Intelligent substation automation – monitoring and diagnostics in HV switchgear installations

Expanding on modern substation automation, in which all the bay-oriented functions are integrated in the bay cubicle, efforts are now being focused on moving the 'intelligence' even closer to the primary process. A precondition for this are new, 'smart' sensors and actuators for all the main measurements and setpoints, linked to each other and to the bay control level by a field bus. Such a concept allows cost-optimized, fully redundant acquisition and processing of all the operating variables, plus a diagnostics and monitoring system that covers the entire substation.

Protection and process control systems are installed in power networks and substations to provide the technical platform for optimized operation and monitoring of all the primary equipment. The tasks cover a wide area, beginning with the instrument transformer or switchgear drive mechanism and ending with complex network control and load management. Collectively, the individual components of such systems are referred to as the secondary technology. However, this term has in the past normally included supervision, interlocking, measurement and control in the substation secondary technology but excluded all the protection equipment. Similarly, monitoring and diagnostic aspects of the primary apparatus have been virtually ignored in the design of the control and monitoring system.

It is common practice today to routinely inspect the individual items of equipment, although the intervals between inspection can differ greatly, depending on the manufacturer and the type of apparatus. For safety reasons, the inspections may even be carried out ahead of schedule. This is because often no clear information is available about the lifetime of the individual components and discrepancies sometimes exist between the manufacturers' figures and the basic lifetime assumptions (25 to 40 years) for the primary equipment in the substation. Continuous, automatic diagnostics are usually restricted to self-checking of the numerical control and protection equipment. Equipment users, however, have difficulty judging the depth of the testing, since neither the algorithms that are used nor the schematics are made available by the manufacturers.

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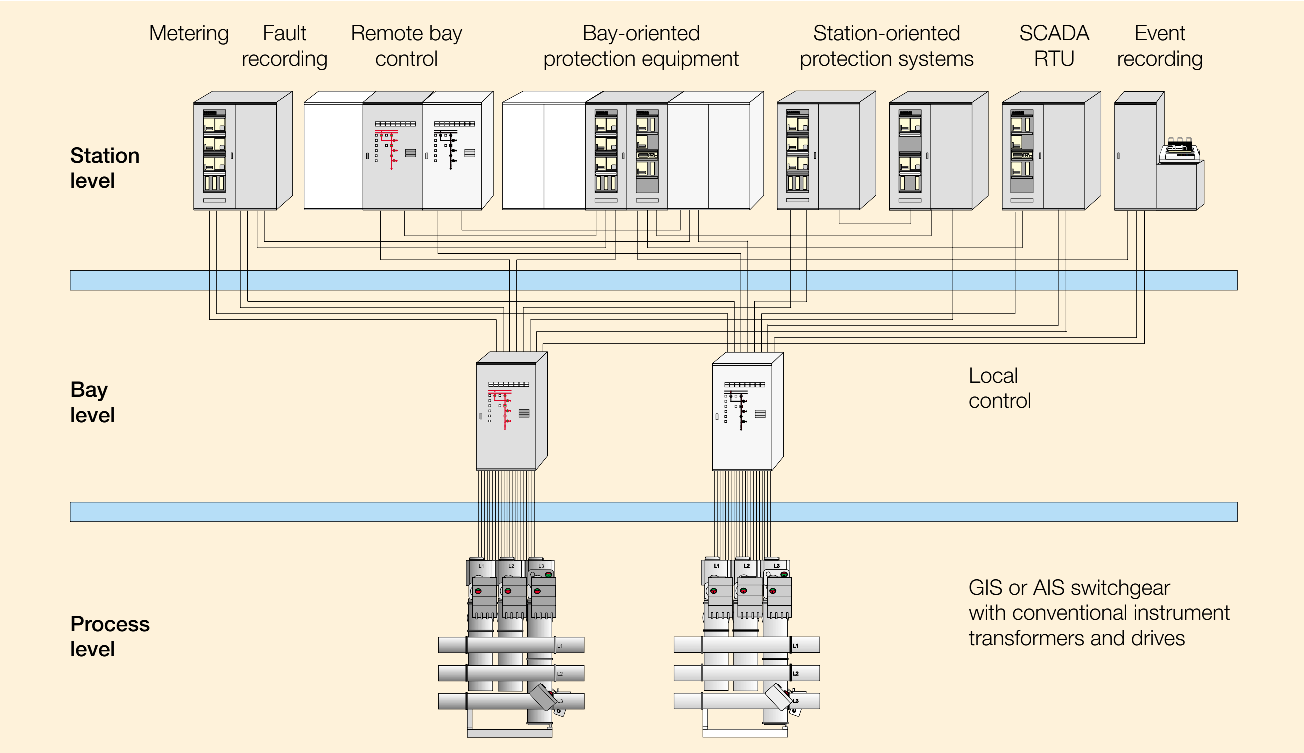
A monitoring system which is designed to cover the entire substation and which integrates continuous diagnostic checking of the primary equipment would allow regular inspections to be replaced by maintenance 'as required' and considerably shorten the mean time between a fault (which usually is not detected until the next inspection is carried out) and its clearance. Routine maintenance involves taking the high-voltage transformers, feeders and busbars out of service for preventive inspection, so its replacement by service 'as required' has a positive effect on the overall network control.

