# ANALYSES OF THE CURRENT SWEDISH REVENUE CAP REGULATION

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## *ABSTRACT*

*The Swedish regulation of distribution system operators' (DSOs') revenues underwent changes in 2016. It is necessary to continuously adapt and improve the regulation as the conditions under which the DSOs operate change over time. However, it is also important to maintain the stability and predictability of the regulatory regime in order to facilitate long-term planning.*

*The Swedish Energy Market Inspectorate (Ei) is currently looking into how the revenue cap regulation may be improved from the next regulatory period (2020-2023) and beyond. In this context, the regulation has been modeled. By changing parameters in the regulation, we illustrate how different parts of the regulatory model interact and how the outcome is affected. This paper presents some result of this analysis. The analysis can be useful to both evaluate the current regulatory model and to analyze the impact of hypothetical changes to the regulation. This will increase the understanding of the model. The paper also aims to facilitate an international knowledge exchange.*

## INTRODUCTION

The Swedish electricity market was deregulated in 1996. Trade and generation of electricity was then exposed to competition, while the infrastructure operation remained as regulated monopolies (i.e. unbundling). Performance based regulation of distribution system operators (DSOs) was first introduced in Sweden in 2003. Since then, many new rules affecting the DSOs have been introduced, e.g. to create incentives for improved Continuity of Supply (CoS) [1] and for a more efficient utilization of the grid [2].

Sweden has approximately 170 DSOs, all with different conditions regarding size, ownership and clime/terrain, making it a great challenge to develop an effective regulatory model. The Swedish national regulatory authority (NRA) for energy, the Energy Markets Inspectorate (Ei), determines a revenue cap for each DSO for a regulatory period of four years. The revenue cap regulation was first introduced in 2012 and underwent changes to the second regulatory period 2016-2019 [3]. This paper presents some results of ongoing analyses. The analyses, in which we study both the current regulatory model and hypothetical changes to the regulation, will serve as input to our work to further develop the regulation.

Table 1 defines some terms concerning CoS that are used later in the paper. More information of the terms, see [4].

**Table 1 Definitions**

| | |
|---|---|
| $CEMI_4$ | The share of customers with four or more interruptions during a year. An indicator used by Ei since 2016 to incentivize DSOs to reduce the number of customers experiencing four or more interruptions per year. This indicator can only lower the reward or the penalty. |
| SAIDI | System Average Interruption Duration Index, the average outage time per customer and year. |
| SAIFI | System Average Interruption Frequency Index, the average number of interruptions per customer and year. |

## CURRENT REVENUE CAP REGULATION

The current regulatory model is illustrated in Figure 1 and described more in a paper published by Ei in 2016, see [3].

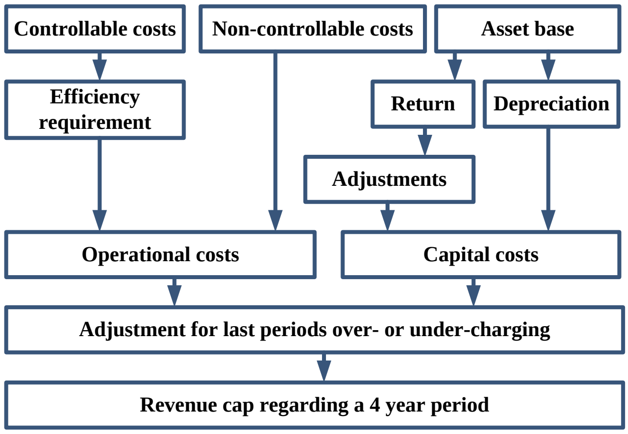


**Figure 1 Overview of the Swedish revenue cap regulation**

More details about current incentive schemes are provided in [4] (CoS) and [2] (efficient utilization/smart grid). Background information regarding the relevant legal framework and the regulatory model, see [1].

