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THE IMPACT OF NEW FUNCTIONALITIES ON SUBSTATION DESIGN

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EXECUTIVE SUMMARY

This brochure provides guidelines on the technical issues and challenges of introducing new technology into the substation environment. The brochure is set out to provide a general overview of the issues in the main body of the document and fine detail for the specialist in the appendices.

The task force has collated a broad spectrum of technologies and this document provides a guide to assist the developer in implementing which ever solution meets the various challenges facing their transmission or distribution network. The brochure is not intended as a problem solver for system issues, but as a guide to some of the practicalities and problems to be faced when installing the solution. While system aspects of new functionalities and their technical details have been broadly investigated in other texts, this brochure aims to fill the knowledge gap relating to installing the application into the substation environment.

One of the factors holding back the implementation of new technology is the lack of experience or confidence in new or different equipment, in addition is the risk of the actual installation and impacts on the existing substation operation. The brochure attempts to address this issue by compiling a source of advice, experience and recommendations from users who have already implemented the technology. The document concentrates on the impact on the design and construction of substations. In some cases, this may fundamentally affect the basic concept of the design and construction of the substation.

The drivers behind the changes forcing substation development are briefly described along with some of the resolutions to these challenges, but the brochure concentrates on the direct impact on the substation itself. Based on an industry wide survey 12 Technology areas are presented highlighting the technologies under consideration and the key impacts which need to be considered. While there maybe some greying of the boundaries, these can essentially be grouped into:

- Power Electronic applications (FACTS devices, Custom Power, HVDC)
- Switchgear (mixed technology switchgear, compact, non conventional instrument transformers)
- Reactive Compensation
- Distributed generation (integrating windfarms)
- Substation automation (protection, diagnostics and condition monitoring).
- Increasing capacity and active power control (GIL, phase shifting transformers and superconductivity).

The bulk content of this brochure is contained in the appendices which are specific to particular functionalities. Each appendix describes specific design aspects, which are likely to be affected and some guidance on how the problem has been dealt with previously.

Some of the key observations during the review which should be taken into consideration include:

- Do not underestimate the additional cost and complexity of interfacing between new and legacy technology, particularly for secondary systems.
- There is an economic trade off between capital and operational expenditure to minimise outage duration during construction, commissioning and maintenance.
- To accrue the real benefits of new technology, adopting different substation practices and maintenance regimes may be required.
- An Information System strategy which can manage substation data, security, access and software upgrading. The pace of change in the telecommunications and microprocessor industry is such that secondary systems can become technology obsolescent sooner than expected.
- Suitability of the existing substation design. Some technologies require a paradigm shift in a utilities approach to substation development
- Utilities should only consider new technology where they can accrue real benefits. New technology should be introduced in a controlled manner.

1 Introduction

“The devil is in the detail”

The brochure covers a scope of challenges facing substations in the future, the range of new functionalities and technologies available and their impact on substation design, construction and operation. The intention is also to help manufacturers of new functionalities, solution providers and utilities to properly define physical interfaces and application guidelines to enable successful integration into a substation.

It is expected that the brochure will be useful to:

- Technical Working Groups to update, if necessary, any related standards, e.g. design/construction principles of substations.
- Substation designers to optimise their concepts and processes e.g. layout, dimensioning and analysis to new functionalities and technologies.

This chapter discusses the challenges facing substations into the future, while chapter 2 discusses the technology survey and its format. Chapter 3 discusses the different technologies in greater detail and their key features and impact on the substation, essentially this summarises the content of the appendices. Chapter 4 and 5 draws out some general observations and conclusions on the substation design at system, single line and bay level. The bulk of the information is held in the 12 appendices which go into specific detail on each technology.

1.1 Pressures on substation design

Substation design [1] aims to provide a cost effective solution, which as far as reasonably practicable demonstrates high availability, reliability and operational flexibility. From the utility perspective this requirement applies to both brand new as well as 30-year-old substations. Whilst this is achievable, it comes at a cost. This section highlights the challenges for operational substations now and into the future.

The power industry is experiencing unprecedented changes, and as a result has to respond in much shorter timescales than it may be used to. The external influences such as climate change, liberalisation of networks and deregulation are greater than ever and all contribute to driving change within transmission and distribution systems. Figure 1 illustrates many of the factors that need to be considered in the development or expansion of a substation.

1.1.1 **Environmental factors**

Climate change is having a significant effect on the substation on both a physical and operational level due to more frequently occurring natural disasters, increase in the climatic extremes the site is exposed to and the demand and expectation from the public.

Limited green field availability and planning restrictions increase the need to up-rate, extend or replace within the existing site. Although, safety is paramount, practicality must be considered to operate and maintain the substation. Added to this is the growing impact on the external community of visual amenity and acoustic noise for city centre sites and housing as it encroaches on existing substations [2].

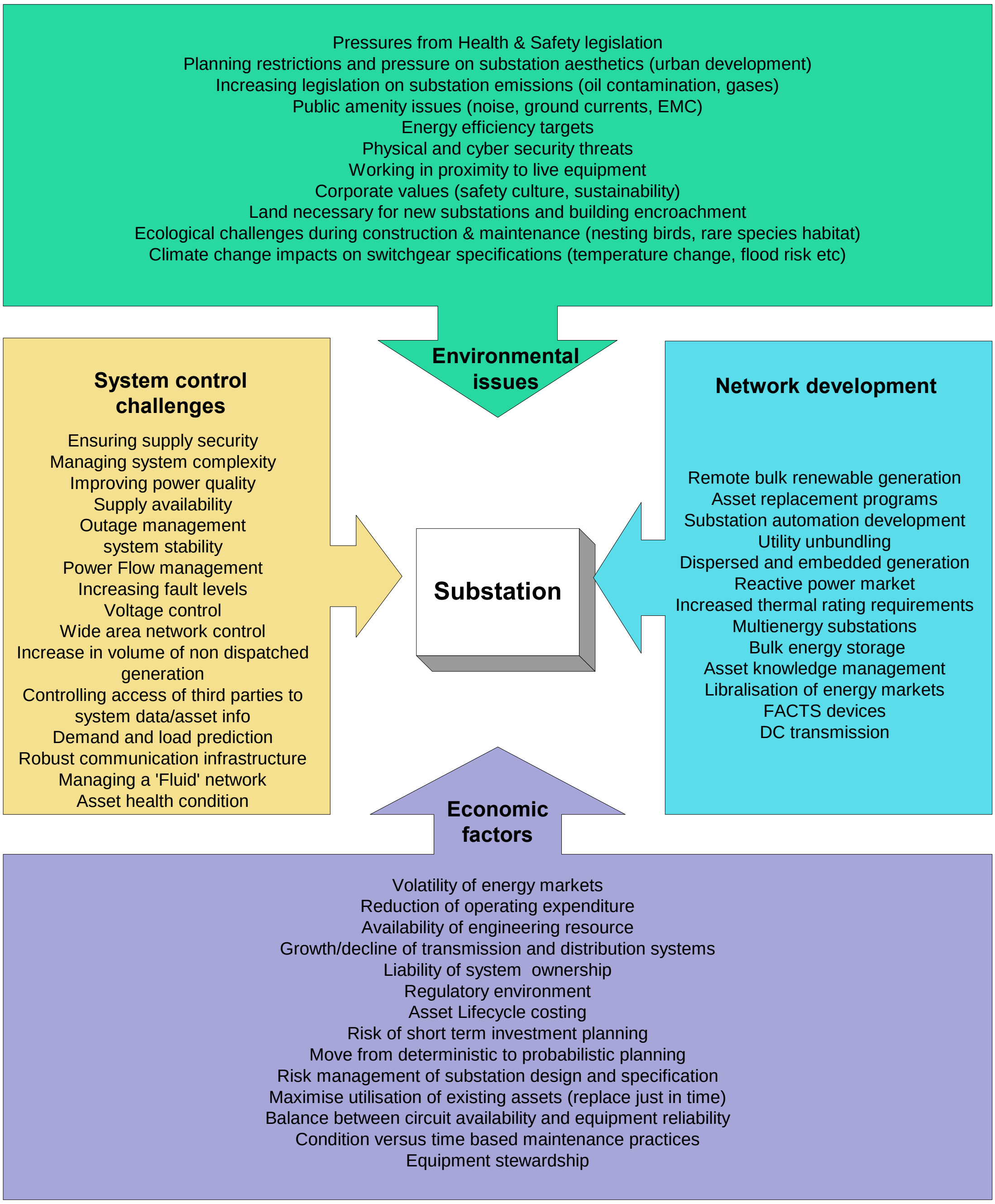

Figure 1. Summary of the influences on substation design

The containment of insulation mediums (oil and SF_6) is a significant responsibility and becoming more constrained. As an industry increasing volumes of SF_6 are being employed and as such it will be imperative that every effort is made to ensure the gas is contained and recycled.

1.1.2 **Market and Regulatory Pressures**

Energy markets require utilities to review the architecture of their networks such that a more flexible approach to achieve expected system access and operation is possible.

Utility ownership may change more frequently than the assets themselves. This is likely to create a misalignment between the asset and business strategies. The lack of long-term asset management strategies within the organization will present a threat to asset reliability and safety, especially since investors favour short-term financial gains (when compared to switchgear lifetime).

The constraints placed on utilities by the System Operators mean that the provision of outages is becoming an increasingly difficult and expensive task. Therefore any new maintenance practice or piece of equipment needs to be efficient regarding outages.

Some countries are seeing resource constraints which affect the cost and timescale to build major new projects.

1.1.3 **Energy Demand**

The composition of daily and seasonal load profiles is changing, reflecting the impact of consumer technology (air-conditioning loads, VSD motors and switch-mode power supplies). Coupled with this is a change in social and cultural patterns as the 24-hour lifestyle proliferates around the globe.

In the longer term the greater use of green energy may see electric cars and public transport taking a higher priority, especially as countries try to meet their CO_2 reduction targets for 2010 and beyond.

The constant system development and asset replacement programs, coupled with a shift in generation management will put increasing pressure on network availability and reliability. Outage programs will be subject to complex switching, increasing power flows, greater negative phase sequence effects and increasing short circuit levels. As a consequence, substations are becoming inflexible and difficult to reconfigure or extend.

1.1.4 **Dispersed & Renewable Generation**

Renewable generation and increasing interest in distributed resources is challenging the network topologies. Generation is typically located at the primary fuel source (gas terminals, coal fields, dams etc). The move towards wind sees generation moving once again, typically this will be to a low demand area (in order to get planning permission) and will require new transmission infrastructure to enable bulk transfer to the load centres.

Remote generation, particularly wind farms will require new circuits or increased loading on the existing network. These long lines will introduce reactive power demands and possibly a move towards the increased use of HVDC and cable circuits. At the transmission level this introduces a number of issues:

- Challenge to operational Grid Codes to facilitate new generation types.
- More cable circuits to ease planning restrictions.
- Increasing mix of AC and DC transmission systems

The opening up of the energy markets and services together with environmental incentives to install ‘greener’ generation sources will make the work of the network designer and asset manager very difficult.

From the substation perspective, the increasing volume of unmanaged non-centrally dispatched embedded generation is likely to increase the fault level and will also make the system recovery following a fault more complex. This potentially may overstress more equipment than previously anticipated, consequently reducing reliability and ultimately the asset life.

The greater susceptibility of modern generation to system faults and transients could result in a more fragile network. Ultimately the transmission and distribution substations will need to be robust and reliable against these changing scenarios.

The lack of large-scale energy storage and impact of climate change factors will make the balancing of the network a more complex activity as dispersed generation proliferates unchecked without coordination of the long-term system security.

1.2 Substation Operation

Once the substation is built and commissioned, the operation phase involves possibly the greatest uncertainty since it lasts for decades. Maintenance and outage management are the key to ensuring circuit availability. The way in which this is marshalled may impact on the equipment reliability and lifetime. All the utilities are looking at ways to manage these challenges. Every challenge will require some form of risk management approach to asset management to find a balance of lifetime knowledge of the equipment condition and perceived market forces.

1.2.1 **Maintenance**

The industry as a whole has seen a decline in the number of power and electrical engineers, not only in terms of graduate recruitment but also a significant element of experienced engineers retiring or leaving the industry. This will further stretch existing resource to ensure that substations into the future are capable of meeting these new challenges.

Mature power systems have the added complexity of different generations of switchgear within the site. Applying the same principals of operation and maintenance to everything is not sensible from both an economic and technical perspective. The persistent drive to reduce operational costs within utilities, will force the need to develop strategies to accommodate this, however experienced resource is necessary to implement the strategy.

The pace of changing technology particularly in substation secondary systems will require the protection engineer to acquire new skills. Telecommunications are shaping the technologies employed within automation, protection and monitoring. , Substation design will need to adapt to these fundamental changes.

The outsourcing of support activities can also have an impact, since insufficient in house knowledge ensure contracts and services are suitably performed may result in ineffective services. Taking out extended warranties or Post Delivery Service Agreements on new equipment is a common practice, however, these are expensive services and it is quite difficult to demonstrate appropriate unreliability to warrant the cost in the early stages. However, as the equipment matures this is where support is more appropriate, unfortunately predicting and providing this support is more difficult to obtain.

1.2.2 **Outage management**

A problem that most utilities experience is the increasing difficultly and cost of obtaining planned system outages for maintenance or construction activity. As system complexity increases so does the ability to coordinate system reliability and flexibility. The utility many need to consider different maintenance strategies to align with the system requirements. This could also dictate ongoing replacement or refurbishment programmes.

Network constraints could be incurred if the planning of site access, outage duration, maintenance and subsequent commissioning programs and resources are not aligned with all other work required on the system. This raises the question of how to accelerate the new build or replacement and keep the outages as short as possible without incurring significant additional project costs.

1.2.3 **Substation extension, refurbishment and replacement**

The lifetime assigned to an asset can have a number of functions, whether it is financial, physical or reliability based. This can also vary dramatically, from a few years for modern light current equipment up to half a century for primary plant. This scenario makes justifying whole scale asset replacement of a substation, or even a bay, complex and ever more subject to economic scrutiny.

Secondary systems are complex, with short lifetimes for microprocessor components (5-6 years) while relays, control boxes and telecoms should last for at least 15 years. The utility needs to determine an economical lifetime for secondary systems, which takes into account, refurbishment and spares availability before equipment becomes obsolete and unobtainable.

Primary switchgear on the other hand is still expected to last much longer (typically 40 years) while maybe power transformers could be longer. A key consideration at the outset is to manage electronic interfaces with the switchgear and establish the overall economic lifetime, since the component lifetimes do not match and the equipment will need to be refurbished at some stage during the switchgear lifetime.

The impact of equipment failure can pose significant risks to health, safety and system security, in addition to any financial penalties for loss of supply. The lack of co-ordinating timely replacement with supplier availability (where long manufacturing lead times are involved) could also result in significant disruption to supply security.

1.3 Substation Life-Cycle Costing

The previous sections have outlined a cross-section of the factors that can affect substation design and operation, however in order to evaluate these issues against each other, Substation Life Cycle Costing (LCC) needs to be considered. This is not a new concept however it is difficult and subjective depending on who is performing the exercise. The industry as a whole needs to act conscientiously and consider the entire lifetime of new equipment. This can be difficult with an asset lifetime of 50 years plus. It is the utility however who needs to ensure any LCC is balanced across the whole asset lifetime, and must consider how to manage risks and the substation for its entire life and not just the construction programme [3].

2 Technology Survey

In response to the pressures described in the previous section there are a number of technology based solutions to help address these challenges placed on utilities. The survey examined how the application of these new functionalities impacted on the substation design and operation. The survey did not address in detail how the technology resolved the system problem, but the challenges facing the engineer when trying to install the equipment into the substation. The technology has been categorised into sectors (Table 1) relevant to the nature of the functionality offered by the equipment.

2.1 Data colection

The information in this brochure was collated from the responses of various users and manufacturers and then supplemented and formatted to provide the reader with hopefully a logical breakdown of problems and possible resolutions. The navigational guide provides an introduction to the structure of technical appendices and how to use the information

The information was collected through responses to a questionnaire issued in 2004 and experience of WG members. The aim of the questionnaire was to gather experience on installation and subsequent operational problems which were experienced during the project.

Responses were received from utilities and solution providers from the following countries, Australia, Austria, Brazil, Belgium, France, Germany, Ireland, Italy, Japan, Korea, Netherlands, Sweden, Switzerland, Thailand and the UK.

Technology		CIGRE WG	Appendix	Page
Power electronics	STATCOM	B4 JWG B4/B3/C2	A4.1	58
	Series Capacitor TCSC	B4	A6.2	107
	HVDC Classic	B4	A9.1	138
	HVDC VSC	B4	A9.2	144
Custom Power devices	D-STATCON	B4	A7.1	114
	DVR	B4	A7.2	119
Reactive Compensation	Switched capacitors	B4 B3	A4.5	84
	SVC	B4	A4.2 A4.3	66 74
	Shunt Reactor	A2	A4.4	79
Switchgear	Hybrid/MTS	A3 B3.20	A1.1	31
	Disconnecting CB Withdrawable CB	A3 B3	A2.1 A2.2	42 47
	Non conventional instrument transformers	A3.15	A5.1 A5.2	91 95
Power devices	Gas insulated line	JWG B3/B1.09	A11.1	162
	Phase shifting transformers	A2	A6.1	100
	Superconducting cable	B1, D2	A11.2	166
	Gas insulated transformers	A2	A11.3	170
Fault current limiter	Neutral reactor	A3.16	A8.1	126
	Series reactor	A2	A8.2	129
	Superconducting FCL	A3.16	A8.3	133
Dispersed generation	Windfarms	C6 B4.39	A3.1	51
Substation Automation	Numerical Protection	B5	A10.1	152
	Monitoring & diagnostics	B3.12 D1	A12.1	175

Table 1. Technology Matrix

2.2 Appendices Navigation guide

This section will describe how to find information with in the technology appendices which discuss the key impacts identified in the review.

The Appendices are sorted by technology. Each Appendix includes a basic technical introduction to the topic, relevant CIGRE Working Groups and references for further information. The subsequent pages are then broken down to individual technologies where the guidelines are in the form of a checklist to help the designer to identify the actual impacts affecting the substation under design.

The designer should not see this as a solution provider to their network problem, but as guidance once a technology has been selected, on how to deal with it.

The guidelines initially look at what type of functionality is being introduced. The impact is categorised as either major, minor or none.

In order to assess the impact that the introduction of these new functionalities have upon substation design, three distinct stages where considered:

System Impact

The initial effect a technology has upon the network and the changes introduced into the fundamental design parameters for the substation. These consider issues like have system studies already been performed to check load flows, fault levels, stability, harmonics etc. or are these required as an initial part of the design of the substation.

Single Line Impact

Secondly, any changes to the single line diagram of the substation and the results of the studies should enable the substation designer to finalise the single line diagram (SLD) of the substation taking into account the availability, control and protection requirements.

Bay Impact

Finally, consider the substation design aspects regarding layout, civil works, primary plant and transformer considerations, protection and control, auxiliary plant and earthing system. The guidelines will endeavour to identify all of the key interfaces which the substation designer needs to take into account and provide a logical and controlled way of dealing with these.

If the particular device has an impact on a particular parameter then an entry is included in the appendix column, which directs the reader to the appropriate section of the Appendix.

All of the possible impacts are listed in numerical order in the overall index. This means that the separate subsidiary sections of this Appendix will generally not have completely sequential numbering.

2.3 Example

This will provide an example to the reader on how to use the appendices to find a specific issue.

Supposing a substation designer was considering a project to install a HVDC station adjacent to an existing substation and was concerned about the possibility of noise issues and any sources.

Table 1 provides the starting point:-

HVDC is covered in Appendix 9

In Appendix 9, there is an introduction and two sections, Conventional HVDC and VSC HVDC. Assuming a conventional design is being considered Appendix 9.1 will be of interest.

Within Appendix 9.1, scanning down the Impact Index, there is reference to acoustic noise, according to the impact column it suggests there is a major impact with an important notice and a reference to a sub section A9.1.20.

Following on from the table is the Advice section containing all the paragraphs pertaining to appendix 9.1, scanning through the list to A9.1.20 will provide further advice on the specific issues, and additional references where relevant.

3 Technology impact on substation design

The functionality and technology considered can loosely be divided into three areas:

- Power system applications
- Switchgear
- Substation automation

This section will outline some of the options (functionality) available and breakdown these into categories. This brochure does not provide a recommendation on the suitability of the solution, but an indication of the range of applications the technology has been used to address. The scope of developments is broad including the compaction of equipment, power electronic applications, new communication architecture and automation and new technology paradigms such as superconductivity.

Note: Further information and references can be found on the technologies in their specific appendices at the back of this report. Table 1 summarises the technology reviewed and the relevant appendix.

3.1 Dispersed and Renewable Generation

This is a huge and expanding subject ranging from domestic micro-generation up to offshore wind farms. The nature of the generation technology, voltage level and location will create different conditions. The preference for remote generation sites introduces many system issues, such as the nature of transmission to the load centres and provision of services/maintenance etc, which will determine the type of solution specified.

While the increased use of dispersed generation may alleviate voltage control problems within the main interconnected network, remote generation (possibly even offshore) is going to require additional reactive compensation to enable transmission to the load centres, this may be an area where power electronic based solutions become feasible whether it’s HVDC or dynamic compensation to provide fault ride through capability. The future for HVDC may be more likely as economics and rights of way issues demand higher power flows through either existing routes or new under-grounding is justified.

3.1.1 Dispersed Generation

Dispersed generation may take many forms, such as wind power, photovoltaic, small diesels, fuel cells etc. The generation may be connected at different voltage levels within the distribution network and may be three phase or single phase connected. This gives rise to a whole range of impacts upon the performance of the system including voltage regulation, voltage unbalance, harmonics, frequency variation, power flow direction, short circuit current levels and fault detection.

Monitoring and awareness of dispersed generation is necessary to manage network operation, especially where system contingency is concerned. Wide area control and protection is frequently mentioned as a possible resolution to these issues, however except for special protection schemes (inter-tripping) there is very limited application (Appendices 10 & 12 protection and diagnostic systems provide some advice).

Inevitably most of these systems incorporate some element of power electronic conversion to interface with the existing power system. One of key functions for power electronics in the future will be to provide the interface between the existing power system and many of the emerging applications such as photo-voltaic (PV), energy storage and superconductivity. Many of the integration issues associated with power electronics are covered in Appendices 4, 7 & 9 on reactive compensation, Custom Power and HVDC respectively, all of which incorporate power electronics to varying degrees. In this scenario Custom power will be the more relevant section, however small DC will also be likely.

3.1.2 **Windfarms**

The type of wind turbine technology employed will determine the dynamic response available to control network disturbance and the associated protection and control required to provide a reliable connection to the grid.

While different countries have different connection codes, issues of fault ride capability, intermittency and compliance are challenging the industry to innovate. In most cases dynamic compensation is necessary to manage these contingencies either through turbine control or external power electronics (SVC, STATCOM).

Quality of supply issues will need to be more carefully monitored as windfarms and distributed energy resources begin to proliferate.

Circuit availability and outage management may also become a major issue regarding the substation configuration, depending on the availability required by the generator, since units are maintained individually rather than en masse. Reliability of the connection transformer and cable between the windfarm and grid connection will become the determining factor.

Dispersed Generation	**Key impacts**
Appendix 3	AC or DC interface with existing network, depending on size and distance.
Distributed generation, CHP, PV, micro-generation, windfarms	Require new connection infrastructure and communications Grid compliance may be necessary for larger generation at point of connection. This may require additional reactive compensation Need to review tolerance of new protection and control settings to system fluctuations. May require Wide Area Control (WAC) and monitoring to enable TSO to manage transmission planning, post fault coordination.

3.1.3 **Energy Storage**

Energy storage is frequently raised as a resolution to intermittency or system islanding during adverse network conditions. Issues of response time and capacity will dictate the type of technique chosen. This is a large and esoteric subject, however where power electronic interfaces are necessary some of the guidelines in Appendix 7 (Custom Power) can be adopted where Super-conducting magnetic storage (SMES), chemical energy storage (Redox-flow, NaS battery) and flywheels are considered.

In most cases energy storage will seen as a generation source, so many of the issues associated with generator compliance will need to be addressed.

3.2 Power System Applications

There is a broad range of equipment (both conventional and power electronic) which can enable a utility to either improve the existing capacity of existing circuits (series compensation), the distribution of power around the network (Phase shifting transformers) or system conditions (reactive compensation). Where new capacity is necessary applications like HVDC, gas insulated lines, gas insulated transformers or eventually superconductivity can be considered [4].

3.2.1 **Reactive compensation**

Voltage control is a very extensive field, catering for steady state and dynamic system conditions. The changing nature of generation and its location will have a profound impact upon the design of substations which need to feed the demand and are remote from the immediate point of connection of the generation. Reactive compensation may need to be relocatable to justify the expenditure.

Where a number of reactive compensation devices are employed in a localised area, careful calculation of the dynamic control setting will be necessary to ensure that hunting or poor response does not occur when the system is disturbed.

All this reactive compensation could increase the risk of resonances on the network, while low loss design equipment is reducing the amount of resistance in the system and therefore damping. Generally the corrective measures should be connected locally to the device which is causing the effect so that the substation affected will be the one which includes the new device. The more advanced applications with sophisticated control system should be designed to neutralise any potential resonance effects.

Switched Capacitor and Reactor banks

Mechanically switched banks have been employed for many years to control steady-state voltage levels, however the installed capacity is increasing significantly as utilities no longer centrally design and must manage new generation and closure of existing plant.

Circuit breaker switching duties must be considered and care must be taken to ensure that electromagnetic VTs and surge arresters are designed to deal with any discharge duties when connected in capacitor circuits.

Dynamic compensation

While the proliferation of steady state voltage support equipment is extensive, the same cannot be said of dynamic equipment. Fast switching post fault voltage support is necessary to prevent system instability, and only power electronic switches can respond in this time frame. The introduction of distributed generation and a requirement for fault ride through capability is being addressed to some degree through the use of dynamic compensation.

Reactive Compensation	**Key impacts**
Appendix 4	Power electronics require reliable control systems and cooling circuits Specific maintenance strategy to ensure availability. Power electronic auxiliary systems, strategic spares, capacitor cans. Relocatable design may be necessary if generation patterns change Requirement for coordinated control if more than one reactive control device is installed on site. Step voltage, transients and resonances for switched units Monitoring of dynamic performance Magnetic fields & acoustic noise near air cored reactors Circuit breaker switching duty for mechanically switched units
Shunt connected equipment to provide steady voltage support and dynamic system compensation post fault Steady state: Fixed/Switched capacitor banks, shunt reactors, Dynamic: SVC, STATCOM	

Static Shunt Compensators derive power using reactive components: thyristor controlled reactor (TCR), thyristor-switched reactor (TSR), thyristor-switched capacitor (TSC) & the static VAr compensator (SVC).

Static synchronous compensators (STATCOM) can provide both capacitive and inductive compensation independently of ac system voltage using DC capacitors.

3.2.2 High capacity conductors

Gas Insulated Line (GIL) technology is different to traditional GIS in the construction and insulation medium. Welding improves the gas tightness and no need for any intrusive maintenance provides a very robust conductor. A gas mixture of SF_6 and nitrogen is used to insulate the conductor. This design enables a high capacity, safe conductor system to be installed within the substation boundary. It can also be surface mounted, so burying and the associated costs and risk with civil works are reduced.

High capacity conductors & gas insulated transformers	Key impacts on substation design
Appendix 11	Gas handling equipment and practice for large volumes of gas. GIL gas mixture (10-20% $SF6$) Fault recovery programme and rating of adjacent plant to handle redistributed current post fault
Gas Insulated Lines Superconducting cables Gas Insulated Transformers	Reliability/redundancy of cryogenic cooling for superconducting cables Opportunity to build underground or consider substation compaction Eliminates the key sources of substation fire hazards Post fault repair strategy to minimise outages

3.2.3 Gas Insulated Transformers (GIT)

This design of a gas insulated transformer enables the unit to be compacted down and installed in a confined space. The absence of oil means that the fire risk is removed so it can be located close beneath public accommodation. A large quantity of SF_6 gas is required (similar to a GIS substation) so procedures for gas handling need to be carefully considered regarding faulted conditions, maintenance etc. See appendix 11.

3.2.4 Superconducting Cables

The application of superconducting systems in the substation has been discussed for decades, but commercial and technical exploitation is slow, although a few demonstrations at MV are underway. Although, the attraction of low loss high current conductors is obvious, integrating this into existing networks is proving a challenge. The impact of equipment failure, through cryogen leakage, effect of system faults and the cryogenic system itself is of great concern, especially in an industry where maintenance budgets are constantly under pressure to be reduced.

The topic is not addressed in great detail as any pilots are still very much in the prototype stage.

3.2.5 Power Flow Control

Flexible AC Transmission systems (FACTS) [5] are commonly referred to as devices capable of controlling the power in a circuit or substation. Most of the recent developments are based on power electronic architectures, however some of the features can also be achieved with electromagnetic applications.

Electromagnetic devices such as Phase shifting transformer (PST) and Quadrature Booster (QB) are based on transformer principals and employ tap changers to control reactive power, which is used to inject a voltage into the circuit which effectively changes the circuit impedance and enables the power flow in that circuit to be controlled.

Power electronic based series compensators such as the thyristor-controlled series compensator (TCSC) provide a smoothly controllable impedance to compensate lines and to mitigate sub-synchronous resonance. Static synchronous series compensator (SSSC) allows control through an injected voltage.

Independent active and reactive power-flow control can be provided by the interline power-flow controller (IPFC) and the unified power flow controller (UPFC). The convertible static compensator (CSC) combines all functionalities of STATCOM, SSSC, UPFC and IPFC.

Active Power Flow control devices	**Key impacts**
Appendix 6	Equipment ratings need to be equivalent to circuit rating
	Must be robust to through faults and transient conditions. The circuit reliability should be no worse than before.
Power flow control devices in a circuit, to increase/decrease capacity, to control thermal constraints	Location of FACTS device can significantly impact effectiveness
e.g. Phase shifting transformer, Quad Booster, TCSC, UPFC	Requires a bypass facility for maintenance/fault condition
	Need to study impact on circuit protection, particularly distance.
	Need to establish resonance, sub-synchronous and reactive power impact of any new equipment installed
	Reliability of cooling systems on equipment availability particularly power electronics
	Spares provision for power electronics and capacitor units

3.2.6 Custom Power devices

Essentially, distribution and industrial applications, these have been developed to improve the power quality or conditioning of the customer's supply. They are seeing wider application in distributed generation connections.

Applications covered include Dynamic voltage restoration (DVR) which provides power during short supply interruptions, a Distribution Statcom which maintains voltage quality. Other devices include active filtering and solid-state transfer switch which through fast coordination can transfer bus supplies to provide uninterruptible supply.

Custom Power Technology	**Key impacts**
Appendix 7	Very application specific, therefore tailored solution.
	Auxiliary systems determine equipment reliability
Distribution and industrial voltage level equipment for power quality control, fault ride through and fast switching.	Require protection system review, high speed communication and transient monitoring to get the most out of the solution
e.g. DSTATCOM, DVR and solid state switch	Similar issues to that of FACTS and HVDC power electronic applications
	Spares provision

3.2.7 HVDC

HVDC is well established, however the pressure on network capacity and emergence of new technologies are challenging some of the existing limitations with conventional HVDC (line commutated converter thyristors) designs.

Recent developments in Voltage source converter (VSC) based DC can provide a complete power transfer solution for distribution and increasingly transmission systems.

HVDC	**Key impacts**
Appendix 9	Significant power flow increase (for large DC links) Reactive compensation will be necessary (VSC DC to a lesser degree) Harmonics and EMC may need to be addressed depending on the technology chosen Significant land-take will be necessary for HVDC station Impact on local protection and control strategies. Fast power reversals Pollution performance of outdoor DC insulation Reliability of the SVC cooling system(s) Strategic spares strategy to ensure high availability.
Direct current transmission, requires converter and inverter station for AC Classic line commutated converters using thyristors, or voltage source converter technology	

3.3 Switchgear developments

Most of the development in switchgear is geared towards making applications more modular, low maintenance and safer. This includes trying to reduce the volume of SF_6 required and improving the gas tightness. Pressure from changes in EU regulations will also strengthen this strategy. This section also considers fault current limiters and non conventional instrument transformers.

3.3.1 Mixed technology switchgear

In an attempt to address safety, and space restriction associated with new build or asset replacement, manufacturers are trying to increasing reliability through use of highly engineered GIS for AIS applications. Also termed mixed technology switchgear, these solutions incorporate the benefits of GIS and flexibility of AIS for outside applications. At present these are specific applications where space is at a premium.

Mixed Technology Switchgear	**Key impacts**
Appendix 1	Reduced lifecycle maintenance compared to conventional AIS Smaller footprint Identify equipment failure replacement strategy and necessary provisions May challenge existing safety practices, so new maintenance practices may be necessary Essentially dead tank design Can enable new optimised substation designs Outdoor GIS so need to ensure joints/seals are adequately robust to the environment for the asset lifetime
Hybrid development of GIS and AIS systems for outdoor application	

Although GIS is much less likely to fail and requires significantly less maintenance the provision for maintenance and equipment spares to minimise unavailability and disturbance to the network is all the more critical. This needs to be agreed with the manufacturer or engineering support division at the time of equipment purchase.

3.3.2 Compact & integrated switchgear

Integrated switchgear combines functions together, generally in a compact manner to provide a synergy of equipment. Typical examples include integral optical CT's on circuit breakers, integral support/surge arresters and CB with integrated disconnection facilities. There are many advantages offered through these solutions, however the utilities need to change their procedures and systems to reap the benefits.

ompact & integrated switchgear	**Key impacts**
Appendix 2 - CBs **Appendix 5 - NCIT**	Reduced lifecycle maintenance compared to conventional AIS Smaller footprint May challenge existing safety rules, new maintenance practice and equipment necessary
Withdrawable CB, disconnecting CB Non conventional instrument transformers (NCIT)	Enables optimised substation design Eliminates safety risks from primary system (NCIT) Requires DC supply to power transducer electronics & protection relays (NCIT) Can be integrated into existing switchgear (GIS) or attached to AIS Interface challenges between NCIT and non digital protection

3.3.3 Fault current limiters

These devices take many forms and can help a utility to control fault-current levels as it develops and expands. Simpler solutions include reactors, but more exotic designs are considering high temperature superconductors (HTS), resonance triggers and power electronics. On a larger scale, back to back HVDC can also provide asynchronous connection between grids. All have benefits and drawbacks, but it is up to the utility to identify the most relevant for its needs. Reliability of performance is probably one of the most important requirements, since failure to control fault current can easily result in equipment failure.

Fault Current Limiter	**Key impacts**
Appendix 8	Energy dissipation and cooling between fault operation (reclose) Coordination & impact on protection settings, particularly down stream
Equipment capable of control fault current to a designed level, protecting local	Bypass facility

switchgear for overstressing Mixture of conventional and novel technologies - series and neutral reactors to resonant series transformers	TRV duty if CB are employed adjacent to the FCL May need to consider a relocatable solution (following asset replacement) Reliability of any control system Strategic spares for complex systems

3.4 Substation automation

Unlike switchgear where the power industry controls the pace of change, substation automation or secondary light current system evolution will be determined by other industries. This results in rapid obsolescence and problems in suppliers providing consistent applications.

Manufacturers are placing more functionality into devices. Relays are no longer single function applications, they are intelligent electronic devices (IED) with microprocessors growing in capability and processing power similar to that of our personal computers. This step change requires a different approach to asset management. Protection engineers need software programming skills to set and interrogate modern systems.

3.4.1 Protection and control

Although substation automation is changing, it is in response to the fast pace of communication protocol development, typified by the Internet. The development of the substation communication protocol IEC 61850 will probably be the most dramatic element seen in the substation for a long time. Implementation of this will enable interoperability between different IEDs and greater equipment information exchange made accessible to interested parties via the internet.

There are also some drawbacks with this change, the greater likelihood of fast equipment obsolescence (from a utility perspective), information and cyber security and greater reliance on automation where systems utilising neural networks or AI technology adapt to changing and evolving system needs.

Phasor measurement, GPS tracking and fast data transfer enables wide area protection and control to be deployed, to prevent system instabilities developing and causing blackouts.

Protection	**Key impacts**
Appendix 10	Protection setting on multifunctional devices (hundreds of settings to check). Default not necessarily secure
Application of numerical protection and IEC 61850 protocol	Intelligent electronic devices (IED) functionality Protection engineers require training Control of firmware updates and revision control Ethernet connectivity and security control Interfacing between old and new protection systems Service agreements

3.4.2 Monitoring

Through the development in sensor technology, again transferred from other industries, there is the increasing capability to monitoring everything. Many utilities are faced with the dilemma of replacing or supplementing traditional maintenance regimes with these systems. There are significant challenges to integrating these systems into the utility decision making tools and to a large degree the reliability of the monitoring system itself. Utilities need to identify what the value in condition monitoring is and how it will be used.

Monitoring & Diagnostics	**Key impacts**
Appendix 12	Reliable data interpretation and advisory systems Equipment may be more maintenance intensive than the primary plant – monitoring equipment may reduce equipment reliability
Condition monitoring and plant diagnostic tools e.g. GIS PD monitoring, transformer nursing units, on-line circuit breaker timing	Cost benefit justification Don't install CM unless it is necessary! Communications infrastructure necessary to access information in a timely fashion. Security issues regarding third party access to substation info systems Control of software/firmware updates

4 General observations on substation design

4.1 System impact on substation design

When we examine the impact of the various influences on substation design (Chapter 1), there are a number of issues which are common to many of the scenarios. This section considers these various impacts.

Primary plant

The substation infrastructure is most likely to experience increased power transfers to meet future demands. Greater interconnection of remote generation will require utilities to increase capacity using either series compensation, HVDC or real time monitoring to enhance ratings. Inevitably, as equipment is pushed harder the electromagnetic stress seen by primary equipment will increase, utilities will need to be able to assess this risk.

The network topologies will need to be much more flexible to meet changing needs, this will see either network expansion or wider application of FACTS devices, the challenge will be coordinating these devices as more appear and possibly interact.

Adverse weather will directly impact on network security and the substation flexibility will determine the system resilience to these effects. This in addition to the climate change targets on renewable and emissions.

Secondary systems

The application of Wide area monitoring, control and protection will become more prevalent as System Operators are faced with more dynamic networks and large scale interconnections. Embedded generation and active control within distribution networks will require significant coordination between neighbours and make traditionally separate networks much more interdependent on each other. The communication necessary to support these developments will be central to the security and reliability of the strategy. There is likely to be a greater dependency on these systems to facilitate the changes in power networks.

4.2 The impact on the substation single line diagram

If we look at the effect upon the single line diagram (SLD) of the substation then one of the immediate effects may be the short circuit rating required for the plant within the substation. Depending upon the device being connected this may require an increase in short circuit level or in some cases (fault current limiters) may enable simplification of the SLD by allowing greater bussing of equipment without too many sections.

The increase in harmonics on the network may give rise to a greater need for filters, either passive or active, however most transmission applications should be specified to reduce or, at least, not worsen system harmonics.

New technologies and integrated applications will affect the substation configuration and insulation coordination dynamics. Application of surge arresters and controlled switching will need to be considered to maintain adequate safety margins. This is particularly important for electronic components, which have a very low tolerance to over-voltages.

Substation configuration

The reliability and maintenance impact of new switchgear should encourage utilities to examine new running arrangements. Much longer intervals between corrective maintenance could lead to different strategies such as replace and maintain off line, rather than in situ maintenance.

For substations incorporating new technologies consideration needs to be given to the operation and running arrangement when the device has to be disconnected for maintenance or under fault conditions. Reducing the duration of outage or bypass arrangements may be required and care needs to be taken with the protection arrangements to cover both conditions. The utility will need to consider the relative cost of getting outages in the future against spare switchgear, so that rapid replacement and offline maintenance can be employed. Any element of wide area protection will also need to coordinate with these changes.

As Substation Life cycle costing becomes a more accepted method for design selection then different single line diagrams may be considered.

4.3 Impact on the substation bay

Whatever new functionality is employed to affect system level attributes such as fault level, power flow etc, it is invariably going to have a significant impact at the bay level.

4.3.1 **Physical Environment**

Once the substation configuration is defined, detailed design can take place to specify aspects of the substation and equipment.

Space is an obvious limitation in most substations where new equipment needs to be installed. The space requirements need to consider the connectivity required with other plant items, the required electrical clearances, clearance required for electromagnetic effects, access for initial installation and maintenance. The impact on civil works may include oil containment and fire requirements if the new devices introduce oil immersed transformers and if air cored reactors are present care has to be taken with the reinforcing bar arrangements, structures and earthing to avoid heating from closed loops.

Climate change is going to have an increasingly direct impact on switchgear specifications such as operational temperature ranges and on the physical location of equipment (e.g. mechanism boxes).

Substation marshalling must be designed to ensure immunity to interference generated from any new applications installed in the substation which may induce transients into site cabling. Use if optical fibre will help to alleviate this problem Special care is needed in the design of the earthing system, to ensure safety whilst avoiding interference into control circuits and avoiding large circulating currents from flowing due to electromagnetic induction.

Audible noise can have a significant effect on the equipment specification and subsequent testing. At the design stage the various options should be investigated such as indoor build, location or operational modes before writing very onerous equipment specifications.

A new directive on EMC regarding substations as fixed installations will require the designer to consider any effects more critically since the substation is now seen a source and will need to demonstrate compliance with the standards.

4.3.2 **Impact on equipment**

There is a move towards modularity and design standardisation in an effort to reduce costs. This does mean utility specific adaptations are more difficult to make and traditional utility procedures may require review.

Primary plant

On going SF_6 gas containment and tightness is a major concern among utilities, lifecycle factors need to be addressed at the specification and installation stage to ensure the desired objective of zero leakage can be reasonable achieved. Any new switchgear, especially at transmission will require SF_6 gas handling, this will require training and certification under new EU regulations.

Utilities will need to specify current transformers and voltage transformers with a view to meeting future digital protection and control needs.

Substation automation

Substation automation will experience the greater change as interfacing new to old legacy wiring, the transfer to powered relays and isolation from the instrument transformer secondary (high impedance). There will also be a high degree of technology obsolescence.

Secondary asset replacement occurs more frequently and switchgear interfacing is proving to one of the most complex challenges. The fact that the secondary wiring may need to be changed a couple of times during the life of switchgear results in long outages to facilitate the replacement. IEC 62271-3 aims to address some of the issues facing primary and secondary integration. Therefore in order to facilitate faster secondary asset replacement additional costs may need to be incurred at the primary asset investment stage.

The implementation of IEC 61850 is underway and utilities need to develop their application requirements and the associated interfaces to any system management tools.

As utilities move from copper multi-core to fibre based marshalling systems, this forces the utility to establish standard termination and data protocols. Utilities need to develop their own IEC 61850 configuration requirements. New tools and training will be necessary to configure multifunctional protection ‘black boxes’ safely and reliably.

Substation and network communication is a major issue. Before many of the new initiatives can be considered rules about ensuring secure portals, management of firmware changes, software version control and access must be resolved. Ensuring that utility personnel can interrogate and download fault recorders or setting is necessary, while at the same time preventing unauthorised access.

As more functionality is incorporated into equipment or Wide area systems are developed, the testing according to existing standards may require some interpretation and development, both in the factory acceptance tests and more importantly at final commissioning.

Ancillary equipment

Most of the new functionality will increase the pressure on auxiliary systems. The steady state loading is increasing and dependency on the DC supply is becoming more important than ever.

Additional AC supplies will be required for cooling of components, additional DC supplies for the control and protection. The protection design needs to consider the particular requirements of the new types of device and also the impact these devices may have upon the performance of existing system protections such as distance relays. Interlocking may be required for both operational and safety reasons.

4.3.3 **Substation operations**

One of the common requirements for most of these new functionalities is that existing maintenance strategies may need to be reviewed. In many cases this may require procedural changes, however in a number of cases specific strategies will be required. This may result in training for substation staff or alternatively service agreements with the supplier. In both cases the costs can be large whether it is in terms of contracts or substation resource tied up in training.

Where diagnostic tools are employed such as condition monitoring or analysis provision for maintenance or calibration of these services will need to be made (exchanging one maintenance intensive system for another), albeit the latter does not tend to incur outages.

New skill sets will be required by substation staff, particularly in the field of information systems and possibly software programming. Staff will need to be IT literate, to interrogate secondary systems, implement test procedures and perform diagnostics on substation automation.

The manner in which condition monitoring is employed will enable the utility to optimise its maintenance and asset replacement strategies. The utility will need to concentrate on how the information is used within the organisation to maximise any benefit, liberal application of CM without a good input into the maintenance and asset management decision making tools will be ineffective.

5 Concluding remarks

Utilities may adopt different strategies to manage change on the system, the brochure has only examined technology biased solutions, not operational or commercial alternatives. However, business and commercial processes will impact on the choice of solution employed. Conversely, behind commercial solutions there might be a need for better technical definitions concerning equipment interfaces, removable containers, post delivery support etc.

The transmission and distribution industry is by its very role conservative, which is reflected in the vintage of installed equipment and the adoption of traditional technologies and architecture. In many cases this is a good thing, but as the world changes utilising developments in other industries and technology transfer is necessary to remain functional and competitive.

Some of the key issues which can be drawn from the work are:

- In most cases some form of Life-Cycle Costing is required to identify the optimal solution for the utility. Depending on the value utilities place on key issues such as operation and maintenance, this will affect the suitability of different solutions.

