CZECH TECHNICAL UNIVERSITY IN PRAGUE

Faculty of Electrical Engineering

Power Engineering Department

Voltage and Current Measurement in Modern High Voltage Substations

Měření napětí a proudů v moderních vysokonapěťových rozvodnách

Diploma Thesis

Study program: (MP1) Electrical Engineering, Power Engineering and Management
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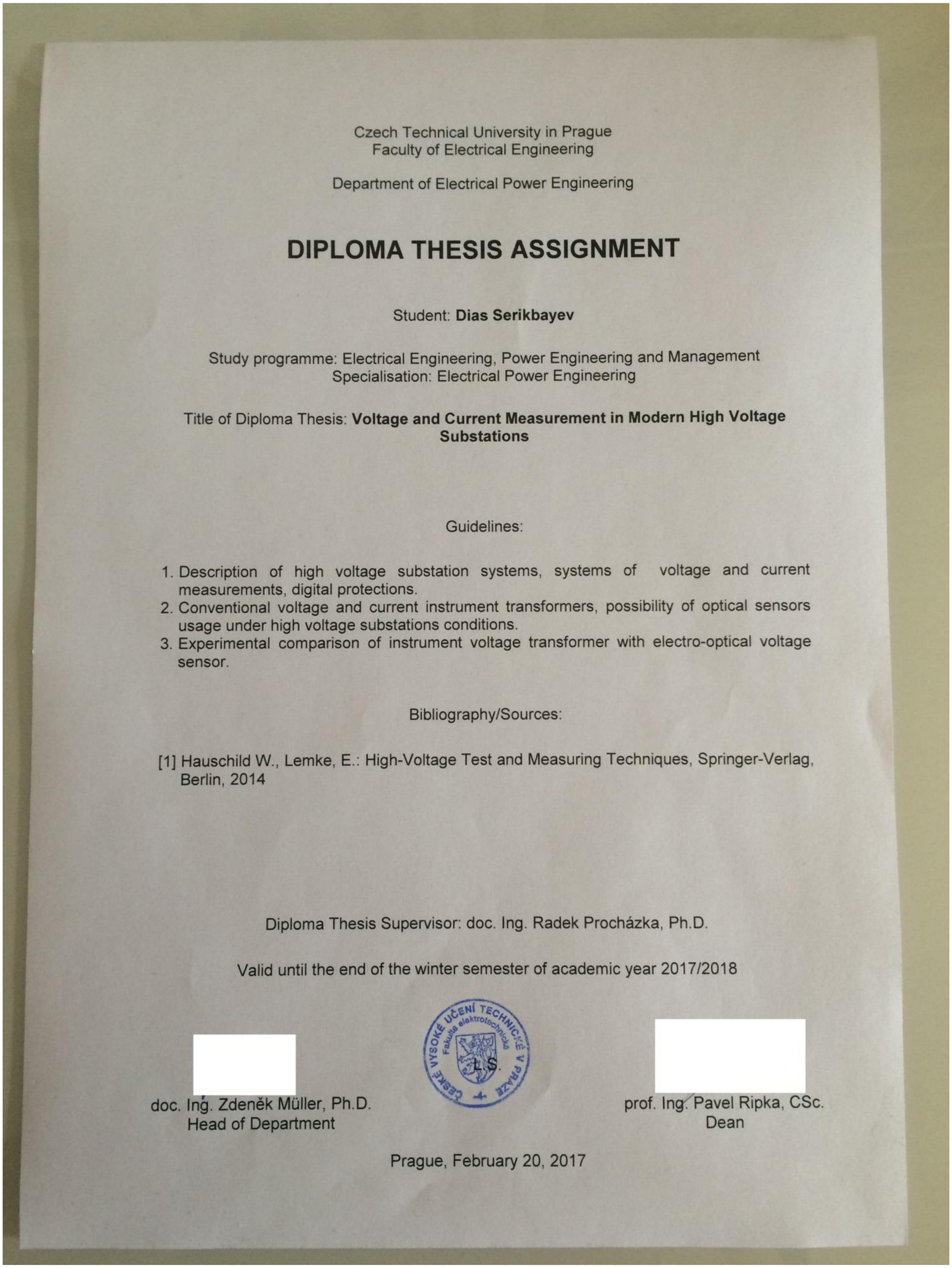
Prague 2017



Czech Technical University in Prague
Faculty of Electrical Engineering

Department of Electrical Power Engineering

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1. Description of high voltage substation systems, systems of voltage and current measurements, digital protections.
2. Conventional voltage and current instrument transformers, possibility of optical sensors usage under high voltage substations conditions.
3. Experimental comparison of instrument voltage transformer with electro-optical voltage sensor.

Bibliography/Sources:

[1] Hauschild W., Lemke, E.: High-Voltage Test and Measuring Techniques, Springer-Verlag, Berlin, 2014

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Declaration

I hereby declare that this thesis is the result of my own work and all the sources I used are in the list of references, in accordance with Methodological Instructions of Ethical Principle in the Preparation of University Thesis.

In Prague, 26.05.2017 Signature.............................

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Abstract

The main aim of this thesis is about measurements of current and voltage in modern high voltage substation, general information of high voltage substation systems, systems of measurement in high voltage substations, description of conventional instrument transformer and optical sensors. Experimental part is comprised of comparison of instrument voltage transformer and electro-optical sensor.

Key Words

High voltage substation, measurement, instrument transformer, optical sensor.

Abstrakt

Hlavním cílem této práce je měření proudů a napětí v moderních rozvodnách vysokého napětí, obecné informace o vysokonapěťových rozvodnách a systémy měření v těchto stanicích. Dále pak popis běžných přístrojových transformátorů a optických senzorů. V Experimentální části je srovnání přístrojového napěťového transformátoru a elektrooptického snímače.

Klíčová slova

Vysokonapěťová rozvodna, měření, přístrojový transformátor, optický senzor

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Introduction

One of the most important processes in power engineering is a high voltage measurement. There are very high requirements to quality of measurements. Accuracy, resistivity on distortion and time of response are main parameters.

In industry and distribution system the high voltage is measured by voltage transformer. The method of measuring high voltage by the electrostatic voltmeter and voltage divider is used in high voltage laboratories. Development of electro-optic and electronics gives a new capability for high voltage measurement.

In recent years optical current and voltage transducers have reached a high degree of maturity and started to compete with conventional instrument transformers. Fiber-optic transducers are ideally adapted to high-voltage environments as they are highly immune to electro-magnetic interference and there is no galvanic connection between the sensor head on high-voltage and substation electronics. Many problems of their conventional counterparts are inexistent such as magnetic saturation or danger of catastrophic failure. The wide bandwidth of optical sensors is important for fast protection and power quality monitoring. Optical transducers can be easily installed on or integrated into existing substation equipment such as circuit breakers or bushings resulting in significant space savings and reduced installation costs. Furthermore, there is no danger of a contamination of the environment due to loss of oil. In the following, we will consider optical current and voltage sensors

Thesis includes description high voltage substation system with most common used switchgear and switchyard, most common arrangements of switchgear.

Experimental part consist of comparison measured values of the electro-optical sensor and the conventional voltage transformer

1. Description of high voltage substation systems

1.1 Gas-Insulated Substation

A gas-insulated substation (GIS) uses a superior dielectric gas, sulfur hexafluoride (SF6), at a moderate pressure for phase-to-phase and phase-to-ground insulation. The high-voltage conductors, circuit breaker interrupters, switches, current transformers (CTs), and voltage transformers (VTs) are encapsulated in SF6 gas inside grounded metal enclosures. The atmospheric air insulation used in a conventional, air-insulated substation (AIS) requires meters of air insulation to do what SF6 can do in centimeters. GIS can therefore be smaller than AIS by up to a factor of 10. A GIS is mostly used where space is expensive or not available. In a GIS, the active parts are protected from deterioration from exposure to atmospheric air, moisture, contamination, etc. As a result, GIS is more reliable, requires less maintenance, and will have a longer service life (more than 50 years) than AIS. [1]

1.1.1 Construction of GIS

GIS consists of standard equipment parts (circuit breaker, CTs, VTs, disconnect and ground switches, interconnecting bus, and connections to the rest of the electric power system) to match the electrical one-line diagram of the substation. A cross-section vision of a 242 kV GIS shows the construction and typical dimensions (Figure 1.1).

The modules are joined using bolted flanges with an “O”-ring seal system for the enclosure and a sliding plug-in contact for the conductor. Internal parts of the GIS are supported by cast epoxy insulators.

These support insulators provide a gas barrier between parts of the GIS or are cast with holes in the epoxy to allow gas to pass from one side to the other.

Up to about 170 kV system voltage, all three phases are often in one enclosure (Figure 1.2). 170 kV and upper, the size of the enclosure for “three-phase enclosure” GIS becomes too huge to be rational. [2]

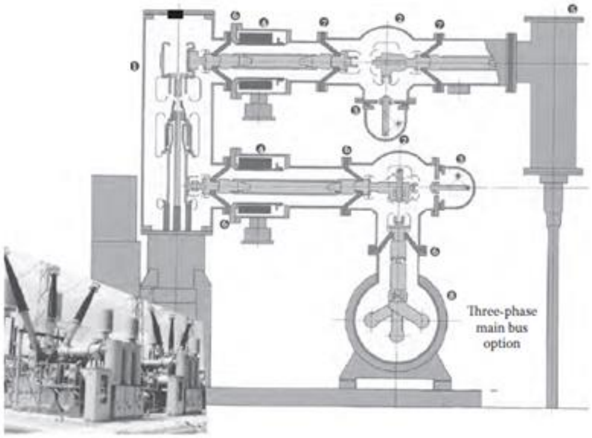


Figure 1.1: Single-phase enclosure GIS.

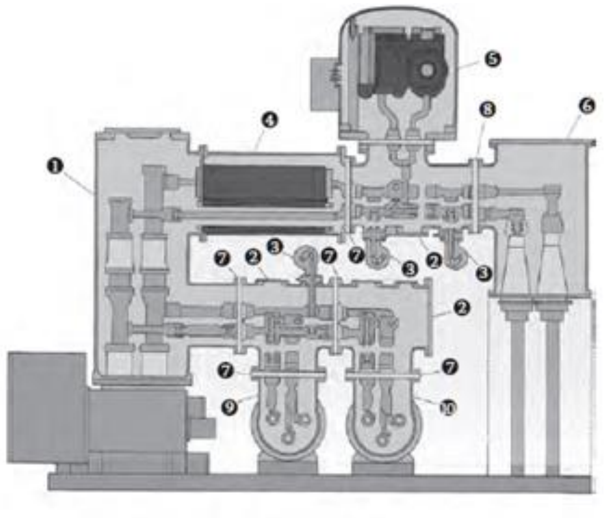


Figure 1.2: Three-phase enclosure GIS.

So a “single-phase enclosure” design (Figure 1.1) is used. There are no established performance differences between the three-phase enclosure and the single-phase enclosure GIS. Some manufacturers use the single-phase enclosure type for all voltage levels. Some users do not want the three phase-to-ground faults at certain locations (such as the substation at a large power plant) and will specify single-phase enclosure GIS.[4]

For today aluminum is used mostly to produce enclosures, but steel is also used. Steel enclosures are painted inside and outside to prevent rusting. There is no necessary to paint aluminum enclosures but could be be painted for ease of cleaning, a better appearance, or to optimize heat transfer to the ambient. The choice between aluminum and steel is made on the basis of cost (steel is less expensive) and the continuous current (above about 2000 A, steel enclosures require nonmagnetic inserts of stainless steel or the enclosure material is changed to all stainless steel or aluminum). Pressure vessel requirements for GIS enclosures are set by GIS standards [4,5], with the actual design, manufacture, and test following an established pressure vessel standard of the country of manufacture. Because of the moderate pressures involved, and the classification of GIS as electrical equipment, third party inspection and code stamping of the GIS enclosures are not required. The use of rupture disks as a safety measure is common although the pressure rise due to internal fault arcs in a GIS compartment of the usual size is predictable and slow enough that the protective system will interrupt the fault before a dangerous pressure is reached.

Nowadays, aluminum is often used as a material of conductor. Copper is sometimes used for high continuous current ratings.

It is usual to silver plate surfaces that transfer current. Bolted joints and sliding electrical contacts are used to join conductor sections. There are many designs for the sliding contact element. In general, sliding contacts have many individually sprung copper contact fingers working in parallel. Usually, the contact fingers are silver plated. A contact lubricant is used to ensure that the sliding contact surfaces do not generate particles or wear out over time. The sliding conductor contacts make assembly of the modules easy and also allow for conductor movement to accommodate differential thermal expansion of the conductor relative to the enclosure. Sliding contact assemblies are also used in circuit breakers and switches to transfer current from the moving contact to the stationary contacts.[3]

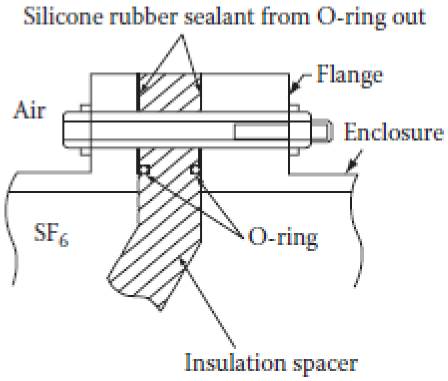


Figure 1.3: Gas seal for GIS enclosure. O-ring is primary seal; silicone rubber sealant is backup seal and protects O-ring and flange surfaces.

Support insulators are made of a highly filled epoxy resin cast very carefully to prevent formation of voids or cracks during curing. Each GIS manufacturer’s material formulation and insulator shape has been developed to optimize the support insulator in terms of electric-field distribution, mechanical strength, resistance to surface electric discharges, and convenience of manufacture and assembly.

Post, disk, and cone-type support insulators are used. Quality assurance programs for support insulators include a high-voltage power frequency withstand test with sensitive partial discharge monitoring.

Experience has shown that the electric-field stress inside the cast epoxy insulator should be below a definite level to avoid aging of the solid dielectric material. The electrical stress limit for the cast epoxy support insulator is not a severe design constraint because the dimensions of the GIS are mainly set by the lightning impulse withstand level of the gas gap and the need for the conductor to have a fairly large diameter to carry to load currents of several thousand amperes. The result is enough space between the conductor and enclosure to accommodate support insulators having low electrical stress.

1.1.2 Circuit Breaker

GIS uses essentially the same dead tank SF6 puffer circuit breakers as are used for AIS. Instead of SF6-to-air bushings mounted on the circuit breaker enclosure, the GIS circuit breaker is directly connected to the adjacent GIS module.

