

THE REGULATION OF ELECTRICITY NETWORK TARIFFS IN SWEDEN FROM 2016

Carl Johan Wallnerström, Swedish Energy Markets Inspectorate, carl.johan.wallnerstrom@ei.se
Elin Grahn, Gustav Wigenborg, Linda Werther Öhling, Herlita Bobadilla Robles, Karin Alvehag,
Tommy Johansson, Swedish Energy Markets Inspectorate, 016-16 27 00 registrator@ei.se

Abstract

While the electricity market in Sweden was deregulated in 1996, the transmission and distribution of electricity is considered a natural monopoly and is therefore subject to regulation. The national regulatory authority (NRA) for energy, the Swedish Energy Markets Inspectorate (Ei), determines a revenue cap for each distribution system operator (DSO) and the transmission system operator (TSO) for a regulatory period of four years. This paper outlines the Swedish revenue cap regulation, with a focus on the changes implemented from the regulatory period 2016-2019, including changes in the economic model, modifications of the incentive scheme for reliability of supply and the implementation of a new incentive scheme for efficient utilization. The latter is a result of the EU Energy Efficiency Directive.

Sensitivity analyses and an overall discussion of the current regulation is included in the paper. The paper may be used as reference material of the regulation and is aimed to providing an opportunity for others to give feedback that can inspire future improvements of the regulatory model. Some ideas of how to improve the regulation are also included in the paper, especially on how to further develop incentives to meet future requirements of power distribution whilst at the same time maintaining a robust regulation over time to avoid too much uncertainty for DSOs in their long-term investment planning. Power distribution is facing large technique shifts (often referred to as smart grid) and is key to meet future requirements of climate goals such as local renewable energy sources, electrical transportation etc. and therefore, the construction of well-balanced incentives is more important than ever before.

Introduction

Background

A short history

The Swedish electricity market underwent a major reform in 1996. Since then, generation and trading of electricity is exposed to competition. Network operations, i.e. the transmission and distribution of electricity, is however considered a natural monopoly as it would be both economically and environmentally unreasonable to have competing infrastructures to each customer. Due to the lack of competition in the transmission and distribution of electricity, network operators are subject to regulation to promote efficiency and quality of supply and to ensure fair prices for customers. According to the Swedish Electricity Act, electricity distribution tariffs shall be reasonable, objective and non-discriminatory.

In 2003, the first performance based tariff regulation was introduced, with a different approach than today's regulatory model, using fictive reference networks (more information see e.g. [1] and [2]). In 2005, a severe storm struck Sweden (referred to as Gudrun or Erwin) and caused outages for ~450 000 customers (more than 8 % of all customers); out of which approximately 100 000 customers had an outage lasting for more than four days. That extreme event largely increased the focus on the importance of reliable energy supply. In 2006, two legislations entered into force that implied new mandatory requirements for DSOs: annual risk and vulnerability analysis with action plan must be made and customer compensation for outages ≥ 12 hours (see Table 2, page 8). From 2011 outages longer than 24 hours are not tolerated by law together with possibilities for Ei to define additional minimum requirements of the reliability of supply; one example is that ≥ 11 outages per customer and year never are tolerated.

The Swedish power system and future tendencies

The Swedish power system is divided into three main levels [3]: *transmission* connected to large power plants, other countries and for long distance energy transportation; *regional* (sub-transmission) and *local* power distribution systems. The transmission system include all ≥ 220 kV parts. Regional power systems is formally defined by two criteria that must be fulfilled: (a) < 220 kV and (b) subject to line concession. Regional systems are the link between local distribution systems and the transmission system, but some larger customers and some generation (for example many wind farms) are connected directly to this system level. Local power distribution systems are the rest; hence

power systems which are subject to area concession. An area concession means that one distribution system operator (DSO) has a monopoly in an area to build the infrastructure up to a certain voltage level. High voltage levels give less losses over large distances, but are on the other hand more complex to handle with more expensive components.

The future development of power systems is characterized by changes on both the supply and the demand side. On the supply side, the power system is integrating more power generation from renewable sources, both small- and large scale. On the demand side, the load characteristics are changing with e.g. more nonlinear loads and more electric vehicles. In addition, the demand of electricity is beginning to be more flexible with the introduction of demand response, local storage and local production. The whole power system is moving in the direction of what is often referred to as the “smart grid”. From a regulatory point of view, it is of great importance to continuously and carefully adapt the regulatory model to accommodate these challenges whilst the same time maintaining a robust regulation over time to avoid too much uncertainty for DSOs in their long-term investment planning.

Our role as a NRA

There are currently approximately 170 distribution system operators (DSOs) and one transmission system operator (TSO) in Sweden. The Swedish TSO, Affärsverket Svenska kraftnät, is owned by the government. With a few exceptions, the TSO owns and operates all parts of the transmission system. All other entities that operate power systems in Sweden are defined as DSOs. The 170 DSOs are of varying size and ownership structure (state, municipal, private and other), and they each have a so called concession (permission) for the distribution of electricity, either for a defined geographical area (local DSOs) or for a specific line (regional DSOs). The concession means a privilege with rights, but also with several obligations, which are governed by laws and a regulation. The national regulatory authority (NRA) for energy in Sweden, the Swedish Energy Markets Inspectorate (Ei), monitors that the network operators are in compliance with the existing rules. Ei’s role as the NRA [4] is for example to ensure that customers have access to a power distribution system, to provide incentives for cost efficient operation with acceptable reliability and with objective, reasonable and non-discriminatory tariffs [5].

Overview of current regulation

Ex-ante regulation of network tariffs was introduced in 2012 and underwent changes to the second regulatory period 2016-2019 [6]. Ei determines a revenue cap for each DSO for a period of four years at a time. The revenue cap indicates the total amount that the DSO may charge their customers. The purpose of the revenue cap is that DSOs shall obtain reasonable coverage for their costs and reasonable return on the invested capital. When calculating the revenue cap, Ei shall also take into account: (a) the reliability of supply, and (b) what extent the operations are conducted in a manner consistent with or contributing to an efficient utilization of the power grid. Such an assessment may result in an increase or decrease in what is considered to be a reasonable rate of return on the capital base. A summary of how the power distribution is regulated in other countries can be found in: [7].

