### Protection Relay Setting Calculation for 66/11 kV Substation KTS West

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**Title:** Protection Relay Setting Calculation for 66/11 kV Substation KTS West

**Customer:** KAHRAMAA / Qatar  
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General: Line length corrected to 3.75km (KTSW-DOC) and 2.6km (KTSW-New Hitmi)

4.3 7SD5331: 66 kV Cable Feeder – Cable Differential Protection: I-Diff reduced to 20%, parameters explained

4.4 REL561: 66 kV Cable Feeder – Distance Protection: Timer Setting 3. Zone reduced to 0.8s

4.5 7SD5331: 66 kV Cable Feeder – Distance Protection: Timer Setting 3. Zone reduced to 0.8s

4.4 REL561: 66 kV Cable Feeder – Distance Protection: R1 IN , X1 IN increased to 120%

4.4 REL561: 66 kV Cable Feeder – Distance Protection: Power Swing Detection enabled

4.5 7SD5331: 66 kV Cable Feeder – Distance Protection: Power Swing Detection enabled + new chapter

4.4 REL561: 66 kV Cable Feeder – Distance Protection: Fuse Failure 3U0> increased to 20%

4.5 7SD5331: 66 kV Cable Feeder – Distance Protection

EF/OC disabled, FL enabled, THOL disabled, Prot. Interface enabled

line angle, FullScaleCurrent, OperationPower, Si times, I4 setting changed

tripping time 3. Zone changed, pickup changed to Z<

4.8 REL561: 66kV -Thermal Overload Protection (49) DOC: no trip, only alarm

5.6 REL561: 66 kV -Thermal Overload Protection (49) KTS: no trip, only alarm

6.5 REX521: 66 kV Cable/Transformer Back up Protection: settings changed to I> 328A, TMS=0.8

8.1 REX521: 66 kV Protection of Bus Section: IDMT Curve added
Qatar Power Transmission System Expansion Phase VI, Part 2
Substation 66/11 kV KTS West, Qatar
Protection Setting Report

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1 Preface

1. Parameterisation/Configuration details
The setting study includes only numerical values for setting parameters of used protection functions. Fully parametrisation/configuration of the relay will be documented in "as built" revision with all required changes and adjustments.

2. Site measured values for CT data, loop resistance, stabilizing resistor, varistor etc.
These values will be determined during commissioning. The settings will be re-calculated and adjusted based on the measurements. The final settings with measured values will be documented in "As Built" revision.

3. General
The proposed settings have to be co-ordinated with the settings in the remote station(s) and the general protection philosophy applied to the network. The settings are submitted as setting proposals for commissioning.

The following documents and data sheets that are considered in the protection relay setting calculation are attached:

[A-1] 66 kV Single Line Diagram KTS West, Drawing No. 05-4/12/ABB-NEX/01/0101
[A-2] 11 kV Single Line Diagram KTS West East, Drawing No. 05-4/12/ABB-NEX/01/0102
[A-5] 40 MVA-Power Transformer 66/11 kV- FAT Report, relevant pages are attached
[A-6] Protection Principle Diagram Doha Central, Drawing No. 05-4/25/ABB-NEX/08/0001
[A-7] Protection Single Line Diagram KTS West, Drawing No. 05-4/12/ABB-NEX/08/0103
[A-10] Protection Principle Diagram KTS West, Drawing No. 05-4/12/ABB-NEX/08/0002
2 Network and Equipment Data

2.1 Base Data Short-Circuit Currents

Data of 66 kV-network and switchgear:

<table>
<thead>
<tr>
<th>Nominal voltage:</th>
<th>$U_N$</th>
<th>66 kV</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nominal frequency:</td>
<td>$f$</td>
<td>50 Hz</td>
</tr>
<tr>
<td>Max. short circuit current value</td>
<td>$I_{SC}$</td>
<td>31.5 kA</td>
</tr>
</tbody>
</table>

Data of 11 kV-switchgear:

<table>
<thead>
<tr>
<th>Nominal voltage:</th>
<th>$U_N$</th>
<th>11 kV</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nominal frequency:</td>
<td>$f$</td>
<td>50 Hz</td>
</tr>
<tr>
<td>Max. short circuit current value</td>
<td>$I_{SC}$</td>
<td>25 kA</td>
</tr>
</tbody>
</table>

Short-Circuit Currents

<table>
<thead>
<tr>
<th></th>
<th>existing SS Doha Central 66kV level</th>
<th>New SS KTS West 66kV level</th>
<th>New SS KTS West 11kV level</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maximum short circuit current, 1phase</td>
<td>$I_{k1''}$ kA</td>
<td>15,9</td>
<td>14,6</td>
</tr>
<tr>
<td>Maximum short circuit current, 3phase</td>
<td>$I_{k3''}$ kA</td>
<td>13,6</td>
<td>12,8</td>
</tr>
<tr>
<td>Minimum short circuit current, 1phase</td>
<td>$I_{k1min''}$ kA</td>
<td>9,7</td>
<td>13,5</td>
</tr>
<tr>
<td>Minimum short circuit current, 3phase</td>
<td>$I_{k3min''}$ kA</td>
<td>7,6</td>
<td>12,0</td>
</tr>
<tr>
<td>DC time constant of network</td>
<td>$T$ s</td>
<td>9,156</td>
<td>8,878</td>
</tr>
</tbody>
</table>

(*) Due to Y-D transformer winding connections and earthing arrangement via earthing transformer, the 1-ph short circuit currents are limited to max. 1.5 kA (each EF-transformer 750A).
2.2 66 kV Cable connection from SS Doha Central to SS KTS West

Cable length

\[ l : 3.75 \text{ km} \]

Specific pos. seq. resistance

\[ r_1 : 0.032 \ \Omega/\text{km} \]

Specific pos. seq. reactance

\[ x_1 : 0.195 \ \Omega/\text{km} \]

Spec. pos. seq. capacitive susceptance

\[ b_1 : 95.5 \ \mu\text{S/km} \]

Specific zero seq. resistance*

\[ r_0 : 0.136 \ \Omega/\text{km} \]

Specific zero seq. reactance*

\[ x_0 : 0.063 \ \Omega/\text{km} \]

Spec. zero seq. capacitive susceptance*

\[ b_0 : 95.5 \ \mu\text{S/km} \]

Pos. seq. cable impedance

\[ Z_{C1} : 0.198e^{j80.7} \ \Omega \]

Zero seq. cable impedance*

\[ Z_{C0} : 0.150e^{j24.8} \ \Omega \]

Earthfault compensation factor*

\[ k_0 : 0.283e^{-j132.4} \ \text{p.u.} \]

Maximum service current*

\[ I_{BMAX} : 700 \ \text{A} \]

cross section of conductors.

\[ 800 \ \text{mm}^2 \]

Power of cable

\[ S_{CN} : 80 \ \text{MVA} \]

Note (as provided):

* Allowable intensity in a continuous working in a cable laid in a trough 1500 x 900 mm, at ground level, filled with sand of thermal resistivity 250 °C.cm/W, in a ground of thermal resistivity 200°C.cm/W, with identical feeders in identical troughs with 1.7 m between axes, laid according to drawing ENG 21382. Shield earthed at one termination

Note: \( X'_0 \) requires verification
2.3 66/11 kV Transformer 40 MVA

Protection object data: Two-Winding Transformer
Vector group: YNd1
Starpoint treatment: Primary starpoints solidly earthed
Rated transformer power: ONAN 32 MVA, ONAF 40 MVA
Rated transformer voltages: 66 kV / 11 kV
Frequency: 50 Hz

Tap changer (on-load type): 66 kV +4 / - 12 x 1.25%

Rated transformer current tap mid:
- 349.9 A (40 MVA @ 66 kV)
- 2099.5 A (40 MVA @ 11 kV)

Transformer current tap 1 (+4x1.25%):
- 333.2 A (40 MVA @ 69.3 kV)

Transformer current tap 17 (-12x1.25%):
- 411.7 A (40 MVA @ 56.1 kV)

Short-circuit impedance at 40 MVA:
- \( u_{kr} = 17.22 \% \) at tap mid (=pos 5)
- \( u_{kr} = 17.64 \% \) at tap min (=pos 1)
- \( u_{kr} = 16.16 \% \) at tap max (=pos 17)

Short-circuit impedance zero-sequence: \( u_{k0r} = 15.28 \% \) at tap mid (=pos 5)

Short-circuit resistance at 40 MVA: \( u_{Rr} = 0.513\% \)

2.4 66 kV Cable connection from SS KTS West to Transformer New Hitmi

Not required at that stage (no distance protection at this cable connection). For charging current estimation (differential protection) a cable type will be assumed. Cable length is 2.6 km.

2.5 6611 kV Transformer 25MVA (New Hitmi)

Please refer to Attachment [A-9].
3 Fault Current Calculations at 66kV Level

3.1 Fault currents

Maximum fault currents calculations base on the 66 kV-switchgear s/c-rating of 31.5 kA (1 sec) and the minimum fault current calculations on given 66kV values of chapter 2.1. For protection settings, the maximum pass-through currents in case of s/c on transformer secondary side (11kV) are of main interest and amounts to 2.2kA at 66kV respectively 12.9kA at 11kV side.

Calculation of maximum 3-phase s/c current acc. To IEC 60909:
Calculation of maximum through-fault current acc. To IEC 60909:

[Diagram showing electrical system with labels and calculations]
Calculation of minimum 2-phase s/c current acc. To IEC 60909:
4 Doha Central 66kV Cable Feeder to KTS West (existing) (=B30, =B40)

4.1 Protection System General

The 66kV cable will be protected by duplicated cable differential protection. Additionally / complementary distance protection will be used. The philosophy of co-operation of the both protection functions shall be discussed and fixed. ABB suggest using of internal communication supervision as a criterion for this co-operation if possible. If the communication link with the opposite side relay is healthy, then the 1st zone of distance protection will be blocked. In this way all faults within the protected line will be tripped with short time of cable differential protection 87C. The higher zones shall remain in operation – as a backup for further objects as busbar and transformers at opposite station. If the communication link is faulty the 1st zone will be released. In this way most of the faults on the protected cable will be clarified with basic time of distance protection.

The main 1 protection for 66kV cable is realized with REL561. The main protection function will be 87C. Distance protection (21) can be activated. The relay communicates with opposite side relay via dedicated fiber optic connection. Additionally a binary signal transmission function (max. 8 channels, 4 of them can be used for direct intertipping) will be used for intertrip send/receive.

The main 2 protection for 66kV cable is realized with 7SD5331. The main protection function will be 87C. Distance protection (21) can be activated. The relay communicates with the opposite side relay via dedicated fiber optic connection. Additionally a binary signal transmission function (max. 8 channels, 4 of them can be used for direct intertipping) will be used for intertrip send/receive.
Simplified protection block diagram for 66 kV cable feeder to SS KTS West (B30)
66 kV Cable Data

According to the database utilized in the load flow calculation the feeder consists of 3.75 km cable XLPE 800 mm². The provided technical data is given in Section 2.2.

Assumptions

1. The individual route data need to be verified, any variations in length or type require consideration and modification of protection setting. Presently the 66 kV-cable feeders at bays B30 and B40 are assumed to have identical characteristics.

2. It is assumed, that the cable metallic shield is designed for 40 kA (1 s) maximum earth-fault current. The directional backup OC and EF protection is set to protect the s/c-strength of the cable. It is set to provide relay operation at 40 kA below 1 s and also ensures co-ordinated with the upstream protection.

Cable Route Charging Current

The differential protection must be set to a value which is higher than the total steady-state shunt current of the protected object. For cables and long overhead lines, the charging current is to be considered particularly. It is calculated from the service capacitance:

\[ I_c = 3.63 \times 10^{-6} \times U_N \times f_N \times C_B' \times s \]

With

- \( I_c \) Charging current to be calculated in A primary
- \( U_N \) Rated voltage of the network in kV
- \( f_N \) Rated frequency of the network in Hz
- \( C_B' \) Per unit line length service capacitance of the line in nF/km
- \( s \) Length of the line in km

The cable capacitance of XLPE 800 mm² cable is 304 nF/km. The total steady-state charging current is calculated for the total cable route of 3.75 km XLPE 800 mm²:

\[ I_c = 3.63 \times 10^{-6} \times 66 \times 50 \times 3.75 \times 304 = 13.6 \text{ A, say 14 A} \]

The cable charging current is base of the selection of the sensitivity setting of the cable differential protection (next Sections).

4.2 REL561: 66 kV Cable Feeder – Cable Differential Protection

The REL561 provides cable differential protection at following cable routes:

- 66kV Feeder B30 and B40, 3.75km cable to SS KTS West

REL561 - Protection Relay CT Data

The CT data are:
CT ratio: 400/800-1A, PX

**REL561 - Differential Protection Setting**

The REL 561 differential protection characteristic is:

![Operating characteristic](image)

CT-Factor

The secondary current that is to be compared in both terminals, must be related to a common current transformer ratio. With a CT-Factor default setting of 1.00, this is achieved when the current transformers at both terminals have the same rated primary current. When one of the terminal has a higher primary rated current than the other, this can be numerically equalized by the CT-Factor setting. By setting the CT-Factor in the terminal with the higher primary rated current to the quote between the lower and the higher rated current, the difference is equalized.

CT Ratio at SS Doha Central 66kV: 400/800-1A, PX
CT-Ratio at SS KTS West 66kV: 400/800-1A, PX
Recommended Setting: CT-Factor = 800A / 800A = 1.0

CT-saturation detection

In case of CT saturation, the degree of stabilization is increased in the affected phase in the differential protections at both ends acc. Figure 45. The Minimum phase current for saturation detection operation $I_{\text{MinSat}}$ is recommended with 1.5 times of $I_{1B}$ (Base current Input 1):

Recommended setting: $I_{\text{MinSat}} = 150$ (% of $I_{1B}$)
**Minimum differential operating current**

The total cable charging current is calculated in section 4.1, the charging current is 13 A. The differential protection should be set at least 2.5 times the maximum charging current, the minimum current value setting is 35 A. However, the setting should not be unnecessary low. A value of 160 A primary, respectively 0.2 times the base current $I_{1B}$ is proposed.

Recommended setting:  $I_{\text{MinOp}} = 20\% \text{ of } I_{1B}$

**Stabilisation slope**

The stabilisation slope is decisive for the stability of the protection during external faults, i.e. in the presence of high through-fault currents. The slope defines the ratio of the differential current to restraint current. The setting should be like this, when operating under load condition, weak faults causing only a low differential current can still be detected, but at the same time there is no risk of false tripping during through-faults. A typical slope is 0.5, which is also suitable in this protection application.

Recommended setting:  
- $I_{\text{diffLvl1}} = 50\% \text{ of } I_{\text{bias}}$  
- $I_{\text{diffLvl2}} = 50\% \text{ of } I_{\text{bias}}$  
- $I_{\text{lv1/l2Cross}} = 500\% \text{ of } I_{\text{bias}}$

**Tripping conditions:**

As there is no emphasis on reducing the operating time, the default parameter Evaluate = 3 of 4 is proposed herein. This is on the conservative side to prevent unwanted operation due to corrupt message of data exchange between relays.

**Setting Parameters for the line differential protection function**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Range</th>
<th>Setting</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operation</td>
<td>Off/On</td>
<td>On</td>
<td>Operation Line Differential Protection</td>
</tr>
<tr>
<td>CT Factor</td>
<td>0.4-1.0</td>
<td>1.0</td>
<td>Factor for matching Current Transformer</td>
</tr>
<tr>
<td>$I_{\text{MinSat}}$</td>
<td>100-1000</td>
<td>150%</td>
<td>Min. phase current for saturation detection operation</td>
</tr>
<tr>
<td>$I_{\text{MinOp}}$</td>
<td>20-150</td>
<td>20%</td>
<td>Minimum differential operating current</td>
</tr>
<tr>
<td>$I_{\text{diffLvl1}}$</td>
<td>20-150</td>
<td>50%</td>
<td>Slope 1 stabilisation</td>
</tr>
<tr>
<td>$I_{\text{diffLvl2}}$</td>
<td>30-150</td>
<td>50%</td>
<td>Slope 2 stabilisation</td>
</tr>
<tr>
<td>$I_{\text{lv1/l2Cross}}$</td>
<td>100-1000</td>
<td>500%</td>
<td>Slope 2 intersection</td>
</tr>
<tr>
<td>Evaluate</td>
<td>2 of 4 / 3 of 4</td>
<td>3 of 4</td>
<td>Tripping Condition</td>
</tr>
</tbody>
</table>
The settings have been chosen to obtain a similar characteristic as the 7SD5331 differential protection relay.

**Master – Slave**

Within a pair of differential relays, one has to be master and the other slave. For this project, the relays at 66kV Busbar Doha Central are proposed as 'Master' while the relays at the SS KTS West are proposed as 'Slave'.

To make sure that differential protection communicates with the correct protection at the opposite terminal, the terminals are numbered. By giving all differential protections transmitting over common multiplexer individual identification numbers, communication with the wrong terminal can be avoided. The identification number of the opposite terminal must also be set. This is always necessary.

**Setting parameters:**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Range</th>
<th>Setting</th>
<th>Unit</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>DiffSync</td>
<td>Master, Slave</td>
<td>Master</td>
<td>-</td>
<td>Select if the terminal shall be Master or Slave</td>
</tr>
<tr>
<td>TerminalNo</td>
<td>0 - 255</td>
<td>Has to set on site</td>
<td>-</td>
<td>Terminal number of local terminal</td>
</tr>
<tr>
<td>RemoteTermNo</td>
<td>0 - 255</td>
<td>Has to set on site</td>
<td>-</td>
<td>Terminal number of remote terminal</td>
</tr>
</tbody>
</table>

**Remote Terminal Communication**

The parameter “Asym delay” can be used if there exists a fixed and known difference between the communication times in the two directions. “Asym delay” is set to 0.00 for normal applications.

**Setting parameter:**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Range</th>
<th>Setting</th>
<th>Unit</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>AsymDelay</td>
<td>0.00 – 5.00 Step: 0.01</td>
<td>0.00</td>
<td>ms</td>
<td>Asymmetric delay for line differential</td>
</tr>
</tbody>
</table>

**Charging Current Compensation**

Due to the small charging current of 14A related to the minimum differential operating current, the CCC-function is recommended to be disables (OFF).
4.3 **7SD5331: 66 kV Cable Feeder – Cable Differential Protection**

The 7SD5331 provides cable differential protection at following cable routes:
- 66kV Feeder B30 and B40, 3.75km cable to SS KTS West

**7SD5331 - Protection Relay CT Data**

The CT data are:
- CT ratio: 400/800-1A, PX

**7SD5331 - Differential Protection Setting**

Differential Protection Settings are given in the following table. For general setting parameters (Functional Scope, General Power System Data, General Protection Data) please refer to chapter 4.5 (7SD53331 – Distance Protection). The settings follow the described principles of chapter 4.2, main parameters are explained below.

**Minimum differential operating current I-Diff >**

The total cable charging current is calculated in section 4.1, the charging current is 13 A. The differential protection should be set at least 2.5 times the maximum charging current, the minimum current value setting is 35 A. However, the setting should not be unnecessarily low. A value of 160 A primary, respectively 0.2 times the base current I_B is proposed.

Recommended setting: \( I_{\text{Diff}} > = 0.2\text{A} \) (20% of \( I_B \))

**Pickup value during switch on I-DIFF>SWITCH ON**

A pickup value I-DIFF>SWITCH ON (address 1213) can be set to reliably prevent single-sided pickup of the protection. This pickup value is always active when a device has recognized the connection of a dead line at its end. For the duration of the seal-in time SI Time all Cl. which was set in the general protection data at address 1132 (Section 2.1.4.1) all devices are then switched over to this particular pickup value. A minimum setting to three to four times the steady-state charging current ensures usually the stability of the protection during switch-on of the line. It is proposed to decrease the sensitivity during switch on to 30%.

Recommended setting: \( I_{\text{Diff}} > \text{Switch On} = 0.3\text{A} \) (30% of \( I_B \))
Charging Current Compensation \( I_{\text{cSTAB}}/I_{\text{cN}} \).

The charging current compensation is switched off, the setting is of no influence. If decision is made to activate the compensation the relay internally calculates and considers the charging current. Additionally, if compensation is active and voltage measurement fails, the compensated charging current will be taken into account with parameter address 1224 \( I_{\text{cSTAB}}/I_{\text{cN}} \). This ratio is proposed with 2.5, so that the current setting is 2.5 times, or \( I_{\text{cSTAB}}/I_{\text{cN}} \times I_{\text{DIFF}} \), of the determined charging current.

Recommended setting: \( I_{\text{cSTAB}}/I_{\text{cN}} = 2.5 \)

**Pickup value Charge comparison stage I-Diff >>**

The pickup threshold of the charge comparison stage is set in address 1233 \( I_{\text{DIFF}} \). The RMS value of the current is decisive. The conversion into charge value is carried out by the device itself. Setting near the operational nominal current is adequate in most cases. Please also remember that the setting is related to the operational nominal values that must be equal (primary) at all ends of the protected object. Since this stage reacts very fast, a pickup of capacitive charging currents (for lines) and inductive magnetizing currents (for transformers or reactors) – also for switch-on condition – must be excluded. This is also true when the charging current compensation is on, since the compensation is not effective for charge comparison. As there is no transformer in protection zone a setting of 120% of base current is proposed.

Recommended setting: \( I_{\text{DIFF}} = 1.2A \) (120% of \( I_{1B} \))

**Pickup value when switching on the charge comparison stage I-Diff >> SwitchOn**

If bushing transformers are used, the setting value of parameter 1235 \( I_{\text{DIFF}}\text{SWITCHON} \) should be 2 to 3 times the setting value of \( I_{\text{DIFF}} \). The default setting of \( I_{\text{DIFF}}\text{SWITCHON} \) corresponds to the default setting of parameter 1233 \( I_{\text{DIFF}} \). In the default setting, this parameter is therefore ineffective. As there are no bushing transformers, an equal setting to parameter 1233 is proposed.

Recommended setting: \( I_{\text{DIFF}}\text{SWITCHON} = 1.2A \) (120% of \( I_{1B} \))

**Inrush Restraint**

Inrush restraint function to be disabled as there is no transformer in protection zone. For the setting parameters 2302-2310 typical figures (equal to default) are proposed.
### 4.4 REL561: 66 kV Cable Feeder – Distance Protection

#### General Data

<table>
<thead>
<tr>
<th>From node</th>
<th>To node</th>
<th>Type</th>
<th>R1L'</th>
<th>X1L'</th>
<th>R0L'</th>
<th>X0L'</th>
<th>Length</th>
<th>Amp-pacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>T</td>
<td></td>
<td>Ohm/km</td>
<td>Ohm/km</td>
<td>Ohm/km</td>
<td>Ohm/km</td>
<td>km</td>
<td>A</td>
<td></td>
</tr>
<tr>
<td>66kV-Doha Central Transformer</td>
<td>HV Terminal Transformer</td>
<td>Cable XLPE 800 mm²</td>
<td>0.032</td>
<td>0.195</td>
<td>0.136</td>
<td>0.063</td>
<td>3.75</td>
<td>700</td>
</tr>
</tbody>
</table>

Note:
The zero-sequence data not only depends on cable design, it further depends largely on earthing properties. The total zero-sequence impedance can vary to great extend. If more details are available, the settings should be adapted accordingly.
The total length impedance data are (pos.-seq.) system:

<table>
<thead>
<tr>
<th>From node</th>
<th>To node</th>
<th>R1L</th>
<th>X1L</th>
<th>Z1L</th>
<th>phi Z1</th>
<th>R1L/X1L</th>
<th>ko</th>
<th>arg ko</th>
</tr>
</thead>
<tbody>
<tr>
<td>66kV Doha Central</td>
<td>HV Terminal Transformer</td>
<td>0.12</td>
<td>0.7313</td>
<td>0.741</td>
<td>80.68</td>
<td>0.1641</td>
<td>0.283</td>
<td>-132.4</td>
</tr>
</tbody>
</table>

\[ k_0 = \frac{1}{3} x (Z_{0L} - Z_{1L}) / Z_{1L} \]

The total length impedance data are (zero.-seq.) system:

<table>
<thead>
<tr>
<th>From node</th>
<th>To node</th>
<th>R0L</th>
<th>X0L</th>
<th>Z0L</th>
<th>phi Z0</th>
</tr>
</thead>
<tbody>
<tr>
<td>66kV Doha Central</td>
<td>HV Terminal Transformer</td>
<td>0.51</td>
<td>0.2363</td>
<td>0.5621</td>
<td>24.86</td>
</tr>
</tbody>
</table>

Current and Voltage Transformer Data, Impedance Ratio
Voltage transformer ratio: \[ \frac{U_U}{(66kV/\sqrt{3})} / \frac{(110V/\sqrt{3})} \]
Current transformer ratio: \[ \frac{U_I}{800/1A} \]
Impedance transformation ratio \[ \frac{U_Z}{U_I/U_U} = 800/600 = 1.3333 \]
\[ Z_{sec} = U_Z \times Z_{prim} \]

Setting Methodology - Zone Reach and Timer Settings
The distance zone reach is determined according to the following principles; “a” denotes the line impedance.

