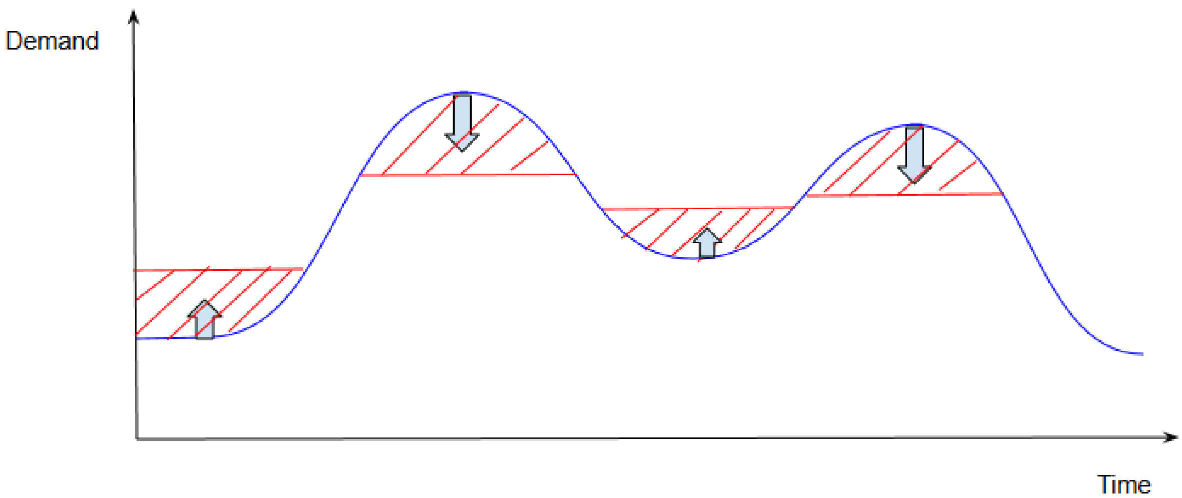

Grid loss reduction with Demand response

Master's thesis in Sustainable Energy Systems

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Department of Energy and Environment
CHALMERS UNIVERSITY OF TECHNOLOGY
Gothenburg, Sweden 2016

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Cover:
Illustration of demand response, made by Niklas Andersson.

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Abstract

In order to achieve more efficient use of the electricity grid, the Swedish market inspectorate has introduced an incentive for the grid companies in Sweden to reduce electricity grid losses and reduce peak demand. The incentive provides an increase in the revenue cap (the maximum allowed income) for the grid companies. One way to achieve reduced losses is to introduce demand response where the idea is to reduce or shift demand during peak hours to off-peak hours. This reduces losses because losses are proportional to the square of the load power. The aim of this thesis is to investigate how much grid loss reduction can be achieved in an electricity distribution grid by using demand response and what the quantitative economic benefits are.

The methodology of this report consists of creating two cases of demand response; one with a conservative estimation of its potential to reduce and shift load, and one optimistic estimation. These are compared with a base case, depicting the current situation without demand response. The consumption data and grid data of the grid in Ulricehamn, Sweden, are analyzed using a data analyzation program called Lavastorm, to extract the necessary data in order to perform loss calculations. The loss calculations are based on the extracted grid data and performed using power flow analysis in MATLAB.

The results show a reduction of losses compared to the base case of 0.6 % for the conservative estimation of demand response and 13.4 % for the optimistic estimation of demand response. There is an increase of the revenue cap compared to the base case for the conservative estimation of 10 237 SEK and 201 698 SEK for the optimistic estimation of demand response. The achievable cost reduction by reducing losses for the two cases of demand response are 20 126 SEK and 449 484 SEK respectively. The load reduction results in a cost reduction of 0 SEK and 983 531 SEK respectively.

These results should be taken as indications rather than absolute truths. Due to the quality of the measurement data, the analysis was only made on a relatively small part of the grid. The economic results above were obtained by scaling the results from the small part of the grid to the entire grid. Another conclusion from the study is that the quality of the grid data and consumption data are relatively low for the purposes of this study. Furthermore, the method of depicting the grid using spreadsheet data instead of grid maps should prove useful when analyzing hourly measurements, but the data needs to have sufficient quality for it to work.

Keywords: grid loss, demand response, demand side management, lavastorm, power flow analysis

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Niklas Andersson, Gothenburg, September 2016

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1 Introduction

To address the growing climate issues, it is common to have policies which set up the future environmental goals to reach in order to mitigate climate issues. One example of this is the Paris-agreement which is a global legally binding deal to mitigate the climate change by limiting global warming to 2° C [1]. Another example is the 20-20-20 target set by the European Union in 2009. The overall aim of the target is to by the year 2020; cut 20 % greenhouse gas emissions from 1990 levels, that 20 % of the energy produced in EU should come from renewable sources and that an improvement of 20 % in energy efficiency is to be achieved [2].

Increasing the energy efficiency can be done in a number of areas, such as increased efficiency in production plants, energy efficient buildings, and more efficient energy distribution. This report focuses on the latter, where the electricity distribution is of main concern. One way to make the electricity distribution more efficient is to reduce losses in the electricity grid.

The Swedish market inspectorate (Ei) created in 2015 an incentive for the electricity grid companies in Sweden to make the electricity distribution more efficient by reducing losses and peak loads in the grid [3]. One way to do this, as mentioned by the Ei in the report [3], is to introduce demand response (DR) or demand side management (DSM). The idea with demand response and demand side management is to reduce or shift power demand during peak-demand hours to low consumption hours, and thereby gaining benefits e.g. loss reduction but also reduce the need to reinforce the grid as a smaller capacity is needed [4].

This report analyzes the potential grid loss reduction in a Swedish electricity distribution grid company using demand response. The grid company in question is Ulricehamns energi.

1.1 Background

In the sections below, a background to the project is provided, together with problem description, delimitations, method and structure of the report.

1.1.1 Structure of the energy market

To give a general insight in the energy market of Sweden, the main actors in the energy market relevant for this work are presented below.

1.1.1.1 Energimarknadsinspektionen (Ei)

Energimarknadsinspektionen (Ei) is the Swedish Energy market inspectorate, who answers to the government and the Riksdag. The tasks of Ei are to monitor the compliance of the laws and regulations of the energy markets for electricity, natural gas and district heating. Another task is to develop suggestions for the government and the Riksdag on how to develop these markets. A part of Ei's mission is to monitor the quality in the electricity network. [5]

1.1.1.2 Electricity grid companies

There are approximately 170 grid companies (or grid owners/operators) in Sweden, each responsible for the distribution of electricity in the regional- and local grid [6]. Grid companies are responsible for operation and maintenance and for developing their grid and the connections to other grids if needed. They are also responsible for having a safe, reliable and efficient grid. [7] The grid companies in Sweden operate under a regulated monopoly. This means that each grid company own specific areas of the grid in Sweden, either at a regional level or local level (or both) where consumers have no possibility of changing grid company. The grid companies are regulated by Ei in terms of the quality of the grid and the revenue received through electricity consumers according to the revenue framework. Grid companies also have to have permission from Ei to operate as grid owners and to build power lines. [6]

The revenue framework calculates the revenue cap for the total amount that they may charge customers for a supervision period of four years, currently from 2016 to 2019. It derives from the fact that a part of Ei's task is to ensure that the electricity network fees to the consumers are reasonable, objective and non-discriminatory. Thus, Ei inspects the total revenues of every grid operator to make sure that the customer charge is not too high. [6] The revenue framework should cover the reasonable costs, meaning that it should reflect the actual costs needed to conduct business. [8] The different parts of the revenue framework are depicted in Figure 1. The total costs are divided in operating costs (e.g. costs for the electricity fee to the regional grid, maintenance, operation and maintenance) and capital costs (e.g. equipment and depreciation). The operating costs are made out of uncontrollable costs (e.g. grid losses, taxes, costs for the electricity fee to the regional grid) and controllable costs (e.g. staff and services, systems operations, maintenance, metering, billing and customer support). The controllable costs are subject to a general efficiency target to make it more cost efficient. The capital cost stems from a capital base where the return of capital and depreciation makes up the capital costs. The capital costs are adjusted for a quality incentive and are also adjusted for a newly introduced efficiency incentive described in 1.1.4 *Incentives for grid loss reduction*. The operating costs and capital costs are then adjusted for the previous supervisory periods over or under charge, and this leads to the allowed revenue, i.e. the revenue cap. [9] [10]

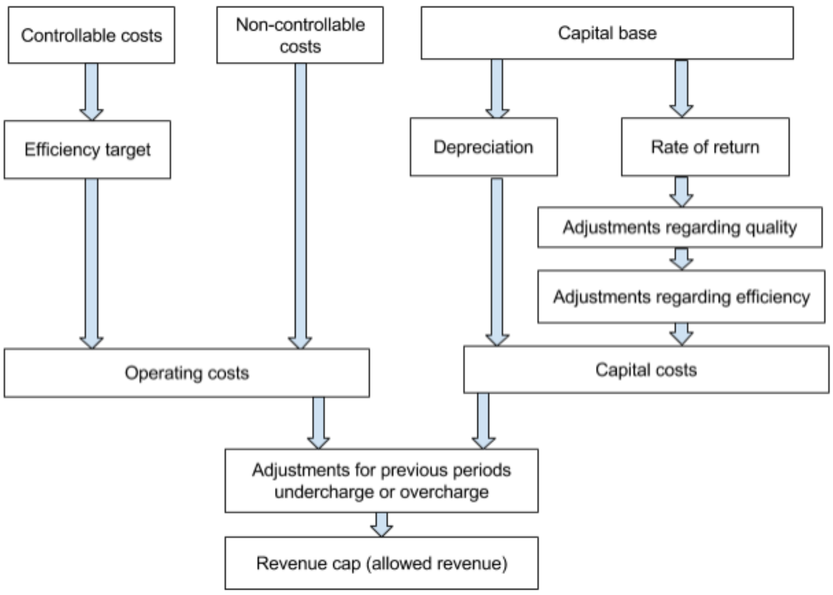

Figure 1: Schematic image of the revenue framework.

1.1.1.3 Electricity consumers

Electricity consumers in Sweden pays two separate electricity bills; one for electricity distribution to the grid company (see 1.1.3 *Tariffs* below) and one for the electricity consumed to the electricity trading company. The consumer may choose freely among the electricity trading companies, but not the grid company which is area specific. [11]

1.1.2 Power system structure

The power system can be viewed in a hierarchic structure. The first part of this structure is the production of electricity. The second part is when the electricity is transmitted through the transmission grid over long distances, for example between the northern parts of Sweden to the south part of Sweden. Transmission lines are normally between 400-220 kV, and are part of the national grid operated by Svenska Kraftnät. The third part of the structure is when the electricity is transformed from the high voltage level in the transmission grid to the regional grid, a voltage level of 135-40 kV [12] [13]. Regional grids are operated by grid companies, but it is only a few grid companies which operate both regional and distribution grids. The main actors operating the regional grid are three companies; Vattenfall, Eon and Ellevio (previously Fortum) [14]. The electricity is then transformed further into the distribution grid where the voltage level is below 40 kV. In the distribution grid, larger consumers such as industries may be connected at 10 or 20 kV and private persons are connected to the lower voltage level at 0.4 kV. See Figure 2 for a schematic picture of the system [12] [13].

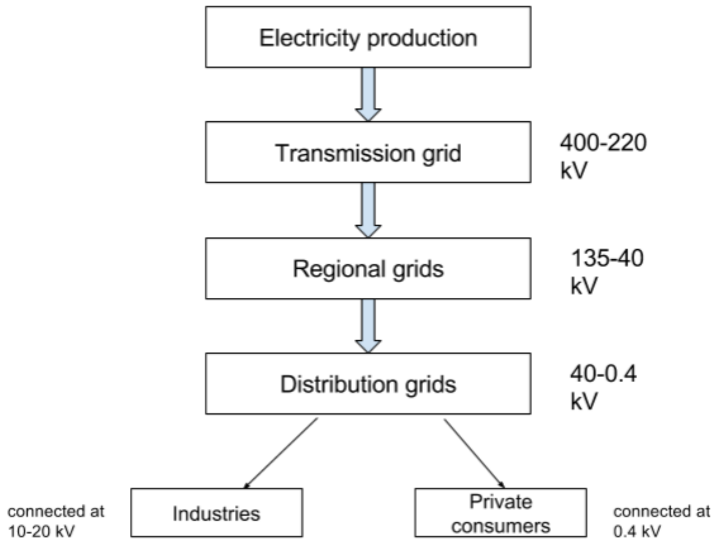

Figure 2: Schematic image of the power system structure.

1.1.3 Tariffs

A tariff is the customer subscription for being connected to the grid. There are different ways for the grid company to construct them, but they must follow the Swedish electricity act when constructing them. The electricity act states that the tariffs must be reasonable, objective and non-discriminatory. This means that the fees must only reflect the actual costs of the grid company and certain customer categories must not be favored at the expense of other customers. [15]

The most common tariff in Sweden for low voltage customers is a tariff based on fuse size. The typical structure of a tariff based on fuse size is a fixed fee per year (SEK/year) together with an energy fee (SEK/kWh). This cost structure promotes less energy use for the customers, but it does not provide any incentive regarding when the electricity is supposed to be used as long as the customer stays within its fuse size. [15] The fuse size tariff is an example of a uniform tariff, but tariffs can also be time-differentiated and can be based on energy (kWh) or power consumption (kW). A power tariff means that a part of the fee is based on the power consumption (SEK/kW), which provides incentives for reducing the load in the grid. If the power tariff is also time-differentiated, it means that the size of the power fee is different during peak or non-peak hours. This will provide even bigger incentives for load reduction during peak hours. [3]

The tariffs of Ulricehamns energi are mainly divided into two categories; fuse size tariffs for low voltage customers and power tariffs. The power tariffs are for the large electricity consumers in the grid (above 250 Amperes of fuse size), where two types are available called “Low voltage” and “High voltage”. In these tariffs, fixed fee, power fee, reactive power fee and time-differentiated energy fee are included. The fuse size tariffs are for the smaller consumers (16-200 Amperes, where 16-25 Amperes could be apartments or villas), where fixed fee and energy fee are included. [16] The smaller consumers of Ulricehamn do not have any incentives to reduce peak load in the grid, based on the above discussion.

