THE IMPACT OF RISK MODELING ACCURACY ON COST-BENEFIT ANALYSIS OF DISTRIBUTION SYSTEM RELIABILITY

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Abstract - This paper develops a new risk-based cost-benefit analysis method for distribution system reliability applications. In the conventional cost-benefit analysis, decisions are based on expected values which correspond to assuming that society is risk-neutral. Furthermore, input variables are assumed to be uncorrelated. In contrast to previous work this paper incorporates risk into the analysis by using time-sequential Monte Carlo simulations. By using the proposed method the impact that different risk strategies (risk-neutral/risk-averse) and risk models (non-time-varying/time-varying) have on the result of a cost-benefit analysis is investigated in a case study. Results show that when incorporating time-dependent failure rates, restoration times, customer interruption costs, and loads (correlated input data) a different reinvestment project is selected compared to when these time dependencies are ignored. This result holds regardless if decisions are made based on a risk-averse or a risk-neutral strategy.

Keywords - cost-benefit analysis, distribution system reliability, risk analysis, Monte Carlo simulations

COMPLETELY reliable distribution systems are impossible and a certain level of risk for power interruptions has to be accepted. However, while underinvestments lead to an unacceptable number of interruptions, overinvestments result in too high costs for society. Finding an adequate level of reliability in a power distribution system is indeed a challenging task.

Cost-benefit analysis is a technique that can be applied in a market that does not produce the desired output on its own [1]. Because distribution system operators (DSOs) generally have a monopoly position, network investments will not be driven to a socioeconomic optimum by market forces and other incentives must be introduced. In its simplest form, cost-benefit analysis shows whether the benefits for society are larger than the costs for a particular project [1].

Customers' benefits of power system reliability is commonly assessed through approximating the unreliability of electric supply and the impact of interruptions [2]. To translate the impact of power interruptions into monetary terms, customer interruption cost data are used. Cost-benefit analysis applied to distribution system reliability evaluates different investment projects by finding the project that minimizes the total reliability cost for society [3]. The total reliability cost for society is the summation of the customer interruption costs and the reliability costs (both capital and maintenance costs) for the DSO [3].

Using cost-benefit analysis when designing and operating distribution systems is referred to as value-based reliability planning (VBRP). VBRP may be applied by public owned DSOs [4]. In the aftermath of the re-regulation of the electricity market many DSOs are now investor-owned, and the overall goal is to maximize profit rather than to maximize social welfare [4]. To give incentives for a socioeconomically optimal level of reliability, performance-based regulations with quality regulations have been adopted in many European countries [5]. With optimal regulations a regulated DSO would choose to implement the network investments that are profitable for society. Results from cost-benefit analysis can therefore be used to evaluate quality regulations.

An accurate cost-benefit analysis is essential in VBRP and when evaluating quality regulations. The common approach is to assume that society is risk-neutral and thereby base decisions on the expected total reliability cost. The expected total reliability cost is often calculated using analytical methods and assuming that the input variables; customer interruption costs, failure rates, restoration times and loads, are uncorrelated [6, 7, 8]. However, research show that the input variables are time-dependent making them correlated and that this fact is important to consider for accurate assessments of customer interruption costs [9]. Customer interruption cost is an important part of the total reliability cost and ignoring the time dependencies can therefore have an impact on the estimated expected total reliability cost. To get a more accurate estimation of the expected total reliability cost the time dependencies can be considered using time-sequential Monte Carlo simulations together with detailed risk models.

Power systems are extremely reliable and power interruptions are rare events. Most years have nearly no interruptions, while a few extreme years have stormy weather resulting in very many and long interruptions. Basing reliability investment decisions only on average values may therefore be misleading since the average year might never occur. A different approach is to assume that society is risk-averse and thereby choose the investment project that minimizes the total reliability cost during the most extreme years. To be able to do this Monte Carlo simulations are necessary since the whole probability distribution of the total reliability cost is needed. Also risk models that can capture the extreme years are required.

The contribution in this paper is a new risk-based cost-benefit analysis method for distribution system reliability applications. The method considers the fact that the total reliability cost is stochastic and consists of time-dependent variables. By using the method it is possible to investigate how the choice of risk strategy and risk models affects the result of a cost-benefit analysis. The proposed method is applied in a case study to see if the same reinvestment project is selected if society is assumed to be risk-averse instead of risk-neutral and if time dependencies in input variables are considered instead of ignored.