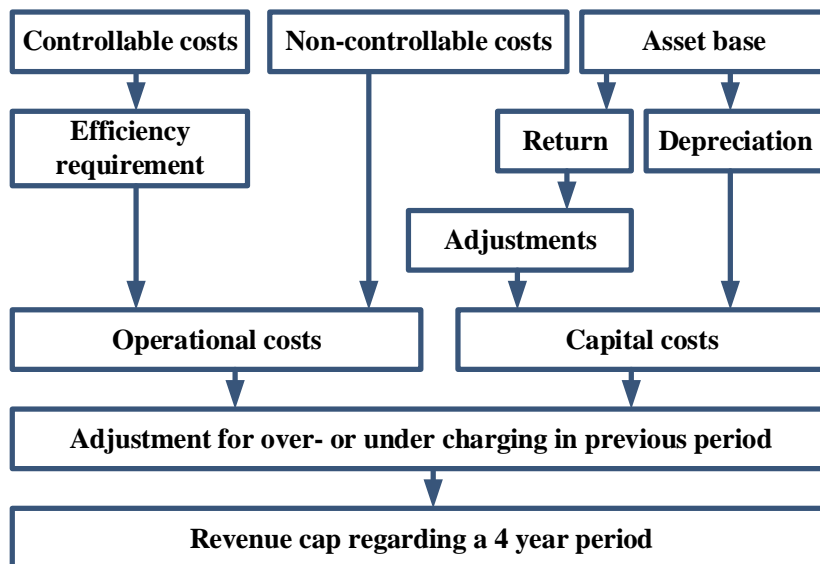


Figure 1 Overview of the Swedish revenue cap regulation

Figure 1 gives an overview of the revenue cap calculation. Despite important changes, the overall structure of the regulation is the same in the first and the second regulatory period. Description of each block in Figure 1:

- *Operational costs* are the sum of *non-controllable* and *controllable* costs.
 - *Non-controllable costs* relate to costs that are considered difficult for the DSO to influence. This is for instance the cost to the feeding grid, the cost of purchasing energy losses and agency fees. However, with new techniques and solutions, some of those costs can to some extent be affected, which in turn has motivated new incentive schemes since 2016.
 - *Controllable costs* relate to other operational costs that the DSO can control themselves. These include all expenses associated with the operation of the grid, than those included in “non-controllable costs”.
 - To simulate conditions on a non-monopoly market, Ei added an *efficiency requirement* of which those cost shall decrease each year.
- *Capital costs* consists of *depreciation* and *return*.
 - The regulatory *asset base* is the sum of all present purchase values (PPV) that are included according to Ei’s directives. The asset base is input to calculation of *capital costs*.
 - The underlying calculation of *depreciation* and *return* is described later in this paper.
 - The *return* is sometimes *adjusted* by incentive schemes: reliability of supply and efficiency. These are described later in the paper
 - The adjustments are limited to ± 5 % of the revenue cap.
- The sums of the operational and capital costs are *adjusted for last period's over- or under -charging*.
- The result of this gives the company's *revenue cap regarding a 4 year period*.

The share between different cost categories vary between DSOs and years. In average, the share is: controllable costs ~23 %, non-controllable costs ~33 % and capital costs ~44 %

Methods – how Ei evaluates and develop its incentive regulation

When calculating the revenue cap, Ei shall take into account the performance of the network operators. Such an assessment may result in an increase or decrease in what is considered to be a reasonable rate of return on the capital base.

When the revenue cap regulation was introduced in 2012, it was largely a new approach for both Ei and the DSOs. Therefore not too many new or complex incentive schemes were implemented from the start. The regulation has since then continuously been evaluated. The conditions under which the DSOs operate as well as the regulatory framework have also developed over time (e.g. EU directives and more “smart grid challenges”), which results in that Ei developing existing and/or introducing new parts in the regulation.

Ei will continue with the follow up work also during the second regulatory period and, if needed, make further improvements in the future. However, it is also important to maintain a predictable regulation that facilitates long-term planning for the DSOs. The plan is therefore to only slowly introduce changes. An important part of the evaluation is to share regulatory information between parties and countries. The publication of international papers on conferences provides an opportunity for others to learn from as well to give feedback to Ei on current Swedish regulation.

See also the discussion part in this paper.

Results – changes applied from the second regulatory period

More information of the regulation during the first regulatory period, see for example [8].

Efficiency requirement related to controllable operational costs

The efficiency requirements (see Figure 1) now consist of two parts: One overall for all DSOs (1.00 %/year) that was already included from 2012 and one specific for each DSO (0.00-0.82 %/year in addition) that is new from 2016.

New capital cost calculation method from 2016

Between the first to the second regulatory period, the method for calculation of depreciation and return has changed (the structure in Figure 1 is however the same). The depreciation time is set to 40 years for current carrying

equipment and 10 years for other equipment such as meters and IT. The changes imply moving from calculating the capital costs with a real annuity method, to a real linear method. Both methods has however challenges that had to be balanced with other part of the regulation or with other legislations. The real linear method requires that the ages of all components are determined. Ei has chosen the detail level of the age to months. The new calculation method is given by equation 1, where:

- LT = depreciation time,
- α a constant for providing some capital costs α more years after the LT . α is 2 years for meters and IT, else 10 years.
- $WACC$ is weighted average cost of capital and was initially proposed to be 4.53 % (this value may differ between regulatory periods), but there are however ongoing legal processes.
- PPV is the present purchase value.

$$\text{Capital cost} = \text{Depreciation} + \text{Return}^1 = \begin{cases} \left(\frac{1}{LT} + \frac{LT+1-age}{LT} * WACC \right) * PPV & \text{if } age \leq LT \\ \left(\frac{1}{age} + \frac{1}{age} * WACC \right) * PPV & \text{if } LT < age \leq (LT + \alpha) \\ 0 & \text{if } age > (LT + \alpha) \end{cases} \quad (1)$$

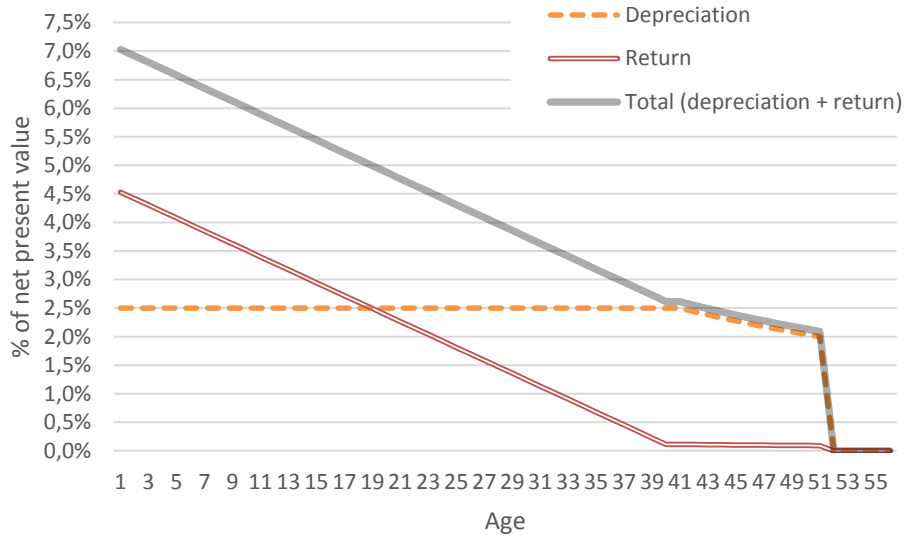


Figure 2 Capital costs as a function of the age

Figure 2 displays how the capital cost decreases over time based on equation 1, exemplified with 4.53 % WACC, 40 year depreciation and $\alpha=10$ years. For current carrying components with 40 years depreciation time no capital cost is allowed beyond 50 years. A transitional rule is also implemented: no components are considered to be older than 38 years at the end of 2015. Over time (2028) the transition rule will lose its effect for all components.