1.1.4 Incentives for grid loss reduction

Ei defines electricity grid losses as the difference between how much electricity that is fed in to the grid and how much electricity that is consumed in the grid, where the grid losses are the losses which occur in the transfer. To achieve an effective use of the electricity grid, Ei has designed an incentive [3] based on reducing grid losses and peak demand, see “adjustments regarding efficiency in Figure 1. The overall purpose of this incentive together with another incentive to achieve quality improvements in the grid, are to drive the development towards smart grids. This is to be done by creating incentives for grid owners to choose intelligent cost effective grid solutions as alternatives to existing solutions. In the previous supervisory period, 2012-2015, the grid losses were treated as an “uncontrollable cost”, meaning that the grid company received coverage for the costs associated of increasing or decreasing grid losses. This meant that if the grid losses were reduced, so would the revenue cap. In the new supervisory period of 2016-2019, the grid losses are still treated as an “uncontrollable cost” but with the new incentive as an important difference. The same goes for the subscription for the regional grid, where a part of the cost is paid per MW to the regional grid owner for the incoming electricity to the distribution grid. If the peak loads were decreased in the supervisory period of 2012-2015, the revenue cap decreased as well. With the new incentive, if the peak loads in MW are reduced and thus also the cost to the regional grid owner (where the price is based per MW), a part of this saving is allowed to be kept. [3]

The idea regarding the incentive concerning the effective use of electricity grids is that if the grid of a grid company is operated in a way that contributes to an efficient use of it, it will lead to an increase in the revenue cap. The opposite also holds, meaning that if the grid is operated more inefficiently, it will lead to a decrease in the revenue cap. This is thus in contrast to what was done in the previous supervisory period. The increased or decreased efficiency is measured by comparing the grid owners own historical measurements of grid losses and peaks for 2010-2013, so the incentive measures improvements or deterioration with the grid owners. The maximum increase or decrease in the revenue cap is 5 % of the total revenue cap. However, the decrease may never exceed the rate of return of the capital base (see Figure 1), to avoid intruding on the reasonable cost. This means that in some cases, the yield of the capital base sets the limit of the decrease. [3]

There is an exception to the incentive regarding grid losses. Increased distributed generation in the grid, such as solar panels, may contribute to the increase of grid losses for a grid owner. On a system level it will reduce grid losses, but the situation is more complex for an individual grid owner. The exception states that if the grid owner increases the grid losses and receives a reduction in the revenue cap, the reduction can be reduced if the grid owner can prove that the increased losses stems from distributed generation. This exception is made so that the development of distributed generation in form of renewable energy is not hindered. [3]

The grid companies report aggregated customer consumption, production, electricity feed from the regional grid, and grid losses on a yearly basis to Ei and the load is reported to Svenska Kraftnät. The load indicator however, is reported to Ei. [3] The Ei always make plausibility checks when reviewing the data to check that everything is in order due to the fact that it concerns economic incentives [17].

In the report by Ei [3], suggestions for grid loss reduction methods are made. One of them is demand response/demand side management which aims to reduce and shift consumer load from peak hours to off-peak hours.

1.2 Problem description

1.2.1 Aim

The aim of the thesis is to investigate how much grid loss reduction can be achieved in an electricity distribution grid by using demand response and what the quantitative economic benefits are of reducing the losses.

1.2.2 Research questions

In order to achieve the aim of the report, the following research questions are to be answered:

- How much grid loss reduction can be achieved for an electricity distribution grid in Sweden when applying demand response?
- How much increase or decrease in the revenue cap will the incentive from the Swedish market inspectorate (Ei) regarding more efficient use of the electricity grid yield if demand response is applied?
- How much cost reduction for grid companies can be achieved by reducing the losses when applying demand response?
- How much cost reduction for grid companies can be achieved from the resulting load decrease when the losses are reduced when applying demand response?

1.3 Delimitations

The investigation is done with a case study approach where grid data from a grid owner in Sweden, namely Ulricehamns energi, are to be used. Therefore, it is to be said that there will be an uncertainty factor if the results of the study were to be used as an indicator for other grids in Sweden or internationally. The investigated method for reducing losses is demand response. There are other ways than demand response to reduce losses, but these methods will not be investigated in the thesis. When estimating the potential of demand response, the practical potential is used. This means that an estimation of how much load that can realistically be shifted or reduced from peak hours to off-peak hours is made. Thus, a theoretical potential is not assessed in this work.

Due to issues with the data quality, only a part of the grid will be analyzed. The results of this will then be scaled to the rest of the grid when evaluating the economic perspective of demand response. Furthermore, only line losses are considered when evaluating the grid losses.

There are both costs and benefits when implementing demand response. However, only the economic benefits stated in the research questions will be quantified. Also, only the perspective of the grid companies will be investigated, and not e.g. a consumer perspective.

1.4 Method

The main methodology of this project consists of sorting and handling consumption data and grid data from a grid owner in Sweden to make it applicable for power flow analysis where the grid losses can be calculated. First, a literature review together with interviews is performed to gain insight in the energy business in general, the incentive from the Ei, grid losses, demand response and demand side management and also power flow analysis. An analysis of the potential of demand response for the Ulricehamn grid is made in sections 2.4.3.2 *Potential of load reduction and shift for smaller consumers* and 2.4.3.3 *Potential of reduction and shift of larger consumers*.

This is used to create three cases which are analyzed in this report. First, a base case is created using the original consumption data to see what the losses are in a normal state. Second, two cases using demand response are analyzed. The first one is a conservative estimation of the potential of demand response and the second one is an optimistic estimation of the potential of demand response.

The sorting and handling of consumption data and grid data is necessary to extract the data needed from large data files and to verify its quality so that it could be used for the power flow analysis. This time consuming task is performed in Lavastorm [18], which is a “big data” analyzation program. When the data is extracted and sorted in the right manner, it is used in MATLAB for power flow analysis where the grid losses can be calculated.

1.5 Structure of report

The structure of the report is as follows. In section 2 *Theory*, the calculation procedure for the incentive is presented together with a section regarding grid losses and demand response and demand side management. In section 3 *Modeling of Local Distribution Grid for Loss Analysis*, the method of the work is presented. The results for three cases together with a sensitivity analysis are presented in section 4 *Results and Analysis*. The report is ended with a discussion in section 5 *Discussion* and an appendix in 8 *Appendix*.

2 Theory

The theory used in the report is presented in this section. The calculation procedure of the incentive, are presented first. Then, a section regarding grid losses is presented containing factors affecting losses, loss calculation methods and methods to achieve grid loss reduction. The section is ended with a deeper review and analysis regarding two of the grid loss reduction methods, namely demand response and demand side management.

2.1 Calculating the economic incentive by Ei

In section 1.1.4 *Incentives for grid loss reduction*, the incentive created by the Ei is introduced. In this section, the calculation method of the incentive is presented. The economic effect of the incentive is calculated by using two formulas, which regards grid losses and peak demand respectively. The first formula regarding grid losses is shown below which is obtained from [3].

$$Kn = \left(Nf_{norm} - Nf_{utfall}\right) * E_{utfall} * Pn * 0.5. \tag{1}$$

Kn is the increase or reduction in the revenue cap in SEK. Nf_{norm} is the percentage share of losses during the period 2010-2013 and Nf_{utfall} is the percentage share of the losses for the period 2016-2019. E_{utfall} is the amount of energy consumption in MWh in the grid for the period 2016-2019 and Pn is the electricity price per MWh based on an average for the energy market during 2016-2019. The factor 0.5 is due to the fact that half of the efficiency improvement is retained by the grid owners and half of the improvement is given to the customers (reducing customer cost by reducing the revenue cap compared to if the factor was 1 instead of 0.5). [3] For the part of the incentive regarding peak demand, when calculating the economic incentive the formula below is used,

$$Kb = Lf_{utfall} * B_{diff} * E_{utfall}. \tag{2}$$

Kb is the economic incentive with respect to the load and Lf_{utfall} is $\sum Lf_{dygn}/D_t$ where Lf_{dygn} is the daily load factor defined as P_{medel}/P_{max} (quota between the average load and the maximum load during a day) and D_t is the number of days during the period. B_{diff} is B_{norm}-B_{utfall} where B_{norm} and B_{utfall} are the cost for the regional grid divided by the consumer energy in MWh for the period 2010-2013 and 2016-2019 respectively. E_{utfall} is the consumer energy in MWh during the period 2016-2019.

2.2 Grid losses

In the Swedish distribution grids, the losses are usually between 3 and 6 % and only a few grid owners have losses up to 10 % according to Ei [3]. In this section, grid losses are presented through factors affecting losses, calculating losses, grid loss reduction and a section devoted to one of the grid loss reduction methods, namely demand response/demand side management.

2.2.1 Factors affecting losses

The losses in electricity grids can be divided into technical and non-technical losses.

Technical losses are load losses and no-load losses. The load losses occur due to the transfer of electricity in the grid where a part of it is dissipates as heat. [3] These losses are resistive in nature and proportional to the square of the current ($P_{loss} = I^2 * R$

where P_{loss} is power loss, I is current and R is resistance). They can occur in both cables and transformers [19]. No-load losses are iron core losses in transformers where the iron core of the transformer is magnetized and where the losses are constant if the voltage levels are constant (which is usually the case in an electricity grid, where the voltage only differ a few percentages) [20]. Transformers may constitute 25 % of the total losses in the grid where no-load losses stand for 75 % of that and the remaining 25 % are load losses [21].

Non-technical losses are maintenance energy, electricity theft, energy outputs without billing and electricity billing errors. Maintenance energy is energy that is used for the optimal function of grid components, e.g. cooling of a transformer or heating of a substation. Electricity theft can occur through illegal connections to the grid, i.e. if you are not a paying customer. Energy outputs which have no billing can be for example street lights or parking meters. Electricity billing errors can occur at for example measurement faults. [3] In this project, only the technical losses in cables are considered.

In Equation (3), the active power losses are further developed according to a standard pi-model of a cable in [22].

$$P_{loss} = \frac{P^2 + (Q - |V|^2 * \frac{B}{2})^2}{|V|^2} * R \tag{3}$$

where P_{loss} is the active power loss, P is the load active power, Q is the load reactive power, V is the load voltage and R is the cable resistance. B is the line susceptance [19] defined as

$$B = \omega * C. \tag{4}$$

ω is the rotational frequency and C is the cable capacitance. From Equations (3) and (4) it can thus be seen that the physical factors affecting the cable losses are active power, reactive power, supply voltage, impedance and cable length. The latter is due to the fact that the impedance increases with increasing cable length.

2.2.2 Methods and simplifications for loss calculation

There are different methods for calculating electricity grid losses, all with varying complexity. In a master thesis made by Eklund [23], a method for calculating losses as a first approximation was developed by using an equation from Shaw et al. [24] which can be seen below.

$$x_{loss-change} = \frac{\int P_A^2 dt - \int P_B^2 dt}{\int P_A^2 dt} \tag{5}$$

where $x_{loss-change}$ is the percentage change in load losses over a time-period t, and where the power flow changes from P_A to P_B in time period t. Eklund uses hourly data for the incoming electricity to a distribution grid together with the average losses in the grid and use that to create a 24 hour- load profile of the grid. Using this, the losses can be calculated according to Equation (5). The load profile is then adjusted for a suitable level of demand response to create a smoother profile with less load peaks, where the losses are calculated once again. Some simplifications are made when calculating losses according to this method [23]. The grid is assumed to be radial (meaning there is only one path in the distribution grid to the consumer), the load is assumed to be spread evenly through the grid and the effect of demand response is assumed to be equal in all lines in the grid. This method is suitable as a first base approximation of modeling grid losses and the effect of demand response. It does not consider the grid topology and the different impedances of the lines and neither reactive power. The method proposed by Eklund may be used when hourly consumption data is unavailable. Instead of the consumption data, Eklund used the incoming electricity to the grid and the average losses of the grid to create a load profile.

A more detailed approach to calculate losses is using power flow analysis, which is used to predict the operating state of a system given a certain known quantities. In that sense it can predict changes in the grid [19], e.g. a changed demand like the case with demand response. In power flow analysis, one must know quantities like grid topology, line impedance, active and reactive load & generation in the grid. To predict the operating state of a grid it uses an iterative procedure with a mathematical algorithm, since the power solution involves a set of nonlinear algebraic equations. [25] Two methods for solving nonlinear equations are the Gauss-Seidel method and Newton-Raphson method. The Gauss-Seidel method needs many iteration steps and with no guarantee for convergence. The Newton-Raphson method is the most commonly used method, and is a successive approximation procedure based on an initial estimate of unknown variables and Taylor series expansion. Newton-Raphson is mathematically better than Gauss-Seidel because it converges more rapidly than Gauss-Seidel, and is less inclined to diverge. [25] The drawback of using power flow analysis when computing losses in the grid is the additional information needed in the grid, and also the additional computational time compared to the above mentioned solution by Eklund. One way of increasing computational speed in the power flow analysis program is to use decoupled power flow solution. The idea is that real power is relatively insensitive to changes in the voltage magnitude and reactive power is relatively insensitive to changes in the phase angle, which leads to the approximation of ignoring their respective dependence. [25]

2.3 Grid loss reduction

Looking at the physical factors affecting grid losses in section 2.2.1 *Factors affecting losses*, many different factors affect the losses and thus there are several different measures to take in order to reduce losses.

