Learning from Experiences of the prior Swedish Electrical Distribution System Regulation

-Reference Material when Developing the Future Regulatory Incentives

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Abstract— The electric power system is under an extensive development phase. This change is today normally expressed in the concept of Smart Grid. It captures different developments for a sustainable electric power system, e.g. including large changes at the electrical distribution level with new features for electricity customers. One move in these changes is the larger role of the regulator. In Sweden, a performance based regulatory model was introduced in 2003 as a tool to support in judging if the distribution system operators (DSOs) was charging the customers the right level of tariffs. The model was referred to as the Network Performance Assessment Model (NPAM). The NPAM was an international unique and innovative regulatory tool. The model evaluated tariffs by enter several system data to a computer program which produce a fictive network with the aim of having the same objective conditions as the real system. However, the NPAM was strongly criticized and since 2009 formally abandoned and a new regulation will be introduced 2012. Moreover, the NPAM not support climate incentives such as low losses, which will be a challenge when adopting a smart grid perspective into the regulation of distribution system tariffs in the future.

The authors of this paper have followed the development of this model, and have a unique insight in the complexity behind the model. No stringent description of the NPAM is available. This paper aims to fill this gap by providing an overall picture of the NPAM including hitherto unpublished details on underlying theory. This could hopefully inspire and give a reference when developing regulations in different countries in the future by learning from its novelties as well as from its drawbacks.

Index Terms—Incentives, Performance-based regulation, Reference networks, Regulatory models.

I. INTRODUCTION

The electric power system is under an extensive development phase, and one development involves the

increased role of the regulatory. The regulatory is getting a larger role for handling the incentives for investments in the electrical distribution system as well as regulation concerning the customer value of the system. The overall change of the electric power system is today normally expressed in the concept of Smart Grid. It captures different developments for a sustainable electric power system, e.g. including large changes at the electrical distribution level with new features for electricity customers [1]. Governments are currently starting different programs and investigations studying how they could best adopt to these changes. E.g. the Market Inspector in Sweden has recently got an assignment to investigate how Sweden should handle Smart metering and intelligent Grid [2].

A. Background

The Swedish electricity market was de-regulated in 1996 and a new regulating authority, the Swedish Energy Agency (STEM), was established in 1998. The distribution was however still operated as regional natural monopolies, with responsibilities as well as privileges for the distribution system operators (DSOs). Earlier, the DSOs were more or less allowed to compensate for all their costs by settle tariff levels regardless the effectively and quality. Following the de-regulation, STEM identified a problem with increased tariff levels. Despite several attempts by STEM to keep the tariffs down, e.g. through price freezing, no solution was found. There was therefore needed to find a new regulation paradigm [3].

In 1998, a project was initiated by STEM to propose a new regulation model. The model was to be based on self-regulation and was to give incentives to increase the cost efficiency and maintain a reasonable quality. The first approach was to use an existing model adjusted to Swedish conditions. However, when no model was suitable enough according to SETM's requirements of customer focus and cost efficiently incentives, it was decided to develop a new model. The proposed regulation model meant a change in perspective from a company to a consumer focus [4]. As a result of this new customer perspective, the legislation was changed [5].

From an international perspective, the NPAM was a unique and innovative regulatory tool. The model evaluated tariffs ex-post by enter several system data to a computer program which produce a fictive network (often with low

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correlation with the real network) with the aim of having the same objective conditions as the real system [6]. Followed by the use of this regulatory tool, STEM demanded repayments from several DSOs each year from the tariffs of 2003, based on strong indications of too high tariff levels according to results from the NPAM. The Energy Markets Inspectorate (EI), a division of STEM, becomes an independent authority in 2008 with responsibilities of e.g. regulate electrical distribution system tariff levels.

