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Department of Economics, Management and Humanities

Distribution grid reliability

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Pokyny pro vypracování:

- sledování spolehlivosti v distribučních sítích
- modely a výpočty spolehlivosti distribučních sítí
- návrh referenčního modelu distribuční sítě
- vztah mezi investicemi a spolehlivostí

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Declaration

I declare that thesis has been made independently and consistent with guidelines on compliance with ethical principles for the development of theses, and that I indicated all the information sources.

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Abstrakt

Táto práca sa zaoberá problematikou výpočtu a ocenenia spoľahlivosti distribučných sietí. Prvá teoretická časť popisuje základné ukazovatele spoľahlivosti z pohľadu matematického a z pohľadu zákazníka. Ďalej tiež popisuje rozdelenie modelov používaných pre výpočet spoľahlivosti sietí a ich základné princípy.

Druhá časť práce je orientovaná prakticky. Obsahuje návrh referenčného modelu časti distribučnej siete a výpočet parametrov spoľahlivosti. Tieto parametre sú popísané a využité v následnom ekonomickom ocenení rôznych variant slúžiacich pre zlepšenie spoľahlivosti siete.

Abstract

This work focuses on the topic of distribution grid calculations and evaluations. The first part describes the basic indices used in reliability from the mathematical and customers' points of view. It also presents various models used to evaluate the reliability of the network.

The second part of this work is practically orientated. It involves the reference model of the part of the distribution grid and the calculation evaluating the parameters of this grid. These parameters are used in the economical evaluation of various variants improving the overall reliability of the network.

Keywords

Reliability, SAIDI, SAIFI, distribution network, power grid, Monte carlo, investments, power supply.

List of Abbreviations

ACCI	Average Customer curtailment index
AENS	Average energy not supplied
ASAI	Average Service Availability Index
ASCI	Average system curtailment index
ASIDI	Average System Interruption Duration Index
ASIFI	Average System Interruption Frequency Index
CAIDI	Customer Average Interruption Duration Index
Czk	Czech crown (currency)
DSO	Distribution system operator
ERU	Energetický regulační úřad
km	Kilometres
kV	kilovolt
MCS	Minimal cut set
MTBF	Mean time between failures
MTTF	Mean time to failure
MTTR	Mean time to repair
NPV	Net present value
RCF	Retained cash flow
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index

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1. Introduction

Although the electric power systems are very complex issue, the electricity and power supply are necessary basics for every developed society with great impact to the lives of people. This fact creates high requirements for the stable power supply. The reliability of electricity distribution is therefore one of the most important topics in electricity industry with high impact to the cost of electricity. Very important aspect of the power system is to provide electric power to its customers at the lowest possible cost with acceptable reliability limits. These aspects often conflict and present the wide range of challenging problems.

In general, the investments into the distribution network cause the improvements in overall distribution grid reliability. There are customers that are willing to pay more to achieve more stable power supplies such as big enterprises and factories, on the other hand, there also are customers who do not want to pay more for better reliability and are satisfied with the current situation. This affects the distribution grid operators to make some tough decisions.

Modelling the parts of the network and their possible variants brings more light to the problematic issue of improving the distribution grid reliability. It can help to evaluate the possible costs of various variants and ultimately it helps to make wise decisions about investments to the power grid.

The goal of this thesis is to try to evaluate the distribution grid reliability through various indices, create different variants leading to the better power supply for customers. Next evaluations from the economical point of view should help to decide what kind of variants are the most suited for the actual use.

2. Theoretical part

2.1. Key definitions

Contingency (unscheduled event) – is unexpected event, for example fault or an open circuit.

Fault – we can divide faults of several categories depending on the time: temporary, permanent and self-clearing. Temporary will be cleared after de-energizing and re-energizing of the unit, self-clearing will be extinguished by itself without an external intervention. Permanent fault is a type of state when human intervention is needed to repair this fault.

Open circuit - a point in a circuit that interrupts load current without causing fault current to flow.

Outage – is a state of object when it is not energized – it can be either scheduled, or unscheduled

Interruptions — interruptions are the loss of voltage to a customer and can divided into momentary or sustained:

Momentary interruption – this occurs when a customer is out of power for less than a few minutes. In most cases this is a result of automated switching or reclosing.

Sustained interruption – sustained interruption occurs when a customer is out of service for more than a few minutes. Most interruptions of this nature are the result of either faults or open circuits.

Availability - Availability is the most basic aspect of reliability. It is the probability of something being energized. It is measured in percent or per unit.

Availability - the probability of being energized.

Unavailability - the probability of not being energized.

Availability or unavailability can be computed easily directly from interruption durations. For example, if a customer experiences 438 hours of interruptions (interrupted power) in one year, availability equals to

$$\frac{8760 - 438}{8760} = 95{,}0\% \tag{1}$$

Therefore unavailability is equal to 100%-95%=5%

2.2. Main mathematical reliability indices

There are several indices based on mathematical models describing the reliability of the system. This work briefly presents the most important of these indices which are used in next parts of the work.

Survivor function (reliability)

$$R(t) = P(\zeta > t) = \int_t^{\infty} f(\tau)d\tau = 1 - Q(t) \tag{2}$$

Failure distribution function

$$Q(t) = P(\zeta \leq t) = \int_0^{t} f(\tau)d\tau = 1 - R(t) \tag{3}$$

We presume that R(0)=1 and R(∞)=0

Failure density function

$$f(t) = \frac{dQ(t)}{dt} = -\frac{dR(t)}{dt} \tag{4}$$

Failure rate

$$\lambda(t) = \frac{f(t)}{R(t)} \tag{5}$$

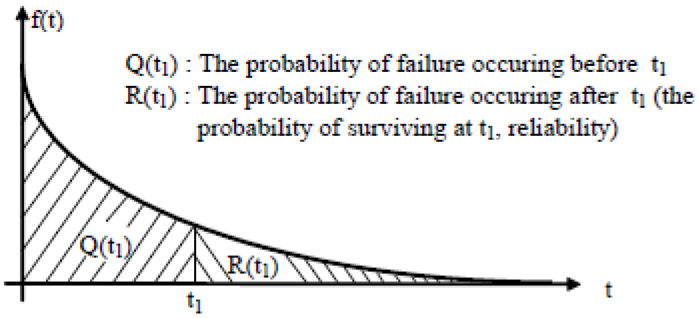
Mean time to failure MTTF

$$MTTF = \int_0^{\infty} t.f(t)dt = \int_0^{\infty} R(t)dt \tag{6}$$

In an exponential failure density, MTTF is given as

$$MTTF = \frac{1}{\lambda} \tag{7}$$

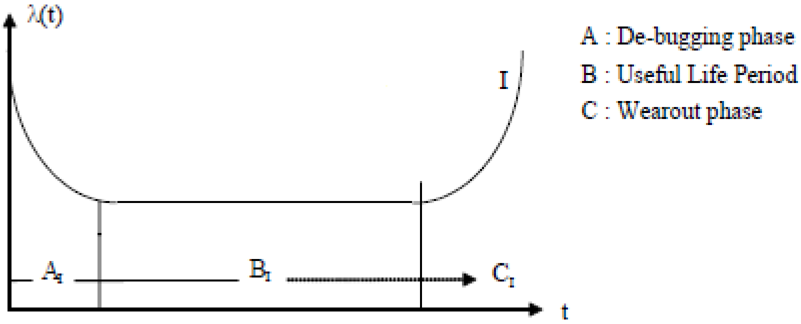
Where t - failure time



Graph 1 - Failure density function, failure distribution function and survival function

2.3. Shape of reliability functions

The hazard rate curve – "bath-tub curve" is a typical example of many physical components. This curve can be divided into three regions.



Graph 2 - Hazard rate as a function of age (1)

Region A, B and C

The failure rate is decreasing as a function of the time in the first part of the curse as a result of de-bugging of component. This time interval is called early failures region and failures are usually caused by manufacturing errors or bad design. This number can be decreased by appropriate testing prior to taking the unit to the service.

In the second stage of a lifespan of a unit is useful period of the unit. The failure is approximately parallel to time-axis and is almost constant. Malfunctions of unit in this period are random without any obvious reasons – the failures are called chance failures.

The failure flow is increasing in the third part of the curve and is called wear out region or fatigue phase. This part is characteristic by rapid increasing of failure rate with time and is caused by aging of the unit. This part can be usually approximated by normal distribution; however, Gamma or Weibull distributions are often preferred for this zone.

Mechanical and electronic component age in different times as can be seen in the figure. We can observe that useful time period of mechanical parts is much smaller than electronic components. Most of the power system components exhibit usually between two extreme cases.

„On the other hand, artificial ageing processes minimize the early failures and appropriate maintenance policies (preventive maintenance) extend the life of useful time period. Therefore we do generally prefer to conduct our studies for the useful life period“. (1). We can presume constant failure rate within the whole lifespan of power system components.

2.4. Interruption causes (2)

The interruptions in power supply are caused by wide range of different phenomena such as weather conditions, human errors, animals, trees, and equipment failure… Identifying the main aspects leading to the failures in the system is the key to evaluate the problem and finding the best way to solve it.

Every equipment has the chance to fail to operate properly. Devices can fail spontaneously for reasons such as aging or can be damaged caused by various circumstances (extreme currents and voltages, bad manipulation, bad weather…).

Animals are one of the largest causes of problems and interruptions for many electrical utilities. The most cases of damages caused by animals are caused by the chewing the insolation of cables (squirrels, rats, mice…) or by birds which damage the transmission and sub-transmission overhead lines.

Bad weather conditions can be the main reason of interruptions for many utilities. Severe weather can have different forms – cold weather, strong wind, tornados, lightning strikes, and earthquakes. On our conditions the main reason for the interruption is icing on the overhead lines.

Trees can be also a big problem causing the interruptions especially with the severe weather conditions. The branch can fall on two conductors causing the shortcut or can tear them down from poles when the heavy branch or tree falls on them. If the tree is close to the overhead line, some of animals living on trees can jump on these lines causing outages in the power supply. It should be made sure that the branches of trees are always in the safe distance from the lines so they cannot cause interruptions.

The last major cause of interruption is the human factor when the bad manipulation with equipment, vandalism human errors can cause the outages. There are really many ways people can cause interruption in the power supply and such precautions should be made to prevent human making unnecessary errors.

2.5. Indices

2.5.1. Customer-based reliability indices

There are several widely used indices used in reliability to weight customers equally. As just small residential customer has the same importance in reliability evaluation as large customers, these indices are popular with regulating authorities. Though they have some limitations, they are generally considered well to measure reliability in power system and also are used for reliability benchmarks and improvement targets. (2)

There are four basic indices:

SAIFI System Average Interruption Frequency Index

SAIDI System Average Interruption Duration Index

CAIDI Customer Average Interruption Duration Index

ASAI Average Service Availability Index

Mathematical expression for mentioned indices:

$$SAIFI = \frac{\text{Total Number of Customer Interruptions}}{\text{Total Number of Customers Served}} \; [\frac{1}{year}]$$

$$SAIFI = \frac{\sum \lambda_i . N_i}{\sum N_i} \tag{8}$$

$$SAIDI = \frac{\sum \text{Customer Interruption Durations}}{\text{Total Number of Customers Served}} \; [\frac{hours}{year}]$$

$$SAIDI = \frac{\sum \lambda_i . \tau_i . N_i}{\sum N_i} \tag{9}$$

$$CAIDI = \frac{\sum \text{Customer Interruption Durations}}{\text{Total Number of Customer Interruptions}} = \frac{SAIDI}{SAIFI} [hours]$$

$$CAIDI = \frac{\sum \lambda_i . \tau_i . N_i}{\sum \lambda_i . N_i} \tag{10}$$

$$ASAI = \frac{\text{Customer Hours Service Availability}}{\text{Customer Hours Service Demand}} []$$
$$ASAI = \frac{\sum N_i . 8760 - \sum \lambda_i . \tau_i . N_i}{\sum N_i . 8760} = 1 - \frac{SAIDI}{8760} \quad (11)$$

Where:

- λ_i is the failure rate in load point i;
- N_i is the number if customers of load point i;
- τ_i is the mean time of outage (interruption duration) of load point i;
- 8760 is the number of hours in one year.
-

SAIFI –gives us an information about how many (or frequency) sustained interruptions one customer will experience in one year. If there is a fixed amount of customers, the way to improve this index is to lower the number of interruptions of customers.

SAIDI – it provides us with the information about the average number of interruption hours an average customer is interrupted from the energy supply. For a fixed number of customers, SAIDI can be reduced either by the duration of interruptions or the amount of interruptions. A reduction of total customer duration of interruptions means an improvement in reliability of power supply. As there are two ways how to improve SAIDI, it is more likely to improve SAIDI than SAIFI.

CAIDI - is the average time of one interruption to an average customer (time needed to restore the supply). This index can be improved by lowering the duration of interruptions or by increasing the number of short interruptions. This means that the lower CAIDI does not necessarily means an improvement in reliability.

ASAI – is basically provides us with the same information as SAIDI but is customer-weighed. Higher values of this index mean higher reliability of the system. We also presume that we need a power supply for full 8760 hours

Next indices are based upon the number of customers that have experienced one or more interruptions in the observed year.

CAIFI Customer Average Interruption Frequency Index

CTAIDI Customer Total Average Interruption Duration Index

$$CAIFI = \frac{\text{Total Number of Customer Affected by Interruptions}}{\text{Number of customers affected at least once}} \left[\frac{1}{year}\right]$$
$$CAIFI = \frac{\sum \lambda_i . \tau_i . N_i}{N} \qquad (12)$$

$$CTAIDI = \frac{\sum \text{Customer Interruption Durations}}{Number\ of\ custommers\ affected} \left[\frac{hours}{year}\right]$$
$$CTAIDI = \frac{\sum \lambda_i . \tau_i . N_i}{N} \qquad (13)$$

CAIFI seems to be similar to SAIFI. Improvements in CAIFI or CTAIDI do not necessarily means improvements in reliability as can be “improved” by the higher number of those customers who are affected by a single interruption.

2.5.2. Load and energy based indices

These indices weight customer based on connected kVA instead of weighing each customer on the same level. Due to this, larger kVA connected to customer means higher revenue and thus should be taking in account when making decisions.

Average System Interruption Frequency Index (ASIFI)

Average System Interruption Duration Index (ASIDI)

Average energy not supplied, AENS or Average system curtailment index, ASCI,

Average Customer curtailment index, ACCI

$$ASIFI = \frac{Connected\ kVA\ interrupted}{Total\ connected\ kVA\ served}\ [\frac{1}{year}] \tag{14}$$

$$ASIDI = \frac{Connected\ kVA\ hours\ interrupted}{Total\ connected\ kVA\ served}\ [\frac{hours}{year}] \tag{15}$$

$$AENS = \frac{Total\ energy\ not\ supplied}{Total\ number\ of\ customers\ served} \tag{16}$$

$$ACCI = \frac{Total\ energy\ not\ supplied}{Total\ number\ of\ customers\ affected} \tag{17}$$

2.6. Models

There are two main approaches used in reliability evaluations: analytical and simulation. The majority of techniques have been based on analytical approach while simulation techniques have taken small part in specialized applications. The reason for this is because simulation generally requires quite large amount of computing time while analytical models and techniques have been sufficient to provide with the results needed to make objective decisions. Analytical techniques represent the system by a mathematical model and evaluate the reliability indices from this model using direct numerical solutions. They generally provide expectations indices in a relatively short time.

2.6.1. Analytical methods based on mathematical models calculation

2.6.1.1. Serial systems

If the components are connected in a way where all of them must operate for the system success of one component failure if sufficient enough for the system failure, we call this system **serial**. This system can be represented as a series of overhead lines, breakers, switches, and transformers and at the end by customers.

Scheme 1 - Series system structure (3)

Average failure rate of the system:

$$\lambda_s = \lambda_1 + \lambda_2 + \dots + \lambda_n = \sum_{i=1}^{n} \lambda_i \tag{18}$$

Average outage of the system:

$$r_s = \frac{\lambda_1 r_1 + \lambda_2 r_2 + \lambda_1 r_1 \lambda_2 r_2}{\lambda_1 + \lambda_2} = \frac{\sum \lambda_i i}{\sum \lambda_i} = \frac{U_s}{\lambda_s} \qquad (19)$$

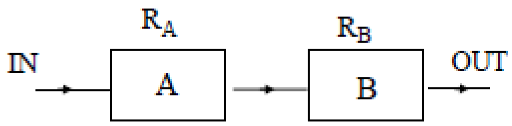
We presume that $\lambda_1 r_1 \lambda_2 r_2 \ll \lambda_1 r_1 or \lambda_2 r_2$

Average annual outage time

$$U_s = f_s r_s = \lambda_s r_s \qquad (20)$$

Where:

- λ_i is the failure rate at node i,
- r_i is the outage time at node i.



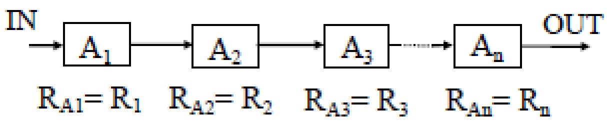
Scheme 2 -The reliability of the system comprising two serially connected units A and B

$$R_S = (R_S \mid R_B)R_B + (R_S \mid Q_B)Q_B = R_A R_B + 0 = R_A R_B < R_A, R_B \qquad (21)$$

$$Q_S = 1 - R_S = 1 - R_A R_B \qquad (22)$$

assuming that the units are operating independently.

Similarly, the reliability of n-serially connected units can be evaluated



Scheme 3 - Serially connected n units

$$R_S = \prod_{i=1}^{n} R_i \tag{23}$$

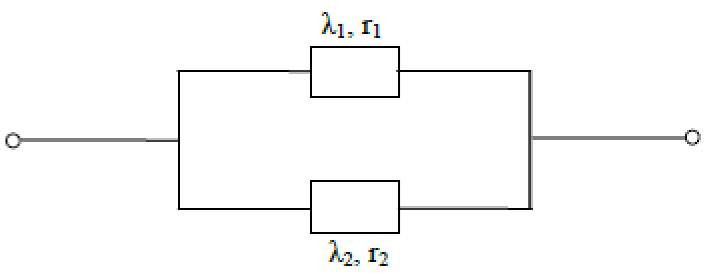
$$Q_S = 1 - R_S = 1 - \prod_{i=1}^{n}(1 - Q_i) \tag{24}$$

"As $R_i < 1$, system reliability is less than the individual reliabilities of serially connected units. System reliability decreases as the number of components increase. On the other hand, since the reliabilities of practical units are close to unity, higher order products of component failures can be ignored and the resulting system reliability can be approximated as " (1)

$$Q_S = \sum_{i=1}^{n} Q_i \tag{25}$$

2.6.1.2. Parallel systems (redundant systems)

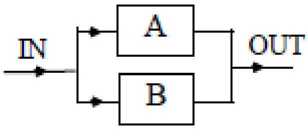
If the components are connected in a way where all of them must fail to operate for the system failure of one component operation if sufficient for the system success, we call this system **parallel**. We assume that failures are independent and restoration involves repair or replacement.



Scheme 4 - Series system structure (3)

Parallel structure

Failure probability of a system comprising two serially connected units A and B



Scheme 5 Parallel connected units

Average failure rate of the system:

$$\lambda_{1p} = \frac{\lambda_1\lambda_2(r_1 + r_2) + \lambda_1 r_1 \lambda_2 r_2}{1 + \lambda_1 r_1 + \lambda_2 r_2} = \lambda_1\lambda_2(r_1 + r_2) \quad (26)$$

We assume that $\lambda_1 r_1 and \lambda_2 r_2 \ll 1$

Average outage time of the system:

$$r_p = \frac{r_1 r_2}{r_1 + r_2} \quad (27)$$

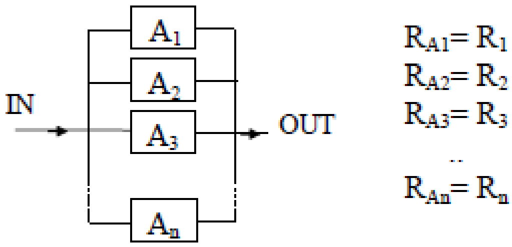
Average annual outage time

$$U_p = \lambda_p r_p \quad (28)$$

$$Q_p = (Q_p \mid R_B)R_B + (Q_p \mid Q_B)Q_B = 0 + Q_A Q_B = Q_A Q_B \quad (29)$$

$$R_p = 1 - Q_p = 1 - (1 - R_A)(1 - R_B) = R_A + R_B - R_A R_B \geq R_A, R_B \quad (30)$$

Similarly, failure probability of n-parallel connected units (Scheme 6 – Parallel connected n units) A1, A2,...,An can be derived as



Scheme 6 – Parallel connected n units

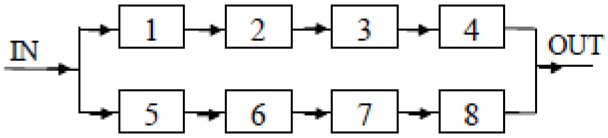
$$Q_p = Q_1 Q_2 Q_3 \dots Q_n = \prod_{i=1}^{n} Q_i \tag{31}$$

$$R_p = 1 - Q_p = 1 - \prod_{i=1}^{n} (1 - R_i) \tag{32}$$

Since Qi « 1, failure probability of parallel connected units is less than the individual failure probabilities of components. Therefore, reliability of a parallel system increases as the number of parallel connected components increases. However, it is impossible to make any approximation neither for system reliability nor system failure probability.

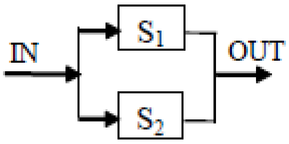
2.6.1.3. Series-parallel

We can count series-parallel reliability indices by the combination of serial and parallel distribution systems. The main principle used for this kind of systems is to reduce the configuration to several serial and parallel systems. Then we calculate the equivalent sub-model represented with joint elements – we add the serial elements in one branch to one equivalent element representing these serial elements. We do the equivalent simplifications with parallel structures too. We continue with simplifying the model until we receive one element representing the whole system and we calculate the reliability indices of this element.

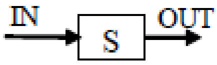


Scheme 7 Series-parallel combination

Serial branches can be represented by their equivalents:



Scheme 8 – Equivalent scheme for series-parallel combination



Scheme 9 – Final equivalent scheme for series-parallel combination

$$R_{s1} = R_1 R_2 R_3 R_4 \tag{33}$$

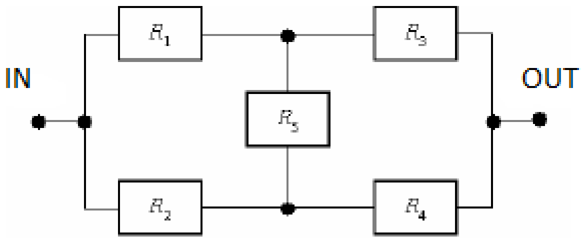
$$R_{s2} = R_5 R_6 R_7 R_8 \tag{34}$$

$$Q_s = Q_{s1} Q_{s2} = (1 - R_{s1})(1 - R_{s2}) = (1 - R_1 R_2 R_3 R_4)(1 - R_5 R_6 R_7 R_8) \tag{35}$$

$$R_s = 1 - Q_s = R_1 R_2 R_3 R_4 + R_5 R_6 R_7 R_8 - R_1 R_2 R_3 R_4 R_5 R_6 R_7 R_8 \tag{36}$$

2.6.1.4. *Complex (connected) systems*

Simple series-parallel type of structure is not that common in the real operating systems and therefore more complex methods and techniques must be introduced to evaluate system reliability. A typical system, where we cannot use series-parallel structure is the bridge type of the network.