More detailed methods to evaluate and consider reliability of supply

Summary

This specific incentive scheme is described in [9] (English) and [10] (Swedish) more in detail. The overall target with this incentive scheme is to strive towards a socioeconomically optimal level of reliability of supply [11]. Every DSO has to, on a yearly basis, submit data to Ei on a customer level which includes all information needed to calculate the incentive schemes described in the paper. For the reliability incentive scheme, data about outages between 3 minutes and 12 hours are used (however both longer and shorter outages are also reported). Outages above 12 hours are excluded to not punish DSOs twice, see Table 2 (page 8).

An incentive scheme for reliability of supply was introduced as part of the revenue cap regulation already in 2012. Compared with the first regulatory period, the method for calculating the incentive scheme was improved to the second regulatory period by making it more detailed and thereby more accurate. For example are customers divided into five

¹ This value can be increased or decreased which is described in other sections of the paper.

categories with different outage costs from 2016: household, industry, agriculture, commercial service and public service (feeding grids also report interconnection points as a category which uses a Swedish average interruption cost). To assess the performance of each DSO, reliability indices (SAIDI² and SAIFI³ at distribution level and energy/power not supplied at sub-transmission level) are compared: actual values each year with norm levels (baselines). A reliability index that is better than the corresponding index value gives an addition to the revenue cap (reward), while the opposite will give a reduction of the revenue cap (penalty).

When developing the incentive scheme, Ei established three specific targets:

- Avoid unmotivated differences *within* the same distribution system
 - A new indicator, CEMI_n, in addition to average reliability indicators is defined by number of customers with n or more outages divided with the total number of customers. In current regulation CEMI₄ (i.e. $n = 4$) is used in calculations to give incentive of having more equal quality within same power system. Improvements in urban areas give more effect on customer weighted indices such as SAIDI and SAIFI compared with improvements in more rural areas. CEMI₄ gives incentives to not improve SAIDI and SAIFI by transfer resources from necessary investments in rural areas and only focus on areas with high customer density.
- Avoid unmotivated differences *between* distribution systems:
 - Besides comparing reliability with own history, a norm level as a function of customer density are used. The aim is to give incentive for power systems with similar condition having similar quality.
- **Keep** current reliability:
 - If the reliability is better than the customer density norm level, the own history is used as norm level instead to give incentives to keep current reliability. The reason for that is that the customers in the area of the over performing DSO already have paid for the current network and the associated reliability level through their historical tariff, and the DSO should not be further rewarded for that.

Calculating the norm levels (baseline)

The basis for the benchmarking method is that reliability indices for each DSO are compared with reliability indices of other DSOs with similar conditions. Ei has chosen to use customer density, defined as the number of customers per km line, to represent the conditions under which the DSOs operate. This is an objective and manageable measure with a strong dependency of the possibility for the DSO having a high reliability of supply. More detailed or complex measures would increase the level of complexity of the model but probably not improve the accuracy to the same extent. The basic idea is that the norm level is calculated so that DSOs with the same customer density will get the same norm level.

To find a norm level for the average performance, the DSOs need to be benchmarked. Historically, the distribution conditions based on customer density is divided into three categories; rural grid, mixed grid and urban grid with 0-10, 10-20 and >20 customers per km line respectively. However, using only three categories is an oversimplification. In reality, the prerequisites vary without such steps depending on the customer density, which should be reflected in the regulation. Thus, based on reliability and customer density data, functions as in equation 2 is calculated for every reliability index except CEMI₄ where the own history is always used as the norm. In Figure 3 one of those functions is exemplified together with the historical outcome for each DSO.

$$Y = \alpha + \frac{\beta}{T+\gamma} \quad (2)$$

where Y is the norm level, i.e. the average performance, given as notified and unnotified SAIDI and SAIFI respectively, T is the customer density (customers/km) and α , β and γ are parameters identified by making a least square fit of the norm level. In order for the norm level to be useful, a sufficient number of DSOs needs to be represented in the benchmarking. In Sweden there are approximately 170 DSOs, which makes the method suitable.

² System average interruption duration index (SAIDI) = total outage time / number of customers [minutes/customer and year]

³ System average interruption frequency index (SAIFI) = total number of interruptions / number of costumers [1/customer and year]

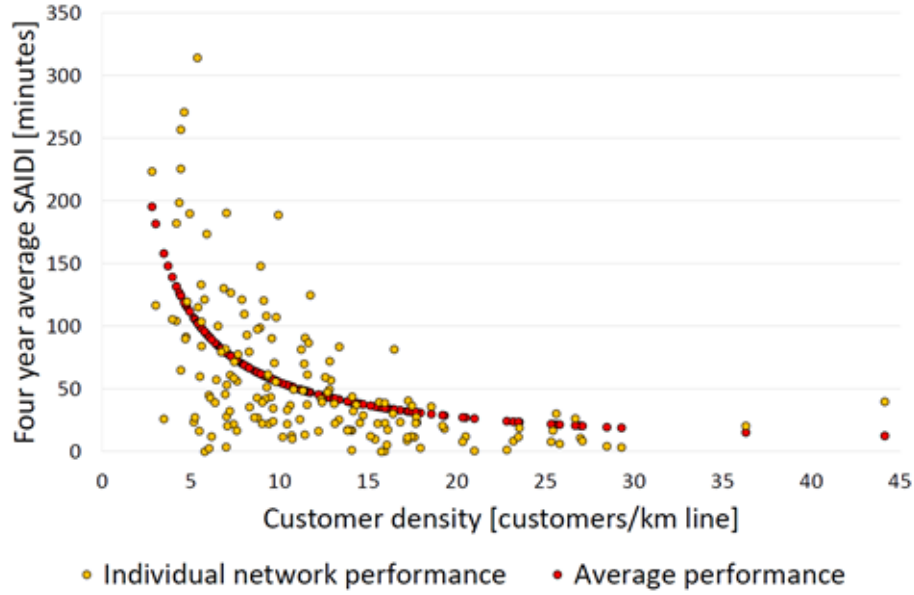


Figure 3 Reliability of supply of the individual DSOs as a function of customer density in yellow and the average performance in red.

