Operation and Maintenance of a Gas Insulated Substation

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Operation and Maintenance of a Gas Insulated Substation

A major difference between conventional air insulated substations (AIS) and the gas insulated substations (GIS) is that the SF6 gas insulated electrical components are placed within an earthed, pressurized metallic container. This is a significant change in operating the switchgear with circuit breakers, disconnectors, and earth switches because there is no direct observation or visual contact of the open or closed disconnect switch gap or the open or closed earthing switch status.

Besides this difference, other special operating characteristics are related to view ports, cameras, endoscopes, induced currents in the metallic containers, alarms, local control cubicles, remote control, mimic schemes, gas zone, unmanned substations, etc.

The maintenance paragraphs give real life experiences from existing GIS technology that has been in service for a number of years. It describes the nature and sources of defects including their repair and sophisticated planning. Usual maintenance methodologies on measures to determine the quality of the SF6 insulating gas, visual and optical verifications, gas handling records, and leak detection routines are presented. Special practices on interlocks, gas zones, spare parts, and special equipment are discussed. Experiences and lessons learned on gas zone identification, secondary interface, wiring methods are combined and presented. Preconstruction staff training that involves continuous monitoring, GIS retrofit and bus leak maintenance topics are also discussed.

This course presents the GIS repair process. Information is presented on the types of anticipated defects, which demand repair of a GIS installation, how much time needs to be expected, and how service continuity is related to the design.

Also course describes how a GIS installation can be extended after it has been installed and used for a number of years. This course provides details about the definition of the interface between two GIS installations of different dimensions. It also presents the work that has to be completed when extension is not expected from the initial design stage, how service continuously during extension work can be given, and how the new interface can be verified after extension. Also, course explains retrofit for

GIS installation upgrade. Here the challenges of old switchgear installations are discussed and details are provided to retrofit or upgrade a substation. A specific view is taken on replacement of circuit breakers in GIS installation to increase switching capacity. The situation of overloading GIS equipment is also described. The principle of the GIS installation for continuous rating current is presented under the thermal and dielectric conditions given in a substation design. The determination of the thermal limits based on IEEE and IEC standards are also included. The maximum continuous load current and the short-time overload capacity are discussed and equations for overload calculations are shown.

Gas Insulated Substation Operation

Both AIS and GIS installations use circuit breakers, disconnect switches (isolators), and earthing switches, and have different means of showing their status, either opened or closed. Operation of a GIS substation involves the same principles as operating an air insulated substation (AIS) even though the different active elements are physically arranged differently. The first obvious difference is that the blades of the disconnect switches and the earthing switches installed in a GIS substation are surrounded by earthed metallic enclosures. This enclosure prevents the blades from being easily visible to discover their fully opened or fully closed status. The second apparent difference relates to the bus conductors being installed inside earthed metallic enclosures. These enclosures prevent the bus from being earthed with portable personnel grounds except at very discrete locations, such as air-to-gas bushing terminations at transmission lines and transformer banks.

Typically, a GIS installation demands more extensive electrical interlocking between the circuit breakers, disconnect switches (isolators), and earthing switches. The specific detailed procedure of operating and interlocking is typically determined by the GIS end user.

Circuit Breaker

Since one of the main circuit breaker functions is to automatically and quickly de-energize faulted transmission lines, transformer banks, and buses, an opening operation is started by protective relays, which are commonly installed remotely in a relay and control room. This operation may also involve automatically reclosing of the circuit breaker for several times.

The opening or closing of a circuit breaker can also be started by human intervention from different locations, including manually from the circuit breaker mechanism, electrically from the LCC, from the relay and control panels remote from the circuit breaker, or from supervisory controls remote from the substation.

Typically, a circuit breaker is not stopped from opening and/or closing by the status of either a disconnect switch or earthing switch. Nevertheless, a circuit breaker is stopped from operating or is automatically demanded to operate by parameters that impact its successful function, such as low interrupting and insulating gas density, low mechanism pressure, pole disagreement tripping (in the case of circuit breakers with separate pole operation), or monitoring of the proper circuit breaker status before starting an operation. For instance, a circuit breaker have to be in the totally closed position before an open operation can be started and, conversely, a circuit breaker has to be in the completely open position before a close operation can be started.

The indication of the circuit breaker status can be monitored at the circuit breaker mechanism cabinet via mechanically operated semaphores, at the LCC, at the relay and control panels remote from the circuit breaker, or from supervisory controls remote from the substation with statuses showing red and green lights or semaphores.

Disconnect Switches

Disconnect switches in a GIS installation are used for the same function as those in an air insulated substation (AIS). They are applied to isolate different elements of the substation, such as circuit breakers, transmission lines, transformer banks, buses, and voltage transformers. Typically, they do not have big interrupting capability except for small quantities of charging current associated with short pieces of bus. Charging currents are in the range of 0.5 A to 2.0 A.

Disconnect switch operating systems involve:

- Only manual hand crank operation

- Motor operated with manual hand crank override
- Single-phase operation or three-phase group service

The disconnect switch status, open or closed, may be discovered by one or more of the following:

- An indicating element, such as red and green lights or semaphores, in the LCC
- A mechanical semaphore in the switch operating mechanism cabinet
- The physical status of the linkages that drive the switch blade

Direct/camera view of the status of the switch blade through a viewport in the earthed metallic enclosure. Where motorized disconnect or earthing switches are installed, some utilities and end users, demand a knife switch to make sure the motor mechanism is deenergized during maintenance. Also, the motor mechanism may demand decoupling from disconnect operating arm. This has to be considered in the initial design stages.

Commonly, during the initial design stages, a utility or new GIS end user will meet with the GIS manufacturer to review their operating routines and functions.

Non-fault-Initiating Earthing Switches

Non-fault-initiating earthing switches in a GIS installation are used for the same staff protection purpose as those in an air insulated substation (AIS) similar to a portable personnel earthing connection made with a hook stick. They are used to earth different de-energized substation elements, such as circuit breakers and voltage transformers. Typically, these earthing switches do not have fault-closing or induced current-interrupting ability, but are capable of conducting fault current when in the closed position and a small quantity of continuous current for the purpose of testing circuit breakers and current transformers that are out of service.

Usually, non-fault-initiating earthing switches have the same type of operating mechanisms and method of discovering switch status as disconnect switches.

External, removable links in the earthing switches are required to disconnect a earthing switch blade from the external ground. In the closed position, the removable links allow electrical access to the center conductor and allow timing tests on circuit breakers, conductivity tests, and current transformer measurements. To help with operator identification the outer housing of earthing switches may be painted a green, red or similar color to distinguish from the gray or aluminum color of the GIS elements.

High Speed Earthing Switches

High speed earthing switches are unique to GIS design as they are not normally used in air insulated substations. Their primary function is the same as earthing switches in air insulated substations and non-fault-initiating earthing switches in GIS installations. They also complete the same function as portable personnel earth connections made with hook sticks.