B. Difficulties followed by the end of the model

The tariff regulation using the NPAM as the primary tool was however strongly criticized by stakeholders followed legal processes. For example the NPAM was criticized to not taking historical circumstances (such as investments to areas with decreasing need of electricity) into consideration and not be robust enough to fulfill the criteria of objectiveness [7]. These legal processes would have taken several years and cost a lot of time and recourses only to treat 2003, while new legal processes was added for each year. In late 2008 the parties made an agreement for 2003-2007, that includes fewer DSOs and, compared with the original demand, low levels of repayments. In January 2009 the regulator decided to formally abandon the NPAM.

C. Objectives and outline

This paper first gives a brief introduction to the upcoming regulatory model including a discussion of how the smart grid concept ought to be handling by the regulator (Chapter II). Some of the theory of the NPAM is presented in [8], and there are several publications studying the model e.g. [9]-[12], but no stringent description of the complete model is available. This paper aims to fill this gap by providing an overall picture of the NPAM including hitherto unpublished details on underlying theory (Chapter III-V). This could hopefully inspire and give a reference when developing regulations in different countries in the future; both by learning from novel theory as well as learning from mistakes done in Sweden.

II. INTRODUCTION TO THE UPCOMING REGULATORY MODEL

A. Overview

The major parts of the new regulation [13] are settled, but details remains to be determine and everything will not be included in the first version. The new regulation aims to give a stable prediction of the revenue which hopefully will facilitate investment- and maintenance planning performed by the DSOs. Historical data from recent years gives a preliminary revenue framework for a period of four years. Changes in conditions compared with the forecast can be later adjusted.

The revenue framework is based on following parts:

- **Capital costs:** The capital cost of a component consists of depreciations and the cost of restricted capital. The regulator intends to apply capacity conservation principles by using real annuity. A constant annuity is calculated based on the estimated net present value and economical lifetime. The constant annuity value is used

despite actual age, which makes it easier for both parties. If a component is older than its estimated economical lifetime, the compensation will be the same (DSOs who maintain their components well are thus rewarded). The required rate of return is calculated with the WACC method (weighted average cost of capital).

- The operating costs is divided into:
 - **Effectible costs:** During the first regulatory period, a general efficiency requirement will be imposed.
 - **Not effectible costs**, such as taxes, are fully compensated.
- **Quality function:** Costumers may collectively obtain revised tariff levels regardless the individual reliability of 0.05-12 hour outages (for outages ≥ 12 hours, se section C.).

B. Possible future quality aspects

EI has by law the ability to integrate more quality aspects in upcoming regulation, but these will probably not be included in the first phase. However, EI has already the possibility to impose sanctions on DSOs to correct major weaknesses. The additional quality aspects that will be considered in the future are:

- **Administrative deficiencies:** Customer service, information etc. Customer services could be overloaded during large disturbance.
- **Voltage Quality:** transients, waveform, deviation from the normal voltage value etc.
- **Very short interruptions (<0.05 h):** These have traditionally not been included in the Sweden.

C. Additional laws

Parallel with the tariff regulation, parallel laws affecting the operation of electrical distribution systems have been introduced, e.g. compensation for outages above 12 hours, functional requirement of 24 hours and mandatory risk and vulnerability analysis. These are described in e.g. [14]-[15].

III. OVERALL PICTURE OF THE NPAM

A. Summary presentation of the NPAM

The Network Performance Assessment Model

Figure 1 – An overview of the NPAM.

Figure 1 provides an overview of the NPAM. The NPAM builds up a radial fictive reference network, based on annual reported data. The fictive network is based on information in the customer or production nodes. In a pure radial network, each component failure would result in system outage. Consequently, electrical distribution systems often include component redundancy to improve system reliability. To capture this effect in the NPAM, a spare capacity feature was included. The amount of spare capacity, i.e. component redundancy, corresponds to what the customers are willing to pay for. The model estimates this amount and the resulting required investment cost. This cost is then added to the estimated cost of the radial reference network, resulting in a *reference network*. Other costs for operation and maintenance are added. Finally, this total cost can be reduced, but what is known as *reliability cost*, if the performance of the electrical distribution system is better than expected, in terms of customer outage cost. The resulting total cost is referred to as the Network Performance Assessment (NPA).

