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System Control in Light of Recent Developments in Substation Control

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Recent Developments in Substation Control

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1. Introduction

This paper consists of two parts. Part one is an overview of substation control systems and communication standards while the second half of the paper reviews the impact of these technologies on system operation.

2. Technology Overview

2.1 SCS

After more than 20 years of development, digital protection and substation control have reached a mature product state. In the mean time, some 100,000 digital relays and some 1000 digital substation control systems are in service.

Global products designed for the world market meet relevant IEC as well as ANSI/IEEE standard requirements and can be adapted to the communication standards used in Europe and USA. The information interface of relays can for example be delivered in IEC60870-5-103 as well as in DNP3.0 or IEC 61850.

Modern substation control systems are able to communicate with IEDs and RTUs from the major vendors in standardised and open protocols. Windows compatible PC programs allow comfortable local or remote operation of IEDs and the connected processes. With the new communication standards in place an abundance of data is available to the operators in real time.

2.2 IEC standards

Among recent IEC standards that support data exchange in utilities, we can distinguish two groups.

The **first group** comprises standards that specify ***communication (network) protocols***, specific to the electrical power industry:

- IEC 60870-6-503, -505, -702, -802, also known as ICCP (Inter Control Centre Protocol) or TASE.2, is a telecontrol protocol for communications among control centres.
- IEC 60870-5-101/104 is a telecontrol protocol for communications between control centres and substations.
- IEC 61850 is a communication protocol initially designed for the communications within a single substation, now being extended to allow for communications among substations, as well as between control centres and substations.

Some parts of these standards specify also reduced communication stack profiles, which are sometimes necessary for performance reasons (e.g., so called GOOSE communications in IEC 61850, for protection tripping). What is common to these standards is:

- The network protocols are specific to the utility industry.
- The protocols provide binary (on-the-wire) specification of bits and bytes, even if they define underlying information/data models – these latter are implicit and have to be binary encoded/decoded by higher level applications on both sending and receiving ends, respectively.

The **second group** comprises standards that specify ***information models***, specific to the electrical power industry:

- IEC 61970 specifies the information (data) model and the application programming interfaces (APIs) that allow applications or systems to exchange the instances of that model. The information model is called Common Information Model (CIM) and covers the domain of EMS/SCADA applications.
- IEC 61968 extends the CIM with specifics of the DMS, metering and distribution networks, as well as information models that cover data exchange within the whole utility organisation. In that direction, the standard also specifies a number of message types that can be exchanged among different IT systems within the organisation, not only those related to electrical network.

What is common to these standards is:

- CIM, as an object model, provides the definition of real world objects and concepts in support of EMS or DMS applications (such as power flow, topology processing or network colouring) and for data exchange with other enterprise-wide systems (such as customer billing and work and outage management).
- None of these standards define any communications (network) protocol. They only define APIs or message formats that can be exchanged over any underlying transport mechanism. These can range from IT industry standard protocols (FTP, HTTP, SOAP), to standard or widely used software component-based frameworks that implement their own transport mechanisms (enterprise java JMS, .NET remoting, CORBA IIOP), to proprietary ones.

One use case for CIM-based data exchange is to exchange network model data files (i.e., power flow solution, similar to what an IEEE format data files support, but much more extended). This data exchange can take place over any communication protocol as the format is based on XML.

Another use case for CIM-based data exchange is to publish and subscribe to messages of different kinds that are available at the enterprise-wide messaging bus, or to send and receive messages among disparate utility IT applications in a point-to-point manner. The content (payload) of these messages is also encoded in XML, and based on the semantics defined by CIM.

The International standard IEC 61400-25 (Communications for monitoring and control of wind power plants, TC 88) provides uniform information exchange for monitoring and control of wind power plants. This addresses the issue of proprietary communication systems utilizing a wide variety of protocols, labels, semantics, etc., thus enabling one to exchange information with different wind power plants independently of a vendor.

The IEC 61400-25 standard is a basis for simplifying the roles that the wind turbine and SCADA systems have to play. The crucial part of the wind power plant information, information exchange methods, and communication stacks are standardized. They build a basis to which procurement specifications and contracts could easily refer.

