Electrical Power Network of Funen

Analyses, calculations, dimensioning, and protections.

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Sworn statement

I hereby solemnly declare that I have personally and independently prepared this report. All quotations in the text have been marked as such, and the report or considerable parts of it have not previously been subject to any examination or assessment.

Odense, on 29th of May of 2011.

Blanca Naudín Aparicio

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Introduction

- ## Synopsis

The overall purpose of this project is to achieve a high degree of understanding of electrical power systems, from low voltage to high voltage networks.

This project is dealing with different topics about electrical power systems, and they could be load flow analyses, calculation of electrical line parameters, load profiles analyses, dimensioning and protection of low voltage installations, distance protection in high voltage networks, etc.

There will be a demonstration both theoretical insight as well as the capabilities of using the theory in a practicable project.

Among the subjects is the modeling of complex networks in NEPLAN.

Finally, the purpose of the project is to communicate the results, background, applied theory, applied methods and the conclusions in a report.

▪ Preface[1]

Denmark's transmission and distribution systems are built to connect not only its power systems, but also to supply or be supplied with other power plants abroad. There are denominated electricity motorways (transmission lines) which supplied electricity to consumer by generation nodes.

These complex transmission and distribution systems consist on facilities with different rated voltages: 400, 150, and 132 kV. It is also divided into two different areas, which have obviously different sizes and which are, at the same time, non-synchronous. It means they have to be managed differently:

- Jutland and Funen belong to the western Denmark, which forms part of the synchronous area of the European continent (UCTE). Here, the transmission grid is operated at 400 kV with a combination of ring connections and radial structure, and at 150 kV as a parallel grid. The ring connection is the most useful tool when finding failures on the network elements.. It is connected to the UCTE synchronous area at the German border via 400 kV, 220 kV and 150 kV AC lines (1200 import/800 export MW). The Western Danish system is also connected to the Nordel synchronous area, which includes Sweden, Norway and Finland, via HVDC links to Norway (1000 MW) and Sweden (720 MW), which makes exchange of energy of energy possible without it being synchronized.
- The eastern Denmark (Zealand) represents a part of another synchronous area, the Nordel. The eastern transmission network is composed by a 400 kV radial grid and a 132 kV ring connected grid. It is connected to Sweden via AC lines (1700 import/1300 export MW) and through a HVDC connection to Germany (600 MW).

Energinet.dk owns the 400 kV installations and the international connections, whereas the 150/132 kV installations are owned by the regional transmission companies, which make the 150/132 kV grids available to Energinet.dk. However, Energinet.dk owns the 132 kV grid in northern Zealand.

There are several elements on the system, which are:

- Electricity consumption - the use of electricity at home and at work.
- Electric power production - is composed of many different types of production units, such as large central power plants, small CHP plants and renewable energy sources, mainly wind power.
- National transmission system - including the largest high-voltage lines and cables in Denmark, which operated between 132,000 and 400,000 volts.
- International connections - connecting Denmark with my neighbors.
- Elm arched - electricity markets ensure that energy is sold at the right price.
- Love, frameworks and rules of operation of the electrical system.
- Tools - requires many computer systems for information system power and optimal utilization.

[1]On wind power integration into electrical power system: Spain vs. Denmark
http://www.energinet.dk

The overall objective of system operation is to secure high and do this as efficiently as possible. Security of supply - there is always power in the plug - is an essential prerequisite for a functioning society.

Power is perishable is the ultimate global product and should be used in the same second, it is produced. As the company responsible for system operators (TSOs) Energinet.dk is responsible for ensuring that there is always a balance between consumption and production. That task is growing steadily in scope, the development of wind energy.

400-150 kV (High Voltage) Network of Funen

The 400-150 kV (High Voltage) network of Funen and the south-eastern part of Jutland is shown in the *Figure 1*. As I can see, there are different lines supplied with different voltages:

- Red line: 400 kV
- Black line: 150 kV
- Blue dotted line: HVDC connection to Zealand
- Green Line: 400 kV Connection to Tyskland (Germany)

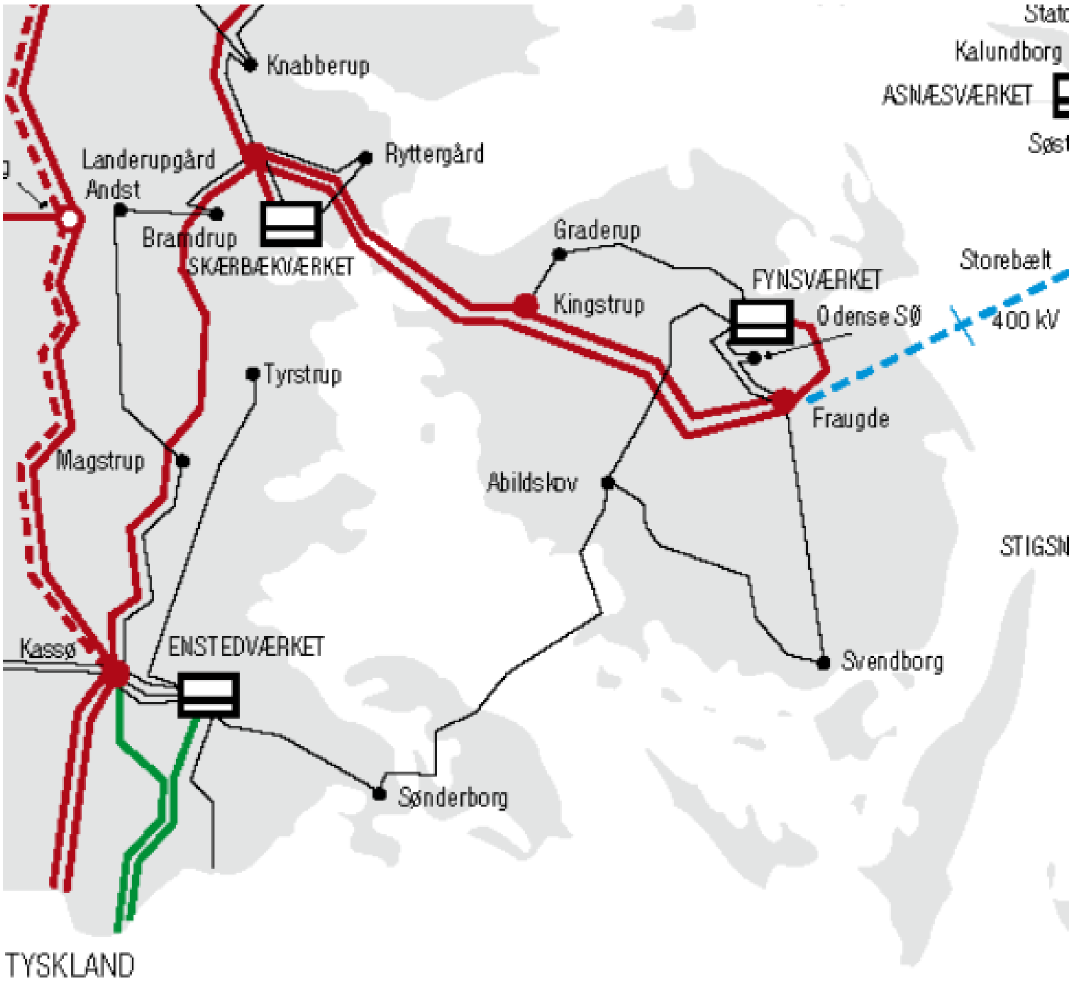

Figure 1.400-150 kV network of Funen and the south-eastern part of Jutland.

In this report, you will find some abbreviations for the name of the different cities, that is, for each place, I will have 3 capital letters, followed by a number (1, 2, 3, or 5), which depends on the rated voltage level. There are few examples bellow:

- LAG5: Landerupgård, with 400 kV like nominal voltage (~410kV)
- FGD3: Fraugde, with 150 kV like nominal voltage (~165kV)
- SØN2: Sønderborg, with 60 kV like nominal voltage (~66kV)
- FBY1: Fåborg, with 10 kV like nominal voltage (~12kV)

You will find a description for all the abbreviations of the cities at the *Appendix I. Abbreviations*

▪ Assumptions

For the High Voltage Network of Funen, I have to make some considerations or assumptions before starting with the calculation of everything. Having a look on the values for the different elements I will have on my network, which I could find on *Table 1 (AII). Line data from the Electrical Power Project specifications*. So then, I could make the next assumptions:

I. Lines

- The operation temperature for the lines will be 20°C.
- There are few underground lines, which are for 400-150 kV. These lines are: KIN5-LAG5, FGD5-KIN5,FGD5-FVO5,SHE3-SØN3. That is that as I know, the lines with high substance are supposed to be close to the ground or even they have to be underground cables. I will have to pay attention when working with the line SHE3-SØN3, due to is a sea-cable
- There are several lines which are divided in different sections. I will call the "not-divided in section lines", and they are: FGD5-LAG5 (total length=73,63km),FVO3-GRP3 (total length=28,24km), ABS3-FVO3 (total length=30,21 km), ABS3-SON3 (total length=50km), FGD3-FVO3 (total length=12,3km). I have the resistance and the inductance of the whole line, and each section has no values for R_1, R_0, X_1, X_0, so I cannot make it as a divided line. The maximum value of the current for each line is the minimum value of all the sections of each line.
- The line ABS3-SØN3 will be considered an overhead line. This line is divided in 5 different sections, and three of them are underground cables. The substance of the entire line is high ($B_{in,1} = 314\mu S$), however, I will consider it such an overhead line, due to the two overhead sections are 22.4 km and 16.1 km length.
- The line FGD5-LAG5 will be considered with 2 conductors per bundle when I will talk about the phase conductor of the pylons.
- The I_{max} for the next lines, are determined at a load factor 1. The lines are: FGD3-FVO3, FVO3-OSØ3, ABS3-FVO3, FVO3-GRP3, and GRP3-KIN3. The values for the current will depend on the load factor, that is that when Load factor=1, then I_{max} = 760 A. On the other hand, when Load factor=0.7. Then I_{max} =995A. I will have different values for the load:
  - The minimum load factor (scaling factor) for all the loads of the selected partial network (same for P and Q demand).
  - The maximum load factor (scaling factor) for all the loads of the selected partial network (same for P and Q demand). If the minimum and maximum load factors are equal, only this load factor is considered.

II. Pylons

Concerning the pylon dimension, I will talk about one kind of pylon which is shown in the *Figure 4. 150 kV pylon description*. The 150kV pylon for all the lines will be described with the next coordinates:

Table1 . 150 kVpyloncoordinates.

Line	X-axis (m)	Y-axis (m)
L1	6.25	28.75
L2	0	26
L3	7.75	23.25

When talking about the distance between pylons, I considered that it could be 150 meters. It means that each line will be a straight line, where I will not find any kind of curve, hill, mountain, or other obstacle.

For the calculations of the number of pylons per line, I will make the next example:

"In a 6 km-length line, I want to know how many pylons I need. I know that each pylon has to be separated like 150 meters from the other, so it means that I will have, in the entire line, forty fortieths. It means that I will need 40-1 pylons."

$$Number\ of\ pylons = \frac{total\ length\ of\ the\ line\ (km)}{distance\ between\ pylons\ (km)} - 1$$

Concerning the distances (%) along the total length of the line which I have to introduce in NEPLAN, I only have to divide the distance between pylons by the total length of this line:

$$Distance\ NEPLAN\ (\%) = \frac{distance\ between\ pylons\ (km)}{total\ length\ of\ the\ line\ (km)} \cdot 100$$

The number of pylons for each line, and the distance (%) will be:

Table 2.Pylon descriptions for 400-150 kV lines.

Line	Length (km)	Number of pylons	Distance (NEPLAN) (%)
ABS3-SØN3	50	332	0,3
ABS3-SVB3	36,2	240	0,4144
ABS3-FVO3	30,21	200	0,4965
FGD3-FVO3	12,3	81	1,2195
FGD3-OSØ3	6,3	41	2,3809
FGD3-SVB3	38	252	0,3947
FGD5-FVO5	14	-	-
FGD5-KIN5	40,5	-	-
FGD5-LAG5	73,63	489	0,2037
FVO3-GRP3	28,24	187	0,5312
FVO3-OSØ3	6	-	-
GRP3-KIN3	8	-	-
KIN5-LAG5	33,1	-	-
SHE3-SØN3	25	-	-

There are few lines where I will not have pylons, due to these lines are underground cables, like I saw in the section before of the assumptions.

III. Feeders

- The short circuit power of the network feeder (N1)in LAG5 has been set to infinite (zero short circuit impedance). This is due to the short distances from LAG5 to other power plants - as well as to Germany – compared with the distance and impedance of the two 400 kV lines between LAG5 and FGD5 and the transformer impedances between FGD5 and FGD3
- The short circuit power of the network feeder (N2) in SHE3 has been set to infinite (zero short circuit impedance). This is due to the short distance to both 220- and 400 kV grids closely connected to the equivalent German grids and the presence of an 825 MVA generator at Enstedværket power station. The impedances of the lines ABS3 – SØN3 – SHE3 are predominant compared with the short circuit impedance of the network feeder N2
- We will assume an equal slack portion in both feeders. It means a 50% of the total slack active power has to be supplied by each one. I will have to consider that the load flow is calculated with distributed slack.

▪ Load Flow Calculations

The load flow calculations are the tools I have to use when I want to know the characteristics in a determined network, how it works on the steady sate. I have to use it if I want to calculate the flow through all the lines, or the voltages at every node, the loads, currents, etc.

Load flow analysis is probably the most important of all network calculations since it concerns the network performance in its normal operating conditions. It is performed to investigate the magnitude and phase angle of the voltage at each bus and the real and reactive power flows in the system components.

Normally, load flow calculations are used to assess if the evaluated system is working within operational limits, or within a secure mode (n-1 elements). It is also used to check how it is going to behave in future situations, like maintenance, critical conditions because of the weather or malfunction, etc.This kind of analysis has a great importance in future expansion planning, in stability studies and in determining the best economical operation for existing systems. Also load flow results are very valuable for setting the proper protection devices to insure the security of the system. In order to perform a load flow study, full data must be provided about the studied system, such as connection diagram, parameters of transformers and lines, rated values of each equipment, and the assumed values of real and reactive power for each load.

I. Line FGD3-SVB3

There will be used three different methods for the calculation of this line: with NEPLAN, by hand, and by making some assumptions.

a. *Assumptions*

The line FGD3-SVB3 should be calculated. I don't know some values like the resistances and the impedances for both sequences positive and zero. What I could do is to compare this line with the values of the lines I already have to get some idea how the line FGD3-SVB3 values could be. I have to make these assumptions following the criteria about the different parameters I will see next. I know that only few of them are relevant for the zero sequence resistance or impedance, however, I decided to consider all of them. The different parameters are:

- Length

The most similar is the line ABS3-SVB3 (1,8km of difference) and even the phase conductor is similar. The problem is that the line FGD3-SVB3 can handle an I_{max} =1380A, on the other hand, the other line support an I_{max} =990A. If I follow this argument, the R_0 (FGD3-SVB3) will be 3·R_1 (FGD3-SVB3)

- I_{max}

Concerning the maximum current, I have two different groups which are similar than the maximum current in this line. These are: +220A (FGD3-FVO3 and FGD3-OSØ3), and -220 A (FGD5-FVO5, FGD5-LAG5, FGD5-KIN5, and KIN5-LAG5). I are going to consider only the lines with a +220A difference, due to the rest are underground lines.

Relate to the line FGD3-FVO3, I will say that it is divided in two different sections, and one of them has its own maximum current equal to 760A, so I cannot consider this line

Finally, I could conclude that the line FGD3-OSØ3 is the most similar, although the length is 6 times less.

- Pylon/Cable

We will consider the pylon/cable criteria, although it will not give me a good advisement. There are two lines that I could contemplate like similar: FGD3-FVO3 and FGD3-OSØ3. Both have a S7/2 pylon/cable, and the line FGD3-SVB3 has a S1/1 pylon/cable. As I saw in the I_{max} criteria, the line FGD3-FVO3 is divided in two different sections, and one of them has its own maximum current equal to 760A, so I cannot consider this line. This is why the most similar line, about this criterion, will be the line FGD3-OSØ3

- Phase conductor

There are different phase conductors in these lines, and I will only consider the Steel-Aluminum (SA) phase conductor. The phase conductor of the line FGD3-SVB3 is 1x772 mm2 SA, so the most similar lines with a 1x594 mm2 SA phase conductor are: FGD3-FVO3, FGD3-OSØ3, and ABS3-SVB3. As I saw before, the line FGD3-FVO3 is divided in two different sections, and one of them has its own maximum current equal to 760A, so I cannot consider this line. So, the most similar lines are FGD3-OSØ3, and ABS3-SVB3.

- Shield

The shield of the line FGD3-SVB3 is SA80 mat./mm2. There are only two similar lines: FGD3-FVO3, and FGD3-OSØ3. As I saw before, the line FGD3-FVO3 is divided in two different sections, and one of them has its own maximum current equal to 760A, so I cannot consider this line. So, the most similar line is FGD3-OSØ3.

- Earth conductor

The earth conductor of the line FGD3-SVB3 is 1x153 mm2. There are only two similar, although they are coupled. They are FGD3-FVO3 and FGD3-OSØ3, so I can consider both as similar.

This way, I will make a table with the similar lines to decide which one I could assume to be the most similar to the line I want to calculate to.

Table 3. Similar lines to FGD3-SVB3 with all the line parameters.

	Length	I_{max}	Pylon/Cable	Phase conductor	Shield	Earth conductor
Similar Line	ABS3-SVB3	FGD3-OSØ3	FGD3-OSØ3	FGD3-FVO3 FGD3-OSØ3	FGD3-OSØ3	FGD3-OSØ3 ABS3-SVB3

- R_0/R_1relationship

As I can see, the line FGD3-OSØ3 is present in all the parameters, except from the length, which I consider more relevant.

Table 4. R0/R1 rated value for the most similar lines to FGD3-SVB3.

Line	R_1 (Ω)	R_0 (Ω)	R_0/R_1
ABS3-SVB3	2.02	11.21	5.55
FGD3-OSØ3	0.61	2.33	3.82

So the R_0/R_1 relationship of the line FGD3-SVB3 will be a value between 3.82 and 5.55, where I could consider around 4. Later on, with the NEPLAN calculations, I will see how this ratio will be equal to 4.49, so I are actually right.

b. Mathematical calculations

In this section I have to calculate the electrical line parameters of the 150 kV line between Fraugde (FGD3) and Svendborg (SVB3). First at all, all the values have to be calculated by hand, and they will be checked out later on by using NEPLAN.

Like I studied before, I have some parameters:

- The conductor dimensions.
- The conductor materials property.
- The pylon geometry.

- Equivalent circuit

The first step in the calculations is obtaining the equivalent circuit of my line. The arrangement of the parameters representing the line depends upon the length of the line. I considered a transmission line as a short-length line if its length is less than 80km. In my case, the length of my transmission line is 38km, and its equivalent circuit is represented the next way:

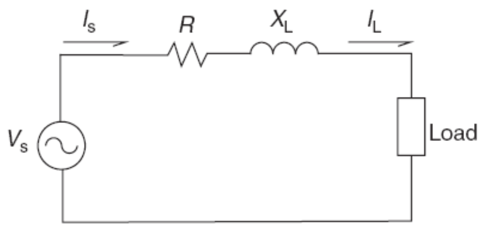

Figure 2.Equivalent circuit of a 150 kV line.

In this drawing I can see that only the inductive reactance and the resistance are considered and the shut capacitance effect is negligible.

- Resistance

The way to calculate the resistance is easy by using the tables. I just have to look at the value of the resistance per kilometer at a given temperature (20º) on the table. When I got this value, I just have to multiply by the length of the line, in my case 38 kilometers.

$$R = R_{20^\circ} \cdot L = 0'0423 \cdot 38 = 1'61(\Omega)$$

We can consider that the distribution over the cross-section on the cable is uniform if the current is flowing along a round cylindrical conductor.

Table 5.Linear resistance for Martin type conductor for overhead lines.

Navn	Crosssec. area A mm² total	stål	alum.	Diameter dv mm d mm total	di mm stål	partialconducters amount/diameter d_1 mm stål	alum.	weight M kg/km	F_b kN	Elasticitetsmodul E GPa	Længdeudv.-koefficient $\alpha \cdot 10^6$ K⁻¹	Linear resistans v. 20 °C r_{20} Ω/km	Geometrisk middelradius GMR mm
Swallow	31,1	4,4	26,7	7,14	2,38	1/2,38	6/2,38	107,4	10,1	79	19,1	1,074	2,742
DIN 50/8	56,3	8,0	48,3	9,6	3,20	1/3,20	6/3,20	195,5	15,8	79	19,1	0,600	3,686
Raven	62,4	8,9	53,5	10,1	3,37	1/3,37	6/3,37	215,9	19,0	79	19,1	0,535	3,882
Pigeon	99,3	14,2	85,1	12,8	4,25	1/4,25	6/4,25	342,7	29,7	79	19,1	0,337	4,896
Pernice	128,9	18,0	110,9	14,8	5,43	7/1,81	26/2,33	446	41,4	79	18,9	0,261	5,970
Partridge	156,9	22,0	134,9	16,3	6,00	7/2,00	26/2,57	543	50,0	79	18,9	0,214	6,607
Ostrich	176,9	24,7	152,2	17,3	6,36	7/2,12	26/2,73	613	56,2	76	18,9	0,190	7,031
Ibis	234,0	32,7	201,3	19,9	7,32	7/2,44	26/3,14	811	72,0	76	18,9	0,143	8,057
Hawk	281,1	39,5	241,6	21,8	8,04	7/2,68	26/3,44	975	86,5	76	18,9	0,120	8,828
Dove	328,5	45,9	282,6	23,6	8,7	7/2,89	26/3.72	1229	99,7	76	18,9	0,102	9,571
Condor	454,5	52,2	402,3	27,7	9,24	7/3,08	54/3,08	1522	127,0	69	19,3	0,0718	11,21
Curlew	593,5	68,2	525,5	31,7	10,6	7/3,52	54/3,52	1979	165,2	69	19,3	0,0553	12,85
Finch	636,6	71,6	565,0	32,8	10,9	19/2,19	54/3,65	2120	178,8	67	19,4	0,0513	13,28
Martin	772,1	86,7	685,4	36,2	12,0	19/2,41	54/4,02	2574	211,7	67	19,4	0,0423	14.62
Bluebird	1187	88,8	1098,2	45,0	12,2	19/2,44	54/4,08	3740	283,4	65	20,7	0,0270	17,95
Dorking	152.8	56,3	96,5	16,0	9,6	7/3,20	12/3,20	707	78,8	105	15,3	0,298	6.869
AWG													
AWAC	100,1	36,9	63,2	13,0	7,8	7/2,59	12/2.59	419	55,8	103	19,3	0.393	5,574

- Frequency effect (skin effect)

This phenomenon is produced by the frequency of the AC voltage. This second effect on the conductor resistance is produced by the non-uniform distribution of the current. It appears when the frequency increases, and then, the current tends to go toward the surface of the conductor, and at the center the current density decreases. The principal consequence of the frequency effect is that it reduces the effective cross-section area used by the current, and the effective resistance increases.

$$R_{AC} = R_{AC} \cdot k = 1^{'}61 \cdot 1^{'}02 = 1^{'}64\Omega$$

k=1'02 for 60 Hz frequency.

- Inductance of transposed three-phase transmission lines

With the actual transmission lines technology and because of the construction considerations, the phase conductors cannot handle symmetrical arrangement along the length. If the spacing of the length is different, then the inductance will be different for each phase, also the voltage is unbalanced in each conductor.

In a transmission line I can assume a symmetrical arrangement in it by transposing the phase conductors. Each cable occupies the location of the other two phases for one third of the total line length.

For my calculations I have to know the GMD, which means the average distance geometrical mean distance substitutes distance D.

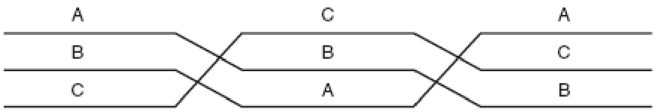

Figure 3. Distance geometrical mean distance description.

In a transmission line the inductance per phase per unit length is:

$$L_{phase} = \frac{\mu_0}{2\pi} ln\left(\frac{GMD}{GMR_{phase}}\right)$$

However, before I have to calculate the GMD, and the GMR. To calculate the GMD I need the drawing below.

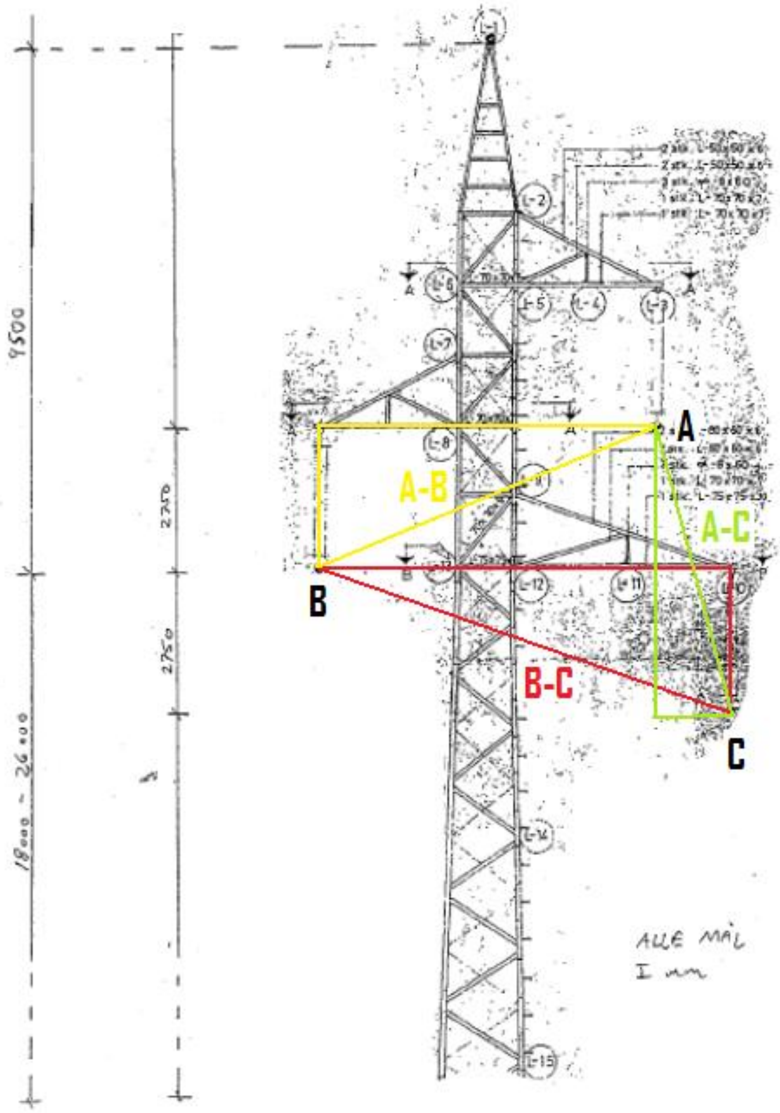

Figure 4. 150 kV pylon description.

We calculated the distances with the simple Pythagoras theorem:

$$D_{A-B} = \sqrt{2750^2 + 6250^2} = 6828{,}25\ mm$$

$$D_{B-C} = \sqrt{2750^2 + 7750^2} = 8385{,}44\ mm$$

$$D_{A-C} = \sqrt{1500^2 + 5500^2} = 5700{,}88\ mm$$

$$GMD = \sqrt[3]{D_{A-B}.D_{B-C}.D_{A-C}} = \sqrt[3]{6828 \cdot 8385 \cdot 5700} = 6885{,}34$$

And the GMR is easy to find in the table below:

Table 6.GMR for Martin type conductor for overhead lines.

Navn	Crosssec. area A mm² total	stål	alum.	Diameter d mm (dy mm) total	(di mm) stål	partialconducters amount/diameter d_i mm stål	alum.	weight M kg/km	F_b kN	Elasticitetsmodul E GPa	Længdeudv.- koefficient $\alpha \cdot 10^6$ K^{-1}	Linear resistans v. 20 °C r_{20} Ω/km	Geometrisk middelradius GMR mm
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DIN 50/8	56,3	8,0	48,3	9,6	3,20	1/3,20	6/3,20	195,5	15,8	79	19,1	0,600	3,686
Raven	62,4	8,9	53,5	10,1	3,37	1/3,37	6/3,37	215,9	19,0	79	19,1	0,535	3,882
Pigeon	99,3	14,2	85,1	12,8	4,25	1/4,25	6/4,25	342,7	29,7	79	19,1	0,337	4,896
Pernice	128,9	18,0	110,9	14,8	5,43	7/1,81	26/2,33	446	41,4	79	18,9	0,261	5,970
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Hawk	281,1	39,5	241,6	21,8	8,04	7/2,68	26/3,44	975	86,5	76	18,9	0,120	8,828
Dove	328,5	45,9	282,6	23,6	8,7	7/2,89	26/3.72	1229	99.7	76	18.9	0,102	9,571
Condor	454,5	52,2	402,3	27,7	9,24	7/3,08	54/3,08	1522	127,0	69	19,3	0,0718	11,21
Curlew	593,5	68,2	525,5	31,7	10,6	7/3,52	54/3,52	1979	165,2	69	19,3	0,0553	12,85
Finch	636,6	71,6	565,0	32,8	10,9	19/2,19	54/3,65	2120	178,8	67	19,4	0,0513	13,28
Martin	772,1	86,7	685,4	36,2	12,0	19/2.41	54/4,02	2574	211,7	67	19.4	0,0423	14.62
Bluebird	1187	88,8	1098,2	45,0	12,2	19/2,44	54/4,08	3740	283,4	65	20,7	0,0270	17,95
Dorking	152.8	56,3	96,5	16,0	9,6	7/3,20	12/3,20	707	78,8	105	15,3	0,298	6.869
AWG													
AWAC	100,1	36,9	63,2	13,0	7,8	7/2,59	12/2,59	419	55,8	103	19,3	0.393	5,574

Finally I can calculate the line inductance per phase:

$$L_{phase} = \frac{\mu_0}{2\pi} ln\left(\frac{GMD}{GMR_{phase}}\right) = \frac{4\pi 10^{-7}}{2\pi} ln\left(\frac{6884{,}34}{14'62}\right) = 1'23\ {}^{\mu H}/_{m}$$

Afterwards, I can calculate theinductive reactance per unit length the inductance per phase, which will be related to the line inductance per phase in this way:

$$X_{L_{phase}} = 2\pi f L_{phase} = 2\pi.50.1'23.10^{-6} = 0'386.10^{-3}\ {}^{\Omega}/_{m}$$

c. NEPLAN

For calculating the line FGD3-SVB3 by using NEPLAN, I have to know the data for the different kind of conductor, like its dimension, its material properties, or even the pylon characteristics.

The phase conductors are steel-aluminum, STAL (ACSR), type Martin, simplex (one conductor per phase). The earth conductor is steel-aluminum, STAL (ACSR), type Partridge. And as I assumed before, a conductor temperature of 20°C is assumed. So the conductor data are:

Table 7. Conductor selected data for FGD3-SVB3 line.

Navn	Crosssec. area A mm² total	stål	alum.	Diameter (dy mm di mm) d mm total	stål	partialconducters amount/diameter d_i mm stål	alum.	weight M kg/km	F_b kN	Elasticitetsmodul E GPa	Længde-udv.-koefficient $\alpha \cdot 10^6$ K⁻¹	Linear resistans v. 20 °C r_{20} Ω/km	Geometrisk middelradius GMR mm
Swallow	31,1	4,4	26,7	7,14	2,38	1/2,38	6/2,38	107,4	10,1	79	19,1	1,074	2,742
DIN 50/8	56,3	8,0	48,3	9,6	3,20	1/3,20	6/3,20	195,5	15,8	79	19,1	0,600	3,686
Raven	62,4	8,9	53,5	10,1	3,37	1/3,37	6/3,37	215,9	19,0	79	19,1	0,535	3,882
Pigeon	99,3	14,2	85,1	12,8	4,25	1/4,25	6/4,25	342,7	29,7	79	19,1	0,337	4,896
Pernice	128,9	18,0	110,9	14,8	5,43	7/1,81	26/2,33	446	41,4	79	18,9	0,261	5,970
Partridge	156,9	22,0	134,9	16,3	6,00	7/2,00	26/2,57	543	50,0	79	18,9	0,214	6,607
Ostrich	176,9	24,7	152,2	17,3	6,36	7/2,12	26/2,73	613	56,2	76	18,9	0,190	7,031
Ibis	234,0	32,7	201,3	19,9	7,32	7/2,44	26/3.14	811	72,0	76	18,9	0,143	8,057
Hawk	281,1	39,5	241,6	21,8	8,04	7/2,68	26/3,44	975	86,5	76	18,9	0,120	8,828
Dove	328,5	45,9	282,6	23,6	8,7	7/2,89	26/3,72	1229	99,7	76	18,9	0,102	9,571
Condor	454,5	52,2	402,3	27,7	9,24	7/3,08	54/3,08	1522	127,0	69	19,3	0,0718	11,21
Curlew	593,5	68,2	525,5	31,7	10,6	7/3,52	54/3,52	1979	165,2	69	19,3	0,0553	12,85
Finch	636,6	71,6	565,0	32,8	10,9	19/2,19	54/3,65	2120	178,8	67	19,4	0,0513	13,28
Martin	772,1	86,7	685,4	36,2	12,0	19/2,41	54/4,02	2574	211,7	67	19,4	0,0423	14,62
Bluebird	1187	88,8	1098,2	45,0	12,2	19/2,44	54/4,08	3740	283,4	65	20,7	0,0270	17,95
Dorking	152,8	56,3	96,5	16,0	9,6	7/3,20	12/3,20	707	78,8	105	15,3	0,298	6,869
AWG													
AWAC	100,1	36,9	63,2	13,0	7,8	7/2,59	12/2,59	419	55,8	103	19,3	0,393	5,574

The parameters I will have to introduce for the phase conductor will be:

Table 8. Phase conductor configuration for the Line FGD3-SVB3.

Phase conductor	Conductors per bundle	Distance (cm)	2*GMR (cm)	R20 (Ω/Km)	Sag (m)
Martin	1	0	2,924	0,0423	2,0125

The distance considered is equal to zero, due to I will have only one conductor per line.

The sag I have considered for the line will be at least the 7%. So I have to calculate the 7% of the higher height of all the lines, what be the height of the L1 (28,75 m).

$$Sag\ (m) = 7\% \cdot L1_{y-axis} = \frac{7}{100} \cdot 28{,}75 = 2{,}0125\ (m)$$

The data for the earth conductor I will have to introduce will be:

Table 9.Earth conductor configuration for the Line FGD3-SVB3.

Earth conductor	x (m)	y (m)	R (Ω/Km)	2*GMR (cm)
Partridge	3,125	35,5	0,214	1,3214

The calculated values I have obtained:

Table 10.NEPLAN calculation for the Line FGD3-SVB3.

Line	Lenght (Km)	R_1 (Ω/Km)	X_1 (Ω/Km)	C_1 (uF/Km)	B_1 (uS/Km)	R_0 (Ω/Km)	X_0 (Ω/Km)	C_0 (uS/Km)	B_0 (uS/Km)
FGD3-SVB3	38	0,04235	0,38631	0,0091	2,853	0,19034	1,3125	0,00461	1,448

II. Transformers

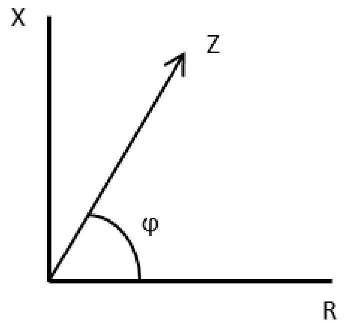
a. Considerations

All 400/150 kV transformers are direct earthed YNyn0 autotransformers. All 150/60 kV transformers are YNd transformers. Earthing of the 150/60 kV transformers depend on the Z_0/Z_1 ratio from faults in the 150 kV network. Typically, at least one transformer in each 150/60 kV station is direct earthed.

b. Calculations and Configurations

- Voltage, and X/R ratios

When talking about unit transformers, I will have to calculate the X/R ratio value. This value will be important for the short circuit calculations, due to determining the total impedance of the circuit will be the key element of it. This impedance is represented like complex impedance, with a module and an angle, where the module is just the hypotenuse of the right angle which you can see below. The angle of this complex impedance will be represented with the phi symbol(φ).



$$tan^{-1}(X/R) = \varphi$$
$$sin(\varphi) \cdot Z = X$$
$$cos(\varphi) \cdot Z = R$$
$$Z = \sqrt{R^2 + Z^2}$$

Figure 5. Impedance representation

A very common assumption is to use an X/R ratio between 12 and 15. I will see how the values for all the transformers (400-150 kV, and 150-60 kV) will be around 30-50, what will be consider like low-medium value in a NEPLAN scale, where the ratio values are: Low value (~35), Medium value (~40), and High value (~60).

