6 till 9 in a city region. Still, if such activations are continuous, this indicates the existence of a structural congestion. The use of continuous IDCONS-activations must be compared against the cost of grid reinforcements or procurement of long-term bilateral contracts discussed in Chapter 4.1.3.

If an order is cleared as a part of an IDCONS, the market parties must deliver at least the service indicated in their offer. This means that a FSP with an ask must upregulate equally or more in the predefined EAN and the FSP with a bid must downregulate equally or more in the other location. The validation of this flexibility delivery is defined relative to the planned network use at this location, which can in general be a: unit-based market position, schedule or a baseline-defined from historical behavior. As shown in Figure 7, self-dispatch and portfolio bidding is in place in Netherlands and in other European countries. Since, there are no unit-based market positions for IDCONS settlement, the delivery is compared to generation or load schedule of the connection. If a connection does not have a plan, the IDCONS party is responsible to deliver an alternative plan. Verification of the delivery is also monitored by grid operators from more detailed or real-time metering data, as examined in the Chapter 7.2.3. (GOPACS 2019a).

The locational intraday product is a hybrid of zonal and nodal market characteristics, as described above. According to Hirth and Schlecht (2019), such hybrids are doomed to fail, and instead a regulated redispatch model should be adopted. Other option is to change from a zonal to a nodal market design, though this transformation will not be made without problems (Alaywan et al. 2004). In this thesis, a zonal market model combined with a market-based redispatch is examined as it is more compliant with the European target model. Once possible problems related to the model are solved, it can provide a solution to solve congestions in the operational timeframe and provide more value for flexibility. Main challenges related to market-based redispatch and especially to locational intraday offers are:

- **Non-existing schedule.** Most network connections do not have a schedule that the market party is delivering, or the accuracy of these is limited. This is especially true for small connections with generation, consumption or both. SOs also forecast schedules, but these SO-schedules are financially decoupled from the locational or system level market position of the market party. For example, in Finland load schedules (exceptions possible for major loads) and generation schedules of small generation units (units below 1 MW or co-operative power plants below 100 MW at unit level) are not delivered to SOs (eSett 2019). The challenge for unit-based bidding or schedules is the unit granularity required. Aggregated small resources, such as retail customers and distributed generation are difficult to define accurately at system level, yet alone for smaller areas. If a FSP would be responsible to forecast and trade at unit level for increasingly smaller units, this could result in increased cost margins due to the difficulty and risks involved.

- **Non-binding schedule.** If a FSP in a market model with self-balancing, portfolio-based bidding and settlement in a single price and single position imbalance settlement model submits schedules for its network use at unit level, there is no responsibility for these schedules. In other words, there is no financial motivation for the market party to monitor the schedule and the realized network use at unit level. Also, non-binding schedules leave room for speculation about the motivation of the market party to deliver the true private unit schedules. If the schedule is replaced with a baseline defined by a SO or other party the possibility of manipulation is reduced but substituted with inaccuracy related to the baseline definition. Chapter 7.3.2 examines these concepts further.

- **Undefinable connection.** If a foreseen congestion is related to an unclearly defined area, such as a city with a complex internal network and multiple market parties, it’s difficult to accurately define what actions would cause or solve a congestion. For example, if a FSP has many consumers within area and a SO needs to solve a congestion at a sub-station level it can be difficult to aggregate resources with accuracy to solve the congestion.

- **Self-balancing and zonal market compliance.** In zonal markets, use of optional locational unit-based offers creates the possibility of mixed incentives. Here it is assumed, that portfolio-based self-balancing results in less-conservative actions and a higher share of available flexibility offered to the system-level markets than in unit-based self-balancing. This is since imbalances can be netted within the portfolio and multiple units can counterbalance. It is also assumed, that unit-based bidding and settlement results in more accurate schedules, due to the balance management philosophy of this market model. It can be counterintuitive to promote self-balancing at portfolio-level while support position compliance at unit-level with other instruments. To summarize, there is a tradeoff between accurate schedules, unit-compliance and system level self-balancing. Also, when SOs actions affect the outcome of the competitive market domain, such as intraday markets, this results in distorted behavior.

Figure 16: A congestion announcement on 22.9.2019 from 7 pm to 12 am for Ketelmeer area. Adapted from (GOPACS 2019b; TenneT 2019).

If an offer is matched as an IDCONS-trade, the market party must follow a schedule of a unit and physically deliver the service. Position freezing can limit the interest of market parties to bid into such markets and at least increases safety margins and bid prices due to obligatory physical delivery. Currently SOs place IDCONS announcements to call for more locational offers usually 2-12 hours before delivery and the situations are approximately 1-10 hours long. (GOPACS 2019b). In Figure 16 an example congestion announcement is presented together with a map illustration showing the impacted area between the two circles and regulation directions regarding the congestion. Locational intraday bids are requested from the resources within the red circle and asks are needed from the blue circle. For example, the situation can be solved with the match of two locational five-hour long block offers. In the selection phase prices of offer combinations are compared but also the locations within the circles must be accounted for. For example, there is higher certainty that a power plant closely connected to the congested network element can solve the issue, compared to an aggregated offer from multiple locations and voltage levels far away from the overloaded component.

4.1.3 Competitive bilateral flexibility contract for congestion management

Competitive bilateral flexibility contract means a market-based contract which after an open auction to find the most suitable offers, results in bilateral service agreements between a network or network operators and FSPs. This is like bilateral contracts for reinforcement deferral described in Chapter 3. The term competitive refers here to the situation where the auction is based on free-for-all entry, instead of private bilateral trading. The term is not established in the industry, regulation or legislation. Still, such market-based procurement of qualified resources is supported in CEP (Nouicer & Meeus 2019). These contracts can be done for the procurement of market-based non-wire alternatives for congestion management during normal network use, during maintenance conditions and other purposes described in chapters 4.2-4.4. Similar to normal situations for an undefined period, in the case of temporary limits, such as maintenance works, the SOs might have to curtail part of network use from many customers for predefined period. For these periods, network operators could opt for locational auctions instead of equal curtailment or mobile back up supplies. If the experienced disadvantage differs among the customers, the customers could also be allowed to trade among themselves or via the corresponding SO these curtailment obligations (Kessels et al. 2019).

There are many possibilities to form and price competitive bilateral contracts, but similarly to reserve markets, a combination of availability and utilization costs is here assumed to be suitable. For example, UK Power Networks has estimated: "services with an approximate cost of £30,000/year can help us defer a reinforcement cost of £2m for 4 years" (UKPN 2019a). Such estimates are dependent on the location, forecasted reinforcement need, regulatory model and many other variables. UK Power Networks compares the submitted offers for reinforcement deferral with comparable rates in Equation 1 (UKPN 2019a).

$$\text{Comparable Rate} = \frac{(\text{estimated availability cost} + \text{estimated utilization cost})}{(\text{tendered service period hours} * \text{maximum run time})} \tag{1}$$

where:

- estimated availability cost = Availability Fee (£/MW/h) * service period hours
- estimated utilization cost = Utilization Fee (£/MWh) * estimated utilization frequency * estimated utilization hours per utilization

Offers are submitted for auctions and if the sum of costs from selected offers is cheaper than the reference cost for the length of the availability window, the SO can procure services instead of reinforcing. The procurement lead-time and contract term are case-specific, but there might be interest to standardize these to make the procurement process simpler for offerors. For example, UK Power Networks has had lead-times of 6 and 18 months for 1–4-year contracts (UKPN 2019a).

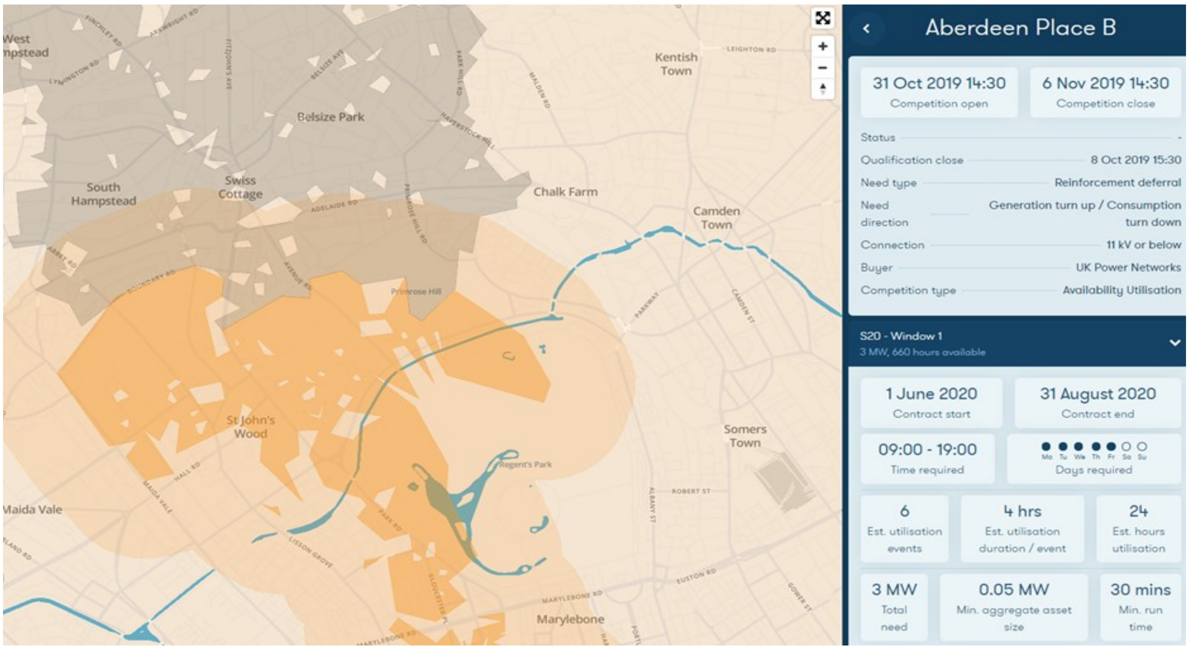

Figure 17: A flexibility competition for a location in a DSO network (Open utility 2019b).

Figure 17 shows an example method to procure flexibility, with an open competition using the Piclo Flex-platform. The offers from prequalified assets are submitted per area. In Figure 17 the assets located in the orange part map are entitled to participate. In Figure 17 the competition is about insufficient local network capacity during winter 2020. Similar competitions could be arranged for voltage support or post-fault outage mitigation, as discussed in following chapters. Assets that pass the testing and procurement processes can be activated by the corresponding SO. This activation can be done either via SMS, email or other electronic signal in the Piclo Flex competition areas (Open utility 2019a). Outside the contracted availability windows, the resource operator can offer the underlying asset to other markets or use the resource itself. To add to the activation logic options above, here in advance defined self-dispatch activations are presented for situations where the activation is continuous or repeated. A preordered activation could be a preferred option for continuous needs, as this flexibility can then be accounted during energy procurement from DAM and IDM.

Areas that need completely new installations, such as electrical energy storages, generation units or demand-side-response equipment, might benefit from longer lead and contract times. This can foster locational liquidity and interest as transactional and risk-based financial costs are reduced. The possibility to allow free offers for utilization near delivery and to use separate availability fees simply to ensure capacity, like balancing capacity markets, would be a possible development step once experience with the described combined model is gathered. TSOs and DSOs are here considered as the sole buyer of these NWA services, even though in islanded or in micro grid segments similar peer-to-peer contracts could be issued behind a connection. As defined in Chapter 3.3.2, SOs can remunerate the delivered service differently, but here separate payments from network tariffs are assumed to be easiest contractually.

4.2 Flexibility products for voltage support

Flexibility products for voltage and reactive power control mean enhanced reactive power reserve services and other trades which ensure the voltage quality in addition to obligatory voltage control of network users and SO resources. Flexibility products can be used for voltage compliance during normal conditions, maintenance works or pre-fault and post-fault outage management. As said in Chapter 3.3.2, the concept of voltage support products varies. Currently there are none or limited market-based ways for networks to procure voltage support. Existing voltage support methods can be complemented with a market for reactive power trading.

A thesis written as a part of SysFlex-project concluded that the further development of a bilateral model would be preferable over a marketplace for reactive power (Takala 2018). The reasons for this are related to long procurement cycles, lack of supply, regulatory support for SO ownership instead of service procurement, location specificity and required strict technological compliance. This thesis follows this conclusion. Here it is assumed, that the competitive bilateral flexibility contract product and procurement model, presented in Chapter 4.1.3 for congestion management, are suitable for voltage support procurement. For example, there are such competitive reactive power competitions active in the Piclo Flex-platform (Open Utility 2019b). Also, ORPR requirements and grid tariffs must be kept updated according to voltage support needs.

The activations due to a flexibility contract can be either continuous during contracted periods, based on SO activation signal or result of self-dispatch. SO signal is here assumed as a not cost-efficient or technically suitable way of delivering service due to the volatile nature of voltage support needs. Continuous fixed compensation or self-dispatch according to locational phase-angle measurement, like frequency dispatch of FCR, during contracted periods are both suitable ways. The result of the tenders are resources which are activated during contracted periods to compensate the reactive power demand according to the bilateral contract.

The reference cost for ERPR procurement with competitive bilateral contracts, is the cost that the SO would pay for an alternative compensation resource itself. Due to the regulation model, land-use possibility at substations, SO expertise related to reactive power and voltage control and low credit risk rating of regulated monopolies, it is here assumed that SOs would be able to procure a new dedicated resources below the cost of a market party (Takala 2018). A reactor or capacitor installation for an area is an example of this. Therefore, SOs could procure market-based voltage support cheaper only if the resource would be used also for other purposes. Another reason for voltage support contracts would be if the resource, such as a power plant, was in some measure more capable of delivering reactive power control, than resources possible for network operators to own and operate. An example of a voltage support flexibility contract is a grid tied EES systems owned by an FSP, providing reactive power control to networks during high need and other times being used for other purposes.

4.3 Dynamic network tariffs

Here dynamic network tariffs refer to grid tariffs where the cost parameters are constantly updated and shown for the network user before, or during delivery. This can lead to implicit behavior based on the locational or system-level network needs to incentive system supporting behavior. These conceptual tariffs could also vary within a network area of a single SO for similar grid services, although current regulation does not allow this. As identified in Chapter 3.3.3, different kinds of cost parameters are included in tariffs but most of these parameters are not locationally and temporally dynamic, or the dynamicity is not in the level needed for active system management (CEDEC et al. 2019). Similar dynamicity was investigated also for electricity taxation in Finland, but this was identified not recommendable (Pahkala 2018). Four kinds of dynamic tariff cost parameters including locational and system level price signals can be identified (Similä et al 2011; Schittekatte et al. 2018; Schittekatte & Meeus 2018):

1. dynamic tariffs linked to real-time energy price,
2. dynamic tariffs linked to frequency,
3. dynamic tariffs linked to local network congestions,
4. dynamic tariffs linked to voltage control.

It is difficult to find suitable pricing for dynamic tariff components to achieve the desired outcome while respecting other market mechanisms. As network costs can be a large share of total electricity costs, tariffs should be compatible with other market mechanisms if price-responsiveness is pursued. As near-zero variable cost generation, such as nuclear and VRES, is added to power systems, the absolute costs or the proportional share of network related costs out of total energy costs can increase. Still, maintaining cost-reflectiveness of networks while calculating an optimal individual dynamic tariff for each network user is impossible if main principles presented in Chapter 3.3.3 are followed. Defining dynamic tariffs is computationally intensive without major approximations. This could mean, that a customer would have a different tariff structure for each market time unit of the day due to system-level capacity adequacy. Also, local parameters, such as a congested or poor voltage quality areas, mean a different tariff structures for similar customers in different parts of the same network (Shen et al. 2019).

Option 1 i.e. using dynamic tariffs linked to real-time energy price, is related to system-level capacity adequacy in wholesale and other energy-based markets. There is a significant challenge in defining an optimal reference for the system-level electricity price to calculate the tariff. For instance, linking a part of tariff costs to off-peak hours with, for example, night and day prices, or to day-ahead market results, would bind customers flexibility as these prices would be amplified. Using only parts of tariff structure as flexibility indicators, is here supported, as tariff revenue predictability is important for network operators who have mainly fixed costs related to the existing infrastructure. This would reduce the interest to participate to other markets, which could experience more flexibility scarcity at that time. Amid the energy transition, it is difficult to define what times, markets, and use-cases on average have flexibility scarcity and will this scarcity vary significantly. Option 2 i.e. using dynamic tariffs linked to frequency, is here excluded since this is interpreted as equal to already functional FCR markets described in Chapter 3.3.1. (Burger et al. 2019; Schittekatte et al. 2018).

Option 3 i.e. using dynamic tariffs linked to local network congestions, can be done with other ways than tariffs, such as SO dispatching or with options presented in Chapter 4.1. Here the introduction and increased share of updatable local power-based components in tariff structures is presented as a complementary option. Dynamic power tariffs are assumed to be impossible to be implemented in the current regulatory environment. Replacing volumetric network charges with net-metering and capacity-based charges, such as power limit tariffs or power tariffs, is an attractive alternative for SOs to recuperate sunk and foreseen network costs. This can be seen reasonable if customers use less energy and more power than before when they for example opt for demand-response or self-generation. (Schittekatte & Meeus 2018).

Still, there are fairness issues between active and passive network users and cost-reflectiveness issues, if too static power tariffs are implemented. This means that if, for example, power-based costs are calculated per network user based on historical peak power utilization, the local congestions or system-level power adequacy at the time of peak-utilization are not considered. Also, some customers with, for example, home automation systems or electrical storages, are more suited to optimize in relation to power-based tariffs. Rarely updated dynamic power tariffs therefore limit peak-power utilization per connection, for example, during yearly or monthly intervals, but do not necessarily shift these reduced peak-loads to times most optimal for power balance or local network capacity. Also, dynamic tariff schemes can neglect the true costs of maintaining the possibility to use the maximum subscription capacity. Inaccurate energy-only-based tariff design results in non-cost-reflective tariffs, unfair cost allocation and especially not price responsive power-based behavior. This could be improved with the introduction of tariffs structures where a share of costs could be based on some degree of spatially and temporally dynamic power-based components. This could, for example, avoid major power peaks and incentive customers to investigate the possibility of intelligent control and invest into capability to control network use. Dynamic power tariffs have a lot of promising attributes, but here no suitable ways to implement these in the existing regulatory environment are foreseeable.

Option 4 is similar to ERPR concept, but as explained in Chapter 4.2, voltage control is best procured with bilateral contracts additional to modifications to existing reactive power network tariffs and to ORPR requirements. The dynamic network tariff options 1-4, are subjected to industry consultation in Chapter 5 to decide whether the solutions are preferable.

4.4 Flexible network service agreement

Flexible network service agreement or flexible grid connection means the procurement of NWAs during the network service agreement contract process of new connections or reinforcement of existing connections (INTERRFACE 2019; Kessels et al. 2019). This can mean additional clauses in connection and network service agreements, separated service contracts, or both. The concept of competitive bilateral flexibility contract presented in Chapter 4.1.3 is assumed to be applicable to these use cases as well. The situation is described from the viewpoint of a single or a group of users within a grid area, though NWAs can reduce costs for all users since unnecessary reinforcements are not socialized trough grid fees from all customers.

When new or larger connections for network use are planned, the requested location might have insufficient existing transmission capacity. Therefore, it would be beneficial for SOs to have other options than to accept or deny a network connection application. The use of NWAs in these locations could result in more cost-efficient grid service, if the alternative would mean a costly grid reinforcement for limited hours of only minor overcapacities, or the complete denial of the additional subscription capacity. The other option is that NWAs are procured as a temporary solution to enable network use while waiting for the grid reinforcements. An example of such a situation is the connection of VRES generation or large consumption units to an existing network segment. This enables the connection, and in addition, the customer can be remunerated with a bilateral service contract or with reduced grid fees. Due to non-discriminatory clauses related to connection fees, tariffs and other grid cost invoicing, it might be easier to apply for a separate case-specific service contract. Network users could allow the SO to curtail network use or the network user could self-dispatch under defined conditions.

Reinforcing a network connection with back-up connections or for example weather-proofing grids to avoid disturbances is costly. Especially for non-critical network users, the use of flexibility can result in cheaper costs. For instance, in rural areas the customers could opt for a different level of security of supply with cheaper network costs or separate remuneration. Muukkonen (2019) indicated the possibility to pay a 347 € to 651 € weather-proof readiness fee to Finnish customers for accepting longer interruption times rather than weather-proofing all existing grids. This option requires significant changes to regulation model, electricity market laws and customer willingness from the entire group of customers connected to the specific radial feeder. The alternative for flexible network service agreements is reinforcing or the procurement of NWAs from market parties, to deliver electricity to the customers in case of disturbances or longer outages with the connection to the common electricity system. The motivation for SOs in these contracts is to avoid mandatory costs related to customer interruption incentives. Also, the inclusion of contract costs in the calculation of allowed profit of regulated monopolies can be a motivation to apply for flexible network service agreements.