The standard is expected to work with IEC 61850 standards and presently uses communication service mapping to MMS as per IEC 61850-8 standards. The communication service mapping to OPC DA and Web services are also considered for the future.

The system operations aspects of controlling wind farms are discussed in the second section of this paper.

3. Impact of New SCS Technology on the EMS and System Operation

This section of the paper addresses the impact of SCS technology on the EMS and on system operation.

3.1 EMS

3.1.1 Communications and Telemetry

The increasing volume of measurement data available to the SCS at a substation is not accessible to the control center EMS because the present communications system usually cannot handle it. Instead, only a subset of the substation data is selected for transmission to the EMS which is then polled by the control center. For this reason, the phasor measurements taken at a substation, with typical rates of 30 or 60 samples per second, are gathered together in phasor data concentrators (PDC) through alternate communication channels (usually high bandwidth leased lines) rather than the communication channels used today between the SCADA and the RTUs.

As the number of synchrophasor measurements at substations increase, it is clear that high bandwidth channels will be needed for all communication. Moreover, the present practice of gathering all the data into one location is neither feasible nor desirable.

Thus a high bandwidth network of communication channels connecting all the substation gateway servers will be needed to move the required data to wherever they are needed. Such a communications configuration is shown in the following figure:

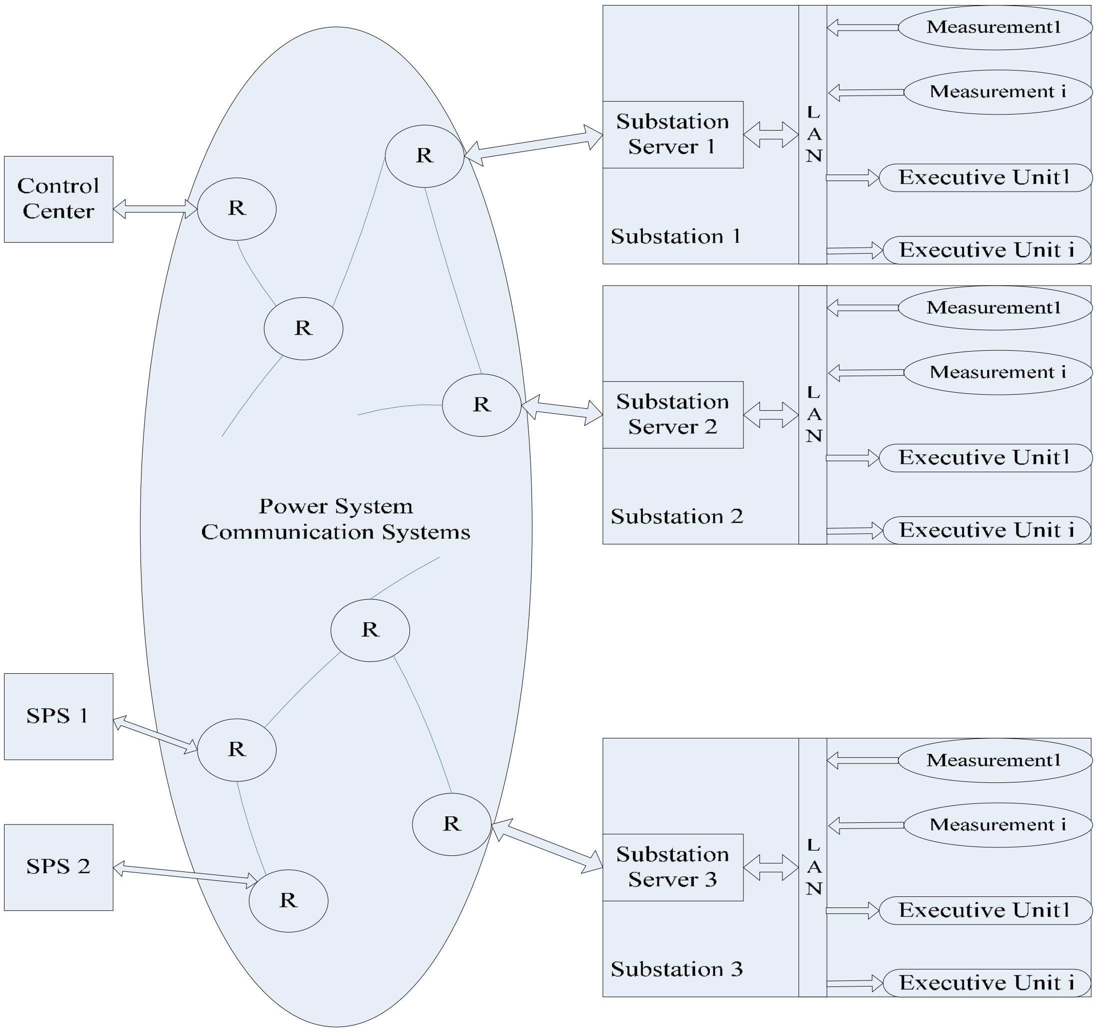


Figure 1: A Networked High-Bandwidth Communication Configuration for the Power System {***R**: Router; **SPS**: Special Protection Scheme; **Executive Unit** is equivalent to an Intelligent Electronic Device (IED)*}

In this figure the internal substation communication for the SCS is shown as a simple LAN connected to one substation server although a large substation could have several communications switching devices. The substation servers are shown as the gateways to the outside world and these can be networked by communications switches so that data can be moved from individual substations to where they are needed for real time control and operations. It should be pointed out that communications protocols external to the substations have not been explicitly developed but in exceptional circumstances the IEC 61850 protocol is already being utilized for inter station communications.

The management of such a wide area communications system will require significant development of middleware. ***Middleware is computer software that connects software***