1 RISK-BASED COST-BENEFIT ANALYSIS

The total reliability cost for society is defined as:

$$C_{Tot}^{SOC} = C_I + C_M + C_R + CIC \quad (1)$$

where C_I, C_M, C_R, and CIC are the investment, maintenance, restoration and customer interruption costs, respectively. This paper proposes a new risk-based cost-benefit analysis method that considers the fact that C_R and CIC are stochastic and time-dependent variables since they depend on the number and timing of power interruptions. The method consists of six parts and is illustrated in Figure 1. The novelty is that the proposed risk-based method estimates the whole probability distribution of C_{Tot}^{SOC} in part III), which makes it possible to test different risk strategies in part IV). Therefore, the focus is on part III) Risk Estimation and part IV) Risk Evaluation.

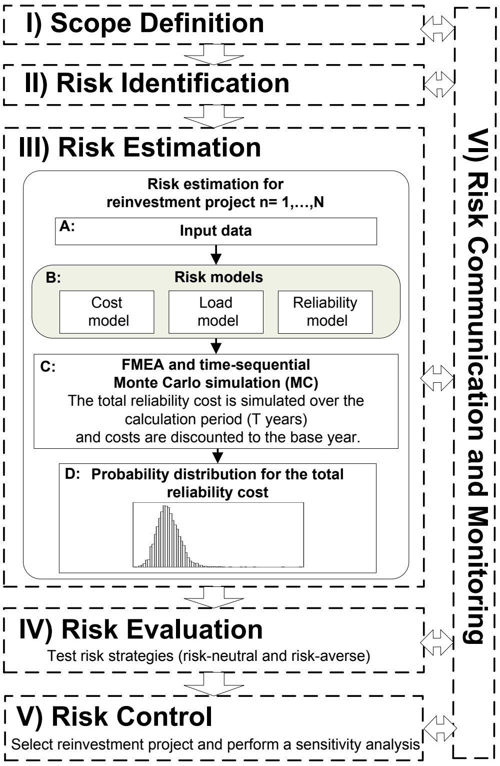

Figure 1: Proposed risk-based cost-benefit analysis method.

In part I) - Scope Definition - the risk analysis study is defined. The motivation of the study is to evaluate different reinvestment projects to improve reliability. The decision criterion is to select the project that minimizes the total reliability cost, which corresponds to the same project that maximizes the net present value (NPV). In part II) - Risk Identification - factors that triggers power interruptions and the consequences for society is identified. Part III) - Risk Estimation - consists of the steps A-D:

A The first step is to collect input data such as network configuration, probability distributions for the inputs, cost data, and load data. If time dependencies in restoration times and failure rates should be modeled additional information on weather conditions at the geographical location of the distribution system is required. For the economic calculations the technical lifetimes of the projects and a discount rate are required. The calculation period (T), over which the total reliability cost is estimated, needs to be set. T is the same for all projects.

B To capture both the probability and consequences of interruptions three risk models are needed: a cost model, a load model and a reliability model. The cost model estimates the total reliability cost for society defined in eqn (1) for the calculation period. To estimate the total reliability cost, the customer interruption cost needs to be estimated for an arbitrary interruption scenario where the interruption duration and timing of the interruption can vary. Customer interruption cost data are usually gathered using customer surveys [2]. Surveys, however, can not include every possible interruption scenario. Commonly, the interruption costs for the worst case scenario, i.e. an interruption occurring at the worst time is surveyed for a few interruption durations. A cost model that can make predictions of interruption costs for any interruption scenario is then needed for a relevant cost-benefit analysis.

Before the customer interruption cost data is applicable in a cost-benefit analysis it must be normalized by for example the annual peak demand. To estimate the customer interruption costs in monetary terms [€] and not in €/kW a load model that predicts the loss of load due to an interruption is used. In order to estimate the probability of interruptions, a reliability model that describes the failure and restoration process of the components in a power system is also required. In this paper both time-varying and non-time-varying risk models are formulated to see how it affects the result of a cost-benefit analysis. The risk models adopted are presented in Section 2.

C A Failure Mode and Effect Analysis (FMEA) is carried out. FMEA is a systematic technique for failure analysis that aims to list the different possible failures for each component and what effect the failures have on the load points. The time to failure of the different failure events identified in FMEA are then randomized in a time-sequential Monte Carlo simulation. The total reliability cost for the calculation period is simulated and costs are discounted to the base year. In the Monte Carlo simulation the time dimension is included and time dependencies can be modeled. The Monte Carlo simulation procedure is illustrated in Figure 4, see Section 6.