For the calculation of the transformers, I have to follow the next steps with the example FGD5-FGD3:

$$\left.\begin{matrix} U_R(1) = 0.23\% \\ U_X(1) = 12.5\% \end{matrix}\right\} U_K(1) = \sqrt{U_R(1)^2 + U_X(1)^2} = \sqrt{0.23^2 + 12.5^2} \rightarrow U_K(1) = 12.5\%$$

We could check the values for the positive sequence impedance:

$$R(1) = \frac{U_R(1)}{100} \cdot \frac{U_2^2}{S_r} = \frac{0.23}{100} \cdot \frac{168^2}{400} = 0.162\Omega \quad ; \quad X(1) = \frac{U_X(1)}{100} \cdot \frac{U_2^2}{S_r} = \frac{12.5}{100} \cdot \frac{168^2}{400} = 8.82\Omega$$

We could check the values for the zero-sequence also

$$R(0) = \frac{U_R(0)}{100} \cdot \frac{U_2^2}{S_r} = \frac{0.2}{100} \cdot \frac{168^2}{400} = 0.141\Omega \quad ; \quad X(0) = \frac{U_X(0)}{100} \cdot \frac{U_2^2}{S_r} = \frac{11.9}{100} \cdot \frac{168^2}{400} = 8.39\Omega$$

And the ratio between the inductance and the resistance, I will have:

$$\frac{X(1)}{R(1)} = \frac{8.82}{0.162} = 54.44 \qquad \frac{X(0)}{R(0)} = \frac{8.39}{0.141} = 59.50$$

The next table shows the results of the short-circuit voltage for the positive and the zero sequences [$U_K(1)$, $U_K(0)$], and the ratios between the inductance and the resistance for the different sequences for all the transformers:

Table 11.Transformer data.Voltage, and inductance/resistance ratios.

Trafo. From-to	Trafo nr.	S_r MVA	U_1 kV	U_2 kV	$U_R(1)$ %	$U_X(1)$ %	$U_K(1)$ %	$U_R(0)$ %	$U_X(0)$ %	$U_K(0)$ %	X(1)/R(1)	X(0)/R(0)
FGD5-FGD3	1	400	410	168	0,23	12,5	12,50	0,2	11,90	11,90	54,35	59,50
FGD5-FGD3	2	400	410	168	0,23	12,5	12,50	0,2	11,90	11,90	54,35	59,50
KIN5-KIN3		400	410	168	0,23	12,5	12,50	0,2	11,90	11,90	54,35	59,50
ABS3-ABS2	A	125	165	66	0,37	13,5	13,51	0	12,30	12,30	36,49	-
ABS3-ABS2	B	125	165	66	0,32	13,5	13,50	0	12,30	12,30	42,19	-
FGD3-FGD2	A	125	165	67	0,30	12,7	12,70	0	10,60	10,60	42,33	-
FGD3-FGD2	B	125	165	66	0,37	13,5	13,51	0	12,30	12,30	36,49	-
FVO3-FVB2	1	150	160	66	0,34	13,6	13,60	0	13,50	13,50	40,00	-
FVO3-FVA2	2	150	160	66	0,34	13,6	13,60	0	13,50	13,50	40,00	-
FVO3-FVA2	3	180	160	66	0,31	12,7	12,70	0	12,60	12,60	40,97	-
GRP3-GRP2	A	125	165	66	0,37	13,5	13,51	0	12,30	12,30	36,49	-
GRP3-GRP2	B	75	158	66	0,40	12,8	12,81	0	10,60	10,60	32,00	-
OSØ3-OSØ2		125	165	66	0,37	13,5	13,51	0	12,30	12,30	36,49	-
SVB3-SFV2	A	125	165	66	0,37	13,5	13,51	0	12,30	12,30	36,49	-
SVB3-SFV2	B	125	165	66	0,37	13,5	13,51	0	12,30	12,30	36,49	-
SØN3-SØN2	1	75	158	66	0,36	11,7	11,71	0	9,50	9,50	32,50	-
SØN3-SØN2	2	125	165	67	0,28	11,8	11,80	0	11,60	11,60	42,14	-
FBY2-FBY1	1	30	67	10	0,31	10,4	10,40	0,31	9,80	9,80	33,55	31,61
FBY2-FBY1	2	30	67	10	0,31	10,4	10,40	0,31	9,80	9,80	33,55	31,61

We will have to decide which kind of configuration I will want to have in my transformers. I already know that all the 150-60 kV transformers are YNd, but they could be YNd1, YNd5 or YNd11. The number at the end depends on that for different kind of connections, I will have different phase between the voltage in the primary side and the voltage on the secondary side. This value represents how the secondary side is retarded respect to the primary side, and it will be a multiple of 30°. The different configuration descriptions are:

- YNd1. The secondary side is 30° backward, or 330° forward
- YNd5. The secondary side is 150° backward, or 210° forward
- YNd11. The secondary side is 30° forward, or -330° backward

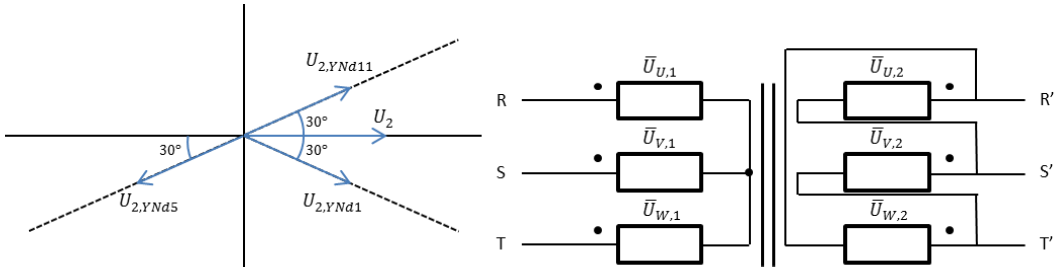


Figure 6.YNd transformer representation.

In this point, I can assume which kind of connection I are going to use by knowing that I will consider my transformer like ideal, with symmetrical load, and in a direct sequence.

$$\bar{U}_{RS,1} = \bar{U}_{U,1} - \bar{U}_{V,1}$$

$$\bar{U}_{RS,2} = \bar{U}_{U,2}$$

$$\frac{\bar{U}_{RS,1}}{\bar{U}_{RS,2}} = \frac{|\bar{U}_1|(1\angle 0 - 1\angle - 120)}{|\bar{U}_2|\angle 0} = \frac{\sqrt{3}|\bar{U}_1|\angle 30}{|\bar{U}_2|\angle 0} = \sqrt{3}\frac{N_1}{N_2}\angle 30$$

So now I can say that I will use the configuration YNd1, where the secondary side is 30° backward, or 330° forward respect to the primary side.

- Regulation

When working with NEPLAN, I have to introduce the values for the different parameters of each transformer. I will have to make also a regulation, and it will depend on the secondary side, which I consider the controlled node is located. This way, I will have to introduce the minimum ($U_{2,min}$), and the maximum ($U_{2,max}$) values which I could measure in the secondary side.

We will have to configure the "*tap position*", where I will choose the different voltages in a total of 21 different positions. The main positions are:

- Position 1. Minimum voltage value $\left(U_{2,min}\right)$
- Position 11. Rated voltage value (U_2)
- Position 21. Maximum voltage value $\left(U_{2,max}\right)$

The next table shows the values I have to introduce in NEPLAN for having well configured transformers. For a normal Load Flow Calculation, I used tap 11, what means nominal voltage values.

Table 12.Description of transformer tap positions.

Trafo.	Trafo nr.	U_2	$U_{2,min}$	$U_{2,max}$	Position 1 (Tap min)		Position 11 (Tap r)		Position 21 (Tap max)	
From-to		kV	kV	kV	$U_K(1)$ (%)	$U_K(0)$ (%)	$U_K(1)$ (%)	$U_K(0)$ (%)	$U_K(1)$ (%)	$U_K(0)$ (%)
FGD5-FGD3	1	168	135	194	10,05	9,56	12,50	11,90	14,44	13,74
FGD5-FGD3	2	168	135	194	10,05	9,56	12,50	11,90	14,44	13,74
KIN5-KIN3		168	135	194	10,05	9,56	12,50	11,90	14,44	13,74
ABS3-ABS2	A	66	54	78	11,05	10,06	13,51	12,30	15,96	14,54
ABS3-ABS2	B	66	54	78	11,05	10,06	13,50	12,30	15,96	14,54
FGD3-FGD2	A	67	59	78	11,19	9,33	12,70	10,60	14,79	12,34
FGD3-FGD2	B	66	54	78	11,05	10,06	13,51	12,30	15,96	14,54
FVO3-FVB2	1	66	54	78	11,13	11,05	13,60	13,50	16,08	15,95
FVO3-FVA2	2	66	54	78	11,13	11,05	13,60	13,50	16,08	15,95
FVO3-FVA2	3	66	54	78	10,39	10,31	12,70	12,60	15,01	14,89
GRP3-GRP2	A	66	54	78	11,05	10,06	13,51	12,30	15,96	14,54
GRP3-GRP2	B	66	54	78	10,48	8,67	12,81	10,60	15,13	12,53
OSØ3-OSØ2		66	54	78	11,05	10,06	13,51	12,30	15,96	14,54
SVB3-SFV2	A	66	54	78	11,05	10,06	13,51	12,30	15,96	14,54
SVB3-SFV2	B	66	54	78	11,05	10,06	13,51	12,30	15,96	14,54
SØN3-SØN2	1	66	58	75	10,29	8,35	11,71	9,50	13,30	10,80
SØN3-SØN2	2	67	59	76	10,39	10,21	11,80	11,60	13,39	13,16
FBY2-FBY1	1	10	8,5	11,5	8,84	8,33	10,40	9,80	11,97	11,28
FBY2-FBY1	2	10	8,5	11,5	8,84	8,33	10,40	9,80	11,97	11,28

As far as I know, the minimum value will be less than the nominal value, and it will be around the 80% of this rated value. On the other hand, the maximum value will be higher than the nominal value, and it will be up to 120% of this value.

The tap position for the transformers is not a relevant value for my analyses. However, I decided to calculate and configure them on NEPLAN.

III. Generators in Fynsværket

''Today more than 85,000 households and about 7,000 institutions (including large-scale greenhouses) and companies are supplied with district heating from Fyn Power Station. It supplies more than 98% of the total district heating available in the heating network – about 78% is generated at Units 3 and 7 and about 20% at Odense CHP Plant.

Fyn Power Station consists of three plant units and the Odense CHP Plant. Unit 3 was built in 1974 and decommissioned on 1 April 2010. Unit 7 was built in 1991 and uses coal and oil as fuel. The two large-scale plant units at Fyn Power Station, Units 3 and 7, burn about 800,000 tons of coal annually, most of which is brought to the power station on coal barges. Oil is basically only used for starting up the plants, while consumption of natural gas depends on supply and price, which vary substantially''[2]

a. Unit 3. FVO3

The generator on Fynsværket, Unit 3, supplies power to the 150 kV busbar FVO3 via a YNd11 coupled unit transformer. The configuration for the generator and the unit transformer are:

Table 13.Generator and unit transformer data, Unit 3 on Fynsværket.

Generator		Unit transformer, YNd11	
SG = 300 MVA	xd'' = 23 %	ST = 335 MVA	xk(1) = 11,5%
UG = 18,0 kV	xd´ = 34 %	U1 = 18,0 kV	xk(0) = 9,8%
		U2 = 170 kV	xyn = 0,0%

[2]Fyn Power Station, Vattenfall A/S.

We could calculate now the different parameters of the generator which I will need for calculating the short-circuit currents in the different lines. The parameters I have to calculate in this point are: the saturated synchronous reactance (xd sat), the negative sequence reactance (x(2)), and the zero sequence reactance (x(0)) of the synchronous machine.

If I consider the saturated transient reactance, the recommended values for the different kind of asynchronous machine are: Turbo-SM: (1.4,1.7)*xd", Salient pole with amortisseur (damper) winding: 20-45%. The provided value is xd'=34%, which is between the 20-45%, and also it is 1,4783 times the saturated subtransient reactance, what represents the 26.1% in this interval. By using this percent, I will calculate the rest of the parameters.

- Saturated synchronous reactance (xd sat). NEPLAN recommends values for the different kind of generator, and these values are: Turbo-SM: 120-270, Salient pole-SM: 70-130. I could consider a value between the two intervals, what could be xd sat=120%.
- Negative sequence reactancex(2). The recommended value for NEPLAN is x(2) = xd", so I will consider x(2)=23%
- Zero sequence reactancex(0). The recommended value for NEPLAN is x(0) = (0.4,0.8)*xd". If I use the 26.1%, the obtained value will be x(0)=10.44%

As I can see, the value in the secondary side is a maximum value. I talked before about the tap position, and I will have to use it again in this point, so I will make the next assumptions:

- Position 21. Maximum voltage value ~170 kV
- Position 11. Rated voltage value ~150 kV
- Position 1. Minimum value ~130 kV

Now I can calculate of the impedance and the resistance, and as I saw in the transformer calculations, I have to calculate the values for this unit transformer the same way I did before:

$$\left.\begin{array}{c} U_R(1) = ?\,\% \\ U_X(1) = ?\,\% \\ U_R(1) = 0.07 U_X(1) \\ U_K(1) = 11.5\% \end{array}\right\} U_K(1) = \sqrt{U_R(1)^2 + U_X(1)^2} = \sqrt{(0.07+1)U_X(1)^2}$$

$$U_K(1)^2 = (0.07+1)U_X(1)^2$$

$$U_X(1)^2 = \frac{U_K(1)^2}{(0.07+1)} \rightarrow U_X(1) = \sqrt{\frac{U_K(1)^2}{(0.07+1)}} \rightarrow U_X(1) = \sqrt{\frac{\left(\frac{11.5}{100}\right)^2}{(0.07+1)}}$$

$$\boldsymbol{U_X(1) = 11.11\%} \rightarrow \boldsymbol{U_R(1) = 0.07 U_X(1)} \rightarrow \boldsymbol{U_R(1) = 0.78\%}$$

Now I could calculate the values for the positive sequence impedance:

$$R(1) = \frac{U_R(1)}{100} \cdot \frac{U_2^2}{S_r} = \frac{0.78}{100} \cdot \frac{150^2}{335} = 0.52\Omega \quad ; \quad X(1) = \frac{U_X(1)}{100} \cdot \frac{U_2^2}{S_r} = \frac{11.11}{100} \cdot \frac{150^2}{335} = 7.46\Omega$$

We could calculate the values for the zero-sequence also:

$$\left.\begin{array}{r} U_R(0) = ?\,\% \\ U_X(0) = ?\,\% \\ U_R(0) = 0.07U_X(0) \\ U_K(0) = 9.8\% \end{array}\right\} U_K(0) = \sqrt{U_R(0)^2 + U_X(0)^2} = \sqrt{(0.07+1)U_X(0)^2}$$

$$U_X(0) = \sqrt{\frac{\left(\frac{9.8}{100}\right)^2}{(0.07+1)}}$$

$$\boldsymbol{U_X(0) = 9.47\% \rightarrow U_R(0) = 0.07U_X(0) \rightarrow U_R(0) = 0.66\%}$$

$$R(0) = \frac{U_R(0)}{100} \cdot \frac{U_2^2}{S_r} = \frac{0.66}{100} \cdot \frac{150^2}{335} = 0.44\Omega \quad ; \quad X(0) = \frac{U_X(0)}{100} \cdot \frac{U_2^2}{S_r} = \frac{9.47}{100} \cdot \frac{150^2}{335} = 6.36\Omega$$

And the ratio between the inductance and the resistance, I will have:

$$\frac{X(1)}{R(1)} = \frac{7.46}{0.52} = 14.29 \qquad \frac{X(0)}{R(0)} = \frac{6.36}{0.44} = 14.45$$

In order to follow my calculations, I have decided to apply the calculated values, although it is less than the half of the regular low value in NEPLAN (~35).

- Power configuration

When working with node type for Load Flow Calculation (LF), I have chosen the “PQ” value, due to I have the assumed power factor, and the apparent power (Sir), so I could calculate the real power (P), and the reactive power (Q) by using the power triangle.

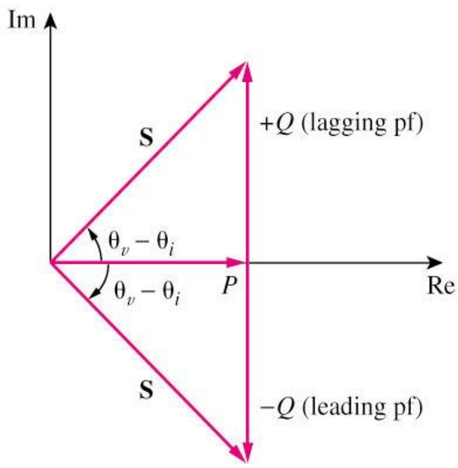


Figure 7. Powertriangledescription

We will assume a pf = 0.8, so I can calculate the real power to introduce this value on NEPLAN:

$$\left.\begin{array}{c} S = P + jQ \\ P = S \cdot cos(\theta_v - \theta_v) = S \cdot pf \\ S = 300MVA \\ pf = 0.8 \end{array}\right\}$$

$$P = 300 \cdot 0.8 = 240\ MW$$

$$Q = S \cdot sin(\theta_v - \theta_v)$$

$$Q = 300 \cdot 0.6 = 180\ MVAr$$

b. *Unit 7. FVO5*

The generator on Fynsværket, Unit 7, supplies power to the 400 kV busbar FVO5 via a YN/auto/d coupled unit transformer. The configuration for the generator and the unit transformer are:

Table 14.Generator and unit transformer data, Unit 7 on Fynsværket.

Generator		Unit transformer, YN/auto/d	
SG = 489 MVA	xd" = 24,7 %	ST = 445 MVA	xk(1) = 14,0%
UG = 21,0 kV	xd´ = 32,4 %	U1 = 21,0 kV	xk(0) = 9,2%
		U2 = 435 kV	xyn = 0,0%

We could calculate like I did before, the different parameters of this generator.

If I consider the saturated transient reactance, the recommended values for the different kind of asynchronous machine are: Turbo-SM: (1.4,1.7)*xd", Salient pole with amortisseur (damper) winding: 20-45%. The provided value is xd'=32.4%, which is between the 20-45%, and also it is 1,3117 times the saturated subtransient reactancexd'', what does not belong to the interval. By considering it, I will take the minimum recommended value for calculating the different parameters

- Saturated synchronous reactance (xd sat). The value will be the same like I took for the Unit 3, xd sat=120%.
- Negative sequence reactancex(2). The recommended value for NEPLAN is x(2) = xd", so I will consider x(2)=24.7%
- Zero sequence reactancex(0). The recommended value for NEPLAN is x(0) = (0.4,0.8)*xd". If I use the 26.1%, the obtained value will be x(0)=9.88%

Like in the Unit 3 calculations, I will have to work with the tap position. The position descriptions are:

- Position 21. Maximum voltage value ~435 kV
- Position 11. Rated voltage value ~410 kV
- Position 1. Minimum value ~385 kV

We will use the same calculations I used before:

$$\left.\begin{array}{c} U_R(1) = ?\,\% \\ U_X(1) = ?\,\% \\ U_R(1) = 0.07U_X(1) \\ U_K(1) = 14.0\% \end{array}\right\} U_K(1) = \sqrt{U_R(1)^2 + U_X(1)^2} = \sqrt{(0.07+1)U_X(1)^2}$$

$$U_X(1) = \sqrt{\frac{\left(\frac{14.0}{100}\right)^2}{(0.07+1)}}$$

$$\boldsymbol{U_X(1) = 13.53\%} \rightarrow \boldsymbol{U_R(1) = 0.07U_X(1)} \rightarrow \boldsymbol{U_R(1) = 0.95\%}$$

Now I could calculate the values for the positive sequence impedance:

$$R(1) = \frac{U_R(1)}{100} \cdot \frac{U_2^2}{S_r} = \frac{0.95}{100} \cdot \frac{410^2}{445} = 3.59\Omega \;;\; X(1) = \frac{U_X(1)}{100} \cdot \frac{U_2^2}{S_r} = \frac{13.53}{100} \cdot \frac{410^2}{445} = 51.11\Omega$$

We could calculate the values for the zero-sequence also:

$$\left.\begin{array}{c} U_R(0) = ?\,\% \\ U_X(0) = ?\,\% \\ U_R(0) = 0.07U_X(0) \\ U_K(0) = 9.2\% \end{array}\right\} U_K(0) = \sqrt{U_R(0)^2 + U_X(0)^2} = \sqrt{(0.07+1)U_X(0)^2}$$

$$U_X(0) = \sqrt{\frac{\left(\frac{9.2}{100}\right)^2}{(0.07+1)}}$$

$$\boldsymbol{U_X(0) = 8.89\%} \rightarrow \boldsymbol{U_R(0) = 0.07U_X(0)} \rightarrow \boldsymbol{U_R(0) = 0.62\%}$$

$$R(0) = \frac{U_R(0)}{100} \cdot \frac{U_2^2}{S_r} = \frac{0.62}{100} \cdot \frac{410^2}{445} = 2.34\Omega \quad ; \quad X(0) = \frac{U_X(0)}{100} \cdot \frac{U_2^2}{S_r} = \frac{8.89}{100} \cdot \frac{410^2}{445} = 33.58\Omega$$

And the ratio between the inductance and the resistance, I will have:

$$\frac{X(1)}{R(1)} = \frac{51.11}{3.59} = 14.24 \qquad\qquad \frac{X(0)}{R(0)} = \frac{33.58}{2.34} = 14.35$$

- Power configuration

Like I did before for the Unit 3, I will use the "PQ" value. Assuming a pf = 0.8, the calculation of the power will be:

$$\left.\begin{array}{c} S = P + jQ \\ P = S \cdot cos(\theta_v - \theta_v) = S \cdot pf \\ S = 489MVA \\ pf = 0.8 \end{array}\right\} P = 489 \cdot 0{,}8 = 391{,}2\ kW$$

$$Q = S \cdot sin(\theta_v - \theta_v) = 489 \cdot 0{,}6 = 293{,}4\ MVAr$$

c. *Configurations and results*

After having calculated all the values and parameters I need, I could introduce them on NEPLAN. These values are shown below.

Table 15. Unit 3, and Unit 7 tap positions.

Trafo.	U_2	$U_{2,min}$	$U_{2,max}$	Position 1 (Tap min)		Position 11 (Tap r)		Position 21 (Tap max)	
	kV	kV	kV	$U_K(1)$ (%)	$U_K(0)$ (%)	$U_K(1)$ (%)	$U_K(0)$ (%)	$U_K(1)$ (%)	$U_K(0)$ (%)
Unit 3	150	130	170	9,97	8,49	11,50	9,80	13,03	11,11
Unit 7	410	385	435	13,15	8,64	14,00	9,20	14,85	9,76

Table 16. Unit 3, and Unit 7 operational configuration

Trafo.	S_G	Cos (ϕ)	Operational		$U_X(0)$	$U_K(0)$	X(1)/R(1)	X(0)/R(0)
Fynsværket	MVA		PGen (MW)	QGen (MVAr)	%	%		
Unit3	300	0,8	240,00	180,00	9,43	9,80	14,29	14,45
Unit7	489	0,8	391,20	293,40	9,14	9,20	14,24	14,35

We have checked the values for the different possibilities: by using the results from my calculations by hand, and by using a Low value (X/R=30). As I can see below, there is a big difference between them. In fact, the X/R ratio will be two times bigger than my calculated values. That is, I will use the calculated parameters by hand.

Table 17. Data of unit transformers 3, and 7 on Fynsværket, using Low value (X/R=30).

Trafo.	$U_R(1)$	$U_X(1)$	$U_K(1)$	$U_R(0)$	$U_X(0)$	$U_K(0)$	X(1)/R(1)	X(0)/R(0)
Fynsværket	%	%	%	%	%	%		
Unit3	0,31	11,45	11,50	0,27	9,80	9,80	36,93	36,93
Unit7	0,42	14,12	14,00	0,27	9,08	9,20	33,62	33,62

Table 18.Data of unit transformers 3, and 7 on Fynsværket, using calculations by hand.

Trafo.	$U_R(1)$	$U_X(1)$	$U_K(1)$	$U_R(0)$	$U_X(0)$	$U_K(0)$	X(1)/R(1)	X(0)/R(0)
Fynsværket	%	%	%	%	%	%		
Unit3	0,80	11,43	11,50	0,66	9,43	9,80	14,29	14,45
Unit7	0,98	14	14,00	0,64	9,14	9,20	14,24	14,35

Like I motioned before, I will need few values for the calculation of the short-circuit currents of different lines. These values are the saturated transient reactance (xd' sat), the saturated subtransient reactance (xd'' sat), the saturated synchronous reactance (xd sat),the negative sequence reactance x(2), and the zero sequence reactance x(0).

Table 19.Reactance data of unit transformers 3, and 7 on Fynsværket.

Trafo.	xd sat	xd' sat	xd'' sat	x(0)	x(2)
	%	%	%	%	%
Unit 3	120	34	23	10,44	23
Unit 7	120	32,4	24,7	9,88	24,7

IV. Analyses.

Having everything perfectly configured, I can start the analyses of the network. First at all, I will describe the steady state for normal conditions. The general obtained results for this network are:

Table 20.400/150 kV Network of Funen values for normal conditions.

From	P Loss	Q Loss	P Imp	Q Imp	P Gen	Q Gen	P Load	Q Load
Area/Zone	MW	MVar	MW	MVar	MW	MVar	MW	MVar
Network	3,859	51,134	-184,341	-199,266	682,376	476,75	678,517	425,617
Zone 1	3,859	51,134	0	0	682,376	476,75	678,517	425,617

As I can see, my network will be connected to the grid (network feeders N1 and N2). In one of the sides (410kV), it will be delivering power to the grid, and in the other side (150kV), it will be supplied by the grid.

At the beginning of the configurations, I could check how the power losses were 2 times bigger. By configuring the saturated synchronous reactance (xd sat) of the Unit 3, and Unit 7, I reduced them to 3,859 MW.

Table 21.Power and Losses data of 400-150 kV Network of Funen for normal conditions.

Un	P Loss Line	Q Loss Line	P Loss Transformer	Q Loss Transformer
kV	MW	MVar	MW	MVar
165	0,85	-35,198	0,9	41,911
410	1,014	-20,392	1,094	64,813

All the busbars are perfectly supplied, between a margin of [98,93%,104,41%], what means I will have, at maximum, a voltage drop around 9kV (FVO5).

Table 22.Node data of 400-150 kV Network of Funen for normal conditions.

Node Name	U kV	u %	Angle U °	P Load MW	Q Load MVar	P Gen MW	Q Gen MVar	ΔU kV
ABS2	65,255	98,87	-3,2	58	29	0	0	-0,7374
ABS3	165,965	100,58	-1,4	0	0	0	0	0,9626
FGD2	67,189	101,8	-1,8	58	29	0	0	1,2094
FGD3	169,366	102,65	-0,1	0	0	0	0	4,4882
FGD5	416,087	101,48	0,9	0	0	0	0	6,1581
FVA2	68,91	104,41	-1,7	77	39	0	0	3,0389
FVB2	68,257	103,42	-2,6	53	27	0	0	2,3344
FVO3	169,603	102,79	-0,1	0	0	0	0	4,7319
FVO5	418,859	102,16	1,5	0	0	0	0	9,0474
GRP2	67,49	102,26	-2	47	24	0	0	1,5253
GRP3	168,608	102,19	-0,3	0	0	0	0	3,6925
KIN3	168,733	102,26	-0,3	0	0	0	0	3,8134
KIN5	412,695	100,66	0,4	0	0	0	0	2,7238
LAG5	410	100	0	235,517	202,617	0	0	0,0000
OSØ2	66,047	100,07	-2,8	45	22	0	0	0,0462
OSØ3	169,441	102,69	-0,1	0	0	0	0	4,5580
SFV2	65,29	98,92	-3,4	58	29	0	0	-0,7051
SHE3	165	100	0	0	0	51,176	3,35	0,0000
SØN2	66,392	100,59	-2,6	47	24	0	0	0,3917
SØN3	164,196	99,51	-1,1	0	0	0	0	-0,8046
SVB3	166,062	100,64	-1,6	0	0	0	0	1,0628
Unit 3	21,277	118,2	3,4	0	0	240	180	3,8724
Unit 7	23,128	110,13	7,7	0	0	391,2	293,4	2,3429

The sharing of the load could be considered properly, due to as I can see, the maximum load in one node will be less than the 40% of the permissible load on this point.

Table 23.Line data of 400-150 kV Network of Funen for normal conditions.

Node	Element	P	Q	I	Angle I	Loading	P Fe	P Comp
Name	Name	MW	MVar	kA	°	%	MW	MW
ABS3	ABS3-SØN3	-59,174	-42,475	0,253	142,9	33,34	0,3131	-0,3078
ABS3	ABS3-SVB3	4,991	-2,488	0,019	25,1	1,96	0,0021	-1,3906
ABS3	ABS3-FVO3	-3,876	13,64	0,049	-107,3	10,96	0,0644	-8,3427
FGD3	FGD3-FVO3	7,951	-6,466	0,035	39	3,01	0,0013	-0,2495
FGD3	FGD3-OSØ3	-0,888	-16,093	0,055	93,1	7,23	0,0035	-6,474
FGD3	FGD3-SVB3	53,294	31,378	0,211	-30,6	15,28	0,2199	-1,0407
FGD5	FGD5-LAG5	127,657	91,737	0,218	-34,8	13,63	0,288	-11,3253
FGD5	FGD5-FVO5	-389,723	-229,169	0,627	150,5	39,21	0,4349	2,2153
FGD5	FGD5-KIN5	143,608	94,938	0,239	-32,5	14,93	0,1844	-5,9911
FVO3	FGD3-FVO3	0,892	9,619	0,033	-84,8	4,33	0,0035	-6,474
FVO3	FVO3-OSØ3	37,144	24,735	0,152	-33,8	21,1	0,0195	-6,1881
FVO3	FVO3-GRP3	11,961	9,661	0,052	-39	7,27	0,03	-2,3796
FVO3	ABS3-FVO3	59,487	42,167	0,248	-35,4	32,66	0,3131	-0,3078
FVO5	FGD5-FVO5	390,157	231,384	0,625	-29,2	39,08	0,4349	2,2153
GRP3	GRP3-KIN3	-11,931	-12,04	0,058	134,4	8,06	0,03	-2,3796
GRP3	FVO3-GRP3	-35,144	-14,453	0,13	157,3	17,12	0,0165	-8,1818
KIN3	GRP3-KIN3	35,16	6,271	0,122	-10,4	16,08	0,0165	-8,1818
KIN5	KIN5-LAG5	108,256	94,263	0,201	-40,7	12,55	0,1069	-5,2913
KIN5	FGD5-KIN5	-143,423	-100,929	0,245	145,2	15,33	0,1844	-5,9911
LAG5	FGD5-LAG5	-127,368	-103,062	0,231	141	14,42	0,288	-11,3253
LAG5	KIN5-LAG5	-108,149	-99,555	0,207	137,4	12,94	0,1069	-5,2913
OSØ3	FGD3-OSØ3	-7,95	6,216	0,034	-142,1	2,96	0,0013	-0,2495
OSØ3	FVO3-OSØ3	-37,125	-30,923	0,165	140,1	22,87	0,0195	-6,1881
SHE3	SHE3-SØN3	51,176	3,35	0,179	-3,7	21,11	0,1801	-0,6435
SØN3	SHE3-SØN3	3,941	-21,983	0,079	78,8	17,45	0,0644	-8,3427
SØN3	ABS3-SØN3	-50,996	-3,994	0,18	174,4	21,16	0,1801	-0,6435
SVB3	ABS3-SVB3	-4,989	1,098	0,018	-169,2	1,79	0,0021	-1,3906
SVB3	FGD3-SVB3	-53,075	-32,419	0,216	147	15,67	0,2199	-1,0407

Like I assumed before, I will work with using a tap 11 configuration for all the transformers. The tap 1 and tap 21 are not really relevant as I could check.

Table 24.Transformer data of 400-150 kV Network of Funen for normal conditions.

Node Name	Element Name	P MW	Q MVar	I kA	Angle I °	P Fe MW	P Comp MW	Q Comp MVar	Tap
ABS2	ABS3-ABS2 A	-28,984	-14,559	0,287	150,1	0,0276	1,162	0	11
ABS2	ABS3-ABS2 B	-29,016	-14,441	0,287	150,3	0,0318	1,161	0	11
ABS3	ABS3-ABS2 A	29,012	15,721	0,115	-29,9	0,0276	1,162	0	11
ABS3	ABS3-ABS2 B	29,048	15,602	0,115	-29,7	0,0318	1,161	0	11
FGD2	FGD3-FGD2 B	-28,162	-6,785	0,249	164,7	0,024	0,8748	0	11
FGD2	FGD3-FGD2 A	-29,838	-22,214	0,32	141,6	0,033	1,3977	0	11
FGD3	FGD5-FGD3 2	-59,207	-20,046	0,213	161,2	0,0221	1,2012	0	11
FGD3	FGD3-FGD2 A	-59,207	-20,046	0,213	161,2	0,0221	1,2012	0	11
FGD3	FGD3-FGD2 B	28,186	7,66	0,1	-15,3	0,024	0,8748	0	11
FGD3	FGD5-FGD3 1	29,871	23,612	0,13	-38,4	0,033	1,3977	0	11
FGD5	FGD5-FGD3 2	59,229	21,247	0,087	-18,8	0,0221	1,2012	0	11
FGD5	FGD5-FGD3 1	59,229	21,247	0,087	-18,8	0,0221	1,2012	0	11
FVA2	FVO3-FVA2 3	-33,703	-17,056	0,316	151,5	0,0297	1,1863	0	11
FVA2	FVO3-FVA2 2	-43,297	-21,944	0,407	151,5	0,0372	1,5245	0	11
FVB2	FVO3-FVB2 1	-53	-27	0,503	150,4	0,075	2,9982	0	11
FVO3	FVO3-FVB2 1	53,075	29,998	0,208	-29,6	0,075	2,9982	0	11
FVO3	Unit 3	-239,626	-157,891	0,977	146,5	0,374	22,1091	0	11
FVO3	FVO3-FVA2 3	33,733	18,243	0,131	-28,5	0,0297	1,1863	0	11
FVO3	FVO3-FVA2 2	43,334	23,468	0,168	-28,5	0,0372	1,5245	0	11
FVO5	Unit 7	-390,157	-231,384	0,625	150,8	1,0425	62,0158	0	11
GRP2	GRP3-GRP2 A	-19,208	-25,83	0,275	124,7	0,0528	1,6916	0	11
GRP2	GRP3-GRP B	-27,792	1,83	0,238	-178,2	0,022	0,8015	0	11
GRP3	GRP3-GRP2 A	27,814	-1,029	0,095	1,8	0,022	0,8015	0	11
GRP3	GRP3-GRP B	19,261	27,522	0,115	-55,3	0,0528	1,6916	0	11
KIN3	KIN5-KIN3	-35,16	-6,271	0,122	169,6	0,0073	0,3951	0	11
KIN5	KIN5-KIN3	35,167	6,666	0,05	-10,4	0,0073	0,3951	0	11
OSØ2	OSØ3-OSØ2	-45	-22	0,438	151,1	0,0742	2,7068	0	11
OSØ3	OSØ3-OSØ2	45,074	24,707	0,175	-28,9	0,0742	2,7068	0	11
SFV2	SVB3-SFV2 A	-29	-14,5	0,287	150,1	0,0318	1,1606	0	11
SFV2	SVB3-SFV2 B	-29	-14,5	0,287	150,1	0,0318	1,1606	0	11
SØN2	SØN3-SØN2 1	-28,284	-3,367	0,248	170,6	0,0185	0,7798	0	11
SØN2	SØN3-SØN2 2	-18,716	-20,633	0,242	129,6	0,0368	1,1968	0	11
SØN3	SØN3-SØN2 1	28,303	4,146	0,101	-9,4	0,0185	0,7798	0	11
SØN3	SØN3-SØN2 2	18,753	21,83	0,101	-50,4	0,0368	1,1968	0	11
SVB3	SVB3-SFV2 B	29,032	15,661	0,115	-29,9	0,0318	1,1606	0	11
SVB3	SVB3-SFV2 A	29,032	15,661	0,115	-29,9	0,0318	1,1606	0	11
Unit 3	Unit 3	240	180	8,141	-33,5	0,374	22,1091	0	11
Unit 7	Unit 7	391,2	293,4	12,207	-29,2	1,0425	62,0158	0	11

A priori, there are a number of transformers I should have in mind, due to they could be considered like special components. I will study them because of they have no regular values on the *Table 11. Transformer data.Voltage, and inductance/resistance ratios*.These transformers are, at least, the transformers I have to analyze like critical components, and they are shown on the next table.

