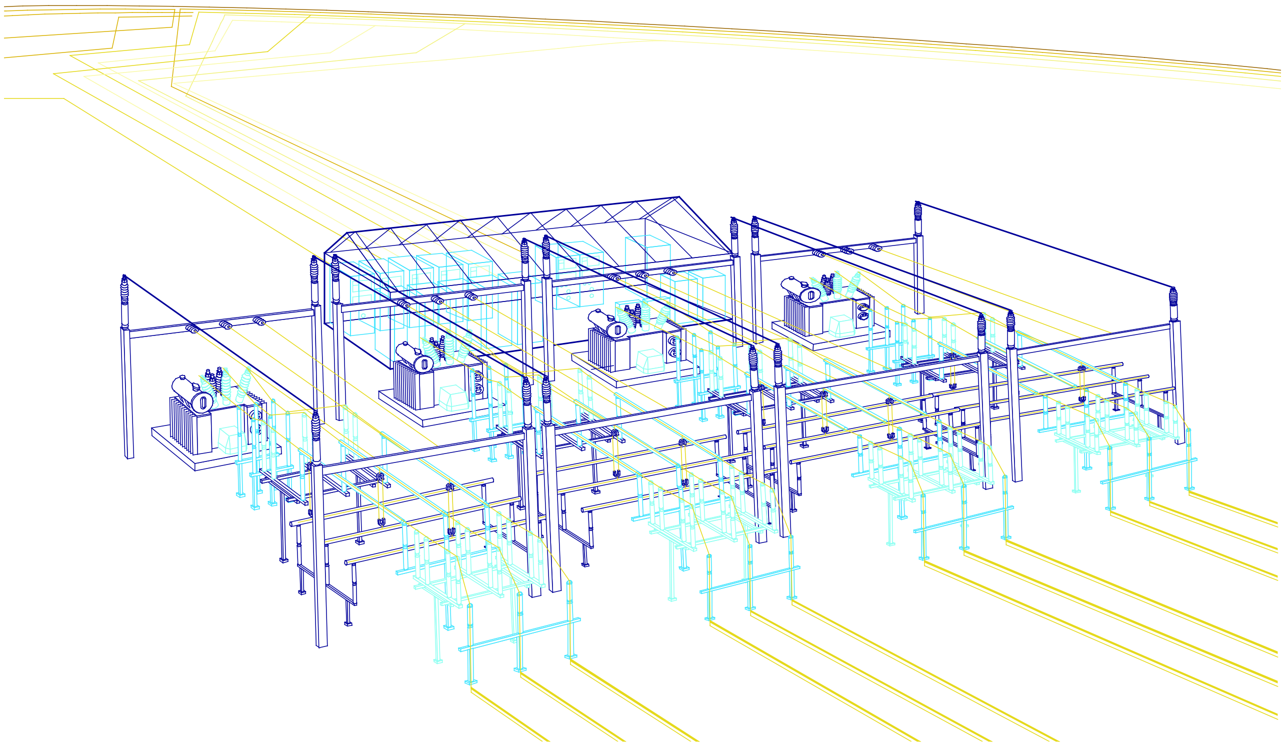
Distribution Automation Handbook

Section 3 Elements of power distribution systems



Contents

3 ELEMENTS OF POWER DISTRIBUTION SYSTEMS

3.14 Primary Distribution Substations

A primary distribution substation is the connection point of a distribution system to a transmission or a sub-transmission network. Outgoing feeders from a primary distribution substation are typically feeding secondary distribution substations and bigger, most often industrial type, consumers directly. What is considered to be the voltage level for a primary distribution substation varies country by country and depends on the whole electricity network structure and extent and historical and organizational issues. To give some kind of a picture of the voltage levels, below is an example about the system level allocation in a certain country.

330 kV	Transmission
132 kV	Sub-transmission
66 & 33 & 11kV	Distribution

Based on the example above, it can be determined that in the country in question the substations having voltage level like 66/11 kV are considered to be the primary distribution substations.

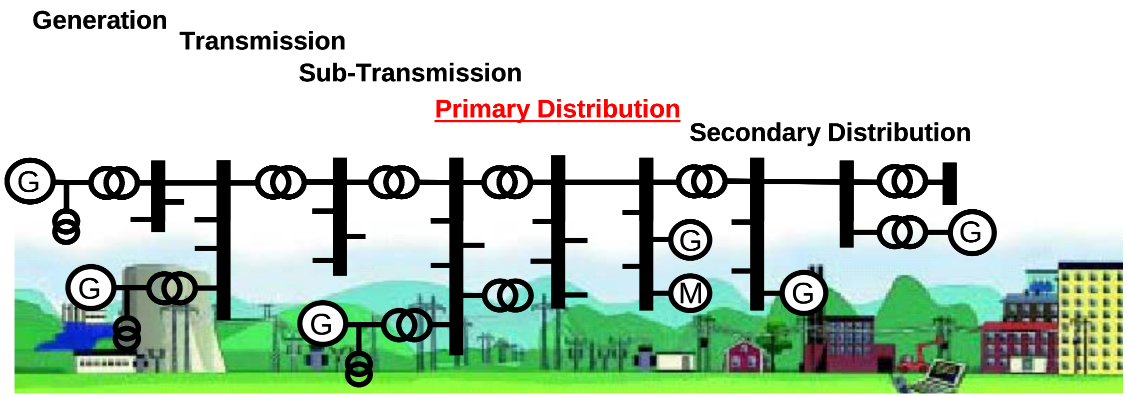


Figure 3.1: Power system

3.14.1 Switchgear Type and Busbar Arrangement

A typical primary distribution substation would include air-insulated outdoor-type high-voltage side (HV) and a metal-enclosed air-insulated indoor-type medium-voltage switchgear (MV). Due to specific reasons, like space limitations, environmental aspects and security, the substation can be built using Gas Insulated Switchgear (GIS) technology. Utilizing GIS technology, both the high-voltage part and the medium-voltage part can be built using metal-enclosed indoor-type switchgear. The GIS technology allows placing the whole substation installation inside a building, either on the ground surface or below the ground level.

Figure 3.2: A typical rural primary distribution substation 110/20kV

Figure 3.2 shows a typical primary distribution substation located in a sparsely populated area. The high-voltage side (110 kV) is an outdoor-type air-insulated switchyard and the medium-voltage side (20 kV) is metal-enclosed air-insulated switchgear located inside the building.

In addition to the high-voltage air-insulated or gas-insulated installation possibilities, also a so-called hybrid solution is available. This solution consists of highly integrated gas-insulated outdoor-mounted bay units. One bay unit includes circuit breaker, disconnector(s), measuring transformers and the local control and interface cabinet in one transportation unit. The unit has been factory-assembled and tested, offering standard connection points to protection and remote control circuits. This solution utilizes air-insulated busbars for connecting the different type of units together to achieve the requested substation layout solution and functionality. Different standard bay units are available for different feeder types and substation layout solutions.

Figure 3.3: Three-phase line feeder module with hybrid construction

While designing the construction of a primary distribution substation, there are a number of different busbar arrangement alternatives for both voltage levels. The choice between the different alternatives is always a compromise where issues like the initial investment cost, operational flexibility, equipment maintenance and availability have to be considered. It is obvious that the different criteria in the consideration have different weight factors depending on the actual customers to be supplied. Industrial type of customers present high demands on the availability and operational flexibility, whereas customer types like recreational housing areas impose higher demands on the investment costs.

The main alternatives for busbar arrangements are covered shortly in the following. For each of the alternatives, a summary of advantages and drawbacks are listed. The actual configuration of a complete substation can be a mixture of the different alternatives in respect of high-voltage and medium-voltage installation.

3.14.1.1 Single-Busbar Arrangement with one Main Power Transformer

The following figure shows the principle of the solution utilizing only one power transformer and a single-busbar configuration on the medium-voltage side. The dotted line on the high-voltage side marks for the optional by-pass disconnector placement enabling the HV circuit breaker service.

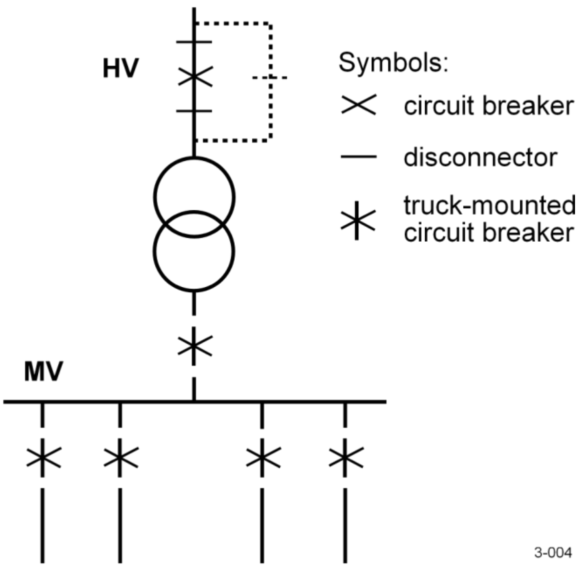


Figure 3.4: Single-busbar arrangement

Advantages:

- simple and low investment cost solution
- control and protection functions straight forward

Drawbacks:

- no redundancy
- whole substation out of service while power transformer (and HV circuit breaker) out of service
- fault in the MV busbar would take the whole substation out of service

3.14.1.2 Single-Busbar Arrangement with Bus Sectionalizer and Two Power Transformers

The following figure shows the single-busbar arrangement having bus sectionalizer circuit breaker in the MV bus. There are different possible operating principles with this solution. The MV bus sectionalizer can be kept open and each part of the busbar can be supplied with its own power transformer or both busbar sections can be supplied with just one power transformer while keeping the other power transformer running idly or de-energized. The power transformers can also be run in parallel with the bus sectionalizer closed. Depending on the operation principle, the utilization of automatic busbar transfer scheme, high speed or delayed, would cater for automatic redundancy in case of one power transformer failure.

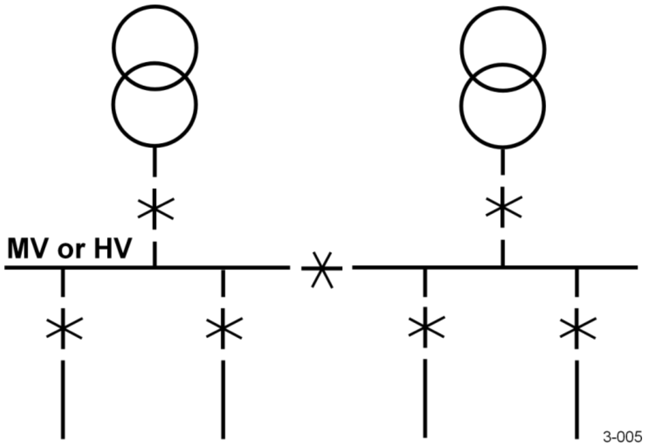


Figure 3.5: Single-busbar arrangement with bus sectionalizer

Advantages:

- redundancy, in case one power transformer can carry the whole load
- increased operational flexibility
- fault in the busbar would be limited to one section only
- limitation of short circuit currents while bus sectionalizer is open
- disturbances caused by a fault in the outgoing feeder is seen only with half of the other outgoing feeders

Drawbacks:

- higher investment cost
- higher no-load losses as compared to solution with one power transformer with equal capacity
- paralleling of the power transformers needs additional control logic

3.14.1.3 Single-Busbar Arrangement with Transfer Bus

The following figure shows the single-busbar arrangement having a dedicated transfer bus. By utilizing the transfer bus and the bus coupler, each feeder circuit breaker can be de-energized for service without any effect to the load. The transfer bus does not have the facility for load-sharing since only one feeder bay is allowed to be connected to it at a time.

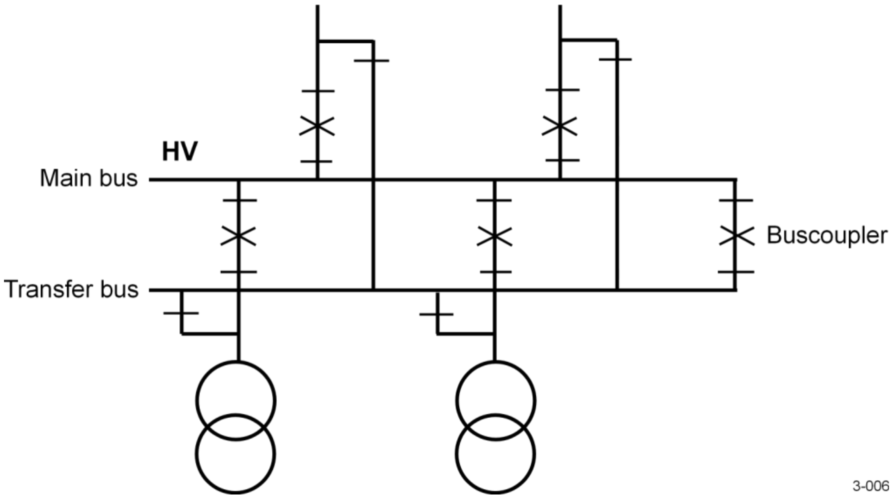


Figure 3.6: Single-busbar arrangement with transfer bus

Advantages:

- maintenance on one circuit breaker does not cause any interruptions for the load

Drawbacks:

- higher investment cost
- whole substation out of service in a busbar fault case
- protection and auto-reclosing circuits have to be switched over to the bus coupler bay during a transfer situation
- interlocking circuits to prevent more than one bay to be connected to the transfer bus simultaneously

3.14.1.4 Double-Busbar Arrangement

The following figure shows the double-busbar arrangement. In a typical operation mode. this type of configuration would have the bus coupler open and line and transformer feeders equally shared between the busses. The bus coupler enables the feeder switching between the busses without load interruption. This configuration needs advanced interlocking circuits to prevent forbidden operations like doing bus coupling using any other bay than bus coupler bay.

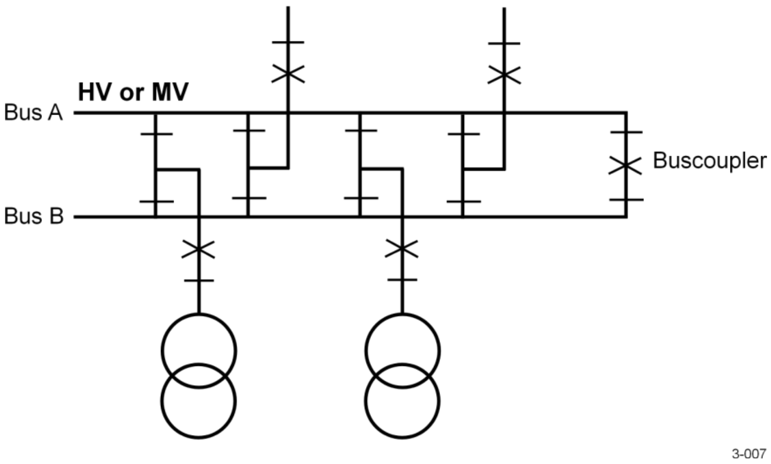


Figure 3.7: Double-busbar arrangement

Advantages:

- operational flexibility i.e. possibility to move loads between busses
- limitation of short circuit currents if operated bus coupler open
- effect of a busbar fault limited
- substation extension possible under service

Drawbacks:

- complicated interlocking
- whole bay out of service when circuit breaker under maintenance
- bus voltage reference needs a selection circuit
- busbar protection and breaker failure protection need a selection circuit

3.14.1.5 Double-Breaker Arrangement

The following figure shows the double-breaker arrangement. In a typical operation mode, this type of a configuration would have all the breakers closed. This configuration needs advanced protection and auto-reclosing circuits. In some cases, the transformer feeders are equipped with one breaker only, thus the power transformers are permanently connected to a dedicated bus. Normally, there is no need to have a special bus coupler bay included, since the bus connection is realized through line feeder (and transformer feeder) bays. Current measurement is carried out for each of the branches separately.

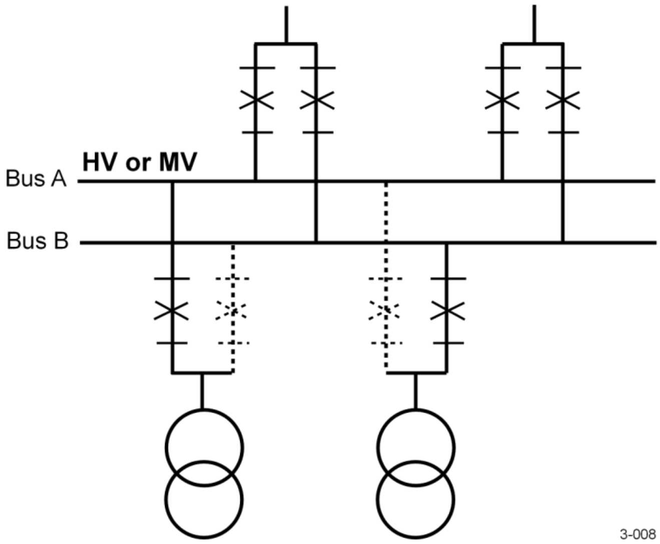


Figure 3.8: Double-breaker arrangement

Advantages:

- busbar fault does not disturb service
- circuit breaker maintenance can be carried out without load interruption
- substation extension possible under service

Drawbacks:

- high investment cost
- complicated protection and auto-reclosing circuits
- protected object current has to be summated from the two breaker branches
- current transformer nominal current selection based on bus connection conditions and circuit breakers' nominal currents

3.14.1.6 H-bus Arrangement

The following figure shows one example of the so-called H-bus arrangements. There are many variations of this basic arrangement where the number of breakers and their location vary. Based on the actual selected configuration, the protection schemes are chosen as a result of the network topology.

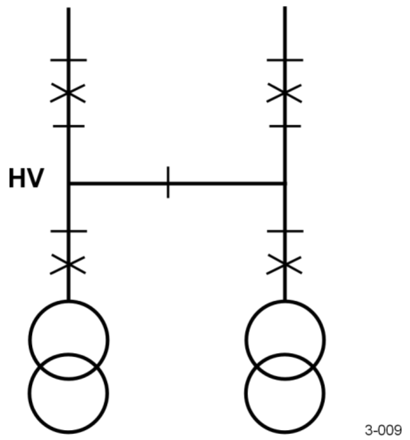


Figure 3.9: H-bus arrangement

Advantages:

- offers limited operational flexibility and redundancy at low cost
- compact design with low space requirements
- can be originally built with one power transformer with a provision for a second one

Drawbacks:

- Extensions accommodating more lines or power transformers are difficult

3.14.2 Insulation Level Coordination

By doing insulation coordination, the dielectric strength of equipment is selected in relation to the operating voltages and overvoltages which can appear on the system. The service environment and the characteristics of available preventing and protecting devices are to be taken into account [3.6]. In other words, the target is to find the optimum solution between system components' overvoltage withstand level, different overvoltage phenomena in the network and the protective characteristics of the utilized overvoltage protection devices.

The electrical installations are exposed to overvoltage stresses caused by various sources. By nature, the overvoltages caused by the sources have different characteristics in terms of magnitude, frequency, duration and rate of rise. The overvoltage phenomena are traditionally classified in three separate categories.

- Temporary overvoltages
- Switching overvoltages
- Lightning overvoltages

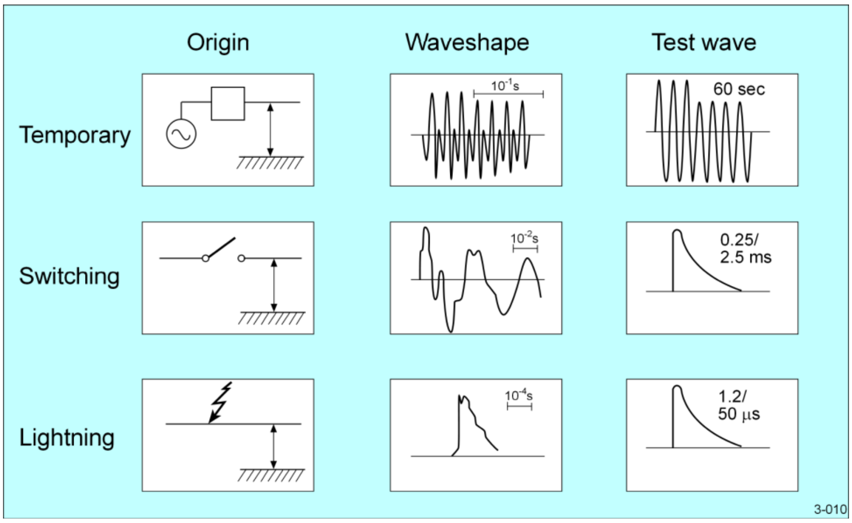


Figure 3.10: Types of overvoltages

The correlation between different classes of overvoltages as a function of duration and magnitude can be roughly illustrated with the following figure.

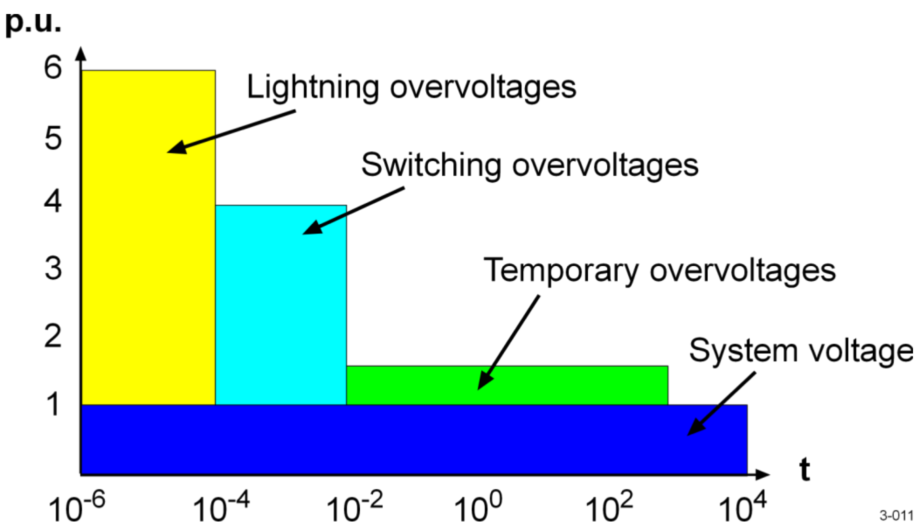


Figure 3.11: Principal overvoltage classification

In primary distribution substations, the main protective device for the installed equipment against overvoltages is the zinc oxide cap-less surge arresters. The selection of suitable surge arrester depends on several factors. Manufacturers of surge arresters have published guidelines and selection examples to demonstrate and support the selection process. The following picture describes in principle the dependences between the system and surge arrester parameters.

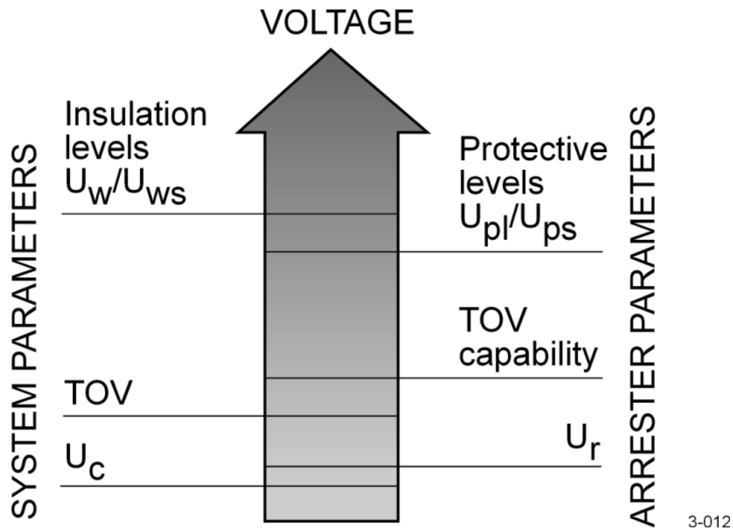


Figure 3.12: Coordination between system and surge arrester parameters

Definitions related to Figure 3.12:

$\mathbf{U_{wl}/U_{ws}}$	is the ratio of lightning to switching impulse withstand level
$\mathbf{U_{pl}/U_{ps}}$	is the ratio of lightning to switching impulse protective level
TOV	is the temporary overvoltage, as differentiated from surge overvoltages, is oscillatory power frequency overvoltages of relatively long duration from a few cycles to hours or even longer.
TOV capability	is the surge arrester's capability to withstand the temporary overvoltages
$\mathbf{U_c}$	is the continuous operating voltage
$\mathbf{U_r}$	is the rated voltage

The surge arrester should withstand the continuous and temporary power frequency overvoltages experienced in the system during normal operation, system faults and switching operations. The surge arresters have to be able to limit the surge overvoltages below the specified withstand level of the equipment in the installation.

A single- or two-phase earth fault leads to a temporary overvoltage situation in the healthy phase(s) and also in the neutral of Y-connected power transformers. The amplitude is determined by the system-earthing conditions and the duration is determined by the protection settings (fault clearance time). The arresters have to be able to withstand the thermal stresses during these situations.

In this book, it is also useful to use some well-define expressions regarding different voltage levels. The following definitions are based on relevant international standards, see Appendix 2 on Terminology: external overvoltage, highest voltage for equipment, highest voltage of a system, internal overvoltage, lightning impulse, lightning overvoltage, lowest voltage of a system, nominal system voltage, nominal voltage of a system, operating voltage in a system, overvoltage in a system, rated voltage of a winding, rated voltage ratio of a transformer, resonant overvoltage, switching impulse, switching overvoltage, temporary overvoltage, transient overvoltage, voltage impulse and voltage surge.

3.15 Primary Equipment

The following section shortly introduces the primary equipment used in distribution networks. The equipment already introduced in Section 3.2 is excluded from this section. The target is to give some basic knowledge of the different equipment, especially in the view of distribution automation concept.

3.15.1 Distribution Overhead Lines

Most of the rural distribution lines on medium-voltage levels (>1 kV) are constructed utilizing overhead lines. On low-voltage side (<1 kV), the trend is towards buried underground cables, even though the bundled overhead cables are still widely utilized. The bundled LV cable is a solution where the three separately insulated phase conductors are twisted around bare steel wire. The steel wire works as the supporting and fixing part for the cable in overhead installation, as well as the neutral (PEN) conductor.

Bare conductor overhead line with normal phase distances

Covered conductor overhead line with reduced phase distances

Figure 3.13: Bare and covered conductors in use

On the medium-voltage level, the solution can be either a covered or a bare conductor. The covered conductor gives a number of benefits, compared to the traditional bare conductor solution. The width of the right-of-way can be significantly reduced, the faults caused by the phase conductors touching each other while swinging are overcome and a tree falling on the line does not necessarily cause immediate fault. The faults taking place at the interfacing points of the network, like arching faults at the distribution transformer connections, still are an issue despite the use of covered conductor.

The smaller width of the right-of-way with covered conductors is due to the lowered distances between phase conductors, typically one third of the distance with bare conductors, and the smaller safety distances to vegetation (trees) along the way. Even though the covered conductor enables the line operation when a tree has fallen on it, the line has to be cleared from the trees during a reasonable time period or the situation develops into a fault. Indication of the fault situations and protective relay operations can be more difficult to realize due to the high ohmic nature of the faults.

Vibrations with covered conductors can also be a problem to an extent, especially under light side wind and low-load conditions. During low-load (and low-temperature) conditions, the covered conductor stringing is at its tightest condition. Light side wind can cause vibrations to the conductor's cylindrical surface. These vibrations can summate at the fixing point of the conductor, ultimately resulting in a conductor breakdown.

A typical construction of the covered conductor is alloyed aluminum conductor covered with relatively thin black weather-proof XLPE plastic coating.

Figure 3.14: Example of a covered conductor construction

3.15.2 Distribution Power Cables

Normal construction is a three-phase cable where separately insulated phase conductors are covered with a common screen and insulation. For applications where the load current demands are high, the use of single-phase cables becomes more convenient. The general handling and especially termination of a large three-phase cable is obviously a problem. For very short distances, a solution of using high-current bus duct assemblies with either aluminum or copper bars inside a metallic enclosure is an option, for both indoor and outdoor applications.

For the conductive material, the use of aluminum instead of copper is the most common and cost effective solution.

Figure 3.15: Examples of 20 kV three-phase and single-phase power cables with copper as conductive material

If cables must run in places where exposed to impact damage, they are protected with flexible steel tape or wire armor, which may also be covered by a water-resistant jacket.

Commonly cross-link polyethylene (XLPE) is used for insulation material, enabling higher operation temperatures and thus higher load currents.

3.15.3 Distribution Power Transformers

The distribution power transformers perform the necessary voltage transition from transmission (or sub-transmission) voltage level to a level suitable for power distribution. One example of such transition would be a change from 66 kV to 11 kV. The size of a distribution power transformer typically varies roughly from 16 MVA to 63 MVA, weighing somewhere between 20 to 50 tons. The transformer is typically a three-phase unit. Three-phase banks, constructed from single-phase units, can also be implemented due to specific reasons like the road transportation restrictions or request for single-phase spare unit. The power transformer is generally the most expensive single component in a primary distribution substation.

In the following, the distribution power transformer features, construction and protection and their influence to the complete distribution system performance are discussed. The focus is in mineral oil-insulated (oil-immersed) three-phase units, which form the majority of distribution power transformers in applications under IEC influence.

Figure 3.16: A mineral oil-insulated 16 MVA 66/11 kV distribution power transformer ready for despatch at factory

3.15.3.1 Physical Fundamentals

A power transformer is a static device with two or more windings that are linked to each other with a strong magnetic field. The purpose of power transformer is to transfer a certain amount of electric power on a specified frequency from a voltage level to another voltage level with minimum losses.

The function of a transformer is based on two physical phenomena, namely electromagnetic induction and the fact that a conductor carrying current is surrounded by a magnetic field [3.16].

$$\overline{u}_i = -N \times \frac{d\phi}{dt} \qquad \textbf{(3.1)}$$

The equation (3.1) states the induced voltage as a scalar value in a coil with an N number of series-connected turns when subjected to magnetic field changes.

To achieve a magnetic field that varies as a function of time, the primary winding is connected to a sinusoidal voltage creating the necessary magnetizing current. The windings are made as concentric shells around laminated steel plate core. Due to the magnetic properties of the steel (low reluctance), the magnetic flux will be several thousand times higher than it would be without it. This makes the magnetic coupling between the windings strong.

Under no-load conditions the relation between applied voltage on the primary side and induced voltage on the secondary side is the same as the relation between primary and secondary coil turns. This relation is referred to as turn ratio.

$$\frac{U_1}{U_2} = \frac{N_1}{N_2} \tag{3.2}$$

When the transformer is loaded, the actual voltage ratio may differ from the turn ratio considerably. This is due to the transformer's internal voltage drop (or rise), caused by the load current passing through the transformer's short circuit impedance. Transformer under load fulfils the following equation, with a small deviation (around 1%) due to the magnetizing current.

$$I_1 \times N_1 = I_2 \times N_2 \tag{3.3}$$

The following simple equivalent circuit of a power transformer demonstrates the behavior of the trransformer. The following abbreviations are used:

Here

Z_0	is the no load impedance
Z	is the short circuit impedance of the transformers ($R + jX$)
Z_L	is the load impedance
U_{20}	is the no-load secondary voltage
U_2	Is the secondary voltage under load (voltage at the secondary terminals of the transformer)
I_2	is the load current

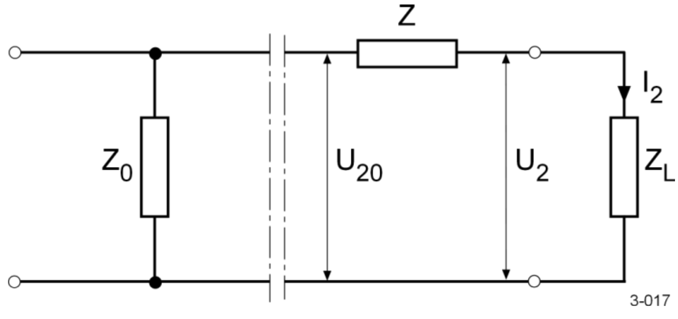


Figure 3.17: Equivalent circuit of a power transformer

The corresponding vector diagram can be drawn as follows. The voltage vectors u_x and u_r represent the voltage losses in the short circuit impedance (Z) imaginary and real part. The voltage drop ΔU_2 is the arithmetic difference between voltages U_{20} and U_2. The influence of a small magnetizing current is negligible, thus not shown.

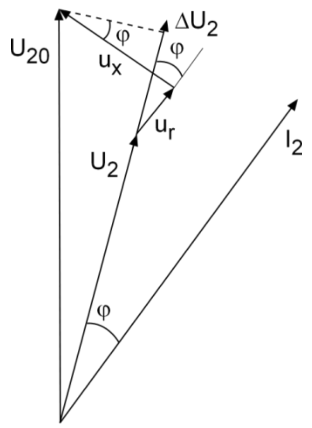


Figure 3.18: A vector diagram based on the transformer's equivalent circuit

The vector diagram above presents a situation where the load current (I_2) is lagging the secondary terminal voltage (U_2) by an angle of φ, thus the transformer is supplying an inductive load. When the current leads the voltage under increasing capacitive loading, at some point the voltage drop turns to voltage rise.The following figure demonstrates this issue with a power transformer having $u_{x\%}$ = 6% and $u_{r\%}$ = 1%. Abbreviation "n" denotes the relation of the transformer's actual load current and the transformer's rated current. Negative angle indicates a lagging (inductive) load current and positive angle indicates a leading (capacitive) load current.

