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Requirements for protection and control systems.
Principles for the Icelandic power transmission network.

Introduction.

The most important thing a power utility must focus on is the quality of the products and services sold and delivered to the customers. Among the parameters of quality of electrical energy, there are terms such as voltage-control, frequency-control, and last but not least minimizing of energy not delivered to the customers.

The tools that a power utility has to influence these factors are protection- and control equipment. This equipment alone is not enough. The power utility must have the know-how and the expertise to make the most of these tools. This means both detailed information about the power system and qualified employees to optimize the use of the control- and protection tools. In order to be able to do the necessary settings, configurations and calculations the base upon which this work shall stand on, must be clear.

With the introduction of the numerical technology into the field of protection and control, power utilities are forced to review the foundation on which their protection- and control-philosophy is based upon. Before the numerical technology was introduced, there was great emphasis on redundancy to increase availability. But by increasing availability this way, the security against unwanted operations has been decreased. In the past years, it has been unwanted operations of equipment that has been a significant contributor in the number of outages in the Icelandic power system. This experience has proven that “more” is not necessarily “better”.

The numerical technology offers considerable benefits in terms of availability and it’s use can lead to an increase in security against unwanted operation as well. Instead of redundancy by duplication, sufficient availability can be achieved by the use of self-supervision which is an integral part of the numerical technology. The need to duplicate is reduced, thereby increasing security. [1]

Another important aspect of numerical technology is the amount and variety of data the equipment can store and deliver to the operator and protection- and control engineers. This data can be used for all sorts of applications such as normal operation, maintenance, fault analysis, statistics, etc. With better and more reliable data coming from the equipment, costs can be cut and quality of the energy delivered, increased without much increase in investment.

One of the benefits of numerical devices is that they offer serial communication. They have the possibility of interchanging information with their surroundings, information that can be used for system operation, fault analysis, maintenance and setting changes, can be accessed remotely. The best solution for a utility is a serial communication from the protection engineer office via the dispatch central, substation and to each unit.

All numerical units have a self-monitoring system in operation. The quality is getting better and today the self-monitoring system covers approximately 95 % of the unit. The detection ability of self-monitoring and manual testing can be comparable. However, the automatically self-monitoring system covers different parts of the unit than manual testing procedure.

It is known that self-monitoring will increase the dependability, security and availability of the equipment, but will have the main impact on security.
Self-supervision reduces the probability of unwanted function significantly (increased security) due to the possibility to block the equipment for internal failure.
How self-monitoring improves the equipment availability is illustrated by how it reduces the mean time to repair (MTTR), which is the time from a fault occur till it is repaired. The self-monitoring is continuous, thus the time for fault detection with self-monitoring is in the order of seconds compared to the time to detect a fault with manual testing, which is in the range of years. [4]

This new technology sets totally new requirements on staff skills, working with protection and control. This issue will be addressed later in this paper.

This paper will describe the overall principles that Landsnet will be using when designing control and protection for the 220 kV and 132 kV transmission systems, as well as on 66 kV sub-transmission and down to 33 kV distributions.

These principles are divided into four stages or levels.

1. Process level contains principles on the bay unit or units and other equipment in a bay. This includes which protection and control functions shall be included, which monitoring functions and other functions needed such as current and voltage measuring.

2. Bay level outlines how a bay shall function, i.e. how the level one units and equipment are connected together and the connection of the level one units to primary equipment to fulfill the intended functionality of the bay. This includes functions such as interlocking schemes.

3. Station level outlines how all the bay levels are interconnected to one station and how the stations functionality is fulfilled. This includes interlocking between bays and station control. Data from the bay units and process level components and handling of this data inside the station is also a part of this level.

4. System level outlines how the station shall function as a part of the power system and the connection between the station and dispatch center. This will also describe other means of communication with the station and equipment, disturbance recorders etc. One aspect is more efficient evaluation of fault and disturbances in the power system.

System requirements

Validity:
These principles apply to new stations as well as renewing and extension of existing stations.

Requirements for protection:
Using these principles, it is possible to fulfill the requirements for protection, set by the system operator. Tripping a faulty component shall have as little effect on the operation of the transmission system. Fault-clearing shall be so that risk to humans, property and components is minimized.

1. All short-circuits and winding fault shall be detected by at least two independent protection systems.
2. One of the two protection systems must fulfill requirements on minimum fault-clearing time of 100 ms and selectivity, unless otherwise specified.
3. Under normal circumstances all short-circuits shall be cleared selectively. A fault in the protection system, both redundant and non-redundant, fault in the circuit breaker, fault between circuit breaker and current transformer and a broken conductor fault can cause unselective tripping.
4. The protection system shall, under normal circumstances, isolate a faulty component from the rest of the power system.
5. All components in the 220 kV, 132 kV and 66 kV shall have a non-directional earth fault protection with RXIDG-characteristic.
6. The protection system shall not trip during transient, dynamic and abnormal stationary conditions caused by fault clearing, switching, islanding, energizing, load shedding and losing of production units.
7. The protection of system components on voltage levels below 66 kV shall be selective against the protections in the main transmission system.
8. The protection- and control systems shall be designed so that the risk of unwanted operation is minimized. [2]
9. Current transformers used for protection purposes shall be of class 5P.

Requirements for information handling:

Requirement for information to Landsnets SCADA system is handled in appendix 2; Specification of requisites to Dispatch Centre

Requirements for communication protocols:

Until now communication protocols have been more or less product –specific. Future communication protocols shall be IEC 61850 or IEC 60870-5-103. In stations already in operation SPA, LON, DNP, and other protocols already in use, are acceptable.

Staff competencies and skills.

In the era of electromechanical- and electronic protection and control, a big emphasis was put on routine testing of protection system. This was due to the fact that there was no way of detecting a faulty protection unless by testing it or by observing improper operation of the protection during faults. Testing was also a considerable source of unwanted operation of protection in the power system. Working on protection equipment always poses a risk to the power system.

Information from the protection during faults was in the form of binary signals to dispatch center and indicators on the protection itself. All connection between the protection and the surrounding equipment were hard-wired. All changes required rewiring work.

The numerical technology requires new competencies for staff. Emphasis on routine testing has been drastically reduced due to self- monitoring of the equipment. Greater emphasis has been given to thorough commissioning of the equipment. New tools and test equipment generate better and more accurate commissioning reports and enable more thorough commissioning done in a shorter period of time, than was possible earlier. Changing of functions and configurations can be done by software thereby eliminating re-wiring work.

A primary fault is the best way to test the performance of the protection and control system. Therefore a great emphasis must be put on thorough fault analysis after each fault. In many cases has fault analysis replaced the need for testing of protection and thereby reduced risk of unwanted operation during and after testing.

A power utility must have staff which is capable of mastering all the skills mentioned above. That requires of the utility constant vigilance regarding new technologies and working procedures. This poses a great challenge on the utility to take good care of staff education and training so that the utility will always have staff with the know-how needed.

Process level

The process level comprises of hardware and software. A process unit shall contain protection- control- and monitoring functions needed for adequate operation of the bay and station. A process unit shall among other comprise of a continuous self supervision, a man-machine interface and data exchange via serial bus. The functions that have to do with protection- control- and monitoring shall be put as close to the actual process as possible.

220 kV Line bay terminals

The line bay terminals shall contain the following functions:

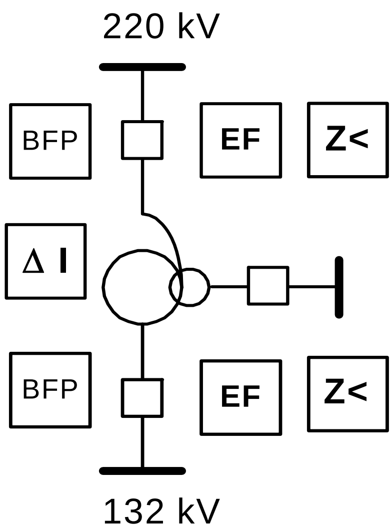
Terminal A

Protection functions	Control functions	Monitoring functions
Distance protection	Interlocking	Distance-to-fault
Breaker failure protection	Autoreclosing	Disturbance recorder
	Synchro-check	Fault values
	Man/Auto Switching	Trip circuit supervision
	Trip-transfer	Event recorder
		VT/CT supervision

Terminal B

Protection functions	Control functions	Monitoring functions
Differential protection	Trip-transfer	Disturbance recorder
Earth fault protection		Fault values
		Circuit breaker supervision
		Trip circuit supervision
		Event recorder
		VT/CT supervision

220/132 kV Transformer bay terminals



The transformer bay terminals shall contain the following functions:

Terminal A

Protection functions	**Control functions**	**Monitoring functions**
Distance protection 220kV	Interlocking	Distance-to-fault
EF - protection 220 kV	Man/Auto Switching	Disturbance recorder
Breaker failure protection	Trip-transfer	Fault values
	Point-on-Wave control	Circuit breaker supervision
	Synchro-check	Trip circuit supervision
		Event recorder
		VT/CT supervision