The NPA is an assessment of the customer values of an electrical distribution system. The fundamental idea of the NPAM is that DSOs will be allowed to collect *revenue* that corresponds to these customer values. The allowed *debiting rate* for a DSO is defined by the quotient of the revenue and the NPA, as shown in (1). The results from NPAM was considered to be the primary tool for the regulating authority to judge the level of tariffs, and to decide if a DSO should be monitored for further review.

$$\text{Debiting Rate} = \frac{\text{Revenue}}{\text{NPA}} \quad (1)$$

The model implies that for an electrical distribution system area with a resulting performance that equals the revenue collected by the DSO (i.e. corresponding to the tariffs), the *debiting rate* is 1. For the first year that the model was used in practice, 1.3 was considered an accepted performance, and for the following year this value was decreased to 1.2.

Moreover, the model resulted in a higher performance value to customers than requested, i.e. NPA larger than the revenue will not be compensated, but, on the other hand, a lower value will result in less accepted revenue. Another aspect to consider is that, since the NPAM studies fictive networks, the customer is not affected by the history of the DSOs or by poor efficiency.

B. Overall picture of the NPAM

Figure 1 illustrates how the *debiting rate* is calculated based on different cost factors and required input data. The bottom of the figure shows the three types of input data from the DSOs. It is seen that the NPA is the total of five different cost factors, e.g. *Connection* which in turn depends on the *reference network* including both *spare capacity* and a *radial network*

C. Calculation of the Network Performance Assessment

The unit used in NPA is Swedish crowns [SEK], where 9 SEK is approx. € 1. It is calculated annually for each electrical distribution system area.

NPA expresses the different customer values in terms of five different costs as follows:

1. The *cost of the connection*, C_{Connect} corresponds to capital cost of the fictive reference network, which has up to four voltage levels, referred to as *Net Levels* (defined in chapter IV.). This cost includes the cost of the *radial network*, C_{Radial} , and additional cost representing investments in component redundancy, referred to as *the cost of the spare capacity*, C_{Spare} . The *cost of the connection* represents the cost of an electrical distribution system built with new technology and efficient solutions. Thus, the model takes into account the fact that a newly built electrical distribution system in Sweden would, if possible, be based on investment in underground cables rather than overhead lines (to minimize the effect of weather). E.g. Net Level 3 and 4 have 50% underground cables and 50% overhead lines in the NPAM. Consequently, the investment cost for the *radial network* has several built-in assumptions of how an electrical distribution system is built. Chapter IV. provides more details on how the cost of the *radial network* and the cost of the *spare capacity* are calculated. The *cost of the connection* is expressed by:

$$C_{\text{Connect}} = C_{\text{Spare}} + C_{\text{Radial}} \quad (2)$$
2. The *cost of the administration*, C_{Admin} includes an administrative cost for each customer, which depends partly on the net level of the reference network. These costs are given as input data from EI.
3. The *cost of the delivery*, C_{Deliv} , is the energy loss in the system. It depends on the subscriber density, which in turn depends on the *radial network*. Note that the price of electricity is determined by period prices on the Nordic Energy Market, Nord pool.
4. The *cost of the services*, C_{Service} , is costs from superior grids. These are actual costs reported by the DSO, such as costs for compensation to local producers. Note that some expenses, like government fees, are not included, but are instead factored in by reducing the *revenue*.
5. The *cost of reliability*, C_{Rel} , provides a means for the DSO to reduce the allowed revenue by reducing the expected cost for the reference network by a maximum of the calculated cost for spare capacity that is worth investing in. Section D. provides more details on how this cost is calculated in NPAM.

The summary presentation of NPA results in the following equation:

$$\text{NPA} = C_{\text{Connect}} + C_{\text{Admin}} + C_{\text{Deliv}} + C_{\text{Service}} - C_{\text{Rel}} \quad (3)$$

From the above presentation of the five cost factors, it is known that some of the cost factors depend on the reference network and/or its performance, i.e. C_{Connect} , C_{Deliv} , C_{Rel} and some are defined by input parameters C_{Admin} , C_{Service} . This paper attempts to throw light on how the first group of cost factors is calculated by the NPAM.