4.5 Flexibility market development projects

Chapters 4.1-4.4 focused on different emerging flexibility contracts, tradable flexibility products, and dynamic tariffs. Table 4 lists the current and foreseen design controversies linked to the different development initiatives mentioned and the use of mFRR balancing energy bids for purposes other than system level balancing. All the alternatives focus on the utilization of locational flexibility in areas smaller than an LFC area. Flexible service agreement, dynamic tariffs, and bilateral flexibility contracts were examined in previous chapters. These are not listed in the table as they are too use-case specific or in the case of dynamic tariffs, part of a regulated domain where no trading takes place. Unclarities are marked with a question mark.

Table 4: Flexibility development initiatives (Schittekatte & Meeus 2019; USEF 2018a, b).

Platform	GOPACS	NODES	PICLO FLEX	ENERA	mFRR offers (MARI)
Support for congestion management	Yes	Yes	Yes	Yes	Yes, possibly
Support for balancing	No	Yes	Yes, possibly	No	Yes
Support for reactive power and voltage control)	No	Yes?	Yes	No	No
Reservation payments (also defined as long term products)	Yes (future)	Yes (future)	Yes	Yes (future)	Yes (capacity markets)
Integration to EU electricity markets	Yes	Yes	No, yes in the future?	No	Is an EU market
Standardized product (s)	Yes	No	Yes	Yes	Yes

Products "similar" to IDM with locational offers	Yes	(see above)	No	Yes	No
Products "similar" to mFRR with locational offers	No	(see above)	Yes	No	Yes
Offer location (where are underlying resources indicated)	Postal code	Below a specific feeder	SO defined area	Resource specific	LFC area or more specific
Market operator	Third party	Third party	Third party	Third party	TSOs
Bid submission time	Before IDGCT	?	Long before delivery	Before IDGCT	Before or at BEGCT
Clearing time	Hours before delivery	?	Long before delivery	Hours before delivery	Before BEGCT or H-12min
Activation	Self-dispatch	SO / platform operator?	SO activation	Self-dispatch?	SO activation
Settlement	Related to unit schedule	?	Baseline	Related to unit schedules	Similar as mFRR
Pricing	Pay-as-bid	Pay-as-bid?	Pay-as-bid	Pay-as-bid	Pay-as-bid
Sources	(GOPACS 2019a)	(NODES 2019)	(Open utility 2019a)	(BMWi 2018)	(ENTSO-E 2018d)

Table 4 shows, that although flexibility initiatives differ significantly, all focus on locational aspects of flexibility use, especially congestion management. Main differences between flexibility product alternatives are related to where and when bids are submitted, how clearing is done, how activations take place, and how settlement and compliance monitoring is achieved. Figure 18 summarizes the different domains where tradable products are exchanged on markets or other regulated mechanisms are in place to deliver flexibility services. These are further divided into existing and emerging options. The division of products into regulated, semi-competitive and competitive domain is not straight forward and many of the emerging flexibility products are in the grey area between domains as shown in Figure 18

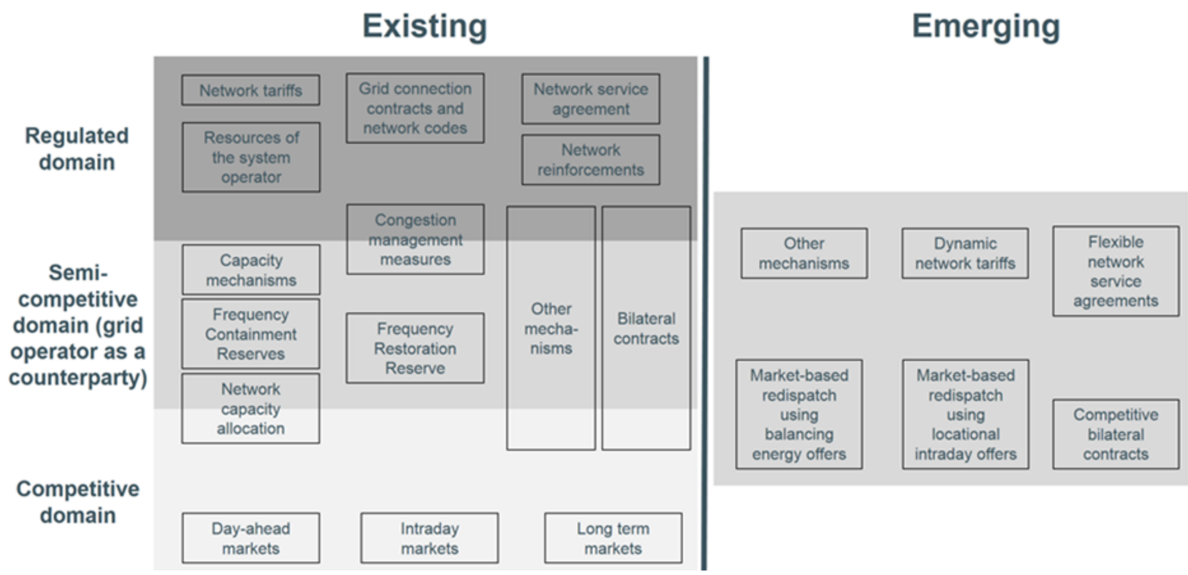

Figure 18: Existing and emerging products and mechanisms in European electricity markets.

5 Industry views on flexibility and flexibility products

This chapter summarizes the results of the industry consultation regarding flexibility and flexibility products. The consultation consisted of 26 industry experts whose interviews took place during autumn 2019. The experts are working with different perspectives related to the electricity domain such as generation and consumption, transmission and distribution system operation, network planning and development, ancillary and reserve markets, wholesale and retail markets, aggregation or other energy services business and regulation. Interviewees represented Finnish organizations, which are active in countries of the Baltic Sea Area, but the research focused on Finnish perspectives. The results are listed as a summary of all answers per theme where direct quotations and detailed information possibly linking to a specific company or interviewee is either anonymized or removed. Comments related to selling of flexibility are listed as a part of the role of FSPs and buying of flexibility as either the role of network operators or BRPs and other types of FSPs. This division is used to firstly maintain structure and secondly to secure the anonymity of interviewees. A list of interviewees is in appendix 3.

The interviews were executed as half-structured expert interviews, which form the empirical part of this thesis. Theme interviews can provide comprehensive answers to complex topics with the help of clarifying questions and discussion (Hirsjärvi & Hurme 2015). Due to time constraints the number of interviewees was limited. Also, the selection of interviewees was discretionary to get overall sampling and priori known expertise. This was necessary, as the research topic is relatively new in zonal electricity markets, there is a limited number of flexibility initiatives in Europe, scarce literature regarding flexibility markets and the theme requires comprehensive expertise. As the topic is an industry cross-cutting theme, the consultation was done with a broad interviewee list, with limited overlapping of expertise. Thus, the results do not fully represent the industry views nor firm positions or decided actions of any individual interviewee, company or organization. Still, the results provide an indication of the future trends of electricity systems and markets as envisioned by the experts.

The interview framework consisted of four themes. Firstly, a technical consultation was done to find out the current and foreseen flexibility needs of different types of electricity network users and operators. Secondly, the market architecture and coordination between different submarkets and mechanisms were examined. Thirdly, the product parameter definitions of existing and emerging options were evaluated. Lastly, the possible conflicts with emerging concepts and the possibility of testing were openly discussed. The interview framework, themes and questions are shown in detail in appendix 4. All the interviews followed this framework to an extent, while most interviewees focused more on specific questions related to their domain expertise. When needed, the interview questions were supported with background material from thesis chapters 1-4 during the interviews. Following chapters list consultation results divided according to the four themes and the roles of flexibility seller and buyer as defined above.

5.1 Flexibility in the electricity system: present and future needs

During interviews the experts had difficulties in defining and quantifying their current local and system level flexibility needs. These estimates also varied significantly depending on the interviewee. For example, an interviewee argued that alongside system-level balancing there are significant local needs in European and Finnish TSO and DSO grids already today, but according to other interviewees not so much in transmission and distribution grids of Finland. This was identified to be dependent on the voltage level definitions between transmission and distribution and the status of existing energy related infrastructure. Still, according to most interviewees system-level markets linked to financial trading and balance management, such as wholesale and TSO reserve markets were seen as the clear primary use case for flexibility. Local use was seen as an emerging market for additional utilization and revenue with potential for future growth. Financial optimization was the unifying factor in all use-cases. Other flexibility needs, based on for example personal user preferences, were identified by few, but are not further elaborated here due to interviewee anonymity.

Experts highlighted the difficulty of evaluating the flexibility needs of 2024 and onwards during major changes of the energy transition and the foreseen market design changes. The comments were split between the supply and demand of flexibility. Risks related to the long lifetime of the networks, costs of flexibility resources and the possible unavailability of flexibility were identified as potential hurdles for networks to trust flexibility as a network supporting element or as non-wire alternatives. Flexibility sellers were in most cases often not familiar or interested about voltage or congestion challenges, as they argued that these are the responsibility of network operators. Still, many added that they would be interested in a clear opportunity to sell services for networks for a reasonable compensation. Not all network operators and market parties were seen capable of participating to fast and real-time flexibility markets. Also, not all parties plan to do around the clock operational monitoring. Outsourcing, utility mergers and automation were mentioned as key solutions to tackle these challenges. Some argued that real-time trading should not be the goal of networks and that flexibility procurement for local network services should be done well in advance, for example with longer service commitments. Comments related to flexibility selling were split here, while some highlighted long contracts as a realistic solution and some strongly opposed these due to market fragmentation and inefficiency

Experts identified and prioritized their local needs and from these answers it can be summarized that currently Finnish grids need local resources for three use-cases. Flexibility is needed firstly for radial distribution grids for outage and maintenance support, secondly for voltage support and thirdly for congestion management. While outage management was mentioned often, it was seen problematic by most experts as the current security of supply is experienced sufficient by most customers and because of difficulty of the execution. It was argued that in the event of disturbances, flexibility would not help unless there is a back-up connection or back-up supply to all nodes. Fast reactive power and voltage control and congestion management were mentioned mainly as existing TSO tasks, but many experts identified these phenomena also as emerging challenges in distribution networks. These local services were seen highly overlapping and some argued that same resources could deliver all of these, sometimes even at the same time. Experts estimated, that only in few cases, flexibility capacity exists and is utilized at local level, apart from night tariffs in electricity distribution and voltage support of power plants. Modest capacity and utilization are restricted by the lack of locational needs, which most experts accounted to reliable networks with high transmission capacity. This status was estimated to be caused by the regulation model and historically successful grid development of network operators. Most of the local flexibility was seen capable of participating to system level markets, where it has already been used to a certain extent.

Flexibility connected to the electricity network was seen as a scarcely divided pool of resources with many owners and operators. These operators optimize the resources for multiple markets and use-cases with competing buyers, such as network operators and other market parties. The sequencing of offers to different use cases on temporally overlapping markets is done according to the availability and expected need of flexibility. Offers are placed and priced taking account to the expected risks and revenue of each trade being successful or not being realized. The experts argued, that increases in need for local or system level flexibility should be indicated by market-based price signals and that system operators should focus on their role only as a market facilitator, not as a dispatcher. Interviewees mentioned existing and emerging use-cases for flexibility, which are here divided into:

- financial, OTC and day-ahead market trading and dispatch planning of flexible capacity for long to medium term portfolio optimization,
- intraday and OTC trading and dispatch schedule changes for short-term portfolio and forecasted imbalance management,
- different long to medium term (capacity) TSO system-level reserve markets,
- different short-term (energy) TSO system-level reserve markets,
- and locational or other use-case specific bilateral contracts or markets.

Multiple interviewees stated that most market parties optimize dispatchable units firstly per unit and then all together with the forecasted non-dispatchable units as a portfolio. Because of this underlying unit-based dispatch planning and private information, interviewees with the capability to sell flexibility, indicated that if there are incentives in place to do so, they have ability to trade flexibility with more specific locational parameters. Still, fully accurate or trustable unit-based schedules and bids cannot be provided economically for small or uncontrollable units, for example below 1 MW. For these dispatches, flexibility sellers must forecast network use after aggregation. Regardless of this private locational knowledge of the available flexibility resources, there is currently little reason for market parties to develop flexibility market models or offer detailed flexibility to markets due to limited financial incentives or rules in place. This is because there are limited financial incentives or rules in place to do so. Some answers questioned the capability of parties from the regulated domain to procure flexibility cost-efficiently from liberalized or bilateral markets and whether these actions would distort other market activities as well. Numerous interviews highlighted, that the capability of different technologies and units to provide flexibility differs significantly when power, reactive power, activation time, duration, energy and any other parameters are discussed. Comments related to network domain added, that needs for flexibility resources vary significantly according to previous parameters and the location.

As an example of flexible resources, existing power plants combined with demand response of industrial consumption was mentioned most often. Second most often mentioned flexibility technology was emerging sector coupling to the heat, mobility and industrial sector via electrification. Industry-scale batteries and other energy storages were mentioned often for local use-cases. There was interest from the network domain to procure energy storages for network support from markets or with bilateral contracts, depending on how regulation interprets CEP. According to many flexibility buyers the fourth often mentioned technology for flexibility use was small-scale demand response. An interviewee highlighted, that different resources are not fully comparable. Many experts were concerned, that many network areas will have only demand side response left for local services if industry and heating systems will be electrified and combined heat and power (CHP) cogeneration is stopped. Experts saw that local and global flexibility is being simultaneously added with sector coupling but also removed with CHP mothballing or decommissioning. According to experts, many network areas face significant uncertainties related to voltage support and congestion management. This results from simultaneous migration of people and industries as well as from a rapid deployment of different and new types of network resources such as heat pumps, underground cabling, electric vehicles and distributed wind and solar generation. In many cases this is happening more rapidly than networks, regulation and permissioning can keep up with. As a conclusion an interviewee added that whatever technology and resources flexibility sellers use, it should be a simple as possible and most preferably wireless. Main reasons for this are the high unit-costs of flexibility control and measurement of distributed assets, as electricians are relatively expensive.

According to the interviewees, currently in most flexibility selling use-cases for the foreseen operating hours, the price levels or price volatility of different markets should be higher to trigger new investments. Investments are needed to use existing flexibility potential that is currently unavailable or to connect completely new flexible resources to networks. It was highlighted by an interviewee, that in parallel to increasing market pull for flexibility, the existing network and market rules must be reformed to support this behavior. Flexibility buyers saw similar emerging issues related to insufficient local supply, but contradictory to sellers, many flexibility buyers saw high price levels as a challenge. Flexibility buyers stated, that a trend of high price levels on local or system-level markets is an indicator for network operators or other market parties to invest into network capacity or flexibility. According to an interviewee, these hypothetical local investments could then destroy a local market and therefore flexibility sellers can trust local markets for only additional revenue. Still, investors should be able to have a locational price signal or at least indication of not preferable zones. Also, some saw system level markets as subjects to certain degree of market cannibalism already.

Flexibility for system-level markets, supported with revenue from voltage support and congestion management was identified as the most realistic near-future use-case for local flexibility. Outage support would be additional benefit from such installations or vice versa. Reactive power and voltage control with different devices was summarized as a joint service for common benefit from a combination of assets of network operators and network users. Reactive power tariffs and network rules issued by TSO or DSOs were seen as a major motivation for customers to invest into resources capable of delivering reactive power compensation. The experiences of experts related to voltage support were divided into two: slower and deterministic and faster and stochastic. Slower capability was needed to deliver scheduled reactive power compensation according to predefined schedules, mainly to limit reactive power tariff costs and minimize power losses. Voltage drops during high consumption have been known, but for example voltage rises during low network use are becoming an increasing challenge.

Lack of faster support, such as voltage control of power plants or other flexible network connected equipment, is a critical issue. According to the experts, there are large areas where voltage control during disturbances are becoming an increasing issue as existing flexible capacity like power plants are being removed and replaced with consumption and distributed generation. Experts added, that therefore network codes like DCC and RfG and new resources for those areas are needed to mitigate the emerging challenges. Identification of these areas includes high uncertainty. An interviewee argued that procuring voltage control and back-up supplies from markets creates a first interesting challenge and need for flexibility markets. The need was seen to exist even if there was no need for congestion management Still, if this additional voltage support is remunerated, it opens new questions about whether existing network users providing voltage support should be remunerated as well. Many experts argued, that both TSO and DSOs have now identified that they must start procuring flexibility for reactive power compensation at all voltage levels and congestion management in higher voltage levels. The reactive power tariffs from TSOs might have been a first push towards investments, but in addition to TSO tariff optimization, DSOs have also personal needs regarding fast voltage support. An expert concluded, that soon system-level balancing and straightforward thermal limit congestion management are not sufficient alone, as faster dynamics and instabilities are also increasing. All agreed that networks should improve their transparency and capability to signal market parties to offer more flexibility for local needs, because in most cases the flexibility will be otherwise offered to system level markets.

Many experts argued, that the need for flexibility is sometimes difficult to forecast or prepare for and the supply available might be insufficient to match the demand. Lack of visibility to the locations of flexible resources in networks and the overall status of the network itself was identified as an issue by many network operators. Real-time or short-term visibility was seen limited in own medium to low-voltage networks, but also in networks of other network operators. Some experts added, that this concept of shared visibility between TSOs and DSOs would be needed if the activation of flexibility were to effect on a broader area. Experts with tasks related to network operations and planning stated, that as the possible buyers of flexibility, they must have a comprehensible view of the available flexibility offers and the status of the network itself in order to procure locational flexibility. Contradictory to the previous, an interviewee stated that to increase their networks cost-efficiency, the company has optimized operations so, that below high to medium voltage transformers networks they have near zero real-time visibility. Expert added that if this needs to change in the future, networks must invest a lot and increase shared transparency, but next generation smart meters can provide a partial solution to this. Due to the limited locational need and the lack of visibility, the interviewees could not concretely say whether there would be temporally and spatially matching flexibility available at a reasonable cost.

Many network experts had done simulations to find possible emerging bottlenecks to proactively plan reinforcements for those grid elements. Some saw little situations where maximum capacity used at low voltage levels caused congestions. Possible congestions where identified to happen at medium to high voltage networks and often at transformers. Queries of experts from other networks in Europe supported these results, as there first challenges have occurred most often at the medium to high networks, most probably at transformers or high-voltage lines. Still, experiences of experts from outside of Finland where such that voltage and capacity issues have emerged suddenly and extremely fast and that existing markets and coordination mechanisms are not keeping up with this pace. Regarding medium to high voltage networks the views of experts where split whether congestions or voltage support challenges would emerge first, but some had already experienced significant voltage challenges and expected these to worsen. In general voltage support was identified as a more urgent need than congestion management, although the two challenges are interlinked. Many argued that they must prepare for both congestions and voltage support and any other yet unfamiliar challenges. As examples of such other phenomena harmonic resonances, dynamic instabilities and low inertia conditions where mentioned. Interestingly, some experts disagreed because they had identified low to medium voltage networks segments more prone to insufficient capacity and especially voltage challenges. Many interviewees argued, that all networks are unique in some way and there will not be one off-the shelf solution that would suit all network needs. Some experts speculated, that there is a high possibility that power systems will need all the possible grid reinforcements and the available flexibility they can get, if they plan to keep up with the energy transition.

5.2 Architecture and coordination of a flexibility market

Market architecture was a difficult theme for many experts as many interviewees considered themselves experts in only some of the submarkets. When dispatching of flexibility was discussed during interviews there was a fundamental difference between the financial and market-oriented viewpoint of flexibility sellers and the technical viewpoint of flexibility buyers. An interviewee pointed out that many flexibility market concepts are in the grey-area between these viewpoints and between regulated and competitive domains. Many comments expressed concerns about the other party being unsuitable of operating outside its domain and whether this kind of cross-domain conduct should be allowed.

Interviewee comments expressed that market parties demand transparent reasons for limited network capacity allocation, bidding zone definitions, redispatching, bid filtering, other special regulation and bilateral contracts. Many identified risks, if regulated parties would be active in competitive markets after network capacity allocation and no clear rules or monitoring are in place. On the other hand, experts raised concerns about the locational market power and other "gaming" possibilities in ancillary and flexibility markets. Some added that since gaming is happening on system-level markets already, local markets are posing a risk for making the situation worse. Other experts argued in favor of strong regulation regarding gaming, while others argued that only true market-based competition can limit gaming. An interviewee argued, that many places in need of flexibility, have in insufficient local competition and capacity for creating a technically or economically viable markets. There can be feeders with tens of kilometers long to only a dozen of small users. Full transparency and lack of market-based competition was seen already as an issue in system-level markets. Also, few experts argued that market parties could see the limited competition and transparency as issues, since full disclosure would reduce activity on such markets. No clear results can be concluded regarding gaming, although almost all saw it as a major issue.