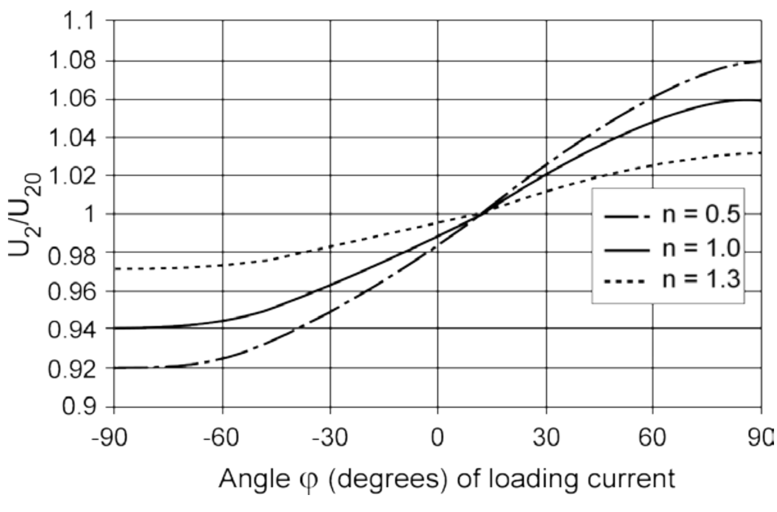


Figure 3.19: Relation of U_{20}/U_2 as a function load current angle under different loading conditions ($u_{x\%}$=6% and $u_{r\%}$=1%)

To calculate the voltage drop (or rise) ΔU_2, the arithmetic difference between U_{20} and U_2, the following formula can be used:

$$\Delta U_2 = I_2 R\cos\varphi + I_2 X \sin\varphi + U_{20} - \sqrt{U_{20}^2 - \left(I_2 R\sin\varphi - I_2 X sos\varphi\right)^2} \qquad \textbf{(3.4)}$$

When calculating the relative voltage drop at any relative loading n, the above equation can be rewritten as follows:

$$\Delta U_2 / U_{20} = n(u_r\cos\varphi + u_x\sin\varphi) + 1 - \sqrt{1 - n^2\left(u_r\sin\varphi - u_x\cos\varphi\right)^2} \qquad \textbf{(3.5)}$$

R	is the short circuit resistance [Ω]
X	is the short circuit reactance [Ω]
n	is the relative degree of loading, at rated current $n = 1$
u_r	is the relative short circuit resistance ($u_{r\%} = 1\% \rightarrow u_r = 0.01$)
u_x	is the relative short circuit reactance ($u_{r\%} = 6\% \rightarrow u_r = 0.06$)
φ	is the angle between load current and load voltage

3.15.3.2 Construction

Common features and dominant materials for most power transformer constructions, regardless of the size and application, are:

- Special type of thin magnetic steel plates in the core, providing a low-reluctance path for the magnetic field. The steel plates are grain-oriented silicone steel; it has been cold-rolled under high pressure to direct the magnetic domains towards rolling direction. This feature gives good loss properties to the rolling direction and correspondingly poor properties to the transversal direction.
- Copper or aluminum used as the conductor materials in the windings.
- Cellulose products like high-density paper and pressboard as solid insulation material.
- Mineral oil as the liquid insulation and cooling fluid.

The iron core and the windings are referred to as the active part of the power transformer. For three-phase units, there are basically two different active part construction types, namely the Core type and the Shell type.

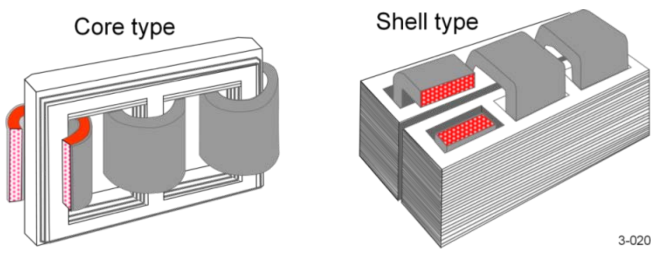


Figure 3.20: Two types of active part constructions

The trend today is towards the core type of construction. The core-type active parts can be further divided into three-limb or five-limb constructions. The following figure shows the principle for both constructions. In both types, the windings are placed on the phase-dedicated limbs separately. Usually, the primary (high-voltage) winding is the outer winding and the secondary winding is the inner winding on each limb.

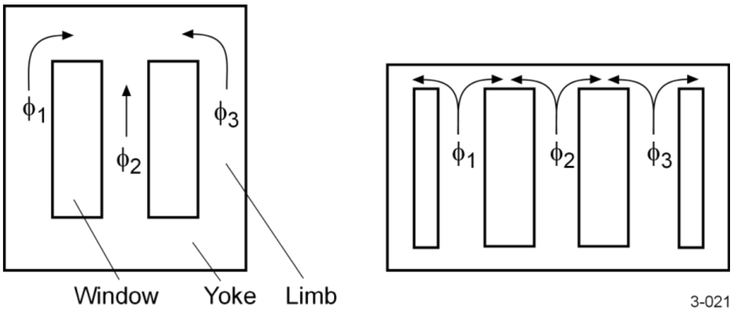


Figure 3.21: Core type construction with three-limb (on the left) and five-limb design

The choice between three- or five-limb designs affects the weight and physical dimensions of the unit. It has also very significant effect on the zero-sequence impedance, as is shown later.

The overall construction of a power transformer has a significant difference in the IEC and ANSI world. The IEC-type construction has the whole main tank filled with oil, and the expansion of the oil, as a result of temperature variations, is handled with a separate oil conservator (expansion vessel).

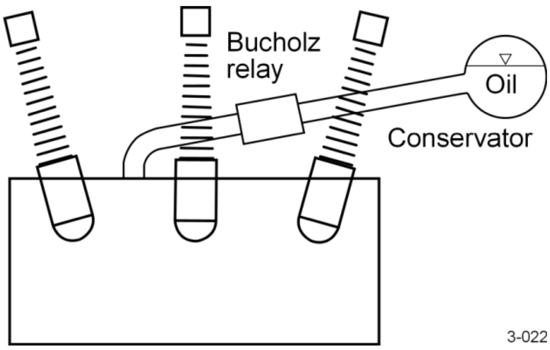


Figure 3.22: A power transformer with conservator

The ANSI-type construction has the main tank filled with oil only partially. The nitrogen gas fills the rest of the tank. The thermal expansion of the oil increases the nitrogen pressure.

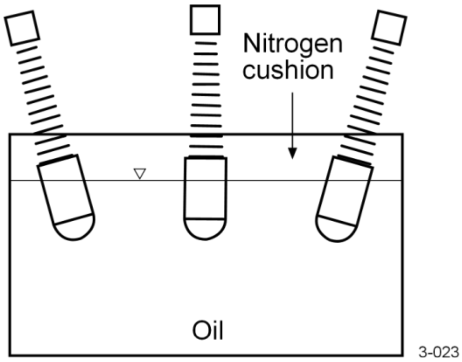


Figure 3.23: A power transformer with nitrogen cushion

The terminal markings on top of the unit are normally either stamped or welded onto the top steel cover plate close to the bushing (insulator) mountings. With the actual markings, two different ways are dominating, as shown below:

Primary side

- A, B, C (phases) and N (neutral)
- U, V, W (phases) and N (neutral)

Secondary side

- a, b, c (phases) and n (neutral)
- u, v, w (phases) and n (neutral)

The terminal markings can be further appended with numbers from 2 onwards, except the winding having the highest rated voltage. As an example, the terminal markings on a three-winding transformer can be as follows:

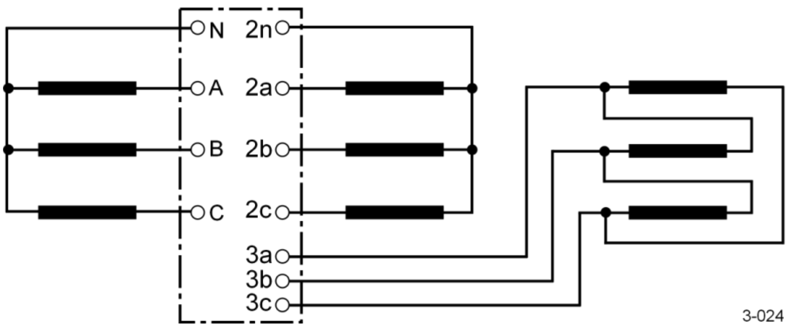


Figure 3.24: Terminal markings on a power transformer

Losses and Efficiency

The losses are divided into two categories, the load losses at rated load current and the no-load losses at rated voltage. Depending on the appreciation of the losses, the transformer construction can be optimized in order to come up with the minimum capitalized losses during the unit's life cycle. Usually, the power transformer purchaser will, as an amendment to the request for bid, supply the loss capitalization formula for the manufacturer for design guidance. This formula is created covering the initial investment cost and the losses. The appreciation balance between load and no-load losses is chosen to reflect the intended use of the transformer.

The efficiency η [%] of a power transformer is directly linked to the losses taking place in the unit. The efficiency can be calculated as follows:

$$\eta = \frac{100}{1 + \dfrac{P_0 + P_L n^2}{P_2 n}} \qquad \textbf{(3.6)}$$

Above

P_0	is the no-load losses at rated voltage [kW]
P_L	is the load losses at rated current [kW]
P_2	is the active power supplied to the load [kW]
n	Is the relative degree of loading (at rated current $n = 1$)

The active power supplied to the load (P_2) is calculated as follows:

$$P_2 = \sqrt{3} \times U_{20} \times I_2 \times (1 - \frac{\Delta U_2}{U_{20}}) \times \cos\varphi \qquad \textbf{(3.7)}$$

Normally, the transformer’s efficiency is very high, with the typical value being around 98-99%.

3.15.3.3 Inrush Current

The magnitude of the inrush current is a statistical variable and therefore each occasion when power transformer is energized might be different from the earlier ones. There are different factors affecting the magnitude and the decaying rate of the inrush current. The following main factors can be identified:

- Moment of time in the sinusoidal voltage curve when the energizing takes place. Worst situation would be when the transformer is energized at the voltage zero-crossing. Connection at the voltage zero-crossing will cause the magnetic flux to reach twice the value during normal operation. As a result, the core will saturate, lowering the winding reactance heavily and increasing the current.
- Value and direction of the remnant flux in the core of the transformer. The value and direction of this remnant flux depend on the instant of time when the transformer has been disconnected from the network. If the disconnecting takes place at the time when the altering flux has its maximum value, the remnant flux will also have its maximum value.
- Magnetic properties of the core

- Size of the transformer
- Source impedance of the supplying network. If the supplying network impedance is relatively high (weak network) the inrush current causes a significant voltage drop across the impedance, thus lowering the supply voltage level at the time of energizing. This lowers the maximum inrush current value, but also increases the decaying time.

With modern power transformers, the inrush current tends to be higher than with older ones. The reason behind this are the properties of the modern core steel, allowing higher flux densities in the transformer design during normal operation and therefore giving less "room" before the core saturation takes place during the connection to the network.

The residual current, sum of the phase currents, should be zero if the core does not saturate and poles are closing exactly at the same time. With a Y-connected and effectively earthed neutral power transformer, the inrush current appears also in the neutral, in case the core saturates.

The inrush current contains the second harmonic, which can be used for detecting the inrush condition by the transformer protection relays, like current differential protection.

The behavior of inrush current with a 16 MVA 63/11 kV power transformer as a function of time is shown in the below figure. The transformer is energized against a relatively weak supply network. The rated primary current of the transformer in question is 147 A. The upper part shows the wave form of each phase current and lower part shows the RMS value of each phase current. From the figure it can be noted that the inrush current includes also a relatively large DC-component. The DC-component can lead to saturation of current measurement transformers, thus giving out false secondary signal to protection relays.

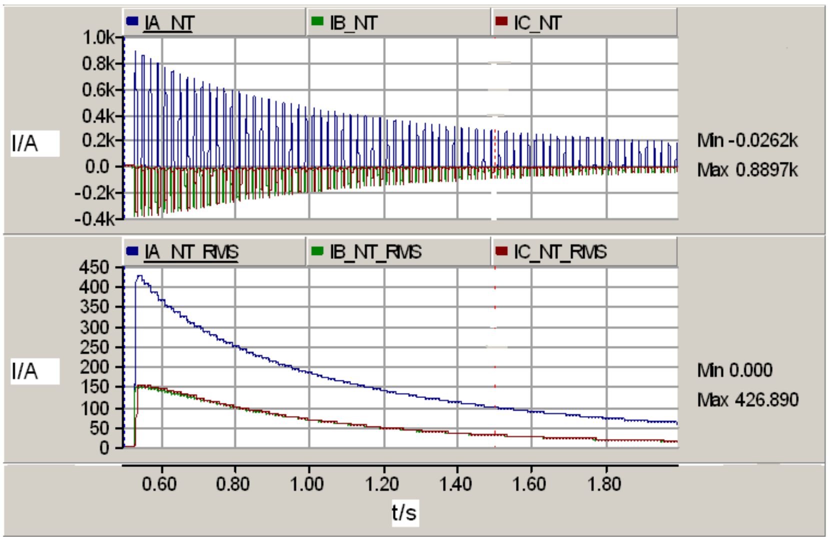


Figure 3.25: Inrush current of a 16 MVA 63/11 kV power transformer

3.15.3.4 Magnetising Current

As stated earlier, the magnetizing current at the rated voltage is very small, around 1% out of the rated current. The magnetizing current is heavily dependent on supply voltage level, though. When the supply voltage level increases, the magnetizing current starts to climb rapidly. The steepness of the rising current curve depends on the magnetic properties of the core and the flux density at rated voltage. The figure below shows the behavior of a certain power transformer.

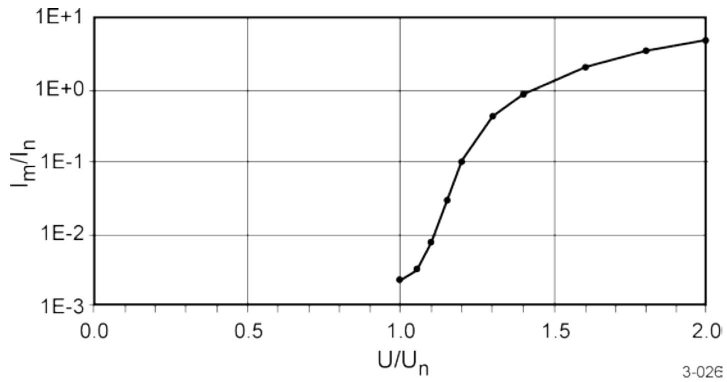


Figure 3.26: The RMS value of the magnetizing current as a function of supply voltage

The increasing magnetizing current has a high content of the fifth harmonic, which can be used to detect the phenomena. The following figure demonstrates the issue and the behavior of a certain power transformer.

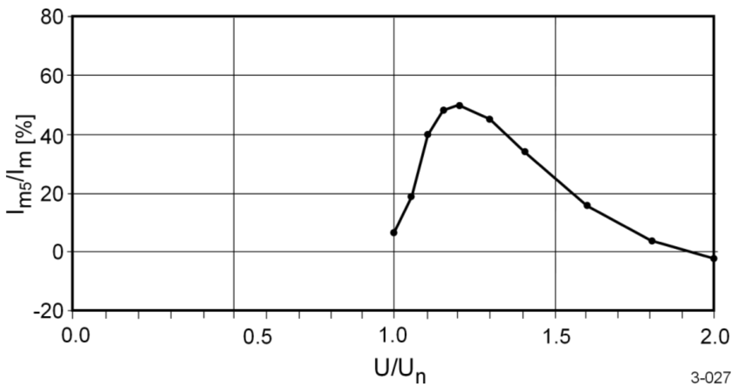


Figure 3.27: The fifth harmonic content in magnetizing current as a function of supply voltage

The phenomenon related to an increasing magnetizing current as a result of increasing supply voltage is referred to as overexcitation.

3.15.3.5 Secondary Voltage Adjustment

The voltage level supplied to the load from the transformer secondary terminals should be kept within certain limits. Factors affecting the fluctuation of the secondary voltage level are the primary side voltage level and the secondary side load current. To enable the secondary voltage adjustment to compensate these fluctuations, the voltage transformation ratio of the power transformer has to be adjustable.

This adjustment is made possible by introducing a number of tappings in the windings. These tappings are usually placed in the primary side windings to minimize the current passing through the switch providing connection to the different taps. This switch can do the change of tap while carrying load current, in which case it is called on-load tap changer, or the transformer has to be de-energized, in which case it is called off-load tap changer (off-circuit tap changer also used). A definition of "principal tapping" refers to the tap position to which all the rated quantities are related to, including the rated voltage ratio.

The tap changer’s physical placement with power transformer can be inside the main tank (in-tank type), in other words within the same oil-filled enclosure where the windings are. The other possibility is to have the tap changer outside the main tank (on-tank or container type) within its own oil-filled enclosure attached to the side of the main tank.

Three different tapping switch implementation principles can be identified, namely plus-minus switching, linear switching and coarse-fine switching. Out of these three, the first one, plus-minus switching, is the most common. The operation principle is shown below.

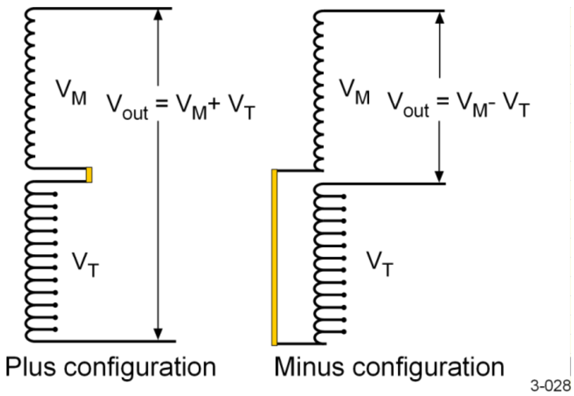


Figure 3.28: Tap changer’s "plus-minus switching" principle

Typically, the on-load tap changer is motor-operated, providing a possibility for remote control. The off-load tap changer is most commonly having manual operation facilities only, but also a motor operation is possible. The on-load tap changer has a number of taps, like ±8×1.25%. This indicates a possibility of an 8-step, each 1.25%, increase or decrease from the rated voltage ratio. The off-load tap changer has fewer steps, like for example ±2×2.5%. The operation of an on-load tap changer can be automated using an automatic voltage regulator (AVR), as is shown later.

3.15.3.6 Connection Groups

The power transformer connection groups are indicated with letter and number symbols. Capital letters refer to the winding having the highest rated voltage and small letters to winding(s) having a lower rated voltage.

Y and **y**: are referring to a star-connected winding.

D and **d**: are referring to a delta-connected winding

Z and **z**: are referring to a zigzag-connected winding

III and **iii**: are referring to an open (not connected) three-phase winding.

N and **n**: indicate that the neutral terminal of a star-connected winding is brought to the surface.

a: indicates an auto-type of winding connection.

The numbers are used to indicate the phase shift between primary and secondary voltages. The reference point is the primary side phase-to-earth voltage, which is compared to a similar voltage on the secondary side. The numbers used are from 1 to 12(0) referring to a normal clock's time dial.

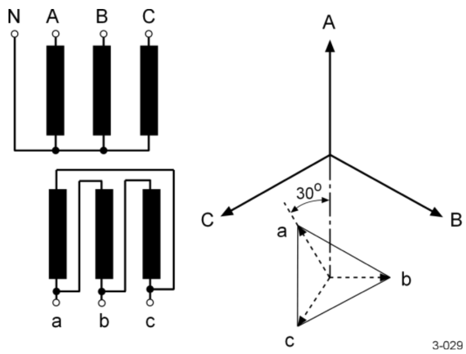


Figure 3.29: Winding arrangement and corresponding time dial of YNd11-connected power transformer

3.15.3.7 Short Circuit Impedance

The following discussion is introducing the (sequence) impedances in relation to three-phase power transformers.

Short circuit impedance $Z = R + jX$ [Ω/phase] is the equivalent impedance at rated frequency and reference temperature, across the terminals of one winding of a pair, when the terminals of the other winding are short-circuited and further windings are open-circuited. For three-phase transformers, the impedance is expressed as phase impedance [3.17].

This quantity is often expressed in relative, dimensionless form, as a fraction z_{pu} of the reference impedance Z_{ref} [Ω/phase].

$$z_{pu} = \frac{Z}{Z_{ref}} \tag{3.8}$$

Or in percentage notation

$$z_{\%} = 100 \times \frac{Z}{Z_{ref}} \tag{3.9}$$

The reference impedance Z_{ref} [Ω/phase] can be calculated from the reference voltage U_{ref} [V], reference current I_{ref} [A] and reference apparent power S_{ref} [VA] as follows.

$$Z_{ref} = \frac{U_{ref}}{\sqrt{3} \times I_{ref}} = \frac{U_{ref}^2}{S_{ref}} \quad \textbf{(3.10)}$$

Combining the above formulas results in

$$Z = z_{pu} \times \frac{U_{ref}^2}{S_{ref}} \quad \textbf{(3.11)}$$

And starting from percentage values.

$$Z = \frac{z_{\%}}{100} \times \frac{U_{ref}^2}{S_{ref}} \quad \textbf{(3.12)}$$

As noted earlier, the short circuit impedance Z is a complex number having a real and an imaginary part. The real part of the impedance can be calculated based on the rated load losses P_L [W]. The following formula gives the result in percent $r_{\%}$ [%].

$$r_{\%} = 100 \times \frac{P_L}{S_{ref}} \quad \textbf{(3.13)}$$

The imaginary part $x_{\%}$ [%] can be calculated as follows.

$$x_{\%} = \sqrt{z_{\%}^2 - r_{\%}^2} \quad \textbf{(3.14)}$$

The real R [Ω/phase] and imaginary part X [Ω/phase] of Z [Ω/phase] can be calculated as follows.

$$R = \frac{P_L}{S_{ref}} \quad \textbf{(3.15)}$$

$$X = \sqrt{Z^2 - R^2} \quad \textbf{(3.16)}$$

3.15.3.8 Sequence Impedances

Here are introduced the sequence impedances related to power transformers. The following definitions are used:

Here

Z_1 is the positive-sequence impedance [Ω/phase]

Z_2	is the negative-sequence impedance [Ω/phase]
Z_0	is the zero-sequence impedance [Ω/phase]

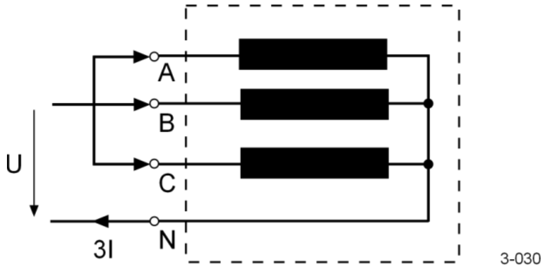


Figure 3.30: Zero-sequence measurement

Equation (3.17) below can be used to calculate the zero-sequence impedance Z_0 [Ω/phase] using voltage U [V] and current I [A] as defined in Figure 3.30.

$$Z_0 = \frac{U}{I} \tag{3.17}$$

With transformers

$$Z = Z_1 = Z_2 \neq Z_0 \tag{3.18}$$

The positive- and negative-sequence impedances equal the short circuit impedance, whereas the zero-sequence impedance differs considerably. The factors affecting the zero-sequence impedance are:

- Transformer connection group
- Core- or shell-type construction
- 3- or 5-limb or three-phase bank constructed of single-phase units

The effect of power transformer's connection group to the zero-sequence impedance is studied more closely. The below stated relative zero-sequence impedance values are for guidance only and the actual values have to be checked from the actual transformer's data sheets. Furthermore, the stated values refer to a core-type construction with three-limb design. The following definitions have been used.

H:	High-voltage (primary) winding
L:	Low-voltage (secondary) winding
T:	Tertiary winding
E:	Earth potential
z:	Relative short circuit impedance
z_{0HL}:	Relative zero-sequence impedance from high-voltage to low-voltage side
z_{0HE}:	Relative zero-sequence impedance from high-voltage side to earth
z_{0LE}:	Relative zero-sequence impedance from low-voltage side to earth

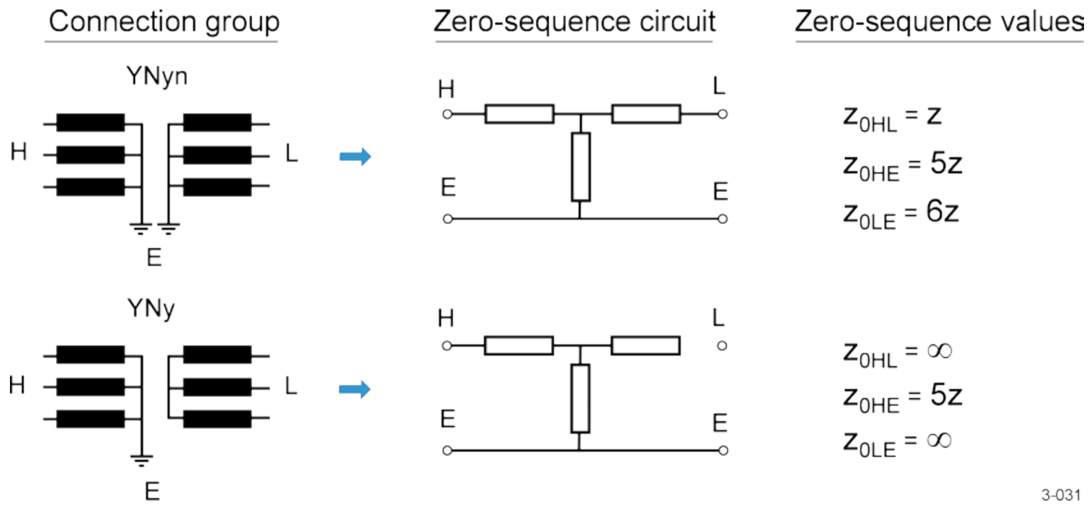


Figure 3.31: Zero-sequence impedances of YNyn- and YNy-connected power transformers as a relation to the units' short circuit impedance

If the above presented power transformer is of the five-limb design or the three-phase bank is constructed out of single-phase units, the values of Z_{0HE} and Z_{0LE} are basically infinite.

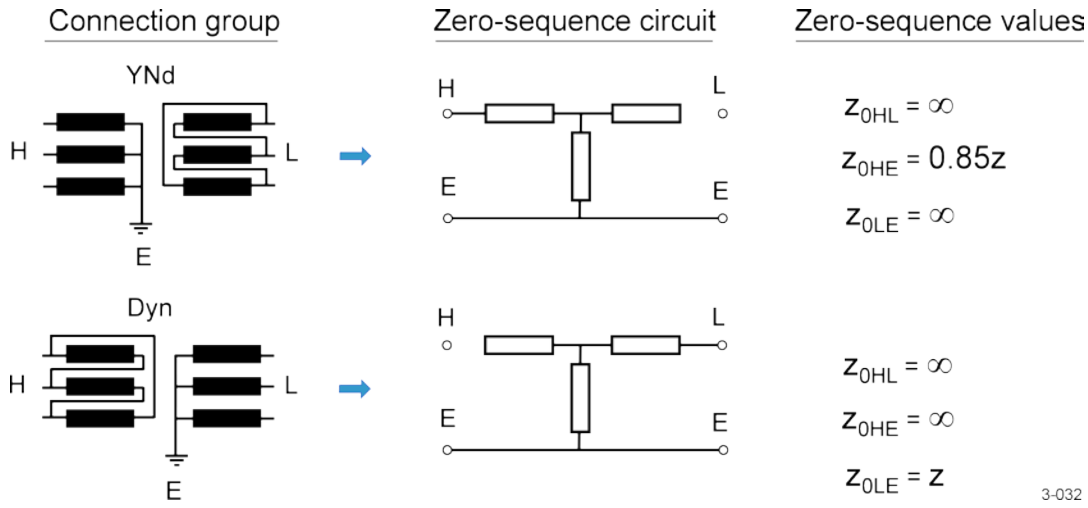


Figure 3.32: Zero-sequence impedances of YNd- and Dyn-connected power transformers as a relation to the units' short circuit impedance

If the above presented power transformer is of the five-limb design or the three-phase bank is constructed out of single single-phase units, the z_{0HE} in the YNd-connection is equal to z.

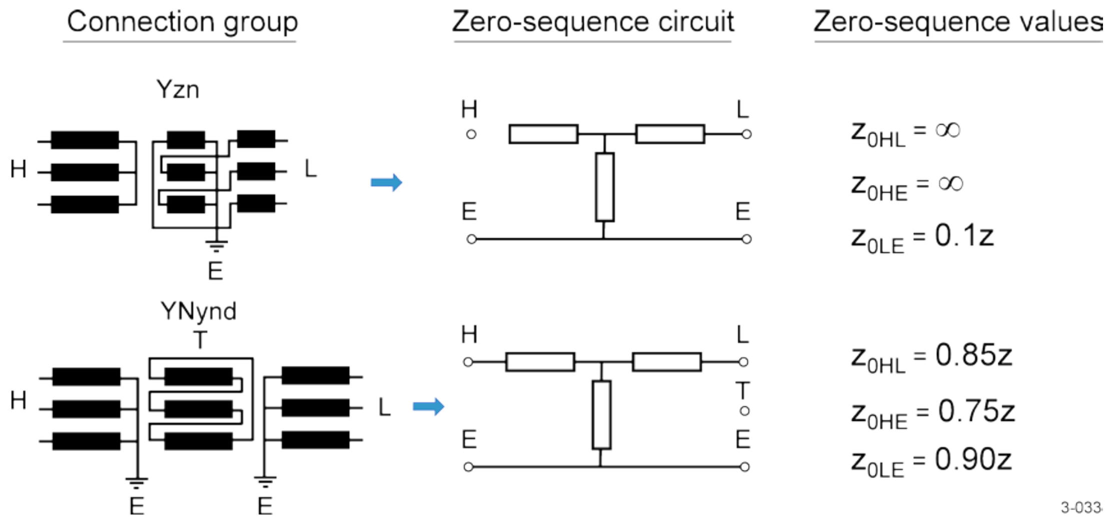


Figure 3.33: Zero Zero-sequence impedances of Yzn- and YNynd-connected power transformers as a relation to the units' short circuit impedance

Normal procedure for the power transformer manufactures is to state the zero-sequence impedance in relative values, either as a fraction or a percentage of the reference impedance. For calculating the actual ohmic values, the same equations as introduced for the short circuit impedance calculations can be used. With transformer connection groups allowing the closed loop for zero-sequence current to circulate, like YNd, the real and imaginary parts of the zero-sequence impedance have the same relation (ratio of R/X) as with the corresponding short circuit impedance. With other connection groups, the situation is more complicated, while the R/X ratio is not necessarily linear.

For three-winding power transformers, the calculation of zero-sequence impedance ohmic values is a bit more complicated. In this example, the following information is available in the power transformer's data sheets.

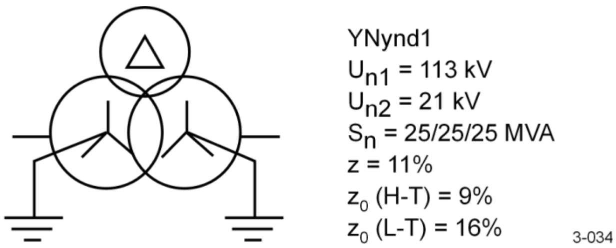


Figure 3.34: Data for the power transformer used in calculation example

The following figure shows the zero-sequence impedance components whose ohmic values should be calculated based on the above data. It is assumed here that the impedances are pure reactance, and the chosen reference voltage is 21 kV (low-voltage side of the transformer).

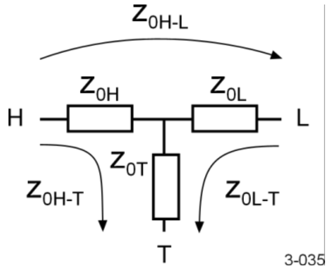


Figure 3.35: Zero-sequence circuit of the transformer used in the example

Calculation of the ohmic values based on the transformer's given data.

$$Z_{0H-T} = \frac{9}{100} \times \frac{\left(21\times10^3\right)^2}{25\times10^6} = 1.49 \ \Omega/\text{phase} \tag{3.19}$$

$$Z_{0L-T} = \frac{16}{100} \times \frac{\left(21\times10^3\right)^2}{25\times10^6} = 2.82 \ \Omega/\text{phase} \tag{3.20}$$

$$Z_{0H-L} = \frac{10}{100} \times \frac{\left(21\times10^3\right)^2}{25\times10^6} = 1.76 \ \Omega/\text{phase} \tag{3.21}$$

The specific component impedances are then calculated.

$$Z_{0H} = \frac{Z_{0H-L} + Z_{0H-T} - Z_{0L-T}}{2} = 0.27 \ \Omega/\text{phase} \tag{3.22}$$

$$Z_{0L} = \frac{Z_{0H-L} + Z_{0L-T} - Z_{0H-T}}{2} = 1.50 \ \Omega/\text{phase} \tag{3.23}$$

$$Z_{0T} = \frac{Z_{0H-T} + Z_{0L-T} - Z_{0H-L}}{2} = 1.33 \ \Omega/\text{phase} \tag{3.24}$$

3.15.3.9 Parallel Connection and Cooling

When two power transformers are to be connected in parallel, there are some conditions that the power transformers have to fulfill. It is possible to realize the parallel connection even if not all of the conditions are met, but the situation should be carefully studied. The conditions are as follows:

- The rated powers have to be within the same range, usually differences bigger than 3:1 should be avoided.
- Short circuit impedances have to be within the same range, differences bigger than 10% should be avoided.
- The rated voltages have to be within the same range, differences bigger than 0.5% should be avoided.

