411

Protection, Control and Monitoring

of

Series Compensated Networks

Working Group
B5.10

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WG B5.10

Protection, Control and Monitoring of Series Compensated Networks

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1. INTRODUCTION

CIGRE Study Committee B5 created working group WG B5.10 in 2002. The scope of work specified was: "Review the presently available integrated techniques for protecting, controlling and monitoring high voltage lines with series capacitors (including thyristor controlled series capacitors) and the capacitor banks used in those lines and provide recommendations for their applications as well."

In accordance with this the working group took up the following tasks.

- Review the techniques used for protection of lines compensated with series capacitors (including thyristor controlled capacitors) especially the techniques that have been developed since the introduction of numerical devices.
- Review the techniques used for protecting high voltage capacitor banks (including thyristor controlled capacitors) used for series compensation of transmission lines especially the techniques that have been developed since the introduction of numerical devices.
- Provide recommendations for using the techniques for protecting the series compensated lines and the capacitor banks used in them
- Review the advancements in the techniques for integrated control and monitoring of those lines including the capacitor banks used in them and provide recommendations for their application
- Discuss the impact of series compensated lines on protection of adjacent lines.

The working group started its work with kick-off meeting in Paris end of August 2002. This report presents the results of the work.

Acknowledgment

The working group wants to specially acknowledge Prof. Dr. Sture Lindahl (SE) for his kind permission to use in this report parts of his personal material on series compensation. The working group wants to express its gratitude also to Dr. Murari Mohan Saha (SE), Dr. Jan Izykowski (PL) and Dr. Eugeniusz Rosolowski (PL) for their special contribution on Fault location in series compensated lines. Dr. Alex Apostolov has contributed parts regarding directional measurement with superimposed quantities in modern numerical devices. The working group acknowledges him as well. Finally, the working group would like to offer their sincere thanks to Miss Ljuba Mikhailova from Chuvas University in Cheboksary, Russia for her invaluable help in preparing most of the figures that appear in this technical brochure.

Background to Series Compensation

New York Power & Light put up their first series capacitor in operation back in 1928. According to [1] this was the world's first series capacitor having rated voltage of 33kV and rated capacity of 1.25Mvar. Utilities there after have been installing series capacitors in their distribution feeders for a long time.

Several countries, among them Argentina, Brazil, Canada, Chile, China, Japan, Mexico, Norway, Russia, Turkey, South Africa, Sweden and USA employ series compensation on their long EHV power transmission lines. Other countries, such as Australia, Bolivia, Colombia, India, Mali, Saudi Arabia, Venezuela and Iceland study series compensation or have started introducing series capacitors on their transmission lines as well.

Why series compensation at all? The answer is in fact very simple. The main purpose of series compensation in power systems is virtual reduction of line reactance in order to enhance the power system stability and increase loadability of transmission corridors. The principle is based on compensation of distributed line reactance by insertion of series capacitor (SC).

The generated reactive power provided by the capacitor is proportional to the square of the current flowing through the compensated line and series capacitor. This means that the series capacitor has a self-regulating effect. When the system loading increases, the reactive power generated by the series capacitors increases as well. The response of SCs is automatic, instantaneous and continuous as long as the capacitor current remains within the specified operating limits.

In 1950 first high voltage series capacitors were introduced by Swedish State Power Board and by Bonneville Power Administration (USA). Both installations were introduced on 220kV transmission systems. The BPA series capacitor had capacity of 24Mvar and made up of 15kvar capacitor units.

Today (2009) we can find series capacitors on practically all voltage levels up to 765kV. Their capacity ranges up to approximately 1200Mvar.

Fast development in power electronics have introduced to series compensation new features, which contribute not only to increased transmission capacity of power corridors, but also significantly improves system stability, decreases system oscillations, etc.

Today it is reasonable to talk about protection, control and monitoring of complete series compensated networks. The term itself includes protection, control and monitoring of:

- Series capacitor banks
- Series compensated lines
- Lines adjacent to series compensated lines (also called adjacent lines)

In many cases it is also necessary to consider protection of turbo-generators located close to series compensated lines against subsynchronous resonance (SSR).

Protection of series compensated networks has always been a special challenge for protection engineers. Modern installations, based on state of the art numerical theory and using all the possibilities of modern digital communications provide reliable protection, control and monitoring systems, which make controlled series compensation even more attractive for system planners than ever before.

Nomenclature

Many symbols used in equations are presented in general. Within the complete document they may obtain some additional indexes, which meaning is related to special conditions presented more in details in figures placed close to the corresponding equations.

1.1.1. Uppercase Roman and Italic

A_{ACC}	Equal area criterion – generator area accelerating area during external fault
A_{DEC}	Equal area criterion – generator decelerating area after clearing of external fault
A_{SM}	Equal area criterion – safety margin area
$E_A\left[kV\right]$	RMS value of induced generator voltage, index (A in this case) specifies the generator position in a system
$G(t)$	Measured quantity (generally current or voltage) in dependence of time

$I_{diff}[A]$	Differential current measured by differential protection
$I_F[A]$	Fault current, also current measured during the fault in relay point
$I_{NC}[kA]$	Nominal current of a series capacitor
$I_{stab}[A]$	Stabilizing current measured by differential protection
$I_{VP}[A]$	Average value of valve current during the positive half cycle
$I_{VN}[A]$	Average value of valve current during the negative half cycle
K_C	Compensation degree of series compensation
K_S	Underreaching safety factor, used in distance relays setting calculations
K_X	Effectiveness of series compensation
$L_L[H]$	Inductance of a power line
$P[MW]$	Active electric power
$P_{Mech}[MW]$	Mechanical power provided to the generator by turbine
$P_E[MW]$	Electrical power available on the generator terminals
$R_{L1}[\Omega]$	Line resistance, index represents either sequence (1-positive, 2-negative, 0-zero sequence) either serial number of line.
$S[Wh]$	Transient energy, used for directional measurement by measuring elements operating on superimposed (Δ) quantities
$T[ms]$	Cycle time, corresponding to 50Hz or 60Hz rated frequency
$U_A[kV]$	RMS voltage in certain network point, marked by index (A in this case)
$U_M[kV]$	Voltage in relay point, measured by protective relay during normal and fault conditions
$U_{MOV}[kV]$	Rated voltage at which MOV starts to conduct theoretically
$U_N[kV]$	Rated (RMS) voltage, general
$U_{NC}[kV]$	Voltage across the series capacitor when conducting it rated its nominal current I_{NC}
$X[\Omega]$	Reactance in general, with index D also related to reactance measured by distance relay
$X_C[\Omega]$	Reactance of a series capacitor
$X_L[\Omega]$	Positive sequence line impedance
$X_S[\Omega]$	Source reactance, in general positive sequence, if not specially marked by index
$Z[\Omega]$	Impedance, general.

1.1.2. Lowercase Roman and Italic

$e_G\left[kV\right]$	Instantaneous value of generator voltage
$f_n\left[Hz\right]$	Nominal system frequency
$f_{sh}\left[Hz\right]$	Subharmonic frequency
$f_{ssy}\left[Hz\right]$	Subsynchronous frequency
$i\left(t\right)\left[A\right]$	Instantaneous current in dependence of time
$i_C\left[A\right]$	Instantaneous current through series capacitor
$i_L\left[A\right]$	Instantaneous current through series compensated line
$i_M\left[A\right]$	Instantaneous current through MOV. Also V (valve) can be used as index.
$k_{sh}\left[-\right]$	Integer multiplier of subharmonic frequency
k_{stab}	Stabilizing factor used by current differential protection
$l\left[km\right]$	Length of a power line under consideration
$s\left[km\right]$	Distance from sending end of power line to the series capacitor
$u\left(t\right)\left[kV\right]$	Instantaneous voltage in dependence of time
$u_C\left[kV\right]$	Instantaneous voltage drop over series capacitor
$y\left[S/km\right]$	Characteristic line admittance
$z\left[\Omega/km\right]$	Characteristic line impedance

1.1.3. Uppercase Greek

Δ	Generally represents difference or change, like voltage difference ΔU and similar

1.1.4. Lowercase Greek

$\delta\left[\deg\right]$	Equal area criterion – rotor angle
$\delta_0\left[\deg\right]$	Equal area criterion – pre-fault rotor angle
$\delta_C\left[\deg\right]$	Equal area criterion – rotor angle at the end of its acceleration (at fault clearing)
$\delta_{EA}\left[\deg\right]$	Equal area criterion – rotor angle at the end of its deceleration
$\delta_{CR}\left[\deg\right]$	Equal area criterion – rotor angle stability limit

$\lambda[\deg]$ General phase angle of measured sinusoidal quantity

$\omega[rad/s]$ Angular frequency

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[1] Dorf, R.C. (editor in chief): The Electrical Engineering Handbook, CRC Press, Boca Raton, 1993

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[3] Gilles D.A., Kimbark E.W., Schaufelberger F.G., Partington: CIGRE Session, Paris, 8 June – 18 June 1966

[4] Hingorani, N.G.; Gyugyi, L.; "Understanding FACTS Concepts and Technology of Flexible AC Transmission Systsems", John Wiley & Sons Inc., Publication

2. GENERAL ON SERIES COMPENSATION IN POWER SYSTEMS

Introduction

The main purpose of series compensation in power systems is virtual reduction of line reactance in order to enhance the power system stability and increase loadability of transmission corridors. The principle is based on compensation of distributed line reactance by insertion of series capacitor (SC).

The generated reactive power provided by the capacitor is continuously proportional to the square of the current flowing at the same time through the compensated line and series capacitor. This means that the series capacitor has a self-regulating effect. When the system loading increases, the reactive power generated by series capacitors increases as well. The response of SCs is automatic, instantaneous and continuous as long as the capacitor current remains within the specified operating limits.

The main benefits of incorporating series capacitors in transmission lines are:

- Steady state voltage regulation and raise of voltage collapse limit
- Increase power transfer capability by raising the transient stability limit
- Improved reactive power balance
- Increase in power transfer capacity
- Active load sharing between parallel circuits and loss reduction
- Reduced costs of power transmission due to decreased investment costs for new power lines

2.1.1. Steady state voltage regulation and increase of voltage collapse limit

A series capacitor is capable of compensating the voltage drop of the series inductance in a transmission line; see Figure 2.1.

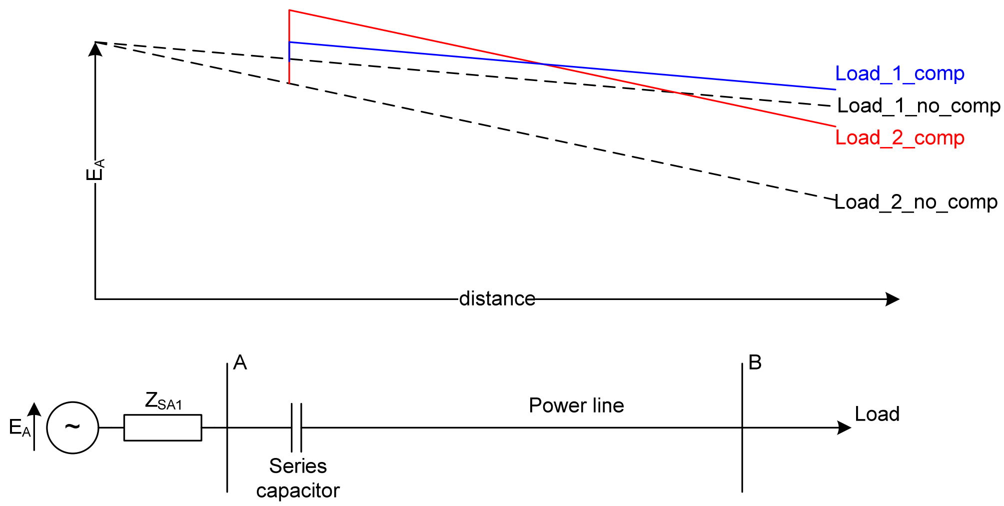

Figure 2.1: A simple radial power system and voltage drop compensation with series capacitor

During low loading (Load_1_no_comp for non compensated line and Load_1_comp for compensated line), the system voltage drop is lower and at the same time, the voltage drop on the series capacitor is lower. When the loading increases (Load_2_no_comp for non compensated line and Load_2_comp for compensated line) and the voltage drop on a line becomes larger, the contribution of the series capacitor increases and therefore the system voltage at the receiving line end will be regulated as desired.

Series compensation also extends the region of voltage stability by reducing the reactance of the line and consequently the SC is valuable for prevention of voltage collapse. Figure 2.2 presents the voltage dependence at receiving bus B (see Figure 2.1) on line loading and compensation degree K_C, which is defined according to equation (2.1). The effect of series compensation is in this particular case obvious and self-explanatory.

$$K_C = \frac{X_C}{X_{Line}} \tag{2.1}$$

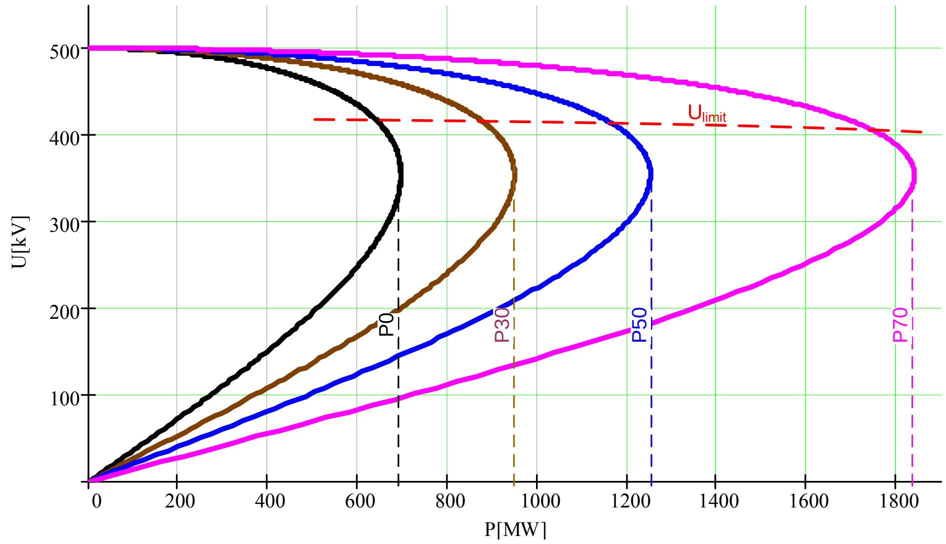

Figure 2.2: Voltage profile for a simple radial power line with 0%(P0), 30%(P30), 50%(P50) and 70%(P70) of compensation degree

2.1.2. Increased power transfer capability by raising the first swing stability limit

Consider the simple one-machine and infinite bus system shown in Figure 2.3. This presentation is used only for better understanding and explanation of phenomenon although this is not a typical operating case. Namely, utilities generally do not reclose generators connected only over one power line.

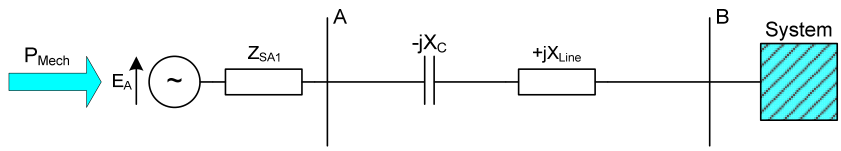

Figure 2.3: One machine and infinite bus system

The equal-areas criterion is used to show the effectiveness of a series capacitor for improvement of first swing transient stability (see Figure 2.4a and b).

In steady state the mechanical input power to the generator (P_{Mech}) is equal to the electrical output power from the generator (P_E) and the generator angle is δ_0. If a 3-phase fault occurs at a point on HV side of step-up transformer near the power plant, the electrical output of the generator reduces to zero. This means that the speed of the generator will increase and that the angle difference between the generator and the infinite bus will increase during the fault. At the time of fault clearing, the angle difference has increased to δ_C. After reclosing of the system, the transmitted power exceeds the mechanical input power and the generator decelerates. The generator will decelerate as long as equal area condition $A_{ACC} = A_{DEC}$ has not been fulfilled. The critical condition for post-fault system stability is that the angular displacement after fault clearing and during the deceleration does not exceed its critical limit δ_{CR}, because if it does, the system cannot get back to equilibrium and the synchronism is lost. The first swing stability and the stability margin can be evaluated by studying the different areas in Figure 2.4 for the same system, once without SC and once with series compensation. The areas under the corresponding P – δ curves correspond to energy and the system will remain stable if the accelerating energy that the generator picks up during the fault is lower than the decelerating energy that is transferred across the transmission line during the first system swing upon fault clearing.

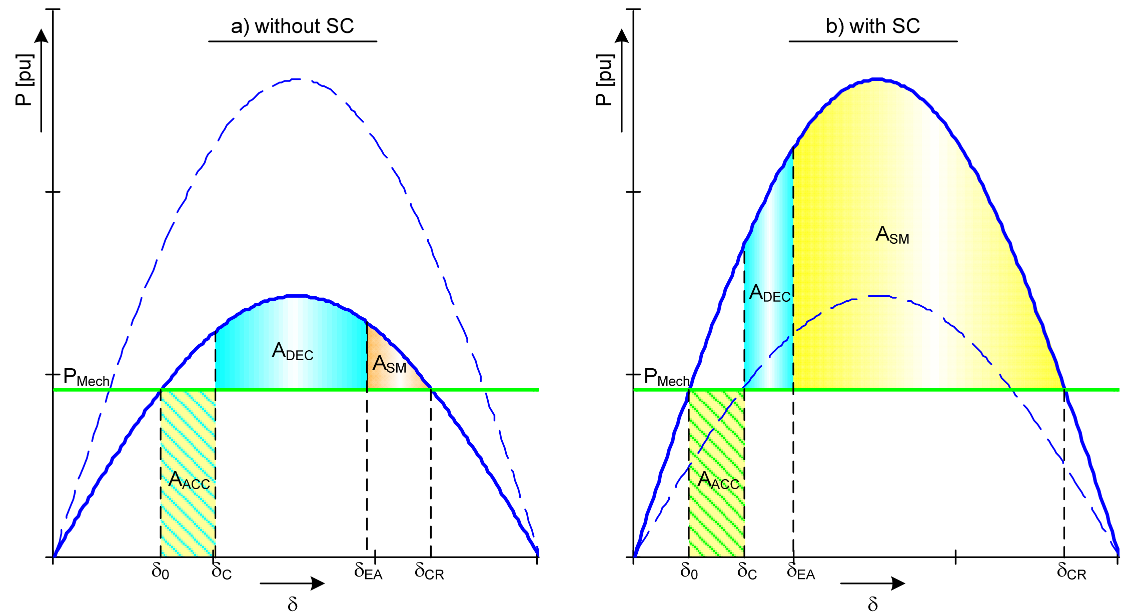

Figure 2.4: Equal area criterion and first swing stability without and with series compensation

This means that the system is stable if $A_{ACC} \leq \left(A_{DEC} + A_{SM} \right)$. The stability margin is given by the difference between the available decelerating energy (area between the $P(\delta)$ and P_{Mech} and the angular difference between δ_C and δ_{CR}) and the accelerating energy. It is represented in Figure 2.4 by the area A_{SM}.

Notice that a substantial increase in the stability margin is obtained by installing a series capacitor. The series compensation will improve the situation in two ways, it will decrease the initial angle difference δ_0 corresponding to a certain power transfer and it will also shift the P – δ curve upwards.

2.1.3. Improved reactive power balance

A series capacitor increases its output of reactive power instantaneously, continuously and automatically with increasing line load. It is thus a self-regulating device, which improves voltage regulation and reduces the need for other means of voltage control e.g. shunt compensation. The reactive power balance (the reactive power consumed or produced by power line) of a series compensated line is shown in Figure 2.5 as an example for a typical 500km long 500kV transmission line with 50% compensation degree.

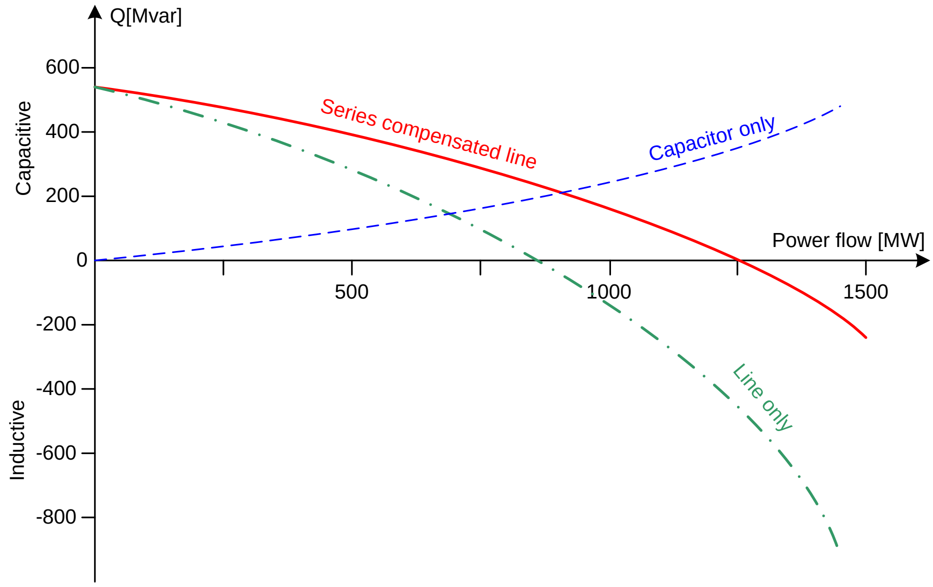

Figure 2.5: Self-regulating effect of reactive power balance on series compensated line

2.1.4. Increase in power transfer

The increase in power transfer capability as a function of the degree of compensation for a transmission line can be explained by studying the circuit shown in Figure 2.6.

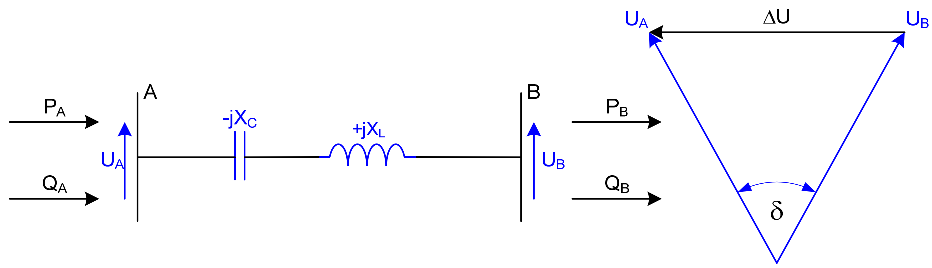

Figure 2.6: Transmission line with series capacitor

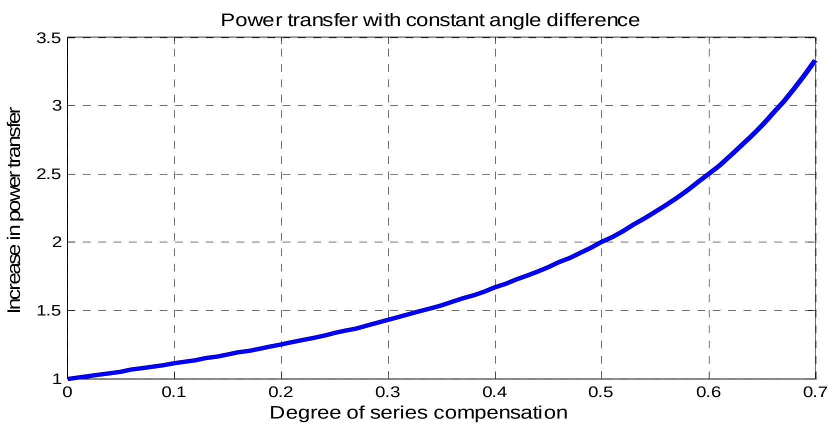

Figure 2.7: Increase in power transfer over a transmission line depending on degree of series compensation

The power transfer on the transmission line is given by the equation (2.2). The compensation degree is defined as presented by equation (2.1).

$$P=\frac{|U_A|\cdot|U_B|\cdot\sin(\delta)}{X_{Line}-X_C}=\frac{|U_A|\cdot|U_B|\cdot\sin(\delta)}{X_{Line}\cdot(1-K_C)} \tag{2.2}$$

The effect on the power transfer when considering a constant angle difference (δ) between the line ends is illustrated in Figure 2.7. Practical compensation degree runs from 20 to 70 percent. Transmission capability increases of more than two times can be obtained in practice.

2.1.5. Active load sharing between parallel circuits and loss reduction

A series capacitor can be used to control the distribution of active power between parallel transmission circuits. The compensation of transmission lines with sufficient thermal capacity can relieve the possible overloading of other parallel lines. This distribution is governed by the reactance, while the resistance determines the losses. A properly designed series compensation system can considerably reduce the total transmission system losses; see Figure 2.8.

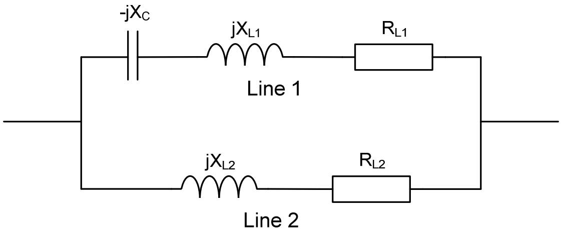

Figure 2.8: Two parallel lines with series capacitor for optimized load sharing and loss reduction

In order to minimize the losses, the series capacitor should be installed in the transmission line with the lower resistance. The size of the series capacitor that minimizes the total losses is given by the expression (2.3). Here it is supposed that $(X_{L1}/X_{L2})>(R_{L1}/R_{L2})$.

$$\frac{X_{L1}-X_C}{X_{L2}}=\frac{R_{L1}}{R_{L2}} \tag{2.3}$$

2.1.6. Reduced costs of power transmission due to decreased investment costs for new power line

As shown in Figure 2.7 the line loading can easily be increased 1.5-2 times by series compensation. Thus the required number of transmission lines needed for a certain power transfer can be significantly reduced.

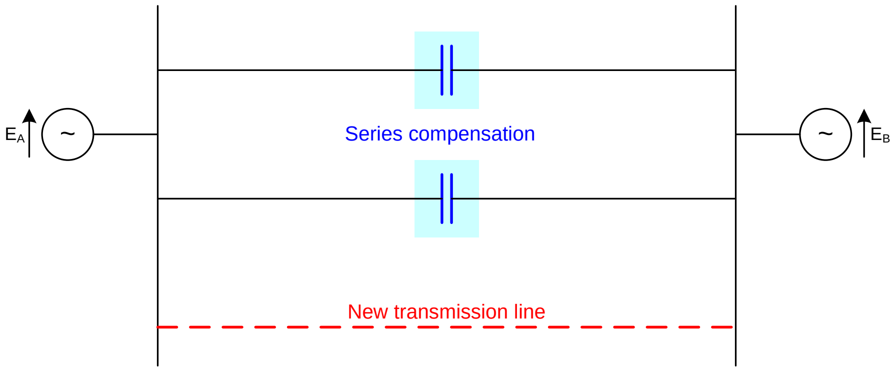

Figure 2.9: Series compensation is an important alternative to new transmission lines

The cost of series compensation is small compared to the cost of a transmission line. When evaluating the cost of a transmission system upgrade also the cost of secondary equipment such as eventual upgrading of line protections on the compensated as well as adjacent lines should be considered.

The main advantages of series compensation against the new transmission line within the same corridor are:

- Significantly reduced investment costs; the same increase in power transmission for up to 90% reduced costs
- In many cases the only practical way to increase the transmission capacity of a corridor
- Series compensation shortens the lead times
- Environmental impact

2.1.7. Advancements in series compensation using thyristor switching technology

A thyristor switched series capacitor (TSSC) can be used for power flow control. This is performed by changing the reactance of the transmission circuit in discrete steps, see Figure 2.10.

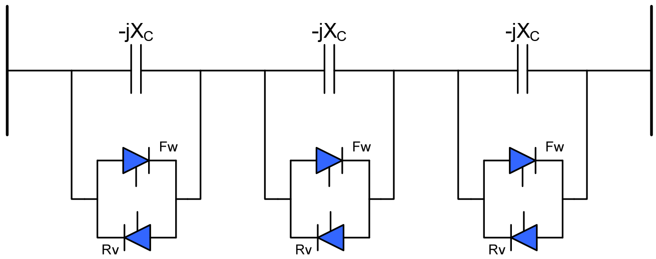

Figure 2.10: Thyristor switched series capacitor

A TSSC typically consists of a few segments in series that can be inserted independently of each other in order to achieve different total series capacitor reactance.

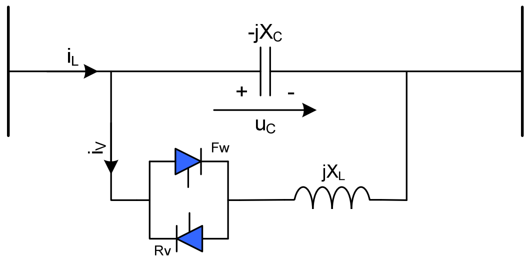

Figure 2.11: Thyristor controlled series capacitor

A thyristor controlled series capacitor (TCSC) allows continuous control of the series capacitor reactance. This is achieved by adding current through the capacitor via the parallel thyristor valve path; see Figure 2.11.

The main circuit of the TCSC consists of a capacitor bank and a thyristor controlled inductive branch connected in parallel. The capacitor bank may have a value of e.g. 10 to 30 Ω/phase and a rated continuous current of 1500 to 3000 A. The capacitor bank for each phase is mounted on a platform providing full insulation towards ground. The thyristor valve contains a string of series connected high power thyristors with a maximum total blocking voltage in the range of hundreds of kV. The inductor is an air-core reactor with a few mH inductance. The waveforms of a TCSC in capacitive boost mode are shown in Figure 2.12.

The apparent impedance of the TCSC (the impedance seen by the power system) can typically be increased to up to 3 times the physical impedance of the capacitor, see Figure 2.13. This high apparent reactance will mainly be used for damping of power oscillations.

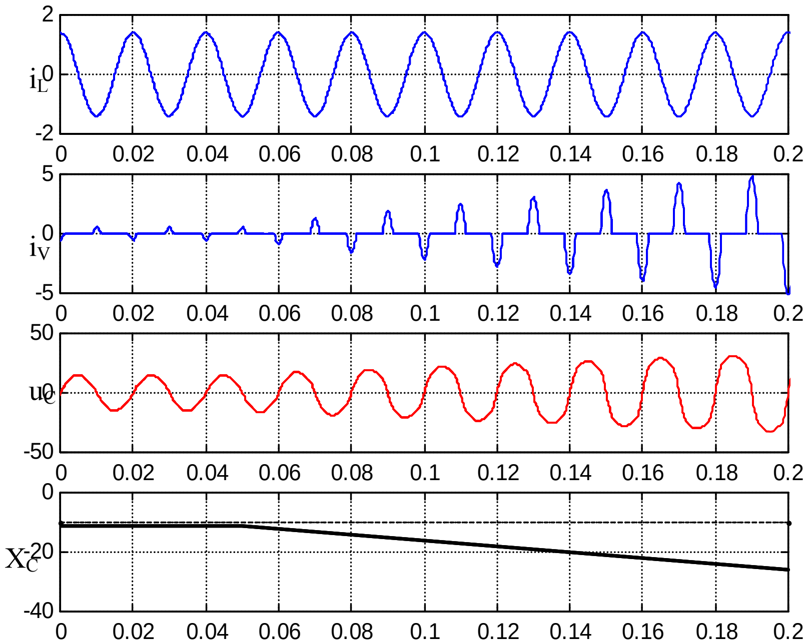

Figure 2.12: TCSC waveforms presented in capacitive boost mode

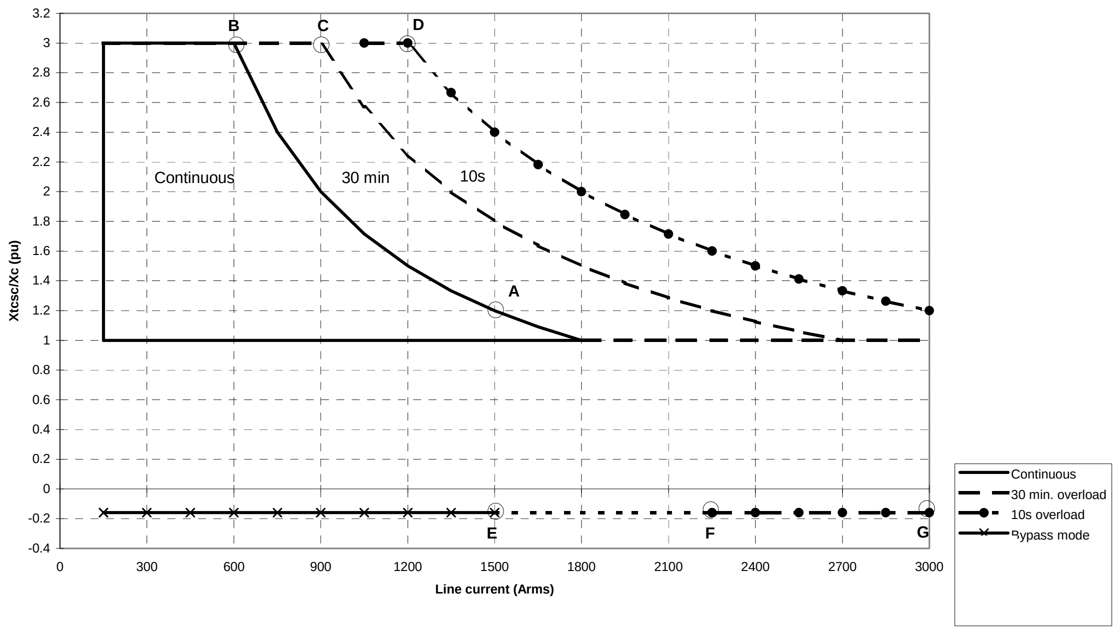

Figure 2.13: Operating range of a TCSC installed for damping of power oscillations (example)

During continuous valve bypass the TCSC represents an inductive impedance of about 20 % of the capacitor impedance. Both operation in capacitive boost mode and valve bypass mode can be used for damping of power swings. The utilization of valve bypass increases the dynamic range of the TCSC and improves the TCSC effectiveness in power oscillation damping.

Arrangement and location of series capacitor Banks

In 1928 New York Power & Light put a series capacitor installation into operation. According to [14] this was the world's first series capacitor. It had a rated voltage of 33 kV and a rated capacity of 1.25 Mvar. Utilities have installed series capacitors on their distribution feeders for a long time.

Several countries, among them Argentina, Brazil, Canada, Chile, China, Japan, Mexico, Norway, Turkey, South Africa, Sweden, and USA, employ series compensation on their long EHV power transmission lines. Other countries, such as: Australia, Bolivia, Colombia, India, Mali, Saudi-Arabia, Venezuela and Iceland study series compensation or have started to introduce series capacitors on their transmission networks.

Figure 2.14: Furnas (Brazil) 765kV, 1056Mvar series capacitors (source ABB)

The development in series compensation has been continuous with respect to the elements used, capacitor bank design as well as applications in power system itself. This led to differences in design of capacitor banks as well as their position in power system. Example of a series capacitor bank is presented in Figure 2.14.

2.1.8. Physical arrangement of series capacitor banks

General layout of series capacitor bank is presented according to [3] in Figure 2.15. Basic related terms and definitions are introduced according to the same reference [3] in Table 2.1.

More complete definitions for series capacitor banks and their parts are available in [3] and [4]. Development of capacitor units and elements in 20th century followed in great extent the increasing nominal voltage level of series compensated transmission networks and increasing required compensating power.

Table 2.1: Basic terms and definition applied to series capacitor banks

Term	Standard definition
Capacitor element	A device with two electrodes separated by a dielectric.
Capacitor unit	An assembly of one or more capacitor elements in the same container with terminals brought out (C_U in Figure 2.15)
Series capacitor phase bank (phase bank)	A number of capacitor units connected in one phase together so as to act together.
Series capacitor bank	Three-phase banks operated in common.

Term	Standard definition
Segment (of a series capacitor)	Where the phase bank is divided into series connected complete parts, each such part is called a segment (see Figure 2.15).
Module/Switching step (3-ph) of a series capacitor	Where the phase bank is divided into segments, and if the phases are operated together, such a group of three segments is called a module (see Figure 2.15)
Overvoltage protector	A quick-acting device that limits the instantaneous voltage across the capacitor to a permissible value when that value would otherwise be exceeded as a result of a circuit fault or other abnormal network condition (element U> in Figure 2.15).

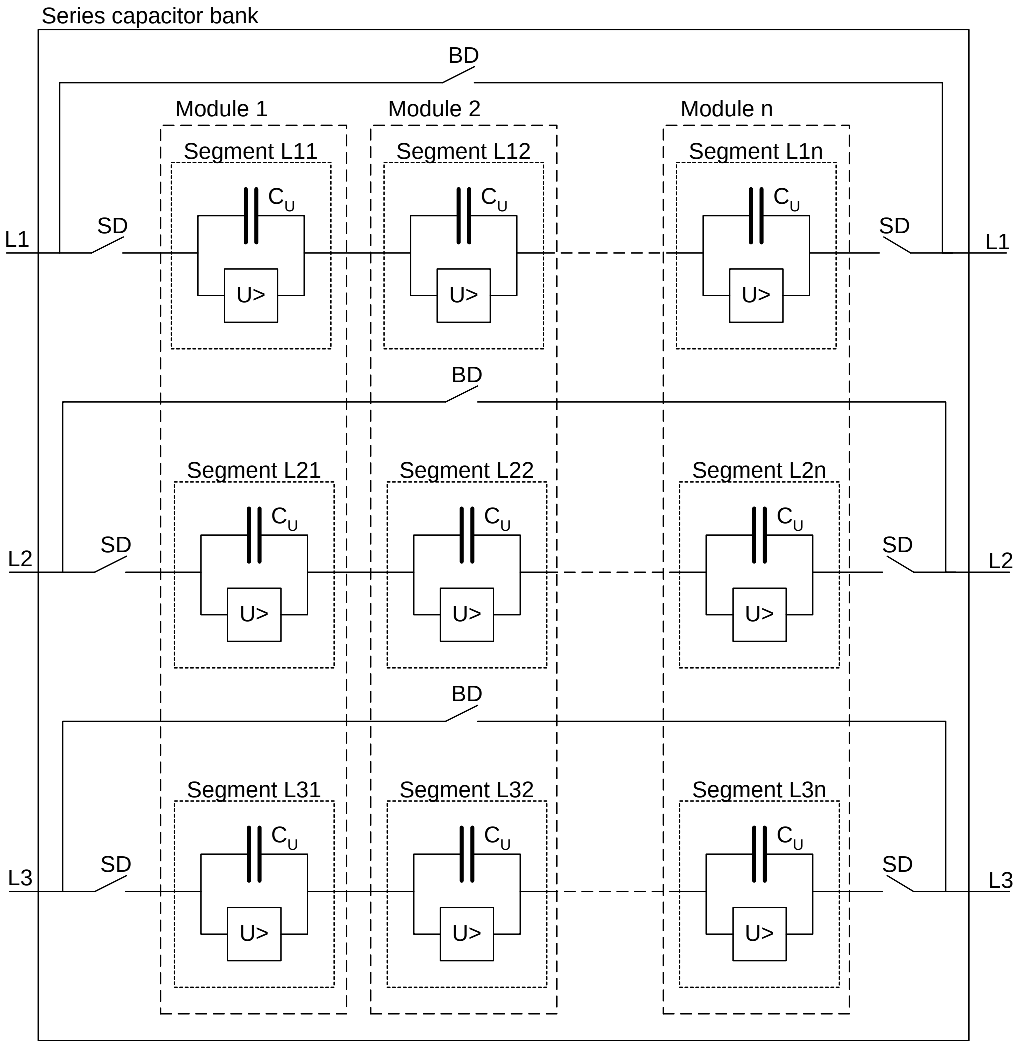

Figure 2.15: General layout of a series capacitor bank (SD is an abbreviation for series disconnectors and BD for by-pass disconnectors)

Typical layout of series capacitor (one phase) is presented in Figure 2.16 and the photo of installation in Figure 2.17.

First capacitor segments from early 1950-es comprised a number of series and parallel-connected capacitor units, each of them comprising only two parallel-connected capacitor elements [5]. They were of round shape with internal over-pressure of 1.5 – 2 kg/cm^2, which was necessary in order to increase the ionization level and to make it possible to use economic dielectric stresses. This type of capacitors was for this reason very heavy and voluminous.

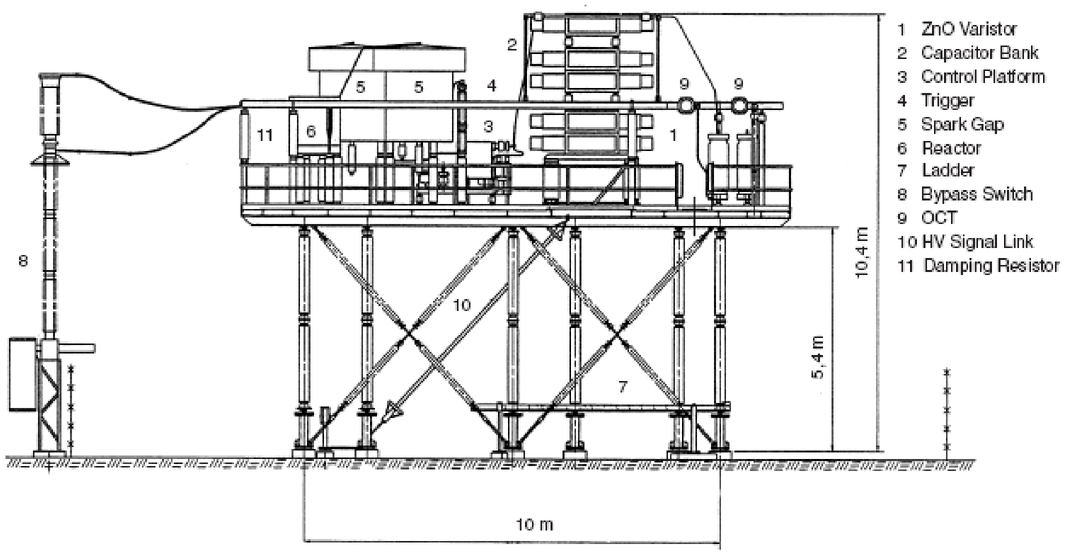

Figure 2.16: Layout, one series capacitor at Dafang (China) 500kV installation (source ABB)

Figure 2.17: Dafang (China): 500kV, 2x372Mvar series compensation (source ABB)

Modern capacitor units are of “box” type, comprising also modern impregnates with dielectric permittivity considerably higher then one typical for mineral oils used in old units. It may be seen from diagram in Figure 2.18 that the capacitors have continuously become smaller and lighter, relatively spoken [5]. Required setting of spark gaps generally decreases the values as presented by continuous lines compared to the possibility to utilize the complete thermal capability of the units, which are presented by dashed lines.

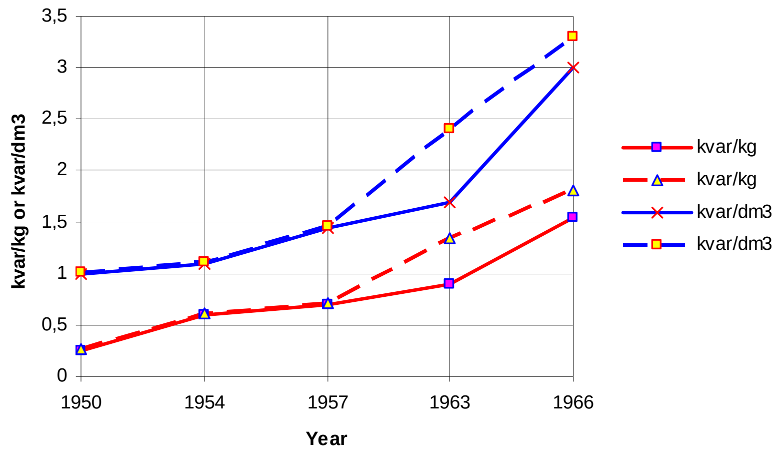

Figure 2.18: Development of series capacitors with time

Nominal system voltage increased over the 20th century from 33 kV up to 800 kV, including the highest rated voltage of 765 kV in Brazil. Figure 2.19 shows this development in dependence of time. Their capacity has developed during the same period from 1.25 Mvar up to the range of 1200 Mvar.

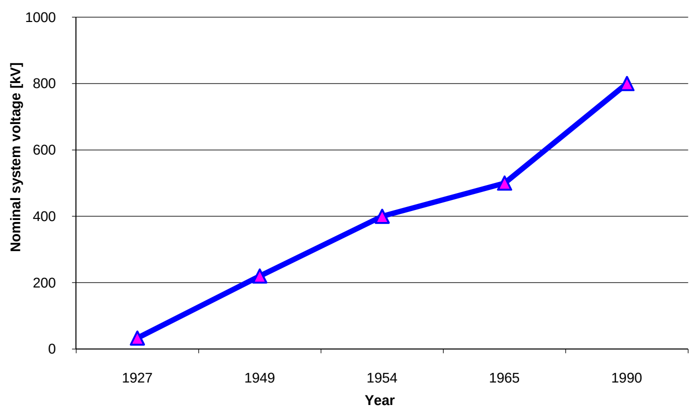

Figure 2.19: Development of series capacitor banks related to nominal system voltage

2.1.9. Locations of series capacitor banks

Locations of series capacitor banks on power lines differ in great extent. Figure 2.20 presents four typical cases.

Single capacitor bank located in the middle of a power line provides the best compensation effectiveness K_X [1], which is defined by equation (2.4).

$$K_X = \mathrm{Re}\left[\cosh\left(\gamma \cdot s\right) \cdot \cosh\left(l - s\right)\right] \qquad (2.4)$$

Different parameters influence final location of series capacitors for a particular installation. The most important between them are listed as follows.

1. Compensation effectiveness, which varies as a function of capacitor location along the power line
2. Voltage profile of the compensated transmission line
3. Requirements on line and bank protection differ with the location of series capacitor
4. Maintainability of capacitor bank represents an important influencing factor

5. Varistor energy requirements are influenced by bank location, if varistors are used for protection of series capacitors.

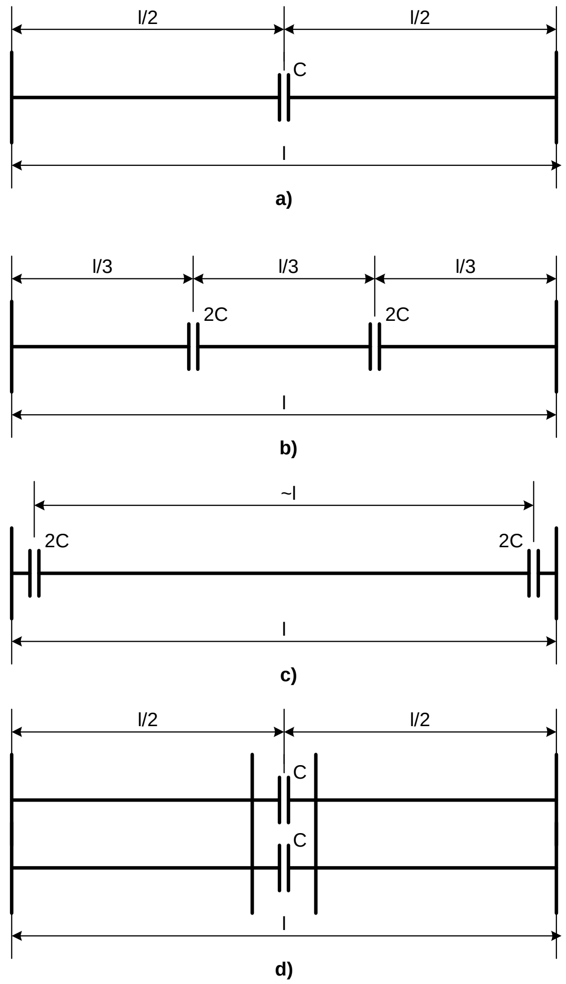

Figure 2.20: Typical locations of series capacitor banks on power lines

Apart to all above-mentioned techno-economical aspects environmental concerns are getting increased importance in modern society. Air pollution in important industrial areas can in modern emerging series compensated networks influence the location of series capacitors. It is on the other hand very difficult to build new series capacitor banks within densely populated areas. It is for these reasons lesser number of new installations, which follow from the capacitor location point of view only techno-economical aspects of their location.