Table25. Possiblecriticaltransformers.

Trafo. From-to	Trafo nr.	S_r MVA	U_1 kV	U_2 kV
FGD5-FGD3	1	400	410	168
FGD5-FGD3	2	400	410	168
KIN5-KIN3		400	410	168
ABS3-ABS2	A	125	165	66
ABS3-ABS2	B	125	165	66
FGD3-FGD2	A	125	165	67
FGD3-FGD2	B	125	165	66
FVO3-FVB2	1	150	160	66
FVO3-FVA2	2	150	160	66
FVO3-FVA2	3	180	160	66
GRP3-GRP2	A	125	165	66
GRP3-GRP2	B	75	158	66
OSØ3-OSØ2		125	165	66
SVB3-SFV2	A	125	165	66
SVB3-SFV2	B	125	165	66
SØN3-SØN2	1	75	158	66
SØN3-SØN2	2	125	165	67
FBY2-FBY1	1	30	67	10
FBY2-FBY1	2	30	67	10

- FVO3-FVB2 (1), FVO3-FVA2 (2). These transformers have different values from the others: Sr=150 MVA, U1=160 kV. This is because the generator on Fynsværket, Unit 3, which supply power to the 150 kV busbar FVO3.
- FVO3-FVA2 (3). As I can see, the power that this transformer can handle is up to 180 MVA. It means that this one is the main transformer between FVO3 and FVA2.
- GRP3-GRP2 (B), SØN3-SØN2 (1). I are in the same conditions: Sr=75MVA, U1=158 kV. Both have a partner transformer with the next values: Sr=125 MVA, U1=165 kV. As I know, the transformers I are studying won't be able to handle the entire load if the "*Transformer A*" between the nodes is not working. I will have to check about the voltage out, because is less than the nominal value

Table 26.Network feeder data of 400-150 kV Network of Funen for normal conditions.

Node Name	Element Name	P MW	Q MVar	I kA	Angle I °
LAG5	N1	235,517	202,617	0,437	-40,7
SHE3	N2	-51,176	-3,35	0,179	176,3

These results have been obtained, like I have said before at the Feeder Assumptions, by using a 50% Slack in each feeder

Table 27.Asynchronous machine data of 400-150 kV Network of Funen for normal conditions.

Node Name	Element Name	P MW	Q MVar	I kA	Angle I °
Unit 3	Unit3	-240	-180	8,141	146,5
Unit 7	Unit7	-391,2	-293,4	12,207	150,8

The angle of the load data just shows me the YNd1 configuration of the transformers on these places.

Table 28. Load data of 400-150 kV Network of Funen for normal conditions.

Node Name	Element Name	P MW	Q MVar	I kA	Angle I °
ABS2	ABS2	58	29	0,574	-29,8
FGD2	FGD2	58	29	0,557	-28,3
FVA2	FVA2	77	39	0,723	-28,5
FVB2	FVB2	53	27	0,503	-29,6
GRP2	GRP2	47	24	0,451	-29
OSØ2	OSØ2	45	22	0,438	-28,9
SFV2	SFV2	58	29	0,573	-29,9
SØN2	SØN2	47	24	0,459	-29,7

V. Critical Operation Conditions

We will consider some situations, with different operation conditions of the network where some of the lines, transformers or generators are disconnected due to maintenance or faults. These situations are considered realistic, what means that all the 150kV busbars are still supplied with power. In this point I will have to work with the Normal Operation and (N-1)-Security Check.

''There is a difference between the optimization of the system in the normal operation case and in the case of line failures. Several load flow calculations are performed in order to estimate the ranges of values of the node voltages and the element loadings. The results are the ranges of values of the node voltages and the maximum loadings of the elements (lines, cables, transformers).

The (N-1)-security check simulates a failure for each element of the considered voltage level. If some part of the system is out of service because of this failure, the procedure changes the network topology in order to resupply this part and to minimize losses (optimal separation point procedures). An evaluation of the new network state is done after each failure. The results are the ranges of values of the node voltages and the maximum loadings of the elements (lines, cables, transformers)''.[3]

a. Network feeders

We will study the two possible situations, which one of them is not completely probable. That is when the 410 kV network feeder (N1) will be disconnected. However, I will consider it.

These will be the possible situations due to having both feeders switched off, it will be something that cannot happen. The network has to be supplied.

- Network Feeder N1 is disconnected

Like I mentioned before, the disconnection of the network feeder N1 will not happen. It will mean a 400 kV broken underground cable. I could check how the power losses increased for this situation, and it was around 3.5 times bigger than for normal conditions.

Table 29.400/150 kV Network of Funen values for disconnected Network Feeder N1.

From Area/Zone	P Loss MW	Q Loss MVar	P Imp MW	Q Imp MVar	P Gen MW	Q Gen MVar	P Load MW	Q Load MVar
Network	26,679	72,634	-161,521	-177,766	631,2	473,4	604,521	400,766
Area 1	26,679	72,634	0	0	631,2	473,4	604,521	400,766
Zone 1	26,679	72,634	0	0	631,2	473,4	604,521	400,766

Table 30. Power and Losses data of 400-150 kV Network of Funen for disconnected Network Feeder N1.

Un kV	P Loss Line MW	Q Loss Line MVar	P Loss Transformer MW	Q Loss Transformer MVar
165	24,894	47,88	0,586	26,807
410	0,288	-54,783	0,911	52,73

[3] Normal Operation and (N-1)-Security Check, NEPLAN Tutorial

Table 31. Node and line overload data of 400-150 kV Network of Funen for disconnected Network Feeder N1.

Overloads			
Nodes (upper) %			
FVA2	136,59	LAG5	134,65
GRP2	136,5	KIN5	134,54
FVB2	135,86	FGD3	134,1
KIN3	135,65	FGD2	133,9
GRP3	135,43	OSØ3	133,69
FVO5	135,25	FVO3	133,62
FGD5	134,69	OSØ2	131,73
Lines			
ABS3-SØN3	222,27	ABS3-FVO3	112,41

As I can see, this situation will be a complete disaster. All the nodes are violating the upper voltage limits, except from 2, which have an overvoltage of 107,83%, and 109,26%. The rest of the nodes, are around 130% up, what means about 550kV at the 410kV nodes, practically impossible to manage.

- Network Feeder N2 is disconnected

This case could be more possible than the circumstance I studied before. In this situation, the network works perfectly, like for normal conditions delivering power to the grid, and even the network feeder for the 400-150 kV side (N1) will be delivering power to the grid.

Table 32.400/150 kV Network of Funen values for disconnected Network Feeder N2.

From Area/Zone	P Loss MW	Q Loss MVar	P Imp MW	Q Imp MVar	P Gen MW	Q Gen MVar	P Load MW	Q Load MVar
Network	4,534	56,786	-183,666	-193,614	631,2	473,4	626,666	416,614
Area 1	4,534	56,786	0	0	631,2	473,4	626,666	416,614
Zone 1	4,534	56,786	0	0	631,2	473,4	626,666	416,614

Table 33. Power and Losses data of 400-150 kV Network of Funen for disconnected Network Feeder N2.

Un kV	P Loss Line MW	Q Loss Line MVar	P Loss Transformer MW	Q Loss Transformer MVar
165	1,612	-30,454	0,906	42,194
410	0,88	-21,996	1,135	67,042

The voltage drops on the nodes are around 97,63% to 104,12%, what meets the ±10% rule I have considered.

b. Lines

As I know, for realistic considerations, all the 150kV busbars are still supplied with power, and this is the definition of n-1 elements. I cannot work when one node is not supplied.

We will analyze only the really extreme situations, due to there is a really large number of plausible states. After trying a few numbers of possible problems, I will show only the problematic ones, where there will some overloaded elements or violated upper or lower voltage limits, what means around ±10% of the rated voltage in each element. The different values for the different nodes can be seen below.

Table 34. ±10% limits for the 410kV, 165kV, and 66kV nodes.

node kV	plus 10% kV	minus 10% kV
410	451	369
165	181,5	148,5
66	72,6	59,4

Few possible situations are shown on the *Appendix Excel 400-150 kV Network*, but I will study here only some of them.

- 410 kV lines are disconnected

In this case, I have checked the possible situations were one or two 410kV lines are disconnected, and I have seen that it works without any problem.

These examples are shown in *Appendix Excel 400-150 kV Network*

- ABS3-FVO3, and FG3-SVB3 are disconnected

For this condition, I will work with two different networks due to one of them will be formed with the 150kV busbars in Enstedværket, Sønderborg, Abildskov, and Svendborg. It will mean that I won't have one ring, I will have two radial networks instead.

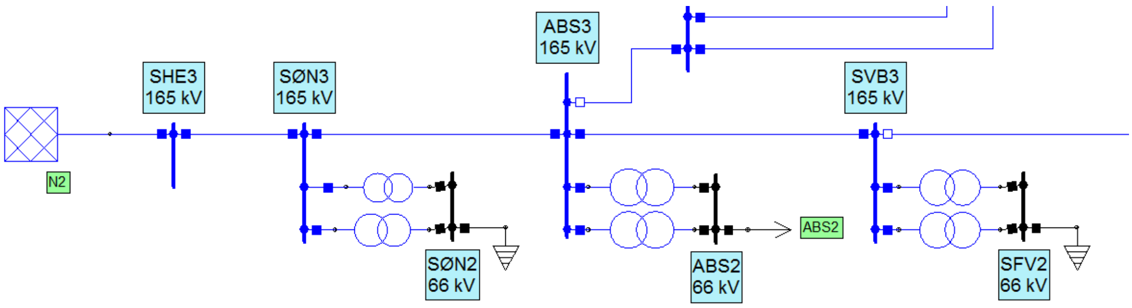


Figure 8. 150-60 kV Network of Funen when ABS3-FVO3, and FG3-SVB3 are disconnected.

Table 35. 150-60 kV Network of Funen when ABS3-FVO3, and FG3-SVB3 are disconnected.

From Area/Zone	P Loss MW	Q Loss MVar	P Imp MW	Q Imp MVar	P Gen MW	Q Gen MVar	P Load MW	Q Load MVar
Network	11,65	85,433	-176,55	-164,967	802,281	588,462	790,631	503,029
Area 1	11,65	85,433	0	0	802,281	588,462	790,631	503,029
Zone 1	11,65	85,433	0	0	802,281	588,462	790,631	503,029

Table 36. Power and Losses data of 150-60 kV Network of Funen when ABS3-FVO3, and FG3-SVB3 are disconnected.

Un kV	P Loss Line MW	Q Loss Line MVar	P Loss Transformer MW	Q Loss Transformer MVar
165	8,159	-4,714	0,931	42,801
410	1,522	-14,39	1,038	61,736

Table 37.Line overload data of 150-60 kV Network of Funen when ABS3-FVO3, and FG3-SVB3 are disconnected.

Overloads	
Line	
ABS3-SØN3	119,9

Table 38. Line data of 150-60 kV Network of Funen when ABS3-FVO3, and FG3-SVB3 are disconnected.

Node Name	Element Name	P MW	Q MVar	I kA	Angle I °	Loading %	P Fe MW	P Comp MW
ABS3	ABS3-FVO3	0	0	0	90	0	0,0001	-2,7414
ABS3	ABS3-SVB3	58,547	34,603	0,273	-38,3	27,58	0,4555	2,2622
ABS3	ABS3-SØN3	-116,627	-66,736	0,54	142,5	119,9	4,4778	7,8484
FGD3	FGD3-OSØ3	-8,816	-21,73	0,079	113,1	6,78	0,0064	-0,222
FGD3	FGD3-FVO3	-17,66	-31,393	0,121	120,4	15,9	0,0226	-6,5966
FGD3	FGD3-SVB3	0	-3,21	0,011	91	0,78	0,0001	-3,2095
FGD5	FGD5-LAG5	176,89	129,312	0,302	-34,9	18,9	0,5453	-8,265
FGD5	FGD5-FVO5	-389,736	-229,822	0,624	150,8	39,03	0,4309	2,1358
FGD5	FGD5-KIN5	181,263	125,392	0,304	-33,4	19,01	0,2976	-4,6786
FVO3	FGD3-FVO3	17,683	24,796	0,102	-53,4	13,4	0,0226	-6,5966
FVO3	FVO3-OSØ3	53,935	39,766	0,224	-35,3	31,13	0,0415	-6,3536
FVO3	FVO3-GRP3	37,883	25,27	0,152	-32,6	21,16	0,2364	-1,7003
FVO3	ABS3-FVO3	0	-2,741	0,009	91,1	1,21	0,0001	-2,7414
FVO5	FGD5-FVO5	390,167	231,958	0,622	-28,9	38,9	0,4309	2,1358
GRP3	FVO3-GRP3	-37,646	-26,97	0,157	144,8	21,84	0,2364	-1,7003
GRP3	GRP3-KIN3	-9,428	0,495	0,032	-176,6	4,22	0,0013	-8,3551
KIN3	GRP3-KIN3	9,429	-8,85	0,044	43,6	5,78	0,0013	-8,3551
KIN5	KIN5-LAG5	171,535	138,87	0,308	-38,4	19,24	0,2484	-3,5818
KIN5	FGD5-KIN5	-180,965	-130,071	0,311	144,9	19,43	0,2976	-4,6786
LAG5	FGD5-LAG5	-176,344	-137,577	0,315	142	19,68	0,5453	-8,265
LAG5	KIN5-LAG5	-171,287	-142,451	0,314	140,3	19,61	0,2484	-3,5818
OSØ3	FGD3-OSØ3	8,822	21,508	0,078	-66,7	6,71	0,0064	-0,222
OSØ3	FVO3-OSØ3	-53,894	-46,119	0,238	140,5	33	0,0415	-6,3536
SHE3	SHE3-SØN3	171,081	115,062	0,721	-33,9	84,87	2,917	14,3536
SØN3	ABS3-SØN3	121,105	74,584	0,526	-35	116,81	4,4778	7,8484
SØN3	SHE3-SØN3	-168,164	-100,708	0,724	145,7	85,22	2,917	14,3536
SVB3	ABS3-SVB3	-58,092	-32,34	0,275	140,9	27,79	0,4555	2,2622
SVB3	FGD3-SVB3	0	0	0	90	0	0,0001	-3,2095

Table 39.Node data of 150-60 kV Network of Funen when ABS3-FVO3, and FG3-SVB3 are disconnected.

Node	U	u	U ang	P Load	Q Load	P Gen	Q Gen
	kV	%	º	MW	MVAr	MW	MVAr
ABS2	56,187	85,13	-10,1	58	29	0	0
ABS3	143,784	87,14	-7,7	0	0	0	0
FGD2	68,284	103,46	-0,6	58	29	0	0
FGD3	172,039	104,27	1	0	0	0	0
FGD5	418,326	102,03	1,3	0	0	0	0
FVA2	70,167	106,31	-0,4	77	39	0	0
FVB2	69,528	105,35	-1,3	53	27	0	0
FVO3	172,603	104,61	1,1	0	0	0	0
FVO5	421,09	102,7	1,8	0	0	0	0
GRP2	68,093	103,17	-1,2	47	24	0	0
GRP3	170,066	103,07	0,4	0	0	0	0
KIN3	170,062	103,07	0,4	0	0	0	0
KIN5	413,936	100,96	0,6	0	0	0	0
LAG5	410	100	0	347,631	280,029	0	0
OSØ2	67,249	101,89	-1,5	45	22	0	0
OSØ3	172,363	104,46	1	0	0	0	0
SFV2	54,426	82,46	-12,5	58	29	0	0
SHE3	165	100	0	0	0	171,081	115,062
SØN2	63,061	95,55	-5,1	47	24	0	0
SØN3	156,222	94,68	-3,4	0	0	0	0
SVB3	139,508	84,55	-10	0	0	0	0
Unit 3	21,623	120,13	4,5	0	0	240	180
Unit 7	23,235	110,64	8	0	0	391,2	293,4

- GRP3-FVO3, FGD3-ØSØ3, and FGD3-FVO3 are disconnected

Like I had before, in this case I will make the configuration of 2 separated networks. The part of the whole network which I will study will be the portion formed with the 150kV busbarson Enstedværket, Sønderborg, Abildskov, Svendborg, Odense, and both sides on Fynsværket (150kV, and 60 kV).

We have checked that everything works in an almostperfect way, so I will not show the results here. They are shown on the *Appendix Excel 400-150 kV Network.*

- ABS3-FVO3, FVO3-ØSØ3, and FGD3-FVO3 are disconnected

In this case, I will found high voltage values at Fynsværket, and some busbarswill not meet the ±10% concerning the rated voltage.

Table 40.Node data of 150-60 kV Network of Funen when ABS3-FVO3, FVO3-ØSØ3, and FG3-FVO3 are disconnected.

Node	U	u	U ang	P Load	Q Load	P Gen	Q Gen
	kV	%	º	MW	MVAr	MW	MVAr
ABS2	62,877	95,27	-5,2	58	29	0	0
ABS3	160,134	97,05	-3,3	0	0	0	0
FGD2	66,35	100,53	-2,4	58	29	0	0
FGD3	167,321	101,41	-0,7	0	0	0	0
FGD5	415,22	101,27	0,9	0	0	0	0
FVA2	74,101	112,27	2	77	39	0	0
FVB2	73,501	111,37	1,2	53	27	0	0
FVO3	182	110,3	3,3	0	0	0	0
FVO5	417,996	101,95	1,4	0	0	0	0
GRP2	69,591	105,44	0	47	24	0	0
GRP3	173,687	105,26	1,6	0	0	0	0
KIN3	173,224	104,98	1,5	0	0	0	0
KIN5	413,501	100,85	0,5	0	0	0	0
LAG5	410	100	0	270,435	215,835	0	0
OSØ2	64,986	98,46	-3,7	45	22	0	0
OSØ3	166,864	101,13	-0,9	0	0	0	0
SFV2	63,66	96,45	-4,7	58	29	0	0
SHE3	165	100	0	0	0	89,014	30,447
SØN2	65,54	99,3	-3,4	47	24	0	0
SØN3	162,156	98,28	-1,8	0	0	0	0
SVB3	162,063	98,22	-2,9	0	0	0	0
Unit 3	22,711	126,17	6,4	0	0	240	180
Unit 7	23,086	109,93	7,6	0	0	391,2	293,4

c. Transformers

We want to know if the transformers will be able to work when, for example, one of them won't be working (in the case of two transformers between two nodes), or even if one of them could handle the load through itself. And also I would like to know the behavior of the network when some of them are off at the same time. I will also make a simulation of "breaking" the ring, and splitting it into two different areas (400 kV, and 150-60 kV) to know what could happen in these conditions.

The different operation conditions for transformers I have considered are shown on the *Appendix Excel 400-150 kV Network*. Like I will see, the network is so perfectly calculated that it will work for the different combinations: when I will have only one disconnected, when two are disconnected too, or even when I will have seven transformers off.

We have found one possible problematic situation, and I are going to study it. I will see how this example shows how the network will behave when all the 400-150 kV transformers will be disconnected. Like I mentioned before, it will represent again the division of the whole network in two different networks, the 410kV and the 150-60kV sides. The schematic and the obtained results are:

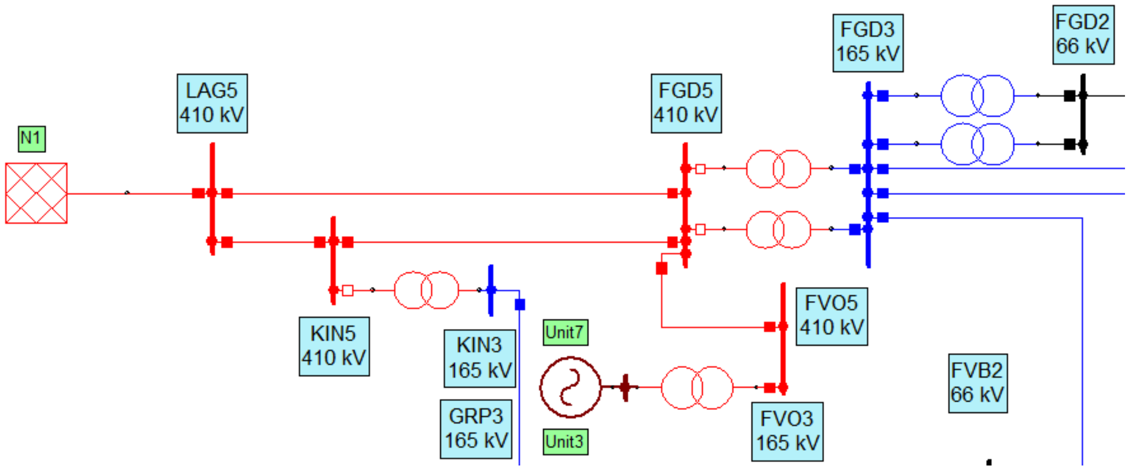


Figure 9.400-150 kV Network of Funen when KIN5-KIN3, FGD5/FGD3 1, and FGD5/FGD3 2 are disconnected.

Table 41.Transformer data of 400-150 kV Network of Funen when KIN5-KIN3, FGD5-FGD3 1, and FGD5-FGD3 2 are disconnected.

Node Name	Element Name	P MW	Q MVar	I kA	Angle I °	P Loss MW	Q Loss MVar	Tap
ABS2	ABS3-ABS2 A	-28,984	-14,559	0,341	140	0,0388	1,6374	11
ABS2	ABS3-ABS2 B	-29,016	-14,441	0,34	140,2	0,0448	1,636	11
ABS3	ABS3-ABS2 A	29,023	16,196	0,136	-40	0,0388	1,6374	11
ABS3	ABS3-ABS2 B	29,061	16,077	0,136	-39,8	0,0448	1,636	11
FGD2	FGD3-FGD2 B	-28,225	-9,261	0,314	146,5	0,0381	1,3899	11
FGD2	FGD3-FGD2 A	-29,775	-19,739	0,377	131,2	0,046	1,9475	11
FGD3	FGD5-FGD3 2	0	0	0	90	0	0	11
FGD3	FGD5-FGD3 1	0	0	0	90	0	0	11
FGD3	FGD3-FGD2 B	28,263	10,651	0,126	-33,5	0,0381	1,3899	11
FGD3	FGD3-FGD2 A	29,821	21,687	0,153	-48,8	0,046	1,9475	11
FGD5	FGD5-FGD3 2	0	0	0	90	0	0	11
FGD5	FGD5-FGD3 1	0	0	0	90	0	0	11
FVA2	FVO3-FVA2 3	-33,703	-17,056	0,387	138,3	0,0445	1,7779	11
FVA2	FVO3-FVA2 2	-43,297	-21,944	0,498	138,3	0,0558	2,2847	11
FVB2	FVO3-FVB2 1	-53	-27	0,619	136,8	0,1136	4,5422	11
FVO3	FVO3-FVB2 1	53,114	31,542	0,255	-43,2	0,1136	4,5422	11
FVO3	Unit 3	-239,468	-148,541	1,165	135,7	0,5322	31,4595	11
FVO3	FVO3-FVA2 3	33,748	18,834	0,16	-41,7	0,0445	1,7779	11
FVO3	FVO3-FVA2 2	43,353	24,228	0,205	-41,7	0,0558	2,2847	11
FVO5	Unit 7	-390,164	-231,769	0,623	151,3	1,0361	61,6309	11
GRP2	GRP3-GRP2 A	-19,035	-20,026	0,294	117	0,0604	1,9339	11
GRP2	GRP3-GRP B	-27,965	-3,974	0,301	155,4	0,035	1,2791	11
GRP3	GRP3-GRP2 A	28	5,253	0,12	-24,6	0,035	1,2791	11
GRP3	GRP3-GRP B	19,096	21,96	0,123	-63	0,0604	1,9339	11
KIN3	KIN5-KIN3	0	0	0	90	0	0	11
KIN5	KIN5-KIN3	0	0	0	90	0	0	11
OSØ2	OSØ3-OSØ2	-45	-22	0,54	137,3	0,1129	4,1191	11
OSØ3	OSØ3-OSØ2	45,113	26,119	0,216	-42,7	0,1129	4,1191	11
SFV2	SVB3-SFV2 A	-29	-14,5	0,349	137,8	0,047	1,7147	11
SFV2	SVB3-SFV2 B	-29	-14,5	0,349	137,8	0,047	1,7147	11
SØN2	SØN3-SØN2 1	-28,32	-4,635	0,265	164,6	0,0212	0,8912	11
SØN2	SØN3-SØN2 2	-18,68	-19,365	0,248	127,8	0,0387	1,2572	11
SØN3	SØN3-SØN2 1	28,341	5,526	0,108	-15,4	0,0212	0,8912	11
SØN3	SØN3-SØN2 2	18,719	20,622	0,104	-52,2	0,0387	1,2572	11
SVB3	SVB3-SFV2 B	29,047	16,215	0,139	-42,2	0,047	1,7147	11
SVB3	SVB3-SFV2 A	29,047	16,215	0,139	-42,2	0,047	1,7147	11
Unit 3	Unit 3	240	180	9,711	-44,3	0,5322	31,4595	11
Unit 7	Unit 7	391,2	293,4	12,169	-28,7	1,0361	61,6309	11

Concerning to problems at the nodes, I have noticed that because of having two different networks, the 150-60 kV part is not properly supplied. In fact, the majority of them are violating the lower voltage limits. This is because of even when working in normal conditions, the 150 kV part of the whole network is supplied by the grid, and like I will see later, the Power

Plant Unit 3 will manage the voltage control on the 150kV part of this network, it will get the approximately 100% of the rated voltage in these nodes.

Table 42. Violation upper voltage limits of 400-150 kV Network of Funen when KIN5-KIN3, FGD5/FGD3 1, and FGD5/FGD3 2 are disconnected.

Overloads			
Nodes (lower) %			
FVA2	85,29	FGD2	82,82
FVO3	84,62	KIN3	82,81
OSØ3	84,42	GRP3	82,8
FGD3	84,21	GRP2	82,09
FVB2	84,02	OSØ2	81,12
Lines %			
ABS3-SØN3	154,99	SHE3-SØN3	104,34

The 400kV network will be delivering power to the grid, however, the 150-60kV network, because of being lower supplied, will need to be supplied by the grid.

Table 43.400-150 kV Network of Funen when KIN5-KIN3, FGD5/FGD3 1, and FGD5/FGD3 2 are disconnected.

From Area/Zone	P Loss MW	Q Loss MVar	P Imp MW	Q Imp MVar	P Gen MW	Q Gen MVar	P Load MW	Q Load MVar
Network	17,023	133,966	-171,177	-116,434	848,597	602,228	831,574	468,262
Area 1	17,023	133,966	0	0	848,597	602,228	831,574	468,262
Zone 1	17,023	133,966	0	0	848,597	602,228	831,574	468,262

Table 44.Power and Losses data of 400-150 kV Network of Funen when KIN5-KIN3, FGD5/FGD3 1, and FGD5/FGD3 2 are disconnected.

Un kV	P Loss Line MW	Q Loss Line MVar	P Loss Transformer MW	Q Loss Transformer MVar
165	13,121	26,243	1,276	59,585
410	1,59	-13,493	1,036	61,631

Table 45. Node and line overload data of 400-150 kV Network of Funen when KIN5-KIN3, FGD5/FGD3 1, and FGD5/FGD3 2 are disconnected.

Node	U kV	u %	U ang º	P Load MW	Q Load MVAr	P Gen MW	Q Gen MVAr
ABS2	54,971	83,29	-13,4	58	29	0	0
ABS3	140,822	85,35	-10,9	0	0	0	0
FGD2	54,661	82,82	-15,3	58	29	0	0
FGD3	138,944	84,21	-12,8	0	0	0	0
FGD5	417,585	101,85	1,4	0	0	0	0
FVA2	56,29	85,29	-14,8	77	39	0	0
FVB2	55,456	84,02	-16,2	53	27	0	0
FVO3	139,62	84,62	-12,5	0	0	0	0
FVO5	420,352	102,52	2	0	0	0	0
GRP2	54,18	82,09	-16,5	47	24	0	0
GRP3	136,612	82,8	-14	0	0	0	0
KIN3	136,629	82,81	-14	0	0	0	0
KIN5	413,484	100,85	0,7	0	0	0	0
LAG5	410	100	0	388,574	245,262	0	0
OSØ2	53,54	81,12	-16,6	45	22	0	0
OSØ3	139,299	84,42	-12,6	0	0	0	0
SFV2	53,714	81,38	-15,6	58	29	0	0
SHE3	165	100	0	0	0	217,397	128,828
SØN2	62,567	94,8	-6,1	47	24	0	0
SØN3	155,039	93,96	-4,4	0	0	0	0
SVB3	137,778	83,5	-13	0	0	0	0
Unit 3	17,837	99,09	-7,5	0	0	240	180
Unit 7	23,2	110,47	8,1	0	0	391,2	293,4

This situation could remind me of the critical condition when the network feeder of the 400 kV side (N1) was disconnected. Actually, is the same state, due to the 150-60 kV side is not being supplied perfectly, only with its network feeder (N2) and the Unit 3, and Unit 7.

d. Generators

- Unit 3 disconnected

This situation will be consider similar than the situation for normal conditions. The Unit 3 is anuseful tool to get the ~100% of the voltage on all the nodes. When disconnecting it, all the 150-60 kV nodes will not meet this condition,they will be around 98% of the rated voltage. The real power losses will increase a 12,68% the power losses for the steady state, although the reactive power losses will decrease around 7%.

Table 46.400-150 kV Network of Funen when Unit 3 in Fynsværket is disconnected.

From Area/Zone	P Loss MW	Q Loss MVar	P Imp MW	Q Imp MVar	P Gen MW	Q Gen MVar	P Load MW	Q Load MVar
Network	4,348	47,609	56,148	-22,791	478,16	318,256	473,812	270,646
Zone 1	4,348	47,609	0	0	478,16	318,256	473,812	270,646

Table 47.Power and Losses data of 400-150 kV Network of Funen when Unit 3 in Fynsværket is disconnected.

Un kV	P Loss Line MW	Q Loss Line MVar	P Loss Transformer MW	Q Loss Transformer MVar
165	1,866	-29,153	0,557	20,99
410	0,52	-26,038	1,405	81,81

Table 48.Node data of 400-150 kV Network of Funen when Unit 3 in Fynsværket is disconnected.

Name	U kV	u %	U ang º	P Load MW	Q Load MVAr	P Gen MW	Q Gen MVAr
ABS2	63,287	95,89	-5,2	58	29	0	0
ABS3	161,138	97,66	-3,3	0	0	0	0
FGD2	65,136	98,69	-3,9	58	29	0	0
FGD3	164,363	99,61	-2,1	0	0	0	0
FGD5	411,768	100,43	0,3	0	0	0	0
FVA2	66,253	100,38	-4,3	77	39	0	0
FVB2	65,569	99,35	-5,3	53	27	0	0
FVO3	163,27	98,95	-2,6	0	0	0	0
FVO5	414,557	101,11	0,8	0	0	0	0
GRP2	66,209	100,32	-3,4	47	24	0	0
GRP3	165,516	100,31	-1,7	0	0	0	0
KIN3	165,916	100,56	-1,6	0	0	0	0
KIN5	410,218	100,05	0	0	0	0	0
LAG5	410	100	0	30,812	47,646	0	0
OSØ2	63,574	96,32	-5,4	45	22	0	0
OSØ3	163,442	99,06	-2,6	0	0	0	0
SFV2	63,26	95,85	-5,5	58	29	0	0
SHE3	165	100	0	0	0	86,96	24,856
SØN2	65,692	99,53	-3,4	47	24	0	0
SØN3	162,521	98,5	-1,8	0	0	0	0
SVB3	161,081	97,62	-3,6	0	0	0	0
Unit 3	0	0	0	0	0	0	0
Unit 7	22,92	109,14	7,2	0	0	391,2	293,4

- Unit 7 disconnected

In this case, instead of delivering power to the grid, the 400kV network will be supplied by it. This is why the reactive power losses are a negative value. Concerning the real power losses, it will decrease a 50% of the normal losses. Like I can see below, all the nodes will meet the ±10% of the voltage limit.

Table 49.400-150 kV Network of Funen when Unit 7 in Fynsværket is disconnected.

From	P Loss	Q Loss	P Imp	Q Imp	P Gen	Q Gen	P Load	Q Load
Area/Zone	MW	MVar	MW	MVar	MW	MVar	MW	MVar
Network	1,965	-20,238	204,965	22,762	444,965	202,762	443	223
Zone 1	1,965	-20,238	0	0	444,965	202,762	443	223

Table 50.Power and Losses data of 400-150 kV Network of Funen when Unit 7 in Fynsværket is disconnected.

Un	P Loss Line	Q Loss Line	P Loss Transformer	Q Loss Transformer
kV	MW	MVar	MW	MVar
165	0,924	-34,273	0,922	42,956
410	0,079	-31,073	0,04	2,152

Table 51.Node data of 400-150 kV Network of Funen when Unit 7 in Fynsværket is disconnected.

Name	U	u	U ang	P Load	Q Load	P Gen	Q Gen
	kV	%	º	MW	MVAr	MW	MVAr
ABS2	64,463	97,67	-4,1	58	29	0	0
ABS3	164,021	99,41	-2,3	0	0	0	0
FGD2	66,172	100,26	-3	58	29	0	0
FGD3	166,888	101,14	-1,3	0	0	0	0
FGD5	409,226	99,81	-0,4	0	0	0	0
FVA2	67,927	102,92	-2,8	77	39	0	0
FVB2	67,263	101,91	-3,8	53	27	0	0
FVO3	167,259	101,37	-1,2	0	0	0	0
FVO5	409,241	99,81	-0,4	0	0	0	0
GRP2	66,782	101,18	-2,9	47	24	0	0
GRP3	166,898	101,15	-1,2	0	0	0	0
KIN3	167,079	101,26	-1,1	0	0	0	0
KIN5	409,512	99,88	-0,3	0	0	0	0
LAG5	410	100	0	0	0	137,17	11,328
OSØ2	65,066	98,58	-4	45	22	0	0
OSØ3	167,058	101,25	-1,2	0	0	0	0
SFV2	64,377	97,54	-4,4	58	29	0	0
SHE3	165	100	0	0	0	67,794	11,434
SØN2	66,115	100,17	-3	47	24	0	0
SØN3	163,533	99,11	-1,4	0	0	0	0
SVB3	163,821	99,29	-2,6	0	0	0	0
Unit 3	21,006	116,7	2,4	0	0	240	180
Unit 7	0	0	0	0	0	0	0

- Unit 3, and Unit 7 disconnected

In this case, both sides of the network (network feeders N1, and N2) will be supplied by the grid. It will be also working in good conditions, so there is no reason to be worried about.

Table 52.Table 41.400-150 kV Network of Funen when Unit 3 and Unit 7 in Fynsværket are disconnected.

From Area/Zone	P Loss MW	Q Loss MVar	P Imp MW	Q Imp MVar	P Gen MW	Q Gen MVar	P Load MW	Q Load MVar
Network	4,071	-10,823	447,071	212,177	447,071	212,177	443	223
Zone 1	4,071	-10,823	0	0	447,071	212,177	443	223

Table 53. Power and Losses data of 400-150 kV Network of Funen when Unit 3, and Unit 7 in Fynsværket are disconnected.

Un kV	P Loss Line MW	Q Loss Line MVar	P Loss Transformer MW	Q Loss Transformer MVar
165	2,524	-25,935	0,571	21,548
410	0,66	-23,568	0,315	17,132

Table 54. Node data of 400-150 kV Network of Funen when Unit 3, and Unit 7 in Fynsværket are disconnected.

