

LAPPEENRANTA UNIVERSITY OF TECHNOLOGY
School of Energy Systems
Electrical Engineering

MASTER'S THESIS

**DESIGN OF POWER SUBSTATION IN PRIONEZHISKY
REGION**

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Abstract

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Design of power substation in Prionezhsky region

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In the nearest future the Republic of Karelia is waiting for industry growth, which consequently leads to a growth in the number of electricity consumers. In order to occur a power supply of new consumers in the region and to partially unload existing substations, it was decided to build a power substation designed for voltage levels of 110, 35, 10 kV. The substation is designed to solve the issue of power supply and to give impetus to the growth of industry in the region.

This work is focused on the designing process of new substation. The main goals of this thesis are to determine the most suitable structure of substation according to techno-economical point of view and to choose equipment according to the structure of substation.

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Abbreviations

AC	Alternating Current
ACSR	Aluminum Steel Reinforced Conductor
CENS	Cost of Energy Not Supplied
CHPP	Central Heating and Power Plant
DC	Direct Current
EIR	Electrical Installations Regulations
GOST	Russian Government Standart
HV	High Voltage
IED	Intelligent Electronic Devices
LTCA	Life-Time Cost Analysis
LV	Low Voltage
MO	Metal Oxide
MV	Medium Voltage
OC	Overcurrent
O&M	Operation and Maintenance
PID	Proportional Integral Derivative
PS	Power Substaton
RAO UES	United Energy System of Russian Federation
SAS	Substation Automation System
SCADA	Supervisory Control And Data Acquisition

1.Introduction

Within the framework of the approved program of development of Karelian Republic it is planned to build a number of factories and plants, which will mine and process minerals. In turn, it will increase the load on the existing electrical network. Therefore, in the framework of the regional development program it was decided to allocate funds for solving problems of electricity supply in the region. This problem includes providing of electricity to new customers and partial unloading of existing power substations.

The main aim of the master's thesis can be identified as selection of the substation structure according to techno - economical calculations. Moreover, it is also necessary to choose substation equipment, which will be the most suitable according to different operational modes.

1.1 Scope

The scope of this thesis is to study and develop methodology by which techno-economical dimensioning of primary substation in power system can be done.

The thesis considers existing power supply system and changes that should be done in the process of designing of new substation. The equipment that will be used in the substation is described. All necessary calculations are made, on the basis of which the equipment is selected according to state standards (GOST).

1.2 Objectives

Designing of a substation is a process, when you have to consider not only technical aspects of the issue, but economical aspects as well. This work considers the special features and parameters of power system that could finally affect a power substation.

The work address the following issues:

- Definition of optimal structure of power substation according to the investment cost, operational cost and reliability cost, in long run;

- Estimating techno-economic range of power substation structure depending on the total peak load of the area;
- Evaluating the effect of outage costs in techno-economic studies.

The second chapter of the work is focused on the techno-economic planning of electricity networks. The main principles of techno-economic planning are mentioned, and introduction into the life-time cost analyses is presented.

Chapter number three introduces primary substation planning process. Also the role of primary substation in the power system is described.

The fourth chapter considers a technical view on primary substation. The main components of primary substation are mentioned and described.

In chapter number five the case studies about substation design are presented. Methodology, which was already described, is adapted to the chosen region.

Chapter number six includes final conclusion.

2. Techno-economic planning of electricity network

2.1 Principles of electricity networks planning

Electricity distribution is experiencing changes now. Nowadays asset management and distribution business start playing a key role in electricity distribution. Because of that, more and more attention is paid to optimization-based investment policies and cost-based investment strategies, which are actively used in network planning and substation design.

The first thing that has to be learned is that rational strategy, which is used for case-environment, is the foundation for successful asset management. Correct strategy provides objective and diversified information, based on which it is possible to make more rational strategic decisions.

The foundation of a rational strategy is a well prepared and analyzed survey. The survey includes the list of factors, which could affect long-term strategy or final result of this strategy. The survey is always unique, because it takes into account unique properties of each region, conditions of distribution network, available resources. The survey, which might be used in case of a chosen network development, should include climate and landscape features, information about radial lines, primary substations, end-users, generation plants in the region. Thus, the voltage level of these elements, the fault statistics, peak power, forecasted peak power, amount of losses in the region's network, consumer group data should be mentioned. Moreover, in case of primary substations some extra data about main transformers, their amount, their capacity and load level should be provided.

The example of survey and strategic analyses is presented on figure 2.1. Based on the presented figure, it might be concluded that techno-economic choices and asset development are very dependent from the survey. That is why it is so important to use only accurate and verified information during survey creation.

In order to create an appropriate long-term strategy for further case-area development, the strategic analysis should be focused on the following questions:

- What are the main reasons of network system renovation? (appearance of new end-users, low system reliability, etc.)
- What are the techno-economic characteristics of different development methods?
- What are the alternatives? What are their techno-economic characteristics?
- What calculation parameters are used in the strategy process?
- What are the owners' intentions and what resources could be used for network development? [1]

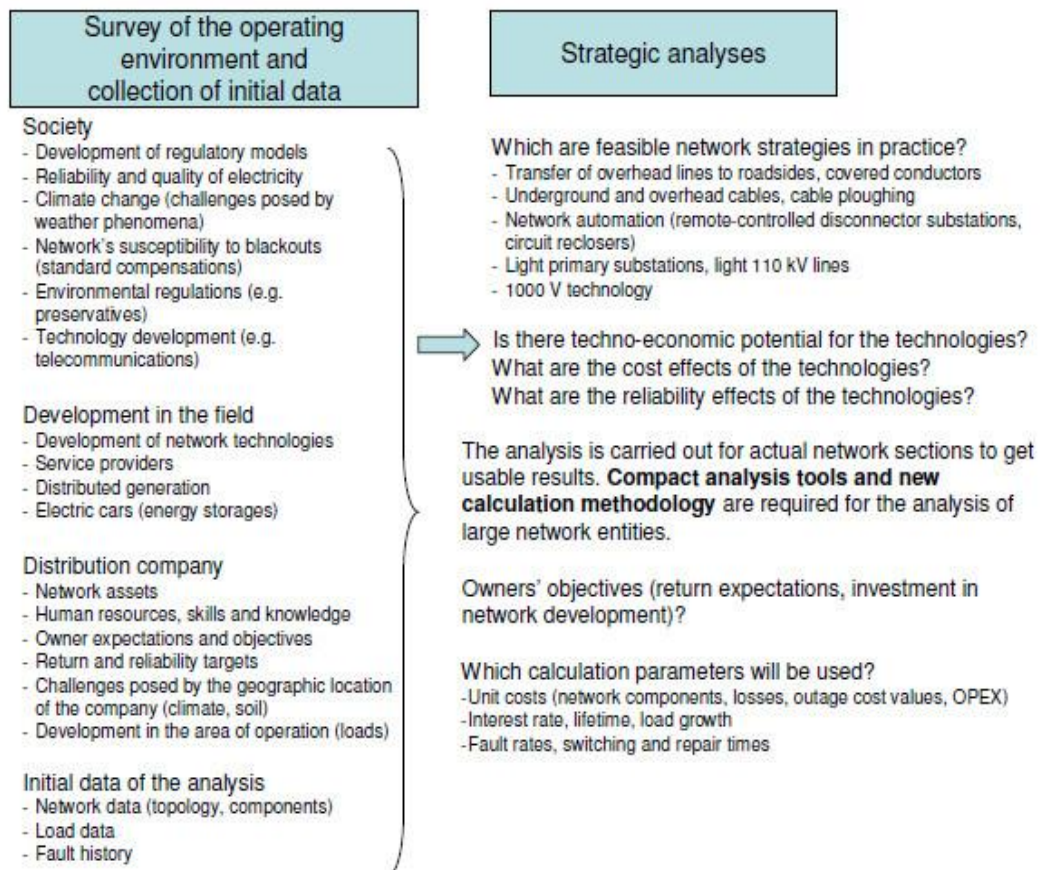


Figure 2.1. Survey and strategic analysis [1].

All possible technologies and alternatives should be compared during strategic analysis. For example, before making the analysis, the economic potential of new primary substation construction should be estimated in long-term perspective. Furthermore, all alternative solutions (as reconstruction of existing substations)

should be analyzed. The main purpose of techno-economic analysis is to find out what solutions have an economic ground for application. There are some tools, which might be used in order to estimate the potential of each solution. The final conclusion should be based on the results, obtained by different tools, which complement each other.

Thus, comparison of different solutions takes place during techno-economic analysis. One of the main criteria, by which evaluation is done, is reliability. The network reliability in case of a new primary substation construction should be compared with the network reliability in case of other alternatives. The main reason for it is that reliability directly effects on the outage cost. The outage tariff should be known in order to calculate the outage cost. These tariffs are defined by regulator and different for various electricity end-user groups. As far as outage cost calculations play one of the main roles in techno-economic analysis, the data for the case-area should be provided by accurate reliability statistics in order to avoid further mistakes and inaccuracies, which could affect some final conclusions.

Certainly, the reliability factor should not be considered as the only factor during substation design. One more target of a network strategy is to establish conditions for cost-efficient development actions. A big attention should be paid to factors, which are closely connected with changes in the network. Thus, the load growth forecast and increasing in number of end-users, which should be powered by new or reconstructed substation, should be included.

Among other things, the case-area analysis should also take into account challenges that will affect the network and constructed or reconstructed primary substations in the future. These things make techno-economic selection complex because of interconnections between each other. In order to develop appropriate strategy, the good knowledge in reliability effects of different network technologies and regulatory modeling has to be shown.

The example of network strategy process is presented on figure 2.2. The presented figure clearly demonstrates that the whole chain begins with strategic analysis. On the basis of strategic analysis, strategic decisions appear. When

strategic decisions are already known, the decision implementation starts. Finally, the conjunction of strategic decisions, which are in the process of implementation, creates a long-term plan.

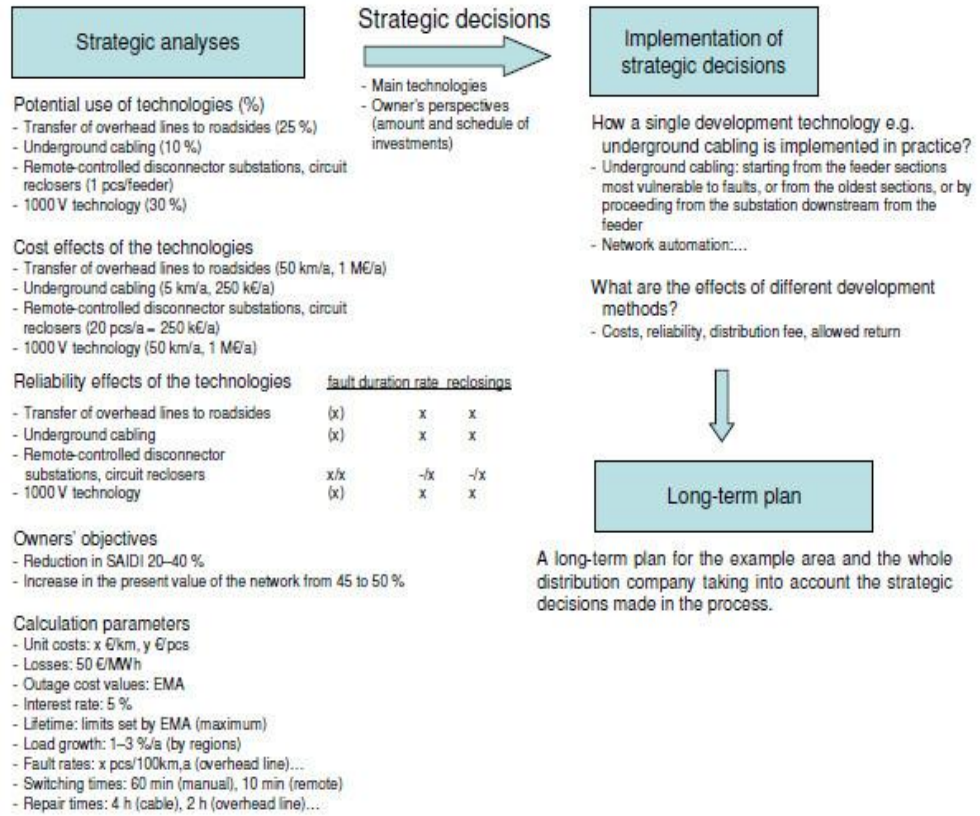


Figure 2.2. Network strategy process [1].

As a result of the analysis, the most cost-efficient network development solutions are defined. During strategic analysis, all alternatives of case-area development, including new substation construction, should be completely analyzed. If these solutions suits to the case-area boundary conditions, it is possible to go to the next stage of long-term planning.

The next stage of long-term planning is a strategic decision. Strategic decisions come from deep strategic analysis. All these decisions deal with complex interconnections, they are always unique, because they are always based on present posture of affairs. For instance, strategic decisions could be aimed at increasing the number of substations in the network or increasing the transformers' capacity of existing substations. In general, such strategic decisions as construction of a new primary substation or reconstruction of existing

substations should be more focused on long-term result than on short-term perspectives. Therefore, the life-time period under consideration in case-area should be more than few years, in order to achieve and compare long-term results; it will be equal to few decades.

When all strategic decisions are defined, the decision implementation stage starts. This stage of long-term planning should cover a problem of selected projects realizing. It means that in case of a new primary substation such issues as substation location, the capacity and amount of main transformers, busbar structure, and switchgear selection should be considered. Before a long-term plan will be created, an investment strategy of the project must be approved. Investment strategy also considers questions, how different solutions might be put into practice. It means that each solution has different variations of implementation and different investment strategies, which finally affects the total cost of the project.

The final stage of the network planning process is a long-term plan. In this stage the amount and schedule of investments should be determined. In other words, long-term planning consists of small tasks, which have a goal to minimize the total cost of power substation in long term. That is why losses, outage costs, maintenance costs, investment costs should be taken into account in case-area. The result of long-term planning is also based on forecast of network load growth. It might be not very accurate in perspective, but nevertheless it should be included.

2.2 Principles of life-time cost analysis in the network development

One of the tools, which is used in order to determine the most cost-effective solution from different alternatives is a life-time cost analysis (LTCA). In the optimal case-area development strategy such parameters as investment cost, load losses cost, no-load losses cost, outage cost, and maintenance cost should be completely analyzed. Some of them are lump-sum costs, but some of them are annual costs. The type of all mentioned above costs is presented on table 2.1.

Table 2.1 Types of LTCA components [2].

	Lump-sum	Annual
Load losses		X
No-load losses		X
Outage costs		X
Maintenance		X
Investments	X	

In order to compare the economic efficiency of different alternatives, all these costs have to be summarized and compared with each other. However, some of the costs refer to different types, therefore they can't be compared and summarized directly. The comparison might be done by two ways. The first one is to calculate the present value of investment cost during the whole period. The second way is to convert investment costs into annual costs, which are distributed among considered period.

2.2.1 Load losses in the network

The contribution of network load losses into the total amount of losses is significant. Load losses in the network are produced by resistance of the conductor to the current flow. These losses are proportional to resistance and quadratically proportional to load growth. Thus, bigger resistivity and bigger current produce higher losses in the radial line in case-environment. Simply, these losses might be calculated:

$$P_{loss} = 3 \cdot I^2 \cdot R \quad (2.1)$$

Since annual values can't be directly compared with lump-sum values, the load losses should be discounted to the present time. In order to do that, capitalization coefficient should be used.

$$k = \psi \frac{\psi^T - 1}{\psi - 1}; \quad (2.2)$$

$$\alpha = 1 + \frac{p}{100}; \quad (2.3)$$

$$\beta = 1 + \frac{r}{100}; \quad (2.4)$$

$$\psi = \frac{\beta^2}{\alpha} = \frac{\left(1 + \frac{r}{100}\right)^2}{1 + \frac{p}{100}}, \quad (2.5)$$

where k – capitalization coefficient;

r – annual load growth, %;

T – system lifetime period, years;

p – interest rate, %.

During load losses calculations, not only power losses in a radial line should be calculated, but energy losses as well:

$$P_{loss} = 3 \left(\frac{P}{U \cdot \cos \varphi} \right)^2 \cdot R, \quad (2.6)$$

where P – active load, kW;

U – nominal line voltage, kV;

$\cos \varphi$ – power factor;

R – line ohmic resistance, Ω

If power losses are already known, it is easy to calculate energy losses in the first year. It should be done by multiplication of power and peak operating time of losses:

$$W_{loss} = P_{loss} \cdot t_h, \quad (2.7)$$

where t_h – annual peak operating time, hours.

The lost cost is calculated as a sum of cost for power and energy losses:

$$C_{L0} = P_{loss} \cdot C_{P_{loss}} + W_{loss} \cdot C_{W_{loss}}, \quad (2.8)$$

where $C_{P_{loss}}$ – price of power losses, €/kW, a;

C_{Wloss} – price of power losses, €/kWh, a.

Knowing annual lost cost, it is easy to calculate lost cost during lifetime period:

$$C_L = k \cdot C_{L0} \quad (2.9)$$

2.2.2 Load and no-load losses of transformer

The role of main transformers and power substations is significant in the network. Thus, a main transformer is also a reason of some additional losses in the system. Therefore, optimal and required amount of transformers have to be carefully analyzed in order not to make some extra losses. Losses of transformer consist of load and no-load losses. These losses correspond to core losses and winding losses. Core losses are equal to no-load losses (P_0), winding losses are equal to short-circuit losses (P_k). They could be found from datasheet or nameplate of each transformer.

Firstly, annual no-load energy losses might be calculated like:

$$E_{L0} = P_0 \cdot 8760 \quad (2.10)$$

Thus, annual no-load lost cost is calculated:

$$C_{1L0} = P_0 \cdot C_{Ploss} + E_{L0} \cdot C_{Wloss} \quad (2.11)$$

Secondly, annuity value for considered lifetime period might be calculated:

$$C_0 = C_{1L0} \cdot \left[1 - \frac{1}{\left(1 + \frac{p}{100}\right)^T} \right] \cdot \frac{100}{p} \quad (2.12)$$

Load losses of transformer are quadratically proportional to load factor. If ratio of a load power to nominal power of transformer is too big, it will increase losses in the network. Therefore, the capacity of main transformers on power substation should be carefully selected.

Load losses can be calculated, if nominal power of transformer, power of the load and short-circuit losses are known:

$$P_L = \left(\frac{S}{S_n}\right)^2 \cdot P_k, \quad (2.13)$$

where S_n – nominal power of transformer, kVA;

S – power of the load, kVA.

The following calculations of load losses cost is identical to calculations, which were performed for the network in paragraph 2.2.1.

2.2.3 Outage cost

Outage cost calculations play one of the most important roles in network strategies. If there is a fault on power substation, a customer may experience significant losses due to breaks in production cycles or other kinds of harm caused by interruptions. In order to estimate harm from outages, the monetary value is used. The outage cost might be assessed by Cost of Energy not Supplied (CENS) model. CENS value varies by the type of fault and the type of consumer, which is powered by substation. Moreover, the tariff for not supplied energy is much higher than the tariff for purchased electricity because of possible damage and harm of end-user.

Determination of the amount and duration of faults, which occur in each element of power substation in the network, is one of the main aims of outage costs calculations in case environment. The reason of different outages might be different, and duration of interruptions varies because of that. For instance, interruptions on substation and in the network might be classified as long fault interruptions, planned maintenance outages, high-speed auto-reclosing and delayed auto-reclosing. Thus, the outage cost, which is caused by high-speed auto-reclosing, differs from the outage cost, which is caused by failure of the transformer, because the duration of interruption in these cases is different. Generally, the outage cost depends on the unit price of the outage, duration and number of faults, power and group of consumer.