The concept of an intelligent switchbay allows for the first time optimum integration of the protection functions in the overall substation automation concept, while such switchbays also provide the basis for station-wide monitoring and diagnostics systems. Due to the size of these systems, only some of the more typical functions are given in the following.

Definitions of five terms used are given here for a better understanding of the subject matter:

- *Conventional control technology* (in fact, conventional control and protection technology): control technology based on electromechanical components, such as relays, contactors, switches, signal lamps, moving-coil elements. Some protection functions and station-wide system components are already electronics-based.
- *Modern control technology:* control technology based on numeric modules for protection and control functions at the bay level, computers at



Conventional solution for substation control and protection **1**

the station level, and a serial (interbay) bus between the station level and the individual bays.

- *Intelligent control technology:* modern control technology, but extended such that individual functions at the bay level are moved closer to the primary equipment. The intelligent primary equipment and the bay level are linked via serial (process) buses, ie one bus per bay.
- *Smart GIS:* gas-insulated substation based on intelligent primary equipment.
- *PASS (Plug And Switch System):* gas-insulated switchbay of hybrid design; replaces AIS bays with a space-saving combination of circuit-breaker, disconnectors, earthing switch and current/voltage transformers, based on intelligent primary equipment.

The examples given in the following sections refer in the most part to gas-insulated switchgear, but could be applied just as easily to AIS systems or PASS.

Hierarchies in the substation secondary technology

The different hierarchies in conventional and modern secondary technology within a substation have already been explained in [1]. Another source of valuable information is [2], which gives an especially detailed insight into the conventional designs and configurations for gas-insulated and air-insulated substations. The different hierarchies in modern secondary technology are given in [3], taking substations of different sizes as examples. The same source also looks at the new technologies for protection and control at the bay level.

1 and **2** allow a comparison of the key elements of conventional and intelligent substation automation systems. The introduction of intelligent substation automation saves the space that is normally required for the protection and telecontrol equipment. Most of these functions are shifted towards the bay level and the station level. Since the large control panels are replaced by computerized workstations, the station control room can also be made smaller.

Limits of conventional and modern control technology – advantages of intelligent substation automation

Wiring

[1] shows that one of the main objectives of introducing modern control technology is to reduce the amount of wiring between the different switchbays and between the bay level and station level. With conventional substation control there are between 200 and 500 signal links per bay, so that a typical 380-kV substation with two transformer and four line bays has up to 3,000 connections between the bay control cubicles and the protection/telecontrol area or control room alone.

A further 2,000 to 3,000 connections have to be reckoned with for the internal wiring in each switchbay, adding up to something like 20,000 signal connections for a six-bay substation. Intelligent substation control technology reduces these numbers by a factor of 30 to 60.

Redundancy

In spite of – or perhaps precisely because of – the parallel wiring between the primary equipment and the local control panel and between the bay level and the protection/telecontrol room, there is no redundancy as such. Instead, to keep costs down individual 'users' (eg, systems for local control, line protection, remote control signalling, busbar protection, fault recording, revenue metering, etc) receive only those signals that they specifically require. Thus, no redundancy is provided for the individual sub-functions in conventional control technology. In its place there is partial redundancy of the overall function.

Intelligent substation automation allows, for the first time, a clearly scalable redundancy of all the secondary technology functions at all levels of the hierarchy within the substation. This is of special importance since, among other things, the rise in cost of the intelligent secondary technology is disproportionately smaller than the additional redundancy that it makes possible.

Limits of conventional technology

The limits to functionality imposed by conventional control systems are a direct result of their technology. For every new secondary function additional equipment and wiring is needed, increasing both the volume and cost. The introduction of modern control systems represented a major technological advance as they clearly separated the hardware from the functions. The user therefore has, within certain limits, some influence on how the secondary technology functions are distributed between the different hardware units, especially at the bay level. For example, it is possible to mix the software functions of the local control computer and the main line protection and implement them simultaneously in two independent but identically structured hardware units. Redundancy at the bay level is therefore ensured.