## MODELING THE REGULATION

The regulation has been modeled in Excel to analyze both how changes in single parameters affect the outcome (i.e. the size of the revenue cap) and how different parameters interact with each other. Currently, there are almost 250 different input parameters that can be changed. The incentive scheme regarding CoS is particularly complex with a lot of input. Also the asset base contains a large number of parameters. Here are some examples of parameters that can be analyzed:

- *Data specific for the DSO*: Network losses, fee to feeding grid, age structure and the size of the asset base; reliability indices, energy per customer group, efficiency requirement etc.

- *Data that is the same for all DSOs, but that can differ between regulatory periods*: WACC, interruption costs, constants that are used to calculate customer density baselines etc.
- *Hypothetical modifications*: Number of years a component generates capital costs, limits of adjustments, the incentive schemes, risk shares between the DSO and its customers, depreciation method (real or nominal) etc.

The example system used in the paper has the following characteristics as base case: a customer density of 8.01 customers/km, 24.23 years as the average age of current carrying equipment such as lines and transformers and 6.5 years for other equipment such as meters and IT (6 % of the capital base consist of such), network losses and reliability indices equal to its baselines (changed in the analyses) and a revenue cap with the same composition as the Swedish average (~44 % capital costs, ~23 % controllable costs and ~33 % non-controllable costs).

## RESULTS OF THE ANALYSIS

### General sensitivity analyses

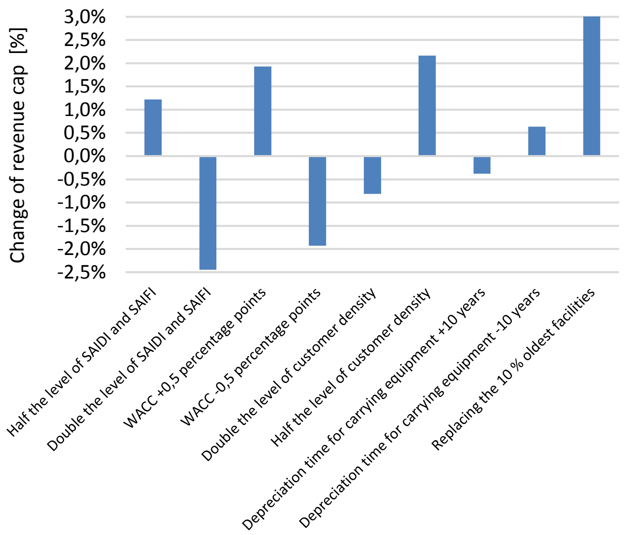


**Figure 2 Overview of how changes in some parameters affect the overall outcome**

Figure 2 provides an overview of how changes in some parameters will impact the outcome of the regulation compared to the base case. The definition of SAIDI, SAIFI and $CEMI_4$ is are provided in Table 1. Note, the examples are not comparable in how difficult, costly or realistic they are for the DSO to achieve or for Ei to change.

### Incentive scheme for CoS

An incentive scheme regarding CoS was first introduced within the Swedish tariff regulation in 2003. In 2016 the incentives scheme became more detailed by e.g. introducing different customer categories, the new $CEMI_4$ indicator, and customer density based benchmarked baselines besides using the DSOs´ own historic levels as baseline. The incentive scheme aims at promoting socioeconomically desirable levels of CoS, and depending on the performance of the DSO, it may result in a reward or penalty on the financial return to the DSO. The incentive scheme is described in detail in [3] and [4].

**SAIDI and SAIFI divided to categories**

Figure 3 shows that the outage time (SAIDI) has a greater impact on the outcome than the number of outages (SAIFI). It also shows that outages notified to the customer in advanced give less economic impact because of lower customer interruption costs.