Choosing more efficient cables or transformers is one way to mitigate losses [3]. For cables, this corresponds to reducing the impedance of the component. When installing more energy efficient transformers, it can reduce losses with 80 % during the whole lifetime of a transformer [21].

Another way of reducing grid losses is Volt/VAr optimization for reducing line losses and thus reducing losses in the grid. The method consists of controlling voltage and reactive power to an optimum level by using sensors, equipment and software in the grid. Volt/VAr optimization may reduce losses in the grid by 2-5 % according to the National Electrical Manufacturers Association in the United States. [26]

Reconfiguration of feeders and transformers in order to maximize load balance and reduce grid losses are also mitigation measures that can be taken. By opening and closing switches in the grid, the network topology can be changed which can reduce the losses by having a more balanced load in the grid. [27] Simulations of finding the optimal grid topology for distribution grids showed that a reduction of grid losses by 9.7 % could be achieved [28]. Transformers can also be re-located, where the goal is to achieve optimal loading of the transformers in the grid so that the losses can be reduced. A transformer which is too lightly loaded is inefficiently operated due to that the no-load losses are still the same as if they would be for higher loading. A too heavily loaded transformer has instead high load-losses. [29]

Distributed generation such as small-scale solar energy and wind energy plants may have a role in mitigating losses as well. If distributed generation is applied in a grid, it is likely that the power will travel shorter distances since the generation is closer to the consumption and in that case thus reducing losses. If the penetration level of distributed generation reaches a certain level however, it may increase the losses according to Méndez Quezada et al [30]. Méndez Quezada et al made simulations of distributed generation in an electricity grid, where it can be seen that solar photovoltaics with a penetration level of 2.5 % of the capacity of the grid decreases losses with 0.25 %. However for a penetration level of 15 %, it increases the losses with 4.5 %.

Demand response and demand side management can also be used to reduce losses. This is presented in the next section.

2.4 Demand response & demand side management

In this section, demand side management and demand response are presented as concepts, together with a literature review of the potential for affecting electricity consumption with these two measures. The section is ended with an analysis on what the potential for affecting the electricity consumption are in the Ulricehamn grid specifically.

2.4.1 Definition of demand response & demand side management

The idea with demand response and demand side management is to reduce or shift power demand during peak-demand hours to low consumption hours, and thereby gaining benefits e.g. loss reduction but also the deferral of the grid reinforcement. [10]

There is a difference between the two concepts demand side management (DSM) and demand response (DR) [31], [32]. DR is defined as "changes in electricity use by demand-side resources from their normal consumption patterns in response to changes in the price of electricity, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized" [31]. DR thus comprises of measures like hourly-based tariffs which provide price incentives for the consumers to change consumption patterns from expensive to cheap hours. It is called a reactive technology, since customers react on an incentive. DSM on the other hand, is a forcing technology where customers are contracted by the grid companies to control power consumption, e.g. controlling a consumer's heat pump and turning it off during certain hours when the consumption in the grid is high. DSM may also include certain parts of energy efficiency and DR elements within it. [32]

2.4.2 Demand response and demand side management potential

In this section, the potential of demand response and demand side management is discussed.

2.4.2.1 *Factors influencing the potential*

The potential of DR & DSM is dependent on a number of different factors. The geographical position is important when assessing it, since countries for example have different systems regarding tariffs; some countries may have the grid fee and electricity fee as two separate fees (like Sweden) and some countries may have the fees lumped together as one. In the latter case, a price incentive will have a bigger effect compared to a case where only the grid fee and not the electricity fee is hourly-based since the money to be saved is larger if the two fees are included and not just one. Another factor affecting the potential is the climate, since temperature affects how much load of the total amount that can be reduced or shifted. The electricity price naturally plays a role as well. Sweden has a relatively low electricity price which hinders the economic incentive that an hourly based tariff provides. [33]

There is also a significant difference between theoretical, economic and practical potential of DR and DSM. The theoretical potential consists of all the devices and components compatible of DSM and DR, the technical potential are those devices that can be controlled by existing infrastructure and economic potential are those that can be operated cost-efficiently. The practical potential is taking the customer attitude in to perspective, a mixture between economic potential and accepted use. [31] When assessing the theoretical potential, consideration is not taken to the consumers' willingness or understanding of the potential benefits to shift or reduce load. In cases when an hourly based tariff has been introduced to stimulate low consumption during peak hours, electricity consumers can be unaware of the fact that they have one, or their attitude regarding their own consumption might be that "it is too small to make a difference". In cases when the consumers are actively participating in shifting or reducing load, in Sweden, it is generally more common to do so for environmental reasons than for economic reasons since the electricity price is relatively low. [33]

When reviewing literature about DR and DSM it is also important to acknowledge the difference between the two concepts, as introducing only an hourly based tariff will not yield the same results as for example introducing the tariff together with controlling customer's heat pumps. The methodology of the studies is thus important when assessing the potential.

2.4.2.1 *Potential according to literature*

Due to previous mentioned reasons, the potential of DR and DSM varies in figures significantly between different studies. Bartusch & Alvehag [34] reports that a review in USA, Canada, Australia and the EU-15 countries showed that a time of use tariff can contribute to a 20-50 % drop in peak demand. The latter figure however included not only tariffs but also technology that could be turned off during peak hours. A review about the potential in Europe [35] studies the theoretical reduction potential of different processes (such as industrial processes, tertiary processes and residential processes e.g. refrigerators, washing machines etc.). The results showed a 9.4 % decrease of the peak load for Europe, where 42 % comes from residential applications, 31 % from the industry and 27 % from the tertiary sector. In Sweden the potential amounted to 10 % of reduction of peak load according to the study. Another study on the same topic shows about the same results, for Sweden a load reduction potential of 10 % can be achieved [31].

However as stated previously, the mentioned studies have only assessed theoretical potential and did not take customer attitudes into perspective. Studies based on real projects take this into account into greater extent. Bartusch & Alvehag [34] studied the long term effects on load reduction and load shifting after the implementation of a time of use tariff in Sollentuna, a Swedish small town. The study comprised of 6 years for single-family homes and 2 years of a pilot project consisting of two small groups living in condominium and rental apartments. The study showed an average reduction in household's peak demand of 9.3 % in the summer and 7.5 % in the winter caused by a shift in electricity consumption from peak to off-peak hours by 2.4 % in the summer and 0.2 % in winter. The difference between summer and winter in the results is due to the fact that there is a higher amount of energy consumption related to heating of houses during the winter, making the percentage share of reducible or shiftable load smaller in the winter. In this study, summer is defined as April to October and winter is defined as November to March. Another study made in Vallentuna consisted of a software, Ngenic, installed in each household and connected to the heat pumps. The software can regulate the heat pump in order to save energy, which is used to be able to shift load. The measurements showed that 10 kWh of heat load could be moved within 24 hours without comfort distortions [36]. 10 kWh heat load represents 2 kWh electricity, assuming a coefficient of performance of 5 for the heat pump.

2.4.3 Assumption of demand response potential in the Ulricehamn grid

Henrik Säwe at Ulriehamns Energi [37] believes that there will be more time differentiated tariffs in the foreseeable future, and that a scenario with Ulricehamns energi paying customers to control their load is unlikely. That is why only DR and not DSM is considered in this report. The scenario with implementing only DR can be resembled with introducing a time-differentiated tariff.

In this section the potential of DR in the Ulricehamn grid is assessed with a basis in what types of load there are in the grid and what kinds of customers there are in the grid. The section is ended with a short summary of the potentials in percentage to be used further in the report.

2.4.3.1 Types of load in the grid

When assessing the potential in the Ulricehamn grid in this report, the practical potential is referred to and not the theoretical potential. What types of loads there are in the grid is essential in determining an estimation of the potential. The types of loads can be roughly estimated by looking at what types of customers exist in the grid, i.e. looking at what kind of grid tariff they have, see section 1.1.3 *Tariffs* for further explanation about the tariffs. Customers with small fuse sizes of 16-25 Amperes [A] have a relatively low consumption and can be expected to live in apartments or houses, and customers from 35-200 Amperes along with the even bigger consumers who have power tariffs can be expected to be anything from larger stores to workshops and industries. To give a rough idea about the consumption distribution for different fuse sizes in the Ulricehamn grid for a year, Table 1 can be seen below where the figures are retrieved from an interview with Henrik Säwe at Ulricehamns Energi [37]. LSP and HSP are power tariffs for low voltage customers and high voltage customers, see section 1.1.3 *Tariffs* for further explanation.

Table 1: Electricity consumption of different fuse sizes (low voltage consumers only) together with power tariffs for low voltage (LSP) and high voltage (HSP) in the Ulricehamn grid during a year.

Fuse sizes	16-25 A	35-63 A	80-200 A	LSP	HSP
Consumption [GWh] 2015	66	12	14	22	62

It can be seen that the consumption of customers in 16-25 A (roughly corresponding to apartments and villas) is approximately half the summarized consumption of the rest. However, due to issues with the hourly measurement data for electricity consumption (see section 3.1 *Description of network and data*), the analysis had to be narrowed to 4 substations and their respective consumers (see section 3.2 *Sorting the data*). The summarized electricity consumption of these with regard to different tariffs is shown below. The figures are retrieved by using Lavastorm [18] (see section 3.2 *Sorting the data*). It can be seen that no LSP and HSP tariffs exist in the grid, and a large proportion of the consumption comes from smaller consumers.

Table 2: Electricity consumption of different fuse sizes for the chosen substations in the Ulricehamn grid during a year.

Fuse sizes	16-25 A	35-63 A	80-200 A
Consumption [GWh] 2015	6.6	0.6	0.5

In the two next sections, the potential of DR is analyzed for smaller consumers and larger consumers respectively. To enhance the readability, a summation of the decided load shift and load reduction is located below in Table 3 after these sections.

2.4.3.2 Potential of load reduction and shift for smaller consumers

As for the 16-25 A customers; the customers with that fuse size (mostly corresponding to residential buildings) are most likely going to both reduce their electricity consumption and shift it somewhat. For example, in a study made by Bartusch et al [38] it could be seen that consumers responded to time of use tariffs by both adjusting their consumption to cheaper hours but also investing in new, more efficient equipment. The latter would suggest that a load reduction could be achieved as well.

As the previously mentioned studies in Sollentuna [34] and Vallentuna [36] are based on real life cases under Swedish conditions, they will be used as a starting point for estimating the potential of DR and DSM. The question is in what way the consumers will be able to reduce or change their electricity use. Apartment consumers are usually only able to change their consumption pattern for the household electricity. This is because the heating of the building is managed by the housekeeper or landlord, and the building is most commonly connected to the district heating grid. As for villas however, the consumer are often in control of the heating. Electrical heating is most common [39] where the heating of the house is often done by heat pumps. This enables a bigger potential for reducing or shifting load.

The study from Bartusch & Alvehag [34] observed a shift of load from peak to off-peak hours of 2.4 % and 0.2 % in summer and winter respectively. These numbers are based on single-family homes whilst the study reported a bit lower numbers concerning apartments. In the study, the only factor for reducing and shifting load was a time of use tariff, so the study did not include any installation of equipment for controlling heat pumps for example. However, that does not hinder consumers from installing new and more energy efficient equipment by their own initiative. The grid of Ulricehamn is connected with both villas and apartments (where the potential was reported a bit lower for apartments [34]), and the study did not include any other measures apart from a time-differentiated tariff. Due to this, a conservative estimation of DR for this report is a shift from peak to off-peak by 1.9 % and 0 % for winter and summer respectively, and without any load reductions. This is based on the numbers of Bartusch & Alvehag, but a bit lower than that due to the conservative nature of the estimation.

The periods for winter and summer is chosen to be the same as Bartusch & Alvehag [34], namely April to October for summer and November to March for winter.

An optimistic estimation of the potential would contain measures like installing new heat pumps or installing equipment like Ngenic; a software and equipment which can control the heat pumps into being more energy efficient [40]. With being able to control heat pumps, the load from the heat pump can be shifted to an hour where it is cheaper to consume. According to [36], 10 kWh heat per day during winter time could be shifted with this measure, which for a coefficient of performance of 5 would mean that 2 kWh of electricity can be shifted. The daily electricity use for households is roughly around 48 kWh per day [41], so a shift of 2 kWh corresponds to 4 %. Adding this potential to the case where only time of use tariffs were implemented in Bartusch & Alvehag [34], shifting the load can go from 0.2 % to 4.2 % in the winter. In the optimistic scenario for the summer case, 2.4 % load shift are used according to the study of Bartusch & Alvehag [34], this time not considering the fact that the figure are based on villas and not considering apartments (which have a bit lower potential according to the study) due to the optimistic approach.

The total energy saving by controlling the heat pump through Ngenic was found to be 10-15 % [36]. The heat need for an average house is 20 000 kWh per year [42], which is 55 kWh per day. The energy saving through Ngenic is 10 %, which is 5.5 kWh per day. With a coefficient of performance of 5, it corresponds to electricity savings by approximately 1 kWh per day. This is 2 % of the total electricity use per day. This is just one measure that can be taken to reduce load, other measures like installing more efficient heat pumps or freezers can be taken. If a new heat pump is installed, improving the coefficient of performance from 3 to 5 and with a heat need of 55 kWh per day, it will reduce electricity consumption by roughly 3 %. New refrigerators and freezers can roughly decrease the energy consumption by half, with energy savings of approximately 750 kWh per year [43]. This corresponds to an electricity use of 150 kWh per year, and 0.41 kWh per day with a coefficient of performance of 5. With the total electricity use being 48 kWh, the electricity saves amounts to roughly 1 %. In an optimistic scenario, reduction of load is included and when summing up the potential energy saving (with measures like Ngenic, more efficient heat pumps and freezers) it is chosen to be 6 % in the summer and winter.