Terminal B

Protection functions	**Control functions**	**Monitoring functions**
Differential protection	Interlocking	Disturbance recorder
Distance protection 132kV	Man/Auto Switching	Fault values
EF – protection 132 kV	Synchro-check	Distance-to-fault
Breaker failure protection	Trip-transfer	Circuit breaker supervision
	Automatic voltage reg.	Trip circuit supervision
	Point-on-Wave control	Event recorder
		VT/CT supervision

220 kV Bus-tie bay terminal (A/B-V bus)

The Bus-tie bay terminal shall contain the following functions:

Protection functions	Control functions	Monitoring functions
	Interlocking	Overcurrent/Overload
	Man/Auto Switching	Trip circuit supervision
	Synchro-check	Circuit breaker supervision

220 kV Bus-tie bay terminal (A-B bus)

The Bus-tie bay terminal shall contain the following functions:

Protection functions	Control functions	Monitoring functions
Overcurrent protection	Interlocking	Overcurrent/Overload
	Man/Auto Switching	Trip circuit supervision
	Synchro-check	Circuit breaker supervision

220 kV Busbar protection terminal (Centralized busbar protection)

The Busbar protection terminal shall contain the following functions:

Protection functions	Control functions	Monitoring functions
Current differential		Trip circuit supervision
Breaker-failure		Circuit breaker supervision
		Disturbance recorder

220 kV Busbar protection terminal (De-centralized busbar protection)

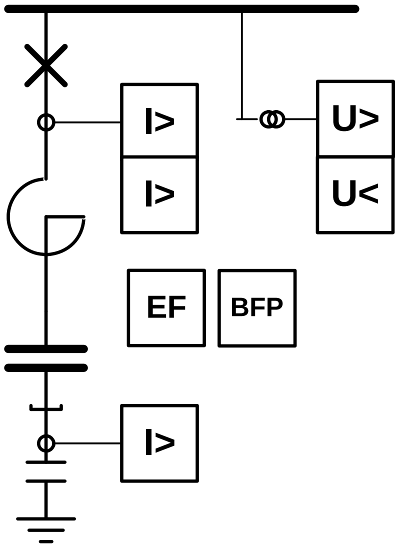
The Busbar protection central terminal shall contain the following functions:

Protection functions	Control functions	Monitoring functions
Current differential		Disturbance recorder

The Busbar protection bay terminals shall contain the following functions:

Protection functions	Control functions	Monitoring functions
Breaker-failure		Trip circuit supervision
		Circuit breaker supervision

220 and 132 kV Capacitor bank bay terminals



The Capacitor bank bay terminals shall contain the following functions:

Terminal A

Protection functions	**Control functions**	**Monitoring functions**
Overcurrent protection	Interlocking	Disturbance recorder
Earth fault protection	Man/Auto Switching	Fault values
Overvoltage protection	Synchro-check	Circuit breaker supervision
Undervoltage protection	Point-on-Wave control	Trip circuit supervision
		Event recorder
		VT/CT supervision

Terminal B

Protection functions	**Control functions**	**Monitoring functions**
Overcurrent protection		Disturbance recorder
Unbalance protection		Fault values
Breaker failure protection		Trip circuit supervision
		Event recorder
		VT/CT supervision

220 kV and 132 kV Generating unit bay

Protection functions	**Control functions**	**Monitoring functions**
Breaker failure protection	Interlocking	Circuit breaker supervision
Overcurrent protection	Man/Auto Switching	Trip circuit supervision
Earth fault protection	Synchro-check	
	Point-on-Wave control	

132 kV Line bay terminal

The line bay terminal shall contain the following functions:

Protection functions	Control functions	Monitoring functions
Distance protection	Interlocking	Distance-to-fault
Earth fault protection	Autoreclosing	Disturbance recorder
Differential protection	Synchro-check	Fault values
Breaker failure protection	Man/Auto Switching	Trip circuit supervision
	Trip-transfer	Event recorder
		VT/CT supervision

132 kV Bus-tie bay terminal (A/B-V bus)

The bus-tie bay terminal shall contain the following functions:

Protection functions	Control functions	Monitoring functions
	Interlocking	Overcurrent/Overload
	Man/Auto Switching	Trip circuit supervision
	Synchro-check	Circuit breaker supervision

132 kV Bus-tie bay terminal (A-B bus)

The Bus-tie bay terminal shall contain the following functions:

Protection functions	Control functions	Monitoring functions
Overcurrent protection	Interlocking	Overcurrent/Overload
	Man/Auto Switching	Trip circuit supervision
	Synchro-check	Circuit breaker supervision

132 kV Busbar protection terminal (Centralized busbar protection)

The Busbar protection terminal shall contain the following functions:

Protection functions	**Control functions**	**Monitoring functions**
Current differential		Trip circuit supervision
Breaker-failure		Circuit breaker supervision
		Disturbance recorder

132 kV Busbar protection terminal (De-centralized busbar protection)

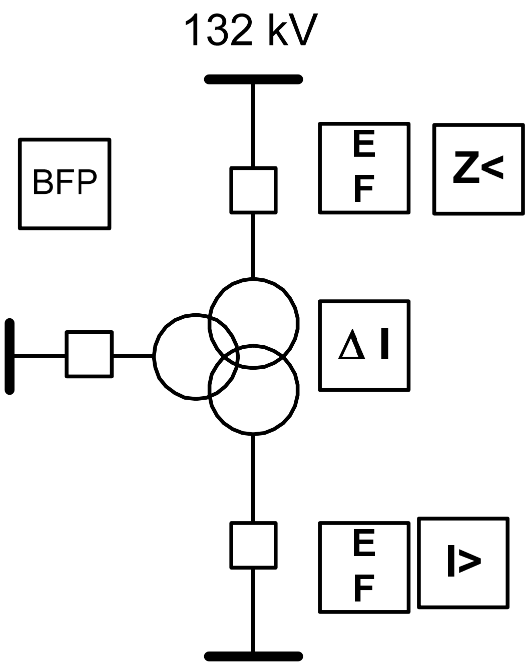
The Busbar protection central terminal shall contain the following functions:

Protection functions	**Control functions**	**Monitoring functions**
Current differential		Disturbance recorder

The Busbar protection bay terminals shall contain the following functions:

Protection functions	**Control functions**	**Monitoring functions**
Breaker-failure		Trip circuit supervision
		Circuit breaker supervision

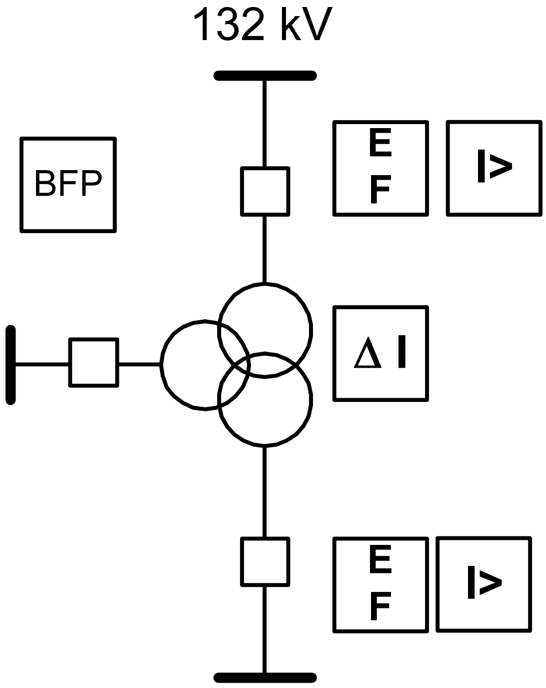
132/xx kV Transformer bay terminal (20 MVA and larger)



The transformer bay terminal shall contain the following functions:

Protection functions	**Control functions**	**Monitoring functions**
Differential protection	Interlocking	Disturbance recorder
Distance protection	Man/Auto Switching	Fault values
Earth fault protection	Synchro-check	Distance-to-fault
Breaker failure protection	Trip-transfer	Circuit breaker supervision
	Automatic voltage reg.	Trip circuit supervision
	Point-on-Wave control	Event recorder
		VT/CT supervision

132/xx kV Transformer bay terminal (Up to 20 MVA)



The transformer bay terminal shall contain the following functions:

Protection functions	Control functions	Monitoring functions
Differential protection	Interlocking	Disturbance recorder
Overcurrent protection	Man/Auto Switching	Fault values
Earth fault protection	Synchro-check	Distance-to-fault
Breaker failure protection	Trip-transfer	Circuit breaker supervision
	Automatic voltage reg.	Trip circuit supervision
		Event recorder
		VT/CT supervision

66 kV Line bay terminal

The line bay terminal shall contain the following functions:

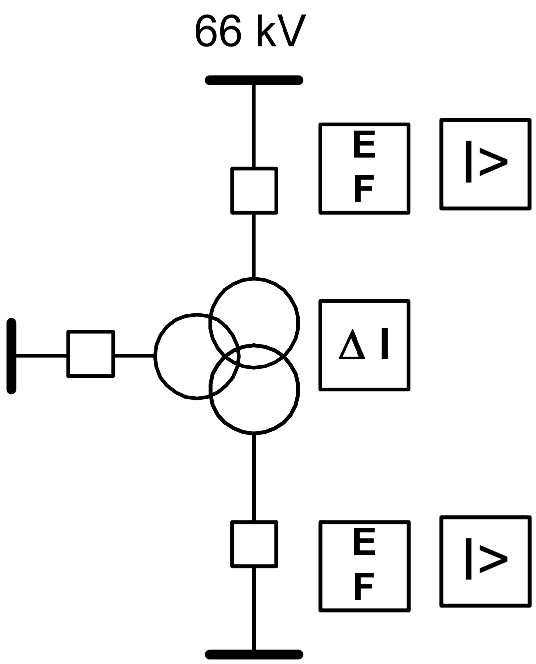
Protection functions	**Control functions**	**Monitoring functions**
Distance protection	Interlocking	Disturbance recorder
Earth fault protection	Autoreclosing	Fault values
	Synchro-check	Distance-to-fault
	Man/Auto Switching	Trip circuit supervision
	Trip-transfer	Event recorder
		VT/CT supervision

66 kV Cable bay terminal

The cable bay terminal shall contain the following functions:

Protection functions	**Control functions**	**Monitoring functions**
Differential protection	Interlocking	Disturbance recorder
Earth fault protection	Synchro-check	Fault values
Distance protection	Man/Auto Switching	Distance-to-fault
	Trip-transfer	Trip circuit supervision
		Event recorder
		VT/CT supervision

66/xx kV Transformer bay terminal



The transformer bay terminal shall contain the following functions:

Protection functions	**Control functions**	**Monitoring functions**
Differential protection	Interlocking	Disturbance recorder
Earth fault protection	Manual Switching	Fault values
Overcurrent protection	Synchro-check	Trip circuit supervision
	Trip-transfer	Event recorder
	Automatic voltage reg.	VT/CT supervision

66 kV and 33 kV Generating unit bay

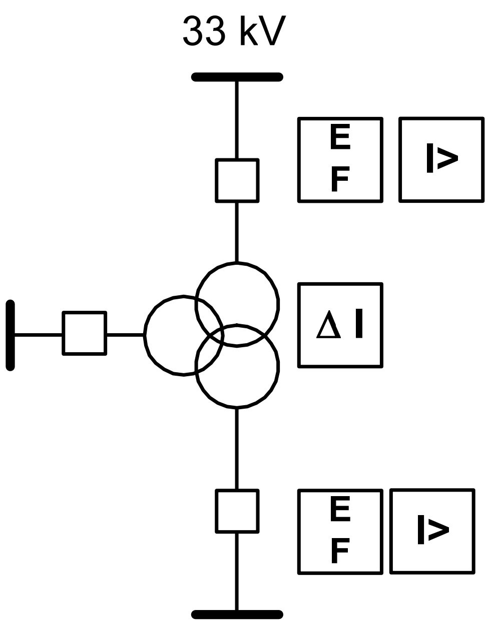
Protection functions	**Control functions**	**Monitoring functions**
Overcurrent protection	Interlocking	Circuit breaker supervision
Earth fault protection	Man/Auto Switching	Trip circuit supervision
	Synchro-check	

33 kV Line bay terminal

The line bay terminal shall contain the following functions:

Protection functions	Control functions	Monitoring functions
Overcurrent protection	Interlocking	Event recorder
Earth fault protection	Manual Switching	Fault values
	Synchro-check	

33/xx kV Transformer bay terminal



The transformer bay terminal shall contain the following functions:

Protection functions	Control functions	Monitoring functions
Differential protection	Interlocking	Event recorder
Overcurrent protection	Manual Switching	Fault values
Earth fault protection	Synchro-check	

Protection-, control-, and monitoring-function definitions

Distance protection

The distance protection shall be full-scheme and have four independent zones with rectangular characteristics for all zones. Setting of resistive and reactive reach shall be independent of each other.
Included in the distance protection function shall be following:

- Permissive schemes
- Blocking schemes
- Single pole tripping possibility.
- Distance-to-fault calculation.
- Switch-onto-fault.
- Power swing blocking.
- Unsymmetry current supervision.
- Transient blocking (current reversal logic).
- Possibility of storing at least two different setting groups must be available.

Line differential protection

The line differential protection shall be phase segregated for single pole tripping. The protection shall be able to communicate to the remote terminal via a multiplexed digital (64 kbits) data link. The differential protection shall have settable characteristics and serial communication to remote. Communication protocol such as V35/36, X21 and RS232 are acceptable.

Non-directional earth fault protection

The non-directional earth fault protection shall measure zero sequence current. Time delay shall be settable according to various characteristics including; constant time, normal inverse, very inverse, extremely inverse etc according to IEC 255-4, and additionally a logarithmic inverse (RXIDG-Inverse, t=5,8-1,35ln(I/Iset))

Busbar protection

The busbar protection shall be three phase and phase segregated. Busbar protection with integrated breaker failure protection is preferable. A decentralized busbar protection is preferred but a centralized protection is acceptable.

Breaker failure protection

The breaker failure protection is a three phase and single step protection. Time delay shall be settable from zero in increments of 10 ms. Current setting for breaker failure shall be settable down to 0,1*In. Single phase and three phase starting of the breaker failure function shall be possible.

Transformer differential protection

The transformer differential protection shall be three phase and phase segregated. The differential protection shall have settable characteristics and serial communication to remote.

Overcurrent protection

The overcurrent shall be three phase. Time delay shall be settable according to various characteristics including; constant time, normal inverse, very inverse, extremely inverse etc according to IEC 255-4.

Overvoltage protection

The overvoltage shall be three phase and sensitive with a high resetting ratio. Time delay shall be settable according to various characteristics including; constant time, normal inverse, very inverse, extremely inverse etc according to IEC 255-4.

Synchro-check function

The synchro-check device shall be capable of energizing (DLLB, DBLL) paralleling as well as synchro-check function. Normally the syncro-check function is started by a close order. A time delay (Waiting time) shall be adjustable between 0 – 600 s.

Interlocking function

This function is to prevent inadvertent or improper operation of disconnector switches and earthing switches. Interlocking shall be such that is impossible to energize or de-energize a component using a disconnector switch. It should not be possible to close the earthing switch when the component is energized.

Mechanical Protections

Tripping from mechanical protection such as Buchholz shall go directly to circuit breaker. A parallel signal shall go into a protection terminal for event logging.

Bay level

Level two defines how primary equipment and a bay unit (or bay units) make up a line-bay, transformer bay or any other type of a bay in a station. For the bay to function properly, sufficient amount of data and information need to be channeled to and from the bay.

Redundant bay units

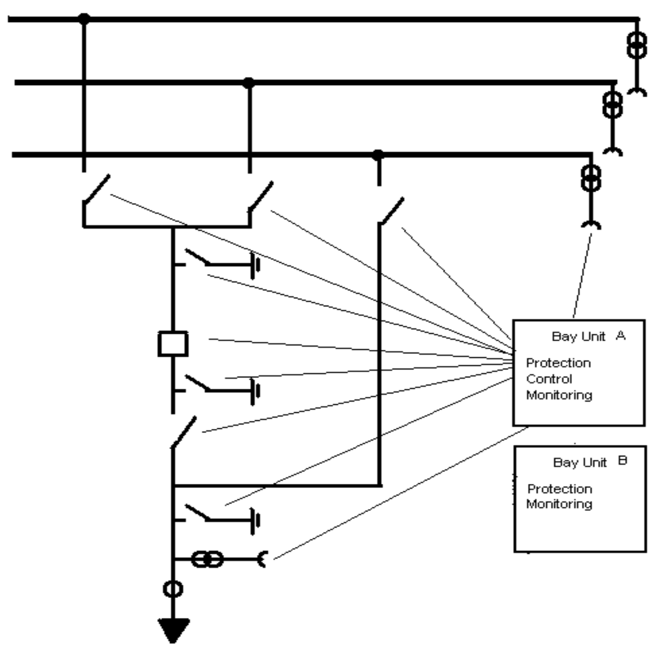
Where system requirement specifies a fault clearing time of maximum 100 ms, the protection system needs to be redundant. This requires double independent systems from

- Separate CT cores
- Separate VT miniature circuit breakers
- Double redundant protection terminals
- Separate DC- supply
- Separate trip coils in the circuit breaker.

Control functions such as autoreclosing, interlocking and voltage regulation do not need to be redundant.

Non-redundant bay unit

Where a fault clearing time of longer than 100 ms is allowed,
a single non-redundant protection system is acceptable, but with the same protection-, control- and monitoring functions included as in the double redundant system. Either a galvanic connection to current- and voltage transformers, or digital measuring transformers are acceptable. As the development and reliable operation experience of digital measuring transformers progresses and prices are comparable, this type of measurement transformers will replace the older type. If digital measuring transformers are installed, they are a part of the components which have self-supervision.



Information generated in the bay it self and information flow to and from the bay.

