The development of a market for Demand Side Flexibility: A study of the pilot project NorFlex

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Preface

This M.Sc. thesis concludes the authors master's degree in Industrial Economics and Technology Management under the faculty of Engineering and Science at the University of Agder. The thesis is written during the spring of 2021.

The thesis is conducted in collaboration with NorFlex, Demo Agder, facilitated by Agder Energi. The purpose of the thesis is to highlight the potential value gain demand side flexibility can provide. The theme perfectly combines the subject of renewable energy in the power system and corporate economics and finance. Both authors have a background in renewable energy engineering studies, which has lead to an interest in studying flexibility in the power grid. The working process has been highly educational and inspiring, as the authors believe that demand side flexibility will play an essential role in the future power system.

Firstly, we would like to thank Agder Energi for the opportunity to research the subject and project closely. In particular, we thank senior advisor Jan Pedersen for counseling and guidance throughout the study. We also thank every informant for taking the time to participate in the study, providing valuable insight and information.

The M.Sc. thesis «Business Models for Extracting the Value of Flexibility in Electricity Systems» by Stine Anette Berntsen and Hege Grønning Vatn proposes models for determining the benefit and cost functions of demand side flexibility. We want to thank the authors for providing a framework and basis for further research, in a field where little previous research has been conducted.

Lastly, a major thanks to our supervisor from the University of Agder, School of Business and Law, Stine Rye Bårdsen. Thank you for your time, guidance, and ability to keep our focus on the important tasks and challenges. The collaboration has truly been educational and motivational.

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Abstract

Demand side flexibility (DSF) is believed to have positive value for the power system. DSF could solve the problems the power grid is facing due to increased electricity consumption and increased production from intermittent renewable energy sources. This is done by enabling demand side participation in the value chain. NorFlex is a pilot project testing and validating the DSF value chain. This thesis follows the NorFlex project, analyzing the potential value gain of DSF. The following problem statement is answered:

In a developing market for Demand Side Flexibility, what is the potential for value gain?

The research is designed as a case study where NorFlex is the object of study. The research follows a deductive approach, analyzing the potential for value gain in the following three steps:

1. Analyse the market demand for demand side flexibility, exemplified by analyzing the grid operator Agder Energi Nett
2. Analyse the cost for making three representative flexible resources available in the power grid.
3. Comparing the supply and demand derived from the analysis with the market clearing at a real market situation.

In steps 1-3, a combination of quantitative and qualitative data is analyzed. The data is collected through interviews with central participants in the NorFlex project. Secondary data is collected from public records and from the market platform NODES.

The findings of this thesis show that a potential for value gain from DSF exists. The three assets analyzed have cost functions that are lower than the DSO's upper willingness to pay. Because the potential for value gain exists, all parties in the DSF value chain can extract value and benefit from DSF trading. However, quantifying the exact value gain requires specific evaluation of the geographical location, grid level, and weather. The demand and cost of supplying DSF will vary with these conditions, as will the price. With an increased demand for DSF and a tendency of decreased cost of acquiring relevant assets, the future development of the DSF looks promising.

Sammendrag

Forbrukerfleksibilitet (DSF) antas å ha positiv verdi for kraftsystemet. DSF er en mulig løsning på problemene kraftnettet står overfor grunnet økt strømforbruk og økt produksjon fra uforutsigbare fornybare energikilder. Løsningen ligger i å muliggjøre strømforbrukerens deltakelse i verdikjeden. NorFlex er et pilotprosjekt som tester og validerer verdikjeden for fleksibilitet. Denne oppgaven følger NorFlex-prosjektet og analyserer potensialet for verdi ved DSF handel. Følgende problemstilling er besvart:

I et marked for forbrukerfleksibilitet under utvikling, hva er potensialet for verdiøkning?

Studien er en casestudie som bruker NorFlex som studieobjekt. Forskningen følger en deduktiv tilnærming og analyserer potensialet for verdi ved følgende trinn:

1. Analyse av markedets etterspørsel etter fleksibilitet, eksemplifisert ved å analysere nettoperatøren Agder Energi Nett
2. Analyse av kostnadene for å gjøre tre representative fleksible ressurser tilgjengelig i strømnettet.
3. Sammenligning av tilbud og etterspørsel fra analysen med prisutviklingen fra en reell markedssituasjon.

I trinn 1-3 analyseres en kombinasjon av kvantitative og kvalitative data. Dataene samles inn gjennom intervjuer med sentrale deltakere i NorFlex-prosjektet. Sekundære data samles inn fra offentlige databaser og fra markedsplattformen NODES.

Funnene i denne oppgaven viser at det eksisterer et potensiale for verdiøkning fra DSF. De tre analyserte lastene har kostnadsfunksjoner som er lavere enn DSOs øvre betalingsvillighet. Fordi potensialet for verdiøkning eksisterer, kan alle parter i DSF-verdikjeden trekke ut verdi og dra nytte av DSF-handel. Imidlertid krever det spesifikk evaluering av den geografiske plasseringen, nettnivået og været for å tallfeste verdiøkningen. Etterspørselen og kostnadene ved å levere DSF vil variere med disse forholdene, det samme vil prisen. Med økt etterspørsel etter DSF og en tendens til reduserte kostnader for å tilgjengeliggjøre relevante laster, ser den fremtidige utviklingen av forbrukerfleksibilitet lovende ut.

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List of abbreviations

Abbreviation	Definition
DSF	Demand Side Flexibility
DSO	Distribution System Operator
TSO	Transmission System Operator
BRP	Balancing Responsible Party
RES	Renewable Energy Sources
CEP	Clean energy for all Europeans package
USEF	Universal Smart Energy Framework foundation
EC	European Commission
NVE	The Norwegian Water Resources and Energy Directorate
RME	Norwegian Energy Regulatory Authority
SSB	Statistics Norway
SEDC	Smart Energy Demand Coalition
AEN	Agder Energi Nett
CENS	Cost of Energy Not Supplied
FCR	Frequency Containment Reserves
aFRR	Automatic Frequency Restoration Reserves
mFRR	Manual Frequency Restoration Reserves
CF	Correction Factor
h	hour
h_D	hours dispatched

Chapter 1

Introduction

The European electricity consumption is constantly increasing across consumer groups and is predicted to increase with 241 TWh in Germany, France, and Great Britain alone towards 2040 (Spilde et al., 2019). A key driver in increasing electricity consumption is the transition from fossil fuels to renewable energy (Spilde et al., 2019). To reach the European Commissions' goal of decarbonizing the European power system, more energy sources need to be electrified (European Commission, 2018). Increased electricity consumption poses challenges to the grid infrastructure, especially during peak hours (Bontius & Hodemaekers, 2018). Such problems can deteriorate performance, power quality, and can lead to power outages if left unaddressed (Bontius & Hodemaekers, 2018).

Today's solution is investing in new grid infrastructure, which is an expensive solution for solving problems occurring within a few hours of peak demand. A more economical solution could be to implement Demand Side Flexibility (DSF) in the power system. Demand Side Flexibility (DSF) is defined by the Universal Smart Energy Framework Foundation (USEF) as «the ability to purposely deviate from a planned or typical consumption or generation pattern» (de Heer & van den Reek, 2018a, p. 4).

Based on the definition given by (de Heer & van den Reek, 2018a) flexible resources are already utilized in the Norwegian power system, but mainly on the producer side. When a producer either increases or decreases production, this ability can be defined as flexibility. In Norway, most of the energy is produced with hydropower which can meet load fluctuations minute-by-minute (IRENA, 2012). The challenges the grid infrastructure is facing are primarily due to capacity constraints and cannot be solved by flexibility from the producer side (de Heer & van den Reek, 2018a). Regulating production up when the demand increases are only a viable solution if the grid is capable of transferring the power from producer to consumer. DSF utilizes flexibility on the consumer side of the power value chain (de Heer & van den Reek, 2018b). Instead of the producer regulating the production, the consumers can increase or decrease the consumption of electricity. The consumer shifts their consumption from hours of high demand to hours of low demand, and the grid capacity is not exceeded (de Heer & van den Reek, 2018b). Implementing more DSF in the power system can increase the amount of flexibility available and decrease the grid operators' need for new investments (Agder Energi, 2019).

In 2019 the EU reached an agreement on a new energy policy framework, the *Clean energy for all Europeans package* (CEP). CEP puts the consumer in the center of the clean energy transition (European Commission, 2018). The framework enables active consumer participation in the power system. A flexibility value chain must be implemented to enable the transition described by the framework from a traditional system, with one-directional power, to a system with consumer participation. The flexibility value chain must be tested and validated, which is conducted through pilot projects and demonstrations across Europe.

In 2019 the Norwegian grid operators Agder Energi, Glitre Energi, Mørenett, and Statnett collaborated with the market platform NODES and started the pilot project NorFlex (Agder Energi, 2019). The project is making existing and new flexible resources available, exploitable, and commercialized by scaling market-based solutions for DSF in the power system (Agder Energi, 2019). The project goal is to evolve the market by increasing the number of providers and sources of DSF, integrating and verifying technology platforms, and verifying the market model in the demonstration area.

In addition to NorFlex, several European projects are testing market-based solutions for DSF. Examples include: Interflex (Europe), Intraflex (UK), Sthlm Flex (Sweden), and Enera (Germany) (USEF, 2015). The projects have different scopes, but every pilot demonstrates a local flexibility marketplace. The projects referred to are, to this date, ongoing projects.

According to economic theory, there must exist a point where supply meets the demand for any marketplace to be viable (Perloff, 2018). The difference between the demand and cost of a good show the potential for the buyer and supplier to extract value from trading at the market. If the parties at the market can extract value from trading demand side flexibility, the value chain and market are beneficial. To the authors' knowledge, limited research has been conducted on the market-clearing and price formation as a result of the European pilot projects.

Most literature regarding DSF is centered around technical development and challenges. USEF has developed several reports as well as a framework for a market design for flexibility (de Heer & van den Reek, 2018a, 2018b; USEF, 2015). These guidelines set the premise for developing a DSF marketplace and have identified how demand side flexibility can provide value to the parties participating. However, USEF guidelines have not attempted to quantify the value gain nor addressed the price formation in such a market. In their M.Sc. thesis Berntsen and Vatn (2014) developed models for cost and benefit functions in a DSF marked based on general market data. The thesis did not have any relation to a pilot project. In addition, Baretto and Eide (2018) performed a case study on the Distribution System Operator (DSO), Agder Energi. The case study investigated whether DSF can be an alternative to grid investments. The thesis addresses the economic value of postponing investments for Agder Energi Nett (AEN).

The following study is conducted in collaboration with NorFlex, Demo Agder, which is one of several demo areas in the project. Further, the study will address both the cost and benefit function suggested by Berntsen and Vatn (2014) and put them into context with the NorFlex project. This study aims to contribute to the research on market-based DSF by further developing models describing the supply and demand. Thus gaining a greater understanding of the potential value that could be extracted by implementing DSF in the power grid. The thesis' problem statement is as follows:

In a developing market for Demand Side Flexibility, what is the potential for value gain?

To understand the value gain of DSF, the demand side and supply side of the value chain need to be examined, as well as the market-clearing point. To answer the problem statement, theoretical models will be compared to data from DSF trade in the NorFlex project. The analysis will be conducted in the following steps:

1. Analyse the market demand for demand side flexibility, exemplified by analyzing the grid operator Agder Energi Nett
2. Analyse the cost for making three representative flexible resources available in the power grid.
3. Comparing the supply and demand derived from the analysis with the market clearing at a real market situation.

There are several stakeholders in the flexibility value chain. All parties, from the grid operator to the electricity consumer, are gaining value. This thesis focuses on the interface between the supplier of DSF, the aggregator and Distribution System Operator (DSO), Agder Energi Nett. The aggregator and DSO are trading at the market platform NODES, and the rules and constraints at the marketplace apply.

The thesis focuses on NorFlex, demo Agder as the case. The grid operator Agder Energi is analyzed to gain insight into how DSF can benefit the DSO. How the Transmission System Operator (TSO), Statnett will affect the market is not analyzed.

A wide range of flexible resources could have the ability to shift their load. This thesis analyses three representative assets. The assets are in the private, commercial, and public procurement markets. The aggregators business model is not evaluated in this thesis, as the thesis focuses on developing a sense of fair compensation rather than developing a competitive compensation or cost strategy.

The following chapter will discuss the most important theoretical concepts concerning the power market and demand side flexibility in the power grid. Then the problem statement will be researched through the three steps explained. In order to analyze the DSF market, information from the NorFlex project is collected through interviews and numerical trade data. The aim is to gain knowledge and better understanding of the potential value gain in the flexibility market for the DSO, aggregators, and the additional participants.

Chapter 2

Theoretical Framework

According to economic theory there must be a buyer acquiring a good and a supplier producing the good for any market to be viable. For a transaction to occur at the marketplace, a price has to exist. For the supplier to be willing to produce a good, the price, at the minimum, need to be sufficient to cover the total cost of production. For the buyer to be willing to purchase a good, the price, at the maximum, need to be below the buyers upper willingness to pay. If these conditions are met, a potential for value gain exist and a transaction will take place.

In 2020 multiple transactions between multiple buyers and suppliers resulted in a total of 132 860 306 MWh being traded at the Nordic power market (Nord Pool, n.d.-c). The power market is closely related to the market for DSF. Because the market is developing it is important to examine related markets as the mechanisms of supply and demand at each marketplace might influence each other.

2.1 The Power System

Electric power is regarded as a fundamental necessity in the modern economy. It is used in almost every aspect of society, therefore ensuring reliability in electric power delivery is essential for any society (Wilson, 2012). As a result, every component in the supply chain is strictly managed and regulated according to engineering standards. Electric power is a flow from producer to consumer. Because it is hard and expensive to store, there must be an exact balance between electricity consumption and generation. Electricity imbalance causes black-outs and can be damaging to components in the grid infrastructure (Wilson, 2012).

The electric power industry is both fuel and capital intensive (Wilson, 2012). The supply chain starts with the fuel (hydro, nuclear, wind, solar, gas, oil) to power plants where mechanic or thermal energy is converted to electric energy. The power is firstly distributed to the high-voltage transmission grid and then transformed to local distribution networks from which consumers can withdraw power at lower voltages (Wilson, 2012). The value chain parties are: power producer, Transmission System Operator (TSO), Distribution System Operator (DSO), and electricity consumer, respectively, as illustrated in Figure 2.1.1. In the Norwegian power market, hydropower accounts for 90% of all-electric power production (Norwegian Ministry of Petroleum and Energy, 2021).

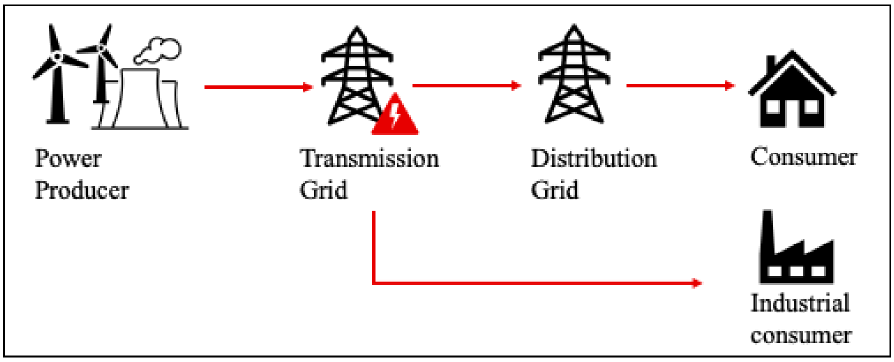

Figure 2.1.1: The supply chain for electric power from producer to consumer. Derived from (Norwegian Ministry of Petroleum and Energy, 2017).

2.1.1 Market structure

In most market situations the price of a good can be influenced by participants, buyers or suppliers, with market power (Weber, 2012). The reason some participants have more market power than others is because the market structure differs from *perfect competition*. Perfect competition is the ideal market structure, where many buyers and suppliers trade an identical good and have perfect information about the market and there are no barriers to enter the market (Acemoglu, Laibson, & List, 2019). In a perfectly competitive market, any individual buyer or supplier does not have enough market power to affect the market price. All buyers and suppliers are price takers and can not negotiate for a better price. No market is perfectly competitive, but some markets have similar characteristics (Acemoglu et al., 2019).

The TSO and DSO are responsible for operating the power grid at their grid level and maintain and extend the grid capacity when necessary. The TSO and DSO are both natural monopolies as they operate on a regional and local basis, respectively, and maintains the infrastructure of national importance (NVE - RME, 2015). A monopoly market structure means that the

TSO and DSO are the sole provider of their services (Weber, 2012). As a monopolist the grid operators have the market power to set the price and quantity to their advantage. As opposed to a monopoly, a monopsony is a market structure where the buyer is the single participant acquiring a good. Similar to a monopolist, the buyer can choose to set the price and quantity to its advantage (Perloff, 2018). In a monopsony a firm exercises its market power by buying goods at a price below the price that competitive buyers would pay (Perloff, 2018). In the market for DSF, the TSO and DSO can be regarded as monopsonists, this is further elaborated in Chapter 2.5.

2.1.2 The regulated and commercial domain

Because the TSO and DSO are both monopolies distributing a fundamental necessity, their services are regulated. In the Norwegian power market, the Norwegian Energy Regulatory Authority (RME) regulates grid operators so that power is transferred to the right quality and price and that the grid infrastructure is utilized and expanded in a socioeconomically rational way (RME, 2019). RME regulates grid companies economically and sets requirements for power quality. One of the economic regulations is the income frame. The income frame is intended to contribute to efficient operation, development, and utilization of the power grid (NVE - RME, 2015). Thus, the companies who are cost-efficient will have a higher profit (NVE - RME, 2015).

RME also regulates the wholesale power markets to ensure safe and efficient transfer of energy (RME, 2019). RME aims for the development of a well-functioning power market that is perceived as easy and understandable by the end-user (RME, 2019). When regulating the wholesale market, RME regulates an open marketplace in the commercial domain. The important distinction between the regulated and commercial domain is that in the regulated domain, the cooperation (TSO and DSO) itself is regulated and not the marketplace facilitating trade. When discussing the power market, it is crucial to beware of the difference between the regulated and commercial domains.

Cost of Energy Not Supplied

The TSO and DSO being monopolies could, if not regulated, have severe consequences for the electricity consumer. If the TSO or DSO stops providing their services because the marginal profit decreases, this will result in power outages for the electricity consumer. This motivates the grid operators to keep the costs down. However, the cost should not compromise the power reliability or quality. The cost of energy not supplied (CENS) is a financial penalty representing the electricity consumers' cost due to a black-out (Heien et al., 2018). CENS is charged to the grid operator when outages occur. CENS is an incentive for the grid operator to invest in the infrastructure and maintain the grid (Heien et al., 2018). In order to give the grid operator incentives to fix problems or outages promptly, the CENS rate increases with the duration of the outage. According to Heien et al. (2018), the CENS is given by the following equation:

$$K_j = k_{P,ref} * P_{ref} * f_{c,m} * f_{c,d} * f_{c,h} \tag{2.1.1}$$

In Equation 2.1.1 K_j is the cost [NOK] as a consequence of a power outage at the given time j. $k_{P,ref}$ is the CENS rate $[NOK/kW]$ for the consumer segment affected. P_{ref} is the quantity of energy not supplied during the outage denoted as kWh/h. The consumer's financial consequence of a power outage varies based on the season, weekday, and time of day, therefore the correction factors are included in Table 2.1.1. $f_{c,m}$ is the correction factor related to the month where the outage occurs. $f_{c,d}$ is the correction factor for the given weekday. Lastly, $f_{c,h}$ is the correction factor for the hour the outage occurs (Heien et al., 2018). The factors in Equation 2.1.1 vary by consumer segment. The different costs are found in Table 2.1.1.

The factor $k_{P,ref}$ is given by different formulas per segment and duration of the outage. In this thesis, the $k_{P,ref}$ for one hour is considered most important. Table 2.1.1 shows $k_{P,ref}$, and CENS rate for 1 hour of power outage.

Table 2.1.1: The CENS rates in different segments (Heien et al., 2018).

Segment	Equation	CENS rate [NOK/kW]	CENS rate [NOK/MW]
Household	$k_{P,ref} = 8,8 + 14,7t$	23,7	23700
Commercial	$k_{P,ref} = 31,5 + 189,2t$	220,7	220700
Industrial	$k_{P,ref} = 38,2 + 95,2t$	133,4	133400

2.2 The Nordic Power Market

While grid operators are strictly regulated, electricity production and trading have been market-based in Norway since 1991 (Norwegian Ministry of Petroleum and Energy, 2017). The 1991 energy act was intended to ensure effective use of resources and reasonable electricity prices. Norway is a part of a joint Nordic power market, Nord Pool with Sweden, Denmark, and Finland. The Nordic power market is further integrated with the European market through interconnectors in the Netherlands, Germany, Poland, Russia, and the Baltic states (Norwegian Ministry of Petroleum and Energy, 2017).

The power market can be divided into consumer and wholesale market (Norwegian Ministry of Petroleum and Energy, 2017). At the wholesale market, larger volumes are bought by power producers, brokers, power suppliers, energy companies, and larger industrial companies. Power suppliers trade on behalf of small and medium-sized electricity consumers (Norwegian Ministry of Petroleum and Energy, 2017). The wholesale market is divided into a financial market (or future market), spot market, and balancing markets (Norwegian Ministry of Petroleum and Energy, 2017).

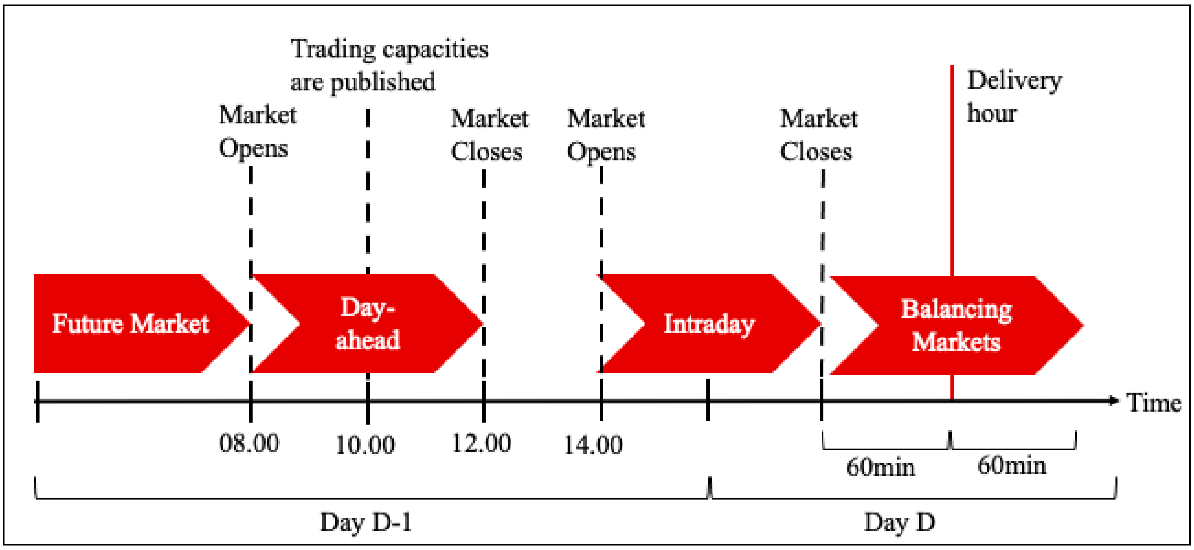

Figure 2.2.1: Timeline explaining how the different wholesale power markets coexist. Day D = Day of Delivery (Nord Pool, n.d.-a, n.d.-b).

2.2.1 Financial Market

The financial market is a market for future contracts of power. The contracts have a time horizon of maximum 10 years and the products cover daily, weekly, monthly, quarterly and yearly contracts (Nord Pool, n.d.-c). The contracts deliver the underlying amount of power in the given time period. The delivery is settled financially, meaning that the spot price's money equivalent is delivered (Benth & Schmeck, 2014). The market is mainly used for hedging and risk management (Nord Pool, n.d.-c).

2.2.2 The spot market

Nord Pool Spot runs the leading power market in Europe and is the market operator of both the day-ahead and the intraday market. Nord Pool Spot is a market platform for trading electricity and is responsible for physical and financial trade in the Nordic market (Nord Pool, n.d.-a).

2.2.3 Day-ahead market

In the day-ahead market, customers sell or buy power for the next 24 hours in a closed auction. This sets the hourly electricity price, each hour, for the next 24h (Nord Pool, n.d.-a). The market actors submit sales and purchasing-bids between 08.00 and 12.00, when the day-ahead market closes. The national TSO releases the transmission capacity for each grid zone before 10.00. Orders are matched based on the transmission capacity and the bids submitted. After the market is cleared, the prices for each hour the following day are set (Norwegian Ministry of Petroleum and Energy, 2017). The market design for the Norwegian (and Nordic) day-ahead market is connected with the European markets. The electricity spot price is connected as Nord Pool calculates the price in the different grid zones via a standard European algorithm called Euphemia (Nord Pool, n.d.-b).

2.2.4 Intraday market

The power balance is primarily ensured at the day-ahead market. Nevertheless, electricity production and consumption are unpredictable, and factors such as changing weather forecasts can change power supply or demand (Norwegian Ministry of Petroleum and Energy, 2017). This will result in power imbalances after the day-ahead market is cleared. The market actors can trade in the intraday market continuously from the day-ahead market is cleared to the intraday market closes, one hour before delivery takes place. Prices are set through a first-come, first-served principle. The best prices come first, which means the highest purchasing bid and the lowest sales bid (Nord Pool, n.d.-b).