High speed earthing switches have an extra capability of closing an energized conductor, creating a short circuit without experiencing major damage to the switch or the enclosure. High speed earthing switches are used to earth different active substation elements, such as transmission lines, transformer banks, and main buses. In some GIS installations high speed earth switches are used to start protective relay functions. Commonly, they are not used to earth circuit breakers or voltage transformers. High speed earthing switches are also made and tested to break electrostatically induced capacitive currents and electromagnetically induced inductive currents occurring in de-energized transmission lines in parallel and close proximity to energized transmission lines. They can also get rid of DC trapped charges on a transmission line.

Normally, high speed earthing switches have motor operating mechanisms with spring assists for quick opening and closing of the switch blade. Normally, they use the same procedure for discovering the switch status as disconnect switches. Dependent on the design and customers maintenance procedures, external removable links in the earthing switches may be required to disconnect an earthing switch blade from the external ground. These removable links are needed to facilitate timing tests on circuit breakers, conductivity tests, and current transformer measurements.

Three-Position Disconnect/Earthing Switches

At voltages in the range of 34.5 kV to 161 kV three-phase GIS, a three-position switch is commonly installed. This switch mixes a disconnect switch with an earthing switch. With one operator and one blade, the switch can be placed into the closed position, the open position, or the earthed position.

Commonly, three-position switches have the same operating mechanisms type and method of discovering switch status as disconnect switches. If three way switches are installed and the GIS station will be operated remotely, provisions have to be made to remotely change the position selector switch (open, closed or earthed) to avoid a need for staff to travel to the GIS substation and manually change the switch.

Similarly, external removable links in the earthing switches may be required to disconnect an earthing switch blade from the external ground for test measurements.

Voltage Transformers

Similar to AIS substations GIS installation includes voltage transformers to decrease the bus high voltage to lower control levels of 120/208volts for protective relays, control and metering and similar functions. Common turn ratio, insulation integrity and additional tests have to be done. It is important in the starting design stages to complete a ferroresonance assessment if the voltage device is a wire would type. The capacitance of the GIS installation may interact with the voltage transformer inductance causing a ferroresonance condition and potential equipment defects. The study has to determine if a load can be connected to the VT secondary to de-tune the condition.

Current Transformers

Current transformers are typically installed in the circuit breaker bushing turrets. Nevertheless, specific designs including direct cable or transformer connections may demand standalone current transformers. As in the case of AIS standard current injection and ratio tests have to be completed. Nevertheless, to access the main bus as previously stated, earth switches will have to be isolated and the test currents or voltages injected thru the earthing switch onto the bus. These tests are done with the main bus denergized and isolated from any operational portions of the remaining GIS installation. It is also important to keep in mind when the tests are done before the bus or equipment is energized, the current transformer has to be connected or shorted, otherwise equipment damage may happen.

Switch Viewports

Normally, viewports are provided in order to fulfil the requirements of being able to visibly check circuit breaker status. A viewport gives the operator via a glass portal a way to discover disconnect or earthing switch blade position. Viewports can be small in diameter and require a borescope or camera in the 50 to 100mm range where an operator can use a flashlight and directly observe.

Operations cautions include:

- Never look into a viewport while an element is being switched, arcing may happen with the switching operation.

- All viewports need to be clearly labelled with the device number being observed. There should be no dilemma from the operator which element opened and its position.

- Before a facility is commissioned staff has to be provided with an opportunity to directly observe a switch operation. It is also useful to give a video for future operators. Since this is one of the unique aspects, GIS operational staff should be well trained in switch operations.

- In the case tools are needed to access a viewport, they should be readily available and kept in a common storage locker.

Gas Chambers and Zones

A gas chamber is described as an enclosure that contains gas isolated from the atmosphere and other chambers. Two or more gas chambers may be externally connected with small diameter gas pipes. A gas zone is described as a part of the GIS installation that contains one or more gas chambers that have a common gas monitoring system and whose gas density fluctuates in unison. Several principles related to gas chambers and zones are:

- Typically, each phase of an isolated phase GIS contains its own chambers and zones separate from the chambers and zones of the other two phases.

- Normally, each phase of the circuit breaker is its own zone to eliminate the spread of pollutants to other compartments. Pollutants are created by the circuit breaker operation.

- Normally, a buffer chamber is installed on each side of each phase of each circuit breaker. In the situation of invasive maintenance or repair, the buffer chamber with decreased gas pressure works as an extra safety barrier against pressurized SF6 gas.

Commonly, the gas quantity in each chamber is restricted to the amount of gas that can be easily handled by the available gas processing devices. Typically, the SF6 gas pressure is higher in the circuit breaker gas zone than other gas zones due to the switching requirements. Each gas zone includes an SF6 gas density monitor, a gas filling valve, and a pressure relief element.

Interlocking Principles

Because of the compactness of a GIS substation, and the apparent difficulty in readily identifying the different active elements, it is accustomed practice to electrically and/or mechanically interlock circuit breakers, disconnect switches, earthing switches, transmission lines, and transformer banks.

The three main demands for an interlocking system are:

1. A disconnect switch has to be stopped from interrupting or making load current.

2. A disconnect switch has to be stopped from closing into a earthed bus.

3. An earthing switch has to be stopped from closing on to an energized bus.

A few examples of interlocking are presented. Typical example involves the breaker status including the circuit breaker, a disconnect switch on each side of the circuit breaker, and two earthing switches. Each earthing switch is between one of the disconnect switches and the circuit breaker. The main bus and the transmission line are assumed to be energized.

1. For the first example, the circuit breaker is closed and is either energized or de-energized. The two earthing switches are open. The two disconnect switches need to be stopped from being closed or opened, therefore stopping the disconnect switch from either interrupting or making load current. Therefore, interlocking rule 1 is satisfied.

2. For the second example, assume that the circuit breaker is out of service and de-energized, and that one or both of the two earthing switches are closed. The interlocking mechanism stops either of the two disconnect switches from being closed, stopping them from connecting an energized circuit into a earthed bus. Therefore, interlocking rule is satisfied.

3. Conversely, for the third example, the circuit breaker is energized (open or closed) and one or both of the disconnect switches are closed. The interlocking mechanism stops either of the two earthing switches from being closed, stopping them from closing on to an energized bus. Therefore, interlocking rule 3 is satisfied.

4. A fourth example includes switching device on opposite voltage sides of a transformer bank. If a high speed earthing switch on one side of a transformer bank is closed, effectively earthing the transformer bank, the disconnect switches isolating the transformer bank on the opposite side will be stopped from being closed into the earthed transformer. Therefore, interlocking requirement 2 is satisfied.

5. Conversely, a fifth example also includes the transformer bank. If one or both of the isolating disconnect switches on one side of a transformer bank are closed or earthed, the high speed earthing switch on the opposite side of the transformer bank will be stopped from being closed into the energized transformer. Therefore, interlocking requirement 3 is satisfied.

6. A sixth example includes the switching element of a transmission line. The most practical method of interlocking is to observe the voltage on the transmission line and stop the high speed earthing switch from being closed if there is system voltage present on the transmission line. Therefore, interlocking requirement 3 is satisfied.

7. A seventh example includes the main bus. If the high speed earthing switch on the main bus is closed, all of the disconnect switches that are connected to that same main bus are stopped from closing. Therefore, interlocking requirement 2 is satisfied.