Thus, the outage cost might be calculated by multiplication of forecasted interruption time and CENS value:

$$C_{out}(t) = \frac{W}{T} \cdot t \cdot \lambda \cdot h(t), \tag{2.14}$$

where $\frac{W}{T}$ – mean power of the reference period;

t – average repair time, hours;

λ – amount of faults per 1 km of line or 1 unit of equipment;

$h(t)$ – CENS, €/kW.

The outage cost values should be calculated independently from each other because each type of outage has different parameters. For instance, the outage cost of planned interruption on substation should be calculated separately from the outage cost of auto-reclosings. The example of outage cost calculations for a single supply area is presented on figure 2.3. As it might be concluded from the figure 2.3, the interruption time, cost of not supplied energy and annual amount of interruptions vary for different types of outages. Knowing all these mentioned parameters, it is easy to calculate the outage cost by using equation (2.14).

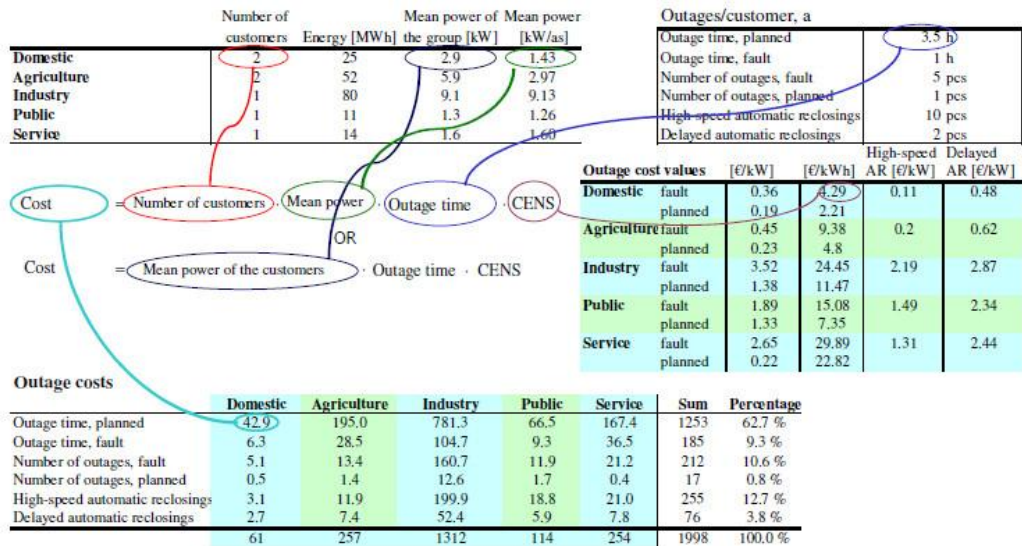


Figure 2.3. Calculation of outage costs [2].

The outage cost value during the whole life-time period can be calculated, if the present value and capitalization coefficient are known.

2.2.4 Investment cost

Power substation and their main transformers are the most expensive individual components of the network. The cost of main transformers depends on their capacity. The bigger unit is used, the higher cost it has. Thus, a deep analysis has to be made in order to select an appropriate capacity and amount of transformers. This analysis will help to minimize the investment cost of power substation as much as it is possible.

Investment costs of power substation should include not only costs, which are directly connected to substation construction (the cost of main transformers, switchgear, relay protection, automation, control system, auxiliary system, busbar system, current transformers and voltage transformers), but also labor, material, transportation cost should be included. Thus, investment cost might be calculated as a sum of all mentioned costs:

$$C_{inv} = C_{tr} + C_{sg} + C_{con} + C_{pa} + C_{ct} + C_{pt} + C_{other}, \quad (2.15)$$

where C_{tr} – cost of transformers, EUR;

C_{sg} – cost of switchgear, EUR;

C_{con} – cost of control system, EUR;

C_{pa} – cost of protection and automation system, EUR;

C_{ct} – cost of current transformers, EUR;

C_{pt} – cost of voltage transformers, EUR;

C_{other} – additional costs, EUR.

2.2.5 Maintenance cost.

Maintenance cost of power substation is spent to keep all objects and equipment in good conditions by regular checking and repairing it. During maintenance, some elements might be disconnected from the system. If some end-users have no backup supply and they are powered from a single substation, maintenance may cause planned outages.

Generally, the price of maintenance work is not constant. It varies from the type of object and equipment conditions. In practice, the direct correlation between equipments' cost and maintenance cost exists.

Maintenance and operational cost of a certain element during the whole life-time period might be calculated, if the present value and capitalization coefficient is known:

$$C_{OM} = k \cdot C_{OMobj}, \quad (2.16)$$

where k – capitalization factor;

C_{OMobj} – operational and maintenance cost of the element.

2.2.6 Sensitivity analysis

Sensitivity analysis is a final stage of life-time cost analysis. It helps to estimate, how input values or different variables might affect a designed substation. In order to reach optimal development strategy for the case-area, it should be determined, which substation structure is the most economical in the long run. To do that, changes in peak load of the area, unit prices for the harm of interruption, interest rate and load growth rate should be taken into account.

Thus, due to sensitivity analysis, it is possible to understand, how variation of input values will affect the final assessment, and to check different scenarios of further network development.

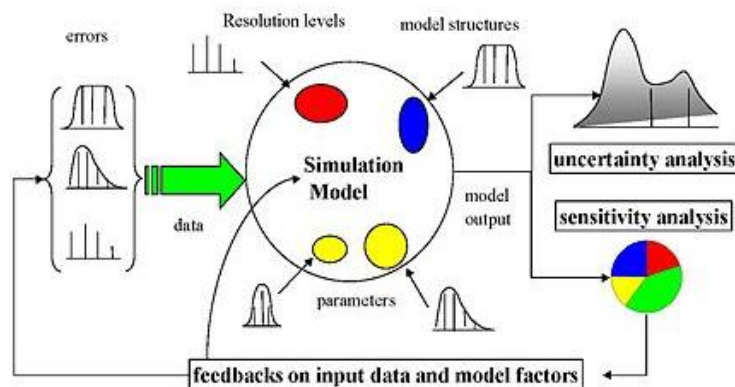


Figure 2.4. Sensitivity analysis [3].

3. Primary substation as a part of network planning process

3.1 Primary substation in a power system

There are different classifications of power substations, which might be used in network. They might be classified by their function, amount of transformers, total power and other parameters. Generally, power substations are used to control the power flow and supply quality in the grid. The main purpose of the equipment, which is used on substation, is to transform the voltage, protect the grid, and make all necessary switchings. Depending on the purpose served, power substations might be classified as:

- Step-up substations. This type of substations steps up the generated voltage to the voltage level, which is used to transmit the electric power.
- Primary substations. These substations receive the electric power, which is transmitted by three-phase overhead system. The transmitted voltage is then stepped down to appropriate voltage level.
- Secondary substations. These substations receive energy from the primary substation and step down the voltage level until the level, which is used at distribution substations.
- Distribution substation. This type of substations is constructed not far from consumers. The main function of these substations is to step down the voltage level to three-phase voltage, which is used in distribution network.

Figure 3.1 represents the structure of a power supply system with all mentioned above substations. Not all power supply schemes may include all these types of substations, and some of substations could be neglected.

Primary substations in a network are used to step down a high voltage level in order to supply secondary substations by lower voltage. Usually they use 110 kV or 220 kV voltage level. Generally, a primary substation includes a high-voltage busbar system, medium-voltage busbar system, auxiliary system, and one or several main transformers. In order to provide operational flexibility and to have more than one supply alternative, there might be several incoming radial lines [2].

As primary substations are used to improve the supply quality in a network, they should be capable of providing backup supply for neighboring primary substations. Thus, one or several main transformers should be able to provide a 10–30 % overloading capacity [7].

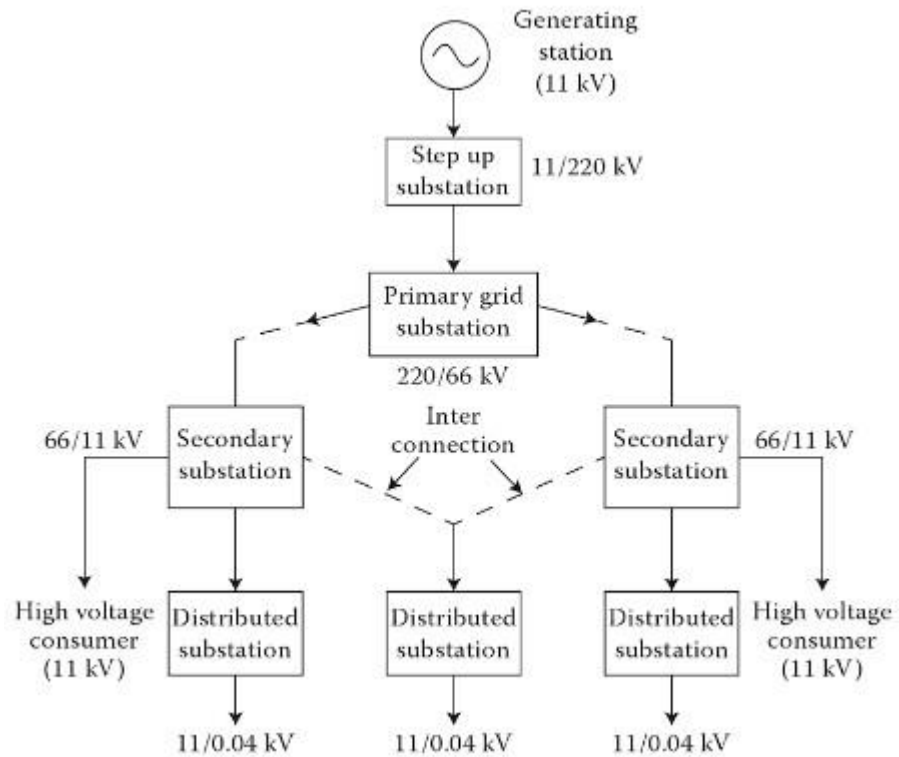


Figure 3.1. Power supply system [4].

3.2 Drivers for a new primary substation

One of the goals of techno-economic planning is to determine the most important needs (drivers) that require construction of a new primary substation. The most important reasons are presented on figure 3.2.

Often there are several reasons for a new substation investment. Thus, when people or business move to a new location, it produces a load growth in the region. However, it might be inefficient to supply new loads with a power from distant substations. If existing substations, even reconstructed, could not provide new loads with a power, the need in new substation will appear.

Moreover, a new primary substation construction could bring some benefits in reliability improvement. The main reason for that is reduction of the line length

downstream from the circuit breaker. Reliability is usually considerably improved, as the line length per circuit breaker may be cut into a half in many places. Thus, the primary substation is shown to the end-consumers by a reduced number of faults. Also the duration of faults per fault reduces slightly, as the time required for isolating the faults and switching on the backup supplies can be somewhat reduced [2].

Furthermore, primary substation occur a voltage level regulation. The network voltage level might be stepped up and stepped down a lot of times in power supply system. For instance, the power is transmitted from step up substations to primary substations, using high voltage ranges in order to decrease losses. However, a high voltage range should be reduced until medium voltage range to be used by secondary substations. Thus, a primary substation is used to transform the high voltage range into the medium voltage range.

In addition to a voltage level regulation, primary substation could control a power flow in a network. Usually a fault requires isolation of the line until the fault is disappeared. In order to break the power flow, circuit breakers are needed. Power substations contain circuit breakers, which allow controlling the power flow through substation.

New primary substation could also improve some network parameters by reducing a power factor value. In AC systems not only resistance, but also inductance, affect the power factor. Big inductance might be a reason of low power factor. In order to compensate inductance in electrical systems, capacitor banks are used. One of their advantages over other alternatives is that they might be installed in different parts of power system. For instance, capacitor banks might be installed on power substation in order to implement centralized control of the power factor in the electrical system. Capacitor banks might be also installed directly before the load, in order to adjust the power factor only on a certain load.

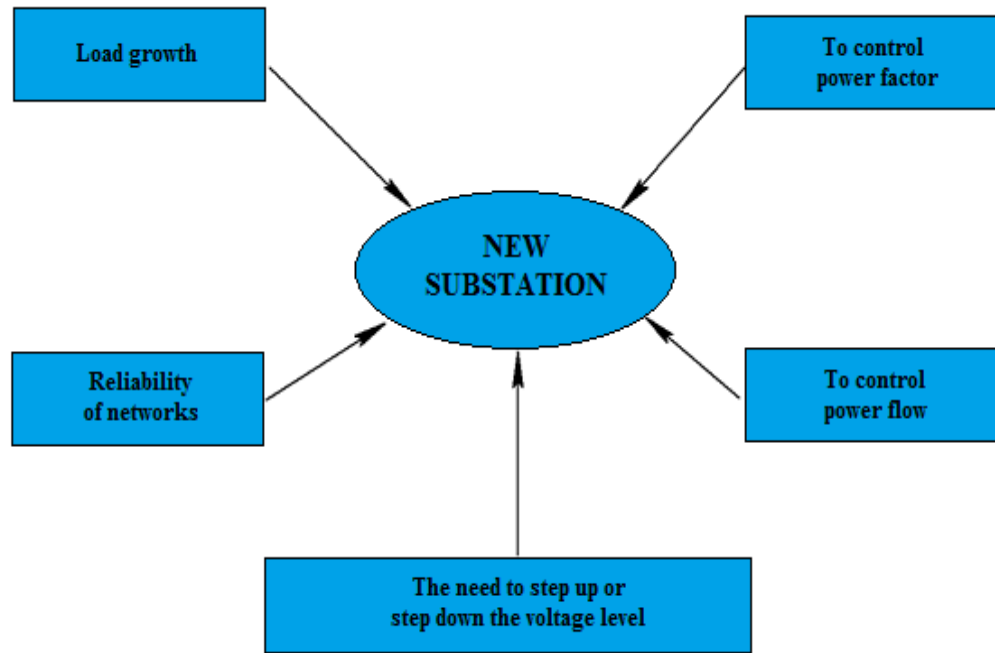


Figure 3.2. Drivers for a substation.

3.3 Substation planning

Substation planning might be represented by schematic decision tree diagram on figure 3.3. Decision tree diagram helps to sum up and compare different alternatives between each other.

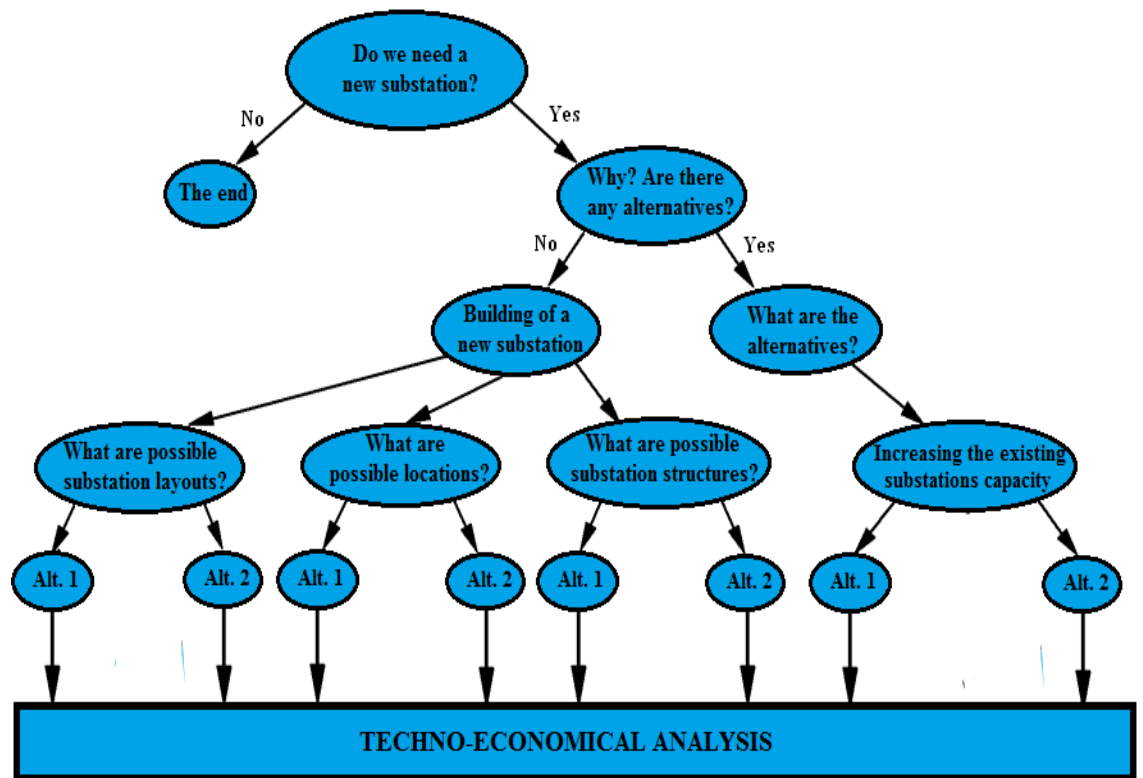


Figure 3.3. Decision tree diagram.

3.3.1 Location selection

Selection of a location is a very important part of substation design. Making site and location selection, parameters as type of substation, availability of chosen land, climate or nature conditions should be taken into account.

In order to choose an appropriate area for power substation, it is necessary to know the type of substation. For instance, to minimize transmission losses, it is more economically justified to build step up substation close to generating objects. However, step down substations should be constructed close to the load center in order to decrease the cost of distribution system and transmission losses. Thus, primary substations should be constructed near estimated load centers, taking into account forecasted load growth in the future.

Moreover, the preference should be given to areas with good accessibility because, in general, it is cheaper and easier to construct substation and maintain it

there. In order to prevent some operating problems in the future, substation should be protected from floodings, storms and other cataclysms.

3.3.2 Structure

Primary substations are divided by their structure into indoor and outdoor. A substation, in which equipment is installed inside the substation building, is called an indoor substation. This type needs less space and is more protected from different weather conditions. Indoor primary substations are more commonly used in urban areas or in some places, where substation is affected by adverse weather conditions. Because of space limitations, power equipment is usually put into a closed cubicle, filled with a gas (SF_6). This gas has better dielectric strength than air and helps to save some space. Thus, indoor primary substations have a higher cost and not as common as outdoor substations.

A primary substation, in which equipment is installed on the open air, is called outdoor. This type needs more space, because power equipment is air insulated. Outdoor substations need fewer investments, and it is easier to construct and maintain them in the future. They are more commonly used in rural areas, where substation is not affected by adverse weather conditions, and where there are not big space limitations.

3.3.3 Main transformers selection

Transformer selection is one of the main tasks in substation design. Thus, all requirements and parameters should be evaluated carefully to be sure that selected unit meets primary needs. In order to choose an appropriate transformer, there are some major factors that should be considered:

- The primary voltage level;
- The secondary voltage level;
- The operating frequency;
- The phase of primary and secondary voltage;
- The existing load and forecasted load growth;

- The type of required transformer (indoor or outdoor; auto transformer or another type of transformer and etc.).

On the basis that power transformer should provide transmission capacity for the lifetime period, selection of the appropriate unit is based on power flow through it. The size and number of transformers on primary substation should be technically and economically justified. Of course, in case of a big load growth during the whole lifetime period, some variants of substation reconstruction might be considered. During reconstruction, it is possible to change existing transformer on a bigger unit or increase the amount of transformers on primary substation. However, because of a big amount of extra expenses, this reconstruction should be also economically justified. In order to estimate the power of transformer, the following equation might be used:

$$S_n \cdot \cos\varphi > P \cdot \left(1 + \frac{r}{100}\right)^T, \quad (3.1)$$

where S_n – rated transformer capacity, kVA;

P – peak network power, kW;

$\cos\varphi$ – power factor;

r – annual load growth, %;

T – system lifetime period, years.