Regardless of domain, experts supported a customer centric market architecture. According to answers, an asset owner should be able to use flexibility itself or sell the flexible capacity if markets provide a better price. One answer pointed out that a flexibility seller does not care if the buyer is a network, another market party or both parties together. Still, coordination processes between different network operators, market operators and market parties should be transparent, market-based, avoid fragmented market situations and unnecessary mandatory requirements for the flexible resources. For a future architecture vision, it was presented that FSPs, BRPs or retailers should be the currently missing link between customers and networks. This must be done via open markets as this should be the primary or only way of doing things. If networks need to procure flexibility, for example when night-tariffs are phased-out, they can get contracts from service providers which can pass on the revenue to their customers. Multiple experts stated that in order to operators and traders to focus on balancing and trading, congestion management and other flexibility trading should be done preferably well before the balancing window. Still, many argued that in cases of disturbances, congestion management and voltage support must be done reactively during the balance period and therefore not everything can be solved with preventive actions before the operational time unit. Also, availability for these moments must be ensured somehow. Experts also argued, that even though accuracy of forecasting is increasing and changes in wholesale trading, balancing markets and imbalance settlement might reduce the bindingness of production schedules there is still a need for schedules, since transmission management and capacity procurement planning is dependent on those. Proactive procurement of balancing, voltage support and congestion management, general forecasting and mFRRsa were seen dependent on good quality schedules. No interviewee had answers what is the TSOs, DSOs and network user's motivation to share good data in the future, if this is needed for multilateral transmission management.

Interestingly, the current status of network operation unbundling was seen to have positive and negative sides when flexibility markets were discussed. For example, when utility unbundling is done at accounting level and there are similar owners in the both networks and users, there is a possibility that the incentivizes of the parties are aligned. Network users know that even though they might not preach their individual limits, the possibility of reducing the costs of the network operator might be directly beneficial to their shared owners or partially to them via reduced tariffs, if the network operator does not have to pay for subscription level violations or invest for rare peak-load situations. Still, limited unbundling, customer lock-in and locational monopolies were seen as a major issue for flexibility markets. Interviewees argued that DSOs who still have competitive business operations in their concern should always separate decision making and pricing. This should be done so that they do not discriminate other market parties or undervalue their own network assets. Aligning of benefits and costs of consumers and networks was mentioned multiple times as a prerequisite to flexibility markets, but with few solution suggestions. Current situation of tariffs was identified as a major hurdle since the share of energy-based generation and consumption costs were seen decreasing and the share of fixed capacity or power-based network costs as an increasing part of total costs.

Interviewees from both the market and regulated domain were unanimous that the only goal of networks should be the minimization of total lifetime cost of network service while keeping sufficient security of supply in mind. Questions were raised on estimates on the cost of developing and operating flexibility markets and if there are any realistic alternatives. Many argued, that TSOs and DSOs should use locational flexibility only if it provides a cheaper option than networks assets in the long run. Therefore, network operators should avoid underinvesting, particularly when medium to high-voltage networks and cross-zonal interconnectors are planned. These network elements were seen as the most inclined to experience the majority and the first incidences of foreseen congestions and voltage challenges. Some added, that low-voltage network voltage challenges are their first priority. According to an expert these connections also have the biggest impact on wholesale market price formation as they are needed to transfer most of the power even in decentralized generation systems. Differing opinions were presented about whether the low voltage networks are the first foreseen challenge. Still, many experts stated that DSOs must invest into lower voltage networks anyway, due to the current regulation model, and some feared that higher voltage level network planning might be neglected as a consequence of this.

An interviewee stated that all historical sizing principles and planning in general are challenged since existing usage is replaced with new types of consumption and generation. Typically, this new usage has varying power factors and higher peak powers and volatility. Therefore, the power and voltage support needs are increasingly spatial and temporal and happen on multiple voltage levels. For example, a specific area might have large network use only during cold days, another one on weekdays and a third one only on summer weekends. Regardless of this, it was identified that even when designing grids for the peak utilization, some locational flexibility must be available. Another expert proposed a design strategy which focused on the costs of flexibility. Where there is foreseen low-cost flexibility available for future use the networks can be sized for the average power consumption situation. If there is foreseen to be a limited amount of locational flexibility or the lifetime cost of utilizing it is estimated to be higher than network reinforcement cost, the reinforcements should be chosen. Many interviewees highlighted that the marginal cost of additional network capacity during reinforcements is extremely low in relation to the cost of flexibility currently and foreseen to be available. One interviewee concluded that grid design should not leave bottlenecks into grids below high-voltage levels. According to interviewees grid segments in many places, must now be rebuild anyway due to their age. This is because of the current reinforcement debt, resulting in congestions, disturbances and poor voltages. When renewing networks, many argued that it would make little sense to undersize networks, since higher capacity removes uncertainties related to voltage and capacity control of future's highly distributed and automated electricity networks and markets, where totally new kinds phenomena and behavior are taking place.

According to experts there are many parties interested to control flexibility: resource owner and operator, other FSPs, DSOs and TSOs. Also, power exchanges or other market operators were seen to have an increasing role in dispatching. The use cases for balancing, wholesale and flexibility markets were seen also interlinked. Questions arose in interviews regarding who will do the actual control of resources physically, financially and contractually. This could not be answered during interviews. Also, locational trading on wholesale or balancing markets with some degree of SO interference raised many comments, where many opinions were not unanimous. No single interviewee had a fully complete set of ideas on how this cross-process and multilateral coordination should ideally take place and many suggestions where contradictory. For example, some argued that DSOs should be given priority to choose flexibility first, but when TSOs and DSOs would have conflicting interests, the TSO need should be prioritized.

Some experts agreed that to enable flexibility markets we must have good prequalification process and bids with locations. For example, DSO topologies can sometimes last only some minutes and flexibility use must adapt to this in some way. Modelling of the entire network with all nodes in the model will take multiple hours. Prequalification and dynamic prequalification will need some abstracting and flexibility must be procured in advance according to the joint TSO-DSO need forecasted. Bid filtering and unavailability marking for congestion management in balancing markets spurred many questions about fair treatment of BSPs that could not be discussed in full detail during interviews. Many argued that if DSOs have very limited needs, they would almost always take very little part in the coordination, except for large TSO activations related to DSO connected resources. Also, many saw the possibility of a DSO requesting or blocking manual balancing activations of mFRR offers for congestion management or voltage support purposes both as a challenge and as an opportunity. Also, joint TSO-DSO impact on wholesale, FCR or aFRR resources was discussed, but some argued that these markets should be outside DSO jurisdiction. One comment stated that in many situations the local flexibility need for an area is in the same direction for both TSOs and DSOs but added that opposite direction system-level balancing needs might worsen the situation if activated. Questions were asked about TSO-DSO coordination and how the linking of this data exchange to market offers and market clearing could be done best, but this was left open. An expert concluded that some abstraction of the topologies must be done so that TSO-DSO coordination can with the network model help flexibility markets to operate.

Many interviewees argued that flexibility markets are now discussed at a difficult time since the role of balancing and wholesale markets is being currently extensively revamped. Many saw self-balancing via dispatch planning and near real-time wholesale trading changing future imbalances and imbalance costs of some parties significantly. Some argued that the need for proactive balancing will change so much that balancing and redispatching with mFRR will be increasingly less desirable. This can lead to situations where mFRR balancing or congestion management with mFRR offers will be impossible. Some experts speculated that real-time knowledge of balancing price or quantity and direction is a must if TSOs want to enable self-balancing, and if this were coupled with locational needs, could self-balancing be locationally specific. Compatibility of self-balancing and single price and single position imbalance settlement model in relation to flexibility markets was a concern raised by almost all interviewees.

Some mentioned independent aggregation as a prerequisite for flexibility markets in this context but had limited ideas what would be an optimal way to proceed. Some added that independent aggregators should be held accountable for the imbalances and any other costs they might cause other parties. An interviewee speculated, that independent aggregation can possibly offer flexibility for balances of multiple retailers or BRPs and networks at the same time and these can change per ISP. Thus, multi-user value-stacking is enabled, meaning higher prices for a flexibility sellers and lower prices for flexibility buyers. In such cases, processes flexibility markets must be highly automated. Many argued that all existing and new market participants must have equal rights and obligations in the market, so therefore closed bilateral products should not be allowed and fair settlement is needed also for independent aggregators. According to experts if these issues are solved, then existing market parties do not have issues with the new forms of competition on markets.

Conflicting market time units, imbalance settlement periods and overlapping bidding periods of many markets make trading and dispatch planning increasingly difficult and increase risks-premiums in prices. Most often the simplification and possible reduction of the number of system operator operated single-buyer markets was mentioned. Many could not say which markets should be eliminated first, but some were in favor of reducing mFRR markets first, while others argued against this. Still, most experts argued that regardless of the difficulty, the tasks of bidding and market selection should be completely left for market parties and their service providers.

Many interviewee comments related to buying of locational flexibility stated that flexibility markets should preferably close well in advance of real-time. Reason for this was the complexity of the TSO-DSO coordination, capacity securing and the physical importance of this market. Counterarguments raised the question about how early the flexibility sellers would be willing to trade system level or locational flexibility if this would then freeze that resource to an unit-based position. Also, some argued that we cannot have two different ways of trading on a specific market, since if unit-based trading is in place alongside portfolio trading, there is a possibility for double-spending the same capacity. Most concerns were raised against unit-based bidding in wholesale markets, but some interviewees argued this as the best option. Reasons for selecting locational wholesale trading as a mean to alleviate intra-zonal congestion were related to liquidity and competitive environment of wholesale markets. Opposing arguments were raised that this would distort the zonal market model and semi-competitive single-buyer markets of both TSOs and DSOs should be preferred. Still, for some, neither locational intraday or balancing are suitable for their needs and bilateral contracts are needed.

Contradictorily interview results indicate, that according to some expert's, market development should lead towards cascading or sequenced markets, while other interviewees stated we should have only overlapping and near or at real time closing markets. When sequenced markets are used, traders should be able to know the results of the previous market clearing before the next, to increase competition and avoid double activations. An expert highlighted that in the current situation capacity is reserved for a single purpose during a market period so it cannot participate to many markets. Therefore value-stacking is possible for many users, but still via only one market. On the other hand, if only overlapping markets are in place, markets should have offers that can be cross-process linked. Then an activation on a flexibility market means, that the resource is not suitable for trading on the intraday or balancing market and vice versa. Automation of market and offer integration was identified as the solution to many issues in both scenarios. Interviewees favored to establish market-based tools for testing flexibility trading, where key needed features are the aggregation, activation and settlement processes.

Few experts indicated that TSOs should more clearly define the roles of FCR, aFRR, mFRR markets. Also, clearer definitions and more flexibility in the way SOs procure mandatory and additional voltage support from network users with the possibility of remuneration was mentioned as a request by some. Part of the interviewees argued, that a full separation of balancing and flexibility markets should be avoided since fragmentation and centered domestic or international competition is an issue already on the FRR markets. Most interviewees agreed that at minimum a reform to the voltage support and current redispatch mechanisms is needed, at least in terms of transparency and market accesses. Opinions related to coordination of local sellers and buyers can be divided into long needs with availability payments and shorter demands with locational energy trading. Some argued, that local markets in general will lead to nodal markets and should be avoided at all possible ways. Still, a vast majority favored market-based redispatch and voltage support procurement over regulated or central-dispatch models as they saw market-based model as fair, cost-efficient and in accordance with CEP and other regulation.

Interviewees agreed, that DSOs must be joined to TSOs flexibility markets or otherwise no flexibility sellers will join such local market. A possible flexibility capacity market linked to balancing capacity markets or as a separate TSO-DSO flexibility capacity market was seen reasonable by many interviewees even with possible network capacity allocation reductions, if the justification, results and costs would be presented openly. Lead-times and contract periods of this hypothetical TSO-DSO flexibility capacity market were under strong debate. Some argued, that many will not sell or buy flexibility if it must be done for short periods, while others stated that they will not buy or sell local flexibility if the resource must be reserved in advance to a market for long periods. Network related comments stated, that they would be interested to pay some compensation and selling related comments stated, that they would sell if the price was high enough. Regardless of differing opinions, many experts agreed that if there is almost any kind of market for local flexibility, market participants will offer.

After short-term discussions, interviewees often asked on how would the longer-term availability or capacity market results for congestion management or other flexibility use-cases be realized and activated. Most argued that it does not make sense to create a separate congestion market for TSO-DSO congestion management, as it would not attract liquidity. Many saw self-dispatch during congestion with no energy trading as most the most reasonable and as the easiest option to implement. An expert added, that distributed flexibility can be controlled in many ways: manual SO control, self-dispatch according trades with FSPs or other machine-readable price or other indicator provided in a SO website. This also raised many concerns to market fragmentation, limited open access in real-time, verification and settlement, unclear remuneration and balance deviation created. Majority saw allowing this as a possibility in special or demonstration cases, but some were worried if such method would then become business-as-usual for networks. Also, when the possibility of combining congestion management either with balancing energy or wholesale markets were discussed and the opinions of experts where split. Some argued in favor of combined balancing and congestion management similar to the current situation in Finland, while others argued that locational wholesale markets should be preferred. Little justifications for these opinions were given. Most interviewees highlighted that it must be jointly discussed within industry whether locational parameter should be included in flexibility offers, regardless of the market, and should these locational parameters be mandatory or optional. An expert added, that a TSO-DSO coordination mechanism to must be formed when two non-optimal bids are compared to choose. Also, it must be monitored how much flexibility can be delivered. Questions were asked if mandatory or even optional unit-based bidding incrementally introduce nodal markets with non-market based central dispatch by TSOs. Production schedules were considered as a similar binding and restricting element, which should be completely removed or changed to better support portfolio-based self-balancing. Experienced issues concerning production schedules were related to the early submission and unit-based compliance because of the existing imbalance settlement model. Introduction of mandatory or optional consumption schedule submitting was not supported. Some saw the timing of flexibility markets as the most important point to define first. Some saw that these should be done well in advance while others supported models where flexibility should be procured together with balancing, after liberalized markets would be closed.

Experts commented also about the actual market interfaces used for flexibility trading and trading in general. For example, reducing the number of interfaces that traders and operators must maintain, would benefit all. One solution this was the possibility of detailed wholesale bids being suitable also for TSO-DSO flexibility or balancing markets. This was suggested because interfaces to exchanges is something that most market participants, BSPs or FSPs have at minimum. One interviewee added that currently traders see more than 20 different products on markets. This is was experienced too divided already, and therefore the need to link products and offers is a evident. To summarize the conflicting views and confusion of experts related to flexibility and future market architecture in general is that many do not know which will be the market for trading local flexibility and how important flexibility markets will be in relation to system level trading which is also in the midst of major changes. To this an interviewee asked: "In retrospect the Nordic market model has seemed historically successful. Now almost every European country, grid planner, system or market operator seems to go in different directions. Towards what architecture vision should the Finnish design develop to?"

5.3 Flexibility products and other steering mechanisms

Expert comments about product parameters were divided into updates to existing products and completely new products. Some of the comments related to market architecture in Chapter 5.2, answered to product questions and are not mentioned here again. This was partly caused by the question layouts, but still underlines that even industry experts talk overlappingly about competitive and regulated domains and sometimes mix markets, products and services under one definition. All interviewees highlighted that we need all available flexibility to the markets. Therefore at least nationally harmonized tradable products are needed. They should work for:

- large and small flexibility assets,
- during short and long durations,
- flexibility needs of DSOs, TSOs, market parties and other FSPs,
- where the activations can be fast or slower.

Firstly, experts were asked about their experiences with the current electricity market products. An expert pointed, out that gate closures, market time units, bidding sizes and activation and settlement rules are the most important product parameters and market design parameters that need to be redesigned first. Constantly updated rules and products on wholesale and ancillary markets were often mentioned by interviewees as an example of the uncertainty that market parties and service providers are facing. Especially capital-intensive investments see this uncertainty as the biggest challenge. For example, many saw that moving towards 15-minute market time units in wholesale and balancing markets means, that some flexibility which is currently not used can be offered to markets, but some existing flexibility can be lost if longer products or block bidding is not allowed. Some also added, that prequalification tests, real-time telemetry requirements and control signals for any product should be thought carefully and designed with universal usability in mind so we do not exclude any possible flexible assets when designing technical rules.

Many saw that wholesale market products have well-defined parameters and that this is the primary market of their operation, although there where exceptions. Few argued that balancing energy markets are not either suitable or profitable and instead many flexibility resources look firstly into FCR. Bids with underlying assets not suitable or not selected for FCR are then offered then mFRR or aFRR markets or to intraday markets if a good match was found. In future, self-balancing and imbalance settlement as a market mechanism was seen to have a growing role. Market time unit definitions for flexibility products resulted in many opposing opinions and the mix seemed confusing for many interviewees. For example, an interviewee pointed out that future FCR-markets work with a 60-minute MTUs, assets are measured and settled either with a 15-minute or 60-minute resolution, balancing markets have overlapping 15-minute MTUs, wholesale market trading is done in 15-minute and 60-minute resolution and flexibility markets can have varying products. Many hoped for a clear answer to what would be an ideal market time unit for flexibility markets. Questions related to wholesale, balancing and flexibility market bidding periods were a topic that spurred arguments. For example, multiple requests for European IDCZGCT and IDGCT harmonization were given by many experts. Majority found overlapping bidding and activation periods of continuous intraday, aFRR, mFRR and flexibility products too difficult for flexibility sellers and flexibility buyers.

Experts were presented with three flexibility product options: locational intraday products, locational balancing products, including both mFRR balancing energy and capacity products, and competitive bilateral contracts. Experts could not present any other alternatives, but some mentioned the utilization of dynamic tariffs jointly with these products as an option. An expert started a discussion about longer competitive bilateral capacity contracts mimicking the current status of many bilateral flexibility use-cases and therefore market development should firstly enable those. Later this can be gradually changed towards shorter auction periods with reduced shares of availability and increased shares of delivery remuneration. Some argued that since the network needs flexibility only occasionally and suddenly, long term and availability products are the only realistic option. Many disagreed with bilateral contract auctions and stated that these should not be used, or if needed, only as a premarket for open flexibility energy markets. Some experts supported locational intraday products, while many argued against these and supported of using only balancing energy products for flexibility activations. In both cases, interviewees argued that SOs should signal via market interfaces to flexibility sellers to what market, where and when they would like have offers placed for local flexibility.

Many experts mentioned that control rooms of DSOs and TSOs should not be limited in any way. Especially in emergency situations they should be able to utilize whatever flexibility via any market or mechanism, as long as they bear the costs. Many experts saw no obvious problems with any of the presented product alternatives but felt uncertain about saying anything concrete straight away. Majority of experts stated that they would first need to see clear examples on how these flexibility services would be procured contractually and how the physical activation would be done. After this they would estimate the financial profitability and offer or procure services from markets if it would make sense for them.

Marginal pricing for both capacity and energy flexibility products was requested, while many argued that in some cases the results would lead anyway to pay-as-bid pricing. Many wished for flexibility capacity and energy markets to be developed with smaller than 0.1 MW minimum bid sizes. For example, a bid size of 1 MW or 0.1 MW of locational balancing or intraday markets can be too large for DSO needs, and thus bilateral flexibility contracts are needed. Also, these markets are not fully compatible to purposes not related to active power control, such as voltage support. Bidding period for long term flexibility capacity was imagined happening well in advance, for example, months or years ahead if new investments must be done. In the case of flexibility capacity markets being used without flexibility energy markets as after-markets, some experts argued in favor of self-dispatch while others for SO dispatch.

Shorter period flexibility capacity market was discussed to happen together with mFRR capacity markets or as a separate market. Some comments highlighted that maybe a separate flexibility capacity market should be established to ensure the mFRR capacity market does not get too complex and because there might be a TSO-DSO flexibility market interface anyway. Some disagreed and supported to use the mFRR capacity market as an interface for local flexibility procurement, even though the possible D-2 GCT was found problematically early for some resources. An alternative suitable bidding period for shorter term flexibility capacity market would be before day ahead trading or after day ahead results. Some comments favored the latter, since this data would provide more accurate results for TSO-DSO flexibility need forecasting and offer matching.

Many experts argued in favor of flexible network connections and competitive bilateral contracts, while others were against these. According to some interviews, there are very little network users, apart from summer cottages, that currently truly want to opt for reduced security of supply, regardless of the possible cost reductions. On the contrary, many large consumers already pay for increased security of supply with back-up connections and reserve generators. Still, there are some customer types that induce large socialized costs to other users, while some customers would like to opt for microgrids. An expert argued that these talks related to grid balkanization affects everyone negatively, and such talks should be abandoned now, if the microgrid or individual users plans to use the existing system even occasionally. Many argued that SOs must anyway reinforce the lines because most flexibility cannot save networks during storms. Only in cases where a reinforcement is coming anyway and there is a faster connection to a weak segment for a limited period or conditional connections for some network users this is reasonable. In these cases, networks can connect users earlier or more resources to a segment without reinforcement for very limited use. An expert argued that in order to simplify things, flexible connections should be done with a two-contract model, where the secondary contract adds on top of the original contract and possibly remunerates the network user separately.