However, in order to incentivize those DSOs that already have a high reliability to maintain their level, their own history is used as a norm level instead, exemplified as norm level B in Figure 4. For underperforming networks, the norm level is implemented periodically as for norm level A in Figure 4. Year 0 represents the norm level based on the DSO's reliability index outcomes during the years 2010-2013 (the norm period), and year 1-4 represents the baseline of each year of the regulatory period. The reason for the periodization is that reliability improvements often take time, and that the DSOs should have a norm level that is reachable. A norm level is calculated separately for SAIDI and SAIFI, for notified and unnotified interruptions and for each customer group, which gives in total 20 different norm levels for each DSO and year.

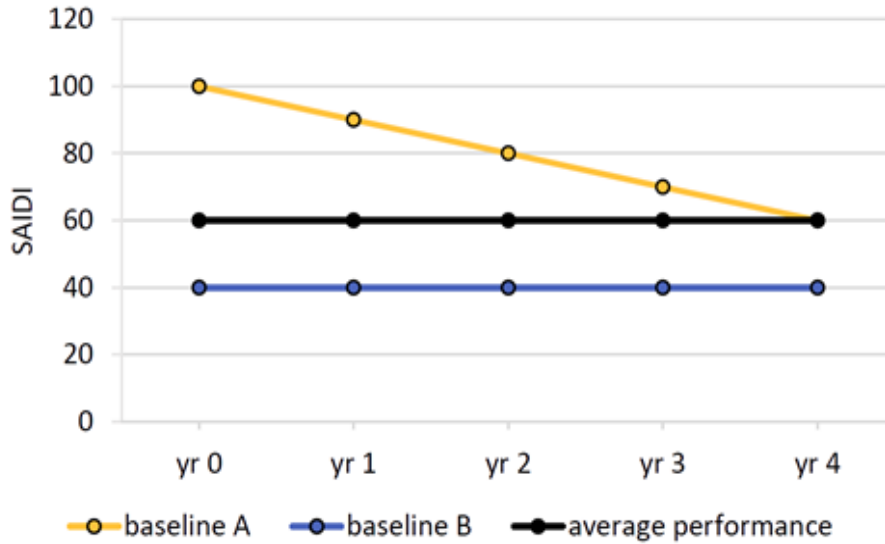


Figure 4 Examples of norm levels (baselines) for an underperforming (A) and an over-performing (B) DSO respectively

Outage costs for different customer categories

If the DSO performance measured by the reliability indices is going to be used as a penalty or reward in the revenue cap regulation, the indices need to be transformed into costs. That can be done by using estimated electricity interruption costs. It is difficult to measure the outage cost for electricity, but it is however a key element of reward and penalty mechanism [12]. For commercial customers, some costs are objective and direct, and therefore relatively

easy to translate to an economic value. For household customers however, there are many subjective and indirect costs. Some customers are more sensitive to many interruptions (e.g. costly start up processes) while other are more sensitive to the length of the interruptions (e.g. frozen products in a grocery store). The interruption cost differ a lot both between and within customer groups [13]. Today's costs is based on studies from [14], updated by SINTEF [15] and annually adjusted by a consumer price index. During the first regulatory period (2012-2015) an average cost was used for all customers, but from 2016 all customer categories has their own average cost as shown in Table 1. Since a lot has happened in the society since the last study of interruption costs, a new study has been initiated, conducted by the same research group as in the previous study [14].

Table 1 Interruption costs currently used in the regulation (2014)

Kundkategori, k	Unnotified interruptions		Notified interruptions	
	$K_{P,2,k}$ [SEK ¹ /kW]	$K_{E,2,k}$ [SEK ¹ /kWh]	$K_{P,1,k}$ [SEK ¹ /kW]	$K_{E,1,k}$ [SEK ¹ /kWh]
Agriculture	8	44	3	26
Industry	23	71	22	70
Commercial service	62	148	41	135
Public service	5	39	4	24
Household	1	2	0	2

¹SEK = Swedish krona, 100 SEK \approx €10 (EUR) or \approx \$11 (USD), in August 2016

Calculating the quality adjustment

When the interruption cost parameters are set, the norm levels are calculated and the values for SAIDI, SAIFI and CEMI₄ are collected, it is time to calculate the total incentive, i.e. the reward or penalty. The calculation of the total incentive is made in several steps. First, the yearly financial outcome, Q_y , based on SAIDI, SAIFI and the interruption costs are calculated as in equation 3:

$$Q_y = \sum_{k=1}^5 \sum_{j=1}^2 \left((SAIDI_{b,j,k} - SAIDI_{o,j,k}) K_{E,j,k} + (SAIFI_{b,j,k} - SAIFI_{o,j,k}) K_{P,j,k} \right) P_{av} \quad (3)$$

where y represent the year, k represents the five different customer groups (1-5), j represents the two categories of interruptions (notified and unnotified), b represents the norm level and o represents the outcome during the period of regulation. $SAIDI$ is the average interruption time given in minutes and $SAIFI$ is the average number of interruptions. K_E is the cost parameter given in SEK/kWh, K_P is the cost parameter given in SEK/kW (see Table 1) and finally, P_{av} is the average yearly power usage, calculated as in equation 4:

$$P_{av} = \frac{E_{y,k}}{H_y} \quad (4)$$

where E is the total energy consumption for each customer type k and year y and H_y is the number of hours during the year y . A difference from the first regulatory is that the DSO get the entire reward or penalty from equation 3, while during the first period that was shared equally between the DSO and the customers by adding a factor 0.5 in the equation. That is motivated by the fact that the marginal cost for increasing reliability should be equal to the marginal interruption cost [16].