Name	U kV	u %	U ang º	P Load MW	Q Load MVAr	P Gen MW	Q Gen MVAr
ABS2	62,438	94,6	-6,1	58	29	0	0
ABS3	159,056	96,4	-4,2	0	0	0	0
FGD2	64,07	97,08	-5,2	58	29	0	0
FGD3	161,766	98,04	-3,4	0	0	0	0
FGD5	404,713	98,71	-1,1	0	0	0	0
FVA2	65,21	98,8	-5,5	77	39	0	0
FVB2	64,514	97,75	-6,5	53	27	0	0
FVO3	160,786	97,45	-3,8	0	0	0	0
FVO5	404,729	98,71	-1,1	0	0	0	0
GRP2	65,459	99,18	-4,4	47	24	0	0
GRP3	163,706	99,22	-2,6	0	0	0	0
KIN3	164,165	99,49	-2,5	0	0	0	0
KIN5	406,904	99,24	-0,7	0	0	0	0
LAG5	410	100	0	0	0	343,264	177,967
OSØ2	62,535	94,75	-6,7	45	22	0	0
OSØ3	160,924	97,53	-3,7	0	0	0	0
SFV2	62,291	94,38	-6,6	58	29	0	0
SHE3	165	100	0	0	0	103,806	34,21
SØN2	65,387	99,07	-3,7	47	24	0	0
SØN3	161,788	98,05	-2,1	0	0	0	0
SVB3	158,708	96,19	-4,7	0	0	0	0
Unit 3	0	0	0	0	0	0	0
Unit 7	0	0	0	0	0	0	0

▪ Distance Protection

I. Theoretical review

Distance protection could also be defined like short-circuit protection. When a fault appears in a distribution network is essential that this kind of fault on a power system circuit are cleared quickly, otherwise they could result in damage to equipment, loss of stability in the system and in the disconnection of customers. Distance protection collects the speed needed to protect the circuits and the requirements of reliability. For these principal reasons, it is the main technology used on high voltage power system networks.

One of the principal characteristic of the distance protection is that it can discriminate between faults occurring in different parts of the system, depending on the impedance measured. This implies comparing the fault current, as seen by the relay, against the voltage at the relay location to determine the impedance down the line to the fault. It is also more difficult to change in systems conditions and the relative source impedances. Another advantage of distance numerical protection is the integrated fault location function.

As I can see the main advantage of using distance relays is that the zone of protection depends on the impedance and I can consider that as an independent value, because it not depends of the values of current and voltage.

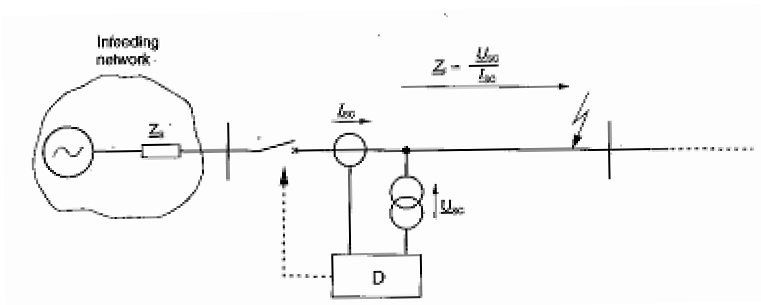


Figure 10. Distance protection principle, measurement of fault impedance.

a. Basis for dimensioning

- Occurrences of faults

First at all, I have to know either the short-circuit voltage and current to determine at the relay. I need these values to obtain the fault impedance to be compared with the line impedance afterwards. Then, I have to check out if the fault impedance is smaller than the line impedance, if that happens the fault is detected and a trip command issued to the circuit-breaker.

This is a really simple technology but by the way it is able to reach a protection decision with the measure voltage and current at the relay protection, and for this protection decision it does not need more information and it does not have to depend on any additional equipment.

When having some problems with the measurement or even with the imprecision of the line impedance, that because of it is usually based on a calculation and not in a measurement, is not possible to set a complete protection on the line length. For this reason I have to set a security margin between 10 and 15% from the remote end of the line must be selected for the so-called under-reaching stage placed on the 1st zone, on that way I can ensure secure the protection selection between internal and external faults. The rest of the line is controlled by an over-reaching in the second zone, which use a time-delayed relative to the protection of the adjacent line to ensure selectivity. If I have an electro-mechanical protection the grading time has to be 400-500 ms, and 250-300 ms in the case of analogue static and numerical protection.

- Relay impedance

Distance protection relay are implemented as so-called secondary relays, because they are fed with signals of current and voltage from the overhead lines by instrument transformers. The secondary impedance comes from the next equation:

$$Z_{sec} = \frac{I_{prim}/I_{sec}}{U_{prim}/U_{sec}} . Z_{prim}$$

- Impedance diagram

The impedance diagram is the most important tool in the field of distance protections. The diagram is composed by the complex R-X plane where the relay characteristics and measured load and short circuit impedance are represented. The main function of this diagram is to check out the performance of the system with the relation of the three impedance components.

The load impedance is equal, during a normal system operation, to the measured impedance. At the same time this magnitude is inversely proportional to the amount of transferred load as I can see in the next equation:

$$Z_{load} = U_{line}^2 / P_{load}$$

The angle between voltage and current is the same than the load angleφ_L, and the value is the ratio between the real and the active power

$$\varphi_{load} = atan\left[P_{reactive}/P_{real}\right].$$

Instantly after the fault appear, the value of the impedance is equal at short-circuit impedance, which is smaller than the load impedance, I have to measure the line impedance between the relay location, and the fault location, it will be depend on the distance where the fault appeared, $F_{LF1}$for close-in faults, and $F_{LF2}$for remote faults. When the fault resistance at the fault location is present an additional resistive component called R_F is added to the line impedance. And, logically, the angle between the short-circuit current and short-circuit voltage is called short-circuit angle (φ_{SC}).

The zone in straight lines means the traditional relay impedance characteristics were geometric figures, but this restriction was due to the limitations of analogue measuring techniques.

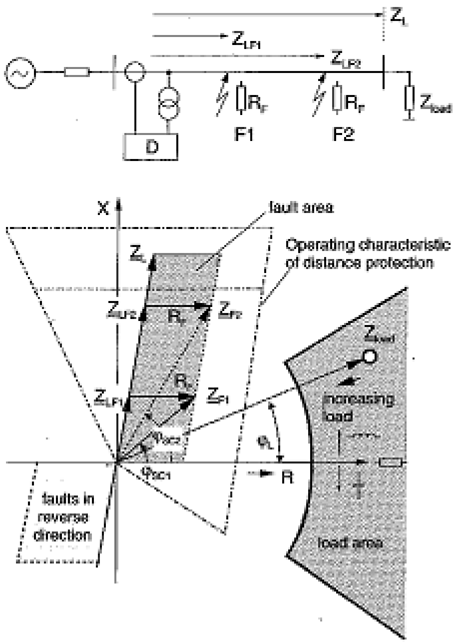


Figure 11. Load and short-circuit impedance.

- Distance measurement

There are many ways and different technologies to check if there is a fault in a transmission lines. For conventional relays the way is compare the short circuit impedance with the line impedance to determine where exactly the fault is, inside or outside of the protected zone.

Another kind of relays is the Electro-mechanical relays made in Germany. This relay uses the technology of rectifier bridge circuit as an impedance balance. With the circle below represents a circle in the impedance plane where I can move it in that plane with the appropriate modification, and in that way obtain a better fault resistance coverage.

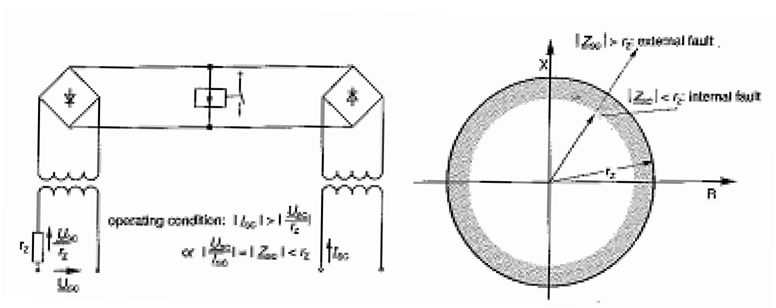


Figure 12. Rectified bridge comparator and impedance circle.

If I buy a relay from England or from America it will be an induction relay. This technology is based on the Ferraris principle, which uses the relay as an induction machine. In my case the rotor is represented by a moving cup, and it is the responsible for carrying the rotor currents.

In the other hand, the stationary magnetic yokes and a fixed core completed the magnetic circuit.

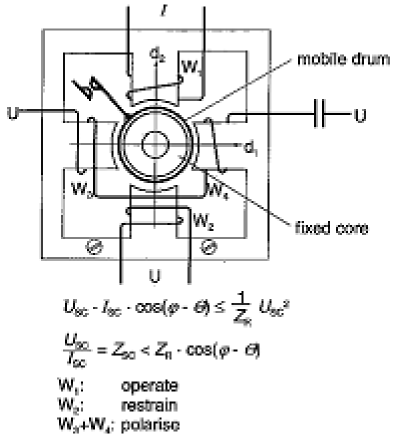


Figure 13.Induction cup relay.

But definitely the MHO-circle is the best known characteristic. The origin of this circumference is the beginning of X-R axis, and consequently inherently combines directional and distance measurement. This is the preferred technology in me for few reasons, as for example it is an economical advantage at the times of electro-mechanical and analogue static relaying technologies, but continues with digital technology. The exception is the ground fault distance protection of short lines where quadrilateral characteristics have been introduced to extend fault resistance coverage.

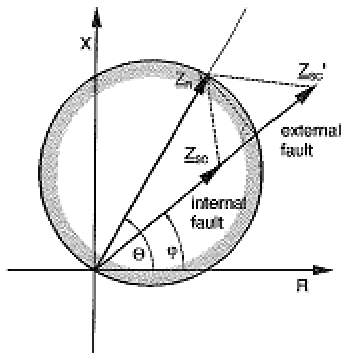


Figure 14.MHO characteristics.

$Z_R$is the set relay impedance, and defines the reach of the zone.

$\theta$is an angle known as the Relay Characteristic Angle (RCA).

The short-circuit angle is very important because the impedance reach depends directly on it:

$$Z = Z_R.[\cos(\theta - \varphi)]$$

$Z_R$normallycorresponds to a replica of the line because the setting of $\theta$is adapted to the impedance angle of the line. This is very important to eliminate the DC part of the fault current of the distance measurement, which appears on high speed electromechanical and static relays.

For distance protection measurement the reactance (X_F) of fault impedance is the only component that you can use to effectively determine the distance to fault, but the resistivity component can vary due to the indeterminate arc resistance at the fault location. The ideal reactance should be as flat as possible running parallel at the R-axis.

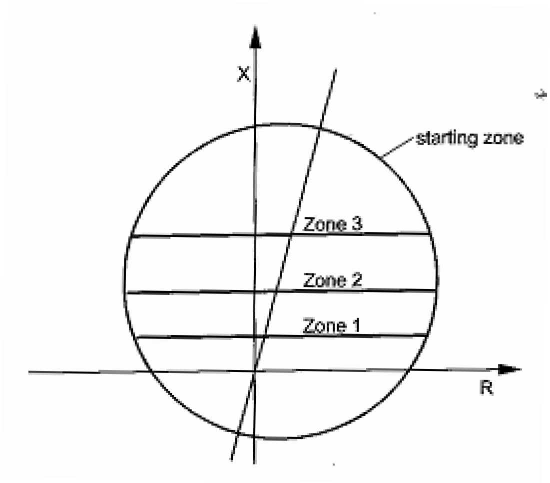


Figure 15.Combined circle- and straight line characteristic.

- Starting

The principal mission of starting function is first to detect and classify a fault (short-circuit) in the power system line without any mistakes, especially in single phase faults to ensure selective phase tripping.

The function of the drop-off and the pick-up of starting are to determine the beginning and the end of the fault. The starting function might for case trigger the zone timers and the fault recorder.

b. Applied methods and practice

There are several methods for calculating and dimensioning the distance protection.

- Over-current starting:

This method is the simplest and the fastest. It can be used in network with small line impedances and where enough large short-circuit current flows. In that way the smallest short-circuit current cannot be smaller than twice the maximum load current. Also the applied setting has to be around 1.3 times the maximum current in the phases and half time I_N for the earth-current.

In the case of parallel lines and when one line is off, the rest may carry twice the current, but just for a short time. So the setting of the phases must be double.

If I want to check out the dependability of the fault detection I have to use a fault in two phases because the fault current is smaller than a current fault in three phases by a factor$\sqrt{3}$.

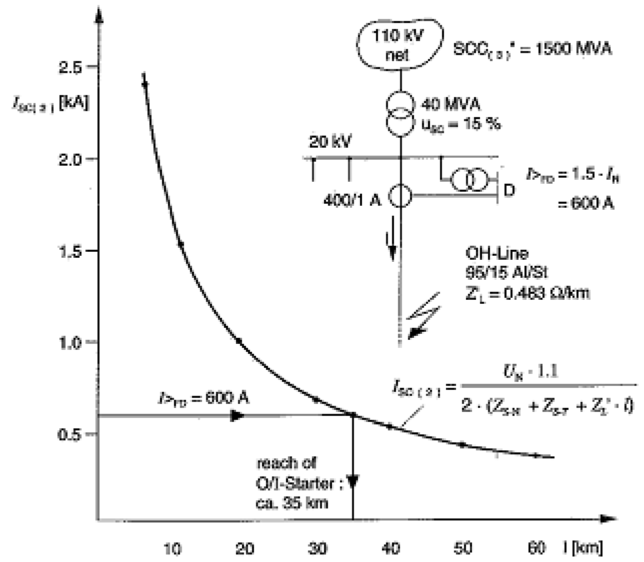


Figure 16. Reach of the overcurrent starter (for phase to phase faults).

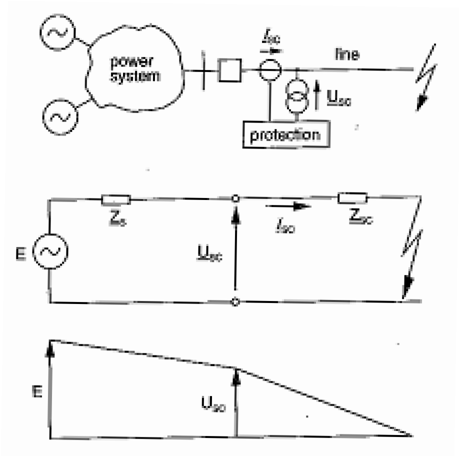


Figure 17.Voltage at the relay location during short-circuit.

- Under-impedance starting (U< and I>)

There are few reasons for why the current when short-circuit appears in the feeder may be too small for overcurrent starting. These reasons are: weak source or high source impedance, current splitting in parallel paths of a meshed system and earth-current limited by reactance or resistance in the transformer star-point.

The source impedance and the fault impedance are the causes of the voltage at the relay location.

In this starting configuration the current controls the voltage thresh-old, this is why the pick-up sensitivity of the voltage is increased as the current increases.

When I>> corresponds to an overcurrent starter stage.

Typical settings are:

I>=0.25I_N

$$I \gg= 2.5.I_N$$

$$U(I >) = 70\%.U_N$$

$U(I \gg) = 90\%.U_N$

- Effectively earthed system:

The method below is required in this method to achieve phase-selective fault detection because normally simple overcurrent starting is not enough. In my case the short-circuit current has the possibility to carry on the healthy phases during earth-faults. The overcurrent starting has to be setting above these healthy phase-currents. Because of the difference between the positive and the zero sequences systems at the two lines and theses currents have to arise.

In the picture above I can see what happens when there is an earthed transformer with no in-feed at the end of one line. I can see, while the fault is just in a single-phase to ground, that the current at the three phases are the same.

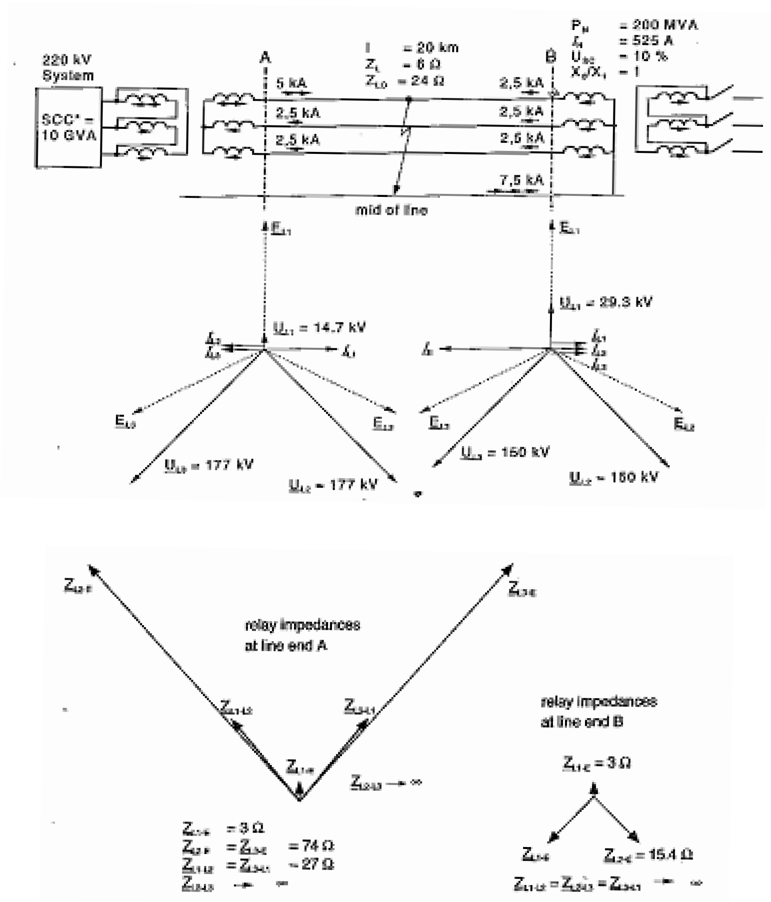


Figure 18.Short circuit in an effectively earthed system with unequal source and earthing conditions.

- Impedancestarting:

An impedance characteristic is well suited to discriminate between fault and lad conditions as well.

All the possibilities of faults loops that I can get in this case are uninterruptedly measured and controlled by several technologies.

The optimization of the starting characteristics, when I are talking about conventional relays, was made with the implementation of the circle and straight line elements.

The objectives of the optimization can be seen below:

- Large reach in X-direction for the detection of remote faults.
- Sufficient arc-compensation in the other direction (R-Axis) while maintaining secure margin against load encroachment.

II. Distance Protection of a string of the 150 kV network of Funen.

For the calculations of Distance Protection, the first step is selecting a string of the 150kV network on Funen. The one that I have chosen is the string between the nodes FGD3, and SHE3. The most important reasons for choosing this line is because it is large enough to make selectivity protection that I have to do at the end of this part of the project.

To set the distance relay I have to calculate first the maximum and the minimum current of the string I chose. I have to make the calculations by hand first, and by NEPLAN afterwards, to check out if both values are equals or close enough.

a. Maximum and minimum short circuit currents

- By hand

For the hand calculations I have to select first where I are going to place the short circuit fault, in my case it is going to be in the ABS3 node. It is actually a random selection but I chose it because it is just in the middle of the string.

The values necessary to make the hand calculations are the impedances of each length of the line, the impedances of the feeders, and the line voltage. The *c* factor is shown in the table below, but for the NEPLAN calculations and for the hand calculations I chose 1,1 for maximum current and 1’00 for minimum current.

Due of the fault location, in the middle of the string, I will obtain two different values of maximum current, one from each end of the line but I are only interested in the current that flows from SHE3, as I are only configuring distance protection from this side. Either I are going to have just one value of the minimum current because I have to calculate it at the end of the string.

Table 55. "c" factor for short circuit calculations.

Nominal voltage U_n	Voltage factor *c* for the calculation of: maximum short-circuit currents c_{max} [1]	minimum short-circuit currents c_{min}
Low voltage 100 V to 1 000 V (IEC 60038, table I)	1,05[3] 1,10[4]	0,95
Medium voltage >1 kV to 35 kV (IEC 60038, table III)	$\boxed{1{,}10}$	$\boxed{1{,}00}$
High voltage[2] >35 kV (IEC 60038, table IV)		

- Maximum Short-Circuit Current:

For the maximum current I need a 3-phase fault in the line, and the definitive value is given by the formula:

$$I_K{}'' = \frac{c \cdot U_\Delta}{\sqrt{3} \cdot Z_{SC}} = \frac{1'1.165000}{\sqrt{3} \cdot 36'05} = 2'906kA$$

But first I need the value of the Z_{SC}.This value is the sum of the impedances in the line before the fault location.

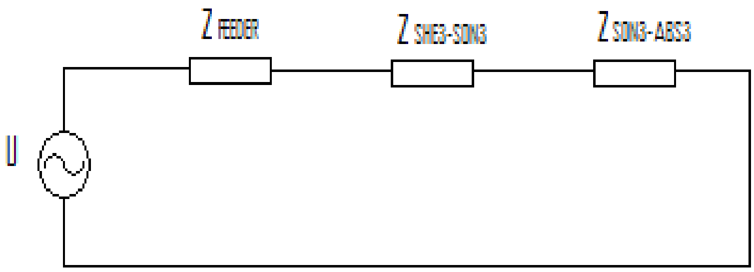


Figure 19.Equivalent circuit of the line from SHE3 to ABS3.

- *Impedance of thefeeder:*

$$Z_{nQ} = c\frac{{U_{nQ}}^2}{S_{nQ}}n^2 = 1'1\frac{165000^2}{4000}.1 = 7'48\Omega$$

- *Short circuitimpedance:*

$$Z_{SC} = 10'3 + 18'27 + 7'48 = 36'05\Omega$$

- Minimum short-circuit current:

For the minimum short-circuit current, the kind of fault that I need is a fault between 2 lines or a single line fault. So for this reason, I need to calculate first in both ways and then I will choose the lower value.

- *Single-phase-to-ground fault.*

$$I''_{k(1)} = \frac{c \cdot \sqrt{3} \cdot U_\Delta}{|2 \cdot Z_1 + Z_0|} = \frac{1´0.\sqrt{3}.165000}{|2 \cdot 10´3 + 28´03|} = 6'46kA$$

- *Line to line fault.*

$$I''_{k(2)} = \frac{\sqrt{3}}{2} I''_{k(3)} = \frac{\sqrt{3}}{2}.5´894 = 5´103kA$$

We have to calculate the 3-Phase current $I''_{k(3)}$in SHE3-SØN3 line:

$$I_K'' = \frac{c \cdot U_\Delta}{\sqrt{3} \cdot Z_{SC}} = \frac{1´1.165000}{\sqrt{3} \cdot (10´3 + 7´48)} = 5'894kA$$

As I can see in the results the minimum short circuit current for me is Line to Line fault because is the smaller of them.

- NEPLAN

As I did for the Load flow calculations, in NEPLAN I have to build the schema of my line, as well I have to determine the different values of cables, nodes, transformers and feeders.

- Maximum Short-Circuit Current:

For the maximum short-circuit current I are going to simulate a 3-Phase short circuit current placed at ABS3 node, but at the same time I have to disconnect the ABS3-SVB3 line as well.

Table 56.3-Phase short circuit current values in ABS3.

3-phase	Fault Location	Un kV	UL-E (RST) kV	ΔU-LE (RST) kV	Ik'' (RST) kA	Δik'' (RST) kA
1	ABS3	165	104,789	180	2,915	-77,38

As I can see the values calculated by hand and by NEPLAN are close enough to say that they are pretty correct.

- Minimum current:

For the minimum short circuit current I have to choose one of the ends of the string and I chose the one at SØN3 node. To deciding witch of the both currents that I are going to calculate the criteria is just chose the smaller one of them.

- *Single-phase-to-ground fault*

Table 57. Single-phase-to-ground fault in SØN3

Single-phase	Fault Location	To Node	UL-E (RST) kV	ΔU-LE (RST) kV	Ik'' (RST) kA	Δik'' (RST) kA
1	SØN3	Faulted	95,263	180	6,41	-79,46
2			15,721	-9,93	0	-90
3			15,721	-9,93	0	-90
4					0,888	94,74
5					0,888	94,74
6					0,68	94,74
7					0,68	94,74
8					1,568	-85,18
9					1,568	-85,18

- *Line to line fault*

Table 58.Line to line fault in SØN3.

	Element	Fault Location	UL-E (RST) kV	ΔU-LE (RST) kV	Ik'' (RST) kA	Δik'' (RST) kA
1	379	SØN3	0	90	0	-90
2			82,5	90	4,773	191,95
3			82,5	270	4,773	11,95
4					0,037	-88,39
5					0,037	91,61
6					0,036	91,61
7					0,036	-88,39
8					4,772	-78,05
9					4,772	101,95

As I can see again the values are close enough tosay that they are equals. Finally I chose is Line to Line value because is the smaller of them.

b. *Distance relays*

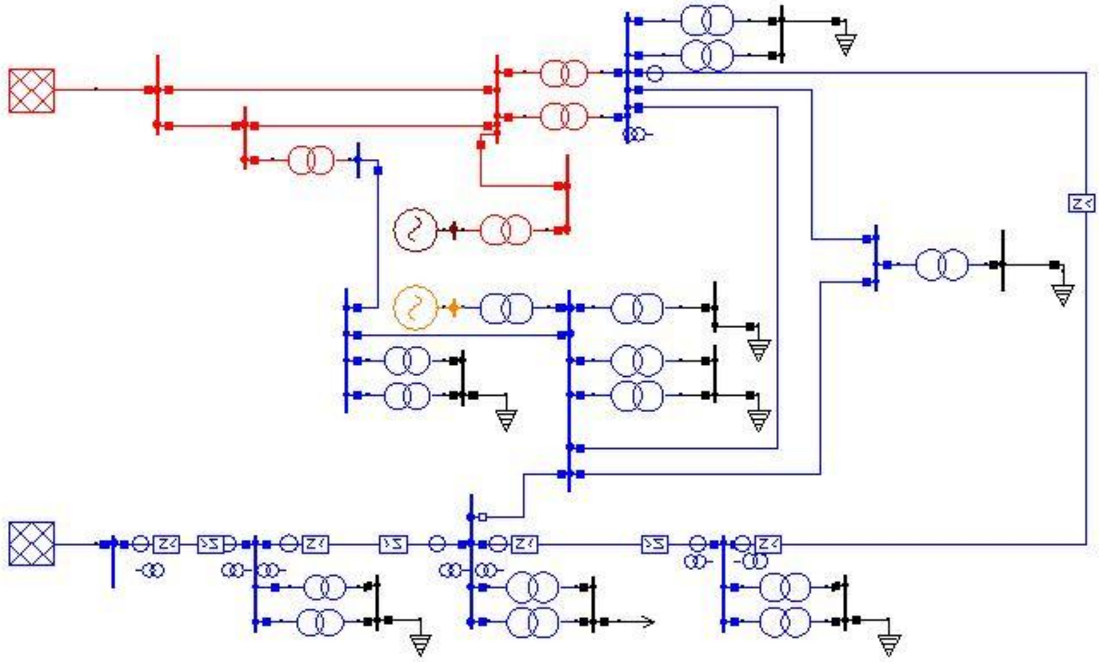
- R/X characteristics

The next step is set the distance relays by all over the line. The best option is to put two relays for each section of the string. This decision was made because I want to control the current in both ways because it is possible for this kind of networks.

The distance relay that I chose for my project is the one called ABB REL 316. The principal characteristic of this relay is that it can work in 3 zones and I assume that these 3 zones are enough for a high protection level. Each relay has its own current transformer and its own voltage transformer.

In the picture below you can see how the schema in NEPLAN looks with all the protection elements.

Table 59.400-150 kV distance relay settings.



- Tripping schedules

The tripping schedule is a graphic given by NEPLAN where I can study how the relays will behave when a fault appears. NEPLAN will give me two graphics, one for each direction of the current.

The tripping schedule graphics is showed below

Table 60.SHE3 to FGD3 line tripping schedule.

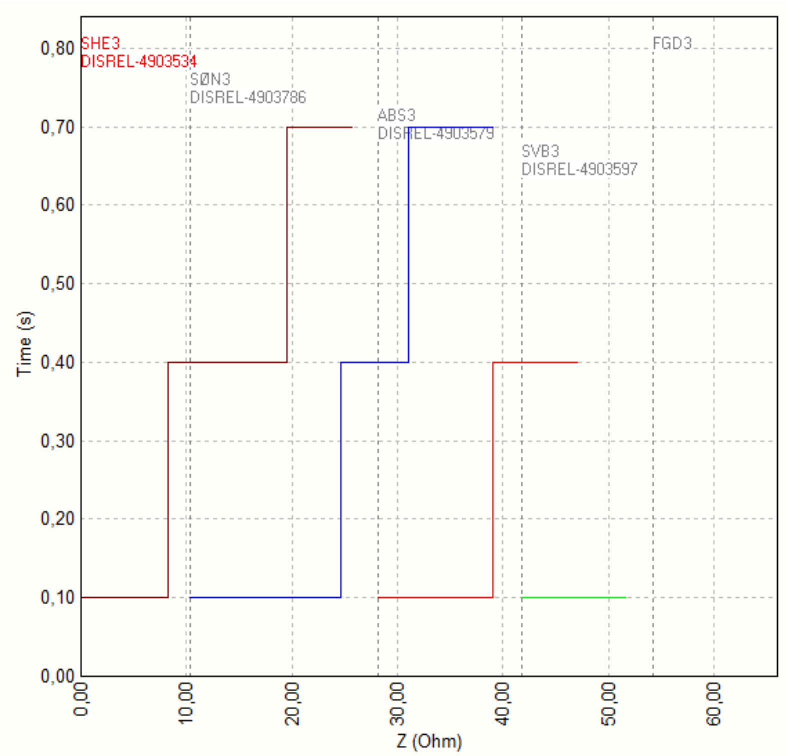
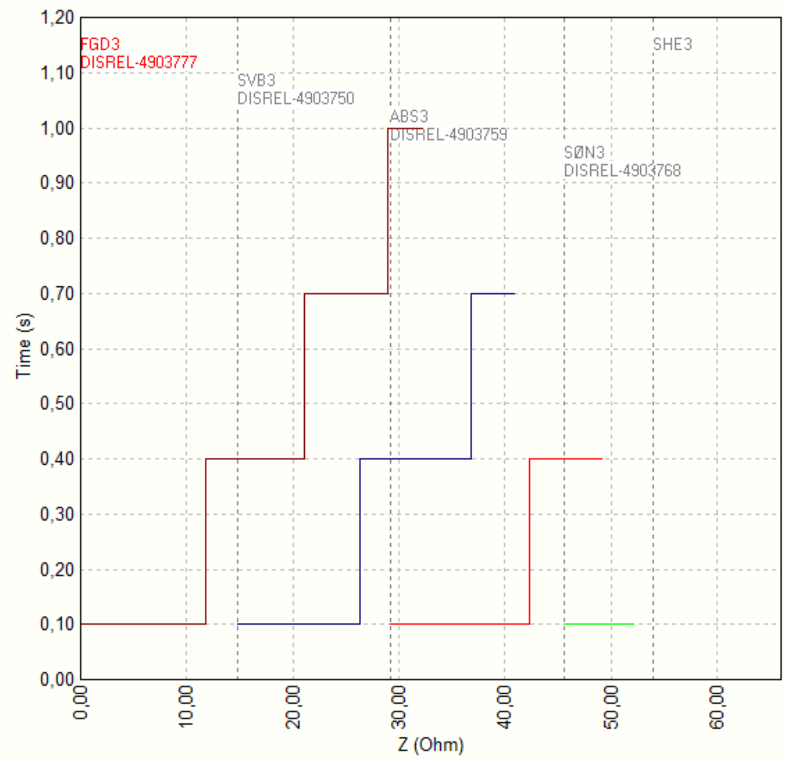


Table 61.FGD3 to SHE3 line tripping schedule.



As I can see both graphic are not exactly equals like they should be, that is because I had some problems with the software. The graphic shows the relation between the impedance of the line, so I can detect a fault in the line, and the time that the relay will need to disconnect the line.

For example I are going to take the tripping schedule of the line from FGD to SHE, and make a short-circuit in the line from ABS to SØN. The system will detects that Z=31 (Ohm) for example, so as I can see in the graphic the relay called ABS3 DISREL-4903759 will disconnect the line 0,1 seconds after the fault appears. If this relay has problems and cannot disconnect the line, then the relay called SVB3 DISREL-4903750 will tries to disconnect the line 0,4 seconds after the fault appears, if after exactly 1 second the fault still there then the relay called FGD3 DISREL-4903777 will be the last opportunity to disconnect the line. If after one second the line is not disconnect, it will mean that I will be situated in the critical zone, and provably the components of the line will be destroyed.

That is one example when I have three opportunities to disconnect the line, but for example in others I only have one or two opportunities.

Table 62.SHE3 to FGD3 line tripping schedule.

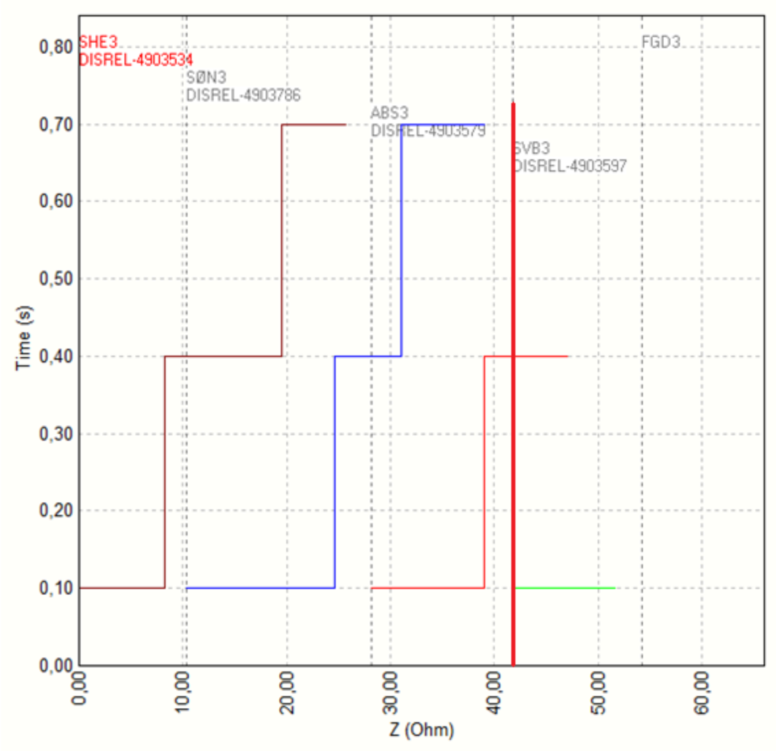
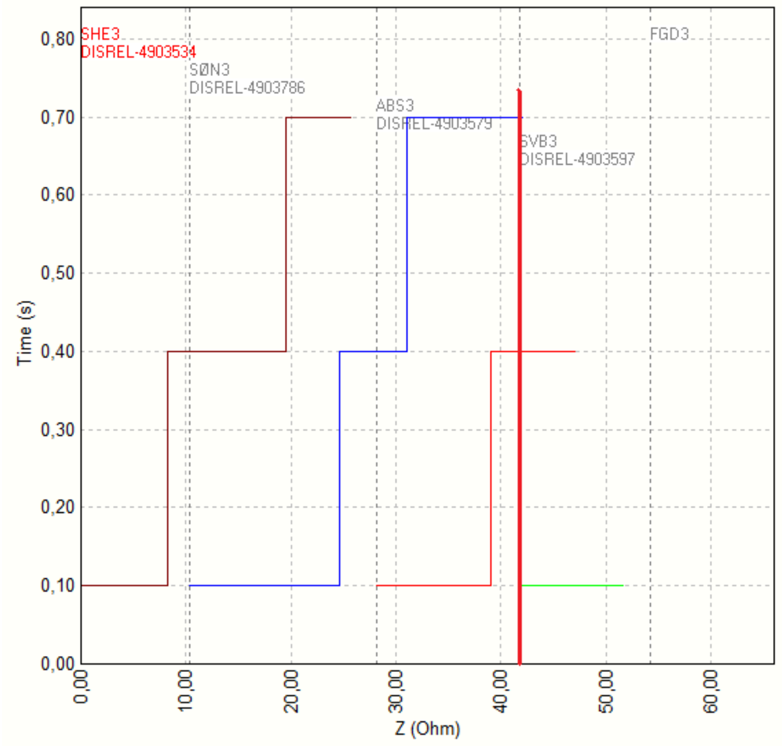


Table 63.SHE3 to FGD3 line tripping schedul with changes in the relay ABS3 DISREL-4903579.



c. Conclusion

The field of distance protections is really complicatedly because you have to keep in mind the criteria of priorities: 1st Personal safety, 2nd Devices Safety and 3rd Electrical Supply. And I have to take care about everything each time when I are going to try to improve the conditions of the line because sometimes the solution is worse that the problem.