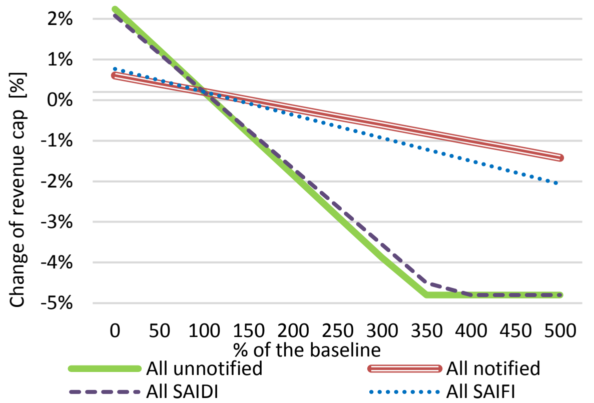


**Figure 3 Changed outcomes as function of changes in different indicator categories [in percentage of the baselines]**

**Table 2 Impact from different customer categories on the revenue cap when SAIDI and SAIFI are doubled**

| Category | Share Number of customers | Share Energy consumption | Share Impact on revenue cap |
|---|---|---|---|
| Agriculture | 1.2 % | 2.6 % | 4.2 % |
| Industry | 0.8 % | 22.9 % | 30.9 % |
| Commercial | 5.6 % | 24.5 % | 57.5 % |
| Public service | 2.3 % | 8.3 % | 5.6 % |
| Household | 90.2 % | 41.8 % | 1.7 % |

Table 2 shows the share each customer category has on the economic impact when SAIDI and SAIFI (all categories) are doubled. Households account for 90.2 % of all customers and 41.8 % of the annual energy consumption, but only 1.7 % of the outage cost is related to this category in the example. These large differences in interruption costs between customer categories are based on interruption cost surveys [4][5][6]. University of Gothenburg is conducting a research study to perform a new customer interruption cost investigation and update the interruption cost parameters used in the regulation.

**Impact from $CEMI_4$**

Figure 4 illustrates the maximum impact of the new indicator $CEMI_4$, if the other reliability indices (SAIDI and SAIFI) are changed equally. The indicator is designed to mitigate the revenue cap adjustment. For more information, see [4].

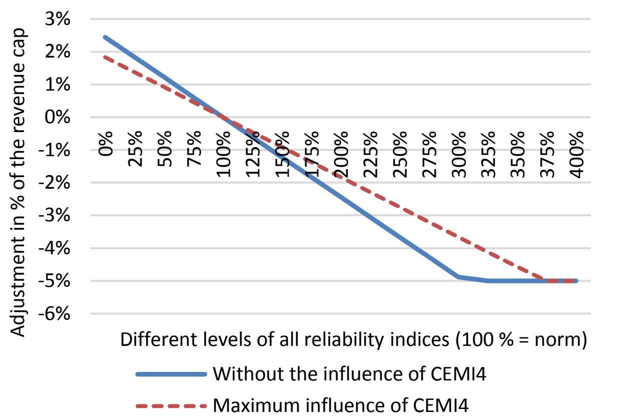


**Figure 4 Adjustment of revenue cap when changing all SAIDI and SAFI equally, with and without the CEMI$_4$ indicator**

**The new baseline function**

The incentive scheme is designed so that the CoS for each DSO is compared to the CoS of other DSOs with similar conditions. Ei has chosen to use customer density to represent the conditions under which the DSOs operate.

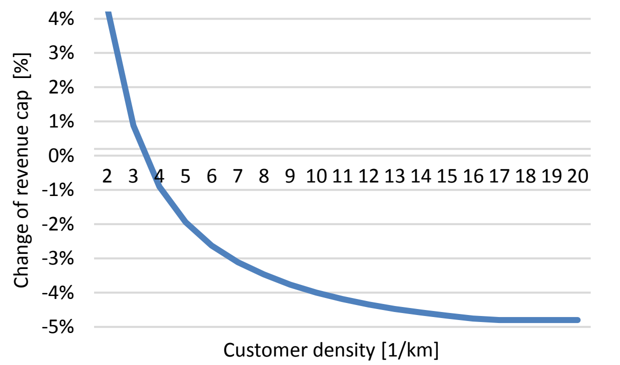


**Figure 5 Sensitivity analysis of the customer density baseline**

Figure 5 exemplifies how the outcome of this incentive scheme depend on the customer density of the DSO. The non-linear curve shape is an effect of the outcome when the baseline functions was calculated by benchmarking. New function parameters are calculated for each regulatory period. All DSOs' different reliability indices and their customer densities are input to least square fit calculations regarding functions with three different constants and with customer density as variable. Two reliability indices (SAIDI and SAIFI), notified and non-notified, and five customer groups gives 2*2*5=20 different baseline functions. DSOs performing above such baseline level, however, uses its own historic level of CoS as baseline instead. More information, see [3] and [4].

