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Foreword

The development of Smart Grid is a global trend. The activities in different parts of the world reflect the regional resources and needs. We have seen large scale integration of wind generators and solar energy devices into the power grids. Very large off-shore wind farms are on the horizon. Increasingly automated and intelligent distribution systems are in operation in various countries. On the transmission side, a significant number of Phasor Measurement Units (PMUs) are now collecting a massive amount of information for monitoring of power system dynamics. Demand side response and other programs for customers' choice are being developed and enhanced by the power industry. To enable the demand side response and customers' services, millions of smart meters are acquiring the customers' electric energy consumption data. These new smart features of the power grid rely on the information and communications technology (ICT) that brings critical connectivity for all elements of the Smart Grid. The increasing degree of integration in a Smart Grid from renewable generations to the power grid, from transmission to distribution, and from smart meters to the distribution system brings a new vision and opportunities for the future power grids. Although we are well under way toward this unprecedented creation, it is also important to recognize the challenges that Smart Grid development is facing from the diverse viewpoints of technology, economics, sociology, and public policy.

The scope of Smart Grid is wide and the complexity is great. There is a growing literature about various aspects of research, development, deployment, and operating experience. However, there is a great need for a comprehensive source of knowledge that spans the spectrum of Smart Grid subjects. This book, "Smart Grids—Fundamentals and Technologies," represents a timely and significant step in our long journey to an ultimate Smart Grid. The vast amount of knowledge as well as industry and leadership experience represented in this book serves as the foundation for an excellent source for practicing engineers, researchers, managers, and policy makers to learn about the exciting field of Smart Grid.

This book is organized in a logical flow of subjects. The vision of the future power grid is articulated in Chap. 1. In Chap. 2, various renewable energy and storage devices are discussed. New technologies for transmission networks and substations are covered in Chap. 3. Chapter 4 is concerned with engineering design of distribution systems including network configurations, grounding, protection, and power quality. The issues of transmission system operation, protection, and control in a wide area are addressed in Chap. 5. The subject of Chap. 6, smart distribution systems, is about the distribution system's capabilities to handle voltage and power flow control, energy management, feeder protection and recovery in an environment with dispersed and renewable devices. Smart metering provides new possibilities for energy markets and consumer's participation. The market design to incentivize stakeholders of electricity supply and demand to follow the Smart Grid strategy is discussed in Chap. 7. The enabling ICT for Smart Grids cannot be an effective support infrastructure unless the critical issues of standards, information and cyber security, and protocols are addressed. Chapter 8 describes the new developments related to ICT. Last but not least, the global development of Smart Grid is summarized in Chap. 9, which reflects the characters and priorities of various regions in the world.

As a professional colleague, I would like to thank Dr. Buchholz and Professor Styczynski for their tremendous effort to bring together this interesting and informative volume. It is a significant contribution to Smart Grid R&D, engineering, and education.

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Acknowledgments

The transformation of the existing electric power systems into Smart Grids is currently embedded in worldwide development and investment programs. This book describes the challenges of the electricity supply in the future and specifies the drivers, the fundamentals, the concepts and technologies of Smart Grids. Special attention is paid to practical experiences. The additional needs and challenges to be solved as well as visions and innovations for the future are also presented in order to offer the readers the main ideas of the Smart Grid concepts for generation, transmission, distribution and consumption.

The book summarizes the experiences of the authors over the last two decades concerning the research and development from both sides (industry and academia) at the Siemens AG and at the Otto- von Guericke University Magdeburg, the leading of national expert groups, the management of practice related Smart Grids projects and the participation in international study committees or working groups (e.g. CIGRE, CIRED European advisory council for the technology platform Smart Grids, IEC, IEEE, VDE).

The initial idea for this book was born in 2012 as a result of the Russian Mega Grant No.132 and the initiation of the project "Baikal—Smart Grid Technologies". The main objective of this project "Baikal" was to introduce an education program regarding the Smart Grid technologies into the Russian research community. The authors are grateful to the Russian Ministry of Education for the opportunity to participate in this program and to Prof. Dr. N. I. Voropai, Director of the Siberian Energy Institute in Irkutsk (member of the Russian Academy of Science), for the discussions regarding the table of contents.

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Germany, Spring 2014

Dr. Bernd Michael Buchholz
Prof. Dr. Zbigniew Antoni Styczynski

Contents

Abbreviations

2DCF	Two-Day Congestion Forecast
AAL	Ambient Assisted Living
AC	Alternating Current
ACER	Agency for the Cooperation of Energy Regulators
ACSI	Abstract Communication Service Interface
AES	Average Energy Saving
AM	Asset Management
AMI	Advanced Metering Infrastructure
ANSI	American National Standards Institute
API	Application Programming Interface
APLS	Average Peak Load Shifting
ASAI	Average System Availability Index
ASN.1	Abstract Service Notation One
BACnet	Building Automation and Control Networks
BB	Busbar
BCU	Basic Currency Unit
BDEW	Federal association for energy and water supply (Bundesverband der Energie- und Wasserwirtschaft)
BGM	Balancing Group Manager
BMU	Federal Ministry for Environment, Nature Conservation and Nuclear Reactor Security (Bundesministerium für Umwelt, Naturschutz und Reaktorsicherheit)
BMWi	Federal Ministry of Economics and Technology (Bundesministerium für Wirtschaft und Technologie)
BPL	Broadband Power Line
BSI	Federal Office for Information Security (Bundesamt für Sicherheit der Information)
CAES	Compressed Air Energy storage
CAIDI	Customer Average Interruption Duration Index
CAIFI	Customer Average Interruption Frequency Index
CAPEX	Capital Expenses
CB	Circuit Breaker
CC	Control Center

CCG	Central China Grid
CCGT	Combined Cycle Gas Turbine
CDC	Common Data Class
CDV	Committee Draft for Voting
CE	Continental Europe
CEN	European Committee for Standardization
CENELEC	European Committee for Electro-technical Standardization
CHP	Cogeneration of Heat and Power
CID	Configured IED Description
CIGRE	Conseil International des Grands Reseaux Electriques
CIM	Common Information Model
CIS	Component Interface Specification
COMTRADE	COMmon format for TRAnsient Data Exchange
COS	Catalogue Of Standards
COSEM	Companion Specification for Energy Metering
CPU	Central Processing Unit
CRC	Cyclic Redundancy Check
CS	Customer Support
CSC	Current Source Converter
CSPGC	China Southern Power Grid Company Limited
DACF	Day-ahead Congestion Forecast
DC	Direct Current
DCC	Distribution Control Center
DER	Distributed Energy Resource
DFIG	Doubly Fed Induction Generator
DIN	German Institute for Standardization (Deutsches Institut für Normung)
DKE	Deutsche Kommission Elektrotechnik, Elektronik, Informationstechnik (German Commission for standardization in the fields of electro-technology, electronics and ICT)
DLMS	Device Language Message Specification Distribution
DMS	Distribution Management System
DOE	Department of Energy (USA)
DSA	Dynamic Security Assessment
DSI	Demand Side Integration
DSL	Digital Subscriber Line
DSM	Demand Side Management
DSR	Demand Side Response
ECG	East China Grid
EDSO	European Distribution System Operators' Association
EEG (REA)	Erneuerbare Energien Gesetz—(Renewable Energy Act)
EEGI	European Electricity Grid Initiative
EESS	Electric Energy Storage Systems
EHV	Extra High Voltage
EIB	European Installation Bonus

EMS	Energy Management System
ENS	Energy Not Supplied on time
ENTSO-E	European Network of Transmission System Operators for Electricity
EPM	Enterprise Process Management
EPRI	Electric Power Research Institute (USA)
ERGEG	European Regulators Group for Electricity and Gas
ESO	European Standardization Organization
ETSI	European Telecommunications Standards Institute
FAT	Factory Acceptance Test
FERC	Federal Energy Regulatory Commission (USA)
FGC	Federal Grid Company (of Russia)
FP	Framework Programme
FRCC	Florida Reliability Coordinating Council
GDOF	General Decision and Optimization Functions
GES	Generic Event and Subscription
GIL	Gas Insulated Line
GIS	Gas Insulated Switchgear (Chap. 3–5)
GIS	Geographical Information System (Chap. 8)
GOMSFE	Generic Object Model for Substation and Feeder Equipment
GOOSE	Generic Object-Oriented Substation Event
GPS	Global Positioning System
GSE	Generic Substation Event
GSM	Global System for Mobile Communications
GSSE	Generic Substation State Event
HAN	Home Area Network
HMAC	Hash Message Authentication Code
HMI	Human Machine Interface
HSDA	High Speed Data Access
HTTP	Hypertext Transfer Protocol
HV	High Voltage
IC	Industrial Computer
ICD	IED Capability Description
ICT	Information and Communication Technologies
IDCF	Intra-Day Congestion Forecast
IEC	International Electrotechnical Commission
IED	Intelligent Electronic Device
IEEE	Institute of Electrical and Electronics Engineers (professional association headquartered in New York City that is dedicated to advancing technological innovation and excellence)
IES-AAS	Intelligent Electro-energy System based on Active-Adaptive Networks (the Russian term for networks is Set)
IID	Instantiated IED Description
IGBT	Insulated Gate Bi-polar Transistor
IP	Internet Protocol

IPS	Integrated Power System
ISDN	Integrated Services Digital Network
ISO	International Organization for Standardization
ISTU	Irkutsk State Technical University
LAN	Local Area Network
LBS	Load Break Switch
LCC	Line Commutated Converter
LD	Logical Device
LED	Light Emitter Diode
LN	Logical Node
LON	Local Operating Network
LTE	Long-Term Evolution
LV	Low Voltage
M-Bus	Meter Bus
MC	Maintenance and Construction
MCC	Mobility Control Center
MENA	Middle East and Northern Africa
MMS	Manufacturing Message Specification
MP	Micro-Processor
MPPT	Maximum Power Point Tracking
MR	Meter Reading
MRO	Midwest Reliability Organization (USA)
MUC	Multi Utility Controller
MV	Medium Voltage
NA	Network Applications
NCG	North China Grid
NE	Network Extension
NECG	North-East China Grid
NEPCC	North-East Power Coordination Council (USA)
NERC	North American Electric Reliability Corporation (USA)
NIST	National Institute for Standards and Technology (USA)
NSM	Network and System Management
NTP	Network Time Protocol
NWCG	North–West China Grid
OBIS	Object Identification System
OE	Office of Electricity Delivery and Energy Reliability (USA)
OHL	Overhead Line
OLE	Object Linking and Embedding
OP	Operational Planning
OPC UA	OLE for Process Control, Unified Architecture
OPEX	Operational Expenses
ORC	Orcanic Rankine Cycle
OSI	Open Systems Interconnection
PAP	Priority Action Plan
PCC	Point of Common Coupling

PDU	Protocol Data Unit
PES	Primary Energy Source
PKI	Public-Key-Infrastructure
PLC	Power Line Communication
PMU	Phasor Measurement Unit
PSA	Protection Security Assessment
PSHPP	Pumped-Storage Hydroelectric Power Plant
PWM	Pulse Width Modulation
RBAC	Role-Based Access Control
RDF	Resource Description Framework
RES	Renewable Energy Source
RFC	Request for Comment
RFC	Reliability First Corporation (USA)
RG	Region
RTD	Research and Technological Development
RTU	Remote Terminal Unit
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAS	Substation Automation System
SAT	Site Acceptance Test
SCADA	Supervisory Control and Data Acquisition
SCD	Substation Configuration Description
SCL	Substation Configuration Language
SCSM	Specific Communication Service Mapping
SERC	South-East Reliability Corporation (USA)
SET plan	Strategic Energy Technology plan
SFTP	Secure File Transfer Protocol
SGAM	Smart Grid Architecture Model
SG-CG	Smart Grid Coordination Group
SGCC	State Grid Corporation of China
SGIP	Smart Grid Interoperability Panel
SGIS	Smart Grid Information Security
SIL	Surge Impedance Load
SMB	Standardization Management Board
SML	Smart Message Language
SMS	Short Message Service
SNMP	Simple Network Management Protocol
SNTP	Simple Network Time Protocol
SOA	Service Oriented Architecture
SOC	State Of Charge
SOH	State Of Health
SPP	Southwest Power Pool (USA)
SS	Substation
SSA	Steady State Assessment
SSC	Smart Supply Cell

SSD	System Specification Description
TC	Technical Committee
TCI	Tele-Communication Interface
TCP	Transmission Control Protocol
UCA iug	Utility Communication Architecture international user group
UCMR	Use Case Management Repository
UCTE	Union for the Co-ordination of Transmission of Electricity
UHV	Ultra High Voltage
UK	United Kingdom
UML	Unified Modeling Language
UPS	Unified Power System (of Russia)
VDE	Verband der Elektrotechnik, Elektronik und Informationstechnik (the German technical-scientific association of Electrical, Electronics and ICT engineers)
VDEW	Verband der deutschen Elektrizitätswerke (Society of the German Power Plants)
VPP	Virtual Power Plant
VSC	Voltage Source Converter
W2E	Web2Energy
WAM	Wide Area Monitoring
WAN	Wide Area Network
WAP	Wide Area Protection
WECC	Western Electricity Coordination Council
WG	Working Group
XML	Extensible Markup Language

Chapter 1
Vision and Strategy for the Electricity Networks of the Future

1.1 The Drivers of Smart Grids

Efficient transmission and distribution of electricity is a fundamental requirement for sustainable development and prosperity throughout the world. However, the world will have to face great challenges in this area in the 21st century.

The main challenges that need to be solved in the European Union are [1]:

- the decreasing availability of fossil and nuclear primary energy sources (PES) and,
- accordingly, their rapidly increasing prices,
- the 70 % dependency of Central Europe on imported PES,
- the increasing impact of greenhouse emissions on the environment.

The expectations regarding the number of years of production of nuclear and fossil PES left in the ground with the most optimistic projected reserves are depicted in Fig. 1.1. This data is based on the current knowledge about the geological production sites and the current worldwide demand. It can be seen that the statements from two different sources regarding the reserves that are exploitable at the known locations are similar. The main difference in the figures consists in the differentiation between the known reserves and the expected increase of resources which could be exploited by non-traditional technologies (e.g. hydraulic fracturing of rock for gas exploitation).

However, both references underline that the extent of nuclear and fossil PES is limited. It is expected that the demand for PES will increase significantly until 2050 (especially according to the rapid economic growth of the countries in Asia and Southern America), which in turn will cause a shorter availability of the traditional energy sources. It is clear that both, fossil fuels and uranium are non-renewable energy resources, and their supply is diminishing rapidly.

Furthermore, the production and use of fossil fuels raise environmental concerns regarding the carbon emissions as shown in Fig. 1.2. A global movement

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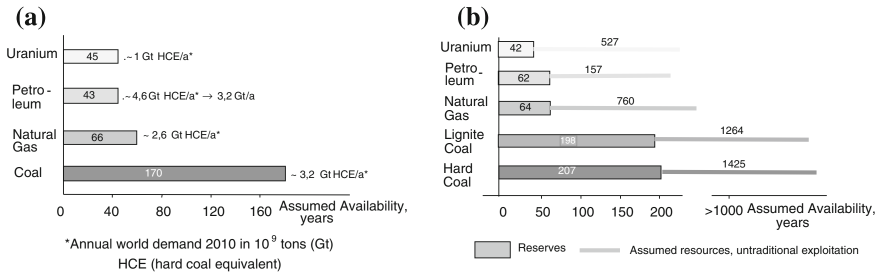
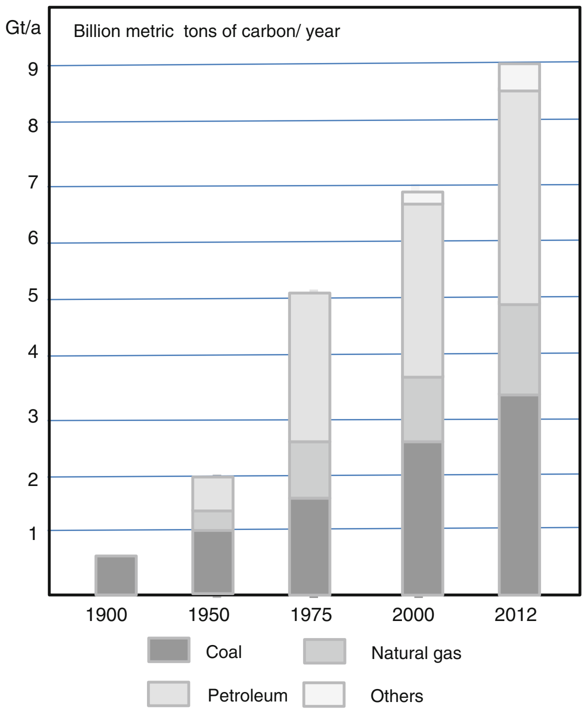


Fig. 1.1 The reserve expectations for primary energy and the annual world demand (*Sources* **a** [2], **b** [3])

Fig. 1.2 The global annual carbon emissions by fuel types (*Source* [4])



toward the generation of renewable energy is therefore the optimum way to meet the increased energy needs of the future.

Consequently, the European Union has set ambitious objectives for the year 2020 to:

- lower energy consumption by 20 % by enhanced efficiency of energy use,
- reduce CO_2 emissions by 20 % and,
- ensure that 20 % of the primary energy is generated by renewable energy resources (RES).

Table 1.1 Potential of RES and CHP for Europe [5]

SET-plan	2020		2030	
Plant type	Energy, %[a]	Power, GW[b]	Energy, %	Power, GW
Wind	11	180	18	300
Photovoltaic	3	125	14	665
Concentrating solar thermal power	1.6[c]	1.8	5.5[c]	4.6
Hydro (large plants)	8.7	108	8.3	112
Hydro (small plants)	1.6	18	1.6	19
Waves	0.8	10	1.1	16
Bio fuel	4.7	30	5.3	190
Cogeneration heat and power	18	185	21	235
Sum	59.4	657.8	75.8	1542

[a] Related to the annual consumption
[b] Installed power
[c] Partly imported from Northern Africa

In the European Union, about 40 % of PES that is used is currently applied for the generation of electricity. (The other 60 % is used for transportation, heating, etc.).

Electric energy offers the best opportunity to be produced by renewable energy sources like wind power, solar energy, bio fuel and hydro power. Consequently, electric energy has to carry the main part of the renewable energy production by having an annual share of >30 % in 2020. All of the member states of the European Union have set their individual targets in support of the common strategy for 2020.

In 2006, the European Commission published the "Strategic Energy Technology Plan" (SET plan) [5] underlining the potential of the various categories of RES and of cogeneration of heat and power plants (CHP), which are also favoured to increase energy efficiency. In Table 1.1 the data of the SET Plan is summarized. This plan also contains figures regarding the importation of energy from solar-thermal power stations in Northern Africa, which corresponds with the Desertec vision [6]. In 2020 the installed RES and CHP power will exceed the currently installed power capacity of the Continental European interconnected transmission system (former UCTE—Union for the Co-ordination of Transmission of Electricity). The rate of dependency of the power production from RES on the weather is considered in the ratio of energy (E) and installed power (P), and it is the worst for Photovoltaic (PV) and the best for biofuel and CHP plants.

The need to modernize the European electricity networks is based first of all on the integration of more sustainable generation resources, especially the partially volatile renewable sources, and secondly, on the growing electricity demand and the establishment of trans-European electricity markets. The context of all these aspects presents major challenges, highlighting the essential need of innovations in this area.

Fig. 1.3 The fundamental smart grid documents of the European Advisory Council

The vision for electricity networks of the future was developed by a European group of experts in the framework of the technology platform "Smart Grids" [7] between 2005 and 2008, and three fundamental documents were published as a result (Fig. 1.3).

The Smart Grid definition is presented in the strategic deployment document [8] as follows:

A Smart Grid is an electricity network that can intelligently integrate the actions of all users connected to it—generators, consumers and those that do both—in order to efficiently deliver sustainable, economic and secure electricity supplies.

A Smart Grid employs innovative products and services together with intelligent monitoring, control, communication and self-healing technologies to:

- enable the network to integrate users with new requirements;
- better facilitate the connection and operation of generators of all sizes and technologies;
- enhance the efficiency in grid operations;
- allow electricity consumers to play a part in optimizing the operation of the system;
- provide consumers with more information and choice in the way they secure their electricity supplies;
- improve the market functioning and consumer services;
- significantly reduce the environmental impact of the total electricity supply system;
- deliver enhanced levels of reliability, quality and security of supply.

Consequently, a Smart Grid supports the introduction of new applications with far-reaching impacts: providing the capabilities for safe and controllable integration of more renewable, especially volatile energy sources (depending on the weather conditions) as well of new categories of network users like electric vehicles and heat pumps into the network; delivering power more securely, cost efficiently and reliably through advanced control automation and monitoring functions providing self-healing capabilities after faults and finally, enabling consumers to be better informed about their electricity demand and to actively participate in the electricity market by Demand Side Response on dynamic tariffs.

This vision will lead to new products, processes and services, improving industrial efficiency and the use of cleaner energy resources while providing a competitive edge for Europe in the global market place. At the same time, it ensures the security of the infrastructure thereby helping to improve the daily lives of ordinary citizens. All this makes Smart Grids a milestone in support of the European strategy for achieving the largest knowledge-based economy in the world.

1.2 The Core Elements of the European Smart Grid Vision

The electricity supply of the future will be shared by central power stations and distributed energy resources (DER). Both concepts may contain renewable energy sources (RES), some of which may be volatile or intermittent in their output (for example wind power plants, which may occur as DER or may build their own central power stations as well). DER tends to have a much smaller output than the traditional forms of generation, but large scale deployment will counterbalance this. In addition, placing sources of generation closer to the users will reduce the energy losses that are due to transmission of power over long distances. Figure 1.4 presents a picture of how the power supply of the future may be imagined [7].

Ultimately, the Smart Grids will combine existing technologies—improved and updated—with innovative solutions. The future grids will be based on the existing grids but will also allow to implement new system concepts, such as “Wide Area Monitoring and Protection”, “Microgrids” and “Virtual Power Plants”. Centralized generation will still play an important role, but many more actors will be involved in the generation, transmission, distribution and operation of the system, including the end consumers.

Based on these considerations, the core elements of the vision are defined in [7] as follows:

1. Create a **toolbox of proven technical solutions** that can be deployed rapidly and cost-effectively, enabling existing grids to accept power injections from distributed energy resources without contravening critical operational limits (such as voltage control, switching equipment capability and power flow capacity);

pp – power plant, 1– large hydro pp, 2– wind farm on-shore, 3–small hydro pp, 4–concentrated solar thermal pp, 5 –biofuel pp, 6- wind farm off-shore, 7–low emission fossil pp, 8 – high voltage DC transmission, 9– control center, 10 – micro- grid, 11 – wave pp, 12 –photovoltaic plants, 13 – underground power transmission,14 – solar heating, 15 – hydrogen filling station, 16 – small electric batteries,17 – thermal storage,18 – electricity storage,19 – cogeneration of heat and power, 20 – fuel cells

Fig. 1.4 Power supply of the future—the vision [7]

2. Establish **interfacing capabilities** that will allow new designs of grid equipment and new automation/control arrangements to be successfully interfaced with existing, traditional grid equipment;
3. Ensure **harmonization of regulatory and commercial frameworks** in Europe to facilitate cross-border trading of both power and grid services (such as reserve power, for instance Nordic hydropower), ensuring that they will accommodate a wide range of operating situations;
4. Establish shared technical standards and protocols that will **ensure open access**, enabling the deployment of equipment from any chosen manufacturer without fear of lock-into proprietary specifications. This applies to grid equipment, metering systems and control/automation architectures;
5. Develop **information, computing and telecommunication** systems that enable businesses to utilize innovative service arrangements to improve their efficiency and enhance their services to consumers.

The creation of the first core element, namely the "toolbox", is possible only in conjunction with the other four core elements. The toolbox presents the overview of the innovative solutions which make up the top priority of the Smart Grid concept.

Two major trends in the development of the power system can be observed:

More transmission

Increasing transmission demands in liberalized markets caused by free energy trading activities, and in some countries, by an unlimited in-feed of volatile wind power are stressing the power systems and causing frequent congestions of the transmission capacity. The existing transmission lines need to be loaded higher than in the past.

Active distribution

A growing share of electricity will be generated in the distribution level. Distribution networks will become active and will have to accommodate bi-directional power flows. Partially, these aspects will lead to a lower utilization of the transmission grids. However, both trends will lead to extremely volatile load flows on all levels of the power system.

The toolbox has to provide means that allow a response to the related challenges in an economic and flexible way, and two different toolboxes have to be established, one for transmission and one for distribution as depicted in Figs. 1.5 and 1.6, respectively.

On the transmission level advanced technologies are requested to enhance the transfer capability of the network and to ensure a flexible and smart operation management in the case of congestions. A situation is called congestion if the N-1 criterion (see below) cannot be satisfied according to the observed load flows through the network.

The majority of changes will take place on the distribution level. The significant growth of the distributed energy generation will significantly impact the network loading and the power quality parameters. In accordance with the Smart Grid definition an interaction of network operations and market activities will become necessary to optimize the distribution network enhancement. Consequently, a communication infrastructure has to penetrate all networks down to the low voltage consumer level to make this kind of interaction possible. Advanced Information and Communication Technologies (ICT) will be the key for:

- advanced distribution automation to enhance the quality of supply,
- a coordinated energy management covering generation, storage and demand in the framework of virtual power plants (VPP),
- provision of new metering services to the consumers including motivation methods for efficient use of electricity
  - by dynamic tariffs,
  - by the real-time communication of information to the end consumers,
  - to visualize the current tariffs, their demand and the related costs.

The other two aspects—the VPP and the Smart Metering—are means to generate flexibility for:

- the adaptation of the demand to the available low cost energy,
- the adaptation of the load flow to the available network capacity.

These aspects are market related but they may support the network operations. In the Smart Grid context the market and grid operations will influence each other mutually. In the environment of large scale volatile power production it will become mandatory to coordinate the network and market operations in a smart way.

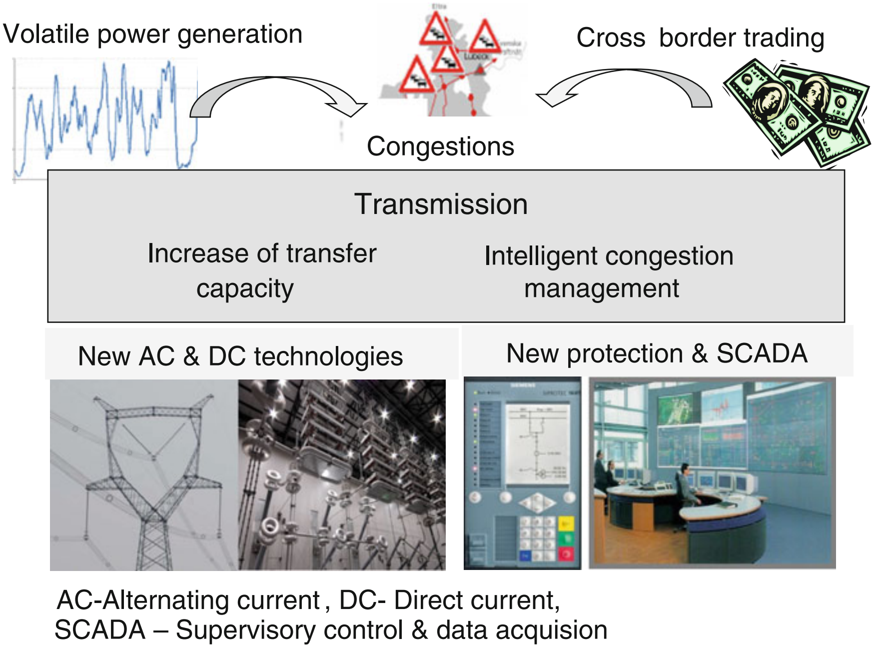


Fig. 1.5 Smart grid challenges, toolbox and solutions for transmission networks

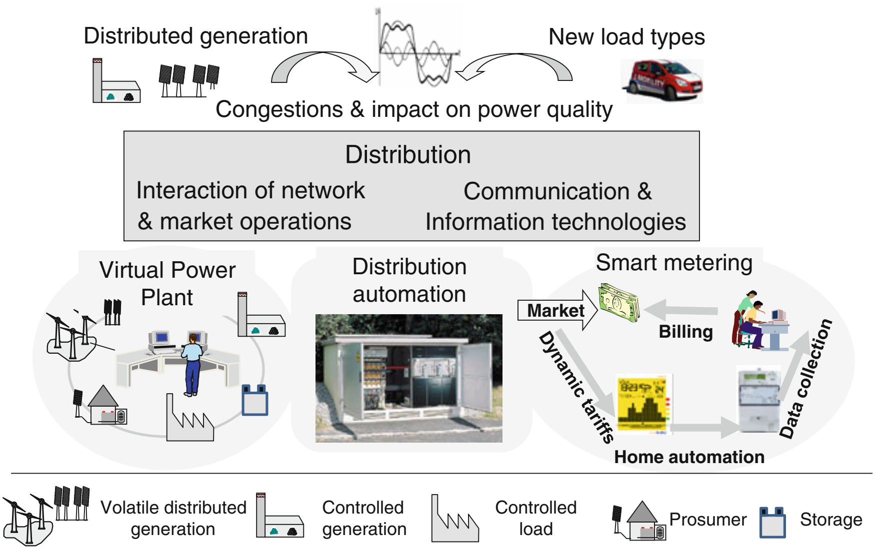


Fig. 1.6 Smart grid challenges, toolbox and solutions for distribution networks

The main goal of these solutions is to integrate the volatile RES into the network operation without any loss of voltage quality, reliability (N-1 criterion) and security of supply.

The current approaches for fulfilling the N-1 criterion presented in Fig. 1.7 have to also be ensured under the prospective changing operational conditions of the networks. The N-1 criterion is defined as follows: A network always meets the requirements of the (N-1) criterion if it survives the failure of an operating device with no inadmissible restriction to its function for an accidental, technically possible and operationally reasonable initial situation.

Figure 1.7 presents the overall power system from left to right with the indication of the voltage levels. However, the High Voltage HV and Extra High Voltage EHV are defined differently in different regions of the world. In most of the countries the HV is defined in the interval between 100 and 220 kV. However, in Japan the 66 kV level is defined as HV. Voltage levels from 230 kV up to 765 kV belong to the EHV level.

On the other hand, the rated voltages of the transmission system used in Continental Europe are 220 and 400 kV (or 380 kV) where they are both defined as EHV. Consequently, the EHV level in Continental Europe is defined beginning with 220 kV below the threshold used, for example, in the USA. The ultra- high voltage UHV level is declared as ±800 kV DC and 1000–1200 kV AC. The voltage levels according to Table 1.2 are used in the considerations of this book.

According to Fig. 1.7 the power flow is described as follows:

- The bulk power plants feed into the transmission network which operates normally on
  - the EHV level e.g.

    220, 400 (380) kV in Continental Europe, (also 275 kV in UK),
    220, 330, 500 and 750 kV in the the Unified Power System of Russia/Integrated Power System (UPS/IPS),
    230, 345, 500 and 765 kV in the USA,
  - the ultra-high voltages with ±800 kV DC and 1000–1200 kV AC are new technologies which have been developed and are ready for the global markets.
- The transmission network transports the energy to the regional distribution or sub-transmission networks operating on the HV) level (66–110–150 kV). Large industrial networks may be directly connected to the transmission networks. Continental Europe uses the rated HV of 110 kV.
- The HV network substations perform three tasks:
  - transforming the HV into Medium Voltage (MV—6, 10, 20, 30, 35 kV) for local energy distribution,

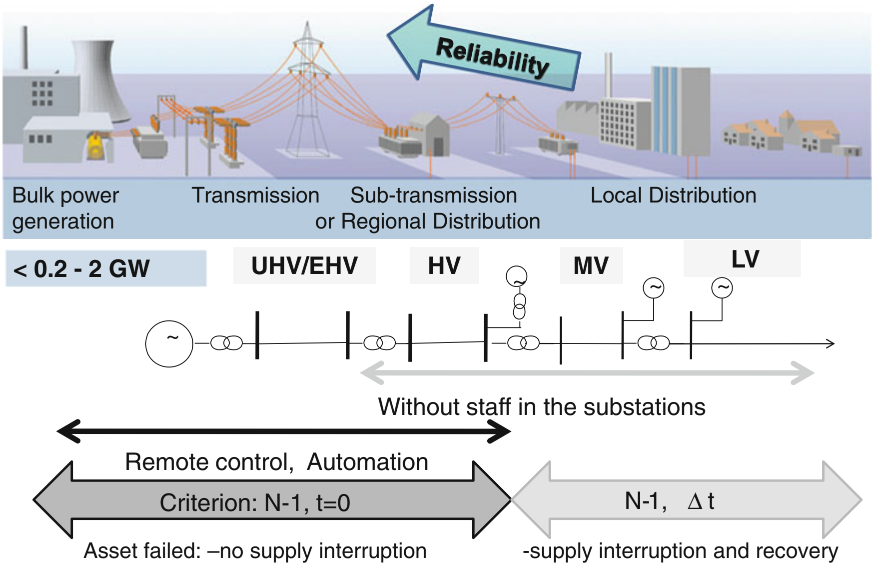


Fig. 1.7 The power system and the operational conditions

Table 1.2 Voltage level specifications applied

Ultra high UHV	Extra high EHV	High HV	Medium MV	Low LV
>800 kV	≥220 to <800 kV	>65 to <220 kV	≥1 to <65 kV	0.1 to <1 kV

– feeding industrial networks and
– connecting regional power plants in the range of ~20–200 MW.

- The MV networks perform similar tasks, but here the range of the power plants is lower from tens of kW up to 10–20 MW.
- The MV/LV transformer terminals feed directly into the low voltage (LV) networks, whereby the worldwide standard for the rated LV is 400 V, although in a small number of regions 200 V is still in use. The LV networks supply households, small enterprises, administration, trade and other business buildings in rural and urban areas. Furthermore, the LV networks are obliged to connect small power producers. Often these producers are also consumers, and in this sense the new term "prosumer" was introduced.

As shown in Fig. 1.7, the network reliability has to grow as the level of the power system increases.

The HV, EHV and UHV networks are completely remote controlled and supervised, and their protection schemes contain the main and the reserve protection.

At the level of the UHV, EHV and HV substations the N-1 criterion has to be fully ensured. This means that the secure network operation has to continue without any time delay after a failure causes any single component of the power system to switch-off, whether it be a generator of a power station, a line, a transformer, a busbar, etc.

The local distribution networks at the MV and LV levels are designed to ensure the N-1 criterion with latency. The supply is interrupted for a certain duration (~ 1 h) which is required for the location and separation of the faulted network component. After these operations are completed the supply has to be recovered without restrictions.

Finally, all of the above mentioned Smart Grid approaches can be developed and introduced successfully if the electric network operators, the users of the networks and other stakeholders of the electricity markets are motivated for additional investment in such a way that economic benefits may be generated for all. Consequently, in order to make Smart Grids economically feasible a deep paradigm change in the existing legal, regulatory and commercial frameworks is required. In addition, standards defining the interfaces between the system components will play an important role.

Besides the electric power and network automation technologies, this text book will also consider the accompanying aspects of Smart Grids in detail.

1.3 Ambitious Changes of the Energy Policy in Europe and the Consequences for Smart Grids

The European Commission is the initiator of the Smart Grid vision and the related concepts as demonstrated above. Some countries of the European Union have established extremely ambitious targets according to deep changes of their energy policies. However, these changes have consequences regarding the operation of the power system in general and the electricity networks at all levels. The establishment of Smart Grids will be accompanied by technological and legislative challenges which have to be met within the interconnected power systems of Europe.

The Western and Central European transmission system operators have established the European Network of Transmission System Operators for Electricity, ENTSO-E, which consists of five synchronous transmission systems interconnected by DC links:

- the continental European transmission network (RG CE—Region Continental Europe, former UCTE),
- the transmission network of the United Kingdom (RG UK),
- the Scandinavian transmission network (RG Nordic),

- the network of the Baltic countries (RG Baltic, synchronous with UPS/IPS),
- the network of Ireland (RG Ireland).

Being the body of transmission system operators of electricity at the European level, ENTSO-E's mission is to promote important aspects of energy policy in the face of significant challenges:

- Security—it pursues coordinated, reliable and secure operations of the electricity transmission network.
- Adequacy—it promotes the development of the interconnected European grid and investments for a sustainable power system.
- Market—it offers a platform for the market by proposing and implementing standardized market integration and transparency frameworks that facilitate competitive and truly integrated continental-scale wholesale and retail markets.
- Sustainability—it facilitates secure integration of new generation sources, particularly growing amounts of renewable energy and thus the achievement of the EU's greenhouse gases reduction goals.

The transmission network of Continental Europe (RG CE) is the largest synchronously interconnected transmission system in the world, serving 450 million people with an annual electricity consumption of 2,500 TW h. It contains an installed power plant capacity of about 630 GW and 230,000 km of transmission overhead lines (400/220 kV).

The transmission network was extended by the East German and the CENTRAL transmission networks of some Eastern European countries in 1994 and by the re-connection of the Balkan countries in 2004 (after the war in the former Jugoslavia). The network is synchronously interconnected with the power systems of the Maghreb countries (Northern Africa) and, since 2010, with Turkey. The largest synchronous interconnected transmission system which neighbours ENTSO-E is the UPS/IPS.

The UPS/IPS is still not interconnected with the ENTSO-E grids (except for a weak High Voltage DC link to Nordel). Strong 750 kV AC lines end in Poland, Hungary and Bulgaria, but they are not used for a synchronous interconnection. Only one 750 kV line from Western Ukraine (Zapadno Ukrainskaja) to Hungary (Albertirsa) is in operation. Some Ukrainian power plants are synchronously disconnected from UPS/IPS, and so this line is used to transmit electric power from this "Burstyn Island" in the Ukraine to and from Hungary.

Figure 1.8 presents the relations of the European power systems where the size of the circular areas is related to the installed power capacity of the systems.

The closing of the Northern African (NA) loop from the Maghreb countries to Turkey has been planned for many years. However, dynamic stability problems have prevented the interconnection with the system of Central Europe up to now.

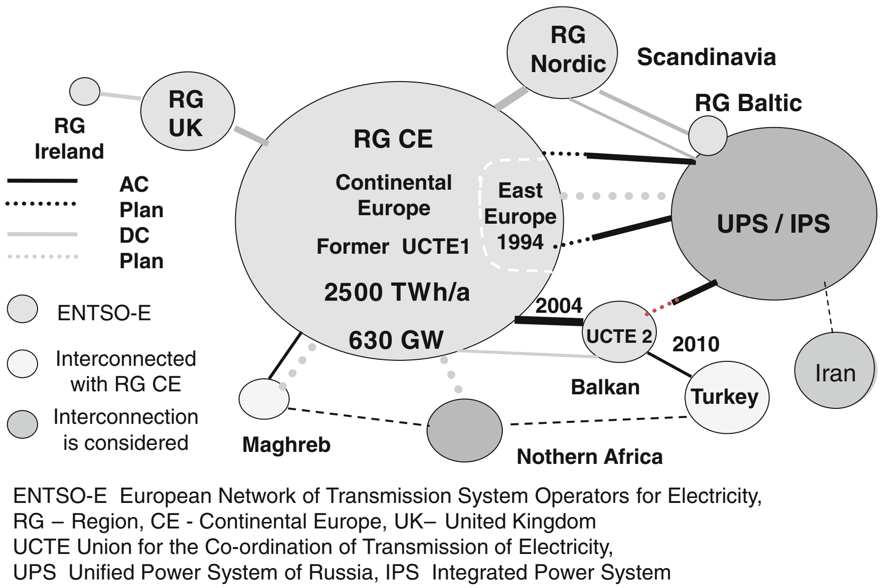


Fig. 1.8 The European power systems and their interconnections

The German power system builds the largest part in the RG CE and is embedded in the middle of the interconnected transmission network. Interconnections to all neighbouring systems are in operation. Furthermore, Germany achieved the highest level of reliability of supply worldwide.

The German government has set the most ambitious targets regarding the fundamental change of the energy policy called "Energiewende". In this context, the German example is selected to demonstrate the special consequences of the Smart Grid philosophy and the appropriate technical solutions enabling to maintain the high level of power quality under the new conditions.

The German transmission system is operated by four transmission system operators (TSO) performing four control areas as shown in Fig. 1.9a. The voltage levels of the underlying networks are 110, 30, 20, 10 and 0.4 kV. About 850 network operators are active in this area (Fig. 1.9b).

The special role of Germany in the global world of electric power systems can be characterized by three specific aspects:

Firstly, Germany has set the most challenging targets for the development of the energy mix. The development of shares of Renewable Energy Sources (RES) of the annual electricity consumption is planned as [9, 10]:

- 2011 19 %—with 10 % volatile RES (Wind, Sun)
- 2020 35 %—with 22 % volatile RES

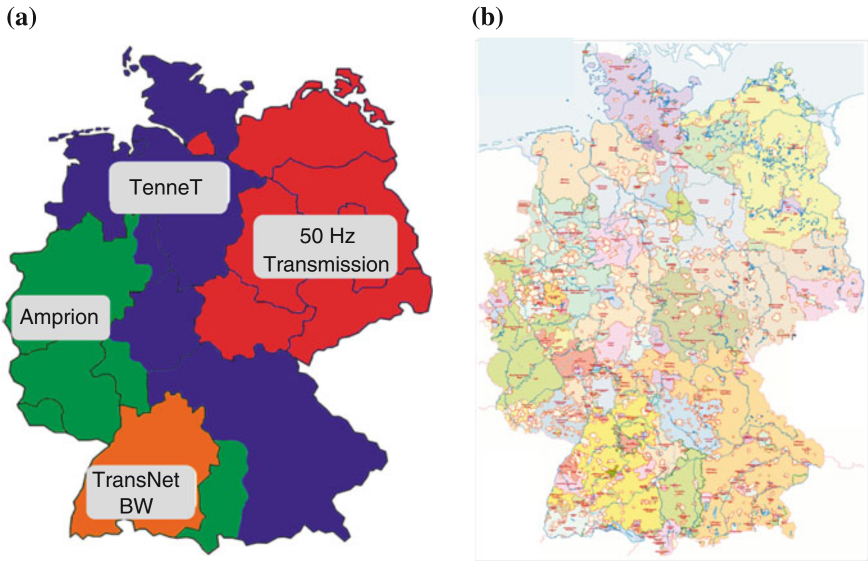


Fig. 1.9 **a** Transmission grid operators. **b** 850 distribution networks in Germany

- 2030 50 %—with 35 % volatile RES
- 2050 80 %—with 50 % volatile RES

Figure 1.10 presents the primary energy mix of the electric power production in Germany for the year 2010 and one of the expected energy mix scenario 2B for 2030 [9].

Secondly, Germany has planned the shut-down of all nuclear power stations by 2022. Nuclear power covered approximately 25 % of the annual electricity consumption in 2010. The nuclear power stations are well distributed throughout Germany and located near to the load centers. As a consequence, a significant dislocation of power production and load centers will occur which requires a strong enhancement of the transmission grid on one hand, and the growth of regional generation in the distribution networks on the other hand.

Thirdly, a significant reduction of the annual demand is foreseen caused by improved efficiency of energy usage. At the same time, however, a significant growth regarding the connection of new types of consumers like electric mobiles (6 million are planned for 2030), heat pumps and other devices is foreseen.

The main challenges of such a development strategy lie in the volatility of a significant share of the energy production and in the geographic allocation of load centers which are mostly located in Central/Southern Germany while the large scale growth of wind power generation is in the North.

In 2010, the distribution of load and generation in Germany was more or less harmonized. As a rule, the large generation plants were located near the load

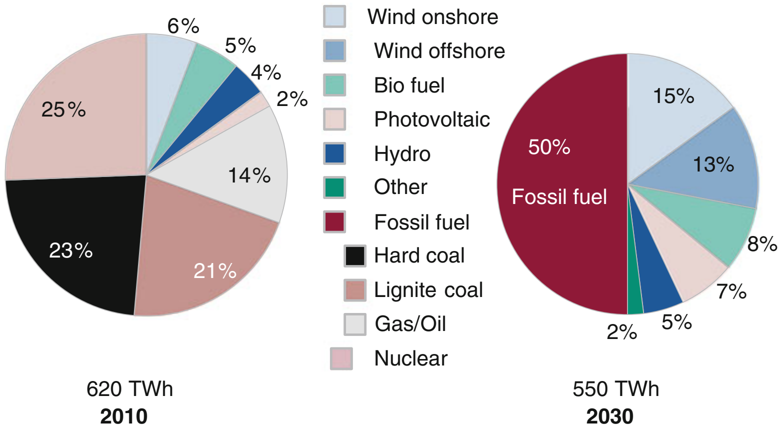


Fig. 1.10 Energy mix in 2010 and the development targets for 2030 in Germany [9]

centers. About 10 % of the peak load of 80 GW could be covered by nuclear power stations located in the South of Germany. When they are shut down, however, the territorial ratio of generation and load will change significantly. Figure 1.11 presents these changes with a comparison of the years 2010 and post-2022.

The growing territorial unbalances of load and generation can be solved in two ways:

1. Enhancement of the transmission grid for bulk power transmission from North to South,
2. Growth of dispersed generation connected to the distribution networks.

In this way, Germany with its ambitious targets has to play a progressive mover role regarding the evolution of the transmission and distribution networks into Smart Grids.

Furthermore, the volatility problems have to be solved. The planning of the energy mix in diagrams as shown in Fig. 1.10 is an approach which needs to be underlined by generation and load profile analysis for the considered year (here 2030). This analysis was performed in [11] with the assumption that by 2030 the annual net consumption consists of 44.8 % industry demand, 24 % business/trade/services, 23.4 % households and 7.8 % traffic (including electromobility and hydrogen production) [10]. Each load group follows special profiles which are different for weekends, working days and seasons. The sum of all the various load profiles has to be covered by the energy production each second of the year.

The typical 1/4 h profiles of the load groups and the generation categories of the renewable energy sources (RES) based on multi-year long analyses by the Fraunhofer Institute for Wind Energy Systems in Kassel were adapted in [11] to the German targets for 2030 according to [9] (details see Sect. 7.2).

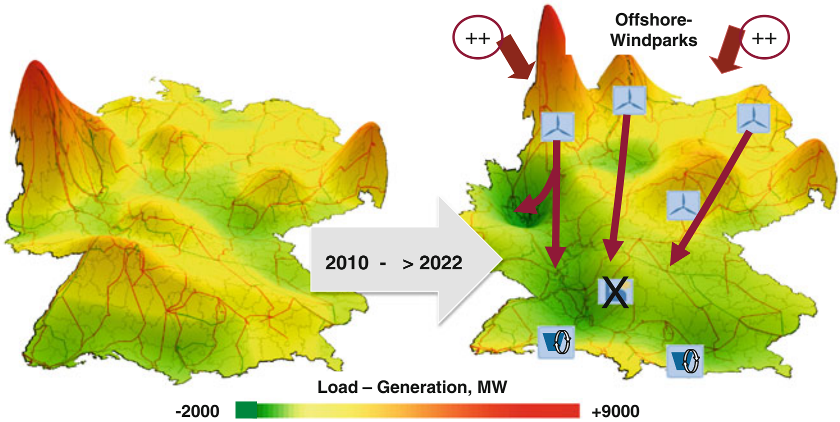


Fig. 1.11 Development of the ratio of load and generation in Germany (*Source* Amprion)

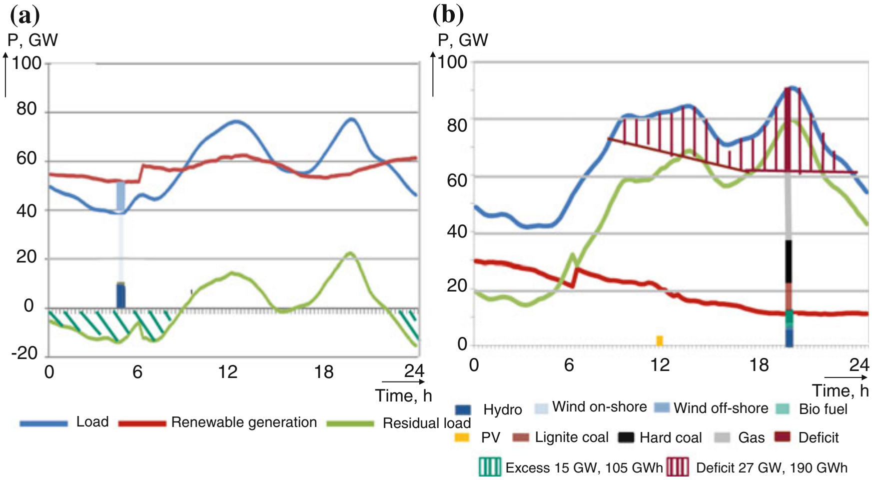


Fig. 1.12 Extreme weather conditions with **a** maximum and **b** minimum of RES [11]

The total load profile was filled with the possible amount of renewable generation for each 1/4 h of the year. In this way the load and renewable power ratios were defined for 35040 1/4 h values in accordance with the planned energy mix for the year 2030. Figure 1.12 presents two extreme days of the annual load—renewable power diagram—one with a maximum the other with a minimum of renewable energy generation. The maximum of RES is presented on the left-hand side: The renewable sources may cover up to 90 % of the daily load profile. Furthermore, a surplus up to 15 GW power with an amount of 105 GW h energy occurs over 9 h in the weak load period.

On the right-hand side of the diagram, the minimum coverage of the load profile by renewable energy can go down to 16 %. This means that during the peak load period up to 77 GW have to be covered by traditional sources when the maximum available power of fossil sources is limited to 50 GW [10] (65 GW installed generation capacity reduced by 15 GW for considering network losses, reserve power and the capacities disconnected for maintenance). Consequently, there is a 27 GW deficit of peak power and 190 GW h of energy lacking during 14 h that have to be covered by more installed fossil power or by using other sources like storage units, adaptive reduction of the demand and/or the importation of electric energy.

The Smart Grid strategy consists of an intelligent coordination of the connected users of the power system in the sense that load and generation may be balanced, also in extreme situations, by a limited volume of available fossil power production. The ambitious German policy for energy development makes it a country where Smart Grids have to be introduced as a top priority. A number of new technological solutions have to be created for meeting the related challenges.

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Chapter 2
Smart Generation: Resources and Potentials

2.1 New Trends and Requirements for Electricity Generation

Electricity generation is the process of electric energy production and requires the use of primary energy sources (PES). PES is defined as an energy form that is available in nature and that has not yet been used in any conversion or transformation process.

The world's annual electricity generation amounted to about 20,250 TWh in the year 2012 [1] and is expected to increase to 25,500 TWh by 2020 [2].

Traditionally, electricity is most often generated in thermo-electric power plants using the expansion of steam in steam turbines that drive electro-mechanical generators. The heat is mainly produced by the combustion of fossil fuels or by nuclear fission.

Nowadays, renewable energy sources (RES) such as geo-thermal power and concentrated solar thermal power (CSP) are also applied for the electricity generation via heat.

Furthermore, the renewable electricity generation is increasingly using the direct conversion of mechanical rotation into electricity by using the kinetic energy of wind, waves and flowing water. Additionally, chemical processes are used to generate electricity in photovoltaic plants (PV) and fuel cells. The different methods of electricity generation are depicted in Fig. 2.1.

By 2010, the worldwide contributions of various PESs applied for electricity generation were [2]:

- 67 % fossil PES (35.5 % coal, 24.5 % natural gas, 7 % oil)
- 19 % RES (16 % hydroelectric, ~1.2 % biomass, ~1.1 % wind, ~0.4 % solar and ~0.3% geothermal),
- 14 % nuclear power.

The high amount of burning fossil fuels releases carbon dioxide CO_2 into the atmosphere in such volumes that its re-absorption by plants and trees is not possible.

B. M. Buchholz and Z. Styczynski, *Smart Grids – Fundamentals and Technologies in Electricity Networks*, DOI: 10.1007/978-3-642-45120-1_2,

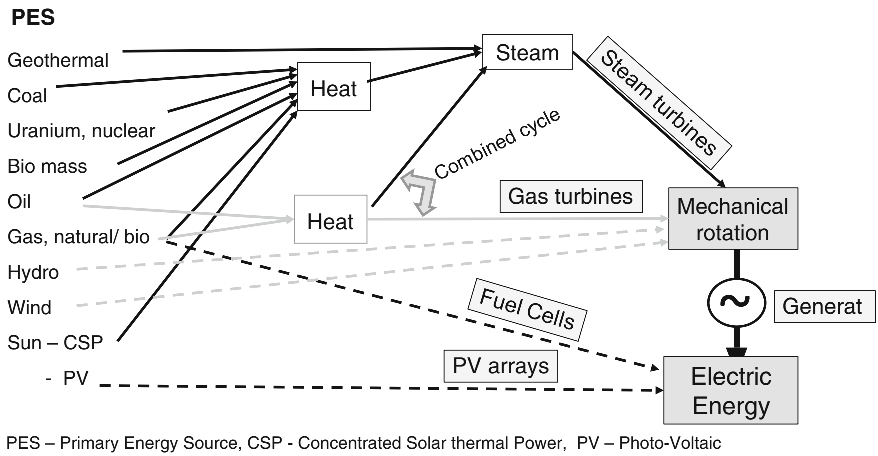


Fig. 2.1 Methods of electricity generation

The effect of excessive amounts of CO_2 in the atmosphere is the increase of the overall temperature of the planet (global warming) with the consequence of a growing risk for extreme weather catastrophes (floods, hurricanes, heat waves and droughts).

The reduction of the CO_2 emissions combined with the increased efficiency of energy usage is a target of the global community and is supported by many governments (see also Sect. 1.2). Parameters regarding CO_2 emissions and the efficiency of electricity generation are presented in Table 2.1.

Table 2.1 demonstrates that the RES provide an enormous potential to reduce the worldwide emissions.

Increasing the efficiency of electricity generation by more than 60 % may be achieved by three means:

- Technological improvement,
- Combined cycle (CC)—using the gas flow after combustion in gas turbines and the generated heat for steam production,
- Cogeneration of heat and power (CHP).

The potential and the efficiency of RES are being investigated in a number of studies. Table 2.2 presents the data of the Desertec vision [5].

The Desertec vision has been published by the Desertec Foundation, which is an organization founded by people from the Mediterranean region and Europe with support from the Club of Rome. The foundation has resolved to develop criteria for large-scale power plant projects that apply renewable energy sources and is acting to involve investors into such projects. The main driver for the Desertec activities is the fact that the world's current electricity consumption could be covered by CSP (concentrating solar power) plants located in a desert territory of 300 × 300 km^2.

Table 2.1 CO_2 emissions and efficiency of fossil PES and RES

PES	CO_2 equivalent, kg/MW h	Electric efficiency, %
Lignite coal[a]	980–1200	35–40
Hard coal[a]	890–950	37–43
Gas[a]	400–550	37–60
Photovoltaic[b]	~30[c]	12–20
Wind[b]	~20[c]	~44
Bio fuel[b]	~0.2	37–60

[a] *Source:* [3], [b] *Source:* [4], [c] Taking into account the emissions for manufacturing

In this context, the Desertec foundation developed a "Renewable Energy location Map" according to Fig. 2.2.

In this figure the territories are shown (red squares) that are required to cover the electricity consumption for the world, for Europe and for MENA (the Middle East and Northern Africa). The area necessary for the world's consumption amounts to only 0.23 % of the total desert territory on our planet.

The realization of this vision would have an enormous impact on the prosperity in Europe and MENA. For example, the surplus of generated energy could be used to solve the fresh water problems in Northern Africa by being used for sea water desalination programs.

In this sense, the main target of the foundation is currently to connect people from the respective regions with each other to begin an intensive dialogue. The aim in conducting this dialogue is to combine legitimate interests of investors and companies with important demands for a reasonable regional development.

The Desertec concept is a visionary ideal at the moment. However, this vision demonstrates clearly how the energy demand of the world's population may be covered in the future without burning fossil fuels.

Most of the countries in the world are trying to increase the contribution of renewable energy sources to ensure a sustainable power supply and prevent further global warming (see Chaps. 1 and 9).

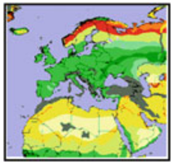
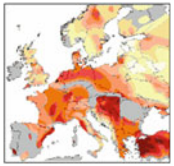
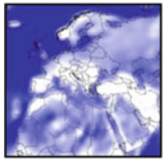
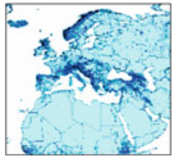
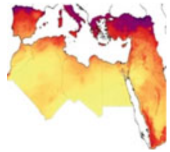
2.2 Volatile Renewable Energy Sources: Wind and Sun

2.2.1 Wind Power Plants

In general, wind power plants include many different concepts with regard to their construction, type of generator, type of network interconnection, type of control system as well as type of operation. Currently, most wind turbines have a construction consisting of three blades shifted at 120°.

Within recent years the development of the wind power plants (wind turbines) has experienced massive technology jumps as demonstrated in Fig. 2.3.

Table 2.2 Potential and efficiency of RES [3]

Type of RES	Bio fuel	Geothermal	Wind	Hydro	Solar
Preferred allocations in Europe, Middle East and Northern Africa (MENA)	Green 	Red 	White 	Blue 	Yellow 
Economic potential, TW h/a	890	750	1,700	1,090	50,000
Energy efficiency, GW h/km^2/a	1	1	50	50	250

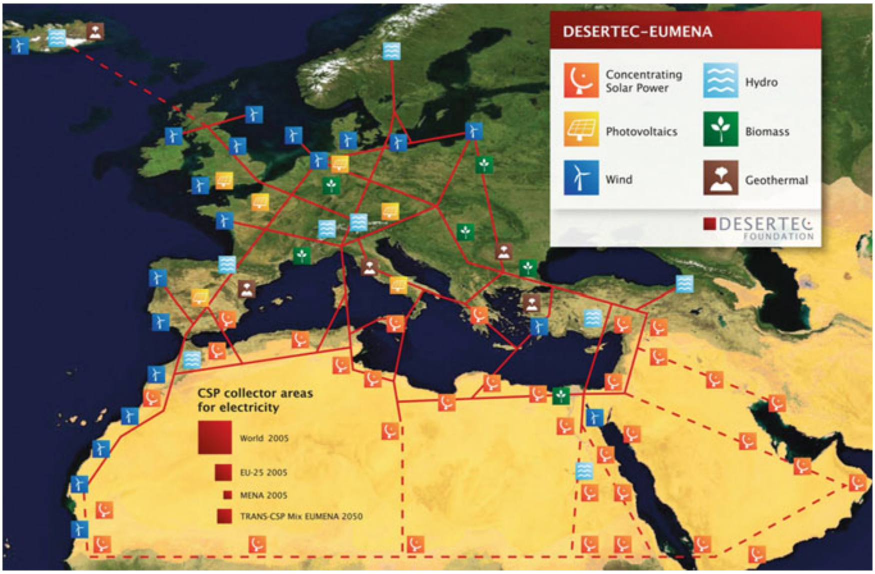
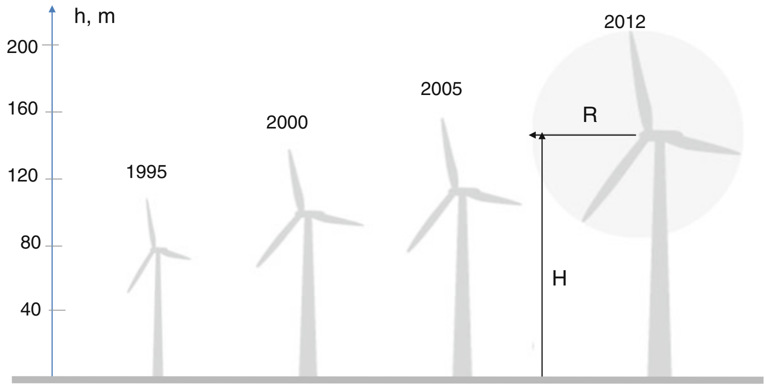


Fig. 2.2 Network of RES to cover the global and regional electricity demands—the Desertec map (*Source* Desertec Foundation [6])



P, MW	0.6	1.5	3.0	8.0
H, m	80	100	115	140
R, m	20	35	50	80

Fig. 2.3 Development of size and rated power of wind power plants [7, 8]

By 2013, advanced wind power plants have reached a rated power of 8 GW, tower altitudes up to 140 m and rotor diameters up to 162 m [8]. And, the development is still going on.

Fig. 2.4 Erection of a wind power plant 6.5 MW: rotor length 60 m (*Source* Regenerativ-Kraftwerk Harz GmbH and Co.KG. [9])

A modern wind turbine of 6.5 MW rated power is presented in Fig. 2.4, in which the transportation of the rotor blade of 60 m length, the view of the rotor connection compartment and the plant as a whole are shown. The plant constructions reach altitudes over 200 m.

The first modern wind turbines that were applied for electric power generation were operated at a constant angular speed independent of the wind speed, and their generators were directly coupled with the network. The generators used in these concepts were based on the squirrel cage or wound rotor induction generators. Additional capacitor banks were used for compensating the reactive power consumption.

The advantage of such wind turbines was that they were simple and robust and, therefore, relatively cheap. On the other hand, the major disadvantages were non-controllable reactive power consumption, reduced efficiency for wind speeds other than rated speed, high mechanical stress, and transmission of the wind speed fluctuations to the electrical network.

The mechanical power of such turbines can be controlled by the following three aerodynamic principles:

1. stall control,
2. active- stall control,
3. pitch control.

The easiest and cheapest control system is the stall control that consists of reducing the turbine output power by using the aerodynamic stall effect starting from a specified wind speed at the blades that are connected to the hub at a fixed angle.

For active-stall controlled wind turbines, the blades can actively be turned around their axis and the rotor angular speed can be better controlled. The active stall control pitches the rotor blades into the stall. However, the construction is here more complex due to the turning mechanism and the active stall controller.

Nowadays, both control principles are replaced by the more efficient pitch control. The pitch control allows the pitching into the stall and into the feather.

Only a small number of vendors still manufacture induction generator based wind power plants and the pitch control is the dominating principle of power control.

The pitch control is also applied for variable speed wind turbines which have been established as the dominant type among installed units. Advanced wind turbines are designed for a variable speed operation.

The variable speed wind turbines regulate their power output by altering the angle of their rotor blades (along their longitudinal axis to the wind). There are two operation modes applied. Below the rated power of the turbine, the blades are pitched into the feather to maximize the power generation. If the rated power is achieved, the control avoids the exceeding of the speed limits by pitching into the stall. This principle is demonstrated in Fig. 2.5.

This concept is supported by the decoupling of the wind rotor speed from the network frequency by frequency converters. The basic principle is applied in two types of wind power plants:

- doubly fed induction generator (DFIG) and
- direct driven synchronous generator with frequency conversion

as presented in Fig. 2.6. For both of these wind plant types pitch control is the most efficient control method and is generally applied to all wind plants.

The converter and its control system play an important role with respect to the wind power plant operation. Due to the volatile character of the wind speed, the mechanical power output of the aerodynamic turbine changes continuously.

In order to obtain a maximum efficiency at different wind speeds, the angular speed of the aerodynamic rotor has to be adapted.

In synchronous generators there is a direct coupling between the mechanical speed of the rotor and the frequency of the voltage. Therefore, synchronous generators that are connected directly to the network are operated at constant speed. The angular speed of the aerodynamic rotor follows the continuous wind fluctuations, which are, due to the direct coupling to the generator, transmitted to the generator and thus the frequency of the voltage changes, too. Therefore, in order to connect a synchronous generator operating at variable speed to the network a frequency converter system has to be used. Since the modern frequency converters use power semiconductor switches with turn-on and turn-off capability (e.g. IGBT—Insulated Gate Bi-polar Transistor) the pulse width modulation (PWM) techniques play an important role in the control of such converters [10].

A frequency converter system for wind turbines with synchronous generators has to be designed for at least the rated power of the generator. Due to the full decoupling of the generator and the network, the operation of the respective wind turbines is more flexible and electrical parameters at the point of common coupling, e.g. voltage and frequency, can be better controlled.

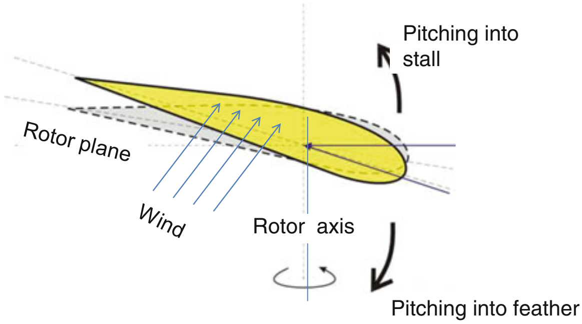


Fig. 2.5 The mechanical power control principles of the pitch control

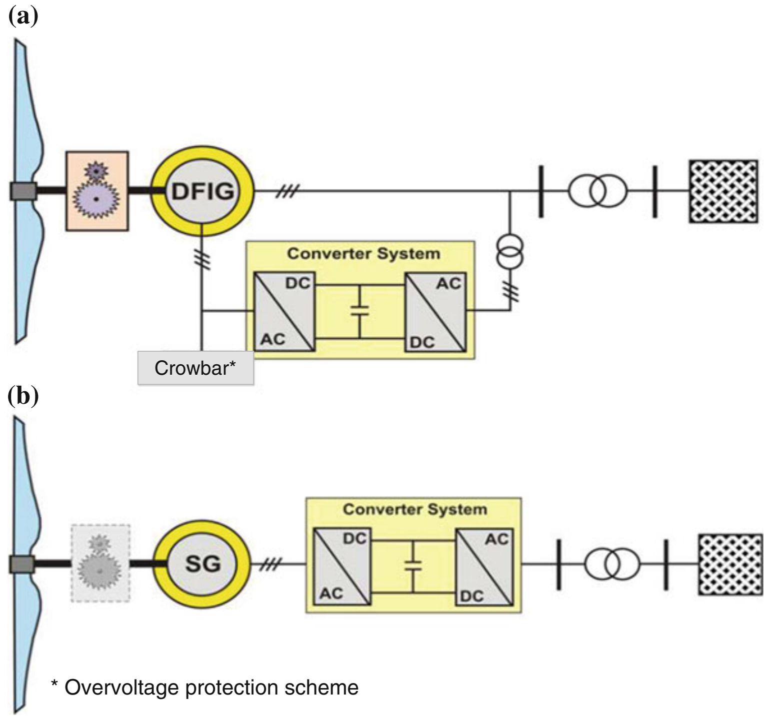


Fig. 2.6 The advanced variable speed principles of wind power plants **a** doubly fed induction generator, **b** Synchronous generator with frequency conversion

In addition to the controllers, which are responsible for control of the frequency converter system, there are two more controllers in variable speed wind turbines with converter connected synchronous generators:

- maximum power point tracking (MPPT) controller,
- speed or power limitation controller.

For wind speeds lower than a specified wind speed (partial load operation) the main controller is the MPPT controller whereby the speed/power controller is not active. The MPPT controller is a technique that grid connected inverters, use to get the maximum possible power from the generator.

The goal of the MPPT controller is to change the angular speed of the turbine into a permissible range in order to maximize the power coefficient of the wind turbine and, thereby, the output power. The limits for the angular speed are related to the acceptable noise emission, mechanical loads, as well as ratings of the generator and the converter.

For wind speeds above a specified value (full load operation) the speed/power controller is activated additionally. If wind speed becomes too high and exceeds the rated value, the output power of the turbine and the angular speed need to be minimized to avoid any damage of the turbine. The reduction of the output power can be obtained by increasing the pitch angle, which is set by the pitch controller.

The function principle of the frequency converter system in wind turbines with DFIG is similar to that considered for wind turbine with synchronous generators.

The adequate control system consists of the following main parts:

- pitch controller,
- controller of network-side converter,
- controller of rotor-side converter including the MPPT controller.

The pitch control system and the MPPT controller are similar to that described above for the synchronous generator.

The rotor-side converter can control the active and reactive power flow in the rotor circuit. Since the operation of the wind turbines has to be optimized for changing wind speed, varying active power in the rotor circuit allows for adjusting the angular speed of the turbine and for obtaining an optimum operation point. Through the change of reactive power the generator can be magnetized from the rotor-side and, therefore, the reactive power demand of the stator can be minimized, even to zero.

The role of the network-side converter is to control the voltage of the DC—circuit and the reactive power exchange with the network.

Both controllers are realized as traditional proportional-integral controllers.

The description of the complex control systems underlines the enormous progress achieved in the development of the wind power technologies as summarized in Table 2.3.

The modern wind power plants have flexible active and reactive power control.

An important feature is also the provision of short circuits and "fault ride through" capability. These features are strictly required in the Grid Codes to ensure the selective fault clearing and the stable network recovery after faults.

The rapid technology development for wind power was accompanied by the massive growth of the worldwide installed power capacity, as shown in Fig. 2.7.

Table 2.3 Technical development of wind power plants—status 2013

Generator type	Rated power, MW	Active power control	Reactive power control	Short circuit currents
Induction [11]	2.1	Power limitation by pitch control	No, capacitor required	No
Doubly fed induction [12]	6.15	Over- and under-frequency feed-in control	By the power electronic scheme	6–10 × rated current for a short time [13]
Synchronous with converter [8]	8	Over- and under-frequency feed-in control, inertia emulation	By the power electronic scheme	Up to 110 % rated current [14]

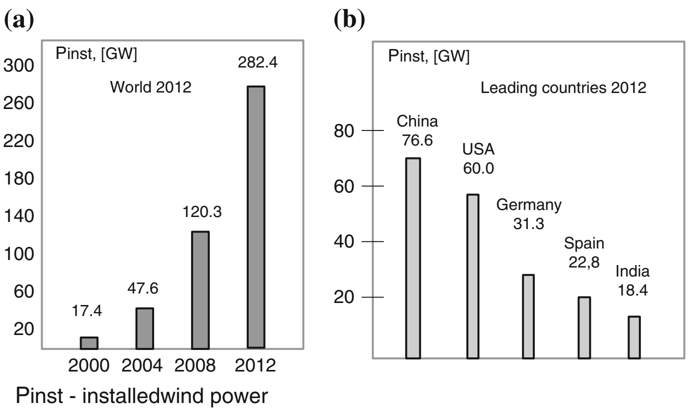


Fig. 2.7 Development of the installed wind power: **a** world, **b** leading countries by 2012 [15]

In the past 10 years the installed power capacity increased approximately tenfold and reached 282.4 GW in 2012. China became the world market leader regarding the installed wind power capacity followed by the USA and Germany.

The remaining disadvantage of the wind power generation lies in the volatility of the power outputs. An example for the statistics of the measured wind power volatilities for hourly averages during a month, for daily averages during a year and for monthly averages during a period of 9 years is depicted from left to right in Fig. 2.8 according to [16].

The leading wind power countries have developed and implemented efficient measures to meet the volatility challenges.

The application of accurate prediction tools, the provision of an adequate availability of control power and the enhanced flexibility of the definitely controllable power stations may ensure the reliable power system, including those with significant shares of wind power in their annual generation balance.

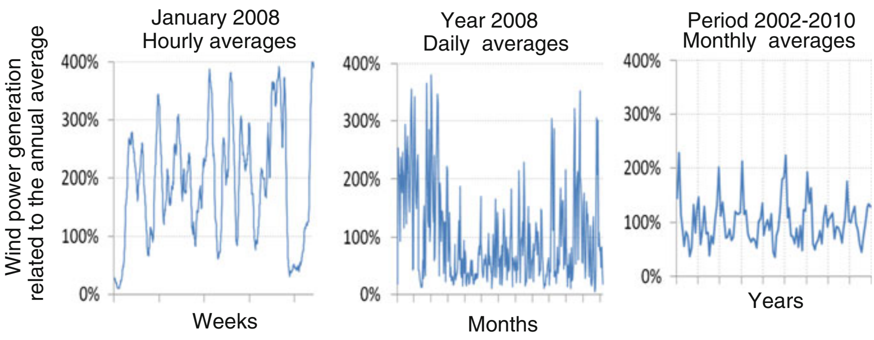


Fig. 2.8 Volatility of wind power generation [16]

The requested innovative solutions are part of the general Smart Grid concept and will be specified in detail within the subsequent chapters.

2.2.2 Utilization of Solar Power for Electricity Generation

Solar power is increasingly being used for electricity generation by converting the sunlight into electricity, either directly using the photovoltaic technology (PV), or indirectly using the principle of concentrated solar power (CSP).

Plant examples of both technologies are shown in Fig. 2.9.

PV converts the photon energy of the solar radiation into electric energy using the photovoltaic effect. The conversion takes place within solar or photovoltaic cells, which are based on semiconductor technologies. Materials presently used for photovoltaic cells are based on mono-crystalline silicon, poly-crystalline silicon, amorphous silicon, cadmium telluride, and copper indium selenide.

Many currently available solar cells are made from bulk materials that are cut into wafers between 180 and 240 μm thick. Other materials are made as thin-films layers, organic dyes and organic polymers that are deposited on supporting substrates. A third group are made from nano-crystals and used as quantum dots (electron-confined nanoparticles).

Table 2.4 presents the market shares of the cell materials in 2010.

The dominating market share belongs to poly-crystalline silicon followed by mono-crystalline silicon and amorphous silicon. Silicon based photovoltaic cells cover about 90 % of the world's market.

The photovoltaic cells *are connected and assembled to build a photovoltaic (or solar) panel*. Each panel is rated by its DC output power under standard test conditions, and typically ranges from 100 to 320 W. The efficiency of a PV panel is determined for each surface area of a panel given the same rated power output. For example, a 10 % efficient 230 W panel will require twice the amount of surface area as a 20 % efficient 230 W panel. Currently the best achieved sunlight

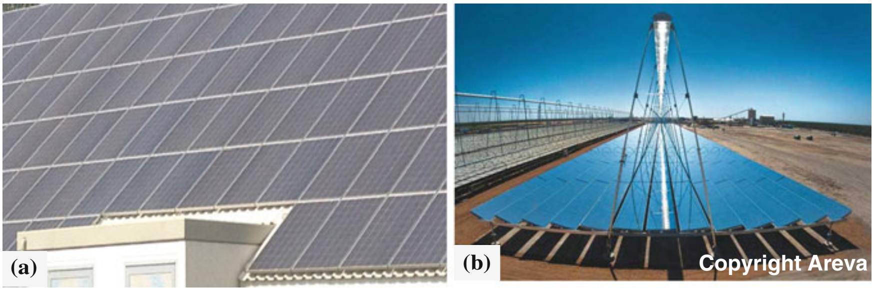


Fig. 2.9 Electricity generation by solar power plants: **a** PV, **b** CSP (*Source* b: Areva)

Table 2.4 Market shares of materials for photovoltaic cells [17]

Cell material	Market share 2010, %
Poly-crystalline silicon	52
Mono-crystalline silicon	33
Amorphous silicon	6
Cadmium telluride	5.5
Copper indium selenide	2
Others	1.5

conversion rate (solar panel efficiency) is around 20 % in new commercial products. The most efficient mass-produced solar panels have energy density values of up to 175 W/m^2.

Because a single solar panel can produce only a limited amount of power, most installations contain multiple panels building a PV array. A photovoltaic system typically includes one or more arrays of solar panels, an inverter with harmonic filters and a control system, interconnection wiring and sometimes a storage battery. Today, significant numbers of PV arrays may be located on large square territories building a PV power station and feeding some tens of MW into the networks.

The three basic components of the PV systems are depicted in Fig. 2.10.

The photovoltaic array shown in Fig. 2.10 is part of a PV power plant covering a territory of 0.2 km^2. In the shown example, the arrays continuously move during the day into the direction of the sun, which allows a higher efficiency of the electricity generation. For that, the arrays are equipped with rotation movers to follow the earth's rotation during a day to bring them in line with the sun.

Figure 2.11 demonstrates the dependency of the power output on the PV array direction during a day.

The erection of PV systems is supported by subsidy schemes in a number of European countries. In countries with normally low sun intensity a significant contribution of installed PV capacity could be achieved only with the help of enormous co-financing programs.

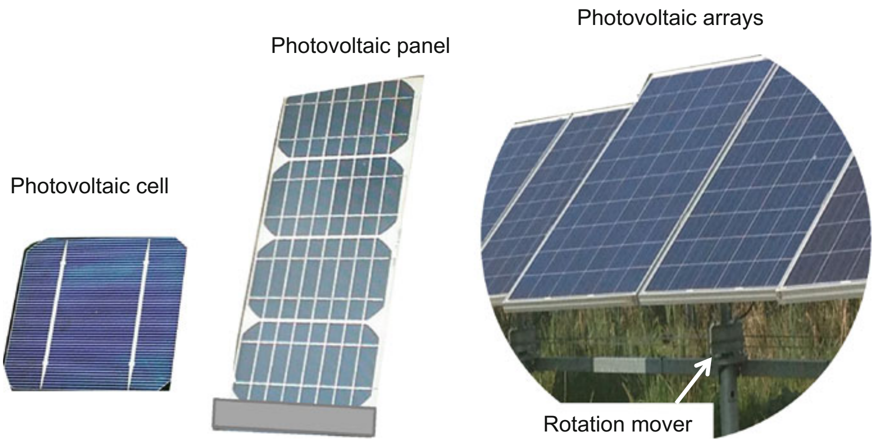


Fig. 2.10 From the PV cell to a PV power plant

Fig. 2.11 Dependency of the power generation on the array direction [16]

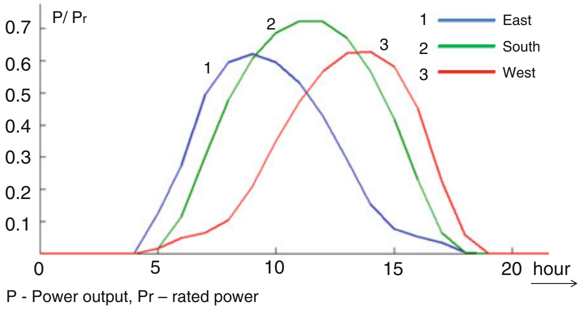


Table 2.5 compares the benefits and the disadvantages of the PV technology.

Obviously, the economic efficiency of PV power plants is higher in countries with more intensive and continuous sun radiation.

The main disadvantage of the PV technology is the unavailability in darkness. The application of CSP systems may overcome this disadvantage and provide an around the clock electricity generation by using thermal storage capabilities.

CSP systems use lenses or mirrors and tracking systems to focus a large area of sunlight into a small beam. The focused solar energy is directed to heat up a working fluid inside absorber tubes or other containers. The concentrated heat is then used as a heat source for a conventional power plant. A wide range of concentrating technologies exists.

The most developed and already applied in practice are:

- the reflector trough principle,
- the concentrating linear fresnel reflector,
- the solar power tower.

Table 2.5 Benefits and disadvantages of PV

Benefits	Disadvantages
Environment friendly renewable generation regarding emissions, noise and cleanness	Low efficiency volatility of electricity generation,
Available during the daily demand peak	Only available when there is daylight
Generation near to the consumers	Toxic chemical elements are used for manufacturing, danger of fire
Easy to install, roofs may serve for installations, flexible in size configuration	Mechanical sensitive
Little maintenance over 20–30 years lifetime	High capital expenses

The reflector trough technology uses reflecting troughs with absorber tubes laid along the trough axis. The reflectors capture the sun radiation and focus it on the absorber tube containing the working fluid. The reflectors turn during the day to capture the optimum radiation. The tubes of each trough end in a pipe network system which transfers the heated working fluid to the heat exchanger of the thermal power station.

The linear fresnel reflector principle aims to improve the efficiency of the reflector trough technology. The linear fresnel reflectors use long, thin segments of mirrors to focus sunlight onto the absorber located at a common focal point of the reflectors. These mirrors are able to concentrate the sun's energy to approximately 30 times over the normal intensity. This technology is still under development, and one of the first power stations Puerto Errado 2 (30 MW) was commissioned in Spain in 2012 [18].

The solar power tower carries the absorber container with the working fluid. A number of heliostats are located around the tower. A heliostat is a construction that contains a reflector (usually a plane mirror) which turns to direct the reflecting sunlight toward the absorber on the top of the tower compensating for the sun's apparent motions in the sky. To do this, the reflective surface of the mirror is kept perpendicular to the bisector of the angle between the directions of the sun and the absorber as seen from the mirror. The solar power tower is stationary relative to the heliostat and the light is reflected in a fixed direction.

Two of the CSP principles are demonstrated in Fig. 2.12.

The scheme of a complete CSP plant with a thermal storage unit is shown in Fig. 2.13.

Most thermal storage units contain liquid salt as the working fluid. On average, the annual hours of use of the installed power are 3,500 h/a.

A large reflector-trough CSP plant is in operation since 1986 at Kramer Junction in the Mojave Desert in California [19]. This facility can generate 150 MW peak output.

The Gemasolar solar thermal plant operated by Torresol Energy O&M in Spain (solar power tower technology) with an installed power of 20 MW may produce 110 GWh/a electric energy [18]. Consequently, this plant achieves an installed power usage of 5,500 h/a. Two examples of installed CSP plants are demonstrated with their technical data in Fig. 2.14.

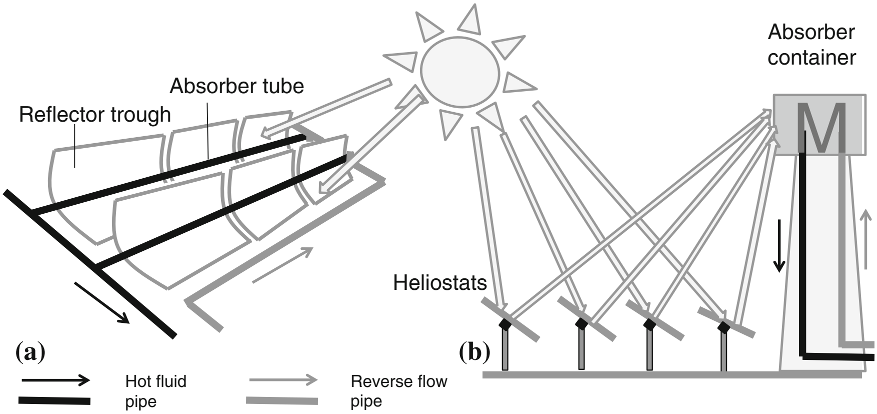


Fig. 2.12 Most commonly applied CSP principles: **a** reflector trough, **b** solar power tower

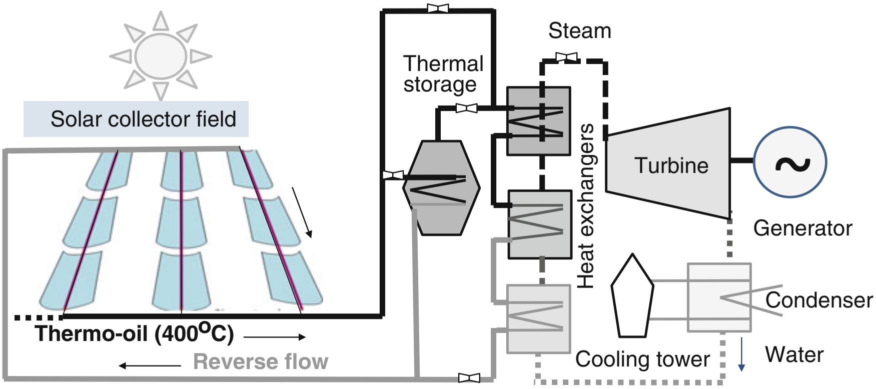


Fig. 2.13 Scheme of a reflector trough based CSP plant with thermal storage

Further technologies of CSP based electricity generation are the Dish—Stirling systems and the upwind generator.

With the Dish—Stirling system, parabolic dishes capture the solar radiation and transfer it to Stirling engines. The concave mirror systems are constructed with diameters of 3–30 m. A Stirling engine is operating by cyclic compression and expansion of air or other gas at different temperature levels. In this way there is a net conversion of heat into mechanical work. This engine drives the electricity generator.

The upwind generator technology is based on the chimney principle. An area of ground is covered by a glass plane. The air under this cover is heated up by solar radiation and as a result of the air expansion the air flows through turbines into the chimney tower that is allocated in the center of the covered area. This principle is simple, but it provides a very low efficiency of about 1 %. A rated power of some 100 MW would require an altitude of 1,000 m and an area of 12 km^2 [7].

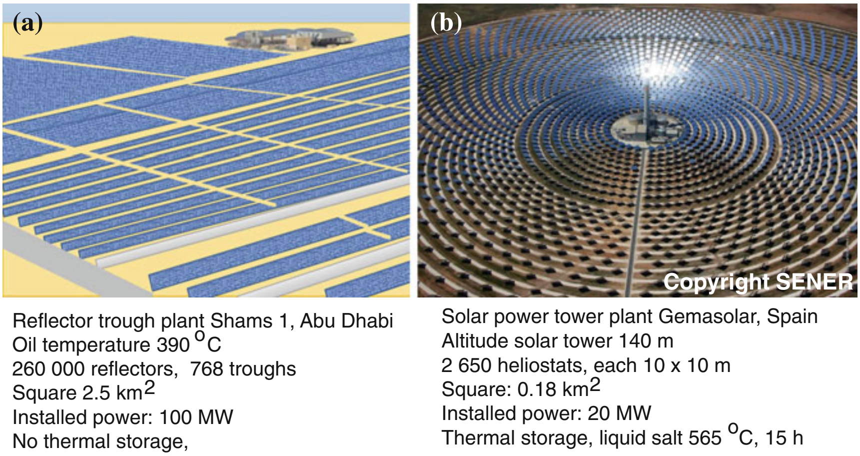


Fig. 2.14 Examples of installed CSP plants: **a** Reflector trough plant [20] **b** Solar power tower plant (*Source* Gemasolar solar thermal plant owned by Torresol Energy © SENER)

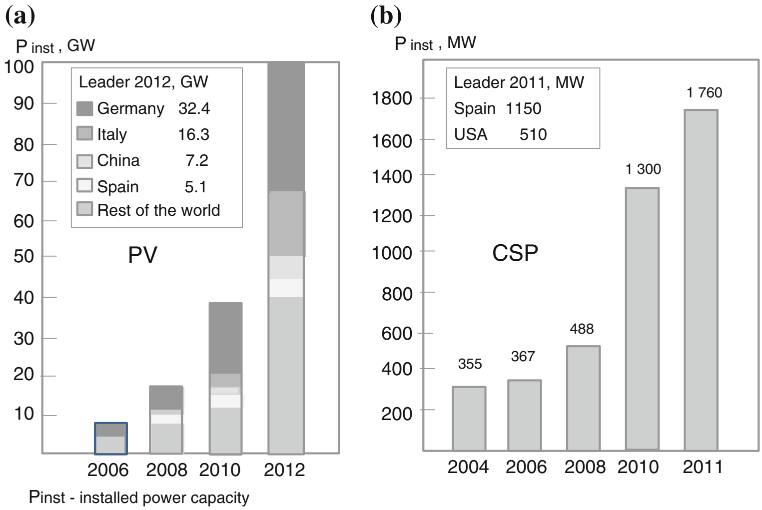


Fig. 2.15 Development of the world capacities of solar electricity generation **a** Photovoltaic (*Source* [21]), **b** Concentrated Solar Power (*Source* [22])

Considering the worldwide power capacity for solar electricity generation, the PV technology is still dominating with about 100 GW of installed PV plants. The overview of the worldwide installed capacity of PV and CSP plants is depicted in Fig. 2.15.

Thanks to a special governmental subsidy scheme, a third of the world's PV capacity was implemented in Germany in 2012.

The leading countries applying the CSP technologies are Spain and the USA.

Table 2.6 CHP technologies based on RES—overview [23]

Parameter	Micro turbine	Gas engine	Gas turbine	Steam turbine	CCGT	Fuel cell
Electric efficiency, %	20–30	25–45	25–40	30–42	40–60	50–70
Electric power, MW	0.025–0.5	0.05–5	3–340	Up to some 100	80–400	0.002–2
RES	Bio gas	Bio gas	Bio gas	Bio mass	Bio gas	Hydrogen
Main thermal applications	Building heat and hot water	Hot water, Industrial steam	Hot water, District heat, Industrial steam	Hot water District heat, Industrial steam	Hot water District heat, Industrial steam	Building heat and hot water

2.3 Cogeneration of Heat and Power Applying Renewable Energy Sources

A significant growth in the shares of cogeneration of heat and power (CHP) is one of the objectives of the European Union (see Sect. 1.1, SET Plan Table 1.1) to increase the energy efficiency.

Some countries introduced supporting schemes offering a bonus added on the market price for electricity in the case of operating a CHP plant. In Germany, for example, the application of the CHP concept in bio-gas power plants became mandatory by law. Consequently, the majority of renewable power plants that operate based on heat production use the CHP technology.

The use of RES in CHP has two positive effects, namely an increase up to 85 % in the overall (electrical and thermal) energy efficiency and a reduction of the CO_2 emissions.

The following RES—CHP technologies are currently being applied:

- Thermal steam power plants based on bio mass combustion,
- Gas turbines fired by bio gas,
- Gas engine driven by bio gas,
- Combined Cycle Gas Turbine (CCGT) using bio gas,
- Geothermal plants with steam turbines,
- Fuel cells.

The main characteristics of the technologies are presented in Table 2.6.

The principle scheme of the CHP plants is presented in Fig. 2.16.

The CHP plants may be optimized for heat or electricity production. The operation with an optimized heat production offers the higher efficiency with a minimum of energy losses. However, the electricity market offers a higher optimization potential according to the economic benefits. The thermal storage unit indicated in Fig. 2.16 is optional. However, the inclusion of thermal storage

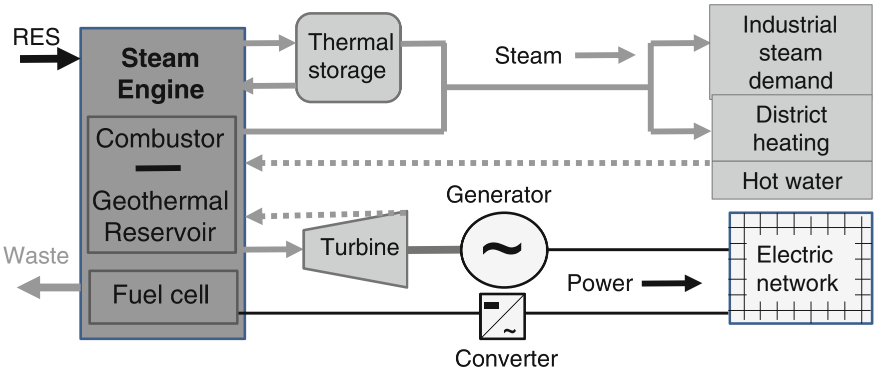


Fig. 2.16 The CHP principle

capabilities allows for a more flexible and economic optimum operation of the electricity generation depending on the related market prices. Thermal storage helps to increase the economic benefits.

2.3.1 Bio Fuel Power Plants

The use of bio fuel provides two major advantages in the sense of the Smart Grid concept:

1. Biological materials contain energy that is derived directly from chlorophyll photosynthesis. Through chlorophyll photosynthesis plants convert energy from the sun, carbon dioxide and water into carbohydrates and oxygen. The plant material itself is the storage of the converted energy. The production of bio fuels by means of biological plant material enables the combustion of biologically renewable material and creates a closed carbon cycle. The closed carbon cycle is self- contained, due to the fact that the carbon dioxide which is released into the atmosphere during combustion will be reabsorbed through subsequent chlorophyll photosynthesis. In contrast, the carbon dioxide in fossil fuels has been sequestered in the earth for many millions of years, the combustion of which increases the overall levels of carbon dioxide in the atmosphere because there is too much CO_2 to be reabsorbed.

Consequently, the bio fuel is being used to replace energy derived from fossil fuels, and thereby reduce emissions of greenhouse gases.

2. Bio fuel is the only renewable energy source that does not depend on the weather and that guarantees a continuous energy generation. The power plants fired by bio fuel are definitely controllable. They can participate on the various electricity related markets without constraints and may compensate the fluctuations of the power generation from wind and sun.

Fig. 2.17 Bio-gas power plant (*Source* Regenerativ-Kraftwerk Harz GmbH and Co.KG)

Table 2.7 Sources of bio fuel

Municipal utilities	Industry	Timber processing	Agriculture
Solid wastes	Industrial wastes	Forest wastes	Animal wastes, digester gas
Sewage sludge	Agro-industrial bi-products	Logging residues	Crop residue, special plant cultivation (e.g. corn, rape)

Heat and power generation in CHPs can be made by direct combustion of solid biomass such as wood chips, dust, bark and shavings. Another practical solution is the gasification of such biomass material. Both conversion paths are the most important for biomass based cogeneration. Figure 2.17 presents a bio gas power plant with included gasification units. The produced bio gas may be filtered and processed in such a way that the quality parameters are in line with the quality of natural gas. Such gasification plants may also feed bio gas into the gas network.

The sources of biomass are quite different and have to be converted in relation to their present form. Sources of biomass can be wastes or residues from biological or industrial processes. Table 2.7 shows a selection of the most important biomass sources that are used for further processing of bio fuels in both forms—as solid bio mass and as bio gas.

By 2012, thousands of bio fuel power plants with a combined capacity of 52 GW were being operated in more than 40 countries throughout the world [24]. The leading countries are the USA, Brazil and Germany.

In Europe alone there are more than 1,000 active biofuel power plants with a combined installed capacity of about 14 GW.

Almost 800 power plants with a capacity of more than 8.7 GW were commissioned between 2007 and 2012, while another 820 plants are slated for construction by 2016 with a power capacity of 12.5 GW [25].

A further benefit of bio gas power plants is that they are able to generate electricity in a combined cycle and, in this way, to increase the plant's electricity efficiency.

In electricity generation the combined cycle is the combination of heat engines that work in tandem with the same source of heat, converting it into mechanical

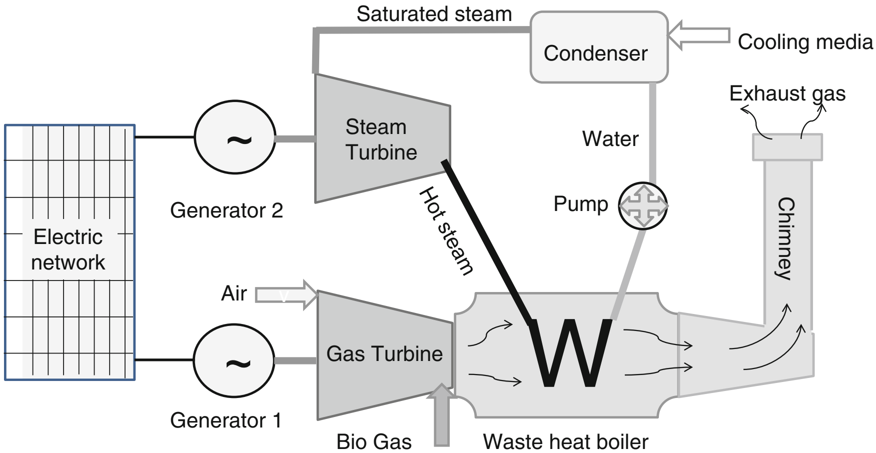


Fig. 2.18 Principle scheme of gas and steam combined cycle

energy, which drives generators. The principle is that the exhaust of one heat engine is used as the heat source for the second, thus extracting more useful energy from the heat and increasing the system's overall efficiency. This works because heat engines are only able to use a portion of the energy from their primary energy sources. The remaining heat caused by combustion is generally wasted.

The combination of two thermodynamic cycles results in improved efficiency and a reduction of fuel costs. For electricity generation, a widely used combination is a gas turbine burning bio gas the heat exhaust of which powers a steam power plant, as depicted in Fig. 2.18.

This is called a Combined Cycle Gas Turbine (CCGT) plant, and can achieve an electric efficiency of around 60 %, in contrast to a single cycle steam power plant which is limited to efficiencies of around 35–42 %. Many new gas power plants in North America and Europe are of this type. For large scale power generation, a typical set would be a 270 MW gas turbine coupled to a 130 MW steam turbine giving a total of 400 MW. A typical power station might consist of between 1 and 6 such sets. The plant size is important for the economy of the plant.

2.3.2 Geothermal Power Plants

Geothermal power plants generate electricity from geothermal energy. Geothermal energy refers to heat within the earth and originates from the residual heat from the formation of the earth and the radioactive decay of isotopes inside the planet, which act as natural nuclear power. Geothermal electricity generation requires transferring the naturally occurring high temperature from deep underground to the surface by fluid circulation.

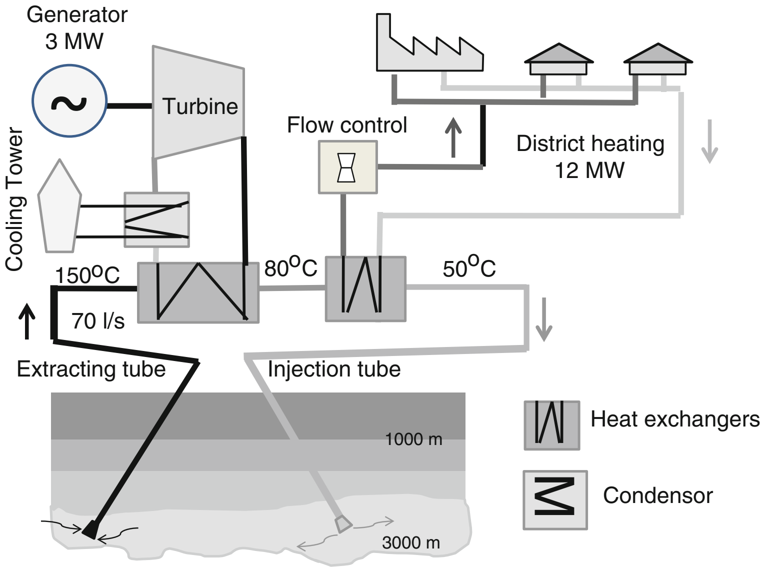


Fig. 2.19 Scheme of the geothermal power station Landau [27]

Geothermal electric plants have, until recently, been built exclusively where high temperature geothermal resources are available near the surface. The development of binary cycle power plants and improvements in drilling and extraction technology may enable enhanced geothermal systems over a much greater geographical range [26].

A binary cycle power plant is a type of geothermal power plant that allows cooler geothermal reservoirs to be used than what is required by traditional steam power plants ($\vartheta > 180$ °C).

With binary cycle geothermal power plants, pumps are used to pump hot water from underground via an extracting tube system, through heat exchangers (for turbine and for thermal energy use); the cooled water is returned to the underground reservoir by injection tubes. A binary fluid with a low boiling point is pumped at high pressure through the turbine heat exchanger, where it is vaporized and then directed through the turbine to drive the generator.

An example of a geothermal CHP plant with indication of the power and temperature parameters is presented in Fig. 2.19 [27].

The International Geothermal Association has reported that 10,715 MW of geothermal power plants were operated worldwide in 24 countries by 2010. The USA is leading the world in geothermal electricity production with 3,086 MW of installed capacity from 77 power plants followed by Indonesia with 1,904 MW of capacity. Geothermal energy covers about 27 % of the electricity demand in Indonesia [28]. The growth of the installed geothermal capacity for electricity generation in recent years (2005–2010) is demonstrated in Table 2.8 by country.

Table 2.8 Newly erected geothermal power capacity in the period 2005–2010 [29]

Country[a]	USA	IDS	Iceland	NZL	TK	ELS	Italy	Kenya	GM	D
P, MW	528	200	373	193	62	53	52	38	19	6

[a] *IDS* Indonesia, *NZL* New Zealand, *TK* Turkey, *ELS* El Salvador, *GM* Guatemala, *D* Germany

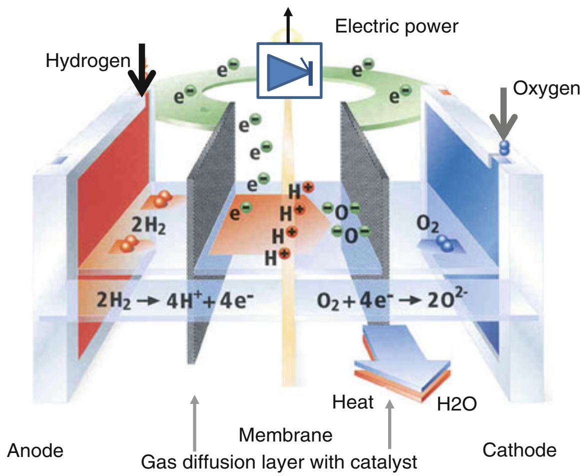


Fig. 2.20 The fuel cell principle of a PEM fuel cell

2.3.3 *Fuel Cells*

A fuel cell is a device that converts the chemical energy from a fuel into electricity through a chemical reaction with oxygen or another oxidizing agent. Hydrogen is the most common fuel, but hydrocarbons such as natural gas and alcohols like methanol are also applicable.

The fuel cell is an efficient energy conversion system that converts the chemical energy of the fuel directly into electricity. With this principle, only one energy conversion step required: chemical energy into electrical energy.

Comparing this single conversion step within the fuel cell with the three conversion steps of a thermoelectric power plant, the fuel cell provides higher efficiency of the energy conversion.

A significantly more efficient use of the chemical energy in the fuel cell of up to 70 % for electricity generation and up to 90 % if applying the CHP technology is achieved.

There are many types of fuel cells, but they all consist of two electrodes (anode–cathode) and an electrolyte that allows charges to move between the two electrodes of the fuel cell.

The fuel cell principle is presented in Fig. 2.20.

This fuel cell is of the Proton-Exchange Membrane (PEM) type that produces, under continuous supply of hydrogen at the anode and oxygen at the cathode, a

Table 2.9 Overview of the fuel cell categories [23]

Fuel cell name	Type	ϑ, °C	Electrolyte	Fuel	Applications
Alkaline	A–FC[a]	20–90	Alkali lye	Hydrogen	Astronautic
LT[b] Proton-Exchange Membrane	LT PEMFC	20–80	Polymer membrane	Hydrogen	Vehicles, CHP 5–500 kW
HT[c] Proton-Exchange Membrane	HT PEMFC	120–180	Polybenzimidazol with phosphoric acid	Hydrogen	CHP 5–500 kW
Direct Methanol	DMFC	60–130	Polymer membrane	Methanol water mix	Electronics for goods and military
Phosphoric Acid	PAFC	160–220	Stabilized phosphoric acid	Hydrogen	CHP 200 kW–1 MW
Molten carbonate	MC–FC	600–700	Molten carbonate solution	Hydrogen	CHP Some MW
Solid oxide	SO–FC	800–1000	Solid ceramic electrolyte	Hydrogen	CHP up to 50 MW

[a] Fuel Cell, [b] Low Temperature, [c] High Temperature

potential difference between these two electrodes. Directly mixing oxygen and hydrogen would be explosive, so the separation of the two gases takes place through the electrolyte. In the PEM fuel cell, the proton exchange membrane is used. This membrane is responsible for the controlled reaction. In addition to the membrane, the two electrodes and the gases, catalysts are necessary to set the reaction going and start the production of electric energy. The catalyst material, mainly platinum, is evaporated onto the electrodes. On the anode side, molecular hydrogen is split into its atomic components, namely, four positively charged hydrogen protons and four negatively charged electrons. Due to the chemical structure of the proton exchange membrane, the porous membrane separates according to the electric charge instead of by the size of the charge carriers (the electron is smaller than the proton, but cannot pass through the membrane channels). The hydrogen proton migrates through the channel structure of the membrane on the other side to the cathode and the electron moves through an external electrical conductor from the anode to the cathode.

The directed external movement of the electron creates electric energy. However, the electron flow through the conductor creates a direct current (DC). The DC power has to be converted into AC power for the electric network access.

Once reaching the cathode through the membrane channels, the protons recombine with the electrons which reached the cathode via the conductor. Both react with the oxygen to create water H_2O.

There are six different types of fuel cells, which are categorized according to the operating temperature and the type of electrolyte. The electrolyte and the fuel also give the name of the fuel cell. Characteristics of the fuel cell types are listed in Table 2.9.

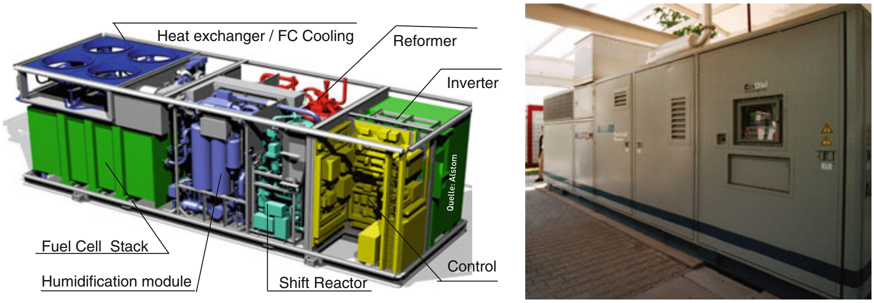


Fig. 2.21 PEM FC for CHP at a swimming hall (*Source* EnBW, project Edison [30])

Low temperature fuel cells, AFC, LT-PEMFC, DMFC and PAFC, operate in a temperature range from 20 to 220 °C. The most well-known type is the PEM fuel cell.

The classical PEM fuel cell operates at temperatures of up to 80 °C and is designated as a low temperature (LT) PEM fuel cell (LT PEMFC). For several years the LT PEMFC has been supplemented by the so-called high temperature (HT) fuel cell (HT PEMFC). This works in the temperature range of 120–180 °C. The main difference lies in the different electrolytes. The benefits of the HT PEMFC compared to the LT PEMFC are the better tolerance to impurities in the gases and the fact that humidification of the reaction gases is not necessary. The main disadvantage of HT PEMFC is primarily due to the higher system complexity.

However, the water management of both LT and HT PEM FCs is crucial to the cell performance: too much water will flood the membrane, too little will dry it; in both cases, power output will drop. Stable PEMFC operation therefore requires a humidification module as an additional system component to solve these issues.

Furthermore, the application of platinum as a catalyst is quite expensive. Therefore, nearly all current PEM fuel cells use platinum particles on porous carbon. Consequently, a main goal of the catalyst design for PEM fuel cells is to increase the catalytic activity of the platinum particles. One method of increasing the performance of platinum catalysts is to optimize the size and shape of the platinum particles.

Another approach of improving the catalyst performance is to reduce its sensitivity to and its poisoning by impurities (e.g. CO) in the primary energy source, which is normally based on hydrocarbon fuels. Therefore, the pure hydrogen gas is produced by a steam reforming process. This is achieved in a special reformer where the steam reacts with the fossil fuel at high temperature. Shift reactors are additionally applied in conjunction with the steam reforming.

The water–gas shift reaction is a chemical reaction in which carbon monoxide reacts with water vapor to form carbon dioxide and hydrogen. The positions of the described components inside a PEMFC are shown in Fig. 2.21.

Direct-methanol fuel cells (DMFCs) are a subcategory of the PEMFC and use methanol as fuel. Their main advantage lies in the ease of transport of methanol, the high energy- density and the liquid stability under all environmental conditions.

However, the energy efficiency for these cells is low. They are targeted especially to portable applications, where energy and power density are more important than efficiency.

Phosphoric acid fuel cells (PAFC) use phosphoric acid as an electrolyte. They were the first fuel cells to be commercialized. Improved stability in performance and low costs have made the PAFC a good candidate for early stationary applications between 100 and 400 kW. Disadvantages include rather low energy—density, the low energy efficiency of 37–42 % and the aggressive electrolyte.

The medium temperature fuel cell MCFC operates in the range of 600–700 °C and has a molten-carbonate electrolyte. Since they are operated at very high temperatures, non-precious metals can be applied as the catalyst, in this way reducing the costs. A high efficiency (about 60 %) is another benefit. When the waste heat is used in a CHP application, the overall fuel efficiencies can be as high as 85 %.

The high temperature fuel cell SOFC (800–1,000 °C) is characterized by a high tolerance against impurities in the gases and has a high efficiency. Due to the extremely high temperature, however, only selected materials fulfill the corresponding requirements.

Because of their low weight, as compared to batteries, and their efficient energy supply, fuel cells are used in the aerospace industry and for submarines as auxiliary power units.

Fuel cell systems can be applied in the stationary sector to supply domestic or industrial systems, as well as in mobile applications for use in vehicles, elevators and motorcycles.

Due to very fast response (rapid energy supply within a few seconds), fuel cell systems also serve as emergency power supplies, such as in hospitals. The electrical power of fuel cells is in the range of a few kW to several MW.

Fuel cells have been introduced for cogeneration of heat and power in a number of projects. Figure 2.21 presents such a PEMFC application within the project "Edison" in Germany [30]. The fuel cell was used for the generation of electricity with an installed power capacity of 100 kW and for the heating of a swimming hall.

However, for the most part, fuel cell systems are not yet economically competitive for the large scale electricity generation in power systems. Only through further cost reductions and long-term stability of the fuel cells, will this technology become usable for the establishment of power plants with significant power capacities. Scientists and experts are intensely working to improve the fuel cell technologies worldwide.