The limits to this type of variable function allocation, however, exist there where different functions require access to similar process signals which are recorded separately. The current signal for the line protection and for monitoring, for example, can originate from different CT cores. Intelligent substation automation allows unlimited allocation of every individual function to one or more freely chosen hardware units at every level in the hierarchy.

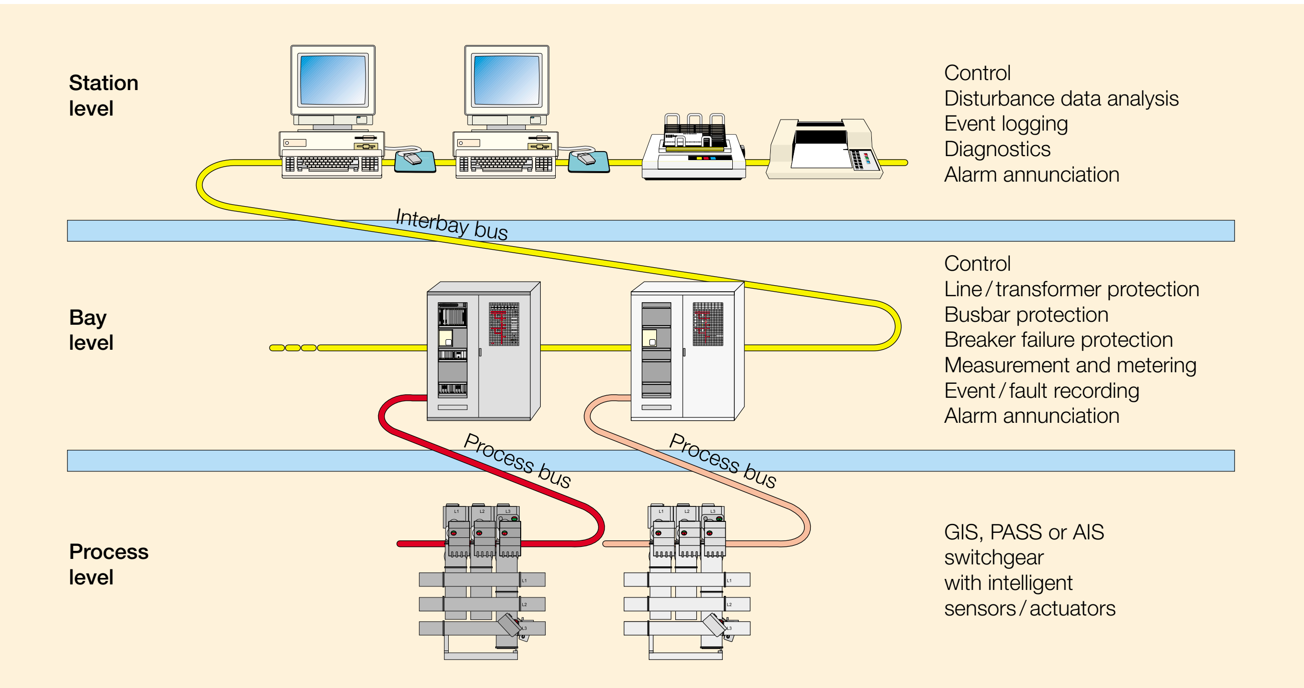
Structure of an intelligent switchbay

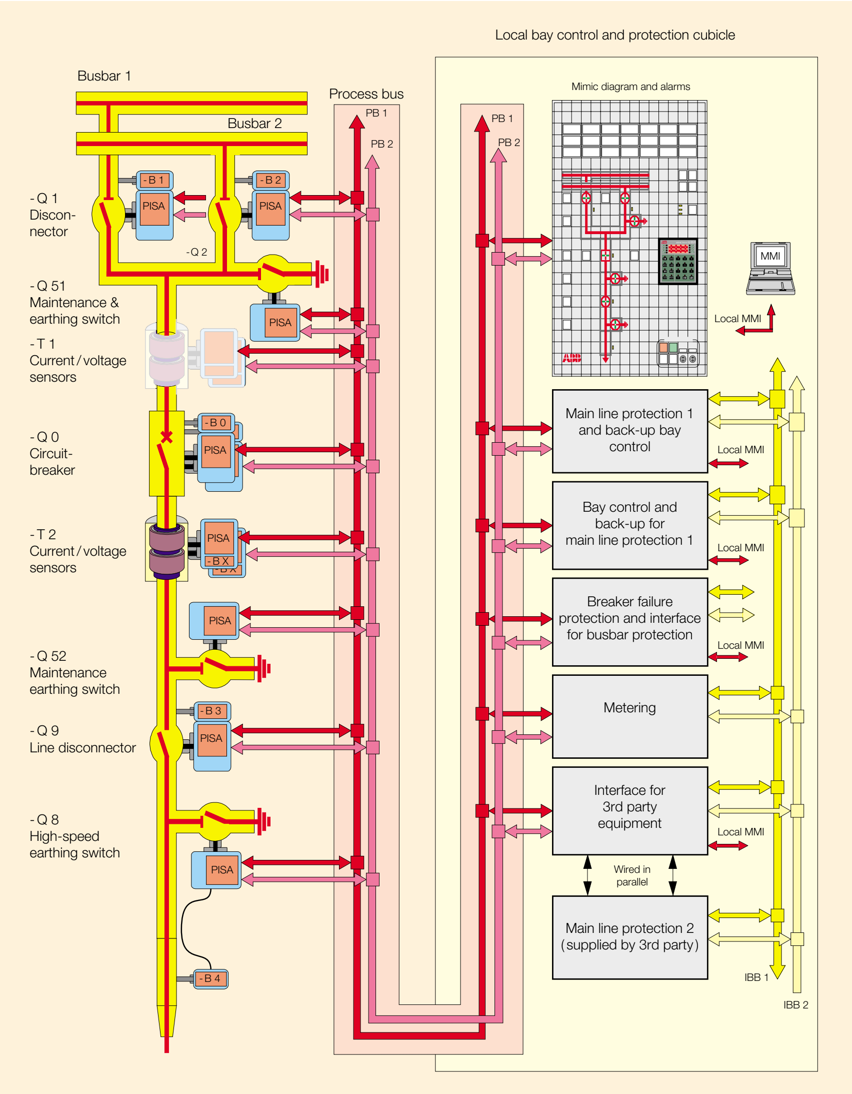
Components at the process and bay level

The intelligent switchbay **3** comprises the following main hardware, software and communication components:

- Sensors and actuators for the conversion of physical changes in the substation into electrical signals (eg, measured values) or vice versa (eg,

Intelligent solution for substation automation **2**





Structure of the intelligent switchbay **3**

control signals). They form the link between the primary equipment in the switchbay and the secondary systems.

- PISAs (Process Interface for Sensors and Actuators). These form the level closest to the process (hereafter referred to as the process level) at which electronic signal processing takes place within the intelligent switchbay. PISAs and their respective sensors and actuators are designed as integral units and are mounted directly on or in the primary equipment.
- The bay level, with a specified number of universally designed electronic units housed in the local control panel. These units handle all the bay-oriented functions, such as power line protection, bay interlocking, bay control, synchrochecking and/or synchronization, bay-sharing of the busbar and circuit-breaker failure protection, intelligent switching, active and reactive power metering, event and disturbance recording, etc.