8. Conversely, an eighth example also includes the main bus. If one or more of the disconnect switches connected to the main bus are closed, the high speed earthing switch connected to that main bus is stopped from closing. Therefore, interlocking requirement is satisfied.

There may be other interlocking requirements for disconnect switches and earthing switches. For instance, if the motor of a switch is running, the manual method of operating the switch will be blocked. If the manual method of operating the switch is engaged, energizing the motor will be blocked.

Local Control Cabinets (LCCs)

By virtue of its compact design, GIS device does not allow the user many options in selection of the components that will be used within the GIS installation. The exception is the local control cabinet (LCC) or marshaling box (MB). Typically, they are interface points between the utility and GIS devices. The user has the possibility to install control or monitoring devices within the cabinet or simply use the enclosure as a wiring marshalling point. For example, many users design their switchyard facilities with the equipment control panels in close proximity to the protective relay panels. In that arrangement, disconnect and earthing switch controls may not be mandatory in the LCC and the cabinet would be primarily used for wiring terminations with possibly a push button control for circuit breaker maintenance needs. Status lights may also be installed on a mimic board with in the LCC to assist staff. In the case the LCC is installed some distance from the control house or protective relay installation, operating switches could be used to minimize the travel distance of the operators.

The LCC also gives the user an opportunity to demand switches, terminal blocks, heaters, lighting, convenience receptacles to be installed that are in compliance with the users regulations. It is crucial to most users to give a consistent representation of the substation or switchyard controls to the operators whether the staff is located in a GIS or AIS facility.

As a guideline the dispatch, operations and maintenance teams need to discuss and agree upon the LCC or MB arrangement. Some discussion points are:

1. Where is the primary control point?

2. If the control will be remote and standard controls are locally installed in the control house - are extra controls required in the LCC?

3. How will the breaker be operated for standard de-energized timing tests?

4. Will the LCC or MB be a central point for gas or equipment defect alarms? One possibility is to provide a PLC that can gather all the alarm point for transmittal to a central processor in the control house where remote alarms signals can be sent and an HMI installed. The historical approach is to provide standard user specified annunciators within the LCC.

5. Will the cabinets be put indoors where typical NEMA 12 cabinets can be placed or outdoors in corrosive atmospheres where a NEMA 4X cabinets may be better suited?

6. How many LCC/MBs are required? Typically, one cabinet per circuit breaker is sufficient with bus and exit runs included in the breaker LCC/MB. However, each LCC/MB has to be given with a gas zone scheme designating the equipment and bus within it zone and the interfaces to nearby zones.

7. Where will the LCC's/MB's be produced? Typically, it is not necessary to produce the cabinets at the point of the GIS equipment manufacture. This is especially correct for GIS assembled overseas.

8. How will the control wiring be run from the GIS installation and the control house.

LCCs/ MBs can be equipped with top side or bottom entry. There should be adequate space and spare capacity within a design so the wiring can be grouped and designated to the GIS or to the control house. In addition the end user has to define if a separation of protection circuits is needed.

Commonly, LCCs have the following devices:

- Devices such as red and green lights or semaphores to show if a circuit breaker, disconnect switch, or earthing switch is open or closed
- A remote/local permissive switch to stop remote operation when local operation is needed
- An annunciator to show and monitor the status of the GIS installation, including gas density
- Electrical interlocking diagrams and circuit breaker controls
- Protection relays when defined by the end user.
- Circuit breaker operating handles
- A marshaling cabinet and junction box for control and power cables emanating from the GIS installation and from the control and relay building and terminating in the LCC.
- Pushbuttons or operating handles for disconnect switches and earthing switches
- A mimic scheme

Alarms

In order to efficiently operate a GIS substation, the status of the devices has to be permanently monitored similar to monitoring the devices in an air insulated substation (AIS). Nevertheless, due to the criticality of the SF6 insulation system gas monitoring in a GIS is much more extensive than in AIS. Commonly, the below listed alarms are used:

- Low–low circuit breaker operating mechanism pressure meaning that the circuit breaker can no longer open or close in this case the protection arrangement may be designed to block any operation. It has to be noted that in addition to providing insulation, in majority of puffer type circuit breakers the gas is also used as a damper/cushion for the operating mechanism.

- Low circuit breaker operating mechanism pressure (pneumatic, hydraulic or spring).

- Low gas density (roughly 90%) in each gas chamber and zone meaning a gas leak.

- Low–low gas density (roughly 80%) in each gas chamber and zone meaning that the dielectric ratings of the devices can no longer be met.

- Overcurrent operation of the circuit breaker mechanism's motor protective circuit

- Excessive circuit breaker operating mechanism's run-time of the motor providing operating energy

- Pole disagreement operation

- Loss of voltage to the circuit breaker mechanism's motor providing operating energy

- Loss of DC control voltage to the annunciator in the LCC

- Loss of the DC control voltage or voltages to the circuit breakers

GIS Switching

This paragraph discussed the actual GIS operation. The operation is best presented by using an example switching scenario. In this specific situation, the portion of the substation is energized. The transmission line 4 has to be taken out of for maintenance on the transmission line. An operator has been dispatched to the station to take the line out of service. Even though experienced with switching AIS and completing training on operating a GIS, this is the first time this operator has actually switched a GIS. The operator has received instructions to remove the transmission line 4 from service. These are the steps that he needs to follow. Figure 1 is can help the reader to follow the instructions.

1. Upon reaching the substation, the operator checks the annunciator that there are no alarms showing low gas pressure in chambers 1102 through 1112. He also finds out that the overall appearance of the circuit breakers and disconnect switches is completely different from what he is used to seeing in an AIS. Moreover, he finds out that there are no open air conductors visible in the station, helpful for tracing the path of power flow and applying portable grounds. He is highly dependent on precise signage to give guidance to operate the correct elements.