1.1.3 Current Transformers

CTs are inductive ring type mounted either inside the GIS enclosure or outside the GIS enclosure (Figure 1.4). The GIS conductor is the single turn primary for the CT. Enclosure of CTs should be shielded inside from the electric field produced by the high-voltage conductor. It needs to protect the secondary through capacitive coupling from transient voltages. For CTs outside the enclosure, the enclosure itself must be provided with an insulating joint, and enclosure currents shunted around the CT. Constructions of those two types are used in worldwide. [3]

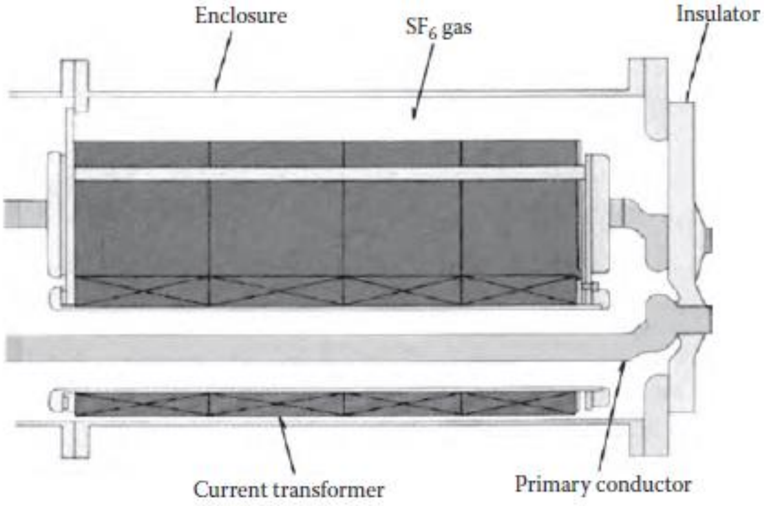


Figure 1.4: CTs for GIS

Rogowski coil is novel CT without core, have been developed to save space and reduce the cost of GIS. The output signal is at a low level, so it is immediately converted by an enclosure mounted device to a digital signal. It can be transmitted over long distances using wire or fiber optics to the control and protective relays. However, most protective relays being used by utilities are not ready to accept a digital input even though the relay may be converting the conventional analog signal to digital before processing. The Rogowski coil type of CT is linear regardless of current due to the absence of magnetic core material that would saturate at high currents.

1.1.4 Voltage Transformers

VTs are inductive type with an iron core. The primary winding is supported on an insulating plastic film immersed in SF6. The VT should have an electric-field shield between the primary and secondary windings to prevent capacitive coupling of transient voltages. The VT is usually a sealed unit with a gas barrier insulator. The VT is either easily removable, so the GIS can be high voltage tested without damaging the VT, or the VT is provided with a disconnect switch or removable conductor link (Figure 1.5). Advanced voltage sensors using a simple capacitive coupling cylinder between the conductor and enclosure have been developed. In addition to size and cost advantages, these capacitive sensors do not have to be disconnected for the Routine high-voltage withstand test. [3]

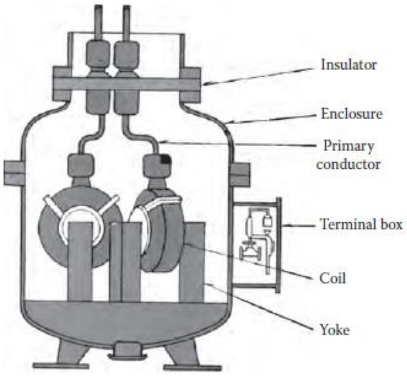


Figure 1.5: VTs for GIS

1.1.5 Disconnect Switches

Disconnect switches (Figure 1.6) have a moving contact that opens or closes a gap between stationary contacts when activated by an insulating operating rod that is itself moved by a sealed shaft coming through the enclosure wall. The stationary contacts have shields that provide the appropriate electricfield distribution to avoid too high a surface electrical stress. The moving contact velocity is relatively low (compared to a circuit breaker moving contact) and the disconnect switch can interrupt only low levels of capacitive current (e.g., disconnecting a section of GIS bus) or small inductive currents (e.g., transformer magnetizing current). For transformer magnetizing current interruption duty, the disconnect switch is provided with a fast acting spring operating mechanism. Load break disconnect switches have been furnished in the past, but with improvements and cost reductions of circuit breakers, it is not practical to continue to furnish load break disconnect switches—a circuit breaker should be used instead.

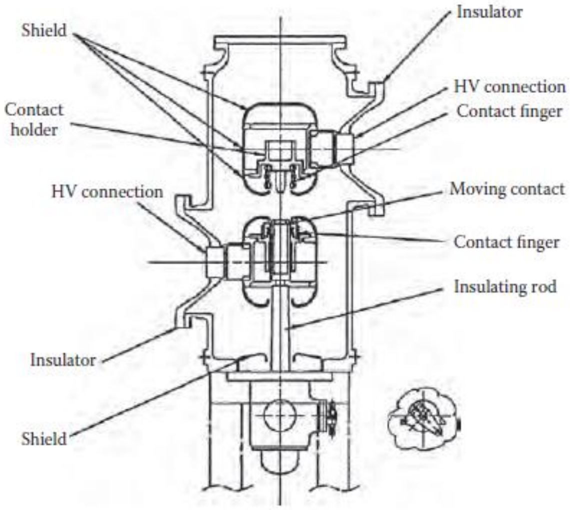


Figure 1.6: Disconnect switches for GIS.

1.1.6 Interconnecting Bus

To connect GIS modules that are not directly connected to each other, SF6 bus consisting of an inner conductor and outer enclosure is used. Support insulators, sliding electrical contacts, and flanged enclosure joints are usually the same as for the GIS modules, and the length of a bus section is normally limited by the allowable span between conductor contacts and support insulators to about 6 m. Specialized bus designs with section lengths of 20 m have been developed and are applied both with GIS and as separate transmission links.

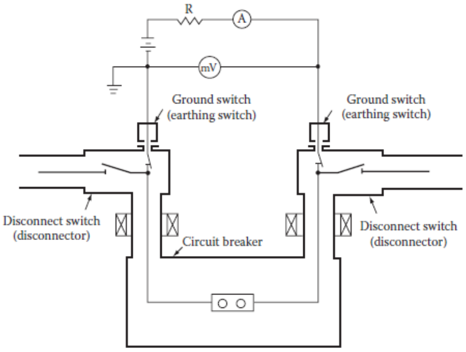


Figure 1.7: Contact resistance measured using ground switch. mV, voltmeter; A, ammeter; and R, resistor

1.1.7 Air Connection

SF6-to-air bushings (Figure 1.8) are made by attaching a hollow insulating cylinder to a flange on the end of a GIS enclosure. The insulating cylinder contains pressurized SF6 on the inside and is suitable for exposure to atmospheric air on the outside. The conductor continues up through the center of the insulating cylinder to a metal end plate. The outside of the end plate has provisions for bolting on an air-insulated conductor. The insulating cylinder has a smooth interior. Sheds on the outside improve the performance in air under wet or contaminated conditions. Electric-field distribution is controlled by internal metal shields. Higher voltage SF6-to-air bushings also use external shields. The SF6 gas inside the bushing has usually the same pressure as the rest of the GIS. The insulating cylinder has most often been porcelain in the past, but today many are a composite consisting of fiberglass epoxy inner cylinder with an external weathershed of silicone rubber. The composite bushing has better contamination resistance and is inherently safer because it will not fracture as will porcelain. [1]

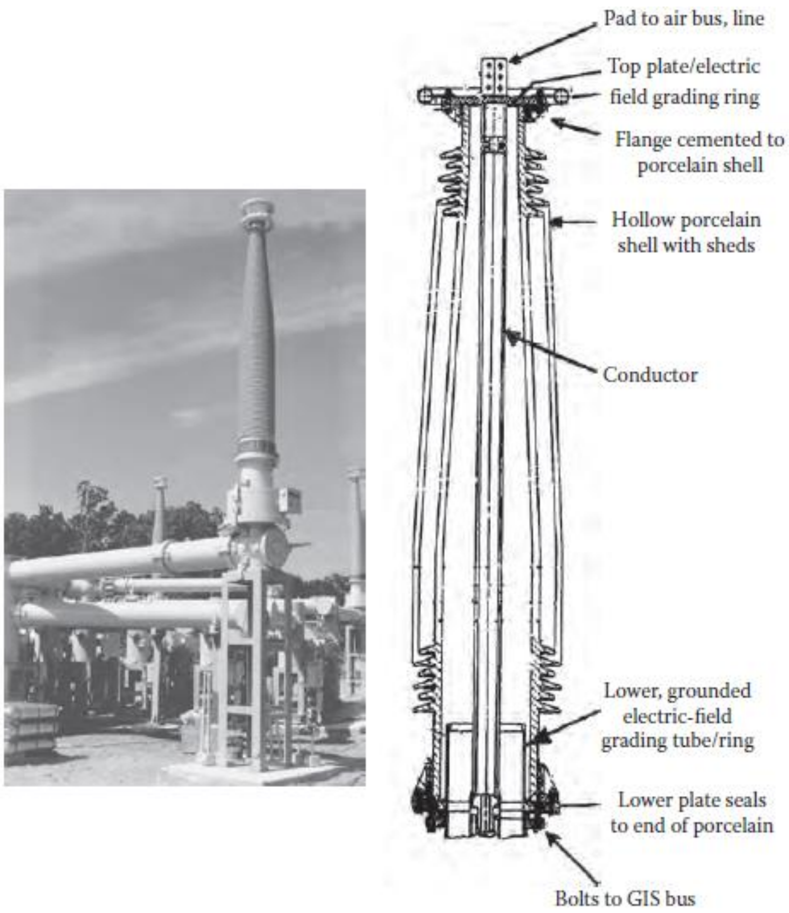


Figure 1.8: SF6-to-air bushing

1.2 Air-Insulated Substations [6]

There are several factors influences on reliability of an substation or switchgear, one of which is the layout of switching devices and buses. The following are the six types of arrangements commonly used:

1. Single bus
2. Double bus–double breaker
3. Main and transfer (inspection) bus
4. Double bus–single breaker
5. Ring bus
6. Breaker-and-a-half

Additional parameters to be considered when evaluating the configuration of a substation or a switchyard are maintenance, operational flexibility, relay protection, cost, and also line connections to the facility. This chapter will review each of the six basic configurations and compare how the arrangement of switching devices and buses of each impacts reliability and these parameters.

1.2.1 Single Bus Arrangement

This is the simplest bus arrangement, a single bus and all connections directly to one bus (Figure 1.9). Reliability of the single bus configuration is low: even with proper relay protection, a single bus failure on the main bus or between the main bus and circuit breakers will cause an outage of the entire facility. With respect to maintenance of switching devices, an outage of the line they are connected to is required. Furthermore, for a bus outage the entire facility must be de-energized. This requires standby generation or switching loads to adjacent substations, if available, to minimize outages of loads supplied from this type of facility.

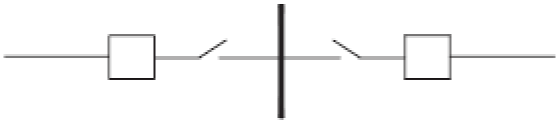


Figure 1.9: Single bus arrangement

Cost of a single bus arrangement is relatively low, but also is the operational flexibility; for example, transfer of loads from one circuit to another would require additional switching devices outside the substation.

Line connections to a single bus arrangement are normally straight forward, since all lines are connected to the same main bus. Therefore, lines can be connected on the main bus in areas closest to the direction of the departing line, thus mitigating lines crossing outside the substation.

Due to the low reliability, significant efforts when performing maintenance, and low operational flexibility, application of the single bus configuration should be limited to facilities with low load levels and low availability requirements.

Since single bus arrangement is normally just the initial stage of a substation development, when laying out the substation a designer should consider the ultimate configuration of the substation, such as where future supply lines, transformers, and bus sections will be added. As loads increase, substation reliability and operational abilities can be improved with step additions to the facility, for example, a bus tie breaker to minimize load dropped due to bus outages.

1.2.2 Double Bus-Double Breaker Arrangement

The double bus–double breaker arrangement involves two breakers and two buses for each circuit (Figure 1.10). With two breakers and two buses per circuit, a single bus failure can be isolated without interrupting any circuits or loads. Furthermore, a circuit failure of one circuit will not interrupt other circuits or buses. Therefore, reliability of this arrangement is extremely high.

Maintenance of switching devices in this arrangement is very easy, since switching devices can be taken out-of-service as needed and circuits can continue to operate with partial line relay protection and some line switching devices in-service, i.e., one of the two circuit breakers.

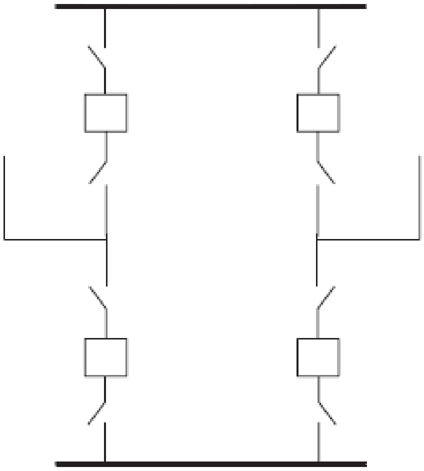


Figure 1.10: Double breaker-double bus arrangement

Apparently, with double the amount of switching devices and buses, cost will be substantially increased relative to other more simple bus configurations. In addition, relaying is more complicated and more space is required, especially for low-profile substation configurations.

Outdoor line connections to a double breaker–double bus substation normally do not cause conflicts with each other, but may require substantial land area adjacent to the facility as this type of station expands.

This layout allows for operational flexibility; certain lines could be fed from one bus section by switching existing devices.

This bus configuration is applicable for loads requiring a high degree of reliability and minimum interruption time. The double breaker–double bus configuration is expandable to different configurations, for instance, a ring bus or breaker-and-a-half configurations.

1.2.3 Main and Transfer Bus Arrangement

The main and transfer bus configuration connects all circuits between the main bus and a transfer bus (sometimes referred to as an inspection bus). Some arrangements include a bus tie breaker and others simply utilize switches for the tie between the two buses (Figure 1.11).

This configuration is similar to the single bus layout; in that during normal operations, all circuits are connected to the main bus. So the operating reliability is low; a main bus fault will de-energize all circuits.

However, the transfer bus is used to improve the maintenance process by moving the line of the circuit breaker to be maintained to the transfer bus. Some systems are operated with the transfer bus normally de-energized. When a circuit breaker needs to be maintained, the transfer bus is energized through the tie breaker. Then the switch, nearest the transfer bus, on the circuit to be maintained is closed and its breaker and associated isolation switches are opened. Thus transferring the line of the circuit breaker to be maintained to the bus tie breaker and avoiding interruption to the circuit load. Without a bus tie breaker and only bus tie switches, there are two options. The first option is by transferring the circuit to be maintained to one of the remaining circuits by closing that circuit's switch (nearest to the transfer bus) and carrying both circuit loads on the one breaker. This arrangement most likely will require special relay settings for the circuit breaker to carry the transferred load. The second option is by transferring the circuit to be maintained directly to the main bus with no relay protection from the substation.

Apparently in the latter layout, relay protection (recloser or fuse) immediately outside the substation should be considered to minimize faults on the maintained line circuit from causing extensive station outages. In addition, if a low-profile configuration is used, land requirements are substantially more.