D The Monte Carlo simulation results in a probability distribution of the total reliability cost. The tail of the distribution on the right side consists of more extreme periods with many interruptions which resulted in high costs.

In part IV) - Risk Evaluation - the projects are analyzed by testing different risk strategies presented in Section 3. Part V) - Risk Control - is decision-making. Depending on the chosen risk strategy a project is selected. Since many parameters such as the discount rate can affect the result of a cost-benefit analysis, a sensitivity analysis is recommended. The last part - Risk Communication and Monitoring - is a parallel activity that exchange information about risk between the parts I)-V) as can be seen in Figure 1.

2 RISK MODELS

The three different risk models used in this paper are presented in this section. Two cases are investigated:

Case 1: No time dependencies - In this case constant failure rates and loads together with non-time-varying restoration times and customer interruption costs are applied:

- Average load, $P^S_{ref} = P_{av}$ in eqn (7),
- Time-varying factors $f = 1$ in eqns (5), (9), and (10),
- Constant failure rate for overhead lines, i.e. $\lambda(w(t), N_g(t)) = \lambda_{tot}$ in eqn (8).

Case 2: Time dependencies - In this case time-varying failure rates, restoration times, customer interruption costs, and loads are applied as stated in eqns (5), (7), (8), (9) and (10).

Note that time independent indices such as SAIDI and SAIFI will be the same in Case 1 and 2.

2.1 Cost model

The cost model estimates the total reliability cost defined in eqn (1) over the calculation period. Only the additional maintenance and restoration costs (or savings) due to the considered reinvestment project are considered. In this paper the projects investigated are investments in lines, therefore these costs are only given per invested kilometer (km).

The investment cost for year τ is modeled as:

$$c_I(\tau) = c_I^{km}\; nr_{km}^{inv}(\tau) \tag{2}$$

where

c_I^{km} = Investment cost [€/km]
$nr_{km}^{inv}(\tau)$ = Line length invested in year τ [km]

The maintenance cost for year τ is modeled as:

$$c_M(\tau) = c_M^{yr}\; nr_{km} + ins(\tau)\; nr_{km}\; \left(c_M^{ins} + c_M^{act}\right) \tag{3}$$

where

c_M^{yr} = Cost for annual maintenance [€/km]
c_M^{ins} = Cost for inspection [€/km]
c_M^{act} = Cost for maintenance actions decided upon after inspection [€/km]
nr_{km} = Line length in the project [km]
$ins(\tau)$ = 1 if inspection in year τ, 0 otherwise

The restoration cost is split into a fixed cost (material cost) and a variable cost depending on the restoration time and number of persons repairing. The restoration cost for year τ is modeled as:

$$c_R(\tau) = \sum_{j=1}^{nrF(\tau)} c_R^{fix} + nr_p\; c_{hour}\; r_j(t_j) \tag{4}$$

where

$nrF(\tau)$ = Number of failures in year τ
c_R^{fix} = Fixed restoration cost per failure [€]
nr_p = Number of persons repairing
c_{hour} = Cost of one working hour [€/h]
r_j = Restoration time of failure j described by the reliability model [h]
t_j = The timing of failure j

The interruption cost for year τ is calculated as:

$$\begin{aligned} cic(\tau) \;=\; & \sum_{lp=1}^{nr_{LP}} \sum_{i=1}^{nr_I^{lp}(\tau)} \sum_{S=1}^{nr_S^{lp}} \left[f_h^S(t_i^1)\, f_d^S(t_i^1)\, f_m^S(t_i^1) \,\cdot \right. \\ & E(P^S(t_i^1)) c_{ref}^S(t_i^1) + f_h^S(t_i^2)\, f_d^S(t_i^2)\, f_m^S(t_i^2) \,\cdot \\ & E(P^S(t_i^2))\; \left(c_{ref}^S(t_i^2) - c_{ref}^S(t_i^1)\right) + \cdots + \\ & + f_h^S(t_i^K)\; f_d^S(t_i^K)\; f_m^S(t_i^K)\; E(P^S(t_i^K)) \,\cdot \\ & \left. \left(c_{ref}^S(t_i^K) - c_{ref}^S(t_i^{K-1})\right)\right] \cdot nr_C^S \end{aligned} \tag{5}$$

where

nr_{LP} = Number of load points (lp) in the network
$nr_I^{lp}(\tau)$ = Number of interruptions in year τ for lp
nr_S^{lp} = Number of customer sectors at lp
nr_C^S = Number of customers of sector S in lp
$f_h^S(t)$ = Time-varying factor for hourly deviation from the reference time for sector S
$f_d^S(t)$ = Time-varying factor for day of week deviation from the reference time for sector S
$f_m^S(t)$ = Time-varying factor for monthly deviation from the reference time for sector S
c_{ref}^S = Customer damage function for

sector S [€/kW]

t_i^k = Hour k of interruption i occurring at time t, $k = 1, 2, \ldots, K$

K = Closest whole hour to interruption duration

$E(P^S(t_i^k))$ = Expected loss of load for sector S at hour k due to interruption i