2.2.5 Balancing markets

The balancing markets, operated by the TSO, are targeted measures to ensure reserve capacity if the spot market fails to equate supply and demand (Tennbakk et al., 2016). The power system is at balance if the frequency is 50Hz. Resources are activated at the balancing markets to restore the frequency to 50Hz in case of power imbalance (Norwegian Ministry of Petroleum and Energy, 2017).

The balancing markets are kept outside the wholesale electricity markets. The balancing market can be separated into two categories: capacity market and activation market. The capacity market ensures the availability of flexible resources, which is either activated automatically or through the activation market (Statnett, 2018). Products traded at the capacity market are: Frequency Containment Reserves (FCR), Automatic Frequency Restoration Reserves (aFRR), and manual Frequency Restoration Reserves (mFRR). The mFRR market is the only market connected to an activation market referred to as the RK-market (Statnett, 2018).

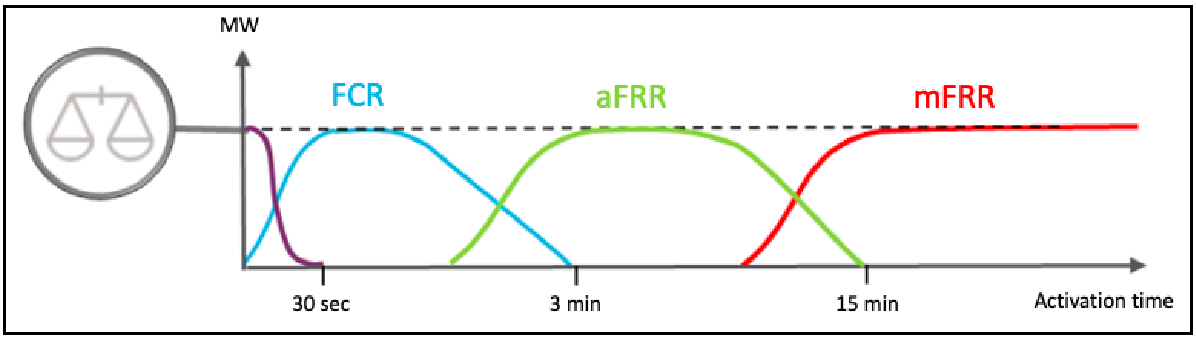

Figure 2.2.2: The relation between response and activation time for the three capacity reserves activated when imbalance occurs. The purple line represents the system inertia. From (Statnett, 2018).

At the capacity market, the TSO can procure resources months ahead of time. Whether they are activated is determined close to real-time. Statnett, the Norwegian TSO, ensures capacity by purchasing the different reserve products on a seasonal basis (mFRR), weekly basis (FCR, aFRR, and mFRR), and/or day-ahead (FCR) (Statnett, 2018). The capacity provider submits bids to Statnett, who accepts the cheapest bids that meet the demand (Statnett, 2018).

Providers who are accepted in the capacity market are compensated according to the marginal capacity offer, regardless if the asset is activated or not (Statnett, 2018). In the activation market, the provider is compensated if the asset is activated. In the RK market, the price determiner is the most expensive activated bid. For down-regulation, it is the cheapest activated bid that determines the price (Statnett, 2020b). The price for up-and down-regulation is set per elspot area after the activation hour (Statnett, 2020b).

The suppliers at the balancing markets submit a price to regulate their consumption or production (Statnett, 2020a). An example of a resource activated at the RK market is an industrial load, drawing the effect of 10MW. By the de Heer and van den Reek (2018b)'s definition, presented in Chapter 1, this resource can be defined as DSF. The same goes for many loads offered at the balancing markets. Statnett and the other Nordic TSOs have an increased need for flexibility (Statnett, 2018). At the same time, the roles in the balancing market are changing. The EU's guidelines and requirements lead to changes in the balancing products, FCR, aFRR, and mFRR. The CEP imposes equal treatment for resources from the demand and production side of the value chain (Statnett, 2018). Statnett (2018) addresses the entry barriers and how they can be reduced to enable more flexible resources to enter the market. NorFlex is testing and validating a market-based solution where small loads are aggregated to meet the TSO's demand. This is a solution to lowering the entry barrier to the balancing markets and increasing the number of flexible resources available for the TSO.

2.3 Electric Power Pricing

The concept of supply and demand is fundamental in price theory. The concept can be described in the following way: In a free market, prices of goods depend on the demand of the buyers. If the demand for a good exceeds the supply, the price of the good will increase, which causes a decrease in demand (Gale, 1955). When the opposite occurs, and the supply exceeds the demand, the price will drop as a result. The demand will increase as a cause of the transaction. In a free market, the price will self-regulate, and the supply and demand will be balanced, creating an economic equilibrium in the prices (Gale, 1955).

When describing electric power pricing, the Nordic power market is used as a reference. At the wholesale market, the power spot prices are determined in an auction-based system (Norwegian Ministry of Petroleum and Energy, 2017). The market operator, Nord Pool, calculates the system price for the following 24h. The system price is a theoretical price calculated applying the assumption that there are no constraints in the transmission grid. Power producers submit sales bids based on the desired amount of power they wish to produce to a price. The power producers mainly use cost-based pricing representing the marginal costs of producing electricity. Marginal cost is the cost of producing one more unit of a good. The term includes all the additional costs required to produce one additional kWh of power. The electricity customer submits bids based on their expected consumption and willingness to pay. The price is set at the equilibrium between supply and demand at the day-ahead market, also refereed to as the market-clearing point (Norwegian Ministry of Petroleum and Energy, 2017). The market-clearing point represents:

- The cost of producing one kWh from the most expensive source needed to be employed to balance the system – either from a domestic installation or from external imports.
- The price that the consumer is willing to pay for the final kWh required to satisfy its demand

2.3.1 General characteristics of electricity prices

As explained in Section 2.1, the electricity system needs to be in exact balance at any given time. This is one of the characteristics that distinguish the electricity market from other commodity markets (Kovacevic, Pflug, & Vespucci, 2013). The inability to effectively store large quantities of electricity prevents intertemporal demand smoothing (Kovacevic et al., 2013). According to Kovacevic et al. (2013), the three main characteristics affecting electricity prices are: seasonalities, mean reversion, and negative prices.

The electricity price varies with the season and temperature. This is because of the (almost) inelastic demand for electricity (Kovacevic et al., 2013). The price elasticity of supply ϵ_s is a measurement of how responsive the quantity supplied is to a change in the price (Acemoglu et al., 2019). The electricity price varies in three different cycles: daily, weekly and yearly seasonality. The price varies in conjunction with the demand, further explained in section 2.3.3.

Electricity prices are often described as unpredictable, making high jumps or pikes (Kovacevic et al., 2013). This is accurate when describing a short-term perspective of electricity prices. However, analyzing electricity prices from a long-term perspective, the price volatility will eventually revert to the long-term mean or average (Kovacevic et al., 2013). This phenomenon is referred to in economic theory as mean reversion. The long-term price follows the marginal cost of producing electricity (Kovacevic et al., 2013). This price formation has similarities to the price formation in a market with perfect competition, explained in Section 2.1. When the electricity demand is high, power generators with high marginal costs are activated, leading the electricity price to increase (Kovacevic et al., 2013). Whereas, when demand is low, only power generators with low marginal cost will be activated, leading the electricity price to fall (Kovacevic et al., 2013).

The prices at an electric power market can, in some instances, be negative. Negative prices can occur due to lack of storage capacity and limited flexibility in changing loads (Kovacevic et al., 2013). In some cases, the cost of completely shutting down production (and restarting production after an unknown time-period) exceeds the costs of accepting negative prices (Kovacevic et al., 2013).

2.3.2 Electricity supply

The cost of producing electricity is a key driver of electricity prices (Kovacevic et al., 2013). This means that analyzing the cost drivers for electricity production is important when addressing electricity pricing. The main cost drivers can be categorized into three groups:

- Investment cost
- Fuel price or availability
- Cost of generation/ Generator capacity

Acquiring generation capacities requires large investments of capital. This is true for almost every type of power plant (Wilson, 2012). However, each generators' ratio of variable to capital or fixed costs varies greatly (Wilson, 2012). In Norway, the majority of power is produced by hydropower plants (Norwegian Ministry of Petroleum and Energy, 2021). Hydropower is a capital-intensive technology, and investment costs, such as construction, infrastructure, and electro-mechanical equipment, account for a large share of the cost per installed kW/year (IRENA, 2012). For comparison, operation and maintenance accounts for 2-2,5% of the installation cost per kW/year (IRENA, 2012).

As mentioned in chapter 2.1, electric power can be generated using different fuels. This means that the fuel price or availability affects the generation costs (Wilson, 2012). When producing hydropower, there is no direct fuel cost. The water used to generate power is never «consumed» but returned to the river system (IRENA, 2012). The availability of water as fuel is affected by weather and reservoir/dam capacity (IRENA, 2012).

The final cost driver is related to the generator capacity. For example: generators using fossil fuels have enormous costs related to up or down-regulating power production and therefore aim for constant production for all hours (Wilson, 2012). Fossil fuel generators are more suited to generate power for baseload consumption. Baseload is defined as the minimum load during a 24h period. Peak load is where the electricity demand is at its highest during a 24h period. In such power plants, generators are activated in the merit order of their marginal costs. This means that the marginal cost for generating electricity at baseload is lower than at peak load (Wilson, 2012). Hydropower plants have the capability to regulate production up or down, dependent on demand. Hydropower production is associated with great flexibility and possible storage opportunities in reservoirs (IRENA, 2012). In the Norwegian hydro production, water reservoirs have a combined storage capacity equivalent to 70% of the yearly power consumption (Norwegian Ministry of Petroleum and Energy, 2021).

2.3.3 Electricity demand

Statistics Norway, SSB (2019b), show that the total electricity demand in Norway has been growing steadily over the past few years. In a 24-hour time-span, two off-peaks of demand can be observed, denoted as off-peak (1) and off-peak (2) (Kovacevic et al., 2013). Off-peak (1) is the first 7 hours of the day when human activity is low because most people sleep and few businesses operate. Off-peak (2) is the last 4 hours of the day when human and corporate activity decreases. It is during off-peak hours that the demand approaches baseload (Kovacevic et al., 2013).

Ericson and Halvorsen (2008) analyzed how the average hourly consumption varies each month in different sectors. The study was performed using market data from the Norwegian Power grid. Ericson and Halvorsen (2008) confirms the off-peaks in Kovacevic et al. (2013), which are especially visible in the industrial sector. The study also confirms that consumption increases during the winter months due to the cold weather. Examples from the household and industrial sectors are illustrated in Figure 2.3.1.

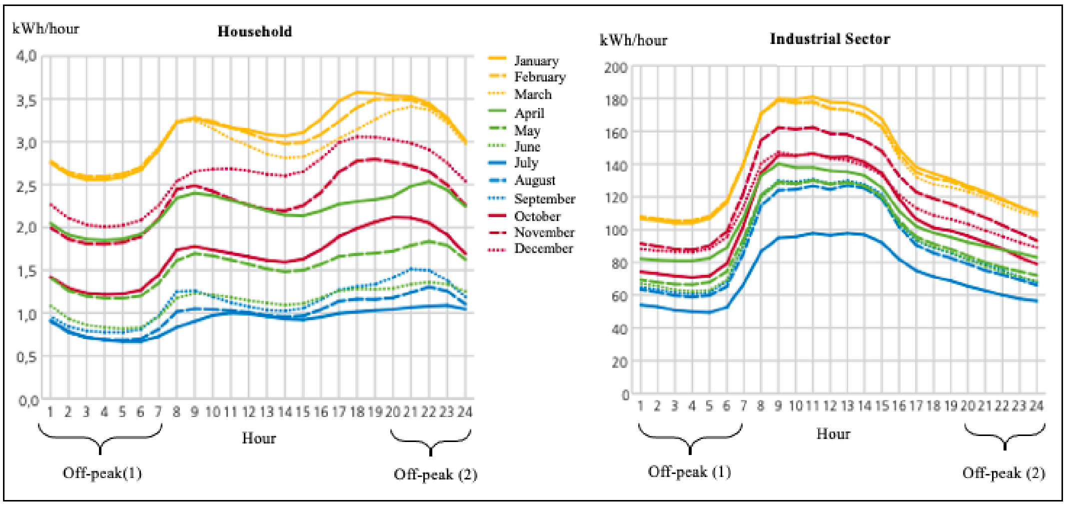

Figure 2.3.1: Average electricity consumption in Norway from (Ericson & Halvorsen, 2008, p.48-49) including off-peak hours.

Ericson and Halvorsen (2008) conclude that there are large differences in consumption patterns when comparing different business sectors to household consumption. An example illustrated in Figure 2.3.1 is how the industrial sector has a more extended, constant peak than households, where the consumption can be separated into two peaks. Figure 2.3.1 also illustrates that the consumption curve has the same shape, regardless if the total consumption is increasing. Implying that when the total consumption increases, the peak load increases.

As mentioned in Chapter 2.3.1, electricity demand is very inelastic and is usually insensitive to short-term price variations. The exception is commercial and industrial consumers, with time-of-use meters (Wilson, 2012). In 2020 the Norwegian regulator NVE opened for changes to the grid tariff (the component in the electricity bill that covers distribution costs)(Eriksen et al., 2020). The change opens up for time-of-use agreements. If the tariff is introduced by the DSO, the average consumer might be more sensitive to price variations.

2.4 Flexibility Value Chain

In later years, the traditional supply chain in Figure 2.1.1 has been challenged by renewable energy technologies. RES are often decentralized and intermittent, which poses changes to the power system's infrastructure (de Heer & van den Reek, 2018b). As mentioned, the grid experiences challenges due to increased demand for electricity and demand side flexibility has been identified as a possible contribution to solving these challenges. Before explaining how DSF can provide services to the grid operators, the term flexibility is further elaborated.

2.4.1 What is flexibility in the power system?

As mentioned in Chapter 1, USEF defines flexibility as: «the ability to purposely deviate from a planned or normal consumption or generation pattern» (de Heer & van den Reek, 2018a, p.4). Flexibility is an ability, and its potential and size are determined by the size of the electrical load and the consumer's ability to react to implicit or explicit signals. The value of flexibility is only determined after it is applied to a specific product. For example, flexibility traded at the balancing markets, introduced in Section 2.2.5, used for Frequency Restoration is valued as regulating power (de Heer & van den Reek, 2018a). Flexibility adds value to the power system when it is solving a problem in the power grid (de Heer & van den Reek, 2018b).

Several attributes can be used to describe flexibility (Esmat, Usaola, & Moreno, 2018). An important distinction is whether the load is up-or down-regulated. Up-regulation is providing more generation or less consumption. Down-regulation is providing more consumption or less generation. These definitions are in line with existing terminology used in the balancing markets. Other traits include quantity (MW), time-interval, and location (Esmat et al., 2018).

As explained in Chapter 1, flexibility can be obtained from assets at the demand and production side of the power system presented in Figure 2.1.1. The flexible resources at the demand side, referred to as Demand Side Flexibility (DSF), are the focal point of the thesis.

The literature on demand response usually distinguishes between two types of DSF: explicit and implicit. The Smart Energy Demand Coalition (SEDC) states that the types of demand side flexibility are complementary and should coexist to give the consumer choices. When coexisting, explicit and implicit flexibility will allow a larger potential of flexible resources to be exploited (SEDC, 2016).

Implicit demand side flexibility

Implicit demand side flexibility is the electricity consumers' reaction to price signals (SEDC, 2016). Consumers who have the ability to choose a spot-price-based power purchase agreement are subjected to price variability. During high-demand hours, where the electricity price is high, consumers can decide to change their electricity consumption to reduce their electricity bill (SEDC, 2016).

The higher the price volatility, the stronger is the incentive for the electricity consumer to shift their consumption. As mentioned in Section 2.3.3, electricity demand is inelastic, indicating that the electricity consumer might not shift their consumption when faced with higher prices. An example of implicit flexible services is Time-of-Use optimization, which uses spot price forecasting and smart devices to shift loads from high-price intervals to low-price intervals (de Heer & van den Reek, 2018b).

Explicit demand side flexibility

SEDC (2016) defines explicit demand side flexibility as committed, dispatchable flexibility that can be traded. When providing explicit DSF, the supplier actively reacts to a signal from the consumers to reduce the load (SEDC, 2016). To be able to trade large volumes of DSF, the flexible resources need to be aggregated into a portfolio. The need for aggregation of volume introduces a key participant in the flexibility value chain: the *aggregator*. The aggregators role is introduced in Section 2.4.2.

2.4.2 Participants in the flexibility value chain

The USEF Foundation has identified a value chain for DSF, illustrated in Figure 2.4.1 (de Heer & van den Reek, 2018b). de Heer and van den Reek (2018b) identifies 4 parties that can gain value from the flexibility value chain:

- Electricity consumer (asset owner) can obtain value by offering DSF, either by regulating their energy production or consumption.
- Balance Responsible Party (BRP) can use DSF to optimize their portfolio and reduce their imbalance costs.
- Distribution System Operator (DSO), might use DSF for congestion management, which in turn will defer or avoid reinvestment costs.
- Transmission System Operator (TSO), can use DSF for ancillary services, balancing purposes, and constraint management.

A conceptual illustration of the DSF value chain is shown in Figure 2.4.1. The asset owner posses the ability to change their consumption of electrical power. The aggregator aggregates the potential volume of flexible consumption and submits a bid to the DSF marketplace. The buyer, denoted in Figure 2.4.1 as DSO, TSO, and BRP, purchases the DSF from the marketplace, signaling the aggregator to dispatch the asset.

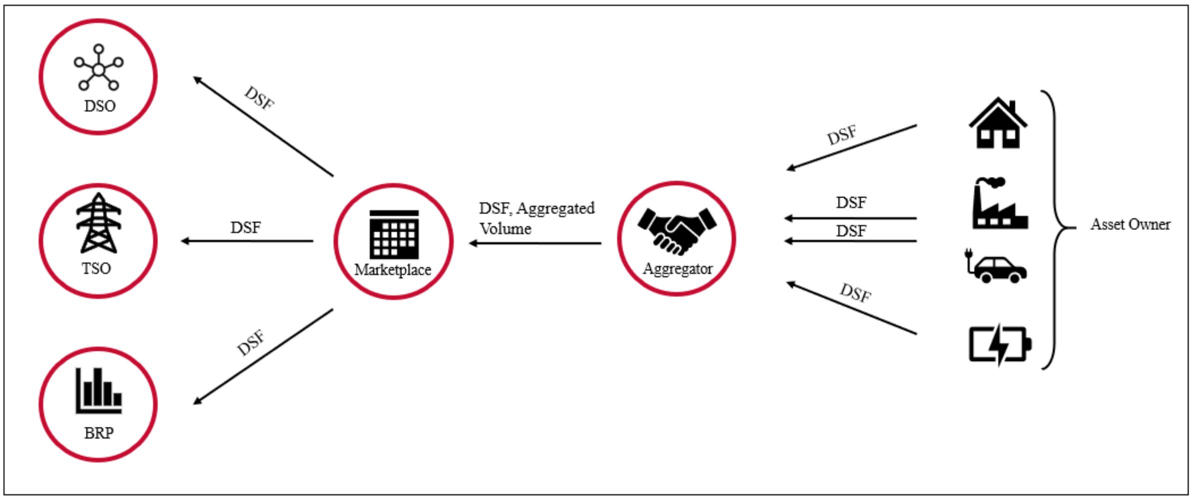

Figure 2.4.1: The flexibility value chain described and illustrated in (de Heer & van den Reek, 2018b).

None of the parties are able to fully exploit the value of DSF in the current supply chain for electric power (Figure 2.1.1). The USEF (2015) framework unlocks the value of flexibility by converting the ability to a tradable good. The good is traded at a marketplace with the associated rules and tools required to make the transaction effective. The USEF (2015) framework emphasizes the importance of fair market access and fairly distributing the benefits amongst the stakeholders.

2.5 The Buyer

There are mainly three buyers in the flexibility market: BRP, DSO, and TSO (de Heer & van den Reek, 2018b). The different customer segments will therefore have different interests and needs when participating in the DSF market. The buyers need flexibility depending on their responsibility and role in the power system. The flexible services valuable for each buyer are summarized in Figure 2.5.1.

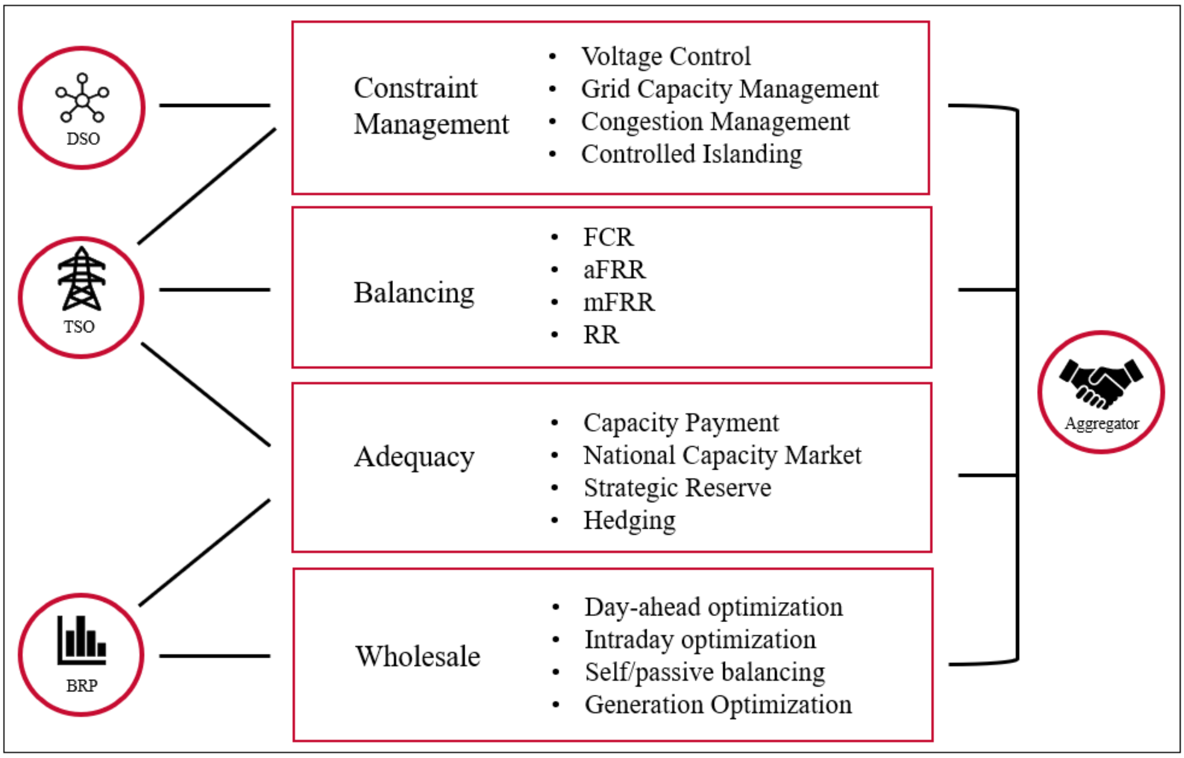

Figure 2.5.1: Flexible services and the customer the service provides value for. The aggregator is the provider of all flexible services. Derived from (de Heer & van den Reek, 2018b).

As shown in Figure 2.5.1, there are three categories of buyers that could benefit from purchasing DSF. The TSO and DSO operates the grid at different grid levels (transmission and distribution) and are both monopolies in providing their services, as explained in Chapter 2.1. Therefore the TSO and DSO are the single buyer of the flexible services within their respective grid areas. This thesis do not examine the demand for DSF from a BRP's perspective and the market structure is regarded as a monopsony (explained in 2.1.1).

2.5.1 Transmission system operator

The transmission grid transports electricity at high voltage, and extreme high voltage across large distances such as from large powerplants to large cities (GEODE, CEDEC, EDSO, & eurelectric, 2018). Electricity is transmitted within the country or between countries. The TSO is responsible for balancing the supply and demand for the electricity market (ERGEG, 2009). This is done by acquiring balancing reserve capacities. As the electricity production is shifting from high and extra high voltage to medium and low voltage, more balancing reserve capacity is shifted from the transmission level to the distribution level. The TSO still maintains responsibility for balancing the market and requires access to the balancing reserve capacities at distribution level (GEODE et al., 2018). The need for flexibility at the transmission level is to maintain grid balance, avoiding frequency instability.

The balancing markets explained in section 2.2.5 is used by the TSO to obtain balance. For the TSO, the flexibility value chain in Figure 2.4.1 could be a replacement or substitute for frequency restoration reserves. The balancing markets are not an open marketplace, shifting to an open marketplace for DSF will make more flexible resources available (de Heer & van den Reek, 2018a).

2.5.2 Distribution system operator

While the TSO is responsible for balancing the grid, the Distribution System Operator (DSO) distributes electricity to the end-user. A DSO is responsible for cost-effectively distributing electricity while maintaining the region's grid stability (USEF, 2015). The DSOs are operating managers (and sometimes owners) of energy distribution networks (USEF, 2015). The DSO's primary need for DSF is constraint management such as: voltage control, grid capacity management, congestion management, and controlled islanding (de Heer & van den Reek, 2018b). According to Esmat et al. (2018), using DSF in constraint management can postpone the need for upgrading the size of the network, postpone re-investments and contribute towards integrating intermittent RES.