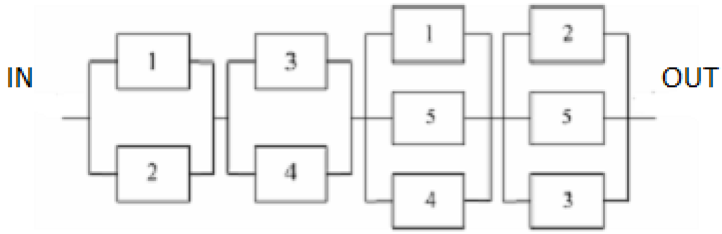
Scheme 10 - The bridge type of the network

2.6.1.5. *Cut-set method*

We can use this method if the failures of each element are independent. This method is based on dividing the system into several subsystems with simple structure.

„A **cut set** is a set of system components which, when failed, causes failure of the system. A **minimal cut set (MCS)** is a set of system components, which, when failed, causes failure of the system but when any one component of the set has not failed, does not cause system failure. We can derive the following conclusions from the definition of a MCS“. (1)

In this method, there exist several MCS of a complex system. As the failure of one MCS is enough for the system failure, these MCSs can be represented as serial connected to each other. Furthermore, as all parts of a MCS must fail for system failure, MCS components can be considered to be connected parallel to themselves.



Scheme 11 - Representation of a complex network with MCS (1)

Thanks to creating series system of MCSs, we basically obtained series-parallel structure. However, there is one notable difference from the ordinary series-parallel network. In this structure, more than just one component may arrear several times – can be included in several MCSs. This means that "failure probabilities of MCSs comprising common elements are not independent than each other". (1)

"There are several methods for determination of MCSs. Most of these methods make use of minimal paths. Set of operating components providing input-output connection is called a path. That is, a path is a set of system components which, when operate, provides system success. A minimal path (MP) is a set of system components which, when operate, provides system success but when any one component of the set fails, system failure occurs. A path is minimal, if in that path, no node or intersection between branches is traversed more than once. Since, each node or branch intersection is allowed to be traversed once; the maximum number of components included in a MP an n-node system is (n-1). For multi input/multi output systems or for the systems where the unit capacities are important, a minimal path is defined is defined as the number of minimum components for the system performs its duty adequately. From these definitions:

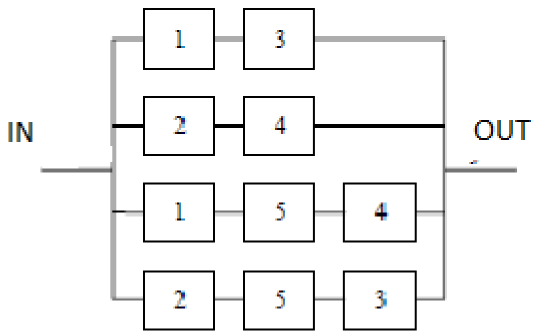
Since a MP provides the input-output connection (system success) when all the units in the path operate, components included in a MP are serially connected.

Since there are several different MPs (different set of components) providing the input output connection, MPs are connected in parallel among themselves. Input and output nodes are enumerated as 1 and n, respectively. Determination of minimal paths can be done either by node removal or by matrix multiplication.*"* (1)

2.6.1.6. Tie set method

„Tie set method is actually the complement of the cut set method. Tie sets give an idea about the operation mode of the system instead an idea of failure modes of the system. It has certain and limited applications.

Tie sets are actually minimal paths of the system and a single failure of a component of a tie set is sufficient for a system failure. Therefore components of a tie set are serially connected among themselves. Since a single tie set is enough for system operation, tie sets are connected in parallel among themselves. As a consequence of these definitions, tie sets form a series-parallel equivalent of a complex connected system. The following figure is such an equivalent of a system.“ (1)



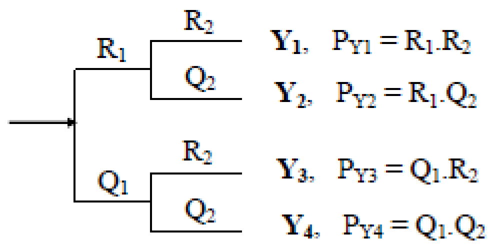
Scheme 12 - Tie-set equivalent of a complex system

2.6.1.7. Event trees

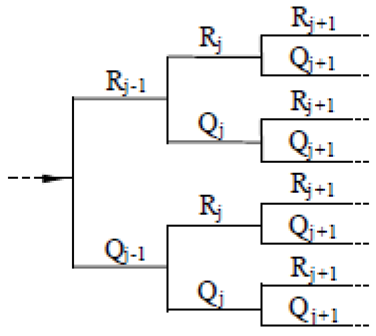
Next method widely used is an event tree method. “An event tree is a graphical representation of the logic model that identifies and quantifies the possible outcomes following an initiating event. “

This method is commonly used for the systems with continuously operating components or for the systems with standby redundant components that requires sequential operating logic and switching. This method is preferred for safety oriented systems such as those in nuclear power plants. There are two representations of event tree with two main differences.

“The first one is that the sequence of the events is not important for the first group but the sequence of events must be represented in a chronological order in which they occur. The second important difference is about the starting event of the tree. Event tree may be initiated by an arbitrary event for the first group. However, initial event for the second group is the starting event." (1)



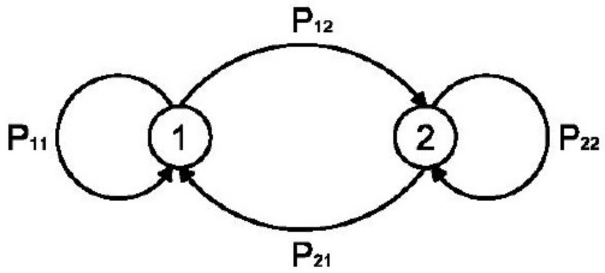
Scheme 13 - Event tree for a system comprising 2 units



Scheme 14 - Event tree for 2-state components

2.6.1.8. Markov chain model

Markov chain models are the function of two variables, the state of the system and the time. Both variables can be either discrete or continuous and therefore there are 4 types of models. This model is quite popular and gives us the main idea about how reliability principles work. Every Markov chain model is defined by the set of probabilities, which gives us the chances of changing the system from one state to another. Characteristic for this method is that the probability of changing from one state to another depends only on the initial state of the system and therefore is independent on last states. We can say that the Markov chain does not have memory.



Scheme 15 – Markov chain model

- P_{11} is the probability that the system stays at the state 1 at the end of the interval, if the system was in this state at the beginning of the interval.
- P_{12} is the probability that system will change from the state 1 into state 2 within the time period
- P_{21} is the probability that system will change from the state 2 into state 1 within the time period
- P_{22} is the probability that the system will remain in the state 2 within the time interval

$$P_{11} + P_{12} = 1 \qquad P_{21} + P_{22} = 1$$

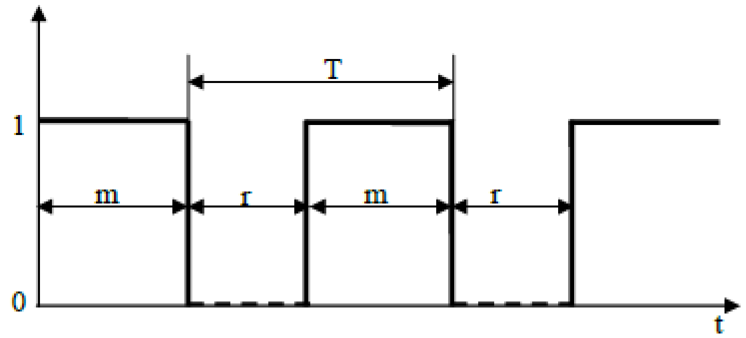


Figure 1 - An average state cycle

Where:

m - MTTF (mean time to failure) is given by: $m = 1/\lambda$

r - MTTR (mean time to repair): $r = 1/\mu$

m+r - MTBF (mean time between failures) = $T = 1/f$

f - Cycle frequency; $f=1/T$

T - Cycle time

2.6.2. Simulation methods based on statistical distributions

2.6.2.1. Monte Carlo

Monte Carlo is simulation oriented method. This simulation does not do analytical calculations but it considers stochastic event occurrences. As a result of two or more simulations based on Monte Carlo with identical inputs we do not receive the exact same outputs. By doing many repeated simulations we obtain results from

Obtaining a distribution of results by means of doing many repeated simulations, we can compute mean, median and other statistical measures that describe the model quite accurately.

$$\bar{x} = \lim_{N \to \infty} \left(\frac{1}{N} \sum_{i=1}^{N} x_i\right) \qquad (37)$$

Where

- $\bar{x}$ = expected value
- x_i = result of simulation i
- N = number of simulations

Obviously, it is very important to decide the number of simulations in Monte Carlo approach. If the result is some expected or known value, simulations can be performed until the mean of results converges to this value. If the event is rare to occur, the number of years input to simulation must be large enough for the event to happen.

We differ between sequential and non-sequential Monte Carlo simulations.

Sequential Monte Carlo models the system behaviour in the way as it occurs in reality. It is a chain of random events connected to each other as they occur through the time. In non-sequential approach we presume that random events are not independent and the behaviour of the system in not connected to previous events. Simulations can be computed in independent order. (1) (2)

2.6.2.2. *Reliability modelling*

The methods used for the obtaining the input data vary on the type of observed objects. These methods can be divided into two groups:

- Historical analysis and empirical reliability

  This method use data based on the system outage histories to compute the indices. It is necessary to have the database of the objects and their states (working, failure state, time to repair…) in the system. It is also good to have the information about similar elements in the network to compute the average indices for the element. The more information collected in the database, the more precise evaluations are. Historical analysis is used to compute failure rates, repair times as input to predictive analysis.

- Predictive analysis and a priori reliability

  We talk about a priori reliability, when the input data are already given. The data can be based either in empirical reliability or the information given by the producer of the element when there is no past information about similar equipment (new kind of element in the network). Input data is evaluated by the analysis of the possible states of the element. Therefore it is necessary to consider the right period of time between revisions of the element. Predictive analysis of the system is based on the methods described in the previous part of this work and combines the set of techniques and system topology to calculate system indices.

(4)

3. Distribution grid modelling

3.1. The simulation of reference model

An average consumption of electricity of households in Czech Republic was 5626 kWh in 2010. An average consumption had a growing trend until 2008 (5799 kWh), then dropped to 5444 kWh in 2009 and continued with slight growth in the next year (5626 kWh). Assuming total increase of electricity consumption in Czech Republic in next years, I have chosen an average consumption of 5800 kWh for a household in the referential model. This consumption is taken for a home with 4 members. As the model is taken for a radial distribution network in rural areas with family houses, chosen value can be considered acceptable for the model.

Each distribution transformer supplies 10 households. Therefore system failure of the output node causes interruption of power supply of each household on the low voltage side of the network. I have chosen the same amount loads for each output node to see how the different transfiguration of distribution network affects the various indices on equal scale.

When considering undersupplied energy we need to take in account the time of a failure in a day. It will differ significantly whether the downing event occurs during the day or night and have to keep in mind the cycle of living for persons in a household. The household would be probably affected more if the undersupply occurs in the evening, when everybody is home and active then in the night, when people sleep or in the lunch time when people are usually at work. There complicated survey had to be done to evaluate precise effects of a system failure for each household in real conditions.

As the simulation was done in the period of 100 years, we can assume normal distribution of downing events during the period of a day in the each household and therefore an average undersupplied energy for each event leads to the same result as floating value in real conditions.

3.2. Modelling

There are many different ways to calculate distribution network reliability. Non-simulation methods require deeper understanding of the problem and usually require more time to calculate the reliability of the system than simulation methods. For basic calculations these methods are sufficient but it is better to use some simulation software to evaluate network reliability. Using software also minimizes the possibility of human-factor errors in the calculations and in general, this approach is more suited for more complex general and sensitivity analysis.

3.3. Software

The basic distribution network was modelled in ReliaSoft software. This software is designed for the reliability calculations in various areas such as reliability planning, process reliability etc. The software offers several moduls for different types of calculations such as reliability growth analysis, reliability prediction, risk based inspection analysis, probability event and risk analysis. The modul used for this work is called BlockSim. It utilizes reliability block diagram and/or fault tree analysis approach and supports wide variety of analyses for repairable and non-repairable systems. It can calculate various indices such as reliability, maintainability, availability, throughput… (5)

The system is represented as a set of blocks connected by lines creating the required system. Each block can be programmed and simulates one element of the system. Input data have to be set in each element prior to running the simulation. The main variables characterizing the each element are reliability model (failure distribution) and the time of repair of the element upon failure. Many different failure distribution functions can be used for desired simulation– weibull, exponential, normal, lognormal, gamma… Blocks can be set into repair groups to perform the maintenance of all elements in the group at the same – this is helpful in maintenance planning of the system and can increase overall reliability of the system. This approach is naturally used in the practical application when the subsystem (i.e. elements connected into serial subsystem) is shut down and the maintenance can be performed in the same time of each component (maintenance of several components is performed upon planned or non-planned transformer cut-off…). Scheduled tasks can be also planned to each element to simulate the system in its true complexity.

As the system can be computed only as whole, each load had to be simulated separately (one input and one output point). Simulations were performed in the period of 100 years and 1000 simulations were performed for each point and variant in order to achieve the sufficient and accurate amount of data.

The print screens of BlockSim environment are enclosed as appendices of this work.

3.4. Input data

The input data for the model are based on notice 22/80 ČEZ (6) and (7)

λ – failure rate

t – mean time of failure

Input data				
Element	**Label**	**λ**	**t**	**length**
		[1/year]	**[hours]**	**[km]**
Line 110 kV	L1.T	0,052/km	3,5	1
	L2.T	0,052/km	3,5	1
	L3.T	0,052/km	3,5	1
	L4.T	0,052/km	3,5	1
Line 22 kV	L1	0,014/km	3	1
	L2	0,014/km	3	1
	L3	0,014/km	3	1
	L4	0,014/km	3	1
	L5	0,014/km	3	1
	L6	0,014/km	3	1
	L7	0,014/km	3	1
	L8	0,014/km	3	1
	L9	0,014/km	3	1
	L10	0,014/km	3	1
	L11	0,014/km	3	1
	L6.2	0,014/km	3	1
	L7.2	0,014/km	3	1
	L8.2	0,014/km	3	1
	L9.2	0,014/km	3	1
	L10.2	0,014/km	3	1
	L1.1	0,014/km	3	1
	L2.1	0,014/km	3	1
	L3.1	0,014/km	3	1
	L4.1	0,014/km	3	1
	L5.1	0,014/km	3	1
	L6.1	0,014/km	3	1
	L7.1	0,014/km	3	1
	L8.1	0,014/km	3	1
	L9.1	0,014/km	3	1
	L10.1	0,014/km	3	1

	L7.3	0,014/km	3	1
Switch 110 kV	SW1.T	0,06	15	
	SW2.T	0,06	15	
	SW3.T	0,06	15	
	SW4.T	0,06	15	
Switch 22kV	SW1.D	0,02	10	
	SW2.D	0,02	10	
	SW3.D	0,02	10	
	SW4.D	0,02	10	
	SW1	0,02	10	
	SW2	0,02	10	
	SW3	0,02	10	
	SW4	0,02	10	
	SW5	0,02	10	
	SW6	0,02	10	
	SW7	0,02	10	
	SW8	0,02	10	
	SW9	0,02	10	
	SW10	0,02	10	
	SW7.3	0,02	10	
Transformer 110/22 kV	T1.T	0,04	280	
	T2.T	0,04	280	
	T3.T	0,04	280	
	T4.T	0,04	280	
Transformer 22/04 kV	T1	0,03	80	
	T2	0,03	80	
	T3	0,03	80	
	T4	0,03	80	
	T5	0,03	80	
	T6	0,03	80	
	T7	0,03	80	
	T8	0,03	80	
	T9	0,03	80	
	T10	0,03	80	
	T7.3	0,03	80	

Table 1 – Input data for model

3.5. Variants

In order to research distribution grid reliability a simple radial distribution network was modelled. This kind of network is usually spread in rural areas of Czech Republic. The grid is supplied from the transmission grid (110 kV) with two parallel lines, switches, disconnectors and transformers. These feeders are connected to one bus-bar on the distribution grid side (22 kV) therefore any unexpected failure of one of feeders does not cause outage of the system. In this point, only simultaneous failure of any part of both feeders cause the outage of the distribution network and thus the electricity cannot be delivered to the loads.

The base variant consists of two separate lines and 5 output points for each line (10 in total). Each output point represents 10 loads so that means 100 households in total. Each point is modelled with another line, switch and distribution transformer. Other elements are considered to be on the low voltage side and are not included in the reliability calculations of the network. The number of loads in every output point was set to the same value so that the comparison of these points is observable.

Other two variants were calculated and compared to the base variant.

The second variant consists of the second feeding point from the transmission network and this point is connected to the farthest point of the distribution line. This means that 5 output points are supplied from two sides and another 5 (on the other line) remained with one supply in order to get new data for comparison of these two distribution lines with the base variant.

The third variant consists of another redundant line to the distribution line. The second line is without doubled line for comparison of these variants.

In all of these variants, there is another variant where two parallel feeders (line, switch and transformer) are connected to the bus-bar (low voltage side) and providing the loads with redundant source.

In addition, the same variants as mentioned above were calculated with ten times longer lines to show the reliability of the households with lower density per square.

Variants with different amount of customers and power consumed were also calculated in order to compare customer based indices in the same type of the distribution network with different structure of consumers.

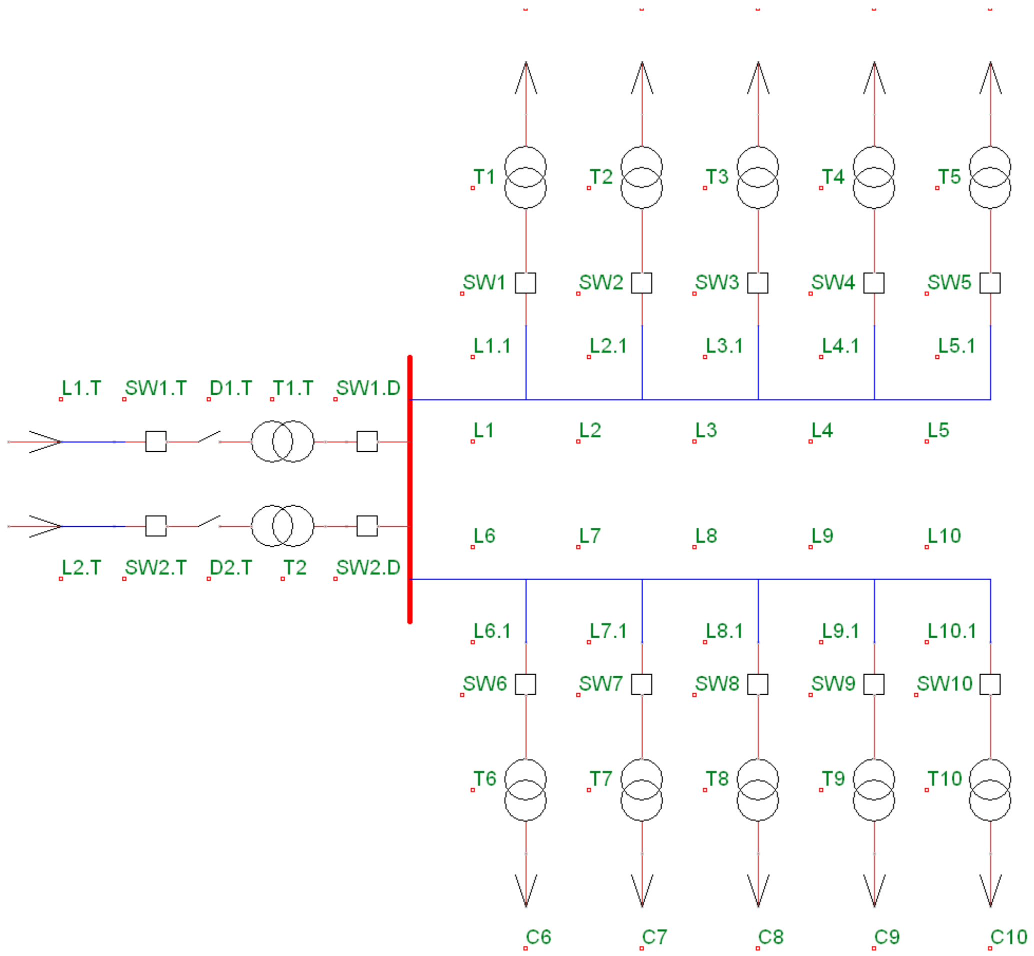
3.5.1. The list of variants

There are 3 main variants and 4 sub-variants within the main ones.