The time dependencies in the customer interruption cost is thus modeled using three time-varying factors multiplied by the customer damage function that shows how the normalized interruption cost vary with interruption duration. This multiplicative approach is described in [10, 11].

The total reliability cost for a calculation period is then obtained by adding the discounted costs:

$$C_{Tot}^{SOC} = \sum_{\tau=1}^{T} \frac{c_I(\tau) + c_M(\tau) + c_R(\tau) + cic(\tau)}{(1 + r_{soc})^{\tau}} \tag{6}$$

where

T = Calculation period

r_{soc} = Discount rate for society

2.2 Load model

The outdoor temperature is modeled to be stochastic, which means that extreme temperature conditions and variations in load patterns from year to year can be captured. Reported load curves are often valid in a certain temperature intervals and it is possible that the modeled outdoor temperature is below the lowest temperature interval or above the highest.

In [12] it was established that there is a linear relationship between energy consumption and temperature in Sweden that holds also at low temperatures. Since the model in this paper will be applied to the Swedish climate, only the case of low temperature is considered. However, it is possible that a similar dependency exists in case of high temperature in warm countries where air conditioning is common. In line with the finding in [12], the temperature dependency in case of very low temperatures can be incorporated through a coefficient that moves the load curve vertically. The time-varying load for customer sector S at hour h, day d, and temperature $temp$, is modeled as:

$$P^S(t) \quad = \quad P_{curve}^S(h, d, temp) \tag{7}$$

2.3 Reliability model

The reliability model applied in this paper is presented in [13]. In [13] failure rates and restoration times for overhead lines during high winds and lightning are determined as a function of the weather intensity and seasonal weather patterns are incorporated. High wind and lightning events are generated by randomizing a wind speed w and a ground flash density N_g.

The time-dependent failure rate for overhead lines is modeled as:

$$\begin{aligned} \lambda(w(t), N_g(t)) \quad &= \quad \lambda_{hw}(w(t)) + \lambda_l(N_g(t)) + \\ &\quad\;\; \lambda_n(w(t), N_g(t)) \end{aligned} \tag{8}$$

where

$\lambda_{hw}(w(t))$ = Failure rate during high winds

$\lambda_l(N_g(t))$ = Failure rate during lightning

$\lambda_n(w(t), N_g(t))$ = Constant failure rate during normal weather, equal to λ_{norm}

During weather conditions with both lightning and high winds the failure rate values are added. This is motivated in [13] by that an overhead line can be modeled as subcomponents in series. Restoration times for overhead lines during severe weather depend on the magnitude of damage. In [13] the weather impact is modeled by the weight factor f_w. Repairs tend to take longer during weekends and non-working hours due to the availability of crew, this is modeled by the factors f_d and f_h.

The restoration time for overhead lines is defined as:

$$r(t) \quad = \quad f_w(w(t), N_g(t))\; f_d(t)\; f_h(t)\; r_{norm} \tag{9}$$

and for other components as:

$$r(t) \quad = \quad f_d(t) f_h(t) r_c \tag{10}$$

where

$f_w(w(t), N_g(t))$ = Time-varying factor due to severe weather

$f_h(t)$ = Time-varying factor for hourly variations

$f_d(t)$ = Time-varying factor for daily variations

r_c = Reference restoration time

r_{norm} = Reference restoration time during normal weather conditions

3 RISK STRATEGIES

There are mainly three decision rules that can be applied in a cost-benefit analysis: net present value (NPV), benefit-cost ratio (B/C) and internal rate of return (IRR) [14]. When mutually exclusive reinvestment projects are investigated, as is the case in this paper, NPV should be used as a decision rule [14].