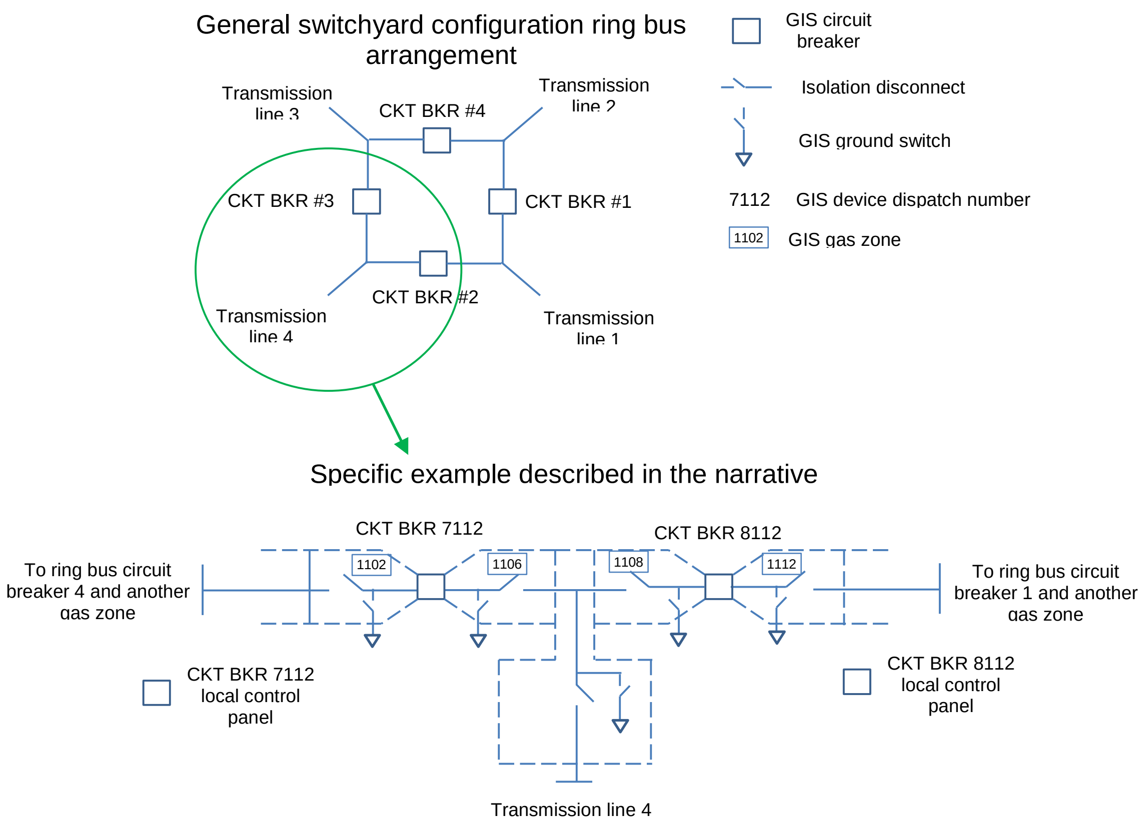

Figure 1. Gas zone illustration

2. The operator checks that the station is in normal operation and all disconnect switches and circuit breakers are closed and all earthing switches are open. The status indicators in the LCC show the status.

3. In the specific LCC the operator finds the control handle for circuit breaker 7112 in and moves it to the opening position. He hears the circuit breaker open and finds out that the indicating lights change from red to green, defining an open circuit breaker. Please note that the colour indication might very from substation to substation. The operator also knows that the circuit breaker could have been operated from the control house at the substation or remote from the regional dispatching center, but today the instructions require him to locally switch the equipment.

4. The control element for disconnect switch 7112 in gas compartment 1102 is then found and manipulated. The noise from the motor driving the disconnect switch open can be heard and the status lights change from red to green, defining an open disconnect switch.

5. The control element for disconnect switch in gas chamber 1106 is then found and manipulated. Again, the noise from the motor driving the disconnect switch open can be heard and the status lights change from red to green, defining an open disconnect switch.

6. The control devices for associated earthing switches are then found in the LCC and individually operated. The noise from the motor driving each earthing switch closed can be individually heard and the status lights change from green to red, defining closed earthing switches.

7. The operator then moves to the nearby LCC containing circuit breaker 8112. Inadvertently, the operator operates the control device for disconnect switch 8112 in gas chamber before opening the circuit breaker.

Because of the interlocking that stops a disconnect switch from interrupting load current, nothing happens and there is no damage. The operator steps back, reviews what he just did, and understands that he had tried to complete an inappropriate switching process. He then continues to correctly complete the similar function of first opening the circuit breaker, followed by opening the adjacent disconnect switches, and lastly closing the earthing switches, as was done in the previous steps.

8. The operator’s instructions demand that the blades of the disconnect switches and earthing switches be visually checked for the correct status. In AIS, a brief glance at the blades would have done the verification. Because this is a GIS, the blades are enclosed in an opaque metallic chamber and are not readily visible. Nevertheless, since each of the viewing ports has previously been clearly, and uniquely labeled as to phase and switch designation, each viewing port is readily found. With the aid of a flashlight, the statuses of the blades are checked.

9. As the operator was checking the status of the switch blades, he notes that the mechanical semaphores on the operating mechanisms for the circuit breakers and disconnect switches show that all phases are open. The mechanical semaphores on the operating mechanisms for the earthing switches show that they are closed.

10. The dispatcher now reports to supervision that the transmission line 4 has been de-energized and completed. He also asks for the status of the switching at the opposite end of the transmission line 4 and demands permission to proceed to ground the line. The remote end of the transmission line 4 has been de-energized and he gets the required approval.

11. The operator comes back to the LCC that contains the control device for high speed earthing switch, finds and operates the controls, hears the noise from the motor driving the earthing switch closed, and observes that the status lights change from green to red, defining a closed earthing switch.

12. With the help of a handheld flashlight, the statuses of the three blades of the high speed earthing switch are found to be in the correct fully closed position.

13. The operator now informs the supervisor that the transmission line 4 line has been earthed and that he is coming back to base.

Conclusion

The GIS equipment uses the same type of equipment as the AIS substation, such as circuit breakers, disconnectors, earthing switches, current and voltage transformers, but in a different way. With the metallic container the high voltage parts are not easily accessible. This gives excellent safety separation from energized elements. It also helps to minimize atmospheric contamination and corrosion of the energized elements. The enclosure also presents a disadvantage, if operations or union contracts need a visible means of disconnection for the switches. Nevertheless, this can be resolved with the use of view ports. In some situations, camera systems are installed in the view ports for convenient verifications. For earthing of bus or equipment parts, earthing switches have to be installed in the GIS. The end user and GIS manufacturers have to review the design to make sure all required earthing operations and maintenance requirements are met. This is different to that of the AIS substation where a earth cable can be installed at any section of the air insulated substation.

The use of earthing switches versus portable or personnel safety grounds may be a new concept to operations and maintenance staff, but with adequate training staff will understand there is no difference in the provided safety and protection.

Maintenance

GIS equipment has showed great reliability over the last several decades. GIS factories are promoting a “maintenance-free” approach. This does not mean that maintenance is not needed at all, but practice has showed that very minimum maintenance is required for GIS installation in comparison to other substation technologies. Following paragraphs focus on different aspects of maintenance and operation of GIS installations.

Typical Maintenance Processes

GIS manufacturers provide end users with suggested maintenance plans. These plans can insignificantly differ between manufacturers but the basic principles are as follows.

Visual Verification

On a frequent basis (few times a year), it is suggested to complete a visual inspection of all GIS devices. The equipment does not require de-energization. The objective of this inspection is to verify that there is no sign of unexpected wear or equipment disoperation. Common operations completed during this inspection are:

- Examine compressor run times and adequate operation for pneumatic systems. In the case of spring operators conduct a visual inspection for any defects.
- Verify oil pressure and tightness.
- Note down switching equipment operations using the operation counters.
- Record and verify SF6 density using meters or installed probes.
- Verify adequate functioning of low voltages devices.

Minor Verification

This verification can be completed every 5–10 years on GIS devices but the verification can also depend on a number of operations of switching elements. The objective is to verify the adequate operation of all switching elements. For this, the corresponding equipment has to be de-energized.

Laboratory assessment of the gas may assist in identifying unusual wear, insulator defects or other problems due to arcing or partial discharge and can be repaired before it degenerates to an unexpected major fault.