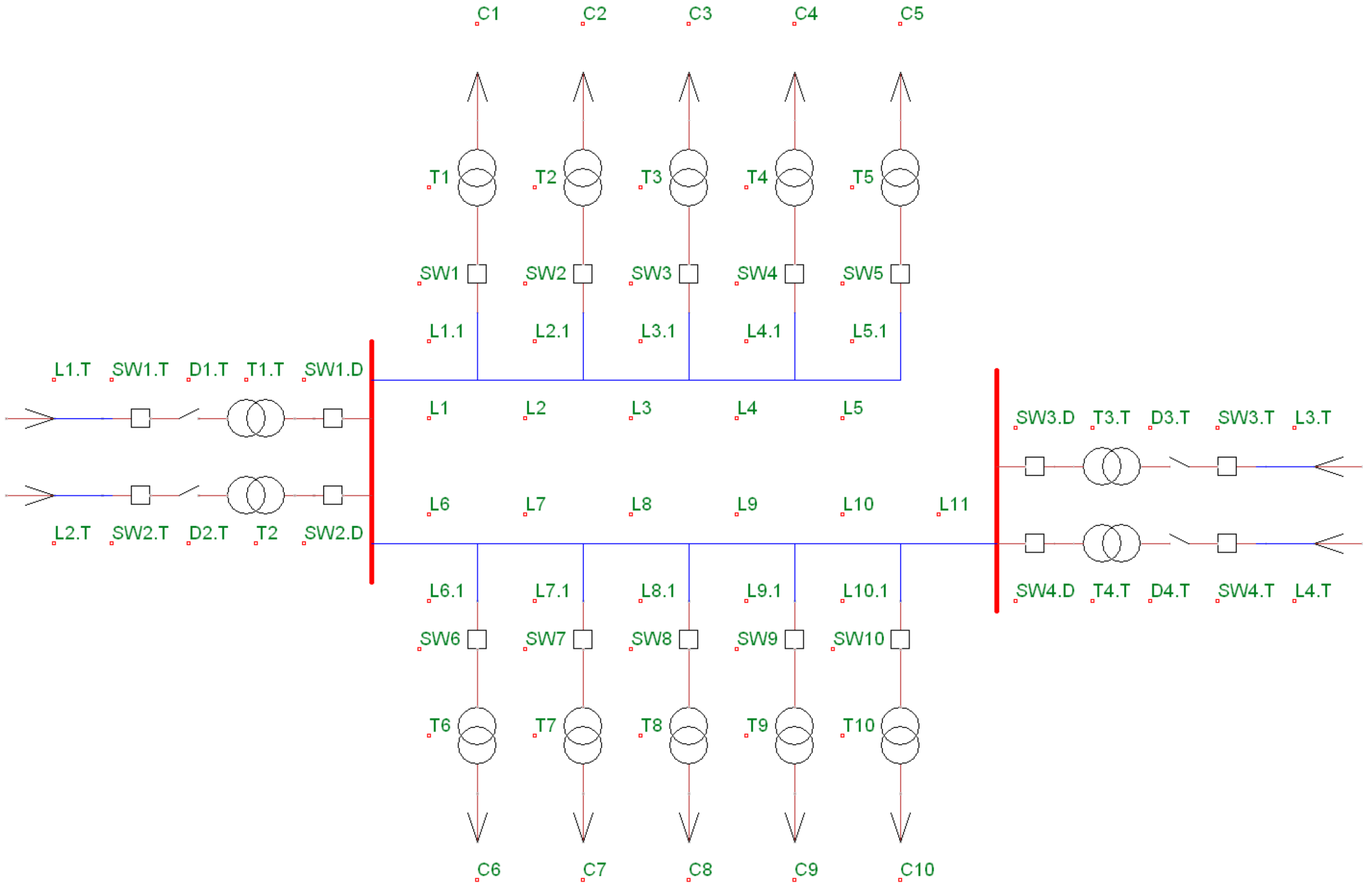
1) Base variant
   a) V1.1 Base variant
   b) V1.2 Base variant with one doubled output point
   c) V1.3 Base variant with longer distribution lines
   d) V1.4 Base variant with longer distribution lines and one doubled output point

2) Two feeding points variant
   a) V2.1 Variant with two feeders
   b) V2.2 Variant with two feeders with one doubled output point
   c) V2.3 Variant with two feeders with longer lines
   d) V2.4 Variant with two feeders with longer lines and one doubled output point

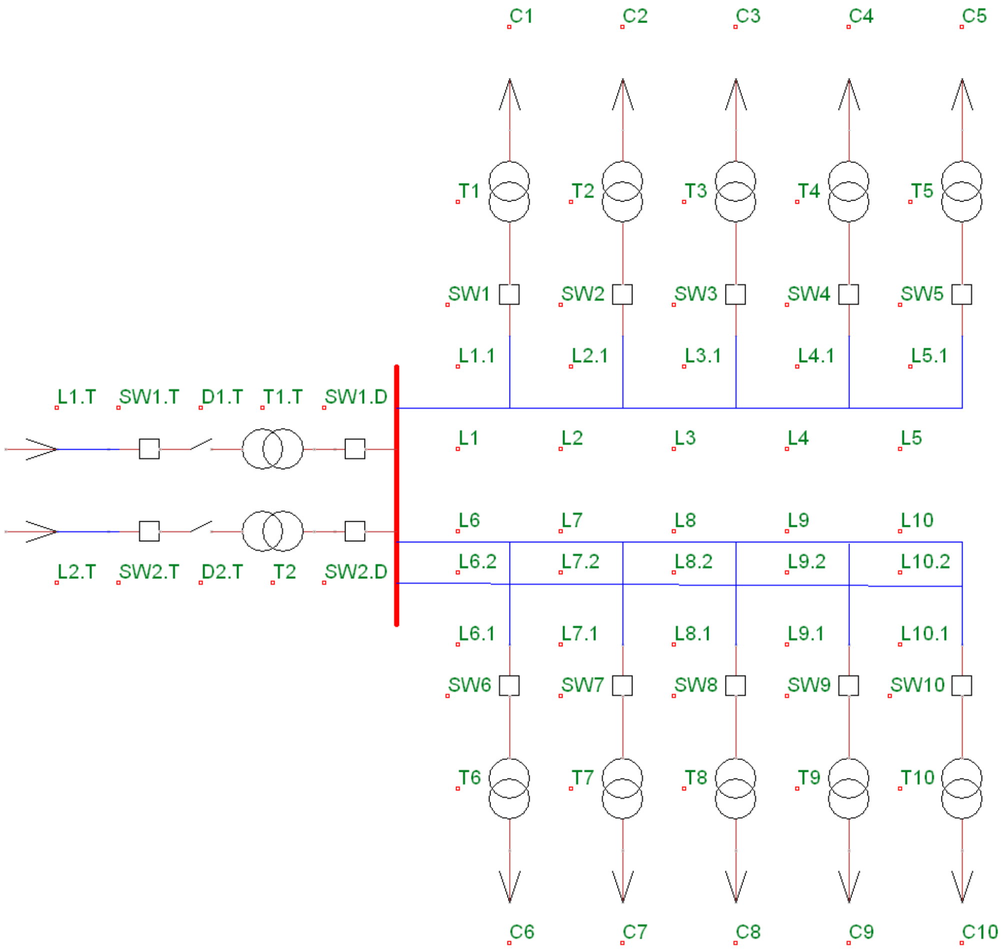
3) V3.1 Doubled lines variant
   a) V3.1 Variant with doubled lines
   b) V3.2 Variant with doubled lines and one doubled output point
   c) V3.3 Variant with doubled lines with longer lines
   d) V3.4 Variant with doubled lines with longer lines and one doubled output point



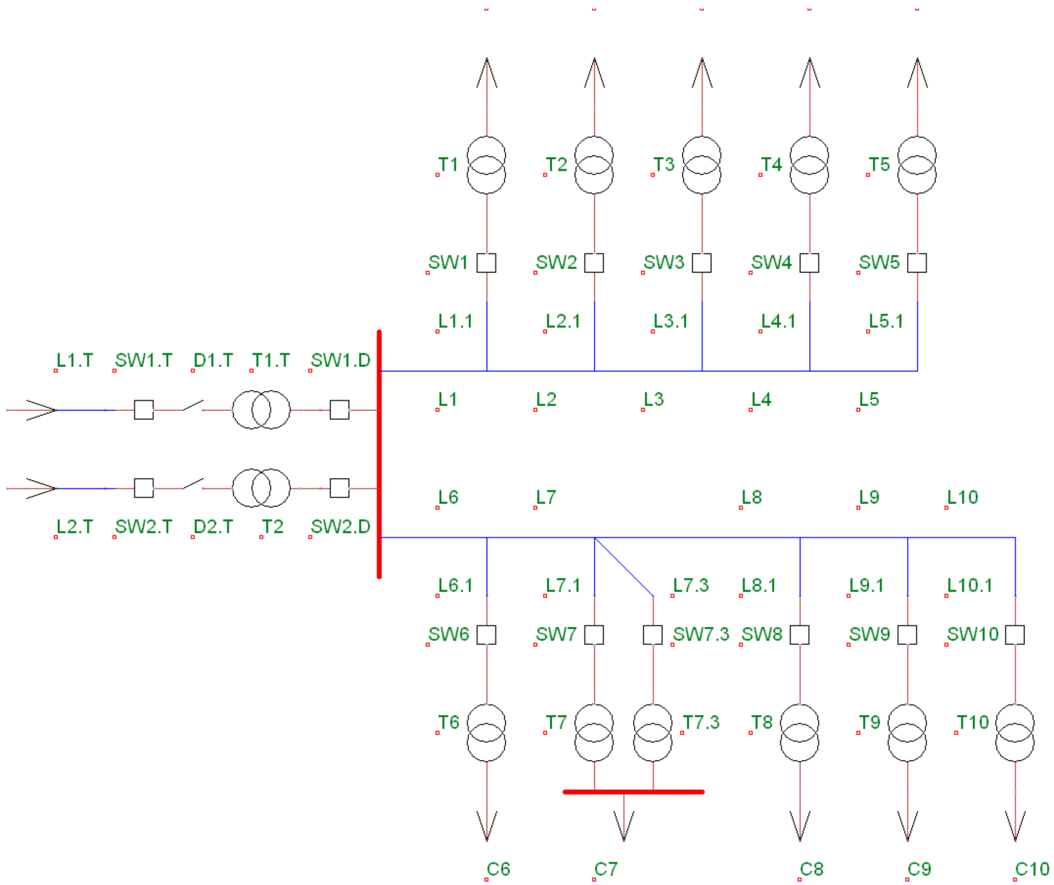
Scheme 16 – Base variant scheme



Scheme 17 – 2 feeders variant



Scheme 18 – Doubled line variant



Scheme 19 – The variant with one special customer

3.6. Output and calculated data

Customer	Number of customers	Load per 1 [kWh]	Total load for a feeding point [kWh]	Availability	MTBF [h]	Events	Events/year	Probability Of failure F(t)	Downtime [h]	Downtime a year [h]	Downtime/event [h]	Total downtime for a feeding poing [h]	Unsupplied energy [kWh]
1	10	5800	58000	0,99957	26881	32,59	0,33	0,278	373,33	3,733	11,456	37,333	247,2
2	10	5800	58000	0,99952	18703	46,84	0,47	0,374	420,12	4,201	8,970	42,012	278,2
3	10	5800	58000	0,99947	14448	60,60	0,61	0,454	466,64	4,666	7,701	46,664	309,0
4	10	5800	58000	0,99943	11727	74,70	0,75	0,526	501,80	5,018	6,718	50,180	332,2
5	10	5800	58000	0,99939	9941	88,12	0,88	0,586	535,86	5,359	6,081	53,586	354,8
6	10	5800	58000	0,99957	26881	32,59	0,33	0,278	373,33	3,733	11,456	37,333	247,2
7	10	5800	58000	0,99952	18703	46,84	0,47	0,374	420,12	4,201	8,970	42,012	278,2
8	10	5800	58000	0,99947	14448	60,60	0,61	0,454	466,64	4,666	7,701	46,664	309,0
9	10	5800	58000	0,99943	11727	74,70	0,75	0,526	501,80	5,018	6,718	50,180	332,2
10	10	5800	58000	0,99939	9941	88,12	0,88	0,586	535,86	5,359	6,081	53,586	354,8
	100	**58000**	**580000**			**605,69**	**6,06**		**4595,49**	**45,955**	**7,587**	**459,549**	**3042,7**

Table 2 – Variant 1.1

The output and calculated data for other variants are enclosed as appendices.

3.6.1. Simulated and calculated values

The simulation in the BlockSim software provides various output data which helps to evaluate the system overall reliability, causes of failures etc. The simulation was performed in the period of 100 years and 1000 simulations were performed for each variant to get proper data and avoid the situations were some of failures with low failure rate would not occur in single simulation.

Output data of simulation

- Availability
- MTBF – Mean time between failures
- Events – the number of downing events in 100 years
- Downtime – the total downtime in 100 for each feeding point

Other data in the Table 2 – Variant 1.1were calculated from data received in the simulation to fully cover the grid reliability values.

Calculated and input data

- Customer – the label of output points of the distribution network.
- Number of customers – the amount of customers for each output point was set to the number of 10
- Load per one – the load per one customer was set to 5800 kWh a year
- Total for a feeding point – the power at the each output point of the distribution network. This value is calculated as LOAD PER ONE multiplied by NUMBER OF CUSTOMERS
- Events/year = λ – an average value of downing events occurring in each output point causing outage of customers. This value is essentially the failure rate. Events/year = events/100
- Probability of failure F(t) – the probability of failure after one year of operation. For the exponential distribution we get:

$$F(t) = 1 - e^{-\lambda . t} \quad (38)$$

where t=1. It is the probability that the system will fail at any time until the time t.

- Downtime a year – the period of time when the customer is experiencing an outage. Downtime a year = downtime / 100.
- Downtime/event – an average time of each outage. The value is calculated as downtime a year / events/year.
- Total downtime for a feeding point – the sum of all periods of time when customers experience an outage. This value is calculated as events/year * the number of customers.
- Unsupplied energy – an average amount of energy not supplied. This value is calculated as the total load of a feeding point/8760*downtime a year.

3.6.2. Causes of failures

In every scenario, there can be many situations causing the outage of the customer. In the base variant, usually the failure of just one components causes the outage, in those variants with actions taken to increase the reliability, multiple failures have to happen in the same time cause the outage of the electricity for one or more output points. The software used for the simulation provides us by the information about events causing the failure but also without this software the events causing the outage could be estimated on the basis of the input data.

3.6.2.1. Base variant

The main reason for the outage of electricity was the failure of the distribution line and the line leading to the distribution transformer. In an average, approximately 14 failing events occurred within 100 years in the line of the length of 1 km. The failure of the distribution transformer lead to an outage in average 2,97 times in 100 years, the switch next to the transformer caused outage in 1, 55 events.

The number of failures of the overhead lines of 110 kV is about 5,3 , each of the transformers 110/22 kV is expected to fail in approximately 4 cases, disconnectors on the 110 kV sides in 1 case each and the switch on the 110 kV side in around 1,5 cases. Obviously, these numbers correspond to the failure rate of each of the components of the network as 1000 simulations were performed for the variant. The failures of the components on the 110 kV side almost did not lead to an outage at all as all of these components are backed up by the second feeder. In order to cause an outage by these components, another failure has to occur in the redundant feeder.

For the comparison, the switches at the 22 kV network have the same failure rate but are not causing the same amount of the downing events. As the switch next to the transformer 110/22 kV can be backed up by the second feeder (110/22 kV), an average number of downing events for these components is just 0,002. On the other hand, the failure of the switch next to the distribution transformer 22/0,4 kV leads to the outage in every case.

Name	Expected # of Failures	System Downing Events
Switch 110kV	1,563	0,003
Switch 22 kV	1,497	0,002
Switch 22 kV distribution	1,498	1,498
Line 110 kV	5,252	0,013
Line 22 kV	14,052	14,052
Disconnector	1,044	0,001
Transformer 110/22 kV	4,037	0,006
Transformer 22/0,4 kV	2,97	2,97

Table 3 – The table of failures for base variant

3.6.2.2. Base variant with longer lines

This variant is very similar to the variant with standard lengths of the lines. The main difference is in the expected number of failures of the lines. As expected, this number is approximately 10 higher compared to the standard variant as the length is also 10 times larger.

Name	Expected # of Failures	System Downing Events
Switch 110kV	1,46	0,003333
Switch 22 kV	1,55	1,556667
Switch 22 kV distribution	1,55	1,556667
Line 110 kV	5,26	0,0066
Line (1 km)22 kV	140,41	140,41
Dictonnector	1,03	0,00333
Transformer 110/22 kV	3,966	0
Transformer 22/0,4 kV	2,97	2,97

Table 4 - The table of failures for base variant with longer lines

3.6.2.3. Variant with 2 feeders

The expected number of failures of components in variant with two feeders is similar to the base variant. The main difference is the expected number of downing events of the distribution lines. In the base variant, every failure of the distribution line lead to the outage however, in this variant the failure of the distribution line leads to the outage in approximately 0,002 cases in 100 years. Moreover, the failure of any component on the transmission side of the network did not lead to any outage for any customer as there are 4 feeders in total and the probability of failure of 4 components, each in different line, is practically zero.

The first branch of customers (customers C1-C5) are affected only by the components on this branch and not by any feeders (as explained above), therefore also these customers are experiencing the increase in overall reliability of the power supply, though very slight.

The second branch (customers C6-C10) customers are essentially affected only by the failure of distribution transformers leading to them and correspondent switch and the line. Their overall power supply reliability is affected significantly and this evaluation is the topic of the next chapter. The table of failing components for the customer C8

Name	Expected # of Failures	System Downing Events
Switch 110kV	1,46	0
Switch 22 kV	1,55	0
Switch 22 kV distribution	1,55	0
Line 110 kV	5,26	0
Line 22 kV	140,41	140,41
Dictonnector	1,03	0
Transformer 110/22 kV	3,96	0
Transformer 22/0,4 kV	2,97	2,97
L1	139,22	0,2267
L2	140,13	0,216667
L3	140,31	0,197
L4	140,386	0,183
L5	140,13	0,21
L11	139,723	0,223
L10.1	138,15	138,15

Table 5 - The table of failures for base variant with 2 feeders

3.6.2.4. Variant with 2 feeders with longer lines

This variant is very similar to the variant with standard lengths of the lines as described in the base variant with longer lines. The slight difference is the fact that the expected number of system downing events in this case is 100 bigger compared to the variant with standard lengths.

Name	Expected # of Failures	System Downing Events
Switch 110kV	0,998	0
Switch 22 kV	1,479	0
Switch 22 kV SW8	1,547	1,547
Line 110 kV	5,313	0
Dictonnector	1,02	0
Transformer 110/22kV	3,917	0
Transformer 22/0,4 kV	2,97	2,97
L1	13,84	0,003
L2	13,814	0,002
L3	13,978	0,001
L4	13,999	0,002
L5	13,924	0,002
L11	14,009	0,001
L10.1	13,947	13,947

Table 6 - The table of failures for base variant with 2 feeders and longer lines

3.6.2.5. Variant with doubled lines

As in the base variant, the transmission lines with their components have the same impact in this scenario as in the base variant. Also the failure of the distribution transformer and corresponding switch and the line would cause the outage if any of them fails. The expected number of failures of each section of the doubled line is approximately the same, the main difference occurs in the system downing events of these sections. As every one of these section is backed up by another line, the failure of any of these sections would lead to the system outage only in about 0,001 case. The possibility of failure of the sections further from the bus-bar leading to an outage is slightly higher compared to sections close to the bus-bar as more events leading to an outage may occur.

Name	Expected # of Failures	System Downing Events
Switch 110kV	0,997	0,003
Switch 22 kV	1,464	0,002
Switch 22 kV distribution	1,495	1,495
Line 110 kV	5,055	0,01
Dictonnector	0,989	0,002
Transformer 110/22 kV	4,031	0,003
Transformer 22/0,4 kV	2,962	2,962
L6	13,828	0
L6.2	13,854	0
L7	13,936	0
L7.2	14,042	0,001
L8	13,803	0,001
L8.2	13,991	0,001
L9	14,13	0,001
L9.2	14,053	0,002
L10	13,932	0,002
L10.2	14,158	0,002
L10.1	14,108	14,108

Table 7 - The table of failures for base variant with doubled lines

3.6.2.6. Variant 3 with longer lines

The main difference of this variant compared to the previous one is in the expected number of failures of lines and their contribution to the loss of energy for the customer. As expected, an average number of failures of distribution line sections is 10 times higher compared to the variant with standard lengths. The failure events of these sections contributing to the outage are approximately 60 times higher compared to the previous variant. This is caused by the higher weight of failures of these components. In the case of the line section leading to the distribution transformer increases in length in the same ratio as distribution lines, this would be the main cause of system downing events.

Name	Expected # of Failures	System Downing Events
Switch 110kV	1,086	0
Switch 22 kV	1,58	0,003
Switch 22 kV distribution	1,506	1,506667
Line 110 kV	5,563	0,003
Dictonnector	1,016667	0
Transformer 110/22 kV	4,1567	0,01
Transformer 22/0,4 kV	3,033	3,033
L6	139,777	0,04
L6.2	139,033	0,0467
L7	140,66	0,0567
L7.2	140,917	0,0633
L8	139,33	0,0667
L8.2	139,507	0,0667
L9	140,373	0,0667
L9.2	140,647	0,073
L10	138,927	0,073
L10.2	139,507	0,083
L10.1	139,7	139,7

Table 8 - The table of failures for base variant with doubled long lines

3.6.2.7. Customer with redundant distribution transformer and corresponding components

As all of customers in the simulation are supplied by one distribution transformer, failure of this component or any of components in the serial line with this transformer (the line, the switch) leads to an outage. For this case, a customer with back-up transformer and corresponding components was included in the second set of the simulations. This customer might be a small factory with special needs for the power supply. As this is just another of possible scenarios, this paragraph will only cover brief evaluation of this customer for standard lengths of lines. This customer is labelled as customer 7 (C7).

In the base variant, the primary cause of system outage was the failure of the distribution line – approximately 14 downing cases for 1 km of the line. The number of downing events for other components was almost zero, thus the possibility of outage caused by any other component than the line is negligible. This variant was simulated just for comparison, as in the real conditions this case not occur as there are still components left without back-up (distribution lines).

The situation is more interesting in the variant with two feeders and doubled distribution lines, as the outage will not occur upon failure of just one of components.

In the variant 2 with double feeders, the downing event almost does not occur and the expected number of failures causing an outage is just 0,024. This can be considered that the probability of power supply for this customer is 100%.

The situation in the variant with doubled lines for the customer 7 is practically identical to the variant with 2 feeders and the expected number of failures is mere 0,047. This number is obviously a bit higher compared to the previous variant as there is higher possibility that the feeder would fail.

If there are some actions made in order to improve the overall reliability of the network, additional custom actions can be made to improve the reliability of the customer. On the other hand, these measures would require the additional investments into the distribution transformer and other corresponding components.

3.6.3. Output data comparison and evaluation

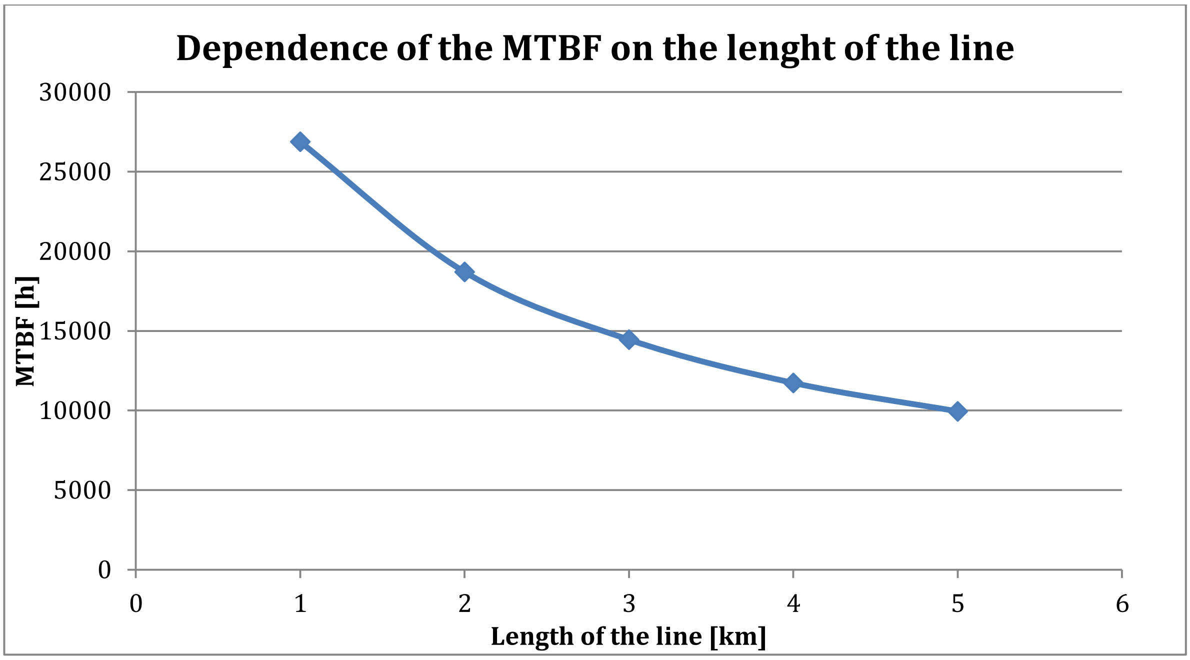
3.6.3.1. Base variant

The only variable in the base variant is the length of the line. It differs from one kilometre for the customer number 1 and 6 to five kilometres for the customer 5 and 10. As the two of branches are equal, only the one branch (customers 1 to 5) will be evaluated.