- Utilities need to consider recommendations on the application of technology not just the technical specification. This will help to ensure the desired conclusion is reached without project delay or exceeding the budget.

- There is a trend towards modularity and more standardisation of solutions, which must be considered when reviewing maintenance, refurbishment and substation extension plans

- The emphasis on maintenance is changing from intrusive testing to diagnostics and monitoring. This is moving the volume of work from the substation to the office. This strategy however requires the monitoring equipment to be more reliable than the switchgear. Unfortunately this is not the case, so a lot of time is spent investigating the monitoring system.

- New resource and skill sets are necessary (software programming and telecoms) to enable the utility to maximise the benefit from modern technology. However this must be combined with experience from the past.

- Detailed and bespoke engineering is necessary when interfacing between different vintages of equipment. This will impact on resource, system access and commissioning programmes.

- Substation automation is very much concerned now with managing technology obsolescence and software version control. The scope of the protection engineer is broadening.

6 References

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Specific references to the various applications can be found in the relevant appendices.

APPENDICES

A1 Mixed Technology Solutions

A1.1 Hybrid AIS/GIS

Mixed technology solutions (MTS) are a combination of Gas Insulated Switchgear (GIS) and Air Insulated Switchgear (AIS) in conventional stations. Substations containing this combination have been in service for perhaps 25 years as the addition of GIS equipment was often the only way of extending existing AIS substations within existing space limitations [1]. However, today new substations have to meet tough requirements in terms of occupied space, environment impact, reliability and availability in addition to the problem of extensions and refurbishment while keeping substations in operation.

The definition of AIS, when all apparatus are air insulated, is as clear as for GIS, when all apparatus are placed in grounded enclosures. Because hybrids are a combination of both technologies several different kinds exist, e.g. at one extreme, very close to AIS, is the design of a compact module by adding AIS disconnectors / earthing switches on both sides of a dead tank circuit breaker (Fig. 1) [2].

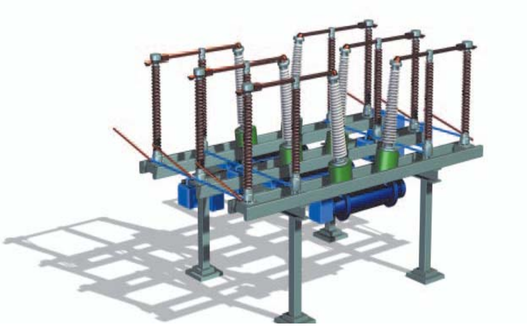


Fig. 1: Hybrid composed of a dead tank breaker accompanied by AIS disconnectors / earthing switches

At the other extreme, very close to GIS, is a single bay in/out arrangement where all switchgear and measurement functions are integrated into the GIS module; only the connections to the transformer and to the line are air-insulated (Fig. 2) [3].

Fig. 2: GIS in/out arrangement

The general idea of mixed technology solutions is to combine the advantages of AIS, such as easy accessibility and inter-changeability, with the advantages of GIS, lower space requirements and nearly no maintenance, because the apparatus is inside an enclosure which protects it against environmental impacts.

This subject has been identified to include such a wide range of equipment and combinations that it is being dealt with in its own in Working Group WG B3-20 entitled “Mixed Technologies Switchgear MTS” and due to produce a full Report in 2008.

Basic System Changes			
Impact Index	**Impact**	**Important Notice**	**Appendix**
Fault level	none		A1.1
Power flow	none		
Frequency	none		
Voltage	none		
Thermal rating	none		
Unbalance	none		
Harmonics	none		
Impedance	none		
Resonances	minor	Disconnector switching in SF_6 might cause Very Fast Transients, which might lead to high frequency voltage distortion in a connected power transformer.	
Losses	minor	Compared to AIS equipment the losses can be reduced significantly by hybrid technology, because of the lower path resistances in the GIS equipment, shorter length of busbar connections and reduced number of clamps.	

Single Line diagram			
Impact Index	**Impact**	**Important Notice**	**Appendix**
Short circuit rating	none		A1.2
Operational switching	none to major	Classical Single Line diagrams (SLDs) can be realized with hybrids as well as new configurations. A fair comparison for technologies with different reliabilities (AIS versus GIS) demands the adaptation of SLDs and layouts.	
Filtering	none		
Compensation	none		
Installation	major	Less apparatus, foundations, civil works; shorter installation time	
Maintenance	major	The more switching functions are integrated into the GIS part the longer are maintenance intervals. Depending on the voltage level and the technology either one phase or an entire bay module may need to be disconnected if repair is required.	
Bypass	none		
Commissioning	major	Due to pre-assembly and factory testing modules can take less commissioning time and effort.	
Insulation coordination	none		

Detailed Bay Design			
Impact Index	**Impact**	**Important Notice**	**Appendix**
Protection (external)	none		A1.3
Protection (internal)	minor	In case of new unconventional SLDs busbar protection needs to be adapted.	
Control	minor	In case of new unconventional SLDs interlocking schemes need to be adapted.	
Communications	none		
Land & layout	major	The footprint of a substation is significantly smaller than for AIS.	
Visual impact	major	Lower visual impact than AIS due to compactness and less steel work.	
External pollution	minor	Need for design of the air-insulated parts to allow for pollution depending on the site's pollution level as for AIS.	
Audible noise	none		
EMC	minor	Disconnector switching in SF_6 might cause Very Fast Transients and needs to be considered in selection of secondary equipment.	
Electrical clearances	none	In air as for AIS. To carry out works such as maintenance the complete module will be taken out of service.	
Safety clearances	minor	In air as for AIS. To carry out works, such as maintenance, the complete module will be taken out of service. Additional short busbar outages may be required.	
EM fields	none		
Civils	major	Less foundations for apparatus and steel works, shorter cable routings, less general site works due to smaller sites.	
Containment	none		
Auxiliaries	none		
Equipment ratings	major	GIS modules connected to AIS busbar to fulfill AIS requirements, see Testing.	
Busbar layout	none to major	Classical SLD and busbar layouts can be realized with hybrids as well as new one. A fair comparison for technologies with different reliabilities (AIS versus GIS) demands the adaptation of SLD and layouts.	
Earthing	none		
Monitoring	none	Equipment monitoring can be applied as for AIS or GIS.	
Testing	major	The combination of functions and the compactness of modules should allow a reduction in site testing because of increased factory testing. Correct selection / combination of test requirements of GIS and AIS is necessary for type testing the components.	
Relocatability	major	The compact module can be relocated as it is easy to de- and re-install.	
Spares requirement	minor	Spare module and spares for other modules to be kept as for AIS or GIS.	
Hazards	minor	As for AIS/GIS with polymeric insulation/bushings, earthquake withstand similar to GIS.	

Advice & recommendations

A1.1 Basic System Changes

With regard to fault level, power flow, frequency, voltage, thermal rating, unbalance, harmonics and impedance there are no changes.

The generation of Very Fast Transients by disconnector switching in GIS is a well known effect which can cause voltage distortions in connected power transformers. For MTS it can not be totally excluded, but as the damping is higher than for GIS with direct transformer bushing today's transformers with interleaved windings should not have any problems.

The closer the mixed technology substation is designed to GIS technology the more compact it can be. Because of the lower path resistances in the GIS equipment, shorter length of busbar connections and reduced number of clamps the loss-generating resistance of the current path can be reduced significantly. For substations with heavy load conditions over longer time it should be considered when comparing different solutions in terms of life cycle cost evaluations [4]. The lower losses of Hybrid solutions can provide advantages compared to AIS in terms of Global Warming Potential. An example of Life Cycle Assessment shows that during an operation of 25 years and referring to an average operating current of 800 A, the improvement is around 47% [5].

A1.2 Single Line Diagram Impact

Nearly all classical Single Line Diagrams (SLDs) can be realized using hybrids, resulting in significantly smaller footprints than conventional AIS (Fig.3) while keeping existing electrical and safety clearances. In this case there is no impact on operational switching. Comparing not only investment costs (Fig.3) but all costs during the life cycle a mixed technology solution can provide the most economical solution (Fig.4). As AIS disconnectors are less reliable than GIS disconnectors and today's circuit breakers the overall switchgear reliability can be improved by mixed technology solutions including GIS disconnectors while keeping the existing SLD. Unconventional SLDs with simpler layouts can result in higher availability, lower overall substation installation costs as well as reduced life cycle costs (LCC) [3,5,6,7]. The evaluation process should start with a functional specification and take into consideration all relevant aspects of life cycle costing as recommended in [8].

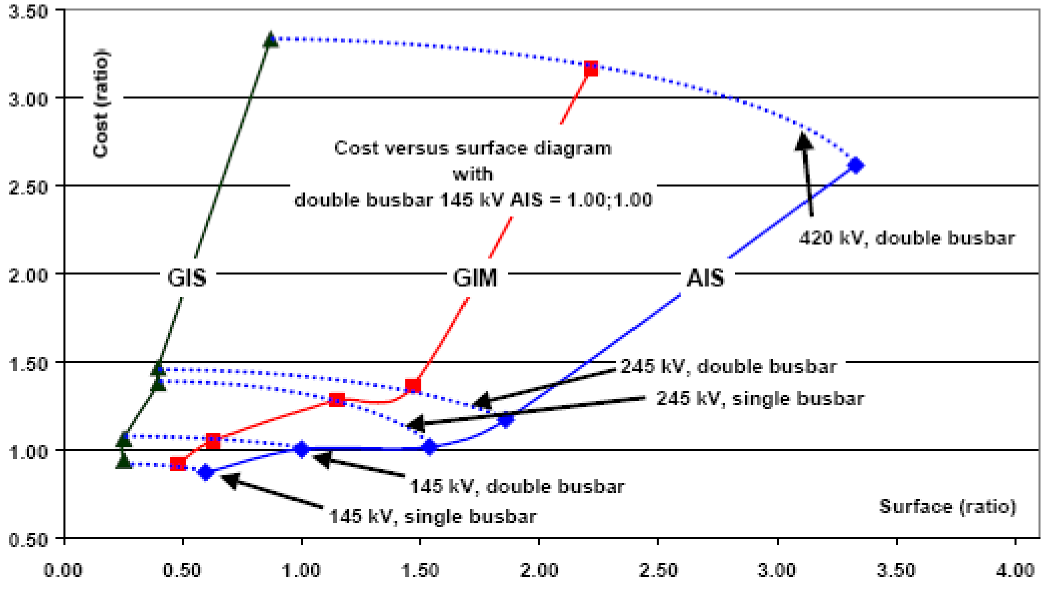


Fig.3: Comparison diagram, complete turn-key (investment cost) in some cases of single and double busbar [6]

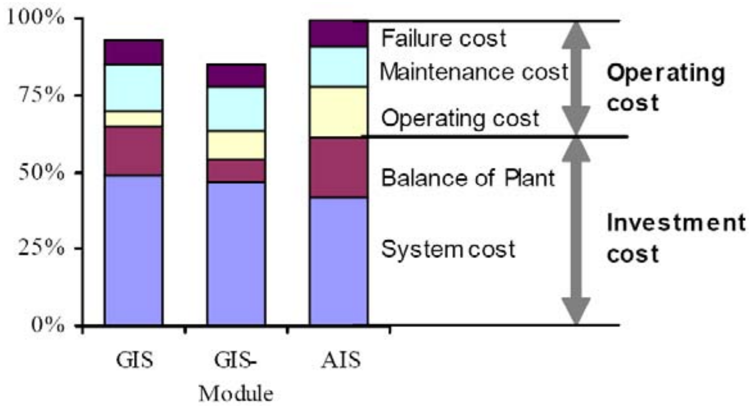
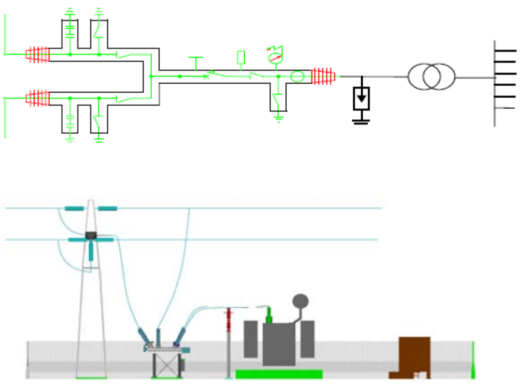


Fig.4: Comparison of LCC cost structure of GIS, GIS modules (MTS) and AIS of a 145 kV H-arrangement with 3 circuit breaker [3, 11]

Some examples of innovative solutions:



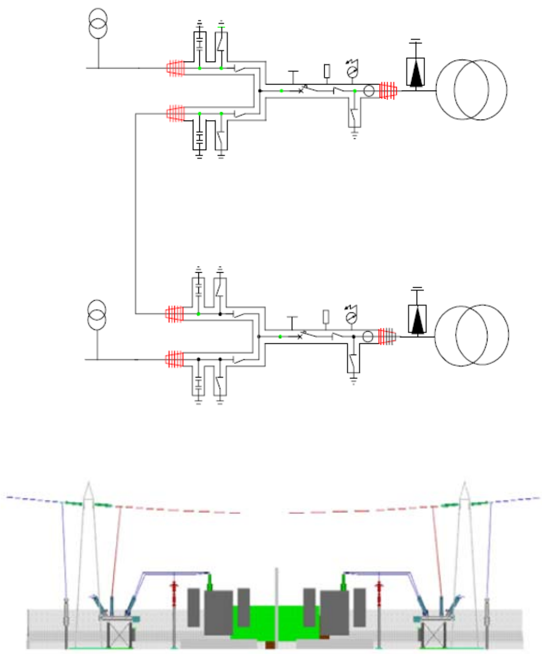


Fig.5: In – Out S/S integration within Fig.6: H scheme integration within right-of-way of existing overhead line [5]

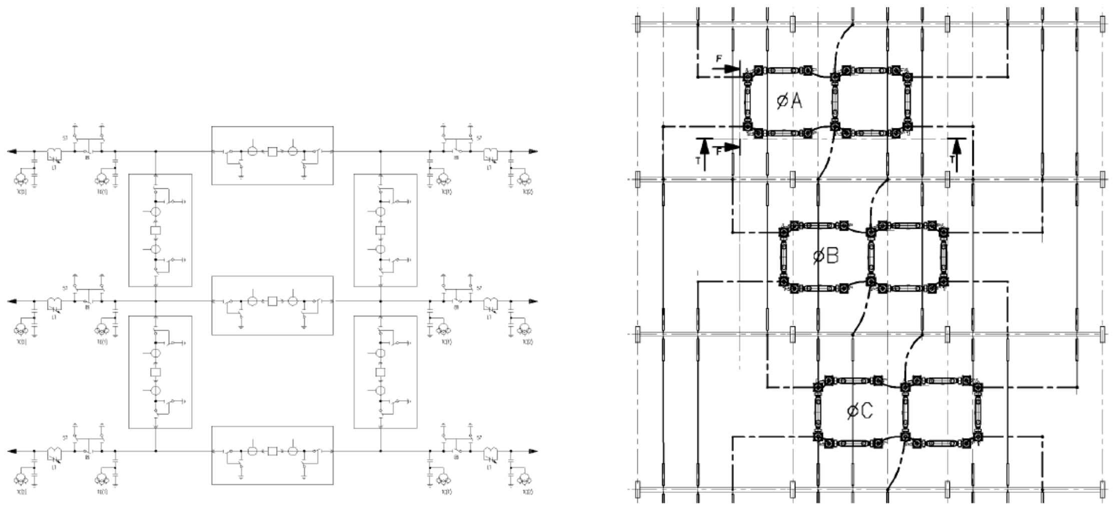


Fig.7 Meshed ring with segregated phases [6]

These configurations can be made simple to operate by means of automated switching procedures.

Because of the compact design the MTS modules can be assembled and tested (totally for lower voltage levels, to a large extent for EHV) within the factory. Site work consists only of installation onto a small number of foundations and/or supporting structures and interconnection of the active parts to the AIS parts. If the gas compartments do not have to be opened for assembly work then in general no further voltage tests are required making commissioning fast and easy.

If all switching functions are integrated in the MTS module the maintenance intervals are as long as for GIS, fiber reinforced bushings and insulators with silicon rubber shields are recommended, especially for locations with high pollution. For utilities often a reduction of the outage time caused by maintenance is more important than the duration of the maintenance itself. This can be achieved by replacing the module to be maintained or repaired by a spare one thus reducing the outage time to the time required for the replacement of the module. Depending on substation layout and also for EHV the gas segregation and mechanical arrangements may need to be designed in a way which permits fast exchange of sub-assemblies [3].

A1.3 Detailed Substation Design

For new unconventional SLDs the schemes of control and protection need to be adapted accordingly.

GIS technology with high reliability combined with the ability for easy and fast replacement allows simpler SLDs, as AIS redundancy level is unnecessary. Much smaller areas, less steelwork, foundations, cable trenches and external insulators than for traditional AIS are needed. Even traditional configurations can be made very compact. The visual impact is significantly reduced. In case of refurbishment existing busbar layouts can be kept or can be compacted in order to provide space for extensions.

Some examples:

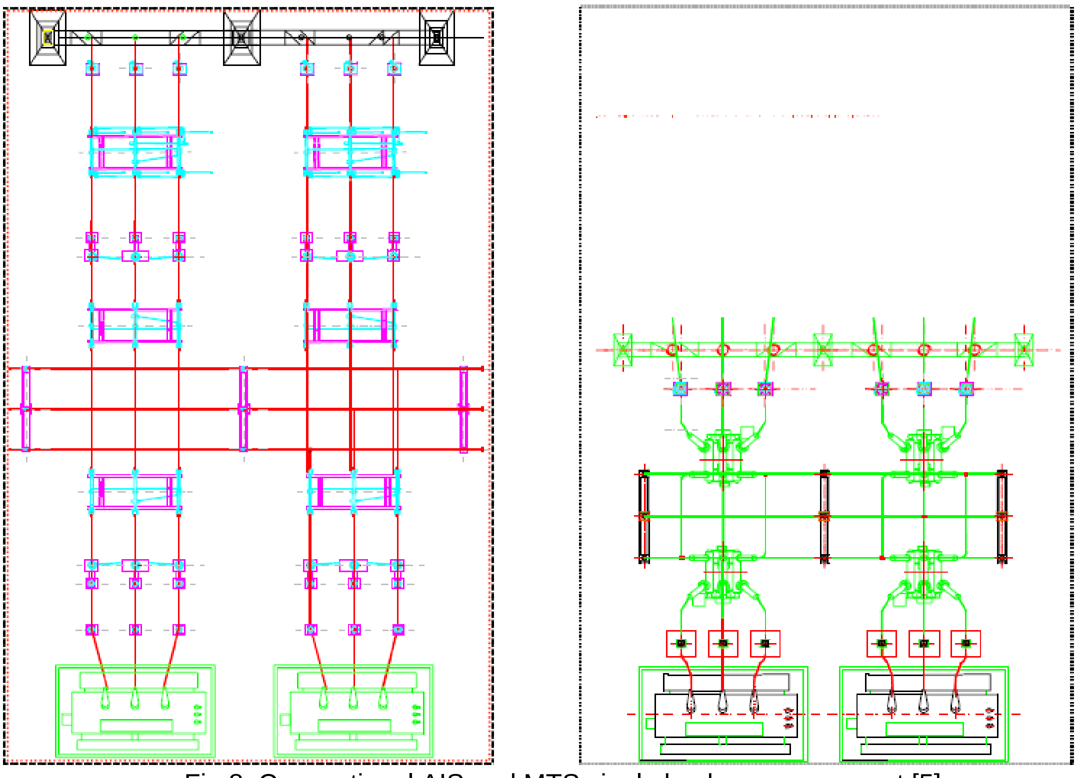


Fig.8: Conventional AIS and MTS single busbar arrangement [5]

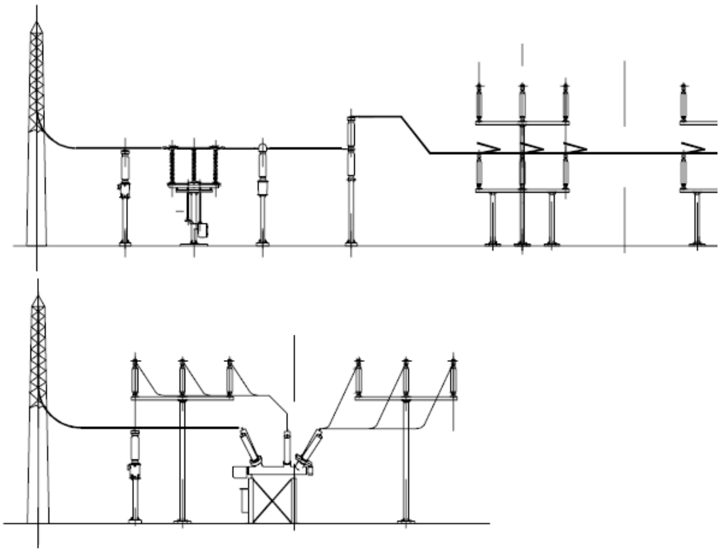


Fig.9: Conventional AIS and MTS double busbar arrangement [5]

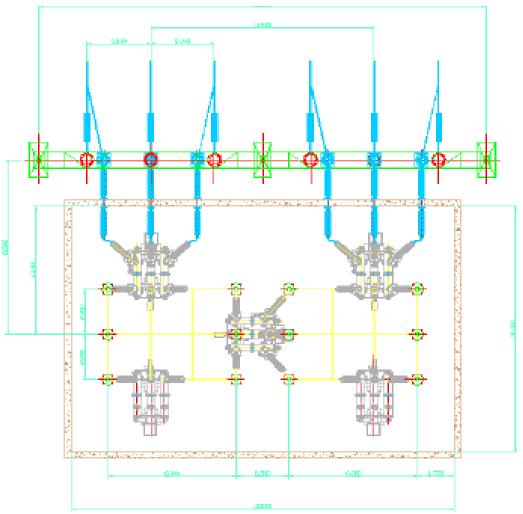



Fig.10: H-scheme with 5 breakers in MTS [9] and outdoor GIS [3]

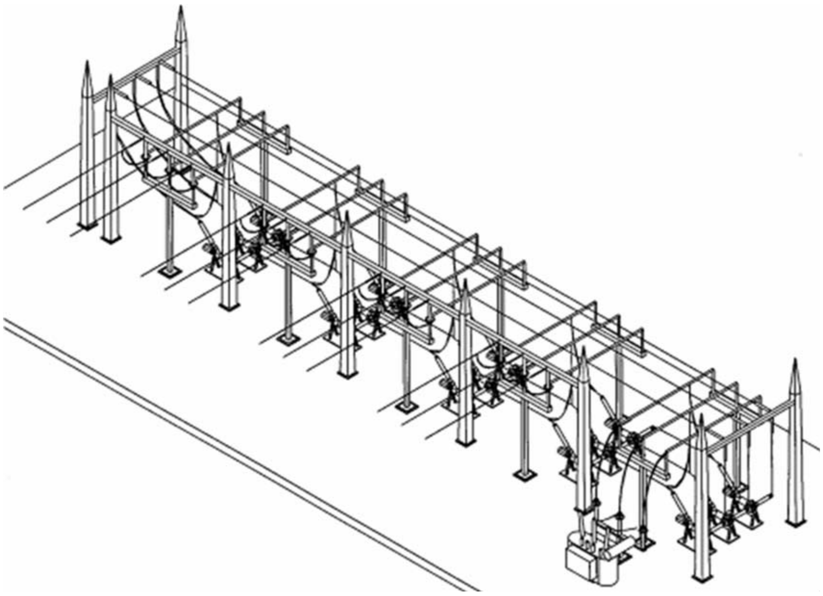


Fig.11: Ring configuration with MTS [10]

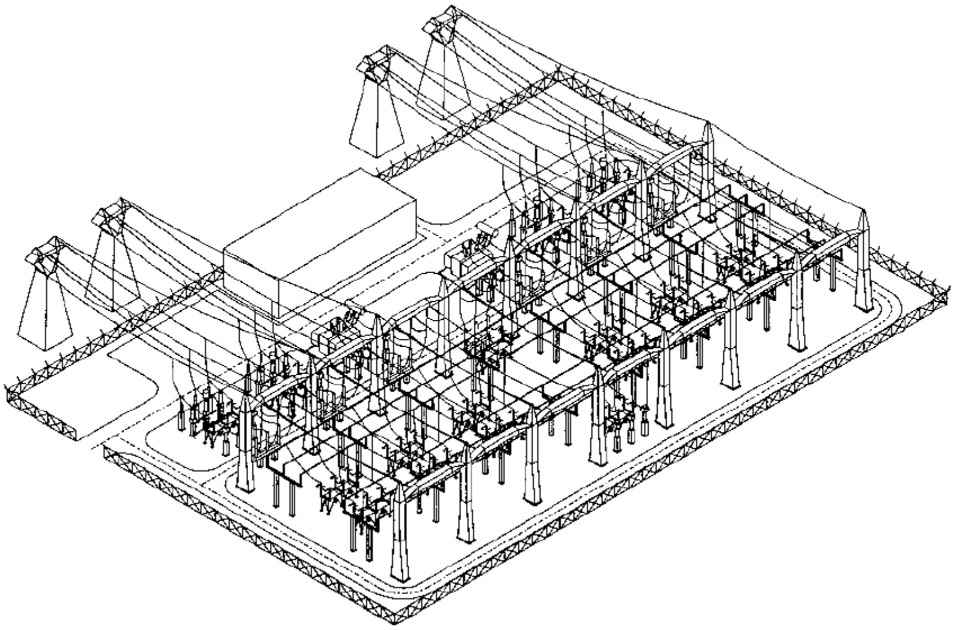


Fig.12a: conventional AIS double busbar arrangement [7]

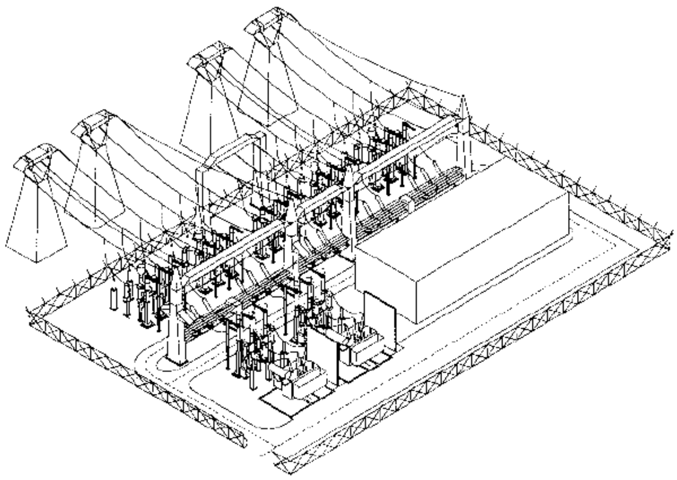


Fig.12b: GIS double busbar including GIS disconnectors combined with conventional AIS bay equipment

Until the planned new IEC 62271-205 “Compact switchgear assemblies for operation at rated voltages above 52 kV” is issued for MTS existing standards for devices or equipment, such as circuit breakers, disconnectors and the GIS standard needs to be combined by experienced substation designers and equipment experts in order to select the appropriate combination of specifications. For example combining a GIS module containing a circuit breaker and disconnectors with an AIS busbar thermal interruption capability (short line fault, initial transient recovery voltage) of the circuit breaker must comply with the more challenging AIS requirements. In case of a double busbar the GIS disconnector tests for bus transfer switching have to take into account the higher voltages induced into the AIS busbar.

A1.4 Conclusions

To select the right solution for your utility, a life cycle cost comparison is necessary, based on the whole substation design and all related ownership costs. For a fair comparison SLDs as well as layouts need to be adapted to the technology’s characteristics and the pre-determined basic conditions. Using a standard format for the generation of a functional specification and for the evaluation process (e.g. [8]) can make the tasks of both asset owner and solution provider easier, when specifying and designing solutions for a specific substation. Close cooperation facilitates a comparison of the relative benefits from a set of different possible solutions.

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[8] CIGRE SC B3 WG13.01: Functional Specification and Evaluation of Substations, 2004 Brochure No. 252,

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A2 Compact AIS Switchgear

This Appendix deals with Compact AIS (Air Insulated Substations) switchgear. This defines as switchgear where more than one primary function, e.g. breaking, disconnecting etc., is integrated in one primary apparatus or that a number of primary apparatus are grouped together and placed on the same foundation to achieve more than one primary function.

The main devices covered in this section are:

- Disconnecting CB (DCB).

A DCB has the disconnecting function integrated into the normal circuit breaker contact sets (Fig. 1). There are no additional contacts or other components for the disconnecting function in the CB breaking chamber. When DCB is used as a circuit breaker closed and open commands are done in an identical was as done for a traditional CB.
When the DCB is used as a disconnector, it is mechanically and electrically locked in open position. Thereafter the adjacent, motor operated earthing switch is closed. The closed earthing switch assures that primary system is de-energised before any work starts on the primary system, and thus assures the personnel safety in the same was as the open disconnector for a traditional solution.

Fig 1. 145kV disconnecting circuit breaker

- Withdrawable circuit breakers (WCB).

A WCB has the disconnecting function built on a traditional CB. The disconnecting function is achieved by moving or rotating the whole CB after it has opened. The movement can be horizontal or vertical or a combination. When movement or rotation is completed a visible open-air gap similar to a traditional open-air disconnector is obtained and maintenance can be done on the adjacent primary system.

This appendix is divided into two parts, one part for each of the two different types of devices as described above. It looks at the impact that the installation of the device within a substation will have on the system, then on the single line diagram and finally on the detailed substation design.

Note: Mixed or with another word hybrid type of switchgear solutions are covered in a separate section of this paper, appendix 1 Mixed technology solutions (Hybrid AIS/GIS).

A2.1 Disconnecting CB (DCB)

The index below lists a standard set of possible impacts. If the particular device has an impact on a particular parameter then an entry is included in the index, which directs the reader to the appropriate chapter of this Appendix. This chapter explains the impact and provides guidelines on the aspects, which may need to be considered.
All of the possible impacts are listed in numerical order in the overall index. This means that the separate subsidiary sections of this Appendix will generally not have completely sequential numbering.

Basic System changes			
Impact Index	**Impact**	**Important Notice**	**Appendix**
Fault level	none		
Power flow	none		
Frequency	none		
Voltage	none		
Thermal rating	none		
Unbalance	none		
Harmonics	none		
Impedance	minor		
Resonances	none		
Losses	none		
Single line diagram impact			
Impact Index	**Impact**	**Important Notice**	**Appendix**
Short circuit rating	none		
Operational switching	high	No separate Disconnector, instead DCB is put in disconnecting position, i.e. mechanically blocked.	A2.1.1
Filtering	none		
Compensation	none		
Installation	minor	Faster installation, no disconnectors with time consuming adjusting of contacts.	A2.1.2
Maintenance	major	Total maintenance is very much reduced by removing the disconnectors. Outage for maintenance of DCB itself should be verified.	A2.1.3
Bypass	none		
Commissioning	minor	Faster commissioning, no complicated disconnector interlocking scheme.	A2.1.4
Insulation coordination	none		
Detailed substation design			
Impact Index	**Impact**	**Important Notice**	**Appendix**
Protection (external)	none		
Protection (internal)	none		
Control	major	DCB have 3 positions, closed-open-disconnected	A2.1.5
Communications	none		

Land & layout	major	Space requirement is reduced with about 50% compared to traditional AIS.	A2.1.6
Visual impact	minor	Size of substation smaller.	A2.1.7
External pollution	none		
Audible noise	none		
EMC	none		
Electrical clearances	none		
Safety clearances	none		
EM fields	minor	No arcs, which can cause unwanted functions in protection and control systems.	A2.1.8
Civils	minor	Less number of foundations.	A2.1.9
Containment	none		
Auxiliaries	minor	Less cabling, less control circuits, less interlocking circuits	A2.1.10
Equipment ratings	none		
Busbar layout	none		
Earthing	minor	Manual earthing to be done before disconnecting.	A2.1.11
Monitoring	none		
Testing	none		
Relocatability	none		
Spares requirement	none		
Hazards	none		
Other (please define)			

Advice & recommendations

A2.1.1 Impact on Operational Switching

The solutions with DCB have the disconnecting function integrated into the normal circuit breaker contact sets. There are no additional contacts or other components for the disconnecting function in the CB breaking chamber. When a power transformer, overhead line, etc. are to be taken out of service for maintenance the following is done.

- DCB is opened in the same way as a traditional CB.
- DCB is put into disconnecting position.

This is done by a separate operating command that energizes a separate operating device on the DCB, which will actuate, mechanical blocking of the pole itself and electrical blocking of the operating device, of the open DCB. This command gives the same function as opening the DSs in a traditional substation with CB and DS.

- Motorised earthing switch on the object to maintain is closed. The closed earthing switch assures that primary is de-energized and is the sign for the maintenance people that work can begin.

The switching sequence will thus be different than for traditional AIS but the difference is not that big, blocking the DCB in open position instead of opening DS. However it is important that operational and maintenance personnel get the proper training to fully understand the concept and realize the difference to traditional solution with separate CBs and DSs.

Maintenance on the DCB itself will be different than maintenance on the CB in the traditional solution. In the traditional solution the CB always have DSs on either side and these can be opened for CB maintenance.
For maintenance of DCB the nearby DCBs must be used to isolate the DCB to be maintained in the same way that nearby DSs must be used to isolate the DS to be maintained in traditional CB

solutions. Today the maintenance frequency of the DSs is much more frequent (1-6 years depending on pollution level at site), while maintenance interval for maintenance of CB or DCB needing to take the primary out of service is 15 years. This fact must not be forgotten when comparing the two solutions.

Depending on the single line configuration, maintenance of the DCB itself might need to have one or more other circuits out of service. This must be considered when choosing suitable single line configuration with DCB solution. A good feature, which is applied for DCB solutions, is to make is possible to disconnect the DCB, in de-energized condition, and re-energize other equipment during DCB maintenance.

A2.1.2 Installation
Installation time at site can be shortened with DCB solution (fig. 2). The DCB installation time is the same as for a traditional CB. This means that installation of DSs will completely disappear and this will save some time since adjusting of DS contacts can be a quite time consuming work.

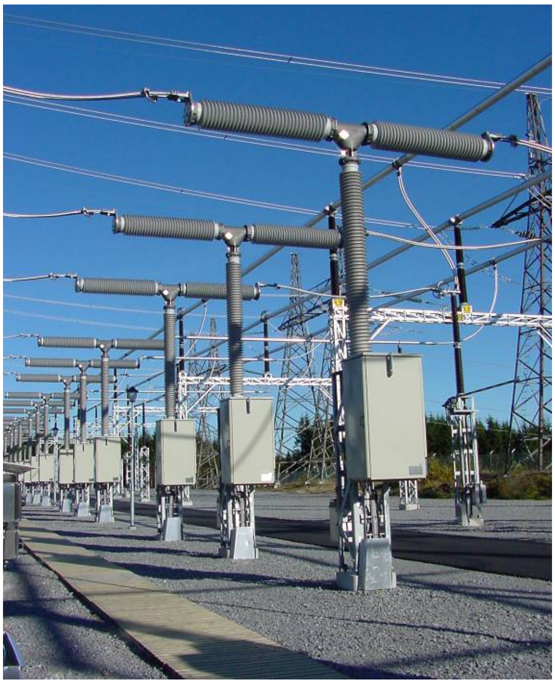


Fig. 2 420kV disconnecting circuit breaker

A2.1.3 Maintenance
Total maintenance in substation is very much reduced by removing DSs. The maintenance frequency for open-air DSs is depending on design and pollution level and in the order of 1-6 years. Maintenance frequency of CB or DCB requiring primary to be taken out of service is 15 years.
The introduction of the DCB thus will in addition to minimize the total maintenance work in the substation also limit the outages caused by the maintenance of the DSs.

For maintenance of the DCB itself the part of busbar that DCB is connected to must be de-energized, which is done using the nearby DCBs. This is similar to the situation when making maintenance of busbar DSs. This means that the part of busbar that DCB is connected to must be de-energized during DCB maintenance.
If the asset owner can live with busbar outage during maintenance of DCB every 15 year then maintenance is done with busbar de-energized during the whole maintenance activity. If this should be to cumbersome there is a special disconnecting facility prepared for in the design, which will limit the busbar outage to a few hours. The disconnecting facility is a mechanical disconnecting of the DCB from the busbar, which can be done under de-energized conditions. The time for three-phase disconnecting of the DCB from busbar is in the order of 1-2 hours for

145-400 kV systems. After disconnecting of the DCB the busbar can be re-energized and be kept in service during the maintenance of the DCB, since layout is done with distances long enough between busbar and DCB to have section clearance between disconnected DCB and live busbar.

The described disconnecting facility can of course also be used to disconnect the DCB from the busbar in case a catastrophic failure should occur on the DCB itself.

A2.1.4 Commissioning
The time for commissioning will be shorter without the traditional open-air DSs. Especially DS interlocking scheme checking can be a very time consuming activity since all the different possible combinations have to be checked to verify the correct function of this important system that is supervising the operation of the disconnectors. Please also consider the higher reliability of the secondary system without this complicated interlocking scheme.

A2.1.5 Control
The solution with DCB will mean a change for the people making the switching operation of the substation. DCB have 3 positions, closed-open-disconnected.

Close-open commands will be done in the same way as for traditional CB solutions.

During a maintenance situation the DCB is put into disconnecting position.
This is done by a separate operating command that energizes a separate operating device on the DCB, which will actuate, mechanical blocking of the pole itself and electrical blocking of the operating device, of the open DCB. This command gives the same function as opening the DSs in a traditional substation with CB and DS.

- Motorised earthing switch on the object to maintain is closed. The closed earthing switch assures that primary is de-energized and is the sign for the maintenance people that work can begin.

The switching sequence will thus be different than for traditional AIS but the difference is not that big, blocking the DCB in open position instead of opening DS. However it is important that operational and maintenance personnel get the proper training to fully understand the concept and realize the difference to traditional solutions with separate CBs and DSs

Operating of earthing switches will be similar to the traditional CB solutions, however all earthing switches for DCB solutions shall be of motor operated type. Closing of earthing switches are allowed when DCB is in disconnected position in the same way that traditional DSs in open position will allow closing of earthing switches.

A2.1.6 Land and Layout
Space requirement for DCB solutions are reduced with about 50% compared to traditional AIS solutions with separate CBs and DSs.

This will of course reduce the cost for the land itself. However even if land itself is not expensive the preparation of land can be quite expensive if blasting, piling, backfilling, terracing etc. is needed. The reduced land area will minimize the cost for such additional costly extra work.

The reduced land requirement will also make retrofit of old substations easier since the rebuilt of substation could be done in “larger” steps, which will make retrofit less complicated and possible also reduced the whole project time and possibly also outage time during retrofit.

A2.1.7 Visual impact
Size of substation smaller but height is the same, but the overall visual impact will be less compared to traditional solution with CBs and DSs.

A2.1.8 EM fields
When opening open-air DSs primary arcs will occur causing EM fields. This has in some cases lead to unwanted functions from the protection system, and/or unwanted alarms from the alarm systems.

With DCB solution these risks are eliminated.

A2.1.9 Civils
Civil works will be reduced since number of foundations for the substation will be fewer.

A2.1.10 Auxiliaries
Secondary cabling will be substantially reduced with DCB solution. A lot of the secondary cabling in traditional solutions are related to DS control and interlocking circuits. The reduction in cabling will mean that cost for both cabling and cable ducts are reduced. But also the secondary system will be more safe due to the reduction in complexity.

A2.1.11 Earthing
If disconnecting facility is used, as described under item A2.1.3 Maintenance, portable earthing must be attached before disconnecting in order to keep both sides of the disconnecting point earthed at all times.

References

[1] P Norberg, M Tapper, W Lord, A Engqvist, “The Future Substation - Reflection About Design,” Report 23-105, Cigré Session, Paris, 1998.

[2] P-O Andersson, H-E Olovsson, B Franzén, U Lager, J Lundquist, “Applications of Disconnecting Circuit Breakers,” Report B3-210, Cigré Session, Paris, 2004.

[3] H-E Olovsson, C-E Sölver “Suitable single line configurations and corresponding availability and space requirements in applications of Disconnecting Circuit Breakers for AIS S/S”, CIGRE SC B3 & A3 Joint Colloquium, Tokyo, Japan, 2005.

A2.2 Withdrawable CB

The index below lists a standard set of possible impacts. If the particular device has an impact on a particular parameter then an entry is included in the index, which directs the reader to the appropriate chapter of this Appendix. This chapter explains the impact and provides guidelines on the aspects, which may need to be considered.
All of the possible impacts are listed in numerical order in the overall index. This means that the separate subsidiary sections of this Appendix will generally not have completely sequential numbering.

Basic System changes			
Impact Index	**Impact**	**Important Notice**	**Appendix**
Fault level	None		
Power flow	None		
Frequency	None		
Voltage	None		
Thermal rating	None		
Unbalance	None		
Harmonics	None		
Impedance	None		
Resonances	None		
Losses	None		
Single Line Diagram Impact			
Impact Index	**Impact**	**Important Notice**	**Appendix**
Short circuit rating	None		
Operational switching	Major	Whole unit is withdrawn to achieve disconnecting function.	A2.2.1
Filtering	None		
Compensation	None		
Installation	None		
Maintenance	None		
Bypass	None		
Commissioning	None		
Insulation coordination	None		
Detailed substation design impact			
Impact Index	**Impact**	**Important Notice**	**Appendix**
Protection (external)	None		
Protection (internal)	None		
Control	Major	Withdrawing whole WCB unit instead of opening DSs	A2.2.2
Communications	None		
Land & layout	Major	Space requirement is reduced compared to traditional AIS.	A2.2.3
Visual impact	Minor	Size of substation smaller.	A2.2.4
External pollution	None		
Audible noise	None		

EMC	None		
Electrical clearances	None		
Safety clearances	None		
EM fields	None		
Civils	Minor	smaller foundations.	A2.2.5
Containment	None		
Auxiliaries	None		
Equipment ratings	None		
Busbar layout	none		
Earthing	none		
Monitoring	None		
Testing	None		
Relocatability	minor		
Spares requirement	none		
Hazards	none		
Other (please define)			

Advice & recommendations

A2.2.1 Impact on Operational Switching

A solution using a with-drawable CB (WCB) has the disconnecting function integrated into the operation by moving or rotating the whole CB after it has opened using the normal circuit breaker contact sets. When a power transformer, overhead line, etc. are to be taken out of service for maintenance the following is done.

- WCB is opened in the same way as a traditional CB.
- WCB is withdrawn.

This is done by a separate operating command that energizes a separate operating device on the WCB, which will move or rotate the WCB giving same physical open-air gap as DSs in a traditional substation with CB and DS.

The switching sequence will thus be different than for traditional AIS but the difference is not that big, withdrawing or rotating the WCB in open position instead of opening DS. However it is important that operational and maintenance personnel get the proper training to fully understand the concept and realize the difference to traditional solution with separate CBs and DSs.

Maintenance on WCB itself is done by moving the whole WCB unit outside energised area in substation. Both sides of the WCB connection to the switchgear can be kept energised during this operation, which can be very useful for substation availability.

Maintenance of the open-air contacts of the WCB can be expected with about the same frequency as for traditional DSs. It is important that the “fixed” contacts remaining in the switchgear when WCB is withdrawn are maintenance free. If any of the “fixed” contacts need to be maintained or repaired both sides of WCB must be de-energized in order to achieve section clearance and personnel safety for this work.

A2.2.2 Control

The solution with WCB will mean a small change for the people making the operation of the network.

Close-open commands will be done in the same way as for traditional CB solutions.

During maintenance the WCB is withdrawn (fig. 3) or rotated compared with the situation of opening DSs for traditional solution. Withdrawing or rotation is done by a separate operating command that energizes a separate operating device on the WCB, which will move or rotate the WCB giving same physical open-air gap as DSs in a traditional substation with CB and DS

Fig 3. Withdrawable circuit breaker

A2.2.3 Land & layout

Space requirement for WCB solutions are reduced with about 50% compared to traditional AIS solutions with separate CBs and DSs.

This will of course reduce the cost for the land itself. However even if land itself is not expensive the preparation of land can be quite expensive if blasting, piling, backfilling, terracing etc. is needed. The reduced land area will minimize the cost for such additional costly extra work. The reduced land requirement will also make retrofit of old substations easier since the rebuilt of substation could be done in “larger” steps, which will make retrofit less complicated and possible also reduced the whole project time and possibly also outage time during retrofit.

A2.2.4 Visual impact

Size of substation smaller but height is the same, but the overall visual impact will be less compared to traditional solution with CBs and DSs.

A2.2.5 Civils

Civil works will be reduced since number of foundations for the substation will be fewer.

References

[1] C-E Sölver, H-E Olovsson, W Lord, P Norberg, J Lundquist, “Innovative Substations with High Availability using Switching Modules and Disconnecting Circuit Breakers,” Report 23-102, Cigré Session, Paris, 2000.

[2] Ph. Roussel, L. Hossenlopp, F. Gallon, “Technical and economical evaluation of new air-insulated substation concepts”, Report 23-205, Cigré Session, Paris, 2002

A3 Dispersed Generation

This Appendix deals with dispersed generation. Many different power sources exist e.g. wind farms, combined heat and power (CHP), microturbines, energy storage (fig1) small hydro, fuel cells, solar power. However of all of these power sources only wind farms (and perhaps CHP) have to date been connected to electricity networks at transmission voltages i.e. 110kV and upwards.