Capacitor in the middle of a transmission line, as shown in Figure 2.20a presents a solution, which secures the best compensation effectiveness and at the same time the least problems for the line protection as long as the compensation degree is less than 50%. It is necessary to mention the possibility that lines presented in Figure 2.20a, b, and c appear also as parallel circuits, generally with capacitors at the same location on both circuits. Parallel circuits can be located close to each other, so that zero sequence mutual impedance plays an important role especially for the operation of line distance protection. Installations with parallel circuits running a few hundred meters apart from each other are also common (e.g. in P.R. China).

Series compensated lines serve often only transmission of electric energy in one direction, from production to consumption areas. In such cases it is feasible to install a single capacitor bank near the consumption buses and provide them this way with optimum voltage. This also reduces significantly requirements on space, maintenance of capacitor banks, and their investment costs.

Installation of two capacitor banks, each of them on approximately $1/3$ of line length (see Figure 2.20b) provides optimal voltage profile in cases with power flow in one or another direction. It also provides the best operating conditions for line distance protection as long as compensation degree of each capacitor does not exceed 33%.

Solution presented in Figure 2.20c is a special version of solution from Figure 2.20b. Capacitor banks are in this case moved to the line terminals. The advantages of this solution are economical (from investment and maintenance point of view) and environmentally kind. The disadvantages are reflected in increased requirements on line protection (voltage and possible current inversion) and less optimal voltage profile on series compensated lines.

Series capacitors can also be installed in switching stations between line buses as presented in Figure 2.20d. The effect of series compensation on complete transmission system is the same as in Figure 2.20a. Possibilities to control the complete bank capacitance of a transmission system makes possible better adjustment to particular operating conditions.

Utilities in Canada, Norway, Sweden and Turkey have elected to use in-line series capacitors. These series capacitor installations are unmanned. Utilities in Brazil and United States have elected to use line-end capacitors. These series capacitor installations are located in manned switching substations. In Argentine, there are series capacitors connected between busbars in the switching substations. New installations of series capacitors in countries like China and India have the capacitor banks located at line ends. Saudi Arabia has decided for capacitor banks in the middle of interconnecting lines. It is also possible to find different installations within the same country, e.g. South Africa.

Basic Requirements on protection of series capacitor banks

The requirements on the protection and control system for series capacitors vary from utility to utility and depend on the utility practice. It, in turn, depends on the operating principles of the network. However, the basic requirements on the protection and control system are similar. This section addresses similarities and variations in requirements on the protection and control system for series capacitors. We have divided the functions of the protection and control system into the following four groups:

- Protection against internal faults,
- Protection against abnormal conditions,
- Protection against harmful effects caused by the series capacitor, and
- Control system for series capacitor.

2.1.10. Protection against internal faults

This group includes:

- Unbalance protection,
- Flashover protection,
- Spark-gap failure protection,
- MOV failure protection,
- By-pass switch failure protection, and
- Pole disagreement protection.

All these protections are necessary to protect the series capacitor against internal faults. These are basically fixed time delay overcurrent functions except for the capacitor unbalance protection that is line current compensated in order to measure the unbalance ratio.

2.1.11. Protection against abnormal conditions

This group includes the following functions:

- Capacitor overload protection,
- MOV overload protection, and
- Spark gap protection.

Capacitor overload protection is a function of the utility practice. Some utilities may not specify this protection if they believe that when an overload occurs the power system is in serious trouble and bypassing of the series capacitor will not help the system to survive. When applied the determining factor for the overload protection is the permissible capacitor overvoltage for the required system overload time.

The amount of MOV overload protection is dependent on the energy absorption required to meet the system design and operating criteria. Because of the usually greater energy absorption required for an internal fault, an MOV scheme is most frequently specified to by-pass the bank for this condition. The limiting criteria for MOV selection are usually the type, number and duration of external faults. In many cases, bypassing is allowed for external multi-phase faults, but not for single-phase faults. The reclosing cycle and the selected number of external faults determine MOV energy capability. The number of allowed faults before bypassing the series capacitor is usually from one to three. The protection of the series capacitor against stresses caused by system conditions such as described above is carried out by functions that measure MOV accumulated energy, MOV single shot energy, MOV energy rate of rise, and MOV current.

The MOV and spark gap protections are basically the same. The spark gap protection will be different depending on the actual protective scheme, single gap, dual gap or MOV with gap protective schemes.

2.1.12. Protection against subharmonic resonance

Subharmonic frequency is defined according to equation (2.5).

$$k_{sh} \cdot f_{sh} = f_n \tag{2.5}$$

Here is k_{sh} an integer bigger than 1.

If subharmonic resonance conditions are foreseen, the protection system could be equipped with a subharmonic protection. Subharmonic resonance shows up as a subharmonic overcurrent superimposed on the fundamental frequency current. This protection will detect subharmonic currents, e.g. below 35 Hz. If the magnitude of these currents exceeds a threshold, the subharmonic resonance protection will send a closing command to the by-pass switch. The threshold may be a few per cent, e.g. 5 to 10% of the rated fundamental frequency current. The subharmonic protection may allow automatic re-insertion of the series capacitor after e.g. 20 s. A repeated operation of the subharmonic during a reclaim time will close the by-pass switch with a definite lockout. The setting of the reclaim time may be e.g. 60 s. After such a long time, most subharmonic oscillation in the network with the series capacitor by-passed should have died out.

2.1.13. Protection against subsynchronous resonance

Subsynhronous frequency is defined according to equation (2.6).

$$f_{ssy} < f_n \quad \text{and} \quad f_{ssy} \neq f_{sh} \tag{2.6}$$

It is difficult to detect SSR because the subsynchronous current is normally less than 0.1% of the fundamental frequency current. Generally, all new series capacitor installations should be designed with a degree of compensation that would not cause SSR. If SSR cannot be avoided by proper selection of the degree of compensation, SSR must be controlled.

Control system for the series capacitor

This group includes:

- Automatic insertion,
- Manual insertion,
- By-passing, and
- Re-insertion functions.

The control functions vary widely between different utilities depending on the utility's operational strategy and practice. Some utilities use automatic functions to insert the series capacitor prior to line energization and automatically by-pass the series capacitor when the line is de-energized. In other utilities, the system operators manually insert and by-pass the series capacitors. Some utilities use a complicated key interlocking system between the various components such as disconnect switches and by-pass switches, while others do not use interlocking system at all.

Electrical environment on the platform

The presence of protection and control equipment on the platform requires careful consideration of electrical environment in which it resides. The issues which have to be addressed in designing series capacitors are basically the same as those faced by the designer of a substation, but are more pronounced and less well understood. The relative compactness of the equipment on the platform emphasizes insulation issues and give rise to electromagnetic interference problems. The series capacitor equipment is exposed to a wide range of current levels, both in amplitude and frequency. These include:

The high magnitude of power frequency currents, ranging from DC to fundamental frequency, which can occur during power system disturbances and are amplified by the presence of the series capacitors in the system,

The high frequency, typically 400 to 1 000 Hz, high amplitude, typically 50 to 100 kA, ring-down of the capacitor discharge current through the damping device, and

The extra high frequencies, typically over 100 kHz, which occur during the opening and closing of the disconnectors of the series capacitor. The flow of the high frequency currents can cause very high voltages due to the $L \cdot \left(di / dt\right)$ rise on the buswork.

Insulations considerations

The devices used to measure the currents must be properly insulated for the application in which they are applied. This requires that an evaluation of the insulation co-ordination be performed to establish the necessary voltage class and basic insulation level (BIL) of the measuring devices. If these devices are not properly insulated, their failure could result in the protection and control equipment being exposed to the flow of power system fault currents. Typically, the protection and control equipment are located at the platform potential at or near the point where the platform is connected to the power circuit. This connection provides a reference point for insulation co-ordination and is monitored for indication of a platform fault.

EMI Considerations

The protection and control equipment on the series capacitor platform is relative compact in comparison with similar equipment in transformer substations. Protection and control equipment for series capacitors must therefore withstand more severe electromagnetic interference (EMI) than conventional protection and control equipment. The high field levels associated with current flow through the discharge device also causes circulating currents in the platform itself which may cause EMI problems if the secondary circuits of the CTs and the protection and control equipment are not properly isolated. The secondary leads from the CTs to the protection and control equipment must be properly shielded and grounded at a single point. If one ground both ends of the shield, there is a risk that normal operating currents or fault currents induce currents in the shield. There is a risk that these currents will induce currents in the secondary circuits from the current transformers. The ground point should be made at the protection cabinet, which is at platform potential. This reduces the risk of exposure to the flow of power currents on the platform since the platform does not normally carry current. The platform can be subjected to induced current flow due to the discharge reactor as well as the buswork. The control cubicle location should be such as to minimize this exposure.

Firing circuits

The presence of a by-pass gap on MOV protected series capacitors requires a triggering circuit. This circuit provides the connection from the low power protection and control circuits to the initiation of the high-energy impulse necessary to trig the gap. As with other protection and control equipment on the platform, these circuits must be designed to withstand the harsh environment on the platform. They must be isolated from the high-energy environment of the by-pass gap. As with any protection scheme, dependable and secure operation is a paramount consideration. The need for reliable firing of the by-pass gap to protect the MOV has usually dictated the use of redundant gap firing circuits. Experience has shown that these circuits have been dependable. The other concern raised is that these circuits may fire spuriously. This issue arises if the circuit has not been properly shielded from EMI or if the fundamental frequency algorithm used to protect the MOV does not properly reflect the MOV characteristics. Proper design practices should address these concerns.

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3. SERIES CAPACITOR BANKS

General on series capacitor banks

3.1.1. Fixed series capacitor banks

A Series Capacitor Bank (SC) is a piece of equipment that is connected in series with a transmission circuit, and it is exposed to the same current-stresses and voltage-stresses as the transmission circuit itself. The voltage stress may additionally be divided to two types: a) series voltage stress (especially during faults and abnormal conditions) and b) shunt voltage stress. The later one is seldom of importance for the line proper. The SC-equipment needs to be designed for these stresses. Of special interest are the different current-stresses and associated voltage-stresses for which the SC needs to be designed. The most important current-stresses for a transmission SC are the following:

1. The normal current
2. The maximum continuous current
3. The 30 min. overload current
4. The 5-10 s swing current
5. Fault currents (essentially power frequency)
6. Low frequency (below power frequency) oscillation currents
7. Traveling wave current surges

The design of a capacitor for the currents and the associated voltages, according to items 1– 3, is usually a straightforward task. High swing currents, item 4 usually require special consideration (see below). Item 7 gives no excess voltages across the capacitor due to the short duration of the lightning or switching surge. However, the transient capacitor voltages associated with item 5 or 6 may be substantial and would generally exceed the inherent short time voltage capability of a capacitor unit. To design the capacitor for these high voltage stresses would result in a completely uneconomical design.

Since the capacitor is sensitive also to short duration overvoltages, the technical/economical solution is to provide the SC with a fast-acting primary overvoltage protection. Traditionally the primary overvoltage protection comprised a self-triggered (voltage triggered) spark gap firmly connected across the terminals of the capacitor (single gap scheme, Figure 3.1). The spark gap had a spark-over time of some hundred microseconds.

A bypass switch was connected in parallel with the gap. The gap was extinguished by closing the bypass switch. A current limiting damping circuit (X_L) was used to limit the capacitor discharge current upon gap spark-over or bypass switch closing. Thus the SC was provided with a bypass circuit. The drawback of this simple bypass circuit was the relatively long recovery time of the spark gap after it had operated, typically 400 – 600 ms depending on the magnitude of the through fault current. The consequence was that the reinsertion time of the SC after external fault clearing was 400 – 600 ms.

The single gap scheme was improved in steps. In order to reduce the reinsertion time of the SC following clearing of an external fault, two spark gaps with different settings were used (dual gap scheme, Figure 3.3). With the dual gap scheme, the reinsertion time after external fault clearing was reduced to 60 ms, using an ordinary circuit breaker as “reinsertion switch” (Figure 3.3).

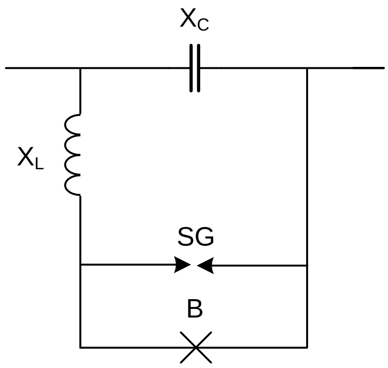


Figure 3.1: Single gap

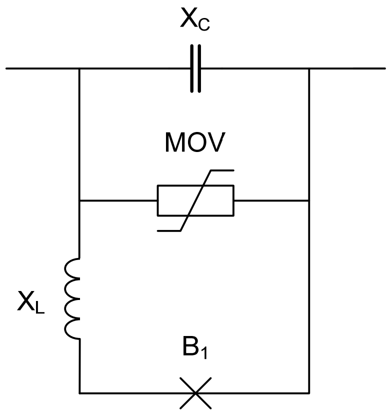


Figure 3.2: MOV (gapless)

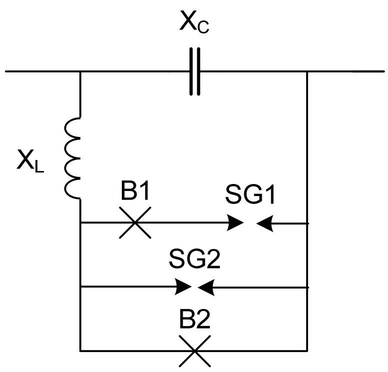


Figure 3.3: Dual gap

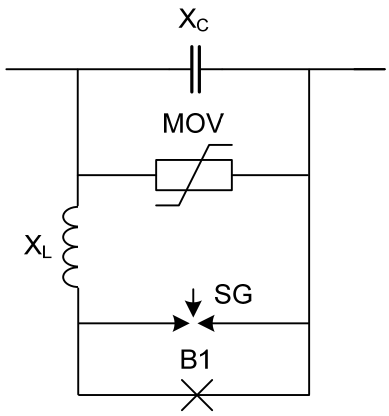


Figure 3.4: MOV + bypass gap

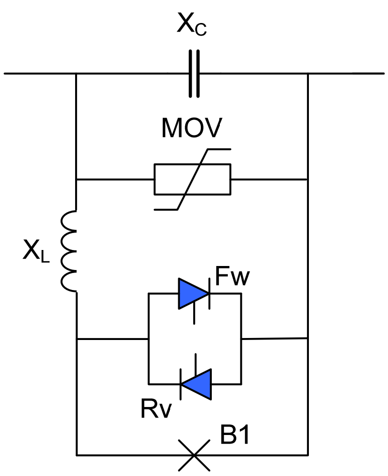


Figure 3.5: TPSC (MOV + thyristor valve)

The next step was to use a metal oxide varistor as overvoltage protection for an SC (gapless MOV scheme, Figure 3.2 or MOV scheme with a bypass gap, Figure 3.4). With the MOV scheme, the reinsertion time after external fault clearing was reduced to zero, provided that the MOV was not bypassed for external faults. Note that the bypass gap, which is designed as a forced triggered spark gap, is used for fast bypassing of the MOV for internal faults.

The thyristor protected series capacitor (TPSC) uses a thyristor valve for fast bypassing of the series capacitor during transmission line faults; see Figure 3.5. In contrast to spark gaps, thyristor valves do not require any time for deionization after conduction and therefore the TPSC can be used for fast bypassing of the series capacitor when a transmission line fault occurs and for rapid series capacitor reinsertion when the fault is cleared.

It is important to note that the primary overvoltage protection also protects the capacitor from the overvoltage that occurs when the capacitor is inserted or reinserted by opening of the bypass switch. The current at capacitor insertion/reinsertion is called the insertion/reinsertion current and is defined in the standards for SC. This current may be added to the list above, since it has a decisive influence on the design of the SC.

3.1.2. TSSC and TCSC banks

A thyristor switched series capacitor (TSSC) can be used for power flow control. This is performed by changing the reactance of the transmission circuit in discrete steps, see Figure 3.6. A TSSC typically consists of a few segments in series that can be inserted independent of each other in order to achieve different total series capacitor reactance.

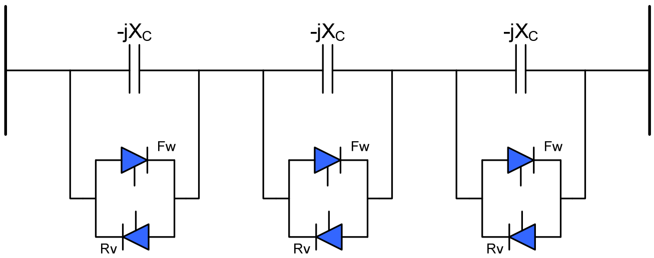


Figure 3.6: Thyristor switched series capacitor

A thyristor controlled series capacitor allows continuous control of the series capacitor reactance. This is achieved by adding current through the capacitor via the parallel thyristor valve path see Figure 3.7.

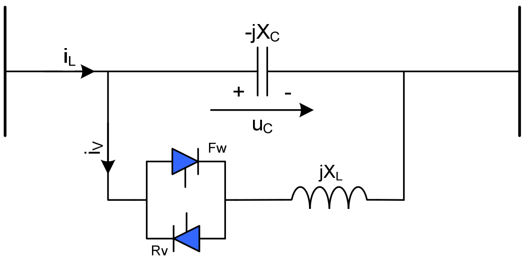


Figure 3.7: Thyristor controlled series capacitor

The main circuit of the TCSC consists of a capacitor bank and a thyristor controlled inductive branch connected in parallel. The capacitor bank may have a value of e.g. 10…30Ω/phase and a rated continuous current of 1500…3000 A. The capacitor bank for each phase is mounted on a platform providing full insulation towards ground. The thyristor valve contains a string of series connected high power thyristors with a maximum total blocking voltage in the range of hundreds of kV. The inductor is an air-core reactor with a few mH inductance. The typical waveforms of a TCSC are shown in Figure 2.12.

The required operating range of a TCSC, i.e. the achievable apparent reactance as a function of the line current depends on the application. A typical TCSC operating range for power oscillation damping purposes is shown in Figure 2.13.

The apparent impedance of the TCSC (the impedance seen by the power system) can typically be increased to up to 3 times the physical impedance of the capacitor. This high apparent reactance will mainly be used for damping of power oscillations. During continuous valve bypass the TCSC represents an inductive impedance of about 20 % of the capacitor impedance. Both operation in capacitive boost mode and valve bypass mode can be used for damping of power swings. The utilization of valve bypass increases the dynamic range of the TCSC and improves its effectiveness in power oscillation damping.

3.1.3. TPSC banks

Many HV and EHV transmission lines around the world are being refurbished with series compensation, as a result of deregulation trends and right of way issues. These series capacitors are commonly protected by a combination of MOVs and forced or self triggered gaps.

If the short circuit level of the network behind the series compensation is very high, the required amount of energy consumed by MOV may become prohibitive and uneconomical due to the required MOV dimension and costs. Consequently, the platform size is negatively influenced by such MOV structures. Furthermore, large reinsertion delays, subsequent to system faults have to be considered to enable the MOVs to cool down.

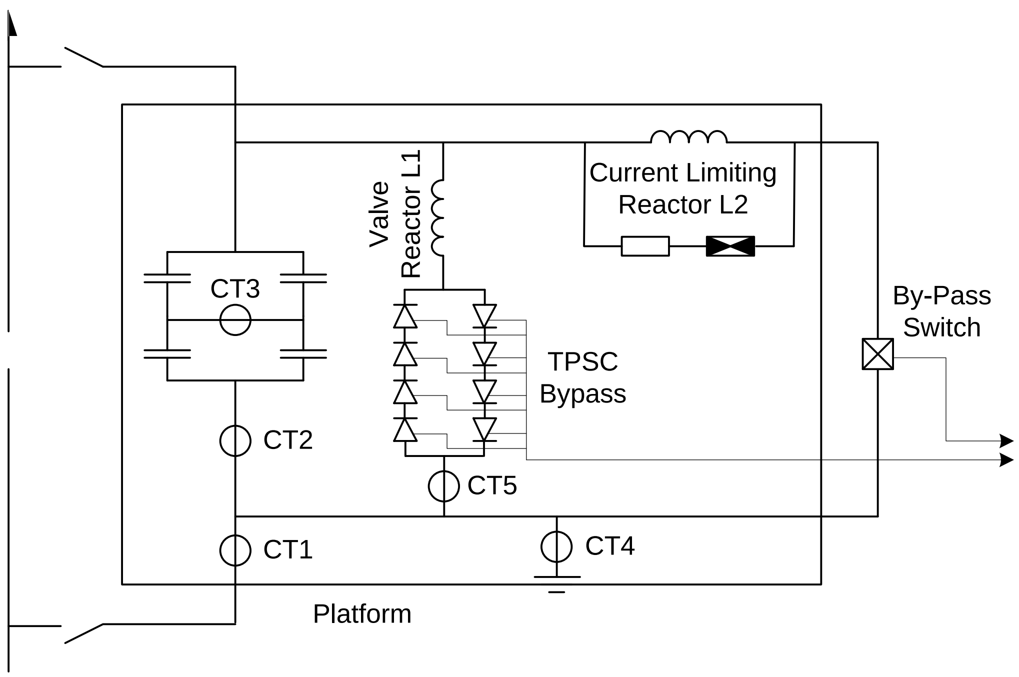


Figure 3.8: TPSC Single line diagram

With the development of light triggered thyristors (LTTs) with high short time current capabilities, it is possible to replace the MOV/Gap-combination with LTTs. Since these thyristors cool down very fast, reinsertion of the series capacitors is possible without any appreciable delay. LTTs can, therefore, replace the MOVs as well the trigger gaps.

3.1.3.1 Characteristics of TPSC

An ac-fault current flowing through an MOV always leads to a high energy dissipation of the MOV. Due to an upper temperature limit the MOV must cool down before the next current stress can be absorbed. Cooling down requires from the power system point of view rather long time. A thyristor provides a high current carrying capability in combination with low conduction loss.

Therefore heating will be decreased as well as cooling down will be faster than with MOVs. A closer look at the single line diagram (see Figure 3.8) of the thyristor protected series capacitor (TPSC) shows a remarkable similarity to a Thyristor Controlled Series Capacitor (TCSC) installation. In fact the TPSC can be upgraded to full TCSC operation by adding the special control features and valve water-cooling equipment. For customers' benefit, this upgrade can be foreseen at the TPSC design stage. The upgrade itself can be carried out at a later stage during commercial operation. Compared to a conventional MOV application, the TPSC solution requires less space on the platform. The thyristor switch is located in a container on the platform.

3.1.3.2 Single line diagram of a typical TPSC-Scheme

The basic single line diagram of a TPSC installation is shown in Figure 3.8. The system can be connected to the line by disconnect switches and the bypass switch. The series capacitor is build up in H-connection to detect capacitor unbalances. The thyristor branch and reactor are connected in parallel to the capacitor, to provide the fast temporary bypass. For permanent lockout and bypass, a switch with an associated damping circuit is located across the capacitor. To protect the equipment on the platform, optical current transformers for measuring ac-line currents, capacitor currents unbalance currents and platform currents are provided.

Protection of capacitor elements and units

Series capacitors are normally protected by conventional methods used for protection of power capacitor elements. Fuse protection, capacitor overload protection and platform protection are discussed below. Internal or external fuses are the primary protection of elements and units for series capacitors. Normally, modern series capacitors are split into a certain number of legs containing capacitor cans in series-parallel combination to form a H-configuration or two parallel strings. The unbalance protection must be coordinated with the capacitor fuses.

The technology of the protection and control equipment used on series capacitors has evolved over the years. Older equipment made extensive use of electromechanical protection and control equipment that was located on the platform. The advancements in fiber optic communications technology have minimized the use of protection and control electronics on the platform. The relocation of protection and control equipment from the platform to the ground level has minimized the level of exposure to electrical environmental problems. However, some electronic equipment will continue to exist on the platform, and must perform properly.

3.1.4. Externally fused Capacitors

Externally fused capacitors provide visual of fuse operation for faster maintenance and achieve protection for dielectric failure, lead failures, internal bushing failures, and bushing flashovers. The fuse operation at a failure within the capacitor elements removes the entire unit from service. The removal of the faulted capacitor unit from the series capacitor upon the operation of an external fuse fulfils an additional desired overvoltage protection requirement for the remaining capacitor units and minimizes the probability of case rupture. Although the probability is low, if a capacitor failure occurs without fuse operation or in case of partial defective capacitor units where the fuse has not blown, the unbalance protection will detect high unbalance current and initiate a trip when only an alarm is required.

3.1.5. Internally fused capacitors

For internally fused capacitor elements, the scheme offers the possibility of allowing failure of internal capacitor elements without affecting the overall expected life of the capacitors, and the removal from service of the remaining capacitor elements in this case is not required. The arrangement also offers lower parallel energy discharge in case of faults and provides compact can (container) size and simplicity in the design. On the other hand, internally fused capacitors provide protection for capacitor elements only within the capacitor sections. Connections between the elements and the bushing are not protected. Moreover, lack of visual indication of fuse operation results in longer maintenance. Faults external to the protected capacitor sections will result in the de-energisation of the entire series capacitor, e.g. during external bushing flashovers.

Protection of series capacitor banks

The main components of protection of series capacitor banks are shown in Figure 3.9 and Figure 3.10.

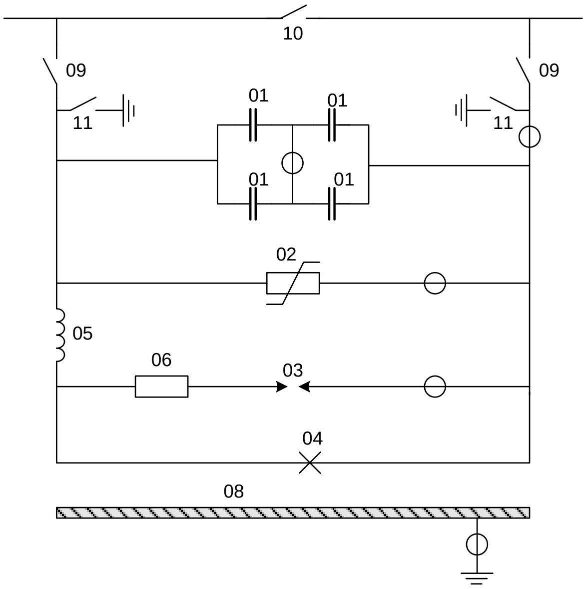


Figure 3.9:Typical connection diagram for FSC

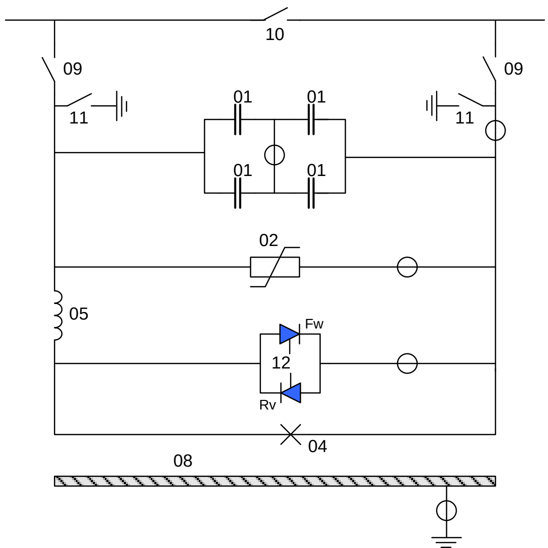


Figure 3.10:Typical connection diagram for TCSC

Description of the components shown in these two figures are : 01- Capacitor, 02-Metal Oxide Resistor (Varistor - MOV), 03-Bypass spark gap, 04-Bypass switch, 05-Reactor, 06-Linear resistor, 08-Platform , 09- Isolating disconnector, 10-Bypass disconnector, 11-Earth switch, 12-Thyristor.

The MOV provides protection against overvoltages caused by high through current due to transmission line faults. These overvoltages may persist until the fault is cleared by opening of the line circuit breakers of the faulted circuit element. Modern series capacitor banks use highly non-linear Metal Oxide Varistors (MOV) to limit the voltage across the series capacitor to a desired protective level. This protective level typically ranges between 2.0 and 2.5 per unit, based on the voltage drop at the rated bank current. When limiting the voltage across the series capacitor to the protective level during fault conditions, the MOV must conduct the excess fault current and thereby absorb energy. A forced triggered spark gap and/or a bypass switch is used to limit the MOV energy to within its absorption capability by bypassing the parallel capacitor/MOV combination.

The current limiting damping reactor is a part of the capacitor discharge circuit. It is designed to limit the capacitor discharge current amplitude and to damp out the oscillations caused by a controlled bypass gap operation or by a bypass switch closing. The inductance is chosen to avoid parallel harmonic resonance between the capacitor and bypass circuit. Table 3.1 presents an overview of typical series capacitor bank protections and corresponding actions during their operation.

Table 3.1: Overview of typical series capacitor bank protections

Function	**Alarm level**	**Bypass**	**Permanent lockout**	**Temporary lockout**	**Permanent bypass**	**Reinsertion**	**Others**
Flashover to platform protection		X	X				
Spark gap protection		X		X			
Trigger circuit supervision	X (1 sys. fail)	X (2 sys. fail)		X			
Sub-harmonic protection	X	X		X	Only at repeated number of subharmonics	X	
Capacitor discharge function		X		X		X	
Bypass switch failure protection: close failure			X				Line breaker trip
Bypass switch failure protection: open failure		X	X				
Bypass switch pole disagreement protection		X	X				
Disconnector pole disagreement protection	X						

Used expressions:

Permanent lockout: The cause of the bypass has to be rectified and the lockout is manually reset.

Temporary lockout: The cause of the bypass is system related and the lockout is automatically reset.

Permanent bypass: The series capacitor can be inserted manually without further actions

3.1.6. Capacitor unbalance protection

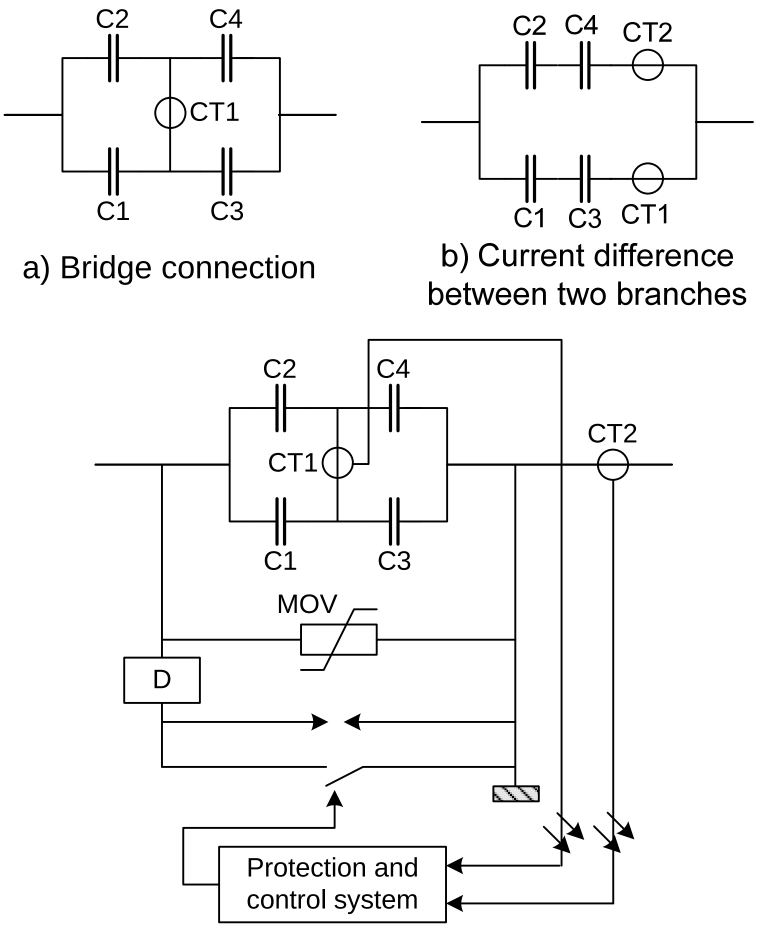


Figure 3.11:Typical arrangements for capacitor unbalance measurement

The capacitor unbalance protection monitors the status of the capacitor bank by measuring the current flowing in the branch of the bridge connection (H-bridge) or the differential current between the two branches, see Figure 3.11.

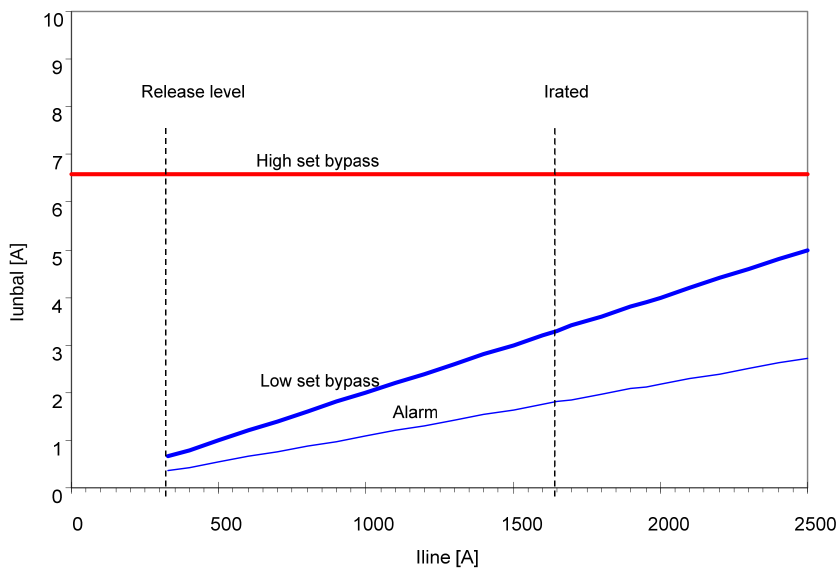


Figure 3.12: Typical capacitor unbalance protection characteristics

Changes in the capacitor bank caused by failed elements or capacitor bushing flashovers result in an increased value of measured capacitor unbalance current.

A capacitor unbalance protection normally has three different setting levels and time delay levels:

- Alarm
- Low set bypass level
- High set bypass level

The alarm level and the low bypass level are set as the ratio between the unbalance current and the capacitor current (line current). The high set bypass level is normally only related to the unbalance current.

3.1.7. Capacitor overload protection

The series capacitor bank is designed to withstand short time overloads, according to the specification, without damage.

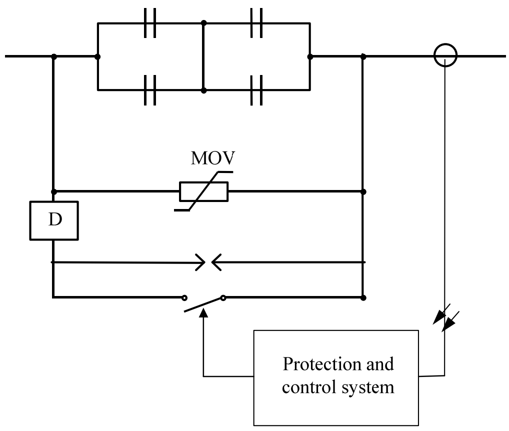


Figure 3.13: Arrangement of capacitor overload protection

However, with occasional peak loads, the overload might be relatively prolonged and of such magnitude that it could result in degradation of the series capacitor units. Therefore the capacitor current is monitored continuously by a capacitor overload protection with inverse time characteristic, see Table 3.2. The start level is always related to the rated series capacitor current (I_{CN}).

Table 3.2: Example of inverse current/time characteristics used in capacitor overload protection

Voltage/Current	Duration
1.50pu U_N rms	10min
1.35pu U_N rms	30min
1.1pu U_N rms	8h
1.0pu U_N rms	continuous

3.1.8. Line current supervision

When the capacitor bank is bypassed by a protection with automatic reinsertion, a reinsertion is initiated after a pre-set time. The purpose of the line current supervision is to avoid reinsertion of the series capacitors on to a fault.

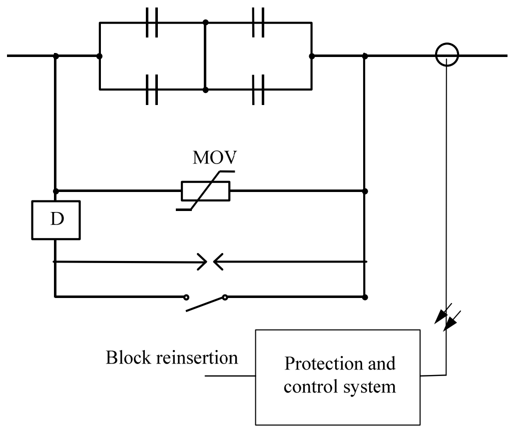


Figure 3.14: Arrangement of line current supervision

3.1.9. MOV overload protection

The object of this protection is to protect the MOV from high energy injection overload as well as thermal overload. The protection initiates triggering of the forced triggered spark gap and the closing of the bypass switch simultaneously. A typical MOV overload protection has three stages.

- Short time MOV energy protection
- High MOV current protection
- High MOV temperature protection

3.1.9.1 MOV Energy Calculations

The protection systems must determine the energy absorbed by the MOV during system faults. The energy can be calculated as the integral of the dissipated power in the MOV. The current is typically readily available from a CT in the MOV branch. The voltage across the MOV, is usually not measured but can be estimated from the MOV U-I characteristic, see Figure 3.15.

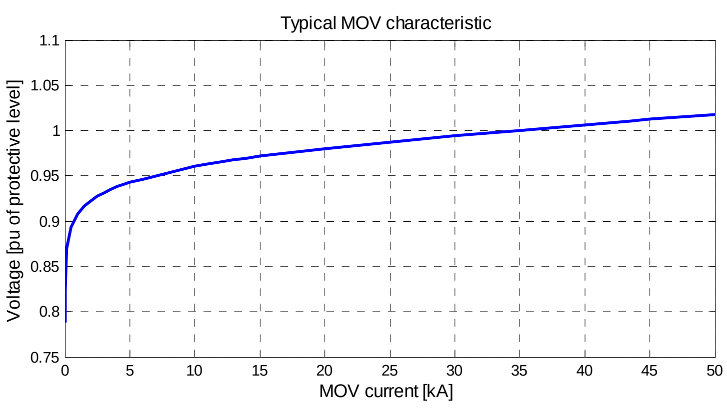


Figure 3.15: Example of MOV characteristic

3.1.9.2 MOV short time energy protection

This protection prevents high energy absorption over a short time period which may cause hot-spots in the metal oxide discs. This protection complements the MOV high current protection for internal line faults. It also provides protection against high energy absorption due to faults external to protected line exceeding those specified in the duty cycles.

The setting is usually based on the maximum energy accumulation due to the external fault duty cycle with some margin in order to avoid bypassing of the series capacitor for external faults. When this energy level is reached, the gap is triggered and/or the bypass switch is closed.

3.1.9.3 MOV high current protection

The purpose of the MOV high current protection is to reduce unnecessary energy absorption for heavy internal faults. The setting should be above the maximum external fault current. Triggering of the spark gap and/or initiation of closure of the bypass switch is instantaneous based upon current magnitude. Reinsertion of the faulted phases follows a short time later (could be made within the dead time of the autoreclosing cycle or after successful autoreclosing, depending on the utility practice).

3.1.9.4 MOV high temperature protection

The purpose of MOV high temperature protection is to prevent damage to the MOV discs due to overheating. The maximum design temperature (approximately 180-200 ˚C) could be reached during a period of successive transmission line faults or long term overload conditions.

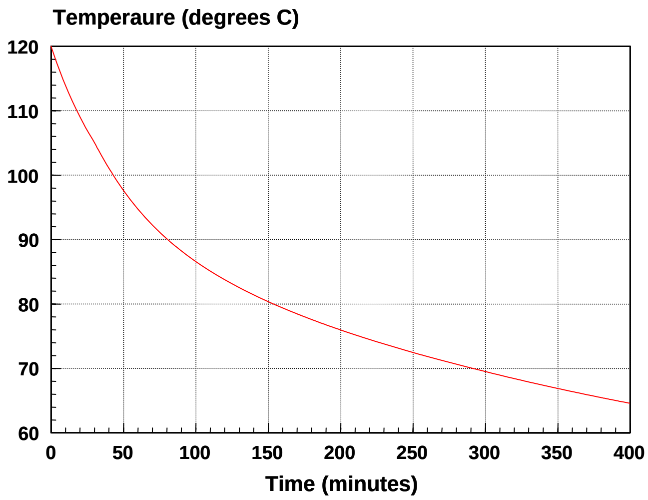


Figure 3.16: Example of MOV cool-down characteristic. Duty: rated energy followed by 2.0 pu 10s, 1.35 pu 30 min, 1.0 pu continous. Initial disc temperature: 60 ˚C.

The thermal model for the protection may include the ambient temperature which can be used in the simulation of the overheating as well as the cooling process. Steady state load current on the series compensated line (to calculate the resulting voltage across the MOV) is usually included in the model.

When the temperature reaches a set value, the spark gap is triggered and/or the bypass switch is closed. The cooling characteristic of the MOV is part of the thermal model for the protection. Reinsertion is permitted only when the MOV can safely withstand a critical fault immediately after the reinsertion has taken place. An example of a MOV cool-down curve is shown in Figure 3.16.

3.1.10. MOV failure protection

The purpose of the MOV failure protection is to bypass the series capacitor in case of a faulty MOV. If a MOV unit fails, the line current will pass through the MOV. One possible implementation of a MOV failure protection is to use the ratio between the MOV current and the line current and order a series capacitor bypass if a pre-set ratio is exceeded (see Figure 3.17). Another possible implementation of an MOV failure protection is to arrange an MOV current unbalance measurement. A bypass and permanent lockout of the series capacitor is given at protection operation.

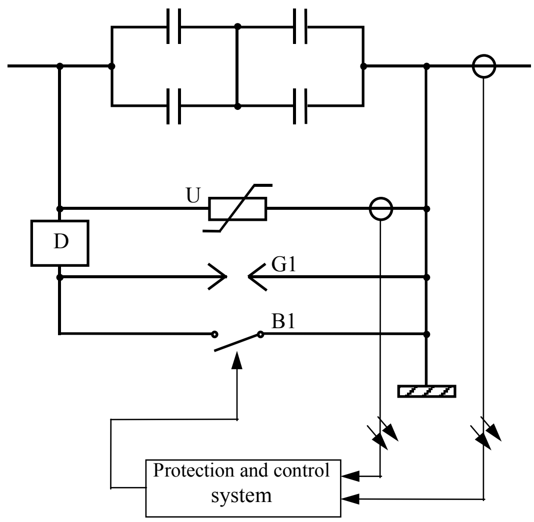


Figure 3.17: Arrangement of MOV failure protection

3.1.11. Flashover to platform protection

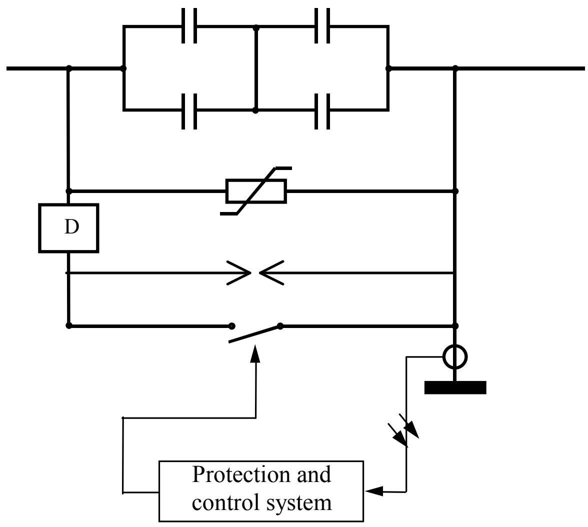


Figure 3.18: Arrangement of a flashover to platform protection

The purpose of the flashover to platform protection is to detect a flashover from any of the platform mounted equipment and the platform. This is done by connecting one side of the main capacitor to the platform via a current transformer; see Figure 3.18. A bypass and permanent lockout of the series capacitor is given at protection operation.

3.1.12. Spark gap protection

The purpose of the spark gap protection is to detect any unwanted spark over of the spark gap. This is done by continuously measuring the spark gap current. The protection will issue a close order to the bypass switch and also cause a permanent lockout of the SC.

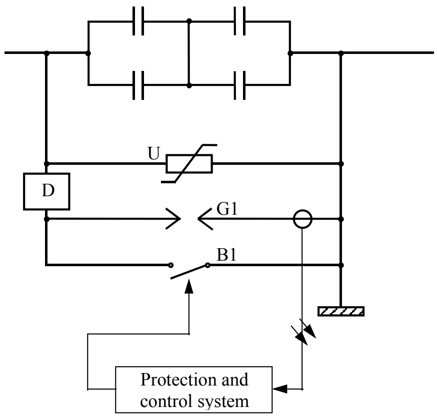


Figure 3.19: Arrangement of spark gap protection

3.1.13. Trigger circuit supervision

The purpose of this protection is to detect faults in the spark gap trigger circuit. The trigger circuit comprises three main components:

- A trigger capacitor
- A trigger transformer
- A thyristor switch

In case of redundant systems, faults in both systems simultaneously will result in a bypass order and a permanent lockout of the series capacitor. Fault in one of the systems will result in an alarm.

3.1.14. Sub-harmonic protection

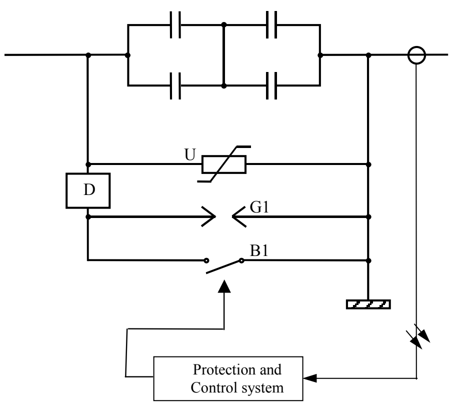


Figure 3.20: Arrangement of sub-harmonic protection

A series capacitor in a power transmission network may, during certain conditions together with energizing of unloaded transformers or reactors, cause sub-harmonic oscillations of such amplitude and frequency that disturbances in the network arise. The purpose of the protection is to bypass the series capacitor if such sub-harmonic disturbances occur. A typical protection uses notch-filters to suppress the fundamental frequency component. The operation of this protection is always three-phase.

3.1.15. Pole disagreement protection

The purpose of the pole disagreement protection is to detect disagreement between the position of the poles of the bypass switch and disconnectors. The bypass switch pole disagreement protection will after a time delay, issue a close order to the bypass switch and start the bypass switch failure protection, if it detects pole disagreement of the bypass switch. The disconnector pole disagreement protection issues an alarm if it detects pole disagreement of a disconnector.

3.1.16. Bypass switch failure protection

The purpose of the bypass switch failure protection is to detect a faulty bypass switch. If the bypass switch has failed to close after a protective operation before the set time has elapsed, a trip order to the line circuit breaker will be given. The position of the bypass switch is normally supervised by the auxiliary contacts. Measurement of the current through the bypass switch is not used. Also a permanent lockout of the SC and an indication will be given.

3.1.17. Capacitor discharge function

The purpose of this function is to discharge the series capacitor via the bypass circuit when the transmission line circuit breakers are opened, either deliberately or in conjunction with an internal line fault. When an internal line fault occurs, the line is disconnected by the line circuit breakers.

This means that a DC voltage will remain on the series capacitor and may give the following consequence:

- Delay of secondary arc extinction at the fault location. This can happen if the line reactors and series capacitors are located in such way that a line reactor, a part of the line, the series capacitor and the earth fault forms a closed loop. Discharging the capacitor with a close operation of the bypass switch can mitigate this problem if it exists.
- Increased transient recovery voltage (TRV) stresses on line circuit breakers. The voltage across the series capacitor may be added to the system voltage across the line circuit breaker at opening. If the resulting TRV stress on the line circuit breakers is too high, the problem can be mitigated by discharging (by-passing) the series capacitor before opening the line circuit breakers.