For example as I can see in the *Table 64*we detected a problem in the line From ABS to FGD, if there is a short-circuit for in this line and Z=40(Ohm) then there is just one protection zone and the relay will try to disconnect the line 0,4 seconds after the short-circuit appear and of course if the relay will not be able to disconnect the line the devices of the line will be probably burned out.

So because I want at least two protection zones for each line I moved the protection zone of the relay called SØN3 DISREL-4903786 until Z=41’77(Ohm). Now I have from Z=31’04(Ohm) to Z=41’77(Ohm) two protection zones. But if I don’t realize if a short circuit appear exactly in the line from SVB to FGD with Z=41’77(Ohm) then I have a big problem because if that short-circuit appear then the relays SØN3 DISREL-4903786 and SVB3 DISREL-4903597 will disconnect at the same time the lines from SØN to ABS and the line from SVB to FGD and then I will have lines disconnected at the same time the population will be in trouble with electrical supply.

Ultimately distance protection is one of the most important parts of an electrical network because if it is not done with the proper criteria at the end a lot of troubles will appear.

60 kV (High Voltage) Network of Funen

In that part I will be describing and comparing values of transferred energy and power losses inthe 60 kV network, concretely in Abildskov. There are three cases. The first one is an analysis of the network with full-load transformers. The second one, assuming that transformers are no-load, and finally, the third part include critical conditions, when one of transformers is disconnected during the all year.

▪ Abildskov

The schematic for this network is shown on figure below:

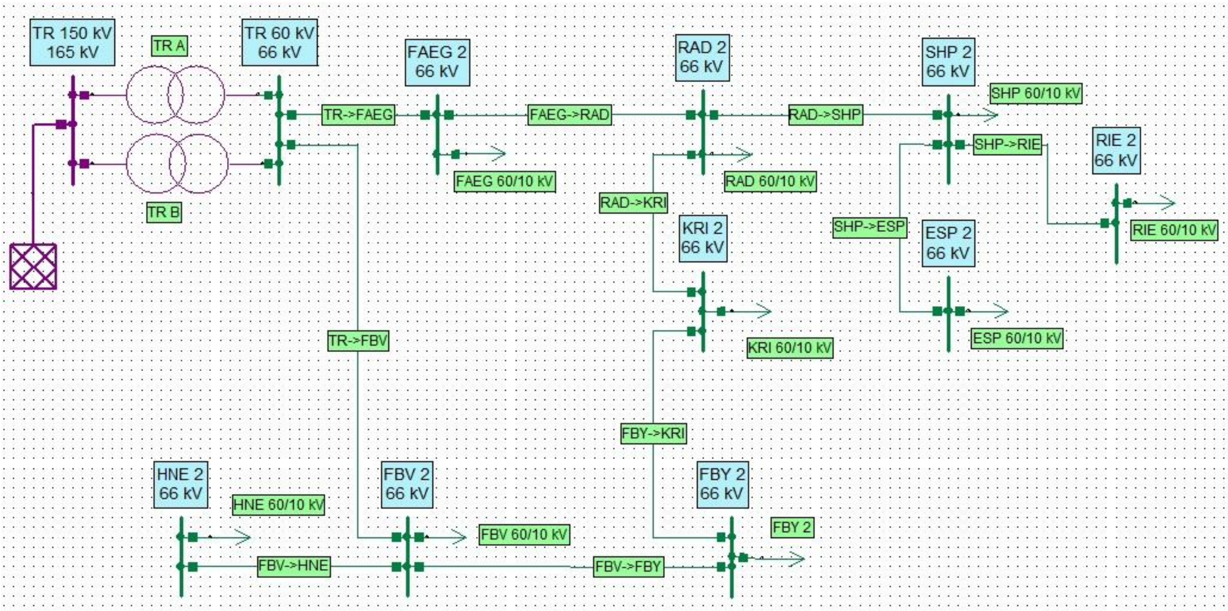


Figure 20. Diagram of the 60 kV network around Abildskov

I. Load data – 60 kV busbars

a. Power generation

When, the companyproducesenergy, takesintoaccountthe valueof electricity demand, power losses (for example in transformers) and transmission losses. That is mean: the value of the energy generated, consist of power demand and power losses.

$$P_{generation} = P_{losses} + P_{demand}$$

Energy demand changes during the day, week and season. It highly depends of lifestyleof the community. Power demand describe load profile curve, about that I can read in c. subsection.

Second important thing in power generation is economical aspect – cost of production. The totalcost oftransmitting anddistributingelectricity, I can identifybythe generalformula as below:

$$K_p = K_n(0) \cdot r + K_{oc} + K_{pel}$$

where:
$K_n(0)$ - discounted investment costs of the line
K_{oc} - Fixed annual operating costs
K_{pel} - cost of power and energy losses
r - rata expanded reproduction

In my case, economical aspect concerns to transformers. I will compare network powered by two and by one transformer. In each situation I would like to have the smallest power losses, and the smallest costs of keeping network.

b. Power losses

In a network I have some kinds of power losses. These are: losses on transformers, losses on lines and on receivers. I have noinfluenceon the energy losses in transformers. General it dependents of value of current, it is like $P \sim I^2$.

If I want to show more details of power dependence, I can determine energy losses as:

$$P_{loss} = 3 \cdot R \cdot I^2$$
$$P_{loss} = 3R(\sqrt{I_{act}{}^2 + I_{react}{}^2})^2 = 3RI_{act}{}^2 + 3RI_{react}{}^2 = P_{loss\_act} + P_{loss\_react}$$
$$if \_ I_{rect} = I_{act} tg\varphi$$
$$P_{loss} = 3RI_{act}{}^2 + 3RI_{act}{}^2 (tg^2\varphi)R = 3RI_{act}{}^2(1 + tg^2\varphi) = P_{loss\_act}(1 - tg^2\varphi) = P_{loss\_act}\frac{1}{\cos^2\varphi}$$

As I can see above losses of active power strictlydepend of angle φ between currents of active and reactive power.

c. Load profiles

Load profile analysis is using to get information about the amount of electricity that is consuming at a given time, so load profile is a set of factors describing maximum of power consumption even in each hour. I can determine a power demand at specific time as one day, one month, a season, year or others. It is useful for energy companies, which can plan how much power they will need to generate.

Energy consumption calculated with the load profile correlates to human life. Around 6 a.m. when factories start working and people make breakfasts, I have increasing consumption of power. It is slow decreasing during work period of day and then it is once again increasing when people preparing dinners after work. There is big difference comparing high load and low load day. That second one include summer time, when I have "longer days" or weekends when people wake up later and in mostly they are using only householdelectric appliance.

In Denmark I have four seasons with different load profile. These seasons start at:

1	21st March	3	15th September
2	15th May	4	1st November

In my case I have load profile curves, given for three different days of the year 2010. They represent the typical winter working day with high load, day with medium load and typical summer Sunday with low load. Data and loading curve are given in e. subsection.

d. Load duration curve

Sum of the annual energy consumed can be presented a load duration curve. It is the same information as on load curve but is presented in a different form. Areas under the daily loading and load duration curves are the same, respectively for high, medium and low loads. If time is 24 hours, these areas represent the total energy consumption of a customer at a day.

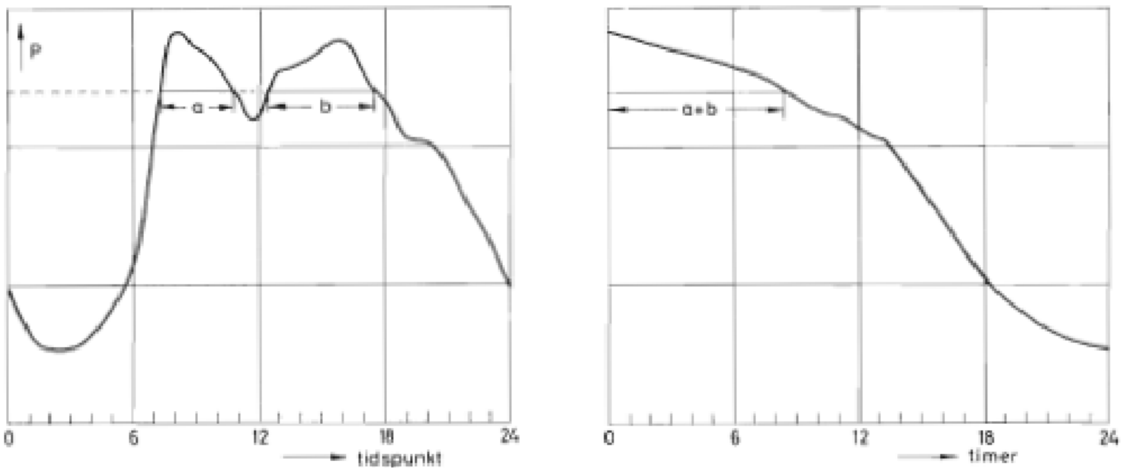


Figure 21.Power demand at specific time and its demand.

e. Assumptions for 60 kV network calculations

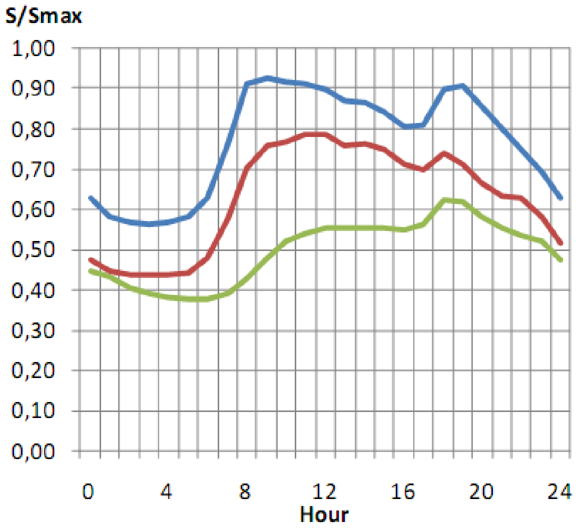
In my case I have load profile curves, given for three different days of the year 2010. They represent the typical winter working day with high load, day with medium load and typical summer Sunday with low load. These are:

1. Thursday 11 February 2010 - high load
2. Monday 26 April 2010 – medium load
3. Sunday 30 May 2010 – low load

For making analysis I also assumed:

- all the 60 kV busbars have the same load profiles
- ratio between active and reactive power (P/Q) is constant
- both transformers are working all year without break
- 91 days (25%) with high load and the same for low load
- 183 days (50%) with medium load

Loading curves are present on *Figure 22 – Loading curves,* and loading data and on*Table 66. Loading profile data.*



- High load – Thursday 11 February 2010 (typical winter working day)

- Medium load – Monday 26 April 2010

- Low load – Sunday 30 May 2010 (typical summer Sunday)

Figure 22. Loading curves

Table65. Loadingprofile data.

Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
High load	0,58	0,57	0,56	0,57	0,58	0,63	0,76	0,91	0,93	0,91	0,91	0,90	0,87	0,86	0,84	0,81	0,81	0,90	0,91	0,86	0,80	0,75	0,69	0,63
Med. load	0,47	0,44	0,44	0,44	0,44	0,48	0,58	0,70	0,76	0,77	0,79	0,79	0,76	0,76	0,75	0,71	0,70	0,74	0,71	0,67	0,63	0,63	0,58	0,52
Low load	0,45	0,41	0,39	0,38	0,38	0,38	0,39	0,43	0,48	0,52	0,54	0,56	0,56	0,55	0,55	0,55	0,57	0,63	0,62	0,58	0,55	0,54	0,52	0,48

Table 66. Load data – 60kV busbars around Abildskov.

Name	Busbar	S max	
		P [MW]	Q [Mvar]
Abildskov	ABS2	0	0
Fælinggård	FÆG2	7,2	4,1
Radby	RAD2	8,6	4,1
Sønder Højrup	SHP2	5,3	2,5
Ringe	RIE2	11,8	6,3
Espe	ESP2	3,6	2,6
Korinth	KRI2	4	1,9
Fåborg By	FBY2	6,5	3,2
Fåborg Vest	FBV2	6,5	2,8
Horne	HNE2	4,7	1,9

I. Energy transferred in 150/60 kV transformers in Abildskov in 2010

After defined theload profiles in NEPLAN, I made some calculations for full-load transformers and no-load transformers. I assume that two transformers were working all 2010 year without any break. Data for transformers are found in *Appendix CD Electrical Power Engineering Project.*

a. *Load transformers*

Using NEPLAN, I generated loads profile off active and reactive power losses over days with high load, medium and low load. They are present on *Figure 23*, *Figure 24*, and *Figure 25*. Then I described all that losses on duration curves, calculated annual losses and annual power transferred.

- Loads profiles

Making analysis of graphs present below and comparing them with loads profile [S/S_{max}] I can say, that power losses strictly depend of power consumption. When power demand is increasing – power losses are also increasing. Value and time changes, depend of type of load – is it high load, medium or low load. Below I present graphs generated by NEPLAN.

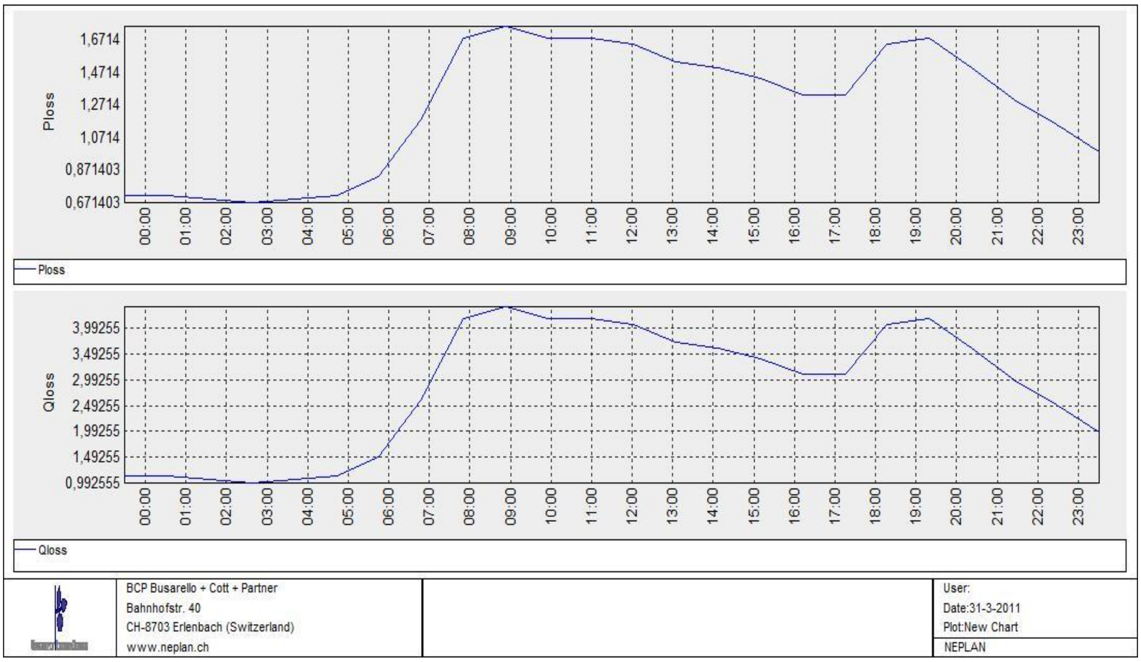


Figure 23. Load profile of power losses over a day with high load.

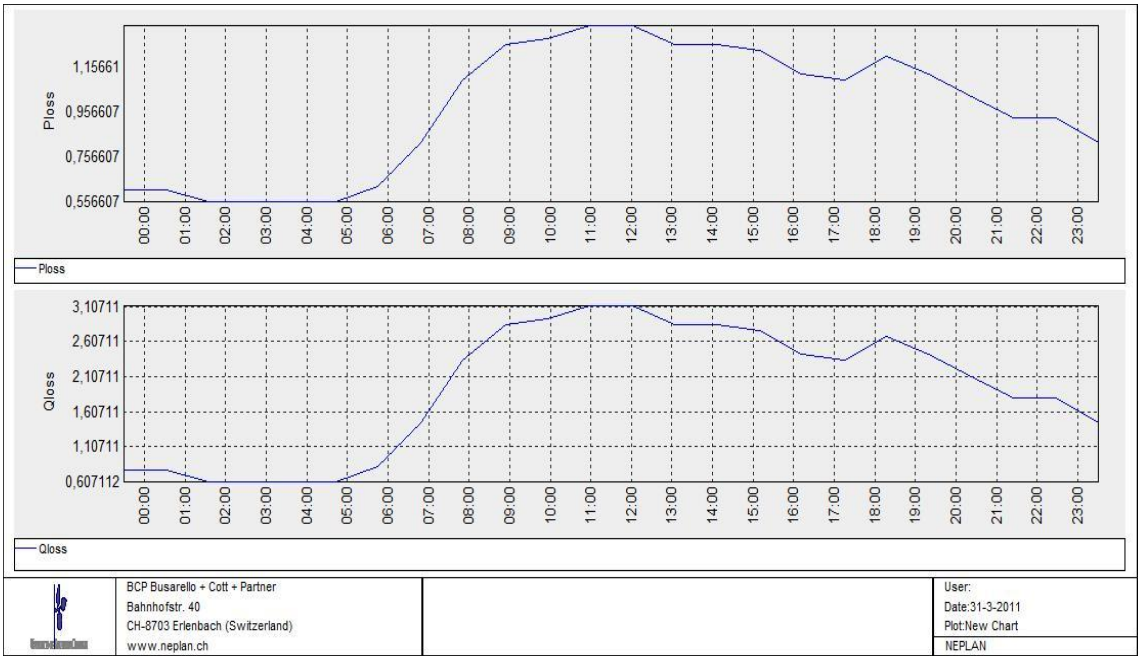


Figure 24. Load profile of power losses over a day with medium load.

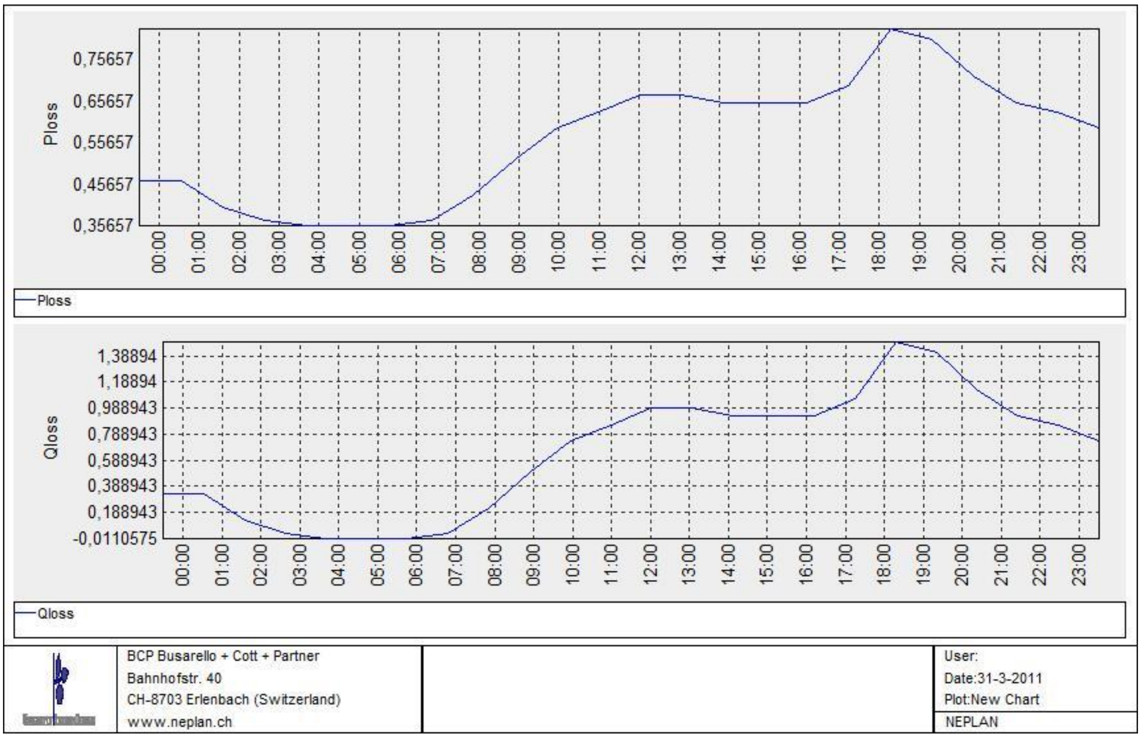


Figure 25. Load profile of power losses over a day with low load.

- Losses duration curve over a day

Load profiles I present as load duration curves, summary of each type of load are present on *Figure 26. Summary of losses duration curve over a day*.We can compare how large are active power losses over a day for two transformers.

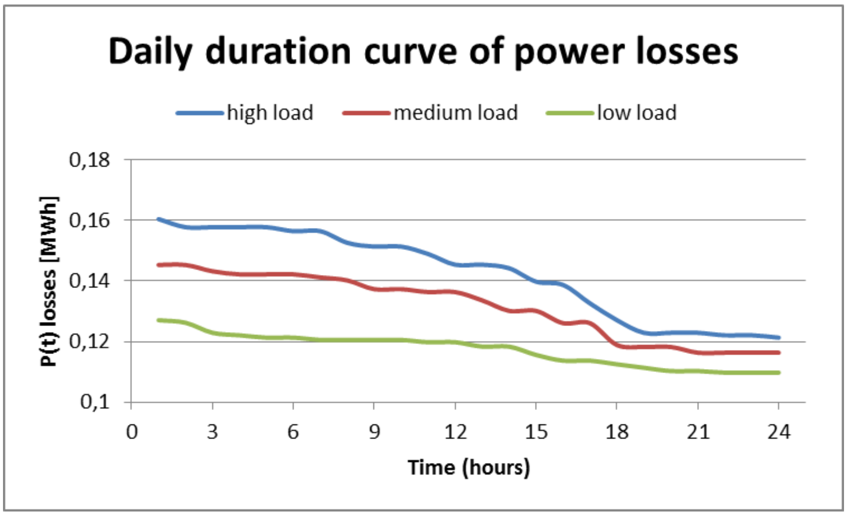


Figure 26.Summary of losses duration curve over a day.

We calculated value of power losses for two transformers, for high load, medium and low load day:

Table 67.Power losses data for Transformers in Abilsdkov.

	Real Power (P) [MWh]	Reactive Power (Q) [MVAr]
High load	3,41669	35,86433
Medium load	3,156226	26,55077
Low load	2,816142	14,43678

We noted that the total losses are the biggest, as I expected, over high load day. I can see on *Figure 27. Annual losses duration,*that almost 16 hours power losses are above value P(t)loss =0,140 [MWh].

After some calculations I made annual losses duration curve.

- Annual losses duration curve

How I get my annual losses duration curve. I assumed 91 days for high load, 91 days - low load and 183 for medium load. I used data from last subsection. I created season consist of 4 days – one high load and one low load, and two days with medium load. I get 96 values (hours). I sorted them and for approximation 8760 hours, I used scaling factor 1/96 on time axis. I got duration Power losses to percents. Relation which I got corresponds to the real annual values.

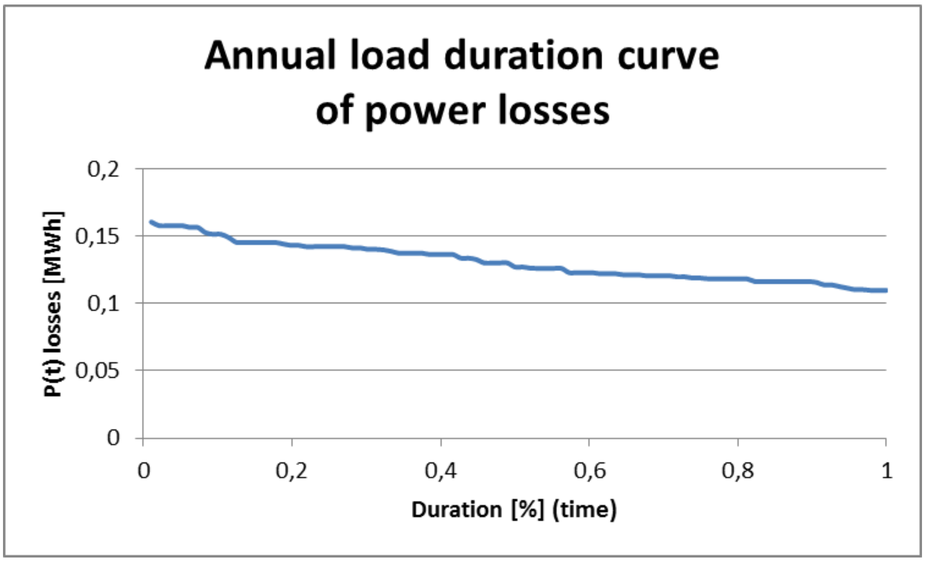


Figure 27.Annual power losses duration curve.

To calculate total power losses I multiplied by 91 each value of high load and low load day and multiplied by 183 values of medium load day. After summed them I got $P(t)_{loss}$ =1144,777[MWh] in all year. This is average $P(t)_{loss}$ =3,136 [MWh] each day.

$$P(t)_{tot\_loss} = 91 \cdot P(t)_{loss\_high} + 91 \cdot P(t)_{loss\_low} + 183 \cdot P(t)_{loss\_medium}$$

$P(t)_{loss}$ =1144,777 [MW]
$Q(t)_{loss}$ =9436,189 [MW]

- Network losses

In all network I have bigger power losses. NEPLAN generated the table with that data.

Table68. Powerlossessummed

Load flow calculations:	24			24			24		
Not converged load flow calculations: %1	0			0			0		
Years from / to	2010	2010		2010	2010		2010	2010	
Months from / to	May	May		April	April		February	February	
Days from / to	30	30		26	26		11	11	
Time from / to / increment	0	0,989583	60	0	0,989583	60	0	0,989583	60
Network energy losses [MWh]	12,985			22,534			29,159		
Network energy losses [Mvarh]	14,997			44,993			66,138		
Areas									
Area 1	12,985	MWh		22,534	MWh		29,159	MWh	
Zones									
Zone 1	12,985	MWh		22,534	MWh		29,159	MWh	

Relations with values of power losses are similar to reported previously load profile analysis for single days. I get the biggest power losses in network during high load day. Power (active) losses in the network are bigger around 4,6 times, compare with power losses in two transformers, on low load day, around 7 times on medium load day and bigger 8,5 times on high load day. Reactive power losses were two times bigger in network for high and medium load days and almost the same for low load. Total power losses in network in 2010 year were:

$P(t)_{loss}$ =7958,826 [MW]

$Q(t)_{loss}$ =15616,731 [MW]

- Energy transferred - load duration curve

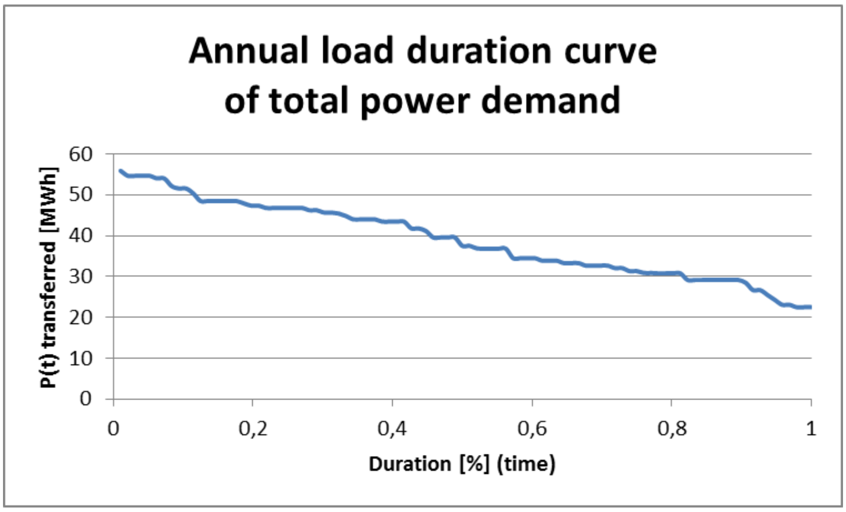


Figure 28.Annual load duration curve of energy transfer in Abildskow network in 2010.

For making annual load duration curve, I used data created by NEPLAN. Procedure and steps for making graph were the same as described annual duration power losses.

Total power demand was P(t)=34011 [MW]

Total transferred power is a sum of power demand and power network losses:

$$P(t)_{tot}=P(t)+P(t)_{loss}$$

$$P(t)_{tot}=34011\ [MW]+1144{,}777\ [MWh]$$

$$P(t)_{tot}=35155{,}777\ [MWh]$$

$P(t)_{loss}$ =1144,777 [MW] that is a big value of power losses, but lossesare only 2% ofthe transmittedenergy.

b. No-load transformers

Transformers are no-load, when I have open circuit on secondary side of transformers. I have very low no-load current on primary sides which causes current losses in cores.

- No-load losses

To calculate no load losses, I changed in NEPLAN, parameters of transformers (deleted 50 no-load losses of each). After analysis NEPLAN generated some data for simulations. For two transformers in 2010 year, no –load losses were equal:

$P(t)_{loss}$ =246,0446 [MW]
$Q(t)_{loss}$ =8973,894 [MW]

To remind, for full load transformers I had: $P(t)_{loss}$ =1144,777 [MWh] and $Q(t)_{loss}$ =9436,189 [Mvarh], and it was 4,65 times more active losses and about 462 Mvarh more reactive power losses.

II. Energy transferred in 150/60 kV two transformers in Abildskov - critical condition

We have to make the simulation assuming that transformer A has been disconnected for some reason in all the year 2010.

a. Lossesduration curve

For preparing annual losses duration curve for B transformer we:

- Made simulation with load profile for high, medium and low load
- Sorted data and calculated some ratios
- Calculated total power losses in one year with only one working transformer

We got:

$P(t)_{loss}$ =940,5899 [MW]
$Q(t)_{loss}$ =17965,61 [MW]

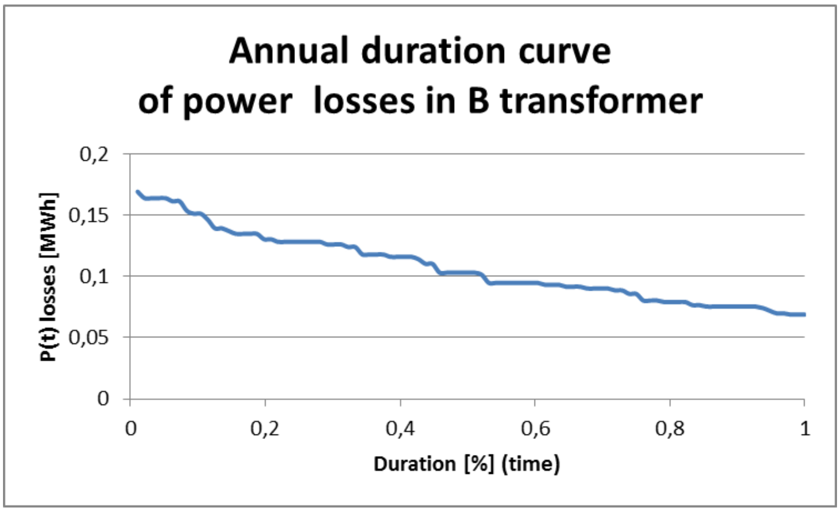


Figure 29.Annual losses duration curve of B transformer.

III. Economic aspects or conclusions

a. *Examples of duration curves analysis*

Load profiles and duration curves I make for forecasting power demand or power losses on given period. If I want to know more details of power consumption or others, I can present my results in specific charts. For example I can compare number of hours in three types of day with different load profile. I made four areas of power consumption during single day:

1) P >50 [MWh]
2) P =(50-40) [MWh]
3) P =(40-30) [MWh]
4) P<30 [MWh]

*Figure30*shows number of hours of energy consumption over three different load profiles days. I can see that the widest range of power consumption value has winter day with high load. Summer day with low load profile has consumption at a value P<40 [MWh].

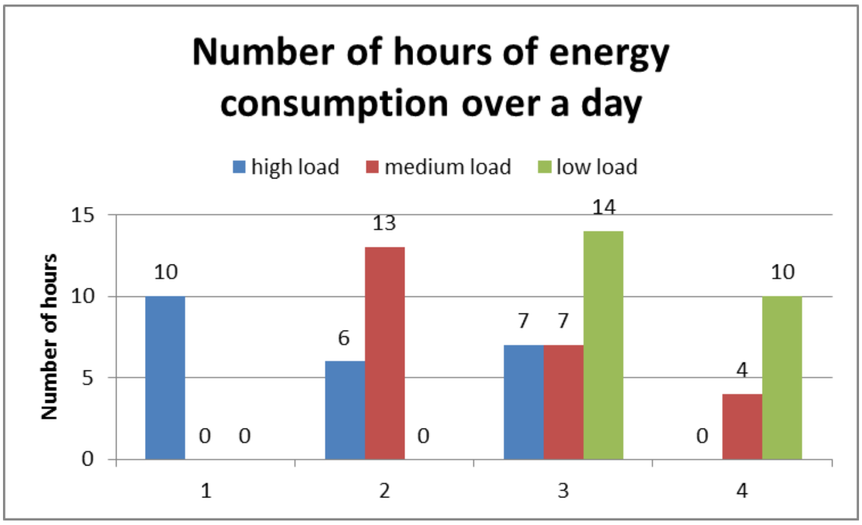


Figure 30.Number of hours of energy consumption over three load profiles days.

We presented also a summ of that hours of enrgy consumption in one year on *Figure 31*

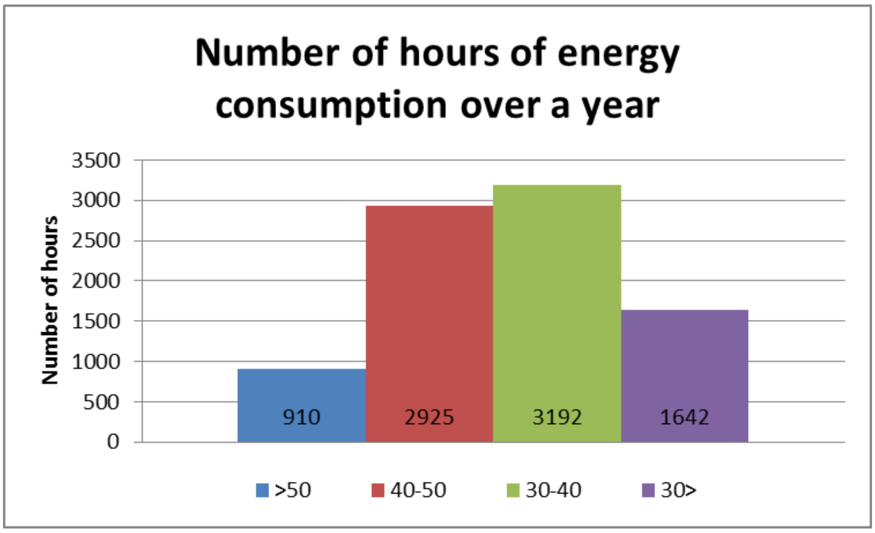


Figure 31.Number of hours of energy consumption in one year.

91 days with consumption above P=50 [MWh] represents a 10% of all annual energy consumption. 69,8% this is consumption in range P=(50-30)[MWh]. Average values of power consumed are present in *Table 69. Average values of power consumption*

Calculations, for present power consumption in [%], I can make using duration curves or graphs as above. Energy companies plan generation and distribution of electrocity, after analysis of data like that. Information about power consumption are very important, when I have more than one kind of energy generators. I decide when I will be using which one to get maximumefficiencyat minimumcost. Making analysis I should also remember about losses in my generators and network. They describe in next subsections.

Table 69. Average values of power consumption.

	High load	Medium load	Low load
Average power consumption per hour [MW]	46,088	39,794	29,6145
Power consumption per day [MW]	1106,125	955,057	710,746
Average power consumption per one day in year [MW]	38,82		
Average power consumption per year (365 days) [MW]	931,81		

b. Power losses in transformers

We made power losses calculations with two working transformers (full-load and no-load) and in bad condition when only one transformer were working all year. Summaryof measurement data are present in table below:

Table 70.Annual power losses on transformers.

	A&B transformers load	A&B transformers no-load	B transformer load
P(t)loss [MWh]	1144,777	246,0446	940,5899
Q(t)loss [Mvarh]	9436,189	8973,896	17965,61

As I expected, I get bigger power losses on full-load transformers as on no-load. It was bigger 4,6 times for active power losses. P=1144,777 [MWh] for full-load and P=246,0446[MWh] for no-load. Most interesting is compare annual power losses in two transformers and with one disconnected. I assumed that, the B transformer was working without break all year. Finally I got higher value of power losses for only one transformer. Lossdifferenceis P=694,5[MWh]. One working transformer is enough and it is cheaper solution for build network but it gives big value of power losses. I need second transformer also to ensure supply protection. If one of two transformers will breakdown or just will have any damage then second one can keep value of transferred power. So I got improved reliability of supply. Other advantage is a longer life of each transformer, when they are working together. Transformers do not have to work on maximum performance all time so they can longer operated. It Is also worth noting,that power losses could be smaller for two transformers work, than for one only.