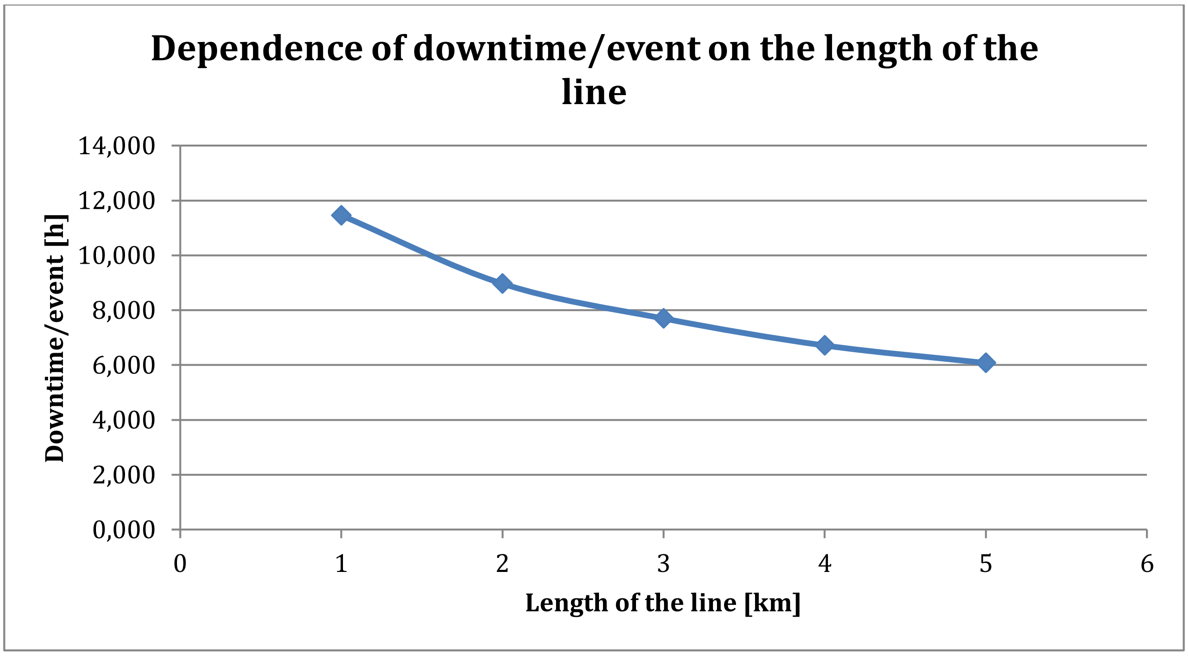
The number of events causing the outage increases linearly with the linear growth of the length of the line as can be seen from the Table 2 – Variant 1.1 The estimated number of failures a year is 0,33 for the customer 5 to 0,59 for the customer 10. This means that additional 1 km of the line causes approximately 0,14 outages a year. For this reason also downtime increases in the same ratio. The lowest downtime a year occurs at the customer 1 with 3,7 hours a year and the highest at the customer 10 with 5,4 hours a year. This means that the average growth of the downtime is 0,4 hours per one kilometre of the line. The estimated unsupplied energy in the output point 1 and 5 differs from 24,7 kWh a year to 35,5 kWh. This means the average increase of the unsupplied energy by 2,7 kWh per one kilometre of the distribution line.

The mean time between failures drops from 26881 hours occurring to the customer 1 to 9941 hours to the customer 10. This decrease is not linear and has the slowing character. This is caused by the fact that the effect of growing length of the line produce more fails and dominates the other causes of failures.

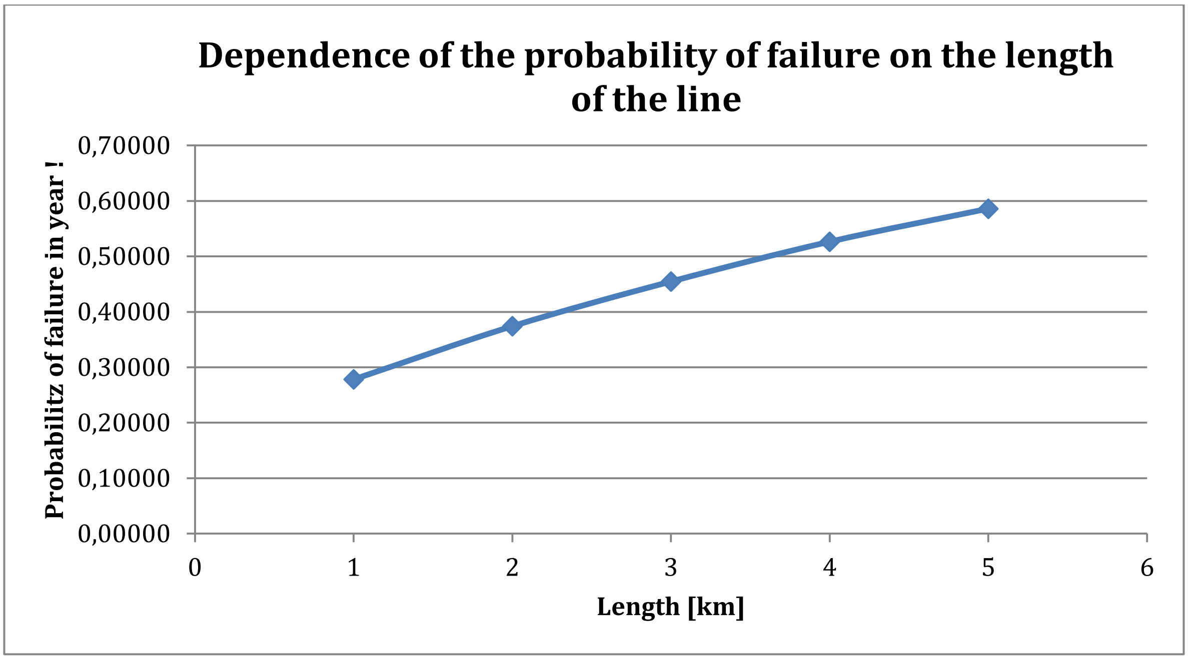
Although the length of the line increases, the downtime/event ratio has decreasing trend. As it takes the longer time to repair the transformer and switches than the line, this causes that shorter lines do not create many outages and the time to repair the transformer or the switch reflects to the downtime/event in the prevailing rate. As the length of the line increases, there are more failures of these lines (mentioned in previous paragraphs) and as the time to repair the lines of relatively short compared to other components, the downtime/event time converges to the time of repair of the line with growing length of the line.



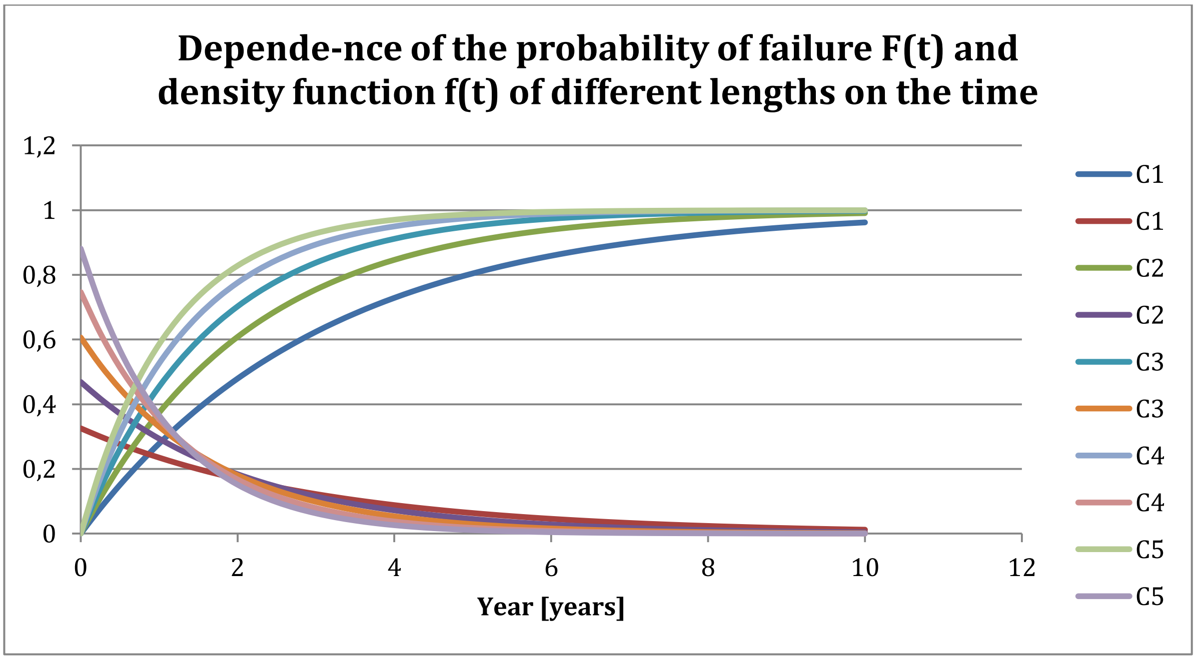
Graph 3 - Dependence of the MTBF on the length of the line



Graph 4 - Dependence of downtime/event on the length of the line



Graph 5 - Dependence of the probability of failure on the length of the line



Graph 6 - Dependence of the probability of failure F(t) and density function f(t) of different lengths on the time

C1 , C2, C3, C4, C5 are customers 1-5.

The density function f(t) and the probability of failure F(t) for a continuous exponential distribution is calculated as:

$$f(t) = \lambda . e^{-\lambda . t} \tag{39}$$

$$F(t) = 1 - e^{-\lambda . t} \tag{40}$$

Where:

- t – the time
- λ – the failure rate

3.6.3.2. *Variant with 2 feeders*

The connection of the simulated grid to the second feeder has a great impact to the overall reliability of this grid, especially to the part (C6-C10) which is directly connected to the second feeder.

The observed variables do not almost change in the part of the distribution grid witch customers C1-C5. These indexes improve only in the point when the feeder fails to operate. As the possibility of the feeder to fail is very low, the reliability of this part of the grid almost does not change. If the probability of the failure of the feeder was relatively high, the influence of the second feeder would raise also to this part of the network.

On the other hand, the situation for the customers C6 – C10 changes drastically. As all of the customers are supplied from two sides, all of the observed variables are almost the same for this part of the grid. In reality, the probability of failure is influenced mainly by the distribution transformer and corresponding components as this part is not doubled. All of the variables are shown in the Table 34 – Variant 2.1

The mean time between failures has increased to approximately 47 380 hours (from original 26 881 at the best case to 9941 for the customer with the longest line between them and the feeder). It means the increase by 76% compared to the shortest line to 376% compared to the longest line.

The number of downing events per year had dropped by 44% (0,326 to 0,185 events a year) compared to the best case to almost 80% compared to the worst case (0,88 cases a year). The downtime a year was simulated to almost 3,27 hours a year and is comparable to 3,73 hours a year for the customer C1, although if we compared this to the customer with the longest line, the difference is significant (-2,13 hours a year). The unsupplied energy is connected to the previous variable and therefore has the similar trend. The estimated amount of energy not supplied is 21,6 kWh for every output point C6 – C10.

3.6.3.3. Variant with doubled lines

The variant 3 is very similar to the variant 2 in the results. The slight difference is in the part of the branch with customers C1 – C5 as building the second line has no impact on this part of the network and the values from the base variant remain the same.

In the second branch of the grid with doubled lines, the values are almost equal to the variant 2. The mean time to failure is in the interval 46767 - 47310 hours. The number of downing events differ between 0,1852 a year to 0,1873 a year. The downtime a year is between 326,28 hours to 332, 16 hours a year and corresponding unsullied energy is 21,6 kWh to 22 kWh.

The difference between variant 2 and variant 3 for customers C6 – C10 is that in the variant 2 the customer with the worst results lies just in the middle of two feeding points (C8). The customer with the worst results in the variant 3 should the one with the longest lines (C10).

3.6.3.4. Comparison of the variants with 2 feeders and doubled line to base variant

For another view of the reliability of different customers in the model, the customer 6 and 10 were chosen for a comparison as both are significantly affected by the changes in the topology of the network and their values should differ by the widest range as the customer 6 lies right next to the transformer station and the customer 10 is the furthest to this station (customer 10 is equally distant from the feeding point as the customer 6 in the variant with two feeding points).

As can be observed from **Chyba! Nenalezen zdroj odkazů.**and **Chyba! Nenalezen zdroj odkazů.**, the difference in the values in the variants with two feeding points and two lines is minor as practically both are supplied from two independent paths. This situation is the same for the variants with long lines.

The only difference worth observing is the difference between the variants with standard and longer lines where the difference is usually higher in the variant with longer lines. Only downtime/event has decreasing trend in the variant with longer lines as the dominant cause of the failure of the system is caused by the failure of lines with short time to repair value. In the standard lengths of the lines variants also other components (with long time to repair value) than lines represent the significant cause of the failure of the system.

	Base variant		2 feeders variant				2 lines variant			
				Compared		Compared		Compared to		Compared
Customer	6	10	6	to base v.	10	to base v.	6	base v.	10	to base v.
Number of customers	10	10	10		10		10		10	
Load per 1 [kWh]	5800	5800	5800		5800		5800		5800	
Total load for a feeding point [kWh]	58000	58000	58000		58000		58000		58000	
Availability	0,998711	0,996798	0,999189		0,999187		0,999182		0,999194	0,0024037
MTBF [h]	3064	1040	6054,4625	98%	6085	485%	6060	98%	6009	478%
Events	285,877	842,593	144,687	-49%	143,960	-83%	144,547	-49%	145,783	-83%
Events/year	2,859	8,426	1,447	-49%	1,440	-83%	1,445	-49%	1,458	-83%
Probability of failure F(t)	0,943	1,000	0,765	-19%	0,763	-24%	0,764	-19%	0,767	-23%
Downtime [h]	1129,265	2805,245	710,124	-37%	712,241	-75%	706,493	-37%	716,690	-74%
Downtime a year [h]	11,293	28,052	7,101	-37%	7,122	-75%	7,065	-37%	7,167	-74%
Downtime/event [h]	3,950	3,329	4,908	24%	4,947	49%	4,888	24%	4,916	48%
Total downtime for a feeding poing [h]	112,927	280,524	71,012	-37%	71,224	-75%	70,649	-37%	71,669	-74%
Unsupplied energy [kWh]	74,769	185,735	47,017	-37%	47,158	-75%	46,777	-37%	47,452	-74%

Table 9 - Comparison of the variants for the customer C6 and C10

	Base variant		2 feeders variant				2 lines variant			
				Compared		Compared		Compared to		Compared
Customer	6	10	6	to base v.	10	to base v.	6	base v.	10	to base v.
Number of customers	10	10	10		10		10		10	
Load per 1 [kWh]	5800	5800	5800		5800		5800		5800	
Total load for a feeding point [kWh]	58000	58000	58000		58000		58000		58000	
Availability	0,998711	0,996798	0,999189		0,999187		0,999182		0,999194	0,0024037
MTBF [h]	3064	1040	6054,4625	98%	6085	485%	6060	98%	6009	478%
Events	285,877	842,593	144,687	-49%	143,960	-83%	144,547	-49%	145,783	-83%
Events/year	2,859	8,426	1,447	-49%	1,440	-83%	1,445	-49%	1,458	-83%
Probability of failure F(t)	0,943	1,000	0,765	-19%	0,763	-24%	0,764	-19%	0,767	-23%
Downtime [h]	1129,265	2805,245	710,124	-37%	712,241	-75%	706,493	-37%	716,690	-74%
Downtime a year [h]	11,293	28,052	7,101	-37%	7,122	-75%	7,065	-37%	7,167	-74%
Downtime/event [h]	3,950	3,329	4,908	24%	4,947	49%	4,888	24%	4,916	48%
Total downtime for a feeding poing [h]	112,927	280,524	71,012	-37%	71,224	-75%	70,649	-37%	71,669	-74%
Unsupplied energy [kWh]	74,769	185,735	47,017	-37%	47,158	-75%	46,777	-37%	47,452	-74%

Table 10 - Comparison of the variants with long lines for the customer C6 and C10

3.6.3.5. Customer Based Indices

In order to evaluate the character of the distribution network from the point of view of reliability, the customer-based reliability indices were created for this purpose. We are able to compare different distribution networks by using these indices and therefore evaluate the impact of the used actions and means to change the network reliability.

The most common indices are used in this work to measure the reliability of the variants and sub-variants.

Due to the fact that the simulation method was used, some of the indices cannot be evaluated in the correct way as the simulation time was set to 100 years (mean time to failure of some components are measured in years and there would not occur in short period of time) to make sure that all possible downing events would occur. From this premise the average values for a year were obtained. In the matter of effect of this we have assumed that all of the customers were affected by some king of outage every year though this would probably not happen every year for some grid variants (any kind of secured network would be affected by an outage if the simulation time was long enough). This means that average values of indices were calculated to evaluate the distribution network reliability. For example, the CAIFI could not be evaluated correctly as the number of customers affected by an outage at least once has to be higher than 1 but in average it is less.

	SAIDI	SAIFI	CAIDI	ASAI	AENS
	[hours/year]	[1/year]	[hours]	[-]	[kWh]
V1.1	4,595	0,606	7,5873	0,9995	3,043
V1.2	4,262	0,587	7,2621	0,9995	2,822
V1.3	19,648	5,642	3,4827	0,9978	13,009
V1.4	18,942	5,498	3,4454	0,9978	12,541

Table 11 – Customer based indices for base variant

	SAIDI	SAIFI	CAIDI	ASAI	AENS
	[hours/year]	[1/year]	[hours]	[-]	[kWh]
V2.1	3,898	0,395	9,878	0,9996	2,581
V2.2	3,571	0,376	9,495	0,9996	2,365
V2.3	13,405	3,543	3,784	0,9985	8,876
V2.4	12,692	3,400	3,733	0,9986	8,403

Table 12 - Customer based indices for variant with 2 feeders

	SAIDI	SAIFI	CAIDI	ASAI	AENS
	[hours/year]	[1/year]	[hours]	[-]	[kWh]
V3.1	3,945	0,396	9,965	0,9995	2,612
V3.2	3,615	0,377	9,582	0,9996	2,394
V3.3	13,383	3,546	3,774	0,9985	8,861
V3.4	12,672	3,401	3,726	0,9986	8,39

Table 13 - Customer based indices for variant with doubled line

Base variant comparison with variant with two feeding points and with the variant with doubled lines.

	SAIDI	SAIFI	CAIDI	ASAI	AENS
	[hours/year]	[1/year]	[hours]	[-]	[kWh]
V1.1	4,595	0,606	7,587	0,9995	3,043
V2.1	3,898	0,394	9,878	0,9996	2,581
V3.1	3,945	0,396	9,965	0,9995	2,612

Table 14 – Customer based indices comparison

The variant with long lines:

	SAIDI	SAIFI	CAIDI	ASAI	AENS
	[hours/year]	[1/year]	[hours]	[-]	[kWh]
V1.3	19,648	5,642	3,483	0,9978	13,009
V2.3	12,692	3,400	3,733	0,9986	8,403
V3.3	13,383	3,546	3,774	0,9985	8,861

Table 15 - Customer based indices comparison – variants with longer lines

In the Table 14 – Customer based indices comparison and Table 15 - Customer based indices comparison – variants with longer lines we can see different values of calculated indices SAIDI, SAIFI, CAIDI, ASAI and AENS for a base variant compared to the variant with two feeder and variant with double lines and the equal situation in the model with longer lines.

At the first sight we can see that the variant with doubled lines and the variant with two feeders show similar results in observed indices. This is caused by the fact that every customer (in the second part of the sub-network) in both cases is essentially supplied from two independent lines. The better results in the variant with two feeders are caused by the fact that the failure in the transformer station will not cause the outage of the system as the network is supplied from another feeding point. Only simultaneous failures in one of the stations and a line leading to the customers from the second station or two stations cause the outage of the system, which is unlikely going to happen in real conditions.

The index SAIDI in the variant with normal lengths of lines improves from the value of 4,6 to around 3,9 which means approximate 15% improvement. On the other hand, the variant with longer lines shows approximate 35% (19,6 to 13) improvement compared to the base variant. This difference is caused by more outages caused by the longer lines in base variant compared to the normal lengths and the relative low possibility of failure in variants with either redundant line or two feeding points.

The key fact to the big difference in the variants with standard lengths of lines and variants with long lines is the different nature of downtime/event values. In the variant with standard lengths the difference in these values is 7, 59 (in the base variant compared) to 9,88 (in the variant with two feeding points and variant with doubled lines) and 3,48 to 3,78 in the variants with longer lines. The dominant cause of failures in the variant with longer lines is lines in every case with the mean time of the repair set to 3 hours. On the other hand, the influence of the failure of other components than lines is obvious in the variant with standard lengths of the lines with higher mean time to repair.

The similar situation occurs in the index AENS where the unsupplied energy depends on the downtime of the system as in the SAIDI index.

As the index SAIFI changes with the amount of downing events of the system and the main cause is the failure of the line in every variant, the improvement in the index SAIFI is similar (35% improvement in the standard lengths of the lines compared to 40% in the variant with longer lines).

3.6.3.6. Subsystem indices

As was mentioned before, every distribution network variant in this work consists of the two sub-variants – the first consists of 5 output points with single cable leading to these points and the second part which is directly affected by the actions leading to the improve the reliability. Although the customer based indices are meant to evaluate the reliability of the whole distribution network, it is also good to take a look at these two parts of the network due to their different structure.

Variant marking example: V2.1.1 is meant for the part of variant V2.1 (base variant with standard lengths of lines) with single lines and one bus-bar and V2.1.2 marks the part with two feeding points. The marking is equally set for variant 1 and 3.

	SAIDI	SAIFI	CAIDI	ASAI	AENS
	[hours/year]	[1/year]	[hours]	[-]	[kWh]
V1.1 1	4,596	0,606	7,587	0,999475	3,043
V1.1 2	4,596	0,606	7,587	0,999475	3,043
V1.1	4,596	0,606	7,587	0,9995	3,043
V2.1 1	4,526	0,604	7,490	0,999483	2,997
V2.1 2	3,269	0,185	17,688	0,999627	2,165
V2.1	3,90	0,395	9,878	0,9996	2,581
V3.1 1	4,596	0,606	7,587	0,999475	3,043
V3.1 2	3,294	0,186	17,709	0,999624	2,181
V3.1	3,9447	0,396	9,965	0,9995	2,612

Table 16 – Customer based indices sub-model results

As we can see from the Table 16 – Customer based indices sub-model results the first two parts of the variant 1 are equal. This means they contribute to the whole network likewise and the grid indices are equal to these parts.

The situation differs significantly in the variants 2 and 3. The first sub-network of the variant 3 is the same as the first part of variant 1, therefore the indices are equal.

The reliability of the first part of the variant 2 is slightly higher compared to the V1.1.1 and V3.1.1. This increase in the reliability is caused by the second feeder of the variant 2. As the probability of failure of the feeding points (transformer, switch, overhead lines with the same redundant feeding system) is low, the second feeding point has almost zero influence on this part of the network. The significance of the second feeding point on this part of the network occurs only when an outage of the whole feeding point 1 occurs.

The index SAIFI of V2.1.1 is about 3 times higher compared to the V2.1.2. Surely this is caused by two feeders in the second sub-network which means much less outages as every output point of this sub-network is fed from two sides (in average 3,02 downing events a year compared to 0,92 downing events of the second part). It might seem that the number of average downing events of the part 2 should be two times lower compared to the part one, as there are basically two sides from which the customers can be fed. The distribution of outage events in output points of the variant V2.1.2 is without significant differences (0,185 downing events a year for an output point), the number of outages for each output point of the part one differs linearly according to the length of the line leading to each point (0,327 event for the output point closest to the bus-bar to 0,88 events for the point with the longest distribution line).