2.4.3.3 Potential of reduction and shift of larger consumers

The interest of being flexible in the electricity consumption amongst consumers within industry, real estate and service seems to be rather low. A survey made by Sweco and Ei [44], asked if it was technically possible to be flexible in the electricity use, and 78 % to 55 % of the above mentioned categories answered “No and not in the foreseeable future". When asked the question "In which ways are you intending to use your flexibility in electricity usage?" roughly around half of the answers were "We have no intention of using our flexibility". 5-17 % answered that their consumption will be hourly measured with flexible price and that they will adjust their consumption based on the price. 9-30 percent did not answer the question. These result needs to be put in the light of the fact that the survey also came to the conclusion that the knowledge of the possibilities with flexible electricity consumption are rather low. Nevertheless, the potential of DR or DSM seems to be quite low for bigger consumers in the Swedish market, even though the *theoretical* potential is higher based on the discussion in the previous section.

If the analysis of grid losses with demand response were to be made on the entire Ulricehamn grid, these findings would probably mean that consumers with larger tariffs than 25 A would get reduced potentials of demand response compared to smaller consumers. However, the analysis is to be made for the case where only a part of the grid is taken into consideration. In this part of the grid, the amount of larger consumers is significantly smaller than for the entire grid. Therefore, the potential of the larger consumers are estimated to the same amount as the smaller consumers for reasons of simplicity.

To summarize, the estimations of the potential of demand response used in this report can be seen below in Table 3 where the same numbers are used for both smaller and larger consumers.

Table 3: Summation of scenarios for estimating potential of Demand Response. The potentials are used for both smaller and larger consumers. The table is read according to the following: first, different components of the potential load shift and load reduction are accounted for. These ones together add up to the total load shift and load reduction potential which can be seen at the bottom of the table.

	Optimistic estimation		**Conservative estimation**		**Comment:**
Component:	**Summer**	**Winter**	**Summer**	**Winter**	
Load shift, conservative case			1.9 %	0 %	[34] had 2.4 % & 0.2 % for villas, but this case contains both villas & apartments
Load shift in winter, optimistic case		4.2 %			Ngenic heat pump control (4 %), +0.2 % according to [34]
Shift in summer, optimistic case	2.4 %				According to [34]
Load reduction, optimistic case	2 %	2 %			Ngenic heat pump energy savings
Load reduction, optimistic case	3 %	3 %			More efficient heat pumps
Load reduction, optimistic case	1 %	1 %			More efficient freezer
Total:	**Summer**	**Winter**	**Summer**	**Winter**	
Load reduction	6 %	6 %	0 %	0 %	2+3+1=6 %
Load shift %	2.4 %	4.2 %	1.9 %	0 %	

3 Modeling of Local Distribution Grid for Loss Analysis

In this section, the method of the work is presented. A description of the network and data are provided together with the general procedure on how the data was sorted and handled in order to calculate the losses. After this, the loss calculation procedure is presented. The section is ended with how the modeling of demand response was performed and how the calculation of the economic incentive was done.

3.1 Description of network and data

The Ulricehamn grid hosts approximately 8000 consumers who consume 181 GWh per year, and 17 producers producing 640 MWh per year. The load profile for the period 1 April 2015 to 30 March 2016 for the grid can be seen in Figure 3, where the incoming electricity to the distribution grid (from the regional grid) is depicted together with the consumer load with subtracted consumer production.

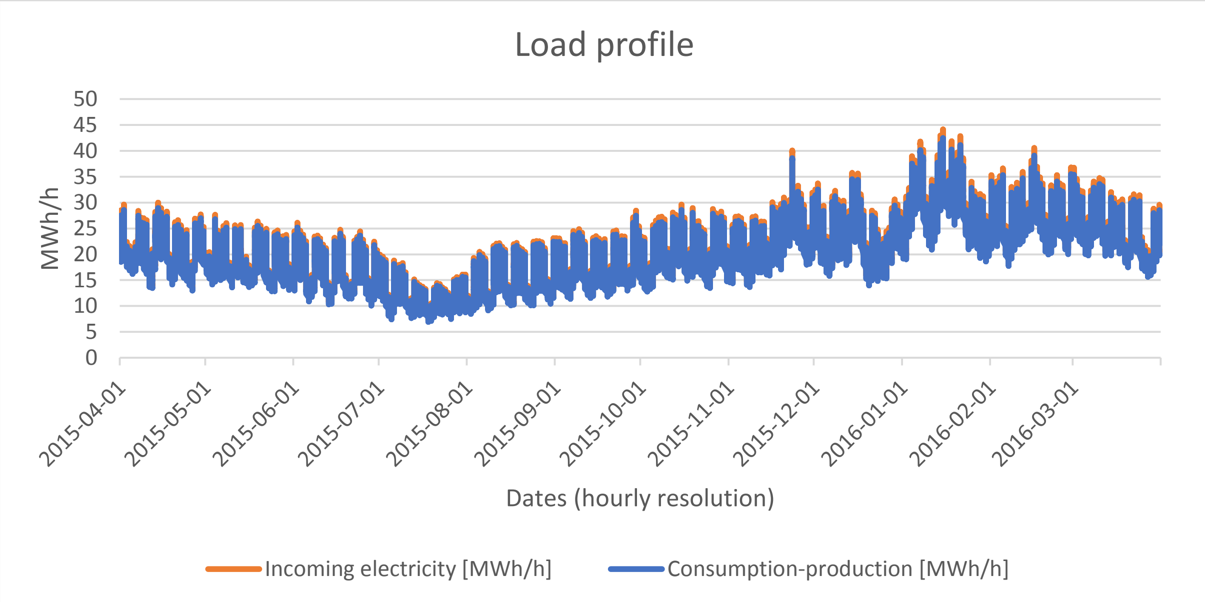

Figure 3: Load profile of the Ulricehamn grid, where the incoming electricity to the grid can be seen together with the consumption minus production.

The data received from the Ulricehamn grid was on hourly resolution, both for consumption data, production data, substation flow and flow from the regional grid. Reactive power (MVAr per hour) was received for some larger consumers, but not for smaller consumers. Active energy (MWh) was received however, for all types of consumers. The period of analysis was from April 2015 to April 2016.

There was however some quality deficits in the data. Hourly measurements from customers were sometimes missing. There were also cases where one consumer could have two reported consumptions for each hour instead of one. Another deficit was that even though the measurements were in hourly resolution, the resolution of the actual values reported from the meters was in many cases low. A lot of the measurement data were reported in full integers without decimals which lead to measurement errors if for example the actual value is 1.4 kWh and the reported value is 1. It seems that the decimal is saved to the next hour, so that if the next hour has the actual value of 0.6 kWh, it is reported as 1 (0.4+0.6=1). This error will be smaller with increasing number of measurements, as errors may then counteract each other. The substation measurements had decimal numbers reported. However, it seemed that there were missing measurements or too small values reported for the substation flow in the distribution grid, as can be seen in Figure 4 below. The figure shows the aggregated flow of all the low voltage substations with connected consumers in the distribution grid, compared with the net load of the low voltage consumers (consumption minus production). It can be seen that the "consumption minus production" is bigger than the substation flow, generating negative losses which is physically impossible.

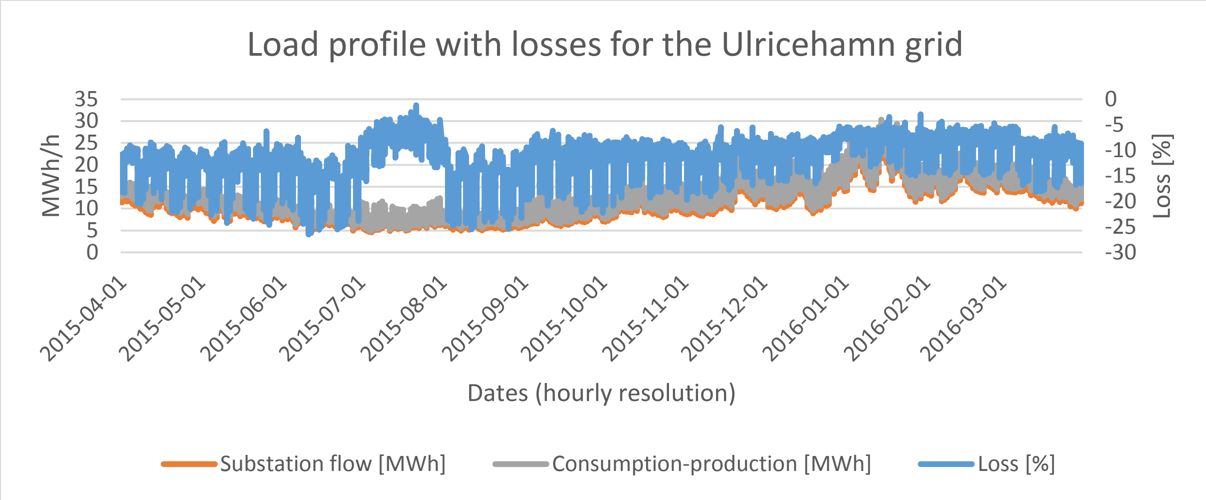

Figure 4: Load profile of the total yearly consumption minus production in the grid together with the substation flow and losses.

In Table 4, a summary of these issues is shown. A discussion on the reasons behind these issues can be seen in section 5.1 *Data quality*.

Table 4: Summary of the issues regarding the measurement data. Note that the comments are based on the data for the entire grid and not only the chosen substations.

Type of data	Issue	Comment
Consumption data	Measurement resolution	Measurements displayed only in integers without decimals
Consumption data	Missing hourly values	362 consumers of 8000 show this behavior, totally 1.5*10^6 h missing out of 75*10^6 h
Consumption data	Multiple hourly values for a customer at a given hour	12 consumers show this behavior, in a total of 3900 h out of 74*10^6 h
Substation flow	Missing hourly values or too small values	36 substations show this behavior, totally 1.5*10^5 h missing out of 2.7*10^7 h
Substation flow	Missing substations	There are 308 substations with measurement data, but total number of substations in the grid is around 350-370
Cable information	Missing cable information	64 of 275 cables are missing information about resistance or inductance.

When matching each substation to its consumers with the associated consumption measurements, these issues led to unreliable results, meaning negative losses or unreasonably high losses in some cases. Below in Figure 5 an example of this is shown, depicting substation T001 with its substation flow together with the associated "consumption minus production" for the month of July.

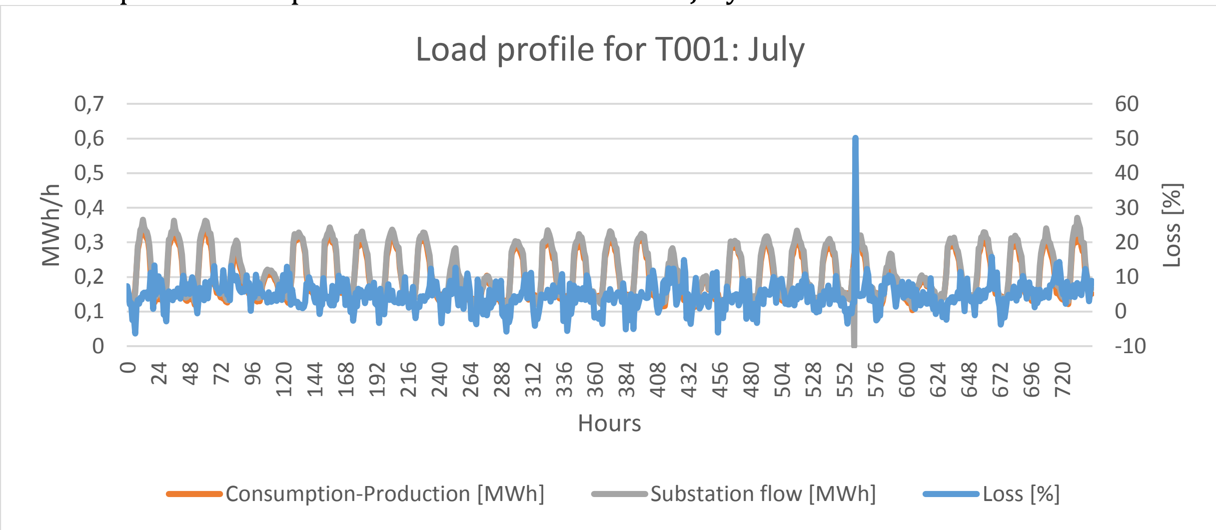

Figure 5: Load profile together with losses of substation T001 for the month of July.

These issues and unreliable results led to changes in the data selection, where instead of calculating the losses of the entire Ulricehamn grid, a smaller selection of substations where chosen. Before choosing which substations to use for the analysis, a conversion from hourly values during a day to "time periods" was done. This was done to aggregate the consumption data so that the "measurement resolution" issue stated in Table 4 could be somewhat resolved. The time periods were chosen to be 8 hour long, where the first time period ranges from hour 0-8, the second from 8-16 and the third from 16-24. After this a selection of substations were done according to the following procedure:

1. Identifying substations with no time periods with negative losses.
2. Of those, identifying the substations with total losses below 4 percent where the figure of 4 was based on the fact that the entire grid had losses of approximately 3-4 %.
3. Of those, choosing substations with not too much missing consumption data (the limit was if there were more than 2 months with occurrences of consumers with missing data), and also choosing an appropriate number of substations to reduce computational time.