Fig 1. NaS 6MW battery storage system, Ohito substation Japan [1].

References

[1] Installation planning and operation control of NaS battery systems considering voltage stability margin. Ohtaka, T.; Tatsuno, M.; Iwamoto, S. Advances in Power System Control, Operation and Management, 2003. ASDCOM 2003. Sixth International Conference on (Conf. Publ. No. 497). Volume 1, Issue , 11-14 Nov. 2003.

[2] CIGRE Brochure 313 - Connection criteria at the distribution network for distributed generation, 2007.

[3] Lessons learned: European pilot installations for Distributed Generation – An overview by the IRED Cluster – C6 302_2006, B. Buchholz, N. Hatziagyriou, U. Schluecking, I. Furones Fartos

A3.1 Wind-farms

Connection to a transmission system is likely to require connection arrangements which maintain existing redundancy and operational flexibilities.

Fig 2. Typical small wind farm array.

A basic arrangement which achieves this aim where a wind farm is to be connected to an existing line is through a switched-tee substations, comprising two standard line bays and the wind farm connection bay. (some stations contain more than one wind farm connection bay).

If the substation is close enough to the wind farm for MV connection then the generator transformer and the generator control room are located in the same compound as the transmission equipment but is separated by a dividing fence. Each section of the compound has separate access and may share some facilities e.g. LT power from the local network or from the generator's MV board or back up diesel generator facilities.

The point of common coupling between the transmission system and the generator is the 110kV bushing of the generator transformer.

If the wind farm is farther away or the generation is large enough that losses from transmission at MV would be uneconomic then the switched tee station can be connected by a 110kV line to a tail station, basically a 1-bay transformer feeder station. In some cases this tail station is enlarged to act as an aggregation point for multiple wind farms. A similar arrangement can be used to connect a wind farm into a new bay in an existing substation.

If the substations are built by the network owner then its standard designs will apply. However where the substations are built by the wind farm for handover to the network owner then construction standard implementation issues are likely to arise in the early installations due to the introduction of first time external designers to the transmission. Another issue is that of increasing non-standardisation of 110kV switchgear on a network as generators, working to functional specifications, may each have their own favoured solution.

All of the possible impacts are listed in numerical order in the overall index. This means that the separate subsidiary sections of this Appendix will generally not have completely sequential numbering.

Basic System changes			
Impact Index	**Impact**	**Important Notice**	**Appendix**
Fault level	high	Must be taken into account in earthing and protection setting calculations	A3.1.1

Power flow	high	variable output must be compensated by reserves	A3.1.2
Frequency	high	if proportion of WTG generation share is high	A3.1.3
Voltage	high	new controls are improving this aspect	A3.1.4
Thermal rating	high	may require uprating of existing circuits	A3.1.5
Unbalance	none		
Harmonics	minor	Measures by generator required to suppress any harmonic resonance	A3.1.7
Impedance	none		
Resonances	minor	high unless measures taken to suppress	A3.1.9
Losses	high	May reduce losses depending on location in the network.	A3.1.10
Others	none		

Single Line Diagram Impact

Impact Index	Impact	Important Notice	Appendix
Short circuit rating	minor	Should not result in any increase	A3.1.12
Operational switching	minor	Normal implication of switching generating stations	A3.1.13
Filtering	minor	some locations may experience resonance which require elimination by the generator.	A3.1.14
Compensation	minor	The impact on load flows may have implications for overall network compensation requirements	A3.1.15
Installation	high	In that a new substation is required	A3.1.16
Maintenance	minor	May be restricted by generator outage requirements	A3.1.17
Bypass	none		
Commissioning	minor		A3.1.19
Insulation coordination	none		
Others	none		

Detailed substation design impact

Impact Index	Impact	Important Notice	Appendix
Protection (external)	high	Reliable loss of mains protection required; protection settings must allow for the varying load flows	A3.1.22
Protection (internal)	minor	Required protection to be provided by the wind farm supplier	A3.1.23
Control	minor	Normal station controls required with minor additions	A3.1.24
Communications	high	Normal design but communications link may be expensive due to remote location	A3.1.25
Land & layout	none		
Visual impact	none		
External pollution	none		
Audible noise	none		

EMC	none		
Electrical clearances	none		
Safety clearances	none		
EM fields	none		
Civils	high	Special foundation designs may be required due to poor ground conditions in the remote location	A3.1.34
Containment	none		
Auxiliaries	minor	Non standard designs may be required due to remoteness from local MV network	A3.1.36
Equipment ratings	none	Assuming that the equipment in the local network is designed for bidirectional power flow	A3.1.37
Busbar layout	none		
Earthing	high	Issues may arise due to poor ground conditions and transferred potential issues	A3.1.39
Monitoring	none		
Testing	minor	Additional time required due to remote location	A3.1.41
Relocatability	none	Not very practicable	A3.1.42
Spares requirement	high	If substation supplied by wind farm supplier. WTG step up transformer should also be considered to preserve availability.	A3.1.43
Hazards	none		
Other (please define)			

Advice & recommendations

A3.1.1 Impact on Fault level
The introduction of generation into what may be a remote location in the network will probably result in a noticeable increase in fault level in the network in the vicinity of the substation This must be taken into account in earthing and protection setting calculations.

A3.1.2 Impact on Power flow
The introduction of wind generation whose output can vary dramatically at short notice will increase the complexity of generation reserve planning.

A3.1.3 Impact on Frequency
The introduction of wind generation whose output can vary dramatically at short notice will have a big impact on frequency control if proportion of WTG generation share is high. This will increase the complexity of generation reserve planning and may also lead to additional requirements for voltage support measures.

A3.1.4 Impact on Voltage
Wind turbine controls must be suitable for operation with increasingly stringent grid codes in particular with respect to ride-through capability.

A3.1.5 Impact on Thermal rating
As wind generation will normally be installed in remote sections of a network the rating of existing circuits and station equipment must be assessed to ensure that it is capable of carrying the additional power.

A3.1.7 Impact on Harmonics
The generating station and its associated equipment must meet the grid code requirements.

A3.1.9 Impact on Resonances
The generating station and its associated equipment must meet the grid code requirements.

A3.1.10 Impact on Losses
The introduction of additional generation in remote sections of a network is likely to reduce transmission losses while it is generating.

A3.1.12 Impact on Short circuit rating
The rating of existing network equipment in the vicinity of the wind generation must be checked to ensure that it is capable of dealing with the new network conditions. Unless it is old or there are large variations in the rated values there should not be a great impact.

A3.1.13 Impact on Operational switching
Wind farms of themselves do not introduce any new complications beyond the co-ordination normally required for network switching of switchgear associated with generating stations Local operational staff will need some additional training.

A3.1.14 Impact on Filtering
The generating station and its associated equipment must meet the grid code requirements.

A3.1.15 Impact on Compensation
System studies should be carried out to determine what impact the addition of the new (variable) generation will have on existing overall network compensation requirements.

A3.1.16 Impact on Installation
A new station or stations are required in remote locations. However a wind farm substation has very few differences from a normal network station there is little difference**.**

A3.1.17 Impact on Maintenance
Normal restrictions on maintenance of network equipment in substations associated with generating stations due to restricted availability of outages and need for coordination of procedures e.g. earthing across an ownership boundary apply.

A3.1.19 Impact on Commissioning
If the substation equipment is commissioned by the wind farm supplier then there is little impact. If it is commissioned by network staff then rapid learning curves will be required on any non-standard equipment.

A3.1.22 Impact on Protection (external)
Reliable loss of mains protection is required; protection settings must allow for the varying load flows.

A3.1.23 Impact on Protection (internal)
The required protection will be provided by the wind farm supplier. In agreeing the location of the interface with the generator the network owner should minimise the extent of equipment solely required for the generation connection which he is required to protect.

A3.1.24 Impact on Control
Normal station controls required with minor additions for interface with the generator e.g. in interlocking and metering. As wind turbines are normally asynchronous machines check synchronising equipment is not required.

A3.1.25 Impact on Communications
Communications staff should be involved early in the project to ensure that the cost of any necessary communication equipment is included in agreements between the generator and the network owner on the cost of the network connection. Due to remote locations the cost of communication circuits back to a control centre may be quite high. Apart from the cost of the link the communication requirements should be standard.

A3.1.34 Impact on Civils
A full ground survey is particularly important as wind farms tend to be located in remote areas with possibly very poor ground conditions.

A3.1.36 Impact on Auxiliaries
As a local MV network may be non-existent the LT supply to the substation may have to come from the generator's MV equipment. Agreement will be required on the appropriate battery stand by time required from the network station in the event of loss of this supply.

A3.1.37 Impact on Equipment ratings
Assuming that the equipment in the local network is designed for bidirectional power flow special ratings should not be required for any of the substation equipment.

A3.1.39 Impact on Earthing
The network operator needs to monitor the earthing design studies very carefully as considerable safety issues may arise in the design of the substation earthing system due to poor ground conditions. If there is extensive MV cabling to the wind turbines this may lead to transferred potential issues.

A3.1.41 Impact on Testing
Additional training may be required if the substation is built by the wind farm supplier with non-standard (to the network owner) equipment. Additional costs may also arise from the time required to reach stations in remote locations.

A3.1.42 Impact on Relocatability
It is possible to make most of the station relocatable but it is probably not worth the cost or design effort as the wind farm is not likely to be going anywhere for a considerable period.

A3.1.43 Impact on Spares requirement
If substations associated with wind farm connections are built be wind farm suppliers then the network owner may end up with a considerable amount of one-off or near one-ff HV equipment. The spares policy will have to cater for this.

References

[1] T. Sato: Effects of many dispersed generations installed in customers on power systems. Extracted from ETRA report “Substation technology towards the 21st century”, Vol. 58, part 2, July 2002.

[2] Development and testing of ride-through capability solutions for a wind turbine with doubly fed induction generator using VSC, B4-302_2004 , K. H. SOBRINK, K.O.H. PEDERSEN, J. EEK

A4 Reactive Compensation

To maintain an efficient power system, the voltage should be constant and the power factor unity. To realize these conditions, reactive power should be properly compensated because it is mainly related to magnitude of power system voltages and power factor while active power is related to angular phase between the voltages at the sending and receiving points. Reactive power compensation can be considered from two perspectives

Reactive power compensation at the customer load

(a) Power factor correction
Most industrial loads have lagging power factors. If the lagging reactive power of some customer is excess, the load current through substations becomes larger than expected, that is, the load current exceeds the rated current and this may lead to the losses in the substations. In addition to this, from the view point of power quality, a bad power factor makes a bad impact on the operation of other customer's equipment. Therefore the power factor has to be corrected by reactive power compensation in substations.

(b) Voltage regulation
Voltage in power systems fluctuates according to the instantaneous level of supply and demand. If this fluctuation is large, it interferes with the efficient operation of customer's equipment. To protect against this, there are defined limits in the standard of voltage supply. Reactive power compensation has an important role in maintaining the voltages within the defined limits.

(c) Load balancing
Most AC power systems are three phase and are designed for balanced operation. Unbalance causes problems in customer's equipment such as additional losses in motors, oscillating torque in machines, increased ripple in rectifiers, saturation of transformers, and excessive neutral currents, etc. To avoid these troubles, the voltage balancing by using reactive power compensation is vital.

Reactive power compensation required by power systems

(a) Improvement of synchronous and voltage stability
There are two kinds of stability in AC electric power systems, that is, synchronous stability and voltage stability. The former is classified by time periods in the state of power system. One is steady state stability, which means whether the power will be transmitted stably (without losing synchronism of generators) when it increases gradually or there is a slight disturbance in the system. The other is dynamic and transient stability, which means whether the system will recover normal operation following a major disturbance such as a fault severe enough to trip a major circuit, or failure of a major equipment of the system. The latter is whether the system voltage will be maintained following some disturbance. Voltage stability can be lost if the reactive power demand of a load increases as the supply voltage decreases, causing a further voltage decrease, after a sudden disturbance. This is called voltage collapse. Reactive power compensation is essential to providing this stability and damping of power system oscillations by means of supplying and absorbing the reactive power rapidly and actively in the power systems.

(b) Maintenance of correct voltage level
Power system items such as generators, transmission lines and substations have the rated voltages and these are not very tolerant of overvoltage in power system. This kind of voltage is a dangerous condition for power system equipment because of the risk of flashover or the breakdown of insulation. The voltage also causes saturation of transformers to produce harmonics currents leading to ferroresonance and harmonic resonance when sufficient capacitance exists in the system.
Some power system loads such as steelmaker's arc furnance can cause random or repetitive voltage fluctuations which give rise to flicker. This flicker also causes the voltage fluctuations at the adjacent customer's place.
Reactive power compensation can be used to control these abnormal voltages.

(c) Regulation of voltage profiles to minimize transmission losses
To minimize transmission losses, it is necessary to prevent unnecessary flows of reactive power. Reactive power compensation is adopted to adjust the reactive power flows.

Technology
The appendices report on a number of reactive power compensators which have been installed in substations:

A4.1 STATCOM: Static Synchronous Compensator
A4.2 SVC: Static Var Compensator (TCR: Thyristor Controlled Reactor),
A4.3 SVC (TSC: Thyristor Switched Capacitor),
A4.4 Shunt Reactor
A4.5 Shunt Capacitor

Among above compensators, those from A4.1 to A4.3 are active compensators, which supply and absorb reactive power momentarily and rapidly by using power electronic technologies, while. A4.4 and A4.5 are conventional passive compensators and are switched to control steady conditions usinf circuit breakers. This appendix deals with these five compensator's impacts on substation designing and describes specific technological notices.

A4.1 Statcom

A STATCOM is a self-commutated converter connected to power system with a reactance of a transformer. A STATCOM controls the amplitude of the output voltage by changing the turn-on/off timing of thyristors in the self-commutated converter. The output voltage is variable with the same phase as the power system voltage. The voltage difference between the output voltage and the power system voltage is applied on the both terminals of transformer reactance, which generates lagging or leading reactive power. A STATCOM can control the reactive power continuously from leading phase to lagging one by making the output voltage greater or smaller than the power system voltage.
As a STATCOM covers a wide range of targets in use such as the voltage control and steady-state stability improvement, its function influences the power system very much. Therefore, the characteristics such as function, harmonics, and loss should be deeply examined. A STATCOM can minimize the generated harmonics by using multi-level converter, multi-stage transformer and multi-pulse PWM. A STATCOM can reduce the losses by using GCT instead of GTO.

Principle and Configuration
A STATCOM is a self-commutated converter connected to power system with a reactance of a transformer. A STATCOM controls the amplitude of the output voltage by changing the turn-on/off timing of thyristors in the self-commutated converter. The output voltage is variable with the same phase as the power system voltage shown in Figure 1. The voltage difference between the output voltage and the power system voltage is applied on the both terminals of transformer reactance, which generates lagging or leading reactive power. A STATCOM can control the reactive power continuously from leading phase to lagging one by making the output voltage greater or smaller than the power system voltage.

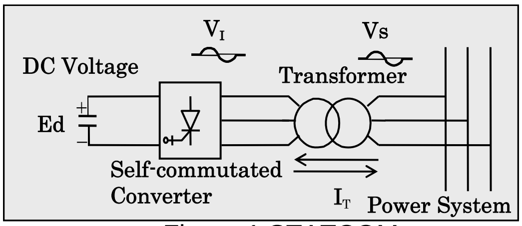
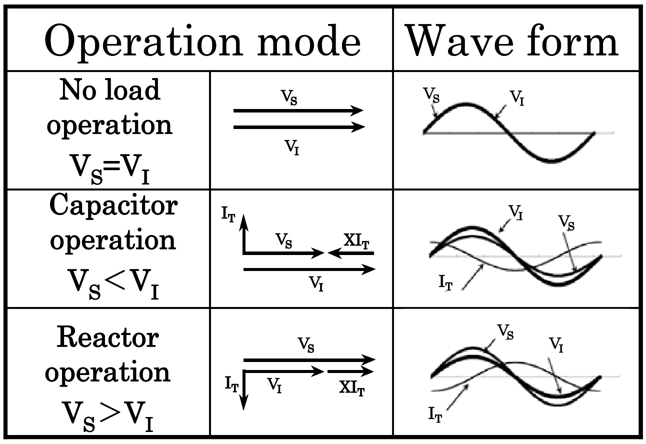


Figure 1 STATCOM



Basic system changes

Impact Index	Impact	Important Notice	Appendix
Fault level	None		A4.1.1
Power flow	Major	STATCOM contributes to stabilize the power flow fluctuation and to enhance steady-state stability of the system. So, both should be deeply considered.	
Frequency	None		
Voltage	Major	The coordination control with existing voltage control equipment (transformer tap control, SC, ShR) should be considered.	
Thermal rating	None		
Unbalance	Major	In the case that STATCOM is used as a countermeasure of voltage imbalance, the charge/discharge degree of capacitors in DC side becomes imbalance. Examine the capacity of the capacitor in consideration of this imbalance.	
Harmonics	Major	Examine multi-pulse PWM, multi-staged transformer and multi-level converter to reduce harmonics.	

Impedance	None		
Resonances	None		
Losses	Major	Decide which device to use to decrease the loss. The loss of GTO (Gate Turn-Off thyristor) is 1.4%. The loss of GCT (Gate Commutated Turn-off thyristor) is 0.6%. Consider the number of PWM pulse.	

Single line diagram impact

Impact Index	Impact	Important Notice	Appendix
Short circuit rating	None		A4.1.2
Operational switching	None		
Filtering	None	No use of filter for STATCOM.	
Compensation	None		
Installation	None		
Maintenance	None	Can be maintained offline.	
Bypass	None		
Commissioning	Major	System interconnection test is done according to the purpose of STATCOM installation.	
Insulation co-ordination	Minor	Same as general insulation design. Analyze the overvoltage level at fault, LIWV level, and SIWV level.	

Impact on detailed substation design

Impact Index	Impact	Important Notice	Appendix
Protection (external)	Major	Same as general protection design. Study the coordination between short/grounding faults' protection of STATCOM and external protection.	A4.1.3
Protection (internal)	Minor	Examine thyristor protection, controller protection, cooler protection, transformer protection.	
Control	Major	Coordination control with existing voltage control equipment is needed in some cases. Examine backup(redundant) controller to enhance reliability. Adopt DC Magnetization control.	
Comms	None		
Land & layout	Major	Design the layout to mitigate noise level that transformer and cooler generate.	
Visual impact	Minor	Same as general design. Consider the environment harmonization in accordance with the site.	
External pollution	Minor	Same as general design. Need the pollution design depending on the site's pollution level for air-insulated parts.	
Audible noise	Minor	Same as general design. Need the noise design depending on noise restriction.	
EMC	Major	Design electric instrument and gate firing circuit to withstand the noise from external EMC.	
Electrical clearances	None		
Safety clearances	Minor	All high voltage parts are isolated from human.	
EM fields	Major	Radio noise should be within the restriction value. The house or cubicle is shielded in some cases.	

Civils	Major	The house is designed in consideration of temperature and relative humidity condition and dust control level for the thyristor valve.
Containment	Major	Install the thyristor in doors.
Auxiliaries	Major	Install the thyristor, the capacitor (for initial charging), deionized water cooler, and house transformer in doors. As for the accessory device, it is same as TCR. Maintenance of the auxiliary systems is important to ensure good availability
Equipment ratings	Major	Thyristor rating is selected according to overvoltage and overcurrent at faults The DC voltage is basically selected by LTDS (Long Term DC Stability). It is considered that the device breakdown is especially caused by cosmic rays. This failure rate increases exponentially as the DC voltage raises.
Busbar layout	None	
Earthing	Major	High resistance neutral earthing system is adopted as the grounding protection in some cases.
Monitoring	Minor	Monitoring the output var and the fault indicator.
Testing	Major	Tests for each equipment(Thyristor valve:Rated current breaking test, Voltage sharing test and so on) Syntactic test connecting each equipment(Startup & Shut-down test, Protection interlock test and so on) System interconnection test(Reactive power generation test, Existing shunt reactor switching test and so on)
Relocatability	None	
Spares requirement	Major	GTO or GCT unit, Control board
Hazards	Major	Same as ordinary oil-filled and air-insulated equipment

Advice & recommendations

A4.1.1. Basic system changes

(1) Application of STATCOM affects to power flow, voltage and unbalance

The application of STATCOM to power systems can perform a variety of performance enhancement functions.

The transmission capacity of a power system is generally limited by the operating voltages and transfer impedances across the system. Application of a STATCOM at a specific location within the transmission system will increase the power transfer capacity by virtue of voltage support provided at each point of connection.

The Automatic Voltage Regulator (AVR) is generally used in the control system of a STATCOM for the voltage stabilization. Occasionally, the existing transformer, shunt reactor or static condenser plays an important role to control the voltage in the same substation where the STATCOM is scheduled to be installed. In this case, the coordination control between voltage regulators is necessary in order not to interfere with each other.

For balancing asymmetrical, continually varying loads such as arc furnaces and railway traction supplies, application of a STATCOM with individual control of its phase to phase reactive components offers a practical solution. But such applications, the rating of the STATCOM could be chosen so as to provide the appropriate power factor correction or controls the load point voltage within closer limits.

(2)Harmonics and Losses of STATCOM
Equipment utilising switching converter technology such as STATCOM generate harmonics. The level and the order of the harmonics generated by such equipment is dependent upon the equipment design and configuration. There are several countermeasures against harmonics as follows.

(a) PWM with Multiple pulses
The PWM to control the output voltage is also used to reduce harmonics with multiple pulses. Figure 2 shows an example of PWM with three pulses.
There are three degrees of freedom in three-pulse PWM that are used to reduce harmonics. The first degree of freedom is used to control the amplitude of fundamental frequency voltage. The others can be used to cancel the specified range of harmonics by pre-calculated pattern of PWM pulses.
However, as the number of pulses increases, the switching loss of the self-commutated thyristors such as GTO or GCT also increases. The relation between the switching loss and the harmonics is deeply examined before the adoption of a STATCOM.

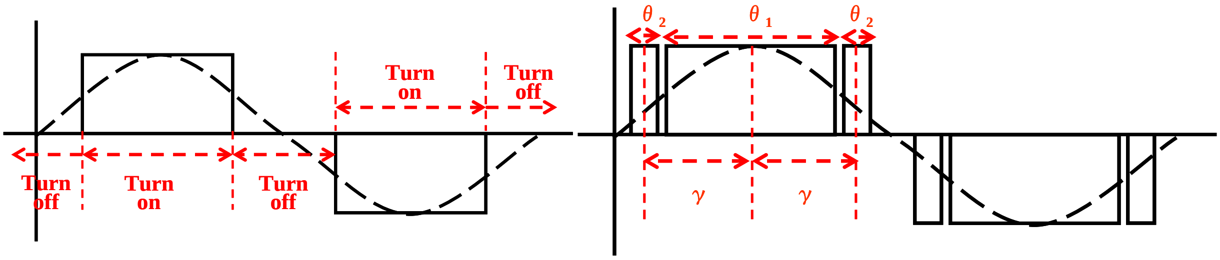
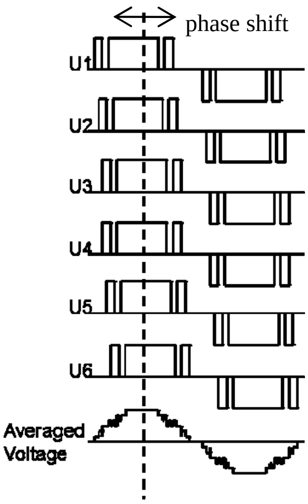


Figure 2 1-pulse PWM and harmonics elimination 3-pulse PWM[1]

(b)Multiple Converters
A STATCOM can make the output voltage wave similar to a sine wave with the multiple converters. The harmonics can be decreased by utilizing the phase shift between converters shown in Figure 3 and 4[2].



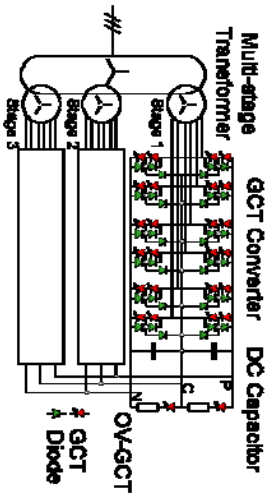


Figure 3 Multiplexing of 3-pulse PWM[2] Figure 4 STATCOM configuration[2]

The converter losses are due to semiconductor conduction and switching losses, as well as to snubber circuit losses (consumed by dv/dt and di/dt limiting circuits). These losses are greatly dependent on the characteristics of the power semiconductors employed in the converter and the number of switching they have to execute during each fundamental cycle.

The power semiconductors such as GTO, GCT, IGBT, IEGT etc. are applied to the converter of STATCOM. To use GCT thyristor does not require a snubber circuit, so that it can reduce the loss more than about 50% compared with GTO thyristor. [3]

A4.1.2. Single line diagram impact
The STATCOM being commissioned is assumed to be installed at a single location, complete with switchgear, transformers, building, thyristor valves, capacitors, control, relaying, instrumentation and auxiliary equipment. Commissioning requirements of a STATCOM are similar to any other similar power

system equipment such as an SVC. Commissioning program will need to be tailored to fit the requirements and application of the specific project.

A4.1.3. Impact on detailed substation design
1. Protection and control
STATCOM is designed for a specific application and may come in a variety of arrangements dependent upon the application. The protective arrangement for the STATCOM is designed to prevent equipment damage under fault or operational conditions outside the STATCOM rating.
Protection schemes comprise combination of conventional protective relays and protective functions performed by the STATCOM control system. The coordination of both protective systems is an important requirement for an optimized and intelligent protection scheme, ensuring both adequate proteciton and maximum utilisation.

The STATCOM protection functions can be subdivided into
(a) Conventional plant component protection
- Transformer protection
- Bus protection
- Phase fault protection
- Ground fault protection
- Overvoltage protection
- Filter protection

(b) Converter protection
- Thyristor valve protection
- Overcurrent protection
- Capacitor protection

A principal overview of the STATCOM controls and their interface with the power system as well as the STATCOM hardware (magnetization, converter, DC capacitor) is given in Figure 5[4].

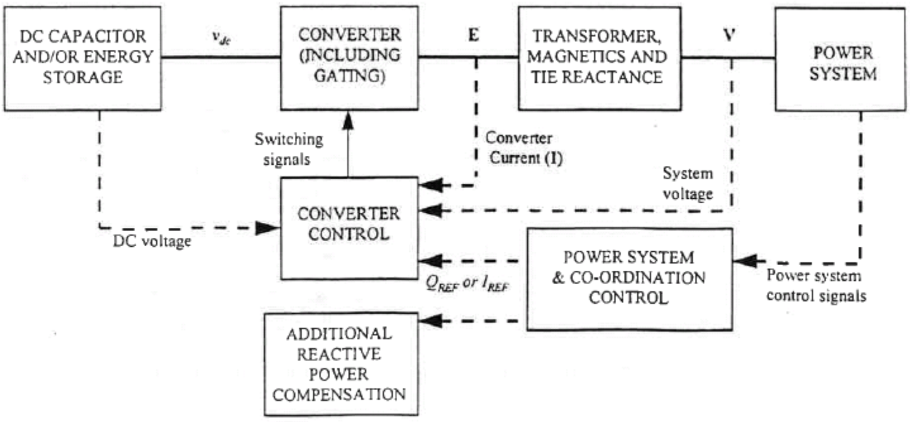


Figure 5 Overview of STATCOM Control System Power Components [4]

(a) Converter control
Converter control utilises a set of triggering signals to accomplish appropriate gating of the power electronic switches in order to provide the required reactive power.

(b) Power system control
Power system control contains the necessary circuitry for the reference reactive power or converter current value and a number of closed loop controls for controlling the appropriate power system quantities.

(c) Co-ordination Control
Co-ordination Control is required if the installation involves several reactive power compensators e.g., STATCOM, conventional SVC, thyristor or mechanically switched capacitors or reactors. The co-ordination control receives the total reactive power requirement form the Power System Control, and from this derives the settings for the individual compensation elements.

(d) Transformer magnetization control
The generation mechanism of transformer DC Magnetizaton.

2. Land & layout

The layout and pictures of the STATCOM (±80MVA) are shown in Figure 6 A 1-pole of the converter is stored in each cubicle in the picture A. The picture B is the converter transformer and its cooler. The picture C is converter cooler in which the number of operating fans is controlled by detecting the water temperature of the converter to minimize power consumption. The picture D is the deionizer of cooling water for GCT thyristors.

The layout should be designed to mitigate noise level that transformer and cooler generate. Electric instrument and gate firing circuit also should be designed to withstand the noise from external EMC and not to through out radio noise. So the house or cubicle is shielded in some cases. Additionally the house is designed in consideration of temperature and relative humidity condition and dust control level for the thyristor valve.

3. Testing

(a) Factory and off-site test
Factory and off-site tests are performed to verify the performance of individual components and subassemblies of equipment prior to transfer to the site. These tests are typically classified as routine and design tests. Routine production tests are performed for quality control purposes and verify that components meet the specified requirements. Design tests are performed to determine the adequacy of equipment and component parts to meet assigned ratings and to operate satisfactorily under required service conditions.

(b)Site test
After delivery and installation of equipment site tests are performed to verify proper operation of all equipment to the specification. The site tests provide a full opportunity to establish the performance of all the STATCOM components working together. The following test are usually incorporated to establish the STATCOM performance:

- STATCOM control system tests
- Voltage regulating performance tests
- Disturbance dynamic performance tests
- Normal and overload capability tests
- Harmonic performance tests
- Radio interference tests
- Environmental tests (noise, heating/cooling losses)
- Special control features tests

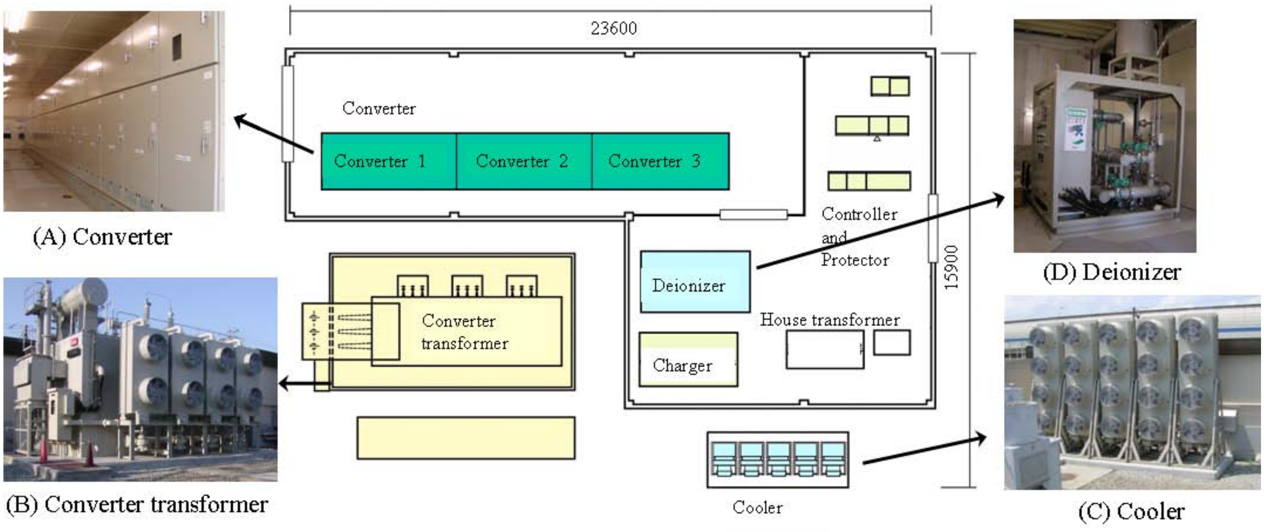


Figure 6 Layout of the STATCOM (±80MVA)[5]

4.Equipment ratings

(a)DC voltage rating

The DC voltage rating is basically determined by LTDS (Long Term DC Stability). It is considered that the device failure is especially caused by cosmic rays and that this failure rate increases exponentially as the DC voltage raises.

In case of 6kV-6kAGCT, the DC voltage rating is determined to be 3000V on the safe side because the DC voltage is 3200V that assures the device failure rate below 100FIT or less. (FIT is the probability of failure at the rate of 100 times every 10^9 hours)

(b)Maximum DC voltage

The maximum DC voltage is the maximum value with which the device can break the maximum short circuit current. There are a lot of voltage increase factors in the ordinary operation. The voltage increase factors are shown as follow.

- DC voltage control error at transient phenomenon
- DC voltage pulsation caused by the voltage imbalance in the power system
- Neutral voltage fluctuation of 3-level converter
- Ripple voltage by PWM

The maximum DC voltage is selected in consideration of these voltage increase factors.

5.Maintenance

These are complex systems and are only as reliable as the weakest link. It is important to consider all the aspects of the Statcom when determining the maintenance strategy. Particular attention should be paid to the cooling elements of the systems as they include motors and liquids which require regular inspection. Spares provision for power electronics and control cards should take into account the long term availability of components and obsolescence. i.e.stock piling products before they become obsolescent maybe worth considering.

References:

[1] T. Sato, Y. Matsushita, K. Temma, N. Morishima, I. Iyoda: Prototype test of STATCOM and BTB based on voltage source converter using GCT thyristor. IEEE 2002, p2037-2042

[2] T. Fjii, S. Funahashi, N. Morishima, M. Azuma, H. Teramoto, N, Iio, H. Yonezawa, D. Takayama, Y. Shinki: A±80MVA GCT STATCOM for the Kanzaki Substation. IPEC-Niigata. 2005

[3] M.Yagi, T. Takano, T. Sato, I. Iyoda, K. Temma: Role and new technologies of STATCOM for Flexible and low cost power system planning. CIGRE session 2002, 14-107

[4] CIGRE WG14.19: STATIC SYNCHRONOUS COMPENSATOR (STATCOM), 1999 Brochure No.144

[5] H. Yonezawa, D. Takayama, Y. Shinki, N. Morishima, S. Funahashi, T. Fujii, M. Azuma, H. Teramoto, N. Iio: Operating performance of the STATCOM in The Kanzaki substation. CIGRE SC A3&B3 Joint Colloquium in Tokyo 2005, 111

A4.2 SVC Thyristor Controlled Reactor (TCR)

A Thyristor Controlled Reactor (TCR) consists of a lagging phase circuitry that controls the reactor current by the thyristor phase-shift control and a leading phase circuitry that possesses capacitors and filters. And it can control the reactive power continuously from a lagging phase to a leading phase by thyristor switching every half cycle. The TCR output current level is controlled by the firing angle. The reactor is substituted by the leakage impedance of a transformer. The TCR that uses such a high impedance transformer is particularly called TCT (Thyristor Controlled Transformer) type SVC. The step-down transformer is applied to adjust the thyristor voltage to the device rating. A TCR output becomes a discontinuous and includes quite a few harmonics so that it usually has the capacitor as the filter to absorb the harmonics. The capacitor is designed to absorb not only the harmonics of TCR but also that of load.

Principle and Configuration
A TCR is a reactor with a thyristor back-to-back connection circuit (see Figure 1). The reactor current is controlled by thyristor switching every half cycle. When the thyristor is switched at the firing angle of 90 degree (a), the output current is the maximum value of continuous sine wave shown in Figure 2. The TCR output current level is controlled by the firing angle. Figure 2 also shows the case of 120 degree firing angle which gives a discontinuous wave form including harmonics. In many cases, a step-down transformer is applied to adjust the thyristor voltage to the device rating. The reactor in Figure 1 is substituted by the leakage impedance of this transformer. The TCR that uses such a high impedance transformer is particularly called TCT.

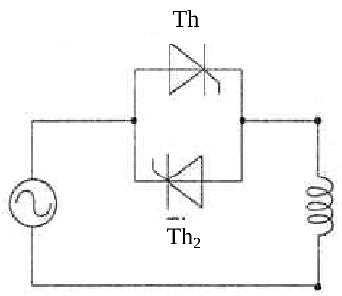


Figure 1. TCR circuit

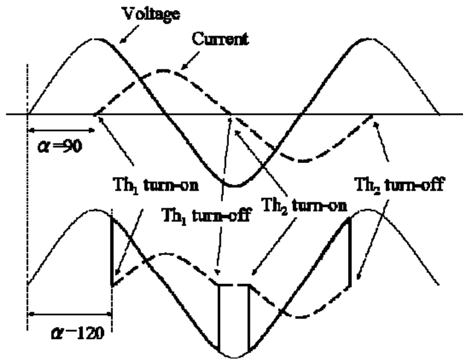


Figure 2. The wave form of TCR

A TCR is equipped with capacitors which supply leading reactive power. The capacitors play an additional role as the filter for harmonics. Figure 3 shows the configuration and the reactive power compensation method of TCR.

The TCR supplies lagging reactive power(QR) by thyristor phase-shift control according to reactive power for load(QL). The TCR can erase the effect of reactive power for load(QL) by adding capacitors' reactive power(QC) to TCR's output so that the voltage fluctuation can be suppressed.

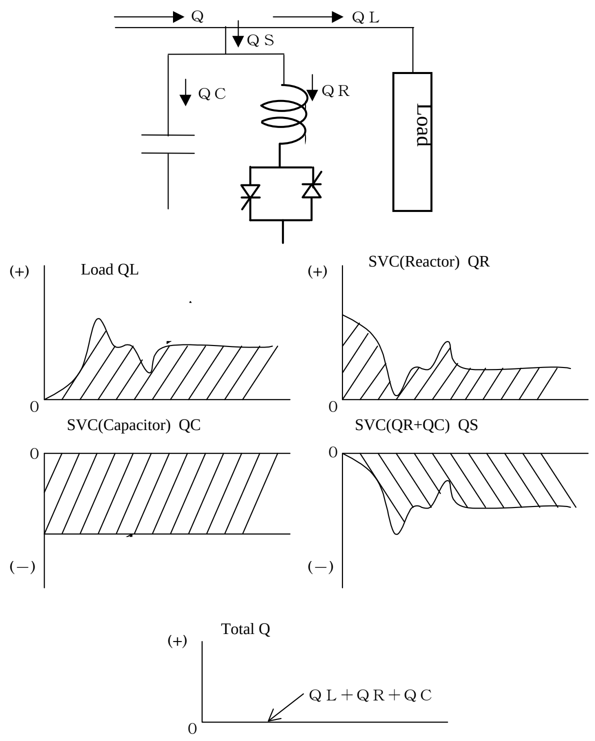


Figure 3. The configuration and the reactive power compensation method of TCR

Basic system changes

Impact Index	Impact	Important Notice	Appendix
Fault level	None		A4.2.1
Power flow	Major	The power flow should be examined if the target of TCR is to prevent from stepping out of the power system.	
Frequency	None	The ordinary level of the frequency fluctuation should be considered.	
Voltage	Major	SVC design must incorporate appropriate range, and voltage step size to meet system requirements. The coordination control with existing voltage control equipment (transformer tap control, SC, ShR) should be considered.	
Thermal rating	Major	The temperature of transformers or reactors might rise because of harmonics. Do the magnetic analysis to reduce it.	
Unbalance	Major	Occasionally, a phase-shifted Scott TCR might be applied to reduce the imbalanced reactive power of loads to minimize the capacity of TCR.	
Harmonics	Major	The harmonics to be absorbed must be identified and specified. Filters are occasionally necessary to reduce the harmonics current generated by the TCR switching A Condenser is applied as a filter for harmonics. Design the impedance of reactance and firing angle to reduce harmonics.	
Impedance	Major	Design the impedance of reactance to reduce harmonics and to gain the target TCR capacity.	
Resonances	Major	Harmonics is generated by resonance with the impedance of the power system and the TCR. Harmonics analysis about the impact of resonance should be examined.	

Losses	Major	Design the filters at the low voltage using step-down transformer to decrease the loss.	

Single line diagram impact

Impact Index	Impact	Important Notice	Appendix
Short circuit rating	None		A4.2.2
Operational switching	None		
Filtering	Major	Condenser is applied as a filter for harmonics.	
Compensation	None		
Installation	None		
Maintenance	Major	Can be maintained offline. Consider the voltage fluctuation due to SVC capacitor at SVC shut-down.	
Bypass	None		
Commissioning	Major	System interconnection test is done according to the purpose of SVC installation.	
Insulation coordination	Minor	Same as general insulation design. Analyze the overvoltage level at fault, LIWV level, and SIWV level.	

Impact on detailed AC substation design

Impact Index	Impact	Important Notice	Appendix
Protection (external)	Minor	Same as general protection design. Study the coordination between short/grounding faults' protection of SVC and external protection.	A4.2.3
Protection (internal)	Major	Examine thyristor protection, controller protection, cooler protection, transformer protection. Apply different protection method depending on thyristor firing-method & connection. Requirements for filter components R,L,C.	
Control	Major	Coordination control with existing voltage control equipment is needed in some cases. Examine backup(redundant) controller to enhance reliability.	
Communication	Major	interface with existing control schemes	
Land & layout	Major	Design the layout to mitigate noise level that reactor, transformer and cooler generate.	
Visual impact	Minor	Same as general design. Consider the environment harmonization in accordance with the site.	
External pollution	Minor	Same as general design. Need the pollution design depending on the site's pollution level for air-insulated parts.	
Audible noise	Minor	Same as general design. Need the noise design depending on noise restriction.	
EMC	Major	Design electric instrument and gate firing circuit to withstand the noise from external EMC.	
Electrical clearances	None		
Safety clearances	Minor	All high voltage parts are isolated from human.	
EM fields	Major	Radio noise should be within the restriction value. The house or cubicle is shielded in some cases.	

Civils	Major	The house is designed in consideration of temperature and relative humidity condition and dust control level for the thyristor valve. Metallic loops in the rebar must be avoided if air cored reactors are used, otherwise heating and corrosion of the rebar may occur.	
Containment	Major	Install the thyristor in-doors.	
Auxiliaries	Major	Install deionized water cooler for thyristor Examine redundant AC power-source for cooler depending on reliability.	
Equipment ratings	Major	Thyristor rating is selected according to overvoltage and overcurrent at faults.	
Busbar layout	Major	High currents may be experienced so appropriate measures should be taken	
Earthing	Major	Harmonic filter air-cored reactor magnetic fields	
Monitoring	Minor	Monitoring the output var and the fault indicator.	
Testing	Major	Test for each equipment(Thyristor valve: Voltage sharing test, Minimum firing sensibility test and so on) Syntactic test connecting each equipment(Startup & Shut-down test, Protection interlock test and so on) System interconnection test(Reactive power generation test, Existing shunt reactor switching test and so on)	
Relocatability	Major	This may be required if the generation patterns are changing	
Spares requirement	Major	Control board, Thyristor device L and C Harmonic filter components	
Hazards	Minor	Same as ordinary oil-filled and air-insulated equipment	

Advice & recommendations

A4.2.1. Basic system changes

1. Application of TSC affects to power flow, voltage and unbalance

SVC is applied to power systems to perform a variety of functions. Through its ability to offer continuous and fast reactive power control economically, it is being increasingly utilised in applications other than the traditional system voltage control such as increasing the power transfer capability of existing transmission systems, increasing the system transient stability margin, providing dynamic reactive power compensation to AC-DC converters in DC transmission and interconnection systems. In addition, SVC is applied to balance phase loading, to damp subsynchronous resonance and to reduce temporary overvoltage.

When SVC is applied to balance phase loading, a phase-shifted scott connection SVC can be more economical than an ordinary three-phase SVC as a countermeasure of the voltage fluctuation caused by an unbalanced load such as an electric train. A phase-shifted scott connection SVC has the advantage in that the capacity of TCR for T-winding or M-winding can be different from that of each other corresponding to the unbalance of load.

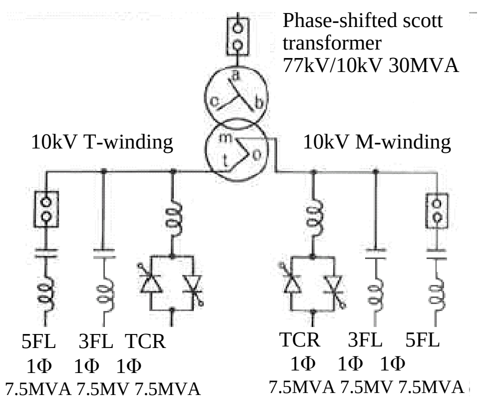


Figure 4 phase-shift scott SVC

2. Harmonics & Resonances
A TCR usually has the capacitor as the filter to absorb the harmonics. The capacitor is designed to absorb not only the harmonics of TCR but also that of load.

The allowable amount of harmonics should comply with each country's harmonics guideline. Additional filters are required if the harmonics exceeds the allowable value.
It is necessary to take the f-z characteristic of power system and an existing harmonics into consideration to suppress harmonics within the allowable level.

(a) Filter
The necessity of the filter is examined in consideration of the system residual harmonics and %Z of the transformer which determine the specification such as the capacity and the degree of the filter.

(b)Transformer
The %Z of the transformer is decided to decrease the harmonics that flows into power system in consideration of the converter harmonics and the residual harmonics in power system.

(c) Thyristor firing angle
The amount of the TCR harmonics increases with the firing angle increased. The best firing angle should be decided in terms of harmonics, the detection time and so on. Once the best firing angle is decided, the reactor rating should be selected to obtain the rated output in the firing angle.

A.4.2.2 Single line diagram impact
SVC being commissioned is assumed to be installed at a single location, complete with switchgear, transformers, thyristor valves, reactor, capacitors, control, relaying, instrumentation and auxiliary equipment. Commissioning requirements of a SVC are similar to any other similar power system equipment such as an STATCOM. Commissioning program will need to be tailored to fit the requirements and application of the specific project.