- Process bus (PB), connecting all the PISAs within a switchbay to each other and to the local control panel. The process bus is the communication medium for all information, such as measured values, trip signals, general control and diagnostic signals, etc, between the process and the bay levels.
- Interbay bus (IBB), interconnecting all the bays at the same voltage level and linking them to the station level.
- A comprehensive software package with all the system database, MMI and application modules required to activate the above components. This software package is installed in its entirety in the running installation.
- Another software package containing all the engineering, calibration, fault-finding and test modules required to define and activate the secondary system functions of the switchbay. This software is not available in its entirety when the systems are up and running.
- An easy-to-use programming and test system (PTS) for installing the above software packages and for the input and simulation of signals during configuration, testing and commissioning.

Demands made on process and interbay bus communication

The process bus and interbay bus are designed to facilitate several modes of communication:

- Continuous, time-deterministic communication of fast-sampled analogue values (eg, current and voltage signals)
- Occasional, but time-deterministic transmission of binary telegrams (eg, interlocking data)
- Occasional, but fast transmission of binary values (eg, trip signals)
- Continuous but non-urgent communication of slow-sampled binary values (eg, monitoring and diagnostic data)
- Occasional, non-urgent, block-oriented communication (eg, disturbance report data or for downloading updated software)

To ensure that signals at the bay level are transmitted in the correct sequence, the process and interbay bus time-stamps all of the system signals. The master clock can be located anywhere in the communication system, but is normally integrated in the station-level computer.