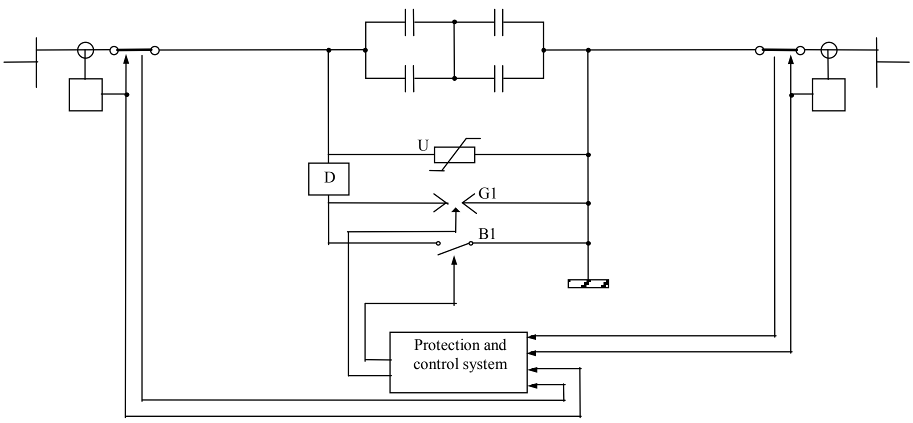


Figure 3.21: Arrangement of capacitor discharge function

If any of the line protections related to the series compensated line issues a trip order to its line circuit breaker, a bypass order will be issued to the series capacitor. A typical implementation of the protection uses two input signals from the line protection:

- Transmission line de-energized
- Line trip

Additional protections for TCSC banks

3.1.18. Thyristor overvoltage protection

The purpose of the thyristor overvoltage protection is to prevent the thyristor valve from blocking in situations that can cause too high a voltage across the thyristor valve. The protection can either be implemented as an indirect thyristor valve overvoltage protection that uses the thyristor current derivative or a direct overvoltage protection that uses the voltage across the thyristors. The protection orders thyristor firing, send a close order to the bypass switch and issues a permanent lockout of the TCSC.

3.1.19. Thyristor thermal overload protection

A TCSC thyristor valve may be protected from thermal overload by a protection that calculates the energy dissipated in the thyristors and then calculates the average temperature of the silicon. If the thyristor temperature increases above an alarm level, an alarm will be initiated and the maximum reactance reference will be limited until the thyristor temperature has decreased below a release level. If the thyristor temperature increases above the trip level then the protection will order a protective bypass and a close order to the bypass switch along with a temporary lockout. All operations are 3-phase and the temporary lockout is reset when the thyristor temperature decrease below a reinsertion block level.

3.1.20. Capacitor DC-voltage protection

The purpose of the capacitor DC-voltage is to bypass the TCSC if there is a sustained DC component in the capacitor voltage. The protection is normally line current compensated, i.e. it utilizes the ratio between the capacitor DC voltage and the line current. In order to avoid undesired protective action due to difficulties in the ratio calculation the protection is disabled if the line current drops below the release level. The protective action is a mechanical bypass and a permanent lockout of the TCSC.

3.1.21. Reactance error protection

The purpose of the protection is to bypass the TCSC if there is a sustained reactance error when the bank is operating in capacitive boost mode. The protective action is a mechanical bypass and a permanent lockout of the TCSC.

3.1.22. TCSC low line current supervision

In addition to the conventional line current supervision that prevents series capacitor reinsertion during transmission line fault conditions, the TCSC line current supervision also supervises low line current. A TCSC cannot remain operating in capacitive boost mode when the line current becomes very low, typically in the range of one tenth of the rated line current. There are two reasons for this:

- The measuring system has a limited resolution and noise suppression capability. Therefore the response signals become too inaccurate for the control system.
- The auxiliary power used for thyristor triggering often is being picked up from the main circuit. When the line current becomes too low this power supply fails and the thyristors cannot be triggered.

When the line current is low, the corresponding fundamental power frequency component of the inserted capacitor voltage is also low. In this condition the power flow in the line depends very little on whether the series capacitor is inserted or bypassed. However, e.g. from a sub-synchronous resonance (SSR) point of view, it may be important that the operating mode of the TCSC is well defined, either in bypass mode or blocking mode.

If the low line current is sustained for a certain period of time the control system may be designed to either block the thyristors entirely or to close the mechanical bypass circuit breaker. Normal operation should automatically be started when the low line current condition disappears.

Additional protections for TPSC banks

3.1.23. Protection and control concepts

3.1.23.1 Control Functions

Control functions consist of:

- Reinsertion of the series capacitor bank after protective device operation with or without delay (manually or automatically),
- Bypass or insertion of the series capacitor bank from ground level controls,
- Provisions for connecting external controls (remote control),
- Lockout from predetermined protection functions, indication and alarm contacts, interlocking of bank disconnectors and earthing switches

3.1.23.2 AC-System Fault Cases

Depending on the severity of the faults, the fault locations in the ac-system are classified in two types. Depending upon the type of fault, different protection actions are initiated:

Internal Faults: are those faults occurring within the series compensated line terminated by breakers. If an internal fault is detected, the thyristor valves are fired and simultaneously the series capacitor gets bypassed by a switch.

External Faults: are those faults occurring outside the series compensated line terminated by breakers. In this case, only the valves receive a firing command. The thyristor valve and reactor must be designed to withstand external faults without damages, as the series capacitor will not be locked out by the switch.

3.1.24. TPSC protection strategies

In case of normal operation, the valves are blocked. The ac-line current flows through the capacitor and is processed by the protection system. If an ac-system fault occurs the capacitor has to carry the current until the thyristor bypasses the capacitor.

If the ac-line current exceeds a threshold value, a fault situation is identified by protection and a valve firing sequence is initiated.

After valve firing, the ac-line fault current splits between the capacitor and the thyristor branch. Due to the fact that the thyristor branch impedance is small compared to the capacitor impedance, most of the fault current flows through the thyristor branch.

The ac-line current peak value is used as a criterion to distinguish between an internal and external fault. Depending on this value, different reactions are initiated for external and internal faults.

As long as the fault is not cleared, the valves continue to get firing pulses. Fault clearance is detected as soon as the current is below a threshold value. In this case, the valve blocks and the capacitor is inserted into the ac-system. The resulting swing current flows through the capacitor and after the decay of this current it settles down to the load value, following the disturbance.

3.1.24.1 Protection Functions

Besides the typical protection functions for series capacitor installations, the scheme has to be supplemented by specific functions for thyristor firing and monitoring.

Protection functions include:

- Bypass the capacitor by firing the thyristors during internal and external line faults
- Lockout the series capacitor on internal faults by closing the bypass breaker
- Limit the duration of sustained capacitor overvoltage to specific level and time (Capacitor Overload Protection),
- Detection of capacitor unbalance resulting in alarm / bypass lockout
- Detection of platform faults
- Bypass breaker pole discordance
- Valve Monitoring
- Valve refuses to fire
- Valve excess duty cycle
- Valve self firing
- Valve asymmetrical firing
- Detection of faulty bypass breaker, initiation of transfer trip

3.1.24.2 Auxiliary Functions

- Supervision and detection of faults in the platform to ground signal transmission system,
- Loss of power supply (ground level power supply)
- Temporary valve blocking on reinsertion
- Valve testing

3.1.25. Valve specific protection and testing functions

The classical series capacitor bank protection functions are not described here since they are well documented. Emphasis is laid on the functions which are specific to the use of thyristors.

3.1.25.1 Capacitor Bypass during Internal and External Faults

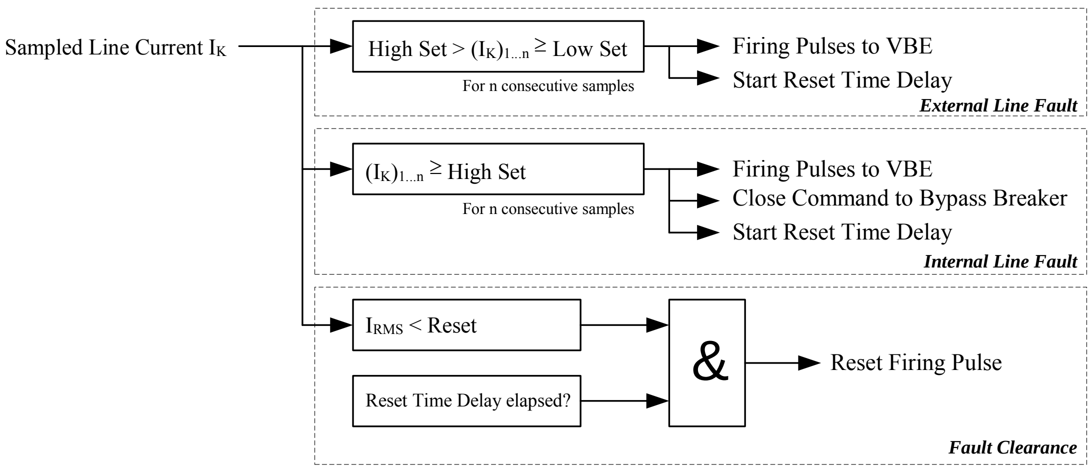


Figure 3.22: Firing pulse logic for external and internal faults

Figure 3.22 summarizes the logic implemented in the measuring algorithm.

The line current is monitored and if the instantaneous sampled value is above a set limit, a firing light pulse is sent to the LTTs via the Valve Base Electronics Unit (VBE). Consequently, the series capacitor gets bypassed. Analogous to the behavior of the MOVs, the valves are fired on external as well as on internal faults. The line current threshold is decided by fault studies and its instantaneous magnitude depends upon the type of fault.

During internal faults, the current magnitudes are higher than for external faults. Due to the fast sampling and use of instantaneous current values, the thyristors bypass the capacitor within very short time subsequent to fault occurrence.

During internal faults, in addition to the firing of the thyristors, a close command is issued to the bypass breaker.

The firing pulse is sustained for a settable time and only resets if this delay has elapsed and the RMS-value of the fundamental component of the line current is below a reset value, indicating fault clearance.

3.1.25.2 Valves refuse to fire logic

As a part of the valve monitoring system, the TPSC protection unit includes a logic which detects the failure of the valves to fire subsequent to receiving the firing pulse. The logic which monitors the valve current is shown in Figure 3.23. If the logic detects a refuse to fire condition, a lockout close command is given to the bypass breaker.

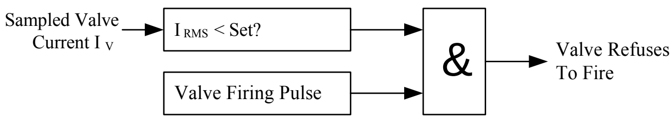


Figure 3.23: Valve refuses to fire detection logic

The logic in Figure 3.23 is supplemented by coordinating time delays, which are not shown in the figure above.

3.1.25.3 Asymmetrical Valve Firing

The thyristor valves in TPSC systems are connected anti-parallel (see Figure 3.8) to permit current flow in both directions. Depending upon the state of the valves and the firing system, it can sometimes happen that only one half of the valves conduct. This situation is detected by the logic shown in Figure 3.24. If asymmetrical valve firing is detected, a lockout close command is given to the bypass breaker.

The measuring algorithm consists of comparing the average values of the current during the positive and negative half cycle over a period of the valve current. Asymmetrical valve firing is detected if the condition in equation (3.1) below is satisfied.

$$\frac{|I_{VP} - I_{VN}|}{I_{VP} + I_{VN}} > 0.8 \qquad (3.1)$$

In the above equation, I_{VP} and I_{VN} are the respective average values of the positive and negative half cycles of the valve current.

In the practical version of the TPSC-protection unit, the logic in Figure 3.24 is supplemented by coordination time delays, which are not shown in Figure 3.24 below.

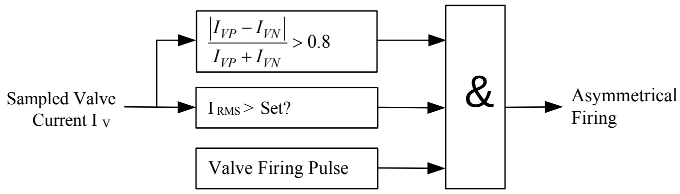


Figure 3.24: Asymmetrical firing detection Logic

3.1.25.4 Valve Excess Duty Cycle

If the line breakers fail to open on internal or external faults, current continues to flow in the valves longer than they are designed for. Logic is required to detect such situations and bypass the valves by giving a close command to the bypass breaker. Such logic is shown in Figure 3.25.

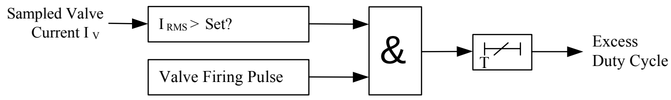


Figure 3.25: Logic for excess duty cycle detection

3.1.25.5 Valve self-firing

As a part of the valve monitoring function, logic is required to detect self-firing conditions. If the valves bypass the capacitor under normal conditions without a firing signal from the protection unit, self-firing is recorded.

The logic consists of supervising the valve current and the firing signal and is shown in Figure 3.26.

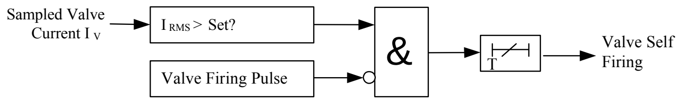


Figure 3.26: Logic for self-firing detection

If self-firing conditions are detected, a closing lock out command is issued to the bypass breaker.

3.1.26. Auxiliary valve functions

Besides valve monitoring and valve firing during faults, the TPSC protection scheme includes a few auxiliary functions, which are described below.

3.1.26.1 Temporary valve blocking on reinsertion

During capacitor bank insertion, the line current may exceed the fault current settings for a short time due to switching transients. Under these conditions, the valve firing should be inhibited for a short duration. System studies suggest a blocking duration of 50 ms.

3.1.26.2 Valve Testing

During normal system operation, it may be desirable to test the valves for proper functioning. The user can initiate a testing cycle via HMI.

If a testing command is given, the logic implemented in the protection, monitors the line current in all the three phases. If the line current is within set limits, a valve firing signal is issued to the corresponding phase, otherwise an alarm “Test Firing Blocked” is set up.

The valve monitoring logic can then check if the valve refuses to fire or if asymmetrical firing results. Additionally, the VBE detects the faulty thyristor valves. Corresponding messages are then transmitted to the user for logging purposes.

Figure 3.27 below shows the processing logic.

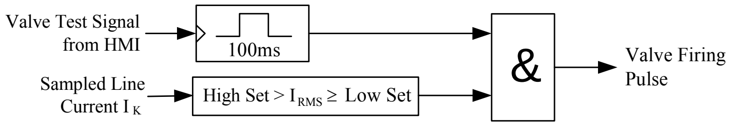


Figure 3.27: Logic for test firing

Due to the bypassing of the capacitor (loss of compensation) during test firing, it is possible that the current in the line falls below the low set value. To prevent a wrong alarm "Test Firing Blocked" subsequent to successful test firing, this alarm is inhibited for 1s.

Fixed series capacitor behavior during transmission line faults

The MOV of a series capacitor is normally designed to handle the energy injection due to a specified sequence of external faults without bypassing. From a system performance point of view, bypass operation of a series capacitor increases the impedance of the circuit. This may, in turn, adversely impact network stability.

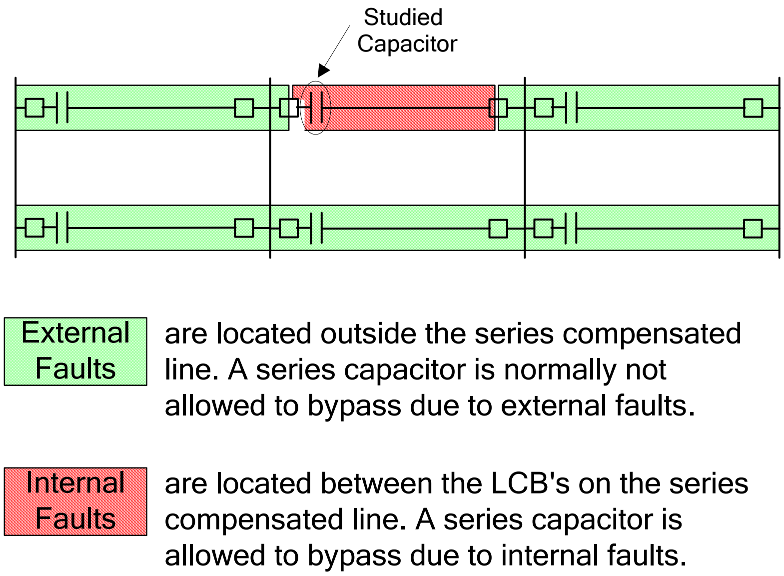


Figure 3.28: Definition of external and internal faults for a series capacitor

The effect is not significant for faults internal to the line section in which the series capacitors are located, since the line section containing the series capacitor bank is, at least, temporarily removed from service to allow fault clearing. For external faults, however, the impact on system stability can be significant. Therefore, whichever type of overvoltage protection scheme is adopted, it is usually designed not to bypass the capacitor bank during external faults. Protective bypassing is normally restricted by design to act only for the more severe internal faults exceeding the determined energy and fault current.

A typical behavior of a MOV protected series capacitor during a normal external and internal transmission line fault with automatic high speed autoreclosing is described in Table 3.3, Table 3.4 and Table 3.5 respectively.

Table 3.3: Typical external fault duty cycle with unsuccessful high-speed autoreclosing

Time [ms]	Power System Event	Fixed Series Capacitor Action
0.0	Fault application	
0.0 – 100	Fault remains	The MOV conducts as required to limit the voltage across the series capacitor
100	Line circuit breakers clear the fault	The MOV stops conducting as the voltage across the series capacitor decreases
100 – 600	Power flows through the line	Current passes through the series capacitor
600	Line circuit breakers close to the fault	The MOV conducts again and the energy integration from this fault is added to that of the first fault (0 – 100ms)
700	Line circuit breakers clear the fault and locks-out	The MOV stops conducting as the voltage across the series capacitor decreases. Current passes through the series capacitor.

Table 3.4: Typical duty cycle for internal fault with successful high-speed autoreclosing

Time [ms]	Power System Event	Fixed Series Capacitor Action
0.0	Fault application	
0.0 – 100	Fault remains	The MOV conducts as required to limit the voltage across the series capacitor. The series capacitor may be bypassed.
100	Line circuit breakers clear the fault	Series capacitor remains bypassed
100 – 600	The line is disconnected. The fault disappears	The series capacitor remains bypassed (The spark gap regains its voltage withstand capability).
600	Line circuit breakers reclose	
600 –		The series capacitor is automatically reinserted

Table 3.5: Typical duty cycle for internal fault with unsuccessful high-speed autoreclosing

Time [ms]	Power System Event	Fixed Series Capacitor Action
0.0	Fault application	
0.0 – 100	Fault remains	The MOV conducts as required to limit the voltage across the series capacitor. The series capacitor may be bypassed
100	Line circuit breakers clear the fault	Series capacitor remains bypassed
100 – 600	The line is disconnected	The series capacitor remains bypassed (The spark gap regains its voltage withstand capability
600	Line circuit breakers reclose to the fault	--
600 – 700	Fault remains	Series capacitor reinsertion is inhibited by the series capacitor line supervision current
700	Line circuit breakers clear the fault and lock out.	

TCSC behavior during transmission line faults

Thyristor triggering at the capacitor voltage protective level may be required during system faults in order to avoid overloading of the MOV. In this case a thyristor valve triggering results in a total valve current that is the sum of the capacitor discharge current and the fault current through the TCSC. Blocking of the valve during these conditions would lead to thyristor overvoltage. Therefore the valve should remain conducting. It should be noted that the thyristors always must be designed to handle the fault current independent of fault handling strategy because a system fault can occur when the thyristor valve is conducting. A typical behavior of a TCSC during a normal external and internal transmission line fault with automatic high speed autoreclosing is described in Table 3.6, Table 3.7 and Table 3.8 respectively.

Table 3.6: Typical external fault duty cycle with unsuccessful high-speed autoreclosing

Time [ms]	Power System Event	Thyristor Controlled Series Capacitor Action
0.0	Fault application	
0.0 – 100	Fault remains	The TCSC line current supervision detects high line current and bypasses the TCSC via the thyristor valve
100	Line circuit breakers clear the fault	
100 – 600	Power flows through the line	The TCSC is reinserted
600	Line circuit breakers reclose into the fault	
600 – 700	Fault remains	The TCSC line current supervision detects high line current and bypasses the TCSC via the thyristor valve
700	Line circuit breakers clear the fault and lock out	
700		The TCSC is reinserted

Table 3.7: Typical duty cycle for internal fault with successful high-speed autoreclosing

Time [ms]	Power System Event	Thyristor Controlled Series Capacitor Action
0.0	Fault application	
0.0 – 100	Fault remains	The TCSC line current supervision detects high line current and bypasses the TCSC via the thyristor valve and the bypass switch
100	Line circuit breakers clear the fault	Series capacitor remains bypassed
100 – 600	The line is disconnected. The fault disappears	The series capacitor remains bypassed
600	Line circuit breakers reclose	
600 -		The series capacitor is automatically reinserted

Table 3.8: Typical duty cycle for internal fault with unsuccessful high-speed autoreclosing

Time [ms]	Power System Event	Thyristor Controlled Series Capacitor Action
0.0	Fault application	
0.0 – 100	Fault remains	The TCSC line current supervision detects high line current and bypasses the TCSC via the thyristor valve and the bypass switch
100	Line circuit breakers clear the fault	Series capacitor remains bypassed
100 – 600	The line is disconnected	The series capacitor remains bypassed
600	Line circuit breakers reclose into the fault	
600 – 700	Fault remains	Series capacitor reinsertion is inhibited by the series capacitor line current supervision
700	Line circuit breakers clear the fault and lock out	

Platform power

All the equipment on the platform of a series capacitor is energized at line potential. It is theoretically possible to have fully insulated EHV class instrument transformers and avoid most of the platform power supply issues. In such cases all the protection and control equipment would then be located in a ground level control building. However, the costs would be prohibitive and would complicate the design of the platform. Various techniques can be used to provide power to the protection and control equipment on the platform. Measures should be taken to ensure safety of the series capacitor on the loss of platform power. In addition, power supplies are required for protection, control and monitoring equipment located in the control building at ground potential.

3.1.27. Requirements on the Power Supply

For any series capacitor installation, the following platform power supply considerations are important:

- Adequate performance during very low line current and voltage conditions; power supplies must be secure and not cause a spurious by-pass of the bank. Consider e.g. the simultaneous energization of the power transmission line and the series capacitor and let us assume that there is an earthing clamp somewhere on one of the platforms.
- For a condition when the series capacitor is energized on the faulted transmission line, the start-up time for the current and voltage based supplies must be negligible so as not to impair the duty cycle or protection operating speed requirements.
- Adequate shielding and de-coupling of power supply circuits from the primary system is important, especially for those circuits used to provide power for spark gap firing circuits.
- Cold weather performance, both while the series capacitor is in service and while the series capacitor is disconnected from the transmission line for a long period of time.
- Reduce the component count for platform power supply related equipment without sacrificing dependability and security e.g. eliminating the requirement for batteries and battery chargers where possible.

3.1.28. Current Transformer Supply

Many installations use line current based power supplies driven by CTs operable down to line currents of less than 10% of the rated line current. There must be current on the line before the power supply will turn on. It is dependable for faults with high currents but not if the line is open circuited or for low line currents. A current transformer supply uses a small core CT, with a thyristor crowbar to short the secondary when the power supply capacitor is charged to a suitable level. The CT must operate over a wide range. The thyristor must be capable of handling the maximum ring down current for a series capacitor fault.

3.1.29. CVT Supply

A CVT supply provides a voltage with the energized, independent of the line current. It is sometimes referred to as an inverted CVT supply since the base unit is mounted at the platform level. Some installations include a ground mounted base unit as a voltage signal for protection and control purposes. The disadvantage of this scheme is that the power supply is unreliable during close-in shunt faults.

3.1.30. Battery Supply

To combat problems of poor power supply performance when the line current drops below the power supply threshold or the series capacitor is isolated for an extended period of time, platform batteries may be provided. Batteries would be charged from a CT or from a CVT supplies discussed above. The battery is sized considering cold weather performance, permissible platform power weight and size, and desired performance for the specified outage interval. The routine maintenance of the battery requires a series capacitor outage, which will affect the availability factor.

3.1.31. Non-conventional Power Supplies

Some installations have used solar collectors to augment the other supply alternatives. Other installations use light pulses sent from ground level to power the platform mounted fiber optic instrument transformers. Future schemes may consider through fiber optic CTs accomplished by using a direct measurement with a Faraday sensor or using Pockels cell technology.

3.1.32. Power Supply for Spark Gap Firing Circuits

Two broad options may be considered: schemes that work on the voltage divider principle, by utilizing the voltage across capacitor cans, or from power CT or CVT base unit mounted on the platform.

3.1.33. Power Supply for Ground Mounted Equipment

The ground mounted supplies would be the same as required in a substation.

Signal transmission

The information from the platform on line potential can be sent to ground level by various methods. The currents could be obtained using conventional iron core CTs. For voltage levels above 100 kV the cost for such solutions is high. Usually, the information is sent to ground potential via fiber optics. Signals from low voltage CTs mounted on the platform can be multiplexed (and) or sent, individually via optical fibers, down to ground level using various methods of modulation or digital transmission protocol. Other direct measuring methods are available. Some optical CTs use a fiber optic from the platform to the ground level and send a laser pulse up to provide energy to the electronics coding at the current level and sending it back down via the same fiber. At the platform an iron CT can be used, since the insulation requirement is not a problem in this case.

A second method of getting the current information down from the platform would be to use the Faraday effect on an optical CT. This requires two fibers per CT. A polarised light signal is sent up from the ground level and the magnetic field shifts the light. The angular shift of the light is a measure of the instantaneous current.

There may be non-power system information that must be sent to or from the platform, e.g. the signal to trig a spark gap. Some designs do this on the platform while others perform the calculations at ground level to determine when the protection level has been reached. The trend is to use fiber optics to send the information from the platform to ground level for high voltage banks because of economical reasons and reliability [1]. There is also a trend to have the protection and control system at ground level to simplify maintenance and trouble shooting. However some installations have all protection and control equipment mounted on the platform and only status information necessary for operating the equipment is sent down to ground level.

References

[1] Lundqvist, B.; Einvall, C.H.; Nirs, J. & Lindberg, P.: "Opto-electronic protection and supervision system for series capacitor banks", Report CIGRÉ Colloquium Åbo, June 1987.

4. SERIES COMPENSATED AND ADJACENT POWER LINES

Challenges in protection of series compensated and adjacent power lines

Series capacitors influence the magnitude and the direction of fault currents in series compensated networks. They consequently influence phase angles of voltages measured at different points of series compensated networks and this in turn has an impact on the performances of various protection functions whose operation is based on properties of measured voltage and current phasors. Other phenomena like voltage and current inversion at relay point, sub synchronous resonance and similar too influence the performance of different protection schemes.

4.1.1. Voltage and current inversion

4.1.1.1 Voltage inversion

Figure 4.1 shows a part of a series compensated line with fault at point F. X_{L1} is line reactance between the relay and the fault point F.

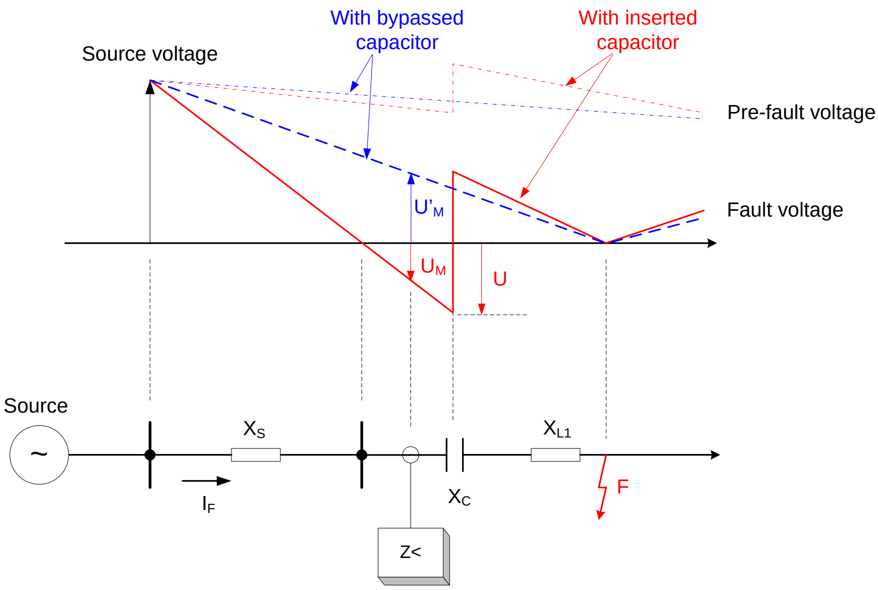


Figure 4.1: Voltage inversion on series compensated line

The voltage measurement is supposed to be on the bus side, and the series capacitor is located between the relay and the fault point F. Figure 4.2 presents the corresponding phasor diagrams for the cases with bypassed and fully inserted series capacitor.

In the case when series capacitor is bypassed the voltage variation on the faulty lossless line from fault point F to the bus is linear depending on the distance from the bus (see Figure 4.2). The bus voltage U_M is equal to voltage drop ΔU_L on the faulty line and the current I_F lags by 90 degrees.

The situation changes with series capacitor inserted in the circuit between the relay and the fault position. The fault current I_F (see Figure 4.2) increases due to the series capacitor bringing down total impedance between the source and the fault point. The voltage drop ΔU_L on X_{L1} line impedance leads the current by 90 degrees. Voltage drop ΔU_C on series capacitor lags the fault current by 90 degrees. It should be noted that depending on the location of series capacitor on the line impedance X_{L1} could be divided into two parts; one between the relay point and the capacitor and another between the capacitor and the fault position. The resulting voltage U_M at the relay point is thus sum of voltage drops in the various impedances between the relay point and the fault position F, as given by equation (4.1).

$$U_M = I_F \cdot j\left(X_{L1} - X_C\right) \tag{4.1}$$

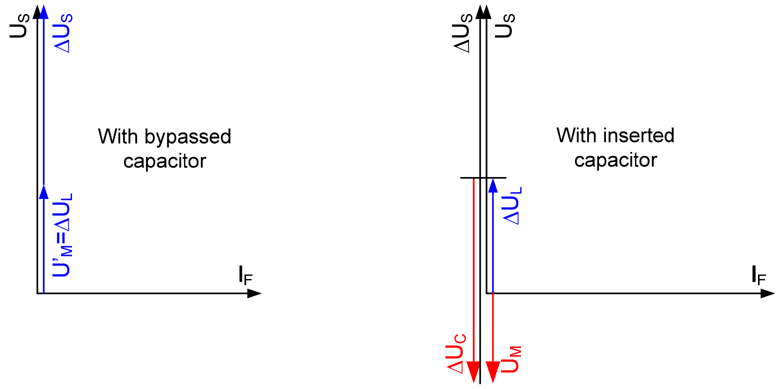


Figure 4.2: Phasor diagrams of currents and voltages for the bypassed and inserted series capacitor during voltage inversion

The voltage U_M will lead the fault current I_F as long as $X_{L1} > X_C$. From the directionality point of view this case is similar to fault taking place on a line without series capacitor.

Voltage U_M at the relay point will lag the fault current I_F if:

$$X_C > X_{L1} \tag{4.2}$$

In this case the voltage at the relay point reverses its direction. This phenomenon is commonly called as voltage inversion. The consequences of this phenomenon on operation of different types of protections in the series compensated networks depend on their operating principle. As for example it influences the directional measurement of distance relays, (see chapter 0 for more details). Special measures must be taken in the distance relays to guard against this phenomenon.

The phenomenon of voltage inversion does not take place when VTs are located on the bus side of the series capacitor. Locating the VTs to the line side does not eliminate the phenomenon since it appears again for faults on the bus side of the relay point.

4.1.1.2 <u>Current inversion</u>

Figure 4.3 presents part of a series compensated line with fault at point F. In non compensated lines the fault current I_F normally flows from power source towards the fault point F. The introduction of Series capacitor may change this situation.

Phase angle of the fault current I_F compared to the source voltage U_S depends if the resultant reactance between the source and the fault position is inductive or capacitive. Two possibilities exist.

$$\begin{aligned} X_S - X_C + X_{L1} > 0 \\ X_S - X_C + X_{L1} < 0 \end{aligned} \tag{4.3}$$

The first case is similar to conditions on non compensated lines or the case when the capacitor is bypassed either by spark gap or by the bypass switch, (see phasor diagram in Figure 4.4). The resultant reactance in this case is inductive in nature and the fault current lags the source voltage by 90 degrees.

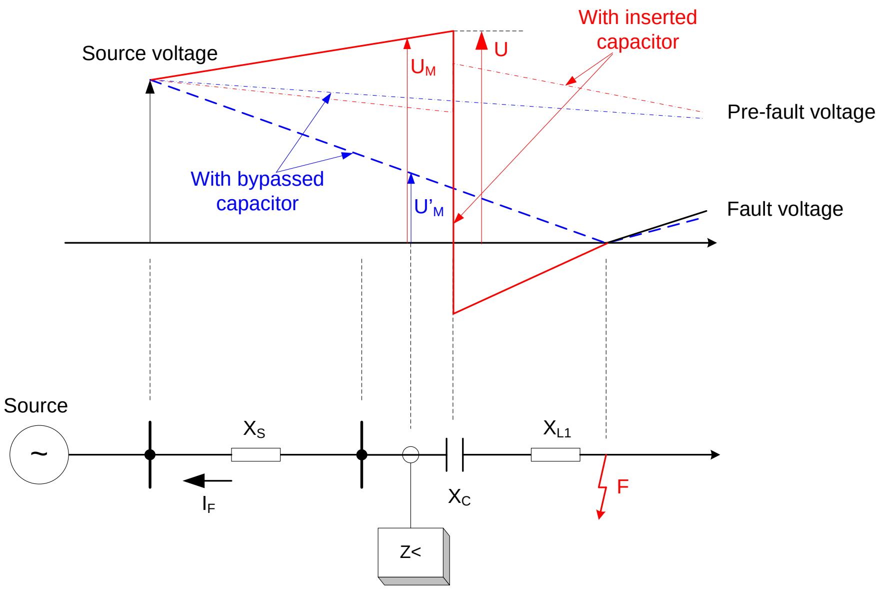


Figure 4.3: Current inversion on series compensated line

In the second case the resultant reactance is capacitive in nature. Fault current in this case will lead the source voltage by 90 degrees, which means that it flows from series compensated line to the system. In this case the system conditions can be given by equation (4.4).

$$X_C > X_S + X_{L1} \tag{4.4}$$

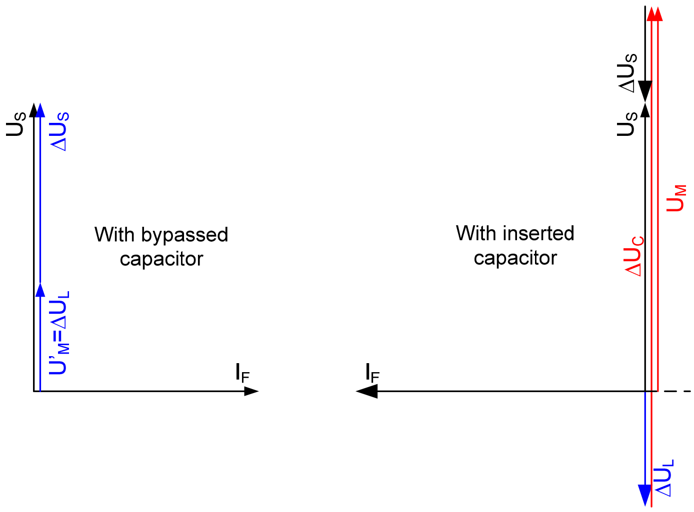


Figure 4.4: Phasor diagrams of currents and voltages for the bypassed and inserted series capacitor during current inversion

This phenomenon is normally called as current inversion. Its consequences on operation of different types of protections in series compensated networks depend on their operating principle. Current inversion influences operation of distance relays and therefore they cannot be applied for the protection of series compensated lines when possibility of current inversion exists (see chapter 0 for more details).

Equation (4.4) also shows the big dependence of possible current inversion on series compensated lines on location of series capacitors. $X_{L1} = 0$ for faults just before the capacitor when located at line end and only the source impedance prevents current inversion. Current inversion has been considered for many years as only a theoretical possibility due to relatively high values of source impedances compared to the capacitor reactance. The possibility for current inversion in modern, highly loaded networks is increasing and must be studied carefully through system studies in the planning stage.

The study of current inversion phenomenon should not be limited to protection devices based on measurement of phase currents. Directional comparison protections, based on residual (zero sequence) and negative sequence currents should be considered as well. Current inversion in systems with low zero sequence source impedance (a number of power transformers connected in parallel) must be considered as practical possibility in many modern networks.

4.1.2. Low frequency transients

Series capacitors introduce oscillations in currents and voltages in the power systems, which are not common in non-compensated systems. These oscillations have frequencies lower than the rated system frequency and may cause delayed increase of fault currents, delayed operation of spark gaps as well as delayed operation of protective relays. The most obvious difference can be generally seen in the fault currents.

Figure 4.5 shows a simplified picture of a series compensated network during fault conditions. The complete mathematical procedure for calculation of fault currents is given in Appendix A to this chapter. The basic performances can be studied for the same network with and without series capacitor. Possible effects of spark gap flashing or MOV conducting can be ignored since the time dependence of fault currents and the differences between them are of interest.

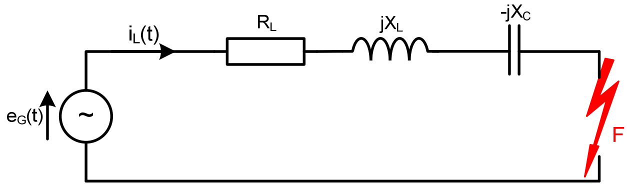


Figure 4.5: Simplified equivalent scheme of SC network during fault conditions

The waveforms of fault currents for a three-phase short circuit at the end of a typical 500km long 500kV line with and without series compensation are shown in Figure 4.6.

For non-compensated line the short circuit current is lower in magnitude and has only transient DC component, which diminishes completely in about 120 ms. In comparison the magnitude of the fault current on compensated line not only is higher due to the decreased apparent impedance of the line (60% compensation degree has been considered for a particular case), but has also low frequency oscillations. The increase of fault current immediately after the fault incidence (on Figure 4.6 at approximately 21 ms) is much slower than on non-compensated line. This happens due to the energy stored in the capacitor before the fault.

Low frequency transients have in general no significant influence on operation of line current differential protection as well as on phase comparison protection. However they may significantly influence the correct operation of distance protection in two ways:

- They increase the operating time of distance protection, which may in turn influence negatively the system stability
- They may cause overreaching of instantaneous distance protection zones and this way result in unnecessary tripping on series compensated lines.

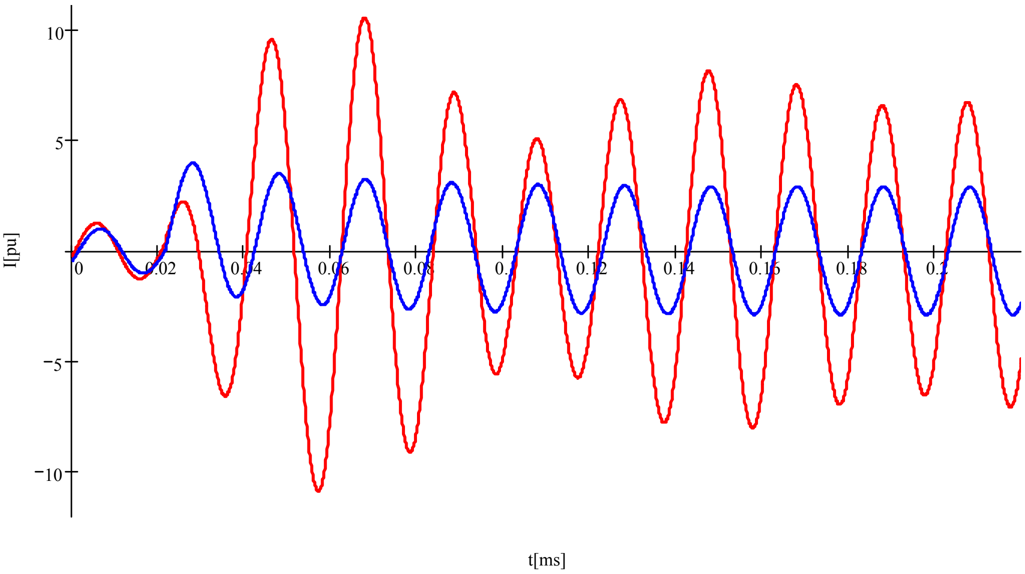


Figure 4.6: Short circuit currents for the fault at the end of 500km long 500kV line without and with SC

Figure 4.7 represents typical impedance trajectory in dependence of time for a fault on series compensated line with MOV used for over voltage protection of capacitor bank.

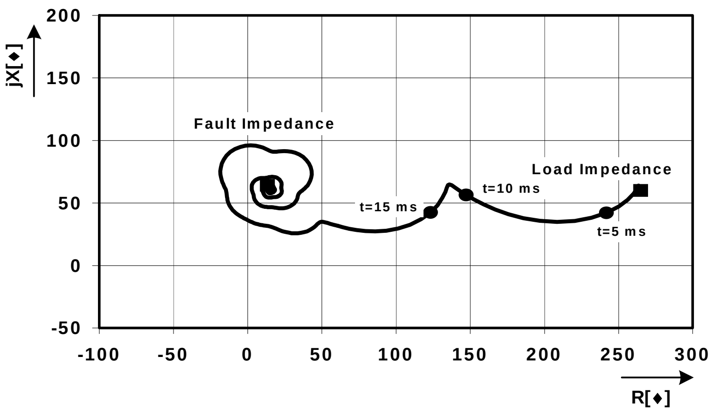


Figure 4.7: Time dependent impedance measurement influenced by low frequency transients

4.1.3. High frequency transients

Presence of shunt reactors close to or on the series compensated line may cause together with series capacitor and line shunt capacitance high frequency transients in the measured voltages and currents, which may influence the operation of line protection. Spark gaps will flash over at line faults and short circuit the capacitor, which will then discharge via the damping reactor, see Figure 3.1 to Figure 3.5. This will cause high frequency transient current, the frequency of which will be determined by the dimension of series capacitor and damping reactor. The damping reactor is generally dimensioned to provide the oscillation in the range of kHz. It is also necessary to provide a damping resistor in series with reactor in order to limit the capacitor discharging current to acceptable value.

Series capacitors are protected by spark gaps, gapped MOV schemes, or gapless MOV schemes. Operation of the gap causes the capacitor to be short circuited during the power system fault, which may result in unequal phase impedances. One must take this into consideration during system studies. Steady-state fault analysis becomes more complex when a MOV is used for overvoltage protection of series capacitors. Typical characteristics of a MOV, based upon expected fault current, can be used to run steady state fault studies. This will be an approximation in determining the settings of the protection system. More accurate fault analysis should be done with a transient simulation program like EMTP.

Applying EMTP generated waveforms to the relays through digitally controlled test sets can do final verification of the settings. Closed loop network simulators will, however, give the best verification.

4.1.4. Transient recovery voltage

Series capacitors in a transmission line can have a significant effect on the transient voltage that appears across the contacts of a circuit breaker when opening to clear a fault. The voltage that appears in such situations is referred to as the transient recovery voltage (TRV). Concerns have sometimes been raised over the potential hazards for line breakers in series compensated lines, due to TRV. Practice has shown, however, that in the overwhelming number of cases, existing circuit breakers on series compensated lines have been able to cope with the TRV. In other cases, it has been demonstrated that by adopting the proper measures, the impact of series compensation on the TRV of line breakers can be minimized 98.

4.1.5. Sub harmonic resonance

Series capacitors can interact with the power system and cause sub harmonic resonance. Sub harmonic oscillations may occur when the system operator switches in an unloaded transformer. The inrush current has instantaneous values that are higher, and sometimes much higher, than the rated current of the transformer. In case of modern EHV transformers connected to non-compensated networks, these high currents may persist for several tens of seconds. The reason is that modern transformers have cores with very low losses. The rated flux of such transformers may be very close to the saturation flux. In case of old transformers connected to HV networks, the high inrush current usually persists only for a few cycles. Sub harmonic oscillation may also occur when the system operator switches in a shunt reactor. The inrush currents have instantaneous values that are higher than the rated current of the reactor. For a system with one or more series capacitors these high currents may continue to flow for a long time. This condition might cause harmful resonance conditions at a sub harmonic frequency $f_k\left[Hz\right]$. Equation (4.5) defines the sub harmonic frequencies.

$$f_k = \frac{f_n}{k} \qquad k = 2,3..... \tag{4.5}$$

Here is $f_n\left[Hz\right]$ the fundamental frequency of the power system, and k is a positive integer greater than or equal to two. The currents might cause overheating of the transformer. It might also overstress the capacitor cans even during normal load conditions. In order to eliminate the sub harmonic resonance condition, the series capacitor should be by-passed. Sub harmonic resonance conditions are very unlikely to occur in EHV transmission systems since the transmission system normally is energized without the series capacitor in service. For series capacitors on distribution systems, sub harmonic resonance may be a problem because these systems are normally radial with a high degree of compensation.

4.1.6. Subsynchronous resonance (SSR)

Sub synchronous resonance (SSR) is a condition in a power system where the electrical network exchanges energy with a steam turbine generating unit at one or more of the natural frequency of the combined system below the synchronous frequency of the power system. It is unlikely that a hydro turbine generating unit and a series compensated network could cause SSR.

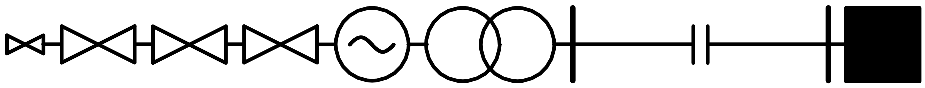


Figure 4.8: Generator connected to a series compensated network

Consider the generating unit and the series compensated network shown in Figure 4.8. SSR encompasses the oscillatory attributes of electrical and mechanical quantities in such systems where the oscillatory energy interchange between the electrical system and the generating unit is lightly damped, undamped, or even negatively damped and growing.

The terms subsynchronous and supersynchronous denote frequencies below and above the synchronous frequency $f_0\left[Hz\right]$ defined by the rotor average speed. Equation (4.6) defines the electrical system resonant frequency $f_{er}\left[Hz\right]$ in Figure 4.8.

$$f_{er} = f_0 \cdot \sqrt{\frac{X_C}{X'' + X_E + X_T}} \tag{4.6}$$

Here $X_C\left[\Omega\right]$ is the reactance of the series capacitor, $X''\left[\Omega\right]$ is the subtransient reactance of the synchronous generator, $X_E\left[\Omega\right]$ is the equivalent reactance of the external network and $X_T\left[\Omega\right]$ is the reactance of the step-up transformer. We evaluate the reactance at frequency f_0. Generally, series compensated networks are more complex than the one in Figure 4.8 and will have many subsynchronous frequencies f_{er}.

Currents of frequency f_{er} in the electrical system give rise to rotor currents of frequency $f_r\left[Hz\right]$ as indicated in equation (4.7).

$$f_r = f_0 + f_{er} \tag{4.7}$$

A balanced three phase set of armature currents at frequency f_{er} produce a rotating magnetic field in the synchronous generator. The time distribution of the phase currents together with the space distribution of the armature windings causes rotation at an angular frequency of $2\cdot\pi\cdot f_{er}$. The relative velocity between the armature field and the rotor governs the frequency of rotor-body currents induced by this armature field. Positive sequence components of the stator current produce rotor currents at subsynchronous frequency $f_r = f_0 - f_{er}$. Negative sequence components of stator current produce rotor current at super-synchronous frequency $f_r = f_0 - f_{er}$. As the rotor magnetic field overtakes the more slowly rotating subsynchronous MMF in the armature, it produces a subsynchronous torque having a frequency, which is the difference between the electrical frequency f_0 corresponding to the rotor average velocity and the electrical subsynchronous frequency f_{er}. The subsynchronous electrical frequency and subsynchronous torque frequency are said to be complementary because they add to unity when expressed in per unit of synchronous frequency. SSR might cause damage to the shaft system of the generating unit. If SSR conditions are suspected for a series compensated network this should be studied during the stage of initial system studies.