As stated in Chapter 1 electricity demand is increasing. In figure 2.5.2 the investments needed to keep up with the demand are shown. The trend is that the investment cost is increasing for the

DSOs. The largest cost item is new investments and reinvestments, respectively. Flattening the power demand curve by introducing DSF can also postpone or reduce the need for investments (Esmat et al., 2018).

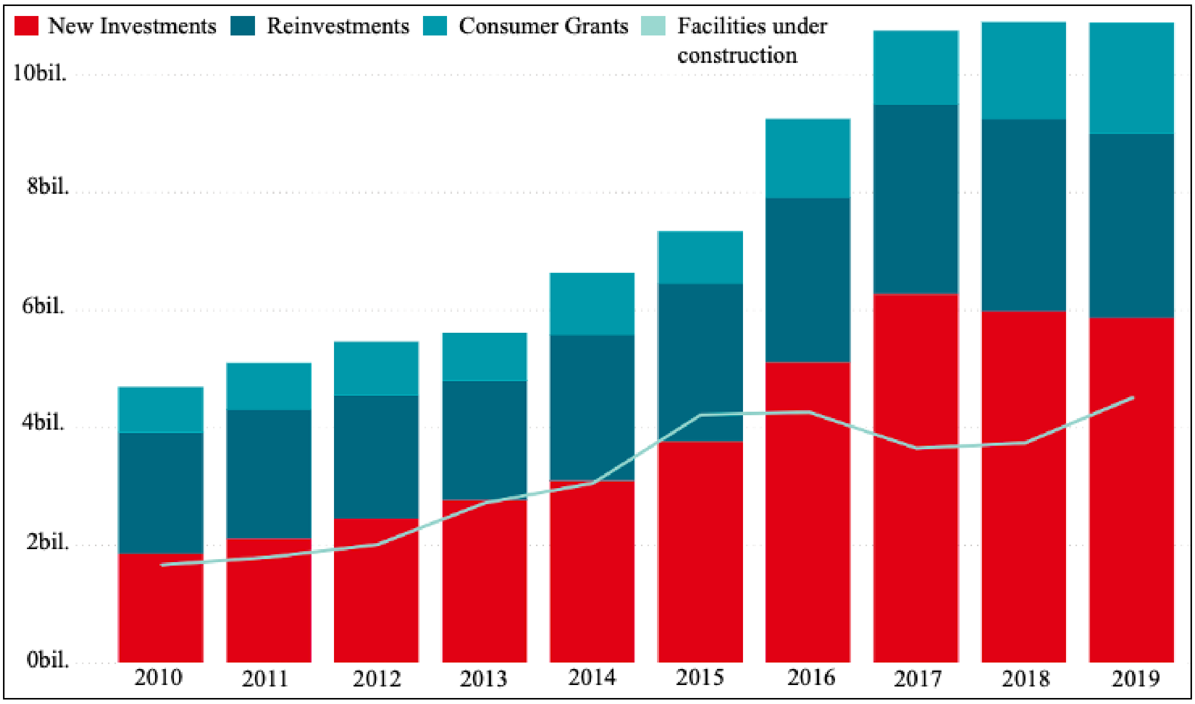

Figure 2.5.2: Investment costs for Norwegian DSOs from 2010-2019 (NVE, 2019). Prices in NOK.

The traditional design of the electricity distribution system is based on the assumption that generation follows demand (GEODE et al., 2018). This is no longer the case when generation from RES increases. Most RES, such as wind and solar power, have unpredictable and intermittent behavior. Large-scale integration of RES, with limited accuracy for forecasted production, can result in a peak in voltage levels (Esmat et al., 2018). If these peaks are over the allowable limits, the RES imposes operational challenges to the system. In these cases, DSF can be of great value to the DSO. In cases of high production by RES, electricity consumers may increase their consumption, increasing the volume, so the load meets the demand.

2.5.3 Balancing responsible party

To participate in the wholesale electricity market and sell electricity to electricity consumers, one must have a direct balancing agreement with the TSO. The companies are either responsible for balancing their own portfolio or enter an agreement with a BRP to settle their imbalance

(Norwegian Ministry of Petroleum and Energy, 2017). The BRP can participate in the flexibility value chain on the supplier (aggregator) side and the buyer side. When the BRP is a DSF customer, the need is to solve imbalances between supply and demand within their own portfolio. When retailers (often with their own BRP agreement) purchase electricity from the Nordic power exchange or directly from production companies, imbalances in demand and supply might occur. The BRP could purchase DSF to reduce the cost of imbalance when conducting day-ahead optimization or intraday optimization (de Heer & van den Reek, 2018b).

An additional benefit the BRP can obtain from purchasing DSF is generation optimization, which refers to optimizing the behavior for dispatched production units to prepare for their next hourly planned production volume (de Heer & van den Reek, 2018b). The control speed of the power units is limited, and the units start ramping up or down minutes before the hour. The balance in the portfolio is maintained by overshooting or undershooting - which may result in a reduced lifetime for the sources (de Heer & van den Reek, 2018b).

2.5.4 The value of flexibility

The value of DSF can be expressed through the buyers benefit function. A benefit function B(g; y,u) is a measurement of the amount that a buyer is willing to trade of a specific good g, for the opportunity to move from utility level u to a consumption bundle y. Thus, the benefit function is a generalization of the willingness to pay concept (Luenberger, 1992). The derivative of the benefit function gives the demand function. Thus, by defining the benefit of a good, it is possible to find the demand for the good (Perloff, 2018).

In their M.Sc Thesis, Berntsen and Vatn (2014) conducted a study examining the value of flexibility. Berntsen and Vatn (2014) presents the following benefit function for procuring DSF. The benefit $B_j(x_j)$ for buyer j for acquiring x_j kW of DSF available in a certain hour is given by:

$$B_j(x_j) = -\alpha_j x_j^2 + \beta_j x_j \tag{2.5.1}$$

Equation 2.5.1 is dependent on the valuation coefficients α_j and β_j for the buyer j. The coefficients are determined by performing quantitative analysis of the customer's benefits from procuring increasing volumes of available DSF.

Berntsen and Vatn (2014) describes a benefit model for a DSO, based on the assumption that the value of DSF is determined by reduced or postponed investment cost as well as the reduction in the cost of energy not supplied (C^{ENS}) and costs associated with operational reliability (C^{R}). The benefit for a DSO is given as a function of available DSF $B_G(x)$:

$$B_G(x) = I - (1 - p(x))I - \frac{p(x)I}{(1+i)^{n(x)}} + \Delta C^{ENS} + \Delta C^{R} \tag{2.5.2}$$

$p(x)$ is the percentage share of investment that can be postponed, I is the total investment cost, n is the number of years the investment can be postponed with x kW of available DSF, and i is the interest rate (Berntsen & Vatn, 2014). Equation 2.5.2 is sensitive for all parameters affecting I. A simplification is made by excluding ΔC^{ENS} and ΔC^{R} (Berntsen & Vatn, 2014).

The numerical estimates of the value of DSF for an average Norwegian Grid company are illustrated in Figure 2.5.3.

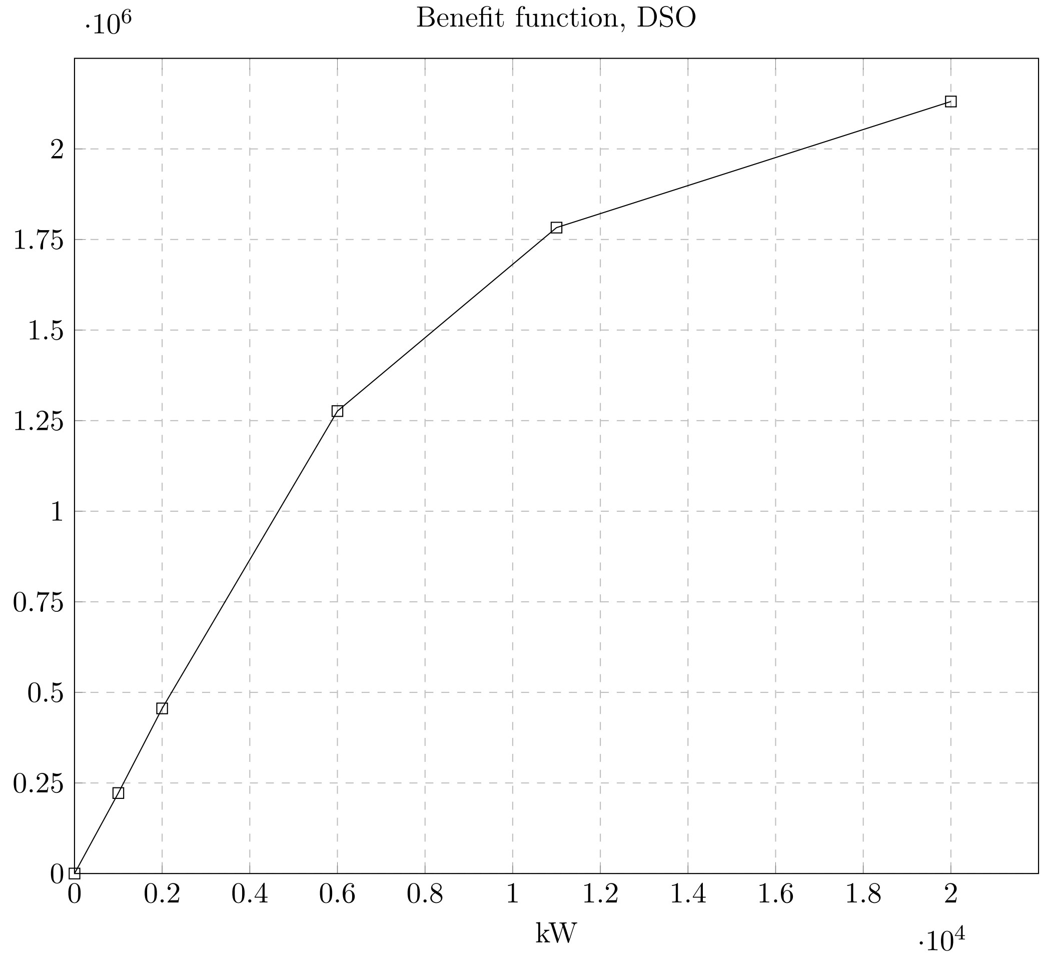

Figure 2.5.3: Numerical estimates of the value of flexibility for an average grid company, from (Berntsen & Vatn, 2014).

The model developed by Berntsen and Vatn (2014) is based on a set of assumptions regarding the customer's value gain and behavior. The assumptions are as follows:

1. The greatest value gain for a grid operator is postponing and reducing investments to expand capacity in the grid
2. The advantages of DSF will increase with increased volume
3. It exists a maximum limit where the buyer does not need more volume of DSF, this limit is defined as a 100% of grid investments is postponed for 11 years.
4. For a DSO, there are small margins to handle congestions in the grid
5. A small amount of flexibility is sufficient to postpone or reduce large investments
6. Large volumes of flexibility are needed less frequently

In addition to the fundamental assumptions, the condition of the grid the buyer is operating is affecting the value of DSF. Berntsen and Vatn (2014) assumes that that congestion occurs 5% of the days in a year, for a duration of 5 hours. Berntsen and Vatn (2014) also assumes that purchasing DSF will solve every congestion problem in the grid. The model does not consider geographical constraints.

Berntsen and Vatn (2014)'s model does not consider all aspects providing value for a DSO. However, the model is generalized and equally relevant for any Norwegian DSO. This means that the graph in Figure 2.5.3 can serve as a benchmark. As mentioned, the model is sensitive to the input data. Therefore, the model will be more accurate when input data specific to Agder Energi Nett is used.

While Berntsen and Vatn (2014) quantified the value of DSF for an average DSO, Baretto and Eide (2018) uses AEN as the subject for a case study and analyses the economic value of flexibility when they can be used to postpone investments of substations at a medium voltage grid level. Baretto and Eide (2018) analyses AEN's need for reducing consumption peeks at a selection of substations and evaluates whether DSF can be used as a tool for peak reduction. Baretto and Eide (2018) maps AEN's potential for postponing substation investments in the distribution grid. The study focuses on transformers and how re-investments in transformers can be postponed.

In Baretto and Eide (2018)'s methodology, it is identified a «flexibility interval» where a transformer investment can be postponed. The interval defines which transformers are eligible for postponing investments, which is transformers that reach over 100% capacity over 11 hours but have an average overload less than 125%. The transformers who run below 100% capacity for 11 hours are not necessary to upgrade. Transformers with an average overload above 125% are outside the interval because the evaluation is that DSF is not sufficient to solve the constraint (Baretto & Eide, 2018).

The findings in Baretto and Eide (2018) were a lower potential for reduced investment cost than AEN expected. The authors point out several factors lowering the economic potential (Baretto & Eide, 2018). Nevertheless, Baretto and Eide (2018) gives a good insight into the potential reduction in costs for a DSO at a local grid level in the distribution grid. de Heer and van den Reek (2018b) emphasizes that there are several ways of extracting value from the flexibility value chain, and *value stacking* should be applied. Value stacking means that the value of flexibility is the sum of all values the customer can draw from DSF. NorFlex has an ambition of testing if DSF can solve capacity problems at different grid levels, further elaborated in Chapter 3. Six hypotheses are identified, and if the hypothesis are verified, the value of DSF can be stacked as the potential for reduced investment costs increases.

2.6 The Supplier

2.6.1 Aggregator

As mentiones, the aggregator plays a vital role in the DSF value chain. The buyers are normally interested in procuring higher volumes of DSF than a single electricity consumer's flexible potential. The aggregators' role is therefore to acquire DSF from electricity consumers and aggregating the volume into a portfolio (de Heer & van den Reek, 2018b). Making the aggregator the supplier in the flexibility value chain. The aggregator provides DSF at a grid node (location), and is responsible for providing a load profile for the portfolio, including a forecast for predicted consumption during the time-period where flexible resources are available (USEF, 2015). This allows for verification of the trade and ensures the buyer that an actual reduction has taken place. The aggregator has not simply disconnected a load that otherwise would not be consuming electricity (USEF, 2015).

2.6.2 Asset owners

The aggregator procures DSF by mapping and enabling the flexible potential of electricity consumers. Meaning that the electricity consumer, who is the owner of one or more electrical asset, have a crucial role in the flexibility value chain. The European Commission strongly supports including electricity consumers who own the assets into the marketplace. The CEP dictates that the electricity consumer should have access to all organized markets and products (European Commission, 2019). Electricity consumers, hereby referred to as asset owners, should benefit from the DSF value chain and should therefore receive compensation for making their assets available. Asset owners from different segments will provide value. The DSF value chain benefits from enabling all consumer segments to participate in the marketplace since a larger DSF potential is unlocked.

In summary, the aggregator aggregates volumes of DSF which are provided by the asset owner. The asset owner has the ability to shift their consumption and should receive compensation for this service. The aggregated DSF can then solve problems the TSO or DSO face when performing grid management.

Industry and business consumers

Big commercial buildings and industrial plants have a large potential of DSF (GEOD, 2014). These consumers often represent large assets and already have implemented sophisticated energy management systems to optimize their energy usage (GEOD, 2014). Spilde et al. (2019) concludes that the transport and industrial sector is the key drivers of increased electricity consumption in Norway. This indicates that the potential for DSF will further increase within the industrial segment.

Small-medium enterprises and residential consumers

In today's market situation, there are few incentives for low volume electricity consumers to participate in the DSF value chain (GEOD, 2014). The electricity prices (especially in the Nordic countries) are low compared to the average income. Average electricity costs represents roughly 6% of a Norwegian households average yearly income (SSB, 2019b, 2019a, 2019c). At the Norwegian electricity market, the price volatility is very low (GEOD, 2014). The Norwegian regulator (NVE) proposes a change to their regulations, allowing price tariffs for power consumption (Eriksen et al., 2020). This will increase electricity prices during demand peaks. The price volatility varies throughout European countries but is expected to increase as electricity demand and penetration of RES increase. Higher price volatility will increase the incentives for low volume consumers to participate in the DSF value chain, either through explicit or implicit flexibility.

2.6.3 The cost of supplying flexibility

A cost function is used to calculate the costs of supplying a good. The cost functions variables will vary between the different suppliers (Perloff, 2018). The study conducted by Berntsen and Vatn (2014) also examined the cost of supplying flexibility by performing an analysis of the cost for an aggregator to supply DSF from industrial, commercial and household electricity consumer. From the analysis Berntsen and Vatn (2014) derives a cost function; $C_s(\theta_s, x_s)$ for curtailing x_s kW of DSF from consumer group, s:

$$C_s(\theta_s, x_s) = a_s x_s^2 + b_s(1 - \theta_s)x_s \tag{2.6.1}$$

θ_s is defined as the willingness of each electricity consumer to curtail or shift load. a_s and b_s are both cost coefficients (assumed equal to all suppliers within the same segment). The cost coefficients are quantified for the different segments using the official CENS rate for one hour as well as the average electricity consumption within the consumer segment. Equation 2.6.1 is strictly convex, and the marginal cost is increasing with the amount of flexibility the aggregator needs to supply (Berntsen & Vatn, 2014).

Berntsen and Vatn (2014) applies a generalization of costs within the three segments. The model is based on how much of the asset owner's total load is curtailed and is not specific to the asset. Different technical solutions or assets have different costs related to activation. Because of the different asset characteristics, the authors argue that the cost analysis should be performed per asset, not the amount of curtailed load.

When solely using the CENS as the basis to determine the cost of supplying DSF, Berntsen and Vatn (2014) neglects the costs of equipment, forecasting and monitoring flexible assets. In Figure 2.4.1, the provider of control technology is illustrated as an essential part of the value chain. The DSF value chain needs to be fully automated to function to its purpose, which is why control technology is an essential cost. To make flexibility available, the aggregator needs to know how much potential each asset can provide. The potential of each asset is the forecasted load for the asset in the hour of activation. The cost of collecting data and develop a forecast also needs to be considered to get a more complete picture of the costs. Berntsen and Vatn (2014) describes a model for estimating the asset owner's cost of supplying flexibility, not the aggregator's total cost.

2.7 Summary

The power system consists of many suppliers and buyers of electricity, but transferring the power from the producer to the consumer is a monopoly service. This is because transferring electric energy requires extensive infrastructure deemed as a critical necessity for the society. Operators providing this service is the TSO and DSO. Because the power system includes both monopoly market structures and free markets, the power market is divided between the commercial and regulated domain. In the commercial domain, power is traded freely at the financial and spot market between power producers and buyers. In the regulated domain, the TSO and DSO are providing their services, within the regulations set by RME. The TSO is acquiring reserve capacity through the balancing markets within the regulated domain.

The traditional, one directional, value chain for electric power (Figure 2.2.1) is challenged by the DSF value chain. The DSF value chain, in Figure 2.4.1, includes the electricity consumer. Of the flexibility platforms introduced by de Heer and van den Reek (2018a), this thesis is examining a DSF value chain where the TSO and DSO purchases DSF from the open marketplace. When a DSF trade is conducted, the electricity consumer, or asset owner receives a signal from the buyer to dispatch or reduce their load. DSF is therefore a service provided by shifting or reducing planned consumption, as opposed to electric power who is regarded as a product produced by a power generator.

Even though it is the asset owner who are shifting their consumption, it is the aggregator who is regarded as the supplier in the DSF value chain. The aggregator aggregates DSF from many assets and places the bid at the marketplace. The aggregator fills an important role in the DSF value chain, as the DSF provided by an asset from small-medium enterprises and the private segment is individually too small to be beneficial to the TSO or DSO. The cost of supplying DSF is therefore seen from the aggregators perspective in this thesis. The benefit and demand for DSF is seen from the DSO's perspective and is determined by the DSO's alternative cost, which is investing in new grid infrastructure. This lays the foundation for examining the potential value gain from DSF trade.

Chapter 3

Research Method

The following chapter describes the method applied to answer the problem statement introduced in Chapter 1. It has already been established that the following three-step analysis will be applied:

1. Analyse the market DSF, exemplified by analyzing the DSO Agder Energi Nett
2. Analyse the cost of making three representative, flexible assets available in the power grid.
3. Comparing the supply and demand derived from the analysis with the market clearing at a real market situation.

The following chapter further elaborates on the research method and approocach. NorFlex, who is the object of study is further described. The method for data collection is described and evaluated to ensure the validity and reliability of the study.

3.1 Object of Study

The object of study is NorFlex, a pilot project facilitating for a flexible electricity consumption (Agder Energi, 2019). Specifically the demo area Agder is studied. The project is run by Agder Energi Innovation and partners include the DSO Agder Energi Nett, the marketplace NODES and seven aggregators (term described in Chapter 2.6.1). Figure 3.1.1 describes the processes conducted at the marketplace tested in the NorFlex Pilot. The aggregators recruit asset owners and aggregate a volume of DSF. The volume is aggregated into a portfolio and registered in the marketplace NODES. The aggregators uses technology to forecast and quantify available DSF and dispatches the asset when a trade is entered. The flexible assets are available in a limited grid area. All aggregators participate in commercial trade on the NODES platform, and AEN is the DSO acquiring DSF.

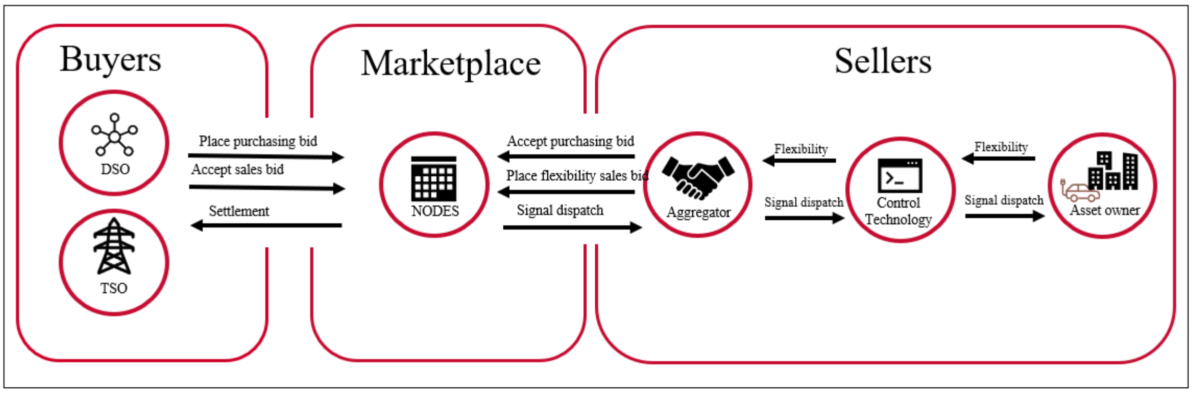

Figure 3.1.1: Process diagram describing the process of acquiring DSF in the flexibility value chain tested in NorFlex.

Compared to the flexibility value chain presented in Figure 2.4.1, the value chain tested in NorFlex do not include the BRP as a buyer of DSF. Figure 3.1.1 includes «Control Technology» as a participant in the DSF value chain. This is to highlight the importance of control technology to perform automatic dispatches of assets. In NorFlex, some aggregators develops and operates their own technology, other enter contracts with third party providers.

Figure 2.5.1, shows that a DSO can use DSF for constraint management. Grid constraints can occur at different levels in the transmission and distribution grid. NorFlex, demo Agder, is testing if DSF can solve problems at different grid levels in the distribution grid. The project have identified 7 hypothesis, denoted as hypothesis 1-7, located at different grid levels, illustrated in Figure 3.1.2.

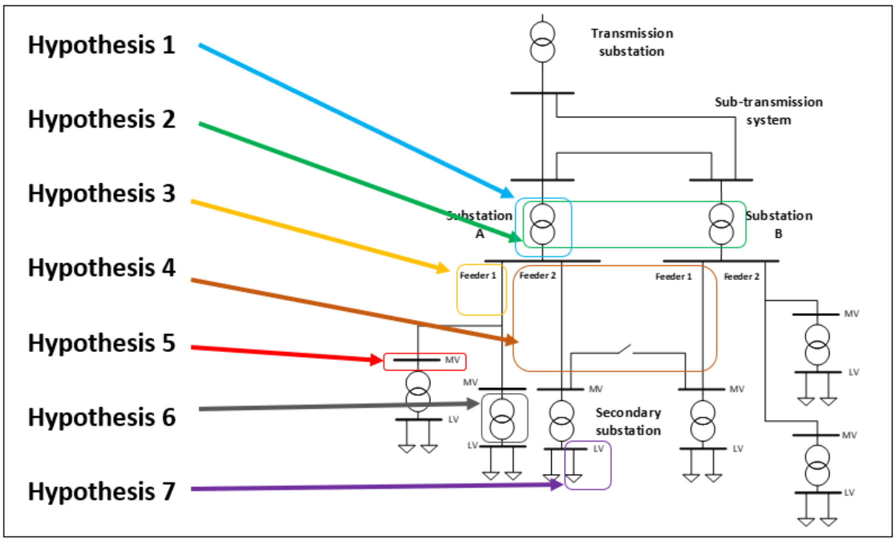

Figure 3.1.2: Illustration of the hypothesis 1-7, showing what grid level the hypothesis address.