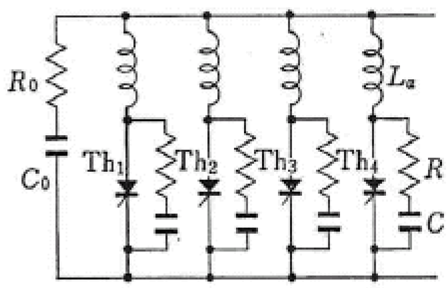
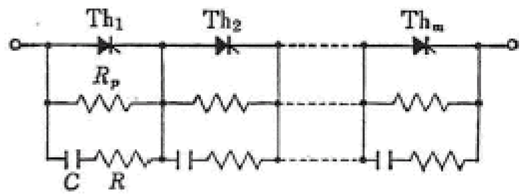
A.4.2.3 Impact on detailed substation design
1. Protection & control
Protection method of a SVC is similar to any other similar power system equipment such as an STATCOM. Protection schemes comprise combination of conventional protective relays and protective functions performed by the SVC control system. The coordination of both protective systems is an important requirement for an optimized and intelligent protection scheme, ensuring both adequate proteciton and maximum utilisation.One of the protective functions performed by the SVC is thyristor valve protection. The protection method depends on thyristor firing method and connection.

Two firing method, an electromagnetic triggering and a light triggering, can be utilized for SVC. There is little difference of reliability in both triggering systems. An electromagnetic triggering requires the parallel connection of thyristors because the series connection of thyristors has the difficulty to keep the voltage for each thyristor balanced due to the dispersion of firing signal access time, which varies with the difference of the circuit distance. In the parallel connection of thyristors, the inverter voltage should be low and the current become large. As the inverter current capacity increases, the current capacity of the high impedance transformer and the bus duct (between inverter and high impedance transformer) also increases. The more capacity SVC requires, the more costly an electromagnetic triggering type SVC becomes. On the other hand, the signal access time for each device is almost the same in light triggering so that the thyristors can be connected in series, which can avoid the deterioration of cost performance.

Generally, in the low capacity about 20MVA or less, an electromagnetic triggering shows better cost performance than a light triggering. It is profitable to consider which thyristor firing method should be adopted according to the SVC capacity. The difference of thyristor firing method results in the difference of its installation space and the protection method.

The main purpose of SVC application is voltage stabilization. It can be achieved according to control reactive power high speed and continuously. Figure 5 shows AC-AVR control circuit of SVC. It controls rms AC voltage to correspond to the reference value.

Table 2. The device connection method

An electromagnetic triggering (series connection)	An light triggering (parallel connection)
	

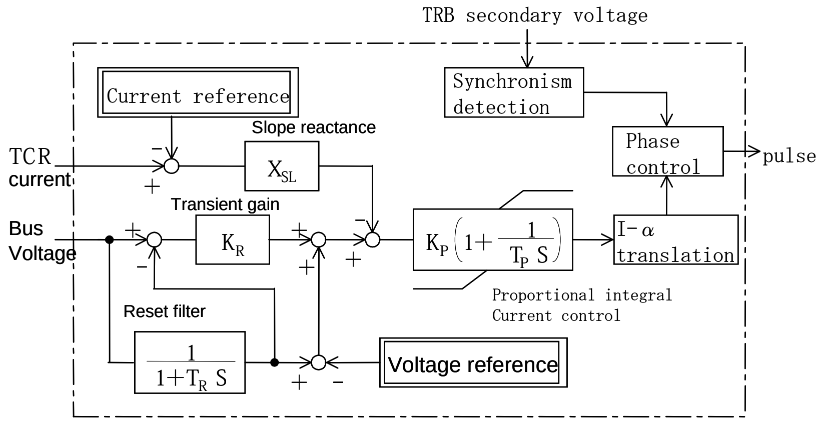


Figure 5 Control circuit of TCR

2. Land & layout

The layout of the TCR is shown in Figure 6. The thyristor, protection and controller is stored in a simple house. The layout should be designed to mitigate noise level that transformer and cooler generate. And the house is designed in consideration of temperature and relative humidity condition and dust control level for the thyristor valve.

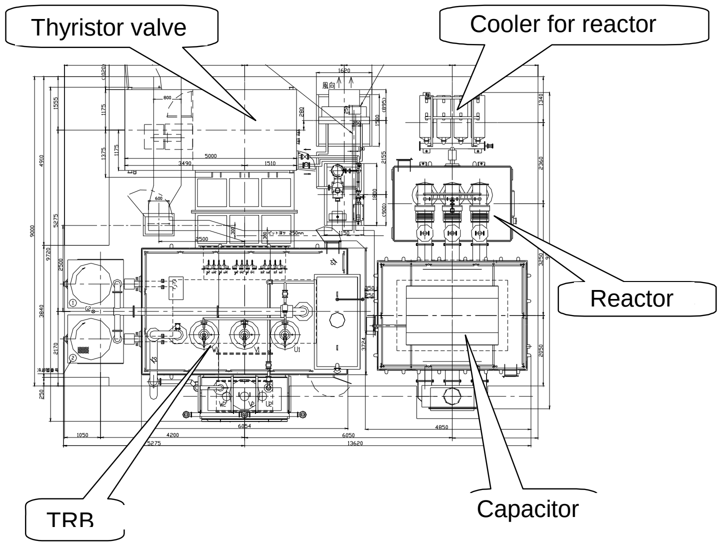


Figure 6 Layout of TCR

3. Auxiliaries
A deionized water cooling system is used to that cool the thyristor, the snubber resistance, and the anode reactor. It consists of an ion exchange resin, a water pump, a heat exchanger, various instrumentation, and controllers. The cooler is important equipment that needs high reliability for the water-cooled thyristor. To improve the reliability, the pump, the heat exchanger, and the cooling tower are multiplexed, and if these parts break down, the standby equipment is activated automatically. And the power source for the cooler can be received from two or more systems, and switch to another system automatically when the receiving power system is blacked out.

Moreover, a controller and a monitoring system, and a alarm system for cooler also require high reliability because of the following reason.

(1)The thyristor insulation may possibly deteriorate due to the condensation on the pipe when water temperature becomes lower below the dew point. (The frozen prevention measures should be considered where the outside temperature becomes 0℃ or less.)

(2)If the water is adulterated and its conductivity rises, the leakage current increases in the cooling water. It is more likely to cause an electric corrosion in the metallic contact parts of cooling system, which may increase water leakage.
With the leakage in the valve or the module, there is a possibility that the system interrupts because of short/grounding circuit faults in the main circuit, etc. In the case of the leakage on the water pipe, the cooling capability comes short due to the decrease of the deionized water.

4. Testing
Two distinct sets of tests are recognised as necessary for SVC, factory and site tests. Factory tests are designed to verify the performance of individual SVC components prior to transfer to the site and are classified as type or routine tests. Major components of TCR are circuit breaker, transformer, reactor, thyristor valve, control and protection.

Thyristor valve design will need to take full account of the voltage and current stresses. The compliance of the valve design and manufacture with the performance specification can only be determined through the appropriate tests.

Site tests for TCR are following,
- Reactance symmetry test
- thyristor equal firing test
- reactive power rating test
- Energisation test
- Harmonic performance test

- Operating Characteristics and
- SVC control system test
- Disturbance test
- Heat run
- Noise control

References:

[1] CIGRE WG38.01: STATIC VAR COMPENSATORS, 1986 Brochure

[2] T.Hasegawa, H.Takesue, D.Kubo, M.Hakoda, O.Kondo, H.Yamamura: THE 77kV 40MVA MULTI-FUNCTION SVC INSTALLED IN SUBSTATIONS. IFAC Symposium on Power Systems and Power Plant Control 1989

A4.3 Thyristor Switched Capacitor (TSC)

A Thyristor Switched Capacitor (TSC) switches the capacitors with thyristor turn-on & off. It consists of a group of capacitors with a thyristor back-to-back connection circuit. The thyristor switching timing should be fixed when the power source voltage and the capacitor charging voltage become equal. If a thyristor is switched on at the phase when the power source voltage and the capacitor charging voltage are different from each other, the inrush current Ic=C(dv/dt) flows into the capacitor. Occasionally, the inrush current might damage thyristors and cause harmonics vibration on the power source. Therefore, the firing phase of the thyristor is usually fixed to the peak point of the power source voltage, which makes a TSC output stepwise, not continuous. However, its harmonics is mitigated and its loss is small compared with TCR. On the other hand, it has the response delay of a cycle or less because the thyristor turn-on phase is limited, so that there is a problem left in the application for the flicker load with the fluctuation characteristic of a cycle order. Actually, a reactor is applied in series with the capacitor to decrease the inrush current (di/dt) and to avoid harmonics inflow to TSC.

Principle and Configuration
A TSC consists of a group of capacitors with a thyristor back-to-back connection circuit. The thyristor switching timing should be fixed when the power source voltage and the capacitor charging voltage become equal. If a thyristor is switched on at the phase when the power source voltage and the capacitor charging voltage are different from each other, the inrush current ic=C(dv/dt) flows into the capacitor. Occasionally, the inrush current might damage thyristors and cause harmonics vibration on the power source. Therefore, the firing phase of the thyristor is usually fixed to the peak point of the power source voltage, which makes a TSC output stepwise, not continuous. However, its harmonics is mitigated and its loss is small compared with TCR. Actually, a reactor is applied in series connection with the capacitor to decrease the inrush current (di/dt) and to avoid harmonics inflow to TSC.

Figure 1 shows the operation wave form of each capacitor of TSC with a thyristor back-to-back connection control. The capacitor terminal voltage v_c is charged to the peak value of power source voltage e_s through turn-on thyristor T_2. Gate pulse is signalled to thyristor T_1 when e_s and v_c become equal. The capacitor current i_c begins to flow after thyristor T_1 is turned on. Current i_c flows continuously by giving the gate pulse every half cycle from t_2 to t_4 when the gate pulse isn't given to T_2. The output current is sine wave so that harmonics is made minimum.

Thyristor-diode back-to-back connection method is also used from the economical point of view. It is a method to replace one of two thyristors with the diode. It becomes advantageous in the cost performance though the response delay is made a little larger than a thyristor back-to-back connection method.

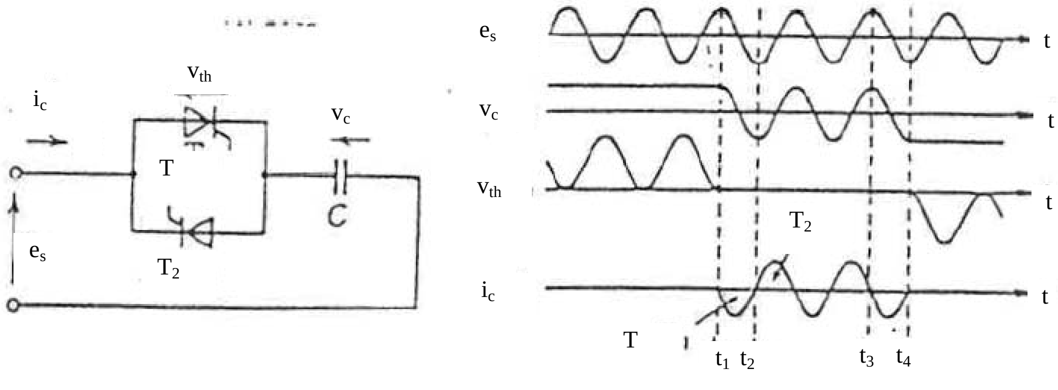


Figure 1 The operational waveform of thyristor back-to-back connection method

Figure 2 and 3 show the configuration and the output for TSC respectively. The output of a capacitor for TSC cannot help becoming stepwise, not continuous so that a TSC requires a group of capacitors to make its output as continuous as possible. A TSC has several features compared with a TCR such as better cost performance by simple configuration, less loss and no inrush operation by synchronous turn-on/off. On the other hand, it has the response delay of a cycle or less because the thyristor turn-on phase is limited, so that there is a problem left in the application for the flicker load with the fluctuation characteristic of a cycle order.

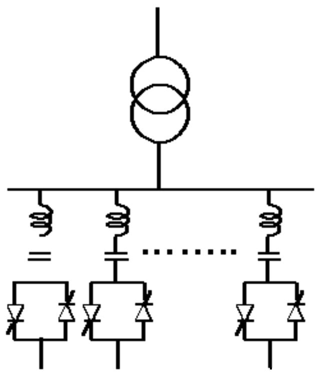


Figure 2 TSC configuration

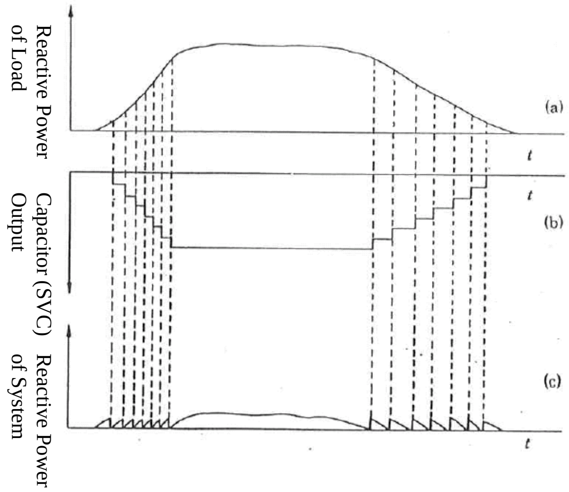


Figure 3 Output of TSC

Basic system changes			
Impact Index	**Impact**	**Important Notice**	**Appendix**
Fault level	None		A.4.3.1
Power flow	Major	TSC response is slower than TCR because the device switching angle is limited to 180 degrees.	
Frequency	None		
Voltage	Major	SVC design must incorporate appropriate range and step size to meet system requirements The coordination control with existing voltage control equipment (transformer tap control, SC, ShR) should be considered.	
Thermal rating	None		
Unbalance	None		
Harmonics	None	TSC generate no harmonics, because the device switching angle is 180 degree.	
Impedance	None		
Resonances	None		
Losses	None	The losses are lower than TCR.	

Single line diagram impact			
Impact Index	**Impact**	**Important Notice**	**Appendix**
Short circuit rating	None		A.4.3.2
Operational switching	None		
Filtering	None	No filter necessary due to no harmonics. Reactor is connected in series with capacitor to reduce the inrush current.	
Compensation	None		

Installation	None		
Maintenance	Minor	TSC can operate in lowering capacity even if one of capacitors is suspended for maintenance.	
Bypass	None		
Commissionin g	Major	System interconnection test is done according to the purpose of SVC installation.	
Insulation coordination	Minor	Same as general insulation design. Analyze the overvoltage level at fault, LIWV level, and SIWV level.	

Impact on detailed AC substation design

Impact Index	Impact	Important Notice	Appendix
Protection (external)	Minor	Same as general protection design. Study the coordination between short/grounding faults' protection of SVC and external protection.	A4.3.3
Protection (internal)	Major	Examine thyristor protection, controller protection, cooler protection, transformer protection. Apply different protection method depending on thyristor firing-method & connection.	
Control	Major	It is necessary to control the firing angle of the thyristor switching at the peak point of the power source voltage to reduce an inrush current that flows to capacitors when thyristor turns on.	
Communication	None		
Land & layout	None		
Visual impact	Minor	Same as general design. Consider the environment harmonization in accordance with the site.	
External pollution	Minor	Same as general design. Need the pollution design depending on the site's pollution level for air-insulated parts.	
Audible noise	Minor	The noise of TSC is lower than that of TCR because TCR is not reactor switching equipment but capacitor switching one.	
EMC	Major	Design electric instrument and gate firing circuit to withstand the noise from external EMC.	
Electrical clearances	None		
Safety clearances	Minor	All high voltage parts are isolated from human.	
EM fields	None	Radio noise shoud be within the restriction value. The house or cubicle is shielded in some cases.	
Civils	Major	The house is designed in consideration of temperature and relative humidity condition and dust control level for the thyristor valve.	
Containment	Major	Install the thyristor in doors.	
Auxiliaries	Major	Install deionized cooler for thyristor Examine redundant AC power-source for cooler depending on reliability.	
Equipment ratings	None	Thyrister rating is selected according to overvoltage and overcurrent at faults Capacity of each capacitor is selected according to the voltage fluctuation at the power system interconnection.	
Busbar layout	None		
Earthing	None		

Monitoring	Minor	Monitoring the output var and the fault indicator.
Testing	Major	Test for each equipment(Thyristor valve:Voltage sharing test, Minimum firing sensibility test and so on) Syntactic test connecting each equipment (Startup&Shut-down test, Protection interlock test and so on) System interconnection test (Reactive power generation test, Existing shunt reactor switching test and so on)
Relocatability	None	
Spares requirement	Major	Control board, Thyristor device
Hazards	Minor	Same as ordinary oil-filled and air-insulated equipment

Advice & recommendations

A4.3.1. Basic system changes
The important notice for the basic system changes is the same as that for TCR.

1. Application of TSC affects to power flow, voltage and unbalance
The dynamic response of the TSC is fast and typically around 0.5 to 1 cycle of supply frequency, but delays in the measurement and control circuits may impose settings that give slower response for control stability reasons of typically around 3 to 10 cycles of supply frequency. The comments made on the response of TCR schemes also apply to TSC schemes.

2. Harmonics & Losses
TSC generate no harmonics, because the device switching angle is limited to 180 degree. But there is a danger of series resonance with the power system at harmonic frequencies and careful co-ordination of the series reactor impedance with respect to the TSC rating is required.

Losses of TSC schemes are less then TCR losses but higher than pure capacitor losses with typical losses.

A4.3.2 Single line diagram impact
The important notice for the single line diagram impact is the same as that for TCR. SVC being commissioned is assumed to be installed at a single location, complete with switchgear, transformers, thyristor valves, reactor, capacitors, control, relaying, instrumentation and auxiliary equipment. Commissioning requirements of a SVC are similar to any other similar power system equipment such as an STATCOM. Commissioning program will need to be tailored to fit the requirements and application of the specific project.

TSC does not need filter, because of no harmonics. But reactor is connected in series with capacitor to reduce the flow-in harmonics and the inrush current. So, TSC can operate in lowering capacity even if one of capacitors is suspended for maintenance.

A4.3.3 Impact on detailed substation design
The important notice for the impact on detailed substation design is the same as that for TCR.

1. Protection
The capacitor is charged by transient current through the diode at the initial charge before its actual operation if the thyristor-diode back-to-back connection method is applied to the TSC. In the worst case, the charged voltage reaches up to twice the rated voltage so that the thyristor voltage between A-K is made up to three times the power system voltage because of that capacitor voltage. Therefore, a circuit breaker with the resistance closing is adopted so that the capacitor is not overcharged.

If the over-voltage of power system takes place in the thyristor turn-off condition, the capacitor is overcharged through the diode. Accordingly, the thyristor voltage between A-K is also overcharged. If need be, a zinc oxide varistor is applied for the over voltage protection.

2. Auxiliaries

The cooler of thyristor is self-cooled or air-cooled because of the simplicity of maintenance. Deionized cooler can be applied according to the capacity. The important notice for the cooler design is the same as that for TCR.

3. Equipment ratings

(a)Capacity

The power system voltage fluctuation should be limited to a specified value regulated by every utility. Now assume its value is 2%. Then, the voltage fluctuation by TSC switching is also maintained within 2%. If the short circuit capacity is 50MVA, a single capacity P_{tsc} of TSC can be calculated in the following equation (not more than 1MVA).

$$\Delta V = P_{tsc} / 50MVA * 100 <= 2\%$$

(b)Step-down transformer

Step-down transformer to match the thyristor's rating is generally applied to TSC from the economical reason. Transformer has a shield between the primary and the secondary to prevent the electrostatic transition voltage.

(c)Reactor

The series reactor has several effects on the harmonics expansion prevention, the inrush current suppression and the fault current limitation. The rating of reactor should be determined according to the characteristic of the power system.

(d)Thyristor

The voltage between A-K of the thyristor device is charged by the following voltage E_{TH} in the thyristor turn-off condition.

$$E_{TH} \quad \sqrt{2}E_c \quad \sqrt{2}E_s \quad \sin(wt)$$

Especially, with the impedance of the series reactor made large, E_c is made larger than E_s and thyristor is charged up to twice or more of the power-source voltage (Figure 4). It is necessary to select the thyristor rating taking the expected voltage tolerance into consideration.

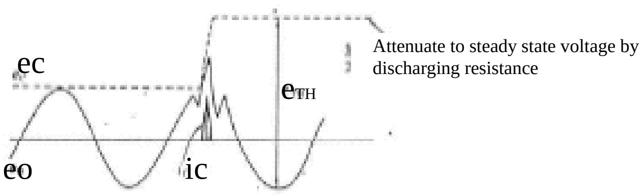


Figure 4 Voltage and Current at transient change

References:

[1] CIGRE WG38.01: STATIC VAR COMPENSATORS, 1986 Brochure

[2] Y.Mino, T.Sato, O.Kondo, T.Yoshichika:Substation TSC Installation To Control Voltage Fluctuation IPEC-Yokohama1995

A4.4 Shunt Reactor

If the system has leading power-factor during off-peak load period, a shunt reactor connected to the system in parallel regulates the system voltage by supplying lagging reactive power. The interrupting current for a shunt reactor is comparably small, which influences the interrupting performance of the circuit breaker(CB). So, it tends to become difficult to make the open operation of a circuit breaker for a shunt reactor. The countermeasure is the adoption of a resistance-closing system or Gas insulated Circuit Breaker because the reduction of the transient recovery voltage is made possible.
During restoration after the total blackout of a substation, shunt reactors should be automatically switched off to prevent the abnormal drop of the system voltage. However, without shunt reactors, there is a possibility that substation facilities particularly ones fed by large cables might suffer the overheated damage because of the over-voltage during the restoration in a power system. Therefore, the characteristics of the power system should be considered to determine the necessity of under-voltage relays.

Basic system changes

Impact Index	Impact	Important Notice	Appendix
Fault level	None		A4.4.1
Power flow	None		
Frequency	None		
Voltage	Major	It causes the larger voltage fluctuation than the regulated value if the capacity of a reactor is too large for the power system. Examine the capacity of a reactor.	
Thermal rating	None		
Unbalance	None		
Harmonics	None		
Impedance	None		
Resonances	Major	Shunt reactors (ShR) isolated with cables or other sources of capacitance could lead to resonance conditions	
Losses	None		

Single line diagram impact

Impact Index	Impact	Important Notice	Appendix
Short circuit rating	None		A4.4.2
Operational switching	Major	The interrupting current for ShR is comparably small so that the interrupting performance of the circuit breaker(CB) is occasionally insufficient to establish withstand voltage.	
Filtering	None		
Compensation	None		
Installation	Minor	ShR is connected to the secondary bus of a transformer directly, or connected to the tertiary side of a transformer. The Voltage regulation and the cost of series equipment should be taken into consideration to decide how to install the ShR.	
Maintenance	None		
Bypass	None		

Commissioning	Minor	System interconnection test is done according to the purpose of ShR installation.	
Insulation coordination	Minor	The surge impedance of ShR is comparatively large. Examine the distance between surge arresters and the ShR.	

Impact on detailed AC substation design

Impact Index	Impact	Important Notice	Appendix
Protection (external)	Minor	ShR is connected to the terminal of the power system so that the operating time of the relay should be as short as possible. At the time of the restoration after the total interruption of the substation, ShR should be automatically separated to prevent the abnormal voltage drop. However, without ShR, the substation might encounter over-voltages due to large capacitance such as cables.	A4.4.3
Protection (internal)	Major	Examine whether the current imbalance relay might malfunction due to the inrush current.	
Control	Minor	The ShR maybe frequently operated.	
Communication	None		
Land & layout	None		
Visual impact	None		
External pollution	Minor	Same as general design. Need the pollution design depending on the site's pollution level for air-insulated parts.	
Audible noise	Minor	The noise of ShR is larger than that of transformer with the same capacity. Countermeasures are the same as the case of transformer.	
EMC	None		
Electrical clearances	None		
Safety clearances	None		
EM fields	Major	If an air cored reactor is employed, the magnetic contours need to be examined to ensure they do not effect adjacent equipment of people	
Civils	None	If an air cored reactor is used, foundation rebar within the magnetic field will heat and corrode, avoid closed loops	
Containment	Major	Oil filled reactors should be considered in the same manner as transformers	
Auxiliaries	Minor	Coolers using pump or fan stop operating in the case of power-down for the cooler. Consider the necessity of redundant power source.	
Equipment ratings	Major	Examine the adoption of non-standard series equipment if the capacitor is installed on the tertiary side of the transformer.	
Busbar layout	None		
Earthing	None		
Monitoring	Minor	Monitoring the output var and the fault indicator.	

Testing	None		
Relocatability	None		
Spares requirement	None		
Hazards	Major	Same as ordinary oil-filled and air-insulated equipment	

Advice & recommendations

A4.4.1 Basic system changes

Voltage fluctuation should carefully be studied to keep stable the condition of the power system when the ShRs will be installed into the power system.
It causes the larger voltage fluctuation than the regulated value if the capacity of a reactor is too large for the power system.
The phase modifying equipment should be divided into some groups in terms of the voltage regulation. But in this case, the financial limit should be considered because a switching gear is necessary for each group. Actually, the capacity of the phase modifying equipment is made as large as possible within the range of the voltage regulation allowance.

A4.4.2 Single line diagram impact

1. Operational switching

The interrupting current for ShR is comparably small compared with a short circuit current at fault, which influences the interrupting performance of the circuit breaker (CB). It tends to become difficult to make the open operation of a circuit breaker for a shunt reactor because a circuit breaker is designed to interrupt a large current at fault.

In a case of a self-extinction circuit-breaker such as OCB, the interrupting performance is insufficient because of a small arc-energy. On the other hand, a forced-extinction circuit-breaker such as ABB makes the interrupting performance too sufficient to prevent the current chopping which might induce the over-voltage at the terminal of the reactor.

The countermeasure is the adoption of a resistance-closing system or Gas insulated Circuit Breaker because the reduction of the transient recovery voltage is made possible.

2. Installation

Phase modifying equipment such as power capacitors and shunt reactors is connected to the secondary side or to the tertiary side of transformer. Although the former has an advantage compared with the latter, it is necessary to take following points into consideration to decide how to install it

(a) Advantages of the tertiary connection of transformer
The tertiary connection makes it possible to suppress the voltage fluctuation to less than the voltage regulation at the secondary side if the secondary connection causes the violation of the voltage regulation.

In addition, it is effective to decrease the rated voltage and the size of the connected equipment.

(b) Disadvantages of the tertiary connection of transformer
The tertiary connection tends to make the voltage fluctuation greater because the tertiary impedance is comparably large. If the phase modifying equipment is connected with house equipment, the attention should be also paid to.

The capacity of a transformer tertiary winding includes the 3rd harmonic component of the exciting current, the zero-phase-sequence current at grounding faults, phase modifying loads, and house loads. It is important to make sure if the tertiary winding capacity is sufficient before the installation of the phase modifying equipment.

Non-standard equipment might be necessary as series equipment because it needs the large short-circuit current rating at tertiary side. Particularly, the circuit breaker might become expensive because the effect of the transient recovery voltage and the interrupting performance are taken into consideration.

(3) Commissioning
The following demonstrations should be required to verify the effect of the installed ShRs and the performance of the protection system.

- Measuring the steady state voltage of the power system after the ShRs are connected with the power system. The compensation capacity of the ShRs is suitable or not.
- Measuring the transient voltage of the power system breakers for the ShRs just after closed and opened. The transient voltage fluctuation is within allowance range or not.
- Observing the protection relays during the above transient state. The protection relays are malfunctioned or not due to the transient voltage fluctuation.

(4) Insulation coordination
A shunt reactor has common features with transformer as follows.

It has the comparatively high surge impedance. The Branch line for the shunt reactor should be as short as possible so that the distance from surge arrester should be minimized for the lightning protection design. If need be, it is necessary to install surge arresters near the shunt reactor.

A4.4.3 Impact on detailed AC substation design
The below matters should be considered on the AC substation design.
(1) Protection
A current imbalance relay is utilized as a protection method for a shunt reactor because it can detect the layer short of a few percent by detecting current imbalance due to the reactance change at fault phase. However, this high sensitivity might cause the relay malfunction by the inrush in the circuit breaker closing period. Therefore, the relay performance should be suspended by the activation of the timer at the closing instance.

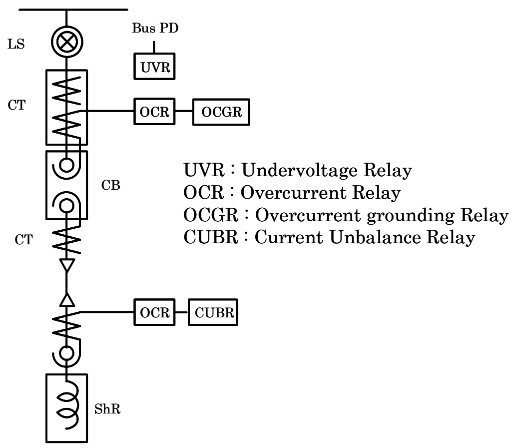


Figure 1 Protection

At the restoration after the total blackout of a substation, shunt reactors should be switched off to prevent the abnormal drop of the system voltage. Usually, the under-voltage relay is utilized to realize the automatic switched-off operation of shunt reactors. However, without shunt reactors, there is a possibility that substation facilities might suffer the overheated damage because of the over-voltage during the restoration in a power system with the large capacity such as cables. In this case, the restoration should be carried out with shunt reactors connected to the system. Therefore, the characteristics of the power system should be considered to determine the necessity of under-voltage relay.

(2) Control
The operation time of the ShRs depend on the load condition .the ShRs are connected with the power system during the light load condition to prevent the excess voltage rise.
The operation time may be fixed because the load curve of each day is fixed generally.
In this reason, the operation time will be controlled by automatically time scheduling.

(3) External pollution
Same as general design. Need the pollution design depending on the site's pollution level for air-insulated parts.

(4) Audible noise
It has the gapped core to increase the value of the impedance. The magnetic tractive force on the gapped core might increase the noise level. The countermeasures are the same as the case of transformer. In order to decrease the noise level, it is necessary to consider the layout of equipment or to install noise barriers. The noise level should be within the range of the legal restriction at the final configuration of the substation.
Oil insulated reactors require the countermeasures for fire and oil outflow, same as transformers.

(5) Auxiliaries
Coolers using pump or fan stop operating in the case of power-down for the cooler. Consider the necessity of redundant power source.

(6) Equipment ratings
If the ShRs will be connected to the tertiary windings of a transformer, the following matter should be considered.
Non-standard equipment might be necessary as series equipment because it needs the large short-circuit current rating at tertiary side. Particularly, the circuit breaker might become expensive because the effect of the transient recovery voltage and the interrupting performance are taken into consideration.

(7) Monitoring
The output reactive power (Var)should be measured, and the condition (active or not) of the electric protection relays and the mechanical relays should be the indicated.

(8) Hazards
The hazards on the ShRs and the transformers are similar because the both are usually oil-filled devices.

A4.5 Shunt Capacitor Bank

If the system has lagging power-factor during peak load period, a power capacitor (mechanically switched capacitor MSC or static condenser SC) is connected to the system in parallel. Power capacitor regulates the power system voltage by supplying leading reactive power. A power system has a resonance frequency due to the existence of the capacitance and the reactance involved in itself. If the resonance frequency of the power system coincides with a harmonics, the system will be made unstable. The installation of a power capacitor might possibly bring about the increase of harmonics in the power system. One countermeasure is a reactor or damping network attached to the capacitor in the series connection to avoid the resonance frequency and reduce inrush currents.

Fig 1. Typical 145kV capacitor bank

Basic system changes

Impact Index	Impact	Important Notice	Appendix
Fault level	None		A4.5.1
Power flow	None		
Frequency	None		
Voltage	Major	An acceptable step change needs to be designed for varying system fault levels. This can have a large impact on lower voltage networks	
Thermal rating	Minor	Harmonics flow-in to the capacitor might cause the overcurrent which leads to the dielectric loss increase and the overheating of the capacitor. Examine the adoption of a series reactor.	
Unbalance	None		
Harmonics	Major	Analysis necessary to identify which harmonics are to be absorbed and where magnification will be minimal e.g. detuning, etc. as appropriate. 5th or higher harmonics components maybe enhanced due to the condensor connected to the system. A filter or damping network may be necessary.	
Impedance	None		

Resonances	Minor	Same as harmonics countermeasure.	
Losses	minor	tuning of the damping network can affects losses	
Single line diagram impact			
Impact Index	**Impact**	**Important Notice**	**Appendix**
Short circuit rating	None		
Operational switching	Major	switching procedures necessary to control step change	
Filtering	Major		
Compensation	None		
Installation	Minor	Can be achieved quickly off-line	
Maintenance	Minor	It is necessary to install fences to prevent from touching to the frame. It should be taken the maintenance space and the insulating clearance into consideration for deciding position of the fence.	
Bypass	None		A4.5.2
Commissioning	Minor	System interconnection test is done according to the purpose of SC installation.	
Insulation coordination	Major	In a half cycle after opening the circuit breaker for the capacitor, the voltage between both contacts of the circuit breaker for the capacitor increases up to twice voltage of power source. If the insulation restoration and the contact distance are not sufficient, the restrike arc takes place easily. Examine the specification of circuit breaker. The reactor/damping filter BIL if one is considered	
Impact on detailed AC substation design			
Impact Index	**Impact**	**Important Notice**	**Appendix**
Protection (external)	Minor	Capacitor is connected to the terminal of the power system so that the operating time of the relay should be as short as possible.	
Protection (internal)	Major	At a case of earthing fault of insulating frame, twice voltage of rated voltage will be applied to each condensor. Decide which relay should be adopted, voltage differential or current differential. Additional requirements for the internal protection of the R,L,C components if employed	
Control	Major	For system restoration power capacitors should be automatically separated to prevent the abnormal voltage rise. Interfacing with any reactive switching scheme (tap changer control). CB Point on wave control may also be required	A4.5.3
Communication	Major	Needs to communicate with existing control systems	
Land & layout	Minor	Examine the type without insulating frame to reduce the area for installation.	
Visual impact	None	Capacitor stacks can be high	
External pollution	Minor	Same as general design. Need the pollution design depending on the site's pollution level for air-insulated parts.	

Audible noise	Major	Air cored reactors (inrush or filter type) can be a major problem
EMC	Minor	Capacitor switching can create some problems with induced voltages in adjacent pilot cables
Electrical clearances	None	
Safety clearances	Major	It is necessary to install a safety fence and warning signs (in a case of the type with insulating frame).
EM fields	Major	Air cored reactor magnetic fields. Need to eliminate any metallic loops within the footprint
Civils	None	Foundation rebar within the magnetic field will heat and corrode, avoid closed loops.
Containment	None	
Auxiliaries	Major	A discharge circuit is very useful, however this needs to be sufficiently rated to discharge the entire capacitor to a safe level within operational timescales
Equipment ratings	Major	Switchgear within the protection zone of a capacitor will need to be rated for capacitive switching duty Ratings for tertiary connected equipment may not be standard.
Busbar layout	None	
Earthing	None	The effect of air cored reactor magnetic fields needs to be managed
Monitoring	Minor	Monitoring the output var and the fault indicator.
Testing	None	
Relocatability	Minor	Can consider portable relay cabin and standard interfaces
Spares requirement	Major	Capacitor units
Hazards	Major	Capacitor can oil leakages - possibility of fires. Proximity of personnel to magnetic fields (pacemakers etc)

Advice & recommendations

A4.5.1 Basic system changes

1. Voltage

It causes the larger voltage fluctuation than the regulated value if the capacity of a reactor is too large for the power system. Examine the capacity of a reactor.
The phase modifying equipment should be divided into some groups in terms of the voltage regulation. This becomes a cost benefits exercise, since switchgear is necessary for each group.

2. Thermal rating, Harmonics & Resonances

A power system has a resonance frequency due to capacitance and the reactance within the network. If the resonance frequency of the power system coincides with a harmonics, the system will be made unstable. The installation of a power capacitor might possibly bring about the increase of harmonics in the power system so that some countermeasures are required. One of these is a series inrush reactor attached to the capacitor to avoid the resonance frequency. The necessary value of the inductive reactance is 4% of the capacitor reactance to avoid the 5^{th} or more harmonics in calculation. Actually, 6% of the capacitive reactance is generally adopted in consideration of the frequency dip, the decrease of capacitor banks at fault, and so on. Other countermeasures include uprating harmonic tolerance or the installation of damping filters.

A4.5.2 Single line diagram impact

1. Operational switching

Voltage step rise is the key issue to consider when switching a capacitor into operation. If the step is too high the rated voltage of equipment maybe exceeded. Where a number of items capable of supplying reactive power are together a coordinated (possibly) automatic reactive switching scheme could be considered. This can coordinate steady state actions such as tap changer operation, capacitor banks and shunt reactors with dynamic equipment like SVCs and also minimise losses.

2. Installation & Maintenance

One type of a power capacitor is lifted by an insulating frame, which is also charged during its operation. So it is necessary to install fences around the capacitor to prevent people from touching to the frame (fig 1&2.). The maintenance space and the insulating clearance should be taken into consideration when deciding the position of the fence.

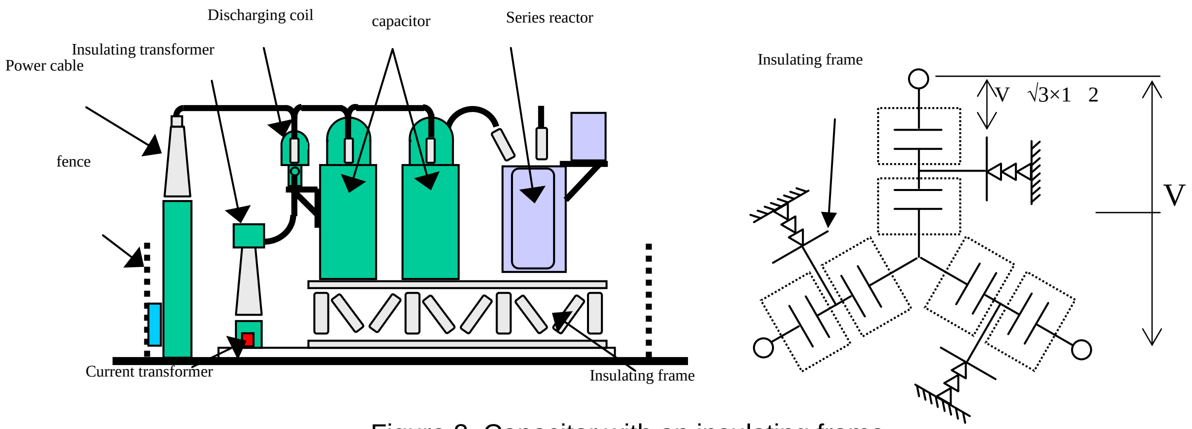


Figure 2. Capacitor with an insulating frame

It is possible to have a dead-tank design (fig. 3) without an insulating frame. This type can make it possible to reduce the equipment size and the area for the installation. In addition, this type can improve the safety and EMC issues
The insulating frame type capacitor is more advantageous than the dead-tank type capacitor in terms of the equipment cost. On the other hand, the latter can reduce the land cost for installation much more than the former.

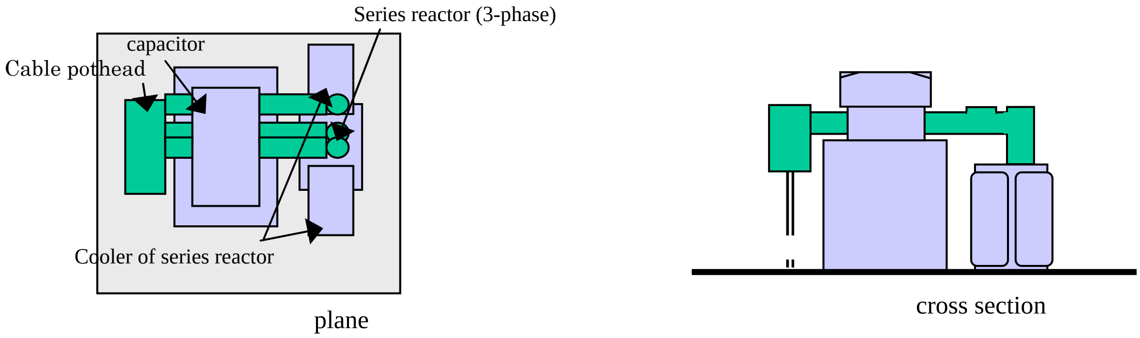


Figure 3. Dead-tank type Capacitor

3. Commissioning

The following tests should be required to verify the effect of the installed SCs and the performance of the protection system.

(a) Measuring the steady state voltage of the power system after the SCs are connected with the power system. To ensure the step change at low fault level is not exceeded

(b) Measuring the transient voltage of the power system breakers for the SCs just after closed and opened. The transient voltage fluctuation is within allowance range or not.
(c) Observing the protection relays during the above transient state. The protection relays are malfunctioned or not due to the transient voltage fluctuation.

A4.5.3 Impact on detailed AC substation design

1. Protection

Fig 4 illustrates the generally used current differential relay method makes it possible to detect a capacitor element breakdown, the discharge coil dielectric breakdown, and the wire cables short-circuit.
However, more detection sensitivity is required if the number of capacitor elements is increased in the series connection for each phase because it becomes difficult to detect the slight change of the reactance. There is a possibility that the current differential relay might malfunction because three-phase current imbalance is slight, and harmonics is involved in the capacitor current at fault.

Accordingly, the voltage differential relay is adopted as the capacitor protection because this method makes it possible to detect the slight change of its reactance. This protection system utilizes the differential voltage from secondary windings of discharge coils. Moreover, this protection system is not affected by harmonics and an inrush.

As unusual fault, an earth fault at the insulating iron frame under the capacitor should be also considered. This fault might apply twice or more the rated voltage to each capacitor with the standardized connection. High sensitivity CT is utilized to detect the minute current accompanied with this fault immediately.

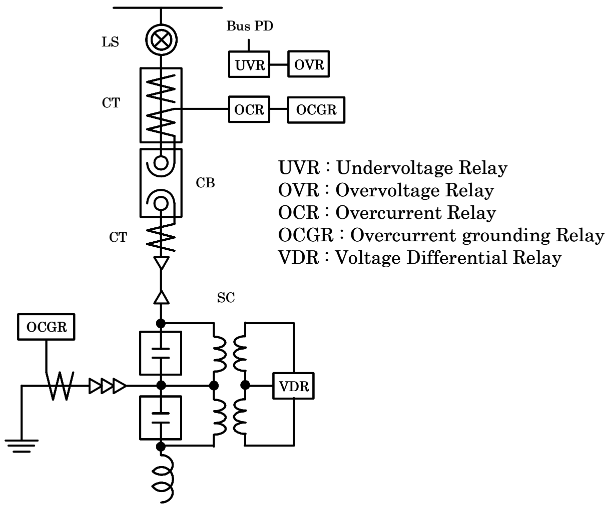


Figure 4 An example of protection relay connection

2. Control

The operation time of the SCs depend on the load condition .the SCs are connected with the power system during the light load condition to prevent the excess voltage rise.
The operation time may be fixed because the load curve of each day is fixed generally.
In this reason, the operation time can be controlled by automatically time scheduling.
At the time of the restoration after the total interruption of the substation, power capacitors should be automatically separated to prevent the abnormal voltage rise.

3. Land & layout and Safety clearance

Insulating frame type (Figure 2)

The fences around the capacitors are essential to avoid electric shock of maintenance person because the insulating frames are also charged with the capacitors. And suitable distance between the capacitors and the fences should be required considering the safety clearance and maintenance space.
Pavement around the insulating frames should also be required to avoid the accidental earth faults caused by the overgrown weeds.

If air cored reactors are installed the civil foundations must be designed so that any reinforcement steel does not induce current and subsequently heat and crack the foundations. Metal fencing around the capacitor needs to consider the same issue. Use insulated materials

Dead-tank type (Figure 3)
If space is not large enough to locate Insulating frame type, Dead-tank type is recommended even though cost of Dead-tank type is expensive.

4. Air cored reactors
Where air cored reactors are employed to provide either inrush control or as part of a filter arrangement, their harmonic rating and location must be carefully examined. The acoustic noise generated can be very loud, this will be very dependent on the site and the harmonic load content. This must be specified if it is perceived as an issue. A sound enclosure can be installed if there is sufficient space
The second key issue for air cored reactors is that of magnetic fields, since there is no iron core the field is not contained and will induce in any adjacent metallic circuits. This causes heating and can damage the structure. Typically, this tends to be metallic fences and reinforcing steel in foundations. Any conductor needs to be insulated, alternatively wooden or plastic fences can be installed.

5. Ancillary switchgear
The discharging coils (usually a heavy duty wound voltage transformer) and the series reactors are installed with the capacitors, if these are required.
The discharging coils perform just after disconnect (open operation) the capacitors from the main circuits to discharge residual charge in the disconnected capacitors in the short time.
The series reactors cancel the capacitance of the capacitors to avoid resonance.

6. Equipment ratings
During a process of capacitor interruption, capacitor current can be interrupted at the time of the zero crossing current and the maximum voltage. After the interruption, the voltage of power source decreases along A – t_2 – B shown in Figure 4 while the voltage of capacitor is kept constant.