- The secondary voltages have to have the same direction. This condition is automatically met if the units have the same connection groups and the same phase order is used. This condition can be met also in some cases when the connection groups are different, but a case-related study has to be performed.

As discussed earlier, the mineral oil inside the transformer tank works as an insulation and cooling medium. When the oil is collecting the heat from the windings, the oil itself also has to be cooled down. For this purpose, the transformer is equipped with radiators, which provide the necessary surface area towards outside air, enabling the heat transfer from oil to air. In some designs, water is used instead of air, like in a case where the transformer is situated in a place where the surrounding air cannot transfer the heat, for example installations below ground level.

With air-cooled units, the flow of the oil, as well as the air, can be either natural or forced. In practice, the forcing means using pump(s) to enhance the circulation of oil between the main tank and radiators and fan(s) to enhance the flow of air through the radiators' outer surface. The transformer's rated capacity is stated according to the cooling method. The following abbreviations are used.

- ONAN: Oil Natural Air Natural
- OFAN: Oil Forced Air Natural
- OFAF: Oil Forced Air Forced
- ONAF: Oil Natural Air Forced

Usually with power transformers designed either with forced oil or air flow, two different rated power figures are stated, like 25MVA ONAN / 33MVA ONAF.

3.15.3.10 Protection Devices

The power transformer protection is realized with two different kinds of devices, namely the devices that are measuring the electrical quantities affecting the transformer through instrument transformers and the devices that are indicating the status of the physical quantities at the transformer itself. An example of the former could be current-based differential protection and of the latter oil temperature monitoring. The following discusses protection devices typically delivered as a part of the power transformer delivery. The power transformer protection as a whole and the utilization of the below presented protection devices are discussed later.

The Buchholz protection is a mechanical fault detector for electrical faults in oil-immersed transformers. The Buchholz (gas) relay is placed in the piping between the transformer main tank and the oil conservator. The conservator pipe must be inclined slightly for reliable operation. Often there is a bypass pipe that makes it possible to take the Buchholz relay out of service. The Buchholz protection is a fast and sensitive fault detector. It works independent of the number of transformer windings, tap changer position and instrument transformers. If the tap changer is of the on-tank (container) type, having its own oil enclosure with oil conservator, there is a dedicated Buchholz relay for the tap changer.

A typical Buchholz protection comprises a pivoted float (F) and a pivoted vane (V) as shown in Figure 3.36. The float carries one mercury switch and the vane also carries another mercury switch. Normally, the casing is filled with oil and the mercury switches are open.

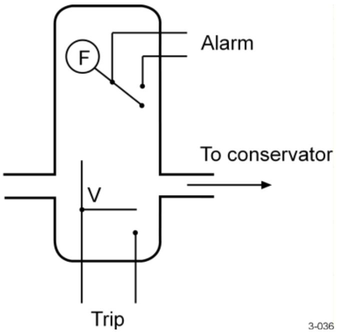


Figure 3.36: Buchholz relay principal construction

Here is assumed that a minor fault occurs within the transformer. Gases produced by minor faults rise from the fault location to the top of the transformer. Then the gas bubbles pass up the piping to the conservator. The gas bubbles will be tapped in the casing of the Buchholz protection. This means that the gas replaces the oil in the casing. As the oil level falls, the float (F) will follow and the mercury switch tilts and closes an alarm circuit.

It is also assumed that a major fault, either to earth of between phases or windings, occurs within the transformer. Such faults rapidly produce large volumes of gas (more than 50 cm^3/(kWs) and oil vapor which cannot escape. They therefore produce a steep buildup of pressure and displace oil. This sets up a rapid flow from the transformer towards the conservator. The vane (V) responds to high oil and gas flow in the pipe to the conservator. In this case, the mercury switch closes a trip circuit. The operating time of the trip contact depends on the location of the fault and the magnitude of the fault current. Tests carried out with simulated operating conditions have shown that operation in the time range 0.050-0.10 seconds is possible. The operating time should not exceed 0.3 seconds.

The gas accumulator relay also provides a long-term accumulation of gasses associated with overheating of various parts of the transformer conductor and insulation systems. This will detect fault sources in their early stages and prevent significant damage.

Figure 3.37: A typical outlook of a Buchholz relay with flanges on both sides for pipe connections

When the transformer is first put into service, the air trapped in the windings may give unnecessary alarm signals. It is customary to remove the air in the power transformers by vacuum treatment during the filling of the transformer tank with oil. The gas accumulated without this treatment will, of course, be air, which can be confirmed by seeing that it is not inflammable.

In addition, the Buchholz relay can detect if the oil level falls below that of the relay as a result of a leakage from the transformer tank.

Many power transformers with an on-tank-type tap changer have a pressure protection for the separate tap changer oil compartment. This protection detects a sudden rate-of-increase of pressure inside the tap changer oil enclosure. Figure 3.38 shows the principle of a pressure relay.

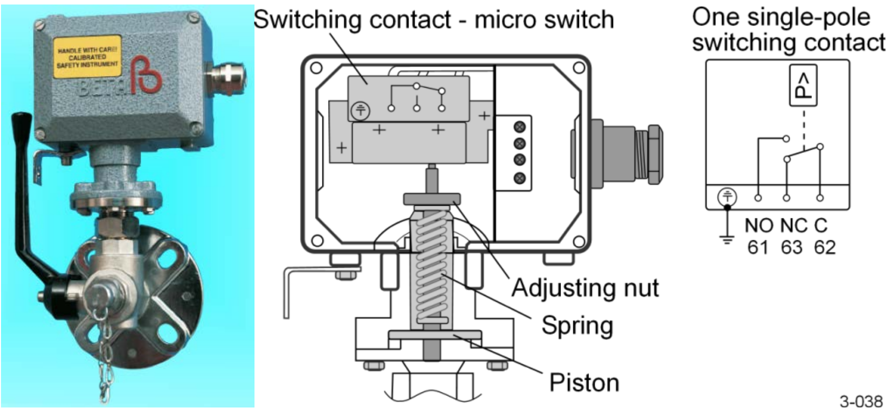


Figure 3.38: Pressure relay

When the pressure in front of the piston exceeds the counter force of the spring, the piston will move operating the switching contacts. The micro switch inside the switching unit is hermetically sealed and pressurized with nitrogen gas.

An internal fault in an oil-filled transformer is usually accompanied by overpressure in the transformer tank. The simplest form of pressure relief device is the widely used frangible disk. The surge of oil caused by a heavy internal fault bursts the disk and allows the oil to discharge rapidly. Relieving and limiting the pressure rise prevent explosive rupture of the tank and consequent fire. Also, if used, the separate tap changer oil enclosure can be fitted with a pressure relief device.

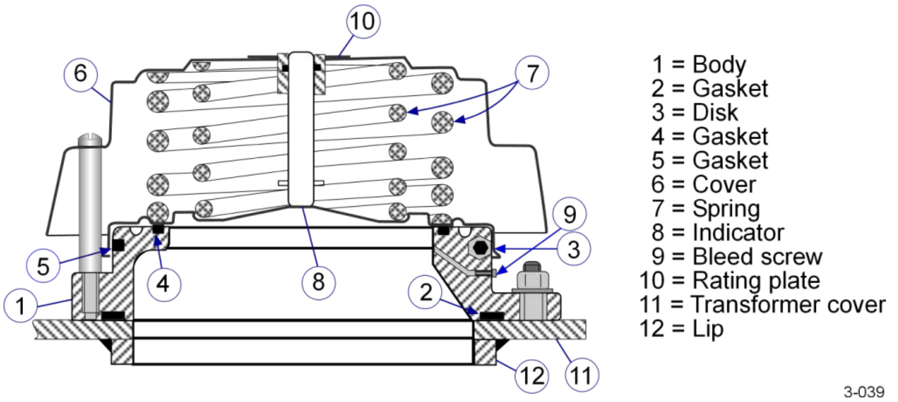


Figure 3.39: Principle construction of a pressure relief device

The pressure relief device can be fitted with contact unit(s) to provide a signal for circuit breaker(s) tripping circuits.

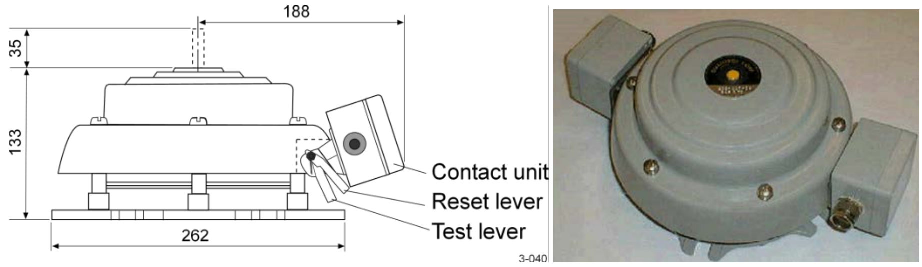


Figure 3.40: A pressure relief device with contact units

A drawback of the frangible disk is that the oil remaining in the tank is left exposed to the atmosphere after a rupture. This is avoided in a more effective device, the pressure relief valve, which opens to allow the discharge of oil if the pressure exceeds the pre-adjusted limit. By providing the transformer with a pressure relief valve, the overpressure can be limited to a magnitude harmless to the transformer. If the abnormal pressure is relatively high, this spring-controlled valve can operate within a few milliseconds and provide fast tripping when suitable contacts are fitted. The valve closes automatically as the internal pressure falls below a critical level.

Transformers with oil conservator(s) (expansion tank) often have an oil level monitor. Usually, the monitor has two contacts for alarm. One contact is for maximum oil level alarm and the other contact is for minimum oil level alarm.

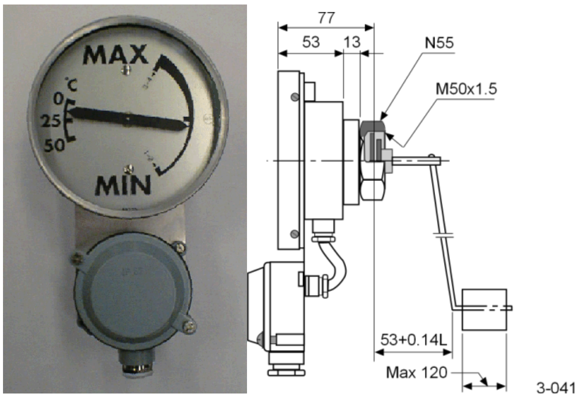


Figure 3.41: A typical outlook of an oil level monitor device

The top-oil thermometer has a liquid thermometer bulb in a pocket at the top of the transformer. The thermometer measures the top-oil temperature of the transformer. The top-oil thermometer can have one to four contacts, which sequentially close at successively higher temperature. With four contacts fitted, the two lowest levels are commonly used to start fans or pumps for forced cooling, the third level to initiate an alarm and the fourth step to trip load breakers or de-energize the transformer or both. The figure below shows the construction of a capillary-type top-oil thermometer, where the bulb is situated in a "pocket" surrounded by oil on top of the transformer. The bulb is connected to the measuring bellow inside the main unit via a capillary tube. The bellow moves the indicator through mechanical linkages, resulting in the operation of the contacts at set temperatures.

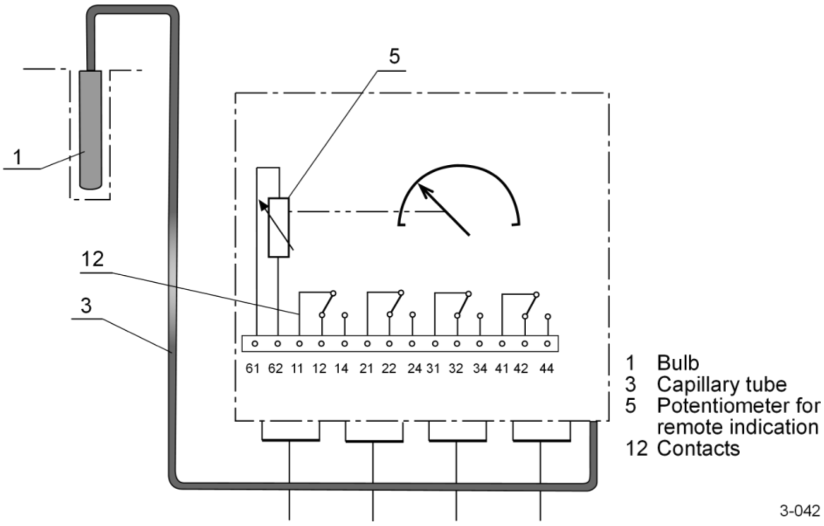


Figure 3.42: Capillary type of top-oil temperature measurement device

The top-oil temperature may be considerably lower than the winding temperature, especially shortly after a sudden load increase. This means that the top-oil thermometer is not an effective overheating protection. However, where the policy towards transformers' loss of life permits, tripping on top-oil temperature may be satisfactory. This has the added advantage of directly monitoring the oil temperature to ensure that it does not reach the flash temperature.

The winding thermometer, shown in the figure below, responds to both the top-oil temperature and the heating effect of the load current.

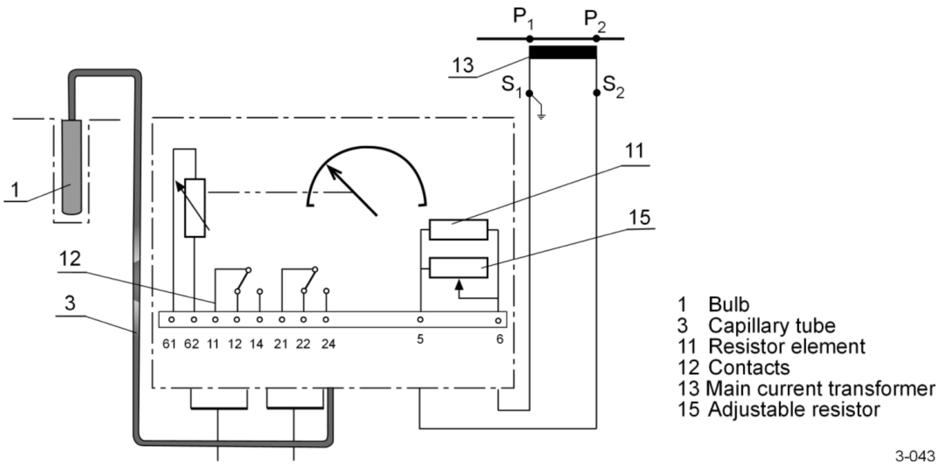


Figure 3.43: Capillary type of winding thermometer.

The winding thermometer creates an image of the hottest part of the winding. The top-oil temperature is measured with a similar method as introduced earlier. The measurement is further expanded with a current signal proportional to the loading current in the winding. This current signal is taken from a current transformer located inside the bushing of that particular winding. This current is lead to a resistor element in the main unit. This resistor heats up, and as a result of the current flowing through it, it will in its turn heat up the measurement bellow, resulting in an increased indicator movement.

The temperature bias is proportional to the resistance of the electric heating (resistor) element. The result of the heat run provides data to adjust the resistance and thereby the temperature bias. The bias should correspond to the difference between the hot-spot temperature and the top-oil temperature. The time constant of the heating of the pocket should match the time constant of the heating of the winding. The temperature sensor then measures a temperature that is equal to the winding temperature if the bias is equal to the temperature difference and the time constants are equal.

The winding thermometer can have one to four contacts, which sequentially close at successively higher temperature. With four contacts fitted, the two lowest levels are commonly used to start fans or pumps for forced cooling, the third level to initiate an alarm and the fourth step to trip load breakers or de-energize the transformer or both. In case a power transformer is fitted with top-oil thermometer and winding thermometer, the latter one normally takes care of the forced cooling control.

Figure 3.44: Top-oil thermometer and winding thermometer main units fitted on the side of a power transformer

3.15.4 Primary Medium-Voltage Switchgear

3.15.4.1 General

Primary medium-voltage switchgear represents an important part within the primary distribution substation functionality. The switchgear works as a connection node between the outgoing distribution feeders and the in-feeding power transformers. The most common construction with the switchgear is an indoor-mounted metal-enclosed one. The rated voltage, current and short circuit withstand ranges for secondary switchgears typically reach up to 36 kV, 1250 A and 50 kA respectively. The same switchgear constructions are used in primary distribution by the utilities and in heavier industrial and power plant applications.

On a 36 kV voltage level also outdoor air-insulated constructions are used to some extent. These switchgears are built at site utilizing individual standard components. This gives the possibility to construct customer-specific solutions like busbar arrangements that are not available with factory-built metal-enclosed switchgears.

3.15.4.2 Construction

The following concentrates on factory-built metal-enclosed indoor switchgears.

The primary switching devices typically include switch disconnectors, fused switch disconnectors, contactors and circuit breakers, either fixed or withdrawable. The current and voltage measurement can be done either with traditional instrument transformers or with sensors. Certain combinations are also possible, depending on the individual switchgear manufacturer.

Two main construction principles exist, namely the air-insulated one and the gas-insulated (SF6) one. The choice between these two alternatives is a result of evaluation of different aspects and differentiating factors during the switchgear's life cycle. This evaluation can typically include the following viewpoints:

- Space requirements
- Service requirements (tools and knowledge)
- Reliability and availability

- Installed base
- Operational safety
- Life cycle costs
- Performance ratings

Switchgear consists of a number of cubicles. The basic construction of each cubicle is chosen to meet the intended use. This means that for example the power transformer in-feed cubicle can have different primary and secondary devices from what the outgoing line feeder cubicle has. The switchgear manufactures provide a selection of typical cubicle constructions. By combining these typical cubicles, one can create switchgear suitable for the intended use.

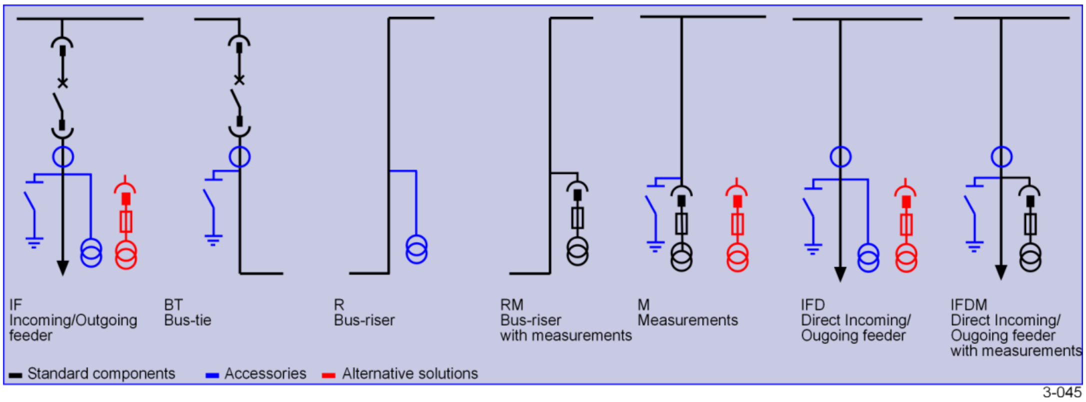


Figure 3.45: Example of typical cubicles for single-busbar solution

The number of different cubicles within the switchgear is coupled together by the busbars. In an air-insulated construction, these busbars are placed in a metal-enclosed compartment surrounded by normal air. With the gas-insulated construction, the busbars are placed in a hermetically sealed metal enclosure under pressurized insulating gas (SF_6). Depending on the manufacturer, the busbar compartment can be divided into cubicle-wide sections.

Typical busbar arrangements supported by the different switchgear manufacturers are the single-busbar and double-busbar arrangements.

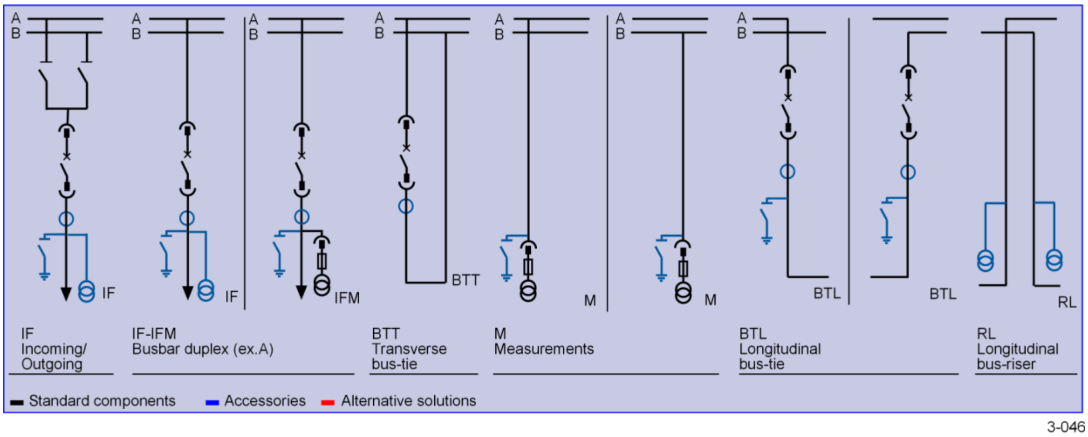


Figure 3.46: Example of typical cubicles for double-busbar solution

3.15.4.3 Protection, Control and Metering

The protection relays are externally powered advanced Intelligent Electronic Devices (IEDs), also referred to as Feeder Terminals.

In a modern primary switchgear, the bay-dedicated functions like protection, control and measurement are carried out with Feeder Terminals. The Feeder Terminal performs the assigned protection functions, carries out the local and remote control of switching devices, gathers and processes and displays measured data and indicates the status of the switching devices.

The horizontal communication between feeder terminals in each cubicle provides the possibility for station level automation and gateway connections to upper level systems for complete primary distribution network real-time control and monitoring.

Figure 3.47: Air-insulated primary switchgear equipped with Feeder Terminals

3.15.5 System Earthing and Compensation Equipment

As discussed under chapter "System Earthing" in this handbook, there are several principal ways to realize the distribution system earthing. This section will concentrate on the actual primary equipment for realizing the system star point (neutral-point) connection to earth at a single primary substation, thus referred to as neutral earthing.

3.15.5.1 Neutral Earthing Resistor

Even though the reference point in the following discussion is the primary distribution substation, the presented equipment can be basically utilized also with generator neutral-point earthing at power stations. With substation *neutral earthing resistor* (NER), the rated resistance values are chosen to cater for the maximum earth-fault current somewhere in the range of a few tens to few hundreds of amperes, thus referred to as low-resistance earthing (resistor). With power plants, the generator neutral-point earthing resistors are quite often chosen to cater for the maximum earth-fault current from a few amperes to few tens of amperes, thus referred to as high-resistance earthing (resistor).

Traditionally, the NERs have been built using liquid-filled resistor containers or metallic, cast iron resistors. The modern NERs use widely a metallic, often stainless-steel grid resistor solutions. The duration time for the rated current flow is limited due to the accumulated heat inside the unit. Typical value for rated current maximum duration is 10 seconds. The continuous current-carrying capacity is just a fraction of the rated current.

Installation location of the NER unit at a substation depends mainly on the primary system structure, i.e., where the system neutral point is available. If the main power transformer has a Y-connected winding on the voltage level in question and the star point is connectable, the NER unit is typically placed close to the power transformer. If the main power transformer does not cater for the connection possibility, one solution is to use a ZN-connected earthing transformer providing the connection possibility. Quite often the substations AC auxiliary power is also taken from the same earthing transformer with a secondary winding, like a ZNyn-connected one. In case where a separate earthing transformer is used, it is convenient to place the NER unit close to the transformer. In some designs where the earthing transformer is placed inside a cubicle of indoor medium-voltage switchgear, it is convenient to place the NER inside the adjacent cubicle.

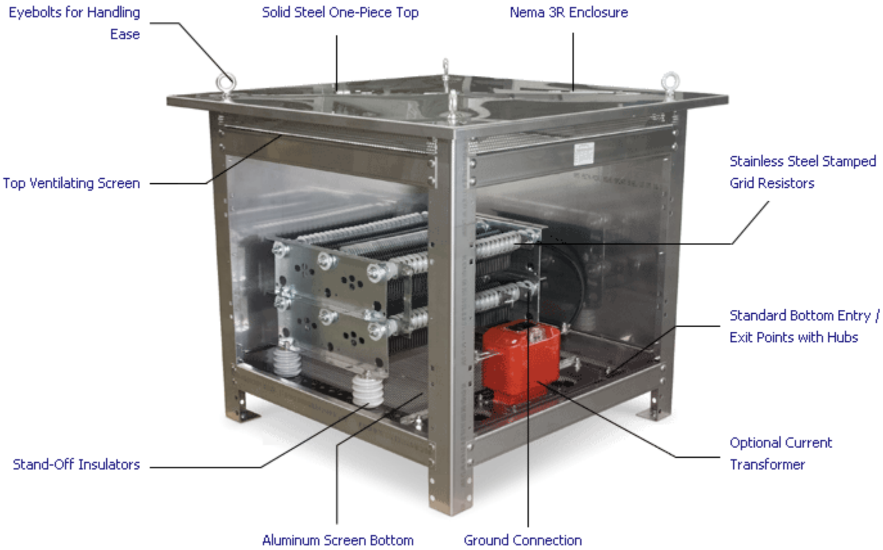


Figure 3.48: Example of Neutral Earthing Resistor with stainless-steel resistor elements for outdoor installation [3.20]

3.15.5.2 Earthing Transformer

As stated earlier, the earthing transformer provides connection point for neutral earthing in cases where such point is not available with the main power transformer or generator. Connection group of an earthing transformer single three-phase winding is normally ZN. The zero-sequence impedance of the unit can be adjusted within a certain range during the design phase, thus providing possibility to realize a low-reactance earthing by simply connecting the star point directly to earth. For other neutral earthing options, namely high-impedance, resonant and resistance earthing, the transformer is appended with necessary component between winding star point and earth, like NER.

The construction of earthing transformer is typically an oil-immersed one, following the basic design of secondary distribution transformers.

3.15.5.3 Arc Suppression Coil

The *arc suppression coil* (ASC), also known as *Petersen coil*, is used to compensate the capacitive earth-fault currents supplied by outgoing feeders at a substation. The compensation can be either centralized or distributed. With the centralized design, one ASC unit will handle the compensation of all of the outgoing feeders. The distributed compensation is designed to compensate one feeder with one unit, thus locating on the consumption side of the medium-voltage feeder circuit breaker in question.

Ideal situation from the system point of view would be a compensation degree of 100%, where the total capacitive earth-fault current would be compensated. With distributed ASCs, the compensation degree for the particular feeder is though kept well below 100% in order to avoid overcompensation under all of the system-switching conditions affecting the feeder length. That is, the distributed compensation sort of reduces the feeder's electrical length from supplied earth-fault current point of view. The current use of distributed ASCs is very limited and the clear trend is towards a centralized ASC.

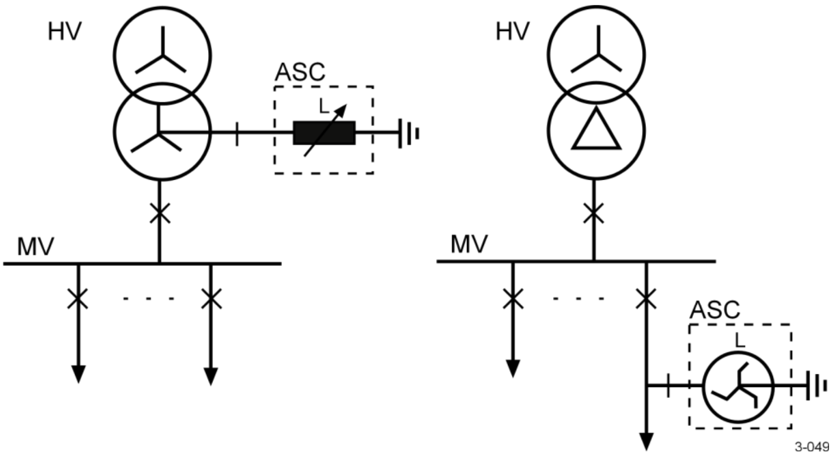


Figure 3.49: Principle of centralized (left) and distributed earth-fault current compensation

As noted earlier, the centralized ASC must compensate the capacitive earth-fault current supplied by a number of outgoing feeders. On the other hand, it is also noted that a compensation degree close to 100% would be preferred. To be able to fulfill these two conditions, it is clear that the ASC's inductive reactance has to be adjustable to match the different system-switching situations (feeder's total length). One implementation method is to provide remote adjustable air gap in the ASC core. The adjustment of the air gap will affect the coil's inductance. The adjustment can be performed manually using a crank, or it can be motorized. The motorized adjustment enables the use of a control device performing the adjustment automatically.

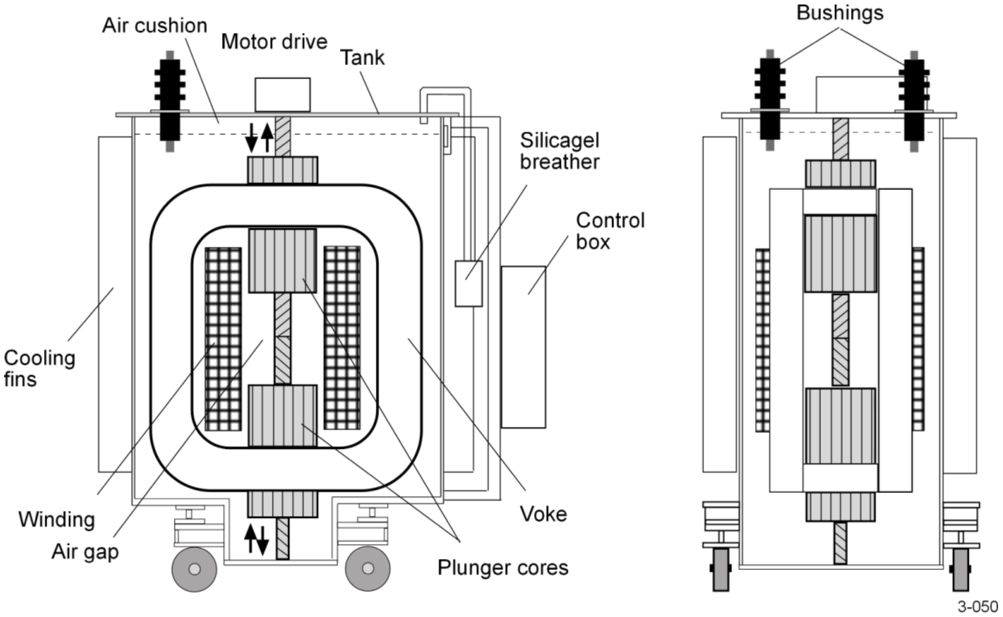


Figure 3.50: Construction of an ASC with air gap (reactance) adjustment [3.21]

The centralized ASC is connected between the system neutral point and earth, typically between the neutral of a star-connected main power transformer and earth. If the power transformer is delta-connected, the earlier introduced earthing transformer can be used to create the connection point.

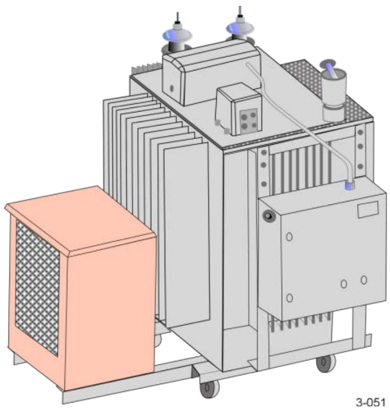


Figure 3.51: Installation of oil-immersed arc suppression coil with external air-cooled load resistor (on the left-hand side) [3.21]

As shown in the figure above, ASC is often installed with external loading resistor. The resistor is installed in parallel to ASC, and the control (switching on/off) of the resistor can be carried remotely by a dedicated controller. The purpose of the resistor is to increase the resistive earth-fault current component to a level which the outgoing feeder protection relays can detect. For insulation level reasons, the resistor connection to primary circuit is typically done through intermediate current transformer.

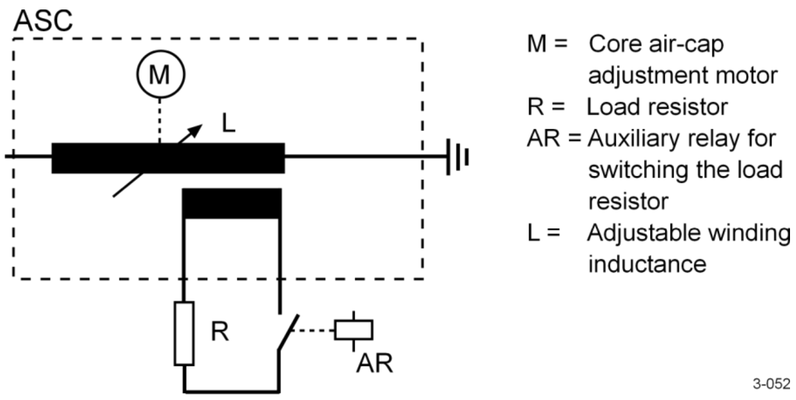


Figure 3.52: Principle of load resistor connection to ASC

3.15.6 Shunt Capacitors and Static Var Compensators

3.15.6.1 General

The shunt capacitors and static Var compensators are introduced in the network to improve the reactive power balance, thus giving voltage support to the system. Most of the loads connected to the distribution feeders have the power factor on the inductive side, thus they introduce a reactive current component as a part of their load current. This reactive current component does not contribute the conversion into useful power, but it stresses the network components, introducing additional voltage drops and heat losses.

Transfer of reactive power through the electrical system, from production to consumption, is mainly managed by a voltage difference. The reactive power flows from the higher voltage level to the lower voltage level. In this context, the voltage level difference refers to a deviation from the rated voltage ratios between the different system levels constituting the path from production to consumption. Transfer of large amounts of reactive power would mean also a large voltage gradient between production and consumption. Naturally, this is not the preferred situation from the system design or operation point of view.