The total number of consumers used for the analysis was 188 with no producers. Two of the substations were situated in rural areas and the other two were situated in the city. Information about the substations can be seen in Table 5.

Table 5: Description of the substations included in the analysis.

Name	City/Rural	Number of consumers	Number of producers	Voltage levels [V]
T7120	Rural	5	0	10500/400
T4020	Rural	48	0	10250/400
T011	City	98	0	10500/400
T075	City	37	0	10500/400

The load profile for the chosen substations can be seen below in Figure 6, where the aggregated consumer load for the chosen substations is depicted.

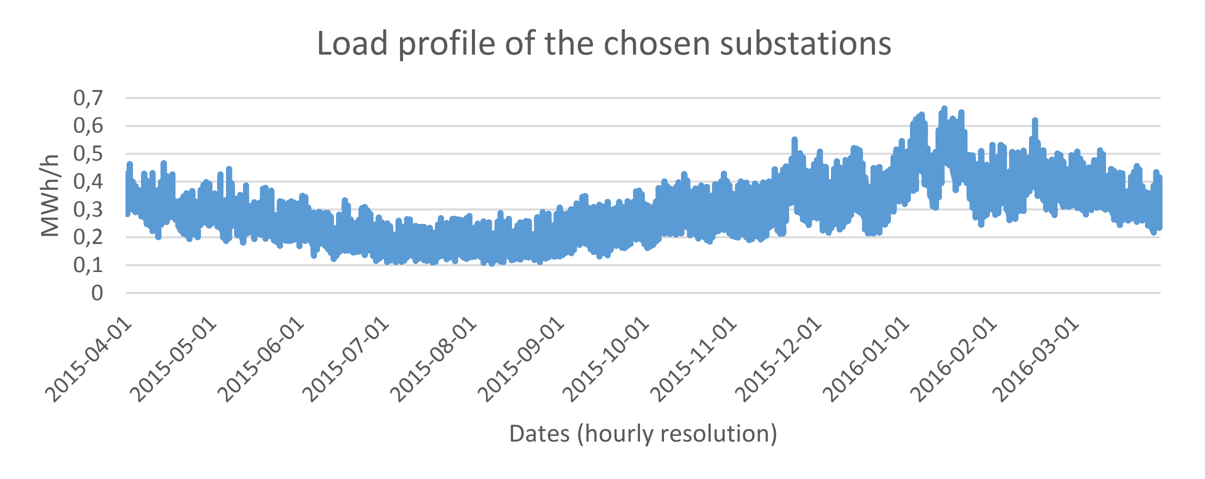

Figure 6: Load profile over the chosen substations.

3.2 Sorting the data

The data received from Ulricehamns Energi came in Microsoft Access files, which is similar to Microsoft Excel but capable of handling larger data samples. In Table 6 a summary of the files used in project can be seen and for what purpose they were used.

Table 6: Summary of the files used in the project.

File name	Content relevant to the project
ANLAB	Consumer information: facility ID, what tariff & connection point in the grid.
ANLSEK	Cable information: "connection point from", "connection point to", under which substation the cable existed, cable length, cable type, cable diameter etc.
TYPLED	Cable information: Depending on what cable type and cable diameter; resistance, inductance & operating capacitance.
Timdata	Hourly measurements of active energy [MWh] for every facility ID.
Producenter	A list of producers in the grid with producer ID, connection point in the grid and under what substation in the grid.
Nätstationer	Hourly measurements of active energy [MWh] for the substations in the grid.

The files shown in Table 6 needed processing to extract the information needed for the calculations. The goal with this part of the process was to: 1) filter the information needed from the unnecessary information and handling "issues" in the data (see Table 4) in order for the calculation program to work; 2) match consumers with their respective consumption and sort them under the right substation to get an overview of how reasonable the data is; 3) extract necessary information needed for the calculation procedure, e.g. representing the grid structure by using "connection point from" and "connection point to" in ANLSEK, coupled with the cable information.

The program used in this project to do this is called Lavastorm [18] which is a software designed to analyze large samples of data. With it, the user can acquire files from e.g. Microsoft Excel or comma-separated text files, and then process it by using programmable "nodes" with specialized functionality, e.g. filter nodes for filtering data and aggregation nodes for aggregating data in a certain way. In Figure 7, an example of the program interface is shown. By doing this, the grid network model could be generated, displayed by rows with bus connections, "bus connecting from" and "bus connecting to", together with the admittance matrix for the system. This was used in the loss calculation-script, see section 3.3 *Calculation of losses*.

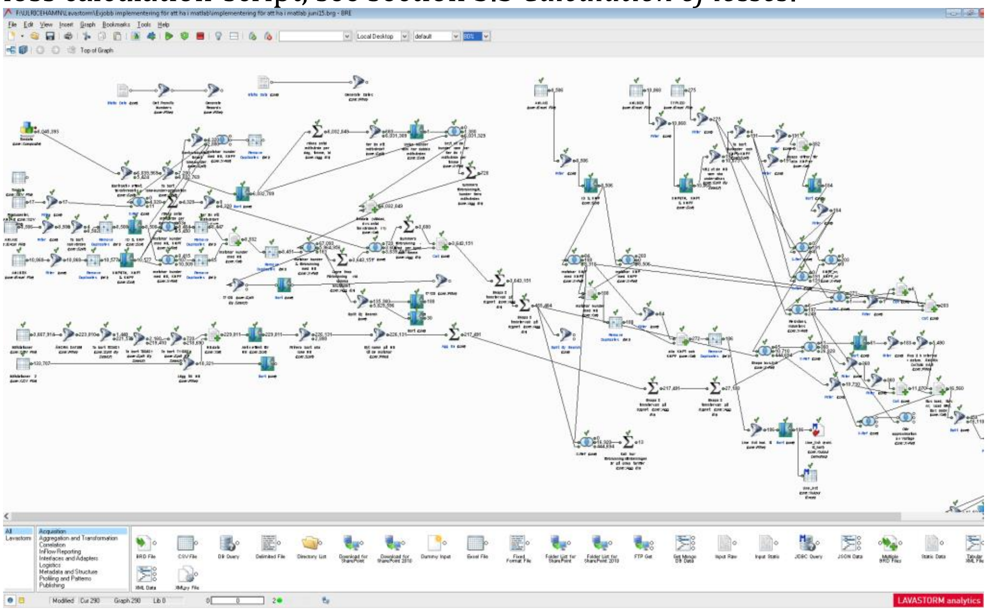

Figure 7: Example of program interface in Lavastorm.

This procedure could not have been done in Microsoft Excel since the maximum number of rows in Microsoft Excel 2013 is approximately $1*10^6$. The hourly measurement data for this project was $6*10^6$ rows for one month. Microsoft Access could have handled the large amount of data, but not with the same interface as Lavastorm which provide a useful overview of the problem. That is why Lavastorm was chosen as the program to be used for this part of the project.

A detailed list of the measures taken in Lavastorm to extract the information needed can be found in 8 *Appendix*.

Two measures that were taken which are worth mentioning are how the missing cable information and the missing hourly measurements (see Table 4) were handled. The missing cable information was added manually with the help of a cable handbook [45]. The missing hourly data was avoided to a great extent by limiting the data selection to only four substations, but in substation T4020, 52 time periods corresponding to 156 h were missing for the whole year. For the calculation program to function, it was necessary to add the load of the consumer manually. This was done by setting the load to 0 for the time periods missing. Note that the missing hours might not be an "issue" in the sense that there was consumption taking place without it being measured. It might be that the measurement was not in place due to natural reasons, such as if a customer was not connected to the grid for a period of time.

3.3 Calculation of losses

To calculate losses in this project, a MATLAB-script was used, written by Saadat, author of the book "Power System Analysis" (see [25]). The script uses power flow analysis to compute the phase angle and voltage magnitude of each bus and power flow of each line.

The power flow script uses the Newton-Raphson method. The line losses are calculated by summing the complex power flow from bus i to bus j with the complex power flow from bus j to i, according to

$$S_{Lij} = S_{ij} + S_{ji}. \tag{6}$$

S_{Lij} denotes the complex power line loss in line i to j, and S denotes the complex power flowing in the line. [25]

The script from Saadat was reconstructed slightly to make it run for a month at a time instead of an hour at a time.

The active load in Lavastorm were given in MWh but were converted to kWh in MATLAB. In MATLAB the kWh had to be converted to kWh/h as well. The inputs were in time periods containing 8 hours in each period, so to convert from kWh to kWh/h, a division by 8 was performed. The voltage magnitude, resistance and reactance were to be given in p.u. (per unit). The voltage reference was chosen to be 0.4 kV since the chosen substations have a voltage level of 0.4 kV on the downside. The base impedance was calculated by using the voltage reference and the base power, set to 0.1 MVA, according to

$$Z_{base} = \frac{V_{ref}^2}{S_{base}}. \tag{7}$$

Z_{base} is the base impedance, V_{ref} is the reference voltage and S_{base} is the base power. The impedance in p.u., Z_{pu}, was given by dividing the impedance Z with the base impedance, Z_{base}, according to $Z_{pu} = Z/Z_{base}$. The resistance in p.u. is the real part of the impedance in p.u., and reactance in p.u. is the imaginary part of the impedance in p.u. The line susceptance, B, is defined as the imaginary part of the inverse of the impedance, $B = im(\frac{1}{Z})$ and also as stated in Equation (4). The line susceptance in p.u., B_{pu}, was calculated according to

$$B_{pu} = im(1/(Z/Z_{base}) = im(Z_{base}/Z) = Z_{base}/(1/(\omega * C)) = Z_{base} * \omega * C = Z_{base} * 2\pi * f * C * l \tag{8}$$

where f is the frequency in Hertz set to 50 in this case and l is the cable length in km. When modeling the system, the four substations with their respective underlying connections to the consumers were treated as separate systems, meaning that the model did not account for any possible connections between the substations. This means that each of these substations could have an assigned slack bus. The slack bus for each system was chosen to be the substation itself. Since the chosen substations have a voltage level equal to the reference voltage, the voltage magnitude for the slack buses was set to 1 p.u. The phase angles for these slack buses were set to 0 degrees as a reference.

All the other buses except the slack buses were set as load buses. When no consumption was present in the buses, the load was set to zero. The initial voltage magnitudes were set to 1 p.u., and the initial angles were set to 0. Since production in the grid did not exist, the generation was set to zero and the reactive generation minimum and maximum was set to zero. Shunt capacitors were not considered in the grid so the injected MVAr of shunt capacitors was set to zero.

The power factor angle was set based on recommendations [46] to 20 degrees which corresponds to a power factor of approximately 0.93. Reactive power was not available as measurements for the chosen substations and its consumers. This had to be calculated through the relation between active power, reactive power and the power factor angle according to

$$Reactive\ power = active\ power * \tan(power\ factor\ angle). \tag{9}$$

3.4 Modeling of demand and demand response

The purpose of modeling demand response was to reduce peak demands and network losses. One way of doing this would be to simply reduce the load of e.g. time period 1 (from 8 o'clock to 16 o'clock) of each day by a certain percentage and distribute that to the other two time periods. However, this would mean creating another peak at one of the other time periods, and depending on the size of the difference between the time periods, the new peak could be of the same magnitude as well resulting in an almost unchanged situation. Thus, an approach involving the intuitive idea of load shifting, where a certain load is simply moved from peak hours to off-peak hours, was assessed not to be useful. That is why the modeling of demand response was performed based on a procedure made by Grahn [47] where the end result is a smoother load profile than before with peak demand. Depending on the period of the year, i.e. summer or winter, a load reduction and/or a load shift were performed (see Table 3 for exact percentage shares). The following steps were taken:

1. If a load reduction was to be performed: A percentage share, determined by the decided load reduction in Table 3, was multiplied to the active power of each consumer in each time period of the day. For example, if the load reduction was 6 %, then 0.94 was multiplied with the active power.
2. If a load shift was to be performed (after step 1): The percentage shift in Table 3 multiplied with the active power in Step 1 were subtracted from the active power in Step 1 of each consumer in each time period of the day. For example, if the load shift was 1.9 % and the active load 10 kW, the equation became 10-10*0.019.
3. An average of the amount of subtraction for each day made in Step 2 was calculated.
4. The average was then added to the active power calculated in Step 2 in each time period of that day. For example, if the average subtraction in Step 3 was 0.1 kW, then the example from Step 2 became 10-10*0.019+0.1.
5. A new reactive power was calculated for each time period of the day based on the new active power values in Step 4, according to Equation (9).

A fictive example of a load profile with three time periods before and after a load shift using the above steps can be seen below in Figure 8. Note that a load shift of e.g. 20 % using the method described above is not the same as when simply moving 20 % of load from one time period to the other. If the peak period has a load of e.g. 200 kW, simply moving 20 % of that period to another would result in 160 kW (200*0.8) for that period. This is not the case for the example below, where the method developed by Grahn was used.

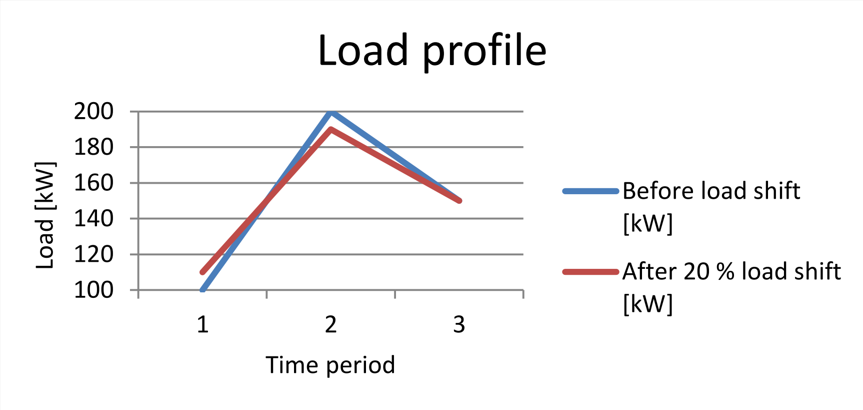

Figure 8: A fictive example of a load profile before and after load shifting with 20 %, using the method developed by Elin Grahn [47] which is used in this project.

