Impact of Reward and Penalty Scheme on the Incentives for Distribution System Reliability

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***Abstract*—Performance-based regulations accompanied by quality regulations are gaining ground in the electricity distribution business. Several European countries apply quality regulations with reward and penalty schemes (RPSs), where the distribution system operator (DSO) is rewarded (or penalized) when fulfilling (or not fulfilling) an adequate level of reliability to its customers. This paper develops a method that the regulator can use before enforcing a regulation to get an understanding of the impact different RPS design solutions have on the DSO's financial risk and incentives to invest in reliability. The proposed method also includes a sensitivity analysis to identify which are the most important parameters in an RPS. The new method is applied to three regulatory challenges to evaluate their RPS design solutions. Results show that the choice of scheme design and cost model used to decide the incentive rate have a large impact on the DSO's financial risk and incentive to invest.**

***Index Terms*—Electric power distribution reliability, quality regulation, reward and penalty schemes.**

I. Introduction

In the aftermath of the reregulated electricity markets, network ownership is privatized and the need for regulation of distribution system operators (DSOs) has been accentuated by the natural monopoly status of these entities. The regulations of DSOs are in many countries based on their performance referred to as performance-based regulation.

Performance-based regulations often have strong efficiency incentives which may lead to deterioration of quality as a result of cost cutting in order to make sufficient profit [1]. To stem such a development, many performance-based regulation regimes in Europe have been accompanied by quality regulations adopting indirect and direct quality controls [2]. With indirect controls customers are provided with information of the DSO's quality, while with direct controls the regulator directly gives the DSO financial incentives for providing an adequate quality level [3]. For distribution networks, quality regulation is applied in three different areas: commercial quality, reliability, and voltage quality [1]. In this paper we focus on system reliability regulated by reward and penalty schemes (RPSs) which is a direct quality control. The power interruptions considered are the ones caused by network failure and not by system balance deficits. RPSs are currently being applied to distribution system reliability in 15 out of the 26 European countries considered in [2].

Severe weather conditions significantly affect the component failure rate and the restoration time in distribution systems [4]. Since quality regulation is always based on actual performance (ex-post) this will mean that yearly variations in system reliability become important for the DSO's risk analysis when estimating their financial risk. If the variances of the reliability indices are underestimated, the DSO is exposed to a higher financial risk than appears to be the case. A common approach to capture the stochastic behavior of power system reliability is to apply Monte Carlo simulations [5]. Many researchers apply Monte Carlo simulations in order to capture the impact of regulatory policies within quality regulation. For example, [6]–[8] apply Monte Carlo simulations to investigate the impact of guaranteed standards (GSs) for worst-served customers. GSs are a part of the selective quality regulation that aims to control the reliability on customer level [1]. Implications due to collective quality regulation such as RPSs are investigated using Monte Carlo simulations in, for example, [9]–[11].

With the RPS the regulator aims to establish the socioeconomically optimal reliability level that minimizes the total reliability cost for society [1]. Apart from this major challenge, the regulator hopes to solve other challenges such as limiting the DSO's financial risk as well as unnecessary tariff changes for customers. The resulting RPS design depends on which challenges the regulator tries to solve and what RPS design solutions are chosen. The difficulties with obtaining a proper RPS design are discussed in [12] and [13]. Many of the publications in the field take the perspective of the DSO. In [14]–[16] financial risk assessments for a DSO subjected to quality regulation were carried out using different reliability methods. How to incorporate the financial risk from an RPS in investment and maintenance planning were shown in [17] and [18], respectively. A method for studying how changes in regulation parameters, due to increasing customer interruption cost over time, affected the economic performance of an investment strategy was developed in [19]. However, few publications take the perspective of the regulator; one exception is [20] that presents a method for the equalization of the total rewards paid and the total penalties received by the regulator.

Strategic behaviors and regulatory economics are important areas within regulatory policy development. In [21] a game theoretic approach are taken where the interactions between the regulator and some DSOs are performed as a Nash equilibrium in order to analyze how the DSOs would react to the implementation of a specific regulation. In [22] a DEA-based regulatory

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model is developed for the multi-period multi-agent case. However, the interactions between the DSOs and the regulator are not included in the paper.

The main contribution in this paper is an RPS impact method that the regulator can use to get an understanding on how well different RPS design solutions solve regulatory challenges as well as identifying which are the most important RPS parameters. It is important for the regulator to know the impact that an RPS design has on the DSO's financial risk and incentive to invest in reliability before enforcing the regulation. The proposed method evaluates the RPS design solutions by examining the probability distribution of the financial risk estimated using time sequential Monte Carlo simulations. Having the distribution it is possible to examine how RPS design solutions can limit the DSO's financial risk as well as unnecessary tariff changes for customers.

The theory behind RPS is described in Section II. The proposed RPS impact method is presented in Section III and examples of regulatory challenges and their RPS design solutions are described in Section IV. In Section V the proposed method is applied in a case study to evaluate possible RPS solutions for three different regulatory challenges. The investigated RPS designs are current or past quality regulations implemented in European countries. Finally, conclusions are drawn in Section VI.