Reactive zone settings

\[ X_1 = 0.7 \times a \text{ forward } \rightarrow \text{ in } 0 \text{ s} \]
\[ X_2 = 1.2 \times a \text{ forward } \rightarrow \text{ in } 0.4 \text{ s} \]
\[ X_3 = 2.0 \times a \text{ forward } \rightarrow \text{ in } 0.8 \text{ s} \]
\[ X_4 = \text{not used} \]
\[ X_5 = \text{set as } X_3 \text{ non directional } \rightarrow \text{ Off (used for start of SOTF logic if required)} \]

X1.. X5 Reactance settings of distance zone
is line impedance from Doha Central to KTS West

**Phase selection logic**

\[ X = 1.15 \times \text{Distance protection zone 2 settings} \]

**Relay Measuring Principles**

The set values for RFPE and RFPP are solely for fault resistance coverage as the following characteristic of the REL 561 phase-to-earth measuring loop shows. The terminal automatically adapts the line characteristic angle according to the line parameters. The measurement of different faults follows the real conditions in a power system. Zloop as phase-to-earth loop measuring impedance, consists of a Z1 line operational impedance, ZN earth return impedance, and the RFPE fault resistance. The characteristic angle of the complete measuring loop automatically follows the real system conditions and the complete line characteristic.

The measurement of phase-earth faults is based on **loop-basis**:

\[ Z_m = Z_{\text{loop}} = Z_1 + Z_N + RFPE \]

The measurement of phase-phase faults is based on **phase-basis**:

\[ Z_m = Z_{\text{ph-ph}} = Z_1 + 0.5 \times RFPP \]

The resistance \( R_m \) and reactance \( X_m \) is compared with the set reach in the resistive and reactive direction.
The maximum zone reach of the phase-to-earth system is:
The maximum resistive reach of the impedance measurements phase-to-earth is:
\[ R_{\text{max ph-e}} = R_{1PE} + \frac{1}{3} \times (R_{0PE} - R_{1PE}) + R_{FPE} \]
this is line resistance \( R_{1PE} \) + earth resistance \( R_N \) = \( \frac{1}{3} \) * (\( R_{0PE} - R_{1PE} \)) + fault resistance \( R_{FPE} \).

The maximum reactive reach of the impedance measurements phase-to-earth is:
\[ X_{\text{max ph-e}} = X_{1PE} + \frac{1}{3} \times (X_{0PE} - X_{1PE}) \]
this is line resistance \( X_{1PE} \) + earth reactance \( X_N \) = \( \frac{1}{3} \) * (\( X_{0PE} - X_{1PE} \)).

The maximum zone reach of the phase-to-phase system is:
The maximum resistive reach of the impedance measurements phase-to-phase is:
\[ R_{\text{max ph-ph}} = R_{1PP} + \frac{1}{2} \times R_{FPP} \]
The maximum reactive reach of the impedance measurements phase-to-phase is:
\[ X_{\text{max ph-ph}} = X_{1PP} \]

The impedance measuring algorithm within the relay calculates automatically the complex value of the earth-return compensation factor on the basis of the set values for the:
- Positive sequence reactance of protected line section \( X_{1PE} \)
- Positive sequence resistance of protected line section \( R_{1PE} \)
- Zero-sequence reactance of protected line section \( X_{0PE} \)
- Zero-sequence resistance of protected line section \( R_{0PE} \)
- Resistive reach for phase-to-phase faults \( R_{FPP} \)
- Resistive reach for phase-to-earth faults \( R_{FPE} \)

Phase-phase and phase-earth resistive reach
A defined setting of \( R_{FPP}/X=3 \) and \( R_{FPE}/X=3 \) for all stages is used, leading to the following secondary values:

A value of \( R_{FPP} = R_{FPE} = 2.0475 \Omega \) (secondary) is set for zone 1 as fault resistance for phase-phase and phase-earth faults. Zone 2 is set to \( R_{FPP} = R_{FPE} = 3.51 \Omega \) (secondary), Zone 3 is set to \( R_{FPP} = R_{FPE} = 5.85 \Omega \) (secondary).

Note: The relay internally measures \( Z_m = Z_1 + 0.5 \times R_{FPP} \) and takes therefore per phase 50% of the entered arc resistance.
Minimum Load Impedance
The load impedance is calculated on the basis of the maximum power flow over the protected lines. The maximum power flow is calculated from the emergency ampacity of the cable (assumed 150% of ampacity 700 A = 1050 A) at a minimum system voltage of 80% of 66kV.

\[ Z_{\text{Load(min)}} = 0.8 \times 66kV / (\sqrt{3} \times 1.5 \times 700 \text{ A}) = 29.03 \Omega \text{ primary} \]

The determination of the load area considers an operational power factor of 1 to 0.7 lagging. The minimum load resistance is given at a power factor of 0.7 as:

\[ R_{\text{Load(min)}} = 0.7 \times Z_{\text{Load(min)}} = 20.32 \Omega \text{ primary} \]

Load encroachment check for phase-to-earth zones measuring zones
To avoid load encroachment for phase-to-earth measuring, the set resistive reach of any distance protection zone must be less than:

\[ \text{RFPE} \leq 0.8 \times Z_{\text{load}} \text{admin} \]

RFPE zone 3 is set to 5.85 Ω (secondary) this is below 0.8 x 29.03 x 1.33 = 30.89 Ω (secondary). The condition is fulfilled.

Load encroachment check for phase-to-phase zones measuring zones
To avoid load encroachment for the phase-to-phase measuring elements, the set resistive reach of any distance protection zone must be less than 160% of the minimum load impedance.

\[ \text{RFPP} \leq 1.6 \times Z_{\text{load}} \text{min} \]

RFPP zone 3 is set to 5.85 Ω (secondary) this is below 1.6 x 29.03 x 1.33 = 61.78.2 Ω (secondary). The condition is fulfilled.

Power Swing Detection (PSD)
Due to short cable distance and no power generation at opposite side, power swings are not expected during the fault and after fault clearing. However, decision is made to enabled the function, the following settings are recommended.

The power swing transient impedance needs to pass the impedance area between the outer and the inner impedance characteristic of the PSD function.
Set the reach of the inner characteristic $R_{1 \text{ IN}}$ in the resistive direction as well as $X_{1 \text{ IN}}$ in the reactive direction, so that the inner operate characteristic completely covers all distance protection zones, which are supposed to be blocked by the PSD function. It is recommended to consider at least 20% of additional safety margin.

$$R_{1 \text{ IN}} = 1.2 \times R_{\text{RFPE (zone 3)}} = 1.2 \times 5.85 \, \Omega \text{ (secondary)} = 7.0 \, \Omega$$

$$X_{1 \text{ IN}} = 1.2 \times X_{1\text{PP (zone 3)}} = 1.2 \times 1.95 \, \Omega \text{ (secondary)} = 2.3 \, \Omega$$

**Limitation of the resistive reach**

The reach in the resistive direction should not exceed more than 90% of the minimum load resistance $R_{\text{Load(min)}}$. This stands for both the reach of the inner as well as for the reach of the outer characteristic.

$$R_{1 \text{ IN}} \leq 0.9 \times R_{\text{Load(min)}} \leq 0.9 \times 20.32 \, \Omega \text{ (primary)} \times 1.3333 \leq 24.38 \, \Omega \text{ (secondary)}$$

The condition is fulfilled.

**Setting the reach of the outer characteristic**

Both ratios $\text{OUT/IN}$ are determined with 125% ($K_{R}=K_{X}=125\%$)

$$R_{1 \text{ OUT}} = K_{R} \times R_{1 \text{ IN}} / 100\% = 125 \% \times 7.0 \, \Omega / 100 \% = 8.8 \, \Omega$$

$$X_{1 \text{ OUT}} = K_{X} \times X_{1 \text{ IN}} / 100\% = 125 \% \times 2.3 \, \Omega / 100 \% = 2.9 \, \Omega$$

$R_{1 \text{ OUT}}$ and $X_{1 \text{ OUT}}$ are the calculated values of the reach for the outer characteristic.

**Power-swing detection timer**

It is recommended to try the first iteration with the default time delay for the $t_{P1}$ timer, which is 45 ms, and calculate, if the set speed of the transition impedance corresponds to the condition:

$$(R_{1 \text{ OUT}} – R_{1 \text{ IN}}) / t_{P1} > (\Delta Z / \Delta t)_{\text{req}}$$

System studies also determine the maximum possible speed of the transition impedance. The default setting is 15 ms. Set the $t_{P2}$ timer so, that the maximum detectable speed of the transition impedance satisfies the condition:

$$(R_{1 \text{ OUT}} – R_{1 \text{ IN}}) / t_{P2} > (\Delta Z / \Delta t)_{\text{max}}$$

The $t_{P2}$ timer become activated for the detection of the consecutive swing if the measured impedance exits the operate area and returns within the time delay, set on the $t_{W}$ waiting timer. The default setting is 250 ms.

System studies should determine the setting for the hold timer $t_{H}$. The default setting is 500 ms. The inputs PSD—I0CHECK and BLKI02 are disabled. So the timer $t_{R1}$ and $t_{R2}$ are not used.
The setting of the $t_{EF}$ timer must cover, with sufficient margin, the opening time of a circuit breaker and the dead time of a single phase auto-reclosing together with the breaker closing time.

$$t_{EF} = 2 \times (t_{CB-OPEN} + t_{1PH} + t_{CB-Close}) = 2 \times (25 \text{ ms} + 500 \text{ ms} + 25 \text{ ms}) = 1100 \text{ ms}$$

| Parameter | Range       | Unit       | Setting | Remarks                                                        |
|-----------|-------------|------------|---------|                                                               |
| Operation | On/Off      |            | ON      | Operation mode for PSD function                               |
| Detection | On/Off      |            | On      | Operation mode for the internal power swing detection PSD function |
| X1 IN     | 0.10-400.00 | Ohm/Phase  | 2.3     | Positive sequence line reactance reach of the inner boundary. |
| R1 IN     | 0.10-400.00 | Ohm/Phase  | 7.0     | Positive sequence line resistance reach of the inner boundary.|
| KX        | 120-200     | %          | 125     | Reach multiplication factor for the outer reactive boundary    |
| KR        | 120-200     | %          | 125     | Reach multiplication factor for the outer resistive boundary   |
| tP1       | 0.000-60.000| s          | 0.045   | Time for detection of internal power swing                     |
| tP2       | 0.000-60.000| s          | 0.015   | Time for detection of subsequent power swing                   |
| tW        | 0.000-60.000| s          | 0.25    | Waiting timer for activation of tP2 timer                      |
| tH        | 0.000-60.000| s          | 0.5     | Timer for holding PSD output                                  |
| tEF       | 0.000-60.000| s          | 1.1     | Timer for overcoming single-pole reclosing dead time           |
| tR1       | 0.000-60.000| s          | 0.3     | Timer giving delay blocking of output by the residual current  |
| tR2       | 0.000-60.000| s          | 2.0     | Timer giving delay blocking of output at very slow swing       |

**Switch-onto-fault Function (SOFT)**

The switch-onto-fault function is a complementary function to the distance protection function. With the switch-onto-fault function, a fast trip is achieved for a fault on the whole line, when the line is being energised. The SOTF tripping is generally non-directional in order to secure a trip at a nearby three phase fault when a line potential transformer is used. The non-directional trip will also give a fast fault clearing when the bus is energised from the line, with a fault on the bus.
The switch-onto-fault function can be activated either externally or automatically, internally, by using the information from dead-line-detection. The distance protection zone used together with the switch-onto-fault function shall be set to cover the entire protected line.

It is suggested to use the distance protection zone 5, when faster operation of SOTF function is required as zone 5 acts faster due to reduced measurement principles.

**Proposed setting:** SOFT function = On & Operating with zone 5 reach

**Dead-line Detection (DLD)**

The dead-line detection function (DLD) detects the disconnected phases of a protected object. The output information serves as an input condition for some other measuring functions within the relay terminals. Typical examples of such functions are:

- Fuse failure supervision function (FUSE) or Switch-onto-fault function (SOTF)

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Setting</th>
<th>Remarks</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operation</td>
<td>On</td>
<td></td>
</tr>
<tr>
<td>U&lt;</td>
<td>70%</td>
<td>Operating undervoltage of U1b</td>
</tr>
<tr>
<td>IP&lt;</td>
<td>15%</td>
<td>Operating undercurrent of I1b. Setting must exceed the cable charging current of complete route</td>
</tr>
</tbody>
</table>

**Single or Three Pole Trip Logic (TRIP)**

The tripping logic in REL561 protection, controlling and monitoring terminals offers three different operating modes:

- Three-phase tripping for all kinds of faults (3ph operating mode)
- Single-phase tripping for single-phase faults and three-phase tripping for multi-phases and evolving faults (1ph/3ph operating mode). The logic also issues a three-phase tripping command when phase selection within the operating protection functions is not possible, or when external conditions request three-phase tripping.
- Single-phase tripping for single-phase faults, two-phase tripping for ph-ph and ph-ph-E faults and three-phase tripping for three-phase faults (1ph/2ph/3ph operating mode). The logic also issues a three phase tripping command when phase selection within the operating protection functions is not possible or at evolving multi-phases faults.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Setting</th>
<th>Remarks</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operation</td>
<td>On</td>
<td></td>
</tr>
<tr>
<td>Prgram</td>
<td>1/3ph</td>
<td>Single and three-phase tripping</td>
</tr>
<tr>
<td>tTripMin</td>
<td>0.150 s</td>
<td></td>
</tr>
</tbody>
</table>
Fuse Failure Supervision (zero sequence) (FUSE)

Different protection functions within the REL 561 protection operate on the basis of the measured voltage in the relay point. These functions can operate unnecessarily if a fault occurs in the secondary circuits between the voltage instrument transformers and the terminal.

The fuse-failure supervision function as built into the REL 561 terminals prevents this, it can operate:

1. On the basis of external binary signals from the miniature circuit breaker or from the line disconnector. The first case influences the operation of all voltage-dependent functions while the second one does not affect the impedance measuring functions.

2. On the base of the zero-sequence measuring quantities: A high value of voltage 3U0 without the presence of the residual current 3I0.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Setting</th>
<th>Remarks</th>
</tr>
</thead>
<tbody>
<tr>
<td>ZeroSeq</td>
<td>On</td>
<td></td>
</tr>
<tr>
<td>3U0&gt;</td>
<td>20%</td>
<td>Operating zero-seq. voltage, as a percentage of U1b</td>
</tr>
<tr>
<td>3I0&lt;</td>
<td>10%</td>
<td>Operating zero-seq. current, as a percentage of I1b</td>
</tr>
</tbody>
</table>

Communication Scheme

Current Reversal and WEI logic (ZCAL)

To achieve fast fault clearing for a fault on the part of the line not covered by the zone 1, the stepped distance protection function can be supported with logic, which uses communication channels. Different system conditions, in many cases, require additional special logic circuits, like current reversal logic and WEI, weak end infeed logic. Both functions are available within the additional communication logic for the distance protection function (ZCAL).

Current reverse and WEI logic are switched off.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Setting</th>
<th>Remarks</th>
</tr>
</thead>
<tbody>
<tr>
<td>CurrRev</td>
<td>OFF</td>
<td></td>
</tr>
<tr>
<td>WEI</td>
<td>OFF</td>
<td></td>
</tr>
</tbody>
</table>

Local Acceleration Logic (ZCLC)

To achieve fast clearing of faults on the whole line, also in case where no communication channel is available, local acceleration logic is used.

Local acceleration logic is switched off.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Setting</th>
<th>Remarks</th>
</tr>
</thead>
<tbody>
<tr>
<td>ZoneExtension</td>
<td>OFF</td>
<td></td>
</tr>
<tr>
<td>LossOfLoad</td>
<td>OFF</td>
<td></td>
</tr>
</tbody>
</table>
Scheme Communication Logic (ZCOM)

The applied communication scheme is permissive underreaching transfer tripping. Zone 2 is the overreaching distance protection zone to be used as the local criterion for permissive tripping on receipt of the carrier signal (ZCOM-CACC). The signal (ZCOM-CR) must be received when the overreaching zone is still activated to achieve an instantaneous trip.

The recommended operation setting is OFF because REL561 distance protection is back-up of differential protection (main1, main2).

There is no race between the ZCOM-CR signal and the operation of the zone in a permissive scheme. So set the tCoord to zero.

The Unblocking function is not used.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Range</th>
<th>Setting</th>
<th>Remarks</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operation</td>
<td>On/Off</td>
<td>Off</td>
<td>Communication logic on</td>
</tr>
<tr>
<td>Scheme-Type</td>
<td>Intertrip/PermissibleUR/PermissibleOR/Blocking</td>
<td></td>
<td></td>
</tr>
<tr>
<td>tCoord</td>
<td>0.000 - 60.000 s</td>
<td>Co-ordination timer</td>
<td></td>
</tr>
<tr>
<td>tSendmin</td>
<td>0.000 - 60.000 s</td>
<td>Minimum duration of a carrier send signal</td>
<td></td>
</tr>
<tr>
<td>Unblock</td>
<td>Off/NoRestart/Restart</td>
<td>Operation mode for an unblocking logic.</td>
<td></td>
</tr>
<tr>
<td>tSecurity</td>
<td>0.000 - 60.000 s</td>
<td>Security timer</td>
<td></td>
</tr>
</tbody>
</table>

Phase selection logic (PHS)

Generally the phase selection elements need not cover all distance protection zones within the terminal. The main goal should be a correct and reliable phase selection for faults on the entire protected line. This way a single phase auto reclosing function has the best possible effect. So the phase selection measuring elements must always cover the overreaching zone 2 for different fault loops. A safety margin of 15% is recommended.
**Zone reach**

To ensure proper operation of phase selection logic, it is recommended to set the zone reach to 115% of the distance protection zone 2.

**INReleasePE and INBlockPP setting**

The setting parameters INReleasePE and INBlockPP (both are settable in percentage of the terminal rated current Ir) control the operation of the phase-to-earth and the phase-to-phase measuring elements. They should in general be set to the default values, which are INReleasePE = 20%, and INBlockPP = 40%. Special system studies and calculations of fault currents are necessary in cases, when the remote end positive sequence source impedance is much higher than the zero sequence source impedance.

**Phase-phase resistive reach**

RFPP is the resistive reach of the PHS logic for three-phase faults. It should be set as a loop value of the measured resistances, according to the formula:

\[
RFPP = 1.15 \times (1.82 \times R1PP (\text{Zone 2}) + 0.32 \times X1PP (\text{Zone 2}) + 0.91 \times RFPP (\text{Zone 2}))
\]

\[
RFPP = 1.15 \times (1.82 \times 0.192 \, \text{Ω} + 0.32 \times 1.17 \, \text{Ω} + 0.91 \times 3.51 \, \text{Ω}) = 4.506 \, \text{Ω sec}
\]

It must be checked that \(RFPP < 1.35 \times R_{\text{Load(min)}}\). This is fulfilled, as \(1.35 \times R_{\text{Load(min)}}\) is about 27.4 Ω sec.
Phase-earth resistive reach

RFPE is the resistive reach of the PHS logic for the phase-to-earth-faults. It should be set as a loop value of the measured resistances, according to the formula:

\[ RFPE = 1.15 \times \frac{1}{3} \times (2 \times R_{1PE} \text{ (Zone 2)} + R_{0PE} \text{ (Zone 2)}) + RFPE \text{ (Zone 2)} \]

\[ RFPE = 1.15 \times \frac{1}{3} \times (2 \times 0.192 \Omega + 0.816 \Omega) + 3.51 \Omega = 4.497 \Omega \text{ sec} \]

Phase Selection Settings (PHS)

Zone reach: 115% of distance protection zone 2 settings

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Description</th>
<th>Setting</th>
<th>Unit</th>
<th>Calculation</th>
</tr>
</thead>
<tbody>
<tr>
<td>X1PP</td>
<td>Positive sequence reactive reach for phase-to-phase loop measuring</td>
<td>1.3455</td>
<td>Ω/ph</td>
<td>X1PP = 115% of zone 2</td>
</tr>
<tr>
<td>RFPP</td>
<td>Resistive reach for phase-to-phase loop measurement</td>
<td>4.506</td>
<td>Ω/Loop</td>
<td>RFPP = 1.15 \times (1.82 \times R_{1PP} \text{ (Zone 2)} + 0.32 \times X_{1PP} \text{ (Zone 2)} + 0.91 \times RFPP \text{ (Zone 2)})</td>
</tr>
<tr>
<td>X1PE</td>
<td>Positive sequence reactive reach for phase-to-earth loop measuring</td>
<td>1.3455</td>
<td>Ω/ph</td>
<td>X1PE = 115% zone 2</td>
</tr>
<tr>
<td>X0PE</td>
<td>Positive sequence reactive reach in forward direction for phase-to-earth faults</td>
<td>0.4347</td>
<td>Ω/ph</td>
<td>X0PE = 115% zone 2</td>
</tr>
<tr>
<td>RFPE</td>
<td>Resistive reach for phase-to-earth measurement</td>
<td>4.497</td>
<td>Ω/Loop</td>
<td>RFPE = 1.15 \times ((1/3) \times (2 \times R_{1PE} \text{ (Zone 2)} + R_{0PE} \text{ (Zone 2)}) + RFRE \text{ (Zone 2)})</td>
</tr>
<tr>
<td>INReleasePE</td>
<td>3I0 limit for releasing phase-to-earth measuring loops</td>
<td>20</td>
<td>% of IphMax</td>
<td></td>
</tr>
<tr>
<td>INBlockPP</td>
<td>3I0 limit for blocking phase-to-phase measuring loops</td>
<td>40</td>
<td>% of IphMax</td>
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</tr>
</tbody>
</table>

Setting Tables Distance Protection

\[ a_1 = Z_1 = (0.12+ j 0.7313) \Omega \text{ prim. } = (0.16 + j 0.975) \Omega \text{ sec.} \]

\[ a_0 = Z_0 = (0.510 + j 0.2363) \Omega \text{ prim. } = (0.680 + j 0.315) \Omega \text{ sec.} \]

Impedance transformation ratio \( TRatio = 1.3333 \)
General Setting Parameters (Zgeneral)

Minimum operating current for forward directed distance protection zones

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Setting</th>
<th>Unit</th>
<th>Calculation</th>
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<tr>
<td>IMinOp</td>
<td>20% of I1B</td>
<td></td>
<td>Setting range 10-30% of I1B</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Default setting value, which is 20% of basic terminal current, proved in practice as the optimum value for the most of applications, setting is 160 A primary.</td>
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</table>

Distance Protection Zone 1

Zone reach: 100% of line in forward direction
Timer: 0.0 s

<table>
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<td></td>
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<tr>
<td>Operation PP</td>
<td>On</td>
<td></td>
<td></td>
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<tr>
<td>X1PP</td>
<td>0.6825</td>
<td>Ω/PH</td>
<td>X1PP = (0.7 *a1) * Tratio</td>
</tr>
<tr>
<td>R1PP</td>
<td>0.112</td>
<td>Ω/PH</td>
<td>R1PP = (0.7 *a1) * Tratio</td>
</tr>
<tr>
<td>RFPP</td>
<td>2.0475</td>
<td>Ω/Loop</td>
<td>RFPP / X1PP = 3</td>
</tr>
<tr>
<td>timer t1PP</td>
<td>On</td>
<td></td>
<td></td>
</tr>
<tr>
<td>t1PP</td>
<td>0.0</td>
<td>s</td>
<td></td>
</tr>
<tr>
<td>Operation PE</td>
<td>On</td>
<td></td>
<td></td>
</tr>
<tr>
<td>X1PE</td>
<td>0.6825</td>
<td>Ω/PH</td>
<td>Line pos. sequence X1PE = X1PP</td>
</tr>
<tr>
<td>R1PE</td>
<td>0.112</td>
<td>Ω/PH</td>
<td>Line pos. sequence R1PE = R1PP</td>
</tr>
<tr>
<td>X0PE</td>
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<td>Ω/PH</td>
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<td>Ω/Loop</td>
<td>RFPE / X1PP = 3</td>
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<td></td>
</tr>
<tr>
<td>t1PE</td>
<td>0.0</td>
<td>s</td>
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**Distance Protection Zone 2**

Zone reach: 120% of line in forward direction  
Timer: 0.4 s

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<tr>
<td>Operation PP</td>
<td>On</td>
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<td></td>
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<tr>
<td>X1PP</td>
<td>1.170</td>
<td>Ω/ph</td>
<td>X1PP = (1.2 *a1) * Tratio</td>
</tr>
<tr>
<td>R1PP</td>
<td>0.192</td>
<td>Ω/ph</td>
<td>R1PP = (1.2 *a1) * Tratio</td>
</tr>
<tr>
<td>RFPP</td>
<td>3.51</td>
<td>Ω/Loop</td>
<td>RFPP / X1PP = 3</td>
</tr>
<tr>
<td>t1PP</td>
<td>0.4</td>
<td>s</td>
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<td>Operation PE</td>
<td>On</td>
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<tr>
<td>X1PE</td>
<td>1.170</td>
<td>Ω/ph</td>
<td>Line pos. sequence X1PE = X1PP</td>
</tr>
<tr>
<td>R1PE</td>
<td>0.192</td>
<td>Ω/ph</td>
<td>Line pos. sequence R1PE = R1PP</td>
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<td>X0PE</td>
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<td>R0PE</td>
<td>0.816</td>
<td>Ω/ph</td>
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<td>3.510</td>
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<td>s</td>
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### Distance Protection Zone 3