Monitoring and diagnostics in substations

The sensors and actuators can be divided into five groups, according to their importance:

- Sensors for current and voltage measurement
- Actuators for circuit-breakers
- Sensors for gas density measurement
- Actuators for disconnectors and earthing switches
- Sensors for all other physical phenomena, such as arcing, partial discharge, temperatures, changes in lengths, etc

The continuous, uninterrupted functionality of the first three is vital for the operation of an installation. Because of this, at least the electronics of these sensors and actuators should be configured redundantly.

Detailed descriptions of several of the sensors used are given in [1] and [4].

Examples of continuous monitoring functions

Gas density monitoring and leakage diagnostics

Whereas conventional gas density monitors measure only two or three predefined density levels to check for upward or downward deviation, an intelligent gas density sensor is able to measure continuously and precisely the instantaneous gas density. Leaks causing a heavy loss of gas can therefore be identified instantly. Continuous measuring of the gas density and non-stop signalling of the data to the bay and station levels has another advantage: the long-time behaviour of all the gas-tight compartments in a substation can be recorded and displayed. A trend analysis allows the diagnostic software to calculate the last date for refilling with gas, making it easier to schedule substation maintenance.

Partial discharge monitoring and sparkover diagnostics

Research and development laboratories have in recent years devoted a great deal of time and effort to the measurement of partial discharge in gas-insulated substations. Acoustic or electrostatic sensors are the current state of the art. At the customer's request these sensors are integrated in the substation, where they generate huge quantities of data at the bay and station levels. The demands this makes on the communication system depend on the local preprocessing capability, and can quickly grow to several times all the other communication needs of the substation added together. The difficulty here is drawing the right conclusions from the large amount of available recorded data, eg identifying the possible development of a high-voltage sparkover. This has to be predicted with sufficient accuracy to be able to draw up a schedule for taking that part of the substation involved out of service in order to carry out maintenance. Since the various installed systems tend to either under-function or over-function, depending on their parameterization, continuous partial discharge monitoring has not yet managed to generally establish itself. Such monitoring systems are often operated off-line, ie the individual sensor signals are recorded at regular intervals and compared with earlier values.

Arc monitoring and sparkover diagnostics

Another type of sparkover diagnosis involves arc monitoring. Optical sensors continuously check the gas compartments for possible arcs and signal their occurrence to the bay and station levels. As with partial discharge monitoring, the traditional methods have the tendency to either under-function or over-function, so the sensor signals are not re-used direct, eg by the busbar protection system. The diagnostic software allows a kind of post-mortem diagnosis, with the gas compartment in which a sparkover has occurred being identified after the event. With this method it is at least possible to localize the part of the substation which has to be scheduled for maintenance.

The next step will be to refine preprocessing criteria or partial discharge and arc monitoring such that over-functioning and under-functioning are eliminated completely and the results of the monitoring can be integrated directly in the operation of the substation.

Examples of a non-continuous monitoring function

'Path-time' function of the circuit-breaker contacts

4 shows the block diagram of an intelligent circuit-breaker drive mechanism. Two position sensors measure the actual compression of the stored-energy disc spring and rod that operates the primary contacts. In the factory the assembled and tested circuit-breakers are operated several times with different loads and the path-time values measured by the position sensors are permanently and indelibly stored in the PISA. Every time the switch is operated in service the measured path-time values are compared, in each case linked to the load, with these as-built values stored in the product data memory. The actual status of the drive mechanism can be derived from the difference between the two values. Using this status as a basis, the diagnostics software at the station level can determine the date on which the next inspection should take place.

Example of a direct diagnostics function

Quasi-continuous function diagnosis of the drive mechanisms of disconnectors and earthing switches

It is common practice when operating substations to control the power network through operation of just the circuit-breakers, whenever possible keeping the disconnectors closed and the earthing switches open. As a result, the drive mechanisms of the disconnectors and earthing switches can suffer from months of non-use and become damaged. However, the same drive mechanisms are not allowed to under-function when fast changeover from one busbar to another becomes necessary. **5** shows the block diagram of an intelligent disconnect/earthing switch drive. The drive train consists of a controlled electric motor, a gearbox, a rotary transducer at the driving end and a position sensor at the output end. The gear reduction ratio is chosen such that even a small number of revolutions of the motor, although not resulting in any notable change in position of the primary contact, can be detected by the position sensor at the output end. This fact is utilized for diagnostic purposes, for example with the intelligent drive turning the shaft one revolution per week in the positive direction and in the week after in the negative direction of rotation. The values recorded by the two sensors are additionally linked to the measured motor currents to allow diagnosis of the drive and the primary-contact friction. If the drive is activated in the course of an actual switching operation, all the values measured over the full running time are recorded and compared with the indelibly stored product data. The diagnostics software at the station level uses the results to continuously calculate the date for the next inspection.