## Incentive scheme for efficient grid utilization

In accordance to the Energy Efficiency Directive [7], 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. This incentive scheme is divided into two parts: a) incentive to reduce network losses and b) incentive to increase grid utilization by improve load factor and reduce cost to feeding grid. This incentive scheme is described in more detail in [2]. Note, the efficient grid utilization discussed here, is a different part of the regulation than the efficiency requirement of operational costs analyzed later.

**Changing network losses**

Costs associated with network losses has traditionally been considered as "non-controllable costs" and transferred directly to the revenue cap. By introducing the new incentive scheme in 2016, the DSOs are incentivized to increase efficiency in the grid utilization. Figure 6 illustrate how different levels of network losses [%] affect the revenue cap. Traditionally, only operational cost changed with network losses (red dashed line), but with the new incentive scheme, the sum (blue solid line) is partly affected by the incentive scheme (green dotted line).

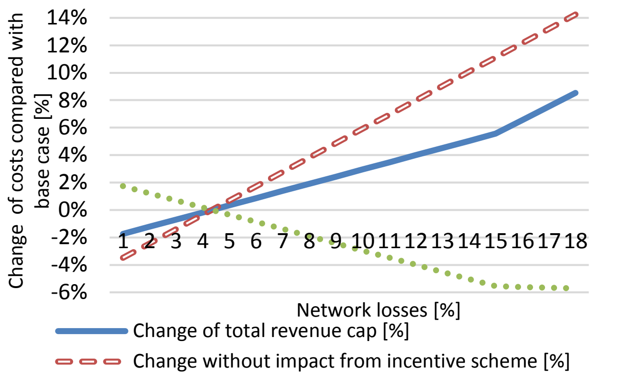


**Figure 6 Sensitivity analysis of changing the network losses**

**Changing the annual energy withdrawn**

From the 2016 year's data, the DSO will report both energy fed into and energy withdrawn from the system in each meter point. The energy withdrawn (in the rest of the paper referred to as just "energy") is one of several input variables in the model that can change the incentive scheme for efficient grid utilization (equations and more details in [2]). In this analysis, the energy is assumed to be changed equally in all meter points and the energy fed into the system is assumed to be constant.

Figure 7 illustrate how a change of the annual energy withdrawn in a system (in the rest of the paper referred to as just "energy") can affect different incentive schemes. If no other parameters are changed in the model, the results is equal with assumption 3 (see Table 3) in Figure 7. However, that only gives a linear correlation with the network losses, while it is for many kind of losses more theoretical correct that they are proportional to the energy^2 (assuming constant voltage). Therefore the model also were modified to include that theoretical assumption (included in assumption 1 and 2 – see Table 3), i.e. the network losses in percentage change linear with energy → network losses in kWh change quadratic. The reality can however be much more complex and e.g. depend on how the energy pattern is changed, the share of standby losses and if the DSO compensate increased energy consumption with investing in more capacity.

**Table 3 Summary of the four different assumptions**

| | | How losses depends on energy | |
|---|---|---|---|
| | | Quadratic | Linear |
| **Feeding grid costs** | Linear dependence with energy | Assumption 1 | Assumption 4 |
| | No dependence with energy | Assumption 2 | Assumption 3 |