3.5 Calculating economic benefits

When calculating the economic incentive (see section 1.1.4 *Incentives for grid loss reduction*), it was calculated in the following way. Since the analysis for this project only considered four substations and not the entire grid, the percentage results of those substations (i.e. grid losses etc.) were used for the entire grid to be able to calculate the economic incentive. Note that when using Equation (1) and (2) in section 1.1.4 *Incentives for grid loss reduction*, the economic incentive is calculated for the year analyzed in this project, April 2015-April 2016, instead of the period 2016-2019 which the equations are intended to be used for by the Ei.

When calculating the incentive regarding grid losses, see Equation (1), data from the Ei [48] was used for the percentage losses of 2010-2013, N_{fnorm}. The price for grid losses, P_n, was chosen to be 500 SEK/MWh. This was based on Ulricehamns energi costs for grid losses [49] and their actual grid losses in MWh [49] for the years 2010-2014. The percentage losses for current period, $N_{futfall}$, were for the base case calculated using Lavastorm, where the incoming electricity to the grid and the consumption and production were aggregated for each hour during the year. When the cases of DR were to be economically evaluated, the results for the chosen substations had to be used when deciding $N_{futfall}$. The percentage change in losses for the DR cases compared to the base case, were used when calculating the economic incentive of the DR cases. Thus, it was assumed that the percentage change in losses when using DR on the four substations were the same as if DR were to be applied for the entire grid. The energy consumption in the grid, E_{utfall}, was calculated using Lavastorm where the load in the entire grid was aggregated for the year. This number was used for the base case and the DR conservative case (where no load reduction was performed). For the DR optimistic case where a load reduction of 6 % was performed, E_{utfall} was multiplied with 0.94. The values used when calculating the economic grid loss incentive can be seen below in Table 7.

Table 7: Values used for calculating the economic incentive regarding grid losses.

Case:	N_{fnorm}	$N_{futfall}$	E_{utfall}	P_n
Base case	3.74 %	3.58 %	181 000 MWh	500 SEK/MWh
DR, conservative case	3.74 %	3.56 %	181 000 MWh	500 SEK/MWh
DR, optimistic case	3.74 %	3.11 %	171 000 MWh	500 SEK/MWh

When calculating the incentive regarding load, see Equation (2), data from Ulricehamns energi regarding the cost for the electricity from the regional grid was used. B_{norm} was obtained from data from Ei [48]. For the base case, the cost for the electricity from the regional grid was summarized for the period April 2015-April 2016. This was divided with the energy consumption for the period (E_{utfall}), thus creating B_{utfall}. The cost to the regional grid consists of fixed cost [SEK], power cost [SEK/MW] and energy cost [SEK/MWh]. For the optimistic case of DR, the energy cost was reduced with a factor 0.94 due to the load reduction of 6 %. The power cost was also reduced by a quota between the maximum power [kW/time period] for the DR optimistic case (523 kW) and the base case (623 kW), giving 523/623. For the conservative case, no change was necessary in the cost, since there were no load reduction and also no load shift during the winter (where the peak load occurs). The load factor, Lf_{dygn}, was calculated by dividing the average load [kW] for a day with the maximum load [kW]. An average of these was calculated, giving Lf_{utfall}. The values used when calculating the economic load incentive can be seen below in Table 8. The negative sign of B_{diff} means that the fee to the regional grid increases for the investigated period compared to 2010-2013.

Table 8: Values used for calculating the economic incentive regarding load.

Cases:	Lf_{utfall}	B_{norm}	B_{utfall}	B_{diff}	E_{utfall}
Base case	0.878	89.48 SEK/MWh	91.78 SEK/MWh	89.48-91.78=-2.3 SEK/MWh	181 486 MWh
DR conservative case	0.879	89.48 SEK/MWh	91.78 SEK/MWh	89.48-91.78=-2.3 SEK/MWh	181 486 MWh
DR optimistic case	0.882	89.48 SEK/MWh	91.87 SEK/MWh	89.48-91.87=-2.39 SEK/MWh	170 597 MWh

Apart from the incentive, there is an achievable cost reduction when reducing losses, which comprises of the reduced cost to the regional grid and the reduced cost for losses. The costs for the regional grid was calculated in the same way as described above, namely by scaling the energy cost and power cost with appropriate constants corresponding to the reductions when DR was applied. For the cost reduction of losses, the reduction of losses in energy [MWh] was multiplied with the price of losses, set to the same number as above, 500 SEK/MWh. However, these cost reductions may not lead to an economic benefit for the grid company. This is due to the fact that the revenue cap may decrease as well. See section 4.3 *Analysis of the economic benefits* for a full explanation.

4 Results and Analysis

The results of the three cases are presented in this section. This includes results for the Base case and the two scenarios of demand response, namely the conservative case and the optimistic case. The section continues with an analysis of the economic benefits of demand response and is ended with a sensitivity analysis of the load shift and power factor.

4.1 Base case

In the base case, the losses are calculated without demand response according to section 3.3. The total load and the corresponding calculated losses for the measured year can be seen below in Figure 9.

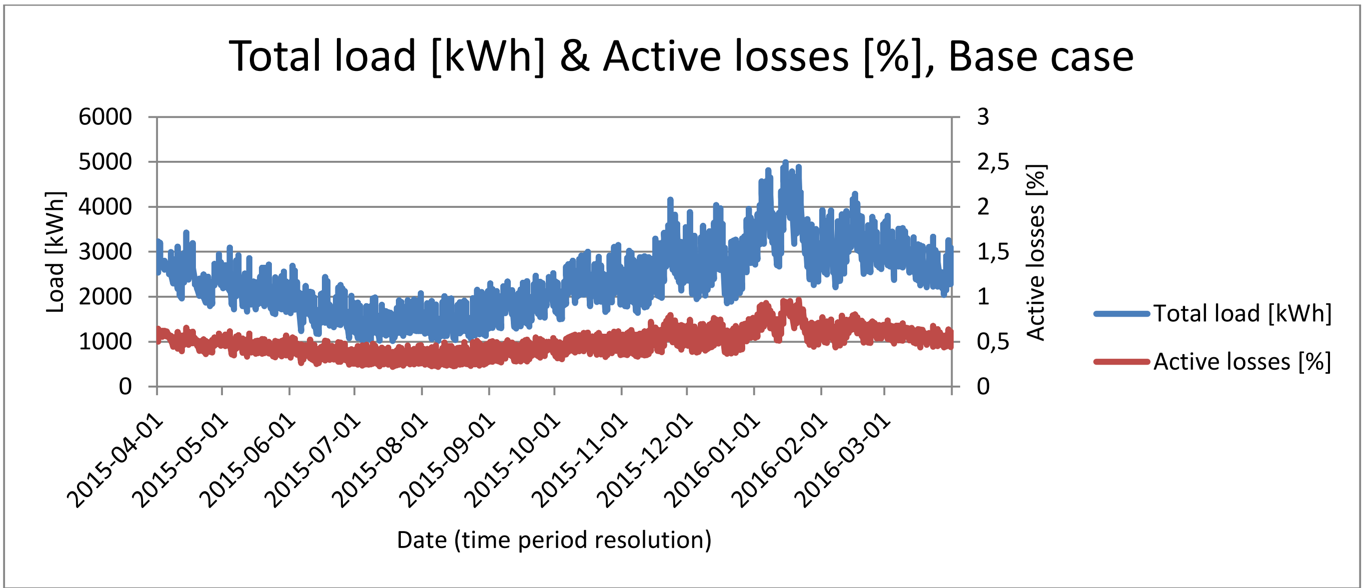

Figure 9: Total load [kWh] with calculated active losses [%] for the measured year, for the base case where no DR is applied.

The total active and reactive load, total active and reactive generation (infeed to the system) and the active losses for the measured year can be seen below in Table 9. Note that the unit MVArh is the reactive power summarized, and should not be considered as energy.

Table 9: Total yearly load, generation, line loss and active losses for the base case where no DR is applied.

Total yearly load [MWh]	Total yearly load [MVArh]	Total yearly Generation [MWh]	Total yearly Generation [MVArh]	Total yearly line loss [MWh]	Total yearly line loss [MVArh]	Active yearly losses [%]
2663.03	968.7	2677.7	978.4	14.9	9.7	0.555

These results are only valid for the chosen substations and not the entire grid. For the entire grid, grid losses amount to 3.58 % when comparing consumer measurements with measurements from the regional grid in Lavastorm. The grid loss for the chosen substations (0.555 %) is thus considerably smaller than the grid losses for the entire grid (3.58 %). However, this can be considered normal when comparing results with [50] and since the chosen substations are only a part of the grid. Also, the calculated losses (0.555 %) only consider cable losses, and not for example transformer load losses or non-technical losses like missing measurements. Having grid losses of 0.555 % close to the consumption as is the case for the chosen substations is deemed reasonable.

4.2 Demand response scenario

There are two different cases where DR is applied; a conservative estimation and an optimistic estimation of DR. A percentage load shift is applied in the conservative case, and a percentage load shift plus load reduction are applied in the optimistic case. A summation of the percentages used can be seen in Table 3.

4.2.1 Conservative case

In the conservative case, a percentage shift of 1.9 % is applied in the summer (April-October) and 0 % in the winter (November-March). The total load and the corresponding calculated losses for the measured year when DR is applied with the conservative case can be seen below in Figure 10.

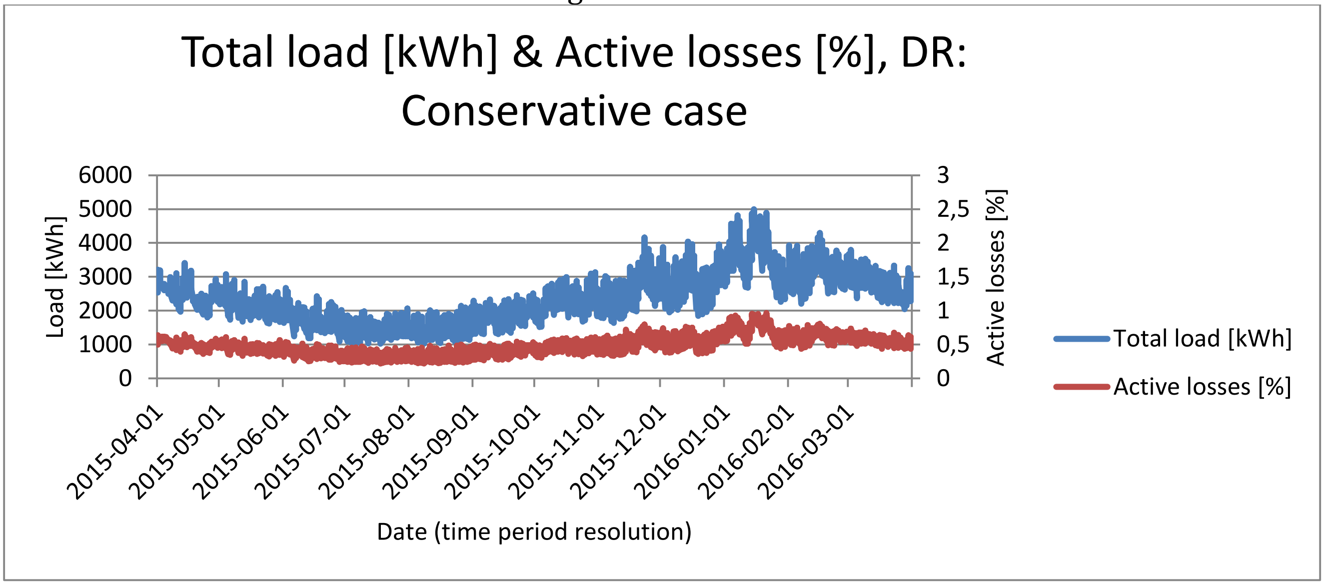

Figure 10: Total load [kWh] with calculated active losses [%] for the measured year, when DR is applied with the conservative estimation.

The total active and reactive load, total active and reactive generation and the active losses for the measured year when DR is applied with the conservative case can be seen below in Table 10.

Table 10: Total yearly load, generation, line loss and active losses when DR is applied with the conservative case.

Total yearly load [MWh]	Total yearly load [MVArh]	Total yearly Generation [MWh]	Total yearly Generation [MVArh]	Total yearly line loss [MWh]	Total yearly line loss [MVArh]	Active yearly losses [%]
2663.03	969.0	2677.6	978.6	14.8	9.7	0.553

4.2.2 Optimistic case

In the optimistic case, a load reduction of 6 % is applied in the summer and winter, and a load shift of 2.4 % and 4.2 % is applied in the summer and winter respectively. The total load and the corresponding calculated losses for the measured year when DR is applied with the optimistic case can be seen below in Figure 11.