II. Reward and Penalty Schemes (RPSs)

Among the three direct quality controls that are applied on reliability—RPS, guaranteed standards and premium quality contract—the RPS is the far most difficult one to use [1]. The difficulty lies in that an optimal RPS design assumes that the regulator knows the monetary value that the customers place on having continuous electricity supply. In RPS the regulator uses so-called system quality indicators to measure the system reliability level. For these indicators the regulator specifies target levels and implements rewards and penalties for DSOs when they succeed and fail to meet these targets. A higher reliability level gives a higher profit for the DSO, and in this way the regulator tries to mimic the outcomes of market-like conditions.

The regulator is responsible for the administration of the RPS. Different administration methods exist. An approach used by the Italian regulator to manage the reward and penalty fund is presented in [1], while a comparison of some proposed methods can be found in [23]. In this section the system quality indicators, the general objective of an RPS and optimal rewards/penalties are discussed.

A. Measuring System Reliability Using System Quality Indicators

The disturbance of interruptions for a customer is reasonably well described by the number and the duration of interruptions [1]. This is why two commonly applied system quality indicators measure the frequency and duration of interruptions by using the system average interruption frequency index (SAIFI) and the system average interruption duration index (SAIDI), respectively [2]. Both SAIFI and SAIDI are *customer-based indices* since they measure the average number and duration of interruption per year and customer. There are also *load-related indices* such as energy not supplied (ENS). ENS is defined as the annual energy not supplied due to interruptions. This index also captures the frequency and duration aspects of interruptions.

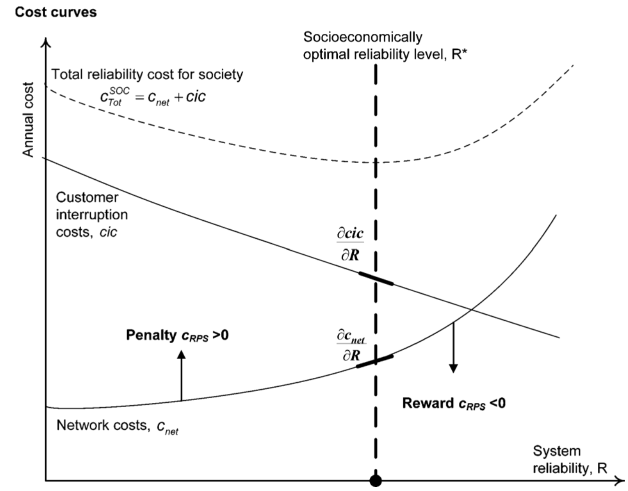

Fig. 1. Cost curves as a function of reliability and the socioeconomically optimal reliability level.

B. General Objective of an RPS

With the RPS the regulator aims to establish the socioeconomically optimal system reliability level [1]. To design an RPS the regulator must make an attempt to answer the question: what is an optimal reliability level and what is a fair price for the customers to pay for it? The monetary value that customers put on having continuous electricity supply is very difficult to assess. Usually the costs due to power interruptions that the customers suffer—the so-called customer interruption costs—are used as its estimate [24]. If the reliability is poor, interruptions are common and customer interruption costs high. However, achieving a very high reliability level demands high network costs such as capital and maintenance costs that the customers have to pay through their tariffs. Somewhere in between is the socioeconomically optimal level of reliability that minimizes the total reliability cost for society which is defined as the sum of the customer interruption costs and the network costs [5]. The relation between the costs as a function of reliability and socioeconomically optimal reliability level is illustrated in Fig. 1. As can be seen in Fig. 1 the optimal reliability R^* is achieved when the additional costs of providing reliability are equal to the resulting decrease in customer interruption costs, i.e.

$$\left.\frac{\partial c_{net}}{\partial R}\right|_{\boldsymbol{R}=R^*} = -\left.\frac{\partial cic}{\partial R}\right|_{\boldsymbol{R}=R^*}. \quad (1)$$

Performance-based regulation unlinks what the DSO is allowed to charge their customers from their actual costs. Profits thus can be earned by cost savings. A profit-maximizing DSO would try to keep the reliability level at a point where its cost is minimized. The DSO's optimum is unlikely to be the same as the socioeconomically optimum. An optimal RPS gives incentives to obtain the socioeconomically optimum by forcing regulated DSOs to include customer interruption costs in their own cost functions [25].

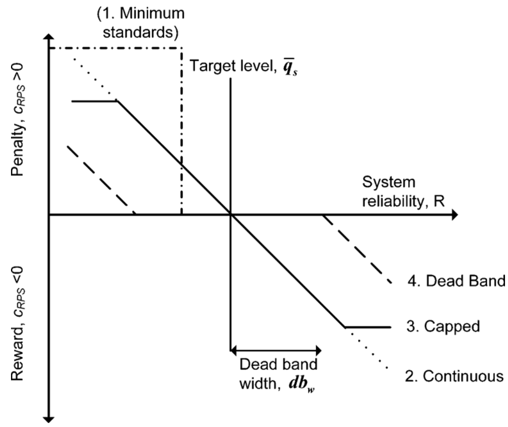

Fig. 2. Different designs of RPS. The x-axis represents the system reliability measured by system quality indicators q_s and the y-axis represents the financial incentives (reward/penalty).