Zone reach: 200% of line in forward direction
Timer: 0.8 s

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<tr>
<td>Operation PP</td>
<td>On</td>
<td></td>
<td></td>
</tr>
<tr>
<td>X1PP</td>
<td>1.950</td>
<td>Ω/ph</td>
<td>X1PP = (2.0 *a1) * Tratio</td>
</tr>
<tr>
<td>R1PP</td>
<td>0.320</td>
<td>Ω/ph</td>
<td>R1PP = (2.0 *a1) * Tratio</td>
</tr>
<tr>
<td>RFPP</td>
<td>5.85</td>
<td>Ω/Loop</td>
<td>RFPP / X1PP = 3</td>
</tr>
<tr>
<td>timer t1PP</td>
<td>On</td>
<td></td>
<td></td>
</tr>
<tr>
<td>t1PP</td>
<td>1.2</td>
<td>s</td>
<td></td>
</tr>
<tr>
<td>Operation PE</td>
<td>On</td>
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<tr>
<td>X1PE</td>
<td>1.950</td>
<td>Ω/ph</td>
<td>Line pos. sequence X1PE = X1PP</td>
</tr>
<tr>
<td>R1PE</td>
<td>0.320</td>
<td>Ω/ph</td>
<td>Line pos. sequence R1PE = R1PP</td>
</tr>
<tr>
<td>X0PE</td>
<td>0.630</td>
<td>Ω/ph</td>
<td>X0PE = (2.0 *a0) * Tratio</td>
</tr>
<tr>
<td>R0PE</td>
<td>1.360</td>
<td>Ω/ph</td>
<td>R0PE = (2.0 *a0) * Tratio</td>
</tr>
<tr>
<td>RFPE</td>
<td>5.850</td>
<td>Ω/Loop</td>
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</tr>
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<tr>
<td>t1PE</td>
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<td>s</td>
<td></td>
</tr>
</tbody>
</table>

### Distance Protection Zone 4

Zone 4 is not used
Distance Protection Zone 5

Zone reach: 200% of line non-directional
Timer: blocked (only used for start of SOFT logic if required)

<table>
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<th>Calculation</th>
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</tr>
<tr>
<td>Operation PP</td>
<td>On</td>
<td></td>
<td></td>
</tr>
<tr>
<td>X1PP</td>
<td>1.950</td>
<td>Ω/φ</td>
<td>X1PP = (2.0 *a1) * Tratio</td>
</tr>
<tr>
<td>R1PP</td>
<td>0.320</td>
<td>Ω/φ</td>
<td>R1PP = (2.0 *a1) * Tratio</td>
</tr>
<tr>
<td>RFPP</td>
<td>5.85</td>
<td>Ω/Loop</td>
<td>RFPP / X1PP = 3</td>
</tr>
<tr>
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<tr>
<td>t1PP</td>
<td>1.2</td>
<td>s</td>
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<td>Operation PE</td>
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</tr>
<tr>
<td>X1PE</td>
<td>1.950</td>
<td>Ω/φ</td>
<td>Line pos. sequence X1PE = X1PP</td>
</tr>
<tr>
<td>R1PE</td>
<td>0.320</td>
<td>Ω/φ</td>
<td>Line pos. sequence R1PE = R1PP</td>
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<tr>
<td>X0PE</td>
<td>0.630</td>
<td>Ω/φ</td>
<td>X0PE = (2.0 *a0) * Tratio</td>
</tr>
<tr>
<td>R0PE</td>
<td>1.360</td>
<td>Ω/φ</td>
<td>R0PE = (2.0 *a0) * Tratio</td>
</tr>
<tr>
<td>RFPE</td>
<td>5.850</td>
<td>Ω/Loop</td>
<td>RFPE / X1PP = 3</td>
</tr>
<tr>
<td>timer t1PE</td>
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</tr>
<tr>
<td>t1PE</td>
<td>0.8</td>
<td>s</td>
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</tr>
</tbody>
</table>

4.5 7SD5331: 66 kV Cable Feeder – Distance Protection

Current and Voltage Transformer Data, Impedance Ratio

CT-Ratio: 400-800/ 1 A  (Doha Central)
VT-Ratio: (66 kV / √3) / (110 V / √3) / (110 V / √3)

Calculation of secondary values

\[ T_{\text{Ratio}} = \frac{CT_{\text{Ratio}}}{VT_{\text{Ratio}}} \]
\[ = \frac{(800 \text{ A} / 1 \text{ A})}{(66 \text{ kV} / 110 \text{ V})} \]
\[ = 1.3333 \]

\[ Z_{\text{secondary}} = T_{\text{Ratio}} \times Z_{\text{prim}} \]

132 kV-Cable Data

Reference is made to the data tables of chapter 4.4.
Measurement Zone and Timer Settings
The distance relay function is only activated when the communication channel utilized for differential protection fails. Therefore this function is back-up for differential protection and is accordingly set to provide protection for the cable route itself and NOT for faults beyond the line.

Setting Methodology - Zone Reach and Timer Settings
The distance zone reach is determined according to the following principles; “a” denotes the line impedance.

Reactive zone settings

\[ X_1 = 0.7 \times a \quad \text{forward} -> \quad \text{in} \ 0 \ s \]
\[ X_2 = 1.2 \times a \quad \text{forward} -> \quad \text{in} \ 0.4 \ s \]
\[ X_3 = 2.0 \times a \quad \text{forward} -> \quad \text{in} \ 0.8 \ s \]

\[ X_1, X_2, X_3 \quad \text{Reactance settings of distance zone} \]
\[ a \quad \text{is line impedance from Doha Central to KTS West} \]

The setting tables follows; the principles of chapter 4.4 have been adopted. For detailed parameter description refer to the Manual 7SD5331, V4.3.

Settings - Functional Scope
<table>
<thead>
<tr>
<th>Addr.</th>
<th>Parameter</th>
<th>Setting Option</th>
<th>Default Setting</th>
<th>Setting</th>
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<td>Disabled</td>
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<td>3pole only</td>
<td>3pole only</td>
<td>3pole only</td>
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<td>112</td>
<td>Diff. Protection</td>
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<tr>
<td>115</td>
<td>Phase Distance</td>
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<td>Ear Distance</td>
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<td>Dis. Pickup</td>
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<td>I&gt;</td>
<td>Z&lt;</td>
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## Settings - General Power System Data

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### Settings – General Distance Protection

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<td>45°</td>
<td>50°</td>
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</tr>
<tr>
<td>1543</td>
<td>R LOAD (PH-PH)</td>
<td>1 A</td>
<td>0.100 .. 600,000 Ω; inf Ω</td>
<td>inf Ω</td>
<td>29.0 (prim) 38.7 (sec)</td>
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<tr>
<td>1544</td>
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<td>20 .. 60°</td>
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<td>50°</td>
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<tr>
<td>1605</td>
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<tr>
<td>1606</td>
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<tr>
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<tr>
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<td>NO</td>
<td>NO</td>
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<tr>
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<td>1902</td>
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<td>3.0s</td>
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<td>1903</td>
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<td>1910</td>
<td>Iph&gt;&gt;</td>
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<td>0.25 .. 10.00 A</td>
<td>1.80 A</td>
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<td>5 A</td>
<td>1.25 .. 50.00 A</td>
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## Settings – Polygon Characteristic of Distance Protection

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<th>Default Setting</th>
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<td>0.050 .. 120.000 Ω</td>
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<td>ALPH POLYG Zone Reduction</td>
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<td>0°</td>
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<td>0.050 .. 120.000 Ω</td>
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<tr>
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<td>T2-1phase</td>
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<td>0.4s</td>
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<tr>
<td>1622</td>
<td>R(Z3) PH-PH</td>
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<td>5.000 Ω</td>
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<td>5 A</td>
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<td>0.050 .. 120.000 Ω</td>
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<tr>
<td>1625</td>
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<td></td>
<td>5 A</td>
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<td>2.400 Ω</td>
<td></td>
</tr>
<tr>
<td>1634</td>
<td>RE(Z4) PH-E</td>
<td>1 A</td>
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<td>12.000 Ω</td>
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<td>5 A</td>
<td>0.010 .. 50.000 Ω</td>
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<tr>
<td>1635</td>
<td>T4 Delay</td>
<td></td>
<td>0.00 .. 30.00 s; ?</td>
<td>0.90 s</td>
<td></td>
</tr>
</tbody>
</table>
Power Swing Detection

7SD5 has an integrated power swing supplement which allows both the blocking of trips by the distance protection during power swins (power swing blocking) and the tripping during unstable power swings (out-of-step tripping). To avoid uncontrolled tripping, the distance protection devices are supplemented with power swing blocking functions. Three parameters have to be set:

The **power swing operation mode** affects the distance protection. If the criteria for power swing detection have been fulfilled in at least one phase, the following reactions are possible in relation to the power swing blocking function (set in address 2002 P/S Op. mode):

- All zones blocked
- Z1/Z1b blocked
- Z2 to Z5 blocked
- Z1, Z1b, Z2 blocked

Additionally the **tripping function** for unstable oscillations (out-of-step condition, loss of system synchronism) can be set with parameter Power Swing trip (address 2006). In the event of power swing tripping it is recommended to set P/S Op. mode = All zones block for the power swing blocking, to avoid premature tripping by the distance protection. Normally the tripping function is only used to divide Transmission Systems into groups in terms of instabilities. The function is proposed to be OFF.

---

<table>
<thead>
<tr>
<th>Adr.</th>
<th>Parameter</th>
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<th>Setting</th>
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<td>Forward, Inactive</td>
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<td>1643</td>
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<td>12.000 Ω</td>
<td>2.400 Ω</td>
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<td>2.400 Ω</td>
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<td>1645</td>
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<td>1651</td>
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<td>No</td>
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</tbody>
</table>
**The tripping delay** after power swing blocking can be set in address 2007 Trip DELAY P/S.

Recommended Setting:
- **2002** P/S Operation Mode: All zones block
- **2006** Power Swing Trip: NO
- **2007** Trip Delay P/S: 0.1s

**Fault Locator**

According KM request the fault locator is enabled (parameter 138). The following settings are proposed:

<table>
<thead>
<tr>
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<th>Parameter</th>
<th>Setting Options</th>
<th>Default Setting</th>
<th>Comments</th>
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<td>Pickup</td>
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<td>CN</td>
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<td>Tmax OUTPUT BCD</td>
<td>0.10 - 180.00 sec</td>
<td>0.30 sec</td>
<td>Maximum output time via BCD</td>
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</tbody>
</table>

### 4.6 REL561: 66 kV Cable Feeder - QC / EF Protection (51, 51N)

The relay is connected to existing CTs:

CT-Ratio: **800 / 1 A; PX**

The relay provides a two step time delayed non-directional phase over-current protection (TOC2).
Recommended Relay Settings Overcurrent Protection TOC2-51:

The OC relay sensitivity of inverse-time function is proposed to be 150% of the maximum load current of approximately 1.5x0.7kA = 1.05kA. The TMS is set to k = 0.33 in order to achieve a fault clearing time of about 2.5s at the fault current of 2.2kA.

The high set stage is proposed to be about 2.4kA, which is above the maximum pass-through s/c-current of 2.1kA (to avoid unselective operation) but surely below the minimum 66kV fault currents. The time delay is recommended to be 0.7s above the 66kV bus coupler.

Setting, low set (inverse time)

- Function: = enabled
- Operate Current Isetlow = 1.31 \( I_r \) (1050A primary)
- Curve Type = Normal Inverse
- Time Multiplier TMS = 0.33s
- t-min = 0.00 s

The relay operating time at a fault current of 2.2 kA is:

\[ t_{\text{Relay}}(2.2 \text{ kA}) = 0.33 \times 0.14 / ((2.2 \text{ kA} / 1.050 \text{ kA})^{0.02} - 1) = 3.0 \text{ s} \]
Setting, high set (definite time)

Function: \(=\) enabled
Operate Current \(I_{\text{SetHigh}}\) \(=\) 3.0 \(\times\) \(I_r\) \(=\) (2.4kA primary)
Time-Setting \(t_{\text{DefHigh}}\) \(=\) 0.7 s

Recommended Relay Settings Earftault Protection:
Adapted to the settings of S/S Old Airport East, this function is to be set inactive.

4.7 7SD5331: 66 kV Cable Feeder - OC / EF Protection

Maximally three definite time stages (DT) and one inverse time stage (IDMT), each for phase currents and for earth currents are possible. The settings are identical to those mentioned above (chapter 4.6), the operation mode should be set to “independent from any events”.

The relay is connected to existing CTs:
CT-Ratio: \(800 / 1\text{ A}; PX\)

Setting, inverse current stage (IEC)

Function: \(=\) enabled
Pickup value \(I_p\) \(=\) 1.31 \(\times\) \(I_r\) \(=\) (1050A primary)
Curve Type \(=\) Normal Inverse
Time Factor TIP \(=\) 0.33s
Additional time delay TIPdel \(=\) 0.00 s

Setting, overcurrent stage (definite time)

Function: \(=\) enabled
Pickup value \(I_{\text{ph}}>\) \(=\) 3 \(\times\) \(I_r\) \(=\) (2.4kA primary)
Delay TIPh> \(=\) 0.7 s

Setting Earthfault Protection
Adapted to the settings of S/S Old Airport East, this function is to be set inactive.
4.8 REL561: Thermal Overload Protection (49)

REL561: Cable Thermal Overload Protection

The THOL thermal overcurrent function supervises the phase currents and provides a reliable protection against damage caused by excessive currents. The temperature compensation gives a reliable thermal protection even when the ambient temperature has large variations.

The thermal overload function uses the highest phase current. The temperature change is continuously calculated and added to the figure for the temperature stored in the thermal memory. When temperature compensation is used, the ambient temperature is added to the calculated temperature rise. If no compensation is used, 20° is added as a fixed value. The calculated temperature of the object is then compared to the set values for alarm and trip.

The output signal THOL--TRIP has a duration of 50 ms. The output signal THOL--START remains activated as long as the calculated temperature is higher than the set trip value minus a settable temperature difference TdReset (hysteresis). The output signal THOL--ALARM has a fixed hysteresis of 5 Degree.

As per latest KM requirement (Nov 2007) the function shall not issue a trip command but only be used for alarm purpose. Alarm setting shall correspond to the temperature at 95% continuous full load current. For cable feeder, the base current refers to the cable current, for cable + transformer feeder the transformer current is taken as reference.

Main Setting Parameters:

Operation mode
NonComp = No Temperature Compensation

Base Current
I_{base} = 700A / 800A \times 100% = 87.5\% \text{ of } I_{1b}

Temperature rise at base current
Cable: type XLPE 800mm², Copper, max. operating temperature 90°

With fixed basic temperature of 20°, applicable temperature rise becomes 90° - 20° = 70°
T_{base} = 70\,\text{Degree}
**Thermal Time Constant**
The thermal time constant $\tau$ as given by the cable supplier is:

Cable: type XLPE 800mm$^2$, Copper, about 78 min

Proposed setting is the max. selectable value of $\tau = 62$ min
The use of this little lower time constant provides an additional safety margin.

**Alarm level**
The achieved temperature rise with 95% continuous current is $0,95^2 = 0,90$ times the full load current temperature rise, corresponding to $0,90 \times 70^\circ = 63^\circ$. Thus with fixed basic temperature of $20^\circ$ the alarm setting is calculated as $20^\circ + 63^\circ = 83^\circ$.

$T_{\text{alarm}} = 83^\circ$

**Trip level**
Because the trip stage will not be used it is proposed to take the highest possible setting of $150^\circ$ as 'dummy value'.

$T_{\text{trip}} = 150^\circ$

**Trip hysteresis**
$T_{\text{dReset}} = 10^\circ$
5 SS KTS West 66kV Cable to Doha Central (=B10, =B20)

5.1 Protection System General

The following schematic diagram provides an overview on the protection scheme.
66 kV Cable Data
3.75 km cable XLPE 800 mm². The provided technical data including the calculated charging current is given in the Section 2.2.

5.2 REL561: 66 kV-Cable Differential Protection
The REL561 provides cable differential protection at following cable routes:
- 66kV Feeder B10 and B20, 3.75km cable to SS Doha Central

REL561 - Protection Relay CT Data
The CT data are:
CT ratio: 400/800-1A, PX

The parameters are identical to those given in chapter 4.2, REL561 66kV Cable Differential Protection. Only Parameter DiffSync has to be set to ‘Slave’ condition.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Range</th>
<th>Setting</th>
<th>Unit</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>DiffSync</td>
<td>Master, Slave</td>
<td>Slave</td>
<td>-</td>
<td>Select if the terminal shall be Master or Slave</td>
</tr>
<tr>
<td>TerminalNo</td>
<td>0 - 255</td>
<td>Has to set on site</td>
<td>-</td>
<td>Terminal number of local terminal</td>
</tr>
<tr>
<td>RemoteTermNo</td>
<td>0 - 255</td>
<td>Has to set on site</td>
<td>-</td>
<td>Terminal number of remote terminal</td>
</tr>
</tbody>
</table>

5.3 7SD5331: 66 kV-Cable Differential Protection
The 7SD5331 provides cable differential protection at following cable routes:
- 66kV Feeder B10 and B20, 3.75km cable to SS Doha Central

7SD5331 - Protection Relay CT Data
The CT data is:
CT ratio: 400/800-1A, PX
The parameters are identical to those given in chapter 4.3, 7SD5331 66kV Cable Differential Protection.

5.4 **REL561: 66 kV-Cable Distance Protection**

Current and Voltage Transformer Data, Impedance Ratio
Voltage transformer ratio: $\bar{U}_U = (66kV/\sqrt{3}) / (110V/\sqrt{3})$
Current transformer ratio: $\bar{I}_I = 800/1A$
Impedance transformation ratio $\bar{U}_Z = \bar{I}_I/\bar{U}_U = 800/600 = 1.3333$ $Z_{sec} = \bar{U}_Z \times Z_{prim}$

The parameters are identical to those given in chapter 4.4, REL561 66kV Cable Distance Protection.

5.5 **7SD5331: 66 kV-Cable Distance Protection**

The CT data is:
CT ratio: 400/800-1A, PX

The parameters are identical to those given in chapter 4.5, 7SD5331 66kV Cable Distance Protection.

5.6 **REL561: 66 kV-Thermal Overload**

The THOL thermal overcurrent function supervises the phase currents and provides a reliable protection against damage caused by excessive currents. The temperature compensation gives a reliable thermal protection even when the ambient temperature has large variations.

The thermal overload function uses the highest phase current. The temperature change is continuously calculated and added to the figure for the temperature stored in the thermal memory. When temperature compensation is used, the ambient temperature is added to the calculated temperature rise. If no compensation is used, 20° is added as a fixed value. The calculated temperature of the object is then compared to the set values for alarm and trip.

The output signal THOL--TRIP has a duration of 50 ms. The output signal THOL--START remains activated as long as the calculated temperature is higher than the set trip value minus a settable temperature difference $T_d\text{Reset}$ (hysteresis). The output signal THOL--ALARM has a fixed hysteresis of 5 Degree.

As per latest KM requirement (Nov 2007) the function shall not issue a trip command but only be used for alarm purpose. Alarm setting shall correspond to the temperature at 95% continuous full load cur-

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rent. For cable feeder, the base current refers to the cable current, for cable + transformer feeder the transformer current is taken as reference.

### Main Setting Parameters:

#### Operation mode

NonComp = No Temperature Compensation

#### Base Current

\[ I_{base} = \frac{700A}{800A} \times 100% = 87.5\% \text{ (of } I_{1b}) \]

#### Temperature rise at base current

Cable: type XLPE 800mm², Copper, max. operating temperature 90°

With fixed basic temperature of 20°, applicable temperature rise becomes 90° - 20° = 70°

\[ T_{base} = 70 \text{ Degree} \]

#### Thermal Time Constant

The thermal time constant \( \tau \) as given by the cable supplier is:

Cable: type XLPE 800mm², Copper, about 78 min

Proposed setting is the max. selectable value of \( \tau = 62 \text{ min} \)

The use of this little lower time constant provides an additional safety margin.

#### Alarm level

The achieved temperature rise with 95% continuous current is 0.95² = 0.90 times the full load current temperature rise, corresponding to 0.90 * 70° = 63°. Thus with fixed basic temperature of 20° the alarm setting is calculated as 20° + 63° = 83°.

\[ T_{Alarm} = 83° \]

#### Trip level

Because the trip stage will not be used it is proposed to take the highest possible setting of 150° as 'dummy value'.

\[ T_{Trip} = 150° \]

#### Trip hysteresis

\[ T_{dReset} = 10° \]
6.1 Protection System General

The following schematic diagram provides an overview on the protection scheme.
6.2 REL551: 66 kV-Cable Differential Protection

The REL551 provides cable differential protection at following cable routes:
- 66kV Feeder B30 and B40 from SS KTS West to SS New Hitmi, length 2.6km

**REL551 - Differential Protection Setting**

The REL 551 differential protection characteristic is:

![Operating characteristic diagram](image)

**CT-Factor**

The secondary current that is to be compared in both terminals, must be related to a common current transformer ratio. With a CT-Factor default setting of 1.00, this is achieved when the current transformers at both terminals have the same rated primary current. When one of the terminal has a higher primary rated current than the other, this can be numerically equalized by the CT-Factor setting. By setting the CT-Factor in the terminal with the higher primary rated current to the quote between the lower and the higher rated current, the difference is equalized.

CT Ratio at SS KTS West: 400/1
CT-Ratio at SS New Hitmi West: 400/1
Recommended Setting: CT-Factor = 1.0

**CT-saturation detection**

In case of CT saturation, the degree of stabilization is increased in the affected phase in the differential protections at both ends acc. Figure 45. The Minimum phase current for saturation detection operation IminSat is recommended with 1.5 times of I1b (Base current Input 1):

Recommended setting: IMinSat = 150 (% of I1b)
**Minimum differential operating current**

The total cable charging current is less than 20A. The differential protection should be set at least 2.5 times the maximum charging current, the minimum current value setting is 50 A. However, the setting should not be unnecessarily low. A value of 80 A primary, respectively 0.2 times the base current \( I_{1B} \) is proposed.

Recommended setting: \( I_{\text{MinOp}} = 20 \% \text{ of } I_{1B} \)

**Stabilisation slope**

The stabilisation slope is decisive for the stability of the protection during external faults, i.e. in the presence of high through-fault currents. The slope defines the ratio of the differential current to restraint current. The setting should be like this, when operating under load condition, weak faults causing only a low differential current can still be detected, but at the same time there is no risk of false tripping during through-faults. A typical slope is 0.5, which is also suitable in this protection application.

Recommended setting:  
\[
\begin{align*}
I_{\text{diffLvI1}} &= 50 \% \text{ of } I_{\text{bias}} \quad \text{Slope 1 stabilisation} \\
I_{\text{diffLvI2}} &= 50 \% \text{ of } I_{\text{bias}} \quad \text{Slope 2 stabilisation} \\
I_{\text{lvI1/I2Cross}} &= 500 \% \text{ of } I_{\text{bias}} \quad \text{Slope 2 intersection}
\end{align*}
\]

**Tripping conditions:**

As there is no emphasis on reducing the operating time, the default parameter \( \text{Evaluate} = 3 \) of 4 is proposed herein. This is on the conservative side to prevent unwanted operation due to corrupt message of data exchange between relays.

**Setting Parameters for the line differential protection function**

**Setting parameters:**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Range</th>
<th>Setting</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operation</td>
<td>Off/On</td>
<td>On</td>
<td>Operation Line Differential Protection</td>
</tr>
<tr>
<td>CT Factor</td>
<td>0.4-1.0</td>
<td>1.0</td>
<td>Factor for matching Current Transformer</td>
</tr>
<tr>
<td>( I_{\text{MinSat}} )</td>
<td>100-1000</td>
<td>150%</td>
<td>Min. phase current for saturation detection operation</td>
</tr>
<tr>
<td>( I_{\text{MinOp}} )</td>
<td>20-150</td>
<td>20%</td>
<td>Minimum differential operating current</td>
</tr>
<tr>
<td>( I_{\text{diffLvI1}} )</td>
<td>20-150</td>
<td>50%</td>
<td>Slope 1 stabilisation</td>
</tr>
<tr>
<td>( I_{\text{diffLvI2}} )</td>
<td>30-150</td>
<td>50%</td>
<td>Slope 2 stabilisation</td>
</tr>
<tr>
<td>( I_{\text{lvI1/I2Cross}} )</td>
<td>100-1000</td>
<td>500%</td>
<td>Slope 2 intersection</td>
</tr>
<tr>
<td>Evaluate</td>
<td>2 of 4 / 3 of 4</td>
<td>3 of 4</td>
<td>Tripping Condition</td>
</tr>
</tbody>
</table>
**Master – Slave**

Within a pair of differential relays, one has to be master and the other slave. For this project, the relays at 66kV SS KTS West are proposed as ‘Master’ while the relays at the 66kV SS New Hitmi are proposed as ‘Slave’.

To make sure that differential protection communicates with the correct protection at the opposite terminal, the terminal are numbered. By giving all differential protections transmitting over common multiplexer individual identification numbers, communication with the wrong terminal can be avoided. The identification number of the opposite terminal must also be set. This is always necessary.

### Setting parameters:

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Range</th>
<th>Setting</th>
<th>Unit</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>DiffSync</td>
<td>Master, Slave</td>
<td>Master</td>
<td>-</td>
<td>Select if the terminal shall be Master or Slave</td>
</tr>
<tr>
<td>TerminalNo</td>
<td>0 – 255</td>
<td>Has to set on site</td>
<td>-</td>
<td>Terminal number of local terminal</td>
</tr>
<tr>
<td>RemoteTermNo</td>
<td>0 – 255</td>
<td>Has to set on site</td>
<td>-</td>
<td>Terminal number of remote terminal</td>
</tr>
</tbody>
</table>

### Remote Terminal Communication

The parameter “Asym delay” can be used if there exists a fixed and known difference between the communication times in the two directions. “Asym delay” is set to 0.00 for normal applications.