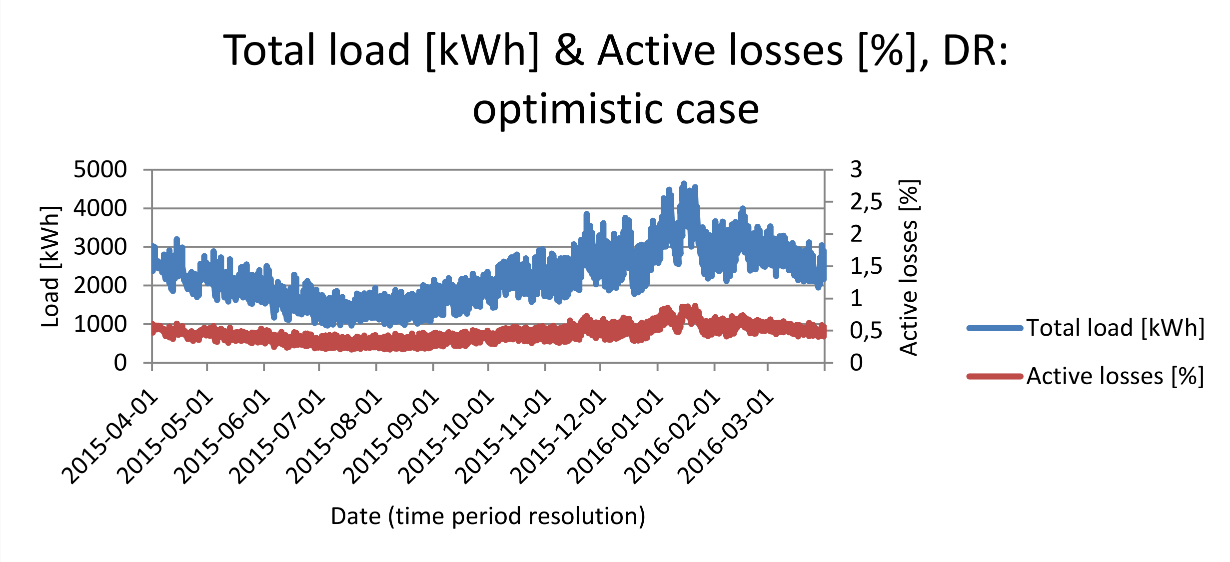

Figure 11: Total load [kWh] with calculated active losses [%] for the measured year, when DR is applied with the optimistic estimation.

The total active and reactive load, total active and reactive generation and the active losses for the measured year when DR is applied with the optimistic case can be seen below in Table 11.

Table 11: Total yearly load, generation, line loss and active losses when DR is applied with the optimistic case.

Total yearly load [MWh]	Total yearly load [MVArh]	Total yearly Generation [MWh]	Total yearly Generation [MVArh]	Total yearly line loss [MWh]	Total yearly line loss [MVArh]	Active yearly losses [%]
2503.2	911.1	2515.8	919.1	12.9	8.1	0.513

The results when DR is applied show a reduction of losses compared to the base case. The loss reduction compared to the base case for the conservative case is 0.1 MWh (14.9 MWh to 14.8 MWh) which corresponds to 0.6 %. The loss reduction for the optimistic case is 2 MWh (14.9 MWh to 12.9 MWh) which corresponds to 13.4 %.

4.3 Analysis of the economic benefits

The potential economic benefits of introducing DR are analyzed below. These comprises of the incentive by Ei which have a potential of making the revenue cap larger, and also the cost reduction that takes place when the losses and load are reduced. The latter will however only be an economic benefit in some cases, see below for explanation.

The economic benefit based on the incentive from Ei is evaluated below according to section 3.5 *Calculating economic benefits*, where the results can be seen in Table 12, where Kn denotes the economic incentive for the grid losses and Kb denotes the economic incentive for the load. Note that these results of the economic incentive are based on the entire grid and not just the substations included in the analysis, where the results of the analysis is scaled to the entire grid. Also, the results are based on the period April 2015-April 2016 (1 year) instead of 2016-2019 (4 years) as the incentive is originally intended for. Thus, if an estimation of the economic incentive for 2016-2019 is to be done, the results in Table 12 need to be multiplied by 4.

Table 12: Results of the calculated economic incentive for one year. Kn denotes the grid loss incentive and Kb denotes the load incentive.

Cases:	Kn	Kb	Total incentive (Kn+Kb)	Improvement compared to Base case
Base case	72 595 SEK	-366 800 SEK	-294 205 SEK	-
DR conservative estimation	83 341 SEK	-367 309 SEK	-283 968 SEK	+10 237 SEK
DR optimistic estimation	267 576 SEK	-360 083 SEK	-92 507 SEK	+201 698 SEK

The reason why the total incentives for all three cases are negative is because they are compared to the period of 2010-2013. The calculations involving numbers from 2010-2013 are however not based on absolute numbers so the fact that 2010-2013 (4 years) is compared to April 2015-April 2016 (1 year) does not make any difference in that respect. The base case thus serves as a prognosis for how the revenue cap will change during a year. For the aim of this study, the improvement the DR cases compared to the base case is more important. The improvement is not so big for the conservative case, where no load reduction occurred and with a relatively small load shift in the summer and not in the winter. For the optimistic case, the improvement is significantly bigger which is mostly due to the grid loss incentive.

The total revenue cap is set by the Ei to 248 840 000 SEK for the period 2016-2019 and the capital base to 532 500 000 SEK [48]. This is 62 210 000 SEK per year for the total revenue cap, to make it comparable to the numbers above. The total incentive shown in Table 12 does not exceed 5 % of these costs so the resulting incentive needs not to be changed.

The cost reduction by simply reducing the losses and load for the investigated period can be seen below in Table 13.

Table 13: Potential cost reduction for reducing losses and load.

Cases:	Cost for losses	Cost to regional grid	Reduction of cost for losses	Reduction of cost to regional grid
Base case	3 354 363 SEK	16 657 012 SEK	-	-
DR, conservative case	3 334 237 SEK	16 657 012 SEK	20 126 SEK	0 SEK
DR, optimistic case	2 904 879 SEK	15 673 481 SEK	449 484 SEK	983 531 SEK

It can be seen that a relatively large reduction of costs is achieved for the optimistic case but a relatively small reduction of costs is achieved for the conservative case. The reason why there is no reduction of cost to the regional grid in the conservative case is that there is no load reduction in the conservative case so the total amount of energy [MWh] is unchanged. Also, there is no peak demand reduction since the winter where the peak load occurs has no load shift. However, these cost reductions may not lead to economic benefits for a grid company. This is due to the fact that as the cost reduces, the revenue cap, i.e. the maximum allowed revenues set by the Ei, will also be reduced. If however the grid company has actual revenues set below the revenue cap, the case may be different: If the revenue cap is reduced but still above the actual revenue level, then the actual revenue level can remain at the same level even if the costs are reduced. Whether or not the reduction of losses will lead to an economic benefit for a grid company thus depends on the situation. That is why the incentive analyzed above exists, where the revenue cap may be increased.

4.4 Sensitivity analysis

Two sensitivity analyses were performed, where in one case the percentage load shift was varied and in the other case the power factor was varied for the base case and the two DR cases. The reason why the impact of percentage load shift was analyzed was to find out how much difference it did, given that the conservative case had a very little percentage of load shift and the optimistic case included not only load shift but also load reduction. The reason why the impact of the power factor was analyzed was that reactive power is not included in the measurements of the data. The power factor was used to calculate the reactive power, as stated in section 3.3 *Calculation of losses*. The analyses were made using one month instead of the whole year to save computational time. The month of April was chosen, due to the fact that it had a fairly average load compared to the other months.

4.4.1 Load shift

The impact of load shift was analyzed for three cases; 10 %, 20 % and 50 %. Below the results can be seen in Figure 12, where the losses are plotted for the cases of load shift in the month of April.

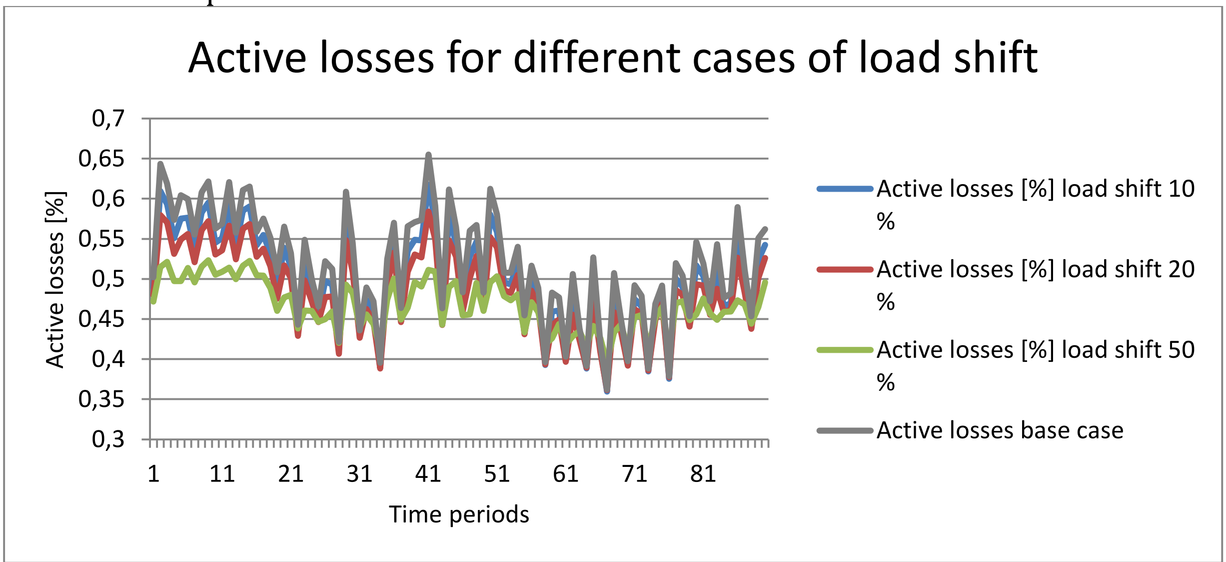

Figure 12: Different cases of load shift for the month of April.

The change in losses can be seen in numbers in Table 14 below.

Table 14: Active losses for different cases of load shift.

Cases:	Active losses [MWh]	Active losses [%]
Base case for April	1.19	0.53
Load shift 10 % for April	1.15	0.51
Load shift 20 % for April	1.11	0.49
Load shift 50 % for April	1.06	0.47

4.4.2 Power factor

The impact of varying the power factor was analyzed for three different values in each case (base case, DR conservative case and DR optimistic case). Below in Figure 13, the impact of three different values of the power factor on the active losses can be seen for the base case for the month of April. The values for the power factor which are used in the analysis are 0.8, 0.9 and 1. This is to be compared with the value used for this project which is 0.93.

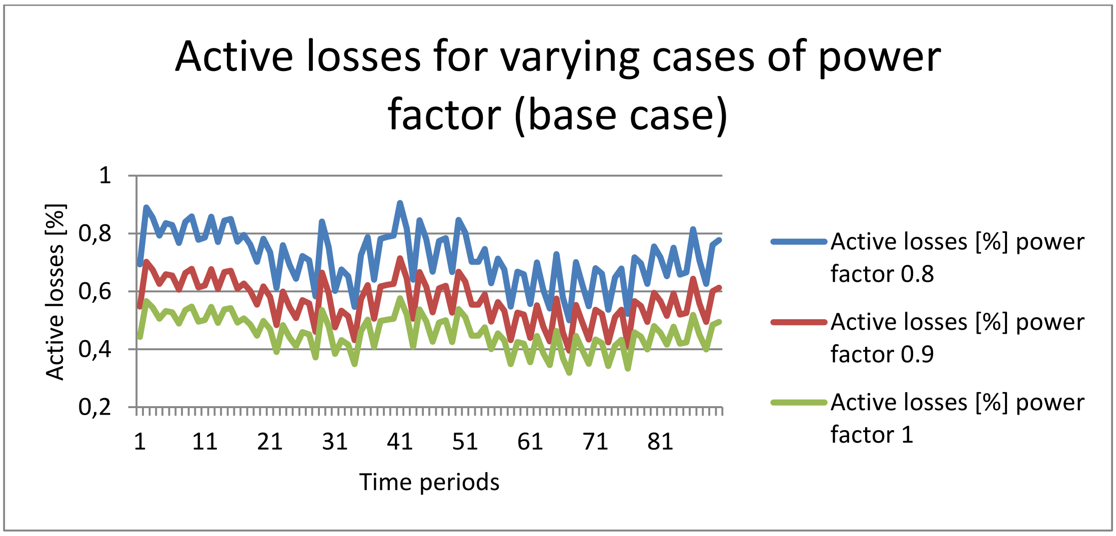

Figure 13: Active losses for the base case with three different values of power factor. The power factor for the base case is approximately 0.93.

The change in losses for the base case as well as the two cases with DR can be seen below in Table 15.

Table 15: Active losses for the three cases (base case, DR conservative and DR optimistic) when varying the power factor. The power factor used in the project is approximately 0.93, which in this table corresponds to *Base case for April*, *DR conservative for April* and *DR optimistic for April*.

Cases:	Active losses [MWh]:	Active losses [%]:
Base case for April	1.19	0.53
Base case for April, pf 0.8	1.65	0.73
Base case for April, pf 0.9	1.30	0.57
Base case for April, pf 1	1.04	0.46
DR conservative for April	1.18	0.52
DR conservative for April, pf 0.8	1.64	0.72
DR conservative for April, pf 0.9	1.29	0.57
DR conservative for April, pf 1	1.04	0.46
DR optimistic for April	1.04	0.49
DR optimistic for April, pf 0.8	1.44	0.68
DR optimistic for April, pf 0.9	1.14	0.53
DR optimistic for April, pf 1	0.92	0.43

As can be seen, the losses increase with decreasing power factor which is logical since the amount of reactive power increases with decreasing power factor.

5 Discussion

In this section, the data quality, the methodology and the results are discussed. This is ended with a general discussion regarding the work.