In Figure 3.1.2 hypothesis 1 and 2 is located at the highest grid level, and hypothesis 7 is at the very lowest grid level. Substations located at higher levels in the grid connects larger grid areas and therefore have more consumers, and assets, allocated (DSO Informant, 03.02.2021, personal communication). The lower grid levels, the fewer assets are allocated to the substation. For example, hypothesis 7 is a substation that distributes electricity to low voltage consumers, such as households, public buildings and commercial businesses. A substation at that grid level might have 10 households allocated under it. Consequentially the consumption of a single consumer have a greater affect at the grid at lower levels. Substations at higher grid levels transfer larger volumes of electricity and therefore require larger volumes of DSF to solve problems. Hence, aggregation of volume is important at higher grid levels (DSO Informant, 03.02.2021, personal communication).

Regardless of the grid level, DSF when used for constraint management is an alternative to grid investments. Meaning that the more hypothesis that DSF are proven to solve constraint problems, the higher is the value DSF will have for the DSO (DSO Informant, 03.02.2021, personal communication). This thesis examines the value of DSF from an holistic perspective, assuming that hypothesis 1-7 is true. The value being reduced or postponed investments at all grid levels in Figure 3.1.2.

3.2 Research Design

When determining research design, researchers chooses the method of collecting data best suited for answering the problem statement. The choice of research method can determine the validity of the research itself (Jacobsen, 2005). This study is a case study, where the researches commonly investigates a few units of information with a large number of variables. The research design described is often called intensive research design. By using a such a design it is possible to get a better grasp of a phenomenon (Jacobsen, 2005).

A single case, NorFlex, is the object of study. As mentioned in chapter 1, there are several pilot projects across Europe where DSF is being traded. This thesis looks into the project and will analyze the potential for value gain from DSF trading. This is because there are many variable factors affecting the flexibility market in the pilot. The trading is conducted in a restricted grid area, as it is in most other European pilot projects. Meaning that the grid areas where DSF is traded do not intersect or affect each other. As the study investigates a closed system, collecting data from other projects have not been considered necessary. The focus on one case allows a more in dept understanding of the situation.

3.2.1 Research purpose

The purpose of the study is to obtain new knowledge about the flexibility value chain described in Chapter 2.4. The knowledge is obtained through research, which could be exploratory, descriptive or explanatory (Sekaran, 2003). Exploratory research aims to explore new questions within a subject, the research conducted is meant to lay a foundation for further studies. Descriptive research is aimed to expand the knowledge on current issues, often through collecting data. Explanatory research is conducted to understand the effects of changes in standard procedures (Sekaran, 2003).

The current study is exploratory, as the authors aims to explore new aspects in the flexibility value chain. The study is conducted as the market for DSF is developing. The study explores how theoretical microeconomic concepts apply to an evolving market situation. Meaning that the authors needs to be open for changes as the project develops and matures. Market clearing in the flexibility value chain is yet to be analyzed in a marketplace.

3.2.2 Research approach

When describing the research approach, the order of the research activities is of importance. It is often referred to two main strategies when conducting research, deductive- and inductive method. A deductive method starts by understanding the theory of a subject before collecting the empirical data. By using this method the researchers can precisely collect data relevant to the study (Jacobsen, 2005). When utilizing the inductive method researchers collects the empirical data without a bias before looking at relevant theory about the subject (Jacobsen, 2005).

This thesis follows a deductive approach. The study was initiated after reviewing price theory in the power market and the theoretical framework describing smart grids and the flexibility value chain. As NorFlex is progressing, the need for a theoretical review and analysis describing pricing of DSF have been identified. For this reason the study started by analyzing relevant theory before collecting data from the object of study.

The literature reviewed in Chapter 2.5.4 and 2.6.3 is used as a point of reference for the cost-and benefit function for DSF. Relevant parts of Berntsen and Vatn (2014) have been selected and applied for this study. «The parts are: The value of flexibility (from a DSO perspective)» and «the Cost of Supplying Flexibility». Using Berntsen and Vatn (2014) as a foundation, a six step method is applied:

1. Evaluating Berntsen and Vatn (2014)'s benefit function, through interviews with Agder Energi Nett
2. Further develop Berntsen and Vatn (2014)'s benefit function, specified for the DSO Agder Energi Nett
3. Evaluate Berntsen and Vatn (2014)'s cost function based on aggregator interviews and propose changes
4. Creating three load specific cost functions for electric vehicle, electric boiler and water heater
5. Derive cost and demand curves, comparing them to identify the potential for value gain
6. Comparing the theoretical market clearing with trade data from DSF trading in the Nor-Flex project

The six steps conducted intertwine in the order shown in Figure 3.2.1.

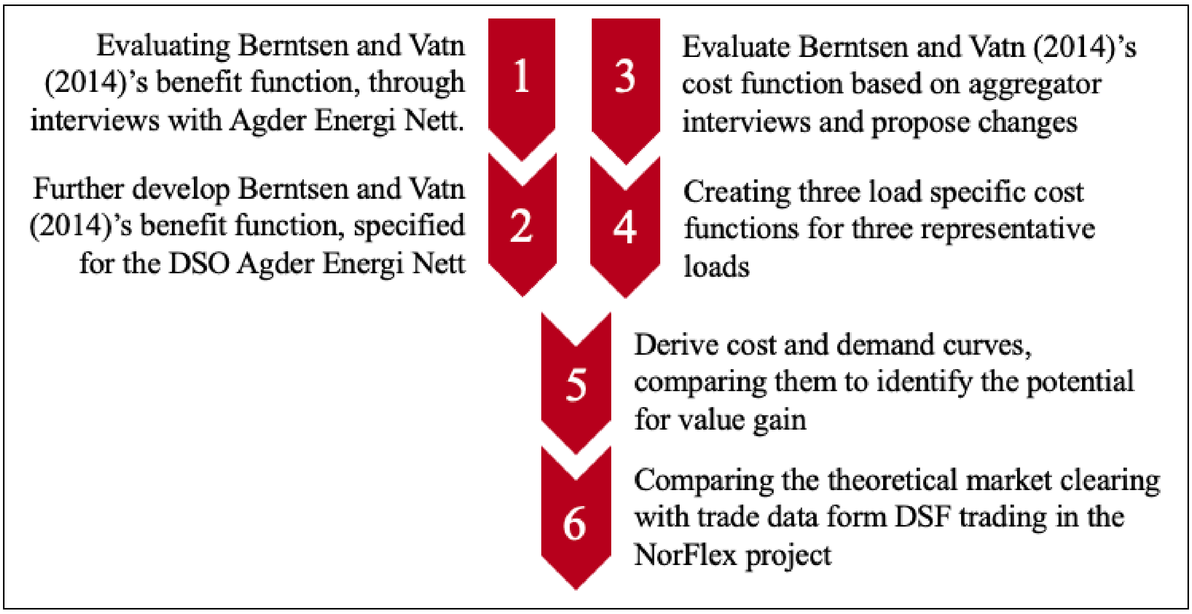

Figure 3.2.1: Research approach applied in the study.

3.3 Data Collection

The research has been conducted using a combination of quantitative and qualitative method to collect data. Quantitative method is usually data expressed through numbers, whereas qualitative method tries to describe the reality using words (Jacobsen, 2005). The problem statement of this thesis addresses the potential for value gain form DSF trading. The factors affecting the value gain is not exclusively numerical, hence a combination of quantitative and qualitative data is best suited for detecting and describing the potential.

Factors affecting the value gain can be categorized in factors affecting the cost and factors affecting the benefit of DSF. When mapping the cost and benefit of DSF, quantitative data have been collected to provide numerical values and analysis. Qualitative data is collected to support the numerical analysis and uncover factors not easily illustrated in a cost- or benefit function. The qualitative data is also used to validate the numerical results and highlight any uncertainties. The method triangulation described is illustrated in figure 3.3.1.

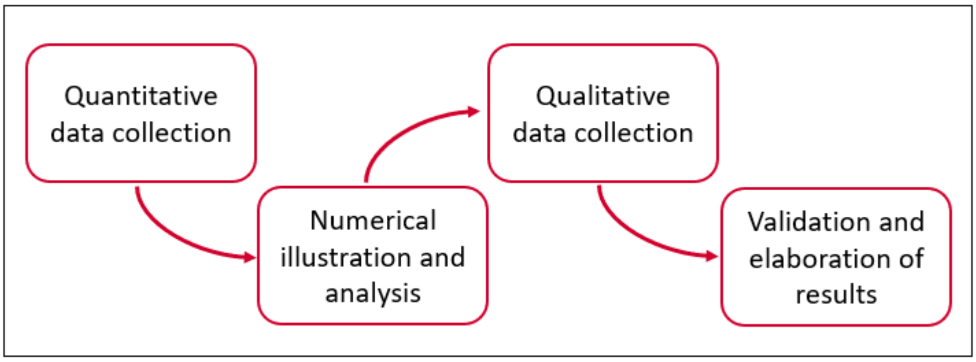

Figure 3.3.1: The method triangulation applied in the study, inspired by (Jacobsen, 2005).

According to Jacobsen (2005), a combination of quantitative and qualitative data is ideal. The different data compliments each other and give a broader understanding of the case and market situation.

Since the thesis is a combination of both quantitative and qualitative data, how the data is collected differs depending on the data source. When collecting qualitative data a combination of primary and secondary sources are used. The primary data is collected through interviews and data collection directly from the NODES market platform. Secondary data is collected from public statistics, accounting data and data from previous project related analysis.

3.3.1 Interview data

The data collected in the interviews are collected to understand the cost and benefit functions of the aggregator and the DSO. The interview data that has been collected is a combination of numerical data and discussion, remarks regarding the project and assumptions regarding the marketplace. The data is used to create both the cost and benefit function which is described in Chapter 4.1 and 4.3.

As NorFlex is a pilot project, it is relevant to collect data directly from the projects participants. The participants have gained experiences and formed opinions regarding the price formation, value and cost of DSF. This insight is valuable when the authors are evaluating and recreating the models. The interviews are also used as reference point when analysing trade data from the marketplace.

The aggregator respondents for the interviews where chosen as respondents due to their position within their company and the NorFlex project. The respondents where evaluated as experienced with the flexibility marketplace. When choosing respondents from the DSO, employees with experience from grid management and insight in the NorFlex project where asked to participate. In total 5 interviews has been conducted, three with aggregators and two from the DSO.

Three aggregators were interviewed with different loads from different asset owner segments. This selection was made in order to compare the costs and highlight universal costs of supplying DSF. The aggregator interviews had two main objectives: To identify and quantify cost drivers and the factors affecting them. The interview mainly consisted of open questions, with the exception of one, where the aggregators were asked to quantify costs. If the aggregators did not have estimates of the costs related to the asset, the size order of the costs were discussed. The reasons open questions were used to obtain numeric data was because the market is in a developing stage. The aggregators might not have a complete overview of their costs, and the aggregators were in a process of scaling up volume (recruiting asset owners) so estimating the potential trade quantum could be hard. The costs of supplying DSF is discovered as the marketplace develops. Hence, getting opinions and experiences was considered to be as valuable for the project as the numeric values themselves. The aggregator interview guide can be seen in Appendix A.1.

When interviewing the DSO, the interview were more structured. The interview contained concrete questions as opposed to themes. However, the interview were open for follow up questions. The DSO interviews was sectioned into three parts: In part 1 the interviewee was asked to confirm or disconfirm a set of assumptions. The assumptions were all based on the assumptions

Berntsen and Vatn (2014) made when developing their benefit-model (listed in Chapter 2.5.4). Part 2 included more in depth questions regarding the demand for DSF from AEN's point of view. In part 3 a draft of Berntsen and Vatn (2014)'s benefit model were presented, to discuss input parameters and the shape of the function. Numerical accuracy was not the focus when presenting the draft. The interview guide for the DSO interview can be found in Appendix A.2.

3.3.2 Statistics and numerical data

As explained in Chapter 2.1, TSO's and DSO's income are regulated by the Norwegian Energy Regulatory Authority, RME. To set the frame of income, the TSO's and DSO's submits yearly reports whit both economical and technical data (NVE - RME, 2015). This is data regarding a grid operators' investment in grid infrastructure, segmented by different categories at different grid levels, and is published yearly. The data from NVE (2019) are used as input data when recreating the benefit function for AEN.

The thesis collects data from the marketplace NODES. This data is trade data from commercial trade conducted in the project. The data will be used to compare the analysis of supply and demand to a real market situation. The data set can be separated into: quantity traded [MW], volume weighted average price [NOK/MWh], maximum price [NOK/MWh] and minimum price [NOK/MWh].

In addition to NODES trading data, data from other marketplaces have been collected. From NordPool, price history from the spot market and balancing market is used to set a benchmark when evaluating the results. Trade data from the UK pilot project IntraFlex is also used to make comparisons. The trade data from IntraFlex is historical data from NODES.

3.4 Evaluation of Empirical Data

3.4.1 Validity

Any study conducted aims to portray a valid picture of the reality. Validity can be defined as the accuracy, legitimacy or gravity of the study and is set in place to secure that the conclusions drawn by the study is valid and accurately describes reality (Jacobsen, 2005). Any study is evaluated by its internal and external validity. Internal validity is whether the results can be perceived as accurate or «right», and external validity is whether the conclusions drawn in the study is applicable outside the object of study (Jacobsen, 2005).

Jacobsen (2005) describes three points used to evaluate the validity of a study:

1. Does the empirical data rightfully describe reality?
2. Does the authors make the right conclusions based on the theory?
3. Does the conclusions drawn reflect reality?

The connection between 1-3 is illustrated in Figure 3.4.1. As Figure 3.4.1 describes, the studies validity is dependent on the connection between reality, the object of study, and the authors findings and conclusions.

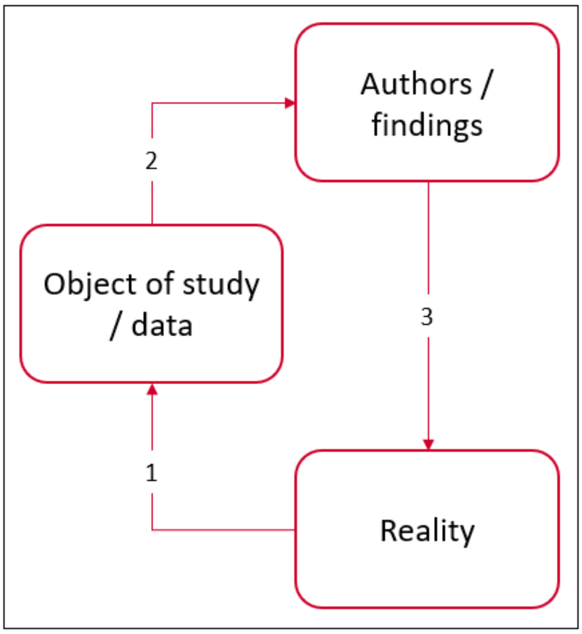

Figure 3.4.1: Illustration describing validity and the connection between reality, object of study, and the authors of the study. Derived from (Jacobsen, 2005).

In this study, qualitative data is collected to support the quantitative data. Through the process of data collection, the authors have been aware of the level of maturity throughout the flexibility value chain tested in NorFlex. As NorFlex is a pilot project, testing out a value chain all parties have limited experience of operating, the empirical findings will be affected by the level of maturity. The study have been conducted during the projects lifetime and not as a post-project study. This exposes the study to the risk of the validity changing as the project evolves. To strengthen the validity results have been presented to a contact within the NorFlex project that are able to compare the results to previous projects and draw parallels to other European flexibility projects. The communication has been conducted as conversations with the contact person and the findings and results have been discussed throughout the study.

The interview guides are, as explained in Chapter 3.3, designed to discuss the validity of quantitative data. In the aggregator interviews the development and drivers of costs were discussed, as well as the costs themselves. Quantitative data were collected to form the DSF benefit function before the interviews were conducted. The interviews were then used to discuss the validity of the model. Updates were later made to the model, and further discussed. Hence, the interviews were uses as a tool for validating quantitative data and developing the models.

Step 6 in Figure 3.2.1 is a comparison of the models developed in the thesis and trade data from NorFlex. This step is included to ensure that the conclusions from the cost and benefit functions reflect reality. As this is an exploratory study, the authors have been open to changes as a result of developments in the project. The authors have also considered how changes in the project could result in changes in trade patterns and the trade data could be affected. Such factors are further discussed in Chapter 5. The results is also compared to data from the spot and balancing markets. These markets will likely affect the DSF market and are considered to be similar markets and therefore useful as benchmarks.

External validity depends on the extent the results can be applied in other cases. This thesis is a single case study, implying that there is exclusively one object of study. The experiences, needs and opinions regarding supply and demand of DSF will differ from situation to situation. Different DSO's will have different challenges, depending on the grid area they are operating. The Norwegian power market is an uncommon market in the sense that 90% of the production stems from hydropower (see Chapter 2.2) (Norwegian Ministry of Petroleum and Energy, 2021). Meaning that hydropower is the main source of power all Norwegian DSO's distributes. On this basis, it is a fear assumption that Norwegian DSO's will have similar needs and a similar benefit function to AEN, the DSO in NorFlex. The uniqueness of the Norwegian power market makes the results applicable to other Norwegian DSO's, however the external validity may be weakened when applying the results to other European or international DSO's. The study's results are compared to results from one other European pilot to highlight and discuss potential differences.

Providing cost and benefit functions that is general and applicable outside NorFlex have been a high priority in this thesis. In a few instances the internal validity have been compromised as a result of this. An example is the aggregator interviews, where concrete quantitative data have been provided. When developing aggregators cost functions generalizations have been made to avoid making the model too specific to a single aggregators costs, business model or electricity consumers. When evaluating the DSO's benefit function, the needs will differ from the geographical location and grid level (Figure 3.1.2). As mentioned in Chapter 3.1 a single, specific electricity consumer might affect the grid at hypothesis 7. The thesis have prioritized generality over examining every specific grid level in Figure 3.1.2.

3.4.2 Reliability

To obtain reliable results in a study, the steps for collecting data needs to be performed as accurate as possible to ensure that the study is reliable. The research itself needs to be designed in such a way that the results is not influenced by the methodology. This phenomenon is called the «research effect» (Jacobsen, 2005).

The interviews were conducted as a conversation and the empirical data collected will be colored by the interviewer and the interviewers behavior (Jacobsen, 2005). In addition, there is no way of guaranteeing that the interviewees provides honest or accurate information. The interviewees may provide the answer they *think* the interviewer want, instead of portraying reality accurately (Jacobsen, 2005). It is the authors opinion that the research effect have had little to no influence on the thesis results. The interviewers have been very aware of the effect, especially when presenting assumptions and discussing functions. Assumptions have been presented in a way that implies that disconfirming an assumption is as useful for the thesis as a confirmation.

As explained in Chapter 3.2.2, the thesis uses Berntsen and Vatn (2014) as a foundation when developing the models utilized. The theoretical framework may have colored the authors perception of the market situation. The interviews have not been entered with no biases or without theoretical assumptions, but this is a consequence of choosing a deductive research approach. The authors believe that having a theoretical understanding before collecting empirical data provides the advantage of knowing what information is essential.

Chapter 4

Results

Using the method presented in Chapter 3, data collected have provided new insight regarding the DSF value chain. Following the order in Figure 3.2.1, Chapter 4.1 - 4.5 presents the results obtained. The results uses the data collected to validate and propose changes to models developed by Berntsen and Vatn (2014). The proposed models can be found in appendix B.

4.1 Evaluation of Berntsen and Vatn (2014) Benefit Function

When evaluating Berntsen and Vatn (2014) benefit function for a DSO, the assumptions presented in Chapter 2.5.4 are important. Therefore these assumptions have been a central focus in the interviews with informants from AEN.

Assumption 1: *«The grates value gain (from DSF) for a grid operator is postponing and reducing investments to expand capacity in the grid»*.

One informant interviewed explains that assumption 1 is one of the hypothesis examined in NorFlex. Ongoing studies, as well as a previous case study, (Baretto & Eide, 2018), is verifying whether this hypothesis is correct. The NorFlex hypotheses is explained in Chapter 3.1. Assumption 1 will be continued when further developing the benefit function.

Assumption 2: *«The advantages of DSF will increase with increased volume»*

Both informants interviewed agrees with assumption 2. However, they comment that it is important to define the advantage of flexibility as it might not be reduced investments exclusively. Assumption 2 is continued.

Assumption 3: *«It exists a maximum limit where the buyer does not need more volume of DSF»*

The informants interviewed approached the maximum limit of demand in two different ways; a theoretical maximum and a realistic maximum. The theoretical limit is when the electricity consumption is a horizontal straight line, equal for all hours of the day and all months. Opposed to the current electricity demand with consumption peaks and off-peaks, as illustrated in Figure 2.3.1. When the theoretical limit is reached, all consumption peaks are flattened. In such a case there is no need for expanding the grid capacity because the electricity consumption is shifted from day to night and winter to summer. At this point, a 100% of the grid investments is postponed, for how many years is still unclear. Berntsen and Vatn (2014) sets this limit to 11 years at 100% of investment costs postponed. In lack of more accurate estimates, the limit is continued in the current study. The theoretical limit is impossible to reach. Shifting consumption from winter to summer and completely flatten the consumption peaks from day to night is considered impossible. Assets providing heat are drawing the majority of power during winter, because of the cold weather. The same logic applies for flattening consumption peaks at a 24 hour perspective, most people, business and industries need power during the daytime. This theoretical maximum is applied in Berntsen and Vatn (2014)'s model and Figure 4.2.1.

A more realistic approach is to define a point where all the DSO's needs are met. The point can be described as a point where all investments that can be postponed using DSF have been postponed, the remaining investments are seen as unavoidable. This maximum limit exist, but it will not be an absolute limit. Results derived from DSO interviews highlights that the need for DSF is highly dynamic. As the situation in the gird, as well as electricity demand, is not constant the demand for DSF will vary from year to year, day to day, and hour to hour. The demand will also vary based on geographical location.

Assumption 3 is continued, the theoretical maximum point is further applied as a maximum point in the benefit function. The point where all investments are unavoidable is used as a reference when evaluating AEN's benefit function.

Assumption 4: *«Small margins are required to handle congestions in the grid».*

Assumption 4 is partly supported by the respondents. It was explained that in some instances the assumption will apply and in others it might not. A transformer, for example, reaches overload when operating at any capacity over 100%. However, a transformer can run with some degree of overload without resulting in immediate damage or cause a black out. Several transformers in AEN's grid area is overloaded by 100% - 180%, indicating that a volume of DSF equal to 80% of the transformer capacity might be needed. In some instances a large quantity of DSF is needed by the DSO. Further, the correspondents confirmed that from a yearly perspective, there are not many hours each year who leads to congestion.

Interviews confirms that the volumes of DSF that will be purchased firstly is the lowest volumes that is sufficient to solve any problem. The DSF bid providing the highest benefit for the lowest cost will be purchased first. For this reason,assumption 4 is continued.

Assumption 5: *«A small amount of DSF is sufficient to postpone or reduce large investments».*

This assumption corresponds with assumption 4 and so does the information from the respondents. An example from one interview is when DSF is used for other services, such as increasing voltage quality. In this example the requirements for voltage quality are absolute. Any deviation could mean that the DSO is required to make improvements and make investments. Assumption 5 is continued on the same basis as assumption 4.

Assumption 6: *«Large volumes of DSF is needed less frequently».*

Respondents states that the grid infrastructure is closer to max capacity during cold weather periods. This means that the large quantities of DSF is needed during a few days or weeks when the temperature is extra cold. Assumption 6 is accurate when describing how many hours each year that requires DSF. However, interviews highlight that it is important to define «large volumes» of DSF. Do we define the quantity of DSF after hours per year or season? Is a large volume defined as a volume that requires many assets to be dispatched? Or is a large quantity defined for how many hours per day the asset is dispatched? The last option to define «large quantum» of DSF is dependent on the availability of flexible resources. As previously explained, lower grid levels in Figure 3.1.2 will have fewer assets located under them. In one of the DSO interviews the following example was used as an illustration: During the cold period in the winter of 2021, a substation at a lower grid level reached 20% overload. In order to reduce this overload, several electricity consumers would have to reduce their consumption for approximately

36 coherent hours. In this example, the need for reduced volume was 40kWh per hour for 36 hours. This quantity might not be defined as «large» from the DSO's standpoint, but as the electricity consumers located under the specific grid node were private consumers, the quantity would be experienced as large. For comparison, Ericson and Halvorsen (2008) found that an average household consumes 3,5kWh/ hour during peak hours in January/February. If there is a limited number of assets located under the relevant grid area, providing DSF would imply a severe disadvantage for the consumer.

4.2 Agder Energi Nett's Benefit Function

As described in Chapter 3.2.2 the benefit function presented in Berntsen and Vatn (2014) is further developed using updated input data, specific to AEN. The key input parameter is derived from NVE (2019), and is AENs average investment cost for new and re-investment. For simplicity, Agder Energi's investment budget for the period after 2019 is not included. Instead, it is assumed that the average yearly investment costs will remain at the same level as in the previous ten years. The same interest rate of 5% as used by Berntsen and Vatn (2014) is set, this is also RME's reference interest rate (NVE, 2019).

Based on the interviews, assumptions 1, 2, 4 and 5 are continued in the updated benefit function. However, in the interviews it was emphasised that assumption 4 and 5 are highly dependent on the situation. The reasoning for keeping the assumptions is that the lowest volume, providing the greatest benefit will be activated first. Assumption 3 is also continued, where the theoretical maximum is applied. Assumption 6 will further be discussed in Chapter 5 as it does not have an affect on the benefit model itself.