The socioeconomically optimal reliability level is unknown for the regulator. Instead the regulator sets a *target level* for the system quality indicator used to measure reliability. Only the customer interruption costs due to the deviation in reliability from this target level are transferred to the DSO. The allowed revenue for the DSO should cover the costs of providing the reliability level defined by the target level [3]. The financial risk in forms of rewards/penalties c_{RPS} has a direct positive/negative impact on the DSO's profits. With the rewards and penalties the regulator aims to affect the cost curve for the DSO as illustrated in Fig. 1. A DSO that does exceed the target level receives a reward $(c_{RPS} < 0)$ and a DSO that fails to fulfill the target receives a penalty $(c_{RPS} > 0)$[1]. The ultimate aim is that the DSO's total reliability cost curve, which includes the impact of RPS, has its minimum at the same reliability level R^* as society.

The practical solution is to construct an RPS, as shown in Fig. 2, for each system quality indicator. *Minimum standards* is sometimes not defined as an RPS since it has a discrete relationship between quality and price [3], hence the brackets in Fig. 2. Independent of how much the DSO under-performs to meet the target level, minimum standards give a constant penalty. This leaves the DSO with no incentives to perform better than the target and the resulting system reliability is thereby defined by the target level [3]. This paper focuses on the types that have a continuous relationship between quality and price: *continuous*, *capped*, and *dead band*. These three types have better prerequisites to give incentives for achieving a socioeconomically optimal reliability level than minimum standards. Also combinations of the schemes exist such as a capped dead band scheme. The schemes can be symmetric as shown in Fig. 2 or asymmetric around the target level [1].

The continuous scheme—type 2—has rewards/penalties that increase with the deviation from the set target level. The capped scheme—type 3—is similar to the continuous scheme. The difference is that maximum reward/penalty levels are set. Type 4 is the dead band scheme that has a "dead band" around the set target level within which the DSO's profit will be unaffected. Outside the dead band rewards/penalties increase as a continous scheme. Types 2 to 4 in Fig. 2 or combinations of these are the most common scheme types applied in European countries [2].

C. Optimal Rewards/Penalties

To adjust the DSO's cost curve so that the DSO would strive to achieve the reliability level R^* that also minimizes the total reliability cost for society is easy in theory and very difficult in practice. It all comes down to defining optimal rewards/penalties, c_{RPS}.

Let c_{Tot}^{DSO} be the total reliability cost curve for the DSO including the impact of an RPS. At the socioeconomically optimal reliability level R^*, the total reliability cost for society is minimized, which implies that

$$\left.\frac{\partial c_{Tot}^{SOC}}{\partial R}\right|_{\boldsymbol{R}=R^*} = \left.\frac{\partial (c_{net} + cic)}{\partial R}\right|_{\boldsymbol{R}=R^*} = 0. \tag{2}$$

For an optimal RPS, the following must also hold:

$$\left.\frac{\partial c_{Tot}^{DSO}}{\partial R}\right|_{\boldsymbol{R}=R^*} = \left.\frac{\partial (c_{net} + c_{RPS})}{\partial R}\right|_{\boldsymbol{R}=R^*} = 0. \tag{3}$$

Setting (2) equal to (3), an optimal RPS must fulfill

$$\left.\frac{\partial c_{RPS}}{\partial R}\right|_{\boldsymbol{R}=R^*} = \left.\frac{\partial cic}{\partial R}\right|_{\boldsymbol{R}=R^*}. \tag{4}$$

A more rigorous derivation of (4) together with assumptions that must be fulfilled can be found in [3]. In [3] it is shown that (4) must not only hold at $R = R^*$; thus for an optimal RPS, the following are true:

$$\frac{\partial c_{RPS}}{\partial R} = \frac{\partial cic}{\partial R}, \quad \forall R \tag{5}$$

$$\Rightarrow c_{RPS} = cic - c_1, \quad \forall R \tag{6}$$

where c_1 is an arbitrary constant. The derivative $\partial c_{RPS}/\partial R$ in (5) is the slope of the types continuous, capped and dead band in Fig. 2. This is the monetary value per unit system quality indicator and is referred to as *incentive rate*. As (6) shows, optimal rewards/penalties at the reliability level R is a function of the customer interruption costs cic at the reliability level R. The regulator's ability to set optimal rewards and penalties clearly depends on the regulators's ability to properly measure and reconstruct customer interruption costs [3]. Note that to formulate an optimal RPS that gives incentives for a socioeconomically optimal reliability level, the regulator does not have to know the DSO's network costs, as long as the incentive rate is set to fulfill (5).

The slopes (incentive rates) for the schemes in Fig. 2 are constant. For (5) to be fulfilled this means that the underlying assumption is that the relationship between the system reliability and customer interruption costs can be described by a linear function. To only use one incentive rate for all reliability levels is the most common RPS design applied in Europe [2]. However, other assumptions are possible, in [26] for example a dead band RPS was proposed where the customer interruption costs were assumed to increase/decrease exponentially with worse/better system reliability.

As long as the incentive rate fulfills (5), all values of c_1 in (6) will lead to the socioeconomically optimal reliability level being achieved. The value of c_1 only affects the transactions between the DSO and the customers. If the constant c_1 is set to zero, all customer interruption costs have been transferred to the DSO. The profit-maximizing DSO would then experience the total reliability cost for society. However, if all customer interruption costs were transferred to the DSO, the DSO would likely incur a loss because the allowed revenues generally only cover the DSO's total reliability cost at the target level [3].