2.4 Electric Energy Storage Systems

2.4.1 Introduction and Categories of Electricity Storage

Electric Energy Storage Systems (EESS) are usually classified by two criteria: the rated power and time of discharge which corresponds with the energy storage capacity. According to these criteria three use cases of EESS may be defined: Power Quality, Power Bridging and Energy Management.

Ensuring Power Quality often requires providing supporting energy to avoid voltage sags, flicker or supply interruptions. The requested power is needed for short time intervals (in the range of seconds and minutes) and may be rated from a few kW to a few MW. Typical EESS for this use case may be based on the technologies of:

- high power fly wheels,
- superconducting magnetic energy storage,
- high power super capacitors,
- several types of batteries.

Power Bridging is mostly used to provide an uninterrupted supply if the main power fails. For example, this use case is applied in hospitals, computer and telecommunication centers. In principle, the DC power supply of the control and protection facilities in substations belongs to the power bridging concept. This use case may be also applied to compensate the fast fluctuations of the wind or solar power generation. Usually, the discharge and the availability times are in the order of minutes. The rated power may gain tenths of MW. Typical EESS technologies for Power Bridging are:

- high energy super capacitors,
- several types of batteries.

Energy Management is mainly used for power balancing, peak shaving, and for energy storage during low price periods and injecting energy during high price periods. This use case will play a significantly growing role in the Smart Grid environment for covering of energy deficits in general and for storing excesses of renewable power. Both the discharge and the charge times are in the order of hours up to days. The rated power may reach the GW order. The EESS technologies suitable for energy management tasks include:

- Pumped—storage hydro-electric power plants (PSHPP),
- compressed air energy storage (CAES),
- high energy batteries of various technologies,
- indirect principles like
  - "power to gas" and
  - a combination of thermal storage/electric heating to ensure a more flexible contribution of CHP plants for energy management.

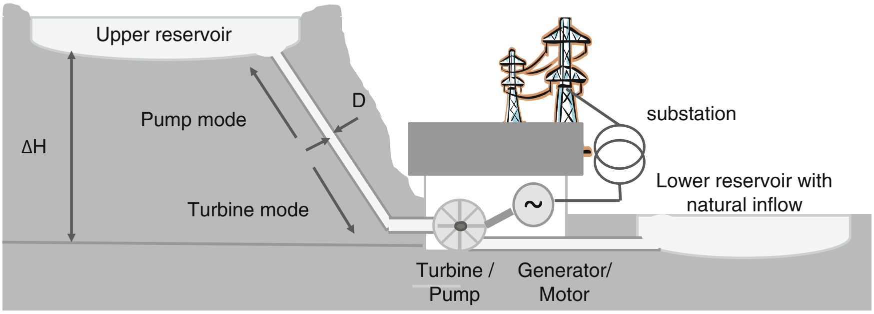


Fig. 2.22 Schematic constellation of a pumped-storage power plant

Because of the growth of more fluctuating power consumption and the increasing installed capacity of volatile renewable energy technologies with weather dependent generation, the need for the use case "Energy Management" is stronger than ever. Further considerations in this chapter will focus on this use case.

2.4.2 Long-Term Bulk Energy Storage Plants

2.4.2.1 Pumped-Storage Hydroelectric Power Plants

Pumped-storage hydroelectric power plants (PSHPP) provide the largest-capacity form of electric energy storage. They consist of upper and lower reservoirs, the connecting tube system, the power plant chamber and the substation as depicted in Fig. 2.21.

The main parameters defining the generation power capability of the plant are the inner diameter D (cross section) of the connecting tubes and the difference of the heights ΔH between the upper reservoir and the allocation of the turbine–pump aggregate. The discharge time and the stored energy depend on the volume of the upper water reservoir (Fig. 2.22).

The optimum operation mode of PSHPP simply consists of using the best turbine time and pump time depending on the demand and market prices to shift as much water as possible between the upper and the lower water reservoirs. This means the pumped-storage hydroelectric power plant operates in a circulation mode. PSHPPs are currently used to store the electric energy during times of weak load and low energy prices by filling up the upper water reservoir and then generate the electric energy during peak load and high price times by using the potential and kinetic energy of the water flowing down through the tubes into the lower reservoir.

Fig. 2.23 Views of the Wendefurth pump storage landscape and of the tube system (*Source* Regenerativ-Kraftwerk Harz GmbH and Co.KG)

Figure 2.23 presents the 80 MW PSHPP Wendefurth located in the Harz Region of Germany with the upper and lower reservoir (Fig. 2.23 left hand side), and the tube system (Fig. 2.23 right hand side).

The power station is equipped with 2 turbines each generating 40 MW of electric power with a water flow of 39 m^3/s and a fall altitude of 126 m. Each generator may be operated as a motor driving the pump mode with a rated power of 36 MW. This example presents only a small PSHPP.

The world largest PSHPPs are currently operated in the USA—Bath County with 3 GW and in China—Huizhou and Gungdong—each with 2.4 GW installed power [31].

The energy efficiency of the PSHPPs varies in practice between 70 and 80 % depending on the age, the technology and the geographical conditions. Excellent pumped-storage hydroelectric power plants reach efficiencies up to 87 % [31].

In the framework of the Smart Grid concept, the role of pump storage plants is significantly increasing. PSHPPs present the only economic means for the long term and bulk storage of electric energy, and they are currently the only type of electric storage in use that is large and dynamic enough to meet the challenges of large scale volatile power in-feeds. PSHPPs are able to store an excess of volatile renewable energy and to provide energy in periods of energy and power deficits (see also Sect. 1.3, Fig. 1.11).

Consequently, the PSHPPs cover more than 99 % of the bulk energy storage worldwide. The global installed power capacity is about 140 GW, and approximately 74 GW of new installations are under construction until 2020 [32]. The limiting factor for this type of storage is the need for certain geographical formations.

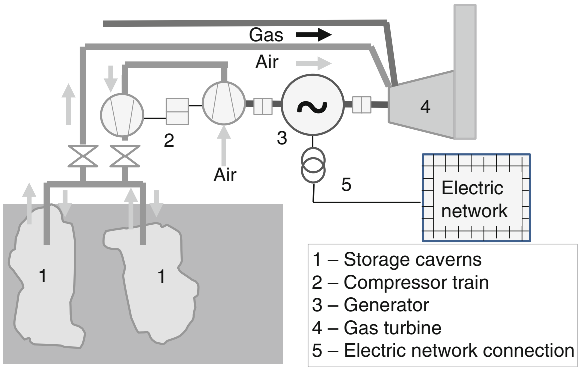


Fig. 2.24 Scheme of the world's first CAES system [33]

2.4.2.2 Compressed Air Energy Storage

Compressed Air Energy Storage (CAES) is a further way to store bulk energy generated at one time for use at another time.

Due to the large volume of air to be compressed, CAES systems often use existing large underground caverns. The main types of caverns suitable for CAES are salt caverns.

A large quantity of energy can be stored with only a small change in pressure. The higher the volume of compressed air the lower the pressure necessary to gain a certain quantity of stored energy. The cavern space can be easily insulated and the air compressed adiabatically with low temperature changes and heat losses according to the compression and expansion processes. (Compression of air generates heat. Expansion requires heat). The efficiency of the storage improves significantly if the heat generated during compression can be stored and then used for the expansion process.

There are several ways in which a CAES system can manage the heat, for example the adiabatic or the isothermal principles.

Adiabatic storage retains the heat produced by compression and returns it to the air when the air is expanded to generate power.

In an isothermal compression process, the air in the system is kept at a constant temperature throughout. This necessarily requires removal of heat from the gas, which otherwise would experience a temperature rise as the result of the compression.

A CAES system as presented in Fig. 2.24 mainly consists of the underground caverns filled with compressed air 1, the compressor train 2, the motor-generator unit 3, the gas turbine 4 and the substation for network connection 5.

The first CAES project was the 321 MW plant in Huntorf, Germany, using a salt dome (1978) [33].

It is based on a combination of a gas turbine and a compressed air combustion engine.

During low-price weak load periods, the motor consumes power to compress and store the air in the underground salt caverns. During peak load periods, the process is reversed and the compressed air is returned to the surface. This air is used twice:

- to burn the gas fuel in the combustion chamber of the gas turbine and
- to provide supplement rotation power for the compressed air combustion engine.

This combination allows a significant enhancement of the efficiency of the overall plant. In a pure gas turbine a significant energy contribution is required for compressing the combustion air. In the CAES power station, however, no compression is needed during turbine operation because the required enthalpy is already included in the compressed air. The expenses for the air compression are transferred to the weak load/low price time periods, and in the peak load period the whole capacity of the gas turbine is available and a significantly higher power output can be offered on the markets.

The world's second CAES plant is a 110 MW plant. It was built in McIntosh, Alabama (1991).

CAES plants are still not widely used. Nevertheless, in recent years several activities were observed [34]:

In December 2012, the construction of a 2 MW near-isothermal CAES project was completed in Gaines, TX, USA. This is the world's third CAES project in operation. The project uses no fuel and has a storage capacity of 500 MWh.

The first adiabatic CAES project is scheduled to begin construction in Germany in 2013. The installed power will be 90 MW and the storage capability will amount to 360 MWh.

In Norton, Ohio, USA, the largest CAES system is planned to be erected for storing 10 million m^3 of compressed air in a former limestone mine at a depth of 700 m. An installed power up to 480 MW will be reached in the first step. The final size of the plant will be 2,500 MW.

2.4.3 Stationary Electric Batteries

An electric battery is a device consisting of electrochemical cells that are able to convert chemical energy into electric energy (discharge) and vice versa (charge). Analogous to the fuel cell, each battery consists of an anode that holds charged ions and a cathode that holds discharged ions and an electrolyte that allows ions to move from anode to cathode during discharge and return during charge. The current flowing between the battery and the electric network goes over the battery connection terminals. Batteries are manufactured from several materials including various metals, carbon, polymers and acids.

Some kinds of battery concepts are already used in the electric network, and newly enhanced battery technologies are candidates for future applications.

Table 2.10 Selected best case characteristics of the most often used batteries [35]

Parameter	Lead acid	NiCd	Li-ion	NaS	ZEBRA	Redox flow	Zinc-bromine
Energy density, kW h/L	0.075	0.15	0.73[a]	0.2	0.16	0.05	0.04
Efficiency per cycle, %	85	75	94	92	83	74	70
Life time battery, years	6	11	14	20	>20	18	7
Cycle durability, n	1,000	2,000	10,000	2,500	15,000	13,000	>2,000
Self-discharge, %/day	0.05	0.4	0.1	0.05	0.05	0.1	0.24
Depth of discharge, %	80	80	80	100	100	100	100
Maintenance, % CAPEX/a	1	1	0.8	0.8	0.8	1.5	1.5
CAPEX converter, €/kW	100	100	100	100	100	600	500
CAPEX battery, €/kW h	120	420	330	170	270	200	100

[a] *Source:* [36]

A special investigation of the German power engineering society (ETG/VDE) analyzed the following battery concepts regarding their applications for energy management [19]:

Lead-acid, nickel–cadmium NiCd, Lithium-ion Li-ion, sodium–sulfur NaS, molten- sodium- nickel- aluminum- chloride NaNiAlCl also called ZEBRA (Zero Emissions Battery Research Activities), redox flow (reduction–oxidation) and zinc–bromine.

There are a number of technical parameters besides the capital and operational expenses that influence the economic efficiency of the battery applications.

This concerns, among others, such parameters as the life time of the battery system, the cycle durability, the charging–discharging efficiency, the self- discharge and the energy density.

Table 2.10 presents an overview of the evaluated best case parameters for the various technologies.

The traditionally used battery system in the past was the lead-acid battery that is mainly applied, for example, in the auxiliary DC- networks of substations (see also Sect. 3.1).

Its basic design incorporates two lead electrodes immersed in a sulfuric acid. During the charge and discharge phases, hydrogen ions (H+) travel in the acid solution between the two electrodes and electrons travel in the external circuit. Lead-acid batteries have the ability to provide high discharge currents, i.e., the cells can maintain a relatively high power-to-weight ratio. However, they have not been applied in energy management because of their short life cycle, the low numbers of charge–discharge cycles and due to the very high environmental issues regarding lead.

The analysis of the technical and economic parameters demonstrates that the NaS, Redox flow and Li-ion batteries are more suitable for energy management applications.

(a) (b)

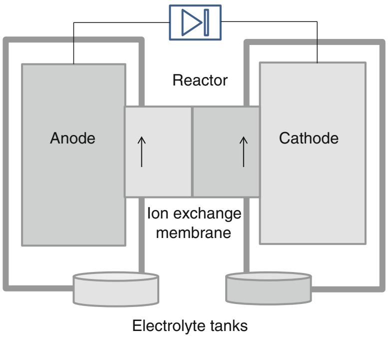


Fig. 2.25 Redox flow battery: **a** principle scheme, **b** 100 kWh battery in operation (*Source* HSE AG)

The sodium–sulfur battery is composed of liquid sodium (Na) and sulfur (S). This type of battery performs an acceptable efficiency of charge/discharge (89–92 %) and has a long life time. It is constructed from inexpensive materials. However, because of the operating temperatures of 300–350 °C and the highly corrosive nature of NaS, such batteries are more suitable for large-scale non-mobile applications, as is requested for energy management.

The NaS—battery technology has found a broader application in Japan [37]. The first large-scale prototype field testing took place at a substation of Tokyo Electric Power Company (TEPCO) between 1993 and 1996, using 3 × 2 MW, 6.6 kV battery banks. Based on the results from this pilot project, improved battery modules were developed and were made commercially available in 2000.

As of 2007, 165 MW of capacity were installed in Japan and, in 2008, the manufacturer announced a plan to expand its NaS factory output from 90 MW a year to 150 MW a year.

For example, Japan Wind Development opened a 51 MW wind farm that incorporates a 34 MW NaS battery system at Futamata in Aomori Prefecture in May 2008.

There are also NaS applications in the USA. For example, in 2010 in Presidio, Texas the world's largest NaS battery was constructed to provide power when the city's connection to the Texas interconnected network is disturbed.

The Redox flow battery is a reversible fuel cell in which all electro-active components are dissolved in the electrolyte. The energy of the redox flow battery is fully decoupled from the power because the energy is related to the electrolyte volume and the power is related to the surface area of the electrode. The electrolyte flows through the cell core and converts its chemical energy into electrical energy. Additional electrolytes can be pumped from storage tanks outside the cell core allowing a rapid recharge. Modern flow batteries generally consist of two electrolyte systems as shown in Fig. 2.25.

The redox flow battery can offer almost unlimited capacity by using larger and larger storage tanks, it can be left completely discharged for long periods with no damage and it can be recharged simply by replacing the electrolyte if no power source is available to charge it. Flow batteries are normally designed for relatively large (e.g. 10 MWh) stationary applications.

The lithium-ion battery family is based on the principle that the lithium ions move between the anode and cathode of the cell to carry the charges. The cathodes are composed of metal oxide containing lithium particles, while the anodes are made of layered graphite carbon. The electrolyte is generally made of lithium salts dissolved in organic compounds. During the charging phase, lithium atoms at the cathode become ions and traverse the electrolyte separator to the carbon anode. Upon reaching the anode, the lithium ions combine with electrons and are deposited between the carbon layers as lithium atoms. During the discharge phase, the reverse process occurs: The lithium atoms lose electrons to the anode and travel back as ions to the cathode.

Li-ion batteries are characterized by light weight, high energy density, high efficiency and low self-discharge rates. To provide more power, connecting many small batteries in a parallel circuit is more efficient.

Li-ion batteries are currently used in portable devices, electric vehicles and electric bikes. In the framework of the European project Web2Energy a number of Li-ion batteries were installed in 20/0.4 kV transformer terminals and in volatile renewable power plants (see also Sect. 9.3.1).

However, lithium-ion batteries can be dangerous under some conditions since they contain a flammable electrolyte and are also kept pressurized. This requires high quality standards for these batteries consisting of many supplement safety features.

The application of stationary batteries for energy management applications throughout the world is still limited due to economic reasons. The most battery storage systems are generally still expensive. However, it is expected that some of the technologies (e.g. high temperature batteries like NaS) are becoming competitive with pumped storage systems. Figure 2.26 shows the estimated operational expenses (OPEX) of different battery systems for energy management applications.

The right handed ends of the beams show the OPEX status in 2008 and the left handed ends demonstrate the expected reductions caused by technological improvements and volume effects.

2.4.4 "Power to Gas" by Electrolysis

In some countries, the ambitious targets regarding the significant growth of volatile of renewable electricity generation are accompanied with periodic excesses of renewable energy as shown in Sect. 1.3. When the contribution of volatile RES becomes higher than 20 % of the total consumption, the external storage will

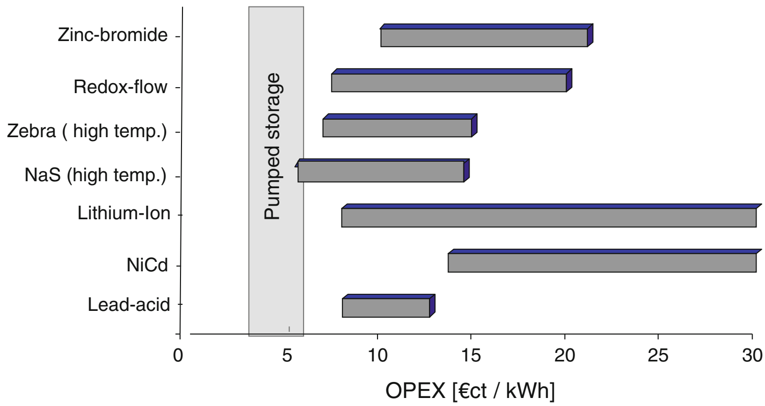


Fig. 2.26 OPEX of stationary batteries—status 2008 and development expectations [35]

become important. If the surplus of electricity may be used to produce hydrogen and other fuel gases, then it can be utilized fully whenever there is a demand. The production of fuel gases will be an instrument to utilize the excesses of available energy.

The hydrogen and other gases produced by electrolysis can be used as a fuel for powering combustion engines or for fuel cells. In this sense, hydrogen is also being developed as an electrical power storage medium. Hydrogen is not a primary energy source because it must first be produced by other energy sources for the application as a fuel in electricity generation.

However, the energy balance of the hydrogen production is negative, i.e. the energy input for the electrolysis is higher than the energy that can be generated afterwards. But, as a storage medium, hydrogen may be a significant factor in using renewable energies.

Electrolysis is a method of using a direct electric current (DC) to drive an otherwise non-spontaneous chemical reaction. The key process of electrolysis is the interchange of atoms and ions by the removal or addition of electrons from the external circuit. The desired products of electrolysis are often in a different physical state from the electrolyte and can be removed by physical processes.

The most important use of electrolysis of water is to produce hydrogen by separation into hydrogen and oxide: ($2\,H_2O \rightarrow 2\,H_2\,(g) + O_2\,(g)$). These gaseous products separate from the electrolyte and are collected.

Large quantities of gaseous hydrogen can be stored in the underground for many years without any difficulties. The storage of large quantities of hydrogen in underground caverns, salt domes and depleted oil or gas fields can function as energy storage, which is essential for the hydrogen economy. By using a turbo-expander, the electricity needs for compressed storage at 200 bars amounts to 2.1 % of the energy content.

The "power to gas" processes and the application of the products are demonstrated in Fig. 2.27.

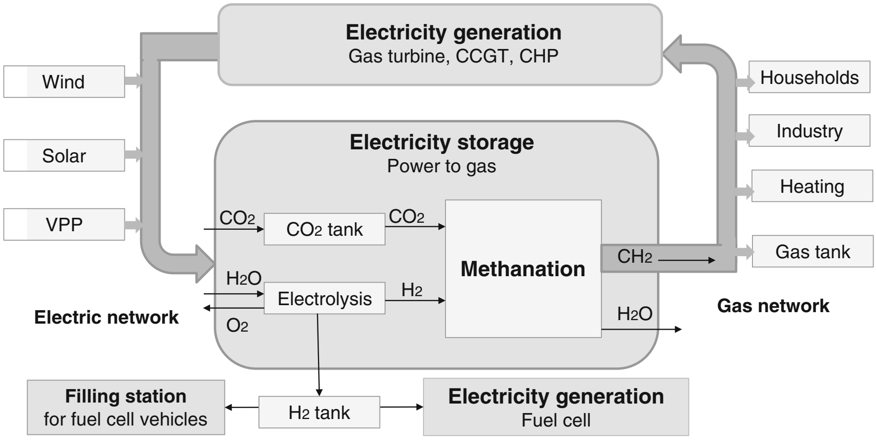


Fig. 2.27 Power to gas electricity storage and the gas application concept

The power to gas process for this concept is performed in a two- step approach. In the first step hydrogen is produced in the electrolysis process. The H_2 can be partially filled into tanks and used either in filling stations for fuel cell driven cars and or in fuel cells for electricity generation.

Secondly, a part of the hydrogen will be used for methanation. Methanation is a physical–chemical process to generate methane from a mixture of CO_2 and H_2. This process is used for the generation of a bio gas substitute, which can be fed into the gas grid and substituted for natural gas.

Finally, methane can be used to supply various gas consumers and as a fuel for electricity generation.

The concept "power to gas" is not widely used because of the negative energy balance. So far only small applications have been introduced in special supply projects [38]:

For example, the small Norwegian island municipality Utsira is supplied by an energy system including wind power plants and a storage system consisting of an electrolysis unit, a compressed air storage system, a fuel cell and a hydrogen turbine.

A similar pilot project using wind turbines and hydrogen generators was undertaken from 2007 in the remote island community of Ramea, in Newfoundland and Labrador, Canada.

Demonstration plants have also been constructed in France and Denmark. Since 2009, a number of activities have arisen in Germany.

The first 25 kW pilot plant for the production of methane started continuous operation in Stuttgart in 2009. This plant absorbs CO_2 from the environment. A second demonstration project was completed in 2011 in the region of Hunsrück.

In 2012, a 500 kW electrolysis unit was combined with 3 wind power plants of 2 MW each in the Uckermark region. A number of additional plants with a larger size up to the order of MWs have been under construction since 2013.

2.4.5 Electric Energy Management by Thermal Storage

Thermal storage consists of the temporary production and storage of heat for a later use.

The expenses for thermal storage are lower than for electricity storage. Wherever volatile renewable energy sources reach high levels of power system penetration, thermal storage becomes one option to contribute for energy management and provide reliable energy supplies. Therefore, thermal storage will play a growing role in the electric energy management in different ways.

For example, CSP plants use thermal storage to guarantee continuous electricity generation even in periods of darkness as considered in Sect. 2.2.2.

A further way consists in using thermal storage for cooling, especially in summer time. An example of the storage of "cold" heat removal for later application is electric ice making during the weak load time hours for use during the hot peak hours and to save energy for air-conditioning in malls, food stores or administrative buildings and for cooling in cold storage chambers. This principle can also be used to compensate an excess of electric energy and to save energy for cooling in periods of weak renewable electricity generation.

Thermal storage is also used in significant volumes in night heating units that demand electricity during periods of weak load. Such units contain high-density ceramic bricks heated to a high temperature with electricity, and well insulated to release heat over a number of hours.

A combination of thermal storage, electric heating and solar heat generation is used also for municipal district heating systems. The basic heat load is generated by solar heat collectors that also feed an excess of thermal energy into storage units which provide heat in the period of darkness. Heat pumps or electric heaters provide peak heat demand and back-up for the solar heat production. They are also used in times of wind energy excess to heat up the thermal storage units.

New ways to coordinate the electricity generation, the heat production and thermal storage in the context of CHP plants has been the topic of broad discussions in recent years.

CHP plants provide a significant share of the annual electricity generation in Europe. A further growth up to 21 % by 2030 is seen as a potential of the "strategic energy technology" plan of the European Commission (see Sect. 1.1, Table 1.1).

For efficiency reasons, the CHP plants are mainly scheduled in accordance with the heat demand, which depends on the weather conditions and is significantly reduced in the summer time when only the provision of hot water and industrial heat is required. A typical heat demand schedule is depicted in Fig. 2.28.

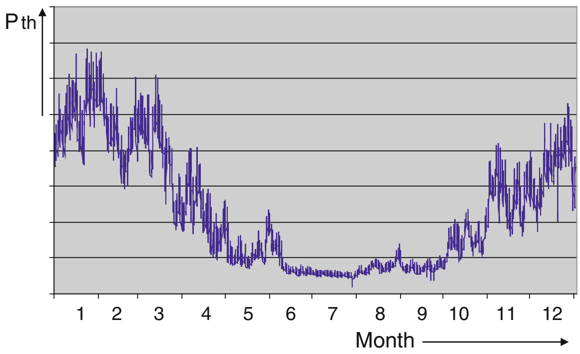


Fig. 2.28 Typical annual heat demand profile for Central Europe

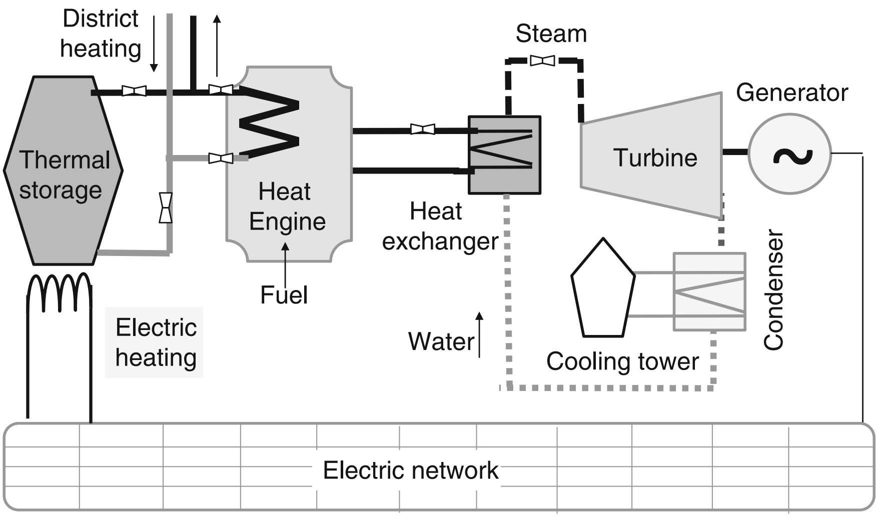


Fig. 2.29 Extended CHP scheme with thermal storage and electric heating

The introduction of thermal storage units into the CHP systems will allow a much more flexible scheduling of the CHP with a focus on the electricity market. Furthermore, the combination of electric heating and thermal storage may play a significant role in the energy management of the future. The related scheme extension of a CHP plant is presented in Fig. 2.29.

This extension provides the following opportunities:

- The CHP plant produces electric power that is market driven in high price/high demand periods and is independent of the thermal power schedule. The excess of thermal energy will be stored.
- In low price/low demand periods the electricity generation of the CHP plant is shut down and the heat demand is covered by the thermal storage.

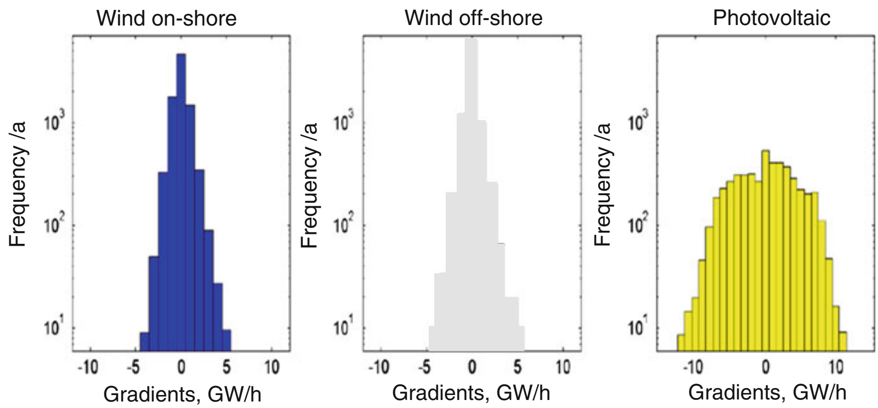


Fig. 2.30 Frequency of fluctuation gradients—energy mix scenario Germany 2020 [16]

- Excesses of renewable electricity production may be compensated by electric heating.

The CHP plant operator benefits from the optimum operation according to the market prices of electricity and heat. Furthermore, this form of flexible CHP management supports the reliable network operations.

2.5 Enhanced Flexibility Requirements for Controllable Power Plants

The compensation management of the fluctuations of volatile renewable electricity generation requires the coordinated operation of all definitely controllable sources of power generation and demand: power plants, storage plants and demand side management DSM.

The wind power generation of individual power plants is often varying between 0 and 85 % of the installed rated power [16].

The PV power output is restricted to the daylight period and may also fluctuate during the day when cloud shifting causes the rapid change of the solar radiation.

The main challenges consist in the compensation of the rapid changing fluctuations with extremely high gradients.

The gradients of the power fluctuations were investigated in the VDE study [16] for onshore wind power, offshore wind power and PV solar power. The gradient distributions are presented in Fig. 2.30 for Germany according to the planned energy mix in 2020. Germany has to face special high compensation requirements due to the large scale shares of PV and wind power plants. The contributions of the installed power of volatile RES according to the peak power demand reached more than 35 % for each—PV and wind power. Further significant growth of the shares is planned according to the concepts of the German governments (see also Sect. 1.3).

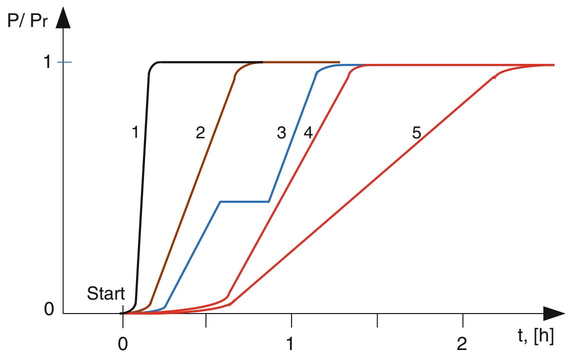


Fig. 2.31 Hot start-up duration of power generation technologies [16]

Wind energy is created in the space gradient field of the air pressure travelling with the extension speed of the weather front. In this context, the maximal fluctuation gradients are relatively low and range between −4.5 and +5.5 GW/h.

The bandwidth of gradients is significantly higher for PV power. The PV electricity generation is synchronous with the solar radiation. During the course of a year gradients of up to 12 GW/h have to be expected. The frequency of such events is 10–15 times per year [16].

Traditional power plants and other definitely controllable generators or loads have to be able to compensate such gradients and to provide quick start up capabilities.

A comparison of the start- up capabilities of different fuel fired generation technologies is presented in Fig. 2.31.

Gas turbines are able to reach their rated power within 5–10 min. Flexible combined cycle gas turbines achieve their rated power within 30 min. The standard CCGT plants achieve the rated power stepwise: first the gas turbine and then the steam turbine in about 1 h. Coal fired thermoelectric power plants require between 1 and 3 h.

A short start-up duration is one of the requested features to meet the fluctuation challenges.

The flexible controllability of the power plant includes further parameters like the power gradient, the flexibility interval and the minimum power generation requested for a stable operation.

These parameters are presented in Table 2.11 in three categories:

- A—current value corresponding with the optimum operation conditions,
- B—current enhanced value that may cause higher risks of equipment damage,
- C—technical potential of innovations.

The growing shares of RES means that RES generation will increasingly substitute the fuel fired power plants in the daily generation schedules. However, the flexible reaction to fluctuations caused by RES requires the fast availability of

Table 2.11 Flexibility characteristics of fuel fired power plants [16]

Characteristic	Hard coal			Lignite coal			CCGT			GT		
	A	B	C	A	B	C	A	B	C	A	B	C
Power gradient % P_r/min	1.5	4	6	1	2.5	4	2	4	8	8	12	15
Flexibility interval, % P_r	40–90			50–90			40[a]–90			40[a]–90		
Generation minimum, % P_r	40	25	20	60	50	40	50	40	30	50	40	20
Hot start-up<8[b] h, h	3	2.5	2	6	4	2	1.5	1	0.5		<0.1	
Cold start-up>48[b] h, h	10	5	4	10	8	6	4	3	2		<0.1	

[a] restricted by emission limits for continuous operation
[b] still stand

certain volumes of control power from power plants operated at the minimum generation level. However, operation at reduced power decreases the efficiency of the power plants.

Consequently, the flexibility of the remaining thermoelectric power generation requires:

- high power control gradients without reduction of the plant life time,
- the availability of high power gradients within the whole flexibility interval,
- the achievement of a minimum generation level of 20 %,
- maintaining high efficiency even under reduced generation conditions.

The annual hours of operation at rated power will be significantly reduced. Traditionally this parameter reached up to 8,000 h/a. The growing share of RES has already reduced the thermoelectric power plant operation at rated power to 1,500–3,000 h. The optimization of the operational conditions at reduced power will be a new task for the engineering of the power plant assets and their interaction.

Another economic challenge concerns the motivation for investment to construct and operate new power plants. This challenge will change the pricing conditions and will require the trade of "power gradient products". In this case, the power stations have to provide a stable power control gradient within a certain time interval which is limited by the maximum and minimum power of the plant. If one of the above mentioned operation points is achieved the power plants can continue to generate the related power. Further demand for changing power has to be performed by additional aggregates.

The general rule for the management of gradient products is: as higher gradients are performed by the aggregates, less rated power is required to achieve the requested gradient, but, at the same time, the limitations of the flexibility interval are reached much faster. The number of power plants operating at minimum power may be lower when high gradients are used than when small gradients are used.

On the other hand, the time interval for the gradient provision will be shorter. The trade of "gradient products" has to consider both aspects—the gradient and the requested duration of availability.

To conclude the considerations in both Chaps. 1 and 2 it can be stated:

The Smart Grid concept requires a significant enhancement of flexibility regarding the electricity generation processes and the power system operations. Furthermore, it is necessary that the generation process becomes "Smart".

Both the Smart Grid and Smart Generation processes will ensure the sustainable and environmentally friendly electric power supply of the future. They will also lead to enormous technical developments in this field.

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Chapter 3
Modern Technologies and the Smart Grid Challenges in Transmission Networks

3.1 Substations: The Network Nodes

Electric power flows through several substations at different voltage levels on its way between the bulk power stations and the end consumers.

The networks at the transmission and sub-transmission level are always mesh operated. The substations perform the nodes of the meshed networks and they connect two or more transmission lines. The simplest case is when all transmission lines have the same voltage. However, typically, the substations transform voltage from high to low and/or vice versa. Substations may perform any of several other important functions like:

- voltage control,
- reactive power control or power factor correction,
- power flow control by phase shifting transformers or power electronic plants,
- UHV, EHV or HV DC/AC conversion to connect High Voltage DC (HVDC) lines,
- connection of two un-synchronous power systems by UHV/EHV/HV DC coupling.

Transmission and sub-transmission substations can range from small to large configurations.

A small "switching substation" may contain little more than one busbar plus some feeders. Large transmission substations, on the other hand, can cover a large area as shown in Fig. 3.1 with multiple voltage levels, many circuit breakers and a large amount of protection and control equipment (voltage and current transformers, automation and control systems).

This chapter is mainly based on the lectures "Electricity grids", "Energy automation" and "High voltage technologies" within the education program "Power transmission and distribution—the technologies at a glance", which were compiled and held by the author Dr. B. M Buchholz at the Siemens Power Academy until 2009 [1]. The examples in the Figures are partially presenting products of the ABB AG and the Siemens AG. Other vendors offer similar products with comparable functions and characteristics.

B. M. Buchholz and Z. Styczynski, *Smart Grids – Fundamentals and Technologies in Electricity Networks*, DOI: 10.1007/978-3-642-45120-1_3,

Fig. 3.1 View of an open air EHV/HV substation (*Source* Siemens AG)

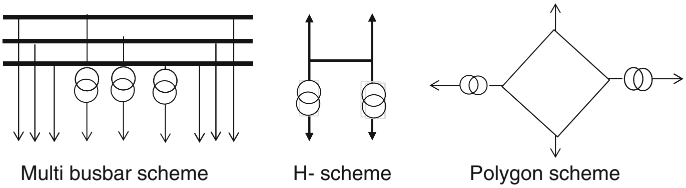


Fig. 3.2 Substation scheme alternatives

3.1.1 Schemes and Components of Transmission Substations

The variety of substation configurations is demonstrated in Fig. 3.2.

The multi-busbar substation configuration is applied in the majority of substations in Central Europe. It requires higher efforts compared to other schemes but it provides the best flexibility, reliability and security parameters. The number of busbars may vary from one up to four (three main and one bypass busbar). The H-scheme is widely applied in HV networks. Polygon schemes are cost effective but the flexibility to perform various configuration alternatives is limited.

Figure 3.3 demonstrates a double busbar (1, 2) scheme with two lines and two transformers. The busbars 1 and 2 may be connected by the cross coupling link containing a circuit breaker that can be tripped by the assigned protection in case of faults in one of the busbar sections. Each busbar can be split into the sections A and B by the lengthwise isolators. In this way, this scheme offers several

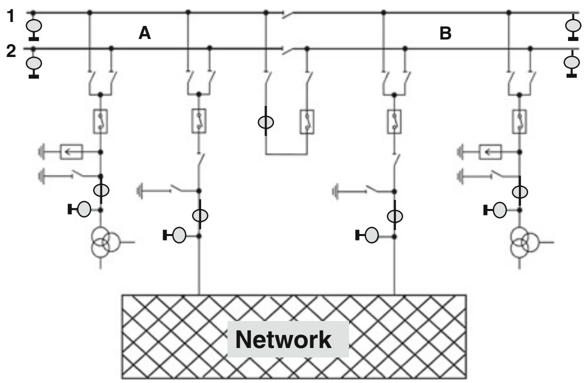


Fig. 3.3 The double busbar scheme and its equipment

configuration variants which is convenient for the restricted operations after fault trips and for the switching off, grounding and short-circuiting of a substation section to perform maintenance work.

Each network element (line, transformer, coupling, voltage transformer) connected to the busbars builds a switch bay. The switch bays are equipped with several primary devices (dimensioned for the primary voltages and currents) and secondary devices for control, measurement and protection. The overview of the primary devices is explained in Table 3.1.

The transformer and line feeders may be connected by the busbar isolators to either busbar 1 or busbar 2. The line feeders are equipped with a line isolator and a grounding switch. They are used for separation and grounding if maintenance work is being done along the line.

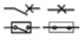
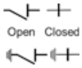
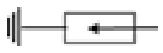
Each busbar section and the feeders are outfitted with voltage transformers delivering rated secondary voltages of 100 V AC. The voltage measurements are used for:

- Monitoring and recording of the voltages,
- Protection devices like distance, voltage or frequency protection,
- Synchronism-check before connecting a feeder to the busbar,
- Voltage control.

The current transformers transform the high primary currents into the secondary currents with various rated ratios in accordance with the load currents (for example 2000/1A). The rated secondary currents may be 1 or 5 A. Current transformers are normally equipped with two cores—one for measurements and one for protection purposes. In fault conditions much higher currents may occur and the reach of the measurement core cannot provide the short circuit currents. Otherwise, the protection core is not able to provide accurate current measurements for low currents.

The protection, regulation and control devices apply the transformed secondary values for their functions. Therefore, these devices make up the category known as secondary technology. The transformers, the switch devices and the busbars are

Table 3.1 Devices applied in the switch bays

Device	Symbols	Function
Circuit breaker (CB)		Can interrupt short-circuit currents e.g. "I_{sc}" = 70 kA, V_r = 380 kV
Isolator or Disconnector Ground switch		Visible disconnection, saves CB's Cannot switch currents Connects phases to ground Cannot switch under voltage
Surge arrestor		Limits atmospheric or switching over-voltages
Current transformer		Transforms high currents to 1/5 A
Voltage transformer		Transforms EHV/UHV/HV/MV to 100/110 V

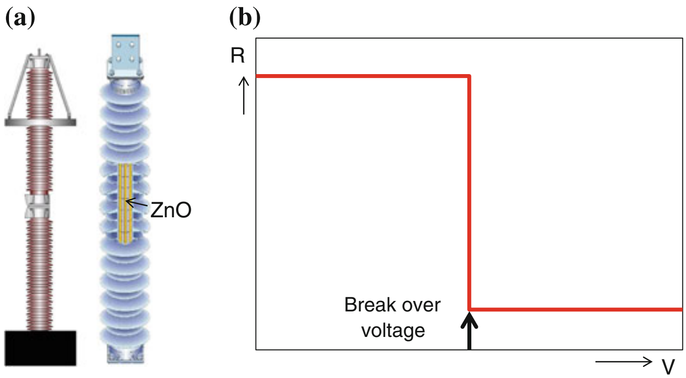


Fig. 3.4 **a** Surge arrestor construction and **b** the conducting characteristic of ZnO

dimensioned for the high primary voltages and currents, and they belong to the primary technology category.

The surge arrestors are connected to the line feeders. Surge arrestors are applied to limit transient high voltage waves to a level which is below the insulation withstand level of the equipment and thereby eliminate the danger of transient high voltage. Transient over-voltages may occur as the result of atmospheric lightning or switching operations. Surge arresters built for power substations consist of either porcelain, silicon or gas insulated metallic tube, typically filled with disks of zinc oxide as shown in Fig. 3.4a. The conducting attributes of zinc oxide depend on the connected voltage. If the voltage exceeds the break-over voltage the resistance of the material decreases significantly and the over voltage will be shorted to the ground (Fig. 3.4b). Surge arresters are rated by the peak current they can withstand, the amount of energy they can absorb and the break-over voltage that they require to begin conduction. The allocation of surge arrestors is defined in

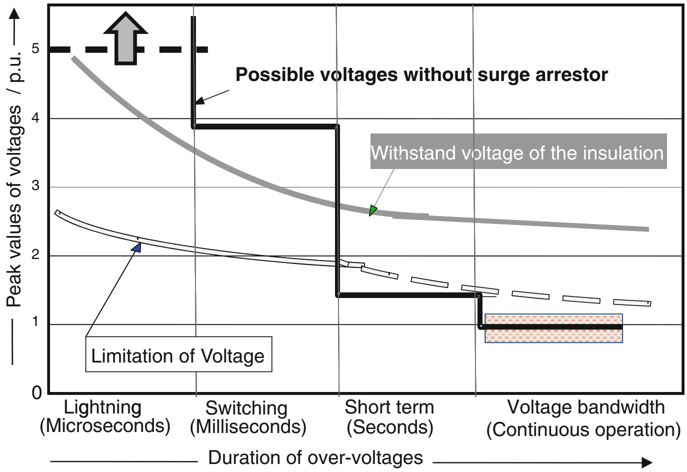


Fig. 3.5 The insulation withstand voltage dependency and the overvoltage limitation

Fig. 3.6 Surge arrestor protecting a large transformer against transient over-voltages (*Source* Siemens AG)

a special investigation known as insulation coordination. Figure 3.5 demonstrates the principle of the insulation coordination. The higher the insulation withstand-ability is, the shorter the over-voltage duration. For example, lightning voltages have the shortest duration but they may exceed the withstand-ability many times over. The insulation coordination ensures that the over-voltages are limited everywhere in the substation below the withstand voltages.

Special attention is directed to the most valuable assets, namely the transformers. Figure 3.6 shows the allocation of a surge arrestor before the EHV

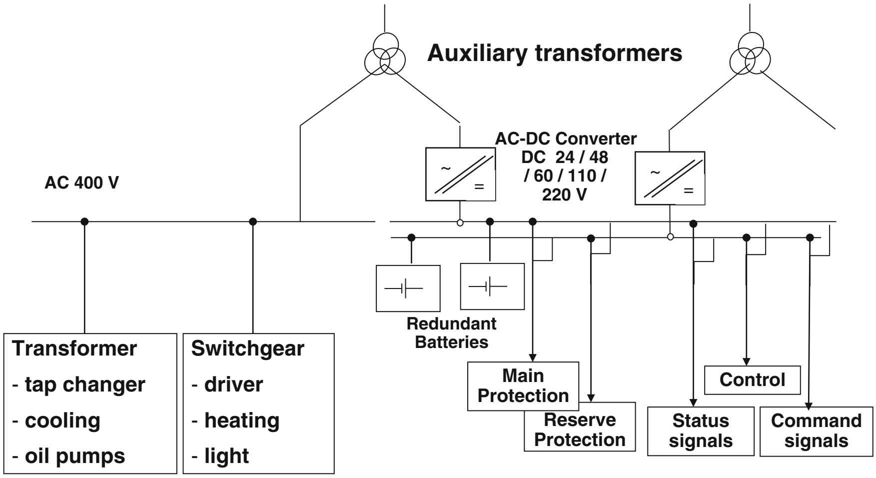


Fig. 3.7 Principle scheme of the auxiliary network in substations

bushings of a 400 kV/1000 MVA transformer. In Fig. 3.3 presented above, a three winding transformer is shown. The third winding is used if a third voltage level has to be connected (e.g. 220/110/30 kV) or if the auxiliary network of the substation is connected to the tertiary winding (e.g. 110/20/0.4 kV). If the tertiary winding is not available special auxiliary transformers have to be installed.

The auxiliary network is used for the electricity supply of all mechanisms required for the substation control, e.g. the drives of the switch devices or the tap changer, the cooling fans or the oil pumps of the transformers as presented in Fig. 3.7.

Furthermore, a redundant DC network containing storage batteries for an uninterruptable supply is connected to the ancillary network by AC/DC converters. The DC network supplies the control and protection devices.

3.1.2 *Innovative Air Insulated Switchgear Technology*

The most valuable device of the switchgear is the circuit breaker. The circuit breaker has to interrupt high short circuit currents which may reach values up to 80 kA in the 400 kV networks. The interruption of such high currents is not simple and requires special arc quenching mechanisms.

In the past various types of circuit breakers were installed in the substations such as the bulk oil tank circuit breaker, the minimum oil circuit breaker or the air blast circuit breaker. In the last few decades there has been a shift from AIS to using only gas insulated circuit breakers in the UHV, EHV and HV substations. They offer the most cost efficient solution with regard to purchase, installation,

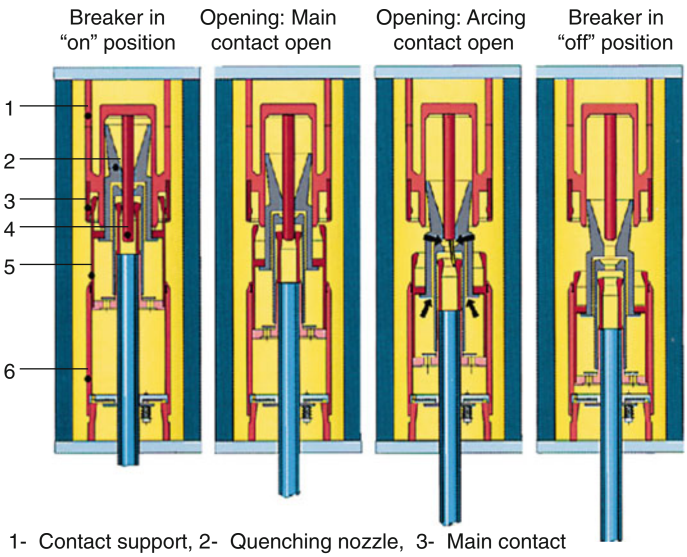


Fig. 3.8 Arc Quenching principle of the self-compression type interrupter unit (*Source* Siemens AG)

maintenance and reliability. The insulation medium is SF_6 (sulfur hexafluoride), which is an inert, nontoxic, colorless tasteless and non-flammable gas. It is about five times as dense as air and provides an extremely high insulation capability at pressures from 400 to 600 kPa. Furthermore, SF_6 is about 100 times better than air for interrupting arcs.

Figure 3.8 demonstrates the arc quenching principle of a "self-compression type" interrupter unit. This unit has two contacts. The main contact builds the cross section for the long term current flow. During the interruption procedure the main contact is interrupted first while the arcing contact interrupts later and will be stressed by the arc. The movement of the contact cylinder leads to the compression of the enclosed gas which is now streaming under high pressure through the arc into the interrupter container. This procedure interrupts the arc current flow and the circuit breaker switches to the off-position—normally within 40–60 ms.

The movement of the contact cylinder is driven by a spring storage mechanism as presented in Fig. 3.9.

This drive contains two springs—one for switching-off and one for switching-on. The springs have multi discharging positions to allow fast switch sequences for auto-reclosing after fault trips. The charging of the springs is performed by a motor drive.

Figure 3.10 presents an SF_6 circuit breaker in an open air 400 kV switch bay. Here two interrupter units are connected serially to achieve a secure quenching. The boxes near the bottom contain the drive mechanism and the bay control facilities.

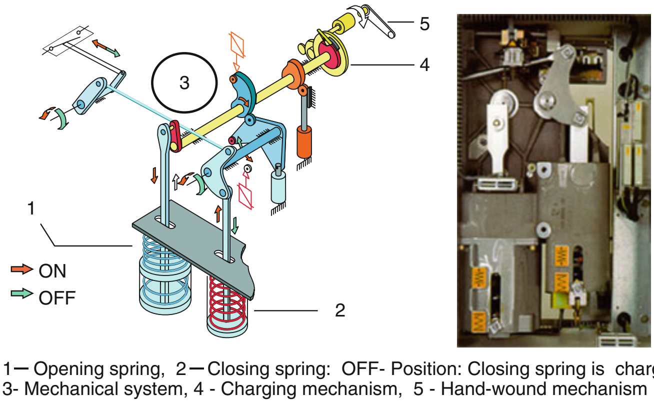


Fig. 3.9 Spring storage drive for circuit breakers (*Source* Siemens AG)

Fig. 3.10 SF_6 circuit breaker in a 400 kV substation (*Source* Siemens AG)

The design of the circuit breakers depends on the short circuit power to be interrupted which is a product of the rated voltage and the rated short circuit breaking current. In Fig. 3.11 it can be seen that up to four interrupter units have to be connected serially to break short circuits at the 750 kV level with short circuit currents up to 80 kA.

Isolators may have various disconnection mechanisms. In the HV level often the horizontal disconnection is applied (Fig. 3.12a), while the EHV substations prefer the pantograph type isolators (Fig. 3.12b). In Fig. 3.12a the horizontal isolator is equipped with an integrated surge arrestor.

The isolators are motor driven and the opening or closing operations may require a few seconds.

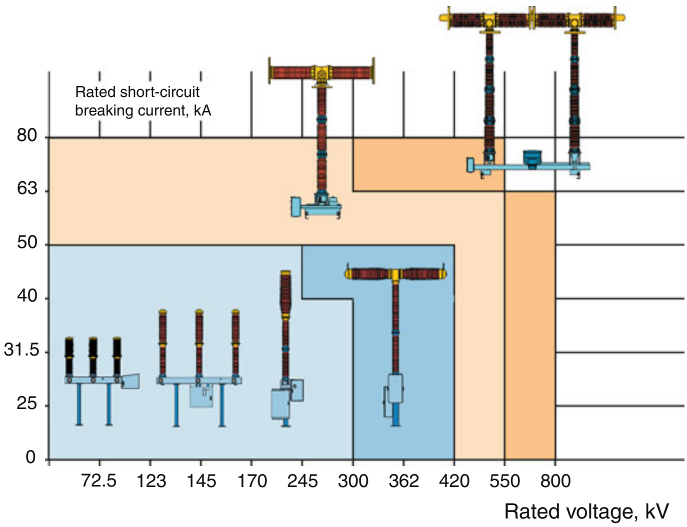


Fig. 3.11 Design of circuit breaker classes (*Source* Siemens AG)

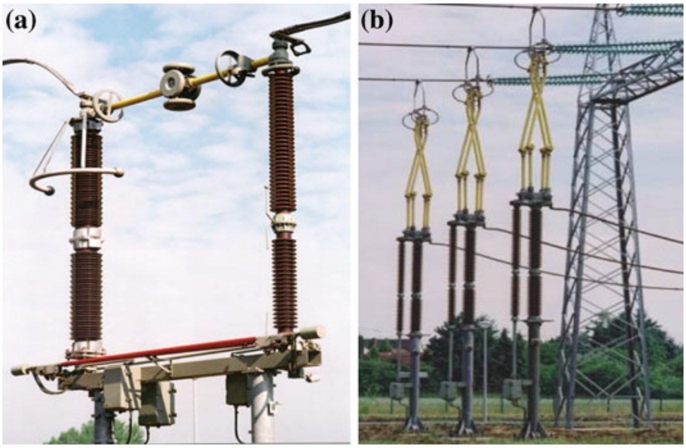


Fig. 3.12 The two main types of isolators: **a** Horizontal isolator (with integrated surge arrestor), **b** Pantograph isolator (*Source* Siemens AG)

The consideration of latency is important for the interlocking mechanisms. The interlocking ensures that an isolator cannot be switched during current loading and a ground switch is not operated when the feeder is still connected to a voltage source. The interlocking algorithms have to block any further operation in the substations which can affect the security during the run time of an isolator or ground switch when the switch status is set as “between”.

Fig. 3.13 A 550 kV SF_6 gas insulated switch plant (*Source* ABB AG, Type ELK_3_S9)

3.1.3 Gas Insulated Switchgear

As mentioned in Sect. 3.1.2, sulfur hexafluoride is a superior dielectric gas that is also used in gas insulated switchgears at moderate pressures for phase to phase and phase to ground insulation. The high voltage conductors, the circuit breaker interrupters, the isolators and switches, the voltage and current transformers are encapsulated in SF_6 gas inside grounded metal enclosures.

The first SF_6 gas insulated switch bays were installed in 1968. Today this technology is often used in urban supply areas, and the number of globally operated SF_6 switch bays exceeds a million. The world's largest SF_6 gas-insulated switchgear installation at Three Gorges Dam in China with 73 bays 550 kV is shown in Fig. 3.13.

The main drivers for using gas insulated switchgear are:

- Restricted space availability what is important in highly populated or mountainous areas,
- Expensive land acquisition or legal restrictions,
- Requirements for environmental compatibility or community acceptance,
- Aggressive environmental conditions, e.g. coastal sites or industrial sites,
- Heavy weather conditions, e.g. strong wind, snow and ice,
- Seismic activity with the need for high seismic stability through a low centre of gravity,
- Extension or refurbishment or upgrading of AIS under restricted space availability.

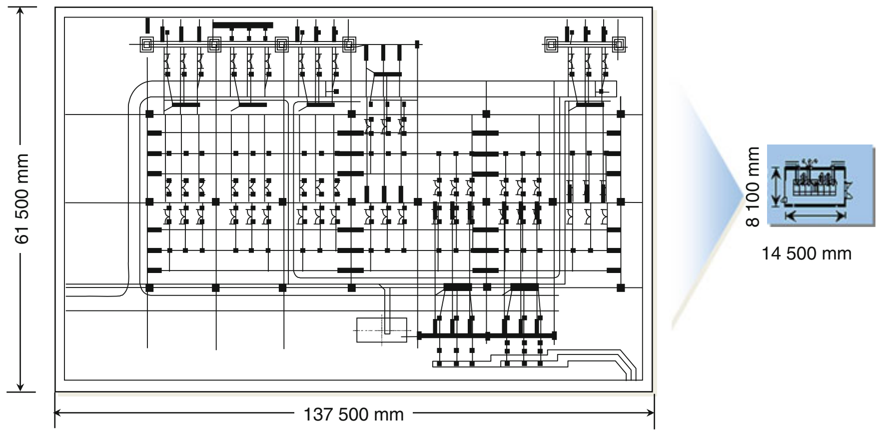


Fig. 3.14 Comparison of space requirements—245 kV AIS/GIS—Indoor—50:1 (*Source* Siemens AG)

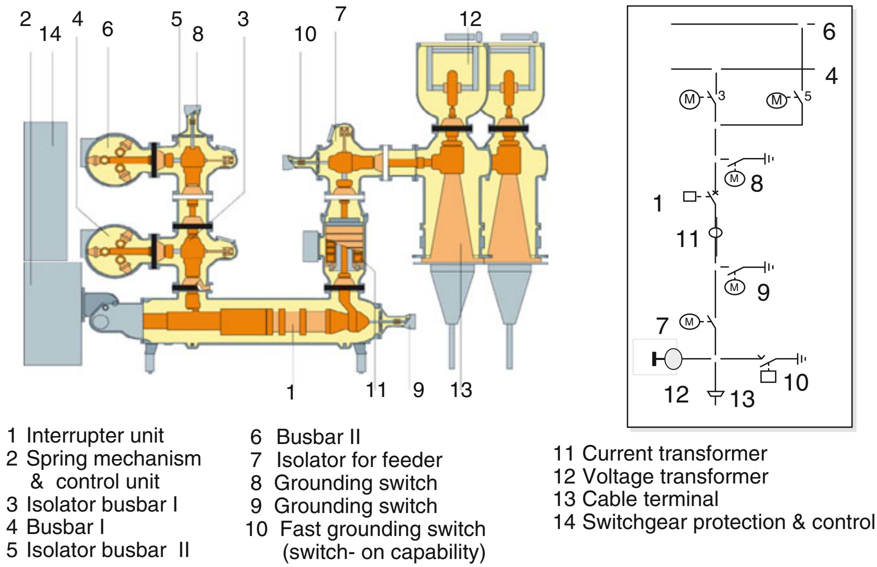


Fig. 3.15 The cross section and the scheme of a 245 kV gas insulated switch bay (*Source* Siemens AG)

The space saving benefit of the GIS compared to AIS is demonstrated in Fig. 3.14.

The required space for the 245 kV GIS is 50 times lower than for the comparable AIS plant. The internal construction of the 245 kV switch bay for a two-busbar scheme is presented in Fig. 3.15.

Besides the fundamental space reduction the compact GIS design provides the following additional benefits:

- Short and economic planning and delivery period possible through customer-tailored and pre-defined combinations of switchgear modules,
- Short and economic installation period possible through factory pre-assembled and pre-tested units,
- Restricted foundations, e.g. in mountainous or river areas realized with outdoor-GIS,
- High level of availability through encapsulation and modular, service friendly design,
- Minimal maintenance efforts realized through encapsulation of moving parts and less insulators,
- High degree of safety for operating personnel realized through earthed encapsulation,
- Long operating life: >50 years.

The GIS bays are outfitted with several sensors for diagnostic like gas density observation, partial discharge monitoring, switch current counters or arc monitoring. Especially, the gas density observation plays a significant role according to the environmental protection. The SF_6 gas is environmental dangerous and has to be strictly kept inside the encapsulation without any losses. The modern switchgear technology is able to meet this requirement.

3.2 Control and Automation of Power Systems by Digital Technologies

3.2.1 The Hierarchy and the Data Processing of Power System Control and Automation

The power system control is performed in a four tiered bottom up hierarchy:

- Process level,
- Bay control level,
- Substation control level,
- Network control levelas presented in Fig. 3.16.

At the process level the

- binary status signals indicate, for example, the positions of the switchgear or the transformer tap changer,
- analogue measurement data (voltage, current) are available at the interfaces of the instrument transformers,
- binary output commands are set for the control of switchgear, tap changers and various equipment for protection, automation or auxiliary needs,

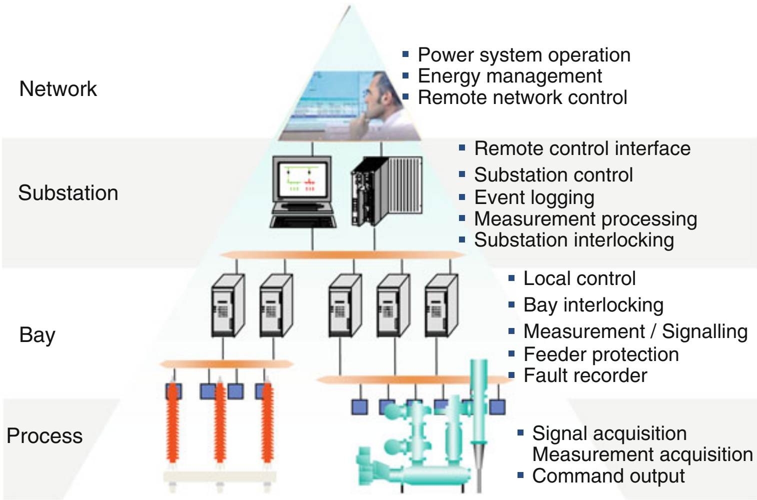


Fig. 3.16 Hierarchy of the power system control

- analogue target values may be set to change the behavior of regulation facilities (e.g. the target value for voltage can be set to the transformer voltage controller).

Nowadays, communication protocols may be applied to transfer all kinds of data between the process and the bay control levels via fiber optic communication links (see also Sect. 8.3). In this way the binary and analogue input/output contacts of the devices and the expensive wiring could be saved. However, this approach is still not broadly applied.

The bay level is equipped with intelligent electronic devices (IEDs) which provide the interfaces for the process data acquisitions. The conventional way for the data exchange is their acquisition or provision on the parallel input and output contacts for binary and analogue values of the IEDs at the bay level. Consequently, each data needs its own wire and contact.

The binary data is provided as DC signals at 24, 48, 60, 110 or 220 V DC. The selection of the rated DC voltage depends on the practice of the network operator. The DC voltage is available in separate, and mainly redundant, DC networks supplied by storage batteries. The batteries are permanently charged from the auxiliary AC network.

The analogue measurement values are acquired as instantaneous values normally sampled in a raster of 1 ms. Special disturbance or transient recorders may offer a significantly higher sampling resolution.

At the bay level the IEDs perform two main tasks:

1. Bay control and processing of the basic data for the Substation Automation System (SAS), data exchange with the substation control level,
2. Protection of the bay related network assets against stress and damages caused by disturbances and/or critical state conditions (e.g. overloading, over voltages).

All signals received from the process are evaluated in the protection and bay control devices. The process data can be

- visualized in the device screens on local request and
- used in a programmable logic to start special automation programs,
- communicated to the upper level of the substation control.

The bay devices calculate the primary RMS values of the instantaneous voltage and current measurements and build associated values like active and reactive power and $\cos\varphi$. Only the primary RMS values are locally displayed and transferred to the substation level. The exception is the fault record presenting the graphic of the instantaneous values before, during and after a fault which can be displayed at the substation screen.

The status signals of the switch devices make it possible to display bay topology and to perform the interlocking function—blocking, an operation of the isolators if the circuit breaker is in the status “ON” and of the ground switches if the feeder is under voltage.

Appropriate command and impact signals for the process can be performed in the following ways:

- generated by automation algorithms (e.g. voltage control, switch sequences, protection trips),
- initiated by the operator locally using the control facilities of the bay devices,
- received from the substation control level via communication.

The substation control level provides an interactive work place for the operator with control and visualization elements. Here the scheme of the whole substation is available. Events are signaled and measurements can be monitored. It is possible to control all parts of the substation. The substation interlocking extends the bay interlocking from a higher point of view. For example, an isolator can be operated if the related circuit breaker is switched “ON” but the topology of the substation scheme shows that there is no current flow.

The substation control level provides communication interfaces to the network control center and, if requested, to further network service providers like the asset and maintenance management, network planning or protection supervision. Not all available data is communicated between all of the levels instead the information exchange has to be engineered.

The network control center observes and controls all substations of the network. Furthermore, the power in-feed of the connected power stations and the power exchange with the neighboring power stations are managed on this level. The transmission system operators (TSO) build the “control area” in the territory of their network, control the reserve power availability and ensure in this way the frequency stability. The network control centers provide several work places with screens and keyboards. An overview of the overall power system is provided on large wall displays.

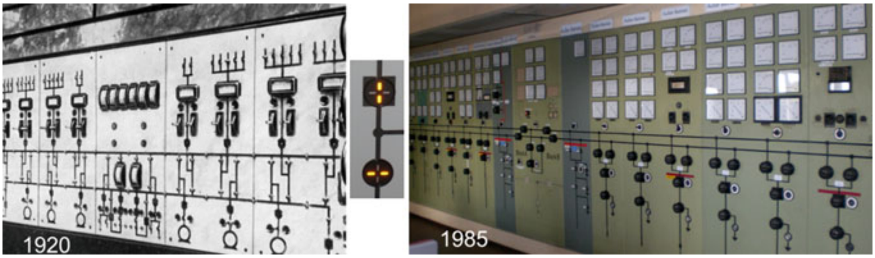


Fig. 3.17 Substation control technology from the last century (*Source* Walter Schossig)

3.2.2 Protection and Control in Substations

3.2.2.1 Historical Development

The digital protection and control systems of the substations were developed and widely introduced during the last three decades. These systems brought about a fundamental change in technology and operation philosophy. These advanced digital technologies are currently applied in 100 % of the important UHV/EHV/HV and HV/MV substations in the progressive industrial countries.

The substation control technology was stable and remained unchanged for about 100 years from the beginning of the electricity supply until the 1990s.

A broad wall of the substations was filled with electromechanical control and measurement elements representing the substation scheme. Figure 3.17 demonstrates this situation showing a view of a substation control wall from 1920 and 1985.

The control and status indication of the switch devices was performed using "command–confirm–switches" shown separately in the middle of Fig. 3.17. Command operation and confirmation was executed by turning in the desired position and pressing the switches. Two manual handlings are necessary to avoid false operations. Events were brought to awareness by acoustic signals. The type of event was recognized by "flag" relays. Disturbance records were written on a paper role.

The technology required parallel wiring from the control room to the switch bays. Each signal or measurement was acquired directly at the bay switch devices or the instrument transformers and transferred some hundred meters through the substation terrain on its own wire. A high probability of disturbances in the secondary system and significant engineering and mounting efforts were associated with this method.

The protection technology has also changed within the last few decades—from the electromechanical relay schemes completed on panels to analogue protection cubicles to digital protection devices and Intelligent Electronic Devices (IEDs) as shown in Fig. 3.18.

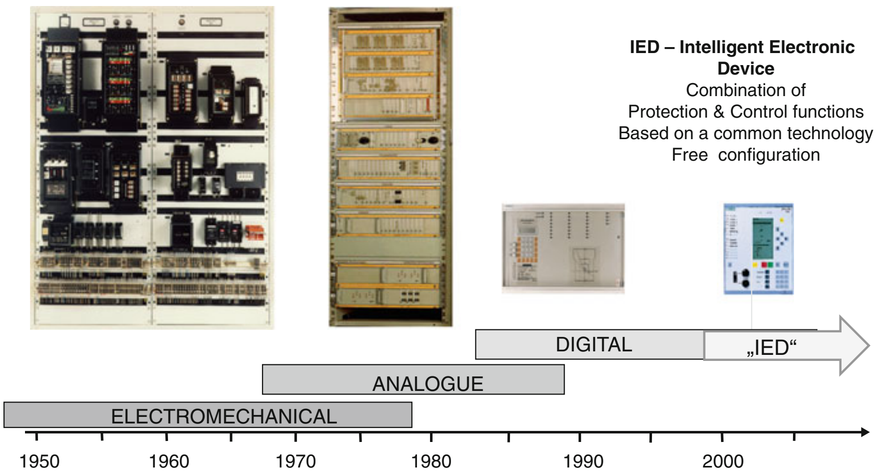


Fig. 3.18 Time line of the protection technologies

The protection cannot avoid disturbances but minimize the consequences through:

- rapid, secure and selective disconnection of the faulty equipment,
- automatic reclosing for supply recovering in case of transient failures,
- logging and recording the disturbance and supporting a fast network recovery.

To perform these tasks the former protection panels (left in Fig. 3.18) were equipped with several devices connected by a complex wiring logic. The analogue electronic technology applied electronic boards and an electronic bus to perform the logical links. Both technologies were installed in a special "relay room" of the substation building. Consequently, all signals were transferred via cables between the relay room and the switch bays with the same disadvantages as considered for control.

The digital protection and control technology which was developed in the early 1980s brought about a technical revolution and a deep paradigm change. Today, each switch bay is equipped directly with protection and control IEDs which are based on the identical technology in hardware and software (Fig. 3.18, right hand side).

The data transfer between the substation control room and the bays is now performed by serial communication. The parallel wiring over long distances has been replaced by a fiber optic Ethernet loop. The control scheme walls (Fig. 3.17) have also been replaced—by industrial computers (IC) offering an Ethernet interface for communication with the bay IEDs as shown in Fig. 8.19.

The screen of the ICs displays the overall substation scheme and offers the selection of a large amount of detail schemes, various event logs, diagrams, measurements and fault records, video observations and others. The flag relays for

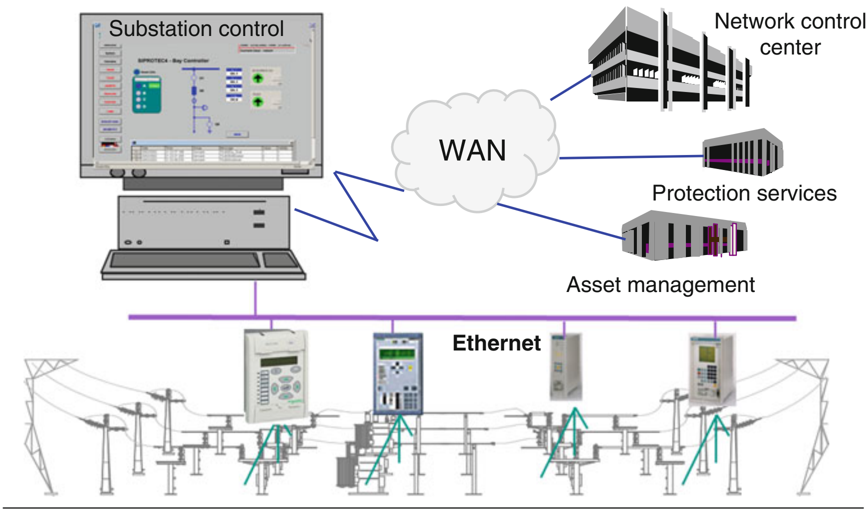


Fig. 3.19 Modern architecture of substation automation systems (SAS)

the recognition of the events are not more applied. The monitoring comfort is fundamentally improved. For example, all event messages and changes of measured values are represented with a time stamp. As a rule, the time resolution of 1 ms is applied. The control is possible using a simplified keyboard by cursor to select the device to be controlled and by simultaneously pressing two separate keys—command and confirm. The IC provides one or more (redundant) links to Wide Area Networks (WAN) for communication with the network control center and further service departments of the network operators as shown in Fig. 3.19.

The application of international communication standards ensures the interoperability of the network control centers and the substation automation systems from different vendors (see also Sects. 8.2 and 8.3). In the same way, the bay related IEDs of different vendors may be integrated into the substation automation systems.

3.2.2.2 Advanced IED Technology

The hardware for protection and control is developed and manufactured using the most innovative micro-processor technologies. The embedding of software into the devices makes them “intelligent”. The term IED is now worldwide used for this technology. The principle hardware scheme of an IED is presented in Fig. 3.20.

The input side acquires the

- analogue values of voltages and currents in synchronized samples of ~1 ms,
- binary process signals and
- requests from the Integrated Human Machine Interface (IHMI).

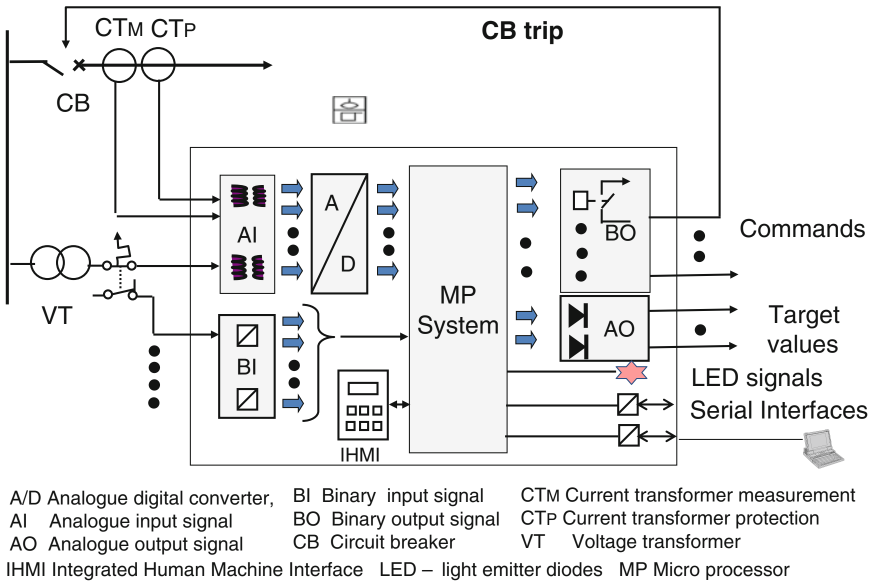
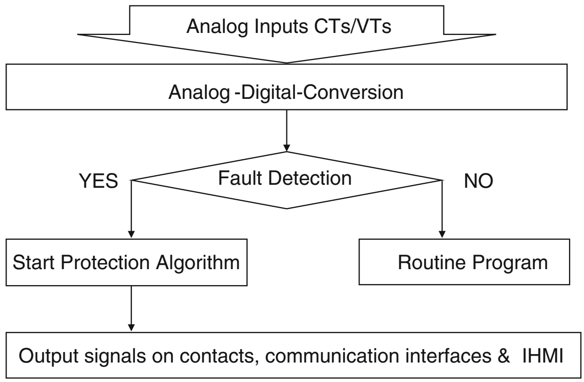


Fig. 3.20 Hardware scheme of an IED

Fig. 3.21 Principle scheme of the data processing for protection



The instantaneous analogue measured samples have to be converted into digital values for further processing within the micro-processor (MP) system. The MP system performs all enabled functions in accordance with the parameter sets. An example for the processing procedures is given in Fig. 3.21.

The first task of the fault detection is the filtering of the array of sampled values (8–15) to avoid an over function of the protection caused by transient or harmonic distortions. If a fault is detected when comparing the measured values and the protection criterion, the protection algorithm is run in order to manage all tasks relating to the pickup signaling, the tripping, the fault location, the starting of fault

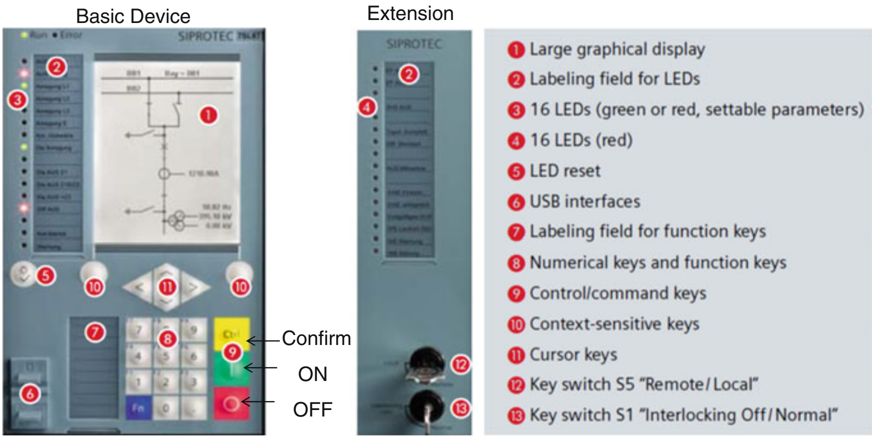


Fig. 3.22 Front of a multifunctional IED performing protection and control tasks (*Source* Siemens AG)

recording and auto-reclosing, etc. Otherwise, if no fault is detected, the routine programs continue checking all inputs and performing the self-diagnostic functions. The digital IED technology is able to detect and to signal internal defects.

If the processing of the input data in the MP system detects the need for impacts on the primary process then the appropriate signals are provided at the interfaces of the IED:

- Binary output for commands,
- Analogue output for target values,
- LEDs (Light Emitter Diodes) for signaling events and alarms,
- Serial interfaces to the SAS system (at bay level) or to remote SCADA systems (at substation level) or to the locally connected PC,
- Integrated display for local visualization.

Figure 3.22 presents the front side of a modern IED.

In this IED all normally required functions for protection and control are implemented by software, which generally provides the following tasks:

- Data collection and archive,
- Monitoring and control of the bay topology,
- Initiating control commands,
- Interlocking,
- Event logging,
- Measurement presentations in records, tables, diagrams,
- Automation, regulation,
- Communication interfaces,
- Multi-protection functions,
- Protection related functions, e.g.

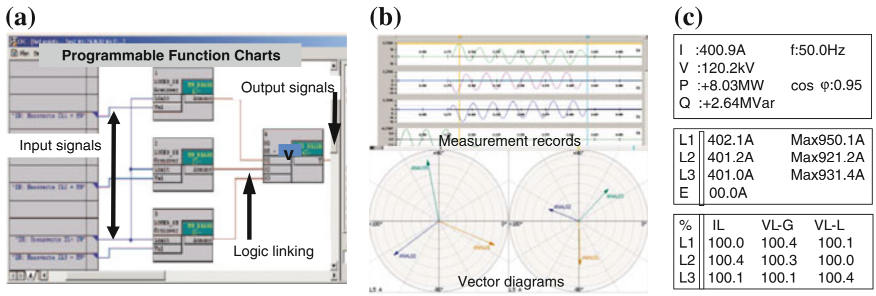


Fig. 3.23 PC views: **a** Function chart, **b** Measurement record and vector diagram, **c** Variants of measured value tables (*Source* Siemens AG)

– Auto-reclosing,
– Synchrocheck,
– Fault location,
– Fault recording.

The user functionality can be configured by enabling/disabling functions and parameterizing the enabled functions.

The configuration change is possible by:

- Using the Integrated Human Machine Interface (IHMI) with keyboard and screen,
- Preparing the parameter sets on a PC and downloading then via the integrated interface,
- Remote communication of the parameter set from an external terminal or the substation IC,
- Parameter set switch initiated by internal (e.g. from a programmable logic) or external requests.

For convenience and efficiency the PC is normally used to engineer and set the parameters.

The second PC function is to present information in the form of tables, logs, diagrams, records and schemes. The IED vendors offer special PC software for these purposes. The changing of functions and parameter sets may also be performed in real time by an integrated programmable logic which is engineered on the PC and can be downloaded from there.

Figure 3.23 presents, from left to right three views on a PC

(a) the linking of functions within a programmable function chart,
(b) the presentation of a measurements in an instantaneous value record and in a vector diagram,
(c) the presentation of actual measured RMS values (identical view on various levels).

The functional chart allows the linking of external input signals or internal conditions with internal functions to produce output signals resulting in a logical combination. The outputs may be a:

- switch command or the start of a switching sequence,
- transformer tap change command,
- change of a target value, e.g. for voltage control,
- change of the parameter set.

The presentation of the instantaneous values in a record and in vector diagrams offers a complete analysis of various aspects evaluating harmonics, un-symmetry, voltage sags and equipment stresses.

The presentation of the measured RMS values is possible in various overviews at all possible levels—IHMI, local connected PC, substation control IPC, remote terminals, e.g.:

- Current, voltage, active and reactive power, frequency, cosφ in general,
- The average values of the line and neutral currents and maximally achieved currents,
- The current line to ground voltages, line to line voltages and line currents.

The PC supports this new flexibility in the function design and event analysis in a convenient and efficient way.

The user friendly front of the IED shown in Fig. 3.22 allows the general work and process control with the IEDs to occur locally at the bay. The screen of the IHMI can be parameterized for bay topology presentation and many other views. A menu on the screen, the cursor control and the "Enter" button allow access to the various screen views and the execution of control operations.

For example, the switch devices can be selected in the topology graphic by cursor control and pressing the "Enter" button. Then, the selected switch device begins to flash. By pressing the green button (ON) or the red button (OFF) together with the yellow "Confirmation" button a switching operation can be executed.

Events and alarms are signaled with LEDs located on the left side of the screen. The allocation of the LED meanings can be marshaled by a "configuration matrix" offered by the PC software. The configuration matrix is also used for further inputs and outputs including the communication links.

The back side of an IED with the contact terminals and communication interfaces is shown in Fig. 3.24. This IED consists of the basic IED and supplemental modules providing additional I/O terminals and interfaces. The modular concept allows the seamless completion of multi- functional IEDs from low protection functionality up to the most complex IEDs which provide protection and control tasks for EHV substation bays.

The difference between the voltage and current contact terminals is clearly visible. The current contacts are dimensioned to carry up to 100 times the rated secondary currents during a 1 min period. Furthermore, there is a short circuiting mechanism included which shorts the current transformer circuit in cases when the

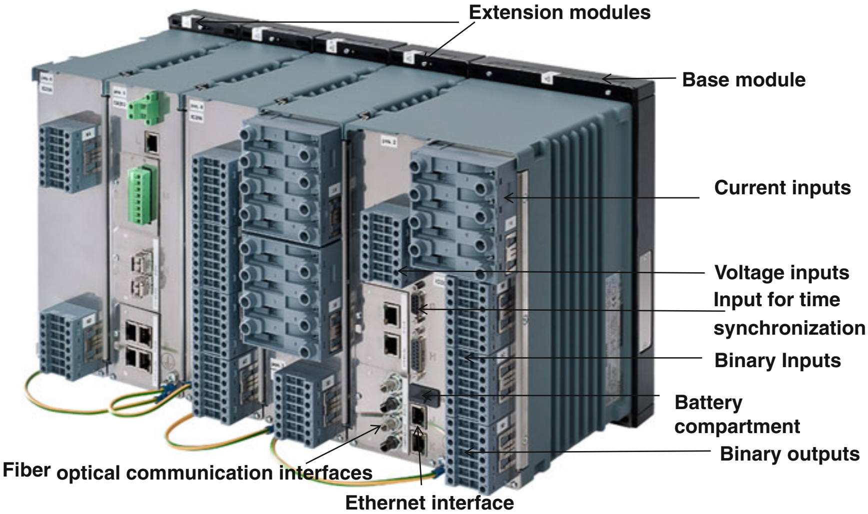


Fig. 3.24 Contact terminals and communication interfaces of an IED (*Source* Siemens AG)

terminal is separated from the internal device circuits. This mechanism prevents the current transformer circuit from opening and also prevents dangerously high voltages from occurring at the open ends. Besides the contacts and interfaces, the back side of the IED also contains a receiver for a time synchronization signal from a satellite. In this way, it is ensured that the time stamps of event logs with a resolution of 1 ms are consistent over the whole network area.

The communication interfaces provide various standardized physical links—fiber optics, electric V24 or RS 458. The modern IEDs perform self-diagnostic functions, and a permanent back-up program for hardware tests is embedded within. Damages to hardware components are recognized and signaled immediately. This feature is a great benefit compared to the conventional technology whereby bugs could only be detected during the cyclic approval procedures.

3.2.2.3 Protection and Control Schemes in UHV, EHV and HV Substations

As a rule, the protection and control schemes of UHV, EHV and HV substation bays contain:

- a main protection,
- a back-up protection,
- a bay control device.

Table 3.2 Principles for UHV, EHV and HV protection schemes [2]

Asset	Main protection	Fault clearing, t_{max}, ms	Back-up protection	Fault clearing, t_{max}, ms
Line HV-UHV	Differential ΔI		Distance Z<	
HV-UHV	Distance Z<	120	Distance Z<	120
HV	Distance Z<		Directional over-current I>	
Busbar	Differential ΔI	100	Distance Z<	300[a]
Transformer	Differential ΔI and Buchholz 	120	Overcurrent I>	150

[a] Breaker failure protection

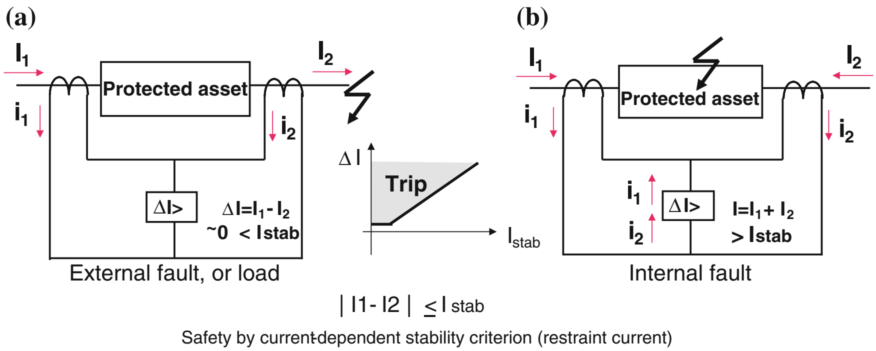


Fig. 3.25 The differential protection principle

The protected network assets are

- lines/feeders,
- busbars,
- transformers.

The main protection principles applied are presented in Table 3.2 and the principles of the protection functions are described in the following Figs. 3.25, 3.26, 3.27, 3.28, 3.29, 3.30, 3.31 and 3.32.

The differential protection principle offers the highest selectivity. Therefore it is often used for the main protection of EHV and HV lines. The protection function is based on the fact that along a fault free line the ingoing current should be equal to the outgoing current. Figure 3.25 explains this principle. However, the current flow along the line will be influenced by the capacitive currents. Therefore, the difference of the ingoing current I_1 and the outgoing current I_2 of a fault free line is not exactly equal to 0. A small difference will be measured for un-faulted lines. A stabilizing current is introduced to avoid an over-functioning of the differential protection.

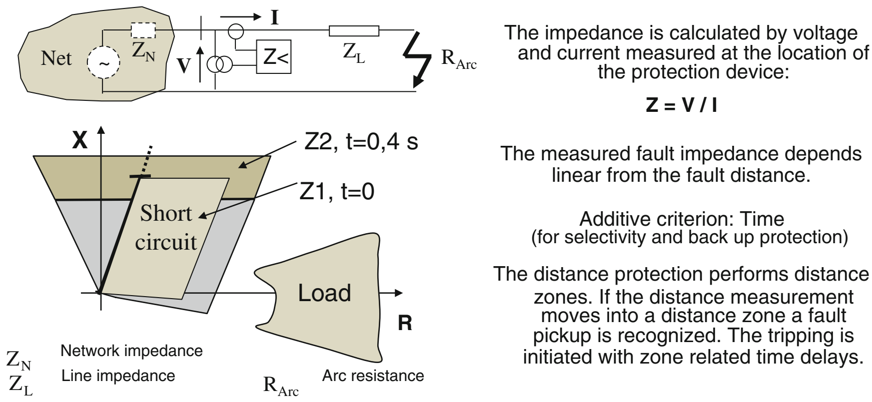


Fig. 3.26 The distance protection principle

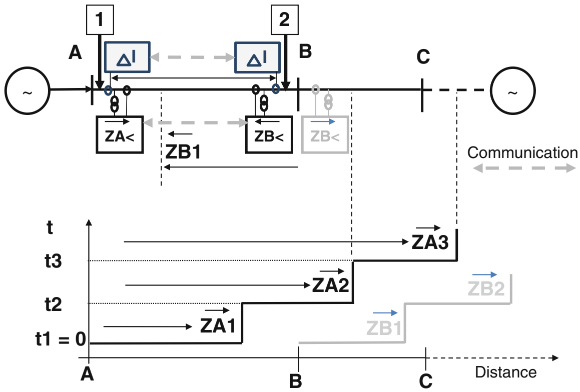


Fig. 3.27 Main and back-up line protection using differential and distance principles

The differential protection function has the disadvantage that the protection selectivity is strictly limited to the zone between the current transformers. A back-up protection cannot be performed with this limitation.

Therefore, the differential protection is mostly combined with the distance protection for back-up. The distance protection continuously calculates the impedance using the instantaneous measurements of the voltages and currents. If a short circuit occurs along the line the voltage declines and the current grows. The impedance will be significantly reduced. The impedance is a measure of the distance to fault. Several impedance zones can be parameterized to ensure both, the selectivity and the back-up protection features. Figure 3.26 demonstrates the distance protection principle.

Figure 3.27 demonstrates the grading principle of the distance protection and the protection zone of the line differential protection.

The differential protection units in the substations A and B mutually communicate the sampled values in real time. However, the differential protection cannot

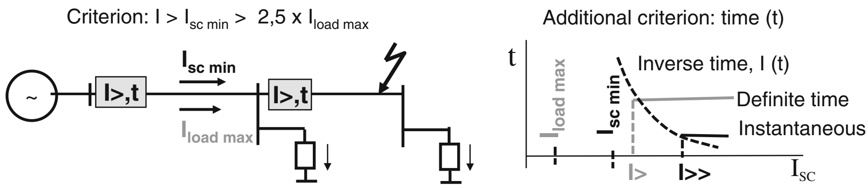


Fig. 3.28 The overcurrent protection principle

recognize faults between the busbar and the access point of the current transformer (fault locations 1 and 2). These sections are protected by the distance protection.

Distance zone 1 is operated with either a small or no time delay (t_1). To avoid wrong trips the reach of the distance zone covers 80–90 % of the line impedance. The reach of zone 2 exceeds the line length and trips after a higher time delay t_2, and zone 3 may overcome the next busbar C with the time delay t_3. The same principle is applied for the line protection of substation B.

A fault in location 1 can be tripped by the distance protection $Z_A<$ in zone 1 and a fault in location 2 can be tripped by the distance protection $Z_B<$ in zone 1. But this would be only a rapid trip of one side of the line and the short circuit could only be finally tripped after the time delay of zone 2. To avoid such an extension of the fault duration, the principle of teleprotection is applied: both protection units submit the pickup to the opposite device by a communication link. If one of the devices detects the fault location within zone 1 both devices trip in the same time. Furthermore, the back-up protection for the line B-C is performed by the distance zones 2 and 3 of the protection in station A.

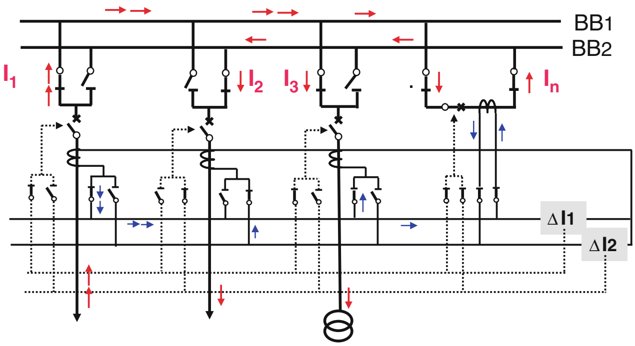
In HV line protection schemes the directional overcurrent principle is often used for back-up protection combined with the main distance protection. The overcurrent protection principle is based on the simplest criterion: the increased current in case of faults as demonstrated in Fig. 3.28.

The overcurrent protection has to trip the circuit breaker as faster as higher the short circuit is. Following this principle, two methods are applied:

- The definite time overcurrent protection trips with a definite time delay if a definite over current I> is exceeded. Extremely high short circuit currents $I\gg$ are tripped without or with a minimum delay.
- The inverse time overcurrent protection trips in accordance with a time delay depending on the short circuit current.

For the application in meshed HV networks, the overcurrent protection is supplemented by the specific directional criterion and needs the input of the phase voltages for processing.

The busbars are the most sensitive components in the network. A busbar fault may cause a trip of the whole or a part of the substation with all connected transformers and lines.

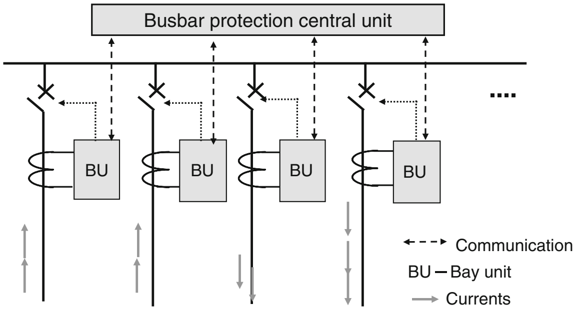


$$|I_1 + I_2 + I_3 + \ldots I_n| = \Delta I \leq I\ \mathrm{stab}$$

The Kirchhoff node equation has to be checked continuously and in real time for each separated busbar (BB) section according to the the isolator replica.

Fig. 3.29 Principle of the busbar differential protection

Fig. 3.30 Digital busbar protection system (BU—Bay Unit)



The busbar differential protection has to continuously check the configuration of the busbars. For example, a three busbar system may be operated as one electrically connected complex or as six separated busbars. The isolator replica ensures the selective trip of the faulted busbar component. Figure 3.29 presents the principle of the busbar protection.

The sum of the complex currents (considering the direction) results in a difference current that will be strictly calculated separately for all electric autonomous busbar segments. In the case of a busbar segment fault all circuit breakers of the connected feeders will be tripped. The busbar protection shall decide to trip within 8–12 ms to avoid equipment damages. Switching operations have to be performed as quickly as possible after the faulty busbar is tripped for connecting the affected feeders to the healthy busbar segments.

The busbar protection is configured as a system with digital bay units and one central IED as presented in Fig. 3.30. Both components of the system are based on the identical technology as described in Sect. 3.2.2.

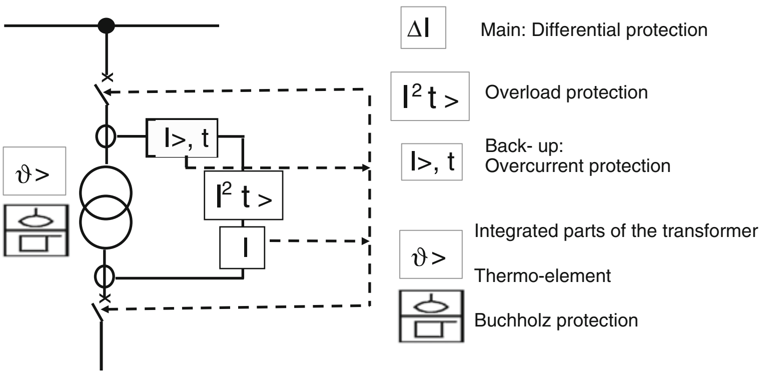


Fig. 3.31 Transformer protection scheme

The bay IEDs continuously submit the measured instantaneous currents and the positions of the isolators to the central unit. The central unit detects the busbar segmentation and the appearance of faults. If a fault detection is definitely recognized all feeders connected to the faulty segment are tripped without any time delay. The back-up protection of the busbars is performed by the protection system of the feeders connected to the faulty busbar segment.

The typical transformer protection scheme is presented in Fig. 3.31.

In general, the transformer differential protection principle is identical with the line differential protection. The differences consist of the

- adaptation of the measured currents in accordance with the transformer ratio,
- direct measurement of the different currents in one IED (no need for communication),
- need for blocking over function in accordance with inrush currents (after switch-on).

The Buchholz protection is also part of the transformer delivery. It monitors the gas stream between the main oil tank and the oil extension container of the transformer. The gas stream detects an internal fault and depending on the stream intensity either an alarm or an instantaneous trip are performed.

Furthermore, the thermal overload protection principle is normally activated in the main protection device. The thermal overload protection is designed to prevent thermal overloads and a subsequent damaging of the protected transformer. The protection function represents a thermal replica of the transformer. Both, the previous overloading history, the current oil temperature measured by a thermo-element and the heat loss to the environment are considered. The thermo-element is a component of the transformer and has to be connected to the protection device for temperature observation. It requires a 20–100 mA DC input of the IED.

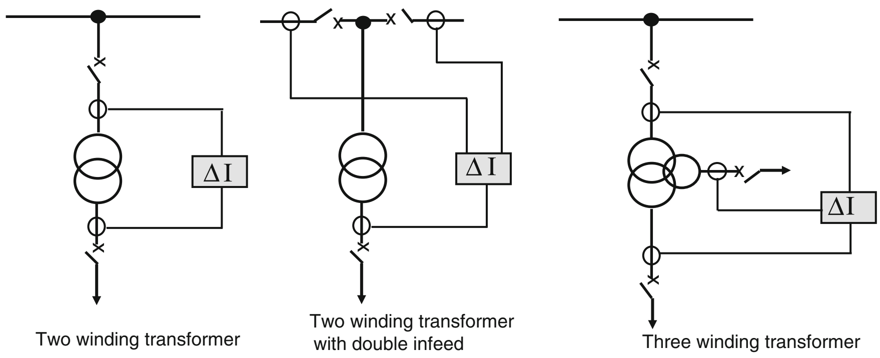


Fig. 3.32 The connection variants of the transformer differential protection

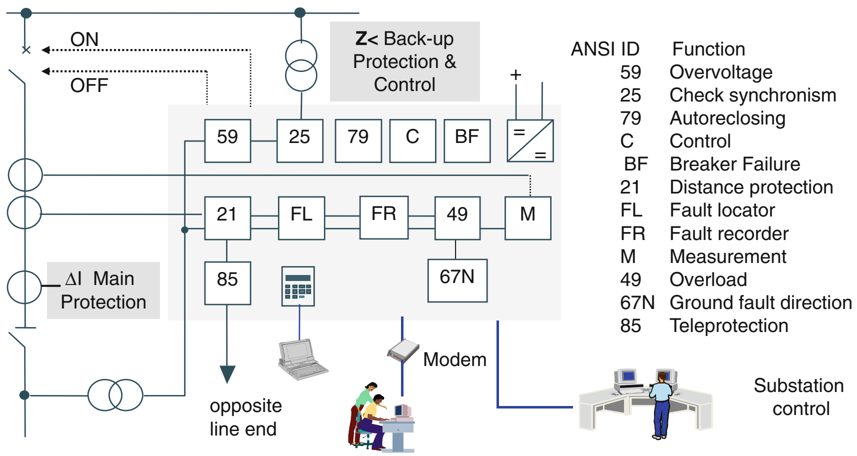


Fig. 3.33 Function set of a combined IED for back-up protection and control 110 kV

The back-up protection is often the overcurrent protection. Also distance protection is applied.

The transformer protection scheme has to consider the number of windings and the connection scheme. This variety is presented in Fig. 3.32.

The digital IEDs for control and protection also contain further protection and protection related functions. Figure 3.33 gives an example of the often applied functions for 110 kV feeders with resonant neutral grounding. The resonant neutral grounding is partially used in HV networks. However, the majority of HV networks use the solid grounding principle which is the only method applied for neutral grounding in EHV networks.

This scheme uses the differential protection as the main protection. The back-up protection is performed by a combined protection and control device using the distance protection as basic protection function. Supplement protection and protection related functions are enabled.

In Fig. 3.30 the identification numbers according to the American National Standards Institute (ANSI) systematic are applied. The ANSI systematic assigns numbers to the different functions and is globally known and accepted. The protection engineers mutually consider protection aspects using the ANSI ID numbers instead of the principle names.

The additional functions applied are defined as follows:

1. The automatic reclosing function is mainly used in networks with overhead lines. Here the experience shows that about 85 % of faults are temporary in nature caused by:
   - atmospheric lightning,
   - wind and phase conductor swing,
   - tree contact,
   - birds.

The external influences generate an arc which shorts the affected phases. The faults disappear when the protection trip interrupts the energy feeding the arcs. This means that the line can be switched-on again. The reconnection is accomplished after a dead time that the air can be deionized.

2. As the name suggests, the overvoltage protection has the task of protecting electrical equipment against over-voltages. Over-voltages may occur on long low loaded transmission lines generating an excess of reactive power. The over-voltages may cause for example insulation problems and damages
3. The check of synchronism function provides the synchronization check before connecting two sections of a network, for example a feeder and a busbar or a busbar and a power station. The “synchrocheck” evaluates the differences of
   - the voltage magnitudes of both sections ΔV,
   - the angles between the voltages $\Delta\delta$ and
   - the frequencies Δf.

This method verifies that the switching does not endanger the stability of the network and is also used in combination with the auto-reclosing.

4. Resonant neutral grounding is partially used in 110 kV networks. In these networks the shorting of one phase to ground does not generate high currents (see also Sect. 4.4, Fig. 4.18). The operation can be continued. However, continuous operation increases the probability of the fault extension to multi-phase faults caused by the $\sqrt{3}$ times increase of the line to ground voltages at the healthy phases. Therefore, a fast detection and subsequent elimination is achieved using the ground fault direction determination.
5. The overload protection protects the line from thermal overloading by observing the power flow over a certain time interval. Either alarms or trips may be performed depending on the length of time that the threshold is exceeded.

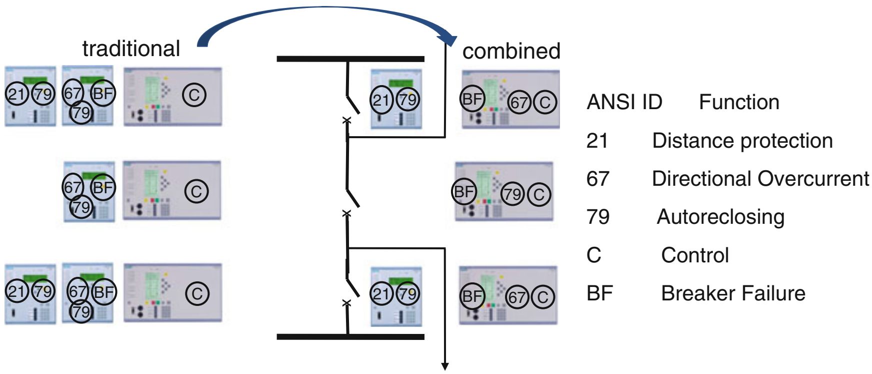


Fig. 3.34 Traditional scheme and combination of protection and control

6. The distance protection principle provides the opportunity to enable the functions "fault locator" and "fault record" with the provision of voltage and current records before, during and after the faults.
7. The breaker failure protection monitors the proper tripping of the relevant circuit breaker. If after a settable time delay the circuit breaker has not operated, the breaker failure protection issues a trip signal to isolate the failed circuit breaker by tripping another surrounding back-up breakers.

In Fig. 3.33 the benefit of the communication interfaces of the IEDs is also demonstrated. Here IED communication interfaces are used for teleprotection, for external (via Modem) or local (by PC) reading of protection data or parameter setting and for the link to the substation control work place.

The philosophy of the protection and control schemes for HV and higher voltage level switch bays strictly requires the installation of separate and autonomous devices for the main, the back-up and the breaker failure protection. It is often required that the devices come from different vendors. That means they are also independent regarding the DC power supply (see also Fig. 3.7).

Nowadays, a combination of the back-up protection, the breaker failure protection and the control IED is used to gain higher economic efficiency.

A comparison of the traditional scheme and the efficient combination of control and back-up protection is presented in Fig. 3.34.

Here the often applied double busbar 1½ circuit breaker configuration is shown. Two lines are connected by three circuit breakers to two busbars. The main protection is performed by the distance protection with auto-reclosing. The directional overcurrent protection with auto-reclosing and breaker failure protection is used for the back-up. The bay control devices complete the scheme. A combination of the back-up functions and the control leads to a significant simplification of the scheme without loss of reliability.

This example makes clear that the digital technology leads to simplified and high efficient protection and control schemes accompanied by a significant reduction of the engineering efforts and operational expenses.

3.2.3 Control Center Technologies

The power system control is structured in the hierarchical levels transmission, sub-transmission (or regional distribution) and local distribution (see also Sect. 1.2, Fig. 1.7.)

The transmission system operation at the highest level performs two basic functions:

- Energy Management System (EMS) and
- Network Supervision, Control and Data Acquisition (SCADA).

The control center of transmission systems is often called "dispatching center" in the context with the combination of both functions.

Most countries in Europe operate their power system within one national dispatching center building one control zone. In Germany, however, four transmission system operators build four control zones, accordingly.

The transmission system operation may be managed in a central or a hierarchical control structure as shown in Fig. 3.35. Data are communicated between the related dispatching center and the:

- Transmission network substations which can perform the
  - UHV/EHV or EHV/EHV voltage transformation (e.g. 400/220 kV),
  - connection to the neighboring networks (transmission or large industrial networks),
  - voltage transformation to the sub-transmission HV level (e.g. 400/110 kV),
- Power plants.

Table 3.3 presents an overview of the configurable data transfer volume between the dispatching centers and the plants to be controlled for large and smaller power systems. Furthermore, the required response time regarding the latency between a status change in a plant and the signaling at the dispatching center is considered.

The technology of the dispatching centers is mainly based on components which are commercially available on the markets for computer and communication technologies. The specific of the vendor solutions consists in the selection and configuration of such hardware components and the software solutions. For example, some vendors still prefer the application of workstations and UNIX as an operation system. Other vendors offer PC/Windows based systems.

Figure 3.36 presents a possible scheme of a dispatching center of a transmission network that also performs the control zone duties by using an EMS.

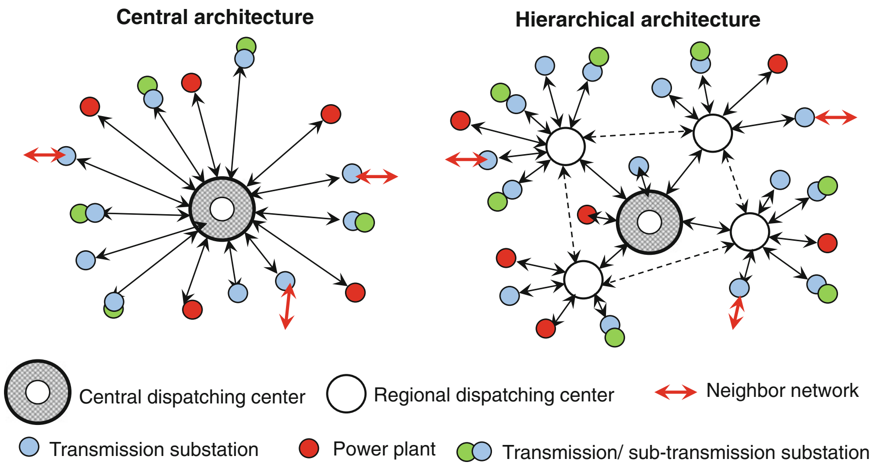


Fig. 3.35 Central and hierarchical architecture of the power system control

Table 3.3 Data volume and maximum response times of modern dispatching centers

Data volume		Response times (average values)
Large network	Small network	
		Display selection time <1 s
100000 Event signals	20000 Event signals	Event update time <1 s
10000 Measured values	2000 Measured values	Measurement change <1 s
1000 Metered values	200 Metered values	Command output time with return information: <2 s
20000 Commands	400 Commands	
2000 Display views	500 Display views	Continuous load: 100 signals/s

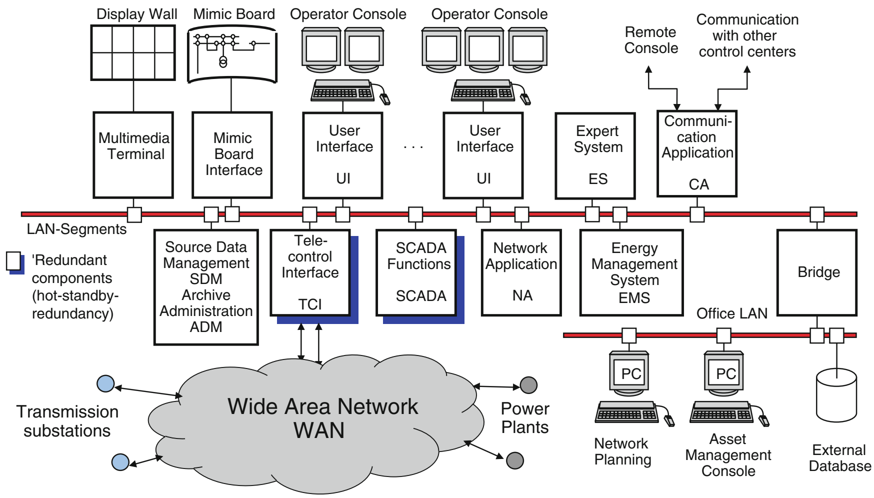


Fig. 3.36 Scheme of a dispatching center at the transmission level

Since 2000, telecommunication via wide area networks WAN using the TCP/IP address scheme has replaced the former point to point communication channels. The transmission system operators use their own internal WAN which is mainly based on fiber optic cables embedded in the ground conductors of the overhead lines. At the HV sub-transmission level a combination of the operators' own WAN components and their own domains in public networks is common. This approach ensures independence from the public communication networks and provides a high level of security for information exchange.

The high security and reliability requirements are also supported by the redundancy of components in the dispatching center. For example, the telecommunication interface (TCI) and the SCADA system are normally operated redundantly in a hot stand- by mode. The TCI performs the gateway between the Local Area Network (LAN) of the dispatching center and the external WAN. The LAN is also configured redundantly. All functional application blocks and the user interfaces exchange data via the LAN. The security concept is completed by a separate remote console which is allocated in an external building and allows emergency network operations if the dispatching center fails.

The SCADA functions in the dispatching center cover all connected users of the network and are, in principle, similar to the substation SCADA. The complete mapping of the physical network infrastructure within the dispatching system is standard. Sophisticated representations and operation functions complement the network mapping to provide maximum operator support for switching operations, voltage control and tap changing or reactive power control with the target to ensure the reliable transmission of the requested power flows also under N-1 fault conditions.

The function block "Network applications" (NA) manages maintenance works in the network and the related switching and grounding activities. In the case of faults and definite trips of network assets the fault clearance and the recovery works are coordinated by the NA block.

The Energy Management System (EMS) is operated in closed cooperation with the day-ahead and intra-day energy spot markets. Based on the load and renewable energy forecasts each time interval has to be covered by the most economic mix of energy sources available. The EMS also includes the management of the system services, ensures the frequency and voltage stability and manages the reserve power provision.

Expert systems build a separate functional block and support the operators in finding the best solutions to manage congestions and to avoid critical network conditions.

Besides the communication with the remote control console for emergency operations further gateways are supported:

- Communication with other dispatching centers,
- Bridges to other enterprise services like
  - network planning,
  - asset management,

Fig. 3.37 View of a transmission system dispatching center (*Source* Siemens AG)

– maintenance management,
– financial control,
– energy trading,
– training simulator for education.