Bay		
Intra	**Inputs**	**Outputs**
Voltage 3ph	Time synchronizing	Protection trip/ BFP trip
Current 3ph	Open/close commands	Protection indications.
Position indications	DC-voltage	U I P Q values
Breaker status	Voltage 1ph	Open/close commands
Protection trip	Position indications	Position indications
Autoreclosing	Protection communication	Protection communication
		Supervision indications
		Event list
		Disturbance/fault data

When operation of the station requires that the outgoing feeder be fed through the tie breaker, the tripping from all protection functions must also trip the tie breaker.

It shall be possible to operate the bay locally from the bay unit through a local HMI. When the bay is being operated locally, it should not be possible to operate the bay from the station level nor remotely from dispatch center.

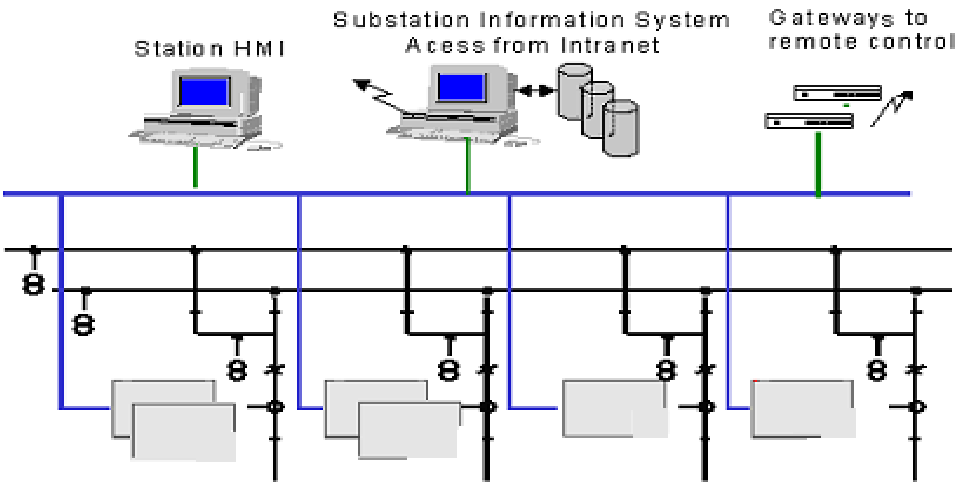
Station level

A station is comprised of a number of bays of different kinds and different voltage levels. The station can be configured in different ways.

The most common configuration used today is where wiring is used through out the station. This is the conventional way of designing a station.

The next step in the evolution is the “mixed” station. There we have conventional wiring from the bay units to the primary equipment and then a bus connection between bays and bay units and to the station control- and information systems.

The so called process-bus is used for exchange of necessary data and information.



The process bus must be set up so that a malfunction in one bay unit will not cause a breakdown on the rest of the process bus. A bus system must compatible to products from different manufacturers. A protocol of some sort must be agreed upon by the manufacturers of equipment. The standards IEC 61850-8 for station bus and IEC 61850-9 for process bus, is most likely to be this common platform that manufacturers will agree upon.
The next generation of stations is a more or less wireless station where the bus connection extents to the measuring transformers and circuit breakers. The bus communication will have to be fast and reliable. To utilize the bandwidth of the bus, it is necessary to prioritize the data flow. An example of data and it's priority can be as follows:

- Continuous, time-deterministic communication of 64kbits communication and of fast sampled analog values such as current and voltage.
- Occasional, but time deterministic transmissions of binary telegrams like interlocking data.
- Occasional, but fast transmission of binary values such as trip signals and carrier signals.
- Continuous but non-urgent communication of slow-sampled binary values such as monitoring- and diagnostic data.
- Occasional, non-urgent communication such as disturbance report data and downloading and uploading of software and settings.

To ensure that the data flow on the process is correct, it is crucial to have a reliable time stamping from a central time source such as a GPS-clock. [3] A time-resolution of 1 ms is required.

The station control system shall provide functions for supervision and control of the station. Basic functions that will have to be available in the system are,

- Manual switching,
- Alarm listing,
- Event listing,
- System status
- Parameter settings
- Single line diagram of the station,
- Status of all switches
- Measured values.

A separate system for information handling is also needed in the station. This system shall be accessible from remote. This system handles fault analysis and evaluation of faults and disturbances.
A station level protection is a busbar protection. Such a protection is needed in a station if the system requires a maximum fault clearing time of 100 ms. The busbar protection shall have separate CT cores with identical turn ratios in all bays.

Interlocking is needed on this level for transfer of bays to bus-tie, or transfer of bays from one busbar to another.

Information handling

In a numerical substation the possibilities for keeping information and data are much bigger than in a conventional station. The most essential data and documentation shall be stored in the station-database. This enables immediate updating of the data after modifications have been done in the station. A printer for hardcopies shall be installed.
For reliable operation of the station the following documentation shall be available:

- List of drawings
- Assembly drawings
- Single line diagram
- Block diagram
- Circuit diagram
- Logic diagram
- List of apparatus
- Functional design specification
- Operator manuals
- Product manuals
- Erection manuals

This information shall be stored locally in the station, but shall be accessible from remote.

Under normal operating conditions all measured values and connections between level 1 units can be monitored continuously. Possibility to alter settings and parameters from remote shall be available.

During and after disturbances it shall be possible to check the performance of each unit or a group of units in the station and alarms and indications generated by the disturbance or fault. One example is monitoring how a reclosing process in a line bay performed during a line fault.

For analysis of faults in the power system,

- Data from disturbance recorders.
- Voltage- and current curves.
- Automatic distance-to-fault calculation.

This information and all the necessary tools for analyzing shall be available both locally in the station and from remote. Task that are essential for analyzing this information are real-time data gathering such as;

- Signals
- Events (SOE)
- Diagnostics functions
- Monitoring
- Trends
- Dynamic values.

All software and software licenses, which have to be used for normal operation, changing of settings and parameters, creating and modifying of diagrams, extension of the station, data retrieval etc, shall be provided along with the documentation.

All necessary serial and parallel cables shall also be provided for communicating with individual units. If any special tools are needed for operation or maintenance, such tools shall be provided.

A commitment by the manufacturer of the equipment, that a replacement part shall be available in the station within 48 hours of ordering. If the manufacturer can not guarantee a delivery time of 48 hours, he must keep a sufficient stock of spare parts in Iceland at his own expense. The equipment manufacturer must guarantee availability of spare parts for minimum of twenty years after commissioning of equipment (or final acceptance certificate).

System level

It must be possible to use serial communication from the protection engineer office via the dispatch center and the substation to each bay unit.

This possibility should be used for interchanging information used for system operation, fault analysis, maintenance and setting changes.

The system level shall be an extension of the station level. With today's technology is this only a goal, but future solutions need to be evaluated.

Since the amount of data from a modern numerical substation is so vast, the information flow between station and dispatch center must be defined in detail so that the dispatch center will not be overloaded with non-relevant data during faults in the power system. The possibility to filter data for various purposes must be available.

Communication between dispatch center and station is today governed by the Harris H5000/6000 communication protocol. For all new power stations and substations the unbalanced version of the IEC 60870-5-101 or IEC 60870-5-104 protocol will be used.

One of the responsibilities of the dispatch center is system restoration after both severe and minor disturbances. Therefore it is very important for the operators to receive relevant data from different stations so that the dispatch center gets an overview of what has happened. It is very important to be able to have the sequence of events and in that way try to establish what caused the disturbance and what are the consequences of the disturbance. A list with sequence of events coming from stations in the power system must be defined. Event names must be identical between stations.

At a later stage of the disturbance analysis, the retrieval of voltage and current curves from different stations, along with time tagged events. The same disturbance evaluation software shall be available in the dispatch center as in the station. Distance to fault information from a distance protection shall be displayed in the dispatch center. This information is valuable to line crews, and to evaluate if there are any weak points on a line, if the same distance to fault keeps coming up again and again.

Control principles

220 kV lines

Single phase automatic reclosing is to be used on all transmission lines, except those that directly feed into customers. In case of a single phase fault and a single phase tripping, a single phase autoreclosing process starts. Dead time before breaker shall be sufficient for secure arc-extinguishing. In case of unsuccessful autoreclosing, a definite three phase trip signal follows and no autoreclosing is initiated after that. Autoreclosing shall not be active during energizing, and shall be blocked until after energizing.

Evaluation of three phase rapid autoreclosing and three phase automatic re-insertion will have to be done.

Interlocking shall be implemented so that a disconnector shall be locked when the circuit breaker is closed. Grounding switch shall be locked open unless the line-side disconnector is open and no voltage is detected on the incoming line.

220/132 kV transformers

Energizing of transformers shall be from the “stronger system” i.e. the 220 kV side. This should be implemented into the synchronizing function.

Interlocking shall be implemented so that a disconnector shall be locked when the circuit breaker is closed. Grounding switch shall be locked open, unless the line-side disconnectors on both (all) sides are open and no voltage is detected on the transformer.