Following interruption, the voltage between both contacts of the circuit breaker for the capacitor increases up to twice voltage of power source. If the insulation restoration and the contact distance are not sufficient, the restrike arc takes place easily. If the arc restrikes at the time of t_3, the inrush is increased up to the transient current caused by the application of the twice voltage. This condition can be controlled to some degree by employing point on wave switching relays in the circuit breaker control. Alternatively a filter can also reduce the switching stress.

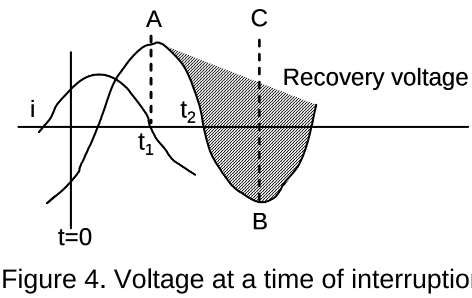


Figure 4. Voltage at a time of interruption of capacitor circuit

If the SCs will be connected to the tertiary windings of a transformer, the following matter should be considered.
Non-standard equipment might be necessary as series equipment because it needs the large short-circuit current rating at tertiary side. Particularly, the circuit breaker might become expensive because the effect of the transient recovery voltage and the interrupting performance are taken into consideration.

A5 Non conventional instrument transformers

This Appendix deals with non conventional instrument transformers (NCIT). Essentially, these are measurement transducers rather than transformers. This approach introduces a step change to secondary systems since the transducer cannot directly power the protection and control modules, so the output signal from the transducers needs to be processed and amplified to meet the conventional input signals for protection relays. The progressive development of digital protection will enable better connectivity and design efficiencies to be made between primary measurement and P&C systems. IEC 61850 substation communication protocols will also aid this shift.

Fig 1. NCIT integrated with a circuit breaker [1]

Hybrid or integrated NCITs (Fig. 1) offer low environmental impact not only in terms of space, with no oil or SF6 required.

The functionality of the devices can address some of the historic drawbacks associated with instrument transformers. As such NCITs have little or no saturation effects, an inherent high bandwidth measurement capacity so that one design can facilitate all types of measurement, protection, metering and monitoring.

The secondary interface, generally termed a merging unit, provides signal processing of the transducer output and suitably scaled inputs for protection and control modules. This can be digital or analogue output. The key difference is that unlike conventional instrument cores which provide a one to one correlation with the relay. For NCITs the relationship is a one to many, i.e. one NCIT feeds many P&C inputs, providing they are located suitably.

References

[1] Field experience with high voltage combined optical voltage and current transducers, A3-111_2004, F. RAHMATIAN, G. POLOVICK, B. HUGHES, V. ARESTEANU.

[2] Pilot application with non conventional instrument transformers and digital protection using IEC protocol for communication, B3-203_2006, D. CHATREFOU, P. PONCHON, D. DUPLAN, M. OSBORNE.

[3] Novel application of optical current and voltage transducers on high voltage switchgear, A3-109_2004, R. BOERO , C. JONES , A. KLIMEK.

A5.1 Current transducers

Current transducers
There are a number of measurement techniques employed to measure current flowing in the primary conductor. Optical transducers can employ the Faraday effect which causes polarised light to be rotated by the EM field relative to the magnitude of current flow in the primary busbar.

A more conventional electronic approach uses a Rogawski coil (Fig. 2), not dissimilar to a normal wound CT, but the electronic isolation between bar primary and secondary provides safety, coupled with design features to counteract temperature and vibration measurement errors. In all cases the transducer provides a voltage proportional to the current flowing in the primary busbar, once calibrated.

Fig 2. NCITs for GIS applications [2]

The index below lists a standard set of possible impacts. If the particular device has an impact on a particular parameter then an entry is included in the index, which directs the reader to the appropriate chapter of this Appendix. This chapter explains the impact and provides guidelines on the aspects, which may need to be considered.
All of the possible impacts are listed in numerical order in the overall index. This means that the separate subsidiary sections of this Appendix will generally not have completely sequential numbering.

Basic System Changes

Impact Index	Impact	Important Notice	Appendix
Fault level	none		
Power flow	none		
Frequency	none		
Voltage	none		
Thermal rating	none		
Unbalance	none		
Harmonics	none		
Impedance	none		
Resonances	none		
Losses	none		

Single line impact

Impact Index	Impact	Important Notice	Appendix
Short circuit rating	none		
Operational switching	none		
Filtering	none		

Compensation	none		
Installation	minor	Faster installation, less primary work required. Communication interface between transducer and secondary systems id completely different	A5.1.1
Maintenance	major	No primary maintenance required, calibration maybe required.	A5.1.2
Bypass	none		
Commissioning	minor	Faster commissioning, isolated from primary.	A5.1.2
Insulation coordination	none		
Detailed substation design			
Impact Index	**Impact**	**Important Notice**	**Appendix**
Protection (external)	major	A merging unit and power amplifier interface required to supply power to protection relays. No CT cores.	A5.1.3
Protection (internal)	none		
Control	none		
Communications	major	Ideally require optical fibre to connect between the primary transducer and the cubicle	A5.1.3
Land & layout	minor	Smaller footprint than conventional VT, so far only integrated into GIS	A5.1.4
Visual impact	minor	Likely to result in smaller substation.	A5.1.4
External pollution	minor	Heavily polluted sites need to ensure adequate creepage to prevent distortion of measurement	
Audible noise	none		
EMC	none	Immune to EM effects	
Electrical clearances	none		
Safety clearances	none		
EM fields	none	No field generated	
Civils	minor	No additional foundations if integrated into switchgear	A5.1.4
Containment	none	No oil or SF6 to escape	
Auxiliaries	major	Transducer requires a DC supply. P&C will require interface to accept the digital/low power output from the NCIT Less cabling, less control circuits, less interlocking circuits	A5.1.5
Equipment ratings	none		
Busbar layout	none		
Earthing	none		
Monitoring	minor	Self supervising transducers and communication system	
Testing	major	New approach will be required since completely different technology and architecture	A5.1.6
Relocatability	none		
Spares requirement	major	Require duplication in the primary transducers, Printed circuit boards and processors. Specific elements should be procured and held as spares.	A5.1.2
Hazards	major	Many traditional CT hazards removed The traditional risk of open CT secondary flashovers is removed	A5.1.7

Advice & recommendations

A5.1.1 Installation & Commissioning

The installation and particularly replacing the secondary wiring with ethernet is very different to conventional configurations, although functionally these perform the same job. New testing procedures will need to be written. There is significant use of optical fibre and ethernet protocols to communicate with P&C systems.
Injection tests to NCIT? Not sure how this is done
Calibration of the transducer, this can be an inherent function if designed into the merging unit.

A5.1.2 Maintenance

These are new devices so the lifetime is uncertain, but the sensing technology should be suitable for 20-30 years. The electronic components are likely to require the most attention. Like modern protection this will have self supervision and cards will need to be replaced on failure. There is no maintenance to speak of other than calibration checks. The transducer isolates the secondary side from the primary inherently, only a low power coupling is possible. This is significant advancement as it removes one of the key dangers associated with the secondary open circuit conditions and flashover risk. The protection engineer is isolated from primary risks.

The impact on protection depletion if the transducer is wholly powered down needs to be carefully considered. Duplication of sensors, power supplies and output needs to be designed to minimise the loss of signal to other operational protection.
The electronic circuit boards are central to the functionality of the transducers. These are usually the most likely component to fail. Spares should be procured and replacement methods established to ensure the minimum down time for any circuits.

A5.1.3 Protection interface and communications

The traditional interface between instrument transformers and protection is completely revised. The transducer output is fed into a merging unit which provides signal processing, time stamping etc which is then fed into the protection relays at

The substation LAN network provides the fastest and most flexible methods to connect NCITs to digital protection.
Through the application of substations LANs, one single combined CT and VT can replace as many as four separate conventional units – a metering CT, a metering VT, a protection CT, and a protection VT.
Where this is retrofitted into a conventional substation low power converter modules are required to convert the digital signal to suitable 110Vdc signals. This explains the slow take up of NCITs.

A5.1.4 Land and Layout

Space requirement for NCIT solutions is significantly reduced with about 50% compared to traditional AIS solutions. An integrated design into GIS or AIS will reduce the bay size. Switchgear integration and enables substation compactness. The use of an optical fibre solution removes the safety issues associated with secondary systems and is inherently isolated from the primary.
Civil works will be reduced since number of foundations for the substation will be fewer.

Smaller & less obtrusive - Integrated units, particularly GIS will remove the CT compartment entirely

In most cases the communication path to the protection will be optical fibre, so any induced EM problems will be eliminated

A5.1.5 Auxiliaries

Secondary cabling will be substantially reduced. No need for cabling to each core. A duplicated output from the transducer will independently feed into a merging unit, from which the protection and control will derive its signals.

The transducers will require DC supplies to be made available. This is a key difference to conventional CT which supplies the power demand for P&C.

The reduction in cabling will mean that cost for both cabling and cable ducts are reduced. But also the secondary system will be safer due to the reduction in complexity.

A5.1.6 Testing

New testing procedures are necessary for this technology architecture.

The transducer sensitivity is high resolution, as such this may detect higher frequency superimposed noise in the busbars. This may need to be filtered to prevent spurious tripping. This may vary with the type of transducer technology and processing used.

A5.1.7 Hazards

This technology removes one of the main safety hazards to engineers working on secondary systems. The risk of an open circuit secondary connection and subsequent flashover.

Managing overall protection changes, where one transducer will feed many P&C functions. This will need t be carefully thought through such as to minimise circuit or busbar outages during transducer failure (printed circuit board rather than sensor).

A5.2 Voltage transducers

Most of the architecture employed within the current transducer is used in the voltage transducer with the exception of the actual measurement techniques. The optical transducer method utilises Electric field measuring techniques which can compensate for various perturbations. The technique most commonly used for voltage transducers is the capacitive divider principal. This also employs electronics to provide the integration functions to generate an output voltage scaled to the busbar voltage and compensation for temperature, mechanical and drift variations.

For most of the designs, there is no secondary inductance, so the system is immune to damaging effect such as ferroresonance or transients.

Basic System Changes			
Impact Index	**Impact**	**Important Notice**	**Appendix**
Fault level	none		
Power flow	none		
Frequency	none		
Voltage	none		
Thermal rating	none		
Unbalance	none		
Harmonics	none		
Impedance	none		
Resonances	major	Transducers are immune to ferroresonance	A5.2.1
Losses	none		
Single line impact			
Impact Index	**Impact**	**Important Notice**	**Appendix**
Short circuit rating	none		
Operational switching	none		
Filtering	none		
Compensation	none		
Installation	minor	Faster installation, less primary work required. Communication interface between transducer and secondary systems id completely different	A5.2.2
Maintenance	major	No primary maintenance required, calibration maybe required.	A5.2.3
Bypass	none		
Commissioning	minor	Faster commissioning, isolated from primary.	A5.2.3
Insulation coordination	none		
Detailed substation design			
Impact Index	**Impact**	**Important Notice**	**Appendix**
Protection (external)	major	A merging unit and power amplifier interface required to supply power to protection relays. No CT cores.	A5.2.4
Protection (internal)	none		

Control	none		
Communications	major	Ideally require optical fibre to connect between the primary transducer and the cubicle	A5.2.4
Land & layout	minor	Smaller footprint than conventional VT, so far only integrated into GIS	A5.2.5
Visual impact	minor	Likely to result in smaller substation.	A5.2.5
External pollution	minor	Heavily polluted sites need to ensure adequate creepage to prevent distortion of measurement	
Audible noise	none		
EMC	none	Immune to EM effects	
Electrical clearances	none		
Safety clearances	none		
EM fields	none	No field generated	
Civils	minor	No additional foundations if integrated into switchgear	A5.2.5
Containment	none	No oil or SF6 to escape	
Auxiliaries	major	Transducer requires a DC supply. P&C will require interface to accept the digital/low power output from the NCIT Less cabling, less control circuits, less interlocking circuits	A5.2.6
Equipment ratings	none		
Busbar layout	none		
Earthing	none		
Monitoring	minor	Self supervising transducers and communication system	
Testing	major	New approach will be required since completely different technology and architecture	A5.2.7
Relocatability	none		
Spares requirement	major	Require duplication in the primary transducers, Printed circuit boards and processors. specific elements should be procured and held as spares.	A5.2.3
Hazards	major	Many traditional CT hazards removed The traditional risk of open CT secondary flashovers is removed	A5.2.8

Advice/Recommendations

A5.2.1 Ferroresonance
Elimination of electromagnetic link between primary and secondary sides of the system, prevent ferroresonance occurring, so the placement of the VT or operational switching restrictions are not necessary.

A5.2.2 Installation & Commissioning
Very different to existing CT. Requires new procedures to be written. There is significant use of optical fibre and ethernet protocols to communicate with P&C systems.
Calibration of the transducer, this can be an inherent function if designed into the merging unit

A5.2.3 Maintenance
No maintenance to speak of other than calibration checks. The transducer isolates the secondary side from the primary inherently, only a low power coupling is possible. This is significant advancement as it removes one of the key dangers associated with the secondary open circuit conditions and flashover risk. The protection engineer is isolated from primary risks..

The impact on protection depletion if the transducer is wholly powered down needs to be

carefully considered. Duplication of sensors, power supplies and output needs to be designed to minimise the loss of signal to other operational protection.
The electronic circuit boards are central to the functionality of the transducers. These are usually the most likely component to fail. Spares should be procured and replacement methods established to ensure the minimum down time for any circuits.

A5.2.4 Protection interface and communications

The traditional interface between instrument transformers and protection is completely revised. The transducer output is fed into a merging unit which provides signal processing, time stamping etc which is then fed into the protection relays at

The substation LAN network provides the fastest and most flexible methods to connect NCITs to digital protection.
Through the application of substations LANs, one single combined CT and VT can replace as many as four separate conventional units – a metering CT, a metering VT, a protection CT, and a protection VT.
Where this is retrofitted into a conventional substation low power converter modules are required to convert the digital signal to suitable 110Vdc signals. This explains the slow take up of NCITs.

Fig 3. Capacitive voltage transducer [2]

A5.2.5 Land and Layout

Space requirement for NCIT solutions is significantly reduced with about 50% compared to traditional AIS solutions. An integrated design into GIS or AIS will reduce the bay size (Fig 3). Switchgear integration and enables substation compactness. The use of an optical fibre solution removes the safety issues associated with secondary systems and is inherently isolated from the primary.
Civil works will be reduced since number of foundations for the substation will be fewer.

Smaller & less obtrusive. Integrated units, particularly GIS will remove the CT compartment entirely

In most cases the communication path to the protection will be optical fibre, so any induced EM problems will be eliminated

A5.2.6 Auxiliaries

Secondary cabling will be substantially reduced. No need for cabling to each core. A duplicated output from the transducer will independently feed into a merging unit, from which the protection and control will derive its signals.
The transducers will require DC supplies to be made available. This is a key difference to conventional CT which supplies the power demand for the P&C.
The reduction in cabling will mean that cost for both cabling and cable ducts are reduced. But also the secondary system will be safer due to the reduction in complexity.

A5.2.7 Testing

New testing procedures are necessary for this technology architecture.

A5.2.8 Hazards

This technology removes one of the mean hazards to engineers working on secondary systems. Open circuit of secondary.

A6 Power Flow Control

This Appendix deals with active power flow control devices and their integration into AC substations. Power system theory shows that when power flows between two networks there is a voltage drop and a phase angle shift between the sending end and the receiving end voltages. If the systems are connected together in two or more parallel paths so that a loop exists, any difference in the impedance's will cause unbalanced line loading. For two interconnected networks it can be shown that:

- MW flow is proportional to voltage phase angle difference.
- MVAr flow is proportional to scalar voltage difference.

There are two practical technologies with different impact on system characteristics according the degree of use of power electronics; control of active and reactive power could also be useful combined and integrated:

A6.1 Regulation transformers (PST, QB)
A6.2 Series Capacitors (SC, TCSC)

A6.1 Regulating Transformers

Phase angle regulating transformers - phase shifting transformer (PST) are used to control the flow of electric power over transmission lines. Both the magnitude and the direction of the power flow can be controlled by varying the phase shift across the series transformer – Figure 1.

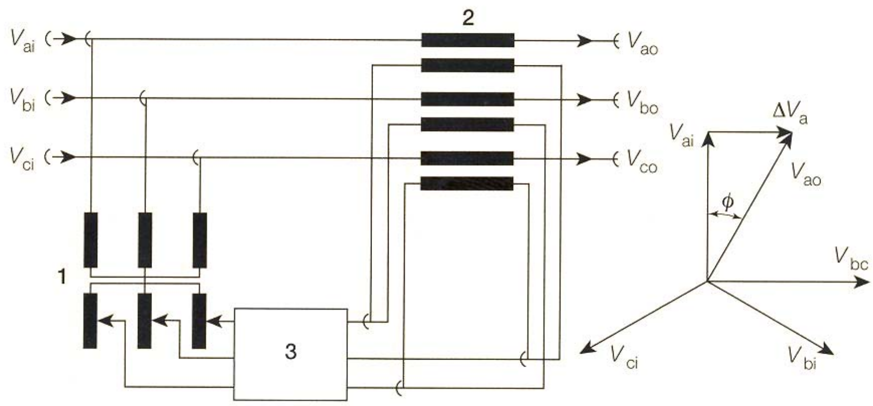


Figure 1 phase shifter with quadrature voltage injection (QB)

1 *Magnetizing transformer*
2 *Series transformer*
3 *Switching control*
Φ Phase shift
V_a *Voltage across series transformer*
$V_{ai, bi, ci}$ *Line to ground voltages*
$V_{ao, bo, co}$ *Line to ground voltages*

Principle of operation
The phase shift is obtained by extracting the line-to-ground voltage of one phase and injecting a portion of it in series with another phase. This is accomplished by using two transformers: the regulating (or magnetizing) transformer, which is connected in shunt, and the series transformer. The star-star and star-delta connections used are such that the series voltage being injected is in quadrature with the line-to-ground voltage.
A portion of the line voltage is selected by the switching network and inserted in series with the line voltage. The added voltage is in quadrature with the line voltage since, e.g., the added voltage on phase 'a' is proportional to V_{bc}.
The angle of a phase shifter is normally adjusted by on-load tap-changing (OLTC) devices. The series voltage can be varied by the OLTC in steps determined by the taps on the regulating winding. Progress in the field of high-power electronics has made it possible for thyristors to be used in the switching network [1].

Basic system changes			
Impact Index	**Impact**	**Important Notice**	**Appendix**
Fault level	Minor	Short circuit impedance between Power systems. Some reduction due to inherent impedance - design dependant.	A6.1.1

Power flow	Major	PST contributes to stabilize the power flow fluctuation and to enhance steady-state stability of the system. Coordination issues arise in case of several installations in different substations.	
Frequency	None		
Voltage	Major	The coordination control with existing voltage control equipment (transformer tap control, SC, ShR) should be considered.	
Thermal rating	Major	The thermal rating of the series transformer could reduced the thermal rating of the line (maximum current and overload admitted)	
Unbalance	None		
Harmonics	None		
Impedance	Minor	Short circuit impedance between power systems	
Resonances	Minor	During energising resonances may occur in the regulator winding connections.	
Losses	Minor	The losses in the network will as a whole increase. Forced air/oil cooling system for PST needed.	A6.1.2

Single line diagram impact

Impact Index	Impact	Important Notice	Appendix
Short circuit rating	none		A6.1.3
Operational switching	Major	special instructions and procedures have been made to taken into account to allow a specific switching sequence to prevent possible resonances	
Filtering	None		
Compensation	None		
Installation	Major	PSTs are installed outdoor or in a specifically designed building with fire detection and extinction system	
Maintenance	Minor	Some additional maintenance is necessary due to the high amount of switching actions	
Bypass	Major	PSTs can only be bypassed according the needs of operation flexibility (by circuit breakers or simply disconnector); some installations show a manually operation (24 hour action) as well.	
Commissioning	Minor	Additional tests have been performed to verify the control action of the PSTs	
Insulation coordination	Minor	Surge arresters location as Power Transformer	

Impact on detailed substation design

Impact Index	Impact	Important Notice	Appendix
Protection (external)	Major	A special protection scheme needed according winding arrangements	A6.1.4
Protection (internal)	Major	A special protection scheme needed according winding arrangements	
Control	Major	Bypass schemes (using circuit breakers or disconnectors)	
Communication	Minor	only a slightly higher amount of information exchange are necessary	
Land & layout	Major	For existing substation footprint could have a deep impact. Indoor solutions with separate building was required	

Visual impact	Major	separate building was required
External pollution	None	
Audible noise	Minor	Most of the application close to urban areas required transformers completely encapsulated to prevent additional noise, cooling fans as well.
EMC	None	
Electrical clearances	Minor	According AIS or GIS solution for connection and by-pass
Safety clearances	None	
EM fields	None	
Civils	Major	It has an high impact according layout solutions and containment.
Containment	Major	Mostly located in buildings
Auxiliaries	None	
Equipment ratings	None	
Busbar layout	None	
Earthing	Minor	Special cases with indoor solution and GIS switchgear of the PSTs needed addtional earthing measures
Monitoring	Minor	Additional equipped as a fiber optic temperature measuring system for monitoring and modelling of the thermal behaviour of the transformer If needed
Testing	Minor	Additional tests needed to verify the control action of the PSTs
Relocatability	Major	PSTs shows low relocability
Spares requirement	Minor	some additional spares required, cooling fans
Hazards	Minor	The total amount of oil in the substation increases

Advice/Recommendations

General specifications for phase-shifting transformers need to give all details known for normal power transformers. Additional data needed to prepare a design and to evaluate impact on substation design are listed below.

Figure 2 - 400 kV 1 phase unit (dimension 8x6x6 m weight: 550 ton)

A6.1.1 Electrical Data

Herewith listed some open questions useful for a preliminary design and data assessment:

- Desired phase shift angle defined at no-load or load?
- If under load, cos φ of load?

Under load the PSTs impedance will decrease the phase shift in advance direction and increase it in retard direction. The no-load phase angle range has to be adjusted to this transformer load angle. The OLTC(s) has to be dimensioned for the extended range.

- Does the phase angle shift have to be symmetrical in advance and retard directions?
- Which will be the power flow direction: source->load or load -> source only or both?
- Voltage ratio defined under no-load or under load ? (ANSI or IEC)
- Does the transformer ratio have to be independent of phase angle?
- Tolerances for phase angle?
- Number of steps? Or in which increments does the phase angle have to be controlled?
- Is it acceptable to double the number of steps?

Doubling the number of steps reduces the step voltage, which may allow a more economic tap changer. However the number of tap changing events as well as the time needed to move from one specified tat to the next would increase

Figure 3 - 400 kV QB 2750 MVA

- Do OLTCs have to be operated simultaneously?

Relevant for symmetric extended delta connection type.

- Is a certain difference in tap position desired/acceptable in order to influence the voltage ratio?
- Minimum and maximum short circuit impedances at zero phase shift and maximum phase shift? Tolerance for impedance?
- Scope of verification measurements on phase angle and impedances in the test room?
- Voltage regulation in addition to phase angle regulation?
- Are there any reservations against internal or external surge arrestors?
- Are series and magnetizing transformers located outdoor or are they located in buildings

Relevant for cooling system and noise assessment

A6.1.2 Losses and economical assessment

- No-load and load loss evaluations needed

- At which tap position should losses be evaluated

It is suggested to determine these values for the most probable operating condition.

Figure 4 - QB large cooling outdoor fans (400 kV 2750 MVA)

A6.1.3 Operating Conditions

- Indoor or outdoor installation? (see Figure 5-7)
- Separated cooling fans admitted from tanks? (see Figure 4)

  Relevant for footprint and noise assessment
- Max. dimensions and weights? Limited by which restraints?
- Overload, emergency loading?
- Short circuit impedance of nearby power transformers? Can their impedance's short circuit current limiting effect be taken into account when dimensioning the PST?
- Type of connection to next transformer? (overhead line or busbar / cable / GIS)?
- Series capacitors nearby?

Resonance to be avoided

- Operation with PST being bypassed foreseen?

Transients will then enter the windings simultaneously from both ends. Has to taken into account in design and test.

- Operation with asymmetric load of the phases foreseen?
- Special requirements for transformer protection?
- Requirements for phase angle control?
- Manual / automatic?
- Real or reactive power? How and where to be measured?
- Control algorithm? Precision of measurement and control equipment?
- Interface to substation? Scope of supply?

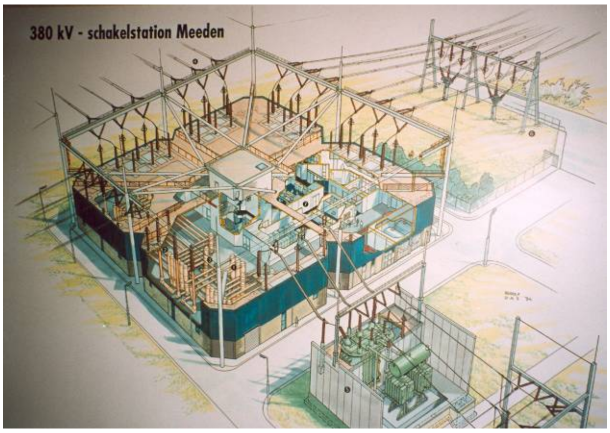


Figure 5 - 400 kV Indoor QBs (Tennet - Meeden susbstation)

With reference to a Single Core Separate Winding Phase-shifting Transformer, the protection of the phase shifting transformer bank is similar to that for power transformers.
The main difference is in differential protection. Normal differential protection detects the difference between primary and secondary currents for each phase. For a phase angle difference of 30° the vector difference between load and source currents is about 52%, which would not allow a sensitive detection of fault currents.
Figure 6 shows that each current path passes through windings in each single-phase tank. In this PST bank all winding ends are brought out either through bushings or cable connectors. In principle each winding could have its own differential protection, with straightforward localization of the fault. However such a solution may be unnecessarily complex.

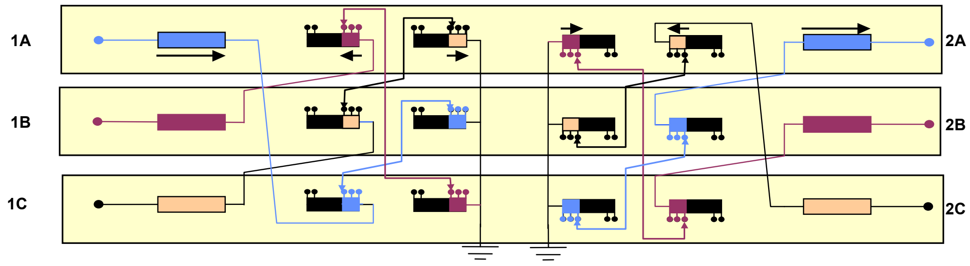


Figure 6 – circuit configuration

1. Overall differential (6 bushing CTs)
Differential scheme detecting the difference between the sum of all source side currents and the sum of all load side currents (1A + 1B + 1 C = 2A + 2B +2C)
Sensitive to: phase-to-ground, phase-to-phase and turn-to-turn faults since currents are transformed between source and load side. Also sensitive to saturation of the core during inrush and heavy through faults. No localization of the fault is provided.

2. Current path differential (12 CTs in cable connecting domes)
Differential scheme detecting the difference of currents measured at the bushing and at the neutral end of each current path (main winding plus two regulating windings and connecting cables).
Sensitive to: phase-to-ground and phase-to-phase faults. Not sensitive to saturation of the core during inrush and heavy through faults, covering times where 1. needs to be de-sensitized. No localization of the fault is provided.

Solution 1. and 2. provide some redundancy.

Several examinations are needed to carried out to determine the CT connection and ratio requirements and to adjust the relays.

3. Buchholz relay
Sensitive to all faults, but with slower response.
Allows to tell in which tank the fault has happened. Gas analysis provides information about type of defect.

4. Overcurrent relay (3 bushing CTs)
Protection against external faults, blocking of OLTC.

5. Thermal image and/or inverse current time relay (3 bushing CTs)
Protection against overheating.

A6.1.4 Dispatching

As it is known the operation of two networks multiply interconnected may be affected by abnormal power flows in the weakest network, especially in conjunction with contingencies in

the most powerful grid. The on-line control of the power flows through the interconnections, operated by Regulating Transformers (PST, QBT)/Flexible AC Transmission Systems (FACTS), may avoid such inconveniences if proper coordination of the control actions is actuated.
Different control rules of the settings of the interconnecting devices aimed to on-line control the power transfers through the interconnections as to increase the security of the weakest network and to improve the performances of the whole system especially during severe contingencies in the main network [2]

Figure 7. Outdoor 400kV QB 1650 MVA (Terna - Rondissone Substation)

A6.2 Series Capacitors

Because series capacitors permit economical loading of long transmission lines, their application to EHV transmission has grown. They have been primarily used to improve system stability and to obtain the desired load division among parallel lines, i.e. they reduce the effective reactance of the transmission line.
Complete compensation of the line is never considered. At 100% compensation, the effective line reactance would be zero, and the line current and power flow would be extremely sensitive to changes in the relative angles of terminal voltages. In addition, the circuit would be series resonant at the fundamental frequency. High compensation levels also increase the complexity of protective relaying and the probability of subsynchronous resonance. A practical upper limit to the degree of series compensation is about 80%.
It is not practical to distribute the capacitance in small units along the line.
Therefore, lumped capacitors are installed at a few locations along the line. The use of lumped series capacitors results in an uneven voltage profile.
Series capacitors operate at line potential; hence, they must be insulated from ground. A widely accepted practice is to mount the capacitors on platforms insulated from ground. Alternatively, ground-base capacitor banks consisting of capacitor cans placed inside oil-insulated tanks may be used.

Principle of operation
The voltage inserted by a series capacitor is proportional to and in quadrature with the line current. Thus, the reactive power generated by the capacitor is proportional to the square of the current. A series capacitor therefore has a self-regulating action. When the system loading increases, the reactive power generated by the series capacitor also increases.

Basic system changes			
Impact Index	**Impact**	**Important Notice**	**Appendix**
Fault level	none		A6.2.1
Power flow	Major	Secondary impacts due to voltage control as well	
Frequency	None		
Voltage	Major	An acceptable step change needs to be designed for varying system fault levels. Can have large impact on LV network	
Thermal rating	Minor	existing busbar rating may need to be checked	
Unbalance	None		
Harmonics	Minor		
Impedance	Major	distance protection should not be affeced	
Resonances	Minor		
Losses	Minor	Secondary impacts due to voltage control	

Single line diagram impact			
Impact Index	**Impact**	**Important Notice**	**Appendix**
Short circuit rating	None		A6.2.2
Operational switching	None		
Filtering	None		
Compensation	None		

Installation	Minor	Can be achieved offline and quickly provided footprint fits in existing site; sometime rearrangement of site required needed	
Maintenance	None	Can be maintained offline with minimal system implication	
Bypass	None		
Commissioning	None		
Insulation coordination	Major	This is unimportant for single line diagram even though this is important for substation design.	

Impact on detailed substation design

Impact Index	Impact	Important Notice	Appendix
Protection (external)	None		A6.2.3
Protection (internal)	Major	Additional requirements for the internal protection of R,L,C components	
Control	Major	Interfacing with any reactive switching scheme. SC is controlled by on-site program controller or remote network control systems.	
Communications	Major	Needs to communicate with existing control systems	
Land & layout	Major	Reasonable footprint is necessary.	
Visual impact	Minor	High capacitor stack should be avoided. On the other hand, this is also for earthquake-resistance structure.	
External pollution	Minor	insulator only	
Audible noise	Major	large volume of audible noise should be avoided.	
EMC	None		
Electrical clearances	Major		
Safety clearances	Major	Visual Inspection and monitoring require accurate safety protocols	
EM fields	Major	Needs to eliminate any metallic loops within the footprint. Effects to control cable are considered.	
Civils	Minor	foundation rebar within the magnetic field will heat and corrode, avoid closed loops.	
Containment	None		
Auxiliaries	None		
Equipment ratings	Major	switchgear within protection zone will need to be rated for capacitive switching duty.	
Busbar layout	None		
Earthing	None		
Monitoring	None		
Testing	None		
Relocatability	Minor	standard relay cabin and interfaces required	

Spares requirement	Major	Iinsulators	
Hazards	Minor	Capacitor can oil leakages - possibility of fires.	

A6.2.1 Impact of series compensation on power systems

Steady-state voltage regulation and prevention of voltage collapse
A series capacitor is able to compensate for the voltage drop in a transmission line due to the series inductance. At low loads, the system voltage drop is smaller and the series compensation voltage is lower.
When loading increases and the voltage drop becomes larger, the contribution by the series compensator increases and the system voltage is regulated accordingly. Series compensation also expands the region of voltage stability by reducing the line reactance, thereby helping to prevent voltage collapse.
Figure 8 shows that the voltage stability limit increases from P_1 to the higher level P_2.

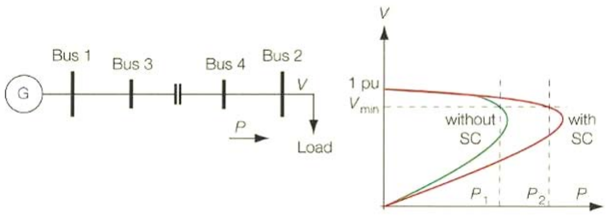


Figure 8

Improvement in transient rotor angle stability
In the single-machine, infinite-bus system in the equal-area criterion is used to show how a series capacitor effectively improves transient stability. Under steady-state conditions Pe = Pm and the generator angle is
δ_0. If a three-phase fault occurs at a point near the machine the electrical output of the generator decreases to zero. At the time the fault is cleared the angle will have increased to δ_C. The system remains stable providing A_{dec} is greater than A_{acc}. Figure 9 shows that the stability margin is substantially increased by installing a series capacitor, causing the P–δ curve to shift upwards.

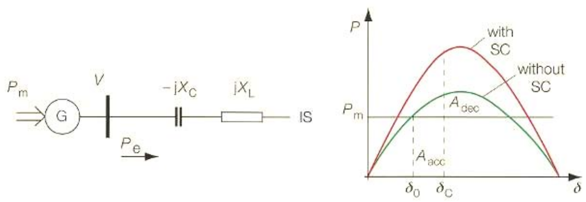


Figure 9
Power flow control
Series compensation can be used in power systems for power flow control in the steady state. In the case of transmission lines with sufficient thermal capacity, compensation can therefore relieve possible overloading of other, parallel lines – careful dispatching control needed in case of outages and power balance of multiple lines.

A6.2.2 series compensation main schemes

Transmission line compensation can be achieved through fixed series capacitors or, offering more versatility, controllable series capacitors. Outlines of typical series compensation schemes are shown in Figure 10

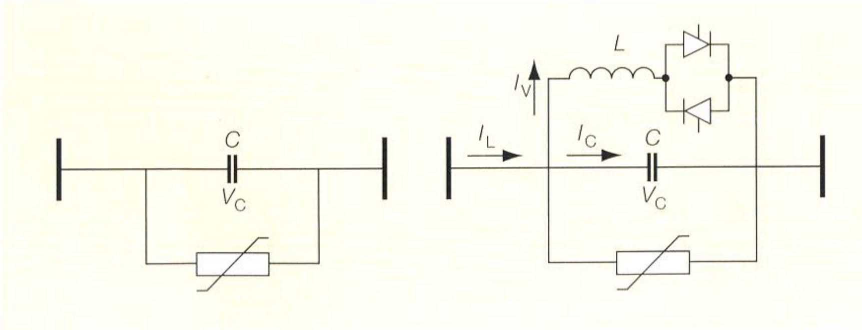


Figure 10

Thyristor-controlled series capacitor (TCSC)

Principle of operation
TCSC configurations comprise controlled reactors in parallel with sections of a capacitor bank. This combination allows smooth control of the fundamental frequency capacitive reactance over a wide range. The capacitor bank for ach phase is mounted on a platform to ensure full insulation to ground. The valve contains a string of series-connected high-power thyristors. The inductor is of the air-core type. A metal-oxide varistor (MOV) is connected across the capacitor to prevent overvoltages. The characteristic of the TCSC main circuit depends on the relative reactances of the capacitor bank X_C, and the thyristor branch, X_V The TCSC can operate in several different modes with varying values of apparent reactance, Xapp.

Figure 11 - TCSC - 500 kV (Brazil – Imperatriz substation)

A6.2.3 Impact on design

The following are some of the key considerations in the application of series-capacitor banks:
Voltage rise due to reactive current.
Voltage rise on one side of the capacitor may be excessive when the line reactive-current flow is high, as might occur during power swings or heavy power transfers. This may impose unacceptable stress on equipment on the side of the bank experiencing high voltage. The system design must limit the voltage to acceptable levels, or the equipment must be rated to withstand the highest voltage that might occur.

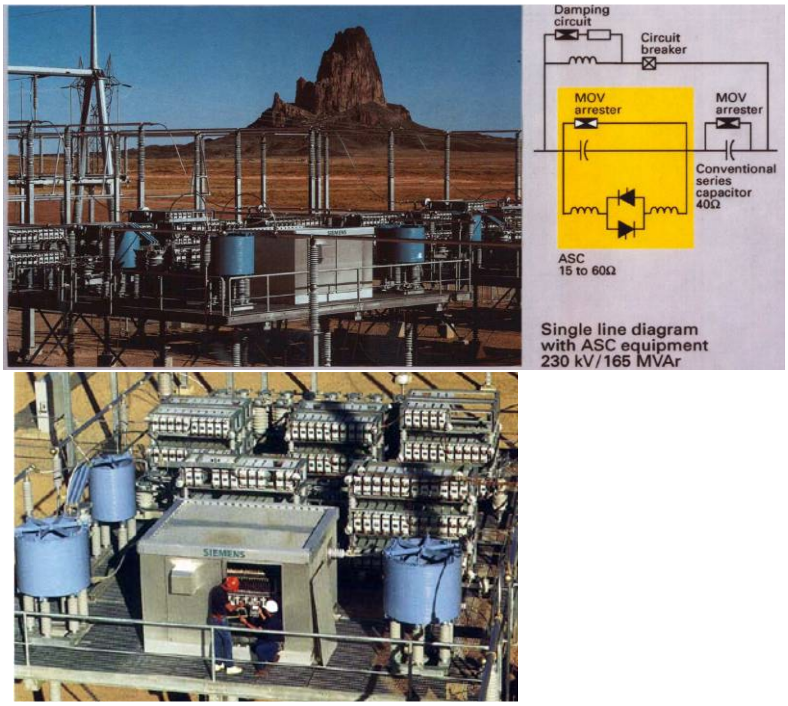


Figure 12 TCSC Kayenta substation 230 kV – 165 MVAr

Bypassing and reinsertion. The series capacitors are normally subjected to a voltage which is on the order of the regulation of the line, i.e., only a few percent of the rated line voltage. If, however, the line is short-circuited by a fault beyond the capacitor, a voltage on the order of the line voltage will appear across the capacitor. It would not be economical to design the capacitor for this voltage, since both size and cost of the capacitor increase with the square of the voltage. Therefore, provision is made for bypassing the capacitor during faults and reinsertion after fault clearing. Speed of reinsertion may be an important factor in maintaining transient stability.

Location

A series-capacitor bank can theoretically be located anywhere along the line. Factors influencing choice of location include cost, accessibility, fault level, protective relaying considerations, voltage profile and effectiveness in improving power transfer capability.
The following are the usual locations considered:

- Midpoint of the line
- Line terminals
- 1/3 or 1/4 points of the line

In practice all of the above arrangements have been used.

Land and Layout

The midpoint location has the advantage that the relaying requirements are less complicated if compensation is less than 50%. In addition, short-circuit current is lower. However, it is not very convenient in terms of access for maintenance, monitoring, security, etc.
Splitting of the compensation into two parts, with one at each end of the line, provides more accessibility and availability of station service and other auxiliaries. The disadvantages are higher fault current, complicated relaying, and higher rating of the compensation.
The effectiveness of the compensation scheme depends on the location of the series capacitors and the associated shunt reactors.

The choice of configuration of the compensation scheme for any particular application requires a detailed study with regard to the overall economy and system reliability. The study should take into account voltage profiles, compensation effectiveness, effect on transmission losses, overvoltages, and proximity to an attended Substation.

As a general impact on land acquisition, space needed is within $3 \div 10$ m^2/ MVAr for rated voltage between 300- 800 kV.

Resonances
Adding a capacitor in series with the inductance of a transmission line forms a series-resonant circuit. The natural frequency of the resonant circuit so formed, for the usual range of compensation (20 to 70% of line reactance), is below the power frequency. The transmission network thus has a natural frequency in the subsynchronous range. Consequently, transient current components of subharmonic frequency are excited during any disturbance and are superimposed on the power frequency currents. The subharmonic currents are usually damped rapidly within a few cycles, due to the resistances of the line and of any connected equipment such as loads. Therefore, the subharmonic natural mode introduced by the use of a series capacitor is rarely troublesome. One notable exception is the possible interaction with a natural frequency of the shaft mechanical system of nearby steam turbine generating units. It may lead to a build-up of torsional oscillations, either spontaneously or after a disturbance. This phenomenon is known as subsynchronous resonance (SSR).

Dispatching
See chapter A.6.1.4

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A7 Custom Power Technology

This Appendix deals with Custom Power technology. Custom Power Technology is the name given to a group of devices dealing with power quality issues associated with customers. There are various issues associated with power quality at the customer's point of connection to the network. These can broadly be divided into two major groups, namely the effect that a customer's load may have on the network and secondly the effect that poor quality of the network can have on the customer's load. In the first sector the most common problems are flicker and harmonics. In the second sector the most common problems are short term voltage dips associated with fault clearance and also pre-existing harmonics.
There are three devices most commonly classed as custom power devices, one dealing with the first aspect namely the distribution STATCOM (D-STATCOM) and two dealing with the second aspect these being the dynamic voltage restorer (DVR) and the solid state transfer switch.

The idea behind the solid state transfer switch is that the customer's load is fed from two totally independent in-feeds. Then if a problem occurs the load is transferred to the other infeed in less than one cycle by means of the solid state transfer switch. As the instances where totally independent infeeds are available for a customer such that the event affecting infeed 1 does not also affect infeed 2 are very rare and consequently we do not have any feedback on the usage of this particular device.

The appendix is therefore divided into two parts, one part dealing with the D-STATCOM and the other dealing with the DVR. It looks at the impact that the installation of the device within a substation will have on the system, then on the single line diagram and finally on the detailed substation design.

References

[1] CIGRE Brochure 205 Custom power - State of the art, 2002
[2] Design of Korea Custom Power plaza for the evaluation of custom power devices, B4-303_2004, Y.H. CHUNG, G.H. KWON, T.B. PARK, H.J. KIM, J.W. CHOE.

A7.1 D-Statcom

A D-STATCOM is a device which is shunt connected and is capable of injecting or absorbing VARs to or from the network. It acts in the same way as a SVC or full size STATCOM (Appendix 4) but is connected at distribution voltage rather than at transmission voltages. As it has the capability of being able to respond very quickly it is eminently suited to alleviating the effects of flicker caused by 'dirty loads'. In certain applications where voltage unbalance may be a problem a D-STATCOM may be used as a static balancer to balance unbalanced three phase loads and reduce the negative sequence levels on the network.

The way in which the device works is that it is an inverter which is connected to a DC bus. The phase angle of the voltage can be adjusted so that the device appears like a capacitor or an inductor. This is not strictly true as unlike a capacitor or an inductor its performance on varying voltage is as a constant current device rather than a constant impedance device. This means that the response at lower voltages is better than that obtained from a conventional SVC. Depending upon the system voltage and the voltage for which the electronics have been designed it may be necessary to utilise a shunt connected transformer to connect the electronics to the network.

Basic System changes			
Impact Index	**Impact**	**Important Notice**	**Appendix**
Fault level	none		
Power flow	Minor	D-STATCOM can support voltage under steady state and dynamic conditions	A7.1.2
Frequency	none		
Voltage	Major	The D-STATCOM can vary the VAR injection rapidly and thus compensate for voltage fluctuations including flicker.	A7.1.4
Thermal rating	None		
Unbalance	Major	D-STATCOM can be used to balance unbalanced loads. If the D-STATCOM is used for this purpose then the impact on unbalance is very high.	A7.1.6
Harmonics	Major	Design of D-STATCOM using multilevel inverters to reduce harmonic generation should be considered.	A7.1.7
Impedance	None		
Resonances	None		
Losses	Minor	The transformer and the power electronic components add losses.	A7.1.10
Single line diagram impact			
Impact Index	**Impact**	**Important Notice**	**Appendix**
Short circuit rating	None		
Operational switching	None		
Filtering	Minor	Depends upon the acceptable level of harmonics and the exact type of inverter.	A7.1.14
Compensation	Major	The D-STATCOM is a form of voltage compensating device.	A7.1.15
Installation	Major	The D-STATCOM needs to be housed in containers. The design may be modular.	A7.1.16

Maintenance	Major	The D-STATCOM adds new components which will require maintenance	A7.1.17
Bypass	None		
Commissioning	Major	Commissioning of the D_STATCOM requires specialist skilled engineers	A7.1.19
Insulation coordination	Minor	May need protecting by surge arresters if connected in an overhead line circuit	A7.1.20
Detailed substation design			
Impact Index	**Impact**	**Important Notice**	**Appendix**
Protection (external)	Minor	No significant change required to existing circuit protection	A7.1.22
Protection (internal)	Major	The D-STATCOM itself needs to be protected. Much of this is built into the control circuitry for the device.	A7.1.23
Control	Minor	The only impact on the S/S control is the operation of the circuit breaker and additional alarms and indications required. Internal control of the device is complex.	A7.1.24
Communications	Minor		
Land & layout	Major	Requires space for the transformer and containers	A7.1.26
Visual impact	Minor	Depends on the site.	A7.1.27
External pollution	None		
Audible noise	Minor	Additional noise from the shunt transformer and the cooling for the electronics.	A7.1.29
EMC	Minor	Firing circuits need to be hardened against interference	A7.1.30
Electrical clearances	None		
Safety clearances	None		
EM fields	Minor		
Civils	Major	Requires space for the containers and the transformer. Bunding required for transformer	A7.1.34
Containment	None		
Auxiliaries	Major	Requires auxiliary power to cool the transformer and the electronics	A7.1.36
Equipment ratings	Minor		
Busbar layout	None		
Earthing	Minor	Equipment requires earthing	A7.1.39
Monitoring	Minor	In built monitoring with device	A7.1.40
Testing	Major	Commissioning of the D-STATCOM requires specialist skilled engineers	A7.1.41
Relocatability	Major	Should be relatively easy to relocate	A7.1.42
Spares requirement	Minor	Spares required for electronic components	A7.1.43
Hazards	None		
Other (please define)			

Advice & recommendations

A7.1.2 Impact on Power Flow

A D-STATCOM is a shunt connected device and its main purpose is to control voltage. However, by injecting VARs at the receiving end of a circuit it has the capability to increase the power transfer capability of the circuit. It can also assist in avoiding voltage instability under outage or fault conditions.