components or applications. Although some conceptual and experimental systems have been developed and some specification efforts are underway, large scale implementation is still absent. Given that such a communication system will span interconnected grids across many jurisdictions, the acceptance of best practices and standards will be crucial.

3.1.2 Data Modelling and Management

The present practice is to gather all the substation measurements available through the RTUs or SCSs in a Real Time Data Base at the control center SCADA. However, the volume of real time data gathered today at many substations by the SCS is already much larger than that which can be collected by the RTUs. Thus, a lot of the measured data at the substations are only accumulated/stored at the substations and only collected and used for later analysis. This trend will continue as long as we continue to increase the measurement sampling at the substations, especially phasor measurements, without increasing the communications infrastructure (mentioned above) to move this data.

Of course, it may not be necessary to send all the substation data to the control center. For example, even if currents and voltages are sampled at 30-60 times a second at the substation, the updating of MW and Mvar values for the operator displays can be done at a slower rate. Also, with the increasing computational capabilities at the substations, many of the functions done at the control center today can actually be done at the substation itself. For example, limit checking for alarms can be done at the higher sampling rates at the substation and sent to the control center SCADA on exception.

This distributed capability may mean that the Real Time Data Base is no longer centralized at the control center but could be distributed between the substations and the applications (SCADA, EMS, SIPS (***System Integration Protection Scheme***), etc). This also implies that the Static Data Base at the control center – this data consists of the connectivity, displays, circuit parameters, etc used in all the application calculations – could to be distributed depending on where the calculations are done. The Historical Data Base – the collection of the Real Time Data Base over time – would then naturally end up distributed in the same way the real time data is distributed. The distributed capability as described above has yet to be addressed by the commercial EMS vendors.

Such a distributed data base is conceptually more complex than the centralized data base used in the control centers today. As mentioned before, the CIM provides a standard model for the data but its instantiation is usually a proprietary data base. Any distributed data base design must then require some higher level of standardization. Also, the software needed to manage such a distributed data base will, like the communications middleware mentioned in the previous section, have to be developed and adopted as a best practice or standard.