Most argued that while the status quo with high and increasing share of fixed costs in tariffs might be cost-reflective to networks, it is not supportive for flexibility. Many agreed, that well-defined static power-based tariffs are suitable to act as a framework for network users. Still, some argued that dynamic tariffs are not cost-reflective and do not solve the true underlying issue related to dynamic network control, linked to both balancing and transmission management. An expert suggested that moving towards a retailer centric model would reduce issues related to the some of these issues, since the retail customers could opt for paying a grid service fee. An expert stated that if no other ways to control networks will emerge, TSOs and DSOs will have to introduce hard power-based tariffs. Regardless of complexity of regulation related to this topic, most argued that different kinds of updatable dynamic tariffs and other fees would be a desired way to incentive network supporting behavior.

Dynamics tariffs in combination with other types of flexibility contracts seemed reasonable according to other experts. Linking dynamic tariffs to real-time energy prices was seen problematic, since for example, day-ahead results following tariffs would distort zonal market behavior and following old day-ahead results would be not beneficial in cases where intraday trading has altered dispatching significantly already. Dynamic tariff parameter components linked to frequency were seen as a poor alternative to FCR-market, which should not be developed. Parameters linked to congestion management, for example, time varying tariffs for an area or parameter components linked to voltage control were seen problematic by experts in many cases, because of regulation and the difficulty of updating correct tariffs for each area continuously. As stated in expert comments in chapters 5.1-5.3, a preferred option would be to procure these as services from markets, while keeping more static power-based tariffs as a framework for flexibility markets. FSP would be able to transfer part of remuneration that they would get from the network operator or market parties for the services provided. For example, a grid user could get remuneration from the FSP if they opted for a flexibility contract.

Related to flexibility product alternatives, the biggest open question left was settlement and verification of flexibility delivery. Flexibility buyers and sellers both stated, that if a product is traded, they must know what is being paid for. Options for using unit-based market position and production and consumption schedules as a reference for flexibility settlement where excluded by most experts, since they were not seen compliant to self-balancing. Baseline-methods with statistical ex-post analysis and fine-resolution metering verification were mentioned as solutions by few. An expert asked who would be the right person to do such a baseline or schedule definition: flexibility seller or flexibility buyer? Both were seen as biased parties and a third-party settler was seen needed. Also, for some types of resources the possibility of granular sub-meter monitoring was discussed. Interviewees did not have answer for what should be the preferred way of proceeding, since the behavior of each unit will differ significantly, and the theme was seen too difficult. For example, a baseline-definition and schedules or fine-resolution metering, for production, consumption or storage devices will differ significantly and therefore one model will not suit all cases. Still, such processes must be reasonably simple and automatable. An expert concluded: “Current market products, verification and settlement are far from perfect, why should flexibility products and processes be any different?”

5.4 General comments, development ideas and other feedback

Contrary to the division of flexibility sellers and flexibility buyers, during interviews many experts interestingly commented on the rules and mechanisms related to flexibility use outside the responsibilities of their current organization. This was a clear indication that utilization of flexibility is an evocative and constantly developing concept with limited harmonization. The overall themes in the questions were familiar to the interviewees, but details divided the experts. Only a part of interviewees was able to say anything concrete about some of the questions. Emerging concepts and topics were the most difficult questions, for example, flexibility initiatives, like GOPACS, PICLO FLEX, NODES and ENERA, were new to most. Some had done, were doing or were about start on-going flexibility development and piloting in other research and development projects. Also, there was no full understanding of current status of flexibility markets. Flexibility activations via bilateral and balancing energy markets like redispatching and countertrades and voltage support procurement raised mostly confusion. Many saw, that they can talk only about their own situation and that flexibility needs of different parties are unclear to them. In general, interviewees were interested in the topic and supported the thesis and further open and industry wide research into the topic. Many highlighted that the topic seemed novel and futuristic, and questioned the industry’s capability to develop such flexibility markets. Experts had significant disagreements regarding the flexibility needs, the suitable technologies and other technical details which are not shared more due to privacy. Many questions in the interview material raised a lot of counter-questions, that could not be answered during the interviews. For example, interviewees asked questions, like:

- How much system-level and local flexibility do we need in the future?
- What will be the cost of this local flexibility and the operational costs of these markets?
- When do we exactly need to have these flexibility markets operational?

- How will the regulation model support the use of flexibility?
- What is an ideal ownership structure of flexibility markets and coordination platforms?

Many added that while they fully support this discussion and launch of a new development project, they are at the same time worried about the capability of the industry, particularly of TSOs, to complete existing projects they have started. Also, many saw that for example, BRPs, electricity retailers and DSOs are in the same difficult situation with the market and regulation changes. There is insufficient internal knowledge in many organizations and many of the few service companies are fully booked already for the 15–minute ISP and Datahub-projects. Developing flexibility markets were seen as a secondary priority in many organizations. A non-exhaustive list of these above-mentioned projects:

- European or Nordic balancing capacity and energy markets,
- independent aggregation pilots,
- shorter ISPs and MTUs on different markets,
- single price and single position imbalance settlement model,
- Datahub,
- bidding zone reconfigurations,
- intraday auctions and harmonization of market GOTs and GCTs in general,
- retail, wholesale and financial market development,
- tariff component harmonization,
- multi-NEMO arrangements,
- market integration or offer linking in multiple markets,
- flow-based capacity allocation, allocation reductions and Nordic RSC company.

Majority argued that flexibility markets will not be a major priority for trading, as system-level balancing is more urgently developed. Experts saw that during next years the trading volumes will increase in the intra-day, balancing, reserve and possibly in the flexibility markets and in general during shorter timeframes. Many interviewees saw that intraday markets and self-balancing start to replace proactive mFRR and day-ahead markets. Some argued that reserves should be procured with shorter rolling auctions near real-time. To enable self-balancing also in possible two-price situations an interviewee argued for an aftermarket for imbalances. Linked markets, meaning that unused bids in one market, should be transferrable to other markets, were mentioned as a target to enable easier flexibility market development. Also, linked offers meaning that an offer being realized can lead to another bid being submitted or removed in the same or other markets, were mentioned by many. Cross-border flexibility market harmonization was argued by experts to be the next step after development of national flexibility markets.

In the interview background material, it was mentioned, that flexibility markets might need a datahub linked flexibility register to possibly monitor, verify, settle and possibly activate flexibility delivery automatically. The possible introduction of a flexibility register raised a lot of questions. Some experts questioned the need and occurred costs of a such flexibility register. Still, many interviewees supported such a functionality, since the introduction of thousands of small-scale flexible resources to markets, fair independent aggregation and future settlement in general requires this. This topic was left open and further researches should analyze if flexibility markets can work without such a register. The concrete functionalities of a TSO-DSO coordination platform were also left open and it raised interviewee speculation. Reliability of IT-based systems and cybersecurity raised a lot of concerns when flexibility platforms and markets were discussed, although all agreed that automated systems are a must.

Many experts argued that the current regulatory model should be updated to match the current situation as for example, currently flexibility and service procurement is undervalued. Allowing total expenditure framework (TOTEX) in some regulatory cases, could support the use of flexibility by aligning network and network user incentives better. This means allowing service procurement as a part of the expenditure allowances of SOs. Examples of possible modifications varied regarding dynamic tariffs, bilateral contracts, unit prices of network components, electrical storages as part of networks and are not discussed here further. As a key next step many mentioned that regulators should define harmonized product parameters for distribution and transmission products and especially tell how power-based issues should be tackled. In general, the capability and resources of market surveillance and regulation were questioned, especially now when flexibility markets are introduced. Extension of Regulation on Wholesale Energy Market Integrity and Transparency (REMIT) or similar monitoring to flexibility markets was discussed as a possible solution. Many added that market-based investments are challenged if rules on different markets are constantly changing. An expert added that in near future we will need tens or hundreds of terawatt hours of clean electricity to clean the electricity sector and other electrifying sectors. Flexibility markets and other rules should be in place before this to reduce the risks related to these changes, not to increase them. Some experts added, that it is interesting to have industry-wide discussions on whether reactive power, inertia and black start capability should be more compensated. Others argued that it would reduce cost-efficiency of all parties, since networks are already maintained with shared resources of SOs and network users. Remuneration of additional or enhanced support above minimum levels was mentioned as a good place to start tests regarding these ancillary service markets.

To alleviate complexity concerns related to existing markets and possibly emerging flexibility marketplaces, interviewees highlighted that allowing close to real time trading on all energy, capacity and flexibility markets as a preferred option to reduce risks. Also, possible network capacity allocation reductions done by SOs should be justified based on demonstrable socio-economical welfare benefit of all affected parties in Europe. When flexibility markets are piloted stakeholders should be provided with an easily accessible interface to test and investigate emerging markets. Experts added that it will be hard to offer flexibility without knowing how much will be procured and therefore flexibility needs, location and revenue forecasts should be provided. In these pilots, end-to-end testing of trading with aggregated bids must be tested, not just conceptualized. Experts argued that since markets and bidding is already automated, next steps should focus on market integration. Market or bid coupling is difficult because most of markets are binding.

Many argued strongly, that further development should separate more clearly the regulated and market-based roles. An expert added that when conducting pilots, demonstrators should not plan market calls, otherwise no natural market behavior will happen. Many added that further development should continue with open debate and incremental experimentation and when doing so data formats, interfaces and processes should be harmonized and open to make joining easier. A domain cross-cutting consensus highlighted that especially now when there are limited local challenges in Finland, network companies should both invest into grids and test flexibility markets, while they can. News of emerging network challenges around Europe were seen as a major concern and many interviewees agreed that these should be avoided in Finland with preventive actions. Most of interviewees provided conditional preliminary interest to test flexibility markets.

5.5 Summary of industry consultation results

Many interviewees had not yet experienced serious local flexibility issues in Finland but were familiar with issues in other countries around the world. System-level flexibility use-cases were given priority over local-level flexibility by many experts. Experts argued, that there has been and will also be in the future more technical needs and market-pull for system-level markets. Many argued that in Finland, local flexibility needs have been minor due to development of strong high-capacity transmission and distribution networks. Some added that this method has been often the only possible technical or economically cost-efficient solution, and this has resulted in higher cost-efficiency than co-utilization of flexibility and networks. Many saw electrification and electrical networks as the platform of many future business and added that as old infrastructure in European electrical networks must be renovated anyway there is little point not to reinforce grids while doing so.

Regardless of this, majority of interviewees saw flexibility worth considering for some foreseen local applications if this could be done cost-efficiently. Outage management and voltage support with flexibility were identified as the most urgent local needs and congestion management was seen less important. Many argued that technical and financial problems in local networks and markets seen in different countries around the world will emerge in Finland soon. Many interviewees found the proposed flexibility product alternatives challenging to asses and had little or no new ideas to add. No clear favorite product alternative emerged, but many opinions of experts were contradictory. Still, preference to go forward with development was mostly divided between three product option categories: locational intraday products, locational balancing products and different kinds of competitive bilateral flexibility contracts. Also, dynamic network tariffs were supported widely, but the correct method to include system-level or local price signals into tariffs could not be answered during interviews.

Flexibility sellers were more optimistic about their capability to sell on flexibility markets, than flexibility buyers were about their capability to buy on flexibility markets. To continue with development of flexibility products, many interviewees wished for interoperability of market interfaces, harmonized data exchange standards and processes, simpler rules and mechanisms on different markets and a clear division of roles between regulated and liberalized domains. Majority were interested in some way planning to continue flexibility development.

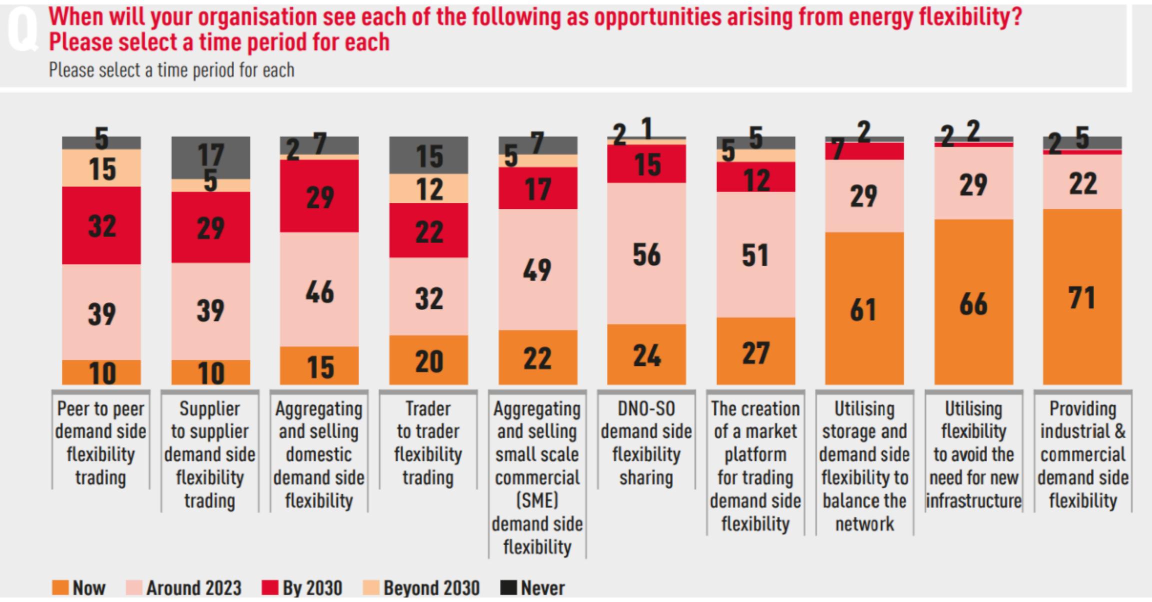

Figure 19: Development drivers for flexibility in 2018 as seen by UK utilities (CGI 2019).

To accurately compare results in chapters 5.1-5.4 to other industry consultations is difficult. Still, Figure 19 shows similar results, which were obtained from a UK utility consultation, where many indicated that flexibility is having a major system-level role. Latest around the year 2023 the local need to have flexibility is increased up to a level where flexibility markets are needed according to a majority. Interestingly reinforcement deferral was seen by two thirds as an opportunity already today. Differences of these to results in chapters 5.1-5.4, are here assumed to be related to the regulatory model and status of energy infrastructure. The results presented in previous chapters, showcasing industry confusion and contradictions related to a complex and non-mature smart grid environment, are aligned with a similar Finnish industry consultation during 2012, regardless of the changes happened since (Aaltomaa 2012).

Table 5 summarizes the results of the survey according to main conditions, while details are shown in chapters 5.1-5.4. There are major changes expected to the physical needs and sources of flexibility in a short period. Also, the ownership and dispatching of flexible assets were seen subject to be modified. Flexibility trading platforms and related mechanisms were seen to be developing fast during the following years, although majority saw that these will not be ready in 2024. Points with limited significance or uncertainty are in parentheses. It can be seen from Table 5 that major uncertainties are linked to year 2024 and flexibility markets.

Table 5: Development trends of flexibility during 2019-2024 as seen by interviewees.

Condition	2019	2024
Flexibility supplied from	Hydro, interconnectors, CHP, fossil fuel power plants, demand response	Hydro, interconnectors, reduced CHP and fossil fuel power plants, demand response, (EES)
Flexibility supply location	Mainly centralized medium to large units	(Increasingly centralized in terms of energy but decentralized in terms of power)
Flexibility needed for	System level: wholesale, balance mechanism. Local: voltage support, occasionally CM during faults or maintenance	System level: wholesale, balance mechanism (including self-balancing). Local: voltage support, outage management, CM
Flexibility need location	Local needs are limited, (north-to-south transmission)	(Hard to forecast. Increasingly dispersed problems)
Flexibility buyer	TSO, (DSO)	TSO, DSO, (FSP energy communities)
Local flexibility procurement method	Limited. Private bilateral trading or using balancing markets	Privat bilateral contracts, competitive bilateral contracts, (flexibility markets)
Flexibility products used	Locational balancing energy products, private bilateral trades	(Locational balancing energy products, locational wholesale products, competitive bilateral flexibility contracts, dynamic tariffs)
Local flexibility pricing	Case-specific	(Increasingly market-based/competitive)
Flexibility settlement	No settlement or case-specific	(Increasingly standardized)
Flexibility dispatch	Mostly TSO or DSO dispatch	Increasingly self-dispatch from to market signals or (multilateral TSO-DSO dispatch)
Harmonization	No harmonization	(European guidelines with national or regional implementation)
Resource ownership	Competitive parties, SOs	Competitive parties, (SOs)

6 Flexibility products for multilateral power system management

This chapter proposes the most promising flexibility products for future development. The proposals are based on literature review in chapters 1-4 and the industry consultation in Chapter 5. Flexibility products are traded multilaterally with many network operators and market parties. Market interface of these markets can be separated or integrated with the existing system-level markets, but in both cases separated pricing, trading and cost-allocation rules are in place. Here flexibility products are in place for the purposes of networks, meaning that different network operators are the buyers of flexibility and different kinds of FSPs as sellers of flexibility. FSP to FSP and other liberalized flexibility trading are assumed to be done on system-level markets. Also, FSPs can optimize their own resources for their own locational needs in the future, as they can today. In cases where many FSPs need to trade locationally and these needs differ from network needs, the trading can be done with bilateral trading. Established system-level products on wholesale, FCR, FFR and FRR markets, are not examined here.

Flexibility products in this chapter are not totally new products to be traded on separate flexibility markets, but rather modifications of existing products. This is done to foster liquidity, increase competition and to make the products reasonably simple to use, while robust enough to deliver many types of services securely. For locational intraday and balancing products, the modification is locational information to existing offers. These offers are multiples of standard products described in Chapter 4. The modification can be the marking of the underlying regulating object (RO) in question or using EANs. In competitive bilateral flexibility offers, the modification is holding open auctions instead of private bilateral trading.

6.1 Technical details of flexibility products

Flexibility products here are like those presented in Chapter 4, but with modifications based on industry views from Chapter 5. For example, in Chapter 4, dynamic tariffs and flexible service agreements were identified as a potential flexibility product, but due to industry consultation results in Chapter 5 and other studies, these are excluded here (Gaia Consulting 2018; Koski 2017). Instead, it is here assumed, that similar results can be achieved with market-based competitive bilateral flexibility contracts. These can be used for similar services as dynamic tariffs and flexible network service agreements, when these contracts are linked to locational or system-level price-signals. In Figure 20 flexibility products are divided into two: flexibility capacity market products and flexibility energy market products.

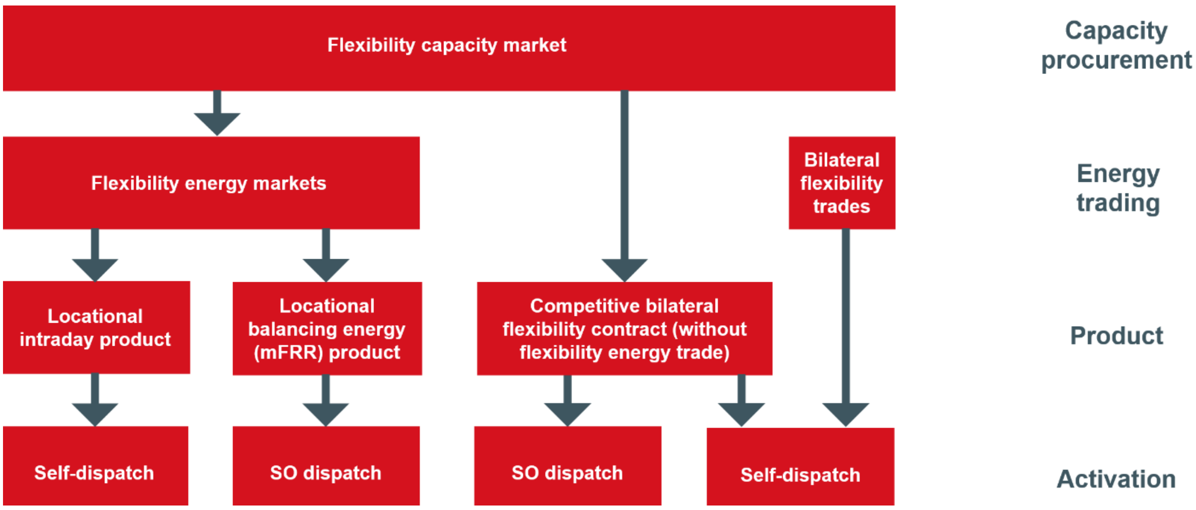

Figure 20: Flexibility capacity and flexibility energy products relationship and utilization.

Flexibility capacity products are here defined as:

- pre-market product for locational flexibility energy markets, which can be:
    - balancing capacity market products with locational information,
    - separate locational flexibility capacity market products,
- or competitive bilateral flexibility contracts, without a mandatory flexibility energy trading, for:
    - congestion management contracts,
    - voltage support contracts,
    - outage support contracts.

Flexibility energy products and mechanisms are here defined as:

- locational intraday product,
- locational balancing energy product (mFRR),
- other bilateral flexibility energy trades.