All functional application blocks deliver the input for the operator displays to monitor the actual topology and the processes of the power system. A few operator work places are equipped with monitors and keyboards for operator interactions. The display wall offers various charts needed for the process control, and the topology of the overall network is presented on the mimic board which can be zoomed and scrolled. A view of one such a dispatching center is presented in Fig. 3.37.

On the display wall are presented top–down and left to right:

- the log of the most recent operations,
- the day diagram of the network load including the forecast,
- the overview of the current power balance (in- and out-feeds),
- the frequency deviations,
- the network territory with the main network components and the connection points to neighboring networks,
- the in-feed from power plants during the day.

The right side of the mimic board presents the network topology in detail indicating the overall network topology and including the positions of switch devices and the indication of load flow and voltage measurements.

The colors of the network assets indicate, for example:

- red—heavily loaded,
- green weakly loaded,
- white—switched-off and grounded.

The operators' work places make the execution of remote control commands possible. The operator is supported by further detailed information on the displays.

3.3 Transmission Technologies

3.3.1 Overview

The transmission and sub-transmission technologies are classified according to the mechanical construction principle as

- Overhead lines,
- Underground or submarine lines which can perform as
  - Cable lines or
  - Gas Insulated Lines (GIL),related to the voltage level as:
- HV Lines (>60–<220 kV)
- EHV Lines (extra-high voltage ≥220–<800 kV)
- UHV Lines (ultra-high voltage ≥800–1200 kV)and according to the physical transmission principle as:
- AC Lines or
- DC Lines.

The AC transfer capacity is limited by two parameters:

- maximum transmission distance,
- maximum transmission power.

The first type of AC transmission limitation is caused by the dynamic stability phenomena. Figure 3.38 presents the equation for the power to be transmitted between two parts of the network parts.

The angle difference between the voltages of the two parts of the network is important for the static and dynamic stability. If the angle difference (δ_1–δ_2) is close to or higher than 90° the static stability is lost.

Furthermore, in the case of faults the voltages decline and the transfer capacity is reduced accordingly. The subsequent power swing can be better dampened if the transmitted power is significantly below the peak of the sinus curve. Consequently, the higher voltage level V allows for a higher power transfer capability ($P_3 > P_2$).

On the other hand, the longer the line length is, the higher the line reactance x. In this way, the line length also limits the power transfer capacity ($P_1 < P_2$).

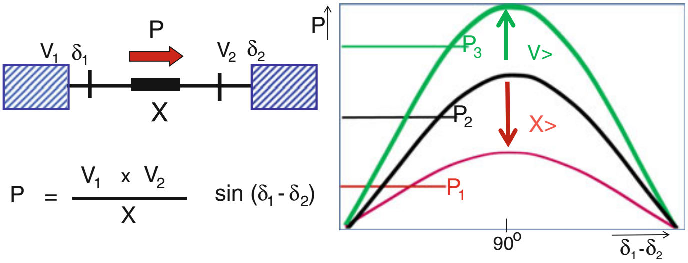


Fig. 3.38 Power equation and the impact of parameters on the AC power transfer capacity

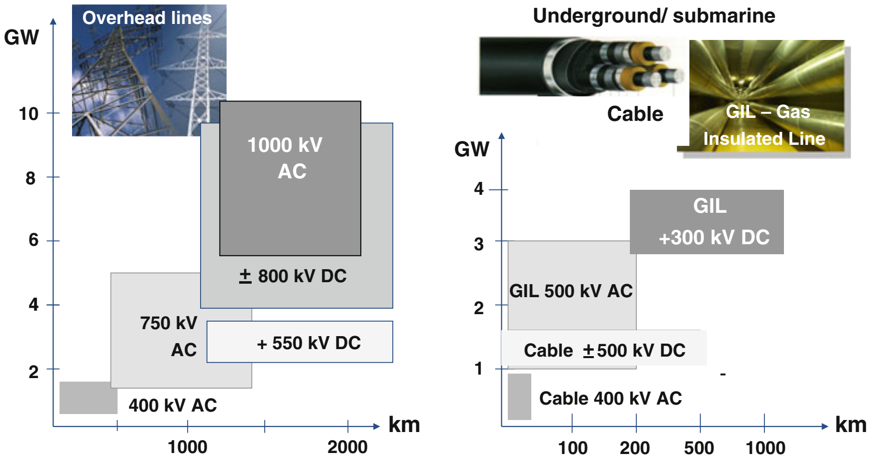


Fig. 3.39 Overview of the transfer capacities of transmission technologies

DC transmission lines do not have this type of stability-caused limitation. However, the second limitation of the power transfer is valid for both AC and DC transmission lines: namely the line resistance causes power losses in proportion to the square of the currents I^2. Higher transmitted power means higher energy losses and a higher temperature hub. For example, the power losses of a line that is 300 km long with 400 kV are:

- 6.3 MW—1.05 % for 600 MVA power transfer,
- 25.2 MW—2.1 % for 1200 MVA power transfer.

The related temperature increase of the conductors also limits the power transfer capacity.

In this way, the power transfer capacity and the distance of transmission build the selection criterion for the category of transmission lines regarding the voltage level and the physical principle. Figure 3.39 presents an overview of various transmission technologies.

It becomes clear that the 400 kV voltage level is well-suited for use in Central European industrial countries where the distances between the substations are less than $\sim$300 km.

The application of underground lines is restricted by the high expenses. The Capital Expenditures (CAPEX) grow in proportion to the voltage level. Consequently, in Germany for example, the ratio of cables and overhead lines to total line length is approximately

- MV lines 300000: 180000 km,
- HV lines 4600: 70000 km,
- EHV lines 120: 45000 km.

The application of 400 kV AC cables is further limited by the fact that the high cable capacitances cause a high generation of reactive power. Additional reactive power compensation plants are required for longer cable distances.

Gas insulated lines are used for special applications where a high power transfer capacity is required but the erection of overhead lines is not possible (for example the fly zones above the Geneva or Frankfurt airports). Worldwide only a few 100 km of GIL are in operation.

3.3.2 AC-Transmission

AC overhead transmission lines are constructed with steel towers, porcelain, silicone or glass insulators, ground and phase conductors consisting of a steel core providing the mechanical stability and aluminium housing providing a low electric resistance. The typically used ratio of the cross cut sections of a phase conductor is 240 mm^2 aluminium/40 mm^2 steel.

Double lines with two phase systems on one tower are often used up to a level of 400 kV. Furthermore, a 400 kV double line tower may also be extended with two systems of 110 kV each. Such a combination is efficient for countries where the track territory is limited and the permission for line erections requires year long legal procedures. Towers carrying up to six phase systems have been erected in Central Europe. At the higher voltage levels only single lines are common. Here a second tower track will be established for ensuring N-1 reliability.

Examples of tower constructions for various voltage levels containing different types of insulators are depicted in Fig. 3.40.

The 400 kV double line in Fig. 3.40a is protected against atmospheric lightning by one ground conductor. The ground conductor and the phase conductors of both systems build a triangle and the ground conductor lightning protection zone may cover the whole triangle. This effect cannot be achieved with the higher distances of the phase conductors at the 750 or 1000 kV lines. Therefore, two ground conductors are foreseen.

In Fig. 3.40 is visible that the phases are performed by a bundle of conductors.

The bundling of conductors starts with the EHV level and has two functions:

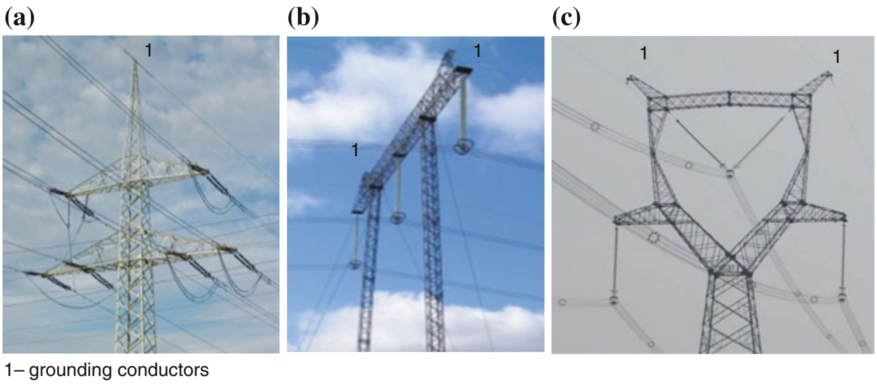


Fig. 3.40 Tower constructions for EHV and UHV AC transmission lines: **a** 400 kV double system line with porcelain stick insulators, **b** 750 kV—single line with glass cap insulator strings, c 1000 kV—single line with silicone composite insulators (*Source* IEC)

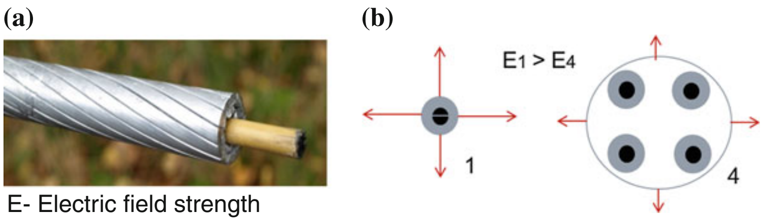
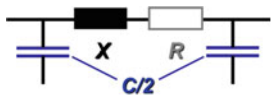


Fig. 3.41 **a** Aluminium-steel conductor and **b** the effect of conductor bundling

Fig. 3.42 The equivalent scheme and parameters of electric power lines



1. Increase of the equivalent diameter of the conductor surface to decrease the electric field strength "E" at the conductor surface. In the result the energy losses caused by the corona effects (ionization of the air environment) may be reduced.
2. Growth of the conductor cross section and reduction of the electric resistance: In the result the energy losses caused by the current flow may be reduced.

The conductor bundling effect is demonstrated in Fig. 3.41.

Each line can be represented by an equivalent scheme of the resistance R, the reactance X and the capacitor C in accordance with Fig. 3.42. The parameters define the behaviour of the transmission line in operation.

The line resistance R causes energy losses and voltage drops along the line.

Table 3.4 Typical parameters of transmission lines

V_{ph-ph}, kV	Number of conductors	X', Ω/km	R', Ω/km	C', nF/km	SIL, MVA	S_N, up to MVA
110	1	0.4	0.12	9.5	33	60
220	2	0.35	0.08	12.5	160	250
400	3–4	0.32	0.02	14	600	1000
500	4	0.3	0.018	15	1000	2000
750	6	0.28	0.012	13.5	2300	4000
1000	8	0.26	0.008	14	4100	11000

Source Siemens AG, D. Retzmann

The line reactance X causes reactive power losses and voltage drops proportional to the current flow.

The line capacitor C generates reactive power proportional to the voltage and increases the voltage at the line end.

The influences of X and C impact in opposite directions:

- If the line is heavily loaded the dominant effect comes from X and the voltage is reduced. This impact may be dangerous because it can lead to a voltage collapse causing instabilities in the power system. Voltage collapse was the main reason for the large black-outs in North America, Sweden/Denmark, Italy, Greece and Russia in the period between 2003 and 2005 (see also Sect. 5.1)
- If the line is weakly loaded the dominant effect comes from C and the voltage will be increased. This impact is dangerous because it can lead to over-voltages which may harm the equipment and cause protection trips.

For each line construction a natural load or surge impedance load (SIL) exists where the voltage at both ends is equal (reactive power losses are equal to the capacitive reactive power generation). Logically, the rated transmission capacity S_r is selected above the SIL. In this way, the voltage declines along the line in the direction of the active power flow.

Table 3.4 presents an overview of the number of bundled conductors, the average values of the line parameters, the SIL and the normally used power transfer capacity S_N.

It can be seen that the reactance value is many times higher than the resistance. The higher the voltage level, the lower the values of R and X are.

The capacitance is influenced by the diameter of the bundled conductors (increase) and the distances between the phases and to the ground (decrease). Therefore, a trend dependency of the voltage level is not clearly visible.

Accordingly, the Smart Grid requirements regarding the higher transfer capacity and enhancement of existing transmission lines with high temperature conductors is foreseen. Such conductors can continuously transfer load currents over 3 kA. Despite such a strong increase of power transfer, the ratio of X and C does not change. It is a task of the network planners to avoid any voltage management trouble by applying high temperature conductors.

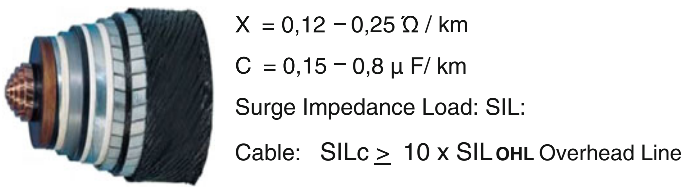


Fig. 3.43 A single phase EHV cable construction and the range of parameters

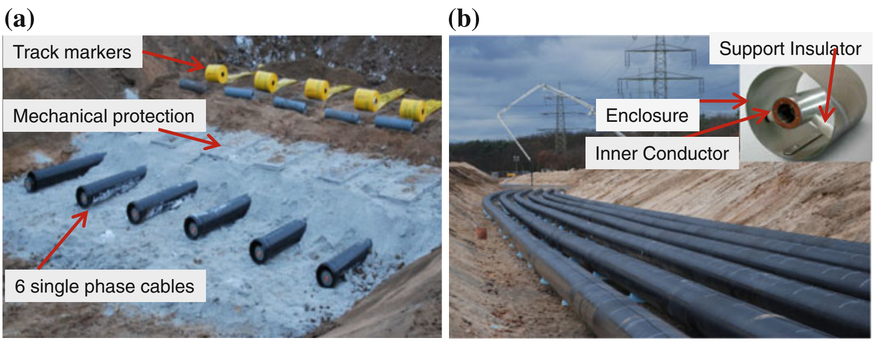


Fig. 3.44 **a** Two systems 400 kV underground cable **b** 400 kV GIL systems (Frankfurt airport) (*Sources* **a**—Amprion GmbH, **b**—Siemens AG)

The parameters of GIL are similar to the overhead line parameters. Therefore, it is not problematic to combine overhead lines and GIL in line tracks.

The parameters of cables, however, strongly differ. The X-value is slightly lower compared to overhead lines, while the capacitance is more than 10 times higher (see Fig. 3.43).

Consequently, the SIL is more than ten times higher than that of the overhead lines (OHL).

However, due to the lack of natural air cooling, the cable's power transfer capacity is strongly limited by the thermal design: typically 20–25 W per m of cable (according to the cable manufacturers data) and is significantly below the SIL. The normal loading below the SIL shifts the reactive power balance along the cable into a surplus of Q generation.

Consequently, the distance of EHV cable lines is restricted and longer distances require the installations of reactors for reactive power compensation to keep the operating voltage within the standardized bandwidth.

At the EHV level, cables perform single phase lines.

Examples for buried cables and GIL are shown in Fig. 3.44.

The Fig. 3.44a shows a 400 kV cable track. The underground laying of two GIL systems and the construction of a GIL phase conductor is presented in Fig. 3.44b. It consists of metal enclosure filled with pressurized SF_6 gas, the inner conductor and the support insulators.

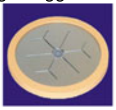
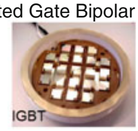
CSC or LCC	VSC
Current Source Converter	Voltage Source Converter
Line Commutated Converter	IGBT
Light triggered thyristor	Insulated Gate Bipolar Transistor
	
≤ ± 800 kV	≤ ± 350 kV
≤ 10 GW	< 2 GW (1 GW/converter - 2012)
Node to node	Multi terminal
Network commutated	Self commutated
Needs external voltage	Generates voltage
No black starts	Black start capability
Needs reactive power	Controls reactive power
Quenching by zero current	Quench angle controllable

Fig. 3.45 Comparison of the HV DC technologies

3.3.3 DC-Transmission

The conversion of AC to DC power and vice versa requires an active and fast control of the valves in the converter stations.

Two converter valve technologies are currently available:

- Current source converters (CSC) or line commutated converters (LCC) applying light triggered thyristors (LTT).
- Voltage source converters (VSC) applying insulated gate bipolar transistors (IGBT).

The main characteristics of both technologies are summarized in Fig. 3.45.

The valves are controlled by light triggering of the gate. The gate status opens or blocks the current flow through the valve. The converter valves have restricted rated voltages (∼6 kV) and currents (∼4 kA). Therefore, the rated voltage and power of a converter station has to be reached by the parallel and serial cascading of the converter valves in towers.

Figure 3.46 presents such a valve tower allocated in the valve hall of the Fengxian UHVDC converter station belonging to the Xiangjiaba-Shanghai 800 kV UHVDC project of the State Grid Corporation of China.

The conversion process is demonstrated in Fig. 3.47 with the six-pulse converter scheme (bottom left).

The 3 phase AC system A-B-C delivers phase to ground voltages with angle shifts of 120° between the neighbouring phases. The voltages at the valves will be "cut" into sections so that the highest voltage of the same polarity is connected to the DC circuit and provides the DC voltage V_d. The valve can be switched by the trigger signal from the blocking state into the conducting state if the voltage at the valve has a positive direction.

Fig. 3.46 Transformer bushings and valve towers of a ±800 kV converter station (*Source* ABB AG)

In accordance with the opposite connection scheme, the valves 1, 3, 5 on one side connect the positive voltages, and the valves 2, 4, 6 on the other side connect the reversed negative voltages to the DC circuit. Whenever the values of the neighbour phases are equal, the transition to the converter with the rising voltage occurs. In this "natural" sequence the triggering angle of the positive waves α is equal to 0 and of the negative wave β is equal to 180° (diagram I right on the top). Diagrams II to V demonstrate how the DC voltage V_d may be controlled and reversed by applying angle combinations. In these cases the opening of the thyristor is delayed depending on the natural opening moment. When $\alpha = 180°$ and $\beta = 0$ the polarity of the maximum DC voltage is reversed. On the left-hand side, the sequence of the DC current flowing through the valves is shown. The AC phase currents may flow only over the open valves. In sum of all valve currents a permanent current flow over the DC circuit is reached. The thyristors will be switched off when the current is flowing through zero.

With regard to the converter scheme, the current flows in the opposite direction if the DC voltage is negative (Cases IV, V). This fact reflects the typical restriction of the CSC technology, namely that a change of the power flow direction requires a change of the voltage polarity.

After the conversion the DC voltage continues to alternate, and harmonic frequencies are superposed. A sufficient damping of the harmonics can be reached in two ways:

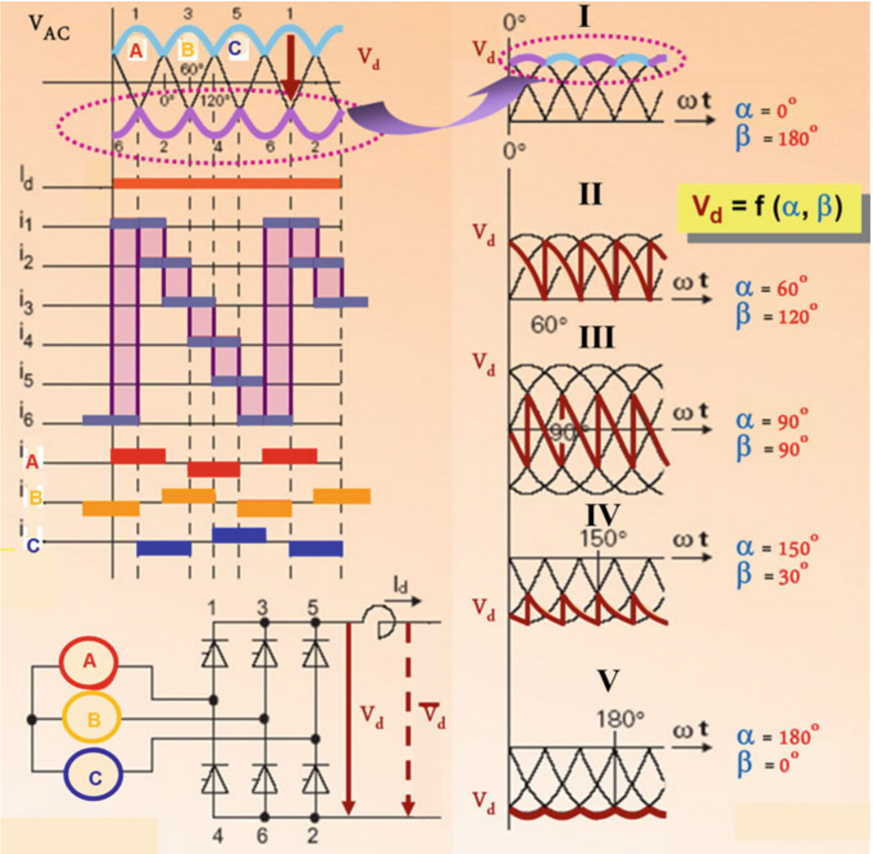


Fig. 3.47 AC–DC conversion sequences

- by a parallel DC filter building LC- resonance circuits for the voltage harmonics,
- by the parallel operation of two AC systems in a 12 pulse converter scheme with a phase shift of 30°. The phase shift is reached by two parallel transformers whereby the secondary windings of one are Y connected and of the other are triangle connected.

Figure 3.48 presents the related scheme.

The AC filters are dimensioned to eliminate the harmonic distortions generated by the converters in the AC circuits. The equalizing reactor is used to avoid a current flow interruption in the case of a low power flow and to limit the DC fault currents.

The line commutated converter requires that the current follows the voltage. Consequently, reactive power has to be available at the AC busbar. Often the AC filter schemes are engineered in such a way that the reactive power is generated at the basic frequency 50 Hz.

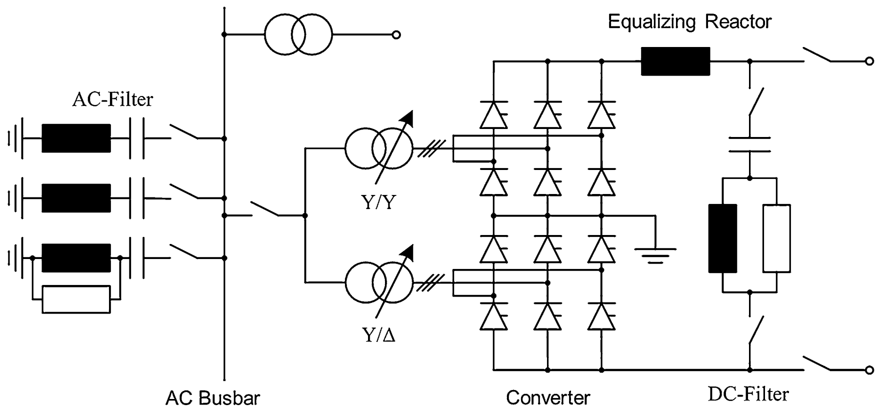


Fig. 3.48 Scheme of a 12 pulse AC–DC converter

The DC–AC conversion uses the identical scheme and performs the interruption of the DC voltage with polarity change every 10 ms per phase (half wave 50 Hz). The same filter technology with resonance loops for the dominating harmonic frequencies is applied.

The main benefit of the self-commutated VSC technology consists in the higher control flexibility. Here the current flow can be interrupted outside the zero crossing. These valves allow for a current flow in both directions without needing to change the voltage polarity. Thus, the establishment of meshed or multi-terminal HV DC networks becomes possible. The reactive power can also be controlled and the converter station may autonomously recover the voltage. Consequently, the black start capability is used. However, the voltage level and, subsequently, the power transfer capacity of the VSC technology are still lower than the CSC or LCC method.

Further, the energy losses of the converter stations are 50 % higher for the VSC technology and amount to 1.5 % on average. Therefore, the large bulk power transmission projects apply the traditional CSC converter technology. The world's first ±800 kV/5000 MW converter substation is operated in China. A view of this substation is depicted in Fig. 3.49.

The additional primary elements of a U/EHV DC transmission link are the transformers and the line itself. Examples are presented in Fig. 3.50.

In accordance with the high rated power and voltage the UHV DC transformers are manufactured as single phase transformers. The size of the 800 kV transformer and the bushings are very impressive when compared to the people standing nearby (bottom left corner of left picture). Figure 3.50 also presents the size parameters of the ±800 kV tower and a view of the line in the landscape.

The resistance of the lines (0.007 Ω/km for ±800 kV) is similar to the adequate AC transmission lines and therefore, the line energy losses are on the same level, e.g. 2.7 % for a 1000 km line with a power transfer of 5 GW.

Fig. 3.49 The ±800 kV converter substation Fulong-Xiangjiaba-Shanghai (*Source* ABB AG)

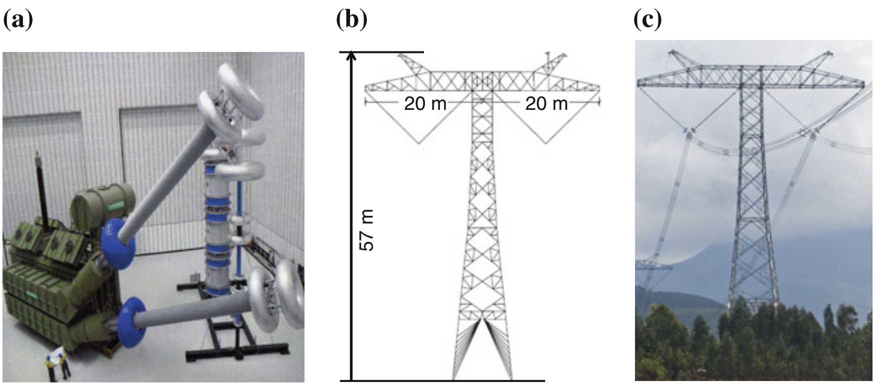


Fig. 3.50 Assets for the ±800 kV DC transmission: **a** Transformer, **b** Measurements of the line tower, **c** Line in operation (*Source* Siemens AG)

At present, DC fault currents are still best and most swiftly interrupted by the converters themselves. No true DC circuit breakers exist yet, although developments and prototype tests have been ongoing for many years. Basically, DC circuit breakers may be realized by

- pyrotechnic type interruption,
- traditional AC circuit breakers modified for DC,
- electronic current control by semiconductors,
- a combination of such solutions.

Metallic return transfer breakers with a limited DC current interruption capability have been successfully applied in a number of DC schemes [3]. They include parallel reactor–capacitor resonance circuits that create an artificial current zero crossing.

3.3.4 Flexible AC Transmission Using Active and Reactive Power Control

The power system of the future must be flexible, secure, cost effective and environmentally compatible. The combination of these tasks can be tackled with the help of intelligent solutions. Flexible AC Transmission Systems (FACTS) will play an increasingly important role in the future development of power systems.

FACTS consists essentially of the power reactors and capacitors for reactive power management and the power electronic equipment, i.e. converter valves and power electronic controllers together with their dedicated control and protection system.

The three function principles of FACTS may be explained on behalf of the equation for AC active power transmission according to Fig. 3.51.

The impact of FACTS on the power transfer is achieved by:

1. Parallel compensation: control of the voltages on one or both sides of the transmission line. Higher voltages cause a higher power transfer.
2. Series compensation: reduction of the line reactance through serially connected capacitors.
3. Load flow control: influence of the voltage angle difference between the line ends.

Parallel compensation uses parallel connected capacitors and reactors at one or both line ends. The capacitor generates reactive power (+Q) and increases the voltage while the reactor demands reactive power (−Q) and reduces the voltage. The power electronic control is able to change the reactive power balance from maximum +Q to maximum −Q or reverse within $\sim$40 ms.

Depending on the converter technology two kinds of compensators are applied:

- SVC—Static Var Compensator—based on LTT valves,
- STATCOM—STATtic synchronous COMpensator—based on IGBT.

Parallel compensation performs the voltage control and reactive power control. Furthermore, the fast control opportunities create a positive impact on the system stability and allow a fast damping of power and voltage oscillations after faults. Remember that voltage oscillations were one of the root cases for the Italian blackout in 2004.

Figure 3.52 presents an example of how the stability improvement can be achieved. After a short circuit on the line between network 1 and substations A, strong oscillations of the voltage at the substation and of the active power flow to network 3 were observed. The reactive power control may be performed in two ways:

- Voltage control leads to the instantaneous damping of the voltage oscillations,
- Power swing damping shortens the duration of the active power swing and damps the voltage oscillations.

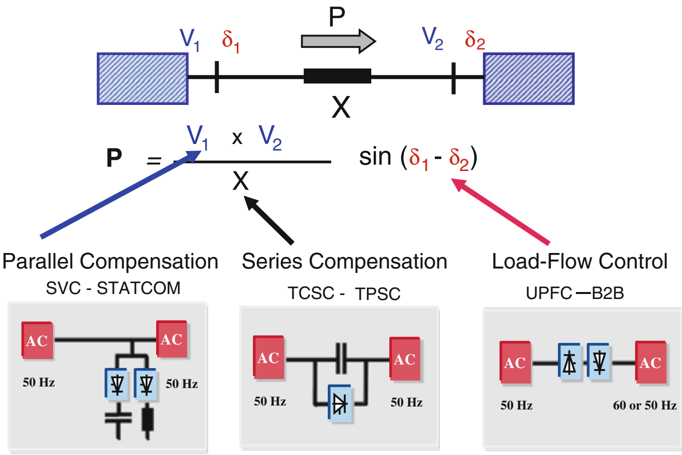


Fig. 3.51 The function principles and schemes of FACTS

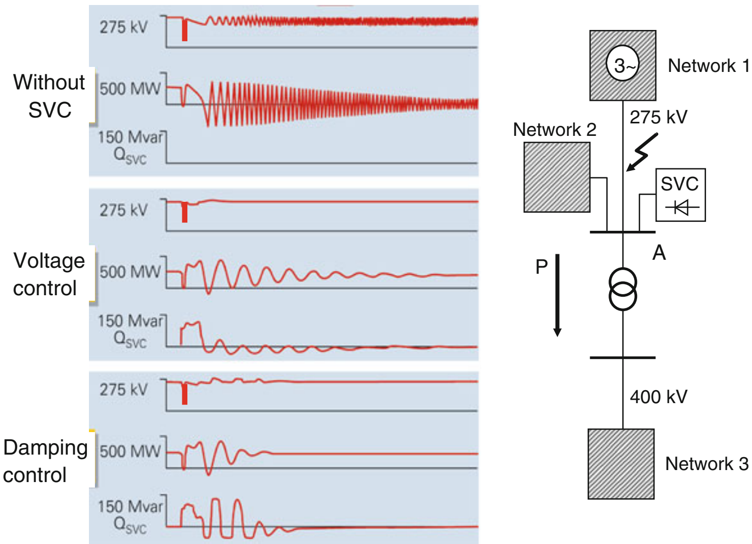


Fig. 3.52 Demonstration of the SCV impact on system stability (*Source* Siemens AG, D. Retzmann)

Figure 3.53 presents the view of an SVC plant with an installed reactive power of ±250 Mvar.

The series compensation connects a capacitor serially with the transmission line, decreasing in this way the line reactance ($X = X_L - X_C$). For control purposes the capacitor may be connected to a parallel circuit containing a reactor and

Fig. 3.53 SVC plant ±250 Mvar (*Source* Siemens AG)

Fig. 3.54 TCSC installation of a 500 kV line (*Source* Siemens AG)

converter equipment. This type of plant is called TCSC (Thyristor Controlled Series Compensation).

If additional protection functions are included the plant is called TPSC (Thyristor Protected Series Compensation). In Fig. 3.54 a TCSC plant installed at a 500 kV transmission line with a length of 500 km is depicted.

The effects of this installation can be described as follows:

- the power transfer capacity is doubled,
- the stability limits are extended,
- the power oscillations after faults can be quickly damped.

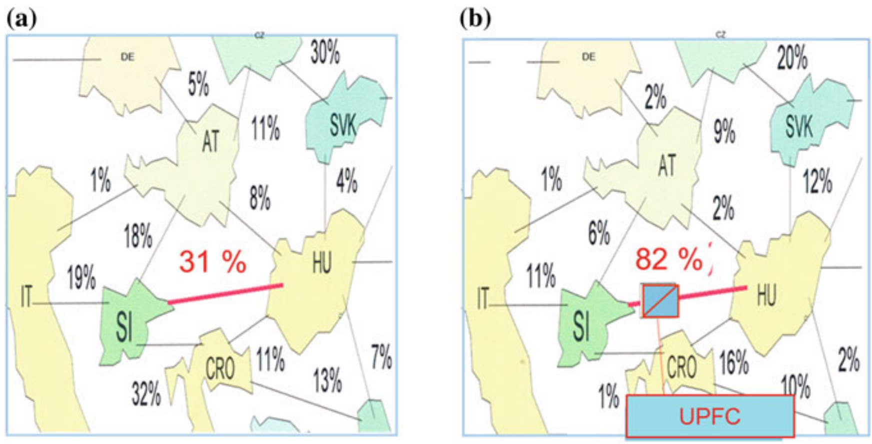


Fig. 3.55 Power flow conditions **a**—without and **b**—with by UPFC operation (*Source* Siemens AG, D. Povh)

The power flow control is based on:

- the AC-DC-AC conversion using a HVDC—Back to Back coupler HVDC B2B, or
- the series and parallel connection of converter plants building a plant called UPFC (Unified Power Flow Controller) which is based on IGBT converters for influencing the voltage angle.

The HVDC B2B is also globally used to connect two autonomous synchronous power systems for power exchange without mutual influence on the frequency or voltage quality.

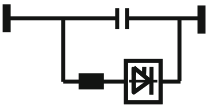
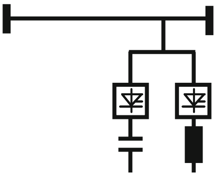
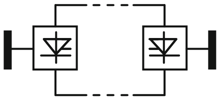
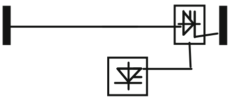
Three such plants were operated at the border between the Western and Eastern European power systems until the synchronous connection of part of the Eastern European countries to the UCTE system was built in 1994.

The efficiency of a UPFC is shown in Fig. 3.55 depicting the power flow bundling between Hungary and Slovenia. In the normal case only 31 % of the power flow between the countries is transmitted over the direct transmission links. The other 69 % of the power flows over the neighbouring networks and causes additional power losses. The installation of the UPFC improves the situation greatly and increases the direct power transfer up to 82 %.

The impact of the FACTs principles is described in Table 3.5.

The FACTS technology is approved and mature and is operating in thousands of projects worldwide. An exception can be found in Central Europe where there was no need for FACTS installations in the past because of the high network density. Now, however, the FACTS technologies build a significant module for meeting the Smart Grid challenges—also for Central Europe.

Table 3.5 Principles, basic schemes and impact of FACT

Principle	Devices	Scheme	Impact on system performance[a]		
			Load flow	Stability	Voltage quality
Variation of the line reactance	Thyristor Protected Series Compensation (TPSC)		•	•••	•
Series compensation	Thyristor Controlled Series Compensator (TCSC)		••	•••	•
Voltage control	Static Var Compensator (SVC)		·	••	•••
Parallel compensation	Static Synchronous Compensator (STATCOM)		·	••	•••
Load flow control	HVDC Back to Back (B2B)		•••	•••	••
	Unified Power Flow Controller (UPFC)		•••	•••	•••

[a] *Influence* · low or no • small •• medium ••• strong
Source Siemens AG, D. Retzmann

3.4 Present Challenges for Transmission Grids

3.4.1 The Impact of Fluctuating Wind and Solar Power Generation

The installed power of wind parks and photovoltaic plants will grow dramatically and, depending on the development concepts for the energy mix, it may exceed the peak power demand in a control area. The power generation from wind and sun varies significantly and influences the loading of the network assets (see Sect. 2.5). The volatility challenge is demonstrated in Fig. 3.56.

The total installed power of a wind or a photovoltaic plant can be rarely used, and over long periods of time the wind power output of single plants goes down to zero. The photovoltaic plants deliver power during the daylight only, and during the day each cloud can lead to intermittency. Typical power generation statistics have been developed based on years of experience. Building an equivalent square

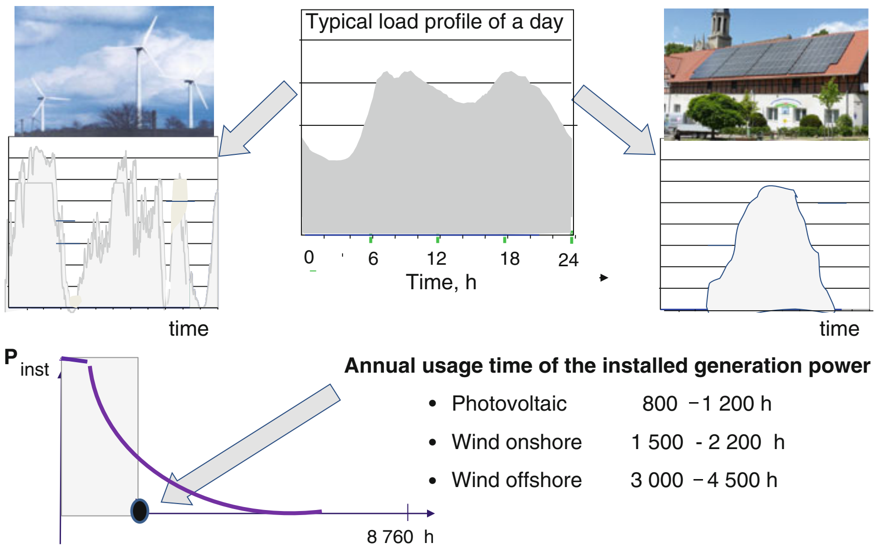


Fig. 3.56 A typical load profile and possible generation profiles of wind and sun

of the annual power availability diagram the average usage times for photovoltaic and wind power plants presented in Fig. 3.56 can be stated.

This behaviour has two impacts on the power system:

1. The power generation of wind and sun shall be predicted and included in the schedule management. However, the prediction tools have only limited accuracy. Significant deviations from the predicted schedules may occur, and the availability of reserve power has to be increased significantly.
2. The loading of network assets will become volatile as well. In accordance with the fluctuations of a significant contribution in the power balance the network dispatching will become more complicated and require more attention and supporting tools than in the past.

The transmission operators today apply sophisticated prediction tools to integrate the volatile renewable energy sources into the schedule management. For example, a German transmission system operator applies three prediction tools from various vendors and performs a day ahead schedule by combining the results of the three tools.

Nevertheless, significant deviations of the forecasted power generation may occur. Figure 3.57 demonstrates an example. The observed deviation of 4 GW is not a single case, but occurs multiple times within a year. The 40 % deviation from the predicted power generation in this example underlines the need to qualify the prediction methods and to reduce the prediction errors by repeated intraday predictions. A shorter forecast period means that a higher accuracy rate can be achieved.

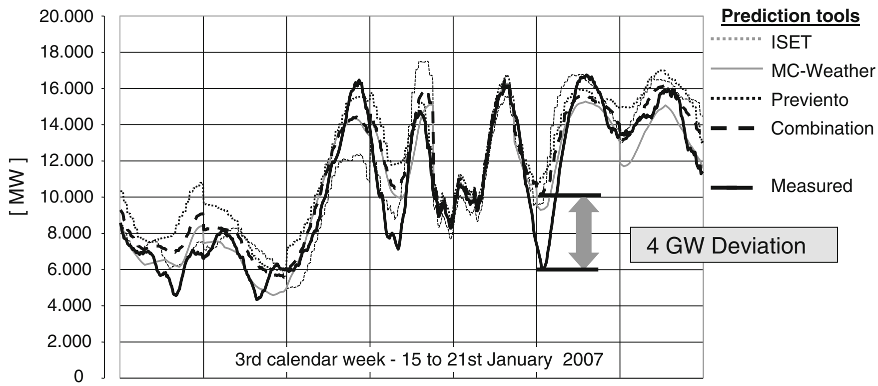


Fig. 3.57 Example of wind power prediction by various methods and the real projections (*Source* Vattenfall Europe Transmission GmbH)

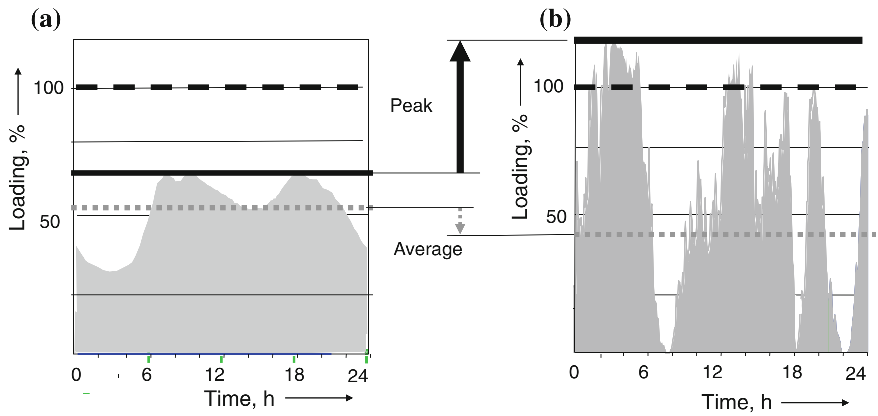


Fig. 3.58 The change in the loading profile character of the network assets **a**—traditional loading, **b**—volatile loading situations in the Smart Grid

The second significant impact of generation volatility is the intermittent loading of the network assets. In the past the loading profile was similar for each day with only slight variations. Nowadays, in the environment of large scale volatile power in-feed the situation has changed fundamentally. It can be observed that the average of the network loading is decreased caused by the growing shares of distributed power generation in the underlying networks. But in rare situations the peak loading of network assets may exceed the thermal asset limits as shown in Fig. 3.58. Consequently, more observation and methods for congestion management are required to operate the networks at today's high level of security and reliability.

3.4.2 The Dislocation of Generation and Load Centers

Formerly, in Central Europe the electric power stations were erected near the coal mines and/or water resources (hydro power, cooling of nuclear power stations). The industrial and urban centres developed in parallel with the local power stations and the main focus was directed to regional and local distribution. The tasks of the transmission networks were restricted

- to exchange power for the coverage of daily peaks and benefit the different time schedules in the various regions,
- to provide support in emergency situations.

Nowadays, large wind power plants are erected in onshore and offshore locations far away from the existing load centres. Furthermore, the electric energy trade crosses country borders. In this way, the new task of transmission is

- bulk power transmission over longer distances.

The best example for such a trend is Germany where all nuclear power stations (mainly located in the south) have to be shut down by 2022, which is equal to $\sim$25 % of the overall power production in 2010. Additionally, by 2030 strong offshore wind farms will be erected in the North and Baltic Seas with an installed power of 28 GW far away from the load centres in central and southern Germany. As previously shown in Sect. 1.3, this development will lead to a significant dislocation of generation and load centres.

The existing transmission networks are not prepared for these new tasks. Consequently, the transmission networks have to be significantly enhanced to meet the new challenges as presented in Fig. 3.58 (and also in Fig. 1.11). Therefore, the transmission system operators developed the transmission network development plan [4] according to Fig. 3.59.

The transmission network development requires the following projects [5] (according to the scenario B2022):

- four tracks of Extra High Voltage Direct Current (EHVDC) lines with a length of 1800 km and a capacity of 12 GW,
- additionally transformation of 300 km AC—lines to EHVDC lines,
- Erection of 1700 km of new line tracks for the 400 kV AC network extension,
- Strengthening the power transfer capacity on 3400 km of existing AC lines (voltage level enhancement 220–400 kV, replacement of the conductor by high temperature conductors and new constructions).

According to this concept, in the AC transmission network the 400 kV level will be kept and most of the 220 kV network will be transferred to 400 kV. Existing tracks will enhanced in an optimum way to bring down the need for new tracks to a minimum. The innovations are focussed on the introduction of an EHV DC overlay network.

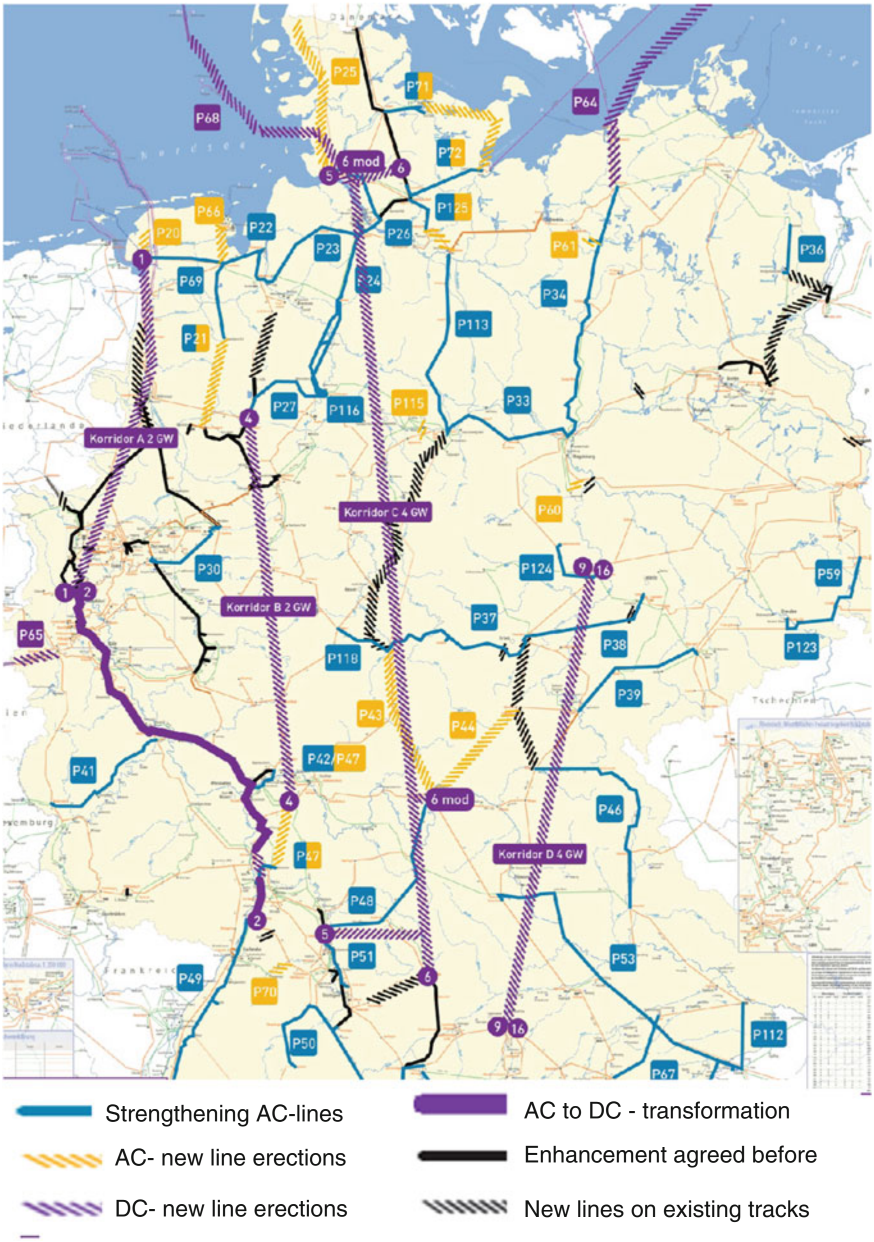


Fig. 3.59 Transmission network development Germany—plan 2013 (*Source* NEP 2013, 2nd edition July 2013, www.netzentwicklungsplan.de [4])

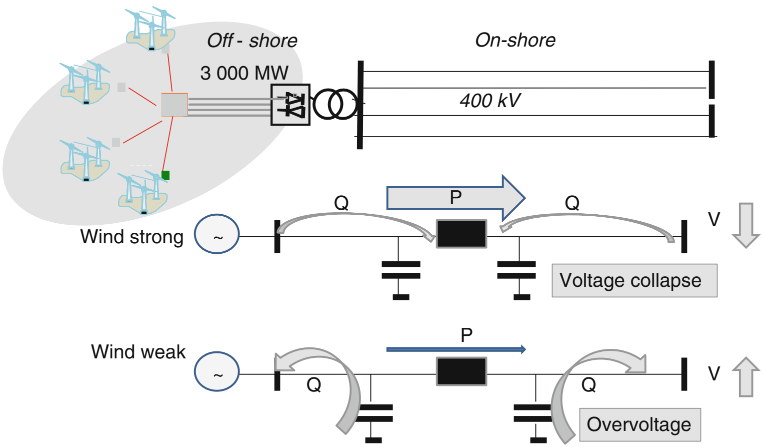


Fig. 3.60 Extreme reactive power conditions caused by wind power volatility

The described enhancement of the transmission network is not the whole picture for meeting the dislocation challenges. Namely, the wind power generation depends on the weather conditions and is volatile. In this sense, it may happen that the AC network loading varies significantly.

During strong wind periods the AC network is heavily loaded and high losses of reactive power may lead to voltage reductions accompanied by the danger of voltage collapses. Alternately, during weak wind periods the AC network is weakly loaded and an excess of reactive power may cause over-voltages. In Fig. 3.60 these conditions are demonstrated.

As a result of such extreme network condition changes the installation of FACTS to compensate for the volatility of reactive power flows will become mandatory.

3.4.3 *Power In-Feed by Power Electronics and Short Circuit Power*

The photovoltaic power plants generate DC power and need converters for network connections. The majority of wind parks are equipped with wind generators feeding the network via power electronic converters. The schemes of the doubly-fed induction generator and the synchronous generator with frequency conversion are shown in Fig. 3.61.

The converter connected power plants are not able to deliver such a significant short circuit power as the synchronous generators do. The fault ride through characteristics of the power, voltages and currents for a converter connected synchronous generator are depicted in Fig. 3.62.

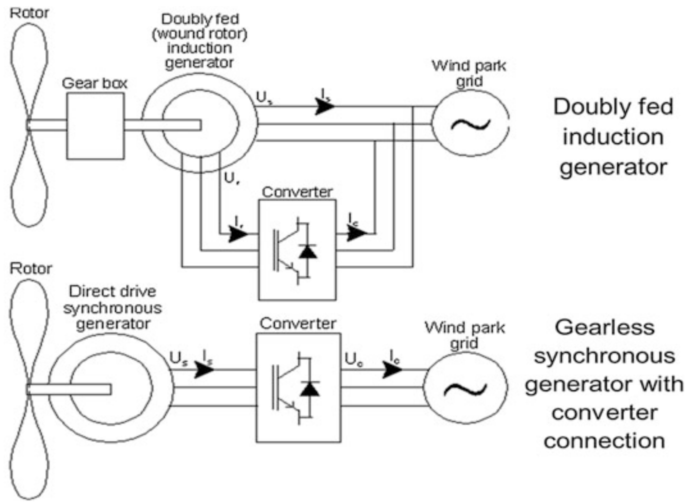


Fig. 3.61 Commonly used types of wind power plants

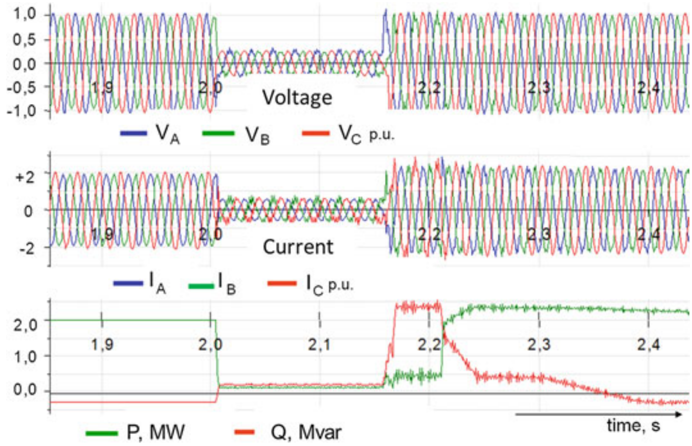


Fig. 3.62 Fault ride through of a converter connected synchronous wind generator (*Source* Siemens AG, PSSE—Netomac simulation without methods of short circuit current increase)

In relation to the decreased voltage the short circuit current will be significantly below the rated current of the generator. However, secure system operation and identification of faults on the network by the protection equipment require the provision of short-circuit currents, which in terms of their magnitude and angle clearly deviate from load currents (minimum short-circuit current). An adequate short circuit power is always requested for fast and selective fault clearing. Furthermore, if during strong wind periods all traditional power stations with

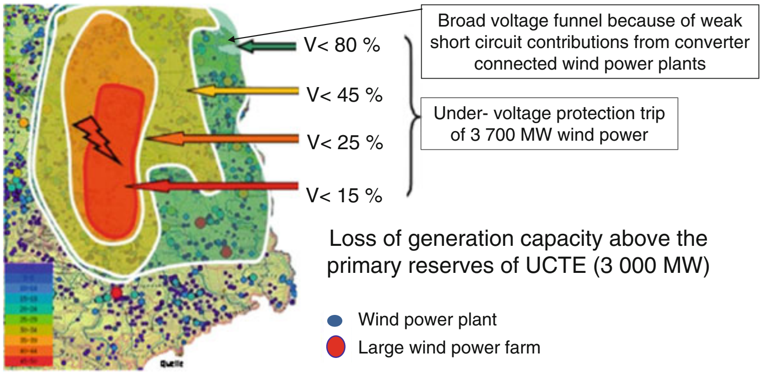


Fig. 3.63 Areas of voltage decrease after a three phase short circuit and the consequences (*Source* Vattenfall Europe Transmission GmbH 2006)

synchronous generators are switched off the voltage funnel around the short circuit location will be significantly increased because of the lack of short circuit power. Figure 3.63 demonstrates such a situation under real three phase short circuit conditions in the 400 kV transmission network of the TSO “50 Hz Transmission GmbH” in a region of Saxony–Anhalt (Germany) with dominating wind power.

In the area of the voltage decrease <80 % about 4500 MW of wind power are installed. A strong wind situation is achieved when 80 % of the installed wind power feed into the network. Consequently, 3700 MW of wind power will be tripped by the under-voltage protection which is normally set at 80 %. This loss of generation is 20 % above the primary reserve of the whole UCTE transmission network. Such a situation may easily lead to large system disturbances including the possibility of blackouts.

To avoid the enlargement of such disturbances the German Transmission Code [6] established new requirement especially regarding the fault ride through behaviour of wind power plants. After a network fault, the wind power plants have to buffer the voltage by supplying inductive reactive current. This reactive current must be made available in addition to the operational reactive power supplied prior to the fault. Reactive current shall be provided within 20 ms after occurrence of the fault and can be limited to the rated current of the generating unit. Applying this rule, the voltage funnel in the example area may be decreased three times.

Secondly, a trip of the wind power plants by under-voltage protection is no longer allowed. They have to remain connected for the duration of the fault.

A second issue of the converter connected renewable energy sources is the strong demand of reactive power in the voltage recovery process after the fault trip, as shown in Fig. 3.62.

This behaviour delays the fast voltage recovery and a solution to avoid disturbance enlargements is necessary. The Transmission Code [6] also gives an answer for solving this problem. Figure 3.64 presents the related diagram fixing the new requirements regarding the fault ride through capability of wind power plants.

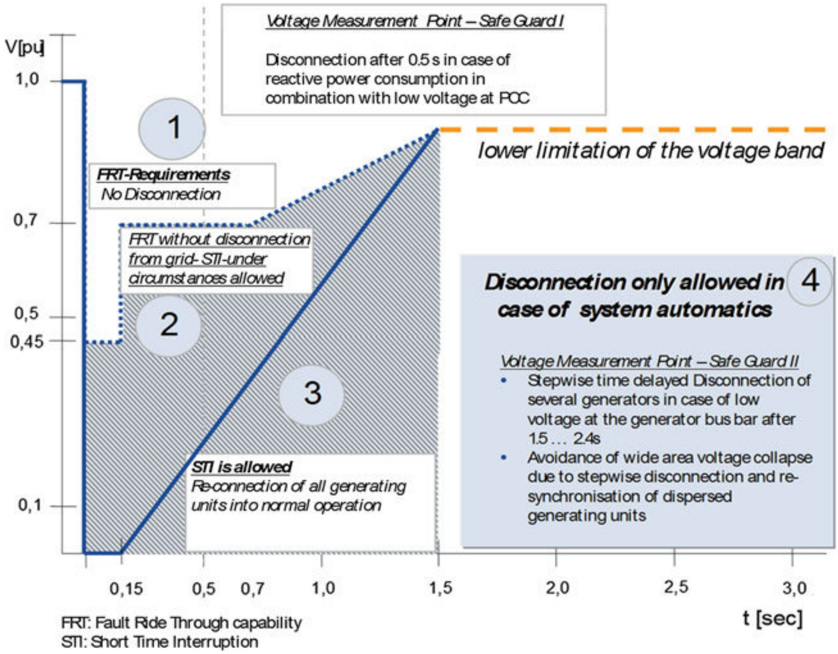


Fig. 3.64 Grid Code rules for fault ride through of wind generators [6]

After the appearance of a fault and the subsequent fault clearing all wind generators with voltages above the border line between the areas 1 and 2 continue to be connected to the network. This is mandatory if the voltage decrease is less the 55 % of the rated voltage.

In case of lower voltages a short time interruption is possible only under certain conditions. At 1.5 s after the fault appearance and 1.35 s after the trip the voltage recovery should be finished, as described with zone (2). In this area in principle all generators continue to be connected to the network. A short time interruption is permitted only under special circumstances. However, if after 0.5 s the voltage does not recover due to the strong reactive power demand then the disconnection of the wind generator is definitely required below the blue curve within zone (3).

After recovery of the voltage into the operational bandwidth a further supervision of the voltage development is required. In cases of bandwidth violations the stepwise disconnection is automatically performed in zone (4) in the time frame between 1.5–2.4 s. With this approach it is ensured that at 2.4 s after the fault appearance the power system recovers into stable operation.

The proper control and automatic facilities avoid the enlargement of the disturbance into a voltage collapse. The majority of wind generator manufacturers are able to meet the above described requirements.

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Chapter 4
Design of Distribution Networks and the Impact of New Network Users

4.1 Categories of Distribution Networks

The definition of distribution networks is currently not consistent throughout the global community of power system operators. In Table 4.1 an overview of the level and category definitions is given.

The distribution networks are designed to distribute the electric energy to the consumers in a maximum economic and reliable way. Consequently, the practice of application of the N-1 reliability criterion is differently applied depending on the voltage level and the impact on the reliability of supply.

The HV networks of the regional distribution (sub-transmission) have to meet the N-1 criterion in the same way that the transmission networks do: The operation has to continue after the trip of a network asset without any time delay. Therefore, the configurations, the automation, remote control facilities, the protection schemes and the operational practice of the HV distribution networks are, in general, common with that of the transmission systems.

Therefore, in this chapter the considerations are mainly focussed on the practice of the local distribution networks at the medium and low voltage levels. (sub-transmission is considered in Chap. 3).

In general, the N-1 criterion is also valid for MV and LV distribution networks. But, different from the overlaying grids (HV), here a supply interruption until the recovery after fault trips is possible (see also Sect. 1.2, Fig. 1.7 of Chap. 1).

The regional and the local distribution networks are normally operated by different Distribution Network Operators (DNO).

This chapter is mainly based on the lectures "Electricity grids", "Medium voltage technologies", "Energy automation", within the education program "Power transmission and distribution technologies at a glance," which were compiled and held by Dr. B. M. Buchholz at the Siemens Power Academy until 2009 [1]. The figures are partially based on the product manuals of Siemens AG. Other vendors are offering similar products with comparable functions and characteristics.

B. M. Buchholz and Z. Styczynski, *Smart Grids – Fundamentals and Technologies in Electricity Networks*, DOI: 10.1007/978-3-642-45120-1_4,

Table 4.1 Voltage levels and definitions of network categories

Voltage level	Continental Europe		Other countries	
	Rated voltages (kV)	Category	Rated voltages (kV)	Category
Low (LV)	0.4	Local distribution LV	0.2, 0.4	Distribution
Medium (MV)	6, 10, 20, 30	Local distribution MV	4–35	Distribution
High (HV)	110	Regional distribution	>60–110–150	Sub-transmission

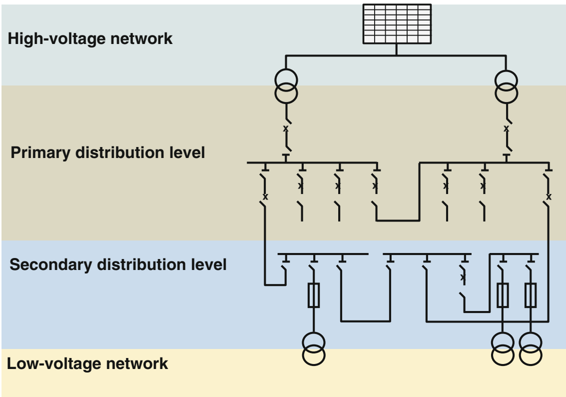


Fig. 4.1 Principle schemes of MV distribution networks

4.2 Primary and Secondary MV Distribution

The MV distribution network begins at the transformer in-feed from the overlaying network (mainly 110 kV), whereby the transformer is connected to the medium voltage busbar.

In about 80 % of the 110 kV/MV substations a single busbar system with a protected longitudinal sectionalizing by a circuit breaker and isolators is applied. Double busbar systems are used in cases of higher reliability requirements. Figure 4.1 presents the scheme of MV networks with a split into primary and secondary distribution.

The primary distribution equipment has to be dimensioned for load currents up to 4,000 A and for short circuit currents up to 72 kA. The feeders connected to the busbar of the substation are equipped with circuit breakers and protection schemes. The primary distribution switchgear is normally encapsulated in metallic cubicles and allocated in buildings.

The modern circuit breakers of the MV feeder are based on vacuum tubes. The surge after a current interruption is quenched quickly in a vacuum because of the unavailability of any ionization media. Figure 4.2 presents a vacuum interrupter and two complete MV circuit breakers of different types.

The majority of feeder bays of the primary distribution are three phase encapsulated in switch cubicles containing the components presented in Fig. 4.3.

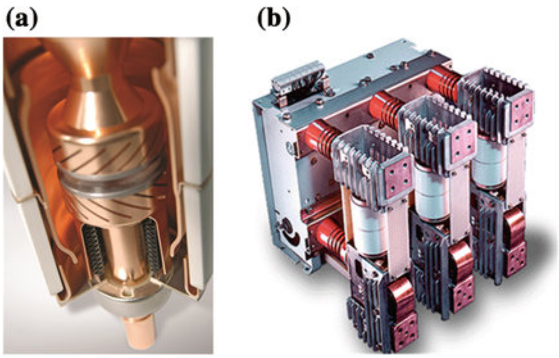


Fig. 4.2 **a** Vacuum interrupter **b** and **c** vacuum circuit breaker modules. *Sources* **a**, **b**—Siemens AG, **c**—Schneider electric energy GmbH

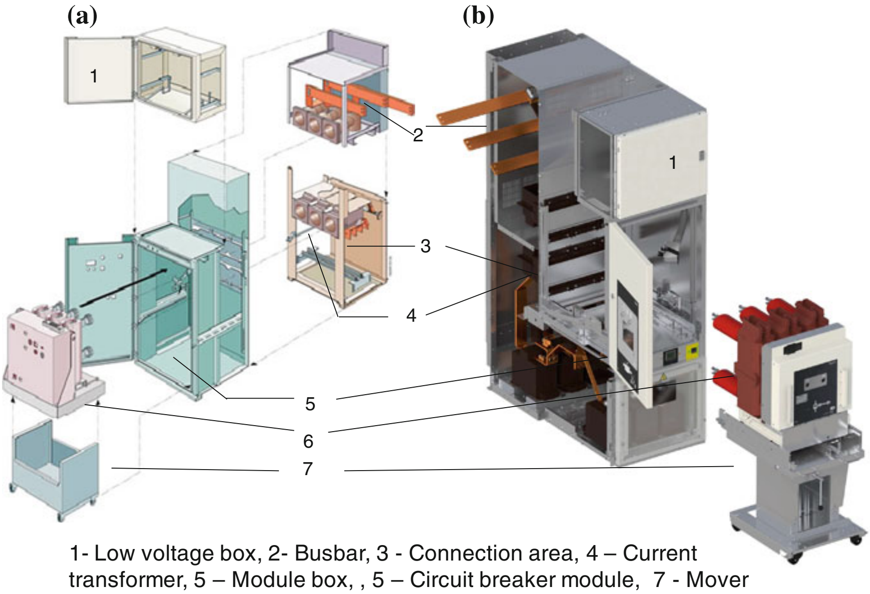


Fig. 4.3 Switch cubicle constructions. *Sources* **a** Siemens AG, **b** Schneider electric energy GmbH

The circuit breaker (CB) is fixed in the mover and the module box. Normally, the contacts of the CB are pressed by pressure resistant compartments to the connectors of the busbar and of the incoming cable in the connection areas. The upper area provides the connection to the busbar section.

In the status “OFF” the CB is removed from the cubicle. With this movement the visible disconnection from the connection area is performed, and this means that special isolators are no longer used in modern MV switchgear.

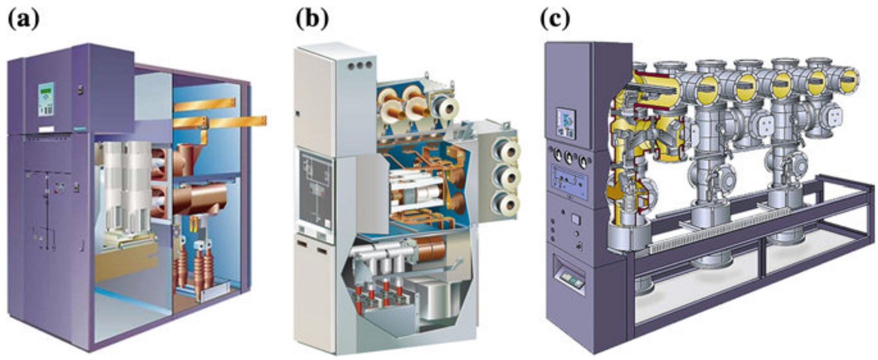


Fig. 4.4 MV switch cubicles: **a** air insulated three phase encapsulated, **b** gas insulated three phase encapsulated, **c** gas insulated single phase encapsulated for double busbar systems. *Source* **a**, **c** Siemens AG, **b** Schneider electric energy GmbH

In all three phases, the connectors contain bushing type current transformers.

The voltage transformer is available in a separate cubicle only once per busbar section of the substation.

A low voltage container is normally set on the top of the cubicle. It contains the low voltage wiring of the analogue and binary signals connected to the bay control and protection unit contacts.

The module box and the busbar container may be designed with air or with gas (SF_6) insulation. In the case of gas insulation the size of the cubicle can be reduced.

Figure 4.4 presents the three most differing switch cubicles of the primary distribution:

(a) a single busbar air insulated MV switch cubicle,
(b) a single busbar gas insulated MV switch cubicle,
(c) the most complex double busbar cubicle with single phase gas insulated encapsulation.

The more complicated single phase encapsulated gas insulated switchgear is designed for special requirements. The busbars and the busbar isolators are allocated in separate gas compartments.

The application of the different types of primary switch cubicles depends on the philosophy of the Distribution Network Operators (DNO), of the environmental conditions and the importance of the switchgear for the consumer supply.

The secondary distribution network leads downstream outside the substation to the supply areas. Each feeder builds a chain connecting the subsequent MV/LV transformer terminals.

These terminals are based on the three scheme principles presented in Fig. 4.5. The dimensioning of the feeders and the transformer terminals is limited to a continuous load current of 630 A. Consequently, the power capacity of the feeders does not exceed 10 MW for 10 kV and 20 MW for 20 kV.

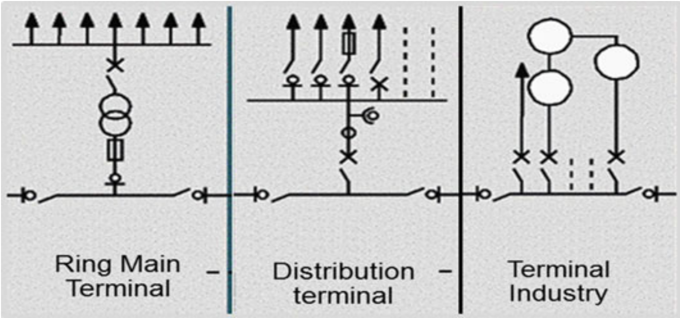


Fig. 4.5 The basic schemes of transformer terminals in the secondary distribution

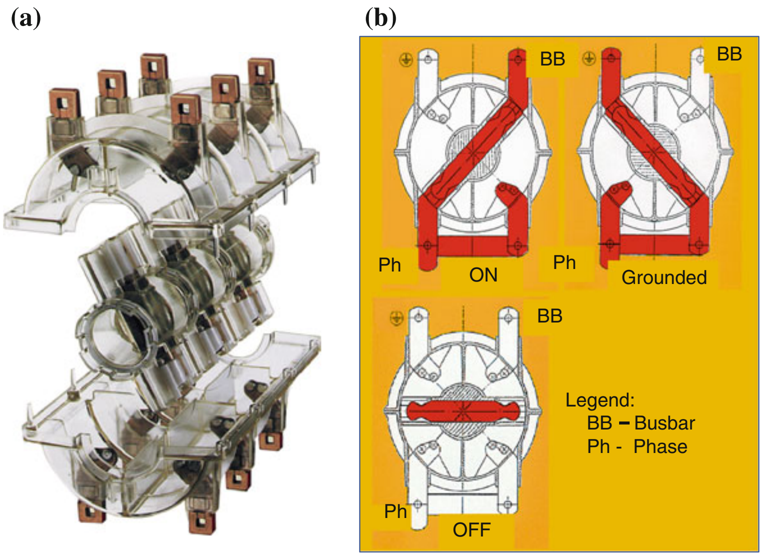


Fig. 4.6 **a** Load break switch and **b** the three positions. *Source* Siemens AG

The majority of the transformer terminals are designed as Ring Main Terminals with ingoing/outgoing MV feeders and the MV in-feed of the MV/LV transformer. These terminals do not use circuit breakers for economic reasons. All three feeders on the MV side may be switched by three position load break switches as shown in Fig. 4.6.

The MV feeders are equipped with short circuit indicators enabling the location of faults along the whole feeder with a number of connected terminals.

A typical gas insulated switch cubicle for MV secondary distribution ring main terminals is presented in Fig. 4.7 in a closed and a cross section view.

In-feed fuses are mainly used for protection purposes on the MV side of the transformer. Circuit breakers are recommended for transformers with a rated

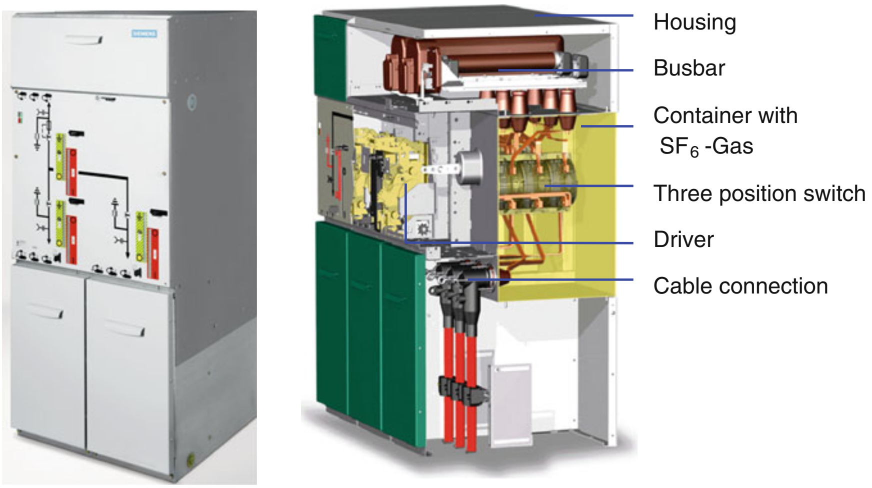


Fig. 4.7 Secondary distribution switch cubicle. *Source* Siemens AG

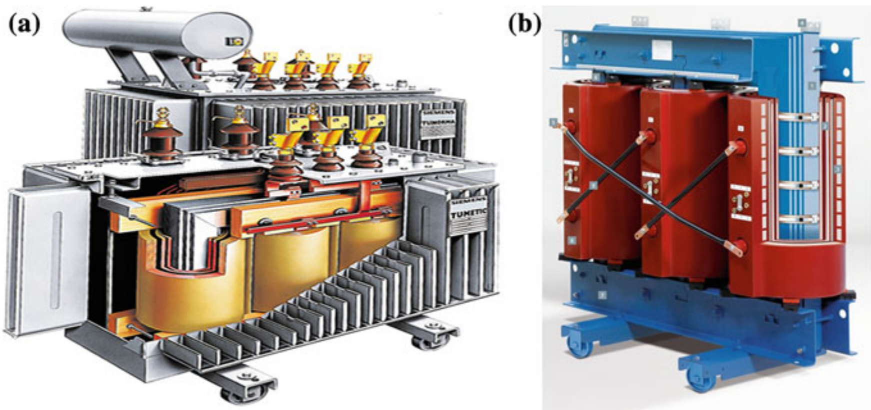


Fig. 4.8 **a** Oil immersed transformer and **b** cast resin transformer. *Source* Siemens AG

power above 630 kVA. The transformers are designed as either oil immersed transformers or as cast resin transformers.

Figure 4.8 offers a view inside both transformer types. Oil immersed transformers can be installed with or without an oil expansion container.

The rated power of these transformers is selected according to the peak demand of the supplied area, e.g. 400, 630 or 1,200 kVA, in such a way that the peak demand of the neighbouring LV network can be additionally loaded in an emergency.

At the low voltage side of the transformer feeder, circuit breakers with integrated overcurrent protection or fuses are applied. The outgoing single feeders of

Fig. 4.9 Ring main terminal with the 400 V distribution panel. *Source* HSE AG

(a) (b) (c)

Fig. 4.10 Examples of MV transformer terminals—**a** compact unit, **b** container, **c** housing. *Sources* **a**—Siemens AG, **b**—Schneider electric energy GmbH, **c**—HSE AG

the LV distribution busbar are equipped with fuses. In Fig. 4.9 a typical LV distribution panel is shown.

Ring main terminals are located in compact containers or in small so-called transformer housings. Figure 4.10 presents some examples of such terminals.

Distribution terminals are used for a wide spread extension of the MV network with parallel feeders. The supplement outgoing feeders are connected to a single busbar which is fed by one feeder connected to the ingoing and outgoing cables of the main feeder (Fig. 4.5). The cubicle of this feeder contains a circuit breaker and protection device. The protection device of the supplement feeders is performed by overcurrent protection or MV fuses.

Thirdly, in typical **industrial terminals** the ingoing and outgoing main feeders are located in normal cubicles with load break switches. However, a busbar is situated between the cubicles of the MV feeders supplying the manufacturing processes of the industrial plants. These feeders are normally equipped with circuit breakers and protection units.

4.3 Network Categories for MV and LV

The N-1 principle in distribution networks is mainly ensured with time delay based on the “connectable radial feeder end or open loop” concept.

In Germany 86 % of all supply interruptions are caused by faults in the MV networks [2]. When faults occur in the MV network, the protection in the feeding substation trips and the affected feeder is switched off (action 1 in Fig. 4.11). Today’s practice requires that the staff drive along the feeder and check the status of the short circuit indicators in the terminals after a fault trip. In this way, the fault can be located—in our example above this is between the terminals b and c. The fault elimination is reached by opening the load break switches in both terminals (2.1. and 2.2.). The recovery of supply will be executed by closing the load break switch 3 and switching—on the circuit breaker 4. This manual procedure takes normally between 1 and 2 h. The statistical average of the interruption time is 63 min (Germany) [3].

In accordance with this principle various network structures are applied such as

- Meshed operated network,
- Open loop network,
- Open loop back-up feeder network,
- Opposite station network.

The related network schemes are demonstrated in Fig. 4.12a–d.

Meshed operated, opposite station and open loop structures are selected depending on the local circumstances. The highest reliability is reached with the opposite station concept. However, in most of the cases an opposite station is not available nearby.

The back-up feeder in an open loop network can support the reliability improvement if required. However, this concept requires higher investment expenses.

Radially operated networks as presented in Fig. 4.13a are rarely applied. Here the connectable feeder end principle is not used in the MV structure. The N-1 principle can be achieved only through the opposite station concept at the low voltage level where the opposite station is not a substation but a MV/0.4 kV transformer terminal.

Industrial networks (Fig. 4.13b) require higher reliability performance. As a rule, short time supply interruption is not allowed. Therefore, often redundant MV feeders are used to feed the industrial terminals. Other terminals are not connected to these parallel feeders and they are mainly protected by differential protection (ΔI) as shown in Fig. 4.13b. An automatic switching sequence ensures that the reserve supply can also be provided by connecting the LV networks. Each asset of this network configuration is dimensioned for the total load.

In principle, the LV feeders supplying the consumers directly use the open loop principle in an analogous way.

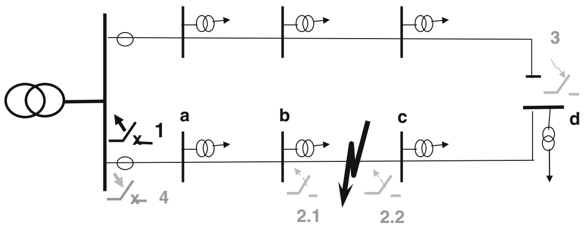


Fig. 4.11 Principle of the open loop concept

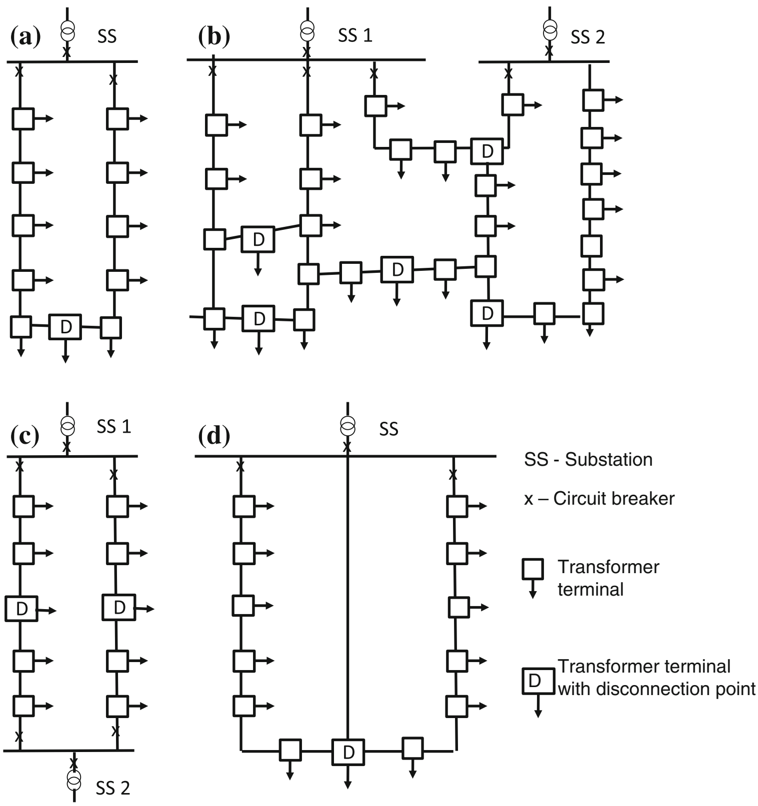


Fig. 4.12 Various MV network schemes using the connectable feeder end principle. **a** open loop, **b** meshed operated, **c** opposite substation in-feed, **d** back-up feeder

A real city network containing different terminal types and network configurations is presented in Fig. 4.14.

The city can be characterized as follows: The overall demand is shared by about 32,000 inhabitants in 14.5 thousand households, three large industrial areas, a number of business, trade, service and administration consumers. The peak load

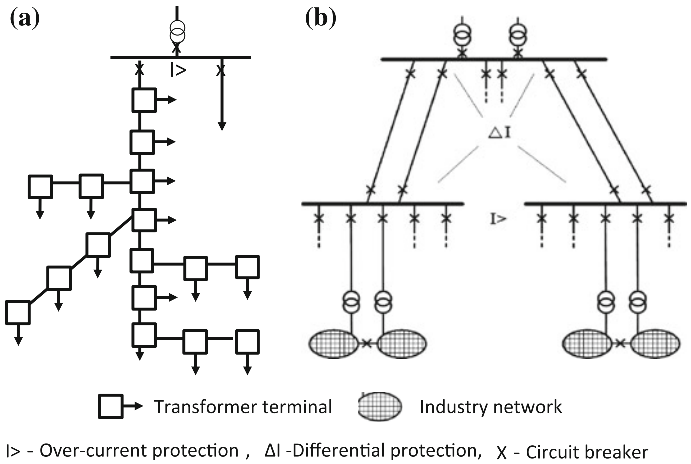
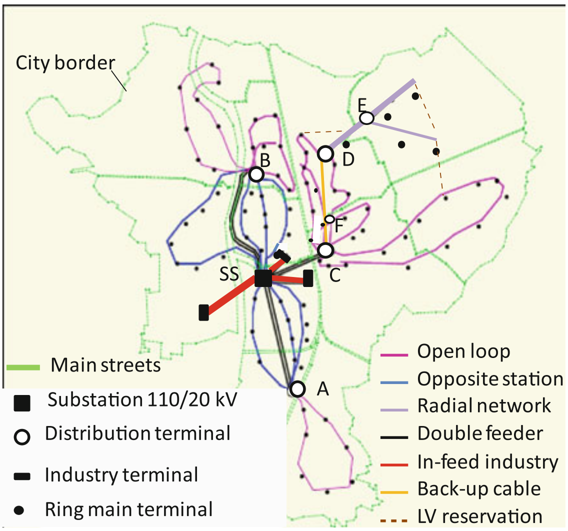


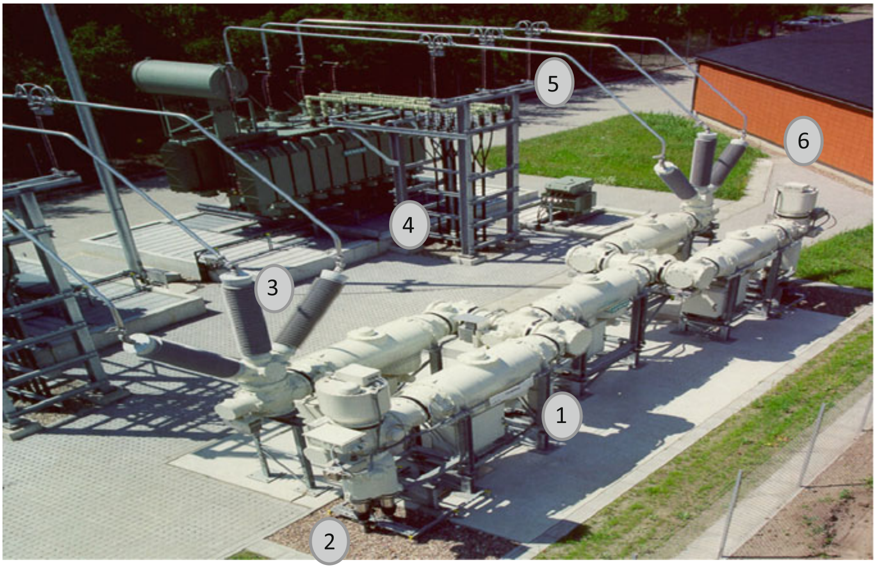
Fig. 4.13 **a** Radial operated network **b** industrial network with LV instantaneous reserve

Fig. 4.14 Scheme map of a 20 kV city network



occurs in the winter time with a maximum value of 38 MVA. The city is supplied by a 110 kV double line.

The 110/20 kV substation is equipped with an open air gas insulated 110 kV switchgear configured in the often applied H scheme with two line circuit breakers, two circuit breakers of the transformer feeders and a circuit breaker connecting both feeding ties as shown in Fig. 4.15. The installation of the gas insulated switchgear allows for a saving of 70 % compared to the air insulated 110 kV plant design.



1 – 110 kV Switchgear
2 – 110 kV Cables
3 – 110 kV Bushings
4 – 110/ 20 kV Transformer
5 – 110 kV Tube conductors
5 – 20 kV Switchgear

Fig. 4.15 Overview of the open air part of the 110/20 kV substation. *Source* Siemens AG

Two parallel 40 MVA transformers feed the primary distribution switchgear. The 20 kV-switchgear is based on a double busbar system. The switchgear is allocated in a separate building to the left of the 110 kV plant and the transformers.

The 20 kV switchgear consists of 23 switch bays; 2 for the transformer feeders, 18 for the outgoing feeders, two for the voltage transformers of each busbar section and one bay for the coupling of the two busbars. The network in Fig. 4.14 contains six distribution terminals. The terminals A, B and C are directly connected to the substation busbar by double cable lines. Open loops lead from these terminals into the supply areas of the city.

Furthermore, the terminals A and B build the opposite station for all feeders coming from the substation busbar.

Between the terminals C, F and D a meshed operated network with disconnection points in D for the loop C- F- D - C and in F for the loop C - F-C is configured. Furthermore, a back-up cable is normally connecting both terminals C and D for higher reliability. The terminal D feeds in a radially operated network where the N-1 security is achieved by LV reservation as depicted by the brown dash marks.

The three industrial areas are supplied by double cable lines. The outgoing feeders of the industry terminal are equipped with protection devices in accordance with the needs of the production processes, e.g. motor protection, out-of-step protection, frequency protection, voltage protection, overload protection.

In this way, the considered city distribution system is designed to reach high reliability parameters and it contains all of the types of terminals and network configurations as presented in the Figs. 4.5, 4.12 and 4.13.

4.4 Neutral Grounding Concepts

The method of neutral grounding does not influence the behaviour of a network under normal operating conditions. However, in the case of the most frequent failure, namely the phase to earth fault, the duration of the disturbance, the number of the affected consumers, the work load for the operators, the voltage and current stresses for the network assets and the extent of the damage into a double earth fault depend on the method of neutral grounding [4].

The application of the different methods depends on the experience and the philosophy of the network operators. A statistical survey of the German distribution networks according to Table 4.2 indicates that resonant grounding is the most frequently used method for neutral grounding in this country.

The selection of the most efficient neutral grounding method depends on the type of lines (overhead or cable), the line to ground capacitance, the size of the network and the fault currents.

In the past, most networks began as overhead line systems. Nowadays, however, many networks have been converted into cable systems or mixed overhead line and cable systems. For example, underground cables have been installed in all Germany cities and villages. Overhead lines are used only outside of the urban areas for connecting rural villages to the network.

Figure 4.16 demonstrates the transition from overhead to cable lines.

The range of phase to ground fault currents related to the different neutral grounding methods is the main selection criterion. Depending of the neutral grounding method it may vary from low currents to high short circuit currents. Figure 4.17 presents these relations.

Networks with a small capacitive earth fault current I_{Ce} are operated with isolated neutral grounding. Resonant grounding is applied in networks with capacitive earth fault currents up to 500 A and more, which results in residual fault current I_{res} at the fault location of 35–50 A. For networks with low impedance grounding the maximum fault current I_{sc1} is normally limited by the impedance between 500 and 2,000 A. In any case, the fault current level has to be larger than the capacitive earth fault current of the network. In case of high impedance grounding the fault current I_F does not exceed 100 A and the capacitive earth fault current of the network and the resistance contribution are of the same magnitude.

Table 4.2 Example for grounding method statistic (Germany)

Method	Share (%)
Resonant grounding	67
Isolated neutral	16
Low impedance neutral grounding	12
Others (combined, solid)	5

Fig. 4.16 Transition from 20 kV overhead lines to cable at the border of urban areas

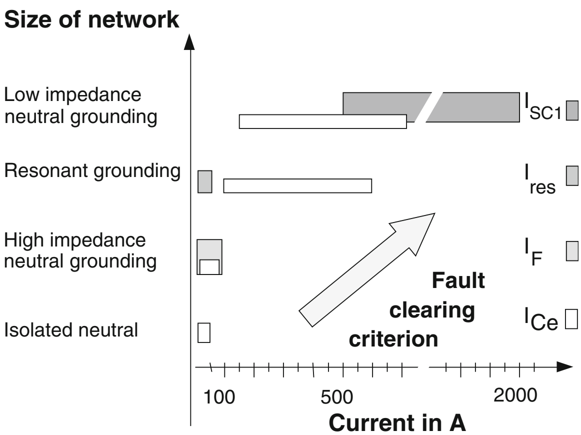


Fig. 4.17 Fault current ranges related to different neutral grounding methods

4.4.1 Resonant Grounding

The system with resonant grounding has a single phase reactor (Petersen coil) connected to the neutral point of the feeding transformer (Fig. 4.18). Under normal operating network conditions the neutral point voltage is zero and, therefore, no coil current is flowing. The coil is sized to a current level which under phase to

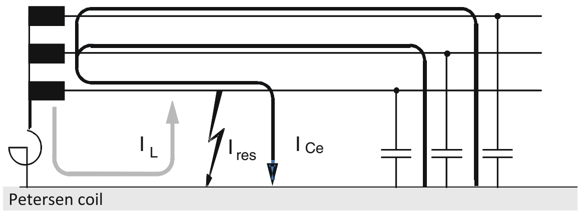


Fig. 4.18 System with resonant grounding

ground fault condition equals the capacitive earth fault current of the network. Both the inductance and the capacitance of the network form an oscillation circuit which provides high impedance values in case of resonance and thus limits the line to earth fault current up to the extinction of the fault arc.

Resonant grounding offers advantages especially for overhead line systems. An inductive current generated by a Petersen coil compensates the capacitive fault current at the fault location. Under favorable conditions the arc at the fault location extinguishes in the transient phase within milliseconds.

Consequently, the values of the phase to earth capacity of the network and the inductance of the coil have to be adapted to achieve resonance conditions (or compensation of the capacity by the inductance). The network operation is accompanied by frequency deviations and topology changes influencing the capacitive line to earth currents. The inductance of the coil has to be controlled by a resonance degree (γ) regulator in such a way that under different network conditions a light overcompensation ($I_L > I_{Ce}$) is reached. The curve and the formula of the resonance degree are shown in Fig. 4.19a. As a rule the target value of the resonance degree is selected as –5 %.

Petersen coils with movable cores are applied for this control (Fig. 4.19b, c). The movement of the core into and out of the coil windings changes the inductance of the coil accordingly.

The recovery voltage rises after the arc extinction in the faulted phase and therefore it is possible that operation continues without any necessary action from the control center. In the case of permanent faults the current at the fault location is minimal. Under these circumstances operation can continue and measures to locate the fault can be started.

The faulted feeder can be detected by use of sensitive directional overcurrent relays based on the active component of the zero sequence currents. The target is to disconnect the faulted equipment or line section without any supply interruption for the customers.

In typical medium voltage networks with ring shaped feeders operated as open loops and load break switches at the ring main terminals, the fault detection and disconnection requires a lot of switching operation if the above mentioned protection is not installed.

The main disadvantage of this method from the operational point of view is the fact that the fault might evolve during the phase of fault localization and elimination. Due to the fact that there is a voltage rise in the two un-faulted phases by

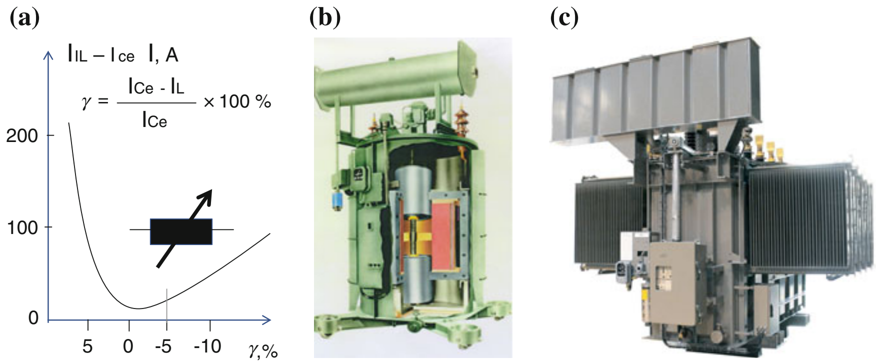


Fig. 4.19 Resonance degree regulation: **a** resonance curve and the formula for the resonance degree, **b** cross section and **c** Petersen coil with controllable inductivity. *Sources* **b** Siemens AG, **c** Schneider electric energy GmbH

the factor of $\sqrt{3}$ and above there is a risk of a second line to earth fault in another phase at another location in the interconnected network. This cross country fault is a short circuit which has to be detected by the protection scheme and will trip one faulted feeder. In addition to the cross country fault there is the danger of intermittent and restricting earth faults which cause operational trouble.

4.4.2 Isolated Neutral

The principal three phase system with isolated neutral is given in Fig. 4.20. Under normal operating conditions, the neutral point of the system has practically the same potential as the ground as long as the line—ground capacities of the three phase system are symmetrical. The system with isolated neutral is characterized by the capacitive earth fault current in the range between 30 and 60 A. The magnitude of this current depends on the voltage level and the length of the interconnected network. The specific earth fault current is 30–40 times higher for cables than for overhead lines of the same length. The phase to earth fault will discharge the capacitance of the faulted phase with a current peak.

As in the resonant grounding situation, under fault conditions the line to ground voltage of the un-faulted phases are increased by a factor of $\sqrt{3}$. The two healthy phases will be charged up to the line to line voltage by an oscillation. The frequency of this oscillation is given by the inductance of the feeding transformer and the line to earth capacitance of the network. This oscillation, which lasts several milliseconds, can lead to surges which stress the equipment of the network. To detect the faulted feeder sensitive capacitive directional overcurrent relays for zero sequence currents are used.

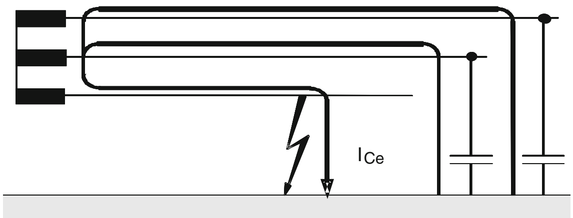


Fig. 4.20 System with isolated neutral

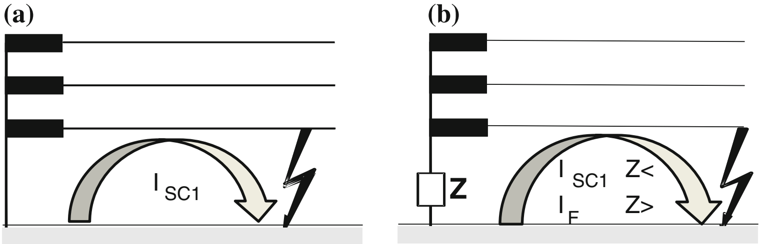


Fig. 4.21 **a**—Solid neutral grounding **b**—low impedance neutral grounding

4.4.3 Solid and Low Impedance (Current Limiting) Neutral Grounding

In a system with solid grounding the neutral point of the feeding transformer is solidly connected to earth, e.g. by a copper bar or cable (Fig. 4.21a). Each line to earth fault is a short circuit with a fault current level up to the three phase fault current.

Systems with solid grounding are hardly used because the high level of line to earth fault current would require adequate measures for safety grounding in sub-stations and network terminals.

The current limiting neutral grounding is achieved by the impedance connected to the transformer neutral point (Fig. 4.21b). During normal operation there is no current through the impedance. In the case of a phase to earth fault a single phase short circuit current occurs that has to be detected by the protection and tripped immediately.

Neutral grounding with current limiting devices provides a fault current which is as high as necessary for fault detection and, at the same time, as low as possible to minimize damages and inductive interference as well as the hazard from touch voltages. Furthermore, the use of a neutral resistor has advantages with respect to transient surges.

In a typical distribution network with radial feeders a line to earth fault will affect all consumers downstream from the circuit breaker.

Fault current indicators are normally used to select the faulted section and to minimize restoration time.

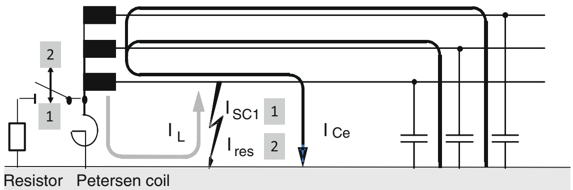


Fig. 4.22 Short time grounding method

4.4.4 Combined Methods

To combine the advantages of different neutral grounding methods as much as possible the system with resonant grounding is equipped with an additional single phase circuit breaker and neutral resistor connected in parallel to the Petersen coil (Fig. 4.22).

There is the option to operate the network under normal conditions as a resonant grounded system. In case of a permanent phase to earth fault a resistor, which is parallel to the Peterson coil, is switched on for <100 ms. The fault current level is selected in such a way to trigger the fault indicators and to start—but not to trip—the line protection. This can be achieved either by coordination of fault current level and pick up current level or by time delay. After the resistor is disconnected the operation will continue with the permanent fault as a resonant grounded system and the operators will try to disconnect the faulted section without interruption of supply. This method is called “short time current limiting neutral grounding for earth fault detection”.

If there is a permanent earth fault, an alternative method is possible if the resistor is switched on as long as necessary to trigger fault indicators and to trip the faulted feeder. In this case, the fault current level and the protection setting have to be coordinated. This method is called “short time current limiting neutral grounding for earth fault disconnection”.

4.4.5 Summary Grounding Methods

The overview of the methods of neutral grounding and the main features are presented in Fig. 4.23. There are many different neutral grounding schemes available and they each offer advantages and disadvantages in technical, operational and economical aspects. For a utility or an industrial network operator the optimal solution has to be identified individually. The result is based on the equipment installed, the operational experience and the targets set for the future. Very often the search for an optimal neutral grounding scheme is triggered by external events such as major network restructuring, network mergers, network automation or customer demand for higher reliability.

Networks with a small capacitive earth fault current are often operated with isolated neutral. These networks are found in small utilities or industrial systems. In case of problems with fault detection or ferro-resonances there is the option to convert the system to high impedance neutral grounding.

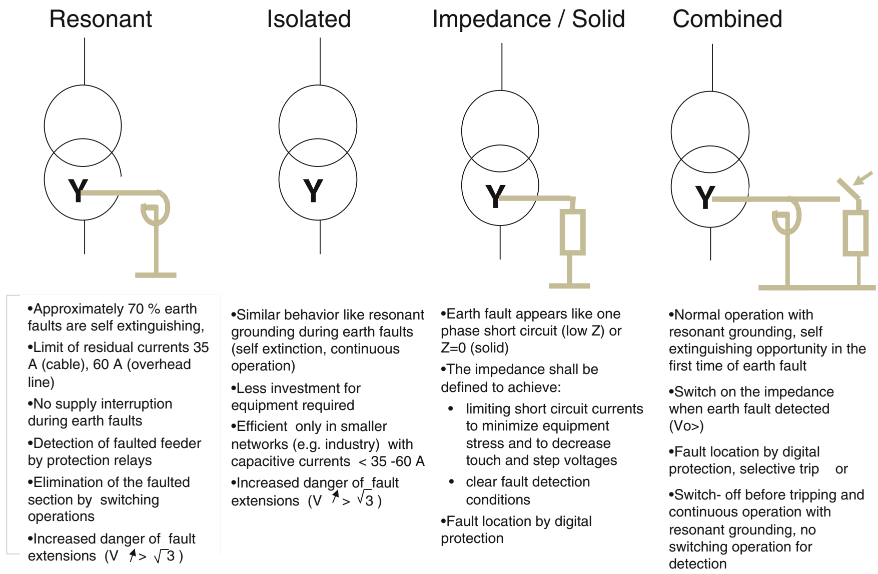


Fig. 4.23 Main features of grounding methods

In systems with overhead lines, the resonant grounding with continuous operation under fault condition is the most frequent method applied in some countries. In case of significant shares of cable sections the short time current limiting neutral grounding offers the benefits of self-extinguishing arcs or reliable fault localization for permanent earth faults.

In cable networks the low impedance neutral grounding is beneficial. A clear network structure together with advanced protection schemes and automation strategies provide minimal interruption time and exclude evolving faults.

To combine the advantages of resonant grounding with self-extinguishing arcs in the air with the fast and selective fault detection in systems with current limiting grounding, short time grounding methods were developed.

The complexity of finding the most efficient neutral grounding method will be considered on practical experiences.

4.4.6 Practical Experiences for Efficient Selection of the Neutral Grounding Method

4.4.6.1 Industrial 6 kV Network

A large factory is operating a 6 kV network with isolated neutral. The capacitive earth fault currents are about 100 A.

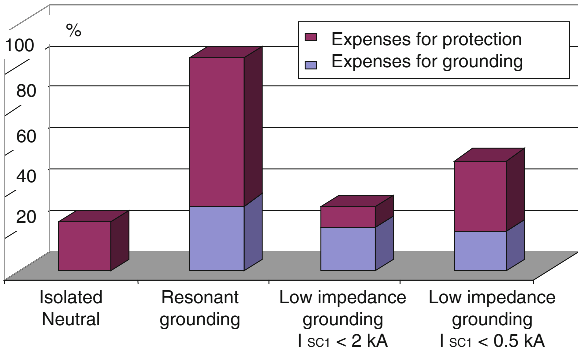


Fig. 4.24 Comparison of investment costs for different neutral grounding methods

Transient earth fault relays were used to locate earth faults. However, these transient earth fault relays were unreliable in operation and the capacitive earth fault current was extremely high. Often an earth fault resulted in a multi-pole short circuit. Although such faults were cleared by the short-circuit protection system, an indeterminate amount of time was needed to complete this operation. In addition, the transition from earth fault to multi-pole short-circuit was associated with major voltage dips in the low-voltage network. In view of this unsatisfactory situation, the network operator sought to optimize the neutral grounding method for the 6 kV power supply system and started appropriate investigations.

In the first step of the study measurements were executed on site to determine the cable impedances, especially the zero sequence impedances. The target was to judge the safety grounding conditions for the different fault current levels and fault durations and to analyze the interference voltages resulting from earth fault currents on communication lines.

In the result of these analyses, the following options were detected as possible solutions, examined and evaluated:

– Isolated neutral with improved earth fault location,
– Resonant grounding,
– Low-impedance neutral grounding with earth fault current limited to 2,000 A,
– Low-impedance neutral grounding with earth fault current limited to 500 A.

Operation with isolated neutral and improved fault location is the most cost-effective method of the various neutral treatment options investigated (Fig. 4.24). In this case equipment for neutral grounding is not required. However, due to

- the high fault current which occurs with an earth fault,
- the high transient over-voltages which accompany an earth fault and
- the power frequency over-voltages for the total duration of the earth fault,

there is still a serious risk of the fault developing into a multi-pole short-circuit or double earth fault. An earth fault would therefore lead to a contest between measurement devices to locate and isolate the fault on the one hand and fault propagation on the other. Given these adverse technical considerations, continued operation of the power system with isolated neutral was not recommended, even with improved fault location.

Resonant grounding involves the highest investment costs of all of the neutral treatment options investigated. This applies equally to the relatively high costs of a neutral grounding transformer and Petersen coil and to the very high capital outlay for protective devices resulting from the necessary installation of window-type current transformers and more sophisticated feeder protection devices. Compared with the isolated neutral option, there is only a minor risk that a fault will develop into a multi-pole short-circuit at the earth fault location owing to the smaller earth fault current. In common with the isolated neutral option, however, there is a risk that transient over-voltages and power frequency over-voltages could lead to a second earth fault with consequent transition to a double earth fault.

The operating staff needs to take action to locate and isolate earth faults, and this is inconsistent with the envisaged automation of power system operation. For the financial and technical reasons stated above, it was decided not to convert the power system to resonant grounding. Low impedance grounding with limitation to 2,000 A would result in a cost close to the level of the option with improved isolated neutral. No problems were expected with respect to intolerable touch voltages and interference to communication systems. But, based on the calculated minimum fault current of 800 A, it became clear that the trip time of existing feeders' protection had to be increased to prevent trips from the inrush situation. Further problems came from the selective coordination of the overcurrent protection and fuse. Finally, it was anticipated to keep the voltage dip as small as possible on the low voltage side.

Low impedance grounding with limitation to 500 A proved to be the best choice. With new digital overcurrent relays it is possible to detect earth fault current well below maximum load currents. The voltage dip on the low voltage side is limited to 4 % in only one phase close to the fault location. Although the solution involved higher costs than other options the protection replacement is also beneficial for multiphase faults and provides valuable new information such as a record of the fault and new features such as self-monitoring.

After more than two years of operation it could be stated that the low impedance neutral grounding with current limitation to 500 A leads to a simplification of network operation. In the testing period two earth faults occurred which were cleared selectively and fast, as anticipated. Supply interruptions did not happen because of the un-delayed N-1 security of the network.

4.4.6.2 Industrial 20 kV System

A large industrial complex with about 100 MW peak load had to shut down its own power station. As a consequence the whole 20 kV network had to be restructured to meet the new power flow situation. This major change was also used to analyze the operational practice and improve fault management. In the past the 20 kV network was operated with resonant grounding. Experience from the old network configuration showed that phase-to-earth faults developed into multi-

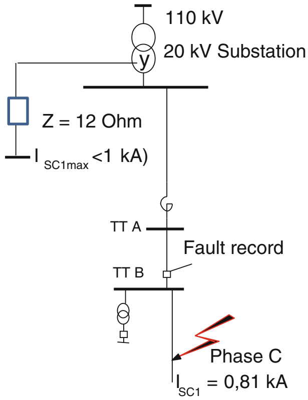


Fig. 4.25 Scheme for earth fault test

phase faults and double earth faults before the location and disconnection were possible. Such faults caused major outages and damages.

For environmental reasons it was necessary to decommission the old oil-filled transformers and Petersen coils that were installed. Before a decision on replacing the coils and investing in improved earth fault detection was taken. A study was carried out to identify the optimum neutral grounding scheme. It became apparent that a neutral grounding scheme which limits the maximum phase-to-earth currents to 1 kA using a resistance is the optimum solution. The main benefits are:

- Automation of network operation,
- Minimum level of transient and power-frequency over-voltages,
- Identical network behavior with line-to-earth and multiple-phase faults,
- No switching operations necessary during earth fault conditions,
- No danger of un-definitely self-attenuating faults.

An earth fault test was carried out as part of the commissioning procedure for the new substation fed from the public network. Figure 4.25 shows the single line diagram of the network for the earth fault test. The earth fault on the 20 kV level was executed at the transformer terminal TT B at phase C of the 20 kV transformer feeder.

Figure 4.26 demonstrates the results of the earth fault test which confirm that the fault was located by the protection and selectively tripped as anticipated. The fault current was detected as 0.81 kA. There were no transient over-voltages.

Measurement of the low voltage level during the phase-to-earth fault revealed a voltage drop in one phase of 15 %. These results perfectly matched with the voltages and currents calculated in advance.

The transformation of the network and implementation of the new neutral grounding scheme was carried out rapidly and without any major problems. The operational experience of three years has proved that the new network is flexible and assures reliable supply even with a reduced number of staff. Actual faults in the network have shown the behavior of the new method of neutral grounding and

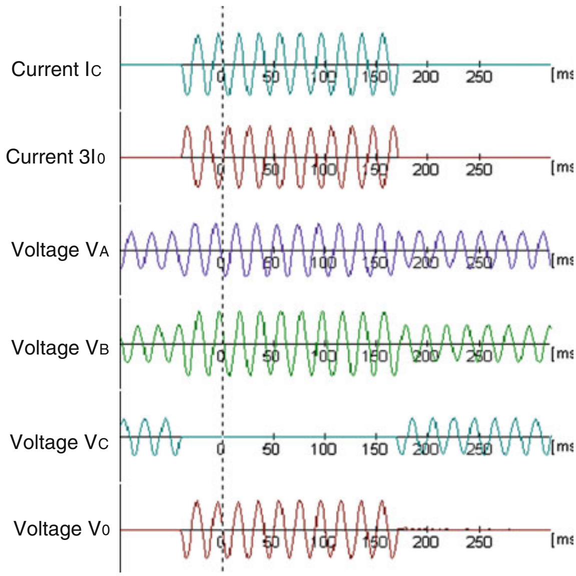


Fig. 4.26 Results of earth fault tests

the protection concept. The faults were cleared without any supply interruption. Therefore the main target of the project was fulfilled, namely maintaining a reliable operation after the shut-down of the industrial power station, and, in addition, the chance for network modernization and optimization was used.

4.5 Protection for Distribution Networks

4.5.1 MV Networks

In MV networks the digital protection relays have been introduced in the majority of substations and distribution terminals of central Europe. It is common now to apply combined devices covering several protection and control functions. Such devices have been available from different vendors since 1995 and they are able to perform various protection principles.

In Fig. 4.27 the internal structure of the combined protection and control devices is presented.

The combined devices are designed with a basic core serving the common system functions like the memory management, the permanent check of the analogue and binary input signals, the display and setting functions, etc. The protection and control tasks use the system functions via the application interfaced. Each application task is organized in a priority chain. The task of a higher priority can interrupt a task of lower priority and use the central processing unit. Consequently, the highest priority in such a chain is assigned to the main protection

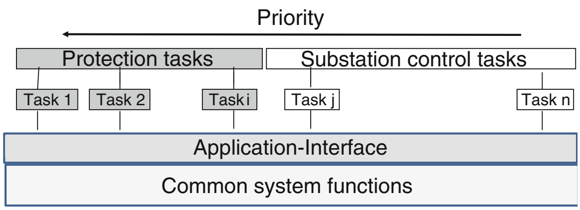


Fig. 4.27 Internal architecture of the combined devices for protection and control

function. The lowest priority is given to the control function which does not require a real time processing within milliseconds.