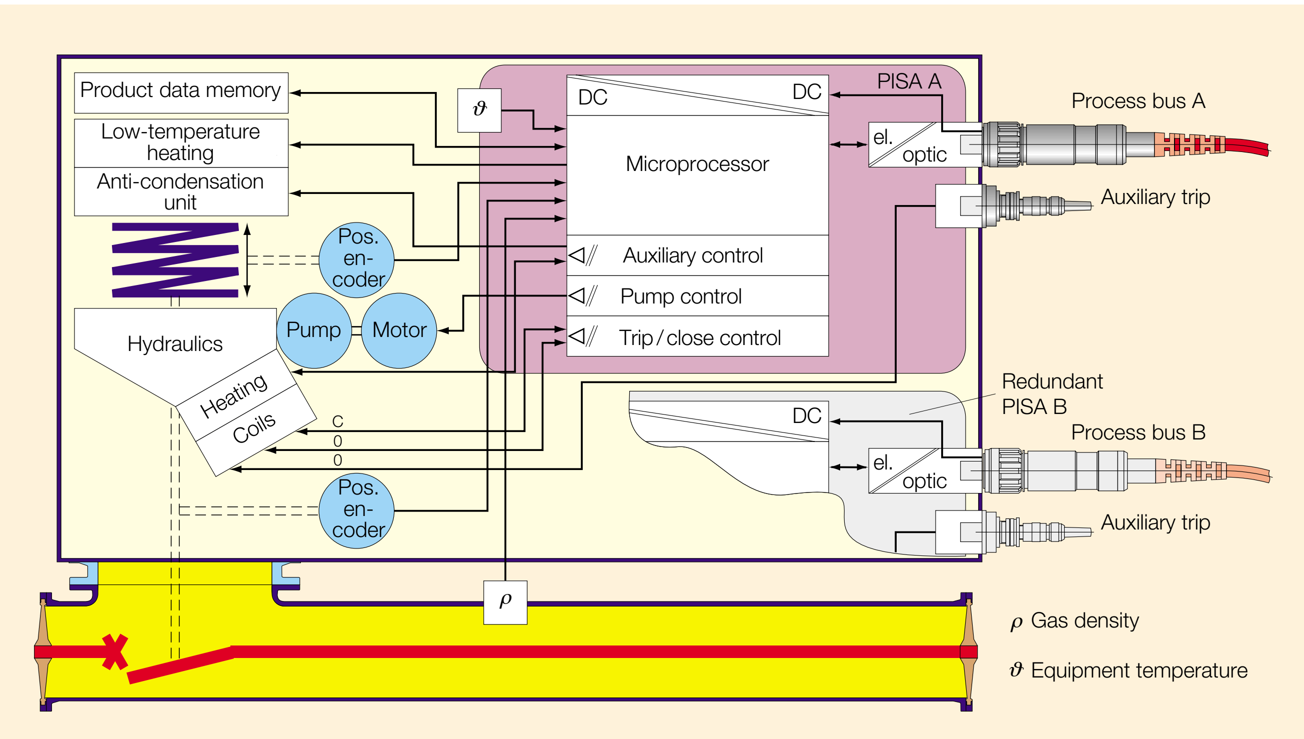
Example of an indirect diagnostics function