Adjusting the result due to CEMI₄

When the incentive Q_y is calculated, the incentive will be adjusted depending on CEMI₄. The size of the yearly adjustment, $CEMI_{4\delta,y}$, is calculated from the norm level based on each DSOs own historical performance $CEMI_{4,b}$ and yearly outcome $CEMI_{4,y}$ as in equation 5:

$$CEMI_{4\delta,y} = CEMI_{4,b} - CEMI_{4,y} \quad (5)$$

To avoid unreasonably large impact of CEMI₄, a limitation is set to $\pm 0,25$, meaning that the addition or reduction of the incentive Q_y can be max 25 % (see equation 6). If the total incentive Q_y is positive (i.e. addition on the revenue cap) and $CEMI_{4\delta,y}$ is negative, the incentive will be reduced. If the total incentive Q_y is negative (i.e. reduction of the revenue cap) but $CEMI_{4\delta,y}$ increased, the reduction of the incentive will be reduced. If Q_y is positive and $CEMI_{4\delta,y}$ is positive, or if Q_y is negative and $CEMI_{4\delta,y}$ is negative, the incentive will be unchanged. In this way, CEMI₄ is only used to mitigate the incentive and cannot make it larger in any direction. For the cases where CEMI₄ does not impact on the

incentive, the final yearly incentive Q_{Ty} is equal to Q_y . For the cases where $CEMI_4$ impact the incentive, Q_{Ty} is calculated by equation 6:

$$Q_{Ty} = \begin{cases} Q_y & \text{if } CEMI_{4\delta,y} \text{ is changed in same "direction" as the reliability index} \\ Q_y(1 - |CEMI_{4\delta,y}|) & \text{if the first not is fulfilled and if } |CEMI_{4\delta,y}| < 0.25 \\ Q_y(1 - 0.25) & \text{if the first not is fulfilled and if } |CEMI_{4\delta,y}| \geq 0.25 \end{cases} \quad (6)$$

The total incentive for the four year regulatory period Q_T is finally summarized as in equation 7:

$$Q_T = \sum Q_{Ty} \quad (7)$$

How the incentive scheme is applied/calculated for regional DSOs (sub-transmission) and for the TSO

The incentive scheme for the regional DSOs (sub-transmission networks) is designed in a slightly different way than the incentive scheme for the local DSOs described earlier in this section.. Although many things are similar, e.g. same customer groups and outage costs per kW and kWh respectively. There are also a number of differences to the model:

- The calculations of average power/energy not supplied are performed for each load point instead of for each customer group as for local level.
- There is no adjustment of the incentive with $CEMI_4$.
- Norm levels are only based on own history (too few to DSOs at this level to benchmark with other).
- Outages between 100 msec and 3 minutes is input to power not supply, while short outages don't affect the revenue cap for local DSOs. At low voltage levels, short outages can indicate that the DSO has invested in fast switching possibilities and should not be punished for that, while it is more realistic for regional DSOs and the TSO to handle failures without resulting in an interruption for its customers.

The incentives provided to the TSO are designed in a similar way as the incentives provided to the regional DSOs. The same indicators are used, but since there are very few interruptions at transmission level, the baseline is based on data from a period of 10 years. Another difference is that the indicators PNS and ENS are based on the actual power and energy not supplied, and not the yearly average.

Outages above 12 hours and other incentives for reliability of supply

Outages above 12 hours are not included in the calculation of the incentive scheme. The reason is to avoid punishing the DSOs twice for same events. While outages longer than 12 hours are subject to individual economic customer compensation, outages lasting between 3 minutes and 12 hours are subject to a possible indirect "collective compensation" by affecting tariff levels. Table 2 illustrates the consequence of an outage as a function of its length.

Table 2 Consequences of outages longer than 12 hours

Outage length [hours]	Customer compensation [SEK*]	Minimum customer compensation**** [SEK]
100 msec – 3 min	Data collected by Ei, but only input to the regulation for regional DSOs and the TSO	
3 min-12 hours	Input to the revenue cap regulation	-
12-24 hours	12.5 % of α^{**}	2 % of β^{***}
24-48 hours	37.5 % of $\alpha + \gamma^{*****}$	4 % of β
Following 24 hour periods	+ 25 % of $\alpha + \gamma$	+ 2 % of β
...
Max	300 % of $\alpha + \gamma$	-

*SEK = Swedish crowns, 100 SEK \approx €10 (EUR) or \approx \$11 (USD), in August 2016

** α = Individual customer's annual network tariff

*** β = Yearly set base amount (44 800 SEK in 2017)

**** Set to even 100 SEK values, rounded up \rightarrow 2 % of β 2017 is rounded up to 900 SEK.

***** γ = Possible additional consequences of breaking the law of 24 hour functional requirement

Furthermore, the Electricity Act defines a minimum requirement that interruptions above 24 hours never are allowed. Ei also has the possibility to define even more strict minimum requirements. An example of such requirement is that it is not allowed to have more than 11 interruptions per year for a customer, i.e. $CEMI_{12}$ (EIFS 2013:1).

Newly implemented incentive scheme for efficient grid utilization

Introduction

In accordance to Article 15(4) of the Energy Efficiency Directive [18], EU member states shall ensure that DSOs are incentivized to improve efficiency in infrastructure design and operation. As a result of the new rules, Ei was given the mandate to decide on what is considered as an efficient utilization and to design new incentive schemes to promote increased efficiency [19]. Costs associated with energy efficiency were previous considered as “non-controllable costs” and were transferred directly to the revenue cap, i.e. to the customer bills. By adding new incentives from 2016, the DSO has been given incentives to increase efficiency in the grid utilization. The utilization incentive scheme is divided into two parts: a) incentive to reduce energy losses and b) incentive to increase system utilization by improve load factor and reduce cost to superior grid. This incentive scheme is described more in detail in [20] or in [21].

Incentive to reduce energy losses

The incentive is designed so that an increase or reduction of the percentage of network losses in comparison to the company’s historical level of network losses will lead to a reduction or addition to the revenue cap. Equation 8 is used to calculate the incentive for network losses.

$$K_n = (Nf_{norm} - Nf_{turn-out}) * E_{turn-out} * P_n * 0.5 \quad (8)$$

where

- K_n is the value of the incentive for network losses, an addition or reduction on the revenue cap. [kSEK – thousands of Swedish kronor].
- Nf_{norm} is the historical share of network losses for each DSO (2010-2013) as a percentage of the total amount of energy distributed. [%]
- $Nf_{turn-out}$ is the share of network losses for each DSO during the regulatory period (2016-2019) as a percentage of the total amount of energy distributed. [%]
- $E_{turn-out}$ is the amount of distributed energy during the regulatory period (2016-2019). [MWh]
- P_n is the price per megawatt hour for network losses calculated as an average price during the regulatory period (2016-2019). All DSOs’ costs for network losses are considered in the calculation. [kSEK/MWh]
- The factor, 0.5, in equation 8 leads to that an improvement regarding network losses will reward the DSO with half of the additional value of the reduction. The other half of the additional value will benefit the customers due to a lower revenue cap. On the contrary, if the share of network losses increases, half of the reduction of the revenue cap will be transferred to the customers from the grid company’s revenue cap.