To conclude, the importance of transformer selection can't be overestimated. If chosen transformer has too small capacity, it will cause some overloading problems. Of course, each main transformer should be capable to operate in overloading mode, but extremely long or high overloadings could cause overheating and corresponding failure of transformer. At the same time, the main transformer of too big capacity will cause extra no-load losses in the grid and extra investments. Thus, the use of too big main transformers on primary substation is also not efficient.

3.3.4 Relay protection and automation

Protection relays and substation automation system on primary substation are used to control and protect primary assets during normal operation and fault conditions, making them vital to network reliability. In general, automation sequences include fault detection, localization, isolation, and load restoration. These sequences will detect a fault, localize it to a segment of feeder, and open the switches around the fault [4]. The main purpose of relay protection and automation is to keep the system stable by localizing and isolating only the damaged part of the system and protect power equipment from the damage. If it is possible, the protection and automation system will use a backup supply in order to feed the load.

Protection and automation system should be as effective as it is possible. Thus, they should provide all reliability, selectivity, speed and sensitivity requirements in order minimize the amount and duration of faults seen by the customer. Additionally, these systems could control equipment loading and determine, whether load transfers can safely take place.

3.4 Alternatives of the network development

The optimal development strategy, which might be used in case-area, usually considers a comparatively long time span period (about 40 – 50 years). The planning process produces directives for the action alternatives. All these alternatives might be implemented in order to develop the network. Another point is that these alternatives include various needs, have different technical features, reliability effects, capital cost. These network development alternatives start from construction of a new primary substation and end with construction of a new overhead line.

During the planning process, several alternatives in case-area have to be studied and compared. In this work the biggest attention will be paid to construction of a new primary substation and increasing the power of existing substations.

3.4.1 Increasing the power of existing substations

The first solution, which might be used in development strategy, is to increase the existing transformers capacity and reinforce power lines from existing substations to the chosen area. There are two main possible solutions, how to increase capacity of existing transformers. The first one is to replace existing transformers with new main transformers. The second one is to add parallel transformers on substation.

Before increasing the power of existing transformers, such factors as forecasted load growth, planned peak load, and transformer overload capacitance should be taken into account. The main characteristic of overload capacitance is a load factor.

$$k_l = \frac{S}{S_n}, \quad (3.2)$$

where S_n – rated transformer capacity, kVA;

S – peak network power, kVA.

Knowing the load factor, type of the transformer, and transformer cooling system, it is possible to estimate the maximum allowable operating time in an overload condition. GOST 14209-85 defines the allowable system overloads and emergency overload for various types of transformers.

In order to estimate required capacity of power transformers, it is necessary to refer to equation (3.1). In this case S_n will be equal to the total required capacity of primary substation. Total required capacity might be calculated as a sum of capacities of all main transformers on the primary substation.

Changes in number and nominal power of transformers lead to changes in load power losses, no-load losses, reliability, and maintenance cost. Moreover, there are some additional investment costs connected with replacement of equipment. In addition, during the period of work, some interruptions in electricity supply might be. Thus, all new losses values, new investment cost and outage cost should be included in techno-economical analysis in order to estimate this solution.

All these construction changes on primary substation lead to changes in total system impedance. Changes in transformers capacity and system impedance cause changes in short-circuit currents. In turn, it might be necessary to replace a part of power equipment.

3.4.2 Construction of a new primary substation

The second solution is to build a new primary substation with a reasonable size and number of transformers. Of course, primary substation is one of the most expensive components in the network. It needs a lot of investments, but its' effect on the network is really significant.

The amount and size of main transformers should be proved by techno-economical calculations. The main principles of transformers selection is similar to the principles, performed in paragraph 3.4.1. In general, the main task is to find a balance between reliability and total investment cost because there is a direct connection between them.

It should be noted that the size and number of main transformers has an effect on the medium-voltage network. After the construction of a new primary substation, the short-circuit currents will increase. In some cases, increase in short-circuit currents may cause a serious renovation of the medium-voltage network. Thus, it should be paid a lot of attention to this problem in network development strategy of each region.

A positive effect from primary substation construction is that it is possible to decrease the earth-fault currents in the network due to new primary substation. Because of that, it is possible to save some money on earthing devices. In case of a big primary substation with several transformers, the effects on the earth-fault currents and short-circuit withstand capacities has to be taken into account with respect to supply districts (Lakervi and Partanen, 2008).

Moreover, construction of a new primary substation helps to increase reliability, reduces investments resulting from the need for increasing transmission capacity of the medium-voltage network, and increases the power supply quality (Lakervi and Partanen, 2008). Thus, a new primary substation should be considered in

case-area development strategy not only as an object, which is necessary for the further development of the region, but also as an object, which could bring some economical profit.

4. Technical view on primary substation

Depending on their tasks and purposes, different primary substations have different requirements, features and layout. These things determine operational flexibility, supply reliability, security, short-circuit withstand capability, maintenance, operational and investment cost of primary substations. The selection of substation layout is based on features of case-area and techno-economical analysis.

4.1 Busbar structure

The main function of electrical bus of power substation is to collect and redistribute energy. The selection of a bus system depends on the voltage level, position of power substation, needed flexibility, and expensed cost. The chosen busbar system should provide desired simplicity and include provision of forecasted load growth.

In practice different variations of busbar structures are used in primary substations. Each of them has their own reliability and operational flexibility characteristics. Some of them provide a good reliability and flexibility, but they have a high investment cost. Some of them are used in cases, when just satisfactory reliability and flexibility is needed, and it is better to reduce investment cost of power system as much, as it is possible. Thus, the most common primary substation busbar structures are mentioned and described below.

4.1.1 Single busbar system

Single busbar system is the simplest bus system, which consists of one busbar for the full length of switchboard. Thus, all generators, transformers and feeders are connected to a single busbar. The main advantages of primary substation, which uses a single busbar system, are low initial cost, low maintenance cost, and simplicity. Nevertheless, good flexibility and high reliability are not provided for these substations. Moreover, when the fault occurs on a busbar, all the feeders are disconnected in order to isolate the fault. This system is usually used for single

transformer primary substation in areas, where good reliability and operational flexibility are not required.

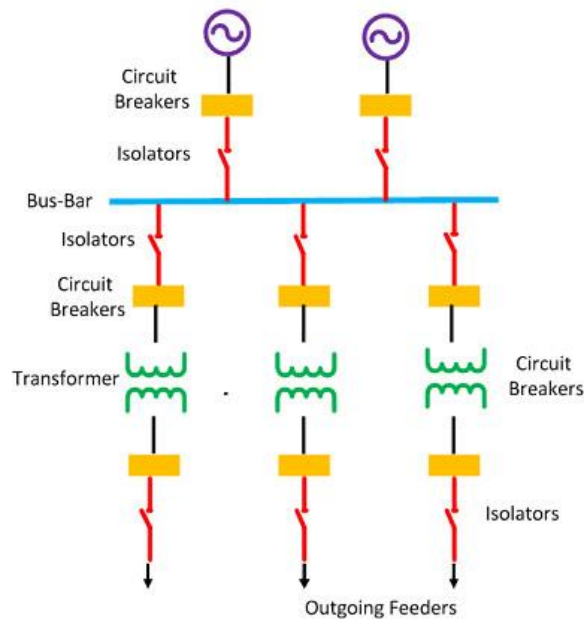


Figure 4.1. Single busbar system [5].

4.1.2 Single busbar system with bus sectionalizer

If there is a need in reliability increasing, a single busbar system might be sectionalized by additional circuit breaker with isolating switches. In general, it helps to decrease the amount of interruptions on primary substation because when a fault on a busbar occurs, it does not cause a complete shutdown of all feeders. Due to circuit breaker, only a damaged part of a single busbar is isolated. The amount of sectionalizers on primary substation is not limited. Of course, additional commutation equipment increases the total cost of primary substation, but it brings some advantages. For example, it becomes easier to isolate the fault on substation, it increases reliability of substation, and makes it simpler to maintain and repair one section of substation without affecting the supply of other sections.

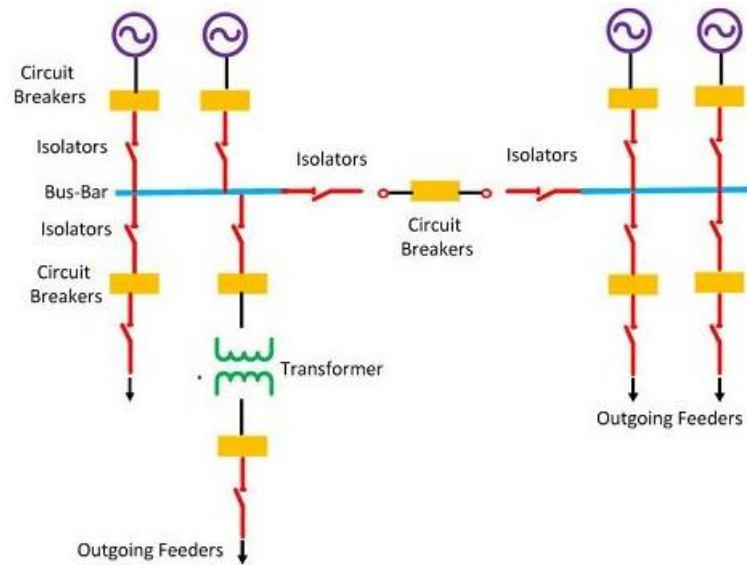


Figure 4.2. Single busbar system with bus sectionalizer [5].

4.1.3 Main and transfer busbar system

The advantage of main and transfer busbar system is that this system imply the use of two busbars in primary substation. Each generator or feeder might be connected to each bus with the help of bus coupler. In this system a bus coupler is used to change one busbar to another. This feature helps to continue supply in case of a failure of the main bus in substation, because the load might be transferred from generators to the reserve bus. Moreover, there would be no interruptions during repair or maintenance. Thus, using this system, it's easier to make maintenance cost of primary substation lower. Main and transfer busbar system is common in case of single transformer primary substations, which should provide a good reliability and operational flexibility. This system also might be used in case of two or more transformer primary substation because of its low investment cost.

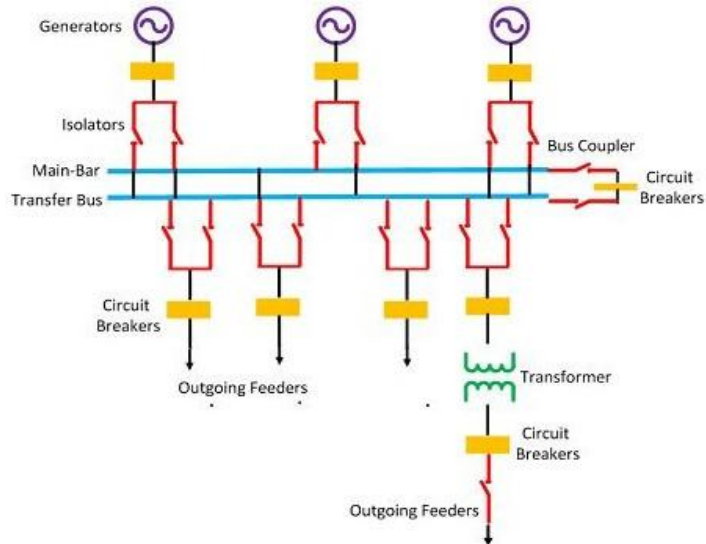


Figure 4.3. Main and transfer busbar scheme [5].

4.1.4 Double breaker busbar system

Double breaker busbar system consists of two absolutely identical busbars. Every feeder is connected through individual circuit breakers to both busses in parallel. Both busses are energized and all feeders are divided into two groups. Each of the group has their own supply busbar, but, due to individual circuit breakers, any feeder at any time might be switched to another bus. Primary substations, which use double breaker busbar scheme, provide maximum reliability and flexibility. The double breaker busbar scheme is usually used for two or more transformer primary substation, but because of its high cost, it's not very common.

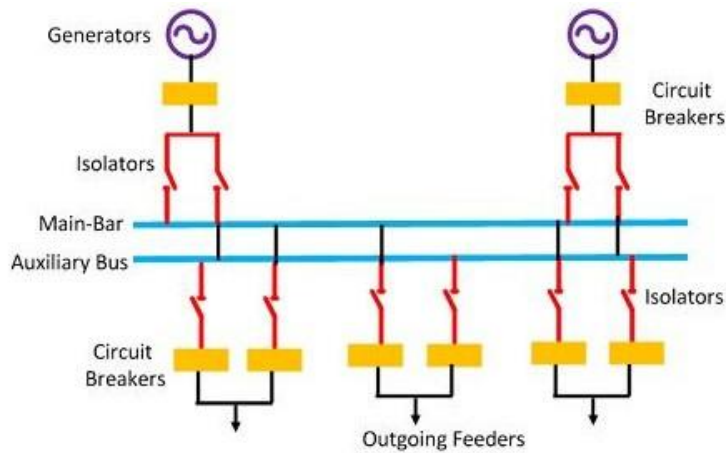


Figure 4.4. Double breaker busbar scheme [5].

4.1.5 One and a half breaker busbar scheme

One and a half breaker busbar scheme is an improved version of double breaker busbar scheme. The main difference from double breaker busbar scheme is that for two circuits only one spare breaker is provided. Two circuits have their associated breakers and one tie breaker, which acts as a connecting element for two feeders. In case of a failure of any feeder breaker, the power is fed through two other breakers.

This scheme is also used for two or more transformer primary substations, when high reliability is still compulsory, but the cost of primary substation should be reduced. The main disadvantage is that these primary substations are difficult in operation, and there might be some problems with this substation automation system.

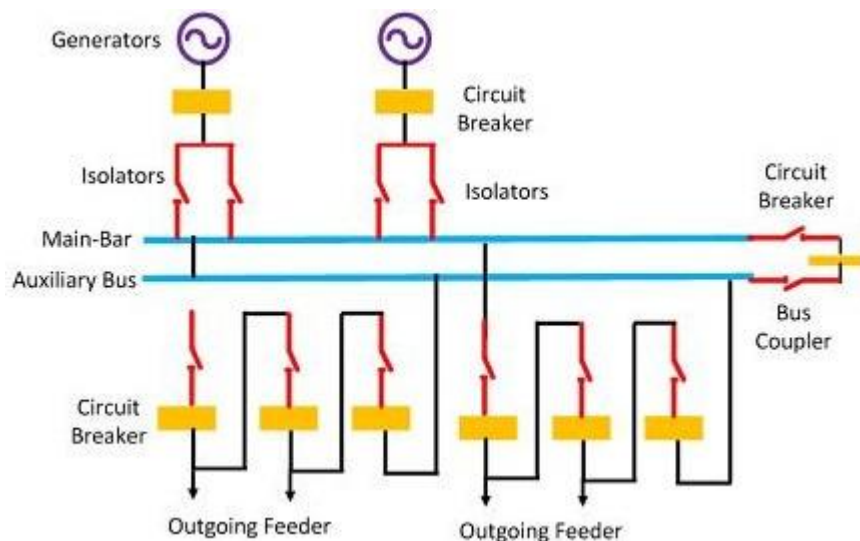


Figure 4.5. One and a half breaker busbar scheme [5].

4.1.6 Ring busbar system

The ring busbar system is a special kind of system, which is used for primary substations with many feeders. The main advantage of ring scheme is its flexibility, because each feeder has a double end power supply. It means that the failure, for instance, of the first energy source would not cause any interruptions. Moreover, due to the structure, the fault might be localized and isolated. The ring

structure makes it possible to maintain and repair circuit breakers on busbar without interruptions in the supply.

Unfortunately, this system is unsuitable for developing systems, because it is very complicated to add new circuits in the ring. One more drawback is that during maintenance of any circuit breaker in primary substation, the ring structure becomes opened. It decreases reliability of the system because at the moment of tripping of any breaker in the loop, interruption of power supply occurs between tripped breaker and open end of the loop [6].

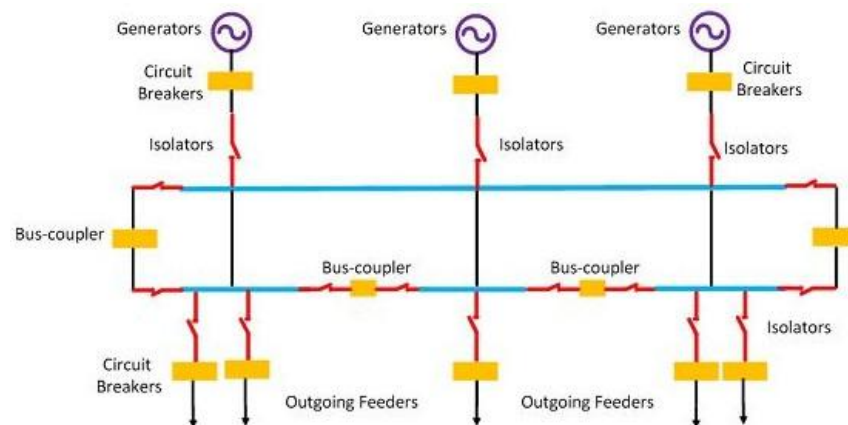


Figure 4.6. Ring busbar scheme [5].

4.1.7 Mesh busbar system

Mesh busbar system is also used in primary substations, which have many circuits. In this busbar system, the circuit breakers are located in the mesh, which is created by busbars. The scheme is tapped from the node point. This busbar system is operated by four circuit breakers. If a fault occurs on any section, two circuit breakers become open and isolate the fault. This busbar scheme is characterized by good operational flexibility. This system is not very popular in primary substations because of its difficulty. It demands a difficult protection and auto-reclosing system, which is not easy to install and operate with.

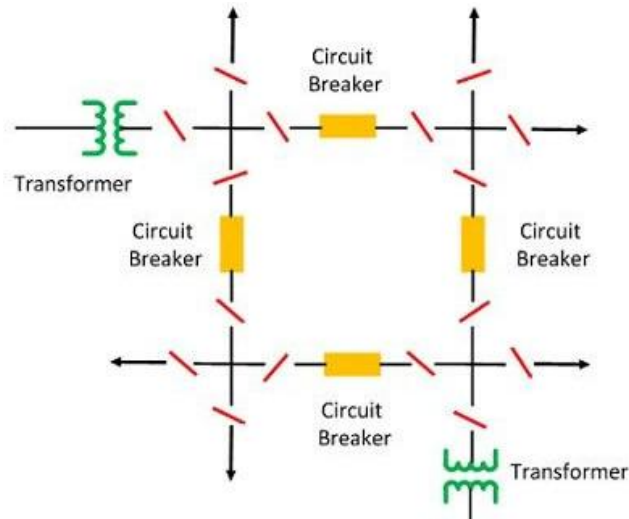


Figure 4.7. Mesh busbar scheme [5].

4.2 Main transformers

The function of main transformers on primary substation is to step-down incoming voltage to a suitable level. Power transformers make the biggest contribution to the total cost and represent to $\frac{2}{3}$ of the total substation cost. The amount of main transformers is selected according to each case-area features, but, in general, it is installed from one to six transformers on primary substations to convert incoming power [7]. The sum of all transformers capacities is equal to a substation's capacity.

4.2.1 Types and number of main transformers

The most common main transformers, which are used in usual regional and MV networks, are three-phase main transformers. The main reason is that the use of one three-phase transformer on primary substation instead of using three single-phase transformer units is more beneficial. One three-phase transformer needs less empty space, has lower losses and lower maintenance cost than three single-phase transformers of equivalent capacity. The type of transformer on primary substation is selected according to its application and case-area features. Sometimes when the load growth is expected in the future, some transformers might be installed without special additional cooling equipment (such as fans). If

the load peak creates the need, it will be possible to add such equipment and to boost the capacity of transformer [7].