### Setting parameter:

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Range</th>
<th>Setting</th>
<th>Unit</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>AsymDelay</td>
<td>0.00 – 5.00 Step: 0.01</td>
<td>0.00</td>
<td>ms</td>
<td>Asymmetric delay for line differential</td>
</tr>
</tbody>
</table>

### Charging Current Compensation

Due to the small charging current of 14A related to the minimum differential operating current, the CCC-function is recommended to be disables (OFF).

6.3  **REL551: 66kV Thermal Overload Protection (49)**

The THOL thermal overcurrent function supervises the phase currents and provides a reliable protection against damage caused by excessive currents. The temperature compensation gives a reliable thermal protection even when the ambient temperature has large variations.
The thermal overload function uses the highest phase current. The temperature change is continuously calculated and added to the figure for the temperature stored in the thermal memory. When temperature compensation is used, the ambient temperature is added to the calculated temperature rise. If no compensation is used, 20° is added as a fixed value. The calculated temperature of the object is then compared to the set values for alarm and trip.

The output signal THOL--TRIP has a duration of 50 ms. The output signal THOL--START remains activated as long as the calculated temperature is higher than the set trip value minus a settable temperature difference TdReset (hysteresis). The output signal THOL--ALARM has a fixed hysteresis of 5 Degree.

As per latest KM requirement (Nov 2007) the function shall not issue a trip command but only be used for alarm purpose. Alarm setting shall correspond to the temperature at 95% continuous full load current. For cable feeder, the base current refers to the cable current, for cable + transformer feeder the transformer current is taken as reference.

Main Setting Parameters:

Operation mode
NonComp = No Temperature Compensation

Base Current
I_{base} = 219A / 400A x 100% = 55 % (of I_{bb})

Temperature rise at base current
Cable: type XLPE 300mm², Copper, max. operating temperature 90°

With fixed basic temperature of 20°, applicable temperature rise becomes 90° - 20° = 70°
T_{base} = 70 Degree

Thermal Time Constant
The thermal time constant \( \tau \) as given by the cable supplier is:
Cable: type XLPE 300mm², Copper, about 70 min

Proposed setting is the max. selectable value of \( \tau = 62 \) min
The use of this little lower time constant provides an additional safety margin.
Alarm level
The achieved temperature rise with 95% continuous current is $0.95^2 = 0.90$ times the full load current temperature rise, corresponding to $0.90 \times 70^\circ = 63^\circ$. Thus with fixed basic temperature of $20^\circ$ the alarm setting is calculated as $20^\circ + 63^\circ = 83^\circ$.

$T_{\text{Alarm}} = 83^\circ$

Trip level
Because the trip stage will not be used it is proposed to take the highest possible setting of $150^\circ$ as ‘dummy value’.

$T_{\text{Trip}} = 150^\circ$

Trip hysteresis

$T_{d\text{Reset}} = 10^\circ$

6.4 REL316: 66kV Cable+Transformer Feeder - Differential Protection (87C+T)

The REL316 provides cable and transformer differential protection. There is an FO to opposite side The relay at opposite side is connected to a 1500/1 A CT.

REL316 - Protection Relay CT Data
The CT data are:
CT ratio 66kV substation: 400 / 1A, PX
CT ratio 11kV substation: 1500 / 1A, PX

REL316 - Differential Protection Setting
The REL 316 differential protection characteristic is:
The restraint current $I_r$ for through-fault currents is $I_r = \sqrt{I_1 \times I_2}$ with $\alpha \geq 0^\circ$. For internal faults fed from one side ($I_2 = 0$) or fed from both sides ($\alpha = 180^\circ$) the restraint current $I_r$ is 0. If $I_r$ and $I_1$ and $I_2$ are higher than the set value "b", the characteristic is switched to infinity in order to inhibit a false tripping due to error currents due to c.t. saturation. If one of the currents is less than the setting of "b", the characteristic is switched back to the gradient according to the setting "v".
Amplitude Compensation Factors a1, a2, a3

Factors a1, a2 and a3 facilitate compensating differences between the rated currents of the protected unit and the CTs. The 'a' factors are defined by the ratio of the CT rated current to the reference current. In the case of a two-winding transformer, both windings have the same rated power and the rated current of the transformer is taken as the reference current. Providing the factor 'a' is correctly set, all the settings of g, v, b, g-High and l-Inst. are referred to the rated current of the transformer and not to the rated primary current of the CT. A-factors only affects the differential protection functions.

Recommended setting:
\[ a_1 = \frac{I_{CT}}{I_{TN1}} = \frac{400 \text{ A}}{218.7 \text{ A}} = 1.83 \]
\[ a_2 = \frac{I_{CT}}{I_{\text{max}}} = \frac{1500 \text{ A}}{1312.2 \text{ A}} = 1.14 \]
a3 not set

Group of connections s1, s2, s3

The factor s1 defines the connection of the phase winding 1. Factors s2 and s3 define the group of connections. They define firstly how the windings are connected and secondly, their phase-angle referred to winding 1. The earthed zigzag winding of the earthing/auxiliary within the protected zone needs special attention as the zero sequence current has to be filtered out on 11 kV side. This is done within REx316 serie relays by setting 'z' instead of 'd'.

Recommended setting:
\[ s_1 = Y \text{ (star connected) } \]
\[ s_2 = z1 \text{ (delta connected main transformer with earthed zigzag winding in protected zone) } \]
s3 not set

Basic setting g

The basic setting "g" defines the pick-up value setting of the differential protection for internal faults. The setting range is 0.1 to 0.5 of the base current defined by a1 and a2.

The differential protection has to consider possible errors of the cable and the transformer.

- The charging current of the cable: <10A
- The maximum current mismatch due to the 66 kV-tap changer at min. and max. tap position is:
  \[ \Delta I = 249.9 \text{ A} - 218.7 \text{ A} = 31.2 \text{ A} \]
  \[ \Delta I = 1312 \text{ A} - 1312 \text{ A} = 0.0 \text{ A} \]
- An additional safety margin of 5% respectively 20A is required to cater for additional error currents and increased magnetizing currents due to over-excitation of CTs
- The maximum through-fault current for LV-faults at EA-Transformer is about 520A at 11kV respectively 86A at 66kV
Therefore, the errors sums up to \( \frac{(10A + 31.2A + 20A + 86A)}{400A} = 0.37 \)

Recommended setting: \( I_{\text{DIFF}} > 0.4 \)

**Increased basic setting g-High**

The increased basic setting g-high may be applied for the differential protection setting. The g-high setting is activated by the signal "HighSetInp = Always True". It is used to prevent false tripping due, for example, to excessive flux (overfluxing).

Recommended setting: HighSetInput = False

Note: The fast-acting supervision of the communication channel integrated in the function blocks, the protection in the event of a communication failure and excludes any possibility of false tripping.

**Pick-up ratio v**

The pick-up ratio "v" is decisive for the stability of the protection during external faults, i.e. in the presence of high through-fault currents. The value "v" defines the ratio of the operating current to restraint current. The setting should be like this, when operating under load condition, weak faults causing only a low differential current can still be detected, but at the same time there is no risk of false tripping during through-faults. A typical setting is \( v = 0.5 \), which is also suitable in this protection application.

Recommended setting: \( v = 0.5 \)

**Restraint current b**

The restraint current b defines the point at which the characteristic is switched. The recommended setting for "b" is 1.5. This provides high stability during through-fault currents and sufficient sensitivity to detect fault currents in the region of the operating current.

Recommended setting: \( b = 1.5 \times I_n \)

With the recommended setting a through-fault current of 330A or higher causes the characteristic to be switched to infinity (operation blocked). At the same time this setting is above the maximum load current. In case of an internal fault \( (I_{ih} = 0) \), the relay acts at a differential current of 110A.

**Differential current I-Inst**

The differential current setting I-Inst facilitates fast tripping of high internal fault currents without considering the inrush detection and inrush time blocking unit. A setting above the through-fault current of 2.2kA is proposed:

Recommended setting: \( I_{\text{Inst}} = 12 \times I_n = 2620A \)
Pick-up ratio for detecting inrush (InrushRatio) “InrushInp” = False
The setting of this ratio determines the sensitivity of the function for detecting inrush. Generally the ratio of 2nd harmonic is greater than 15%. Allowing a safety margin to ensure that an inrush condition is detected, a setting of 10% is recommended. If the differential current exceeds I-Inst = 3 x I_n, this function is bypassed.

Duration of active inrush detection (InrushTime) “InrushInp” = False
The setting determines the blocking time of the differential protection when detecting an inrush condition. The proposed time setting is 5 second. If the differential current exceeds I-Inst = 3 x I_n this function is bypassed.
Both inrush detectors (master relay and slave relay) have to be activated.

6.5 **REX521: 66 kV Cable/Transformer Back up Protection**
The back up transformer protection terminal is of the ABB type REX521 H04. In this protection device the following protection and monitoring functions are implemented:
- 50 Instantaneous Over-current Protection
- 51 Time Delayed Over-current Protection
- 51N Time Delayed Earth fault Protection

**REX521: Over-current Protection (50/51)**

**CT data**
- 66 kV Transformer Feeder (Core 2) 400 A - 800 A / 1A, PX, 30 VA

**Cable Rating**
- Type XLPE 300mm², Copper, max. operating temperature 90°
- Rating current cont. 350 A

**Transformer operating currents:**
- Rated transformer current tap mid: 218.7 A (25 MVA @ 66 kV)
- Transformer current tap 1: 203.4 A (25 MVA @ 70.9 kV)
- Transformer current tap 17: 249.9 A (25 MVA @ 57.8 kV)

The maximum three-phase transformer through-fault current is 2.2 kA.
According KM request, the start current of the I> stage is set to 150 % of the transformer rating current of \( I_T = 218.7 \text{ A} \), which gives a primary current setting \( I> = 328 \text{ A} \). This current setting is also above the maximum transformer current at tap 17 of 249.9 A.

The secondary relay setting is:
\[ I> = 1.50 \times 218.7 \text{ A} \times 1/400 = 0.82 \text{ A} \text{ secondary} \]

The proposed time multiplier setting is \( k = 0.8 \). The TMS is selected to achieve a relay operation time of 1.9 s at the maximum transformer through-fault current of 2.2 kA at the 66 kV-feeder.

The relay operating time at maximum through fault current is:
\[ t_{\text{Relay}}(2.2 \text{ kA}) = 0.8 \times 13.5 / ((2200 \text{ A/328 A})^1 - 1) = 1.89 \text{ s} \]

The transformer thermal short-circuit withstand capacity of 2 sec (assumed value, 2 s is according to IEC 76) is protected.

**I>>-stage**

Start current of the I>> stage is set to 150% of the max. 66 kV-through fault current at 11 kV-faults:
\[ I>> = 1.5 \times I_{sc}(11 \text{ kV}) \times 1/CT_{Ratio} = 1.5 \times 2.2 \text{ kA} \times 1 / 400 = 8.25 \text{ A} \]

The relay time \( t>> \) is 0.10 s.

The setting corresponds to \( I>> = 3.3 \text{ kA} \) primary current, the time delay of 0.1 s stabilizes the I>>-stage against transient phenomena.

**Recommended setting**

Relay module: REX521 “Three-phase non-directional over-current protection, low-set stage, 3I>”
\[ I_\text{>,} = 1.31 \times I_N \quad \text{(is 524 A primary)} \]
\[ \text{TMS} = 0.45 \]
\[ I_\text{>,} \text{ curve is very inverse} \]

Relay module: REX521 “Three-phase non-directional over-current protection, high-set stage, 3I>>”
\[ I_{\text{>>,}} = 8.25 \times I_N \quad \text{(is 3300 A primary)} \]
\[ t_{\text{>>}} = 0.1 \text{ s} \]

**REX521: Earth-fault Protection (51N)**

**Recommended setting Io>-stage**

Relay module: REX521 “Non-directional earth fault protection, low-set stage, Io>”

According KM practice, function not used.
7. **New Hitmi 66 kV (=B30, =B40) cable to KTS West**

7.1 **REL551: 66kV Cable Differential Protection**

The REL551 provides cable differential protection at following cable routes:
- 66kV Transformer New Hitmi to SS KTS West

**REL551 - Differential Protection Setting**

The REL 551 differential protection characteristic is:

![Graph showing the differential protection characteristic](image)

**CT-Factor**

The secondary current that is to be compared in both terminals, must be related to a common current transformer ratio. With a CT-Factor default setting of 1.00, this is achieved when the current transformers at both terminals have the same rated primary current. When one of the terminal has a higher primary rated current than the other, this can be numerically equalized by the CT-Factor setting. By setting the CT-Factor in the terminal with the higher primary rated current to the quote between the lower and the higher rated current, the difference is equalized.

CT Ratio at SS KTS West: 400/1
CT-Ratio at SS New Hitmi West: 400/1
Recommended Setting: CT-Factor = 1.0
CT-saturation detection
In case of CT saturation, the degree of stabilization is increased in the affected phase in the differential protections at both ends acc. Figure 45. The Minimum phase current for saturation detection operation IminSat is recommended with 1.5 times of I1b (Base current Input 1):
Recommended setting:  IminSat = 150 (% of I1b)

Minimum differential operating current
The total cable charging current is less than 20 A. The differential protection should be set at least 2.5 times the maximum charging current, the minimum current value setting is 50 A. However, the setting should not be unnecessary low. A value of 80 A primary, respectively 0.2 times the base current I1B is proposed.
Recommended setting:  IminOp = 20 (% of I1B)

Stabilisation slope
The stabilisation slope is decisive for the stability of the protection during external faults, i.e. in the presence of high through-fault currents. The slope defines the ratio of the differential current to restraint current. The setting should be like this, when operating under load condition, weak faults causing only a low differential current can still be detected, but at the same time there is no risk of false tripping during through-faults. A typical slope is 0.5, which is also suitable in this protection application.
Recommended setting:  IdiffLv1 = 50 (% of Ibias)  Slope 1 stabilisation
IdiffLv1 = 50 (% of Ibias)  Slope 2 stabilisation
Ilv1/I2Cross = 500 (% of Ibias)  Slope 2 intersection

Tripping conditions:
As there is no emphasis on reducing the operating time, the default parameter Evaluate = 3 of 4 is proposed herein. This is on the conservative side to prevent unwanted operation due to corrupt message of data exchange between relays.
Setting Parameters for the line differential protection function

Setting parameters:

<table>
<thead>
<tr>
<th>Parameter</th>
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<th>Setting</th>
<th>Description</th>
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<td>On</td>
<td>Operation Line Differential Protection</td>
</tr>
<tr>
<td>CT Factor</td>
<td>0.4-1.0</td>
<td>1.0</td>
<td>Factor for matching Current Transformer</td>
</tr>
<tr>
<td>IMinSat</td>
<td>100-1000</td>
<td>150%</td>
<td>Min. phase current for saturation detection operation</td>
</tr>
<tr>
<td>IminOp</td>
<td>20-150</td>
<td>20%</td>
<td>Minimum differential operating current</td>
</tr>
<tr>
<td>IdiffLv1</td>
<td>20-150</td>
<td>50%</td>
<td>Slope 1 stabilisation</td>
</tr>
<tr>
<td>IdiffLv2</td>
<td>30-150</td>
<td>50%</td>
<td>Slope 2 stabilisation</td>
</tr>
<tr>
<td>Ilv1/I2Cross</td>
<td>100-1000</td>
<td>500%</td>
<td>Slope 2 intersection</td>
</tr>
<tr>
<td>Evaluate</td>
<td>2 of 4 / 3 of 4</td>
<td>3 of 4</td>
<td>Tripping Condition</td>
</tr>
</tbody>
</table>

Master – Slave

Within a pair of differential relays, one has to be master and the other slave. For this project, the relays at 66kV SS KTS West are proposed as 'Master' while the relays at the 66kV SS New Hitmi are proposed as 'Slave'.

To make sure that differential protection communicates with the correct protection at the opposite terminal, the terminal are numbered. By giving all differential protections transmitting over common multiplexer individual identification numbers, communication with the wrong terminal can be avoided. The identification number of the opposite terminal must also be set. This is always necessary.

Setting parameters:

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Range</th>
<th>Setting</th>
<th>Unit</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>DiffSync</td>
<td>Master, Slave</td>
<td>Slave</td>
<td>-</td>
<td>Select if the terminal shall be Master or Slave</td>
</tr>
<tr>
<td>TerminalNo</td>
<td>0 - 255</td>
<td>Has to set on site</td>
<td>-</td>
<td>Terminal number of local terminal</td>
</tr>
<tr>
<td>RemoteTermNo</td>
<td>0 - 255</td>
<td>Has to set on site</td>
<td>-</td>
<td>Terminal number of remote terminal</td>
</tr>
</tbody>
</table>

Remote Terminal Communication

The parameter “Asym delay” can be used if there exists a fixed and known difference between the communication times in the two directions. “Asym delay” is set to 0.00 for normal applications.
Setting parameter:

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Range</th>
<th>Setting</th>
<th>Unit</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>AsymDelay</td>
<td>0.00 – 5.00 Step: 0.01</td>
<td>0.00</td>
<td>Ms</td>
<td>Asymmetric delay for line differential</td>
</tr>
</tbody>
</table>

**Charging Current Compensation**

Due to the small charging current compared to the minimum differential operating current, the CCC-function is recommended to be disabled (OFF).

### 7.2 REL551: 66kV Thermal Overload Protection (49)

The THOL thermal overcurrent function supervises the phase currents and provides a reliable protection against damage caused by excessive currents. The temperature compensation gives a reliable thermal protection even when the ambient temperature has large variations.

The thermal overload function uses the highest phase current. The temperature change is continuously calculated and added to the figure for the temperature stored in the thermal memory. When temperature compensation is used, the ambient temperature is added to the calculated temperature rise. If no compensation is used, 20° is added as a fixed value. The calculated temperature of the object is then compared to the set values for alarm and trip.

The output signal THOL--TRIP has a duration of 50 ms. The output signal THOL--START remains activated as long as the calculated temperature is higher than the set trip value minus a settable temperature difference TdReset (hysteresis). The output signal THOL--ALARM has a fixed hysteresis of 5 Degree.

**Main Setting Parameters:**

**Operation mode**
NonComp = No Temperature Compensation

**Base Current**

It is assumed, that the 25MVA transformer at New Hitmi is equipped with transformer overload protection (oil temperature, winding temperature), therefore the thermal overload protection can be applied to the cable rating current.

\[ I_{\text{base}} = \frac{350A}{400A} \times 100\% = 87.5\% \ (\text{of} \ I_1 \ \text{equal to transformer rating}) \]
Temperature rise at base current
\( T_{\text{base}} = 90 \) Degree

Thermal Time Constant
The maximum thermal time constant \( \tau \) can be derived from the cable/transformer data:
Cable: type XLPE 350mm\(^2\), Copper, max. operating temperature 90°
Rating current cont. 350 A
Transformer: \( I_r = 220A \) (25MVA at 66kV)

A thermal time constant of \( \tau = 30 \)min is proposed.

Alarm level
Alarm will be given at 80°.
\( T_{\text{Alarm}} = 80° \)

Trip level
A Trip will be applied at 110° (due to no compensation mode: 90° + 20°)
\( T_{\text{trip}} = 110° \)

Trip hysteresis
\( T_{\text{Reset}} = 10° \)

7.3 REL316: 11kV Cable+Transformer Feeder - Differential Protection (87C+T)
The REL316 provides cable and transformer differential protection. There is an FO to opposite side. The relay at opposite side is connected to CT4 of 66kV Feeder at substation KTS West (=B30/B40).

REL316 - Protection Relay CT Data
The CT data are:
CT ratio 66kV substation: 400 / 1A, PX
CT ratio 11kV substation: 1500 / 1A, PX

REL316 - Differential Protection Setting
The REL 316 differential protection characteristic is:
The restraint current \( I_R \) for through-fault currents is \( I_R = \sqrt{l_1 \times l_2} \) with \( \alpha = 0^\circ \). For internal faults fed from one side \( (l_2 = 0) \) or fed from both sides \( (\alpha = 180^\circ) \) the restraint current \( I_R \) is 0. If \( I_R \) and \( l_1 \) and \( l_2 \) are higher than the set value "b", the characteristic is switched to infinity in order to inhibit a false tripping due to error currents due to c.t. saturation. If one of the currents is less than the setting of "b", the characteristic is switched back to the gradient according to the setting "v".

\[
I_R = \begin{cases} 
\sqrt{l_1 \times l_2} & \text{for } \cos \alpha \geq 0 \\
0 & \text{for } \cos \alpha < 0
\end{cases}
\]

where

\[
l_1, l_2, \quad \alpha = \tan^{-1} \left( \frac{l_2}{l_1} \right)
\]

\[
l_a = |l_1 + l_2|
\]

\[
I_R = \begin{cases} 
\sqrt{l_1 \times l_2} \cos \alpha & \text{for } \cos \alpha \geq 0 \\
0 & \text{for } \cos \alpha < 0
\end{cases}
\]

The restraint current \( I_R \) for through-fault currents is \( I_R = \sqrt{l_1 \times l_2} \) with \( \alpha = 0^\circ \). For internal faults fed from one side \( (l_2 = 0) \) or fed from both sides \( (\alpha = 180^\circ) \) the restraint current \( I_R \) is 0. If \( I_R \) and \( l_1 \) and \( l_2 \) are higher than the set value "b", the characteristic is switched to infinity in order to inhibit a false tripping due to error currents due to c.t. saturation. If one of the currents is less than the setting of "b", the characteristic is switched back to the gradient according to the setting "v".
Amplitude Compensation Factors a1, a2, a3

Factors a1, a2 and a3 facilitate compensating differences between the rated currents of the protected unit and the CTs. The 'a' factors are defined by the ratio of the CT rated current to the reference current. In the case of a two-winding transformer, both windings have the same rated power and the rated current of the transformer is taken as the reference current. Providing the factor 'a' is correctly set, all the settings of g, v, b, g-High and I-Inst. are referred to the rated current of the transformer and not to the rated primary current of the CT. A-factors only affects the differential protection functions.

Recommended setting:
\[ a_2 = \frac{I_{CT}}{I_{TN1}} = \frac{400\, \text{A}}{218.7\, \text{A}} = 1.83 \]
\[ a_1 = \frac{I_{CT}}{I_{\text{max}}} = \frac{1500\, \text{A}}{1312.2\, \text{A}} = 1.14 \]
a_3 not set

Group of connections s1, s2, s3

The factor s1 defines the connection of the phase winding 1. Factors s2 and s3 define the group of connections. They define firstly how the windings are connected and secondly, their phase-angle referred to winding 1. The earthed zigzag winding of the earthing/auxiliary within the protected zone needs special attention as the zero sequence current has to be filtered out on 11 kV side. This is done within REx316 serie relays by setting 'z' instead of 'd'.

Recommended setting:
\[ s_1 = \text{Y (star connected)} \]
\[ s_2 = z_1 \, (\text{delta connected main transformer with earthed zigzag winding in protected zone}) \]
\[ s_3 \, \text{not set} \]

Basic setting g

The basic setting "g" defines the pick-up value setting of the differential protection for internal faults. The setting range is 0.1 to 0.5 of the base current defined by a1 and a2.

The differential protection has to consider possible errors of the cable and the transformer.

- The charging current of the 66kV cable: <10A
- The maximum current mismatch due to the 66 kV-tap changer at min. and max. tap position is:
  \[ 66 \, \text{kV-current} \quad \Delta I = 249.9 \, \text{A} - 218.7 \, \text{A} = 31.2 \, \text{A} \]
  \[ 11 \, \text{kV-current} \quad \Delta I = 1312 \, \text{A} - 1312 \, \text{A} = 0.0 \, \text{A} \]
- An additional safety margin of 5% respectively 20A is required to cater for additional error currents and increased magnetizing currents due to over-excitation of CTs
- The maximum through-fault current for LV-faults at EA-Transformer is 517A at 11kV respectively 86A at 66kV
Therefore, the errors sums up to \((10A+31.2A+20A)*66/11+517A)/1500A = 0.406\)

Recommended setting: \[I_{\text{DIFF}} > 0.4\]

**Increased basic setting \(g\text{-High}\)**

The increased basic setting \(g\)-high may be applied for the differential protection setting. The \(g\)-high setting is activated by the signal "HighSetInp = Always True". It is used to prevent false tripping due, for example, to excessive flux (overfluxing).

Recommended setting: HighSetInput = False

Note: The fast-acting supervision of the communication channel integrated in the function blocks, the protection in the event of a communication failure and excludes any possibility of false tripping.

**Pick-up ratio \(v\)**

The pick-up ratio \(v\) is decisive for the stability of the protection during external faults, i.e. in the presence of high through-fault currents. The value \(v\) defines the ratio of the operating current to restraint current. The setting should be like this, when operating under load condition, weak faults causing only a low differential current can still be detected, but at the same time there is no risk of false tripping during through-faults. A typical setting is \(v = 0.5\), which is also suitable in this protection application.

Recommended setting: \(v = 0.5\)

**Restraint current \(b\)**

The restraint current \(b\) defines the point at which the characteristic is switched. The recommended setting for \(b\) is 1.5. This provides high stability during through-fault currents and sufficient sensitivity to detect fault currents in the region of the operating current.

Recommended setting: \(b = 1.5 \times I_n\)

With the recommended setting a through-fault current of 1.968kA or higher causes the characteristic to be switched to infinity (operation blocked). At the same time this setting is above the maximum load current. In case of an internal fault (\(I_i = 0\)), the relay acts at a differential current of 656A.