4.1.7. Location of instrument transformers

Location of instrument transformers in case of lines with series capacitors located at the end of the line plays an important role on the dependability and security of the complete protection system. Protection schemes that depend for their operation only on current measurement like line current differential protection are relatively independent of CT location. The protection schemes, which use VT voltage for their operation, are affected by the VT location. It is therefore necessary to understand particular dependence of those protection schemes on the location of CTs and VTs.

Figure 4.9 shows schematically the possible locations of instrument transformers in case of line-end series capacitor.

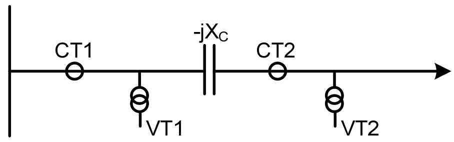


Figure 4.9: Possible positions of instrument transformers relative to line end series capacitor

4.1.7.1 Bus side instrument transformers

CT1 and VT1 on Figure 4.9 represent the case with bus side instrument transformers. The protection devices in this case are exposed to possible voltage and current inversion for line faults, which bring down their dependability. In addition to this series capacitor may cause negative apparent impedance to distance relays for close-in line faults (see also Figure 4.11, LOC=0%). The distance relays will have to be specially designed to cope with such phenomena.

One advantage of such installation is that the protection zone covers the series capacitor also as a part of protected power line. Thus the line protection will detect and clear shunt faults in series capacitor too.

4.1.7.2 Line side instrument transformers

CT2 and VT2 on Figure 4.9 represent the case with line side instrument transformers. The protective devices will not be exposed to voltage and current inversion for faults on the protected line, which increases their dependability. Zone 1 of distance protection may be active in most applications, which is not the case when the bus side instrument transformers are used.

Distance relays are exposed especially to voltage inversion for close-in reverse faults, thus reducing their security. The effect of negative apparent reactance must be studied carefully in case of reverse directed distance protection zones used by distance relays for teleprotection schemes. Series capacitors located between the voltage transformer and the bus reduce the apparent zero sequence source impedance and may cause voltage as well as current inversion in zero sequence equivalent networks for line faults. It is for this reason absolutely necessary to study the possible effects on operation of residual (zero sequence) directional earth fault over current protections before installing them.

4.1.7.3 Dual side instrument transformers

Installations with line side CT2 and bus side VT1 are not very common. More common are installations with line side VT2 and bus side CT1. They appear as de facto installations also in switchyards with double-bus double-breaker and 1½ breaker arrangement. The advantage of such schemes is that the unit protections also cover shunt faults in series capacitors and at the same time the voltage inversion does not appear for faults on the protected line.

Many installations with line-end series capacitors have voltage transformers available on both sides. In such case it is recommended to use the VTs for each particular protection function that is best suited to it, considering expectations on dependability and security. The line side VT for example can be used by the distance protection and the bus side VT by the directional residual OC earth fault protection.

4.1.8. MOV influence on apparent impedances

Series capacitors reduce the apparent impedance measured by the distance relays on protected lines. Typical locations of series capacitor banks on power lines together with generally corresponding compensation degrees are shown in Figure 4.10. A fault on remote bus is seen by distance relay close to the bus differently, depending on location of series capacitor and the type of over voltage protection used on the capacitor bank (spark gap or MOV).

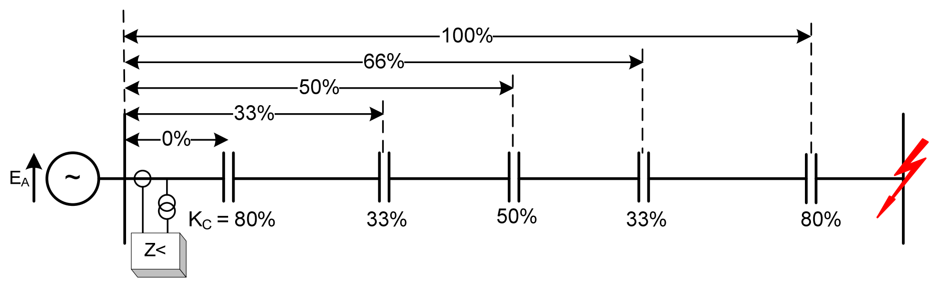


Figure 4.10: Typical locations of capacitor banks on series compensated line

Use of spark gaps for capacitor overvoltage protection makes the picture relatively simple, because they either flash over or not. The apparent impedance in first case corresponds to the impedance of a non-compensated line as shown in Figure 4.11 case $K_C = 0\%$.

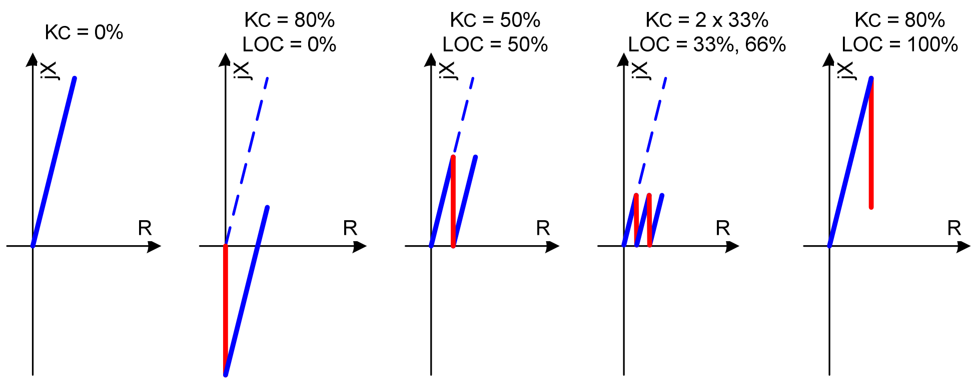
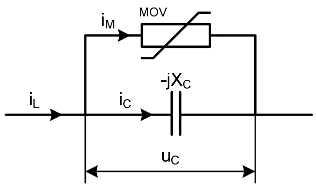


Figure 4.11: Apparent impedances seen by distance relay for different SC locations and spark gaps used for overvoltage protection

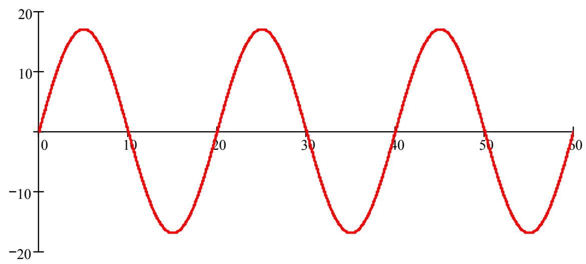
The apparent impedance seen by the distance relay is always reduced by the amount of capacitive reactance included between the fault and relay point, when the spark gap does not flash over, as shown for typical cases in Figure 4.11.

Here it is necessary to distinguish between two typical cases:

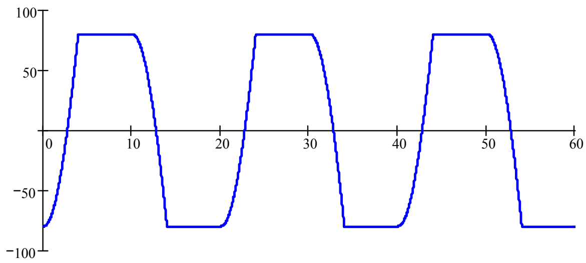
- Series capacitor only reduces the apparent impedance, but it does not cause wrong directional measurement. Such cases are presented in Figure 4.11 for 50% compensation at 50% of line length and 33% compensation located at 33% and 66% of line length.
- The voltage inversion occurs in cases when the capacitor reactance between the relay point and fault appear bigger than the corresponding line reactance as shown in Figure 4.11, 80% compensation at local end. A voltage inversion occurs in relay point and if no special measures have been taken in the relay design the distance relay will see wrong direction towards the fault.



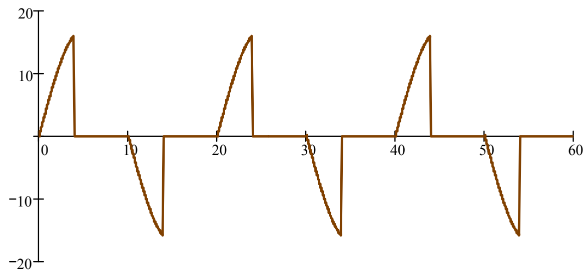
MOV protected series capacitor



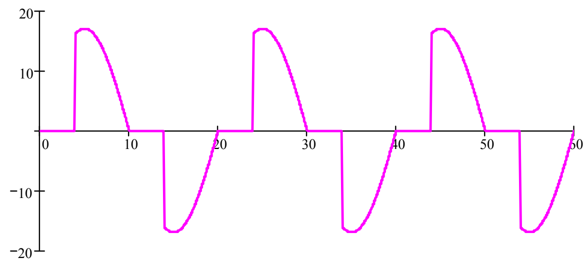
Line current $i_L\left[kA\right]$ as a function of time



Capacitor voltage $u_C\left[kV\right]$ as a function of time



Capacitor current $i_C\left[kA\right]$ as a function of time



MOV current $i_M\left[kA\right]$ as a function of time

Figure 4.12: MOV protected capacitor with examples of capacitor voltage and corresponding currents

The situation changes when metal oxide varistors (MOV) are used for capacitor overvoltage protection. In contrast to spark gaps, MOVs carry current when the instantaneous voltage drop across the capacitor becomes higher than the protective voltage level in each half-cycle as shown in Figure 4.12.

Extensive studies have been done by Bonneville Power Administration in USA (see references [1] and [2]) to arrive at a non-linear equivalent circuit for a series connected capacitor using an MOV. The composite impedance depends on total fault current and protection factor k_p. The later is defined by equation (4.8).

$$k_p = \frac{U_{MOV}}{U_{NC}} \quad (4.8)$$

Figure 4.13 presents three typical cases for series capacitor located at line end (case $LOC = 0\%$ in Figure 4.11). The following can be observed from these.

- Effect of series capacitor prevails as long as the line current remains lower or equal to its protective current level ($I \le k_p \cdot I_{NC}$). The apparent line impedance in this case is reduced by the total reactance of the series capacitor.
- About 50% of capacitor reactance appears in series with resistive value, which corresponds to approximately 36% of capacitor reactance when the line current equals to two times the protective current level ($I > 2 \cdot k_p \cdot I_{NC}$). This is valuable information for arriving at the resistive reach setting of distance relay, for phase-to-earth fault measurement as well as for phase-to-phase fault measurement.
- Series capacitor becomes nearly completely bridged by the MOV when the line current is more than 10-times the protective current level ($I > 10 \cdot k_p \cdot I_{NC}$).

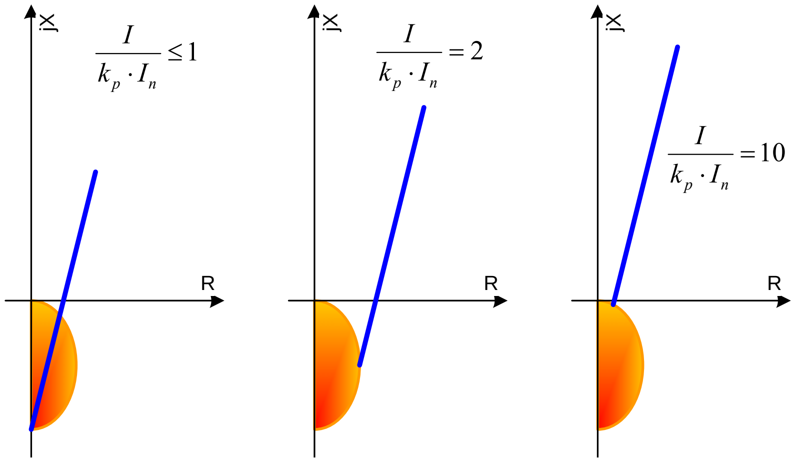


Figure 4.13: Equivalent impedance of MOV protected capacitor in dependence of fault current

Impact of series compensation on protective relays of adjacent lines

Voltage inversion is not limited only to the buses and to the relay points close to the series compensated line. It can spread deep into the network and this way influence the selection of protection devices (mostly distance relays) at remote ends of the lines adjacent to the series compensated circuit, and sometimes even deeper in the network.

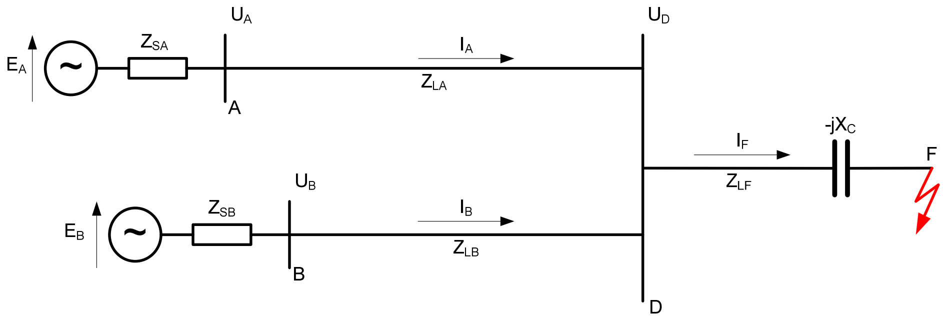


Figure 4.14: Voltage inversion in series compensated network due to fault current infeed

In the network shown in Figure 4.14, voltage at the B bus can be calculated for the loss-less system according to the equation (4.9) below.

$$U_B = U_D + I_B \cdot jX_{Lb} = \left(I_A + I_B\right) \cdot j\left(X_{LF} - X_C\right) + I_B \cdot jX_{LB} \quad (4.9)$$

Further simplification of equation (4.9) gives the following expressions:

$$U_B = jI_B \cdot \left[X_{LB} + \left(1 + \frac{I_A}{I_B}\right) \cdot \left(X_{LF} - X_C\right) \right] \quad (4.10)$$

From equation (4.10) it can be seen that the in feed current I_A increases the apparent value of capacitive reactance in system. The higher the in feed of fault current, higher is the apparent reactance of series capacitor. This makes voltage inversion spread deep in to the network. To understand this substitute in equation (10) with $U_B = 0$. For this case:

$$X_C = \frac{X_{LB}}{1 + \frac{I_A}{I_B}} + X_{LF} \quad (4.11)$$

It is possible to say that equation (4.11) indicates how deep in the network the influence of series compensation is experienced in the form of voltage inversion. Higher is the infeed $\left(I_A / I_B\right)$, deeper is the spread of voltage inversion in the network.

It is also obvious that the location of series capacitor on compensated line influences to great extent how deep voltage inversion is experienced in adjacent system. Line impedance X_{LF} between D bus and the fault becomes equal to zero, if the capacitor is installed near the bus and the fault appears just behind the capacitor. This may cause the phenomenon of voltage inversion to be experienced very deep into the adjacent network, especially if on the one hand the compensated line is very long and has high degree of compensation, and the adjacent lines are on the other hand, relatively short.

Extensive system studies are necessary before taking a decision to install series capacitor and define its location in the network. Estimating their influence on performances of (especially) existing distance relays correctly is a must. It is possible that the cost of number of protective relays, which need to be replaced by more appropriate ones due to the introduction of series compensation, may influence the future of series capacitors in the power network.

Possibilities of voltage inversion at remote buses should not be studied for short circuits with zero fault resistance only. It is necessary to consider cases with higher fault resistances, for which spark gaps or MOVs on series capacitors will not conduct at all. At the same time this kind of investigation must also consider the maximum sensitivity and possible resistive reach of distance protection devices.

If MOVs are used for capacitor overvoltage protection, the impact of these nonlinear elements makes simple calculations often impossible. Different kinds of steady state and dynamic network simulations need to be done in such cases.

Distance protection

Distance protection is due to its basic characteristic the most commonly used protection on series compensated and adjacent lines worldwide. At the same time it has caused a lot of challenges to protection society, especially when it comes to directional measurement and transient overreach. Figure 4.15 describes the basic reason for this in a very simplified way.

Conventional distance relay in fact does not measure directly impedance or quotient between line current and voltage. It operates as a comparator and compares the operating quantity with stabilizing quantity. The operating quantity is usually a voltage drop caused by measured current on line replica impedance, which corresponds exactly to the desired percentage (reach) of line impedance. The stabilizing quantity is actual voltage drop on the protected power line, which in case of internal fault is lower than the voltage drop on replica impedance and vice versa.

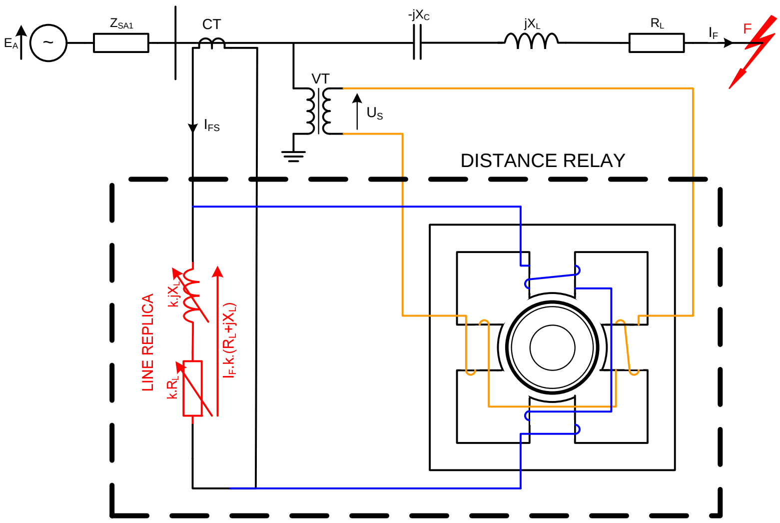


Figure 4.15: Basic operating principle of distance relay

Distance relays have in their replica impedance only the replicas of line inductance and resistance, but they do not have any replica of series capacitor on the protected line and its protection devices (spark gap and or MOV). This way they form a wrong picture of the protected line and all the "solutions" related to distance protection of series compensated and adjacent lines are focused on finding some ways that help eliminating the basic reason for the wrong measurement. The most known of these are decrease of the reach due to presence of series capacitor which apparently decreases the line reactance, and introduction of permanent memory voltage in directional measurement.

4.1.9. Distance protection with communication

Series compensated and adjacent lines are often the most important links in a transmission networks and delayed fault clearance is undesirable. This makes it necessary to install distance protection in combination with telecommunication. The most common of them is distance protection in permissive overreaching mode (Permissive Overreaching Transfer Trip – POTT).

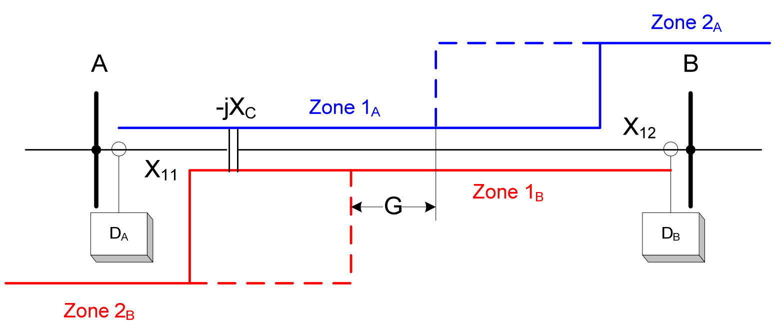


Figure 4.16: Underreaching (Zone 1) and overreaching (Zone 2) zones on series compensated line

As a basic rule the underreaching distance protection zone should under no circumstances overreach for the fault at the remote end bus, and the overreaching zone should always, under all system conditions, cover the fault in the protected line. In order to obtain selectivity, the underreaching zone (Zone 1) must be set to a reach less than the reactance of the compensated line as shown in Figure 4.16.

The underreaching zone will have reduced reach in cases of bypassed series capacitor as shown by dashed line in Figure 4.16. The overreaching zone (Zone 2) this way has reach much beyond the protected line, but must be ensured that it always covers the remote end bus with certain margin. Distance protection Zone 1 is often set to

$$X_{Z1} = K_S \cdot \left(X_{11} + X_{12} - X_C \right) \quad (4.12)$$

Here K_S is a safety factor, presented graphically in Figure 4.17, which covers for possible overreaching due to low frequency (sub-harmonic) oscillations. Here it should be noted that compensation degree K_C in Figure 4.17 relates to total system reactance, inclusive of line and source reactance. This safety factor is applicable regardless of whether MOV or spark gaps are used for capacitor overvoltage protection.

Equation (4.12) is applicable for the case when the VTs are located on the bus side of series capacitor. It is possible to remove X_C from the equation in cases of VTs are installed on line side, but it is still necessary to consider the safety factor K_S.

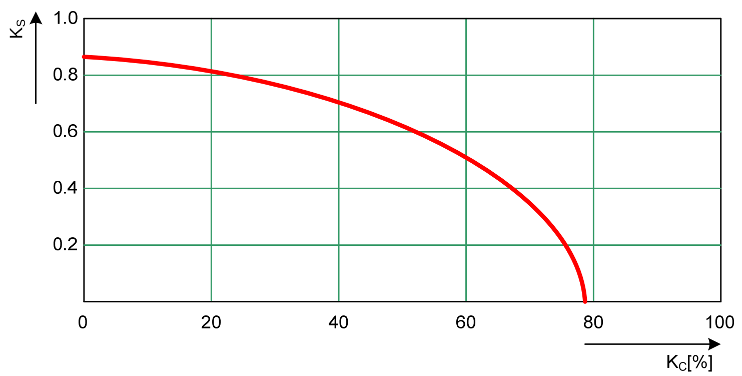


Figure 4.17: Underreaching safety factor K_S in dependence on system compensation degree K_C

If the capacitor is out of service or bypassed, the reach with these settings can be less than 50% of protected line depending on the compensation degree and there will be a section denoted by G in Figure 4.16 of the power line, where no instantaneous and communication independent tripping occurs from either end.

For this reason permissive underreaching schemes can hardly be used as a main protection. Permissive overreaching distance protection or some kind of directional or unit protection must therefore be used.

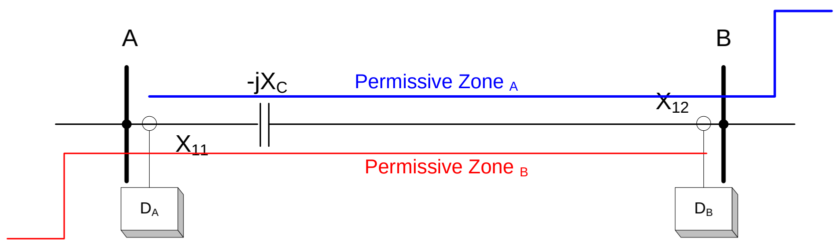


Figure 4.18: Permissive overreach distance protection scheme

The overreach must be of an order that it overreaches when the capacitor is bypassed or is out of service. Figure 4.18 shows the permissive zones. The first underreaching zone can be kept in the total distance protection scheme but it can only serve as a fast back-up protection for close up faults. The overreach usually is of the same order as the permissive zone. When the capacitor is in service the permissive zone will have a very high degree of overreach, which can be considered as a disadvantage from security point of view.

4.1.10. Negative impedance seen by the relay, positive fault current

In the Figure 4.19 assume $X_C > X_{11}$ and a three-phase fault occurs beyond the capacitor. The resultant impedance seen from the relay DB to the fault point may become negative (voltage inversion) till such time the spark gap has flashed over.

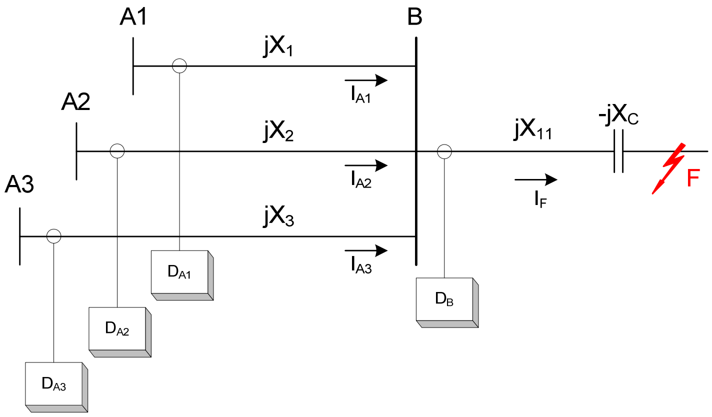


Figure 4.19: Distance relays on adjacent power lines are influenced by the negative impedance

Distance protections of adjacent power lines shown in Figure 4.19 are influenced by this negative impedance as well. If the intermediate infeed of short circuit power by other lines is taken into consideration, the negative voltage drop on X_C is amplified and a protection far away from the faulty line can maloperate by its instantaneous operating distance zone, if there are no special precautions taken. Impedances seen by distance relays on adjacent power lines can be presented by equations (4.13) to (4.16).

$$I_F = I_{A1} + I_{A2} + I_{A3} \tag{4.13}$$

$$X_{DA1} = X_{A1} - \frac{I_F}{I_{A1}} \cdot \left(X_C - X_{11} \right) \tag{4.14}$$

$$X_{DA2} = X_{A2} - \frac{I_F}{I_{A2}} \cdot \left(X_C - X_{11} \right) \tag{4.15}$$

$$X_{DA3} = X_{A3} - \frac{I_F}{I_{A3}} \cdot \left(X_C - X_{11} \right) \tag{4.16}$$

Normally the first zone of these protections must be delayed until the gap flashing has taken place. If the delay is not acceptable, some directional comparison must be added to the protection of all adjacent power lines. As stated above, a good protection system must be able to operate correctly both before and after the gap flashing occurs. Distance protection can be used, but careful studies must be made for each individual case. This applies to both conventional spark gap and MOV protected capacitors.

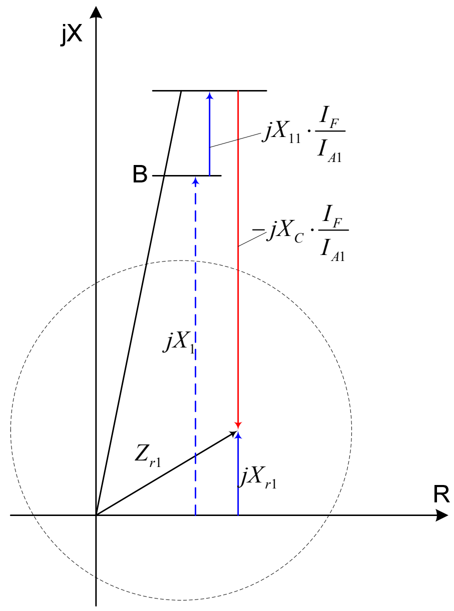


Figure 4.20: Impedance seen by distance relay at A1 bus (Figure 4.19) with fault current infeed

Special attention should be paid to selection of distance protection on short adjacent power lines in cases where series capacitors are located at the line end. In such cases the reactance of a short adjacent line may be lower than the capacitor reactance and voltage inversion phenomenon may also occur at the remote end of adjacent lines. Distance protections of such lines must have all the built-in functionalities that apply normally to protection of series compensated lines.

It usually takes some time before the spark gap flashes. Sometimes the fault current is of such a magnitude that there will not be any flashover and the negative impedance will be sustained. If $|X_{SL} + X_{11}| > |X_C|$ in Figure 4.21, the direction of fault current will be same as the case when the capacitor is bypassed.

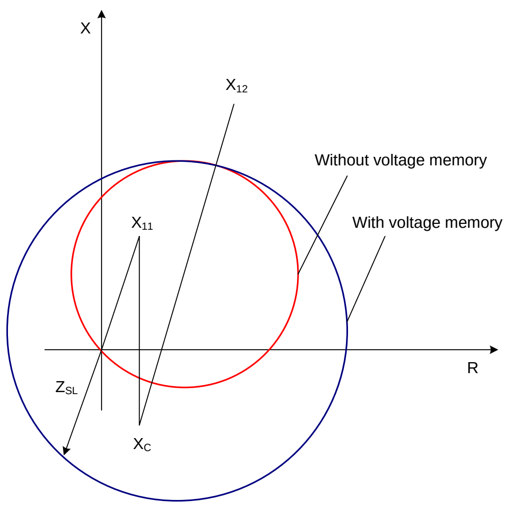


Figure 4.21: Mho characteristic for a three-phase fault

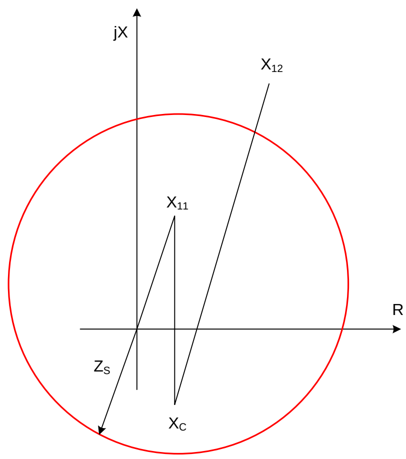


Figure 4.22: Cross-polarized mho characteristic

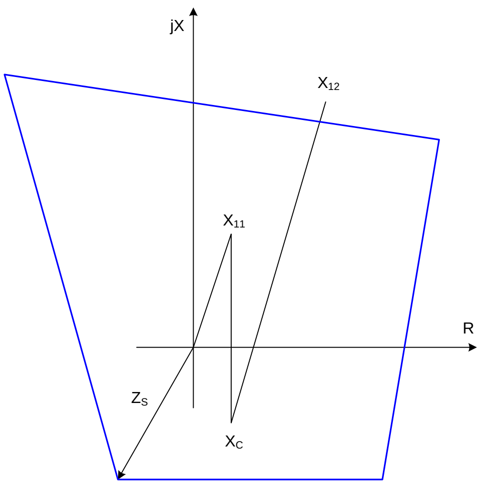


Figure 4.23: Cross-polarized quadrilateral characteristic

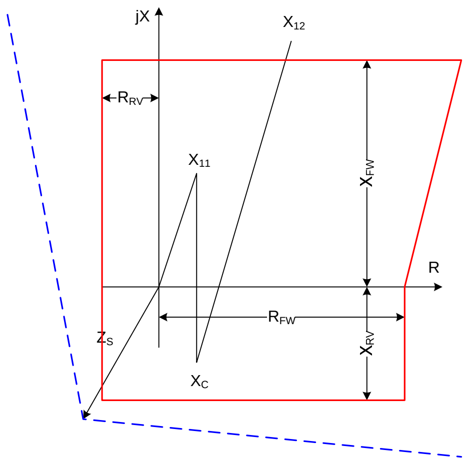


Figure 4.24: Quadrilateral characteristic with separate impedance and directional measurement

Therefore the directional measurement will be correct but the impedance measured will be negative and if it falls outside the relay characteristic (without voltage memory) as shown in Figure 4.21 the relay cannot operate. However, if there is a memory circuit designed so that it covers the negative impedance, a three-phase fault can be successfully cleared by the distance protection. As soon as the spark gap has flashed the situation for protection will be similar to an ordinary fault. However, a good protection system should be able to operate correctly before and after the gap flashing.

If the distance protection is equipped with an earth fault measuring unit, the negative impedance occurs when:

$$|3 \cdot X_C| > |2 \cdot X_{1\_11} + X_{0\_11}| \qquad (4.17)$$

Cross-polarized distance protection (either with mho or quadrilateral characteristic) can normally handle earth faults satisfactory if the negative impedance lies inside the characteristic. The operating area for negative impedance depends upon the magnitude of the source impedance and calculations must be made on a case-to-case basis (See Figure 4.22 and Figure 4.23).

Distance relays with separate impedance and directional measurement offer additional setting and operational flexibility when it comes to measurement of negative apparent impedance (see Figure 4.24).

4.1.11. Negative impedance seen by the relay, negative fault current (current inversion)

If in Figure 4.21 $|X_C| > |X_S + X_{L1}|$ and a fault occurs behind the capacitor, the resultant reactance becomes negative and the fault current will have an opposite direction compared to fault current in a power line without a capacitor (current inversion). The negative direction of the fault current will persist until the spark gap has flashed. Sometimes there will be no flashover at all, because the fault current is less than the setting value of the spark gap. The negative fault current can cause a high voltage in the network. The situation will be the same even if a MOV is used. However, depending upon the setting of the MOV, the fault current will have a resistive component.

The difficulties described here are accentuated with a three phase or phase-to-phase fault, but the negative fault current can also exist for a single-phase fault. The condition for a negative current in case of an earth fault can be written as follows:

$$\left|3 \cdot X_C\right| > \left|2 \cdot X_{1\_L1} + X_{0\_L1} + 2 \cdot X_{0\_S} + X_{1\_S}\right| \tag{4.18}$$

For all the designations refer to Figure 4.3.

The good protection systems must be able to cope with both positive and negative direction of the fault current, if such conditions can occur.

A distance protection cannot operate for a negative fault current. The directional element in this case gives wrong direction. Therefore, if negative fault current exists, distance protection is not a suitable solution. In practice, negative fault current seldom occurs. In normal network configurations the gaps will flash in this case.

4.1.12. Double circuit, parallel operating series compensated lines

Two parallel power lines both series compensated running close to each other and ending at the same busbar at both ends (see Figure 4.25) can cause some additional challenges for distance protection due to the zero sequence mutual impedance. The current reversal phenomenon can also raise problems from the protection point of view, particularly when the power lines are relatively short and when permissive overreach schemes are used.

4.1.12.1 Influence of zero sequence mutual impedance

Zero sequence mutual impedance Z_{m0} will not significantly influence the operation of distance protection as long as both circuits are operating in parallel and all precautions related to settings of distance protection on series compensated line have been considered. Influence of parallel line switched off and earthed at both ends on the operation of distance protection on single operating circuit is well known [4].

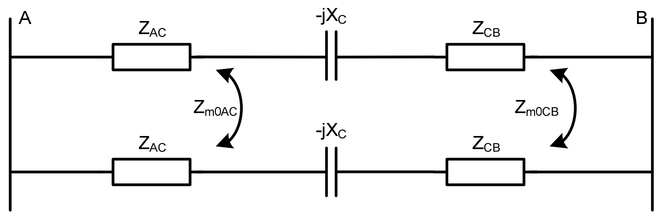


Figure 4.25: Double circuit, parallel operating line

The presence of series capacitor additionally exaggerates the effect of zero sequence mutual impedance between two circuits. Zero sequence equivalent circuit for a fault at B bus of a double circuit line with one circuit disconnected and earthed at both terminals is shown in Figure 4.26. The effect of zero sequence mutual impedance on possible overreaching of distance relays at A bus is increased further compared to case of non compensated lines. This is because while the series capacitor will compensate self impedance of the zero sequence network the mutual impedance will be same as in the case of non compensated double circuit lines. The reach of underreaching distance protection zone 1 for phase to earth measuring loops must further be decreased for such operating conditions.

Zero sequence mutual impedance may also disturb the correct operation of distance protection for external evolving faults during auto reclosing, when one circuit is disconnected in one phase and runs in parallel during dead time of single pole autoreclosing cycle. All such operating conditions must be carefully studied in advance by dynamic simulations in order to fine tune settings of distance relays.

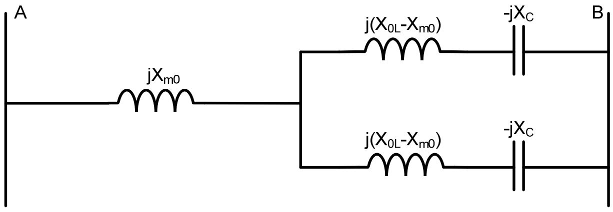


Figure 4.26: Zero sequence equivalent circuit of a series compensated double circuit line with one circuit disconnected and earthed at both terminals

4.1.12.2 Current reversal on parallel operating circuits

If the fault occurs in point F of the parallel operating circuits, as shown in Figure 4.27, one of the distance relay (operating in POTT teleprotection scheme) in the parallel healthy circuit will send a carrier signal CSAB to the remote line end, where this signal will be received as a carrier receive signal CRBB.

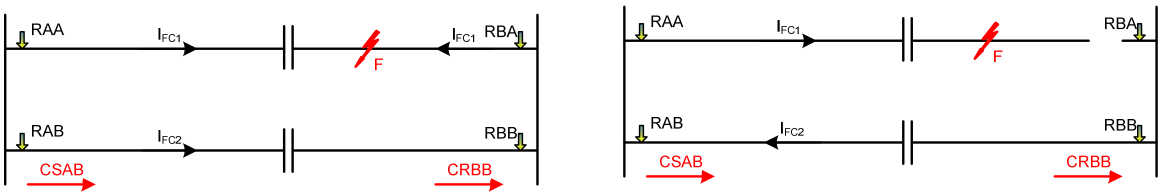


Figure 4.27: Current reversal phenomenon on parallel operating circuits

It is possible that on the faulty line the relay that is closer to the fault acts faster resulting in faster opening of corresponding breaker, which then will reverse the current direction in healthy circuit. Distance relay RBB will now detect the fault in forward direction. If CRBB signal still is present due to the long reset time of relay RAB and especially the telecommunication equipment the relay RBB will operate and trip its circuit breaker, since all conditions for POTT have been fulfilled. Zero sequence mutual impedance will additionally influence this process, since it increases the magnitude of fault current in healthy circuit after the opening of first circuit breaker. The so-called current reversal phenomenon may cause unwanted operation of protection on healthy circuit and this way endangers even more the complete system stability.

To avoid the unwanted tripping, some manufacturers provide a feature in their distance protection, which detects that the fault current has changed in direction and temporarily blocks distance protection. Another method employed is to temporarily block the signals received at the healthy line as soon as the parallel faulty line protection initiates tripping. The second mentioned method has an advantage in that not the whole protection is blocked for the short period. The disadvantage is that a local communication is needed between two protection devices in the neighboring bays of the same substation.

Distance protection used on series compensated lines must have a high overreach to cover the whole transmission line also when the capacitors are bypassed or out of service. When the capacitors are in service, the overreach will increase tremendously and the whole system will be very sensitive for false teleprotection signals. Current reversal difficulties will be accentuated because the ratio of mutual impedance against self-impedance will be much higher than for a non-compensated line.

If non-unit protection is to be used in a directional comparison mode, schemes based on negative sequence quantities offer the advantage that they are insensitive to mutual coupling. However, they can only be used for phase-to-earth and phase-to-phase faults. For three-phase faults an additional protection must be provided.

Directional comparison protection

The directional comparison protection scheme consists of directional relays with generally unrestricted or not well-defined reach. With directional elements similar to those used by distance relays, the directional comparison protection will have the same limitations as described in section 0 about distance protection. To overcome some of these limitations, protection engineers have developed different protection principles, using communication links and directional elements suitable for series compensated lines more or less independent of presence of series capacitor. Figure 4.28 presents their basic operating principle.

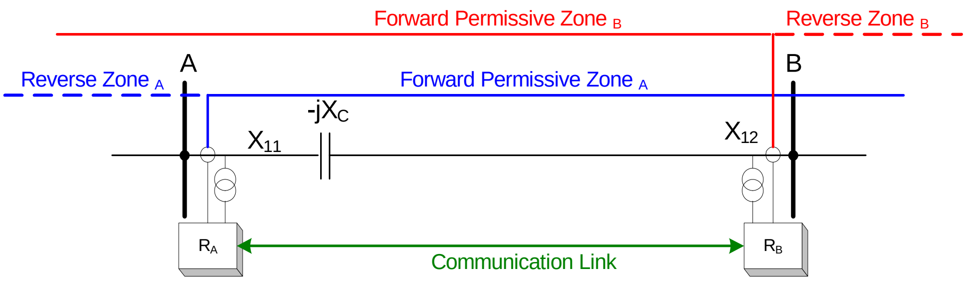


Figure 4.28: Basic operating principle of directional comparison protection

Measuring functions in relay points R_A and R_B base their operation on phase relations between different measuring quantities (generally voltages and currents and their derivatives). This way they determine whether the fault is in forward or in the reverse direction. It is a common practice to have in each relay point directional measurement in forward and reverse direction, especially on series compensated lines. This will help in securing correct operation of communication logic in cases of current reversals and weak-end infeed under different system operating conditions.

Tripping action at each line end is conditioned by the operation of local forward directional element and receiving of permissive communication signal from remote line end. This signal corresponds to operation of forward directional element at remote end. The scheme depends heavily on reliable communication link between two line ends, and is the only possible solution for fast tripping by measuring elements, which do not have a defined reach.

Some details of following protections based on directional comparison principle are given below.

- High-speed directional comparison protection, more known as, so called “Traveling wave protection”
- Directional residual overcurrent earth fault protection
- Directional negative sequence overcurrent protection

4.1.13. High speed directional comparison protection

The operating principle of high-speed directional comparison protection is based on directional comparison of superimposed (so called Δ – delta) quantities. The principle has been developed in 1977 and was known under the name “Traveling Wave Protection” although it does not have very much in common with basic definition and theory of traveling waves [13].

The essential advantages of processing these transient signals are:

- High speed operation (typically 2 ms), which is significant in case of series compensated lines
- Fast determination of fault direction
- Insensitive to electromechanical oscillations in power system
- Insensitive to CT saturation and short circuits in voltage measuring circuits
- Reduced performance requirements of CTs and PTs or CVTs

The inception of a fault in a power system will cause the post-fault voltage $u(t)$ and current $i(t)$ at a relaying point to deviate from the steady state, pre-fault voltage $u_p(t)$ and current $i_p(t)$, respectively.

We thus have:

$$u(t) = u_p(t) + \Delta u(t) \tag{4.19}$$

$$i(t) = i_p(t) + \Delta i(t) \tag{4.20}$$

Here $\Delta u(t)$ and $\Delta i(t)$ denote the fault generated voltage and current deviations from the pre-fault steady state signals as functions of time.

In the present approach, the direction to the fault is determined by evaluating the deviation signals $\Delta u(t)$ and $\Delta i(t)$. These deviation signals are readily obtained from the measured voltage $u(t)$ and current $i(t)$ by suppressing the sinusoidal pre-fault components. Under normal steady state conditions, the deviation signals are zero except for the presence of noise [13] and [14].

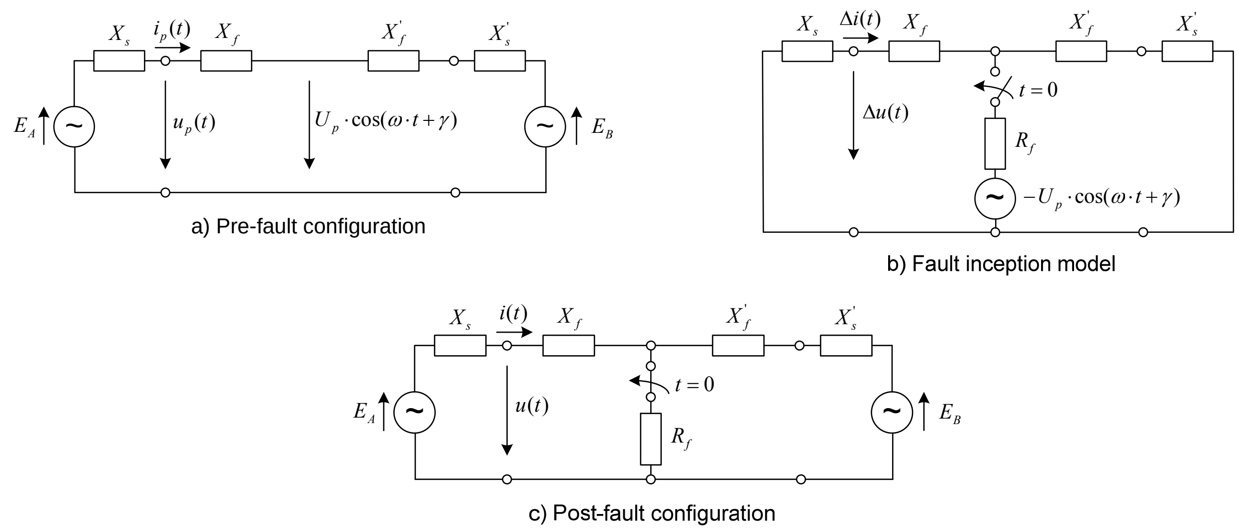


Figure 4.29: Principle of superposition applied to a faulty network

An important tool for investigating the present approach is the principle of superposition, which is indicated in Figure 4.29. The deviation signals can be considered to be generated by switching on a fictitious voltage source at the fault point with a voltage equal in magnitude and opposite sign to the pre-fault voltage at the fault point (Figure 4.29b). The superposition of the resulting deviation signals and the pre-fault waveforms clearly yield the post-fault waveforms.

The deviation signals are illustrated in Figure 4.30. Comparing the deviation signals of current and voltage can be used for the detection of fault direction. The directional discrimination operates on the premise that the deviation signals of voltage and current are initially of equal signs for forward faults and of opposite signs for reverse faults.

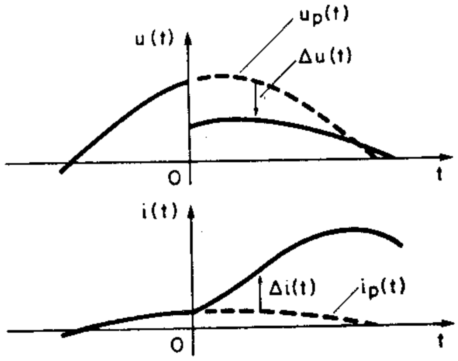


Figure 4.30: Quasi-stationary voltage and current waveforms at fault inception

The operating principle of the high-speed directional comparison protection is based upon the use of directional detectors, which evaluate the sudden change in voltage and current caused by a fault. The directional discrimination is accomplished in 2-4ms. The voltage across the series capacitor bank changes very little during this short measuring time. To change the capacitor voltage, energy must be forced in to the bank. The inductances in the system will limit the amount of energy that can be transferred during the first few ms.

Since the capacitor bank voltage does not change significantly during the time required for directional measurement, the series capacitor does not influence the measurement. The directional measurement is used in a directional comparison scheme by linking the two line terminals via a single communication channel. This protection can be used on compensated lines as well as adjacent lines, which are affected by the compensation. The sensitivity can be increased by weak end infeed echo and trip functions.

In principle this protection is particularly suitable for use on series compensated lines, because the directional detector remains unaffected by voltage and current inversions. In addition, it can cope successfully with all the problems presented in the chapter 0 on distance protection like under reach, negative impedance and negative fault current. However on parallel power lines it has the same disadvantages as all overreaching protection schemes.

The disadvantage of Δ based measuring principle is a fact that it can be active only for a short time after the fault inception. Different transients in power system may afterwards influence the shape of post fault currents and voltages and cause this way wrong directional discrimination. The measurement is for this reason blocked after approximately 20ms. It is for this reason impossible to detect evolving faults with longer evolving times. Therefore the high speed directional measurement has been combined with a conventional distance protection measurement to overcome this problem.

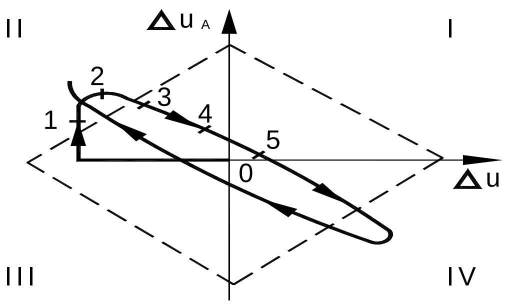
The high speed operating capability and a number of other advantages compared to classical relay protection schemes have made this basic operating principle interesting to different experts and relay manufacturers who have worked continuously on its further development.

Initial development has brought different operating modes for this type of protection, namely: dependent, independent and neutral current mode of operation.

- The dependent mode of operation has already been discussed in the text above. The name comes from dependence on communication channel between relays at line ends. This communication channel, even when completely operative, introduces some delay in final tripping time. This to some extent can be overcome by independent operating mode described below.