Apart from the issues of voluminous data movement and data storage that argues for a distributed data base, there are some major advantages in distributing the applications instead of concentrating all in the control center. The limit checking at the substation source has been mentioned before but there are many more. For example, bad data detection/identification and topology processing is now carried out in the EMS state estimator whereas a much more efficient bad data detection/identification and topology processing can be done at the substation. Thus the coordination of the SCS functions with the control center functions can result in much better accuracy and efficiency of the control center applications

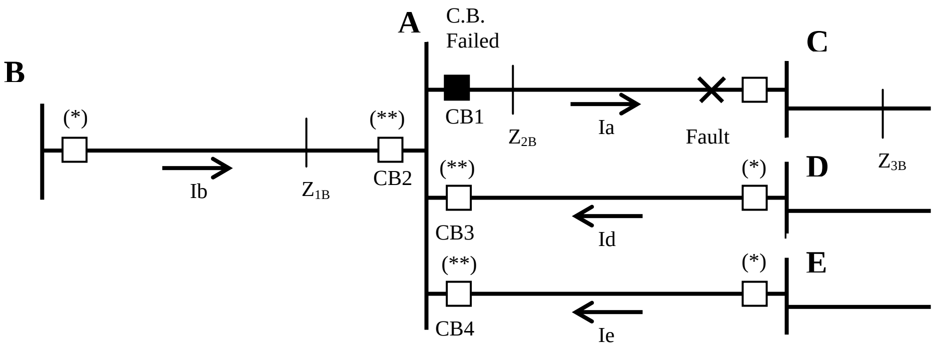
3.2 System Operation

This section of the paper discusses protection operation, asset management and wind farm operation and management. The protection operation section concentrates on the management and operation of Zone 3 step-distance protection and remedial action schemes.

3.2.1 Protection Operation

3.2.1.1 Managing Zone 3 Impedance Protection [9]

Zone 3 of step-distance protection is used as backup protection for adjacent lines, protecting against possible failures of fault clearance by local systems due to mal-operation of relays, circuit breakers, etc. Taking the example in Figure 2, a failure on circuit breaker 1 (CB1) at substation A, (this substation is not equipped with Breaker Failure Protection), the fault on line AC is cleared by Zone 3 of step-distance protections at substations B to E, or by reverse Zone 3 of step-distance protections at A.



Caption:
(*) – Circuit breaker tripped by Zone 3 of step-distance relays.
(**) - Circuit breaker tripped by reverse Zone 3 of step-distance relays.

Figure 2 – Example of a fault at line AC with a simultaneous operation failure on circuit breaker 1 (CB1)

The Zone 3 settings, in particular their reach setting is a complex problem, due to possible high load conditions, which can cause unwanted Zone 3 tripping of step-distance relays, which will have a negative impact on the power system.

The timer associated to Zone 3 is coordinated with timers of Zone 2 on the adjacent lines. Taking the relay at substation B of Figure 2 as an example, typical settings for its step-distance protection are the following:

- Zone 1 (Z_{1B}):
    - Reach setting: 80% of the impedance of line AB;
    - Timer setting: 0 seconds;

- Zone 2 (Z_{2B}):
    - Reach setting: 120% of the impedance of line AB
    - Timer setting: 300 to 500 milliseconds;

- Zone 3 (Z_{3B}):
    - Reach setting:
      $Z_{3B} = Z_{ab} + 1.2\, Z_{bc}\, [1 + (Id + Ie)/Ib] = Zab + 3.6\, Zbc$, considering similar contributions to the fault from all lines connected at A;
    - Timer setting: 1.5 to 1.8 seconds;

The decision to implement Zone 3 is an issue which is more complex than its actual settings and is not within the scope of this study. Although, once actual protection systems are based on computer relays with communication facilities, as described in Figure 3, cooperation between remote SCADA and local protection systems can be explored in order to mitigate the probability of Zone 3 mal-operation under high load conditions.