There are a lot of special types of transformers, which are used to accommodate special requirements. For instance, for distribution applications it is often required to convert power to two voltage ranges. In this case three-winding transformers are used to provide three voltage levels for some substations and few loads nearby. Figure 4.8 shows a primary substation with three-winding transformer. One more very important special transformers type is low footprint transformer. It is used to be fit into substations, which were originally designed for smaller units. Another category is high impedance transformers, which are designed to limit fault currents. These transformers have a higher cost, but reduce fault currents and breaker requirements to appropriate levels.

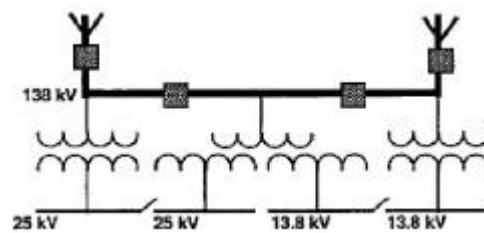


Figure 4.8. Substation with three-winding transformer. [7]

The majority of primary substation main transformers are delta-connected on the high side and either wye-connected on the low side. If power transformer has a big capacity, wye-connection is utilized in order to decrease linear currents on the low side. The same rules are also used for three-winding transformers. The majority of three-winding transformers also have delta-connection scheme on the high voltage side. If it is needed to decrease linear current on medium-voltage or low-voltage side, wye-connection might be used.

As it was mentioned, primary substations vary by the amount of transformers. Each variation has advantages and disadvantages. For instance, a substation with a single transformer will be unable to provide a supply, if this transformer fails. A substation with two or more transformers could still function in case of a failure of any transformer. Thus, the loading on remaining transformers could be increased, and they could operate for few hours before overheating.

Moreover, main transformers of big capacity (over 60 MVA) are costly and difficult to transport. Because of that, there are some economic reasons for using two or three transformers of smaller capacity instead of using a single transformer of greater capacity.

It should be noted that the forecasted load growth is not always accurate enough, and there might be a need in increasing transformers capacity. But, it is not easy to carry out for all types of substations. For example, the capacity of main transformers on primary substation, which is originally planned for multiple transformers, could be increased in stages by paralleling of additional transformer without serious reconstruction of primary substation. The reconstruction of a single transformer substation will take more time and investments.

Of course, single transformer primary substations also have some advantages. The investment cost of these substations is lower than multiple transformers investment cost. Moreover, it is easier to maintain single transformer substations.

4.2.2 Principles of transformers configuration

Main transformers on primary substation might be configured in different ways. In general, there are only few schemes of transformer configurations, which are used in practice.

Main transformers on primary substation should be applied as individual units with no direct connections, except connections to a common source. Moreover, paralleling of outgoing feeders is not recommended. It means that each low-side busbar should be operated separately. The main reasons for that are problems, which could lead to fault current loading, and problems with voltage regulation. Serial application is also not very common. According to technical and economical point of view, it is more beneficial to use a single transformer instead of two serial connected transformers. A serial connected configuration of main transformer and configuration with paralleled feeders are presented on figure 4.9.

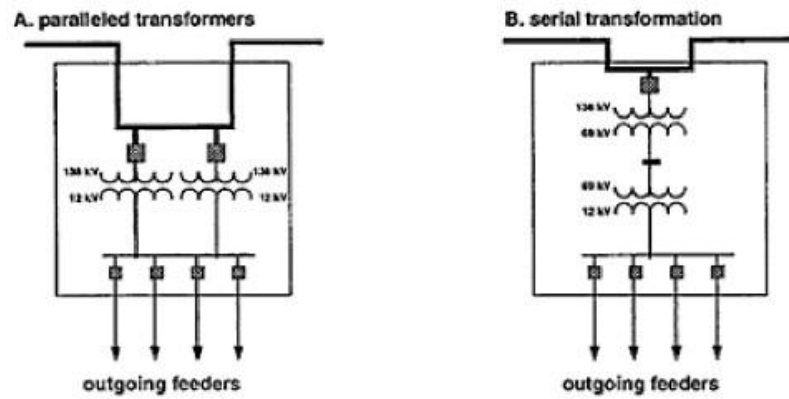


Figure 4.9. Transformers configurations: a) – with paralleled outgoing feeders; b) – serial connection. [7]

The most common configuration is presented on the figure 4.10. All transformers are fed from a common high-side bus, which is energized by two incoming transmission lines. Each low-side bus is sectionalized from the others. For repair and maintenance purposes all low-side buses could be connected to each other due to circuit breakers, which are normally in open state.

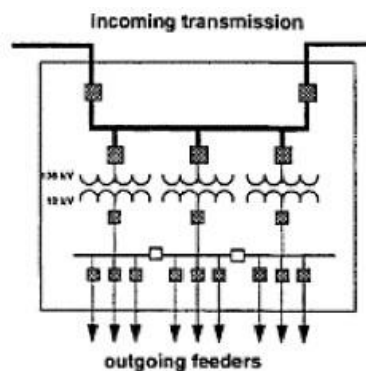


Figure 4.10. Usual configuration [7].

4.3 Instrument transformers

Instrument transformer is a necessary part of control, protection, and auxiliary system on primary substation. Instrument transformers are used in AC system to step-down the current and voltage to necessary level. On primary substations this level is usually 5 A or 1 A for current transformers and 110 V for voltage transformers.

The voltage and current level in power system is very high. Thus, it is more beneficial to use instrument transformers together with low-voltage and low-current measuring instruments, rather than to utilize high-voltage or high-current instruments.

In general, instrumental transformers on primary substation are usually used for measurement of electrical parameters and in complex with protective and control system. As it was noted, it is possible to use just one or several voltage and current ranges in primary substation. Thus, all measuring instruments could be standardized, which helps to decrease the cost of control and protection system. Furthermore, because of low current and voltage level, there is possible to achieve low power consumption of mentioned instruments.

Two main types of instrumental transformers, which are used on primary substation, are current transformers and voltage transformers. Both types are presented on figure 4.11.



Figure 4.11. 110 kV instrumental transformers: a) – current transformer; b) – voltage transformer [9].

4.3.1 Current transformers

The main purpose of current transformers in substation is to step down the primary current and to measure secondary current by smaller amperemeter. The primary winding of current transformer is connected in series with other

elements. The secondary winding is connected directly to amperemeter or another measuring instrument.

Usually current transformers on primary substation are installed in such a way that conductor or a bus play a role of primary winding. One of the most important characteristics of current transformer is a current ratio. It describes relationship between primary and secondary current in the transformer. In practice it is very important to have an accurate value of current ratio, because big discrepancies in current ratio could affect the work of primary substation.

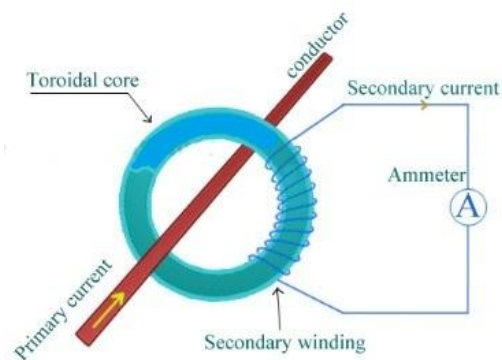


Figure 4.12. Principal scheme of current transformer [8].

Current transformers, which are used in primary substation, are selected according to the 7th edition of the Electrical Installations Regulations (EIR). The main requirements are operating voltage level, accuracy class, and thermal resistivity to thermal impulse during short circuit, and maximum normal operating current. Thus, it is possible to represent relationships between current transformer requirements and apparatus characteristics:

$$U_{ap} \leq U_{nom};$$

$$I_{max} \leq I_{nom};$$

$$B_t \leq I_{sc}^2 \cdot t_{imp},$$

where U_{ap} – apparatus voltage level, kV;

U_{nom} – primary winding voltage level, kV;

I_{max} – maximum normal operating current of electrical equipment, kA;

I_{nom} – nominal operating current of transformer, kA;

B_t – thermal resistivity to thermal impulse of transformer, $\text{kA}^2 \cdot \text{sec}$;

I_{sc} – maximum value of short-circuit current, kA;

t_{imp} – duration of thermal impulse, sec.

4.3.2 Voltage transformer

Voltage transformers are used to step down the voltage to a lower value to be measured by voltmeter or used by another instrument. Potential transformers are also classified by extremely accurate turns ratio. The primary winding of transformer should be connected across the line (usually between the line and the ground). In other words it is possible to say that this type of transformer is connected in parallel.

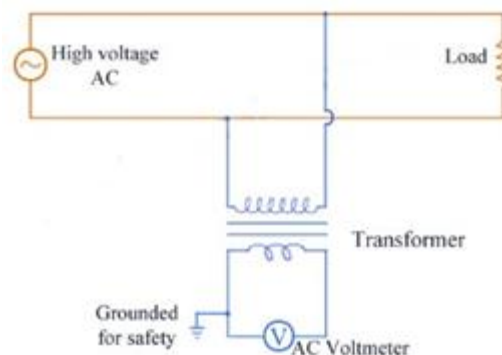


Figure 4.12. Principal scheme of voltage transformer [8].

Voltage transformers, which will be installed in a case-area primary substation, have their own selection requirements. According to the 7th edition of EIR, these transformers are selected according to the load, frequency, and operated voltage level. Moreover, they might be used in primary substation protection systems or other systems, which require very accurate current or voltage ratio. Therefore, voltage transformers should also provide a needed accuracy class.

Thus, the following criteria might be used:

$$U_{ap} \leq U_{nom};$$

$$S_{load} \leq S_{nom},$$

where S_{load} – power of the load, kVA;

S_{nom} – transformer capacity, kVA.

4.4 Protection

Sometimes primary substation could suffer from high currents, high voltages or other effects. In order to prevent a damage of electrical equipment, the protection system is used. All equipment, which is used in electrical system, has its own standardized ratings for withstand current and voltage. The main function of relay protection is to follow that these ratings should not be exceeded and to isolate the fault as soon as it's possible. In addition, protection system helps to avoid danger to stuff or public, and to minimize outages in power supply.

Protection system of primary substation is a complex system, which consists of protection relays, circuit breakers, fuses, auto reclosing system, and monitoring equipment. The level of protection of a primary substation is selected according to case-area features and determined by how critical the outage it to the end-user. In general, substations have overcurrent, overvoltage, and differential and distance protection systems.

A correctly designed protection system of primary substation has to meet special requirements. For example, a primary substation should be capable to operate in all allowable modes, and protection system should not make any kinds of interferes. Thus, a carefully developed protection system of primary substation should provide reliability, simplicity, selectivity, high operation speed, and to be not very expensive.

4.4.1 Overvoltage protection

If the voltage range on primary substation exceeds already defined voltage level, it may cause insulation breakdown and failure of power equipment. For example, the insulation failure of main transformers could cause long fault interruption and expensive transformer replacement. Thus, primary substations should be

protected from peak voltages. The main purpose of overvoltage protection is to reduce the stress, which is caused by overvoltage.

In order to reduce the stress and protect substation elements, in most cases spark gaps and surge arresters are used as the main protection equipment. These elements should be installed before the protected equipment in primary substation. Primary substations of small capacities and small transformers are usually protected by combined protection, which include a spark gap and metal oxide (MO) surge arrester in a single product. A combined protection operates in such a way that when a spark gap is ignited, surge arrester becomes conductive and discharges the overvoltage to ground. Moreover, spark gaps, which are installed together with surge arrester, help to prevent leakage current flow.

Overvoltage protection of HV substations and transformers with the rated power more than 200 kVA includes surge arresters without spark gaps. The use of this protection system on primary substations helps to reduce the number of auto reclosings and voltage dips [2]. Thus, it might be concluded that the use of MO surge arresters on primary substation helps to improve the quality of supply and decrease the risk of equipment failures due to climatic overvoltages.

The overvoltage protection in primary substations is usually used to protect the most important and expensive elements of substation. Thus, this system is usually used to protect main transformers, circuit breakers, busbar system and outgoing radial lines.

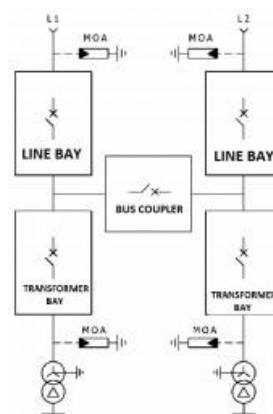


Figure 4.13. The principal scheme of overvoltage protection of power substation [10].

4.4.2 Overcurrent protection

Overcurrent protection plays a key role in protection of a whole substation. According to the statistics, short-circuit currents and earth fault currents are the most common type of failures in the network. In order to improve reliability of electrical system, the overcurrent protection is used. The main purpose of overcurrent protection is to prevent thermal damages caused by fault currents.

One of the key elements in overcurrent protection is an overcurrent (OC) relay. OC relay provides instantaneous tripping at a high value of current. OC relay operates, when the current exceed already established level. Most of overcurrent protection systems in primary substation react to fault currents and overload currents. In general, power equipment, switchgear, main transformers, busbar and conductors on primary substations are protected from overcurrents by fuses or circuit breakers.

The protection of LV components usually occurs by fuses, which are very cheap, but have strict borders of applications [2]. The main disadvantage of fuse protection is that it works just once. Thus, the element becomes shut down until the fuse wouldn't be changed. This principle is not very effective for primary substations. Consequently, in case of primary substations, the use of reclosers is more common. Reclosers are used to interrupt a huge current flow. They are more flexible in operation and could operate many times.

4.4.3 Differential protection

Differential protection system is a system, which protection principle is based on comparison of two electrical quantities. The main element of this system is a differential relay. The most common type of differential relays, which is used on primary substations, is an attraction armature type relay. This type of relay became very common in differential protection of primary substations because it has a high operational speed, and it is not highly affected by AC transients of power circuit.

Different electrical quantities might be compared in differential protection, but the most popular type of differential protection systems is a current differential

protection system. This type of system is mostly used to protect conductive elements of primary substation such as main transformers and busbar.

The operating principle of current differential protection system is described on the figure 4.14. A pair of current transformers is installed on each end of protected section. Two secondary windings of transformers are connected with each other by pilot wire in such a way to carry the induced current in the same direction. The operating coil of differential relay is connected across two pilot wires. When there is no fault current on protected section, the currents flowing through secondary winding of current transformers are equal to each other and there is no current through operating coil. If there is a fault on protected main transformer, for example, secondary currents start to flow in different directions, and the current will flow through differential relay.

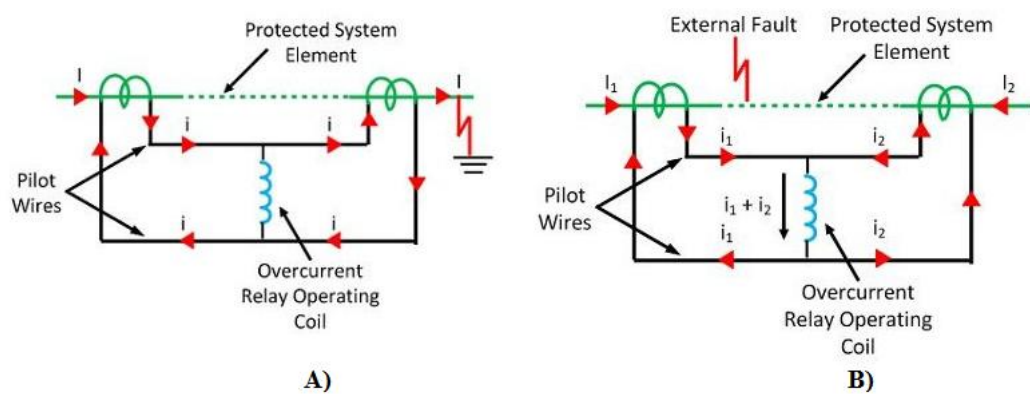


Figure 4.14. Differential protection principle. A) – a fault is outside protected section; B) – a fault is inside protected section [8].

In order to prevent false triggering of differential relays on primary substation, which could let to shut down of main transformers, current transformers should be the same (they should have the same current ratio and accuracy class). Otherwise, the current through differential relay might flow because of small differences in current ratio.

4.4.4 Distance protection

One of the functions of primary substations, which are constructed according to case-area requirements, is to protect outgoing radial lines from possible faults. In general, distance protection is used for that needs.

The principle of distance protection operation is based on impedance comparison. In fact, distance protection is equipped by impedance relay, voltage transformer and current transformer. Thanks to current and voltage transformer, it is possible to estimate the impedance of protected zone of radial line. If a fault occurs in protected zone, the impedance of these zones will decrease, and relay will operate.

Thus, if it is necessary to protect outgoing transmission line in case-area, the use of distance protection system is more preferable because this system is characterized by high operating speed (faster than overcurrent protection), high sensitivity and wide operating ranges.

4.5 Switchgear

Switchgear is a special type of equipment, which is used to control, protect and isolate electrical apparatus. Nowadays modern primary substations use remote-controlled switchgears, which helps to minimize the operating speed and reduce interruption time. The most common types of these switchgears, which might be used in primary substation, are remote controlled disconnectors and remote-controlled circuit breakers with protection relays. The use of remote-controlled disconnectors and circuit-breakers make it possible to utilize the full network capacity, which will decrease network investments in the long term.

4.5.1 Remote-controlled disconnector

In general, disconnectors are used to deenergize the chosen apparatus in primary substation from all possible sides. It should be noted that disconnectors do not interrupt a current flow (as circuit breakers do). They are used to make sure that the electrical equipment is completely de-energized.

The use of remote-controlled disconnector on primary substation helps to reduce the duration of interruptions, seen by end-users [2]. This advantage is achieved by remote control, which helps to avoid a time-consuming manual control. For example, if it is a failure on primary substation, and it is needed to switch backup supply connection, remote-controlled disconnectors will deenergize the damaged part, which is already isolated, and energize a backup connection part. Thus, the

duration of interruption and outage cost will be decreased by remote-controlled disconnectors. The example of HV remote-controlled disconnector is presented in figure 4.15.



Figure 4.15. HV remote-controlled disconnector [9].

Disconnectors on primary substation should be also chosen according to special requirements. Thus, as stated in EIR, the normal operating conditions of apparatus (voltage and current) should be higher or equal to the maximum normal conditions of primary substation. The verification of selected disconnectors should be made according to thermal and dynamical influence of short-circuit currents because a switchgear should be capable to withstand this influence during short-circuit. Consequently, it is possible to represent all these requirements as:

$$U_{ap} \leq U_{nom};$$

$$I_{max} \leq I_{nom};$$

$$B_t \leq I_{sc}^2 \cdot t_{imp};$$

$$i_{pc} \leq i_{dyn},$$

where i_{pc} – peak current during short-circuit, kA;

i_{dyn} – maximum allowable electrodynamic current of disconnector, kA.

4.5.2 Remote-controlled circuit-breaker with protection relay

The remote-controlled circuit-breaker with protection relay (recloser) is used to control the power flow through primary substation, and to protect apparatus from overloading, faults and short-circuit currents. The use of reclosers also decreases the number and duration of interruptions seen by end-user. The main reason for it is that recloser could isolate the fault, and the user upstream the recloser will not experience any problems connected with a fault or short-circuit currents.

In order to break a circuit, huge currents should be interrupted. During current interruption, an electric arc occurs between contacts of switchgear, which could damage electrical equipment. In order to prevent this damage, such isolators as SF₆ gas, vacuum, special oil and compressed air are used to interrupt the arc. All of them have different dielectric strength properties and different efficiency. Thus, due to a high efficiency and low maintenance cost of switchgear SF₆ gas and vacuum circuit-breakers are used in primary substations. The example of HV vacuum recloser is presented on figure 4.16.