NPV is the sum of discounted flows of costs and benefits over a presumed time period [14] and defined as:

$$NPV = \sum_{\tau=1}^{T} PB(\tau, r_{soc}) - PC(\tau, r_{soc}) \tag{11}$$

where

PB = Present value of benefits due to the project
PC = Present value of costs due to the project
r_{soc} = Discount rate for society
T = Calculation period
τ = Year in which the benefits and costs occur, $\tau = 1, \ldots, T$

In a cost-benefit analysis the projects are compared to a status-quo alternative. According to the Hicks-Kaldor criterion the project with the highest positive NPV should be chosen when selecting between mutually exclusive projects [14]. Since the benefits of a reinvestment project is measured as lowered costs, minimizing the total reliability cost corresponds to maximizing NPV. When stochastic variables are included in the analysis the expected net present value, $E(NPV)$, can be used which corresponds to assuming that society is risk-neutral according to risk strategy S1.

S1: Risk-neutral - When mutually exclusive projects are considered, a risk-neutral strategy is to choose the project n that maximizes the expected NPV, which is a function of the status-quo alternative (P0):

$$\arg\ \max_n\ E(NPV_n) = \arg\ \max_n \left\{ E(C_{Tot}^{SOC,\,P0}) - E(C_{Tot}^{SOC,\,n}) \right\} \quad (12)$$

The Arrow-Lind theorem shows that spreading the risks to many individuals implies (under a number of assumptions) that a project can be evaluated only on the basis of $E(NPV)$ even though individuals are assumed to be risk-averse [15]. However, concerning cost-benefit analysis applied to distribution system reliability assumptions made in the Arrow-Lind theorem are questionable. In [15] it is assumed that risks can be spread among an infinite number of individuals and that they can be shared equally by all individuals. A distribution system has a limited number of customers and customer's location in the network structure will determine the received reliability of electric supply. Hence, it can be argued that if individuals are assumed to be risk-averse, a risk-averse strategy should be applied when making decisions on distribution system reliability. Another argument is that during the more extreme periods with long-lasting and widespread outages simply adding the costs of individual customers may lead to an underestimation of the total customer interruption costs, since intangible costs due to, for example, lack of public services are ignored.

Different risk-averse strategies exist and the maximin criterion is one of these [16]. According to the maximin criterion the worst possible period (the one with the highest cost for society) is studied and the project that maximizes NPV for this period is chosen. Instead of only considering the absolutely worst period, a risk-averse strategy is proposed in this paper that makes decisions based on the expected value during a group of worst periods. This is done by using the financial risk tool Conditional Value-at-Risk (CVaR) also called Expected shortfall [17]. CVaR$_{0.95}(C_{Tot}^{SOC})$ equals the expected total reliability cost during the five percent periods with highest costs. The proposed risk-averse strategy is defined in S2.

S2: Risk-averse - When mutually exclusive projects are considered, a risk-averse strategy is to choose the project n that maximizes the decrease in the costs during the 5 % periods with highest costs:

$$\arg\ \max_n \left\{ \text{CVaR}_{0.95}(C_{Tot}^{SOC,\,P0}) - \text{CVaR}_{0.95}(C_{Tot}^{SOC,\,n}) \right\} \quad (13)$$

4 TEST SYSTEM AND REINVESTMENT PROJECTS

The proposed risk-based cost-benefit analysis method described in Section 1 is here applied to evaluate different reinvestment projects in a case study. The purpose of the case study is to investigate how the risk strategy (risk-neutral/risk-averse) and formulation of risk models (non-time-varying/time-varying) affect which reinvestment project that is selected in a cost-benefit analysis. In the case study, the proposed method is applied to Swedish conditions but, of course, the method is general and can be applied to any distribution system using different input data.

The test system used in the case study is the Swedish Rural Reliability Test System (SRRTS) presented in [18]. SRRTS, shown in Figure 2, has 44 load points, around 900 customers and consists of both overhead lines and cables. Five different customer sectors are represented: residential, commercial, industrial, agricultural and governmental. Two reinvestment projects have been chosen to be investigated further from a large set of projects. To compare the impact of the projects a status-quo alternative is also considered. The question is if the four uninsulated overhead lines located on the backbone of Module A and Module B (marked with thicker lines in Figure 2) should be kept or not. The projects investigated are:

P0: Keep the uninsulated lines (Status-quo alternative used as reference).

P1: Replace the uninsulated lines with underground cables.

P2: Replace the uninsulated lines with insulated lines.

The calculation period is set to thirty years, i.e. $T = 30$. No aging or maintenance effects on component failure rates are considered. It was assumed that there will be no load growth in the considered rural area during the calculation period.