In that case could be only one disadvantage. On the beginning, there are higher costs of purchase andinstallation two transformers, than only one. However, I can conclude that definitely it is better to have two transformers.

c. *Power losses in network*

On the end I present the sum of network losses. That data generated NEPLAN. As I can see on *Table 71*, power losses on the network are quite high. Mostly it is because of losses on lines (we have 10 lines) and connection losses.

Table 71.Network energy losses.

		Network energy losses								
		Load 2 transformers			No-load 2 transformers			Load 1 transformer		
		high load	med. Load	low load	high load	med. Load	low load	high load	med. Load	low load
P(t) losses	[MWh]	29,15922	22,53363	12,9852	26,82537	18,03196	10,6647	28,96524	19,85174	12,21519
	Total /year	7958,7965			6711,44505			7380,28755		
Q(t) losses	[Mvarh]	66,38756	44,99312	14,99724	66,33004	38,39739	14,96054	101,222	61,86177	28,84281
	Total /year	15639,7577			14424,16515			23156,60162		

IV. Conclusion

If electricity cannot be stored, this is very important to know loading curve. It helps to keep the correct balance between supply and power demand. “Energy supplied must always be equal to consumed.” So it is also necessary to know how much power should be generate in real time, under all system operating conditions. When I have large power consume at given time I can determine is it because of damage line or it is just high load.

Using duration curve I can plan power demand in future and plan power supply. I calculate total power transferred and total power losses also I can try to minimize power losses. I can use it for make some statistics or to find out the solutions for economical questions.

10-0,4 kV (Low Voltage) Network of Funen

- **Protection in Low Voltage Installations**

I. Introduction

In Fåborg town, there is a company that has its own 10/0.4 kV transformer outside the building. The transformer is fed by a 10 kV line, which belongs to the Medium Voltage Installation that has been described above.

Although more cables are shown in the schema of the low voltage installation, only L1, L2 and L3 are considered during calculating.

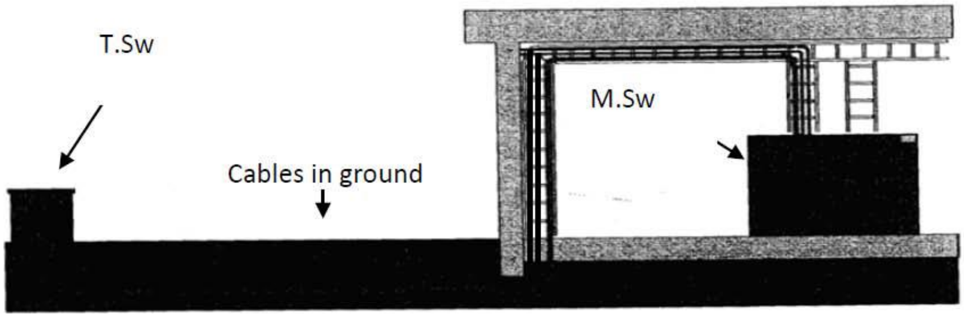


Figure 32.Entry part of a low voltage installation at a company in Fåborg town. Cables connect the transformer switchboard (T.Sw) via cables to the main switchboard (M.Sw) inside the building.

L1, L2 and L3 will be analyzed in order to obtain the cable dimension, the switch gear of overload, the short circuit protection and the protection from indirect contact.

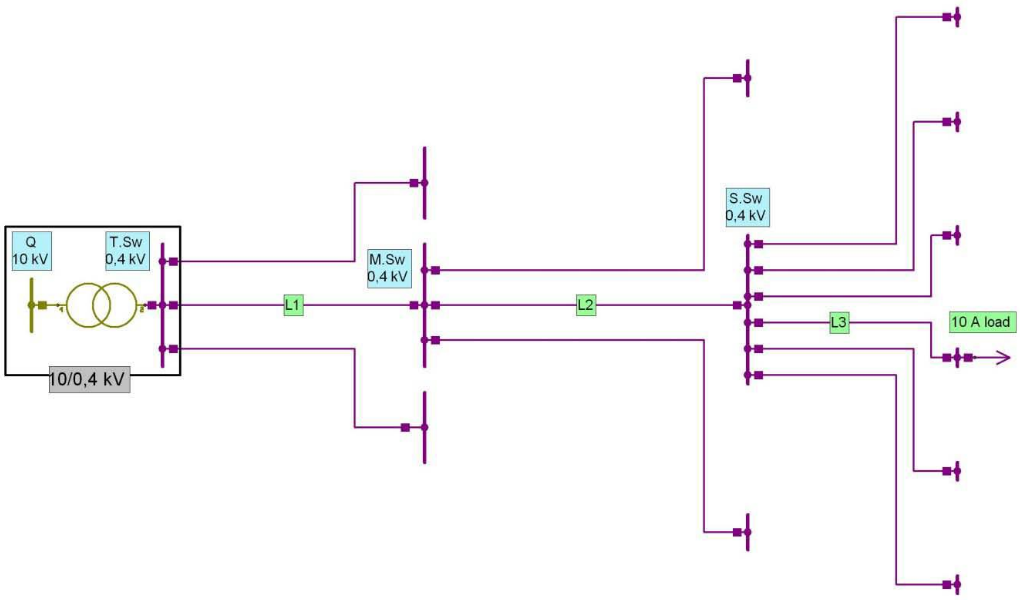


Figure 33.Diagram of a low voltage installation at a company in Fåborg town.

A brief description to different protection criteria for dimensioning low voltage installations is done below.

The descriptions are obtained from the *ReglamentoElectrotécnico de Baja Tensión (REBT).* The REBT is the legislation for low voltage installations that is used in Spain. Due to the facility to find this legislation in Internet, in this project REBT is the chosen option to analyze the low voltage installation.

"The objective of system protection is to detect faults and to selectively isolate faulted parts of the system. It must also permit short clearance time to limit the fault power and the effect of arcing faults."[4]

a. Protection of gear and cables against overload currents

In the REBT, GUÍA-BT-22, overload current protection explains that the circuits have to be protected from the overload currents, so the interruption of these circuits has to be done in a convenient time or the circuits have to be dimensioned considering the predictable overload currents.

The overload current may be produced by:

- The used devices or isolated defects due to big impedance.
- Short circuits.
- Atmospheric electrical discharges.

The limit of the current carrying capacity in the cables has to be guaranteed by the used protection device.

The protection device may be a circuit breaker with omnipolar cut or a calibrated fuse.

The operating characteristics of the circuit breaker that protects a cable from overload currents have to satisfy the two following conditions:

1. $I_B \leq I_N \leq I_Z$
2. $I_2 \leq 1.45 \cdot I_Z$

Where:

I_B is the current, with which the circuit has been designed according to the predictable load.

I_Z is the current carrying capacity.

I_n is the rated current in the protection device. In the case of regulated protective devices. I_n is the regulated current selected.

I_2 is the current that ensures the protection of the device for a long time (t_c).

[4] Electrical Installations Handbook. Part 1.3: System Protection. John Wiley &Sons.Third edition, 2000.

The operating current of the fuse (If) that ensures the protection of the device for a long time is, in the case of gG fuses:

1. $I_f = 1.60 \cdot I_N$ $\quad if \quad$ $I_N \geq 16A$
2. $I_f = 1.90 \cdot I_N$ $\quad if \quad$ $4A \quad < I_N < 16A$
3. $I_f = 2.10 \cdot I_N$ $\quad if \quad$ $4A \leq I_N$

b. *Protection of gear and cables against short circuit currents*

Based on the REBT, GUÍA-BT-22, Overload current protection.

In the origin of the circuits will have a short circuit protection device. Thecurrent breaking capacity of the device will be set using the short circuit current in the circuit at that point. It is possible that circuits, which are derivated from the main circuit, may have only overload current protection devices, while a unique general device in the main circuit can guarantee the short circuit protection for all the derivated circuits.

A circuit breaker with omnipolar cut or a calibrated fuse can be considered as short circuit protection devices.

The current breaking capacity of the protection device has to be equal or higher than the maximum short-circuit current that can be produced at the point where the device will be installed. This maximum short-circuit current is produced when a three phase short-circuit appears.

The performance of the circuit breakers is defined by a curve, in this curve, there are two sections:

- Overload tripping: thermal characteristic of inverse time or depending time.
- Short-circuit tripping: without intentional delay. It is characterized by the instantaneous tripping current (I_m). It is also called as magnetic characteristic or independent time.

In molded-case circuit breaker or magneto thermal device are three types of magnetic tripping (I_m) depending on the multiple of the rated current:

- Curve B: $I_m = (3 \div 5)I_n$
- Curve C: $I_m = (5 \div 10)I_n$
- Curve D: $I_m = (10 \div 20)I_n$

The curve B is used when protecting circuits, where there aren't transients. The curve D is used when there are important transients (e.g. starting a motor).The curve C is used for circuits with mixed loads (domestic uses).

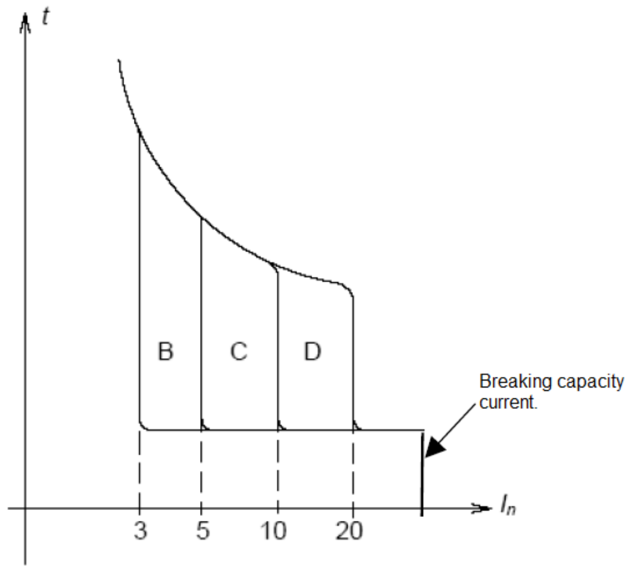


Figure 34.Types of magnetic tripping current of the molded-case circuit breaker.

In the case of the fuses, they depend on the fusion curve. Fuses are represented by two letters. The first letter shows the zone where the current breaking capacity is guaranteed in the fuse. The second letter shows the operating category according to the receptor or the circuit that is being protected.

"The standard identifies application categories which classify the time-current characteristic of each type of fuse. The application category is a two-digit code. It is based on IEC 60269.

- The first letter is "*a*" if the fuse is for short-circuit protection only; an associated device must provide overload protection.
- The first letter is "g" if the fuse is intended to operate even with currents as low as those that cause it to blow in one hour. These are considered general-purpose fuses for protection of wires.

The second letter indicates the type of equipment or system to be protected:

- D North American time-delay fuses for motor circuits, UL 248 fuses
- G General purpose protection of wires and cables
- M Motors
- N Conductors sized to North American practice, UL 248 fuses
- PV Solar Photovoltaic Arrays as per 60269-6
- R, S - rectifiers or semiconductors.
- Tr Transformers. "[5]

Below, the curves of different fuses are shown.

[5] http://en.wikipedia.org/wiki/IEC_60269#Application_categories_and_time-current_characteristics.

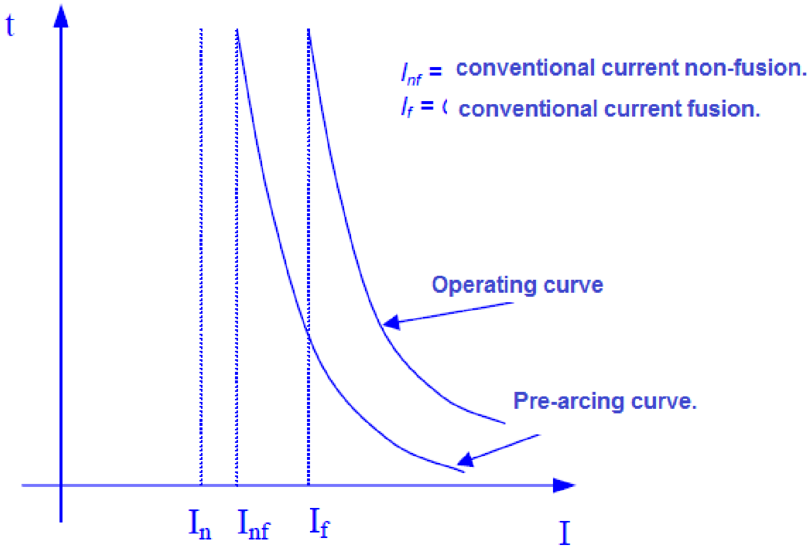


Figure 35.Time-current characteristic of a fuse, type “g”.

If fuses, type “a” are used, an overload protection will be needed.

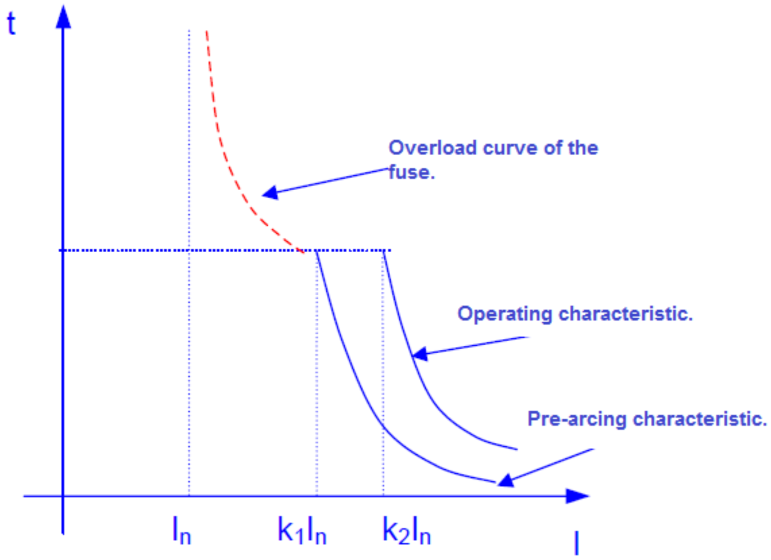
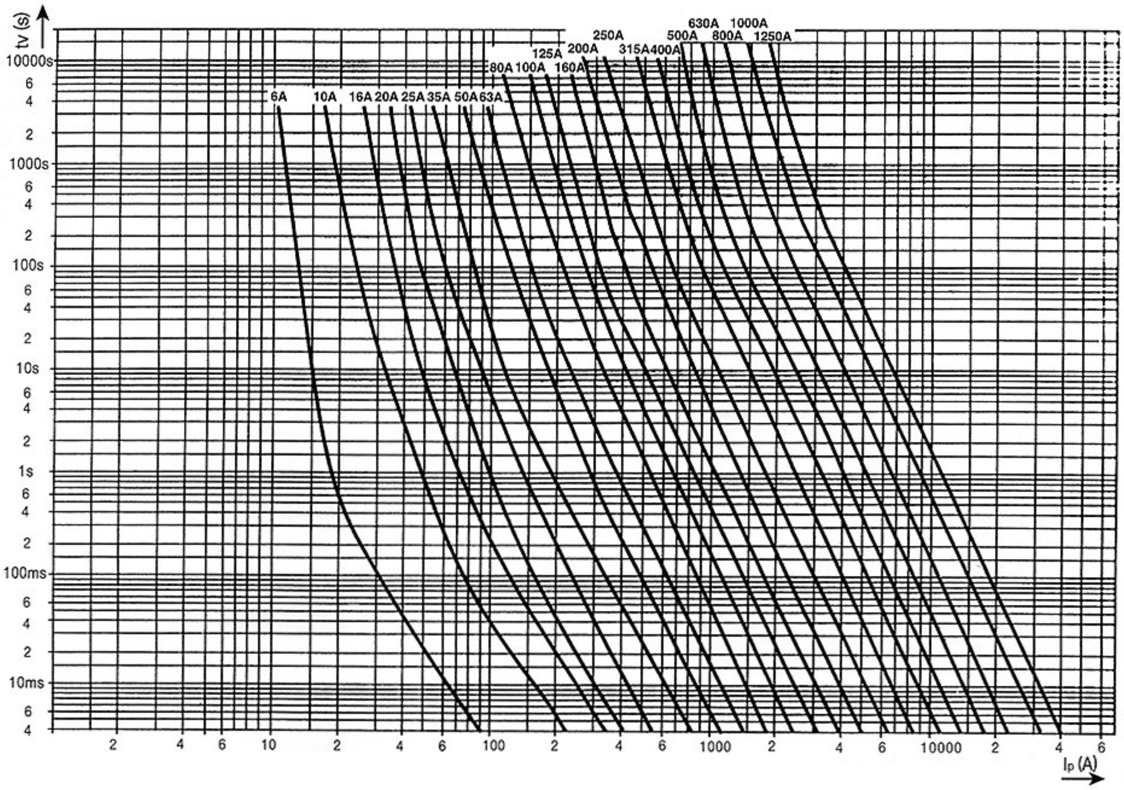


Figure 36.Time-current characteristic of a fuse, type “a”.

Table 72. Typical Time to current characteristics for a gL / gG fuses series.



All the devices, that protect the circuit from short-circuit currents, will satisfy the below two conditions:

1) The current breaking capacity of the protection device has to be equal or higher than the maximum short-circuit current that can be produced at the point where the device will be installed. It can be lower if there is a device with a higher current breaking capacity installed upstream.
2) The breaking time of a short circuit current, at a point of the circuit, cannot be higher than the time that takes to the cable to reach the limit of the permissible temperature. If the duration of the short circuit takes less than 5 seconds, the maximum time that the short circuit can last, can be calculated with the below formula.

$$(I^2t)_{CB} \leq (I^2t)_{Cable} = k^2 \cdot S^2$$

$$\sqrt{t} = k \times \frac{S}{I}$$

where:

t is the duration of the short circuit in seconds.

S is the cross section in mm^2.

I is the short circuit current in amperes A. In RMS.

K is a constant. UNE 20460-4-43.

c. *Selectivity in electrical installations*

"Selectivity is advisable for series-connected protection devices to ensure the greatest possible level of supply reliability for the unaffected feeders."[6]

The definition of selectivity is also given by the law IEC 60947-1 Standard "Low voltage equipment, Part 1: General rules for low voltage equipment".

Trip selectivity (for overcurrent) is coordination between the operating characteristics of two or more overcurrent protection devices, so that when an overcurrent within established limits occurs, the device destined to operate within those limits trips whereas the others do not trip.

Selectivity techniques:

– Current selectivity.

The base concept is that closer to the power supply the fault point is, higher the fault current is.
In order to guarantee selectivity, the protections must be set to different values of current thresholds in every hierarchical level. The ultimate selectivity value which can be obtained is equal to the instantaneous trip threshold of the downstream protection.

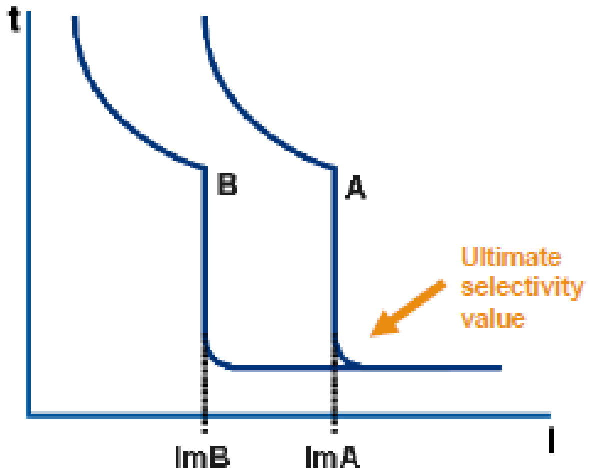


Figure 37.Current selectivity.

Therefore other methods are needed to have a total selectivity.

– Time selectivity.

Time (chronometric) selectivity is obtained by introducing intentionally always greater delays in the intervention tripping timings of the upstream circuit breakers in the chain (different devices trip delays for different hierarchical levels).

[6]Electrical Installations Handbook. Part 1.3: System Protection. John Wiley &Sons.Third edition, 2000.

d. *Protection from electric shock, directly and indirectly*

In the REBT, the law GUÍA-BT-24, Protection from electric shock, directly and indirectly explains the actions taken to guarantee the protection of persons and domestic animals against electric shocks.

- Protection against direct electric shock.

This protection consists on the actions taken to protect the persons against the electric shock from direct contact of active parts of electric materials.

The law UNE 20.460-4-41 describes the ways taken to protect:

1. Protection to isolate the active parts.

   The active parts have to be covered by an isolation which can't be eliminated, only by destruction.

2. Protectionbybarriers.

   The active parts have to be placed inside the covers or behind the barriers. the barriers must have a minimum grade of protection IP XXB, according to UNE 20.324. "The IP Code (or International Protection Rating, sometimes also interpreted as Ingress Protection Rating) consists of the letters IP followed by two digits and an optional letter.

   The first digit indicates the level of protection that the enclosure provides against access to hazardous parts (e.g., electrical conductors, moving parts) and the ingress of solid foreign objects. The second digit is the protection of the equipment inside the enclosure against harmful ingress of water"[7]

[7] http://en.wikipedia.org/wiki/IP_Code

Table73. IP digits.

Symbol (IP$_{XY}$)	
1st number (X)	
0	No protection against hand or body contact.
1	Maximum object dimension which can be inserted is 50mm. Protected against body contact , but fingers may be inserted.
2	Maximum object dimension which can be inserted is 12mm. Human fingers may NOT be inserted.
3	Maximum object dimension which can be inserted is 2,5mm. Contact using tools bigger than 2,5mm (screwdrivers e.t.c.) is NOT possible.
4	Maximum object dimension which can be inserted is 1mm. Contact using tools bigger than 1mm (screwdrivers e.t.c.) is NOT possible.
5	Inserted dust may NOT overlay equipment parts. No contact is possible.
6	Full protection against dust insertion. No contact is possible.
2nd number (Y)	
0	No protection
1	Equipment is protected against vertical drops fall .
2	Equipment is protected against drops falling with 15° slope regarding the vertical axis.
3	Equipment is protected against drops falling with 60° slope regarding the vertical axis.
4	Equipment is protected against splashing water coming from any direction.
5	Equipment is protected against water jets coming from any direction. (6 inch jet nozzle)
6	Equipment is protected against powerful water jets. (12inch jet nozzle)
7	Equipment is protected against temporary immersion for a given time duration.
8	Equipment is protected against permanent immersion in given pressure.

3. Protectionthroughobstacles.

This action doesn't guarantee a complete protection and its application is limited, in a practical way, to the locals where electric services are done. In these locals, only electric workers have access to it.

The obstacles have to prevent from:

- a not deliberate physical approach to the active parts.
- not deliberate contacts with active parts, in the case of the intervention in low voltage equipment while this is in service.

4. Protection by distance to the active parts.

This action doesn't guarantee a complete protection and its application is limited, in a practical way, to the locals where electric services are done. In these locals, only electric workers have access to it.
This protection only prevents from accidental contacts with the active parts.

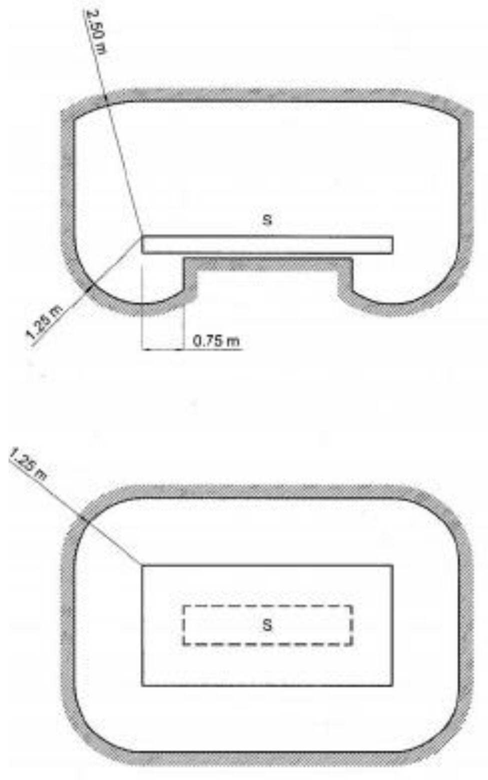


Figure 38.Accessibility volume to the area S.

5. Additional protection by residual current devices.

   This action is intended for complementing other protection actions against direct contacts.

   Using current differential-residual devices, which value is equal or under 30 mA, is a complementary protection action in the case of failure of the other protection against direct contact or reckless of the users.

- Protection against indirect electric shock.

"Protection against indirect contact hazards can be achieved by automatic disconnection of the supply if the exposed-conductive-parts of equipment are properly earthed.

Two levels of protective measures exist:

- 1st level: The earthing of all exposed-conductive-parts of electrical equipment in the installation and the constitution of an equipotential bonding network.

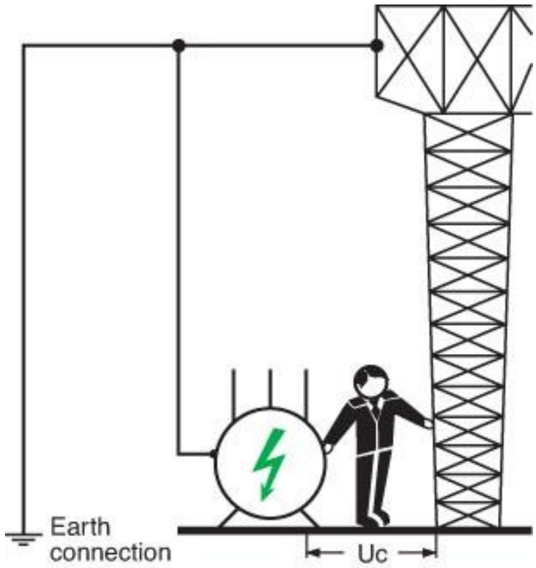


Figure 39.Illustration of the dangerous touch voltage Uc.

- 2nd level: Automatic disconnection of the supply of the section of the installation concerned, in such a way that the touch-voltage/time safety requirements are respected for any level of touch voltage Uc(1)."[8] There are three methods of automatic disconnection depending on how the electric system is.

  - Automatic disconnection for TT system.

    "Automatic disconnection for TT system is achieved by RCD having a sensitivity of $I_{\Delta n} \leq \frac{50}{R_A}$ where R_A is the resistance of the installation earth electrode."[9]

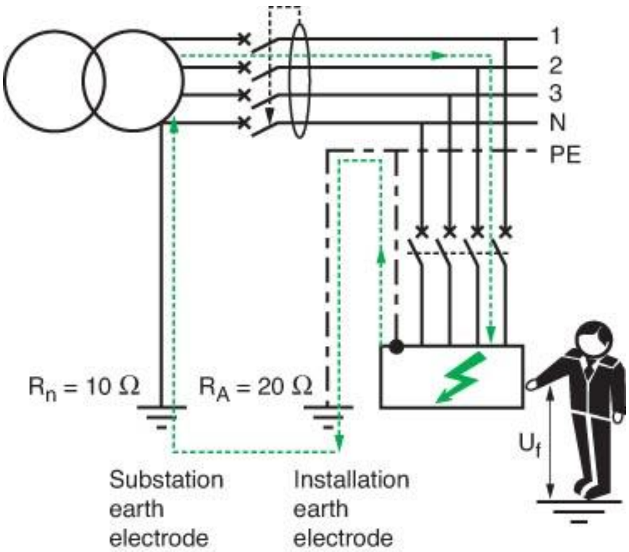


Figure 40.Automatic disconnection of supply for TT system.

  - Automatic disconnection for TN systems.

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[8] http://www.electrical-installation.org/wiki/Measures_of_protection:_two_levels.
[9] http://www.electrical-installation.org/wiki/Automatic_disconnection_for_TT_system

"The automatic disconnection for TN system is achieved by overcurrent protective devices or RCD's."[10]

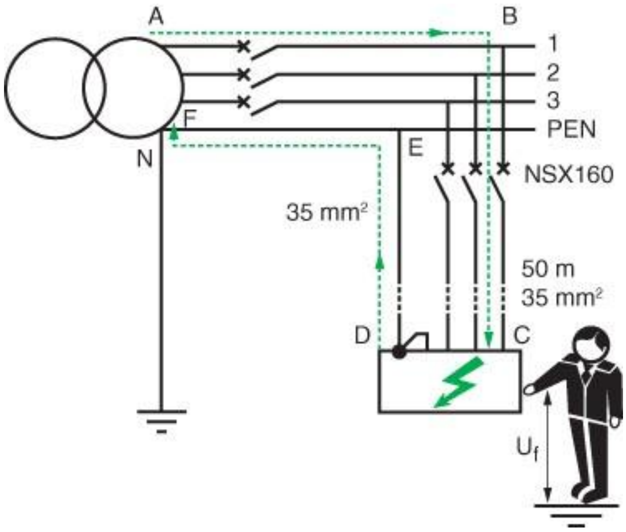

Figure 41.Automatic disconnection in TN system.

- Automatic disconnection on a second fault in an IT system.

"In this type of system:

- o The installation is isolated from earth, or the neutral point of its power-supply source is connected to earth through a high impedance.
- o All exposed and extraneous-conductive-parts are earthed via an installation earth electrode.

First fault situation: In IT system the first fault to earth should not cause any disconnection.

[10] http://www.electrical-installation.org/wiki/Automatic_disconnection_for_TN_systems.

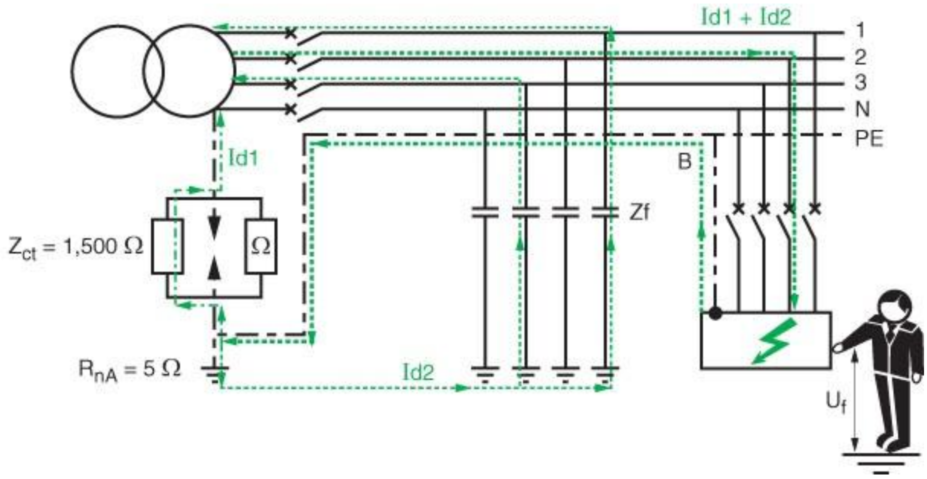

Figure 42. Fault current path for a first fault in IT system.

Second fault situation: The simultaneous existence of two earth faults (if not both on the same phase) is dangerous, and rapid clearance by fuses or automatic circuit-breaker tripping depends on the type of earth-bonding scheme, and whether separate earthing electrodes are used or not, in the installation concerned.”[11]

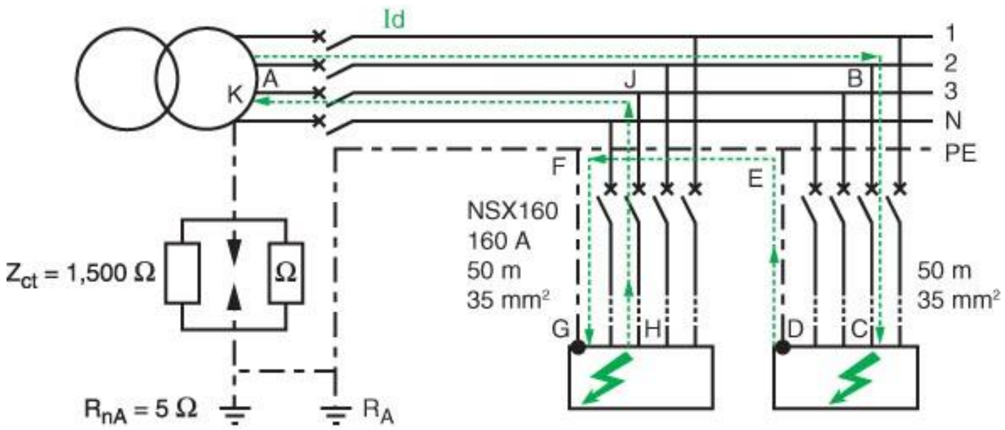

Figure 43. Circuit-breaker tripping on double fault situation when exposed-conductive-parts are connected to a common protective conductor.

[11] http://www.electrical-installation.org/wiki/Automatic_disconnection_on_a_second_fault_in_an_IT_system.

II. Fåborg

a. Cable dimension

The first step when dimensioning the cables is to calculate the currents that flow through these cables.

The description of the cables is the following one:

"L3 supplies a 10 A load and is most of the way bundled along with five other cables on a wall, each loaded with 10 A.

The load current of L2 is determined from the maximum load current of the six cables that are supplied from S.Sw multiplied with a simultaneity factor of 0.6.

The load current of L1 is determined from the maximum load currents of L2 plus the two other cables that are supplied from M.Sw. A simultaneity factor of 0.6 is used to calculate the load current."[12]

To start the calculation, it is assumed a cosφ = 1. A resistive load supplied through a – more or less – resistive cable gives the worst case for voltage drop.

When calculating the currents, a simultaneity factor is considered according to the project description. The calculations have been made in Excel, and are shown in Appendix CD - 10 kV Network - Low Voltage Installation.

[12]Electrical Power Engineering Project.

Table 74.Calculation of L1, L2 and L3 currents.

Load toS.Sw

					POLAR					
			I phase R		I phase S		I phase T		I phase N	
	U phase (V)	Factor	RMS	ANGLE	RMS	ANGLE	RMS	ANGLE	RMS	ANGLE
Load 1	230,00	1,00	10,00	0,00	10,00	-120,00	10,00	120,00	0,00	0,00
Load 2	230,00	1,00	10,00	0,00	10,00	-120,00	10,00	120,00	0,00	0,00
L3	230,00	1,00	10,00	0,00	10,00	-120,00	10,00	120,00	0,00	0,00
Load 4	230,00	1,00	10,00	0,00	10,00	-120,00	10,00	120,00	0,00	0,00
Load 5	230,00	1,00	10,00	0,00	10,00	-120,00	10,00	120,00	0,00	0,00
Load 6	230,00	1,00	10,00	0,00	10,00	-120,00	10,00	120,00	0,00	0,00

From S.Sw to M.Sw

					POLAR					
			I phase R		I phase S		I phase T		I phase N	
	U phase (V)	Factor	RMS	ANGLE	RMS	ANGLE	RMS	ANGLE	RMS	ANGLE
Line 1	230,00	1,00	100,00	0,00	100,00	-120,00	100,00	120,00	0,00	0,00
L2	230,00	0,60	36,00	0,00	36,00	-120,00	36,00	120,00	0,00	0,00
Line 3	230,00	1,00	50,00	0,00	50,00	-120,00	50,00	120,00	0,00	0,00

From M.Sw to T.Sw

					POLAR					
			I phase R		I phase S		I phase T		I phase N	
	U phase (V)	Factor	RMS	ANGLE	RMS	ANGLE	RMS	ANGLE	RMS	ANGLE
L1	230,00	0,60	111,60	0,00	111,60	-120,00	111,60	120,00	0,00	0,00

After calculating the currents, the dimension of the cables is the next step. L1, L2 and L3 are studied using different laws from the REBT.

- Assumptions

In the Danish legislation, loaded cables loaded which exceed more than 75% are considered when applying the reduction factor depending on grouped cables.

In the English legislation, loaded cables loaded which exceed more than 30% are considered when applying the reduction factor depending on grouped cables.

In the Spanish legislation, this reduction factor is considered in all the cases. It doesn't matter that the cables are not exceeding a specific per cent.