**Differential current \(I_{\text{Inst}}\)**

The differential current setting \(I_{\text{Inst}}\) facilitates fast tripping of high internal fault currents without considering the inrush detection and inrush time blocking unit. A setting above the through-fault current of 2.2kA (13.2kA secondary side) is proposed:

Recommended setting: \(I_{\text{Inst}} = 12 \times I_n = 15.7\text{kA}\)

**Pick-up ratio for detecting inrush (InrushRatio) “InrushInp” = False**
The setting of this ratio determines the sensitivity of the function for detecting inrush. Generally the ratio of 2nd harmonic is greater than 15%. Allowing a safety margin to ensure that an inrush condition is detected, a setting of 10% is recommended. If the differential current exceeds \( I_{\text{Inst}} = 3 \times I_n \), this function is bypassed.

**Duration of active inrush detection (InrushTime) “InrushInp” = False**

The setting determines the blocking time of the differential protection when detecting an inrush condition. The proposed time setting is 5 second. If the differential current exceeds \( I_{\text{Inst}} = 3 \times I_n \), this function is bypassed.

Both inrush detectors (master relay and slave relay) have to be activated.
8 KTS West 66 kV Bus Section Protection (=B12)

8.1 REX521: 66 kV Protection of Bus Section

Relay Functions:
The protection terminal is of the ABB type REX521 H04. In this protection device the following protection functions are implemented:
- 51 Over-current Protection
- 51N Earth-fault Protection

CT Data
CT-Ratio:
2000 / 1 A, PX, 10 VA

Busbar Data
Switchgear rated current: 2500 A
Switchgear s/c-rating: 31.5 kA (1 s)

Protection Scheme
REX521 – 66 kV-Bus Section Over-current Protection (51)

In case of short circuit currents due to 66kV feeder faults or 11kV faults, the Bus Coupler relay is stressed by the same currents than the DOHA Central feeders. Equal settings should be applied with a reduced TMS and a s/c time of 0.4s. With the proposed settings, selectivity between KTS West transformer feeders, the bus coupler and the Doha Central feeders is given over the full current range (refer to figure [5] at chapter 20).

Recommended setting
Relay module: REX521 “Three-phase non-directional over-current protection, low-set stage, 3I>”
\[ I_\text{>,} = 0.5 \times I_N \quad \text{(is 1000 A primary)} \]
\[ \text{TMS} = 0.27 \]
\[ I_\text{>, curve is normal inverse} \]

Relay module: REX521 “Three-phase non-directional over-current protection, high-set stage, 3I>>”
\[ I_\text{>>,} = 1.2 \times I_N \quad \text{(is 2400 A primary)} \]
\[ t_\text{>>,} = 0.4s \quad \text{Definite Time} \]

REX521 – 66 kV-Bus Section Earth-fault Protection (51N)
An EF relay sensitivity of 400 A is proposed, this is 20% of CT rated primary current. The secondary current setting is: \( I_\ge \ge 0.2 \text{ A} \). The TMS is set to \( k = 0.2 \).

Recommended setting
Relay module: REX521 “Non-directional earth fault protection, low-set stage, \( I_0> \)”
\[ \text{CT} = 2000 \text{ A} \div 1 \text{ A} \]
Base current \[ I_{0>/IN} = 0.2 \times I_N = 400 \text{ A} \]
Time multiplier \[ 0.20 \]
Time characteristic \[ \text{normal inverse} \]
The relay operating time at a fault current of 6.0 kA is:
\[ t_{\text{Relay} (6.0 \text{ kA})} = 0.2 \times 0.14 / ((6.0 \text{ kA}/0.4 \text{ kA})^{0.02} - 1) = 0.5 \text{ s} \]
9 KTS West 66 kV Bus Bar and Breaker Failure Protection (REB 500)

The busbar and breaker failure protection terminals are of the ABB type REB500. In this protection device the following protection functions are implemented:

- 50BF Breaker Failure Protection
- 87B Busbar Differential Protection
- CT data

The REB500 is connected to CTs of 2000 / 1 A, PX

9.1 REB 500 - Busbar Protection Setting

- Restrained amplitude comparison - \( I_{k_{\text{min}}} \) and k setting

The restrained amplitude comparison algorithm detects an internal fault when the settings for \( I_{k_{\text{min}}} \) and k are exceeded. A tripping command is only issued, however, providing the phase comparison function detects an internal fault at the same time.

The pick-up setting for the fault current (\( I_{k_{\text{min}}} \)) must be less than the lowest fault current which can occur on the busbars, recommended level is 80% of \( I_{\text{scmin}} \). There is a risk of the protection being too insensitive at higher settings. Providing the minimum fault current is high enough, \( I_{k_{\text{min}}} \) should be set higher than the maximum load current.

- Minimum fault current
  The minimum fault current at 66 kV is calculated with 3.0 kA. A setting below the minimum fault current is required.

- Maximum load current
  The busbar current rating is 2500 A, the loading will not be above that value.

\[ I_{k_{\text{min}}} = 125\% \times ICT = 1.25 \times 2000 \text{ A} = 2500 \text{ A} \] is proposed.

This current value is below the minimum fault current and is equal to the expected maximum load current.

- The factor k is set to 0.8

Numerous tests on a network model have shown this setting to be most favourable according to the REB500 relay manual.

- Differential Current Alarm Setting
  The setting is given as a percentage of the minimum fault current setting. A typical setting according to the REB500 manual is \( I_{\text{diff}} = 5\% \).

- Differential Current Alarm Delay Setting
  Should the differential current alarm pick up, alarm is not actually given until the time delay has expired. A typical setting according to the REB500 manual is Time Delay for \( I_{\text{diff}} = 5 \text{ s} \).

- Busbar protection setting table
### Protection Relay Setting Calculation for 66/11 kV Substation KTS West

#### Proj. no. 8765002300

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Min.</th>
<th>Max.</th>
<th>Default</th>
<th>Step</th>
<th>Unit</th>
<th>Proposed settings</th>
</tr>
</thead>
<tbody>
<tr>
<td>( I_{\text{min}} ) (Phase fault current)</td>
<td>500</td>
<td>6000</td>
<td>1000</td>
<td>100</td>
<td>A</td>
<td>2500 A</td>
</tr>
<tr>
<td>Op. char. 'L1, L2, L3'</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>( K )</td>
<td>0.7</td>
<td>0.9</td>
<td>0.80</td>
<td>0.05</td>
<td></td>
<td>0.8</td>
</tr>
<tr>
<td>Op. char. 'L1, L2, L3'</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>( I_{\text{diff}} ) Differential current alarm</td>
<td>5</td>
<td>50</td>
<td>10</td>
<td>5</td>
<td>% ( I_{\text{min}} )</td>
<td>5%</td>
</tr>
<tr>
<td>Op. char. 'L1, L2, L3'</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Time Delay (differential current alarm)</td>
<td>5</td>
<td>50</td>
<td>5</td>
<td>5</td>
<td>s</td>
<td>5 s</td>
</tr>
<tr>
<td>Op. char. 'L1, L2, L3'</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Additional parameter can be set, the following settings are proposed:

- **System response to a differential current alarm = Continue in operation**
  The busbar protection continues to function regardless of the differential current alarm.

- **System response to an isolator alarm = Continue in operation**
  The busbar protection continues to function regardless of the isolator alarm.

- **Isolator alarm delay = to be set during commissioning**
  The REB500 has a common alarm circuit and timer for monitoring the operation of all isolators and bus-tie breakers. The time delay must be set longer than the slowest isolator operating time.

- **Remote trip impulse width = to be set during commissioning**
  The busbar, breaker failure and end fault protection can send an intertripping signal to a remote station.

- **Neutral Current Supervision (operating characteristic Lo)**
  This function should only be enabled in impedance grounded networks as the minimum fault currents are low i.e. below the nominal current; hence neutral current supervision offers an advantage.

  In this protection application the system is solidly grounded, the function **should be disabled**.

- **Overcurrent check for enabling tripping**
  The tripping of a circuit-breaker by the busbar protection can also be made dependant on whether the feeder in question conducts a certain minimum current.

  It is proposed to set this **option inactive**.

- **Undervoltage release of trip function**
  In general, a short circuit on a busbar causes a voltage dip. The undervoltage function senses this dip and can be used to release the busbar protection and/or the breaker backup protection.
trip. If all voltages are higher than the setting of the undervoltage criteria, the trip function of the circuit breakers will be blocked.

This function is set active, the pick-up value for the undervoltage check \(<U\) is set to 0.8x \(Un\).

9.2 REB 500 - Breaker Back-up Protection

The circuit breaker is the last and most important link in the protection chain. The purpose of the breaker backup protection is to take the right action in order the circuit-breaker should fail to execute the trip command. This involves tripping the nearest circuit breakers surround the fault, which are mainly in the same station. The principle of the breaker backup protection function is based on monitoring the time the fault persists after a trip command has been issued to the circuit breaker and has been enabled by the main protection.

The breaker backup protection has two adjustable timers. At the end of time \(t_1\), a second attempt is made to trip the breaker, which has failed to trip. At the end of time \(t_2\) the surrounding breakers are tripped. A transfer-tripping signal to the remote station generated either at the end of time \(t_1\) or \(t_2\) can also be enabled. The currents of the three phases are measured individually and compared with the pick-up setting, which is identical for the three phases.

- **Current setting**

  If the pick-up current of the breaker backup function is set too low there is a risk that the breaker backup protection will not reset quickly enough after a circuit-breaker has been successfully tripped. This can be the result of decaying oscillations in the CT secondary circuit. Conversely, the breaker backup protection may fail to operate if the setting is too high. This situation could arise, for example, due to severe CT saturation when the secondary current falls below the setting and the breaker backup protection resets. Basically, the current setting \((I_e)\) should be less than the minimum fault current \((I_{kmin})\) of the corresponding feeder. The proposed setting is: \(I_e/I_{n} = 0.1\) - this is the lowest possible relay setting.

- **Timer setting for two-stage breaker back-up protection**

  Timer \(t_1\) is started 33 ms after the breaker backup protection receives a starting signal from the main protection. A second attempt is made to trip the circuit breaker and the timer \(t_2\) is started at the end of the set time \(t_1\). Should the circuit breaker again fail to trip within the set time of \(t_2\), the surrounding breakers are tripped. Intertripping to the opposing side can be configured after completion of timer \(t_1\) as well as after \(t_2\). The minimum possible timer settings are:

  Minimum setting for \(t_1\):
  \[ t_1 > t_{CB} + 18\text{ms} + t_{Res} \]

  Minimum setting for \(t_2\):
  \[ t_2 > t_s + t_{CB} + 18\text{ms} + t_{Res} \]

  \(t_{CB}\) is circuit-breaker operating time plus arc ignition time, the circuit breaker’s opening operating time is less than 30 ms and the max. arcing time is less the 22 ms in accordance to IEC60056.

  \(t_{Res}\) is a recommended additional margin of 20 ms on the above minimum setting.

  \(t_s\) is delay time between timing stage and trip command (max. 22 ms)
The proposed minimum setting for \( t_1 \) with a circuit breaker operating time of 52 ms is:
\[ t_1 \geq 52 + 18 + 20 = 90 \text{ ms} \]

The proposed minimum setting for \( t_2 \) with a circuit breaker operating time of 52 ms is:
\[ t_2 \geq 22 + 52 + 18 + 20 = 112 \text{ ms} \]

According to KM practice, the following settings will be applied:
- \( t_1 = 70 \text{ ms} \) (re-trip of circuit-breaker)
- \( t_2 = 110 \text{ ms} \) (trip of bus-section at 180ms, timer \( t_2 \) is started at the end of the set time \( t_1 \))

### Breaker back-up protection setting table

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Min.</th>
<th>Max.</th>
<th>Default</th>
<th>Step</th>
<th>Unit</th>
<th>Proposed settings</th>
</tr>
</thead>
<tbody>
<tr>
<td>BFP active</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Setting (per current transformer)</td>
<td>0.1</td>
<td>2.0</td>
<td>1.2</td>
<td>0.1</td>
<td>( I_n )</td>
<td>0.1</td>
</tr>
<tr>
<td>Timer 1 active</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Timer ( t_1 )</td>
<td>10</td>
<td>5000</td>
<td>100</td>
<td>10</td>
<td>ms</td>
<td>70 ms</td>
</tr>
<tr>
<td>Timer 2 active</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Timer ( t_2 )</td>
<td>10</td>
<td>5000</td>
<td>150</td>
<td>10</td>
<td>ms</td>
<td>110 ms</td>
</tr>
<tr>
<td>Intertripping pulse duration</td>
<td>100</td>
<td>2000</td>
<td>200</td>
<td>10</td>
<td>ms</td>
<td>200 ms*)</td>
</tr>
<tr>
<td>Logic type</td>
<td>1</td>
<td>4</td>
<td>1</td>
<td>1</td>
<td></td>
<td>1</td>
</tr>
</tbody>
</table>

*) Intertripping: Setting to be verified during commissioning
• **OPTIONAL** Timer setting for single-stage breaker back-up protection

A single stage breaker failure protection is achieved by setting timer t2 to zero. Providing the starting conditions are fulfilled, the current check function is picked up and time t1 has expired, a trip signal goes to the bay's own breaker, an intertripping signal to the surrounding breakers and a transfer tripping signal to the remote end of the feeder.

The setting proposal is:
Timer t1 is started 33 ms after the breaker backup protection receives a starting signal from the main protection.

Minimum setting for t1  
\[ t_1 > t_{CB} + 18\text{ms} + t_{Res} \]

- **tCB** is circuit-breaker operating time plus arc ignition time, the circuit breaker's opening operating time is less than 30 ms and the max. arcing time is less the 22 ms in accordance to IEC60056.
- **tRes** is a recommended additional margin of 20 ms on the above minimum setting.
- **ta** is delay time between timing stage and trip command (max. 22 ms)

The minimum setting for t1 with a circuit breaker operating time of 52 ms is: \[ t_1 > 52 + 18 + 20 = 90 \text{ms} \]

A safety margin is required; about twice the minimum timer setting is proposed as delay before tripping the bus section. The following settings are finally proposed:

- \( t_1 = 200 \text{ms} \) (re-trip of circuit-breaker, trip of bus-section & intertripping as \( t_2 = 0 \text{ms} \))
- \( t_2 = 0 \text{ms} \)

Logic 1 or 4 is possible. Proposed is logic 1 (default logic)
10  **KTS West 66 kV Protection of 40 MVA Station Transformer 66/11 kV (=B11,=B21)**

40 MVA Power Transformer 66/11 kV - data see Section 2.3
Relevant short-circuit currents are reported in Section 3.1.

**Protection Scheme**

**Diagram:**
- Protection scheme for 66 kV busbar
- Transformer 66/11 kV: 40 MVA
- Signals from power transformer devices
- Alarm stages signaling to SAS via RTS21-T1
- Trip stages signaling to SAS via RTS21-T1

**Settings:**
- 4x SPER181
- 2x MVA105
- SPA/1105
- RETS21-H04
- BCU/REF5421

**CTs:**
- From 11 kV side
- From 66 kV side

**CT Specifications:**
- 400/5 A, cl. 1.0 / 5P20, R2ct < 1.70 Ω
- 2000 A, cl. PX, UK > 400 V, IM < 40 mA at UK/2, R2ct < 8.30 Ω
- 400/5 A, cl. PX, UK > 1060 V, IM < 20 mA at 20 V, R2ct < 1.30 Ω

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10.1 RET521: 66 kV Transformer Differential Protection

The main transformer protection terminal is of the ABB type RET521*2.5-T23. In this protection device the following protection and monitoring functions are implemented:

- **87T** Transformer Differential Protection
- **50TCB**
- **50TC**
- **50BF**
- **DR** Disturbance Recording
- **FR** Fault Recorder

**RET521 - Power transformer data settings**

The settings are done under “Settings / Setting groups n”.

Because all protection algorithms in RET 521 do all calculations in primary system quantities, and all settings are related to the rated quantities of the protected power transformer it is important to properly set the data of the protected transformer. All data need to be set. Rated voltage values, as an example, are required even when there are no over-/under-voltage functions installed, because the transformer differential protection function uses these values to calculate the turns ratio of the power transformer.

Following data for a two winding transformer are entered:

<table>
<thead>
<tr>
<th>Parameter description</th>
<th>Parameter name</th>
<th>Setting</th>
<th>Remark</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transformer Vector Group</td>
<td>VectorGroup 2W</td>
<td>YNd1</td>
<td>7 = YNd1</td>
</tr>
<tr>
<td>Rated Transformer Power in MVA</td>
<td>Sr</td>
<td>40</td>
<td>MVA</td>
</tr>
<tr>
<td>Rated Current for Primary Winding in A</td>
<td>Ir1</td>
<td>350</td>
<td>A</td>
</tr>
<tr>
<td>Rated Phase to Phase Voltage for Primary Winding in kV</td>
<td>Ur1</td>
<td>66</td>
<td>kV</td>
</tr>
<tr>
<td>Rated Current for Secondary Winding in A</td>
<td>Ir2</td>
<td>2100</td>
<td>A</td>
</tr>
<tr>
<td>Rated Phase to Phase Voltage for Secondary Winding in kV</td>
<td>Ur2</td>
<td>11</td>
<td>kV</td>
</tr>
</tbody>
</table>

**RET521 - Current and voltage transformer data**

The CT data are:

- 66 kV Transformer Feeder CT (Core 1) 400 A-800 A / 1 A, Cl. PX
- 11 kV Transformer Feeder CT (Core 1) 2000 A / 1 A, Cl. PX

The settings are done under “Configuration / Analogue Input Module AIM”.

Following CT data for a two winding transformer are entered:
### 66 kV Transformer Feeder CT

<table>
<thead>
<tr>
<th>Parameter Description</th>
<th>Parameter name</th>
<th>Range</th>
<th>Remark</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rated CT primary current in A</td>
<td>CTprim</td>
<td>400 A</td>
<td></td>
</tr>
<tr>
<td>Rated CT secondary current in A</td>
<td>CTsec</td>
<td>1 A</td>
<td></td>
</tr>
<tr>
<td>Used input tap for CT on AIM card</td>
<td>InputCTTap</td>
<td>Input 1A</td>
<td></td>
</tr>
<tr>
<td>Current transformer staring</td>
<td>CTstarpoint</td>
<td>ToObject</td>
<td></td>
</tr>
<tr>
<td>(i.e. current direction)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Rated VT primary voltage in kV</td>
<td>VTprim</td>
<td>n/a</td>
<td>No VT input</td>
</tr>
<tr>
<td>Rated VT secondary voltage in Volts</td>
<td>VTsec</td>
<td>n/a</td>
<td>No VT input</td>
</tr>
</tbody>
</table>

### 11 kV Transformer Feeder CT (Core 1)

<table>
<thead>
<tr>
<th>Parameter Description</th>
<th>Parameter name</th>
<th>Range</th>
<th>Remark</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rated CT primary current in A</td>
<td>CTprim</td>
<td>2000 A</td>
<td></td>
</tr>
<tr>
<td>Rated CT secondary current in A</td>
<td>CTsec</td>
<td>1 A</td>
<td></td>
</tr>
<tr>
<td>Used input tap for CT on AIM card</td>
<td>InputCTTap</td>
<td>Input 1A</td>
<td></td>
</tr>
<tr>
<td>Current transformer staring</td>
<td>CTstarpoint</td>
<td>ToObject</td>
<td></td>
</tr>
<tr>
<td>(i.e. current direction)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Rated VT primary voltage in kV</td>
<td>VTprim</td>
<td>n/a</td>
<td>No VT input</td>
</tr>
<tr>
<td>Rated VT secondary voltage in Volts</td>
<td>VTsec</td>
<td>n/a</td>
<td>No VT input</td>
</tr>
</tbody>
</table>

### RET521 - Current transformer staring

Parameter "CTstarpoint" determines in which direction current is measured. Internal reference direction is that all currents are always measured towards the protected object (i.e. towards the power transformer).

Following exemplary diagram explains the relay definition of "FromObject" and "ToObject":

![Connection of Instrument Current Transformers](image-url)

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**RET521 - Differential Protection Setting**

The settings are done under “Settings / Setting groups n / Basic settings”.

The following parameters require setting, following table provides the proposed parameter, and explanations are given in the following paragraphs of this section.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Range</th>
<th>Setting</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operation</td>
<td>Off/On</td>
<td>On</td>
<td>Operation Transformer Differential Protection</td>
</tr>
<tr>
<td>CharactNo</td>
<td>1 - 5</td>
<td>3</td>
<td>Stabilizing characteristic number</td>
</tr>
<tr>
<td>Idmin</td>
<td>10-50</td>
<td>30% (1)</td>
<td>Maximum sensitivity in % of Ir</td>
</tr>
<tr>
<td>Idunre</td>
<td>200 - 2500</td>
<td>1000%</td>
<td>Unrestrained limit in % of Ir</td>
</tr>
<tr>
<td>StabByOption</td>
<td></td>
<td>Conditionally</td>
<td>Second harmonic blocking: Conditionally/Always</td>
</tr>
<tr>
<td>I2/I1 ratio</td>
<td>5 - 25</td>
<td>15%</td>
<td>Second to first harmonic ratio in %</td>
</tr>
<tr>
<td>I5/I1 ratio</td>
<td>10 - 50</td>
<td>25%</td>
<td>Fifth to first harmonic ratio in %</td>
</tr>
<tr>
<td>ZSCSub</td>
<td>Off/On</td>
<td>On</td>
<td>Operation Zero Sequence Current Subtraction</td>
</tr>
<tr>
<td>CrossBlock</td>
<td>Off/On</td>
<td>On</td>
<td>Operation Crossblocking</td>
</tr>
</tbody>
</table>

(1) recommendation is 40%, according customer request 30% to be applied. See below.

**CharactNo and Idmin (Maximum sensitivity in % of Ir)**

The differential current should theoretically be zero during normal load or external faults if the turn-ratio and the phase shift are correctly compensated. However, there are several different phenomena the others than internal faults which will cause unwanted and false differential currents. The main reasons for unwanted differential currents are:

- mismatch due to different position of the tap changer
- different characteristics, loads and operating conditions of the current transformers
- zero sequence currents that only flow on one side of the power transformer
- normal magnetizing currents
- magnetizing inrush currents
- over-excitation magnetizing currents

The maximum sensitivity defines the pick-up value setting of the differential protection for internal faults, the setting must not be too low, however, to avoid the danger of false tripping due to CT errors, maximum off-load transformer currents and the tap changer range:
The maximum current mismatch due to the 66 kV-tap changer at min. and max. tap position is:

- 66 kV-current at min. tap = 411.7 A  \( \Delta I = 411.7 \, \text{A} - 350 \, \text{A} = 61.7 \, \text{A} \) or 17.6% rel. to \( I_{lHV} \)
- 11 kV-current at max. tap = 2099.5 A  \( \Delta I = 2099.5 \, \text{A} - 2099.5 \, \text{A} = 0 \) or 0% rel. to \( I_{lHV} \)

An additional safety margin of 5% is required to cater for additional error currents and increased magnetizing currents due to over-excitation.

An additional safety margin of 15% is required to cater for faults at LV-side of the EA-transformer.

Therefore, a maximum sensitivity setting of \( I_{\text{dmin}} = 40\% \) of \( I_r \) and Characteristic number 3 is proposed.

According experiences from prior substations a setting of \( I_{\text{dmin}} = 30\% \) (KM practise) will be applied for a more sensitive protection of the transformer. It must be noted that there is a risk of tripping the transformer after low voltage faults at the secondary side of the EA-transformer at strong tapping.

The specifics of the different characteristic are given in following diagram.

\[ \text{idunre} \ (\text{Unrestrained limit in} \% \ \text{of} \ I_r) \]

If differential current is found to be higher than a certain limit, called the unrestrained limit, so that a heavy internal fault is beyond any doubt, then no restrain criteria (such as the 2-nd harmonic, the 5-th harmonic, and the waveform) is taken into consideration; a trip request is "instantaneously" issued by the overall differential protection. In fact, 2 consecutive trip requests from the unrestrained differential protection must be counted in order for a TRIP to appear on the DIFP function block output.
The unrestrained differential protection limit can be set in the range 200% to 2500% of the power transformer rated current (2 pu to 25 pu) in steps of 1% (0.01 pu).

The setting must be higher than any normal inrush current to be expected. However, inrush currents are never higher in magnitude than the maximum through-fault current. Maximum through-fault current is about 6 times the rated transformer current, the exact value is 2.2 kA.

A generous safety margin is recommended to cater for all transient phenomena, recommended setting is:

\[ I_{dunre} = 1000\% \times I_r = 10 \text{ pu} \]  

(10 times transformer rated current)

**StabByOption (Second harmonic blocking)**

The terminal uses the 2-nd harmonic criterion to detect initial inrush and to stabilize the differential protection against heavy external faults. The criterion (conditionally) is enabled when transformer is not energized and when an external fault has been detected.

The algorithm is as follows:

- employ both the 2nd harmonic and the waveform criteria to detect initial inrush,
- switch off the 2nd harmonic criterion 1 minute after energizing, in order to avoid long clearance times for heavy internal faults and let the waveform criterion alone (and the 5-th harmonic) take care of the sympathetic inrush and recovery inrush,
- switch on the 2nd harmonic criterion for 6 seconds when a heavy external fault has been detected in order to increase stability against external faults.