D. Input data to NPAM

EI performed annual reviews of the revenues of the DSOs using the NPAM. The input data was therefore annually

updated with data from EI and the DSOs. All the input data was entered using a computer program, Netben, which creates the *reference network* and gave the resulting output data from the model expressed as the debiting rate, or NPA, or different cost factors in NPA.

The input data from EI was a set of parameters, which same was revised each year. They include constants used in the calculation algorithms and the price of electricity. The total number of parameters could vary from year to year and was approximately 50 for each Net Level, i.e. an approximate total of 200 parameters.

Three types of input data to NPAM from the DSOs:

1. The total *revenue*. The revenue is the sum of all reported customer tariffs during the year plus revenues from connection and changing fees, with a reduction for the annual government fee. Some other reductions of the revenue could be made if allowed by EI.
2. The performance data expressed as annual system reliability indices, including both advertised and unadvertised interruptions, during the year in question which are:
 - a. The System Average Interruption Frequency Index (SAIFI), defined as the average number of interruptions per year and customer,
 - b. The System Average Interruption Duration Index (SAIDI), defined as the average outage duration (minutes) per year and customer.
3. The system and component data for the actual electrical distribution system with customer data, and a list of nodes. These data are also referred to as *objective data*. The nodes must be listed within four categories: low-voltage customers, high-voltage customers, border feed points, and local supply points. For every node, the following data must always be reported: a unique number, its category, and two coordinates of the location, the sum of electrical consumption minus the electrical supply, revenue (can be zero), and cost (can be zero). For all nodes, except the low-voltage customers, the subscribed electrical power must be reported. The electrical power of the low-voltage customers was assumed by the NPAM to be the individual annual electrical consumption divided by 1900 hours, i.e. load factor function.

The system and component data to the NPAM for a specific electrical distribution system area resulted in a *reference network* including different voltage levels, which had different subscriber density for different feeders. Together with the performance data, the NPAM calculated different sets of cost factors. The subsequent chapters will provide some underlying theory showing how these calculations have been performed.

IV. THE REFERENCE NETWORK AND RELIABILITY ASSESSMENT IN THE NPAM

This chapter summarizes how the assessment of reliability is treated by the NPAM. (This part of the model is also

called the quality function. However, it does not address aspects of voltage quality.) The chapter aims to show, how the cost functions $C_{Connect}$ and C_{Rel} are calculated by the NPAM. The first cost factor concerns the reference network and the calculated spare capacity (i.e. the motivated investment in redundancy). The second cost factor concerns the reliability performance for the reference network based on system reliability indices, reported by the DSOs. Consequently, both the cost factors depend on the reference networks in the NPAM and on the underlying theory on developing these. This chapter will therefore begin by clarifying the background for developing the reference network.

A. The radial reference network in the NPAM

A radial fictive network is built by the NPAM for an electrical distribution system area based on yearly reported data from a DSO. The input data for the network includes the subscribers, boundary nodes, and production nodes. Therefore, the model does not consider the actual electrical distribution system, but only its nodes and its performance.

The radial reference network is used when calculating several of the cost factors in the NPAM. Specifically, the subscriber density of this radial reference network, i.e., the meter fictive radial line per customer, is input for several calculations in the model.

The radial reference network has four voltage levels:

1. *Net Level 1 (NL1)* [0.4 kV] for nodes ≤ 1.0 kV
2. *Net Level 2 (NL2)* [10 kV] for nodes 1.1-25.0 kV.
3. *Net Level 3 (NL3)* [40 kV] for nodes 25.1-60.0 kV.
4. *Net Level 4 (NL4)* [135 kV] for nodes >60.0 kV.