While Berntsen and Vatn (2014) calculates the benefit function per hour of congestion, in the updated model the choice to make the model independent of hours of congestion have been made. The benefit function is then describing the total benefit for a DSO of requiring DSF. The total value is more applicable for the current study because hours of congestion varies from year to year. The hours of congestion is predicted to increase in the future as the electricity consumption increases. Hours of congestion is later included as a variable. This change have been implemented in order to make comparisons to the cost function introduced in Chapter 4.4.

AEN's benefit function is shown in Equation 4.2.1. $B(x)$ is the total benefit for AEN when acquiring x MW of DSF. Note that Equation 2.5.1 and 4.2.1 is almost identical. The difference being the additional coefficient c, denoted in $[NOK]$. In addition, the coefficients α and β now have the units $[NOK/MW^2]$ and $[NOK/MW]$, respectively. The coefficients are found by performing a regression analysis. The values of α , β and c is shown in Table 4.2.1. The benefit function is plotted in Figure 4.2.1.

$$B(x) = \alpha x^2 + \beta x + c \tag{4.2.1}$$

Table 4.2.1: Output data from the regression analysis, α, β and c, as input to the benefit function.

Alpha $[\alpha]$	Beta $[\beta]$	c
-672917,53	23691262,16	6088500,48

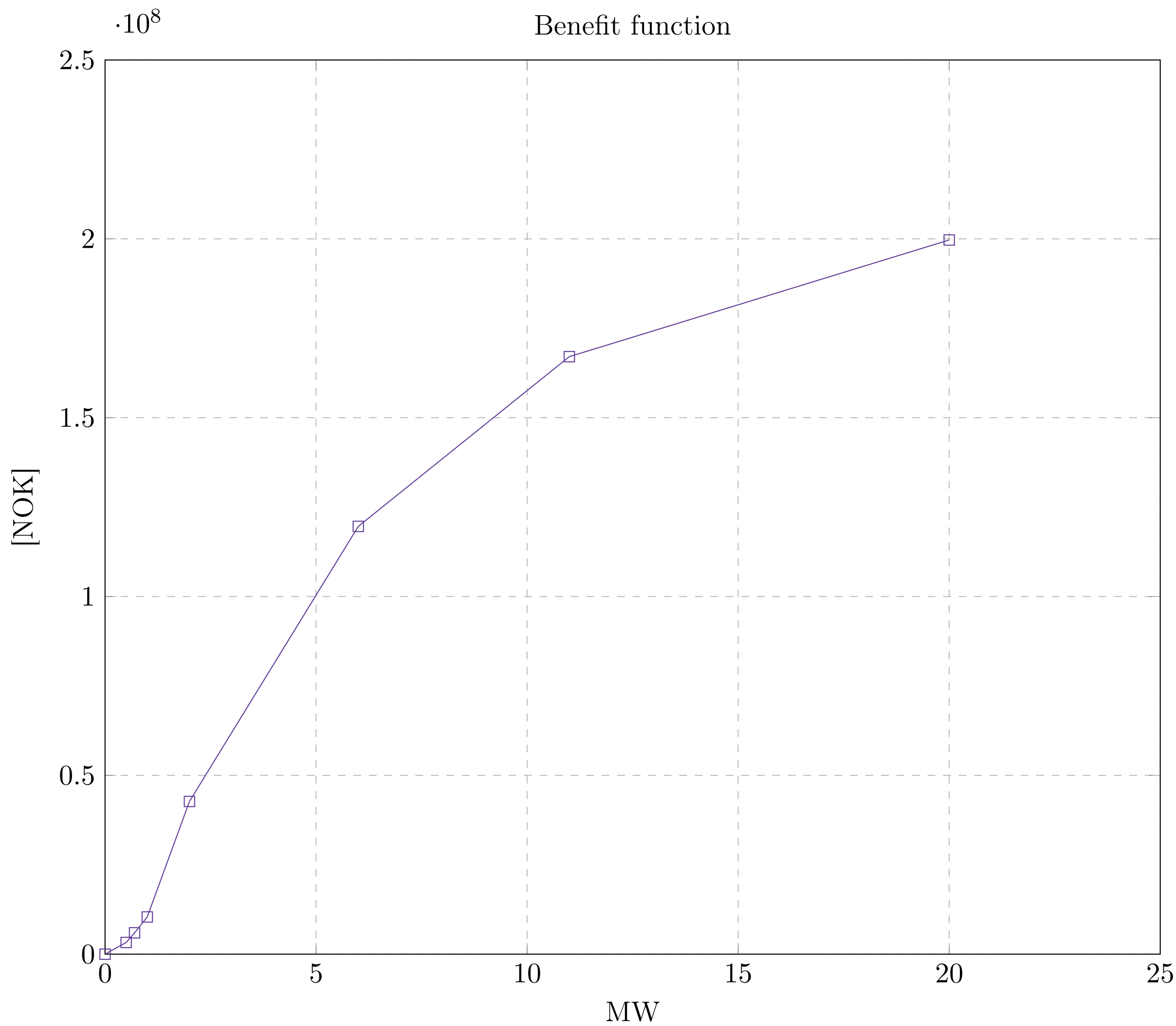

Figure 4.2.1: Agder Energi Netts DSF benefit function, calculations in Appendix B.1

Figure 4.2.1 shows AEN's benefit function per year for acquiring DSF. In absence of more accurate information, the correlation between available volume [MW] and share of postponed investment is kept identical to Berntsen and Vatn (2014). Berntsen and Vatn (2014) defines 20MW available DSF as the point where 100% of new and re-investments are postponed for 11 years. From interviews, it is known that the point of 100% postponed investments is the point where the electricity consumption is equal for every hour of the day and equal for every season. Results from Figure 4.2.1 shows that 20MW equals a yearly benefit of 199 677 066 NOK. This means that the theoretical maximum value gain for AEN when purchasing DSF is 199 677 066 NOK. The model sets a perspective of 11 years, this is not confirmed nor disconfirmed by interviews, but the time perspective is kept as the grid infrastructure have a limited lifetime.

In order to make the benefit function comparable to the cost of supplying DSF, the benefit [NOK] is divided by available flexibility [MW] and hours of congestion [h]. As the theoretical maximum would involve shifting consumption from the winter season to the summer season, it is assumed that in order to reach the maximum benefit, all assets needs to be dispatched 24h every weekday during the 26 weeks. This is also defined as the maximum point of the cost function presented in Chapter 4.4.7. Using the maximum hours of DSF demand as a reference, a relationship between percentage of postponed investment and hours of congestion is derived. For simplicity, the relationship is assumed to be linear. This might not be representative for every situation, but will function as a illustration of assumption 2, Chapter 4.1.

The value gain seen in the benefit function, Figure 4.2.1, is divided by hours of congestion. This provides a function describing the change in increased value gain for AEN per hour of congestion, denoted [NOK/MWh], which is an expression of the demand for DSF. As explained in Chapter 2.5.4, a buyers demand function is usually found by deriving the buyers benefit function. This thesis have constructed a demand function by describing the change in increased benefit per interval, as opposed to a mathematical derivation. This allows hours of congestion to be included as a parameter, making the demand function comparable to the aggregators cost function, presented in Chapter 4.4. AEN's demand function is shown in Figure 4.2.2, where hours of congestion define the hours of dispatch, H_D, needed to meet the demand for DSF.

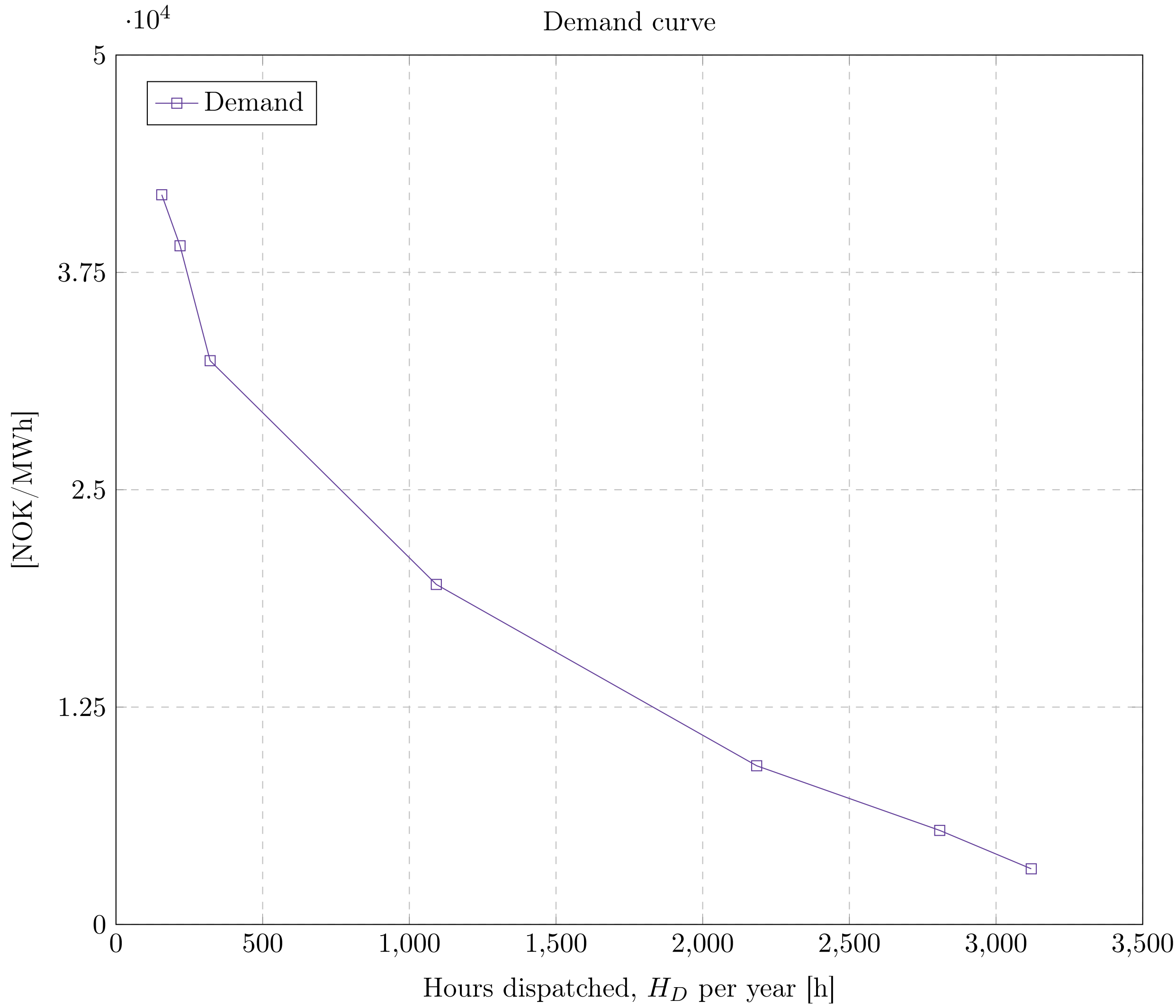

Figure 4.2.2: Agder Energi Netts demand curve, calculations in Appendix B.1.

4.3 Evaluation of Berntsen and Vatn (2014) Cost Function

Berntsen and Vatn (2014) suggests a compensation model describing what the asset owner should receive for curtailing a percentage of their total consumption. Their model is based on the premise that the asset owner will gradually dispatch more and more of their total usage of electricity. However, interview respondents explain that in reality only a few, predetermined, assets are curtailed or fully dispatched. Therefore, the assessment is that a model based on hours the asset owner is dispatched per day would give a more correct picture of the asset owner compensation.

Berntsen and Vatn (2014) uses the CENS rate as their basis for setting the level of asset owner compensation per segment. The CENS rate is, as established in Chapter 2.1.2, a rate describing the direct and indirect cost of being deprived access to electric power. SINTEF (2011) states that the CENS rate gives a good estimate of the electricity consumers discomfort when not having access to electricity. In Berntsen and Vatn (2014), a scaling factor is introduced. The scaling factor scales the CENS cost down, justified by the fact that the asset owner does not loose access to all electricity and the dispatch is planned and therefore not equivalent to a power outage. The scaling factor increases as more loads are curtailed and is based on the CENS rate for 1 hour.

The results from aggregator interviews show that the cost function from Berntsen and Vatn (2014) is not directly applicable when estimating the cost of supplying DSF from a given asset. However, the idea of using a scaled CENS rate as for asset owner compensation is used when further developing a cost function for DSF. The difference is that the rate will be based on hours of dispatch as opposed to curtailed load and the model will be used to describe the asset owner compensation, not the total cost of supplying DSF.

4.4 The Aggregator's Cost Function

From the interviews with the aggregators, the conclusion is that the cost of acquiring assets can be separated into similar categories regardless of the asset. Installation Cost C_I, Marketplace Fee C_M, Software Cost C_{SW}, Operating Cost C_O, Imbalance Cost C_{IB} and Asset Owner Compensation Cost C_{AO}. Using these components, a cost function per asset have been developed.

4.4.1 Installation cost

The installation cost C_I is described as the cost of enabling the asset to perform an automatic dispatch. The cost may include equipment or tools that enables the aggregator to control the asset. The cost is listed as a fixed cost, and the main cost driver is the number of assets, not the installed effect of the asset.

Aggregator interviews show that the installation cost for an electric boiler and water heater will remain constant regardless of the electric boilers' installed effect. The installation cost for a water heater is at the same cost per unit as an electric boiler. This information is confirmed by two separate aggregator respondents. The estimated lifetime of the installation is 5 years. A respondent explains that when including an electric vehicle (EV) in the flexibility value chain, there is no installation cost. The dispatchable asset is the EV charger, purchased by the asset owner and already including the technology needed to control the asset. As the installation cost is accounted for by the asset owner, $C_I = 0$ for an EV.

One respondent predicts a decline in installation cost in the years to come. This is because the majority of the installation cost is making the asset dispatchable. The technical development has lead more electric assets to have integrated smart technology upon purchase. The term «smart» in this case means that the asset have integrated sensors and communication. This means that the equipment and installation to make an asset «smart» will not be needed, eliminating the installation cost in a future perspective.

4.4.2 Marketplace fee

The marketplace fee C_M is listed as a monthly fee for using the marketplace to conduct the transaction. The fee is a fixed cost and is therefore equal for all the different loads disused in this thesis. NODES' fee structure has not yet been implemented in the NorFlex project.

4.4.3 Software cost

The software cost C_{SW} is the cost of the software that performs the automatic dispatch. The software needs to be able to dispatch the asset, collect meter data from the asset and generate a forecast for the asset portfolio. In other words the software calculates the amount of flexibility available (per portfolio of assets), signals dispatch and reconnecting the asset. The software needs to be developed and upgraded. From interviews it is explained that the software cost affect on the total cost depends if the software is developed in-house or if it is outsourced to a technical provider.

Some of the aggregators interviewed have outsourced the software development to a technical provider. The aggregator then pays a monthly or yearly fee, and do not experience any changes related to the cost of development, upgrades or improvement.

Respondents from aggregators who develops the software in house, consider the software cost as a one-time cost. The upgrades to the software can be denoted as a yearly, fixed cost. The aggregator interviewed were not able to provide an accurate estimate of the development cost or the cost of upgrades, so the general function treats the software cost as a fixed, yearly cost.

4.4.4 Operating cost

The operating cost C_O is used in this thesis as a collective term for the cost of all market activities the aggregators perform. This includes submitting sales bids, following up trades conducted and the settlement process. Respondents relates the cost to personnel costs, and the cost is increasing with the number of hours the aggregators personnel spend on operating activities. It is assumed that the operating cost remains constant regardless of the load, number of assets or the volume of DSF traded. This assumption is based on aggregator interviews, who confirm that the operation aims to be atomized.

4.4.5 Imbalance cost

In the flexibility value chain, Figure 3.1.1, the aggregator is either a BRP themselves or have an agreement with a BRP to account for imbalances as a consequence of DSF trading. As explained in Chapter 2.5.3, the BRP is financially responsible for balancing their own portfolio. When trading DSF, the aggregator is per definition, shifting the consumption from a planned or forcasted consumption. This will directly result in a cost of imbalance, C_{IB}, per trade.

According to aggregator interviews there have been detected an increased imbalance cost as a result of DSF trading. However, because small volumes of DSF had been traded per the date the interviews were conducted the cost have been hard to quantify. As the project matures, the imbalance cost's affect on the cost of supplying DSF will become more clear. For this reason C_{IB} is currently set to zero.

4.4.6 Asset owner compensation cost

The Asset owner compensation C_{AO} is the compensation given to the asset owner for allowing their asset to be traded at the DSF market. How much the asset owner is compensated is dependent on the aggregators business model. The aggregator decides whether the asset owner is paid per dispatch, per MWh dispatched, a fixed sum for availability or a combination. However, the asset owner should receive a form of compensation, because a dispatch limits the asset owners ability to freely utilize their asset. Results from interviews also shows that it is hard for the aggregator to recruit asset owners if the trade-off represent less than 10% of the asset owners electricity bill.

During the interviews, most aggregators listed C_{AO} as a shared revenue model, and not as a cost. The asset owner is compensated by a shared percentage of the profit the aggregator is making by trading their asset at the DSF market. This perspective on asset owner payback is based on the assumption that the aggregators trade the asset an acceptable amount of hours each day and the asset owner never experiences any discomfort as a result of their asset being dispatched. The result of such a model is a cost function that continues to decrease per hour of dispatch per day.

If the asset owner is disconnected from a source of electricity to the point of discomfort, this should be compensated to match the level of discomfort the asset owner is experiencing. The CENS regulation presented in Chapter 2.1.2 represents the electricity consumers discomfort as well as direct cost during a power outage. For the cost function to reflect this, a theoretical model has been developed. In this model, C_{AO} increases with the hours the asset owner is dispatched per day.

The function describing C_{AO} is based on the CENS for 1 hour of undelivered energy. The CENS has different rates according to what type of consumer is affected by the energy not supplied. The rate is highest for industrial consumers and is the lowest for private consumers (SINTEF, 2011). In this thesis the CENS rates for the segments commercial and private electricity consumer will be used. The following equation describes asset owner compensation as a function of $CENS$, hour of dispatch h_D, scaling factor SF and correction factor CF:

$$C_{AO} = h_D * \mathrm{SF} * \mathrm{CENS} * \mathrm{CF} \tag{4.4.1}$$

In equation 4.4.1 The CENS cost is the CENS rate specific to the consumer segment the asset owner is a part of. In Equation 4.4.1, the CENS rate remains constant at the cost for 1h of energy not supplied. As mentioned in section 2.1.2, the CENS rate is based on the discomfort of a power outage. The CENS rate is structured to increase with the duration of the power outage. The Asset Owner is not necessary dispatched several hours in a row. In fact, the interviews imply that aggregators try to avoid continuous hours of dispatch. This is the reasoning for using the rate for 1h of energy not supplied.

The correction factor CF is used to scale the CENS cost down. The argument for including an correction factor is because CENS rates is calculated for situations where all electric assets are disconnected. In a flexibility market the asset owner choose to make their assets available at the marketplace and can therefore not be compared to a power outage. Table 4.4.1 shows the CENS rate per MWh for 1h of energy not supplied and the correction factor chosen for each segment.

The CF for the commercial segment is set to 0,1 of the total CENS. This evaluation is based on the assumption that an asset owner within the commercial and private segment will have similar experiences of discomfort when being dispatched. An average commercial asset have a higher installed effect than a private one, but the difference is not significant. However, the CENS rate for commercial and private asset owners are not equal, and C_{AO} is still higher for a commercial asset owner. This is because more people are affected by the possible discomfort a dispatch of a commercial asset represents.

Table 4.4.1: CENS rate [NOK/MWh] for 1h of dispatch and correction factor CF per segment (Heien et al., 2018).

Segment	Commercial	Private
CENS [NOK/MWh]	220 700	23 700
CF	0,1	0,5

Table 4.4.2: Input data, H_D and SF to the cost function for C_{AO} and numerical calculations of C_{AO} for a commercial asset.

H_D [h]	Scaling Factor	C_{AO} [NOK/MWh]
0	0%	0
0,5	2,1%	230
1	4,2%	920
1,5	6,3%	2069
2	8,3%	3678
3	13%	8276
4	16,7%	14713
5	20,8%	22990
6	25%	33105
7	29%	45060
8	33,3%	58853
9	37,5%	74486
10	41,7 %	91958
11	45,8%	111270
12	50%	132420
16	66,7%	235413
24	100%	529678

The asset owners discomfort of a dispatch is assumed to increase the longer the asset is dispatched. The scaling factor SF is used as a tool to represent how the discomfort increases when the asset is disconnected several hours per day. SF is calculated as the percentage of hours per day the asset is dispatched. Table 4.4.2 illustrates SF corresponding with hours dispatched H_D and the cost per MWh dispatched.

Using the data for H_D and C_{AO} in Table 4.4.2, a regression analysis was performed. The analysis provided the following equation describing the asset owner compensation for segment s:

$$C_{AO} = \alpha_s x^2 + \beta_s x + c_s \tag{4.4.2}$$

Equation 4.4.2 is increasing exponentially, as shown in Figure 4.4.6. α_s, β_s and c_s are all constants specific to the consumer segment. Table 4.4.2 shows that is expensive to dispatch an asset many hours per day. Comparing Figure 4.4.6 to results from aggregator interviews, the aggregator aims to disconnect an asset in the commercial sector 2 times per day.

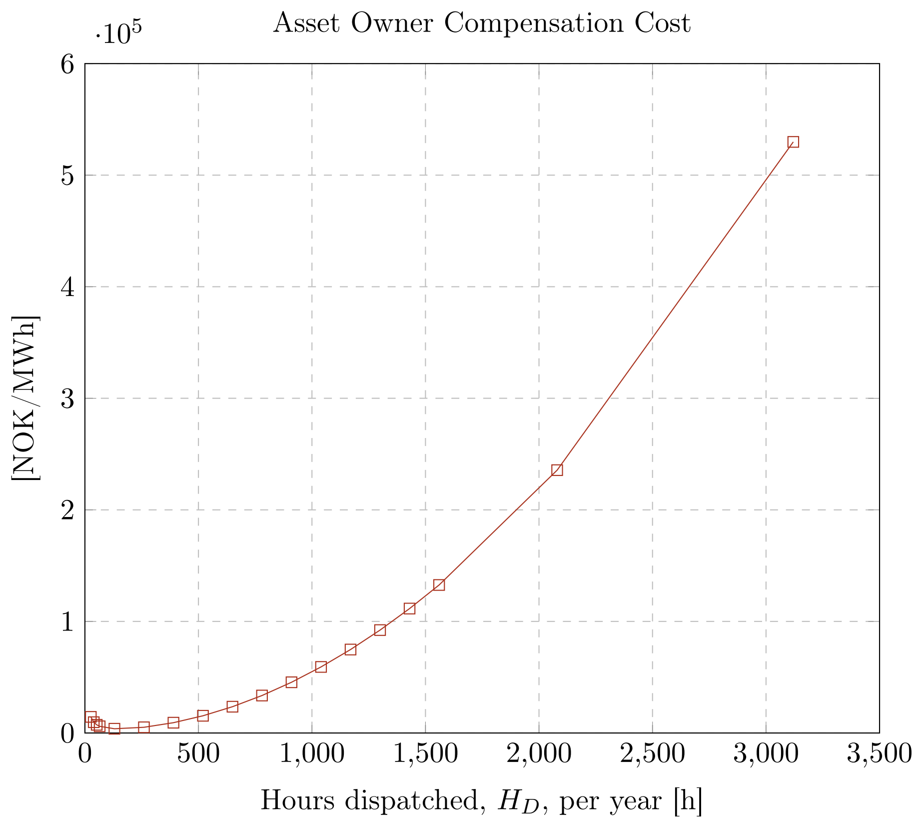

Figure 4.4.1: Asset owner cost function C_{AO}, illustrated for a commercial asset. Further calculations in Appendix B.2.

4.4.7 Total cost function

The aggregator cost C_A can be decomposed into installation cost C_I (per installation), market place fee C_M, cost of developing or license cost for software C_{SW}, operating cost C_O, imbalance cost C_{IB} and asset owner compensation C_{AO}. The aggregators trades a total number of n assets. The cost per asset, with the volume of x MW, traded h hours per day is:

$$C_A = \frac{C_I + \frac{C_M + C_{SW} + C_O}{n}}{hx} + C_{IB} + C_{AO} \tag{4.4.3}$$

When developing the cost function, the following input parameters, illustrated in table 4.4.3, have been applied:

Table 4.4.3: Input data used when calculating the aggregators cost of supplying DSF, separated per asset.

Input	Value	Unit
Total no. of Electric Boilers	100	assets
Total no. of EV	1000	assets
Total no. of Water Heaters	10	assets
Lifetime, investment	5	years
Duration, trade season	26	weeks
Days of trade per week	5	days
Average Volume, load		
Electric Boiler	0,033	MW
EV Charger	0,022	MW
Water Heater	0,30	MW

From aggregator interviews a season for DSF trade have been identified. As Table 4.4.3 states, the cost function is based on a DSF Season of 26 weeks per year. This is based on information from aggregator interviews, who implies that DSF demand will be higher during the winter. This assumption aligns with the demand for electricity, which is higher during the winter season (see Chapter 2.3.3). The model assumes that no DSF is traded during the summer half of the year. The input parameter «days of trade per week» from Table 4.4.3 is set to 5 days based on aggregator interviews. As illustrated in Figure 2.3.1 electricity consumption is lower during the weekends, which supports the assumption.

The lifetime of the installation is set as 5 years, in line with information per aggregator interviews. The total number of assets and the average volume for the given load will vary from aggregator.