As can be seen in the table, the variant with redundant lines almost equals to the variant with two feeding points although the variant 2 shows slightly better results in reliability. The similarity is caused by the fact that output points in variants V3.1.2 and V2.1.2 are practically fed by one line and the base variant and one back-up structure. The difference in these variants are caused by the fact that an outage of the system leading to the distribution network bus-bar causes the outage in every output point in the variant 3 though in the variant 2 this outage would cause the outage of the system only if another downing outage would occur in the bask-up part of the system. The probability of failure of the bus-bar feeding is very low, the probability of failure of the subsystem leading to the bus-bar on the distribution network plus an outage in the redundant distribution network is practically zero.

The actions taken to increase the reliability of the subsystem in variant two and three respectively, cause more reliable power supply thus the index AENS lowers by approximately 38% in sub-networks affected more by these action compared to the base variant of the network (the value of index AENS for V2.1.1 equals 2,997 kWh and the value on V2.1.1 is V2.1.2 is 2,165 kWh). BY the same ratio the index SAIDI improves as both indices depend on the downtime of the customers.

The index ASAI almost does not change as it depends on availability of the system and that is relatively high in every case.

	SAIDI	SAIFI	CAIDI	ASAI	AENS
	[hours/year]	[1/year]	[hours]	[-]	[kWh]
V1.3.1	19,649	5,642	3,483	0,997757	13,009
V1.3.2	19,649	5,642	3,483	0,997757	13,009
V1.3	19,648	5,642	3,483	0,997757	13,009
V2.3.1	19,690	5,643	3,489	0,997752	13,037
V2.3.2	7,120	1,442	4,937	0,999187	4,7143
V2.3	12,692	3,400	3,733	0,998551	8,403
V3.3.1	19,648	5,642	3,483	0,997757	13,009
V3.3.2	7,117	1,451	4,905	0,999188	4,7124
V3.3	13,383	3,546	3,774	0,998472	8,861

Table 17 - Customer based indices sub-model results for variants with longer lines

The big difference in the variant with longer lines compared to the variant with standard lengths of the lines is explained in the previous chapter. The main reason for the difference in SAIDI index is caused by the different nature of the downtime/event value in variants with standard lengths and longer lengths of the lines. The index SAIFI is mainly influenced by the amount of failures of lines.

3.7. Power supply quality in Czech Republic

"The power supply quality in Czech Republic has been defined by the regulation of **ERÚ** [1] number 540/2005 Sb., on power supply quality and related services in power industry, as amended, which stipulates:

- **Required power supply quality** and additional services related to regulatory activities in power industry (standards),
- **Amount of compensation** for non-observance of prescribed standards,
- **Terms** for determination of financial compensation,
- **Procedures for proving** the compliance of power quality and services [with standards]

Standard define the level of quality, which must be attained in each individual case. These standards can be divided into two main groups:

Standards for power transmission or distribution

- The first part contains the information related to *the continuity of power supply in grids,* i.e. the data influenced by fault events or planned events in operated distribution grids.

- The second part contains standards related to *the commercial quality,* which characterizes the ability of power distributor or producer to respond to applicable requirements of end customers; such quality is not directly related to the physical operation of systems.

Standards for power supply

The Regulation of **ERÚ** as mentioned above represents also the basis for monitoring and evaluation of **Power Transmission / Distribution System Continuity Level**.

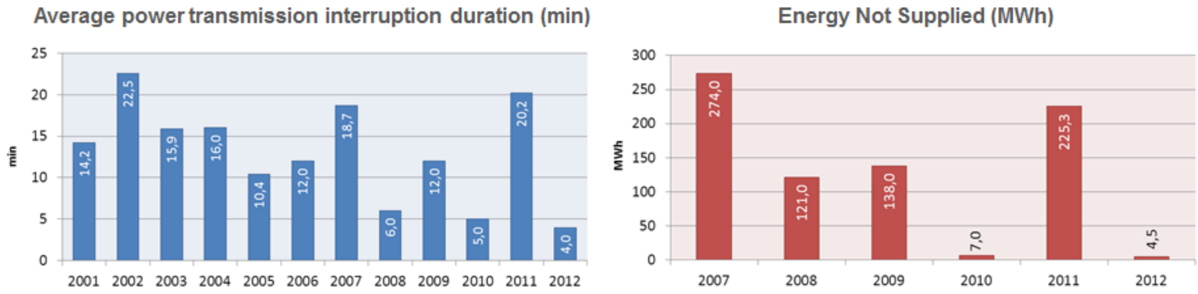
Power transmission indices:

- **Average power transmission interruption duration** – in the evaluated year),
- **Energy Not Supplied** (ENS)." (8)

Power distribution indices:

[1] ERÚ – Energy Regulatory Office

- **SAIDI, SAIFI, CAIDI –** described in the previous part of this work



Graph 7 - Development of indices (8)

Profiles of DSOs[2] in the Czech Republic :

Company profiles	Voltage levels	Number of customers [-]	Length of cable lines [km]	Length of overhead lines [km]	Number of transformers [-]
ČEZ Distribuce	LV	3 519 281	50 677	47 962	43 332
	HV	14 393	9 777	40 131	293
	VHV	296	13	9 707	231
E.ON Distribuce	LV	1 480 810	22 902	16 838	18 301
	HV	8 339	3 533	18 630	109
	VHV	41	6	2 391	6
PRE distribuce	LV	747 566	7 756	80	4 008
	HV	1 942	3 746	117	288
	VHV	5	58	144	0
Total Czech Republic	LV	5 747 657	81 335	64 880	65 641
	HV	24 674	17 056	58 878	690
	VHV	342	77	12 242	237

Table 18 - Profiles of DSO's in the Czech Republic (8)

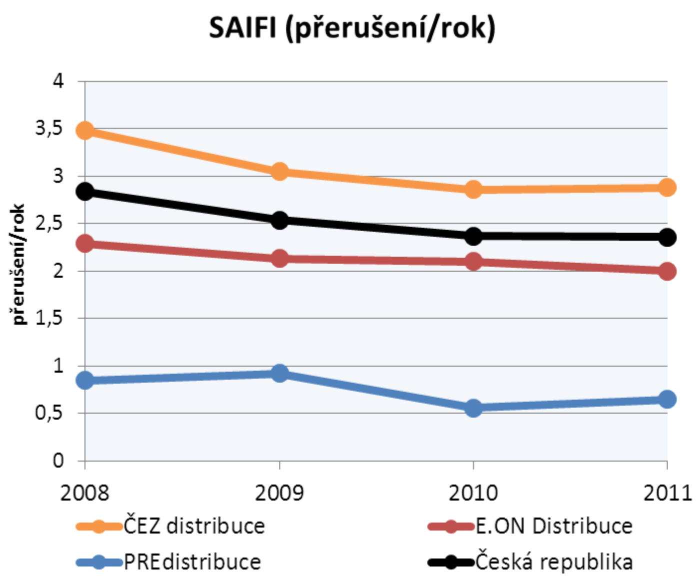
[2] DSO - Distribution system operator

Indices of reliability in 2011:

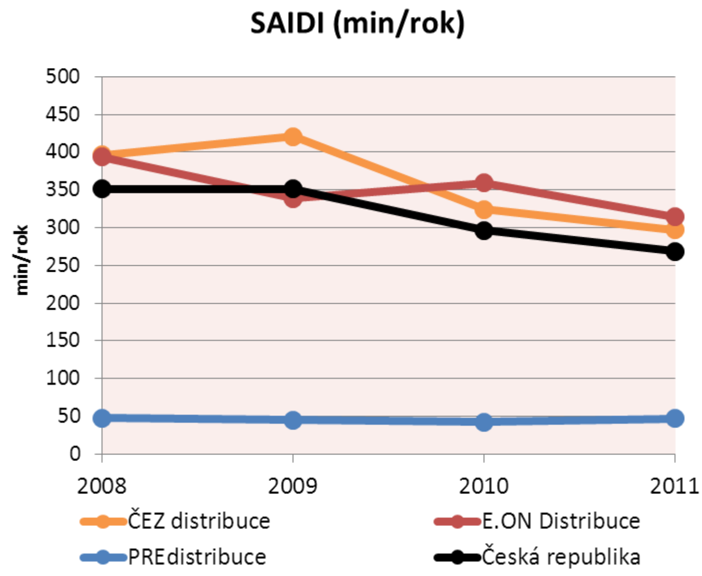
Index	ČEZ Distribuce	E.ON Distribuce	PREdistribuce	Czech Republic
SAIFI [interruptions/yr]	2,88	2,00	0,65	2,36
SAIDI [min/yr]	296,70	314,40	46,79	268,82
CAIDI [min]	103,15	157,26	72,13	113,87

Table 19 - Indices of reliability in 2011 (8)

Development of indices of reliability:



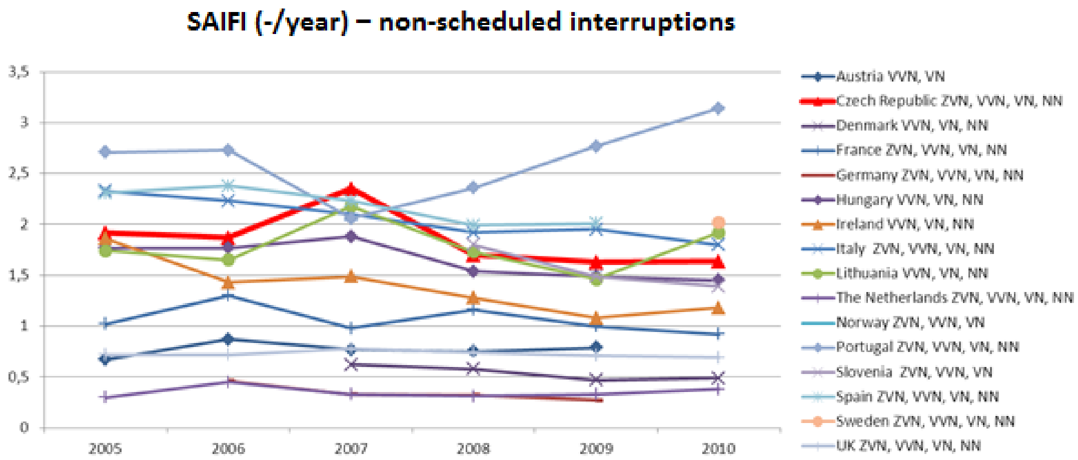
Graph 8 – SAIFI development (8)



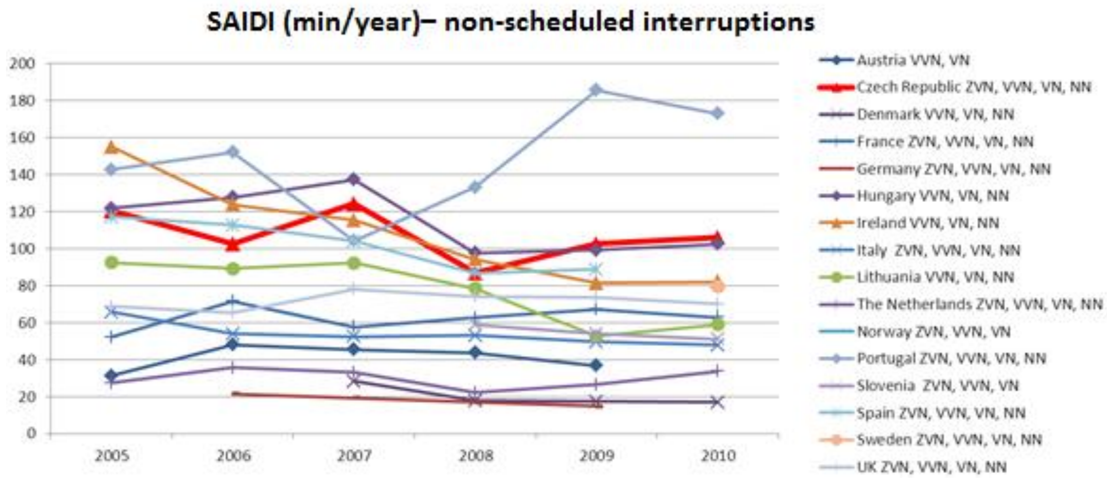
Graph 9 – SAIDI development (8)

As can be observed from Table 19 - Indices of reliability in 2011, Graph 8 – SAIFI development and Graph 9 – SAIDI development , the specified indices differ among various distribution system operators in Czech Republic due to the different character of the grid they operate.

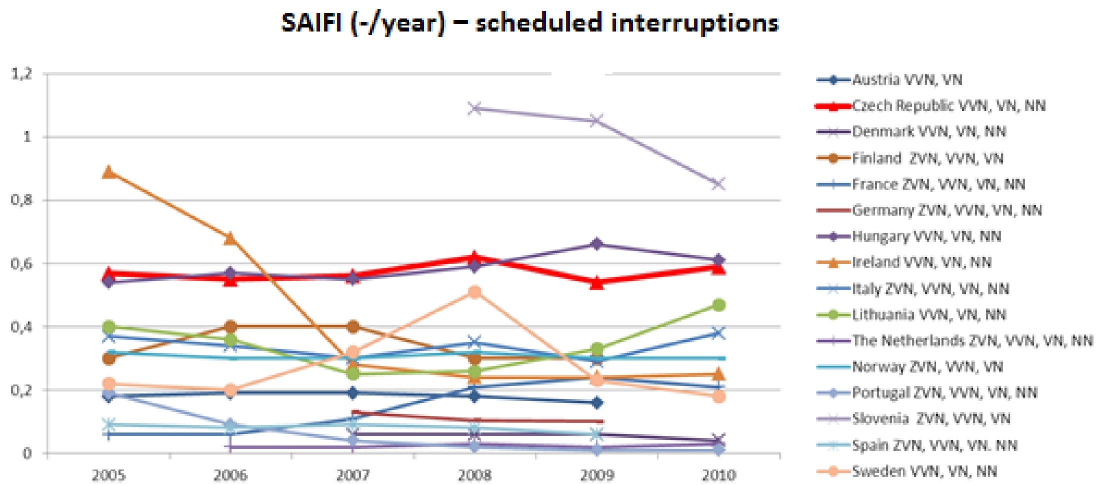
The comparison of power supply quality is quite difficult and often misleading among distribution system operators. It is important to take into consideration the various specifics of each countries and the character of the grids they operate, such as proportion of cable lines/overhead lines, lengths of the lines, age of the grids, the amount of customers, amount of transformers, but also natural conditions and the nature of customers. It is also important to mention that the indices evaluated in various countries can differ significantly as the methods of calculation of indices are not unified.



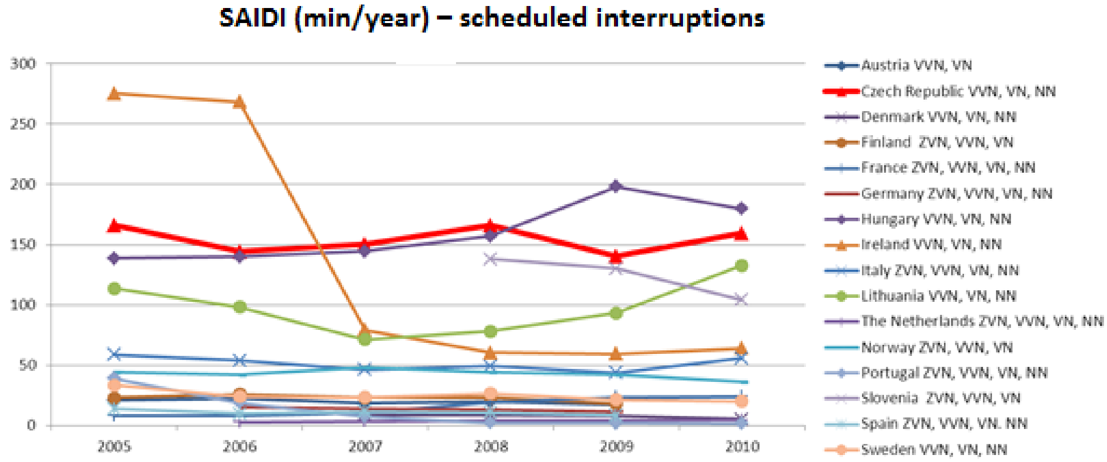
Graph 10 - Index SAIFI – non-scheduled interruptions



Graph 11 - Index SAIDI – non-scheduled interruptions (8)



Graph 12 - Index SAIFI – scheduled interruption (8)

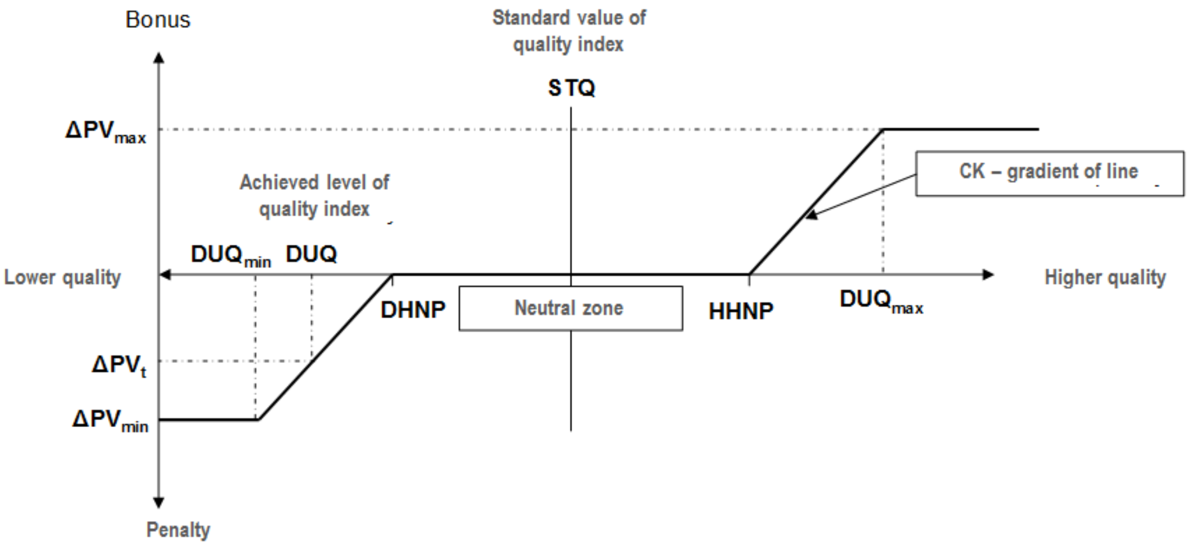


Graph 13 - Index SAIDI – scheduled interruptions

3.7.1. Motivational quality control (penalties and bonuses)

"The main goal of the motivational quality control is to reduce the number and time of power distribution interruptions. Another goal is the gradual unification of power supply quality throughout the Czech Republic, as the Czech customers pay now comparable power distribution fees for different power quality. The last but not least goal of the Regulation is the achievement of better results in the process of comparing power quality levels with other EU countries. The combination of these two mechanisms should ensure the gradual improvement of power supply quality for all customers in the Czech Republic." (8)

"In 2012, ERU has determined the quality indices and values of these indices for 2013 for the area of power distribution. This results into concept of Motivational quality control with its main goal which is to set the required level of quality for provided services in relation to their prices. In order to achieve this goal, the system with bonuses and penalties was introduced – any bonus or penalty shall be related to the amount of profit determined by ERU for respective period of regulation. Required values of indices SAIFI and SAIDI for 2013 have been determined on the basis of available data from previous periods; such values include further reduction by approximately 5 % (depending on respective company and indices). Such Indices are specifically whole-system continuity indices as defined by the Regulation No. 540/2005 Sb., without taking in consideration those events, which happened without any influence of respective Distribution System Operator.” (8)



Graph 14 - Diagram of motivational quality control (8)

Graph 14 - Diagram of motivational quality controlshows the 5 areas of penalty/bonus distributions. It can be noticed there are restraining areas for bonus and penalty and these values cannot be overcame. There is also the neutral zone (5% from demanded value) in the middle where the operator is neither rewarded nor penalized.

“Setting of required values of indices SAIFI and SAIDI for 2013:

- The values of parameters for the regulation period [year] 2013 have been set on the basis of detailed evaluation of available data of ERÚ according to the capabilities of individual Distribution System Operators.
- This relates in particular to the whole-system continuity indices SAIFI and SAIDI as defined by the Regulation No. 540/2005 Sb., without taking in consideration those events which happened without any influence of respective Distribution System Operator.
- The events which will not be included in the required values of indices for 2013 are in particular the following interruptions:

- *faulty interruptions caused by any fault with the origin in the equipment or operation of any transmission or distribution system operator under unfavourable weather conditions ,*
- *faulty interruptions caused by any interference or action of a third person (*
- *forced interruptions*
- *exceptional interruptions*
- *interruptions caused by events from outside (out of TS or DS) or events in power generation units.”* (8)

It is important to make a study to determine the possible relation between measured taken to improve the reliability and costs of these actions. Based on these calculations and their conclusions it would be possible to revise the values of parameters of customer based indices in the next period of time.

4. Economy part

This part of the work is aimed at possible economy evaluation of precautions taken to improve the power grid reliability – building the second line in one variant and connecting the grid to the second transformer station.

The variant with doubled line is straight-forward project where the second line has to be built. The variant with second feeding point can be considered from two points of view: the first possibility the connection of the network to the existing transformer station and the second variant is to build the new transformer station. The variant with connection to the existing feeder is simple and just the line connecting the transformer station and the model grid has to be built. In the second variant there has to be taken into account that whole station has to be built with proper technology, transformer, overhead lines 110 kV and the connecting 22kV line to the model grid.

The economy part is based on the evaluation of the power grid reliability made in the previous part of this work. At first, the cost of the whole project is calculated and then this cost is distributed to the price of electricity of customers of the model. As the modelled power network is relatively small and would be connected to the bigger part of the network with much more customers, the costs of the project would be distributed among large amount of customers in the network. There has to be made some assumption in order to evaluate the project and the impact of the project to the customers.

4.1. Input data

The actual data had to be obtained for the proper evaluation of the projects, although it is fairly difficult to obtain some of data as some this kind of information is the company's secret – that's why some of data used in this work are obtained from the anonymous distribution grid operator.

As mentioned before, there are two variants of projects which lead to the improving the overall distribution grid reliability. Some of the input data are the same for both projects and therefore these data will be described together.

The cost of overhead lines 110kV and 22 kV for one kilometre is an average cost of the project including the project documentation, material costs (poles, lines…), the purchase of the land etc. The same attitude is used with transformer station – an input data contains the whole costs for the station including the adequate technology. The data for the overhead lines 110 kV, transformer and transformer station were obtained from one of the distribution grid operators, the cost of the line 22 kV was obtained from Slovak URSO (9)

The operating cost of the lines was set to 2% of the project per year; the operating cost of the transformer station (including the transformer) was set to 3% of the project per year. The escalation of these costs was set to the value 2% according to the assumed value of inflation in Czech Republic for next years (aimed inflation goal set in 2007 by Czech national bank (10)). The WACC index was calculated at the value 5,38% - this value is close to the current value approximately 5,5%. The depreciation period of transformer is 10 years and the period for lines is 20 years – according to Czech standards (11), (12)The taxes are 19%. According to the input data of the model (an average consumption 5800 kWh a year) the average price of 1 kWh of electricity was set to 4,21 Czk. (the cost of electricity consumed by one customer a year is set to 24000 Czk according to the price calculator (13)). The distribution grid operator was chosen CEZ Distribution due to the similar character of their grid as modelled in this work. All input data are shows in the Table 20 – Input data for economy calculations. Furthermore, the construction of the new lines brings the additional loss of power in these lines. In order to simplify the calculations, these losses were not included in the calculations as the different in the economy evaluation of the project would be minimal (due to the relative small values of costs of these losses compared to the whole project). The whole project was calculated in the period of 50 years.