As a result of the above, it is most favorable to compensate the reactive current as close to the consumption as possible. Bigger consumers, like industrial type of customers, do their own compensation at their installations to avoid charges based on measured reactive energy consumption.

The utilities face the same situation when they are charged for the distributed energy by the usually nationwide transmission company. Therefore, the utilities have to evaluate the reactive power balance within their distribution network and do the necessary compensation at the most suitable location. Another aspect to this evaluation is the voltage support from the system voltage stability point of view.

3.15.6.2 Shunt Capacitors

The following discussion mainly relates to capacitor solutions intended for medium-voltage-level applications, and thus they are to be installed to primary or secondary substations, or along the medium-voltage distribution lines.

The shunt capacitors are typically constructed from one-phase units, and a number of units are mounted together on a common rack. The units within the rack are connected in parallel or in series, depending on the desired voltage and reactive power rating. The units themselves can be protected with internal fuses, external fuses or without fuses. Some designs introduce also three-phase units covering typically the lowest rated capacities within their complete range.

Figure 3.53: Three-phase capacitor bank built out of rack-installed one-phase capacitor units

Three-phase capacitor banks are typically connected in a star (Y-) formation, with unbalance current measurement between the banks. The unbalance current monitoring provides means to detect a capacitor (or blown fuse) failure within the banks. With larger banks, also the so-called H-bridge connection is often used. The star point of the banks can be unearthed, as shown here, or it can be directly connected to earth.

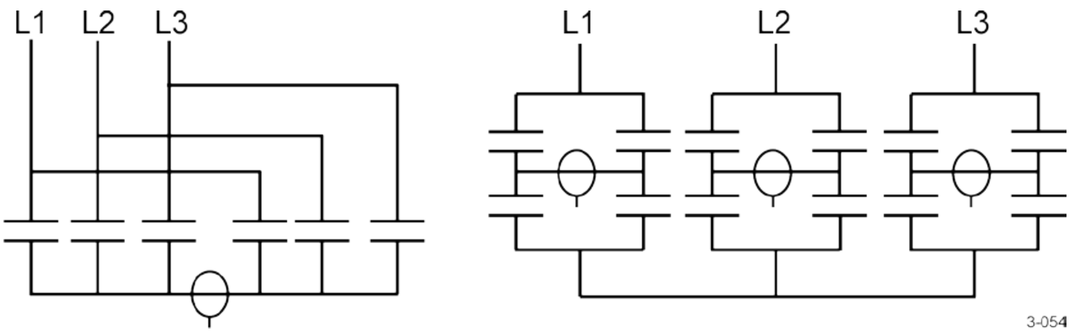


Figure 3.54: A three-phase star (left) and H-bridge-connected (right) capacitor bank with unbalance current measurement

The reactive power of a capacitor is determined by its capacitance, the rms-value of the operating voltage and system frequency.

$$Q_c = 2\pi f C U^2 = \omega C U^2 \qquad \textbf{(3.25)}$$

The rated power of a capacitor Q_r is stated in relation to its rated voltage U_r and rated frequency f_r. The reactive power supplied by capacitors varies heavily depending on the voltage to which the capacitors are exposed.

The demand for the reactive power compensation varies together with load variations and distribution system switching conditions, usually one step (one capacitor bank) does not give sufficient adjustment possibilities. To cater for this adjustment, the maximum need of compensation is divided between several capacitor banks which can be switched on and off separately. The switching in and out the capacitor banks is most often automatized; a dedicated controller will issue the opening and closing commands to each step individually.

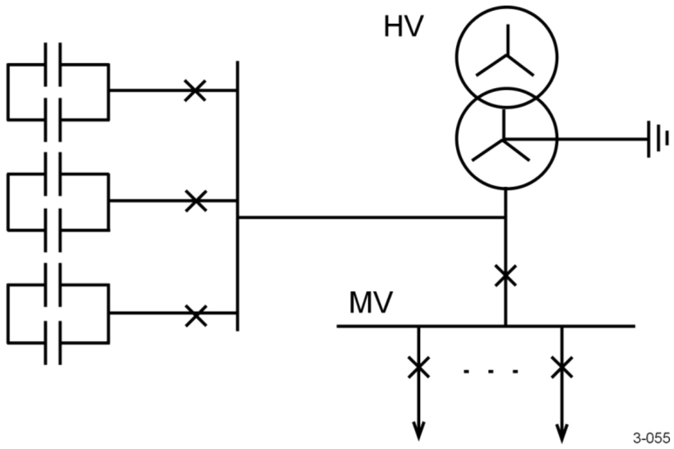


Figure 3.55: Three three-phase capacitor banks in a primary distribution substation

The capacitance of the capacitor banks and the network inductances form a resonant circuit under certain conditions. The resonant frequency can be calculated based on the network inductance and the capacitor rating, thus the resonant frequency can be located to create minimum disturbances. Unfortunately the network impedance is not a constant value, but will change due to different switching and load conditions. To avoid the additional stress for power transformers and the capacitor banks themselves caused by the resonance conditions, filter units are introduced.

A filter unit includes a reactor coil connected in series with each capacitor bank. The filter unit can be a tuned or a detuned one.

The detuned filter unit's resonant frequency f_{LC} [Hz] level is set to a level below the typical harmonic frequency. The impedance of the filter unit is capacitive with frequencies below f_{LC} and inductive with frequencies above f_{LC}, that is, the resonant point between network impedances and the filter unit, with frequencies higher than f_{LC}, cannot be found.

$$f_{LC} = \frac{f_1}{\sqrt{\frac{X_L}{X_C}}} \qquad \textbf{(3.26)}$$

Above

f_{LC}	is the resonant frequency of the filter unit [Hz]
f_1	is the fundamental frequency [Hz]
X_L	is the reactance of the filter reactor coil [Ω/phase]
X_C	is the reactance of the capacitor [Ω/phase]

The tuned filter units aim for absorbing the harmonic currents that already exist in the network before the introduction of the filter units, in addition to improving the power factor at fundamental frequency. Typically, each filter unit (individual step) is tuned for a certain harmonic frequency. Like in Figure 3.55, the filter units (capacitor banks) would be tuned for 5th, 7th and 11th harmonic in case the harmonics are caused by 6-pulse rectifiers.

As mentioned earlier, the capacitor bank optimal location within the distribution network is an important question. For cases where the installation of the compensation capacitors would be required outside a substation area, pole-mounted capacitor units are available.

Figure 3.56: A three-phase bank of pole-mounted one-phase capacitor units with voltage measurement, primary load current switching devices and control box

3.15.6.3 Static Var Compensators

While a shunt capacitor provides reactive power compensation in one or a few steps at most, a *static var compensator* (SVC) provides a stepless adjustment range. An SVC is a thyristor-controlled reactive power compensator. The compensation range of an SVC can cover the adjustment range starting from the inductive-side ending at the capacitive side. Due to the thyristor firing time-based (angle) control, the response to reactive load variations is very quick.

The SVCs require filtering for the harmonics produced by themselves: the same filters can be adjusted to filter the harmonics produced by external sources. The above features make the SVCs ideal for utility and especially for industrial applications, like steel industry with arc furnaces, where the following targets are to be met:

- Flicker reduction
- Voltage support (stability)
- Reactive power compensation
- Reduction (filtering) of harmonics

The types of static var compensation can be divided in three categories as follows:

- Thyristor-controlled reactor (TCR)
- Thyristor-switched capacitor (TSC)
- Combination of the two types (TSC/TCR)

Different equipment manufacturers prefer different methods to realize the SVC. Without going into the details on each of the method, one possibility is introduced in the following figure, where the TCR method is utilized.

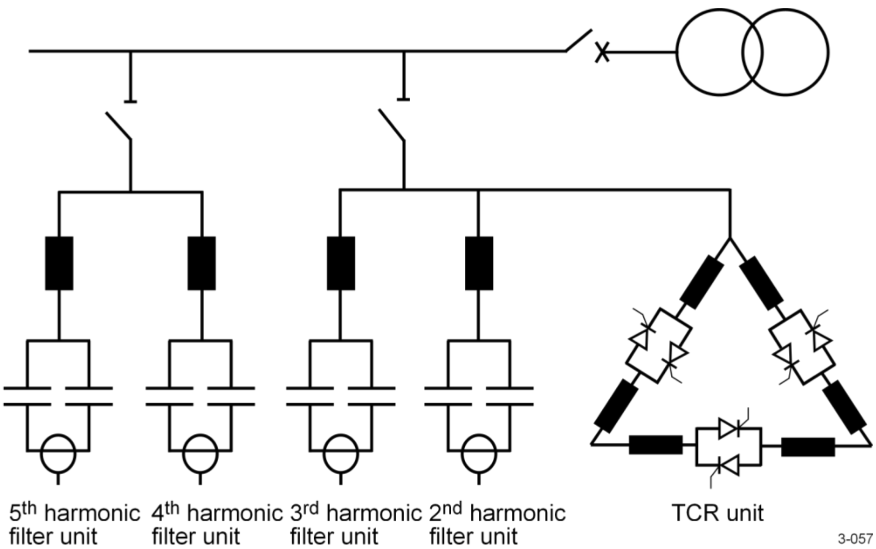


Figure 3.57: TCR-based static var compensation principle

In the above figure, the firing time (angle) of thyristors in front of the reactor determine the amount of reactive power drawn by the reactors. If the reactive power drawn by the reactors is zero, then the whole reactive power produced by the capacitor (filter) banks goes to network compensation. In other words, if the adjustment range is to be from -10 to 0 to +20 Mvar, the rated output of the capacitors has to be +20 Mvar and the rated output of the reactors has to be -30 Mvar.

3.15.7 Medium-Voltage Switching Equipment

The following section covers shortly the medium-voltage switching equipment intended mainly for primary substation installations. Both indoor and outdoor installation alternatives are presented. The indoor installation refers to the switching equipment used in metal-enclosed medum-voltage switchgears. Main focus with the discussions is on the air-insulated solutions. The following switching equipment will be covered:

- Circuit Breakers
- Contactors
- Switch Disconnectors
- Disconnectors

3.15.7.1 Circuit Breakers

A circuit breaker must be capable to make and break all the load and fault currents that it might be subjected to at the specific installation. Key factors with circuit breakers' performance are; opening (break) and closing (make) time, rated continuous current-carrying capability, rated dynamic short circuit withstand capability, rated thermal short circuit withstand capability, maximum operation voltage and rated operation sequence.

Earlier, the small-oil circuit breakers were common on medium-voltage indoor installations and air-blast or oil breakers in outdoor installations. Today, these technologies have been replaced with SF_6-gas and vacuum technologies. SF_6-gas is dominating with outdoor installations, whereas with indoor installations both vacuum and SF_6-gas technologies are utilized.

Two main constructional types with circuit breakers are the live tank breakers and the dead tank breakers. With live tank breakers, the outer surface of the breaking chamber is not earthed and is under primary voltage influence, thus "live." With dead tank breakers, the outer surface of the breaking chamber is earthed, thus "dead." Dead tank breakers are generally only available for outdoor installations from 33 kV upwards.

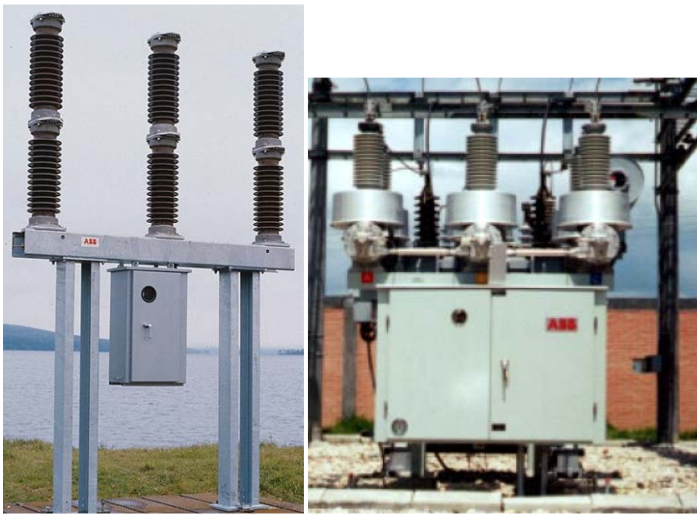


Figure 3.58: On the left a 66 kV live tank breaker and on the right a 66 kV dead tank breaker with bushing current transformers

The circuit breakers for outdoor mounting are generally fixed ones, whereas the breakers intended for indoor use, as a part of metal-enclosed switchgears, are generally mounted on a truck, although exceptions exist, like ABB's Compass concept and gas-insulated metal-enclosed medium-voltage switchgear solutions in general.

Figure 3.59: Indoor-mounted 24 kV vacuum-type circuit breaker on a truck

The actuating system, operation mechanism, is the unit within the circuit breaker that supplies the power and movement for the primary contacts to close or open. Depending on the arc-extinguishing principle the breaker utilizes, the needed power is different. With modern design SF_6 and vacuum breakers, the power need is relatively low. There are a number of different actuating systems available. The choice between systems depends on the application, the breaker type and reliability as well as maintenance interval requirements. What is common for all the actuator systems is the demand for a fast response to control commands and the capability to store enough energy for the breaker to complete the specified operation sequence without recharging the energy storage. The following actuator types are commonly available:

- Charged spring operation mechanism (spring)
- Pneumatic (compressed air)
- Hydraulic (compressed air)
- Hydraulic spring (Metallic spring bellows)
- Magnetic (capacitor)

Means of storing the energy with different actuator types is shown in the brackets.

The control of the actuator within a circuit breaker is carried out by utilizing electrical commands, either locally or remotely. The electrical signal activates the shunt trip or closing coils that in turn will activate the actuator, either closing or opening the breaker. Normally, also a mechanical control of the actuator to open the breaker is provided locally at the breaker, that is, the emergency trip. The traditional shunt coils can be replaced with an electronic circuit for actuator control. The important breakers, like the main power transformer feeders, at the higher distribution voltage levels are often equipped with duplicated tripping coils or corresponding electronic circuits.

For outdoor installations with a voltage level of 66 kV and up, the modern technology provides a possibility to combine the functionality of circuit breaker, disconnector and earthing switch into one physical component called disconnecting breaker. The circuit breaker construction has been modified to fulfill the disconnector requirements in the open position. The earthing switch is separately mounted on the same disconnecting breaker unit and interlocked with the main contacts position.

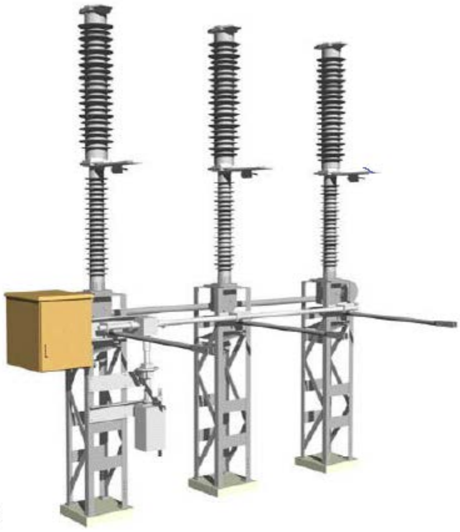


Figure 3.60: 66 kV Disconnecting circuit breaker with earthing switch

The fast and reliable operation of the circuit breaker is of paramount importance for the complete distribution system. Therefore the operation of the breaker is closely monitored by the protection and control system, that is, the IEDs and the upper-level systems. The modern IEDs are typically monitoring the following issues:

- Trip circuit continuity (both in open and closed positions)
- Breaker travel time (IED for fixed limits and upper-level systems for trends)
- Breaker stress (I^2t, in the view of maintenance intervals)
- Breaker's response to trip commands (breaker failure protection)
- Gas pressure or density in case of SF_6 type of breakers
- Actuator's energy storage charging current, like motor current with charged spring operation mechanism

Switching reactive loads, like shunt capacitors and unloaded power transformers, can be sometimes a source for undesired overvoltages or overcurrents. To overcome this problem, a device for synchronized switching can be introduced. This device will coordinate the breaker's control commands to perform the operation at the most advantageous time of the sinusoidal voltage waveform. With three-phase breakers, one of the phases is monitored by the device and the other phases have a 120-degree mechanical delay in their operation, thus the breaker has to be specifically tuned for this kind of operation.

3.15.7.2 Contactors

Medium-voltage contactors are used instead of circuit breakers typically in industrial indoor metal-enclosed switchgear applications up to 12 kV where the switching frequency is very high, like certain motor feeders for pumps and fans. The contactor is either the vacuum type or the SF_6-insulated one. Since the contactor cannot handle (break) the high fault currents associated with faults like short circuits, it is normally equipped with series HRC fuses. If the primary device, like motor, requires overload protection, the feeder in question can be equipped with a suitable protection IED. In such cases, the IED protection functions' settings will be coordinated with the contactor's breaking capability and the protective fuse characteristics.

Figure 3.61: A 12 kV vacuum-type contactor-mounted on a truck

3.15.7.3 Switch Disconnectors

The switch disconnectors, also called load disconnectors, are used either as fixed or truck-mounted switching devices in metal-enclosed indoor switchgears. The switch disconnector has a rated breaking capacity up to its rated nominal current, that is, the maximum load current, and it provides visual separation point fulfilling the requirements for isolation distance. The making capacity normally corresponds to the short circuit rating of the switch. The switch disconnectors can be either air-insulated or gas-insulated ones. The unit can be further expanded with series HRC fuses and with line-side earthing disconnector.

Figure 3.62: An air-insulated indoor switch disconnector with fuses for fixed mounting

The operation mechanism is typically of the charged spring type, where the energy needed for closing or opening operation is manually charged into the spring. The closing or opening sequence is initiated using local mechanical control. The unit can be equipped with electrical trip shunt coil, enabling a remote opening control of the main switch.

3.15.7.4 Disconnectors

Disconnectors are mechanical switching devices which provide an isolating distance and a visual separation gap in the open position. They are capable to open or close a circuit if both the negligible current is switched and there is no significant difference in the voltage between the terminals of the poles. Currents of negligible quantity have values ≤ 0.5 A; examples are capacitive charging currents for bushing, busbars and connections, very short lengths of cable and currents of voltage transformers. Disconnectors can carry rated currents under operating conditions continuously and under abnormal conditions, such as short circuit, based on their rated short circuit withstanding capability. Since the disconnectors are not designed to break or make current, they have to be interlocked with primary switching equipment, like circuit breakers, that are capable of making or breaking current. The interlocking can be realized with electrical or mechanical interlocking, or a combination of both. Earlier, a common practice was to employ overall substation-wide mechanical interlocking schemes, like a system called "castle-key" interlocking. Today, a common practice is to use overall electrical interlocking schemes, supported by mechanical interlocking between the switching equipment mounted on the same physical construction.

The classic design is the knife contact (single-break) disconnector, as shown in the following figure. Other designs intended mainly for outdoor use exist, like double break, single-center break and pantograph. In medium-voltage indoor switchgear installations, the need for separate disconnectors has become less common with the increasing use of withdrawable circuit breakers and switch disconnectors. With gas-insulated switchgears and outdoor installations, the disconnector is still a very common component.

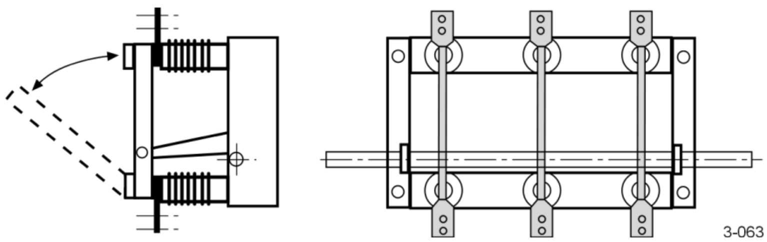


Figure 3.63: Medium-voltage indoor knife contact disconnector

Disconnectors can be actuated manually and, in remotely operated installations, by motor or compressed-air drives. Earthing switches are used for earthing and short-circuiting de-energized station components. Earthing switches can at their rated short circuit withstand currents under abnormal conditions, such as a short circuit, but they are not required to carry continuous load currents. The earthing switch can be also equipped with spring-charged closing device, making it capable of making fault currents, like in a case where the earthing switch is closed against an energized feeder. In general, earthing switches are combined with the adjacent disconnectors or switch disconnectors to form one unit. However, earthing switches can also be installed separately.

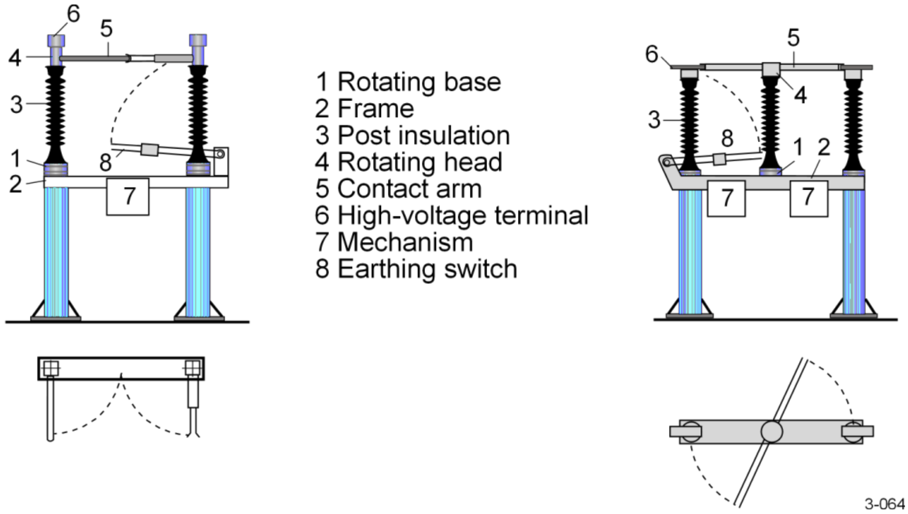


Figure 3.64: On the left a center single-break outdoor 66 kV disconnector with earthing switch and on the right a double-break outdoor 66 kV disconnector with earthing switch

3.15.8 Induction Machines

Induction machines, also called asynchronous machines, can be used as generators or motors. Induction machines can be either of one or three-phase construction. The following discussion focuses on the three-phase machines and their properties. Bulk of the applications for three-phase induction machines are with power ranges varying from a few kilowatts to a few hundred kilowatts with rated voltages below 1 kV. The range can be extended roughly up to 20 MW with rated voltages up to 15 kV. The simple, robust and low loss construction of an induction machine has contributed to its wide-spread success in different applications.

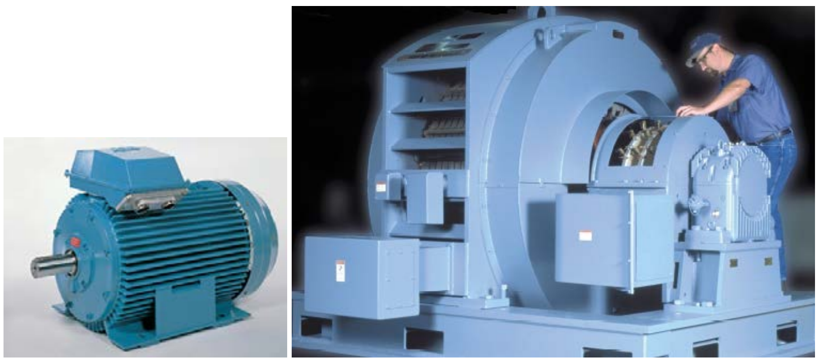


Figure 3.65: Examples of induction motors of different size. The left one is a 400 V, 15 kW squirrel cage motor and the right one is a 6 kV, 5 MW wound winding rotor motor with slip rings

The stator has basically the same construction as with synchronous machines. It is fed by three-phase alternating current providing rotating flux. This flux rotates at synchronous speed.

$$n_s = \frac{120f}{p} \tag{3.27}$$

$$\omega_s = \frac{4\pi f}{p} \tag{3.28}$$

Where

f	is the network frequency [Hz]
p	is the number of the poles in the machine [1]
n_s	is the synchronous speed [rpm]
ω_s	is the synchronous angular velocity [rad/s]

The rotor is a three-phase short-circuited winding. This winding can be a normal wound winding or it can be done by casting aluminum "cage" windings into the slots in a laminated iron rotor construction. In the earlier case, it is referred to as "wound rotor machine," and in the latter case, it is referred to as "squirrel cage rotor machine."

The rotating stator field induces a flux in the rotor windings. Since the rotor windings are short-circuited, the induced flux will create a current in the rotor. This current will produce a flux of its own, opposing the flux that created it. As a result, there will develop a torque on the machine shaft. When the developed torque is higher than the resisting load torque, the machine starts to rotate as a motor.

During operation, under no-load conditions, the speed of the rotor is very close to the synchronous speed, thus the currents induced in the rotor will have a low frequency. The rotor currents will have a frequency corresponding to the rotating speed difference between stator field and rotor (shaft). This difference is referred to as slip. Normally, the slip is stated in relation to the synchronous speed i.e. relative slip (s).

$$s = \frac{\Delta\omega}{\omega_s} = \frac{\omega_s - \omega}{\omega_s} = \frac{n_s - n}{n_s} \tag{3.29}$$

When the slip is positive, the machine is working as a motor, and when it is negative, the machine is working as a generator. The slip is often given as percentage value $s_{\%}$.

$$s_{\%} = 100 \times \frac{\Delta n}{n_s} = 100 \times \frac{n_s - n}{n_s} \tag{3.30}$$

The name "induction machine" comes from the fact that the induced voltage in the rotor windings is due to the rotating stator field, whereas the term "asynchronous machine" refers to the fact that the rotor is always rotating at a different speed than the stator field.

The performance of an induction machine can be studied based on a one-phase equivalent circuit.

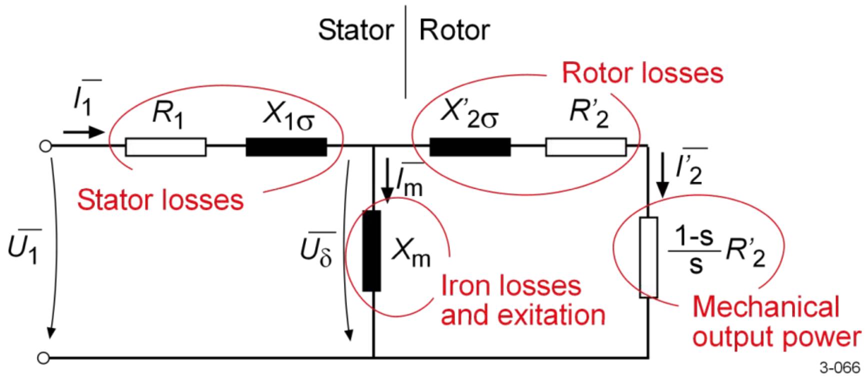


Figure 3.66: **Equivalent circuit of an induction machine**

Above

U_1	is the phase voltage [V]
I_1	is the phase current [A]
R_1	is the stator resistance [Ω]
$X_{1\delta}$	is the stator leakage reactance [Ω]
X_m	is the exciting reactance [Ω]
I_m	is the exciting current [A]
U_δ	is the air gap voltage [V]
R'_2	is the reduced rotor resistance [Ω]
$X'_{2\delta}$	is the reduced rotor leakage reactance [Ω]
I'_2	is the reduced rotor current [A]

The reduced rotor current flowing through the slip-related rotor resistance component describes actually the mechanical power developed at the rotor shaft at each operation point. Also the rotor leakage reactance value is depending on the slip, since the rotor current frequency is depending on the slip. Under light load conditions the significance of the rotor leakage reactance is negligible, but the situation will change as the load, and slip, increases.

Without going further into the induction motor theory, it can be stated that the above equivalent circuit gives the basis for studying motor performance under different conditions. As a result, a typical torque-versus-slip characteristic of a three-phase induction motor is presented. From the below figure, it can be seen that when the load torque requirement rises, the slip increases until a point of equilibrium is found. The torque can be increased until the breakdown torque point is reached, and sliding on the left hand side of this point with a constant-load torque would mean stopping of the motor. It can be also noted that the starting torque is much less than the maximum, breakdown, torque. Also the rated torque of the motor is below the maximum, at least by a relation of 1.6.

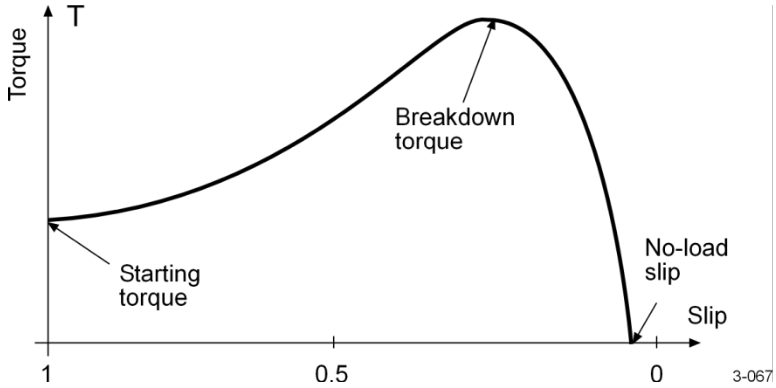


Figure 3.67: Torque as a function of slip with a three-phase induction motor

The shape of torque curve is heavily dependent on the stator resistance. By the motor design it is possible to affect the rotor resistance in order to form the torque curve towards the desired shape. The following simplified equation of motor torque T_m describes the dependence:

$$T_m = 3I_2^2 \frac{R_2}{s\omega_s} \qquad \textbf{(3.31)}$$

At the motor starting, the slip is equal to 1, so the starting torque is T_s [Nm]:

$$T_m = 3I_2^2 \frac{R_2}{\omega_s} \qquad \textbf{(3.32)}$$

Increasing the rotor resistance increases the starting torque, and this lowers the torque curve gradient between no-load and breakdown torque points. On the other hand, the rotor resistance does not affect the maximum, breakdown, torque value.

This phenomenon is utilized with induction motors having wound winding-type rotor with slip rings. External variable resistance is connected to the non-short-circuited rotor windings using the slip rings. By adjusting the external resistance, it is possible to increase the starting torque, lower the starting current and within certain limits to control the motor speed. The drawbacks are the losses in the external resistor, limited speed adjustment range, speed variations with variable torque (load) and more complex structure of the motor.

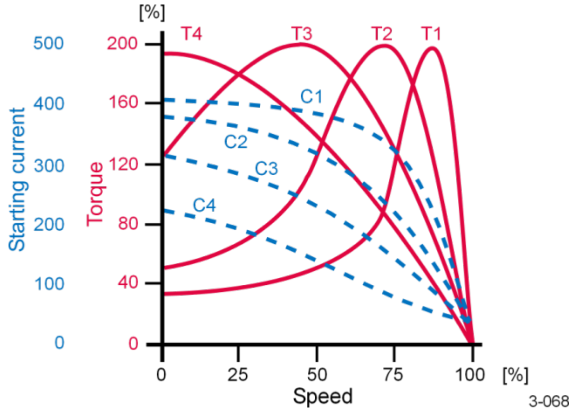


Figure 3.68: Torque and starting current as a function of motor speed with a slip ring induction motor [3.21]

The above figure describes the behavior of torque and starting current as a function of motor speed with a wound type of rotor winding using different values of the external rotor resistance. Torque and current curves (T&C) from 1 to 4 refer to different resistance value, index 1 having the lowest value and index 4 having the highest value. From the figure it can also be seen that if the motor in question is loaded with its rated torque, the speed can be varied roughly between 75 to 95% of the synchronous speed by adjusting the rotor resistance.

Other possibilities to control the rotation speed of the motor are double stator windings and frequency control.

Introducing double windings inside the stator actually gives the possibility to choose, by external switching, the number of poles out of two options. As learned earlier, the number of poles determines the synchronous speed of the motor.

Another factor that has a direct impact to the synchronous speed is the frequency. The most typical way nowadays to control the motor rotation speed is by adjusting the frequency.

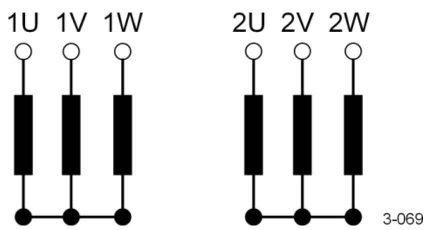


Figure 3.69: Terminal markings of double-speed (double-winding) induction motor; Higher numbers refer to a lower number of poles, thus a higher synchronous speed

The starting current during direct starting of an induction motor varies a lot based on the machine properties and size. As some kind of a guiding principle, a range from 5 to 8 times the rated current can be used. As we already learned, the adjustment of the rotor resistance by external resistors is one way to handle the situation, but this can be applied only to a machine with slip rings. Other means to cope with the situation are star/delta starting, soft starters and frequency converters. Whichever method is chosen, the effect to the starting torque with reference to the actual load has to be taken into account.