The broad application of combined devices for protection and control with a large display in MV switch bays has had a strong impact on the design of the switch cubicles. It is now possible to forgo the formerly used mechanical control elements on the front of the cubicle. All control and supervision tasks may be performed using the various presentation facilities on the display, the control buttons and the cursor shifting. Figure 4.28 shows the switch bays of a 20 kV busbar without any external mechanical control elements on the front of the cubicle.

Besides the main protection function, the digital protection normally offers a set of supplementary protection functions. Each function operates independently of the others and may be enabled or disabled by parameter settings depending on the use case. This approach allows a universal application of the devices for various tasks such as feeder, motor or generator protection.

The non-directional overcurrent protection is mostly used as the main principle corresponding with the predominant application of radial or open looped MV network configurations supplied from a single source.

An exception is the wide spread application of distance protection relays at the feeding substations of MV networks in Germany. The reason for this is the desire to keep the possibility open for a partial time change of the network configuration from radial with a connectable feeder end to meshed operation. Furthermore, the convenient disturbance record and fault location function often motivate the application of the distance protection.

In general, for networks using a connectable feeder end configuration the non-directional overcurrent protection is recommended as the main function.

Ring operated networks require the directional overcurrent protection for selectivity reasons. In closed meshed networks without disconnection points the application of the distance protection is common.

The most used protection principles of MV networks are presented in Table 4.3.

The overcurrent protection provides three various elements for the three phase currents and the ground current. The high current element $I\gg$ and the overcurrent element $I > t = n$ always operate with a definite time delay that can be set in milliseconds.

The time delay of the "$I\gg$" element is normally set for 0 or <10 ms. Therefore, this element is named "instantaneous overcurrent" grade.

Fig. 4.28 Advanced switch bay cubicles 20 kV with local control by a combined device for protection and control. *Sources* **a** Siemens AG, **b** ABB AG

Table 4.3 Mainly implemented protection functions for MV networks

Protection related functions	Type 1*	Type 2**	Type 3**
Distance protection			X
Overcurrent protection I≫, I > t = n or t = f(I)***	X	X	X
Directional overcurrent protection	X	X	X
Voltage protection		X	X
Negative sequence protection	X	X	X
Frequency protection		X	X
Thermal overload protection	X	X	X
Motor protection	X	X	X
Ground fault protection ****with fault direction	X	X****	X****
Intermittent ground fault protection	X	X	X
Breaker failure protection	X	X	X
Automatic reclosing	X	X	X
Synchronization			X
Fault location		X	X
Disturbance record and report	I	I, V	I, V, P, Q

* Current inputs, ** Voltage/current inputs, *** I≫ Instantaneous, I> Definite or inverse time

The 3rd element I > t = f(I) provides a set of inverse tripping curves which means the time delay is dependent on from the measured current value.

By using the overcurrent principle, the protection grading is required if subsequent protection relays are installed along a feeder (e.g. in a distribution terminal).

Figure 4.29 gives an example of this grading for the transformer in-feed and two feeders.

The settings of the I> element are coordinated in such a way that the selectivity of the protection trips is achieved. The overcurrent setting is normally selected ≥2.5 times the maximum load current or >1.2 times over the rated current.

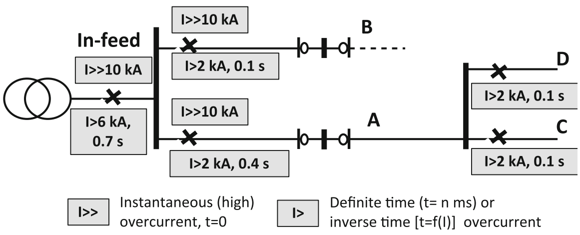


Fig. 4.29 Protection grading in an open looped MV network

The time settings or the selection of the inverse curves ensure that a fault behind the distribution terminal (feeders C or D) will be tripped faster than the I> elements in the substation can either trip the whole feeder A or the whole busbar by tripping the in-feed. The selected delay time can be shortened if a subsequent protection is not available (feeder B).

The grading will be performed in a similar way if a distance protection is applied—by coordination of the distance zones.

The I$\gg$ element is set for the transformer in-feed and for both feeders at the substation. The current setting is 10 kA and the time setting is 0 for this element in all three protection devices. That means that the pickup causes an instantaneous trip if the short circuit exceeds 10 kA. Such a high short circuit current can be measured if the fault occurs at the busbar or at the feeders in the closed environment of the substation.

The instantaneous trip is desired to avoid damaging of the switchgear and its assets. However, if the fault occurs at the feeder the instantaneous trip of the in-feed is not necessary. Here the selectivity is achieved by the principle of "reverse interlocking".

The reverse interlocking principle is based on the following: If the fault is located behind the feeder protection in the network direction (case 2 in Fig. 4.30) the pickup of the I$\gg$ element sends a trip blocking signal to the in-feed protection.

After receiving this signal in real time ($\leq$1 ms) the trip of the I$\gg$ element will be blocked. Consequently, only the feeder protection sends the trip signal to the feeder circuit breaker. The in-feed and the other feeders are kept in operation.

Otherwise if the fault is located at the busbar (case 1 in Fig. 4.30), there is not a pickup at the feeder protections. The in-feed protection does not receive an interlocking signal and trips instantaneously. A fast busbar protection is realized by using this reverse interlocking principle.

In the past the I$\gg$ pickup signal was set from each feeder protection on a loop wire as shown in Fig. 4.30a. Nowadays, advanced communication systems based on Ethernet and fibre optics are applied in the substations. The performance of these systems is high enough to transfer the pickup signal to the in-feed protection securely and in real time (Fig. 4.30b). The communication standard IEC 61850 provides a special broadcast service for this purpose named Generic Object Oriented Substation Event (GOOSE)—see Sect. 8.3.

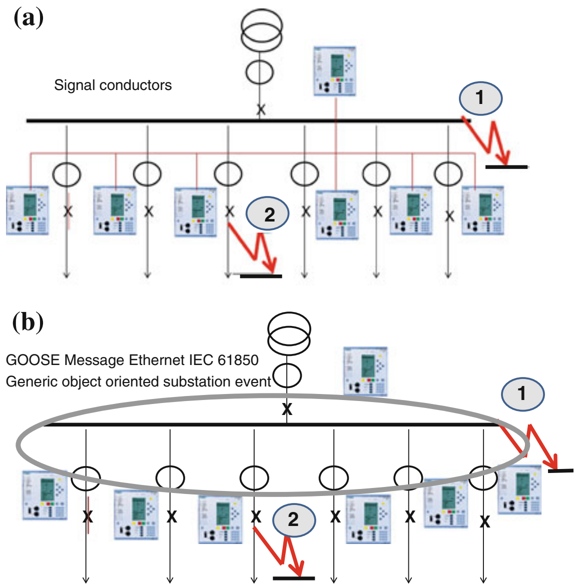


Fig. 4.30 Signal transfer for reverse interlocking **a** by wire, **b** by communication

The costly wiring can be avoided today by applying this advanced communication service over a fibre optic cable which is also used for the other control and supervision tasks.

The **directional overcurrent protection** is applied in networks where the protection coordination depends on both the magnitude of the short circuit current and the direction of the power flow to the fault location. This type of protection is requested for parallel feeders or transformers, in line sections supplied by two or more sources and, generally, in ring operated networks. The overcurrent protection is supplemented by the specific directional element and needs the input of the phase voltages for processing.

The **voltage protection** has the task to protect electrical equipment against under- and over-voltages. Both operational states are abnormal and hazardous because overvoltage may cause, for example, insulation problems and damages while under-voltage may cause stability problems.

Abnormally high voltages occur on low loaded long distance lines mainly in rural areas where more reactive power is generated along the line by the line capacitance than is lost over the line reactance. The distributed generation may cause a reverse load flow on radial feeders and, depending on the generation, load ratio overvoltage may occur at the access points of the generators. The overvoltage protection U> detects and trips in such critical situations.

The under-voltage protection U< detects critical voltage decreases on heavily loaded lines or electrical engines. It prevents inadmissible operation states and a possible loss of stability.

The **negative sequence protection** detects unbalanced loads in the network. The application of unbalanced load protection to motors has a special significance. Unbalanced loads generate counter rotating fields in 3 phased induction motors which act on the rotor on double frequency. Eddy currents will be induced at the rotor surface and cause overheating.

Furthermore, this protection function may be used to detect phase interruptions, un-symmetric short circuits with fault currents below the I> setting and polarity problems with current transformers.

The **frequency protection** detects abnormally high and low frequencies in the network or in electric machines. If the frequency lies outside of the permissable settings range then appropriate actions are initiated such as load shedding (f<) or separating a generator from the network (f>).

The **thermal overload protection** is designed to prevent thermal overloads and subsequent damaging of the protected assets. The protection function represents a thermal replica of the asset to be protected. Both the previous overloading history and the heat loss to the environment are considered. In particular, the thermal overload protection allows for the monitoring of the thermal status of overhead lines, cables, transformers, motors or generators.

The **motor protection** contains a set of functions like the motor starting protection, a restart inhibit and a load jam protection. The starting protection protects the motor from prolonged start-up procedures and supplements the thermal overload protection. The restart inhibit prevents a restarting of the motor if this restart could lead to exceeding the threshold of the motor's permissible thermal limits. The load jam protection protects the motor during a sudden rotor blocking.

The **ground fault protection** has to be designed in accordance with the neutral grounding method applied in the network. Depending on the method the ground current input is equipped with a

- sensitive input transformer for isolated or compensated networks ($I_E < 1.5$ A) or a
- standard transformer for 1/5 A rated current (measuring up to 100/500 A) for networks with large ground fault currents.

Advanced protection devices may be equipped with two ground current input contacts and both kinds of transformers.

Sensitive ground fault detection is used to determine lines affected by ground faults and to specify the direction. However, determining the fault direction requires the input of the shifted neutral to ground voltage U_0. This function can operate in two modes:

The standard procedure uses the "cosφ/sinφ measurement" and evaluates the part of the ground current which is perpendicular to the settable directional characteristic.

The second method—the "$U_0 \; \Lambda \; I_0 - \varphi$ measurement"—calculates the angle between the ground current and the neutral to ground voltage. The directional characteristic is also settable.

In solid or low resistance grounded networks the standard input transformer is used. The sensitive ground fault detection can be additionally applied to detect high impedance ground faults.

The typical characteristic of **intermittent ground faults** is that they disappear autonomously only to strike again after some time. This mainly can happen in cables due to aged insulation or in cable joints caused by water ingress.

The ground fault pulses can last between a few milliseconds and several seconds. If pulse durations are extremely short, not all protection devices in a ground fault path may pick-up. This is why such faults are either not selectively or not at all detected by the ordinary ground fault protection. Due to the time delay of the ground fault protection such impulses are too short for initiating a trip.

Nonetheless, such intermittent ground faults bear the risk of thermal damage to the equipment. Therefore, the intermittent ground fault protection operates in the following way: The intermittent ground fault impulses are detected and their duration is recorded and accumulated. If the sum reaches a settable value within a certain time, the limit of the thermal load capacity has been reached and a trip will be initiated. The intermittency of a ground fault will also be signalled before the tripping to provide a warning about a developing danger.

The **breaker failure protection** monitors the proper tripping of the relevant circuit breaker. If after a settable time delay the circuit breaker has not operated, the breaker failure protection issues a trip signal to isolate the failed circuit breaker by tripping another surrounding back-up breaker. If the circuit breaker of feeder C in Fig. 4.29 fails then the breaker of line A will trip, or this breaker fails then circuit breaker of the transformer in-feed has to trip.

The protection reservation works on the same principle in the MV distribution networks. A special reserve protection like that applied in the transmission and sub-transmission networks is not required for MV networks.

The **automatic reclosing** function is mainly used in networks with overhead lines. Here the experience shows that about 80 % of faults are connected with electric arcs. They are temporary in nature and disappear when the protection trip interrupts the energy feeding the arcs. This means that the line can be connected again (after a short break of about 1–2 s). The reconnection is accomplished after a dead time so that the deionization of the air may happen. If the fault still exists after the auto-reclosing, then the protection will re-trip the circuit breaker.

The **synchronization** function provides the synchronization check before connecting 2 sections of a network, for example a feeder and a busbar. The synchronization check evaluates the difference of the voltage magnitudes of both sections, the angle difference between the voltages and the frequency deviations. In this way the synchronization check verifies that the switching does not endanger the stability of the network.

The **fault locator** is a supplement to the protection functions and calculates the distance to the fault. This supports the fast elimination of faults and increases the reliability of supply. The fault locator is a standalone and independent function which uses the voltage and current measurements and the line parameters. The protected asset can be an inhomogeneous line. For accurate calculation such a line may be divided into sections which can be configured individually.

Advanced protection devices also provide **fault or disturbance records**, meaning the registration and presentation of the measured analogue values in a millisecond raster before, during and after the fault. Such registered curves can be read via an interface by and presented on a PC. A remote reading via communication links is also foreseen.

Additionally, **disturbance reports** may present the sequence of pickup, trip and reset events in the form of an event log.

4.5.2 The Feeding Substations of MV Networks

In Europe, the MV overlaying networks mainly use the voltage range of 110 kV.

As a rule, the 110 kV networks are meshed operated and have to meet the N-1 criterion without time delay.

Therefore, these networks are equipped with remote control and protection schemes as are common in the transmission networks. For example, the line protection schemes include a main and a back-up protection. The complete protection scheme for the H- configured 110/20 kV substation as shown in Fig. 4.15 is presented in Fig. 4.31.

The 110 kV lines in this scheme are equipped with a distance protection as the main protection and a differential protection as the back-up protection. The distance protection uses the method of tele-protection which means that it sends the pickup signal to the protection device of the opposite line end. With this method both protection devices can trip at the same time, even when the fault occurs near the substation and does not correspond with the reach of the distance zone 1 of one of opposite distance protections.

In this scheme the main and the back-up protection devices have to use communication links to the opposite station of the protected line. The communication links have to be independent. In the same way, the analogue values for the main and back-up protection have to be provided redundantly by separate instrument transformers.

The 110 kV busbar contains five segments with the circuit breakers A–E. If segment B is switched off, the H—scheme builds two busbars. Otherwise, the single busbar with the switched on segment B may build various configurations with two or one lines and two or one feeding transformers in operation.

The 110 kV busbar protection follows the current differential principle and needs the supervision of the isolators and circuit breaker positions for mapping the differential criterion to the current scheme configuration.

The autorecloser is applied for the 110 kV overhead lines. The 20 kV feeders, however, are equipped with cables, and an autorecloser is not foreseen in this case.

The in-feed segment at the 110 kV level is protected by an overcurrent protection which also performs the back-up protection for the transformer.

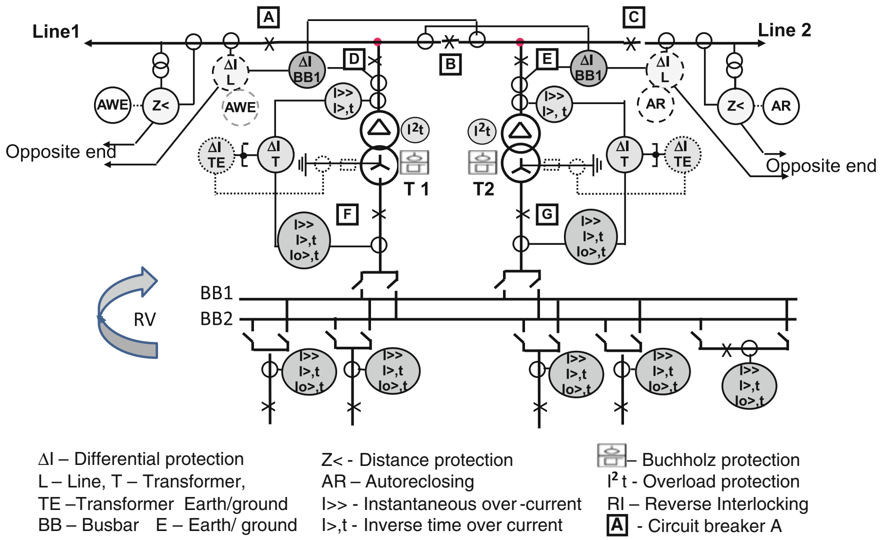


Fig. 4.31 The protection scheme of an H-configured 110/20 kV substation

The main transformer protection is the differential protection. The transformer is additionally protected by

- the Buchholz protection which reacts with the gas stream, which is caused by damages in the internal insulation, and which appears between the main oil tank and the extension container and
- the thermal overload protection.

On the 20 kV side the protection scheme follows the considerations in Sect. 4.5.1
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4.5.3 LV Networks

In LV networks the short circuit power is provided via the MV/LV transformers at the feeding terminals and appropriate protection functions have to be implemented.

The protection of the LV networks is standardized. Normally low voltage—high current fuses are applied. The standard thresholds are 630 or 800 A for the transformer in-feed. In industrial networks a higher rated power of the transformers may be required, and fuses of higher ratings have to be used accordingly.

The selectivity of the protection is achieved by the fuse coordination. That means that the fuse rating is downgrading starting from the MV/LV transformer along the feeders to the consumers. Figure 4.32 presents a grading scheme of an LV network.

Along the LV feeders a grading is applied like in the MV networks considering that the fuses for the single customer circuits have thresholds of 16 A and the

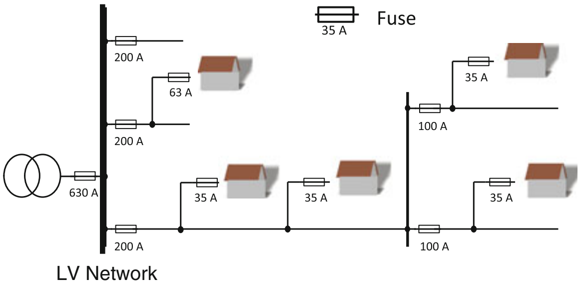


Fig. 4.32 Fuse grading in LV networks

customer connection boxes contain fuses of 35 or 63 A. These fuses perform the interface to the public network where the fuses have thresholds of $\geq$100 A.

4.6 Distribution Network Operation

4.6.1 Ensuring Power Quality

The distribution network operators are obliged by law to ensure a reliable, consumer friendly, ecologic and economically efficient electric power supply to the society with the highest possible level of power quality.

The definition of the power quality is based on the three pillars:

- reliability of supply,
- voltage quality and
- service quality.

The reliability of supply is verified by statistical analyses of such indices as the frequency of supply interruptions, the average time of supply interruptions or the energy not delivered on time. The application of probabilistic calculation methods helps to evaluate the reliability indices in the planning phases regarding new erections, extensions or enhancements of distribution networks. The most used reliability indices are presented in Table 4.4.

The European benchmarks show that the highest reliability of supply (SAIDI) is achieved with 16 min/a. The benchmark of the European regulators is presented in Fig. 4.33.

The majority of supply interruptions are caused by faults in the MV networks. In Germany, supply interruption occurred as follows [2]:

- MV distribution 84 %,
- LV distribution 14 %,
- 110 kV- regional distribution 1.9 %,
- Transmission 400/220 kV 0.1 %,
- Power generation 0 %.

Table 4.4 Globally used reliability indies [2]

Index	Name	Definition	Unit
SAIFI	System average interruption frequency index	Interruption frequency per customer served	n/a
SAIDI	System average interruption duration index	Service unavailability per customer served	Min/a
CAIFI	Customer average interruption frequency index	Interruption frequency per customer interrupted	n/a
CAIDI	Customer average interruption duration index	Mean duration of a customer interruption	Min/a
ASAI	Average system availability index	Measured/required system availability	%
ENS	Energy not supplied on time	Sum of the energy amounts not delivered in time of all customer interruptions	MVAh/a

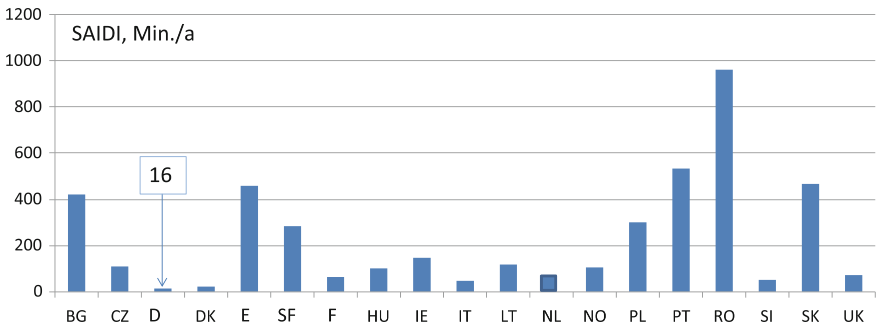


Fig. 4.33 European benchmark of the system average interruption duration index. *Source* 2011 www.energy-regulators.eu

Figure 4.34 presents a distribution of the total number of faults in each voltage level, the fault rate per 100 km and the number of faults causing supply interruptions (example of Germany). It can be stated that the majority of faults occur in 20 kV networks, which is due to the fact that this level has by far the longest total length of lines (290,000 km) combined with a higher fault rate per 100 km. The 20 kV level is used in large cities with strong load concentrations and for rural networks where a longer distance with overhead lines has to link the rural villages to the feeding substation. The 30 kV networks, in comparison, build a total line length of only 18,000 km.

It can be observed that in the MV distribution networks only 50 % of the faults lead to a supply interruption.

This fact can be evaluated as the result of the advanced primary technology, the excellent protection concepts and the selection of the most appropriate grounding principles applied by the DNOs.

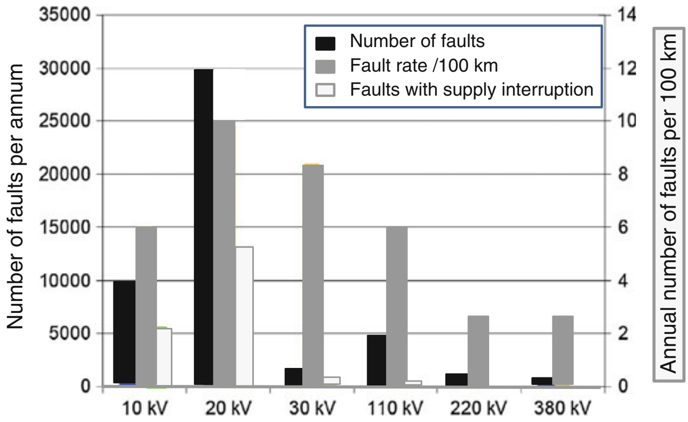


Fig. 4.34 Fault statistic of Germany related to the voltage levels [2]

The voltage quality is affected by the technical parameters of the network (like short circuit power or network impedance), the characteristics of the network assets and, especially, by the technical processes and parameters of the network users.

The majority of the applied electric plants, machines and devices—from powerful converter controlled motors down to small household devices—more or less provide reverse influence on the network voltage at the access points. The demand processes of the network users may impact the voltage quality on all voltage levels. The damping of the voltage quality disturbances depends on the technical parameters of the network and its assets: The lower the impedance, the higher the damping.

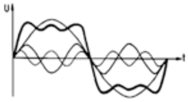
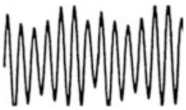
The impact of the users may concern the network frequency, the voltage magnitude with slow or fast changes that may have an intermittent character (i.e. flicker—voltage fluctuations producing the subjective impression of fluctuations in the lighting density of lighted objects via the chain of perception from electric lamp—eye—brain), the distortion of the sinus curve by harmonics or the dis-symmetry of the line to ground voltages (unbalances).

Harmonics (sine-shaped oscillations whose frequency is an integral multiple of the fundamental network frequency) are generated from non-linear loads and are very intense when produced by inverters or frequency converters. The typical harmonics are assigned ordinal numbers (v) and have and uneven ordinal number: 1st, 3rd, 5th etc. whereby the 5th harmonic is often the dominating one.

Events like short circuits, atmospheric lightning or switch operations may cause fast voltage sags and transient over-voltages. Table 4.5 presents an overview of the voltage quality disturbances, their causes and the possible negative consequences.

The voltage quality requirements for MV and LV networks are defined in the CENELEC standard EN 50160. The standard describes the admissible maximum bandwidths and tolerances in regard to the rated voltages of public LV and MV

Table 4.5 Disturbances of the voltage quality and their impact

Type of disturbance		Possible causes	Consequences
Voltage dips		Successfully cleared fault Start-up of large motors	Shutdown of equipment, particularly electronic devices
Over-voltages		Uncontrolled active or reactive power in-feed	May harm equipment withinadequate design margin
Harmonics, harmonic distortions		Non-linear load resonance DC/AC converter	Voltage distortion causes additional heating in motors Misoperation of electronic device
Flicker, voltage fluctuations		Start-up of large motors Electric arc furnaces	Weakening of components Malfunctions Annoyance of human
Transient over-voltages		Lightning strike Switching events	Misoperation of electronic device Reduced lifetime of equipment Insulation failure
Supply interruptions		Faults	Shutdown of equipment Misoperation of electronic device
Phase unbalances		Unbalanced loads	Risk of disconnection of the overload phase Machine overheating

networks. This standard is embedded in the supply contracts between the distribution network operators and network users. The users have to ensure an appropriate level reverse impact and the DNO guarantees the voltage quality in accordance with the requirements of EN 50160. In cases of deviations, appropriate measures have to be implemented.

High harmonic distortions may require the installations of harmonic filters which build a resonance circuit for the relevant ordinal numbers of the harmonics.

Fast voltage sags and flicker can be compensated by applying dynamic voltage restorers which perform an extremely fast in-feed of reactive power to stabilize the voltage. The establishment of such devices is often used in industrial networks supplying manufacturing processes which are extremely sensitive to voltage disturbances (e.g. semiconductor industry, computer industry, chemical industry etc.).

Slow voltage changes can be kept within the bandwidth by transformer step regulation and the control of generators feeding into the distribution networks.

The main requirements of EN 50160 are presented in Table 4.6.

Table 4.6 Bandwidths and requirements of EN 50160 for voltage quality [5]

Parameter	LV	MV	Verifi-cation	Requirement
Frequency	50 Hz ± 1 % 50 Hz + 4 %,−6 %	50 Hz ± 1 % 50 Hz + 4 %,−6 %	10 s Average	99.5 % in 1 year 100 %
Rated voltage	230 V phase to ground	Network related		
Slow changes	+10 %,−15 % ±10 %	±10 %	10 min Average	100 % 95 % during a week
Fast changes	Normal 5 %, Infrequently 10 % $P_{lt} \leq 1$*	Normal 4 % Infrequently 6 % $P_{lt} \leq 1$*	Sequence of 12 P_{st}* values (600 s) within 2 h	95 % during a week
Voltage dips < 1 min	Indicative p/a a few tenth to a thousand	Indicative p/a a few tenth to a thousand		Majority < 1 s, Dip < 60 %
Harmonic distortions	Limits for v = 5–25 from < 6 % to < 0.4 %	Limits for v = 5–25 from < 6 % to < 0.4 %	10 min Average	95 % of a week
Interruptions <3 min	Indicative p/a a few tenth to several 100	Indicative p/a a few tenth to several 100		70 % <1 s
Interruptions >3 min	<10 up to ≤50	<10 up to ≤50	Sum of planned and unplanned minutes	Depending on the region

**P* Flicker intensity, *lt* long term, *st* short term

The provision of an appropriate voltage quality is often the pre-requisite for the allocation of industries.

The service quality expresses the quality of the relationship between the electric power supply companies and the consumers. As a result of the unbundling of the power supply processes, the consumers interact with the trader of electricity, with the DNO and with the meter service provider (if this function is not assigned to the DNO). Consequently, all three actors of the electricity market have to provide service quality in their consumer relations.

Despite the reliability of supply and the voltage quality, the service quality does not have a direct impact on the secure supply of the consumers and their connected devices or plants. Therefore, general standards regarding the service quality do not exist yet. However, within the European Union the individual countries apply guidelines concerning the main characteristics of service quality. Table 4.7 presents an overview of the most common characteristics of service quality in Europe with the bandwidth durations and possible financial penalties in case of violation.

The overview shows a wide range depending on the rules established in the various countries. In Germany, for example, the installations of the consumer connection and the meter have to be performed within two days, and there are usually not any penalties.

Table 4.7 Service quality characteristics, bandwidth of limits and penalties [2]

Service characteristic	Time limits	Penalties, €
Appointments scheduling	2–3 h	0–35
Connection and meter installation	2–5 d	0–50
Estimation of charges for simple works	5–20 d	0–65
Response to metering problems	5–20 d	0–35
Response to queries on charges and payments	5–20 d	0–30
Number of meter readings per annum	1–6	0–30
Response to consumer letters	8–20 d	0–20
Response to consumer claims	5–20 d	0–35

In Spain and Italy, however, the establishment of connections can take up to five days and the penalties can reach 30 €. On the other hand, Ireland requires an installation within three days and claims the highest penalties of 50 €.

In the sense of liberalization, each consumer can select and contract the trader and the meter service provider himself, but he still depends on the local acting DNO.

4.6.2 Process Management

The Distribution Control Centre (DCC) performs the core of the process management in distribution. Advanced DCCs present on screen the network topology, measurements, meter values, event messages in schemes, diagrams, profiles, tables and reports. The control is possible by using keyboards.

Nowadays, the DCCs do not cover only the management tasks of electricity networks. Multi-utility DCCs are often established in accordance with the overall supply structure of urban areas. Such multi-utility DCC may perform the process management tasks for several media like electricity, gas, heat and water. Figure 4.35 presents a view of the multi-utility DCC with three separate work places to control electricity, gas and district heating networks.

The staff members are trained in all three fields of network management. Practical experience has shown that the employees are highly motivated to expand their knowledge and to perform combined tasks. The multi-utility approach creates synergies and efficiency in the overall supply processes.

The management of the electricity distribution is focused on two basic systems:

- SCADA—supervisory control and data acquisition,
- GDOF—general decision and optimization functions.

Fig. 4.35 Multi-utility DCC with three work separate workplaces for electricity, gas and heat. *Source* HSE AG

The SCADA system performs the functions:

- Alarms in case of critical loading, disturbances of the voltage quality and faults,
- Acquisition and processing of measurements and meter values,
- Switch commands and further control (e.g. transformer tap changing),
- Monitoring of the network topology,
- Evaluation and archiving of the results of the performed application functions.

The GDOF system is more concentrated on the power balancing functions which have a strong impact on the network operations:

- Load and local generation prediction,
- Load control,
- Optimization of the purchase and import of electric energy,
- Condition simulations.

The network operator is able to estimate the current network situation by an appropriate visualization on the screens.

The following functions are performed in this way:

- Network supervision,
- Switching and control procedures,
- Starting of actions to eliminate faults and disturbances.

Figure 4.36 presents the work place of the electricity distribution operator. The screen in the middle presents the topology of a network part. This may be scrolled up/down and zoomed in/out. The icons present the status of the switch devices. Each element of the scheme can be selected by the cursor and detailed information can be opened, e.g. voltages and power flow. The other screens may display different event

Fig. 4.36 The workplace for electric network operations in a DCC. *Source* HSE AG

reports, the record of the network loading and others. For these tasks the DCC provides communication links to the supervised and controlled assets.

In the regional distribution and transmission networks normally all node elements are linked to the control centers and may be monitored and controlled. This is a pre-requisite to ensure the N-1 criterion without interruption of the network services.

The number of remote controlled assets is limited in the DCCs for economic reasons. As a rule, the SCADA functions are completely available for the primary distribution level. In this way, the **network supervision** of the local distribution is designed differently.

In the local MV distribution normally the feeding substations and the distribution terminals are subject to remote control. The status of the majority of the transformer terminals is visualized as a substituted value. Operations have to be executed locally and manually. The staff has to submit changing conditions to the DCC, and here the changes will be set manually in the topology schemes.

Regarding the monitored assets, the permitted bandwidths and tolerances of the measurements are implemented in the DCC. Every threshold excess will be signaled by flashing icons on the screen and by acoustic alarms.

The monitoring of the LV networks ends at the transformer in-feed.

The communication links require special security measures to avoid external attacks and to also ensure the communication in cases of supply interruptions.

In general, the LV networks are not remotely monitored and controlled. An exception is often made in industrial networks in accordance with the considerations made above in Sect. 4.3 (Fig. 4.13b).

The **switching and control procedures** are a matter of the daily repetitive tasks in the DCC.

Control operations may be planned or un-planned. Planned operations are executed to reconfigure the network topology for optimization purposes or for switching-off and grounding assets to perform maintenance, testing or replacement works.

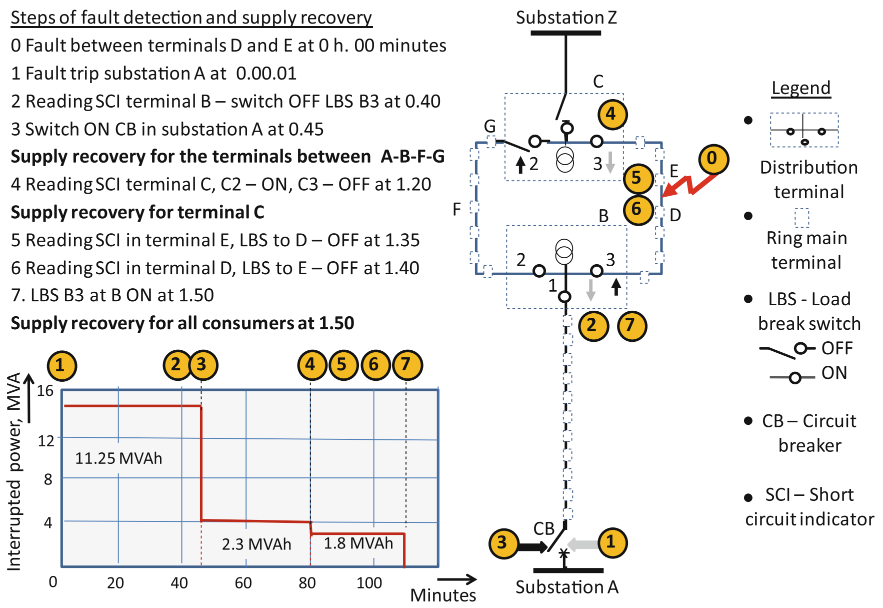


Fig. 4.37 Example of fault location and supply recovery in a 20 kV network

The un-planned control consists of switching sequences to isolate faulted assets or critical network conditions including the operations for supply recovery. The planned control operations that are not executed by the DCC but have to be performed locally require typical operation sequences. The preparation of such operations requires the detailed operation plan which has to be confirmed by the DCC in advance. The local operations are simultaneously reported by phone call to the DCC.

The **fault location, elimination and recovery of supply** are supported by the DCC. The part of the MV network that is interrupted is visible on the screen scheme of the MV network. However, disturbances in the LV networks are not centrally observable. They are only recognized when the consumers call into report disturbances.

As a rule, the accurate fault location requires that maintenance staff drive along the feeders and check the status of the short circuit indicators in the terminals. This work is also coordinated by the operator in the DCC who is further responsible to document all findings and actions in reports. All fault reports are transferred to a central office for statistical reporting.

The sequence of actions to detect the fault location and to recover the supply of the interrupted consumers is presented on an example in Fig. 4.37.

The presented network scheme follows the "connectable radial feeder end" concept. In this example two configuration schemes of this concept are combined:

- The open loop scheme between the distribution terminals B and C,
- The opposite substation scheme between the substations A and Z.

As mentioned above, the traditional practice requires that the maintenance staff drives along the feeder, checks the status of the short circuit indicators in the terminals and performs the appropriate switching operations for the supply recovery.

The supply interruption of the consumers after a fault between the ring main terminals E and D is recognized by the protection trip of the whole feeder A–C in the substation A (1). All terminals between A and C, therefore, are no longer in service, which is equal to a power interruption of 15 MW.

The traditional recovery of supply is performed in the steps mentioned in Fig. 4.37.

First of all, the staff drives to the distribution terminal B and arrives, on average, after 40 min (2). Here it is seen that the short circuit went through in the direction D. The staff switches off the load break switch (LBS) 3 in the direction D and confirms this operation to the DCC. The dispatcher can now switch ON the circuit breaker of the feeder A–C and the majority of the consumers of the feeder A–C–F–G (11 MW demand) is supplied again (3).

In the next step, after an average of 80 min, the staff arrives at the distribution terminal C, recognizes that a short circuit current was not detected, switches ON the LBS 2 and switches OFF the LBS 3 (4). Now supply of the consumers connected to the terminal with a demand of 400 kVA is recovered.

The next targets of the maintenance staff are the terminals of the feeder C- D. After 95 min it is detected that a short circuit current did not flow through terminal E (5).

The short circuit indicators of the neighboring terminal D indicate that the short circuit current flows through (6). The staff switches OFF the LBSs of the feeder section E-D in both terminals after 100 min.

For the last step (7) executes the switching ON of the LBS 3 in the in terminals B after 110 min. The supply of all consumers is now recovered.

The time line of the supply recovery is expressed by the graphic in the presented "power interruption—duration" diagram of Fig. 4.37.

The reliability characteristics for the presented example are

- 61.5 min average interruption time per power unit and
- 15.35 MVAh. Energy not delivered on time.

These values correspond with the average values in the German statistics of 2010, which stated the average interruption duration after faults in the medium voltage networks of 63 min [3].

4.7 New Trends in Distribution Systems

4.7.1 Distributed Generation and New Types of Load

The new challenges for distribution network operation are caused by global targets to reduce the CO_2 emissions, to increase the share of renewable energy in the energy balance and to increase the energy efficiency (see also Sects. 1.1 and 1.3).

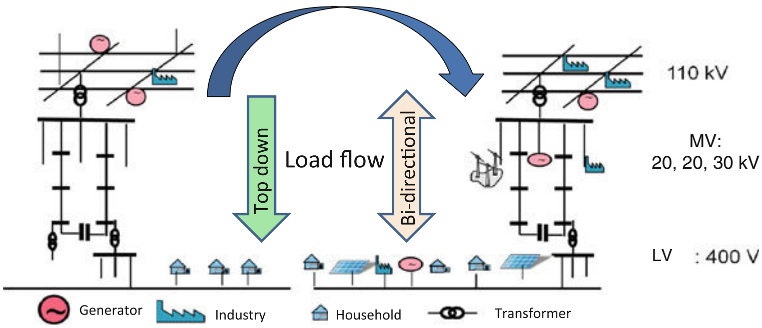


Fig. 4.38 Changing conditions in the distribution networks due to DER integration

In many countries, the renewable generation has the priority to in-feed by law, and it is not foreseen to control the renewable generation (see Sect. 7.1).

A significant part of the renewable energy will feed into the distribution networks from a large amount of small sized distributed energy resources (DER). As a consequence of these trends, the operation conditions of the distribution networks will change fundamentally. Figure 4.38 presents the changing situation. Traditionally, the power flow is in a top down direction (left).

The connection of DER in the LV and MV networks, however, may cause bi-directional load flows between the LV, MV and HV networks. If the load is lower than the generation, bottom–up (reverse) power flows will occur. And, because the meteorological conditions which directly affect generation levels are volatile, the load—generation balance can change multiple times during the day. Consequently, the power flow becomes volatile and changes its direction multiple times during the day as well.

Furthermore, the energy efficiency and environmental protection targets will also be reached through replacement of traditional combustion engine cars by electric cars (e-mobiles). The German Federal Ministry for Transportation expects one million electric vehicles in 2020 and six million in 2030. The benefit is seen in the fact that the "electric fuel" for the cars comes mainly from renewable energy sources. However, the power needed for the rapid charging of one electric vehicle may be as much as 15–20 kW. This amounts to 52–70 % of the tripping power of the standard 35 A fuses in the LV networks.

The simultaneous rapid charging of a number of electric vehicles along a LV feeder, therefore, creates a critical situation for the majority of LV networks.

The achievement of the energy efficiency targets will also be supported by a paradigm change regarding the heating systems for households, small enterprises and public buildings. Program have been started to install small units for cogeneration of heat and power (CHP) of some kW of electric and thermal energy.

Moreover, a significant improvement of the heating efficiency is expected from the installation of heat pumps. The connection of heat pumps will significantly increase in the coming decades.

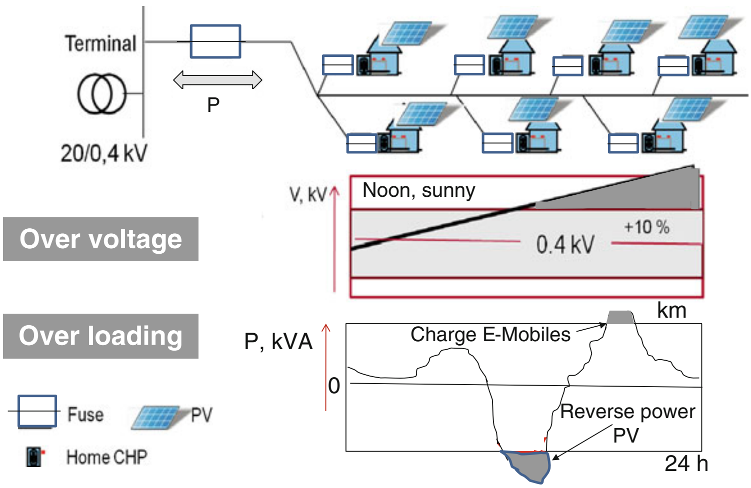


Fig. 4.39 Possible stress situations in 400 V networks

4.7.2 Impact on Power Quality

Due to the significant shares of DER, especially volatile energy sources and the appearance of new loads like e-mobiles, extreme situations may occur which may cause short-term over-stressing of the network assets and of devices on the consumer side.

The appearance of stresses by overloading and/or over-voltages is demonstrated in Fig. 4.39.

At noon in a long 400 V feeder with many connected photovoltaic plants, a reverse power flow may occur exceeding the thresholds of equipment dimensioning. The voltage grows along the feeder and may exceed the standardized threshold of +10 % of the rated voltage. In the evening the sun no longer shines, but the customers return home from work and want to charge a large number of electric vehicles simultaneously. Here an overload of equipment may occur in the supply direction.

Great challenges are seen in the reverse interferences of the new network users regarding the voltage quality:

- Over-voltages through the connection of generators,
- Under-voltages through powerful simultaneous loads,
- Flicker by wind power and photovoltaic plants,
- Harmonic distortions generated by the power electronic converters of wind power and photovoltaic plants and by the charging units for e-mobiles.

Table 4.8 Admissible values of total harmonic currents [6]

Ordinal number ν	Admissible, related harmonic current $i_{\nu,\mu}$, A/MVA		
	10 kV network	20 kV network	30 kV network
5	0.058	0.029	0.019
7	0.082	0.041	0.027
11	0.052	0.026	0.017
13	0.038	0.019	0.013
17	0.022	0.011	0.07
19	0.018	0.009	0.006
23	0.012	0.006	0.004
25	0.010	0.007	0.003

Therefore, the Distribution Code [6] established new guidelines for the connection of renewable power plants.

To avoid an inadmissible exceeding of the voltage bandwidth at the most critical junction point (PCC—Point of Common Coupling) of generating plants, the voltage hub of all generating units must be limited to: $\Delta U_{max} \leq 2\ \%$.

To avoid inadmissible network interactions, sudden voltage changes attributable to switching on or off operations at the junction point of generating plants must be limited to the following values:

- Switching of individual generating units: $\Delta U_{max} \leq 2\ \%$.
- Switching of the entire plant or a number of generating units: $\Delta U_{max} \leq 5\ \%$.

To assess the connection of one or several generating plants at a PCC, the following long-term flicker intensity has to be observed at the PCC with regard to flicker-effective voltage fluctuations: $P_{lt} \leq 0.46$.

In principle, in order to determine the harmonic voltages caused by generating plants, all harmonic generators connected to the network in question shall be superposed in proper phase relation. This requires a large expenditure in terms of calculations. To simplify matters, it was therefore assumed that only those harmonic currents from generating plants connected to a transformer station or line section (line between two transformer stations) superpose one another. Table 4.8 shows the admissible values of total harmonic currents (related to the network short-circuit power at the junction point of the generating plant) injected at a transformer station or a line section.

The manufacturers of the relevant generating plants are obliged to ensure the admissible thresholds regarding all of the influences mentioned above.

In conclusion, the considerations regarding the impact of new users of distribution networks clearly demonstrates that distribution network operations will becomes more complex and will need more intelligent coordination, control and supervision in the sense of Smart Grids.

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Chapter 5
Smart Operation and Observability at the Transmission Level

In the course of liberalization, deregulation and the increase in shares of volatile renewable electric power production, the responsibility for the complex guidance of the power system has been passed on to the transmission system operators in Europe. They are responsible for the network control, for the generation–load balancing and the provision of system services such as frequency control and maintaining the voltage control, as well as for the availability of reserve capacity. For these tasks, comprehensive information about the current conditions of the system is required in the network control centres, including the unit commitment, the load development as well as information on the adjoining systems. Based on this information, critical situations may be identified, and timely measures for stabilization have to be initiated. The changing network operating conditions lead to increasingly stressful situations for the dispatchers and the probability of operation failures is rising.

The application of advanced power automation technology helps to increase the system observability, to provide guidance for the dispatchers and to automatically perform the proper countermeasures in emergency situations. In this context, the term "congestion management" is introduced. Congestions occurred if the N-1 criterion cannot be satisfied according to the observed load flows through the network. Congestions may occur within a short time as a result of unforeseen outages of power stations or network assets or due to significant deviations from the registered schedules that are larger than expected.

In the first part of this chapter, the root causes of large system disturbances during the 21st century in leading industrial countries are considered. In the following sections, the practice of modern power system control is described and solutions for an intelligent and preventive congestion management are presented.

This chapter is mainly based on the lectures of the VDE seminar "Smart Grids" which have been compiled and given by the author Dr. B.M. Buchholz since 2009, on the VDE study "Active Energy Networks" (2013) [12] under the leadership of the author Dr. B.M. Buchholz and also contains considerations of rules specified by ENTSO-E RG CE (UCTE) and BDEW (VDN).

B. M. Buchholz and Z. Styczynski, *Smart Grids – Fundamentals and Technologies in Electricity Networks*, DOI: 10.1007/978-3-642-45120-1_5,

5.1 The Root Causes of Large Blackouts and the Lessons Learned

5.1.1 Overview and the Voltage Collapse Phenomena

Power system operation includes the harmonious co-ordination of many processes in a large cybernetic system composed of millions of components of equipment. The main challenges are:

1. Balanced interplay of transmission capabilities, electricity demand and power generation,
2. Coordinated protection, control and communication functions supporting a flexible, real-time adaptation of the system conditions to actual situations.

The analysis of the system blackouts or large disturbances in North America, London, Sweden and Italy from August and September 2003, in Athens 2004, in Moscow 2005 and in Germany in November 2006 (overview in Fig. 5.1) has shown different causes. Here a system blackout is understood as a complete collapse of the power system with wide area break downs of power stations and supply interruptions. It needs a longer time to recover the system for full service.

On the other hand, the system is not collapsed in the result of a large disturbance and may continue the service after a short interruption time.

The main reasons for the above mentioned events are understood to be in the missing information about the critical conditions and the lack of criteria regarding how to act in the control centres in such emergency situations. Furthermore, the catalyst of the events was a voltage collapse in the five cases of USA/Canada, Sweden/Denmark, Italy, Athens and Moscow.

Voltage collapse can occur if the reactive power demand of the loads rises significantly due to voltage reduction in the grid. This mainly applies to motor-driven loads. The additional reactive power demand leads to an increased voltage drop through the impedances of the network—especially if the network is topologically weakened due to line disconnections and if the equivalent system impedance has been increased respectively. In a cascading effect, the complete breakdown of the power supply can be the result.

Figure 5.2 explains the dependency of voltage and rotation speed of the electric moment of an induction machine load. At the normal operation point OP1 (rated voltage and rated rotating speed) the curves of the mechanical torque 2 and mechanical load 4 crosses. The reactive power demand (curve 1) is low. Due to reduced supply voltage, the new curve of the torque–speed dependency 3 is significantly reduced and a new operation point of the machine (balance of electrical and mechanical moment) at reduced speed is adjusted. This is shown with the position of the operation point OP2 corresponding to 60 % of the rated voltage. At reduced speed, however, reactive power is needed on an extended level for a stable operation. Higher reactive power demand causes further significant voltage drops in the supplying grid: the voltage collapse continues and may lead to a system collapse.

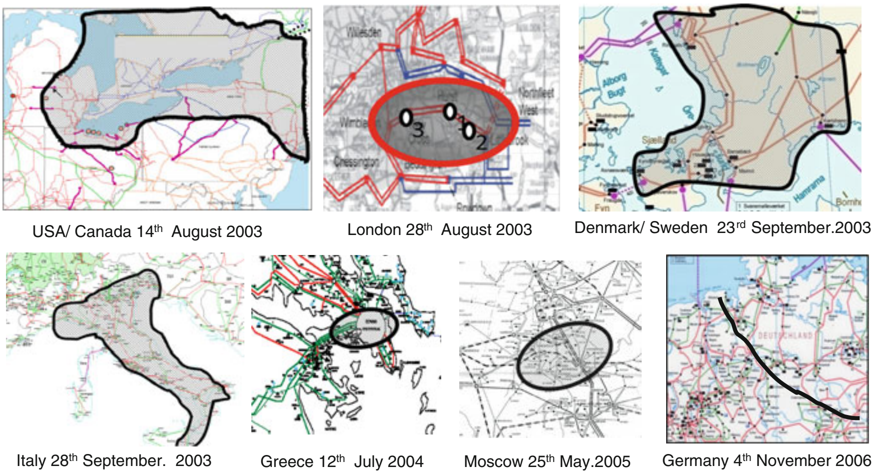
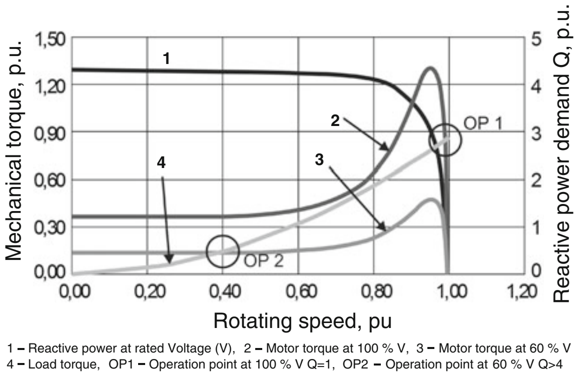


Fig. 5.1 Large system disturbances in industrial countries 2003–2006

Fig. 5.2 Physical behaviour of induction machines



This condition can only be prevented if part of the supplied, especially reactive load is tripped, if additional reactive power is fed in close to the loads, or if the impedance of the supplying network is reduced (e.g. by switch-on of reserve transformers). Then, the system voltage can recover; the machines accelerate to rated speed and reduce their reactive power demands.

An example for these physical relations was simulated in accordance with the voltage decrease as the result of a fault on one system of a double line. Figure 5.3 presents the scheme, the fault consequences and the voltage diagrams.

As a result of the fault the voltage V_L at the busbars B_1 and B_2 supplying the load centres with strong shares of induction machines (e.g. for air conditioning) breaks down. After the fault trip only one system of the double line stays available for the power transfer. Consequently, the volume of power transfer over one line and the equivalent of the line impedance (L_1 instead $L_1 \| L_2$) are now twice as high

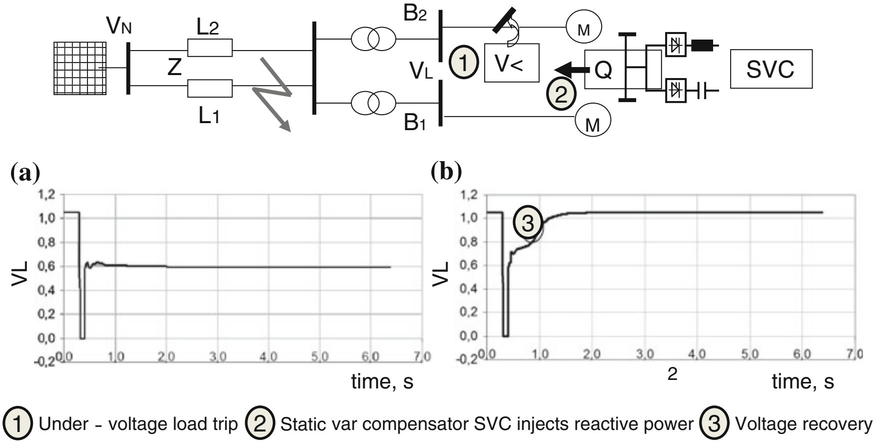


Fig. 5.3 Voltage collapse and avoidance after a fault

as before the fault. But the reactive power required by the machine loads has increased significantly. Without safety measures—either load tripping (1) or reactive power injection (2)—the voltage cannot recover.

The diagrams in Fig. 5.3 present the voltage developments:

- Left: voltage collapse whereby the voltage does not recover into the bandwidth,
- Right: the appropriate recovery action 2, shown on the top, is performed to avoid the collapse.

Measure 1 can be performed by the under-voltage protection in combination with the setting adaptation after the observation of strong reactive power flows. Without this combination an over-function of the protection could happen in normal recovery cases.

Measure 2—the fast in-feed of reactive power—is performed by a static var compensator SVC. This example makes clear that the real time observation of congestions and the rapid activation of appropriate measures may prevent large system disturbances.

5.1.2 Northeast USA/Canada Blackout 2003

In the USA, the blackout of August 14th, 2003, started along the Southern shore of Lake Erie. It was a hot day with a temperature of 31 °C at 12:00, and a high share of air-conditioning in the urban centres was observed. First Energy—the transmission system operator (TSO) serving this area—faced its annual peak load of 12.635 MW on this day [1].

Between noon and 1:30 p.m. the outage of three power plants caused a 1,757 MW loss of power in-feed and additional load flows between the

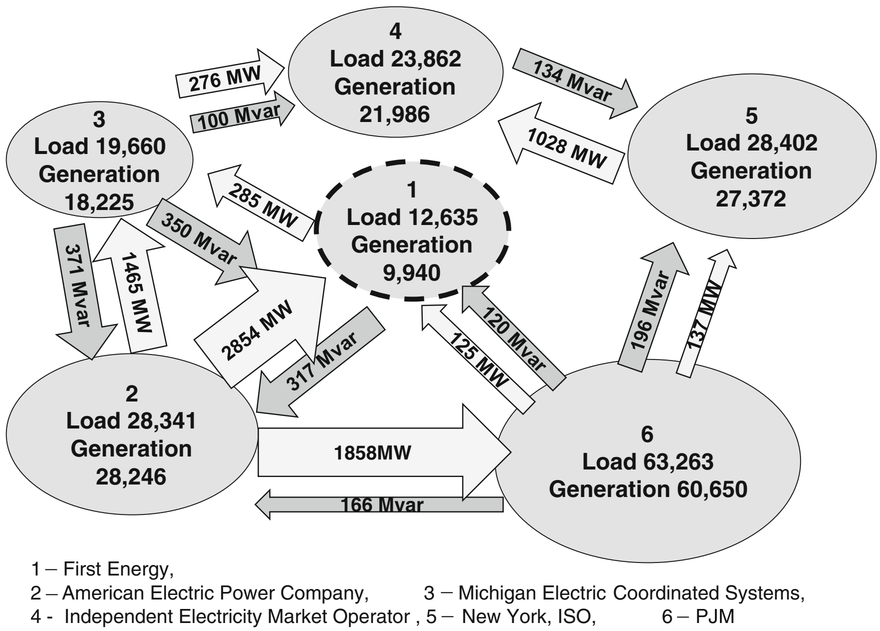


Fig. 5.4 Area load situations and power flows between the TSOs [1]

transmission systems (Fig. 5.4). At 2:00 the SCADA system of First Energy failed, and a redundant system was not available. Between 2:02 and 3:45 five 345 kV lines tripped (several tree contacts)—all with >10 min between the events. However, the line trips were not automatically reported to the TSO First Energy caused by the SCADA malfunction. Therefore, the on-going topological degradation of the system due to tripped lines and power plants was not recognized in details and could not be stopped just by phone talks.

Figure 5.4 demonstrates the loading situation of First Energy and the surrounding TSOs.

At 3 p.m. the heaviest inter-area power flow of 2,850 MW was observed from Dayton Power and Light to First Energy over the path which was weakened by the line trips mentioned above.

The still operating lines were extremely strongly loaded and the losses of reactive power were extremely high. The voltage at the 345 kV substation Sammies declined to 320 kV, which additionally increased the reactive power flows.

At 4:06 p.m., the additional 345 kV line Sammies–Star was disconnected by a trip of the distance protection in the overloaded area (zone 3) of the MHO distance protection characteristic (Fig. 5.5).

This event was the main trigger of the final blackout sequence.

It caused a fast cascade with hundreds of incidents in all system areas, 26 of them in the EHV networks as shown in Fig. 5.6.

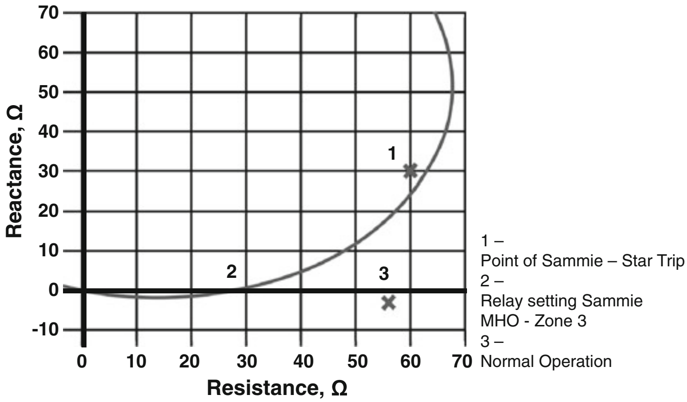


Fig. 5.5 Trip conditions of the 345 kV line Sammie–Star at 4:06 p.m. [1]

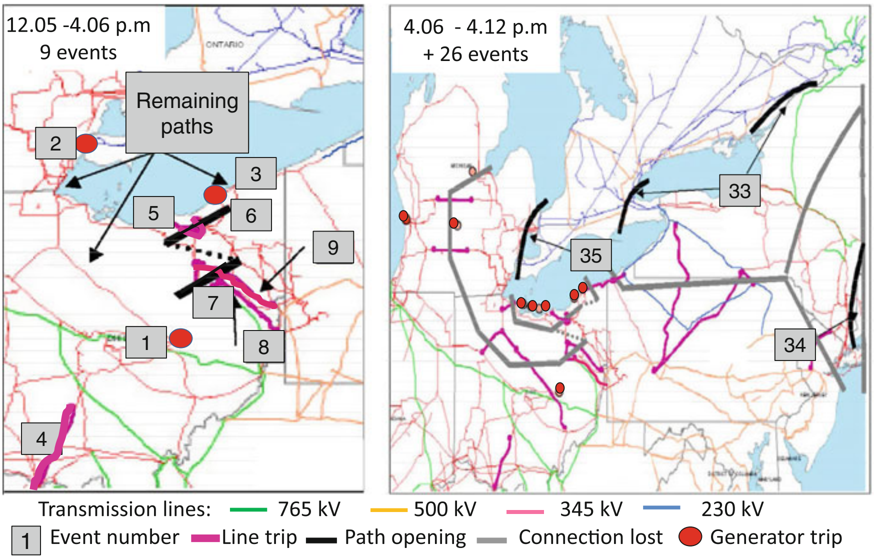


Fig. 5.6 Sequence of events up to 4:06 and the final blackout state 6 min later [1]

Just 6 min later, not only First Energy but six neighbouring systems were also split into autonomous islands and faced a wide-area blackout.

The lessons learned from this event are:

- SCADA systems and communication links have to be secure under all circumstances and have to be engineered so that they are uninterruptable,

- Appropriate guidance for dispatchers accompanied by automatic network congestion management have to be performed if the transmission network is weakened for hours at a time,
- The protection parameters should be adapted to the network conditions.

Furthermore, the work of the USA/Canadian blackout task force was complicated by un-synchronized time stamps of the protection signals in the affected substations. The time synchronization via satellite of all intelligent electronic devices (IEDs) for protection and control in the power system is now a strong request.

5.1.3 Large Supply Interruption in London 2003

On 28th August 2003—2 weeks after the large blackout in USA/Canada, the city of London was affected by a large supply interruption. The city network is mesh operated by 275 kV double cable systems building loops. One path of a double loop connects the substations Wimbledon, New Cross, Hurst and Little Brook. Two cable lines of the system were out of service for maintenance: Wimbledon–New Cross and Hurst–Little Brook as shown in Fig. 5.7 [2].

When a transformer "Buchholz" alarm was monitored at 6:11 p.m. in the substation Hurst, the dispatcher decided to switch off the related transformer. Due to the scheme of the substation, the remaining line between Hurst and Little Brook had to be switched off. This operation opened the 275 kV loop and the supply of the substations Hurst and New Cross could continue only from the substation Wimbledon.

As a result of this operation, the power flow over the line Wimbledon–New Cross increased strongly from 72 to 558 MW. Recognizing this power increase, the protection in Wimbledon tripped the line instantaneously. This trip was caused by an error of the protection engineers. The protection parameters were set for a secondary current of 1 A instead of 5 A.

Then, resulting from this trip the area supplied by the substations Hurst and New Cross experienced a blackout. The power stations in this area were also shut down and the power that was not provided was over 700 MW.

In conclusion it should be stated:

- Each operation requires a network security calculation in advance of taking action,
- Operations that bring the system into a N-1 unsecure situation should be strictly avoided,
- The settings of the protection have to be archived and approved regularly in accordance with the substation documentation.

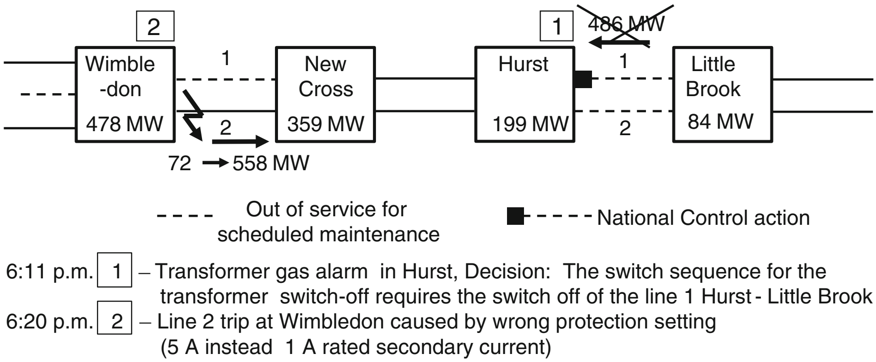


Fig. 5.7 The events leading to the London supply interruption [2]

5.1.4 Blackout in Sweden and Denmark 2003

On 23rd September 2003, 5 weeks after the blackout in the USA/Canada, the power system of Sweden and Denmark faced a collapse. The network and the events leading to the blackout are presented in Fig. 5.8.

On this day, the network was weakened by the switch-off of the two EHV DC links to the UCTE network, an additional 400 kV line and a power station for maintenance.

At 12:30 a 1250 MW power station was shut down due to cooling problems. 5 min later a busbar fault at the 400 kV substation Ringhals occurred [3].

After the busbar was tripped the disconnection of the power station supplying 1750 MW caused strong power oscillations on the remaining lines.

The subsequent frequency drop was followed by automatic load shedding. However, the frequency stabilization could not prevent the blackout. The final reason for the system blackout was the subsequent voltage collapse.

Again the requirement for better observability of the transmission network comes up. Furthermore, the N-1 criterion has to include busbar faults and also consider the connected power generation.

5.1.5 The Italian Blackout 2003

During the night of September 27th 2003 Italy celebrated a “white night” causing higher electric power consumption than usual. A permanent power importation of 6,500 MW flowed through the neighbouring networks into Northern Italy. About 50 % of the power was used to drive the Italian pump storage plants.

In Switzerland to the north this was a stormy night. The distance protection tripped a 400 kV line in Switzerland due to a tree contact at 3:01 a.m. on the 28th

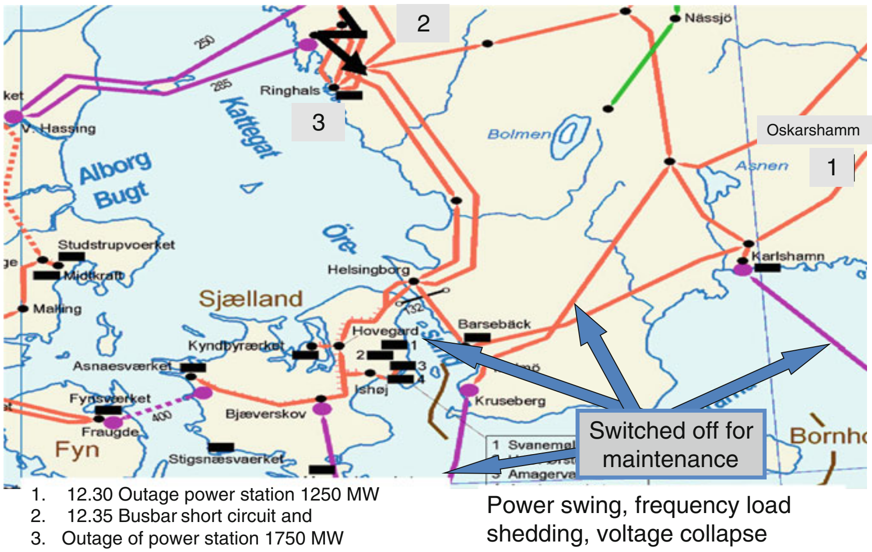


Fig. 5.8 Situation in the Southern Swedish transmission network leading to the blackout

of September. Recognising the definite outage after an unsuccessful auto-reclosing of the line Lavorno–Mettlen the dispatcher in Switzerland stated that the N-1 security could no longer be provided. The reduction of the imported power in Italy was requested. However, the initiated power reduction of 200 MW [4] was not sufficient to re-establish the N-1 security. After a second line trip in Switzerland 20 min later, the ten remaining interconnections of the UCTE-network to Italy were instantly switched off through protection trips in the overloaded area.

As a result, Italy became completely disconnected from the UCTE network. Figure 5.9 presents an excerpt of the related UCTE report [5].

After the disconnection Italy faced a power deficit of 27 % to cover its current load of 24,400 MW. The load shedding of 10.8 GW and the activation of 1.5 GW of primary reserve power [5, 6] could not prevent the system collapse.

These relations and the subsequent courses of the voltage and frequency (based on simulations) are demonstrated in Fig. 5.10.

Strong power and voltage oscillation caused the stepwise outages of power plants by the protection schemes (out of step protection, voltage protection, frequency protection). 13,800 MW of power generation were lost. The load–generation balance could not be stabilized and the frequency fell to down to 47.5 Hz.

Only 2.5 min after the disconnection from the UCTE network, Italy faced a complete country-wide blackout.

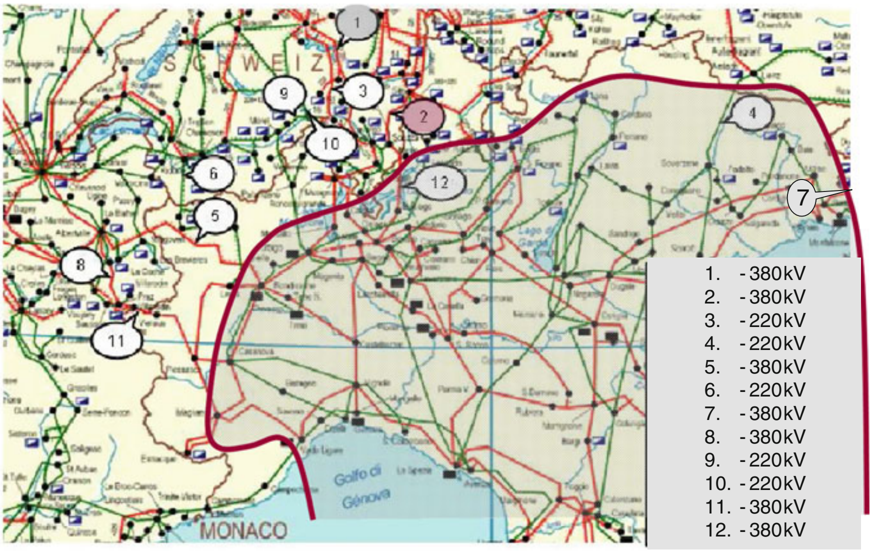


Fig. 5.9 Tripping sequence leading to the disconnection of Italy from the UCTE network [5]

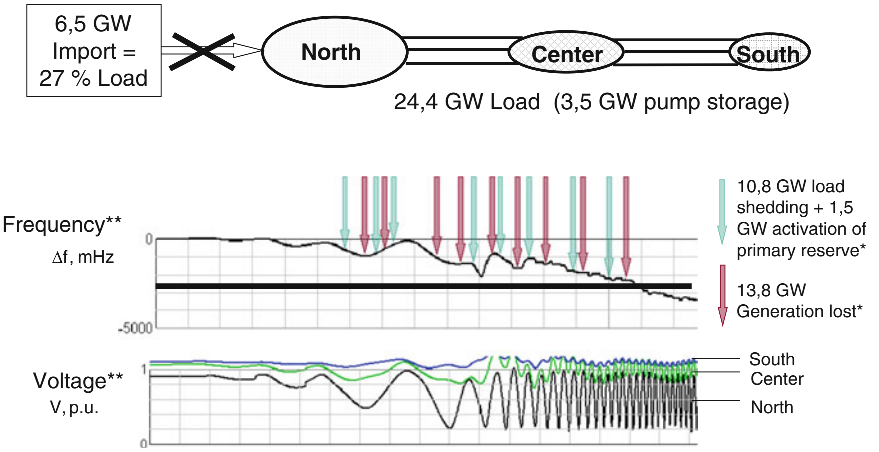


Fig. 5.10 Network conditions, the frequency and voltage courses after disconnection (*Sources* * [6], **own simulations)

5.1.6 The Blackout of Athens 2004

On the morning of the 12th July 2004 the southern part of the Greece electric power system started operating with two units in outage, these were

- an oil-fired 280 MW unit at Lavrio due to failure in the auxiliary network, and
- a 125 MW unit (lignite) at Megalopoli (Peloponnese region) for scheduled maintenance.

So, from the start of the day, the Southern network was lacking 405 MW of capacity. The Lavrio station is very important because it is located close to Athens, which requires most of the load [7].

The bulk of generation comes from north-western Greece and has to be transmitted to Athens over four long 150 kV overhead lines.

In addition, the following transmission elements were unavailable on this day due to various failures and repairs:

1. One system of a 150 kV double line from the west of the Athens supply area.
2. Two 150 kV cables connected to the power station in the area of Piraeus (port of Athens).
3. One (out of four) 150 kV circuit between the 400/150 kV substation Koumoundourou in the north and the Piraeus power station AHSAG.

The result of these un-availabilities was an unusually heavy loading of the 400/150 kV substation Pallini with three autotransformers almost fully loaded.

This situation led to unusually low voltages in the entire Athens grid. The voltages in the Athens area were constantly dropping and reached 90 % of the nominal value. The voltage decline stopped as soon as the power station Lavrio was synchronized and started generating. However, at 12:12 the power station Lavrio, still in the process of achieving its technical minimum and on manual control, was lost again due to a high water level in the steam drum. The new loss of Lavrio brought the system to an emergency state, since the other generating stations in Athens and Central Greece had trouble keeping up with the demand for reactive power. The voltage development of three 150 kV substations in the Athens area is presented in Fig. 5.11.

At 12:25 a load shedding of 100 MW was requested by the Hellenic Transmission System Operator (HTSO) Control Center. At 12:30 a disconnection of 80 MW was achieved manually. However, this was not enough to stop the voltage decline, so a further shedding action of 200 MW was requested at 12:35. At that time the load had reached its peak of 9320 MW.

The second load shedding command did not have time to be executed.

At 12:37 Unit 3 of the Aliveri power station in the weak area of Central Greece was automatically tripped. At 12:38 the remaining unit in Aliveri was manually tripped. After that voltages began to collapse and the system was split at 12:39 by the under-voltage protection of the North-South lines. After splitting, all of the remaining generation in the areas of Athens and Peloponnese were disconnected which led to the blackout.

10 days after the blackout stabilizing measures were connected to the network.

One of the measures was the connection of a 132 Mvar capacitor bank for voltage stabilization. These measures ensured the reliable power supply of the area during the 2004 Olympic Games.

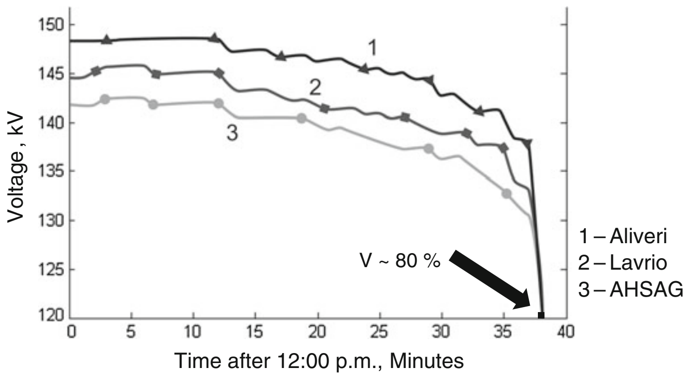


Fig. 5.11 Voltage reduction course in Athens substations [7]

5.1.7 The Large Disturbance in the Southern Moscow 2005

A sequence of six subsequent events that damaged equipment between May 23rd to May 25th 2005, led to the complete disconnection of the 500/220/110 kV substation Cagino and the connected power plant TEC 22 in Southern Moscow [8], as shown in Fig. 5.12.

The equipment that was mainly affected consisted of current transformers and air blast circuit breakers.

As a result of the Cagino substation outage on May 25th, the 220 and 110 kV networks of Moscow were significantly weakened: three lines 500 kV, nine lines 220 kV and 12 lines 110 kV lines were out of service.

Due to the load increase—especially air conditioning—on the morning of May 25th, the lines in operation became heavily loaded and the voltage decreased, e.g. to 88.5 kV in the 110 kV substation Certanovo and 172.1 kV in the 220 kV substation Baskakovo at 11 a.m.

A typical voltage collapse followed and caused a blackout in the Southern region of Moscow.

Here, better power system observation and the activation of a significant amount of reactive power could have prevented the system collapse.

5.1.8 The Large System Disturbance in Germany and Continental Europe 2006

The 400 kV network was weakened by a planned switch-off of a double line system for a ship crossing in the North of Germany on November 4th, 2006 at 9:38 p.m.

The wind power in-feed into this area increased during the whole day from 200 MW in the morning to 12,000 MW late at night. Consequently, the 400 kV network became increasingly heavily loaded.

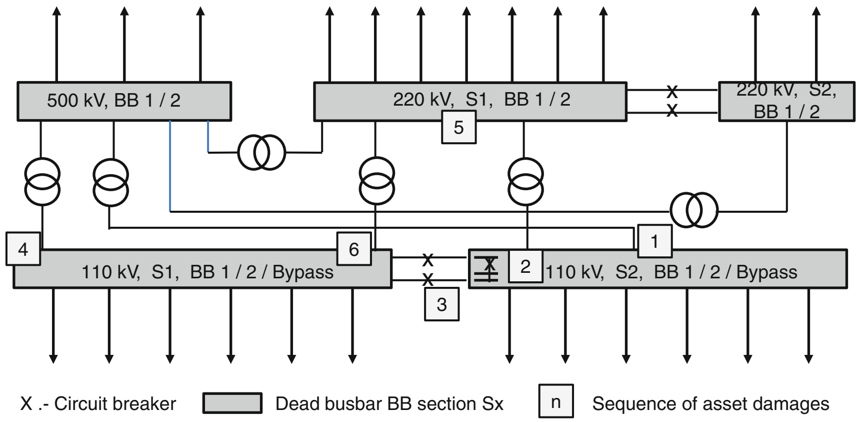


Fig. 5.12 Connection state of the Cagino substation, May 25, 2005, after asset damages [8]

To improve the situation, an additional network coupling was executed at 10:10 p.m. in the dispatching centre of the E. On control area (since 2011 called TenneT), without any prior N-1 security assessment.

However, this operation led to higher loading of the lines in the North-Southwest direction, and after a few seconds the first 2 lines were tripped by the overload protection. After these line outages a cascade of further line trips began [9].

Figure 5.13 presents the part of the related transmission network with the planned operation 1, the wind power development course of the day (2), the coupling operation (3), the two line trips (4) and (5) and direction of the bulk power flow (6).

As a result of the line outages the UCTE network was split into three autonomous islands with unbalanced generation and load, as shown in Fig. 5.14.

The western and the south-eastern islands faced a lack of power and the frequency dropped down as shown in Fig. 5.14. In the south-eastern-island the frequency drop had no consequences. However, in the western island the frequency dropped down to 49 Hz. This is the setting of the 1st stage of frequency load shedding and the protection system switched off 13,350 MW of load in the affected countries (except Switzerland where the load shedding mechanism was not installed). The majority of the load was shed in France with 5,200 MW. After the load shedding, the frequency could recover by the activation of primary and secondary reserve power.

A critical situation occurred in the north-eastern region due to the excess of wind power. Here the frequency increased up to 50.6 Hz, which is also dangerous for the system stability. This peak was eliminated within tenth of milliseconds by the frequency protection tripping the majority of the wind power plants (3,010 MW out of 4,448 MW) within one of the affected control zones (Fig. 5.15).

However, within the following 40 min an uncoordinated reconnection of 2,800 MW of wind power was executed as demonstrated in Fig. 5.15. The

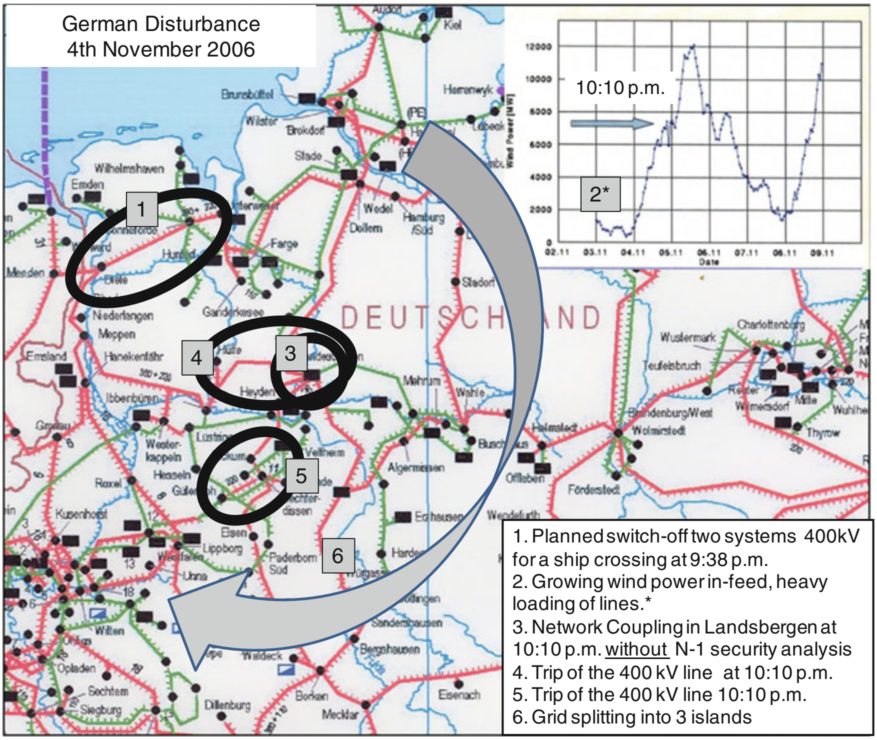


Fig. 5.13 Transmission network and the allocation of the events on 4th November 2006 (*Source* Fraunhofer IWES)

frequency could be kept stable only by the fast activation of negative minute reserve power, the re-dispatch of traditional power plants and by having the pump storage plants take over a significant portion of the load. In principle, all three islands could successfully manage the situation avoiding the enlargement of the disturbance.

The lessons learned from this event may be summarized as follows:

- Under the new changing network conditions the experience of the dispatchers in the control centres is no longer sufficient to execute operations under critical circumstances without a computer supported N-1 security assessment.
- The N-1 contingency calculations have to consider the development of the wind power in-feed in accordance with the latest intra-day predictions.
- Under critical system conditions, the TSO shall obtain the right for the network access coordination of all generation units.

However, in conclusion it can be stated that the automatic system settings operated well and avoided an enlargement of the disturbance. After 38 min the system could be synchronously reconnected and all of the shed loads were

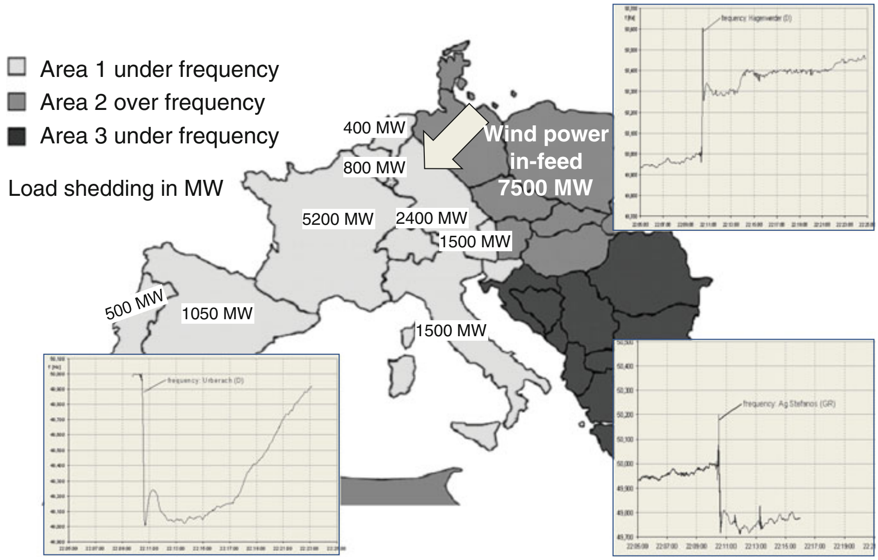


Fig. 5.14 Grid islands after line trips due to overloads and their frequency diagrams [9]

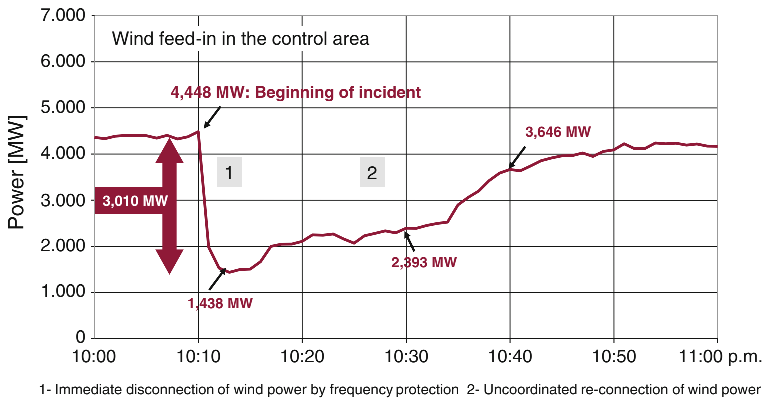


Fig. 5.15 Tripping of wind generation by the frequency protection and subsequent reconnections (*Source* Vattenfall Europe Transmission GmbH)

resupplied. The power balance could be managed in islands with over- and under frequencies.

Therefore, this disturbance is not considered a system blackout.

5.2 Control Areas and System Services

As operators of the transmission system, the TSOs are responsible for the secure and reliable operation of the electricity network in their respective control area, and for interconnections with other electricity networks. In Continental Europe, the majority of countries have established one central control area. In Germany, however, 4 control areas are operated by the four transmission system operators according to Fig. 1.8a.

The TSOs are obliged by law to operate their control area in a manner which assures the most secure, economical and environmentally sound network-dependent supply of electric power in the public interest.

This includes the following main tasks [10]:

1. Secure operation of the transmission network ensuring the N-1 criterion at all times.
2. Management of the balance of generation and load at all times, provision of the interface to the liberalized electricity markets and carrying out the basic physical work necessary for the commercial power transfers.
3. Control of the import/export of electric power between the underlying networks and the neighboring control areas.

With regard to maintaining the proper operation of the control area, the TSOs provide system services to network users that decisively determine the quality of the electricity supply. The most important of these system services are [11]:

- Power system management,
- Frequency control,
- Voltage control,
- Restoration of supply.

5.2.1 Power System Management

The power system management at the transmission level involves two aspects, namely the operational planning and execution of the network related tasks and the generation–load balancing.

First, the top priorities of the network related tasks are:

- the supervision and control of the network topology including monitoring the bandwidths of voltages and power flows,
- the assurance of the network N-1 security,
- the recognition of emergency situations and the initiation of congestion management,
- the requesting and execution of switching operations,
- the voltage/reactive power and power/frequency control operations and

- the commissioning and maintenance of all the network assets, including the requisite facilities for metering and pricing regarding the horizontal energy exchange between the transmission system operators and the vertical energy exchange relating to the connected sub-transmission networks.

Secondly, the power system management includes the generation and load balancing. This involves the operational implementation of the agreed upon power exchange based on the schedules of the “Balancing Groups” and the generation schedules for power stations, also keeping in mind the requirements for reserve power provisions.

The control area consists of an arbitrary number of balancing groups containing:

- power injection nodes (usually metering points for the generating units of power stations) and
- withdrawal nodes reflecting the demand.

The energy balance of the control area is subject to the responsibility of a number of balancing group managers (BGM). The balancing groups work together so that injections and withdrawals can be netted out for several injection and withdrawal nodes. For the net balance settlement, the balancing group manager shall ensure that energy exchanges with other balancing groups are implemented in accordance with schedules registered in advance and, where applicable, shall take care of the adequate power station commitment.

The TSO shall enter into contracts with the BGMs for each balancing group. In commercial and administrative terms, the BGM has the responsibility to

- inform in a timely manner the responsible system operators about injection and withdrawal points assigned to his balancing group,
- aggregate the electrical energy exchanges in such a way that only one schedule is exchanged between two balancing groups,
- deliver day-ahead schedules between 2 and 4 p.m. to the TSO. The schedules contain 96 values of the average power within each 1/4 h of the following day.

Remaining imbalances within the balancing group are offset by the control area operator (imbalance settlement).

The assignment of each injection and withdrawal node shall be specified to the system operator responsible for the supply connection.

Withdrawal nodes can be assigned to exactly one balancing group only. Normally the supply companies or traders take over the balancing group responsibility by performing the day-ahead load schedules for all their consumers. Under the conditions of the liberalized markets, each consumer has the opportunity to select his/her supplier independent of the territory and the distribution network operator responsible for the network access. As a result of these rules, the supply companies are serving consumers in different territories and the balancing group of a trader is not assigned to a certain territory or distribution network operator. Figure 5.16 presents the current situation which does not provide a certain schedule for the

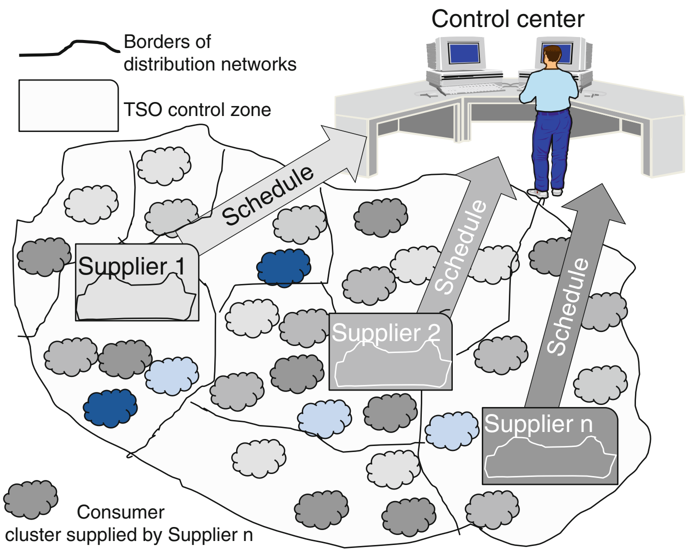


Fig. 5.16 Current load schedule management in a control area [12]

physical connection points between the transmission networks and the distribution systems.

Each supplier delivers the schedules for its distributed consumers based on standard load profiles considering the size of households or the characteristics of the supplied enterprises and the time of year. This practice is efficient if the load profiles do not significantly deviate from the standard and if the limits at the physical connection points are not exceeded.

Injection points can be assigned to several balancing groups. The balancing of power injections is closely coordinated with the markets for electric energy (see Sect. 5.3).

In some European countries the priority of renewable power injection is dictated by law (see also Sect. 7.1). The TSO is obliged to take over the balancing group management for the renewable energy sources. Furthermore, the TSO is also responsible for the reading, processing and forwarding of the pertinent metered values.

In conclusion, the significant power system management functions include the load and the renewable generation predictions for the control area, the managing of the interrelations with the electricity markets to cover the load schedule, the congestion forecasting and management, the observation of the instantaneous deployment of the power stations, and the co-ordination or utilization of system services.

The central functions of power system management shall be performed by an administrative department assigned to the TSO. The performance of these functions requires comprehensive technical facilities, including in particular the process instrumentation, the data processing facilities and the communications facilities for transferring the measured values and status reports from power stations and the network.

5.2.2 Frequency Control

In an electric power system, power generation must be constantly adjusted to follow the demand. Changes in demand or power station disturbances impair this balance and cause a deviation of the system frequency. To meet the requirements of frequency control, transmission system operators need access to the control power so that they are able to comply with their responsibility for the system stability in general. Accordingly, the TSOs have an obligation to permanently maintain sufficient control power within three categories, the time characteristics of which are presented in Fig. 5.17.

- Primary control (or reserve) power
- Secondary control (or reserve) power
- Tertiary control power or Minutes reserve.

The TSOs contract the provision of control power through a bidding process. The TSOs shall invite bidders for this control power in the liberalized electricity market and shall procure control power on competitive terms and conditions. The evidence of meeting the minimum requirements that are requested by the bidders needs to be provided through a pre-qualification procedure. The terms and conditions concerning the provision of the different types of control power are settled in framework agreements made between the TSO and the connected bidders. The results of the bidding procedure shall be published.

Furthermore, the TSO shall take measures to ensure not only secure transmission of the maximum projected load for his network, but also transmission of the primary and secondary control power and minutes reserve power (the primary control power being replaced successively by secondary control and minutes reserve power).

These three categories have different origins, parameters and targets of application.

The purpose of the primary control is the assurance of the frequency control in emergency situations after the unplanned outages of important power plants. The primary control is activated in accordance with a rapid drop of the frequency.

In accordance with UCTE rule [10], the primary control power of 3,000 MW required for the entire synchronously connected system of Continental Europe shall be distributed among the different TSOs, who shall be responsible for continuous secure maintenance of their share in the primary control power, calculated in accordance with this provision, for their respective control areas. The full assigned primary control power has to be provided within 30 s.

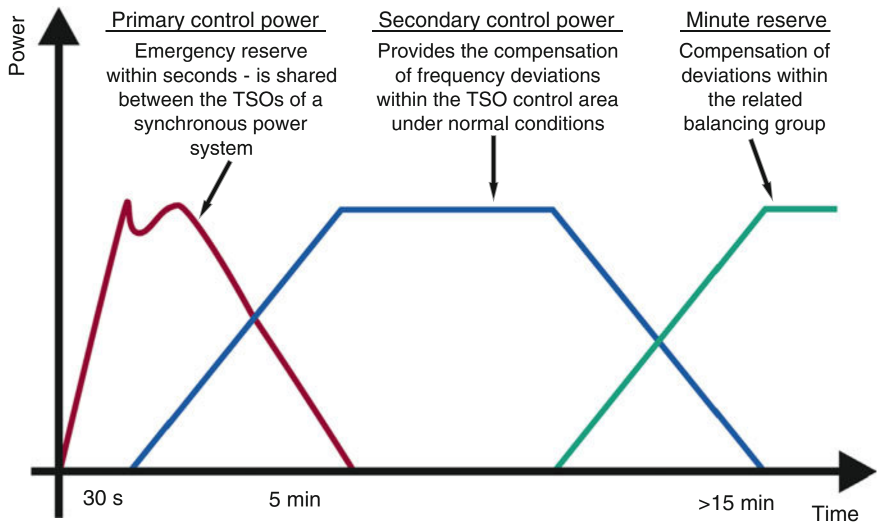


Fig. 5.17 Time constraints and purpose of control power categories [11]

Each generating unit (e.g. power plant unit) that has a nominal capacity which exceeds 100 MW must be capable of primary control.

Each control area within the synchronously interconnected system as a whole shall ensure the balance between generation and consumption in consideration of the schedule agreements made with other control areas (see UCTE rule [10]). The TSOs responsible for the individual control areas shall achieve this objective mainly by the deployment of secondary control. The secondary control is activated in intervals of minutes in accordance with the deviations of the real-time measured frequency from 50 Hz.

The secondary control power may be positive or negative. Both kinds of secondary power have to be contracted in parallel.

The TSOs shall deploy minutes reserve power in the event of large imbalances between generation and consumption and/or for the restoration of a sufficient secondary control band. The request for and delivery of minutes reserve is implemented as scheduled power exchange between the balancing group for minute reserve of the contracted bidder and the balancing group of the TSO. The request for delivery shall be based on the principle of minimum costs, sufficient power availability, and the concerns of operational system security.

The request for delivery shall be made with a lead time of at least 7.5 min at the beginning of the following quarter hour. The bidder is bound to provide the corresponding minutes reserve power in physical terms.

Table 5.1 presents a summary of some of the minimum requirements regarding the control power provision that the bidders have to demonstrate during the pre-qualification process.

Table 5.1 Example: main requirements for the control power categories [12]

Requirement	Primary reserve	Secondary reserve	Minute reserve
Minimum offer	1 MW	5 MW	5 MW
Power gradient	3.5 %/s	2 %/s	<7 min
Availability	<30 s–5 min	<5–220 min	≥15 min
Activation	Frequency	Online	On call
Contracting	Weekly	Weekly	Daily
Pooling possible	Yes	Yes	Yes

The term "pooling" in the last row means the opportunity to aggregate small generation, storage or demand side management (DSM) quantities for meeting the minimum amount of the power request. Consequently, small distributed energy resources DER, storage units or DSM—activities may build a pool to be able to offer the 1 or 5 MW of the requested control power. However, each single plant of the pool has to be approved in the pre-qualification procedure.

5.2.3 Voltage Control

Voltage control forms part of the measures for provision of a secure supply, for which the network operators at all levels of the power system (transmission system operators TSO and distribution network operators DNO) bear responsibility. The network concerned, the generating units, the consumers connected to the network, and—in an interconnected system—the boundary areas of the adjacent networks, shall be involved in maintenance of voltage stability under the co-ordination of the responsible network operator.

The TSO and DNO shall bear responsibility for balanced reactive power management in his network installations, including the demand of the connection users. The TSO and DNO shall either maintain facilities for reactive power control on the network and in the connected power stations himself or provide them by contractual arrangements. Such facilities must be sufficiently comprehensive and have the requisite features (switching/control capability) to ensure adequate compliance with the specified limit values and agreed upon operational voltage parameters.

Therefore, each generating unit must meet the defined basic requirements with regard to the power factor as specified in Fig. 5.18 (example) with a view to being connected to the transmission or distribution network.

Each power station shall operate the generating units, as specified by the TSO/DNO, with the requested reactive power to support the compliance with the operational voltage bandwidth. Consequently, under high voltage conditions the generators have to be operated by under excitation and demand reactive power up to a $\cos\varphi$ of 0.95. Contrarily, if the voltage is low the generators have to inject reactive power up to a $\cos\varphi$ of 0.925 at the transmission level (0.95 at distribution level).

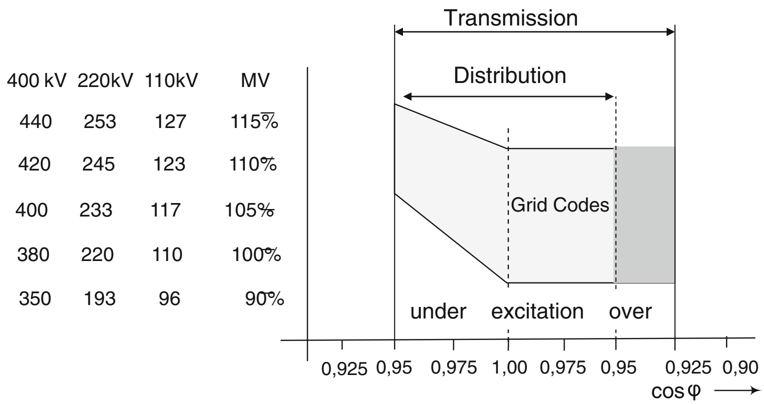


Fig. 5.18 Reactive power control bandwidth of generator units [13]

The conditions for supply and purchase of reactive power shall be specified in bilateral contracts.

5.2.4 Restoration of Supply

The TSO is responsible for reliable system operation and its prompt restoration following large-scale failures and to draw up appropriate plans for preventive and operational measures, with due respect to the respective system infrastructure, in conjunction with adjacent TSOs or with subordinated DNOs and power station operators.

The providers of preventive measures for the restoration of supply may be the TSO, the network users and system operators of adjacent and subordinate networks as well as power station operators. According to the measures required, the providers must take technical measures for the restoration of supply and demonstrate the efficiency of their facilities to the TSO.

The TSO has to resort to the capability of isolated operation and black-start capability of appropriate installations, and to other TSOs and network users for provision of the "restoration of supply" system service. The TSO has to compensate the bidders for contracted availability of facilities with black-start capability.

5.2.5 Generation Scheduling: Merit Order Principle

Based on the schedules delivered by the balance group managers, each afternoon the TSO completes the day ahead load schedule for the control area. A significant

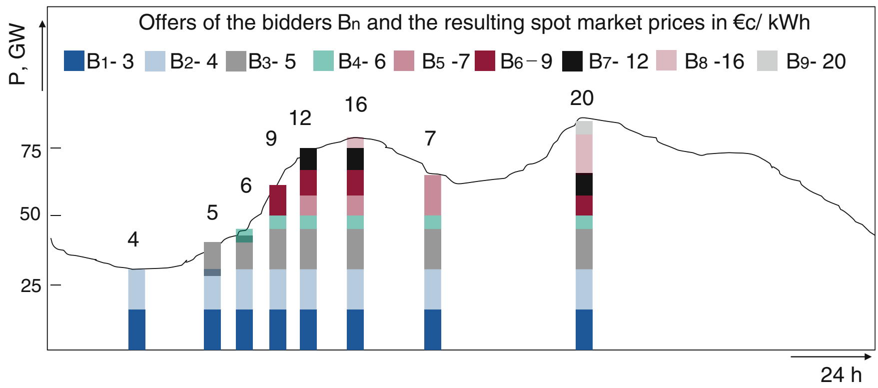


Fig. 5.19 The load profile coverage in accordance with the merit order principle [12]

part of the load is normally covered by contracted electricity delivery (for example in the industrial sector).

The further requested generation has to be covered by market activities. Several bidders of electric energy offer their prices for each hour to cover the requested demand.

In accordance with the merit order principle, the basic load will be filled by the lowest price bidders, e.g. bidder 1 and 2 (B_1, B_2) are offering prices of 3 and 4 €c/kW h at 4:00 a.m in accordance with Fig. 5.19. Consequently, they have to be contracted to cover the low load during the night. The price for electricity during this hour is defined in accordance with the highest price of the last bidder needed for demand coverage: 4 €c/kW h.

When the power offered by the lowest bidders is not sufficient to cover the demand, the next bidder (B_3) will be contracted to inject the related power for a higher price (here 5 €c/kW h).

In this way the load profile will be covered during the whole 24 h period. The offer of the last bidder needed to cover the load builds the price for the related hour. In the example of Fig. 5.19, nine bidders participate in covering the load profile with a spread of the subsequent prices between 4 and 20 €c/kW h. In reality the number of bidders is much higher.

This practice leads to different prices of electric energy for each hour of the day and the prices may vary significantly as shown in an example in Fig. 5.20 for a time period of 3 years. In Continental Europe, price peaks may occur in the winter time in accordance with an extremely high demand, but also in the summer time when the temperature of the cooling water restricts the operation of nuclear power stations.

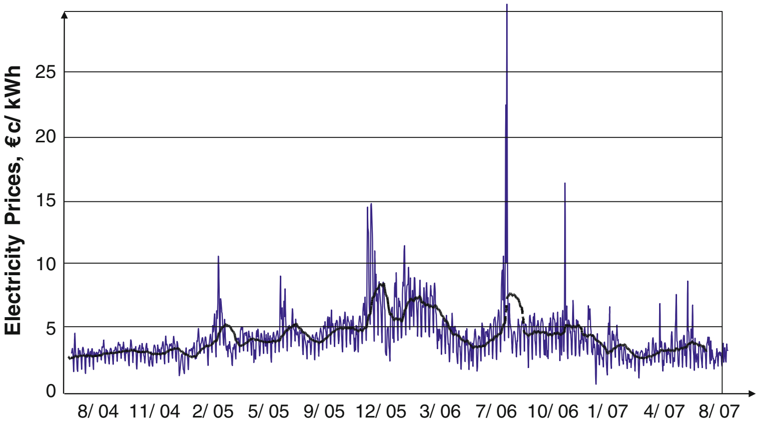


Fig. 5.20 Electricity price changes—half-day and weekly averages [13]

5.2.6 System Service Provision by Distributed Energy Resources

The distributed energy resources (DER) are mainly based on renewable energy sources RES (wind, solar, biofuel, hydro) and on cogeneration of heat and power plants (CHP). Until 2012 they were mostly operated without remote control mechanisms, feeding-in a maximum possible power corresponding to the political and regulatory frameworks in most of the European countries. The further growth of the DER installed power may reach close to the peak load (2013 in Germany up to 85 %), and the generated power of the DER can exceed the weak load. This requires innovative approaches to integrate DER into the sustainable power system operation. The contribution of DER to the provision of system services will become mandatory.

Today the TSOs are obliged to manage and operate the electric power transmission networks, and to do so they rely on system service procurement from the free market. However, the TSO cannot efficiently manage system services provided by thousands of DER units with only a small contribution of each.

For managing the frequency control, limits for minimum control power provision are set for the three categories as presented in Table 5.1. In this table is also mentioned that the TSO allows a pooling of small units and the aggregated offer of control power.

Therefore, the provision of system services by DER requires technical solutions in the sense of a coordinated operation of DER, storage and controllable loads (Demand Side Management—DSM) within virtual power plants (VPP). The virtual power plant shall be able to provide system services in the same way as the traditional power plants.

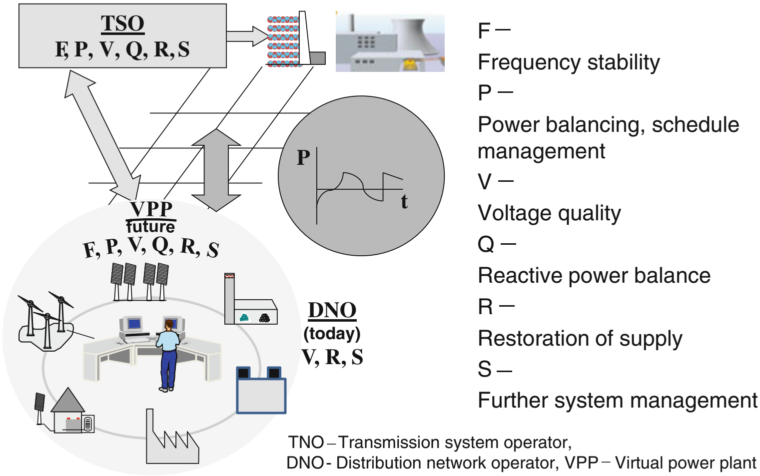


Fig. 5.21 Provision of system services to the TSO and DNO by VPPs

Today, the system services provided by the DNO in their networks are limited to voltage stability, the network operation as a part of the system management and the restoration of supply.

In the future, the VPPs will be able to support the frequency control by offering control power to the TSO. The VPPs are also able to participate in the schedule management, in the restoration of supply and in the reactive power control. Figure 5.21 demonstrates the new opportunities to provide system services at the distribution level.

The potential of the DER to contribute to system services depends on their physical characteristics and the market incentives. An overview of the general potential of the different kinds of DER and Demand Side Integration (DSI) is presented in Table 5.2. DSI consists of DSM (Demand Side Management)—the active control of loads and DSR (Demand Side Response)—the influence on the demand by dynamic tariffs.

The photovoltaic plants, for example, inject power during the daylight and therefore, during the strong load period. The reduction of the power production to provide control power does not make sense because of the higher energy prices compared to the prices for control power during the strong load period. Their scheduling is based on day-ahead predictions. Nowadays, the photovoltaic plants use IGBT converters (see Sect. 3.3.3). Therefore, they are able to support the voltage stability by reactive power control and the restoration of supply.

The wind power plants may generate the maximum power during the low load periods in the night. The provision of negative control power may be useful here and can offer additional profitability. In general, wind power plants have to shut down if their power injection causes congestions in the network. The other system services can be provided in the same way as described for the photovoltaic plants.

Table 5.2 Potentials of DER and DSI [14]

Plant type	Power profile	System services			
		Frequency control	Power balancing	Voltage control	Restoration of supply
Photovoltaic	Volatile	No	Prediction	Yes if IGBT	Yes if IGBT
Wind park	Volatile	Negative control power	Prediction	Yes if IGBT or SVC	Yes if IGBT
DER based on hydro, bio/Fossil fuel	Controllable	Control power	Yes	Yes	Yes
DSM	Switch load	Control power	Yes	No	Yes
DSR		No	Prediction	No	No
Storage	Controllable	Control power	Yes	Yes	Yes

DSM can provide positive control power by switching-off the load for a certain time. Many enterprises use such opportunities today to create additional earnings if the load switch-off does not influence the production quality. For example, aluminum factories may offer a significant amount of primary control power by continuing the production processes after a 10 min interruption time when the secondary control power becomes available.

DSR is not actively controllable and therefore it is not suitable for the control power market.

Finally, fuel driven power plants and storage units are completely controllable and may provide all kinds of system services.

As a rule, fuel driven power plants (bio, fossil, with and without CHP) and hydro have their optimum operation point in the minimum of the related production expenses for energy.

It is economically advantageous to produce power only during periods when the energy price is significantly above the costs of production. The frequency of possible shut downs and repeated starts depends on the cost-price relationship including the costs for shut down and starting. Figure 5.22 demonstrates this relationship. In principle, each fuel driven power plant has the opportunity to provide all three kinds of reserve power by control in the bandwidth between the technical constraints of power generation and in accordance with the rules of Table 5.1. Consequently, the fuel driven power plants can participate in both markets at the same time—for energy and for reserve power.

In the low energy price period a shutdown is advantageous. During the shutdown period the provision of minute reserve power is possible and profitable if the black start time and the power gradient respond to the requirements.

For all kinds of CHP—fossil fuel and RES—a thermal storage is the key to an electrical driven operation. Mostly CHP plants are designed for a thermal driven operation mode, where the cogenerated electric power depends more or less from the heat demand. A thermal storage allows an active storage management and

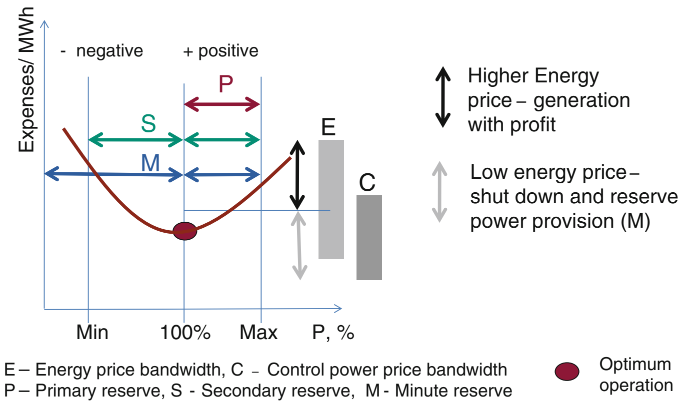


Fig. 5.22 Generation expenses and the economy of control power provision [14]

therefore thee CHP plant is able to produce heat in advance to fill the storage while electrical power could be generate following a schedule. Additionally, thermal storages have much lower investment and operational costs than electrical storage plants. The storage size should fit the market rules. For example, the minute reserve has to be offered for four continuous hours, thus the thermal storage either has to deliver heat for 4 h (negative reserve) or has to store the generated additional thermal power of the CHP for 4 h (positive reserve). This also indicates the need for an intelligent thermal storage management.

VPPs may play a significant role in supporting the quality of supply regarding the voltage quality and the reliability. Figure 5.23 presents a rural 20 kV network which is supplied by only one double overhead line.

The feeding double line was some times interrupted by tree falling in the forest through which the line has to cross. The average interruption duration achieved the extremely high value of 1.14 h/a causing an average value of energy not delivered in time of 3 MW h/a.