Input data		
Overhead lines 22 kV	1667250	Czk/km
Overhead lines 110 kV	25000000	Czk/km
Transformer station	30000000	Czk
Transformer 110/22 kV 63 MVA	14000000	Czk
Maintenance of lines	2,00%	of investment cost
Maintenance of transformer	3,00%	of investment cost
Maintenance escalation factor	2,00%	/year
WACC	5,38%	
Tax depreciation period of transformer	10	years
Tax depreciation period of lines	20	years
Taxes	19,00%	
The number of customers in model	100	
Average load of a customer	5800	kWh/year
The cost of electricity for a customer	24000	Czk/year
Average price of electricity	4,21	Czk/kWh
The number of customers in the network	3566175	
The number of customers in the network at low voltage	3551582	
The energy transmitted in the network (total)	32773652,38	MWh/year
The energy transmitted in the network (low voltage)	14167723,77	MWh/year

Table 20 – Input data for economy calculations

4.2. Methodology of calculations

The calculation of NPV[3] approach was chosen in order to evaluate the economy aspects of simulated variants leading to the improvement of the desired indices. At the beginning, the NPV calculation included only operational costs and investments without any loans (included in WACC) or revenues. The NPV values calculated this way are negative for obvious reasons. Also RCF[4] was calculated from the NPV to obtain year equivalent value of cash flow in each year. As no company would build a project that would bring only the numbers in red, the two approaches were chosen to pay back the project. The first one is mentioned RCF, where this value should be distributed to the customers (Table 29 – NPV calculations. preview for 7 years). The second approach is to include the revenues in the model so that the NPV=0 (Table 30 – Npv calculations, preview for 7 years. Revenues included) We also assume that the revenues will have rising trend through the years (2%). We obtain the revenues in every year and should be paid by the customers so that the project would not be losing money.

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[3] NPV – net present value
[4] RCF – retained cash flow

$$NPV(r,T) = \sum_{t=0}^{T} \frac{CF_t}{(1+r)^t} \ [Czk] \tag{41}$$

$$RCF = A_{tz} \cdot NPV \ [Czk] \tag{42}$$

$$A_{tz} = \frac{(1+r)^T . r}{(1+r)^T - 1} \tag{43}$$

$$RCF = \frac{(1+r)^T . r}{(1+r)^T - 1} \cdot NPV \ [Czk] \tag{44}$$

Where

- T – time
- NPV – net present values
- RCF – retained cash flow
- r – discount rate

The preview of calculations are shown in the Table 29 and Table 30

4.3. Results

In the variant with doubled lines total 5 kilometres of lines have to be built. The total investment cost of this project would be 8336250 Czk. In the variant with longer lines this investment would be 10 times higher as the lines are also considered to be 10 times longer compared to the base variant – this investment would cost 83362500 Czk. As mentioned before, the variant with the second feeding point can be divided into taken from two sides: the variant with the existing transformer station would cost 1667250 Czk as only the line has to be built to connect the transformer station and the modelled network. The variant without existing transformer station would be much more expensive as the two transformers would have to be built with two lines 110 kV and another line between the simulated network and the transformer station. This project would cost 109667250 Czk.

The revenues shown in the tables are revenues in the first year of the project.

Double line		
Investment costs	8336250	Czk
NPV	-5714424	Czk
RCF	-331364	Czk
Revenues	290522	Czk

Table 21 The results for the variant with double lines

Long double line		
Investment costs	83362500	Czk
NPV	-57144242	Czk
RCF	-3313640	Czk
Revenues	2905219	Czk

Table 22 -The results for the variant with long double lines

2 feeders with new station		
Investment costs	109667250	Czk
NPV	-40581644	Czk
RCF	-2353220	Czk
Revenues	2063177	Czk

Table 23 - The results for the variant second feeding point with new transformer station

2 feeders without new station		
Investment costs	1667250	Czk
NPV	-1142885	Czk
RCF	-66273	Czk
Revenues	58104	Czk

Table 24 - The results for the variant second feeding point with existing transformer station

There are more ways to decide, who and how would pay for these projects so that the distribution network operator would not loss. The costs of investments can be distributed either to each customer of the network or can be included in the price of electricity. The second variant seems to be fairer as the big customer would pay the same price as the small household if the costs were distributed to each customer equally. On the other hand, it has to be kept in mind that these projects would affect only the reliability of small part of the distribution network and the vast majority of customers would not benefit from it. The distribution of costs among the simulated network customers was also made to show what effect these variants would have just on this small part of the distribution network. The simulated network would be connected to CEZ Distribuce distribution network with 3 566 175 customers (3 551 582 low voltage customers) with total distributed power 32 773 652 MWh/year (14 167 724 MWh/year at low voltage). These values were valid in 2013 (14). The values in the Table 25 - The table of costs calculated to customers include taxes.

	Double lines	Long double lines	2 feeders w/ transformer	2 feeders w/o transformer	
Additional costs for 1 customer in the simulated network	3457	34572	24552	691	Czk
Additional costs for 1 customer in the network	0,097	0,969	0,688	0,019	Czk
New price for 1 kWh in simulated network	6,044	17,256	8,294	4,468	Czk
Average additional costs for 1 MWh in the network	0,033	0,231	0,072	0,005	Czk/MWh
Average additional costs for 1 MWh in the network - low voltage	0,024	0,244	0,173	0,005	Czk/MWh
The price of non-supplied kWh	8023	8334	53176	1498	Czk/kWh
NPV	-5714424	-57144242	-40581644	-1142885	Czk

Table 25 - The table of costs calculated to customers

As can be seen from the Table 25 - The table of costs calculated to customers, the highest capital costs are spent in the variant with long double lines followed by the variant where a transformer station is needed to be built. The best results are achieved at the variant with 2 feeding points with no necessity to build the whole transformer station and the grid is connected to existing station. The variant bringing the similar results in the reliability of network compared to the previously mentioned variant is the one with doubled lines. Although these two variants are very close in all observed values, the capital costs of the variant with connection to the existing transformer station are approximately 5 times lower compared to the variant with doubled lines. As the only measures in these two variants is building the lines, the difference in capital costs is obvious due to the fact that the total length of lines in variant with double lines is 5 times higher compared to the variant with connection to the second transformer station. If the transformer station lied in the further area, the capital costs of variant with connection to the second station would be much higher and would rise linearly. It has to be noted that the capital costs of variants depend mostly on the lengths of lines in variants. If the input line lengths the variant were different, the order of the variants would be totally different. It is necessary to evaluate the individual parts of networks with particular variables and their variants in order to find out which variant is the best in the matter of capital costs and which one brings the best results to the reliability of the system.

The price of non-supplied energy in kWh is theoretical price, which is based on the difference in unsupplied energy in the base variant and the desired variant. That is the additional price for 1 kWh in the base variant which would pay the project and this lack of energy would not occur. Theoretically, If the some variant would guarantee us 100% electricity delivery, this would be the additional price for 1 kWh of non-supplied energy we are willing to pay to have the supply without any outages. Note that the investment costs of the variant with longer lines and 2 feeding points equal to the variant with standard lengths of lines.

4.4. Indices (SAIDI, SAIFI) to NPV relationship

<u>The list of variants</u>

V1.1 Base variant

V2.2 Variant with two feeders

V3.1 Variant with doubled lines

V1.3 Base variant

V2.3 Variant with two feeders

V3.3 Variant with doubled lines

Standard lengths						
Variant	SAIDI	SAIFI	CAIDI	ASAI	AENS	"-NPV"
	[hours/year]	[1/year]	[hours]	[-]	[kWh]	Czk
V1.1	4,59	0,61	7,59	0,9995	3,04	0
V2.1	3,90	0,39	9,88	0,9996	2,58	40581644
V2.1	3,90	0,39	9,88	0,9996	2,58	1142885
V3.1	3,94	0,3958	9,97	0,9995	2,61	5714424

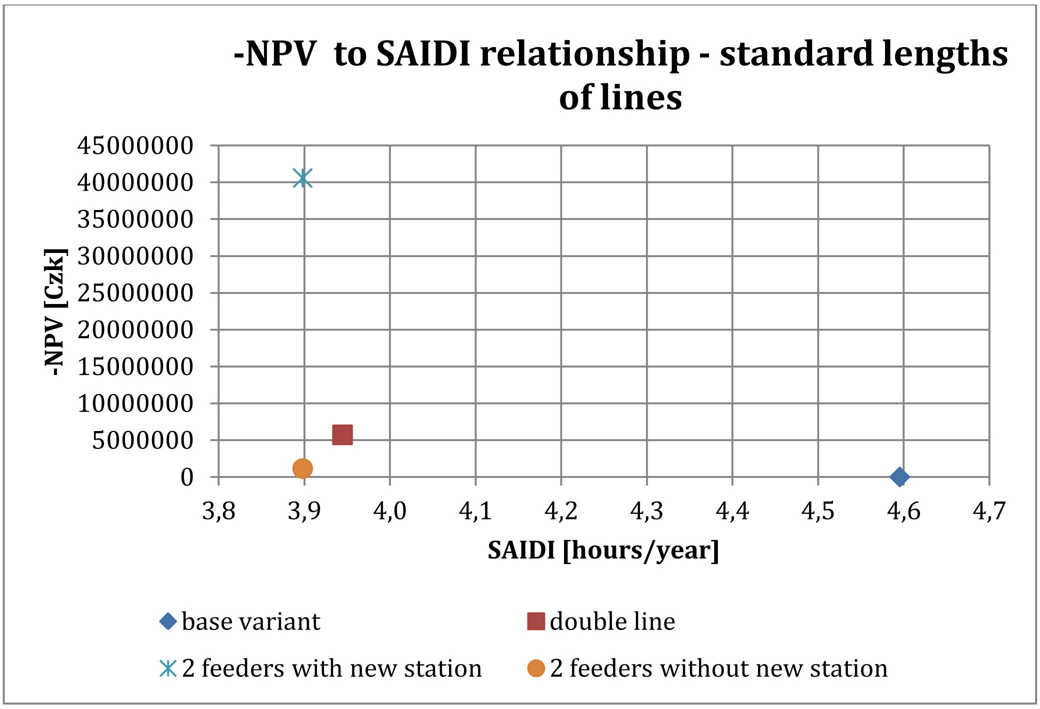
Table 26 – Customer based indices for standard lengths of lines

Longer lengths						
Variant	SAIDI	SAIFI	CAIDI	ASAI	AENS	"-NPV"
	[hours/year]	[1/year]	[hours]	[-]	[kWh]	Czk
V1.3	19,65	5,64	3,48	0,9978	13,01	0
V2.3	12,69	3,40	3,73	0,9986	8,40	40581644
V2.3	12,69	3,40	3,73	0,9986	8,40	1142885
V3.3	13,38	3,55	3,77	0,9985	8,86	57144242

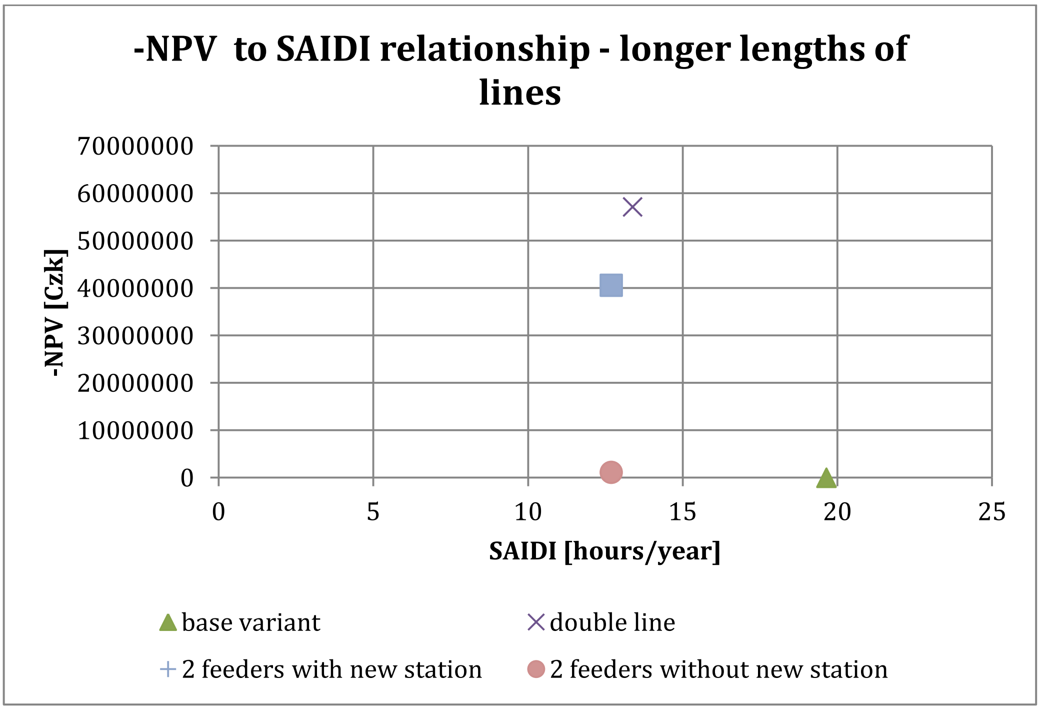
Table 27 - Customer based indices for longer lengths of lines

Difference in indices			
Variant	SAIDI	SAIFI	"-NPV"
	[hours/year]	[1/year]	Czk
V2.1	0,70	0,211	40581644
V2.1	0,70	0,211	1142885
V3.1	0,65	0,209	5714424
V2.3	6,96	2,241	40581644
V2.3	6,96	2,241	1142885
V3.3	6,26	2,095	57144242

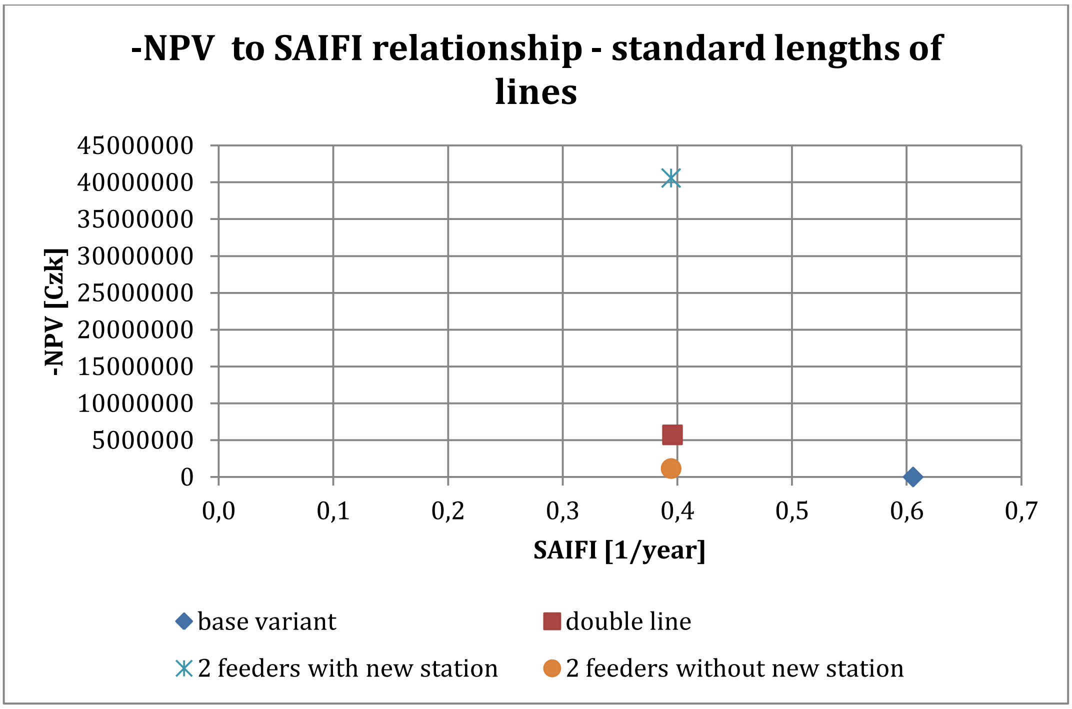
Table 28 – The table with differences of customer based indices



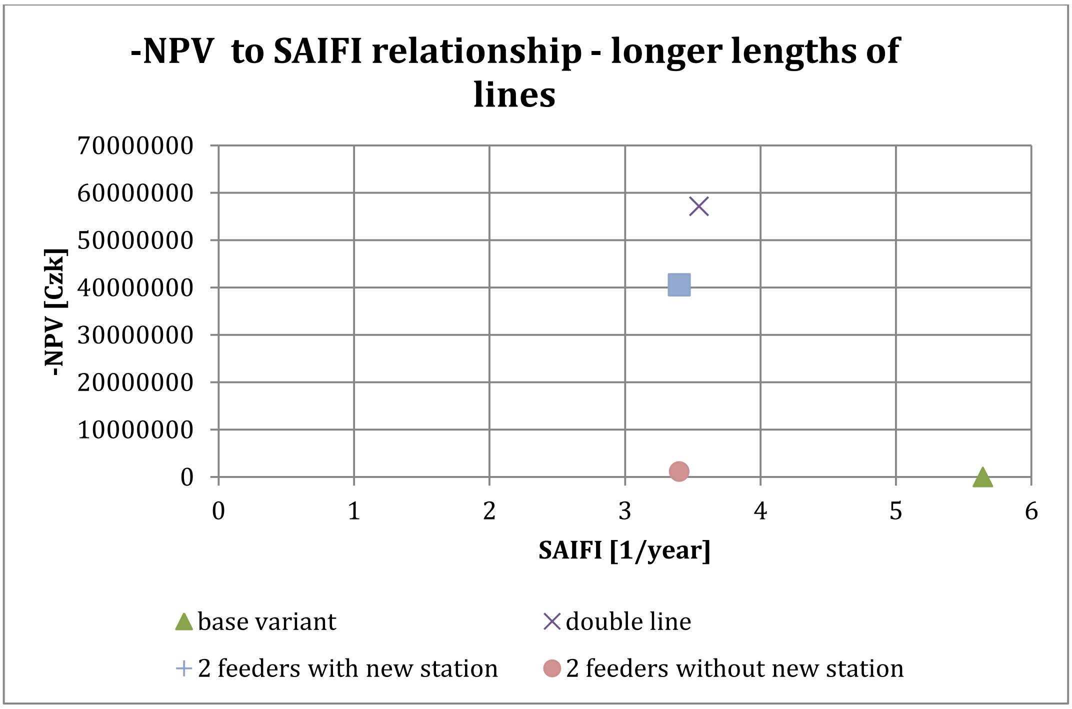
Graph 15 - -NPV to SAIDI relationship



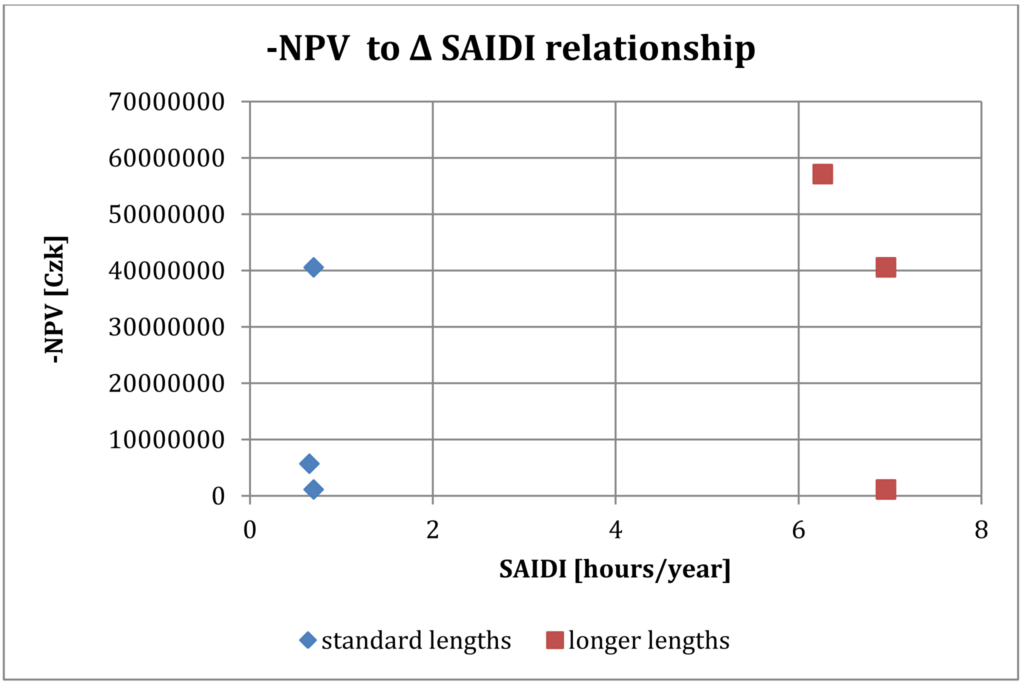
Graph 16 - -NPV to SAIDI relationship for variants with longer lines



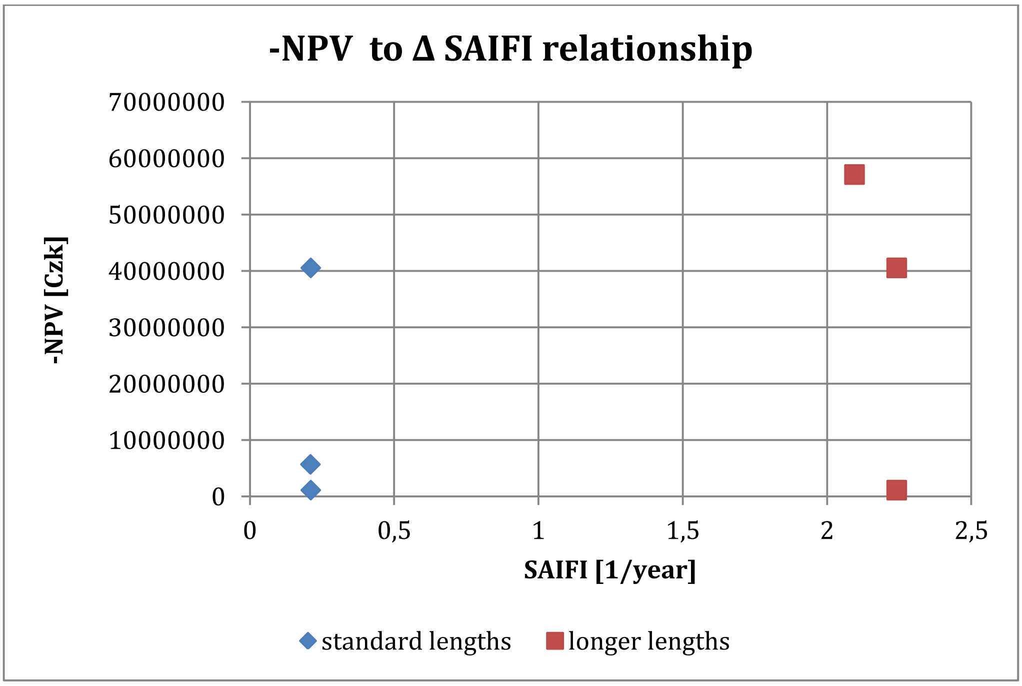
Graph 17 - -NPV to SAIFI relationship



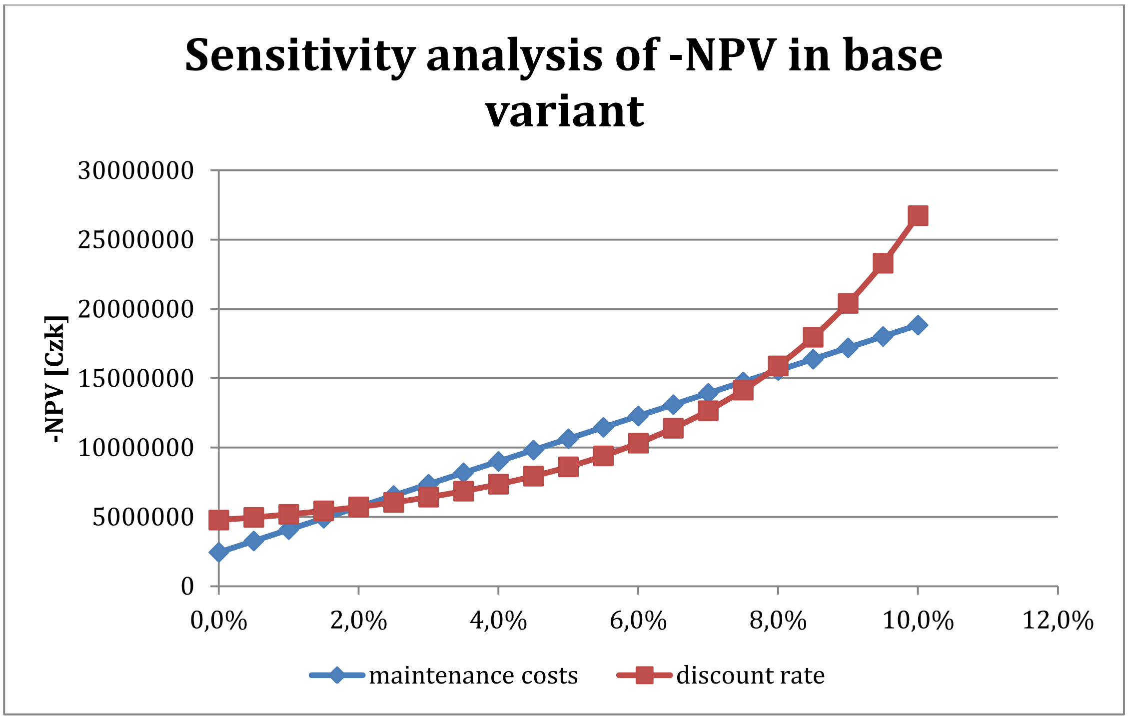
Graph 18 - -NPV to SAIFI relationship for variants with longer lines



Graph 19 - -NPV to Δ SAIDI relationship



Graph 20 - -NPV to Δ SAIFI relationship



Graph 21 – Sensitivity analysis

The relationship between NPV and the difference in SAIDI (SAIFI) between base variant and other variants is shown in the Table 26 – Customer based indices for standard lengths of lines, Table 27 - Customer based indices for longer lengths of linesand Table 28 – The table with differences of customer based indices.