Figure 4.16. HV vacuum recloser [9].

A lot of short-circuits clear themselves over a short period of time. Reclosers could energize the isolated part, if a fault is cleared. Thus, the use of reclosers in a primary substation makes it possible to significantly decrease the outage cost.

In general, circuit-breakers are selected according to case-area features. Circuit-breakers should be chosen based on normal operating current and voltage. Verification should be done according to thermal and dynamical influence of short-circuit current. Furthermore, a circuit-breaker should be capable of

interrupting the maximum possible value of short-circuit and earth-fault currents on substation. All mentioned criteria are presented below.

$$U_{ap} \leq U_{nom};$$

$$I_{max} \leq I_{nom};$$

$$B_t \leq I_{sc}^2 \cdot t_{imp};$$

$$i_{pc} \leq i_{dyn};$$

$$I_{sc} \leq I_{int},$$

where I_{int} – maximum possible current, which might be interrupted by circuit-breaker.

4.6 Automation

Control and automation system is used in order to provide a synchronous operation and control of all systems and apparatus in designed primary substation. In general, this system makes it possible to increase performance and reliability of designed protection system in primary substation.

The advantage of substation automation system (SAS) could be illustrated by a simple example. The recloser, which is installed in a primary substation, divides the line into two zones. If the fault appears in the zone, which is upstream the recloser, the whole circuit will be de-energised. As a result, there will be an interruption in power supply. In practice it will take some time to check loading data and to determine a fault location. Only after that a backup supply will be switched on. The automated system will receive a signal about de-energized circuit, and will re-energize the circuit automatically. Consequently, the interruption time and outage cost will be reduced.

Typically, SAS is based on data acquisition, supervision and control. Traditionally, primary substations use SCADA control system, which provide a real-time remote control. The advantage of this system is in possibility to monitor and control all processes on primary substations, using operator interface. The

supervisory control and data acquisition is occurred by PID controllers and logic controllers, which could operate with remote-controlled units of SAS.

The data acquisition and data collection in SCADA are provided by special sensors or intelligent electronic devices (IEDs), which are physically connected to primary substation apparatus. These sensors take data from reclosers, disconnectors, main transformers, busbars and send it to control center.

In a control room all received data is analyzed and monitored. The supervision of received information is occurred by supervisory computers or by substation personnel. Supervisory computers provide live data using graphs or diagrams. Thus, it is easier for substation personnel to monitor the status of substation.

The control of primary substation is occurred by microprocessors, programmable logic controllers, protective relays and remote-controlled circuit-breakers. The main principle of SCADA control is based on a feedback control loop. Thus, supervisory computer receives data from primary substation and try to adjust them, if it is necessary. Moreover, a feedback control is not absolutely automatical and, due to human machine interface, substation stuff could also control all commands, sent by supervisory computer.

Thus, data acquisition, power system supervision and power system control are working together and in coordinate with each other. In this case they produce a SAS, which could significantly increase substations protection system.

5. Case study

This part includes case studies about real example, to which all described methodology could be applied. Calculations include comparing and assessment of several alternatives.

5.1 Case-area overview

5.1.1 The region's network overview

For the case study, the Prionezsky region in Karelian Republic was chosen. This region is located in the North-West of Russia. The climate in the region is mild. There are no big industrial enterprises, which could pollute the atmosphere, in close proximity to the region. Thus, there is no need to protect switchgear from extreme climate or pollution conditions. Because of that the majority of power substations, which are used in the region, are outdoor type substations.

The case region belongs to the South-Karelian electric networks. A simplified network scheme of the region is presented on the figure 5.1. All network components, which have a voltage level less than 35 kV, are neglected on the scheme.

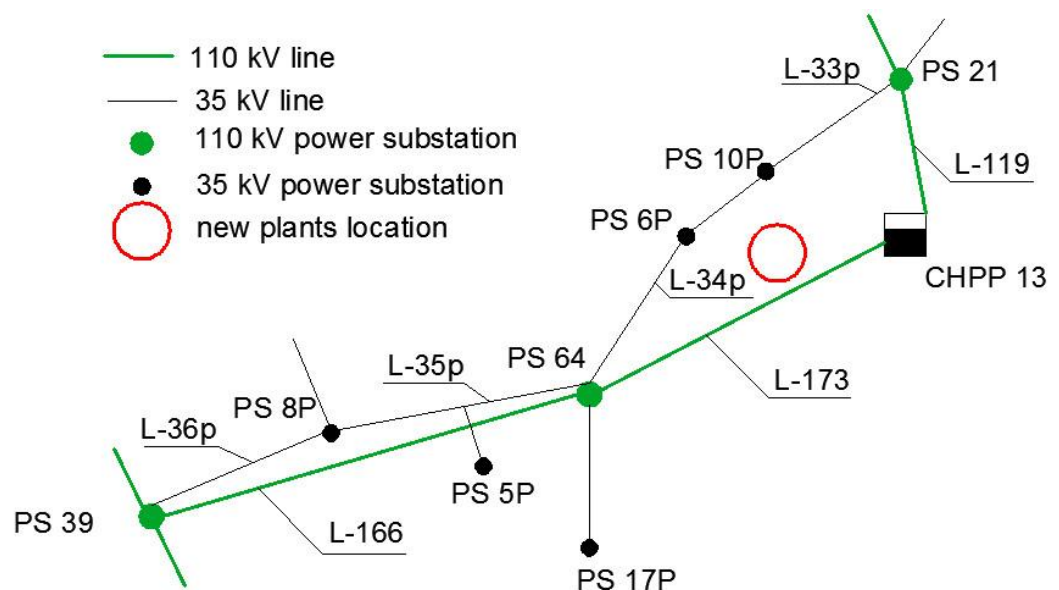


Figure 5.1. Scheme of the network

Based on the presented map, central heating and power plant (CHPP) is the main electrogenerating object in the region. According to the data, provided by federal energy supplying company RAO UES (United Energy Systems), the power of CHPP is 310 MVA. CHPP is a power source for several 110 kV overhead lines, which go through the whole region. 110 kV lines are highlighted with a green color, and 35 kV lines are highlighted with a black color. Power lines are made from aluminum steel reinforced conductor (ACSR). The additional information about them is presented on the table 5.1.

Table 5.1. Overhead lines

Power line	Length [km]	Cross-section [mm ²]
Line 173	48	120
Line 166	66	120
Line 119	18	120
Line 36p	24	95
Line 35p	37	95
Line 34p	25	95
Line 33p	36.9	95

The survey should also include some data about power substations in the region. The location of 110 kV and 35 kV substations is presented on the figure 5.1. Some of them have three voltage levels, and some of them have just two voltage levels. More detailed information about substations' power and voltage ranges is presented on the table 5.2

Table 5.2. Power substations

Power substation	Main transformers' capacity, MVA	Voltage ranges, kV
PS 39	2 x 16 MVA	110/35/10
PS 21	2 x 25 MVA	110/35/6
PS 8p	2 x 1 MVA	35/10
PS 64	2 x 25 MVA	110/35/10

PS 6p	2 x 1.6 MVA	35/10
PS 10p	2 x 2.5 MVA	35/10
PS 17p	2 x 4 MVA	35/10
PS 5p	2 x 1 MVA	35/6

The average annual load level of existing substations is in normal operating ranges (60–75%), but the load level of PS 64 and PS 21 is quite high. According to the data, provided by RAO UES, the annual load level of these substations is 96.3% and 82.8% respectively. The peak load is 53.8 MVA and 52.2 MVA respectively.

Prionezsky region combine different user groups. The majority of them relate to domestic and public user groups. The outage cost tariff for different types of outages will be defined according to the table 5.2.

Table 5.2. Unit costs for different customer groups [2]

Customer	Permanent faults		Planned interruptions		Auto-reclosings	
	€/kW	€/kWh	€/kW	€/kWh	High-speed €/kW	Delayed €/kW
Residential	0.36	4.29	0.19	2.21	0.11	0.48
Agriculture	0.45	9.38	0.23	4.8	0.2	0.62
Industry	3.52	24.45	1.38	11.47	2.19	2.87
Public	1.89	15.08	1.33	7.35	1.49	2.34
Service	2.65	29.89	0.22	22.82	1.31	2.44

5.1.2 Drivers for network development

In the nearest future a number of factories and plants would be constructed in Prionezsky region. The supposed location for the construction of industrial facilities is defined by red circle on the figure 5.1. According to RAO UES the peak load of supposed factories and plants will be 15.5 MVA. According to the data, presented on the table 5.2 and annual load level of existing substations, it might be assumed that existing substations couldn't power such a big load.

Moreover, one of the tasks of the project is unloading of existing substations PS 21 and PS 64. Thus, in order to provide the further load growth in the region, the

network should be developed. As alternative solutions of network development the construction of a new primary substation and reconstruction of existing substations might be considered.

5.1.3 Calculation parameters

The offered alternatives should be analyzed and compared in the project. Thus, in order to do that, such values as load growth, considering lifetime period, interest rate, network power factor, growth of consumption, and price of losses should be included in the survey. All the mentioned values and parameters are presented on the table 5.3.

Table 5.3. Calculation parameters

Parameter	Value
Lifetime, years	40
Time of load growth, years	15
Peak operating time losses, hours	2000
Interest rate, %	5
Power factor	0.95
Annual growth of consumption, %	1
Price of power losses, €/kW	30
Price of energy losses, €/kWh	0.03

5.2 Network development alternatives

The load growth in the region became one of the reasons for network development. There are several network development alternatives, which might be proposed. Thus, according to the figure 5.1 new loads might be powered by reconstructed substation PS 64 or by substation PS 21. The power supply might be implemented by new 35 kV lines (line 1 or line 2).

Another alternative is construction of a new primary substation. It is reasonable to locate a new substation not far from the future industrial facilities in order to decrease the amount of losses in the line. The power supply is planned to be

occurred by 35 kV line (line 3). All development alternatives are presented on the figure 5.2.

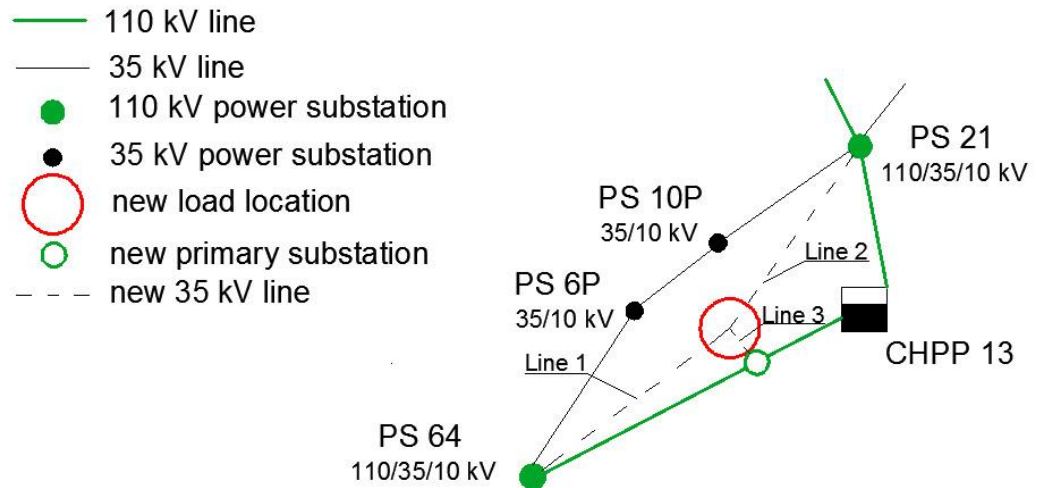


Figure 5.2. Development alternatives

In order to choose the most cost efficient solutions, all alternative should be analyzed. Figure 5.3 shows possible analysis's structure.

STRUCTURE OF ANALYSIS

A) Reconstruction of existing substations + new MV-lines



- 1) Techno-economic dimensioning of MV-lines
- 2) Defining the present value of substation, cost of losses, O&M cost, outage cost
- 3) Defining the investment cost of substation reconstruction, cost of losses, O&M cost, outage cost after reconstruction
- 4) Life-time cost analysis of reconstruction

B) Building of a new substation + new MV-lines



- 1) Techno-economic dimensioning of MV-lines
- 2) Techno-economic dimensioning of main transformers and busbar system selection
- 3) Defining the investment cost of a new substation, cost of losses, O&M cost, outage cost
- 4) Life-time cost analysis

Figure 5.3. Case study analysis

5.3 Reconstruction of PS 64

Reconstruction of PS 64 is the first possible solution. According to the RAO UES, this substation was constructed in 1980. It has two main transformers with a total capacity 50 MVA. There are two options to reconstruct existing substation.

The first one is to increase the amount of transformers on primary substation. The second one is to replace existing main transformers on transformer units with bigger capacity. Based on the features of PS 64 and data, provided by RAO UES, the increasing of the amount of transformers in this substation is difficult to occur. Thus, only replacing of existing transformers will be considered.

This project should also include construction of additional power line (line 1), which will power industrial facilities. The estimated length of the line 1 is 34 km.

5.3.1 Line dimensioning

In order to select a medium-voltage line, several factors as voltage drop, investment cost, cost of losses, and outage cost should be considered. One of the limiting factors of conductor cross-section selection is a voltage drop. The voltage drop in MV networks is not usually a result of technical restrictions, but the result of economic analysis. Sometimes too large voltage drop makes no problems to a customer (Lakervi, 2012). Nevertheless, if the voltage drop is too high, it means that cross-section should be increased in order to reduce power losses.

In three-phase AC systems the voltage drop might be easily calculated, if linear current, power factor, and conductor parameters are known:

$$\Delta U = \sqrt{3} \cdot I \cdot L (R_0 \cdot \cos\varphi + X_0 \cdot \sin\varphi), \quad (5.1)$$

where I – current in the line, A;

L – length of a line, km

R_0, X_0 – electrotechnical characteristics of conductor, Ω/km .

The amount of parallel lines in medium-voltage line can vary. The use of several parallel lines brings some advantages. For instance, it helps to decrease the current in each line. Thus, it becomes possible to use a conductor with a smaller cross-section. Usually parallel lines are installed on the same power line supports or in the same cable trench in order to reduce investment cost.

The comparison of possible alternatives is made by techno-economical calculations. The most economical solution in long run should be selected. The total cost of a line in long run is calculated based on the equation (5.2):

$$C_{line} = C_{invest} + k2 \cdot C_{loss} + k1 \cdot C_{out} + k3 \cdot C_{o\&m}, \quad (5.2)$$

where C_{invest} – investment cost of the line, €;

C_{loss} – cost of losses, €;

C_{out} – outage cost, €;

$C_{o\&m}$ – maintenance cost, €;

$k1, k2, k3$ – capitalization factors.

The typical interruption rates for MV lines are presented on the table 5.5. They were provided by Suur Savon Sähkö Distribution Company and summarized in (Haakana 2013). The designed line goes through the forest area. Thus, interruption ranges for this area are used.

The amount of planned outages is estimated as $\lambda_P = 0.03$ faults/km per year for overhead lines and $\lambda_P = 0.02$ faults/km for cable lines (Lassila, Partanen). The average duration of interruptions is presented on the table 5.6.

Thus, comparing power lines with different number of parallel conductors in it, it might be concluded that the average duration of interruptions and fault frequency are the same. The difference is in interrupted transmitted power, which is presented on the table 5.4. In case of several parallel conductors, interrupted power during a fault is several times smaller. As the result, the outage cost in case of several parallel conductors will also decrease.

Table 5.4. Blackouts probability

A number of parallel conductors	Single line	Two parallel lines	Three parallel lines	Four parallel Lines
Probability of the line for fault	λ_f	λ_f	λ_f	λ_f
Interrupted power during a fault	P_{tot}	$P_{tot}/2$	$P_{tot}/3$	$P_{tot}/4$

Table 5.5. Interruption rates

MV Line	Permanent faults, (faults/100km,a)	Automatic reclosing, (faults/100km,a)	
		High-speed	Delayed
Overhead line (OHL)			
Forest	10	21.9	30
Roadside	6	10.95	15
Field	1.3	4.38	6
Covered conductor (PAS)			
Forest	5	2.92	4
Roadside	2	2.19	3
Field	1	2.19	3
Underground cable (UC)			
UG cable	1	-	-

Table 5.6. Average interruption times for different number of power lines.

Time period	Abbreviation	Average time
Repair time	t_R	1.5 [h]
Switching time	t_S	0.5 [h]
Planned outage	t_P	0.5 [h]
High-speed automatic reclosing	t_{HSAR}	0.2 [sec]
Delayed automatic reclosing	t_{DAR}	2 [min]

Applying data from the tables 5.3 - 5.6, it is possible to calculate the total cost of a line, which will be used to power industrial facilities.

Assuming a local value of voltage drop $\Delta U = 5\%$ and applying equations (2.6) – (2.9), (2.1), (5.1), transmission limit for different types of conductor might be determined. Consequently, maximum allowed length for bare, covered conductors and underground cables are shown on figures 5.4 – 5.6. The maximum allowable length is calculated for different amount of parallel lines.

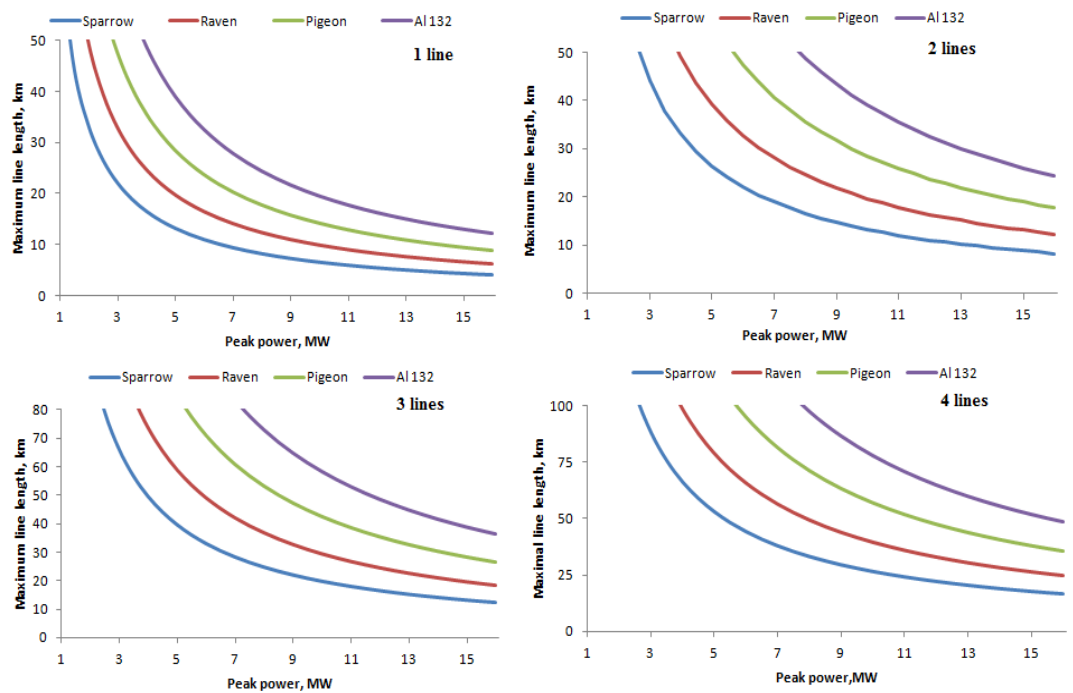


Figure 5.4. Maximum allowable path length for a bare conductor (voltage drop $\Delta U = 5\%$).