A7.1.4 Impact on Voltage

The D-STATCOM is effectively a shunt connected compensation device and has the capability of injecting or absorbing VARs. This means that it can be used to control the voltage at the point of connection generating VARs to increase the voltage or absorbing VARs to reduce the voltage.

A7.1.6 Impact on Unbalance

If the D-STATCOM is being used for voltage or flicker control then there will be no effect upon unbalance. However, if the load is unbalanced and this is likely to cause a problem on the network, the D-STATCOM can be used as a static balancer using the Steinmetz principle for balancing unbalanced loads. When used in this mode the balancer can convert any unbalanced load, even if varying continuously with time, to a balanced unity power factor load.

A7.1.7 Impact upon harmonics

As the D-STATCOM is a power electronics device it will inherently generate harmonics. Using higher order bridges and multilevel converters can mean that the harmonics occurring at the lower orders is minimal. For more information on this topic refer to Appendix A4.1.3.

A7.1.10 Impact on Losses

The D-STATCOM is a power electronics device and there are losses inherent in these devices. Furthermore, there may be fans required or water cooling pumps and these will also increase the losses. Finally if a transformer is required to connect the power electronics then this will also add both no load and load losses.

A7.1.14 Filtering

Usually the level of harmonics created by a D-STATCOM are of a significantly lower magnitude than those from a conventional SVC and it is not normally necessary to have filter circuits to deal with these. The acceptable level of harmonics and the pre-existing harmonics will need to be considered and the levels predicted after the connection of the D-STATCOM discussed and agreed with the network operator.

A7.1.15 Compensation

The D-STATCOM is a form of compensation device. It will not require any compensation to allow for its connection to the network. If a number of compensation devices exist in close proximity on the network it may be necessary to look at co-ordinated control to avoid hunting between devices.

A7.1.16 Installation

The power electronics will be accommodated in a building or a container. It may have been designed in a modular format so that higher power levels can be created by connecting modules in parallel. If a transformer is required to connect the equipment then space will also have to be found for this.

A7.1.17 Maintenance

Maintenance will be required in accordance with the manufacturer’s instructions. The frequency of maintenance may be reduced if there is redundancy built into the design of the power electronics. Co-ordination of the maintenance periods for the D-STATCOM with those for the load which it is associated with should be considered.

A7.1.19 Commissioning
Commissioning tests in accordance with the manufacturer's instructions will be required. A full factory acceptance test (FAT) should have been completed before the device is shipped to site and this will help to reduce the amount of tests required during commissioning. The tests will usually include a functional test to prove that the device is responding correctly to changes in the system voltage.

A7.1.20 Insulation Co-ordination
The insulation levels of the components should be chosen according to the network conditions in the usual way. If the device is to be connected to an overhead line network susceptible to lightning strikes it will probably require the use of surge arresters to protect it.

A7.1.22 External Protection
The D-STATCOM has no effect upon the external protection other than connection of current transformers into the associated busbar or connections protection.

A7.1.23 Internal Protection
The shunt transformer will normally have the usual protection. The power electronics devices are usually protected by the control equipment. Protection is provided to prevent the devices from experiencing excessive voltage or excessive current.

A7.1.24 Control
The impact on the substation control is limited to the control status indication and alarms arising from the device. The D-STATCOM will have its own control system which will take in system parameters such as voltage, current, real and reactive power depending upon the exact function of the D-STATCOM. In certain circumstances where there are other compensation devices in proximity it may be necessary for the control system to be co-ordinated with the others.

A7.1.26 Land and Layout
Space needs to be allocated for the containers for the power electronics and for the transformer if required.

A7.1.27 Visual Impact
The measures necessary to be adopted will depend upon the particular site. Although containers may be the cheapest housing for the power electronics it may be necessary to consider a building to blend into the surroundings in certain locations. Alternatively the colour of the containers may be carefully chosen for the same reason.

A7.1.29 Audible Noise
There is likely to be additional noise from the cooling equipment associated with the power electronics. If a shunt transformer is used then this will also contribute significantly to additional noise.

A7.1.30 EMC
Screening of the control circuits to the power electronic components may be required to protect them from interference.

A7.1.34 Civils
Allowance needs to be made for the foundations for the transformer if required. If the power electronics are in a container rather than a building then compacted hardcore may suffice as the base for the container. Cable trenches may be required between the transformer and the container.

A7.1.35 Containment
If an oil filled transformer is used then oil containment will need to be provided. It may be necessary to consider a fire barrier between the transformer and adjacent equipment on other circuits to prevent a fire on the transformer from damaging equipment on the other circuits.

A7.1.36 Auxiliaries
The D-STATCOM will require auxiliary ac supplies to feed the cooling equipment for the power electronics. Additional dc supplies will also be required for the control and protection.

A7.1.39 Earthing
If the device is star connected earthing of the star point will be required. Earthing of all of the metalwork associated with the device such as containers, panels etc. will require to be earthed. It may be necessary to consider instrumentation earthing in association with the control circuitry.

A7.1.40 Monitoring
Usually the control associated with the D-STATCOM will have its own monitoring equipment to ensure the safe and continuous operation of the device.

A7.1.41 Testing
In addition to the commissioning testing the device and particularly its control system should undergo a thorough factory acceptance test to ensure that it is functioning as intended.

A7.1.42 Relocatability
Since privatisation it is becoming an increasingly common request that the equipment should be relocatable. As this device lends itself to a modular construction then it should be a relatively simple exercise to relocate it.

A7.1.43 Spares requirements
As the power electronics will be different from any other components already existing on the site it will be necessary to hold additional spare parts. Advice should be sought from the supplier on the quantities of spares to be held.

REFERENCES

[1] B4-306_2004 -- STATCOM for safeguarding of power quality in feeding grid in conjunction with steel plant expansion.

A7.2 Dynamic Voltage Restorer (DVR)

A dynamic voltage restorer (DVR) is a device which can add additional voltage into a series circuit (Fig. 1). The way in which the device works is that it consists of a power electronic circuit consisting of an inverter which is connected into the primary electrical circuit by means of a series transformer. The inverter DC bus is also connected to an energy source which in some cases may be a capacitor to provide the necessary stored energy.
The voltage which can be injected into the circuit is dependent on the rating of the DVR in MVA compared to the rating of the primary circuit. For example, as in the case of the example used for the table below, if the rating of the primary circuit is 8 MVA and the DVR is rated at 4 MVA then the maximum injected voltage will be 50%. This will also decide the voltage ratio of the series transformer. The length of time for which the voltage can be injected is governed by the amount of stored energy available, particularly in the case of a three phase fault. For single phase faults some energy can be transferred from the healthy phases into the faulty phase which enables the DVR to support the voltage for a longer duration. When deciding the rating for the DVR the customer and the supplier must discuss the problem which the customer is experiencing and also carry out power quality measurements at the point of connection over a period, usually at least six months, to enable the exact problem to be defined. The magnitude of the injected voltage and the duration can then be agreed between the customer and the supplier to enable the specification for the DVR to be developed.

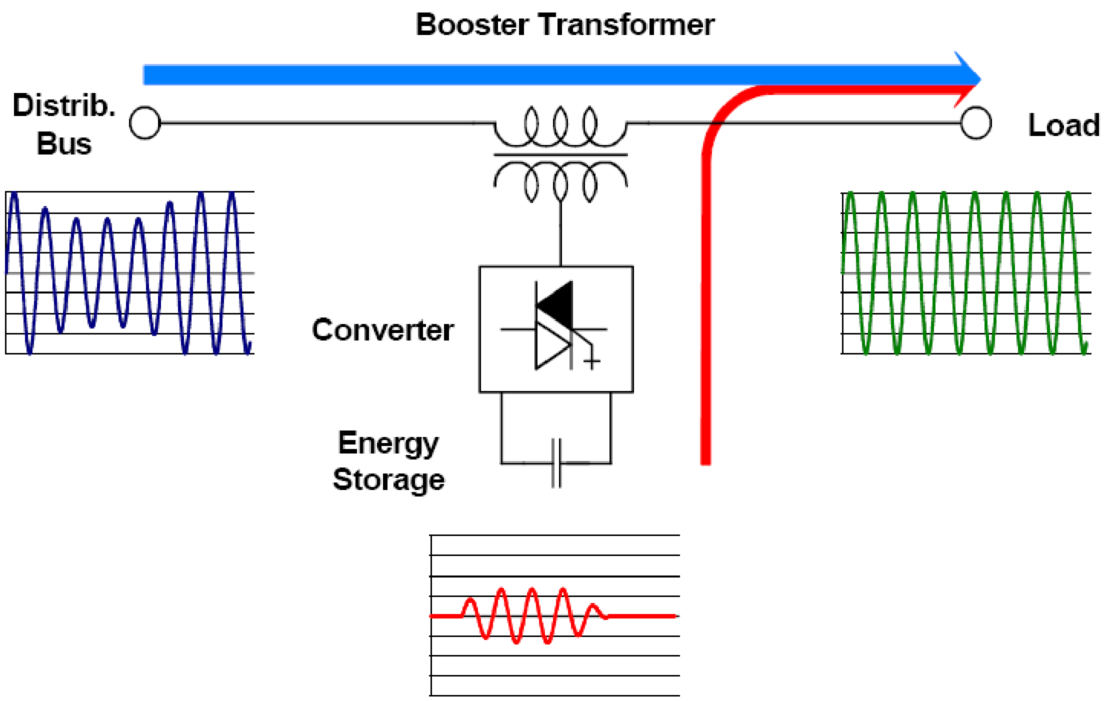


Fig 1. DVR Philosophy, ABB Automation, IEEE PES 2000 [1].

The index below lists a standard set of possible impacts. If the particular device has an impact on a particular parameter then an entry is included in the index which directs the reader to the appropriate chapter of this Appendix. This chapter explains the impact and provides guidelines on the aspects which may need to be considered.
All of the possible impacts are listed in numerical order in the overall index. This means that the separate subsidiary sections of this Appendix will generally not have completely sequential numbering.

Basic System changes			
Impact Index	**Impact**	**Important Notice**	**Appendix**
Fault level	Minor	Introduction of series transformer reduces fault current	A7.2.1
Power flow	Minor	Increased impedance has minor effect on power flow	A7.2.2
Frequency	None		
Voltage	Major	The device is capable of injecting up to 50% voltage during faults to prevent the voltage supplied to the load from dipping.	A7.2.4
Thermal rating	Minor	The series transformer must be rated for the full throughput of the circuit	7.2.5
Unbalance	None		
Harmonics	Minor	As the device uses power electronic components there is some increase in harmonics. This depends on the type of inverter.	A7.2.7
Impedance	Minor	Series transformer increases the impedance in the circuit	A7.2.8
Resonances	None		
Losses	Minor	The transformer and the power electronic components add losses.	A7.2.10
Single line diagram impact			
Impact Index	**Impact**	**Important Notice**	**Appendix**
Short circuit rating	None		
Operational switching	Minor	The DVR is in series with one circuit and usually has a bypass, so switching in and out of service required.	A7.2.13
Filtering	Minor	Depends upon the acceptable level of harmonics and the exact type of inverter.	A7.2.14
Compensation	Major	The DVR is a form of voltage compensating device.	A7.2.15
Installation	Major	The DVR requires to be housed in containers. The type provided to Caledonian Paper is modular with one container per 2MVA injection. Also construction of the bypass circuit is required.	A7.2.16
Maintenance	Major	The DVR adds new components which will require maintenance	A7.2.17
Bypass	Major	A bypass is required to facilitate maintenance without losing the use of the circuit.	A7.2.18
Commissioning	Major	Commissioning of the DVR is longer than for a normal transformer and requires specialist skilled engineers	A7.2.19
Insulation coordination	Minor	May need protecting by surge arresters if connected in an overhead line circuit	A7.2.20
Detailed substation design			
Impact Index	**Impact**	**Important Notice**	**Appendix**
Protection (external)	Minor	No significant change required to existing circuit protection	A7.2.22

Protection (internal)	Major	The DVR itself needs to be protected. Much of this is built into the control circuitry for the device.	A7.2.23
Control	Minor	The only impact on the S/S control is the operation of the bypass and additional alarms and indications required. Internal control of the device is complex.	A7.2.24
Communications	Minor		
Land & layout	Major	Requires space for the containers	A7.2.26
Visual impact	Minor	Depends on the site.	A7.2.27
External pollution	None		
Audible noise	Minor	Additional noise from the series transformer and the cooling for the electronics.	A7.2.29
EMC	Minor		
Electrical clearances	None		
Safety clearances	None		
EM fields	Minor		
Civils	Major	Requires space for the containers and the transformer. Bunding required for transformer	A7.2.34
Containment	None		
Auxiliaries	Major	Requires auxiliary power to cool the electronics	A7.2.36
Equipment ratings	Minor		
Busbar layout	None		
Earthing	Minor	Equipment requires earthing	A7.2.39
Monitoring	Minor	In built monitoring with device	A7.2.40
Testing	Major	Commissioning of the DVR is longer than for a normal transformer and requires specialist skilled engineers	A7.2.41
Relocatability	Major	Should be relatively easy to relocate	A7.2.42
Spares requirement	Minor	Spares required for electronic components	A7.2.43
Hazards	None		

Advice & recommendations

A7.2.1 Fault Level
The inclusion of a series transformer adds additional impedance which will slightly reduce the fault level although this is not the main purpose of the device.

A7.2.2 Power Flow Control
The increased impedance may have a small effect upon the power flow in certain circumstances.

A7.2.4 Voltage
Under normal condition the device will not have any effect upon the voltage. However, in the event of a voltage dip on the network the DVR will attempt to restore the voltage to the full value by injecting an additional voltage into the circuit to replace the missing voltage. This injection will happen very quickly in less than one cycle and can enable the load to ride through the disturbance on the network.

A7.2.5 Thermal Rating
The primary winding of the series transformer must be rated for the full load throughput current of the circuit and not just based upon the rating of the DVR.

A7.2.7 Impact upon harmonics
As the DVR is a power electronics device it will inherently generate harmonics. Using higher order bridges and multilevel converters can mean that the harmonics occurring at the lower orders is minimal. For more information on this topic refer to Appendix A4.1.3.

A7.2.8 Impedance
The inclusion of the series transformer will change the impedance in the network although this is not the prime reason for installing it.

A7.2.10 Losses
The DVR is a power electronics device and there are losses inherent in these devices. Furthermore, there may be fans required or water cooling pumps and these will also increase the losses. Finally the series transformer which is required to connect the power electronics will also add to the losses.

A7.2.13 Operational Switching
It is usual when connecting a DVR to fit a bypass circuit. This bypass enables the circuit to be put into service if it is necessary to carry out some essential maintenance or repair work on the DVR. Switching is required to put the bypass into action before commencing any work and also to replace it after completion of the work.

A7.2.14 Filtering
Usually the level of harmonics created by a DVR are of a significantly lower magnitude than those from conventional power electronic devices using thyristors and it is not normally necessary to have filter circuits to deal with these. The acceptable level of harmonics and the pre-existing harmonics will need to be considered and the levels predicted after the connection of the DVR discussed and agreed with the network operator.

A7.2.15 Compensation
The DVR is a form of voltage compensation device. It will not require any compensation to allow for its connection to the network.

A7.2.16 Installation
The power electronics will be accommodated in a building or a container. It may have been designed in a modular format so that higher power levels can be created by connecting modules in series or parallel. The transformer is required to couple the voltage into the circuit and this will also need to be installed.

A7.2.17 Maintenance
Maintenance will be required in accordance with the manufacturer’s instructions. The frequency of maintenance may be reduced if there is redundancy built into the design of the power electronics. Co-ordination of the maintenance periods for the DVR with those for the circuit which it is associated with should be considered.

A7.2.18 Bypass
In common with most other series connected devices it is usual to connect a bypass to allow usage of the circuit in the event that the device is out of service for maintenance or repair.

A7.2.19 Commissioning
Commissioning tests in accordance with the manufacturer’s instructions will be required. A full factory acceptance test (FAT) should have been completed before the device is shipped to site and this will help to reduce the amount of tests required during commissioning. The tests will usually include a functional test to prove that the device is responding correctly to changes in the system voltage.

A7.2.20 Insulation Co-ordination
The insulation levels of the components should be chosen according to the network conditions in the usual way. If the device is to be connected to an overhead line network susceptible to lightning strikes it will probably require the use of surge arresters to protect it.

A7.2.22 External Protection
The DVR has no effect upon the external protection other than the location of the protection current transformers.

A7.2.23 Internal Protection
The series transformer will require protection in the normal way. The power electronics devices are usually protected by the control equipment. Protection is provided to prevent the devices from experiencing excessive voltage or excessive current.

A7.2.24 Control
The impact on the substation control is limited to the control status indication and alarms arising from the device. The DVR will have its own control system which will take in system parameters such as voltage, current, real and reactive power.

A7.2.26 Land and Layout
Space needs to be allocated for the containers for the power electronics and for the series transformer.

A7.2.27 Visual Impact
The measures necessary to be adopted will depend upon the particular site. Although containers may be the cheapest housing for the power electronics it may be necessary to consider a building to blend into the surroundings in certain locations. Alternatively the colour of the containers may be carefully chosen for the same reason.

A7.2.29 Audible Noise
There is likely to be additional noise from the cooling equipment associated with the power electronics. The series transformer will also contribute significantly to additional noise.

A7.2.30 EMC
Screening of the control circuits to the power electronic components may be required to protect them from interference.

A7.2.34 Civils
Allowance needs to be made for the foundations for the transformer. If the power electronics are in a container rather than a building then compacted hardcore may suffice as the base for the container. Cable trenches may be required between the transformer and the container.

A7.2.35 Containment
If an oil filled transformer is used then oil containment will need to be provided. It may be necessary to consider a fire barrier between the transformer and adjacent equipment on other circuits to prevent a fire on the transformer from damaging equipment on the other circuits.

A7.2.36 Auxiliaries
The DVR will require auxiliary ac supplies to feed the cooling equipment for the power electronics. Additional dc supplies will also be required for the control and protection.

A7.2.39 Earthing
Earthing of all of the metalwork associated with the device such as containers, panels etc. will require to be earthed. It may be necessary to consider instrumentation earthing in association with the control circuitry.

A7.2.40 Monitoring
Usually the control associated with the DVR will have its own monitoring equipment to ensure the safe and continuous operation of the device.

A7.2.41 Testing
In addition to the commissioning testing the device and particularly its control system should undergo a thorough factory acceptance test to ensure that it is functioning as intended before despatch to site.

A7.2.42 Relocatability
Since privatisation it is becoming an increasingly common request that the equipment should be relocatable. As this device lends itself to a modular construction then it should be a relatively simple exercise to relocate it.

A7.2.43 Spares requirements
As the power electronics will be different from any other components already existing on the site it will be necessary to hold additional spare parts. Advice should be sought from the supplier on the quantities of spares to be held.

References

[1] Field Experience with Dynamic Voltage Restorer (DVR) MV Systems, Woodley, Siemens, IEEE PES 2000

A8 Fault Current Limiters

This Appendix deals with fault current limiters. In this instance this means any device which has the purpose of limiting the fault current whether this be the three phase fault current or the earth fault current. The devices covered in this section are neutral earth resistors or reactors which are installed in the neutral connection of transformers in order to limit the earth fault current, series reactors and high temperature superconducting fault current limiters. The appendix is therefore divided into three parts, one part dealing with each of the three different types of device detailed above. It looks at the impact that the installation of the device within a substation will have on the system, then on the single line diagram and finally on the detailed substation design.

[1] Fault current limiters - Application, principles and testing, Electra_211_3, 2003

[2] CIGRE Brochure 239, Fault current limiters in electrical medium and high voltage systems, 2003

A8.1 Neutral Earthing Resistors & Reactors

The index below lists a standard set of possible impacts. If the particular device has an impact on a particular parameter then an entry is included in the index which directs the reader to the appropriate chapter of this Appendix. This chapter explains the impact and provides guidelines on the aspects which may need to be considered.
All of the possible impacts are listed in numerical order in the overall index. This means that the separate subsidiary sections of this Appendix will generally not have completely sequential numbering.

Basic System changes

Impact Index	Impact	Important Notice	Appendix
Fault level	Minor	reduces the earth fault level of the network	A8.1.1
Power flow	None		
Frequency	None		
Voltage	Minor	voltage rise on healthy phase during single line to ground fault	A8.1.4
Thermal rating	None		
Unbalance	None		
Harmonics	None		
Impedance	Minor	Addition of impedance in neutral connection	A8.1.8
Resonances	None		
Losses	None		

Single line diagram impact

Impact Index	Impact	Important Notice	Appendix
Short circuit rating	Major	The earth fault level is reduced	A8.1.12
Operational switching	None		
Filtering	None		
Compensation	None		
Installation	Minor	need small space and small clearance proximity effect	A8.1.16
Maintenance	Minor	check the fixation & continuity of the lead	A8.1.17
Bypass	Minor		
Commissioning	Minor	check reactive reactance impedance & factory test report	A8.1.19
Insulation coordination	Minor	check insulation withstand voltage on the related equipments & BIL of neutral point	A8.1.20

Detailed substation design

Impact Index	Impact	Important Notice	Appendix
Protection (external)	Minor	setting of over current relay due to reduced fault current	A8.1.22
Protection (internal)	Minor	protection should be set to protect device against damage	A8.1.23
Control	None		
Communications	None		
Land & layout	Minor	need small area to install	A8.1.26
Visual impact	Minor	some additional equipment	A8.1.27

External pollution	None		
Audible noise	None		
EMC	None		
Electrical clearances	None		
Safety clearances	Minor		
EM fields	None		
Civils	Minor	designing in supporting structure and foundation	A8.1.34
Containment	Minor	If oil filled then oil containment will be required	A8.1.35
Auxiliaries	None		
Equipment ratings	None		
Busbar layout	None		
Earthing	None		
Monitoring	None		
Testing	None		
Relocatability	None		
Spares requirement	None		
Hazards	None		

Advice & recommendations

A8.1.1 Impact on Fault Level
A neutral resistor or reactor is installed in the neutral connection of a transformer. Its purpose is to limit the earth fault current that can flow in order to limit the damage to plant. As the device is connected in the neutral connection it has no effect upon the three phase fault level.

A8.1.4 Impact on Voltage
When an earth fault occurs the neutral point becomes displaced and the voltage to earth on the healthy phases rises.

A8.1.8 Impact upon impedance
The installation of a neutral earthing resistor or reactor is intended to increase the impedance under earth fault conditions.
If a resistor is used it must be remembered when calculating the effect upon fault current that the resistance is in quadrature with the normal system reactance which traditionally dictates the fault current. If the resistance to be inserted is much greater than the reactance to the point of fault then the fault current to a first approximation will be determined by the phase to neutral voltage divided by the resistance of the neutral earthing resistor.
If however a reactor is used then the impedance will add arithmetically to the system reactance.
In both cases when carrying out fault calculations using symmetrical component techniques it must be remembered that, as the resistor or reactor is connected in the earth return path, then the value to be used in the calculations has to be three times the impedance of the device.

A8.1.12 Short Circuit Rating
Normally the device will not see any current. Under fault conditions the short circuit current through the device is largely limited by its own impedance. The magnitude of the short circuit current is therefore that for which the device has been designed in order to ensure that this level is achieved. However, when specifying the device the time duration for which it must be able to carry this current without damage must be defined. This time will usually be decided

by the slowest anticipated earth fault clearance time by the protection with an added safety margin.

A8.1.16 Installation
Space must be allocated as close to the transformer neutral connection bushing as possible to accommodate the resistor or reactor. Ideally from a cost point of view an air connection will be preferred but in some circumstances it may be necessary to utilise a cable.

A8.1.17 Maintenance
Maintenance will be required in accordance with the manufacturer's instructions. Typically cleaning of metal grid resistors and air cored reactors, checking of electrolyte for liquid resistors and checking of oil level for oil filled reactors. In addition a check of the impedance of the device may be required.

A8.1.19 Commissioning
Commissioning tests in accordance with the manufacturer's instructions will be required. These will usually include a check of the impedance.

A8.1.20 Insulation Co-ordination
When connecting in a neutral reactor it should be remembered that the voltage on the neutral terminal of the transformer will rise to phase to ground voltage and so an appropriately rated bushing will be required. The input terminal will also need to be rated for this voltage. The neutral end can use a bushing with a nominal voltage rating.

A8.1.22 External Protection
When a neutral resistor or reactor is connected the current which will flow under earth fault conditions will be significantly reduced. This reduced value must be used in the setting calculations for earth fault relays on the system connected to this transformer.

A8.1.23 Internal Protection
It is normal to set a standby (final backup) earth fault relay to protect the neutral resistor or reactor to prevent it being damaged by earth fault current passing through it for longer than it's time rating.

A8.1.26 Land and Layout
Space needs to be allocated for the resistor or reactor. Usually this does not significantly impact upon the site area.

A8.1.34 Civils
Allowance needs to be made for the foundations for the resistor or reactor. If an air cored reactor is used advice should be sought with regard to dealing with the magnetic fields even though the current flow through the rector may be for only a short duration.

A8.1.35 Containment
If an oil filled reactor is used in the neutral then oil containment will need to be provided. It may be necessary to consider a fire barrier between the reactor and the main transformer to prevent a fire on the neutral rector from damaging the main transformer.

A8.2 Series Reactor

The index below lists a standard set of possible impacts. If the particular device has an impact on a particular parameter then an entry is included in the index which directs the reader to the appropriate chapter of this Appendix. This chapter explains the impact and provides guidelines on the aspects which may need to be considered.
All of the possible impacts are listed in numerical order in the overall index. This means that the separate subsidiary sections of this Appendix will generally not have completely sequential numbering.

Basic System changes

Impact Index	Impact	Important Notice	Appendix
Fault level	Minor	reduction of short-circuit level	A8.2.1
Power flow	None	small impedance	A8.2.2
Frequency	None		
Voltage	Minor	small voltage drop	A8.2.4
Thermal rating	None		
Unbalance	None		
Harmonics	None		
Impedance	None	small impedance	A8.2.8
Resonances	None		
Losses	None	small losses	A8.2.10

Single line diagram impact

Impact Index	Impact	Important Notice	Appendix
Short circuit rating	None	reduction of short-circuit level	A8.2.12
Operational switching	None		
Filtering	None		
Compensation	None		
Installation	Minor	erection of the series reactor	A8.2.16
Maintenance	Minor	maintenance of series reactor	A8.2.17
Bypass	Minor	bypass may be required	A8.2.18
Commissioning	Minor	erection of the series reactor	A8.2.19
Insulation coordination	Minor		

Detailed substation design

Impact Index	Impact	Important Notice	Appendix
Protection (external)	Minor	protection must consider reduced fault current	A8.2.22
Protection (internal)	Minor	series reactor protection required	A8.2.23
Control	None		
Communications	None		
Land & layout	Minor	erection of the series reactor	A8.2.26
Visual impact	Minor	erection of the series reactor	A8.2.27
External pollution	None		
Audible noise	Minor	may need noise enclosure	A8.2.29
EMC	None	due to the series reactor	A8.2.30
Electrical clearances	none	due to the series reactor	

Safety clearances	Minor	due to the series reactor	
EM fields	None	due to the series reactor	A8.2.33
Civils	Minor	due to the series reactor	A8.2.34
Containment	Minor		A8.2.35
Auxiliaries	Minor		A8.2.36
Equipment ratings	None	reduction of short-circuit level	A8.2.37
Busbar layout	None	due to the series reactor	A8.2.38
Earthing	None		
Monitoring	Minor	series reactor monitoring	A8.2.40
Testing	Minor	type or routine tests required	A8.2.41
Relocatability	Minor		
Spares requirement	None		
Hazards	None		

Advice & recommendations

A8.2.1 Fault Level
The inclusion of a series reactor into a substation is specifically intended to reduce the fault level. The reactor may be connected in one particular circuit, but more usually it will be used in the connection between two sections of busbar. This method of connection makes the two adjacent sections of busbar appear to be electrically further apart and usually reduces the fault level on both sections if fault infeeds are present on both sections.

A8.2.2 Power Flow Control
Series reactors may be used intentionally to control power flow although they are more commonly used for fault current limiting. Even if they are specifically there for fault current limiting they will still have an effect upon the power flow. The power flow will be proportional to the voltage either side of the reactor multiplied by the power angle across the reactor and divided by the reactance. When planning to install a series reactor for fault current limiting, system studies should be carried out to check the effect this has on power flows.

A8.2.4 Voltage
Although the series reactor is not installed to provide any control of the voltage it will have an effect upon the voltage. The current flow through the reactor will cause a VAR loss which will need to be supplied form the system and the flow of these VARs will cause a voltage drop. It would be prudent to carry out an AC load flow study to check the impact on the voltage profile that the installation of the series reactor will have.

A8.2.8 Impedance
The inclusion of a series reactor will change the impedance in the network which, of course is the prime reason for installing it in order to limit fault currents.

A8.2.10 Losses
A series reactor is used to increase the reactance in the system, but the reactor will inherently have some resistance and this will result in losses. In addition there will be iron losses associated with an iron cored reactor, although these will not appear as no load losses as the reactor is series connected and so no voltage will be present unless there is current flowing through it. When specifying the reactor a capitalise value for load losses should be stated to ensure that the reactor is designed to give the best compromise between initial capital cost and running cost of losses.

A8.2.12 Short Circuit Rating
The series reactor is installed to reduce the short circuit rating of equipment in the substation. The short circuit rating for the reactor itself will normally be decided by assuming a short circuit across one set of terminals and applying full voltage to the other (i.e. assuming an

infinite busbar). The reactor should be designed to withstand this short circuit current for the required duration for thermal rating and should be able to withstand this current for the electromechanical forces.

A8.2.16 Installation
The details of the installation will depend on whether the reactor is being installed as an interconnector between two sections of busbar or in series with one outgoing circuit. The most usual situation would be between two sections of busbar. In this case switchgear will be required to connect the reactor to the busbars at either end. This will normally require a disconnector and a circuit breaker at both ends. The reason for the circuit breaker is to ensure that a fault on the reactor itself will only cause the tripping of the reactor and not result in the loss of one section of busbar. If the substation is a double busbar more disconnectors may be used to increase the flexibility of the connections.

A8.2.17 Maintenance
Maintenance should be carried out in accordance with the manufacturer’s instructions. This will be similar to but less extensive than for a power transformer.

A8.2.18 Bypass
Consideration should be given to whether or not a bypass should be provided to enable the busbars to be coupled directly at times of lower fault level to enable maintenance of the series reactor.

A8.2.19 Commissioning
Commissioning tests in accordance with the manufacturer’s instructions will be required. These will usually include a check of the impedance.

A8.2.22 External Protection
When a series reactor is added in the network it will reduce the fault current. A check should be made on overcurrent and earth fault relays to ensure that the settings are still satisfactory.

A8.2.23 Internal Protection
The series reactor itself will normally require its own protection. Typically this will consist of a circulating current protection across the reactor. If the reactor is oil filled it would be usual to fir a Buchholz relay and probably winding temperature. Pressure relief devices may also be fitted.

A8.2.26 Land and Layout
As the reactor will be in series under normal operating conditions it must be rated to carry the full load of the busbars continuously. This will usually result in the reactor being of considerable physical size. Space must be allowed for the installation and the connection to the busbars at either side. This will not normally be a problem if it is designed into the original layout but may cause difficulties when being added to an existing substation. Consideration will need to be given to segregation distances for fire or alternatively fire protection may need to be fitted.

A8.2.27 Visual Impact
The reactor is likely to be of considerable size and will appear externally like a power transformer.

A8.2.29 Audible Noise
Reactors generally will be one of the significant contributors to noise in a substation. The acceptable noise level should be defined in the specification. In certain cases it may be necessary to fit a noise enclosure to achieve acceptable noise levels.

A8.2.30 EMC
If the reactor is air cored EMC will be significant. If the reactor is oil filled then generally the tank will provide significant screening.

A8.2.33 Magnetic Fields
Same comments as A8.2.30 above.

A8.2.34 Civils
For the more likely use of an oil filled reactor a substantial foundation will be required for the reactor. Consideration will be required on how the reactor is to be moved onto the foundation in terms of skidway or other methods. If the reactor is air cored, careful consideration is required to take account of the magnetic fields and to ensure that the reinforcing bars are insulated from one another to prevent circulating currents from damaging the concrete.

A8.2.35 Containment
For an oil filled reactor oil containment will be required. This may be in the form of a self contained bund or have a connection to a common dump tank. Consideration will need to be given to segregation distances for fire or alternatively fire protection may need to be fitted.

A8.2.36 Auxiliaries
If an oil filled reactor is installed then it will probably be fitted with coolers. Allowance needs to be made for the auxiliary supplies to these and any dryer that may be fitted.

A8.2.37 Equipment Ratings
The installation of the series reactor may enable the fault level of the substation to be kept within a particular rating. The reactor itself will need to be rated to carry the full load continuously and withstand a short circuit on its terminals.

A8.2.38 Busbar Layout
Allowance needs to be made in the layout of the busbar to accommodate the connection of the series reactor. This may be a fixed arrangement between two sections of busbar or a selectable one. The short circuit level of the busbars may be reduced which may simplify the busbar design.

A8.2.40 Monitoring
Monitoring equipment may be required for the series reactor.

A8.2.41 Testing
The factory testing will normally be the routine tests. However, if the series reactor is a new design a short circuit test may need to be considered.

A8.3 Superconducting Fault Current Limiter

The index below lists a standard set of possible impacts. If the particular device has an impact on a particular parameter then an entry is included in the index which directs the reader to the appropriate chapter of this Appendix. This chapter explains the impact and provides guidelines on the aspects which may need to be considered.
All of the possible impacts are listed in numerical order in the overall index. This means that the separate subsidiary sections of this Appendix will generally not have completely sequential numbering.

Basic system changes

Impact Index	Impact	Important Notice	Appendix
Fault level	Minor	high short circuit ratio at reduced short circuit currents	A8.3.1
Power flow	None		
Frequency	None		
Voltage	None		
Thermal rating	None		
Unbalance	None		
Harmonics	None		
Impedance	Major	depending on type of limiter impedance during fault conditions changes	A8.3.8
Resonances	None		
Losses	None	additional cooling losses but possible savings of equipment (e.g. transformer	A8.3.10

Single line diagram impact

Impact Index	Impact	Important Notice	Appendix
Short circuit rating	Major	reduced short circuit rating of equipment installed	A8.3.12
Operational switching	None		
Filtering	None		
Compensation	None		
Installation	Minor	space required due to cooling and cryo system	A8.3.16
Maintenance	Minor	new device, at the beginning short maintenance intervals useful	A8.3.17
Bypass	Minor		A8.3.18
Commissioning	Minor	new device, cooling and cryo system need more efforts	A8.3.19
Insulation coordination	Minor		

Detailed substation design

Impact Index	Impact	Important Notice	Appendix
Protection (external)	Minor	reduced fault currents and modified fault duration to be considered	A8.3.22
Protection (internal)	Minor	reduced fault currents and modified fault duration to be considered	A8.3.23
Control	Minor	additional signals (e.g. quench, temperature) to be considered	A8.3.24

Communications	None		
Land & layout	Minor	additional space required due to cryo system	A8.3.26
Visual impact	Minor	new, additional equipment	A8.3.27
External pollution	None		
Audible noise	Minor	Cryo system, cooling machines	A8.3.29
EMC	None		
Electrical clearances	None		
Safety clearances	Minor		
EM fields	None		
Civils	Minor	more space, more civils	A8.3.34
Containment	None		
Auxiliaries	Major	cooling and cryo system, redundancy	A8.3.36
Equipment ratings	None	reduced fault current ratings of downstream equipment	A8.3.37
Busbar layout	Minor	simplified due to reduced fault levels	A8.3.38
Earthing	None		
Monitoring	Minor	additional signals (e.g. quench, temperature) to be considered	A8.3.40
Testing	Minor	up to now no standards available, tests to be agreed on	A8.3.41
Relocatability	None		
Spares requirement	Minor	redundant cooling system required	A8.3.43
Hazards	None	device must be inherent safe in case of an internal fault	

Advice & recommendations

A8.3.1 Fault Level
The inclusion of a superconducting fault current limiter (SCFCL) into a substation is specifically intended to reduce the fault level. The SCFCL may be connected in one particular circuit, but more usually it will be used in the connection between two sections of busbar. This method of connection makes the two adjacent sections of busbar appear to be electrically further apart under fault conditions and usually reduces the fault level on both sections if fault infeeds are present on both sections.

A8.3.8 Impedance
The SCFCL will have a small impedance under normal load conditions and the impedance (resistive or reactive) will change significantly under fault conditions to limit the fault current.

A8.3.10 Losses
The SCFCL will have some losses due to the current flowing through the device under normal load conditions. However, in addition there will be a loss due to the cryogenic cooling plant required to maintain the superconductivity.

A8.3.12 Short Circuit Rating
The SCFCL is installed to reduce the short circuit rating of equipment in the substation. The short circuit rating for the SCFCL itself must be designed to be inherently safe in case of an internal fault.

A8.3.16 Installation
The details of the installation will depend on whether the SCFCL is being installed as an interconnector between two sections of busbar or in series with one outgoing circuit. The most

usual situation would be between two sections of busbar. In this case switchgear will be required to connect the SC FCL to the busbars at either end. This will normally require a disconnector and a circuit breaker at both ends. The reason for the circuit breaker is to ensure that a fault on the SCFCL itself will only cause the tripping of the SCFCL and not result in the loss of one section of busbar. If the substation is a double busbar more disconnectors may be used to increase the flexibility of the connections.

A8.3.17 Maintenance
As the SCFCL is a new type of device it would be prudent to consider more regular maintenance inspections during the early years. Maintenance of the cryogenic plant will be of great importance.

A8.3.18 Bypass
Consideration should be given to whether or not a bypass should be provided to enable the busbars to be coupled directly at times of lower fault level to enable maintenance of the SCFCL.

A8.3.19 Commissioning
Commissioning tests in accordance with the manufacturer's instructions will be required. Extra consideration is the commissioning of the cryogenic plant.

A8.3.22 External Protection
When a SCFCL is added in the network it will reduce the fault current. A check should be made on overcurrent and earth fault relays to ensure that the settings are still satisfactory. Furthermore consideration of the time for the SCFCL to return to normal condition may be required if autoreclose is being used.

A8.3.23 Internal Protection
Protection is required to cover for faults on the SCFCL itself and also on the cryogenic plant.

A8.3.24 Control and Alarms
Additional alarm signals will be required to cover the cryogenic plant.

A8.3.26 Land and Layout
Space must be allowed not only for the SCFCL itself but also for the connection to the busbars at either side. This will not normally be a problem if it is designed into the original layout but may cause difficulties when being added to an existing substation. In addition space will be required for the cryogenic plant.

A8.3.27 Visual Impact
The SCFCL will add a significantly sized new equipment in the substation.

A8.3.29 Audible Noise
The addition of the SCFCL will introduce noise form the cryogenic coolers. If noise is already a problem on the site consideration may need to be given to housing the coolers in a noise enclosure.

A8.3.34 Civils
Foundations will be required to accommodate the SCFCL and its associated cryogenic plant. Adequate access ways will be required.

A8.3.36 Auxiliaries
The SCFCL requires cooling and cryogenic plant. Because of the importance of this equipment redundancy needs to be considered. Design of the auxiliary supplies to this equipment needs to take into account the redundancy requirements.

A8.3.37 Equipment Rating
The installation of the SCFCL may enable the fault level of the substation to be kept within a particular rating. The SCFCL itself will need to be rated to carry the full load continuously and withstand internal short circuits.

A8.3.38 Busbar Layout
Allowance needs to be made in the layout of the busbar to accommodate the connection of the SCFCL. This may be a fixed arrangement between two sections of busbar or a selectable one. The short circuit level of the busbars may be reduced which may simplify the busbar design.

A8.3.40 Monitoring
Monitoring will be required of the cryogenic plant in addition to the SCFCL itself.

A8.3.41 Testing
At present there are no standards which define the tests which are required for SCFCLs. Testing must therefore be agreed between the customer and the supplier.

A8.3.43 Spares Requirements
As the cooling system is critical to the performance a redundant cooling system may need to be provided. In addition stock of the critical items of the cooling system should be considered.

References

[1] Design, modelling and testing of resistive fault current limiter prototypes based on high temperature superconductors, D1-302_2006, L. MARTINI, I. ARCOS, M. BOCCHI, R. DALESSANDRO, V. ROSSI

[2] D1-306, 2006. Development and application trend of Superconducting materials and electrical insulating techniques for HTS power equipment. HITOSHI OKUBO (JAPAN) MICHAEL MCCARTHY (USA), SHIGEO NAGAYA (JAPAN) MATHIAS NOE (GERMANY), FRANK SCHMIDT (GERMANY) CHRISTOF SUMEREDER (AUSTRIA), OLE TØNNESEN (DENMARK) BERND WACKER (GERMANY) - Working group SC D1.15

A9 High Voltage Direct Current

This Appendix deals with High Voltage Direct Current (HVDC) systems and their integration into AC substations. HVDC is an established technology for long distance bulk transmission, undersea transmission and the connection of asynchronous systems.
HVDC technology can be employed to provide point to point transmission, back to back asynchronous connections or multi link terminals. HVDC converts three-phase AC into DC, which is transmitted to the receiving point by an overhead line or cable and then converted back to AC in a another converter station and injected into the receiving AC network. Typically, HVDC transmission has a rated power up to 3,000 MW. HVDC enables power flow to be controlled rapidly and accurately as to both the power level and the direction. This possibility is often used in order to improve the performance and efficiency of the connected AC networks.

There are different operational architectures possible with HVDC, but typical arrangements include Bipolar (fig. 1) and monopolar modes. The differences between designs have technical, operational and economic implications, such as the impact on availability of the link under fault conditions or maintenance outages.

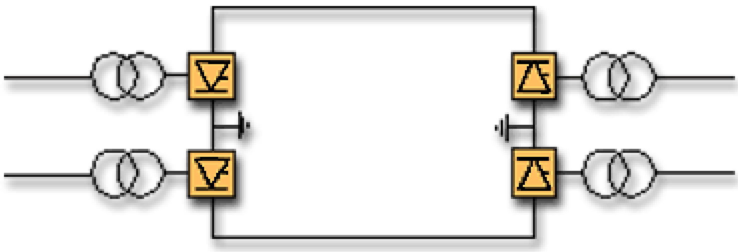


Fig. 1. A typical bipolar HVDC arrangement.

There are two types of HVDC technology and the appendix is therefore divided into two parts, one part dealing with:
A9.1 Classic - Line commutated converters (LCC) HVDC and

A9.2 Voltage sourced converters (VSC) HVDC.

In either case a HVDC station will have a significant impact on the adjacent lands and substation. The reader is reminded the appendix looks at the impact that the installation of a HVDC link within a substation will have on the system, then on the single line diagram and finally on the detailed substation design, not the converter station itself. However sometimes it is difficult to isolate the issues.

A9.1 Line commutated converter HVDC

Conventional or classic HVDC is typically referred to as Line commutated converter HVDC, because the switching technology is based on the use of line commutated thyristors. These power electronic switches are triggered into conduction by a gate signal, and conduct until the current passes through zero, such that the switch off is achieved by natural commutation. Single thyristors have ratings in the order of 8kV/2kA so can handle large power transfers.

Conventional HVDC benefits larger power transfers, when economic trade-off is considered and a bipole link can transmit up to 3000MW.