The input in Table 4.4.3 is constructed to illustrate the affect the total number of assets have. It is assumed that low volume assets within the private consumer segment is easier to recruit and require a higher level of aggregation to provide a sufficient amount of DSF. The average volume per load is an estimate of average installed effect, based on market research. For simplicity it is assumed that the aggregator exclusively provide DSF from one type of load. The cost function for an Electric Boiler, Electric Vehicle and Water heater is illustrated in Figure 4.4.2

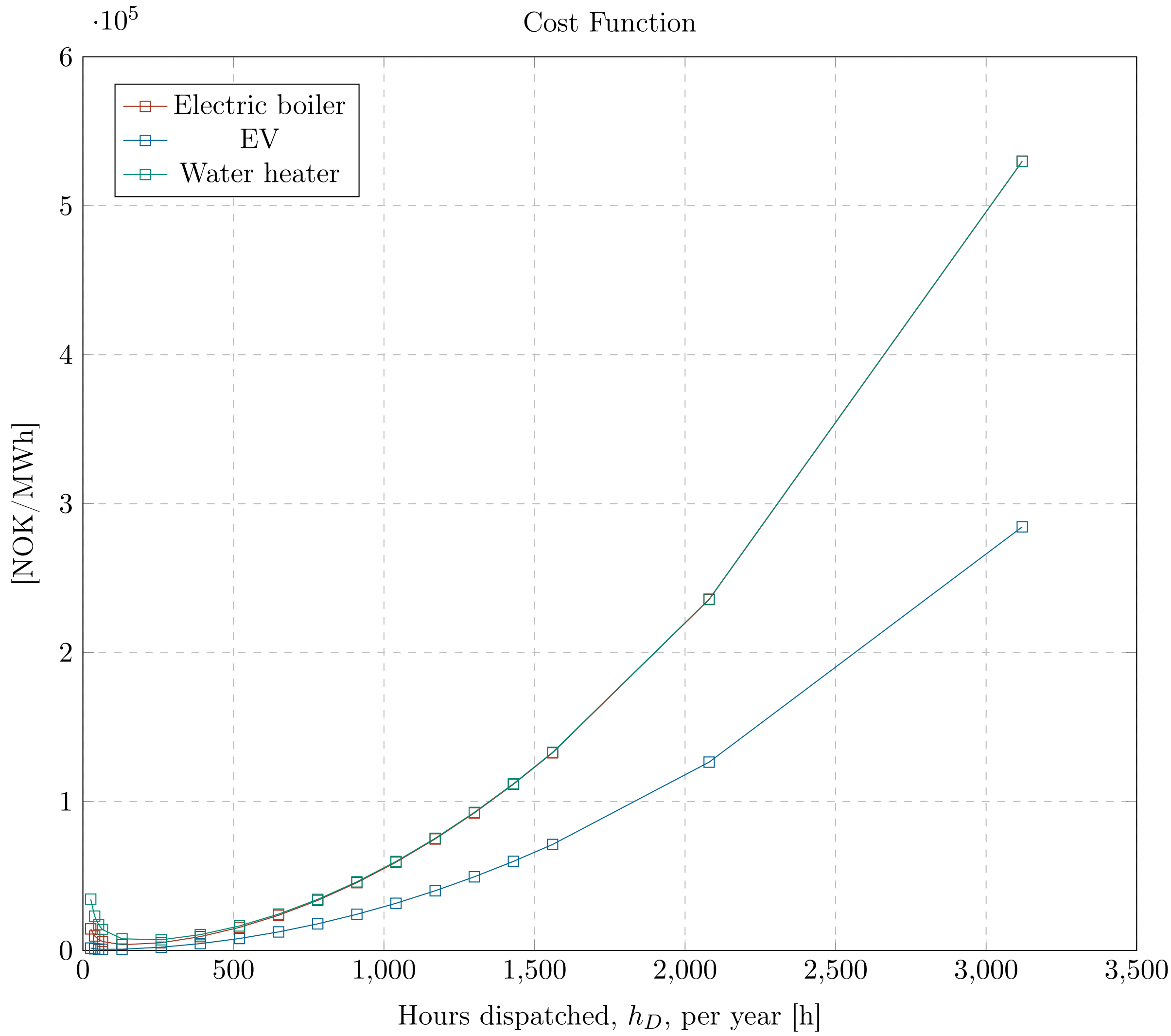

Figure 4.4.2: Cost function, C_A, for Electric Boiler, Electric Vehicle (EV) and Commercial Water Heater using Equation 4.4.3. Calculations in Appendix B.3

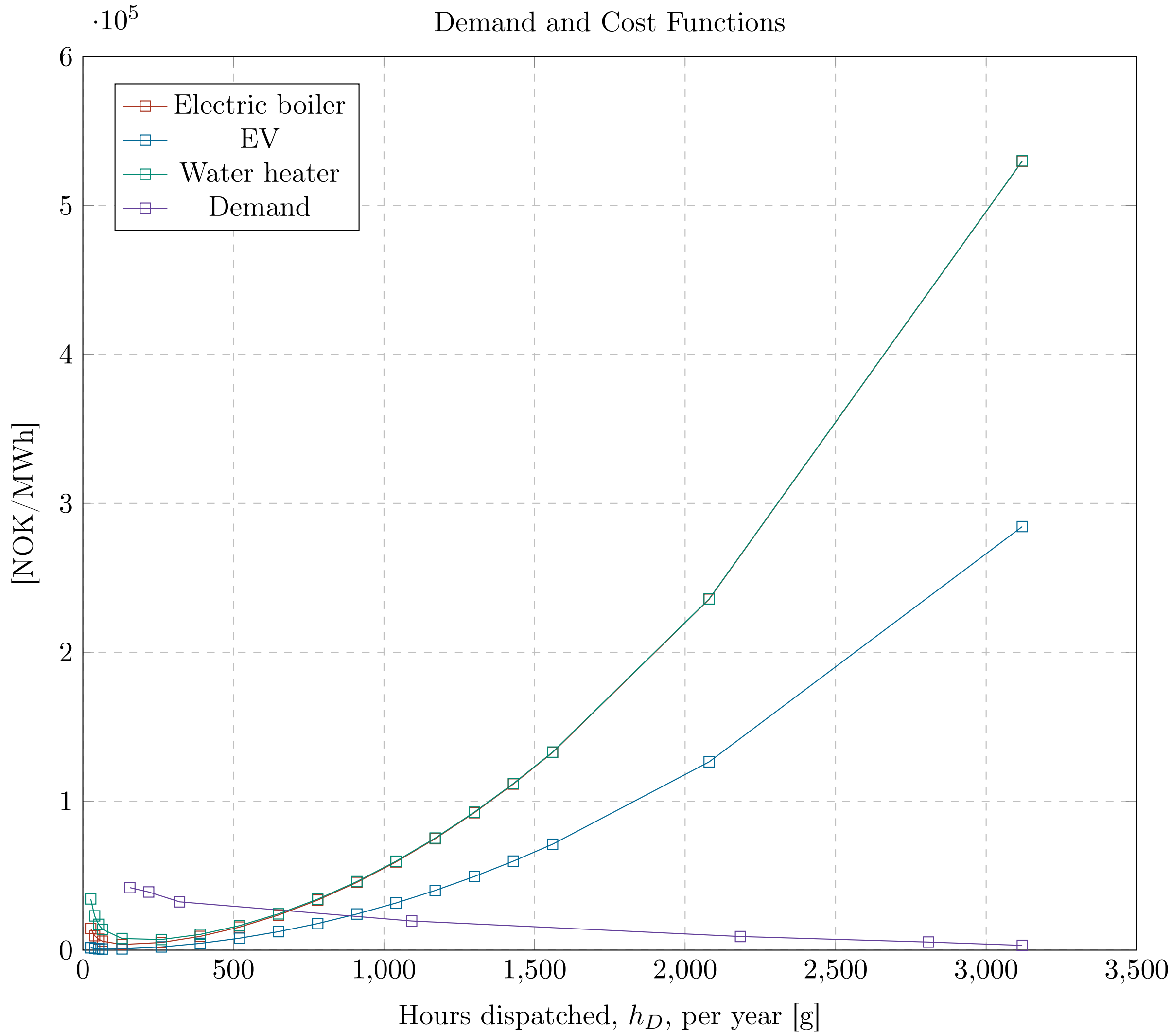

Figure 4.5.1: The cost of supplying DSF from three assets compared to the demand of DSF per hour of dispatch. Calculations in Appendix B

4.5 Market Clearing

4.5.1 Theoretical market clearing

Figure 4.5.1 Shows that there exists an interval for all assets where the cost of supplying DSF is below the benefit of DSF. A theoretical market clearing point is where the demand function in Figure 4.5.1 meets each cost function. Table 4.5.1 shows the data points where the cost function for different assets meets AEN's demand function.

Table 4.5.1: Market clearing price and hours dispatched per asset.

Asset	h_D per year	h_D per day	Market clearing price [NOK/MWh]
Electric Boiler	650	5	23 566
Electric Vehicle	910	7	24 238
Water Boiler	650	5	24 364

4.5.2 Trade data NorFlex

From NODES (2021), historic trade data from the trading period in NorFlex is collected. This data is empirical data where the entire process in Figure 3.1.1 have been conducted. The project is in early stages of trading, which may have been reflected in the data. The trading period lasted from week 3-12 2021.

Table 4.5.2: Trade data from the NorFlex Trading period derived from (NODES, 2021).

Week	Price [NOK/MWh]				Volume [MW]
	Volume weighted average	Min	Max	spread	
3	3 746.42	2 500.00	5 000.00	2 500.00	1.396
4	3 702.14	2 500.00	5 000.00	2 500.00	1.541
5	3 340.82	2 500.00	5 000.00	2 500.00	2.984
6	4 042.95	2 500.00	7 800.00	5 300.00	6.477
7	4 218.58	2 500.00	5 600.00	3 100.00	4.225
8	4 193.62	2 500.00	6 000.00	3 500.00	4.222
9	4 415.70	2 500.00	7 000.00	4 500.00	1.637
10	4 718.20	100.00	5 200.00	5 100.00	1.062
11	4 638.94	4 500.00	6 200.00	1 700.00	2.332
12	4 571.49	2 500.00	7 500.00	5 000.00	3.329

Table 4.5.2 shows a summary of trade data from NorFlex ranging from week 3-12 2021. The week with the highest average price was, as shown in Table 4.5.2, week 10. Week 6 had the highest total volume traded, despite the volume weighted average not being the highest. Nevertheless, the highest price for a single trade was accepted during week 6. The highest price spread was also in week 6, with a difference of 5 300 NOK/MWh from the lowest to the highest bid accepted. The week where the price spread were at the lowest was in week 11, at 1 700 NOK/MWh.

A couple of trades have been further analysed. The trades are the trade with the highest and lowest unit price, and volume. From trade data, only 1 trade have been conducted at the maximum and the minimum price.

Table 4.5.3: Detailed data from selected trades.

Trade	Price [NOK/MWh]	Volume [MW]	Period from	Period to	Temperature [°C]
Maximum price	7 800	0.025	07:00:00	08:00:00	-6.7
Max volume	2 500	0.55	16:00:00	19:00:00	-2.4 - -5.0
Minimum price and volume	100	0.002	08:00:00	09:00:00	2.1

The trade with the highest price had a unit price of 7 800 NOK/MWh. As shown in Table 4.5.2, the trade occurred during week 6, one of the coldest weeks at the southern part of Norway during the winter of 2021. The temperature difference between the highest and lowest price is 8.8°C. The lowest unit price is also the trade with the lowest volume, the trade is the only trade with such a significant low price. The trade is beleived to be a test-trade, and is not further considered when analysing the price. Table 4.5.3 shows that the trades with the maximum volume happened at the same date and all trade hours occurred consecutively. A closer look at the trades shows that all trades were located under the same grid node and therefore is likely one portfolio traded continuously for all three trade hours.

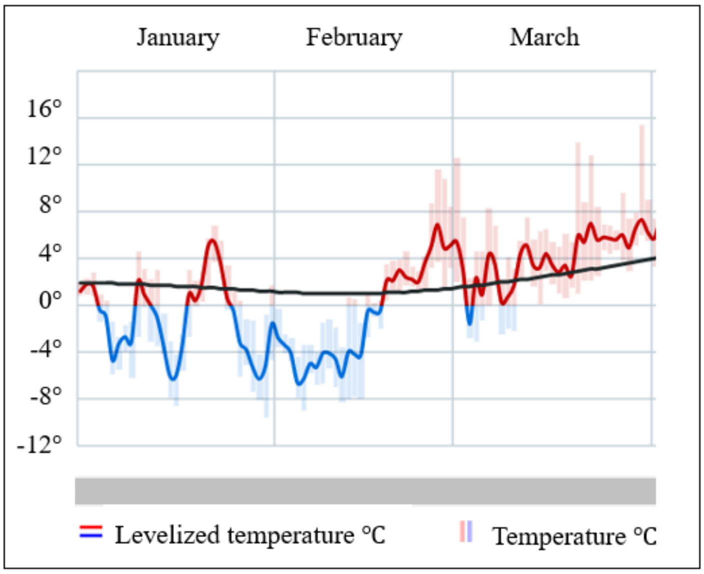

Figure 4.5.2: Historical temperature data from Arendal, from January 2021 to March 2021. Derived from (Yr, n.d.).

Figure 4.5.2 shows the temperature from January 2021 until the end of March 2021. The coldest temperature being -9.6°C in January and the warmest temperature being 15.4°C in March. Arendal is not the only city included in the project area, but the temperature data represents the general picture of the region (Yr, n.d.).

Chapter 5

Discussion

The potential for value gain in the DSF market can be defined as the difference between the demand and cost of supplying DSF. Following the demand curve for DSF, the DSOs upper willingness to pay is illustrated. At this point, DSF is equally as beneficial for the DSO as investing in grid infrastructure. Equation 4.4.3 shows the costs of providing DSF for the aggregator without addressing the aggregators profit. When the potential for value gain is highest, it is possible to obtain the most value for DSF by the aggregator and DSO. To evaluate the potential for value gain, the demand and supply side of the value chain and the reliability of the benefit and cost function in Chapter 4 is discussed. In addition, the theoretical market clearing point is compared to real market data as well as similar markets.

5.1 Evaluation of the Benefit and Demand Function

When analyzing the market demand for DSF, the DSO Agder Energi Nett is used as an example. AEN is the DSO which is the buyer in the pilot project NorFlex. When analyzing the demand for DSF, the theoretical model developed in Chapter 4.2 is the main focus. The model is later compared to the trade data from NorFlex in Chapter 4.5.

The assumptions evaluated in Chapter 4.1 is the foundation for the benefit function and is the reasoning for the shape of the benefit function (Figure 4.2.1). Of the assumptions presented, assumption 1 might be of most significance. If NorFlex's hypothesis that DSF can postpone or reduce investments at grid levels 1-7 in Figure 3.1.2, are invalidated, the benefit function in Equation 4.2.1 is invalidated. Assumption 1 is wildly accepted in the literature regarding DSF (see Chapter 2.5.2).

5.1.1 Situational constraints of the benefit and demand function

All of the assumptions behind the benefit function created by Berntsen and Vatn (2014) are continued into the benefit function specific for AEN. The significant difference being that the maximum limit where the DSO does not need more DSF is redefined. The assumptions are continued, although assumptions 4 and 5 are identified as partially correct. Assumption 4 and 5 are correct, given the right circumstances. These assumptions are continued based on the DSO interviews where it was confirmed that the smallest margins needed to solve the biggest congestion (providing the highest value) would be prioritized or activated first. Meaning that the model used to derive the benefit function is not applicable for every specific situation.

The benefit function is created for the total value gain for AEN in the period 2010-2019 and not per hour of congestion as originally proposed by Berntsen and Vatn (2014). The relationship between hours of congestion and value gain is later applied using the theoretical maximum as a reference. Assumption 2 states: «the advantages of DSF will increase with increased volume». When adding hours of congestion as a variable, the assumption is expanded to include hours; MW DSF needed for hours of congestion, providing a result per MWh.

When developing the demand curve using the the approach described in Chapter 4.5, the change in value gained per data point is described. The reason for applying this approach has been to include hours of congestion as a variable, making the demand curve comparable to the cost functions in Chapter 4.4. This is done instead of deriving the demand curve based on the benefit function.

5.1.2 Geographical constraints of the benefit and demand function

Figure 4.2.1 do not consider geographical constraints. As explained in Chapter 3.1, the DSO can experience capacity constraints at different grid levels and different geographical locations. NorFlex is testing whether purchasing DSF can contribute to reduced investments at each grid level. At lower grid levels, the geographical area where the DSF is needed is smaller. This means that the assets located within the specific grid area have a greater impact when solving constraints at the local grid level. This effect was discussed in the DSO interviews. Assumption 6, stating that «large volumes of DSF are needed less frequently», was challenged. As explained in Chapter 4.1, what is considered a small amount of DSF by the DSO might be a large percentage of the electricity consumer's consumption. The assumption might be correct when it states that these volumes are needed less frequently because periods of significantly cold weather might only occur a few days each year (if they occur at all). However, if these volumes are needed for a continuous period, it might not be relevant how few hours per year they would equal. The example from the interview, 40kWh for 36h, was a load reduction a few consumers could provide at that gird level. The discomfort of dispatching an asset for 36h continuously is high and therefore this quantity is experienced as large. Even though this does not often occur, the discomfort will be significant enough to affect the supply.

In a market situation, the geographical dependency of the DSO's demand will likely result in significant variations in value gain, and therefore also prices, at different grid areas. In some grid areas, there might not be a demand for DSF at all, while other grid areas face many challenges. At a lower grid level (see Figure 3.1.2), the value gain per asset owner is higher. This is because one particular asset owner can be crucial to solving a grid constraint. Leading to the upper willingness to pay at lower grid levels to be higher than at higher grid levels. At higher grid levels, the geographical constraints are fewer and more assets can contribute to solving the DSO's need.

5.1.3 The flexibility interval and how it effects the demand for DSF

The demand for DSF will behave differently in a real market situation as opposed to the theoretical model presented in Chapter 4.2. As described in Chapter 2.5.4, a «flexibility interval» exist for each situation where DSF can serve as an alternative to grid investments. This interval is where a grid constraint is identified but is small enough for DSF to be a satisfactory solution. In other words, in some cases, investing in grid infrastructure is unavoidable. This has been confirmed by interviews and will limit the demand for DSF. The flexibility interval is also why analyzing the total demand for a DSO at all grid levels is difficult because it involves individual analysis and assessing every possible scenario. Making the accuracy of Figure 4.2.1 and 4.2.2 hard to evaluate. Figure 4.2.2 will show an average price, but one should expect deviations from that average depending on the situation.

Figure 4.2.1 increases to a maximum point at a 100% postponed investment cost. This point is impossible to reach. From interviews, it is assumed that postponing 10% of the total investment cost is a more realistic target for a DSO. If this assumption is correct, and 90% of all investments need to be conducted regardless of available DSF, the demand curve will stop at that 10% mark. However, reports such as Spilde et al. (2019) predict an increased electricity consumption. It is hard to estimate how much of the increased consumption will lead to grid congestions solvable by DSF and how much will inevitably lead to new grid investments.

5.1.4 Weaknesses regarding the benefit and demand function

The shape of the benefit function, see Figure 4.2.1, is justified when assumption 1-7 were evaluated in Chapter 4.1. Quantifying the value of DSF is challenging, the respondents interviewed explains that estimating an upper value of DSF or an upper willingness to pay per MWh is nearly impossible. This poses challenges when estimating the relationship with the available volume of DSF [MW] and postponed investments. The relationship between available DSF and the percentage of postponed investments is directly derived from Berntsen and Vatn (2014). It should be noted that there are insecurities related to the accuracy of this relationship, as the relationship has been impossible to confirm or disconfirm by respondents interviewed. It should also be noticed that the volume introduced in the benefit function is available DSF with no constraints. The DSF is assumed to be available when and where it is needed. In a more realistic situation, a larger quantity of DSF might be needed to ensure that the DSF activated can meet the buyer's need.

For simplicity, the relationship between the share of postponed investment and hours of congestion is linear, which might result in inaccuracies when evaluating the DSO's demand. Assumption 2 states that the advantages of DSF will increase with the volume. If, for example, a transformer is overloaded by 80%, 80% of the transformer capacity is needed to solve the constraint, and a lower volume might not be sufficient. This means that the advantage of DSF might increase in stages and not as a continuous linear function.

5.2 The Cost of Supplying DSF

The results from interviews with aggregators show that the cost of supplying DSF is affected by a few key factors. These factors are: the installation cost, the asset owner compensation, and the number of assets recruited by the aggregator.

When analyzing the cost functions for electric boiler, electric vehicle, and water heater illustrated in Figure 4.4.2, one can see that from 26-1300 h_D per year (0.2 - 1 b_D/day), the aggregators fixed costs, C_I, C_M, C_{SW} and C_0 is the major cost drivers of the asset. Of the fixed costs, the number of assets recruited determines which is the largest. With a substantial number of assets, the installation cost C_I is the biggest cost driver of the cost function. When the asset is dispatched 260 hours per year (2 h_D /day), C_{AO} accounts for 50% of the total aggregator cost.

From that point, C_{AO} is the largest cost driver. A close-up section of Figure 4.4.2 is presented in Figure 5.2.1.

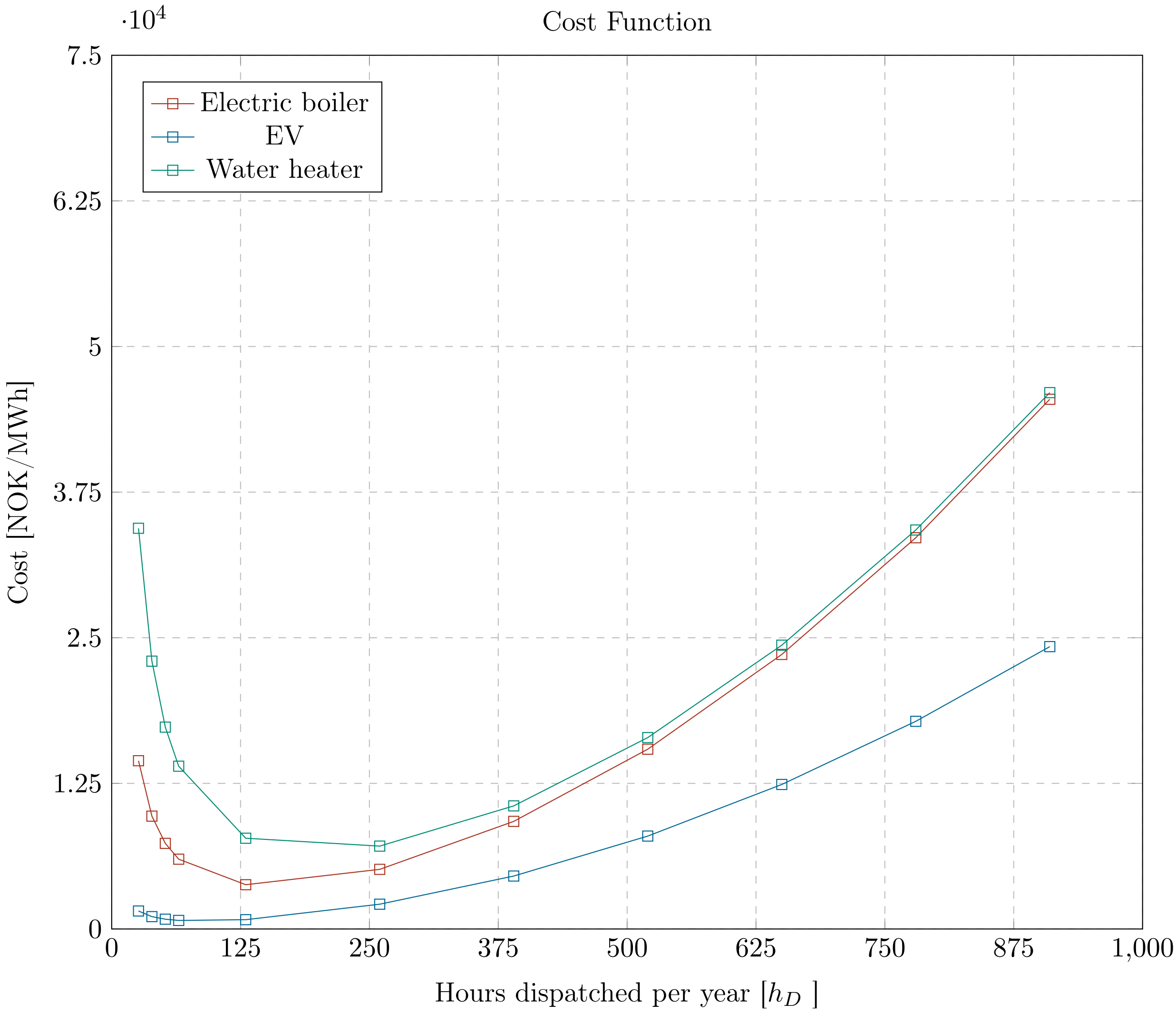

Figure 5.2.1: Close up framed picture of Figure 4.4.2.

C_{AO} is estimated and illustrated using a theoretical model (Equation 4.4.1). Nevertheless, it is confirmed by aggregator interviews that the asset owner compensation accounts for the majority of the cost of supplying DSF. When developing the asset owner compensation function, it has been important to avoid incentives for the aggregator to dispatch an asset to the extent where the asset owner experiences discomfort. How many hours of dispatch that lead to discomfort for the asset owner will be highly individual and needs to be evaluated by each aggregator.