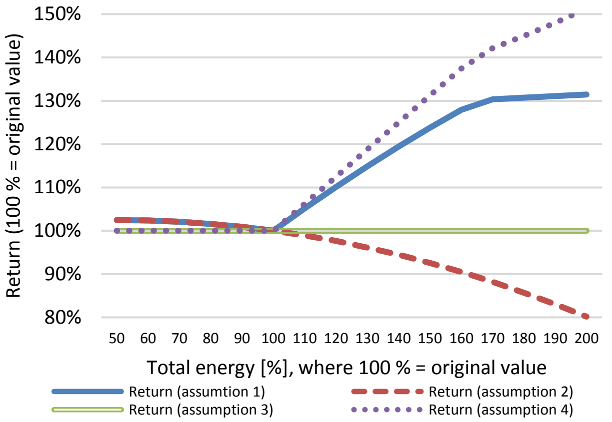


**Figure 7 How changing the total annual energy change the return part of the regulation for four different assumptions**

Regarding the other part of the utilization incentive scheme (fee to feeding grid), the input parameters are defined in a way that it is constant when the energy and the fee to feeding grid have the same change in percent. Consequently, if the fee to feeding grid is unchanged while the energy increases, the DSO will get a bonus (but never the opposite since that part currently only can give a reward). However, the dependency between energy and fee to feeding grid can be complex and depends on e.g. the tariff structure. Therefore also the other extreme, i.e. linear dependency, was tested (assumption 1 and 4). The reality is often between those two extremes. Two possible assumptions regarding network losses and fee to feeding grid respectively, gives four assumptions, see Table 3.

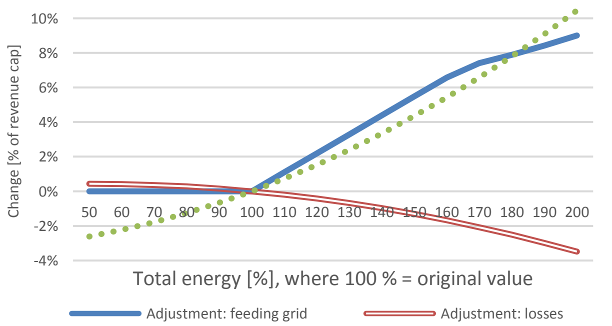


**Figure 8 Non-controllable costs and incentive schemes as function of the energy consumption**

Figure 8 illustrates how non-controllable costs and the incentive scheme (assumption 1 in Table 3) are affected as a function of the energy. All other cost categories are unaffected and hence omitted.

**Other changes of this incentive scheme**

A change in load factor (see [3]) only affects the results if the DSO get a bonus from the feeding grid incentive. If that is the case, the correlation between load factor and bonus is linear. Other parameters such as baseline values and fee to feeding grid, also has simple linear relations with the incentive scheme outcomes and are therefore omitted in the paper to increase focus on more complex analyzes. However, the method of calculating baselines for network losses should be evaluated to decide if a benchmarking method with network losses from other DSOs as input could be suitable.

## Capital cost calculations

**Introduction and discussion of calculation method**

In 2016, the method for calculating capital cost was changed from *real annuity* to *real linear*. A *linear* method requires that the ages of all components are determined, while the old *annuity* method was age independent. *Real* means that the present purchase values of all assets are calculated and summarized as input to the capital cost calculations with a *real* WACC.

A hypothetical nominal approach can also be analyzed in the model. Results shows that a nominal method is more sensitive for changes in depreciation time and gives stronger incentives regarding faster re-investments. On the other hand, such method is less sensitive for changes in WACC. Drawbacks with a nominal approach are e.g. increased risk for “gold plating”, less incentives for making good deals during investments and higher demands on collecting historical data from all DSOs. Example of benefits are more stable capital costs and perceived higher customer acceptance due to not re-calculating the asset base to present purchase values.

**Current real linear method**

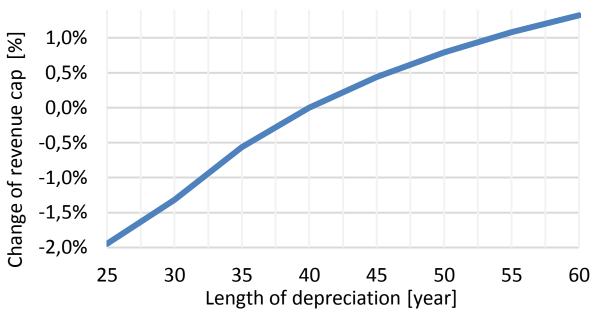


**Figure 9 The revenue cap as a function of depreciation time**

The depreciation time is set to 40 years for current carrying equipment such as lines and transformers and 10 years for other equipment such as meters and IT. For more details of current capital cost calculation method, see [3]. Figure 9 shows how the revenue cap outcome depends on the depreciation time. To avoid threshold effects that depend on the specific example, the age structure was changed so all current-carrying facilities is the same as the average. If some facilities are older than the tested depreciation times, the effects would of course be larger.