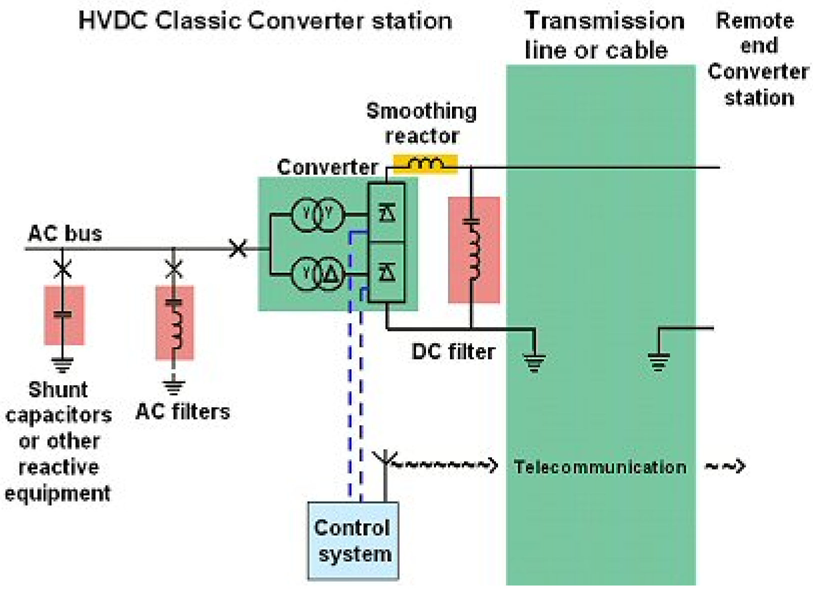


Fig 1. Typical configuration for a Classic HVDC Converter station

A HVDC converter station is similar to a generator in terms of its impact on the substation environment. The index below lists a standard set of possible impacts.

Basic system changes			
Impact Index	**Impact**	**Important Notice**	**Appendix**
Fault level	major	Can be used to isolate networks	A9.1.1
Power flow	major	Key purpose of HVDC is to provide controllable bi-directional power interchange between sending and receiving ends of the link.	A9.1.1
Frequency	major	Loss of the link can cause the frequency to change significantly, similar to losing a generator or large load –	A9.1.2
Voltage	major	Load rejection can cause large over-voltages.	A9.1.3
Thermal rating	major	Additional power flows may affect existing limits	A9.1.1
Unbalance	none		
Harmonics	major	Converters will generate harmonics.	A9.1.5
Impedance	none		
Resonances	none		
Losses	minor	Lower system losses for equivalent AC power transfer	A9.1.6
Single line diagram impact			
Impact Index	**Impact**	**Important Notice**	**Appendix**

Short circuit rating	none		
Operational switching	major	Operated and dispatched similar to a generator. Wide area protection and control may be necessary particularly in weak networks	A9.1.7
Filtering	major	HVDC station design incorporates harmonic filtering.	A9.1.5
Compensation	major	Significant reactive compensation necessary.	A9.1.8
Installation	major	Significant new build for converter station and new bays will be necessary to connect the AC link	A9.1.9
Maintenance	major	HVDC maintenance is complex. AC bays will require same maintenance as any other generator bay.	A9.1.10
Bypass	none		
Commissionin g	major	extensive programme required to test HVDC converter controls significant involvement of all parties.	A9.1.11
Insulation co-ordination	minor	Same as general insulation design. Extensive use of surge arresters	A9.1.12
Impact on detailed substation design			
Impact Index	**Impact**	**Important Notice**	**Appendix**
Protection (external)	major	Same as general protection design. Impact of faults on AC filters, SVCs and busbar protection. Possible need for wide area protection scheme	A9.1.13
Protection (internal)	minor	HVDC converter protection is complex and incorporated into the control system.	A9.1.14
Control	major	Extensive control of converter station necessary – requires coordination with substation control. wide area control?	A9.1.15
Comms	major	Any WAC will require reliable fast communication links	A9.1.16
Land & layout	major	Significant land take for the converter station, additional bays will be required in the AC compound to connect the link into the existing AC network.	A9.1.17
Visual impact	major	Significant. Tall valve hall, large layout for AC and DC switchyards.	A9.1.18
External pollution	major	DC field will attract dust to insulators, larger bushings will be required	A9.1.19
Audible noise	major	AC Filter compound and converter transformers will be big sources of acoustic noise. The impact on the local community needs to be considered.	A9.1.20
EMC	major	Valve hall and AC filter compound will generate high EMC levels. Need to ensure compliance with new regs	A9.1.21
Electrical clearances	none	AC switchyard - No different to existing design clearance. DC yard will be different	A9.1.22
Safety clearances	none	AC switchyard - No different to normal rules. DC switchyard will require attention	A9.1.22
EM fields	minor	Reactors will generate high EM fields. High currents will also be present in the DC and filter yards	A9.1.23
Civils	major	Extensive works required for the valve hall, DC and filter yards. New bay foundations will be required for connection into AC substation	A9.1.24
Containment	major	DC transformers and reactors will require bunding.	A9.1.25
Auxiliaries	high	Significant services required for HVDC station, may drain resources of existing ac substation. Cooling systems for converter valves, SVCs and transformers	A9.1.26
Equipment ratings	none	Should be designed to match existing substation equipment	

Busbar layout	major	Connect into existing substation, may require extension in order to add new bays	A9.1.27
Earthing	major	Earth return method adopted on the HVDC converter station can affect the existing substation earth. Earthing transformer will be necessary for any delta connections	A9.1.28
Monitoring	major	Large degree of monitoring required to ensure operational compliance	A9.1.29
Testing	major	Significant type testing and FAT for HVDC converter station. Testing of existing protection may be necessary	A9.1.30
Relocatability	none		
Spares requirement	major	Significant for HVDC station. AC spares will be determined by the availability level sought.	A9.1.31
Hazards	major	Large scale project	A9.1.32

Advice & recommendations

A9.1.1. Fault level & Power Flow
Operation of the HVDC link will determine the power flow through the substation and can be considered as a power flow controller. The fault current contribution into the substation will need to be coordinated with the HVDC control scheme. The rating of switchgear in the AC substation will need to be checked.

A9.1.2. Frequency
Loss of the link may cause system frequency fluctuations. This is a particular problem in weak networks

A9.1.3. Voltage
Link load rejection or commutation failure can cause fundamental frequency overvoltage during load rejection and recovery.
The reactive compensation in the HVDC station should be specified to control any reactive current output to maintain the AC voltage within acceptable margins. The coordination control with the transformers is necessary to reserve sufficient capacity for a sudden voltage deviation.

A9.1.5 Harmonics
Harmonic filters are necessary to control any harmonics generated by thyristors switching. These occupy a significant element of the DC and AC yard depending on system compliance requirements. Rating and configuration during various directional flow and outage conditions needs to be carefully examined.
Ref: CIGRE Brochure 139 Guide to specification, design and evaluation of AC filters

A9.1.6. Losses
The losses concerning the substation are associated with AC filters, auxiliary supplies for SVC. The DC losses are not really in the scope of this work. However the overall HVDC transmission loss is lower than the AC equivalent, depending on the loading.

A9.1.7. Operational switching
It will be necessary to review the local network switching regime to optimally integrate the HVDC and manage contingency. This may also be coordinated as wide area control to manage power flow and fault conditions.

A9.1.8. Reactive compensation
Similar to harmonic filtering, a significant degree of reactive compensation will be necessary to provide dynamic compliance during system fault conditions. Again land take will be significant. For details on the specific reactive compensation issues see Appendix 4.

A9.1.9. Installation
This is a major project and will require major resource. A large number of new bays will be necessary to connect in DC link, filters and reactive compensation into the AC substation

A9.1.10 Maintenance
There will be a major maintenance activity associated with the converter station, filters and SVCs. Possibly the converter station may be awarded as a separate contract with the manufacturer. Auxiliary systems require the most attention involving routine inspections for coolant levels and fluid checks. Aspects relating to reactive compensation are covered in appendix Appendix 4. Coordinating maintenance outages with other system works will be a key planning challenge, since availability of the DC link is similar to that of a generator.

A9.1.11 Commissioning
This is a significant system event and will need to be coordinated with the network operator well in advance. Tests will include power reversals, which can dramatically affect local network security. Specialist skilled engineers will be required.
Ref CIGRE Brochure 97: System tests for HVDC installation.

A9.1.12 Insulation coordination
The DC switchyard voltage is generally equivalent to peak phase to phase of the AC. Electrical clearances are similar however insulation creepage needs to be longer. The impact of overvoltages due to link problems needs to be analysed.

A9.1.13. Protection (external)
Same as general protection design. Study the coordination between short/grounding faults' protection of SVCs and external protection. Need to limit the sensitivity of external protection to DC faults. Most HVDC links require some type of special protection scheme to coordinate the network response and prevent instability. Typically this will be unique to the network and difficult to test.

A9.1.14 Protection (internal)
HVDC converter protection is integrated into the control scheme. Application will require significant input from the manufacturer

A9.1.15. Control
Extensive control of converter station necessary – requires coordination with substation control. Possibility of wide area control may depend on system fault level. Operation during pole outages will need to be agreed.

A9.1.16. Communications
Any wide area control will require reliable fast communication links. The integrity and reliability of this path is important as spurious signals are not desirable.

A9.1.17. Land take
There will be significant land take for the converter station, additional bays will be required in the AC compound to connect the link into the existing AC network.

A9.1.18 Visual Impact
Planning permission will be very likely as the impact will be significant. Tall valve hall, large layout for AC and DC switchyards, new circuit or cable route.

A9.1.19 External pollution
DC insulation is more sensitive to the effects of external pollution, as a DC field will attract dust to insulators. The creepage needs to be increased above that of AC insulation, typically 40mm/kV.

A9.1.20 Acoustic noise
There are a number of potential sources of noise. In particular the AC Filter compound (air cored reactors), converter transformers and SVCs will be big sources of acoustic noise. Their

location arrangement and load profile should be designed to minimise noise at normal operation.
Ref CIGRE brochure 202 HVDC stations audible noise.

A9.1.21. EMC
The valve hall, active filters and reactive compensation valves will all be source of EMC. Building design and cubicles should be specified accordingly to contain these sources. Cabling between modules should also be screened. Conversely the valve firing circuits need to be hardened against interference. The use of light triggered thyristors should alleviate this risk.

A9.1.22 Clearances
There should be no changes to clearance in the AC substation. Clearances associated with DC will generally align to impulse and switching overvoltages. DC insulation creepage is longer than the equivalent voltage AC, so structures may need to be larger to accommodate longer insulators.

A9.1.23 EM fields
Magnetic field issues associated with reactive compensation and AC filters are discussed in Appendix 4.

A9.1.24 Civils
The converter and associated AC yard will require substation earth works. Reinforcement in the presence of magnetic fields will need to prevent current induction in metallic loops (insulated rebar). Structures in the DC switchyard may be larger than their AC equivalent on a per phase basis.
Plans should be established for the replacement of large plant items following either an equipment failure of asset replacement.

A9.1.25 Oil containment
The converter transformers and DC reactors will require oil containment bunds. It may be necessary to consider a fire barrier between the transformer and adjacent equipment on other circuits to prevent a fire on the transformer from damaging equipment on the other circuits.

A9.1.26. Auxiliaries
The converter station will require a new LV supply. New capacity should be installed rather than extend the existing system. Additional dc supplies will also be required for the control and protection. Risks associated with power electronic systems are also covered in A4, A6 and A7.

A9.1.27 Busbar layout
A number of new bays will be necessary. The running arrangement should aim to accommodate the flexibility offered by the DC link. Pole outage conditions should also be considered to maintain some availability during faults or outages.

A9.1.28. Earthing
The type of earth return method adopted on the HVDC converter station may affect the existing substation earth. Any earth return mode can impose detrimental currents into neutrals.
The reactive compensation will require an earthing transformer for delta connections.

A9.1.29. Monitoring
High accuracy instrument transformers and quality of supply monitoring will be necessary to ensure compliance of harmonic levels – similar to generator. A system side transient fault recorder and data logger should also be installed to assist with resolving any abnormal operational events. The converter and compensation systems will all have sophisticated fault recorders built in.

A9.1.30. Testing
A major type testing programme may be required on the stage of development for the technology. Most testing will be associated with FAT on control and protection systems to prove dependability and reliability. Manufacturer assistance due to special equipment such as thyristor, cooling equipment control and valve monitoring will be required. This along with commissioning requires careful coordination with the system operation as any effects can be wide spread.

A9.1.31 Spares
The provision of spares can be significant for HVDC stations. The criticality will depend on the required availability. Key items to consider are replacement valves, control boards. Spare transformers and reactors need to be financially justified. For the AC switchyard capacitor units, spare or redundant reactors and cooling part are useful. Essentially the spares kept will be dependent on availability level sought. Items with long lead times which affect link availability should be selected

A9.1.32 Other hazards
The HVDC switchyard contains a mixture of technologies and should only be accessible to trained personnel.

References

[1] Compendium of HVDC schemes throughout the world 1987, CIGRE Brochure 003

[2] Operation experience from bulk power HVDC links from the Three Gorges complex, B4-208_2006, R. DASS, B. LINDEN, S. RINALDO, S.P. CHEUNG.

[3] Survey of the reliability of HVDC systems throughout the world during 2003-2004, B4-202_2006, . VANCERS, A. LEIRBUKT, D.J.CHRISTOFERSEN, M.G.BENNETT.

[4] Operating experience of HVDC stations with regard to natural pollution, 33-01_1984, W. LAMPE, K.A. ERIKSSON, C.A.O. PEIXOTO

A9.2 Voltage source converter HVDC

Voltage source converters (VSC) are more compact and functional devices than the classic alternatives. VSC designs employ self commutating switches (IGBT, MCT and GTO thyristors), which can turn off when required, rather than waiting for line commutation. This results in a converter which can operate independently of the AC voltage sinusoid. VSC HVDC links use cable, since this can be easily buried and minimise the environmental impact.

The converter architecture and control methodology inherently cater for reactive compensation and filtering functionality, significantly reducing the additional plant required to enable HVDC operation.

The power transfer capability is limited at this stage to, however the ratings are increasing all the time. To achieve this higher degree of control the losses are higher, this is due to a higher switching frequency (PWM) and higher on state losses in the power electronics.

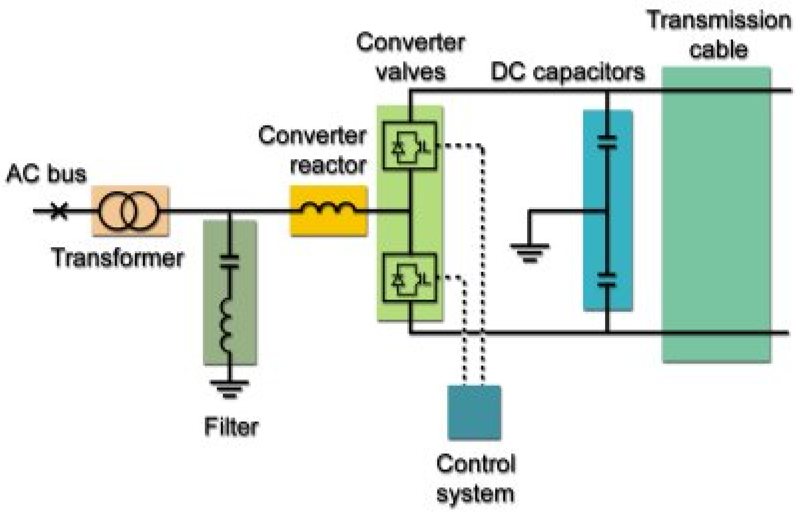


Fig.1 Typical arrangement for a VSC HVDC substation

This new technology is suitable for the connection of potentially asynchronous sources, between low fault level systems and frequently islanded networks such as remote wind farms.

Basic system changes			
Impact Index	**Impact**	**Important Notice**	**Appendix**
Fault level	none	Can be used to isolate networks	
Power flow	major	Bi-directional power interchange between sending and receiving ends of the link	A9.2.1
Frequency	major	Loss of the link can cause the frequency to change significantly, similar to losing a generator or large load.	A9.2.2
Voltage	major	Load rejection can cause large over-voltages.	A9.2.3
Thermal rating	major	Additional power flows may affect existing limits	A9.2.1
Unbalance	none		
Harmonics	major	Converters will generate high order harmonics, much less than classic design.	A9.2.4
Impedance	none		
Resonances	none		

Losses	minor	Lower system losses for equivalent AC power transfer, but higher than classic design	A9.2.5
Single line diagram impact			
Impact Index	**Impact**	**Important Notice**	**Appendix**
Short circuit rating	none		
Operational switching	minor	Operated and dispatched similar to a generator. Wide area protection and control may be necessary	A9.2.6
Filtering	Major	HVDC station design incorporates harmonic filtering.	A9.2.7
Compensation	Major	Reactive compensation may be necessary.	A9.2.8
Installation	major	New bays will be necessary to connect the AC link	A9.2.9
Maintenance	Major	HVDC maintenance is complex. AC bays will require same maintenance as any other generator bay.	A9.2.10
Bypass	None		
Commissioning	major	Major programme required to test HVDC converter controls significant involvement of all parties.	A9.2.11
Insulation coordination	minor	Same as general insulation design. DC will require further analysis	
Impact on detailed AC substation design			
Impact Index	**Impact**	**Important Notice**	**Appendix**
Protection (external)	major	Ned to coordinate with protection settings. Impact of faults on filter and SVCs and external protection. Wide area protection may be required	A9.2.12
Protection (internal)	minor	HVDC converter control & protection is complex and will require significant input from the manufacturer.	A9.2.13
Control	major	Extensive control of converter station necessary – requires coordination with substation control. wide area control?	A9.2.14
Communication	major	Any WAC will require reliable fast communication links	A9.2.15
Land & layout	major	The converter station will require reasonable space, additional bays will be required in the AC compound to connect the link into the existing AC network.	A9.2.16
Visual impact	major	Significant. New building will be required and large layout for AC and DC switchyards.	A9.2.17
External pollution	minor	DC field will attract dust to insulators.	A9.2.18
Audible noise	major	Any AC Filter or SVC compound and converter transformers may be sources of acoustic noise.	A9.2.19
EMC	major	Power electronics will generate high EMC levels	A9.2.20
Electrical clearances	none	No different to normal substation rules for AC substation.	A9.2.21
Safety clearances	none	AC switchyard - No different to normal rules. DC switchyard will require attention	A9.2.21
EM fields	major	Reactors will generate high EM fields. High current will also be generated in the DC and filter yards	A9.2.22
Civils	major	Extensive works required for the valve hall, DC and filter yards. New bay foundations will be required. Bunding will be required for the transformer	A9.2.23
Containment	major	DC transformers will require bunding.	A9.2.24
Auxiliaries	major	Supplies required for VSC cooling and control systems	A9.2.25
Equipment ratings	none	Should be designed to match existing substation equipment	A9.2.1

Busbar layout	major	Connect into existing substation, may require extension in order to add new bays	A9.2.26
Earthing	major	Earth return method adopted on the HVDC converter station may affect the existing substation earth. Earthing transformer will be necessary for Delta connections	A9.2.27
Monitoring	major	Large degree of built in monitoring. QoS required to ensure operational compliance	A9.2.28
Testing	major	Significant type testing and FAT for HVDC converter station. Testing of existing protection may be necessary	A9.2.29
Relocatability	none		
Spares requirement	major	Significant for HVDC station. AC equipment will be dependent on availability level sought.	A9.2.30
Hazards	minor	Major project	

A9.2.1. Fault level & Power Flow
Operation of the HVDC link will determine the power flow through the substation and can be considered as a power flow controller. The fault current contribution into the substation will need to be coordinated with the HVDC control scheme. The rating of switchgear in the AC substation will also need to be checked against any new conditions.

A9.2.2. Frequency
Loss of the link may cause system frequency fluctuations. This is a particular problem in weak networks. The active control of the VSC may enable faster recovery.

A9.2.3. Voltage
Link load rejection can cause fundamental frequency overvoltage during load rejection and recovery. The reactive compensation in the HVDC station should be specified to control any reactive current output to maintain the AC voltage within acceptable margins. The coordination control with the transformers is necessary to reserve sufficient capacity for a sudden voltage deviation.

A9.2.4 Impact upon harmonics
The VSC power electronics will inherently generate harmonics. However the switching mode employed will minimise the harmonics occurring at the lower orders. For more information on this topic refer to Appendix A4.1.3.

A9.2.5 Losses
The VSC exhibits higher losses per MVA than LCC however the system losses might still be better than the equivalent AC circuit. Furthermore, there will be auxiliary system (fans required or water cooling pumps) and these will also increase the losses.

A9.2.6 Operational Switching
Similar to that of the LCC, however the VSC can operate in island mode. The boundary conditions for this mode will need to be established prior to commissioning, particularly synchronisation back to the network.

A9.2.7 Filtering
Usually the level of harmonics created by a VSC are of a significantly lower magnitude than those from conventional HVDC power electronic devices using thyristors, depending on the network strength, it may not normally be necessary to have additional filters to deal with these. The acceptable level of harmonics and the pre-existing harmonics will need to be considered and the VSC design rated to meet these levels.

A9.2.8 Compensation
The VSC is more of an active application than LCC and a large degree of the voltage compensation is inherent in the VSC architecture. Similar to the filter requirements, additional reactive compensation may be required, but the network conditions will determine the size and it will be much smaller than the LCC requirement.

A9.2.9 Installation
The VSC is a more modular application than the LCC but will be accommodated in a building or a container. It may have been designed in a modular format so that higher power levels can be created by connecting modules in series or parallel. The transformer is required to couple the voltage into the circuit and this will also need to be installed. New AC bays will be required.

A9.2.10 Maintenance
Maintenance will be required in accordance with the manufacturer’s instructions. The frequency of maintenance may be reduced if there is redundancy built into the design of the power electronics. Cooling and auxiliary systems will once again be the critical items to consider for inspection & maintenance.

A9.2.11 Commissioning
Commissioning tests in accordance with the manufacturer’s instructions will be required. A full factory acceptance test (FAT) should have been completed before the device is shipped to site and this will help to reduce the amount of tests required during commissioning. The tests will usually include a functional test to prove that the device is responding correctly to changes in the system voltage. Coordination with the system operator will be necessary.

A9.2.12 External Protection
The VSC HVDC is not reliant on AC commutation, but its interaction with the network will need to be examined. Alternatively the VSC has no effect upon the external protection other than the location of the protection current transformers.

A9.2.13 Internal Protection
The VSC protection is incorporated into the control scheme. Protection is provided to prevent the devices from experiencing excessive voltage or excessive current. This is outside the scope of this review.

A9.2.14. Control
Extensive control of converter station necessary – requires coordination with substation control. Possibility of wide area control may depend on system fault level. Operation during pole outages will need to be agreed.

A9.2.15. Communications
Any wide area control will require reliable fast communication links. The integrity and reliability of this path is important as spurious signals are not desirable and can cause system wide disturbances.

A9.2.16 Land and Layout
Land take will be significant to the existing site, but not as great as for a LCC station.

A9.2.17 Visual Impact
The measures necessary to be adopted will depend upon the particular site. Although containers may be the cheapest housing for the power electronics it may be necessary to consider a building to blend into the surroundings in certain locations. Alternatively the colour of the containers may be carefully chosen for the same reason.

A9.2.18 External pollution
DC insulation is more sensitive to the effects of external pollution, as a DC field will attract dust to insulators. The creepage needs to be increased above that of AC insulation. Site specific conditions will need to be established and creepage specified accordingly

A9.2.19 Acoustic noise
There are a number of potential source of noise. Air cored reactors and transformers, cooling equipment may also contribute. Their location arrangement and load profile should be designed to minimise noise at normal operation.
Ref CIGRE brochure 202 HVDC stations audible noise.

A9.2.20. EMC
The valve hall, active filters and reactive compensation valves will all be source of EMC. Building design and cubicles should be specified accordingly to contain these sources. Cabling between modules should also be screened. Conversely the power electronic modules need to be hardened against interference.

A9.2.21 Clearances
There should be no changes to clearance in the AC substation. Clearances associated with DC will generally align to impulse and switching overvoltages. DC insulation creepage is longer than the equivalent voltage AC, so structures may need to be larger to accommodate longer insulators.

A9.2.22 EM fields
Magnetic field issues associated with reactive compensation and AC filters are discussed in Appendix 4.

A9.2.23 Civils
New AC bays will be required. Allowance needs to be made for the foundations for the transformer. If the power electronics are in a container rather than a building then compacted hardcore may suffice as the base for the container. Cable trenches may be required between the transformer and the container.

A9.2.24 Oil containment
The converter transformer will require oil containment bunds. It may be necessary to consider a fire barrier between the transformer and adjacent equipment on other circuits to prevent a fire on the transformer from damaging equipment on the other circuits.

A9.2.25. Auxiliaries
The converter station will require a new LV supply. New capacity should be installed rather than extend the existing system. Additional dc supplies will also be required for the control and protection. Risks associated with power electronic systems are also covered in A4, A6 and A7.

A9.2.26 Busbar layout
New bays will be necessary. The running arrangement should aim to accommodate the flexibility offered by the DC link. Pole outage conditions should also be considered to maintain some availability during faults or maintenance outages.

A9.2.27. Earthing
The type of earth return method adopted on the HVDC converter station may affect the existing substation earth. Any earth return mode can impose detrimental currents into neutrals.

A9.2.28. Monitoring
High accuracy instrument transformers and quality of supply monitoring will be necessary to ensure compliance of harmonic levels – similar to generator. A system side transient fault recorder and data logger should also be installed to assist with resolving any abnormal operational events. The converter and compensation systems will all have sophisticated fault recorders built in.

A9.2.29. Testing
A major type testing programme may be required on the stage of development for the technology. The modular nature of VSC will enable most FAT to be performed at the manufacturer premises. Auxiliary equipment must be checked. This along with commissioning requires careful coordination with the system operation as any effects can be wide spread.

A9.2.30 Spares requirement
As the power electronics will be different from any other components already existing on the site it will be necessary to hold additional spare parts. Advice should be sought from the supplier on the quantities of spares to be held. Consideration should be given to the likelihood of equipment obsolescence after 10years life.

References

[1] CIGRE Technical Brochure 269: VSC Transmission

[2] CIGRE Technical Brochure 280: HVDC and FACTS for Distribution

[3] The direct link VSC based HVDC project and its commissioning, 14-108_2002, B.D. RAILING, J.J. MILLER , G. MOREAU-. WASBORG, Y. JAING-HAFNER, D. STANLEY

A10 Protection

This Appendix deals with the new generation of Numerical Protection which encompasses a range of Multi-Functional relays not only having a variety of Protection functions within one relay, they also include other non-Protection functions such as Control, Measurements, Self-Diagnostics, limited Primary equipment Monitoring, Fault Location, Disturbance Recorder and Protection Signalling.

In this instance the subject “Protection” means any device that has the purpose of Protection. The devices covered in this section are combined and contained in under one equipment heading, that of Numerical Protection. The appendix, therefore, only has one part. It looks at the impact that the installation of the Numerical Protection devices within a substation will have on the Basic System changes, then on the Single Line Diagram, and finally on the Detailed Substation Design.

Introduction

The 1960s produced unprecedented expansion of electricity networks in many European Countries, culminating in the establishment of 380 - 400kV systems. Protection was electromechanical, and generally substations were manned, and control took place locally.

In the 1980s many utilities worldwide started to replace the main electromechanical protection with static relays. They also widely installed remote control systems, versions of Remote Terminal Units (RTU) and Substation Control And Data Acquisition (SCADA), and de-manned substations except for the main control points.

From the mid-1990s numerical multifunction relays were being introduced, mainly due to the fact that a few years earlier digital control had been implemented including digital communication. Keeping the protection analogue meant that all information from protection to control needed to be done via contact output on protection, and corresponding inputs on control systems. By also changing protection to numerical type, digital communication could be made between Protection and Control (P&C). This change also allowed the integration of protection and control functionality in the same equipment.

With numerical technology self-monitoring was then possible, which allowed the traditional time-based protection maintenance periods to be varied. The main benefit of self-monitoring was not always trusted by maintenance engineers, nor was the relay software trusted, nor the testing of software. In some instances contractual service agreements were put in place that called for quick manufacturer responses, however they over-estimated failure rates and problems.

Today, in practice, overall reliability has increased and proved that the numerical relays are far more reliable than engineers and utilities first feared, or expected. Hence reliance on self-monitoring is now taken for granted, which is dramatically changing the concept of maintenance with some users.

These concepts, inherent in modern P&C equipment, are further discussed in Appendix 12, Monitoring and Diagnostics. It will also point the way forward that builds on substation controllers and Intelligent Electronic Devices (IEDs), along with sensor technology, to allow operators to monitor and diagnose incipient problems not only in protection, but also in the power equipment itself before failure, thus optimising maintenance and preventing costly outages.

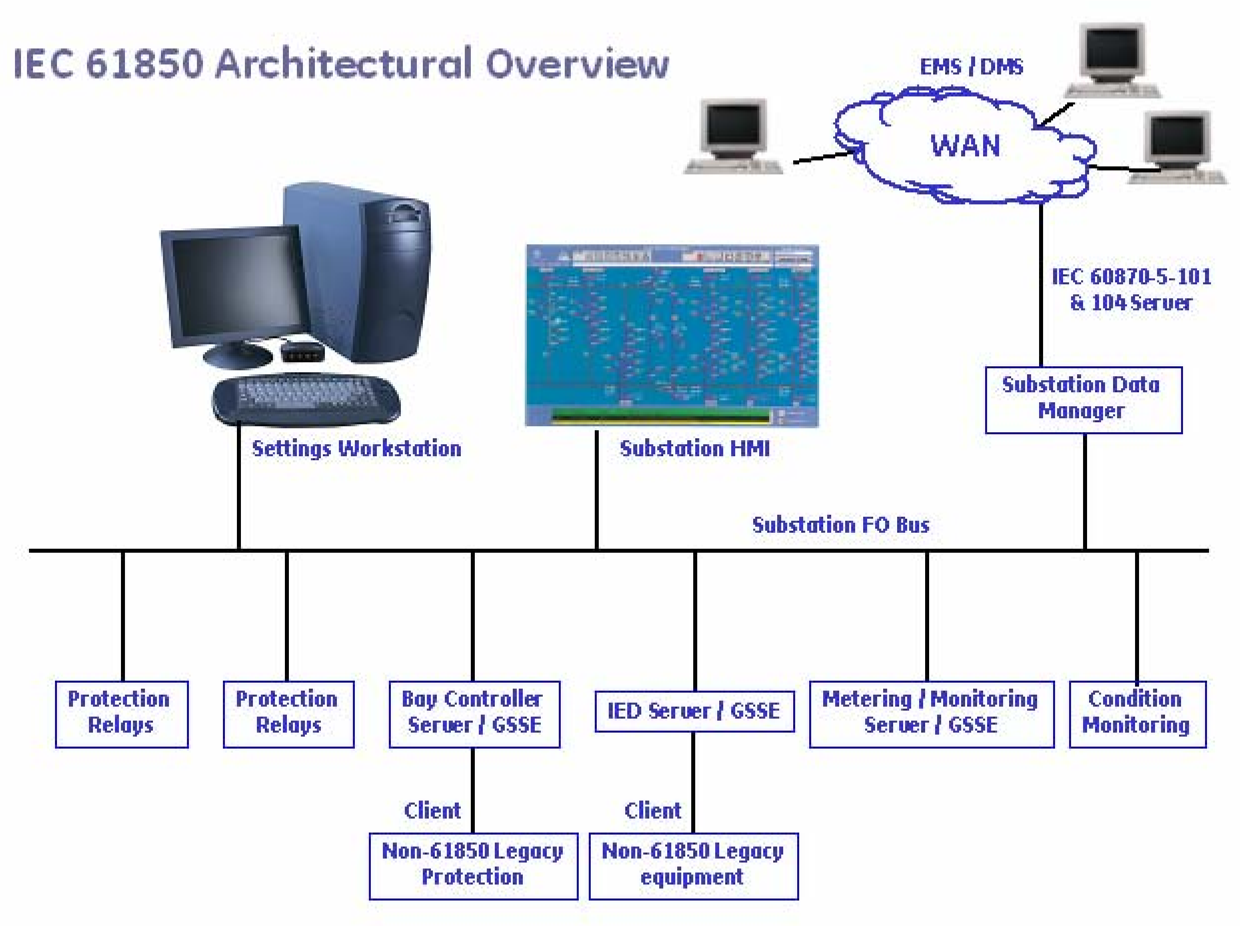
Integrated Protection and Control Systems

Integrated Substation Control Systems (iSCS) are at the heart of the new functionality in Substation Design. However, due to the wide-ranging subject of Protection, it is fully dealt with in a separate Cigre Study Committee, B5, which is charged with all aspects of Protection and Automation.

For this reason it is not proposed to elaborate further on the Protection advances themselves within substations, solely to make the reader aware of what subjects are being studied elsewhere, and to show the impact on substation design. See Reference 1.

An integrated protection and control approach is as shown on the following figure for IEC 61850 protocol. Other substation protocols are also being used for integration, however in general suppliers are now heading towards this route. All IEC 61850 protection, no matter from which supplier, is connected straight onto the Substation Bus. Suppliers' protection and other equipment using non-IEC 61850 protocol are taken through to the Substation Bus via Bay Controller or general IED servers.

At present very little stand-alone Condition Monitoring uses this protocol, so other protocols would go through an IED in the same manner as non-IEC 61850 protection equipment, however it is expected that this will increase.



A10.1 Numerical Protection

The index below lists a standard set of possible impacts.

Basic system changes

Impact Index	Impact	Important Notice	Appendix
Fault level	none		
Power flow	minor	Only in the case where specific protection is used to trip for certain power levels in a particular direction	A10.1.1
Frequency	minor	Only in the case where specific protection is used to trip outside certain frequency limits	A10.1.2
Voltage	minor	Only in the case where specific protection is used to trip outside certain voltage limits	A10.1.3
Thermal rating	minor	Only in the case where specific protection is used to trip outside certain thermal limits	A10.1.4
Unbalance	minor	Only in the case where specific protection is used to trip outside certain unbalance limits	A10.1.5
Harmonics	none		
Impedance	none		
Resonances	none		
Losses	none		

Single Line Diagram Impact

Impact Index	Impact	Important Notice	Appendix
Short circuit rating	none		
Operational switching	minor	Only in the case where specific protection relays are configured as operational switching devices	A10.1.6
Filtering	none		
Compensation	none		
Installation	major	As temporary protection during stages in refurbishment, and as a means of keeping the original protection in situ whilst pre-commissioning the new protection	A10.1.7
Maintenance	minor	Can be used for monitoring to enable Condition Based Maintenance to be used for primary equipment	A10.1.8
Bypass	minor	Can be used to protect most SLD arrangements, however Bypass is only used in a small number of substations	A10.1.9
Commissioning	minor	Current, voltages, phase-angle, etc. information is available to help with primary equipment commissioning	A10.1.10
Insulation coordination	none		

Detailed Substation Design

Impact Index	Impact	Important Notice	Appendix
Protection (external)	major	Protection has built-in end-to-end communication channels for intertripping, circuit breaker fail, etc.	A10.1.11

Protection (internal)	major	The Multifunctional protection enables the elimination of many traditional individual stand-alone protection relays	A10.1.12
Control	major	Integrated Substation Control Systems make use of many Control Functions within the substation	A10.1.13
Communications	major	Protection and Control functions can now communicate with various Protocols. Advent of IEC 61850 aims to make this universal between manufacturers	A10.1.14
Land & layout	minor	Cubicle footprints are considerably reduced from older electro-mechanical devices	A10.1.15
Visual impact	minor	Switchrooms and/or block-houses are smaller	A10.1.16
External pollution	none		
Audible noise	none		
EMC	minor	All products are manufactured to strict EMC levels, and have a beneficial effect on reducing EMC coming from secondary circuits	A10.1.17
Electrical clearances	none		
Safety clearances	none		
EM fields	none		
Civils	minor	Cubicle footprints are considerably reduced from older electro-mechanical devices. Switchrooms and/or block-houses are smaller	A10.1.18
Containment	none		
Auxiliaries	minor	DC requirements are higher, however they are consistent, and not peaky	A10.1.19
Equipment ratings	none		
Busbar layout	none		
Earthing	none		
Monitoring	major	Many built-in monitoring functions	A10.1.20
Testing	major	Current, voltages, phase-angle, etc. information is available to help with primary equipment commissioning and testing	A10.1.21
Relocatability	minor	Cubicle footprints are considerably reduced from older electro-mechanical devices, enabling relocatable equipment to be smaller and lighter	A10.1.22
Spares requirement	minor	The self-diagnosis of the protection can point to a particular card being at fault, hence modules can be held as spares	A10.1.23
Hazards	none		

Advice & Recommendations

A10.1.1 Impact on Power Flow
Minor
Only in the case where specific protection is used to trip for certain power levels in a particular direction.

Some protections have directional functions to control power flow in a reverse direction. For substations this includes directional overcurrent functions for transformers where a reverse flow could indicate a failure of fast protection on an associated overhead line. Directional earth fault settings are applicable to overhead lines.
Directional relays existed during the static era, however they were separate units, which meant that this function was more expensive, and took more physical space to include.

Numerical protection has added reverse directional characteristics that can be set completely independent of the forward characteristic, and to the same settings and accuracy. There is a considerable advantage here over previous generations of protection.
These characteristics can be used as a traditional but more accurate means of controlling power flow, and can have several stages of overload in a correct direction if desired.
Reverse power flow into a generator can be detected at the substation infeed.
In general these functions can be custom used within the range of protection relays, and made flexible by the abundant use of AND/OR/TIMER configurable software within the relays.

A10.1.2 Impact on Frequency

Minor
Only in the case where specific protection is used to trip outside certain frequency limits.

Multifunction relays can have multiple stages, allowing more control and/or indications of the system frequency. This has an impact when connected to the sub-transmission network for load-shedding schemes, or to generators, whether main or auxiliary used for frequency control of the network. In the latter case this could be automatically starting gas turbines and/or control of pumped storage schemes.
The numerical protection not only has more configurable stages, it can also have more accurate response to rate of change of frequency.

Underfrequency relays for load shedding were used during the static era, however they were separate units, and each stage meant a considerable increase in the cost of the units. Some relays had 4 or 5 stages, especially where the substation was close to a power plant.

A10.1.3 Impact on Voltage

Minor
Only in the case where specific protection is used to trip outside certain voltage limits.

Multifunction relays can have multiple stages, allowing more control and/or indications of the system voltage. This has an impact when connected to the sub-transmission network for automatic tap change control of the transformers to the higher voltage levels. Bespoke schemes have been designed to enable a group of transformers on different busbars and different voltage levels to be controlled by essentially protection products.
The advent of different setting groups in numerical protection relays enables the voltage settings to be varied in accordance to the system conditions, for instance where a distributed generator is, or is not, connected to the substation system.

A10.1.4 Impact on Thermal Rating

Minor
Only in the case where specific protection is used to trip outside certain thermal limits.

Multifunction relays can have multiple stages, allowing more control and/or indications of the circuit loading. This has an impact when connected to any circuit, particularly overhead lines and cables. The advent of different setting groups in numerical protection relays enables the current settings to be varied in accordance to the system conditions, or ambient conditions, enabling a more accurate profile of the allowable loading.

A10.1.5 Impact on Unbalance

Minor
Only in the case where specific protection is used to trip outside certain unbalance limits.

Numerical relays use the sequence components of voltage and current, so that unbalance can be measured much more accurately. This can be used to determine failing joints in overhead lines and cables, badly worn or misaligned disconnectors, or circuit breakers where phases have not closed/opened together.

The detection circuits can also be used to monitor unbalance in the secondary equipment, a failing CT or a high resistance joint.

A10.1.6 Impact on Operational Switching

Minor
Only in the case where specific protection relays are configured as operational switching devices.

Multifunction relays can have multiple stages, allowing more control and/or indications of the system. This has an impact when connected to the network for automatic switching control of the circuit breakers.
The majority of substations traditionally use a single line diagram where each outgoing circuit has their own circuit breaker (CB), or even have two CBs (double breaker, 1½-breaker, ring busbar) making auto-switching logics obsolete, independent of which secondary technique is used.
However, there are bespoke schemes that have been designed to enable protection/control relays using configurable logic to either automatically operate circuit breakers and/or disconnectors at the substation, e.g. Mesh or Mesh Corner switching at a Mesh substation. This can extend to full operational switching to remote substations using direct intertripping, or direct transfer trips via the communication channels of Distance and Line Differential relays.
The advent of a high number of digital inputs in numerical protection relays enables the various generator or line circuit breaker inputs to cater for a range of system conditions to be pre-programmed as start functions for any operational switching from the substation to remote substations.

A10.1.7 Impact on Installation

Major
As temporary protection during stages in refurbishment, and as a means of keeping the original protection in situ whilst pre-commissioning the new protection.

Multifunctional numerical protection takes much less space than traditional relays, consequently it is often possible to install the new protection panels in a small space prior to removing the old protection. This allows a considerable reduction in the length of the required outage, and hence reduces the time of risk of a loss of supplies to the customers. There can, therefore, be savings for regulated utilities of customer minutes lost, and number of interruptions. These can be directly financial from the Regulator, or political and can then have a major effect on share prices.

A10.1.8 Impact on Maintenance

Minor
Can be used for monitoring to enable Condition Based Maintenance to be used for primary equipment.

Numerical relays use the sequence components of voltage and current, so that unbalance can be measured much more accurately. This can be used to determine failing joints in overhead lines and cables, badly worn or misaligned disconnectors, or circuit breakers where phases have not closed/opened together.
The detection circuits can also be used to monitor unbalance in the secondary equipment, a failing CT or a high resistance joint.
These can all be built in to a Condition Based Monitoring (CBM) system in order to vary the old Time Based Maintenance (TBM) systems of the past.
Some utilities use Expert systems using information from protection relays in conjunction with other Condition Monitoring equipment as a basis for their CBM scheme.

A10.1.9 Impact on Bypass

Minor
Can be used to protect most SLD arrangements, however Bypass is only used in a small number of substations.

Provided that the CTs are located in the correct positions the numerical protection can protect any SLD arrangement. In cases where CTs are only one side of circuit breakers (CB), as is the case for the majority of SLDs using non-dead tank circuit breakers, the protection relay can be programmed with fast single-end or interlocked functions that allow logic to determine where the fault is located, and take appropriate tripping and/or intertripping action. This logic is built in to the relay using accurate and fast timers, and does not require separate external timing relays as with the previous static relays.
For tripping of the correct CB you must rely on CB failure protection circuits that will trip after a delay of appr. 150 ms for these type of faults. For bus-couplers and bus-sectionalizer CB´s
The advance from the static relays is that CB failure protection today can be a software option in the ordinary protection while it before was a considerable number of separate units.

A10.1.10 Impact on Commissioning

Minor
Current, voltages, phase-angle, etc. information is available to help with primary equipment commissioning.

Measurement values are available directly on the relays to help with CT phasing checks.
Many features are built in to the relays that can negate a lot of the traditional testing. For instance with Phase Comparison Protection if phases or end-to-end channels are crossed, the built-in diagnosis flags this up as an alarm.

A10.1.11 Impact on Protection (external)

Major
Protection has built-in end-to-end communication channels for intertripping, circuit breaker fail, etc.

Measurement values are available directly on the relays to help with CT phasing checks. For instance with Phase Comparison Protection if phases or end-to-end channels are crossed, the built-in diagnosis flags this up as an alarm. Also many tests and checks can be done at the local end negating visits to the remote end.
Direct Transfer Tripping (DTT) can be used with all unit and non-unit protection that employs communication channels. In the case of the former current differential protection there is usually at least one other DTT channel, and in the case of the latter, distance protection, there can be several DTT channels. This reduces the need for external intertripping channels by providing one direct path. At best it can eliminate the need for intertripping where other parallel protection channels are available, although many users still prefer to keep at least one path independent of protection, and route lengths have to be considered.

A10.1.12 Impact on Protection (internal)

Major
The Multifunctional protection enables the elimination of many traditional individual stand-alone protection relays.

Virtually the whole range of individual protection relays have now been modelled in software, and their functionality introduced into the numerical relays.
This enables use of a One-Box solution at MV substations if back-up can be taken care of by protection in nearby substations, i.e. remote back-up. There is a need, however, to ensure that a primary failure on the low voltage side of a power transformer is detected from the remote substation.
At sub-transmission a Two-Box solution has one relay for the main protection, and a second relay for back-up protection and other ancillary functions and control.
At transmission a Two-Box solution is also feasible, each relay having a main protection with numerical relay and self-supervision it is sufficient to have two main protections and back-up is not needed. Having a back-up will increase the risk of over-tripping. For UHV a solution with 4 boxes might be considered having 2 connected in series in each subsystem. A maloperation from one protection will then not lead to tripping of the primary while at the same time the protection function is guaranteed at a primary fault even if one protection should fail to operate, and other

ancillary functions spread around the two relays, or completely duplicated. At present, however, most transmission utilities specify more than two relays, some up to a Five-Box solution, entailing the use of two relays for the main protections, a third for back-up and ancillary functions, a fourth as a bay controller, and a fifth as the network management system.
With self-supervision, and detection of a protection failure instantly as it happens, a two-protection solution should always be sufficient. The original idea with 2 main, and an additional back-up protection, comes from the time without supervision when a failure in the protection might happen just after the maintenance testing, and could be sitting undetected to the next maintenance testing a year or more later.
Having more than 2 protections could also increase the risk of unnecessary tripping when there is no primary failure.

A10.1.13 Impact on Control

Major
Integrated Substation Control Systems make use of many Control Functions within the substation.

The multifunctional nature, and configurable logic, enables the numerical protection relays to be easily adapted for control purposes. Many traditional distinct functions can now be already pre-programmed building blocks, or custom made for a particular customer's requirement. Examples of these are switchgear Open and Close controls, Check- and System-Synchronising, Auto-Reclose (single- or three-phase, single- or multi-shot), Automatic Tap Change Control, Auto-Trip and Close schemes, and automatic transfer.
The above has lead to the integrated protection and control approach, or integrated Substation Control System (iSCS) being adopted at many new and refurbished transmission substations.