Flexibility capacity markets are based on competitive auctions, where pre-qualified assets of the flexibility area can offer their capacity. Flexibility capacity markets can be realized together with flexibility energy markets, meaning that the successful trades of flexibility capacity markets obligate the selected FSP to bid to the corresponding flexibility energy market. If a FSP does not bid to the corresponding flexibility energy market, this is penalized according to terms and conditions. Flexibility capacity markets are in place to secure locational flexibility capacity, similarly as balancing capacity markets secure system-level balancing capacity. Flexibility capacity markets can be part of existing balancing capacity markets if balancing capacity offers include locational signals, or a separate flexibility capacity market.

An alternative result of a flexibility capacity market is a competitive bilateral flexibility contract, which does not include mandatory flexibility energy trading. Optionally either the FSP itself or the SO can settle possible imbalances of activations on wholesale markets or with bilateral trades. In the case of using competitive bilateral flexibility contracts, the product remuneration can be based on availability and/or utilization costs, depending on the use-case. Bilateral flexibility contract could exist between many kinds of parties, although according to industry feedback, contracts directly between network operators and an end-user, should not be preferred over networks procuring flexibility via markets from FSPs. A bilateral flexibility contract is, for example, a separate contract between a FSP having network connected flexibility asset and a network operator, where the asset provides voltage support, congestion management or uninterrupted power supply. FSP controls assets according to its own, networks or according to other FSP needs through trading. The activation can base on in advance defined self-dispatch or SO activation decision. As these contracts are the result of locational and individual use-case specific auctions, the product parameters details are also use-case specific. Still, a framework and product parameter definitions can be harmonized. For example, UK Power networks and National Grid Electricity System Operator have held such auctions for reactive power support and congestion management (NGESO 2019; UKPN 2018). A DSO product structure based on bilateral contracts is shown in Appendix 6.

Flexibility energy products are activated according to locational and use-case specific needs. These are suited for congestion management services. These markets should be used when a flexibility activation results in a significant energy activation which is not netted during an imbalance settlement period. This can be accomplished with locational bilateral flexibility trades, intraday markets or balancing energy markets. Here it is assumed, that bilateral and locational intraday trades are executed with self-dispatch, while locational balancing energy product is activated by the corresponding TSO or DSO.

The possibility of joining flexibility products and existing products together and creating one super-platform or single market as described by Ofgem (2019) is here neglected. This is due to the limited industry support in Chapter 5 for such a market design. The creation of such a mechanism is extremely complex and it would reduce the possibility of market-based trading. Here it is assumed, that market-based competition will create better results than centralized concepts. Table 6 summarizes the flexibility product concepts based on template in appendix 5. As in Chapter 3.4, only the standard flexibility products for year 2024 are described. Proposed flexibility products are regionally specific for Finland, but most likely applicable to other European electricity markets. Longer, faster or complex services can be procured with blocks and offer linking of standard flexibility products or using special products defined later.

Table 6: Flexibility products.

Parameter	Locational balancing offers	Locational intraday product	Competitive bilateral flexibility contract
Short description	Utilization of mFRR (or similar) offers for congestion management either preventively or during occurring congestions.	Utilization of locational intraday offers where SO pays a congestion spread between offers to manipulate zonal market dispatch to preventively alleviate congestions.	SOs arranging auctions to competitively procure contracts for congestion management, voltage support or outage support.
Market time unit /validity period	15 min. (Same as balancing offers or longer if special products used.)	15 min. (Same as intraday MTU or longer if blocks are used.)	Contract specific. (Typically, months to years. Within the validity there can be periods where contract doesn't oblige delivery.
Market opening	D-1 12:00 (same as balancing market)	D-1 15.15. (similar as continuous trading on intraday markets)	Contract specific (Months or years ahead of validity period. Depends whether the procurement is done from existing or new resources.)
Market closure	~H-25 min. (Same as balancing markets or before if special products are needed.)	~IZ H-0 min. (Same as IDM, but most likely trading hours before delivery.)	
Minimum lead time	~17.5 min. (Same as balancing market or longer if special products used.)	~0 min. (Same as intraday market, but most likely hours before delivery.)	Contract specific (e.g. months or years.)
Full activation time	~12.5 min. (Same as balancing markets or different if special products.)	Not applicable/0min. (Results are known in advance.)	Contract specific depending on the mode of activation (e.g. continuous, procurement to deliver in advance or from SO signal.)
Duration of delivery period (minimum-maximum)	~5 min. (Can be same as balancing markets, but most likely hours)	~15 min. (Can be same as intraday markets, but most likely hours.)	Contract specific. (e.g. hours or continuous).
Minimum bid size [granularity]	1 MW [0.1 MW]. (Same as balancing market.)	0.1 MW [0.1 MW]. (Same as intraday markets.)	Contract specific. (e.g. 0.05 MW [0.05 MW])
Divisibility	Yes (indivisible offers can also be allowed).		

Symmetric/asymmetric product	Asymmetric		Asymmetric/symmetric (contract specific)
Mode of activation	SO manual dispatch	Self-dispatch	Contract specific (e.g. procurement in advance to deliver, SO activation signal or self-dispatch).
Locational information (order book, bid resources)	Underlying resource(s) are indicated in the offer.	Underlying resource(s)/ (and postal code) are indicated in the offer.	Contract specific, but in most cases resource or at least location specific.
Aggregation rules	Can be allowed.		
Link to primary service(s)	Congestion management		Many: Congestion management, reactive power and voltage control, uninterrupted power supply (and other services).
Link to secondary or other services	Same offers can be used for balance mechanism. Possible link to locational balancing/flexibility capacity markets.	Same offers can be used for intraday trading.	Outside the availability window the resource can be offered to other markets or purposes.
Market or other procurement channel	Balancing energy market	Power exchange (and a coordination mechanism)	Separate auctions
Buyer(s)	TSOs (DSOs)	TSOs and DSOs	TSOs and DSOs
Seller(s)	BSPs (FSPs)	BRPs/BSPs, (FSPs)	FSPs
Remuneration and compliance monitoring	Pay-as-bid energy remuneration for utilization. Compliance is monitored with measurements.	Pay-as-bid energy remuneration for utilization. Compliance is monitored with measurements in relation to (unit-based market position), delivery schedule or a baseline.	Contract-specific. Remuneration for utilization (energy) and/or availability (capacity). Pricing can be marginal, pay-as-bid or a regulated price. Compliance is monitored with measurements in relation to unit-based baseline or other.
Existing examples	European TSOs with mFRR (or RR) offers, NODES.	GOPACS, ENERA	TSO and DSO contracts, PICLO-FLEX
Source	(NODES 2019; ENTSO-E 2019d)	(GOPACS 2019a)	(Open utility 2019a; NGESO 2019; UKPN 2019)

These three proposed emerging flexibility products are needed in addition to existing products described in Chapter 3, because there are specific needs to procure more flexibility services from markets and the existing products do not adequately enable this. In the cases of congestion management products, the need is the inadequacy of the transfer capacity of networks or the management of its congestions. There are significant similarities between locational balancing product and a locational intraday product as both have a role in the balancing mechanism and can be used for congestion management. In the case of products for voltage support, the background is related to insufficient capability or increased costs of network operators maintaining voltage quality during all situations. In cases of other flexibility needs, such as uninterrupted power supply, the need is use-case specific and therefore the product definition must be flexible.

6.2 Utilization of flexibility products

The bidding period, market clearing time and activation point in time of the flexibility products described in Chapter 6.1, have many alternatives. One option is to do all flexibility product trading at the same time as the corresponding system-level market products. Other option is to do flexibility trading after or before system-level products are cleared. As system-level products are traded close to delivery, earlier trading is the more likely option. The difficulty related to this timing is shown in Figure 21, where hypothetical flexibility procurement from flexibility markets is indicated by the three bidirectional arrows representing trading.

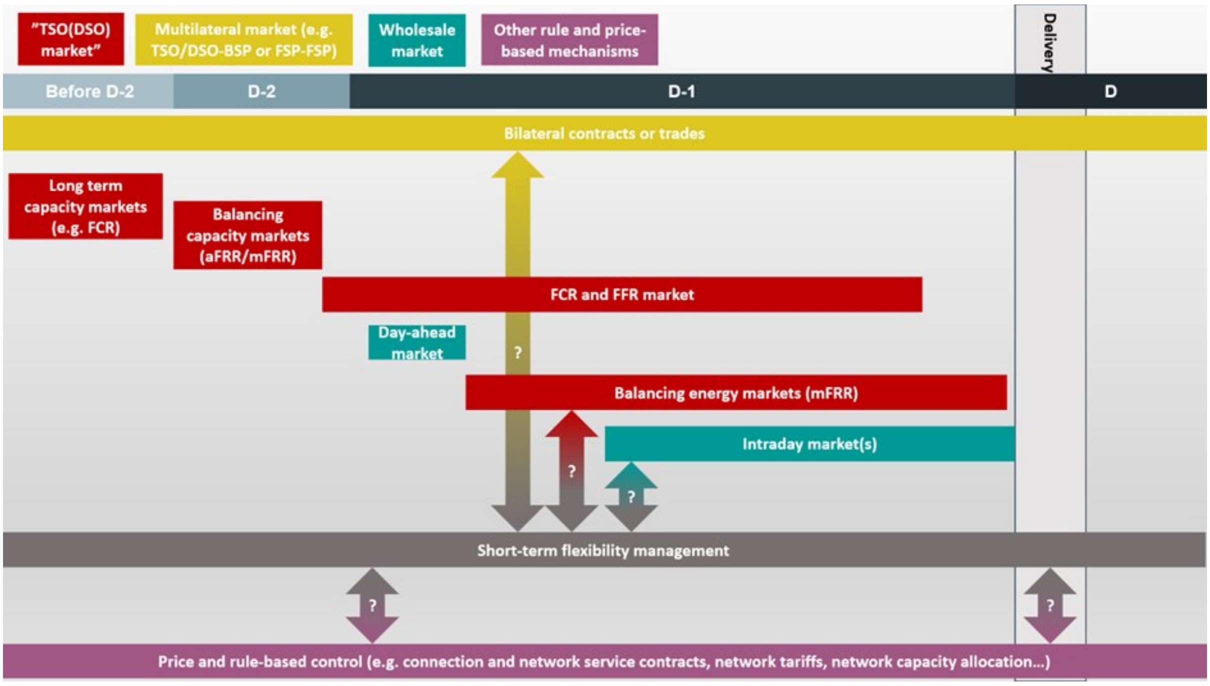

Figure 21: Scenario of parallel energy, capacity and flexibility trading.

As said in previous chapters, there might not be a separate market interface for such trades. Instead, system-level market offers with more detailed bids can operate like a market within a market. During this process many overlapping and simultaneous mechanisms, rules and markets need to be accounted for. The main difficulty is related to times where different offers linked to an underlying resource could be unfeasibly realized multiple times. Such times are:

- after BEGCT, at H-25 min, where system-level or locational mFRR, normal aFRR and normal or locational intraday-offers could be double or triple activated,
- at FCR-market clearing, at D-1 21:00, where FCR offers, normal or locational intraday-offers could be double, or triple activated,
- at flexibility market (undefined) clearing and all other market offers,
- at any time with continuous bilateral trades and all other market offers.

These issues can be solved either with flexibility seller doing sequential bidding one product at a time or intelligent market integration where bids are cross process linked. The latter option is here preferred and is further examined in Chapter 7.

According to industry feedback in Chapter 5, bilateral energy trades and competitive bilateral flexibility contracts are assumed to be completed well in advance, and most likely with longer contract periods. These are not assessed here further as these are case-specific and the FSP assumedly knows these commitments when submitting other offers. If short-term flexibility capacity market auctions are needed, these could be separated or integrated in balancing capacity markets as locational offers. If flexibility capacity markets would operate as a separate market, suitable times to hold auctions could be either before or after day-ahead auction. A possible time to hold flexibility capacity auctions is after first intraday auction results, most preferably during traditional office hours to minimize interfering with zonal market price discovery. If further studies find challenges related to this, a time before day-ahead auctions can be considered as an alternative.

Activation of offers on flexibility energy markets is assumed to happen well in advance of delivery. This is because near the delivery, only balancing can be concentrated on. If continuous intraday with locational parameters is used, the flexibility market could operate after intraday auction results (D-1 15.15 CET). Still, as majority of intraday trading volumes occur near delivery, the liquidity of early trading can become an issue (Schraff et al. 2016). Other bilateral flexibility trades shown in Figure 20, are here assumed to be like locational intraday products and are not further examined. The unclarities for locational balancing energy flexibility offers are further assessed in chapter 4.1.1. These unclarities include questions like can and should flexibility market clearing be synchronized with system-level balancing energy offers or not, and should special products be allowed.

Based on this thesis, it is difficult to say what product and product utilization agreements would be optimal different network operators. There is a possibility that all three product options could be used together. This was also the result of the industry consultation. This could happen in a scenario scheme where different needs are fulfilled during all times with a procurement strategy for:

- **Long-term:** TSO and DSO flexibility capacity markets are used:
  - to secure short-term congestion management capacity for locational balancing energy markets (either separated or combined with balancing capacity markets),
  - to secure long-term local capacity with bilateral flexibility contracts for:
    - congestion management, in cases where flexibility energy markets are proven not sufficient or efficient,
    - security of supply during disturbances,
    - fast and slow voltage support (additional to ORPR and SO resources).
- **Medium to short-term:** flexibility energy markets prioritize the use of locational continuous intraday trading if preventive congestion management activations are needed.
- **Real-time:** in case of reactive congestion management or other unforeseen situations locational balancing energy products are used by TSOs, DSOs or by TSOs under DSO request.

There are many alternatives how the products described above could be used together and no, or limited experience with these concepts. Reasons why the flexibility products could not coexist at the same time were not identified. Still, different procurement strategies and operational guidelines should be tested.

6.3 Evaluation of flexibility products

This subchapter evaluates the viability of the product options presented in part 6.1. Figure 22 shows an assessment, using traffic light-concept as diagnostic tool to present the strengths and weaknesses of the three preferred flexibility products (Hirsjärvi & Hurme 2015). Assessment is based on literature study in chapters 1-4 and industry consultation results from Chapter 5. Red light indicates that the product does not fulfill evaluation criteria, yellow light means partial compliance and green light implies compatibility. Multiple lights mean that the product option is in between light criterions, or it is not feasible to say whether the product complies or not.

Product option [services product is suitable for]	Locational balancing energy/capacity (mFRR) product [congestion management]	Locational intraday prudct [congestion management]	Competitive bilateral contracts [congestion management, reactive power control and outage support]
Description	Utilization of mFRR (or similar) offers for congestion management either preventively or during occurring congestions.	Utilization of locational intraday offers where SO pays a congestion spread between offers to manipulate zonal market dispatch to preventively alleviate congestions.	SOs arranging auctions to competitively procure contracts for congestion management, voltage support or outage support.
Compatibility with foreseen European market design	🟢🟡	🟡	🟢🟡🔴
Suitable for low liquidity use	🟡	🟡🔴	🟢🟡
Ease of TSO-DSO coordination	🟡	🟢🟡	🟢
Participation of small distributed resources	🟡🔴	🟡	🟢
Ease of implementation	🟡	🟡	🟡
Simplification of electricity markets	🟢🟡	🟡	🔴
Preventive or longer (>15 min) activations	🟡🔴	🟡	🟢
Continous activations (>Day)	🔴	🔴	🟢
Reactive activation (during delivery)	🟢	🔴	🟡
Regulation reguirements and the possibility of gaming	🟡	🟡🔴	🟢🟡

Figure 22: Evaluation of three product options to be included in the flexibility market design.

From Figure 22, it can be interpreted that all product options have weaknesses and strengths in different ways. For purposes other than congestion management the use of competitive bilateral flexibility contracts is here the only option. It is also the most realistic alternative in low voltage radial networks or in locations of insufficient local capacity and in need of investments. In cases of congestion management in higher voltage networks with meshed grid topologies and enough supply, TSOs and DSO can use locational flexibility energy products alongside competitive bilateral flexibility contracts.

From the viewpoint of network operators, the use of competitive bilateral flexibility contracts is simple and robust as auctions can be customized to be case-specific. Still, it has a major disadvantage as markets are increasingly fragmented. Locational intraday offers can be used within the day to solve congestions, but not for longer durations nor during delivery. Balancing energy offers with locations can be used for reactive congestion management near or during delivery, but smaller resources can have difficulties in participation to the market. With modifications, all options are seen compatible with future European electricity markets.

As indicated by most stakeholders in Chapter 5, there is a possibility that network operators need to reinforce networks as fast as possible and use all available flexibility, to keep up with the energy transition. To enable this, the three presented emerging flexibility product options and possibly the preceding flexibility capacity markets could all be used simultaneously. Testing and case-specific analysis must be done to find out which of these products would be preferred in each case. Therefore, evaluation in this chapter and scenario in Chapter 6.2 is presented as an initial suggestion and as a benchmark.

When designing flexibility products and their utilization, it is important to remember the context. This includes the probable updated versions of existing products from Chapter 3 and possible emerging products from chapters 4 and 6. Below is a possible product structure for future electricity markets in Finland and Europe:

- Financial market:
    - Financial products
- Wholesale market:
    - Day-ahead products
    - Intraday products
- Network service products and rules
    - Network tariffs
    - Network service agreements
    - Other rules
- Frequency-based reserve products
    - FCR-N hourly product
    - FCR-N yearly product
    - FCR-D hourly product
    - FCR-D yearly product
    - FFR hourly product
- Balancing products
    - aFRR balancing capacity product
    - aFRR balancing energy product
    - mFRR balancing capacity product
    - mFRR balancing energy product
    - (self-balancing in relation to the expected imbalance price)
- Flexibility products:
    - Flexibility capacity products:
        - balancing capacity market with locational information
        - separate flexibility capacity market
        - competitive bilateral flexibility contracts
    - Flexibility energy products:
        - locational flexibility intraday product,
        - locational flexibility balancing energy product (or similar),
        - other bilateral flexibility trade.

There are many variations on how to define and utilize flexibility products and the product structure presented above is not the only option. Along with the possible implementation of discussed flexibility products, the existing products on different markets will be revamped. Existing and emerging products will be traded in parallel and there will be price-competition between different markets, products and different users for the same resources.

7 Discussion

This chapter discusses relevant themes related to the definitions of flexibility products. The motivation for flexibility product development derives from the quintessential need to give the right value for flexibility to foster fair network and system friendly behavior. As stated above, this need can be seen increasing due to technical development, market liberalization, environmental protection goals and other global phenomena related to on-going energy transition. The premise for this goal can be found in numerous global agreements and European legal documents. For example, the 2030-vision for the Nordic electricity market is: "In 2030, the Nordics should have the world's most competitive, innovative and consumer-oriented electricity market, that contributes to reaching the Nordic climate goals" (Nordic council of Ministers, 2019). To enable this vision the visibility, transparency and automation of existing markets needs to increase. In this thesis this is argued to be achieved with the combination of market pull and technology push, where multilateral and integrated market environment enforces market-based competition to use flexible assets when and where most needed. Flexibility market data must also be accessible by regulators, so that fair competition can be ensured.

Firstly, national and regional rules, products and markets for flexibility are needed. Later a common European model should be developed with the harmonization of best practices. Product reforms or implementation of totally new flexibility products can increase interoperability and efficiency of market mechanisms controlling electrical systems. To enable the use of flexibility with flexibility products, there are significant challenges that need to solved, such as: compatibility of flexibility products with the existing zonal market models, difficulty of cross-process offer linking or market integration, settlement and verification of flexibility delivery, market fragmentation due to flexibility products and whether participation to flexibility markets is optional or mandatory. The following chapters will discuss these themes.

7.1 Market architecture and product reform

Limited or non-existing possibility of network operators to procure flexibility from markets must be solved with simultaneous development of flexibility products and installation of flexible assets. The needed market architecture and product reform include product definitions and modified operational guidelines for trading the market-based flexibility products. In general, SOs procuring flexibilities for local purposes are a must in some situations and could be a good alternative to grid expansion, if enough flexible capacity exists to enable a cost-efficient flexibility market. As industry consultation in Chapter 5 indicates, a local flexibility market alone is very seldomly preferable. Therefore, combability of local flexibility markets with existing system-level market must be ensured. In this thesis, competitive flexibility contracts and integration of flexibility markets into system-level intraday or balancing markets, with more detailed offers, are assumed to be able to tackle this issue.

Competitive bilateral contracts should be preferred if a very specific service is be procured, short-term liquidity is missing, or if longer-term contracts can create savings as flexibility seller's transactional costs are divided over a longer contract period. It must be ensured, that the resource can be used elsewhere outside of the service window if competitive bilateral flexibility contracts for a single purpose are used. Market integration and removal of separate and unnecessary markets is here assumed as a competitive way to facilitate the use of flexibility as resources are not locked to a specific use-case. This means, that the existing market products and bids must include more locational and resource specific information and that market coordination needs to improve. This thesis does not have a preferred answer if this detailed offer information should be optional or mandatory, but for portfolio trading this can create gaming opportunities as discussed in Chapter 7.3.

Figure 23 illustrates a possible single flexibility market environment where multilateral trading on overlapping markets and products can create increased value for flexibility. Market parties selecting markets and products in the foreseen multilateral and multi-market environment and pricing the same resource differently for overlapping use-cases is and should remain as competitive business. Selecting bids from semi-competitive SO single-buyer markets, such as balancing and flexibility markets, is regulated business.