These levels are a simplification of the way in which the Swedish electrical distribution system is built; for instance, two common operating levels are 11 kV and 22 kV, which with the NPAM corresponds to the same Net Level. It has, however, been decided to use these two levels in the model, and it is important to note that it could significantly affects the cost functions when different investment alternatives are calculated, in that it would mean a different price invested in a spare component at different voltage levels.

Figure 2 – Example of two radial networks at Net Level 1 presented in Netben. (The right system has three feeders: one to node a and b, one to node d, and one to node e, and also one transformer, T2, to the network at Net Level 2)

Figure 2 illustrates a radial reference network presented in the NPAM tool, Netben. This figure corresponds to a

fictive radial reference network that is based on input data to NPAM for an electrical distribution system area.

The resulting cost of the radial network, C_{Radial} , is the calculated investment cost for a radial network derived by the NPAM. The result depends on input parameter values from EI for costs of transformers and feeders, and from the system and component input data, in accordance with previous presentations of input data, from the DSO.

B. Estimation of maximal aggregated power

The probability that all load points connected to a feeder simultaneously demands maximal power (P^{max}) is neglected and consequently there is not motivated to dimension the system regarding this theoretical maximal demand. Hence P^{max} has to be multiplied with an “aggregate factor” S :

$$P_{aggregated}^{max} = P^{max} * S \quad (4)$$

In the NPAM P^{max} and S was calculated by following equations based on Monte Carlo simulations and discussions with the DSOs [16]:

$$P^{max} = \frac{\sum_{i=1}^N E_i}{1900} \quad (5)$$

$$S = e^{-(0.1849 \cdot \ln(s^{-1}) + 0.0172) \cdot \ln(N)}$$

Where N is the total number of load points, E_i is the annual electrical energy consumption of load point i and s is a variable determined by EI, which depends on the NL:

$$s = \begin{cases} 0.50 \text{ NL1 (0.4 kV)} \\ 0.90 \text{ NL2 (10 kV)} \\ 1.04 \text{ NL3 (40 kV)} \\ 1.06 \text{ NL4 (135 kV)} \end{cases} \quad (6)$$

C. Incremental cost

The fundamental idea of the NPAM is to calculate customer values corresponding to the performance of the reference network. The model represents these customer values in terms of costs. For the reliability factor, this implies that the model assumes a customer interruption cost. Investments for a radial network by adding redundant components would improve the availability of the network and consequently lower the customer interruption cost. This could be expressed as a marginal reliability benefit ΔR at a marginal cost ΔC . The incremental cost, i.e. $\Delta C / \Delta R$, is often used to review investments [17].

The NPAM uses the incremental cost analysis to evaluate the worth of different alternative investments in spare components. The approach in NPAM was to (1) calculate the incremental cost of different alternative investments in the radial reference network, (2) list the results and implement the solution with the highest incremental cost, (3) calculate the incremental cost of different alternative investments in the new system as a result of (2), and continue as long as there are solutions with an incremental cost over 1. The total cost of spare capacity resulting from the incremental cost analysis is therefore the maximum number of profitable spare components to include in the radial reference network, and is referred to as C_{Max} .

D. Spare capacity in the reference network

The resulting reference network in the NPAM implies that the radial network is added component redundancy, by the amount that increases the customer value corresponding to

the required investment cost. This section will shed light on how this amount, called the spare capacity for the reference network, has been derived.

The calculations of spare capacity for the reference networks in the NPAM were made during the development phase. The calculations were repeated for numerous electrical distribution system areas. The resulting spare capacity is the calculated optimal value for investment in redundant components that provides an incremental improvement in reliability performance for customers. (Section B. presents more details.) The results from these assessments were then transformed into functions that vary with the subscriber density and Net Level providing values for the cost of the spare capacity. This cost can involve investment costs for either spare transformers or additional feeder length. For example, a feeder at *Net Level 2* results in around 25 % (10 % *Net Level 1*) for urban systems and around 18 % (1 % *Net Level 1*) for rural systems in extra feeder length.

The resulting cost of the spare capacity C_{Spare} is thus a cost for investment in the amount of spare capacity, which the NPAM has defined as the optimal solution. This gives that $C_{Spare} = C_{Max}$.