The default or standard method (conditionally) is to let the harmonic and the waveform methods operate in parallel only when the power transformer is not yet energized, and switch off the second harmonic criterion when the power transformer has been energized. The second harmonic method is also active a short time when heavy external fault has been detected. The second harmonic method is also active a short time when heavy external fault has been detected. The second harmonic method be active all the time. The waveform method operates in parallel all the time. The choice of combination of restraint method is done with a setting parameter.

Option “Conditionally” is recommended as the default setting.

**I2/I1 ratio - Pick-up ratio for detecting inrush**

The second harmonic restraint function has a settable level. If the ratio of the second harmonic to fundamental harmonic in the differential current is above the settable limit, the operation of the differential protection is restrained. Generally the ratio of 2\text{nd} harmonic is greater than 15%.

It is recommended to use the setting 15 % as a default value.

**I5/I1 ratio**

RET 521 differential protection function is provided with a fifth harmonic restraint to prevent the protection from operation during an over-excitation condition of a power transformer. If the ratio of the fifth harmonic to fundamental harmonic in the differential current is above a settable limit the operation is restrained.

It is recommended to use the setting 25 % as a default value.
Both functions are set to 130% of the rated transformer current (acc. to method of Siemens), which is 1.3 x 350A = 455 A primary and $t_{set} = 0.0$ s. This corresponds to $1.13 \times ICT$.

- **Recommended settings:**
  - Overcurrent Tripping (50TC)
    
    $I_{set} = 455$ A primary, $1.13$ A secondary
    
    $t_{set} = 0.0$ s
  
  - Overcurrent Blocking (50TCB)
    
    $I_{set} = 455$ A primary, $1.13$ A secondary
    
    $t_{set} = 0.0$ s

According manufacturer information the OLTC rating of the cont. thermal current is 900A. The proposed setting falls below this rating.

### 10.2 SPAJ 115C: 66 kV Station Transformer Restricted Earth-Fault Protection (87NH)

The restricted earth fault (REF) protection (87N) for high voltage transformer side within the SPAJ115C relay is the high impedance protection principle. The differential current operates instantaneously when it exceeds the set start value of the REF stage. The restricted earth fault stage operates exclusively on earth faults inside the area of the transformer. The area of protection is limited by the phase and neutral current transformers. The operation of the REF on faults outside the protection area is prevented by a stabilizing resistor, which is connected in series with the matching transformer of the relay.

Voltage dependant and stabilizing resistors are provided to protect and stabilize the relay.

### CT Data

<table>
<thead>
<tr>
<th>Description</th>
<th>Characteristics</th>
</tr>
</thead>
<tbody>
<tr>
<td>66 kV Transformer Feeder CT (Core 1)</td>
<td>400 A – 800 A / 1A, Cl. PX, $U_R &gt; 1060$ V, $R_{CT} &lt; 1.3 , \Omega$, $I_{mag} &lt; 20$ mA / 25 V</td>
</tr>
<tr>
<td></td>
<td>Acc. 66 kV Single Line Diagram</td>
</tr>
<tr>
<td>66 kV Transformer Neutral CT</td>
<td>400 A – 800 A / 1A, Cl. PX, $U_R &gt; 1060$ V, $R_{CT} &lt; 2.0 , \Omega$, $I_{mag} &lt; 20$ mA / 25 V</td>
</tr>
<tr>
<td></td>
<td>Acc. 66 kV Single Line Diagram</td>
</tr>
</tbody>
</table>

- **CT Test Report Data** n/a

- **CT Lead Connection**
  
  - Number of CTs connected in parallel: $n = 4$ (3-phase CTs and neutral CT)
  
  - Length of longest CT connection cable: $l = 150$ m (single way)
  
  - Specific resistance of lead copper: $\rho = 0.021 \, \Omega\,m/mm²$ (at 75°C max. site temp)
  
  - Type of CT connection cable: 4 mm2
Lead wire resistance of CT cable 5.25 mΩ/m [75°C]
Lead loop resistance $R_L = 0.00525 \, \Omega/m \times 300m = 1.575 \, \Omega$

- Additional relay burden connected to same CTs: ABB RET521*2.5 with 0.25 VA

$\Delta I_o> \text{ Differential Neutral Setting Range and Characteristics}$

Start current $\Delta I_o> = 0.5…5\% \times I_n$ (In is either 1 A or 5 A input, selected is 5 A input)
Fixed operate time, typ. 35 ms
Reset time, typ. 60 ms
Operate time accuracy $\pm 25$ ms

Stability of REF

When circulating current protection schemes are subjected to heavy through faults, the sudden and often heavy asymmetrical growth in the system current can cause the protective current transformers to approach or even reach the saturation level. Because of the variations in the magnetizing characteristics of the transformers a secondary unbalance current may result. To ensure stability under these conditions, it is modern practice to use a voltage operated, high impedance relay, and set to operate at a voltage higher than the developed one by the current transformers under maximum external fault conditions. The stabilizing voltage $U_s$ can be calculated as follows:

$$U_s = \frac{I_{kmax} \times (R_C + R_L + R_B)}{n}$$

$I_{kmax}$ = Maximum through fault current, for which the relay must not operate
$R_C$ = Resistance of the CT secondary circuit
$R_L$ = Total resistance of the longest measuring circuit (to and from)
$R_B$ = Total resistance of additional relays
$n$ = CT transforming ratio

The maximum transformer through-fault current is 2.2 kA.

Stability of the protection is required during a through fault of 2.2 kA. At this current and in the presence of CT saturation the stability of the protection scheme must be assured. The stabilizing voltage $U_s$ in through-fault situation considering $R_C = 1.3 \, \Omega$ and $R_L = 1.575 \, \Omega$ as lead loop resistance is:

The minimum voltage $U_s$ is:
$$U_s = 2.2 \, kA \times (2.0 \, \Omega + 1.575 \, \Omega + 0.25 \, \Omega) / (400 \, A/1 \, A) = 21.0 \, V$$

The chosen voltage $U_s$ is:
$$U_{s,chosen} = 30 \, V$$

A higher value for the setting voltage $U_s$ is chosen in order to cater for all possible transient phenomena - with a safety factor of about 1.5, a value of 30 V is selected. The CT knee-point voltage of 1060 V exceeds the selected stabilizing voltage of 30 V several times, so under in-zone fault condition the CTs will produce enough output to operate the relay.
Sensitivity of REF
A start current setting of $I_r = 0.15 \, \text{A}$ is chosen - this is a $\Delta I_o >$ setting of 3% related to the 5 A-relay input ($I_n = 5 \, \text{A}$). The 5 A relay input is connected to the CTs of 400 A / 1 A. The stabilizing resistor $R_s$ to ensure protection stability is: $R_s = 30 \, \text{V} / 0.15 \, \text{A} = 200 \, \Omega$. The stabilizing resistor range is 0 - 1000 $\Omega$.

$\Delta I_o > m \times I_e$

The start current $I_r$ should be higher than the sum of the CT excitation currents at stabilizing voltage $V_s$: $I_r > (m \times I_e)$. The CT excitation current at $U_{\text{required}} = 30 \, \text{V}$ is $I_e = 24 \, \text{mA}$ ($I_e = 30 \, \text{V} / 25 \, \text{V} \times 20 \, \text{mA}$). The relation is fulfilled: $I_r = 150 \, \text{mA}$ and $I_r = 150 \, \text{mA} > m \times I_e = 4 \times 24 \, \text{mA} = 96 \, \text{mA}$.

Minimum effective operation current (POC)
The current flow $I_o$ through the Metrosil S256 at $U_{\text{required}} = 30 \, \text{V}$ is below 0.001 A (see V-I curve as attached). The effective max. and min. primary pick up current is: $I_p = CT \times (I_r + n \times I_e + I_u)$

$\Delta I_o >$ Start current $I_r = 3 \%$ (CT is connected to 5 A relay input)

$\Delta I_o >$ stage is blocked

Metrosil S256
NOTE:
Site measured values for CT data (resistance, magn. Curves), loop resistance, stabilizing resistor, varistor will be determined during commissioning. The settings will be re-calculated and adjusted based on the measurements. The final settings with measured values will be documented in "As Built" revision.

10.3 **REX521: 66 kV Transformer Back up Protection**

The back up transformer protection terminal is of the ABB type REX521 H04. In this protection device the following protection and monitoring functions are implemented:

- 50 Instantaneous Over-current Protection
- 51 Time Delayed Over-current Protection
- 51N Time Delayed Earth fault Protection

**REX521: Over-current Protection (50/51)**

**CT data**

66 kV Transformer Feeder (Core 2)  
400 A - 800 A / 1A, PX

Transformer operating currents:

- Rated transformer current tap mid: 349.9 A  (40 MVA @ 66 kV)
- Transformer current tap 1 (+4x1.25%): 333.2 A  (40 MVA @ 69.3 kV)
Transformer current tap 17 (-12x1.25%): 411.7 A (40 MVA @ 56.1 kV)
The maximum three-phase transformer through-fault current is 2.2 kA.

I>-stage
The start current of the I> stage is set to 150% of the transformer current of \( I_T = 349.9 \text{ A} \) at mid tap, which gives a primary current setting \( I_1 = 524 \text{ A} \). This current setting is also above the maximum transformer current at tap 17 of 411.7 A (worst-case condition 40 MVA at 56.1 kV).
The secondary relay setting is:
\[
I_1 = 1.50 \times 349.9 \text{ A} \times 1/400 = 1.31 \text{ A secondary}
\]
The proposed time multiplier setting is \( k = 0.45 \). The TMS is selected to achieve a relay operation time of 1.5 s at the maximum transformer through-fault current of 2.2 kA at the 66 kV-feeder.
The relay operating time at maximum through fault current is:
\[
t_{\text{Relay}}(2.2 \text{ kA}) = 0.45 \times 13.5 / ((2200 \text{ A/524 A})^1 - 1) = 1.9 \text{ s}
\]
The transformer thermal short-circuit withstand capacity of 2 sec (assumed value, 2 s is according to IEC 76) is protected.

I>>-stage
Start current of the I>> stage is set to 150% of the max. 66 kV-through fault current at 11 kV-faults:
\[
I_{\text{>>}} = 1.5 \times I_{\text{sc}}(11 \text{ kV}) \times 1/CT_{\text{Ratio}} = 1.5 \times 2.2 \text{ kA} \times 1/400 = 8.25 \text{ A}
\]
The relay time \( t_{\text{>>}} \) is 0.10 s.
The setting corresponds to \( I_{\text{>>}} = 3.3 \text{ kA} \) primary current, the time delay of 0.1 s stabilizes the I>>-stage against transient phenomena.

Recommended setting
Relay module: REX521 “Three-phase non-directional over-current protection, low-set stage, 3I>”
\[
\begin{align*}
I_1 & = 1.31 \times I_N \quad \text{(is 524 A primary)} \\
TMS & = 0.45 \\
I_1 & \text{curve is very inverse}
\end{align*}
\]
Relay module: REX521 “Three-phase non-directional over-current protection, high-set stage, 3I>>”
\[
\begin{align*}
I_{\text{>>}} & = 8.25 \times I_N \quad \text{(is 3.3 kA primary)} \\
t_{\text{>>}} & = 0.1 \text{ s}
\end{align*}
\]

REX521: Earth-fault Protection (51N)

Recommended setting Io>-stage
Relay module: REX521 “Non-directional earth fault protection, low-set stage, Io>”
According KM practice, function not used.
11 KTS West Substation 11 kV

11.1 Fault currents

The 11 kV-switchgear s/c-rating is 25 kA (3 sec). The calculated maximum s/c current is 12.9 kA (open bus coupler). The minimum 2-phase fault current at the busbar is 8.5 kA.

Calculation of minimum 2-phase s/c current acc. to IEC 60909:
12.1 REX521: Back up Transformer Protection

The back up transformer protection terminal is of the ABB type REX521 H02. In this protection device the following protection and monitoring functions are implemented:

- **67** Directional Over-current Protection,
- **67N** Directional Earth fault Protection

- CT data

11 kV Transformer Feeder (Core 2) 2000 A / 1A, 5P20, 10 VA
• Transformer data
The rated transformer current is: 2099.5 A (40 MVA @ 11 kV)
The maximum three-phase transformer through-fault current is 11.9 kA.

**REX521: - Directional Over-current Protection at Transformer 11 kV-side (67)**

The relay acts as back-up protection to the transformer differential protection for faults at the transformer feeder itself; such faults are fed by the parallel transformer. The maximum fault current is 11.9 kA (OC), which is the maximum through-fault current of one parallel transformer unit. The relay is set to trip at this current with a time delay between 0.28s and 0.43s as back-up towards the transformer differential protection.

The start current of the I> stage is set to 50 % of the CT current, which gives a primary current setting I> = 1000 A. The secondary relay setting is: I> = 1000 A x 1 / 2000 = 0.5 A secondary. The proposed TMS is 0.1. The relay operating time at maximum through-fault current is:

\[ t_{\text{Relay}}(11.9 \text{ kA}) = 0.1 \times 0.14 / ((11900 \text{ A} / 1000 \text{ A})^{0.02} - 1) = 0.28 \text{ s} \]

In case that associated fuse failure supervision relay is not available, a suitable start current for temporary operation is 120 % of the CT current for I> stage. This provides a primary current setting I> = 2400 A and prevents from undesired relay operation in case of disturbed signal from voltage transformer. At this current setting and with maintained TMS of 0.1 the achieved time delay is about 0.4s:

\[ t_{\text{Relay}}(11.9 \text{ kA}) = 0.1 \times 0.14 / ((11900 \text{ A} / 2400 \text{ A})^{0.02} - 1) = 0.43 \text{ s} \]

**Proposed settings**

Relay module: REX521 “Three-phase directional over-current protection, low-set stage, 3I>->”

<table>
<thead>
<tr>
<th>CT = 2000 A / 1 A</th>
</tr>
</thead>
<tbody>
<tr>
<td>Direction: Forward = towards own incoming transformer feeder</td>
</tr>
<tr>
<td>Base current I&gt; = 0.5 x 2000 A = 1000 A (VT-supervision in service)</td>
</tr>
<tr>
<td>Base current I&gt; = 1.2 x 2000 A = 2400 A (VT-supervision not available)</td>
</tr>
<tr>
<td>Time multiplier 0.1</td>
</tr>
<tr>
<td>Time characteristic normal inverse</td>
</tr>
<tr>
<td>Basic angle +45°</td>
</tr>
</tbody>
</table>

Forward direction is towards the own incoming 11 kV-transformer feeder and is indicated by reactive power flow into the transformer feeder.

**REX521 - Directional Earth-fault Protection at Transformer 66 kV-side (67N)**

The relay may acts as back-up protection to the transformer differential protection for faults at the transformer feeder itself; such faults are fed by parallel transformers. The maximum fault current is 11.9kA, which is the maximum through-fault current of one parallel transformer unit.
Relay module: REX 521 “Directional earth fault protection, low-set stage, Io->->”
According KM practise this function will be inactive.

**REX521 – Transformer Monitoring**
As per KM request, alarm to NCC will be provided at 110% full load current. The currents of the incomer bay (A18, A28) will be monitored. By exceeding of the set value of 110% of transformer rated current on any phase the timer will start. After the set time of t=1.0s expires, the event will be issued.

- **Recommended setting**
  Relay module: REX521 “Three-phase non-dir. overcurrent protection, low-set stage, 3I>”
  
  \[
  \begin{align*}
  CT &= 2000 \text{ A} / 1 \text{ A} \\
  I_o &= 1.15 \times I_n \quad \text{(is 2300 A primary)} \\
  t_o &= 1.0 \text{ s} \\
  \end{align*}
  \]

  \(I_o\) curve is definite time

  Relay trip signal will issue NCC signal

**12.2 SPAJ 115C: Station Transformer Restricted Earth Fault Protection (87NL)**

**SPAJ 115 C - CT Data**

<table>
<thead>
<tr>
<th>11 kV Transformer Feeder CT</th>
<th>2000 A / 1 A, Cl. PX, U_k &gt; 400 V, R_CT &lt; 10 (\Omega), I_mag &lt; 15 mA at 95 V</th>
<th>Acc. 11 kV Single line diagram</th>
</tr>
</thead>
<tbody>
<tr>
<td>11 kV Earthing Transformer Neutral CT</td>
<td>2000 A / 1 A, Cl. PX, U_k &gt; 456 V, R_CT &lt; 9 (\Omega), I_mag &lt; 15 mA at 95 V</td>
<td>Acc. 11 kV Single line diagram</td>
</tr>
</tbody>
</table>

- **CT Test Report Data n/a**
- **CT Lead Connection**
  Number of CTs connected in parallel \(n = 4\) (3-phase CTs and neutral CT)
  Length of longest CT connection cable \(l = 100\) m (single way)
  Specific resistance of lead copper \(\rho = 0.021 \Omega m/mm^2\) (at 75°C max. site temp)
  Type of CT connection cable 4 mm2
  Lead wire resistance of CT cable 5.25 mOhm/m [75°C]
  Lead loop resistance \(R_L = 0.00525 \Omega/m \times 200m = 1.05 \Omega\)
• Additional relay burden connected to CTs: max. 0.25 VA / 0.25 Ω at 1 A (RET521)

• ΔIo> Differential Neutral Setting Range and Characteristics
  Start current \[ ΔIo> = 0.5\ldots5\% \times In \] (In is either 1 A or 5 A input, selected is 5 A input)
  Fixed operate time, typ. 35 ms
  Reset time, typ. 60 ms
  Operate time accuracy ±25 ms

• Stability of REF
  When circulating current protection schemes are subjected to heavy through faults, the sudden and often heavy asymmetrical growth in the system current can cause the protective current transformers to approach or even reach the saturation level. Because of the variations in the magnetizing characteristics of the transformers a secondary unbalance current may result. To ensure stability under these conditions, it is modern practice to use a voltage operated, high impedance relay, and set to operate at a voltage higher than the developed one by the current transformers under maximum external fault conditions. The stabilizing voltage \( U_s \) can be calculated as follows:
  \[ U_s = I_{k_{\text{max}}} \times (R_{\text{CT}} + R_L + R_B) / n \]
  \( I_{k_{\text{max}}} \) = Maximum through fault current, for which the relay must not operate
  \( R_{\text{CT}} \) = Resistance of the CT secondary circuit
  \( R_L \) = Total resistance of the longest measuring circuit (to and from)
  \( R_B \) = Total resistance of additional relays
  \( n \) = CT transforming ratio
  The maximum transformer through-fault current is \( I_{k_{\text{max}}} = 11.9 \text{ kA} \).
  Stability of the protection is required during a through fault of 11.9 kA. At this current and in the presence of CT saturation the stability of the protection scheme must be assured. The stabilizing voltage \( U_s \) in through-fault situation considering \( R_{\text{CT}} = 10 \text{ Ω} \), \( R_L = 1.05 \text{ Ω} \) as lead loop resistance and \( R_{\text{Burden}} = 0.25 \text{ Ω} \) is:
  The minimum voltage \( U_s \) is:
  \[ U_s = 11.9 \text{ kA} \times (10 \text{ Ω} + 1.05 \text{ Ω} + 0.25 \text{ Ω}) / (2000 \text{ A/1 A}) = 67.6 \text{ V} \]
  The chosen voltage \( U_s \) is:
  \[ U_s,\text{chosen} = 120 \text{ V} \]
  A higher value for the setting voltage \( U_s \) is chosen in order to cater for all possible transient phenomena - with a safety factor of 1.5, a value of 120 V is selected. The CT knee-point voltage of 400 V clearly exceeds the selected stabilizing voltage of 120 V, so under in-zone fault condition the CTs will produce enough output to operate the relay.

• Sensitivity of REF
  A start current setting of \( I_r = 0.08 \text{ A} \) is chosen - this is a \( ΔIo> \) setting of 1.6% related to the 5 A-relay input (In = 5 A). The 5 A relay input is connected to the CTs of 2000 A / 1 A. The stabilizing resistor \( R_s \) to ensure protection stability is:
  \[ R_s = 120 \text{ V} / 0.08 \text{ A} = 1500 \text{ Ω} \]. The stabilizing resistor range is 0-2700 Ω.
• \( \text{Ir} > m \times I_e \)

The start current \( \text{Ir} \) should be higher than the sum of the CT excitation currents at stabilizing voltage \( \text{Vs} \): \( \text{Ir} > (m \times I_e) \). The CT excitation current at \( \text{U_s,chosen} = 120 \text{ V} \) is Phase CTs \( I_e = 19 \text{ mA} \) (\( I_e = 120 \text{ V} / 95 \text{ V} \times 15 \text{ mA} \)) + Neutral CT \( I_e = 19 \text{ mA} \) (\( I_e = 120 \text{ V} / 95 \text{ V} \times 15 \text{ mA} \)). The relation is fulfilled: \( \text{Ir} = 80 \text{ mA} \) and \( \text{Ir} = 80 \text{ mA} > 4 \times 19 \text{ mA} \) = 76 mA.

• **Minimum effective operation current (POC)**

The current flow \( I_u \) through the Metrosil S256 at \( U_s, \text{required} = 120 \text{ V} \) is below 0.001 A (see V-I curve as attached). The effective max. and min. primary pick up current is: \( I_p = \text{CTRatio} \times (I_R + n \times I_e + I_u) \)

\[ I_{p_{\text{min}}} = 2000 \times (0.08 \text{ A} + 4 \times 0.019 \text{ A} + 0.001 \text{ A}) = 320 \text{ A} \] (is 42% of \( I_{\text{Fault (Earth Tx)}} \) of 750 A)

According ESI Standard 48-3 (Electric Supply Industry Standard, UK), a setting between 10% and 25% of the minimum fault current at the transformer terminals in grids with restricted grounding is proposed. A setting above this proposal is required to fulfill the excitation criteria \( \text{Ir} > m \times I_e \).

• **Recommended setting:** \( R_s = 1500 \Omega \ (U_s = 120 \text{ V}, I_r = 0.08 \text{ A}) \)

\( \Delta I_{\text{op}} \) Start current \( I_r = 1.6 \% \) (CT is connected to 5 A relay input)

\( I_{\text{op}} \) stage is blocked

Metrosil S256

• **SPAJ 115C - Metrosil S256 V-I Characteristics (Curve No. 3)**

![Graph](attachment:graph.png)

**NOTE:**
Site measured values for CT data (resistance, mag. Curves), loop resistance, stabilizing resistor, varistor will be determined during commissioning. The settings will be re-calculated and adjusted based on the measurements. The final settings with measured values will be documented in "As Built" revision.
13 KTS West 11 kV Bus Section Protection (=A12)

Simplified protection block diagram

13.1 REX521: Bus Section Protection - Time Delayed & Partial Differential Busbar PBB

Two protection function groups require setting:

- Partial Differential Busbar Protection
  The partial differential busbar protection consists of two terminals of the ABB type REX521 H04, where one of each relay is connected to the current transformers of the transformer incoming feeder and the respective side of the bus coupler and measuring the difference of both currents.
  In the stable condition the measured current is the maximum bus section load current. In case of a busbar fault the short circuit current will be measured and if no blocking signal from the outgoing feeders is present the relay will trip the respective incoming and the bus coupler feeder.

- Time Delayed OC and EF Protection
  In this protection device the following protection and monitoring functions are implemented:
  50 INST Over-current protection (blocked by feeder)
  50N INST Earth fault Protection (blocked by feeder)
  51 Time Delayed Over-current Protection
  51N Time Delayed Earth fault Protection

- CT Data
  11 kV Transformer Feeder CT 2000 A / 1A, PX, 10 VA
11 kV Bus Coupler CT 2000 A / 1A, PX, 10 VA

- **Busbar Data**
  - Switchgear rated current: 2500 A
  - Switchgear s/c-rating: 25 kA (3 s)

### REX521 – 11 kV-Bus Section OC Partial Differential Busbar Protection (50)

- **I>>-Stage Setting**
  
  An OC relay sensitivity of 1.3-times x number of outgoing feeders x 400 A is proposed including the transformer rated current. The number of outgoing feeders at the 11 kV-busbar sections is 8. The OC start setting is applied to \( I_\geq = 2100A + 1.3 \times 8 \times 400 A = 6260A \) (maximum load current).

  An OC relay sensitivity of 6200 A is proposed, this is 3.1-times ICT. The minimum s/c current at 11kV is 8.4kA, the setting ensures a clear pick-up.

  The relay operates in case no blocking signal from outgoing feeders is received. Therefore a definite time characteristic is proposed, the relay must be delayed in order to allow incoming blocking signals to be received. A time delay of 100 ms is proposed, however this requires verification during commissioning.

- **I>-Stage Setting**
  
  The I>-stage is blocked.

- **Recommended setting**
  
  Relay module: REX521 “Three-phase non-directional overcurrent protection, high-set stage, 3I>>”

  \[
  CT = 2000 A / 1 A \\
  I_\geq = 3.1 \times I_N \quad \text{(is 6200 A primary)} \\
  t_\geq = 0.1 \text{ s} \\
  I_\geq \text{ curve is definite time} \\
  \text{Relay is blocked by outgoing feeder protection pick-up signal.}
  \]

### REX521 – 11 kV-Bus Section EF Partial Differential Busbar Protection (50N)

- **Io>>-stage**
  
  The start current \( I_\geq \) is set to 17% of the CT nominal current which is 340 A primary, the secondary relay setting is \( I_\geq = 0.17 \text{ A} \).