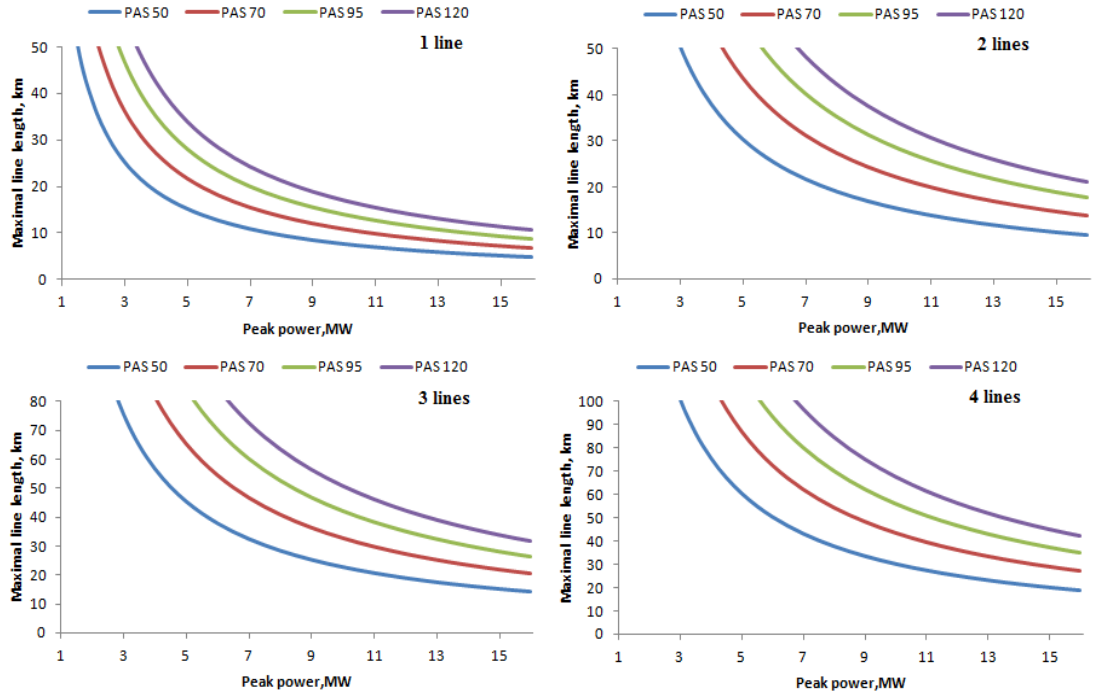


Figure 5.5. Maximum allowable path length for covered conductor (voltage drop $\Delta U = 5\%$).

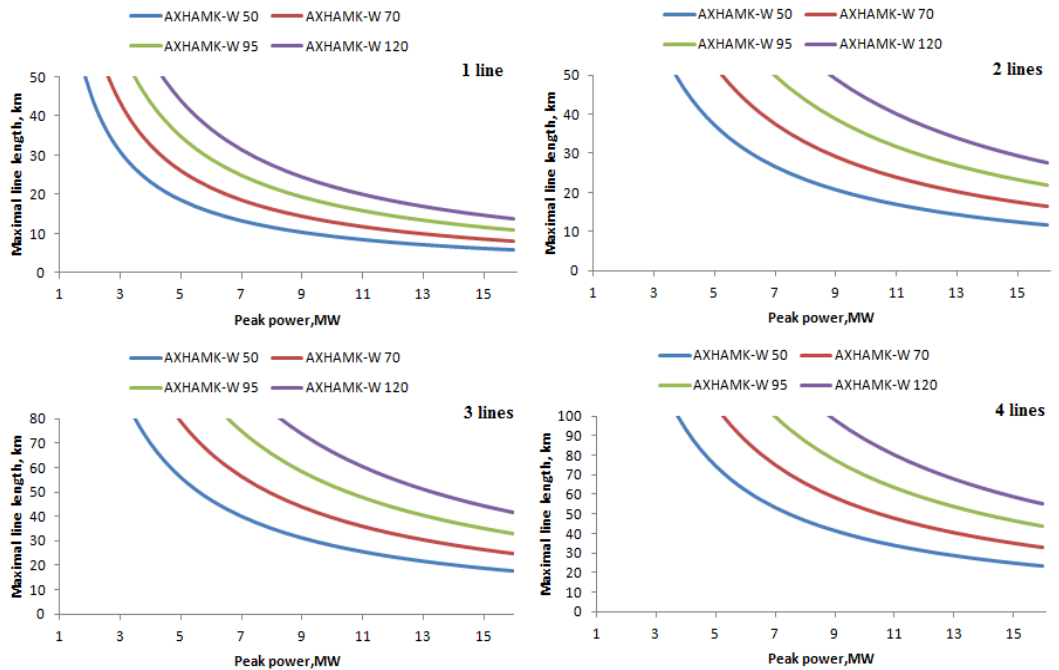


Figure 5.6. Maximum allowable path length for an underground cable (voltage drop $\Delta U = 5\%$).

According to information, provided by figures 5.2 – 5.4, there are just few alternatives of line type, which might be chosen according to voltage drop requirements. The estimated length of line 1 is 34 km. The chosen alternatives are provided in table 5.7.

Table.5.7. Different power line alternatives

Conductor	Number of lines	Maximal allowable line length, km	Maximal allowable transmitting power with line length 34 km, MW
Al 132	3	37.8	17.2
Al 132	4	50.4	22.9
Pigeon	4	36.8	16.7
PAS 95	4	36.3	16.6
PAS 120	4	43.8	20
AXHAMK-W 3x120	3	42.8	19.4
AXHAMK-W 3x120	4	57	25.9
AXHAMK-W 3x95	4	45	20.5

Alternative MV lines can be compared by limit curve method. This method helps to define economically optimal cross-sections. The comparison is made for similar line types.

$$S_0 \geq U \sqrt{\frac{C_{I,A2} - C_{I,A1}}{k2 \cdot C_{loss} \cdot (r_{A1} - r_{A2})}}, \quad (5.3)$$

where $C_{I,A1}$ – investment cost of the line 1;

$C_{I,A2}$ – investment cost of the line 2;

r_{A1} – resistance of the line 1, Ω/km ;

r_{A2} – resistance of the line 2, Ω/km .

According to the table 5.3 the considering lifetime period is 40 years, and annual load growth is assumed to be about 1 %. Nevertheless, it is not really justified to suppose a 1 % annual load growth during the whole period. Thus, it might be assumed that the real load growth will be only in first 15 years. After that the load level will be stable. In this case, capitalization coefficient might be calculated:

$$k = \psi_1 \frac{\psi_1^{t^*} - 1}{\psi_1 - 1} + \beta^{2t^*} \psi_2 \frac{\psi_2^{T-t^*} - 1}{\alpha^{t^*}(\psi_2 - 1)}, \quad (5.4)$$

where t^* – period of load growth, years;

T – lifetime period, years.

Based on equations (5.4) and (2.2) – (2.5) it is possible to calculate capitalization factor, which is applied for outage cost calculations during the whole lifetime period:

$$\psi_1 = \frac{\beta}{\alpha} = \frac{1 + \frac{r}{100}}{1 + \frac{p}{100}} = \frac{1 + \frac{1}{100}}{1 + \frac{5}{100}} = 0.962$$

$$\psi_2 = \frac{1}{\alpha} = 1 + \frac{p}{100} = 1 + \frac{5}{100} = 0.952$$

$$k_1 = 20.287$$

In order to calculate the present value of losses during the whole lifetime period, a special capitalization coefficient for losses calculations should be used. Based on equations (5.4) and (2.2) – (2.5) it is possible to calculate capitalization coefficient:

$$\psi_1 = \frac{\beta^2}{\alpha} = \frac{\left(1 + \frac{r}{100}\right)^2}{1 + \frac{p}{100}} = \frac{\left(1 + \frac{1}{100}\right)^2}{1 + \frac{5}{100}} = 0.972$$

$$\psi_2 = \frac{1}{\alpha} = 1 + \frac{p}{100} = 1 + \frac{5}{100} = 0.952$$

$$k2 = 21.135$$

Some factors (maintenance cost of equipment for example) are not dependent from annual load growth ($r = 0$). Based on equations (2.2) – (2.5) it is possible to calculate capitalization coefficient, which is used to determine maintenance cost of equipment during the whole considered period of time.

$$\alpha = 1 + \frac{p}{100} = 1 + \frac{5}{100} = 1.05$$

$$\beta = 1 + \frac{r}{100} = 1 + \frac{0}{100} = 1$$

$$\psi = \frac{\beta^2}{\alpha} = \frac{(1)^2}{1.05} = 0.952$$

$$k3 = \psi \frac{\psi^T - 1}{\psi - 1} = 0.952 \frac{0.952^T - 1}{0.952 - 1} = 17.159$$

Power lines, which consist of four Al 132 and four Pigeon conductors, might be compared between each other. The result is presented on the figure 5.7. According to the figure 5.7, when the load growth is 1 % annually, and the load is smaller than 21 MVA, it is more economically beneficial to use four Pigeon conductors.

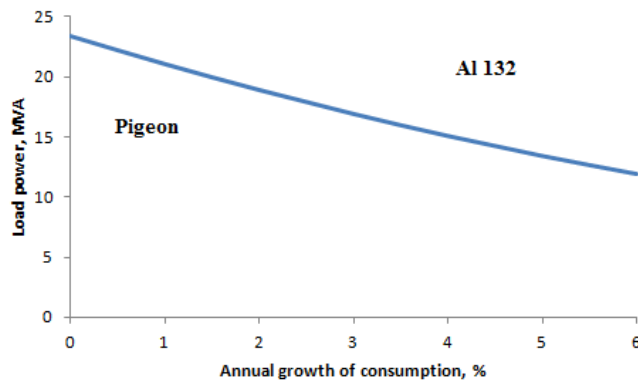


Figure 5.7. Limit curves for four parallel bare conductors (load growth period is 15 years).

Moreover, the comparison of a power line, made by four parallel PAS 95 and PAS 120 covered conductors, should be done. According to figure 5.8, when the annual load growth is 1 %, it is more economically justified to use four parallel PAS 95 conductors.

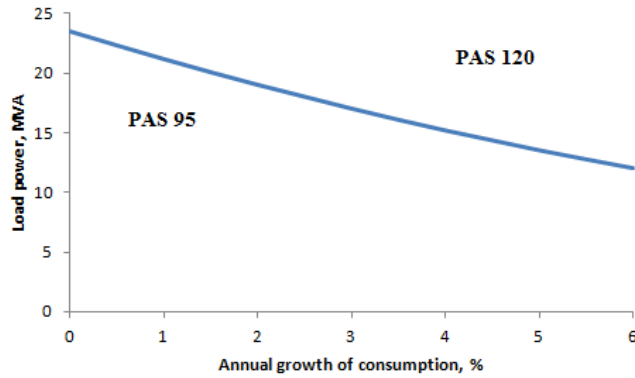


Figure 5.8. Limit curves for four parallel covered conductors (load growth period is 15 years).

On the figure 5.9 comparison of four parallel lines made by AXHAMK–W 3x95 and AXHAMK–W 3x120 cables is presented. According to the figure, it is more economically justified to use four parallel AXHAMK–W 3x95 cables in the case area.

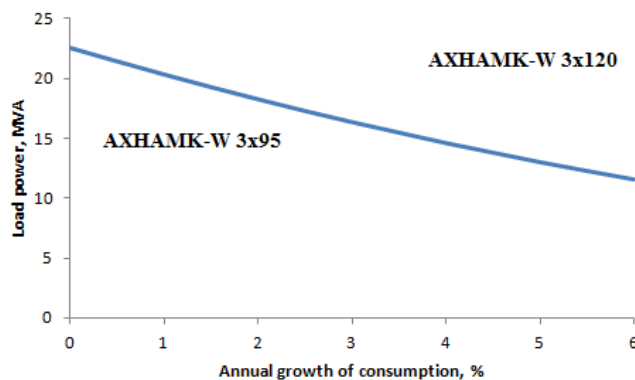


Figure 5.9. Limit curves for four parallel cables (load growth period is 15 years).

The value of power and energy losses plays a significant role in network planning. Applying equations (2.1) – (2.8) it is possible to calculate the annual cost of losses for each type of line. The cost of losses for a line, which consists of three parallel AXHAMK–W 3x120 cables, is presented below. All techno-economical parameters of conductors and lines are presented in appendix A.

The power is transmitted through three parallel cables. It is assumed that transmitting power is equally divided between all three conductors. Thus, currents in three cables are equal to each other:

$$I = \frac{P_{load}}{\sqrt{3} \cdot U \cdot \cos \varphi \cdot n_{conductors}} = \frac{14.75 \text{ MW}}{\sqrt{3} \cdot 35 \text{ kV} \cdot 0.95 \cdot 3} = 85.22 \text{ A}$$

Total power losses in a cable line are equal to sum of losses in each cable:

$$P_{loss} = 3 \cdot I^2 \cdot R_0 \cdot n_{conductors} = 3 \cdot (85.22 \text{ A})^2 \cdot 0.253 \text{ Ohm/km} \cdot 3 \\ = 16.54 \text{ kW/km}$$

$$W_{loss} = P_{loss} \cdot t_h = 16.54 \frac{\text{kW}}{\text{km}} \cdot 2000 \text{ h} \\ = 33.08 \frac{\text{MWh}}{\text{km}} / a$$

$$C_{L0} = P_{loss} \cdot C_{Ploss} + W_{loss} \cdot C_{Wloss} \\ = 16.54 \text{ kW/km} \cdot 30 \frac{\text{€}}{\text{kW}} + 33.08 \frac{\text{MWh}}{\text{km}} \cdot 0.03 \frac{\text{€}}{\text{kWh}} = \\ = 1.489 \left(\frac{\text{k€}}{\text{km}} \right) / a$$

The cost of losses during considered period equals:

$$C_{L1} = k2 \cdot C_{L0} = 21.135 \cdot 1.489 \frac{\text{k€}}{\text{km}} = 31.46 \frac{\text{k€}}{\text{km}}$$

Thus, the cost of losses in the whole line during considering period of time equals:

$$C_L = C_{L1} \cdot l = 31.46 \frac{\text{k€}}{\text{km}} \cdot 34 \text{ km} = 1069.6 \text{ k€}$$

The annual outage cost for industrial end-user is calculated by equation (2.14). The interruption rate and average interruption are taken from tables 5.5 and 5.6. According to the data, provided by supplying company, the estimated annual energy of industrial facilities is 96000 MWh. In case of three separate lines and loads, the fault of any line does not affect other lines. Thus, power supply interruption time equals to a switching time.

The outage cost for the underground cable line will be:

$$C_{out} = \frac{W}{T} \cdot t \cdot \lambda \cdot C(t) = \frac{1}{3} \cdot \frac{W}{T} \cdot l \cdot \left(\lambda_f \cdot (C_{fP} + C_{fE} \cdot t_s) \right),$$

where λ_f – fault rate of underground cable line, f/km ;

C_{fP} – CENS value, $\text{€}/kW$;

C_{fE} – CENS value, $\text{€}/kWh$;

t_s – switching time, hours;

l – line length, km.

$$\begin{aligned} C_{out} &= \frac{1}{3} \frac{96000 \text{ MWh}}{8760 \text{ h}} \cdot 34 \cdot \left(0.01 \frac{f}{km} \cdot \left(3.52 \frac{\text{€}}{kW} + 24.45 \frac{\text{€}}{kWh} \cdot 0.5 \text{ h} \right) \right) \\ &= 8.83 \text{ k€}/a \end{aligned}$$

The outage cost in long-term perspective:

$$C_{OUT} = C_{out} \cdot k1 = 8.83 \text{ k€} \cdot 20.287 = 179.3 \text{ k€}$$

The investment cost of the line consists of material cost and installation cost. During investment cost calculations, it is assumed that parallel conductors are constructed in the same cable trench or on the same power line support. Thus, investment cost of cable line, which consists of three parallel cables, is calculated:

$$C_{invest} = (C_{cabling} + n \cdot C_{cables}) \cdot l, \quad (5.5)$$

where $C_{cabling}$ – construction cost of a line, $\text{€}/km$;

C_{cables} – cost of cable, $\text{€}/km$;

n – amount of parallel cables;

l – cable line length, km .

The cabling cost depends on the environment, where cable line is installed. According to the data provided by Energy Market Authority, the cabling cost of 20 kV line in traditional environment is 24200 $\text{€}/km$. If the same cables are used on 35 kV voltage level, it will cause some investment cost increasing. According

to the report, which was provided by RAO UES, the investment cost will increase approximately by 7% [13]. Assuming that cables are installed in traditional environment, the investment cost will be:

$$C_{invest} = 1.07 \cdot \left(24200 \frac{\text{€}}{\text{km}} + 3 \cdot 29600 \frac{\text{€}}{\text{km}} \right) \cdot 34 = 4110.9 \text{ k€}$$

The O&M cost of overhead and cable lines is assumed to be 1 % from investment cost [11]. Thus, according to equation (2.20) the maintenance cost of overhead or cable line can be calculated:

$$C_{OM} = k3 \cdot C_{O\&MLine}, \quad (5.6)$$

where $C_{O\&MLine}$ – operational and maintenance cost of the line, k€.

$$C_{OMLine} = 17.159 \cdot 41.1 \text{ k€} = 705.4 \text{ k€}$$

Thus, using equation (5.2):

$$C_{line} = 4110.9 \text{ k€} + 1069.6 \text{ k€} + 179.3 \text{ k€} + 705.4 \text{ k€} = 6065.2 \text{ k€}$$

The comparison of different alternatives is provided in table 5.8. According to the analysis, the most economical justified solution is to construct a MV line, which is made by four parallel PAS 95 conductors.

Table 5.8. Life-time cost analysis of different MV lines.

Conductor	Construction cost of a single line, €/km	A number of lines	Investment cost, k€	Cost of losses, k€	Outage cost, k€	O&M cost, k€	Total cost, k€
Al 132	33000	3	1462,5	921,7	4519	251,0	7154
Pigeon	31200	4	1386,1	1069	3389	237,8	6082
PAS 95	35500	4	1867,8	1151	1695	320,5	5034
AXHAMK-W 3x120	57600	3	4110,9	1069,6	179,3	705,4	6065
AXHAMK-W 3x95	56200	4	4998,6	1065	134,5	857,7	7056

5.3.2 Substation calculations

The peak load of existing substation is approximately 50.2 MW (consumer group 1). The peak load of industrial facilities is approximately 14.8 MW (consumer group 2). It is assumed that peak load of group 1 and group 2 does not absolutely overlap each other. In this case, the total peak power of group 1 and group 2 is smaller than a sum of corresponding peak loads. Assuming that actual peak load

equals to 88 % of the sum of group 1 and group 2 peak loads, it might be concluded that reconstructed primary substation should be capable to power the new peak load.

$$P = 0.88 \cdot (P_1 + P_2) = 0.88 \cdot (50.2 \text{ MW} + 14.8 \text{ MW}) = 57.2 \text{ MW}$$

Based on equation (3.1) it is possible to estimate a needed transformers' capacity during long-term period. The considering life time is 40 years, but in order to estimate a needed transformers' capacity it will be assumed that the load growth will be only during first 15 years. In this case:

$$S_n \cdot \cos\varphi > P \cdot \left(1 + \frac{r}{100}\right)^T$$

$$S_n \cdot 0.95 > 57.2 \cdot \left(1 + \frac{1}{100}\right)^{15}$$

$$S_n \cdot 0.95 > 66.4 \text{ MW}$$

The nearest rated power of transformer, which satisfy all necessary requirements, is 40 MVA transformer. It means that the total capacity of PS 64 will be 80 MVA.

$$40 \text{ MVA} \cdot 2 \cdot 0.95 > 66.4 \text{ MW}$$

$$76 \text{ MW} > 66.4 \text{ MW};$$

The outage cost, cost of losses, O&M cost and investment cost before and after reconstruction should be compared in order to estimate the effect and total cost of reconstructed substation.