Setting the value for c_1 in a continuous or capped scheme then corresponds to setting the target level for the system quality indicator since

$$c_1 = cic(R = \bar{q}_s) \tag{7}$$

must hold for (6) to be zero at $R = \bar{q}_s$. For the dead band type the incentive is zero in the entire dead band zone. Thus, a dead band scheme that should fulfill (5) corresponds to assuming that the customer interruption costs have small fluctuations in the dead band and that the derivative in this interval can be approximated by zero. The constant c_1 is then defined as the constant customer interruption costs around the target. However, outside the dead band the customer interruption costs are assumed to vary with reliability level and the incentive rate will therefore be nonzero.

To conclude, irrespective of the level at which the target is set, the optimal reliability level will be achieved by a profit-maximizing DSO as long as the incentive rate is set on the basis of customer interruption costs [3].

The impact of an optimal continuous RPS is illustrated in Fig. 3. In Fig. 3(a) the continuous RPS is defined. The magnitude of the penalties and rewards are the length of the arrows. These arrows will thus adjust the DSO's network costs and form the resulting total reliability cost curve for the DSO as shown in Fig. 3(b). As can be seen in Fig. 3(b) with optimally defined rewards and penalties the resulting total reliability cost curve for the DSO will have its minimum at the reliability level R^* that also minimizes the total reliability cost for society. For c_{RPS} in Fig. 3, the two derivatives in (5) are the same; hence, c_{RPS} is defined to be optimal according to (5). The constant c_1 which moves the total reliability cost curve for society down to the total reliability cost curve experienced by the DSO is also illustrated in Fig. 3.

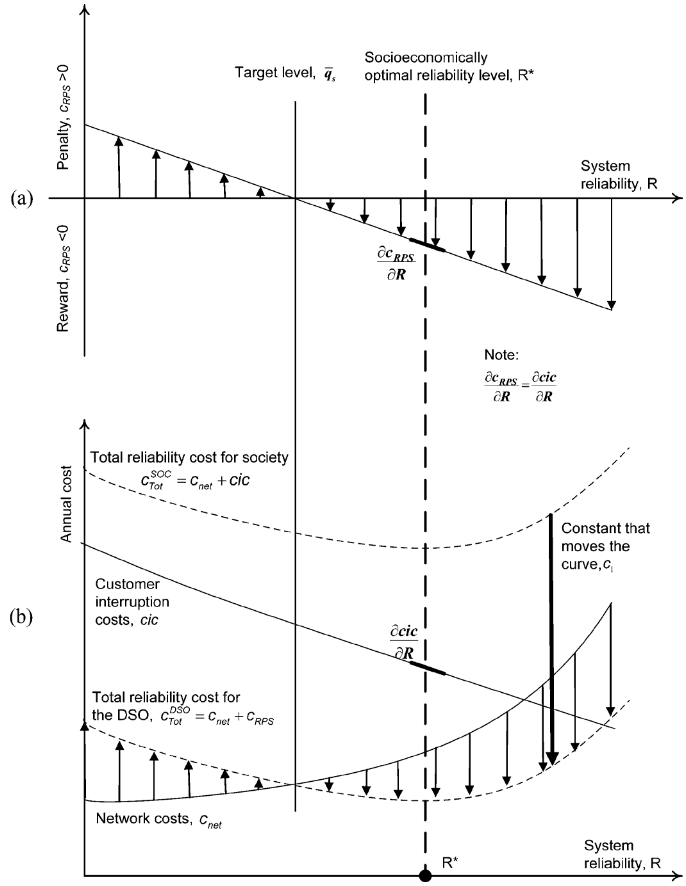

Fig. 3. Impact of an optimal continuous RPS on the DSO's network costs. (a) shows the rewards/penalties from a continuous RPS and (b) shows the impact of such a scheme on the DSO's network costs.

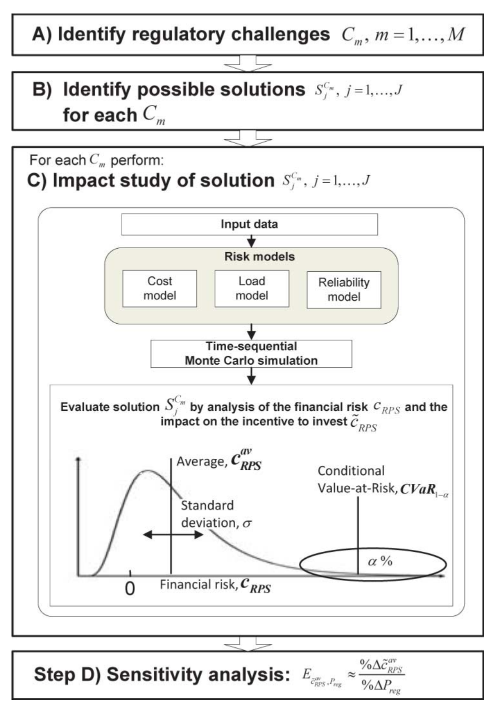

Fig. 4. Proposed RPS impact method.

III. RPS Impact Method

An RPS design is the result of how the regulator chooses to solve different challenges. Examples of regulatory challenges that can be solved by an RPS design are described in the following section. This paper proposes an RPS impact method that the regulator can use to get an understanding of the impact different RPS design solutions have on the DSO's financial risk and incentive to invest in reliability as well as identifying which are the most important parameters. The proposed RPS impact method consists of the steps A to D and is illustrated in Fig. 4. In step A, the investigated regulatory challenges $C_1, \ldots, C_M$ are defined. In step B possible solutions $S_1^{C_m}, \ldots, S_J^{C_m}$ for each challenge are identified.