There are several ways for a network operator to decrease energy losses:

- Increase the voltage level (often not an option)
- New equipment (material, feeder area etc.)
- More even utilization (e.g. smart grid solutions)

Incentive to increase system utilization

The capacity of power systems must consider peak loads. Hence, the larger gap between peak and average load, the less average utilization. Better utilization can lead to lower fee to feeding grid since that cost often depends on the highest load. However, its level haven’t any effect on the return part of the regulaion, only what the customer pays. To increase the incentive to reduce this fee, this incentive scheme was introduced, where the DSO can get a share of such cost reduction. This incentive is designed to only be able to reward and not punish the DSO.

In order to monetize the incentive, Ei combined the load factor (see equation 11) with the reduction of the cost that DSOs pay to the feeding grid for withdrawal of electricity, i.e. a feeding grid charge. Equation 9 is used to calculate the incentive for cost of feeding grid and average load factor.

$$K_b = \begin{cases} Lf_{turn-out} * B_{diff} * E_{turn-out} & \text{if } B_{diff} < 0 \\ 0 & \text{if } B_{diff} \geq 0 \end{cases} \quad (9)$$

$$Lf_{turn-out} = \frac{\sum_{i=1}^{D_t} Lf_i}{D_t} \quad (10)$$

$$Lf_i = \frac{P_{average,i}}{P_{max,i}} \quad (11)$$

where

- K_b is the value of the incentive for cost of feeding grid and average load factor. [kSEK]
- $Lf_{turn-out}$ is the sum of all daily load factors, Lf_i , divided by the number of days, D_t , during the regulatory period.
 - Lf_i is the average load divided by the maximum load during day i .
 - $P_{average,i}$ is the average load during day i . This is calculated as the sum of load in the connection points between DSOs during a day divided by 24 (hours during a day). [MWh/h]
 - $P_{max,i}$ is the maximum load during day i . This is calculated as the sum of all connection points loads at the hour of the day when the highest load sum occur. [MWh/h]
 - The calculation of $P_{average,i}$ and $P_{max,i}$ requires that the load is measured on an hourly basis.
- $B_{diff} = B_{norm} - B_{turn-out}$ is the saving per megawatt hour for the cost that DSOs pay to the feeding grid, i.e. the feeding grid charge, for the withdrawal and costs for the input of electricity. [kSEK/MWh]
 - B_{norm} is the cost that DSOs pay to the superior grid, i.e. the feeding grid charge, for the withdrawal and costs for the input of electricity during the reference period (2010-2013) divided by the amount of distributed energy during the reference period. [kSEK/MWh]
 - $B_{turn-out}$ is the cost that DSOs pay to the feeding grid, i.e. the feeding grid charge, for the withdrawal and costs for the input of electricity during the regulatory period (2016-2019) divided by the amount of distributed energy during the regulatory period. [kSEK/MWh]
- $E_{turn-out}$ is the distributed energy during the regulatory period (2016-2019). [MWh]

In this incentive, there is no fixed factor for what share of the addition to the revenue cap that the DSO may keep, compared to the factor 0.5 for the incentive regarding network losses. In this case, the DSO first need to make an improvement regarding the cost for the feeding grid and that amount will be shared between the DSO and its customers. The percentage that the grid company may keep corresponds to the load factor, which in the extreme case, where the average load and maximum load are the same, results in keeping the whole profit.

How to calculate the size of the adjustment to the revenue cap

The adjustments are based on two incentive schemes: 1) reliability of supply and 2) efficient utilization part. The results from these incentive schemes are summarized and integrated in the rest of the revenue cap regulation as described in this sub-section.

Two changes on how to summarize the adjustments of incentive schemes has been implemented from 2016. The first one is that the upper and lower limit in percentage of the revenue cap has increased from $\pm 3\%$ to $\pm 5\%$. The other change is that during the first period (2012-2015), the limits was calculated on the sum of each year and from the second period (2016-2020) a limit will be calculated based on the sum of all four years. The total adjustment is based on equation 7, 8 and 9, and then calculated as showed in equation 12:

$$Total\ adjustment = \begin{cases} -0.05 * [revenue\ cap] & \text{if } (Q_T + K_n + K_b) \leq -0.05 * [revenue\ cap] \\ +0.05 * [revenue\ cap] & \text{if } (Q_T + K_n + K_b) \geq 0.05 * [revenue\ cap] \\ Q_T + K_n + K_b & \text{else} \end{cases} \quad (12)$$

Where Q_T , K_n and K_b are defined by equation 7, 8 and 9 respectively. The absolute value of the reduction in equation 12, $|-0.05 * [revenue\ cap]|$, is not allowed to be higher than the return according to the Electricity Act. If that is the case, the reduction is set to be equal to the return. Ei had however conducted analyzes showing that the return almost never is lower than 5 % of the revenue cap with today's parameters.

Discussion – preview of some analyses results and ideas of future development

Preview of results from sensitivity analyses

A great part of the regulation is currently modelled in Excel, where several hundred parameters (input data) can be changed. The regulation can both be tested regarding current rules, but also with hypothetical modifications of e.g. the depreciation time or by using nominal instead of real depreciation method. This model will be used within the developing work and results based on the model may be presented in the future. Some overall initial results from sensitivity analyses are presented here.

Figure 5 illustrates a sensitivity analysis of the developed reliability of supply incentive scheme presented in the paper. All reliability indices are increased or decreased equally and the possible impact from CEMI4 is also illustrated. Figure 6 illustrates how the incentive scheme in equation 8 (losses) can affect the revenue cap. In reality however, the interval of realistic changes of losses between two regulatory periods is quite small and it is not possible to reach zero network losses. Figure 7 exemplifies some more sensitivity analyses. The system used as input when performing those sensitivity analyses has following characteristics as base case: a customer density of 8.01 customers/km, 24.23 years as the average age of current carrying equipment and 6.5 years for other equipment (6 % of the capital base consist of such), losses and reliability indices equal to its norm levels (changed later in the analyses) and a revenue cap with 44 % capital costs and 56 % operational costs.