This maintenance procedure does not demand opening gas chambers. Common operations completed during this inspection are:

- Verification of SF6 by-product and impurity content (SO2 and moisture, in situations when chambers are not equipped with absorbers)
- Verification of SF6 pressures (density)

- Find any SF6 leakages (in case of alarms since the last verification)

- Verification of SF6 gas purity
- Verify proper operation of pressure switches, in the case of hydraulic mechanism use

- Verification of SF6 density relay operations

- Verification of control and alarm functions

- Verify the correct alignment and operation of position indicators

- Note down and verify circuit breakers operating times (from auxiliary switches) Exercise the circuit breakers and switching elements

Major Verification

This verification can be completed every 15–20 years but it strongly depends on the number of operations of switching equipment. Typically, major verifications are more condition-based than time-based maintenance. Opening of some chambers may be needed during such verifications.

In addition to the tasks completed during minor verifications, the common operations completed during major inspections are:

- Lubrication of different linkages and drives

- Replacement of gaskets and absorbers when chambers are opened

- Record and verification of travel curves for circuit breakers

- Opening and verification of the switching elements if they have reached the limits suggested by the GIS manufacturers

- Overhaul of the hydraulic mechanism with oil, filter, and switches replacement plus maintenance on the rams and drive mechanisms. Inspection of the circuit breaker interrupter mechanism including nozzles and contacts

Overhaul of devices is required when it has reached its end-of-life. Typically, this is determined based on the suggestions and end user experience. Nevertheless, an overhaul operation asks for the expertise of the original equipment provider, while the other inspections can typically be completed by the user, provided that adequate training has been given by the GIS manufacturer. The conditions of the tools and devices used for maintenance, such as the gas-recovery cart, have also to be carefully verified.

Repairing SF6 Gas Leakage

SF6 gas leakage is an important concern on numerous levels including the environmental effects, degradation of the GIS insulation system integrity and gas cost. Releases of SF6 are also becoming reportable incidents in some countries due to the atmospheric greenhouse gas effects. In GIS installations most leaks are discovered during the initial assembly and are related to flange mis-alignment, pinched O-rings or gaskets and dirty or corroded surfaces. Leaks are also assigned to wrongly installed by-pass piping, loose flange nuts, poor gas density gauge mounting, and similar instrumentation adjustments.

Once a gas density meter has indicated a loss of gas problem, bagging and using an electronic sensor is one way to discover leakage. Other proven ways include using soap/snoop liquid that will create bubbling and IR cameras are available that “detect” the leakage. Once the leak is discovered, it should be highlighted and documented.

Simple fixes like tightening a fitting may be done quickly, nevertheless a major leak as in the case of a pinched O-ring will likely demand an outage, gas removal of the impacted zone, disassembly and cleaning the flange, O-ring replacement, reassembly, pressurized testing, bus evacuation and refilling. Dependent on the repair size a high voltage test may also be a wise step to both verify that no foreign materials are in the bus and allow for particle conditioning or movement into low potential traps. Tripping a test set due to a problem is far better than a fault happening with a transmission line and system connected. All these steps for a big bus section may demand a several days or a week.

If a leak repair is mandatory, maintenance teams need to carefully plan the work including:

1. Identification and assembly of all the required elements. If materials are needed from the OEM supplier overnight shipments need to be considered depending on the device criticality and the leak rate.

2. Assemble and verify the required gas storage (ensure adequate volume is available), vacuum and gas handling devices.

3. Have the needed cranes, dunnage, temporary bus or equipment supports available. Ensure the material handling equipment is correctly rated and has been recently tested in line with local standards.

4. Organise team training

- Assign experienced staff in charge of vacuum and gas processing. Staff has to keep the gas handling records and weigh the removed and replaced gas including additional new gas.

- Highlight cleanliness of the work surfaces, control of cleaning materials and hazardous waste disposal

- Describe the work gas zone and the nearby chamber gas pressures; and post a marked-up gas zone and one-line diagram.

5. Pre-plan the switching, tagging and earthing to isolate the leaky part.

6. Inventory all tools that are to be used for opening and repairing the bus.

7. Before sealing the bus – count all tools to ensure all hardware is accounted for and have at least two team members inspect the interior bus work area for foreign materials, cleaning rags or tools.

The aim is to minimize the time the bus is open and exposed to pollution and moisture.

In an emergency or if spare parts have a long lead time to manufacturer, there are companies that are specialized in SF6 leakage stops using polyurethane materials. For instance, if a cast bushing fitting leaks, these companies after decreasing pressure in the bus, can install an external container, inject a sealant and remove the cover. The sealant will harden in several hours but stay elastic to allow for thermal expansion.

Sources of Faults and Repairs

Faults in iso-phase bus arrangement are usually line to earth and due to bus contamination including moisture. In the case of 3-in-1 bus arrangement in addition to single line to earth faults, double line to earth faults and three phase faults are possible. In the case of faults and a pressure relief opening, maintenance staff has to be trained how to approach the equipment. A smell of “rotten eggs” suggests caustic gases and potentially solid contaminates. Adequate respiratory and skin personal protective equipment has to be provided before disassembly.

Repair Times and Service Continuity

When GIS installation fails, the repair time and the service continuity of the GIS installation depends on the level of damage, location of repair facilities and spare parts availability. Regarding the spare parts, the GIS factories usually suggest that a minimum set of spare parts covering minor operations has to be available on site (e.g., a set of gaskets in case a gas chamber has to be opened). For some special applications, it may be suggested that special GIS elements (like a circuit breaker interrupter assembly or disconnect active parts or a complete spare pole) have to be available. The availability of these elements on site may decrease overall repair time.

It has to be noted if spare elements are purchased it is equally important how the spare parts are kept. Majority of the metal elements have to be in a dry, location, in a sealed box or drum with enough desiccant to make sure the part stays free of moisture accumulation and rust. Optionally, if complete assemblies are bought, they could be kept under gas or dry air pressure. Stored elements have to be occasionally checked to make sure the storage gas pressure is adequate. Material in drums should have the desiccant occasionally replaced. The purchase of O-rings, gaskets and similar materials has to be seriously assessed. Rubber, neoprene and similar materials may dry out, become brittle and unusable after 10 years on the shelf. GIS providers should define the shelf life. End users may want to plan periodic purchases for critical elements as shelf lives are reached.

The physical configuration of the GIS installation also has a major impact on the repair time. For a circuit breaker repair due to interrupter assembly defects, the time will be shorter if active elements can be removed without dismantling the circuit breaker container. Nevertheless, due to the design demands for some restricted space installations, other GIS elements or structural members may need to be disassembled and removed before the circuit breaker can be accessed. The best time to define and avoid these issues is during the project preliminary design discussions. Nevertheless, if limitations cannot be avoided, the design documentation and drawings have to provide instructions for access. Specifically, to enhance the service continuity, some special characteristics can be implemented directly into the original GIS installation (e.g., the installation of removable parts or isolating gaps at the right locations). The user needs to specify what is expected in terms of service continuity. The repair time and service continuity have to also be discussed during transmission system planning (for instance, what configuration gives the most reliability for the critical transmission line etc.).