1. L1

"The main cable (L1) between T.Sw and M.Sw is placed in ground outside the building. It enters the building through a pipe in the concrete wall, and is fixed on a cable rack inside the building. L1 is grouped with two other cables – 95 mm2 Cu cables – both loaded more than 30 %. The distance between the cables in the ground is 15cm."[13]

1.1 Thermal criteria.

L1 has different sectors, so it has to be dimensioned according to three different laws:

1.1.1. Cables underground.

In this case, tables and reduction factors are found in ITC-BT-07, from the REBT. The ITC-BT-07 is shown in the*Appendix III. Low Voltage 1*, at the end of this Project.

The current which has been calculated above in L1 is $I_{L1} = 111.60\ A$.

The *Table 3 (AIII) - Appendix III. Low Voltage 1*shows the maximum permissible current. The maximum current has to be higher than I_{L1}.

$$3 \times XLPE \qquad \rightarrow \qquad s = 16\ mm^2, \qquad I_{max\ ,table} = 115\ A.$$

Reductionfactors in *Appendix III. Low Voltage 1*:

- Table 4. Reduction factor depending on temperature.

$$T_{GROUND} = 15ºC, XLPE \qquad \rightarrow \qquad f_T = 1.07$$

- Table 5. Reduction factor depending on thermal resistivity to ground.

$$\rho = 1.5\ {}^{º K \cdot m}/_{W}\ , Three\ phases\ \rightarrow \quad f_\rho = 0.87$$

To get this value, an interpolation is needed.

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[13]Electrical Power Engineering Project.

$$f_\rho = 0.89 + \frac{0.84 - 0.89}{1.65 - 1.40}(1.5 - 1.4) = 0.87$$

– Table 6. Reduction factor depending on grouped cables.

$$Three\ cables, d = 0.25m \quad \rightarrow \quad f_g = 0.8$$

The formula to apply now is:

$$I_{\max,permissible\ \ current} \geq I_{table} \cdot f_T \cdot f_\rho \cdot f_g$$

$$I_{\max,permissible\ \ current} \geq 115 \cdot 1.07 \cdot 0.87 \cdot 0.8 = 88.6428\ A$$

The obtained value is lower than $I_{L1} = 111.60\ A$. So a bigger cross section is required from table 3.

$$3 \times XLPE \quad \rightarrow \quad s = 25mm^2, \quad I_{max,table} = 150\ A.$$

$$I_{\max,permissible\ \ curren\ t} \geq 150 \cdot 1.07 \cdot 0.87 \cdot 0.8 = 111.7\ A$$

The difference betweenI_{L1} and $I_{\max,permissiblecurrent}$ is so low, that a bigger cross section is needed.

$$3 \times XLPE \quad \rightarrow \quad s = 35mm^2, \quad I_{max,table} = 180\ A.$$

$$I_{\max,permi\ ssible\ \ current} \geq 180 \cdot 1.07 \cdot 0.87 \cdot 0.8 = 134.0496\ A$$

1.1.2. Cables underground in contact with concrete.

In this case, tables and reduction factors are found in ITC-BT-07, in *Appendix III. Low Voltage 1*.Although tables and reduction factors are the same as the previous case, now the cables are in contact with a different material, concrete.

The current L1 is $I_{L1} = 111.60\ A$.

The Table 3 (AIII) *Appendix III. Low Voltage 1*shows the maximum permissible current. The maximum current has to be higher thanI_{L1}.

$$3 \times XLPE \quad \rightarrow \quad s = 16\ mm^2, \quad I_{max,table} = 115\ A.$$

Reductionfactors in *Appendix III. Low Voltage 1*:

– Table 4. Reduction factor depending on temperature.

$$T_{WALL} = 25ºC, XLPE \quad \rightarrow \quad f_T = 1$$

– Table 5. Reduction factor depending on thermal resistivity to ground.

$$\rho = 2.5\ {}^{ºK \cdot m}/_{W}\ , Three\ phases \ \rightarrow \quad f_\rho = 0.71$$

- Table 6. Reduction factor depending on grouped cables.

$$Three\ cables, d = 0.25m \quad \rightarrow \quad f_g = 0.8$$

The formula to apply now is:

$$I_{\max, permissible\ \ current} \geq I_{table} \cdot f_T \cdot f_\rho \cdot f_g$$

$$I_{\max, permissible\ \ current} \geq 115 \cdot 1 \cdot 0.71 \cdot 0.8 = 65.32\ A$$

The obtained value is lower than $I_{L1} = 111.60\ A$. So a bigger cross section is required from table 3.

$$3 \times XLPE \quad \rightarrow \quad s = 25mm^2, \quad I_{max, table} = 150\ A.$$

$$I_{\max, permissible\ \ current} \geq 150 \cdot 1 \cdot 0.71 \cdot 0.8 = 85.2\ A$$

So a higher cross section is needed.

$$3 \times XLPE \quad \rightarrow \quad s = 50mm^2, \quad I_{max, table} = 215A.$$

$$I_{\max, permissible\ \ current} \geq 215 \cdot 1 \cdot 0.71 \cdot 0.8 = 122.12A$$

1.1.3. Cables inside a gallery.

In this case, tables and reduction factors are found in ITC-BT-07, in *Appendix IV. Low Voltage 2.Outdoorinstallation conditions*.

The current in L1is $I_{L1} = 111.60\ A$.

The *Table 1- Appendix IV. Low Voltage 2* shows the maximum permissible current. The maximum current has to be higher thanI_{L1}.

$$3 \times XLPE \quad \rightarrow \quad s = 35\ mm^2, \quad I_{max, table} = 135\ A.$$

Reduction factors:

- Table 2. Reduction factor depending on the temperature of the air.

$$T_{AIR} = 35ºC, XLPE \quad \rightarrow \quad f_T = 1.05$$

- Table 3. Reduction factor depending on how the cables are grouped.
  Considering a tray with holes (ventilation), with a distance D between cables.

$$A\ tray, distance\ D\ between\ cables \rightarrow \quad f_g = 1$$

The formula to apply now is:

$$I_{\max, permissible\ \ current} \geq I_{table} \cdot f_T \cdot f_g$$

$$I_{\max, permissible\ \ current} \geq 135 \cdot 1.05 \cdot 1 = 141.75\ A$$

So the cross section is kept because $I_{\max,permissiblecurrent}$ is higher than I_{L1}.

1.2. Protection criteria.

L1 is protected by a molded-case circuit breaker (MCCB). In a document uploaded to Blackboard, there is a catalogue for MCCB (Maksimalafbrydereiht IEC 60947-2). From this catalogue, the model DW125N gives the following rated currents of the device:

$$10 - 16 - 20 - 25 - 32 - 40 - 50 - 63 - 70 - 80 - 100 - 125$$

From the thermal criteria, the worst case is when the cable is underground in concrete. So there is a cross section of $s = 50mm^2$ and a maximum permissible current of 122.12 A. The protection criteria is based on the following formula, which has been explained in in the theory.

$$I_B \leq I_N \leq I_Z$$

$$111.6A \leq I_N \leq 122.12A$$

A regulated MCCB can be set with a rated current of 120 A. So the cross section hasn't got to be raised.

2. L2.

"L2 is most of the way placed along with two other cables (also supplied from M.Sw) in a cable tray, in a single layer. One of the cables is loaded with 100 A exceeding 80% of the current carrying capacity, and the other cable is loaded with 50 A without exceeding 30% of the capacity."[14]

2.1 Thermalcriteria.

2.1.1 Cables inside a gallery.

In this case, tables and reduction factors are found in ITC-BT-07, in *Appendix IV. Low Voltage 2*, on the *Outdoor installation conditions* part

The current which has been calculated above in L2is $I_{L2} = 36\ A$.

The *Table 1 (AIV) - Appendix IV. Low Voltage 2*shows the maximum permissible current. The maximum current has to be higher than I_{L2}. Cable materialchanges from thepreviouscase, PVC instead of XLPE.

$$3 \times PVC \qquad \rightarrow \qquad s = 6\ mm^2, \qquad I_{max,table} = 36\ A.$$

Reduction factors:

- Table 2. Reduction factor depending on the temperature of the air.

$$T_{AIR} = 35ºC, PVC \qquad \rightarrow \qquad f_T = 1.08$$

[14]Electrical Power Engineering Project.

- Table 3. Reduction factor depending on how the cables are grouped. Considering a tray with holes (ventilation), with a distance D between cables.

$$A\ tray\ ,distance\ D\ between\ cables\ \rightarrow \quad f_g = 1$$

The formula to apply now is:

$$I_{\max ,permissible \quad current} \geq I_{table} \cdot f_T \cdot f_g$$

$$I_{\max ,permissible \quad current} \geq 36 \cdot 1.08 \cdot 1 = 38.88\ A$$

So the cross section is kept because $I_{\max ,permissiblecurrent}$ is higher than I_{L1}.

2.2 Protection criteria.

L2 is protected by a fuse. The rated values of the fuses are:

$$10 - 16 - 20 - 25 - 32 - 40 - 50 - 63 - \cdots$$

From the thermal criteria, a cross section of $s = 6mm^2$ is set and the maximum permissible current is 38.88 A.

The protection criterion is based on the following formula, which has been explained in in the theory.

$$I_B \leq I_N \leq I_Z$$
$$36A \leq I_N \leq 38.88A$$

There is not rated value of the fuse, so a higher cross section is required.

Coming back to the *Table 1 (AIV) - Appendix IV. Low Voltage 2*, the following values are gotten:

$$3 \times PVC \qquad \rightarrow \qquad s = 10\ mm^2, \qquad I_{max\ ,table} = 50\ A.$$

Applying the reduction factors, the maximum permissible current is $54\ A$.

$$36A \leq I_N \leq 54A$$

Finally, the fuse, which will be used, will have a rated value of 40 A.

3. L3.

"L3 supplies a 10 A load and is most of the way bundled along with five other cables on a wall, each loaded with 10 A."[15]

3.1 Thermal criteria.

3.1.1 Indoors installations or receptors. General requirements

In this case, tables and reduction factors are found in ITC-BT-19, *Appendix V. LowVoltage 3*.

[15]Electrical Power Engineering Project.

The current which has been calculated above in L3is $I_{L3} = 10\ A$.

The *Table 1 (AIII) - Appendix III. Low Voltage 1* shows the maximum permissible current. The maximum current has to be higher than I_{L3}.

$$Ref\ B2 \times 3 \times PVC \qquad \rightarrow \qquad s = 1.5\ mm^2, \qquad I_{max\ ,table} = 13\ A.$$

Reductionfactors in *Appendix V. LowVoltage 3*:

- Table 2. Reduction factor depending on temperature.
  In this case, the table only affects to XLPE cables. This factor is not applied in L3.

- Table 3. Reduction factors of grouped cables.
  There are six cables into a tube, so in this table it is considered a surface without holes and six cables.

$$Ref\ 2 \times 6\ cables\ \rightarrow \quad f_\rho = 0.7$$

The formula to apply now is:

$$I_{\max ,permissible\ \ current} \geq I_{table} \cdot f_T \cdot f_\rho \cdot f_g$$

$$I_{\max ,permissible\ \ current} \geq 13 \cdot 0.07 = 9.1\ A$$

The obtained value is lower than $I_{L3} = 10\ A$. So a bigger cross section is required from table 3.

$$Ref\ B2 \times 3 \times PVC \qquad \rightarrow \qquad s = 2.5\ mm^2, \qquad I_{max\ ,table} = 17.5\ A.$$

$$I_{\max ,permissible\ \ current} \geq 17.5 \cdot 0.07 = 12.25\ A$$

3.2 Protection criteria.

L3 is protected by a miniature circuit breaker (MCB). In a website in Internet, there is a catalogue for MCB (ABKN high breaking capacity mini circuit breaker). From this catalogue, the rated currents of the device are given:

$$1 - 2 - 3 - 4 - 6 - 10 - 16 - 20 - \cdots A$$

From the thermal criteria, there is a cross section of $s = 2.5\ mm^2$ and a maximum permissible current of 12.25 A. The protection criteria is based on the following formula, which has been explained in in the theory.

$$I_B \leq I_N \leq I_Z$$

$$10\ A \leq I_N \leq 12.25\ A$$

A MCB can be set with a rated current of 10 A. So the cross section hasn't got to be raised.

After dimensioning the cable with the thermal criteria and the protection criteria, the voltagedrop has to be analyzed.

NEPLAN is used to get the resistance and the impedance of the cables according to the cross section previously set.

Table75. Valuesfrom NEPLAN.

	R(Ω/km)	X(Ω/km)
L1	0,39	0,08
L2	1,81	0,09
L3	7,28	0,11

The formulas used in to calculate the drop voltage are: $\Delta V_{REAL}(V) = \sqrt{3} \cdot R_K \cdot l \cdot I_{LOAD} \cdot \cos\varphi + \sqrt{3} \cdot X_K \cdot l \cdot I_{LOAD} \cdot \operatorname{sen}\varphi$

$$\Delta V_{REAL}(\%) = \frac{\Delta V_{REAL}(V) \cdot 100}{V_{LINE}}$$

Table76. Accumulateddropvoltage.

From S.Sw to T.Sw

									S by CRIT. Thermal	S by PROTECT.	S to INSTALL				
		Voltage(V)	Xcables (Ω/km)	R(Ω/km)	Lenght(m)	cos φ	sen φ	I line (A)	Sfct(mm2)	Sfp(mm2)	Sf(mm2)	Sneutro(mm2)	ΔVreal(V)	ΔVreal(%)	ΔVacumul (%)
L1	3P+N	400,00	0,08	0,3890	40,00	1	0	111,60	50	50	50,00	25,00	3,01	0,75	3,11
L2	3P+N	400,00	0,09	1,8100	50,00	1	0	36,00	6	10	10,00	10,00	5,64	1,41	2,36
L3	3P+N	400,00	0,11	7,2800	30,00	1	0	10,00	2,5	2,5	2,50	2,50	3,78	0,95	0,95

In the project, it is explained that the voltage drop must not exceed 4% at the 10 A load supplied from S.Sw. The accumulative drop voltage in L1 is 3.11%, so is less than 4%. It is not needed to raise the cross section of the cables.

a. *Swith gear for overload*

The Switch gears for overload of the three cables were set in the project. When dimensioning the cables, the protection criterion has been explained.

Below, the information from the catalogue is analyzed.

- L1

$$L1 \rightarrow Adjustable\ MCCB:\ \ 120\ A$$

In the blackboard, there is a catalogue for this type of devices. MCCB (Maksimalafbrydereiht IEC 60947-2) is chosen from the company WEG. From the catalogue, the below information is shown:

Table 77.Data for the MCCB.

3 Polet udførelse (versioner i 2 og 4 polet på forespørgsel)			DW125N
Mærkespænding	Un	VAC	500
		VDC	250
	Iu (45°C)	A	125
Mærkestrøm Termisk fastindstillet eller justerbart indstillingsområde (termisk udløsning)	In	A	10-16-20-25-32-40-50-63-70-80-100-125
Ultimativ brydeevne	I_{CU}	220/240VAC	25
	KA	380/415VAC	16
		440VAC	10
		500VAC	8
		660/690VAC	-

The model chosen is DW125. The rated current of the device was evaluated in the protection criteria of L1. In this type of devices, it is also important to see that the current breaking capacity of the protection device has to be equal or higher than the maximum short-circuit current that can be produced at the point where the device will be installed..

From NEPLAN, the maximum short circuit current at the node T.Sw is 10.957 A.

$$I_{max,sc} \leq I_{breaking\ \ SC}$$

$$10.957\ A \leq I_{breaking\ \ SC} = 16A$$

With the below formula, the energy passing through the device has to be lower than the allowed energy of this.

$$(I^2t)_{CB} \leq (I^2t)_{Cable} = k^2 \cdot S^2$$

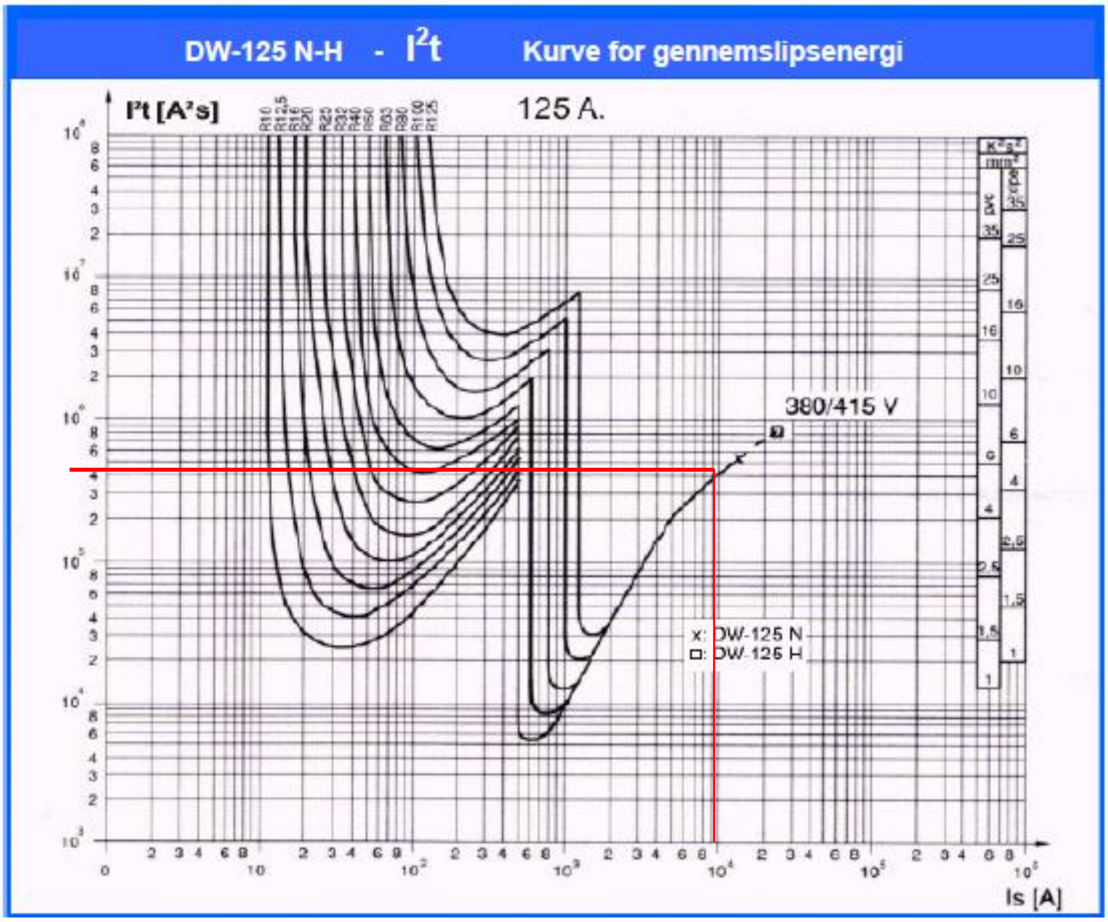


Figure 44. Curve of energy of the MCCB.

Knowing that the maximum short circuit current is approximately 11 kA, the energy, that is related to this value in the above curve, is 4.5 x 10^5 A^2s.

In the formula, the factor "K" is determined bt the law UNE 20460-4-43.

	PR/EPR
Temperatura inicial °C	90
Temperatura final °C	250
Material conductor: Cobre Aluminio Conexiones soldadas con estaño para los conductores de cobre	 $\boxed{143}$ 94 -

Figure 45.K factor by UNE 20460-4-43.

Although XLPE doesn't appear in the table, the material PR/EPR has the same characteristic temperatures as the XLPE. The factor also depends on the material of the cable, in this case, copper.

$$4.5 \cdot 10^5 \leq 143^2 \cdot 50^2 = 51122500$$

So the chosen protection is OK.

- L2

$$L2 \rightarrow Fuse: \ 40\,A$$

In the catalogue NH- Fuse system (Low voltage) from the company Ferraz Shawmut, GROUPE CARBONE LORRAINE, the required information is found.

The type of fuse is gG (general purpose protection of wires and cables). The model is NH-fuses, ~400 V gG.

Table 78. L2 fuse model data.

size	rated current I_N (A)	power dissipation (W)	FS ref.-no.	Lindner ref.-no.	weight kg/pce	pack. unit
000	40	3,1	Z223697	1E647.	0,12	9

As in the previous case, the energy has to be evaluated following the literature from blackboard:

The first step is to calculate the time of the short circuit.

$$t = \left(\frac{k \cdot S}{I_k}\right)^2$$

The material of the cable is PVC and the conductor is made of copper. The factor "K" used is 115.

Table 79.K factor by UNE 20460-4-43.

	PVC 70ºC $\leq$300 mm^2
Temperatura inicial ºC	70
Temperatura final ºC	160
Material conductor:	
Cobre	$\boxed{115}$
Aluminio	76
Conexiones soldadas con estaño para los conductores de cobre	115

In the case of the fuses, the lowest short circuit current is associated with the highest energy. Therefore, the minimum short circuit current is required to make this calculation. Further down, the minimum short circuit calculations are shown. In NEPLAN, the minimum values are obtained with ine ohase to ground fault. The minimum short circuit current at the node S.Sw is 0.967 kA.

$$t = \left(\frac{115 \cdot 10}{0.967 \cdot 10^3}\right)^2 = 1.4143\ s$$

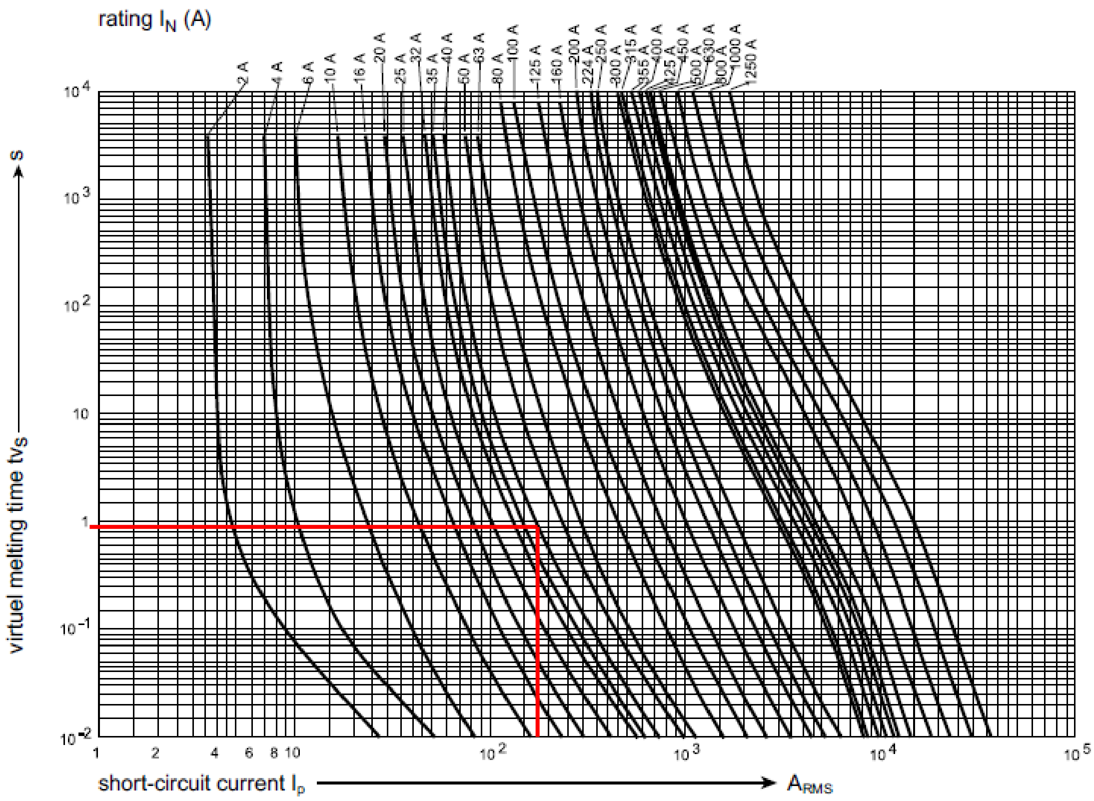
The time is bigger than 0.1 seconds. The curve where the energy has to be found is below. From the figure 14, the short circuit current related to 1.4 s is around 350A. the energy will be checked using:

$$(I^2 t)_{CB} \leq (I^2 t)_{Cable} = k^2 \cdot S^2$$

$$(350^2 1.4143)_{CB} = 173251 \leq 115^2 \cdot 10^2 = 1322500$$

The chosen fuse is OK.

Table 80.The curve of the fuse.



- L3.

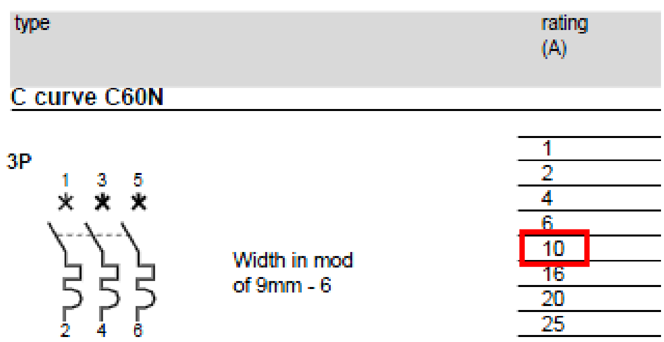
$$L3 \rightarrow MCB:\ 10\ A$$

The maximum short circuit current that device has to protect is 2.105 kA. This current is calculated by NEPLAN, at the node S.Sw.

The used catalogue is from Merlin Gerin, Multi 9 System, ProtectionMiniature Circuit Breakers, SCHNEIDER ELECTRIC.

The model selected is circuit-breakers up to 63 A, C60N, 6kA, C curve, AS/NZS 4898. The MCB has three poles.

The device protects the line, because the ultimate breaking capacity is 6 kA and the maximum short circuit current that the line withstands is 2.105 kA.



C curve

utilisation
cables feeding conventional loads.

technical data

■ power circuit
□ tripping curves: the magnetic trip units operate between 5 and 10 In
□ breaking capacity according to AS/NZS 4898, Icu ultimate breaking capacit (O-CO cycle):

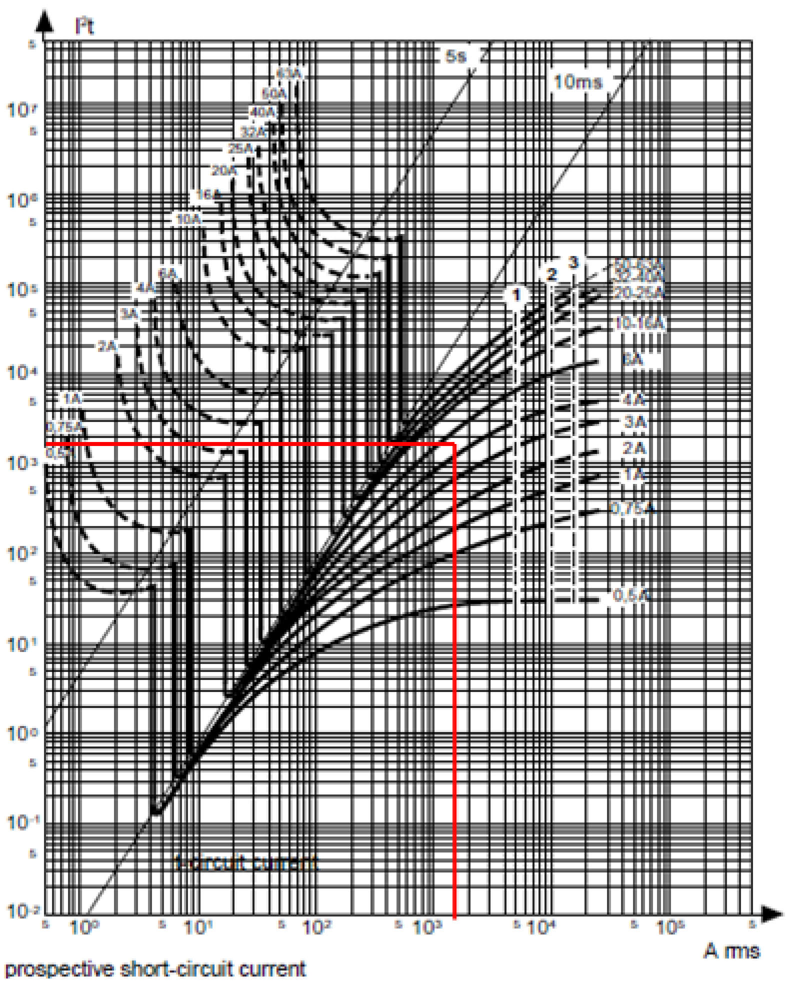
rating (A)	type	voltage (V)	breaking capacity Icu (A)
1...63	**1P**	240/415	6 000
	2P	415...480	6 000
	3P	415	6 000

type	rating (A)
C curve C60N	
3P Width in mod of 9mm - 6	1
	2
	4
	6
	10
	16
	20
	25

Figure 37. Data sheet for the MCB. Schneider Electric.

The following curve shows the maximum short circuit current related to the energy.

Table 81.Thermal stress limitation curve of the MCB. Curve C, model 60 N.



From the graphic, knowing that the maximum short circuit current is 2.105 kA at that point, and energy of $6x10^3$ A^2s is set.

As the previous case, the factor “K” will depend on the type of conductor and cable (copper and PVC), so the value is 115. This data can be checked in table 7.

Applying the formula that has being explained in the theory:

$$(I^2t)_{CB} \leq (I^2t)_{Cable} = k^2 \cdot S^2$$

$$6 \cdot 10^3 \leq 115^2 \cdot 2.5^2 = 82656$$

So the chosen device is OK.

b. Short circuit protection

The short circuit currents are calculated by hand and using NEPLAN. The maximum and minimum short circuit current helps me in order to choose the protection.

To calculate the short circuit currents in NEPLAN, first the low voltage installation is configured in this software. Some of the parameters used when setting the elements, come from the calculation by hand. This is the case of the impedance in the feeder and the impedance in the transformer. However, the characteristics of the cables are gotten from the library of NEPLAN, with the cross sections which have been previously set.

The impedances calculated by hand are explained below:

- Impedance of thefeeder.

$$Z_{nQ} = c\frac{{U_{nQ}}^2}{S_{nQ}}n^2$$

Data from the transformer: $n = \frac{U_{rTHV}}{U_{rTLV}}$

So the impedance is related to the low voltage side of the transformer.
An approximation can be done to get the values of the resistance and the impedance.

$$X_Q = 0.995 \cdot Z_{nQ} R_Q = 0.1 \cdot X_{nQ}$$

- Impedance of thetransformer.

In the library of the NEPLAN there are transformers. One of those is chosen, with the rated voltage and the apparent power S already set in the project.

From NEPLAN, U_K and U_R are given in the data of the transformer.

$$Z_T = \frac{U_K \cdot {U_{2L}}^2}{100 \cdot S_n}$$

$$R_T = \frac{U_R \cdot {U_{2L}}^2}{100 \cdot S_n} X_T = \sqrt{{Z_T}^2 - R^2{}_T}$$

The resistance and the impedance of L1, L2 and L3 cables are gotten from the data in the library of NEPLAN.

Table 82.Values of the resistance and the impedance of all the elements.

	Scc (MVA)	Un1 (kV)
NETWORK MT	30,000	10

	Sn transfo (kVA)	Ucc (%)	URc (%)	Pcun (kW)	Un1 (kV)	Un2 (V)	In1 (A)	In2 (A)
TRANSFO 1(Line)	400,000	4	1,150	6	10	400	23,094	577,350
TRANSFO 1(Phase)	400,000	4	1,150		10	231	13,333	577,350

	R phase (mΩ)	X phase (mΩ)	R neutro (mΩ)	X neutro (mΩ)	R0(mΩ)	X0 (mΩ)	R0 neutro (mΩ)	X0 neutro (mΩ)
NETWORK MT	0,531	5,307	0,000	0,000	2,123	21,227	0,000	0,000
TRAFO 1	4,60000	15,324	0,000	0,000	4,600	15,324	0,000	0,000
L1 3P+N	15,560	3,320	28,960	3,440	45,920	3,320	68,040	44,600
L2 3P+N	90,500	4,700	90,500	4,700	133,050	4,700	133,050	4,700
L3 3P+N	218,400	3,300	218,400	3,300	229,320	3,300	229,320	3,300

In the tables above are shown the values for the positive and the negative impedance.

The zero sequence in the feeder is calculated supposing that:

$$Z_{0Q}/Z_{1Q} \sim 4$$

The zero sequence in the transformer can be supposed as:

$$Z_{0T}/Z_{1T} \sim 1$$

- Maximum short circuit current.

The maximum short circuit current appears when there is a fault in the three phases. To calculate this current by hand, the next formula has to be used:

$$I_K'' = \frac{c \cdot U_\Delta}{\sqrt{3} \cdot Z_{SC}}$$

The factor "c" is shown in the table below.

Table 83. "c" factor for short circuit calculations.

Nominal voltage U_n	Voltage factor c for the calculation of maximum short-circuit currents c_{max} [1]	Voltage factor c for the calculation of minimum short-circuit currents c_{min}
Low voltage 100 V to 1 000 V (IEC 60038, table I)	1,05[3] 1,10[4]	0,95
Medium voltage >1 kV to 35 kV (IEC 60038, table III)	1,10	1,00
High voltage[2] >35 kV (IEC 60038, table IV)	1,10	1,00

The factor "c" is set as 1.05 in NEPLAN and in the calculations by hand.

The faults are done in four different points, in the nodes T.Sw, M.Sw, S.Sw and L3.

It is only needed the accumulative impedance of one phase in the four different points.

Below, the results that have been obtained in NEPLAN and the calculations by hand are shown. The values are very similar in both cases. These values are very reasonable.

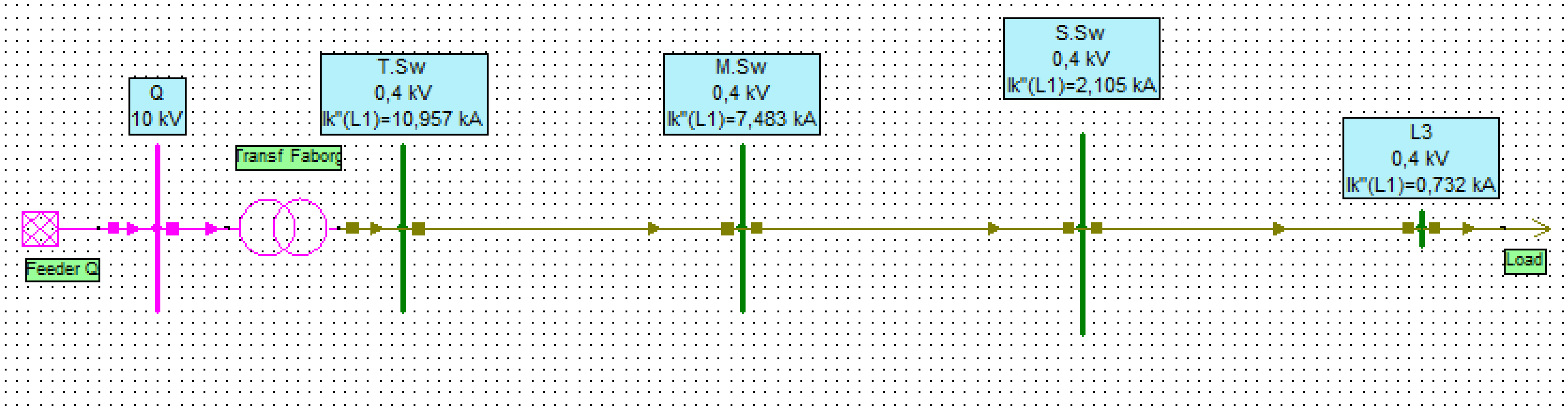


Figure 46.Maximum short circuit currents in NEPLAN.

Table 84. Maximum short circuit currents obtained with calculations by hand.

	Rsc (mΩ)	Xsc (mΩ)	Zsc (mΩ)	I"sc (kA)
Short circuit in T.Sw	5,131	20,631	21,260	11,406
Short circuit in M.Sw	20,691	23,951	31,651	7,661
Short circuit in S.Sw	111,191	28,651	114,823	2,112
Short circuit in the node L3	329,591	31,951	331,136	0,732

- Minimum short circuit current.

The minimum short circuit currents have to be analyzed by two different faults. The calculations by hand are made using the following formulas:

- Single-phase-to-ground fault.

  In this case, the impedance zero is used.

$$I''_{k(1)} = \frac{c \cdot \sqrt{3} \cdot U_{\Delta}}{|2 \cdot Z_1 + Z_0|}$$

- Line to line fault.

$$I''_{k(2)} = \frac{\sqrt{3}}{2} I''_{k(3)}$$

These calculations were made by EXCEL, but the obtained values were lower than the results made by NEPLAN. Therefore, these calculations are not shown because of a mistake in these.