In step C the impact of the RPS solution is investigated. In most quality regulations the adjustment of the DSO's revenue

TABLE I
REGULATORY CHALLENGES AND RPS DESIGN SOLUTIONS

Regulatory challenge, C_m	**RPS design solution, $S_j^{C_m}$**
C1: Reconstruction of cic	Nation/Area/Outage-specific cost model
C2: Decrease variation	Multi-year quality indicator/Dead band
C3: Limit financial risk	Capping

due to RPS is carried out ex-post for each year. The DSO's financial risk c_{RPS} therefore varies from year to year since it is affected by stochastic factors such as weather. The proposed RPS impact method uses time sequential Monte Carlo simulations in order to capture the stochastic variations to calculate the probability distribution for c_{RPS}. Three risk models—a reliability model, a load model and a cost model—are used in the Monte Carlo simulations. The reliability model describes the failure and restoration processes of the components in a power system and considers the effect of severe weather. Quality regulations may contain load related indices such as ENS and therefore a load model that predicts the loss of load due to an interruption is also needed. The cost, reliability and load models applied in this paper are described in [16], [27], and [28], respectively. The Monte Carlo algorithm is described in [16].

Having the probability distribution of c_{RPS}, the standard deviation σ and the average of the $\alpha\%$ of the highest costs $CVaR_{1-\alpha}$, illustrated in Fig. 4, are estimated. The average incentive for a reliability investment which is defined as the difference in c_{RPS}^{av} before and after an investment

$$\tilde{c}_{RPS}^{av} = c_{RPS}^{av,I} - c_{RPS}^{av,0} \tag{8}$$

is also estimated. The three tools— σ, $CVaR_{1-\alpha}$, and $\tilde{c}_{RPS}^{av}$—are then used to evaluate the RPS design solutions. Finally, in step D a sensitivity analysis is performed to see how sensitive the incentives are to changes in parameter values used in the solution. This is measured using the elasticity

$$E_{y,x} = \frac{\partial \ln y}{\partial \ln x} = \frac{\partial y}{\partial x} \cdot \frac{x}{y} \approx \frac{\%\Delta y}{\%\Delta x} \tag{9}$$

where $y = \tilde{c}_{RPS}^{av}$ and $x = P_{reg}$.

IV. REGULATORY CHALLENGES AND THEIR RPS DESIGN SOLUTIONS

Three of the regulatory challenges, referred to as C1 to C3, that the regulators aim to solve with a certain RPS design are listed in Table I and described in the following sections. These challenges are how to reconstruct customer interruption costs cic, decrease variation in, and limit the financial risk of the DSO.

A. C1: Reconstruction of Customer Interruption Costs (cic)

The fact that customer interruption costs are functions of many different factors such as interruption duration, timing and customer sector, make them challenging to estimate. Due to this fact, not all regulators choose to use customer interruption costs as input when defining incentive rates [2].

Many regulators choose to apply incentive rates based on customer interruption costs. This is the case in, for example, the Netherlands, Italy, Norway, Sweden, and Finland [29], [30]. For these regulators, the first step is to collect customer interruption cost data by national surveys for different customer sectors. Before the collected data can be used in an RPS they must be normalized by for example the annual peak demand. The Council of European Energy Regulators (CEER) has prepared guidelines for customer interruption data collection and normalization [29]. Commonly, only the interruption costs for the worst case scenario, i.e., an interruption occurring at the worst time, are surveyed for a few interruption durations [29].

The second step is to use the collected data to construct *customer damage functions* for each customer sector that shows how the cost depends on outage duration [31]. Composite customer damage functions may also be derived. A composite customer damage function is defined as the aggregated interruption cost for a mixture of customer sectors in a region and is obtained by weighting the customer damage function for the different sectors [32]. The regulators then base the cost parameters in the RPS on these customer damage functions.

The last step is to reconstruct the customer interruption costs. The cost models used by the regulator estimates the annual customer interruption costs in order to estimate the annual rewards/penalties defined by (6). Many researchers have proposed various cost models with different number of outage and customer characteristics included. Seven of these cost models are described and compared in [33]. According to (5) the detail level in the cost models that the regulator choses to use for reconstruction of customer interruption costs will have a direct impact on the likelihood of achieving optimal rewards/penalties. However, a detail reconstruction demands more data to be recorded and reported by the DSO to the regulator. To record all the required data the DSOs may have to upgrade their equipment [34] which will in turn imply higher tariffs for customers. The detail level in the chosen cost models applied in current quality regulations are very different from country to country [2].

Roughly, the used cost models can be grouped into four categories with increasing detail level in the information used: national-, area-, sector-, and outage-specific. The annual customer interruption cost cic for year τ using cost models in the four categories are described in the following sections. In the presented cost models it is assumed that the customer damage function is normalized by peak load.