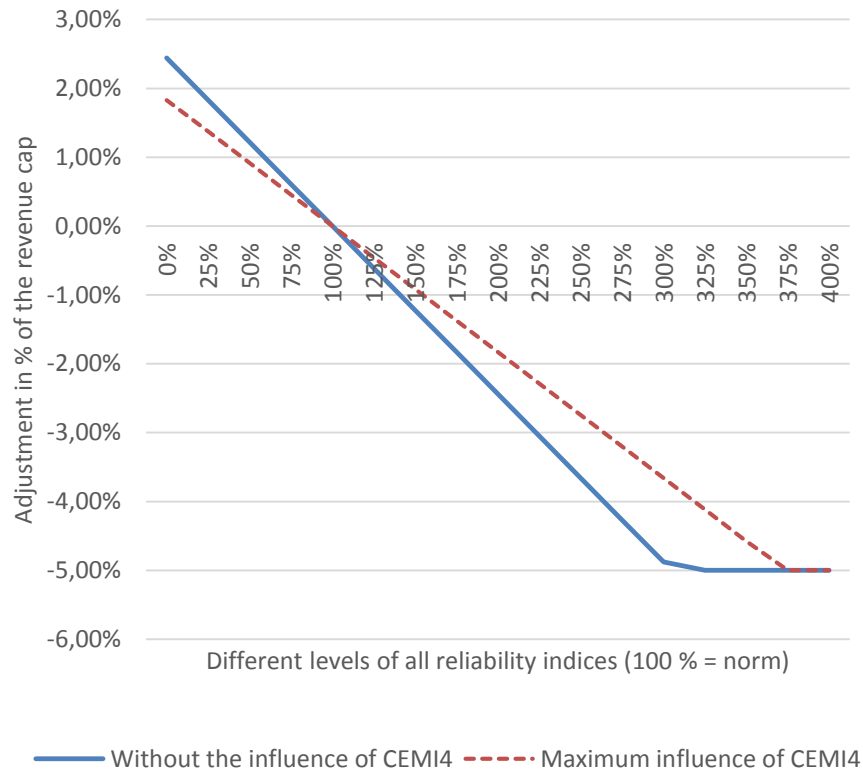


Figure 5 Example of changes of revenue cap as a function of changes in all reliability indices at the same time with two examples: influence of CEMI4 = a) largest possible and b) no influence at all.

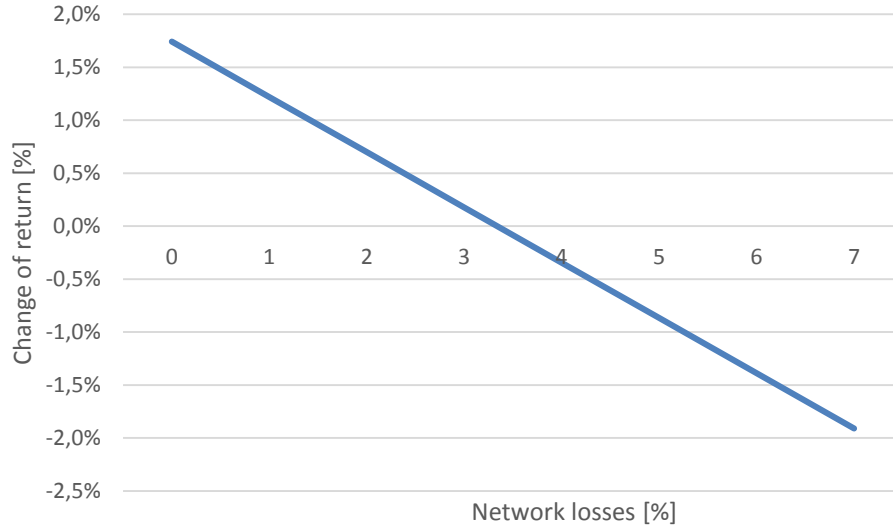


Figure 6 Change of the return part of the revenue cap (the change of the total revenue cap goes however in opposite direction since losses also affect operational costs) as a function of network losses. In this example norm level = 3 %.

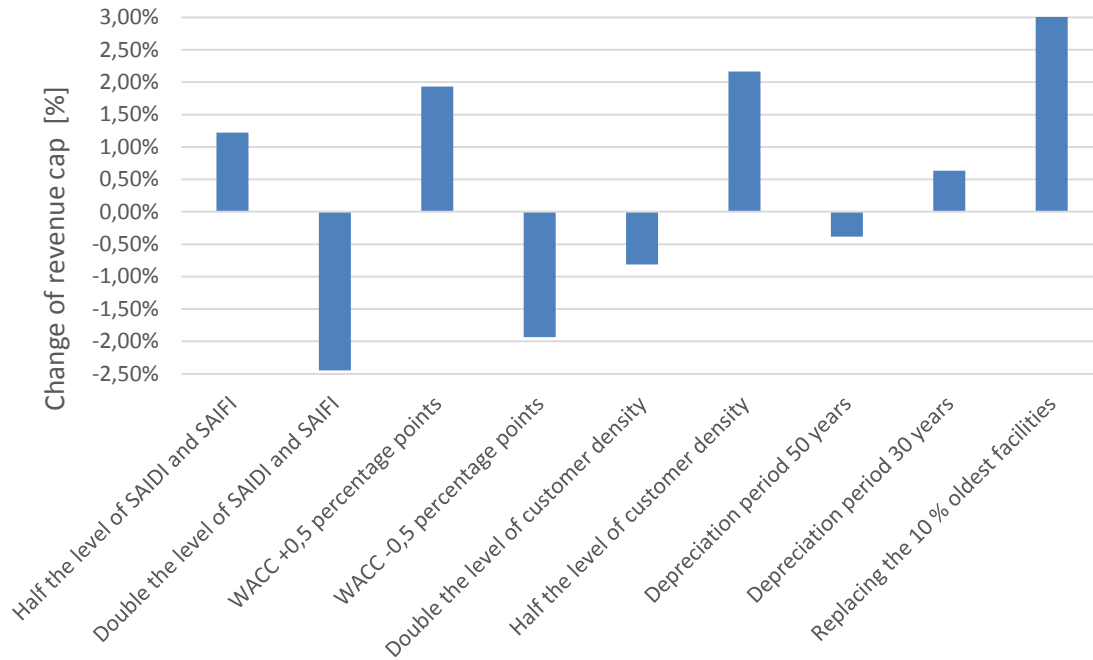


Figure 7 Examples of overall sensitivity analyses results regarding the current regulation

Re-investment strategy incentives

To get a rough estimation of how current economic assumptions affect the incentive of choosing re-investment strategy, an approximatively calculation is presented here:

$$\text{Average profit per year} = \frac{\sum_{i=1}^y \text{Capital cost}_i - \text{PPV}}{\text{PPV} \cdot y} = \frac{\sum_{i=1}^y \frac{\text{Capital cost}_i - 1}{\text{PPV}}}{y} \quad (13)$$

where y is the re-investment year, Capital cost_i is the result from equation 1 regarding year i and PPV is the present purchase value. The results is however independent from the PPV. Figure 1 illustrates the result as a function of re-investment year.