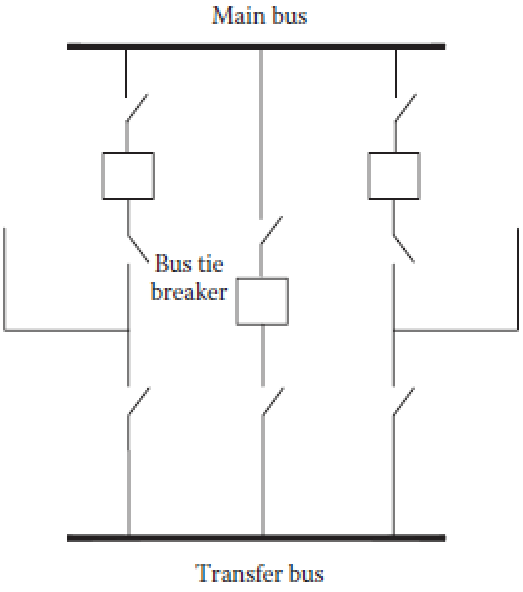


Figure 1.11: Main and transfer bus arrangement

Connections of lines to the station should not be very complicated. If a bus tie breaker is not installed, consideration as to normal line loading is important for transfers during maintenance. If lines are normally operated at or close to their capability, loads will need to be transferred or temporary generators provided similar to the single bus arrangement maintenance scenario.

The main and transfer bus arrangement is an initial stage configuration, since a single main bus failure can cause an outage of the entire station. As load levels at the station rise, consideration of a main bus tie breaker should be made to minimize the amount of load dropped for a single contingency. Another operational capability of this configuration is that the main bus can be taken out-of-service without an outage to the circuits by supplying from the transfer bus, but obviously, relay protection (recloser or fuse) immediately outside the substation should be considered to minimize faults on any of the line circuit from causing station outages.

1.2.4 Double Bus-Single Breaker Arrangement

The double bus–single breaker arrangement connects each circuit to two buses, and there is a tie breaker between the buses. With the tie breaker operated normally closed, it allows each circuit to be supplied from either bus via its switches. Thus providing increased operating flexibility and improved reliability. For example, a fault on one bus will not impact the other bus. Operating the bus tie breaker normally open eliminates the advantages of the system and changes the configuration to a two single bus arrangement (Figure 1.12).

Relay protection for this arrangement will be complex with the flexibility of transferring each circuit to either bus. Operating procedures would need to be detailed to allow for various operating arrangements, with checks to ensure the in-service arrangements are correct. A bus tie breaker failure will cause an outage of the entire station.

The double bus–single breaker arrangement with two buses and a tie breaker provides for some ease in maintenance, especially for bus maintenance, but maintenance of the line circuit breakers would still require switching and outages as described above for the single bus arrangement circuits.

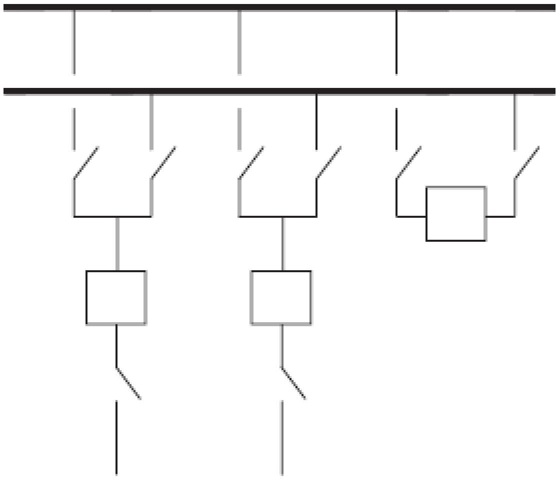


Figure 1.12: Double bus-single breaker arrangement

Once again, low-profile configuration of this arrangement would require more area. In addition, bus and circuit crossings within the substation are more likely.

Application of this arrangement is best suited where load transfer and improved operating reliability are important. Though adding a transfer bus to improve maintenance could be considered, it would involve additional area and switching devices, which could increase the cost of the station.

1.2.5 Ring Bus Arrangement

As the name implies, all breakers are arranged in a ring with circuits connected between two breakers. From a reliability standpoint, this arrangement affords increased reliability to the circuits, since with properly operating relay protection, a fault on one bus section will only interrupt the circuit on that bus section and a fault on a circuit will not affect any other device (Figure 1.13).

Protective relaying for a ring bus will involve more complicated design and, potentially, more relays to protect a single circuit. Keep in mind that bus and switching devices in a ring bus must all have the same ampacity, since current flow will change depending on the switching device's operating position.

From a maintenance point of view, the ring bus provides good flexibility. A breaker can be maintained without transferring or dropping load, since one of the two breakers can remain in-service and provide line protection while the other is being maintained.

Similarly, operating a ring bus facility gives the operator good flexibility since one circuit or bus section can be isolated without impacting the loads on another circuit.

Cost of the ring bus arrangement can be more expensive than a single bus, main bus and transfer, and the double bus–single breaker schemes since two breakers are required for each circuit, even though one is shared.

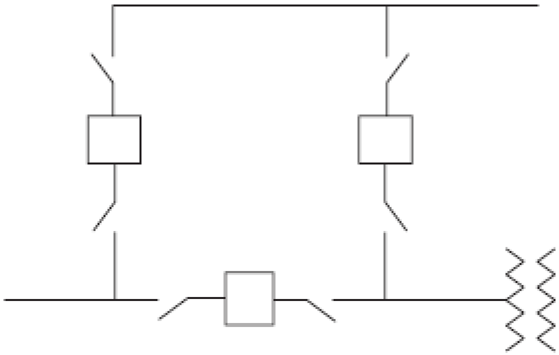


Figure 1.13: Ring bus arrangement

The ring bus arrangement is applicable to loads where reliability and availability of the circuit is a high priority. There are some disadvantages of this arrangement: (a) a "stuck breaker" event could cause an outage of the entire substation depending on the number of breakers in the ring, (b) expansion of the ring bus configuration can be limited due to the number of circuits that are physically feasible in this arrangement, and (c) circuits into a ring bus to maintain a reliable configuration can cause extensive bus and line work. For example, to ensure service reliability, a source circuit and a load circuit should always be next to one another. Two source circuits adjacent to each other in a stuck breaker event could eliminate all sources to the station. Therefore, a low-profile ring bus can command a lot of area.

2. Systems of current and voltage measurements [7]

2.1 Design of terminals for current transformers

In conformity to IEC standards, design of terminals should be implemented as shown below in diagrams. The terminals should have the identical polarity.

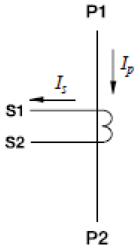


Figure 2.1:
Transformer with one secondary winding

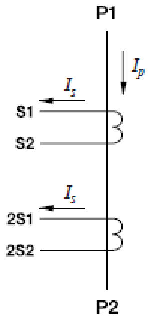


Figure 2.2:
Transformer with two secondary winding

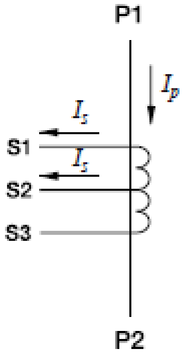


Figure 2.3:
Transformer with one secondary
winding which has an extra tapping

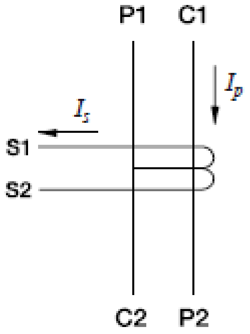
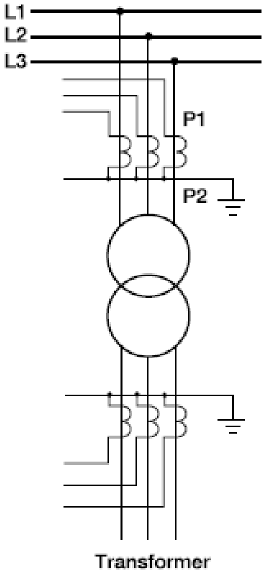


Figure 2.4:
Transformer with primary windings
and one secondary winding

2.2 Secondary grounding of current transformers

To prevent the secondary circuits from attaining dangerously high potential to ground, these circuits have to be grounded. Connect either the S1 terminal or the S2 terminal to ground. For protective relays, ground the terminal that is nearest to the protected objects. For meters and instruments, ground the terminal that is nearest to the consumer. When metering instruments and protective relays are on the same winding, the protective relay determines the point to be grounded. If there are unused taps on the secondary winding, they must be left open. If there is a galvanic connection between more than one current transformer, these shall be grounded at one point only (e.g. differential protection). If the cores are not used in a current transformer they must be short-circuited between the highest ratio taps and shall be grounded.



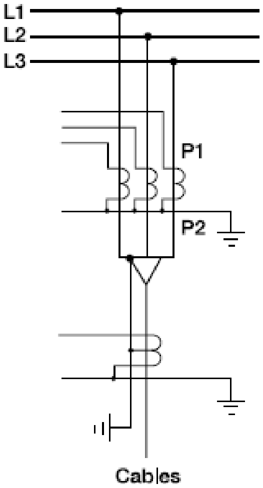


Figure 2.5: Transformer

Figure 2.6: Cables

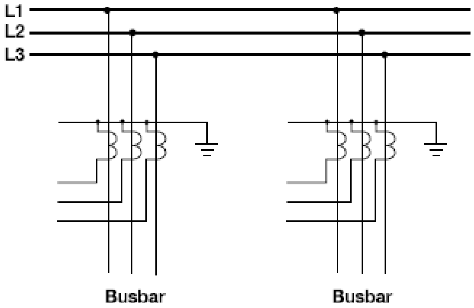


Figure 2.7: Busbar

2.3 Secondary grounding of voltage transformers

To prevent secondary circuits from reaching dangerous potential, the circuits should be grounded. Grounding should be made at only one point on a voltage transformer secondary circuit or galvanically interconnected circuits. A voltage transformer, which on the primary is connected phase to ground, shall have the secondary grounding at terminal n. A voltage transformer, with the primary winding connected between two phases, shall have the secondary circuit, which has a voltage lagging the other terminal by 120 degrees, grounded. Windings not inuse shall be grounded.

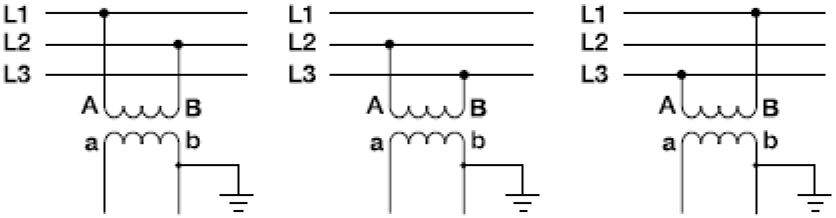


Figure 2.8: Voltage transformers connected between phases

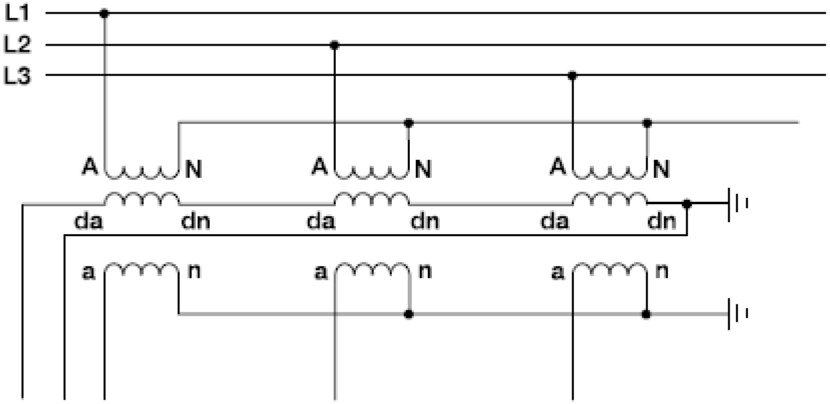


Figure 2.9:A set of voltage transformers with one Y-connected and one broken delta secondary circuit

2.4 Fusing of voltage transformer secondary circuits

Fuses should be provided at the first box where the three phases are brought together. The circuit from the terminal box to the first box is constructed to minimize the risk of faults in the circuit. It is preferable not to use fuses in the voltage transformer terminal box, as this will make the supervision of the voltage transformers more difficult. The fuses in the three-phase box enable a differentiated fusing of the circuits to different loads like protection and metering circuits. The fuses must be selected to give a fast and reliable fault clearance, even for a fault at the end of the cabling. Earth faults and two-phase faults should be checked.

2.5 Arrangement of current and voltage transformers in substations

Instrument transformers are used to supply measured quantities of current and voltage in an appropriate form to controlling and protective apparatus, such as energy meters, indicating instruments, protective relays, fault locators, fault recorders and synchronizers.

Instrument transformers are thus installed when it is necessary to obtain measuring quantities for the above-mentioned purposes. Typical points of installation are switchbays for lines, feeders, transformers, bus couplers, etc., at transformer neutral connections and at the busbars.

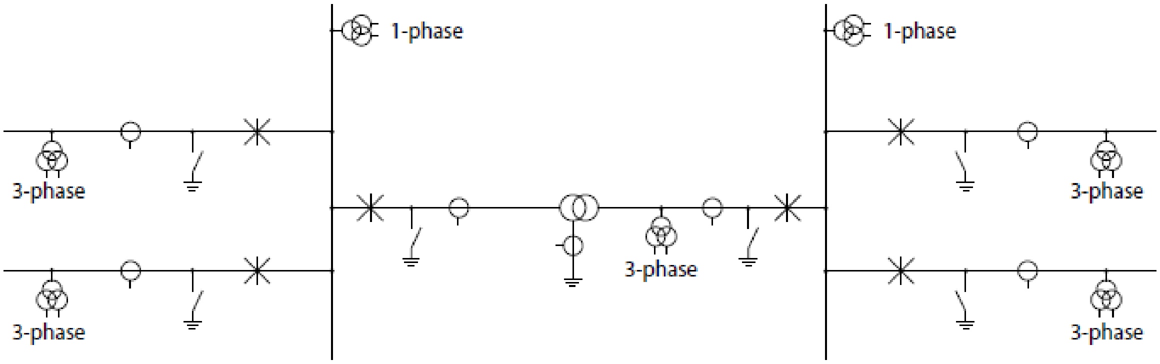


Figure 2.10: Current and voltage transformers in a substation

Location of instrument transformers in different substation arrangements

Below are some examples of suitable locations for current and voltage transformers in a few different switchgear arrangements.