220 kV busbars

Busbar fault or a breaker failure trip shall activate a lockout-function preventing closing of circuit breakers in the station until a manual reset has been done in the station.

132 kV lines

Although single phase automatic reclosing is not used on 132 kV transmission lines today, this function should be used on 132 kV lines. This relies on the fact that 132 kV circuit breakers need to have single pole tripping. In case of a single phase fault and a single phase tripping, a single phase autoreclosing process starts. Dead time before breaker shall be sufficient for secure arc-extinguishing. In case of unsuccessful autoreclosing, a definite three phase trip signal follows and no autoreclosing is initiated after that. Autoreclosing shall not be active during energizing, and shall be blocked until after energizing.

Evaluation of three phase rapid autoreclosing and three phase automatic re-insertion will have to be done.

Interlocking shall be implemented so that a disconnector shall be locked when the circuit breaker is closed. Grounding switch shall be locked open unless the line-side disconnector is open and no voltage is detected on the incoming line.

132 kV busbars

If a dedicated busbar protection is present, a busbar fault or a breaker failure trip shall activate a lockout-function preventing closing of circuit breakers in the station until a manual reset has been done in the station. If no busbar protection is present and a busbar fault is tripped from 2nd zone in the remote end, no lockout function shall be activated.

132/xx kV transformers

Energizing of transformers shall be from the “stronger system”, in this case, the 132 kV side. This should be implemented into the synchronizing function.

Interlocking shall be implemented so that a disconnector shall be locked when the circuit breaker is closed. Grounding switch shall be locked open, unless the line-side disconnectors on both (all) sides are open and no voltage is detected on the transformer.

66 kV lines

Although automatic reclosing is not used on 66 kV transmission lines today, the possibility exists. Evaluation of autoreclosing and automatic re-insertion will have to be done for each individual case.

Interlocking shall be implemented so that a disconnector shall be locked when the circuit breaker is closed. Grounding switch shall be locked open unless the line-side disconnector is open and no voltage is detected on the incoming line. In stations where the circuit breaker is mounted on a truck and no disconnector switches are present, the truck shall be locked and not movable when the circuit breaker is closed. The grounding switch can not be closed unless the truck is withdrawn and no voltage is on the incoming line.

66/xx kV transformers

Energizing of transformers shall be from the “stronger system”, in this case, the 66 kV side. This should be implemented into the synchro-check or the synchronizing functions.

Interlocking shall be implemented so that a disconnector shall be locked when the circuit breaker is closed. Grounding switch shall be locked open, unless the line-side disconnectors on both (all) sides are open and no voltage is detected on the transformer. In stations where the circuit breakers are mounted on a truck and no

disconnector switches are present, the truck shall be locked and not movable when the circuit breaker is closed. The grounding switch can not be closed unless the trucks on all sides of the transformer are withdrawn and no voltage is on the transformer.

33 kV lines

Although automatic reclosing is not used on 33 kV transmission lines today, the possibility exists. Evaluation of autoreclosing and automatic re-insertion will have to be done for each individual case.

Interlocking shall be implemented so that a disconnector shall be locked when the circuit breaker is closed. Grounding switch shall be locked open unless the line-side disconnector is open and no voltage is detected on the incoming line. In stations where the circuit breaker is mounted on a truck and no disconnector switches are present, the truck shall be locked and not movable when the circuit breaker is closed. The grounding switch can not be closed unless the truck is withdrawn and no voltage is on the incoming line.

33/xx kV transformers

Energizing of transformers shall be from the HV side. This can be implemented into the synchro-check or the synchronizing functions if those functions are present. Otherwise this can be done by interlocking so that the LV-breaker can only be closed when the HV-breaker is closed.

Interlocking shall be implemented so that a disconnector shall be locked when the circuit breaker is closed. Grounding switch shall be locked open, unless the line-side disconnectors on both (all) sides are open and no voltage is detected on the transformer. In stations where the circuit breakers are mounted on a truck and no disconnector switches are present, the truck shall be locked and not movable when the circuit breaker is closed. The grounding switch can not be closed unless the trucks on all sides of the transformer are withdrawn and no voltage is on the transformer.

The future protection- and control system

In the last years the trend in the development of equipment has been to digitize as much as possible. One of the advantages of digital equipment is the self-monitoring. Self-supervision of equipment reduces the need for maintenance work in the station, and thereby reduces risk of unwanted operation of equipment.

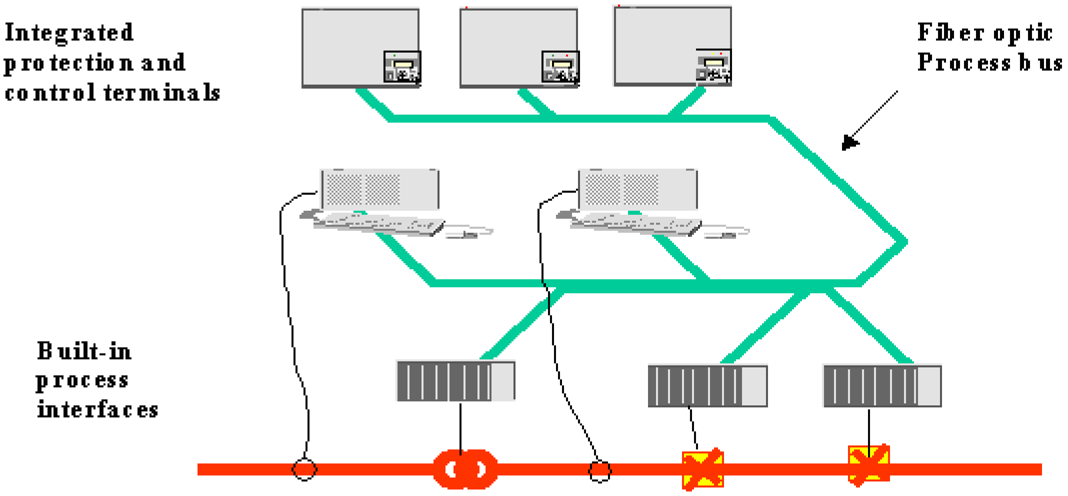
In the next years, the development and evolution will be on the bay level. Wiring between components and units will disappear and more modern data flow will take over. After the introduction of the numerical protection- and control terminals the development of digital optical measuring transformers has gained momentum. This type of optical transformers has both advantages and disadvantages when compared with conventional measuring transformers.

Conventional Measuring transformers		**Optical measuring transformers**	
Pros	**Cons**	**Pros**	**Cons**
Known technique	Cumbersome	Small construction	Short experience
Long experience	Oil filled	No saturation	Competence
Spare parts	Saturation problem	Self supervision	Spare parts
	Risk of open CT	No open CT risk	

All of the disadvantages of the optical measuring transformers, which are mentioned here above will disappear as time goes by and more utilities begin using the technology. The cost of optical measuring transformers will also go down as production numbers go up and more manufacturers compete on the market.

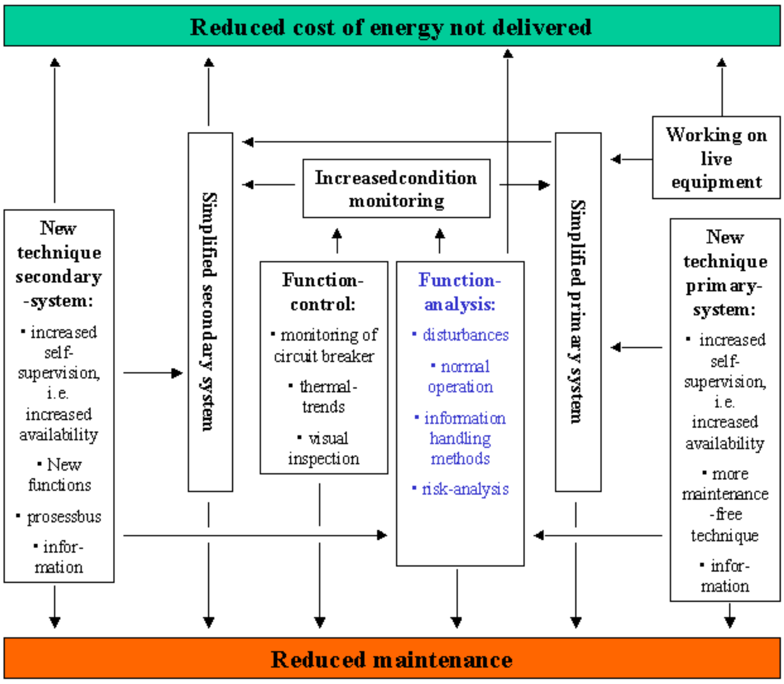
Another primary component which is also being digitized is the circuit breaker. The purpose of digitizing the circuit breaker is monitoring. The performance of the circuit breaker can be monitored and evaluated so that maintenance work can be done on the circuit breaker when it is needed, not sooner and not later.

When building a new station using equipment which generates data on a digital form, it is possible to use a bus system to convey this data between the appropriate units and systems in the station. The bus communication will have to be fast and reliable. To ensure that the data flow on the process is correct, it is crucial to have a reliable time stamping from a central time source such as a GPS-clock.