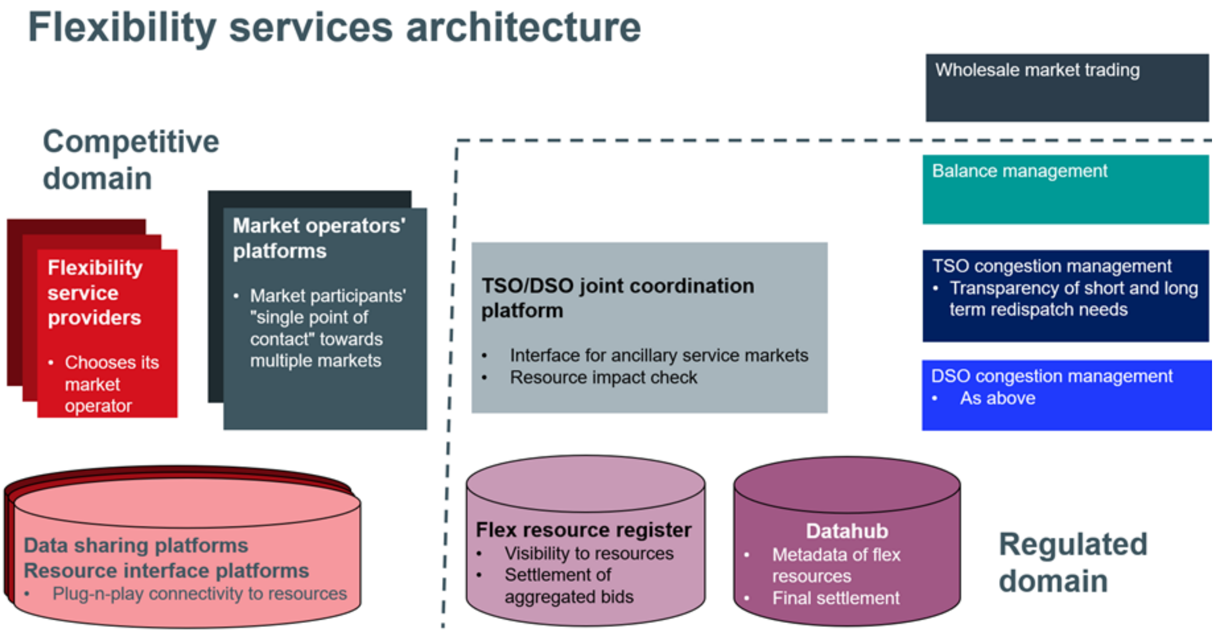

Figure 23: Flexibility services architecture. Adapted from: (Fingrid 2019d).

In Chapter 5 most industry experts indicated that they are interested in flexibility markets and support all three proposed flexibility products, with the precondition that market interfaces, data-exchange formats and that market participation is made easier than it currently is. Here it is proposed, that market interfaces and data-formats are harmonized, but the actual markets will remain separated. Detailed bid linking within a single market and cross-process linking is proposed to tackle the issues that flexibility sellers and flexibility buyers are experiencing already. This means that offers being activated on one market can result in linked bids being instantaneously removed or added to the same and other markets (Boomsma et al. 2014). For example, intraday offers could be forwarded to balancing markets. Also, intraday and balancing market offers could be made usable for congestion management. CEDEC et al. (2019) argues that in order to have functional flexibility markets, the reformed market environment will need new functionalities, such as a flexibility register and datahub, as shown in Figure 23. These market services are not discussed further here.

7.2 Operational changes

The use of flexibility will result in short-term operational activations and changes to the operational planning processes. This subchapter addresses four themes in relation to this operational window. Also processes related to long-term operational or network planning, such as grid reinforcements, must be updated when flexibility products are being used in larger extent, although these are excluded here.

7.2.1 TSO-DSO coordination

Short-term or operational TSO-DSO coordination means multilateral processes that ensure secure and cost-efficient utilization of infrastructure of many network operators and flexibility of the network connected resources (CIGRE 2018). This is a market service. Therefore TSO-DSO coordination should enable following functionalities:

- TSO-DSO need coordination (for example congestion zone definition),
- additional request of flexibility offers,
- offer filtering (physically unfeasible offer),
- selection of feasible flexibility bids according to technical effectivity and cost-efficiency, which can result to:
    - in-advance defined self-dispatch of the FSP,
    - dispatch by the TSO,
    - dispatch by the DSO (directly or request from TSO).

Figure 24 illustrates a possible timeline related to TSO-DSO coordination, where the concept of a TSO-DSO-coordination-platform (TDCP) is introduced. The product sequence in Figure 24 follows the procurement scheme presented in Chapter 6.

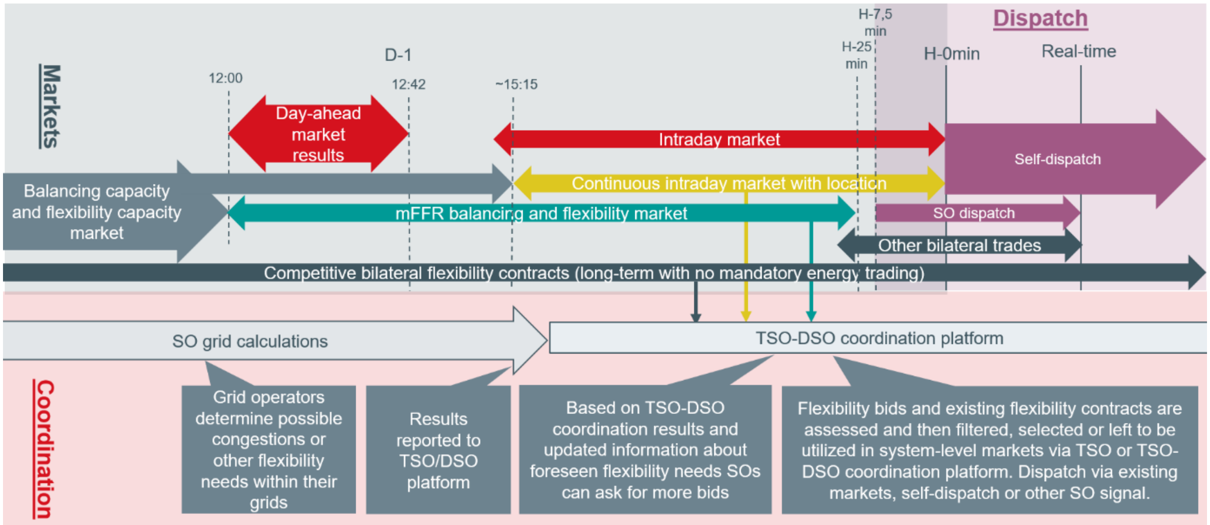

Figure 24: TSO-DSO coordination and multilateral markets - scenario of parallel energy, capacity and flexibility trading and delivery.

To avoid complexity, Figure 24 does not show other parallel markets, such as FCR markets. Also, possible interactions between the illustrated markets are not shown. Previous is regardless of the fact, that these interactions exist, as same resources are traded for many products on many markets. As discussed in Chapter 7.1, there should be a possibility to cross-process link offers between markets, so that risks and complexity FSPs face regarding flexibility product trading is reduced. Also, as indicated by experts in Chapter 5, energy-activations related to competitive bilateral flexibility contracts and other bilateral trades should be preferably known before day-ahead trading. Still, near real-time bilateral trades must be allowed in case of emergencies. Figure 24 assumes, that balancing and locational balancing energy bids are part of the same market and that intraday markets will have separate merit order lists for locational and zonal offers. In Figure 24, the SO grid calculations are done by each SO individually, and then combined in the shared operator interface. TDCP has the TSO-DSO functionalities listed above. One main goal is to calculate an effectivity matrix of different order combination alternatives in reference to the network needs. This is to select the most efficient offers to be activated.

7.2.2 Operational chain of flexibility

Once multilateral planning of SOs results into a need to activate flexibility, there must be operational processes in place. These ensure, that the entire operational chain of flexibility activation works as desired. This includes contractual, financial and physical interactions. Figure 25 visualizes one possibility of different interactions and operational value chains of market-based flexibility trading from the FSPs, resource owners and network operators' point of view. Relationships of other parties are not shown to make the figure more readable. Non-market-based flexibility procurement, like curtailment, directly between a network operator and a network user, which is not a FSP, is not considered. The arrows in Figure 25 indicate the assumed direction or bidirectional relationship of the financial transactions, activation signals, and contractual relationships between the parties.

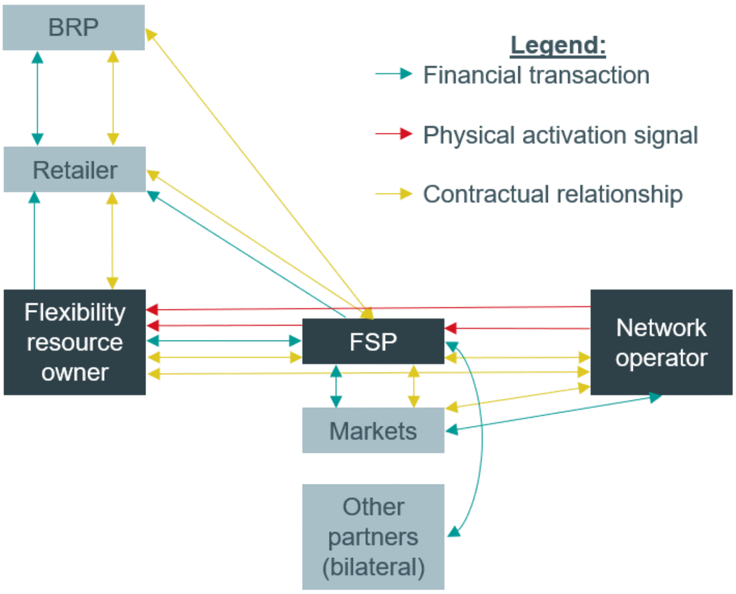

Figure 25: Value chains of market-based flexibility from viewpoints of FSP, flexibility resource owner and network operator.

According to Figure 25, if a network operator needs to procure additional flexibility to support its own resources, it should do this via markets. Network operator will have contracts in place with market operators, FSPs and flexibility owners. The activation signal from the network operator to the flexible asset can go through the FSP or directly to the asset owner, but the contractual relationship and financial transactions will go only to the FSPs. Also, FSP can self-dispatch flexible assets according to market price-signals and to their own preference without an activation signal from network operators. The possibility of a flexibility market operator sending activation signals, is not examined here, since either FSP self-dispatch or SO dispatch is preferred. Still, market operators can enforce self-dispatch by matching trades, supportive price-signals, or obligating penalties and other rule-based control. FSP has a contractual relationship and financial transactions with all parties.

The financial compensation for delivered flexibility is here transferred from networks to FSPs via markets. In turn, FSPs remunerate resource owners for the utilization of their assets while making profit on operational margins. The FSPs can sell flexibility from the controllable assets to other market parties, networks or use the flexibility for private purposes. Also, the possibility of doing private bilateral trades with other parties is shown in Figure 25, but not further examined here as it is not preferred. FSPs also compensate the possible imbalances and other costs that retailers and BRPs might experience from the flexibility delivery in the flexibility scenario presented in Figure 25. BRPs and retailers can have uni- or bidirectional financial and contractual relationships with different parties. If the retailer is also a BRP and a FSP or the owner of the flexible resource, the figure will have less roles and interactions.

7.2.3 Flexibility delivery verification and settlement

Settlement and verification of flexibility delivery are important functionalities of the end-to-end chain of flexibility and needed for securing fair financial transactions. Flexibility delivery verification and settlement processes must be in place so that network operators can fairly and confidently procure flexibility with flexibility products. Also, flexibility sellers will need this functionality to trust flexibility markets. Flexibility delivery verification can happen during real-time or after delivery. Flexibility delivery settlement after physical delivery can happen separately or jointly with imbalance settlement processes. In the foreseen market environment, flexibility settlement and verification are difficult regardless of what kind of flexibility products are being used. Settlement is an inseparable part of product definitions and markets.

Here it is proposed, that flexibility verification and settlement should be done for different kinds of production and energy storage units with the combination of a schedule and fine-resolution monitoring, as their network varies significantly depending on dispatcher decisions. For some forms of consumption also statistical baselines based on historical consumption can be used as schedules (Elering et al. 2017). Therefore, one key element of functional flexibility markets, is an accurate baseline-definition or good quality schedules. These are needed when the amount of flexibility activated must be identified and settled. Firstly, a baseline or a schedule is needed if there are no unit-based market positions or trustable schedules available. The possibility of mandatory unit-based trading is excluded, as the shift towards unit-based bidding in European wholesale trading is seen unlikely. Possible other ways to settle flexibility could not be answered in this thesis. For example, if a SO activates virtual power plant consisting of distributed resources, there must be a way to know what the true private plan of a FSP was before the activation took place. This is needed because the buyer and seller must be able to compare measurements in relation to something in real-time or ex-post. This is needed to settle and remunerate the delivered service. Secondly, if aggregation is done from resources measured under different BRP balances, there must be a mechanism to settle and handle these activations fairly among all affected parties. This can be done either with a separate financial payment and/or the imbalance deviation should be transferrable during imbalance settlement. Also, good quality baseline-definition or schedules are needed for verification, when using flexibility products where the balance energy might not be a major motivation to deliver flexibility, such as congestion management or frequency containment reserve products.

As discussed in Chapter 5, it should be decided, who sets the schedules or baselines. Before a seller of flexibility has made a sell offer, it has analyzed the flexible asset in order to determine, how much it can flex. This analysis results in schedules and trading. Accurate forecasting requires knowledge about whether the resource has been flexing in the past. The seller has this historical information and the flexibility buyer doesn’t. There is a risk, that the seller or buyer manipulates the baseline or schedule and a risk-free solution would require impartial third-party.

Figure 26 presents a scenario to clarify the proposed flexibility verification and settlement method. In both scenarios A and B, there is a dispatcher with three power plants, privately planned to produce 60 MWh, 40 MWh and 20 MWh. This is based on a 120 MWh portfolio offer on day-ahead market and a production portfolio with a 10 MWh offer. Both portfolios are realized in market clearing. Fixed and variable costs, for example fuel costs, related to production or consumption are here assumed to be zero and all profit margins are assumed to be included in the prices. Local flexibility market clearing price is assumed as given, although it can be foreseen that the dispatcher could impact the market price. Hypothetical prices used:

- Wholesale system-level, day-ahead price = 45 €/MWh
- Wholesale system-level, intraday price = 65 €/MWh
- Local flexibility market price = 150 €/MWh
- Imbalance price = 75 €/MWh (downward regulating ISP assumed)

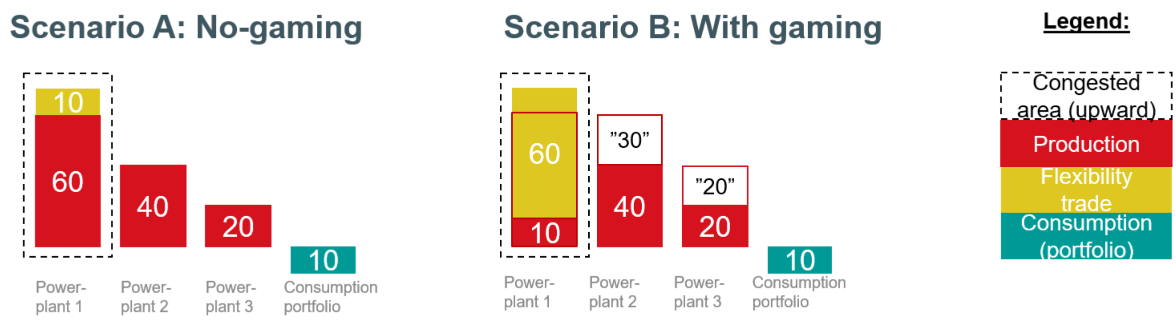

Figure 26: Arbitrage of private and public schedules during verification of flexibility delivery.

In both scenarios there is a need to order upregulation for an area where the powerplant 1 is located. This amount will differ depending on the need of the SO, but it is here assumed that the SO trusts the schedules given by the dispatcher and procures all locational flexibility. It is also assumed, that if the powerplant 1 produces 70 MWh or more the congestion is solved. In scenario B the dispatcher manipulates the public schedules of power plants so that firstly the need to order locational upregulation seems to increase and secondly the dispatcher can sell more of the production of powerplant 1 with the higher local flexibility market price. It is here assumed that when the dispatcher is doing this manipulation, he has full insight of the foreseen revenues, costs and regulation direction. This example is not realistic and competition in the area could limit the chances of gaming. In scenario A the dispatcher informs the private schedules, but in scenario B it informs that powerplant 1 will produce only 10 MWh of the 120 MWh and powerplants 2 and 3 will produce the rest. After this, the dispatcher has three options:

- Option 1: Take full cost of imbalance
- Option 2: Self-balance (assuming zero costs)
- Option 3: Balance the portfolio with a trade system-level intraday

If the dispatcher uses true private schedules, it can generate more and gain extra revenue with the localized flexibility trade in scenario A. In scenario B this local premium is increased with generation schedule manipulation. Possibility of flexible consumption or consumption schedule manipulation is here excluded. Additional revenue from flexibility trades:

- Scenario A:
  - 10 MWh*150 €/MWh = 1500 €, where the calculation is flexibility amount times the flexibility price.
- Scenario B
  - Option 1: 60 MWh*150 €/MWh – 50 MWh*75 €/MWh = 5250 €, where the calculation is flexibility amount times the flexibility price minus the imbalance costs.

- Option 2: 60 MWh*150 €/MWh = 9000 €, where the calculation is flexibility amount times the flexibility price minus the imbalance costs.

- Option 3: 60 MWh*150 €/MWh – 50 MWh*65 €/MWh = 5750 €, where the calculation is flexibility amount times the flexibility price minus the intraday trade costs.

- Interestingly if in option 1, the ISP would have been an upward regulating one with same price, the dispatcher would have gained through local flexibility and self-balancing: 60 MWh*150 €/MWh + 50 MWh*75 €/MWh = 12750 €. This is because the activation would have helped the local area congestion and the system-level area frequency at the same time.

In all five cases, the dispatcher gains additional and relatively more revenue from the local trade than from the system-level markets. Also, the dispatcher has the possibility to further increase revenue with schedule manipulation. As stated in Chapter 5, the best way to address gaming is to increase local competition. Also, regulation, monitoring and fine-resolution measurements can help where there are many options to limit gaming, such as:

- in case of a flexibility trade, trading on that regulating object (RO) or on the entire portfolio is frozen until delivery,
- in case of a flexibility trade, self-balancing is disallowed, by doing unit-based settlement,
- in case of a flexibility trade, market behavior and other activity is monitored,
- introduction of regulated prices, price-caps or other rules on flexibility trades.

In future, overlapping flexibility, balancing and wholesale markets provide situations for near-real time trading. It must be ensured that these processes and settlement are compatible, to avoid situations where same capacity and energy would be sold multiple times. It is here assumed, that if flexibility activations via balancing or locational intraday markets are done near delivery, the possibility of gaming is reduced. This results from the limited time to re-trade the flexibility or to do self-balancing. Also, competitive bilateral contracts can limit gaming as there is less urgency to select bids. Assumptions above, are highly dependent on the GCTs and transparency of balancing, intraday and flexibility market results. Still, it is likely that SOs would prefer to procure locational flexibility well in-advance, since TSO-DSO coordination can take time and the activity of SOs must focus more on system-level balancing near delivery.

According to Pakalén (2019) TSOs should implement operational processes and practices that are in line with a reactive balancing philosophy to support efficient system-level balancing. As mentioned in Chapter 5, there is industry support for the transition towards a more reactive balancing model of TSOs. There are market changes foreseen despite and due to a reactive balancing philosophy. Examples of these are: single price and single position imbalance settlement model, near real-time trading on wholesale markets and limited preventive activations from balancing energy markets. These can decrease frequency deviations and increase cost-efficiency of balance mechanism. A reactive balancing model is here assumed to be the future of the balancing mechanism, even though it can limit the operational environment of flexibility markets. This limitation is because of the near delivery trading and because balancing offers cannot be used for redispatching as extensively as before. Therefore, the situation is a tradeoff between the two options. If financial bindingness of production schedules is reduced and reactive FRR balancing energy activations are increased, there will be increased challenges with all presented flexibility product options. Still, according to findings in this thesis, some locational flexibility must be procured from markets and therefore there must be mechanisms to monitor and settle deliveries. Reconciliation of flexibility markets and a reactive balancing philosophy with other foreseen changes must be continued in future development.

7.2.4 Transparency

As said in previous chapters, there are foreseeable changes ahead, where a transparent and fair market environment must be ensured. Firstly, there must be visibility to the supply and demand of different amounts and types of flexibility to be able to use flexibility markets. As mentioned in Chapter 5, flexibility sellers have good understanding of the geographical and time-varying characteristics of their resources. Flexibility buyers indicated that currently SOs have limited short-term visibility to the areas for which they might need flexibility and that they do not know if there is matching supply. Also, information sharing between different network operators should increase, as described in chapters 5 and 7.2.1.