A10.1.14 Impact on Communications within the Substation

Major
Protection and Control functions can now communicate with various Protocols. Advent of IEC 61850 aims to make this universal between manufacturers

Most protection manufacturers now supply protection relays with IEC 61850, although this is still relatively new, and in many cases its use is considered to be on trial. The Station Bus enables communications between protection relays of all manufacturers using the protocol, and its immediate effect is communication with two main protections, which most customers stipulate should be from different manufacturers.
The Process Bus is not so widely available, and at present its use is limited because of the lack of digital CT, VT, switchgear tripping and closing circuits.
In the future we will see the use of process bus also in cases without digital CT, VT. Transformer units can be placed close to the primary, converting the 1 A and 110 V to digital signals, which then can be transferred via process bus to the control/relay boxes.
Tripping and closing circuits will for quite a long time in the future need some kind of relay closest to the CB to release the energy stored in springs, hydraulic or pneumatic. What will happen is that distributed I/O will be put out in the switchyard close to the CB and CT. Process bus will then be used to transfer all information both digital and analogue. Copper cables would only be needed for transferring of AC and DC power.

A10.1.15 Impact on Land & Layout

Minor
Cubicle footprints are considerably reduced from older electro-mechanical devices.

This has an impact on refurbishing older substations, and for Greenfield sites, in that the relay rooms, or relay blockhouses in the substations, are considerably smaller allowing better use of the land space and the advent of compact substations. In some instances the protection can be mounted on the switchgear, for instance with Gas Insulated Switchgear (GIS) it can be mounted on the Local Control Cabinet, saving a separate relay room.

A10.1.16 Impact on Visual
Minor
Switchrooms and/or blockhouses are smaller

This has an impact on refurbishing older substations, where older block-houses can be reduced in size, or in number. The major impact would be for Greenfield sites, in that the relay rooms, or relay block houses in the substations, are considerably smaller allowing better use of the land space and the advent of compact substations. In some instances the protection can be mounted on the switchgear, for instance with Gas Insulated Switchgear (GIS) it can be mounted on the Local Control Cabinet, saving a separate relay room.

A10.1.17 Impact on EMC
Minor
All products are manufactured to strict EMC levels, and have a beneficial effect on reducing EMC coming from secondary circuits.

The products are not only designed to a high degree of immunity to EMC, they also have a high degree of radiated EMC. The much reduced footprint also means that the copper wiring is also much reduced, hence reducing the overall EMC from the wiring. The main contribution for reduction of EMC is the use of Fibre Optic connections, which also has a two-way effect. Mounting the relays on the switchgear in the case of GIS eliminates most copper wiring, and reduces the lengths of AC and DC wiring. There can then be very little radiated EMC from the protection and control, although this must still be classed as a minor effect, as the switchgear itself, especially disconnectors and circuit breakers, has EMC far in excess of the protection, and this will still remain.

A10.1.18 Impact on Civils
Minor
Cubicle footprints are considerably reduced from older electro-mechanical devices. Switchrooms and/or blockhouses are smaller

The impact on refurbishing older substations, and for Greenfield sites, is that the relay rooms, or relay block-houses in the substations, are considerably smaller allowing better use of the land space and the advent of compact substations. In some instances the protection can be mounted on the switchgear, for instance with Gas Insulated Switchgear it can be mounted on the Local Control Cabinet, saving a separate relay room. All this limits the amount and size of civil work required.
Many blockhouses in the past were brick built, they can now be pre-wired and tested as containers that can be delivered to site and placed on small plinths.

A10.1.19 Impact on Auxiliaries
Minor
DC requirements are higher, however they are consistent, and not peaky.

All the modern protection products require DC supplies, whereas some of the existing pre-static protection only used the DC during operations. Hence a standing DC load is always present, and consequently the AC load is also slightly higher. In effect this has not necessitated much greater Auxiliaries, as the requirement for peaky loads during operation are not required. The protection relay takes a steady load even during trip operation, hence the Auxiliaries are designed for consistent loads, rather than over-designed for the peaks of several operations occurring at the same time.

If we compare with static relays they also need continuous DC-supply and usually also takes higher power than numerical protection in addition they take even more power during a disturbance in the network.

Although the numerical relays themselves do not have peaky requirements the tripping coils, especially for a busbar trip when many CB operates simultaneously, still has a big peak. This peak, at the end of the discharging time, is in the most cases still gives the dimensional criteria for battery size.

A10.1.20 Impact on Monitoring

Major

Many built-in monitoring functions.

With numerical technology self-monitoring is possible, which allows the traditional time-based maintenance periods to be varied. The main benefit of self-monitoring was not always trusted by maintenance engineers, nor was the relay software trusted, nor the testing of software. In some instances contractual service agreements were put in place that called for quick manufacturer responses, however they over-estimated failure rates and problems.

Today, in practice, overall reliability has increased and proved that the numerical relays are far more reliable than engineers and utilities first feared, or expected. Hence reliance on self-monitoring is now taken for granted, which is dramatically changing the concept of protection maintenance.

These concepts, inherent in modern P&C equipment, are further discussed in Appendix 12, Monitoring and Diagnostics. It will also point the way forward that builds on substation controllers and IEDs, along with sensor technology, to allow operators to monitor and diagnose incipient problems not only in protection, but also in power equipment before failure, thus optimising maintenance and preventing costly outages.

A10.1.21 Impact on Testing

Major

Current, voltages, phase-angle, etc. information is available to help with primary equipment commissioning and testing.

Measurement values are available directly on the relays to help with CT phasing checks.

Many features are built in to the relays that can negate a lot of the traditional testing. For instance with Phase Comparison Protection if phases or end-to-end channels are crossed, the built-in diagnosis flags this up as an alarm.

A10.1.22 Impact on Relocatability

Minor

Cubicle footprints are considerably reduced from older electro-mechanical devices, enabling relocatable equipment to be smaller and lighter.

As with normal substations, the protection allows a reduced footprint. In the case of relocatability, containerised blockhouses or relay rooms enables self-contained units to be moved around the site, or to different sites. It has a major effect with rail substations, in that the smaller footprints enable these containers to be built narrow and squat to enable relocation by rail freight, with limited width requirements, and bridge heights, direct to sites often inaccessible to road transport. Using these type of houses also will facilitate retrofit of relay and control equipment. The life time of secondary equipment will be about half of the primary equipment and it will therefore be necessary to make a retrofit of secondary equipment after about half of the substation life time. The retrofit will be very much simplified by just exchanging those houses and keep outage to a minimum.

A10.1.23 Impact on Spares Requirement

Minor

The self-diagnosis of the protection can point to a particular card being at fault, hence modules can be held as spares.

It is often not required to hold the whole relay, instead a range of cards, or modules, can act as spares.

References

At present B5's Working Groups are split into four strategic sections as below.

1 WG B5-51 : Substation Automation and Remote Control
This section comprises the following subsections;

- Applications for Protection Schemes based on IEC 61850
- Acceptable functional integration in HV substations
- Guide for specification and evaluation of SSC
- Introduction of IEC 61850 and impact on P&C
- Functional testing of IEC 61850 systems
- Techniques for protection and monitoring of transmission lines
- Techniques for protection and monitoring of generator plant

2 WG B5-52 : Protection and Monitoring of Main Plant and Circuits
This section comprises the following subsections;

- Coordination of digital relays using conventional CTs
- Protection of Series Compensated lines
- Distance protection functions
- Protection, control and monitoring of shunt reactors
- Modern techniques for busbar protection
- Transformer protection, monitoring and control

3 WG B5-53 : Monitoring, Metering, Recording and Overall System Protection
This section comprises the following subsections;

- Fault and disturbance analysis
- New trends for auto fault and disturbance analysis
- P&C for dispersed generation and impact on transmission
- Protection relay coordination
- Remote on-line management P&C
- Impact of renewable energy sources and distributed generation on S/SP&A

4 WG B5-54 : Asset and Information Management , Training and Education
This section comprises the following subsections;

- Management of protection settings
- Software certification and version management
- Refurbishment strategies, etc.
- High impedance faults
- New local P&C approaches to minimise impact of system disturbances
- Wi-Fi protected access for P&A

A11 Gas Insulated Lines, Transformers & Superconductivity

This Appendix deals with Gas insulated lines (GIL), transformers (GIT) and superconducting cables. Only the impact in the substation is examined not the technical challenges associated with the circuit design. The key issue is to manage the different insulation medium, although there is much experience of SF_6, in these applications large volumes are used, so gas handling and maintenance activities need to be considered in advance.

A11.1 Gas Insulated Lines (GIL)

The Gas insulated line can be a very effective solution when environmental limitations make it necessary to build underground transmission systems in areas with special requirements. Typically it enables the existing overhead line rating to be maintained but also can be used to reduce magnetic field effects, or provide a compact solution. The gas-insulated line (GIL) is one technical solution to allow the transmission of electricity under ground at high transmission ratings.
The key departure from long runs of gas insulated busbar is that GIL employs a gas mixture for insulation (SF_6/N_2). Typically values between 10-20% of SF_6 are mixed with Nitrogen.

Fig 1. Gas Insulated Line [2]

The solution can be competitive in scenarios where two cables or more per phase will be required. Generally mounted in troughs or tunnels, there is very limited application for direct buried although it is technically feasible.

Basic system changes			
Impact Index	**Impact**	**Important Notice**	**Appendix**
Fault level	major	New current infeed	A11.1.1
Power flow	high	Principal function of GIL to increase circuit capacity	A11.1.2
Frequency	none		
Voltage	none	Low dielectric	
Thermal rating	high	Capacity may exceed existing substation equipment ratings	A11.1.3
Unbalance	none		
Harmonics	none		
Impedance	none		
Resonances	none		
Losses	minor	Lower system losses for equivalent power transfer	A11.1.4

Single line diagram impact			
Impact Index	**Impact**	**Important Notice**	**Appendix**
Short circuit rating	none	Adjacent switchgear	
Operational switching	major	System security constraints needs to be considered if GIL trips out	A11.1.5
Filtering	none		
Compensation	none		
Installation	high	Similar clean conditions to GIS necessary. Welding also required,	A11.1.6
Maintenance	minor	Very little routine, however corrective maintenance needs to be planned for. Gas handling	A11.1.7
Bypass	none	Not generally	
Commissionin g	minor	Similar to GIS busbar.	A11.1.8
Insulation co-ordination	minor	Surge arresters should be considered	A11.1.9

Detailed substation design			
Impact Index	**Impact**	**Important Notice**	**Appendix**
Protection (external)	minor	Just like any other circuit. Impact of any circuit reclose should be examined	A11.1.10
Protection (internal)	none		
Control	none		
Comms	none		
Land & layout	high	Depends where and how the GIL is installed – troughs, tunnels or direct buried.	A11.1.11
Visual impact	high	Depends on installation . Similar to oil refinery if above surface. No impact if buried or tunnelled	A11.1.12
External pollution	none		
Audible noise	none		
EMC	none		
Electrical clearances	none	Wholly enclosed. Same as GIS.	
Safety clearances	none	See above	
EM fields	none	Contained within trunking	
Civils	high	Extensive works required for any tunnel or excavations for burial	A11.1.12
Containment	high	Contains SF6. Leakage should be zero since welded joints	A11.1.13
Auxiliaries	none		
Equipment ratings	none	Should be designed to match existing substation equipment	
Busbar layout	minor	Connect into existing substation	
Earthing	none		
Monitoring	high	PD monitoring and gas density	A11.1.14
Testing	minor	Similar to GIS backparts	
Relocatability	none		
Spares requirement	minor		
Hazards	none		

Advice & Recommendations

A11.1.1. Fault Level
This is essentially a new low impedance circuit, so substation fault levels could be increased as a result. Confirmation that the existing infrastructure is good for a new infeed should be made

A11.1.2 Power Flow
Substation and network power flows should change, this is a new high capacity circuit and is only likely to be installed to remove an existing bottleneck.

A11.1.3. Thermal rating
This is designed for high current capacity, therefore high loads are expected. A switchgear rating and protection setting review will be necessary.

A11.1.4. Losses
The losses for GIL are much lower than the equivalent rated cable both partially and fully loaded (indicate %). Dielectric losses are very small, resulting in no auxiliary cooling circuit requirement, or reactive compensation.

A11.1.5. Operational switching
It may be necessary to review the local network switching regimes to optimally integrate the GIL and manage contingency.

A11.1.6. Installation
This requires clean room conditions to GIS erection. Welding is used to connect conductor lengths together. Particle free conditions are required within the GIL to avoid discharge and possible flashovers. Where tunnelling is used various access shafts will be necessary to drop in the lengths of pipe prior to welding.

A11.1.7 Maintenance
There should be very little routine maintenance activity associated with the GIL. Gas handling for mixtures is not routine. Specialist equipment will be necessary to separate and clean any gas should it need to be extracted. A contingency plan should be developed should a failure occur and corrective maintenance is necessary. Need to consider where the gas mixture or separation process can be accommodated during any corrective repairs

A11.1.8 Commissioning
Similar to GIS. Main check is to locate any foreign bodies within the assembly prior to welding

A11.1.9 Insulation coordination
The dielectric strength is similar to that of GIS. Typically surge arresters are necessary to control impact of system o/v on the circuit and will be located at line entries. Voltage rise at mid points on long sections (or bends) of GIL is more difficult to control. Need to concentrate on preventing the overvoltage occurring in the first place

A11.1.10. Protection (external)
Where GIL is part of an overhead line circuit the operation of any auto reclose should be examined to consider the risks if GIL faults are reclosed onto.

A11.1.11. Land take
Similar requirement to that of a cable tunnel or direct burial. Surface installation can be either flat or trefoil or vertical. Any above ground installation outside of the substation boundary needs to be carefully considered for security reasons (this is a high capacity circuit). Issues of access and impact on existing site access must be examined.

A11.1.12 Visual Impact
Construction activity associated with tunnel spoil needs to be managed. In general only surface mounted applications will have visual impact risks, similar to GIS busbar.

A11.1.13 Civils
Any GIL burial direct or tunnelled will require a major works. A large quantity of earth will need to be removed (transport logistics)

A11.1.14 Gas containment
As with any gas insulated system, containment cannot be guaranteed, however welded joints and no active compartments should limit the problem arising. Whilst no intrusive maintenance is necessary gas mixture handling equipment should be employed when emptying the compartments.

A11.1.15. Monitoring
Depending on the length of the connection continuous monitoring may be required. Gas density monitoring should be installed to comply with EU legislation.

A11.1.16. Testing
PD testing prior to energisation following any intrusive or abnormal event which may have affected the integrity of the insulation system. Provision of sufficient PD couplers to reliably identify location of particles should be provided.

References

[1] Joint Working Group 23/21/33.15, CIGRÉ Brochure n 218, Gas Insulated Transmission Lines (GIL) Feb. 2003.

[2] B1-103, CIGRE 2004. New generation of GIL: Characteristics and applications, P. Coventry, M. Bues, Ph. Ponchon, A. Girodet, F. Loray, D. S. Pinches

[3] IEEE TRANSACTIONS ON POWER DELIVERY, VOL. 22, NO. 1, JANUARY 2007 619 High-Capability Applications of Long Gas-Insulated Lines in Structures, Roberto Benato, Member, IEEE, Claudio Di Mario, and Hermann Koch, Member, IEEE

A11.2 Superconducting cable

A high temperature superconducting cable comprises a cryogenic core, with a superconducting material either inside a cryogenic core or wrapped around the core. A conventional dielectric at room temperature surrounds the super-insulation, and a conventional ground shield surrounds the conventional dielectric. This cable does not require a cryogenic dielectric and is of suitable size and nature to be used in retrofitting conventional cable pipes.
Superconducting cables can offer the advantages of lower loss, lighter weight, and more compact dimensions, as compared to conventional cables. In addition to the improvement of the energy efficiency of the utility grid, this can lead to easier and faster installation of the cable system, fewer joints, and reduced use of land
Applications are more prominent at MV 15-40kV, however a few higher voltages are appearing up to 132kV.

Superconducting cables are one solution to the challenging task of providing sufficient electric power to densely populated areas. In an increasing number of cities, there is little room underground to bury cable. The cost of building new tunnels or ducts, including the cost of acquiring the rights-of-way, to lay additional cable is prohibitive - representing up to 75 percent of a cable project. With their higher capacity, superconducting cables have the potential to multiply the supply of electricity to an area using the existing infrastructure footprint.

At lower voltages a superconducting cable offers a much higher energy density for the equivalent cable size to that of conventional cable systems.

Fig 1. Example of a super conducting cable sealing end – AEP Bixby substation, USA.

Basic system changes			
Impact Index	**Impact**	**Important Notice**	**Appendix**
Fault level	major	Higher current infeed	A11.2.1
Power flow	high	Increase to circuit capacity	A11.2.1
Frequency	none		
Voltage	none		
Thermal rating	high	Capacity may exceed existing substation equipment ratings	A11.2.1

Unbalance	none		
Harmonics	none		
Impedance	major	Very low	A11.2.2
Resonances	none		
Losses	major	Low conductor losses, Losses associated with the cooling system are unknown at present	A11.2.2
Single line diagram impact			
Impact Index	**Impact**	**Important Notice**	**Appendix**
Short circuit rating	none	Adjacent switchgear	
Operational switching	major	System security constraints needs to be considered if circuit trips out	A11.2.1
Filtering	none		
Compensation	none		
Installation	high	Similar clean conditions to GIS necessary. Welding also required,	A11.2.3
Maintenance	major	Very little routine for cables, auxiliary system will require routine inspection. Critical to SC cable performance,	A11.2.4
Bypass	none	Not generally	
Commissioning	major	Cryogenic systems unknown quantity in electricity substations	A11.2.3
Insulation co-ordination	minor	Surge arresters might be wise	A11.2.5
Detailed substation design			
Impact Index	**Impact**	**Important Notice**	**Appendix**
Protection (external)	minor	Impedance change may be possible on a circuit replacement project	
Protection (internal)	major	Protection of the superconducting state of the cable is vital to ensuring the longevity of the cable system. Cooling leaks will need to be quickly detected and located	A11.2.6
Control	none		
Comms	none		
Land & layout	none	Install in existing duct or tunnels.	A11.2.3
Visual impact	none		
External pollution	none		
Audible noise	none		
EMC	major	Induced currents in adjacent systems could be a big problem, especially in MV systems	A11.2.7
Electrical clearances	none		
Safety clearances	none		
EM fields	major	High current, depends on shielding design	
Civils	minor	Minimal if existing ducts used	A11.2.3
Containment	high	Contains cryogen. Leakage could result in damage to the conductor. No environmental risk	A11.2.3
Auxiliaries	major	Cryogenic system, novel substation technology	A11.2.8
Equipment ratings	major	Bay equipment will need to be uprated	A11.2.1

Busbar layout	minor	Connect into existing substation	
Earthing	none		
Monitoring	high	monitoring of temp and cryogen	A11.2.6
Testing	major	lots	A11.2.9
Relocatability	none		
Spares requirement	major	Parts for the cryogenic system	A11.2.4
Hazards	major	Risk of burns from liquid nitrogen	A11.2.10

Advice & Recommendations

A11.2.1. Impact on system parameters
Essentially a new circuit so, substation fault levels could be increased

Substation and network power flows should change, this is a new circuit

This is designed for high current capacity, therefore high loads are expected. Switchgear rating and protection setting review will be necessary.

Consideration needs to be given to the security of the local network where power flows are significantly enhanced, in particular the risk of overloading of adjacent circuits should the superconducting cable fault.
It may be necessary to review the local network switching regimes to optimally integrate the super conductor and manage contingency.

A11.2.2. Impedance & Losses
The losses for a superconducting are much lower than cable, since dielectric losses are very small. The auxiliary cooling circuits will contribute to the losses significantly, depending on the circuit loading.

A11.2.3. Installation & commissioning
Commissioning tests in accordance with the manufacturer's instructions will be required. Extra consideration is the commissioning of the cryogenic plant.

A11.2.4 Maintenance
Integrity of the cooling system is the key element to the availability of the HTS system. This is similar to any power electronic application where the reliability is usually determined by the cooling system.
Suggest a duplication or partial redundancy of the cooling system, coupled with monitoring and routine inspection until a better understanding of the failure modes are established.

A11.2.5 Insulation coordination
The dielectric strength of the liquid cryogen will have a major impact on the dielectric strength of the cable system. In addition under superconductivity quenching bubbles may be created, which could reduce the dielectric strength at a very critical moment. A lot of care is required to ensure the HTS cable system is not exposed to overvoltages or transients which could damage the ceramic conductor

A11.2.6 Protection of HTS equipment
Leak detection of any cryogen/cooling is critical to preventing damage of the superconductor

A11.3.12 EMC
The design of the HTS cable system will determine the nature of any electromagnetic effect on neighbouring circuits services, especially under high current conditions.

A11.3.14 Auxiliary systems
Cryogenic systems

A11.3.15. Monitoring
Continuous monitoring of the coolant system to ensure no leaks and uniform cooling of the HTS conductor is being provided. Fault/leak location will also be very useful.

A11.3.16. Testing

A11.3.17 Hazards
Cold burns from liquid nitrogen. Basic training will be necessary in handling and maintaining the cooling systems.

References

[1] Brochure 229 - High temperature superconducting (HTS) cable systems.

[2] ELECTRA 208_6, 2002. Superconducting Cables

[3] D1-306, 2006. Development and application trend of Superconducting materials and electrical insulating techniques for HTS power equipment. HITOSHI OKUBO (JAPAN) MICHAEL MCCARTHY (USA), SHIGEO NAGAYA (JAPAN) MATHIAS NOE (GERMANY), FRANK SCHMIDT (GERMANY) CHRISTOF SUMEREDER (AUSTRIA), OLE TØNNESEN (DENMARK) BERND WACKER (GERMANY) - Working group SC D1.15

A11.3 Gas Insulated Transformer

Gas insulated transformer (GIT) technology is principally the same as the more conventional oil filled transformer, with the exception that SF6 gas is used for insulation. The winding construction is also similar. GITs are principally installed where the risk of a transformer oil leak or fire are unacceptable. Typically this will be where the unit is located underground or high profile public building.

Fig 1. Gas Insulated Transformer, Haymarket, Australia [3].

Basic System Changes

Impact Index	Impact	Details	Appendix
Fault level	none		
Power flow	minor	reduced overload capacity unless considered in design	
Frequency	none		
Voltage	none		
Thermal rating	minor	Particular consideration for design review as internal limits determined by specific design	A11.3.1
Unbalance	none		
Harmonics	none		
Impedance	none		
Resonances	none		
Losses	minor	different thermal limits and cooling requirements can impact losses	A11.3.1

Single Line Impact

Impact Index	Impact	Details	Appendix
Short circuit rating	none		
Operational switching	minor	Very limited natural cooling rating so starting process needs to be considered	A11.3.2

Filtering	none		
Compensation	none		
Installation	minor	Civil requirements to ensure gas tightness. Large gas handling capability is required	A11.3.3
Maintenance	minor	Gas sampling required. Gas handling capacity to ensure adequate response.	A11.3.4
Bypass	none		
Commissioning	none		
Insulation coordination	none		

Detailed Substation Design

Impact Index	Impact	Details	Appendix
Protection (external)	none		
Protection (internal)	minor	Low gas monitoring and cooling monitoring is required.	A11.3.5
	major	No pressure relief or fire protection is required.	A11.3.5
Control	minor	Starting sequence control and gas monitoring is required	A11.3.2
Communications	none		
Land & layout	major	Reduced area and height and associated infrastructure	A11.3.6
Visual impact	major	Easier to incorporate in low impact developments	A11.3.6
External pollution	minor	Risk of SF6 loss very low but should be considered	
Audible noise	minor	Low noise levels achievable but cooling noise is a consideration	
EMC	none		
Electrical clearances	minor	totally enclosed, similar to GIS	A11.3.6
Safety clearances	minor	totally enclosed	
EM fields	minor	totally enclosed	
Civils	minor	Stable and level requirements to achieve gas tightness	A11.3.3
Containment	major	No oil containment required. SF6 containment is possible if required.	A11.3.3
Auxiliaries	minor	Increased auxiliaries infrastructure for blowers and cooling. Sufficient rating is required on site	A11.3.1
Equipment ratings	none		
Busbar layout	none		
Earthing	none		
Monitoring	minor	SF6 pressure and temperature monitoring is required	A11.3.5
Testing	minor	SF6 sampling instead of oil	
Relocatability	minor	Gas handling is a consideration	
Spares requirement	minor	Some new spares required	
Hazards	major	Significantly reduced fire and explosion hazards associated with consequence of failure	
Other (please define)			

Advice & Recommendations
A11.3.1 System impact

Transformer overload capacity (and duration) may be different to conventional oil filled transformers. This needs to be determined and specified at the tender stage.

A11.3.2 Operational switching
As with all transformers on forced cooling, there needs to be sufficient auxiliary supply capacity to ensure the cooling is available for the appropriate duration. This may require reinforcement of the existing auxiliary supply system.

A11.3.3 Installation & commissioning
Similar to that of a GIS substation, this is a site assembled SF6 filled system so stable foundations are required to ensure gas tightness can be achieved, preventing an future gas leakage due to settling, earth movement or subsidence later in life.
Fire and explosion hazards are significantly reduced enabling indoor or underground installation. Provision needs to be made for safe access and escape should a gas escape occur
Large mass of SF6 gas installed sufficient gas handling facilities need to be provided, since retrospective access or action is likely to be difficult.
Commissioning activity will involve elements of a GIS substation in terms of assembly and SF6 containment.

A11.3.4 Maintenance
Safe working methods to ensure staff are not exposed to risk of asphyxiation during inspection or work activities in proximity to the transformer

A11.3.5 Protection and Monitoring
SF6 Pressure and Leak detection
Transformer winding temperature indication
Sampling of SF6 to provide information on the transformer condition?

A11.3.6 Land take
The unit is large for an equivalent rated transformer, however removing the fire risk enables it to be installed in occupied buildings, underground as such compacting the substation design. Safety clearances will be similar to GIS connections

References

[1] Gas insulated transformers for Haymarket substation, Ebb, G.M.; Spence, G.S. Transmission and Distribution Conference and Exhibition 2002: Asia Pacific. IEEE/PES Volume 1, Issue , 6-10 Oct. 2002 Page(s): 511 - 516 vol.1

[2] ELT_215_1, 2004. Design Concept of Urban Substations and State-of-the-art Gas Insulated Transformers.

[3] Sydney's Haymarket Substation – a major milestone in applied innovation in substation design, D. Kunze, K. Toda and D. Paton, Paper 106, 2005 CIGRE SC A3 & B3 Joint Colloquium in Tokyo,

A12 Monitoring & Diagnostic Equipment

This Appendix deals with the new generation of Monitoring & Diagnostics equipment that encompasses a range of individual equipments, and some functions built in to Numerical Protection relays. These relays not only have a variety of Protection functions within one relay, they also include other non-Protection functions such as Control, Measurements, Self-Diagnostics, limited Primary equipment Monitoring, Fault Location, Disturbance Recorder and Protection Signalling.

In this instance the subject “Monitoring & Diagnostics” means any device that has the purpose of Monitoring, or Diagnosing results from a Monitoring device. The devices covered in this section are combined and contained under one equipment heading, that of Monitoring & Diagnostics. The Appendix, therefore, only has one part. It looks at the impact that the installation of the Monitoring & Diagnostics devices within a substation will have on the Basic System changes, then on the Single Line Diagram, and finally on the Detailed Substation Design.

This subject has been identified to include such a wide range of equipment that it is being dealt with in its own right in Working Group WG B3-12 entitled “Obtaining value from Substation Condition Monitoring” and due to produce a full Report end-2009. [1].

Equipment that can benefit from Monitoring

The following list refers to plant / equipment within a substation that can benefit from Condition Monitoring;

Transformers and Reactors
- Gas In Oil (single or multi-gases)
- Humidity (water in oil)
- Partial Discharge

Transformers and Reactors Cooling
- Pumps
- Fans
- Motor currents

Transformer On Load Tap Changer
- Acoustic
- aging

History of overall substation surges
- Over-voltages
- Over-Frequency
- Short-circuit current severity

Bushing Pollution

Thermal loading
- Temperature
- Thermal

Surge Arresters

Instrument Transformers

Bushings

Circuit Breakers
- Mechanism travel
- Mechanism timing, operation times
- aging (e.g. i^2t)
- Motor / pump starts, duration, current
- Gas density and quality
- Oil levels
- Stored energy (Spring position, Hydraulic / Pneumatic pressure)
- Air humidity
- Partial Discharge (AIS)
- Partial Discharge (GIS)
- Internal Arcing
- Bushing Pollution

Cable Entry

Auxiliary Systems / batteries / compressors

Overall substation – eg by Partial Discharge in complete substation

Assessing the impact of Monitoring

The End-User needs to know whether he will get Value from Monitoring his equipment. However, Value means different things to different End-Users, and hence the actual impact is very subjective and owners of substations need to look at all these issues as it impacts his utility.

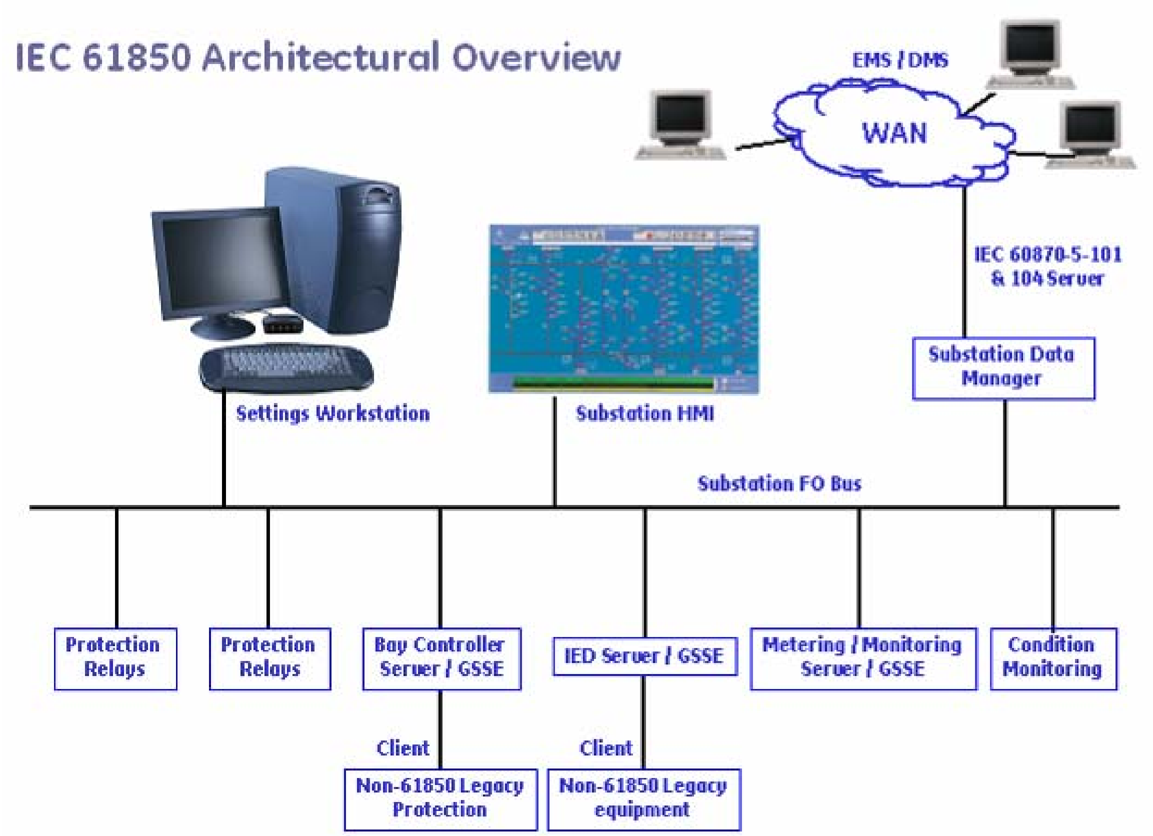
Value includes;
- Risk of Failure
- Capital cost of equipment – eg transformer
- Importance of equipment – eg battery

- Importance of substation – eg associated with a generator or a process plant
- Most important piece of substation equipment is that which is required "NOW" – eg the circuit breaker if it is required to trip, or the transformer if it is required to provide an overload whilst another transformer is out of action
- Cost benefit in GBP / USD / EURO / YEN saved over the monitoring period of the electrical equipment, primary or secondary
- Delayed asset replacement
- Optimised operation (e.g. thermal loading) and maintenance
- How the plant is performing
- Value to the Operator of the equipment
- Value to the Maintenance personnel
- Value to the Asset Manager
- Value to the Company share price
- Ensuring Heath and Safety – risk to personnel / explosion / EMC
- Regulatory pressure
- Penalties if equipment is not available or bonus if equipment is available
- Political pressure
- Loss of power to a key industrial customer
- Public perception of Customer Minutes Lost or a Blackout
- Environmental damage can be limited or avoided

Integration of Monitoring

Although many Monitoring equipments are still stand-alone products, the introduction of Fibre Optic Substation LANs (Local Area Networks), and particularly the new IEC 61850, will lead to more integrated Protection, Control and Monitoring into new and refurbished substations.

An integrated approach is as shown on the following figure for IEC 61850 protocol. Other substation protocols are also being used for integration, however in general suppliers are now heading towards this route. At present very little stand-alone Condition Monitoring uses this protocol, so other protocols would go through an IED in the same manner as non-IEC 61850 protection equipment.



A12.1 Monitoring & Diagnostics Equipment

Basic system changes

Impact Index	Impact	Important Notice	Appendix
Fault level	None		
Power flow	Minor	Only in instances where the Monitoring & Diagnostics equipment deems there to be a reason why the circuit should be switched out immediately or left in service	A12.1.1
Frequency	None	Only in instances where the Monitoring & Diagnostics equipment deems there to be a reason why the circuit should be switched out immediately or left in service	A12.1.2
Voltage	None	Only in instances where the Monitoring & Diagnostics equipment deems there to be a reason why the circuit should be switched out immediately or left in service	A12.1.3
Thermal rating	None		
Unbalance	None		
Harmonics	None		
Impedance	None		
Resonances	None		
Losses	Minor	Only in instances where the Monitoring & Diagnostics equipment deems there to be a reason why the circuit should be switched out immediately or left in service	A12.1.4

Single line diagram impact

Impact Index	Impact	Important Notice	Appendix
Short circuit rating	None		
Operational switching	None		
Filtering	None		
Compensation	None		
Installation	Major	Installing Monitoring & Diagnostics equipment can allow refurbishment and replacement installation of primary plant to be delayed	A12.1.5
Maintenance	Major	Monitoring & Diagnostics equipment is the input to Condition Based Maintenance	A12.1.6
Bypass	None		
Commissioning	None		
Insulation coordination	None		

Detailed substation design

Impact Index	Impact	Important Notice	Appendix
Protection (external)	None		
Protection (internal)	Major	Numerical protection has in-built functionality that can be used to monitor the primary plant, secondary equipment, and the system itself	A12.1.7

Control	Major	The output from Monitoring & Diagnostics equipment enables operations staff to determine control actions	A12.1.8
Communications	None		
Land & layout	None		
Visual impact	None		
External pollution	None		
Audible noise	Minor	Only in the case where Monitoring equipment is used to measure transformer noise to determine the condition of the transformer	A12.1.9
EMC	None		
Electrical clearances	None		
Safety clearances	None		
EM fields	None		
Civils	None		
Containment	None		
Auxiliaries	Minor	Monitoring & Diagnostics equipment requires a small additional load on the substation auxiliary supplies	A12.1.10
Equipment ratings	None		
Busbar layout	None		
Earthing	None		
Monitoring	Major	In addition to stand-alone equipment, there are many built-in monitoring functions available in protection relays	A12.1.11
Testing	Minor		
Relocatability	None		
Spares requirement	Major	Knowing the condition of the primary equipment has an impact on spares holding, and their locations	A12.1.12
Hazards	Major	Incipient failures can be flagged up before a catastrophic failure occurs, hence there is a high impact on safety of the primary plant	A12.1.13
Other (please define)	-		

Advice & Recommendations

A12.1.1 Impact on Power Flow

Minor

Only in instances where the Monitoring & Diagnostics equipment deems there to be a reason why the circuit should be switched out immediately or left in service.

Monitoring and Diagnostics equipment has a two-way function; it can ascertain the primary plant condition to determine;

- Whether the primary plant requires immediately to be taken out of service, or
- Whether it can remain in service for remedial action to be taken at a more convenient time

Hence there could be a minor indirect impact on the power flow during failures, or impending failures, of the primary equipment.

Monitoring the temperature of the equipment with lowest rating might enable temporary overloading.

A12.1.2 Impact on Frequency

Minor

Only in instances where the Monitoring & Diagnostics equipment deems there to be a reason why the circuit should be switched out immediately or left in service.

Monitoring and Diagnostics equipment has a two-way function; it can ascertain the primary plant condition to determine;

- Whether the primary plant requires immediately to be taken out of service, or
- Whether it can remain in service for remedial action to be taken at a more convenient time

Hence there could be a minor indirect impact on the frequency during failures, or impending failures, of the primary equipment.

A12.1.3 Impact on Voltage

Minor

Only in instances where the Monitoring & Diagnostics equipment deems there to be a reason why the circuit should be switched out immediately or left in service.

Monitoring and Diagnostics equipment has a two-way function; it can ascertain the primary plant condition to determine;

- Whether the primary plant requires immediately to be taken out of service, or
- Whether it can remain in service for remedial action to be taken at a more convenient time

Hence there could be a minor indirect impact on the voltage during failures, or impending failures, of the primary equipment.

A12.1.4 Impact on Losses

Minor

Only in instances where the Monitoring & Diagnostics equipment deems there to be a reason why the circuit should be switched out immediately or left in service.

Monitoring and Diagnostics equipment has a two-way function; it can ascertain the primary plant condition to determine;

- Whether the primary plant requires immediately to be taken out of service, or
- Whether it can remain in service for remedial action to be taken at a more convenient time

Hence there could be a minor indirect impact on the losses during failures, or impending failures, of the primary equipment.

A12.1.5 Impact on Installation

Major

Installing Monitoring & Diagnostics equipment can allow refurbishment and replacement installation of primary plant to be delayed.

The primary function of continuously on-line Monitoring & Diagnostics equipment is to determine the necessary actions to be taken in order to prolong and extend the life of expensive primary plant that could take a considerable amount of outage time in which to install the replacement equipment. This is particularly the case for Transformers, Reactors and Switchgear.

A12.1.6 Impact on Maintenance

Major

Monitoring & Diagnostics equipment is the input to Condition Based Maintenance (CBM)

With numerical technology self-monitoring of the protection is possible, which allows the traditional time-based protection maintenance periods to be varied. The main benefit of self-monitoring was not always trusted by maintenance engineers in the early days, nor was the relay software trusted, nor the testing of software. In some instances contractual service agreements were put in place that called for quick manufacturer responses, however they over-estimated failure rates and problems.

Time Based Maintenance (TBM) has been the traditional approach in substations, however CBM enables maintenance to be carried out at a time depending on the condition of the equipment itself. This is a much more efficient, safe, and cost effective means of maintenance.

Today, in practice, overall reliability has increased and proved that the numerical relays are far more reliable than engineers and utilities first feared, or expected. Hence reliance on self-monitoring is now taken for granted, which is dramatically changing the concept of maintenance.

Because of the advent of Integrated Substation Control Systems (iSCS) these Monitoring functions are inherent in modern Protection & Control equipment, substation controllers and Intelligent Electronic Devices (IEDs) These devices, along with sensor technology, allows operators to monitor and diagnose incipient problems not only in the protection, but also in the connections to, and in the power equipment itself, before failure, thus optimising maintenance and preventing costly outages.

A12.1.7 Impact on Protection (internal)

Major

Numerical protection has in-built functionality that can be used to monitor the primary plant, secondary equipment, and the system itself.

With numerical technology self-monitoring of the protection is possible, which allows the traditional time-based protection maintenance periods to be varied. The main benefit of self-monitoring was not always trusted by maintenance engineers in the early days, nor was the relay software trusted, nor the testing of software. In some instances contractual service agreements were put in place that called for quick manufacturer responses, however they over-estimated failure rates and problems.

Today, in practice, overall reliability has increased and proved that the numerical relays are far more reliable than engineers and utilities first feared, or expected. Hence reliance on self-monitoring is now taken for granted, which is dramatically changing the concept of maintenance.

Because of the advent of Integrated Substation Control Systems (iSCS) these Monitoring functions are inherent in modern Protection & Control equipment, substation controllers and Intelligent Electronic Devices (IEDs) These devices, along with sensor technology, allows operators to monitor and diagnose incipient problems not only in the protection, but also in the power equipment itself before failure, thus optimising maintenance and preventing costly outages.

The internal protection functions are very much central to Monitoring in general.
For instance, numerical relays use the sequence components of voltage and current, so that unbalance can be measured much more accurately. This can be used to determine failing joints in overhead lines and cables, badly worn or misaligned disconnectors, or circuit breakers where phases have not closed/opened together.
The detection circuits can also be used to monitor unbalance in the secondary equipment, a failing CT or a high resistance joint.
These can all be built in to a Condition Based Monitoring (CBM) system in order to vary the old Time Based Maintenance (TBM) systems of the past.
Some utilities use Expert systems using information from protection relays in conjunction with other Condition Monitoring equipment as a basis for their CBM scheme.

The network characteristics can also be monitored by the protection equipment that measures current, voltage, load transfer, phase angles, harmonics and synchro-phasors.

A12.1.8 Impact on Control

Major

The output from Monitoring & Diagnostics equipment enables operations staff to determine control actions.

The impact is such that the condition of the primary plant can be determined, and hence this has a major effect on the control operator's decision process regarding whether faults are developing, and what requires to be carried out in what timescale.

A12.1.9 Impact on Audible Noise
Minor
Only in the case where Monitoring equipment is used to measure transformer noise to determine the condition of the transformer.

A change in the noise pattern of the transformer, and/or tap change mechanism, can be analysed by Monitoring & Diagnostics equipment to determine the condition of the transformer.

A12.1.10 Impact on Auxiliaries
Minor
Monitoring & Diagnostics equipment requires a small additional load on the substation auxiliary supplies.

In most case Transformer and Reactor monitoring is powered by AC, as is the tap-change control and cooling pumps and fans, so there is some small additional load put onto the Essential AC supplies. In the case of Switchgear and other plant, the Monitoring & Diagnostics equipment is powered by DC, so there is some small additional load put onto the DC supplies.

A12.1.11 Impact on Monitoring
Major
In addition to stand-alone equipment, there are many built-in monitoring functions available in protection relays.

With numerical technology self-monitoring is possible, which allows the traditional time-based maintenance periods to be varied. The main benefit of self-monitoring was not always trusted by maintenance engineers, nor was the relay software trusted, nor the testing of software. In some instances contractual service agreements were put in place that called for quick manufacturer responses, however they over-estimated failure rates and problems.
Today, in practice, overall reliability has increased and proved that the numerical relays are far more reliable than engineers and utilities first feared, or expected. Hence reliance on self-monitoring is now taken for granted, which is dramatically changing the concept of protection maintenance.

Monitoring functions are inherent in modern Protection & Control equipment, substation controllers and Intelligent Electronic Devices (IEDs) These devices, along with sensor technology, to allow operators to monitor and diagnose incipient problems not only in protection, but also in power equipment before failure, thus optimising maintenance and preventing costly outages.

A12.1.12 Impact on Spares Requirement
Major
Knowing the condition of the primary equipment has an impact on spares holding, and their locations.

Knowledge of the condition of any item of equipment enables the owner to more accurately determine his Spares holding, both in number and where best to locate his Spares. It also enables him to plan purchases of Spares which for primary plant has long lead and transport delivery times.

A12.1.13 Impact on Hazards
Major
Incipient failures can be flagged up before a catastrophic failure occurs, hence there is a high impact on safety of the primary plant.

Knowledge of the condition of any item of equipment enables the owner to more accurately assess the risks of working on or around primary plant equipment, thus reducing the hazard to personnel and other adjacent equipment and to the environment.

References

[1] Working Group WG B3-12 entitled "Obtaining value from Substation Condition Monitoring" is due to produce a full Report end-2009.

In recent years there has been an increase in the availability of condition monitoring devices, both stand alone and integrated into protection and control devices, and many claims made for the advantages of Condition Based Maintenance (CBM) over Time Based Maintenance (TBM). However the right choice will vary according to the system voltage level and other plant factors as well as from one Utility to another. The objective of this WG B3-12 is to investigate the technology currently available and to analyse the factors which need to be considered to determine the degree of application which will provide the optimum solution for an individual Utility, taking into account the improved reliability and availability of modern plant.

The anticipated customers for the output of this work are Utilities to enable them to make the right decisions for improving the performance of their networks and Solution Providers to assist them in deciding where future development will be more effective, together with Industrial Plants that have critical process controls, and Generators.

[2] CIGRE TF D1.02.08: Instrumentation and measurements for in-service monitoring of high voltage insulation, CIGRE Brochure 286, 2005

[3] CIGRE WG B1.02: optimization of power transmission capability of underground cable systems using thermal monitoring, CIGRE Brochure 247, 2004

[4] CIGRE WG 13.09: User guide for the application of monitoring and diagnostic techniques for switching equipment for rated voltages of 72.5kV and above, CIGRE Brochure 167, 2000

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