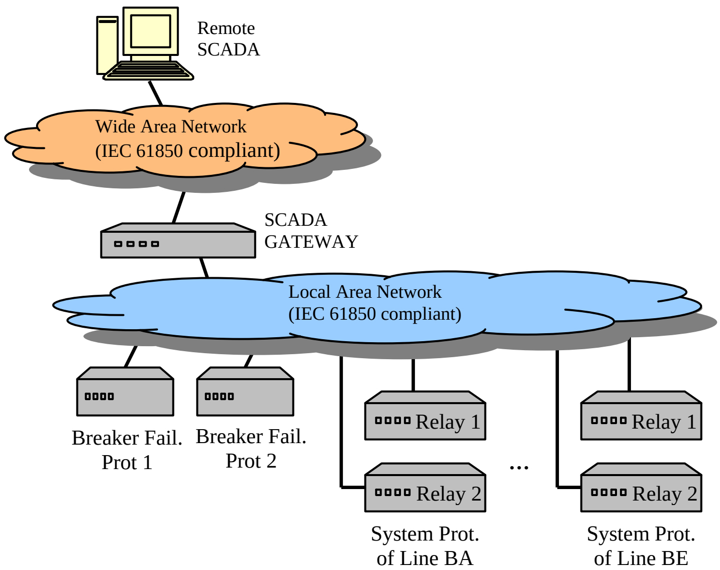


Figure 3 – Communication diagram example of substation automation system, installed on Substation B, including SCADA connection.

Zone 3 Dynamically Blocking Scheme

Consider the one line diagram of Figure 2, but suppose that substation A is equipped with equipment which can mitigate the probability of non-fault clearance on any of its lines by the actuation of their protection systems and circuit breakers. In this case, the equipment installed at substation A would probably be the following:

1. Two independent batteries
2. Line protection relays in a redundant scheme
3. Circuit breakers with redundant trip coils
4. Double breaker failure protection
5. Duplicated current transformers or, at least, a current transformer with redundant secondary windings
6. Duplicated voltage transformers or, at least, a voltage transformer with separate secondary circuits

In the conditions described above, it is not difficult to assume the deactivation of Zone 3 at substations B to E and the reverse Zone 3 at B, eliminating the risk of undesirable trips under high load conditions. Although, this assumption would not be acceptable for equipment failures in substation A, since the protection system redundancy is not adequate to guarantee secure fault clearance on the lines connected to this substation. To define the correct level of redundancy several failure modes should be considered and analysed in detail. In these circumstances backup Zone 3 at substations B to E and reverse Zone 3 at A should be unblocked preferably automatically. Since actual protection systems do have communication interfaces and SCADA is available at the remote control centre, cooperation between protection relays within substation A and between protection relays at substations A to E using SCADA, can be established to implement a dynamic scheme to block Zone 3 on step-distance protections.

The implementation of Zone 3 dynamic blocking scheme must consider that the actions of blocking and unblocking Zone 3 are not instantly taken by protection relays. In fact, the example of the occurrence of a failure or a block condition on Breaker Failure Protection at substation A, which can then unblock Zone 3 on step-distance protections at B to E, and the reverse Zone 3 at A, will need some time to take effect. The following delays must be taken in to consideration:

1. For substations B to E:
    a. Time for Breaker Failure Protection to declare its one failure or block condition
    b. Time for SCADA to detect the failure or block condition on Breaker Failure Protection, to process this information and send Zone 3 unblocking controls to protection relays
    c. Time for protection relays to assume Zone 3 unblocking control

2. For substation A:
    a. Time for Breaker failure protection to declare its one failure or block condition
    b. Time for relays to detect the failure or block condition on Breaker Failure Protection

c. Time for protection relays to assume the reverse Zone 3 unblocking status

The delays mentioned above depend of several issues such as (i) the type or manufacturer for each one of the installed protection relays, (ii) the type of failure occurrence detected by the breaker failure protection (iii) the communication infrastructure between the protection relays inside the substation (Local Area Network), (iv) the speed and type of communication between SCADA and substations and (v) the SCADA speed performance, for which it is difficult to define precise values. Although, for the communication between SCADA and relays, a value in the order of seconds can be expected, whereas for the communication between relays, considering a IEC 61850 compliant substation automation system, the delay is expected to be less than one second. This and other aspects, such as the overall system reliability, must be taken into consideration in order to establish the correct implementation criteria for Zone 3 dynamic blocking scheme.