The installation of the DER presented in Fig. 5.23 made the islanded operation of the network possible. The probability of a stable island operation without the use DSM is 94 %.

In the worst case (peak load and no wind, no sunshine) a DSM of maximum 0.75 MW is required. After the installation of the VPP in this village the reliability could be improved many times as stated in Fig. 5.24.

Furthermore, the voltage was influenced by the voltage losses along the 18 km long 20 kV line. Each tap changing at the feeding 110 kV substation was observed in the voltage profile.

The active and reactive power control of the VPP is now able to keep the voltage at the rated level all the time (Fig. 5.24).

Consequently, the aggregation of RES, CHP, storage and DSM in a virtual power plant allows their parallel participation on both markets—energy and

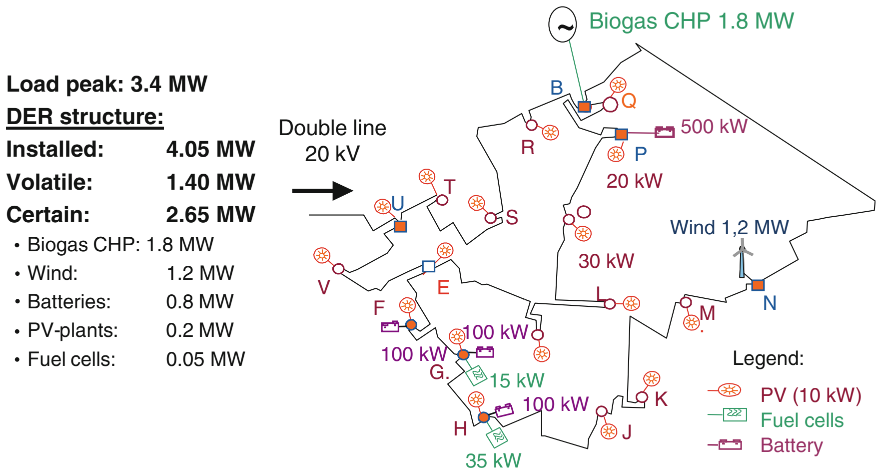


Fig. 5.23 Allocation and size of DER in a rural distribution network [13]

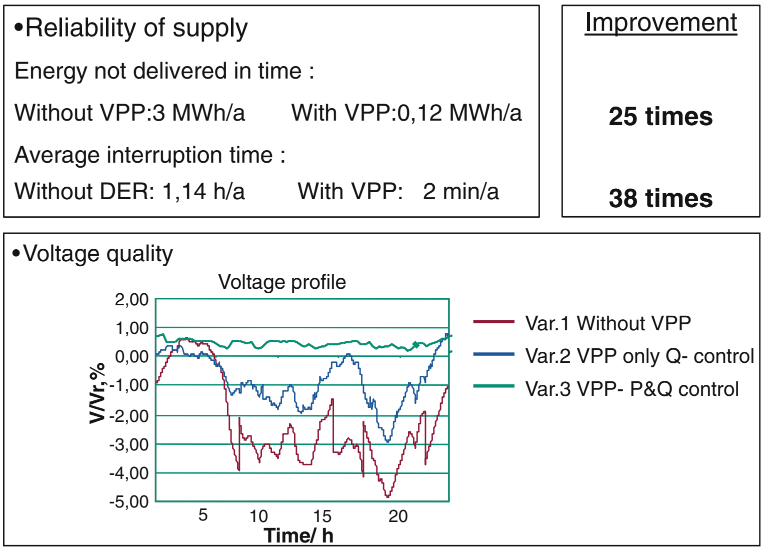


Fig. 5.24 Improvement of the power quality characteristics in a rural network by a VPP [13]

control power. Special optimization tools are useful to define the optimum operation regarding the energy generation and the provision of system services including reserve power (see Sect. 6.3).

5.3 Power System Observation and Intelligent Congestion Management

5.3.1 Need for More Observation in the Power System

Today's transmission networks are synchronously interconnected and cover large territories as shown in Fig. 1.6 for Europe and the Mediterranean area. As a result of the liberalized energy markets and the extremely fast growth of volatile renewable energy production the power flows through the networks and the interconnection nodes between the control areas has become strongly volatile. The strengthening of the network by erection of new transmission lines takes many years. Long term delays are often caused by the protests of people and communities preventing the permissions for the ground use.

Consequently, congestions may occur much more frequent than in the past where congestions occurred only in emergency situations after the outages of power plants or of more than 1 important network assets. Now the congestions in one network may have a strong impact on the secure operation of the neighboring networks.

For the real time estimation of such influences, the European interconnected network organization ENTSO-E decided on the mandatory introduction of "Observability Areas" for all TSOs in Continental Europe [12]. The observability area covers all neighboring network elements whose outages cause a power flow change of 5 % or more in their own network.

These elements have to be included in the online security assessment calculations. The neighboring TSOs are obliged to deliver:

- the related parameters of the transformers, lines, power stations,
- the real time measurements of voltages, power flows and
- the topology dataof the related network parts.

At the control area of the TSO Amprion for example, this approach leads to an increase of the online information exchange of more than 200 % as shown in Fig. 5.25.

In order to recognize in real-time time upcoming congestions and dangerous conditions in the network, it is necessary to estimate the current state and the prospective state (next few hours) of the network in the responsibility and observability areas including also the conditions in the sub-transmission networks. The relevant network parts of the TSO neighbors and connected sub-transmission networks have to be modeled for the relevant calculations. Furthermore, the predictions of load and power injections have to be made and the predictions shall be included in the security assessment calculations.

This extended observation beyond the control area borders allows to estimate prospective congestions and to start measures for their intelligent management in real time.

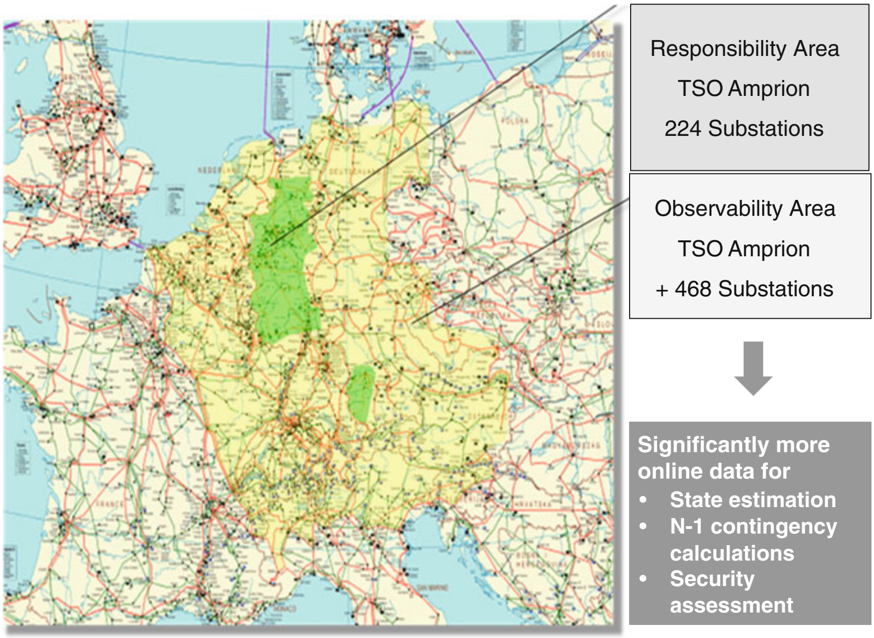


Fig. 5.25 Responsibility and observability areas of a TSO (*Source* Amprion GmbH)

The assessment methods are closely connected to the congestion management activities.

An overview of the advance congestion management methods is presented in Fig. 5.26.

The real-time data acquisition and the prediction of the power system conditions in the observation area build the basis for the estimation of upcoming congestions. If critical situations are recognized four categories of operations may be performed:

1. The protection settings may be adapted to keep a high level of selectivity under the changed conditions.
2. The wide area monitoring applies phasor measurement units (PMUs) to recognize congestions after unplanned faults or outages. If necessary, appropriate operations may be executed within seconds to improve the network operation conditions (e.g. load shedding, re-dispatch of active power injections, reactive power control).
3. Continuous steady state and dynamic network calculations are performed for the observability area and the selected prediction period. Alarms are generated if congestions or violation of the N-1 criterion are estimated. Advanced security assessment tools may provide recommendations on how to improve the network conditions and how to restore the system to N-1 security.

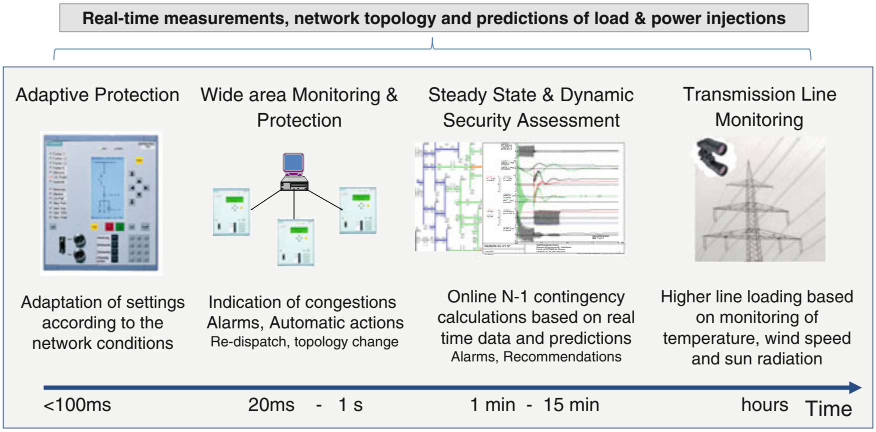


Fig. 5.26 Overview of intelligent congestion management methods

4. The transmission lines may be loaded higher than the standard specifications based on the observation of the meteorological conditions.

The presented methods are considered in the following chapters in detail.

5.3.2 Prediction Methods for a Secure Power System Operation

5.3.2.1 Basic Prediction Principles of Power Injections from Volatile RES

In accordance with the growing contribution of volatile RES in the power balance the prediction of the RES injections will become more and more important for the network security [12].

Two developing trends have to be considered:

- The further growth of the installed power of photovoltaic plants and smaller wind power parks will affect the distribution and sub-transmission network operations.
- The number of large scale wind parks with installed power of some 100 MW that are erected in onshore and offshore locations and have direct access to the transmission network will continue to increase.

Consequently, the further development of prediction systems has to be focused on:

1. The improvement of the prediction accuracy,
2. The introduction of prediction methods in the distribution level,

Table 5.3 Average prediction errors for volatile power injections [12]

RES	Prediction period	2009	2010	2011	2012
Photovoltaic	Day-ahead	6.7 %	4.82 %	4.9 %	4.21 %
	Intra-day	–	–	3.5 %	3.11 %
Wind	Day-ahead	4.86 %	3.93 %	3.69 %	3.53 %
	Intra-day	3.37 %	2.48 %	2.08 %	1.81 %

3. The extended data exchange between the transmission and distribution networks.

Network security will require more interaction between the TSO and the DNOs because of the volatility of the power flows at the coupling nodes between the network levels.

Prediction tools have been developed and implemented since 2000 especially for the wind power production within the control area of the TSO.

The TSOs have established a data base of all wind power plants with the regional and technical characteristics. This data base is permanently under adaptation (e.g. outage for maintenance) and extension (new erected plants).

Since 2005 the share of photovoltaic plants has become significant in Germany, exceeding 2 % of the peak power in 2005 and $\sim$38 % in 2013. It was therefore necessary to include the prediction of the photovoltaic plants into the schedule management as well.

Based on the level of experience that has been achieved in this field, the accuracy of the volatile power prediction could be enhanced in the recent years. Table 5.3 presents this trend of the average accuracy improvement for the transmission network of TenneT, which connects about 65 % of the wind power plants in Germany. Table 5.3 demonstrates also the efficiency of short term, intra-day predictions.

The stated errors represent the average deviations related to the predicted values. The distribution of errors follows a typical probability diagram and the maximum deviation may achieve 40 % or more but with a low probability.

A typical error frequency distribution for the day-ahead predictions is presented in Fig. 5.27.

The frequency of 0.1 % for the prediction error of -40 % appears quite low at first glance. However, taking into account the period of 1 year such an error may occur during 9 h.

The security of the power system operation requires the parallel execution of the day-ahead predictions and the short-term predictions to be prepared in advance for possible congestions caused by such strong deviations as shown in Fig. 3.57.

By using this combination the need for control power availability may be significantly reduced. Figure 5.28 presents the related two-step approach applied for wind power predictions.

The wind energy data base delivers the characteristics and the allocations of the wind power plants. The day-ahead schedule is performed based on the weather

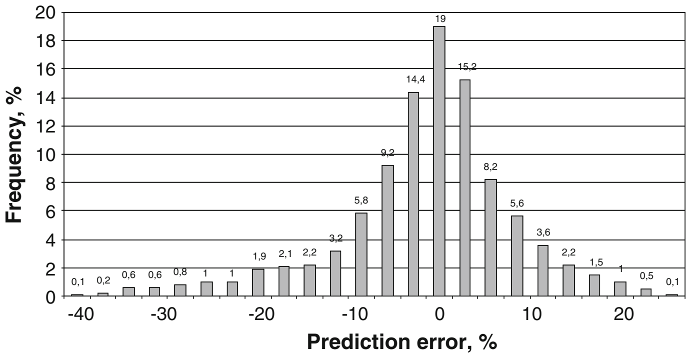


Fig. 5.27 Frequency of prediction errors for wind power (*Source* Fraunhofer IWES)

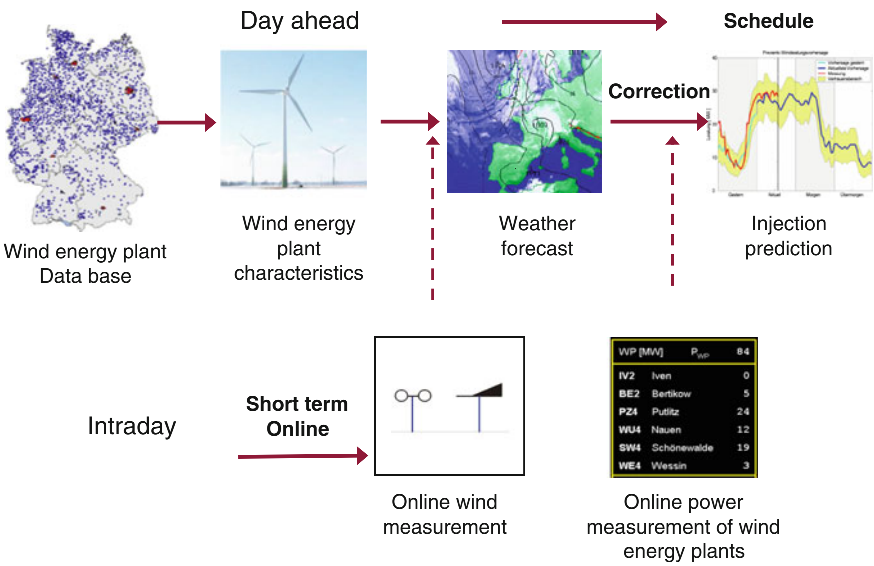


Fig. 5.28 Day-ahead and intra-day wind power prediction (*Source* Vattenfall Europe Transmission GmbH)

forecast. To enhance the prediction quality it is common practice to combine the results of various prediction tools from different sources.

The combined predicted power injection P_c is the sum of the power predictions P_i multiplied by a weighting coefficient w_i:

$$P_c = w_1P_1 + w_2P_2 + w_iP_i + \ldots + w_nP_n$$

Significant improvements of the prediction quality are achievable if intelligent weighting methods with regard to the weather situation are applied. Here the

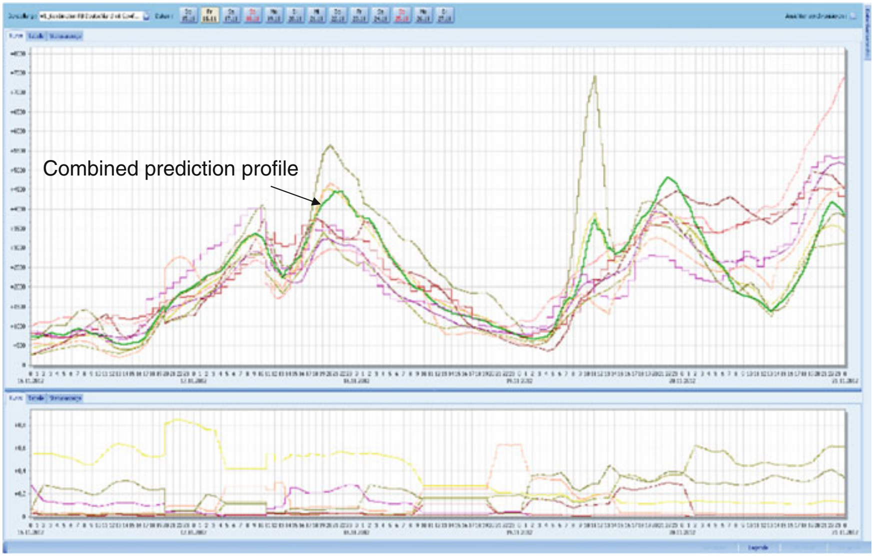


Fig. 5.29 Combination of prediction and weighting methods (*Source* Amprion GmbH)

benefits and weaknesses of the different tools may be taken into account. Figure 5.29 demonstrates such a combination of 10 single predictions for a prediction horizon of 5 days.

The resulting combined predictions follow the dark profile.

In the lower part of Fig. 5.29 the change of the weighting coefficients is shown.

In the next step the intraday prediction is executed. The online wind measurements correct the weather forecasts and the online measured wind power injections are used in combination with the corrected weather forecast and the deviations from the day-ahead prediction to provide an optimized prediction of the power injections for the coming hours.

The deviations between the day-ahead schedule and the short term predictions have to be compensated via the intra-day spot market trading, which predicts 45 min ahead.

5.3.2.2 Day-Ahead Congestion Forecast (DACF) in the Interconnected Transmission System

Within the interconnected transmission network in Continental Europe the DACF approach was implemented to estimate critical network conditions in advance. This approach realizes the prediction of the operation conditions for the whole power system 2 days in advance (2DCF) and for the current "intra-day" (IDCF).

The network condition predictions are performed by the TSOs of the interconnected system ENTSO-E RG CE (Continental Europe—former UCTE) for selected time frames during the current day (d) and the coming 2 days (d + 1, d + 2).

The intra-day predictions use load and generation data from actual snapshots.

At the moment of the predictions for d + 2, the schedules for the power plants are still not available. Therefore, for d + 2 the schedules of d + 1 are assumed considering the current load schedules and predictions of the volatile RES injections.

Each TSO prepares for 6 time points (Germany-24) of the day-ahead data sets including the loads and injections of all network nodes. For the load prediction a reference day from the past is taken into account, for example on a Monday from one of the past weeks with similar weather conditions is selected as a reference. It is assumed that the demand behavior of the consumers will be comparable with the selected reference day.

In the next step, the snapshot of the network conditions of the reference time points are taken from the archive. However, the use of this data set requires a transition into the normal state. This is the network state when all assets are available for operation and no outages for maintenance or due to faults have to be considered. Based on the archived information about such outages the transfer into the normal state may be performed. In the next step the data set is adapted to the planned topology of the prediction time.

The power producers provide the predicted power injection schedules to the TSO taking into account the load schedule. The injection values of the reference data set will be replaced by the predicted schedule values.

To balance the load and generation, the loads in all nodes will be adapted in proportion to compensate the deviations between the reference and the predicted power plant schedules.

The predicted data sets of all TSOs and the overall data set for the interconnected system are available for all network operators on a common server. The Common Information Model according to IEC 61970 has been introduced within ENTSO-E to ensure that each TSO can use the data sets without conversion into proprietary data formats.

5.3.2.3 The Need for Network Level Overlapping Congestion Forecasts

The growing share of DER feeding into the distribution networks means that the distribution networks may be stressed above their capability limits (see also Fig. 4.39). The need for the introduction of congestion forecasts in the distribution networks is growing. Currently, though, the application of congestion forecast tools is still not common in distribution networks.

However, the prediction of the of the distribution network conditions will play an increasingly important role for the general power system operation. The volatile bi-directional load flows at the coupling nodes between the network levels has a growing impact on the security of the whole power system.

It is an urgent need that the network operators on the different levels cooperate in the prediction of RES power injections and the prediction of congestion conditions in a common way.

The common "level overlapping" prediction of the network conditions has to be performed in a cascade beginning with the MV/LV transformer terminals in the local distribution level all the way up to the transmission network.

In the first step accurate predictions of the load and the power injections have to be performed for the local distribution networks at the MV level. The DNO will be able to recognize overloading conditions of feeders, switchgear, transformers or busbars.

In the next step the predicted data of the several connected nodes has to be transferred to the planned topology of the MV network. In this way, the power flow conditions at the coupling nodes with the overlaying distribution network(s) are estimated. An overlaying network may be also a MV network for extended local distribution or be the direct regional distribution (or sub-transmission) network at the HV level.

The power flow estimations serve as the inputs for the network condition forecasts at the upper network level which is based on the planned topology, the predicted loads and power injections.

Finally, the predicted network conditions of the HV sub-transmission networks create the power flow conditions at the coupling nodes with the transmission network at the EHV level. The TSO is now able to predict its own network conditions based on the topology, loads and power injections.

The TSO provides the topology and voltage conditions in reverse to the underlaying networks and the prediction procedures may be improved using the feedback from the overlaying networks. Based on these considerations an overlapping N-1 security assessment may be introduced.

These procedures require an extensive data transfer between the networks at the different levels. In the past an information exchange between the network levels was limited to important operational aspects. Consequently, the data transfer between the DNOs and TSOs has to be significantly increased. Figure 5.30 presents the required data flows.

In the process of unbundling the power systems, the networks belong to different network operation enterprises. Therefore, the requested data transfer shall be agreed upon between autonomous legal entities.

5.3.2.4 The Cellular Approach for Predictions, Balancing and Schedule Management

The weakness of the current balancing and prediction processes described in the previous chapters consists of the following aspects:

1. The suppliers are mostly the balance group managers for the withdrawal nodes. They schedule their day-ahead demand based on standard load profiles for all of

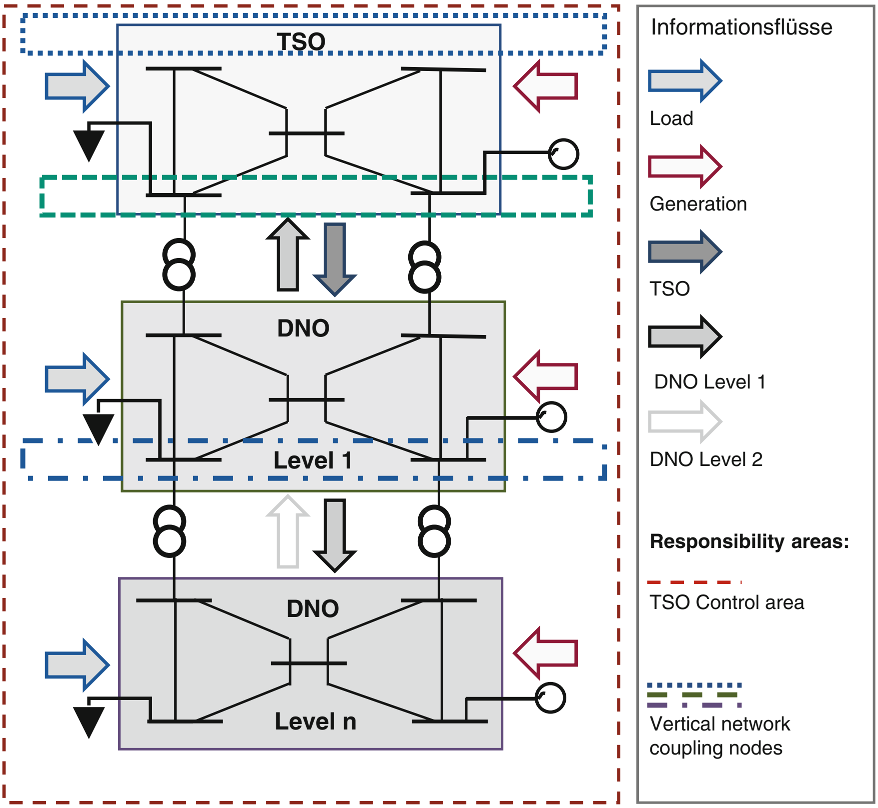


Fig. 5.30 Information exchange between the network levels congestion forecasts (*Source* BDEW)

their consumers who are allocated in different territories, as shown in Fig. 5.16. The accuracy of these schedules is often low. Furthermore, the schedules do not deliver a coupling node oriented power flow as requested in Sect. 5.3.2.3.

2. The reference day principle used for the DACF congestion forecasts is also of low accuracy. The TSOs increasingly need the coupling node oriented forecasts for the secure system operation within their control area.
3. The TSO is responsible for balancing all of installed RES in its control area.
4. The prediction of the power injections from RES is based on the general weather forecasts for larger regions. However, the weather conditions may differ greatly within one region. The prediction accuracy can be significantly improved if the predictions for the RES power injections are performed for smaller territories.

Control power is often required in significant quantities to compensate the schedule deviations caused by the above considered weaknesses.

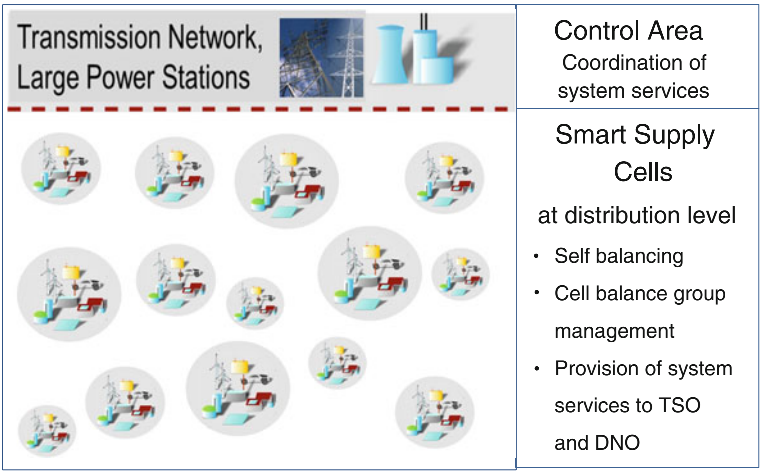


Fig. 5.31 The "Smart Supply Cell" approach [12]

However, the targets to reduce the expensive demand of control power and to keep the reliability of supply at today's high level requires more precise balancing mechanisms.

A more cellular approach for balancing and forecasting based on "Smart Supply Cells" (SSC) in the distribution level is considered in [12]. The SSCs support the TSO to reduce the complexity of power system operation self-balancing, provide the cellular balancing group responsibility and offer system services as presented in Fig. 5.31.

An SSC may cover one or more distribution networks containing DER that are fully involved in the balancing processes. They are obliged to predict and deliver their individual schedules. If the DERs have to provide this kind of participation in the power system operation and if they have to compensate the control power expenses caused by their schedule deviations, the participation in a VPP will be advantageous for the DER operators.

The VPPs take over the balancing obligations for the aggregated plants. The VPP prepares the day-ahead schedules for its participants—generators, storage units and controllable loads. In cases of intra-day schedule deviations, the VPP optimizes the alternatives regarding internal correction activities or the payment for external control power. The VPP creates win–win conditions for the participants by operating on various markets (see Sect. 6.3.3).

The cells perform the balance group management in their territory based on the schedules

- delivered from the suppliers/traders who are active in the territory and
- from the generation units which are mainly coordinated by VPPs.

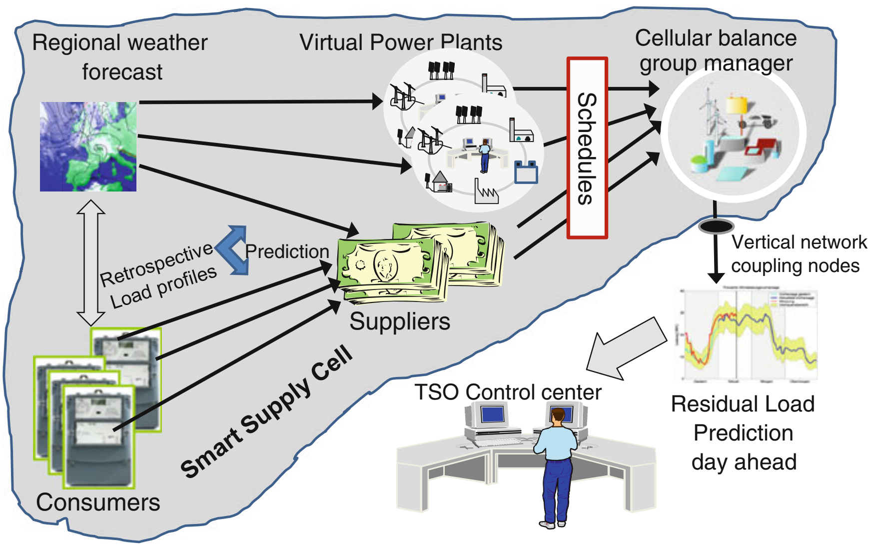


Fig. 5.32 Processes for a cellular balance group management

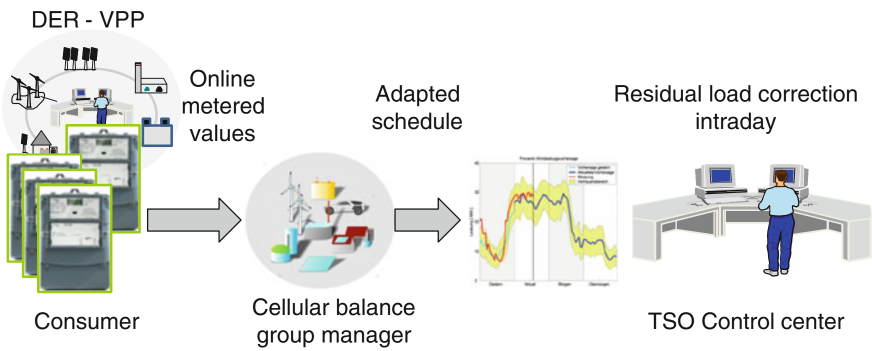


Fig. 5.33 Intra-day schedule adaptation in the event of deviations recognized by metering

The suppliers/traders are obliged to apply advanced load prediction methods based on the local weather forecast and the correlation to retrospective metered load profiles. The VPP also predicts the volatile renewable power generation based on the local weather forecast.

The above considered steps for scheduling are demonstrated in Fig. 5.32.

The TSO is served with coupling node oriented schedules of the residual loads (the difference of the load and the generation within the cell territory).

Based on the on-line communicated 1/4 h m data, and in coordination with the VPPs, the SSC has the opportunity for intra-day corrections if deviations of the schedule occur as shown in Fig. 5.33.

The inclusion of smart meter data into the balancing procedures allows a significant reduction of the control power activations and supports the economic improvement of the balancing processes in general.

5.3.3 Modern Protection Concepts

5.3.3.1 Protection Security Assessment

The analysis of the large system disturbances in Sect. 5.1 has demonstrated that in most of the cases wrong or critical settings of the protection contributed to the disturbance enlargement. The protection schemes have to be prepared for the Smart Grid challenges regarding the

- increasing complexity, extent and loading of the power systems,
- change of the generation structure by use of DER with partly volatile power injections,
- energy trading which does not consider the limitations of the network capacity.

For example, the distance protection may lose its selectivity at high operation currents close to the minimum short circuit currents and low voltages. The load impedance will decline and come closer to the short circuit impedance.

Repeated problems of the protection settings were frequently observed regarding:

- Zone 3 trips of distance relays, often used for overload protection instead of use of thermal models in digital relays,
- Trip of distance relays due to the lack of load and power swing blocking,
- Uncoordinated protection and/or overload settings across borders between various network operators,
- Low synchro-check settings not corresponding with the current network loading and topology,
- Overcurrent backup in parallel with distance or differential protection without time delay,
- Development of the network topology without the adaption of the protection schemes and settings.

Special investigations have demonstrated that the selectivity of the protection schemes may be disturbed under certain network conditions.

Consequently, it will become more and more important for the general security of network operations to observe the selectivity of the protection schemes. An important instrument for the prevention of disturbance enlargements is the "Protection Security Assessment" (PSA), demonstrated in Fig. 5.34.

First of all, the PSA method requires a detailed data base of all protection schemes, characteristics and settings of the network.

Secondly, a data base for condition simulations has to be established containing

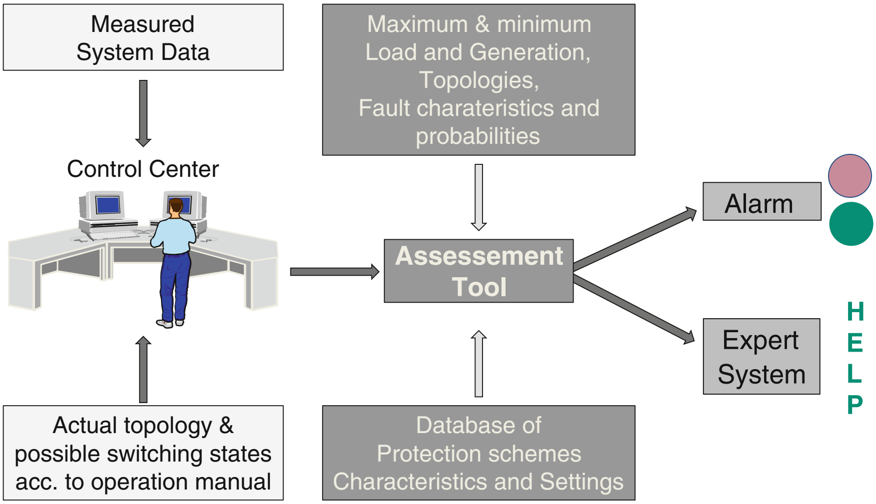


Fig. 5.34 Protection security assessment approach

- the load and generation conditions,
- the possible network topology changes and
- fault characteristics, disturbance records, fault probabilities.

Based on the described data the assessment tool may provide a stepwise off-line event simulation including all protection devices, all possible faults and ground resistances at various locations along the network considering also the fault probabilities and breaker failure conditions.

As a result of the simulations, alarms may be created showing critical conditions or congestions. Furthermore, an expert system may generate recommendations on how to improve the protection characteristics at the detected protection locations.

The PSA method may also be used in an on-line mode using the current and predicted network conditions (measured voltages and power flows, topology) to ensure that the protection schemes meet the current and upcoming challenges.

If large networks with tens of thousands of protection devices have to be approved, the results should be presented separately in three levels:

1. the main protection schemes,
2. the back-up protection schemes,
3. the main and back-up protection schemes together.

The results may be presented in a multilevel diagram.

Figure 5.35 presents the diagram for the assessment of the back-up overcurrent protection devices with inverse trip characteristics of a small 110 kV network with 23 lines. The results summarize a large variety of loading conditions.

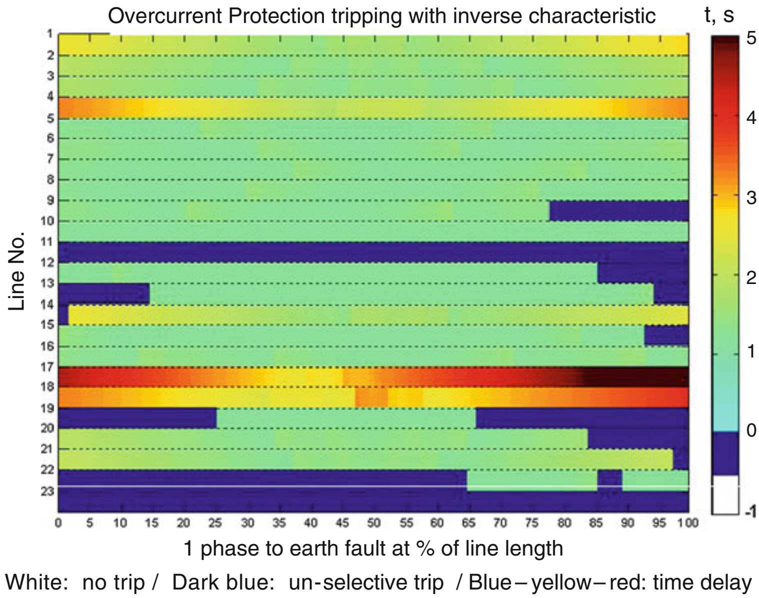


Fig. 5.35 PSA diagram of a 110 kV network, back-up overcurrent protection [15]

In this presentation it is immediately visible on which lines unselective trips may happen in strong loading situations (dark blue). Furthermore, extremely high tripping delays are recognized (red).

The same presentation form is used for all kinds of protection schemes. The benefit of this method is that with the coloring the quality of the protection settings of a network may be presented in a simple way without detailed presentation of the protection characteristics. By zooming in on the diagram the detailed information about the conditions is displayed.

5.3.3.2 Adaptive Protection

The Smart Grid challenges have a strong impact on the idea of what modern protection means.

In the past, the protection schemes were designed to protect the assigned asset against damages caused by faults by tripping the faulted network elements rapidly and ensuring in the same way the secure continuation of the network operations. The only criterion for activities was the detection of faults that exceeded the pickup settings.

Now, however, due to the quickly changing network conditions the protection behaviour has to become smarter and provide more flexibility.

The protection takes part in the observation of the power system conditions from its position in the network as presented in Fig. 5.36.

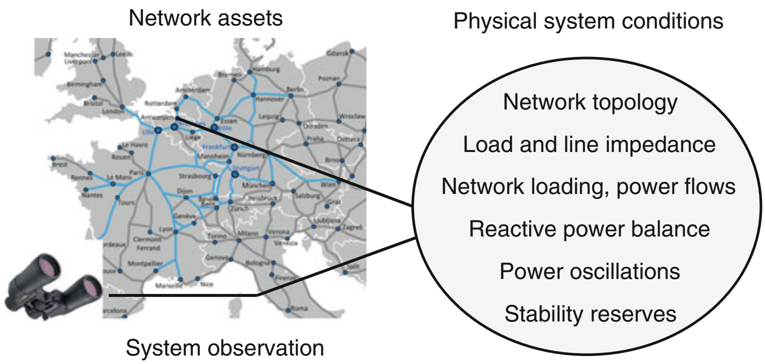


Fig. 5.36 The protection system as an observer of the power system conditions

The target of this new role is that the protection automatically recognizes that the actual settings and characteristics may cause over or under function.

The adaptive protection is able to adapt the settings in such a way that the selectivity is improved and any malfunction can be avoided under the observed circumstances. Here the observation may be performed autonomously by the protection or by receiving signals from outside (e.g. from the online PSA system).

The programmable logic function implemented in the modern digital protection IEDs (see also Sect. 3.2.2.2) is normally used to realize the adaptive protection principle. Figure 5.37 presents the logic scheme to adapt the protection behaviour in both ways—by internal and external observations.

Examples to demonstrate the benefits of the adaptive protection principle can be presented on behalf of the blackouts in the USA and Italy 2003.

The blackout in the USA was the result of more than 4 h of sequential line and power station outages. The point of no return was reached when the 345 kV line Sammie–Star tripped in Zone 3 of the distance protection (see Sect. 5.1.2).

The high line loading (MW) and the reactive power flows (MVar) above the line‘s emergency rating together with depressed voltage led to the distance trip decision, which was made using only the circular MHO characteristic. However, the loading development, the voltage depression and the growing reactive power flows had been observed for hours. The trip of the line could have been avoided by a change of the trip characteristic by (see Fig. 5.38):

- activating a load blocking area or
- switching over from the MHO characteristic to the T-Bone characteristic, which is mainly used in Continental Europe to avoid protection over-functions on heavily loaded lines.

Using the adaptive protection principle, the point of no return could have been delayed and appropriate measures to strengthen the transmission system could have been activated.

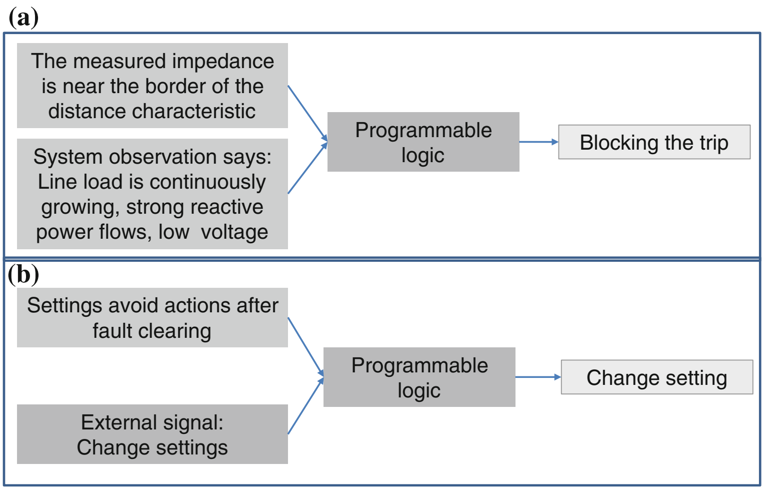
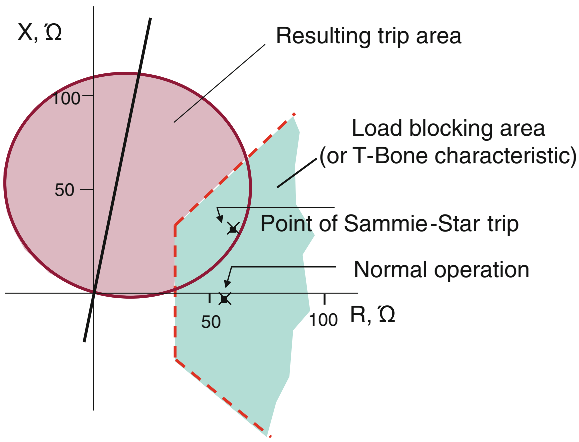


Fig. 5.37 Use of the programmable logic for the adaptive protection function: **a** own system observation and **b** external signal

Fig. 5.38 The possibility of the Sammie–Star trip avoidance by adaptive protection



The second example related to the Italian blackout is shown in Fig. 5.39.

On the stormy night of 27th September 2003, all lines connecting Italy and the neighboring countries were heavily loaded and hanged through. One system of the 400 kV double line Mettlen–Lavorgno was first tripped after a tree contact and a single phase short circuit. This tree contact was continuous and the auto-reclosing of the line could not eliminate the fault. However, the N-1 security criterion was no longer ensured after the line trip.

The auto-reclosing was allowed by the synchronism-check which recognized an angle below 20° between the line ends. This low angle resulted from the stable low impedance connection at this track by the not faulted system of the double line.

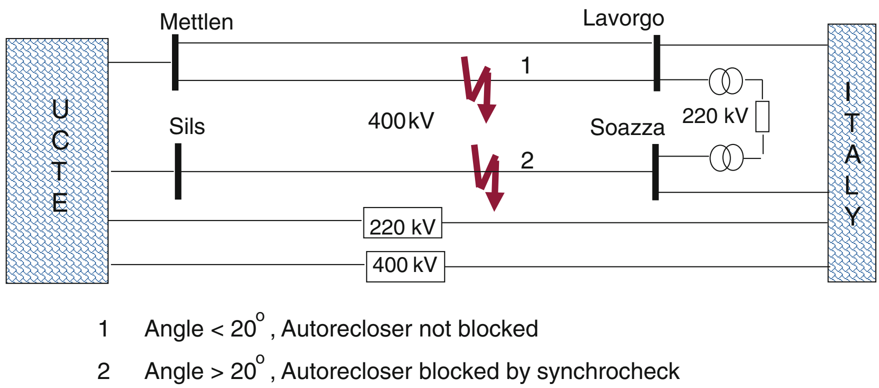


Fig. 5.39 The line trips initiating the disconnection Italy–UCTE

20 min after the first trip the strong winds caused heavy conductor oscillations of the single line Sils–Soazza leading to a two phase short circuit. Normally this kind of fault is not stable and can be cleared by the auto-reclosing function.

In this case, the angle between the substations increased because of the heavy loading and the high impedances of the remaining network connections (via the 220 kV network). Consequently, the synchronism check blocked the auto-reclosing. The adaptation of the angle setting to the new network conditions would allow the auto-reclosing and the reconnection of the line.

The complete disconnection of Italy and the subsequent blackout could have been avoided if the adaptive protection scheme in accordance with Fig. 5.37b were applied.

5.3.3.3 System Protection

In addition to the traditional tasks of the rapid, secure and selective fault elimination, the protection schemes may perform system protection tasks ensuring the power system stability in emergency situations and avoiding the enlargement of disturbances into blackouts.

The practice of under-frequency load shedding is the traditional example for system protection and is applied worldwide.

In the case of large disturbances with strong unbalances of load and generation the under frequency, load shedding is activated by definite frequency settings. Within the range of 49.2 and 48 Hz up to 50 % of the network load may be switched off in separate steps.

As a rule, the frequency relays are installed at the feeders of the HV/MV transformers. In accordance with their step setting they trip the whole MV busbar.

However, under the conditions of large scale power injections into the MV networks by DER the traditional practice may be contradictive. The DER power injections supporting the Frequency control may be also switched off.

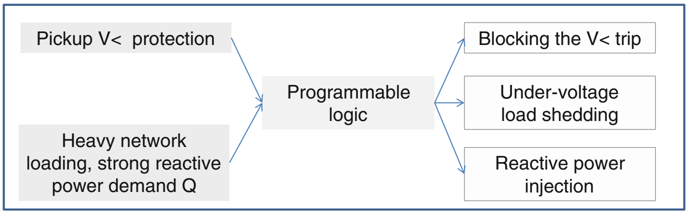


Fig. 5.40 The V-Q system protection principle

In the environment of large scale contributions of DER, selected feeders, not the whole busbar, have to be switched off in the load shedding process. The feeder selection has to consider that mainly load and not active DER will be shed. The selection of the feeders to be switched off may be executed online by.

- combining the measured load flow directions of the feeders with the under frequency criterion or
- by blocking signals communicated by the DER generating a significant amount of power.

However, the blocking may mean that the expected load to be shed cannot be achieved. Consequently, the load shedding practice also has to become more intelligent and requires the involvement of system observations.

From the perspective of advanced system protection schemes they will be able to detect system conditions that threaten the stability in advance. Such "System Integrity Protection Schemes" will initiate switching operations, load shedding or re-dispatch measures.

A first example for these new schemes is the V-Q protection, which was introduced in many power systems as a result of the voltage collapse phenomena that occurred during the large blackouts of the year 2003.

The V-Q protection is also based on the programmable logic of the digital protection devices. The under-voltage protection is implemented in these devices as a standard function which can be enabled or disabled. The V-Q protection requires the enabling of the $V <$ function.

The programmable logic links the pick-up criterion of the $V <$ protection with information about the heavily loaded network and strong reactive power demand (Fig. 5.40).

As a result of the linking the trip of the asset assigned to the $V <$ protection will be blocked. Instead of a trip—which would be contradictive in this case—the under-voltage load shedding is initiated in a similar way as is practiced for the under-frequency load shedding. Furthermore, the enhancement of reactive power injections by the nearest power plants or by FACTS will be a relevant action of the V-Q system protection (Fig. 5.40).

The distance protection partially performs system protection functions today. Besides the fault elimination this protection provides further functions like the disconnection of asynchronous network parts.

Today, the operation of islanding networks is not practiced in Continental Europe and has to be eliminated by the protection schemes. In the future, the operation of islanded network with DER may increase the reliability of supply and will be desired, as shown in Sect. 5.2.6. However, the prerequisite of stable island network operations is the ability of the DER to participate in the frequency control. The aggregation into VPPs will provide this ability.

The introduction of system protection solutions or system protection integrity schemes will require data communication. The communication infrastructure is suitably established in the transmission and HV networks. In the MV/LV distribution level, however, a communication infrastructure does not yet exist for network control purpose. The establishment of the communication infrastructure in the distribution level will be decided based on economic benefits considering also further tasks requiring data exchange by communication networks.

5.3.4 Wide Area Monitoring by Phasor Measurement

Wide area monitoring systems (WAM) are based on accurate measurements of voltages, phase angles, currents, frequency and frequency sags and reactive and active power flows by phasor measurement units (PMU) installed in selected nodes of the network system. The innovative idea of this method consists of the analysis of multiple real-time measurements from wide spread nodes acquired at exactly the same moment at a phasor data concentrator, as shown in Fig. 5.41.

The PMUs are based on the digital IED technology and may also contain the fault recorders and further protection functions. The PMUs form time stamped measurement sets and communicate these packages to the phasor data concentrator via high speed communication channels using an IEEE standard protocol with a delay of $\sim$20 ms. The measurements will be refreshed in time intervals between 20 and 100 ms.

The phasor data concentrator is normally installed at the network control center and performs the network condition analysis comparing the received measurement sets from different nodes of the network. To achieve accuracy in the comparison and suitable analysis results, the measurements have to be acquired with a high time accuracy. If the normal sampling interval of the protection devices of 1 ms is used for the synchronization, an angle difference of 18^{o} may occur. This is not suitable for the stability analysis. The time synchronization by satellite with an accuracy of <1 μs will be necessary.

With a suitable software solution, the information coming from the PMUs supports the dispatchers of the networks in being aware of the stability situation in the whole network. This helps them to make the right decisions, even in critical situations. In some cases automatic initiated operations like a fast reactive power injection are started as countermeasures. Then the WAM extends the level of its function to Wide Area Protection (WAP), which is a special form of the system protection.

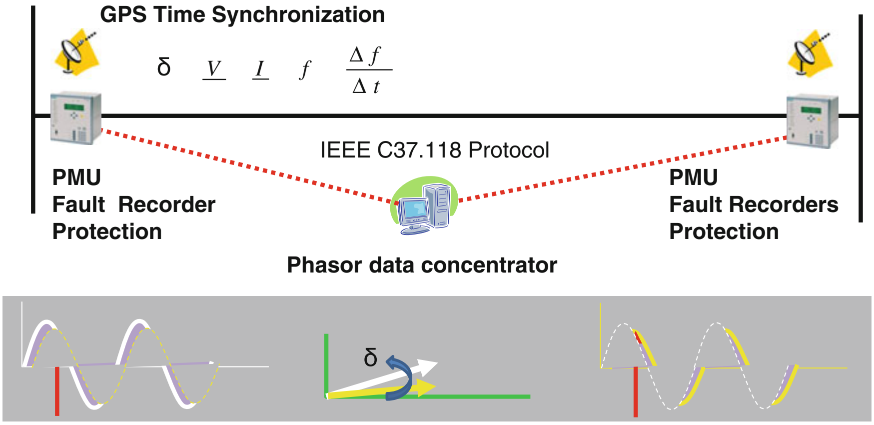


Fig. 5.41 The PMU principle

The results of the phasor measurement analysis by the data concentrator provide:

- a real-time state estimation and stability observation of the networks,
- the detection of power oscillations, their analysis and the generation of appropriate countermeasures,
- the dynamic load flow control,
- improved accuracy of the analysis of faults and the fault location,
- the monitoring of asset condition for their higher utilization.

The WAM method recognizes stability problems much faster than the traditionally used state estimation. The difference consists in the estimation methods. A comparison of both methods is presented in Fig. 5.42.

The traditional state estimation requires the network calculation using the current topology and measurements.

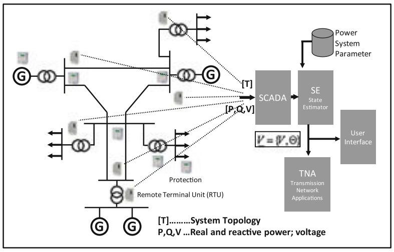
The phasor measurement analysis of the complex voltages and currents allows the rapid calculation of a system state identifier which presents a snapshot of the network conditions. The state estimation time is reduced from minutes to $\sim$100 ms. The PMUs were successful applied for precise fault location. During faults electromechanical oscillations occur which travel over the network in the form of frequency deviations.

The ability of the PMUs to record the frequency with an accurate time stamp is used to find the exact location of faults. The data concentrator recognizes the frequency deviations at several nodes with installed PMUs and analyzes the time delays. Using this information the correct location of the oscillation origin—the fault location—is defined (Fig. 5.43).

A further use case is currently broadly considered and investigated. In principle, PMUs can be installed to monitor any system node and, in particular, the network assets like lines or transformers (see also Sect. 5.3.6).

Traditional system state estimation.

The complete „network tree “has to be considered to estimate the system conditions



Advancement of system state estimation by PMU

- The complex voltages and currents provide the state vector z
- State equations are linear - thus iterations are not necessary
- System observability is rapidly recognizable

System state identifier

$$\boxed{\hat{x} = G^{-1} * H^{T} * R^{-1} * z}$$

x – the system state identifier summarizes the information about voltages in the network nodes;
z – the measured vector contains the information about complex components of voltage and currents;
$G = H^T * R^{-1} * H$ – constant correction matrix;
H – the measured Jacobian -matrix is constant and depends only on the network structure
$R = E(e * e^T)$ – diagonal covariance error matrix , e – the measurement vector error

Fig. 5.42 Comparison of the traditional and the PMU state estimation

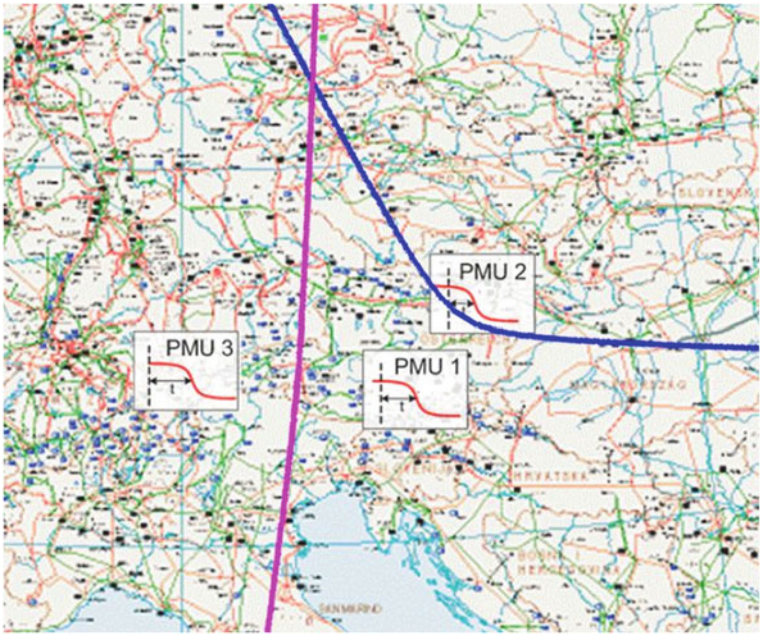


Fig. 5.43 Fault detection using distributed PMUs (*Source* M. Heide, TU Vienna [16])

The loading of the line causes energy losses which heat up the line. As a result of the metal is warming up, the resistance R rises, i.e. for aluminum R rises about 12 % with a line temperature growth of $\Delta\vartheta = 30$ °C. The exact calculation of the resistance R by the PMU can be used to calculate line temperature and to consider

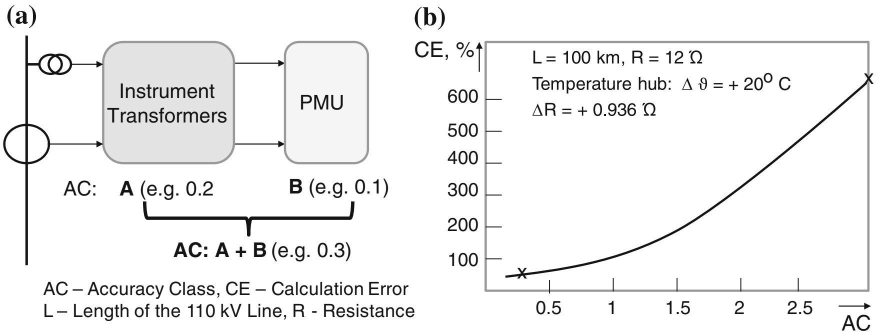


Fig. 5.44 **a** accuracy class of device combinations, **b** calculation error dependency

the remaining transfer capacity. For example, the measured R increase of 12 % identifies that the transfer capacity of a 400 kV line ΔS_{max} is reduced by 6.5 %.

However, the accuracy of these calculations strongly depends of the accuracy class of the used measuring set—including the instrument transformers and the PMU. The common accuracy class has to consider the sum of the measurement errors as shown in Fig. 5.44a.

Special investigations of the authors concerning the calculation errors according to different accuracy classes of the measuring set underlined that the PMU is not applicable for the temperature monitoring of the assets if devices with normal accuracy classes are used. The investigations were performed for a 110 kV line (single conductor 240/40 Al/St) of 100 km length.

As presented in Fig. 5.44b, the PMU calculated growth of the resistance for a temperature hub of 20 °C amounts 0.65 Ω instead 0.936 Ω (error 30.5 %) by using a high set accuracy class of 0.3 and rises up to 6.44 Ω (error 588 %) with a normal accuracy class of 3 %. This high error of the temperature estimation is caused by the relative low temperature coefficient of aluminum (3.9×10^{-3}/°K) which resistance changes can be observed in the voltage change range of ppm (‰). The application of a measurement set with an overall accuracy class of 0.1 (not relevant for series products) would allow the reduction of the temperature errors below 10 %.

The real-time analysis of power oscillations and their damping as the result of large disturbances by PMUs—for example an outage of a large power station of 1,000 MW—is an important way to recognize whether there is an emergency or not.

Figure 5.45 presents the jump of the voltage angles between the nodes A and B of 7° after the outage of a 1,000 MW power station in node A. The distance between the nodes is over 600 km. The subsequent fast damping of the oscillations identifies that this outage is not dangerous for the stable network operation.

WAM systems are widely introduced in the transmission systems of Continental Europe. The application in distribution systems is under consideration and first pilot project have begun.

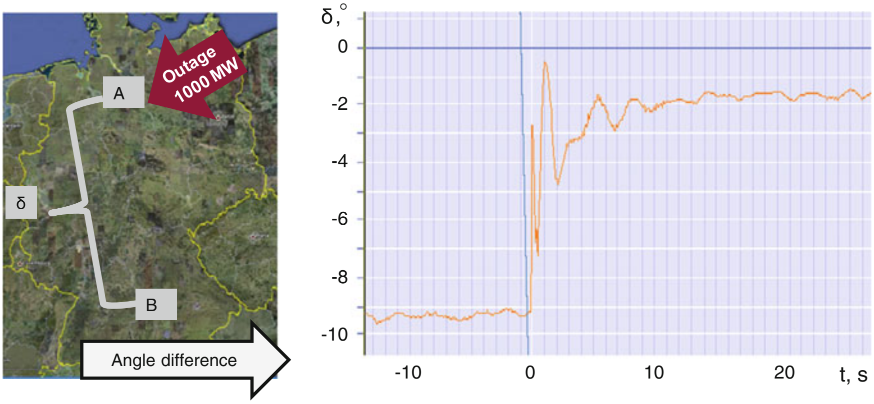


Fig. 5.45 The voltage angle oscillations recoded by PMUs after a power plant outage [17]

The interactive user interface of the data concentrator has to be designed to provide an optimum support to the dispatchers. The following design rules are common in the advanced WAM systems of different vendors:

- fast identification of the system conditions (okay, critical, alarm),
- free selection of the desired measurement records or phasor diagrams in a configuration field,
- setting of thresholds to be observed,
- simple shift between on-line and off-line mode for the interactive analysis of events,
- geographical presentation of the network with the allocation of PMUs allowing the fast location of areas with stability problems,
- gateways for data export and import to allow the cooperation with other assessment tools.

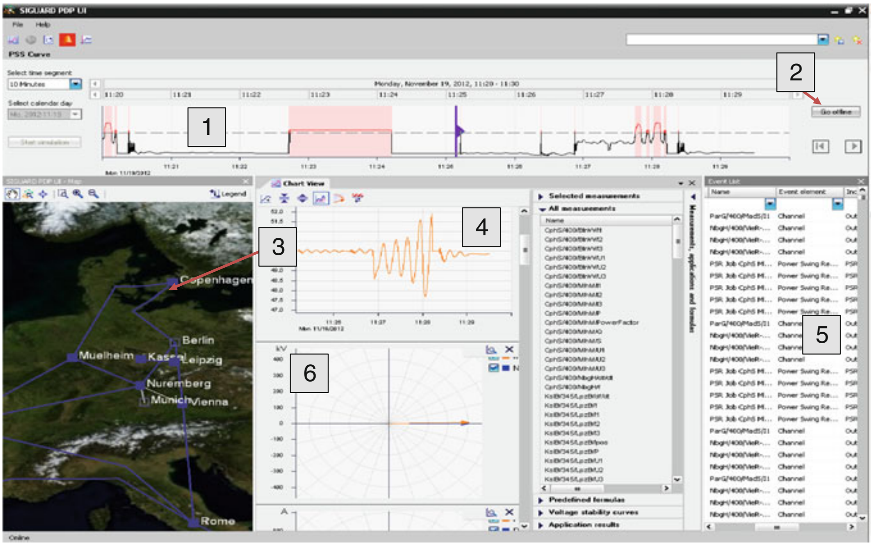
Figure 5.46 presents an example of a display applying the above mentioned features.

The installation of about 50 distributed PMUs in the whole ENTSO-E interconnected network of Continental Europe allows the fast identification of emergency situations, stability problems and congestions in all partial control areas.

5.3.5 Steady State and Dynamic Security Assessment

In general, the security assessment principle is based on real-time security calculations using the actual topology and online measured data of the network.

Security calculations today are mostly performed as load flow contingency calculations (sequence of N-1 violations using the current network conditions). As a result the operator is getting an overview of the situations in which overloads of



1- State of the power system
2- Selection of online view or historic view
3 - Geographical display
4 – Measurement records
5 – Event report
6 – Phasor diagrams

Fig. 5.46 Typical user interface display of a WAM system [17]

equipment and congestions may occur. All decision making is the responsibility of the operator.

However, the on-line steady state security calculations are not able to consider the complex dynamic interactions of generators and grid equipment. Furthermore, the predicted developments of the volatile power injections from RES and the dynamic system behavior were not included in the past.

Innovations are focused on extending the scope of security calculations and on creating proposals for stabilizing actions. Both the steady state assessment (SSA) and the dynamic security assessment (DSA) methods have to be enhanced and introduced as a combined method to provide better support to the network dispatcher.

In emergency situations it is necessary that the dispatcher makes a decision quickly. However, in these situations a large amount of different information is reported on the display. Wrong actions may lead to large disturbances as demonstrated by the German disturbance (see Sect. 5.1.8). On the other hand, operations like load shedding or the re-dispatch of power stations may have economic consequences, and the dispatching center may be made responsible for economic losses of the network users if the related operation exceeds the needs or is not mature with regard to the power system security. In this sense, stress situations may occur and the automatic creation of recommendations would be helpful for the dispatcher.

An example can be demonstrated on behalf of the Italian blackout as shown in Fig. 5.47.

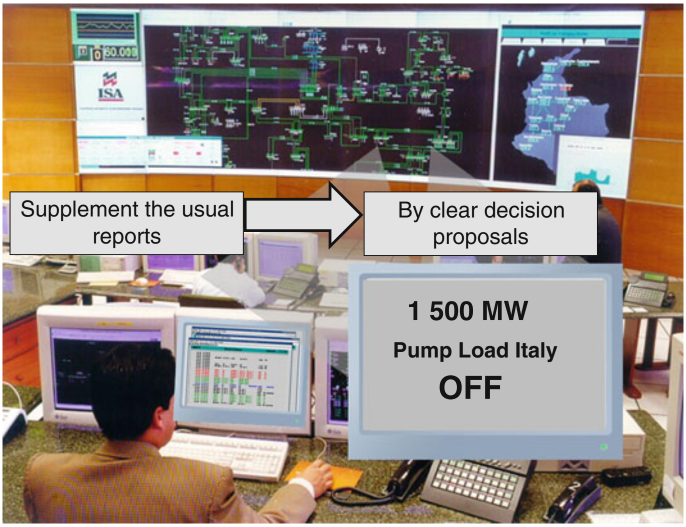


Fig. 5.47 Guidance for the network dispatcher by clear recommendations

After the 1st line trip it was clear that the N-1 criterion was no longer fulfilled. The request of the Swiss dispatcher to the Italian colleague to lower the load in Italy was only of a qualitative nature.

A security assessment could provide the quantitative request of load reduction. For example, lowering the pump storage load by 50 % would not affect the consumers. The Italian blackout could have been avoided if the dispatcher received and followed such a quantitative order.

The advanced steady state security assessment has to be executed on-line. It consists of the following steps depicted in Fig. 5.48:

- on-line performance of subsequent N-1 contingency load flow calculations,
- consideration of the volatility of power injections with a time horizon of minimum 1 h,
- indication of possible congestions and emergency situations,
- start of an optimized load flow calculation for the indicated N-1 violation conditions taking into account the available control opportunities (e.g. change of grid topology, reactive power control etc.),
- recognizing the differences to the current operation conditions,
- creation of recommendations for how to shift the system to secure N-1 conditions.

In this example the recommendation to the dispatcher may be generated by applying an optimized power flow calculation for the N-1 conditions indicted as critical.

Comparing the results of the actual network conditions and the optimized power flow calculation, improvement actions may be generated for guidance.

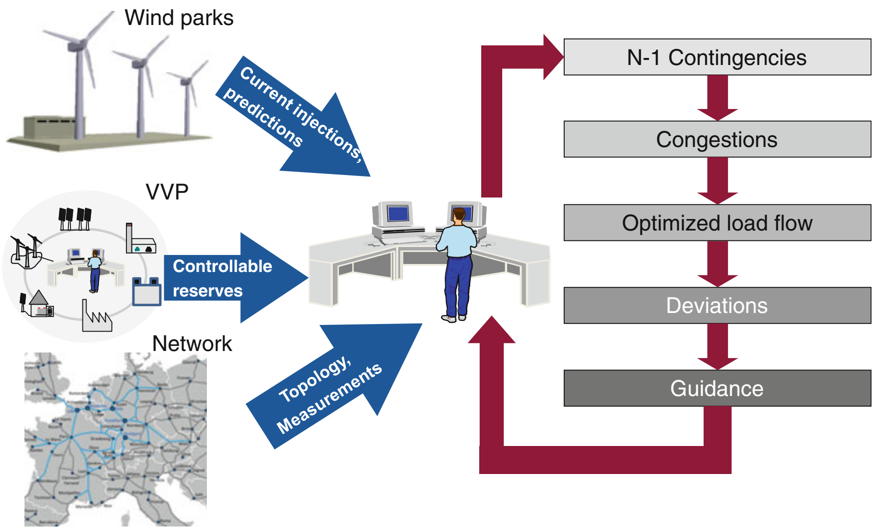


Fig. 5.48 Principle of the advanced online steady state security assessment

The *dynamic security assessment* is based on advanced power system simulation methods. In many cases it has been demonstrated that the simulation delivers a highly accurate depiction when compared with the recorded disturbances. In Fig. 5.49 such a comparison is shown.

Here the frequency oscillations after an outage of a 900 MW power plant in Spain are presented. The frequency oscillations at the border of the interconnected system in Spain and Poland swing in the opposite direction. The axis of the frequency swings is located along the German–French border. Furthermore, a power swing is shown for one 400 kV line connecting the control areas of France and Germany.

This example demonstrates that the dynamic system behavior is accurately predictable using simulation tools. Furthermore, the countermeasures for stability enhancement may also be simulated and their efficiency may be approved.

The dynamic investigation of the power system has to consider the three major aspects of stability disturbances:

- the voltage stability (avoidance of voltage collapse according to Sect. 5.1.1.)
- the small signal stability (when the system is near to the initiation of un-damped power swings according to the eigenvalue method, or if the voltage angle difference between the neighboring nodes is close to 90°),
- the transient stability reflecting the damping of power oscillations after faults.

Furthermore, the fault clearing method by the protection schemes plays a role in the investigation of the power system dynamic. Therefore, it is useful to integrate the protection schemes and the protection security assessment in a complex dynamic security assessment approach as shown in Fig. 5.50.

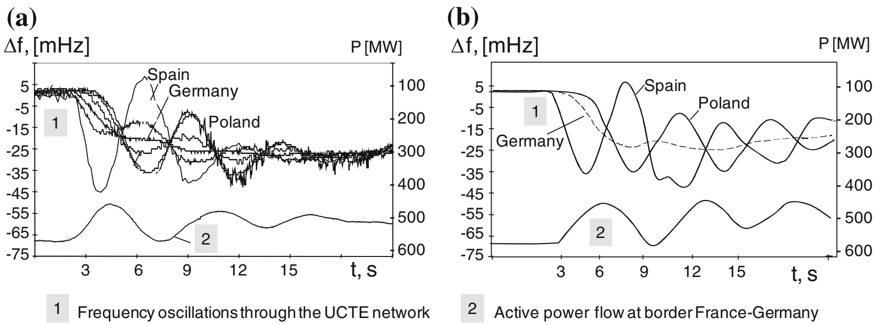


Fig. 5.49 Comparison of measured and simulated oscillations after a power outage (*Sources* **a** RWE Net, **b** Siemens AG)

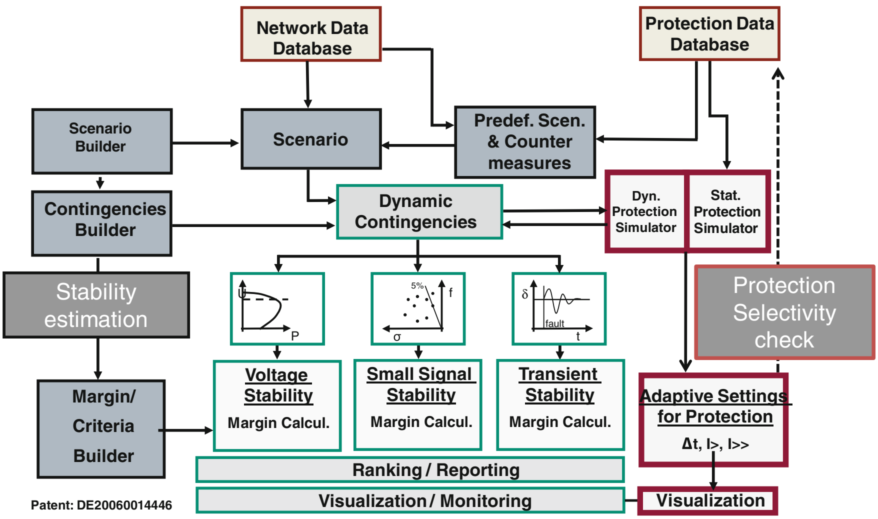


Fig. 5.50 General scheme of the dynamic security assessment (*Source* R. Krebs, Siemens AG)

A DSA tool is based on the network data base containing the parameters of the plants like lines, transformers, FACTS, generators and the on-line acquired network data (measurements, topology). Additionally, the protection data base is required.

The automatic generation of scenarios and contingencies to be investigated is based on the network topology and the structure of the feeding power stations. Predefined scenarios and countermeasures will be applied for an efficiency check if a stability congestion is recognized.

The calculated margins of the stability aspects demonstrate the stability reserves. Furthermore, the protection simulation may provide recommendations for adaptive settings.

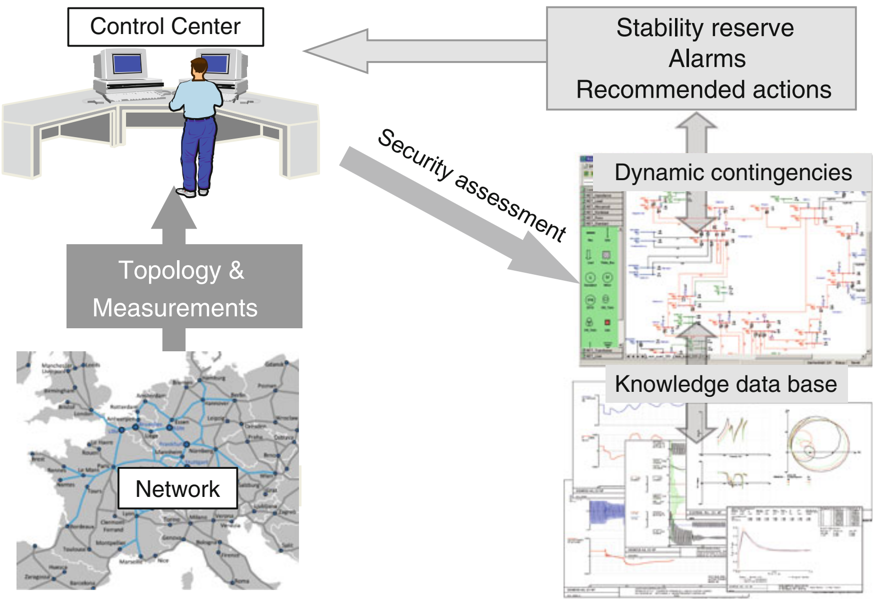


Fig. 5.51 DSA approach using expert systems with knowledge data base

The 1st priority of the dynamic security assessment is to provide detailed information of the power system stability and to create alarms in critical situations.

Worldwide research and development activities are ongoing to create expert systems based on neural networks which are able to generate possible improvement actions.

For such expert systems a broad knowledge data base of the dynamic system behavior has to be developed. The neural network is able to select the appropriate countermeasures for improving a recognized critical situation using the knowledge data base.

Figure 5.51 demonstrates the DSA approach using such a knowledge data base and creating suitable recommendations for shifting the system to higher stability conditions.

Dynamic stability calculations are time intensive, but in order to provide the DSA results in time for the control center to make a decision, all contingencies should be calculated within $\sim$5 min. Consequently, about 100 dynamic cases must be handled within this time interval.

This real-time requirement is quite critical for the provision of the dynamic contingency calculations. Therefore, an advanced operation management is requested. An advanced DSA-system analyzes the events using an intelligent and flexible criteria editor which gives the opportunity to select criteria for critical system time behavior. These criteria allow the observation of how critical the system is acting based on under voltages, frequency deviations, angle differences etc.

To save calculation time, an internal runtime management adapts the integration step of the simulation when the time behavior is not critical and stops the simulation when the criteria are fulfilled.

As a conclusion it can be stated:

The basic idea of the steady state assessment and dynamic security assessment of the power system in real-time is based on on-line provision of the operating data of the network as shown in Figs. 5.48 and 5.51. The current network topology and measurement values are supplied on-line through the network control center to a planning tool for power flow calculations and stability analyses.

With the help of knowledge data bases, critical situations are noticed in real-time, that means within minutes; warnings, alarm signals and decision guides are generated.

The aim of such systems is to supplement the generally extensive event reports with simple instructions, as shown in Fig. 5.47.

Practical experience with such assessment systems is being collected and makes clear the efficiency of the enhanced power system observability.

5.3.6 Weather Condition Monitoring and Flexible Line Loading

The maximum loading of transmission lines is limited by the temperature of the conductors which is influenced by the weather conditions and the current flow. The thermal threshold is calculated based on the:

- electric parameters of the conductors (e.g. material, cross section, length) and
- worst-case environmental conditions as specified in the standard EN 50182 [18]
  - high environment temperature of 35 °C,
  - low wind speed in the horizontal direction of 0.6 m/s,
  - high sun radiation of 900 W/m^2.

This traditional method of dimensioning in combination with thermal protection settings ensures that the power flow will not exceed the thermal threshold.

However, the worst case conditions are very rarely valid. In practice, the traditional thermal overload protection avoids the full utilization of the physical transport capability of the transmission lines. In the case of lower temperature or higher wind speed, an increase of the line loading will be possible without exceeding the thermal thresholds.

Monitoring the meteorological conditions along a transmission line in combination with the network state estimation function performed in the control center may support a more flexible line loading and avoid measures like re-dispatch in critical situations.

Furthermore, a day-ahead prediction of the transfer capacity for each transmission line may be included in the above described congestion management methods, for example, the "day ahead congestion forecast" (DACF) in accordance with the weather forecast and the intra-day capacity allocation.

This approach is currently being investigated in several projects.

5.4 Conclusions

The new conditions of network operation with volatile power injections lead to a higher loading of the network assets and the growing danger of stability violations. Maintaining the high level of reliability has to be performed in two ways:

- network enhancement by advanced primary technologies,
- improved monitoring and intelligent congestion management.

The new tasks of network planning are directed at defining the optimum ratio between both approaches.

The intelligent congestion management is based on the set of the above described methods and instruments allowing better observation of the network conditions, more efficient utilization of the installed assets and adaptation of the network control/automation/protection according to these conditions.

However, the described methods cannot stand alone. It is necessary to manage their mutual interaction in order to gain optimum efficiency and operational benefits. For example, the meteorology dependent line loading can serve as an input for the DACF introduced in the interconnected transmission systems of ENTSO-E. On the other hand, the extended line loading requires the

- monitoring and communication of the weather conditions to the control center,
- integration into the state estimation procedures of the control center,
- approval by the dynamic security assessment and protection security assessment to avoid, for example, voltage collapse or stability problems and the
- dynamic adaptation of the thermal overload protection characteristics.

The intelligent congestion management supplements the network extension by using primary assets. The appropriate measures have to be included in the advanced methods of network planning. Intelligent congestion management is requested to ensure the efficiency of the transmission network enhancement and the stability of the entire interconnected transmission system.

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Chapter 6
The Three Pillars of Smart Distribution

6.1 The Relationship Between Smart Grids and Smart Markets in Distribution Systems

The changing conditions at the distribution level described in Sect. 4.7 require the adaptation of the network assets and operational processes accordingly. The coordination of all network users in the sense of the Smart Grid definition seems to be useful to ensure the economic feasibility, the reliability, the sustainability and the reduced ecological impact of the electricity supply processes.

The question arises, how the optimum relationship can be found between:

- the network enhancement required to respond to the requested bidirectional power transfers with extremely high variability, and
- the impact on the network users to adapt their behaviour to the available power transfer capacity.

For the distribution network a coordinated impact on the demand and/or the power injections will be an alternative to expensive network extensions to perform secure network operations in extreme conditions that may occur with a low probability and for short time periods (see also Sect. 4.7.2, Fig. 4.39).

However, the coordination of the connected consumers and the distributed energy resources (DER) has an impact on the market processes. It will become necessary to approach such challenges like:

- balancing the intermittent power injections of the DER with the demand,
- monitoring and controlling the voltage increase at the connection points of DER,
- observing the loads, especially the charging of electric cars to avoid any overloading of network equipment,

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This chapter is mainly based on (1) the results of the European Lighthouse project Web2Energy (www.web2energy.com), Darmstadt 2010–2013 under the technical leadership of Dr. B.M. Buchholz and (2) the VDE Seminar "Smart Grids" compiled and held by Dr. B.M. Buchholz since 2009.

B. M. Buchholz and Z. Styczynski, *Smart Grids – Fundamentals and Technologies in Electricity Networks*, DOI: 10.1007/978-3-642-45120-1_6,

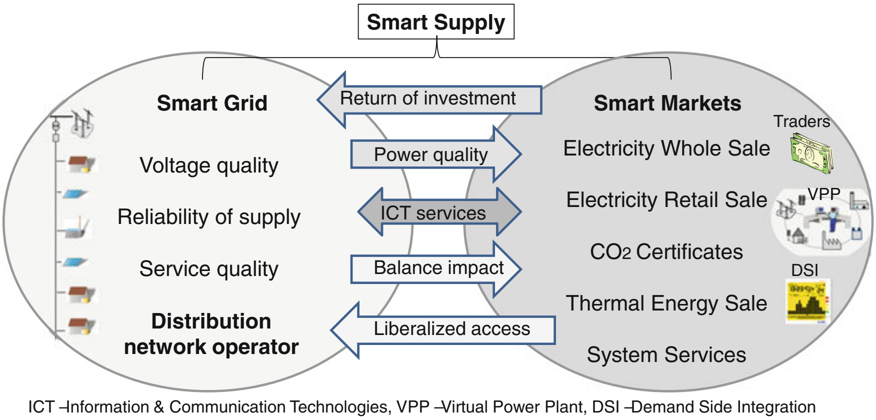


Fig. 6.1 Relationship between network and market processes

- maintaining the reliability of supply at today's high level despite the changing conditions.

The quality of supply including the voltage quality and the reliability may be maintained under the new conditions in two ways:

1. Extremely strong enhancement of the network to meet all possible, including very rare varieties, of load flows or
2. Smart interaction between grid operations and market activities concerning the producers and consumers.

Both approaches may be applied in an efficient way depending on the local conditions of the grid operations. However, the second approach is the most innovative and is defined in [1] as "Smart Supply", see Fig. 6.1:

The relationship between the markets and the distribution network operators (DNO) is complex and diverse.

Traditionally, the network users had to offer the return of the investment (ROI) through the markets and, in exchange, the DNO offered a high power quality consisting of three components—voltage quality, reliability of supply and service quality. The liberalized markets nowadays require the unlimited access of all kinds of network users, free from any discrimination.

On the other hand, the economy of the grid operation expenses will require the adaptation of loads or generation to the available network capacity in the environment of volatile power in-feed and strong simultaneous demands. In this sense, the DNO will apply methods to impact the balance of generation and load through variable network charges as a component of the tariffs and/or by switching-off network users in accordance with special contracts.

Figure 6.1 presents these relationships whereby the markets cover the wholesale and the retail-sale of electricity, ancillary services (e.g. balancing reserves), CO_2—certificates and thermal energy (with regard to cogeneration of heat and power—CHP).

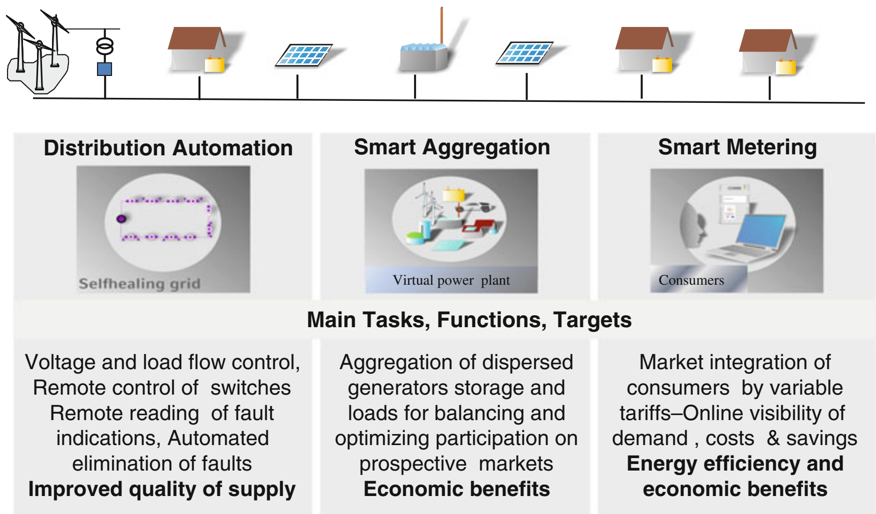


Fig. 6.2 The three pillars of smart distribution

The stakeholders of the markets are the traders, the power plants, the virtual power plants (VPP—aggregating and coordinating distributed energy resources, switchable loads and storage), providers of electricity storage and the consumers. The consumers will be integrated into the markets by dynamic tariffs. Demand Side Response (DSR) on the dynamic tariffs is expected to occur in the form of saving energy and/or shifting of demand, which will not influence the consumers' quality of life.

To summarize the described aspects, the Smart Supply approach is defined as:

> Smart Supply is a system approach that can intelligently coordinate the distribution grid operations and the market activities by means of information and communication technologies in order to efficiently create economic benefits for all participating stakeholders—DNOs, power producers, traders, consumers, storage and ICT service providers.

The establishment of Smart Grids in the distribution level has to include the Smart Supply approach. In this sense Smart Distribution consists of the following three pillars:

1. Distribution Automation—Network automation and remote control to avoid over voltages or overloads and to improve the reliability by speeding up the supply recovery after fault induced trips,
2. Smart Aggregation—Energy management on the distribution level to coordinate the DERs, storage units and controllable loads for balancing and participation in markets for energy, ancillary services and carbon certificates,
3. Smart Metering—Consumer involvement in the electricity market as a motivation for higher energy efficiency via variable tariffs and the visualization of tariffs, demand and costs.

The pillars, their main functions and targets are considered in detail in Fig. 6.2.

Table 6.1 Smart grid flexibility provision and smart market activities

Activity	Smart Grid	Smart Market
Network automation	Ensuring power quality	Unlimited access of users
DER	Load flow/Voltage control	Energy and reserve power
Electricity storage	Load flow/Voltage control	Sell and buy on energy market
DSM	Load flow/Voltage control	Reserve power market
VPP	Load flow/Voltage control	Optimum on various markets
DSR	Load flow/Voltage control	Consumer market integration

DER Distributed Energy Resources, *DSM* Demand Side Management (switching load), *DSR* Demand Side Response, *VPP* Virtual Power Plant

Consequently, the DNO will be able:

- to establish its own enhanced automation and remote control facilities for ensuring a high level of power quality under the changed conditions,
- to apply flexibility offers to network users on a contractual basis to optimize the operational expenses (OPEX).

The use of the three pillars of Smart Distribution in a Smart Supply context is presented in Table 6.1.

The DNO impacts the market actors by applying the Smart Supply approach, which is based on an optimization between network enhancements and offering benefits to the network users for their flexibility via market mechanisms.

6.2 Pillar 1: Automation and Remote Control of Local Distribution Networks

The main tasks of the distribution network automation include voltage control, power flow control, remote executed operations for changing the network topology and the improved fault elimination/restoration of supply.

6.2.1 Voltage Control

6.2.1.1 Traditional Voltage Quality Control and the Adaptation to the Smart Grid Conditions

Traditionally, the voltage control is limited to the tap changer control of the transformers that feed into the MV networks under load. The tap changer increases or reduces the winding ratio of the upper/lower voltage side of the transformer. To do this, a number of supplement windings on the upper voltage side are connected to the tap changer contacts and may be connected or disconnected stepwise to the basic windings. In general the upper voltage side is used because of the lower

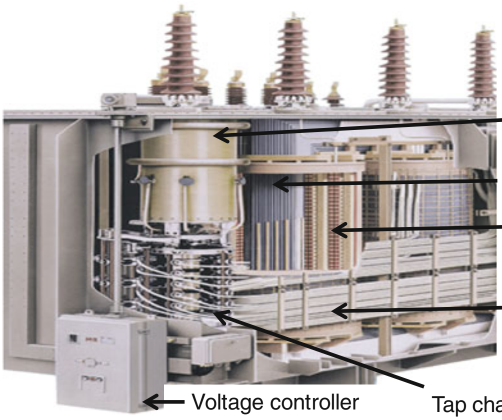


Fig. 6.3 Tap changer and winding connections of a 110/20 kV transformer

currents that have to be switched in the process of winding connections or disconnections.

In Fig. 6.3 a view into a transformer 110 kV ± 12 %/21 kV, 40 MVA is presented. In this figure one can see how the winding conductors coming from the three phases are connected to the tap changer contacts on the left-hand side.

As a first priority, the algorithm of the voltage controller requires the voltage measurement at the MV busbars. The voltage controller compares the measured voltage with the target voltage which is normally selected in the range of 105–110 % of the rated voltage, and adapts the transformer ratio to achieve the target voltage.

The second influencing parameter is the measured current. If the current is high the voltage drop along the MV feeders will be higher. Contrarily, during weak load conditions a significantly lower voltage drop will occur. Consequently, the target value of the busbar voltage will be increased in peak load conditions (up to 110 %) and reduced in weak load conditions (maximum 105 %) by the parameterized current compound algorithm.

However, the voltage control of the feeding transformer cannot be used only to ensure the voltage quality at the consumer connection in the same level. The consumers connected to MV/LV transformer terminals at the beginning of the MV feeder close to the substation busbar would be served permanently with a higher voltage than the consumer at the feeder end.

Therefore, the MV/LV transformers are also equipped with supplement windings. But, a tap changing under load was not implemented in the past.

The definition of the transformer ratios of the MV/LV transformer terminals is a task of the network planning and has to consider that all consumers should be served at all times with a high voltage quality in accordance with EN 50160 (see Table 4.6).

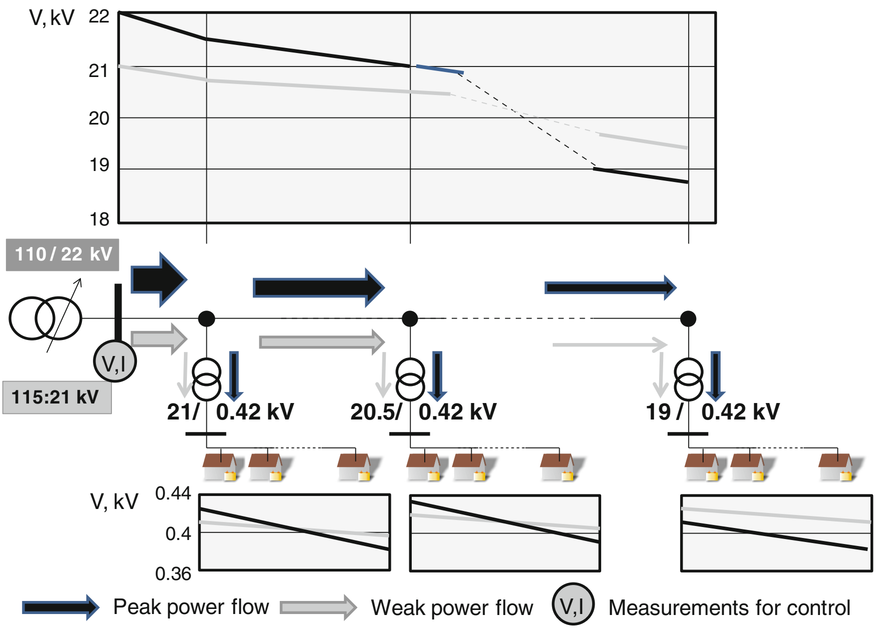


Fig. 6.4 Voltage profiles along the MV/LV feeders and the selected MV/LV transformer ratios

Consequently, the ratios of the windings have to be selected and fixed depending on the position of the transformer terminal along the MV feeder and the relevant voltage drops in peak and weak load conditions in both the MV and LV networks. The traditional network planning is based on the consideration of the extreme conditions for peak load and weak load. The general planning approach is demonstrated in Fig. 6.4. It can be seen that the transformer ratio declines along the MV feeder to keep the voltage bandwidth for all connected consumers.

However, this traditional approach is no longer suitable and has to be adapted for the situation that under Smart Grid conditions bi-directional power flows occur.

Nowadays, the vendors of distribution transformers offer MV/LV transformers with voltage control and tap changers as shown in Fig. 6.5.

The voltage control becomes much more complex and the border conditions are no longer weak and peak load but instead are weak load/strong generation and peak load/weak generation, as presented in Fig. 6.6.

Under the bi-directional power flow conditions, the problem of stationary overvoltages exceeding the allowed bandwidth now has to be solved in weak load/strong generation situations. The voltage profile becomes the inverse of the traditional voltage reduction from the busbar to the feeder end.

New algorithms have to be implemented for the voltage control including the coordination of the target values of the MV busbar in the substation and of the terminal voltage controllers. For this purpose, the low voltage measurements are

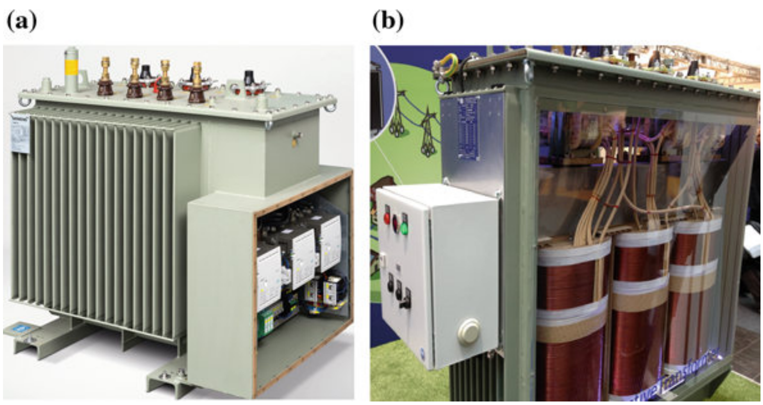


Fig. 6.5 Examples of distribution transformers with integrated voltage control facilities (*Sources* **a** Siemens AG, **b** Schneider Electric Energy GmbH at Hannover Fair 2013)

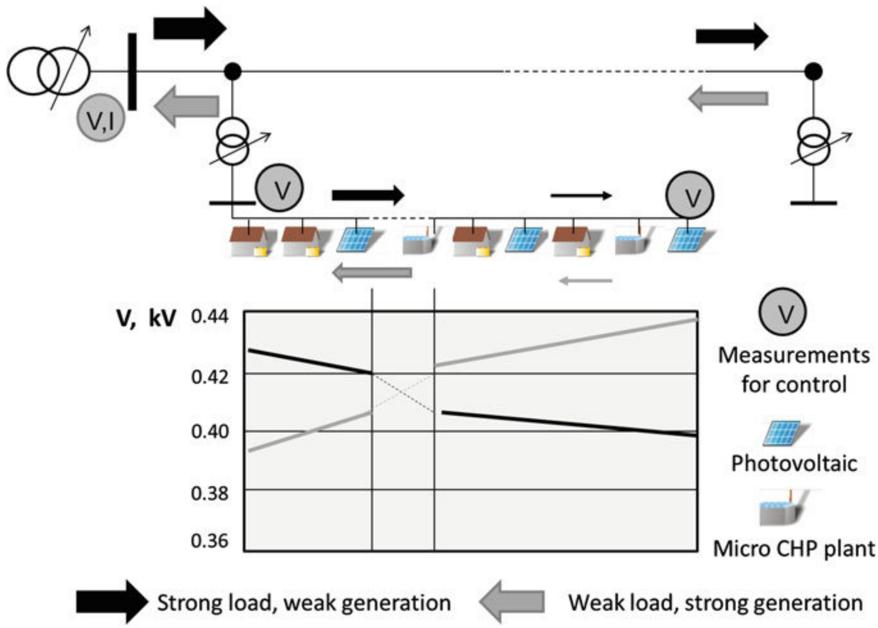


Fig. 6.6 Adapted low voltage control in Smart Grids

requested at both LV feeder ends, at the transformer terminals and at the last connection nodes of the LV feeders.

The transformer terminals are normally outfitted with measurement facilities. The terminals have to be extended in the way that the measured values may be communicated to the feeding substation and to the distribution network control center.

Traditionally, the measurement and remote reading of voltages are not available at the consumer connection nodes. Here two alternatives are possible: installation of measurement points or the application of smart meters.

In principle, the smart meters will be installed at the connection nodes of the majority of network users to provide dynamic tariff systems (pillar 3 in Fig. 6.2).

Smart meters principally perform digital measurement. Consequently, they are able to offer the voltage measurements without additional installations.

As a rule, the communication standards developed and applied for meters do not support data models for voltage measurements. This is a lack which has to be corrected. Furthermore, the provision of metered data is restricted and must adhere to the "Data Security Acts". It is also necessary to adapt the laws if users other than the suppliers obtain data from the meters.

6.2.1.2 Involvement of the Smart Supply Approach into Voltage Control

Voltage control may be supported by the means of Smart Supply in the following way:

If over-voltages occur which are caused by strong power injections (mainly from photovoltaic plants at noon), the voltage may be decreased by an increased active and/or reactive power demand near to the power injection node. Three methods may generate such effects:

1. Low tariffs are offered during midday on sunny days. The DNO can influence the tariff by a significant reduction of the network charges. A special trial in the supply area of the city of Mannheim, Germany, under the slogan "Washing with the sunshine" [2] demonstrated the efficiency of this approach. About 60 % of the households started the washing machines accordingly and used the integrated time delay functions when leaving the household early in the morning. A pre-requisite for the success was the intensive awareness campaign to inform the public.
2. The DNO may install storage batteries at the affected nodes. They can be charged during high power injections and decrease the voltage in this way.
3. The DER, including storage batteries, may be operated with under excitation and demand reactive power. The photovoltaic plants use IGBT converters which offer the opportunity of reactive power control. However, in LV feeders the active power control is more efficient because the resistance of 400 V cables is much higher than the reactance.

Figure 6.7a presents the related schemes with the options 1–3. The installation of a 5 kWh Lithium-Ion battery in a 20/0.4 kV transformer terminal is depicted in Fig. 6.7b.

Contrarily, if it is necessary to increase the voltage because a peak load/low generation situation occurs with under-voltage, then the three actions should be

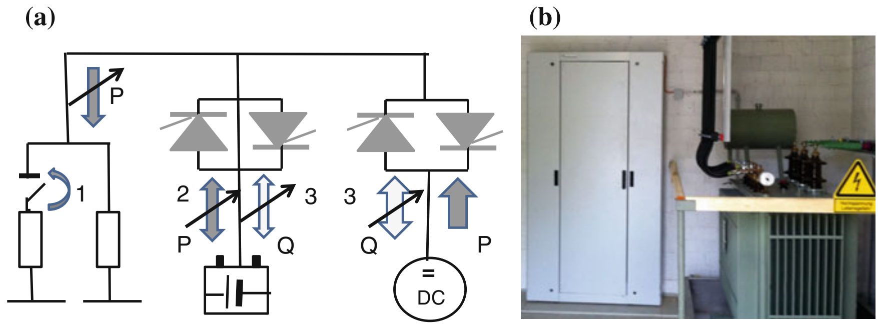


Fig. 6.7 **a** The three methods of smart voltage control, **b** Battery installation in a 20/0.4 kV terminal (*Source* HSE AG)

reversed to control the load, namely: offering higher tariffs, discharging batteries and DER operation with over excitation.

However, all of these methods require the remote reading of measurements, status indications and remote control. Communication networks have to be introduced at the distribution level for the smart distribution network operation.

6.2.2 Opportunities for Power Flow Control

Overloading of network assets may occur bi-directionally in cases of:

- weak load/strong generation situations (e.g. on a sunny day at noon in a network with large scale connection of photovoltaic units) in the direction bottom–up, or
- peak load/weak generation situations (e.g. in evening when people come home from work and simultaneously cook, wash and charge the electric cars) in the direction top–down.

The first priority of the power flow control requires the remote monitoring of the currents and/or the power flow measurements at the MV/LV transformer terminals. The power flow control may also be executed by network operations and market activities.

The network operations for power flow control consist of the monitoring of the power flows, the detection of congestions and the subsequent changing of the network topology by dislocation of the separation points in an open loop configuration depending on the loading situation and the possible congestions (e.g. rated power of transformers, feeders, switchgear).

In Fig. 6.8 an example of an opposite network configuration with two open end MV feeders between the substations A and B is presented.

Here the two extreme situations are presented. Considering the peak load/weak generation situation, the disconnection point of the MV feeder is allocated in

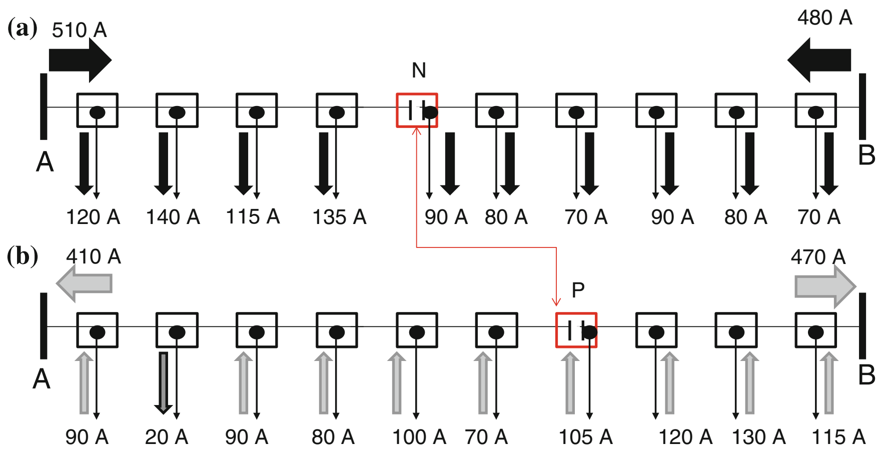


Fig. 6.8 Re-configuration of the network topology dependent on power flow conditions. **a** Strong load, weak generation, **b** Weak load, strong generation

transformer terminal N. With this assignment the peak power flow is harmoniously distributed between both feeder sections and kept below the limit for secondary distribution of 630 A.

On the other hand, under weak load/strong generation conditions with strong reverse power flows this configuration would lead to an overloading of the assets between terminal N and substation B. Shifting the disconnection point to terminal P also allows for a harmonious power flow distribution for this situation.

The switch operations have to be executed remotely from the control center. Consequently, remote controllable load break switches and communication facilities need to be established.

The market driven power flow control activities may be categorized as definite (hard) and probable (soft) methods. The definite methods are based on special contract or tariff conditions and consist of the:

- Reduction or increase of the power output of DER by using the reserve power mechanisms on the distribution level,
- Switch-off or increase of controllable loads like air conditioners in summer or heat pumps in winter, which are offered on the positive reserve power market,
- Controlled discharging or charging of storage units, including the batteries of connected electric vehicles,
- Switch-off of previously contracted load or generation in emergency situations.

Furthermore, the soft influencing of the demand by dynamic tariffs (e.g. washing with sunshine, see Sect. 6.2.1) can help to avoid congestions and the need for high investments into network enhancement.

For the switch off of dedicated loads, special interruption units are offered on the market.

Fig. 6.9 From circuit breaker to power flow management (*Source* ABB AG)

In Fig. 6.9 the patented combined LV circuit breaker/power matcher of one vendor (ABB) is presented. Thanks to the added power flow control function, the available power transfer capacity and the available power can be utilized more efficiently.

The power controller disconnects the LV feeders supplying non-priority load or generation during the times when the power transfer capacity of the MV feeder or the transformer terminal is at the upper limit and connects them again when the stress situation has been overcome.

Such a unit may contain the needed measurement functions to analyze the voltage quality parameters.

Furthermore, the complete protection functions required at the distribution level (see Chap. 3) are embedded and may be parameterized using the integrated touch panel.

The described unit also offers communication facilities for the data exchange with the control center. The unit is designed to be directly integrated in several types of LV switchgear and energy management systems.

6.2.3 Automated and Remote Controlled Recovery of Supply After Fault Trips

As demonstrated in Sect. 4.6.2, the fault location and elimination in MV networks is traditionally executed manually by driving along the faulted feeder and checking the short circuit indicators of the MV/LV transformer terminals (Fig. 4.37). The average time of supply interruptions after faults in the local distribution networks of Germany is approximately 1 h. This time can be significantly reduced if the transformer terminals are equipped with remote controllable switches and remote

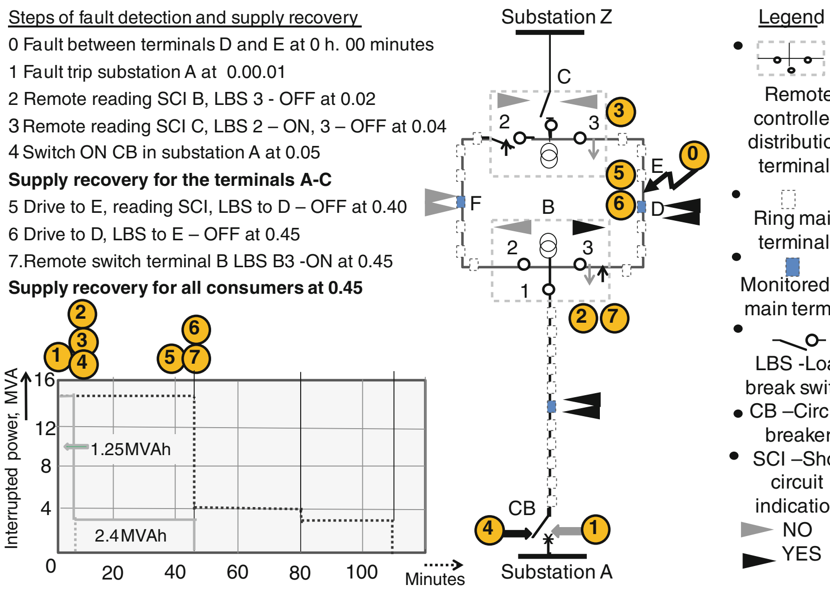


Fig. 6.10 Example of fault location and supply recovery in a 20 kV network

readable short circuit indicators so that the fault elimination and supply recovery could be executed automatically.

However, a partial enhancement is currently seen as the most appropriate solution to achieve the best ratio between the investment expenses and the achievable improvements.

Figure 6.10 demonstrates an example of how this improvement is reached. The presented network scheme and the fault location are identical with Fig. 4.37.

But, in Fig. 6.10 the distribution terminals B and C are remote controlled and monitored, and some ring main terminals in between are remote monitored.

The following average reliability parameters were defined for this example using the traditional approach of fault elimination:

- 61.5 min of supply interruption,
- 15.35 MVAh energy not delivered in time.

Now, the steps for supply recovery are demonstrated for the case of remote monitoring and control of terminals B and C and the remote monitoring of terminal D.

After the short circuit appeared between terminals D and E the protection trips the circuit breaker in substation A (1) of the faulted feeder and the supply of 15 MVAh power is interrupted.

The control center can detect the fault location at the right feeder between terminals B and C by remote reading of the short circuit indications in terminal B. Consequently, the normally connected right load break switch 3 in terminal B will be switched-off remotely (2) and the circuit breaker in substation A can be switched-on (3). Furthermore, the switching operations to connect the consumers of terminal C to the left feeder (C-F-B) may be executed immediately based on the shown short circuit indications for terminal C.

As a result of these switching operations the supply recovery is achieved for the majority of the interrupted consumers (11,400 kVA) within 5 min instead of 45 min when manual checks are required.

3,600 kVA power remain interrupted at the right feeder, which is still disconnected between terminals B and C.

The remote reading of the short circuit indicators in terminal D showed that the fault went through it. Using this information, the emergency staff can access terminal E (behind D in direction C) only after the duration for driving of 40 min. The manual reading of the short circuit indicators in E shows that the fault is located between terminals E and D.

The load break switch in the direction D (5) will be switched off.

Finally, it was remotely observed that the short circuit went through terminal D. After accessing terminal D within 5 min, the load break switch in the direction C is switched-off (6). The fault is now separated.

After the remote switching-on of the right load break switch 3 in terminal B (7), the last of the consumers (3600 kVA) can be supplied again after 45 min.

Applying this approach the

- average interruption duration is shorted to 14.6 min and
- the energy not delivered on time amounts 3.65 MWh.

Consequently, the remote control and/or supervision of a limited number of terminals (e.g. 14.3 % in the considered part of the network in Fig. 6.10) allows for

- 4.2 times reduction of the average interruption time and
- 4.3 times reduction of the energy not supplied in time.

Considering all possible fault locations at the feeders between the substations A and Z in the way demonstrated above, the average interruption duration can be calculated and amounts to 12.1 min.

The average interruption duration after faults in the medium voltage networks of Germany is stated in the statistics of 2010 with 63 min.

Applying the above described innovations, the average interruption duration could be reduced from these 63 to 12.1 min in the considered network part A–Z.

That means this parameter of the reliability could be improved by a factor of 5 by the described partial enhancements of the MV transformer terminals.

Taking into account the probability of faults with supply interruptions of 0.18/a in this network part, the SAIDI will be 2.18 min/a.

This is 7.3 times better than the overall system average interruption duration index SAIDI in Germany with 16 min/a, as demonstrated in Fig. 4.33.

6.2.4 Enhanced MV Protection Concepts

6.2.4.1 The Changing Protection Conditions

The connection of DER in MV distribution networks provides a significant impact on the protection behavior.

Impact on the protection selectivity
The DER acts as the source of an additional short circuit current $I_{sc\ DER}$ at the network connection node. As a consequence, at the network connection node NC the voltage increases and the voltage drop along the feeder from the connection node to the fault location increases as well, as shown in Fig. 6.11

This effect causes a reduction of the measured short circuit current and an increase of the voltage at the coupling node C. Consequently, the protection measurements are not correct.

Both possible main protection functions are affected:

- The overcurrent protection measures a lower short circuit current and the overcurrent pick-up may be prevented or delayed.
- The distance protection measures lower short circuit currents and higher voltages. The V/I or the impedance criteria are incorrectly recognized; the pick-up may be prevented or delayed.
- The fault locator cannot measure the correct fault distance.

In general, the open end feeder topology does not unmistakably define the short circuit direction—the direction may become bi-directional in a similar way as the power flow.

The un-directional protection principles no longer operate reliably and securely. They have to be replaced by directional protection principles.

Furthermore, the traditional (mostly mechanical) short circuit indicators may also indicate wrong messages. The short circuit indicators have to become digital intelligent electronic devices (IEDs) to perform the proper indications under the new conditions.

Reverse short circuit currents
The reverse short circuit direction also has an impact on the feeding network as shown in Fig. 6.12. It is necessary to disconnect the power flow from the DER during faults in the feeding networks.

Stable islanded operation
In accordance with the increasing share of DER feeding into the local distribution networks the operation of island networks has to be reconsidered. Currently, the appearance of islanded networks is not desired in Central Europe and has to be recognized and avoided.

The standard [3] requires that DER need to continue the connected operation within a frequency interval of 47.5–51.5 Hz.