- The independent operating mode has been introduced in order to increase the operating speed for close-in faults, where not only the relative polarities of Δ quantities are monitored, but also their magnitudes. By the introduction of independent operating mode and use of for that time revolutionary solid state tripping circuits (in late seventies of the last century), minimum tripping times of 2-3ms have been recorded.
- The neutral current mode of operation has been introduced in order to make the protection sensitive enough for high resistive single-phase to earth faults, but still stable in operation for lightning strokes and surge arrester discharges. The operating times of this operating mode, which measures the magnitude of residual current, have been significantly longer.

An important step in the development of superimposed quantity measurement has been done with introduction of replica impedances Z_A and observation of voltage drops $\Delta u_A(t)$, caused on these replicas by superimposed current components $\Delta i(t)$, together with measured deviation voltage $\Delta u(t)$. This observation has been done in a so-called delta plane (see Figure 4.31), where the trajectory of both measured voltages has been observed in equal time intervals (milliseconds). An elliptic movement from second to the fourth quadrant has been characteristic for forward faults, while transition through first and the third quadrant indicates fault in the reverse direction.



I, II, III, IV – Quadrants in the delta plane
1,2,3 – time as parameter after fault inception

Figure 4.31: Trajectory in delta plane for the fault in forward direction

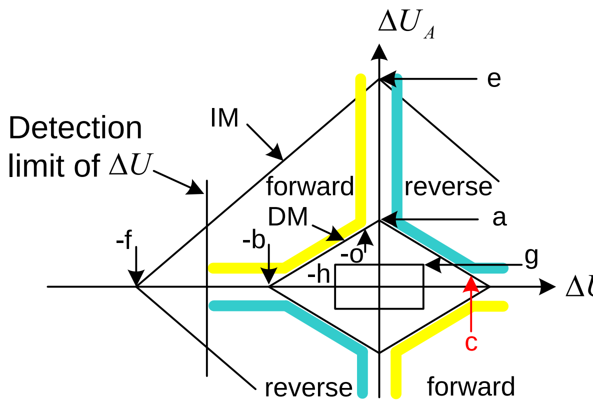


Figure 4.32: Different operating characteristics and associated setting parameters

Introduction of line replica impedance Z_A has made possible also better estimation of fault position on protected power line, similar to the distance protection. Introduction of diamond operating characteristic (see Figure 4.32) made it possible to provide fast and communication independent tripping for faults up to 40% of protected power line, even if the fault currents have not been extremely high.

Further development of the superimposed quantities based measurement has been observed with introduction of microprocessor based protective relays and first attempts for functional integration within the same device. It is extremely fast in operation, has excellent phase selection capability and is independent of different disturbing factors that have made it a very useful complement to traditional distance protection functionality.

In the numerical devices, the calculation of the superimposed components of the phase currents and voltages is based on the latest samples measured and samples stored in the memory of the relay (see Figure 4.33). There are different approaches to the derivation of the superimposed components.

The general aim is to estimate what the expected no-fault current or voltage sample should be at this moment and then subtract that from the latest sample captured.

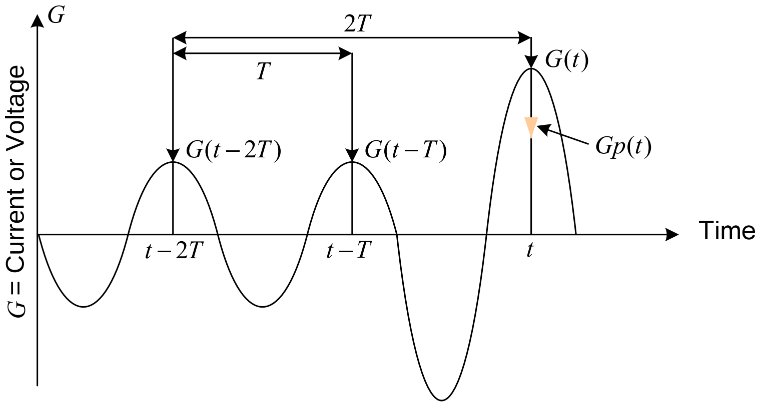


Figure 4.33: Calculation of superimposed quantities

One method is to use two samples, captured one and two cycles earlier than the last sample captured by the relay at the same angle on the waveform to predict the expected non-fault sample value at time (t) as shown in equations (4.21) to (4.23) with reference to Figure 4.33. This requires the relay to have a buffer that holds two cycles of samples for each observed analog signal.

$$G_p(t) = G(t-T) + \left[G(t-T) - G(t-2\cdot T)\right] \quad (4.21)$$

$$G_p(t) = 2\cdot G(t-T) - G(t-2\cdot T) \quad (4.22)$$

$$\Delta G(t) = G(t) - G_p(t) \quad (4.23)$$

An advantage of the above method for calculation is that it provides a good estimate of the predicted sample value based on two pre-fault samples. However, the predicted values can be accurately calculated for only one cycle after the fault inception. After that $G(t-T)$ will be affected by the fault, i.e. the predicted value will not be accurate, and so the superimposed component will not be accurate as well. Considering the fact that the relay will make a decision and issue a trip signal based on one cycle of data, this is not a problem.

If the superimposed components have to be calculated accurately for more than one cycle, the calculation can be based on a single sample taken two cycles before the predicted sample, i.e.

$$G_p(t) = G(t-2\cdot T) \quad (4.24)$$

If the relay has a two cycles buffer; the superimposed components will be accurately calculated for two cycles after the fault inception.

A further development of the method based on the sign of the ratio of $\Delta i(t)$ and $\Delta u(t)$ is to use their product, i.e. the transient power or even further integrate this transient power over certain period of time directly after the fault inception to derive the transient energy.

The direction of the transient energy is based on the three phase products of the superimposed phase currents and voltages. The direction of the fault is determined by the sign of the transient energy caused by the inception of the fault, given by

$$S = \int U \cdot I \cdot dt \tag{4.25}$$

The three phase energy transition is calculated in the relay as

$$S = \sum \left(\Delta U_{L1i} \cdot \Delta i_{L2i} + \Delta U_{L2i} \cdot \Delta i_{L1i} + \Delta U_{L3i} \cdot \Delta i_{L3i} \right) \tag{4.26}$$

Based on the earlier discussions on the effect of the fictitious source at the fault location on the changes of the phase currents and voltages measured at the relay location we can conclude that the three phase energy is always negative for forward faults and positive for reverse faults.

This method allows accurate directional detection under varying system conditions and is not affected by series compensated transmission lines or mutual coupling. Therefore, it reduces the probability of relay misoperation and provides a very fast (between ¼ to ½ of a cycle) and reliable directional decision that can be used by a directional comparison protection system.

Further development of the measuring principle, introduction of new algorithms, based on measurement of Δ quantities, has been going on even today. The transient overreach in measurement has been significantly reduced so that it is possible to use the "independent mode of operation" up to 70% of line lengths and still obtain extremely short operating times of approximately 8.5ms (including time taken by electromechanical tripping relays). Protection devices with such "modernized" measurement are today used on the most modern series compensated networks, which are using fixed as well as thyristor controlled series capacitors. On the other hand still in operation on the oldest series compensated lines are, some of the first static relays introduced in late seventies of the last century that have excellent operating experience.

4.1.14. Directional residual overcurrent protection

The operating principle is based on directional comparison of residual currents $I_{RSD} = 3 \cdot I_0$ at both line terminals during earth faults in power systems. Residual (open delta) voltage $U_{RSD} = 3 \cdot U_0$ in relay point is used as a reference quantity for directional discrimination. The communication scheme used may be either permissive overreach or blocking. Directional residual overcurrent protection schemes are in general used as complementary schemes to distance protection or back-up schemes for operation at high resistive earth faults. All basic application considerations, characteristic for directional residual overcurrent protection on normal power lines apply also to series compensated lines with following additions.

Low fault currents are characteristic of high resistive faults. This means that the fault currents may not be enough to cause voltage drops on series capacitors that would be sufficient to start their overvoltage protection. Spark gaps may not flash over in most cases, and metal oxide varistors (MOVs) may not conduct any significant current. Series capacitors may remain fully inserted during high resistive earth faults.

4.1.14.1 Zero sequence reactance of series capacitors on a power line

Figure 4.34 shows a simplified zero sequence equivalent scheme of a non compensated power line from its source to the fault position F $\left(R_{L0} + jX_{L0}\right)$, corresponding source impedance $\left(R_{S0} + jX_{S0}\right)$ and a zero sequence part of remaining power system, including the remote end of protected line behind the fault.

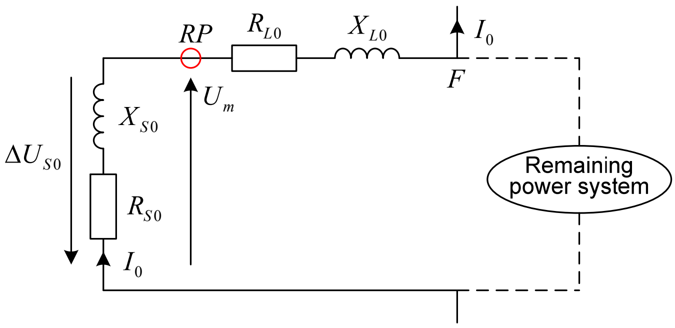


Figure 4.34: Simplified presentation of equivalent zero sequence circuit for protected power line, corresponding source impedance and remaining power system in one phase

Reactance of series capacitors X_{SC} is always lower than positive sequence line reactance of the compensated line. Figure 4.35 shows the basic scheme for arriving at the line zero sequence impedance. From this it can be seen that the capacitance of the series capacitors C_{SC} appears also as zero sequence capacitance C_{0SC} in the corresponding zero sequence equivalent network. It is for this reason possible to write the following basic equations.

$$X_{0SC} = X_{SC} \quad \text{and} \quad C_{0SC} = C_{SC} \tag{4.27}$$

In the above equation X_{0SC} represents zero sequence reactance of the series capacitor on a power line.

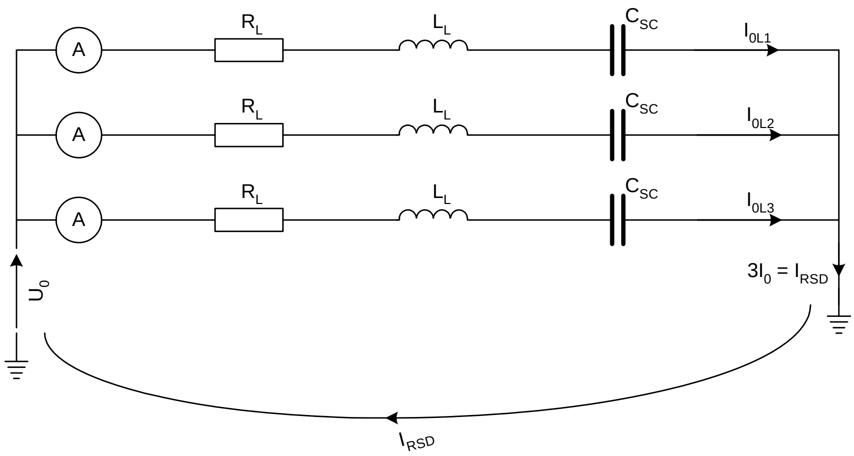


Figure 4.35: Basic scheme for measurement of line zero sequence impedance

4.1.14.2 <u>Operating cases for directional residual OC protection</u>

Operation of directional residual overcurrent protection (DEF stands for directional earth fault protection) depends to a great extent on the magnitude of residual $3 \cdot U_0$ voltage in relay point. The measured voltage is in fact the voltage drop caused by zero sequence current on zero sequence source impedance. In this way it may depend very much on relative position of VTs with respect to the position of series capacitor on the protected line (see Figure 4.9).

As mentioned earlier the reactance of the series capacitor remains always lower than the reactance of the compensated line. This also means that DEF protection will operate properly for all faults in reverse direction, regardless of the position of series capacitor on the protected line and position of VTs with respect to the series capacitor.

The situation becomes interesting in cases of faults in forward direction, and capacitors installed at line ends. Two possibilities exist for VT connection, as shown in Figure 4.36.

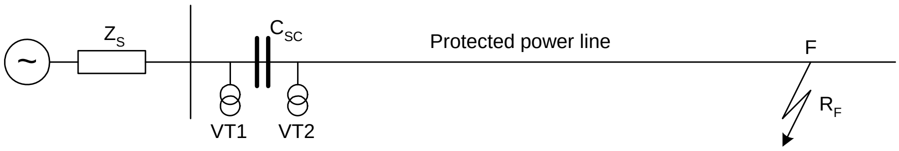


Figure 4.36: Series capacitor at the end of power line and possible locations of voltage instrument transformers

Series capacitors installed at line ends do not influence significantly the directional measurement of the DEF protection with VTs installed on the bus side of capacitors. Inductive character of zero sequence source impedance secures correct directional measurement for forward faults. Magnitude of residual current and zero sequence source impedance might limit the value of the residual voltage below the minimum possible levels determined by the DEF protection itself. Zero sequence line reactance is always higher than the zero sequence capacitive reactance. This will ensure that residual voltage of sufficient value and inductive in nature is available for reverse faults.

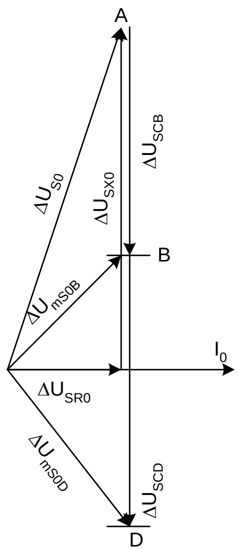


Figure 4.37: Influence of series capacitor on measured residual voltage in relay point

Directional measurement of the DEF protection may be influenced by series capacitor installed at the end of protected line, when the VTs are placed on the line side of series capacitors. Reverse faults are always detected correctly, since line zero sequence impedance always secures high enough zero sequence source impedance. Zero sequence capacitance of series capacitor becomes part of source impedance for all forward faults. In these cases the correct operation of DEF protections becomes dependent on values of inductive zero sequence source reactance and zero sequence capacitive reactance of series capacitor. Phasor diagram in Figure 4.37 shows the situation for three different cases.

4.1.14.2.1 Short circuited series capacitor

In this particular case residual voltage in relay point for forward faults depends on residual current and system source impedance only. Voltage drops ΔU_{SR0} and ΔU_{SX0} appear on zero sequence source resistance and inductive reactance respectively. The conditions are the same as in networks without series compensation, where the reference zero sequence voltage ΔU_{S0} leads the $3 \cdot I_0$ current for the characteristic angle of zero sequence source impedance.

4.1.14.2.2 Zero sequence reactance of series capacitor is smaller than the zero sequence reactance of the remaining power system

Voltage drop ΔU_{SCB} caused by zero sequence current on zero sequence capacitance has direction that is opposite to the direction of voltage drop ΔU_{SX0} caused by the same current on the remaining system zero sequence reactance, which is inductive in nature. The resulting reactive component of residual voltage ΔU_{mS0B} still has the correct direction for proper relay operation, but with a reduced phase angle with respect to residual current $3 \cdot I_0$. The DEF protection will generally operate with correct directionality, but in case of a power relay with operating characteristics as shown in Figure 4.38 a higher fault current is required for its operation compared to the case with short circuited series capacitor. The sensitivity of the protection in this way comes down.

4.1.14.2.3 Zero sequence reactance of series capacitor is larger than the zero sequence reactance of remaining power system

The polarity of voltage drop ΔU_{SCD} caused by zero sequence current on zero sequence capacitance has again direction that is opposite to direction of the voltage drop caused by the same current on remaining system zero sequence reactance, which is inductive in nature. The resulting reactive component of residual voltage in this case lags with respect to the residual current $3 \cdot I_0$ by an angle depending on the relative values of system and capacitor zero sequence reactance. It may finally prevent operation of the DEF protection.

4.1.14.2.4 Operating characteristic of residual power relay for three operational cases

Figure 4.38 shows all the above three described cases A, B, and D symbolically together with operating characteristic of the residual power relay.

In case A, when the series capacitor on protected line is short circuited, the zero sequence fault current is sufficient for correct relay operation.

In case B when the zero sequence reactance of series capacitor is smaller than zero sequence reactance of the remaining power system, the value of fault current necessary for relay operation can be sufficient, but is higher than in case A due to the nature of operating characteristic of the residual power relay.

In case D when the zero sequence reactance of series capacitor is higher than the zero sequence reactance of the remaining power system no operation of the relay is possible. The DEF protection will in this case fail to operate for forward high resistive faults.

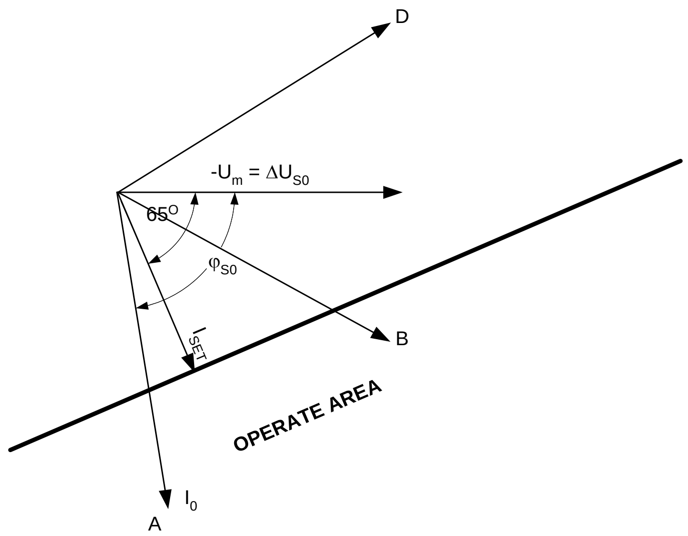


Figure 4.38: Operating characteristic of residual power relay for three operational cases

4.1.14.3 <u>Additional zero sequence source impedance to compensate for the effect of series capacitors</u>

It is possible to compensate for effect of series compensation on formation of residual voltage in relay point by introduction of additional zero sequence source impedance in DEF protection. The magnitude of additional impedance depends on system parameters as follows.

4.1.14.3.1 VTs installed on bus side of series capacitors

No additional zero sequence source impedance is necessary in the cases, when system source impedance can secure sufficient voltage drop and sensitivity for forward high resistive earth faults.

Correct directionality and sufficient sensitivity will generally always be secured for reverse faults due to the fact that zero sequence line impedance always remains higher than zero sequence capacitance of series capacitor.

4.1.14.3.2 VTs installed on line side of series capacitors

In this particular case it is necessary to distinguish between three different cases.

It is not necessary to introduce additional zero sequence source impedance, if the system zero sequence source reactance remains higher with sufficient margin compared to the zero sequence capacitive reactance of series capacitor. A sufficient margin means that the residual voltage appeared must remain high enough to secure correct directional discrimination and sensitivity of DEF protection.

Additional zero sequence source reactance should be introduced in cases, when system zero sequence source reactance secures correct and sensitive enough operation of DEF protection for forward faults, but the effect of series capacitors either decreases the sensitivity of current measurement or prevents correct directional operation. In this case it is necessary to compensate for the effect of zero sequence capacitance only.

Special attention must be paid to selection of additional source reactance in cases when system zero sequence source impedance does not secure high enough sensitivity and magnitude of residual voltage in relay point already without the influence of series capacitor. Additional zero sequence reactance in such cases must be higher than the capacitive zero sequence reactance of the series capacitor, which might on the other hand reflect in overcompensation for reverse high resistive faults. The problem might become significant on lines with high compensation degree, where it is no more possible to achieve sufficient margin for correct directional operation. Such cases must be examined on a case-to-case basis, and sometimes it may be necessary to decrease the required sensitivity in order to maintain secure and reliable operation of DEF protection.

4.1.14.4 Operation of DEF protection on remote end of a protected line

Series capacitor at one line end influences at high resistive faults the magnitude of the residual current at the remote line end. Zero sequence equivalent circuit of a single power line in a two-machine system is shown in Figure 4.39. Suffix C denotes the line and source impedance values on the capacitor side of the fault F. Suffix R denotes the line and source impedances on the remote part of line. It is clear that the distribution of zero sequence currents in both parts of the loop depends on ratio of these two impedances.

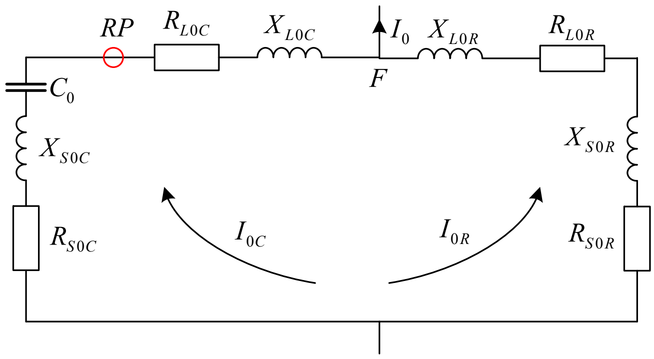


Figure 4.39: Zero sequence equivalent circuit of a single power line in a two-machine system

The combined zero sequence reactance of series capacitor and the source behind is negative when the capacitive reactance is higher than the inductive reactance of the source behind it. This resulting negative reactance influences the reactance of the line up to the fault point F and at a particular fault position F, specific to each installation the total loop reactance on the capacitor end of the loop becomes zero. If we neglect the resistance of line and resistance of the source impedance, we can always find a fault position, which results in zero impedance of a loop part on the capacitor side. This results in all the zero sequence current to flow only through the capacitor side of loop, and no zero sequence current will flow through the remote end relay point. This means same time that the remote end DEF protection cannot operate until the protection on capacitor side of the line opens the corresponding circuit breaker.

A combination with similar type of protection based on measurement of negative sequence voltages and currents is the possible solution. Here it is necessary to point out a fact that this protection scheme can also meet similar operating difficulties, but for a different fault position. The conclusion is that none of both principles is better than the other one, but their combination covers the problem in a satisfactory way.

Introduction of weak infeed logic circuits for each of the two mentioned schemes, when operating in permissive overreaching teleprotection scheme might improve the performance, but will in general result in prolonged fault clearing time due to delays introduced in communication logic in order to increase its security.

4.1.15. Directional Negative Sequence overcurrent Protection

Practically everything that has been presented under section 4.1.14 for directional residual overcurrent protection is valid also for directional negative sequence overcurrent protection. There is no general preference for any of them in different applications on series compensated lines. System simulation study both steady state and dynamic may show, which of them is more suitable for certain application. If possible it is best to have both of them in the same protection scheme and permit the operation to only the one with better operating conditions. This will provide the best dependability of the complete scheme.

Phase comparison protection

Phase comparison protection is a current only protection scheme; it requires a communication channel to transmit the current signal relative phase position to the remote end unit. CTs associated with phase comparison scheme are connected to look "into" the protected line as depicted in Figure 4.40.

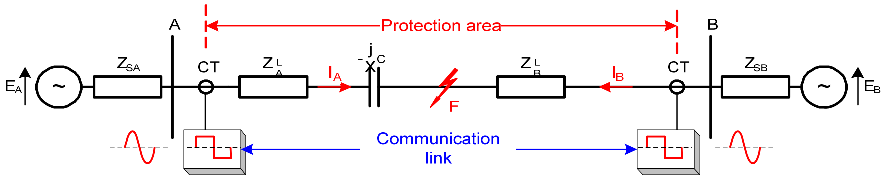


Figure 4.40: Phase comparison protection – internal faults

The relay compares the phase difference between the current measured locally with the one received from the remote unit to determine if a fault is on the protected line. Assuming propagation delay is fully compensated, and line charging current and measurement errors are negligible, for a fault on the protected line, the current signals from either end of the line should be in phase as depicted in Figure 4.40, but out of phase if the fault is external to the protected line (Figure 4.41). These signals should be out of phase during normal operational conditions, as well as external fault conditions.

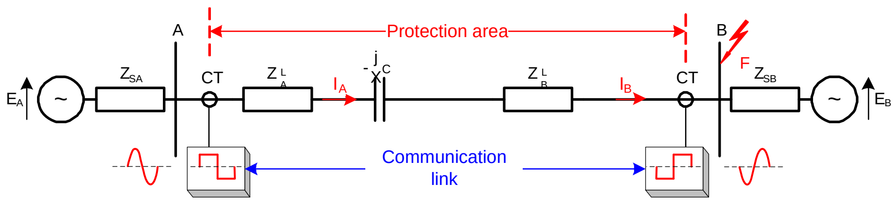


Figure 4.41: Phase comparison protection – external faults

Phase comparison scheme is inherently a blocking scheme if associated with power line carrier communication. The acquired current signals at the local unit (end A) are modulated into “Mark (+)” and “Space (-)”, and are transmitted over the communication link to the remote unit B, see Figure 4.42. The relay compares the current signals modulated from the local CTs with the ones received from the remote unit to determine the fault position.

A stability angle threshold θ_S is commonly introduced and settable in phase comparison relays, and a blocking condition is defined as:

$$180^O - \theta_S \le \theta_A - \theta_B \le 180^O + \theta_S \quad (4.28)$$

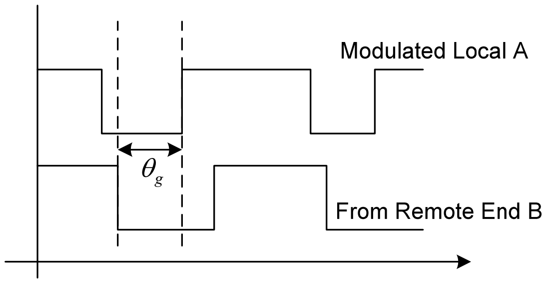


Figure 4.42: Phase measurement gap

Where, θ_A denotes the phase angle measured at local end A, θ_B as the phase angle at remote end B, and θ_S as stability angle threshold.

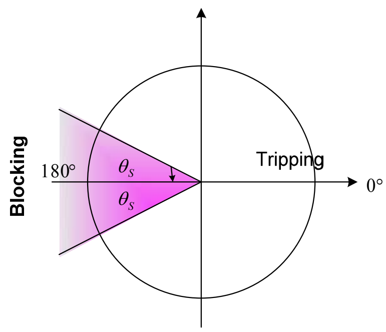


Figure 4.43: Phase comparison stability characteristics

Compensation needs to be incorporated to account for external factors such as measurement errors, drift in source angles, charging current, propagation delay and power swings, and to ensure stability during normal and external fault conditions, as well as power swing conditions. A stability angle threshold θ_S is commonly introduced and user settable in phase comparison relays, and a blocking condition is defined as:

$$180^O - \theta_S \leq \theta_A - \theta_B \leq 180_O + \theta_S \qquad (4.29)$$

Figure 4.43 shows the phase comparison stability characteristics. Assuming that the stability threshold is set to 30˚, θ_g is the gap measured between local end A and remote end B ($\theta_g = \theta_A - \theta_B$) as depicted in Figure 4.43. For a trip decision at 50Hz frequency, the measured gap must be greater than $\theta_g = (2 \cdot 30 / 360) / 50 = 3.3ms$.

Phase comparison protection is sensitive to channel propagation delays and phase errors introduced by the charging current. Measurement errors, drift in source angles could bring additional phase shift in phase comparison schemes. The capacitive component introduced by the charging current leads the current by 90°. This effect could be substantial if protecting an extra high voltage transmission line or where the load current is low and therefore must be compensated when applied to HV and EHV line protection. Compensation for charging current by expanding the stability angle effectively ensures correct operation of the scheme but will have an influence on limiting the protected line length.

Advantages of phase comparison scheme for series compensated line protection:

- Unit protection scheme requires less communication bandwidth
- Current only based scheme inherently not subject to voltage inversion

- Phase segregated scheme with excellent phase selection (when applied on a phase segregated measuring principles, which significantly increases the required investment)
- No sampled values to be transmitted suitable for use with power line carrier communication

Disadvantages are as follows:

- Communication dependent scheme must be incorporated with back-up functions
- Sensitive to power swing, line charging current, propagation delays; these must be considered in relay algorithm development

Several series compensated lines have phase comparison protection. As mentioned already it has no underreaching problem and has no problem with voltage inversion. Phase comparison protection can fail to operate in case of capacitive fault current. An internal fault appears to the phase comparison protection like an external fault. The phase comparison protection can, however, operate when the overvoltage protection has by-passed the series capacitor. The fault current will have a resistive component when MOV is used to protect the series capacitor against overvoltage. This can endanger the dependability of phase comparison protection when applied to series compensated lines.

A number of non-segregated (composite) current phase comparison protections are still in service on older installations. The problem is that the composite current from the symmetrical component filter may not be sufficiently high for certain combinations of internal faults and non-symmetrical bypassing of the series capacitor. Phase segregated phase comparison protections are therefore more suited for series capacitor applications than the older non-segregated current phase comparison protections.

Current differential protection

Figure 4.44 shows a basic operating principle of a current differential protection for a series compensated line. The currents at both ends of the series compensated line are used as input for the protection.

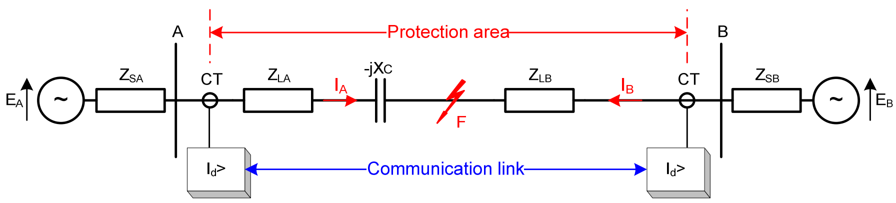


Figure 4.44: Line current differential protection – basic operating principle

A communication link transmits information between the protection equipment at each end of the transmission line. The zone of protection is strictly limited to the line length between the two current transformers at the line ends. This always puts a demand for providing an additional non-unit protection scheme.

Equation (4.30) describes the basic operating principle of line current differential protection.

$$I_{diff} = k \cdot I_{stab} \qquad (4.30)$$

The differential current I_{diff} and stabilizing current I_{stab} are generally defined as follows.

$$I_{diff} = \left| I_A + I_B \right| \qquad (4.31)$$

$$I_{stab} = k_{stab} \cdot f\left(I_A, I_B\right) \qquad (4.32)$$

Different vendors define different dependence of stabilizing current on line currents I_A and I_B. The k factor in operating equation (4.30) may also differ on its dependence on stabilizing current. This makes the operating characteristic, as shown for a typical case in Figure 4.45, dependent on the magnitude of through fault (stabilizing) current.

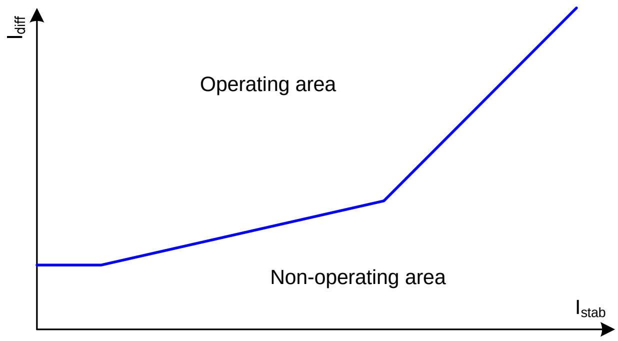


Figure 4.45: Line current differential protection – typical operating characteristic

Fast development in communication technologies as well as development of microprocessor based technologies is initiating positive changes in characteristics of state of the art line current differential protections. This makes them today the most attractive protection for series compensated lines with the following advantages in comparison to all other protection principles.

- Phase segregated measurement assures excellent phase selection
- Independence on voltage measurement in relay point makes it insensitive on voltage inversion
- True current measurement at line ends makes it *practically insensitive* to current inversion
- Comparison of line end currents in each phase separately makes it immune to current reversals on parallel operating lines
- Phase segregated current measurement makes them insensitive to effects of zero sequence mutual impedance on multi-circuit lines, independent of whether these lines are connected to the same or different zero sequence sources.

Their most exposed disadvantages are:

- Dependence on communication links, which are still relatively unreliable for protection purposes, even if they have their availability declared up to 0.9999. This requires always some kind of parallel protection functionality within the same hardware, which takes over immediately after the faulty communication link has been detected. Distance protection is a typical example, but it must not be mixed with Main 1 or Main 2 protection functionality
- Communication links have their transmission time, which is directly added to the protection operating time. It may happen this way that line current differential protection become in some cases too slow to secure strict system stability requirements.

Series capacitor itself practically does not influence the operation of line current differential protection. Very small changes in its sensitivity may be observed when capacitors are protected by

MOVs, which may, due to their capacitive – resistive equivalent serial connection, introduce some additional small phase angle in fault current supplied through the series capacitor.

Basic operating algorithms of line current differential protections differ between different manufacturers. It is important to check their operation for different system phenomena, which may cause false continuous or transient differential currents. For this reason it is always necessary to perform extensive dynamic simulation testing for each particular installation and check their suitability in connection with the following items.

- Sensitivity dependence on line capacitive charging currents in steady state and transient conditions.
- Stability of operation for line switching transients. Here it is extremely important to correctly simulate eventual shunt reactors and their switching transients.
- Line discharging currents for external faults in power system, etc.

Line back-up protection philosophies

Series compensated lines form generally backbones of many power systems. Their protection must for this reason be highly reliable, which means should have high dependability and high security. They are normally protected with two independent protection systems, so called Main 1 and Main 2. There is generally no special back-up, time delayed protection. The reason for this is need for a very short fault clearing time, which influences to a great extent the total system stability.

Autoreclosing on series compensated lines

The re-energizing of lines after a fault in general is not considered to create any particular problems for the protection systems. The following cases can be distinguished as far as autoreclosing after a fault on a SC line is concerned.

- **The capacitor is bypassed.** This is the case after spark gaps flashover and subsequent closing of the bypass-circuit breaker. The bypass circuit breaker is normally opened after successful re-energizing and after establishment of normal load conditions.
- **The capacitor is not bypassed**. This is normally the case for MOV-protected capacitors if the MOV protection has not closed the bypass circuit breaker due to the thermal stress caused by the fault.

For MOV-protected SCs, the protections can experience both of the above cases depending on the fault current amplitude and duration. For series capacitors protected exclusively with spark gaps, the bypass-circuit breaker will normally be closed during an autoreclosing sequence.

Series capacitors may also be bypassed for close-in external faults according to the first case. The series compensated line does not normally trip since the fault is cleared by the protection of the faulted network element. However, some of the phenomena described below may be experienced on the series compensated lines depending on network topology and characteristics. Network behavior associated to series compensated lines after an autoreclosing sequence is thus to be considered:

- On the series compensated lines for faults on the line,
- On the series compensated lines for external faults,
- On the adjacent lines for faults on the compensated line.

If the fault appears on the SC itself (i.e. if the trip is initiated by one of the SC protections), autoreclosing of the line has to be inhibited or at least delayed until the SC is bypassed. This requirement is valid for recloser operation from both line ends and may require the installation of a particular teleprotection scheme in order to disable the recloser at both line ends. This feature may be especially required when the capacitor is installed in the middle of a line.

In some of the series compensated lines autoreclosing is not permitted when SC (or shunt reactor) is not in service due to network constraints [21]. In these cases, even manual energizing of the line will not be possible after a fault is cleared. For these lines, the SC is first inserted in the de-energized line before closing operation is done. Typical delays stated in literature for spark-gap protected series capacitors are automatic insertion within 13 cycles (217 ms at 60Hz) after fault occurrence (clearance) and a successive phase-by-phase energizing of the line within 35 to 60 cycles (583 ms to 1000 ms), followed by the closing of the circuit breaker at the opposite line end within 45 to 70 cycles (750 ms to 1167 ms) after fault occurrence (clearance) [24]. The line is available for power transmission only after the completion of this sequence.

The following options for the reinsertion of the line are thus available:

- Autoreclosing on the line with bypassed SC and opening of the bypass after establishment of normal power transfer in the line. This option can be used for both spark-gap and MOV protected series capacitors. Since MOV protected series capacitors may be desirable in the first moments after reclosing in order to sustain the network stability, a bypass for faults that do not cause the protective spark gap operation should be avoided.
- Autoreclosing on line with inserted SC. This would be the normal case for MOV protected SC. For spark-gap protected SC, the extinction of the spark-gap and the opening of the shunt breaker leads to a relatively long reclosing sequence as stated above.

In general, SCs are conceived in order to limit the high frequency surge voltages and currents, which can occur when using high speed reclosing [21]. However, it is recommended to verify this point before implementing high-speed reclosing on a series compensated line. The use of adaptive reclosing techniques may reduce the surge stress if it is found to be beyond the allowable limit of the SC equipment [26].

If the series capacitor is bypassed, from the protection point of view the line behaves like a normal, uncompensated line.

If the series capacitor is inserted when the line circuit breaker closes, the following phenomena may appear:

- Low frequency power system oscillation may be enhanced by the series capacitor [25]. This phenomenon is also known as subsynchronous resonance (SSR). If power system analysis confirms this risk, special control algorithms on generator level and/or in thyristor-controlled capacitors can be implemented. As far as the line protection is concerned, it is possible to use a particular protection scheme in order to detect this phenomenon and to trip the line.
- High frequency oscillation phenomena due to the resonant circuit formed by the shunt capacitor, line reactance and line-to-ground capacitance are possible [21]. Depending on the line parameters, this may introduce constraints for high-speed reclosing. This phenomena has to be distinguished from the above mentioned power system oscillations (usually, those that have a very low frequency of some Hz or below).

As far as subsynchronous resonance SSR is concerned, this phenomenon can also appear without an initiating event like the tripping of a line subsequent to a fault. Thyristor controlled series capacitors can be used to damp these self-excited oscillations.

Fault location on series compensated lines

SCs and their overvoltage protection devices (typically Metal Oxide Varistors – MOVs) and/or air-gaps, when installed on a transmission line, create several challenges for its protective relays and fault locators. This is so since in this case the fault loop impedance measurement entirely differs in comparison to the plain (uncompensated) line case. The difference concerns both the static (steady state) and dynamic features of the measurement. Amount of capacitor compensation for the steady state depends on the operation point of the MOV characteristic. Moreover, a specific dynamic feature of transients in the circuits containing SCs and MOVs result from such phenomena as:

- Voltage and/or current inversion,
- Sub-harmonic oscillations,
- Additional transients caused by the air-gaps triggered by thermal protection of the MOVs.

In general, an accurate location of faults on series compensation transmission line can be performed by using the approaches developed for the uncompensated transmission lines, however with certain modifications. From this reasons the issue of representing SCs and MOVs for the most popular impedance-based fault location algorithms is of prime importance. Adequate compensation of series compensation effect is the key to assuring high accuracy of fault location. Analogously as for the uncompensated lines, also different availability of measurements can be considered for impedance-based fault location designated for series compensated lines. Apart from the one-end technique different options with respect to the two-end measurements can be considered as well.

The other approaches to locating faults on series compensated lines include the traveling wave principle and utilization of the high potential offered by the artificial intelligence methods, which are presently more and more being applied in power engineering.

4.1.16. Representing SCs and MOVs for fault location algorithms

Figure 4.46 presents the arrangement of double circuit lines with single series compensation applied in both: *LA and LB* lines. In this case there is a mutual coupling between the lines Z_m .

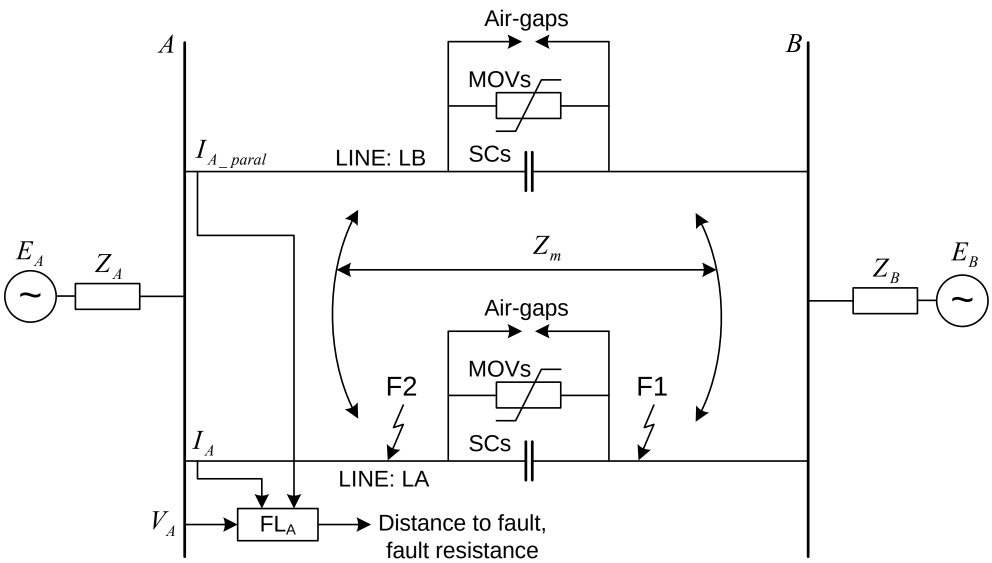


Figure 4.46: A double-circuit power line with single series compensation (mid-line capacitors)

The single series compensation can be also applied for single transmission lines, and such a case can be considered with the use of the scheme from Figure 4.46 by removing the parallel healthy line (*LB*) and of course with no mutual coupling consideration. Figure 4.47 shows the case of double end compensation applied on a single power transmission line.

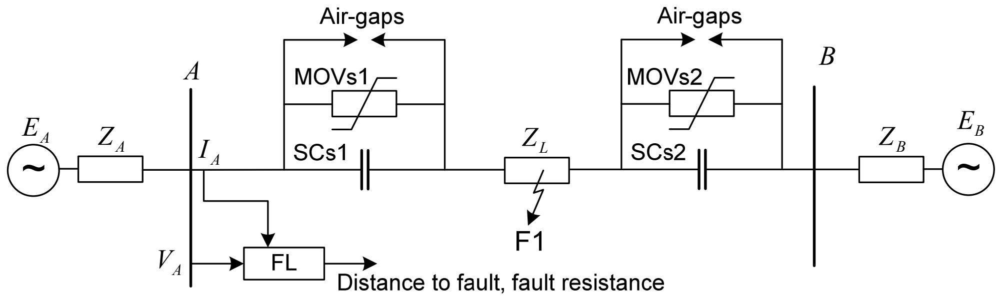


Figure 4.47: A single power line with double compensation (line-end capacitors)

Different approaches to locating faults on series compensated lines are considered in the references of the subject. Majority of them requires representing the SCs and MOVs [35] to [43] in the calculations performed for determining the sought distance to a fault. The following figures presents the respective illustrations for that: Figure 4.48: typical MOV characteristic, Figure 4.49: schematic of series capacitor and MOV, Figure 4.50: equivalent circuit for series capacitor and MOV, Figure 4.51: equivalent resistance of SC and MOV at different compensation degrees, Figure 4.52: equivalent reactance of SC and MOV at different compensation degrees, and Figure 4.53: typical voltage waveform across SC and MOV (simulated and calculated ones).

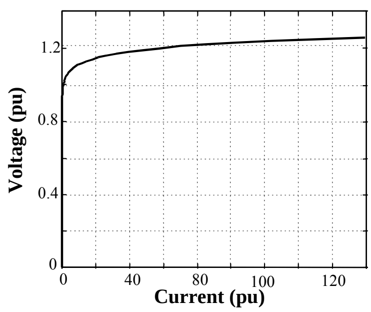


Figure 4.48: Typical MOV characteristic

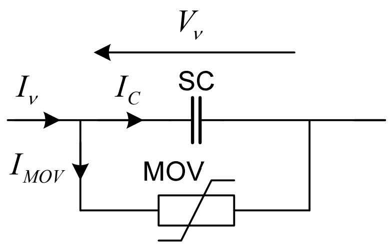


Figure 4.49: Series capacitor and MOV

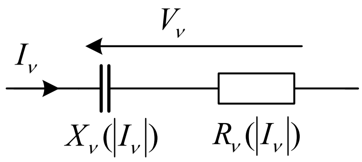


Figure 4.50: Equivalent circuit for series capacitor and MOV

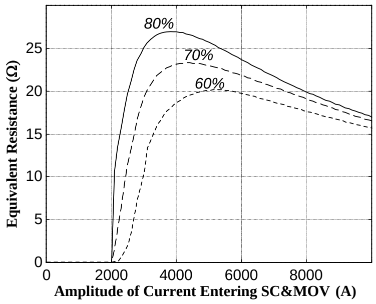


Figure 4.51: Equivalent resistance at different compensation degrees

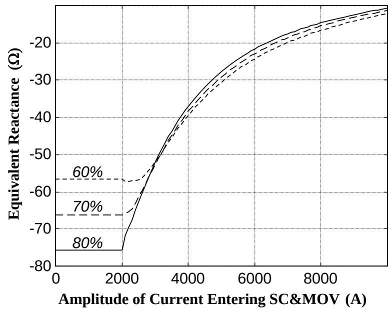


Figure 4.52: Equivalent reactance at different compensation degrees

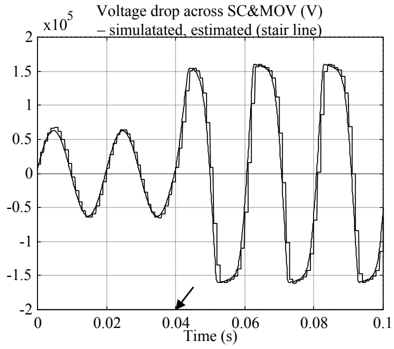


Figure 4.53: Typical voltage waveform across SC and MOV

Under unsymmetrical faults the fundamental frequency equivalents in particular phases are different. Therefore in order to account for that the phase co-ordinates approach has been proposed in [40] to [43] for formulation of the one-end fault location algorithm. According to this method the three-phase banks of SCs and MOVs are represented in the algorithm by the impedance matrix with the diagonal elements dependent on amplitudes of currents:

$$Z_V(|I_V|) = \begin{pmatrix} Z_v(|I_{va}|) & 0 & 0 \\ 0 & Z_v(|I_{vb}|) & 0 \\ 0 & 0 & Z_v(|I_{vc}|) \end{pmatrix} \tag{4.33}$$

Where: I_{va}, I_{vb}, and I_{vc} are phasors of the currents flowing through the banks of SC and MOV in particular phases (*a, b, c*).

Usage of the SCs&MOVs representation in the form of the matrix (4.33) is suitable for the method based on both, the phase co-ordinates and the fundamental frequency phasor approaches.

The other form of representing the SCs MOVs is required when instead of the phasor notation the differential equation approach is used for formulating the fault location algorithm. Then, the instantaneous voltage drop across SC and MOV in particular phases has to be estimated. Such estimation (see [38] and [39]) can be performed by numerical solution of the non-linear differential equation formulated for a parallel connection of the SC and the MOV:

$$C\frac{dv_v}{dt} + P\cdot\left(\frac{v_v}{V_{REF}}\right)^q - i_v = 0 \tag{4.34}$$

Where:

P, q, V_{REF} are the parameters of the MOV characteristic approximation,

C is the capacitance of the SC,

i_v *is the* current entering the SC and MOV circuit; it is assumed to be identical to the phase current measured at the beginning of the line.

4.1.17. One-end impedance based fault location technique

In [40]and [41] the one-end impedance based fault location technique for single series compensated transmission lines has been introduced, while in [42] and [43] fault location on double circuit lines has been considered. These approaches can be considered as the extension of the impedance-based fault location principle designated for uncompensated transmission line [44], which is widely known. Consideration of the double circuit lines case is important since this is the arrangement, which is mainly used in practice.

Under unsymmetrical faults, which are the majority of the power system faults, amplitudes of phase currents are unsymmetrical and in consequence the fundamental frequency equivalents in particular phases differ with respect to the amount of the equivalent resistance and reactance. The phase co-ordinates approach for the system description has been proposed to deal in a convenient way for this particular application. In addition, a generalized fault model, covering different fault types, is used in this algorithm as well:

$$\mathbf{I_F} = \frac{1}{R_F}\cdot\mathbf{K_F}\mathbf{V_F} \tag{4.35}$$

Where $\mathbf{V_F}$ and $\mathbf{I_F}$ are the vectors of voltages and currents at fault point, R_F is the aggregated fault resistance, and $\mathbf{K_F}$ is the fault matrix built upon the type of fault.

The fault location algorithm for double circuit series compensated lines (the scheme of Figure 4.46) branches into two separate subroutines considering the two characteristic fault spots:

- SUBROUTINE 1 – for faults behind the SCs (fault: F1),
- SUBROUTINE 2 – for faults in front of the SCs (fault: F2).