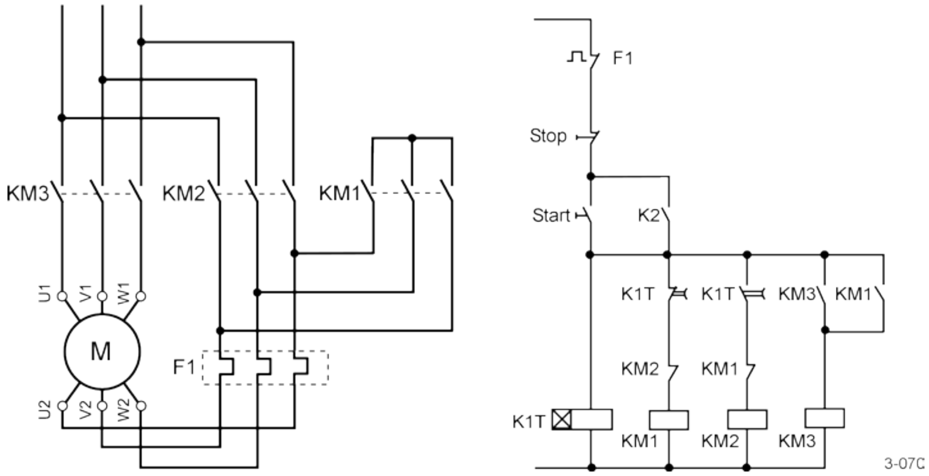


Figure 3.70: Star/Delta induction motor primary and control circuit

The star/delta starting method is quite common with low-voltage squirrel cage induction motors when connected to a relatively weak supply network. The motor is started with the stator windings as star-connected and after it has reached its rotating speed (time delay) the connection is automatically changed to delta. Using this method, the starting current can be lowered to a level of approximately two times the delta connection rated current. Equally, the starting torque is ¼ of the delta connection rated starting torque.

As noted earlier, the induction machine can work as a motor or as a generator. With generator applications, the slip is positive, i.e. the prime mover rotates the generator slightly above the synchronous speed. The active power production is adjusted by controlling the prime mover torque, thus adjusting the slip. The reactive power needed for generator excitation is taken from the network and can be compensated locally with a capacitor bank. The shape of the torque curve is similar as with motor applications. The control features of an induction generator can be significantly improved using frequency converters in between generator and network.

3.15.9 Synchronous Machines

Synchronous machines can be used as generators or motors. They are of three-phase construction, even though some special exceptions can be found. A bulk of the applications are within power ranges roughly varying from a megawatt level to several tenths (or even hundreds) of megawatts with rated voltages from 3 kV to 15 kV. Special designs of the HV synchronous machines have also been introduced whose rated voltages can be of several tenths of kilovolts.

More complicated construction, control and protection demands of synchronous machines resulting higher unit costs limit the use of synchronous machines on lower output power levels. On the other hand, the excitation control features cater for more flexible means of operating the machine with the optimal reactive power flow according to the network conditions.

Figure 3.71: Reciprocating compressor motor 24 MW

The armature winding is commonly placed in the stator whose construction is of the three-phase design and quite similar to asynchronous machines. The field winding is placed in the rotor whose design is quite different from the ones in asynchronous machines. Two different basic designs can be separated, namely round or cylindrical and salient pole. The round or cylindrical designs are used in machines operating on high speed, whereas the salient pole design is used in machines operating on slow or moderate speed. A typical example of slow-speed applications is a hydro power plant generator, whereas a steam turbine generator would represent an example of high-speed applications.

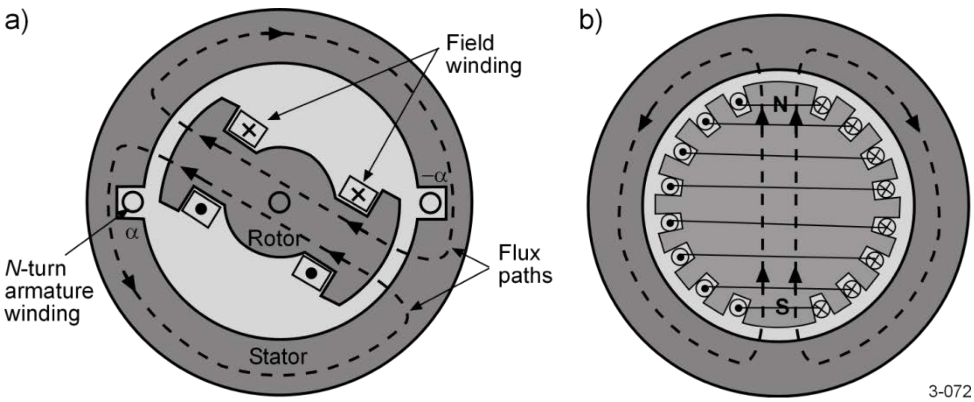


Figure 3.72: a) salient pole rotor b) round or cylindrical rotor

The rotor is excited through the field winding with a DC-power source. In motor applications, the excited rotor rotates according to the speed of the three-phase AC-field in the stator. In generator use, the prime mover rotates the excited rotor generating an emf to the stator windings, whose magnitude and frequency correspond to the excitation power in the rotor and the rotating speed of the prime mover. Under normal operation conditions, the rotating field in the stator and rotating rotor remain in synchronism. Unlike with asynchronous machines, the difference slip between rotor and rotating field speed in stator is an indication of abnormal operation situation and must be dealt with immediately. The synchronous speed n_s [rpm] is given by equation (3.33) below.

$$n_s = \frac{120 f}{p} \tag{3.33}$$

The synchronous angular velocity ω_s [rad/s] is given by equation (3.34)

$$\omega_s = \frac{4\pi f}{p} \tag{3.34}$$

Here

f	is the network frequency [Hz]
p	is the number of poles in the machine [1]

Some synchronous machines rely on brushes for delivering the DC-current to the rotor for excitation. A more modern solution is the so-called brushless design, where the needed power is transferred to the rotor by induction and the rectifying takes place in the rotor itself. For some applications, like for really low rotating speeds, the solution utilizing permanent magnets in the rotor is suitable. For generating the power for excitation purposes, PMGs are commonly used. PMG stands for Permanent Magnet Generator. The PMG works as a pilot generator connected to the main generator’s shaft, supplying the power for the main generator’s excitation.

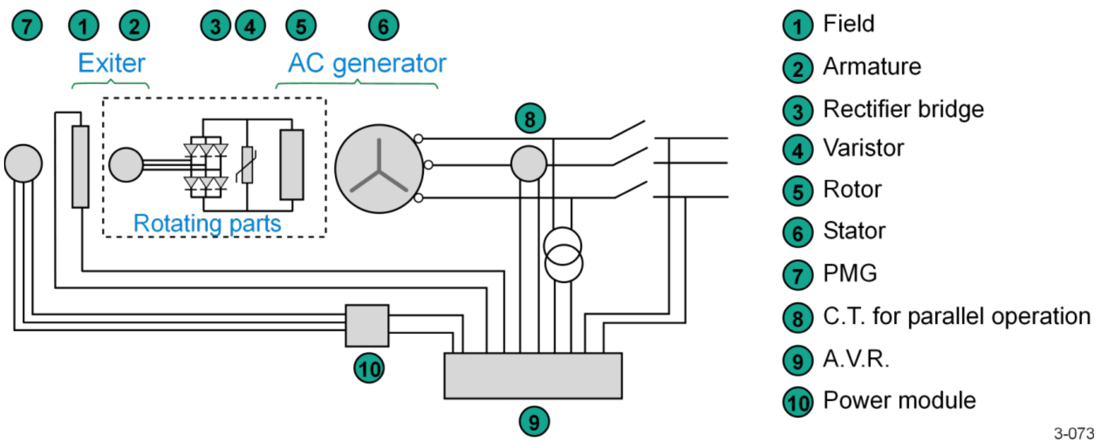


Figure 3.73: Synchronous AC generator with PMG excitation

With a single synchronous machine running as generator, the control of the output voltage is carried out by controlling the excitation. Increased excitation current will result in a higher output voltage, and vice versa. The frequency control of the output voltage is carried out by controlling the running speed of the prime mover.

When the generator is connected in parallel to a strong network, excitation control changes only the reactive power output of the generator. An increase of the excitation current makes the generator produce more inductive reactive power, thus compensating the inductive loads. A decrease in excitation ultimately leads to a situation where the generator starts to absorb inductive reactive power from the network. This situation is referred to as "underexcitation " and is not a normal operation mode of the generator.

The increase in prime mover’s torque cannot increase the rotation speed of the generator, since it is electrically coupled to the strong network. Instead, it increases the active power output of the generator. If the prime mover torque is decreased below the level of rotating losses of the generator, the generator starts to work as a motor trying to rotate the prime mover with the synchronous speed. This situation is referred to as reverse power operation. The reverse power operation is harmful to the generator and also to the prime mover, thus the situation has to be recognized by the protection relays.

The following figure shows an example of synchronous generator’s capabilities and constructional limitations for operation under different conditions. A normal operation is carried out overexcited, injecting reactive and active power to the network.

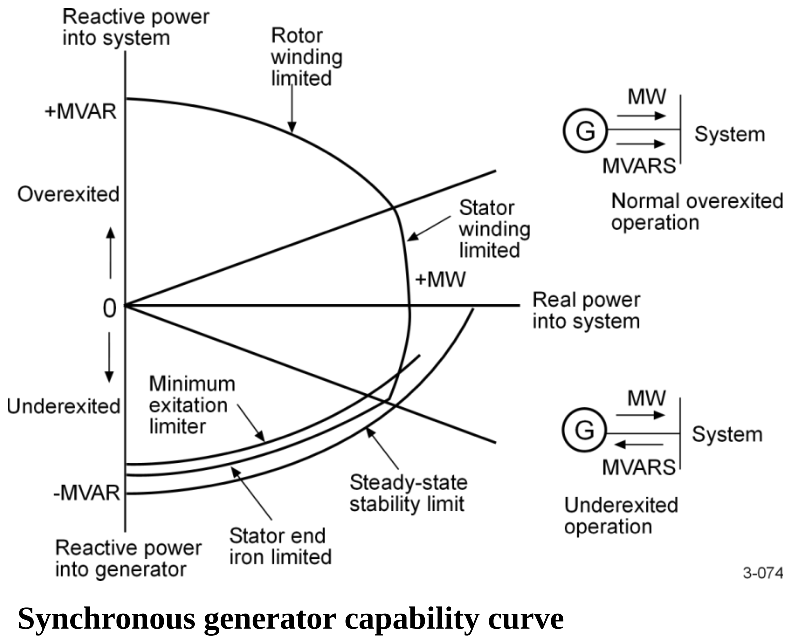


Figure 3.74: Synchronous generator capability curve

When a synchronous generator is started, it is speeded up with the prime mover close to the network frequency and the excitation current is applied to reach the nominal terminal voltage. After this, the automatic synchronizer takes over the actual network connection procedure. The synchronizer adjusts the excitation current so that the generator’s terminal voltage matches the network voltage. The synchronizer also checks the phasing and adjusts the prime mover speed to match the generator frequency with network frequency. In fact, the synchronizer adjusts the generator's frequency to climb towards the network frequency and closes the breaker when the frequencies have met but the generator frequency is still climbing. This is to ensure that the generator starts producing active power right after network connection has taken place, otherwise the reverse power protection relays would disconnect the generator from the network.

The construction of a synchronous generator and motor are basically identical, except regarding the external connections. The synchronous motor is not synchronized against the network in similar ways as with the synchronous generators. The simplest way to connect a synchronous motor to the network is the so-called Direct On-Line (DOL) starting, where the motor is started as an induction motor. The motor is "pulled" into the network with approximately 5% slip. Figure 3.75 describes other starting methods too. The selection of the starting method depends on several criteria, like:

- Required load torque during starting sequence
- Voltage drop in the supplying network during starting
- Permitted starting time (thermal stress to rotor)
- Number of starts in a time period

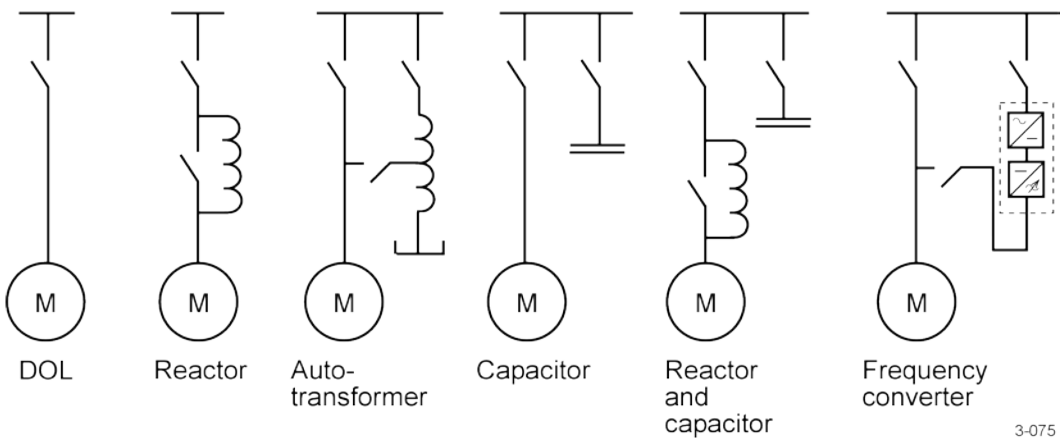


Figure 3.75: Different starting methods for a synchronous motor

The capability to control the reactive power output of a synchronous machine becomes a handy feature also in motor applications. By controlling the excitation of the synchronous motor, it is possible to compensate the variable reactive power needs in an industrial plant, thus minimizing the need of additional compensation devices.

Special application of a synchronous motor is a setup where the motor does not supply any active power from its drive shaft, but it is used only to inject reactive power into the network. This kind of synchronous machine is called synchronous condenser. Today, the synchronous condensers are replaced with SVC devices, as explained in Section 3.15.6.

- Brushless synchronous machines
- Excitation / reactive power / voltage control
- Prime mover / active power / frequency control
- Permanent magnet motors (generators)

3.15.10 Distributed Energy Converters

The development of power electronics has also made possible a large variety of applications where the power converters play an essential role. With converters, the electric power is transformed from one form to another. The basic conversion is from AC to DC (rectifier) or from DC to AC (inverter). A frequency converter combines these two basic conversions.

The converters are becoming more common devices also in power distribution systems due to the increasing amount of small distributed generation (DG). DG is in many cases based on energy sources that are inherently DC sources, e.g., fuels cells or photovoltaic (PV). In order to feed the power from these kinds of sources to the grid, an inverter is always needed. Converter-based grid interfaces are also necessary in wind power generation systems when the so-called variable-speed concepts are being used. Allowing variations in wind turbine speed means an increased efficiency as well as decreased power fluctuations.

Depending on the size of the generating unit, the inverter may be either three-phase (see Figure 3.76) or single-phase. Furthermore, the inverters are divided into two classes: line-commutated and self-commutated. Line-commutated inverters are based on thyristors and thus they are the simplest and the least expensive inverters [3.1]. On the other hand, line-commutated inverters produce a large amount of harmonics and require also some reactive power supply from the grid. Therefore, this technology is nowadays applied only in very large units, for which there is not yet suitable self-commutated designs.

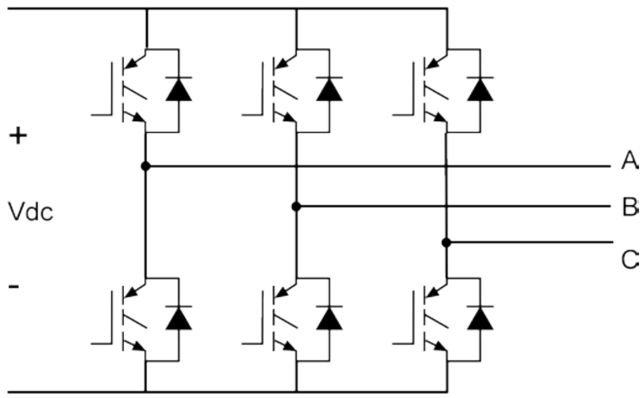


Figure 3.76: Three-phase IGBT inverter

In the self-commutated inverter circuits, the power electronic devices from the category of *controllable switches* are applied. This means that these devices can be turned on and off by an external signal. Devices included in this category are, e.g., metal-oxide semiconductor field-effect transistors (MOSFET), gate turn-off thyristors (GTO) and insulated gate bipolar transistors (IGBT), the last one being the most common in new applications. [2]

The switches of the self-commutated inverter can be controlled applying different control schemes. One of the most common is the PWM (pulse width modulation), but the so-called vector control schemes are preferred when rotating machines are involved.

From the network point of view, the key characteristics of the inverter-based generating units are related to the power quality and to the network protection issues. Depending on the design, inverters produce various amounts of harmonics. Thus, suitable filters must be accompanied. However, modern switching schemes of self-commutated inverters also include an active filtering function, which means that the inverter can also be used to actively cancel out the harmonics in the network. The reactive power output from the self-commutated inverters can be adjusted independently from the active power so that they can also be used for maintaining the reactive power balance or mitigating the network voltage fluctuations.

From the network protection point of view, one issue related to inverter-based small-scale generation is that these units are typically not capable to produce any significant short circuit current. IEC standard [3] assumes that the short circuit current is three times the rated current. However, in many cases the maximum fault current is limited to about twice the rated current in order not to damage the sensitive power electronic components. This aspect must be considered when designing the system overcurrent protection.

3.16 Instrument Transformers and Sensors

Instrument transformers and sensors are used to provide a secondary signal that is proportional to the actual prevailing primary value. These signals are used to supply measuring instruments, meters, relays and other similar apparatuses. The primary values measured are system currents and voltages. The secondary signal available has to fulfill the following criteria:

- Standardized nominal value
- Minimum ratio and phase displacement errors
- Capability to supply the power needed by the secondary protection and measurement devices
- Necessary insulation level against the primary circuits
- Predictable performance under primary system normal conditions and specially under abnormal conditions

The detailed demands for the secondary signal behavior are depending on whether it is used for protection or measurement purposes. In measurement circuits, the key issue is to produce a secondary signal that is following the primary value as correctly as possible over the whole normal load range of the installation in question. Whereas with protection circuits, the emphasis is in the capability to follow the primary value's dynamics as high (or low) as possible during power system faults and disturbances.

Since the protection and measurement circuits have different demands for the instrument transformers' secondary signal behavior, it is obvious that these demands cannot be met with a single secondary output from the transformer. One solution of course would be to install totally different transformers for the two different applications, but this would not be possible from the economical and space requirement point of view. So, the solution is to provide one transformer with several secondary cores suitable for different purposes or utilize a sensor measurement technique. These two different approaches will be covered in more detail in the following.

3.16.1 Magnetic Current Transformers

The primary winding is a part of the network, carrying the actual load current. The transformer's secondary circuits usually consist of several units, each of them having its own magnetic core and winding. The transformer has a rated current transforming ratio, like for example 200/1 A, stating the rated primary current and the corresponding rated secondary current. It is often desired that the transformer should have multiple ratios. This can mean that all or some of the windings have more than one ratio from which to choose. The selection of the desired ratio can be done on site and changed later if so needed. For doing current transformers with multiple ratios there are two possibilities, namely primary re-connectable or secondary re-connectable.

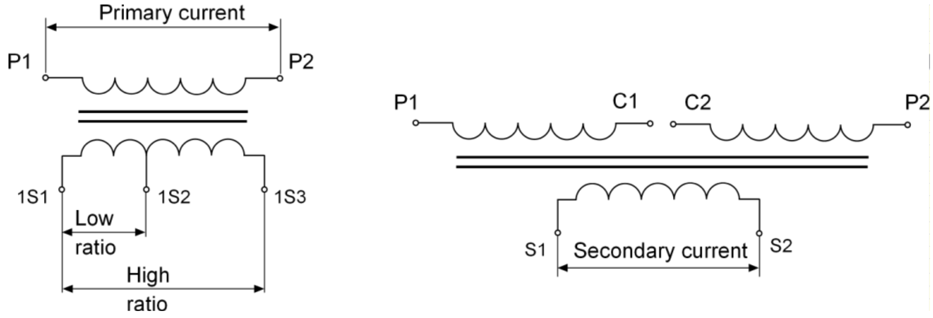


Figure 3.77: Secondary re-connectable (left) and primary re-connectable (right) current transformer winding presentation

Primary re-connectable means that the primary circuit connection has to be changed to change the ratio. Usually only two connection alternatives exist having a ratio of 2:1. An example below:

- <u>200</u> – 400 / 1/1 A

The ratio can be selected to be either 200/1 A or 400/1 A. The selection affects all the secondary windings. The secondary core data, except for the ratio, remains the same with either of the ratio selections. The underlined value shows the presently utilized ratio.

Secondary re-connectable means that the ratio can be changed by utilizing tappings in each of the secondary cores. More than two ratio alternatives can exist, with uneven ratios. An example below:

- 600/1+<u>200</u>-300-400/1/1 A

One of the cores (600/1 A) is having a fixed ratio, whereas with the two other cores the ratio can be selected by means of a secondary re-connection. The secondary core data will change along with the ratio selection. The underlined value shows the presently utilized ratio, where the selection possibility exists.

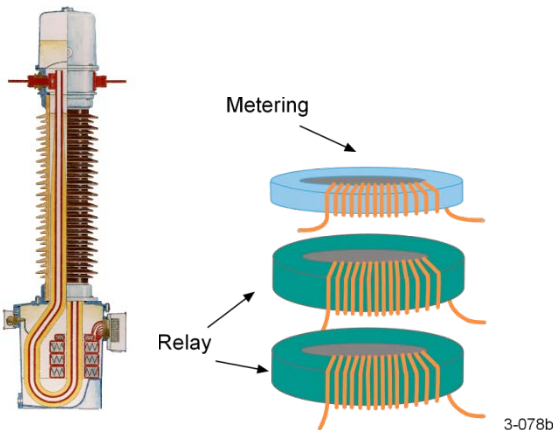


Figure 3.78: A 66 kV outdoor-mounted oil-insulated one-phase current transformer with three secondary cores

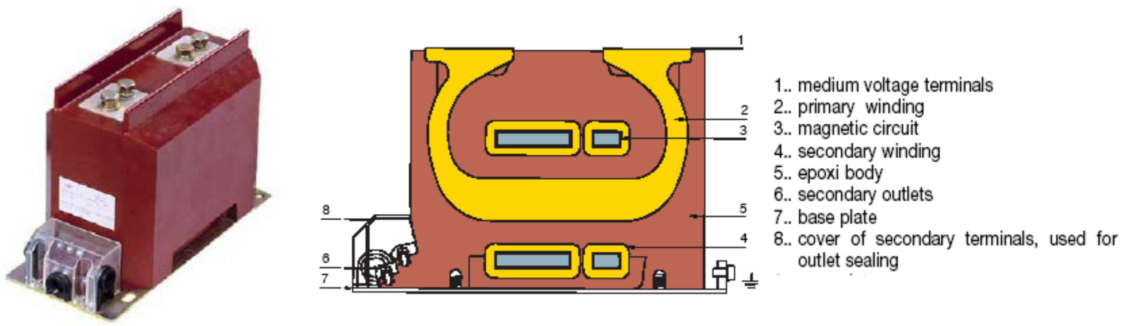


Figure 3.79: **A 12 kV indoor epoxy resin-cased one-phase support current transformer with two secondary cores**

With an ideal current transformer under short-circuited conditions, there is always a balance with the ampere turns, meaning that the product of primary current and primary winding turns equals the product of secondary current and secondary winding turns.

$$I_1 \times N_1 = I_2 \times N_2 \qquad (3.35)$$

Error! Bookmark not defined.

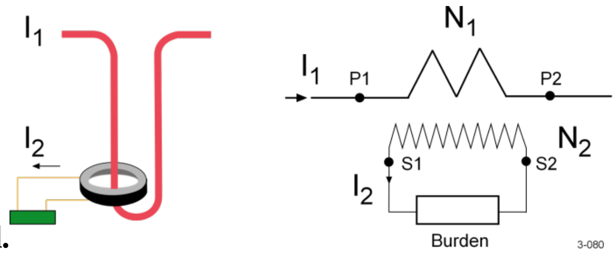


Figure 3.80: **Principle presentation of a magnetic current transformer**

The behavior of current transformers and the conformities to basic electrical laws can be demonstrated by the use of equivalent circuit shown below.

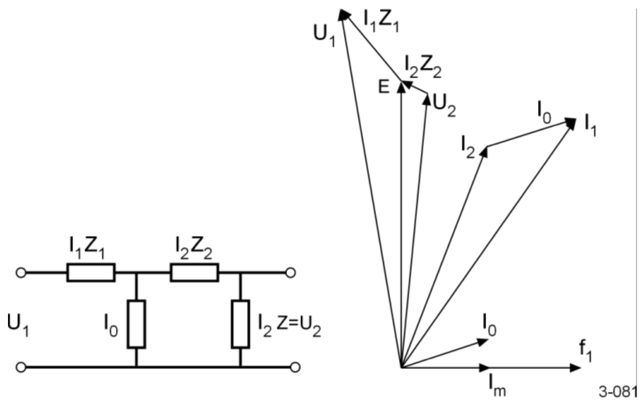


Figure 3.81: **Equivalent circuit of a magnetic current transformer**

From the above equivalent circuit, it can be seen that with a non-ideal transformer there are always some errors included in the measurement. These errors are mainly caused by the excitation current (Ie) and the load current (I_2), which introduces both ratio errors and angle errors between the reduced primary current and the actual secondary current. It can also be further observed that if the CT secondary side is left open-circuited (infinite burden connected), the whole primary current starts to excite the CT, resulting in overloading and induced dangerous voltage in the secondary terminals.

The detailed core data describes the core performance with respect to the intended application. This data can be expressed according to guidelines of one of the several international standards, like IEC, British Standards or IEEE. The following is based on the standards provided by IEC [3.14].

The issue is approached through an example. It is assumed here that a three-phase current transformer set, having the below shown data labels, is used for energy measurement and overcurrent protection.

200 – 400/1/1A		
1S1-1S2	5VA cl.0.5	Fs5
1S1-1S3	10VA cl.0.5	Fs5
2S1-2S2	10VA	5P10
2S1-2S3	20VA	5P10
12/28/75kV 50Hz		40(1s)/100kA

200-400/1/1A

The transformer has dual-ratio re-connection (from secondary) possibilities and two secondary cores. The rated primary current is either 200A or 400A. The rated secondary current is 1A. If not otherwise stated, the maximum continuous allowed primary current is the same as the rated primary current. In some cases, it is specially stated that the maximum allowed continuous current is for example 120% of the rated primary current.

1S1-1S2 5VA cl. 0.5 Fs5

1S1-1S3 10VA cl. 0.5 Fs5

The first secondary core is for measuring. The ratio selection between 200/1A and 400/1A is made by the secondary re-connection. Connection between 1S1 and 1S2 gives a ratio of 200/1A whereas 1S1 and 1S3 gives a ratio of 400/1A.

The accuracy class of this measuring core is 0.5. To comply with this accuracy class, the transformer has to fulfill certain requirements regarding current error and phase displacement error as shown below. These limits apply to secondary burdens between 25-100% of the rated burden.

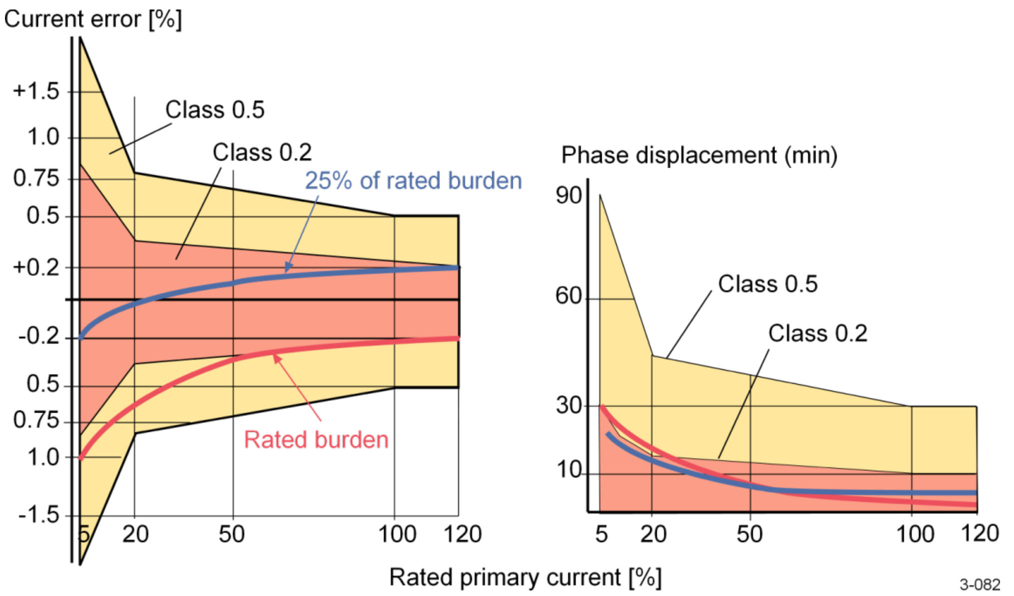


Figure 3.82: Current transformer measurement requirements for classes 0.5 and 0.2 according to IEC standards. Plotted lines show the behavior of the transformer used in above example

The secondary rated burden of the measurement core is changing according to the used secondary re-connection (tapping). With the highest ratio (400/1A) the rated burden is 10VA and with the lowest ratio (200/1A) the rated burden is 5VA.

The instrument security factor (Fs) describes the transformer's saturation with rated primary current multiples. This is an important factor for securing the capability of the connected measuring devices to withstand the injected currents during power system faults. Primary current of magnitude five times (Fs 5) the rated primary current causes a combined error of at least 10%. The protective feature for measurement devices is the better the lower the overcurrent limit factor is. It should be further noticed that the given overcurrent limit factor value applies with the stated rated burden and is subject to change if the actual burden differs from the rated burden.

- 2S1-2S2 10 VA 5P10
- 2S1-2S3 20 VA 5P10

The second secondary core is for protection. The ratio selection between 200/1A and 400/1A is made by the secondary re-connection. Connection between 1S1 and 1S2 gives a ratio of 200/1A whereas 1S1 and 1S3 gives a ratio of 400/1A.

The secondary rated burden of the measurement core changes according to the used secondary re-connection (tapping). With the highest ratio (400/1A) the rated burden is 20VA and with the lowest ratio (200/1A) the rated burden is 10VA.

The marking 5P10 is a combination of two things, namely the accuracy class of 5P and accuracy limit factor of 10. The complete marking 5P10 indicates that the composite error will not exceed 5% with ten times the rated primary current when the rated secondary burden is connected. The accuracy limit factor changes in relation to the actual connected burden. For example, if the ratio of 400/1A was used and the total connected actual burden, including all leads and connected devices, was 15VA, the accuracy limit factor would then result as follows:

$$\frac{20}{15}\times 10 \approx 13.3 \text{ (Actual accuracy limit factor)}$$

If the ratio of 200/1A was used instead, the actual accuracy limit factor would be:

$$\frac{10}{15}\times 10 \approx 6.7 \text{ (Actual accuracy limit factor)}$$

12/28/75kV

12 kV is the highest voltage for the equipment (RMS value). 28kV is the rated power frequency withstanding voltage (RMS test value). 75kV is the rated lightning impulse withstanding voltage (peak test value).

40(1s)/100kA

This states the short thermal current withstanding level being 40kA/1s (RMS) and the dynamic current withstanding level being 100kA (peak value).

3.16.1.1 Measurement of Residual Current

The measurement of the residual (earth fault) currents on a distribution system feeder can be done by the so-called summation connection, where the three current transformers, one in every phase, are connected and the summated current is brought to the inputs of an earth fault protection relay. This is a convenient method for cases where the level of the earth fault current is relatively high, i.e. directly earthed systems. When the level of the fault current to be measured starts to decline heavily, the measurement sensitivity and accuracy that can be reached with this summation connection is no longer sufficient. The measurement accuracy is affected by the fact that the three different current transformers, even with similar core data, start to introduce different kind of errors when it comes to ratio and phase displacement. These errors are summated together in the summation connection, and in the worst case they are cascading on top of each other. The sensitivity is affected by the fact that current-transforming ratio of the phase current transformers is mainly selected based on the maximum load currents, whereas the anticipated earth fault currents can be only some fractions of those.

To overcome the accuracy and sensitivity requirements with low earth fault currents, a cable, also called a window-type, current transformer can be utilized. Following figures describes the installation.

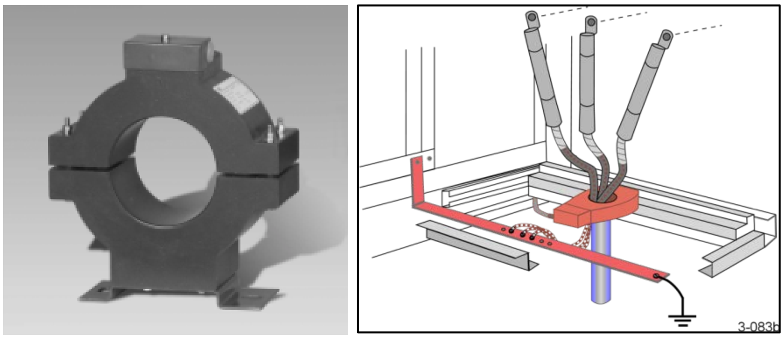


Figure 3.83: Cable CT and a typical installation

In the figure above, a cable current transformer is utilized for measuring the residual (earth fault) current of an outgoing three-phase cable feeder. The CT type used is a one that can be installed even after the medium-voltage power cable installation is done, by opening the bolted connections and separating the CT into two parts. It is important to notice that the medium-voltage power cable screen earthings are drawn back via the CT's window before connecting them to the earthing bar. Similarly, it is important to notice that if a separate "escort earthing" wire is installed alongside the power cable, it may not pass through the CT's window.

The suitable current-transforming ratio of the cable current transformer is depending on the actual anticipated earth fault current levels. As an example, the ratio of 70/1A is commonly used for earth fault protection in Finland with unearthed and resonant earthed systems. The cable current transformer can also have several ratios by utilizing different tappings in the secondary side, as shown below.