This thesis does not examine transparency of existing markets. Still, during interviews, experts were worried about possible abuses of market power in system-level markets. Some argued, that the situation would worsen especially in cases where market transparency would increase, or locational flexibility would be more valued. For example, limited market access and low data transparency of redispatching, network allocation reductions and other capacity mechanisms in Europe were mentioned during interviews. SOs varyingly indicate what ancillary service costs and congestion management expenses they have had (ENTSO-E 2019a). There is room for improvement in the transparency of European TSOs and DSOs.

Table 7 lists the redispatching and countertrade costs and special regulation activations done by Fingrid during 2015-2018. Activations for special regulation, such as redispatching, are currently done from balancing energy market or with bilateral trades. The average price on the last row of the Table 7 is an indicator that does not consider other power-based regulation, which are included in the total costs, but not in the special regulation quantities. Considering this would lower the average prices below 100 €/MWh in all years, according to an interviewee from Appendix 4. Still, this is a good indicator of the locational value of flexibility, as these locational mFRR prices are higher than the normal balancing energy market. Based on the data, it can be argued that there haven't been significant structural congestions in Fingrid's network. The occurred congestions, within the Finnish LFC area or between bidding zone borders have been mainly due to disturbances and occasional maintenance needs.

Table 7: Special regulation done by Fingrid during 2015-2018. Data: (Fingrid 2019a, e).

Year	2015	2016	2017	2018
Total RD and CT cost [M€]	3.8	3.9	1.8	4.1
Special up-regulation [MWh]	25054	22992	8842	38521
Special up-regulation hours [number of hours]	216	239	125	383
Special up-regulation average activation [MWh,h]	116	96	71	101
Special down-regulation regulation [MWh]	8771	6584	2591	7040
Special down-regulation hours [number of hours]	112	130	67	139
Special down-regulation average activation [MWh,h]	78	51	39	51
Average price [€/MWh] *	112	132	157	90

*This is a price-indicator, not an exact price as explained above.

It is important to compare flexibility mechanisms. For example, the same numbers as in Table 7 for 2017 for the German part of TenneT-network are: 57.9 €/MWh for the average redispatch, 26 101 GWh of redispatching and total cost of 1,511.5 million euros (TenneT 2018). This is significantly higher compared to Fingrid, but an average price is lower. Also, TenneT's costs are larger than the total European costs according to ENTSO-E (2019a), but this contradiction is not further examined. Fingrid's special regulation is, in terms of energy, roughly one tenth of the of the balancing energy market. From these comparisons it can be concluded that existing network, consumption and generation infrastructure together with market design impact significantly what kind of total service costs network users will face. Increased transparency in the rules, market access and market data together with fair settlement and easy interfaces are key to spur interest of market participants to sell their flexibility both locally and at system-level. As an example of this, Fortum (2019) argues for the benefits from harmonization of redispatch, congestion income and network planning processes of TSOs.

7.3 Locational market power

Market power in markets is a situation, where an induvial supplier can have pivotal effects on the markets clearing prices with their trading decisions. Due to marginal pricing and many other phenomena of electricity markets, defining an exact threshold where a supplier becomes dominant is hard to determine. Still, a market share of greater than 40% is assumed to be an indicator of existing market power. REMIT-regulation is in place to monitor market abuse on different energy markets in Europe. During interviews, the market power of some large European market parties in the system-level markets was experienced challenging. Broadening both long-term and continuous market regulation and monitoring to flexibility markets was mentioned by interviewees as a prerequisite for having fair competition in emerging flexibility markets. (Hirth & Schlecht 2019).

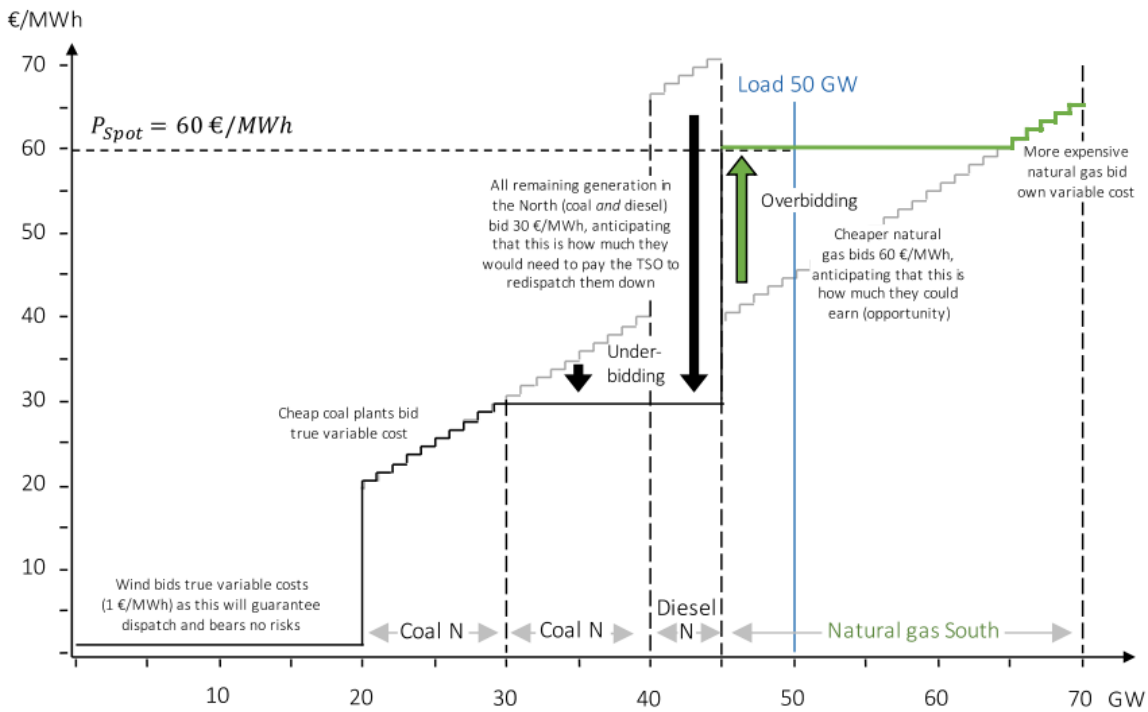

Figure 27: Spot market equilibrium with anticipation of redispatch (Hirth & Schlecht 2019).

Alongside regulation many argued in favor of ensuring true market-based competition to solve gaming issues. Hirth and Schlecht (2019) argue that locational market power in redispatch or other locational markets is not avoidable with sufficient competition, as gaming results from inconsistent power market design. Gaming can be present even with many equally sized competitive bidders. Hirth and Schlecht (2019) argue, that since congestions can be predictable, flexibility mechanisms of zonal electricity markets should opt for regulated prices instead of market-based mechanisms or switch to nodal pricing. In Figure 27 a hypothetical gaming situation in the German power system is shown, where anticipation of a congestion leads to gamed behavior on zonal wholesale markets and later the employment of the redispatch mechanisms with higher prices. The severity of the problem is clear. Similar forecastable north-south transmission trends, major VRES generation capacity concentrations or major load centers struggling with insufficient local flexibility supply and network capacity are seen in many European networks. Other type of gaming was presented in Chapter 7.1, where non-physical gaming with unit-based schedule manipulation can result in windfall profits even in cases, where no physical network limits were threatened. These scenarios are not further assessed in this thesis, as there are little reports of such behavior in Finland. Still, if significant gaming behavior is noticed using regulated prices, price caps or other types of remuneration in flexibility markets, should considered as a secondary option instead of flexibility products presented above.

Table 8: Post tender results (UK Power Networks 2019b).

Total offered capacity (MW)	66.5
Accepted capacity (MW)	43.1
Rejected capacity (MW)	23.4
Total overall capacity share of accepted bids of the largest bidder (%)	85.9 %
Total capacity share of accepted bids of largest bidders in each competition (%)	99.8 %

Locational gaming can occur also outside flexibility energy markets. There is little coherent data available for assessing issues with locational market power while using competitive bilateral flexibility contracts. All European countries and different networks have their own nuances. Still, an indication of the situation can be seen from recent UK Power Network’s auction data. Table 8 shows some key indicators of the DSO held auction. Share of realized bids indicates that in general, there is one large company selling flexibility in many areas. When examining each area individually, it is evident that only one incumbent bidder is often available. Holding auctions to procure capacity from existing resources of a network area can result in a situation, where a bilateral contract would have resulted in less transactional costs. Still, in cases where an auction results to new installations, it is preferable to have more than supplier. Regardless of the possibility of sellers having monopolies in flexibility markets, open market access should be provided according to transparency principles described in Chapter 7.2.4.

7.4 Regulatory and industry chances

To have flexibility supportive markets in place, the rules of different mechanisms and incentives of different parties must be aligned to ensure this. Regulation model of networks and market monitoring has a significant role regarding this. Unbundling, principles of calculating allowed profit, cost remuneration principles, tariff parameter harmonization, abuse of market power and many more themes were discussed in earlier chapters. This thesis does not go into detail regarding the historical or future regulatory models in Finland, as according to Kuosmanen (2018), the historical model has worked well. Still, during interviews regarding Chapter 5, stakeholders presented three development ideas for regulators:

1. Harmonization of network tariff components and retail market rules nationally and later market harmonization in regional or European context

2. Increased market monitoring of system-level and local markets.
3. Discuss or trial total expenditure framework (TOTEX) in some cases or otherwise allow some service procurement as a part of the expenditure allowances of SOs.

Development ideas one and two were examined in chapters 4.3 and 7.3. Regarding idea 3, networks and regulation should approach flexibility with the comparison of lifetime costs. Discounted availability and utilization costs of flexibility combined with flexibility optimized network costs should be compared against the network costs without the use of flexibility over the lifecycle. This does not consider the current regulation model, other markets, price and interest rate development of different cost parameters and assumes that network and flexibility utilization forecasting have perfect foresight. The actual lifetime calculation of flexibility and network costs is a multi-variable non-convex optimization problem with many possible solutions (Esmat 2019).

The procurer of flexibility, in this case a network operator, can use the above described method to compare the possible lifetime savings from flexibility use in relation to the financial and technical risks related to the use of flexibility. Still, this oversimplifies the case, as in some cases it is almost impossible to use flexibility and, in some cases, it is almost impossible not to use flexibility. For example, in cases where system-level security is threatened, the risks outweigh almost any costs. In cases where network reinforcements should be done to secure a back-up supply for an islanded area being utilized very rarely, the cost of flexibility is minor. On the other hand, in cases where there is a structural bottleneck, the alternative costs can approach infinite, as the costs of flexibility are much higher than the cost of network reinforcements.

According to Muukkonen (2019) the utilization of flexibility in networks can create significant societal cost reductions, and regulation model of networks should adapt to this as quickly as possible. According to industry experts in Chapter 5 the regulation model should not lapse and lead into a situation where networks over procure flexibility or reinforce networks for locations that do not create societal net benefits, discriminate users or that networks undervalue long-term total network service costs over short-term savings. Still, as said in Chapter 2, according to CEP, flexibility comparisons against network assets should be done by many European network operators. Regulators and flexibility traders have a significant role to define fair market rules and suitable reference costs for infrastructure, non-wire alternatives and the cost of market-based flexibility procurement, which all have major uncertainties. As said in the chapters 6 and 7.3 the use of competitive bilateral flexibility contracts seems in most cases the realistic approach for radial distribution network segments with limited competition while higher voltage meshed networks could use flexibility energy products in addition.

According to Saulny (2017) and Manner (2019) flexibility procurement for networks is happening in Finland already. Technical feasibility and financial profitability can be achieved in the current regulation model in Finnish distribution networks, if flexibility can create value from multiple sources. It must be highlighted that these results are often case-specific, and the true total costs of flexibility are changing rapidly. For example, traditional power plants using fossil fuels are increasingly expensive to run while demand response and electrical energy storages are more economical than before. In these bilateral cases regulation should ensure that the procurement process is open for all flexibility sellers and separate and allocate the regulated and competitive costs fairly.

Technical profitability estimates for flexibility utilization from uncertain and non-existing flexibility energy markets are more difficult than competitive bilateral flexibility contracts. Firstly, market and technical data needed for quantitative empirical analysis is not yet existing, available or isn't coherently comparable among different systems and countries. As shown in a study by Korhonen (2018), analyses using realized balancing energy prices as a proxy for realized flexibility prices work in cases considering large areas. A similar analysis also using balancing energy prices for a small area showcased results, where flexibility markets work better in load-dominated urban areas, but in rural generation-dominated areas network reinforcements and bilateral contracts work better (Mennel et al. 2015).

Flexibility cost-benefit analyses are needed for regulators to compare different alternatives. As said in Chapter 1.3, the method deployed in the analyses above was considered also for this thesis, but not selected as the research method. This was identified not to be realistic as different areas do not have the same resources always available and costs of flexibility are rapidly changing due to energy transition. For example, using LFC-area-level balancing energy prices as reference cost for congestion management or voltage support costs of a large power plants, does not work everywhere. In many cases the true cost of utilizing flexibility in an area can be significantly more expensive than system level balance pricing would imply or approaching infinite, as there is not enough capacity available when needed. Bilateral contracts are better suited to situations where there is need to procure entirely new capacity or limited local flexibility supply and only occasional needs. Therefore, only in cases of meshed networks with reasonable certainty of competitive alternatives from different sellers, flexibility energy products should be allowed by regulation. Only real-life testing can provide results on the applicability of flexibility markets.

To achieve functional flexibility markets, major industry and regulation changes must be achieved. Appendix 7 has a list of industry and regulatory guidelines for flexibility market implementation and flexibility product development. To facilitate market-based procurement of flexibility, multilateral flexibility markets and tradable flexibility products must be defined. Also, clear market rules, TSO-DSO flexibility coordination, and flexibility delivery verification and settlement principles based on open architecture between all parties must be deployed. When using such flexibility markets SOs must increase the level of transparency regarding flexibility activations and design market rules and operation based on open access. To ensure the completion of such a complex vision and such ambitious goals, incremental development and testing together with the industry should take place. Two possible goals for next steps are presented in Appendix 8.

8 Conclusions

This thesis studies the definitions of flexibility products for electricity markets by evaluating parameters of existing and emerging product alternatives and identifying gaps in services that existing products are not able to adequately fulfill. Due to the impact of the ongoing energy transition to electrical systems and expected changes in electricity markets, the need for network operators and market participants to procure flexibility for both system and local-level services is expected to increase during the following years. Parameters of tradable products on existing electricity markets must be updated to utilize market-based flexibility in multilateral electricity markets Also, completely new flexibility products could be developed.

The scope of this thesis is European electricity market development, particularly the electrical system and markets of the Baltic sea area and Finland for the next five years. To complement academic literature and industry data, an empirical industry consultation was done with half-structed theme interviews. This included expert views on various aspects of flexibility utilization, flexibility markets and flexibility products. Moreover, the flexibility market environment was studied to understand the context and to propose the optimal flexibility product structure and practices, to be tested in physical demonstrations in real-market conditions. Thus, this thesis answers to the question: What kind of electricity market product structure would match the needs of the flexibility buyers and capabilities of the flexibility seller's best, while ensuring cost-efficient and secure delivery of electricity?

In addition to possible parameter modifications of the existing products and mechanisms, different kinds of emerging flexibility product and mechanism alternatives are identified, such as: flexible network service agreements, dynamic network tariffs, locational balancing energy products, locational balancing capacity products, locational intraday offers, competitive bilateral flexibility contracts, nodal products and other mechanisms like forced curtailment. These product alternatives were subjected to further analysis and industry consultation. From the expert interviewees, it can be recognized that the research topic and different flexibility products are novel to many of the industry professionals. Discussions during industry consultations focused more on Finnish and regional aspects of electricity systems and markets and therefore European context was given less attention by many experts. Due to this the results of the consultation may be partially applicable for electricity systems and markets in general, but it is important to note the differences between environments.

According to the industry consultation there are limited local flexibility issues in Finnish electricity networks, but this is expected to change in the foreseen years. According to interviewees, the primary local needs for flexibility are related to voltage support and network outages, while congestions are less of an issue. System level use cases provide the primary market for flexible assets, but local needs can provide additional value. The views of experts where split between different products and many favored the development of products incompatible with other suggestions. Many interviewees argued in favor of reducing complexity of the foreseen flexibility markets and products, as they are already struggling with the on-going market design chances, regulatory changes and energy transition in general. Majority agreed, that the coordination between different parties and interoperability between existing and emerging markets should be a primary target for improvement. This would foster the use of flexibility where it is most valued.

According to the findings in this thesis, the most suitable products for development are modifications of the existing products. Additional locational information and open competition are best suited for the foreseen challenges. Next, the network operators and market parties should test the suitability of the three preferred flexibility product categories:

- locational intraday products,
- locational balancing products,
- competitive bilateral flexibility contracts.

These tests should be done with physical demonstrations in real-market conditions. The development of different market services, such as: TSO-DSO coordination, market coordination and offer-integration and flexibility verification and settlement, should be started with tests in parallel. In addition to the above-mentioned testing and development of flexibility products and markets, this thesis identifies themes for further studies. These themes are related to flexibility products, such as: dynamic tariffs, independent aggregation and settlement models, flexibility register, supportive regulatory model regarding procurement of flexibility services, compatibility of reactive balancing with flexibility markets, and flexibility needed for harmonic resonances and dynamic instabilities. Flexibility settlement and the reconciliation of flexibility markets with a reactive balancing model are identified as the two most urgent topics for further investigation.

Since energy transition is developing at an increasing pace, it is evident that existing infrastructure, but also tradable products, price- and rule-based mechanisms and zonal-market models, are not suitable to handle the change. Emerging electrical network challenges, such as congestions, frequency deviations, outages and voltage instabilities, are major problems that should be avoided whenever possible with preventive actions. To solve these challenges, holistic development of market models must address long-term investment signals while developing short-term balancing, congestion management and other ancillary service markets. These are needed to solve network challenges while minimizing the total cost of network service. This work should consider both the physical infrastructure and the rules, products and mechanisms on markets. Development with incremental experimentation should start immediately and go forward with cooperation of all network users and operators. The market-based short-term trading of system-level flexibility with updated existing products and local level flexibility trading with flexibility products is expected to increase in the future. According to the findings in this thesis, it is seen that flexibility products will have an increasingly important role in intelligent electricity markets to ensure high security of supply and cost-efficient delivery of electricity.