Recent standards and regulations have also started to discuss some demands for improving the service continuity. This can be further studied in Annex F of IEC 62271-203 or in the IEEE GIS Guide C37.122.1.

Repair Examples

GIS installation problems especially in older designs, can happen from internal insulator flashovers due to moisture or pollution, broken operator insulator arms, chamber failures like misaligned disconnect or breaker contacts, dispatch errors including incorrect switching, and other mishaps all of which, could be severe in nature and demand a huge amount of time to assess the failure, access the elements, order replacement elements and install the new equipment. As previously mentioned unlike AIS facility repairs, GIS installation may demand weeks and lengthy outages. Commonly, gas leakage is the most typical maintenance issue. Unfortunately small or slow gas leakage may not be promptly discovered on a gas density meter. Given the cost and environmental issues with SF gas it may be a wise measure to occasionally use an IR camera to check for gas leakage, similar to using thermography to identify conductor hot spots in an AIS facility. If a major service is needed, staff from operations, maintenance and dispatch has to prepare a repair plan with one person “in charge”. Normally, it is also a good approach to involve a manufacturer’s representative in the process.

GIS Extensions

GIS installations have now more than 40 years of service around the world. Similarly to AIS substations, GIS installations have also been extended during their lifetime. Due to the special GIS design and configuration, most extensions have been done by the original equipment provider. Nevertheless, some have been done by a different provider. As the number of GIS installed around the world is rising, it is expected that more and more GIS installations are extended in the future.

There are no international standards or regulations that address GIS interfaces, as there is between GIS and power cables or between GIS installation and transformers. Nevertheless, there is an IEEE document and has recently been revised. It is IEEE C37.122.6, Recommend Practice for the Interface of New Gas-Insulated Equipment in Existing Gas-Insulated Substations rated above 52 kV. This document provides suggestions when a GIS installation is designed to accommodate a future extension or when an extension is needed for a GIS for which an extension was not initially planned. The document also addresses extensions made by the original manufacturer or by a different provider.

The main issues when extending a GIS installation are the knowledge and information of the existing devices and the division of responsibilities of the different involved parties. The connection elements are typically design-protected by the original GIS provider and the needed design drawings usually cannot be easily found. It is the responsibility of the end user to give the necessary data to the extension provider. Apparently, when the extension is done by the original equipment provider, many of the problems are avoided.

In situations, when the extension is done by a different provider the data collection from the original design can be complicated process. Hence, it is suggested that any potential extension is predicted during the initial design and GIS installation.

Necessary Work When an Extension Is Anticipated in the Initial Design Stage

When first designing the GIS installation, it is suggested that any requirement for the future extension is defined. These demands are:

- Necessary civil work
- Sufficient space in the GIS building
- Integration into the control configuration
- Sizing of auxiliaries
- Site installation demands of new GIS equipment
- Equipment earthing
- HV testing of newly installed devices

IEEE C37.122.6 includes all of these requirements. More importantly, it provides some suggestions for the integration of a standard GIS interface that would ease future extensions. This interface is done of a rather simple bolted connection and hence is independent of the original equipment manufacturer design.

Basic information must be presented by the original GIS provider, such as gas densities, diameter of flanges and enclosures, and size of connecting bars. This information is included in Annex A of the IEEE C37.122.6 document.

Necessary Work When an Extension Is Not Planned in Initial Design Stage

When an extension is needed, but without an optimum extension plan, work can be more challenging than with the case presented above. In addition to the previously discussed items, special attention has to be devoted to the following points:

- Obtain photographs of existing material on site. Obtain all nameplate data and measure exterior items like bus diameters and flange bolt patterns.

- Collect detailed drawings of each element where a connection is needed (type and size of contacts, detailed design schemes).

- Obtain technical data about the existing devices (dielectric ratings, different gas pressures and alarm levels).

When this data is gathered, the next step is to complete a detailed interface design. This typically demands precise geometric information of the existing substation (altitude, level, axis, civil work reservations, building, etc.) as this will impact the exact configuration of the interface connection and location of extension bays. Special care has to be devoted to the pressure withstand capability of different elements, especially the insulators.

For some applications, the detailed drawings of existing devices may not be easily available. That will complicate the interface design by the extension supplier, particularly if he was not the original equipment provider. To address this special situation, some extra work is needed, including a site survey involving the opening of chambers where the interface has to be done. This work is done under the strict responsibility of the GIS end user. If opening of chambers is not feasible, reverse engineering from existing spare elements is another option, as is X-ray assessment of the interface area. With these last two approaches, there is a small possibility of mismatch between the elements.

Service Continuity During Extension Operation

When the work is done at site, certain outages will be needed to connect the new device to the existing installation. Depending on the existing GIS arrangement, some adjacent feeders may be disconnected during the work in order to assemble the connection or to HV test the connection. In the case of heavily loaded transmission systems, these operations need to be properly planned in advance perhaps over months or a year.

The IEEE C37.122.6 document provides some detailed suggestions to minimize the outages during the extension process. This can be accomplished by adopting special features during the initial GIS design, such as the inclusion of extra gas zones in the bus bar, including maintenance links, including isolation disconnects, or gapping the bus.

Interface Testing

After installation of the interface and extension bays, the typical on-site tests, as suggested by IEEE or IEC standards, have to be completed to verify the integrity of the newly installed devices. The dielectric (HV withstand) test is among the suggested tests. However, this test has to be fully discussed with the GIS end user, as the test will put stress on some existing GIS elements. The voltage level used during the test has to consider the condition and quantity of the existing elements to be stressed during the test. There is no precise answer to the issue of testing and a clear method statement has to be established between the parties before starting the test.

GIS Upgrade or Retrofit

GIS technology is about 45 years old. Several GIS substations are in service for more than 40 years. These substations are reaching the end of their service life. Although, there is no clear regulation or method to define the switchgear service life, its performance will be diminished because of aging.

Deterioration may happen in the areas of gas leaks and mechanical wear, asking for frequent maintenance. Normally, the switching devices (particularly circuit breakers) get worn out towards the end of the service life due to switching actions under load and fault conditions, while the majority of the other GIS elements typically stay in relatively good condition. As a result, it may be more practical just to replace the defective/worn-out element instead of the complete gear, therefore extending the device service life at minimal cost. Figure 2 presents a common trouble/availability life cycle of GIS device.