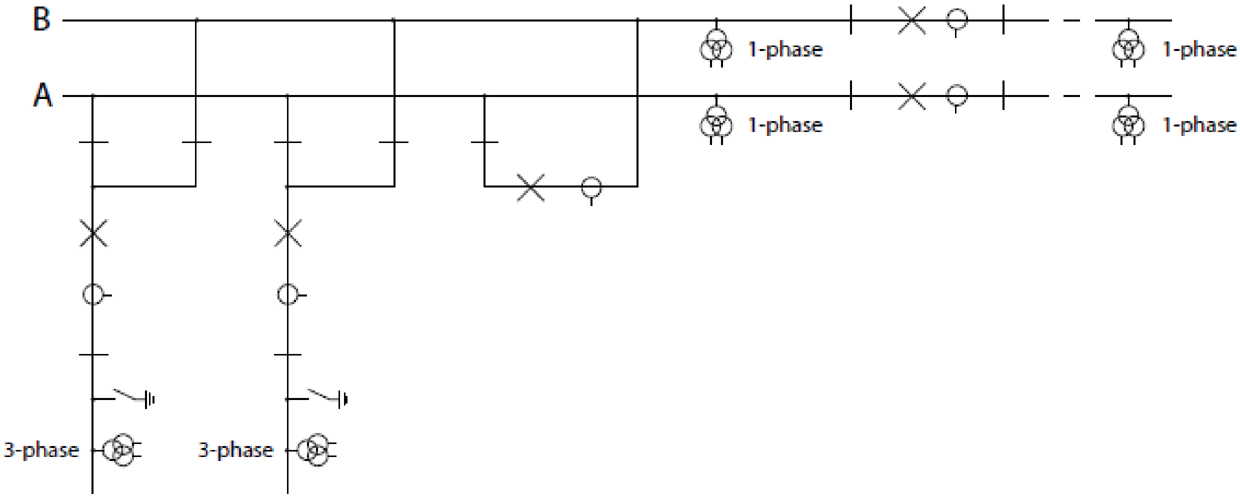


Figure 2.11: Double busbar station

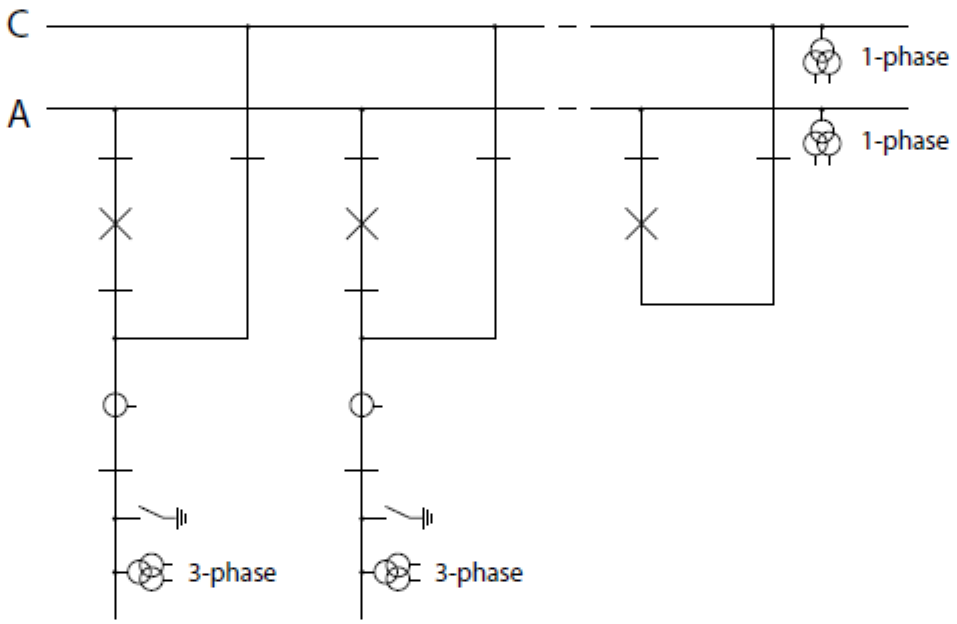


Figure 2.12: Station with transfer busbar

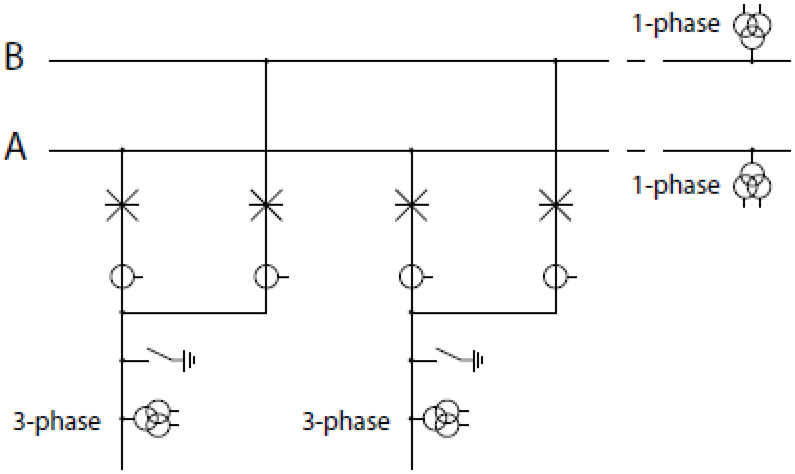


Figure 2.13: Double breaker and double busbar station

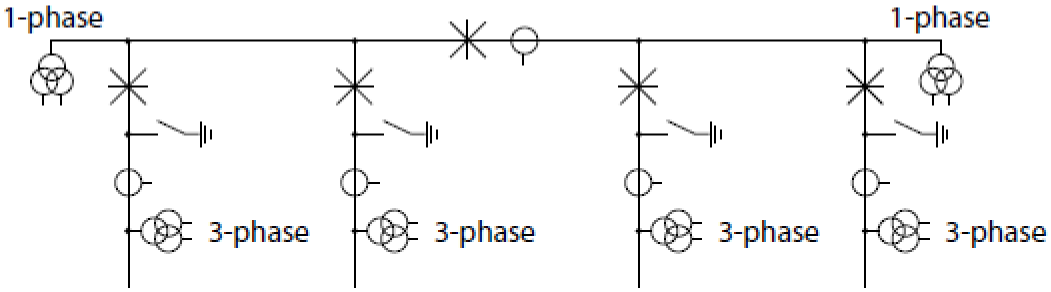


Figure 2.14: Sectionalized single busbar station

2.6. Location of current transformers

Current transformers in line bays

The current transformers are placed near the circuit breakers and on the line side. The detection zones of line relays and busbar relays start at the current transformers and the tripping point is the circuit breaker. It is advantageous if these two points are close to each other. In the improbable case of a fault between the current transformer and the circuit breaker, the busbar protection will detect and clear the fault.

Bus coupler and bus sectionalizer bays

A set of current transformers is necessary to enable different busbar protection zones to be formed. The protection can be arranged to give complete fault clearing with a short time-delay for faults between circuit breaker and current transformer. Sometimes current transformers on both sides of circuit breakers are used but are usually not necessary. It will depend on the arrangement of protective relays.

Transfer busbar station

It is advantageous to locate the current transformers on the line side of the disconnectors for circuit breakers and the transfer bus. In this way the protective relay connected to the current transformer will remain connected to the line when it is switched over to transfer busbar and standby circuit breaker.

Double breaker station

It is usual to locate the current transformers on the line side of the circuit breakers. The two current transformers shall be identical. To determine the line current, the secondary currents of the two current transformers are added together.

One and a half breaker station

As with the double breaker station, current transformers are located at the circuit breakers. In addition, transformer bushing current transformers are used. At the central circuit breaker (tie circuit breaker) two current transformer sets are shown. It is also possible to use a single set of current transformers, but sometimes it can be difficult to accommodate all cores in one current transformer tank.

2.7 Location of voltage transformers

In line bays a three-phase set of voltage transformers or capacitor voltage transformers is used for metering, protection and synchronization. Located at the entry they can also enable indication of voltage on a line energized from the opposite end.

Single-phase voltage transformers on the busbars and at transformers provide reference voltage for synchronization. If these voltage transformers are selected a voltage selection scheme must be used. It will be more or less complex depending on the switchgear configuration. A similar case is the single-phase voltage transformer on the station side of the line disconnector in a 1 ½ circuit breaker station.

3. Protection in modern high voltage substation [8]

3.1 Introduction

Gone are the days of the simple electro-mechanical relay without firmware and communication interfaces. The fact exists that protection and control systems have changed significantly in the past decade and will continue to change with technology advancements. The digital world has impacted the protection system from the introduction of microprocessor based relays in the 1980s to protection relays with communication interfaces in the 1990s. Today's advanced digital protective relays utilize high speed communication to replace copper wires for inter-bay control, safety interlocking and even breaker trip and closing. Modern sensor technology also allows for the digitization and analog acquisition in the switchyard replacing hazardous inductive CT and PT circuits with process bus communications. The Digital World has brought many benefits but also introduces challenges. This paper will focus on the impact of the protection and control system as a result of microprocessor relay introduction in the 1990s. It will discuss key issues the protection and control engineer has encountered in the past and will face with the deployment of the advanced protective relay. Key areas discussed will be performance and benefits including the digitization and transfer function of Non-conventional Instrument Transformers, security threats and best practices for the protection system, fleet management in the age of NERC PRC/CIP regulations and performance consideration to achieve high availability of the protection and control system. As well the paper will address some protection issues such as; since fiber optic current sensor systems have no iron, and no CT saturation, the differential relay need not have multiple slopes to account for CT performance, just a minimum pick up thus increasing the sensitivity several fold.

3.2 The Standard – IEC 61850

First multifunction microprocessor relays were developed in the early 1980s. One was based on the Washington State University Master's Degree Thesis by Ravi Iyer. He joined Brown Boveri Corporation under the mentorship of Stanley Zocholl to design the distribution protection unit becoming the first multifunction microprocessor relay in 1984. This relay performed three phase and ground instantaneous and time overcurrent protection, multi-shot circuit breaker reclosing and integrated per phase metering in a single device that was slightly larger than two single phase electromechanical overcurrent relays. The innovation of the modern digital system roots from this era by the industry pioneers understanding the interworks of the electro-mechanical relationship to engage the revolutionary computer scientist replacing induction discs and spring constants with data acquisition, digital conversion and four point algorithms. These early devices were based on 8-bit microprocessors and programmed in highly optimized assembly source code as the algorithms had to be extremely efficient and program memory size of 64 kilobytes was a luxury. [9]

The microprocessor relay is our industries first venture into The Digital World and it has revolutionized our protection and control systems. The key benefit of the microprocessor relay has been the significant reduction of panel space required to accomplish the same protection system. Figure 1 depicts a line protection system for 1 ½ breaker arrangement.

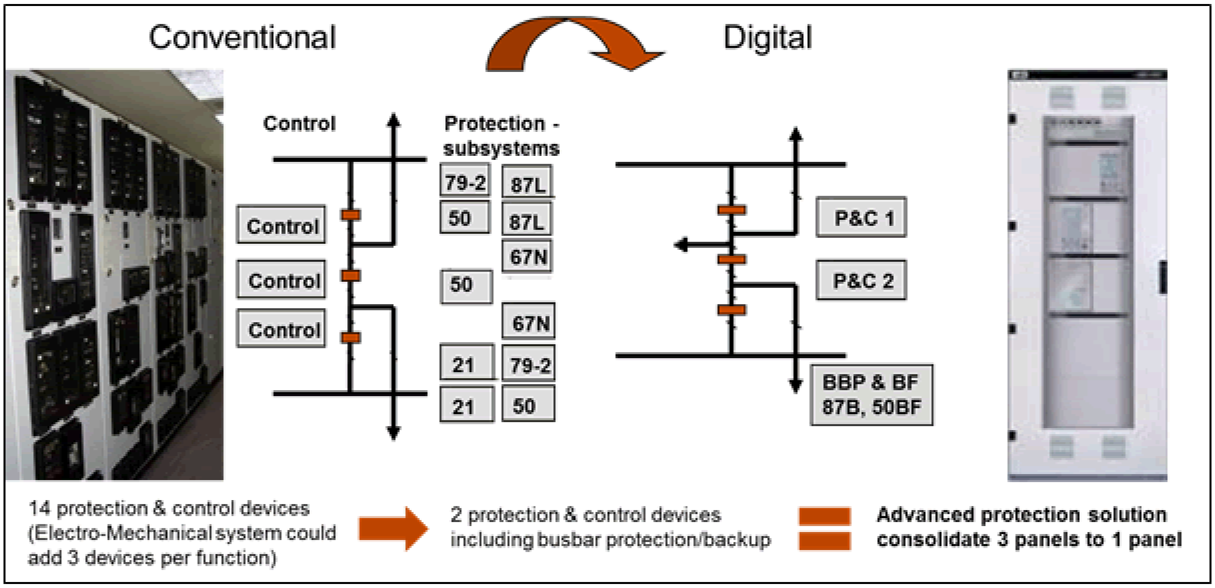


Figure 3.1: Substations secondary systems showing the same application with electro-mechanical relays versus modern digital system

In the Figure 3.1 example, the protection function indicated by the ANSI relay elements were traditionally implemented utilizing discrete relays requiring several relay panels to protect this scheme. The utilization of modern multi-object (protection of more than one primary apparatus) relays and open standards for device to device communications allows for functional consolidation, elimination of control and interlocking copper wire interconnections greatly improving the system performance while increasing both reliability and personnel safety.

The protection and control system may seldom be called upon to operate until the abnormal condition threatens the apparatus. It is this instance that the system must operate to protect the utility assets. A major benefit of the modern protection devices is the advanced self-diagnostics and self-supervision to ensure the highest availability of the system. Electro-mechanical and solid state relays were only found to be non-operational when a fault occurred resulting in a misoperation or during routine testing. The modern protection device has advanced diagnostics to ensure performance or indicate of pending problems. [8.1]

Today, the digital world continues to morph as modern primary apparatus embeds digital technology and the benefits of non-conventional instrument transformers further improve system performance and personnel safety. These enablers on the primary system process level will continue revolutionizing the next generation of system protection, control and automation.[9]

3.3 The Digital Systems

In the digital system, sampled analog values are communicated according IEC 61850 9 2 from merging units or non-conventional instrument transformers (NCITs) to the protection and control IEDs and trip commands are sent as IEC 61850 GOOSE messages to the circuit breaker interfaces. By this, the communication system becomes a critical part in the fault clearance chain affecting the total fault clearance time of the protection system.

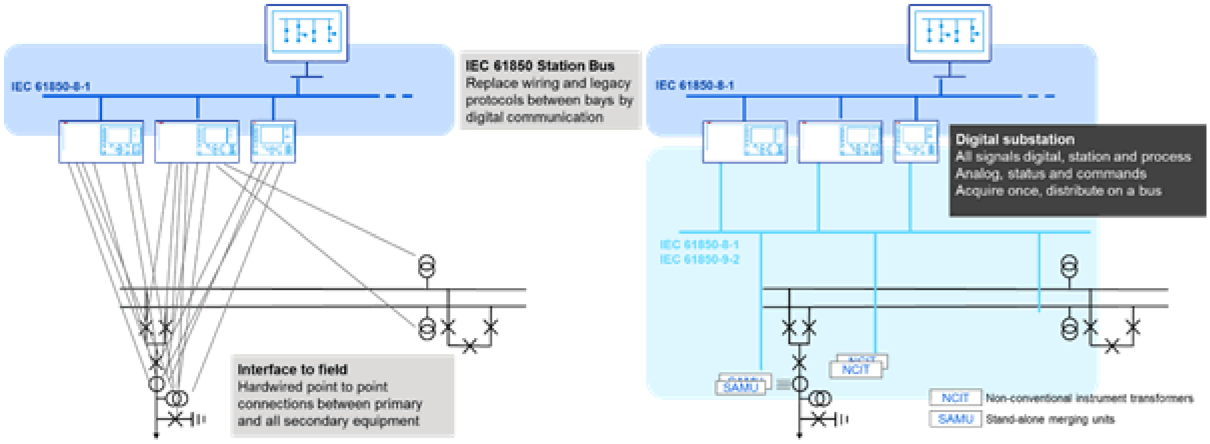


Figure 3.2: Substations secondary systems with direct point-to-point wiring and process bus communication network

3.4 Reduce material

Using fiber optics instead of copper cables not only reduces the copper cabling in a substation by around 80%, depending on voltage level and switchgear type and layout. It also means less material transport to site.If conventional instrument transformers are replaces by non-conventional ones, further weight can be saved. An optical CT for a 400kV AIS installation weights about 20% of its conventional (SF6 filled) counterpart.