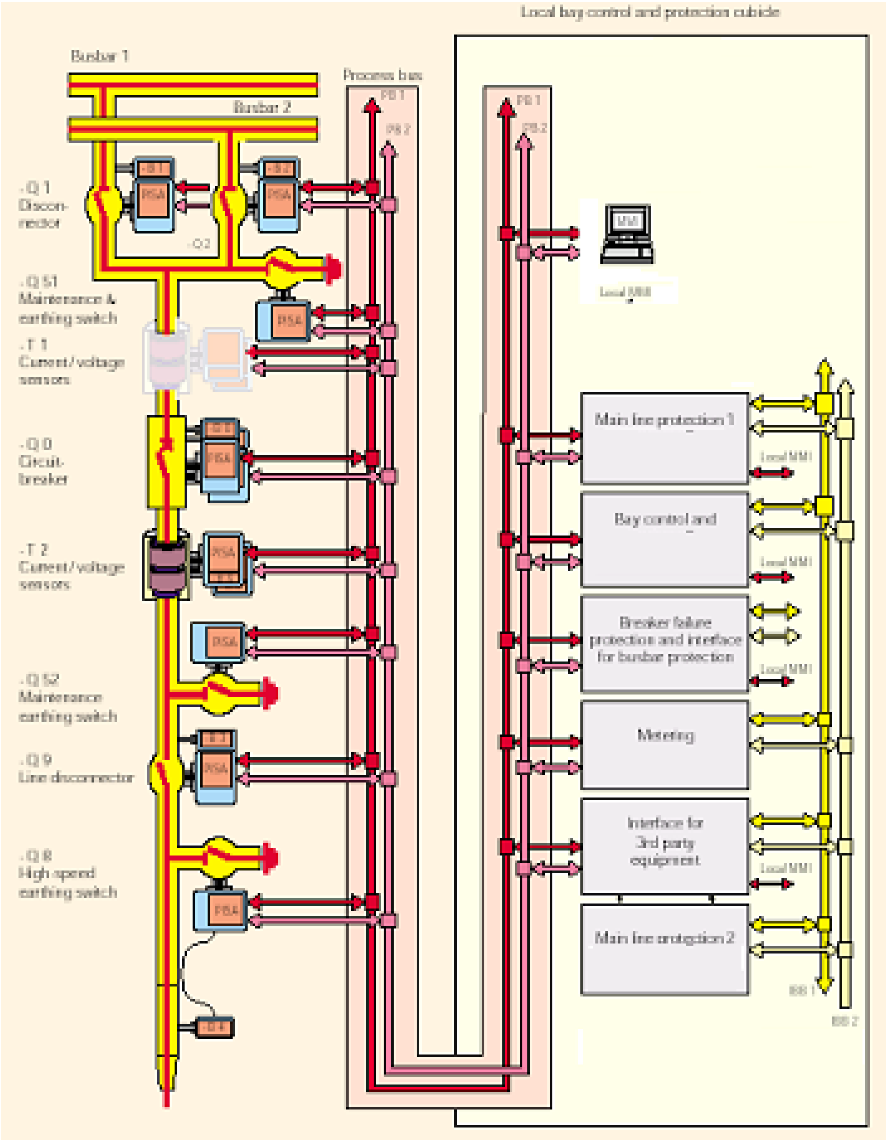


With the use of self supervision of all components in a station, the maintenance work can be focused on where the need is for maintenance. A consequence of this is the complexity of the station in terms of primary equipment will go down. The need for double busbars and transfer buses will decrease and it will be harder to justify such an added investment in terms of maintenance needs.

Another important factor that will influence maintenance scheduling is the introduction of the term “energy not delivered” and the rates that the utilities will have to pay for each kWh not delivered to the customer. Since maintenance work is a significant contributor to unwanted outages, and each outage will be more expensive for the utility, the need to focus the maintenance when there is a need for it. The numerical technology is therefore an important tool for maintenance scheduling.



A simplified busbar arrangement has a great impact on the complexity of the secondary system. It is easy to envisage that a simplified busbar arrangement will give a simplified and more economic secondary system. It will lead to a reduced number of position indications, simplified autorecloser schemes, simplified interlocking, simplified busbar protection, etc. This will have an impact on both economy and availability. [1]



[7]

It is only a matter of time before new substations are almost 100% self-supervised. It is therefore important for the power utilities to be ready and be familiar with the technology when the time comes.

Appendix 1; Protection principles

220 kV lines

Protection shall be redundant with distance protection, non-directional earth fault protection and line differential protection. The distance protection uses two forward looking zones and one backwards looking. The reverse zone is used for indication only.
Non-directional earth fault protection is set to 80 A primary value. A minimum time delay must be set. Characteristic curve of type RXIDG is used.
(t=5,8-1,35ln(I/Iset))

220 kV busbars

A busbar protection shall be installed in all 220 kV stations.

220/132 kV transformers

The main protection of the transformer is the current differential protection. A redundant distance protection is needed on the 220 kV-side and on the 132 kV-side. Two forward looking zones and one reverse are needed.

Non-directional earth fault protection is needed on both sides of the transformer. The protection is set to 80 A primary value. A minimum time delay must be set. Characteristic curve of type RXIDG is used.
(t=5,8-1,35ln(I/Iset)). The protection function must be stable against 2nd harmonic inrush currents.

220 kV and 132 kV Shunt capacitor banks

A shunt capacitor bank shall be protected by an overvoltage protection, an unbalance protection and two types of overcurrent protection. One overcurrent protection shall measure only the 50 Hz component of the current, whereas the other protection shall measure all frequency components. Protection on 220 kV shunt capacitors shall be redundant.

132 kV lines

On lines where a fault clearing time of 400 ms is acceptable, a non-redundant protection is sufficient. The protection functions shall be the same as for the redundant system.
Protection functions shall be distance protection, non-directional earth fault protection and line differential protection. The distance protection uses two forward looking zone and one backwards looking. The reverse zone is used for indication only.
Non-directional earth fault protection is set to 80 A primary value. A minimum time delay must be set. Characteristic curve of type RXIDG is used.
(t=5,8-1,35ln(I/Iset))

132 kV busbars

A busbar protection shall be installed in all GIS stations and where fault clearing time of maximum 100 ms is needed. Otherwise a 2nd zone distance protection trip from the remote stations is sufficient.

132/xx kV transformers

The main protection of the transformer is the current differential protection. A non-redundant distance protection is needed on the 132 kV-side. Two forward looking zones and one reverse are used.
On the 132 kV side, a non-directional earth fault protection is set to 80 A primary value. A minimum time delay must be set. Characteristic curve of type RXIDG is used. (t=5,8-1,35ln(I/Iset)). The protection function must be stable against 2nd harmonic inrush currents.
A three-phase overcurrent protection is used on the 132 kV-side instead of a distance protection on transformers smaller than 20 MVA.

66 kV lines

On lines with 66 kV voltage a non-redundant protection is sufficient. The protection functions shall be distance protection and non-directional earth fault protection. On short overhead lines and cables the differential current protection function shall be added. The distance protection uses two forward looking zone and one backwards looking. The reverse zone is used for indication only. The use of the 3rd zone shall be evaluated for each individual case.

Non-directional earth fault protection is set to 80 A primary value. A minimum time delay must be set. Characteristic curve of type RXIDG is used.
(t=5,8-1,35ln(I/Iset))

66 kV busbars

A busbar protection shall be installed in all GIS stations. Otherwise the busbar is protected from 2nd zone distance protection trip from the remote stations and the 2nd zone of distance protection on 132 kV side of incoming transformer.

66/xx kV transformers

The main protection of the transformer is the current differential protection. On the 66 kV side, a non-directional earth fault protection is set to 80 A primary value. A minimum time delay must be set. Characteristic curve of type RXIDG is used. (t=5,8-1,35ln(I/Iset)). The protection function must be stable against 2nd harmonic inrush currents.
A three-phase overcurrent protection is needed on the 66 kV-side, MV-side and the tertiary if applicable.

33 kV lines

On lines with 33 kV voltage or lower, a non-redundant protection is sufficient. The protection functions shall be three-phase overcurrent protection. Settings for the function will have to be evaluated for each individual case.
If the neutral point of the system is grounded, a non-directional earth fault protection function is needed. In a system with the neutral point isolated, a sensitive directional earth fault protection shall be used, if capacitive currents generated by an earth fault are sufficient.

33/xx kV transformers

The main protection of the transformer is the current differential protection.
A three-phase overcurrent protection is needed on the HV-side, MV-side and the tertiary if applicable. A non-directional earth fault protection is also needed if the neutral point on the transformer HV-side is grounded. On smaller and less important transformers, the current differential protection can be omitted.

33 kV busbars

To protect the busbar against short circuit, the instantaneous overcurrent stage on the incoming transformer bay should be used if possible. An alternative, if no short-circuit in-feed is from any of the outgoing bays, is to accelerate the time delayed overcurrent stage in the incoming transformer (The poor man’s busbar protection).
If the neutral point of the system is isolated, an open-delta voltage is needed for earth fault supervision.