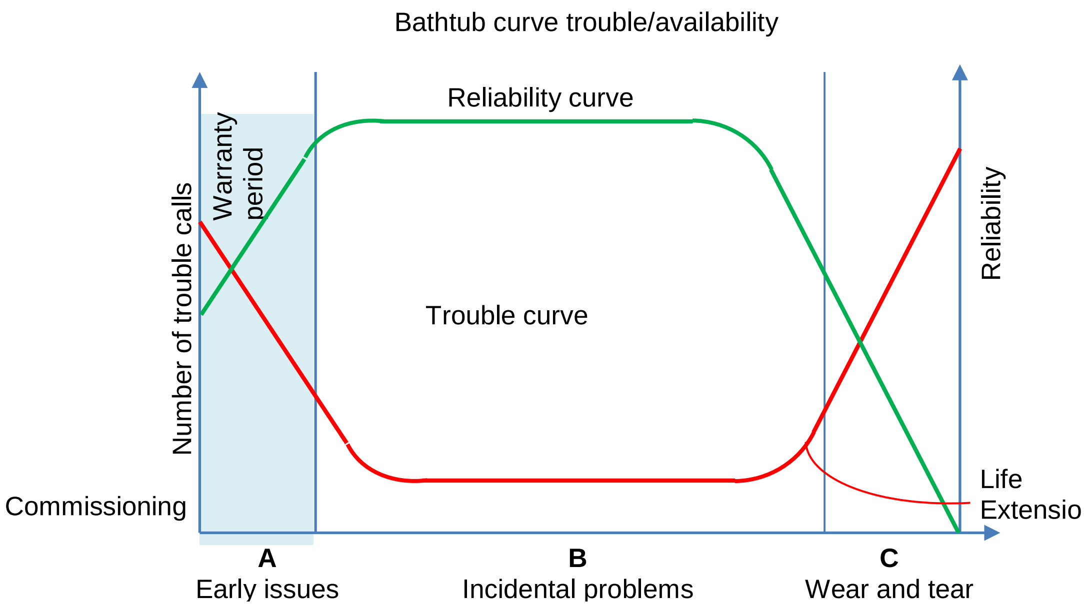

Figure 2. Common life cycle behavior of GIS device

Issues with Old GIS Installations

Some of the issues with old GIS installations include:

- Longer down-time resulting in loss of revenue
- Frequent maintenance resulting in bigger maintenance costs
- Bigger gas chambers
- Lower safety
- Bigger risk of internal faults due to insulator deterioration, aging and cracks
- Higher SF6 gas leakage at flanges and monitor piping

Upgrade or Retrofit

Retrofit is a process of replacing or upgrading aged or defective switchgear elements, with latest state-of-the-art elements resulting in bigger reliability, operational performance, and switchgear prolonged service life. The cost of replacing a GIS element is typically lower than replacing the complete GIS installation. Retrofit also gives the flexibility of replacing one element at a time, so that there may not be any major financial impact to the end user at any given point in time. During the retrofit, the majority of the substation still stays in operation.

The new generation elements are also typically more compact than older generation devices, so no extra space would be required for retrofitting. Interface modules have to be used, to connect old elements with new components.

Although it is not common, it is possible to retrofit one manufacturer's GIS with another as long as the interface information is given by the initial provider. Another retrofit aspect could be refurbishment of AIS with GIS to utilize the benefits of this technology.

The retrofit advantages can be pointed as follows:

- Minimized maintenance
- Reliability
- Increased reliability and availability
- Short lead-time of spare parts
- Long-term spare availability

The new generation design look much simpler and uses less elements for the same function, which leads to increased reliability of the GIS installation, better safety, reduced risk of internal faults and improved staff protection.

The solidly earthed GIS enclosure provides maximum safety from touching the high voltage substation elements. The strong metallic container also provides maximum safety in the case of an internal arc. Pressure relief elements save the GIS enclosure from bursting. The latest GIS design provides:

- Lower mechanism energy requirement

- Faster operating times
- Lower reaction forces
- Lower gas volumes
- Decreased gas leakage rates
- Shorter mechanism charging times
- Increased continuous and short circuit current rating
- Type testing done in line with the latest standards
- Short project execution time
- More compact gear
- Avoid long land acquisition and permitting process
- Minimum outage time
- Minimization of maintenance costs
- Lower investment
- Warranty for retrofitted elements

Replacement and upgrading of old circuit breakers is usually done in existing substations. Since the newer design is smaller in size than the older one, replacement and extensions are no issue.

GIS Thermal Limits and Overloading

The GIS installation is designed for predetermined current ratings. These ratings are set by the users and depend on the network demand. In order to limit the number of possible ratings, the international regulations have established a series of ratings that should be chosen from the R10 series. Common ratings are 1250, 2000, 3150, 4000, 5000, and 6300 A. These ratings are set for an ambient temperature, which does not surpass 40°C, and the average value measured over a period of 24h, which does not surpass 35 °C. The devices are designed so that the temperature rises do not surpass the limits defined in the IEC 62271-1 or IEEE C37.122.1regulations.

During normal service the load current going through the GIS equipment should not surpass these rated continuous currents. Nevertheless, in some situations it is possible to exceed these values without jeopardizing the integrity of the installation. These conditions are known as overload ratings.

Continuous Rating Current Design

Two critical elements have an impact on the GIS sizing: the dielectric withstand and the current rating.

When designing a GIS installation, the size of the elements is first affected by the dielectric characteristics. These characteristics are related to different voltage conditions on the network and also to the minimum temperature the GIS is made for. Tables provided in IEC 62 271-1 or IEEE C37.122.1 provide dielectric values that the GIS has to withstand according to different system voltage levels.

Another characteristic affecting the GIS size is the filling pressure of the dielectric fluid, like SF6 gas. The bigger the pressure, the better is the dielectric withstand. However, the maximum pressure is also conveniently fixed according to the minimum temperature GIS has to support, usually -25 °C or -30 °C. Indeed, below a specified temperature limit, the SF6 gas inside the GIS container will condense and the dielectric integrity of the GIS installation can be at risk. This dielectric approach usually determines the size of the containers and internal conductors. Nevertheless, sizes of GIS installations have decreased over the years, thanks to optimization of the dielectric designs. The current rating assigned to the GIS installation can also affect the dimensions of the GIS. Now that transmission networks are operated at increased current values, the rated current can considerably impact GIS design.

Table 1 provides some common dimensions of GIS equipment for different voltage levels. With the conductor dimensions, common current ratings that can be reached using standard aluminum enclosures and conductors are in the range presented in Table 2. The figures presented in Table 2 do not mean that bigger current ratings cannot be reached, but the size of the GIS installation may need to be slightly adapted to meet higher current performances.

Table 1. Dielectric required size

Parameter	Voltage rating (kV rms Φ-Φ)			
	145	242	362	550
BIL (impulse, kV peak Φ-G)	650	900	1050	1550
Conductor field (kV/mm, peak, BIL)	15.67	16.78	15.79	17.02
60 Hz max. operating voltage (kV, rms, ΦG)	84	141	209	318
Conductor field (kV/mm, rms, 60 Hz, operating)	2.02	2.63	3.14	3.49
Ratio of BIL/peak operating voltage	5.47	4.51	3.55	3.45
Standard factory test voltage (kV, 60 Hz, rms, Φ-G)	310	425i	500	740
Size of conductor OD (mm)	88.9	101.6	127	177.8
Enclosure ID (mm)	226.1	292.1	362	495.3

Table 2. Common current ratings

72.5 kV	2500 A
145 kV	3150 A
245 kV	3150 A
362 kV to 420 kV	4000 A
550 kV	5000 A
800 kV	6300 A

Setting the Limits

IEC and IEEE standards use the same rules to determine and test the limits of current ratings. They are given by the temperature rise test demands. The maximum temperature limitations of different GIS elements when transferring rated continuous current are defined for an ambient temperature of 40 °C.