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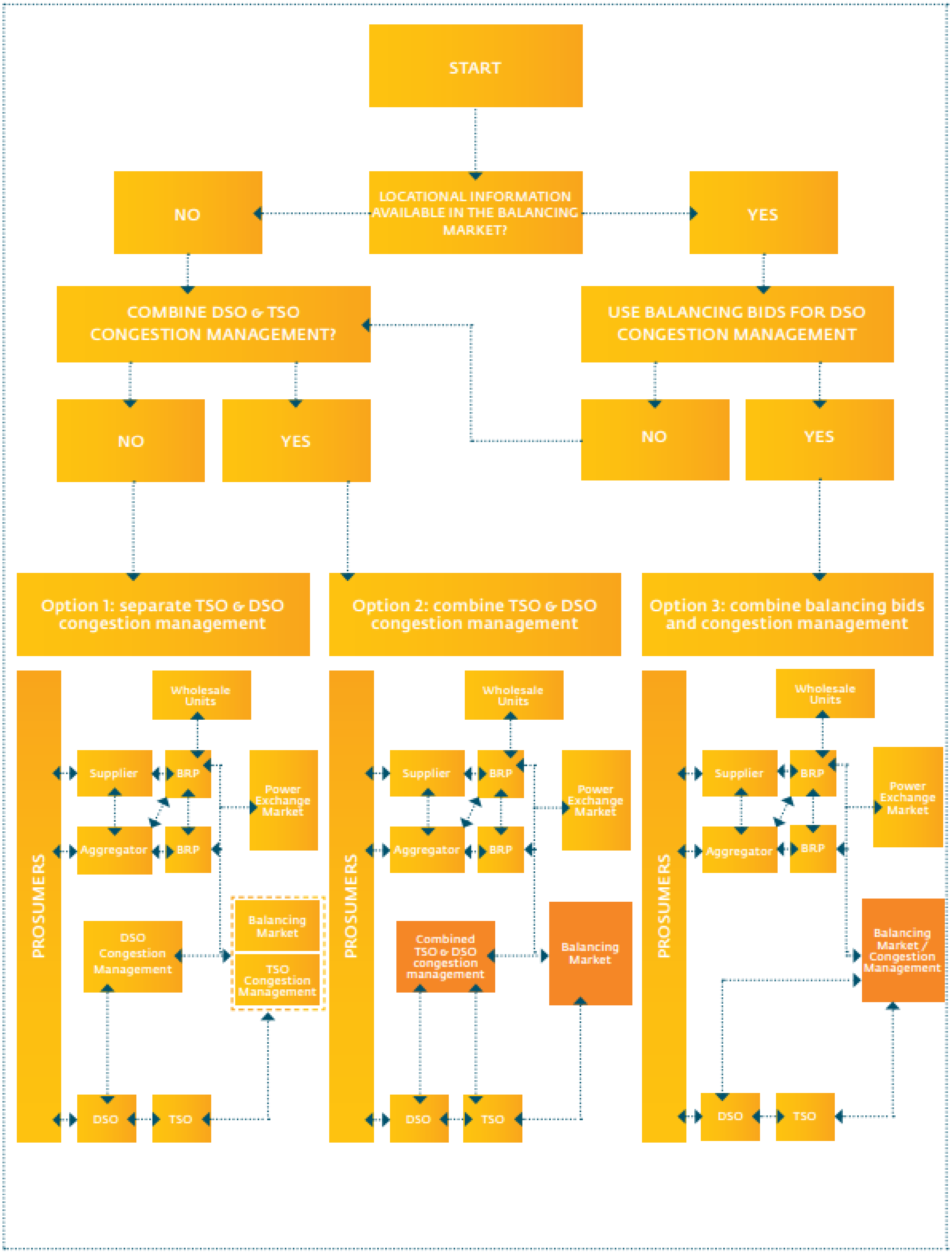
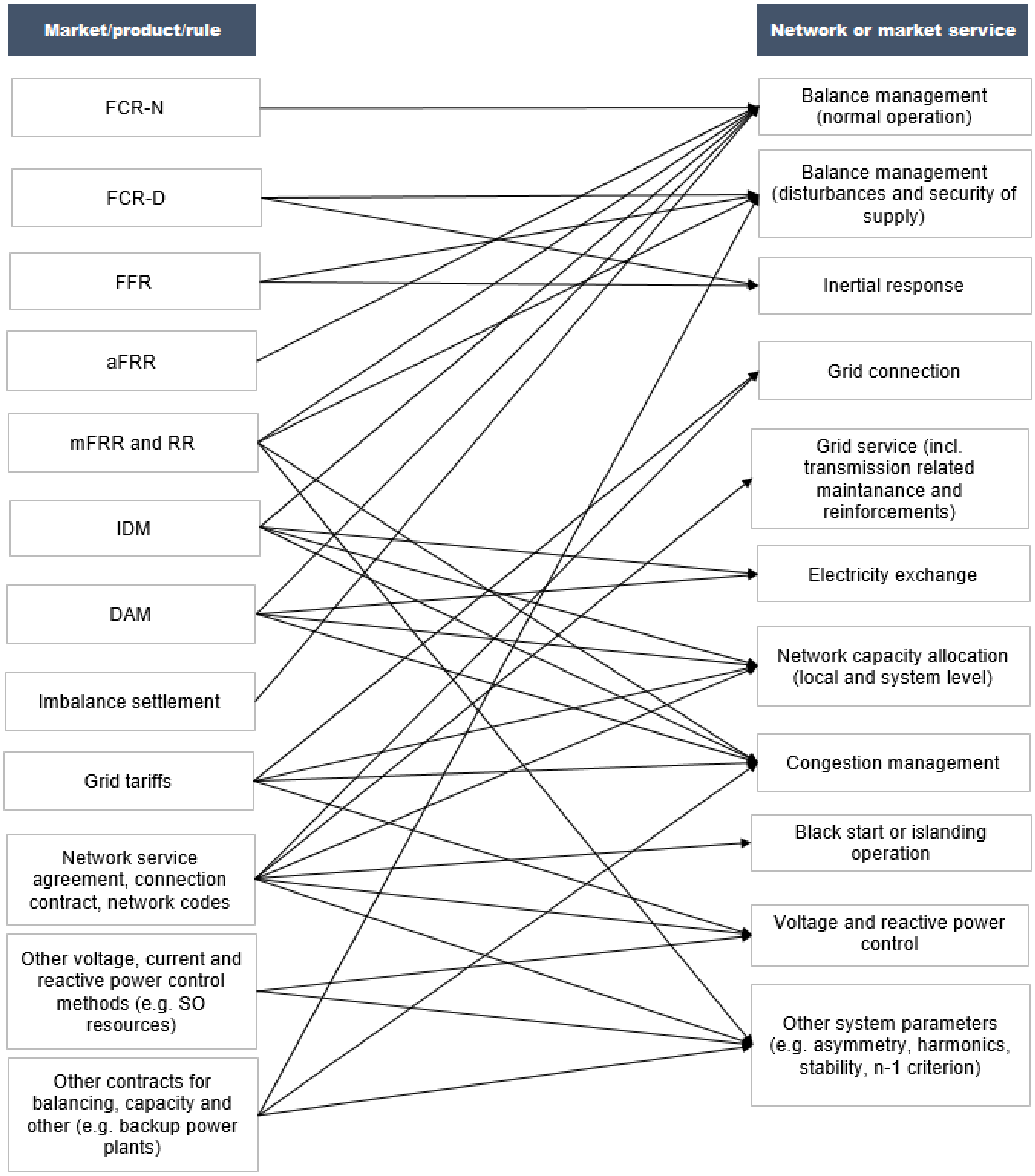
Appendices

Appendix 1. Three possible models for market coordination. 1 page.
Appendix 2. Relation of products to grid and market needs. 1 page.
Appendix 3. List of the interviewees in industry consultation. 1 page.
Appendix 4. Interview framework. 3 pages.
Appendix 5. Definition of product parameters. 1 page.
Appendix 6. DSO flexibility needs and products summary. 1 page.
Appendix 7. Industry guidelines for flexibility markets. 1 page.
Appendix 8. Next steps for flexibility markets. 1 page.

Appendix 1. The three possible models for market coordination (CEDEC et al. 2019)



Appendix 2. Relation of products to grid and market needs



Appendix 3. List of the interviewees in industry consultation

- Aumala, Sanni. Development Lead, Strategic Development. Elenia Oy. Steering group interview in Helsinki 20.9.2019 and interview in Tampere 23.9.2019.
- Hollmén, Katja. Operations manager. Sympower Oy. Interview in Helsinki 24.9.2019.
- Hyvärinen, Markku. Director, Development and ICT. Helen Sähköverkko Oy. Steering group interviews in Helsinki 17.6.2019 and 20.9.2019 and interview in Helsinki 10.9.2019.
- Härmä, Onni. Expert. Fingrid Oyj. Interview in Helsinki 27.9.2019.
- Jouni Pylvänäinen. Chief executive officer. Kymenlaakson Sähköverkko Oy. Interview via phone 3.10.2019.
- Jäppinen Jonne. Manager, System operation digitalization. Fingrid Oyj. Interview in Helsinki 26.9.2019.
- Kaukonen, Timo. Manager, operational planning. Fingrid Oyj. Steering group interview in Helsinki 20.9.2019.
- Konttinen, Lasse. Business Analysis Manager. Caruna Oy. Interview in Helsinki 20.8.2019.
- Karlsson, David. Chief executive officer. Ålands Elandelslag. Interview via phone 24.9.2019.
- Kuusi, Risto. Expert. Fingrid Oyj. Interview in Helsinki 27.9.2019.
- Laakkonen, Mika. Head of physical trading. Power-Deriva Oy. Interview in Helsinki 25.10.2019.
- Latsa, Antti. Service manager. Järvi-Suomen Energia Oy. Interview via phone 4.10.2019
- Lehtinen, Suvi. Chief specialist, Networks, Technical Regulation. Energy Authority. Steering group interviews in Helsinki 17.6.2019 and 20.9.2019.
- Lindroos, Risto. Corporate adviser. Fingrid Oyj. Steering group interviews in Helsinki 17.6.2019 and 20.9.2019.
- Lundberg, Anders. Special Adviser, Regulating services. Fingrid Oyj. Interview in Helsinki 26.9.2019.
- Mutanen, Antti. Project Manager. Elenia Oy. Steering group interviews in Helsinki 17.6.2019 and 20.9.2019 and interview in Tampere 23.9.2019.
- Nyrhinen, Jarkko. Internal accounts manager. UPM Energy Oy. Interview in Helsinki 22.8.2019.
- Rantakokko, Jukka-Pekka. Manager, Energy policies and regulation. UPM Energy Oy. Interview in Helsinki 22.8.2019.
- Rantamäki, Heikki. Business Director. Pohjois-Karjalan Sähkö Oy. Interview in Helsinki 17.9.2019.
- Saajo, Veli-Pekka. Deputy Director General, Networks. Energy Authority. Steering group interviews in Helsinki 17.6.2019 and 20.9.2019.
- Schöpper, Carina. Student assistant. e2m-Voimakauppa Oy. Interview in Helsinki 23.8.2019.
- Segerstam, Jan. Development director. Empower IM Oy. Steering group interview in Helsinki 17.6.2019.
- Toivanen, Aki. Executive consultant. Korkia Consulting Oy. Interview in Helsinki 24.9.2019.
- Uimonen, Heidi. Electricity market specialist. Fingrid Oyj. Steering group interviews in Helsinki 17.6.2019 and 20.9.2019.
- Uusitalo, Jyrki. Development manager. Fingrid Oyj. Steering group interview in Helsinki 20.9.2019.
- Väre, Ville. Senior manager, Energy. Virta Ltd. Interview in Helsinki 16.9.2019.

Appendix 4. Interview framework

Introduction:

- Background and context
  - INTERRFACE-project
  - Current congestion management process of Fingrid Oyj
  - Foreseen electricity market updates (that are linked to flexibility products):
    - European balancing energy markets (Nordic Balancing Model)
    - Pilots and other emerging concepts
- Scope of thesis:
  - Real-time and local electricity market products for:
    - Market-based congestion management?
    - Enhanced voltage and reactive power control?
    - Other flexibility needs indicated by the interviewees?
  - From the year 2024 onwards
  - Focus on themes linked to the role of the organization of the interviewee
- Utilization of interview results
  - Anonymity of interviewees in the thesis
  - Recording of the interview

Theme 1: Flexibility in the electricity system: present and future needs

1.1. What flexibility needs do you have now? What flexibility needs do you foresee from the year 2024 onwards? How locational is this flexibility need?

1.2. During what kind of situations, you will need flexibility:
   a) now?
   b) from 2024 onwards?

1.3. What flexibility supply do you have now? What flexibility supply do you foresee from the year 2024 onwards? How locational is this flexibility supply?

1.4. Does the supply and demand of flexibility match:
   a) temporally?
   b) spatially?

1.5. What experiences do you have about utilization of flexibility:
   a) at system level?
   b) locally?

1.6. What kind of capability do you have to asses locational needs and select specific assets to provide locational services:
   a) in general?
   b) in real-time?
   c) in relation to unit's schedule or your balance position (if a market party)?

Theme 2: Architecture and coordination of a flexibility market

2.1. How network utilization should be decided at unit level (alternatives: with central dispatch, with portfolio-based self-dispatch, with unit-based self-dispatch?) in:
   a) wholesale markets?
   b) ancillary services markets (e.g. balancing energy markets)?
   c) flexibility markets?

2.2. Who should have a priority control in ancillary services (e.g. balancing) and flexibility markets?
   a) Transmission system operator
   b) Distribution system operator if the resource is connected to the distribution network
   c) Owner or operator of the resource

2.3. What kind of network coordination is needed? What information needs to be shared and what decisions must be multilateral in:
   a) TSO-TSO coordination?
   b) TSO-DSO coordination?
   c) DSO-DSO coordination?

2.4. What existing practices, parameters and rules should be changed to spur the utilization of all flexibility in:
   a) system level markets?
   b) locational markets?

2.5. What is the optimal relation of wholesale, balance and congestion management markets/mechanisms:
   a) Option 1: separate TSO and DSO congestion management, but combine TSO balancing and congestion management? How DSO congestion management is achieved?
   b) Option 2: Combine TSO and DSO congestion management, but separate TSO balancing:
      Option 2.1. Utilize a separate congestion management market?
      Option 2.2. Utilize intraday markets for congestion management?
   c) Option 3: Combine TSO and DSO congestion management and TSO balancing?

2.6. Do small bidding zones in flexibility market create the possibility of "gaming" due to locational market power? How should market design and regulation limit this?

2.7. How do you think that market design should coordinate existing markets and mechanisms and emerging flexibility markets together? Should some markets be integrated, or should some markets be used for purposes other than the current one?

2.8. How should the contract relation and remuneration between the network, flexibility resource owner and energy retailer or trader be formed when flexibility is traded? What if there is an independent aggregator in place?

2.9. How should network reinforcement planning and network capacity allocation take the utilization of flexibility into account?

Theme 3: Flexibility products and other steering mechanisms

3.1. Should mFRR or RR balancing energy offers used also for purposes other than balancing (e.g. congestion management or voltage support)? If yes, when should the flexibility market compliant balancing energy bids be submitted and activated?
   a) "Flexibility bid" submission at balancing energy gate closure (at H-25)?
   b) "Flexibility bid" submission before balancing energy gate closure (before H-25)? When?

3.2. Should flexibility market compliant balancing energy bids be activable also by DSOs and should DSOs or TSOs be able to activate these for longer durations than the standard balancing energy product (>15min)?

3.3. Should mFRR or RR balancing capacity offers used also for purposes other than the reservation of balancing capacity (e.g. locational congestion management or voltage support)?

3.4. Should intraday market offers used for other purposes than the zonal wholesale market trading? Are networks capable and willing to choose and remunerate trades based on delivery from locational intraday offers? Are market parties willing to trade with locational intraday offers?

3.5. Should there be locationally specific auctions for the procurement of competitive bilateral contracts? How should these bilateral contracts be realized:
   a) in advance defined delivery with self-dispatch?
   b) in advance defined availability times with SO activation?
   c) as a capacity mechanism with an obligation to offer to balancing energy markets?
   d) as a capacity mechanism with an obligation to offer to intraday markets?

3.6. How should grid tariffs, network connection contracts, network service contracts and other mechanisms in place support the utilization of locational flexibility? Should networks be able to opt for bilateral contracts or limit delivery?

3.7. How should flexibility offers be priced, settled and monitored and how should the related costs be allocated? Verification in relation to:
   a) unit-based market position or schedule?
   b) baseline method?
   c) fine granularity monitoring with sub-metering or high-resolution metering?

Theme 4: General comments, development ideas and other feedback

4.1. Are you aware of any existing flexibility market solutions or initiatives?
4.2. Where any flexibility products or mechanisms missing from the background material?
4.3. How do see flexibility products and markets in general?
4.4. How should network operators enable flexibility markets?
4.5. How should the regulatory model take the utilization of locational flexibility into account?
4.6. Do you wish to test flexibility markets as a part of the INTERRFACE-project or with Fingrid Oyj in general?

Appendix 5. Definition of product parameters

Adapted from: (CEDEC et al. 2019; Nolan et al. 2019; Kessels et al. 2019.)

Parameter	Definition
Short description	Short description of the product
Market time unit /validity period	The period when a bid offered to a market can be activated or is procured in advance to deliver for that market time unit.
Market opening	The point in time when bids can be submitted to the market. Time in CET.
Market closure	The point in time when bids must be submitted to the market. Time in CET.
Minimum lead time	The minimum period between the market closure and the start of the validity period. After closure there can also be market clearing which indicates whether the bid is valid for the market time unit. D symbolizes days and H symbolizes delivery hour. For example, H-25 min is 25 min before delivery.
Full activation time	The period between the activation and the full delivery of the product. This consists of a preparation and a ramping period.
Duration of delivery period (minimum-maximum)	The minimum and maximum length of the delivery period which can shorter, equal or longer than the corresponding validity period. Delivery period can also exceed the end of the validity period, if conditions allow this.
Minimum bid size [granularity]	Minimum bid size is the minimum amount of power for one bid. Granularity is the smallest additional increment in volume of a bid.
Divisibility	Possibility for a buyer to use only part of the bids.
Symmetric/asymmetric product	Symmetricity determines whether only symmetric products or also asymmetric products are allowed.
Mode of activation	Mode of activation refers what is the activation logic (manual or automatic) and who is responsible for the dispatch (e.g. SO or resource owner).
Locational information (order book, bid resources)	Locational information refers to at what spatial accuracy bids are given (e.g. for a bidding zone) and at what underlying resources must be indicated in the bid (e.g. a specific resource will deliver x share of an offer).
Aggregation rules	Description on the possibility to aggregate resources in bids.
Link to primary service(s)	Description of the situation for what primary reason(s) this product is traded i.e. what system service does it manage.
Link to secondary or other services	Description of whether a product is currently used or could be used in the future for additional services.
Market or other procurement channel	Description of what is the main market for trading and are there significant additional procurement mechanisms.
Buyer(s)	Description of what parties are most likely to actively procure services with this product.
Seller(s)	Description of what parties are most likely actively selling services with this product.
Remuneration and compliance monitoring	Description of how product delivery is monitored and what is remunerated in settlement.
Sources	Source(s) of information

Appendix 6. UK Power Networks flexibility needs and products summary

Source: (UK Power Networks, 2019a)

Flexibility Products		Reinforcement Deferral	Planned Maintenance	Unplanned Interruptions	
				Pre-Fault Response	Post-Fault Response
Value Drivers		The present value of deferring capital expenditure	Managing unplanned interruption risk during planned maintenance	Customer Interruption (CI) and Minutes Lost (CML) incentives	Avoided cost of temporary generation and potentially CMLs
2023 Flexibility Potential (MW)		206	Available to eligible DER capacity		
High-Level Requirements	Location Specific	Yes			
	Response Time	30 mins maximum		<10 mins preferred, 30 mins maximum	
	Response Duration	Full availability window – case dependent. Pro-rated payment if available for part of window		3 hours. Pro-rated payment if available for part of window	
	DER Type	Generation, Storage and Load Reduction			Generation and Storage
Contracting Principles	Procurement Type	Competitive tenders or administratively set prices if low liquidity		Framework agreement. Optional updating of pricing through contract	
	Procurement Lead Time	6 months ahead and 18 months ahead	Case specific 1–12 months	DER applies if eligible	
	Payment	Availability and Utilisation		Utilisation only	
	Contract Term	1–4 years	Monthly or seasonal	Framework agreement	

Appendix 7. Industry guidelines for flexibility markets

Adapted from: (Energiföretagen Sverige 2019).

- Promote the use of flexibility in multiple ways and with many communication channels
- Identify parties responsible for the situation and trough settlement ensure fair flexibility cost allocation to the responsible parties
- Develop a discussion culture and increase transparency among different network operators and market parties to anticipate network reinforcement and operational needs in a timely manner
- In case of allocation reductions release transmission capacity on the market after reassessing the capacity requirements of different network operators
- Explore and promote the possibility of introducing locationally and temporally dynamic power tariffs or other bilateral contracts via FSPs for the pricing of network service
- Ensure compatibility of flexibility markets and other markets and rules in general with national, regional and European development
- Ensure long-term commitment to the necessary network reinforcements and flexibility resource installations
- Develop market mechanisms in place to promote the provision of the services needed by the network and identify and remove obstacles that reduce flexibility and price responsiveness
- Streamline permit processes related to networks and network users
- Ensure consistency of legislation, regulation and policy objectives

Appendix 8. Next steps for flexibility markets

I. Test the suitability of different flexibility product options with physical demonstrations in real-market conditions. Possible sub-tests:
   - Use of locational mFRR balancing products:
     - Activation of a locational mFRR balancing energy offer.
     - Activation of a locational mFRR balancing energy offer with a counter-activation in another location.
     - DSO activation of a locational mFRR balancing energy offer.
   - Locational intraday product:
     - Activation of a locational intraday offer.
     - Activation of a locational intraday offer with a counter-activation.
   - Activation of a locational flexibility energy offer, either IDM or mFRR, which is linked to a locational mFRR balancing capacity offer or other flexibility capacity market offer.
   - Competitive bilateral flexibility contracts:
     - Hold an auction for the procurement of locational flexibility from:
       - new installations,
       - from existing resources.
     - Hold an auction for the procurement of locational flexibility for:
       - reactive power control,
       - for congestion management with:
         - self-activation (according to the predefined contract),
         - system operator activation (e.g. electrical signal).
       - uninterrupted power supply or other post-fault support.

II. Develop and test market services needed for the physical demonstrations (I). Possible sub-tests:
   - TSO-DSO coordination:
     - TSO-DSO need coordination (for example flexibility zone definition),
     - additional request of locational offers,
     - selection of feasible flexibility offers according to technical effectivity and cost-cost-efficiency which results to:
       - in-advance defined self-dispatch of the FSP,
       - dispatch by the TSO,
       - dispatch by the DSO (directly or with request from TSO).
   - Market coordination and offer-integration:
     - Regulated domain:
       - Offer filtering (unfeasible bids and bid selection)
     - Market operator domain:
       - Cross-process linking offers (wholesale, balancing and flexibility)
     - Competitive domain
       - Offering and market selection
       - Offer sequencing
   - Flexibility verification and settlement:
     - Fine resolution monitoring
       - ex-post and/or in real-time
     - Baseline-definition and settlement
     - Unit-based schedule and settlement
     - Imbalance adjustments and other financial compensation