The costs that are included in the cost-benefit analysis are:

1. Investment costs to be depreciated over five years. The technical lifetime is needed to calculate the residual value. The technical lifetime is always longer than the calculation period. Linear devaluation of the network is used throughout the technical lifetime and the residual value is calculated as the remaining part of the investment cost in the end of the calculation period.
2. Maintenance costs
3. Restoration costs due to interruptions
4. Customer interruption costs

The price level of 2009 is used in the analysis. It was assumed that the reinvestment projects do not affect the DSO's operation cost and cost of power losses and therefore these costs were not included in the analysis. Since it is a socioeconomic analysis quality regulation costs are not considered.

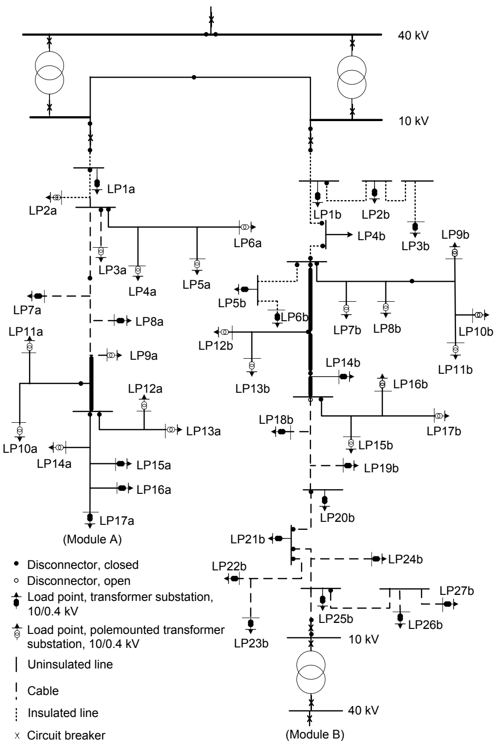

Figure 2: The test system used in the case study. The uninsulated lines which are considered in the reinvestment projects are marked with thicker lines.

5 INPUT DATA

In this section the input data used in the case study is presented. The notations used are defined in Section 2.

5.1 Cost model

A discount rate of 4 percent (2 % inflation), which is recommended for socioeconomic studies in Sweden [19], is applied in the cost-benefit analysis. Hence, $r_{soc} = 0.04$. Since the projects are compared to the status-quo alternative (P0) only the maintenance and restoration costs for the affected components due to the considered projects need to be estimated. The investment costs, technical lifetimes, and maintenance costs for the different projects are listed in Tables 1 and 2. The cost of one working hour is $c_{hour} = 65$ €. These costs are gathered from the database of EBR [20]. EBR is a system that provides standard costs for all types of different maintenance and repair work for distribution networks in Sweden.

Project	c_I^{km} [€/km]	Technical lifetime [yr]	nr_{km} [km]
P0 - base case	0	35	2.6
P1 - cables	37000	35	2.6
P2 - insul lines	31000	40	2.6

Table 1: Investment costs and technical lifetimes for the projects.

Project	c_M^{yr} [€/km]	c_M^{ins} [€/km]	c_M^{act} [€/km]	c_R^{fix} [€/failure]
P0 - base case	137	275	1648	255
P1 - cables	0	275	206	6224
P2 - insul lines	96	275	1648	897

Table 2: Maintenance costs and the fixed restoration costs for the projects.

Inspections are performed every eight year. The repair crew is assumed to consist of two persons for overhead line and cable failures.

Customer interruption cost data from the customer survey conducted in Sweden 2003-2005 [21] is used. Based on these data, customer damage functions can be derived for each customer sector. The customer damage functions are shown in Figure 3.

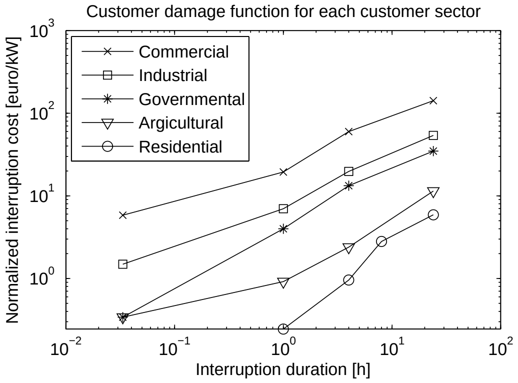

Figure 3: Customer damage functions in €/kW for all customer sectors. The surveyed durations are marked with different symbols. Note the log scale on both the x-axis and the y-axis.