3.5 Time of installation

Less cables to be pulled, less equipment to be connected and less connections to be tested. This leads on one hand to shorter installation times of new secondary systems, on the other hand it also helps to reduces outage times during secondary system replacements. The outage time in the latter case can be reduces due to the shorter time required to install the new equipment, but also because the new equipment comes from the factory fully tested from SCADA through protection and control IEDs to process interfaces. Hence testing of the new system that requires outages is reduced. [8]

3.6 Impacts of non-conventional instrument transformers

That non-conventional instrument transformers can provide excellent accuracy of 0.2% or better has been demonstrated in various installations, where the NCITs have been connected to IEC 61850-9-2 process bus enabled grid meters. To verify the accuracy of the digital measuring chain, they have been installed in parallel to a conventional metering system. The installation described in [8], showed that after three years of operation the difference of the accumulated energy measured by the conventional and the digital system was at around 0.35%. This is not the absolute accuracy but the difference of the two measuring systems, which could be up to 0.8% as both systems were allowed to introduce errors of 0.2% for current and voltage.

Even better results are presented in , which describes two installations with NCITs, process bus and grid meters. Here the observed differences for active energy between conventional and non-conventional systems range from 0.01 to 0.19%, far lower than the tolerable error given the accuracy classes of the installed conventional instrument transformers and NCITs of class 0.2 and 0.2s respectively. [9.1]

4. Conventional voltage and current instrument transformers [10]

4.1 Introduction

Whenever the values of voltage or current in a power circuit are too high to permit convenient direct connection of measuring instruments or relays, coupling is made through transformers. Such 'measuring' transformers are required to produce a scaled down replica of the input quantity to the accuracy expected for the particular measurement; this is made possible by the high efficiency of the transformer. The performance of measuring transformers during and following large instantaneous changes in the input quantity is important, in that this quantity may depart from the sinusoidal waveform. The deviation may consist of a step change in magnitude, or a transient component that persists for an appreciable period, or both. The resulting effect on instrument performance is usually negligible, although for precision metering a persistent change in the accuracy of the transformer may be significant. However, many protection systems are required to operate during the period of transient disturbance in the output of the measuring transformers that follows a system fault. The errors in transformer output may abnormally delay the operation of the protection, or cause unnecessary operations. The functioning of such transformers must, therefore, be examined analytically. It can be shown that the transformer can be represented by the equivalent circuit of Figure 4.1, where all quantities are referred to the secondary side.

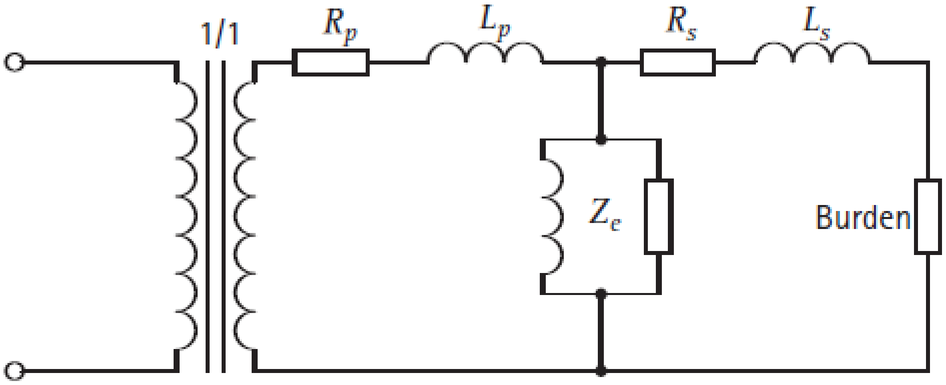


Figure 4.1: Equivalent circuit of transformer

When the transformer is not 1/1 ratio, this condition can be represented by energizing the equivalent circuit with an ideal transformer of the given ratio but having no losses.

4.2 Measuring Transformers

Voltage and current transformers for low primary voltage or current ratings are not readily distinguishable; for higher ratings, dissimilarities of construction are usual. Nevertheless the differences between these devices lie principally in the way they are connected into the power circuit. Voltage transformers are much like small power transformers, differing only in details of design that control ratio accuracy over the specified range of output. Current transformers have their primary windings connected in series with the power circuit, and so also in series with the system impedance. The response of the transformer is radically different in these two modes of operation.

4.3 Electromagnetic voltage transformers

In the shunt mode, the system voltage is applied across the input terminals of the equivalent circuit of Figure 4.1. The vector diagram for this circuit is shown in Figure 4.2.

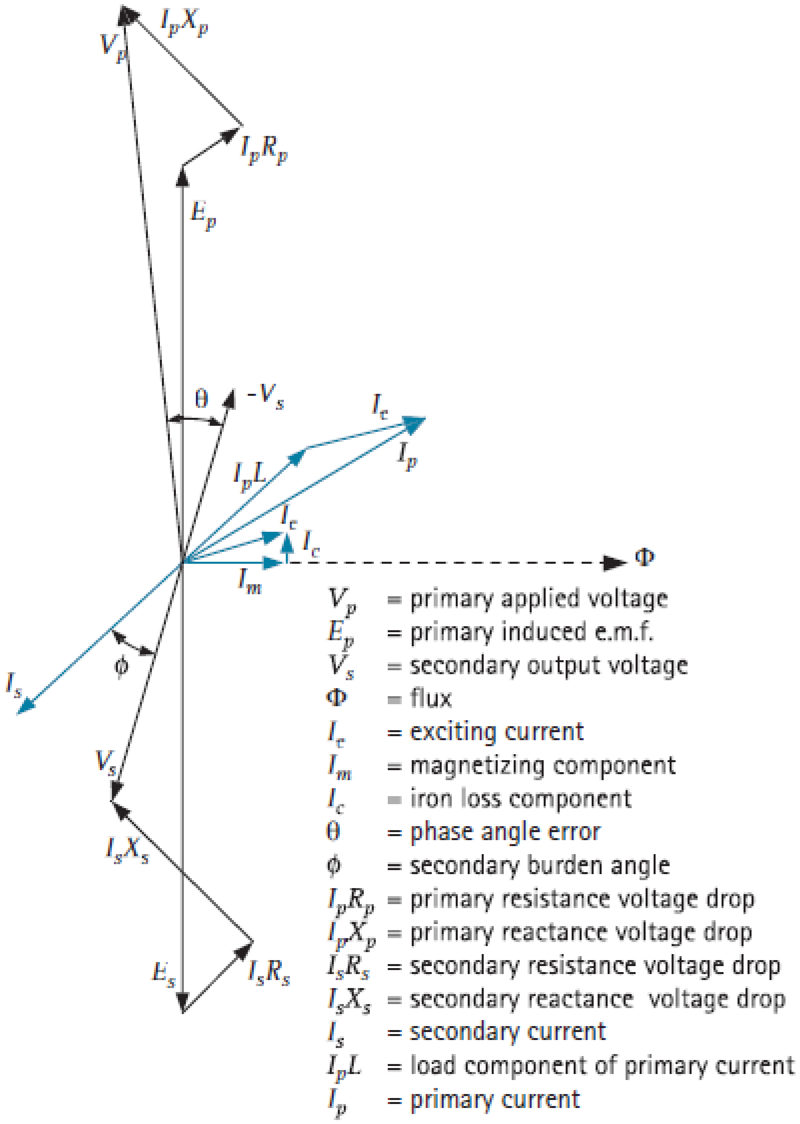


Figure 4.2: Vector diagram for voltage transformer

The secondary output voltage V*s* is required to be an accurate scaled replica of the input voltage V*p* over a specified range of output. To this end, the winding voltage drops are made small, and the normal flux density in the core is designed to be well below the saturation density, in order that the exciting current may be low and the exciting impedance substantially constant with a variation of applied voltage over the desired operating range including some degree of overvoltage. These limitations in design result in a VT for a given burden being much larger than a typical power transformer of similar rating. The exciting current, in consequence, will not be as small, relative to the rated burden, as it would be for a typical power transformer.

4.3.1 Errors

The ratio and phase errors of the transformer can be calculated using the vector diagram of Figure 4.2. The ratio error is defined as:

$$\frac{K_n \times V_s}{V_p} \times 100\%$$

where

K_n is the nominal ratio

V_s is primary voltage

V_p is secondary voltage

If the error is positive, the secondary voltage exceeds the nominal value. The turns ratio of the transformer need not be equal to the nominal ratio; a small turns compensation will usually be employed, so that the error will be positive for low burdens and negative for high burdens.

The phase error is the phase difference between the reversed secondary and the primary voltage vectors. It is positive when the reversed secondary voltage leads the primary vector. Requirements in this respect are set out in IEC 60044-2. All voltage transformers are required to comply with one of the classes in Table 4.1.

Accuracy class	0.8-1.2 x rated voltage 0.25-1.0 x rated burden at 0.8pf	
	Voltage ratio error (%)	Phase displacement (minutes)
0.1	+/- 0.1	+/- 5
0.2	+/- 0,2	+/- 10
0.5	+/- 0.5	+/- 20
1.0	+/- 1.0	+/- 40
3.0	+/- 3.0	not specified

Table 4.1: Measuring voltage transformer error limits

4.3.2 Voltage Factors

The quantity Vf in Table 4.2 is an upper limit of operating voltage, expressed in per unit of rated voltage. This is important for correct relay operation and operation under unbalanced fault conditions on unearthed or impedance earthed systems, resulting in a rise in the voltage on the healthy phases. Voltage factors, with the permissible duration of the maximum voltage, are given in Table 4.3.

Voltage factor V_f	Time rating	Primary winding connection/system Vf rating earthing conditions
1.2	Continuous	Between lines in any network. Between transformer star point and earth in any network
1.2	Continuous	Between line and earth in an effectively earthed network
1.5	30 s	
1.2	Continuous	Between line and earth in a non-effectively earthed neutral system with automatic earth fault tripping
1.9	30 s	
1.2	Continuous	Between line and earth in an isolated neutral system without automatic earth fault tripping, or in a resonant earthed system without automatic earth fault tripping
1.9	8 hours	

Table 4.3: Voltage transformers: Permissible duration of maximum voltage

4.3.3 Secondary Leads

Voltage transformers are designed to maintain the specified accuracy in voltage output at their secondary terminals. To maintain this if long secondary leads are required, a distribution box can be fitted close to the VT to supply relay and metering burdens over separate leads. If necessary, allowance can be made for the resistance of the leads to individual burdens when the particular equipment is calibrated.

4.3.4 Transient Performance

Transient errors cause few difficulties in the use of conventional voltage transformers although some do occur. Errors are generally limited to short time periods following the sudden application or removal of voltage from the VT primary. If a voltage is suddenly applied, an inrush transient will occur, as with power transformers. The effect will, however, be less severe than for power transformers because of the lower flux density for which the VT is designed. If the VT is rated to have a fairly high voltage factor, little inrush effect will occur. An error will appear in the first few cycles of the output current in proportion to the inrush transient that occurs.

When the supply to a voltage transformer is interrupted, the core flux will not readily collapse; the secondary winding will tend to maintain the magnetizing force to sustain this flux, and will circulate a current through the burden which will decay more or less exponentially, possible with a superimposed audio-frequency oscillation due to the capacitance of the winding. Bearing in mind that the exciting quantity, expressed in ampere-turns, may exceed the burden, the transient current may be significant.

4.4 Capacitor voltage transformers

The size of electromagnetic voltage transformers for the higher voltages is largely proportional to the rated voltage; the cost tends to increase at a disproportionate rate. The capacitor voltage transformer (CVT) is often more economic. This device is basically a capacitance potential divider. As with resistance-type potential dividers, the output voltage is seriously affected by load at the tapping point. The capacitance divider differs in that its equivalent source impedance is capacitive and can therefore be compensated by a reactor connected in series with the tapping point. With an ideal reactor, such an arrangement would have no regulation and could supply any value of output. A reactor possesses some resistance, which limits the output that can be obtained. For a secondary output voltage of 110V, the capacitors would have to be very large to provide a useful output while keeping errors within the usual limits. The solution is to use a high secondary voltage and further transform the output to the normal value using a relatively inexpensive electromagnetic transformer. The successive stages of this reasoning are indicated in Figure 4.3.

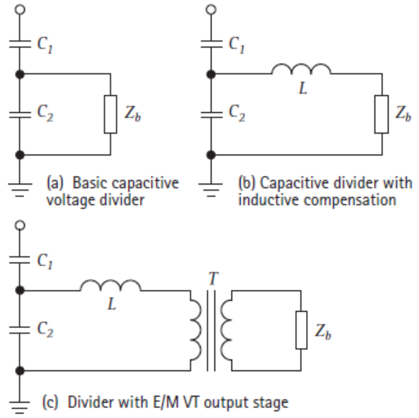
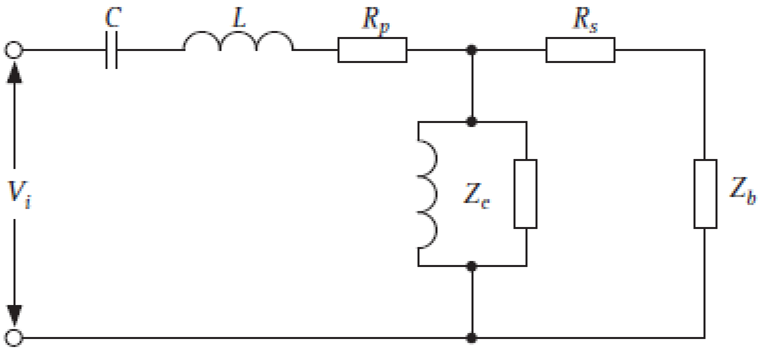


Figure 4.3: Development of capacitor voltage transformer

There are numerous variations of this basic circuit. The inductance *L* may be a separate unit or it may be incorporated in the form of leakage reactance in the transformer *T*. Capacitors *C1* and *C2* cannot conveniently be made to close tolerances, so tappings are provided for ratio adjustment, either on the transformer *T*, or on a separate auto-transformer in the secondary circuit. Adjustment of the tuning inductance *L* is also needed; this can be done with tappings, a separate tapped inductor in the secondary circuit, by adjustment of gaps in the iron cores, or by shunting with variable capacitance. A simplified equivalent circuit is shown in Figure 4.4.



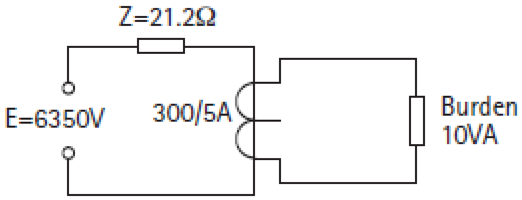
L - tuning inductance
R_p - primary winding resistance (plus losses)
Z_e - exciting impedance of transformer T
R_s - secondary circuit resistance
Z_b - burden impedance
C - $C_1 + C_2$ (in Figure 6.6)

Figure 4.4: Simplified equivalent circuit of capacitor voltage transformer

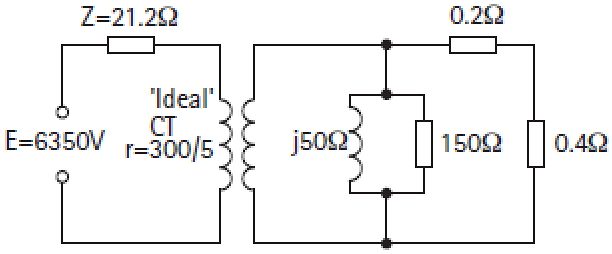
It will be seen that the basic difference between Figure 4.4 and Figure 4.1 is the presence of *C* and *L*. At normal frequency when *C* and *L* are in resonance and therefore cancel, the circuit behaves in a similar manner to a conventional VT. At other frequencies, however, a reactive component exists which modifies the errors. Standards generally require a CVT used for protection to conform to accuracy requirements of Table 4.2 within a frequency range of 97-103% of nominal. The corresponding frequency range of measurement CVT's is much less, 99%-101%, as reductions in accuracy for frequency deviations outside this range are less important than for protection applications.