Appendix 2; Specification of requisites to Dispatch Centre

Specification of riquisite points sent to Dispatch Centre

Eining / Device	Key	Lýsing á merki	Status point	Time stamp
Aflrofi / Circuit breaker	P001	Rofastaða - aflrofi inni/lokaður	Breaker status - CLOSED	X
	P002	Rofastaða - aflrofi úti/opinn	Breaker status - OPEN	X
	P003	Rofastaða - inni/útdreginn	Breaker status - IN / WITHDRAWN	
	P004	Rofi læstur/ekki tilbúinn (hindraður, staðstýrður)	Breaker blocked / not ready	
	P005	Mismunastaða póla	Breaker pole discrepancy	
	P006	Viðvörun um bilun í aflrofa	Breaker warning/failure - alarm	
	P007	Aflrofabilun (BFP) - útleysing	Breaker Failure Protection - trip	X
Skilrofi / Disconnector	P008	Rofastaða - skilrofi inni/lokaður	Status - CLOSED	X
	P009	Rofastaða - skilrofi úti/opinn	Status - OPEN	X
Jarðblað / Earting switch	P010	Jarðblað inni/lokað	Status - CLOSED	X
	P011	Jarðblað úti/lokað	Status - OPEN	X
SF6 gas / SF6	P012	Viðvörun vegna SF6 gasþrýstings/-leka	SF6 low pressure/leakage - alarm	
	P013	Læsing á rofa vegna SF6 gasþrýstings/-leka	SF6 low pressure/leakage - breker locked	
Varnarbúnaður almennt / Protection System - common alarms	P014	Varnarbún. óvirkur vegna bilunar eða hindrunar	Protection System failure or blocked – alarm	
	P015	Vöktun á útleysirásum	Trip circuit supervision	
	P016	Vöktun á mælirásum	Measuring circuit supervision	
Lína -fjarlægðavörn / Line distance protection	P017	1.þreps útleysing	Zone 1 - trip	X
	P018	2.þreps útleysing	Zone 2 - trip	X
	P019	3.þreps útleysing	Zone 3 - trip	X
	P020	Start á R-fasa	Start fault phase L1	X
	P021	Start á S-fasa	Start fault phase L2	X
	P022	Start á T-fasa	Start fault phase L3	X
	P023	Start á bakþrepi	Start of reverse zone	X
	P024	Start á jörð	Start earth fault	X
	P025	Fjarmerki sent (carrier sent)	Carrier send	X
	P026	Fjarmerki móttekið (carrier receive)	Carrier receive	X
	P027	Endurlokun	Reclosing send	X
	P028	Mislestun	Load unbalance	
Lína - mismunastraumsvörn / Line differential current protection	P029	Útleysing, þriggja fasa	Trip 3 phase	X
	P030	Útleysing R-fasa	Trip phase L1	X
	P031	Útleysing S-fasa	Trip phase L2	X
	P032	Útleysing T-fasa	Trip phase L3	X
	P033	Endurlokun	Reclosing send	X
	P034	Vörn óvirk vegna bilunar í fjarskiptum	Protection blocked - Telecom. failure	
Lína - jarðstraumsvörn / Earth fault protection	P035	Útleysing	Trip	X
	P036			
Lína - yfirstraumsvörn / Overcurrent protection	P037	Útleysing	Trip	X
	P038			

Aflspennir - varnarbúnaður / Transformer protection	P039	Útleysing frá undirsýndarviðnámsvörn	Min. impedance protection - trip	X
	P040	Viðvörun frá Bucholzliða	Bucholz relay - alarm	
	P041	Útleysing frá Bucholzliða	Bucholz relay - trip	X
	P042	Útleysing frá þrýstiliða	Pressure relay - trip	X
	P043	Viðvörun um vafhita	Winding temp. - alarm	
	P044	Útleysing vegna vafhita	Winding temp. - trip	X
	P045	Viðvörun vegna olíuhita	Oil temp. - alarm	
	P046	Útleysing vegna olíuhita	Oil temp. - trip	X
	P047	Viðvörun vegna olíuhæðar	Oil level - alarm	
	P048	Útleysing vegna olíuhæðar	Oil level - trip	X
	P049	Útleysing vegna yfirstraums	Overcurrent - trip	X
	P050	Útleysing vegna jarðstraums	Earth fault - trip	X
	P051	Mismunastraumsútleysing	Diffrential current - trip	X
	P052	Viðvörun vegna köfnunarefnis (N2)	N2 - alarm	
	P053	Kæling spennis bilun (viftur - dælur)	Cooling equipment (fans) - alarm	
Aflspennir - þrepaskiptir / Transformer - tap Controller	P054	Viðvörun frá þrepaskipti	Tap controller failure	
	P055	Staða stýringar - fjar-/stað-	Control - Local/Remote	
	P056	Þrepastýring handvirk / sjálfvirk	Control - Auto/Manual	X
Þéttir - varnarbúnaður / Capacitor protection	P057	Útleysing vegna yfirstraums	Overcurrent - trip	X
	P058	Útleysing vegna yfirspennu	Overvoltage - trip	X
	P059	Viðvörun um mislestun	Load unbalance - alarm	
	P060	Útleysing vegna mislestunar	Load unbalance - trip	X
	P061	Innsetningarbúnaður	Control system failure	
Teinn / Busbar protection	P062	Viðvörun frá safnteinavörn	Busbar Protection - alarm	
	P063	Útleysing frá santeinavörn	Busbar Protection - trip	X
Samfösun / Synchronizer	P064	Staða samfösunar	Status of synchronization	
	P065	Staða hliðtengdrar samfösunar	Status of parallel synchronization	
	P066	Bilun í samfösun	Synchronizer failur	
	P067	Samfösunartími útrunninn	Synchronization time-out	
Stöð / Station	P068	Vöktun á stjórnkerfi stöðvar	Station control system supervision - alarm	
	P069	Staða stýringar - fjar-/stað-	Control - Local/Remote (pr. Control element)	X
Vél – almennt / Unit - common alarms	P070	Staða vélar	Unit status - (on/off)	X
	P071	Staða stýringar - fjar-/stað-	Control - (local/remote)	X
	P072	Tilbúin til ræsingar	Ready for start - (yes/no)	
	P073	Ræsing	Start - (yes/no)	
	P074	Stöðvun	Stop - (yes/no)	
	P075	Tilbúin til samfösunar	Ready for synchronization - (yes/no)	

Vél - rafali / Unit - generator	P076	Flokkur 1 - merkjahópur - útleysing -> útkall	Group 1 - Trip - Call field	X
	P077	Flokkur 2 - merkjahópur - alvarleg viðv., útleysihætta -> útkall	Group 2 - High severity alarm - Call field	
	P078	Flokkur 3 - merkjahópur - viðvörun -> útkall	Group 3 - Medium severity alarm - Call field	
	P079	Flokkur 4 - merkjahópur - viðvörun -> útkall innan 10 tíma	Group 4 - Medium severity alarm - Call field within 10h	
	P080	Útleysing vegna jarðstraums í sátri (95% og 100% vörn)	Stator earth fault - trip	X
	P081	Viðvörun um jarðstraum í snúð	Rotor earth fault - alarm	
	P082	Útleysing vegna jarðstraums í snúð	Rotor earth fault - trip	X
	P083	Viðvörun vegna öxulstraums	Shaft current - alarm	
	P084	Útleysing vegna yfirstraums/undirspennu	Overcurrent/undervoltage - trip	X
	P085	Útleysing vegna yfirstraums	Overcurrent - trip	X
	P086	Viðvörun um yfirálag	Overload - trip	X
	P087	Útleysing vegna yfirálags	Overload - alarm	
	P088	Útleysing vegna undirspennu	Undervoltage - trip	X
	P089	Útleysing vegna yfirspennu	Overvoltage - trip	X
	P090	Útleysing vegna yfirtíðni	Overfrequency - trip	X
	P091	Viðvörun um hita í sátri	Stator over temperature - alarm	
	P092	Útleysing vegna hita í sátri	Stator over temperature - trip	X
	P093	Útleysing vegna mismunastraums	Differential protection - trip	X
	P094	Útleysing vegna mismunastraums samstæðu	Block differential protection - trip	X
	P095	Viðvörun vegna mislestunar milli fasa	Negative phase sequence - alarm	
	P096	Útleysing vegna mislestunar milli fasa	Negative phase sequence - trip	X
	P097	Útleysing vegna yfirhita rafala	Generator over temperature - trip	X
	P098	Viðvörun um bakafl	Reverse power - alarm	
	P099	Útleysing vegna bakafls	Reverse power - trip	X
	P100	Viðvörun vegna undirsegulmögnunar	Loss of excitation - alarm	
	P101	Útleysing vegna undirsegulmögnunar	Loss of excitation - trip	X
	P102	Spennureglunarháttur (AVR)	Excitation system - Voltage control mode (on/off)	
	P103	Launaflsreglunarháttur	Excitation system - Mvar control mode (on/off)	
	P104	Viðvörun um hita í segulmögnunarspenni	Excitation transformer over temperature – alarm	
	P105	Útleysing vegna hita í segulmögnunarspenni	Excitation transformer over temperature – trip	X
	P106	Útleysing vegna yfirstraums í segulmögnunarspenni	Excitation transformer - overcurrent - trip	X
	P107	Útleysing vegna mismunastraums í segulmögnunarspenni	Excitation transformer differential protection - trip	X
	P108	Útleysing vegna jarðhlaups í segulmögnunarspenni	Excitation transformer earth fault - trip	X
Vél - hverfill / Unit - turbine	P109	Flokkur 1 - merkjahópur - útleysing	Group 1 - Trip - Call field	X
	P110	Flokkur 2 - merkjahópur - alvarleg viðv., útleysihætta -> útkall	Group 2 - High severity alarm - Call field	
	P111	Flokkur 3 - merkjahópur - viðvörun -> útkall	Group 3 - Medium severity alarm - Call field	
	P112	Flokkur 4 - merkjahópur - viðvörun -> útkall innan 10 tíma	Group 4 - Medium severity alarm - Call field within 10h	
	P113	Viðvörun - brotbolti brotinn		
	P114	Viðvörun - lágt ásþéttisflæði		