The time-varying factors (f_h^S,f_d^S, and f_m^S) from [11] are used after being rescaled to match the reference scenarios in the Swedish survey and adjusted to be used together with the customer damage function.

5.2 Load model and weather modeling

The load curves in [18] are adopted. The considered test system is assumed to be situated in midland Sweden and weather statistics are used to derive the probability distributions for the average daily temperature in different months. The load curves are calibrated so the average load over a year agrees with the annual averages (P_{av}) given in [18]. Applied weather parameters for modeling high winds and lightning events are presented in [13].

5.3 *Reliability model*

The reliability data for the different components and line lengths are given in [18]. However, the restoration time for overhead lines in [18] is for normal weather conditions. An average restoration time of 10 hours estimated in [13] over the whole year with all weather conditions included is used here. The time to failure is assumed to be exponentially distributed and restoration times (r_{norm} and r_c) are assumed to be log-normally distributed. The time-varying factors (f_w, f_h, and f_d) for the restoration time of overhead lines and mean of r_{norm} are given in [13].

6 SIMULATIONS AND RESULTS

Project P1 and P2 are evaluated compared to the status-quo alternative (P0) by employing the proposed risk-based cost-benefit analysis method. This is done using both the non-time-varying (Case 1) and the time-varying (Case 2) models described in Section 2. Both the risk-neutral (S1) and risk-averse (S2) strategies presented in Section 3 are applied.

The time-sequential Monte Carlo procedure applied in this paper is described in Figure 4. In the simulation, 5000 calculation periods were simulated, i.e. $N_{max} = 5000$ in Figure 4. The simulations resulted in probability distributions of the total reliability cost for the calculation period. Having the probability distribution the risk strategies S1 and S2 can be applied. The dashed boxes in Figure 4 represent the considerations of time-varying failure rates (TVFR), restoration times (TVRT), customer interruption cost (TVCIC) and load (TVLD). In these dashed boxes the algorithm is different depending on if non-time-varying (Case 1) or time-varying (Case 2) models are used.

Both reinvestments in cables (P1) and in insulated lines (P2) will decrease the expected annual customer interruption cost compared to the status-quo alternative P0. The decrease in customer interruption cost for project P1 and P2 compared to P0 are presented in Table 3.

Project	Case 1: Non TV Δcic [k €]	Case 2: TV Δcic [k €]
P1 - cables	57.5	74.4
P2 - insul lines	51.9	65.1

Table 3: Decrease in expected annual customer interruption cost cic compared to the status-quo alternative (P0).

The NPV results are shown in Table 4. Taking decisions on expected NPV (S1), the status-quo alternative (P0) is chosen in Case 1 and reinvestment in cables (P1) is chosen in Case 2. This shows that the incorporation of time dependencies in the input variables is important and can affect which project that is selected in a cost-benefit analysis. As can be seen in Table 4 the selected project is the same if decisions instead where based on the risk-averse strategy (S2). Sometimes, however, a risk-averse strategy can clarify benefits with a project that is hard to discover by only looking at the expected NPV. For example, reinvestments in cables (P1) only have a slightly positive expected NPV, but were shown to have a much higher positive effect on the worst possible outcomes.

Project	Case 1: Non TV S1: Mean [k €]	 S2: CVaR [k €]	Case 2: TV S1: Mean [k €]	 S2: CVaR [k €]
P1 - cables	-16.3	-14.9	0.5	5.1
P2 - insul lines	-13.7	-12.4	-1.4	-10.3
Cable costs increased, P1	-18.9	-17.6	-2.1	2.4

Table 4: Note that a negative result indicates that P0 is the preferable alternative. TV = Time-Varying models.