1) National-, Area-, and Sector-Specific Cost Models: Cost models in these categories use cost parameters for system quality indicators and yearly averages for outage duration estimated on different levels when reconstructing $cic(\tau)$. For the nation- and area-specific models the cost parameters are functions of the composite customer damage functions on national or area level and the outage duration estimate is the average interruption duration the so-called $CAIDI = SAIDI/SAIFI$ index estimated on the national or area level. For sector-specific models the indices are calculated per customer sector and multiplied with sector-specific cost parameters based on CAIDI for that particular sector. In these three categories either load related or customer-based system quality indices are used. Two cost models adopting each of the different types of indices—one using SAIDI and SAIFI, and another using ENS—are shown in (10) and (11):

$$cic(\tau) = P_{av}\ SAIFI\ c_{ref}(0^{+}) + + P_{av}\ SAIDI\ \left.\frac{dc_{ref}}{dr}\right|_{r=r_a} \tag{10}$$

$$cic(\tau) = ENS\ \left.\frac{dc_{ref}}{dr}\right|_{r=r_a} \tag{11}$$

where

$c_{ref}(r)$ = Customer damage function $\{c^{N}_{ref}, c^{A}_{ref}, c^{S}_{ref}\}$ on {National, Area, Sector} level for interruption duration r [€/kW]

$\frac{dc_{ref}}{dr}$ = Slope of the customer damage function [€/kWh]

r_a = Average interruption duration (CAIDI) $\{r^{N}_{a}, r^{A}_{a}, r^{S}_{a}\}$ for {National, Area, Sector} level [h]

P_{av} = Average hourly load $\{P^{N}_{av}, P^{A}_{av}, P^{S}_{av}\}$ based on the annual energy consumption on {National, Area, Sector}level [kW].

Note that for sector-specific models using (10) and (11) $cic(\tau)$ need to be summed over the number of customer sectors.

A national-specific model specified by (10) is applied in the Swedish quality regulation since 2012 [35]. The previous quality regulation in Norway adopted a sector-specific model specified by (11)[36]. An area-specific cost model is used in Italy where the cost parameters are set depending on population density which results in different parameters for urban and rural areas [1]. The cost parameters also depend on the measured SAIDI indicator in the DSO's district area [1].

2) Outage-specific Cost Models: Cost models in this category use outage-specific information such as outage duration and timing when reconstructing $cic(\tau)$ as shown in (12):

$$cic(\tau) = \sum_{lp=1}^{nr_{LP}} \sum_{i=1}^{nr_I} \sum_{S=1}^{nr_S} \sum_{n=1}^{nr_C} E(\tilde{f}^{S}_{h})\, E(\tilde{f}^{S}_{d})\, E(\tilde{f}^{S}_{m}) \cdot c^{S}_{ref}(r_i)\, P_{ref,n} \tag{12}$$

where

$\tilde{f}^{S}_{x}$ = Time-varying factor $\{\tilde{f}^{S}_{h}, \tilde{f}^{S}_{d}, \tilde{f}^{S}_{m}\}$ for {hourly, daily, monthly} deviation from reference time used in survey for sector S

nr_x = Number $\{nr_{LP}, nr_I, nr_S, nr_C\}$ of {load points (lps), interruptions per τ in lp, customer sectors (S) in lp, customers in S}

$E(\tilde{f}^{S}_{x}) = \frac{[\tilde{f}^{S}_{x}(t^{1}_{i}) + \tilde{f}^{S}_{x}(t^{2}_{i}) + \cdots + \tilde{f}^{S}_{x}(t^{K}_{i})]}{K}$, average time-varying factor for the interruption

t^{k}_{i} = Hour k of interruption i occurring at time t

K = Closest whole hour to interruption duration r_i

r_i = Interruption duration for interruption i

$P_{ref,n}$ = Interrupted power in kW at reference time for customer n.

The outage-specific cost model described by (12) is applied in the current Norwegian quality regulation [34].

B. C2: Decrease the Variation in the DSO's Financial Risk

The annual reliability level is highly dependent on stochastic factors such as weather and will thus vary from year to year. To decrease variation of the DSO's financial risk and thereby avoid unnecessary tariff adjustments due to natural deviations from the target level, a dead band scheme (Type 4 in Fig. 2) or *multi-year system quality indicators* can be applied. Dead bands, in contrast to multi-year indicators, create the problem that genuine quality improvements may go unnoticed [13]. Different methods on how to decide the dead band are proposed in [15] and [20]. Examples of countries applying a dead band scheme are Finland, Portugal, and Slovenia [2]. Examples of countries applying multi-year system quality indicators are Hungary (three-year rolling averages) [1] and Italy (two-year rolling averages) [2].

C. C3: Limit the DSO's Financial Risk

A cap is sometimes applied to the penalty or reward (Type 3 in Fig. 2), to limit the financial risk to which the DSO is exposed. Some regulators that use RPS parameters based on CDF obtained from customer interruption cost surveys motivate the use of a capped scheme as a way to limit the effect of the uncertainty due to customer interruption cost estimates [1]. A capped RPS type, however, implies that a reliability improvement/degradation beyond the capped level does not give any increased rewards/penalties.

Ajodhia and Harvoort question the reasoning for having a capped RPS in [13]. If DSOs receive the maximum penalty they would not be more penalized if having an even worse reliability level, hence there is a risk for further reliability degradation. To prevent this a high capped penalty is needed, but if the cap needs to be high why having a capped penalty after all? A capped reward is also questioned since it does not help customers that the DSO is likely only to improve the reliability to the level that correspond to the maximum reward. In European countries such as Sweden, the U.K., and Ireland where capped reward and penalty schemes are used, the cap is usually defined as a percentage of the allowed revenue of the DSO [37].