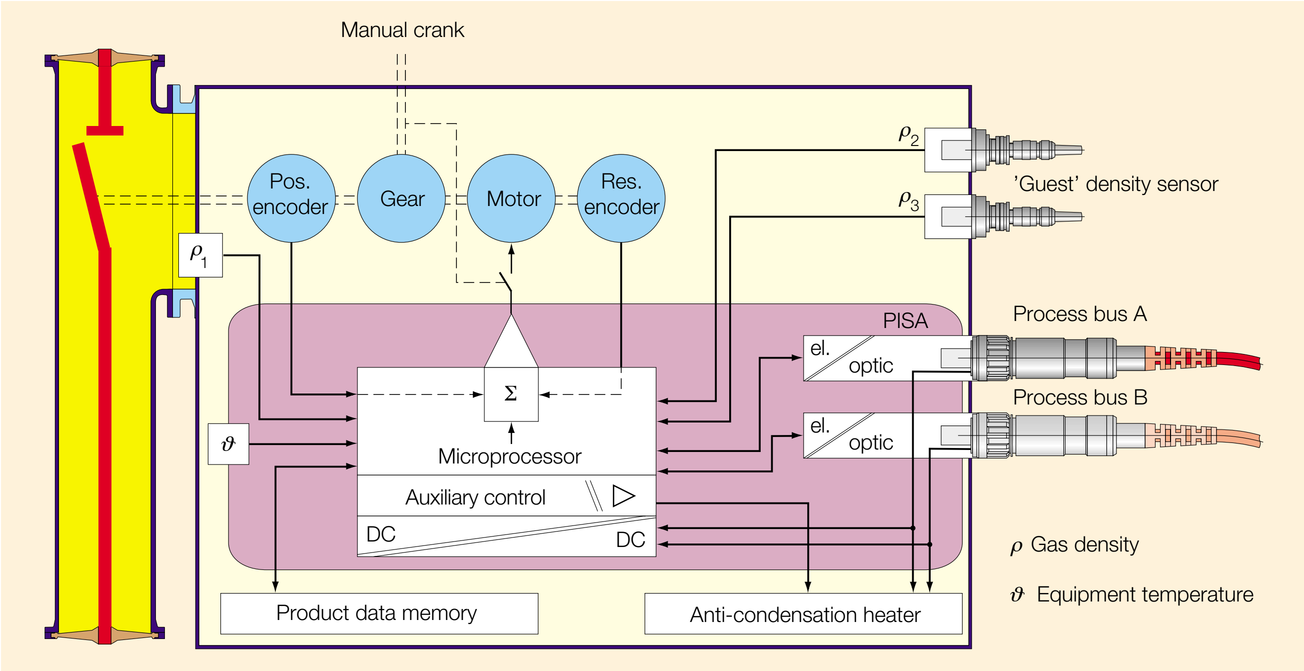
In the example involving the circuit-breaker, it is mentioned that the measured path-time values for the operating rod and disc-spring system can be linked to the actual load involved in switching. This is possible due to all the monitored values related to the drive mechanism as well as the sampled voltage and current values of the U/I sensor being time-stamped with an accuracy better than 25 microseconds. By comparing these instantaneous values with the originally stored characteristics it is possible to calculate the primary-contact erosion. The results of this diagnosis are a prerequisite for continuous updating of the parameter settings used to synchronize closing of the circuit-breaker.

Demands made on monitoring sensors and retrofitting of existing primary equipment

Before work began on the development of the primary hardware for the intelligent switchbay, ABB carried out countless laboratory tests on existing primary equipment to determine the sensitivity

Block diagram of a circuit-breaker drive mechanism **4**





Block diagram of a disconnect/earthing switch drive mechanism **5**

that would be required of the monitoring and diagnostics sensors and functions. These tests showed that:

- To obtain reproducible diagnostic values the primary equipment should be designed from the beginning with the monitoring requirements in mind.
- The diagnostics sensors have to be integrated in the direct chain of action of the primary equipment.
- To obtain useful values for comparison it is essential for the product data representing the original mechanical behaviour of all the primary equipment to be stored and retrievable over the entire lifetime of the apparatus.
- The sensors must be fully integrated in the diagnostics concept. A defective sensor must be clearly distinguishable from defective primary apparatus.
- Sensors for monitoring and diagnostics functions often have to be custom-designed; very little of the series-produced equipment is usable. The sensors have to satisfy the highest reliability and lifetime requirements.