For GIS devices, common values of maximum temperature rise are the following:

- Enclosures that do not need to be touched during normal service: 40K

- SF6 contacts: 65K

The overall temperature of these elements depends both on the actual load current and the actual ambient temperature. If the temperature is lower than the 40 °C, the GIS equipment can be continuously operated at a current higher than the rated continuous current. If the current is lower than the rated continuous current, the maximum ambient temperature of GIS operation can be greater than 40 °C.

Another case that has to be assessed is the temporary overload. GIS elements have a thermal time constant. Until the limit is reached, the devices can be operated at bigger values than it is intended for. Continuous or temporary overload has to be established, based on the results obtained from the temperature rise test and test characteristics, like rated current, temperature rise, thermal time constant, maximum operating temperatures and ambient air temperature.

Maximum Continuous Load Current

Devices may be assigned an overload capacity for higher than rated normal currents based on a lower ambient temperature provided the temperature does not surpass the maximum value temperature shown in IEC 62 271-1. The relationship of the maximum overall temperature, the ambient temperature and the temperature rise due to the I2R losses are shown in Figure 3.

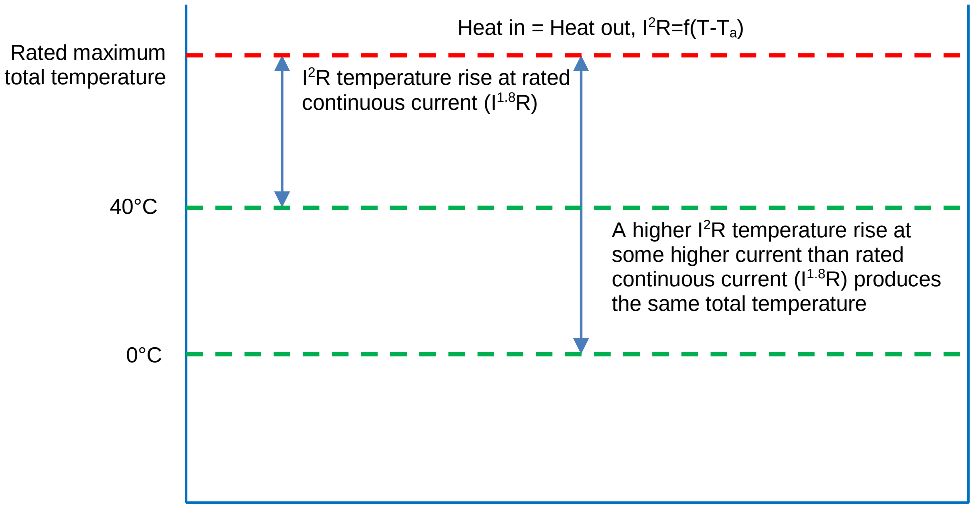

Figure 3. Relationship between the rated maximum temperature, ambient temperature and I2R losses

Short-Time Overload Capacity

Devices may be assigned an overload capacity for a higher than rated normal current for a temporary period given the temperature does not surpass the maximum temperature value defined in IEC 62 271-1 standard. To find the maximum overload values, a pre-load condition has to be determined. The relationship between exponential heating and the overload, rated continuous, and pre-load currents is presented in Figure 4.

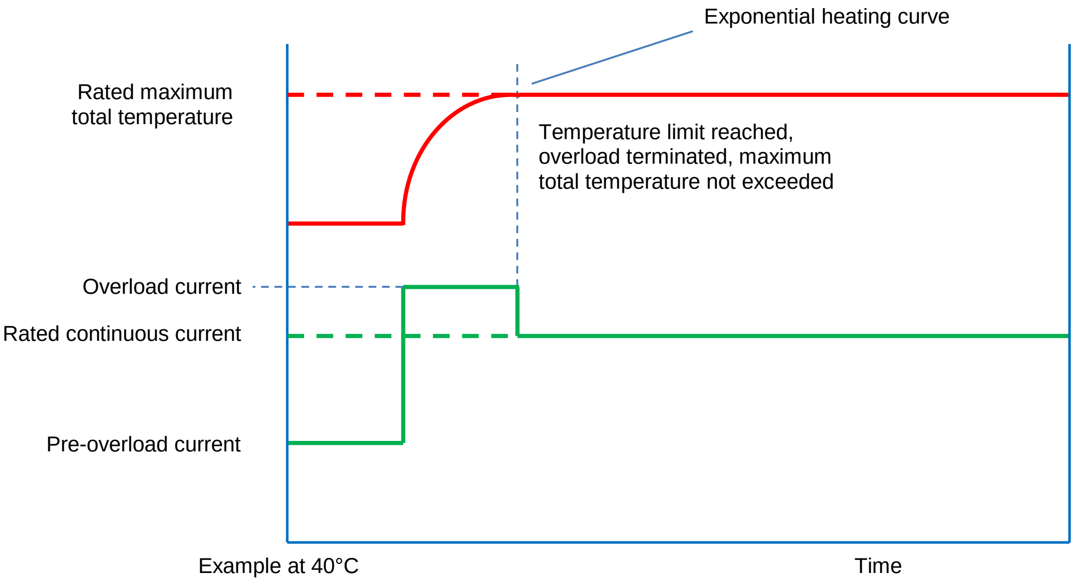

Figure 4. Relationship between exponential heating and the overload rated continuous and pre load currents

Calculating Overloads

The equations to compute the temperature rise are available using the following parameters: The allowable continuous current (I_S) for a given ambient temperature θ_a (Equation 1), the operating temperature during overload (Equation 2).

$$I_S = I_r \left[\frac{\theta_{max} - \theta_a}{\Delta\theta_r}\right]^{\frac{I}{n}} \qquad (1)$$

$$\theta_S = \Delta\theta_r \left(\frac{I_S}{I_r}\right)^n e^{-\frac{t}{\tau}} + \theta_a \qquad (2)$$

The allowable duration (t_s) of the temporary current I_s after transferring a current I_i (Equation 3)

$$t_s = -\tau \ln\left[1 - \frac{\theta_{max} - Y - \theta_a}{\left(Y\left[\frac{I_s}{I_i}\right]^n - 1\right)}\right] \qquad (3)$$

$$Y = (\theta_{max} - 40)\left[\frac{I_i}{I_r}\right]^n$$

where

θ_{max} - maximum allowable total temperature (°C) according to IEC 62 271-1

θ_a - actual ambient temperature (°C)

$\Delta\theta_r$ - temperature rise at normal current I_r

I_r - rated normal current (A)

τ - thermal time constant (h)

n - overload exponent taking into account material, heat radiation, etc.

I_i - initial current before application of overload current (A)

I_s - overload current (A)

t_s - permissible time (h) that the overload current (I_s) can be transferred without surpassing the maximum temperature allowable (θ_{max})

Generally, no extra temperature rise verifications are needed if an exponent n=2 is applied for the determination of the operating temperature during overload or allowable overload duration. An exponent lower than n=2 can be applied for the overload rating computation. It has to be showed by calculation from test values. Please note that the time constant corresponds to the time taken to reach 63% of the final temperature rise after stabilization.