4.5 Current transformers

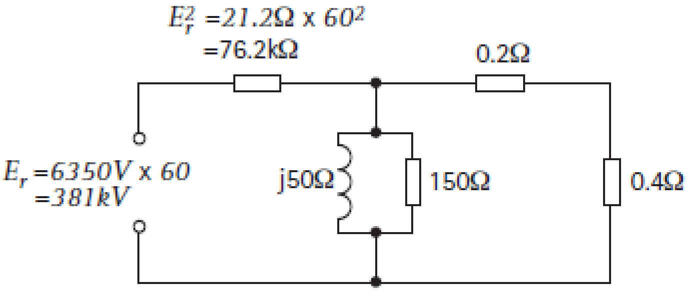
The primary winding of a current transformer is connected in series with the power circuit and the impedance is negligible compared with that of the power circuit. The power system impedance governs the current passing through the primary winding of the current transformer. This condition can be represented by inserting the load impedance, referred through the turns ratio, in the input connection of Figure 4.1. This approach is developed in Figure 4.5, taking the numerical example of a 300/5A CT applied to an 11kV power system. The system is considered to be carrying rated current (300A) and the CT is feeding a burden of 10VA.



(a) Physical arrangement



(b) Equivalent circuit of (a)



(c) Equivalent circuit, all quantities referred to secondary side

Figure 4.5: Derivation of equivalent circuit of a current transformer

A study of the final equivalent circuit of Figure 4.5(c), taking note of the typical component values, will reveal all the properties of a current transformer. It will be seen that:

a. the secondary current will not be affected by change of the burden impedance over a considerable range

b. the secondary circuit must not be interrupted while the primary winding is energised. The induced secondary e.m.f. under these circumstances will be high enough to present a danger to life and insulation

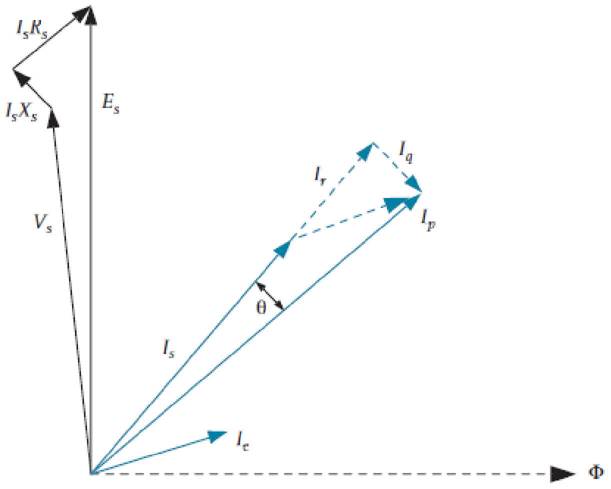
c. the ratio and phase angle errors can be calculated easily if the magnetizing characteristics and the burden impedance are known

4.5.1 Errors

The general vector diagram (Figure 4.2) can be simplified by the omission of details that are not of interest in current measurement; see Figure 4.6. Errors arise because of the shunting of the burden by the exciting impedance. This uses a small portion of the input current for exciting the core, reducing the amount passed to the burden. So $Is = Ip - Ie$, where Ie is dependent on Ze, the exciting impedance and the secondary e.m.f. Es, given by the equation $Es = Is (Zs + Zb)$, where:

Zs = the self-impedance of the secondary winding, which can generally be taken as the resistive component R_S only

Z_b = the impedance of the burden



E_s = Secondary induced e.m.f.
V_s = Secondary output voltage
I_p = Primary current
I_s = Secondary current
θ = Phase angle error
Φ = Flux
I_sR_s = Secondary resistance voltage drop
I_sX_s = Secondary reactance voltage drop
I_e = Exciting current
I_r = Component of I_e in phase with I_s
I_q = Component of I_e in quadrature with I_s

Figure 4.6: Vector diagram for current transformer (referred to secondary)

4.5.2 Phase Error

This is represented by Iq, the component of Ie in quadrature with Is and results in the phase error . The values of the current error and phase error depend on the phase displacement between Is and Ie, but neither current nor phase error can exceed the vectorial error Ie. It will be seen that with a moderately inductive burden, resulting in Is and Ie approximately in phase, there will be little phase error and the exciting component will result almost entirely in ratio error. A reduction of the secondary winding by one or two turns is often used to compensate for this. For example, in the CT corresponding to Figure 4.5, the worst error due to the use of an inductive burden of rated value would be about 1.2%. If the nominal turns ratio is 2:120, removal of one secondary turn would raise the output by 0.83% leaving the overall current error as -0.37%. For lower value burden or a different burden power factor, the error would change in the positive direction to a maximum of +0.7% at zero burden; the leakage reactance of the secondary winding is assumed to be negligible. No corresponding correction can be made for phase error, but it should be noted that the phase error is small for moderately reactive burdens.

4.5.3 Composite Error

This is defined in IEC 60044-1 as the r.m.s. value of the difference between the ideal secondary current and the actual secondary current. It includes current and phase errors and the effects of harmonics in the exciting current. The accuracy class of measuring current transformers is shown in Table 4.4.

Accuracy class		+/- Percentage current (ratio) error				+/- Phase displacement (minutes)			
	% current	5	20	100	120	5	20	100	120
0.1		0.4	0.2	0.1	0.1	15	8	5	5
0.2		0.75	0.35	0.2	0.2	30	15	10	10
0.5		1.5	0.75	0.5	0.5	90	45	30	30
1		3	1.5	1.0	1.0	180	90	60	60

(a) Limits of error accuracy for error classes 0.1-1.0

Accuracy class		+/- current (ratio) error,%	
	%current	50	120
3		3	3
5		5	5

(b) Limits of error for error classes 3 and 5

Table 4.4: CT error classes

4.5.4 CT Winding Arrangements

There are several types of CT winding arrangement are used. They are described below

Wound primary type

This type of CT has conventional windings formed of copper wire wound round a core. It is used for auxiliary current transformers and for many low or moderate ratio current transformers used in switchgear of up to 11kV rating.

Bushing or bar primary type

Many current transformers have a ring-shaped core, sometimes built up from annular stampings, but often consisting of a single length of strip tightly wound to form a close-turned spiral. The distributed secondary winding forms a toroid which should occupy the whole perimeter of the core, a small gap being left between start and finish leads for insulation. Such current transformers normally have a single concentrically placed primary conductor, sometimes permanently built into the CT and provided with the necessary primary insulation. In other cases, the bushing of a circuit breaker or power transformer is used for this purpose. At low primary current ratings it may be difficult to obtain sufficient output at the desired accuracy. This is because a large core section is needed to provide enough flux to induce the secondary e.m.f. in the small number of turns, and because the exciting ampere-turns form a large proportion of the primary ampere-turns available. The effect is particularly pronounced when the core diameter has been made large so as to fit over large EHV bushings.

Core-balance current transformers

The core-balance CT (or CBCT) is normally of the ring type, through the centre of which is passed cable that forms the primary winding. An earth fault relay, connected to the secondary winding, is energised only when there is residual current in the primary system. The advantage in using this method of earth fault protection lies in the fact that only one CT core is used in place of three phase CT's whose secondary windings are residually connected. In this way the CT magnetizing current at relay operation is reduced by approximately three-to-one, an important consideration in sensitive earth fault relays where a low effective setting is required. The number of secondary turns does not need to be related to the cable rated current because no secondary current would flow under normal balanced conditions. This allows the number of secondary turns to be chosen such as to optimise the effective primary pickup current. Core-balance transformers are normally mounted over a cable at a point close up to the cable gland of switchgear or other apparatus. Physically split cores ('slip-over' types) are normally available for applications in which the cables are already made up, as on existing switchgear.

Summation current transformers

The summation arrangement is a winding arrangement used in a measuring relay or on an auxiliary current transformer to give a single-phase output signal having a specific relationship to the three-phase current input.

Air-gapped current transformers

These are auxiliary current transformers in which a small air gap is included in the core to produce a secondary voltage output proportional in magnitude to current in the primary winding. Sometimes termed 'transactors' and 'quadrature current transformers', this form of current transformer has been used as an auxiliary component of unit protection schemes in which the outputs into multiple secondary circuits must remain linear for and proportioned to the widest practical range of input currents.

5. Optical current and voltage sensors and transformers

5.1 Introduction

Fiber-optic current and voltage sensors offer significant advantages over traditional current and voltage measurement technologies:

1. The sensor element is naturally decoupled from the voltage line.
2. There is minimal electrical interference on the signal line.
3. They offer extremely fast response times with high measurement accuracy.
4. The size and weight of the sensors is reduced in comparison with existing technologies.
5. They do not explode during catastrophic failure, unlike oil-filled electrical insulation towers.

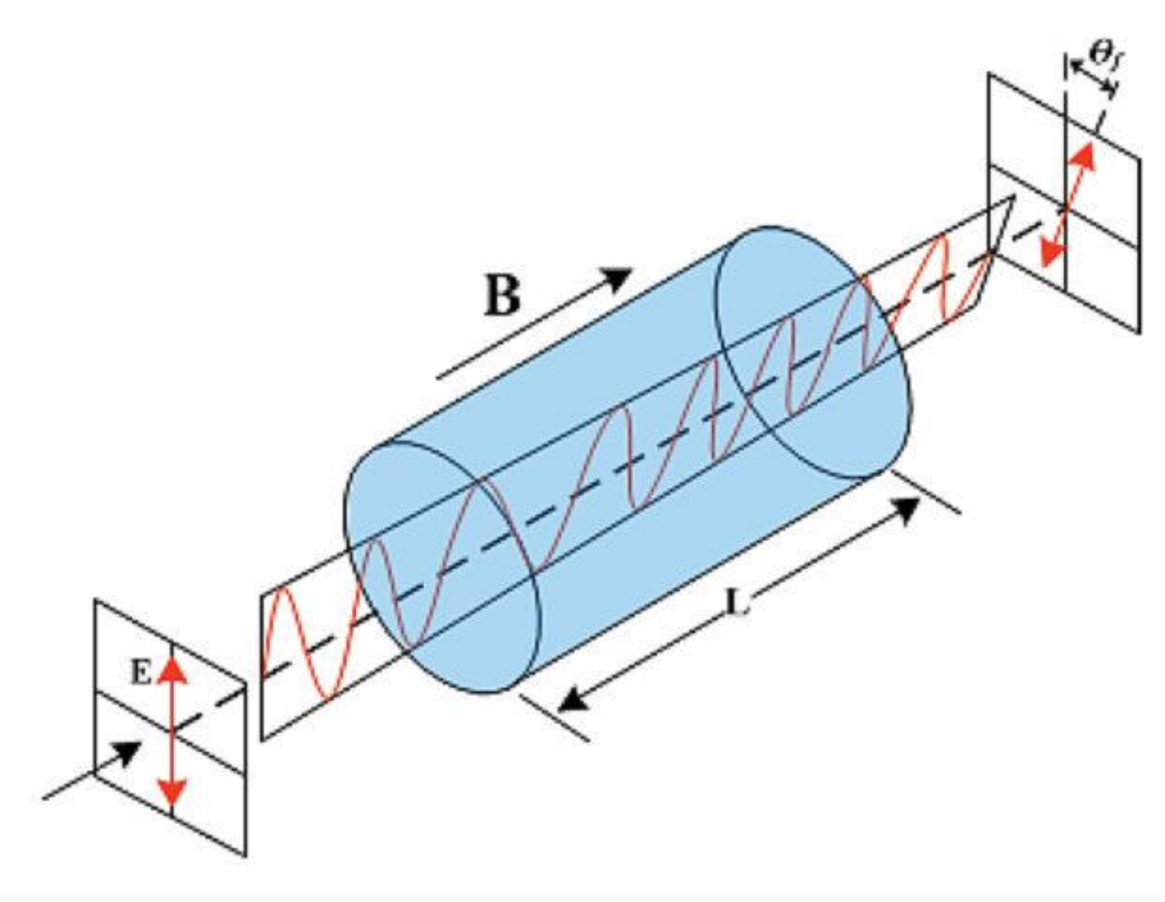


Figure 5.1: The optical-magnetic Faraday effect [12].

In addition, they are inherently free of magnetic saturation and typically have a measurement bandwidth in the kHz range. Bandwidths in the range of tens or hundreds of kHz are also feasible. As a result fiber-optic current transformers deliver, within their measurement range, a true image of the primary current, also in case of fast transient currents, short circuit currents, and AC with DC offset.

Optical VCTs are lightweight and of small size. This makes it possible to operate them not only as freestanding devices but one can easily integrate them into other power products. Substation footprint and installation costs are reduced. Other advantages are enhanced safety (no risk from open secondary CT circuits or catastrophic failure) and environmental friendliness (no oil). Optical current sensors are immediately compatible with modern digital substation communication, which helps to eliminate large amounts of copper cabling [12].

Optical fiber sensors are of particular interest for applications in the high-voltage environments of the electric power industry due to their characteristic properties including a dielectric nature, immunity to electro-magnetic interference, and small size and weight. The current sensor employs the Faraday effect in a thermally annealed coil of sensing fiber. Voltage sensors are based on the Pockels effect in electro optical crystals or the converse piezoelectric effect in a cylinder-shaped quartz crystal.

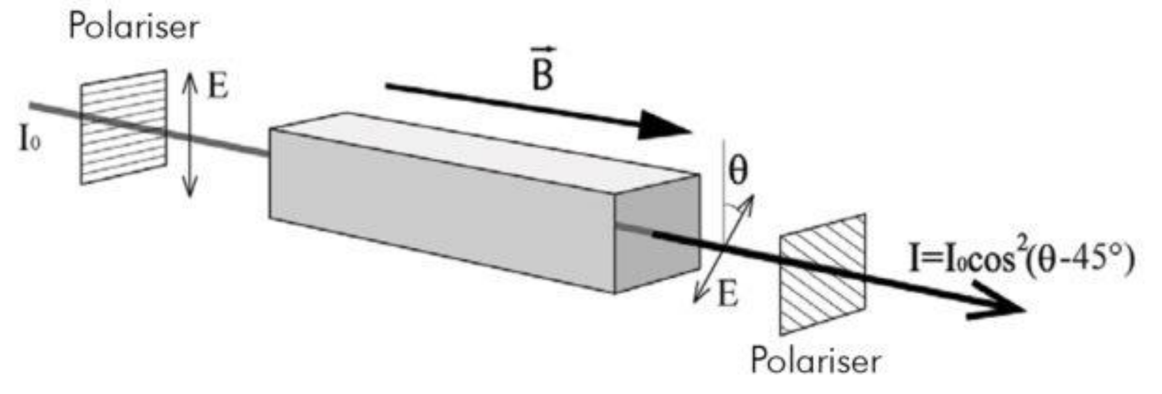


Figure 5.2: Basic method of measuring polarisation rotation [12].