As a consequence of C_{AO} being the primary cost driver, the cost function for an electric boiler and a water heater approaches the same cost. This is because the water heater in question falls within the commercial segment. A commercial water heater and electric boiler have approximately the same installed effect, and both assets are thermal loads. Therefore, approaching costs functions seems reasonable.

EV's is, as shown in Figure 5.2.1, the cheapest asset to make available and activate. This is because EV's do not have any associated installation cost and fall within the private segment of asset owners.

5.2.1 Is the asset owner compensation sufficient?

How much an asset owner will expect to be compensated for providing flexible consumption will likely vary from segment to segment and within each consumer segment. The theoretical model presented in Chapter 4.4.6 is based on the assumption that the asset owner's discomfort increases by increasing the hours per day the asset is dispatched. For an asset owner to agree to participate in the DSF value chain, the yearly compensation has to be sufficient. For an illustration, Table 5.2.1 shows the yearly asset owner compensation when the asset owner is dispatched 1, 2, and 4 hours per day.

Table 5.2.1: Examples illustrating yearly asset owner compensation.

Asset	Average volume	Yearly asset owner compensation		
	[MW]	$1h_D$/day	$2h_D$/day	$4h_D$/day
Electric Boiler	0,033	3 945	31 560	252 481
EV	0,022	1 412	11 297	90 376
Water Boiler	0,03	3 586	28 691	229 528

As Table 5.2.1 shows, the yearly compensation depends on the volume of DSF the asset owner provides, as well as the hours of dispatch. As the discomfort of the asset owner increases with h_D, it is not in the asset owner's interest to be dispatched as many hours as possible. On the other hand, if the asset is not dispatched at all, the asset owner receives 0 NOK in compensation, as the model is constructed. The aggregator and asset owner needs to identify an ideal number of hours dispatched, where the value gain is sufficient enough for the asset owner, but not high enough to compromise the asset owners comfort.

Broberg, Brännlund, Kazukauskas, Persson, and Vesterberg (2014) performs a quantitative study examining Swedish electricity consumers' expected compensation for allowing their BRP to control, and reduce, the heat source and electric consumption during specified time intervals per day.

The study concluded that an asset owner needed to be compensated 625 NOK/year for controlling a heating system between 17:00-20:00. 823 NOK/year[1] for controlling electric consumption between 07:00-10:00 and 1 424 NOK/year[2] for controlling electric consumption between 17:00-20:00 (Broberg et al., 2014). The study presented the options as contractual agreements and not as traded services at an open marketplace. Controlling an asset during a time interval is not equal to dispatching the asset for all hours, but the asset owner will have limited flexibility during the interval.

The results from Broberg et al. (2014) is most comparable to the asset owner compensation for an EV because the loads in the study all fall within the private segment. The yearly compensation for 1h of dispatch is almost equal to the highest yearly compensation required in the study. Results from aggregator interviews show that most EV's charge between 17-20 at night, making this the most comparable interval. Indicating that the asset owner compensation is sufficient for private asset owners.

From the DSO interviews, it is found that AEN's demand for DSF will vary each year. This could be a result of a warm winter, where the power consumption is not high enough to cause congestion. The volume [MW] of DSF the DSO needs to solve their congestion problems might also vary from each year. Meaning that the aggregator (and asset owner) faces the risk of being dispatched few hours or not being dispatched at all depending on the demand that year. Leading to the question: which party in the DSF value chain should bear the financial risk of the demand not being present? Should the aggregator compensate the asset owner for agreeing to the possibility of dispatching an asset? Will the asset owner agree to participate in the DSF value chain when faced with the risk of receiving no compensation at all? Should the asset owner receive an availability payment?

The colder the temperature, the more likely it is that congestion occurs and the more likely it is that an asset is dispatched. Meaning that the asset owner receives more compensation when electricity prices are high. Participating in the DSF value chain might then be seen as an option for saving money on electricity consumption when the electricity prices are high. The counter-argument is related to the price elasticity of electricity. As explained in Chapter 2.3, electricity is almost inelastic. Meaning that the electricity price has little to no effect on the consumer's behavior. It could therefore be argued that it is unlikely that the asset owner would be willing

[1] Converted from SEK to NOK, 01.05.2021

[2] Converted from SEK to NOK, 01.05.2021

to receive compensation as a cost reduction during cold winter periods. The finding that the need for DSF will be at the highest when the electricity demand and price is at the highest, will have consequences for the asset owner compensation cost. The demand for DSF is highest when the discomfort as a consequence of an asset being dispatched is highest. An electric boiler and water heater are both thermal assets. Using these assets as an example, one can reason that the discomfort of disconnecting such a load is highest when the outside temperature is coldest. A thermal load will always have some element of inertia, the temperature in a building does not instantly drop to an uncomfortable level when the heat source is dispatched. However, if there is a need for an asset to be dispatched continuously for several hours, the discomfort is likely to be extra high when the temperature is low.

5.2.2 Alternative asset owner compensation models

As mentioned, Equation 4.4.1 increases by hours dispatched per year (and in practice per day). Other solutions for asset owner compensation are, as mentioned in Chapter 4.4 a shared revenue model or a flat fee compensation structure. Both solutions will result in a function of C_A that is decreasing per hour of dispatch. The option does not consider the discomfort of the asset owner, for example, the cost of dispatching the asset owner 2 and 15 hours will be equal. In this case, regulations are needed to prevent the asset from being dispatched for an unreasonable long period. Interview respondents have mentioned that the asset owner can set limitations for how long their asset is dispatched. Implementing such a limit could ensure asset owner satisfaction when applying a flat fee C_{AO}. The asset owner has the power of withdrawing from the DSF value chain, therefore maintaining the asset owner's interests is crucial.

If reasonable regulations and contracts between asset owner and aggregator are applied, a flat fee C_{AO} could be a viable option. However, a model representing the discomfort of being dispatched is considered more fair, as it provides more compensation to asset owners who are being dispatched more hours. The asset owner discomfort is also considered to be an important factor when comparing C_A to the theoretical demand function.

5.2.3 Weaknesses regarding the cost function

The cost function do not include the imbalance cost, see Chapter 4.4. The significance of this cost is unclear. The DSF market and value chain have not had the ability to fully mature, and as seen in table 4.5.2, the quantity traded during the trading period has likely not been sufficient enough to see the effect of imbalance costs.

In this thesis, the operation cost is assumed to be equal regardless of the total number of asset owners recruited by the aggregator. The cost itself will likely vary for different aggregators, and whether the operation cost will increase with the number of asset owners required depends on the level of automation. If every step in the value chain, from asset, to aggregator, to the marketplace, is automated, the operation cost is likely to remain constant. If the aggregators business model includes manual processes, for example, manual market monitoring, the operation cost is likely to increase with the number of assets recruited.

Another cost that has not been included in the analysis relates to asset owner recruitment. Activities related to marketing, information, or following up asset owners have not been addressed. In a future scenario, with a fully developed market and DSF value chain, the aggregator might face competition when recruiting assets. The aggregators who are also BRP's face similar competition when acquiring electricity consumers.

As for the asset owner compensation cost, C_{AO}, the compensation is based on segment rather than the asset characteristics. Meaning that the electric boiler and water heater will require the same compensation. The model fails to include that the actual experience of discomfort will vary by the characteristics of an asset. Dispatching a water heater 5 hours per day will likely not give the same experience of discomfort as dispatching an electric boiler for 5 hours. Because a water heater heats water, and the electric boiler is used to heat the building itself. Both assets will have a level of inertia, but the capacity of a water heater and flexibility enabled by preheating water are likely larger. Meaning that the cost function in Figure 5.2.1 should have a lower decrease from 250 to 625 h_D year than an electric boiler in order to give a more accurate picture of the asset owner discomfort. This thesis has used a scaling factor solely based on the share of hours dispatched per day and has not examined where the threshold for asset owner discomfort falls per asset type.

5.3 Market Clearing and Value Gain

When discussing the market-clearing point, the theoretical clearing point at the intersection between the theoretical demand curve and the cost curve developed in Chapter 4 is compared to market-clearing points from NorFlex, similar markets, and other pilot projects. The market-clearing point can also be defined as the point where no additional value can be gained from one asset.

As mentioned in section 5.1, the DSO needs a lower quantity of DSF than the theoretical maximum in Figure 4.2.1 indicates. If 10% postponed investment cost is set as a reference, the benefit function will stop at a value gain of 10 407 586 NOK/MWh. At this point, the demand or willingness to pay is 32 422 NOK/year, and the cost for all three assets examined is below this point. A close-up picture of Figure 4.5.1, is shown in Figure 5.3.1.

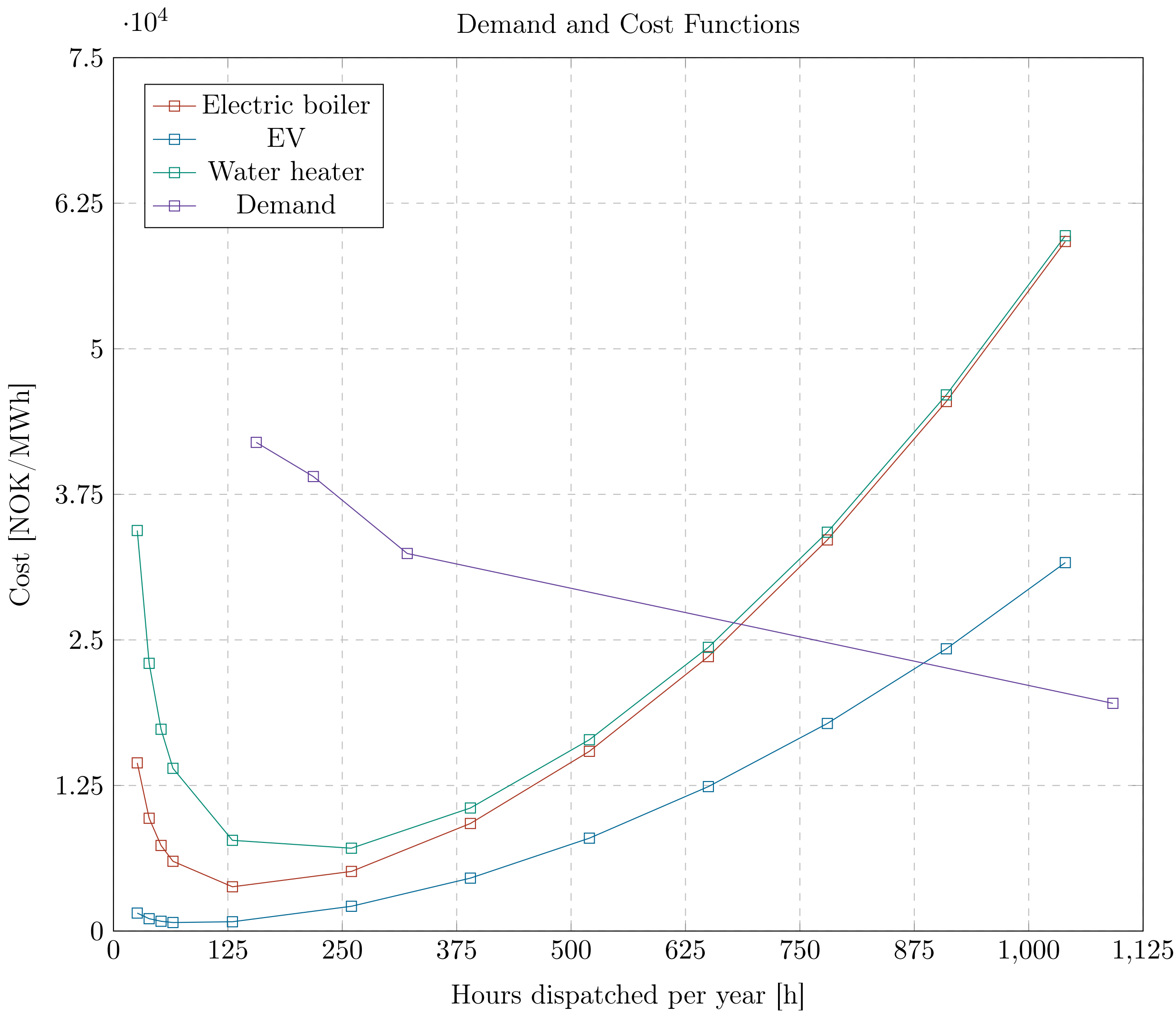

Figure 5.3.1: Close up framed picture of Figure 4.5.1.

When describing the DSF value chain in Chapter 2.4.2, de Heer and van den Reek (2018b) describes how parties can extract value. The point where the asset owner can extract the most value from the DSF value chain is at the market-clearing point illustrated in Figure 5.3.1. However, this is the point where the asset owner experiences the highest level of discomfort. Thus, the asset owner might not be willing to be dispatched for more than a few hours per day as discussed in section 5.2.1. More dispatched hours could lead to a less viable business model, decreasing the total value gain for the aggregator. Therefore, the most interesting area in Figure 5.3.1 is where the cost of supplying DSF is lowest. This point is within the range of 125-250 hours per year for each asset analyzed. At this point, the potential value gain is highest for both the DSO and the aggregators. The DSO is in a monopsony buyer (further discussed in section 5.3.1), which enables the DSO to lower the price of DSF. It is in the DSO's interest to maximize the value gain from the flexibility value chain in terms of reduced investment costs. The DSO obtains the value of DSF if the cost of DSF is lower than the alternative cost. Further, the aggregators cost function from chapter 4.4 does not include a profit margin. To maintain a sustainable value chain, the aggregator needs to establish a profitable business model and include a profit margin in the price. The point of the highest difference between demand and cost is when the aggregator has the most room to gain profit and simultaneously ensure the most value gain for the DSO. Aiming to dispatch assets between 125-250 hours per year will ensure a viable and sustainable value chain. Ensuring value gain for all parties and will be a socioeconomic reasonable solution for the power grid.

5.3.1 The DSO as a monopsonist

As explained in Chapter 2.5, the DSO is the only buyer making the market a monopsony. Making the largest difference between the power market and the DSF market the market structure. At the wholesale power market, power is traded between many suppliers and buyers and both the buyer and supplier is subject to competition. Hence, the dynamics in the DSF value chain will differ from the power market. In a monopsony market structure, the quantity of DSF traded is set by the DSO, which means that if every investment made is unavoidable regardless of the available DSF, no more quantity is traded. In Figure 5.3.1, this point can be found at 321 hours per year, if we assume that 10% of investments can be postponed using DSF (see Chapter 5.1.3). The EV, electric boiler, and water heater have a cost function lower than the highest price the DSO is willing to accept. This indicates that the DSF from the assets can provide value to the DSO. The DSO will prioritize purchasing DSF over making re-investments if a sufficient volume of DSF from these types of assets is available.

As discussed in Chapter 2.1.1 when the buyer is a monopsonist, it can use its market power to dictate the price. The DSO is, as discussed in Chapter 3.1, the only buyer represented at the marketplace in NorFlex. Bontius and Hodemaekers (2018) emphasizes the importance of TSO/DSO coordination when purchasing DSF, therefore it is likely that the buyers will not compete for the same flexible resources at a DSF marketplace. Meaning that even though the demand or willingness to pay for the DSO is much higher than the cost in several instances in Figure 4.5.1, the DSO might utilize their market power, and the prices will reflect the cost. Comparing the trade data in Table 4.5.2, the average price each week is close to C_A of an electric boiler and water heater when dispatched 1 hour each day of the trading period. As there are different asset types participating in the marketplace, one can not conclude that all trades represent the asset's cost, C_A. The finding does, however, indicate that a cost-based strategy is applied when placing bids.

5.4 Comparisons and External Validity

To ensure the research validity, the results presented in Chapter 4 are compared to relevant markets, studies, and other pilot projects. Trade of flexible resources has been conducted before a DSF value chain has been implemented. Therefore, it is important to include established markets and pilot projects when analyzing the market-clearing for DSF.

5.4.1 Comparison to NorFlex trade data

Comparing the theoretical market-clearing to the price formed during the trade period from 18.01.2021 - 26.03.2021 in NorFlex, the price of DSF has never been higher than the theoretical market meeting price. The trade with the highest unit price was, as shown in Table 4.5.1, 7 800 NOK/MWh. This trade was conducted during week 6, where the trade volume was at its highest. The maximum price per trade is less than a third of the theoretical market-clearing price in Table 4.5.1.

NorFlex is a project who aims to «develop the power grid of the future» (Agder Energi, 2019). The project is developing and facilitating a value chain because it is believed that DSF can reduce future costs. Through interviews, it has been pointed out that planing investments to account for future demand is hard. This is because it is hard to predict how much consumption the future electricity consumers will have. In addition, grid infrastructure could take several years to acquire. This makes the decision-making process for the DSO difficult when evaluating whether to invest in grid infrastructure or purchase DSF. The current grid infrastructure is mostly equipped to handle the consumption peaks in today's electricity market, but to be able to benefit from DSF in the future a reliable value chain has to exist. DSF trade in 2021 during the pilot NorFlex has therefore been based on an artificial demand. The DSO has not *actually* needed DSF to solve constraints. The lack of actual congestion problems solvable by DSF may be reflected in the prices from Table 4.5.2.

5.4.2 Comparison to other markets

As seen in Table 4.5.2, the average price of DSF traded in NorFlex from 18.01.2021 to 26.03.2021 ranges between 3340.82 NOK/MWh to 4718.20 NOK/MWh. The minimum trading price equaled 2500.00 NOK/MWh the majority of the weeks, and the maximum varied from 5000.00 to 7800.00 NOK/MWh. When comparing the price obtained at the DSF market, the electricity price can be used as a reference. If the price of DSF is below the electricity price, there would be no incentive for an asset owner to participate in the DSF value chain. Figure 5.4.1 shows the average electricity price for each week in the trading period.

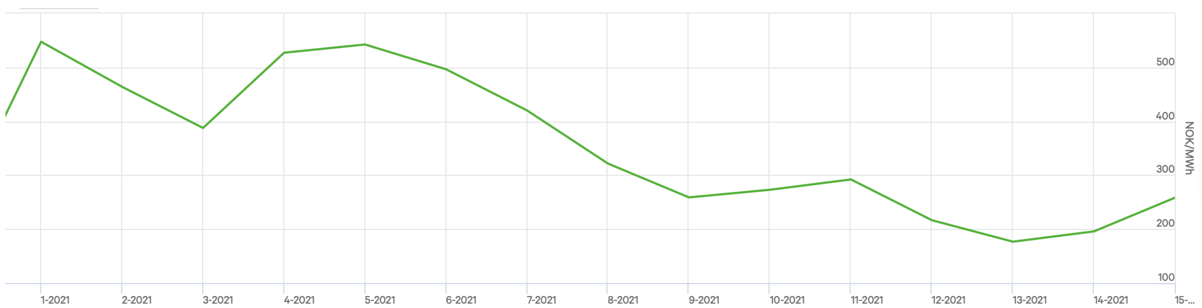

Figure 5.4.1: Electricity prices week 1-15, 2021 (Nordpool, n.d.).

Figure 5.4.1 shows that the highest average electricity price can be found during week 5 at 542.35 NOK/MWh, the lowest electricity price occurred during week 12 at 216.46 NOK/MWh (Nordpool, n.d.). All trades conducted in NorFlex have had a price higher than the highest electricity price.

The balancing markets is as discussed in Chapter 2.2.5, per the definition introduced in Chapter 2.4.1, trading flexibility. The balancing markets are the closest comparable market for DSF. The trade with the highest unit price in the NorFlex trading period was made at the same time the price for up-regulating in the regulation power market was 752.19 NOK/MWh. Figure 5.4.2 shows the prices at the mFFR market, the same day the highest priced trade in NorFlex was accepted. The prices are in NO2, the same grid area NorFlex is located.

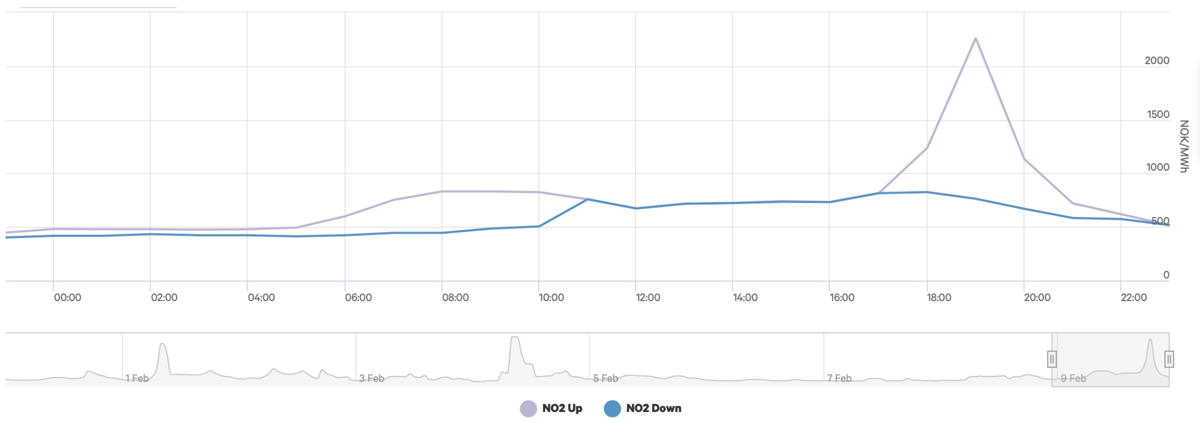

Figure 5.4.2: Example of the regulating price in February 2021 (Nordpool, n.d.)

The price of regulating power varies greatly. Figure 5.4.2 ranges from 474,63 NOK/MWh to 2259,26 NOK/MWh. The average price was 765.28 NOK/MWh. However, the price for regulating power did not reach higher than 2 500 NOK/MWh between 18.01.2021 and 26.03.2021. 2 500 NOK/MWh can be regarded as the lowest price traded in NorFlex. Leading to the conclusion that if the aggregator has the opportunity to trade at both markets, trading at NODES is more favorable.

When using the mFRR market as a reference, it is important to notice that there is a minimum requirement of 10MW to participate in the market. If a 10MW load is traded 2 hours per week, the compensation (based on daily average prices for the mFRR season 2020/2021) is 176 563 NOK per year. Comparing this compensation to Table 5.2.1, an eclectic boiler and water heater reaches the same level of compensation at 3-4 hours dispatched per day. Because the volumes traded at the balancing market are so high, making a high total profit from mFRR trades is possible. When including smaller assets in the private and commercial market, the asset owner has to be compensated enough to see the benefit of participating in the market. Therefore the prices at the local DSF market need to be higher for these assets to be incorporated.

5.4.3 Comparison to other pilot projects

In Chapter 1 several other pilot projects which are testing DSF solutions across Europe is introduced. IntraFlex is one of the pilot projects testing market-based DSF and is using NODES as a marketplace. From August to September 2020, the DSO Western Power Distribution had procured 50.15MW of DSF from 214 trades.

Table 5.4.1: Price history from IntraFlex, traded in August and September 2020. Derived from (NODES, 2021).

Week (2020)	Average price [GBP/MW/HH]	Price [NOK/MW/HH][3]
40	166.98	1921.33
39	150.23	1728.60
38	162.00	1864.03
37	158.00	1818.00
36	150.00	1725.95

The average price shown in Table 5.4.1 is lower than the average price (Table 4.5.2) for all weeks traded in NorFlex. The Intraflex average price is lower than the minimum price traded in NorFlex. Indicating that Western Distribution Power has a lower price they are willing to accept for DSF.

5.4.4 Comparison to other studies

Chapter 2.5.4 introduces Baretto and Eide (2018), a study of the potential for postponing grid investments at the grid level denoted as hypothesis 6 in Figure 3.1.2. Baretto and Eide (2018) identifies two substations where the DSO's upper willingness to pay for DSF is sufficient to use DSF to reduce consumption peaks by 10%. The upper willingness to pay was 2 190 NOK and 667 NOK per asset owner per year. 14 asset owners were reducing their consumption by 1kW during peak hours. Assuming 70 hours of substation overload per year, the upper willingness to pay is 31286 NOK/MWh and 9529 NOK/MWh, respectively. Comparing this to the cost functions in Figure 4.4.2 one can see which assets could be traded under the particular substations. At the substation with the highest willingness to pay, DSF from all assets analyzed could be traded. At the second substation, the EV and electric boiler have a cost lower than the highest willingness to pay. The water heater has a higher cost in Figure 4.4.2 because it is assumed that the aggregator recruiting the asset owners have 10 assets as opposed to 100 in the case of electric boilers. When dispatched few hours per year, the number of asset owners has a greater effect. Applying the concept of value stacking, the assets could be traded more hours per year, resulting in an even lower cost.

[3] Converted from GBP to NOK 26.04.2021.

5.5 Correspondence Between the DSF and Electricity Demand

Circling back to the definition of demand side flexibility, presented in Chapter 2.4.1, the DSF does not exist if a planned consumption does not exist. Meaning that if the asset would not otherwise be consuming electricity during the time of trade, the DSF from the asset has a quantity of 0 MW. Thus, the potential of DSF is highest when the electricity consumption is high.

Chapter 2.3.3 states that electricity demand is at its highest during cold winter months, especially January and February. Figure 4.5.2 shows that the temperature during January and February 2021 was low, most weeks below 0°C. When looking at detailed trade data from three example trades, Table 4.5.3 shows that the maximum unit price for a trade and the maximum volume traded took place during hours of cold temperatures. Indicating that the demand for DSF, despite it being artificial, has followed the outside temperature.