Although it seems that with higher investment costs into reliability we receive actual improvement of the indices (reliability respectively), it significantly depends on the type of measures that are used and many variables that characterize the system. It cannot be said in general that the higher investment costs into the system brings the better reliability than lower investments. Very different measures with different investment costs can be used to achieve the similar improvement of the reliability in the affected part of the network.

We receive very similar improvements in the simulated grid using two different approaches. As can be seen from Table 26 – Customer based indices for standard lengths of lines, Table 27 - Customer based indices for longer lengths of linesand Table 28 – The table with differences of customer based indices these variants with similar results in the reliability would cost very different amount of money. In the variant with doubled lines, the full length of parallel lines is needed to be built, although only one line in the variant with two feeders is required to be built connecting this part of grid to the second transformer station. If the distance of the second transformer station is very long, the doubled line seems to be the better option; connecting the grid to this station would the better option if the second transformer is close. The option where the new power station has to be built is very expensive, although this option would grant the high reliability of the simulated distribution network if this station would be built close to this grid. Another parts of the distribution network could be connected to this station so the improvement in the reliability would affect the more customers than just customers in the simulated grid.

What can be also observed from simulations and calculation is that in the areas with lower density of customers higher investment cost are required to improve the reliability of the system. It is generally caused by the longer lengths of lines in this type of grid and also lower density of transformers there grids could be connected to. Also the repair of the broken equipment (part of the grid) lasts longer due to the longer time until the repairmen reach the problematic part of the grid in order to repair it.

There weren't made any deeper sensitivity analysis of values in the economical part as the changes of these values would bring minimal impact to the project costs compared to the changes inducted by different input parameters of the technological part of variants (for example, the change in the WACC parameter would bring the minimal impact compared to the capital costs of different lengths of the lines). The basic sensitivity analysis is shown on the Graph 21 – Sensitivity analysis. The relationship between NPV and maintenance costs and discount rate has growing trend. It has to be kept in mind that these values are not going to change dramatically throughout the time and this analysis just implies that these coefficients have to be chosen correctly in the beginning of the project as their values can be significant to the evaluation of the project.

The distribution network operators are required to keep the reliability indices (SAIDI, SAIFI) in set limits in order not to be penalized as mentioned in the previous part of this work. The first part of this work also mentions how these indices are calculated therefore also the way to improve these indices (for the fixed amount of customers). The way how to improve the SAIFI index is by minimizing the number of interruptions of customers. On the other hand, there are two ways how to improve SAIDI index: it is either to minimize the number of interruptions of customers of the duration of these interruptions. As there are two ways how to improve SAIDI, it is more likely to improve SAIDI than SAIFI. As these indices are calculated for whole network, distribution grid operators can decide which part of the network the reliability should be improved to get the required values of SAIDI and SAIFI. It is likely that the measures would be taken in the parts of the network with higher density of customers – index SAIDI worsen more if one interruption affects more customers. Also the investment costs to the part of the network with higher density of customers are lower compared to the parts with low density of population as shown in the previous part of this work. This means that some parts of the network would be left with worse reliability than other due to the fact that distribution grid operators would try to find such measures that would bring the best improvement for the least investment costs. Author of this work thinks that there should be some limits in reliability indices set to the smaller parts of the network so that the similar reliability of power supply would be achieved in all parts of the network and the investments would not be made just in some parts of the network and the rest would be left with worse parameters.

5. Conclusion

The aim of this work was to show the methods used to evaluate the distribution network reliability.

The first part of this work is theoretical and describes the models used for the evaluation of the network. These can be divided into two larger groups –analytical methods based on mathematical models calculations and simulation methods. Analytical methods are suitable for small networks evaluation to give us the basic idea about the grid reliability. These methods also require the good theoretical knowledge of the method used. Simulation methods are more usable for large and more complex systems and can calculate the vast quantity of values describing the network. It is also pretty easy to change the topology of the network and input data in these evaluations. This method was used in the second part of this work as the simulation is suitable for the analysis of the different variants of the modelled network. The first part of this work also describes the monitoring of grid reliability using different indices.

The second part of this work is to design the reference network model, its evaluation from the point of view of reliability and capital costs of different variants. The simple network was set as the reference model with 10 output and 100 customers in total (10 customers for each output). After the evaluation of the reliability of this network, two other variants were simulated trying to improve the base variant's reliability. One of variants is based on the doubled distribution line, the other one is based on the connecting this network to the second transformer station. There are actually two reference models and its variants described in this work – the second one has the same topology as the first model, the difference is in the longer lengths of lines trying to simulate the network with different density of customers. Alongside to all of these simulations, the same amount was performed with one special customer demanding the higher reliability in power supply (doubled distribution transformers). As the overall reliability of the simulated network changed marginally due to this customer, further analysis of this variant was omitted.

The third part of the work was trying to evaluate the measures taken to improve the reliability from the economical point of view. The first and the third part also contain the methods and evaluations of the reliability monitoring in the network.

The results of the second part of the work is that the variant with doubled line and the variant with the connection to the second transformer station show similar reliability in power supply. The main difference would rest in the customers lying on the furthest point of the radial network – in the variant with doubled lines these customers would have the worst reliability of the power supply; the worst results for the customers in the variant with second feeding point would be in the middle between the two transformer stations. In general, the variants with long lines result in more outages as the main cause of the failures are the lines themselves.

The primary goal of the author was trying to find some formula describing the relationship between the capital costs and reliability in the very beginning of this work. Throughout the work it was realized that it is difficult (if possible) to find any formula describing the exact relationship between investments and reliability. It was found out there are too many input variables changing the whole calculations of the variants and therefore the last part of the work was just about the economical evaluation of the projects. Author believes that the best way to evaluate the investments bringing better reliability results is to make the calculations individually for real parts of the network. There should be more variants introduced how to improve the grid reliability and the proper decision could be made based on these calculations.

The only thing that can be claimed is that the capital costs into the network with low density of customers are usually higher compared to the networks with higher density of population. Also, the desired values of indices describing the reliability of the network are more likely to be easily achieved in the areas with high density of population (less investments costs and higher impact of the measures performed compared to the areas with low density of population).

As the result, this thesis shows the way of determining the reliability of chosen distribution network and the evaluation of possible variants.

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7. Appendices

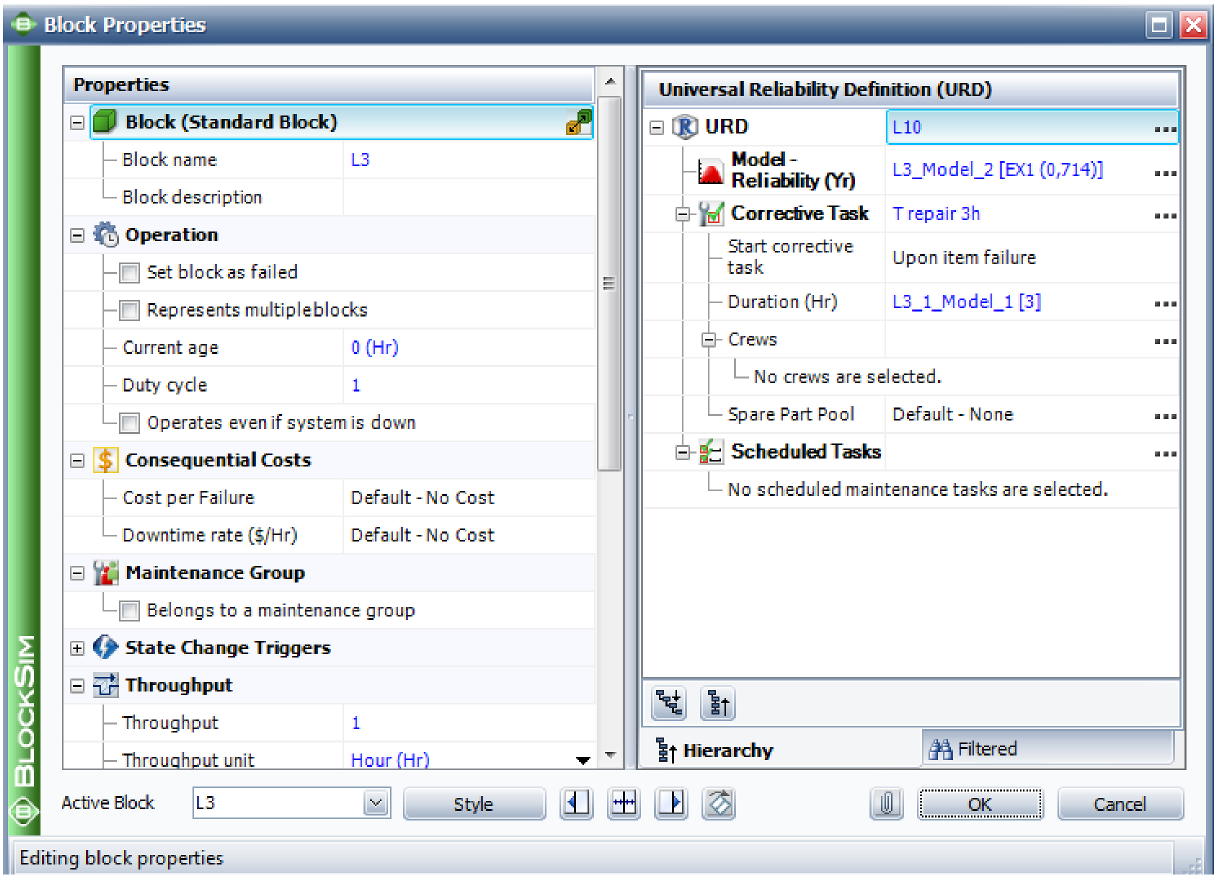


Figure 2 – Block properties

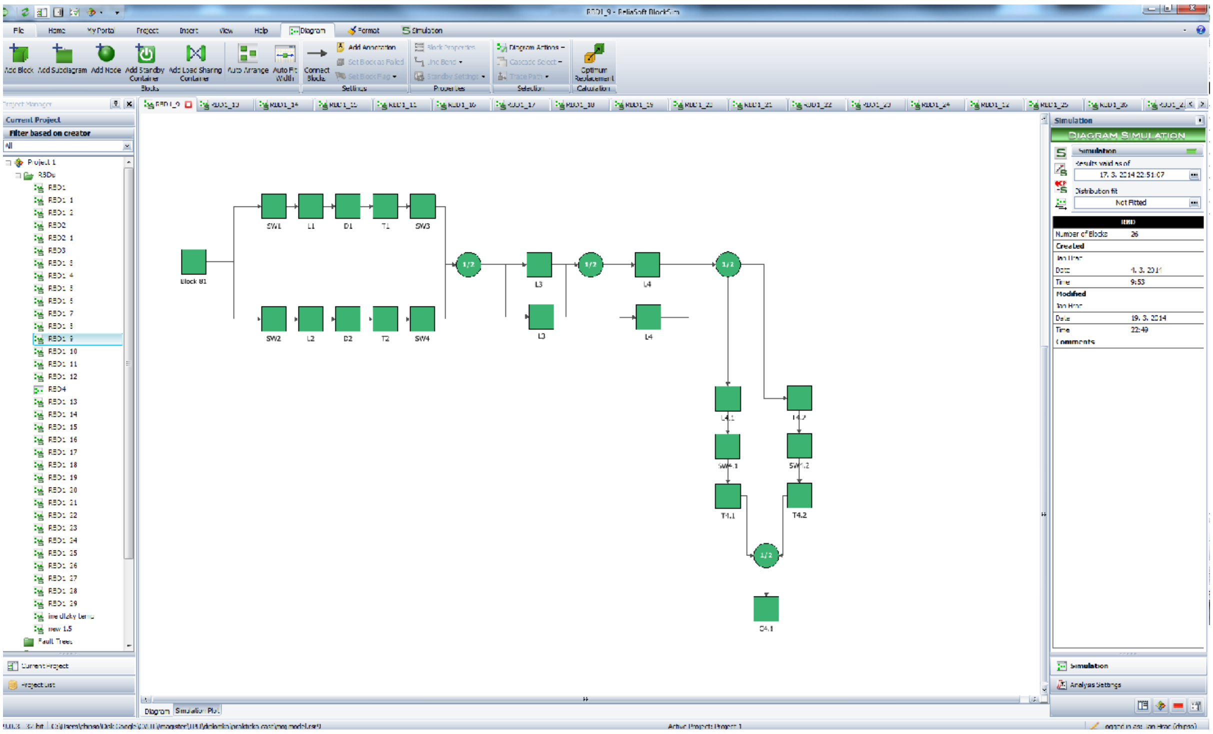


Figure 3 – Modelled system

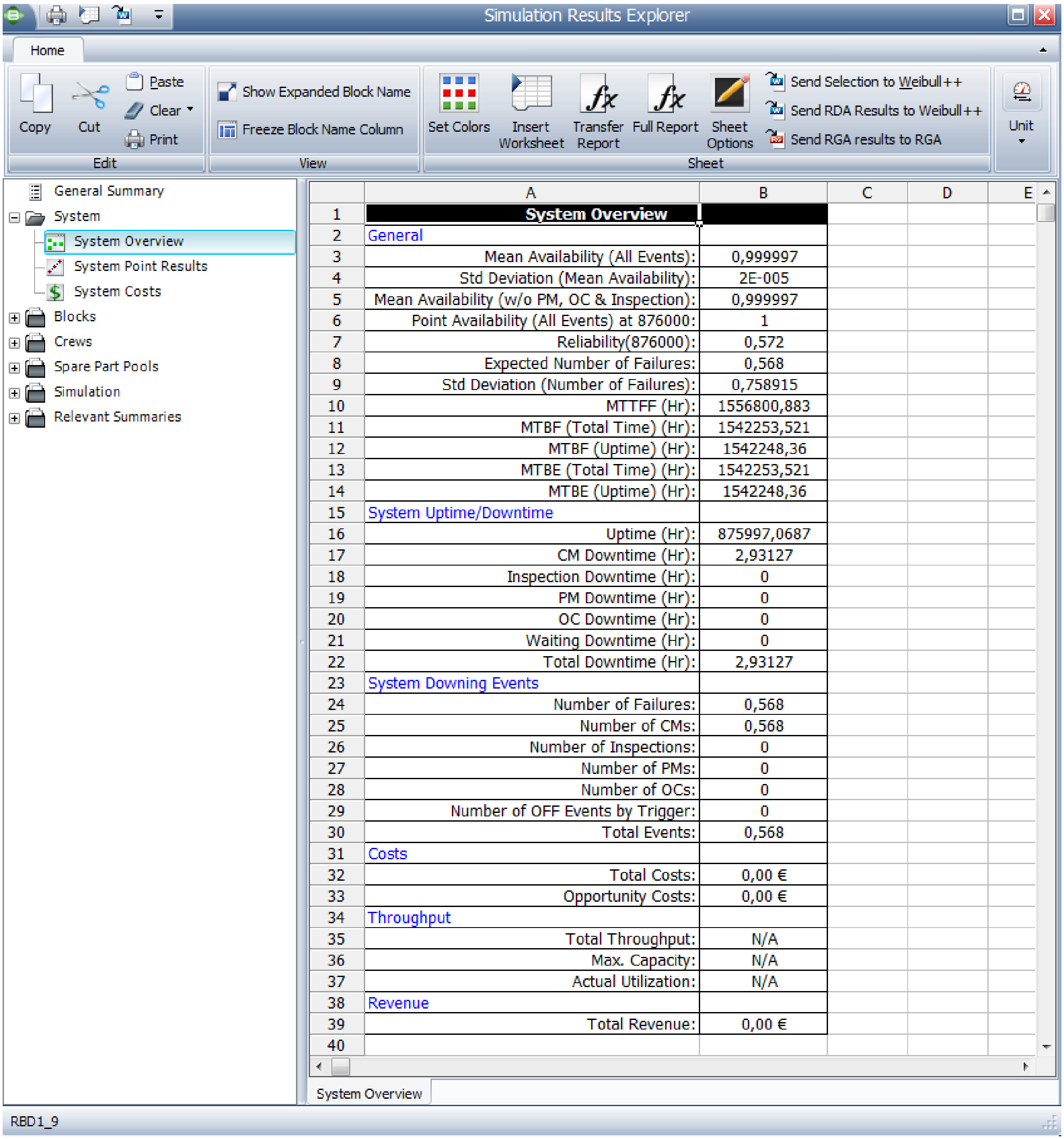
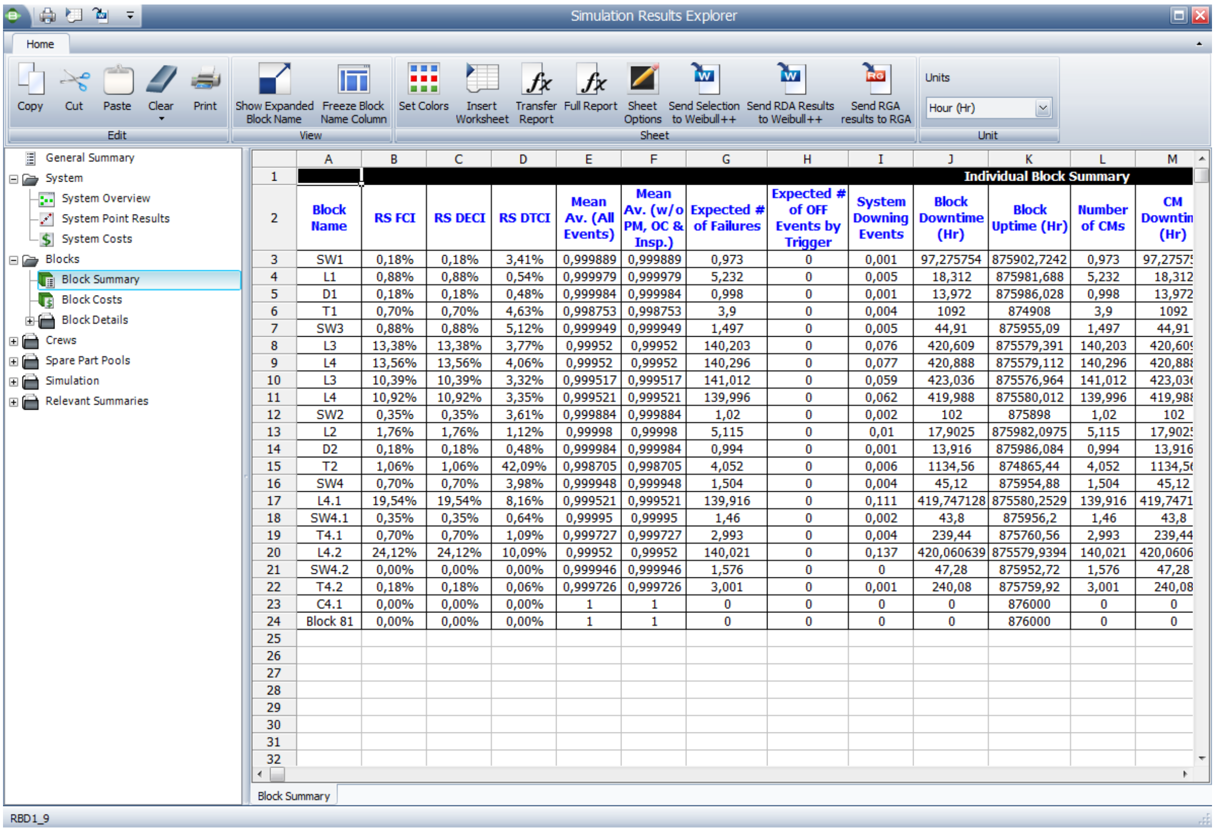