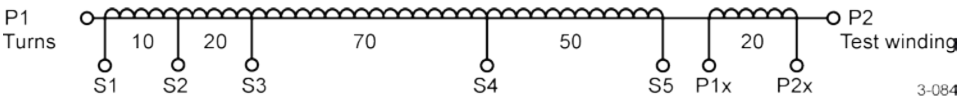


Figure 3.84: A cable CT with several ratio possibilities

When the earth fault protection relay is connected to a certain secondary tapping of the CT, the remaining tappings should not be shorted. This applies also to the test winding tappings. On the other hand, if the cable CT has several cores utilizing separate iron cores inside the CT, each of the cores has to either be connected to a secondary device or short-circuited and earthed.

3.16.2 Magnetic Voltage Transformers

The primary winding is affected by the actual network voltage at every instant of time. This primary voltage value is then converted to a secondary voltage value based on the rated voltage-transforming ratio of the voltage transformer. The most common connection of the voltage transformer is between each phase and the ground separately (single pole), thus the value measured is the phase-to-earth voltage value. In certain applications, the connection between phases (double-pole) is also used. The third variant would be a three-phase unit where the three-phase units are in one physical enclosure and the phases are star-connected against earth. Like with the current transformers, a number of separate secondary cores are used for measuring and protection purposes. It is also possible to use one core for both measuring and protection. Unlike with current transformers, the voltage transformers normally cater for one fixed transforming ratio, and special designs with double transforming ratios can be employed based on the individual application needs. The rated secondary AC voltage levels are usually either 100 V or 110 V, though also others exist, mainly in countries under the ANSI standard influence.

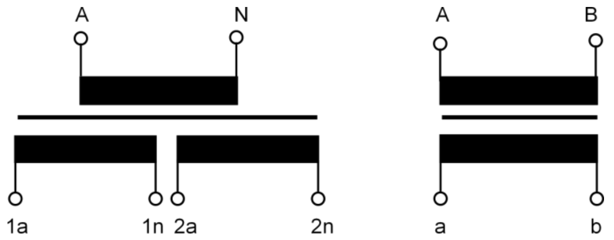


Figure 3.85: Representation of a single-pole (on the left) voltage transformer with two secondary cores and a double-pole (on the right) with one secondary core

The most common type of a voltage transformer on the distribution side is a set of three single-pole ones having two separate cores, namely the star-connected one for measuring purposes and the broken-delta-connected one for residual voltage measurement.

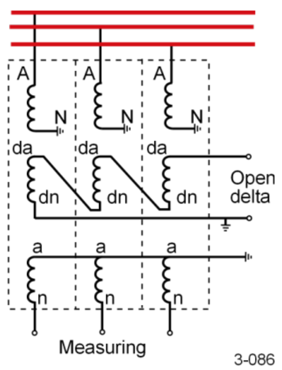


Figure 3.86: A set of three single-pole VTs having two secondary cores

The secondary circuits of a voltage transformer have to be protected with fuses or miniature circuit breakers. These protection devices should be mounted as close to the voltage transformers as possible. If there is a load resistor connected to the open-delta core of the voltage transformer for damping oscillation caused by the ferroresonance phenomenon, the resistor has to be connected to the voltage transformer side of the secondary circuit protection device.

The ferroresonance phenomenon, referred to in the previous paragraph, is due to the resonance circuit formed by the single-pole VT inductance to earth and the unearthed system capacitance to earth. This resonance circuit can cause oscillations resulting in heating, and finally damaging, the voltage transformers. To damp down these oscillations, a load resistor is connected across the open-delta winding. These problems are most likely to occur in unearthed systems with minimum feeder length connected.

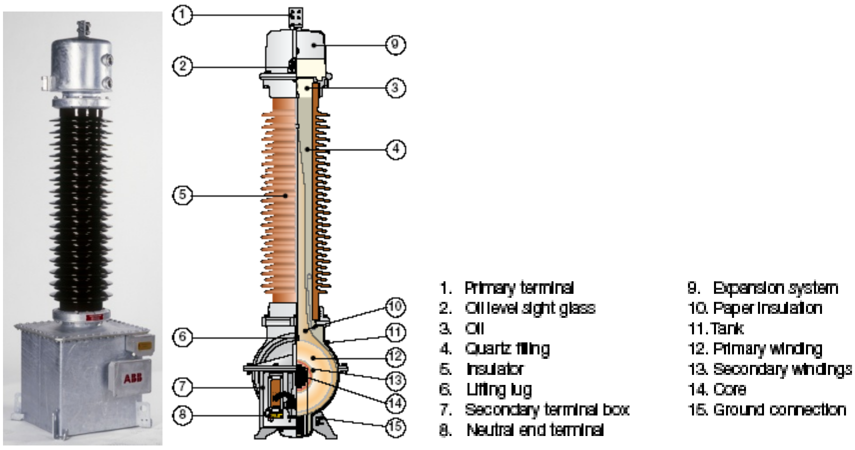


Figure 3.87: **A 66 kV oil-insulated outdoor-type one-pole magnetic voltage transformer**

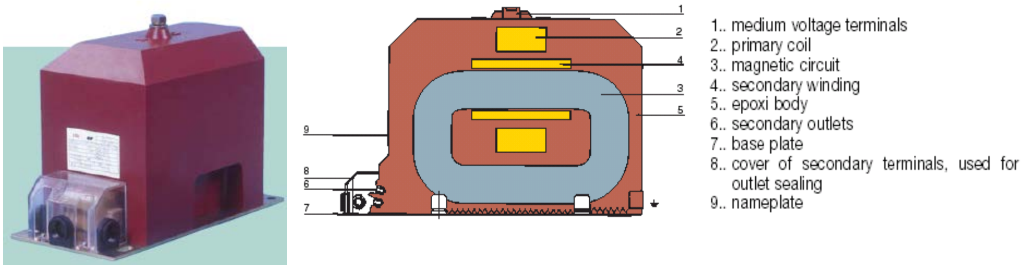


Figure 3.88: **A 12 kV indoor epoxy resin-cased one-pole magnetic voltage transformer**

With an ideal voltage transformer, the ratio between the primary and secondary voltage always equals the ratio between the primary and secondary winding turns.

$$\frac{E_1}{E_2} = \frac{N_1}{N_2} \qquad (3.36)$$

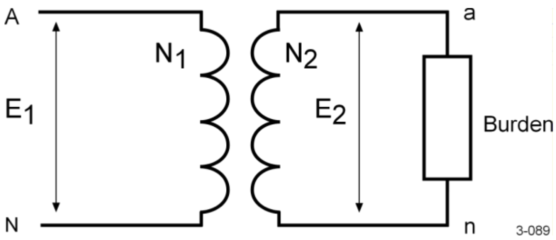


Figure 3.89: **Principle presentation of a magnetic voltage transformer**

The behavior of voltage transformers and the conformities to basic electrical laws can be demonstrated by the use of equivalent circuit shown below.

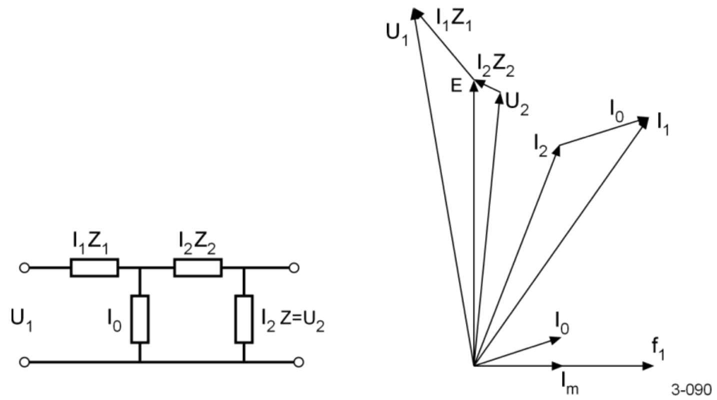


Figure 3.90: Equivalent circuit of a magnetic voltage transformer

From the above equivalent circuit, it can be seen that with a non-ideal transformer there are always some errors included in the measurement. These errors are mainly caused by the excitation current (Io) and the load current (I_2), which introduces both ratio errors and angle errors between the reduced primary voltage and the actual secondary voltage.

The detailed core data describes the core performance with respect to the intended application. This data can be expressed according to the guidelines of one of the several international standards, like IEC, British Standards or IEEE. The following is based on the standards provided by IEC [3.15].

The issue is approached through an example. It is assumed here that a three-phase set of one-pole voltage transformer, having the below shown data labels, is used for energy measurement and residual overvoltage protection.

6600:√3/100: √3/100:3V	
a - n	30VA cl.0.5
da - dn	100VA cl.6P
50Hz 400VA	
7.2/20/60kV	
1.9xUn 8h	

6600:√3/100: √3/100:3V

These values determine the rated voltage ratio. The voltage transformer is a single-pole one intended for phase-to-ground voltage measurement. The rated primary voltage is 6600:√3V and the rated secondary voltages are 100:√3V and 100:3V. The first secondary core is intended for a star connection giving out the phase-to-ground voltage signal on 100: √3V (approximately 57.7V) bases. The second secondary core is intended for a residual voltage measurement utilizing open-delta connection on 100:3V (approximately 33.3V) bases. Under full (fault impedance is zero) earth fault situation in unearthed systems, the measured value from open-delta connection would be approximately 100V.

The marking a - n 30VA cl.0.5

is the detailed data for the first secondary core intended for measurement. The rated secondary burden is 30VA and the accuracy class is 0.5. The markings "a" and "n" refer to the secondary terminal markings on the voltage transformer secondary connection box. To comply with the stated accuracy class, the voltage transformer has to fulfill certain requirements regarding voltage and phase displacement errors as shown below. These limits apply to the secondary burdens between 25-100% of the rated burden.

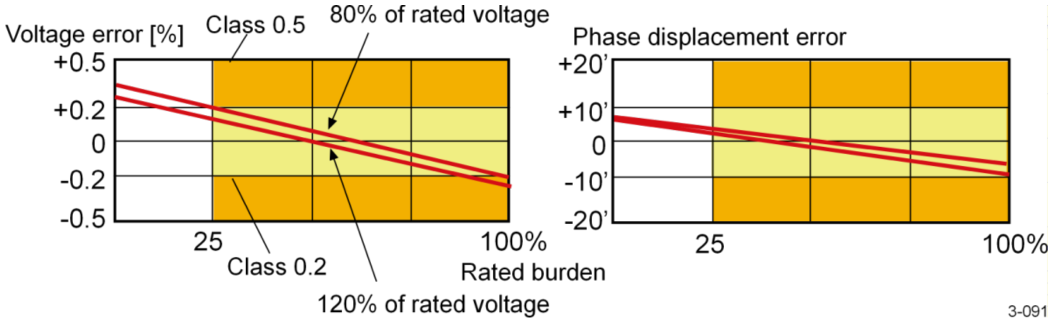


Figure 3.91: Voltage transformer measurement requirements for classes 0.5 and 0.2 according to IEC standards. Plotted lines show the behavior of the transformer used in above example

The marking da - dn 100VA cl.6P

is the detailed data for the second secondary core intended for protection. The rated secondary burden is100 VA and the accuracy class is 6P. The markings "da" and "dn" refer to the secondary terminal markings on the voltage transformer secondary connection box. To comply with the stated accuracy class, the voltage transformer has to fulfill certain requirements regarding voltage and phase displacement errors as shown below. These limits apply to the secondary burdens between 25-100% of the rated burden. If the open-delta-connected secondary protection winding is used only for ferroresonance damping resistor, it does not have to comply with accuracy requirements.

Table 3.1: Accuracy requirements of the voltage transformers' protection classes

Protection class	Voltage error ±%	Phase displacement ± min.
3P	3.0	120
6P	6.0	240

50Hz 400VA

Voltage transformers' rated frequency is (50 Hz). The stated thermal-limiting output is 400 VA. This refers to an apparent power value at the rated secondary voltage that can be taken from a secondary winding under rated primary voltage conditions, without exceeding the limit of temperature rise (classes specified by the standard). In this condition, the limits of error may be exceeded. If the voltage transformer has more than one secondary winding, this value is to be given separately, as an addition to the secondary core's specific data.

7.2/20/60 kV

7.2 kV is the highest voltage for the equipment (RMS value). 20 kV is the rated power frequency withstanding voltage (rms test value). 60 kV is the rated lightning impulse withstanding voltage (peak test value).

1.9xUn 8h

The rated voltage factor (1.9) is the multiple of rated primary voltage to determine the maximum voltage at which the transformer must comply with the relevant thermal requirements and the stated accuracy requirements for a specified (8 h) rated time. The voltage factor is determined by the maximum operating voltage in a specific system. The maximum operating voltage is on the other hand affected by the voltage transformers' primary winding connections and system earthing conditions. The following table demonstrates the dependencies.

Rated voltage factor	Rated time	Method of connecting the primary winding and system earthing conditions
1.2	Continuous	Between phases in any network Between transformer star-point and earth in any network
1.2	Continuous	Between phase and earth in an effectively earthed neutral system
1.5	30 s	
1.2	Continuous	Between phase and earth in a non-effectively earthed neutral system with automatic earth-fault tripping
1.9	30 s	
1.2 1.9	Continuous 8 h	Between phase and earth in an isolated neutral system without automatic earth.fault tripping or in a resonant earthed system without automatic earth-fault tripping

NOTE 1 The highest continuous operating voltage of an inductive voltage transformer is equal to the highest voltage for equipment (devided by √3 for transformers connected between a phase of a three-phase system and earth) or the rated primary voltage multiplied by the factor 1.2, whichever is the lowest.

NOTE 2 Reduced rated times are permissible by agreement between manufacturer and user.

3-092

Figure 3.92: Standard values of rated voltage factors and rated times according to IEC [3.15]

3.16.3 Capacitive Voltage Transformers

Capacitive-type voltage transformers (CVTs) are used on higher voltage levels, starting from 66 kV and upwards. The type of the CVT is always a single-pole one, thus the connection is between phase and earth. The higher the voltage level is, the more price-competitive the capacitive type becomes. One of the advantages the capacitive type has, in comparison to the inductive type, is the possibility to use CVTs as high-frequency coupling units towards the primary system (over headlines). A typical application would be to utilize the CVTs for *power line carrier* (PLC) high-frequency signal interface units. For the voltage measurement purposes, the behavior and the data specification of CVTs follow the same guide lines as the inductive ones. In addition, the possibility for high-frequency signal coupling calls for a specified value for rated capacitance (Cn). This value is chosen considering the following issues:

- Voltage magnitude to be measured
- Demands from PLC system (frequency, bandwidth, connections)
- CVT manufacturing considerations

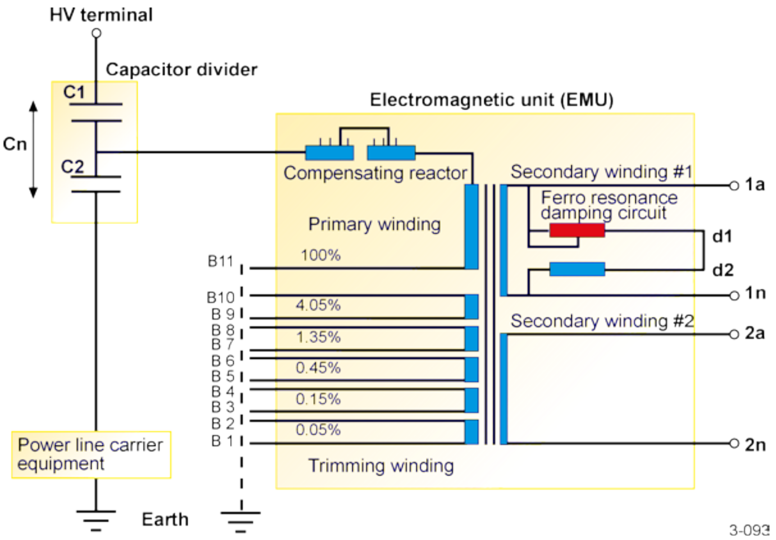


Figure 3.93: Capacitive voltage transformer's principal construction

The figure above shows the principle of a capacitive voltage divider on which the CVT is based. The trimming windings are used for fine-tuning the output signal to correspond with the required accuracy class requirements. The compensating reactor compensates the phase angle shift caused by the capacitive voltage divider.

All CVTs require some sort of ferroresonance damping circuit since the capacitance in the voltage divider, in series with the inductance of the compensating reactor and the wound transformer (inside the *electromagnetic unit* EMU), constitutes a tuned resonance circuit. Unlike with the inductive type of voltage transformers, the CVTs usually have the ferroresonance damping circuit inbuilt in the CVT itself, as shown in the previous figure. At higher system voltages, the resonance phenomenon usually takes place on fundamental or on subharmonic frequencies, resulting in voltage transformer heating (finally damages) and non-selective operations of protective relayingpossible protective relaying non-selective operations. The modern CVTs are utilizing the so-called "adaptive" damping circuits. The circuit consists of a saturable series reactor and a loading resistor. This circuit is connected in parallel to one of the secondary cores. During ferroresonance conditions, high voltages (possible with low frequencies) appear, saturating the reactor and turning the damping resistor on to effectively mitigate the parasitic voltage. During normal system conditions, the reactor presents high reactance, effectively "switching off" the damping resistor. Possible triggering factors for the ferroresonance phenomena could be:

- Planned primary switchings in the system
- Circuit breaker trippings caused by primary fault
- High-speed autoreclosing

3.16.4 Sensors

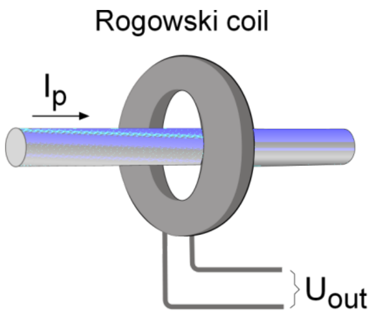
As an alternative for traditional primary current and voltage measurement techniques, as introduced in earlier sections, the use of sensor technique is gaining field. This technique is typically applied to current and voltage measurement in medium-voltage metal-enclosed indoor switchgears. There are many undeniable advantages with sensors when compared to the traditional solutions:

- Non-saturable
- High degree of accuracy
- Personnel safety
- Extensive dynamic range
- Small physical size and weight
- Possibility to combine current and voltage measurement into one physical device with compact dimensions
- Environmental friendliness (less raw material needed)

The above statements are discussed in more detail in the following paragraphs while introducing the sensor techniques and the actual related apparatus.

3.16.4.1 Current Sensors

The measurement of current is based on the Rogowski coil principle. The Rogowski coil is a toroidal coil without an iron core. The coil is placed around the current-carrying primary conductor. The output from the coil is a voltage signal, proportional to the derivative of the primary current. The signal is then integrated in the secondary device to produce a signal proportional to the primary current wave form. Since no iron core is employed, no saturating occurs, unlike with traditional current transformers. As discussed earlier, the open-circuited traditional current transformer produces dangerous voltages to the secondary side and lead to a serious overloading of the transformer. Since the output from the current sensor is a voltage signal, the open-circuited secondary conditions do not lead to a dangerous situation, neither to human beings nor apparatus.



• The transmitted signal is a voltage:

$$u_{out} = M \frac{di_p}{dt}$$

• For a sinusoidal current under steady state conditions the voltage is:

$$\underline{U}_{out} = M j \omega I_p$$

Figure 3.94: Principle of current measurement based on Rogowski coil

With traditional current transformers, the ratio of the CT is fixed to one value, or in case of multi-ratio CTs, to several values. These values are chosen according to the specific application needs and load currents. As a result, one, for example medium-voltage primary switch-gear, installation usually requires several CT types. With a current sensor, the situation is simpler, since one type of sensor covers a range of primary currents and in optimum case the whole installation can be covered with one type only. To give an idea of the secondary-voltage signal level, one fixed point (ratio) inside the rated current range could be 400 A primary value, typically corresponding to 150 mV secondary signal level.

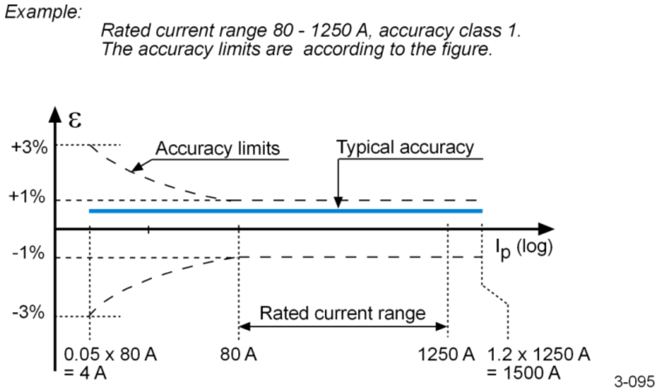


Figure 3.95: Example on current sensor's rated current range

As mentioned earlier, the problems related to saturating iron core in conventional current transformers can be overcome with the sensor technology. The below figure demonstrates the difference between the secondary-signal performance for both traditional current transformer and current sensor.

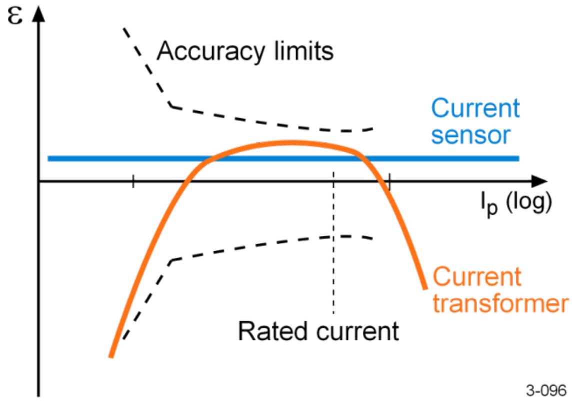


Figure 3.96: Principle comparison of current sensor and current transformer secondary-signal performance as a function of combined error (ε) and primary current (I_P)

Due to the compact size of a current sensor (no iron core), there are better possibilities to integrate the measurement devices inside other constructional parts of a metal-enclosed switch-gear. An example of this possibility would be the integration of a sensor inside plug-in-type medium-voltage cable terminations.

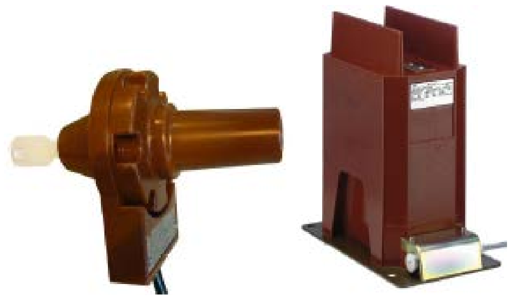


Figure 3.97: On the left a current sensor inside cable plug-in termination and on the right a current sensor inside conventional housing

3.16.4.2 Voltage Sensors

The measurement of voltage is based on voltage divider. Two main types are available, namely the capacitive one and the resistive one. The output in both cases is a low-level voltage signal. The output is linear throughout the whole rated measurement range. The considerations and protection methods against the ferroresonance phenomena, discussed with traditional voltage transformers, are not applicable with voltage sensors.

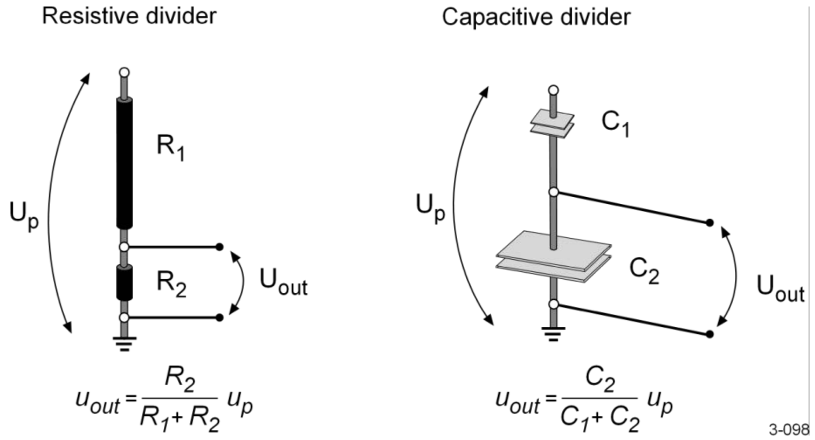


Figure 3.98: Two main principles for voltage sensor implementation

As with current sensors, also with voltage sensors it is possible to cover certain voltage range with one sensor type. To give an idea of the secondary voltage signal level, one fixed point (ratio) inside the rated voltage range could be 20000/√3V primary value, typically corresponding to 2/√3V secondary-signal level.

Figure 3.99: Voltage sensor implementations. On the left a dedicated voltage sensor and on the right a sensor located inside a support insulator

3.16.4.3 Combined Sensors

The sensor solution being quite compact and space saving, it is possible to combine both current and voltage sensors in one physical device. This device can be part of the switchgear's mechanical basic construction, having other functions beside the measurement, like being a part of medium-voltage cable termination or busbar support construction. These features give new possibilities to design switchgear constructions that are built according to specific customer needs and on the other hand they help the standardization work for the bulk type of switchgears.

Figure 3.100: A combined current and voltage sensor acting also as a busbar tube support insulator

3.16.4.4 Conclusion

The features of the sensor measurement technique compared to the traditional approach are shortly summarized in the figure below. It could also be asked why the sensor approach has not totally taken over the traditional approach, at least when it comes to medium-voltage indoor switchgear. This is a very valid question and several answers could be given, depending on the viewpoint of the person answering. Without going into this discussion any deeper, one valid argument is the limited selection of sensor-connectable secondary devices other than protection relays (IEDs).

Feature	CT/VT	Sensors
Signal	1/5 A / 100/110 V	150 mV / 2 V
Secondary cables	To be added	Incl. and tested
Linearity	No	Yes
Saturation	Yes	No
Ferro-resonance	Yes (VT)	No
Temperature coefficient	No	Incl. in accuracy
EMC	No	Shielded
Short-circuited secondary	Destructive (VT)	Safe
Open secondary	Destructive (CT)	Safe
Weight	40-60 kg (CT+VT)	2-25 kg (Combi)
Standardisation possible	Limited	Wider possibilities

3-10

Figure 3.101: Comparison between traditional current and voltage transformers and sensors

3.17 Secondary Distribution Substations

A secondary distribution substation is the linking node between primary distribution substation and electrical power consumption. This substation can include a power transformer for voltage level step-down, like 33/11 kV or 11/0.4 kV. The substation can also exclude power transformer, working only as a switching node in the network, in which case it is often referred to as a switching station.

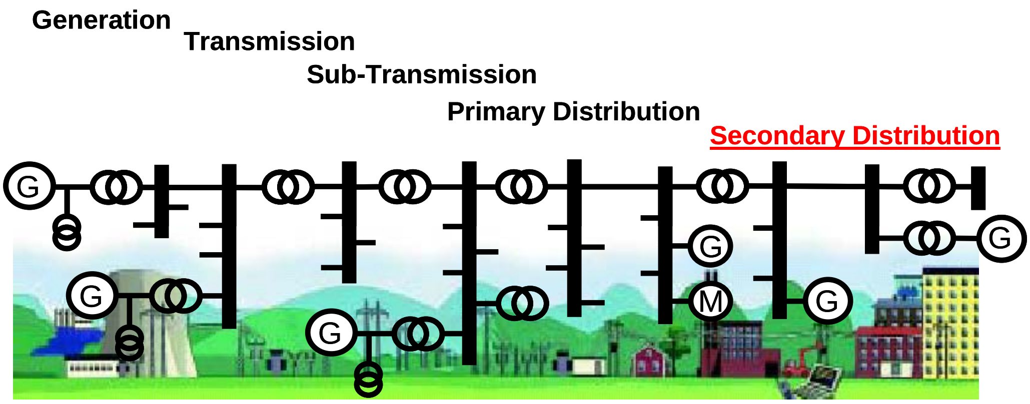


Figure 3.102: Power system

In the following, the key primary elements of secondary distribution substations are shortly introduced.

3.17.1 Ring Main Units

A Ring Main Unit (RMU) is a totally sealed, gas-insulated compact switchgear unit. The primary switching devices can be either switch disconnectors or fused switch disconnectors or circuit breakers. Different combinations of these primary switching devices within the unit are commonly used. In case a circuit breaker is the switching device, it is also equipped with protective relaying, either with a very basic self-powered type or a more advanced one with communication capabilities.

The rated voltage and current ranges for RMUs typically reach up to 24 kV and 630 A respectively. With many of the manufacturers of RMUs, the basic construction of the unit remains the same for the whole of the voltage range. The increase in rated voltage is handled by an increase in the insulating gas pressure.

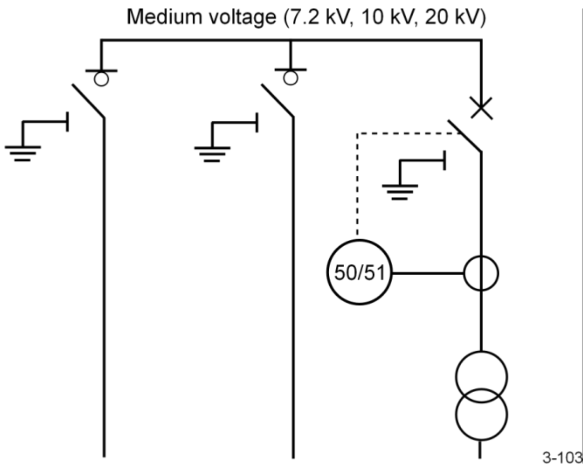


Figure 3.103: Single-line representation of a typical RMU configuration

The figure above shows a typical RMU configuration where load disconnectors are the switching devices for the incoming cable feeders and circuit breaker works as the switching device for distribution transformer feeder. All of the switching devices are of three-position design, having the possibility to close or open or earth the feeder in question.

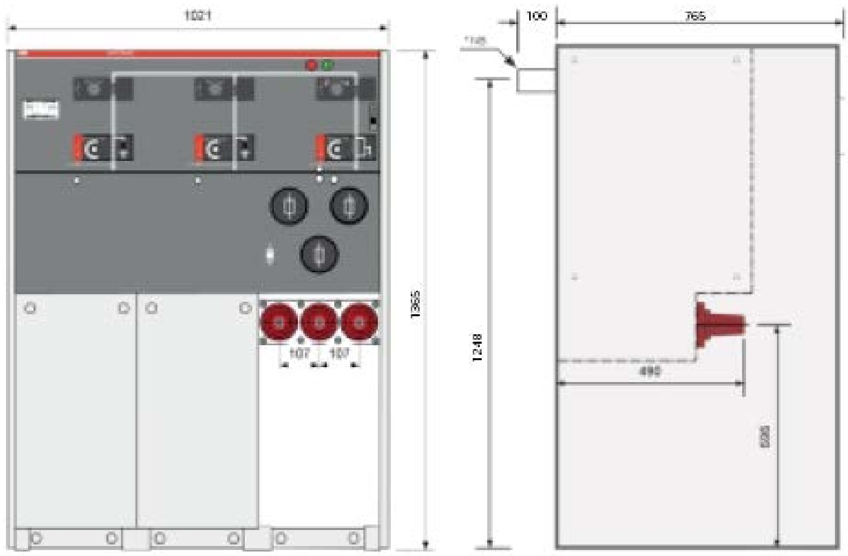


Figure 3.104: Outlook of a typical three-feeder 24 kV RMU unit

The figure above shows typical outlook of a three-feeder RMU. In the figure, the combination consists of load disconnectors for the incoming two feeders and a fused load disconnector for the distribution transformer feeder. The incoming and outgoing medium-voltage cables are attached using elbow-type plug-in cable ends.

3.17.2 Secondary Medium-Voltage Switchgear

Whereas the RMU type of units represents the very compact gas-insulated design for a dedicated purpose, the secondary medium-voltage switchgears represent an air-insulated, quite freely extendable and configurable solution. The intended application area for secondary medium-voltage switchgear falls between the RMU and heavier switchgear constructions intended for primary distribution.

The primary switching devices typically include switch disconnectors, fused switch disconnectors, contactors and circuit breakers, either fixed or withdrawable. The rated voltage, current and short circuit withstanding ranges for secondary switchgears typically reach up to 36 kV, 1250 A and 12.5 kA respectively.

Figure 3.105: A section of typical 24 kV secondary medium-voltage switchgear

The figure above shows one section of typical secondary switchgear. The section consists of a bus-riser cubicle, bus-sectionalizer cubicle with voltage measurement and circuit breaker and a feeder cubicle with circuit breaker. The circuit breakers in this example are of the withdrawable type.

Whereas with primary medium-voltage switchgears, the use of feeder terminals (IEDs) with station and upper-level communication is more a rule than exception, the secondary switchgears still widely separate the functions of protection, measurement and control. Basic protection relays are utilized solely for protection purposes, the control is carried out locally only and measurement is based on indicating analog and calculating energy meters. However, typically the secondary switchgear design facilitates the full use of modern feeder terminal features when this is seen necessary.

3.17.3 Outdoor Switch Disconnectors

The outdoor-type switch disconnectors, also referred to as load disconnector, can be classified into open-type air-insulated ones and gas-insulated enclosed type. The most common installation method with both types would be pole mounting.

The current-breaking capacity with the air-insulated ones starts from very modest figures like 20 A, intended for disconnecting the line-charging current only, and goes up to a few hundred amperes with a special breaking chamber attached. The open-type switch disconnectors can also be equipped with medium-voltage fuses. Line earthing possibility, when the disconnector is in the open position, is typically offered as an option.

Figure 3.106: A 24 kV switch disconnector with earthed when open device

With the enclosed gas-insulated ones, the switching device inside the enclosure is normally a load disconnector. One physical enclosure can in fact accommodate several switches, either with two- or three-position operation. A three-position switch allows the feeder to be closed or open or open and earthed. With the enhanced features, an enclosed-type disconnecting switch actually reaches the same functionality as a traditional basic ground-mounted RMU.