These observations show that not only does the demand for DSF correspond with electricity demand, so does the ability to supply DSF. For non-thermal assets, such as an EV, the consumption may be unaffected by the outside temperature, but the overall supply of DSF will decrease when the temperature increases.

5.6 Supply and Demand at Different Grid Levels

As mentioned in Chapter 5.1.2, the demand for DSF will vary from grid level and based on geographical constraints. Stea and Våge (2021) is a ongoing study analyzing the hypothesis addressing if DSF can be applied to improve voltage quality. This is hypothesis 7 in Figure 3.1.2, at the lowest local grid area. To illustrate how situation-dependent and local DSF demand can be, the example from Stea and Våge (2021) is used. In one of Stea and Våge (2021)'s cases, DSF can improve voltage quality. In this example the lowest value gain would be if the DSF can postpone an investment for 1 year and is equal to 17 500 NOK/year. Further, one electricity consumer is the sole consumer who can provide DSF to solve the problem. This consumer would have to reduce the consumption by 5kWh, the total number of hours are unclear and could vary depending on the year (Stea & Våge, 2021). The case seems like a high value gain for a low volume of DSF. As discovered through DSO interviews, Chapter 4.1, it is very individual what can be described as a large quantity of DSF. In this example, electricity consumer would fall within commercial segment. To increase the voltage quality, the consumer would have to reduce the consumption by 5kW for as long as 4 coherent hours. Table 4.4.2 shows that 4 hours of dispatch per day should equal a payment of 14 713 NOK/MWh. As the asset owner compensation cost is the main cost driver after 2 hours of dispatch per day, it is fair to assume that the cost is below the DSO's willingness to pay. However, the asset owner might not agree to participate in the marketplace because 4 coherent hours of dispatch might prohibit the asset owner from conducting work or other value-creating activities.

A possible solution to reduce the discomfort of a dispatch is to reduce the asset owner's load by rolling dispatches of more than one asset. It still needs to be the same asset owner, but more than one asset is available for dispatch. This will increase the installation cost, and if the investment is postponed by 1 year, the investment cost cannot be depreciated over 5 years (as used in the cost function, Equation 4.4.3) unless the asset can later be traded at a higher grid level.

This example illustrates how local DSF demand and supply can be and how much the demand and supply of DSF will vary based on the situation. At lower grid levels, the DSF value chain needs to identify flexible resources that can be dispatched without a significant level of discomfort to meet a DSO's specific and local needs. More assets will be located under the grid node at higher grid levels and therefore be an eligible DSF resource. In cases where one electricity consumer is the only consumer that could provide the DSF, a bilateral agreement might be a more targeted and efficient measure than to acquire the DSF at an open marketplace.

5.7 The Future for the DSF Market

5.7.1 Market maturity

Throughout the research period, the understanding of the DSF value chain has matured. Previous studies, such as Berntsen and Vatn (2014) and Baretto and Eide (2018), have been conducted without following a pilot project that includes all parts of the value chain. In particular, the aggregator role has not been implemented in the Norwegian power system and is still a developing role. This is the role in the value chain that has evolved the most since the previous studies. This study has had the advantage of analyzing the DSF market as the market evolves and trading activities in a real market situation have started. However, all participants in the NorFlex pilot is still undergoing a learning process. Aggregators are mapping out their marginal costs in a situation where optimal asset volume and demand for DSF per day or per season is unclear. All hypotheses of the value of flexibility for AEN are not confirmed, and the potential for DSF is not fully mapped out. At the same time, the framework surrounding trade activities is evolving, and the marketplace develops products so that different DSF resources can provide value under optimal conditions. In the research period, from week 3-12 2021, TSO trading has not been conducted. How including the additional buyer will affect the value chain is yet to be tested in NorFlex.

As the value chain is still maturing and developing, the prices from the pilot indicated in Table 4.5.2 may not give a completely accurate picture of the price of DSF. As the market develops, the DSO will have a clearer picture of their benefit and thus their willingness to pay for DSF. If the relationship between postponed investments and available DSF is further studied, the demand can be fully understood. In a more mature market, the difference in price at different grid levels, as well as the the difference at between geographical areas, will also be more visible in the marketplace. Aggregation will enable larger volumes of DSF to be traded, making it easier to document the affect DSF has on grid management.

5.7.2 Changes in the cost of supplying DSF

As the DSF market develops, some of the costs of making DSF available in the marketplace may change. The investment cost C_I will likely decrease as «smart» technology develops and becomes an integrated part of the assets. As described in Chapter 4.4, there is an investment cost per asset that is currently considered a major cost driver in the interval 0-125 h_D in Figure 5.2.1. With «smart» technology integrated into the asset upon purchase, a large part of C_I is likely reduced. The cost function of an electric boiler and water heater will then resemble the cost function of an EV, in terms of shape.

Another factor that can lower the aggregators' costs is the duration an asset is dispatched. The minimum dispatch time today is 1 hour, which will likely change in the future. 15 min and 30 min contracts have already been introduced in the Nordic and other European spot markets (Nord Pool, n.d.-b), the authors beleive that the DSF market will follow this development. A dispatch time of 15 minutes will decrease the cost of supplying DSF. When reducing the dispatch span from 1 hour to 15 minutes, thermal assets could take full advantage of the assets' inertia. The aggregator could then optimize the dispatch so that the asset owner does not notice the dispatch while trading frequently.

5.7.3 Increased demand for DSF

The grid area in the Agder region is connected to the European grid infrastructure. Some of the connection points are through sub-sea cables such as North Connect (Scotland), Cross Skagerrak (Denmark) and Nordlink (Germany). Many of these sub-sea cables are under construction and will be connected to the transmission grid in the near future. The sub-sea cables could cause problems in the transmission grid that may propagate to the distribution grid (Statnett, n.d.). Most of the problems will relate to frequency and voltage management (see Figure 2.5.1) in the transmission grid, but the effects of the sub-sea cables could also become problems further down in the grid (Statnett, n.d.).

The authors believe that the demand for DSF is likely to increase in the future. In this thesis the season for DSF trading has been limited to 26 weeks in the winter. This is because the electricity consumption increases in the winter, especially in Norway where electricity is a common heating source. With an increased share of EV's and an electrification of industrial processes, as forecasted in Spilde et al. (2019), the demand for DSF is likely to expand into the summer season. In that case, the grid will face many of the same problems in the summer as it does in the winter. EV's and water heaters are examples of assets that still draws electricity during the summer. Consequently the assets still have the ability to offer DSF during the summer. Increasing the DSF season from 26 to 52 weeks will enable more hours of trade per asset, without increasing the discomfort of being traded. This would drive the total cost of DSF down, while the total yearly amount the asset owner is compensated will increase.

Chapter 6

Conclusion

In this thesis, the potential value gain from demand side flexibility is identified through the examination of a developing market. To identify and visualize the potential, a three step analysis of the market has been performed. The market demand, specific for Agder Energi Nett and the cost for supplying DSF from three loads is analyzed. The supply and demand curves are compared to trade data from a real market situation in NorFlex. The thesis has further developed a model describing the cost and benefit of DSF inspired by the framework developed by Berntsen and Vatn (2014). The two functions are compared based on hours of trade per year. By doing so, a potential for value gain is identified which enables the parties to extract value.

Compared to similar markets, studies and trade data from NorFlex and IntraFlex, the DSO's willingness to pay in Figure 4.5.1 is high, indicating that the value of DSF is underestimated. However, the benefit function developed in this thesis can not be directly applied. This is because the demand for DSF is highly dependent on the situation and location of the grid constraint and DSF resource. As the market develops, the most important factor affecting the value and demand of DSF, from a DSO perspective, will be the «flexibility window». As the hypothesis 1-7 from Chapter 3, describing how the DSO can obtain value from reduced investment costs at different grid levels are confirmed or disconfirmed, the window where DSF is profitable can be defined for each grid level. When this window is defined, the DSO can fully develop a trading strategy based on the constraints.

The three assets analyzed: electric boiler, electric vehicle, and water heater all have costs functions that fall below the DSO's upper willingness to pay. Meaning that they are relevant and profitable assets to trade at the DSF marketplace. The three assets have a low enough cost to enable all parties, the aggregator, DSO, marketplace, and asset owner, to extract value from the

DSF value chain (see Figure 2.4.1). The key factors affecting the cost of providing DSF are: installation cost, asset owner compensation, and the number of assets recruited by the aggregator. As the technology develops, the installation cost is predicted to decrease, ensuring profit when trading even fewer hours than suggested in today's market.

Figure 5.3.1 shows that it exists a potential between the theoretical demand for and cost of supplying of DSF. In Figure 5.3.1, the interval between 125-250 hours of dispatch per year is the interval where the cost of supplying DSF from the three assets analyzed is at its lowest. This interval is also the interval where the potential for value gain is the highest. 125-250 hours can be considered the ideal number of hours of dispatch per year to ensure asset owner comfort while providing a sufficient asset owner compensation.

Trade data from NorFlex (Table 4.5.3) shows that the volume-weighted average price is close to the aggregator's cost of supplying DSF from an asset dispatched 90 hours per year (1 hour per day in the trading period). As the market structure is a monopsony, this is a natural point of market clearing. As the market develops, it is important to ensure aggregator profit, as the majority of the value gain seems to be extracted by the DSO.

The supply and demand of DSF are highly dependent on the market situation at each grid level and geographical location. In Chapter 5.1.1, the example highlights many complex factors that affect the DSO's demand for DSF and the aggregator and asset owners' ability to provide a sufficient amount of DSF in MW and hours dispatched. The availability of DSF is lower at lower grid levels simply because fewer assets are located under the grid node. This will likely result in a higher price per MWh at lower grid levels. As the electricity and DSF demand both correlate to temperature, the DSF price is likely to increase as the outside temperature decreases.

This study shows that there is potential for value gain in a demand side flexibility value chain. However, quantifying the exact value gain requires specific evaluations of the geographical location, grid level, and weather during the winter season. The demand and cost of supplying DSF will vary with these conditions, as will the price. With the expectation of increased demand for DSF and a tendency of decreased cost of acquiring relevant assets in the future, the development of the DSF value chain looks promising. The potential for gaining value is predicted to increase and expand across Agder Energi Netts grid area.

6.1 Further Research

The development and testing of market-based DSF in the power grid could support further development within the research fields of renewable energy and smart grid technology. DSF supports grid infrastructure and integration of renewable energy sources, and includes the electricity consumer in the clean energy transition. This makes further research on the topic highly relevant and necessary for developing and integrating the DSF value chain.

In this thesis, a potential for gaining value has been identified. To develop a more accurate benefit function, the hypothesis of reduced investment cost from DSF trading needs to be confirmed or disconfirmed at each grid level illustrated in Figure 3.1.2. If the advantage of DSF at each grid level is verified, an analysis quantifying the value at each grid level will provide a more accurate picture of the DSO's benefit from DSF.

The function describing C_{AO} could be further validated by studying the asset owners' actual willingness to shift their consumption and discomfort of being dispatched. Equation 4.4.1 is based on the CENS, and may not be the most representative way of describing asset owner discomfort. Broberg et al. (2014) concludes that limiting the consumer's electricity consumption is negatively perceived. Broberg et al. (2014) describes several reasons for the electricity consumer to prefer a «status quo» option. There might be several reasons for an electricity consumer to be hesitant to shift their consumption. Is a dispatch preventing the asset owner from executing work? Does it pose challenges in everyday life of the consumer? These questions need to be further examined to get a complete picture of the asset owner's compensation.

The trade data used in this thesis is derived from trades of DSF as a short term product, similar to electricity traded at the spot market (explained in Chapter 2.2.2). The marketplace, NODES, also enables DSF to be traded as longer-term availability contracts. How the DSF product type affects the potential for value gain and how the availability of flexible resources should be priced and valuated is a topic that should be further researched.

In today's electricity market, advanced algorithms and prognoses are used to forecast electricity pricing. Forecasts will likely play a role in the future market for DSF when predicting the available volume of DSF, evaluating the probability of congestion occurring, and verifying the quantity of flexibility traded. Further studies regarding forecasts and how forecasts will influence the market for DSF are needed as the value chain evolves.

Market-based demand side flexibility is in need of further research at the buyer and supplier side of the value chain. As European Commission (2018) places the consumer in the center of the clean energy transition in Europe, the subject of DSF is highly relevant. The authors predict a rapid development and maturity of the value chain in the upcoming years. Hopefully, this thesis can contribute to gaining a better understanding of the potential for value gain from demand side flexibility in the power grid.

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Appendices

Appendix A

Interview Guides

A.1 Interview guide aggregator

Intervjuguide

1. **Kort om virksomheten og virksomhetens rolle i NorFlex.**

2. **Hvilke kostnader regner dere med når dere beregner deres marginalkostnad for lasten?**
    a. Hva er kostnadsdriverne knyttet til lasten?

    b. Er det noen karakteristikker ved lasten som påvirker kostnadsbildet?

    c. Ser dere at det vil være ekstra kostnader ved å utvikle en prognose for lasten?

    d. Har dere en oversikt/ beregning av kostnader vi kan få innsikt i?

        i. Eventuelt, kan dere gi oss innsikt i kostnadsbildet deres (slik at vi kan prøve å beregne en marginalkost).

    e. Hvordan ser dere for dere kostnadsbildet vil endre seg med tid?

3. **Hvordan prissetter dere fleksibilitet i dag? (hvilke faktorer ligger til grunn?)**
    a. Hvor stort volum (kundevolum, eller fleksibelt volum) ser dere for dere at er realistisk for å drive lønnsom handel av fleksibilitet?

4. **Har dere sett noe på hvordan ulike laster i en portefølje vil påvirke marginalkostnaden?**

Vi vil sammenstille referat til gjennomlesning og godkjenning. Er det mulig å ta kontakt ved en senere anledning for eventuelle oppfølgingsspørsmål?

A.2 Interview guide DSO

Intervjuguide DSO

Intervjuet er tredelt: Del 1 er en presentasjon av antakelser vi ønsker din mening om, del 2 er spørsmål knyttet til DSOs behov for fleksibilitet og del 3 er en gjennomgang av en modell som fremstiller verdien av fleksibilitet for AEN.

DEL 1

Hvilke påstander under stemmer/stemmer ikke og hvorfor?

1) Den største fordelen med fleksibilitet for AEN er utsatte og reduserte innvesteringer fremfor å ekspandere kapasiteten i nettet.

2) Fordelene med fleksibilitet vil øke med økt volum av tilgjengelig fleksibilitet

3) Det eksisterer en grense for fleksibilitetsvolum hvor behovene til Agder Energi er innfridd.

4) For en DSO er det små marginer som skal til for å håndtere en flaskehals

5) Et lavt volum av fleksibilitet er tilstrekkelig for å utsette / redusere store innvesteringer.
Utdypet: et lite volum av fleksibilitet skal til for å forhindre en flaskehals og kan dermed redusere / utsette en stor innvestering

6) Det vil sjeldent være behov for store volum/kvantum av fleksibilitet *(for å løse et problem)*

7) Innvesteringer er av en høyere størrelsesorden på høyere nettnivå

Påstand	Usann	Delvis usann	Hverken sann eller usann	Delvis sann	Sann
1					
2					
3					
4					
5					
6					
7					

DEL 2

1) Hvor mange timer i året opplever AEN kapasitetsutfordringer (flaskehalser el)
    a. Hvor mange dager i året opplever DSO kapasitetsutfordringer?
    b. Hvor mange timer per dag (med kapasitetsutfordringer) opplever DSO kapasitetsutfordringer?
    c. Ser dere for dere at det vil være en fleksibilitets-sesong (tilsvarende en RK-sesong)?

2) Agder Energi Nett har i perioden 2010-2019 i gjennomsnitt brukt 468 173 064 NOK/år på kostnadsposten nye innvesteringer og re-innvesteringer, hvor mye av denne investeringen må gjøres uavhengig av om AEN løser alle sine problemer med fleksibilitet.

3) Ref. påstand 3, hvor mye fleksibilitet tenker dere at dere maksimalt trenger?
    a. I dagens situasjon
    b. Om 5 år
    c. Om 10 år

4) Om dere som DSO skal gå inn for å kjøpe fleksibilitet, hvor ville dere kjøpt fleksibilitet først?
    a. Er de punktene i nettet med størst problemer også de plassene det er mest å tjene ved å kjøpe fleksibilitet?

5) Med økt tilgjengelighet av fleksibilitet, vil dette føre til at investeringene kan utsettes i flere år?

DEL 3

Modellen vi nå presenterer er en benefit-function for et nettselskap. Modellen blir i sin helhet gjennomgått under intervjuet. Den tar utgangspunkt i følgende funksjon:

$$B_G(x) = I - (1 - \rho(x))I - \frac{\rho(x)I}{(1+i)^{n(x)}} + \Delta C^{ENS} + \Delta C^{R}$$

Hvor:

I = Innvesteringskostnad (fordelt per time med kapasitet utfordringer per år)

P(x) = hvor mange % av innvesteringen XMW av fleksibilitet kan føre til

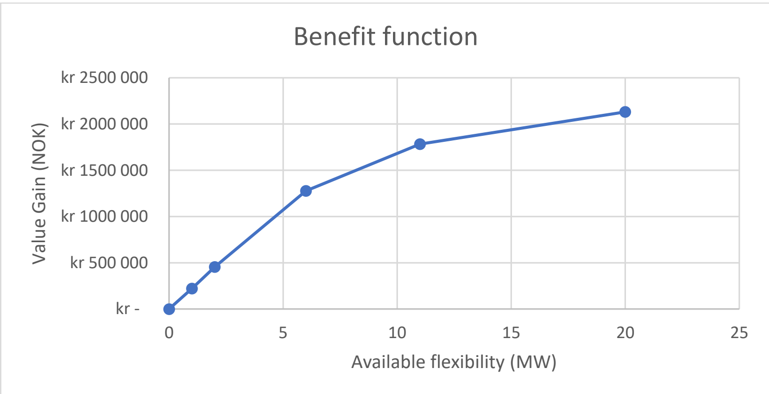
N(x) = XMW av fleksibilitet utsetter investeringen i n år.

i= rente = 5%

1) I denne tabellen er det en antatt sammenheng av hvor stor andel av totale nye og reinvesteringer som utsettes ved XMW fleksibilitet og hvor mange år denne andelen utsettes. Hvordan samsvarer dette med AEN sin vurdering av fleksibilitet?

MW	Andel utsatt investering	År	Spart investeringskostnad (per h)
0	0%	0	0
1	20%	5	222 131
2	35%	6	455 729
6	70%	9	1 276 374
11	90%	10	1 782 793
20	100%	11	2 130 871

2) Stemmer formen til benefit funtion? Vil den marginale fordelen med DSF være positiv (frem til 20MW(maks behov) og vil økingen være avtakende med økende volum av fleksibilitet?



Appendix B

Models for deriving benefit and cost functions

B.1 Benefit and demand function

Demand function DSO

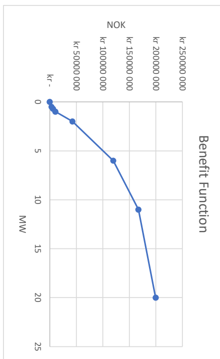
Total yearly investment (NOK)	kr 480 788 011	
Interest rate	5 %	
No. Of days with overload	5 %	

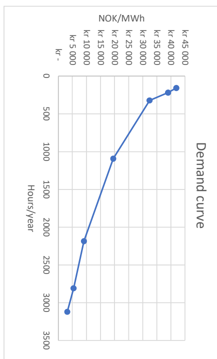
	Agder Energi	
Total investment 2010-2019	4 807 780 115	
No years in the period	10	
Re and new investment	kr 480 788 011	

- Assuming Re and New Investments for Agder Energi from 2010-2019
NVE: Nøkkeltall for nettselskapene (report)

Calculations and results

Available flexibility (MW)	Share of postponed investment	Years postponed	Value gain (NOK)	Value Gain (NOK/MW)	Hours (h)	NOK/MWh
0	0 %	0	kr -	-		
0,5	5 %	3	kr 3 273 263	kr 6 546 525	156	41 964,90
0,7	7 %	4	kr 5 966 977	kr 8 524 252	218,4	39 030,46
1	10 %	5	kr 10 407 802	kr 10 407 802	321	32 423,06
2	35 %	6	kr 42 705 808	kr 21 352 904	1092	19 553,94
6	70 %	9	kr 119 607 441	kr 19 934 573	2184	9 127,55
11	90 %	10	kr 167 063 291	kr 15 187 572	2808	5 408,68
20	100 %	11	kr 199 681 219	kr 9 984 061	3120	3 200,02





B.2 Asset Owner Compensation Function

Asset owner compensation

Season	26
days/week	5

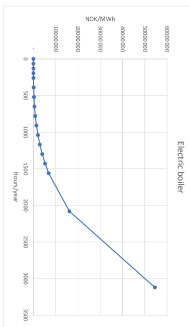
	Commercial	Industrial	Private
CENS rate [NOK/MWh]	220700	133400	23700
Correction factor	0,1	0,5	0,5
Regression line h/Day	919,58x^2-0,01x+0,04	2780,13x^2-24,26x+39,51	493,75x^2+0,03x-0,01
Regression line h/Year	7,07x^2+0,08	21,38x^2+0,07	3,8x^2+0,18

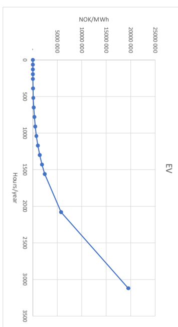
Asset Owner Compensation function

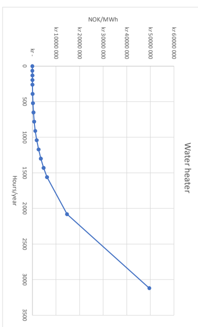
	Dispatch h/day	h/year	Cost (NOK/MWh)		
Scaling factor			Commercial	Industrial	Private
0,0 %	0	0	-	-	-
2,1 %	0,5	65	230	695	123
4,2 %	1	130	920	2 779	494
6,3 %	1,5	195	2 069	6 253	1 111
8,3 %	2	260	3 678	11 117	1 975
13 %	3	390	8 276	25 013	4 444
16,7 %	4	520	14 713	44 467	7 900
20,8 %	5	650	22 990	69 479	12 344
25 %	6	780	33 105	100 050	17 775
29 %	7	910	45 060	136 179	24 194
33,3 %	8	1040	58 853	177 867	31 600
37,5 %	9	1170	74 486	225 113	39 994
41,7 %	10	1300	91 958	277 917	49 375
45,8 %	11	1430	111 270	336 279	59 744
50,0 %	12	1560	132 420	400 200	71 100
66,7 %	16	2080	235 413	711 467	126 400
100 %	24	3120	529 680	1 600 800	284 400

Examples, yearly compensation

NOK/MWh/year	NOK/MWH/year	NOK/MWh/year
Electric boiler	EV	Water heater
-	-	kr -
493	177	kr 448
3 945	1 412	kr 3 586
13 314	4 766	kr 12 104
31 560	11 297	kr 28 691
106 515	38 127	kr 96 832
252 481	90 376	kr 229 528
493 127	176 516	kr 448 297
852 123	305 019	kr 774 657
1 353 139	484 359	kr 1 230 127
2 019 846	723 008	kr 1 836 224
2 875 914	1 029 439	kr 2 614 467
3 945 013	1 412 125	kr 3 586 375
5 250 812	1 879 538	kr 4 773 465
6 816 982	2 440 152	kr 6 197 256
16 158 771	5 784 064	kr 14 689 792
54 535 853	19 521 216	kr 49 578 048







B.3 Aggregator Cost Function

Cost function Aggregators

Costs:	Yearly Costs	Per asset
Software*	100 000	1 000
Marketplace*	100 000	

Variables:	Amount:
Depreciation year	5
Season	26
Day/week	5

	Kilekostnad	Alpha	Beta	c	Customer function
Industrial		2780,13	-24,26	39,51	2780,13x^2-24,26x+39,51
Commercial		919,58	0	-0,04	919,58x^2-0,01x+0,04
Private		493,75	0,03	0,01	493,75x^2+0,03-0,01

Operating:	Installation Cost*	Operating Cost*	Avarage Volume	Asset Owner
Electric boiler	100 000	100 000	0,033	100
EV	0	100 000	0,011	1000
Water heater	100 000	100 000	0,03	10

*The costs: Software, Marketplace, Instalation cost and Operationg cost have been set to 100 000 NOK to anomynize the data provided by aggregators.

		Electric boiler	EV	Water heater
Dispatch h/day	Dispatch h/year	Total cost (NOK/MWh)	Total cost (NOK/MWh	Total cost (NOK/MWh)
0,2	26	26 843	1 069	52 601
0,3	39	17 954	744	35 125
0,4	52	13 550	603	26 429
0,5	65	10 952	543	21 255
1	130	6 281	704	11 432
2	260	6 359	2 080	8 935
3	390	10 063	4 514	11 780
4	520	16 054	7 953	17 341
5	650	24 062	12 386	25 092
6	780	33 998	17 810	34 857
7	910	45 825	24 224	46 561
8	1040	59 523	31 626	60 167
9	1170	75 082	40 017	75 654
10	1300	92 494	49 396	93 009
11	1430	111 757	59 763	112 225
12	1560	132 866	71 118	133 296
16	2080	235 748	126 414	236 069
24	3120	529 901	284 409	530 116