All technical and economical characteristics of main transformers are provided in appendix a.

First of all, the total cost of PS 64 should be calculated. Investment cost into PS 64 might be calculated by equation (2.15). The cost of power transformers, switchgear and current transformers make the biggest share into the total cost of primary substation. Thus, it is possible to neglect the cost of automation system, telecommunication system, relay protection, busbar system, surge arrestors and DC batteries in order to simplify further calculations. The PS 64 has a double

breaker-double bus busbar system with two transformers. This system consists of four circuit-breakers, ten disconnectors and eight current transformers. The cost of main transformers, circuit-breakers and disconnectors is provided in appendix A.

In order to do the life-time cost analysis, the actual substation's cost is needed. Using the present value of the network, it is possible to estimate substation's cost, taking into account age of the network. Present value depends on component's age, its lifetime and replacement value. In this case, the present value of primary substation is calculated:

$$C_{PV} = \left(1 - \frac{age}{lifetime}\right) \cdot RV, \quad (5.7)$$

where *age* – age of the network, years;

lifetime – techno-economical lifetime, years;

RV – replacement value of the network, €.

Replacement value of the network in case of primary substation consists of replacement value of main transformers, circuit-breakers, disconnectors and current transformers. Thus, equation (5.7) will look like:

$$C_{PV} = \left(1 - \frac{age}{lifetime}\right) \cdot (2 \cdot C_{MT} + 4 \cdot C_{CB} + 10 \cdot C_D + 8 \cdot C_{CT}),$$

where C_{MT} – replacement value of main transformer, €;

C_{CB} – replacement value of circuit-breakers, €;

C_D – replacement value of disconnectors, €;

C_{CT} – replacement value of current transformers, €.

PS 64 was constructed 37 years ago. In this case present value of the network equals:

$$\begin{aligned} C_{PV} &= \left(1 - \frac{37}{40}\right) \cdot (2 \cdot 338000 \text{ €} + 4 \cdot 49400 \text{ €} + 10 \cdot 2000 \text{ €} + 8 \cdot 22000 \text{ €}) \\ &= 80.25 \text{ k€} \end{aligned}$$

No-load transformers losses are calculated by (2.10) - (2.12) equations. No-load and load losses are equal to 28.5 kW and 140 kW respectively. Thus, cost of no-load losses in substation in long term is equal:

$$E_0 = 2 \cdot P_0 \cdot t = 2 \cdot 28.5 \text{ kW} \cdot 8760 \text{ h} = 499.3 \text{ MWh/a}$$

$$\begin{aligned} C_{1L0} &= 2 \cdot P_0 \cdot C_{Ploss} + E_0 \cdot C_{Wloss} \\ &= 2 \cdot 28.5 \text{ kW} \cdot 30 \frac{\text{€}}{\text{kW}} + 499.3 \text{ MWh} \cdot 0.03 \frac{\text{€}}{\text{kWh}} = \\ &= 16.69 \text{ k€}/a \end{aligned}$$

$$\begin{aligned} C_0 &= C_{1L0} \cdot \left[1 - \frac{1}{\left(1 + \frac{p}{100}\right)^T} \right] \cdot \frac{100}{p} = 16.69 \text{ k€} \cdot \left[1 - \frac{1}{\left(1 + \frac{5}{100}\right)^{40}} \right] \cdot \frac{100}{5} \\ &= 286.4 \text{ k€} \end{aligned}$$

Load losses in long term can be calculated by (2.9) and (2.13). In case of a two transformer substation load losses are calculated for a single transformer and then multiplied by two. The peak power in this case is divided equally between two transformers.

$$P_{LoadLosses} = 2 \cdot \left(\frac{S/2}{S_n}\right)^2 \cdot P_k = 2 \cdot \left(\frac{26.4 \cdot 10^3}{25 \cdot 10^3}\right)^2 \cdot 140 \cdot 10^3 = 312 \text{ kW}$$

$$W_{loss} = P_{LoadLosses} \cdot t_h = 312.2 \text{ kW} \cdot 2000 \text{ h} = 624.5 \text{ MWh/a}$$

$$\begin{aligned} C_{LoadLosses} &= P_{LoadLosses} \cdot C_{Ploss} + W_{loss} \cdot C_{Wloss} = \\ &= 312.2 \text{ kW} \cdot 30 \frac{\text{€}}{\text{kW}} + 624.5 \text{ MWh} \cdot 0.03 \frac{\text{€}}{\text{kWh}} = 28.1 \text{ k€}/a \end{aligned}$$

$$C_{LTot} = C_{LoadLosses} \cdot k2 = 28.1 \text{ k€} \cdot 21.135 = 594 \text{ k€}$$

The outage cost calculations is based on fault outages ranges, planned outage ranges, and reclosing ranges. The double breaker-double bus system provides good flexibility and reliability. The annual fault range of this busbar system is assumed to be $\lambda=0.00572$ faults/year (Nack D., 2015). The evaluation is done according to minimal cut-set method. This method takes into account failure rates of all elements, which could lead to outages (Nack D., 2015).

The probability of planned outages on this system is very small because of a system's reliability, double end power supply, and two main transformers in substation. Thus, planned outages might be not taken into account during outage calculations.

The duration of fault in case of a double breaker – double bus system is very short and equals to the duration of high-speed automatic reclosings.

The outage cost calculations should be done separately for different consumer groups. The total load of different consumer groups, which are supplied by PS 64, is presented on the table 5.9.

Table 5.9. Consumer groups before reconstruction.

Consumer group	Energy, MWh/a
Residential	118000
Agriculture	92000
Industry	61000
Public	32000
Service	21000

The annual outage cost can be calculated:

$$C_{out} = \frac{W_{res}}{T} \cdot \lambda_f \cdot C_{HS_{res}} + \frac{W_{agr}}{T} \cdot \lambda_f \cdot C_{HS_{agr}} + \frac{W_{ind}}{T} \cdot \lambda_f \cdot C_{HS_{ind}} + \frac{W_{pub}}{T} \cdot \lambda_f \cdot C_{HS_{pub}} + \frac{W_{ser}}{T} \cdot \lambda_f \cdot C_{HS_{ser}},$$

where $C_{HS_{res}}$, $C_{HS_{agr}}$, $C_{HS_{ind}}$, $C_{HS_{pub}}$, $C_{HS_{ser}}$ – CENS value for interruption caused by high-speed auto-reclosings for different consumer groups, €/kW;

λ_f – fault rate for double breaker double bus system, faults/years.

In this case the annual outage cost is calculated:

$$\begin{aligned}
C_{out} = & \frac{118000 \text{ MWh}}{8760 \text{ h}} \cdot 0.00572 \frac{\text{faults}}{\text{year}} \cdot 0.11 \frac{\text{€}}{\text{kW}} + \frac{92000 \text{ MWh}}{8760 \text{ h}} \\
& \cdot 0.00572 \frac{\text{faults}}{\text{year}} \cdot 0.2 \frac{\text{€}}{\text{kW}} + \frac{61000 \text{ MWh}}{8760 \text{ h}} \cdot 0.00572 \frac{\text{faults}}{\text{year}} \\
& \cdot 2.19 \frac{\text{€}}{\text{kW}} + \frac{32000 \text{ MWh}}{8760 \text{ h}} \cdot 0.00572 \frac{\text{faults}}{\text{year}} \cdot 1.49 \frac{\text{€}}{\text{kW}} \\
& + \frac{21000 \text{ MWh}}{8760 \text{ h}} \cdot 0.00572 \frac{\text{faults}}{\text{year}} \cdot 1.31 \frac{\text{€}}{\text{kW}} = 1.15 \text{ k€}/a
\end{aligned}$$

Thus, the outage cost in long perspective:

$$C_{TOTout} = C_{out} \cdot k1 = 1.15 \text{ k€} \cdot 20.287 = 23.4 \text{ k€}$$

The O&M cost of primary substation can be calculated by (2.16). Annual O&M cost of primary substation with two main transformers can be estimated as 3 % from investment cost of a primary substation [12].

$$C_{O\&MTOT} = C_{O\&M} \cdot k3 = 32.1 \text{ k€} \cdot 17.159 = 550.8 \text{ k€}$$

In a similar way it is possible to calculate the cost of reconstructed PS 64. The investment cost into reconstruction might be estimated as a cost of equipment plus the cost of the work related to reconstruction. In this case, the cost of this work is estimated as 10 % from the cost of equipment and switchgears [12]. The failure rates of 25 MVA and 40 MVA transformers are assumed to be the same. The power of different consumer groups is presented on the table 5.10.

Table 5.10. Consumer groups after reconstruction.

Consumer group	Energy, MWh/a
Residential	118000
Agriculture	92000
Industry	157000
Public	32000
Service	21000

All calculated costs of PS 64 before and after reconstruction are presented on the table 5.11.

Table 5.11. Life-time cost of a PS 64

	C investment, k€	C no-load losses, k€	C load losses, k€	C outages, k€	C o&m, k€	Total, k€
Before reconstruction	80,3	286,4	593,9	23,4	550,8	1535
After reconstruction	1617,0	391,9	429,4	41,5	756,9	3237
Effect from reconstruction	1536,8	105,5	-164,5	18,1	206,1	1702

According to the table 5.11 it can be concluded that some extra investments will be needed for reconstruction. Moreover, the outage cost, maintenance cost and cost of no-load losses on substation will increase. Nevertheless, substation load losses will decrease. Thus, in long term period the total cost of reconstructed substation will be 1702 k€.

5.4 Reconstruction of PS 21

The second possible alternative is PS 21 reconstruction. This primary substation was also built in the 1980s. The total capacity of two main transformers is 50 MVA. PS 21 was not designed to increase the amount of transformers in it. Consequently, replacing of transformers is the only one possible solution. The project includes building of a new MV line (line 2), which should power industrial facilities. The estimated length of line 2 is 30 km.

5.4.1 Line dimensioning

The dimensioning principle of line 2 is quite similar to dimensioning principle of line 1, which was described in 5.3.1 paragraph. According to the data provided by figures 5.4 – 5.6 estimated length of line 2 it is possible to select few MV line alternatives. The chosen alternatives are provided in table 5.12.

Table.5.12. Different power line alternatives

Conductor	Number of lines	Maximal allowable line length, km	Maximal allowable transmitting power with line length 30 km, MW
Al 132	3	37.8	19.5
Al 132	4	50.4	26
Pigeon	4	36.8	19
PAS 95	4	36.3	18.7
PAS 120	3	32.8	17
PAS 120	4	43.8	22.6
AXHAMK-W 3x120	3	42.8	22.1
AXHAMK-W 3x120	4	57	29.5
AXHAMK-W 3x95	3	33.8	17.5
AXHAMK-W 3x95	4	45	23.3
AXHAMK-W 3x70	4	33.9	17.5

Some alternative MV were compared by limit curve method previously. The result is presented on the figures 5.5 – 5.7. Nevertheless, some additional MV line alternatives should be also compared by the same method.

On the figure 5.10 comparison of three parallel lines made by AXHAMK–W 3x95 and AXHAMK–W 3x120 cables is presented. According to the figure, when the load growth equals to 1 % and load level is lower than 17.6 MVA, it is more economically justified to use three parallel AXHAMK–W 3x95 cables.

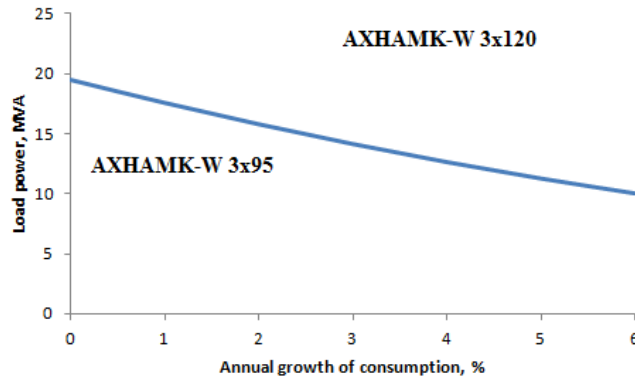


Figure 5.10. Limit curves for three parallel cables (load growth period is 15 years).

The next point is to compare four parallel lines made by AXHAMK–W 3x70, AXHAMK–W 3x95 and AXHAMK–W 3x120 between each other. The comparison of four parallel lines made by AXHAMK–W 3x95 and AXHAMK–W 3x120 cables was presented on the figure 5.7. According to the data, provided by this figure, the use of four parallel AXHAMK–W 3x95 cables is more economically justified in the case area. Thus, it might be concluded that it is possible to compare lines made by AXHAMK–W 3x70 and AXHAMK–W 3x95 cables. The comparison of these lines is presented on the figure 5.11.

The analysis of figure 5.11 shows that the use of four parallel AXHAMK–W 3x70 cable lines is more beneficial.

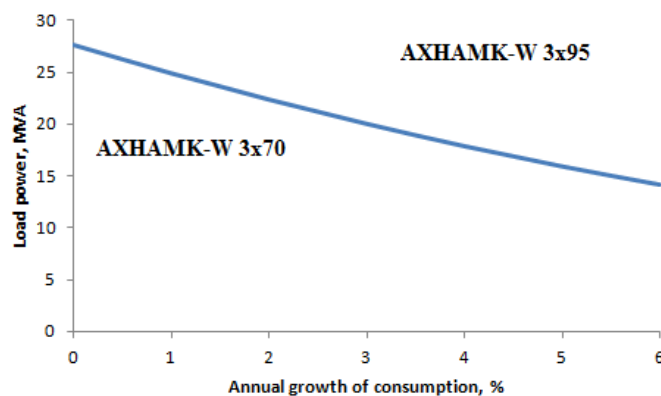


Figure 5.11. Limit curves for four parallel cables (load growth period is 15 years).

The result of life–time cost analysis for different MV lines is presented on the table 5.13. According to the analysis, the most economical justified solution is to construct a MV line, which is made by four parallel PAS 95 conductors.

Table 5.13. Life-time cost analysis of different MV lines.

Conductor	Construction cost of a single line, €/km	A number of lines	Investment cost, k€	Cost of losses, k€	Outage cost, k€	O&M cost, k€	Total cost, k€
Al 132	33000	3	1290,5	813,3	3987	221,4	6312
Pigeon	31200	4	1223,1	942,9	2991	209,9	5367
PAS 120	37600	3	1640,4	1074	1994	281,5	4990
PAS 95	35500	4	1648,1	1016	1495	282,8	4442
AXHAMK-W 3x95	56200	3	3502,2	1216	158,2	600,9	5477
AXHAMK-W 3x70	51900	4	3897	1248	118,6	668,7	5932

5.4.2 Substation calculations

Substation calculations of PS 21 are similar to calculations, presented in 5.3.2 paragraph. Thus, the peak load of PS 21 is 49.6 MW (consumer group 1). The peak load of industrial facilities is 14.8 MW (consumer group 2). It is assumed that peak load of group 1 and group 2 does not absolutely overlap each other. In this case, the total peak power of group 1 and group 2 is smaller than a sum of corresponding peak loads. Assuming that actual peak load equals to 89 % of the sum of group 1 and group 2 peak loads, it might be concluded that reconstructed primary substation should be capable to power the new peak load.

$$P = 0.89 \cdot (P_1 + P_2) = 0.89 \cdot (49.6 \text{ MW} + 14.8 \text{ MW}) = 57.3 \text{ MW}$$

A needed transformers' capacity during long-term period equals:

$$S_n \cdot \cos\varphi > P \cdot \left(1 + \frac{r}{100}\right)^T$$

$$S_n \cdot 0.95 > 57.3 \cdot \left(1 + \frac{1}{100}\right)^{15}$$

$$S_n \cdot 0.95 > 66.5 \text{ MW}$$

The nearest rated power of transformer, which satisfy all necessary requirements, is 40 MVA transformer. It means that the total capacity of PS 64 will be 80 MVA.

$$40 \text{ MVA} \cdot 2 \cdot 0.95 > 66.5 \text{ MW}$$

$$76 \text{ MW} > 66.5 \text{ MW}$$

The PS 21 has a double breaker-double bus busbar system with two transformers. Moreover, PS 21 has the same main transformers' capacity, as PS 64 has, and was also constructed in 1980. In this case the present value of PS 21 might be assumed to be the same as present value of PS 64.

The principle of load losses cost, no-load losses cost, outage cost, maintenance cost and investments cost calculations is similar to calculations provided for PS 64. Based on the data provided in tables 5.4 – 5.6 and 5.14 – 5.15 it is possible to make a life-time cost analysis of PS 21.

Table 5.14. Consumer groups before reconstruction.

Consumer group	Energy, MWh/a
Residential	123000
Agriculture	97000
Industry	54000
Public	30000
Service	15000

Table 5.15. Consumer groups after reconstruction.

Consumer group	Energy, MWh/a
Residential	123000
Agriculture	97000
Industry	150000
Public	30000
Service	15000

Table 5.16. Life-time cost of PS 21

	C investment, k€	C no-load losses, k€	C load losses, k€	C outages, k€	C o&m, k€	Total, k€
Before reconstruction	80,3	286,4	580,5	21,8	550,8	1520
After reconstruction	1617,0	391,9	432,3	39,9	756,9	3238
Effect from reconstruction	1536,8	105,5	-148,2	18,1	206,1	1718

According to the table 5.11 the outage cost, maintenance cost and cost of no-load losses on substation will increase. Furthermore, substation load losses will decrease. Thus, in long term period the total cost of reconstructed substation will be 1718 k€.

5.5 Reconstruction of PS 21 and PS 64.

One more possible alternative of network development is to reconstruct PS 21 and PS 64. It means that the total power of existing substations should be increased. The load of industrial facilities should be equally divided between two reconstructed substations. This solution will include constructing of two power lines from PS 64 and PS 21.

5.5.1 Line dimensioning

The principles of line dimensioning are similar to the principles, which were used in 5.3.1. and 5.4.1. Line 1 and line 2 should be dimensioned in order to supply a 7.36 MW load. Based on figures 5.2 – 5.5 several MV line alternatives can be considered. These alternatives are presented in table 5.17.

Table.5.17. Different power line alternatives

Conductor	Number of lines	Maximal allowable line length, km	Maximal allowable transmitting power with line length 30 km (34 km), MW
Pigeon	2	38.7	9.5 (8.4)
Pigeon	3	58.1	14.2 (12.6)
Pigeon	4	77.4	19 (16.8)
Al 132	2	53	13 (11.5)
Al 132	3	79.6	19.5 (17.2)
Al 132	4	106.1	26 (22.9)
Raven	3	40.1	9.8 (8.7)
Raven	4	53.5	13.1 (11.6)

Sparrow	4	36.1	8.8 (7.8)
PAS 50	3	30.9	7.6
PAS 50	4	41.2	10.1 (8.9)
PAS 70	3	44.4	10.9 (9.6)
PAS 70	4	59.2	14.5 (12.8)
PAS 95	2	38.2	9.4 (8.3)
PAS 95	3	57.3	14 (12.4)
PAS 95	4	76.5	18.8 (16.6)
PAS 120	2	46.1	11.3 (10)
PAS 120	3	69.2	17 (15)
PAS 120	4	92.3	22.6 (20)
AXHAMK-W 3x120	1	30	7.36
AXHAMK-W 3x120	2	60	14.7 (13)
AXHAMK-W 3x120	3	90	22.1 (19.5)
AXHAMK-W 3x120	4	120.1	29.5 (26)
AXHAMK-W 3x95	2	47.4	11.6 (10.3)
AXHAMK-W 3x95	3	71.1	17.4 (15.4)
AXHAMK-W 3x95	4	94.9	23.3 (20.5)
AXHAMK-W 3x70	2	35.7	8.8 (7.72)
AXHAMK-W 3x70	3	53.5	13.1 (11.6)
AXHAMK-W 3x70	4	71.4	17.5 (15.4)
AXHAMK-W 3x50	3	37.9	9.3 (8.21)
AXHAMK-W 3x50	4	50.6	12.4 (11)

Based on the limit curve method MV line alternatives are compared. The result of comparison is presented on figures 5.12 – 5.15. The limit curve analysis, which presents on figures 5.12, 5.13 and 5.15 can be implemented for line 1 (34 km) and

line 2 (30 km). Furthermore, because of its length, line 2 has more construction alternatives. The analysis of additional alternative is presented on figure 5.14.