E. Customer outage cost

The *Customer outage cost* in the NPAM represents the cost that the customer sees. (This cost is also referred to as attained cost.) The *Customer outage cost* depends on delivered electrical energy, system reliability indices, and customer interruption costs. The customer interruption costs depend on the subscriber density, and have been calculated based on a customer survey made by the association of Swedish DSOs, Svensk Energi (SwedEnergy) in 1993 [18], including updated data in 2003 [1]. The *Customer outage cost* is calculated both for advertised, i.e. planned events, and unadvertised interruptions, i.e. stochastic events. Table 1 gives examples of functions for the customer interruption cost in the NPAM. As seen from the table, the interruption costs decrease with increased density. Hence, for the NPAM it follows that customers in an urban distribution system, with typically few meters per customer, receive more compensation than customers in a rural distribution system, with typically many meters per customer.

Table 1 –Example of interruption costs in the NPAM

Density [m/cust.]	Fixed cost x_i , [SEK/kW.int.]		Non fixed cost y_i , [SEK/kWh.int.]	
	Planned, x_1	Stochastic, x_2	Planned, y_1	Stochastic, y_2
10	5	22	81	117
50	4	20	62	91
100	2	18	50	72
300	2	18	48	71

(Data from [9], [14], €1~ SEK 9, \$1 ≈ SEK 7)

Equation (7) summarizes the calculation of the *Customer outage cost* in NPAM [SEK/year]:

$$C_{Outage} = \frac{E}{8760} \cdot \sum_{i=a,b} (x_i \cdot SAIFI_i + y_i \cdot SAIDI_i) \quad (7)$$

Where:

- E is delivered electrical energy for an electrical distribution system area [kWh/yr],
- 8760 is the total number of hours per year [h/yr],
- the index i indicates if the interruptions are planned events, with a , or stochastic, with b ,
- $SAIFI_i$ [int/yr] and $SAIDI_i$ [h/yr] are system reliability indices,
- x_i [SEK/kW, int.] and y_i [SEK/kWh] are customer interruption costs.

From (7) it can be seen that the actual undelivered energy is not included in the calculation of the customer outage cost. This implies the simplification that every customer are considered to consume a mean value with respect to the total annual delivered electrical energy E , i.e. the NPAM does not take into account the different loads for the individual customers when calculating the outage cost.

F. Expected outage cost

The *Expected outage cost*, C_{Expect} , in the NPAM is the expected outage cost that the reference network would incur. The cost is calculated by algorithms in the NPAM, and the output depends on subscriber density, *Net Level* and the total amount of delivered kWh per year. Table 2 shows examples of expected outage costs in the NPAM. The expected outage cost is clearly higher, with higher density per subscriber, and for lower *Net Level*. Both these results are as expected for a real electrical distribution system.

Table 2 – Examples of values for the expected outage costs in the NPAM.

Density [m/cust.]	Net Level 1 [öre/kWh]	Net Level 2 [öre/kWh]	Net Level 3-4 [öre/kWh]
1	0.30	0.11	0.00
100	0.32	0.17	0.00

(Data from [9], [14], SEK 1 = 100 öre)

G. The reliability function in the NPAM

The reliability cost, C_{Rel} , provides a means to reduce the revenue that the DSO is allowed to collect, by reducing the expected cost for the reference network. This reduction is made with a maximum of the calculated cost for spare capacity, C_{Max} . This maximum value equals the calculated optimal solution for investment in component redundancy, C_{Spare} . The reduction is made if the resulting system reliability performance, C_{Outage} , is higher than the expected reliability performance, C_{Expect} , for the reference network. The reliability cost is summarized as follows:

$$C_{Rel} = \begin{cases} 0 & \text{if } C_{Outage} - C_{Expect} \leq 0 \\ C_{Outage} - C_{Expect} & \text{if } 0 \leq C_{Outage} - C_{Expect} \leq C_{Max} \\ C_{Max} \Leftrightarrow C_{Spare} & \text{if } C_{Outage} - C_{Expect} \geq C_{Max} \end{cases} \quad (8)$$

V. UNDERLYING THEORY FOR THE NPAM

The previous chapter has presented the different cost factors included in the assessment using the NPAM. The NPAM model uses a set of so called *template functions* to assess these cost functions. The template functions were defined during the development phase, and they stem from

a set of simulation studies. This chapter will present for the first time details of how these simulations were made. It is, however, not necessary to understand this underlying theory to apply the NPAM.