5.1 Data quality

When assessing the data in Lavastorm in the beginning of the project, the numbers regarding consumption and substation flow (infeed to the substations) did not add up. This caused negative and unreasonable losses when looking at it in Lavastorm. After extensive error searching of the Lavastorm procedure, it was concluded that it most likely was a data quality issue rather than an error in the Lavastorm procedure that caused the unreasonable and negative losses.

There may be several data quality related reasons to why the data showed unreasonable results. As mentioned in section 3.1 *Description of network and data*, one of them may be that the resolution of the consumer data is not high enough. The majority of measurement values showed only integers without decimals, where it seems that the decimal of the actual value is saved to the next hour. This problem increases with higher resolution of data. If the entire customer consumption is aggregated then the issues seems to be masked, meaning that the measurement faults are compensated with each other. Another possible explanation of poor data quality may be incorrect documentation. Incorrect documentation may be that the meter is not documented under the right substation, or that the time on the meter is not updated between summer and winter time so that the measurement is incoherent when matching it against other meters. Another possible case of incorrect documentation may be the meters in the substations. An electricity meter measures voltage and current either directly or indirectly. If it is measured indirectly, measurement transformers are used, thus there is a scaling factor involved. If that scaling factor in the measurement system does not correspond to the physical value in the metering system, the resulting measurements will show an error proportional to the error in scaling factor.

It needs to be said however, that there may be good reasons for a grid company not to have perfect data quality. The level of quality depends on what the data is supposed to be used for. The measurements for the substations are only used for statistical measurements for documentation of the energy flow and are not used for charging customers. The measurements are thus not quality assured according to Henrik Säwe at Ulricehamns energi [37]. Billable measurements have a higher priority for quality assurance since they deal with the economics of the consumer and the grid company. Furthermore, hourly measurements are only law-binding for customers with a fuse size larger than 63 Amperes, with the exception being if consumers actively requests hourly measurements [51]. This means that hourly measurements may not even be available at all for smaller consumers in many grid companies, or that hourly measurements exists (like for Ulricehamns energi) but the quality of the measurements might be relatively low for this project's purposes. Also, a grid company may not have tariffs that require hourly measurements for smaller consumers (such as power tariffs or hourly time-differentiated tariffs) but they might still have hourly measurements (as is the case with Ulricehamns energi). The quality of those measurements may not need to be high since only monthly measurements are needed as a basis for charging customers in that case.

5.2 Discussion of methodology and results

As an implication of the data quality, a methodological choice of converting the 24 hours during the days to 3 time periods was done. The data was deemed not to be reliant when using hourly data, so the choice was made to aggregate data to make it less dependent on the hourly resolution. This choice naturally has an implication on the results, since aggregating load into time periods makes the load curve more flat even before demand response was implemented. This methodological choice thus impacts the results by underestimating the effect of DR, since the load curve for each day had already been flattened somewhat due to the aggregation of hours into time periods.

Another implication of the data quality was that the load for some consumers was set to zero when consumer data was missing. This is deemed not to affect the results significantly since the total number of defect hours is small (156 h out of 8784 h). Also, the consumer who was the source of the problem was a relatively small consumer (a tariff with a fuse of 25 Amperes).

One of the methodological choices made was regarding the load shifting method. In this project, a method used in Grahn's work [47] was chosen. This method was chosen because it contributed to creating a more flat demand curve than before, as opposed to if load would have been simply moved from one time period to another. For this case, the latter would have created a new peak at a different time period instead. Also, with the method chosen, care need not to be taken to the fact that occurrences of peak periods can vary from day to day; in the majority of cases for this grid the peak period occurs between 08-16 o'clock but sometimes it can occur at a different time. However, the methodological choice has the implication that it underestimates the actual load shift. For example, when using 10 % "load shift" with this method it is not the same as moving 10 % of the load from a peak period and placing that amount at a different time. This is due to the execution of the method explained in section 3.4 *Modeling of demand and demand response*.

The results are largely affected by the potential load reduction and potential load shift that DR may have. A lot of studies have used or have reported a load shift of roughly 10 %. However, these studies have dealt with the theoretical potential of DR. This study deals with the practical potential in a relatively short-term perspective. It is thus trying to answer the question "how much load reduction and load shift can be achieved if DR were implemented within a few years?" instead of "how much electricity load can theoretically be moved?". As can be seen in the sensitivity analysis in section 4.4.1 *Load shift*, the percentages of load shift affect the results significantly.

As can be seen in the sensitivity analysis in section 4.4.2 *Power factor*, the amount of reactive power affected the amount of grid losses significantly. The fact that reactive power measurements were not considered in this project thus needs to be taken under consideration when assessing the results. Also, the fact that only line losses and not transformer load losses were considered needs to be taken under consideration as well. The transformer losses may constitute 25 % of the losses in the grid and 25 % of those are transformer load losses, as stated in section 2.2.1 *Factors affecting losses*.

When calculating the economic results, some approximations were made which may impact the results significantly. The period of study for this project ranged over a year instead of four which is the intended period when calculating the incentive. This might have either underestimated or overestimated the results depending on the load and losses for the coming years. The fact that the project covered four substations instead of the whole grid also affected the results by scaling the loss reduction and load reduction to the rest of the grid when making the economic calculations. When scaling the load, the scaling is done equally on all infeed stations in the grid (Ulricehamns energi has four infeed stations to their grid), thus assuming that the losses are reduced equally on all of the infeed stations. This might not be the case since the grid company can choose to obtain more load from some infeed stations than the others. When calculating the economic result, the load factor (P_{medel}/P_{max}) was overestimated when hours were aggregated to time periods. This may affect the economic results for the load incentive significantly. The load reduction performed in the optimistic case of DR clearly contributes to less grid loss and thereby a higher economic advantage in that sense. However, load reduction may also mean lost revenue for the grid company if the revenue cap decreases so whether or not load reduction is economically beneficial for a grid company is not always straightforward.

The methodology of this project was to depict the grid by using data from spreadsheets rather than using grid maps. Accompanied with grid data and consumption data, this has enabled the analysis of the line losses in the grid. If grid maps were to be used instead of the spreadsheet data, the power flow analysis made in this project would be very difficult to perform since the grid would have to be depicted in MATLAB by hand. With a grid as large as a typical grid owner's, this would have been a far too time consuming task for it to be realistically possible. The method used in this project is applicable to other grids as well and works in theory, but as can be seen in this project, it is difficult for it to work in practice due to the low quality of the measurement data.

5.3 General discussion

The direct benefits of loss reduction in the distribution grid and cost reductions of the fee to the regional grid have been analyzed in this project, but other potential benefits that are difficult to quantify may exist. If the losses and the load decrease in the grid, the wear and tear of electrical components in the grid may be less, thus prolonging the life time of those components and delaying investments in the grid. However, this reasoning depends on how much the DR will affect the losses. Another potential benefit may be a decreased number of interruptions in the grid if the load decreases.

There are costs related to the implementation of DR through the implementation of a time differentiated tariff. To develop a tariff and to communicate it to the customers and educate personnel in the grid company (e.g. customer services) are related to a cost. Another factor that needs to be taken into consideration is the hourly measurements. If a grid company does not have hourly measurements, there is a cost related to the implementation of it. If the grid company has hourly measurements, there may be a cost related to increasing the quality of the measurements, to make them reliable enough to make it billable. However, it can be argued that the quality of the hourly measurements may need to be increased in the future for other purposes besides DR, which will make this cost to be split between other measures. It may also occur problematic situations if a tariff based on power is introduced. If an interruption in the grid occurs it may shut down load, such as the heating of houses. The hour when the power comes back on, the delayed heat load may try to recover from the interruption, causing a peak load. When a power tariff is in place, the customer needs to pay extra for this peak load even though it was the grid company who were responsible for the interruption.

The above mentioned benefits and costs are difficult to quantify and are only reasoned qualitatively in this report. However, if the objective is to quantify the potential economic advantage of implementing DR and make a cost-benefit analysis, these factors discussed above needs to be addressed. Is the economic perspective the only perspective for a grid company? The economic perspective will of course always be very strong but there may be reasons to pursue a DR implementation even if the economic situation is not crystal clear favorable. A municipality owned grid company for instance, might have reasons to pursue DR for environmental reasons, or it may be the other way around; that a municipality owned grid company may be reluctant towards implementing a time of use tariff (thus enabling DR) because they want to keep the tariff structure simple and understandable for their customers.

Is the incentive introduced by the Ei strong enough to make its mark on the grid owner's operations? The results of the conservative estimation of DR showed an improvement compared to the base case of roughly 10 000 SEK for one year. The results for the optimistic case showed a significantly larger improvement, approximately 200 000 SEK for one year. However, the conservative case is assessed by the author to be a bit closer to reality. If the total revenue cap per year is 62 210 000 SEK, increasing it with 10 000 SEK or even a bit higher than that is not a very large increase. Thus judging by the results from this study, the incentive needs to be strengthened. In an interview with Linda Werther Öhling [17] who works at Ei, there is always a risk that the incentive becomes too weak when it is created. However, previously there were no incentives at all so this is a start, although the incentive might have to be adjusted for the coming periods. When interviewing Henrik Säwe at Ulricehamns energi [37], reducing peak demands for them was very important. Not because of the incentive however, since they assessed it to be relatively weak. Instead, they thought it would be important to reduce peak demands to free capacity in the grid.

To summarize the discussion, the results of this project should be viewed as indications rather than absolute truths. There are many factors affecting the results, which have been discussed in this section and many of them are difficult to assess how much they influence the results. To achieve more trustworthy results, the quality of the data may need to be improved, and also more time would be needed. As discussed in the previous section regarding methodology, the method used in the project can be used for other cases, i.e. other grids. It provides a way of depicting an electricity grid using data from e.g. Microsoft Excel, without the need of using grid maps. This makes it possible to analyze the grid together with e.g. consumption data.

6 Conclusions

In this section, the research questions stated in the Introduction will be answered. Also additional conclusions drawn from the project will be stated.

The results when demand response is applied show a reduction of losses compared to the base case. The loss reduction for the conservative case compared to the base case is 0.6 %. The loss reduction for the optimistic case is 13.4 %.

The incentive from the Swedish market inspectorate, Ei, regarding efficient use of the electricity grid showed an economic increase of the revenue cap for Ulricehamns energi compared to the base case when demand response is applied. For the conservative case, the increase amounts to 10 237 SEK. For the optimistic case, the increase amounts to 201 698 SEK.

The cost reduction by reducing losses for the conservative case compared to the base case is 20 126 SEK. The corresponding figure for the optimistic case is 449 484 SEK. For the conservative case, there is no cost reduction achieved from the potential load decrease when reducing losses. For the optimistic case, this cost reduction is 983 531 SEK. These figures needs to be put in light of the fact that if the costs of the grid company decrease, so does the revenue cap.

These results should be taken as indications rather than absolute truths. Due to the quality of the measurement data, the analysis was only made on a relatively small part of the grid. In the analysis made, there were also missing consumption data, with 156 defect hours of 8784 hours. The missing data however is assessed not to affect the results significantly since the source of the problem was a relatively small consumer. The economic conclusions seen above are the result from scaling the results of the small part of the grid to the entire grid. Another measure taken due to the quality of the data was to aggregate the 24 hours of the day to three time periods. This is deemed to overestimate the results, especially the results of the load incentive. Other factors worth mentioning are the assumptions regarding the demand response potentials and the assumption regarding power factor. These two factors have a significant impact of the results, as can be seen in section 4.4 *Sensitivity analysis*.

An additional conclusion drawn from the project is that the incentive introduced by the Ei is relatively weak when looking at the conservative estimation of demand response which is assessed to be a bit closer to reality than the optimistic estimation. However, this needs to be put in light of the uncertainties of the results mentioned above. Another conclusion of this project is that the data quality is relatively low. This needs to be improved in order to give trustworthy results when analyzing hourly data. Yet another conclusion drawn from the project is regarding the method. To represent the grid by using spreadsheet data instead of grid maps, ought to be useful when analyzing consumption data and grid data. This however, requires sufficient quality of the measurement data.

7 References

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8 Appendix

In section 3.2 *Sorting the data*, the use of the program Lavastorm is explained. Below, a list of the measures taken in Lavastorm to extract the data needed to perform loss calculations is shown.

Measures taken to match consumers with their respective consumption and sort them under the right substation, and also filtering the unnecessary information:

- Removed blank rows (Null-rows) in the files.
- Matched consumer data (facility ID and connection point in the grid) in ANLAB with "connection point to" or "connection point from" in ANLSEK and thereby learn under which substation each consumer is.
- Matched consumer data (facility ID and which substation it belongs to) with hourly consumption- and production data.
- If both consumption and production were shown at the same connection point in the grid (meaning that a consumer has both consumption and production): the production was subtracted from the consumption, i.e. consumption-production.
- Searched for consumer data that had more than one measurement per consumer for each hour. If that was the case, the hourly measurements were aggregated together to 1 per hour.
- Filtered away substations not needed in the hourly measurement list for the substations.
- Aggregated all the hourly measurements per hour to be able to calculate the overall losses and make load profiles.
- Calculated losses based on the aggregated data.

Measures taken to extract necessary information needed for the calculation procedure:

- Removed duplicate rows.
- Extracted the connection points in the grid belonging to the chosen substations.
- Extracted cable information from TYPLED and match it with the cable information in ANLSEK.
- Assigned numbers for the connection points in the grid for "connection point to" and "connection point from".
- When there was missing information about the cables needed for the calculations, this information was written manually with data from a Cable handbook [45].
- When there was consumption data missing for some consumers, the load for these hours were added manually and set to zero, otherwise the calculation program could not function.
- Created three time periods each containing 8 hours. This meant aggregating the consumption and production data for these hours.
- Created Microsoft Excel files with the necessary information needed when calculating the losses.