	P115	Ristartöp - viðvörun	Intake grating losses - alarm	
	P116	Inntaksloka - neyðarlokun	Inlet valve - emergency closing	
	P117	Afllreglunarháttur gangráðs	Governor - load control mode (on/off)	
	P118	Hraðareglunarháttur gangráðs	Governor - speed control mode (on/off)	
	P119	Opnunarstýring gangráðs	Governor - opening control mode (on/off)	
Vél - kælivatnskerfi / Unit - cooling system	P120	Flokkur 1 - merkjahópur - útleysing	Group 1 - Trip - Call field	X
	P121	Flokkur 2 - merkjahópur - alvarleg viðv., útleysihætta -> útkall	Group 2 - High severity alarm - Call field	
	P122	Flokkur 3 - merkjahópur - viðvörun -> útkall	Group 3 - Medium severity alarm - Call field	
	P123	Flokkur 4 - merkjahópur - viðvörun -> útkall innan 10 tíma	Group 4 - Medium severity alarm - Call field within 10h	
Stoðkerfi stöðvar / Station supervision	P124	Flokkur 1 - merkjahópur - útleysing	Group 1 - Trip - Call field	X
	P125	Flokkur 2 - merkjahópur - alvarleg viðv., útleysihætta -> útkall	Group 2 - High severity alarm - Call field	
	P126	Flokkur 3 - merkjahópur - viðvörun -> útkall	Group 3 - Medium severity alarm - Call field	
	P127	Flokkur 4 - merkjahópur - viðvörun -> útkall innan 10 tíma	Group 4 - Medium severity alarm - Call field within 10h	
	P128	Innbrotsvörn	Braek-in-alarm system - alarm	
	P129	Vöktun innbrotsvarnar	Braek-in-alarm system failure	
	P130	Brunaviðvörun	Fire-system alarm	
	P131	Vöktun á brunaviðvörun	Fire-system failure - alarm	
	P132	Loftræsikerfi	Ventilation system alarm	
	P133	Hitakerfi	Heating system alarm	
Stöðvarnotkun / Station service load	P134	Flokkur 1 - merkjahópur - útleysing	Group 1 - Trip - Call field	X
	P135	Flokkur 2 - merkjahópur - alvarleg viðv., útleysihætta -> útkall	Group 2 - High severity alarm - Call field	
	P136	Flokkur 3 - merkjahópur - viðvörun -> útkall	Group 3 - Medium severity alarm - Call field	
	P137	Flokkur 4 - merkjahópur - viðvörun -> útkall innan 10 tíma	Group 4 - Medium severity alarm - Call field within 10h	
	P138	DC kerfi 48V - viðvörun	DC system 48V - alarm	
	P139	DC kerfi 110V - viðvörun	DC system 110V - alarm	
	P140	AC kerfi 400V	AC system 400V - alarm	
	P141	AC kerfi 11kV	AC system 11kV - alarm	
	P142	Neyðarrafstöð	Station auxiliary generator	
Vatnsvegir / Hydro system	P143	Flokkur 1 - merkjahópur - útleysing	Group 1 - Trip - Call field	X
	P144	Flokkur 2 - merkjahópur - alvarleg viðv., útleysihætta -> útkall	Group 2 - High severity alarm - Call field	
	P145	Flokkur 3 - merkjahópur - viðvörun -> útkall	Group 3 - Medium severity alarm - Call field	
	P146	Flokkur 4 - merkjahópur - viðvörun -> útkall innan 10 tíma	Group 4 - Medium severity alarm - Call field within 10h	
Gufuveita / Geothermal system	P147	Flokkur 1 - merkjahópur - útleysing	Group 1 - Trip - Call field	X
	P148	Flokkur 2 - merkjahópur - alvarleg viðv., útleysihætta -> útkall	Group 2 - High severity alarm - Call field	
	P149	Flokkur 3 - merkjahópur - viðvörun -> útkall	Group 3 - Medium severity alarm - Call field	
	P150	Flokkur 4 - merkjahópur - viðvörun -> útkall innan 10 tíma	Group 4 - Medium severity alarm - Call field within 10h	

Specification of riquisite analogs sent to Dispatch Centre

Eining / Device	**Lýsing á mælingu**	**Analog**	**Unit**
Lína / Transm. Line	Raunaflsflæði	Powerflow, real power	MW
	Launaflsflæði	Powerflow, reactive power	Mvar
	Spenna	Line voltage	kV
	Straumur í einum fasa	Current in one phase	A
Spennir / Transformer	Raunaflsflæði	Powerflow, real power	MW
	Launaflsflæði	Powerflow, reactive power	Mvar
	Spenna	Line voltage	kV
	Straumur í öllum fösum	Current in all phases	A
	Þrepastaða	Tap position	unit
	Viðmiðunarspenna reglis	Reference Voltage	kV
Þéttir / Shunt Capacitor	Launafl, Mvar	Reactive Power Output	Mvar
	Spenna, kV	Line voltage	kV
	Straumur í öllum fösum	Current in all phases	A
Teinn / Busbar	Spenna	Line voltage	kV
	Tíðni	Frequency	Hz
Vél / Gen. Unit	Raunaflsvinnsla	Power generation	MW
	Launaflsvinnsla	Power generation	Mvar
	Spenna	Terminal voltage	kV
	Straumur í einum fasa	Current in one phase	A
	Tíðni	Frequency	Hz
Vatnsaflsstöð / Hydro station	Rennsli	Water flow rate	m3/s
	Vatnshæð við inntak, m y.s.	Head water elevation m.a.s.	m
	Vatnshæð við frárennsli, m y.s.	Tail water elevation m.a.s.	m
	Vatnshiti	Water temperature	C
Loka / Gate	Rennsli	Water flow rate	m3/s
	Staða	Gate position	m or %
Miðlunarlón / Reservoir	Vatnshæð, m.y.s.	Water elevation, m.a.s.	m

Specification of riquisite controls to be sent from Dispatch Centre

Eining	Lýsing á stýringu	Control
Aflrofi	Stýring - ÚT	Control - OUT
/ Circuit breaker	Stýring - INN	Control - IN
Skilrofi	Stýring - ÚT	Control - OUT
/ Disconnector	Stýring - INN	Control - IN
Aflspennir	Þrepun - upp/niður	Tap - up / down
/ Transformer	Óskgildi á viðmiðunarspennu reglis	Reference voltage setpoint
	Stýrihamur - handvirk / sjálvirk (AVR)	Control mode - manual / auto
Vél	MW stýring - hækka/lækka	MW control - raise / lower
/ Gen. Unit	MW stýring - óskgildi	MW control - setpoint
	MW stýring - stýrihamur (h/l - óskg.)	MW control mode - r/l / setpoint
	Stýring á rafalaspennu - hækka/lækka	Gen. voltage control - raise / lower
	Stýring á rafalaspennu - óskgildi	Gen. voltage control - setpoint
	Stýring á rafalaspennu - stýrihamur	Gen. voltage control mode - r/l / setpoint
	Mvar stýring - óskgildi	Mvar control - setpoint
	Stýring á launafls-stýriham (rafalasp. - Mvar óskg.)	Reactive control mode - Gen. Volt. / Mvar ctrl.
	Ræsing vélar	Unit start
	Stöðvun vélar	Unit stop
	Stýring á reglunarhaml gangráða	Governor control mode
Loka	Opnun - minnka	Opening - lower
/ Gate	Opnun - auka	Opening - raise
	Opnun - óskgildi	Opening - setpoint
	Rennsli - óskgildi	Flow - setpoint
Samfösun	Samfösun af/á	Synchronization - on / off
/ Synchronizer	Hliðtengd samfösun af/á	Parallel synchronization - on / off

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