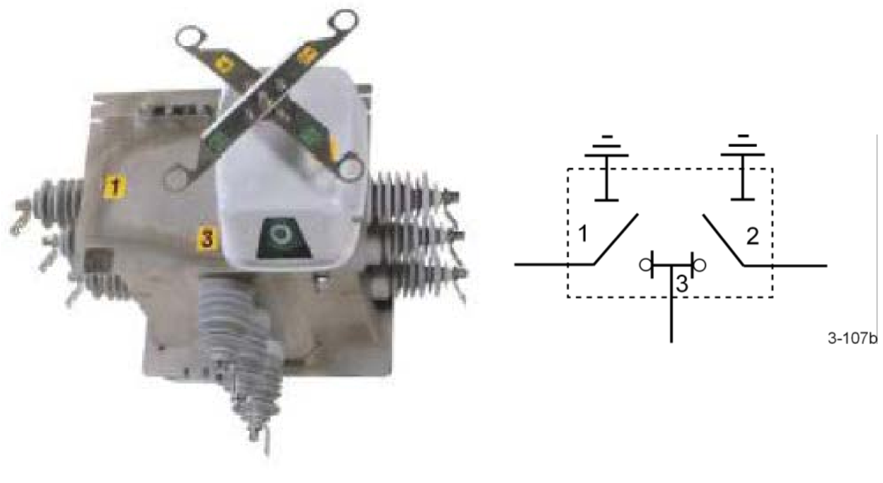


Figure 3.107: A 24 kV gas-insulated enclosed-type switch disconnector with two three-position load disconnectors

The operation of the switch disconnectors can be either manual or motorized with remote control and monitoring possibilities. Utilizing the possibilities that the motor control device and local control and measurement unit provides the installation fulfills the functionality demands exposed to an automated sectionalizer.

3.17.4 Reclosers

Reclosers are self-contained fault interrupting and reclosing devices, specifically designed for overcurrent protection in secondary distribution systems. Reclosers are situated in selected locations within the overhead distribution network. With the correct protection setting and MV fuse selection coordination, concerning the whole supply loop from the supplying primary distribution substation feeder to the fuse-protected distribution transformer, it is possible to achieve a discriminative fault isolation function. Traditionally, the recloser units do not have any remote communication facilities. To enhance the system monitoring and restoration facilities, the reclosers can be equipped with remote communicating protection and control units.

The recloser assembly consists of the fault-breaking primary unit, typically pole-mounted with brackets, and a control cabinet mounted near the ground level. Both three-phase and single-phase units are used, depending on the secondary distribution operation and protection philosophy. The current measuring is carried out with internally mounted bushing current transformers. The switching device is typically either a vacuum-type or oil-type of a circuit breaker with nominal currents up to 1250A and a rated voltage up to 38kV. The breaking capacity of the circuit breaker can reach up to 16kA.

Figure 3.108: Typical recloser's breaking unit (vacuum type) on the left and control cabinet on the right

Following principal system diagrams describe one basic "stand-alone" application of reclosers [3.13]. The below described automatic fault isolation functionality has been achieved with the correct coordination of protection and auto-reclosing scheme settings. Red color marks for a closed switch and green color marks for an open switch. Furthermore, a solid line marks for an energized line and a dashed line marks for a de-energized line.

In the first diagram, the two feeders are supplied from two separate primary distribution substations with the tie recloser open.

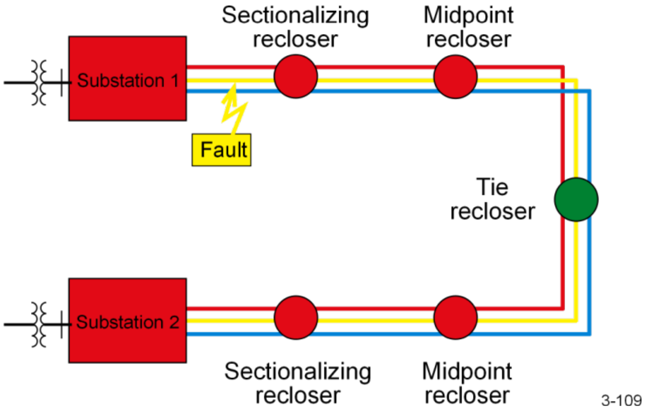


Figure 3.109: System status just before fault appears in the marked location

The second diagram shows a permanent fault situation on the first feeder. As a result of the fault, the feeder in the substation has made an unsuccessful autoreclosing attempt and has locked out with the breaker open.

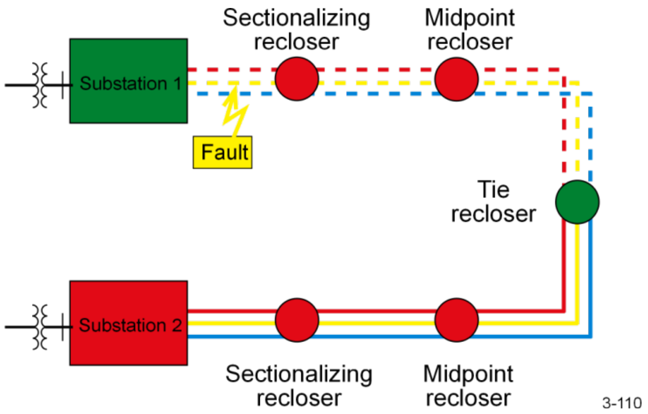


Figure 3.110: System status after unsuccessful autoreclosing of the supplying feeder in substation 1

In the third diagram, the sectionalizing recloser has opened, isolating the faulty section of the feeder.

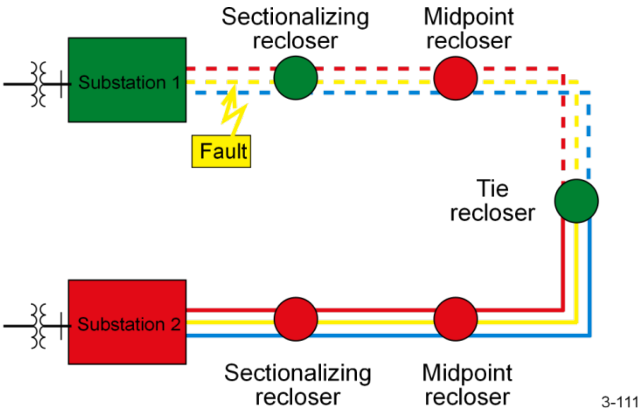


Figure 3.111: Figure caption

In the fourth diagram, the tie recloser has closed energizing the healthy section of the looped feeder.

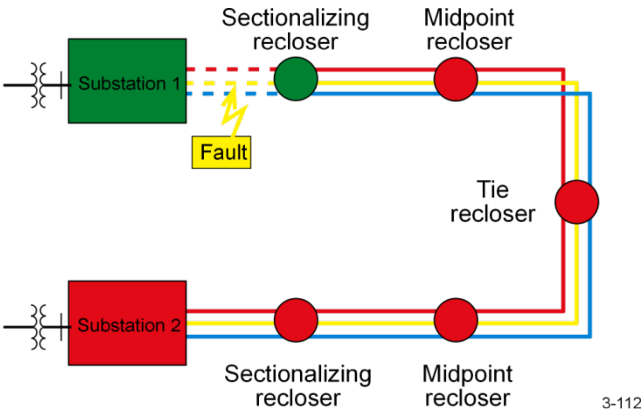


Figure 3.112: System status after tie recloser has closed

3.17.5 Secondary Distribution Transformers

Secondary distribution transformers perform the necessary voltage-level transition from the secondary distribution voltage level to a level suitable for household-like consumption. One example of such transition would be a change from 11 kV to 0.4 kV. The transformer can be three-phase, two-phase or single-phase, depending on the country and application.

Transformers are placed in strategic locations in the network, considering the load to be supplied, load and voltage losses, environmental aspects and minimum acceptable fault level at the end of the longest low-voltage feeder. The installation method can be pole-mounting (small ones), pad mounting or mounting inside a metallic enclosure or a building. The rated capacity of the transformer varies roughly between 5 kVA and 1 MVA. The transformers are typically equipped with off-load tap changers with a moderate adjusting range, like ±2 x

2.5%. The operation of the off-load tap changer is performed manually with the transformer de-energized.

The secondary distribution transformers can be divided into liquid-filled (most common) and dry-type ones. The liquid used for insulation and cooling purposes is usually mineral oil (oil-immersed). Due to special circumstances, also dimethyl silicone or esters with synthetic hydrocarbons can be used. The dry-type transformers are used to minimize the fire hazard and other environmental impacts in case of a severe transformer breakdown. Tank construction with the liquid-filled ones can be either hermetically sealed or with a conservator. The dry-type ones do not have any special tank construction around the transformer core, thus a protective housing around the transformer is always a must.

Figure 3.113: Medium-size oil-filled hermetically sealed pad-mounted secondary distribution transformer

Figure 3.114: Vacuum-cast coil dry-type secondary distribution transformer

Typical protection device with the oil-filled type is a plain top oil thermometer, measuring the oil temperature at the top of the tank. The dry-type ones are normally fitted with temperature sensors for each winding. The sensor can be for example a PTC-type temperature variable resistance, which is then connected to an external monitoring and protection device.

3.17.6 Low-Voltage Switchgear

The low-voltage switchgear is the distribution point for outgoing feeders supplying the end customers. The construction of the low-voltage switchgear varies from simple open-design fuse holder racks to metal-enclosed switchgears. The simplest ones are normally installed with pole-mounted secondary distribution substations, whereas the more comprehensive ones are typically associated with compact or cellar type of secondary substations.

Figure 3.115: Outdoor-mounted, free-standing cable distribution cabinet

The picture above shows a typical free-standing low-voltage outdoor-mounted cable distribution cabinet. The incoming feeder from the secondary distribution power transformer is protected with a *molded-case circuit breaker* (MCCB), and the outgoing feeders are protected with line-mounted three-phase switch disconnector fuse assemblies. Such low-voltage switchgear solution is typically used in connection with pole- or pad-mounted secondary distribution substations.

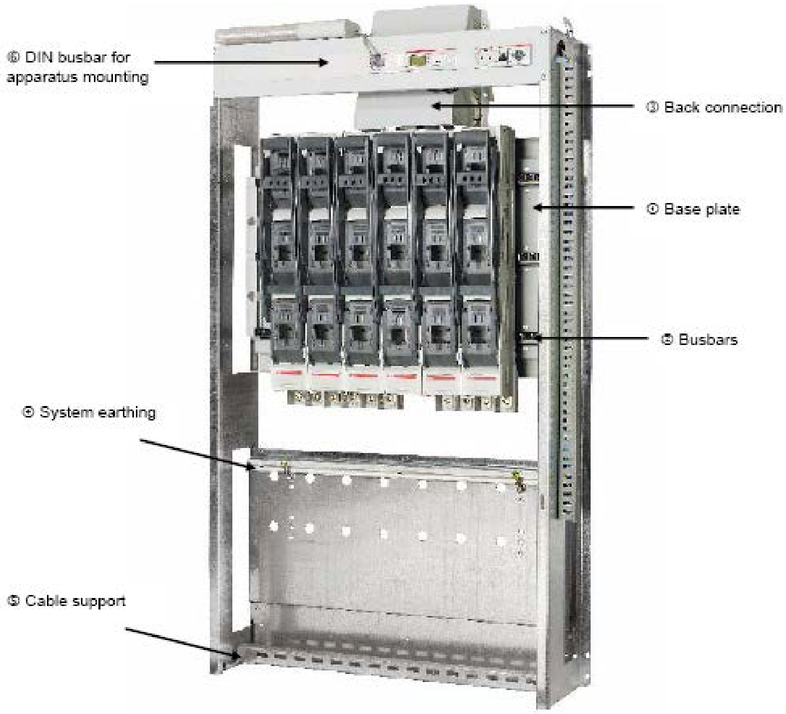


Figure 3.116: Indoor-mounted free-standing cable distribution cabinet

The figure above shows a typical free-standing low-voltage indoor-mounted cable distribution cabinet. The incoming feeder is directly connected to the low-voltage busbars and the outgoing feeders are protected with line-mounted three-phase switch disconnector fuse assemblies. The switchgear can be also equipped with incoming feeder protection and energy measurement, depending on the actual needs. Such low-voltage switchgear solution is typically used in connection with compact secondary substations.

The main primary elements of secondary distribution substations, introduced above, are used as such or in different combinations to form the actual secondary distribution substation installation. Feeder Automation process involves the control and monitoring of these key primary elements. This process and its elements are described under section 3.15.4.3 in this handbook.

The most common secondary distribution substation types, utilizing a combination of the above main primary elements, are presented in the following.

3.17.7 Compact Secondary Substation

A *compact secondary substation* (CSS) is a pre-fabricated unit transported in one or several pieces to the installation location. The unit includes normally the medium-voltage switching devices, secondary distribution power transformers and low-voltage switchgear. The building material can be steel, aluminum or concrete. The smaller units are of the so-called " non-walk-in" design, where all the operation and maintenance tasks are carried out from outside the building. Bigger units are based on the "walk-in" design, where the operation or maintenance personnel can physically enter the building. The medium-voltage switching devices are mostly based on RMU solution, which caters for the minimum space requirements. The bigger units can also utilize the air-insulated secondary switchgear alternative. The distribution power transformer is installed on top of an oil reservoir to comply with environmental regulations. The oil reservoir can be either a steel construction or a concrete construction. In case the concrete construction is used, it will typically also form the foundation for the whole CSS unit.

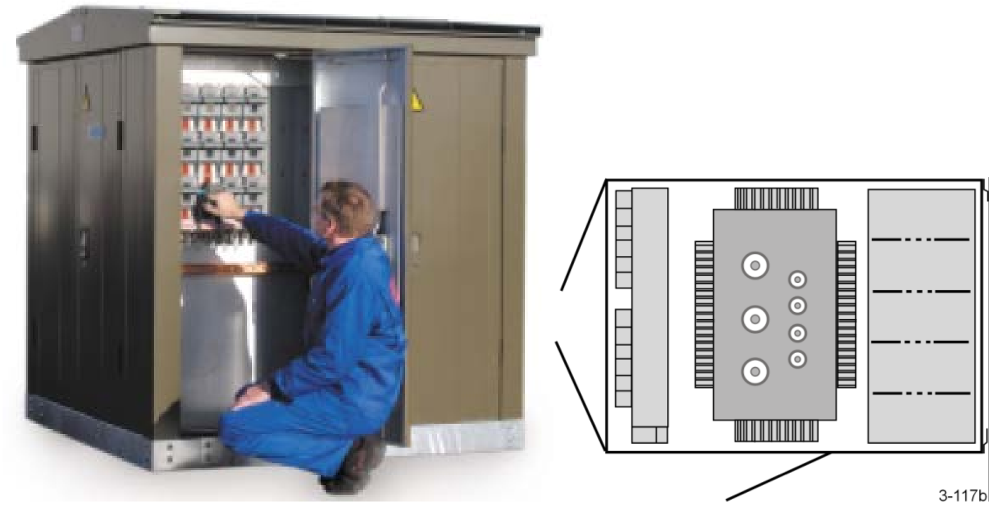


Figure 3.117: Compact secondary substation based on metallic construction and non-walk-in design

The picture above shows a CSS unit utilizing metallic outer enclosure with the "non-walk-in" design. The internal layout picture on the right shows the placement of different modules of the CSS. The low-voltage switchgear is the most left one, followed by a secondary distribution power transformer and finally the medium-voltage switching unit RMU.

3.17.8 Indoor Secondary Substation

The basic components with indoor secondary substations are basically the same as with compact secondary substations, except the different components are supplied as loose items and installed into a dedicated space inside a larger building or building complex. Obviously, the space limitations are not as tight as with the CSS solutions, thus enabling the use of air-insulated medium-voltage secondary switchgear. Also the fact that the needed power transformer capacity is often higher than with CSS solutions drives for medium-voltage switchgear options having higher performance values than for which the RMUs can cater.

Figure 3.118: Indoor secondary substation with air-insulated medium-voltage secondary switchgear

Typical installation sites for indoor secondary substations include large office complexes, shopping malls and small and medium-size industry.

3.17.9 Pole-Mounted Secondary Substation

Pole-mounted secondary substations consist of medium-voltage over-headline(s) feeding the substation, pole-mounted medium-voltage switching equipment, pole-mounted secondary distribution power transformer and low-voltage switchgear cabinet. The equipment used for medium-voltage switching varies from simple air-insulated manual-operated disconnectors to automated functions of reclosers and sectionalizers. The pole-mounted secondary substations are common solutions for widespread rural networks where the power intensity is relatively low. The low-voltage cabinet can be either pole-mounted or free-standing ground surface-mounted in the vicinity of the other equipment. The first one is typically used in case where the low-voltage overhead lines are used for supplying the end customers and the later one in case of underground low-voltage cables.

Figure 3.119: Pole-mounted secondary distribution substation

The above picture shows one pole-mounted secondary distribution substation application. On the medium-voltage level, the switching equipment consist of three air-insulated load disconnector switches for incoming overhead lines, one load disconnector switch is used for connecting underground medium-voltage cable and one disconnector is used for connecting the secondary distribution power transformer. All of the load disconnector switches are motor-operated with remote communication. The low-voltage switchgear cabinet can be seen at the very bottom of the picture, providing the connection point for outgoing underground low-voltage cables.

3.17.10 Sectionalizers

The Sectionalizer is a medium-voltage switching device that can break the de-energized medium-voltage feeder into two or several sections in order to isolate the faulty part of the feeder. The switching device used is normally pole-mounted, either open-type air-insulated switch disconnector or encapsulated gas-insulated load disconnector.

Around 80% of the faults in the medium-voltage overhead lines are of transient nature and thus often self-clearing type. To restore the supply for the faulty feeder after line tripping, different autoreclosing schemes are employed. In case the feeder is affected by a non-self-clearing type of fault, a lot of customers are affected by a long supply break after several unsuccessful autoreclosing attempts. If the actual fault is close to the end of the feeder, the customers closer to the substation could be still supplied if the faulty section of the feeder could be isolated. For such cases, the optimally located automated sectionalizers can be the answer.

When the sectionalizer is equipped with a motor-operating mechanism, measuring transformers (or sensors) and local control and supervising features, the sectionalizer becomes a so-called automated sectionalizer. With an automated sectionalizer, it is possible to build discriminative fault isolation schemes. The automated sectionalizer works in coordination with up-stream switching devices, utilizing the de-energized periods during the autoreclosing scheme to operate and isolate faulty sections. The automated sectionalizer counts the reclosing attempts made by the upstream device, like reclosing breaker at the upstream substation, and after a pre-selected number of attempts, it automatically opens during the de-energized period of the autoreclosing sequence.

Following picture shows a simple radial feeder case of utilizing the functionality of an automated sectionalizer together with the circuit breaker's autoreclosing scheme for discriminative fault isolation.

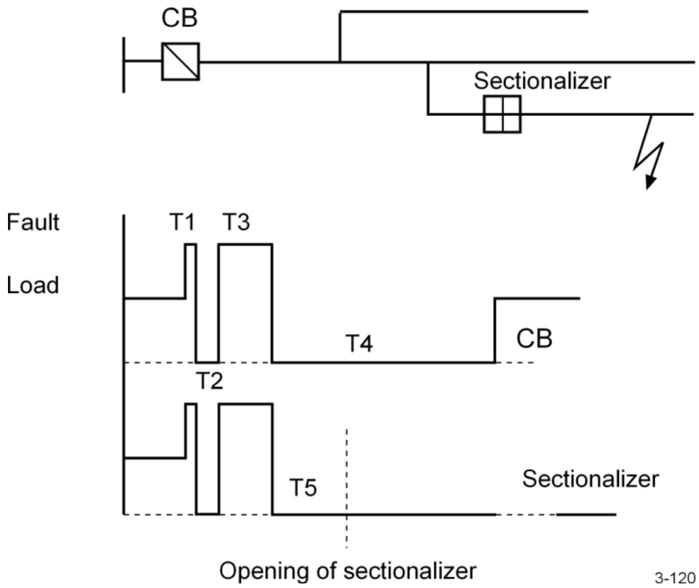


Figure 3.120: An example of utilizing sectionalizers for discriminative fault isolation in radial feeder application

When the fault appears on the overhead line section beyond the sectionalizer, the protective relaying at the supplying substation and at the sectionalizer recognizes the case. The protective relaying at the substation starts the autoreclosing sequence by tripping the circuit breaker in time of T1. The sectionalizer acknowledges this action. After a preset time delay (T2), the circuit breaker recloses. Since the fault has not been cleared, the circuit breaker trips again after a preset time delay of T3. The sectionalizer commences its opening cycle during the feeder's de-energized period of T4. The actual sectionalizer opening command is issued after a preset time delay of T5. After the time delay of T4 of the autoreclosing scheme has elapsed, the sectionalizer is fully open and the circuit breaker recloses, energizing the healthy sections of the feeder.

3.18 Auxiliary Power Supply Systems

This chapter concentrates on the characteristics, dimensioning, protection and typical applications of a substation auxiliary power supply systems.

The purpose of auxiliary power supply systems is to cater for the necessary energy for the operation of primary and secondary devices at the substation. The auxiliary power systems are normally divided in two categories, namely the AC-system and the DC system(s). The AC system normally operates with the country's standardized utility low-voltage level, for example 400 V 50 Hz. The DC systems utilize a wider range of different voltage levels, depending on the common practice within a specific utility and the specific demands exposed by the loads to be fed.

The loads fed by the AC-system are normally so-called inessential loads, which are not crucial for the substation operation. These loads would typically include the following:

- Substation building(s) climate control and lighting
- Outdoor equipment and indoor panels desiccation heaters
- Power transformer cooling fans
- Driving motor for on-load tap changer of a power transformer
- Station battery (DC system) charger(s)
- Normal wall socket outlets

The loads fed by the DC system(s) are normally so-called essential loads, which are crucial for the correct, reliable and safe operation of the substation. These would typically include the following:

- Protection relaying, including circuit breakers' tripping and closing coils
- Interlocking circuits
- Circuit breaker operation mechanism (spring charging)
- Circuit breakers' and disconnectors' control circuits
- Disconnectors' motor operation mechanism
- Alarm circuits
- Communication systems
- Substation access control and intruder alarm system
- Fire alarm system
- Emergency exit signs and lights

In case the substation is equipped with computerized substation control system (SCS), the computers and other associated equipment can be fed from the substation's DC system via an inverter. Another possibility is to have a dedicated UPS (uninterruptible power supply) for the SCS-related equipment.

3.18.1 DC Auxiliary Supplies

As indicated earlier, a substation can have one or several DC systems. Factors affecting the number of systems are the need of more than one voltage level and the need of duplicating systems. Today, normal DC systems are operating either on the 110 V or 220 V level, though lower levels exist. Some systems at the substation may require lower voltages as their auxiliary supply source. A typical example of these systems would be the optical telecommunication devices or the power line carrier (PLC) equipment, which normally requires 48 V. If the power consumption of these devices is low enough, their supply can be arranged with DC/DC converters, supplied by the higher voltage level DC system.

3.18.1.1 Elements of DC Auxiliary System

The main components of the system are battery, charger and distribution switchboard including the DC system monitoring relay. Figure 3.121 shows the main line diagram of a single-battery and charger application.

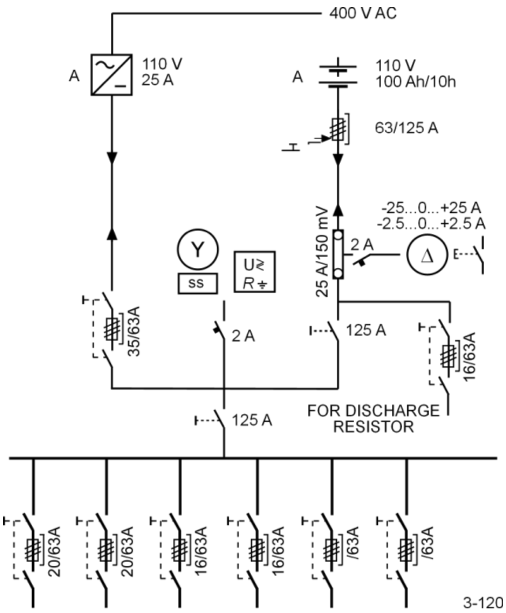


Figure 3.121: Typical single-battery and charger application

In a typical installation, especially with batteries of considerable size, the batteries are installed in a separate battery room. The ventilation of the battery room shall be adequate, considering the type and size of the battery. Temperature level in the battery room should not exceed 25°C, since temperatures above this significantly affect the lifetime of the battery. The charger and distribution switchboard are normally located in the same room, separate to the battery.

The main fuses of the battery are housed in separate plastic boxes, one for plus connection and one for minus connection. These main fuse boxes should be placed close to the battery itself. The main fuses are supervised and an alarm is given in a case of a blown fuse (Figure 3.122). If a main fuse (F1 or F2) is blown, the overcurrent tries to divert its path via paralleled miniature circuit breaker (F1.1 or F2.1). This miniature circuit breaker has a very small rated current and is also tripped immediately, causing the alarm contact 95-96 to close.

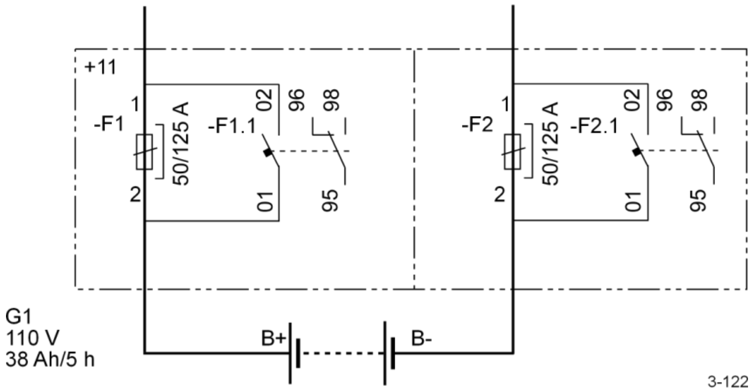


Figure 3.122: Battery main fuse supervision

The cables leading from the main fuse boxes to the distribution switchboard are run separately for both polarities with at least a 10 cm distance between each other. The cables are installed in non-conductive (plastic) pipes for the total length.

Usually at the distribution switchboard there is provided a separate fuse switch output for connecting external battery discharger equipment, as shown in Figure 3.121. This output can be utilized while making a battery discharge test during substation commissioning or regular maintenance and testing.

3.18.1.2 DC system earthing

As a general rule, the DC systems are not earthed. A system having no earth connection can be run even under one-pole earth fault situation, thus increasing the availability of the DC system. For detecting the one-pole earth faults, the distribution switchboard is equipped with a battery monitor relay that constantly monitors the insulation resistance of both of the poles against earth. If the insulation resistance goes below a settable limit, the monitor relay issues an alarm signal. An earth fault situation should be attended immediately, since the risk of double-pole earth fault is significantly increased.

Some loads might require either a plus- or minus-pole earth connection. Typically, these loads could be power line carrier (PLC) equipment, telephone exchanges (PABX) or remote terminal units (RTU) for remote control and supervising purposes. The mentioned systems are normally running on lower voltages than the rest of the DC-loads. Thus, they are supplied with a separate dedicated DC system.

3.18.1.3 Duplication of the system

Since the DC system supplying specially relay protection, control and interlocking circuits is of paramount importance to the substation’s reliable and safe operation, the energy supply has to be always available. The need of this reliable supply becomes even more important during disturbances and faults in the high- or medium-voltage primary circuits. As a result of these faults, the AC auxiliary voltage may not be available, because the incoming feeders may have tripped. After such situation, the re-energizing of the substation is solely depending on the DC auxiliary power available.

The importance of this reliable DC-auxiliary power is crucial for the substation as such. The higher (more important) role the substation plays from the complete distribution or transmission network point of view, the higher are the demands for the substation's DC auxiliary power systems. To meet the increased demands for reliability and availability, the DC system can be doubled (Figure 3). This means that there are two separate systems, at the same voltage level, running in parallel. Both of the systems have their own batteries and chargers. The distribution switchboard is divided into two separate sections, where both battery and charger sets are supplying their own sections. There is a bus tie switch connecting the busbars of the different sections together. Under normal conditions, this bus tie switch is kept open. In case of faults or maintenance on one of the battery and charger sets, the bus tie can be closed, thus enabling the other battery and charger set to supply the whole load.

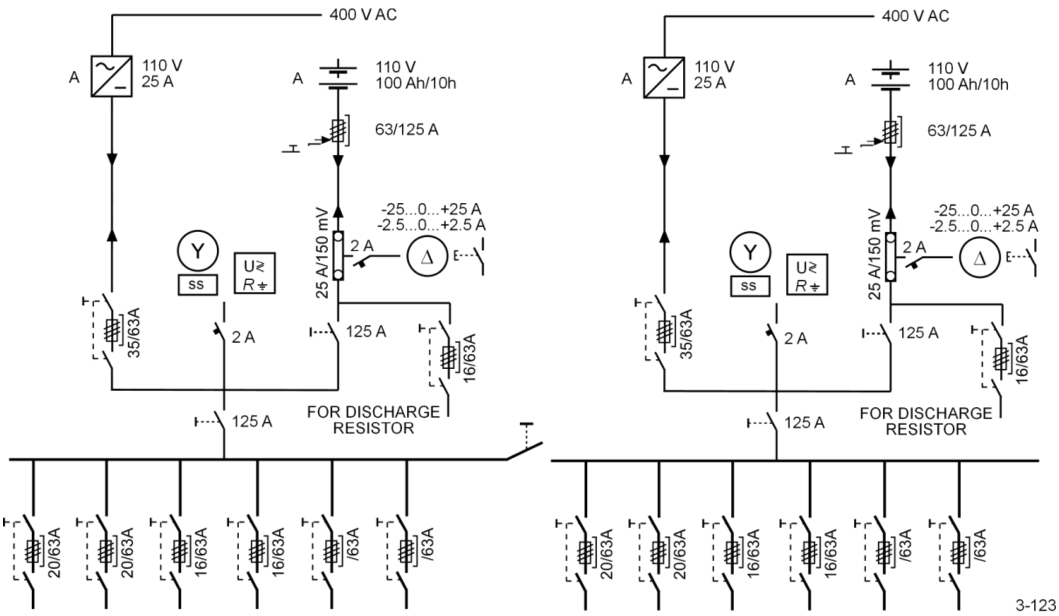


Figure 3.123: Typical doubled battery and charger application

The actual circuits that the doubled DC system is supplying are distributed equally among the two sections in the switchboard. Circuits with doubled functions, like trip circuit 1 and trip circuit 2, are connected to separate sections. This way, the fault in one of the sections does not affect the tripping circuits connected to the second section.

The doubling of circuits, especially regarding protection circuits, should continue all the way to the actual primary devices. This means that for example with the circuit breaker there should be two separate tripping coils, one for trip circuit 1 and second one for trip circuit 2. The cabling for these two circuits (tripping coils) should be done with separate cables utilizing, as far as possible, also different cabling routes. Furthermore, a common practice is that the main protection relays receive their auxiliary supply from as well as give their trip commands to the trip circuit 1, whereas the backup protection relays utilize the trip circuit 2 for the same functions. The local and remote circuit breaker control functions (opening command) typically utilize the trip circuit 1.

3.18.1.4 Battery Technology

The main types of battery cells used for stationary (substation) applications are Lead-Acid and Alkaline (nickel-cadmium). The choice between these two types depends on several factors, including at least the following:

- Lifetime expectancy
- Maintenance requirements
- Lifetime costs, from purchase to replacement
- Reliability
- Charging and discharging characteristics
- Operating temperature requirements
- Existing spare cell stock
- Seismic conditions

In the following, two of the most common type of batteries are in focus, namely the Valve-Regulated Lead-Acid batteries (VRLA) and Nickel-Cadmium batteries.

The complete battery consists of a certain number of individual cells. Depending on the battery type and design in question, the cells can be partly series-connected already at the factory. Then, a number of cells, for example six pieces, form a one-cell package. These cell packages are then connected in series to reach the required number of individual cells.

The number of battery cells to be connected in series depends on the required float charge voltage level of the battery. This float charge level also determines the actual operating voltage level of the DC system, under normal conditions. Nominal float charge cell voltage depends on the type of the cell. With Lead-Acid battery cells, the nominal float charge voltage of a cell is around 2.23 V and with Nickel-Cadmium cells it is around 1.41 V. So, for example for a 110 V DC system Lead-Acid battery, 53 cells would be chosen, giving a battery float charge voltage of 118 V.

3.18.1.4.1 Valve-Regulated Lead-Acid Batteries

-*Valveregulated lead-acid* (VRLA) batteries are the most common ones for stationary substation installations. This battery is the oldest type on the market and has been successfully utilized through the years. The cell plates inside the battery are usually made out of pure lead. However, because of some mechanical strength limitations on pure lead, certain alloys are used, most common ones being lead/antimony and lead/calcium [3.10]. The electrolyte used with the Lead-Acid batteries is thinned sulphur acid. The electrolyte is actively taking part into the chemical reactions inside the cell, and its density varies according to the charged capacity of the cell. Thus, the charging state of the battery can be determined based on the electrolyte density. The battery cell is of a sealed type, except for the regulating valve, which opens and leads out the cell’s internal pressure if it exceeds the atmospheric pressure with a predefined amount. In addition to the valve regulating type, also the so-called vented of cells are available. The vented type utilizes the free-breathing principle, where all the evaporating gas from the cells has free access to the surrounding atmosphere.