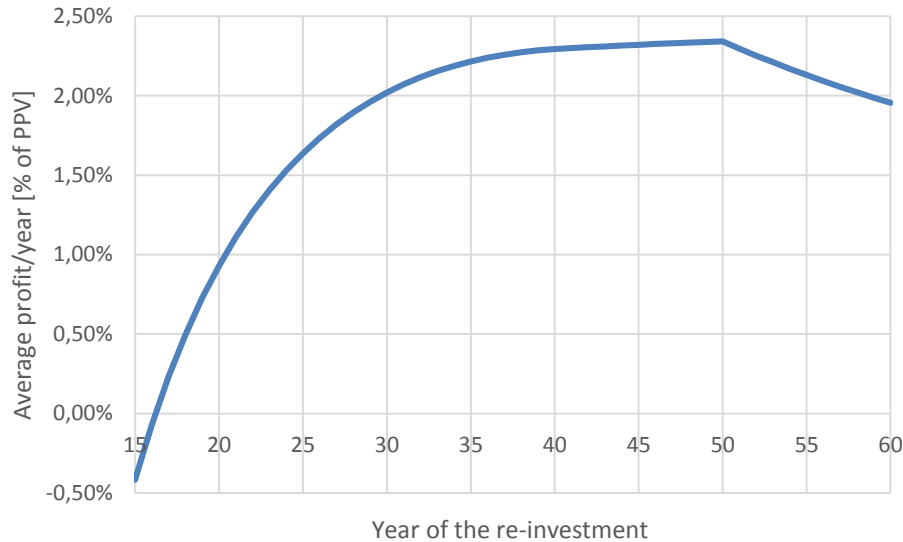


Figure 8 Average profit per year as a function of when the re-investment is done

The optimal time to re-invest is after 50 years. The results is however very stable and the DSO will hence give similar results if the re-investment is done sometime between ~30 and ~58 years. That can be positive since that give more incentive to re-invest when it is technical motivated and not only looking at a theoretical optimum. This also shows that the ten extra years with capital costs give an incentive to keep system parts longer than 40 years if they still are working well. The profit and the optimal re-investment strategy can also differ from this result if the modelled PPV (based on norm lists provided by Ei) isn't the same as the actual PPV. This calculation is just a pre-view of upcoming evaluation and developing work at Ei. Some important things that this model does not capture is:

- How controllable costs such as maintenance are changed with the age and after a re-investment with a more modern component.
- How incentive schemes included in the adjustment part such as reliability and losses are changed with the age and after a re-investment with a more modern component.
- How to move money between years.

Next steps and ideas of future developments

Overall plans of future developments

The overall structure and the most parts within the revenue cap regulation will likely not undergo significant changes when moving from this regulatory period to the next period starting in 2020.

Ei has established a reference group consisting of senior researchers in economics for the purpose of evaluating the economic method, economic assumptions and to discuss the development process. As regards the incentive schemes (see Figure 1), Ei will start a new development project in 2017. The development will consider changes for the regulatory period starting in 2020, but also more long-term ideas. Focus will likely be on the utilization incentive scheme (also referred to as smart grid incentive scheme), which is the newest part in the regulation and also the part that will mostly be affected by new future smart grid techniques and solutions.

Evaluation and development of the utilization incentive scheme

During the first half of 2016, a Master of Science thesis was supervised by Ei [22]. The master's thesis, named "Indicators for assessing efficient power grid utilization", investigated other possible indicators than the load factor and network losses in the utilization incentive scheme. The analyses evaluated the used load factor as well as three other indicators that also treats load in the interconnection points between DSOs. The used load factor has also been further analyzed and possible changes to the load factor was suggested.

To analyze the indicators, a simulation model was created. A previously developed test network was used as model for the customer mix and load patterns used. During this work, data from a medium-sized Swedish DSO was also analyzed. The created model treats three different scenarios and their impact on the analyzed indicators. The scenarios

are about demand response, an increased proportion of solar cells in the network as well as an increased amount of electric cars and their resulting load from home charging.

For the used load factor, the indicator is calculated as an arithmetic average with the same weight for each daily load factor. The arithmetic mean implies that all daily load factors are equally important. Depending on what the indicator should try to incentivize, other ways of weighting is relevant to investigate in addition. The largest concern with giving each daily load factor an equal weight is that an even load has bigger advantages on days with a higher load than on less congested days. To further incentivize evening out the load on days with a higher load a weighted average with respect to the amount of energy transmitted for the daily load factors was suggested. The suggested calculation for the weighted load factor is presented in equation 14 to use instead of equation 10:

$$Lf_{turn-out} = \sum_{i=1}^{D_t} \left(\left(\frac{E_i^x}{\sum_{i=1}^{D_t} E_i^x} \right) Lf_i \right) \quad (14)$$

where Lf is the same as defined in equation 11, D_t is number of days during the regulatory period, E_i is the total energy during day i and x can be adjusted to weight the load factor differently according to the energy, for example:

- The extreme case $x = 0 \rightarrow$ equation 10 = equation 14.
- x between 0 and 1 gives less weight than linear a linear relation, but still some weight.
- $x = 1$ gives a linear relation between energy and weight.
- When x increases above 1, the importance of the energy increases with x .
- If x is very high, only the days with most energy consumption matters.

Results from the master thesis, based on the scenario $x=1$, mainly showed small changes in the value of the analyzed indicators for the analyzed scenarios. The most important thing to consider, based on the results, was that an increase in solar power in a network could have a negative impact on the analyzed indicators. This should be taken into consideration when using the analyzed indicators in an incentive scheme for efficient utilization.

This and other aspects of potential changes in the utilization incentive scheme will be investigated further. Further analysis of the approach described in equation 14 could be to make analyses regarding different choices of x or to using max daily power instead of the daily energy to weight different days. The highest power is often more important than the energy when optimizing the utilization. Other ideas on next steps is for example to evaluate the incentive based on network losses and to evaluate if the relation between load factor and fee to feeding grid should continue as today. It is also of interest to investigating new approaches that is not included today.

Conclusions

Electric power transmission and distribution is considered as natural monopolies. Ei has the role, as the Swedish national regulatory authority, to provide incentives for cost efficient operation with acceptable reliability and with objective, reasonable and non-discriminatory customer tariffs regarding this infrastructure. A revenue cap regulation developed by Ei is described with focus on changes implemented from 2016. The changes consist e.g. of a new economic model and new and changed incentive schemes. The paper aims to be a reference material in English to inspire as well as a chance for others to give feedback to us (Ei has earlier published Swedish reports).

Currently, the whole power system is moving in the direction of what is often referred to as the “smart grid” and the infrastructure is an important part to consider when meeting future climate challenges. From a regulatory point of view, it is of great importance to continuously and carefully adapt the regulatory model to accommodate these challenges whilst at the same time maintaining a robust regulation over time to avoid too much uncertainty for DSOs in their long-term investment planning. Finally, existing methods and future plans are briefly discussed and some sensitivity analyses results are published.

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