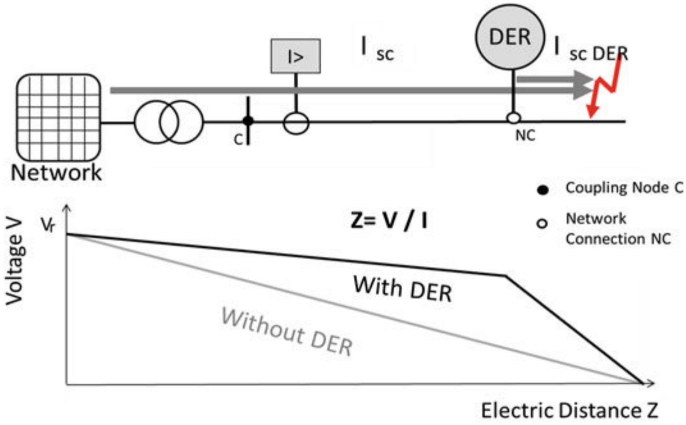
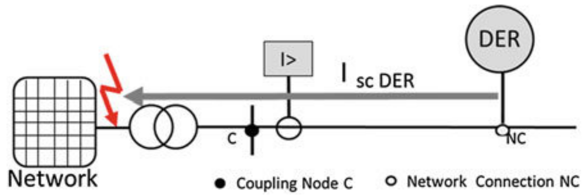


Fig. 6.11 Change of the protection conditions due to DER connection

Fig. 6.12 Short circuit contribution of DERs to faults in the feeding networks



Under such conditions it is possible that after a disturbance stable islanded networks may continue the power supply. The islanding can improve the reliability of the supply in general and should be supported by the prospective network connection rules. However, based on the local conditions the protection and control schemes have to be adapted in a way that the islanding will be recognized and the control system will be transferred in a mode which ensures a stable island operation.

Impact on the auto-reclosing function

The DERs are obliged to continue their power injection during voltage sags and short circuits for voltage stabilization and short circuit provision [4]. However, if the auto-reclosing function is foreseen after a fault trip, the DERs have to be disconnected in the trip moment. Otherwise, the DER may feed the fault arc and the extinguishing of the arc may be prevented. In this case the auto-reclosing would be unsuccessful.

Furthermore, the un-synchronous coupling of networks by auto-reclosing has to be prevented. Therefore, a synchronism-check needs to be used in the MV protection schemes.

Impact of the DER connection scheme

Traditionally, the voltage source is provided by synchronous generators. Consequently, the short circuit currents are significantly higher than the rated currents.

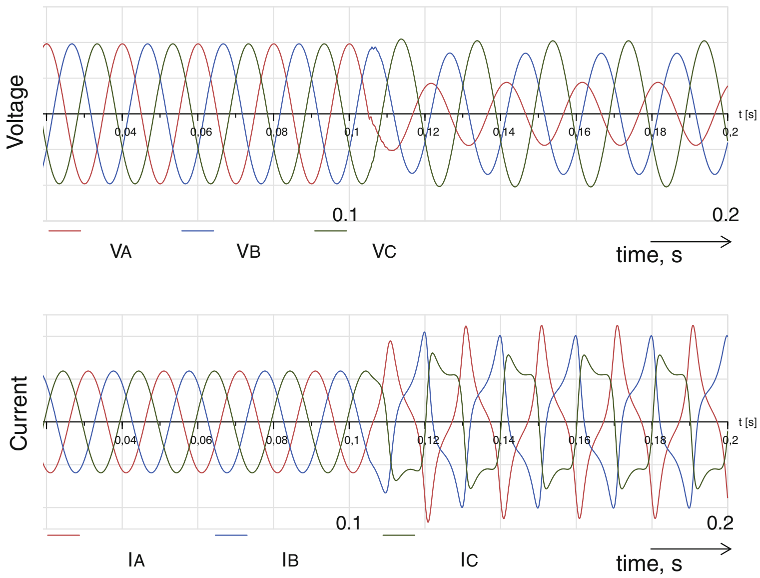


Fig. 6.13 Fault current contribution of DER feeding via converter a single phase earth fault (*Source* W. Gawlik, TU Vienna)

They consist of a 50 Hz wave and a transient exponentially declining DC contribution. Harmonics may be neglected.

DERs based on small synchronous generators provide a much lower inertia than the traditional generators do, even when referring to the generator rating. In the context with the lower inertia and the different impedance ratios, significant frequency deviations and an un-definite behavior of the DC contribution may happen during the fault ride through period. The protection parameters have to be adapted accordingly.

Otherwise, if the network access is performed via power electronic converters the short circuit current form is influenced by the embedded control mechanisms and the capacity of the valve modules.

The control and protection system of the modules may cause transient short circuit currents which are far away from a sinus wave. Figure 6.13 presents such a distortion in the case of a single phase short circuit when the control scheme is set to maintain a constant active power output.

Investigations of these phenomena are currently ongoing in order to develop appropriate calculation algorithms.

Mostly, the DERs connected via power electronic schemes may be considered as current sources. They inject an active current against the network voltage. In the case of short circuits, a reactive (capacitive) current in the range of the rated current may be injected and supports the voltage if an appropriate voltage level remains at the connection node. However, if the connection node is close to the short circuit location, a driving voltage is not available. A short circuit power may be completely missed or the short circuit curve may not contain a 50 Hz contribution. The current protection principles cannot handle such behavior in a definite way.

Furthermore, DERs have to support the network voltage during and after faults. The control schemes of the valves have to react to the fault appearance within milliseconds and transfer their behavior from normal operation to voltage support. This transfer deeply depends on the internal control schemes and the structure of the DER. The transfer processes are vendor and type specific. They cannot be described in general and thus it is hard to consider them for the protection algorithms. However, the protection has to trip during this transient transfer period of up to 60 ms.

The protection system permanently measures changing, partly non-linear conditions during this period. Malfunction and over-function of the protection have to be prevented by special investigations.

Furthermore, the protection system has to differentiate between the normal and the faulty conditions in a selective and secure way. This is difficult if only low short circuit currents of the converter connected DERs are measurable. The converters are not able to provide significant short circuits like the rotating generators can. Accordingly, the pick-up setting of the protection has to be selected low.

On the other hand, it can happen that the simultaneous maximum power injections from a significant number of DERs lead to the exceeding of the protection pick-up setting and cause a wrong trip.

This contradiction between the DER capabilities and the protection scheme may limit the efficient application of the installed and connected DERs. The adaptive protection principle (see Sect. 5.3.3) with changeable settings depending on the DER power injections may help to solve this issue.

Increasing importance of the thermal overload protection

The thermal overload protection is normally available as an enabling function of the digital protection IEDs used in distribution networks. However, this function is often not activated. In accordance with the traditional operation rules overloads are recognized by the load flow monitoring in the control centers. In the event of thermal overloading the dispatchers receive alarms and provide actions to reduce the excessive load flow (see Sect. 6.2.2).

The higher usage of the power transfer capability of the network assets and the quickly changing loading conditions may request the activation of the thermal overload protection function to avoid damages and disturbances in the network. The integration of new parameters like temperature, wind speed and global radiation into the overload protection algorithms will be helpful for an efficient application.

6.2.4.2 Adapted Protection Schemes in Distribution Networks with Connected DERs [4]

Traditionally, the protection schemes of MV distribution networks were installed at the coupling node of the MV feeder and the busbar of the feeding substation. In some cases, the distribution and industrial terminals were also outfitted with protection units and circuit breakers.

Nowadays, the integration of DERs into the distribution network operation requires that the DERs have to be equipped with their own protection schemes at the connection point. Two different connection conditions have to be considered:

1. Coupling the DER directly to the busbar (C),
2. Network access (NA) at a connection node within the MV or LV network.

Coupling the DER directly to the busbar
A short-circuit protection of the DER is required for clearing short-circuits if the DER is coupled to the busbar. In addition, it serves as back-up protection in the event of faults within the generating units and in the DNO's network. A distance relay with V–I pick-up criterion is recommended for this purpose.

The short-circuit protection devices of the DER operator must be integrated into the overall protection concept of the network operator. For this reason, the protection scheme shall be agreed upon with the network operator during the planning stage. The protection equipment settings are specified by the network operator as far as they have an impact on his network.

The protection schemes at the network connection act upon the circuit breaker at the coupling node and disconnect the DER in the event of internal faults.

Additionally, the following devices are required as primary protective disconnection equipment at the busbar coupling node:

- reactive power/under-voltage protection $Q \rightarrow$ & $U<$,
- instantaneous and definite time over-voltage protection $U \gg$ and $U>$,
- under-voltage protection $U<$,
- under-frequency protection $f<$,
- over-frequency protection $f>$.

The protective disconnection devices act upon the circuit breaker at the coupling point or on the coupling switch.

Through the reactive power under-voltage protection ($t\ Q \rightarrow$ & $U <$) the DER is disconnected from the network after 0.5 s, if all three line-to-line voltages at the coupling node are below 0.85 Uc (logical "AND") and if the generating plant simultaneously extracts inductive reactive power from the DNOs network. It is expedient to use the positive sequence component for the determination of the reactive power.

This protection serves to monitor the behavior of the generating plant satisfying the system needs after a fault in the network. Generating plants that impede the restoration of the network voltage through demand of reactive power from the network or due to a lack of voltage support are disconnected from the network prior to achieving the time setting of the protection.

The voltage protection function is to protect customer plants against inadmissible voltage conditions in the case of isolated operation, and to ensure a disconnection of the DER after faults occurrence in the network. For this purpose, under-voltage protection devices must also respond to asymmetrical faults.

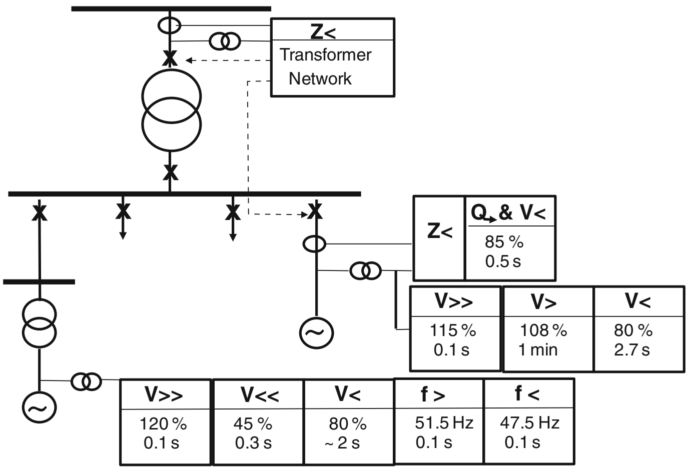


Fig. 6.14 Protection schemes and recommended settings for DER connection [4]

Therefore, the pick-up criteria of the three phase measuring elements of the under-voltage protection shall be performed in accordance with a logical "OR".

The frequency protection measures the frequency of a phase to phase voltage. At frequencies between 47.5 and 51.5 Hz, automatic disconnection from the network is not permissible due to the requested frequency support. However, if the frequency falls below 47.5 Hz or increases over 51.5 Hz, the DER must be automatically and immediately disconnected from the network.

Network access (NA) at a connection node
The function of the protection schemes is to disconnect the DER from the network in the event of disturbed operating conditions in order to protect the generating plant and other customer plants connected to the network. Examples are network faults, unstable islanding, or a slow recovery of the network voltage after a fault. The plant operator is personally responsible for a reliable protection of his plants.

The protective disconnection devices at the generating units can be connected on the high or on the low-voltage side of the DER transformer.

The following functions of the protective disconnection equipment shall be realized:

- under-voltage protection U $<$ und U $\ll$,
- over-voltage protection U $>$ und U $\gg$,
- under-frequency protection f $<$,
- over-frequency protection f $>$.

The function principles are equal to those described above

The protection schemes in accordance with the network integration of DER and the recommended settings are presented in Fig. 6.14.

When disturbances occur in the overlaying network (Fig. 6.9 the problem of the reverse short circuit current flow) can be solved by the installation of a distance protection system in the transformers' feeder at the higher voltage side, as shown in the Fig. 6.14.

The distance protection trips the transformer if the measured fault current direction is top–down. Otherwise, if the fault current direction is bottom–up, the protection has to trip all outgoing feeders with connected DER at the lower voltage busbar.

6.2.4.3 Phasor Measurement in Distribution Networks

The application of phasor measurement units (PMU, see Sect. 5.3.4) at the local distribution level is also being globally considered since the CIRED conference 2009 in Prague [5].

The main application areas for PMUs are seen as:

- Central voltage controller in distribution networks,
- Master power controller for the DER connection by power electronic converters,
- Voltage quality monitoring,
- Islanding detection,
- Synchronism check for re-connection of islanded network parts,
- Shaping awareness for system stability with the visualization of phasor measurements.

The installation of PMUs in the distribution networks as shown in Fig. 6.15 requires high expenditures which are not in line with the traditional cost saving philosophy in the distribution level.

Therefore, the introduction of PMUs in the distribution level is still very limited and needs a cost–benefit analysis. A broader investigation of the PMU application in the local distribution networks has been executed in one project [6], and valuable experience was gained within these investigations.

In Fig. 6.16 the frequency and voltage courses measured during a day at the 10 kV and at the 0.4 kV level of a connected distribution network are shown.

It can be seen that the frequency and voltage deviation vary in both measurements, which demonstrates the strong impact of the DERs connected near to the measurement points.

The opportunity of the voltage quality monitoring is presented in Fig. 6.17.

Voltage dips up to 60 % of the rated voltage can be seen in the left diagram. The right diagram shows rapid voltage variations of <1 % within milliseconds.

The recognition of an islanded network and the monitoring of the re-synchronization process are demonstrated in Fig. 6.18.

The presented examples show the technical opportunities of the PMUs in the distribution level. The broad application, however, will only be possible if the technical benefits create economic benefits.

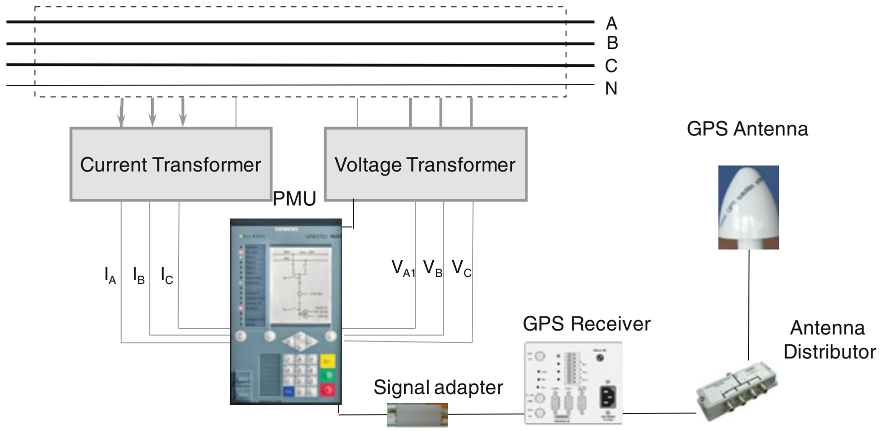


Fig. 6.15 Installation scheme of PMUs

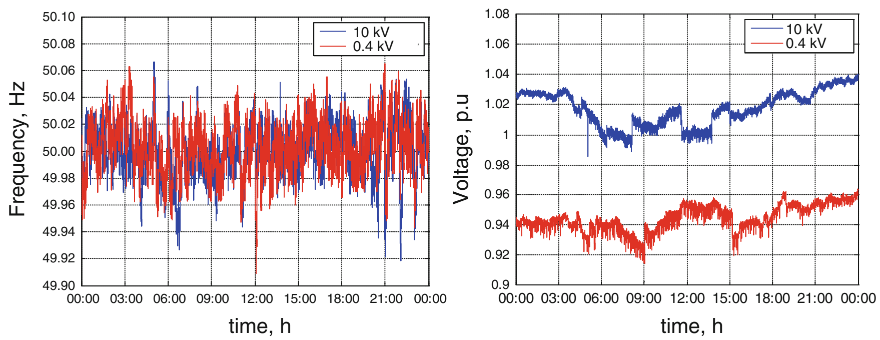


Fig. 6.16 Frequency and voltage deviations during a day at the 10 and 0.4 kV levels

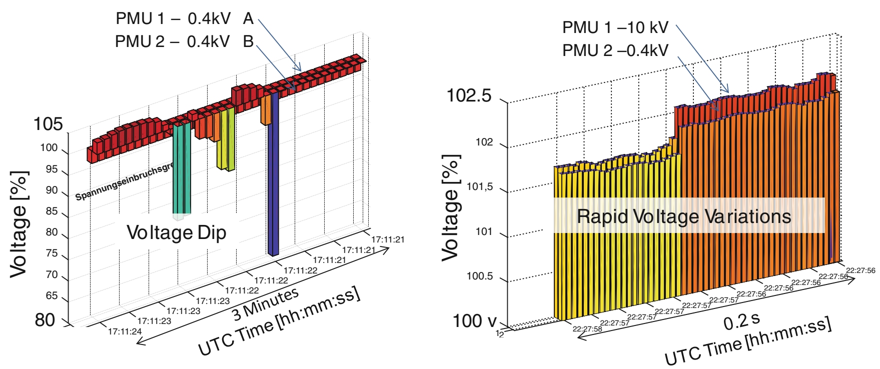


Fig. 6.17 Experience of voltage quality measurements by PMUs

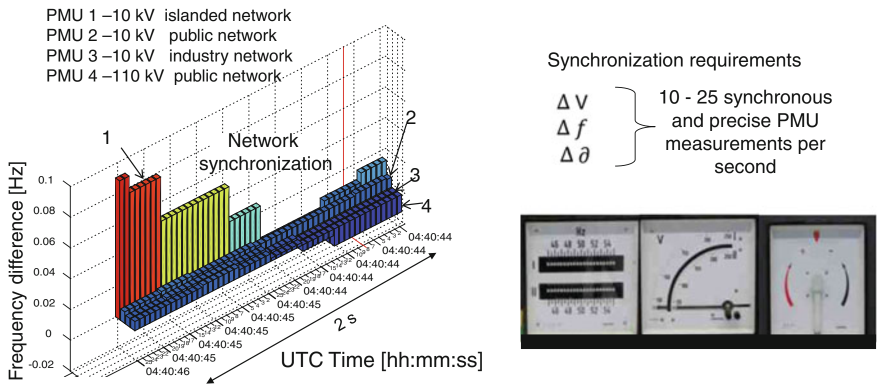


Fig. 6.18 Frequency monitoring during the re-synchronization of an islanded network

6.2.5 The Economy of the Smart Grid Enhancement in Distribution

A distribution network operator has to operate some thousands of transformer terminals.

The enhancement of such a large number of terminals for controllability requires a significant investment. But, is it economically useful to enhance all transformer terminals?

In this sense, a new optimization task for the network planning appears by selecting:

- the terminals which require enhanced voltage control,
- the terminals which require enhanced power flow control,
- the terminals which provide the best benefit–cost ratio for reliability improvement.

The result of the optimization will be different for various distribution networks and strongly depends on the local conditions.

For the 20 kV network enhanced in the framework of the European project Web2Energy [1] it was shown that all three selection criteria are common for ~85 % of the selected terminals to be enhanced.

That means, 15 % of the selected terminals require only one or two criteria (mostly voltage and power flow control). About 85 % of the terminals are suitably located for the speeding-up of the fault elimination and they also require the advanced voltage and power flow control.

A special benefit/cost index (BCI) was introduced and investigated for the whole supply area with about 4,200 transformer terminals.

In the result of this investigation it was shown that the optimum enhancement volume can be reached with between 13–20 % of the terminals, as demonstrated in Fig. 6.19. For the considered network that means: about 600 transformer terminals

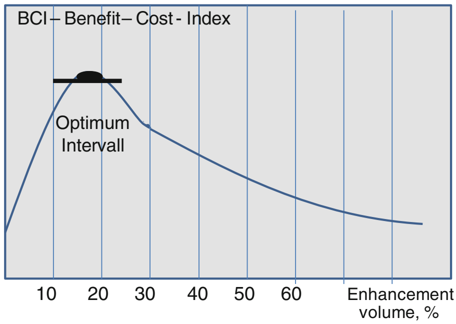


Fig. 6.19 Benefit/cost index in relation to the share of enhanced terminals

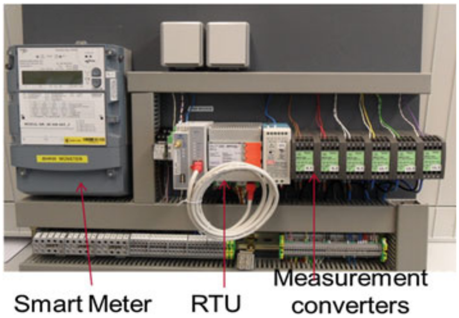


Fig. 6.20 The IED compartment (*Sources* HSE AG)

need to be enhanced with remote control facilities to reach the optimum ratio of benefits and expenses.

There are three effects influencing the benefit–expenses ratio:

- Volume effects in the interval 200–800 decrease the expenses per terminal,
- Less than 10 % enhancement volume does not create significant improvements of the reliability and not all congestions are covered,
- Over 20 % (>1000 terminals) the benefits grow only weakly but the expenses grow in proportion to the number of enhanced terminals because of a nearly constant contribution of volume effects.

In conclusion it can be stated that a Smart Grid does not require the complete introduction of new technologies in all network parts. However, the Smart Grid approach does require the economic intelligent weighting of the efficiency.

A detailed analysis of the economy of the network enhancement was performed based on the experiences of the project Web2Energy [2]. In this project 9 terminals were enhanced for remote control and supervision by installations of:

- A compartment of intelligent electronic devices (IEDs) shown in Fig. 6.20 with
  - a remote terminal unit (RTU),
  - a smart meter,
  - measurement converters.

Fig. 6.21 Digital short circuit indicator

Table 6.2 CAPEX for the smart grid enhancement of 20 kV terminals in BCU

Configuration	IEDs	Link to WAN	Switch-gear	Human efforts	Share for CC	Sum
1 terminal of 9	0.06	0.12	0.16	0.25	0.19	0.78
1 terminal of 600	0.042	0.06	0.124	0.23	0.105	0.56
600 terminals	25.2	36	74.4	138	63	336.6

- Remote readable short circuit indicators (Fig. 6.21),
- Switchgear enhanced for remote control,
- Communication links to a Wide Area Network (WAN).

Additional efforts were required to adapt the control center to the new functionality.

Table 6.2 presents the overview of the Capital Expenses (CAPEX) expressed in Basic Cost Units (BCU) where one BCU is equal to the investment for one ring main terminal.

Table 6.2 demonstrates the impact of volume effects, which is different for the various technologies and highest for human efforts.

It was detected that the majority of the expenses is caused by human efforts for:

- Engineering and design,
- Development of utility standard solutions,
- Installations and mounting,
- Approvals, tests and commissioning.

The enhancement costs are high and reach 56 % of the investment of a ring main terminal when considering the volume effects for 600 installations.

Nevertheless, the investigation has shown that a return of investment of the overall CAPEX of 336.6 BCU within 10 years may be achieved if the network charges of all network users such as households, trade, business, administration, industry and power plants are increased by 6.5 %.

This is a reachable target if a bonus for the improved reliability of supply is introduced.

6.3 Pillar 2: Flexibility by Virtual Power Plants: Smart Aggregation

6.3.1 Basics of Virtual Power Plants

The growing shares of volatile renewable power in the annual electricity consumption require the introduction of new methods to compensate for fluctuations and prediction errors (see Sect. 5.3.2). The aggregation of diverse DER and the coordination within a virtual power plant (VPP) builds the pre-requisite of the cellular approach of schedule management as described in Sect. 5.3.2.4.

The main task of the VPP is directed to the electricity market and contains the following basic tasks:

- Forecasting, balancing and coordination of all aggregated assets like generators, storages and controllable loads including the highly volatile wind and photovoltaic generation,
- Completion of the day-ahead schedules of the whole VPP and sale of the scheduled energy on the electricity market,
- Online monitoring of the electric power production and estimation of schedule deviations,
- Decision making in an optimization process about the use of its own resources (control of the power generation and/or Demand Side Management DSM to adapt the controllable loads) for the compensation of fluctuations or for paying the charges for the use of external reserve power provided by the control area manager.

In this way a VPP may provide the same behavior as the traditional power plants do.

Figure 6.22 presents the processes described above.

The participation of independent power producers, consumers and storage operators in a VPP requires a voluntary base offering economic benefits for all stakeholders.

The first pre-requisite for this is the obligation of all power producers to participate in the balancing process and to take over the responsibility for schedule deviations.

In this sense, the VPP can provide the balancing services to the power producers for significantly lower expenses than the single producers can.

The DERs normally sell electric energy to the day-ahead market. They are not able to participate on additional markets. The VPP has the opportunity to maximize the earnings by an optimized participation on various markets.

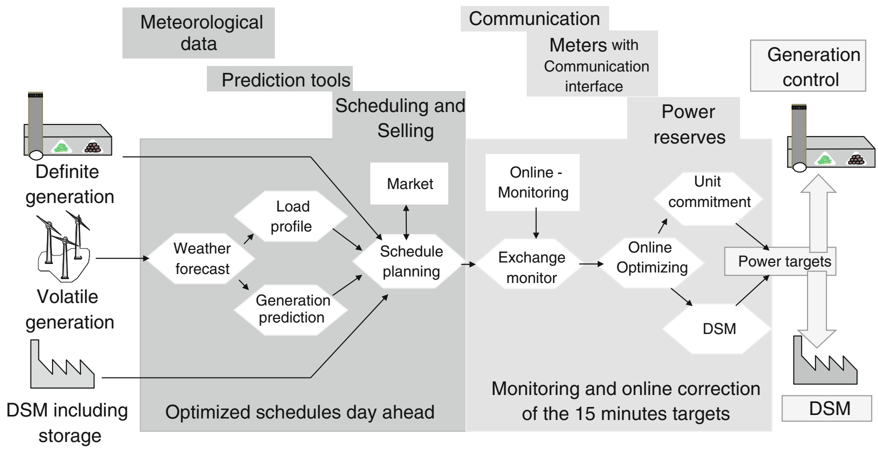


Fig. 6.22 Basic principle of the VPP management

The optimization goal and mathematical target function is to maximize the benefit by using all possible market indications taking into account network fees and must run requirements due to heat or electric power:

- Electric energy day-ahead and intraday markets,
- Reserve power markets,
- Ancillary service provision to the DNO,
- Fuel costs,
- Charges for network use,
- Heat energy market (by optimized operation of Cogeneration of Heat and Power (CHP) plants on the electric energy market and storage of heat energy which is not required in periods with high electricity prices),
- CO_2—Certificate trade.

The aim is to achieve benefits for each VPP component which a single asset could not address alone. For this, the VPP coordination is based on optimization tools. The inputs and outputs of such an optimization tool are presented in Fig. 6.23.

The establishment of virtual power plants requires the installation of a control center which is linked with the participating stakeholders by communication networks. The VPP needs online access to the precise weather forecasts for the region and to the various markets serving the energy supply.

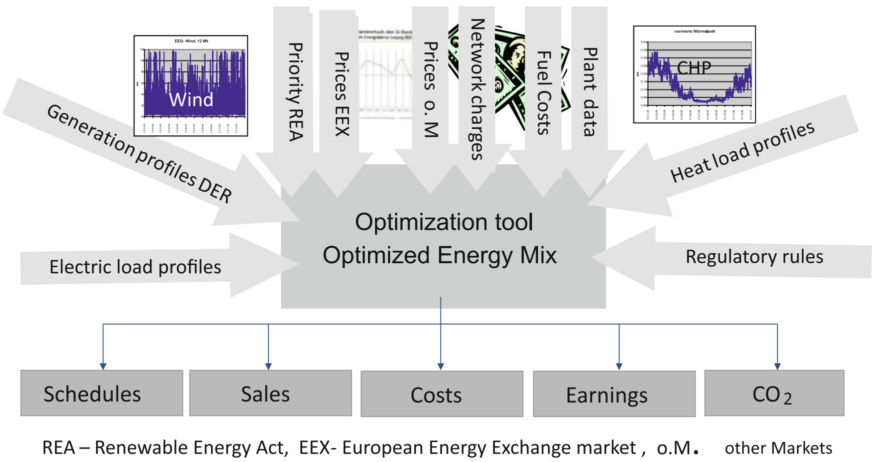


Fig. 6.23 Optimization of the VPP market activities

6.3.2 Demand Side Management: The Role of Storage and Controllable Loads

The adaptation of the demand to the available power generation will gain importance in the environment of fluctuating power generation. The demand has to be integrated into the power system management in general. The Demand Side Integration (DSI) has two aspects:

DSM—Demand Side Management is the active switching of load either on a contractual basis with the VPP provider or based on offers on the reserve power market if the offered switchable power corresponds with the requirements accordingly Table 5.1.

DSR—Demand Side Response is the impact on the consumer behavior by dynamic tariffs coupled with means to achieve consumer awareness regarding the changing tariffs, the current demand and the related costs. However, the DSR depends on the willingness of the consumers to shift intensive load into periods with low tariffs. The DSR outcome can be estimated by predictions only and cannot be applied to perform the VPP function. DSR will be considered in Sect. 6.4.

The potentials of DSM were investigated in several studies and projects considering the residential consumers, commercial sector and the industry separately for summer and winter seasons. The following considerations are based on the studies [1, 7–9].

The DSM potentials shown in Fig. 6.24 may be reached if a benefit can be offered to the related actors.

The main potential is seen in the electric heating or cooling processes where a shifting of the load is possible without loss of convenience because of the high inertia of the thermal energy. The heating and cooling processes have a significant contribution in the energy balance of the branches presented in Fig. 6.24.

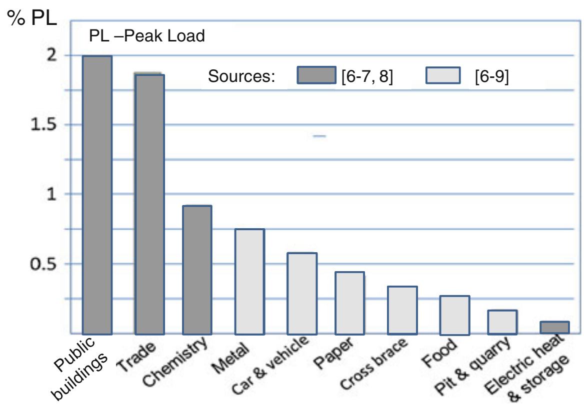


Fig. 6.24 The DSM potential evaluation in an industrial country

The highest potential can be provided by public establishments like administrative buildings, malls, swimming halls, cinemas, restaurants, hotels and others. An example of how this DSM potential can be managed is shown in Fig. 6.25.

The VPP evaluates the optimum demand intervals for the six involved DSM groups and sets green and red traffic lights which can be also used by home automation facilities for the controlling of household devices in accordance with their settings.

To the DSM groups belong:

- in general the cooling of deep freeze stores,
- in winter time heat pumps, electric heaters with thermal storage capability,
- in summer time air-conditioning groups in malls ore administrative buildings.

In principle, the demand during periods of weak load in the night will be used to supply all of the DSM groups. Normally, the DSM groups require an additional electricity supply during the day to keep the temperature for cooling or heating in the required bandwidth.

The VPP controls the bandwidth and decides in which intervals of low electricity prices the DSM group will be switched on during the day.

Besides the application of heating and cooling processes for DSM some industries may offer DSM capabilities in the sense of short time supply interruptions for selected production lines. For example, an aluminum factory is able to interrupt the supply without causing damages in the production processes. The manufacturers can offer such DSM potential to the VPP mainly for use as primary reserve power. In this case, the manufacturer continuously receives additional earnings for the primary reserve power provision which is requested only in emergency situations.

Furthermore, the fluctuations of the volatile DER can be compensated by electric and thermal storage units.

Electric storage capabilities will play a significant role in the Smart Grid environment. Electric storage providers can act on the electricity market by benefitting

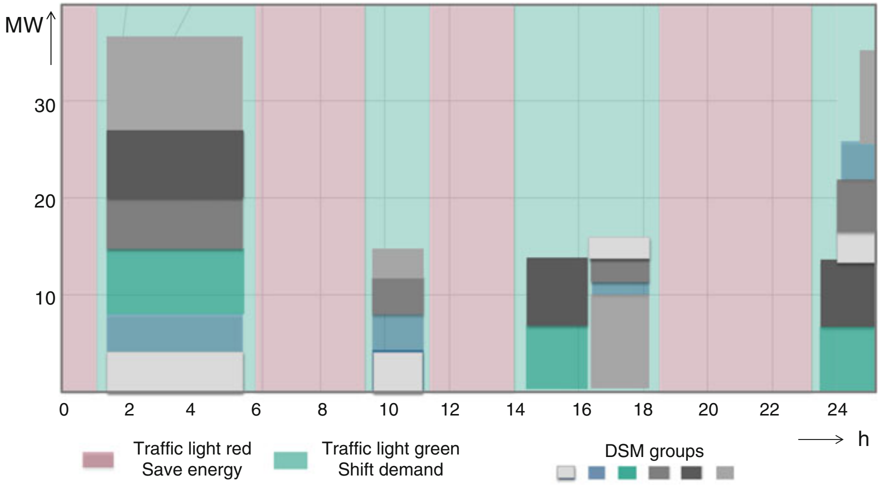


Fig. 6.25 Demand side management with six DSM groups

from the spread of electricity prices (charging in low price periods, discharging in high price periods) and on the markets for reserve power within a VPP.

Thermal energy is often produced by CHP plants. The European SET plan supports the increase of the CHP contribution in the annual electricity consumption from 18 % in 2020 to 21 % in 2030 (see Table 1.1). The application of thermal storage capacities in combination with a CHP allows for a much higher flexible operation on the electricity market. Furthermore, the thermal storage is currently much more cost efficient than the electric storage.

All these aspects have to be considered in the optimization algorithms of the VPP.

In [10] the optimization of the VPP activities is described based on a case study for a supply area with 40 MW peak load, 16 MW definite generation, 16 MW volatile generation, 8 MW DSM and 8 MW × 5 h electric storage capacity.

Figure 6.26 presents the load profiles and their coverage for two different days—one with more, the other with less power generation by the volatile DER wind power and photovoltaic plants.

In these diagrams it is shown that the maximum definite distributed generation and the discharge of the electric storage units is shifted as much as possible to the peak load intervals where the prices on the markets are high. These activities cause two effects:

- The peak load is significantly reduced by the discharging of the storage units, as shown in the diagram.
- The importation from the external network is significantly reduced in the peak load period by the internal generation, which is accompanied by a significant reduction of the network charges.

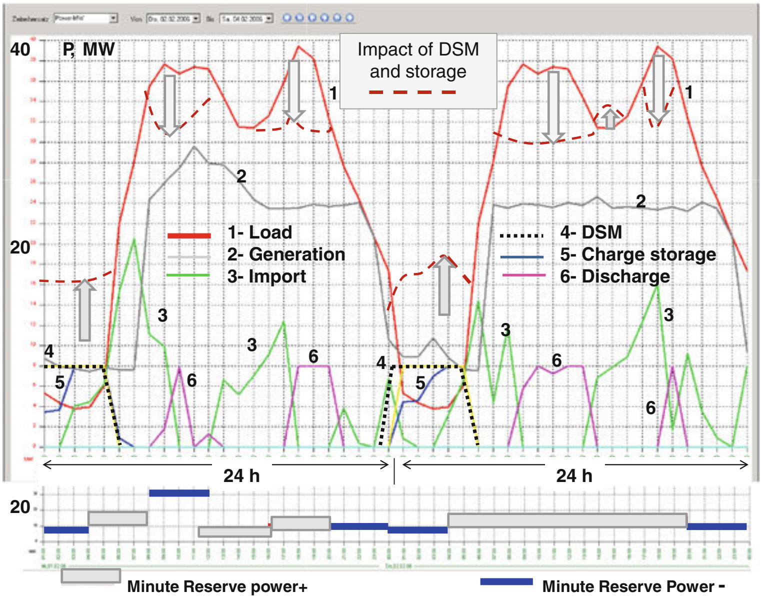


Fig. 6.26 Load profile coverage and provision of minute reserve power by a VPP [10]

On the other hand, during the weak load time the storage units are charged and the DSM groups are switched on. These actions increase the demand of the supply area when the prices for electricity are low.

Consequently, the load profile of the supply area is significantly harmonized by the control impact of the VPP. Furthermore, the VPP uses the readiness of its participants to offer and sell reserve power, thereby providing additional sales and earnings.

In this sense, additional business models can create win- win situations for all participating stakeholders.

6.3.3 Business Models of Virtual Power Plants on Prospective Markets

Various business models of a VPP were developed and considered in a supply area accordingly [1].

Due to the strong volatility of the market conditions the stability of VPP benefits will be higher as it becomes possible to apply more business models.

The overview of the investigated business models is presented in Table 6.3.

Table 6.3 Possible business models of VPP providing additional value

Business model	Function
BM 1	Reduction of the balancing deviations
BM 2	Additional sales income for energy/multi-commodity optimization
BM 3	Peak load reduction/avoided network charges
BM 4	System services: Reactive power and voltage control
BM 5	Sales Intraday Market
BM 6	System services: Sales positive Reserve power
BM 7	System services: Sales negative Reserve power
BM 8	CO_2—Certificate trade (Maximum use of renewables)

BM 1—Balancing group deviation/minimizing imbalance costs

It is the task of the balancing group responsible party to balance the consumption and generation within their balancing group in time steps of 15 min. Actually, this has to be done the day ahead and described by a schedule. Due to prediction errors and unpredictable outages of generators, deviations between the real situation and the schedule predicted the day before may cause imbalances. These deviations/imbalances result in charges for the balancing group responsible party in proportion to the volume of deviations in each 15 min time step.

The business model BM 1 is used to minimize these deviations during the day, based on a short term forecast and the knowledge of the actual load and generation situation. The Fig. 6.27 shows the typical deviation of the suppliers balancing group during one year.

The deviation costs on the real market vary significantly (Fig. 6.28 shows an example). These costs may be significant and exceed 300 €/MWh.

The task of the VPP within business model 1 is

- to observe the deviations and the related costs in real time,
- to optimize the ratio between the use of own resources for compensation and the provision of the external payment.

If the deviation costs are low, it may be more expensive to correct the internal schedule than it is to pay the deviation costs.

BM 2—Additional sales income for energy/multi-commodity optimization

In contrast to the business model of minimizing the balancing group deviation costs, here the general and day-ahead planned economical use of the available producers, controllable loads and storages is considered. The potential of this business case is based on the thermal and electrical storages, which allow producing electrical power during low fuel cost times or high spot market prices for electricity and the best economical load distribution to the generators. By applying the electric storage, the excess of power from RES can be stored during periods with low spot market prices and a high availability of power. The stored energy can be sold later when the prices go up. By applying thermal storage opportunities, a CHP plant can be shut down if the electricity market price is low and the requested heat power is delivered from the storage. Positive reserve power can be

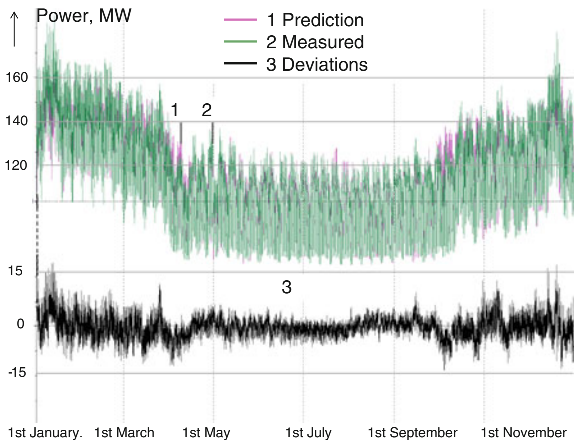


Fig. 6.27 Balancing group deviations

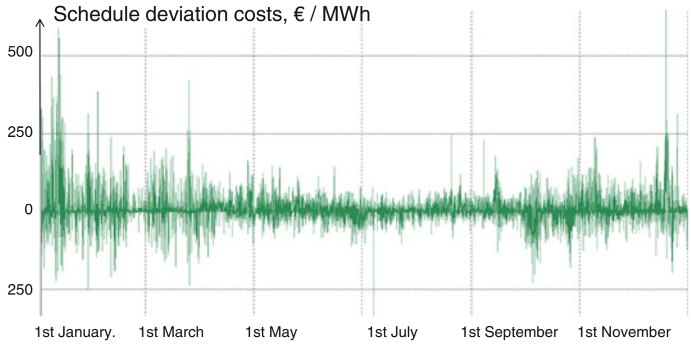


Fig. 6.28 Balancing group deviation costs over one year

offered during the shut- down or the restricted production time. If heat is stored the CHP plant can offer negative reserve power. Otherwise, if the electricity price is high the CHP plant can offer a maximum of electricity production behind the rated power (see Fig. 5.22 in Sect. 5.2.6) and store an excess of heat energy.

Consequently, the heat storage allows the flexible market participation of the CHP plants and it becomes possible to optimize in this way the sales income by "multi-commodity optimization".

BM 3—Peak load optimization

The DNO has to pay a network user fee for the highest 1/4 h-power peak of the year to the overlaying network operators (Regional distribution operator, TSO).

The VPP is able to lower this peak and to keep a set threshold by active load and generation management. In Fig. 6.29 below, the overall load of the electrical grid, displaying the forecast, the real load and the correcting influence of the VPP is shown.

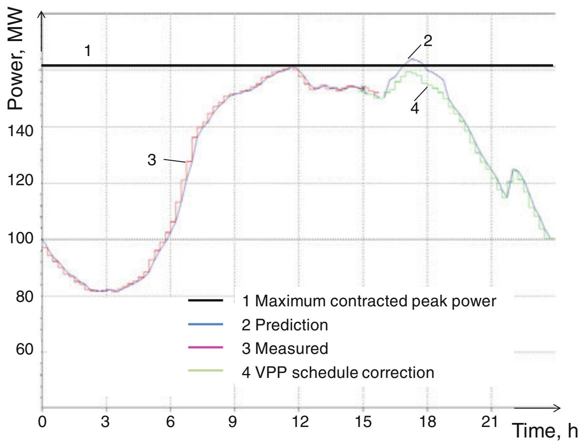


Fig. 6.29 Peak load optimization

In this example the VPP lowers the predicted power demand (4) to prevent the peak violation. Without this correction the forecasted load (2) will violate the threshold value (1). The current load values (3) are shown as additional information on the diagram.

BM 4—Voltage control/Reactive power balance

A DNO is allowed to use a specific range of reactive power as load or injection from the TSO. If the reactive power balance exceeds these limits additional network charges have to be paid. Single wind farms that are connected to the 110 kV network by MV cable lines of some tens of kilometres of length may inject a huge amount of reactive power into the overlaying network in periods of low wind. The charges required by the network operator for the take-over of the reactive power may reduce the earnings of the wind farm by as much as 20 %.

Business model 4 is directed to avoid these costs by controlling the reactive power of the VPP components. Since several generators could be set to provide reactive power as a function of excitation without additional fuel costs, this will be an effective business case. A typical price for reactive power outside the tolerance range is in the range of 8–10 €/Mvarh.

Another effect of the control of reactive power, especially in critical nodes of the medium and low voltage networks, is the voltage control. This is currently not a business case in the sense of pure economic benefit, but it enhances the voltage quality which can be essential for sensitive productions. In prospective markets the DNO will be able to contract contributions to the voltage control with the network users (see Sect. 6.2.1.2). The aim of this business model is a better and more efficient use of the grid assets in order to prevent costs for grid expansion or reinforcement.

BM 5—Intraday market

In addition to the usual day-ahead market, a separate intraday market for energy exists. Here electrical energy is offered with a very short lead time of one hour. Since the VPP is able to react very fast, this is generally a market to place free power capacities. However, the intraday market is in direct competition with the

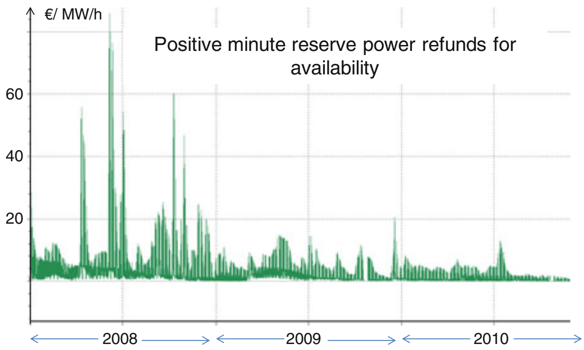


Fig. 6.30 Positive minute reserve power refunds

reserve power market where the refunds are mostly higher. The intraday market is a typical place for traders who try to balance their balancing group due to forecast error and not due to additional power capacities.

BM 6—Reserve power (positive minute reserve)

Traditionally, the system services are mainly managed by the TSOs, and they obtain the ancillary services from bidders on the free market. The TSO pays the balancing power provider in different ways: for availability (power capacity, €/MW/h) and for use (energy, €/MWh). Special rules were established in the Grid Code to ensure the quality and quantity of the providers (see Sect. 5.2.2).

In general, the underlying business case is to provide the ability to deliver power (more generation or reduction of load) within at least 15 min after request of the TSO and not the power itself, since only a small amount of the ordered capacity is called for use, typically 1–2 %. Figure 6.30 demonstrates an example of the average power provision price for positive minute reserve power in €/MW/h.

BM7—Negative minute reserve power

The controllable power stations and batteries can be mainly applied for the provision of negative minute reserve by the readiness to reduce the power generation. The DSM capabilities can only be considered, if a compensation of the increased demand does not occur a short time later (rule of not having a backlog demand). This limitation is relevant for the switching of heat pumps and the charging of heat storage units.

The prices of negative minute reserve power vary also in a wide spectrum as shown in Fig. 6.31.

BM 8—CO2—Certificates—RES integration

In this business model the target is to implement and use as much RES energy as possible and to have the opportunity to sell CO_2—certificates which are distributed in a definite ratio of CO_2—output/MWh electricity to all power producers. If a power producer exceeds the given CO_2 limit for its power production he can buy additional certificates on the market. If the VPP maximizes the output of RES it will be able to offer certificates on the market and create additional earnings.

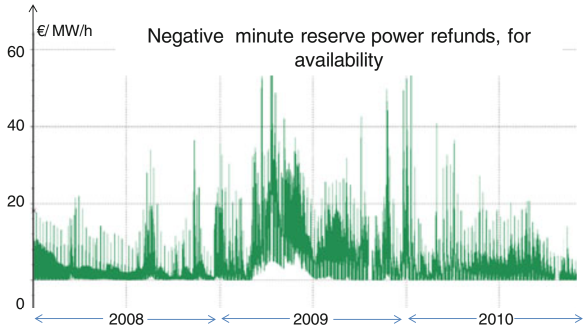


Fig. 6.31 Negative minute reserve power refunds

The business models 1–8 were investigated over a one year period in the framework of a VPP consisting of:

- 5.8 MW gas fired CHP plants with,
- 0.9 MW biogas and waste fired power plants,
- 9 MW wind power plants,
- 2.55 MW photovoltaic plants,
- 10 MW hydro power plants,
- Batteries of 3 MW power and 12 MWh storage capacity,
- DSM capacities of
  - 1.5–15 MW in winter time (depending of the outside temperature)
  - 1.2 MW in summer time.

The complete set of business cases was used in the investigated supply area [1]. A controllable power flexibility of 10 MW is applied by using the optimization mode of the VPP.

The maximum possible benefits of the business models in comparison with the annual operational expenses OPEX are presented in Table 6.4.

The presented benefits cannot be simply added together. A reduction coefficient for concurrency of 0.443 was defined in this combination of business models. This coefficient will decrease as more business cases are used in parallel.

The benefits and expenses are again expressed in BCUs where one BCU is equal to the capital expenses for one 20 kV ring main terminal (see Sect. 6.2.5).

The achieved results express a positive difference between the sales incomes of 10.9 BCUs and the OPEX of 8.73 BCUs, which amounts to 2.17 BCUs/a. This result is equal to 19.9 % earnings before interests and taxes (EBIT).

In conclusion, it can be stated that VPPs can be operated with economic benefits if prospective market conditions are considered. However, such benefits can be achieved only by a flexible and optimized application of different business models (described above). Consequently, the VPP may offer win–win situations for all its participants

- by taking over the balancing duties and
- by sharing the earnings created through various business models.

Table 6.4 Additional sales income and the operational expenses of the VPP

BM	VPP Sales, BCU/a
1	6.3
2	2.5
3	3.5
4	6.6
5	0.2
6	2.7
7	3.4
8	2.0
Sum × 0.443	10.9 BCU/a
VPP Cost Component	OPEX, BCU/a
Operation	7
IED compartment	0.76[a]
Access to WAN	0.32[a]
CC-establishment	0.65[a]
General OPEX	8.73
Benefit: 2.17 BCU/a	

[a] 10 Years Return of Investment
BM Business model, *BCU* Basic currency unit, *CC* Control center, *OPEX* Operational expenses, *IED* Intelligent electronic device

This conclusion can be seen as the pre-requisite for an interest of the power producers, operators of storage batteries and the consumers offering DSM to be aggregated into a VPP.

6.4 Pillar 3: Smart Metering and Market Integration of the Consumers

6.4.1 *Basics of the Digital Metering Technology*

The digital technology was successfully introduced for protection and control and has been in use since the late 1980s (Sect. 3.2.2.1). This was mainly driven by offering economic and technical benefits compared to the previous analogue electronic and electro-mechanical technologies. The digital metering technology was developed and introduced about 15 years later, and this mainly concerns industrial meters.

The reason for this is that there is a significant price difference between meters on the one hand and protection schemes on the other hand in a ratio of ~1:100. The higher costs for digital meters compared to the traditional electro-mechanical “Ferrari” meters were a barrier for a long time.

The technological development and volume effects in the sector of micro-electronic components brought about a significant reduction of the component prices and made the digital metering technology competitive. The term “Smart

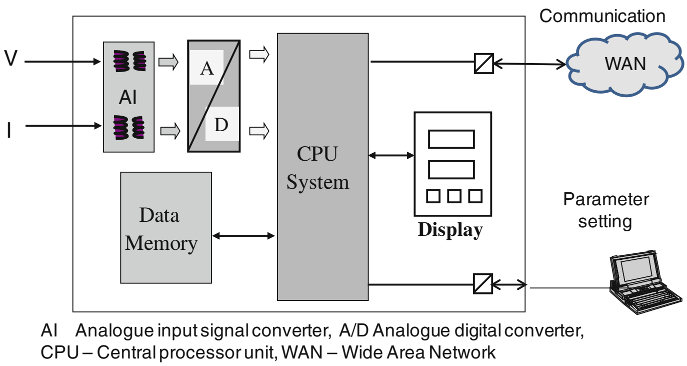


Fig. 6.32 The principle of digital metering technology

Meter" was introduced to express that these digital meters are a component of the Smart Grid philosophy.

A Smart Meter is mainly an electrical meter that records the consumption of electric energy in short time intervals (from minutes to one hour) and then communicates that information to the traders for monitoring the demand profiles and for billing.

The digital technology has now been broadly introduced for the metering functions. The technology principle of digital meters is depicted in Fig. 6.32.

The digital meter samples the analogue current and voltage values and calculates the active and reactive power values for the synchronous samples. The integration of the power values is mainly performed within time intervals of ¼ h. The metered values are stored in a memory, may be displayed on an integrated screen and transferred via a communication interface linked with a wide area network (WAN) to the trader and other stakeholders requiring the information for their operations (e.g. DNO, VPP).

Digital meters enable two-way communication between the meter and the control centers. In this way they may report the metered data as well as receive tariff information and other signals. The digital meters are time synchronized, and often the time synchronization is performed via the communication link.

The display can also be used to present the tariff information, the demand and the related costs.

The behavior of the digital meters may be locally parameterized by a PC. The remote setting of parameters is possible from the technical point of view, however, due to security constraints, it is still restricted by legal acts in most countries.

The main functions of Smart Metering are presented in Fig. 6.33.

Additional important features include voltage quality monitoring, load profile recording, gateway to home automation facilities (for energy management) and security functions.

With the introduction of smart meters the following objectives are often targeted:

Communication interface
Remote reading of metered data
Metering active & reactive energy
Receiving tariff signals and forecasts
Time synchronization
Visualization of tariffs, demand & costs
Voltage and power measurements

Data provision in short intervals
Voltage quality monitoring
Load profile recording
Gateway to Home Automation
Digital setting of parameters
Disturbance diagnostics
Detection of manipulations

Fig. 6.33 Smart metering functions

- Significant benefits for market participants,
- Market driven approach with the integration of DER–RES,
- Energy savings and climate protection by giving more real-time consumer feedback,
- Limiting the peak power of segments of the grid by enabling Demand Side Response,
- Competition in the metering data collection service and customer care,
- As fast as possible widespread distribution of intelligent measuring systems,
- Acceptable cost-benefit ratio by automating the metering processes,
- Smart Grid "Readiness".

The European Commission has set the target that 80 % of electricity consumers shall be outfitted with meters which are able to support Demand Side Response by 2020.

Meanwhile, 13 member states of the European Union have decided to go ahead with the national roll-out or have already completed it, e.g. Italy and Sweden.

6.4.2 Dynamic Tariffs

The expectation regarding the introduction programs is that smart metering will offer a number of potential benefits to the consumers, traders and network operators.

These benefits concern both the commercial and the electricity supply processes, and provide:

- an end to estimated bills, which are a major source of complaints for many consumers,
- a tool to help consumers better manage their energy use—stating that Smart Meters with an in-house display could provide up-to-date information about the actual electricity consumption and, in so doing, help people to manage their energy use and reduce their energy bills and carbon emissions.

Electricity pricing usually varies at certain predictable times of the day and the season. In particular, if generation is constrained, prices can significantly rise if power from more costly generation or from import is requested outside the planned schedules.

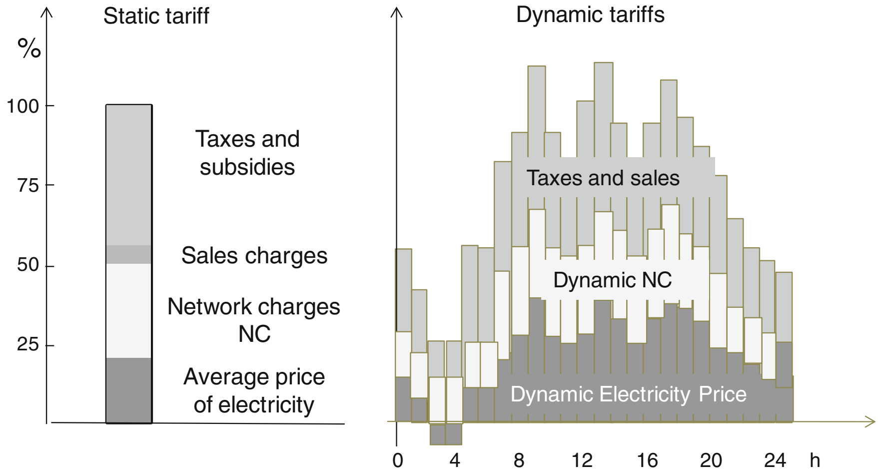


Fig. 6.34 Components of the static tariffs and the structure of dynamic tariffs

The billing of the consumers by time-of-day, applying dynamic tariffs in proportion to the electricity prices and network charges will encourage consumers to adjust their consumption habits to be more responsive to market prices.

Furthermore, these "price signals" could delay the activation of expensive generation or at least the purchase of energy from higher priced sources with higher carbon emission rates.

The current tariff structure is based on the average prices on the energy market and also includes the network charges, sales charges and several taxes. In Fig. 6.34 the traditional tariff structure is presented on the left and the prospective dynamic tariff structure on the right.

A significant share of the additional charges and taxes is caused by the subsidies for renewables in the majority of the European countries, where the installation and operation of RES is co-financed by fixed feed- in prices that are normally significantly higher than the electricity market prices (see Sect. 7.1). In Germany, for example, the relevant charge for the subsidization of renewables amounts to 5.28 €c/kWh in 2013.

In the future such averaging mechanisms to create the tariff cannot support the above mentioned expectations regarding the adaptation of the demand to the energy availability. Dynamic tariffs will be based on the hourly changing energy prices:

- to compensate energy deficits by applying higher tariffs,
- to utilize excesses of renewable energy by offering lower tariffs.

Furthermore, an additional dynamic of the network charges will become necessary to avoid congestions in the distribution network. This will be done by influencing the demand shifting by tariff growth as a result of higher network charges.

The prospective principle of dynamic tariff structures is presented in Fig. 6.34 right (not splitting into the contributions of taxes and sales charges).

Table 6.5 Principles of static and dynamic tariff building

Parameter	A	B	C	D
Interval	Static	Static	Dynamic	Dynamic
Tariff	Static	Dynamic	Static	Dynamic

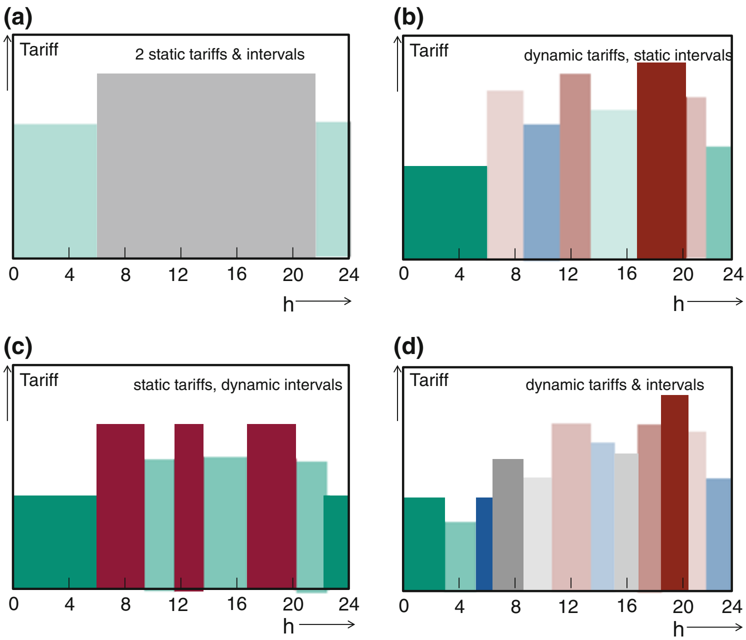


Fig. 6.35 Tariff structure alternatives

In this figure the practice of negative electricity prices is shown between 2 and 4 a.m in the dynamic tariff structure. This has been happening in Germany since 2008 whenever an excess of renewable energy cannot be utilized within the control area. The control area manager is obliged by law to bring this surplus of RES to the market (in accordance with the Renewable Energy Act).

The dynamic of the tariffs may be managed in different ways as shown in Table 6.5.

The decisive parameters defining the dynamic are the value of the tariff itself and the interval when the tariff is valid. In principle, the three opportunities B-D in Table 6.5 exist to perform dynamic tariffs.

The traditional static tariff uses one tariff value for a definite time period (usually one year) or it may be split into a high and low tariff, where fixed intervals are set, e.g. high tariff is valid on week days from 6 p.m. to 10 a.m, and on Saturdays from 6 p.m. to 2 a.m. During the other time intervals, including Sundays, the low tariff is valid.

In Fig. 6.35 the overview of the tariff variants is presented. Theoretically, the tariff could be changed every ¼ h. In practice, however, longer time periods will be applied to build average tariffs for intervals in which the electricity price does not change significantly.

6.4.3 The Impact on Consumer Behavior: Demand Side Response

In industrial countries the household consumers make up only about 25 % of the annual electricity demand. However, their contribution to the peak load may exceed 50 %. The household load profiles provide the most changing load profiles compared to the other consumer categories like industry (40–50 %), trade and other business (20–30 %), transportation (5–10 %) and agriculture (2–5 %).

Consequently, the household consumers provide the highest potential for the harmonization of the overall load profiles by DSR.

The potential of such paradigm changes in the consumer behavior has been investigated in several studies. The results of the DSR analyses are summarized in [11] and depicted in Fig. 6.36.

Looking at every single shift-able household application, the theoretical potential of DSR was estimated taking into account the installed power, the frequency of use and the simultaneous use of devices. Considering a predicted significant growth of air conditioners and heat pumps, the German potential in 2020 will reach 21 GW in the summer and 22 GW in the winter [8], as presented in Fig. 6.36. However, the DSR depends on the willingness of the consumers to shift intensive load to periods of low tariff. If current electric usage remains the same—and without a broad application of home automation facilities and a significant tariff spread—the realistic potential will only be about 8–10 % of the theoretical.

Now is the time to develop the mechanisms for Demand Side Response into the power balancing and trading schemes to double this realistic potential.

Therefore, the European Community and the German Federal Government have funded several projects to investigate the opportunities for the adaptation of load by dynamic tariffs.

In Fig. 6.37 the approaches of two of such projects.

- Web2Energy (W2E) www.web2energy.com (European Union, one of six SEDN—projects—Smart electricity distribution networks) and
- Meregio www.meregio.de (Germany, one of six E-Energy projects) are presented.

Web2Energy uses a web portal or SMS to notify the consumers of traffic light time periods—red means "save energy", green means "it is advantageous to use energy" (Fig. 6.37a). The demand of the consumers is compared to a reference profile (Fig. 6.38a). A bonus system rewards the consumers for exceeding the reference curve during the green intervals and for having lower demand during the red zones.

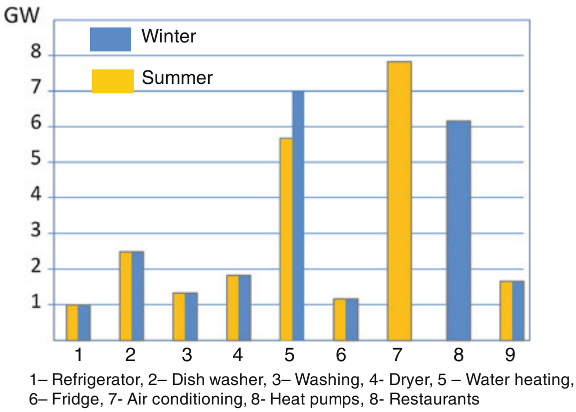


Fig. 6.36 Prospective (2020) DSR potential [11]

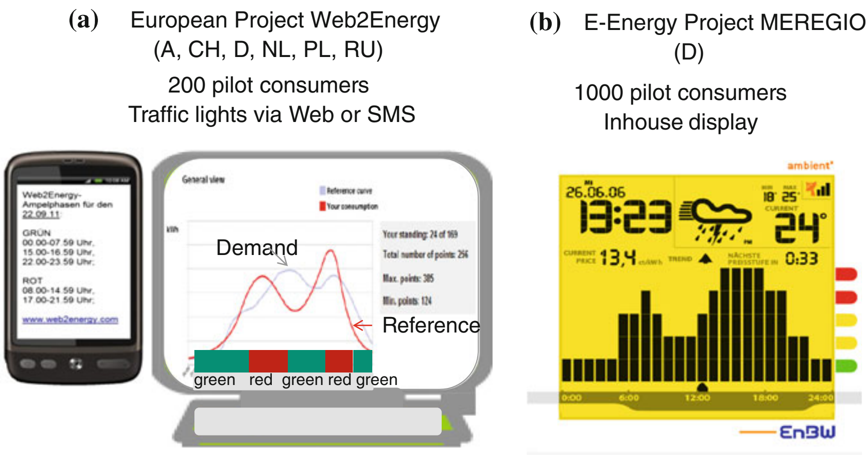


Fig. 6.37 Visualization forms of dynamic tariffs in two projects (*Source b* H. Frey, EnBW)

Meregio applies an in-house display (Fig. 6.37b) presenting the time variable availability of three fixed tariffs (High, Medium, and Low) as shown in Fig. 6.38b. The time periods of the tariffs are submitted the day ahead.

After investigation periods of more than a year for each project, it can be stated that the consumers are ready to shift load and to save energy if they become aware of the information about pricing, demand and costs.

Figure 6.39 demonstrates some examples of the DSR observed in both projects—daily load profiles during one week for W2E and the average change of demand inside the tariff intervals of Meregio for 14 months. A significant average shifting of load from red into green intervals can be observed in both investigations. The energy savings are mainly caused by turning off stand- by devices. The consumers are now able to feel the costs of such permanent un-necessary demand.

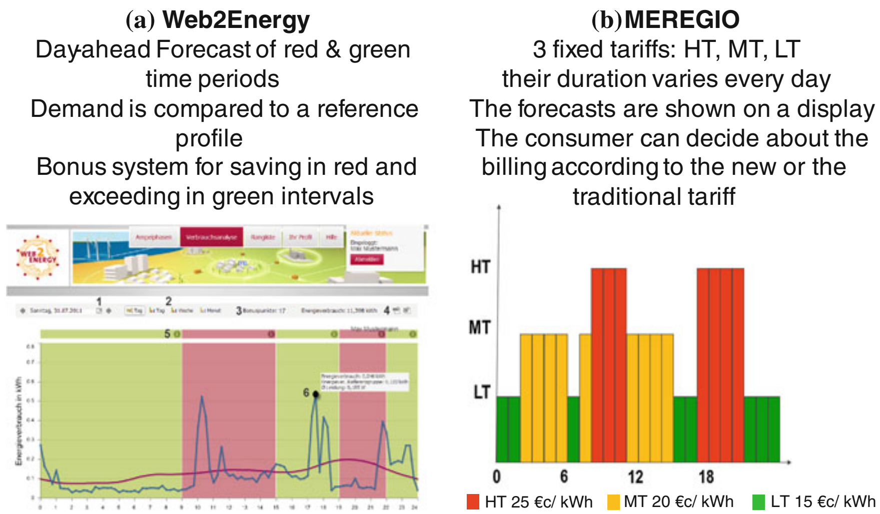


Fig. 6.38 DSR approaches of the projects **a** Web2Energy, **b** MEREGIO (*Source* H. Frey, EnBW)

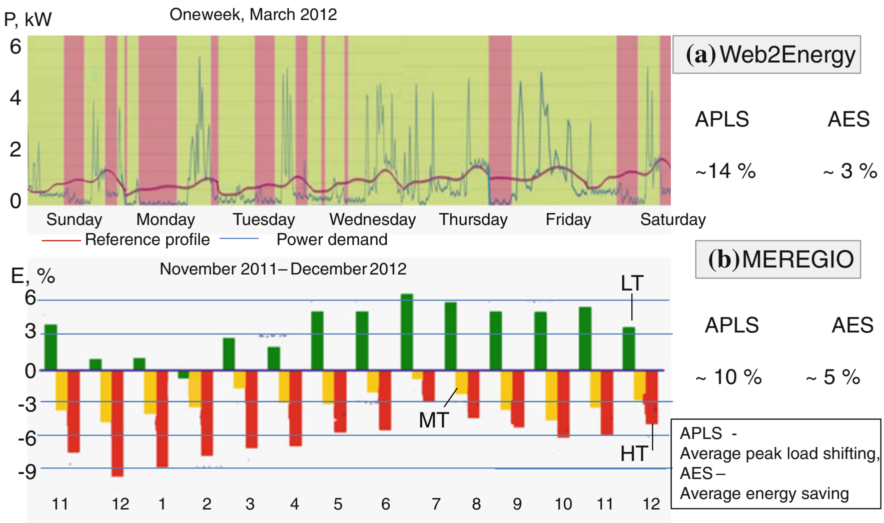


Fig. 6.39 DSR examples of the projects: **a** Web2Energy, **b** MEREGIO (*Source* H. Frey, EnBW)

The presented results are achieved only by means of visualisation and consumer awareness. The observed energy savings of W2E reached on average 3 % (0.3 kWh/day) of the daily consumption of the households. This is less compared to the Meregio project, but it appears as a consequence of the selected approach to honour the load shifting which reached a higher level in W2E. The daily load peak

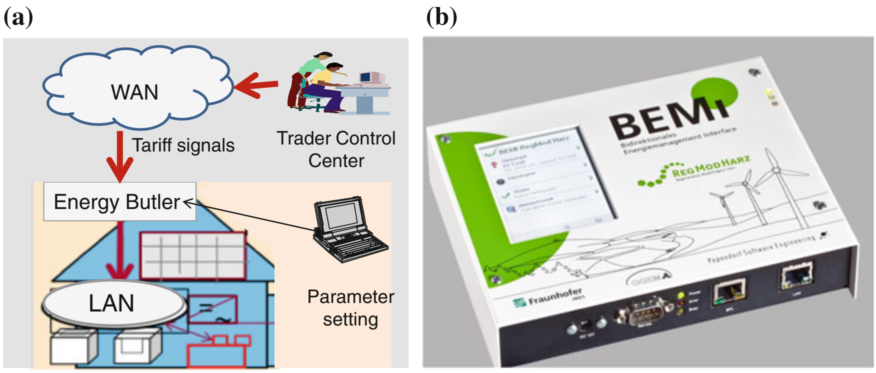


Fig. 6.40 “Home automation” **a** the principle, **b** the example of an “Energy butler” (*Source* Fraunhofer IWES—*BEMI* Bidirectional Energy Management Interface)

was reduced by approx. 14 % by shifting intensive demand from the red into the green phases.

From the 200 pilot consumers in the W2E project about 60 were strictly watching and responding to the red and green phases each day. The other consumers did not respond regularly but occasionally.

Nevertheless, the average demand shift of 14 % is an excellent result for the first confrontation of the consumers to the aspects of energy efficiency.

However, it could be observed that the engagement of the consumers in both projects declined during the year. As a conclusion it can be stated that a sustainable DSR requires the application of automated energy management systems in the sense of “Smart Home” facilities.

It can be expected that the realistic DSR potential will come closer to the theoretical in 10–20 years when all consumers will be served based on dynamic tariff contracts and home automation facilities are broadly in use.

Nowadays, home automation facilities, referred to as “Energy Butlers”, are commercially available on the markets. They allow electric devices to be controlled while considering the constraints of the consumers. The consumers are able to set parameters which define the time periods in which the energy butler can influence the selected device operations. This home automation principle is depicted in Fig. 6.40a. For example, the compressor operation of refrigerators may be shifted in a way that a given temperature interval will be definitely maintained. The example of an “Energy Butler” is shown in Fig. 6.40b.

Further considerations related to the W2E project:

W2E performed an economical investigation regarding the expenses and benefits of such innovative approaches. The components of the Capital Expenses (CAPEX) and the related Operational Expenses OPEX (depreciations and part of the maintenance expenses) are presented in Table 6.6 for an assumed return of investment (ROI) period of 10 years considering the experience of the market integration of the 200 pilot consumers. The CAPEX and OPEX are calculated in

Table 6.6 Expenses for the market integration of household consumers in BCU

Enhancement case	CAPEX	OPEX
Installation of 200 household meters	1	0.1
Enhancement of the control office	2.8	0.31
Communication network extension	2.4	0.27
Energy management for 200 households	2	0.2
Sum	8.2	0.88

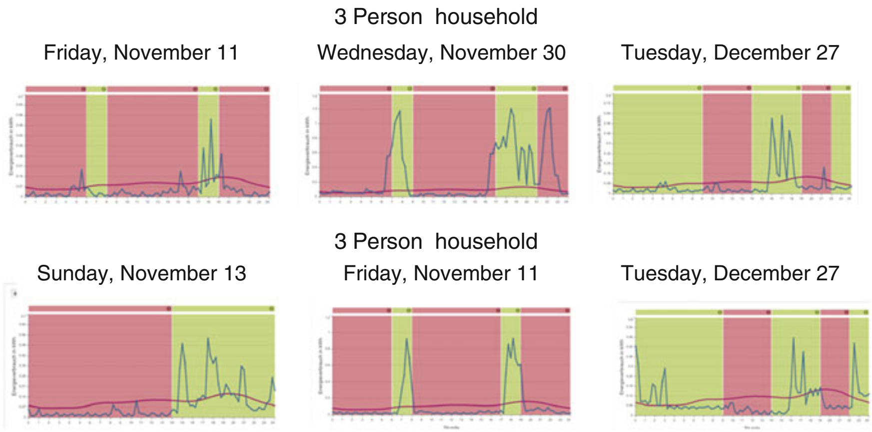


Fig. 6.41 Daily load profiles of consumers who consistently responded to the traffic lights

Basic Cost Units (BCU) where one BCU is equal to the investment for one ring main terminal (see also Sect. 6.2.5).

In the result of this analysis, the annual OPEX of the consumer market integration amounts to 0.0044 BCU/a. The question arises, how can these expenses be paid back?

In Fig. 6.41 examples of the DSR of two households monitored during selected days within the project Web2Energy are presented. The 12 most active consumers achieved a high shifting potential between 36 and 44 % of the whole energy demand. In extreme cases, up to 90 % of the reference peak could be shifted to green.

A monetary benefit evaluation can be only performed if dynamic tariffs with a significant spread between the low and high tariffs are introduced. The building of such a tariff model is described in Sect. 7.2 in the framework of a case study.

Combining the annual load profiles of the best practice consumers with the developed tariff model it can be stated that the consumers may save about 26 % on their annual electricity bill. This is equal to 0.0052 BCUs. Compared to the OPEX of 0.0044 BCU/consumer, the benefits of the consumers may be 16 % higher than the annual expenses.

In general, the introduction of dynamic tariffs in combination with home automation will become advantageous if, within the next 10–20 years, all consumers obtain home automation facilities and can adapt their electricity consumption automatically in the same way as the best practice consumers did within the W2E project.

6.4.4 Electric Vehicle Management

The large scale introduction of electric vehicles (further called E-mobiles in accordance with [12]) corresponds with the goals of the European Union in saving fossil primary energy, reducing carbon emissions and increasing energy efficiency. National programs have been established in many countries. In Germany, for example, the target of six million E-mobiles is set for the year 2030.

However, the simultaneous network connection and rapid charging of such a high number of E-mobiles creates new challenges for the network loading. The rapid charging of one E-mobiles requires about 20 kW of power.

The following case study is used to consider the upcoming new challenges:

A village area with 80 households is supplied by a transformer terminal 10/0.4 kV with a transformer capacity of 400 kVA.

In this area 30 households use E-mobiles. If all of the E-mobile owners simultaneously start the rapid charging process, the transformer capacity is exceeded by 50 % for just the charging power alone, not considering the additional demand of the basic load of the area.

The question arises again: Is it necessary to enhance the network capabilities in a way that such simultaneous charging will become possible or it is more useful to introduce innovative methods for the electric vehicle management?

A traffic light system for network operations and interactions with market activities is being considered. The red light signals that network equipment is overstressed. In such an emergency situation the distribution network operator is allowed to switch off part of the load or generation depending on the origin of the overloading. He is obliged to offer benefits (e.g. reduced network charges) to the network users who are ready for such emergent disconnection.

The yellow light presents a situation where the network operation is in a critical condition, e.g. the N-1 criterion cannot be maintained (for example if the LV feeder has to supply the consumers normally connected to the neighboring transformer terminal in the case of disturbances). In yellow light phases, the DNO can apply market mechanisms (e.g. increase the network charges significantly) with the target to return the network to normal operating conditions (green light).

In principle, it can be assumed that the E-mobile owners can be grouped as follows:

- 1—owners who will receive the charging quickly due to urgent usage needs,
- 2—owners who need the E-mobile charged later, but it should be fully charged at a specific time,
- 3—owners whose E-mobiles are already charged and connected to the network. They are ready to provide their storage capability for supporting the network

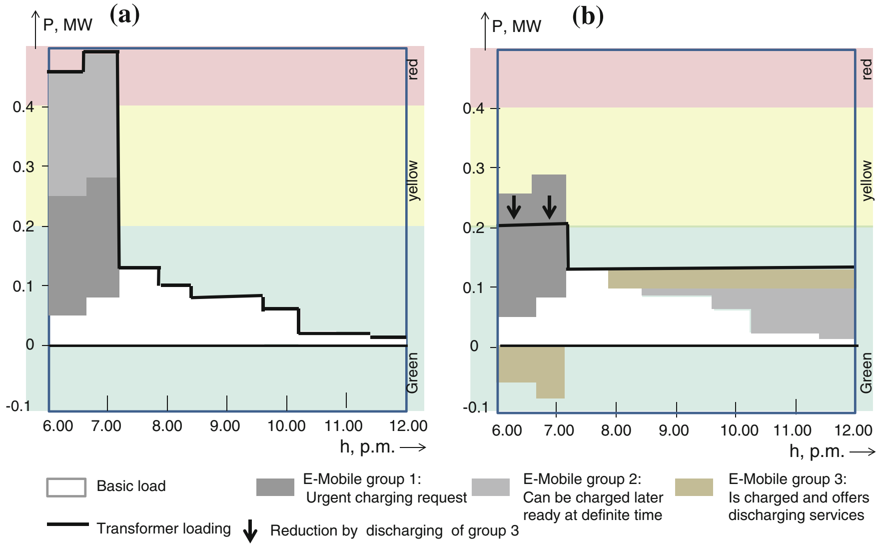


Fig. 6.42 **a** Uncontrolled and **b** managed charging of E-Mobiles

operations by receiving an adequate compensation. Nevertheless, the cars have to be fully charged at a specific time.

Figure 6.42a presents the loading situation of the supplying terminal if the drivers of groups 1 and 2 (10 per group) simultaneously start charging after arriving home from work at 6 p.m. The charging power of the 20 E-mobiles combined with the basic load for the area will overload the 400 kVA transformer. The load of the transformer has moved into the red area of the diagram.

The DNO has the possibility to limit the number of rapid charging processes or to switch off other loads to avoid the "red light" situation. However, this can be achieved smarter by

- offering a high charging tariff during the related critical time interval and for rapid charging in general,
- signaling lower charging tariffs for a delayed time interval and,
- offering benefits for using the storage capacity of charged E- mobiles to meet the urgent charging request within the "green" network conditions.

The right side of Fig. 6.42 presents the approach where the green operation conditions can be maintained by shifting the charging of group 2 and applying the storage capacity of group 3 to keep the network operation in the green area. The requested rapid charging can be performed without any stress to the network.

Such an electric vehicle management requires extended instruments for remote control and monitoring. For example, the tariffs for charging have to be offered online and the charging processes have to be controlled externally.

The appropriate aspects and technical solutions were investigated in several projects. Here, the results of the project Harz.E E-Mobility [12] are used to consider how to meet the challenges by smart vehicle management methods.

Smart vehicle management requires the establishment of an additional electromobility control system. This system consists of several components.

E-mobiles may be charged or discharged at charging stations. In the first case, they take energy from the network, while in the second case they feed energy into the network. The charging stations build the interface between the batteries of the vehicles and the electric networks. The charging stations are connected via communication links with a control system—the mobility control center (MCC). The MCC receives information about

- the current electricity prices from the traders,
- the current loading situations of the parts of the network that contain charging stations,
- the appropriate charges for additional network use from the DNO.

Based on this information the MCC offers the tariffs for rapid or delayed/slow charging and the compensation for discharging in the moment when the driver connects to the charging station. The driver selects the desired mode and submits the final state of charge (SOC) and the final time of charging via a mobile phone.

The MCC manages the charging process in accordance with the driver request. If the charging station is located in a "red light" network area, the MCC informs about the nearest available public charging station. Upon request the driver information system installed in the E-mobile informs the driver on the road about the SOC and gives advice about the nearest available charging stations and the related tariffs. During the connection to the charging station the driver can observe the charging procedure via the internal driver information system or via a mobile phone if he is outside the E-mobile. Furthermore, the driver can observe and download information about previous charging procedures and the related costs through a WEB portal.

The components of the electro-mobility control system are presented in Fig. 6.43.

The driver information system is linked with the internal battery system by the link box. This box is activated during the driving and provides information about the SOC and the reachable distance. The link box also performs the communication between the MCC and the driver information system to receive information about the nearest charging opportunities. If the driver decides to charge and selects one of the proposed charging stations a navigation system may offer the shortest route.

After connecting to the charging station, the COM box manages the information exchange between the E-mobile and the charging station. At the beginning of the charging procedure the E-mobile submits its identifier to the charging station. The charging station receives the charging schedule from the MCC and communicates this schedule to the COM box, which in turn manages the charging of the battery in accordance with the schedule. During the charging the COM box sends the current SOC and further measurement information to the charging station. The various

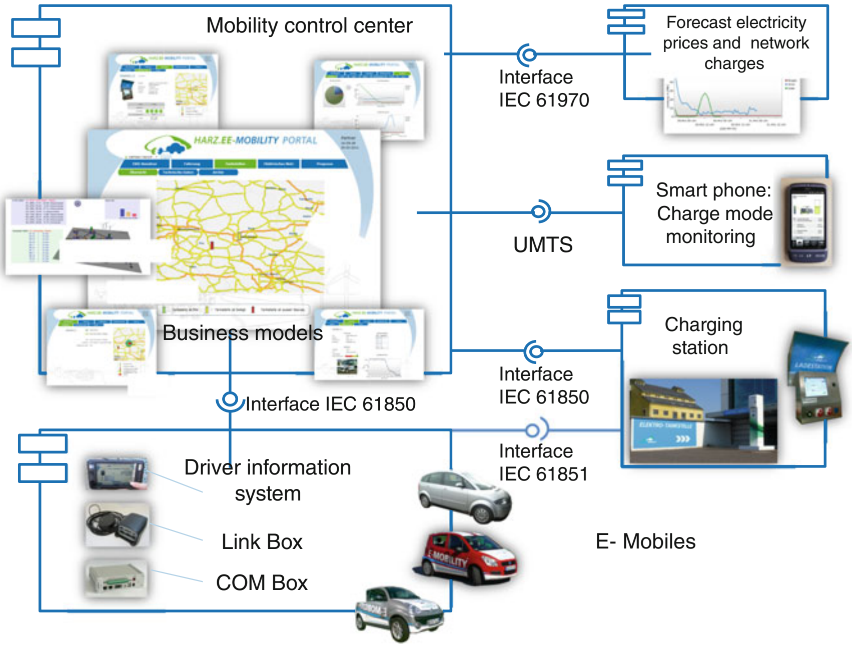


Fig. 6.43 The principle of electric vehicle management according to Harz.EE-Mobility [12]

interfaces between the system components use international standards that are currently published and being extended (see Chap. 8).

The complexity of the described procedures underlines the need to establish a complete information and communication infrastructure for the electric vehicle management that ensures at all times reliable network operations and the avoidance of congestions.

Such systems have been in the status of project related trial operations since 2011.

6.5 Communication Needs for Smart Distribution

Traditionally, the local distribution networks are mostly operated without remote control mechanisms and automation functions. The distributed energy resources (DER) feed in the maximum possible generation corresponding to the weather conditions.

The introduction of the three pillars of distribution is aimed at improving the traditional approaches and requires a deep paradigm change. This will change the role of the distribution system from a passive to an active one that takes more responsibility in the overall power system.

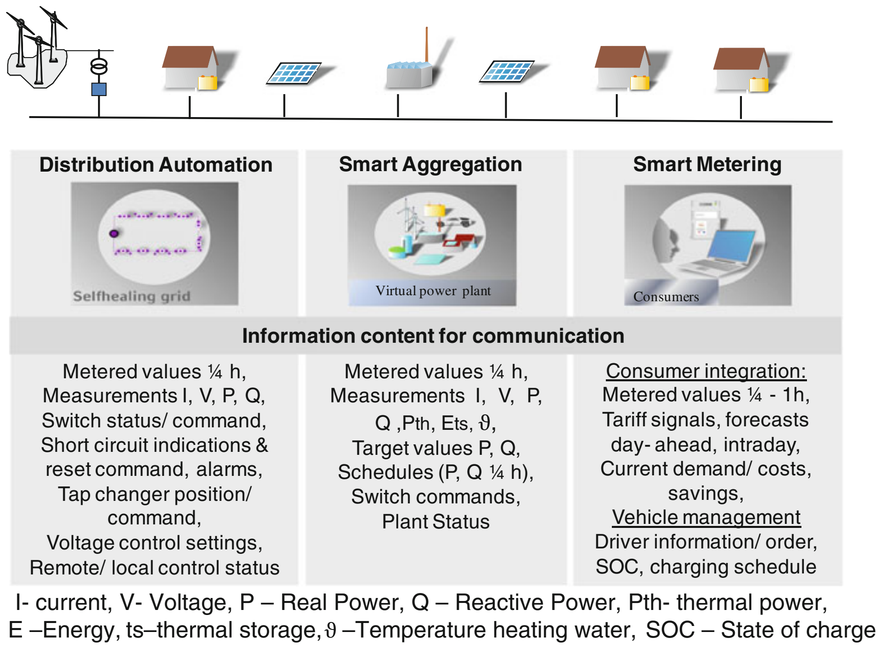


Fig. 6.44 The information exchange needed for the three pillars of Smart Distribution

In the future the distribution will have the important role of keeping the local balance between energy production and energy consumption. The enhancement of distribution networks into Smart Grids is accompanied by the new functions and technologies described above. All of these functions require the exchange of information between several system components and the control centers.

Consequently, information and communication technologies (ICT) will play the key role to ensure the sustainable and reliable network operation in the context of an increasing share of DER and new types of consumers connected to the distribution networks.

The overview of the information exchange needed for the establishment of the three pillars of Smart Distribution is presented in Fig. 6.44.

As a consequence, the ICT must penetrate the distribution systems all the way down to the end customers at the low voltage network level. The presently used systems for supervisory control and data acquisition (SCADA) are not able to provide all the functions needed to realize the mentioned tasks of Smart Distribution. These future functions can only be achieved by creating new SCADA systems. The experiences of the appropriate pilot projects are considered in Chap. 9.

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Chapter 7
Design of the Smart Energy Market

Smart Grids are regarded as the pre-requisite for meeting the challenges of the electricity supply of the twenty first century with its significant share of renewable energy sources (RES) in the annual electricity consumption, most of which are volatile and dependent on the weather conditions. However, Smart Grids require an enormous investment and in this context the question arises:

> Are Smart Grids in the above considered context cost effective—do they guarantee the return of investment?

Considering the market design of most European countries in 2013, the answer to this question is a resounding "NO"!

The main idea of Smart Grids—namely, the intelligent integration of all their users (see Sect. 1.1) —is currently prevented by the market design in the majority of European countries that apply the "feed-in tariff" supporting scheme. Currently, three different types of supporting schemes for the electricity generation by RES are applied within the European Union. Figure 7.1 presents the application of supporting schemes for RES within the European Union: **a** - feed-in tariffs which are market independent and fixed for long time periods (up to 20 years), **b** - quota for the shares of RES in the portfolio of the traders and proof by certificates, **c** - tax incentives and/or investment grants.

Using the supporting scheme "a", the network users including the operators of RES plants and the network operators do not gain any benefits by following the three pillars of Smart Distribution as described in Chap. 6.

The main barrier corresponds with the privileges of RES fixed in legal acts (Renewable Energy Acts—REA), according to the supporting scheme "a", feed-in tariffs:

- RES may feed-in the maximum possible power depending on the weather conditions or on the availability of bio fuel regardless of the demand,
- RES are compensated by a fixed feed-in tariff which is completely independent of the market price for electricity and is normally significantly higher,
- RES are not obliged to participate in the balancing processes.

B. M. Buchholz and Z. Styczynski, *Smart Grids – Fundamentals and Technologies in Electricity Networks*, DOI: 10.1007/978-3-642-45120-1_7,

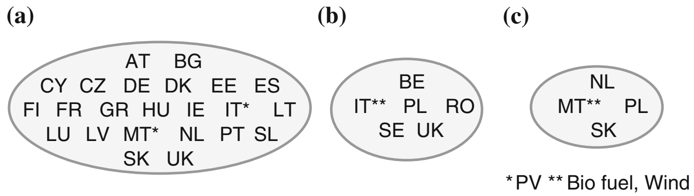

Fig. 7.1 RES supporting schemes within the European Union (status 2012) [1]. **a** Feed-in tariffs. **b** Quota/Certificates. **c** Tax incentives/Investment grants

Consequently, the RES operators are not interested in being integrated into the grid operations in an intelligent way. The market design does not offer incentives for this.

According to the supporting scheme "a", the control area managers are obliged by law to:

- predict the renewable energy production,
- perform the day ahead schedules,
- sell the energy on the spot market and
- compensate the intra-day deviations from the schedules.

In this context, the supporting scheme "a" creates a number of contradictions and, in principle, builds a massive barrier against the economically useful establishment of Smart Grids:

1. The feed-in tariffs are fixed by law and guaranteed for long term periods (e.g. 20 years for PV plants in Germany). Consequently, a growing share of electricity production is not integrated into the market.
2. A paradox of the scheme "a" is that the majority of subsidies are paid to the less efficient technologies.
3. The growing proportion of volatile RES increases the need for control power provision due to higher prediction errors. In this way, the observed reduction of prices for control power and the improvement of the prediction tools cannot gain significant economic benefits for the power system operations when the control power demand rises.
4. The obligation for selling the renewable energy on the market has the consequence that the control area manager has to offer the energy for prices that correspond with the merit order principle. In this way, the renewable energy lowers the electricity market prices if a large amount is available. It may even happen that an excess of renewable energy can be brought to market only by negative prices.
5. However, the lower the energy market price the higher the difference to the fixed feed-in tariffs becomes. The consumers have to compensate these differences by paying special charges that are included into the tariffs (see also Sect. 6.4). The subsidy charges in Germany reached 5.28 €c/kW h in 2013,

and a further significant growth is expected (e.g. 6.24 €c/kW h in 2014). By 2013, about €20 billion in subsidies for RES have been co- financed by the consumers and the governments [2].

6. The pump storage power plants earn a profit when the upper water reservoir is filled during low price periods and used to generate electricity during high price periods. However, the price spread is significantly reduced by the above described effects. Consequently, the erection and operation of pump storage plants is becoming less and less cost effective. For example, the generation hours of the 120 MW pump storage plant "Niederwartha" near Dresden, Saxony, were reduced from 2785 h in 2009 to 277 h in 2012. The consequences are that some existing pump storage plants are no longer in operation, and their complete decommissioning is planned (including Niederwartha). Furthermore, the erection of planned new pump storage plants has been put on hold despite the urgent need for storage capacities [2].
7. The engagement to invest in fossil power plants has also been also significantly disturbed. The fossil power plants have to operate according to a "stop and go" schedule giving priority to the volatile RES, and the annual hours of the use of the installed power has declined from >7000 to <3000. The return of investment is no longer ensured under such conditions.
8. The lack of the erection of modern high-efficient fossil fired power plants will lead to a growing demand of using inefficient, aged coal fired thermoelectric power plants. In principle, the carbon emissions will grow as the result of this development.
9. Consequently, the prices of negative control power and energy exceed the prices for positive control power and energy caused by the frequent excess of the RES and the need for closing down the fossil fired power plants. Figure 7.2 presents the German example of the price development regarding the availability of secondary control power between January 2012 and August 2013.
10. The energy management of the distributed generation within a virtual power plant is not incentivized when the supporting scheme "a" is applied and will not happen if this supporting scheme is continued.

The supporting schemes "b" and "c" offer a much more efficient market integration of RES.

Supporting scheme "b" is based on one legal obligation only: Each electricity supplier has to provide an energy mix containing a fixed percentage (quota) regarding the RES contribution. It is up to the supplier to select the types of RES in his portfolio—hydro, bio fuel, wind or sun.

The suppliers are obliged to prove the conformance with the quota by "green" certificates. Each certificate presents 1 MW h of electric energy produced by RES. If the renewable energy generation is low, the prices for the certificates will grow. Consequently, investors will be interested to erect new power plants based on RES or storage capabilities allowing to gain an optimum sales schedule. Heavy penalties are applied if a supplier is not compliant with the quota.

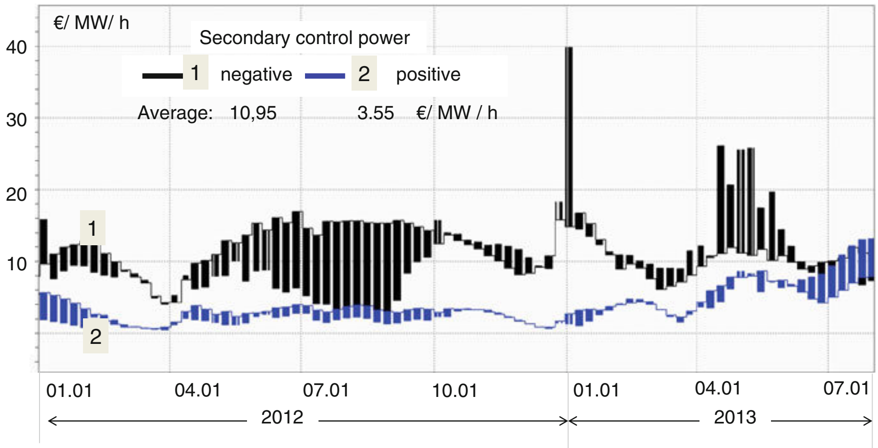

Fig. 7.2 Prices for availability of secondary control power (*Source* EUS GmbH acc. to [3])

On the other hand, the suppliers are interested to minimize their expenses for the completion of the quota. Consequently, a competition between the renewable power producers will happen. The most efficient green technologies may succeed what helps to reduce the energy prices.

The supporting scheme "c" has the consequence, that only the investment is supported. Further-on, the renewable power producers are normal market participants.

The legal acts introducing the supporting scheme "a" are only one great barrier on the way to Smart Grids.

A further issue is the practice that the traders balance and purchase the energy by standardized or analytical but not by predicted load profiles. The tariffs are performed based on the average electricity prices and are adapted to new electricity prices and/or tax conditions in definite time intervals of several months. These methods are simple and do not require much efforts. Therefore, the traders are not strongly interested to introduce complicated data management systems to provide dynamic tariffs and to integrate the consumers into the electricity market by motivating demand response activities. However, this prediction approach is an additional source for incorrect schedules and the need for higher reserve power provision.

The consumers are billed by static tariffs and they are not integrated into the real market. Furthermore, if a static two- tariff system is applied, the spread between the low and high tariff is normally low and does not support any load shifting.

Finally, the network operators (transmission and distribution networks) are compensated by regulated network charges. More investment for the network enhancement by means of information and communication technologies (ICT) is not incentivized.

Consequently, the main stakeholders of the electricity supply process are not motivated and cannot gain benefits in accordance with the Smart Grid approach. It is mandatory to change the rules and to introduce Smart Market functions in the way that all stakeholders may gain an economical benefit and that the network operations can be coordinated with market activities.

7.1 Prospective Markets for Power Supply: A Vision and a Case Study[1]

The development of a prospective market design is mandatory to meet the challenges of the electricity supply of the twenty first century in an economic and sustainable way.

The future (≥2030) market design has to support a harmonic network loading and the balancing of generation and load. New market oriented legal and regulatory rules have to be introduced so that such a target can be reached. Such possible rules were developed and investigated in a case study [4] which underlines the efficiency of the assumed market rules. It considers the German conditions for the year 2030. For this year the German government has set the target of a 50 % share of RES in the annual consumption of electricity, whereby 35 % has to come from volatile sources like wind and sun (see Sect. 1.3).

The following aspects are considered as the foundation of the prospective market in the electricity supply processes.

1. *Interaction of Smart Grid and Smart Market*

Smart Grid and Smart Market are operated in close coordination and use common ICT services. For synergy reasons and cost optimization, the ICT service providers obtain concessions for closed cell territories in bidding procedures and perform their functions for all actors within the cell in accordance with the cellular approach described in Sect. 5.3.2.4.

Grid and market compensate the fluctuations and the volatility of the generation in such a way that a cost efficient grid enhancement will become possible and short term congestions with a low probability will be managed by impacting the generation and load balance.

2. *Renewable power producers become active market players*

The power producers using renewable energy sources (RES) are real active market players. They are obliged to participate in the schedule management and are compensated by market prices. However, the expenses for electricity produced by RES may be fundamentally reduced in the future due to volume effects and the

[1] The figures of the case study do not claim prospective prediction correctness or consistency. The case study presents a first attempt to demonstrate a possible estimation approach for prospective market conditions and the reachable benefits.

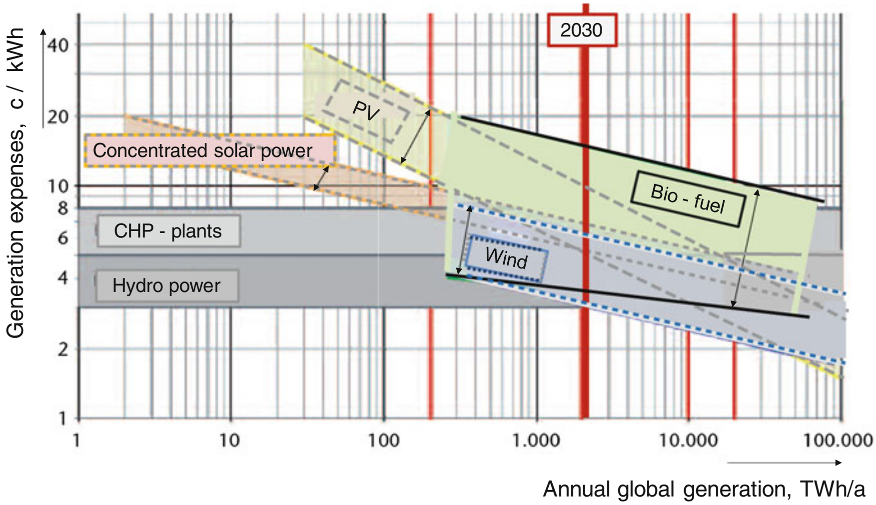

Fig. 7.3 Generation cost dependency on volume effects for various types of RES [5]

improvement of the technologies. The related effects were investigated in several studies. Figure 7.3 presents the results of one such investigation.

The thick red line shows the estimated status of the year 2030.

3. *More flexibility of the definite power production*

Fast reacting controllable power stations, including at the distribution level, and an increased capacity of storage plants offer an appropriate flexibility to compensate the high fluctuation gradients of the volatile RES (see Sect. 2.5).

4. *Price growth for fossil electricity generation*

The prices for electricity production based on fossil fuels will grow significantly due to the price increase for the fuel itself and the reduction of the annual hours of use.

Two examples for this development are presented in Fig. 7.4.

For the future, it is estimated that electricity prices from RES generation will become lower than the prices from fossil power production (see also Fig. 7.3).

Table 7.1 presents the price assumptions based on an analysis of several scientific investigations and the add-on of carbon certificate prices for fossil electricity production.

5. *Changed coverage of the load profile*

In accordance with the merit order principle (see Sect. 5.2.5) the RES will be applied as a first priority not because it is mandated by law but because of their lower energy prices.

Figure 7.5 presents the related changes of the load profile coverage compared to 2010.

For the case study the scenario 2B-2030 [9] (see Fig. 1.9) was selected and focused on dynamic load and renewable generation profiles.

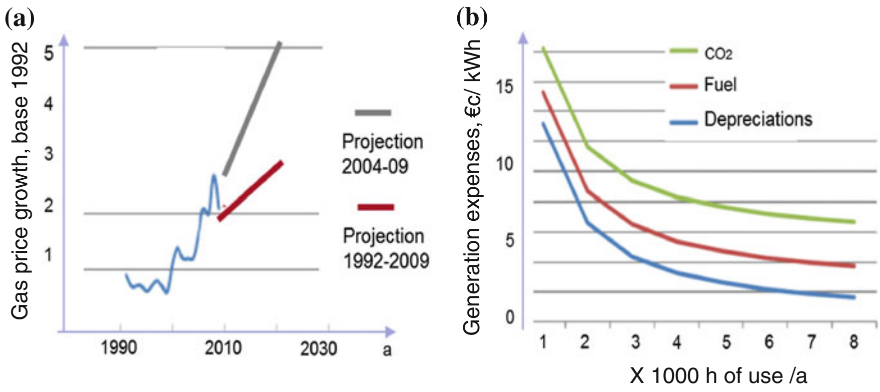

Fig. 7.4 **a** Gas price development [6], **b** Dependency of generation costs (lignite coal) on annual hours of rated power use [7]

Table 7.1 Generation price assumptions per primary energy source for 2030 [€c/kW h]

€c/kW h	Hydro	Wind onshore	Wind offshore	Bio fuel	PV	Lignite coal	Hard coal	Gas/ Oil	Import
Costs	4	4	5	6	7	6.5	10	18	30
CO_2^a						2.4	2	1.2	
Sum	4	4	5	6	7	8.9	12	19.2	30

[a] Estimations according to [8]

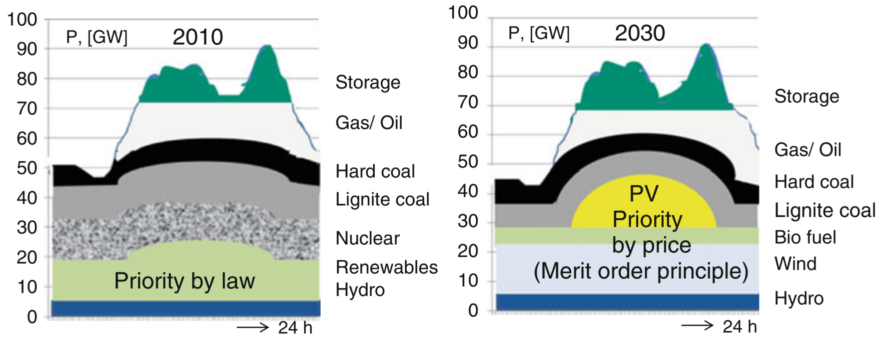

Fig. 7.5 Changes in load profile coverage (Germany: nuclear power will be shut down in 2022)

Based on this selected scenario a dynamic analysis was executed considering:

- The typical annual production profiles (1/4 h values, 96 values per day, 35,040 per annum) of onshore and offshore wind plants and photovoltaic plants in accordance with the year-long observations of the Fraunhofer Institute IWES,

- The production profiles of hydro power plants and bio fuel power plants with their typical annual hours of use, and
- The load profiles with shares of 44.8 % industrial demand, 23.4 % household demand, 24 % demand from business/trade/services, 7.8 % demand from transportation including new loads regarding electro-mobility and "Power to Gas" technologies.

The load profiles for households and business are taken from the standard load profiles. The industrial and transportation profiles were synthesized based on examples of various types of related profiles.

Examples of different generation and load profiles from the case study are shown in Fig. 7.6. The volatile renewable generation varies significantly during the selected period of 11 days. Consequently, the residual load (the difference between load and renewable generation) may become negative in periods with weak load and strong wind. On the other hand, in peak load periods with low wind and low sunshine significant shares of the traditional power generation are required to cover the residual load.

In extreme situations the available power of the fossil power stations cannot cover the residual load as shown in Chap. 1, Fig. 1.11.

It has to be considered that the maximum available power is lower than the installed power stated in the scenario 2B-2030 for reasons of network losses, reserve power provision and the shut- down of power plants for maintenance. Consequently, electricity needs to be imported at higher prices.

Consequently, the prices of electricity based on the merit order principle vary significantly as presented in Fig. 7.7.

6. *Qualified schedule management based on the cellular approach*
The regional power production will have to be significantly developed. Smart Supply territories, including one or more DNOs, build partially self-balancing cells that support the operation of the whole power system by schedule management and offers of system services in a regional context. In general, the schedule management is based on the cellular approach described in Sect. 5.3.2.4.

The DERs are aggregated in virtual power plants (VPP) and benefit from the optimized VPP participation in several markets (see Sect. 6.3).

The traders apply innovative prediction methods for the schedule management and gain an accuracy of the predicted schedules. They benefit from:

- reduced costs for reserve power usage, which were caused by inaccurate schedules and
- optimized purchase planning.

They are obliged to deliver their schedules to the balance responsible parties of the cells where they are active. Furthermore, the traders manage the market integration of the consumers by offering dynamic tariffs.

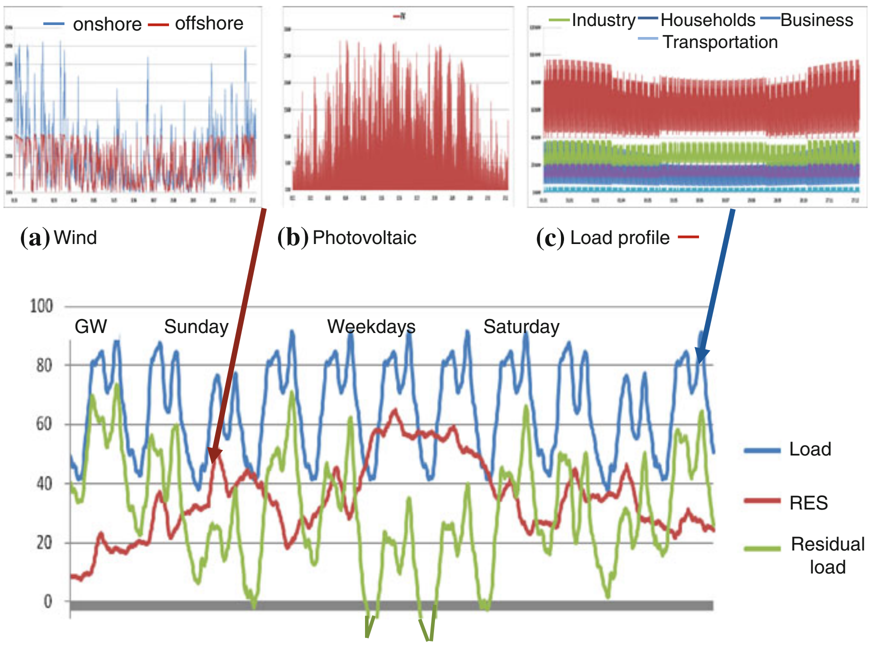

Fig. 7.6 The load and generation profiles scaled to the scenario 2B-2030 [9]. **a** Wind, **b** Photovoltaic, **c** Load profile (*Sources* **a**, **b**—Fraunhofer IWES long term statistics, **c**—BDEW standard profiles)

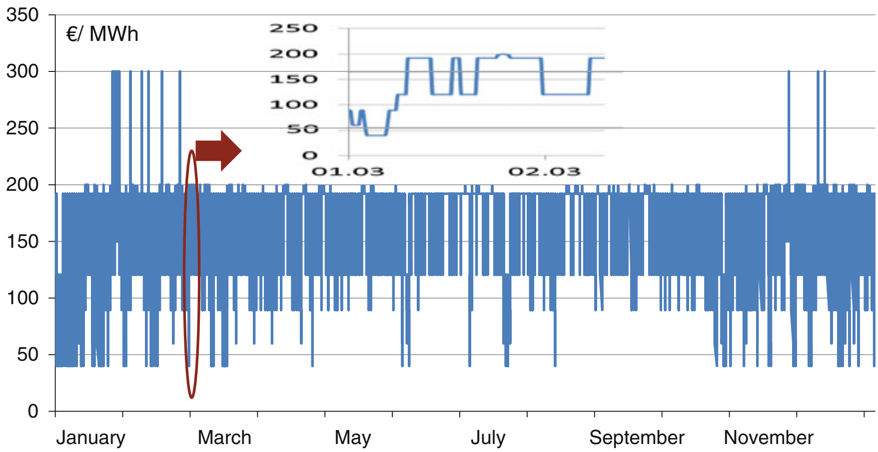

Fig. 7.7 Electricity price curve (assumptions from Table 7.2 and dynamic transformation of the development scenario 2B-2030 [9])

Table 7.2 Assumptions for dynamic network charges

Network charges, €c/kW h	Average	Low time	Low charges	High time	High charges
Winter	10	9 p.m.–6 a.m. 2–5 p.m.	4	6 a.m.–2 p.m. 5–9 p.m.	12
Summer	6	Same as above	3	Same as above	8

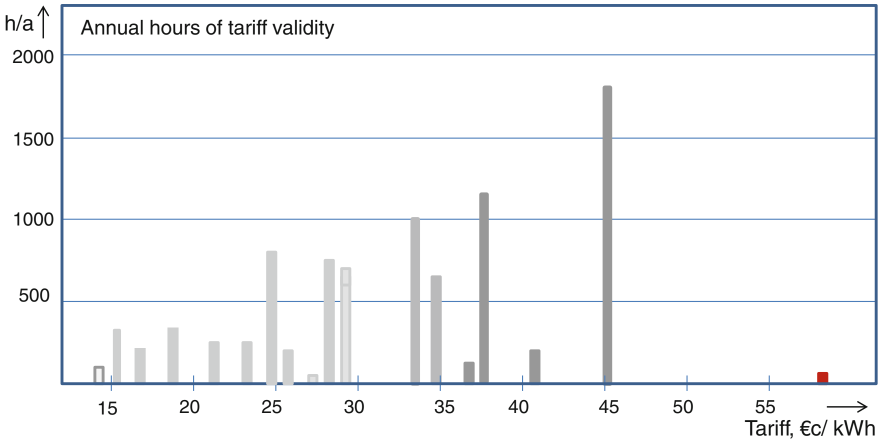

Fig. 7.8 Annual tariff distribution according to the case study for 2030

7. *Tariffs based on dynamic electricity prices and network charges*
Dynamic tariffs are broadly introduced and they are based on dynamic electricity prices and network charges.

The simplified model assumptions for dynamic network charges used in this case study are presented in Table 7.2.

The evaluation of the dynamic tariffs does not consider inflation effects and is based on the current practice of tariff building.

Figure 7.8 presents the distribution of tariffs taking into account the electricity price model for 2030 (Fig. 7.7) and the assumed dynamic network charges according to Table 7.2.