5.2 Optical current transformers

The Faraday effect is a magneto-optical effect that causes a change of the state of polarisation of light in the presence of a magnetic field. It describes the rotation of polarisation of light propagating in the direction of a magnetic field. When a beam of light is sent through a material exhibiting the Faraday effect, the polarisation of the light will be rotated by the angle θ which is dependent on the magnetic field strength parallel to the direction of propagation of the light.

The Faraday effect is proportional to the magnetisation of the material, The rotation can then be described in terms of the magnetic field strength β and the Verdet constant V.

$$\int_0^L V \cdot \beta \cdot dl$$

Which, in the case of a constant uniform magnetic field reduces to

$$\theta = V \cdot \beta \cdot L$$

The Verdet constant V is the specific rotation of a material and is defined as the angle over the magnetic field times the length. V is determined by the magnetic properties of the material.
β is the component of the magnetic flux density parallel to the light propagation direction.

5.2.1 Measurement of phase rotation

All Faraday effect detection principles are fundamentally based on intensity detection. The structure, materials and the path of light of the different Faraday sensors however, differ greatly. There are several methods used for measuring phase rotation. The simplest and most general makes use of a polariser as shown in Fig. 5.2 [12]. The magnetic field in a Faraday medium can be measured by determining the rotation of polarisation θ, that occurs after a linearly polarised light beam passed the Faraday medium. This can be done by measuring the intensity of the light beam after passing a second polariser. The intensity of this light beam is a function of the angle of rotation and thus the magnetic field strength.

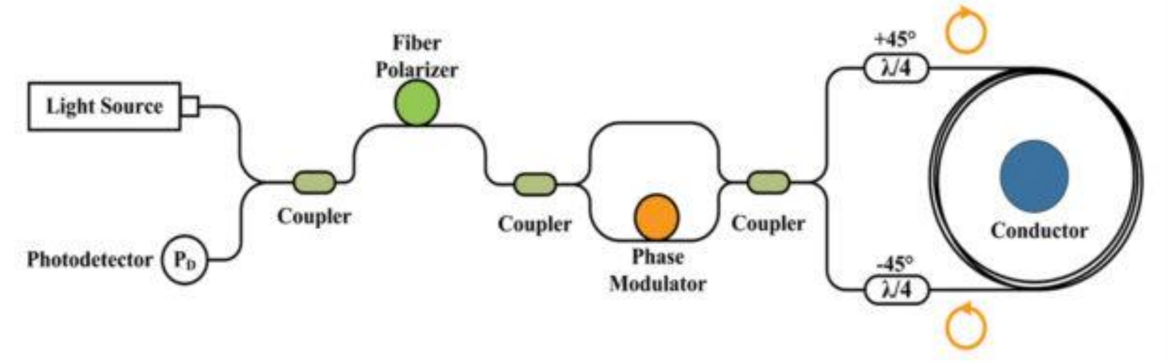


Figure 5.3: Current sensor using an interferometer [11].

The characteristic of the sensor is determined by the orientation of the two polarisers to each other. The angle between the transmission axes of the polarisers determines by how much the value of the transmitted intensity varies with a varying magnetic field. The angles can be chosen anywhere between 0° and 90° giving the same results for all other quadrants. The resulting intensities can be calculated employing Malus' law: considering a linearly polarised light beam incident on a polariser, its perpendicular component of the beam is blocked. Therefore, the amplitude of the light transmitted by the polariser is shown in equation below:

$$E(\theta) = E_0 \cos(\theta)$$

And the intensity of the transmitted light is given by the formula in equation below:

$$I(\theta) = I_0 \cos 2(\theta)$$

Where:
E_0 is the electric field vector,
I_0 is the intensity of the incident beam.

Other detection methods use polarisation separating prisms and two detectors. The two orthogonal linearly polarised beams are detected separately. This technique has the advantage that optical losses in the fibres and sensor material can be compensated. The rotation of the polarisation can directly be obtained by comparing the two sensor signals.

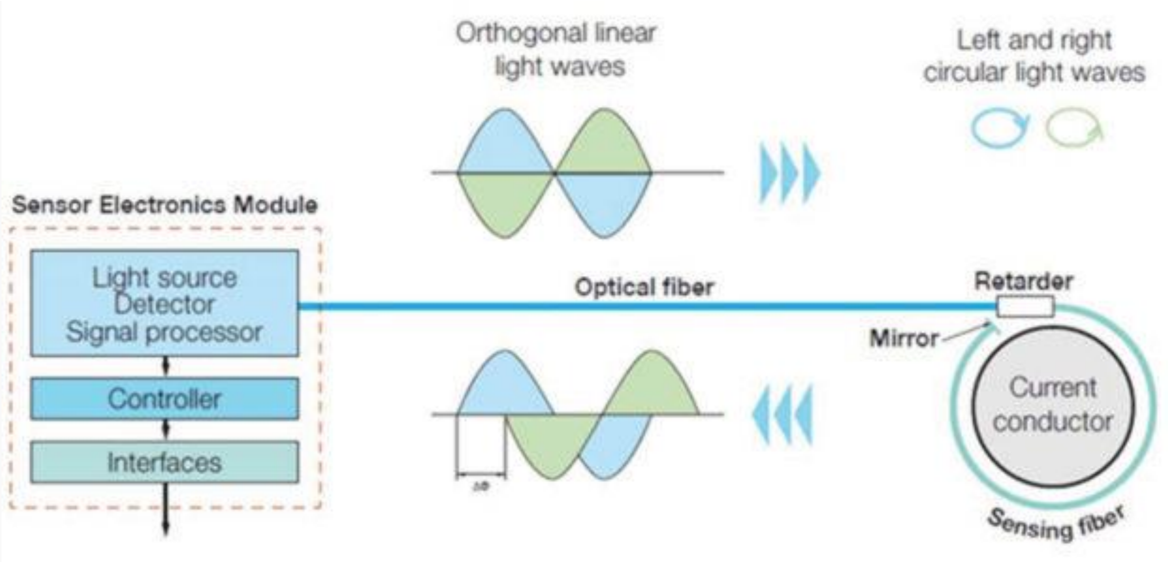


Figure 5.4: Typical construction of a fiber optic based current sensor (ABB)

More advanced methods use interferometers to measure the degree of rotation [1]. In the polarimetric detection scheme, the rotation of the plane of polarisation of linear polarised light was measured. This rotation can also be measured in terms of circular polarisation, corresponding to a phase difference between the two circular orthogonal modes (left-handed and right-handed circular polarisation). This can be done using an interferometric detection scheme where a modulation frequency carrier is generated, and the optical phase variation that is modulated by time delay induced between arms of the interferometer, will contain the electric current information.

Figure 5.3 shows a current sensor based on an interferometer principles.

Optic fibre rings

In this application the fibre itself acts as a transducer mechanism. The magneto-optical effect is used to induce a rotation in the angle of polarisation of the light propagating in the fibre, which is proportional to the magnetic field. Usually, the fibre is coiled around the electrical conductor, making it immune to external currents and magnetic fields. Although the Verdet constant of a fibre is not very high, a measurable rotation can be achieved with a long fibre wound around the conductor many times. The sensitivity of the instrument can be changed by varying the number of turns of fibre. The fibres are typically single-mode silica fibres and do not require a precision matching or alignment. The sensitivity can be adjusted by adding dopants to the core or by varying the number of turns. In order to remain the state of polarisation in the fibre between the sensing region and the light source/detectors, polarisation-maintaining single-mode fibres are used. These fibres have a core of elliptical cross-section or index of refraction anisotropy introduced by dopants or uniaxial stress [11]. Fig.5.4 shows the typical construction.

This type of instrument has the advantage that the light transmission to and from the region of current measurement is done by optical fibers which are compatible with low voltage analogue and digital equipment used for metering and relaying applications.

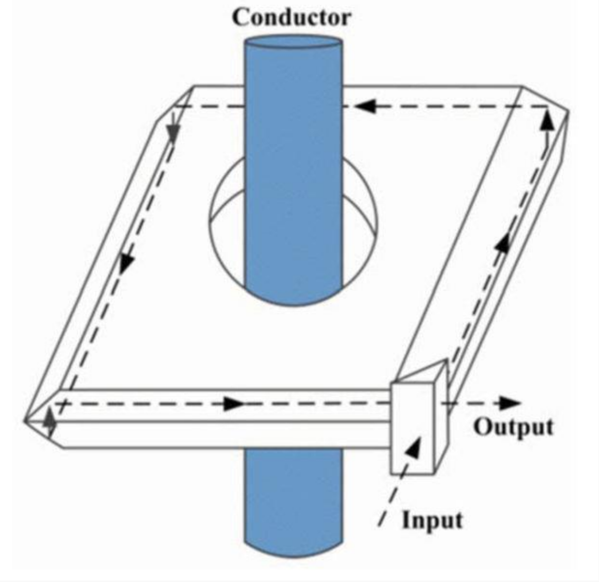


Figure 5.5: Current transformer using bulk optical material [11].

Bulk optical material

This type of OCT is analogous to an optical implementation of a conventional CT. It consists of a electro-optical material completely enclosing the conductor (Fig. 5.5). Numerous designs have been proposed with light beams encircling the current carrying conductor exactly once or several times. These sensors are fabricated from single-glass blocks with relatively low Verdet constants and do not suffer from bending induced problems occurring in optical fibre sensing elements.

5.3 Optical voltage transformers

Optical voltage sensors (OVT) differ from OCT in that the voltage is applied across the length of the sensor. In a similar fashion to the OCT, the voltage affects the properties of the light passing through the optical material, and this is used to provide the measurement.

Pockels effect: birefringence (birefraction)

Most optical voltage sensors are based on an electro-optic (EO) crystal and longitudinal Pockels effect. Light transmission to and from the region of voltage measurement is done by optical fibers which bring inherent immunity to electromagnetic interference and compatibility with low voltage analog and digital equipment used for metering and relaying applications. EO materials, usually crystals, change their refractive index under the influence of an electric field. The field may be applied along the direction of propagation or at right angles to it. The effect of a change in refractive index is to introduce a change in phase of the light beam passing through the crystal. This change in phase also introduces a change in polarisation of the beam. Electro-optic crystals are typically anisotropic.

Typical crystals used in pockels cells are Potassium Dihydrogen Phosphate (KDP), lithium niobate (LiNbO3), and Bisumuth germanganate (Bi4Ge3O12).

The Pockels cell alters the polarisation of a transmitted light beam when voltage is applied to the cell by causing a phase retardation between orthogonal polarisation components of the beam. In the absence of an applied field, there is no difference in the phase retardation between orthogonal polarisation components of the light beam because the refractive index is the same for both polarisation directions and so there is no polarisation change in the transmitted light. However, an applied electric field creates fast and slow axes at 90° to one another. The difference in velocity for beams with polarisation components along these two directions, with voltage applied, retards the phase of one polarisation component relative to the other thereby changing the polarisation state of the emerging beam.

To be detectable polarisation must change by less than 90°, and this limits the maximum voltage that can be applied to a crystal of any particular dimensions. This maximum voltage is known as the half-wave voltage or half-wave field strength. Typical half-wave voltages for some EO materials range from 3 to 75 kV [13,16].

The problem with using the Pockels effect for high voltages is the sensitivity of the EO crystal, which is usually too high in comparison with the measured voltage.

The conventional solution is to use capacitive dividers to obtain a small part of the total voltage on the optical voltage sensor However, the method limits the performance of the optical measurement technology due to the high cost and the stability problem of the capacitive dividers. Another method is to use the multi-segmented sensor which consists of crystal slices and spacers of dielectric material The half-wave voltage of the multi-segmented sensor is far larger than a single EO crystal in longitudinal modulation [13].

Piezo-optic voltage sensor

High voltage OVTs which make use of the piezo-electric effect have been developed. The system consists of a piezo-electric crystal which deforms mechanically under the influence of an electric field. The deformation is transferred to an optic fibre wound around the crystal, producing a phase and polarity shift in the light transmitted through the fibre, which is proportional to the voltage applied. Units with measurement ranges up to 420 kV have been produced. [15].

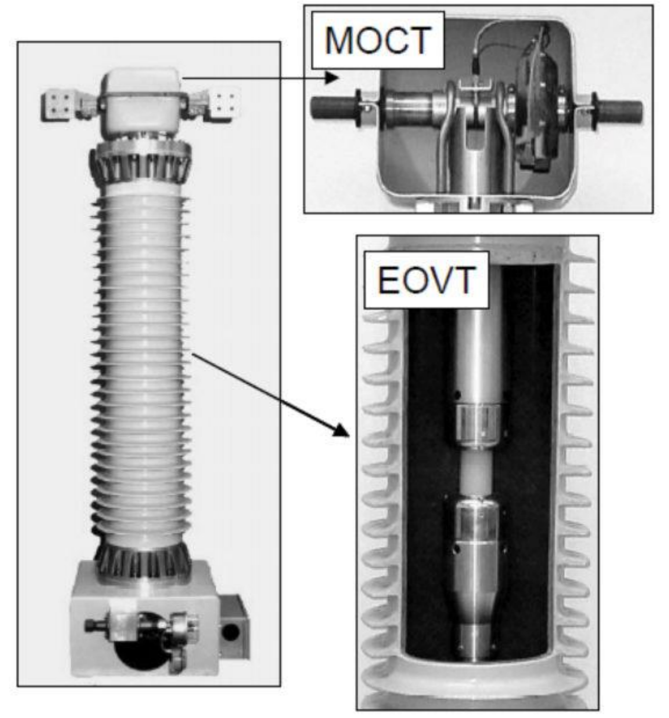


Figure 5.6: Combined optical current and voltage transformer [3].

Combined composite insulator

One of the more useful applications is the combined current and voltage transformer, which combines an OCT with an OVT in a single insulator shell. The OCT is mounted at the top of the insulator and the OVT is inside the insulated shell. Fig. 5.6 shows one of the products on the market.

5.4 Possibilities of implementation optical sensors in substation

Current transducers with optical sensors.

This is a development of a stand-alone device capable of measuring the current in high voltage network from 72.5 kV to 800 kV, for mainly metering and protection applications. The design of one phase includes a head with an optical sensor based on the Faraday effect in a ring glass (or bulk glass) supported by a composite insulator adapted to the voltage insulation and including the optical fiber that carries the light and the information. The electronic is made of a junction box with optical connectors, optical cable with all the fibers, and an electronic card module included in a 'concentrator' or rack The series of apparatus of Current Transformer with Optical sensors have the serial name of CTO as standalone range of devices. [17]

Circuit breaker mounted optical sensors.

For very high voltages (362 kV, 550 kV and 800 kV) the live tank circuit breakers offer certain advantages compared to dead tank circuit breakers:

- a very small volume of gas SF6 (in a ratio of 15 to 1 at 550 kV) for environmental concerned users,
- lower intrinsic cost and capable to be included with disconnecting switch as a pole unit (Compact *Air* Insulated Modules (AIM) as used in Europe).

This elegant solution of compactness, enhanced in using opto-electronic technology directly installed on the circuit breaker, has the following features:

- capability of connecting a large range of devices able to measure the current and combined revenue metering units with optical sensors and use it also as protection.
- possible direct installation on a breaker high voltage terminals of disconnecting switches contacts, easy add-on on the voltage terminal for different protection schemes (relaying for example),
- no additional supporting foundation required for the current transformer as in live tank circuit breakers.