If the fault occurs behind the SCs (SUBROUTINE 1), the current flowing through the compensating bank $(\mathbf{I_v})$ is directly measured by the fault locator $\mathbf{I_A}$ and the following matrix equations apply to the faulty network:

$$\begin{aligned}
&\mathbf{E_A} - \mathbf{E_B} = \left[\mathbf{Z_A} + x_1\mathbf{Z_L} + \mathbf{Z_V}(|\mathbf{I_A}|)\right]\mathbf{I_A} - \left[|(1-x_1)|\mathbf{Z_L} + \mathbf{Z_B}\right]\mathbf{I_B} + (\mathbf{Z_A} + \mathbf{Z_B} + \mathbf{Z_m})\mathbf{I_{A_paral}} \\
&\mathbf{V_A} - \mathbf{V_F} = \left[x_1\mathbf{Z_L} + \mathbf{Z_V}(|\mathbf{I_A}|)\mathbf{I_A}\right] + x_1\mathbf{Z_m}\mathbf{I_{A_paral}} \qquad (4.36) \\
&\mathbf{I_F} = \mathbf{I_A} + \mathbf{I_B}
\end{aligned}$$

Here x is the distance to a fault in pu values ($p < x_1 < 1$).

For the pre-fault network (the subscript 'pre' denotes the pre-fault values), the following holds:

$$\mathbf{E_A} - \mathbf{E_B} = \left[\mathbf{Z_A} + \mathbf{Z_L} + \mathbf{Z_V}(|\mathbf{I}_{\mathbf{A}\_pre}|) + \mathbf{Z_B}\right]\mathbf{I}_{\mathbf{A}\_pre} + (\mathbf{Z_A} + \mathbf{Z_B} + \mathbf{Z_m})\mathbf{I_{A\_paral\_pre}} \qquad (4.37)$$

The set of the above matrix equations is solved for x_1 and R_F, which yields the simple quadratic equation:

$$Ax_1^2 + Bx_1 + C - R_F = 0 \qquad (4.38)$$

Where A, B, C *are* the complex scalars determined with the system parameters and the local measurements.

Resolving the above quadratic equation into the real and imaginary parts allows calculating the sought distance to fault (x_1).

On the other hand, in the case of a fault between the substation A and the SCs (SUBROUTINE 2), the current flowing through the SCs and MOVs is not directly measured by the locator $\mathbf{I_v} = \mathbf{I_B} \neq \mathbf{I_A}$ and the following applies to the faulty network:

$$\begin{aligned}
&\mathbf{E_A} - \mathbf{E_B} = (\mathbf{Z_A} + \mathbf{x_2}\mathbf{Z_L})\mathbf{I_A} + (\mathbf{Z_A} + \mathbf{Z_B} + \mathbf{Z_M})\mathbf{I_{A_paral}} - \left[(\mathbf{1} - x_2)\mathbf{Z_L} + \mathbf{Z_V}(|\mathbf{I_B}|) + \mathbf{Z_B}\right]\mathbf{I_B} \\
&\mathbf{V_A} - \mathbf{V_F} = x_2\mathbf{Z_L}\mathbf{I_A} + x_2\mathbf{Z_m}\mathbf{I_{A_paral}}
\end{aligned} \qquad (4.39)$$

Where: $0 < x_2 < p$

In consequence, one also obtains the quadratic equation as for the SUBPROUTINE 1, but the iterative numerical solution is required because the coefficients depend on the unknown amplitudes of the phase currents from the remote substation B.

Final result is obtained with the selection algorithm based on estimated:

- Fault resistance
- Amplitude of a total fault current from healthy phases.

In [43] the improved version of the algorithm presented here has been introduced. The improved algorithm has been obtained as a result of utilizing the flow of currents through the healthy parallel line. Its advantages rely on not requiring the sources impedances and not using the pre-fault measurements. In consequence of that an improvement of fault location accuracy can be assured.

The above mentioned fault location algorithms are primarily derived with neglected shunt capacitances, however the compensation for the capacitances can be easily incorporated as well. This is important for assuring high accuracy of locating faults on long series-compensated lines.

Similar approach can be applied for the transmission line with double series capacitor compensation (Figure 4.47). In this case the subroutines are designated for locating faults corresponding to the shown characteristic two fault spots: F1, F2. For the subroutine of the fault F1 the single series compensation is considered, while for the subroutine of the fault F2 the double compensation is taken into account.

4.1.18. Two-end impedance based fault location techniques

Utilization of two-end information to fault location is highly recommended for further improvement of fault location accuracy.

Firstly, unsynchronised two-end measurements [46] can be applied. It is evident that the already developed one-end algorithms for series-compensated transmission lines can further be improved by simple utilizations of the two-end information. The simplest way of utilization of unsynchronised two-end measurements can be performed by:

- Tracing the source impedances at each line end and using them as the input parameters, instead of using the representative values,
- Measuring amplitudes of phase currents and utilizing them for equivalenting the SCs and MOVs which are considered as in the remote infeed path (Figure 4.46 – subroutine of the Fault Locator FL_A designated for locating faults F2, which happen in front of the SCs and MOVs).

It is important that the above tasks do not require synchronizing the measurements.

Superior utilization of two-end information appears when the satellite GPS feasibility [47] to [51] is at disposal. In such cases the two-end measurements have the common time reference and the fault location task can be easily performed.

The main advantage of the two-end fault location relies on the possibility of limiting an influence of uncertainty with respect to the parameters and status of SCs and MOVs upon the fault location accuracy. This can be achieved by performing the fault location from the side from which the SCs and MOVs are not seen as contained in the fault loop. In this way the representation of the SCs and MOVs is not utilized in the distance to fault calculation itself. However, knowledge of the SCs and MOVs parameters is required for indicating at which side of them (in front or behind) the fault has occurred.

4.1.19. Traveling waves based fault location technique

Traveling waves approach to locating faults on uncompensated lines is known from many years (see [52] and [53]) and the advantages of such fault locators are clearly known. This approach is considered for application to series compensated lines as well. In [54] the scheme based on using wavelet transform for construction of the fast protection and fault location for series compensating lines is described. Current traveling waves, which are more easily captured than voltage waves, are used and decomposed into mode components. The line mode component is represented by its wavelet modulus maxima. Analyzing the amplitudes and polarities of their wavelet modulus maxima identifies the incident and reflection traveling waves. The interval between incident and reflection traveling waves reveals the fault position. In turn, in [55] the fault location for teed circuits with mutually coupled lines and series capacitors is presented. The fault initiated traveling wave and the backward traveling wave reflected are analyzed with application of the wavelet transform.

Application of the traveling wave method in conjunction with two-end synchronized measurements can assure very high fault location accuracy. On the other hand, this method requires comparatively high sampling frequency, i.e. of the order of 1 MHz, what is the main limitation for wide usage of the traveling waves based fault locators.

4.1.20. Application of artificial intelligence methods to fault location

Making a review of fault location methods one can also perceive application of artificial intelligence methods to that purpose [56] to [60]. In the references artificial neural networks are utilized for estimation of the instantaneous voltage drop across the SC and MOV circuit. Then, this estimation result is utilized in the distance to fault calculations performed in the way delivered for the uncompensated lines. Besides using the artificial neural networks one can also observe application of the other intelligence methods (wavelet transform and fuzzy sets theory) for solving the fault location and the protection problems of series-compensated lines. It is expected that the other effective artificial intelligence based methods of fault location for series-compensated lines will be developed in the near future.

4.1.21. Conclusions

Series compensating capacitors are installed on single, double circuit and teed transmission power lines. Arrangement of the compensation (installation place and the compensation rate) can be different, depending on particular application case. When faults occur on power lines the actual amount of compensation is not equal to the one observed for normal operation since it depends very much on the point on characteristic of MOV at which it operates for protecting the SC against over-voltage. This varying value of compensation is the main difficulty for locating faults on series compensated lines.

In case of the impedance-based fault location principle, which is the most common in practice, special modeling of the SCs and MOVs in the fault location algorithms is required. Such representation can be performed for the fundamental frequency phasors. Estimating a voltage drop across the SC and MOV branch can do the other form of SCs and MOVs representing, for example with model as presented in [1] and [2]. The impedance-based fault location in series compensated lines can be performed with use of one-end local measurements or by utilizing different options of the two-end information. Benefits of using the two-end information are the same as encountered in case of uncompensated lines. Moreover, it allows limiting adverse influence of uncertainty with respect to the status and parameters of the SC and MOV banks on the accuracy of fault location accuracy. For these reasons use of the two-end information for locating faults on series compensated lines appears very attractive and prospective.

Traveling waves principle applied for locating faults on series compensated lines can be considered as the approach which guaranties achieving high accuracy of fault location, especially in conjunction with two-end synchronized measurements and use of wavelet transform. However, the required high frequency sampling is still the main limitation for wide usage of the traveling waves based fault locators.

It is expected that in the nearest future extensive research efforts will be concentrated on developing the fault location techniques, which will fully utilize the potential offered by the artificial intelligence methods.

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Appendix A

We consider the instantaneous value of generator voltage on Figure 4.5 following the sine wave according to equation (4.40).

$$e_G = E_G \cdot \sin(\omega \cdot t + \lambda) \qquad (4.40)$$

The basic loop differential equation describing the circuit in Figure 4.5 without series capacitor is presented by equation (4.41).

$$L_L \cdot \frac{di_L}{dt} + R_L \cdot i_L = E_G \cdot \sin(\omega t + \lambda) \qquad (4.41)$$

The solution over line current is presented by group of equations (4.42).

$$\begin{aligned} I_L &= \frac{E_G}{Z} \cdot \sin(\omega t + \lambda - \varphi) + \left[I_{L(t=0)} - \frac{E_G}{Z} \cdot \sin(\lambda - \varphi) \right] \cdot e^{-t \cdot \frac{R_L}{L_L}} \\ Z &= \sqrt{R_L^{\,2} + \left(\omega \cdot L_L^{\,2}\right)} \\ \varphi &= atg\left(\frac{\omega \cdot L_L}{R_L} \right) \end{aligned} \qquad (4.42)$$

The line fault current consists of two components:

- The steady-state component which magnitude depends on generator voltage and absolute value of impedance included in the circuit
- The transient DC component, which magnitude depends on the fault incident angle decays with the circuit time constant $(L_L / R_L)[s]$.

The basic loop differential equation describing the circuit in Figure 4.5 with series capacitor is presented by equation (4.43).

$$L_L \cdot \frac{d^2 i_L}{dt^2} + R_L \cdot \frac{di_L}{dt} + \frac{1}{C_L} i_L = E_G \cdot \omega \cdot \cos(\omega \cdot t + \lambda) \qquad (4.43)$$

The solution over line current is in this case presented by group of equations (4.44). The fault current consists also here from the steady-state part and the transient part. The difference with non-compensated conditions is that

- The total loop impedance decreases for the negative reactance of the series capacitor, which in fact increases the magnitude of the fault current
- The transient part consists of the damped oscillation, which has an angular frequency β and is dying out with a time constant α

$$
\begin{aligned}
i_L &= \frac{E_G}{Z_{SC}} \cdot \sin(\omega \cdot t + \lambda - \varphi) + \left[K_1 \cdot \cos\left(\beta \cdot t\right) + K_2 \cdot \sin\left(\beta \cdot t\right)\right] \cdot e^{-\alpha \cdot t} \\
Z_{SC} &= \sqrt{R_L{}^2 + \left(\omega \cdot L_L - \frac{1}{\omega \cdot C_L}\right)^2} \\
K_1 &= I_{L(t=0)} - \frac{E_G}{Z_{SC}} \cdot \sin(\lambda - \varphi) \\
K_2 &= \frac{1}{\beta \cdot L_L} \left[\begin{array}{l} E_G \cdot \sin\left(\lambda\right) - U_{C(t=0)} - \frac{R_L}{2} \cdot I_{L(t=0)} - \frac{E_{G \cdot \omega \cdot L_L}}{Z_{SC}} \cdot \cos\left(\lambda - \varphi\right) \\ - \frac{E_G \cdot R_L}{2 \cdot Z_{SC}} \cdot \sin\left(\lambda - \varphi\right) \end{array} \right] \\
\alpha &= \frac{R_L}{2 \cdot L_L} \\
\beta &= \sqrt{\frac{1}{L_L \cdot C_L} - \frac{R_L{}^2}{4 \cdot L_L{}^2}}
\end{aligned}
\qquad (4.44)
$$

The difference in performance of fault currents for a three-phase short circuit at the end of a typical 500km long 500kV line is presented in Figure 4.6

5. CASE STUDIES

Feasibility study for the application of series compensation in the ESKOM Empangeni 400 KV network

5.1.1. Introduction

In order to strengthen the Empangeni 400kV network (a section of the Eskom Main Transmission Network in South Africa), an option of relocating existing series-capacitors from another part of the network into this area was considered. The main objective was to improve the power quality due to problems experienced with flicker in the region. Flicker is the impression of fluctuating intensity of light, occurring when the frequency of observed variation lies between a few Hertz and the fusion frequency of images.

The normal project studies were conducted and successfully completed. Management approval for the project was virtually granted. A last minute study, conducted with the focus on protection issues, indicated "unexplained" power network behavior. To the dismay of the project team, project approval was delayed until this behavior could be explained and its influence on the protection studied in more detail. Additional detailed studies followed and the behavior was eventually classified as current inversion (combined with voltage inversion) due to specific ratios of power network equipment impedance values with respect to fault position.

As the current and voltage inversion could adversely affect protection and result in incorrect protection operations, and hence power network blackouts, different protection scheme philosophies and the effect of such phenomena on each type of scheme were considered, with reference to old and new protection technologies existing on the particular network. The value of quality information databases and their management also proved invaluable. It was finally concluded that project implementation could be catastrophic to the power network stability and security.

Various options for resolving the problem were studied and finally the project was diverted to a more suitable alternative, with implementation pending financial justification based on sound engineering practices and principles. The best alternative proved to be strengthening of the power network by the installation of an additional transmission line.

The studies conducted also indicated that strengthening of power network with VAR compensation devices has limitations that need to be carefully considered during network planning stages. One such example is the sudden network voltage collapse under apparent network healthy conditions with no prior warning to power network operators. The above also clearly demonstrates that power network expansion and refurbishment needs to be considered from all aspects and not only from those aspects that may be directly related.

This case study consists of a detailed description of the project, as well as the study results (from a power network protection perspective as well as from an operational perspective). Ignorance of sound engineering practices could have resulted in huge financial implications and losses to the company. This also indicated the value of skilled and well-equipped resources.

5.1.2. Empangeni 400kV network description

Eskom is the electricity utility of South Africa. The current (year 2005) installed generation capacity is 42 GW (which includes 6 GW of mothballed generation) consisting mainly of coal-fired power stations concentrated in the North Eastern part of the country.

There is also a 1800 MW nuclear plant in the South Western tip of the country. A 765 kV, 400 kV and 275 kV transmission network spans the country providing the transmission backbone. The relevant portion of the network to which this case study refers is in the South African Kwazulu Natal region in the South East of the country, see Figure 5.1 and Figure 5.2.

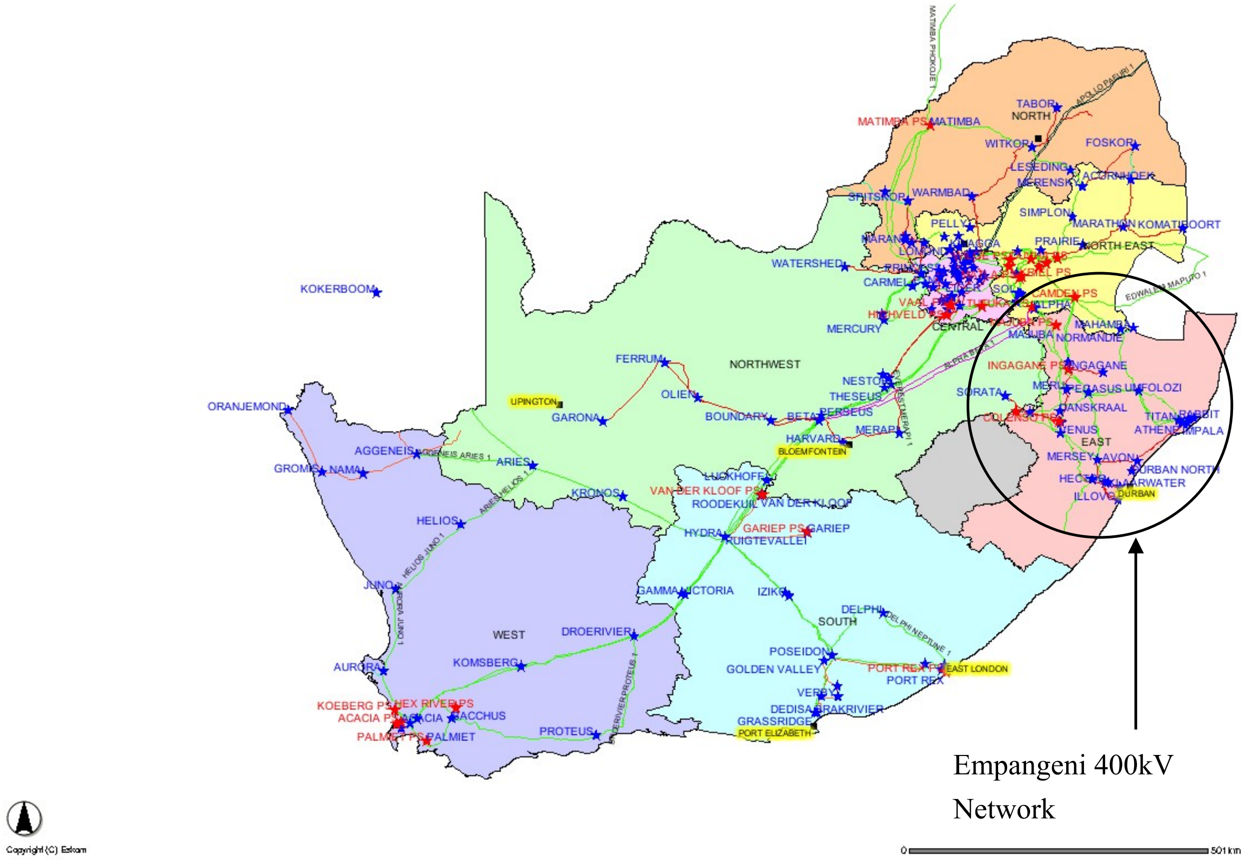


Figure 5.1: ESKOM transmission network single line diagram

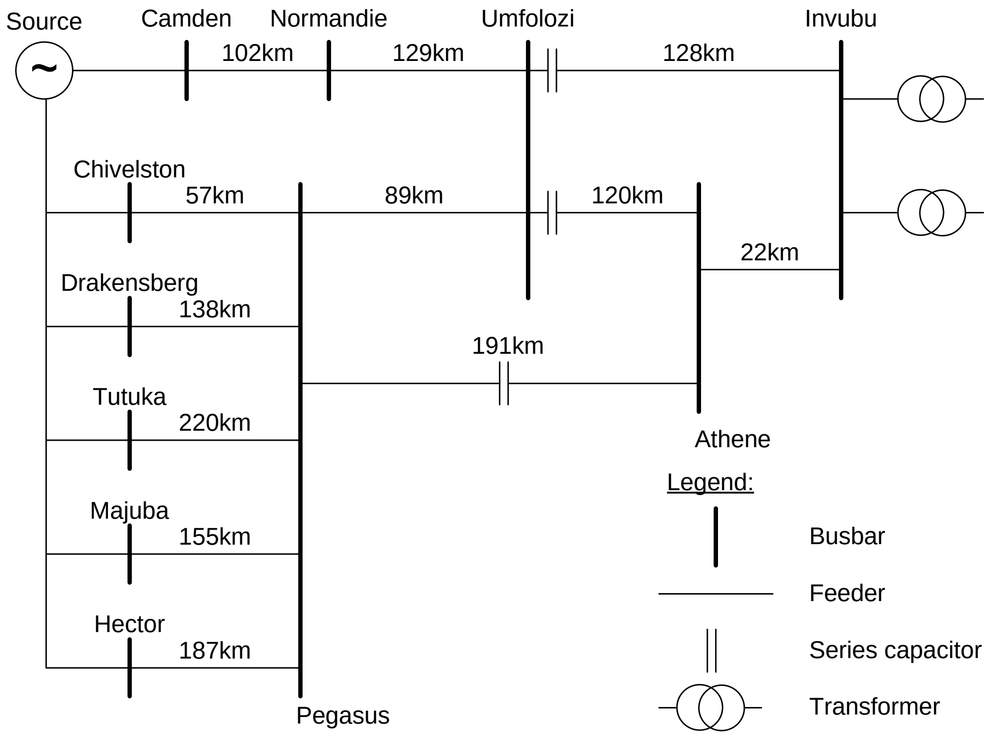


Figure 5.2: Empangeni 400 kV network single line diagram

5.1.3. Case study problem statement

To curtail the flicker effect on the Natal (Empangeni) Transmission network and in order to increase the transfer capability of the network, a proposal to insert series-capacitor compensation was evaluated.

As part of the project, an analysis of the impact on protection performance was required, given the proposed series compensation information.

The protection study was divided into two main groups: steady state and transient protection performance analysis. The protection performance of feeders as analyzed under steady-state conditions is represented in this case study. This case study aims to share information about the steady state protection study; e.g. theoretical background, method, results and recommendations.

The study focused mainly on general protection issues and capabilities of the existing installed protection in the network, rather than on specific supplier or new products available in the market.

5.1.4. General series capacitor influences on power network protection

The addition of series capacitors in transmission feeders has a substantial effect on the transmission feeder protection, not only on the series compensated feeders themselves, but also on adjacent transmission feeders. The influences of series compensation on transmission line protection are described in Chapter 4.

5.1.4.1 <u>Detailed study methodology and results</u>

It was necessary for the following information to be compiled before the study could be conducted:

- Network diagram
- Proposed series-compensated feeders and magnitude of compensation
- Electrical parameters of equipment in the network (for fault calculation software)
- Protection scheme information of the network
- Data manipulation and graphical representation software

The study methodology followed can be briefly summarized by the following series of steps:

- Obtain power network model for use in fault calculation software, allowing for in and out-of-service operation of the series capacitors in different proposed locations
- Study and obtain a feel for the power network behavior, with and without the series capacitors in service, during minimum and maximum network conditions and during normal operation and fault conditions
- Study the effect of the power network behavior on the existing power network protection scheme behavior during normal operation and fault conditions
- Study possible future power network improvements or changes and the effect on existing protection during normal operation and fault conditions
- Analyze results obtained and identify possible problem areas as well as solutions with regard to the protection performance and co-ordination
- Analyze any additional non-protection related problems identified (if any)
- Analyze possible solutions and feasibility of each
- Evaluate study
- Specify recommendations

Most of the study focused on fault throwing exercises on the proposed series compensated feeders (refer to Figure 5.3):

- Umfolozi – Invubu 400 kV

- Umfolozi – Athene 400 kV
- Pegasus – Athene 400 kV

5.1.4.2 Assumptions made

The following assumptions were made during the protection study and recommendations that followed:

- The magnitudes of the proposed series-capacitor compensation were as follows:

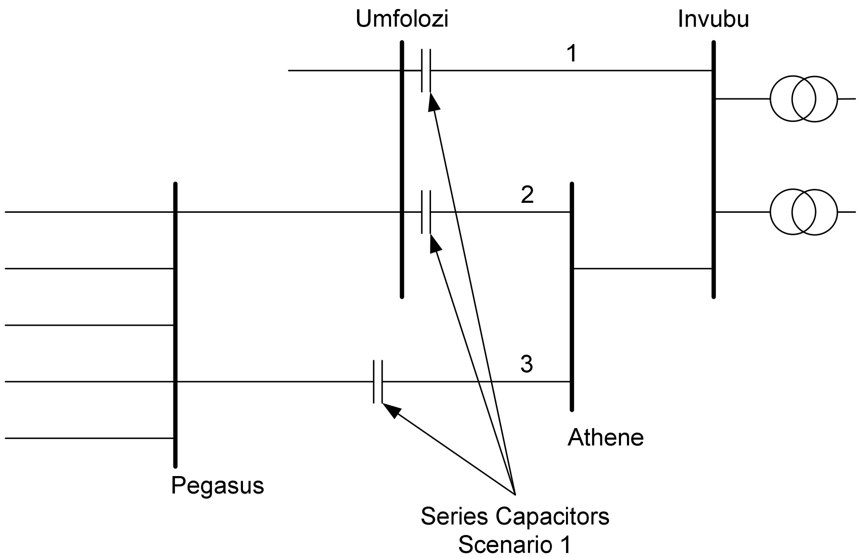
Table 5.1: Series compensation information

Feeder	Compensation magnitude
Umfolozi – Invubu 400 kV	70%
Umfolozi – Athene 400 kV	70%
Pegasus – Athene 400 kV	50%

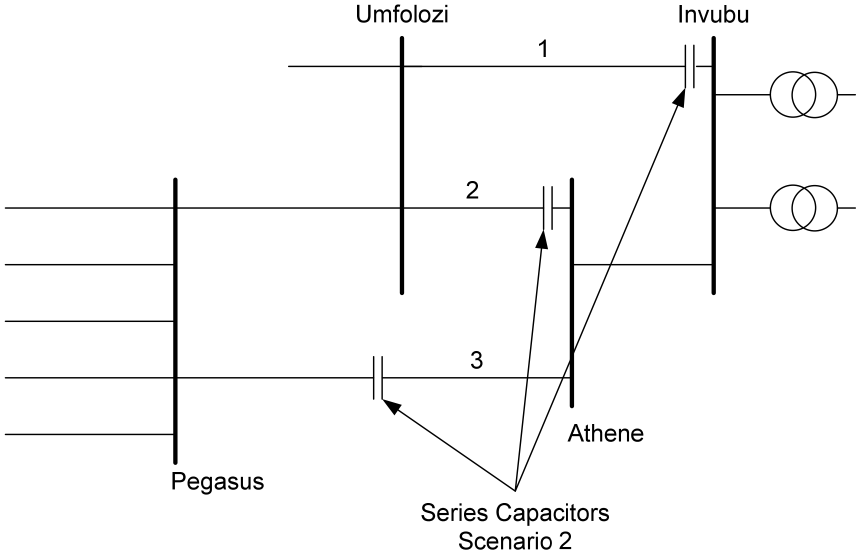
- Suitable (high voltage) unit type protection schemes that are capable of protecting the network under the proposed conditions is available on the market.
- The necessary digital communications network with diverse routes for main 1 and main 2 protections are in place and exist in the Empangeni 400 kV network.
- The spark gaps and bypass circuits of the proposed series-capacitors are not 100% reliable.

5.1.4.3 Network Study Scenario Diagrams

The proposed and studied series capacitor compensation locations are indicated in Figure 5.3, where Network Study Scenario 1 illustrates the series compensation situated at the source end of the proposed feeders and Network Study Scenario 2 illustrates the series compensation situated at the load end.



Network study scenario 1



Network Study Scenario 2

The descriptive numbers 1 or 2 (or 3) as indicated above, are used in the figures to reference the series compensated feeder numbers as follows:
1 = Umfolozi – Invubu feeder
2 = Umfolozi – Athene feeder
3 = Pegasus – Athene feeder

Figure 5.3: Network study scenario diagrams

The only difference between the two scenarios studied is the location of the series-capacitors on each feeder. The following is a summary of the series-capacitor locations for each scenario.

Table 5.2: Network study scenarios

Feeder	Network Study Scenario 1	Network Study Scenario 2
Umfolozi – Invubu	Series-capacitors installed at Umfolozi end	Series-capacitors installed at Invubu end
Umfolozi – Athene	Series-capacitors installed at Umfolozi end	Series-capacitors installed at Athene end
Pegasus – Athene	Series-capacitors installed at mid-point of feeder	Series-capacitors installed at mid-point of feeder

5.1.4.4 Software used

The steady state study was compiled using PSS/E software (Power Network Simulator Version 24.19 by Power Technologies Incorporated).

A number of specialized software programs were compiled during the study in order to speed up manual processes, data manipulation and representation. These included IPLAN programs and Microsoft Excel spreadsheets. Even with the additional software support, the study method was extremely time-consuming.

5.1.4.5 Protection scheme information:

Table 5.3 below indicates the particular type of protection scheme (as per Eskom standard) existing on the feeders at the time of this study being conducted.

Table 5.3: Protection scheme information

Feeder Name	Protection type on local end	Protection type on remote end
# Athene - Umfolozi	Phase 3	Phase 3
# Athene - Pegasus	Phase 3	Phase 3
# Invubu - Umfolozi	Phase 1	Phase 1
*Normandie - Umfolozi	Phase 1	Phase 1
*Pegasus - Umfolozi	Phase 1	Phase 1
*Athene - Invubu	Phase 3	Phase 3
Pegasus - Majuba	Phase 3	Phase 2
Pegasus - Chivelston	Phase 1	Phase 1
Pegasus - Hector	Phase 1	Phase 3
Pegasus - Tutuka	Phase 1	Phase 1
Pegasus - Drakensberg	Phase 1	Phase 1
Camden - Normandie	Phase 1	Phase 1

Proposed series compensated feeders

* Adjacent to 70% series compensated feeders

Legend:

Phase 1 = Electromechanical relays

Phase 2 = Static relays

Phase 3 = Numerical based relays (first generation)

Phase 4 = Numerical based relays (second generation)

5.1.5. Study results

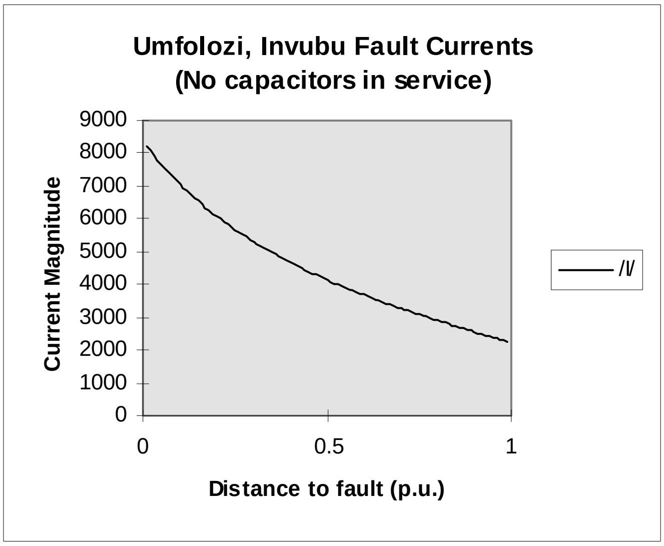
The following results are mostly represented in graphical form with related discussion text. Throughout the study and result representations, it is the intention not to focus on the actual values obtained but rather on the behavior.

The results were typically compiled by fault throwing on a particular feeder (and moving the fault location on the same feeder from the local to remote end) and then measuring and displaying different quantities as seen either on the same feeder or elsewhere in the network. This process was repeated for different feeders and measuring locations and the summarized results are indicated below.

5.1.5.1 <u>Series-capacitor bypassed</u>

Without the series compensation, the network behaves as usually expected; including the apparent impedances presented to the protection relays.

As an example of typical relay measurement behavior, Figure 5.4 illustrates the maximum fault currents flowing through the Umfolozi, Invubu 400 kV current transformer (CT) for faults at different locations on the same feeder.



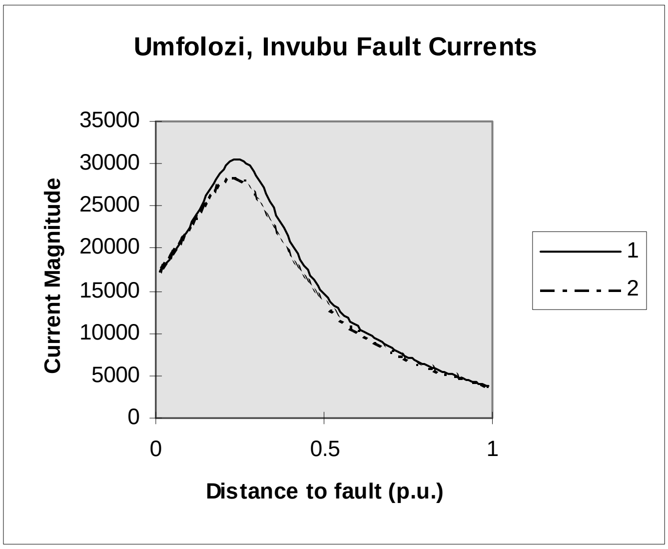
The distance to fault value indicated on the X-axis relates to the per unit (p.u.) value of the position of the fault location with respect to the feeder length and referenced to the local end (Umfolozi or Pegasus). The same applies to the figures below as well.

Figure 5.4: Maximum fault current through Umfolozi, Invubu 400 kV CT prior to the addition of series compensation

5.1.5.2 Network Study Scenario 1 (all series-capacitors in service)

Since $X_C > X_S + X_L$, current inversion is possible, which is a phenomena not previously experienced on the Eskom Transmission network.

The maximum fault currents through the series compensated Umfolozi, Invubu 400 kV CT changes drastically, from 8 kA to 30 kA, as shown in Figure 5.5.



The legend descriptive numbers 1 or 2 (or 3) as indicated in the following graphs refer to the series compensated feeder numbers, as labeled in figure 3.

Figure 5.5: Maximum fault current through Umfolozi, Invubu 400 kV CT after the addition of series compensation

The maximum fault current is reached for faults, approximately 25% of the feeder length from Umfolozi. At this point, the value of X_C is almost equal to the sum of X_S and X_L and the equivalent network impedance is almost totally resistive. This is obviously slightly different from the basic theory (where only reactance was focused on and resistance was excluded), since resistance is included in the network under consideration.

Four different network scenarios were studied to analyze the protection performance during minimum fault conditions (see Figure 5.6 as an example). These were:

- Half of the generation in the area out-of-service
- Half of generation and Pegasus - Umfolozi 400 kV feeder out-of-service
- Half of generation and Umfolozi - Normandie 400 kV feeder out-of-service
- Half of generation and Umfolozi busbar split so that Pegasus and Normandie infeeds are not linked

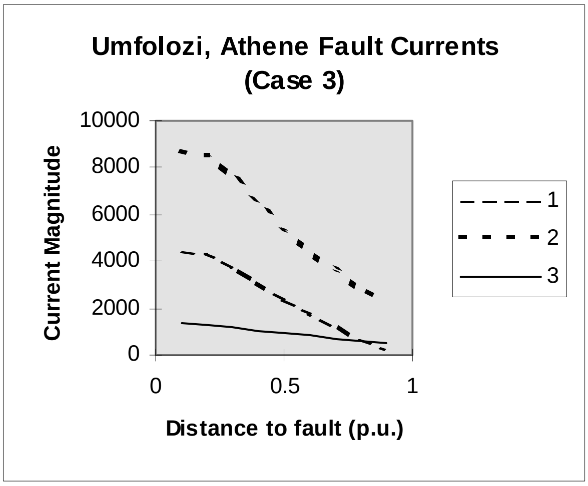


Figure 5.6: Minimum fault current (case 3) through Umfolozi, Athene 400 kV CT, with series compensation

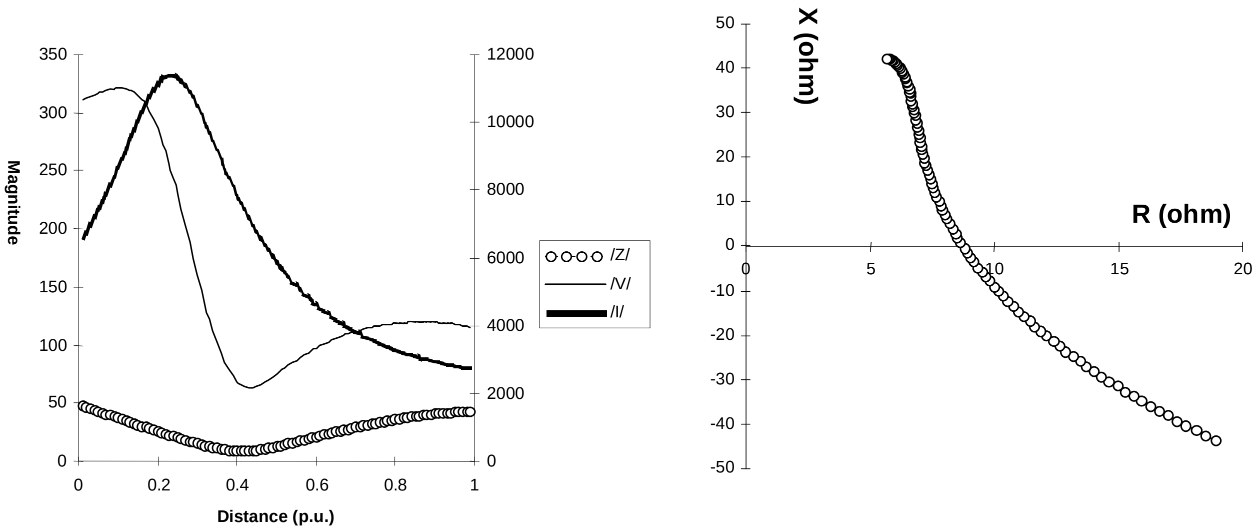


Figure 5.7: Measurement values by Pegasus, Umfolozi impedance relay for faults, at various distances, on the Umfolozi-Athene 400 kV feeder during maximum fault conditions

For the impedance protection relays, the worst-case apparent impedance conditions existed during maximum fault current scenarios.

Typically, the following network behavior was experienced by each impedance relay considered, the only difference being:

- Magnitude values, and
- Shifting of the axis to the left or right, depending on particular conditions.

The relays looking towards the fault tend to see the apparent impedance in quadrant 1 or quadrant 4 on the impedance plane, depending on if the current inversion occurs or not (see Figure 5.7).

Similarly, relays looking away from the fault tend to see the fault in quadrant 2 or quadrant 3 on the impedance plane, as indicated in Figure 5.8.

5.1.5.3 Network Study Scenario 2 (all proposed series-capacitors in service)

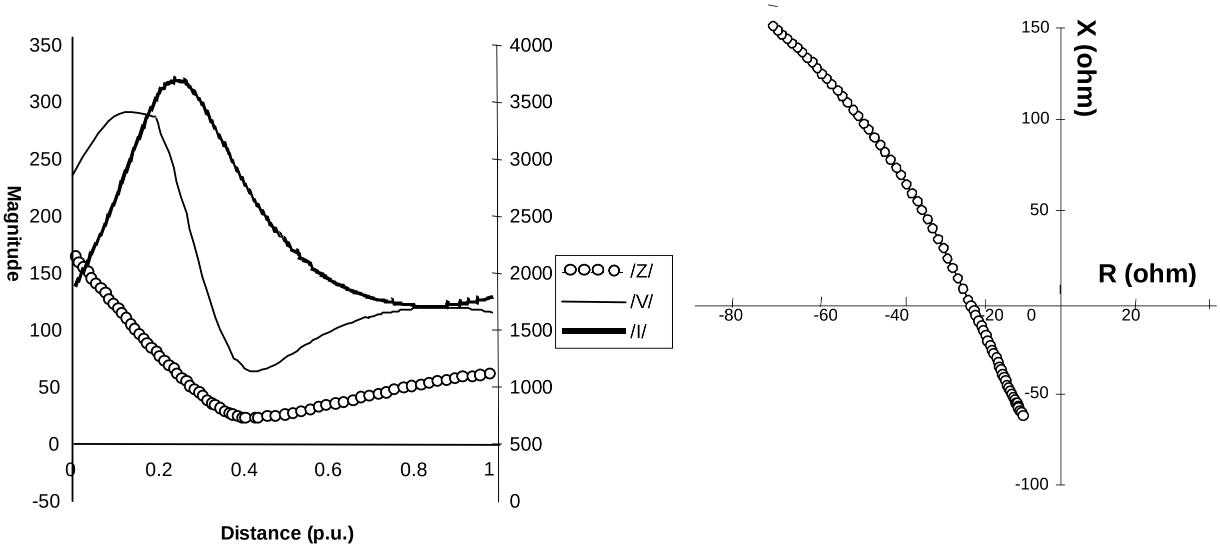


Figure 5.8: Measurement values by Pegasus, Chivelston impedance relay for faults, at various distances, on the Umfolozi - Athene 400 kV feeder during maximum fault conditions

The same behavior was experienced as in Network Study Scenario 1, with the exception that the possibility of incorrect protection operations decreased.

Due to the addition of reactance between the protection relay and series capacitor locations, the apparent impedances to the protection relays appear further away from the zone 1 characteristics, as compared with the case of Network 1. However, the apparent impedances do not move far enough to prevent similar problems being experienced.

The results also indicated that the majority of protection related problems are caused by faults occurring on the proposed 70% compensated feeders. Faults on the 50% compensated feeder did not present major problems.

5.1.5.4 Study analysis and risk considerations

The following factors were considered to determine the associated risk to the network:

- Spark gap flashover speed
- Sequential bypassing of series-capacitors
- Fault position
- Impedance relay problem areas
- Network stability and associated load losses

- Future network enhancements
- Personnel requirements
- Protection study limitations

5.1.5.4.1 Spark gap flashover speed

When the spark gaps flash, the apparent impedance presented to the impedance relays changes.

Prior to the spark gap flashing, the impedance relays may experience voltage and/or current inversion problems. However, these problems are not encountered after flashover.

Fortunately, the speed of spark-gap flashover is normally sufficient to bypass the series-capacitance before operation of the instantaneous elements occur, thereby minimizing unwanted protection operations.

Some utilities rely on the fast operation of the spark gaps to prevent incorrect protection operations whilst other utilities rely on advanced protective relaying techniques.

During the spark gap flashover process transients are induced which may also be problematic for the impedance relays. This study does not cover the effect of spark-gap operations and transients on the impedance protection.

The impact of incorrect protection operations on the network influenced the decision to rely entirely on fast spark gap flashover or not.

5.1.5.4.2 Sequential bypassing of series capacitors

Due to the nature of the studied network and behavior under fault conditions (e.g. dynamic fault resistance), sequential bypassing of the series-capacitors is possible, specifically under low fault level conditions.

This may result in prolonged dynamic and steady state apparent impedances being presented to the relays, which may in turn result in incorrect protection operations.

5.1.5.4.3 Fault location and effect on impedance measurement

From the study results, it is evident that the fault location dramatically influences the possibility of protection problems being experienced or not.

The worst-case fault locations tend to move along the series compensated feeders, depending on network configuration and fault characteristics.

5.1.5.4.4 Impedance relay problem areas

The study results indicated three problem areas, in terms of apparent impedance measurements.

Incorrect tripping in zone 1 for faults on series compensated feeders

Incorrect operation by the zone 1 measuring elements could occur for faults on the series-compensated feeders. This would result in instantaneous tripping of the breaker and the loss of at least one supply route to the Kwazulu-Natal network. The incorrect operations could occur on protection relays looking towards (e.g. Tutuka, Pegasus) and away (e.g. Pegasus, Tutuka) from the series compensated feeders. Any decrease of source impedance will tend to shift the fault impedance measured towards the zone 1 impedance characteristic.

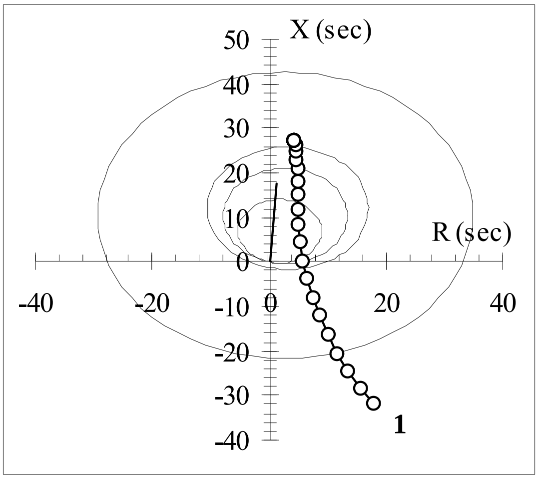


Figure 5.9: Incorrect zone 1 measurement

Incorrect tripping in zone 1 due to extended resistive coverage of relay characteristic

Polarized impedance protection relays can extend the resistive impedance coverage under different fault conditions. This has the advantage of greater coverage for high resistance faults and results in faster protection operation. This additional fault resistance coverage, under these network conditions, creates problems for the relays concerned, due to the fact that both reactance and resistance criteria are incorrectly satisfied and may result in tripping.

Problems may also be experienced, should some relays be replaced by relays with quadrilateral impedance characteristics.

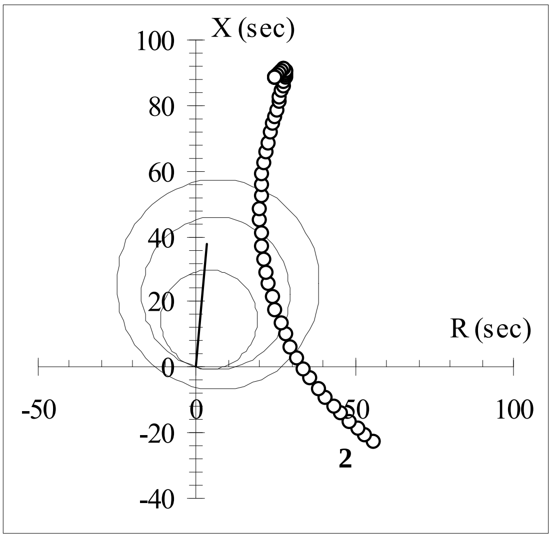


Figure 5.10: Incorrect operation due to extended resistive coverage of relay characteristic

Incorrect permissive tripping

Incorrect operation of the protection starter elements may occur and cause protection carrier signals to be transmitted, depending on the particular protection and settings. This may result in incorrect permissive tripping protection operations.

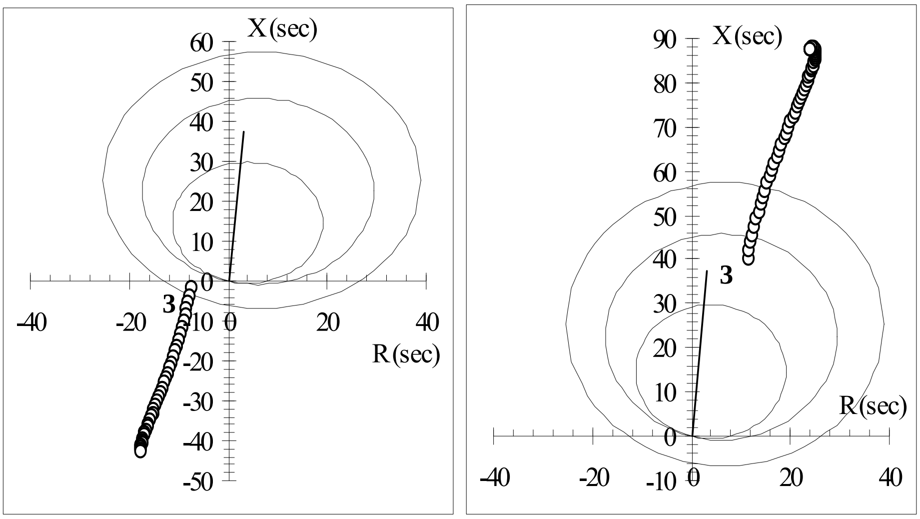


Figure 5.11: Incorrect permissive tripping

5.1.5.4.5 Distance from the fault position

With the occurrence of current inversion, the network current inverts. The effect of this in steady state is that the measured impedance for all impedance relays in the network may change.

Security against incorrect relay or element operations in the simplest form is provided by the magnitude of network impedance between the relay and fault position, depending on the applied settings of the relay. For relays situated on adjacent or feeders further away from the fault position, the measured fault impedance will increase in magnitude and thus de-sensitize relay elements accordingly.

5.1.5.4.6 Network stability and associated load losses

The Empangeni 400 kV network is presently prone to voltage stability problems in the case of multiple feeders being on outage.

The study results indicated that a number of feeders supplying the network could trip simultaneously for a single fault, under certain network conditions.