A. The subscriber density in the NPAM

All template functions have one variable, the subscriber density x , i.e. number of feeder meters per customer. This is the density of the radial reference network that the NPAM derives, and is consequently a result during assessment with the model. Since there are four net levels in the model, each electrical distribution system area has four functions for x . x is the local subscriber density of each line, and not a mean value of subscriber density, which is presented by Netben as an output from the NPAM.

B. The template functions in the NPAM

The general approach to defining the template functions in the NPAM is as follows:

1. Sequential Monte Carlo Simulations (MCS) are performed, for the radial network, for example, using the incremental cost theory to define an optimal investment alternative.
2. The MCSs are repeated numerous times for different sets of distribution system areas.
3. The result from the MCS studies is expressed as a function of the subscriber density, x .
4. The results are plotted and a curve is fitted to the plot using the function $ModTanh(x)$ (9). This function has five parameters $k_0, \dots, k_4$, which define the shape of the curve (which could also be a constant function). The function has been used because it could represent a general function with different characteristics depending on the parameter values.
5. Based on the results, pilot studies are made, and the parameter values are adjusted.

$$ModTanh(x) = \left(k_1 + k_2 \cdot \tanh(k_3(x - k_4)) \right)^{k_0} \quad (9)$$

Where:

- x is the subscriber density at the actual net level and for a specific line [meter/customer],
- k_0 defines the sharpness of the curve,
- k_1 defines the horizontal position of the curve,
- k_2 determines the rake of the curve,
- k_3 stretches the curve vertically,
- k_4 defines the vertical position of the curve.

C. The Approach for deriving the template functions of the reference network in the NPAM

1) A summary of the approach, divided into 5 steps

The *reference network* for the NPAM has been calculated in five steps as follows:

1. The *customer outage cost*, C_{Outage} , is calculated from data reported to the DSO, see (7).
2. A fictive radial network is created based on input data to the NPAM. The sequential Monte Carlo simulation approach is used to simulate the expected behavior of the system. The generally known Weibull distribution

has been used to model failure occurrences for components in the system. Components are in one of three states: operation, service or failure. The simulation includes the effect of component failures with both planned and stochastic events. A resulting outage cost is evaluated for the radial network.

3. The incremental cost approach is used to investigate different alternatives for component redundancy (See also Section A.). MCS studies are used to evaluate the resulting outage costs for the different investment alternatives. From a resulting list of possible redundancy solutions, the first profitable one is selected, i.e. where the gain in outage costs is higher than the required annual cost for investment in component redundancy. This results in C_{Spare} .
4. The radial network is simulated, including failure occurrences for transformers, and possible solutions for transformer redundancy. The resulting outage cost is compared with the required annual investment cost.
5. MCSs are made for the resulting redundant *reference network* system including possible redundancy for feeders and transformers. Events are simulated as for the radial network. The resulting C_{Expect} is calculated.

2) A summary of assumptions

The NPAM models a complex system, and as such involves many simplifications. A few of those that show limitations in modeling the distribution system, have been identified by the authors as important, and are as follows:

- Isolation of component failures, i.e. feeders or transformers, is assumed to be perfect and occur momentarily, i.e. the breaker components are assumed to work with a probability of 100%.
- Only single failure is considered, i.e. simultaneous failures are neglected.
- No load flow analysis is made for dimensioning of the spare capacity defined for the feeders. This implies that the resulting reference network could have feeders that are not dimensioned to deliver the energy requested by the customers and modeled by the NPAM.