Figure 10 illustrates that there is a linear relation between he WACC and the revenue cap. It is only the return part that change, so the potential impact a DSO's revenue can be relatively large.

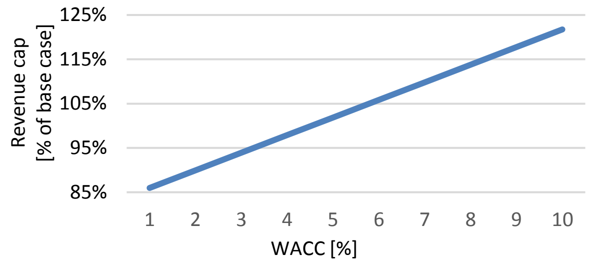


**Figure 10 The revenue cap as a function of WACC**

Figure 11 show how different level of the annual efficiency requirement of controllable operational costs impact on the total revenue cap. Currently this efficiency requirement for each DSO is between 1.00 and 1.82 %.

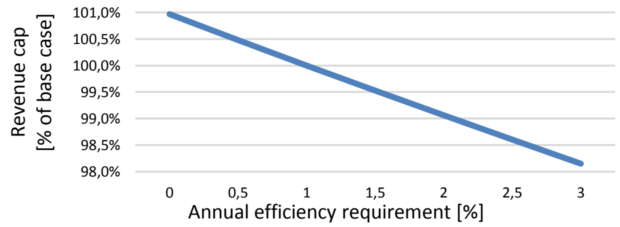


**Figure 11 Changes in the annual efficiency requirement**

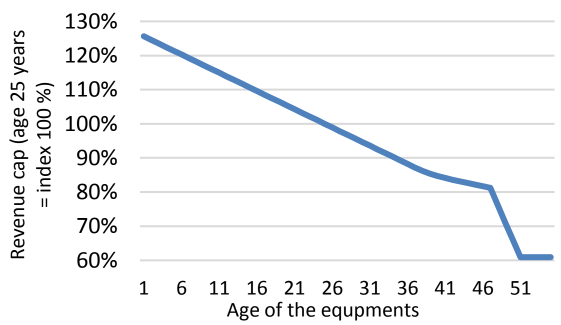


**Figure 12 Revenue cap as a function of age of equipment**

Figure 12 shows how the total revenue cap change if the age of all current-carrying components change equally at the same time. The depreciation time is 40 years, but components between 41 and 50 years still generate capital costs to a lesser extent (more information in [3]). A simplification in the model is that ages is rounded to even years instead of even half years as in the regulation. The curve shape between 47 and 51 years is explained by that the age increases during the simulated regulatory period. If a component is 48 years old it gives capital costs during the three first years of the regulatory period (i.e. 75 % of the time); 49 years old components gives capital costs during 50 % of the period; 50 year old during 25 % and ≥51 years no capital costs at all.

## CONCLUDING REMARKS

It is valuable for Ei to have an international knowledge exchange to learn from as well as to inspire other. The entire Swedish revenue cap regulation has been modeled. It is both possible to change single parts or to analyze how different parts interact with each other. This paper presents a selection of analysis results, representing different parts of the regulation such as all incentive schemes, capital cost calculations and other assumptions. The results can increase the understanding for the regulation and are valuable inputs in the ongoing developing work to analyze current regulation and hypothetical changes.

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 conditions under which the DSOs operate have also developed over time. Ei will continue to monitor the outcome of the regulation 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. Ei is currently looking into how the regulation may be improved from the next regulatory period (2020-2023) and beyond.

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