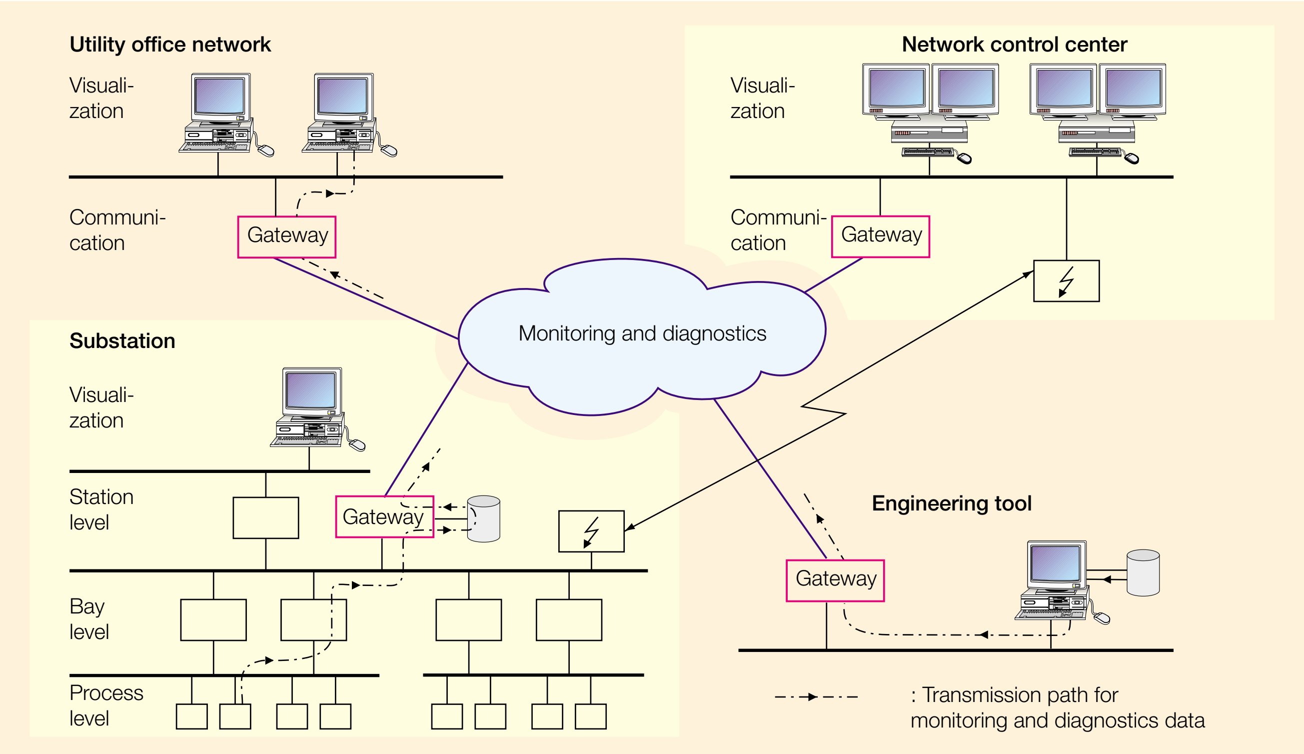
These requirements indicate that retrofitting existing primary equipment with diagnostic sensors is both difficult and cost-intensive. An additional problem is that in most cases the individual as-built mechanical values for the primary equipment are missing. For a retrofit project, the primary goal must be to plan and then implement a diagnostics concept tailored exactly to the substation in question. Substation operators having many years of experience with their switchgear and in possession of disturbance, inspection and maintenance reports, can provide valuable information, and may be able to draw up their own customized diagnostics concept. With a professionally designed and built diagnostics system in place, it is possible to predict more accurately the lifetime of existing substation components and/or increase the lifetime in order to shorten the pay-back time for the retrofit.

Monitoring and diagnostics interconnections in the substation and network

In addition to the necessity of conditioning and, when necessary, storing the values collected in a substation it is equally imprtant to make these values available to a large number of users in a convenient and easily retrievable form.

6 shows an overview of such a system. The values collected in the substation are transmitted to the monitoring and diagnostics network via a coupler, which conditions and stores them as necessary. The data can be accessed via the monitoring and diagnostics network, which also makes the configuration data used for substation planning and commissioning available for comparisons. Access to the network can be local, by means of switched modems, or direct, eg from the in-house network of a electric utility.

As shown in **6**, the monitoring and diagnostics network is clearly segregated from the command and control network. While this network can be



Monitoring and diagnostics in interconnected substation and network configurations **6**

used to request information, it is not possible to use it for control purposes. The segregation ensures that operations management is kept apart in every respect from monitoring and maintenance. What is more, the two communication networks make completely different demands on reliability and availability.

Benefits of intelligent substation automation

Intelligent substation automation permits new functions such as 'intelligent switching' at the bay level. Although these functions have nothing to do with the fundamental operation of the substation they allow, with the help of smart algorithms, both the space requirement and the cost of the primary components in the switchbay to be reduced.

The new components at the process level further allow, for the first time, uninterrupted monitoring of a wide range of signals. Thus, a continuous and comprehensive diagnosis of the primary equipment, including the sensors and actuators, is possible over its entire service life.

This local process diagnostics facility is complemented by powerful software packages at the bay and station levels which process the results of the station-wide monitoring and provide detailed diagnostic information based on a comparison with the product data and planning values. Maintenance work can therefore be scheduled to suit and carried out as it becomes necessary instead of routinely. This has benefits that include reduced overall lifetime costs for the substation.

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