D. Summary of the Monte Carlo simulations during the developing phase of the NPAM

In summary, four different types of simulation studies were made during the development phase of the NPAM. They all used the sequential Monte Carlo simulation approach. Note that the studies were made for all *net levels*. For NL4, the result early indicates of using a constant template function, whose value, to a great degree, was chosen based on discussions with the industry. The third simulation study is described in more detail in this paper, and Figure 3 shows the underlying logic of this MCS. The other simulations have similar and simpler algorithms.

1) Assessment of outage costs for the radial reference

Failure events were simulated, the generated outages were summarized, and a mean value was calculated. These simulations were input to calculation of the C_{Radial} , to be used in further development of the NPAM (and were not input to a template function used by the NPAM).

2) Assessment of redundancy in transformers

Simulations were made at each *Net Level* of the *radial reference network*. The resulting improvement in outage costs was compared with the required investment in redundancy for all transformers at the current *Net Level*. Consequently, the result from the simulations was either to have no redundant transformers for the *Net level* in question or to have redundancy for all transformers. The results provide input data for calculating the C_{Spare} .

3) Assessment of the reference network – i.e. with feeder redundancy

This algorithm uses MCSs to identify an “optimal” (i.e. first profitable) investment in additional feeder length for the radial network. The resulting *reference network* provides input for the study presented in simulation 4, and also provides input data for calculating the C_{Spare} . The algorithm for the MCS to identify component redundancy of feeders for the reference network is shown in Figure 3 and presented as follows:

0. The basic conditions :

- a. Every node in the system has a list with the alternative types of redundancy, together with two amounts each: a fixed sum corresponding to the cost of including the alternative in question, and a non-fixed sum which starts at zero.
 - b. Some of the alternatives in the lists are connected to other nodes, because a redundant feeder can be used from both directions.
1. The input data includes customer experienced outage costs, the *radial reference network*, estimated costs of introducing the different redundancy alternatives, and reliability statistics on the components (failure rate and mean outage time).
 2. The simulation begins, and failures are generated randomly for the radial reference network (including failure location and time to failure), based on reliability statistics. Not more than one failure is simulated at a time.
 3. A new failure occurs and all alternatives, including redundant feeders that could have prevented the failure, are identified.
 4. An algorithm investigates, and excludes from further calculation, redundant feeders with a length above a maximum value.
 5. A sum corresponding to the hypothetical prevented outage cost is added to the non-fixed sum of one of the alternatives identified in step 3 and step 4.
 6. For each addition, a comparison is made between the two sums of the alternative. If the non-fixed sum exceeds the fixed sum, go to step 8; else go to step 7. The two sums must be adjusted to the same time period.
 7. If all alternatives identified in step 3 and step 4 have been reviewed, go to step 9; else go to step 5.
 8. The alternative is introduced, and the simulation continues on the changed *reference network* (i.e.

including the new alternative). All the non-fixed sums of the alternatives are set to zero.

9. The stop criterion is defined as follows: when the results begin to converge, i.e., there is a long time lapse between newly introduced alternatives, the simulation is stopped; else go to step 3.

4) Assessment of outage costs for the reference networks

The MCSs for the *reference network*, i.e. with redundancy, were made in a similar way as for 1, above. The result is a template function for the C_{Expect} .

Figure 3 – The logic for MCSs to identify the optimal redundancy in feeder length for the NPAM.

VI. CONCLUSIONS

This paper provides the first overall presentation of the NPAM including the underlying theory for calculating cost factors in the model based on simulation studies, for example, of how redundancy is treated by the model.

The regulatory model presented in this paper was created for one of the first de-regulated markets in the world. The learning from this model is an important part for future developments. The ongoing developments of the future electric power system into a smart grid will increase the importance of advanced regulatory model and the NPAM can be used as reference for its novelties as well as from learning from its drawbacks. The NPAM not support climate incentives such as low losses, which will be a challenge when adopting a smart grid perspective into the regulation of distribution system tariffs in the future.

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