For the one line diagram of Figure 2, assuming the equipment installed in substation A, is as described above, Table 1 provides an example of the criteria that can be established to unblock Zone 3 on step-distance relays as a function of the identified failure modes. For this example it is assumed an IEC 61850 communication platform inside and outside substation A, which means each protection unit can establish its one communication link with remote SCADA. An IEC 61850 platform can contribute to the engineering simplification by facilitating the integration of SCADA and substation data models and speed up the overall system reaction (protocol translation on gateway level is not needed) but is not mandatory for such cooperation between SCADA and protection systems. Therefore, other standards such as IEC 60850-5-101 or IEC 60850-5-104 can be used.

Failure Modes Description at Substation A	**Dynamic Blocking Scheme Reaction**
Communication link failure between at least one of the step-distance protection relays at Substation A and remote SCADA	Unblock Zone 3 on step-distance relays at substations B to E
Communication link failure between at least one of the Breaker Failure protection relays and remote SCADA	
Failure detection on trip circuits at one or more circuit breakers	No action is taken (assuming Breaker Failure Protection can eliminate the fault)
Failure detection in a secondary winding of a current transformer by at least one of the step-distance protections, which inhibit the relay detecting a fault	Unblock Zone 3 on step-distance relays at substations B to E Unblock reverse Zone 3 on step-distance relays at substation A
Fuse failure detection by at least one of the step-distance protections, which inhibit the relay detecting a fault	
Step-distance relay internal failure on at least one of the lines, which inhibit relay operation	
At least one of the Breaker Failure protection relays	

declare an internal failure or block condition, which inhibit relay operation	
Communication link failure between at least one of the Breaker Failure Protection schemes and one of the step-distance protection relays at Substation A	Unblock reverse Zone 3 on that step-distance protection relay
Failure Modes Description at Substations B to E	**Dynamic Blocking Scheme Reaction**
Communication link failure between one of the step-distance relays and remote SCADA	Unblock Zone 3 on that step-distance protection relay

Table 1 – Failure modes identification and Dynamic Blocking Scheme Reactions

3.2.1.2 Remedial Action Schemes (RAS)

Typically remedial action schemes are used to reduce line loadings by tripping load or by reducing a generator's output. Load shedding for low voltage and low frequency are not usually counted as remedial action schemes.

If you use SCS for special protection (SPS) or remedial action schemes, then it must follow the four main design criteria which apply to protection schemes, namely:

- Dependability – The certainty that the SPS operates when required, that is, in all cases where emergency controls are required to avoid a collapse.
- Security – The certainty that the SPS will not operate when not required, does not apply emergency controls unless they are necessary to avoid a collapse.
- Selectivity – The ability to select the correct and minimum amount action to perform the intended function, that is, to avoid using disruptive controls such as load shedding if they are not necessary to avoid a collapse.
- Robustness – The ability of the SPS to provide dependability, security and selectivity over the full range of dynamic and steady state operating conditions that it will encounter.

3.2.2 Asset Management

Asset management: e.g. monitoring transformer and cable loadings in order to calculate overload capabilities; monitoring transformer temperatures; monitoring alarms for GIS equipment; monitor weather conditions to perform dynamic line rating calculations;

The SCS provides the system operator with the following equipment monitoring capabilities:

- Switching statistics
- Transformer loadings
- Other transformer data including oil and core temperatures
- Cable loadings
- Line loadings

It is possible to perform these tasks at present with the EMS but all of the data has to be stored centrally. Having these data available locally allows both station operations staff and the control centre operators to make informed decisions on plant operation.

Simple applications for the SCS would include operations counters for circuit breakers and tap changers. Typically these data are not available in the control centre but the SCS makes this data available to the control centre or a transmission maintenance centre.

Management of cable loadings post fault is a more complex application of the SCS. Typically cable loadings post fault, are predicated by the pre-fault loading. The SCS continuously monitors all plant in the station it controls so it is a very simple task for the SCS to continuously report, say, on the cable loading for one hour prior to the fault. This will allow the system operator or possibly even the SCS calculate the level of overload the cable can accept post fault.