As the IEEE Standard 1375-1998 publication [3.7] indicates, the VRLA battery's available capacity depends greatly on the temperature of the surroundings (battery room) and the temperature of the cell itself. The battery's nominal capacity is normally stated at 25°C temperature. With lower temperatures, the capacity starts to decrease. With higher temperatures, the capacity starts to increase, resulting in a higher charging current from the charger to meet the requirement for the specified float charging voltage level, which in turn results in increased heating inside the cell. This chain reaction can be dangerous for the battery if certain precautions are not taken. The chain reaction can be prevented by controlling the temperature of the battery room and by limiting the charging current. The charging current limitation can be realized by temperature compensation and by fixed current limiting. As shown in Figure 3.124, the VRLA battery lifetime is also significantly pending on the operating temperature. Generally, it can be said that the lifetime is halved after every 10°C temperature increase beyond 25°C.

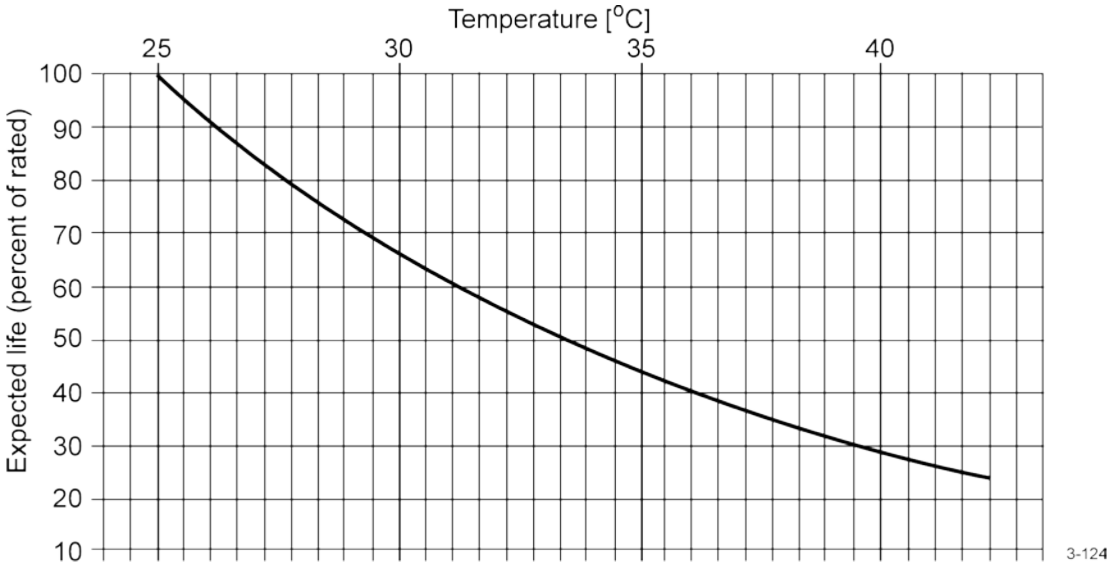


Figure 3.124: Correlation with VRLA cell lifetime and temperature [3.7]

The battery is very sensitive to deep discharges and can be easily damaged under such conditions. The lifetime expectancy varies between five to ten years, depending on the actual type of cells, type of use and the manufacturer, whereas the lifetime expectancy for Nickel-Cadmium battery is approximately double. The initial purchase cost for a VRLA type of battery is considerably lower than for a Nickel-Cadmium battery.

3.18.1.4.2 Nickel-Cadmium Batteries

The actual cell construction in Nickel-Cadmium batteries varies with the cell type and cell manufacturer. Usually, the active material in positive cell plates consists of a mixture of nickel hydroxide and graphite, whereas the negative cell plate consists of cadmium hydroxide and iron compounds. Potassium hydroxide solution works as the electrolyte inside the cell. The electrolyte does not take part in the reaction chemically, working only as a distributor of ions. The electrolyte density does not change with the state of the charge. Thus, the charging state of the battery cannot be determined based on the electrolyte density.

The temperature characteristics dependency of a Nickel-Cadmium battery is not at all as high as with the VRLA type of batteries. The expected lifetime of a Nickel-Cadmium battery decreases when the temperature increases but in a much more moderate pace. Generally, it can be said that the lifetime is decreased by 20% after every 10°C temperature increase beyond 25°C. The battery has excellent recovery features after a severe deep-discharge situation. As already noted, the lifetime expectancy with a Nickel-Cadmium battery is at least twice that of the VRLA battery.

3.18.1.5 Charger Technology

Two different main technologies commonly exist, namely the switched mode and the thyristor-controlled. The chargers utilizing the switched mode technology are basically intended for lead acid battery applications. The chargers utilizing the thyristor-controlled technology can be used for both lead acid and nickel-cadmium applications. The switched mode technology results as by its nature in a very low ripple voltage and dynamic performance. Thus, it can be used to supply the load even without batteries. The thyristor-controlled chargers have quite a high inherent ripple voltage, and normally additional smoothing is required.

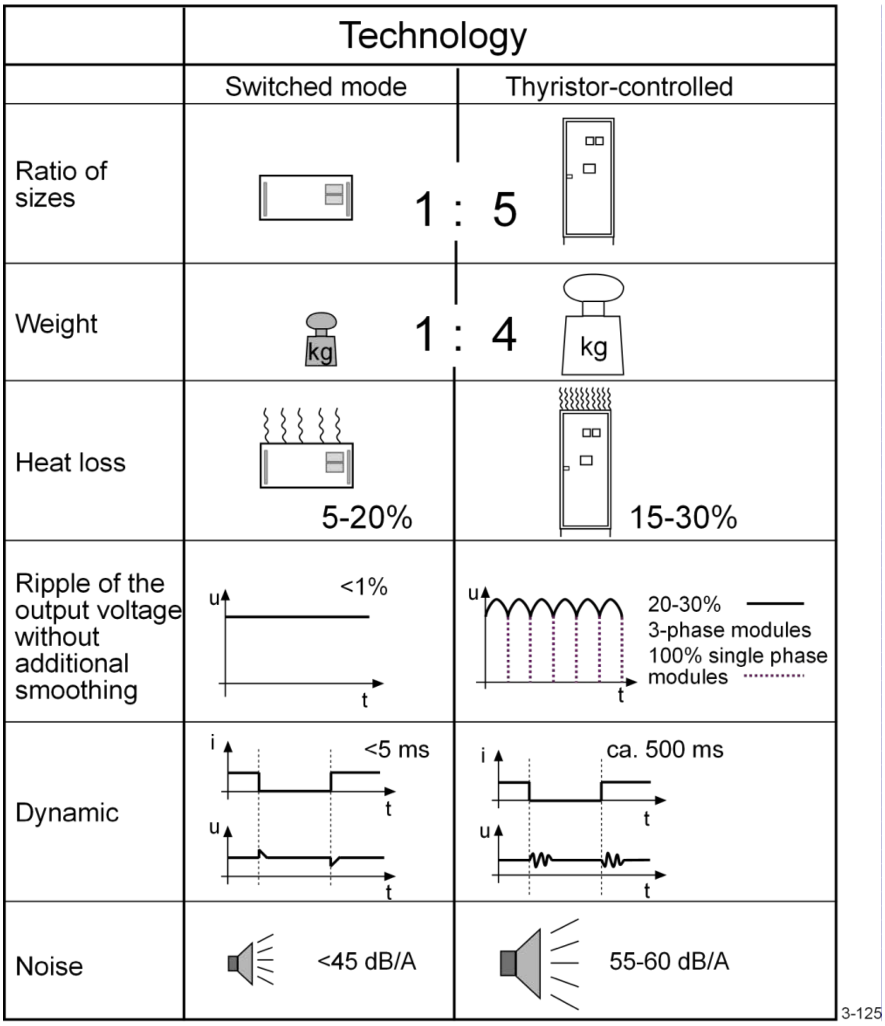


Figure 3.125: Comparison between the charger technologies [3.12]

3.18.1.6 Dimensioning of the System

Dimensioning of a DC system contributes to the following technical aspects:

- Battery-rated capacity and number of cells
- Selection of battery charger and determination of its rated output
- Distribution switchgear, and components, short circuit withstand value and nominal current
- Cross-section and length of cabling between distribution switchgear and load, in respect of voltage loss and minimum fault current available.

The above mentioned dimensioning questions will be shortly covered in the following.

3.18.1.6.1 Calculating the Number of Cells in a Battery

The required number of cells in a battery depends mainly on the nominal voltage of the DC system, the allowed voltage variations during the considered duty cycle and the recommended float-charging voltage of an individual cell.

Assumed that the stated nominal voltage of a DC system is 110 V and the allowed voltage variations are +10% and -15%, the cell type chosen is valve-regulated lead acid and the capacity of a cell has been chosen so that the required duty cycle can be covered. It is further assumed that the cell manufacturer states the recommended float float-charging voltage being 2.23 V/cell. The maximum system voltage would be 110 V+10%, which equals 121 V. When this maximum system voltage is divided with the nominal float-charging voltage, the result is 54 pieces of individual cells. A common practice with the lead acid cells is to state the capacity with cell end voltage of 1.8 V. When this end voltage is multiplied with the number of cells, the result is 97 2 V. On the other hand, the minimum allowed system voltage is 110V-15% equals 93.5V. In the example, the chosen number of cells (54 pcs) seems to be a correct choice.

What the above example did not take into account are the voltage losses within the cabling. Normally, the stated allowed voltage variations, within a DC system, refer to the maximum and minimum voltage levels at the connection point of energy-consuming device. In other words, the voltage losses that take place in the cabling between the battery and consumption point have to be taken into account. This consideration obviously becomes important with long cabling distances and can result in an increase in the cable cross-sections in order to lower the voltage losses.

3.18.1.6.2 Battery Capacity Dimensioning

As the IEEE Standard 485-1997 publication [3.11] indicates, the battery must be capable to supply the DC-power when any of the following situations occur:

- Load of the DC system exceeds the maximum output of the battery charger
- Output of the battery charger is interrupted
- AC-power is lost

The most severe condition of the above should be the basis for battery dimensioning, considering the load and duration. A complete lack of AC-power may result in a greater demand of DC-power than if only the charger output is interrupted.

The capacity of a battery equals the capacity of one series-connected battery cell. The capacity of a battery is determined by the load and the time that the battery is expected to supply the load. Usually, this discharging time is taken as ten hours. The capacity demand gained based on this consideration is incorrect. To attain the corrected capacity, certain correction factors have to be taken into account.

$$C = \int_0^t I \times dt \qquad \textbf{(3.37)}$$

Equation (3.37) shows the basic principle of calculating the total capacity of the battery, the load current is integrated over a time period.

C	is the total battery capacity [Ah]
I	is the load current [A]
t	is the discharge time [h]

As can be seen from above equation, the behavior of the load current (load profile) is critical. To form estimation, as accurate as possible, of the load behavior during the duty cycle, the loads are usually divided into three different classes, as defined in the IEEE Standard 485-1997 publication [3.11].

- 1. Continuous loads
- 2. Non-continuous loads
- 3. Momentary loads

The continuous loads are energized during the whole duty cycle and are normally carried by the battery charger.

The non-continuous loads are energized only during a certain part of the duty cycle. These loads might appear at any time of the duty cycle and disappear (automatically or manually), or continue until the end of the duty cycle.

The momentary loads can appear once or several times during the duty cycle. The loads are short in duration, not more than one minute. If several momentary loads appear at the same time, the total load should be considered to be the sum of all the loads during their common time period. If the discrete sequence of the simultaneous momentary loads cannot be established, the sum of the loads should be considered over the one-minute time period.

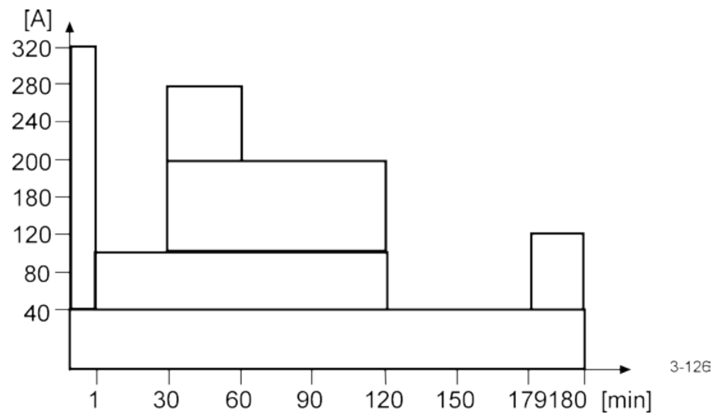


Figure 3.126: Example of a duty cycle

After the load profile is known, there are different ways to calculate the actual minimum battery (cell) capacity needed. The method giving usually the most conservative outcome is the one based on the IEEE Standard 485-1997 publication [3.11]. In Finland, the most common way is to follow the SLY (Sähkölaitosyhdistys, association of Finnish utilities) method. Also the battery manufacturers are distributing computer programs for battery capacity calculations. These programs select the right cell type, within the manufacturer's range, based on the given data on load profile, discharge time, minimum and maximum battery voltage and ambient conditions.

3.18.1.6.3 Charger Dimensioning and Selection

A battery charger has several tasks. It should keep the battery charged to its full capacity when no load is connected, thus no current is withdrawn from the battery. A charged battery will slowly discharge over time, even if there is no load connected to it. The charger has to compensate for this discharge current.

When the battery is supplying the load without the charger or when the amount of the withdrawn current exceeds the supply rating of the charger, the charger has to be able to recharge the battery within a specified time after this abnormal situation is over. The normal load current supplied by the charger has to be also taken into account while making this consideration.

In some applications, it is required that the charger has to be able to supply the load temporally without the battery being connected. This requirement sets demands for the charger's maximum ripple voltage and dynamics performance.

Also the charger's AC-supply voltage and the number of phases have to be considered. If large enough chargers are not available for one phase supply, it is normally possible to use two or more chargers in parallel operation. This has to be confirmed from the supplier and also normally stated in the chargers' purchase order.

Majority of the chargers available can be equipped with a monitoring unit that supervises the charger and battery status and performance. The monitoring unit supervises the battery voltage, charger output voltage, system insulation resistance against earth, charger AC-supply and battery charging status.

The monitoring of the battery cell voltages, insulation against earth and battery running temperature can be also realized with separate monitoring devices. The current status and trends on the battery voltage and differences between different cell voltages can be shown on a remote supervision system.

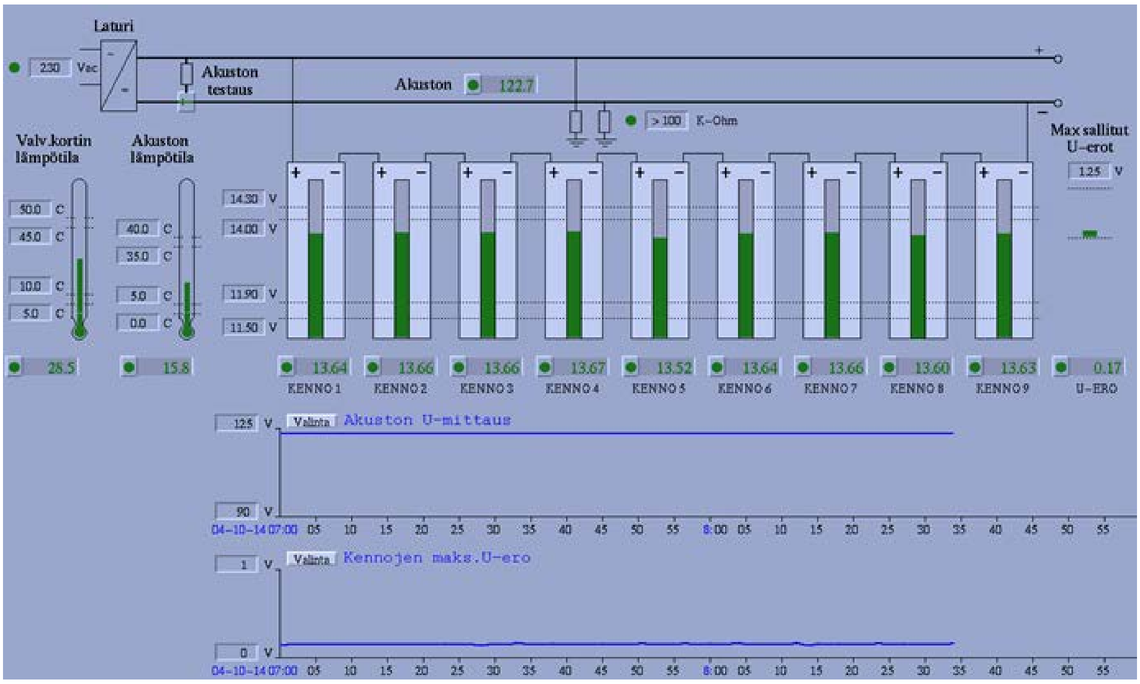


Figure 3.127: Battery supervision page on SCADA display

As a summary, the following items should be considered while choosing the right charger type and rating:

- DC system normal load current
- Required battery recharging time
- Requirements on charger ripple voltage and dynamics performance
- Possible parallel running with other charger(s)
- Battery's float and boost charging voltages
- Battery type (lead acid or nickel cadmium)
- Monitoring requirements, both local and remote
- Charger AC-supply (voltage, frequency, one or three phase)
- Available space

3.18.1.6.4 DC system Switchgear

Switchgear size and the utilized primary switching devices depend on the actual application. A DC system can be a relatively compact one, utilizing only one charger and battery set, or it is a relatively large one with duplicated batteries and chargers. For the larger ones, a normal switchgear design would be a free-standing metal-enclosed construction with a number of separate compartments.

Switchgear's nominal current dimensioning would be based on the actual maximum load currents with a reasonable margin future load increase. For the short circuit strength dimensioning, the battery-supplied DC system has quite different phenomena as compared to normal AC-system dimensioning. For a DC system, with battery and charger connected, a short circuit in the system corresponds to heavy-load situation. The battery voltage will rapidly drop to a constant value, and a constant fault current is supplied. The short circuit currents of a battery can easily be in the region of a few kilo amperes.

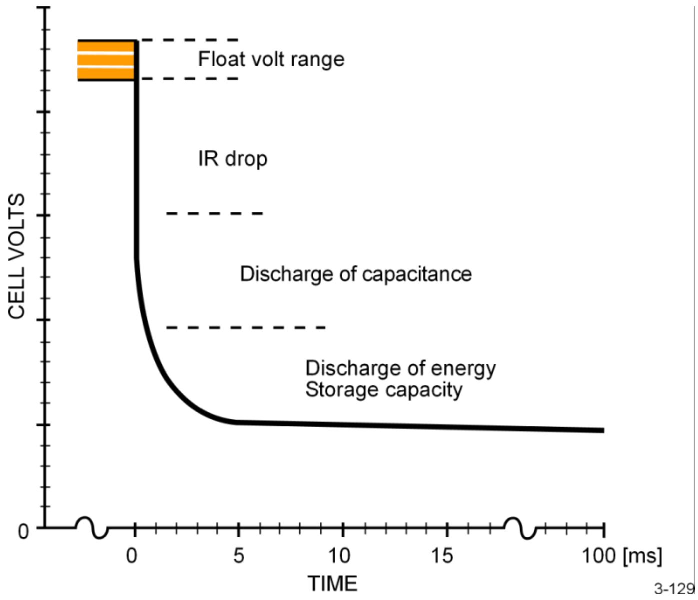


Figure 3.128: Lead acid battery's typical initial voltage characteristics during a short circuit [3.7]

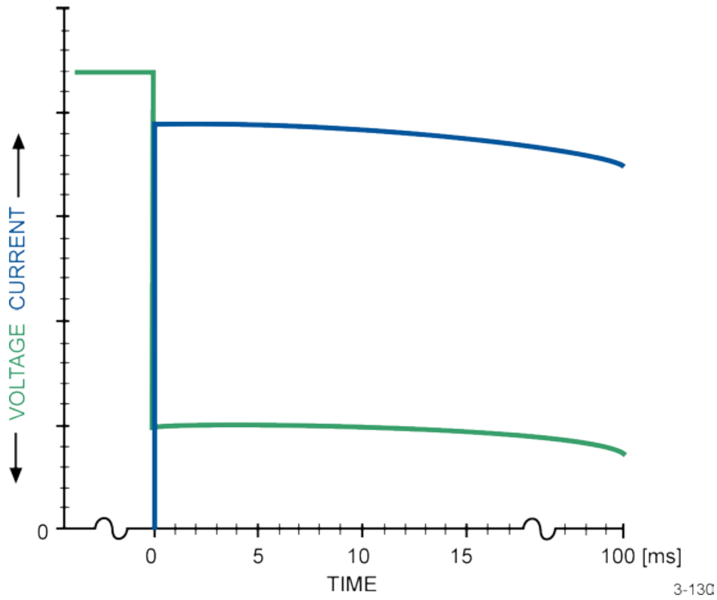


Figure 3.129: Lead acid battery's long-duration characteristics during a short circuit [3.7]

The actual constant short circuit current supplied by the battery can be checked from the manufacturer’s manuals. Below is an example of typical lead acid battery cells’ short circuit levels.

Nominal capacity (Ah) at 20°C 10 hrs to 1.80 VPC	Short circuit current (A) IEC 60896-21	DC internal resistance (mΩ) IEC 60896-21
25	1150	11.0
30	1300	9.0
50	2030	6.0
75	3000	4.0
100	3800	1.7
105	4000	1.6
125	4300	1.4
150	5000	0.70
160	3050	1.96
180	3400	1.75
200	3800	1.0
250	5900	0.35
275	6100	0.33
300	6300	0.32
400	7600	0.26
500	9700	0.21
580	10800	0.19

3-131

Figure 3.130: Typical short circuit currents of lead acid battery

In case the DC system utilizes duplicated charger and battery sets, the common practice is to dimension the switchgear for one set at a time. The switchgear should have a bus sectionalizer interlocked with the two battery incomers so that only two of these three switches can be closed simultaneously. The normal operation would have the bus sectionalizer open and both battery and charger sets supplying their own section of the switchgear. If one battery and charger set is to supply the whole switchgear, the changeover would happen through supply break.

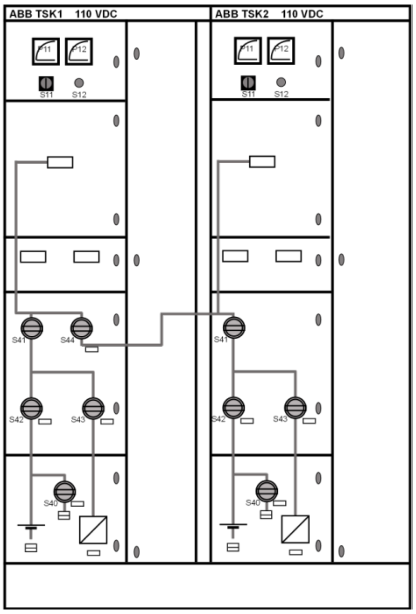


Figure 3.131: Typical DC-switchgear layout for doubled system

3.18.2 AC Auxiliary Supplies

Usually the AC-power distribution at a substation utilizes the same voltage levels and principles as the normal household electrification of that country. Depending on the practice and the legislation in the target country, the AC distribution system can either be 4-wire (TN-C) or 5-wire (TN-S).

3.18.2.1 Elements of AC Auxiliary System

The main components of the system are station auxiliary transformer(s), AC main distribution switchgear, AC sub-distribution board(s) and the cable network. As with the DC auxiliary system, the AC auxiliary system can be also doubled. The doubled system would utilize two station auxiliary transformers, each supplying their own section in the main distribution switchgear. The doubled system can be also constructed so that the second supply is coming from an external source, often the surrounding aerial low-voltage network.

The supply for the station auxiliary transformer is arranged from the medium-voltage level side. If there is no medium voltage available at the substation, like a 330/132 kV substation, normally the main power transformer's tertiary (stabilizing) winding is utilized.

The following figure shows an application where the combined station auxiliary and system-earthing transformer is supplied directly from a main power transformer's (220/33 kV) low-voltage side. Figure 3.132 shows the auxiliary transformer's physical placement as a part of the bay layout. Since the 33 kV side of a 220/33 kV power transformer is delta-connected, thus not offering a point for system earthing, the station auxiliary transformer is also serving as a system-earthing connection point. The station auxiliary transformer has a connection group of ZNyn. The zigzag-connected primary winding provides the 33 kV system-earthing point. By its nature, the zigzag connection provides also means to limit the earth fault currents into desired level. The zero-sequence impedance of a zigzag winding can be influenced, within certain limits, by the transformer design.

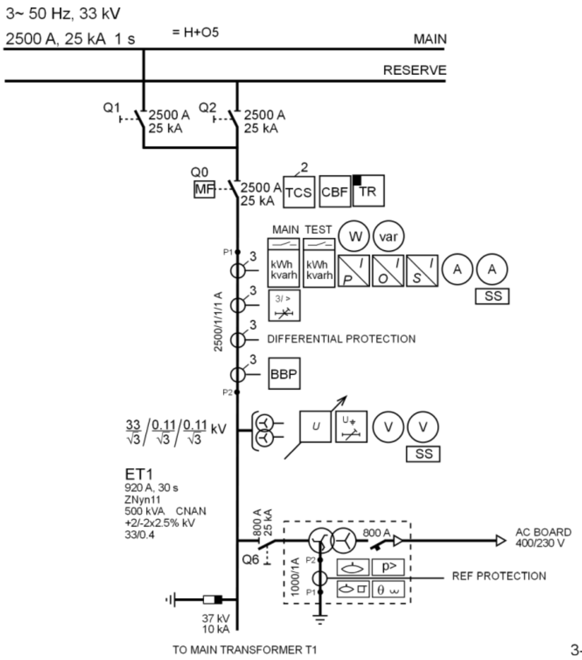


Figure 3.132: **Combined station auxiliary and system earthing transformer connected directly to 33 kV**

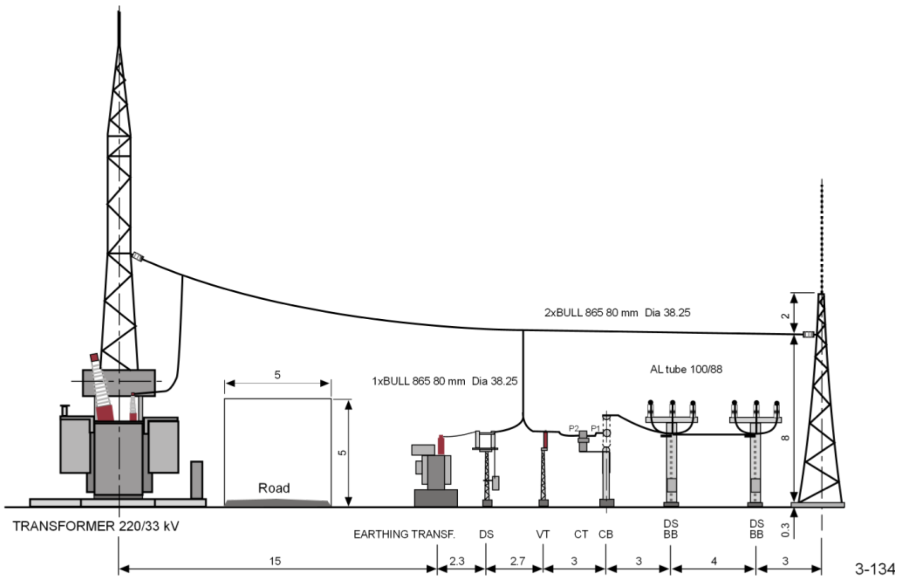


Figure 3.133: **Station auxiliary and system earthing transformer as a part of the bay layout**

When the ZNyn-connected earthing transformer is used for low-voltage AC-power supply, the magnitude of the available earth fault current on the low-voltage side has to be checked, since the zero-sequence reactance of the transformer can limit the current to an unacceptably low value.

3.18.2.2 AC Auxiliary System Earthing

The primary AC auxiliary system typically uses effectively direct grounded system, having all the supply points connected to earth. Affected by the legislation in each country, the system is either utilizing the 4-wire or 5-wire principle.

The use of a 5-wire (TN-S) system enables also the use of residual-current protection in the whole system or in selected feeders. The residual-current protection measures the sum current in all of the phases and the neutral. The sum current must be zero during normal operation. During a system insulation fault, the sum current will rise and the residual current protection switch will open, separating (de-energizing) the section behind the measurement point from the rest of the system. A typical operating current for residual switch is either 30mA or 300mA, the first being used for human protection and the latter for fire protection.

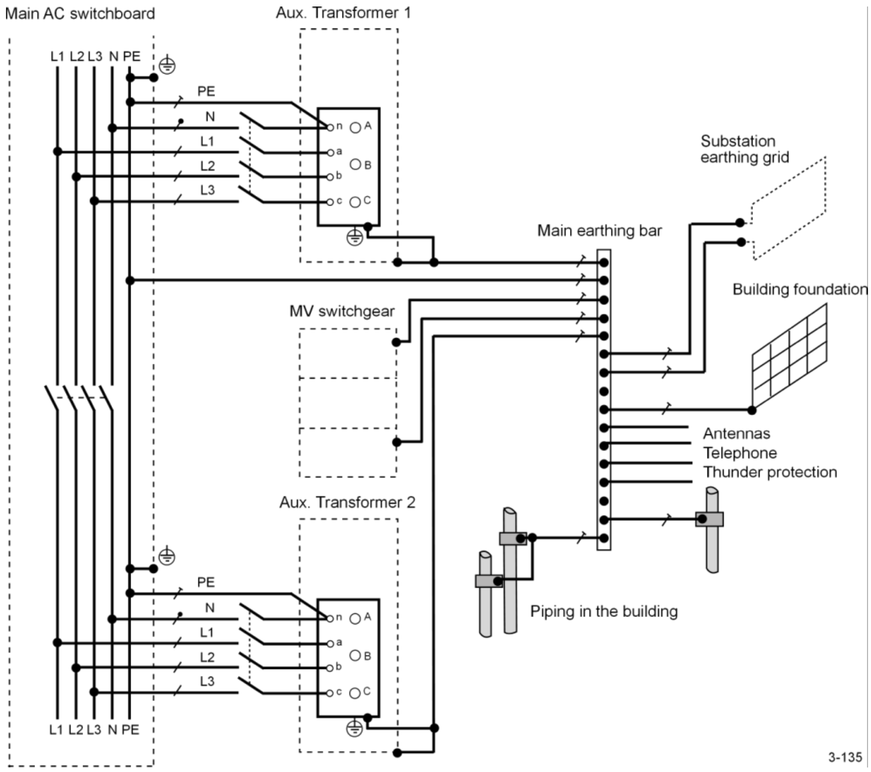


Figure 3.134: Principle of TN-S system with double supply

References

[3.1] Short, T.A.: "Electric Power Distribution Handbook", CRC Press, 2004.

[3.2] Mohan, N.: "Power Electronics – Converters, Applications and Design", 3rd Edition, John Wiley & Sons, 2003.

[3.3] IEC 60909-0, "Short-circuit currents in three-phase a.c. systems - Part 0: Calculation of currents", International Electrotechnical Commission, 2001.

[3.4] "AC metal-enclosed switchgear and controlgear for rated voltages above 1kV and up to and including 52kV" IEC International Standard 62271-200, first edition 11-2003.

[3.5] "Insulation co-ordination – Part 1: Definitions, Principles and Rules" IEC International Standard 60071-, eighth edition 01-2006.

[3.6] "IEEE guide for the protection of stationary battery systems", IEEE Std 1375-1998, New York, 1998.

[3.7] "IEEE Guide for Selection of Valve-Regulated Lead-Acid (VRLA) Batteries for Stationary Applications", IEEE Std 1189-1996.

[3.8] "IEEE Recommended Practice for the Design of DC Auxiliary Power Systems for Generating Stations", IEEE Std 946-2004.

[3.9] Norrgård, Leif: "Auxiliary Voltage Systems for a Substation" Bachelor’s Thesis 1992 for Vasa Swedish Institute of Technology.

[3.10] "IEEE Recommended Practice for Sizing Lead-Acid Batteries for Stationary Applications", IEEE Std 485-1997.

[3.11] Commercial documentation regarding battery chargers by BENNING.

[3.12] "A standarized approach to the application of line reclosers" by ABB (USA) and Progress Energy.

[3.13] "Instrument transformers – Part1: current transformers" IEC International Standard 60044-1, edition 1.2 2003-02.

[3.14] "Instrument transformers – Part2: Inductive voltage transformers" IEC International Standard 60044-2, edition 1.2 2003-02.

[3.15] "Transformer Handbook" ABB Power Technologies Management Ltd. 2004.

[3.16] "Power transformers – Part 1: General" IEC International Standard 60076-1, edition 2.1 2000-04.

[3.17] "Guide for Protective Relay Applications to Power Transformers", Draft 13, ANSI/IEEE Standard C37.91-1999, IEEE, July 1999.

[3.18] "Power Transformer Protection – Application Guide", AG03-5005, ABB Relays, March 1988.

[3.19] Commercial brochure by PostGlover (www.postglover.com/).

[3.20] Commercial documentation of Trench Austria GmbH (www.trenchgroup.com/).

[3.21] Commercial brochure by TECOWestinghouse (www.tecowestinghouse.com/).

Document revision history

Document revision/date	History
A / 02 September 2013	First revision

Disclaimer and Copyrights

Trademarks

This page is intentionally left blank.

This page is intentionally left blank.

This page is intentionally left blank.

Contact information

ABB Oy, Medium Voltage Products,
Distribution Automation
P.O.Box 699
Visiting address: Muottitie 2A
FI-65101 Vaasa, FINLAND
Phone: +358 10 22 11
Fax: +358 10 22 41094

www.abb.com/substationautomation