  The relay operates in case no blocking signal from outgoing feeders is received. Therefore a definite time characteristic is proposed, the relay must be delayed in order to allow incoming blocking signals to be received. A time delay of 100 ms is proposed, however this requires verification during commissioning.
• **Recommended setting**

Relay module: REX521 “Non-directional earth fault protection, high-set stage, I0>”

\[
\begin{align*}
CT &= 2000 \text{ A} / 1 \text{ A} \\
I_{0>/IN} &= 0.17 \quad \text{(is 340 A primary)} \\
t_{0>} &= 0.1 \text{ s} \\
I_{0>} \text{ curve is definite time} \\
\text{Relay is blocked by outgoing feeder protection pick-up signal.}
\end{align*}
\]

**REX521 – 11 kV-Bus Section Time Delayed OC Protection (51)**

• **I>-Stage Setting**

An OC relay sensitivity of 1.2-times x number of outgoing feeders x 400 A is proposed. The number of outgoing feeders at the 11 kV-busbar sections is 8. The OC start setting is applied to I> = 1.1 x 8 x 400 A = 3520 A. (maximum load current).

An OC relay sensitivity of 3520 A is proposed, this is 1.76-times ICT. The minimum s/c current at 11kV is 8.4kA, the setting ensures a clear pick-up.

The TMS is set to k = 0.26 in order to achieve a fault clearing time of 1.5 s at the maximum transformer through-fault current of 12.9 kA.

• **I>>-Stage Setting**

The I>>-stage is blocked.

• **Recommended setting**

Relay module: REX521 “Three-phase non-directional over-current protection, low-set stage, 3I>”

\[
\begin{align*}
CT &= 2000 \text{ A} / 1 \text{ A} \\
I_> &= 1.76 \times I_N \quad \text{(is 3520 A primary)} \\
TMS &= 0.26 \\
I_\text{c curve is normal inverse}
\end{align*}
\]

The relay operating time at the 40 MVA-transformer maximum through-fault current is:

\[
t_{\text{Relay}}(12.9 \text{ kA}) = 0.26 \times 0.14 / ((12.9 \text{ kA}/3.52 \text{ kA})^{0.02} - 1) = 1.38 \text{ s}
\]

**REX521 – 11 kV-Bus Section Time Delayed EF Protection (51N)**

• **I>-Stage Setting**

An EF relay sensitivity of 140 A is proposed, this is 7% of CT rated primary current. The secondary current setting is: I>= 0.07 A.

The TMS is set to k = 0.5 in order to achieve a fault clearing time of 2.0 s at earthing transformer 750 A fault current.

• **I>>-Stage Setting**

The I>>-stage is blocked.
• **Recommended setting**
  Relay module: REX521 “Non-directional earth fault protection, low-set stage, I0>”
  
  \[
  \begin{align*}
  CT &= 2000 \text{ A} / 1 \text{ A} \\
  I_0/IN &= 7\% \quad \text{(is 140 A primary)} \\
  k &= 0.5 \\
  I_0\text{-curve is normal inverse}
  \end{align*}
  \]

  The relay operating time at the earthing transformer maximum fault current is:
  \[
  t_{\text{Relay}}(750 \text{ A}) = 0.5 \times 0.14 / ((750 \text{ A}/140 \text{ A})^{0.02} - 1) = 2.0 \text{ s}
  \]

13.2 **REX521: Bus Coupler Overload Protection (49) and OC Protection (51)**

**Stage Overload Settings (49)**

A REX 521 is foreseen for overload protection of the 11 kV-bus coupler.

The relay applies the thermal model of one time constant for temperature measurement, which means that both the temperature rise and the cooling follow an exponential curve. The temperature evaluated for alarm and tripping is calculated from following parameter:

- Rated current as maximum sustained load current value allowed for the object. Proposed is setting of 1.1*2500 A = 2750 A from rated busbar current.
- Maximum temperature allowed for an object under sustained load. The value depends on the insulation material used; proposed is 90°C which is Class A temperature rise.
- Reference temperature which is the rated current has been defined; proposed is setting of 40°C as estimated annual average temperature.
- Time constant for the temperature rise and cooling of an object. Setting is calculated from given SWG short-circuit rating 25 kA allowable for 3 s. The time constant is:
  \[
  t [\text{min}] = (3 \text{ s} / 60 \text{ s}) \times (25 \text{ kA} / 2750 \text{ A})^2 = 5 \text{ min.}
  \]
- Ambient temp as temperature, which can be either a set value or a one measured by sensors. If set value is used, setting of 40°C as maximum annual temperature is proposed.
Relay is connected to a CT = 2000 A / 1 A. The following table summarizes the proposed settings.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Values</th>
<th>Unit</th>
<th>Default</th>
<th>Setting</th>
<th>Explanation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Time constant</td>
<td>1...999</td>
<td>min</td>
<td>45</td>
<td>5 min</td>
<td>Heating / cooling time constant for the object</td>
</tr>
<tr>
<td>Rated current</td>
<td>1.0...5000.0</td>
<td>A</td>
<td>300.0</td>
<td>2750 A</td>
<td>Maximum load current for the protected object</td>
</tr>
<tr>
<td>Maximum temp</td>
<td>40.0...150.0</td>
<td>°C</td>
<td>90.0</td>
<td>90°C</td>
<td>Maximum temperature permitted for the conductor</td>
</tr>
<tr>
<td>Reference temp</td>
<td>-50.0...100.0</td>
<td>°C</td>
<td>20.0</td>
<td>40°C</td>
<td>Ambient temperature for determination of the maximum load current</td>
</tr>
<tr>
<td>Trip temperature</td>
<td>80.0...120.0</td>
<td>%</td>
<td>100.0</td>
<td>100%</td>
<td>Tripping temperature, per cent value</td>
</tr>
<tr>
<td>Prior alarm</td>
<td>40.0...100.0</td>
<td>%</td>
<td>80.0</td>
<td>90%</td>
<td>Prior alarm temperature, per cent value</td>
</tr>
<tr>
<td>Reclosure temp</td>
<td>40.0...100.0</td>
<td>%</td>
<td>75.0</td>
<td>80%</td>
<td>Temperature value which enables reclosing</td>
</tr>
<tr>
<td>Ambient temp</td>
<td>-50.0...100.0</td>
<td>°C</td>
<td>40.0</td>
<td>40 °C</td>
<td>Setting value for ambient temperature</td>
</tr>
</tbody>
</table>

**Stage Time Delayed OC Settings (51)**

The function should allow grading to the downstream 11kV feeder protection and to the upstream 11kV PBB OC protection and 66kV transformer feeder OC protection. It was found that a sufficient grading for a sequence of four Relay with a grading time of at least 300ms is not possible. It is recommended to disable the function. If decision is made to activate the function, identical settings to the 11kV PBB OC protection should be used.

- **I>-Stage Setting**
  The I>>-stage is disabled.
14 **KTS West 11 kV Auxiliary & Earthing Transformer Protection**

Protection Scheme: Refer to chapter 12.

14.1 **REX 521: Auxiliary and Earthing Transformer Protection (500 kVA-Transf.)**

The protection terminal for the auxiliary and earthing transformer is of the ABB type REX521. In this protection device the following protection and monitoring functions are implemented:

### 50 Instantaneous Over-current Protection

### 51 Time Delayed Over-current Protection

### 51N Time Delayed Earth fault Protection

**CT data**

- 11 kV Auxiliary and Earthing Transformer Feeder CT: 50 A / 1A, PX, 15 VA
- 11 kV Earthing Transformer Neutral CT: 750 A / 1A, PX, 15 VA

**Auxiliary and Earthing Transformer Data**

- **Rated power**: 500 kVA
- **Rated voltage ratio**: 11 / 0.415 kV
- **Rated current 11 kV**: 26.24 A
- **Rated current 415 V**: 695.6 A
- **Rated frequency**: 50 Hz
- **Vector group**: ZNyn11 (d)
- **Impedance voltage**: 9.6 % +/- 10 %
- **HV neutral**: 750 A for 30 s with reactor earthed
- **LV neutral**: solidly earthed

The maximum three-phase transformer through-fault current is about 300 A (transformer impedance uk of 9.6% according data sheet).

**REX521 – Over-current Protection at Auxiliary and Earthing Transformer 11 kV-side (50/51)**

- **CT data**
  - 11 kV Auxiliary and Earthing Transformer Feeder CT: 50 A / 1A, PX, 15 VA

Note that for the CT a delta connection will be used. This will avoid that the function acts on earth-faults. The measured values will be 1.73 times higher than the phase values. This is considered at the following setting recommendations.
I>-stage (non-dir)
The start current of the I> stage is set to 150% of the transformer current of \( I_T = 26.24 \) A, which gives a primary current setting \( I> = 39.4 \) A. The secondary relay setting must be:
\[
I> = 1.5 \times 26.24 \times 1.73 \text{ (see note above) x } 1 / 50 = 1.36 \text{ A secondary}
\]

The proposed time multiplier setting is \( k = 0.56 \). The TMS is set for an operation time below 2.0 s at the maximum transformer through-fault current of 300 A at the 415 V-feeder. The relay operating time is:
\[
I\text{relay}(300 \text{ A}) = 0.56 \times 13.5 / \left( (300 \text{ A x 1.73} / 68.1 \text{ A})^1 - 1 \right) = 1.15 \text{ s}
\]
The transformer thermal short-circuit withstand capacity of 2 sec (according test report) is protected.

I>>-stage
Start current of the I>> stage is set to 130% of the max. through fault current at 415 V-faults:
\[
I>> = 1.3 \times I_{sc}(415 \text{ V}) \times 1.73 \times 1 / CT\text{Ratio} = 1.3 \times 300 \text{ A x 1.73 x 1} / 50 = 13.5 \text{ A secondary}
\]
The relay time \( t>> \) is 0.1 s.

The setting corresponds to \( I>> = 0.390 \text{ kA primary current, the time delay of 0.1 s stabilizes the I>>-stage against transient phenomena.}

Recommended setting
Relay module: REX521 “Three-phase non-directional over-current protection, low-set stage, 3I>”

\[
\begin{align*}
&CT = 50 \text{ A / 1 A} \\
&I> = 1.36 \times I_N \text{ (is 39.4 A primary)} \\
&TMS = 0.56 \\
&I> \text{ curve is very inverse}
\end{align*}
\]

Relay module: REX521 “Three-phase non-dir. over-current protection, instantaneous stage, 3I>>>”

\[
\begin{align*}
&I_{>>} = 13.5 \times I_N \text{ (is 390 A primary)} \\
&t_{>>} = 0.1 \text{ s}
\end{align*}
\]

REX521 – Standby Earth-fault Protection at Aux & Earthing Transformer Neutral (51N)
Standby EF at Earthing Transformer Neutral acts in two stages:
- 1\(^{st}\) stage is delayed by 3.5 sec and trips the 11 kV-bus coupler
- 2\(^{nd}\) stage is delayed by 4.5 sec and trips the connected 66/11 kV-transformer

Both stages are set with definite time characteristic, the start current is 150 A primary.

Recommended setting
Relay module: REX521 “Non-directional earth fault protection, low-set stage, Io> and Io>>”

\[
CT = 750 \text{ A / 1 A}
\]
lo>>-stage (is 2nd stage SEF in 4.5 s)
\[ \frac{I_{0>>}}{I_N} = 0.4 \] (is 300 A primary)
\[ t_{0>>} = 4.5 \text{ s} \]
Definite time
Stage trips the connected 66/11 kV-transformer

lo>-stage (1st stage SEF in 3.5 s)
\[ \frac{I_{0>}}{I_N} = 40\% \] (is 300 A primary)
\[ t_{0>} = 3.5 \text{ s} \]
Definite time
Stage trips the 11 kV-bus coupler

14.2 SPAJ 115C: 500 kVA Earthing Transformer Restricted Earth Fault Protection (87NHE)

**SPAJ 115C- CT Data**

11 kV Earthing Transformer Feeder CT  
50 / 1A,  
Cl. PX, Uk > 100 V, RCT < 1.2Ω Imag < 15 mA/ 50 V  
Acc. 11 kV Single line diagram

11 kV Earthing Transformer Neutral CT  
50 / 1A,  
Cl. PX, Uk > 100 V, RCT < 1.2Ω Imag < 15 mA/ 50 V  
Acc. 11 kV Single line diagram

- **CT Test Report Data n/a**

- **CT Lead Connection**

  Number of CTs connected in parallel \( n = 4 \) (3-phase CTs and neutral CT)
  Length of longest CT connection cable \( l = 100 \text{ m} \) (single way)
  Specific resistance of lead copper \( \rho = 0.021 \Omega \text{mm}^2 \) (at 75°C max. site temp)
  Type of CT connection cable 4 mm²
  Lead wire resistance of CT cable 5.25 mΩ/ m [75°C]
  Lead loop resistance \( R_L = 0.00525 \Omega \text{m} \times 200\text{m} = 1.05 \Omega \)

- **Additional relay burden connected to same CTs: no other relays connected**
• \( \Delta I_{o} > \) Differential Neutral Setting Range and Characteristics
  
  Start current \( \Delta I_{o} > = 0.5 \ldots 5\% \times I_n \) (In is either 1 A or 5 A input, selected is 5 A input)
  
  Fixed operate time, typ. \( 35 \text{ ms} \)
  
  Reset time, typ \( 60 \text{ ms} \)
  
  Operate time accuracy \( \pm 25 \text{ ms} \)

• Earthing Transformer Data
  
  Rated power \( 500 \text{ kVA} \)
  
  Rated voltage ratio \( 11 \text{ }/\text{ }0.415 \text{ kV} \)
  
  Rated current \( 11 \text{ kV} \) \( 26.24 \text{ A} \)
  
  Rated current \( 415 \text{ V} \) \( 695.6 \text{ A} \)
  
  Rated frequency \( 50 \text{ Hz} \)
  
  Vector group \( \text{ZNyn11 (d)} \)
  
  Impedance voltage \( 9.6 \% \text{ + } /\text{ -10 } \% \)
  
  HV neutral \( 750 \text{ A for 30 s with reactor earthed} \)
  
  LV neutral \( \text{solidly earthed} \)

• Stability of REF
  
  When circulating current protection schemes are subjected to heavy through faults, the sudden and often heavy asymmetrical growth in the system current can cause the protective current transformers to approach or even reach the saturation level. Because of the variations in the magnetizing characteristics of the transformers a secondary unbalance current may result. To ensure stability under these conditions, it is modern practice to use a voltage operated, high impedance relay, and set to operate at a voltage higher than the developed one by the current transformers under maximum external fault conditions. The stabilizing voltage \( U_s \) can be calculated as follows:

  \[
  U_s = \frac{I_{k_{\text{max}}} \times (R_{CT} + R_L + R_B)}{n}
  \]

  \( I_{k_{\text{max}}} \) = Maximum through fault current, for which the relay must not operate
  
  \( R_{CT} \) = Resistance of the CT secondary circuit
  
  \( R_L \) = Total resistance of the longest measuring circuit (to and from)
  
  \( R_B \) = Total resistance of additional relays
  
  \( n \) = CT transforming ratio

  The maximum earthing & auxiliary transformer through-fault current is \( I_{k_{\text{max}}} = 300 \text{ A at 11 kV} \), the maximum earthfault amounts to 750A.

  Stability of the protection is required during a through fault of 750 A. At this current and in the presence of CT saturation the stability of the protection scheme must be assured. The stabilizing voltage \( U_s \) in through-fault situation considering \( R_{CT} = 1.2 \text{ }\Omega \), \( R_L = 1.05 \text{ }\Omega \) as lead loop resistance and \( R_{\text{Burden}} = 0 \text{ }\Omega \) is:

  The minimum voltage \( U_s \) is:

  \[
  U_s = 750 \text{ A} \times (1.2 \text{ }\Omega + 1.05 \text{ }\Omega) / (50 \text{ A/1 A}) = 33.75 \text{ V}
  \]

  The chosen voltage \( U_s \) is:

  \[
  U_{s,\text{chosen}} = 50 \text{ V}
  \]

  A higher value for the setting voltage \( U_s \) is chosen in order to cater for all possible transient phenomena with a safety factor of about 1.5, a value of 50 V is selected. The CT knee-point voltage of 100 V ex-
ceeds the selected stabilizing voltage of 50 V, so under in-zone fault condition the CTs will produce enough output to operate the relay.

- **Sensitivity of REF**
  A start current setting of \( I_r = 0.07 \) A is chosen - this is a \( \Delta I_o > \) setting of 1.4% related to the 5 A-relay input (\( I_n = 5 \) A). The 5 A relay input is connected to the CTs of 50 A / 1 A. The stabilizing resistor \( R_s \) to ensure protection stability is: \( R_s = 50 \text{ V} / 0.07 \text{ A} = 715 \Omega \). The stab. resistor is 0 - 1000 \( \Omega \).

- **\( I_r > m \times I_e \)**
  The start current \( I_r \) should be higher than the sum of the CT excitation currents at stabilizing voltage \( V_s \): \( I_r > (m \times I_e) \). The CT excitation current at \( U_s, \text{chosen} = 50 \text{ V} \) is \( I_e = 15 \text{ mA} \) (\( I_e = 50 \text{ V} / 50 \text{ V} \times 15 \text{ mA} \)). The relation is fulfilled: \( I_r = 70 \text{ mA} \) and \( I_r = 70 \text{ mA} > m \times I_e = 4 \times 15 \text{ mA} = 60 \text{ mA} \).

- **Minimum effective operation current (POC)**
  The current flow \( I_u \) through the Metrosil S256 at \( U_s, \text{chosen} = 50 \text{ V} \) is below 0.001 A (see V-I curve as attached). The effective max. and min. primary pick up current is: \( I_p = C T_{\text{Ratio}} \times (I_r + n \times I_e + I_u) \)
  \( I_{p_{\min}} = 50 \times (0.07 \text{ A} + 4 \times 0.015 \text{ A} + 0.001 \text{ A}) = 6.5 \text{ A} \)
  is 24.8% of \( I_r \) of 26.24 A
  According ESI Standard 48-3 (Electric Supply Industry Standard, UK) a setting between 10% and 25% of the rated transformer current in grids with restricted grounding is proposed.

- **Recommended setting:**
  \( R_s = 715 \Omega \) (\( U_s = 50 \text{ V}, I_r = 0.07 \text{ A} \))
  \( \Delta I_o \) Start current \( I_r = 1.4 \% \) (CT is connected to 5 A relay input)
  \( I_o \) stage is blocked
  Metrosil S256
NOTE:
Site measured values for CT data (resistance, mag. Curves), loop resistance, stabilizing resistor, varistor will be determined during commissioning. The settings will be re-calculated and adjusted based on the measurements. The final settings with measured values will be documented in "As Built" revision.

14.3 SPAJ 115C: 415V (500kVA) - Earthing Transformer Restricted Earth Fault Prot. (87NLE)

SPAJ 115 C- CT Data

415 V Transformer Feeder CT
750 A / 1 A
Cl. PX, Uk > 250 V, RCT < 6.0 Ω
Imag < 17 mA at 125 V
Acc. CT specification

415 V Earthing Transformer Neutral CT
750 A / 1 A
Cl. PX, Uk > 250 V, RCT < 6.0 Ω
Imag < 17 mA at 125 V
Acc. CT specification
• **CT Test Report Data**
  - 415 V Transformer Feeder CT: n/a
  - 415 V Earthing Transformer Neutral CT: n/a

• **CT Lead Connection**
  Number of CTs connected in parallel: n = 4 (3-phase CTs and neutral CT)
  Length of longest CT connection cable: l = 100 m (single way)
  Specific resistance of lead copper: ρ = 0.021 Ωm/mm² (at 75°C max. site temp)
  Type of CT connection cable: 4 mm²
  Lead wire resistance of CT cable: 5.25 mOhm/m [75°C]
  Lead loop resistance: \( R_L = 0.00525 \ \Omega/m \times 200m = 1.05 \ \Omega \)

• **Additional relay burden connected to CTs**: max. 0.0 VA

• **Earthing & Auxiliary Transformer Data**
  - Rated power: 500 kVA
  - Rated voltage ratio: 11 / 0.433 kV
  - Rated current 11 kV: 26.24 A
  - Rated current 433 V: 695.6 A
  - Rated frequency: 50 Hz
  - Vector group: ZNyn11 (d)
  - Impedance voltage: 9.6 % +/- 10 %
  - HV neutral: 750 A for 30 s with reactor earthed
  - LV neutral: solidly earthed

• **ΔIo> Differential Neutral Setting Range and Characteristics**
  - Start current: \( \Delta Io > = 0.5 \ldots 5\% \times In \) (In is either 1 A or 5 A input, selected is 5 A input)
  - Fixed operate time, typ.: 35 ms
  - Reset time, typ.: 60 ms
  - Operate time accuracy: ±25 ms

• **Stability of REF**
  When circulating current protection schemes are subjected to heavy through faults, the sudden and often heavy asymmetrical growth in the system current can cause the protective current transformers to approach or even reach the saturation level. Because of the variations in the magnetizing characteristics of the transformers a secondary unbalance current may result. To ensure stability under these conditions, it is modern practice to use a voltage operated, high impedance relay, and set to operate at a voltage higher than the developed one by the current transformers under maximum external fault conditions. The stabilizing voltage \( U_s \) can be calculated as follows:
  \[
  U_s = I_{k\text{max}} \times (R_{CT} + R_L + R_B) / n
  \]
Ik_{max} = Maximum through fault current, for which the relay must not operate
R_{CT} = Resistance of the CT secondary circuit
R_L = Total resistance of the longest measuring circuit (to and from)
R_B = Total resistance of additional relays
n = CT transforming ratio

The maximum transformer through-fault current is I'_{kmax} = 7.95 kA at 415 V.

Stability of the protection is required during a through fault of 7.95 kA. At this current and in the presence of CT saturation the stability of the protection scheme must be assured. The stabilizing voltage U_s in through-fault situation considering R_{CT} = 6.0 \, \Omega, R_L = 1.05 \, \Omega as lead loop resistance and R_{Burden} = 0.0 \, \Omega is:

The minimum voltage U_s is:  

\[ U_s = 7.95 \, kA \times (6.0 \, \Omega + 1.05 \, \Omega + 0.0 \, \Omega) / (750 \, A/1 \, A) = 74.7 \, V \]

The chosen voltage U_s is:  

\[ U_{s,\text{chosen}} = 200 \, V \]

A higher value for the setting voltage U_s is chosen in order to cater for all possible transient phenomena - with a safety factor above 1.5, a value of 200 V is selected. The CT knee-point voltage of 250 V clearly exceeds the selected stabilizing voltage of 200 V, so under in-zone fault condition the CTs will produce enough output to operate the relay.

- **Sensitivity of REF**

A start current setting of I_r = 0.15 A is chosen - this is a \( \Delta I_o > \) setting of 3 % related to the 5 A-relay input \( (I_n = 5 \, A) \). The 5 A relay input is connected to the CTs of 1500 A / 1 A. The stabilizing resistor R_s to ensure protection stability is: \( R_s = 200 \, V / 0.15 \, A = 1333 \, \Omega \). The stabilizing resistor is 0 – 5600 \( \Omega \).

- **I_r > m x I_e**

The start current I_r should be higher than the sum of the CT excitation currents at stabilizing voltage V_s: \( I_r > (m \times I_e) \). The CT excitation current at \( U_{s,\text{required}} = 200 \, V \) is \( I_e = 27.2 \, mA \) (\( I_e = 200 \, V / 125 \, V \times 17 \, mA \)).

The relation is fulfilled: \( I_r = 150 \, mA \) and \( I_r = 150 \, mA > m \times I_e = 4 \times 27.2. \, mA = 108.8 \, mA \).

- **Minimum effective operation current (POC)**

The current flow I_u through the Metrosil 600A/S1/1088 at \( U_{s,\text{chosen}} = 200 \, V \) is below 0.001 A (see V-I curve as attached). The effective max. and min. primary pick up current is: \( I_p = CT_{Ratio} \times (I_n + n \times I_e + I_u) \)

\[ I_{p_{\text{min}}} = 750 \times (0.15 \, A + 4 \times 0.027.2 \, A + 0.001) = 195 \, A \quad (is \, 28\% \, of \, I_T \, of \, 696 \, A) \]

The POC should be close to 20% of I_T - this is achieved. This is in line with ESI Standard 48-3 (Electric Supply Industry Standard, UK), requiring a setting between 10% and 60% of the rated transformer current in solidly grounded systems.

- **Recommended setting:** \( R_s = 1333 \, \Omega \) \( (U_s = 200 \, V, I_r = 0.15 \, A) \)

\( \Delta I_o > \) Start current \( I_r = 3 \% \) (CT is connected to 5 A relay input)

\( I_o > \) stage is blocked

Metrosil 600A/S1/1088

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NOTE:
Site measured values for CT data (resistance, mag. Curves), loop resistance, stabilizing resistor, varistor will be determined during commissioning. The settings will be re-calculated and adjusted based on the measurements. The final settings with measured values will be documented in "As Built" revision.
15 **KTS West 11 kV Feeder Protection**

Protection Scheme:

15.1 **Solkor Rf: 11 kV Feeder Differential Protection**

In case where pilot wires are available the main line differential protection of the 11 kV outgoing feeder is of type Solkor Rf and consists of following protection function:

87L  Line differential protection.

Solkor Rf is designed to operate over pilot circuits of a standard resistance. This standard operating value is obtained by adding padding resistance at each feeder end. This ensures that the protection is...
always operating under constant conditions of pilot resistance and its performance is therefore independent of this.

At each end of the feeder the secondary circuits of 3 current transformers (ct) are connected to a summation transformer which provides a single phase quantity for use over the pilot wires. Stability is achieved by current balancing using the Solkor operating principle of establishing the electrical centre of the pilot circuit within the relay which has positive polarity. Under healthy conditions, the measuring elements remain in the negative part of the circuit and thus biased against operation.