Here two extremes are shown on the left and the right end of the diagram:

The lowest tariff of 14.3 €c/kWh will happen within 56 h on windy summer nights if the load is completely covered by onshore wind and hydro power.

High tariffs occur, for example, during the winter peak loads with 45.2 €c/kWh for 1824 h (gas turbine generation) and with 58.4 €c/kWh for 32 h if intra-day imports of energy are requested.

The presented tariff distribution was applied to estimate the benefits of the consumer market integration considered in Sect. 6.4.3.

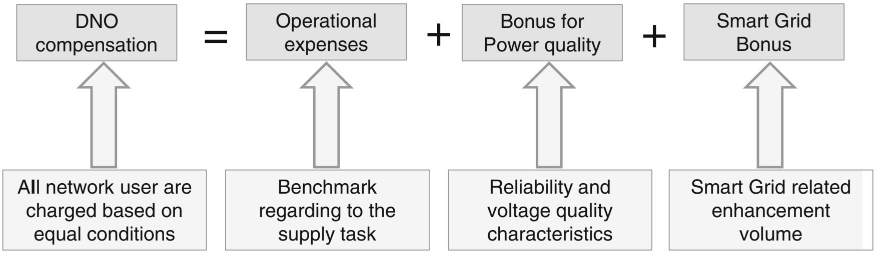

Fig. 7.9 Calculation of the compensation of DNO expenses and the charging of users

8. *Motivation of the network operators*

The network operators are motivated by innovative compensation rules to improve the power quality and the Smart Grid design functionality. In accordance with Fig. 7.9 a prospective business model for DNOs has to consider the benchmarked expenses for the required network services and the quality parameters of power supply including the Smart Grid facilities like the percentage of installed "Smart Meters", the provision of a cellular balancing responsibility or the operation of automation and remote control facilities.

This recommendation defines how the DNOs expenses may be compensated, but it does not answer the question of how the network clients have to participate.

In the Smart Market the calculated costs have to be shared by all connected users of the network in proportion to:

- their peak power demand and energy consumption—for consumers,
- their peak power injection and energy production—for producers.

Benefits regarding the network charges should be agreed on between the network operator and the network user in the context of flexibility provisions by the users.

7.2 Smart Services for Network Operations and Electricity Markets

7.2.1 The Overview of the Smart Services

The prospective interaction of smart network operations and market activities require the establishment of new services in the area of information and communication technologies.

The cellular concept of balancing (Sect. 5.3.2.4) especially requires more information exchange between the stakeholders.

Traditionally, the metered values are sent to the traders and are used for billing purposes only. In the prospective Smart Supply Cells, data from meters are also requested for the targets of the three pillars of Smart Distribution as the prerequisite for the cellular balancing and securing the power quality (see Chap. 6):

- The DNO needs metered and measured values for the load flow supervision and the voltage observation in critical nodes (digital meters are able to provide voltage measurements).
- The party responsible for balancing needs the online provision of the balance between load and generation to control the schedules of the Smart Supply Cell and minimize the costs for schedule deviations.
- The VPP needs the ¼ h meter values from the aggregated plants and controllable loads for an online schedule observation and to perform intra-day optimization decisions.
- The traders need load profiles of their consumers to improve the scheduling by using predictions based on the correlation between the weather conditions and the demand profiles.
- The metering services for other media (water, heat, gas) in a multi- utility may also be integrated into the operations of the service provider responsible for the cell.
- The charging of e-mobiles needs special supervision and influencing methods in order to avoid a large number of simultaneous charges in a limited part of a network, which would create overloading stress.

Consequently, with the advent of Smart Supply, the level of the information and communication infrastructure will go two levels deeper. Entities to be interfaced will include the generators, storage units and the end-consumers. The infrastructure of other utilities like water, heat and (bio-) gas may also be interfaced for synergy reasons, but electricity will be at the forefront.

In several countries regulatory agencies have defined a service called "information provider" (in the European Union often referred to as a Data Access Manager—DAM).

The purpose of the information provider is to serve other actors in the business chain. Major requirements of the information provider are to be non-discriminatory, (cybercrime-) secure, reliable and compliant with privacy legislation. The information provider collects, condenses and delivers data within actor defined communication protocols, response times and latencies. The primary source for data input is the metering service provider. The interrelation between the various actors and the information provider is depicted in Fig. 7.10.

The figure illustrates the concept of the information provider services with regard to the local communication infrastructure. The data exchange functions serve commercial and physical network control operations at the transformer terminals MV/0.4 kV. In [10] it is stressed that both tasks require separate and independent communication domains. The network control needs shorter response times than the market communication.

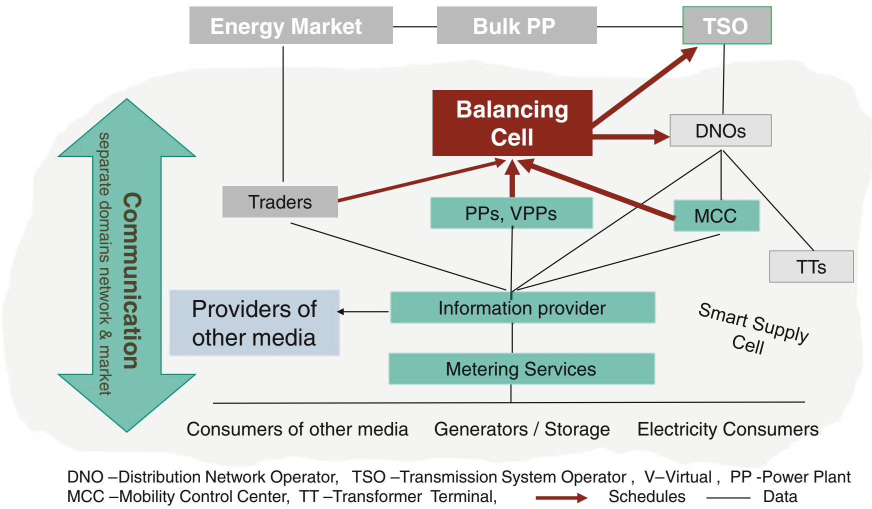

Fig. 7.10 Actor and service relations in a Smart Supply Cell [10]

7.2.2 Metering Services

The independent market role of the meter service provider was established in the European Union in the context of the unbundling of the electricity supply business. However, the degree of liberalization varies greatly from country to country. For example, a high level of liberalization has been achieved in the UK. Here the metering services may close the whole value chain around the metering from the purchase of meters up to the revenue control and compensation of the traders as shown in Fig. 7.11. The metering service concessions are tendered for closed territories and may cover the electricity metering and metering of other media (e.g. gas—“dual fuel”).

In other countries the basic responsibility and the back-up level for metering services is assigned to the DNO by law.

However, all consumers have the opportunity to select their own meter service provider. A complicated chain of contracts between the trader, the meter service provider, the network operator and the consumer has to be completed. As a result there are a large number of meter service provider domains in one territory, and the opportunity to enhance the efficiency via a common management of resources in a territory is lost.

Normally, the metering services end at the step of data acquisition and do not cover the billing and revenue control.

Furthermore, the compensation of the metering service efforts is regulated by definite charges for all kinds of services.

These charges do not cover the expenses if the metering service activities are not concentrated but instead are split over a large territory. Consequently, the DNO

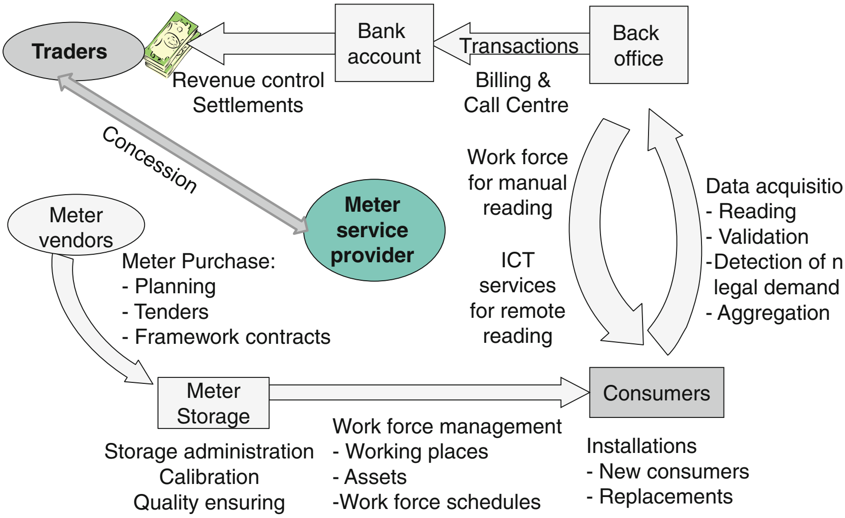

Fig. 7.11 Complete metering service value chain

is still responsible for the metering services in the majority of cases. A real liberalization is not achieved with such rules.

A future business model could integrate the following practices:

- Concession assignment for a closed territory as the result of a bidding process.
- The concession covers not only the metering services for electricity but also for other supplies like gas, water and district heating.

As a result of this business model, synergies of the metering processes for different media can enhance the efficiency by a common use of resources, planning of work force, and concentrated establishment of the infrastructure including vehicles, instruments, laboratories, stores.

Several European countries are currently discussing smart metering trajectories and the considerations regarding performing metering services by giving concessions in certain areas.

In a cellular context, it has to be realized that data provisioning also has to extend to reconciliation and that the collection of real-time measurement and control data will also be necessary.

With the use of smart meters, it is possible to additionally obtain values for network monitoring and quality assessment of current and voltage. The requirements for the smart metering systems are numerous and will increase once smart meters are actively engaged in the network.

7.2.3 Data Communication and Information Management

The three pillars of Smart Distribution require the establishment of a communication infrastructure in the distribution networks all the way down to the consumers connected to the low voltage networks. Furthermore, the data to be communicated between the actors of the supply processes have to be processed in the control centers and exchanged between various enterprise management systems. This requires a significant enhancement of the data bases in the control centers. The new market roles of the communication service provider and the information provider have to be installed.

The communication provider rolls out the data communication network and the data traffic according to the quality attributes for the Smart Grid and the Smart Market. In principle, the required communication infrastructure already exists in the developed industrial countries. The telecommunication providers acting in the territories of Smart Supply Cells can use the opportunity to obtain concessions for the market and network communications. They may be charged on a flat-rate basis for data communication access points. In this way, the communication providers may extend their business models.

The information provider (or data access manager) receives payments according to the volume of data acquired by the customers. This new market role also can be performed based on an area concession. The DNOs are able to perform this function based on the existing infrastructure in their control centers. They are also able to take over the responsibility of the balance management of the Smart Supply Cell.

Detailed information regarding the information and communication technologies is considered in the next chapter.

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Chapter 8
Advanced Information and Communication Technology: The Backbone of Smart Grids

8.1 The Importance of Uniform ICT Standards for Smart Grids

8.1.1 Functions of ICT Standards

The information exchange necessary to properly run Smart Grids has to cover all levels of the electric power system and will take on a new quality compared to the traditional communication methods. The immense increase in the volume of data to be transferred requires the application of advanced information and communication technologies (ICT) in order to avoid extremely increased engineering efforts and to ensure consistency and security of the data transfer from level to level.

The efficiency of the ICT system architecture requires that all modules are designed in accordance with uniform, open and globally accepted standards.

The new standards have to cover the following main functions, as presented in Fig. 8.1.

- Online data transfer through communication networks,
- Consistent information management and data exchange between the data bases of various enterprise management systems,
- Protection against data manipulations and to ensure information security.

The Sects. 8.1.2, 8.2 and 8.3 are mainly based on the lectures of the VDE seminar "Communication as the backbone of Smart Grids" which were compiled and held by the author Dr. B. M. Buchholz and C. Brunner, president of IT4Power (Zug, CH) and convenor of the WG 10 "System relations of IEC 61850" of TC 57/IEC.

B. M. Buchholz and Z. Styczynski, *Smart Grids – Fundamentals and Technologies in Electricity Networks*, DOI: 10.1007/978-3-642-45120-1_8,

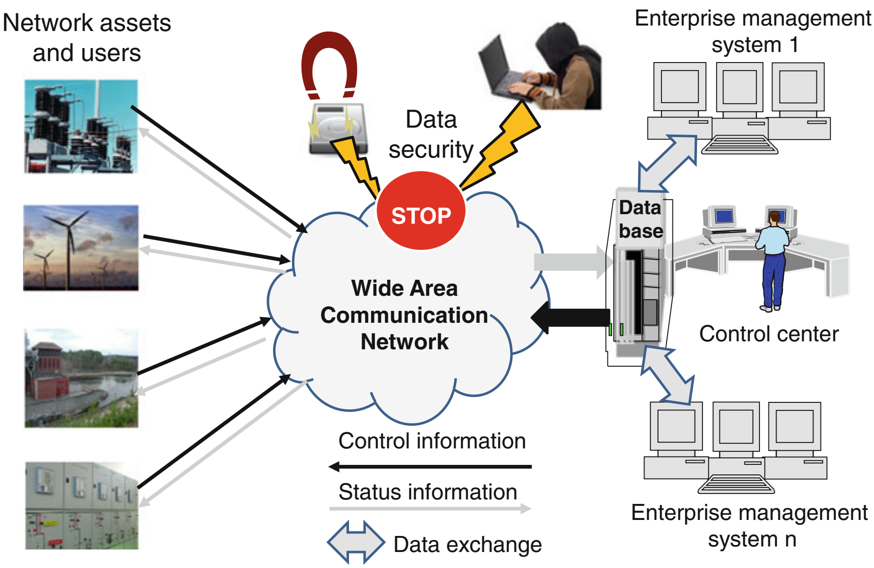


Fig. 8.1 The main standardization aspects of the ICT for Smart Grids

8.1.2 Communication Standards

In general, communication standards follow the seven layer ISO/OSI (International Organization for Standardization/Open Systems Interconnection) reference model according to Fig. 8.2. The seven layers are mutually independent which allows for various combinations of the layers. For example, it becomes possible to apply layers with long term stability (e.g. the application layer covering the data models and the communication services) with layers which change according to the technology progress (e.g. link layer or physical layer).

The functions of the layers are described with the analogy “Letter”. The letter itself expresses the thoughts and necessary information for the receiver in sentences with a definite syntax and semantic of the chosen language within the application layer. The information has to be presented in written form—e.g. with black letters on white paper. The method of transfer needs to be defined at the session layer—e.g. by air mail. The transportation layer requests the address of the receiver and the network layers defines which provider is used for the transfer (e.g. the company DHL). The link layer is mainly responsible for secure transfer of the information. In the case of a posted letter this can be done by checking the transfer status online and by mandatory confirmation upon arrival at the addressee.

The physical layer defines the physical media of the communication channel—in the case of the airmail letter this is the aircraft and the car.

The exact definition of all layers builds the communication protocol. Simple communication protocols may use only the layers 1, 2 and 7. However, they are

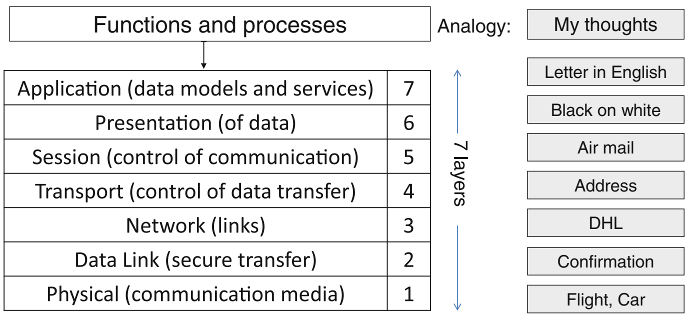


Fig. 8.2 The 7 layer ISO/OSI communication reference model

limited for definite point to point connections. Wide area communication networks (WAN) use the Tele-Communication Protocol/Internet Protocol (TCP/IP) addressing scheme at the transport and network layers.

The link or physical layers can be changed along the way through a communication network. But, a conversion is requested for the change over into the new protocol.

The addressing scheme of the previous layers (assigning each participant of the communication a definite identification) has to be kept stable to ensure that the message arrives at the right receiver.

The application layer is very important for the consistent, plausible and definite expression of the information. The standard has to define the syntax and semantics of the data models, because the computer intelligence is not capable of abstractions like the human intelligence, as is presented in Fig. 8.3.

If the control center communicates with the partners representing the system components by using different application layers all of these application layers need to be embedded into the control center computer.

The definition of uniform data models of the application layer is the mandatory pre-requisite of an efficient communication system for Smart Grids.

For historical reasons, various communication standards are currently used for the electric network operations, e.g. inside the substations for different types of assets (e.g. protection, switchgear or meters) and between the substations and control centers. This practice requires the conversion of data formats between the different system levels, which in turn requires high engineering efforts and is a source of inconsistencies. Furthermore, the detection of inconsistencies in the information exchange causes higher efforts for commissioning tests.

The traditional remote control of the power system is structured in accordance with the importance of the system components for the reliability of supply. The remote control and supervision function based on communication facilities covers the transmission grid, the regional distribution (or sub-transmission) network and the MV busbars in the HV/MV substations as shown in Fig. 8.4. For economic reasons, the MV and LV networks are not equipped with a remote control function

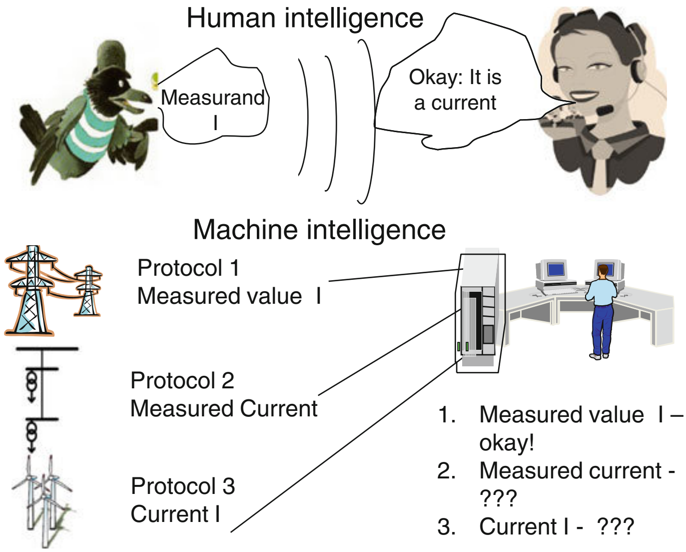


Fig. 8.3 Machine intelligence requires definite semantics and syntax

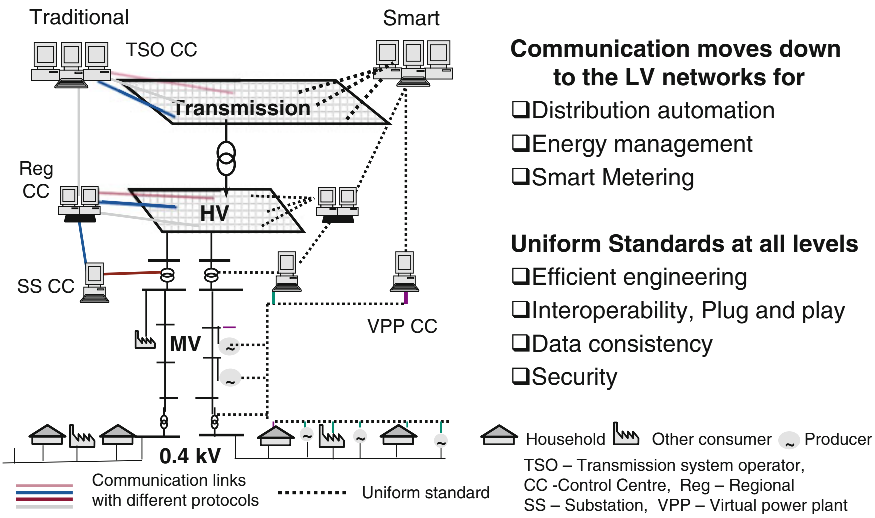


Fig. 8.4 The traditional communication in the power system and the needs of the Smart Grid

and the related communication facilities. All operations in this network levels require the local presence of operators. However, in unplanned situations like disturbances the personnel can only arrive at the affected network section after some time delay.

The Smart Grid challenges require a deep paradigm change in the area of supervisory control and data acquisition (SCADA) for the electric networks.

First of all, the communication has to penetrate the distribution level down to the low voltage network users in order to perform the three pillars of Smart Distribution, as shown on the right-hand side of Fig. 8.4.

Secondly, global standard protocols using uniform data models and services have to be applied to ensure engineering efficiency, interoperability and "plug and play" capabilities of the intelligent electronic devices (IEDs) from different vendors, data consistency and information security at all levels of the electric power system.

The transmission system operators often use internal communication networks for their SCADA systems. However, the enhancement of the distribution network operation may use the existing infrastructures for communication.

The distribution network operator (DNO) can either establish its own communication channels using the power line carrier (PLC) technologies or contract a communication service provider who is able to ensure the offer of a separate communication domain with high information security and performance of the network related SCADA functions. The most efficient communication technologies that can be applied depend on the local conditions and may be in different physical forms: copper cables, fiber optic cables, radio.

The prospective uniform communication standard should offer the following aspects:

- Global acceptance,
- Less engineering by object oriented instruments and models,
- Services ensuring quality, efficiency, accuracy and security of the information exchange,
- High performance,
- Open for extensions regarding future applications,
- Flexibility in applying prospective innovative communication on the physical and link layers,
- Application of mature technologies in the 7-Layer Model,
- Interfaces to other standards and continuity in new standard extensions.

The interoperable data exchange/interoperability over all levels of the power system—from the electricity sockets up to the network control centers—using uniform data models and services is a pre-requisite for the successful Smart Grid enhancement.

The development of the appropriate communication standards began in 1980 and is still ongoing. The development of the standard communication protocols had a deep impact on SCADA system architecture and performance. Both, the SCADA technology and the communication standards were developed in a mutual context as will be described in Sect. 8.2. However, the development history caused the introduction of a number of proprietary, regional and international standard series which are still applied in the practice of the power system control. The migration strategies are considered in Sect. 8.6.

8.1.3 Standards for Data Management

Enterprise process management (EPM) systems nowadays are broadly used to manage all processes of the enterprise based on digital data bases in an efficient way.

The enterprises use a wide variety of EPS for the different processes and such EPM systems are developed and delivered by various vendors. Consequently, the data formats used in the commercial data bases are vendor specific.

The overall enterprise management consists of many components interacting with each other, and those systems will become more complex in the future. In Fig. 8.5 an overview of typical EPM systems in the field of electricity supply is given.

In practice, the same data is often relevant for several EPM systems. For example, parameters of a transformer are used in the data bases of the following EPM systems for the network management:

- SCADA,
- EMS (Energy management systems of TSOs) or DMS (Distribution management systems of DNOs),
- geographical information system (GIS),
- network planning,
- asset management,
- maintenance management,
- outage management.

Metered values, for example, may be required in the various classes of EPM systems:

- Generation management—for scheduling,
- Network management—for SCADA,
- DMS,
- Service and customer care—for
  - Billing,
  - Customer information,
  - Energy balance management,
  - Meter data management,
- Sales and trading—for
  - Energy trading,
  - Sales forecast.

Due to the multiple uses of data, the wide variety of data formats used in the data bases of different vendors create the following problems:

The exchange of data between the data bases is complicated because of the various data formats. Each data exchange procedure needs a conversion from one into the other format.

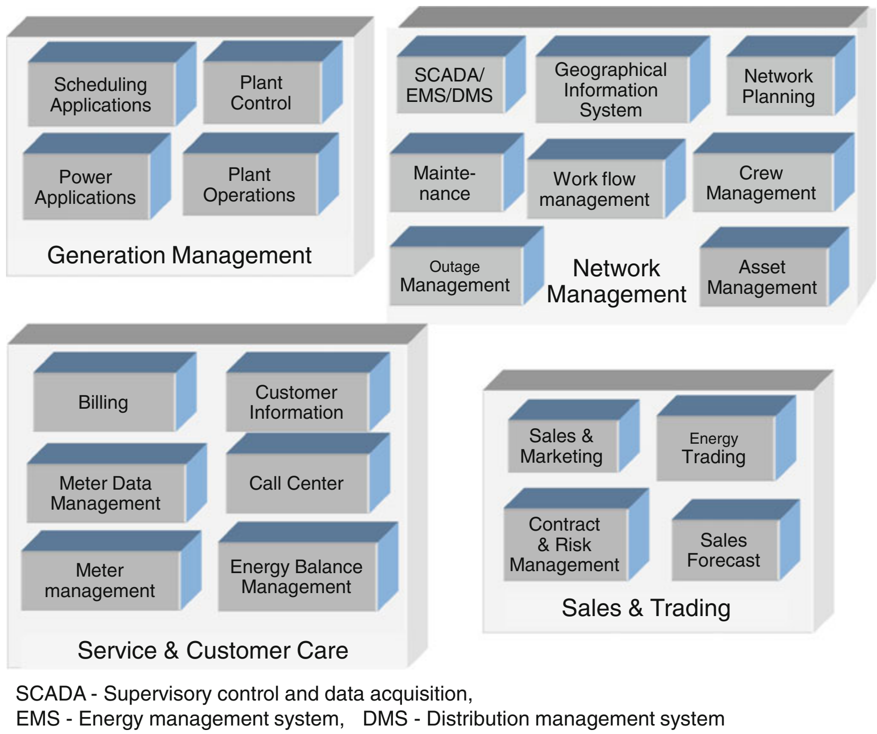


Fig. 8.5 Enterprise process management systems used in the area of electricity supply

Data changes have to be performed in all data bases where the data are used. Otherwise, the consistency of the EPM systems will be lost.

The data base maintenance is assigned to different entities inside an enterprise or to different enterprises in general (e.g. DNO, trader, power producer). The simultaneous adaptation of the data is hard to execute.

The automatic distribution of data would be a solution to keep the data consistency in all data bases used for the electricity supply processes. However, this would request data format converters between all the data bases involved—in all directions (e.g. from data base 1 with data model A to data base 2 with data model B, as well as from data base 2 with data model B to data base 1 with data model A).

Here the need for a common data repository arises which can be used to maintain all the data bases by using a common information model, since the number of adapters between the components grows if proprietary data formats are used. When applying a common information model, there is only the need for one adapter between the relevant data bases and the common data repository.

This relation is shown in Fig. 8.6 where every arrow represents a bidirectional data format converter.

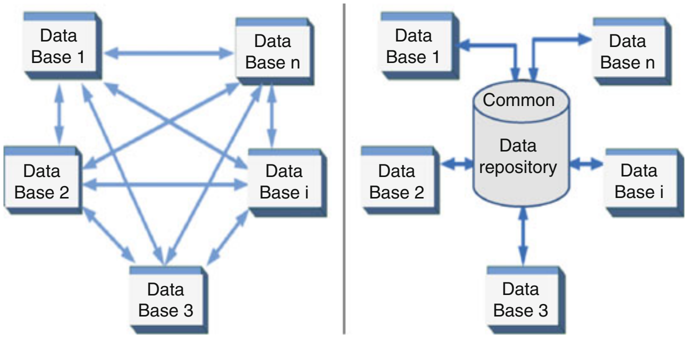


Fig. 8.6 Amount of data converters when using various proprietary data formats and a common data format

The simplest way to exchange data between entities or enterprises and to keep all data bases consistent is to apply the common information model in all data bases.

The transmission system operators in Europe and North America have begun to follow this method and transfer their data bases to the common information model (CIM) according to IEC 61970 "Energy management system application program interface" [1].

8.1.4 Information Security

Electricity networks belong to the critical infrastructure systems. The remote control and supervision of electric networks are vulnerable to several security threats like:

- External attacks,
- Internal attacks,
- Natural disasters,
- Equipment failures,
- Carelessness,
- Data manipulation,
- Loss of data.

Figure 8.7 illustrates the possible threats to information security.

The reactions to the threats can physically damage the network assets and have tremendous legal, social, and financial consequences.

In order to be able to meet the requirements in terms of confidentiality, availability, integrity, and non-repudiation standards for information security have to be applied. Advanced encryption methods and the objectives of the standard IEC 62351 "Power systems management and associated information exchange—Data and communications security" [2] must be applied to ensure the security of the power system control via communication networks.

Fig. 8.7 Threats to information security

8.2 The History of Communication Development for Supervision and Control in Power Systems

8.2.1 The Design Development of Remote Substation Control

The transmission networks throughout the world experienced tremendous development and expansion during the 1960s and 1970s, and for the first time the interconnections crossed country borders. Since the 1970s more and more data was exchanged between the substations and the control centers. Also, for the first time substations were operated remotely.

The first generation of remotely operated SCADA systems still used a single wire for each signal. The wires were bundled in cable channels leading from the equipment through the substation area to the control building of the substation. All control, automation and protection devices including the control panel were located in this building as shown in Fig. 8.8.

Telecommunication cables or power line carrier facilities were used for the information exchange with the control center. The remote terminal unit (RTU) used a multiplexer for the signal acquisition and converted the sequence of the sampled signals into bitmaps which were transferred via point to point connections

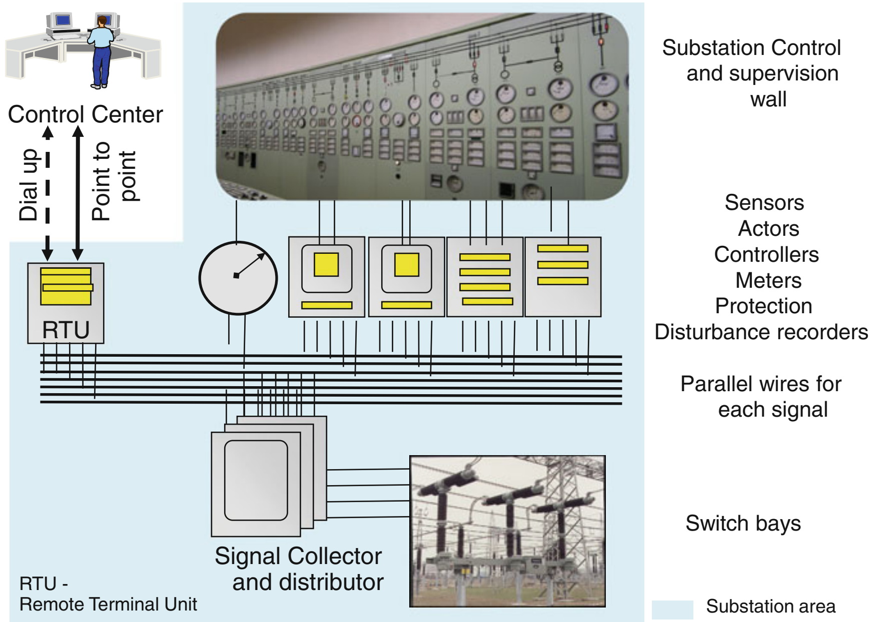


Fig. 8.8 Principle scheme of the first and second generation of SCADA connection to substations

(partly dial up) to the control center. The application of digital technologies was very restricted because of their high costs.

A fundamental change occurred with the appearance of the cost efficient microelectronic computer technology in the early 1980s. The 2nd generation of SCADA systems was based on digital remote terminal units and serial communication protocols. The digital technology allowed the transfer of a significantly increased data volume. However, this technology did not provide a significant change regarding the signal wiring inside the substation and the principle scheme corresponds with that in Fig. 8.8.

The 3rd generation of SCADA was introduced in 1986. This technology was based on a substation automation system (SAS) with a central coordination unit at the substation level and distributed digital bay units.

The functionality of the bay units followed the traditional function methodology but with distributed locations in autonomous devices. Separate devices were applied for control and supervision, for protection and for interlocking, as depicted in Fig. 8.9.

These bay units were located directly at the switchgear location and provided an interface for the serial communication with the station unit. Consequently, each switch bay required only one serial link—copper or fiber optics.

The central station units served the communication interfaces to the control center and to the bay units (station bus), and were capable of further advanced

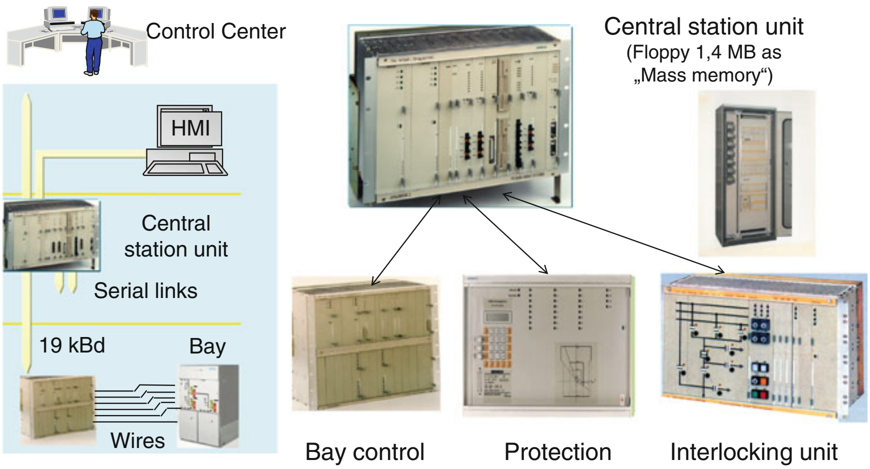


Fig. 8.9 The 3rd generation of SCADA systems based on digital substation automation systems (SAS)

functions like automatic sequences of operations, report management or station interlocking. Color screens and simplified keyboards—the human machine interfaces (HMI) replaced the former large control panel walls.

Two floppy disc drivers were used for a removable data repository—the "mass memory" with 1.4 MB storage capacity. With this solution the network operators could easily transfer reports and disturbance records to their own computers. The communication inside the substation was based on the master–slave polling principle with a speed of 9.6 or 19.2 kBd.

The 4th generation of SCADA is based on networked substation automation systems and has been applied since 2004 in accordance with the standardized application of Ethernet in the link layer (Fig. 8.10).

The function of the central station unit is now performed by an industrial PC which provides the needed interfaces to the station bus and to the WAN for remote control and remote data delivery to several "clients".

The opportunity to apply digital sensors and actors at the process level is foreseen in these systems by offering Ethernet interfaces at the bay units to provide the digital data acquisition and control by serial communication on the lower level—the process bus. The process bus is also suitable to connect optical instrument transformers based on the Faraday-effect (current) and the Pockels-effect (voltage).

Ethernet represents a revolution in the communication technology because of its data management principle and high level of performance. Figure 8.11 compares the master–slave principle and the Ethernet "Client–Server" model of communication.

The master needs a few seconds to interrogate all the slaves in the polling sequence for data acquisition (balanced mode). Only high priority signals like disturbance messages or commands may interrupt the polling sequence (unbalanced mode).

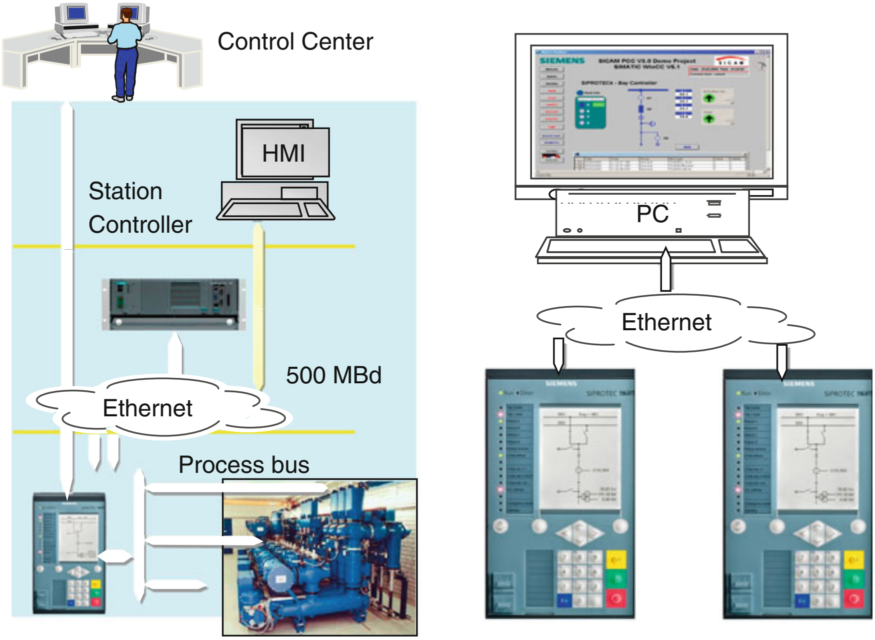


Fig. 8.10 The 4th generation of SCADA—networked substation automation system

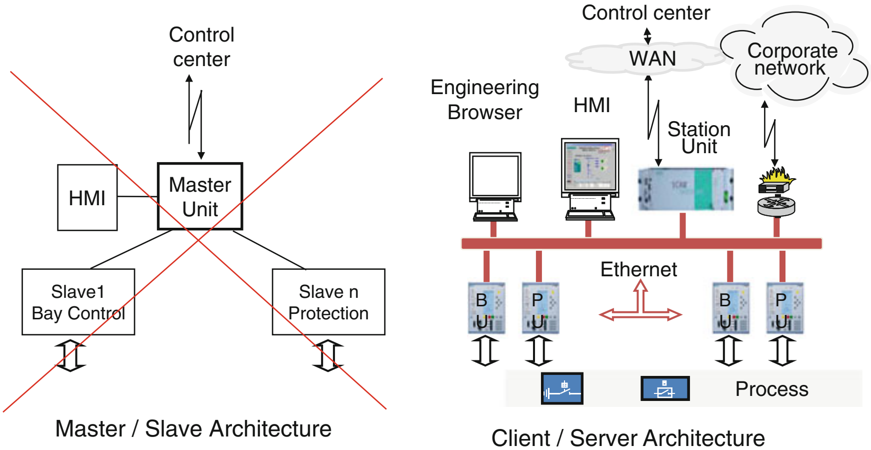


Fig. 8.11 The master–slave and the client–server communication architecture

Using Ethernet, the traditional master–slave principle is replaced by the client–server model. The client–server model allows each server to access the Ethernet at the same time, i.e. at the moment of message transfer request. If more than 1 message accesses the Ethernet at the same time, it serves first the higher priority message and then the lower priority message.

The Ethernet also allows direct data transfer between the servers in the "publisher–subscriber" mode. This principle allows the publisher to send actual data directly to all subscribers which were assigned to this kind of information during the engineering process.

Today Ethernet is the standard for the LAN/WAN-communication. Ethernet supports many protocol layers and services. The communication tasks of the industry, of power systems and of the office environment may be commonly executed based on Ethernet.

8.2.2 Introduction of Digital Communication Protocols

The SCADA technology development described above was accompanied and driven by the development of the appropriate serial communication protocols.

At the end of the 1970s the leading manufacturers of SCADA systems introduced their specific proprietary protocols like Sinaut, Telegyr, Indactic and DNP for communication between the substations and the control centers.

The control centers had to understand all protocols implemented in the remote control technologies of different vendors installed in the substations. The urgent need for standards in this area was obvious. After a standardization process that took several years, various regional and international protocols were created, as shown in Fig. 8.12.

In the mid of the 1980s the telecommunication standard series IEC 60870 began to be developed. For application in the power system control the protocol "101" was adapted to the series IEC 60870-5. However, the first edition as the official standard IEC 60870-5-101 [3] was not published until 10 years later in November 1995.

The first published international standard IEC 60870-5-101 is a standard for power system monitoring, control and associated telecommunications for electric power systems. This is a companion standard which is based on and completely compatible with the IEC 60870-5-1 to IEC 60870-5-5 standards defining basic rules of the communication procedures. It uses the standard asynchronous serial interface with a communication speed of 19.2 kBd.

The standard is based on the polling principle and supports unbalanced (only master initiated messages) and balanced (data communication can be master/slave initiated) modes of data transfer.

The standard defines the frame formats of the information exchange as presented in Fig. 8.13. The start frame contains the start character (repeated for reliability), the length of the frame, the control field to indicate the message direction and the link address which is used as the station address.

The identification field of this frame contains the type identifier and the variable structure identifier. Both define the structure and the length of the Application Service Data Unit (ASDU). The type identifier describes the type and the attributes

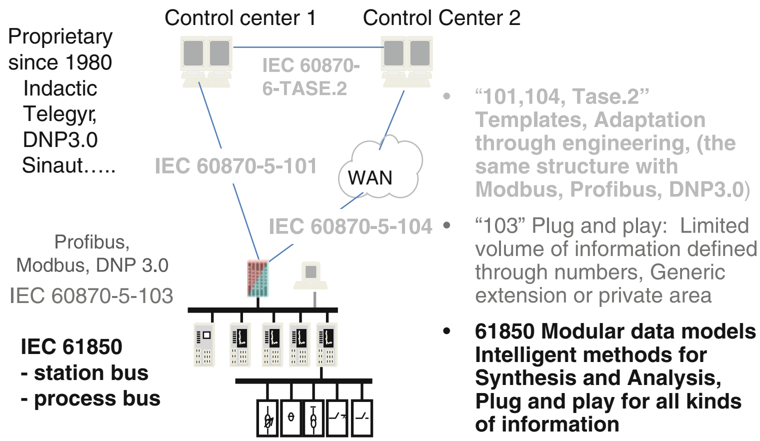


Fig. 8.12 Standards for communication in power systems—of IEC and regional importance

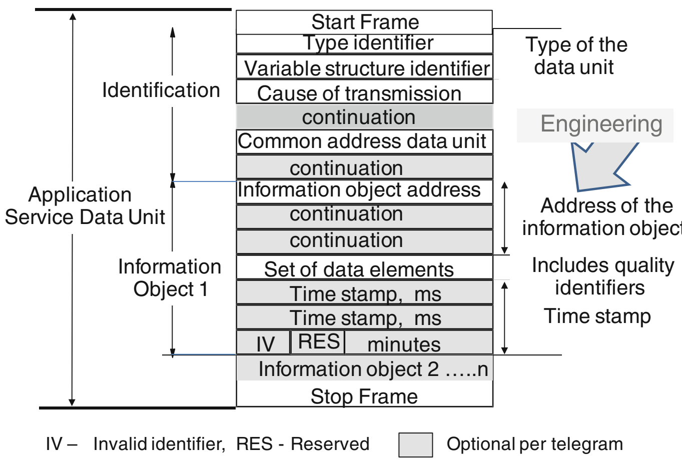


Fig. 8.13 The frame structure and content accordingly IEC 60870-5-101

(e.g. time stamp) of the information object. The types presented in Table 8.1 are supported by IEC 60870-5-101.

Each type identifier is assigned a number code. The selection of types with or without time stamps belongs to the past. Nowadays, time stamps with a resolution of 1 ms are assigned to the ASDUs.

The variable structure identifier defines the number of subsequent information objects within the ASDU. Reasons for transmission may be in the supervision direction: spontaneous, cyclic, on request, general interrogation, command confirmation, etc. In the control direction, the general command, general setting,

Table 8.1 Type identifications (TI) supported by IEC 60870-5-101

Supervision	TI	Control	TI
Single indication without/with time stamp	1 2	Single commands	45
Double indication without/with time stamp	3 4	Double commands	46
Step position indication without/with time stamp	5 6	Regulating step command	47
Bitmap without/with time stamp	7 8	Digital set-point commands (bitmaps)	51
Measured value normalized without/with time stamp	9 10	Analogue set-point command normalized	48
Scaled without/with time stamp	11 12	Analogue set-point command scaled	49
Floating point without/with time stamp	13 14	Analogue set-point command floating point	50
Metered values without/with time stamp	15 16	General interrogation command Metered value interrogation command	100 101
		Request of disturbance record command	102
		Clock synchronization command	103

switch parameter set and others are applied. The causes of transmission are coded by definite numbers. The ASDU address is provided for classifying the receiving end station and its different segments. Consequently, when the identification field is completed then the structure of the ASDU frame is fixed.

The information object is provided with a specific address number which has to be assigned by engineering. This address defines for example that the type "measured value" expresses the current in phase A of the 110 kV transformer feeder 101 or that the type "double point indication" expresses the position of the circuit breaker of the 110 kV transformer feeder 102.

This address number has to be engineered identically at the control center (master) and at the substation (slave). The set of data elements contains the value of the message or command—a measured floating point value, a number of the transformer tap position or the position of a switch device in accordance with the type identifier.

The set of data elements also contains several quality identifiers as depicted in Fig. 8.14 for the example of a Double Point Indication (DPI).

The time stamp in milliseconds and minutes is counted from a definite starting moment. One bit in the time stamp field is foreseen for the quality identifier (IV = 0 valid, IV = 1 invalid) of the time stamp.

The stop frame concludes the ASDU. It contains the check sum and the stop character.

The check sum together with a parity bit for each data field ensures the information security with a Hamming distance of 4.

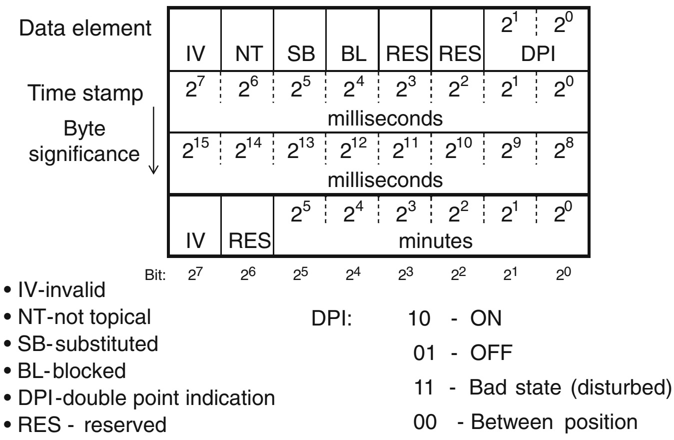


Fig. 8.14 The information set of the type Double Point Indication with time stamp

IEC 60870-5-101 was extended to the standard IEC 60870-5-104 which uses Ethernet and the TCP/IP addressing scheme at the layers 2–4. Therefore, this communication standard may be applied in wide area communication networks. Furthermore, the standard IEC 60870-6-TASE.2 was developed and published for the communication needs between the control centers.

The standards IEC 60870-5-101 and IEC 60870-5-104 are currently applied worldwide in the majority of SCADA systems for electric network control.

The main disadvantage of these standards is the need for engineering the information object addresses. This method prevents the desired feature of “plug and play”.

The engineering of the information address requires a huge amount of human effort. The engineering has to be performed by using different engineering tools for the master and the slave and is normally executed by different specialists on both sides of the communication. This approach is accompanied by a high risk of inconsistent data sets for the master and the slave.

Besides the IEC protocol standards other protocols gained importance for standards in special regions or application areas. This concerns the protocols Modbus and DNP3.0, which are well distributed in North America, and the Profibus, which is often applied in industrial networks to ensure the compatibility with the communication used for the manufacturing processes. All three protocols are based on a similar structure to the IEC 60870-5 protocols and do not allow plug and play without extensive engineering.

Beginning in 1986 the distributed digital protection and control technologies according to Fig. 8.9 were introduced to the market. The serial communication reached the substation level.

The protocols used for protection data communication were again vendor specific. However, it is the common practice of the transmission system operators to install protection relays of different vendors for main and reserve protection.

The proprietary protocols and the request for intensive engineering in the context with the above described communication standards cannot be accepted in accordance with this protection philosophy. Consequently, the interoperability of devices of different vendors and the “plug and play”—feature became a high priority requirement.

At the end of the 1980s, VDEW (German society of network operators) began to develop recommendations for the protection communication based on the structure elements of IEC 60870-5-101. These recommendations became an official document in 1993. All protection manufacturers acting on the German market were obliged to implement the recommended protocol into their digital protection devices.

In 1994 the ad hoc working group (WG) of the IEC Technical committee TC 57 was established to develop a general standard for communication in substations.

This WG decided to approach this important task using a two-step approach.

1. The short term approach had to use the existing systematics to meet the urgent request for a compatible data exchange of different protection units. Consequently, the VDEW recommendations were approved and qualified for the global market.
2. The long term approach was considered with the target to create an overall standard for substation communication (station bus and process bus for inclusion of digital sensors, actors and instrument transformers) without limitations, avoiding extensive engineering, also allowing plug and play, and would be open for extensions and future technologies.

In the framework of the short term approach, the VDEW recommendations were extended by the opportunity of generic extensions. The relevant standard IEC 60870-5-103 was published as a CDV (committee draft for voting) in 1995 and has been valid since 1997 [4].

The standard IEC 60870-5-103 enables interoperability between protection equipment and devices of a control system in a substation. The standard is based on a framework similar to IEC 60870-5-101. The main reason for the plug and play behavior consists in the fixed definition of the information object address.

The information object address was replaced by two definite identifiers:

- The function type of the protection device,
- The information number.

The standard defines only four protection functions types with the number codes:

128 Distance protection
160 Over current protection
176 Transformer differential protection
192 Line differential protection

Table 8.2 Categories and amount of information numbers defined in IEC 60870-5-103

Supervision	Amount	Control	Amount
System indications	6	System commands	2
Status indications	25	General commands	8
Monitoring messages	9	Generic commands	9
Earth fault indications	5		
Short circuit indications	30		
Autorecloser messages	3		
Measured value sets	5		
Generic functions	8		

Furthermore, the number 254 is reserved for generic function types and 255 is foreseen for a global type. Other numbers of the one byte function type field can be used for private extensions of the protection manufacturers.

The information of the protection related functions like auto-reclosing, synchronism check, fault locator or disturbance record are assigned to function type of the main protection principle. The standard offers 83 compatible and 17 generic information numbers in accordance with Table 8.2.

Consequently, the compatible part of the standard is very limited and not open for future extensions. Extensions may be performed by the generic approach defined in the standard and within the private address arrays of the manufacturers. This limitation is the main disadvantage of the standard.

The standard defines two physical layers: RS 485 bus or fibre optic cables with 19.2 kBd.

The low speed of data transfer and the applied polling principle (unbalanced) are further disadvantages. However, since the CDV was publishing in 1995 this standard protocol has been used in some tens of thousands of substations worldwide.

The "long term approach" began in 1995 with the organization of three new international WGs within the TC 57. The responsibilities of the WGs were focused on:

- the overall system architecture,
- the details of the station bus and
- the details of the process bus.

The following targets were set for the foreseen standard development:

- Interoperability
  - Free information exchange between IED's (Intelligent Electronic Device) from several manufacturers based on self-explaining object oriented data models,
  - Use of this information for the own function,

- Free Configuration
  - Free allocation of functions to devices,
  - Support of any type of user philosophy, e.g.—in centralized or decentralized systems,
- Long Term Stability
  - Application of mature technologies for the protocol layers,
  - Future compatibility,
  - Following the progress in the mainstream of communication technology,
  - Following the evolving system requirements needed for new applications,
- Efficiency
  - Reduction of the engineering efforts,
  - Decrease of the risk of inconsistencies,
- Performance
  - Reduction of the latencies of the master–slave communication,
  - Vertical (bay-station level) and horizontal (bay to bay) communication,
  - High speed communication,
- Security, quality supervision
  - Security services,
  - Detection of wrong data and loss of data,
  - Confirmation services,
  - Quality identifiers,
- Comfort
  - Directory services,
  - Diagnostic services,
  - Time synchronization,
  - Independent engineering.

Today, it should be stressed that these targets were reached only after long years of hard work by many international experts. Significant progress was made based on the synthesis of the experiences of two international bodies: IEC and IEEE.

The experience of the IEC communication protocols was used regarding the continuity of the

- structure elements and types of information,
- quality identification of the data,
- security and confirmation services.

The IEEE experts opened and adapted the previously developed UCA approach (Utility Communication Architecture) for international application in the common IEC standard. This agreement brought a paradigm change in the application layer by using

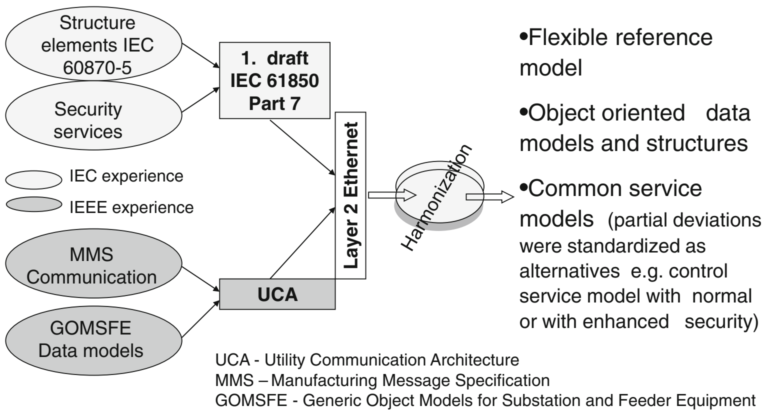


Fig. 8.15 Harmonization of IEC and IEEE experiences for the common standard protocol

- the manufacturing message specification (MMS) for the basic services,
- the Generic Object Models for Substation and Feeder Equipment (GOMSFE) as the object oriented data model.

The Manufacturing Message Specification is an international standard (ISO 9506) dealing with the messaging system for transferring real time process data and supervisory control information between networked devices. The standard was developed and is maintained by the ISO Technical Committee 184 (TC184). MMS defines the following:

- A set of standard objects which must exist in every intelligent device, which can be used to execute operations like read, write, event signaling etc.
- A set of standard messages exchanged between a client and a server for the purpose of monitoring and/or controlling these objects.
- A set of encoding rules for mapping these messages to bits and bytes when transmitted.

GOMSFE describes the basic approach for object oriented data model building and is described in Sect. 8.3.

Figure 8.15 demonstrates this selected approach which supported the successful inclusion and the worldwide acceptance of the standard IEC 61850.

The communication standard series IEC 61850 “Communication networks and systems for substations” now offers the above mentioned characteristics and benefits. The first priority for the development of this standard series was the communication needs in substations.

In the framework of the Smart Grid context the standard will now be extended to meet the requirements of other components of the networks and of the network users. Consequently, the second edition of the standard was published in 2011 and renamed “Communication networks and systems for power utility automation” [5].

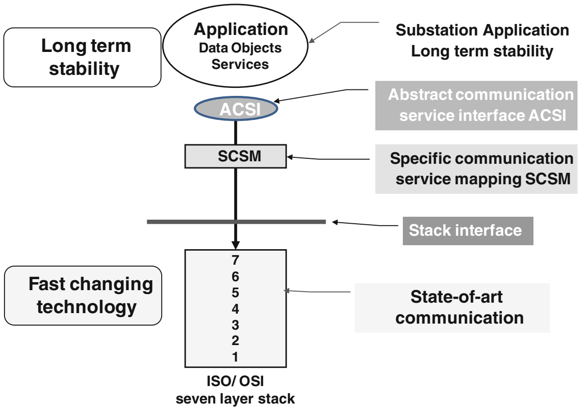


Fig. 8.16 The IEC 61850 reference model

8.3 Seamless Communication by Applying the Standard Series IEC 61850

8.3.1 The Reference Model and the Structure of IEC 61850

The standard series IEC 61850 offers more than just the definition of the communication protocol. The foundation of the requested flexibility was laid with the development of the reference model of the standard which is depicted in Fig. 8.16.

Here, the main idea is to separate the solutions with features of long term stability on one side and the fast changing communication technologies on the other side. The basic applications of the network operations will be kept stable in the future but may request extensions. A fast progress can be observed in the development of the information and communication technologies.

Consequently, the reference model of the standard IEC 61850 is designed to provide the requested

- stable foundation for basic applications accompanied by flexible extension methods,
- high flexibility regarding the application of new communication technologies.

The network control applications require the definition of the requested data objects, their modeling and the appropriate communication services. The standard defines these items within the abstract communication service interface ACSI.

The specific communication service mapping SCSM offers the opportunity to combine the data models and services of the ACSI with the up to date communication technologies used within the seven layer protocol stack.

The standard series IEC 61850 supports a general system approach by linking the practice of electric network operations with the communication architecture.

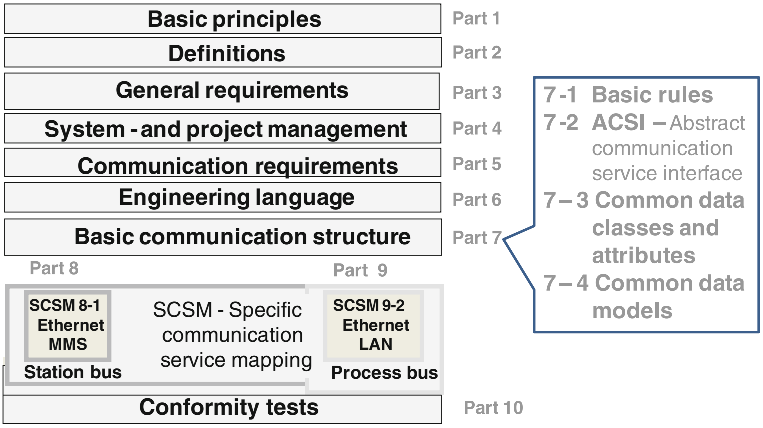


Fig. 8.17 The IEC 61850 structure

The following aspects are considered and defined in the separate parts of the standard:

- the system aspects and management in general,
- the advanced communication services,
- the generic data models,
- the mapping to real communication networks,
- the engineering process,
- the conformance and commissioning testing.

The structure of the 1st edition of IEC 61850 is presented in Fig. 8.17. This structure is related to the communication tasks in substations, which was the initial objective of the standard development. Today many more parts have been added to this series (see Sect. 8.3.7).

The system aspects are contained in the parts 1, 2, 3, 4 and 5.

Part 1 gives an introduction and the overview of the standard series. Part 2 contains the definitions and the glossary. In part 3 the general requirements are considered in detail.

The part 4 was developed to support the interoperability of intelligent electronic devices IEDs not only from the communication point of view but also related to the management of assets and the compatibility of IED products during and after their life time.

Part 5 deals with the communication requirements for functions and the relevant IED models.

One objective of the standard IEC 61850 is the simplification of engineering and the opportunity to support a vendor independent engineering process. Therefore, the substation configuration language SCL based on XML is developed and defined in the standard part 6. The Extensible Markup Language (XML) is a definition of language which is understandable for human and computers.

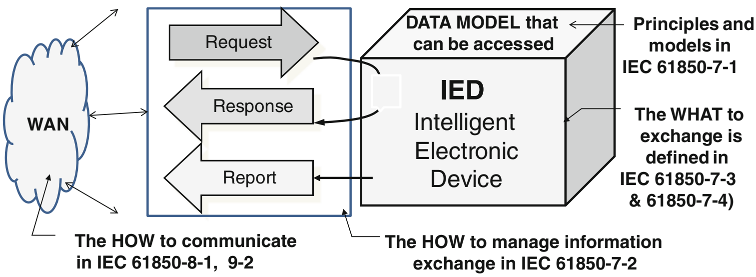


Fig. 8.18 The main standard applications ensuring the protocol interoperability of IEDs

Part 7 describes the object oriented data model building and the communication services. This part is structured in four chapters underlining the importance and the size of information requested for achievement of interoperability. Part 7-1 defines the communication principles and the requirements regarding the data models. These principles perform the basic rules for the ACSI which is defined in part 7-2. The data model requires common data classes CDC which define neither the data describes a complex control mechanism, a measured value or others. A CDC defines the relation between the data attributes and the functional constraint. The structure of the CDCs is partly inherited from the types defined in the standard IEC 60870-5-101 (Table 8.1). However, they are adapted and extended in accordance with the technology progress. For example, all data classes describing the process related online data contain a time stamp. A set of attributes assigned to the data is defined also in part 7-3. The attributes may be defined as mandatory or optional.

The concrete structure and the definitions of the data models are given in the part 7-4.

Part 8-1 describes the currently available SCSM for the station bus based on the manufacturing message specification (MMS) for the application layer.

Part 9-2 offers the SCSMs for the process bus applications. (Part 9-1 is withdrawn. It was developed to define the communication for sampled values delivered by digital instrument transformers.) Part 9-2 is defines the communication of all online data to be exchanged between the bay IEDs and the process level via serial Ethernet links.

Finally, part 10 defines the rules and instruments for the protocol conformance testing.

Each intelligent electronic device (IED) serving as a component of the substation automation system has to provide interoperability based on:

- an accessible data model corresponding with the parts 7-1, 7-3 and 7-4,
- the principles of data exchange in accordance with the parts 7-1 and 7-2 and
- the relevant specific communication service mappings with the parts 8-1 and 9-2

as depicted in Fig. 8.18.

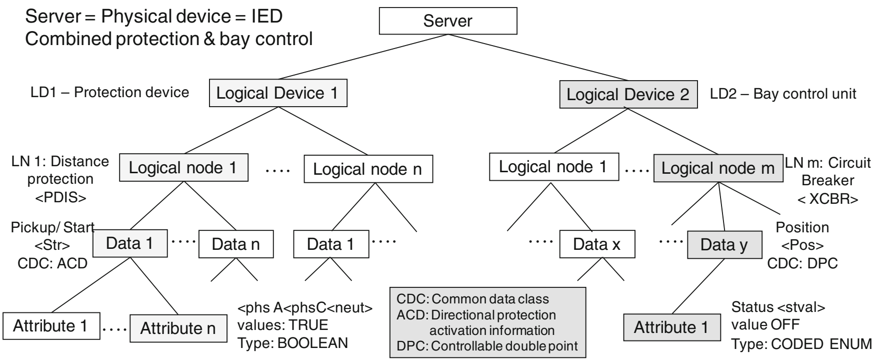


Fig. 8.19 The data model structure of IEC 61850-7-4

The standard offers the data model definitions for the “WHAT”, the ACSI for the “HOW” of data exchange and the SCSM for the complete communication protocol stack.

8.3.2 The Data Model

The structure of the data models uses standardized terms for the structure elements and follows the hierarchy shown in Fig. 8.19.

A physical device is an IED that implements a part of the substation automation functionality. From the communication point of view the physical device acts as the server. A physical device may contain one or more Logical Devices (LD). An LD implements a type of substation functions like protection relay, bay control unit or voltage controller. Each LD contains Logical Nodes (LN).

A logical node is a container for functional data. The type and the format of the functional data is described based a common data class according to IEC 61850-7-3.

Each LN contains a set of data. Finally, a set of attributes is assigned to each of the data. The structure of the data model is demonstrated in Fig. 8.19 with two examples (see also Fig. 8.21).

The physical device consists of two logical devices—a protection device and a bay control unit. One of the logical nodes of the LD “protection” is the distance protection PDIS which contains several data e.g. Start (pickup) and Operate (trip). The data in this example is the start “Str” according to the CDC “ACD” (directional protection activation information). The start is caused by a measured two phase (phsA, phsC) to ground (neut) short circuit. In this case the attributes phsA, phsC and neut contain the value 1 coded as a Boolean object. The value 1 here means TRUE. Otherwise, 0 expresses FALSE. The protection return after the trip of the circuit breaker will be indicated by the changes from TRUE into the FALSE values.

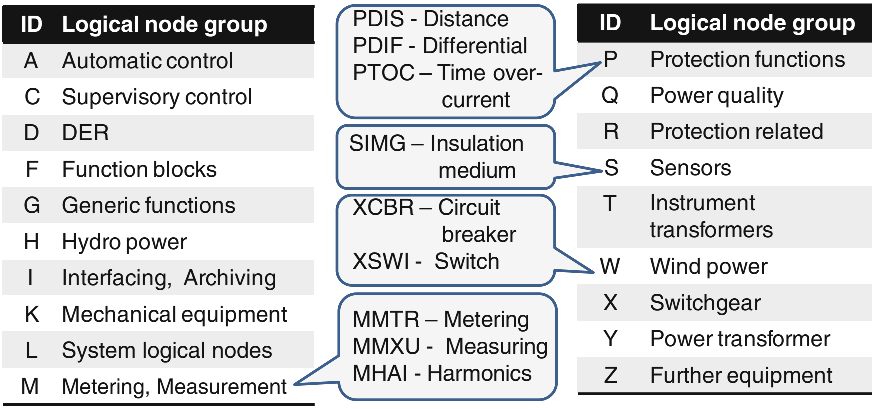


Fig. 8.20 Logical node groups and examples of logical nodes

The LD "bay control" contains (among others) the LN circuit breaker XCBR. One of the data is related to the circuit breaker position and one of the position attributes is the status which is expressed in a Coded Enumeration type with the values 0-Intermediate, 1-OFF, 2-ON and 3-Bad state.

The character of the data and their attributes may be classified into:

- Online process data describing the current process conditions,
- Setting data influencing the functionality, which may be changed online, and resetting data e.g. for online reset of counters,
- Configuration data describing the stable behavior of the function or device and which will be communicated to configure the system behavior and
- General device information like name plate information, technical data and other information which is normally used for directory services.

The last two classes of data allow the automatic recognition of new IEDs integrated into the SAS structure.

The logical nodes are assigned to functional groups which may be related to the primary technology (switchgear, transformer, lines) or to the secondary technology (control, interfacing, automation, protection). The logical node groups have group identifications (ID) as shown in Fig. 8.20.

The second edition of IEC 61850 contains 150 logical nodes. The structure elements of the data model are identified by their specific names. Some name examples for LNs are presented in Fig. 8.20. The names always begin with the character representing the LN group.

A detailed example for the data model structure is depicted in Fig. 8.21 beginning with the server at the highest level moving down over the logical device "bay control" to the logical node level. Most LDs apply the system LN Zero (LLN0) addressing common aspects of the LD like a counter of operation time or the local control behavior.

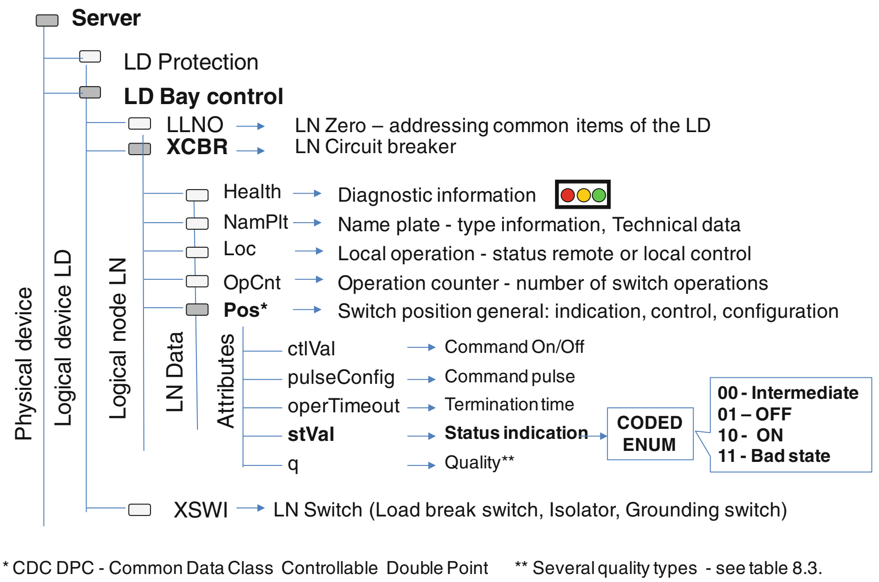


Fig. 8.21 Engineering example of the data model

The LN "circuit breaker" XCBR is presented with the assigned main data and attributes. The data and their attributes are related to common data classes—CDC. The CDCs play an important role according to the interoperability target. They also define which data and attributes are mandatory or optional.

Figure 8.21 presents the structure of an advanced engineering tool that allows the configuration of the physical device by enabling or disabling the relevant structure elements.

Here the assigned data are:

- Health—is an online process data and provides the diagnostic information for the circuit breaker in a traffic light form: healthy, warning and alarm.
- NamPlt—is a configuration data describing the technical data of the circuit breaker.
- Loc—is an online process data defining the local control behavior.
- OpCnt—is the resettable counter of operations.
- Pos—is the general data for all attributes in accordance with the XCBR position control and status indication.

The data Pos in this example contains the following attributes:

- ctlVal—represents the online switch command with the values ON and OFF,
- pulseConfig—is a setting defining the control behavior. The control pulse may be configured with a definite pulse time in seconds or a continuous signal which will be terminated after receiving the return information of the switching operation.

Table 8.3 Examples of Common Data Classes (CDC) and quality type definitions

Common data class examples	Name	Quality attribute names	Type
Single point status	SPS	Validity	CODED ENUM
Double point status	DPS	DetailQual	PACKED LIST
Integer status	INS	• Overflow	BOOLEAN
Protection activation information	ACT	• OutOfRange	BOOLEAN
Measured value	MV	• BadReference	BOOLEAN
3 phase measured values	WYE	• Oscillatory	BOOLEAN
Binary counter reading	BCR	• Failure	BOOLEAN
Harmonic value	HMV	• OldData	BOOLEAN
Controllable double point	DPC	• Inconsistent	BOOLEAN
Controllable integer status	INC	• Inaccurate	BOOLEAN
Controllable analogue process value	APC	Source (e.g. substituted)	CODED ENUM
Enumerated status setting	ENG	Test	BOOLEAN
Device name plate	DPL	OperatorBlocked	BOOLEAN

- operTimeout—is a setting limiting the duration of the control signal if the return information of the operation is not received within the set time limit..
- stVal—is the online process data attribute representing the switch status in the known four positions.
- Q—defines the quality of the information and consists of a set of attributes in accordance with the relevant common data class.

Examples of common data classes and the details of the quality attribute are shown in Table 8.3. The quality detail attribute is of the attribute type “Packed List” and contains a set of details expressed in Boolean values. The quality attribute is configured in accordance with the common data class. The detail “overflow”, for example, is typical for measured values and cannot be used for status information. The quality attributes are also shown in Table 8.3. The examples in Table 8.3 demonstrate that the CDCs and the quality attributes significantly exceed the adequate type and quality definitions of the IEC 60870-5 series.

The role of the data model in the mapping of the interactions between an IED and the primary process is demonstrated in the example of Fig. 8.22.

The primary process is demonstrated on behalf of the feeder scheme connected to a double busbar. The IED presents a protection unit with the main protection function “time over-current”. The current curves are acquired online by sampled values from the LN TCTR “current transformer” and directed to the LNs MMXU “measurement unit” and PTOC “overcurrent protection”. The LN MMXU calculates the primary RMS values of the phase currents to be presented on the display of the IED and in a measurement record. Changed measurements are reported and communicated to the client.

The LN PTOC observes the sampled values and may detect fault currents. After the protection pickup several security procedures for avoiding over-functions are processed and the trip signal is sent in accordance with the relevant time delay to the LN CSWI “switch control”. The pickup and the trip information is available at

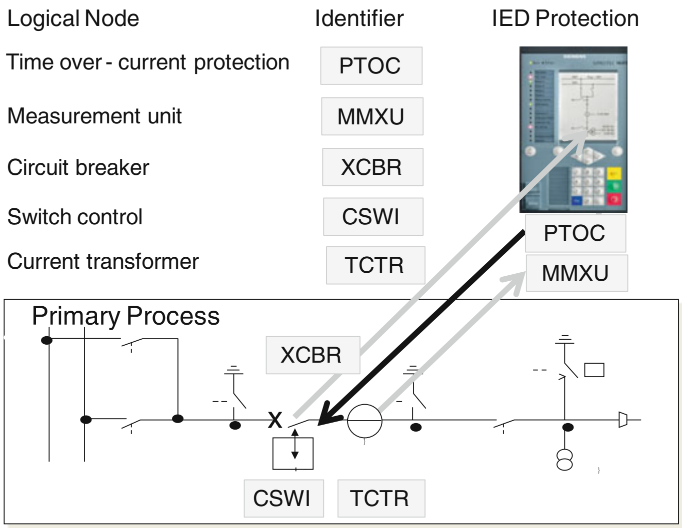


Fig. 8.22 Data modeling and the relation between the IED and the primary process

the IED display and sent to the client. The LN CSWI activates the output command for the trip of the circuit breaker.

The LN XCBR "circuit breaker" acquires the changed status indication "OFF", represents this on the IED display and on the event report which is readable on the same display and sends the information to the client and/or other servers (subscribers) in a multicast.

One of the special things about IEC 61850 data models concerns the preparation of measured values in the format of primary RMS values within the LN MMXU. The IED acquires the instantaneous values (instMag) of the voltage and current waveforms from the instrument transformers either via analogue input contacts or via the process bus according to IEC 61850-9-2, as shown in Fig. 8.23.

The MMXU calculates not only the primary values for the acquired voltages and currents but also the active, reactive and appearance power values, the cosφ and the frequency.

The CDCs relevant for measurements like MV or WYE define the requested configuration parameters like the unit, the sampling rate, the scale factor and others in IEC 61850-7-3. Consequently, the communicated measured values are ready for application at all receiving IEDs without further configuration. In this way, the engineering of measured values is performed only once at the server level.

A further benefit of the data model is the possibility to freely configure LNs in accordance with the philosophy of the network operator. In Fig. 8.24 two possible assignments of LNs to logical devices are shown.

Further, special attributes of the data model support the convenient management of the assets. The general diagnostic information regarding the IEDs and the

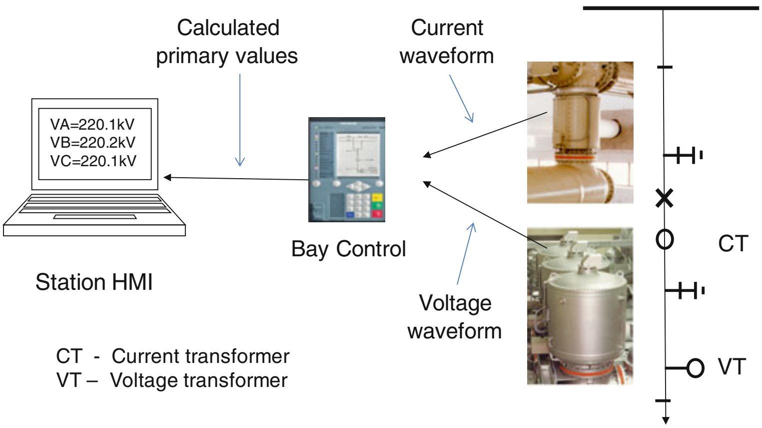


Fig. 8.23 Measurement conversion from instantaneous values to primary RMS values

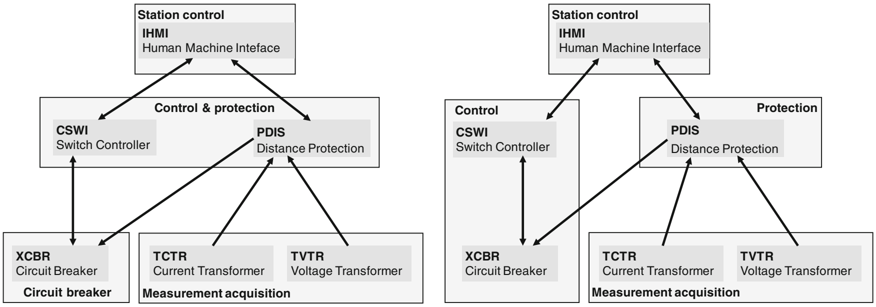


Fig. 8.24 Free assignment of LNs to logical devices

primary equipment (Health) enables the spontaneous creation of information regarding the changing conditions.

The type information of the IED (NamePlt) allows the fast integration of replaced IEDs into the SAS and is available for directory services. The asset manager can get a fast overview of the installed equipment directly from the plants.

8.3.3 Three Protocols on One Bus: The Communication Service Structure

The communication service structure of IEC 61850 offers two general communication principles where the second principle is used for two different application methods:

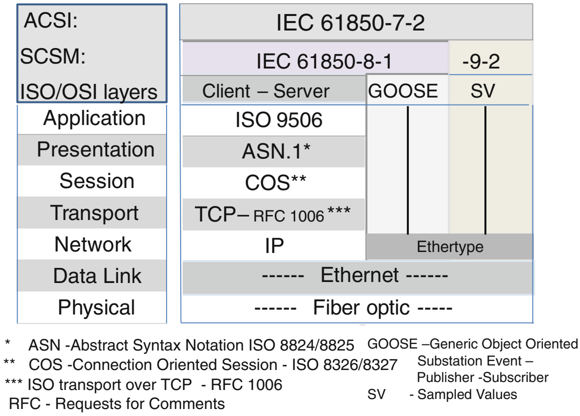


Fig. 8.25 The three protocols defined in IEC 61850 and the seven layers

1. the client–server principle
2. the publisher–subscriber serving:

- the multicast of urgent messages using the GOOSE mechanism (Generic Object Oriented Substation Event),
- the transfer of sampled values (SV).

Consequently, IEC 61850 offers the services of three different kinds of protocols on one Ethernet bus, as shown in Fig. 8.25.

The client–server principle provides the information exchange between the client and the servers and is applied for the typical substation automation system (SAS) applications like control and supervision of substation equipment, transmission of event reports, data requests (read), data settings, time synchronization, storing and retrieving sequences of events (log), and transfer of files (i.e. Comtrade files). Mature standardized solutions applied in the communication technology are used to cover the layers of the seven layer model. The client server principle uses sequences of information exchange with confirmation messages ensuring in this way that the data is received by the addressed IED (via TCP/IP addressing scheme).

The extremely time critical information exchange uses the GOOSE principle for fast transmission within milliseconds. Here, one IED acts as the publisher providing the exchange of urgent information (by multicasting) immediately after the appearance of a configured event. The transfer of the event message has the highest priority and is received by all subscribers defined within the engineering process. The client or the servers may be configured as publishers or subscribers for various events. Such time critical information may be the pickup of protection IEDs, the tripping of circuit breakers or the status changes of all kinds of switches for interlocking purposes. One example of the benefits of the fast event transmission is demonstrated in Sect. 4.5.1 (Fig. 4.30) regarding the reverse interlocking principle used for MV busbar protection.

The GOOSE mechanism does not apply confirmation sequences. However, for security reasons the multicast may be repeated within short time intervals.

The large amount of sampled analogue values (CDC SAV) is also transferred in accordance with the publisher and subscriber principle. The values are usually transmitted using the "transmission of sampled value model" according to IEC 61850-7-2. Here the inconsistency of the subsequent time stamps and the sampling rate may support the detection of data loss.

The communication principles of the ACSI are shown with the indication of communication services and links between the IEDs.

8.3.4 Protocol Services

The Figs. 8.18 and 8.26 show how the information exchange can be managed.

IEC 61850 provides an appropriate set of service models for these purposes.

Besides the "plug and play" feature supported by the data model, the innovative feature "plug and run" is gained by implementing the association services. The "plug and run" concept is based on the opportunity that new servers have to submit their functional features to the client. In the next step the client decides how the functions may be embedded into the system. The system relevant adapted configuration data and settings can be downloaded to the IED to ensure the efficient system integration of the IED.

The information management includes the following services:

Client server:

- Read and write data,
- Create/delete datasets,
- Substitute data,
- Spontaneous data transmission (Reporting),
  - Configuring reports,
  - Transmit buffered (sequence of events) or un-buffered reports,
- Setting groups,
  - Edit setting groups,
  - Activate setting groups,
- File transfer,
  - Read and write files,
  - Delete files,
- Directory and interrogation services.

Publisher–subscriber:

- Fast transmission of events—multicasting GOOSE,
- Transmission of sampled values.

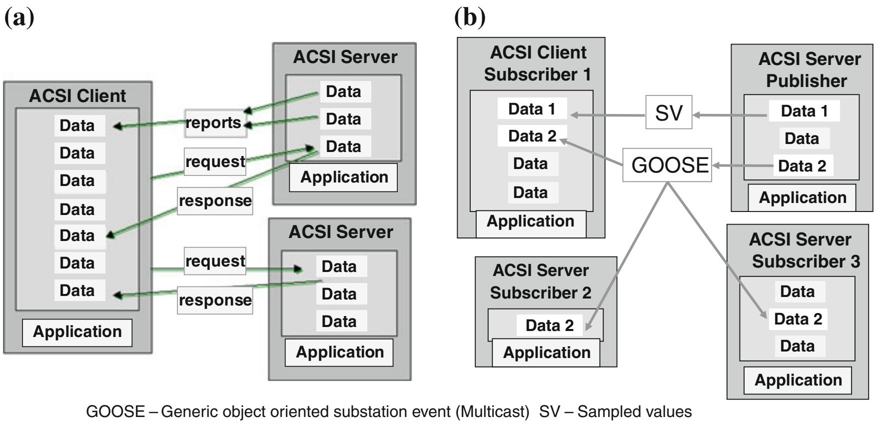


Fig. 8.26 The basic concepts: **a** "client–server", **b** "publisher–subscriber" (GOOSE and SV)

All services of the client–server information management (except the reports) are based on a "request–response sequence" of information exchange. For all information exchanges with control character like writing, setting, creating, substituting, configuring or editing, the response is created as a confirmation message.

The spontaneous transmission of data is applied to inform about changing conditions in the process (status indications, protection information, diagnostics, measured values, etc.).

The basic principles of information management are presented in Fig. 8.27, and the acquisition of sampled values is demonstrated in Fig. 8.28.

Each hierarchical level provides directory services to request the overview of all model elements configured at that level.

The set of the requested data within interrogation groups may be configured. Furthermore, data values may be substituted by the operator (e.g. if the communication link is interrupted).

These services are presented in Fig. 8.29.

Additionally, the information model of the standard offers the configuration of convenient services regarding the

- Creation of event sequences (Logging) with the option to:
  - Configure logs,
  - Read logged information.

The control model includes further services like:

- "Select before operate" signal,
- Time activated operation.

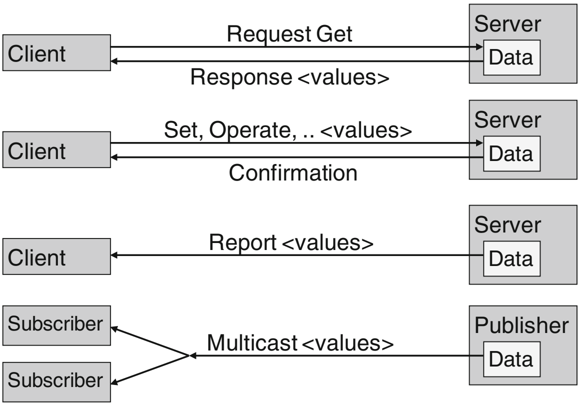


Fig. 8.27 Information exchange principles

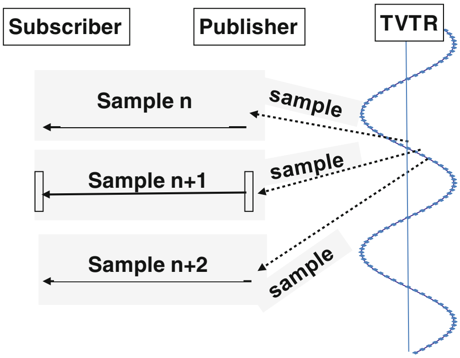


Fig. 8.28 Acquisition of sampled values

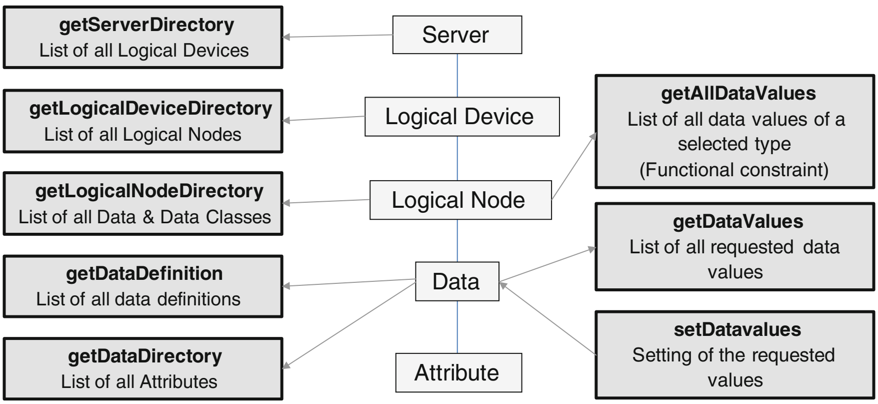


Fig. 8.29 Directory, interrogation and substitution services

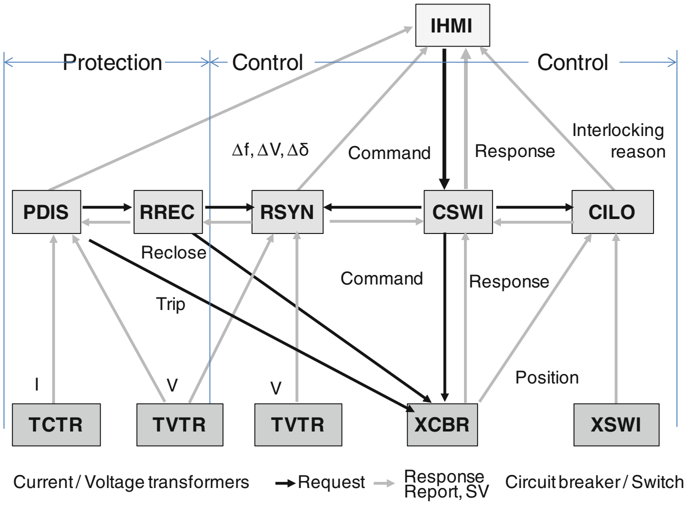


Fig. 8.30 Service relations of the control model

The functions of the control model are demonstrated in Fig. 8.30 on behalf of protection and control sequences.

The distance protection (PDIS) decides whether to trip a circuit breaker (XCBR) based on the acquired voltage (TVTR) and current (TCTR) samples. After the trip the time activated operation of the auto-recloser (RREC) is started. However, the auto-recloser checks the synchronism by sending a request to the LN "synchrocheck" (RSYN) before starting the switch ON command. The violation of one of the synchronism conditions Δf, ΔV and $\Delta\delta$ prevents the switch ON of the XCBR. The protection IED communicates the protection and the auto-recloser information to the human machine interface IHMI at the substation level.

The circuit breaker control can be started via the IHMI by starting the "select before operate" service signal to the LN switch control CSWI for switch ON operations. The CSWI checks two conditions:

1. synchronism Δf, ΔV and $\Delta\delta$ via the LN RSYN,
2. the interlocking conditions through the LN CILO "interlocking".

Any violation of the switch conditions is submitted together with the prevention reason such as:

1. $\Delta\delta > 30°$ (where 30° is the set limit) or
2. the grounding switch of the feeder is closed

to the station control IHMI by the LN responsible for checking.

Otherwise, the positive response is sent from the LN CSWI to the IHMI.

The switching operation is started after the positive response and is executed by activating the switch ON actor of the circuit breaker via setting a pulse at a binary output of the IED or via a process bus command.

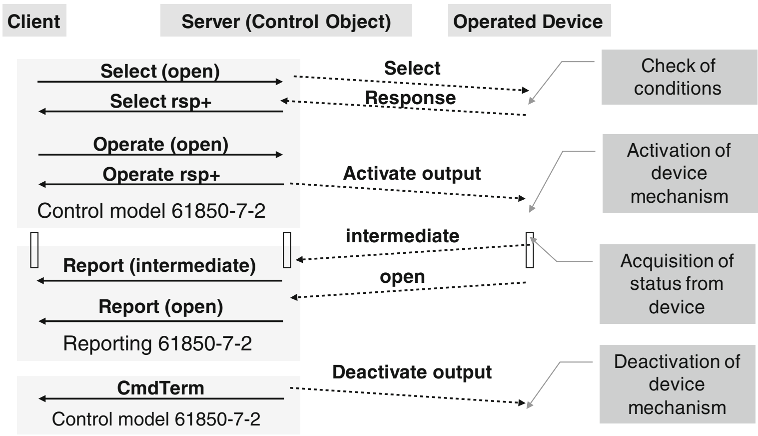


Fig. 8.31 Sequence of the services of the control model

The return information about the XCBR status is submitted to the CSWI and the IHMI using the reporting service of IEC 61850.

There are two choices for the IEC 61850 control model:

- Control with normal security, meaning that the selected status is set in the process image immediately after sending out the command (US standard).
- Control with enhanced security, which first sets the status as intermediate after the command output, and only after receiving the changed status information is this status stored in the process image (European request).

The details of the control model service sequences are presented in Fig. 8.31.

In accordance with the control model of IEC 61850-7-2 the control procedure ends with the deactivation of the control output (if a short term pulse is not configured) and the last message "Command termination" is sent to the client.

Finally, the service package of IEC 61850 also includes such system services like "Time synchronization". For the time synchronization either the simple network time protocol SNTP (often applied for the time synchronization of personal computers) or, for higher accuracy requirements, IEEE 1588 [6] may be applied.

8.3.5 Independent Engineering

The section IEC 61850-6 was developed to support a vendor independent engineering process of substation automation systems. Therefore, this part specifies the engineering process and a description language for configuration the substation automation system (SAS) and its IEDs. This language is called Substation Configuration Language (SCL). The configuration language is based on the Extensible Markup Language (XML) version 1.0.

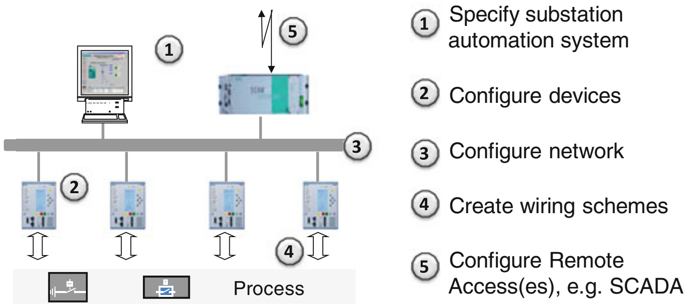


Fig. 8.32 The engineering steps of the substation automation systems

SCL is used to engineer the IED configurations and the communication systems in accordance with the data models and services of IEC 61850. It allows the formal description of the relationships between the SAS and the processing units (substation, switch bay). The SCL is used to formalize and to support the chain of the 5 steps belonging to the complex engineering process of the SAS and its components.

The engineering steps are depicted in Fig. 8.32. They are related to:

1. the specification of the SAS in general,
2. the IED configuration,
3. the design of the communication network,
4. the connection schemes between the IEDs and the process equipment and
5. the configuration of the data exchange with the remote control center(s) and other external users of the substation automation.

The SCL allows the description of an IED configuration to be passed on to a communication and application system engineering tool, and to pass back the whole system configuration description to the IED configuration tool in a compatible way. Its main purpose is to allow the interoperable exchange of communication system configuration data between an IED configuration tool and a system configuration tool.

The complex engineering approach is depicted in Fig. 8.33.

In the first step, the functions of the bay related IEDs have to be specified in the context of the substation automation system. Templates are used to design the functional interactions and to develop adequate single line diagrams. The transforming process to XML is supported by a specification tool and creates the ssd.file (system specification description). The ssd.file specifies the single line diagrams considering the logical nodes interfacing the process equipment, the functional requirements, the protection and the protection related functions, the control models, the measurement and metering capabilities, the disturbance recording and the automation sequences. A signal list in terms of data and data attributes can be created.

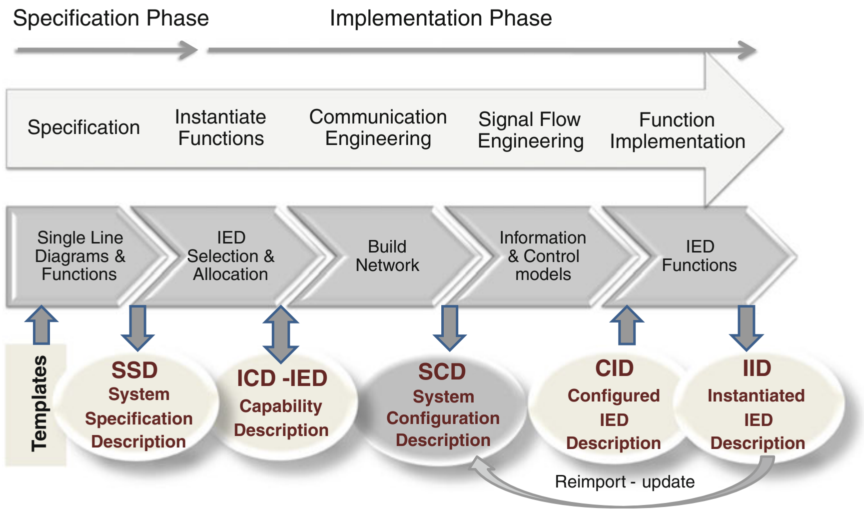


Fig. 8.33 The engineering process and the related SCL descriptions

In the second step, the described functional specifications have to be allocated and pre-configured to concrete IEDs. The IEDs have to be selected in the context of functions and capabilities. The transformation of the capability description into XML creates the icd.file (IED capability description) which presents the "type" of the IED. The icd.file contains communication interfaces and the logical nodes, data and data attributes to be configured within the IED. The elements requested for data exchange are pre-configured. The binding of data to the input/outputs of the IEDs will be pre-engineered. An IED configurator can support all of these engineering tasks.

Thirdly, the configuration of the communication network defines the communication links and parameters, the addressing scheme for the IED instances and the communication sub-networks.

The results of the first three engineering steps provide the input for the system configurator. The IEDs represented as type have to be instantiated to be established in the system. The system configurator creates the system configuration description based on the IED instances in the form of the scd.file.

The scd.file describes all of the links between the elements of the data model and the primary process as well as the data transfer between the IEDs building the SAS.

Consequently, the inputs to and the outputs from the LNs are designed to occur within the IEDs and the external data flow between the IEDs is finally configured as:

- Client–server communication including the service elements (reports, controls, directory services, data sets, logs etc.) of the substation automations system,
- Publisher–subscriber services (GOOSE, SV and the relevant data sets).

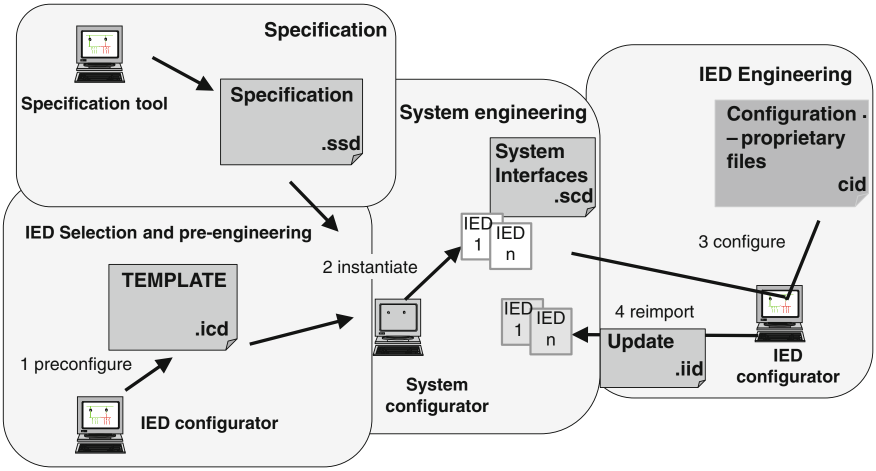


Fig. 8.34 The engineering process and the applied engineering tools

- WAN access of the client to perform the data exchange with the control center (SCADA) and other actors requesting data from the SAS.

In this way, the scd.file includes the description of the overall SAS. The engineering process with the application of engineering tools is demonstrated in Fig. 8.34.

However, the creation of the scd.file is not the last step of engineering process. The system engineering leads to a more precise definition of the IED functions, the communication data, data flows etc. The scd.file now performs the input for the IED configurator. The IED configurator adapts all the IED pre-configurations to the precise requests and definitions of the scd.file. The engineering process is completed when the IED configurations and the re-importation of the instantiated IED description (iid.file) are updated into the system configuration description.

Consequently, the IED engineering covers the four sequential steps shown in Fig. 8.34:

1. Pre-configuration,
2. Instantiation for system integration,
3. Precise configuration based on the integration progress,
4. Update of the instances within the SCD.

After concluding the engineering processes, a testing phase is required for the approval of the engineered SAS with all communication links and data flow conditions.

Configuration tools for the different steps of system and IED engineering are offered from different suppliers on the market.

8.3.6 Conformance and Acceptance Testing

The conformance testing is an activity which results in determining whether a product or a system corresponds to the requirements contained in a specification. The IEC 61850 standard series is such a specification requiring a conformance test.

In accordance with IEC 61850-4, each product applying the communication protocol of the IEC 61850 series for integration into an SAS has to go through a multi-level system and type test. The type test verifies the correct functions of the IEDs of a SAS by using of the system tested software under the test conditions corresponding with the technical data. IEC 61850-4 develops a general classification of the type test components.

The conformance test is that part of the type test verifying the communication behavior of an IED in the context of the IEC 61850 protocol specifications.

The conformance test of an IED concerns the information exchange with other system components of an SAS. Consequently, the conformance test is also always a test of the proper system integration of the IED.

In this sense, IEC 61850-10 describes standardized conformance test procedures to ensure that all vendors applying these procedures comply with the specifications of IEC 61850.

The successful conclusion of the multi-level type tests marks the final stage of a product development and is the pre-requisite to release a product for serial production and for market introduction.

The conformance testing does not replace project specific acceptance tests. Each SAS has to be approved through acceptance tests before the operation on site can be started. IEC 61850-4 defines two classes of acceptance tests:

1. The factory acceptance test (FAT) is a customer-agreed functional tests of the specifically manufactured power SAS or its IEDs using the parameter set for the planned application as specified in the project related customer specification. The FAT may be executed in the factory of the vendor or in another agreed upon location by the use of process simulating test equipment.
2. The site acceptance test (SAT) is the verification of each data and control point and the correct functionality within the SAS and between the IEDs and their process environment at the whole installed plant by use of the final parameter set as defined in the project related customer specification.

The FAT and SAT are normally performed by the system integrator and witnessed by the customer. These tests verify that the functions of the SAS and the IEDs are performed as specified and increase the confidence that potential bugs in the system have been detected and eliminated.

The standardized test procedures of the conformance testing significantly reduce the risk of bug problems occurring during system integration in the FAT and SAT. Furthermore, the test procedures of IEC 61850-10 offer guidelines for the FATs and SATs.

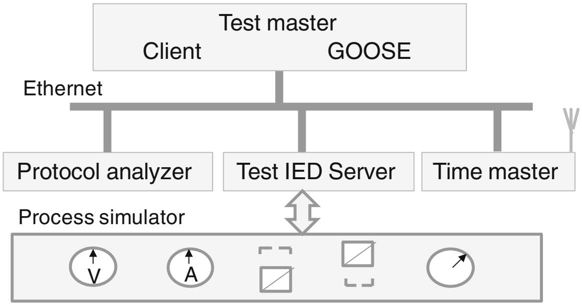


Fig. 8.35 Conformance test scheme for server/subscriber IEDs

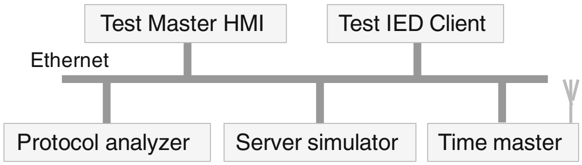


Fig. 8.36 Conformance test scheme for the client IED

IEC 61850-10 provides a complete description of the methodology, structure, equipment, engineering, schemes and tools of the tests. The general approaches to the conformance testing are specified including also the documentation of the results. For all specified test cases an engineering tool has to ensure the conformance of the cid.files and scd.files.

Figure 8.35 presents the test configuration for IEDs acting as a server or GOOSE subscriber.

The test IED is connected to a process simulator providing voltage and current waveforms, binary input signals, receiving binary output signals and analogue set points (from left to right). The test master is responsible for the control of all test cases (initiate, stop), for triggering the protocol analyzer and for documentation of the test results. The test cases are assigned to either the client simulator or the GOOSE publisher. In the first step the cid.file of the IED has to be brought into conformance with the scd.file of the protocol simulators of the client and GOOSE publisher.

Advanced commercial configuration tools allow the mutual adaptation of the relevant files.

A time master ensures a high accuracy of the time synchronization of all participating users of the Ethernet link in the test configuration. The data traffic over the Ethernet is monitored and stored by the protocol analyzer.

Secondly, in Fig. 8.36 the client test configuration is depicted.

The client test requires a test master which initiates and stops the test cases, controls the analysis and archives the test results. The multi-server simulator responds to the client requests and creates data reports in accordance with the test cases initiated by the test master. The protocol analyzer and the time master perform the same tasks as in the server test scheme.

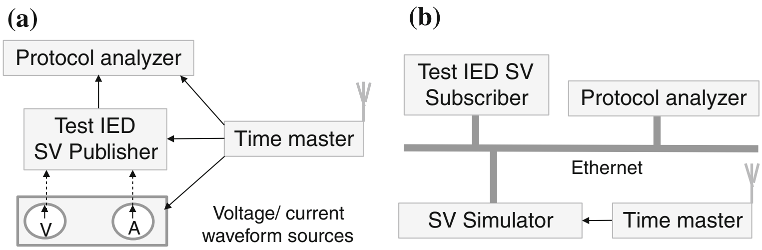


Fig. 8.37 Conformance test scheme for sampled value transfer: **a** publisher, **b** subscriber

Thirdly, the test of the transfer of sampled values is also specified in accordance with Fig. 8.37.

The publisher test scheme in Fig. 8.37a requires in the first priority sources for generation of voltage and current waveforms which have to be sampled by the test IED. The test IED performs the transfer of the sampled values in accordance with the specific communication service mapping SCSM of IEC 61850-9-2 to the protocol analyzer which monitors and archives all sampled data. The time master manages the time synchronization of all participating test elements.

The subscriber test scheme according to Fig. 8.37b applies a time triggered simulator of sampled values sending the values over the Ethernet in accordance with the SCSM.

The protocol analyzer monitors and archives the data transfer over the Ethernet. At the same time, the test IED stores the sampled values.

IEC 61850-10 specifies various test cases in the form of tables.

The test cases cover the whole specification environment of IEC 61850 and are grouped into:

- Server documentation tests (1 table),
- Server configuration tests (1 table),
- Server data model tests (1 table),
- Mapping of ACSI models and services tests (server and subscriber side) with 13 subgroups and 31 tables,
- Network redundancy test (1 table),
- Client documentation tests (1 table),
- Client configuration tests (1 table),
- Client data model tests (1 table),
- Mapping of ACSI models and services tests (client and publisher side) with 13 subgroups and 26 tables,
- Sampled values test cases (7 tables),
- Engineering and configuration tool related tests (18 tables),
- GOOSE performance tests (1 table) and
- Time synchronization tests (1 table).

(a) **(b)**

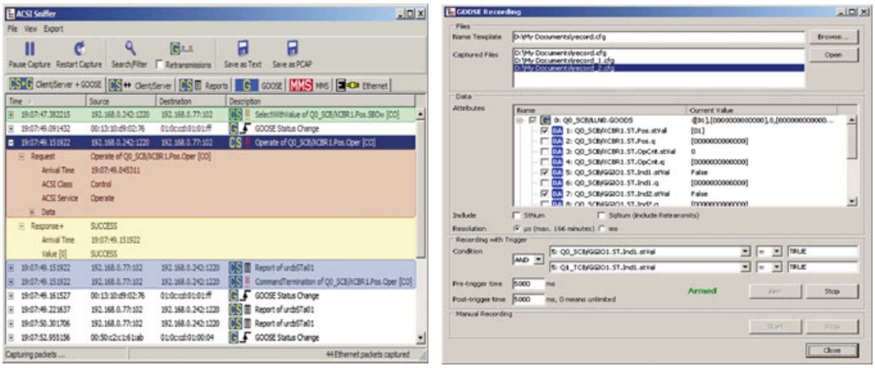


Fig. 8.38 Screen shots of a test supporting tool: **a** client–server, **b** GOOSE/COMTRADE files (*Source* Omicron electronics GmbH [7])

The test cases are mainly defined in two ways:

1. Positive test cases to verify normal data exchange conditions, typically resulting in the positive response rsp+,
2. Negative test cases for the verification of abnormal or incorrect data transfer, typically resulting in a negative response rsp−.

This huge number of mentioned test cases is difficult to manage without supporting test tools.

Today, some vendors have developed and provide convenient tools to support both the engineering and the testing of the IEC 61850 specifications.

Figure 8.38 presents screen-shots of such a universal tool which combines the tasks of the client simulator, the publisher/subscriber simulator for GOOSE messages, the protocol analyzer and several functions of a configuration tool.

Advanced tools may maintain the following functions and tasks by accessing the IEDs of all vendors which provide conformance to IEC 61850:

- Convenient presentation of the ACSI combined with GOOSE and visualization of the Client/Server data model,
- Reading the directories of the data model levels from an IED,
- Analysis of the Client/Server data transfer including the detailed presentation of MMS, also for “foreign” traffic between other clients and servers,
- Receiving and interpretation of reports,
- Cyclic request of data and data sets from the servers,
- Initiating control data and data sets for the servers,
- Simulation of GOOSE messages,
- Identification of GOOSE messages on the Ethernet and general GOOSE monitoring,
- Conversion of GOOSE messages into COMTRADE files,

- Creation of SCL files for IEDs and systems (e.g. cid, scd) in the form of an engineering tool.

These tools normally offer a convenient user interface reflecting the data model structure of IEC 61850. Figure 8.38 presents two screen shots of such a tool.

In Fig. 8.38a the client–server traffic analysis (CS) is demonstrated on the ACSI level.

The record also contains GOOSE messages, so these two ACSI services are analyzed in combination according to their sequence. The chronological record of all request and response sequences is provided.

Figure 8.38b presents the conversion of selected data items from subscribed GOOSEs input streams into COMTRADE files. (This common format for transient data exchange for power systems is a file format for storing oscillography and status data related to transient power disturbances.)

Recordings can be started manually or automatically by using a trigger condition. In this way, the events can be user friendly analyzed in detail by investigating the COMTRADE records.

These tools simplify the engineering, the preparation and the execution of tests. The engineers have efficient options to enhance the quality of testing during the development phase of the IEDs, for conformance testing in the laboratory of the vendors or enterprises providing certification and in the framework of FAT and SAT.

The enormous complexity of IEC 61850 can be managed efficiently by using advanced tools that make the engineering and the simulations for testing convenient and easy.

8.3.7 New Standard Parts for Smart Grid Extensions

The great success of the applications of IEC 61850 in substation automation systems worldwide generated the desire to apply the benefits of the standard series to other applications within the overall power system control as well. The standard IEC 61850 that was originally introduced for substation automation systems is now being expanded to be applied to all the different domains of the power system like wind power plants, distributed energy resources DER or hydro power plants. The IEC has established additional working groups within the technical committees TC 57 (power system management and associated information exchange) and TC 88 (wind turbines).

The basic idea of the standard to split the data models and services at the application level (specified in the ACSI) from the fast changing technologies covering the ISO/OSI 7 layer model supports the extension efforts of IEC and the wide spread application of the communication standard.

Figure 8.39 presents the possibility to use the common data models and services of the ACSI and to extend their application to wide area networks WAN

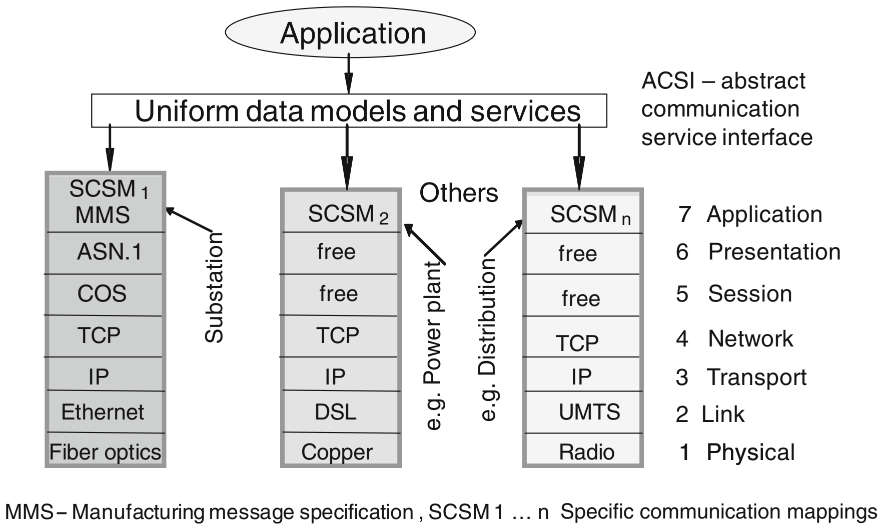


Fig. 8.39 Adaptation options of IEC 61850 for other applications

applying, for example, telecommunication cables with DSL or radio communication with UMTs or others.

The efforts are directed to integrate the new network users like distributed energy resources (DER), wind power plants or storage batteries connected the lower network levels into a common communication network which is uniform up to the level of information exchange with the control center of the transmission system operator.

The application of IEC 61850 for the data transfer between substations and control centers is now prepared in two ways.

The first approach considers that IEC 60870-5-101/104 is globally introduced in thousands of power systems for the data exchange between the control centers and the substations. Therefore, a soft migration is standardized by applying the data models of IEC 61850 within the structure elements of IEC 60870-5-101/104. The IEC 61850 data models may replace the former information object address for all extensions of the SCADA system. In this way, the benefits of applying one engineering technique and gaining data consistency may be achieved. This approach is specified in IEC 61850-80-1.

Secondly, the data exchange between substations and control centers using the full comfort of the ACSI data models and services is specified in IEC 61850-90-2. This part of the standard can be applied for the establishment of new SCADA systems.