Major customers in the area include Hillside and Bayside smelters, Richards Bay Minerals and other industrial customers. Further industrial development is also in progress in the area.

The possibility of loosing the entire Empangeni network for a single fault, due to combined protection and network stability problems (n-2 condition), is very low, but does exist.

5.1.5.4.7 Future network enhancements

From the basic theory it follows that any of the following could change the network behavior and apparent impedances presented to the relays:

- Building of parallel feeders and transformers to supply the load demand
- Any addition of generation in the area (e.g. Majuba)

Any reduction of source impedance will increase the possibility of incorrect protection operations.

5.1.5.4.8 Personnel requirements

The proposed network and associated behavior are complex and impact on the personnel requirements in the following areas:

- Protection settings
- Fault investigations
- Planning

- Feeder personnel
- Maintenance

A concern was also raised during the study about the importance of continuous future management of the identified problems.

5.1.5.4.9 Protection study limitations

Due to the complexity of the network configuration and behavior, it was not feasible to study all possible scenarios that include future enhancements.

Most of the study focused on worst-case conditions and specifically for single- and three-phase faults. Phase-phase and phase-phase-ground faults were not studied.

Other factors that may cause under- or over-reaching problems, such as mutual coupling between adjacent feeders and differences between phase-phase and phase-ground impedance's during phase-phase-ground faults, were not considered.

The protection study described focused on steady state conditions. Some assumptions were made prior to the study and are mentioned earlier.

Even with all the energy and effort put into the study, not all potential problem areas may have been identified. This adds an unknown risk factor to be considered.

5.1.6. Suitability of existing protection on the Empangeni network feeders

5.1.6.1 Series compensated feeders

5.1.6.1.1 Umfolozi – Athene and Pegasus – Athene

The presently installed transmission feeder protection on these two feeders is Eskom Phase III generation (first generation numerical technology) that was specified and model power network tested for the protection of series compensated transmission feeders. With the addition of the series capacitors to the above two feeders and correct relay setting changes, this protection is capable of handling voltage inversion but not current inversion.

5.1.6.1.2 Umfolozi – Invubu

The protection on this feeder is pre-Phase II generation equipment (early generation solid-state technology). This protection is not capable of protecting the series compensated feeder due to its inherent design limitations that include, inter alia, the lack of voltage memory, the use of cross polarizing and the lack of suitable transient filtering. This protection would therefore need to be changed.

5.1.6.2 Adjacent feeders

5.1.6.2.1 Umfolozi – Normandie and Umfolozi – Pegasus

These feeders are adjacent to the two proposed series compensated feeders (70 % compensation factor) with the series capacitors located at Umfolozi substation. The protection on these two adjacent feeders is Eskom pre-Phase II schemes.

None of these relays are equipped with polarizing memory and will therefore not be capable of handling the voltage inversion problem created by faults on the proposed series compensated feeders. The situation is most onerous for three-phase faults. These voltage inversions can occur if the series capacitor protective gaps do not flash and also during the transition period when the gaps are in the process of flashing. The problem associated with single- and double-phase faults can differ for the three relay types used due to differences in the polarizing quantities used. Positive sequence polarizing is the least susceptible to the problem, and faulted phase polarizing is the most susceptible.

(Two of the relay types use cross polarizing which can cause these relays to overtrip for some fault conditions).

The relays are also potentially vulnerable to gap flashing transients, which can cause the relays to either operate slowly or, in some cases, not at all.

A third issue is the vulnerability of these relays to low frequency transients, which can cause overreaching of Zone 1 elements at the remote terminals looking into the capacitors.

As there is a risk of the series capacitor gaps not flashing for certain network scenarios and/or fault conditions, the risk of one or more adjacent feeders tripping for a fault on one of the series compensated feeders should be considered in the overall risk assessment.

5.1.6.2.2 Pegasus – Chivelston; Pegasus – Tutuka; Pegasus – Drakensberg, and Pegasus – Hector

These feeders are adjacent to the Pegasus – Athene feeder that has the proposed series capacitor located approximately midway, and with a proposed compensation factor of 50 %. The problems mentioned in the previous section are less severe for these cases, but could still exist. Detailed network studies would be required to show the risk conditions. Reducing the percentage compensation such that no voltage inversion was possible would help to mitigate against the adjacent feeder relaying problems.

5.1.6.2.3 Pegasus – Majuba

This adjacent feeder is protected using Eskom Phase III type relaying (first generation numerical technology) and with the correct relay setting changes, this protection is capable of handling voltage inversion but not current inversion.

5.1.6.3 <u>Options considered</u>

The following options were considered for replacement of protection schemes in the immediate surrounding network around the proposed series-capacitor feeder installations and were based on steady-state results only. Each option was then analyzed in terms of financial cost and associated steady-state risk factors that were manually estimated from analysis of the studies conducted.

The uncertainty of transient or dynamic behavior to more remote protection schemes also added weight to the risk evaluation criteria.

In the end it was concluded that the immediate upgrade cost as well as the added risk did not justify the installation of the proposed series-capacitors. Discussed below are three options that were considered based on the analysis of the steady-state conditions only which excluded risk considerations due to transient or dynamics presented to the network protection schemes.

The costs associated with each option can be summarized by:

- Protection scheme and relay replacements
- Relay evaluation and testing overseas, including costs for travel and subsistence for 2 persons

Option 1: Series-capacitors positioned at Umfolozi 400 kV substation

Risk: Low (to feeders North of Camden 400 kV substation.)

Implementation Period: ±1 ½ years

Approximate Cost: USD 2 – 2.5 million (exchange rate 10 ZAR for 1USD)

Option 2: Series-capacitors positioned at Invubu and Athene 400 kV substation

Risk: Low/Medium (to the following feeders):

Chivelston - Pegasus 400 kV

Drakensberg - Pegasus 400 kV

Tutuka - Pegasus 400 kV
Majuba - Pegasus 400 kV
Camden - Normandie 400 kV

Implementation Period: ±1 year

Approximate Cost: *USD* 1.25 – 1.5 million (exchange rate 10ZAR for 1USD)

Option 3: Series-capacitors positioned at Invubu and Athene 400 kV substation

Risk: No increased risk

Implementation Period: ±1 ½ years

Approximate Cost: USD 1.95 – 2.2 million (exchange rate 10ZAR for 1USD)

5.1.7. Conclusions

The study conducted indicated potential problem areas for the impedance protection relays in the Empangeni 400 kV network.

It was identified that impedance protection is not suitable on a number of 400 kV feeders for the proposed network conditions, without increasing the risk of incorrect protection operations and subsequent network stability problems.

Unit type protection schemes, combined with option 3, were recommended for implementation.

Various options for consideration were given with associated risk levels and approximate implementation costs.

5.1.8. References

[1] Cigré: "Application Guide on Protection of Complex Transmission Network Configurations", 1999

[2] Stokes-Waller, E. and Keller P.: "Power Network and protection performance analysis on the Eskom Transmission network based on digital fault records", 1998, Southern African Power Network Protection Conference, South Africa

[3] Stokes-Waller, E.:"Automated Protection Performance Analysis From Digital Fault Recordings On The Eskom Transmission Network", 2000, Cigre 4th International Regional Conference, South Africa

Series compensation Requirements in India

5.1.9. Introduction

India is spread over an area of about 3 million sq. km, and presently, Indian power system comprises (see Figure 5.12) about 57,000 circuit km of EHV AC and three long distance HVDC bi-pole lines, besides more than 5 million circuit km of 220/132kV/66kV lines. The country is operationally divided into five electrical regions namely Eastern (ER), Western (WR), and Northern (NR), North-eastern (NER) and Southern (SR) regions. There are 4 nos. of HVDC back-to-back links interconnecting NR-WR, WR-SR, SR-ER and ER-NR, whereas ER, NER and WR are operating in synchronous mode. Development of optimal transmission system plays a vital role in ensuring reliable and secure power supply at an affordable cost.

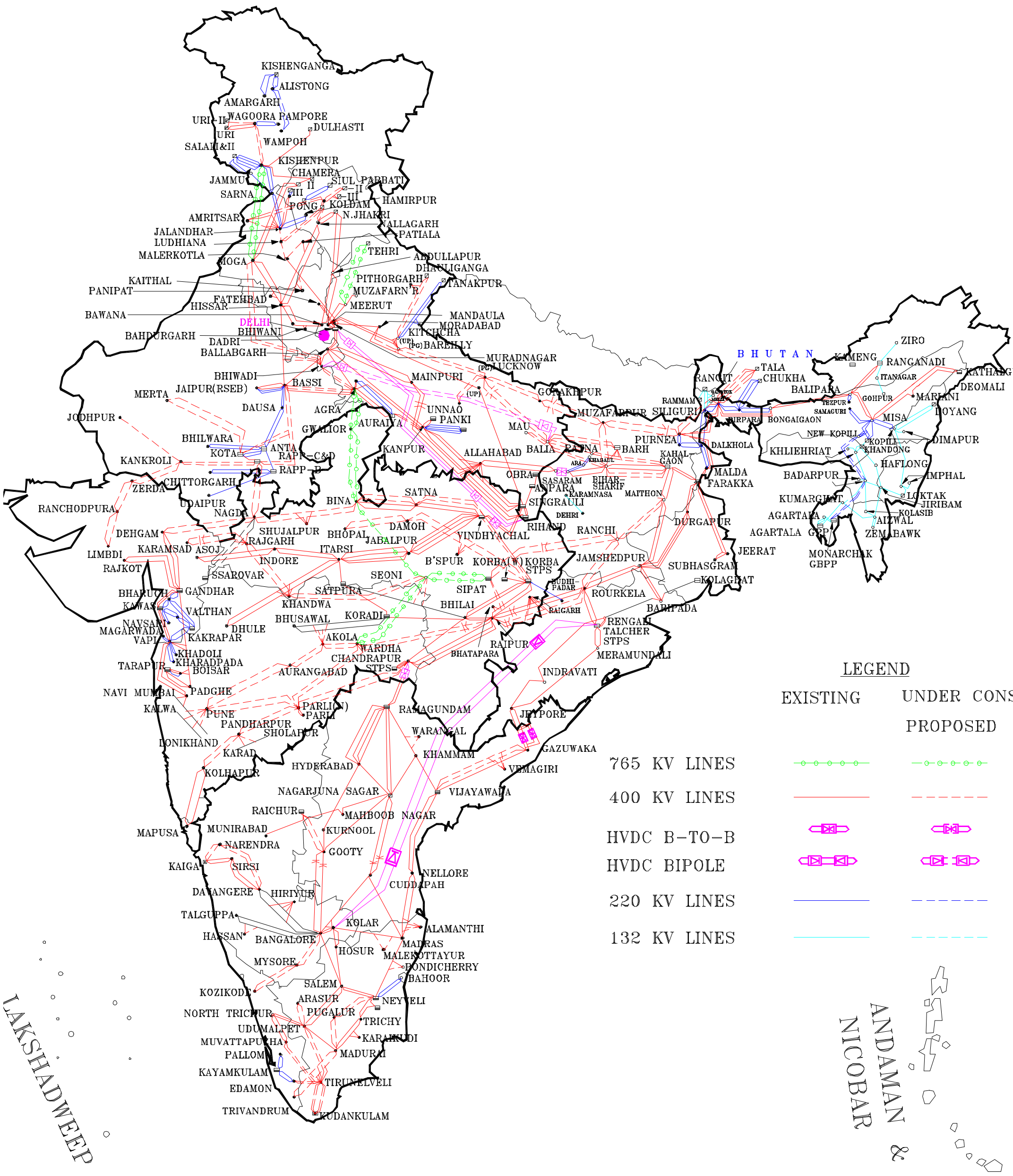


Figure 5.12: A power line map showing transmission lines of Power Grid Corporation of India

In India major energy resources are concentrated in a few pockets only. For example, major chunk of coal deposit, the primary generation resource in India, is confined to Eastern part, while hydro potential is located in North-eastern and upper Northern parts of the country. To meet the growing demand, development of large sized resource head generating stations and transfer of bulk power over long distances from the generation resources to the load centers across the country is required, which is not only capital intensive but has to satisfy other constraints like Right-of-Way (ROW), stringent regulatory requirement on environment and social aspects, flexibility to enhance the transfer capacity, uncertainty in generation projects, implementation in different phases etc.

A power line map showing transmission lines of the Central Transmission Utility "Power Grid Corporation of India" is shown in Figure 5.12. This carries more than 45% of total power generated in the country. It may however be mentioned that apart from network shown in fig 1, there also exists network owned by other utilities.

5.1.10. Series capacitor application

In India, the trunk 400kV transmission lines are quite long which restricts the power transfer capacity of the lines at their stability limit – much less than thermal capacity. Therefore, to ensure optimal development of transmission network, it is necessary to utilize the existing infrastructure to the maximum extent possible so that the cost of delivered power to the ultimate consumers would be at an affordable price. In this direction, series capacitor on EHV line plays a major role. The series compensation aims at compensating the inductive reactance thereby reducing effective electrical length of transmission lines.

Therefore, the series capacitors are beneficial where:

- Transmission lines are long and having enough thermal capacity to carry more power
- Parallel lines are available to support during contingencies

It is, however, important that all the parallel lines are required to be compensated to ensure balanced sharing of power.

5.1.11. Program for installation of series capacitors in Indian grid

Recognizing the utility of series compensation in Indian Context, a program has been chalked out for installation of series compensation at select transmission corridors with the following objectives:

- Enhance the transmission capacity of the existing transmission lines where constraints are being faced in evacuation of power, at minimum investment and time
- To plan high capacity lines with series capacitors in the new corridors where more generating projects in future are expected to come.

Further Thyristor Controlled Series Capacitors (TCSC) are also being applied in case of two different networks connected by weak inter-area links (less number of transmission lines). TCSC helps to damp active power oscillations (inter-area mode) caused by any disturbances to the area and maintain system stability.

As discussed earlier, application of series capacitor is beneficial for long lines where power transfer capacity is restricted by the stability limit and application of series compensation enhances the line loadability towards thermal limit. This ensures optimal utilization of transmission assets. At the same time, it is necessary to ensure that in the event of outage of compensated line, capacity of parallel lines in the same corridor should be sufficient to cater to the outage with reliability and security. Hence, based on the network configuration and power transfer requirement, extensive load flow studies need to be carried out for identifying the candidate line for series compensation.

Further, the degree of compensation, which is defined as the ratio of capacitive reactance and line inductive reactance, is a very important design parameter and should be selected judiciously. Following aspects are considered in selection of degree of compensation:

- Improvement in static and transient stability in normal as well as contingent conditions
- Power flow on the compensated line does not increase to unsatisfactory level
- Possibility of sub-synchronous resonance should be checked for
- In case of variable compensation, the compensation range is to be decided in such a way that maximum limit is effectively utilized to damp out inter-area oscillations

Following are the details of existing as well as planned series compensation installations in India.

Table 5.4: List of existing Series Compensated lines (220kV and above voltage level)

Sl No.	**Name of the line**	**Compensation degree (%)**	**SC location**
1.	Muzaffarpur – Gorakhpur 400kV D/c	40% fixed + 5-15% TCSC	Gorakhpur
2.	Purnea – Muzaffarpur 400kV D/c	40% fixed + 5-15% TCSC	Purnea
3.	Panki – Muradnagar 400kV S/c	40% fixed	Muradnagar
4.	Kanpur – Ballabgarh 400kV S/c	27% fixed + 8-20% TCSC	Ballabgarh
5.	Rourkela- Raipur 400kV D/c	40% fixed+ 5-15% TCSC	Raipur
6.	Nagarjuna Sagar – Cuddapah 400kV 2xS/c	40% fixed	Cuddapah
7.	Gooty – Bangalore 400kV 2xS/c	40% fixed	Gooty
8.	Rengali- Indravati 400kV S/c	40% fixed	Rengali
9.	Pampore – Kishenpur 220kV D/c	40% fixed	Kishenpur
10.	Gwalior – Bina 220kV D/c	45% fixed	Pichhore
11.	Karad – Miraj 220kV	70% fixed	Miraj
12.	Itarsi- Burwaha 220kV D/c	45% fixed	Handia
13.	Bableshwar – Aurangabad 220kV D/c	60% fixed	Aurangabad

Table 5.5: List of future Series Compensated lines (220kV and above voltage level)

Sl No.	Name of the line	Degree of compensation (%)	Series capacitor location
1.	Allahabad – Mainpuri 400kV D/c	40% fixed	Mainpuri

Sl No.	Name of the line	Degree of compensation (%)	Series capacitor location
2.	Balia – Lucknow 400kV D/c	40% fixed	Lucknow
3.	Anpara – Unnao 400kV S/c	30% fixed	Unnao
4.	Unnao – Bareily 400kV D/c	45% fixed	Bareily
5.	Gorakhpur – Lucknow 400kV D/c	30% fixed	Lucknow
6.	Bareily – Mandaula 400kV D/c	30% fixed	Bareily
7.	Raigarh - Raipur 400kV D/c	40% fixed	Raipur
8.	Seoni- Khandwa 400kV D/c	40% fixed	Khandwa
9.	Raipur – Wardha 400kV D/c	25% fixed	Wardha
10.	Rajgarh – Karamsad 400kV D/c	25% fixed	Rajgarh
11.	Ranchi-Sipat 400kV D/c	40% fixed	Ranchi
12.	Jeypore – Gazuwaka 400kV D/c	50% fixed	Jeypore
13.	Meramundali – Jeypore 400kV S/c	40% fixed	Jeypore

5.1.12. Studies for checking suitability of line protections for series compensated and adjacent lines

Distance protection schemes are quite widely used in Indian Power System. Some faults in the power system may cause voltage inversion at certain locations and the normal distance protection at such locations will have difficulties to determine correct directionality to the fault point. In such cases distance protection having special directional functionality to handle voltage inversion will have to be used. Therefore, the effect of series compensation along with its MOV, during fault conditions and its effect on line protection need to be studied in each case, both for the line being compensated as well as for adjacent sections. For this purpose, present practice followed in India is to conduct project specific testing on line protection equipment by modeling the system using EMTP generated files. Faults are simulated at different locations on the line being compensated as well as on adjacent lines and the busbar(s) and voltage and current waveforms are obtained at different relay locations, which are of interest. These are fed to relays using suitable test equipment and performance of relays is analyzed.

It may be recognized that while for new lines, relays suitable for series compensated lines can be provided upfront in compensated and adjacent sections as per requirement, in case of addition of series compensation on existing lines, some of the existing distance relays may need to be replaced and protection schemes may have to be modified. It is, therefore, important that protection studies are carried out in the beginning by the utility itself when series compensation is being planned in order to identify any need for replacements and modifications and likely expenditure is budgeted for and activities are planned accordingly.

Recent development of series compensation in Saudi Arabia

In Saudi Arabia, Saudi Electricity Company – SEC is responsible for generating, transmitting and distributing the electricity to the entire country that has an area of about 2 million km^2. The country is operationally divided in to four electrical regions: Central, Eastern, Western and Southern as seen in Figure 5.13. The two power systems in Eastern and Central Regions are presently interconnected via two series compensated 380 kV double circuit lines and one 230 kV line. Due to availability of generation on the eastern coast, connections are used to transfer power from Eastern Region towards Central Region and the power flow is mostly passing thru the 380 kV circuits with stability limit of about 2600 MW under double contingency criteria with series capacitors. Installation of series compensation was found to be the optimal solution to increase the power flow from Eastern to Central region by about 500 MW.

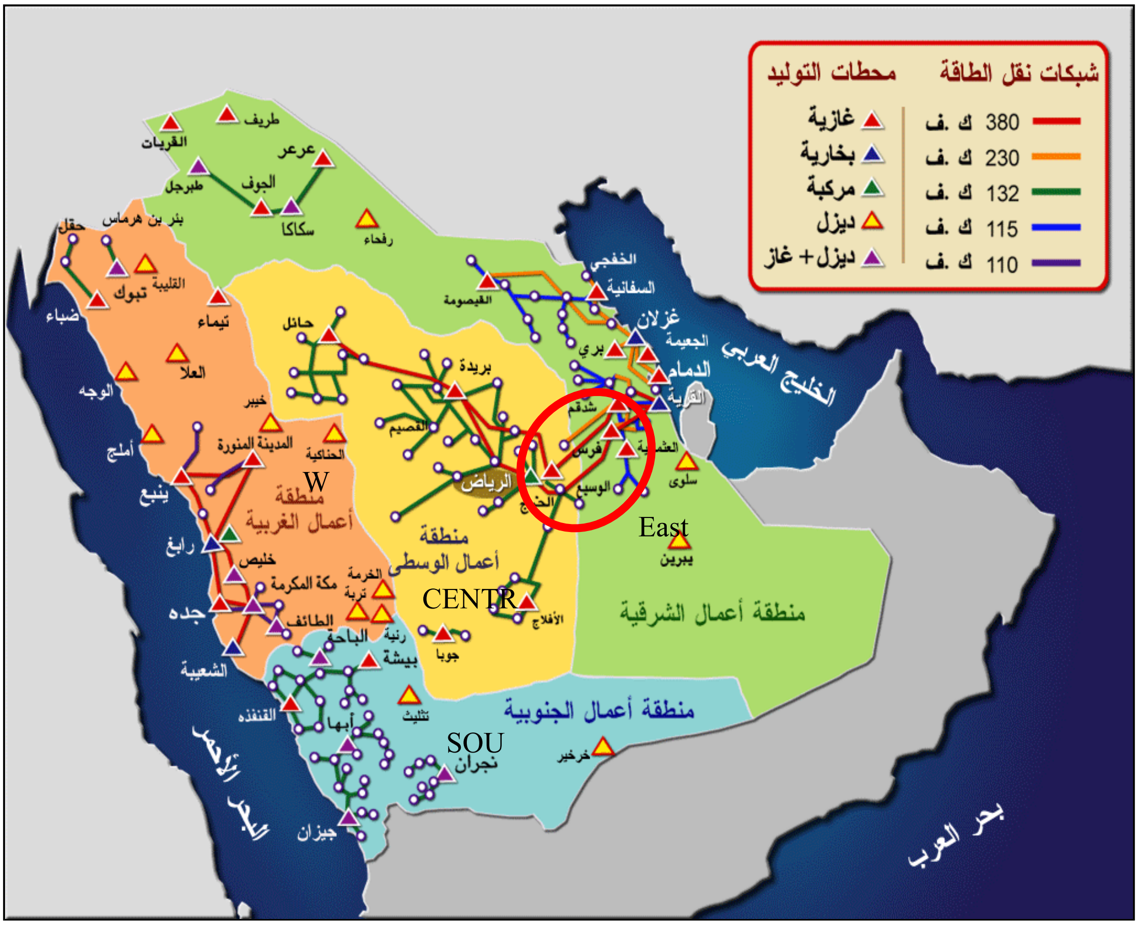


Figure 5.13: Transmission network in Saudi Arabia

5.1.13. East-Central compensated tie lines

The project started on January 2003 and the first Fixed Series Capacitors (FSC) has been energized on early May 2005 followed by rest of the circuits. The first tie line is 313 km from Shedgum to Riyadh (see Figure 5.14), and the second tie line is 265 km from Faras to Al-Kharj. Both tie lines are double circuit and at 380 kV voltage level.

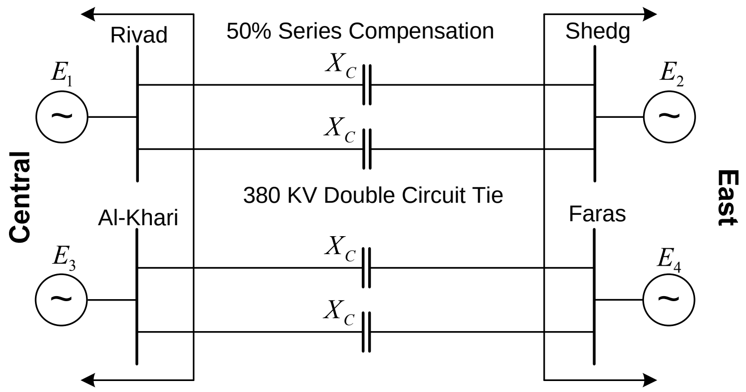


Figure 5.14: East – Central tie lines

The detailed single line diagram of the series capacitor bank installed in SEC system is shown in Figure 5.15. For more detailed configuration information reader might refer to chapter: "Survey Results of Questionnaire".

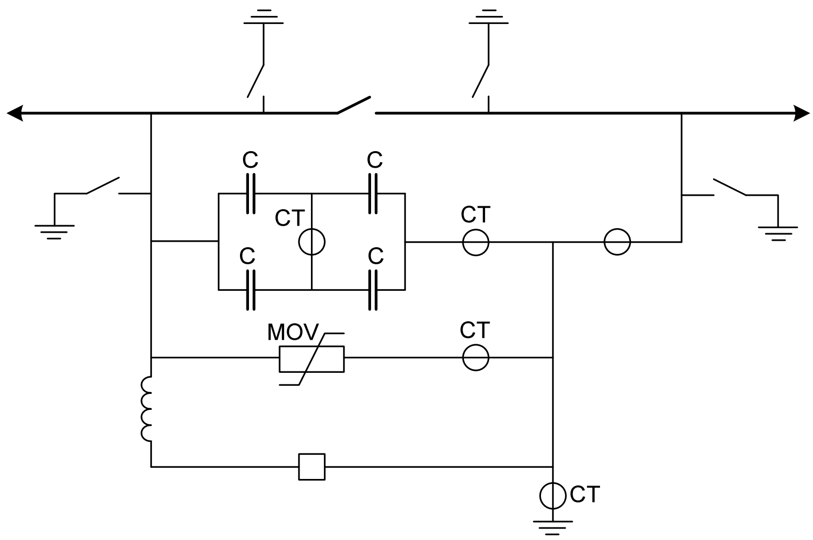


Figure 5.15: Layout of the series capacitor bank

5.1.14. Conducted studies on the East-Central series compensation project

Whenever new equipment is to be installed on a transmission system, simulation studies are usually required to determine the effects of the new equipment to the power system.

Several simulation studies have been carried out to see the impact of the series capacitor on SEC system. The studies are listed below:

- Lighting study
- Switching study
- Temporary Over-voltage study
- Transient Recovery Voltage on the line circuit breakers study
- Subsynchronous Resonance study
- Unbalance investigation
- Harmonic impedance simulation, and
- Investigation of protection system on series compensated lines.

5.1.15. Control and protection

5.1.15.1 Series Capacitor Protection

For series capacitors two sets of integrated control and protection system, using digital technology, have been installed for each circuit. The systems have been installed, commissioned, and put in service without any problems reported. For more information about the control and protection functions integrated with the system refer to chapter: "Survey Results of Questionnaire".

5.1.15.2 Compensated Lines Protection

Two sets of discrete protective numerical relays are used for line protection. Each relay set consist of the following:

- Set 1: Distance and Longitudinal Differential
- Set 2: Same as set 1 but from different manufacturer

Each relay set is from different manufacturer to avoid malfunction of relays of the same make. All relays have been installed, commissioned, and put in service without problems reported.

5.1.15.3 Fault Locator

High frequency-based "traveling waves" fault locator device is installed and commissioned at the compensated lines.

5.1.16. Distance protection settings

The FSC (50%) have been provided at the mid of the 380KV D/C lines. Overcurrent protection for the capacitors has been provided by MOV and a bypass switch. The series compensated lines with the adjacent 380KV lines from both line ends are shown in Fig.4.

The distance protection of the series compensated lines is with memory voltages for directional decision at both ends. The existing protection on the adjacent transmission lines comprised of the following types:

- Two sets of static distance relays
- Directional Comparison Earth Fault relay
- Directional time delay earth fault relay.

5.1.16.1 Zones' reaches

The distance protection zones from one end at Faras 380KV S/S is shown in Figure 5.17. Same setting is applied at the other ends in addition to other protection schemes such as Switch On To Fault (SOTF), Weak End Infeed (WEI), and current reversal with DEF & Distance.

- *Zone 1*: (65% of X_{L1}) or (32.5% of [X_{L1}+X_{L2}]) with no time delay. X_{L1} and X_{L2} are line reactances on each side of centrally installed series capacitor, see Figure 5.17.
- *Zone 2*: 150% of [X_{L1}+X_{L2}] set for trip and carrier with time delay of 0.65 sec. Permissive Over Reach is applied with zone 2.
- *Zone 3*: 240% of [X_{L1}+X_{L2}] with time delay of 0.65 sec. It is also used for the SOTF scheme.
- *Zone 4*: 80% of [X_{L1}+X_{L2}] reverse direction, not used for trip, and used for the distance protection current reversal logic.
- *Zone 5*: Not used..

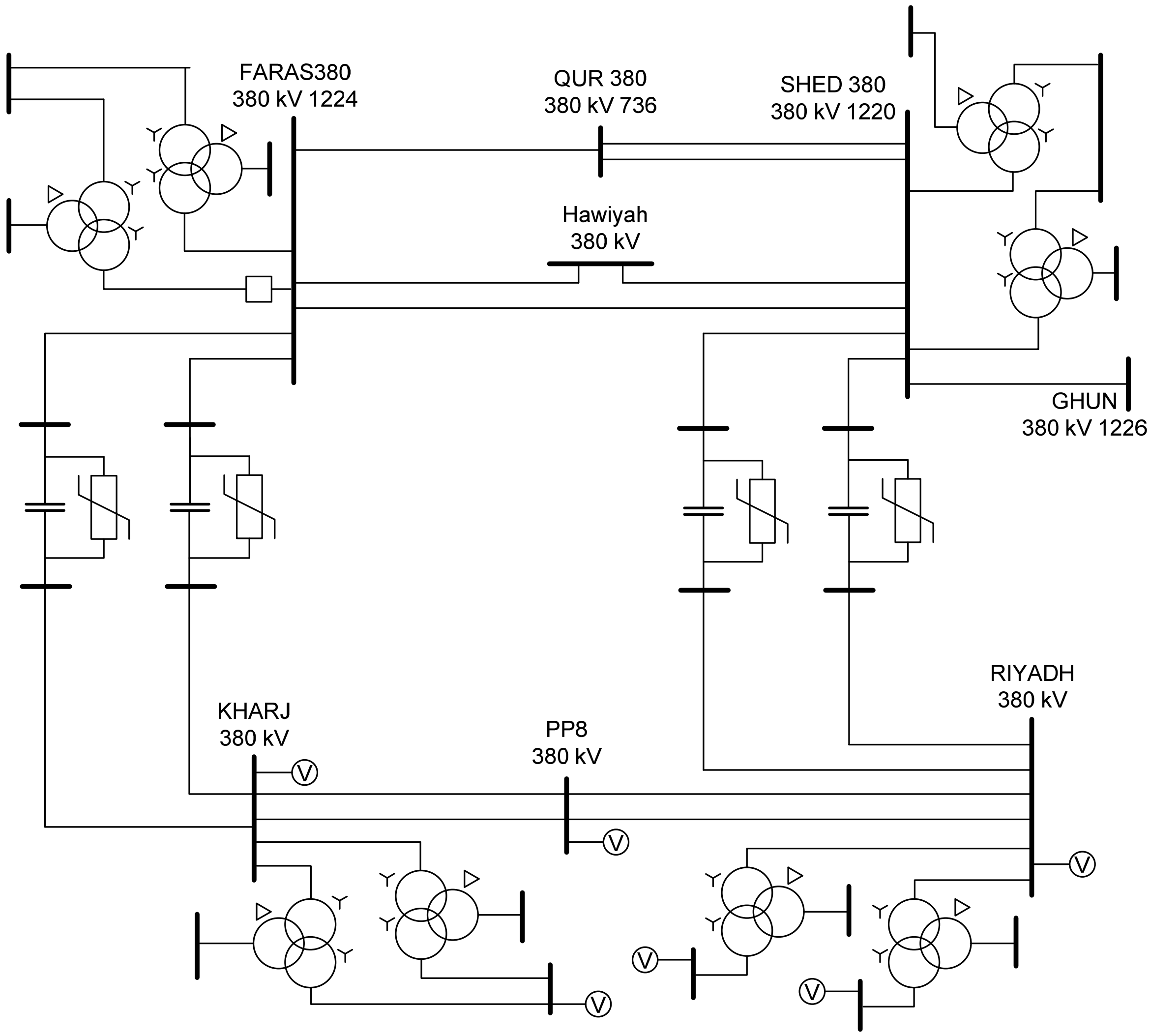


Figure 5.16: 380kV transmission network adjacent to the series compensated lines

DCEF: Directional Comparison Earth Fault protection as a built in feature in the distance relay is applied. No time delay overcurrent phase or earth functions are applied.

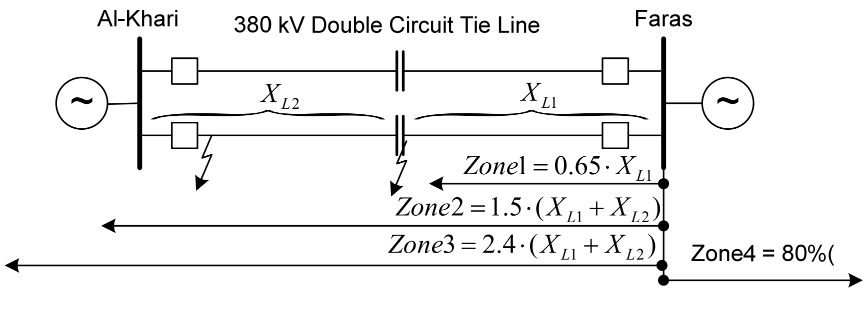


Figure 5.17: Reaches of distance protection zones

The phase and ground setting zones in quadrilateral characteristics are shown in Figure 5.18. The locus of Ph-Ph fault seen by relay at (A) along the first line section up to point (1) with 1% increment is shown in the left side of Figure 5.18, whereas on the right side of Figure 5.18shows the same fault locus but at the second section of the line and with 1% increment. The phase measuring element's locus is the one shown inside the characteristic of zone-1 operation while the others measuring elements' locus is out side.

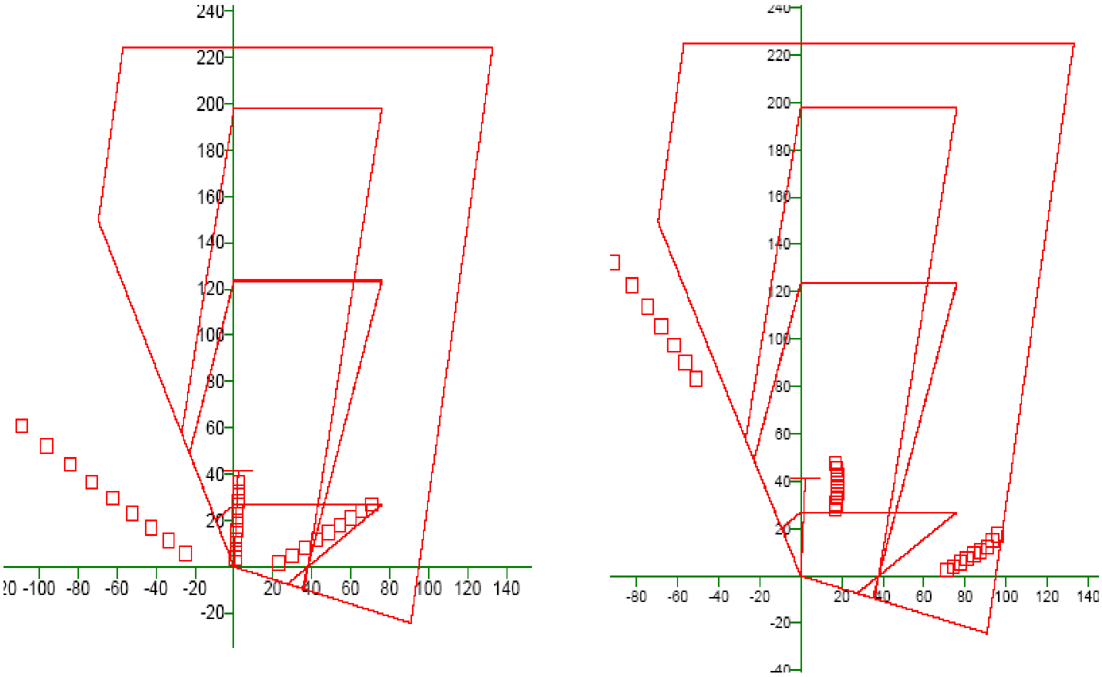


Figure 5.18: Phase-phase (left) and Phase-Earth (right) operating characteristics with apparent fault impedances

5.1.17. Transient recovery voltage (TRV) issue

Due to the installation of Series Capacitors (SCs) in the tie lines with existing CBs at both line ends, the Transient Recovery Voltage (TRV) capabilities of the existing breakers at Eastern side (Faras & Shedgum) raise above the capabilities of these existing breakers.

The problem is that the line breakers at the Central side of the line can open in 38 ms and at the Eastern side 34 ms, while the longest time for the FSC to bypass is 46 ms. This implies that line breakers can open before the FSC bypasses, resulting in high TRV stresses on the line breakers

The matter was explored through several studies that show FSC increases the TRV stress on the existing line breakers. This additional stress by FSC incase of faults will be eliminated if the FSC is bypassed before line breakers open. Hence, it is decided to send a trip signal from the line protection to close the bypass switch of SC before tripping the line breakers which leads to delaying in the line trip by about 14 ms until the bypass switch closed. Details of engineering requirements to implement the scheme were done along with the communication channel on Protection Signaling Equipment (PSE).

Further investigation of the TRV problem if the bypass switch failed to close, indicates that using different delay times at each end of the line does not reduce the TRV stress in case of *3-phase faults*. However, the results did show a reduction in TRV stress for *phase-to-phase-to-ground and phase-to-ground faults* when protection time delay is used on both side of the line.

In our case it was recommended that the line trip action delay the line breakers by 14 ms until the bypass switch of the FSC has closed, be applied. The differential line protection will detect the fault at the same time while the impedance protection will detect the fault at different times depending upon the location of the fault on the line. The line protection that detects the fault first should send a bypass signal to the FSC and delay its signal to the line breakers. This will ensure that the bypass breaker always bypass before the line breakers open and minimize the TRV stress on the line breakers.

With the implemented recommended solutions, the possibility for the FSC not to bypass before the line breakers open is extremely small, as this will only happen when the bypass switch fails to close. In addition to the failure of the bypass switch the fault must occur at the right position on the line, as well as at the right point on the voltage wave, further more the line breakers must open at the right instance in time to create the excessive TRV stress on the line breakers. The average values from the simulation results where the FSC does not bypass are within the line breaker TRV capability. It can therefore be assumed that the possibility of damaging the line breakers due to a TRV is negligibly small.

5.1.18. 2010 Eastern -Central Series Compensation Project

Because of the availability of water in the Eastern Region (located on the Arabian Gulf), it is economical to build large power plants (combined cycle or steam) in East and transfer the power to Central (of course in addition to Central generation expansion plans). SEC is planning to construct a 415 km 380kV double circuit line by year 2010 proposed from Fadhili in Eastern Region to Sudair in the Central Region. A new intermediate switching station, Shumlul, located near the Shumlul village is to be built in the middle of the line. The new 380 kV East-Central tie lines will be 50% Fixed series compensated with the series capacitor located at Shumlul switching station, as shown in Figure 5.19.

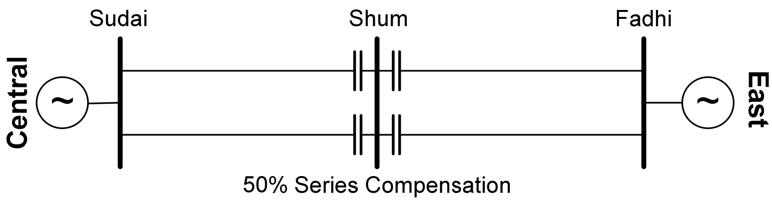


Figure 5.19: Year 2010 planned additional series compensated Eastern – Central tie lines

Table 5.6: Protection scheme information

No.	Line	Compensation degree	Compensation type	Implementation date
1	Shedgum- Riyadh 380kV D/c	50 %	MSSC*	2005
2	Faras-Al.Kharj 380kV D/c	50 %	MSSC*	2005
3	Fadhili-Sudair 380kV D/c	50 %	MSSC*	2010

* Mechanically Switched Series Compensation

6. SURVEY RESULTS OF QUESTIONNNAIRE

Introduction

6.1.1. General

This chapter is based on the survey conducted by the working group B5-10 to investigate the situation in the protection, control, and monitoring of series compensated networks.

The Working Group received responses from 12 participants from 12 countries. These are listed below.

Brazil (BR):	CHESF
Canada (CA):	Manitoba Hydro
Colombia (CO):	Interconexion Electricia S.A. ESP-ISA
France (FR):	RTE
Greece (GR):	Public Power Corporation
Korea (KR):	Korea electric Power Research Institute
Norway (NO):	Statnett SF
India (IN):	Power Grid Corporation of India Ltd
Saudi Arabia (GS):	Saudi Electricity Company
Sweden (SE):	Svenska Kraftnat
South Africa (ZA):	ESKOM Transmission
USA (US):	Pacific Gas and Electric Co

The objective of the survey was to get some details of the following:

- Existing SC lines, installations, trends in the future and issues confronting the technology.
- Reasons for refurbishment and trends
- Control and protection equipment used in SC lines and capacitors
- Special issues concerning distance protections which are predominantly used as line protection

6.1.2. Highlights of survey

Some highlights of the findings from the survey are described below.

6.1.2.1 <u>Existing SC lines, installations, trends in the future and issues confronting the technology.</u>

Series compensation is used only in few of the countries. The reasons for its usage are given below.

- To avoid voltage collapse and to improve quality of supply
- To increase stability limits
- To optimize load distribution
- To transmit more power

In some countries that considered Series Compensation, fears of sub-synchronous resonance were a deterrent. Out of the countries that use SC only a few foresee more lines being equipped with SC in future.

TCSC is used in very few countries. The reasons for its usage are:

- Power Oscillation detection
- Sub-synchronous resonance
- Load flow control

Use of MOVs across SC is a norm. Older installations that were using spark gaps are either replaced with MOVs or are in the process of being replaced.

In some of the countries non-conventional CTs and VTs are used in series capacitor banks.

Directional discrimination of distance relays both in the protected line and in adjacent lines is one of the main problems with regard to line protection. Project specific testing using either EMTP files or real time simulators is done by all the utilities before going in for SC installations to find out adjacent line protections that need to be replaced. While modeling the network for this purpose most countries use only a part of the network.

Current inversion is also one of the problems foreseen by some utilities. Few of them plan to take care of it by selecting suitable protection whereas one utility has reported that in a particular case, this was a reason for not taking up SC installation to avoid costs involved in replacing the protections in adjacent lines.

1.1.2.2 Reasons for refurbishment and trends

Countries that are using SC for a long time are either refurbishing or have plans for refurbishment of HV equipment and secondary equipment. The main reasons for refurbishment are:

- New technology
- Obsolescence, difficulty in getting spare parts
- Environmental concerns with respect to old capacitors containing PCBs

6.1.2.3 Control and protection equipment used in SC lines and capacitors

- Use of duplicated line protection is common. Distance/ Distance and Distance/ Directional comparison protection are the normal combinations used. One country has reported use of Distance / Line differential protection. Most countries now use numerical line protections except for few who still are continuing with static type of line protections.
- In most cases directional or non directional IDMT earth fault relay based on residual current is used for high resistive faults. Use of negative sequence current based directional earth fault relay is also reported by one country. Control/ Monitoring equipment used for lines and banks use both discreet devices and in recent times digital integrated devices.
- Bank protection is duplicated in most cases although single protection exists too (mostly in older installations).
- In most countries bank protection is mounted on the ground. Mounting of these on capacitor bank is also reported by one country.
- Bypassing of capacitor bank is done mostly on a three phase basis. In some cases it is also done on a single phase basis.

6.1.2.4 Special issues concerning distance protection which are predominantly used as line protection

- Zone 1 is set usually at 80% of difference between line and capacitor impedance. Some set even lower. Some do not use Zone 1 at all.
- Zone 2 is set to 120 % of uncompensated line impedance by most countries. In some countries it is set up to 150% of uncompensated line impedance.
- Phase locked voltage memory is used to cope with the voltage inversion. Some countries use an intentional time delay to overcome directionality problems related to voltage inversion.

- Most of the countries carry out system studies or EMTP generated files to find out the impact on protections provided in adjacent lines. Often these studies reveal that some of the protections on the adjacent lines need to be replaced.
- MOVs have impact on settings. Increased resistive reach is required. One country has reported that since protection operates before MOV conducts, extra reach is not required.
- Zero sequence current compensation from parallel lines is not used for distance protection by any of the countries.
- Gap flashover is expected for faults in the protected series compensated line even for faults with resistance ranging from 4-50 ohms.
- Due to unsymmetrical gap flashover no major problems have been faced by any country. One country has stated that the settings had to be revised due to this.
- One country has reported problems due to subharmonic oscillations, which was addressed by reducing zone 1 setting and in some places disabling it completely.
- Only country has reported problems due to high frequency transients that was overcome by providing negative sequence current supervision. All others have not reported any problems due to these.
- Use of phase comparison relay is not common except in US. These are of static segregated type which they plan to replace.

General Questions

The objective of this section is to give an idea of the existing installations of series compensated lines, both Fixed and Thyristor controlled types, the likely trends in the future and the issues confronting this technology. The summary of the responses received to various questions is given below.

Q: Do you use series capacitors in your power system? If no, are you planning to introduce series compensation in future?

BR, CA, CO, IN, NO, GS, SE, ZA, US use series capacitors. FR and GR do not have them at present and there are no plans to introduce them in the near future. KR does not use series capacitor, but has installed UPFC.

Q: Are there any reasons that deter the use of series compensation?

FR does not require it considering present needs of the network. If in future increased power transfer capacity is required then construction of new lines or upgrade of existing lines is the preferred solution. KR uses UPFC for power flow control. In ZA at times sub-synchronous resonance has deterred the use of series compensation. In NO both sub-synchronous resonance and protection issues deter the use of series compensation.

Q: If series capacitors are used in the power system what are the reasons?

The reasons vary from country to country; see Table 6.10 below.

Table 6.1: Reasons for using series compensation in different countries

	BR	CA	CO	IN	NO	GS	SE	ZA	US
To avoid voltage collapse				X			X	X	X
To increase transient stability			X	X		X	X	X	X

	BR	CA	CO	IN	NO	GS	SE	ZA	US
To optimize load distribution			X	X	X		X		
To improve quality of supply	X							X	X
To increase power transfer capability						X		X	X

Q: Do you see more lines being equipped with series capacitors?

BR, CA, CO do not foresee any new lines being equipped with Series Capacitors.

IN, NO, GS, SE and ZA foresee more lines being equipped with Series Capacitors.

Q: Do you use series compensation in shorter lines in order to improve the load distribution?

Only NO uses series compensation in shorter lines to improve load distribution.

Q: Do you use thyristor controlled series compensation (TCSC) in your system? If YES, what are the reasons?

IN, SE, and US use TCSC. The reasons for its usage are as follows:

- Power oscillation detection: IN, US
- Sub-synchronous resonance: SE
- Load flow control: US

In US apart from the reasons given above, MOV requirements to withstand high short circuit current values for series capacitor installations is another reason.

Q: Do you use non-conventional CTs and VTs on series capacitor banks?

IN, GS, SE use non-conventional CTs and VTs on series capacitor banks. BR, CA, CO, NO and ZA have not used them so far.

Q: Did you change your plan to install series capacitors in the past due to some reasons and choose another alternative?

In one particular case ZA has changed plans to install series capacitor due to too high costs involved in replacing adjacent line protections.

Q: If spark gap technology is used is there any plan to change over to metal oxide varistor (MOV) or a combination of spark gap and MOV?

BR, CA, CO, NO, GS, SE have been using MOV or combination of spark gap and MOV from the beginning. In IN on all 400 kV lines this is being used from the beginning. ZA has used spark gap technology but is replacing them with MOV when refurbishment is taken up.

Q: Have you experienced any problems with the protection of series compensated lines? If YES, what are the main issues detected?

BR, CO, IN, NO, GS have replied that they have not experienced any problems. CA, SE have faced cases of false operation, IN has faced problems related to directional discrimination and in ZA low success rate of autoreclosing is one of the problems faced by them. US have experienced problems of directional discrimination, current inversion and false operation.