Voltage sensors and combos.

The application of an optical voltage sensor requires today that we use the "Pockels effect' as seen above. In addition, the "Potential difference" has to be correctly applied on the two crystal faces to integrate the electric field along the optical path. The measure voltage becomes independent of other nearby conductors at any voltages and of the geometry variations of optical elements. The detection and the signal processing are similar to the one developed for current sensors.

The combos’ solution is a standalone series of devices that measure the current and the voltage for high voltage lines, as well as for revenue metering application and protection. We call them Combined Measurement Optical sensors or CMO. [18]

6. Experimental comparison of instrument voltage transformer with electro-optical voltage sensor

Introduction

This experiment was held in the university laboratory of high-voltage engineering of the Electric Power Department. An electrical circuit was assembled by the provided equipment to implement the voltage measurement.

The Pockels effect (or linear electro-optic effect) is an electric field-induced linear birefringence or anisotropic change in the refractive index of the material. The Pockels effect can be used in two modes. When the applied electric field is normal to the direction of propagation of the incident light, the transverse Pockels effect is said to occur. When the applied field and the propagation direction are parallel, the longitudinal Pockels effect is said to take place. [20,21]

Most optical voltage sensors are based on an electro-optic (EO) crystal and longitudinal Pockels effect. The problem for this case is the sensitivity of EO crystal, which is usually too high in comparison with the measured voltage. The conventional solution is to use capacitive dividers to obtain a small part of the total voltage on the optical voltage sensor [22].

6.1 Experimental setup

Voltage transformer specifications:

- Voltage up to 35 kV;
- Rated frequency 50 Hz;
- Voltage ratio 6000/100;
- Accuracy classification 0,5;

Electrostatic voltmeter specifications:

- Voltage limits of measurement – 7,5 kV – 15 kV – 30 kV;
- Rated frequency up to 20 MHz;
- Dimensions – 280x600x240 mm;
- Weight – 11 kg;

BGO crystal:

BGO, (Bismuth germinate Bi4Ge3O12) is the crystalline form of an inorganic oxide with cubic eulytine structure, colorless, transparent, and insoluble in water. When it is exposed to radiation of high energy particles or gamma-rays, x-rays, it emits a green fluorescent light with a peak wavelength of 480nm. With its elevated stopping power, high efficiency scintillation, first-rate energy resolution and nonhygroscopes, BGO is an excellent scintillation material and is ideal for a wide range of applications in high energy physics, nuclear physics, space physics, nuclear medicine, geological prospecting and other industries.

BGO crystal properties:

- Diameter - 2’’ or 2’’
- Length - 1” or 6”
- Orientation - <110>, <100>, <001>
- Density - 7.13 g/m^3
- Radiation length - 1.10 cm
- Photofraction - 40%
- Index of refraction - 2.15

Photo- detector:

The Thorlabs DET36A is a biased, Silicon (Si) detector designed for detection of light signals over 350 to 1100 nm range. The unit comes complete with a photodiode and internal 12 V bias battery enclosed in rugged aluminum housing. The DET36A includes a removable 1” optical coupler (SM1T1), providing easy mounting of ND filters, spectral filters, fiber adapters (SMA, FC and ST style), and other Thorlabs 1” stackable lens mount accessories. [19]

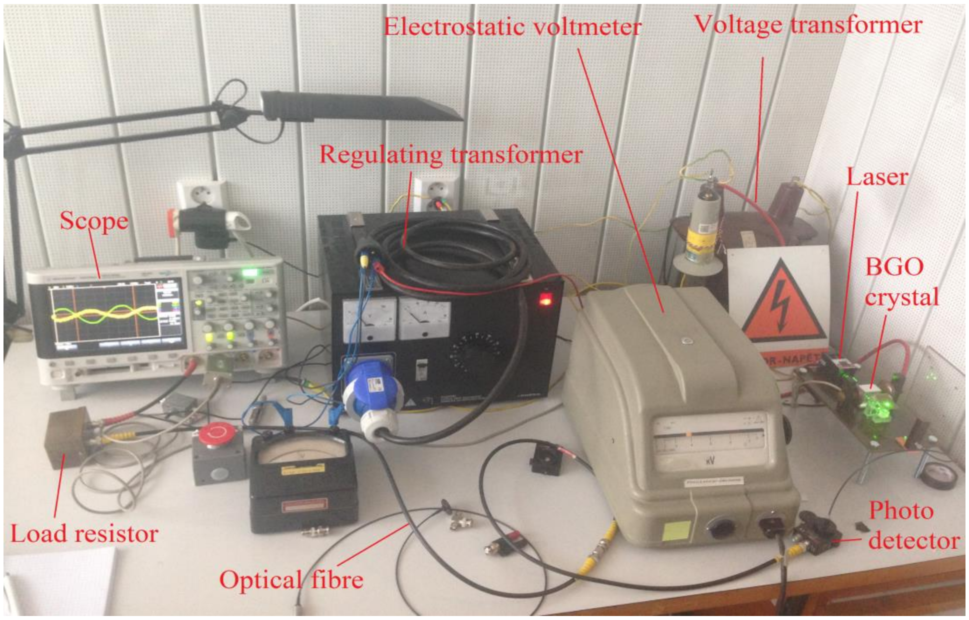


Figure 3.1: Measurement setup

6.2 Determination of Electro Optical sensor ratio.

According to the aim of experimental part based on comparison of measurements between conventional instrument voltage transformer and electro-optical voltage sensor, first part of experiment were consist of measurements of electro- optical sensor voltages in mV to determine ratio of electro- optical sensor using electrostatic voltmeter. Determined ratio gives us values which one should be convert from millivolts to kilovolts.

The element of circuit:

- Regulating transformer
- High voltage transformer
- Voltmeter
- Electro-optical sensor

Scheme of determination ratio represented below.

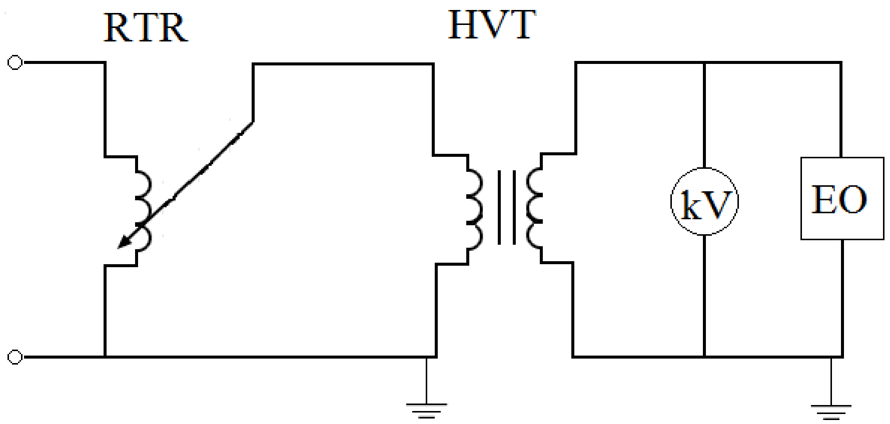


Figure 3.2: The equivalent circuit to determine a ratio.

RTR – Regulating transformer
HVT – High voltage transformer
IVT – Instrument voltage transformer
EO – Electro optical sensor

The table 6.1 shows reference values of electrostatic voltmeter, measured values of electro-optical sensor and calculated ratio.

The ratio was calculated by:

$$\text{ratio} = \frac{U_{ESV}}{U_{EO}}$$

Where:

U_{ESV} reference voltage of electrostatic voltage in kV;

U_{EO} voltage measured by electro-optical sensor;

Electrostatic voltmeter [kV]	Electro optical sensor [mV]	Ratio
2,0	73	0,027
2,5	98	0,026
3,0	108	0,028
3,5	131	0,027
4,0	133	0,030
4,5	155	0,029
5,0	174	0,029
5,5	186	0,030
6,0	214	0,028
6,5	226	0,029
7,0	235	0,030

Table 3.1: Measured values of voltages to determine ratio

To be more clearly, according measured values of voltages and calculated ratio was constructed curve. Curve shows voltage dependency of the ratio.

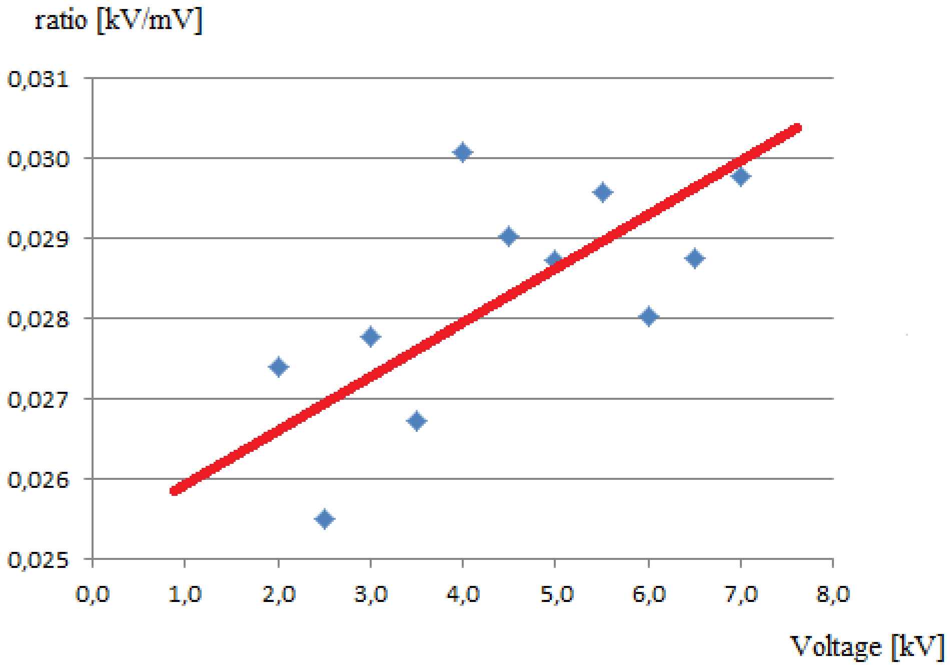


Figure 3.3: Voltage dependency of the ratio.

Also, to be sure that chosen method is correct, were calculated average of the ratio and standard deviation for ratio.

Average of the ratio equal:

$$\mathrm{Ratio}_{\mathrm{average}} = \frac{0.311}{11} = 0.028$$

Standard deviation for ration:

$$STD=\sqrt{\frac{1}{n-1}\sum_{i=1}^{n}(x_i-x_{av})^2}=0.0014$$

6.3 Definition errors and uncertainty estimation.

In this stage of experimental part were measured secondary voltage of the instrument voltage transformer, voltage values of electro-optical sensor, calculated difference of voltages between instrumental voltage transformer and electro-optical sensor.

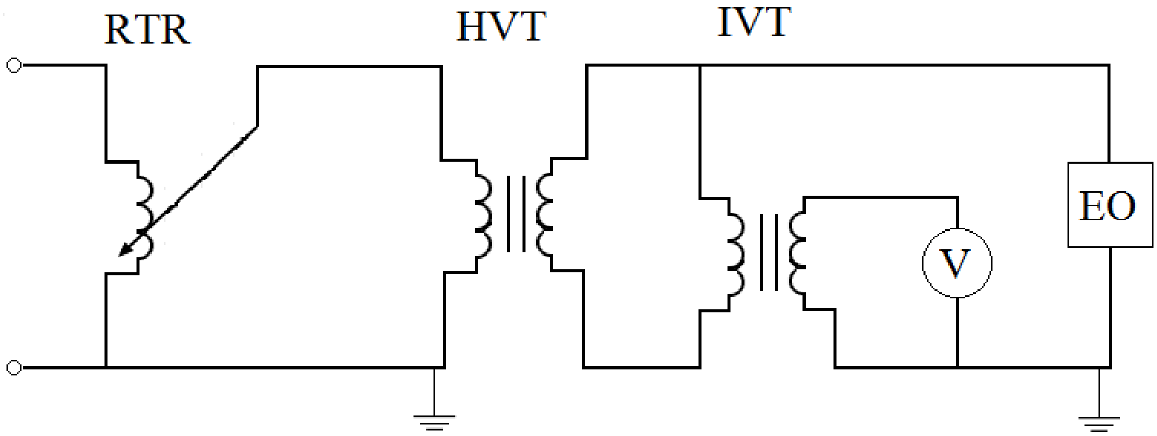


Figure 3.4: Equivalent circuit for definition errors.

RTR – Regulating transformer
HVT – High voltage transformer
IVT – Instrument voltage transformer
EO – Electro optical sensor

IVT		EO					
Uprim [V]	Usec [kV]	Ueo [mV]	U [kV]	ΔU[kV]	Ub[kV]	Ue[kV]	Error[%]
34	2,04	73	2,04	0,004	0,059	0,118	0,196
42	2,52	98	2,74	0,224	0,073	0,146	8,889
51	3,06	108	3,02	0,036	0,088	0,177	1,176
60	3,6	131	3,67	0,068	0,104	0,208	1,889
68	4,08	133	3,72	0,356	0,118	0,236	8,725
76	4,56	155	4,34	0,220	0,132	0,264	4,825
84	5,04	174	4,87	0,168	0,146	0,291	3,333
92	5,52	186	5,21	0,312	0,160	0,319	5,652
100	6	214	5,99	0,008	0,173	0,347	0,133
108	6,48	226	6,33	0,152	0,187	0,375	2,346
117	7,02	235	6,58	0,440	0,203	0,406	6,268

Table 6.2: Calibration of electro optical sensor

Difference of the voltages calculated by:

$$\Delta \mathrm{U} = \frac{\mathrm{U}_{\mathrm{IVT}}}{\mathrm{U}_{\mathrm{EO}}}$$

Since values for calculating uncertainty type A to low, it should be neglect. In this case was calculated only uncertainty type B.

$$\mathrm{U}_{\mathrm{B}} = \frac{\mathrm{U}_{\mathrm{IVT}} \times \mathrm{Error}}{\sqrt{3}}$$

Extended measurement uncertainty:

$$\mathrm{U}_{\mathrm{E}} = \mathrm{U}_{\mathrm{B}} \times k$$

k - coverage ratio. Where *k=2;*

The error calculated by:

$$\mathrm{Error} = \left(\frac{\mathrm{U}_{\mathrm{EO}} \times 100}{\mathrm{U}_{\mathrm{IVT}}}\right), [\%]$$

Conclusion

In this diploma project, according to the assignment, were investigated the most common types of the substation. Description of the main equipment at the substation. The most common arrangement of the switchgear at the air insulated substation. Current and voltage measuring systems, as well as current transformers, voltage transformer and their location at the substation, a secondary grounding of instrument transformers.

The third chapter describes the digital protection of the substation. Implementation IEC 61850 standard and its main requirements to the modern protection equipment. Advantages of using IEC 61850 standard.

In chapter four of the project, were considered measurement systems of the conventional instrument transformers: error, accuracy, arrangement in the substation.

The main purpose of chapter five is to describe general advantages of electro optical current and voltage transformers.

In the final part, implemented an experimental comparison between conventional voltage instrument transformers and electro-optical sensor. Constructed a graph of voltage dependency. Determined errors and standard deviation of the electro optical sensors

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