When using NEPLAN, A factor “c” of 0.95 is set. This value is obtained from the table 9.

Below, the results from NEPLAN are shown. The lowest values are obtained in the case of one phase to ground.

- Single-phase-to-ground fault.

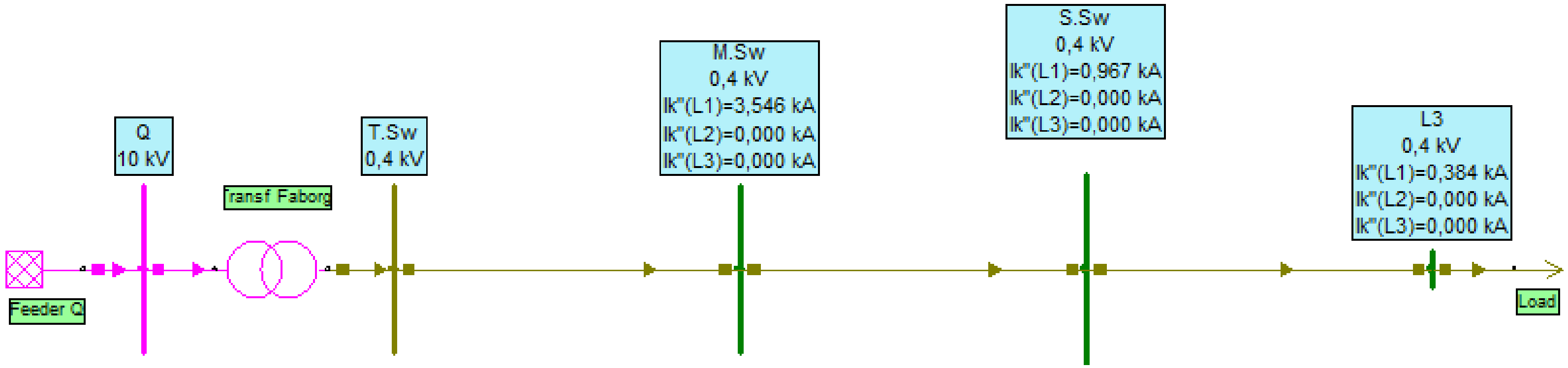


Figure 47. NEPLAN - minimum short circuit current – one phase to ground fault.

- Line to line fault.

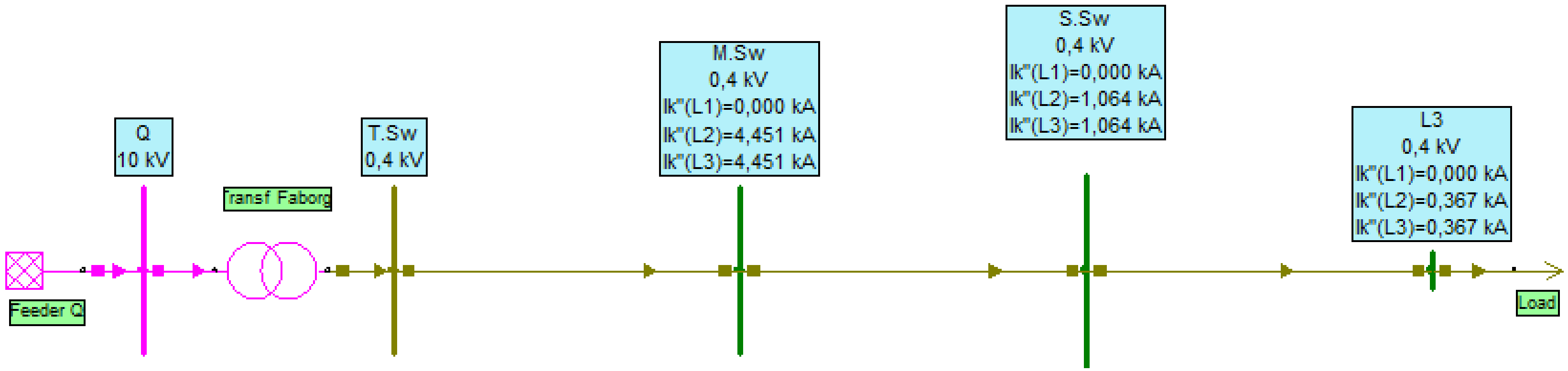


Figure 48.NEPLAN - minimum short circuit current – line to line fault.

c. *Indirect contact protection*

The laws are described in the GUÍA-BT-24 in the REBT.

The assumption taken is that the system has a TT schema. The TT system is chosen due to the type of cables in NEPLAN were TT.

In the low voltage installation, the neutro of the transformer has to be connected to ground.

The below condition has to be fulfilled:

$$R_A \times I_A \leq \mathrm{U}$$

Where:

R_A is the sum of the resistances from the grounding and the protective cables of the devices.

I_A is the assigned differential – residual current.

U is the limit of the contact voltage (50, 24V).

The limit voltage is equal to 50 V, RMS in AC, in normal conditions. In other conditions, 24 V is set as the limit voltage. These conditions are for example the street lights installations (ITC-BT-09).

In Denmark, a normal value for the differential-residual current circuit interrupter is 30 mA. In this case, the grounding resistance is not known, so it will be estimated following the formula above.

$$R_A \leq \frac{U}{I_A} = \frac{50\ V}{30\ mA} = 1.6667\ k\Omega$$

The fault due to indirect contact can be protected by two devices:

- Differential residual current circuit interrupter.

  The rated differential-residual currents are

  s/UNE-EN 61008; $I_{\Delta n}$ = (0,006 – 0,01 – 0,03 – 0,1 – 0,3 – 0,5) A
  s/UNE-EN 61009; $I_{\Delta n}$ = (0,006 – 0,01 – 0,03 – 0,1 – 0,3 – 0,5) A
  s/UNE-EN 60947-2; $I_{\Delta n}$ = (0,006 – 0,01 – 0,03 – 0,1 – 0,3 – 0,5 – 1 – 3 – 10 - 30) A

  In the law, maximum breaking time is set as it follows:

Table 85.Maximum breaking time of the differential residual current circuit interrupter in TT systems.

	$I_{\Delta n}$	$2I_{\Delta n}$	$5I_{\Delta n}$
Tiempo máximo de corte (s)	*0,3*	*0,15*	*0,04*

- Devices to protect from the overload current, like fuses and circuit breakers. These devices can be only applied when R_A has a low value.

The protection that has been explained above is a complementary protection in the case of indirect contact.

d. FBY1-Q. Length of the 10 kV cable

In NEPLAN, the medium and the low voltage installations are linked together. The aim is to calculate the short circuit apparent power at the busbar FBY1. The 60 kV network is connected to a feeder, but the value of the maximum short circuit power is missed. Assuming different values, the value of the maximum short circuit power at FBY1 is very slow, so this calculation can't be implemented by NEPLAN.

Calculating this value by hand and assuming a short circuit power of 40 MVA at the busbar FBY1:

$$S_{K-FBY1} = 40\ MVA \ \rightarrow\ I_K = \frac{S_{K-FBY1}}{\sqrt{3}\cdot 10\ kV} = 2.3094\ KA \quad\rightarrow\quad Z_{FBY1} = \frac{c\cdot U_\Delta}{\sqrt{3}\cdot I_K} = 2.8875\ \Omega$$

$$S_{K-FBY1} = 30\ MVA \ \rightarrow\ I_K = \frac{S_{K-FBY1}}{\sqrt{3}\cdot 10\ kV} = 1.7320\ KA \quad\rightarrow\quad Z_{FBY1} = \frac{c\cdot U_\Delta}{\sqrt{3}\cdot I_K} = 3.8501\ \Omega$$

There arenot enough data to make a correct calculation, but approximately the difference between both impedance is 0.8751 Ω.

The type of cable that is being analyzed is N2XSY 3 x 50 mm^2 which is found in the NEPLAN element library.

$$R_K = 0.387\ ^{\Omega}/_{\mathrm{km}}\, X_K = 0.106\ ^{\Omega}/_{\mathrm{km}}$$

To prove the calculation which have been shown above, the impedance at the point FBY1 will be calculated.

$$Z_{nFBY1} = c\frac{{U_{nQ}}^2}{S_{nQ}}n^2 = 1.1\frac{10\ kV^2}{40\ MVA}\cdot 1 = 2.75\ \Omega$$

$$X_Q = 0.995\cdot Z_{nFBY1} = 2.7362\ \Omega R_Q = 0.1\cdot X_{nFBY1}\ =\ 0.2736\ \Omega$$

The length can be calculated with:

$$Z_Q = \sqrt{(R_{FBY1} + R_{line}\cdot l)^2 + (X_{FBY1} + X_{line}\cdot l)^2}$$

Substituting the values, the formula looks like

$$0.1608\cdot l^2 + 0.7917\cdot l - 7.2617 = 0$$

$$l = 4.6951\ km \sim 4.7\ km$$

The resitance and the reactance of the cables are shown below, considering a length of 4.7 km.

$$R_{line}\ = 1.8189\ \Omega X_{line}\ = 0.4982\ \Omega$$

Conclusion

The 400-150 kV network of Funen has been checked and as I could see it was built withsmart as well as efficient considerations. The ring was built properly, and I have been studying for different situations (steady state, some disconnected transformers, few lines out, etc), it will work without important problems such a violating upper or lower voltage limits, handling loads, or even carrying a permissible current. It will be delivering power to the south-eastern part of Jutland in all cases, the rest of them (when the network will be disconnected from this part), I could find some nodes which won't be correctly supplied, because the 150 kV part of the network and the power plant inFynsværket (Unit 3, and Unit 7) won't be able to handle all the load.

Denmark's 400-150 kV network needed not only to be analyzed, but also to be protected. By using the knowledge on distance protection I could study its behavior. The protection of the system is probably the most important part. It doesn't matter if everything works perfectly for different conditions or situations, if it is nevertheless protected. I always had to keep in mind the criteria of priorities, which were: 1st personal safety, 2nd devices safety and 3rd electrical supply. And I have to take care about everything each time when I are going to try to improve the conditions of the line because sometimes the solution is worse that the problem.

The load profile of the networks is a useful tool which shows me its loading curve, and it helps to keep the correct balance between supply and power demand. By using the loading curve I could check if the electricity cannot be stored and it is necessary to know how much power should be generate in real time, under all system operating conditions, not only for power reasons, but also for economical ones. When I have large power consume at given time I can determine is it because of damage line or it is just high load.By using duration curve I can plan power demand in future and plan power supply. I calculate total power transferred and total power losses also I can try to minimize power losses. I can use it for make some statistics or to find out the solutions for economical questions. These economic aspects represents the use e.g. of one transformers instead of two, due to the losses of the second one is more expensive than using only one plus the possible problems if this one is not working or needs maintenance. There will always be an exhaustive study behind these considerations.

The low voltage installation has been analyzed following the Spanish legislation, REBT. I could observe that there are several differences between the REBT and the IEC. One important difference is that the reduction factors and the laws of dimension are based on a temperature of 40ºC, while in IEC is based on a lower temperature. This higher temperature is due to the fact that Spain is a warmer country. When applying the reduction factors, in the REBT cannot be obviated the cables that are grouped together despite its low load. All these things have made that the cross section of the cables are a little bit lower than the ones from other groups.

In the project, the protection has been proved using the curves in the catalogues which have been found in blackboard or in internet.

The calculations of the short circuit currents have been made for the three cases. Nevertheless, the results of the minimum short circuit currents weren't exact. Thus, these calculations weren't shown. NEPLAN made these calculations, and these were analyzed by the supervisor.

The last point to do was more difficult. The maximum apparent power in the feeder wasn't given. Moreover, this value wasn't found in the medium and high voltage systems in NEPLAN. Thus, I assumed a value, and the length of the cable was calculated based on this faked value.

While making the low voltage study, I have spent a lot of time dimensioning. The followed criteria has been changed several times when dimensioning,thus, the cross sections and the short circuit calculations changed. Thanks to work with Excel, this problem didn't take me long time when making again the calculations.

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Appendix I. Abbreviations

LAG - Landerupgård

FGD - Fraugde

KIN - Kingstrup

FVO - Fynsværket

GRP - Graderup

FVB - Fynsværket

FVA - Fynsværket

SHE - Endstedværket

SØN - Sønderborg

ABS - Abildskov

SVB - Svendborg

SFV - Svendborg

FÆG - Fællinggård

RAD - Radby

SHP - SønderHøjrup

KRI - Korinth

ESP - Espe

RIE - Ringe

HNE - Horne

FBV - Fåborg Vest

FBY - Fåborg By

OSØ - Odense SØ

Appendix II. Values

Table 1 (AII).Line data from the Electrical Power Project specifications.

Line	U_n	R_1	X_1	R_0	X_0	$B_{in,1}$	$B_{out,1}$	$B_{in,0}$	$B_{out,0}$	Section	Length	I_{max}	Pylon/ Cable	Phase conductor	Earth conductor	Shield	Year
From-to	kV	Ω	Ω	Ω	Ω	µS	µS	µS	µS	-	km	A	-	mm^2	mm^2	Mat./mm^2	-
FGD3-FVO3	170	0,61	3,08	2,33	5,93	226	226			1[1] 2	6,3 6,0	1160 760[2]	S7/2 PEX	1×594 SA 1×1600 AL	2×153	SA 80	1973 1998
FGD3-OSØ3	170	0,35	2,44	1,27	5,50	9	9				6,3	1160	S7/2	1×594 SA	2×153	SA 80	1973
FVO3-OSØ3	170	0,26	0,64	1,06	0,426	217	217				6,0	720[2]	PEX	1×1600 AL			1998
FGD3-SVB3	170										38,0	1380	S1/1	1×772 SA	1×153	SA 80	1989
ABS3-SVB3	170	2,02	14,57	11,21	39,21	51	51				36,2	990	Y2/1	1×594 SA	2×95	ST 65	1971
ABS3-SØN3	170	5,25	17,50	15,88	42,62	314	734			1 2 3 4 5	22,4 0,13 5,62 5,75 16,1	620 660 450 450 725	Y2/1 APB KAB KAB S1/1	1×281 SA 1×500 CU 1×310 CU 1×310 CU 1×281 SA	2×95 2×95	ST 65 SA 65	1968 1968 1968 1968 1968
ABS3-FVO3	170	1,66	12,09	8,97	31,86	92	92			1 2	29,6 0,61	990 760[2]	Y2/1 PEX	1×594 SA 1×1600 AL	2×95 95 CU	ST 65	1968 1998
SHE3-SØN3	170	1,86	10,14	7,82	26,91	60	60				25,0	850					
FVO3-GRP3	170	3,29	11,88	10,12	30,31	87	87			1 2	0,64 27,6	760[2] 720	PEX Y2/1	1×1600 AL 1×281 SA	95 CU 2×95 ST		1998 1959
GRP3-KIN3	170	0,35	0,85	1,41	0,57	289	289				8,0	760[2]	PEX	1×1600 AL	95 CU		1998
FGD5-FVO5	420	0,37	4,40	2,36	10,61	17	17				14,0	1600					
FGD5-LAG5	420	1,91	23,29	12,37	55,72	87	87			1 2 3	62,2 1,54 9,89	1600 2080 1600	Y4/1 Y5/1 Y4/1	2×636 SA 1×1940 SA 2×636 SA	2×153 2×126 2×153	SA AW SA	1973 1990 1990
FGD5-KIN5	420	1,05	12,81	6,80	30,65	48	48				40,5	1600					
KIN5-LAG5	420	0,86	10,48	5,57	25,07	39	39				33,1	1600					

Table 2 (AII).Transformer data from the Electrical Power Project specifications.

Trafo.	Trafo. nr.	S_r	U_1	U_2	$U_{2,min}$	$U_{2,max}$	$R_{k,1}$	$X_{k,1}$	$R_{k,0}$	$X_{k,0}$	No load losses	Manuf.
From-to		MVA	kV	kV	kV	kV	%	%	%	%	kW	
FGD5-FGD3	1 2	400 400	410 410	168 168	135 135	194 194	0,23 0,23	12,5 12,5	0,2 0,2	11,9 11,9		
KIN5-KIN3		400	410	168	135	194	0,23	12,5	0,2	11,9		
ABS3-ABS2	A B	125 125	165 165	66 66	54 54	78 78	0,37 0,32	13,5 13,5	0 0	12,3 12,3	50 50	 National
FGD3-FGD2	A B	125 125	165 165	67 66	59 54	78 78	0,30 0,37	12,7 13,5	0 0	10,6 12,3	54 50	Alstohm
FVO3-FVB2 FVO3-FVA2 FVO3-FVA2	1 2 3	150 150 180	160 160 160	66 66 66	54 54 54	78 78 78	0,34 0,34 0,31	13,6 13,6 12,7	0 0 0	13,5 13,5 12,6	74 78 103	ASEA ASEA ASEA
GRP3-GRP2	A B	125 75	165 158	66 66	54 54	78 78	0,37 0,40	13,5 12,8	0 0	12,3 10,6	50 50	National National
OSØ3-OSØ2		125	165	66	54	78	0,37	13,5	0	12,3	50	National
SVB3-SFV2	A B	125 125	165 165	66 66	54 54	78 78	0,37 0,37	13,5 13,5	0 0	12,3 12,3	50 50	National National
SØN3-SØN2	1 2	75 125	158 165	66 67	58 59	75 76	0,36 0,28	11,7 11,8	0 0	9,5 11,6	64 80	Thrige Tr.Union
FBY2-FBY1	1 2	30 30	67 67	10 10	8,5 8,5	11,5 11,5	0,31 0,31	10,4 10,4	0,31 0,31	9,8 9,8	- -	

Table 3 (AII).Conductor data for overhead lines.

Navn	Crosssec. area A mm² total	stål	alum.	Diameter dy mm di mm d mm total	stål	partialconducters amount/diameter d_s mm stål	alum.	weight M kg/km	F_b kN	Elasticitetsmodul E GPa	Længdeudv.-koefficient $\alpha \cdot 10^6$ K^{-1}	Linear resistans v. 20 °C r_{20} Ω/km	Geometrisk middelradius GMR mm
Swallow	31,1	4,4	26,7	7,14	2,38	1/2,38	6/2,38	107,4	10,1	79	19,1	1,074	2,742
DIN 50/8	56,3	8,0	48,3	9,6	3,20	1/3,20	6/3,20	195,5	15,8	79	19,1	0,600	3,686
Raven	62,4	8,9	53,5	10,1	3,37	1/3,37	6/3,37	215,9	19,0	79	19,1	0,535	3,882
Pigeon	99,3	14,2	85,1	12,8	4,25	1/4,25	6/4,25	342,7	29,7	79	19,1	0,337	4,896
Pernice	128,9	18,0	110,9	14,8	5,43	7/1,81	26/2,33	446	41,4	79	18,9	0,261	5,970
Partridge	156,9	22,0	134,9	16,3	6,00	7/2,00	26/2,57	543	50,0	79	18,9	0,214	6,607
Ostrich	176,9	24,7	152,2	17,3	6,36	7/2,12	26/2,73	613	56,2	76	18,9	0,190	7,031
Ibis	234,0	32,7	201,3	19,9	7,32	7/2,44	26/3.14	811	72,0	76	18,9	0,143	8,057
Hawk	281,1	39,5	241,6	21,8	8,04	7/2,68	26/3,44	975	86,5	76	18,9	0,120	8,828
Dove	328,5	45,9	282,6	23,6	8,7	7/2,89	26/3,72	1229	99,7	76	18,9	0,102	9,571
Condor	454,5	52,2	402,3	27,7	9,24	7/3,08	54/3,08	1522	127,0	69	19,3	0,0718	11,21
Curlew	593,5	68,2	525,5	31,7	10,6	7/3,52	54/3,52	1979	165,2	69	19,3	0,0553	12,85
Finch	636,6	71,6	565,0	32,8	10,9	19/2,19	54/3,65	2120	178,8	67	19,4	0,0513	13,28
Martin	772,1	86,7	685,4	36,2	12,0	19/2,41	54/4,02	2574	211,7	67	19,4	0,0423	14.62
Bluebird	1187	88,8	1098,2	45,0	12,2	19/2,44	54/4,08	3740	283,4	65	20,7	0,0270	17,95
Dorking	152.8	56,3	96,5	16,0	9,6	7/3,20	12/3,20	707	78,8	105	15,3	0,298	6.869
AWG													
AWAC	100,1	36,9	63,2	13,0	7,8	7/2,59	12/2,59	419	55,8	103	19,3	0,393	5,574

Appendix III. Low Voltage 1

ITC-BT-07 Redessubterráneasparadistribución en bajatensión, "Underground networks for low voltage distributions".

These conductors, which are used in underground networks, they will be made by copper or aluminium. These conductors must have corrosion protection and enough strength.

The cables can have one or more conductors and its rated voltage won't be less than 0.6/1 KV. The cross section of copper conductor won't be less than 6 mm^2 and the cross section of aluminium conductor won't be less than 16 mm^2.

Depending on the number of conductors that are used in the distribution, the minimum cross section of the neutro conductor will be:

a)Two or three conductors: The cross section is the same as the phase conductors.

b) With 4 conductors, the minimum cross section of the neutro conductor depends on *table1*.

Table 1 (AIII).Minimum neutro cross section depending on phase conductor cross section.

Phase cross section (mm^2)	Neutro cross section (mm^2)
6 (Cu)	**6**
10 (Cu)	**10**
16 (Cu)	**10**
16 (Al)	**16**
25	**16**
35	**16**
50	**25**
70	**35**
95	**50**
120	**70**
150	**70**
185	**95**
240	**120**
300	**150**
400	**185**

When the cross sections are known, the neutro can be set.

1. Maximum current carrying capacity.

1.1 Maximum permissible temperature.

The maximum admissible currents depend on the permanent performance. In each case, the maximum temperature that the insulation can withstand without alteration of their electrical, mechanical or chemical properties.

Table 2 (AIII). Cables with dry isolation, ºC assigned to the conductor.

Tipo de Aislamiento seco	Temperatura máxima °C	
	Servicio permanente	Cortocircuito t ≤ 5s
Policloruro de vinilo (PVC)		
S ≤ 300 mm^2	**70**	**160**
S > 300 mm^2	**70**	**140**
Polietileno reticulado (XLPE)	**90**	**250**
Etileno Propileno (EPR)	**90**	**250**

2. Conditions in underground system.

A tripolar or tetrapolar cable or a set of three single-core cables in mutual contact, or a wire cable or two single-core cables in mutual contact, directly over its entire length buried in a trench 0.70 m deep in ground, resistivity thermal average of 1 Km / W and ground temperature at this depth, 25 ° C.

3. Tables that are used to dimension the cable.

L1 conductors are made from copper. This decision is made due to the two other cables that are buried with L1. L1 is grouped with two other cables -95 mm^2 Cu.

Table 3 (AIII).Maximum permissible current,in amps, forcableswithcopper conductors in underground systems (permanent service).

SECCIÓN NOMINAL mm^2	Terna de cables unipolares (1) (2)			1cable tripolar o tetrapolar (3)		
						
	TIPO DE AISLAMIENTO					
	XLPE	EPR	PVC	XLPE	EPR	PVC
6	**72**	**70**	**63**	**66**	**64**	**56**
10	**96**	**94**	**85**	**88**	**85**	**75**
16	**125**	**120**	**110**	**115**	**110**	**97**
25	**160**	**155**	**140**	**150**	**140**	**125**
35	**190**	**185**	**170**	**180**	**175**	**150**
50	**230**	**225**	**200**	**215**	**205**	**180**
70	**280**	**270**	**245**	**260**	**250**	**220**
95	**335**	**325**	**290**	**310**	**305**	**265**
120	**380**	**375**	**335**	**355**	**350**	**305**
150	**425**	**415**	**370**	**400**	**390**	**340**
185	**480**	**470**	**420**	**450**	**440**	**385**
240	**550**	**540**	**485**	**520**	**505**	**445**
300	**620**	**610**	**550**	**590**	**565**	**505**
400	**705**	**690**	**615**	**665**	**645**	**570**
500	**790**	**775**	**685**	**-**	**-**	**-**
630	**885**	**870**	**770**	**-**	**-**	**-**

First cross section set for L1.

4. Reduction factors.

- Buried cables in ground, with a different temperature to 25ºC in the ground.

Table 4 (AIII).Reduction factor depending on temperature.

Temperatura de servicio Θ_s (ºC)	Temperatura del terreno, Θ_t ,en ºC								
	10	15	20	25	30	35	40	45	50
90	1.11	1.07	1.04	1	0.96	0.92	0.88	0.83	0.78
70	1.15	1.11	1.05	1	0.94	0.88	0.82	0.75	0.67

L1 in concrete.

- Buried cables in a ground with a thermal resistivity different to 1 ºK m /W.

Table 5 (AIII).Reduction factor depending on thermal resistivity to ground.

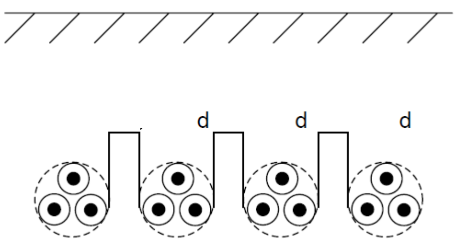
Tipo de cable	Resistividad térmica del terreno, en K.m/W										
	0.80	0.85	0.90	1	1.10	1.20	1.40	1.65	2.00	2.50	2.80
Unipolar	1.09	1.06	1.04	1	0.96	0.93	0.87	0.81	0.75	0.68	0.66
Tripolar	1.07	1.05	1.03	1	0.97	0.94	0.89	0.84	0.78	0.71	0.69

By interpolation, 0.87.

- Number of tripolar or tetrapolar cables which are grouped under ground.

Table 6 (AIII).Reduction factor depending on grouped cables.

Factor de corrección								
Separación entre los cables o ternas	Número de cables o ternas de la zanja							
	2	3	4	5	6	8	10	12
D=0 (en contacto)	0,80	0,70	0,64	0,60	0,56	0,53	0,50	0,47
d= 0,07 m	0,85	0,75	0,68	0,64	0,6	0,56	0,53	0,50
d= 0,10 m	0,85	0,76	0,69	0,65	0,62	0,58	0,55	0,53
d= 0,15 m	0,87	0,77	0,72	0,68	0,66	0,62	0,59	0,57
d= 0,20 m	0,88	0,79	0,74	0,70	0,68	0,64	0,62	0,60
d= 0,25 m	0,89	0,80	0,76	0,72	0,70	0,66	0,64	0,62



- Cables buried in ground at different depths.

Table 7 (AIII).Reduction factor depending on the depth of the cables.

Profundidad de instalación (m)	0,4	0,5	0,6	0,7	0,80	0,90	1,00	1,20
Factor de corrección	1,03	1,02	1,01	1	0,99	0,98	0,97	0,95

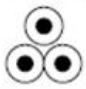
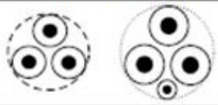
Appendix IV. Low Voltage 2

ITC-BT-07 Redessubterráneasparadistribución en bajatensión, "Underground networks for low voltage distributions"

1. Outdoorinstallation conditions.

A tripolar or tetrapolar single cable or a set of three single-core cables in contact with each other, with a placement that allows effective air renewal, with the environmental temperature of 40 ° C. For example, in cable trays placed on or attached to a wall, etc...

Table 1 (AIV). Maximum permissible current,in amps, forcables with copper conductors in airy installations in ventilated gallery (permanent service).

Sección nominal mm^2	Tres cables unipolares (1)			1 cable trifasico		
						
	TIPO DE AISLAMIENTO					
	XLPE	EPR	PVC	XLPE	EPR	PVC
6	46	45	38	44	43	36
10	64	62	53	61	60	50
16	86	83	71	82	80	65
25	120	115	96	110	105	87
35	145	140	115	135	130	105
50	180	175	145	165	160	130
70	230	225	185	210	220	165
95	285	280	235	260	250	205
120	335	325	275	300	290	240
150	385	375	315	350	335	275
185	450	440	365	400	385	315
240	535	515	435	475	460	370
300	615	595	500	545	520	425
400	720	700	585	645	610	495
500	825	800	665	-	-	-
630	950	915	765	-	-	-

L2.

L1, inside gallery.

2. Reduction factors.

- Cablesinstalledinairy installations with a different temperaturethan40°C.

Table 2 (AIV).Reduction factor depending on the temperature of the air.

Temperatura de servicio Θ_s en °C	Temperatura ambiente, Θ_a, en °C										
	10	15	20	25	30	35	40	45	50	55	60
90	1.27	1.22	1.18	1.14	1.10	1.05	1	0.95	0.90	0.84	0.77
70	1.41	1.35	1.29	1.22	1.15	1.08	1	0.91	0.81	0.71	0.58

- Reduction factor of three-phase cables which are grouped in airy installations.

Table 3. Reduction factor depending on how the cables are grouped.

Tipo de instalación		Nº de circuitos trifásicos (1)						
		Nº de bandejas	1	2	3	4	6	9
Bandejas perforadas (2)	Contiguos ≥ 20 mm	1	1,00	0,90	0,80	0,80	0,75	0,75
		2	1,00	0,85	0,80	0,75	0,75	0,70
		3	1,00	0,85	0,80	0,75	0,70	0,65
	Espaciados ≥ 20 mm	1	1,00	1,00	1,00	0,95	0,90	-
		2	1,00	1,00	0,95	0,90	0,85	-
		3	1,00	1,00	0,95	0,90	0,85	-
Bandejas verticales perforadas (3)	Contiguos	1	1,00	0,90	0,80	0,75	0,75	0,70
		2	1,00	0,90	0,80	0,75	0,70	0,70
	Espaciados	1	1,00	0,90	0,90	0,90	0,85	-
		2	1,00	0,90	0,90	0,85	0,85	-
Bandejas escalera, soportes, etc. (2)	Contiguos ≥ 20 mm	1	1,00	0,85	0,80	0,80	0,80	0,80
		2	1,00	0,85	0,80	0,80	0,75	0,75
		3	1,00	0,85	0,80	0,75	0,75	0,70
	Espaciados ≥ 20 mm	1	1,00	1,00	1,00	1,00	1,00	-
		2	1,00	1,00	1,00	0,95	0,95	-
		3	1,00	1,00	0,95	0,95	0,75	-

Appendix V. LowVoltage 3

ITC-BT-19 Instalaciones interiores o receptoras. Prescripcionesgenerales, “Indoors installations or receptors.General requirements”.

1. Cross section of the cables. Drop voltages.

For industrial installations directly feed at high voltage through its own distribution transformer, it is considered that the interior installation of low voltage comes from the transformer output. In this case, the maximum permissible drop voltage will be 4.5% for lighting and 6.5% for other uses.

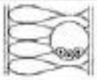
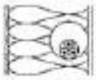
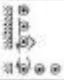
In interior installations, to take account of harmonic currents due nonlinear loads and possible imbalances, unless justified by calculation, the section of the neutral conductor is at least equal to the section of the phases.

2. Maximum permissible currents.

This law is based on Norma UNE 20.460.

The followingtable showsthe rated current forambient air temperatureof40 °Cand fordifferentinstallation methods, groups and typesofcables. For temperatures, installation methods, groups and typesofcable, as wellasburied conductors, it is needed to seek reduction factors in the UNE20 460-5 to 523.

Table 1 (AV).Maximum admissible currents depending on assembly, number of conductors and type of isolation. Table 52- C20.

A		Conductores aislados en tubos empotrados en paredes aislantes		3x PVC	2x PVC		3x XLPE o EPR	2x XLPE o EPR					
A2		Cables multiconductores en tubos empotrados en paredes aislantes	3x PVC	2x PVC		3x XLPE o EPR	2x XLPE o EPR						
B		Conductores aislados en tubos[2] en montaje superficial o empotrados en obra				3x PVC	2x PVC			3x XLPE o EPR	2x XLPE o EPR		
B2		Cables multiconductores en tubos[2] en montaje superficial o emprotrados en obra			3x PVC	2x PVC		3x XLPE o EPR		2x XLPE o EPR			
C		Cables multiconductores directamente sobre la pared[3]					3x PVC	2x PVC		3x XLPE o EPR	2x XLPE o EPR		
E		Cables multiconductores al aire libre[4] Distancia a la pared no inferior a 0,3D[5]						3x PVC		2x PVC	3x XLPE o EPR	2x XLPE o EPR	
F		Cables unipolares en contacto mutuo[4] Distancia a la pared no inferior a D[5]							3x PVC			3x XLPE o EPR[1]	
G		Cables unipolares separados mínimo D[5]									3x PVC[1]		3x XLPE o EPR
		mm²	1	2	3	4	5	6	7	8	9	10	11
Cobre		1,5	11	11,5	13	13,5	15	16	-	18	21	24	-
		2,5	15	16	17,5	18,5	21	22	-	25	29	33	-
		4	20	21	23	24	27	30	-	34	38	45	-
		6	25	27	30	32	36	37	-	44	49	57	-
		10	34	37	40	44	50	52	-	60	68	76	-
		16	45	49	54	59	66	70	-	80	91	105	-
		25	59	64	70	77	84	88	96	106	116	123	166
		35		77	86	96	104	110	119	131	144	154	206
		50		94	103	117	125	133	145	159	175	188	250
		70				149	160	171	188	202	224	244	321
		95				180	194	207	230	245	271	296	391
		120				208	225	240	267	284	314	348	455
		150				236	260	278	310	338	363	404	525
		185				268	297	317	354	386	415	464	601
		240				315	350	374	419	455	490	552	711
		300				360	404	423	484	524	565	640	821

L3

3. Reduction factors.

- Reduction factor when the air temperature is different than 40ºC.

Table 2 (AV). Reduction factors depending on temperature. UNE 20 460-5-523.

Temperatura ambiente (°C)	10	15	20	25	30	35	40	45	50	55	60	65	70	75	80
Cables aislados con XLPE	1,26	1,23	1,19	1,14	1,10	1,05	1,00	0,96	0,90	0,83	0,78	0,71	0,64	0,55	0,45

según UNE 20-460-94/5-523 Tabla 52-D1

- Reduction factor depending on the number of cables that are grouped together.

Table 3 (AV). Reduction factors of grouped cables. UNE 20 460-5-523: 2004.

Ref.	Disposición de cables contiguos	Número de circuitos o cables multiconductores								
		1	2	3	4	6	9	12	16	20
1	Empotrados o embutidos	1,00	0,80	0,70	0,70	0,55	0,50	0,45	0,40	0,40
2	Capa única sobre pared, suelo o superficie sin perforar	1,00	0,85	0,80	0,75	0,70	0,70	Sin reducción adicional para más de 9 circuitos o cables multiconductores.		
3	Capa única fijada bajo techo	0,95	0,80	0,70	0,70	0,65	0,60			
4	Capa única en una bandeja perforada vertical u horizontal	1,00	0,90	0,80	0,75	0,75	0,70			
5	Capa única con apoyo de bandeja escalera o abrazaderas (collarines) etc.	1,00	0,85	0,80	0,80	0,80	0,8			

If the reference E is used in the table 52-C20, the reduction factor for multi-conductor cables grouped is different from the above table. In this case, the below table is used.

Table 4 (AV). Reduction factors of grouped cables. Reference E. UNE 20 460-5-523: 2004.

Tipo de instalación de la tabla	52-B2		Nº de bandejas	Número de cables 1	2	3	4	6	9
Bandejas perforadas[3]	13	Contiguos 20 mm	1	1,00	0,90	0,80	0,80	0,75	0,75
			2	1,00	0,85	0,80	0,75	0,75	0,70
			3	1,00	0,85	0,70	0,75	0,70	0,65
		Espaciados D_e 20 mm	1	1,00	1,00	1,00	0,95	0,90	—
			2	1,00	1,00	0,95	0,90	0,85	—
			3	1,00	1,00	0,95	0,90	0,85	—
Bandejas verticales perforadas[4]	13	Contiguos	1	1,00	0,90	0,80	0,75	0,75	0,70
			2	1,00	0,90	0,80	0,75	0,70	0,70
		Espaciados D_e	1	1,00	0,90	0,90	0,90	0,85	—
			2	1,00	0,90	0,90	0,85	0,85	—
Bandejas escalera, soportes, etc.[2]	14 15 16	Contiguos 20 mm	1	1,00	0,85	0,80	0,80	0,80	0,80
			2	1,00	0,85	0,80	0,80	0,75	0,75
			3	1,00	0,85	0,80	0,75	0,75	0,70
		Espaciados D_e 20 mm	1	1,00	1,00	1,00	1,00	1,00	—
			2	1,00	1,00	1,00	0,75	0,75	—
			3	1,00	1,00	0,95	0,75	0,75	—

según UNE 20-460-94/5-523 Tabla 52-E4