A more advanced application may involve the use of two SCSs at both ends of a feeder monitoring wind direction and speed together with temperature to calculate the current carrying capacity of the feeder. This data could then be transmitted to the EMS where the feeder rating would be used in power flow and contingency analysis.

3.2.3 Operation and Management of Wind Farms

3.2.3.1 Background

With the increased quantity of wind farms within conventional utility systems, the subject of integration of wind farms into power networks is gaining importance. The utility grids with relatively small amounts of wind farms do not face any large operational problems or difficulties maintaining the reliability and the quality of supply. However, when substantial amount of wind power is connected to a conventional utility system, significant operational problems could appear in the grid.

Wind turbines can affect networks in many ways. One of these can be a reduction in customers' power quality. Network operators must limit or eliminate impacts such as these. The main issues to be considered are voltage step changes, voltage flicker, harmonic distortion, and voltage imbalance [5]. Furthermore, sudden changes in wind power production (i.e. during storms and subsequent shutting down of turbines) can affect the stability of the overall grid.

3.2.3.2 Description of Controlling System of Wind Plant

In order for a utility to achieve full control of a wind farm, it is essential to have the necessary information from all the parts of the wind farm. Therefore, the function of each component of the control system needs to be fully understood. The control system consists of the elements described below.

3.2.3.2.1 Wind Turbine Control Panel

The wind turbine controller panel (WTCP) contain all equipment which is required for constantly monitoring the condition of wind turbine and collecting statistics on its operation. The controller is typically located both at the bottom of the tower and in the nacelle. It consists of a number of computers which provides control of a large number of components including switches, hydraulic pumps, valves, and motors. To maintain a full control and monitoring a substantial amount of data needs to be constantly transmitted via communication links. Those links could be copper wire or fibre optic. To achieve optimum performance of the wind turbine, and detect potential failures the control panel is monitoring networking components through closed-loop control.

3.2.3.2.2 SCADA System [4]

Although the wind farm SCADA system characteristics are dependent on the type of wind turbine, as well as from SCADA system supplier, the basic characteristics are standard and they include remote control to start and stop the wind turbines and to reset them after a trip. The wind turbines should run independently of the SCADA system.

The parameters which are available for each wind turbine are wind speed, power output and generator status. In addition some statistical and event information about the individual machines and the wind farm are also stored by the SCADA system. The SCADA system can access the operating parameters at each machine and change these as required. As wind farm developers start to operate several wind farms, potentially with different wind turbines at each wind farm, there will be a requirement for SCADA systems to provide common interface and reports for different machines.

Offshore application have furthermore the requirement that the SCADA system might not only be controlling the wind farm itself, but it is usually designed to control the turbines and the MV substation as an integrated system, thus allowing the operator to run the wind farm as a whole, somewhat like a virtual power plant.

3.2.3.2.3 International Standard 61400-25

The IEC 61400-25 standard has been developed in order to provide a uniform communications basis for the monitoring and control of wind power plants. It defines wind power plant specific information, the mechanisms for information exchange and the mapping to communication protocols. [8] It could be considered as a basis for simplifying exchange of data between SCADA systems and wind farms. This standard allows vendor-independent data access to and control of the wind farm via remote links, but also for additional equipment in the wind farm itself. This provides the SCADA system with the ability to communicate with wind turbine controllers from multiple vendors. The wind power plant specific information describes the crucial and common process and configuration information. The information is hierarchically structured and covers for example common information found in the rotor, generator, converter and grid connection. From a utility perspective, unified definitions of common data minimize conversion and re-calculation of data values for evaluation and comparison of wind farm data.

3.2.3.2.4 Typical Architecture of Controlling System

The wind turbines would be comprehensively monitored, providing information for closed-loop control, alarm and sequencing. Each turbine has its own controller (Wind Turbine Control Panel, WTCP) which is located in the tower base and operates independently. Typically, the control system also provides a local communications link via a local terminal and a remote communications link for connection to a SCADA system [3]. Some European countries regulations require wind farm operators to be connected to a national control center SCADA EMS (Energy Management System). The SCADA EMS would then be able to control the output of the wind farm thus controlling the power feeding into the grid.