Figure 4 – Simulation results explorer



	A	B	C	D	E	F	G	H	I	J	K	L	M
1										Individual Block Summary			
2	Block Name	RS FCI	RS DECI	RS DTCI	Mean Av. (All Events)	Mean Av. (w/o PM, OC & Insp.)	Expected # of Failures	Expected # of OFF Events by Trigger	System Downing Events	Block Downtime (Hr)	Block Uptime (Hr)	Number of CMs	CM Downtin (Hr)
3	SW1	0,18%	0,18%	3,41%	0,999889	0,999889	0,973	0	0,001	97,275754	875902,7242	0,973	97,2757
4	L1	0,88%	0,88%	0,54%	0,999979	0,999979	5,232	0	0,005	18,312	875981,688	5,232	18,312
5	D1	0,18%	0,18%	0,48%	0,999984	0,999984	0,998	0	0,001	13,972	875986,028	0,998	13,972
6	T1	0,70%	0,70%	4,63%	0,998753	0,998753	3,9	0	0,004	1092	874908	3,9	1092
7	SW3	0,88%	0,88%	5,12%	0,999949	0,999949	1,497	0	0,005	44,91	875955,09	1,497	44,91
8	L3	13,38%	13,38%	3,77%	0,99952	0,99952	140,203	0	0,076	420,609	875579,391	140,203	420,60
9	L4	13,56%	13,56%	4,06%	0,99952	0,99952	140,296	0	0,077	420,888	875579,112	140,296	420,88
10	L3	10,39%	10,39%	3,32%	0,999517	0,999517	141,012	0	0,059	423,036	875576,964	141,012	423,03
11	L4	10,92%	10,92%	3,35%	0,999521	0,999521	139,996	0	0,062	419,988	875580,012	139,996	419,98
12	SW2	0,35%	0,35%	3,61%	0,999884	0,999884	1,02	0	0,002	102	875898	1,02	102
13	L2	1,76%	1,76%	1,12%	0,99998	0,99998	5,115	0	0,01	17,9025	875982,0975	5,115	17,902
14	D2	0,18%	0,18%	0,48%	0,999984	0,999984	0,994	0	0,001	13,916	875986,084	0,994	13,916
15	T2	1,06%	1,06%	42,09%	0,998705	0,998705	4,052	0	0,006	1134,56	874865,44	4,052	1134,5
16	SW4	0,70%	0,70%	3,98%	0,999948	0,999948	1,504	0	0,004	45,12	875954,88	1,504	45,12
17	L4.1	19,54%	19,54%	8,16%	0,999521	0,999521	139,916	0	0,111	419,747128	875580,2529	139,916	419,7471
18	SW4.1	0,35%	0,35%	0,64%	0,99995	0,99995	1,46	0	0,002	43,8	875956,2	1,46	43,8
19	T4.1	0,70%	0,70%	1,09%	0,999727	0,999727	2,993	0	0,004	239,44	875760,56	2,993	239,44
20	L4.2	24,12%	24,12%	10,09%	0,99952	0,99952	140,021	0	0,137	420,060639	875579,9394	140,021	420,0606
21	SW4.2	0,00%	0,00%	0,00%	0,999946	0,999946	1,576	0	0	47,28	875952,72	1,576	47,28
22	T4.2	0,18%	0,18%	0,06%	0,999726	0,999726	3,001	0	0,001	240,08	875759,92	3,001	240,08
23	C4.1	0,00%	0,00%	0,00%	1	1	0	0	0	0	876000	0	0
24	Block 81	0,00%	0,00%	0,00%	1	1	0	0	0	0	876000	0	0
25													
26													
27													
28													
29													
30													
31													
32													

Figure 5 – Simulation results explorer with details

Year	0	1	2	3	4	5	6	7
Investments	8336250							
Maintenance		170060	173461	176930	180469	184078	187759	191515
Depreciation		213750	427500	427500	427500	427500	427500	427500
Costs	0	383810	600961	604430	607969	611578	615259	619015
Revenues	0	0	0	0	0	0	0	0
EBT	0	-383810	-600961	-604430	-607969	-611578	-615259	-619015
Tax shield/Taxes	0	-72924	-114183	-114842	-115514	-116200	-116899	-117613
EAT	0	-310886	-486778	-489588	-492454	-495378	-498360	-501402
CF	-8336250	116614	368222	365412	362546	359622	356640	353598
DCF	-8336250	110665,1927	331610,274	312291,5	294035,3	276784,8	260486,48	245089,3894
NPV	-5 714 424							
RCF	-331364							
Revenues	290522,1833							

Table 29 – NPV calculations. preview for 7 years

Year	0	1	2	3	4	5	6	7
Investments	8336250							
Maintenance		170060	173461	176930	180469	184078	187759	191515
Depreciation		213750	427500	427500	427500	427500	427500	427500
Costs	0	383810	600961	604430	607969	611578	615259	619015
Revenues	0	296332,627	302259,28	308304,5	314470,6	320760	327175,16	333718,6681
EBT	0	-87477	-298701	-296125	-293498	-290818	-288084	-285296
Tax shield/Taxes	0	-16621	-56753	-56264	-55765	-55255	-54736	-54206
EAT	0	-70856	-241948	-239862	-237733	-235563	-233348	-231090
CF	-8336250	356644	613052	615138	617267	619437	621652	623910
DCF	-8336250	338449,4503	552097,328	525715,1	500621,7	476753,2	454048,72	432450,7512
NPV	0							
RCF	0							
Revenues	290522,1833							

Table 30 – Npv calculations, preview for 7 years. Revenues included

Customer	Number of customers	Load per 1 [kWh]	Total load for a feeding point [kWh]	Availability	MTBF [h]	Events	Events/year	Probability Of failure F(t)	Downtime [h]	Downtime a year [h]	Downtime/event [h]	Total downtime for a feeding poing [h]	Unsupplied energy [kWh]
1	10	5800	58000	0,99957	26881	32,59	0,33	0,278	373,33	3,733	11,456	37,333	247,2
2	10	5800	58000	0,99952	18703	46,84	0,47	0,374	420,12	4,201	8,970	42,012	278,2
3	10	5800	58000	0,99947	14448	60,60	0,61	0,454	466,64	4,666	7,701	46,664	309,0
4	10	5800	58000	0,99943	11727	74,70	0,75	0,526	501,80	5,018	6,718	50,180	332,2
5	10	5800	58000	0,99939	9941	88,12	0,88	0,586	535,86	5,359	6,081	53,586	354,8
6	10	5800	58000	0,99957	26881	32,59	0,33	0,278	373,33	3,733	11,456	37,333	247,2
7	10	5800	58000	0,99990	31170	28,10	0,28	0,245	87,13	0,871	3,100	8,713	57,7
8	10	5800	58000	0,99947	14448	60,60	0,61	0,454	466,64	4,666	7,701	46,664	309,0
9	10	5800	58000	0,99943	11727	74,70	0,75	0,526	501,80	5,018	6,718	50,180	332,2
10	10	5800	58000	0,99939	9941	88,12	0,88	0,586	535,86	5,359	6,081	53,586	354,8
	100	**58000**	**580000**			**586,95**	**5,87**		**4262,50**	**42,625**	**7,262**	**426,250**	**2822,2**

Table 31 – variant 1.2

Customer	Number of customers	Load per 1 [kWh]	Total load for a feeding point [kWh]	Availability	MTBF [h]	Events	Events/year	Probability Of failure F(t)	Downtime [h]	Downtime a year [h]	Downtime/event [h]	Total downtime for a feeding poing [h]	Unsupplied energy [kWh]
1	10	5800	58000	0,99871	3064	285,88	2,86	0,943	1129,27	11,293	3,950	112,927	747,7
2	10	5800	58000	0,99823	2065	424,12	4,24	0,986	1548,31	15,483	3,651	154,831	1025,1
3	10	5800	58000	0,99777	1552	564,48	5,64	0,996	1952,35	19,523	3,459	195,235	1292,6
4	10	5800	58000	0,99727	1245	703,82	7,04	0,999	2389,04	23,890	3,394	238,904	1581,8
5	10	5800	58000	0,99680	1040	842,59	8,43	1,000	2805,24	28,052	3,329	280,524	1857,4
6	10	5800	58000	0,99871	3064	285,88	2,86	0,943	1129,27	11,293	3,950	112,927	747,7
7	10	5800	58000	0,99823	2065	424,12	4,24	0,986	1548,31	15,483	3,651	154,831	1025,1
8	10	5800	58000	0,99777	1552	564,48	5,64	0,996	1952,35	19,523	3,459	195,235	1292,6
9	10	5800	58000	0,99727	1245	703,82	7,04	0,999	2389,04	23,890	3,394	238,904	1581,8
10	10	5800	58000	0,99680	1040	842,59	8,43	1,000	2805,24	28,052	3,329	280,524	1857,4
	100	**58000**	**580000**			**5641,78**	**56,42**		**19648,42**	**196,484**	**3,483**	**1964,842**	**13009,2**

Table 32 – variant 1.3

Customer	Number of customers	Load per 1 [kWh]	Total load for a feeding point [kWh]	Availability	MTBF [h]	Events	Events/year	Probability Of failure F(t)	Downtime [h]	Downtime a year [h]	Downtime/event [h]	Total downtime for a feeding poing [h]	Unsupplied energy [kWh]
1	10	5800	58000	0,99871	3064	285,88	2,86	0,943	1129,27	11,293	3,950	112,927	747,7
2	10	5800	58000	0,99823	2065	424,12	4,24	0,986	1548,31	15,483	3,651	154,831	1025,1
3	10	5800	58000	0,99777	1552	564,48	5,64	0,996	1952,35	19,523	3,459	195,235	1292,6
4	10	5800	58000	0,99727	1245	703,82	7,04	0,999	2389,04	23,890	3,394	238,904	1581,8
5	10	5800	58000	0,99680	1040	842,59	8,43	1,000	2805,24	28,052	3,329	280,524	1857,4
6	10	5800	58000	0,99871	3064	285,88	2,86	0,943	1129,27	11,293	3,950	112,927	747,7
7	10	5800	58000	0,99904	3127	280,10	2,80	0,939	841,68	8,417	3,005	84,168	557,3
8	10	5800	58000	0,99777	1552	564,48	5,64	0,996	1952,35	19,523	3,459	195,235	1292,6
9	10	5800	58000	0,99727	1245	703,82	7,04	0,999	2389,04	23,890	3,394	238,904	1581,8
10	10	5800	58000	0,99680	1040	842,59	8,43	1,000	2805,24	28,052	3,329	280,524	1857,4
	100	**58000**	**580000**			**5497,76**	**54,98**		**18941,79**	**189,418**	**3,445**	**1894,179**	**12541,4**

Table 33 – variant 1.4

Customer	Number of customers	Load per 1 [kWh]	Total load for a feeding point [kWh]	Availability	MTBF [h]	Events	Events/year	Probability Of failure F(t)	Downtime [h]	Downtime a year [h]	Downtime/event [h]	Total downtime for a feeding poing [h]	Unsupplied energy [kWh]
1	10	5800	58000	0,99958	26751	32,75	0,33	0,279	364,50	3,645	11,131	36,450	241,3
2	10	5800	58000	0,99953	18919	46,30	0,46	0,371	411,41	4,114	8,885	41,141	272,4
3	10	5800	58000	0,99949	14525	60,31	0,60	0,453	451,10	4,511	7,480	45,110	298,7
4	10	5800	58000	0,99943	11719	74,75	0,75	0,526	495,63	4,956	6,631	49,563	328,2
5	10	5800	58000	0,99938	9946	88,07	0,88	0,586	540,60	5,406	6,138	54,060	357,9
6	10	5800	58000	0,99963	47385	18,49	0,18	0,169	326,98	3,270	17,687	32,698	216,5
7	10	5800	58000	0,99963	47377	18,49	0,18	0,169	326,99	3,270	17,684	32,699	216,5
8	10	5800	58000	0,99963	47380	18,49	0,18	0,169	326,99	3,270	17,686	32,699	216,5
9	10	5800	58000	0,99963	47390	18,49	0,18	0,169	326,98	3,270	17,689	32,698	216,5
10	10	5800	58000	0,99963	47397	18,48	0,18	0,169	326,98	3,270	17,692	32,698	216,5
	100	**58000**	**580000**			**394,61**	**3,95**		**3898,16**	**38,982**	**9,878**	**389,816**	**2581,0**

Table 34 – Variant 2.1

Customer	Number of customers	Load per 1 [kWh]	Total load for a feeding point [kWh]	Availability	MTBF [h]	Events	Events/year	Probability Of failure F(t)	Downtime [h]	Downtime a year [h]	Downtime/event [h]	Total downtime for a feeding poing [h]	Unsupplied energy [kWh]
1	10	5800	58000	0,99958	26751	32,75	0,33	0,279	364,50	3,645	11,131	36,450	241,3
2	10	5800	58000	0,99953	18919	46,30	0,46	0,371	411,41	4,114	8,885	41,141	272,4
3	10	5800	58000	0,99949	14525	60,31	0,60	0,453	451,10	4,511	7,480	45,110	298,7
4	10	5800	58000	0,99943	11719	74,75	0,75	0,526	495,63	4,956	6,631	49,563	328,2
5	10	5800	58000	0,99938	9946	88,07	0,88	0,586	540,60	5,406	6,138	54,060	357,9
6	10	5800	58000	0,99963	47385	18,49	0,18	0,169	326,98	3,270	17,687	32,698	216,5
7	10	5800	58000	1,00000	36500000	0,02	0,00	0,000	0,16	0,002	6,781	0,016	0,1
8	10	5800	58000	0,99963	47380	18,49	0,18	0,169	326,99	3,270	17,686	32,699	216,5
9	10	5800	58000	0,99963	47390	18,49	0,18	0,169	326,98	3,270	17,689	32,698	216,5
10	10	5800	58000	0,99963	47397	18,48	0,18	0,169	326,98	3,270	17,692	32,698	216,5
	100	**58000**	**580000**			**376,15**	**3,76**		**3571,33**	**35,713**	**9,494**	**357,133**	**2364,6**

Table 35 – Variant 2.2

Customer	Number of customers	Load per 1 [kWh]	Total load for a feeding point [kWh]	Availability	MTBF [h]	Events	Events/year	Probability Of failure F(t)	Downtime [h]	Downtime a year [h]	Downtime/event [h]	Total downtime for a feeding poing [h]	Unsupplied energy [kWh]
1	10	5800	58000	0,99871	3077	284,67	2,85	0,942	1126,87	11,269	3,958	112,687	746,1
2	10	5800	58000	0,99824	2064	424,43	4,24	0,986	1540,86	15,409	3,630	154,086	1020,2
3	10	5800	58000	0,99774	1554	563,75	5,64	0,996	1976,88	19,769	3,507	197,688	1308,9
4	10	5800	58000	0,99727	1243	704,98	7,05	0,999	2393,92	23,939	3,396	239,392	1585,0
5	10	5800	58000	0,99680	1038	843,82	8,44	1,000	2806,68	28,067	3,326	280,668	1858,3
6	10	5800	58000	0,99919	6054	144,69	1,45	0,765	710,12	7,101	4,908	71,012	470,2
7	10	5800	58000	0,99918	6087	143,92	1,44	0,763	715,44	7,154	4,971	71,544	473,7
8	10	5800	58000	0,99918	6079	144,10	1,44	0,763	715,87	7,159	4,968	71,587	474,0
9	10	5800	58000	0,99919	6065	144,44	1,44	0,764	706,40	7,064	4,891	70,640	467,7
10	10	5800	58000	0,99919	6085	143,96	1,44	0,763	712,24	7,122	4,947	71,224	471,6
	100	**58000**	**580000**			**3542,76**	**35,43**		**13405,29**	**134,053**	**3,784**	**1340,529**	**8875,6**

Table 36 – Variant 2.3

Variant 2.4

Customer	Number of customers	Load per 1 [kWh]	Total load for a feeding point [kWh]	Availability	MTBF [h]	Events	Events/year	Probability Of failure F(t)	Downtime [h]	Downtime a year [h]	Downtime/event [h]	Total downtime for a feeding poing [h]	Unsupplied energy [kWh]
1	10	5800	58000	0,99871	3077	284,67	2,85	0,942	1126,87	11,269	3,958	112,687	746,1
2	10	5800	58000	0,99824	2064	424,43	4,24	0,986	1540,86	15,409	3,630	154,086	1020,2
3	10	5800	58000	0,99774	1554	563,75	5,64	0,996	1976,88	19,769	3,507	197,688	1308,9
4	10	5800	58000	0,99727	1243	704,98	7,05	0,999	2393,92	23,939	3,396	239,392	1585,0
5	10	5800	58000	0,99680	1038	843,82	8,44	1,000	2806,68	28,067	3,326	280,668	1858,3
6	10	5800	58000	0,99919	6054	144,69	1,45	0,765	710,12	7,101	4,908	71,012	470,2
7	10	5800	58000	1,00000	723369	1,21	0,01	0,012	2,03	0,020	1,678	0,203	1,3
8	10	5800	58000	0,99918	6079	144,10	1,44	0,763	715,87	7,159	4,968	71,587	474,0
9	10	5800	58000	0,99919	6065	144,44	1,44	0,764	706,40	7,064	4,891	70,640	467,7
10	10	5800	58000	0,99919	6085	143,96	1,44	0,763	712,24	7,122	4,947	71,224	471,6
	100	**58000**	**580000**			**3400,05**	**34,00**		**12691,88**	**126,919**	**3,733**	**1269,188**	**8403,3**

Table 37 – variant 2.4

Customer	Number of customers	Load per 1 [kWh]	Total load for a feeding point [kWh]	Availability	MTBF [h]	Events	Events/year	Probability of failure F(t)	Downtime [h]	Downtime a year [h]	Downtime/event [h]	Total downtime for a feeding poing [h]	Unsupplied energy [kWh]
1	10	5800	58000	0,99958	26751	32,75	0,3275	0,27925	364,50	3,645	11,131	36,450	24,1
2	10	5800	58000	0,99953	18919	46,30	0,4630	0,37063	411,41	4,114	8,885	41,141	27,2
3	10	5800	58000	0,99949	14525	60,31	0,6031	0,45289	451,10	4,511	7,480	45,110	29,9
4	10	5800	58000	0,99943	11719	74,75	0,7475	0,52645	495,63	4,956	6,631	49,563	32,8
5	10	5800	58000	0,99938	9946	88,07	0,8807	0,58552	540,60	5,406	6,138	54,060	35,8
6	10	5800	58000	0,99963	47397	18,482	0,1848	0,16875	326,98	3,270	17,692	32,698	21,6
7	10	5800	58000	0,99963	47390	18,485	0,1849	0,16877	326,98	3,270	17,689	32,698	21,6
8	10	5800	58000	0,99963	47385	18,487	0,1849	0,16879	326,98	3,270	17,687	32,698	21,6
9	10	5800	58000	0,99963	47380	18,489	0,1849	0,16880	326,99	3,270	17,685	32,699	21,6
10	10	5800	58000	0,99963	47377	18,490	0,1849	0,16881	326,99	3,270	17,685	32,699	21,6
	100	**58000**	**580000**			**394,61**	**3,95**		**3898,16**	**38,982**	**9,878**	**389,816**	**258,1**

Table 38 – variant 3.1

Customer	Number of customers	Load per 1 [kWh]	Total load for a feeding point [kWh]	Availability	MTBF [h]	Events	Events/year	Probability of failure F(t)	Downtime [h]	Downtime a year [h]	Downtime/event [h]	Total downtime for a feeding poing [h]	Unsupplied energy [kWh]
1	10	5800	58000	0,99958	26751	32,75	0,3275	0,27925	364,50	3,645	11,131	36,450	241,3
2	10	5800	58000	0,99953	18919	46,30	0,4630	0,37063	411,41	4,114	8,885	41,141	272,4
3	10	5800	58000	0,99949	14525	60,31	0,6031	0,45289	451,10	4,511	7,480	45,110	298,7
4	10	5800	58000	0,99943	11719	74,75	0,7475	0,52645	495,63	4,956	6,631	49,563	328,2
5	10	5800	58000	0,99938	9946	88,07	0,8807	0,58552	540,60	5,406	6,138	54,060	357,9
6	10	5800	58000	0,99963	47397	18,48	0,1848	0,16875	326,98	3,270	17,692	32,698	216,5
7	10	5800	58000	1,00000	36500000	0,02	0,0002	0,00024	0,16	0,002	6,781	0,016	0,1
8	10	5800	58000	0,99963	47390	18,49	0,1849	0,16877	326,98	3,270	17,689	32,698	216,5
9	10	5800	58000	0,99963	47385	18,49	0,1849	0,16879	326,98	3,270	17,687	32,698	216,5
10	10	5800	58000	0,99963	47380	18,49	0,1849	0,16880	326,99	3,270	17,686	32,699	216,5
	100	**58000**	**580000**			**357,66**	**3,76**		**3244,35**	**32,443**	**9,985**	**357,133**	**2364,6**

Table 39 – Variant 3.2

Variant 3.3

Customer	Number of customers	Load per 1 [kWh]	Total load for a feeding point [kWh]	Availability	MTBF [h]	Events	Events/year	Probability of failure F(t)	Downtime [h]	Downtime a year [h]	Downtime/event [h]	Total downtime for a feeding poing [h]	Unsupplied energy [kWh]
1	10	5800	58000	0,99871	3064	285,88	2,8588	0,94266	1129,27	11,293	3,950	112,927	74,8
2	10	5800	58000	0,99823	2065	424,12	4,2412	0,98561	1548,31	15,483	3,651	154,831	102,5
3	10	5800	58000	0,99777	1552	564,48	5,6448	0,99646	1952,35	19,523	3,459	195,235	129,3
4	10	5800	58000	0,99727	1245	703,82	7,0382	0,99912	2389,04	23,890	3,394	238,904	158,2
5	10	5800	58000	0,99680	1040	842,59	8,4259	0,99978	2805,24	28,052	3,329	280,524	185,7
6	10	5800	58000	0,99918	6060	144,55	1,4455	0,76436	706,49	7,065	4,888	70,649	46,8
7	10	5800	58000	0,99919	6045	144,92	1,4492	0,76524	710,67	7,107	4,904	71,067	47,1
8	10	5800	58000	0,99919	6040	145,03	1,4503	0,76551	710,87	7,109	4,901	71,087	47,1
9	10	5800	58000	0,99919	6032	145,22	1,4522	0,76595	713,95	7,140	4,916	71,395	47,3
10	10	5800	58000	0,99919	6009	145,78	1,4578	0,76726	716,69	7,167	4,916	71,669	47,5
	100	**58000**	**580000**			**3546,40**	**35,46**		**13382,89**	**133,829**	**3,774**	**1338,289**	**886,1**

Table 40 – Variant 3.3

Customer	Number of customers	Load per 1 [kWh]	Total load for a feeding point [kWh]	Availability	MTBF [h]	Events	Events/year	Probability of failure F(t)	Downtime [h]	Downtime a year [h]	Downtime/event [h]	Total downtime for a feeding poing [h]	Unsupplied energy [kWh]
1	10	5800	58000	0,99871	3064	285,88	2,8588	0,94266	1129,27	11,293	3,950	112,927	74,8
2	10	5800	58000	0,99823	2065	424,12	4,2412	0,98561	1548,31	15,483	3,651	154,831	102,5
3	10	5800	58000	0,99777	1552	564,48	5,6448	0,99646	1952,35	19,523	3,459	195,235	129,3
4	10	5800	58000	0,99727	1245	703,82	7,0382	0,99912	2389,04	23,890	3,394	238,904	158,2
5	10	5800	58000	0,99680	1040	842,59	8,4259	0,99978	2805,24	28,052	3,329	280,524	185,7
6	10	5800	58000	0,99918	6060	144,55	1,4455	0,76436	706,49	7,065	4,888	70,649	46,8
7	10	5800	58000	1,00000	1555030	0,56	0,0056	0,00562	2,53	0,025	4,491	0,253	0,2
8	10	5800	58000	0,99919	6045	144,92	1,4492	0,76524	710,67	7,107	4,904	71,067	47,1
9	10	5800	58000	0,99919	6040	145,03	1,4503	0,76551	710,87	7,109	4,901	71,087	47,1
10	10	5800	58000	0,99919	6032	145,22	1,4522	0,76595	716,69	7,167	4,935	71,669	47,5
	100	**58000**	**580000**			**3256,14**	**34,01**		**11960,60**	**119,606**	**3,892**	**1267,147**	**839,0**

Table 41 – Variant 3.4