The high speed pilot wire feeder protection type Solkor Rf is foreseen to be used as protective device for the 11 kV cable feeders. It compares the magnitude and phase angle of the currents entering and leaving the protected feeder by means of a pilot wire circuit. The proposed relay has the following features:

- High speed operation.
- High transient stability.
- Low phase and earth fault settings.
- Pilot wire isolation for 15 kV via isolating transformer.
- Pilot supervision device

**Cable Data**

The cable data are unknown. **Following cable type is assumed:**

Assumed cable type: 3 x 1c x240mm² Cu XLPE Cable

Assumed ampacity acc. site condition with reduction of 0.8: 0.8 x 525 A = 420 A

The cable type data require verification on-site, the setting must be adjusted to the actual ampacity of the cable type used.

Therefore CT ratio 400 A / 1 A is selected.

**Solkor Rf CT Data**

- Solkor Rf CT Data

11 kV Cable Feeder CT: 300 A - 400 A / 1A

- Solkor Rf CT Data at remote side

Unknown, identical CT tap to be selected.

**Solkor Rf Setting Parameter**

The pilot wire differential protection of the outgoing cable feeders is carried out by the SOLKOR RF relay with isolating transformers. The settings require on-site measurements of the pilot wire resistance, therefore the templates for the on-site measurements are provided.
Padding resistor

The purpose of the padding resistors at each end is to bring the total pilot loop resistance up to a standard value (SV). With the pilots disconnected at both ends of the feeder, the cores are joined together at one end and the pilot loop resistance is measured from the other end. If the pilot loop resistance is less than the standard value (SV) for the particular arrangement being used (see table below) padding resistance is added at each end. The secondary tap is set to suit the measured pilot resistance. Thus for a pilot loop resistance lower than 440 ohms choose tap T1; for a pilot loop resistance between 440 ohms and 880 ohms choose tap T2. For a pilot loop resistance between 880 ohms and 1760 ohms choose tap F2. This will ensure that pilot capacitance will have a minimal effect upon the relay fault setting. The padding resistor comprises five series-connected sections, each section has a short-circuiting link. The values of resistance in the sections are 35 ohms, 65 ohms, 130 ohms, 260 ohms and 500 ohms. One or more sections can be inserted by removing the appropriate link or links which are located on the link-board. Choose the same value at each end.

The value chosen should be as near as possible to:

\[ R_{\text{Padding}} = 0.5 \times \frac{(R_{SV} - R_P)}{T} \]

with:
- \( R_P \) is the measured on-site pilot wire resistance
- \( R_{SV} \) standard resistance value for tap on transformers (see following table)
- \( T \) isolating transformer tap (see following table)
  - = 1.0 if no isolating transformer fitted
  - = 1.0 for isolating transformer tapping F2
  - = 0.5 for isolating transformer tapping T2
  - = 0.25 for isolating transformer tapping T1

Table 10.1 shows the standard pilot loop resistance and maximum inter-core capacitance permissible. When isolating transformers are fitted, it is recommended that the tap chosen should be the one which allows the maximum value of pilot capacitance for the measured pilot loop resistance. When inserting a padding resistance in Vedette case versions, the link should be completely removed. Do not merely open-circuit the link by pivoting the link on one terminal and leaving it in this position, as this can reduce the insulation level between the padding resistor and earth.
• **O/C sensitivity setting of the guard relays**

Chosen O/C sensitivity is set to 100% of the nominal CT current of 400 A. This setting ensures pick-up of the scheme with no delay in operation time at minimum fault currents, but is safely above the full load current of the cable. The OC unit can be set from 50% to 200% of I_{CT}.

O/C setting \(= 1.0 \times I_{CT} = 1.0 \times 400\text{A} = 4000\ \text{A (prim.)} = 1.0\ \text{A (sec.)}\)

• **E/F sensitivity setting of the guard relays**

To detect high resistive earth faults, a low operating current is required. On the other hand, a low setting will increase the risk for unwanted operation due to unbalance in the network and in the current transformer circuits. The EF unit can be set from 20% to 80% of I_{CT}. In this protection application the minimum setting of 20% I_{CT} is proposed as 11 kV-system is operated with restricted earthing to 750 A.

E/F setting \(= 0.2 \times I_{CT} = 0.2 \times 400\text{A} = 80\ \text{A (prim)} = 0.2\ \text{A (sec.)}\)

---

**Table 10.1: Resistance and Capacitance limitations**

<table>
<thead>
<tr>
<th>Transformer and Capacitance limitations</th>
<th>Transformer terminal</th>
<th>Transformer tap value</th>
<th>Standard value of pilot loop resistance (S.V.)</th>
<th>Maximum capacitance between cores F</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sulkor R</td>
<td>-</td>
<td>1.0</td>
<td>1000</td>
<td>2.5</td>
</tr>
<tr>
<td>E/F setting</td>
<td>1.0</td>
<td>2000</td>
<td>0.8</td>
<td></td>
</tr>
<tr>
<td>Sulkor Rf without isolating transformers</td>
<td>-</td>
<td>1.0</td>
<td>1760</td>
<td>1</td>
</tr>
<tr>
<td>E/F setting</td>
<td>0.2</td>
<td>880</td>
<td>2</td>
<td></td>
</tr>
<tr>
<td>Sulkor Rf with isolating transformers</td>
<td>T2</td>
<td>0.25</td>
<td>440</td>
<td>4</td>
</tr>
</tbody>
</table>

---

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Solkor Rf setting template for commissioning

The relay will be set based on the pilot wire resistance measurement, the following tables are intended for the on-site setting calculation to be included in the final "as-built" revision of the setting calculation.

Substation: ..............................

Feeder No: .............................. to S/S .............................. Bay ..............................

Cable type: .............................. Imax = .............................. A

Current Transformer Data
Ratio: 400 / 1A

On-site measurement
Pilot wire loop resistance (measured) $R_p$

Setting Calculation
The value $R_{\text{Padding}}$ should be as near as possible to:

$$R_{\text{Padding}} = 0.5 \times \frac{(R_{SV} - R_p)}{T} =$$

$R_p$ is the measured on-site pilot wire resistance
$R_{SV}$ standard resistance value for tap on transformers (see following table)
$T$ isolating transformer tap (see following table)

<table>
<thead>
<tr>
<th>Transformer Terminal / Tap Value</th>
<th>SV loop resistance (SV) in ohms</th>
<th>Max capacitance between cores in $\mu$F</th>
</tr>
</thead>
<tbody>
<tr>
<td>Solkor R</td>
<td>- / 1.0</td>
<td>1000</td>
</tr>
<tr>
<td>Solkor Rf without isolating transformer</td>
<td>- / 1.0</td>
<td>2000</td>
</tr>
<tr>
<td>Solkor Rf with isolating transformer</td>
<td>F2 / 1.0</td>
<td>1760</td>
</tr>
<tr>
<td></td>
<td>T2 / 0.5</td>
<td>880</td>
</tr>
<tr>
<td></td>
<td>T1 / 0.25</td>
<td>440</td>
</tr>
</tbody>
</table>

Padding resistance setting table

<table>
<thead>
<tr>
<th>Value</th>
<th>35 $\Omega$</th>
<th>65 $\Omega$</th>
<th>130 $\Omega$</th>
<th>260 $\Omega$</th>
<th>500 $\Omega$</th>
<th>$R_{\text{Padding}}$ Setting</th>
</tr>
</thead>
<tbody>
<tr>
<td>Set</td>
<td>$\Sigma$</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

O/C sensitivity setting of the guard relays
O/C setting $= 1.0 \times I_{\text{CT}} = 1.0 \times 400A = 400$ A (prim.) $= 1.0$ A (sec.)

E/F sensitivity setting of the guard relays
E/F setting $= 0.2 \times I_{\text{CT}} = 0.2 \times 300A = 60$ A (prim.) $= 0.2$ A (sec.)
15.2 **REX521: 11 kV Back up Feeder Protection**

The back up feeder and busbar protection terminal is of the ABB type REX521 H04. In this protection device the following protection and monitoring functions are implemented:

- 50 Instantaneous Over-current Protection
- 51 Time Delayed Over-current Protection
- 51N Time Delayed Earth fault Protection
- 50-BB Instantaneous Phase Over-current Busbar Protection (Blocking Signal)
- 50N-BB Instantaneous Earth fault Busbar Protection (Blocking Signal)

- **Cable Data**
  
The cable data are unknown. Following cable type is assumed:
  
  Assumed cable type: 3 x 1c x 240mm² Cu XLPE Cable
  
  Assumed ampacity acc. site condition with reduction of 0.8: 0.8 x 525 A = 420 A
  
  The cable type data require verification on-site, the setting must be adjusted to the actual ampacity of the cable type used.

- **Number of feeders per busbar section**

- **CT data**
  
  11 kV Feeder CT  
  
  400 A / 1A, 5P20, 15 VA

  The maximum three-phase transformer through-fault current is 12.9 kA (per each 40 MVA-transf). Maximum earth-fault current is 750 A.

**REX521: 11 kV-Feeder Over-current Protection (51)**

- **I>-stage (non-dir)**

  The start current of the I>- stage is set to 100 % of the CT nominal current of 400 A, which gives a primary current setting I> = 400 A. The secondary relay setting is 1.0 A.

  The proposed time multiplier setting is k = 0.4. The TMS provides an maximum operation time of 0.78 s at the transformer through-fault current of 12.9 kA at the 11 kV-feeder. The relay operating time is:  
  
  \[
  t_{\text{relay}}(12.9 \text{kA}) = 0.4 \times 0.14 / ((12900 \text{A} / 400 \text{A})^{0.02} - 1) = 0.78 \text{s}
  \]

- **Recommended setting**

  Relay module: REX521 “Three-phase non-directional over-current protection, low-set stage, 3I>”

  \[
  CT = 400 \text{A} / 1 \text{A} \\
  I_> = 1.0 \times I_N \quad (\text{is} \ 400 \text{A primary}) \\
  TMS = 0.4 \\
  I_\text{curve} \text{ is normal inverse}
  \]
**REX521 – 11 kV-Feeder Earth-fault Protection (51N)**

- **Io>-stage**
  
The start current Io> is set to 120 A or 30% of the CT nominal current; the secondary relay setting is Io> = 0.3 A. The TMS is 0.4. The relay operating time at maximum earth fault current of 750 A is:

\[
t_{\text{relay}}(750 \, \text{A}) = 0.4 \times 0.14 / ((750 \, \text{A} / 120 \, \text{A})^{0.02} - 1) = 1.5 \, \text{s}
\]

- **Recommended setting**
  
  Relay module: REX521 “Non-directional earth fault protection, low-set stage, Io>”

  \[
  \begin{align*}
  \text{CT} &= 400 \, \text{A} / 1 \, \text{A} \\
  I_{\text{o>}}/I_N &= 30\% \quad \text{(is 120 A primary)} \\
  k &= 0.4 \\
  I_{\text{o>}} \text{ curve is normal inverse}
  \end{align*}
  \]

**REX521 – 11 kV-Feeder Over-current Partial Differential Busbar Protection (50-BB)**

The instantaneous over-current (50-BB) protection is set instantaneously to detect a fault phase current on the outgoing feeder. This signal will be used to block the operation of the partial differential busbar instantaneous over-current protection of the 11 kV infeed transformer and bus coupler feeders.

- **I>-Stage Setting for blocking the busbar protection**
  
  An OC relay sensitivity of 1.3 x I_{CT} = 520 A is proposed, this setting is above possible maximum load currents and is certainly below the minimum fault current.

- **Recommended setting**
  
  Relay module: REX521 “Three-phase non-dir. over-current protection, instantaneous stage, 3I>>>”

  \[
  \begin{align*}
  \text{CT} &= 400 \, \text{A} / 1 \, \text{A} \\
  I_{>} &= 1.3 \times I_n \quad \text{(is 520 A primary)} \\
  t_{>} &= 0.0 \, \text{s} \\
  I_{>} \text{ curve is definite time}
  \end{align*}
  \]

  Relay pick-up signal blocks the partial OC busbar protection

**REX521 – 11 kV-Feeder Earth-fault Partial Differential Busbar Protection (50N-BB)**

The instantaneous earth fault (50N-BB) protection is set instantaneously to detect an earth fault current on the outgoing feeder. This signal will be used to block the operation of the partial differential busbar instantaneous earth fault protection of the 11 kV infeed transformer and bus coupler feeders.

- **Io>-stage**
  
  An EF relay sensitivity of 40 A is proposed (typical setting as provided), this corresponds to 10% of the nominal CT current.
• **Recommended setting**

Relay module: REX521 “Non-directional earth fault protection, instantaneous stage, Io>>>

CT = 400 A / 1 A

\[
\frac{I_{o}}{I_{N}} = 0.1 \quad \text{(is 40 A primary)}
\]

\[
t_{o} = 0.0 \text{ s}
\]

\[I_{o}\text{ curve is definite time}
\]

Relay pick-up signal blocks the partial EF busbar protection

15.3 **REF542 - Switch-on-to-fault (SOTF) function for 11kV cable outgoing feeders**

The proposed logic is implemented within the BCU (type REF542+) and uses an instantaneous overcurrent protection (pick up current \(0.1\ldots40,0 \times I_{N}\)), drop out timer and some logic elements. It is activated with any close command and causes a delayed tripping of 0.2s acc. to KM request in case of detected overcurrent. This tripping will be signalled as event to SAS and locally by an alarm LED. The SOTF feature is active by close command and remains active for 1000 ms (drop out timer), activation of the instantaneous overcurrent module \(I_{>>>}\) stage within this time window issues SOTF tripping of CB.

The settings of the instantaneous overcurrent module \(I_{>>>}\) is:

CT = 400 A / 1 A

Relay module = Overcurrent definite time instantaneous (\(I_{>>>}\))

Start Current \(I_{>>>}\) = 3 \(x\) In \(\quad (3 \times 400 \text{ A} = 1200 \text{ A prim.})\)

Time = 0.2 s

Curve = definite time

According information the feeder can be stressed by one transformer inrush currents. Approximately inrush currents of 11kV/LV transformers can reach 10 times of the rated current, which is about 500A for a 1MVA transformer. However, based on experience in already energized substations 0.2 second shall be set as per KM distribution request.

It should be noted that due to selected time delay of 0,2 sec as per KM advice, the overall fault clearing time of SOTF - function will be increased accordingly. Therefore instantaneous fault clearance will be only achieved by the cable differential protection.
16  **11 kV Load Shedding Settings**

The frequency protection for 11 kV load shedding consists of the ABB type RET316*4ST460.

The following underfrequency load shedding settings will be applied:

- **Stage 1:** 49.2 Hz
- **Stage 1A:** 48.8 Hz
- **Stage 2:** 48.4 Hz
- **Stage 3:** 48.0 Hz
- **Stage 4:** 47.8 Hz

All stages with a time delay of $t_{set}=100$ms.

17  **REF542 – General Settings for Synchronism check**

**Synchrocheck Settings for manual closing**

The synchrocheck function is used for checking whether CB closing is permitted or not. Before CB operation the following closing conditions must be fulfilled:

1. The voltage difference over the CB must be small enough. The allowed voltage difference is determined by the set voltage difference value $\Delta U$:
   - A setting of DELTA VOLTAGE = 0.2 x Un is proposed.

2. The network sections to be connected (voltages) have the same phase angle. The phase angle condition is fulfilled when the allowed phase angle difference between the network voltages is smaller than the set phase angle difference $\Delta \phi$.
   - A setting of DELTA PHASE = 15° is proposed.

3. The validity time for CB closing conditions
   - A setting of TIME = 0.4 sec is proposed.

**Voltagecheck Settings for manual closing**

The required voltage check functions must be implemented in the REF542 FUPLA as not part of the synchrocheck function module. The following voltage check logic is proposed:

(Both sides "de-energized") OR ("dead line" AND "live bus") OR ("live line" AND "dead bus")

Is one of the above cases fulfilled, closing is permitted without synchrocheck. Only in case of both sides “energized” is synchrocheck required. The level above with a network is considered to be energized or de-energized is defined by the following settings:
1. The voltage magnitudes of the energized networks are determined by the set value for the upper threshold voltage $U_{\text{max}}$.
   - A setting of $U_{\text{max}} = 80\%$ is proposed.

2. $U_{\text{min}}$ is the lower threshold voltage level below the measured bus/line voltage is considered to be de-energized.
   - A setting of $U_{\text{min}} = 20\%$ is proposed.

Should any network show a voltage between $U_{\text{min}}$ and $U_{\text{max}}$ reclosing must be blocked.

Synchrocheck for manual closing is performed by SPAU140 relay, for all other cases by the REF542.

The settings for SPAU140 are proposed to be the same as for REF542+:

Delta $U = 0.2 \, U_n$
Delta phase = 15 deg
Delta frequency $df = 0.2$ Hz

The last setting correspond with delta phase (dp) and delta time (dt) of REF542+.

\[
df = \frac{dp}{(180 \times dt)} = \frac{15}{(180 \times 0.4)} = 0.2 \, \text{Hz}
\]

Remark: $U_n$ for SPAU140 is the phase-phase voltage (110V)

18 **AVR – General Settings for Automatic Voltage Regulator**

Settings for Parallel Operation:

<table>
<thead>
<tr>
<th>Operation mode</th>
<th>Transformer boundary conditions</th>
<th>Pre-requisites regarding the regulator</th>
<th>REG-DA Programs</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Voltage change per tap-change</td>
<td>Deviation of the relative short circuit voltages</td>
<td>Maximum tap-change difference when in operation</td>
</tr>
<tr>
<td>Parallel operation on the busbar</td>
<td>no change</td>
<td>no change or various</td>
<td>≤ 10 %</td>
</tr>
<tr>
<td></td>
<td>no change or various</td>
<td>no change</td>
<td>≤ 10 %</td>
</tr>
<tr>
<td></td>
<td>no change or various</td>
<td>various</td>
<td>≤ 10 %</td>
</tr>
<tr>
<td>Parallel operation on a network</td>
<td>no change or various</td>
<td>no change or various</td>
<td>no change or various</td>
</tr>
</tbody>
</table>
Master Slave was picked as the optimal parallel program. The voltage change per tap change is the same across the parallel transformers, the nominal power is the same and a different tap change between two parallel transformers is not allowed. Operation will be at the same busbar.

Other parameters in the parallel operation settings can be left out for this type of parallel operation. Only the group list has to be edit and has to contain the regulators present in the setup for parallel operation. In this case there are two regulators/transformers possible for parallel operation listed – B1 and B2.

**Configuration:**

**Mounting Knu:**

The voltage transformers always have the same nominal voltage. To display the right Voltage Level at the regulator, Knu is used.

Nominal Voltage of Voltage Transformer: 110V  
Voltage level in this case: 11kV

\[
Knu = \frac{\text{Voltage Level}}{\text{Nominal Voltage Transformer Voltage}}
\]

\[
Knu = \frac{11000 \text{ V}}{110 \text{ V}} = 100
\]

**Mounting Kni:**

Same with Kni. The Ratio of the current transformers can be different, but it is always to 1A like for example 400/1A or maybe 800/1A. So the regulator needs to know the right Kni to compute further values.

Primary current of current transformer = 2000A  
Secondary current of current transformer = 1A

\[
Kni = \frac{2000 \text{ A}}{1 \text{ A}} = 2000
\]

**Analogue I/O**

Oil-Temp and Winding Temp are present as mA signal, so function ANA (please see technical description for more detailed information) is used for channel 1 and channel 2. Channel 3 is the tap changer position as mA, so function iTapPos is used.

The channels can have different characteristics like stated below
Because all three values have a linear equation, the characteristic P0P2 is used and to scale the range for the specific application (0-150°C and 0-17 steps) the beginning and end points have to be set.

**Temperature Input:**
For the range 0 – 150°C the beginning point P0 is [0/0.2] and P2 is [150/1]

The x-axis represents the temperature and the y-axis the scaled mA.

P0(x) is 0 because the temperature range starts at 0 and P0(y) is 4mA of 20mA (4/20=0.2).

So as result P0 is [0/0.2] as starting point.

The endpoint P2 is 20mA and 150° Celcius so the x-axis is 150 and the scaled value for the y-axis is 1 (20/20). As result P2 is [150/1]

**Tap Changer Position:**
In the same manner the scale of the OLTC Input can be calculated.

In this case the number of steps is represented by the x-axis and as before the y-axis represents the scaled mA signal.

The lowest tap position is 1, so P0(x) is 1 and P0(y) is like before 4mA of 20mA (0.2). P2 is [17/1] for 17 steps and 20mA of 20mA.

P1 isn’t used in any application because characteristic P0P2 is picked. So only P0 and P2 has to be calculated and values for P1 entered in the parameters are ignored by the regulator.
19 Selectivity Diagrams of Components

19.1 REL561 – 66kV Doha Central Cable Feeder OC Protection (51/51N)

Fig.No.: [4]
Doha Central 66kV Cable Feeder Protection OC (50/51)
19.2 KTS West 66kV OC Protection at 40MVA Transformer (51/51N)

![Graph showing transformer protection settings](image-url)

**Fig. No.: [1]**

KTS West 66kV 40MVA Backup Transformer Protection (50/51)
19.3 REX521 – 11kV Directional OC at 40MVA Transformer (67)

**Fig. No.: [2]**

**KTS West 11kV 40MVA Transformer Directional OC (67)**
19.4 11kV OC Protection at 500kVA EA-Transformer (51/51N)

Fig.No.: [3]

KTS West 11kV 0.5MVA EA-Transformer Directional OC (50/51)
20 Selectivity Diagrams for Protection Co-ordination

20.1 66 kV Doha Central to 66kV KTS Transformer Feeder – Over-current Protection

The following diagram documents the selective grading of the OC protection 66kV cable feeder (Doha Central), 66 kV bus coupler (KTS) and the outgoing 66 kV transformer feeder (KTS).

![Selectivity Diagrams for Protection Co-ordination](image_url)

**Fig.No.: [5]**

66kV Protection Coordination
20.2 66kV KTS Transformer Feeder to 11kV – Over-current Protection

The following diagram documents selective grading of the 66kV KTS Transformer Feeder, 11 kV Bus Section and the outgoing 11 kV Cable Feeder OC protection for single transformer operation.

Fig.No.: [6]

66/11 kV Protection Coordination - Single Transformer Operation

<table>
<thead>
<tr>
<th>Trip Time in sec</th>
<th>11kV</th>
<th>11kV</th>
<th>66 kV</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Cable</td>
<td>Bus Section</td>
<td>Transformer</td>
</tr>
<tr>
<td>Feeder</td>
<td>PBB</td>
<td>Feeder</td>
<td></td>
</tr>
<tr>
<td>Max.s/c: 12.9 kA</td>
<td>0.78</td>
<td>1.40</td>
<td>1.90</td>
</tr>
</tbody>
</table>

REX521 66 kV KTS Transf. Feeder OC

p=524 A t=0.450pu
IEC255-3 very inverse

REX521 11kV KTS Bus Section PBB

p=3520 A t=0.260pu
IEC255-3 normal inverse

REX521 11kV KTS BackUp Cable Feeder OC & EF

p=400 A t=0.400pu
IEC255-3 normal inverse
The following diagram documents selective grading of the 66kV KTS Transformer Feeder, 11 kV Bus Section and the outgoing 11 kV Cable Feeder OC protection for parallel transformer operation.

Fig. No.: [7]  
66/11kV Protection Coordination - Parallel Transformer Operation

<table>
<thead>
<tr>
<th>Trip Time in sec</th>
<th>11kV</th>
<th>11kV</th>
<th>66 kV</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Cable</td>
<td>Bus Section</td>
<td>Transformer</td>
</tr>
<tr>
<td>Feeder</td>
<td>PBB</td>
<td>Feeder</td>
<td></td>
</tr>
<tr>
<td>Max. s/c per Transf.:</td>
<td>11.9 kA</td>
<td>2.10</td>
<td></td>
</tr>
<tr>
<td>Max. s/c total:</td>
<td>23.7 kA</td>
<td>0.66</td>
<td>0.96</td>
</tr>
</tbody>
</table>
20.3 11kV KTS West – Earth Fault Protection

The following diagram documents the 11 kV-EF protection at the earthing transformer neutral, the bus section and of the outgoing 11 kV-feeder. The displayed current value is the minimum earth fault current of 750 A.

Remark: tripping of bus section relay is blocked in case of outside earth fault.

<table>
<thead>
<tr>
<th>Trip Time in sec</th>
<th>11kV Cable</th>
<th>11kV Bus Section</th>
<th>11kV Earthg Transf.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Max.e/f per Transf.: 750 A</td>
<td>1.50</td>
<td>2.00</td>
<td>3.5 / 4.5</td>
</tr>
</tbody>
</table>
21 Attachments

[A-1] 66 kV Single Line Diagram KTS West, Drawing No. 05-4/12/ABB-NEX/01/0101
[A-2] 11 kV Single Line Diagram KTS West East, Drawing No. 05-4/12/ABB-NEX/01/0102
[A-5] 40 MVA-Power Transformer 66/11 kV- FAT Report, relevant pages are attached
[A-6] Protection Principle Diagram Doha Central, Drawing No. 05-4/25/ABB-NEX/08/0001
[A-7] Protection Single Line Diagram KTS West, Drawing No. 05-4/12/ABB-NEX/08/0103
[A-10] Protection Principle Diagram KTS West, Drawing No. 05-4/12/ABB-NEX/08/0002