Overall control of the wind farm is achieved through a central SCADA system, with each turbine connected to the SCADA system through communications lines. The SCADA system allows for remote control and monitoring of individual turbines and the wind farm as a whole from both the central host computer or from a remote control personal computer. The SCADA system enables full communication with the operator, manufacturer and maintenance crew. [3]

An alternative configuration is to have all wind turbines communicating with a general wind farm controller and one communication link between the wind farm controller and the SCADA system. The location of the SCADA system is application-specific. It may be installed at the substation control house or in the O&M building.

3.2.3.3 Affect of wind power plants on the grid

Wind farms can affect the grid in different ways. The main aspects for consideration are as follows:

Voltage control and reactive power compensation
The main challenge related to voltage control is to maintain acceptable steady-state voltage levels and voltage profiles in all operating conditions, ranging from minimum load and maximum wind power production to maximum load and zero wind power.

The control of reactive power and terminal voltage can be achieved by power electronic controllers which are installed in modern wind turbines. After the generators themselves, capacitor banks and transformer tap changers represent the most common means to control voltage profiles. One of the possibilities which provide the benefits for both grid and wind power plants is the use of Static Var Compensators (SVC) and STATCOMs.

Voltage stability
Disturbances in the grid could cause the reactive power shortage at the wind power plant. A further consequence of the inability of the power system to supply reactive power is voltage instability or collapse. Conventional generation can be controlled to produce or consume reactive power almost at will and at little cost. This feature is used to control voltages at points on the system. If conventional generation is displaced, wind must fulfil the same function. This is not currently possible with most wind turbines, but some manufacturers offer such a facility and more are expected to follow. The costs for this function are expected to be minor for variable speed wind turbines and more expensive for fixed speed turbines. [5] Voltage stability by fast control of reactive compensation constraints could be also provided through the use of external compensators (SVCs and STATCOMs)

Transient and dynamic stability ("fault ride-through")
Wind farms should not be disconnected from the grid in the event of system transient disturbances. As wind penetration increases due to less synchronous generators being coupled directly to the grid, the inertia of the power system is decreased. Therefore, it is increasingly important that wind generation continues to operate during transient system disturbances. It is usually necessary to demonstrate that this is possible to the network operator before any such event occurs, which is done by using simulation models. Some simulation results indicate that with new equipment designs and proper plant engineering, system stability in response to a major plant or line outage can actually be improved by the addition of wind generation.[5] Such models are being developed for wind turbines but there is considerable difficulty in understanding, developing and validating these models. This is currently a research area.

Transmission capacity and efficiency
The impact of wind power on the power transmission depends on the location of wind power plants relative to the load, and the correlation between wind power production and load consumption. Transmission capacity problems associated with wind power integration may typically be of concern for only a small fraction of the total operating time. Nevertheless with an increasing installation of offshore capacity this problem will get more severe in the near future.

Network investments can be avoided or postponed by several means. Applying control systems that limit the wind power generation during critical hours is one possible solution. Alternatively, if other controllable power plants are available within the congested area, coordinated automatic generation control (AGC) may be applied. Demand side management that is controlled according to the wind and transmission situation is another option. The latter two may be more beneficial than limitation of wind power as energy dissipation is avoided. Despite application of wind generation controllability and DSM, grid expansion and/or capacity reinforcement may become necessary not only in cases of very high wind penetration but also when it is necessary to extend the grid to areas to connect proven wind resources.

4. Conclusions

Substation control systems offer the system operator a new range of system control capabilities. Reliable implementation of new schemes is demanding but the increased information and control possibilities appear to be worth the effort. This paper has discussed a number these possibilities and provided a comprehensive background on the developments in these areas.

In the case of wind power, increasing the capacity of wind generation connected to grid and increasing the size of wind turbine generators needs further development in SCADA / EMS systems and standardized protocols for communications and interfaces between the wind power plants and the power system.

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