Q: Do you use different setting groups (adaptive) for line protection to better adjust to system conditions?

CA, IN, NO, GS and ZA do not use different setting groups. BR uses different setting groups to better adjust to system conditions. SE is considering implementing it. US use different setting groups.

This also depends on the type of line protection, number of segments, and location of series capacitor viz: at the end of the line or in the middle.

Q: Do you conduct project specific testing on line protection equipment? If YES, who executes it?

All the countries that are using series capacitors conduct project specific testing on line protection equipment. The details of the agency that carries out the testing are given in Table 6.2 below.

Table 6.2: Project specific testing

	BR	CA	CO	IN	NO	GS	SE	ZA	US
Independent laboratory				X			X		
Utility representative	X							X	X
Equipment manufacturer	X	X	X	X		X		X	
Independent consultant									
Others		*)	*)	*)	*)				*)

*) Ourselves

Q: If YES, how do you model the system? In a real time simulator or use EMTP or similar generated files for carrying out testing?

SE uses real time simulators.

ZA carries out comprehensive testing of the standard relay product on a power system simulator and the tests include series compensated line cases.

CO, IN, NO, GS, US use EMTP or similar generated files for off line testing.

BR and CA use real time simulator as well as EMTP or similar generated files.

Q: If you are modeling the system, do you model: the whole network, just the series compensated line, part of the network around series compensated line or any other?

All the countries use network modeling for conducting studies. All the countries except US use only a part of the network for modeling. US use the whole network for modeling.

Q: Do you conduct studies to check influence of introducing series capacitor on the behavior of existing protection in adjacent lines?

All the countries that are using series capacitors conduct studies to check influence of introducing series capacitor on the behavior of existing protections in adjacent lines. US also perform open and closed loop tests on adjacent lines for series capacitor installations that have the capacitor placed at the line end and lines that are heavily compensated.

Q: Do you foresee any cases of current inversions in your system particularly when expansion in the system takes place? If YES, what precautions you have taken to take care of the phenomenon?

SE and GS foresee cases of current inversions in their system when expansion in the system takes place. They plan to take care of it by selecting suitable protection.

ZA foresees cases of current inversion when system expansion is taken up. And this is the reason series compensation is not pursued in a particular case due to large costs associated with having to replace adjacent line protection equipment.

US too anticipate this due to unforeseen expansion or system changes and plan to take care of it by selection of suitable protection.

BR, CA, CO and NO do not foresee cases of current inversions in their system.

Refurbishment of series compensation installations

There are many old installations of series compensated lines, which are now due for refurbishment for a number of reasons. The objective of this section is to give an idea of the reasons for refurbishment and the trend. Summary of the responses received to various questions is given below.

Q: Do you have any plans to refurbish some of the old series compensated installations?

CA, SE and ZA have plans to refurbish some of the old installations. In BR, CO, IN, NO and GS the series capacitors have been in use only recently and therefore refurbishment is not in the plan now

Q: If yes, what are the main reasons?

The reasons for refurbishing in CA, SE and ZA are given in Table 6.3 below.

Table 6.3: Reasons for refurbishment of series capacitors

	CA	**SE**	**ZA**
Changed compensation factor *)			X
New technology	X		
Environmental concerns Replacing capacitors containing PCB)		X	X
Obsolescence	X		
Others			

*) Increased Mvar transfer capability

Q: What is the extent of the refurbishments planned?

The details of refurbishments planned by CA, SE and ZA both for the primary equipment and for secondary equipment are given in Table 6.4 and Table 6.5 below.

Table 6.4: Refurbishment planned for primary equipment

	CA	**SE**	**ZA**
Circuit breakers			X
Spark gaps			X
Capacitor banks		X	X
Thyristors			
MOVs		X	
Others			*)

*) Completely new bank with primary equipment

Table 6.5: Refurbishments planned on secondary equipment

	CA	**SE**	**ZA**
Protection equipment on capacitor banks			X
Control and monitoring equipment on capacitor banks			X
Line protection equipment			

	CA	SE	ZA
Communication equipment	X		X
Line control and monitoring equipment			
Other			*)

*) Turnkey project. Complete system supplied by the contractor.

Q: Reasons for refurbishment of line or bank protection:

ZA has stated that the reason is refurbishment of series capacitor itself as well as modernization of secondary system.

Specific details on Protection of Series compensated installations

The objective of this section is to get some details of the control & protection equipment used in the series compensated networks (lines and capacitor banks) by different utilities. The details given in this section are with reference to a selected line in the respondent country and can be considered as the representative ones.

The Table 6.6 below gives some data pertaining to these series compensated transmission lines and capacitor installations. Some details of line configuration, series capacitor bank configuration and major components used are given in Annexure 1.

Table 6.6: Details of SC lines and capacitor banks installations

	Voltage [kV]	Length [km]	Max. power [MW]	Comp. degree [%]	Location [%]
BR	500	234	-	70	0
CA	500	537	1800	45	42
CO	-	-	-	-	-
IN	400	412	1000	FSC, TCSC	0
NO	300	84.7	2000	40	0
GS	380	313	728	50	50
SE	400	507	-	-	74
ZA	400	406	1180	58	50
US	500	151	-	-	0 *)

*) At both line ends

Summary of the replies received from various questions is given below.

Q: What is the operating principle of primary (Main 1) line protection and the technology used for it?

Detail of Main1 protection used in various countries are presented in Table 6.7 below.

Table 6.7: Primary line protection used

	BR	CA	CO	IN	NO	GS	SE	ZA	US
Distance protection	X	X	X	X	X	X	X	X	X
Phase comparison protection									
Line current differential protection						X			
Directional comparison protection					X				

	BR	CA	CO	IN	NO	GS	SE	ZA	US
Technology used	NM	NM	NM	NM	ST	NM	EM	NM	NM

NM…numerical ST…static EM…electromechanical

In CA unblock communication scheme over power line carrier supplemented with a direct transfer trip over PLC system is used.

Q: What is the operating principle of secondary (Main 2) line protection and the technology used.

Details of Main 2 protection used in various countries are given in Table 6.8 below.

Table 6.8: Secondary line protection used

	BR	CA	CO	IN	NO	GS	SE	ZA	US
Distance protection	X			X	X	X		X	
Phase comparison protection									
Line current differential protection						X			
Directional comparison protection		X	X		X		X		X
Technology used	NM	NM	NM	NM	ST	NM	ST	NM	NM

NM…numerical ST…static EM…electromechanical

In CA overreach transfer trip over microwave channel supplemented with a direct transfer trip over microwave is used.

Q: Do you also use a separate earth fault function together with the main line protection to detect high resistance faults? If YES, what kind of scheme do you use? What is the operating principle based on (residual or negative sequence current)?

Details of the earth fault protection used for detection of high resistive faults are presented in Table 6.9 below.

Table 6.9: Earth fault protection used for detection of high resistive faults

	BR	CA	CO	IN	NO	GS	SE	ZA	US
Separate earth fault protection used	Yes	No	Yes	Yes	Yes	No	Yes	Yes	Yes
Non-directional O/C unit with IDMT delay					X		X	X	
Directional O/C unit with IDMT delay	X		X	X					
Directional comparison									X

In all the countries that use directional or non directional O/C relays , they are based on residual current principle. US have stated that they use both residual current and negative sequence current based relays.

Q: Does the control and monitoring equipment used for series compensated lines comprise: discreet devices or integrated one using numerical technology?

CA, IN, NO, GS, SE, US use discreet devices.

BR, CO, ZA use integrated one using numerical technology.

Q: Does the control and monitoring equipment used for series capacitor banks comprise: discreet devices or integrated one using numerical technology?

CA, NO, SE use discreet devices. BR, CO, IN, GS, ZA, US use integrated one based on numerical technology.

Q: Is the control & protection equipment for the banks mounted on the: capacitor bank or on ground?

In all the countries except in CA the control and protection equipment is normally mounted on the ground. In CA the control and protection equipment is mounted on the capacitor bank platform.

Q: The following are some of the protection functions normally provided for fixed capacitor banks. Indicate the ones applicable to your installations. If duplicated, please mention this. Please indicate also which of them are used for temporary and which for permanent bypass.

The tables given below contain details of protection function used in fixed capacitor banks. CA, CO, NO and SE have been using in their systems single protection while BR, IN, GS, ZA and US use duplicated protection.

Table 6.10: Basic protection used on capacitor banks

	BR	CA	CO	IN	NO	GS	SE	ZA	US
Capacitor unbalance protection	X	X	X	X	X	X	X	X	X
Bypass gap protection	X	X	X		X		X	X	X
Platform flashover protection		X	X	X	X	X	X	X	X
Bypass circuit breaker failure prot.	X	X	X	X	X	X	X	X	X
Line current monitoring	X	X	X	X	X	X		X	X

Note: CA also uses Loss of fibre optic signal and platform control failure

Table 6.11Additional protection used on capacitor banks

	BR	CA	CO	IN	NO	GS	SE	ZA	US
Capacitor overload protection	X	X		X	X	X	X	X	X
Sub-harmonic protection				X	X	X	X		X
Gap triggering circuit protection	X	X	X		X			X	X
Pole disagreement protection	X	X	X	X	X	X		X	X

Q: Protection of varistors

For the protection of varistors all the countries use varistor overload protection and varistor failure protection.

Q: Protections used for temporary bypass

Generally in all the countries the protection is used for permanent bypass of the capacitors except in SE and ZA who use only the Capacitor overload protection and Spark gap protection for temporary bypass.

Q: What is the bypassing method? Per phase or on three phase basis?

BR, CA, IN, NO, GS, SE and US carry out bypassing on three phase basis. In CO it is done on per phase basis. In ZA, both three phase and single phase bypassing is used.

Q: Describe the sequence used to reinsert the capacitor bank. Indicate also the technical parameters like specific times, etc.

Some of the details of sequences used in reinserting the capacitor banks are given below.

- BR: Capacitor is always reinserted following line reinsertion
- CA: There is no automatic insertion. It is done manually via remote control
- CO: In normal operation, system control opens the bypass circuit breaker and the series compensation is energized this way. This action can also be done manualy.
- IN: Series Capacitor is reinserted after a time delay of 1.5s provided minimum line current check is satisfied. The dead time for line auto reclose used is 1 s
- NO: Reinsertion time depends on the fault (Harmonics, overvoltage, overload etc) and varies from 10 s to 30 min.
- GS: Reinsertion is done after closing the line breaker with some time delay
- SE: Remote operation of bypass breaker
- ZA: Method 1: The MOVs are rated to withstand three consecutive faults. Re-insertion is permitted once the MOVs have cooled down sufficiently (MOV energy monitored). Method 2: The health of the line voltage is checked before allowing re-insertion, in combination with the MOV having cooled down sufficiently - whichever is the last to occur.
- US: Automatic insertion occurs after successful restoration of line by rapid reclosing. For lines having single phase trip, capacitors on all the three phases are bypassed. After successful auto reclosing and check of under voltage / over voltage conditions the series capacitors are reinserted.

Q: The following are some of the protection functions normally provided for thyristor controlled capacitor banks. Indicate the ones applicable to your installations. If duplicated, please mention this.

TCSC is used in IN, SE and US. Tables given below contain details of protection functions used in installations that have TCSC. SE and US have been using in their systems single protection while IN have used duplicated protection.

Table 6.12: Basic protection used on TCSC banks

	IN	**SE**	**US**
Capacitor unbalance protection	X	X	X
Bypass circuit breaker failure protection	X	X	X
Line current monitoring protection	X		X

Table 6.13: Additional protection used on TCSC banks

	IN	**SE**	**US**
Capacitor overload protection	X	X	X
Sub-harmonic protection	X		X
Pole disagreement protection	X	X	X

Table 6.14: Protection for varistors used on TCSC banks

	IN	SE	US
Varistor overload protection	X	X	X
Varistor failure protection	X	X	X

Table 6.15: Basic thyristor protection used on TCSC banks

	IN*)	SE	US
Thyristor valve overload protection	X	X	X
Thyristor monitoring system	X		X
Valve recovery overvoltage protection	X		X
Damping reactor overvoltage protection		X	X
Valve overvoltage protection	X	X	X

*) In addition to the above IN have used capacitor discharge function, back up protection, TCSC line current supervision, TCSC reactance limiting function, cap DC voltage protection, reactance error protection, reactance asymmetry protection, over/under frequency protection

Specific questions on line protection of SC lines

6.1.3. Questions related to distance protection

These questions pertain to some specific details when distance protection is used either as the primary or secondary protection.

Summary of the replies received from various questions is given below.

Q: What is the under reaching (Zone 1) setting used in teleprotection schemes

Summary of response from the respondent countries is given below.

Table 6.16: Distance protection Zone 1 reach settings

	Zone 1 reach [% of line length]	Rationale
BR	0	Overreach problems confirmed by testing with EMTP simulation.
CA	80	Manufacturer recommendation. Confirmed by testing with Comtrade files from EMTP simulation
CO	35	-
IN	80	- All lines are provided with series capacitor at one end - At capacitor end Z1 is set to 80% of line impedance. - At remote end (if single circuit line) Z1 is set to 80% difference between line impedance and capacitor impedance. Additionally a reduction factor for taking care of sub-harmonic oscillations without any time delay is used. - At remote end (if double circuit line) Z1 is set to 80% of line impedance and capacitor impedance. Additionally a reduction factor for taking care of sub-harmonic oscillations with 100ms time delay is used.
NO	80	80% of the difference between the line inductance and the capacitor reactance.
GS	40	Since line differential protection is provided to cover complete line and also POTT is used with Zone 2 which covers the whole line.
SE	85	85% of the difference between the line inductance and the capacitor

	Zone 1 reach [% of line length]	Rationale
		reactance
ZA	80	80% of the difference between the line inductance and the capacitor reactance (unless there is a need for further reduction to avoid overreaching due to resonance)
US	50	Lines are heavily compensated with multiple segments at each end of the line

Q: What is the overreaching (Zone 2) setting in used teleprotection schemes?

Details of Zone 2 setting used are given below.

Table 6.17: Distance protection Zone 2 reach settings

	Zone 1 reach [% of line length]	Rationale
BR	120	120% of uncompensated line impedance is used with POTT
CA	120	The value is typically 100% of the line positive sequence impedance + 50% of positive sequence impedance of the shortest line leaving the remote bus. Else 120% of the line so as to shorten the reach when the capacitors are in service.
CO	120	120% of uncompensated line impedance is used with POTT communication scheme
IN	120	120% of uncompensated line impedance is used with POTT communication scheme
NO	150	Normally 150% of uncompensated line impedance is used with POTT communication scheme. Can vary dependent on short circuit studies.
GS	120	120% of uncompensated line impedance is used with POTT communication scheme.
SE	150	150% of uncompensated line impedance is used with POTT communication scheme
ZA	120	As a percentage of uncompensated line impedance. Minimum 120% and as far as possible considering system limitations such as overreaching of remote end transformers, etc.
US	120	Lines are heavily compensated with multiple segments at each end

Q: What kinds of measurement techniques are used to cope with voltage inversion?

In all the countries phase locked memory is used to cope up with voltage inversion. Saudi Arabia has also informed that they use an intentional time delay.

Q: Have you conducted any system studies to find the impact of series compensation on the performance of protections installed on adjacent lines? If YES, was there any need to change the protection on adjacent lines after the introduction of series compensation? If YES, what criteria were used and how many line ends were affected?

In all the countries system studies are carried out to find the impact of series compensation on the performance of protection installed on adjacent lines.

The types of faults considered were: 3ph faults, 2ph to earth faults and 1ph to earth faults.

In BR, CA, GS there was no need to change the protection on adjacent lines whereas in CO, IN, NO, SE, ZA and US some protection in the adjacent lines had to be replaced. The number of protection systems replaced varied from 2 to as many as 21 line ends.

Some countries also consider fault resistance, minimum/maximum source impedance, and minimum/maximum load flow.

Q: If you use MOVs, what is their impact on the operation / setting of line protection?

IN, CO, NO, SE, US had to increase the resistive reach due the usage of MOVs. GS had to adjust filtering characteristic. In CA, EMTP studies have revealed that the MOV operation do not affect the line protection settings as the line protection decision is taken before the MOV bypass takes effect. ZA has experienced that zero sequence compensation factor had to be reduced by the same percentage as the positive sequence compensation factor to prevent overreaching of Zone 1 for external faults involving ground.

Q: What is your experience with zero sequence current compensation from parallel line?

None of the countries that have parallel lines are using zero sequence current compensation from parallel lines.

Q: When do you expect flashover of spark gaps?

The responses here vary. Some have indicated that this is expected for faults in the protected line for fault resistance values ranging from 4 Ohms to 50 Ohms. Some countries have stated that it relates to continuous voltage of the capacitor rather than the fault impedance.

Q: Does unsymmetrical flashover of the gaps occur in your power system? If YES, what problems have been experienced and what countermeasures have been taken?

NO, SE, ZA and US have reports of unsymmetrical flashover of the gaps occurring in their system. While NO and ZA has not faced any problems so far, SE has faced false operation of protective relays which has led to revision of settings. BR, CO and GS have replied that they have not experienced it.

Q: Have you experienced any under/overreach problems at sub-harmonic oscillations? If YES, how did you address the problem?

None of the countries except ZA have experienced any such problems. ZA faced some problems and this was addressed by reducing zone 1 setting and in some places disabling zone 1 completely.

Q: Have you experienced any security problems with high frequency transients caused by flash over of spark gaps or line energisation? If YES, how did you address the problem?

No country except CA has experienced any such problems. CA experienced that the Main 2 protection was too sensitive to SC switching. This was overcome by providing negative sequence supervision.

6.1.4. Questions related to unit protection

These questions pertain to if older generation of unit protections like phase comparison relays are used either as the primary or secondary protection for the series compensated lines.

Q: Do you have older generation of phase comparison relays? If YES, do you plan to replace them in near future and if so what is the reason for their replacement? What will be the operating principle of the replacing protection scheme?

None of the countries except US have any older generation of phase comparison relays based either on the segregated principle or on non-segregated principle.

US has used static type segregated phase comparison relays. They plan to replace them in near future due to obsolescence, performance problems and lack of spares. They plan to replace them with numerical segregated phase comparison relay and directional comparison protection.

6.1.5. Questions related to protection of multi-circuit lines

These questions are to find out the experience, when series capacitors are used in double or multi-circuit lines. Here mutual impedance plays an important role. The capacitor will reduce the self-impedance while the mutual impedance will be the same as is without series capacitors. This means that the effect of the mutual impedance will be much higher than on power lines without series capacitors.

Q: Have you experienced protection problems in such cases? If YES, can you describe the problems? Do you think unit protection is the best for such lines?

Out of all the respondent countries only SE has faced fault current reversal problems in such cases. In their opinion unit protection is the best to overcome this. US have faced problems and they too feel unit protection is best in such cases.

Annexure – 1

Some details of large series compensated transmission lines and capacitor installations from different utilities listed under Table 6.6 in section 0 are shown below.

Table 6.18: Description of components shown in series capacitor installation drawings

S. No.	Description	S. No.	Description
01	Capacitor	07	Non linear resistor or gap
02	Varistor	08	Platform
03	Bypass spark gap	09	Isolating disconnector
04	Bypass switch	10	Bypass disconnector
05	Reactor	11	Earth switch
06	Linear resistor	12	Thyristor

6.1.6. Brasil

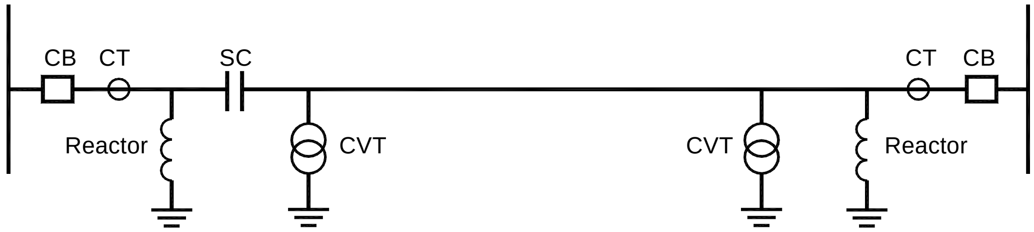


Figure 6-1: Typical series compensated line (single circuit) with major components shown

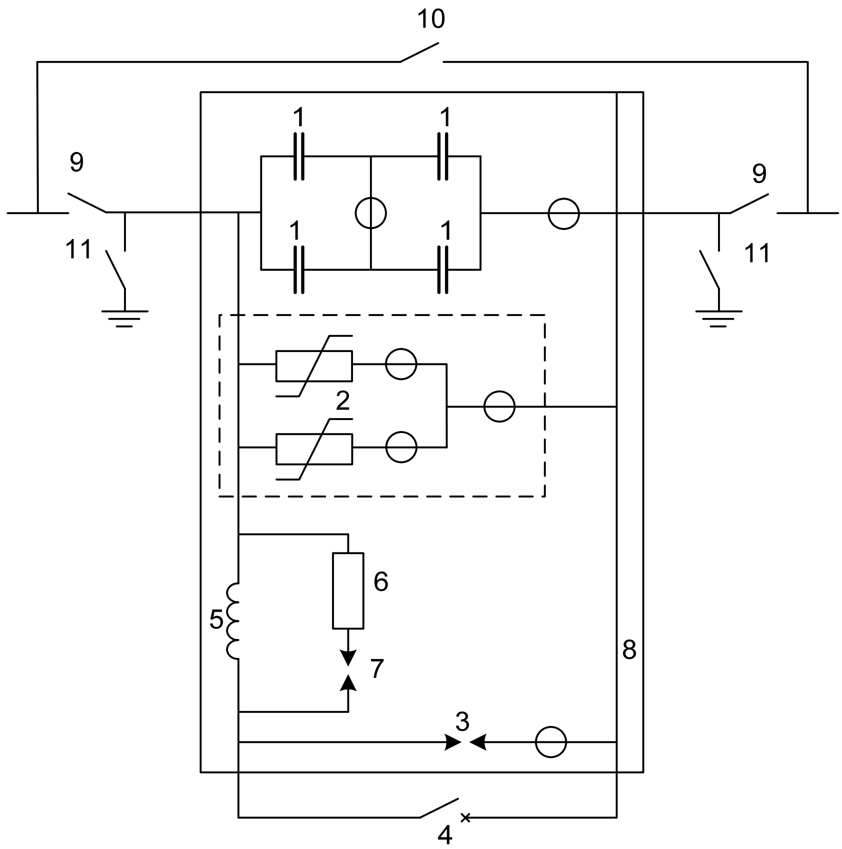


Figure 6-2: Connection diagram for series capacitor installation with major components shown

6.1.7. Canada

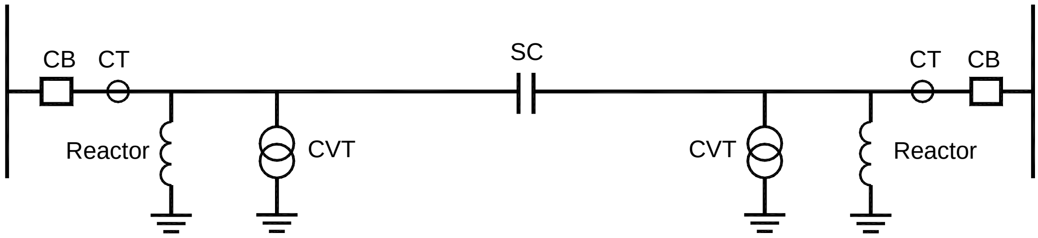


Figure 6-3: Typical series compensated line (single circuit) with major components shown

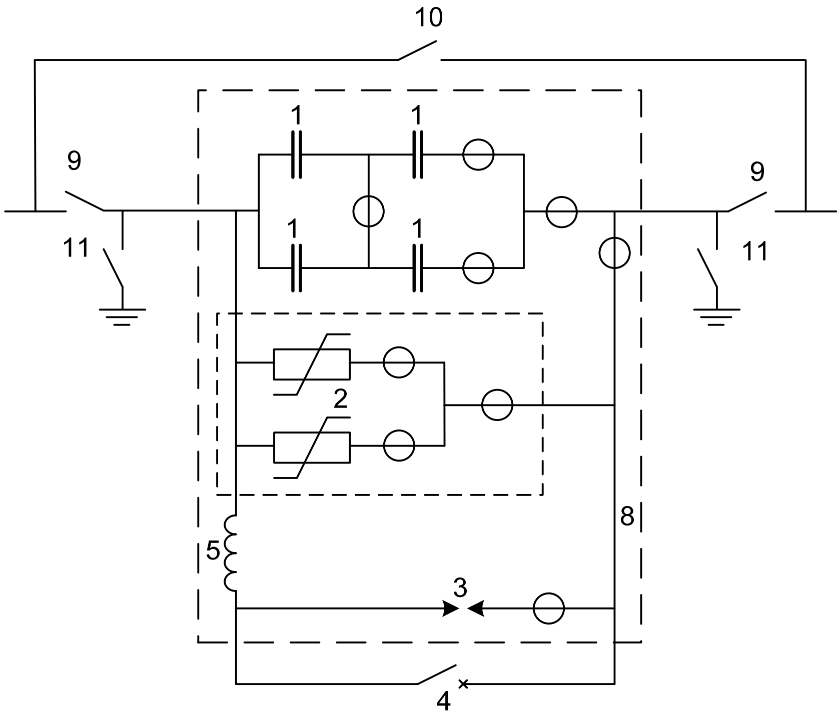


Figure 6-4: Connection diagram for series capacitor installation with major components shown

6.1.8. India

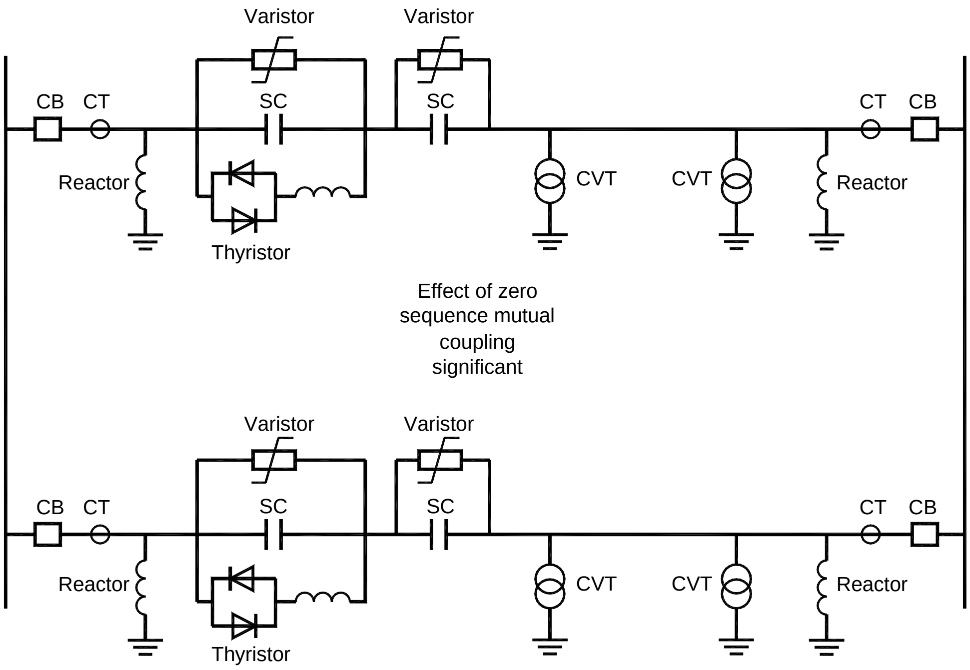


Figure 6-5: Typical series compensated line (double circuit) with major components shown

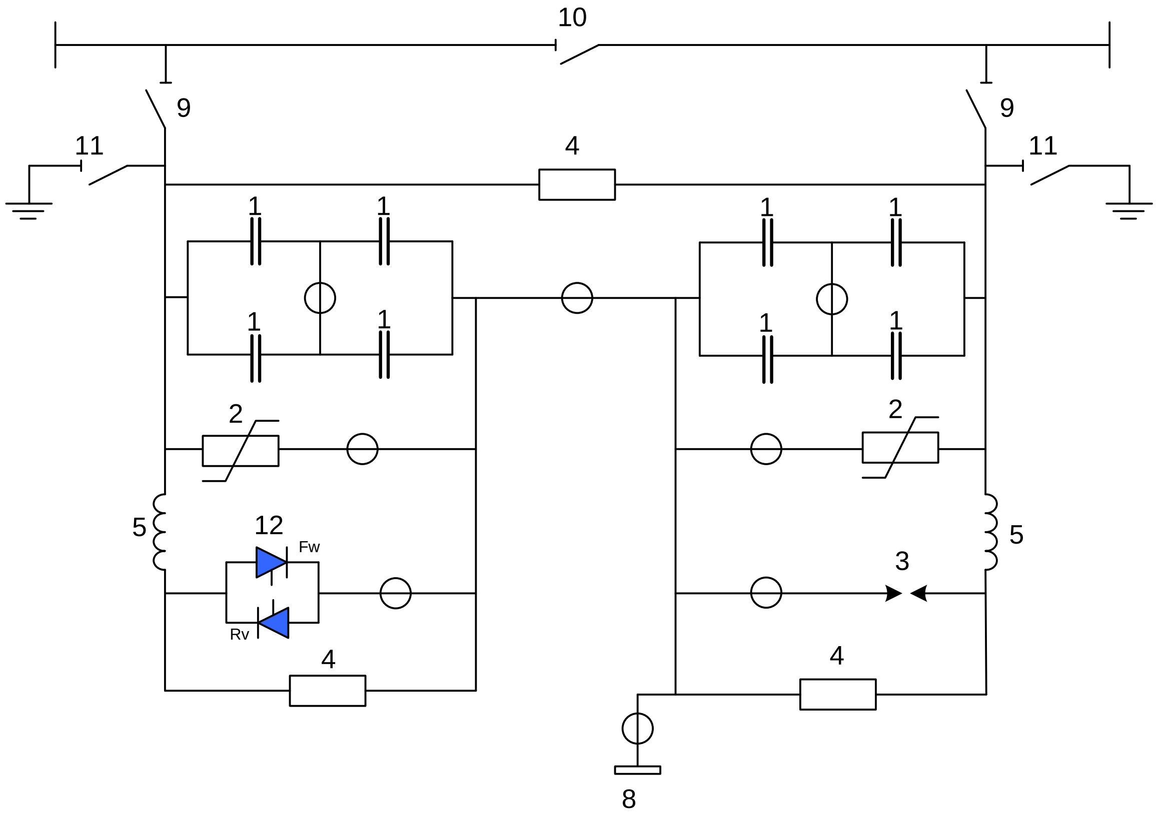


Figure 6-6: Connection diagram for TCSC installation with major components shown

6.1.9. Norway

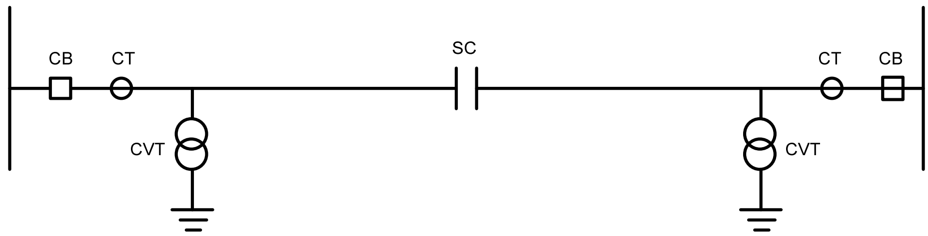


Figure 6-7: Typical series compensated line (single circuit) with major components shown

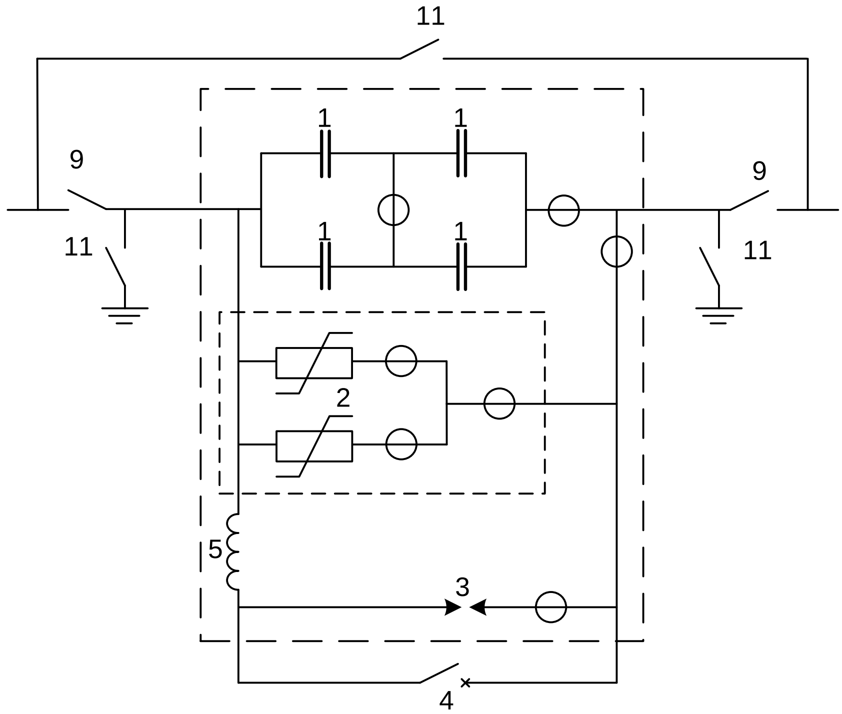


Figure 6-8: Connection diagram of series capacitor installation with major components shown

6.1.10. Saudi Arabia

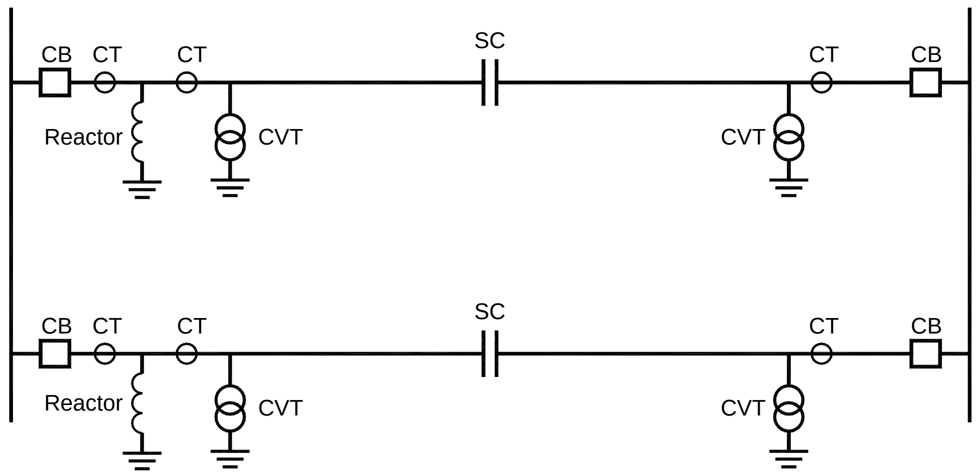


Figure 6-9: Typical series compensated line (double circuit) with major components shown

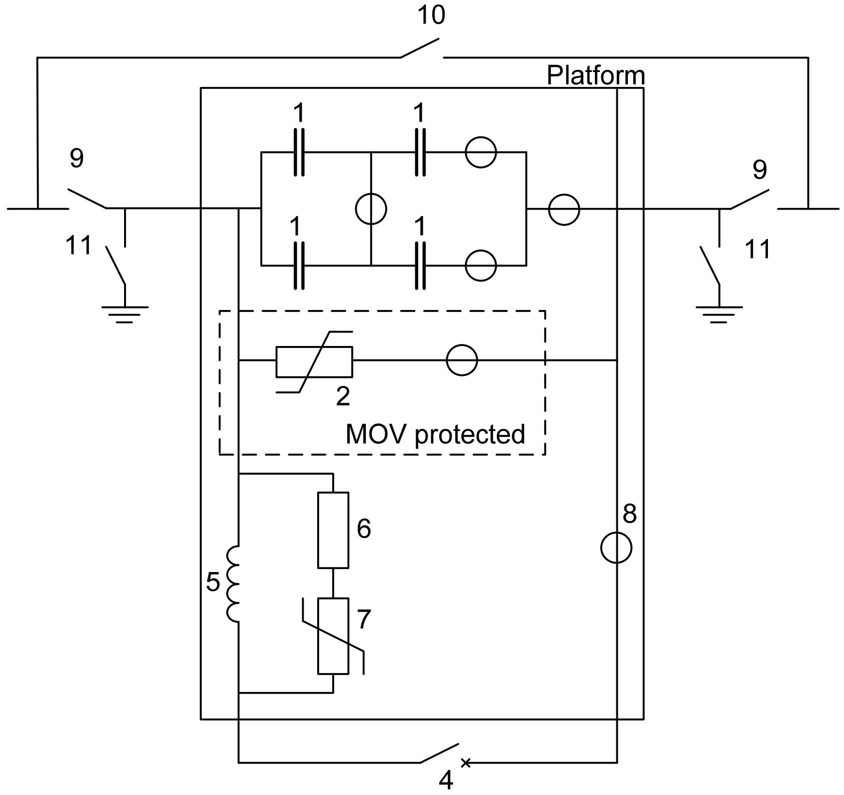


Figure 6-10: Connection diagram for series capacitor installation with major components shown

6.1.11. Sweden

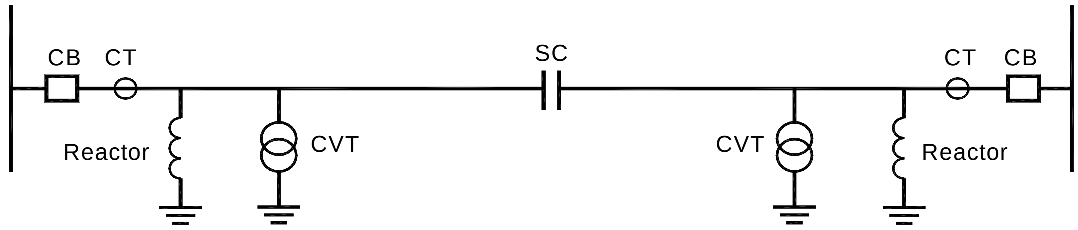


Figure 6-11: Typical series compensated line (single circuit) with major components shown

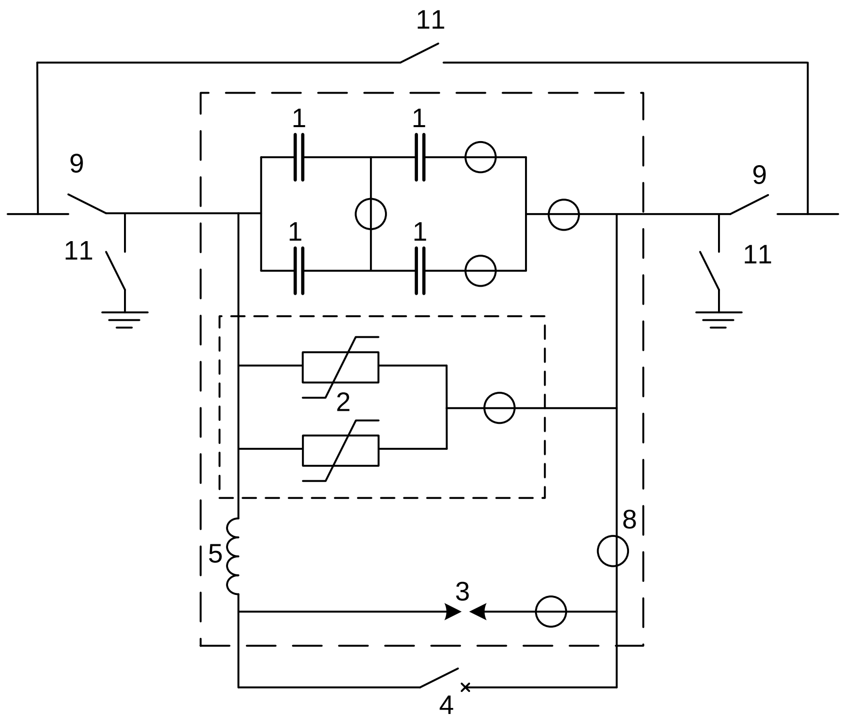


Figure 6-12: Connection diagram for series capacitor installation with major components shown

6.1.12. South Africa

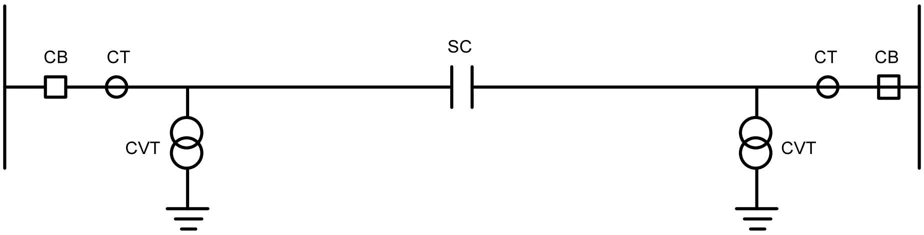


Figure 6-13: Typical series compensated line (single circuit) with major components shown

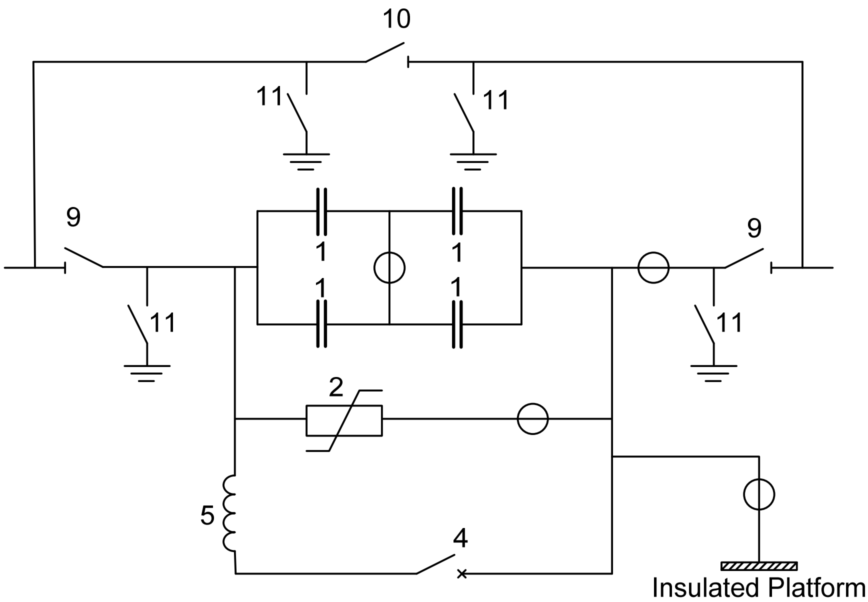


Figure 6-14: Connection diagram for series capacitor installation with major components shown

6.1.13. USA

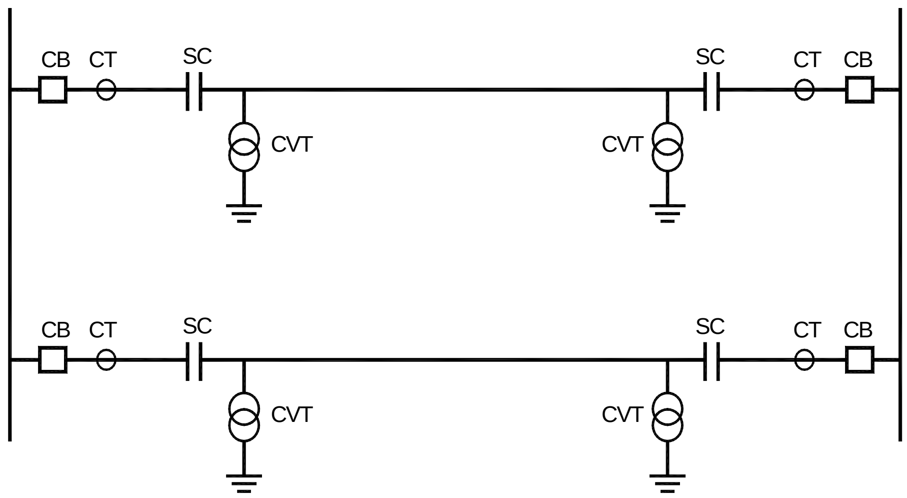


Figure 6-15: Typical series compensated line (double circuit) with major components shown

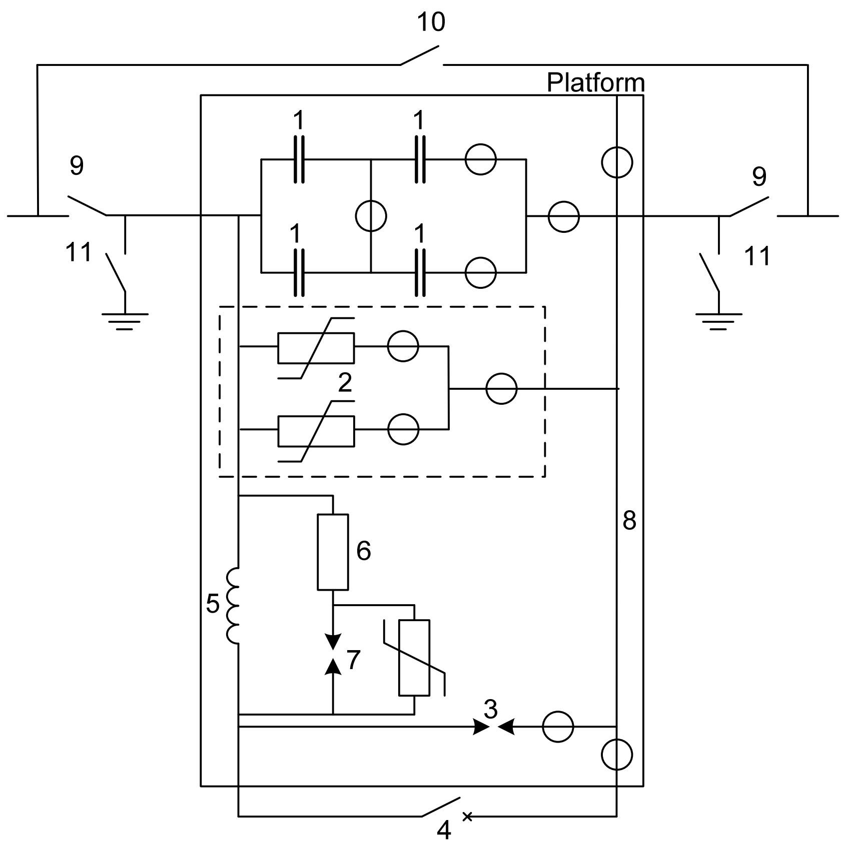


Figure 6-16: Connection diagram for series capacitor installation with major components shown

7. CONCLUSIONS

The development of series compensation in electric power systems showed an extremely big progress since introduction of first series capacitors in 1950. Today (2009) we can find them on practically all voltage levels up to 765kV with their capacity ranges approximately 1200Mvar.

The main purpose of series compensation in power systems is virtual reduction of line reactance in order to enhance the power system stability and increase loadability of transmission corridors. The principle is based on compensation of distributed line reactance by insertion of series capacitor (SC).

The generated reactive power provided by the capacitor is proportional to the square of the current flowing through the compensated line and series capacitor. This means that the series capacitor has a self-regulating effect. When the system loading increases, the reactive power generated by the series capacitors increases as well. The response of SCs is automatic, instantaneous and continuous as long as the capacitor current remains within the specified operating limits.

Fast development of microprocessor based technologies and digital communication possibilities influences in a very positive way development of protection, control and monitoring functionality applied on series capacitor banks as well as on series compensated and adjacent power lines. Introduction of MOVs and power electronics (thyristors) enhanced additionally the applicability of series compensation.

The development did not stop at this point. New materials and equipment have been developed in order to enhance the operation of series capacitor banks and especially reduce the times when they are disconnected from power lines due to limited loadability of MOVs and thyristors. This may bring significant changes in operation practice within near future. It is also expected that the operating algorithms of line protection devices will in near future be enhanced with online information from capacitor banks. All this will definitely contribute higher availability of series compensated networks, which will definitely grow also in future.