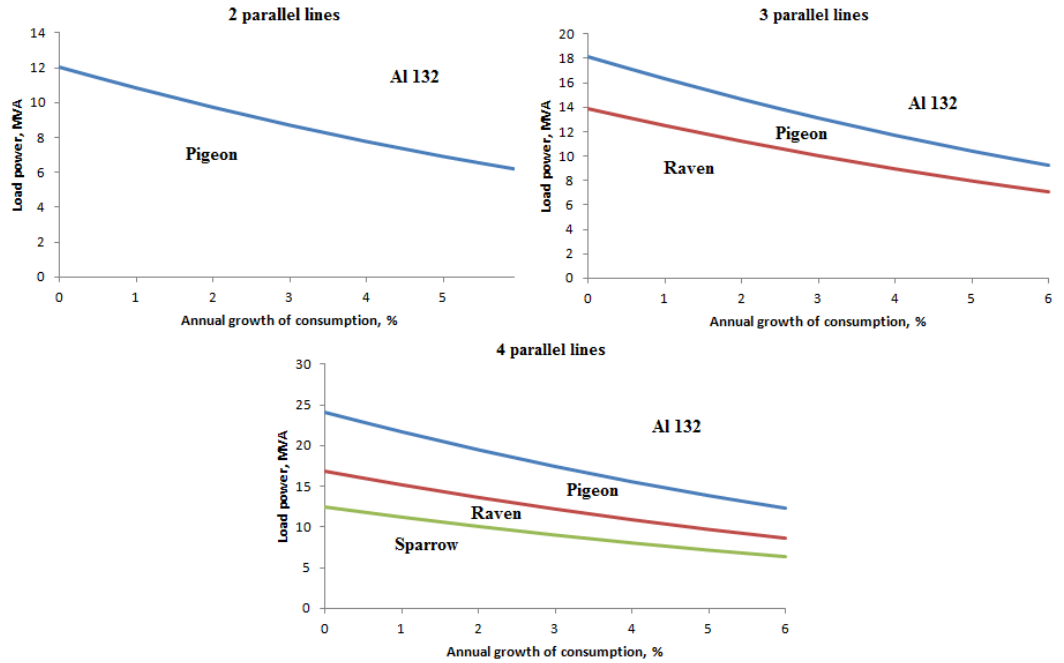


Figure 5.12. Limit curves for bare conductor (load growth period is 15 years).

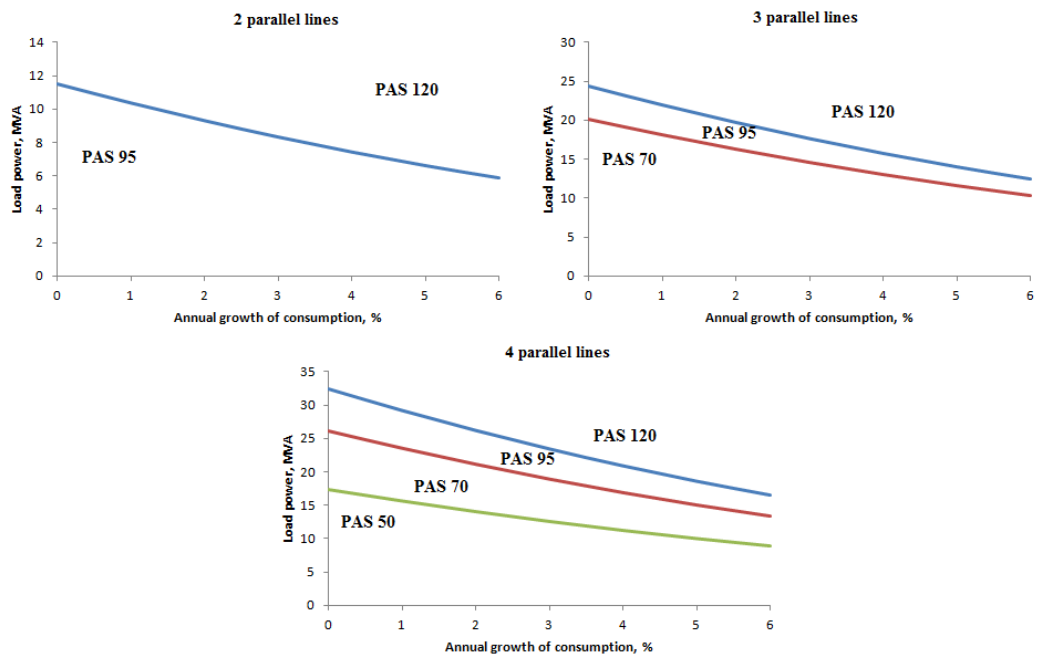


Figure 5.13. Limit curves for covered conductor (load growth period is 15 years).

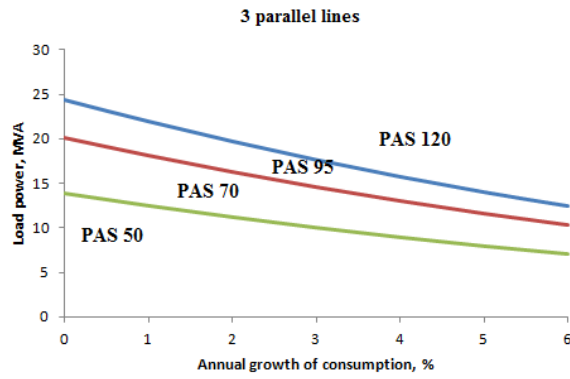


Figure 5.14. Limit curves for covered conductor with a line length 30 km (load growth period is 15 years).

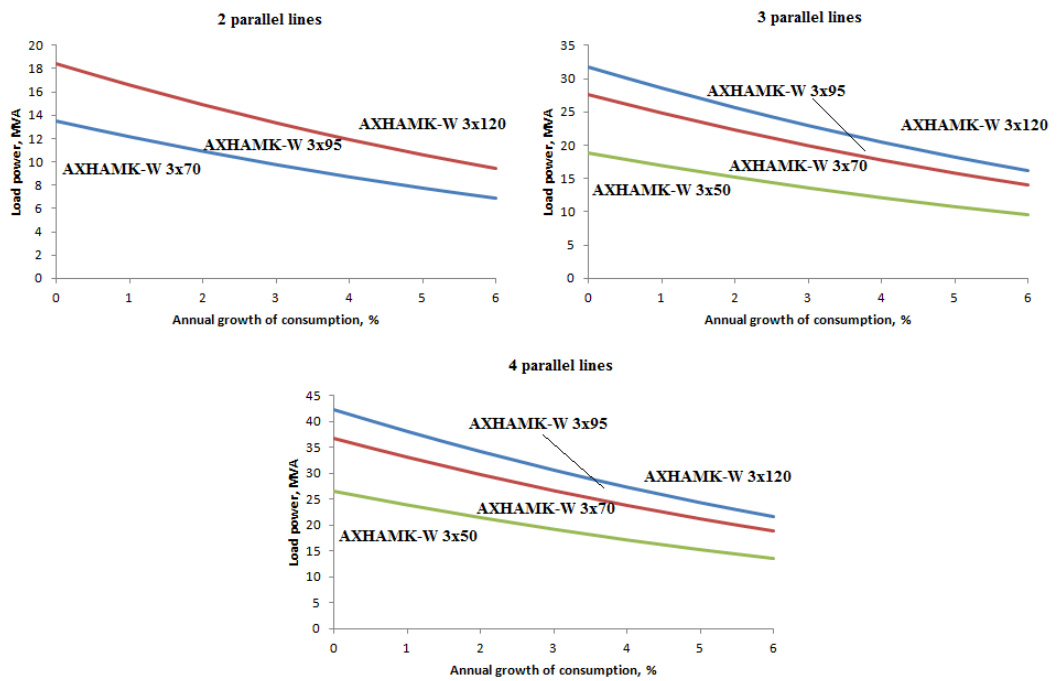


Figure 5.15. Limit curves for underground cable (load growth period is 15 years).

The result of life–time cost analysis for different MV lines is presented on the table 5.18 (line 1) and 5.19 (line 2). According to the analysis, the most economical justified solution is to construct a MV line, which is made by four parallel PAS 50 conductors in case of line 1 and line 2.

Table 5.18. Life–time cost analysis of different alternatives of MV line 1.

Conductor	Construction cost of a single line, €/km	A number of lines	Investment cost, k€	Cost of losses, k€	Outage cost, k€	O&M cost, k€	Total cost, k€
Pigeon	31200	2	1167,8	534,3	3389	200,4	5291
Raven	26900	3	1095,1	568,7	2259	187,9	4111
Sparrow	23500	4	1011,4	671,5	1695	173,5	3551
PAS 95	35500	2	1426,9	575,5	1695	244,8	3942
PAS 70	32200	3	1367	521,1	1130	234,6	3253
PAS 50	28200	4	1306,1	570,8	847,3	224,1	2948
AXHAMK-W 3x70	51900	2	2939,5	707,1	134,5	504,4	4285
AXHAMK-W 3x50	46000	3	3248,8	677,5	89,6	557,5	4573
AXHAMK-W 3x50	46000	4	4038,2	508,2	67,3	692,9	5307

Table 5.19. Life–time cost analysis of different alternatives of MV line 2.

Conductor	Construction cost of a single line, €/km	A number of lines	Investment cost, k€	Cost of losses, k€	Outage cost, k€	O&M cost, k€	Total cost, k€
Pigeon	31200	2	1030,5	471,5	2991	176,8	4670
Raven	26900	3	966,3	501,8	1994	165,8	3628
Sparrow	23500	4	892,4	592,5	1495	153,1	3133
PAS 95	35500	2	1259	507,8	1495	216,0	3478
PAS 50	28200	3	1049,7	671,5	996,8	180,1	2898
PAS 50	28200	4	1152,5	503,6	747,6	197,8	2601
AXHAMK-W 3x120	57600	1	1728	707,9	237,3	296,5	2970
AXHAMK-W 3x70	51900	2	2593,7	623,9	118,6	445,1	3781
AXHAMK-W 3x50	46000	3	2866,6	597,8	79,1	491,9	4035
AXHAMK-W 3x50	46000	4	3563,1	448,4	59,3	611,4	4682

5.5.2 PS 21 calculations

If the load is powered by two substations and equally divided between them, it means that in case of PS 21 the peak load of consumer group 1 will be 49.6 MW, and the peak load of consumer group 2 will be 7.4 MW. Taking into account that the actual peak load of PS 21 equals to 89 % group 1 and group 2 peak loads, it is possible to estimate a needed transformers capacity:

$$P = 0.89 \cdot (P_1 + P_2) = 0.89 \cdot (49.6 \text{ MW} + 7.4 \text{ MW}) = 50.7 \text{ MW}$$

$$S_n \cdot \cos\varphi > P \cdot \left(1 + \frac{r}{100}\right)^T$$

$$S_n \cdot 0.95 > 50.7 \cdot \left(1 + \frac{1}{100}\right)^{15}$$

$$S_n \cdot 0.95 > 58.9 \text{ MW}$$

The nearest rated power of transformer, which satisfy all necessary requirements, is 40 MVA transformer.

$$40 \text{ MVA} \cdot 2 \cdot 0.95 > 58.9 \text{ MW}$$

$$76 \text{ MW} > 58.9 \text{ MW}$$

The present value, investment cost and maintenance cost of PS 21 were calculated earlier. Moreover, the principle of load losses cost, no-load losses cost, outage cost is similar to calculations provided in 5.3.2 paragraph. Based on the data provided in tables 5.4 – 5.6 and 5.14 – 5.15 it is possible to make a life-time cost analysis of PS 21.

Table 5.20. Consumer groups before reconstruction.

Consumer group	Energy, MWh/a
Residential	123000
Agriculture	97000
Industry	54000
Public	30000
Service	15000

Table 5.21. Consumer groups after reconstruction.

Consumer group	Energy, MWh/a
Residential	123000
Agriculture	97000
Industry	102000
Public	30000
Service	15000

Table 5.21. Life-time cost of PS 21

	C investment, k€	C no-load losses, k€	C load losses, k€	C outages, k€	C o&m, k€	Total, k€
Before reconstruction	80,3	286,4	580,5	21,8	550,8	1520
After reconstruction	1617,0	391,9	339,0	30,8	756,9	3136
Effect from reconstruction	1536,8	105,5	-241,5	9,0	206,1	1616

5.5.3 PS 64 calculations

The peak load of consumer groups 1 and 2, which are fed by PS 64, are 50.2 MW and 7.4 MW respectively. The actual peak load of PS 64 equals to 88 % group 1 and group 2 peak loads. In this case it is possible to estimate a needed transformers capacity:

$$P = 0.88 \cdot (P_1 + P_2) = 0.88 \cdot (50.2 \text{ MW} + 7.4 \text{ MW}) = 50.7 \text{ MW}$$

$$S_n \cdot \cos\varphi > P \cdot \left(1 + \frac{r}{100}\right)^T$$

$$S_n \cdot 0.95 > 50.7 \cdot \left(1 + \frac{1}{100}\right)^{15}$$

$$S_n \cdot 0.95 > 58.9 \text{ MW}$$

The nearest rated power of transformer, which satisfy all necessary requirements, is 40 MVA transformer.

$$40 \text{ MVA} \cdot 2 \cdot 0.95 > 58.9 \text{ MW}$$

$$76 \text{ MW} > 58.9 \text{ MW}$$

The present value, investment cost and maintenance cost of PS 64 were calculated in 5.3.2 paragraph. The principle of load losses cost, no-load losses cost, outage cost was also explained in 5.3.2 paragraph. According to the tables 5.4 – 5.6 and 5.14 – 5.15 a life-time cost analysis of PS 64 can be done.

Table 5.22. Consumer groups before reconstruction.

Consumer group	Energy, MWh/a
Residential	118000
Agriculture	92000
Industry	61000
Public	32000
Service	21000

Table 5.23. Consumer groups after reconstruction.

Consumer group	Energy, MWh/a
Residential	118000
Agriculture	92000
Industry	109000
Public	32000
Service	21000

Table 5.24. Life-time cost of PS 64

	C investment, k€	C no-load losses, k€	C load losses, k€	C outages, k€	C o&m, k€	Total, k€
Before reconstruction	80,3	286,4	593,9	23,4	550,8	1535
After reconstruction	1617,0	391,9	339,0	31,2	756,9	3136
Effect from reconstruction	1536,8	105,5	-254,9	7,8	206,1	1601

5.6 Summary.

In this chapter three different network development alternatives were analyzed. Based on result, which were obtained in chapter 5, table 5.25 is created.

Table 5.25. Life-time cost of network development alternatives

Solution		Investment cost, k€	Cost of losses, k€		Outage cost, k€	O&M cost, k€	Total cost, k€	Total cost of solution, k€
			Cost of load losses, k€	Cost of no-load losses, k€				
Reconstruction of PS 64 + MV line construction	MV line	1867,8	1151		1695	320,5	5034	6736
	Effect from sub. reconstruction	1536,8	-164,5	105,5	18,1	206,1	1702	
Reconstruction of PS 21 + MV line construction	MV line	1648,1	1016		1495	282,8	4442	6160
	Effect from sub. reconstruction	1536,8	-148,2	105,5	18,1	206,1	1718	
Reconstruction of PS 21 and PS 64 + MV lines construction	MV lines	2458,6	1074,4		1594,9	421,9	5550	8767
	Effect from sub. reconstruction	3073,6	-496,4	211	16,8	412,2	3217	

According to the data provided in table 5.25, the most economically justified solution is to reconstruct PS 21 with increasing the main transformer's capacity. Power supply of industrial facilities should be done by overhead power line, made by four PAS 50 parallel conductors.

Reconstruction of both substations is the least reasonable solution because of too high investments into PS 64 and PS 21 reconstruction and construction of two power lines from these substations. The operation and maintenance cost of power substations and MV line is very high as well. The main advantage of this solution is the outage cost and transformers' load losses reduction.

Reconstruction of PS 64 is not so efficient as reconstruction of PS 21 mainly because of the difference in MV lines cost. The reason is that line 2 is 4 km longer than line 1. This difference in line length causes extra losses, extra investments, extra O&M cost, and extra outage cost.

6. Conclusions

The main task of the work was to study and implement methodology, by which different network development alternatives could be assessed from techno-economic point of view.

The second chapter of the thesis provided the main principles of electricity networks planning, which were summarized and described. The introduction into the principles of life-time cost analysis in the network was conducted.

In the third part of the thesis different types of power substations, their functions, their structures were discussed. Moreover, different substation drivers were mentioned and explained. In addition, the features and steps of power substation planning process were covered.

In chapter number four power substations were studied from technical point of view. Advantages and disadvantages of different busbar structures were defined, the features of main transformers dimensioning was described. Then, a switchgear equipment, protection and automation system, instrument transformers, which are used on power substation, were defined in order to explain, what functions they perform in substation.

Finally, network planning and development methodology was implemented to the chosen region in Russia. Based on the features of Prionezsky region and existing issues in power supply, different alternatives of network development were considered. These alternatives were focused on reconstruction of existing substations. The network development process included construction and dimensioning of a new power line and reconstruction of existing substations at the same time. Different types of power lines were analyzed and compared in long term perspective. The total cost of solution was taken as a sum of power line cost and power substation reconstruction cost. The total cost of reconstruction was estimated by life-time cost analysis.

As it was mentioned, this master thesis was focused on reconstruction of existing substations. In some cases it is more economically justified to construct a new

primary substation. Thus, the further work on the thesis may include techno-economical assessment of a new primary substation construction potential.

The further researches may also include sensitivity analysis of different alternatives. Sensitivity analysis will make it possible to determine all influencing factors and their impact on final conclusion. Moreover, sensitivity analysis will help to determine sustainability of the final solution in case of different scenarios.

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Appendix A. Technical and economical parameters of transformers, conductors, and power equipment.

Table 7.1. Technical parameters of conductors

Conductor type	R_0 [Ω/km]	X_0 [Ω/km]
Sparrow	0,847	0,383
Raven	0,538	0,368
Pigeon	0,337	0,354
Al 132	0,218	0,344
PAS 50	0,72	0,4
PAS 70	0,493	0,302
PAS 95	0,363	0,292
PAS 120	0,288	0,281
AXHAMK-W 3x50	0,641	0,157
AXHAMK-W 3x70	0,446	0,138
AXHAMK-W 3x95	0,326	0,133
AXHAMK-W 3x120	0,253	0,12

Table 7.2. Main transformers

Type of transformer	Nominal power, kVA	Voltage levels, kV			Losses		Unit cost, €
		HV	MV	LV	P_0 , kW	P_k , kW	
TDTN-16000/110	16000	110	35	10	21	100	289000
TDTN-25000/110	25000	110	35	10	28,5	140	338100
TDTN-40000/110	40000	110	35	10	39	200	538400
TDTN-63000/110	63000	110	35	10	53	290	664000

Table 7.3. Power equipment cost

Type of equipment	Voltage level	Unit cost, €
Circuit breaker	110 kV	49400
Disconnecter	110 kV	2000
Current transformer	110 kV	22000