V. Case Study

The purpose of the case study is to illustrate how the proposed RPS impact method can be used to evaluate different RPS design solutions for regulatory challenges. Each of the method's four steps—steps A to D—is illustrated in chronological order. This case study is based on Swedish conditions; however the

RPS impact method is general and can be applied to various conditions using different input data. In the case study the Swedish Rural Reliability Test System (SRRTS) developed in close collaboration with electricity utilities [38] is used. A test system is used to compare the results of different RPS designs applied in current or past European quality regulations. Two reliability improvements are considered: P_1 and P_2. P_1 and P_2 consist of increased maintenance for the overhead lines which is expected to decrease the failure rates by 2% and 10%, respectively.

A. Identify Regulatory Challenges and Solutions

For the challenges C1 to C3 presented in Section IV nine RPS design solutions have been chosen to be evaluated in the case study. Sweden is not a densely populated country, which implies that cost parameters on national level and area level for a rural test system are very similar. Therefore area-specific models are not included in the case study. The solutions are

$$S_1^{C_1} = \{con, I_{cust}, f(c_{ref}^N)\}, S_2^{C_1} = \{con, I_{cust}, f(c_{ref}^S)\}$$
$$S_3^{C_1} = \{con, I_{load}, f(c_{ref}^N)\}, S_4^{C_1} = \{con, I_{load}, f(c_{ref}^S)\}$$
$$S_5^{C_1} = \{con, O, no_{time}\}, S_6^{C_1} = \{con, O\}$$
$$S_1^{C_2} = \{con, I_{cust}^{nr_\tau}, f(c_{ref}^N)\}, S_2^{C_2} = \{db_w, I_{cust}, f(c_{ref}^N)\}$$
$$S_1^{C_3} = \{cap, I_{cust}, f(c_{ref}^N)\}$$

where

$$\{con, cap, db_w\} = \text{Type of scheme, e.g., } \{\text{continuous, capped, dead band}\}$$
$$db_w = \text{Dead band width (defined in Fig. 2)}$$
$$cap = \text{Capped value defined as percentage of allowed revenue}$$
$$I_{cust} = \text{Customer-based indices, eqn (10)}$$
$$I_{load} = \text{Load related indices, eqn (11)}$$
$$f(c_{ref}^{N,S}) = \text{National or Sector } \{\text{N, S}\} \text{cost parameters } \{c_{ref}, \frac{d\, c_{ref}}{dr}\}$$
$$O = \text{Outage-specific, eqn (12)}$$
$$no_{time} = \text{Timing not included, } \tilde{f}_x^S = 1 \forall x \text{ in eqn (12)}$$
$$I^{nr_\tau} = \text{Multi-year indices based on } nr_\tau \text{ years.}$$

Note that for the challenges C2 and C3 the cost model used in the Swedish quality regulation described in (10) with cost parameters aggregated to national level is applied.

B. Impact Study of Solutions

The input data and evaluation results for the impact study of the solutions are described here.

1) Input Data: In line with the Swedish quality regulation only interruptions shorter than 12 hours are included when calculating the system quality indices q_s and its targets $\bar{q}_s$. Target levels are assumed to be based on the DSO's historical performance and are defined as the average values in the test system SRRTS, hence $c_{RPS}^{0,av}(\bar{q}_s) = 0$. The target levels $\bar{q}_s$ for SAIDI, SAIFI, ENS, $CIC_{no_{time}}$ and CIC_{time} are 2.79 h, 1.58, 5263 kWh, 32.7 k €[1] and 42.2 k €, respectively. CIC_{notime} and CIC_{time} are the customer interruption costs at the average reliability level based on interruptions shorter than 12 hours when timing is not included and included, respectively. In Sweden storms during winter time are common when customer interruption costs also are high. Since only cost models including the timing captures this correlation $CIC_{time} > CIC_{notime}$. The cost parameters used in the reconstruction of customer interruption costs are all based on the latest Swedish customer survey [39] and c_{ref}^S are given in [28]. The national parameters were estimated to 2.00 €/kW and 5.33 €/kWh. The effect of the timing of the interruption was not investigated in the Swedish customer survey. For solution $S_6^{C_1}$ the time-varying factors $\tilde{f}_x^S$ from [34] are instead used after being rescaled to match the reference scenarios in the Swedish survey. The load parameters in eqns (10), (11) and (12) can be obtained from load data given in [38]. The cap value used in solution $S_1^{C_3}$ is 15.82 k € which corresponds to $cap = 3\%$ of DSO's revenue. For solutions $\{S_1^{C_2}$ and $S_2^{C_2}\}$, three-year rolling averages in $(nr_\tau = 3)$ and a dead band width $db_w = \pm 3\%$ are applied, respectively. For $CVaR_{1-\alpha}$, α was set to 5%.

2) Risk Models and Time Sequential Monte Carlo Simulation: The three risk models are used in time sequential Monte Carlo simulations to estimate the probability distribution for the DSO's financial risk c_{RPS} and the incentive for the investment $\tilde{c}_{RPS}^{av}$.