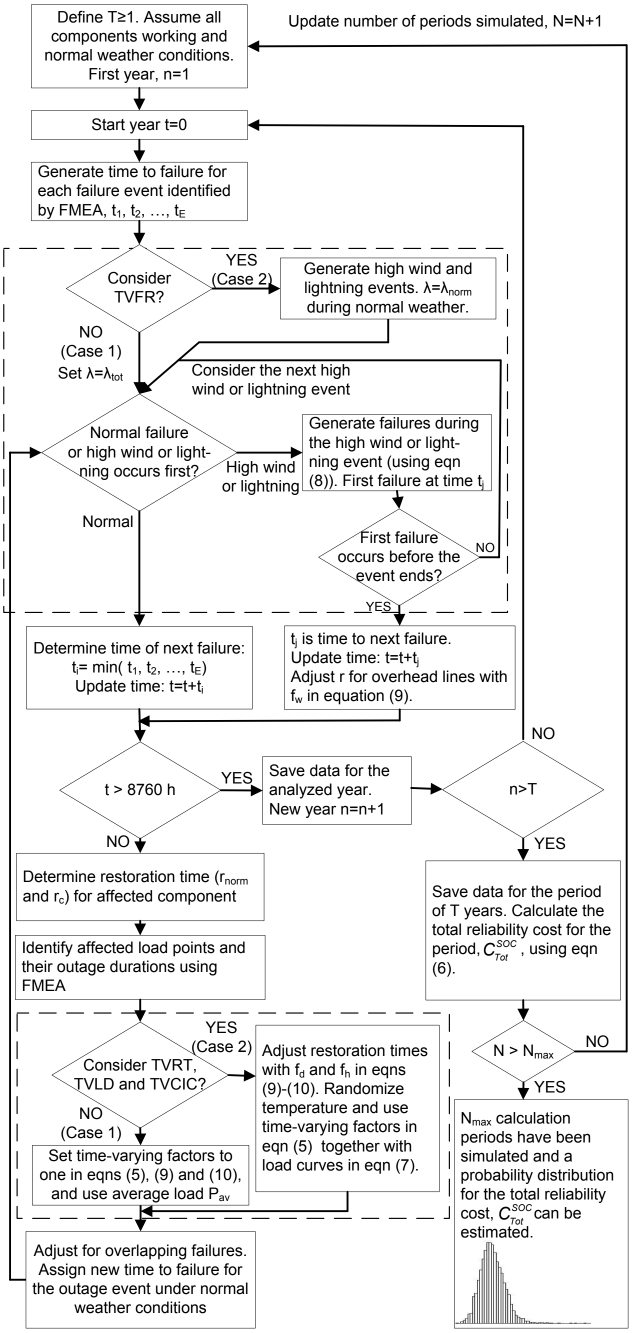

Figure 4: Flowchart for the applied time-sequential Monte Carlo algorithm. The dashed boxes represent the considerations of time-varying failure rates (TVFR), restoration times (TVRT), customer interruption cost (TVCIC) and load (TVLD).

The investment cost for cables can vary a lot depending on the ground conditions. As a sensitivity analysis the investment cost for cables was increased to 38 000 €/km, referred to as $\bar{P}1$ in Table 4. The project $\bar{P}1$ represents somewhat more difficult ground conditions than in project P1. Assume that the choice is between P0, $\bar{P}1$, and P2. As can be seen in Table 4, P0 will be the preferable project for both Case 1 and Case 2 if a risk-neutral strategy (S1) is applied. However, if a risk-averse strategy is applied, $\bar{P}1$ will be the selected project when time dependencies are considered in Case 2.

The result of a cost-benefit analysis using NPV as decision rule is sensitive to the choice of discount rate. Therefore sensitivity analyses were carried out where a discount rate of 3 % and 5 %, respectively, were tested. With a discount rate of 3 % the same project as before would be selected. However, with a discount rate of 5 % P0 would be selected in both Case 1 and Case 2. The latter result is due to that a higher discount rate gives more weight to cost occurring early in the considered time period (such as investment costs) and less weight to costs occurring later (such as decreased customer interruption costs and maintenance costs). P0 has no investment cost, only costs distributed throughout the time period, and is therefore favored by a higher discount rate.

7 CONCLUSION

This paper develops a new risk-based cost-benefit analysis method for distribution system reliability applications. Convential cost-benefit analysis makes decisions based on the expected outcome which corresponds to assuming that society is risk-neutral. Furthermore, time dependencies in input variables are ignored. The proposed method incorporates risk into the analysis by using time-sequential Monte Carlo simulations, and thereby makes it possible to capture the time dependencies in the input variables as well as testing different risk strategies.

The proposed method is applied in a case study to see if the same reinvestment project is selected if society is assumed to be risk-averse instead of risk-neutral and if time dependencies in input variables are considered instead of ignored. Results show that a different project is selected when time dependencies are considered, compared to if they are ignored, regardless if decisions are made based on a risk-averse or a risk-neutral strategy. This emphasizes the importance of risk modeling accuracy in cost-benefit analyses. In the case study there was a lack of conflict between the two risk strategies (risk-neutral/risk-averse); the same reinvestment project was selected with both strategies. However, the sensitivity analysis show that if the investment cost for cables is slightly higher, changing overhead lines into underground cables is only preferable if a risk-averse strategy is adopted.

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