3) Evaluation of RPS Design Solutions: Impact study results for improvement P_2 for the RPS design solutions to the regulatory challenge C1—reconstruction of customer interruption costs—are given in Table II. Results for $\tilde{c}_{RPS}^{av}$ show that the incentive is heavily dependent on the choice of cost model. The highest incentive (outage-specific models with timing included) is almost twice as large as the lowest incentive (load-based models). Also the financial risk for the DSO measured in σ and $CVaR_{1-\alpha}$ is affected to a great extent by the choice of cost model. These remarks also holds for improvement P_1.

TABLE II
RESULTS FOR RPS DESIGN SOLUTIONS $S_j^{C_1}$ GIVEN IN [k €]

	$S_1^{C_1}$	$S_2^{C_1}$	$S_3^{C_1}$	$S_4^{C_1}$	$S_5^{C_1}$	$S_6^{C_1}$
$\tilde{c}_{RPS}^{av}$	-2.3	-2.4	-1.8	-1.7	-2.3	-3.0
$\sigma(c_{RPS}^0)$	20.1	19.3	17.6	17.1	17.0	23.3
$CVaR_{1-\alpha}(c_{RPS}^0)$	51.6	47.1	47.1	44.7	42.0	58.3

Impact study results for improvement P_2 for the RPS design solutions to the regulatory challenges C2 and C3—decrease the variation in and limit the DSO's financial risk—are shown in Table III. For these solutions the same cost model as in $S_1^{C_1}$ is used.

By comparing results inTable III with results for $S_1^{C_1}$ in Table II two remarks are made. Firstly, a multi year index scheme ($S_1^{C_2}$) or a capped scheme ($S_1^{C_3}$) are, compared to a dead band scheme ($S_2^{C_2}$), more effective in reducing the variation and limiting the DSO's financial risk. Actually, a dead band of as much as $\pm 40\%$ is needed to get the same reduction

[1]8.6 SEK $\approx$ 1€

TABLE III
RESULTS FOR RPS DESIGN SOLUTIONS $S_j^{C_2}$ AND $S_j^{C_3}$ GIVEN IN [k €]

	$S_1^{C_2}$	$S_2^{C_2}$	$S_1^{C_3}$	$S_{2,\pm 40\%}^{C_2}$	$S_{1,5\%}^{C_3}$
$\tilde{c}_{RPS}^{av}$	-2.4	-2.2	-1.4	-1.1	-1.9
$\sigma(c_{RPS}^0)$	11.6	19.3	12.2	11.3	16.3
$CVaR_{1-\alpha}(c_{RPS}^0)$	27.6	50.6	15.8	37.8	26.4

in σ as a three year rolling average. The incentive to invest is then halved. Secondly, in contrast to the other two RPS design solutions, a capped scheme dilutes much of the incentive to invest. A cap of 5% gives the same reduction in CVaR as a three year rolling average but reduces the incentive to invest by 20%. The improvement P_2 will result in average SAIDI and SAIFI indices outside the dead band while P_1 correspond to indices still within the band. However, the results show that the two remarks also holds for P_1. Hence, the dead band does not dilute the incentive even if the investment does not improve the average reliability to such an extent that it ends up outside the band.

C. Sensitivity Analysis

In the sensitivity analysis the elasticity $E_{y,x}$ was investigated, where the incentive is $y = \tilde{c}_{RPS}^{av}$ for P_2 and regulation parameters $x = P_{reg} = \{c_{ref}, db_w, nr_\tau, cap\}$. Two cases for parameter change were carried out $\Delta x = \pm 33\%$. Results show that $E_{y,c_{ref}} = 1$ for all the nine RPS design solutions except for the capped scheme where $E_{y,c_{ref}} = 0.13$. This means that with a change in the customer damage functions the incentive will change equally much even when using a dead band or multi year index scheme. However, if using a capped scheme the incentive change is very small.

The sensitivity analysis for the dead band width db_w and number of years nr_τ included in the multi year index result in very low elasticities; $E_{y,db_w} = -0.045$ and $E_{y,nr_\tau} = 0.01 - 0.02$. In contrast, the elasticity for the capped value is large, $E_{y,cap} = 0.7 - 0.9$ with the lower value corresponding to an increase in cap.

Three additional tests were made where both c_{ref} and one of the parameters db_w, nr_τ and cap were changed. The results show that changes in db_w or nr_τ still have small impact on the incentive and the capped scheme gets an elasticity of one when changing both c_{ref} and cap. Thus, with a capped design solution, changes in c_{ref} and cap cannot only be considered separately, since the results indicate a nonlinear behavior for the system in this case.

VI. CONCLUSION

This paper develops a new method for the regulator to evaluate how different RPS solutions affect the incentives to the DSO to invest in reliability as well as reducing the variance and limiting the DSO's financial risk. The proposed method includes a sensitivity analysis to identify which are the most important RPS parameters to specify accurately.

The method is applied in a case study on a rural network to evaluate dead band, capped and multi-year RPS design solutions as well as six cost models that the regulator might use for defining the scheme's incentive rate when reconstructing the customer interruption costs. The choice of cost model is shown to have a large impact on the incentive to invest in reliability. The highest incentive (outage-specific models with timing included) is almost twice the size of the lowest incentive (load-based models). A multi-year solution appears to be the most efficient design if the regulator's aim is to both decrease the variance and limit the DSO's financial risk without diluting the incentive to invest. However, for urban networks with small annual variations in reliability the results might be different. The sensitivity analysis shows that the incentive rate is the most important RPS parameter to specify as accurately as possible since it has the highest elasticity.

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