The first priority is to create new data models so that the communication standard series can be extended to further applications. The majority of the new parts of the standard series were developed under the guidance of the TC 57 and

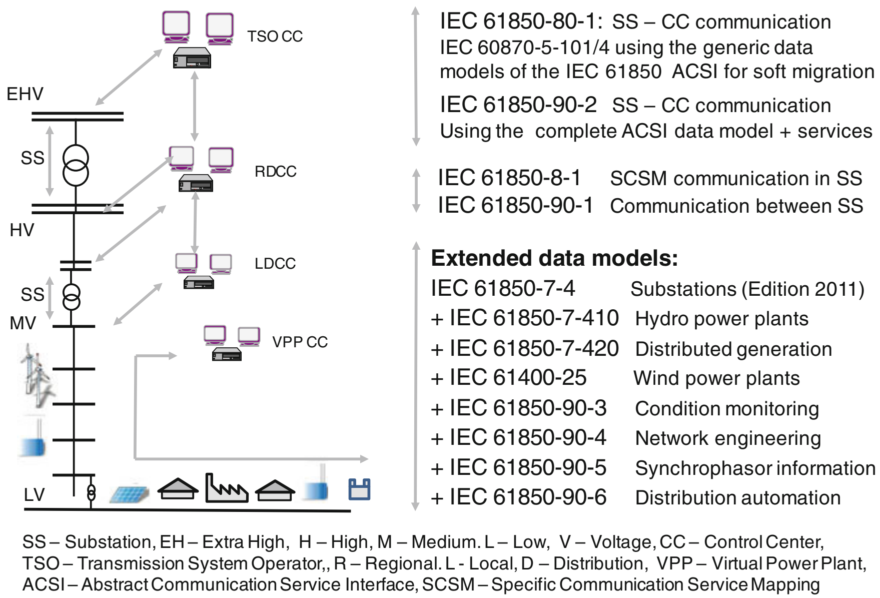


Fig. 8.40 Seamless communication over the whole power system using IEC 61850

deal with the data model extensions under the condition that everything that is available should be inherited from the published IEC 61850-7 parts.

The new parts of the standard, which have either been published or are partially still in the works, are presented in Fig. 8.40.

The standard for the communication exchange of wind power plants was developed within the TC 88 and therefore, it has another identification number. The standard IEC 61400-25 extends the data models of IEC 61850 with logical nodes related to wind power plants and uses WEB services at the link layer level.

With the expansion of the scope beyond the substation, IEC 61850 supports the use of an integrated solution across the power system.

For the first time, an interoperable data exchange over all levels from the low voltage socket up to the network control center of the transmission system is covered by one standard series offering uniform data models and services, as depicted in Fig. 8.40.

The high engineering expenses for applying different vendor specific engineering tools, data model conversions from level to level and inconsistency risks (see Sect. 8.1.2) can be now avoided.

The application of communication standard series IEC 61850 is rapidly penetrating all levels of the power system control and supervision.

8.4 Data Management Based on the Common Information Model CIM IEC 61968/70

In Sect. 8.1.3 it is considered that there has been an increasing need for all actors operating and using the electricity networks to exchange data on a common basis. This is to ensure the reliable network operation at all levels of the overall power system.

The IEC standard 61970 [1] specifies the semantic "Common Information Model" CIM that

- describes the assets and the components of the energy management system and transmission system from the electrical point of view and
- establishes the relationships between the components.

The basic concept of IEC 61970 is focused on the following topics:

- The data objects are presented in classes. Each class specified in CIM maps a type of a real-world object into the form of a virtual object containing the data of the original object.
- The classes provide functions for presentation of the real parameters, retrospective, operational and general technical data.
- The relationship between the real-world objects may be represented in the virtual mapping by using such principles as inheritance and various kinds of associations.
- The data models are extendable.
- The data models are specified using the Unified Modeling Language (UML). The UML class diagrams perform a useful instrument for object oriented modeling and for representing object hierarchies.
- The Extensible Markup Language (XML) is applied to encapsulate this data for the exchange of the data object models and the inter-application relations.

After the first applications of CIM in the USA for data base management of TSOs, the need for the extended application in the distribution level was identified.

Consequently, the subsequent standard series IEC 61968 [8] extends the CIM to cover the aspects of distribution network operations beginning from the network assets down to the consumer market integration.

The CIM is the core of both standard series and is specified mainly in the parts IEC 61970-301, -302 and IEC 61968-11. Due to the large number of classes, it is useful to perform packages of classes. Figure 8.41 presents the class packages related to the standard parts.

The part IEC 61970-301 specifies the basics of the CIM concept concerning the transmission system operation and the energy management aspects. The part 302 adds the information models concerning the reserve provision, the schedule management and financial specifics. Finally, IEC 61968-11 extends CIM regarding the distribution management system (DSM) in general.

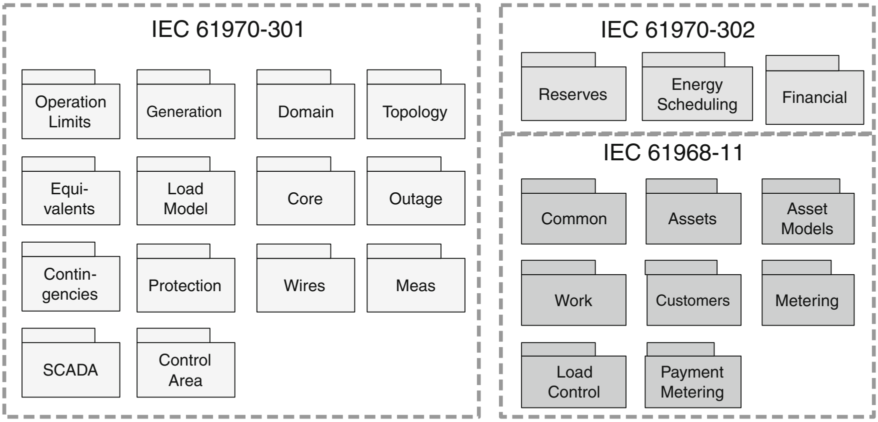


Fig. 8.41 Class packages of IEC 61970 and 61968

The parts 3–10 of IEC 6168 [8] define the interfaces for an overall DMS interface architecture. The intention is to support the inter-application integration of a distribution network operator and other actors in the area of power supply that need to collect data from different applications with different interfaces and run-time conditions.

The parts 12 and 13 support the application of CIM for DMS by

- specifying significant “use cases” and
- the Resource Description Framework (RDF) model exchange format for distribution.

As stated above, the class hierarchy builds the basics of the data modeling. The class hierarchy is an abstract model defining every object of the system as a separate class. The class hierarchy reflects the structure of the real system.

The classes are outfitted with their own internal attributes and relationships with other classes. Since the CIM class model is an object oriented approach, relationships are used to associate several information pieces with each other.

Each class can be instantiated into any number of separate instance objects. The objects contain the same content of attributes and relationships, but with their own internal values.

Inheritance may be used to define a class as a sub-class of the source class. It inherits all the attributes of the source, but can also be extended by its own attributes.

Association describes the relationship between classes. For example, several classes of one type may be assigned to another class via association.

The aggregation relationship is a special kind of association indicating that one class is a container for the other class.

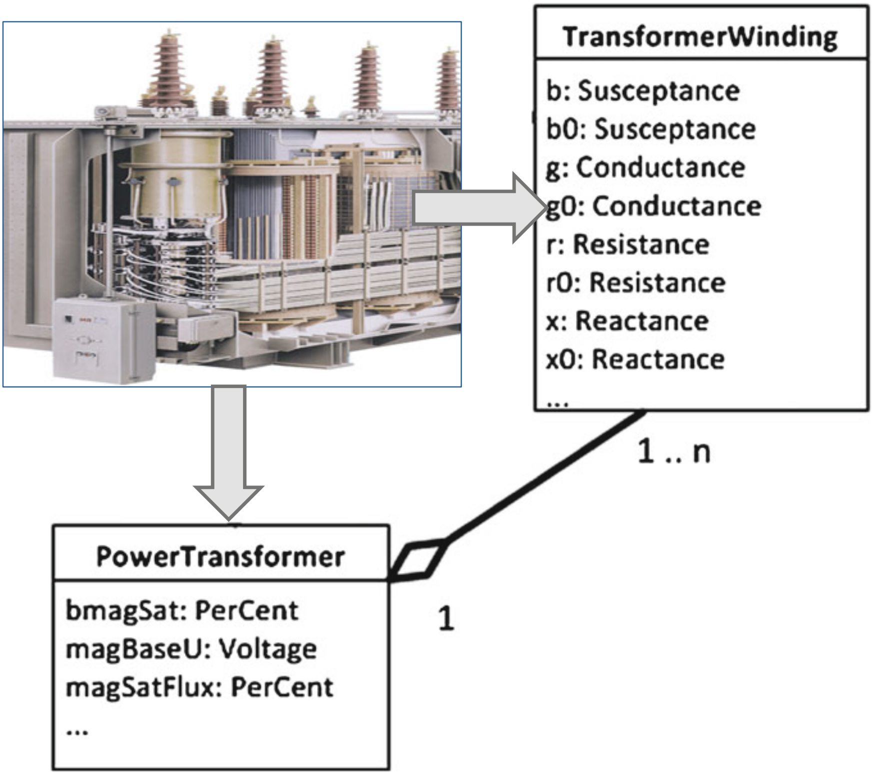


Fig. 8.42 The relationships between the classes power transformer and transformer winding

Composition is a special form of aggregation in which the contained class is a basic part of the container class. If the container is disturbed than all objects within the container class are similarly disturbed.

The relationships of the class hierarchy are demonstrated in Fig. 8.42, using a power transformer with two windings as the example.

The transformer is the container of the windings. This relationship is presented by a connecting line. The line denoting the relationship on the diagram contains a diamond. This indicates that the two classes have an aggregation relationship. The relationship is also marked by a multiplicity at each end of the line. These indicate that a class may be related from 0 or 1 to many < 1…n >) associated objects of the same type.

In the considered case the transformer is outfitted with two windings. If the CIM class for winding 1 is defined, than the class of winding 2 can be instantiated from winding 1. The complete CIM for the transformer contains many more classes and relationships.

Figure 8.43 shows and extended part of the transformer CIM.

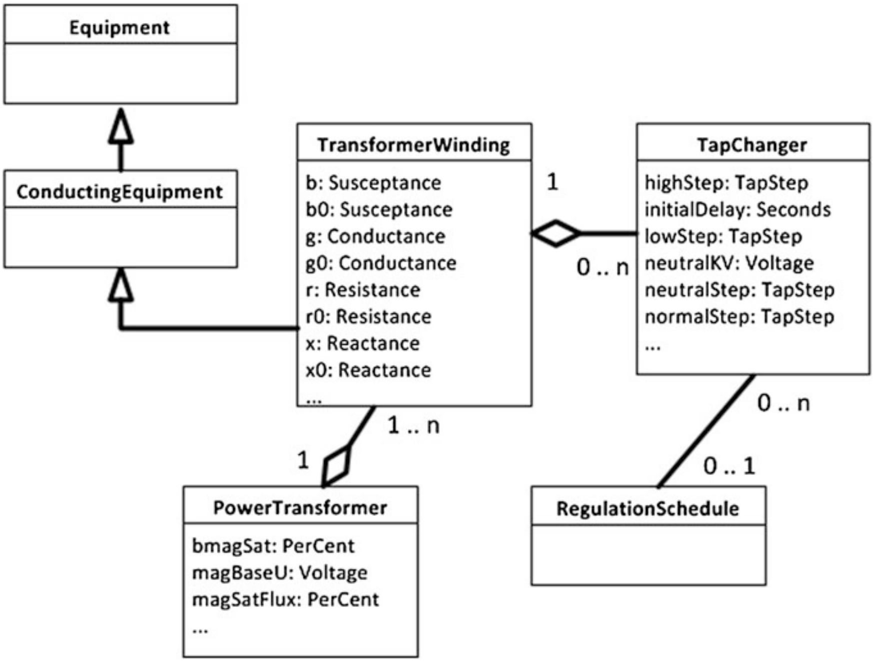


Fig. 8.43 Extended part of the transformer class model within CIM

Here the transformer class is the container for the class "transformer windings". The winding class has an aggregation relation to the class "tap changer".

Associations are demonstrated with the connection lines ending with an arrow.

For example, the windings are associated with the conducting equipment, and they have a relationship with the equipment class. The tap changer is associated with the voltage regulation schedule.

The principle demonstrated for the transformer modeling in CIM may be applied to model a complex electric network step by step.

In Fig. 8.44 the modeling of a transformer feeder is presented in a simplified way.

For a simplified presentation of complex models, the CIM uses connectivity nodes (CN) which have associations with terminals. The terminals define how the components of the electric network are joined together.

The assets build their own classes like busbar (BB), disconnector (DC), circuit breaker (BR), transformer (T), transformer windings (TW), tap changer (TC) and voltage controller (VC).

Figure 8.44 also shows how the measurements may be assigned to the assets and their links. To do this, the CIM concept contains measurement classes which may be associated to a class (e.g. busbar voltages) or to a terminal for the clear definition of the measurement access point (e.g. power flow through a feeder).

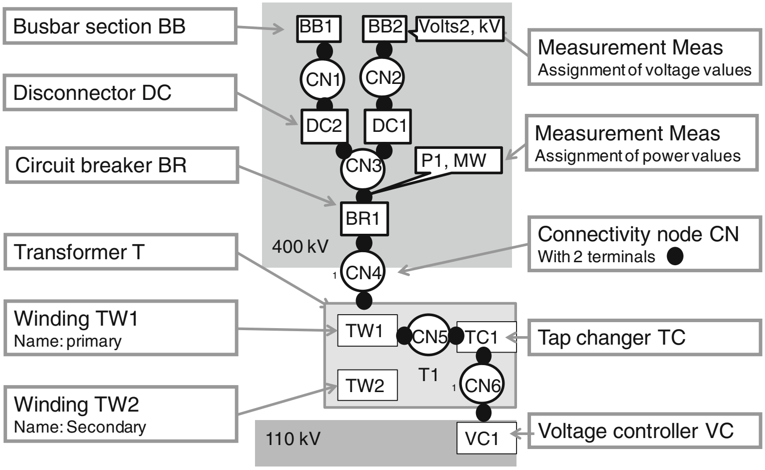
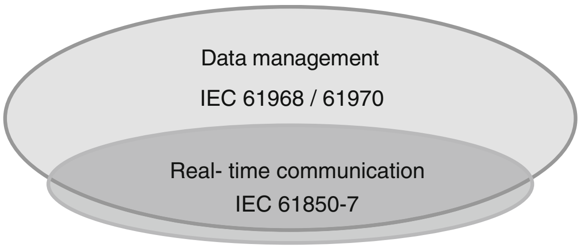


Fig. 8.44 Modeling of a transformer feeder in CIM

Fig. 8.45 The qualitative ratio of data volume for data bases and real-time communication



The main benefit of this way of modeling is the simple opportunity for applications to exchange information. The CIM provides not only a common data format but also offers a common semantic model. This allows the uniform interpretation of each class and attribute.

The packet based structure arranges all used classes according to their field of application (e.g. for network topology issues, for measurements, for asset specific information management, etc.). This structure also allows the extension of the model just by adding problem specific modules and the related classes.

However, it was demonstrated above (e.g. Fig. 8.1) that the data models of the communication protocol have to be transferred into the data bases of a control center or other actors involved in the power supply process.

The two information models described above according to IEC 61850 and IEC 61968/70 cannot be transferred one to one between each other because both data models are designed to fulfill their different tasks in an efficient way.

Furthermore, the data bases contain a much higher volume of data compared with the content of the online information exchange for network operation, as expressed in Fig. 8.45.

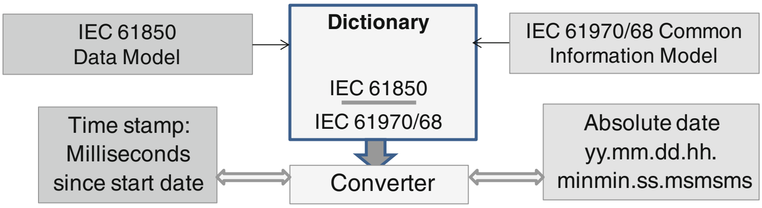


Fig. 8.46 Conversion of the data models

Consequently, a translation between the two different information models by the usage of converters has to be executed, as shown in Fig. 8.46.

The difference in the two models is demonstrated here on behalf of the time stamp. The communication protocol for the data model uses a relative time stamp (Fig. 8.46, left hand side), while the information model expresses the date and the time absolutely (Fig. 8.46, right hand side).

The target is set to develop standardized converters to ensure a convenient and consistent data export/import between both models. The first experiences with this translation are reported in Sect. 9.2.

8.5 Data and Communications Security IEC/TS 62351

The scope of the IEC/TS 62351 [2] series is focused on the information security, especially for power system control operations. The main objectives are two-fold in undertaking

1. The provision of standards for information security concerning the ICT standards defined by IEC TC 57, specifically for:
   - the IEC 60870-5 series (parts 101 and 104 for substation-control center, part 102 for meter and part for 103 protection communication),
   - the IEC 60870-6 series (for inter-control center communications),
   - the IEC 61850 series (for multilevel communication in power systems),
   - the IEC 61970 series (for data management at the transmission level) and
   - the IEC 61968 series (for data management at the distribution level).
2. The development of standards or technical reports on end-to-end security solutions.

The standard series consists currently of several parts which consider the specific objectives of information security

Part 1 gives the introduction to the subsequent parts of the standard, primarily to introduce various aspects of information security according to power system operations

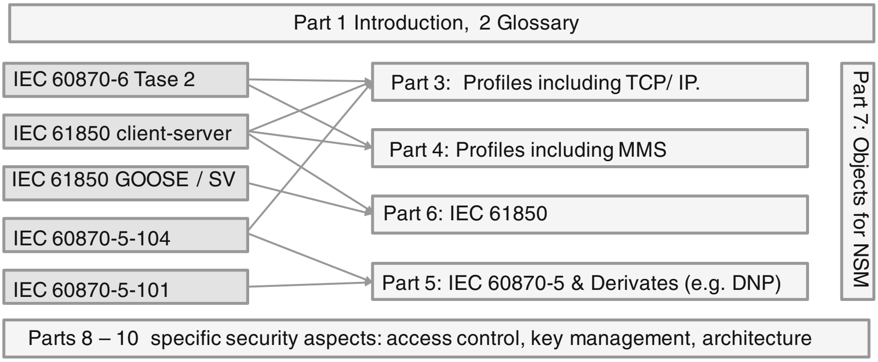


Fig. 8.47 The structure of IEC/TS 62351 and the relations to the communication standards

As usual, part 2 contains the glossary of terms

The parts 3–6 specify security standards for the IEC TC 57 communication protocols and the special layer profiles TCP/IP and MMS. These can be used to provide various levels of communication security, depending upon the protocol and the parameters defining the concrete implementation.

The part 7 addresses one specific area of end-to-end information security, namely the enhancement of the general management of the communication networks used for power system operations: the network system management (NSM). NSM provides the administration of the information infrastructure of the communication network, analogous to SNMP (simple network management protocol) applied in local area networks for PC communication. NSM is focused on the communication for power system operations by introducing naming conventions which correspond with the IEC 61850 data models. The data models can be mapped, for example, to IEC 61850, IEC 60870-5, SNTP, and Web services.

The parts 8–10 define the management of specific security aspects, which are also valid for the data management in data bases applying the CIM.

The relationships of the mentioned standard parts to the communication protocols are described in Fig. 8.47.

The standard parts define a large variety of protection measures against:

- un-authorized information access,
- un-authorized modification or theft of information,
- loss of information,
- denial of service or prevention of authorized access,
- accountability for loss of information including
  - denial of events that took place or
  - claim of events that did not take place.

In addition to features like encryption, fire walls, anti-virus/spy-ware, passwords etc., a key element of the information security measures consists in the

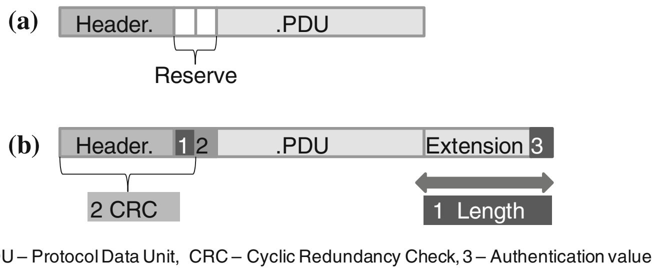


Fig. 8.48 IEC 61850 protocol frames: **a** without and **b** with authentication

introduction of the authorization for role-based access control (RBAC) via a digital signature added to each protocol frame sent out from either the client, a server or a publisher.

This method uses a special keyed-hash message authentication code (HMAC). HMAC is a specific construction for calculating the message authentication code involving a cryptographic hash function in combination with a cryptographic key. The cryptographic strength of the HMAC depends on the underlying hash function, the size of its hash output, and on the size and quality of the key.

A comparison of the protocol framework without and with the authentication is depicted in Fig. 8.48.

The work on the standardization of data and communication security for the power system management is still continuing. Additional parts are expected to address further areas of information security in accordance with the development of know-how regarding the newly (and yet-to-be) detected security issues and threats.

8.6 Global Activities for Uniform Smart Grid Standards

8.6.1 The Reference Model IEC/TR 62357

The Smart Grid concept has an impact on all stakeholders of the electricity supply processes:

- network operators at all levels of the power system,
- small and bulk power producers,
- traders and service providers,
- traditional consumers and
- consumers using new types of loads requiring specific network access conditions.

All of these stakeholders require a set of consistent standards to ensure that a high quality of power supply may be maintained, also under the Smart Grid conditions.

"Over 100 IEC standards have been identified as relevant to the Smart Grid [8, 9]".

A significant part of these standards belongs to the area of information and communication technologies. Smart Grids require interfacing capabilities that will allow new designs of network equipment and new ICT solutions to be successfully fitted with the existing, traditional network equipment and ICT solutions in operation.

In this context, the continued support of the worldwide established "older" communication standards is very important and cannot be neglected.

The technical committee TC 57 of IEC developed a technical report describing all the existing object models, services, and protocols that play a key role for Smart Grids and shows how they relate to each other.

IEC/TR 62357-1:2012 [10] specifies a reference architecture and framework for the development and application of IEC standards for the exchange of information covering all levels of the power system—beginning with the LV building networks and ending with the levels of the wholesale markets for electricity and the control areas of the transmission system operators.

This technical report provides an overview of the available new and traditional standards as well as guidelines and general principles for their application in distribution, transmission, and power production regarding the electric network operations, the asset and maintenance management, the network planning, the engineering methods, the external ICT applications and the power system interaction with market activities.

The prospective multi-layer reference architecture described in this technical report takes into account new concepts and advanced technologies, such as semantic object modelling or innovative specification methods, in order to build on innovative technology trends and standard activities to achieve the conformance and interoperability targets of the Smart Grid concept. Figure 8.49 presents the reference architecture in accordance with the technical report [10].

This reference architecture contains all the above considered core ICT standards (grey) and provides the assignment of the related parts to their application levels. Besides the systematic allocation of the ICT standards, bridges to other domains are presented like:

- the application of mature ISO and industrial standards to cover the 7 layer model of the communication standards,
- the inter-system specification instruments like XML or RDF,
- the mappings to other technologies,
- the interrelations with other technical committees, especially concerning the meter and building automation standards (TC 13, TC 14).

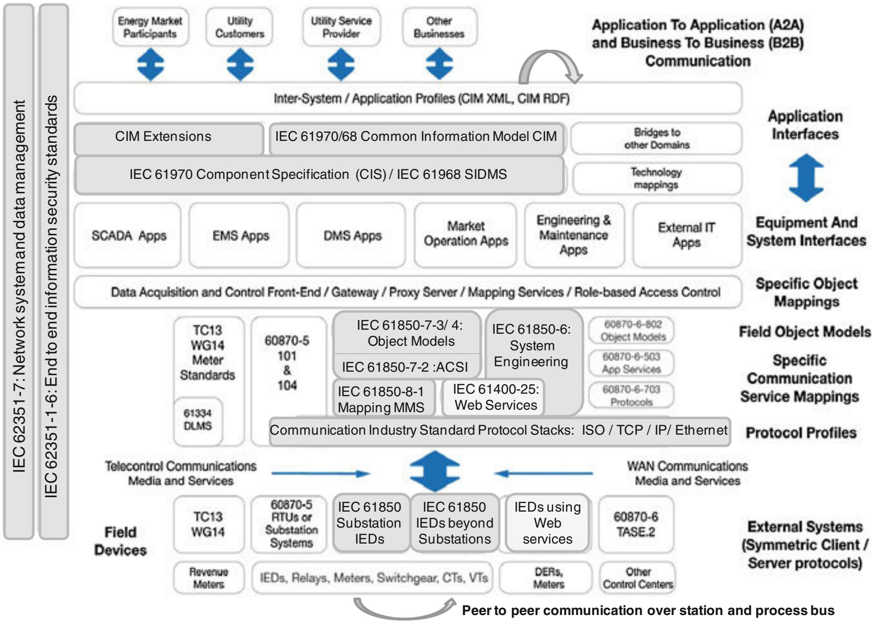


Fig. 8.49 IEC TC57 reference architecture for power system information exchange—update according to [10] and [13]

In this way, a strategy is presented that considers where common models are needed, and if possible, recommends ways to harmonize the different modeling approaches.

The work on the reference architecture is still continuing. The enhanced reference architecture is planned to be in conformance with the Smart Grid Architecture Model SGAM. This model provides a method to represent system aspects of Smart Grids.

8.6.2 The European Mandate M/490

In March 2011, the European Commission issued the Mandate M/490 "Standardization Mandate to European Standardization Organizations (ESOs) to support European Smart Grid deployment" [11] which was directed to the three ESOs: CEN, CENELEC and ETSI.

M/490 requests CEN, CENELEC and ETSI "to develop a framework to enable ESOs to perform continuous standard enhancement and development in the field of Smart Grids, while maintaining transverse consistency and promote continuous innovation. The expected framework will consist of the following deliverables:

1. A technical reference architecture, which is representing the functional information data flow between the main domains and integrate many system and subsystem architectures. The use cases were completed until 2013 for further considerations.
2. A set of consistent standards, which will support the information exchange (communication protocols and data models) and the integration of all users into the electric system operation.
3. Sustainable standardization processes and collaborative tools to enable stakeholder interactions, to improve the two deliverables above and to adapt them to new requirements based on gap analysis, while ensuring the fit to high level system constraints such as interoperability, security and privacy, etc. [11].

The European mandate M/490 requires the ESOs to build on pre-existing documents delivered by various standardization bodies and through other mandates such as M/441 (smart metering) and M/468 (charging of electric vehicles).

In order to perform the requested work, the ESOs combined their strategic approach and, in July 2011, established the common CEN-CENELEC-ETSI "Smart Grid Coordination Group" (SG-CG), which is responsible for the common work on the M/490 aspects.

Between the end of 2011 the end of 2012, the SG-CG worked intensively and published the following reports (approved in January 2013 by the Technical Boards of all three organizations) [12]:

- Framework document which provides an overview of the concepts and results,
- Reference architecture,
- First set of consistent standards,
- Sustainable processes,
- Smart Grids information security.

The framework document considers how the different standard elements fit together to provide a consistent framework for Smart Grids in accordance with M/490.

The document presents the deliverables of the mandate and their classification. An overview of the results of the four working groups is given. The process for future identification of standard needs is described.

The reference architecture document has to specify the communication and energy flows, main elements of the power system and their interrelations.

In the first step, existing architecture models have been analyzed. The Smart Grids Conceptual Model (developed by the National Institute of Standards and Technology—NIST, USA) was identified as a sound and recognized basis. However, it has been necessary to extend it in order to take into account the specific requirements of the EU.

Two main components are introduced for enhancement:

- the Distributed Energy Resource (DER) domain that allows addressing the growing importance of DER connected to the networks,

- the flexibility concept that aggregates consumption, generation and storage into a flexible entity.

Furthermore, the Smart Grids Architecture Model (SGAM) Framework was recognized as an appropriate instrument to support the design of Smart Grids use cases with an architectural approach that also offers the needed openness for further extensions. This model merges five interoperability layers (business cases, functions, information content, communication and components) with the two domains of the Smart Grid concept:

- the hierarchy of the power system management and energy markets,
- the chain of energy conversion from the generation to the end-consumers.

The architecture viewpoints specify a set of ways to represent abstractions of different stakeholder's view of a Smart Grid. Four viewpoints have been selected and associated with adequate architectures: business cases, functions and use cases, information models, communication protocols.

The usage of the reference architecture is described on behalf of a large range of applications.

The analysis of Smart Grids use cases via the SGAM methodology is a way to support the work of engineers who will implement such use cases.

The first set of consistent standards is a selection guide which, depending on the targeted application area, will set out the most appropriate standards to consider. In the first step, 24 Smart Grid systems were identified to be considered regarding the needs for a consistent set of standards. The 24 Smart Grid systems are classified as follows:

- Generation management,
- Transmission management:
  - Substation automation,
  - Wide area measurement,
  - Energy management system EMS and SCADA,
  - Flexible AC transmission system—FACTS,
- Distribution management:
  - Substation automation,
  - Feeder automation/smart reclosers,
  - Distributed power quality control,
  - Distribution management SCADA and geographical information systems,
  - FACTS,
- Distributed energy resources (DER) management:
  - DER operation,
  - DER EMS and
  - Virtual Power Plants,
- Smart Metering:

  - Advanced metering infrastructure,
  - Metering back office system,
- Demand and production flexibility—aggregated "prosumers" management systems,
- Market place system,
- Trading system,
- E-Mobility (connection to network),
- Administration systems:
  - Asset and maintenance,
  - Communication network management,
  - Clock reference,
  - Device remote configuration,
  - Weather observation and forecast.

The Smart Grid Architecture Model SGAM is applied to map all of the mentioned 24 systems into a structured system description. Each of the above mentioned systems is mapped to SGAM in the context of use cases following the identical approach:

1. Definition of the set of generic use cases the considered system may support.
2. Design of the typical architecture and components used by this system (component layer).
3. Provision of the list of standards to be considered for interfacing all components within this system at the component, communication and information layers.

The relationships between the systems and the appropriate standards are established and presented in tables.

In this context, the document assigns more than 400 standard references coming from over 50 standardization bodies to the 24 Smart Grid systems. The working group received and considered about 500 comments from various international experts in the review phase of the document.

The specification of sustainable processes is based on the developed use case methodology in standardization. Use cases have been collected from a diverse range of stakeholders based on the developed use case template.

The collected use cases have been grouped and generic use cases have been specified accordingly. The generic use cases can be considered as the description of functions and processes responding to the needs of an array of actors. The generic use cases define the general concepts and are not project specific.

Conceptual descriptions of the main Smart Grids use case clusters have been developed. Generic use cases are stored and maintained in the Use Case Management Repository (UCMR). The description of the UCMR structure was published.

The collected and modified use cases perform the basis to evaluate the needs for further Smart Grid standards. The use case methodology is now a part of the complete set of instruments to gain interoperable solutions.

The Smart Grid Information Security (*SGIS*) *report* provides guidance regarding the application of standards for information security. The main pillars of information security for Smart Grids are specified as Confidentiality, Integrity and Availability (CIA).

The report introduces a European Smart Grids stability scenario based on the components:

- Smart Grid Architecture Model (SGAM),
- Smart Grid Information Security Level structure,
- Smart Grid Data Protection Classes and
- Security View per SGAM layers.

Recommendations regarding the implementation of these components have been established.

The considered SGIS Toolbox provides a user friendly guidance concerning the special security needs for use cases.

The report comes to the conclusion that the standards requested for Smart Grid Information Security already exist today. Nevertheless, the need for enhancement and for additional standards to cover specific needs of Smart Grids is recognized.

The mandate M/490 was prolonged in 2013 to provide further specifications. For example, the specification of a "Mapping Tool" has to be developed to harmonize and improve the linking of the different IEC standards.

The results of the M/490 findings have had an great impact on the creation of further initiatives in several IEC Technical Committees, e.g. TC8 (micro-grids and connection conditions), TC 23 (energy management and micro-grids in buildings), TC 57 (reference architecture, enhancement of the basic ICT standards, specification of the interfaces network-consumers), TC 64 (Smart Grid and building installations), TC 65 (Smart Grid and industry), TC 88 (communication of wind power plants), TC 120 (integration of storage technologies). An additional impact has been observed in several national activities to deploy the recommended set of standards in national roadmaps.

8.6.3 Global Activity Analysis Within the E-Energy/Smart Grid Standardization Roadmap

The above described efforts of IEC and of the European Mandate M/490 have been accompanied and influenced by several international and national activities concerning standard related recommendations, guidance and roadmaps for the efficient deployment of Smart Grids.

The German Standardization E-Energy/Smart Grids Roadmap was issued in two volumes—volume 1.0 in April 2010 [13] and volume 2.0 in November 2012 [14].

The roadmap [13] begins with a survey and an analysis of global initiatives regarding the Smart Grid standardization. This serves to provide the various national committees with information on the work of the other committees, and also to describe and link up with the European and international standardization activities. In addition, it is intended to provide outsiders with an insight into the various evolutionary developments. The document [13] contains detailed descriptions of the following initiatives:

The SMB of IEC (Standardization Management Board) established a strategy group of Smart Grids which published an initial roadmap regarding the IEC standards and eleven high level recommendations. The IEC standards identified as core standards are the standards considered in detail above, namely IEC 62357, IEC 61850, IEC 61970/68 and IEC 62351.

The CIGRE study committee D2 founded a working group to investigate the "EMS architectures of the 21st century". Eleven design principles are specified to ensure interoperability and reusability in the area of ICT.

IEEE started the project P2030 with the target to ensure the interoperability of energy technologies and ICT in Smart Grids with the special focus on the end-user applications.

The UCAiug (Utility Communication Architecture international user group) is an international association of users of the standard series IEC 61850 and IEC 61970/68. The group supplies important inputs for the harmonization of both standard series based on their experience in several projects.

NIST (in cooperation with EPRI—Electric Power Research Institute, USA [15]) published a framework and a roadmap for Smart Grid interoperability standards in January 2010. It describes an abstract reference model and identifies almost 80 standards which are essential for the deployment of Smart Grids. Additionally, fourteen key areas are considered in which new or enhanced standards are requested. NIST publishes action plans with timetables and cooperates with the standardization bodies. The target is set to close the still existing gaps and to achieve Smart Grid interoperability in the near future.

Japan's Roadmap to International Standardization for Smart Grids and collaboration with other countries [16] was considered in a 1st report in January 2010. Seven main fields in the electricity supply processes were identified and 26 priority action areas were assigned to the processes. Special core effects of the Japanese economy are analyzed.

The Electric Networks Strategy Group of the UK [17] published a Smart Grid Routemap. 12 major challenges are considered with regard to the objectives carbon emission reduction, reliability of supply and competition.

The Spanish Electrical Grid platform FutuRED [18] presents a number of recommendations regarding the technology progress and the political, legislative and regulatory support for the deployment of Smart Grids.

The Smart Grid Roadmap of Austria [19] defines fields of technology in which the technical progress is indispensable for the future Smart Grids.

The German Standardization Roadmap 1.0 presents an overview of several activities which have been performed in Germany:

- The investigation of the standardization environment of the E-Energy projects [20] issued in January 2009 [21],
- The basic study of the German Institute for Standardization (DIN) regarding the future needs for standardization published in April 2010 [22],
- The initiative of the Federal Association of German Industry (BDI) "Internet for Energy—ICT for the energy markets of the future" published in February 2010 [23],
- The energy integrated roadmap Automation 2020+ of the automation division of the German Electrical and Electronic Manufacturer's Association (2009) [24],
- In-house automation joint working group of DKE and E-Energy Research.

The German Standardization Roadmap 1.0 analyzes the common aspects of the described international and national investigations. The studies and roadmaps stress the need for:

- Global, uniform and harmonized standards with stringent definitions of the semantics and syntaxes of the applied data models,
- high information security to ensure reliable and stable power system operations,
- inclusion of metering and home automation standards into the harmonization efforts to deploy the consumer market integration and the approaches of demand side integration, also on a common standard basis, and, last but not least,
- paradigm changes in the regulatory and legislative frameworks.

Furthermore, the areas of engineering, distributed energy resources, electricity storage and electric vehicle management will play a significant role in the prospective power system operations. Consequently, the standardization in these areas has to be taken into account and added to the set of core standards.

However, on a global level these areas are only partially relevant.

In conclusion of the analyses of global studies and the German experience, the document [13] specifies a set of recommendations covering the following 12 domains (with indication of the number of domain specific recommendations):

1. General aspects (12)
2. Regulatory and legislative frameworks (3)
3. Information security and data protection (4)
4. Information exchange via communication (4)
5. Architectures, data exchange and power system management (4)
6. Active distribution systems (2)
7. Smart Metering (5)
8. Distributed generation and virtual power plants (3)
9. Electro-mobility (3)
10. Storage of electric energy (3)

Table 8.4 Core standards for Smart Grids according to the global activity analysis

Application	Standard
Seamless ICT landscape—reference architecture	IEC 62357
Established communication in power systems	IEC 60870
Advanced and seamless communication in power systems	IEC 61850
Advanced communication for wind power plants	IEC 61400
Data management for EMS and TSO using CIM	IEC 61970
Data management for DMS using CIM	IEC 61968
Data management for market communication using CIM	IEC 62325
Information security	IEC 62351
Compliant development instruments for distributed control and automation using function building blocks	IEC 61449
Electric vehicle conductive charging system	IEC 61851
Companion Specification for Energy Metering COSEM	IEC 62056
Meter communication using the Device Message Specification DLMS	IEC 61334
Electric energy metering—including customer-utility information exchange	IEC 62051
Building automation KNX	IEC 14543 EN 50090 EN 13321
Building automation BACnet	ISO 16484
Building automation LON	EN 14908
Household appliances interworking	EN 50523

11. Load management and demand side response (2)
12. Building and in-house automation (5)

The extended overview of the core standards for Smart Grids was compiled according to the above mentioned recommendations and is presented in Table 8.4.

Today, in the areas of "Smart Metering" and "Building automation" throughout the world too many standards are applied, which is only particularly reflected in Table 8.4.

A large amount of proprietary solutions and standards with regional or utility related importance was developed and is applied by different vendors and companies.

It is desirable to move toward a common worldwide accepted standard (as happened with IEC 61850 in the area of power system control) or to reduce the number of alternative standards. But, for the moment, such a target is seen as unrealistic.

The European Union has set up the Mandate M/441 to develop strategies in the area of Smart Metering.

The communication at lower levels for building automation and metering should be simple, cost efficient and should not require such advanced protocol services as are implemented for the power system control in IEC 61850.

However, the amount of information objects that are common for metering or building automation at the lower level, and of network control at the higher level, is very low. In principle, it contains the metered values, network signals (e.g. load should be lowered in industrial enterprises), the setting of actual energy tariff signals and the tariff forecasts—much less in comparison with the many thousands of data required for power system control.

The use of gateways converting the data models of the applied protocols at the lower level to the IEC protocol at the level of power system control is a possible solution to perform the needed data exchange between the closed metering and home automation systems on one hand and the power system control system on the other hand.

In the area of IEC, a closer cooperation of TC 57 (System aspects) and TC 13 (Metering) is seen as an opportunity to add the DLMS/COSEM objects to the IEC 61850 data model without the direct need for changing the related standards.

DLMS/COSEM specification is part of the standard IEC 62056. DLMS or Device Language Message Specification is the set of standards developed and maintained by the DLMS User Association (UA) and has been taken over by the IEC TC13 and added to the IEC 62056 series of standards. COSEM or Companion Specification for Energy Metering includes a set of specifications that defines the transportation and application layers of the DLMS profile.

The following three standards for building automation are the leading standards in Europe and have been applied worldwide in thousands of projects:

- KNX according to EN 50090 is a European construction standard containing technical rules for homes and buildings including the sensor-actor communication protocol. The current version as KNX standard is also specified in IEC 14543-3.
- BACnet according to EN ISO 16484 specifies in part 5 the BACnet protocol for communication of a control device with sensors and actors.
- LON according to EN 14908 is a protocol optimized for networking devices over media such as twisted copper pair of wires, fiber optics, power line carrier and radio frequency. This standard specifies a multi-purpose control network protocol stack optimized for smart building and for smart city applications.

These standards are being further developed for enhancement and harmonization, e.g. with ZigBee—the device communications and information model used in the USA.

The document [13] concludes with the definition of concrete steps to deploy phase 1 of the roadmap. The main topics for a subsequent phase 2 are also considered.

It is expected that the technologies of energy trading, power generation, network operation, vehicle management, ICT services and multi-utility concepts (gas, water, district heating) will converge and grow to a Smart Multi-utility Energy System. This kind of merging requires further activities in the international standardization.

Important new functions in the area of transmission systems will also require more attention. New standards are required to ensure the efficient establishment of new bulk power transmission lines in accordance with the DESERTEC vision [25] (see also Chap. 2).

The German E-Energy/Smart Grid Standardization Roadmap 2.0 is based on the analyses and intends to explore the topics initially addressed in the first 1st roadmap. It was developed in close cooperation with the Smart Grid Coordination Group and the related working groups regarding the European Mandate M/490.

The survey of the international efforts was updated and describes the following extensions.

International and overseas initiatives:

On the *IEC* level, the Strategic Group on Smart Grids (SG3) was established, and its work is currently focused on an updated version of the Smart Grid Roadmap and on the enhancement of the above described ICT standard series. The next version of the IEC roadmap also considers the prospect of future standards. Other Technical Committees in addition to TC 57 have founded working groups to develop Smart grid requirements according the relevant domains of the TCs.

The ongoing activities in the *USA* under the leadership of NIST produced a second version of the framework and roadmap for Smart Grid interoperability standards in February 2012. Additionally, a new organization was founded (Smart Grid Interoperability Panel—SGIP). Currently, around 800 companies and organizations joined SGIP. The work of SGIP is concentrated on developing a Priority Action Plan (PAP) and the Catalog of Standards (CoS).

The State Grid Corporation of *China* established a Smart Grid standardization system with eight domains. These domains are network planning, generation, transmission, transformation, distribution, consumption, dispatching and ICT. Ninety two series of standards were identified as essential for the Smart Grid deployment and their enhancement or revision was requested.

In *Korea* a Standardization Roadmap has been available since 2010, and an Interoperability Framework was issued in March 2012. The three top-level domains Smart Service, Smart Power Generation and Smart Consumer were specified to support the Smart Grid deployment. The work is strongly oriented towards the NIST framework.

In *Brazil and India* Smart Grid Standardization Groups have been established.

Further international standards initiatives on Smart Grids are ongoing.

European activities:

The *European Commission* has issued the three above considered mandates (M/490, M/441, M468) related to Smart Grid standards and, consequently, the three parallel coordinating groups are actively working on the set objectives.

In addition to the standardization mandates, four Expert Groups have been formed under a high level Steering Committee:

- Reference Group for Smart Grid Standards,
- Regulatory Recommendations for Data Privacy and Data Protection in the Smart Grid Environment,
- Regulatory Recommendations for Smart Grid Deployment,
- Smart Grid Infrastructure Deployment.

ETSI has developed a domain-independent M2M communications architecture (functional architecture) based on the results of M/490 and M/441. The specifications of the "M2M Release 1" were published in February 2012.

Furthermore, the 3rd package on the internal market for energy has been implemented in legislation and stipulates a number of fundamental changes in the energy policy. This package contains also a provision for the development of ENTSO-E wide, consistent, uniform and binding Grid Codes. Accordingly, various Grid Codes of the TSOs are to be compiled by 2014, with the objective of ensuring safe and efficient network operation for the establishment of a single European electricity market.

The *German activities* are concentrated on all domains specified by the EU mandate M/490. The objectives and targets of several national working groups are described in [14].

The "Future-Oriented Grids" Platform and "Smart Grids and Meters" Working Group have been established by the Federal Ministry of Economics and Technology (BMWi) considering important topics in the development of the electricity networks together with the various stakeholders.

For the introduction of smart meters, the Federal Office for Information Security (BSI) is developing a technical directive based on protection profiles according to common criteria for the use of secure smart meter communication links.

The German Federal Government launched a complex program in 2008 "E-Energy—ICT-based energy system of the future" [20]. By 2013, six industrial and scientific consortia have been examined and tested the fundamental elements of a smart power supply system using renewable energy sources in various scenarios and regions.

Under the umbrella of the DKE (the German Commission for standardization in the fields of electro-technology, electronics and ICT), the Expertise Centre for E-Energy/Smart Grid standardization and the E-Energy/Smart Grid Standardization Steering Group were formed. Their aim is to coordinate the standardization issues raised by Smart Grids in cooperation with the national technical committees, with various stakeholders and associations. The steering group coordinates the work of 11 focus and working groups to cover the different domains in the Smart Grid standardization.

Two additional standardization roadmaps were developed with references to Smart Grids, the aim of which is to present the current results of global initiatives and to identify the requests for further structured approaches:

The Standardization Roadmap on AAL—Ambient Assisted Living [26] responds to the request for the widespread use of smart assistance systems making cost-efficient, uniform, consistent and interoperable system components possible. The roadmap assists vendors in the development of products and promotes a uniform understanding of the interoperability and the compatibility of AAL components from different vendors.

The German Standardization Roadmap on Electro-mobility 2.0 [27] considers the performance and consumption characteristics of electric vehicles. Attention is paid to the consumption of the charging stations themselves. Furthermore, the aspects of electrical safety and electromagnetic compatibility are described with regard to the existing standards.

In general, further topics of the roadmap [14] are conform with the results of the European SG-CG, which is supported and followed with great interest by the national committees, associations and working groups. This conformance is especially expressed in regard to:

- the introduction of the use case methodology,
- the systematic and profiling of the standardization processes,
- the Smart Grid Information Security,
- the Smart Grid Architecture Model.

Examples of use cases and their move towards the application in the practice of power system operations have been demonstrated. Best practice examples are presented in the appendix.

The German E-Energy/Smart Grid Standardization Roadmap 2.0 provides a great impact on the IEC and European M/490 activities. The recommended "Use Case" and "Smart Grid Architecture Model" methodologies are now used at the international level and were introduced in a number of related areas below the power system control level such as Electro-mobility, Ambient Assisted Living (AAL) und Smart Home.

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Chapter 9
Smart Grids Worldwide

9.1 Smart Grids for the World's Largest Power Systems

9.1.1 Ambitious Power System Development Strategy in China

China became the world's largest producer and consumer of electricity during the first decade of the 21st century. The Chinese electricity generation increased rapidly and achieved an annual generation of 4,692.8 TWh in 2011 [1]. The Chinese electricity generation is expected to double over the next decade and to triple by 2035 [2].

The need for establishing Smart Grids in China is driven by two major objectives:

1. Establishment of a unified national transmission system and
2. Significant growth in the use of renewable energy sources.

The Chinese power system is operated by six regional transmission networks. Five of these transmission networks are managed by the State Grid Corporation of China (SGCC):

- NWCG—North-West China Grid,
- NCG—North China Grid,
- NECG—North-East China Grid,
- CCG—Central China Grid,
- ECG—East China Gridas depicted in Fig. 9.1.

The China Southern Power Grid Company Limited (CSPGC) is the second state owned Chinese transmission enterprise and operates the China South Grid CSG.

The lack of a unified national transmission system with strong interconnections is a barrier to the nation-wide efficient use of the power plants and heightens the risk of local congestions. For example, the peak and weak load situations are quite different in different regions in China. The Northern areas experience a strong winter peak load. On the other hand, a high summer demand is observed in the

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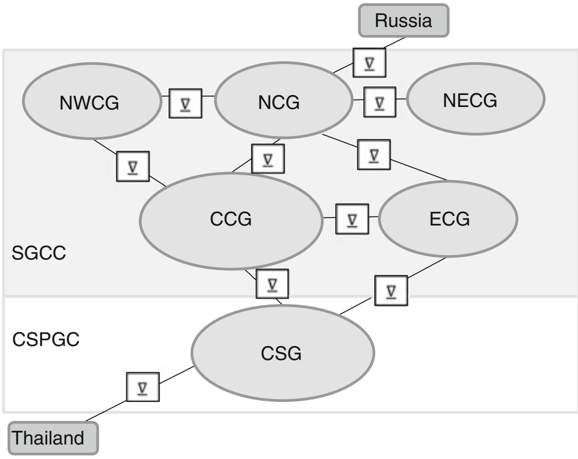


Fig. 9.1 Transmission grids in China and interconnections for establishing a unified grid

Southern regions where the levels of the reservoirs of the hydro power plants located there drop. The power gap has to be covered by expensive oil and diesel aggregates.

The stronger interconnection of the transmission systems by DC and AC links with high transfer capacities offers an optimal use of the generation and transmission capacities.

China's power system is mainly based on coal fired thermal power plants (approximately 75 %). However, China is also the world champion regarding the electricity generation based on renewable energy sources (RES). First of all, this result is based on the enormous hydro power resources providing an annual generation of more than 600 TWh/a.

Furthermore, China will soon take over the world market leadership in photovoltaic and wind power technologies. The installed wind power capacity of China achieved 76 GW in 2012, which amounts to more than 25 % of the whole installed capacity worldwide (see also Sect. 2.2.1).

By 2012, 17 % of Chinese electricity generation was from RES, and a further rapid growth is planned. The planned installed wind power capacity of 200 GW in 2020 is only one of the growth targets.

The integration of China's growing RES capacity into the national power system requires the upgrade of the electric network infrastructure at all levels and ultimately, the establishment of a Smart Grid.

China's Smart Grid policy is closely connected to its overall energy policy and is controlled by the central government. The goal of the Chinese government is to build a strong national Smart Grid capable of long distance transmission of bulk power from conventional and renewable energy sources. In March of 2010 China announced its plan for the establishment of a "unified and strong Smart Grid" by 2020.

The SGCC is the leading driver in developing the Smart Grid and has announced plans to invest $250 billion in electric power infrastructure upgrades by 2015, of which $45 billion is assigned to Smart Grid technologies. Another $240 billion between 2016 and 2020 will be added to conclude the Smart Grid enhancement [3].

A deployment strategy has been decided upon, which includes the following three stages:

- Phase 1 is focused on the development planning, the setting of technology standards and the initiation of pilot projects.
- Phase 2 is a comprehensive construction phase from 2011 to 2015, and is concentrated on the following objectives:
  - The establishment of a UHV overlay grid, which will apply (for the first time in the world) ultra-high voltage transmission lines 1000 kV AC and $\pm$800 kV DC (see also Sect. 3.3). By 2015, UHV and other intra-regional transmission capacity will reach 240 GW.
  - The improvements of the urban-rural distribution network are directed at improving the power quality. The electricity supply has to reach a reliability rate of 99.915 % or higher in the cities and 99.73 % or higher in rural areas.
  - The Smart Grid operation philosophy and the appropriate control technologies.
  - Key technological solutions will be broadly applied. For example, Smart Meters will be in widespread use and charging stations for electric vehicles will be deployed in numbers that will satisfy demand. $2.5 billion expenses per year are foreseen for smart meter deployment, and in 2020 the number of installed Smart meters will reach 380 Million.
  - The construction phase has been accompanied by Smart Grid standardizations efforts. SGCC is actively involved in developing international Smart Grid Standards specifying that 22 core criteria will be applied to determine and introduce the key standards in China in 2014.
- Phase 3, the "leadership phase", is directed at completing a strong nation-wide interconnected Smart Grid. By 2020, UHV and other intra-regional transmission capacity will reach 400 GW, enough for the transmission of the requested power from the installed coal, hydro, nuclear and wind power plants to the areas with high demand and with a gap of local generation. The distribution networks will be strengthened and the rural networks will be renovated. The electricity market will enable the active participation of consumers in demand side integration.

Besides the strong enhancement of the interconnected networks at all levels, intelligent solutions will be applied to ensure the efficient power supply of remote rural areas. Islanded power systems or so called "microgrids" using a combination of renewable sources and storage units will be established in such areas. In this way, the expensive and environmentally unfriendly electricity generation by diesel aggregates may be completely replaced or used for reserve purpose only.

As a result of the extensive Smart Grid strategy and the related deployment efforts, China intends to become the world leader in management, technology and system operation solutions.

9.1.2 Development Targets for Interconnections in the USA

The second largest electric power system in the world is operated in the USA. The annual power generation of the USA has not significantly changed since 2002 (growth <8 %) and varies from year to year. By 2012, the power generation capacity of the USA was 1,168 GW (76.7 % fossil primary energy sources (PES), 9.4 % nuclear power, 13,9 % RES), and it produced about 4,100 TWh electric energy [4]. The USA is the second largest user of wind energy with an installed capacity of 60 GW in 2012.

The North American power system of the USA consists of 4 synchronous transmission systems which are called “interconnections”. The voltage levels are 230, 345, 500 and 765 kV. The areas of the three main interconnections (except Alaska and islands) are presented in Fig. 9.2 [4].

Including Alaska, the four transmission systems serve more than 334 million people in North America.

The Eastern Interconnection covers the most of the territory of the Eastern USA, extending from the foot of the Rocky Mountains in the Mid-West to the Atlantic coast. The Eastern Interconnection is linked with the other interconnections and with Canada (Quebec) via high voltage DC transmission lines. The transmission system of Ontario (Canada) is connected by AC links.

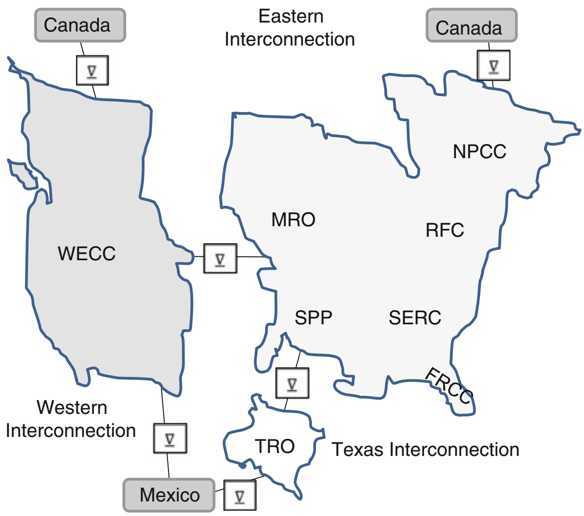
Within the Eastern Interconnection seven Reliability Councils coordinate the interactions of the TSOs:

- NEPCC—North-East Power Coordination Council,
- MRO—Midwest Reliability Organization,
- RFC—Reliability First Corporation,
- SPP—Southwest Power Pool,
- SERC—South-East Reliability Corporation,
- FRCC—Florida Reliability Coordinating Council.

The Western Interconnection covers the Western USA, from the Rocky Mountains to the Pacific coast. It is linked to the Eastern Interconnection over 6 DC transmission lines, and also has connections to Southwestern Canada and Northwestern Mexico. The reliability council for the Western Interconnection is WECC—the Western Electricity Coordination Council.

The Texas Interconnection covers most of the territory of Texas. It is linked with the Eastern Interconnection by two transmission lines and with the power system of Mexico. The reliability council for the Texas Interconnection is the TRE—Texas Reliability Entity.

Fig. 9.2 The three main transmission systems (interconnections) in the USA [4]



The Alaska Interconnection covers the territory of Alaska and is not linked with other interconnections. The reliability council for the Alaska Interconnection is ASCC—the Alaska System Coordination Council.

The reliability councils are members of the North American Electric Reliability Corporation NERC [5]. NERC is the electric reliability organization for North America and its mission is to ensure the reliability of the transmission systems in North America by:

- developing and enforcing reliability standards,
- observing the reliability parameters and publishing appropriate statistics,
- monitoring power flows between the transmission networks through system awareness.

NERC's area of responsibility spans the continental USA, Canada and the Northern part of Baja California, Mexico. It is responsible for the reliability parameters and publishes appropriate statistics, and it monitors the power flows. NERC is only one of several US organizations involved in the Smart Grid strategy of the USA.

FERC—the Federal Energy Regulatory Commission—is an independent agency that regulates the interstate transmission of electricity, natural gas, and oil. The Energy Policy Act of 2005 gave FERC the following additional responsibilities [6].

- Regulation of the transmission and wholesale sales of electricity in interstate commerce;
- Review of certain mergers and acquisitions and corporate transactions by electricity companies;
- Review of the siting applications for electric transmission projects;

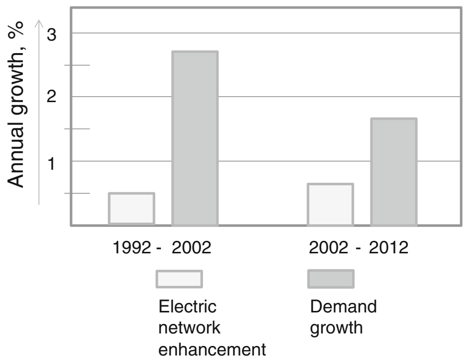


Fig. 9.3 Divergence between demand growth and the extension of the electric networks [8]

- Protection of the reliability of the high voltage interstate transmission system through mandatory reliability standards;
- Monitoring and investigation of energy markets;
- Enforcement of FERC regulatory requirements through imposition of civil penalties and other means.

FERC is engaged to pursuing market reforms that would provide advantageous market access for all types of RES. These efforts could include amendments to market rules, the modification of rules for ancillary services and related policies, or the implementation of operational tools that support the reliable integration of renewable resources. By implementing these or other reforms, the Commission's actions have the potential to increase the amount of electricity being produced from RES.

EPRI—the Electric Power Research Institute—is responsible for research and technology development (RTD) projects supporting the Smart Grid deployment and the National Institute for Standards and Technology—NIST. NIST supports the development of Smart Grid standards (see also Sect. 8.6).

The Department of Energy (DOE) is a governmental ministry and has a leading role regarding the power system development strategies. The Office of Electricity Delivery and Energy Reliability (OE) is an entity of the DOE and is responsible for enhancing the reliability and resiliency of the nation's energy infrastructure [7]. However, the reliability of the supply within the US power system is low compared to what has been reached in the central European countries.

The reason for the low reliability of supply is seen in the disparity between the fast growth of the demand compared to the level of investments for the electric network enhancement, caused by missing incentives for power quality provision. In Fig. 9.3 the divergence of both indices is presented [8].

The electricity consumption per capita of 12,700 kW h is in the USA twice higher compared to the industrial countries in Europe (e.g. Germany with 6,700 kW h) [9]. There are two main reasons for the high energy demand in the USA. Firstly, the annual electricity consumption of an average household adds up to 11,000 kW h, which is caused by a significant number of single family houses

Table 9.1 Outage statistics in the USA for the 1st half of 2004

Date	Location	Affected consumers	Comment
January 14th	Minnesota	12,000	
January 28th	Baltimore, Maryland	70,000	
February 6th	Ohio	2,500	Reasons not known
March 1st	Florida	15,000	
March 12th	Albuquerque, New Mexico	20,000	
April 22nd	Lax, California	30,000	Fault caused by birds
April 29th	Washington state	200,000	
May 12th	Utah	31,000	Tree contact
May 17th	Michigan-Indiana	Border area	Multiple faults
May 27th	Detroit, Michigan	Schools closed	Power outage
May 31st	Illinois	Fire at hospital	Power outage
June 3rd	Texas	400,000	

Source DOE, 2004

and the typical American end-user behavior. The main single appliances are electric space heating and water heating as well as air conditioning systems, which cover slightly less than 50 % of the total residential energy consumption [10]. On the other hand, the rate of energy efficiency, mainly in the industrial sector, is lower than in other industrialized countries.

Due to the high demand for electricity and the deficits in the appropriate electric network enhancements the reliability of the supply characteristics are weak what is demonstrated by a comparison of the System Average Interruption Duration Indices SAIDI of 2008 (see Sect. 4.6.1): USA—~300 min/a [11], Germany—16 min/a [12].

The consequences of a low reliability are frequent supply interruptions. Table 9.1 presents a survey of large supply interruptions in the USA for the period of the 1st half year of 2004, indicating the supply interruptions caused by the transmission and sub-transmission networks. Frequent supply interruptions are a daily problem for rural consumers who are usually supplied by MV and LV overhead lines with pole pots (MV/LV transformers installed on wooden poles). However, statistical data of such supply interruptions is not known.

After the large blackout in the Northeast of the USA in August 2003, it became clear that the USA needs a fundamental enhancement of its electricity supply system infrastructure.

Consequently, the efforts to enhance the electric power system in the USA were strengthened by research and several legislative initiatives. EPRI started the technology platform project "Intelligrid" in 2004, which became the "Smart Grid Initiative" after the introduction of the term "Smart Grid" in the context of the European Technology Platform (ETP) for the electricity networks of the future (see also Sect. 1.2).

OE has taken over a leadership role and established a partnership with the key stakeholders from network operators, industry, academia, and state governmental

Table 9.2 Activities towards the Smart Grid in the USA

Initiator	Year	Activity	Comment
OE/DOE	2003	Study: Grid 2030—A national vision for electricity's second 100 years. Transforming the grid to revolutionize electric power	Vision and deployment controlling
OE/DOE	2004	National electric delivery technologies roadmap	Action plan
OE/DOE	2005	Grid-works multi-year plan	Research priorities
Congress	2007	Energy Independence and Security Act "EISA"	Security of supply
Congress	2009	American Recovery and Reinvestment Act	Network enhancement

offices to modernize the US electricity supply system. The related Smart Grid initiatives are presented in Table 9.2.

The study "Grid 2030" defines the national vision as follows:

"Grid 2030 energizes a competitive North American market place for electricity. It connects everyone to abundant, affordable, clean, efficient, and reliable electric power anytime, anywhere. It provides the best and most secure electric services available in the world."

The EISA provided the legislative support for DOE's Smart Grid activities. Key specifications of the Title 13 include [7]:

- Section 03 establishes at the DOE the "Smart Grid Advisory Committee" and the "Federal Smart Grid Task Force",
- Section 04 authorizes the DOE to develop a "Smart Grid Regional Demonstration Initiative",
- Section 05 assigns responsibilities to the National Institute of Standards and Technology (NIST), and
- Section 06 authorizes DOE to develop a Federal Matching Fund for "Smart Grid Investment Costs".

In the framework of the Recovery and Reinvestment Act, funding in the amount of $3.4 billion was awarded. This sum was later extended by an additional fund of $9 billion.

OE provided a two year-long workshop program to identify the principal Smart Grid functional characteristics for the USA Smart Grid program. These are:

- Self-healing distribution networks,
- Enabling active participation by consumers in demand response,
- Operating vulnerably against external attacks,
- Providing power quality at higher levels for 21st century needs,
- Accommodating all generation and storage options,
- Enabling new products, services, and markets,
- Optimizing the use of assets and increasing the efficiency of network operations.

The US vision of a Smart Grid uses digital technology to improve reliability of supply, resiliency, flexibility, energy efficiency, and economy of the electricity supply processes at all levels of the power system.

The key activities that comprise the Smart Grid strategy are directed:

- to generate research and development initiatives for the design of prospective technologies in the areas of transmission, distribution, energy storage, power electronics, cyber-security,
- to support demonstration projects and the subsequent deployment strategies,
- to develop and introduce standards in the area of interoperability,
- to create greater certainty with respect to the future extension of the electricity network,
- to address the impending workforce shortage by developing a greater number of well-trained, highly skilled electric power sector personnel knowledgeable in Smart Grid operations,
- to motivate the stakeholder's engagement by informing them about benefits, sharing of lessons learned for continuous improvement, and exchanging technical and cost performance data,
- to establish data collection to show the national progress with respect to overcoming challenges and achieving Smart Grid characteristics.

The Obama administration will pursue these activities in order to ensure that all Americans can benefit from investments in the nation's electricity supply infrastructure.

A policy framework for the Smart Grid describes the four main goals: better alignment of economic incentives to support the development and deployment of Smart Grid technologies; a greater focus on standards and interoperability to enable advanced innovations, the integration of consumers into the market by providing better information on how to save energy, and improved network reliability and resilience.

9.1.3 The Power System Enhancement in Russia and its Neighbouring Countries

The territories of Russia and of the Community of Independent States (the former republics of the Soviet Union) are mostly supplied by the synchronously interconnected systems:

- UPS—the Unified Power System of Russia and
- IPS—the Integrated Power System, which includes the national networks of Ukraine, Kazakhstan, Kyrgyzstan, Belarus, Azerbaijan, Tajikistan, Georgia, Moldova and Mongolia.

The UPS (Единая энергетическая система России) is currently operated by the Federal Grid Company (FGC) of Russia and includes six transmission operators: Centre, South, North-West, Middle Volga, Ural and Siberia. The regional TSO East still operates independently of the UPS of Russia [13].

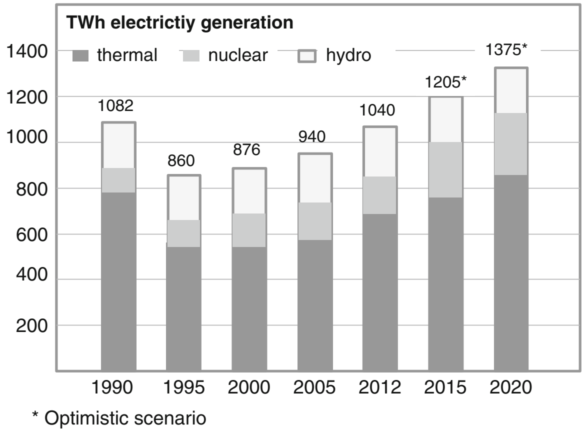


Fig. 9.4 Development of electricity generation in Russia (*Source* Ministry of Energy of the Russian Federation according to [15])

The IPS portions of the transmission system are operated by the national TSOs and the related dispatching centres.

The electricity market served by the UPS/IPS transmission system exceeds an annual generation of 1,500 TWh.

Based on this amount of energy, the UPS/IPS system makes up the 4th largest power system and market in the world (behind China, the USA and the European ENTSO-E, and followed by Japan and India). However, from the territorial point of view, UPS/IPS covers the largest territory including, for example, 131,000 km of transmission lines and 891 substations operated solely by the FGC in 2012 [13]. The UPS/IPS network spans 11 time zones. The transmission system applies the voltage levels 220, 330, 500 and 750 kV.

The Russian share of the annual energy consumption served by the interconnected transmission system amounts to 1,040 TWh based on the installed generation capacity of 218 GW [14].

The Ukrainian electric power consumption (as the second in volume within UPS/IPS) was about 147 TWh in 2009 (according to a World Bank report, published in 2010).

The following considerations are concentrated on the Russian Smart Grid policy due to its energy related dominance within UPS/IPS. Since the collapse of the Soviet Union, the electricity generation in Russia dramatically declined between 1990 and 2000 followed by a stable recovery, as presented in Fig. 9.4 [15].

About 64 % of the present generation comes from fossil fired thermoelectric plants, 19 % is produced in nuclear power plants and 17 % is hydro power. These contributions for the annual energy balance are related to Russia's unique situation with its enormous natural resources.

Russia has some of the largest reserves of coal and natural gas in the world, leading to a low cost of energy and creating a barrier for the extensive development of RES. Over 60 % of the thermal power capacity is currently gas fired.

Furthermore, Russia has an enormous potential of hydro power. The largest hydroelectric plants are located on the Volga, Kama, Ob, Yenisej, and Angara rivers, where large reservoirs are in the exploitation stage. Large thermoelectric and hydroelectric plants are located in Siberia because of the availability of fuels and water power. The energy is transmitted to the center of Russia through a system of EHV transmission lines [16].

Other renewable energy sources (besides hydro power) do not play a significant role in the current energy strategy of Russia. In January 2009, Russia's energy policy included a mandate to increase energy from non-hydro RES to 4.5 %, up from less than 1 %, by the year 2020 [15]. A special benefit of renewable sources (others than hydro power) is expected by the substitution of expensive diesel aggregates, which are currently used to ensure the power supply of autonomous networks in remote areas or on islands. The transportation of fuel over long distances to these autonomous supply areas significantly increases the costs of electric energy.

According to the rapidly growing demand in Russia, the extension of power generation capacity is foreseen in two ways:

- Erection of new power plants with the focus on hydro and nuclear power,
- Renovation of the existing power plants and increasing the power production by enhanced efficiency.

About €100 billion Capital Expenses (CAPEX) are foreseen for this program by 2020.

As its 1st priority, Russia has set the target to double nuclear production by 2020. Over 8.7 GW of nuclear power capacity are currently under construction, and an additional 28 GW are planned [16].

Secondly, Russia's largest hydro-electric power producer RusHydro is extending the hydro power capacity by erecting new plants, for example, a total of 8.1 GW installed power between the years 2012 and 2013 [17]. Additionally, the replacement of aged assets of hydro power plants will allow a further increase of about 1 GW capacity. The replacement program will be completed by 2020 and includes 154 turbines (55 %), 119 generators (42 %), 176 transformers (61 %) and further assets—especially for the modernization of the control technologies [17].

The existing electric networks of the UPS/IPS are not able to meet the challenges in the context of the increasing demand and the accompanying extension of the power generation capacities. Furthermore, the FGC has to cope with enormous problems regarding the ageing of asset.

Consequently, the Russian national Smart Grid strategy may be specified by the following four essential elements:

1. Extensive renovation and development of the transmission networks [14],
2. Development, erection, demonstration and operation of a showcase Smart Distribution network in the 20/0.4 kV supply area of Skolkovo near Moscow with the target to provide a national benchmark and to copy the appropriate solutions in other regions [14],

3. Enhancement of the protection and control technology up to the world standards based on the national concept of the "Intelligent Electro-Energy System with Active-Adaptive Networks" (IES-AAS) [18],
4. Introduction of Smart Grid education programs at a leading technical university in cooperation with international leading experts and scientists [19] with the target to multiply the gained experiences.

These four essential elements will now be discussed in detail:

1. The FGC is on its way to perform an ambitious investment program. The appropriate projects between 2013 and 2017 include:

- Construction of 12,239 km of new transmission lines and 22,068 MVA transformer capacity (€11,675 million),
- Renovation of 908 km of transmission lines and 28,300 MVA transformer capacity (€6,575 million),
- Enhancement of the energy efficiency, research projects and infrastructure (€587 million).

A massive project concerning the construction of an "electric power bridge" between Siberia and the central regions of Russia was initiated by Russia's President Putin at the APEC (Asia Pacific Economic Cooperation) meeting in Vladivostok, September 2012. The project details were considered during the 3rd Siberian Energy Forum in Krasnojarsk, December 2012. The transmission line with a length of 3,500 km is foreseen to transmit 5.2 GW from the Siberian power plants to central Russia at a voltage level of 1150 kV AC or $\pm$750 kV DC.

The planning and design work will be performed between 2013 and 2017. The erection of the UHV transmission line should be concluded in 2022. The expected CAPEX amounts €29.5 billion.

2. Construction has already begun on a high technology business area in the Skolovo Innovation Center. The Energy Efficient Technologies cluster aims to introduce advanced technologies focused on the introduction of a Smart Distribution network and on the increase of energy efficiency in industrial, housing and municipal infrastructure facilities in the sense of "Smart supply" (see Chap. 6). The 20/0.4 kV network consists of 13 substations, 190 transformer terminals, 1200 km MV and LV underground cable feeders.

The most innovative technologies have to be implemented for the establishment of the first Smart Distribution network of Russia, e.g. an advanced Control Center and SCADA system, SF_6 switchgear technology, digital Substation Automation Systems (SAS), digital protection and Smart Meters. The erection of photovoltaic panels on the roofs of buildings is planned with a capacity of 650 kW. The PV plants will be combined with accumulators for electric energy storage. Furthermore, 45 charging stations for electric vehicles are planned, 18 of which allow rapid charging within 15 min.

The complete Smart Distribution network has to be ready for operation in 2016 and should serve as a benchmark for further projects. Priority is assigned to 11 cities which were selected to host games of the football World Cup in 2018 [17].

3. Russian scientists and engineering enterprises are working on the concept of an IES-AAS, the aim of which is that all actors on the electricity market—power producers, network operators, service providers and consumers—are actively involved into the processes of transmission and distribution [18].

In principle, this definition is compliant with the European Smart Grid definition (see also Sect. 1.2). The concept contains elements which are described in the chapters above. Special attention is directed on the development of a "digital substation" which contains not only digital control, automation, protection and information and communication technologies (ICT), but also, a superconducting cable and optical instrument transformers using the communication principle in accordance with IEC 61850-9-2. The components of the digital substation are currently in the approval phase.

The reliable network integration of distributed energy resources also plays an important role within the concept.

4. The Russian government founded the project "Baikal—Technology Smart Grid" in 2011.

As the result of a global bidding procedure, the grant was assigned to a consortium consisting of the

- Otto-von-Guericke University of Magdeburg (OvGU), Chair of Electric Power Networks and Renewable Energy Sources and
- Irkutsk State Technical University (ISTU) with the chairs of
  - Power Plants, Power Grids and Electric Power Systems,
  - Power Supply and Electrical Engineering and
  - Heat and Power Engineering.

The main target of the project is to set up a research infrastructure in the field of power generation, energy efficiency and energy saving. The research topic is the development of smart grid strategies and technology. The research infrastructure will be implemented in the infrastructure of the Irkutsk State Technical University. One of the main goals of this project is to form a group of researchers, including all pertinent equipment, in order to sustainably perform research and teaching. After the funding period of this project ends, the research group should continue working and be able to finance itself. The proposed concept is founded on three main pillars:

- the establishment of a research group of Russian scientists,
- the creation of a laboratory infrastructure of four labs:
  - Laboratory 1: Cogeneration of heat and power, fuel cells and energy storage;
  - Laboratories 2 and 3: Simulation for optimization, observability and control of Smart Grids;
  - Laboratory 4: PMU, protection systems and FACTS.
- the introduction of a new lecture program on Smart Grids.

Both authors of this text book were involved in this project. Prof. Styczynski from the OvGU was acting as the senior project coordinator and he was supported by Prof. Voropaj as the coordinator from the ISTU side.

Fig. 9.5 Impressions from the Baikal project: **a** opening ceremony (*left hand side* Prof. Z. A. Styczynski), **b** WEB report about the Smart Grid lectures held by Dr. B. M. Buchholz

Figure 9.5a presents a picture of the opening ceremony of the project Baikal. An excerpt of the ISTU web portal reporting about the first set of lectures regarding the innovative Smart Grid solutions is depicted in Fig. 9.5b.

9.2 Overview of Smart Grid Projects in Europe

An enormous number of projects concerning research and technological development (RTD) and investigations related to Smart Grid components are currently on-going within the European Union—as the initiator of the Smart Grid vision. European projects are initiated by calls and sponsoring of the European Commission. Normally, European projects are assigned to international consortia after the bidding process, and they support mutual European cooperation. Special attention is paid to the involvement of small and medium enterprises.

National projects are also being performed in most of the EU countries. These projects are:

- partly sponsored by the national governments or by several ministries of the countries,
- initiated by national associations and others with participation of experts from network utilities, industry and scientific institutions,
- performed by order of the network operators and/or power producers in the framework of their normal investment activities.

An overview of both aspects of Smart Grid development is given in the next chapters.

9.2.1 Projects of the 5th–7th Framework Programmes of the European Union

The Framework Programmes (FP) for Research and Technological Development (RTD) are funding programs created by the European Union in order to support and encourage research in the European strategic research area.

The main strategic objectives of the FPs are to strengthen the scientific and technological base of the European industry and to encourage its international competitiveness [20]. The specific objectives and actions vary between funding periods.

The EU has supported Smart Grid projects for more than a decade within the 5th–7th framework programmes (FP) running between 1998 and 2013.

During 1998–2002 (FP5), 50 projects on the large-scale integration of distributed energy resources and key enabling technologies were supported with more than €60 million. A large portion of these projects were focused on storage batteries and addressed research areas such as infrastructures (including ICT), microgrids and network integration of distributed energy resources (DER).

Under the 6th Framework Programme (FP6, 2002–2006) 27 projects were funded with an EU contribution of approximately €65 million for the same thematic priorities.

The FP7 (2007–2013) has funded projects with €55.8 billion [21].

The largest research theme within the specific programs of FP7 was ICT with €9.1 billion in funding.

"The objective of the energy research under the FP7 is to aid the creation and establishment of the technologies necessary to adapt the current energy system into a more sustainable, competitive and secure one. It should also depend less on imported fuels and use a diverse mix of energy sources, in particular renewables, energy carriers and non-polluting sources. The EU Member States and the European Parliament have earmarked a total of €2.35 billion to sponsor this theme over the duration of FP7" [22].

In principle, the main directions of the energy sector of FP7 are related to Smart Grid vision and contain some hundred projects regarding:

- Smart energy networks,
- Renewable electricity generation,
- Hydrogen and fuel cells,
- Renewable fuel production,
- Renewables for heating and cooling,
- CO_2 capture and storage technologies for zero emission power generation,
- Clean Coal Technologies,
- Energy efficiency and savings,
- Energy policy making.

In general, Smart Grids are one of the priority topics in the FP7. The focus is on the efficiency, safety, reliability and quality of the European electricity networks, notably within the context of a European energy market.

The activities are structured along the following RTD areas:

- Development of interactive distribution energy networks with the aim to contribute to a higher penetration of RES and DER into the distribution networks, improving the security of supply of critical loads (e.g. electric vehicles), enabling an active participation of the network users in electricity markets,

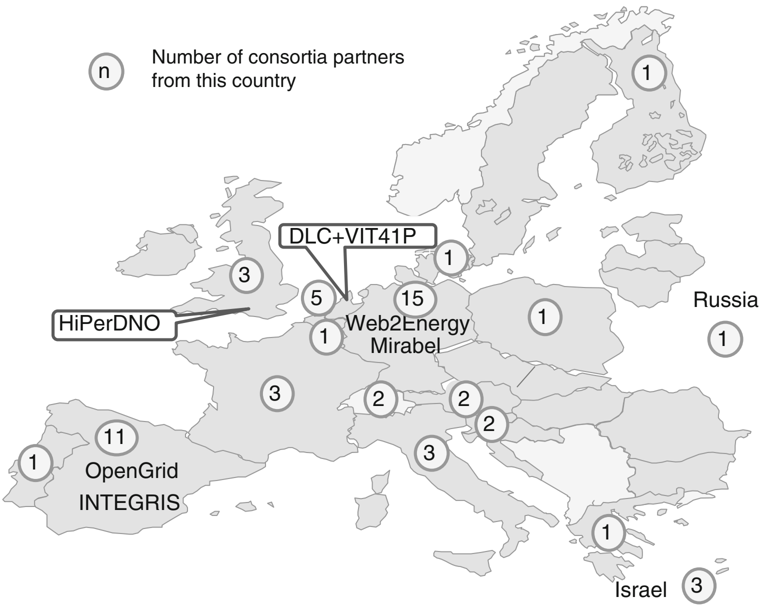


Fig. 9.6 Projects for novel ICT solutions in distribution networks

increasing the load factor of distribution feeders, and enabling real-time electricity pricing for all network users.

- Pan-European energy networks, which focus on the development of technical and regulatory solutions necessary for the rapid establishment of a real pan-European power system.
- Cross cutting issues and emerging technologies of a technical and non-technical nature to support the development of the Smart Grids with a special focus on the
- Development of Information and communication technologies which provide the pre-requisites for the first two RTD areas.

Smart Grids were also supported by the ICT sector. Under the FP7 ICT theme, €118 million were allocated to Smart Grids projects. The first call was published in 2009 (Call 2009.7.3.5): "Novel ICT Solutions for Smart Electricity Distribution Networks" and will be further considered to demonstrate an example. The response to this call contained 38 project proposals from several European consortia. Figure 9.6 presents the names, the number of participating enterprises (country wise) and the coordinator locations of the six projects selected after a validation and negotiation procedure.

All projects started in 2010 and had their final review in 2013. The enormous variety of aspects to be investigated in response to this call is demonstrated in Table 9.3.

Partners of the consortia were also enterprises from countries outside the EU like Switzerland, Israel and Russia. This cluster of projects managed two events

Table 9.3 Overview of European projects for novel ICT solutions in distribution

Project	Coordinator	Partners and countries	Main aspects
DLC-VIT41P	KEMA, NL	11—A, B, D, I, ISR, UK	Distribution line carrier from LV networks up to the primary substation
HiPerDNO	Brunel Institute of Power Systems, UK	10—D, E, F, ISR, SL, UK	High performance processing of large data volumes in distribution networks
Integris	Endesa, E	8—CH, E, F, I, SF,	Intelligent sensor communication in substations
Mirabel	SAP, D	7—D, DK, GR, NL, SL	Schedule management applying improved demand predictions
OpenGrid	Atos Origin, E	7—E, F, D, NL, P	Open ICT architecture for MV/LV transformer terminals
Web2Energy	HSE AG, D	10—A, CH, D, NL, PL, R	Three pillars of smart distribution applying the core IEC standards for ICT

for an exchange of experience in the area of ICT applications for Smart Distribution networks, namely the European symposium “ICT as the backbone of Smart Grids-Distribution networks of the future” in Darmstadt, April 2011, and the “Smart Grid Demonstration Forum” during the UPEC conference in London, September 2012.

The approval of the deployment relevance of the developed technological solutions is part of the review processes of the project results.

Thousands of innovative solutions were developed and introduced to the markets in accordance with the strategic objectives of the European Framework Programmes.

9.2.2 *The European Inventory of National Smart Grid Projects*

In 2013 the European Commission published an inventory study regarding the national Smart Grid projects in Europe [23].

This study is based on a questionnaire and presents the 2012 update of the inventory carried out in 2011 focusing specifically on the Smart Grid RTD and demonstration projects.

The inventory document contains 281 Smart Grid RTD and demonstration projects from 30 European countries (EU 28 plus Norway and Switzerland), representing a total investment of €1.8 billion. Figure 9.7 presents the distribution of projects regarding the number and the budgets.

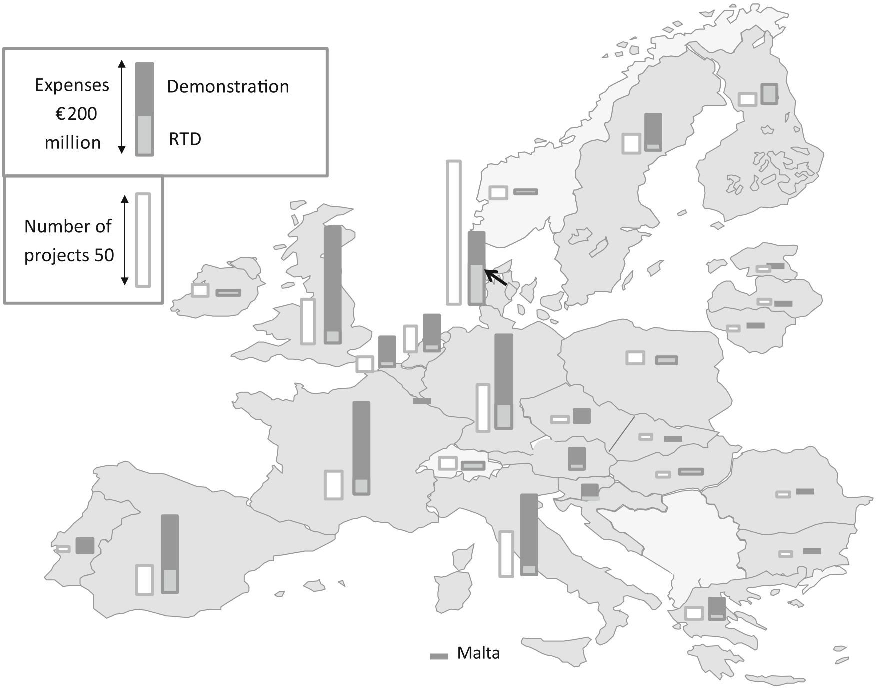


Fig. 9.7 Geographical distribution of national Smart Grid projects in Europe [23]

151 RTD projects and 130 demonstration projects were analyzed. The majority of projects (93 %) were performed within the EU15 countries, while the new member countries EU13 are significantly behind. Some countries are in advance regarding the funding: The UK represents 15 % of the total sum. Germany and France follow with 12 % each. Denmark, Italy and Spain are each spending about 10 %.

Denmark is the leading country regarding the

- number of projects and
- the investment per
  - capita (30 €/person) and
  - consumed energy (0.5 €/MWh).

Denmark is active in several small-scale projects supported by the national Forskel funding program.

The large number of projects is the result of the ambitious Danish energy policy [24].

The Danish consumption was kept nearly constant between 34.5 and 36 TW h from 2005 to 2012 with a slight tendency of reductions caused by Demand Side Integration and energy efficiency projects.

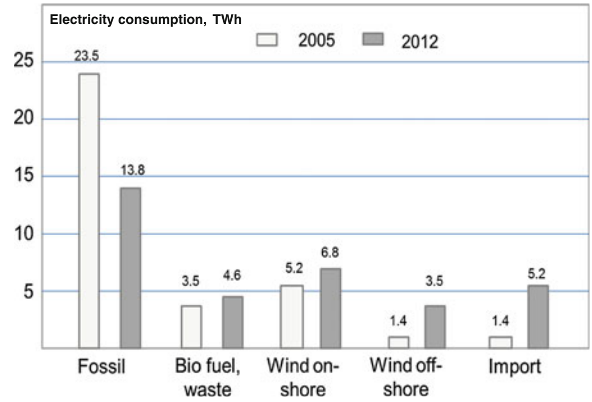


Fig. 9.8 Development of the energy mix in Denmark [24]

Denmark has an installed power generation capacity of 14.3 GW with 9.7 GW from thermal power plants (of which 8.8 GW are CHP), 4.2 GW from wind power plants and 400 MW from PV panels.

By 2012, Denmark reached a 30 % contribution of wind energy in its annual consumption. This is the worldwide largest contribution of wind energy in the annual balance.

In 2012, the Danish government adopted a plan to increase the share of electricity production from wind to 50 % in 2020 and to cover 100 % of the consumption by RES in 2050.

Consequently, the shares of RES are permanently growing while the contribution of fossil fired thermal power plants is declining, as presented in Fig. 9.8.

Denmark meets the challenges of wind power volatility by using innovative solutions to gain a flexible balancing. Furthermore, the Danish transmission networks (the Western part is synchronous with the Region "Continental Europe" of European transmission systems ENTSO-E, the Eastern part is embedded in the Scandinavian power system Region "Nordic") are outfitted with strong interconnections (partly HVDC links) to the neighboring transmission systems, which are also used to compensate fluctuations.

The majority of the Smart Grid projects are focused on these aspects to ensure the reliable, efficient and secure power supply under all circumstances.

Another interesting result of the European inventory study [23] concerns the shares of participant categories. The 281 Smart Grid projects have an average of seven participating organizations. The relations of participant categories are demonstrated in Fig. 9.9.

Distribution network operators and energy supply companies are involved in about 80 % of the Smart grid projects. Obviously, the dominating role in the funding of European Smart Grid projects is the need for innovative solutions to perform the paradigm change of transforming the currently passive distribution networks into active ones.

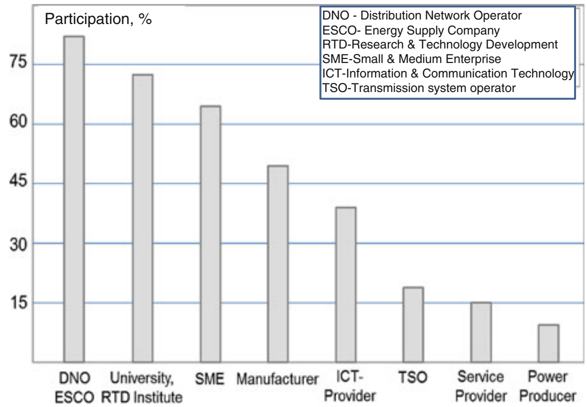


Fig. 9.9 Shares of participant categories in the European Smart Grid projects [23]

This trend is also highlighted by the allocation of the projects and budgets to application clusters according to Table 9.4:

In several European countries, Smart Grid projects are receiving increasing levels of national support funded by the responsible governmental organizations. The German E-Energy initiative is mentioned in [23] as a best practice example for such support.

"E-Energy—ICT-based energy system of the future" was initiated by the Federal Ministry of Economics and Technology (BMWi) in line with the German federal government's technology policy and became a common funding program of the BMWi in an inter-ministerial partnership with the Federal Ministry for the Environment, Nature Conservation Protection and Nuclear Reactor Security (BMU).

In 2008, a technology competition and an intensive evaluation procedure identified six model regions to perform RTD, demonstration and deployment activities with the focus on the deployment of new technologies and the development of deregulated markets. They follow an integral systematic approach that spans all value adding segments. The objectives include the supply-specific business activities both at the market level and the technical operational level. A short overview of the six selected E-Energy projects is presented in Table 9.5.

The E-Energy projects started in 2009 and were concluded at the end of 2012.

On January 17 and 18th 2013, the main actors of the E-Energy model regions and of the accompanying research council presented the results of 4 years of research, development and deployment of solutions concerning "E-Energy—ICT-based energy system of the future".

Beginning from 2012, the focus of the European Smart Grid initiatives have been shifted from RTD and demonstration projects to the direction of deployment, implementation and dissemination activities.

Table 9.4 Cumulative budget and number of projects [23]

Application group	Level	Number projects	Budget, million €
Smart network management	D	~60	~400
Integration of distributed energy resources	D	~50	~340
Smart consumer/smart home	D	~50	~340
Aggregation, demand side integration, VPP	D	~45	~260
Electric vehicle management	D	~30	~200
Integration of large scale RES	T	~10	~100

D distribution, *T* transmission

Table 9.5 The German E-Energy projects [25]

Project	Lead	Partner	Region	Project priorities
EDeMa	RWE	8	Rhein-Ruhr	Demand flexibility—smart home, deregulated markets, ICT architecture, integration of DER, information security
eTelligence	EWE	5	Cuxhaven	De-centralized power generation, integration of DER, demand flexibility, congestion management and power quality, ICT architecture, smart metrology
MeRegio	EnBW	5	Baden-Württemberg	Demand flexibility, congestion management and power quality, deregulated markets, information security
moma	MVV Energie	8	Mannheim Rhein-Neckar	ICT architecture, energy efficiency, demand flexibility, congestion management and power quality
RegModHarz	RKW Harz	19	Harz	De-centralized power generation, DER integration, congestion management and power quality, storage capability, ICT architecture, smart metrology, demand flexibility—smart home, E-Mobility[a]
Smart Watts	Utili-count	5	Aachen	Demand flexibility, smart metrology, deregulated market, information security

[a] In cooperation with the linked project Harz.EE-Mobility (see Sect. 6.4.4)

The European Electricity Grid Initiative (EEGI) [26] is one of the European industrial activities in response to the European Strategic Energy Technology Plan (SET-Plan, see also Sect. 1.1). The strategic objectives of the EEGI are:

- to enhance the electricity contribution of RES up to 35 % by 2020 and to establish a completely decarbonized electricity production by 2050,

- to integrate national networks into a market-based, pan-European network, to guarantee a high-quality of electricity supply to all customers and to engage them as active participants in energy efficiency,
- to speed up new developments such as the electrification of transportation;
- to substantially reduce CAPEX and OPEX for the enhancement and operation of the networks while fulfilling the objectives of power quality.

Both governing bodies of the European network operators

- ENTSO-E—the European Network of Transmission System Operators for Electricity, representing 42 Transmission System Operators (TSOs) from 34 countries and
- EDSO for Smart Grids—the European DSO Association for Smart Grids, which was recently created by 17 Distribution System Operators and is open for additional members.play the key role in the planning, monitoring and dissemination of the EEGI targets.

The first EEGI Roadmap 2010–2018 and the appropriate EEGI Implementation Plan were prepared by both associations in close collaboration with the European Commission, with ERGEG—the European Regulators Group for Electricity and Gas (since 2011: Agency for the Cooperation of Energy Regulators—ACER) and with other relevant stakeholders. The roadmap was approved by the European Commission and the member states in June 2010. In 2013 an upgraded version was produced in order to cover new RTD and knowledge needs. In addition, the EEGI Implementation Plan was also updated. It summarizes the priorities that the projects launched in the period 2014–2016 should focus on regarding both transmission and distribution aspects.

9.3 Selected Smart Grid Application Experiences[1]

9.3.1 Web2Energy: The Three Pillars of Smart Distribution in Practice

The Web2Energy (W2E) [27] project has been sponsored by the European Commission in the period from 2010 to 2013 under the call "Energy.2009.7.3.5—Novel ICT solutions for smart electricity distribution networks". Twelve partners

[1] The Sects. 9.3.1 and 9.3.2 summarize the results of the European project Web2Energy and the German E-Energy project RegModHarz. These projects were also emphasized in the European inventory [23] as best practice experiences. The authors Dr. B.M. Buchholz and Prof. Z.A. Styczynski were actively involved in both projects.

from Germany, the Netherlands, Austria, Switzerland, Poland and Russia were involved in the project. In the course of the project, the information and communication technology requirements for the three pillars of Smart Distribution were implemented and tested in the operation of the HSE AG 20 kV network around Darmstadt, Germany:

- Network automation, remote control and supervision in the distribution network—upgrading of nine 20/0.4 kV transformer terminals along a feeder corresponding with Fig. 6.10 and linking to the communication network.
- Smart aggregation of distributed generation facilities, storage facilities and controllable loads to form a virtual power plant (VPP) incorporating 17 power plants (six combined heat and power plants (CHP), three large wind power plants, six PV plants and two hydro power plants), 12 battery storage facilities and up to 15 MW of DSM capabilities by controllable loads for optimization of market activities and support of the network operations regarding the maintenance of power quality.
- Smart metering and involvement of consumers in the electricity market by means of variable tariffs in six residential areas with 200 pilot consumers.

The functions and the data traffic required for their implementation between the plants and consumers involved (server) and the control center (client) correspond with the Figs. 6.2 and 6.44 in Chap. 6.

The recommendations of the IEC reference architecture and the European mandate M/490 were consistently implemented in the project. For the first time in the distribution network, the forward-looking standard IEC 61850 is used for communication in combination with the Common Information Model (CIM) to IEC 61968/70 for data management in the control center.

Figure 9.10 shows the practical implementation of the communication system with the newly developed components.

The transformer terminals and the power plants are equipped with small remote terminal units (RTU) and smart meters (see also Fig. 6.20). The RTU applies the IEC 61850 communication standard for the wide area communication, provides a communication link to the meter and converts the meter protocol DLMS to IEC 61850. The batteries have their own IEC 61850 interface for control and monitoring data exchange. The interface also provides the internally calculated meter data for monitoring (not suitable for billing). The data from the household consumers are collected hourly by radio communication from the meter data management system of the trader and transmitted from there to the W2E control center by means of the IEC 61850 file transfer.

In this way, three methods of integrating meters in the communication world of IEC 61850 come to be used.

In the control center, all three pillars described above are managed in a database applying the CIM class model (see also Sect. 8.4).

The incorporated plants and pilot consumers are monitored and controlled via the W2E control center with a user friendly interactive Human Machine Interface HMI which provides the access icons to the three pillars at the start menu.

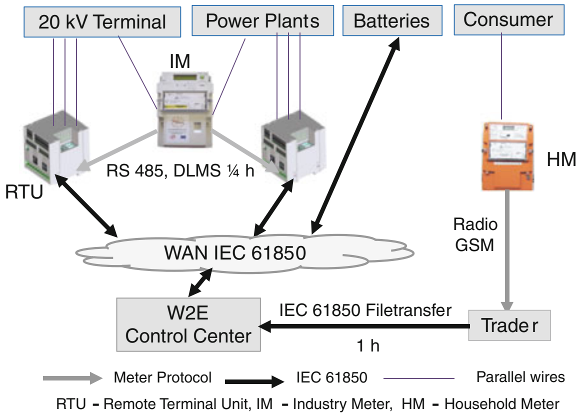


Fig. 9.10 Communication architecture of the W2E project [27]

Figure 9.11 presents the start menu and the initial displays of the three pillars—20 kV feeder automation, consumer market integration and virtual power plant.

The 20 kV feeder is presented as a single line scheme with indication of the switch conditions and measured values. It is possible to select the controllable transformer terminals by cursor and to perform the control of the switchgear remotely.

The HMI provides the results of the pilot study for the consumer market integration by various displays with demand profiles, diagrams and tables. The operator can observe the results for single consumers, for clusters (e.g. size of households, locations) and the summary.

The consumers receive their individual information via their consumer account in a web portal and/or via mobile phone as depicted Fig. 6.37a.

The household customers are provided with information on the tariffs, their consumption compared to a reference profile and the costs. They can select displays for the day-ahead forecast, for the current day and for retrospective data in the form of tables and diagrams according to definite time intervals.

The initial display of the VPP presents on the left hand side the overview of the different categories of participants indicating some important measured data. On the right hand side, the optimized schedule of energy production is presented. The cursor control allows the selection of displays regarding the different plants and DSM facilities (left hand side) and regarding the various business models (right hand side) according to Sect. 6.3.3.

Important aspects in the ICT chain “process—data acquisition—communication—data management—interactive HMI” are:

- the implementation of the data models of IEC 61850 and IEC 61968/70 and
- the application of web services for data exchange between the data base, on the one hand, and between the HMI and the consumers on the other hand.

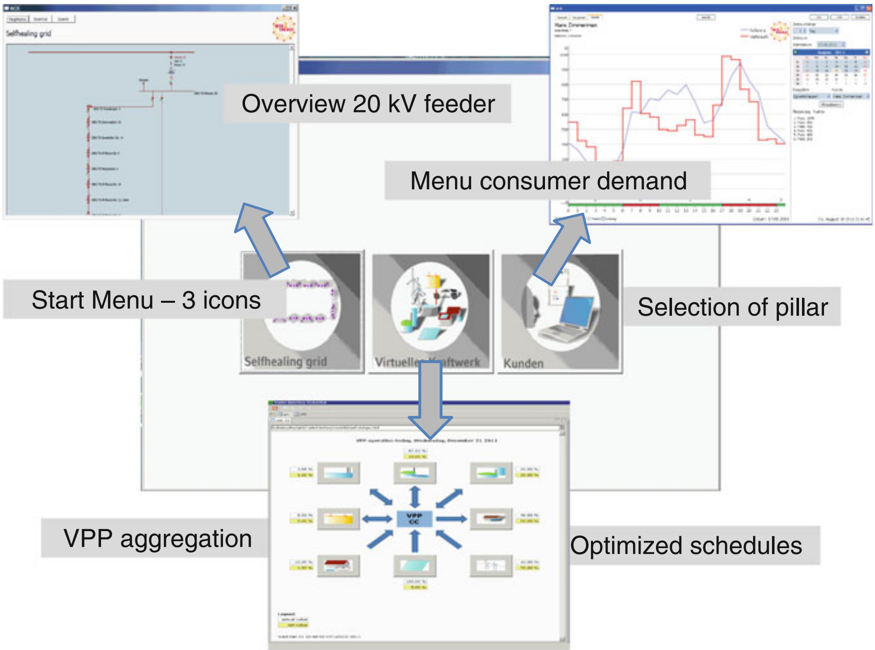


Fig. 9.11 Start menu and the initial displays of the three pillars of Smart Distribution in Web2Energy [27]

Figure 9.12 presents the related chain of data exchange. For the first time, the conversion between both standardized data models was performed for the operational practice in a distribution network.

The servers provide fiber optic interfaces via 100 MBd Ethernet. The most efficient communication link was used for each of the servers depending on the local conditions. Commercially available adapters were applied to convert the protocol accordingly.

The following advanced solutions have been developed, introduced and brought to maturity within the framework of the W2E project:

- Architecture design, security and performance analysis of the complete ICT system,
- Mapping of IEC 61850 layers 3–7 to various physical and link layers.
- Development of suitable remote terminal units (RTU) "speaking" IEC 61850,
- System integration of the available smart meters applying communication protocols other than IEC 61850,
- Design, development, approval and operation of the control centre for the three pillars,

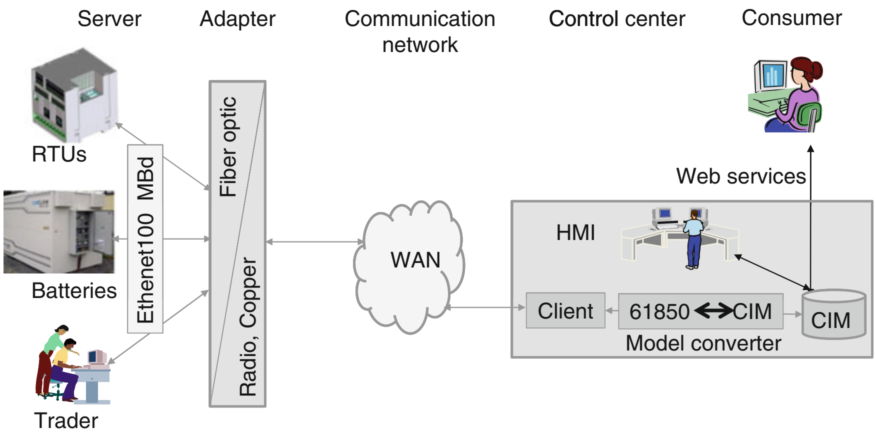


Fig. 9.12 Chain of information exchange and data management [27]

- Data base systems applying IEC 61968/70 CIM (common information model) for the control centre with a converter for IEC 61850 data models into the CIM format and vice versa,
- Business strategies for virtual power plants (VPP) with generators, storage and controlled loads,
- Concept for a dynamic pricing and Internet presentation for consumer market participation,
- Adaptation and extension of the IEC 61850 and IEC 61968/70 data models according to the needs of distribution systems followed by the consideration of the new models in the relevant IEC working groups to enhance the standards accordingly.

The integration and the trial operation of the new system allowed conclusions to be made about the economic benefits which are partially considered in Chap. 6.

The need for the extension of both standards for application in the distribution network was identified in the project with 12 new classes and attributes for the CIM structures, 26 logical nodes and data, and improved operating schedule management for IEC 61850.

9.3.2 *RegModHarz: Region Supplied by a Virtual Power Plant*

The Renewable Model region Harz is one of the six winners of the E-Energy competition. The project was sponsored and coached by the German BMU between 2008 and 2012.

Fig. 9.13 The administrative district Harz and a sample of the located RES [28]

It is the project with the largest number (19) of participating organizations due to the involvement of all municipal utilities, the transmission, sub-transmission and local distribution network operators acting within the territory of the district Harz.

The administrative district Harz has a high potential of RES. The annual consumption of the district was estimated with 1.3 TW h. About 30 % of the annual electricity consumption in the district Harz was already covered by renewable energies in the beginning of the project (2008). Wind power has been the dominant category with 311 GW h of annual electricity generation [28].

Additionally, large photovoltaic plants, bio fuel fired thermal power plants, CHP plants and hydro-electric plants are involved in the internal power generation of the rural district with a population of 230,000 citizens. Figure 9.13 presents the map of the districts and the localization of a sample of the renewable energy plants. A significantly increasing share of the renewable energies within this district is expected. A high share of renewable energies in Germany implies that rural districts will need to generate more than their own consumption in order to supply the urban areas. For this reason, the district Harz is engaged to generate more than double its own consumption to contribute to a 100 % RES supply in Germany.

The main objective of the project concerns the joint marketing of regionally available renewable energy sources and flexibility by aggregation into a virtual power plant (VPP) acting on different markets.

The prerequisite of this objective is the technical development and economic integration of distributed energy sources by deploying modern ICT solutions.

Consequently, the three focus targets of the project are defined as:

- Establishment of a control center for the VPP including the ICT infrastructure,
- Marketing of energy and system services produced and offered within the VPP,
- Network supervision and management of system services to support the distribution networks operations.

The different renewable energy producers, controllable consumers and energy storage capabilities have been coordinated by two means:

- the electronic market places and
- the aggregation into the VPP.

For the trial operation and demonstration, several participants were embedded into the related ICT infrastructure of the VPP:

- 2 wind farms (70 MW),
- 4 CHP plants (between 400 kW and 2 MW),
- 2 PV units (2.5 MW),
- 2 biogas plants,
- 1 residential CHP plant (15 kW),
- 1 micro fuel cell,
- 1 controllable industrial load (150 kW) and
- 1 simulator of a pumped storage plant.

The VPP consists of the VPP control center and the distributed energy resources that are linked to the VPP via a gateway called "Power Bridge". A registry service was introduced to ensure a flexible and scalable administration of the involved VPP components. The "Power Bridge" was developed and implemented to link the information about the available services of the providers to the VPP control center and, in turn, to receive the operation schedule. To be able to plan this energy management, all components including the market data estimation are created with precise prediction tools that can be integrated as external services. The ICT architecture is shown in Fig. 9.14.

The VPP coordinates the operations of the linked plants in accordance with the market conditions. The applied communication protocol uses the data models of IEC 61850 and the web services of IEC 61400. For this, the IEC 61850 standard was adapted to enable a simple and secure information exchange between the VPP participants, the control center and the network operators. Furthermore, the assimilation of the plants into the energy management is enabled by new IEC 61850 data models.

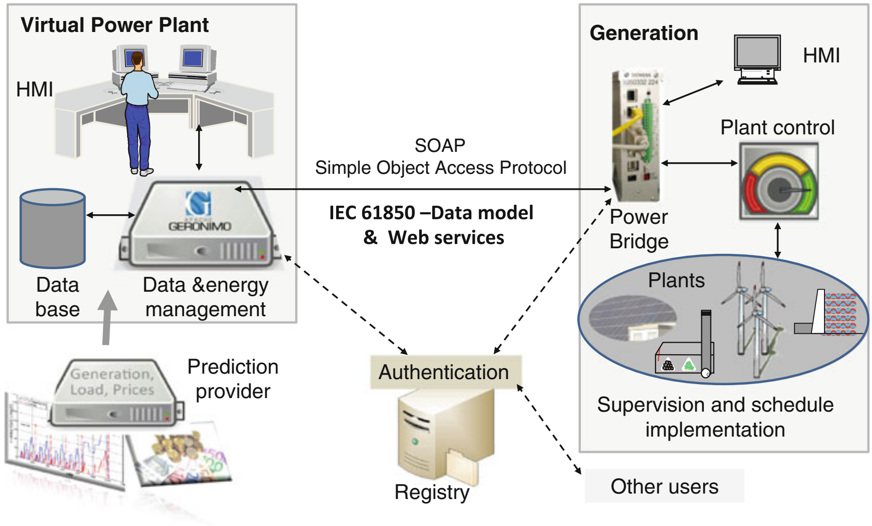


Fig. 9.14 ICT architecture of RegModHarz [28]

The trial operation also includes the application of the "Bidirectional Energy Management Interface" (BEMI) described in Sect. 6.4.3 shown in Fig. 6.40. Several households were equipped with a BEMI.

The demand shifting on the consumer side was recognized as a means to increase the consumption during a period of high supply from the renewable energies and to decrease it in the opposite case. The readiness on the side of the consumers for demand side response was evaluated in a special sociology study. For example, the readiness to shift the operation of devices was different according to the type:

- Operation during the night for
  - Dish washers 78 %
  - Washing machine 50 %
- Delay of operation >1 h
  - Freezer 67 %
  - Refrigerator 60 %

Figure 9.15 presents the main HMI displays of the VPP control center.

Further ongoing investigations performed within the project are focused on the current and future market mechanisms, the integration of electric vehicles into the distribution network operations, the network simulation and observation, the application of phasor measurement units (PMU) in distribution networks (see also Sect. 6.2.4.3), 110 kV line monitoring, the improvement of the schedule planning

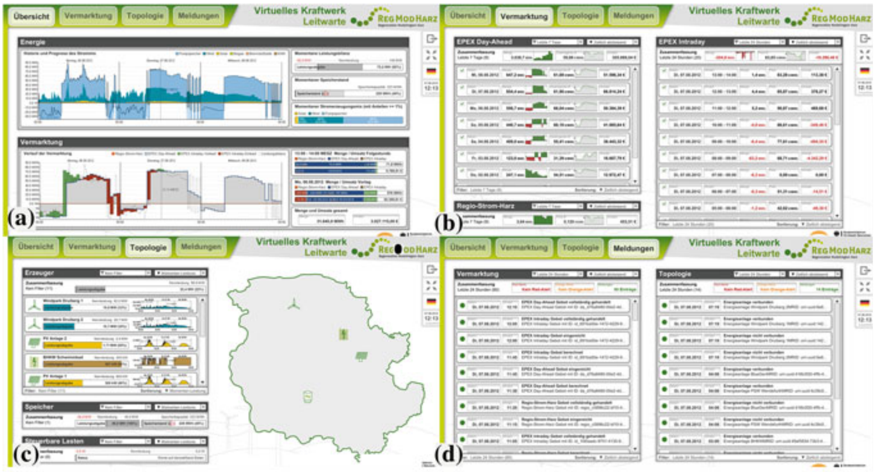


Fig. 9.15 Entrance displays of the control center HMI: **a** overview, **b** business market, **c** topology, **d** message report (*Source* Fraunhofer IWES, [28])

processes, and the application of advanced tools for simulation, planning, data processing and control strategies for power plants.

The consortium consisting of network operators, energy supply companies, municipal utilities, a wind farm operator, manufacturers, the Otto-von-Guericke University of Magdeburg, the University of Kassel, two research institutes (Fraunhofer IWES and Fraunhofer IFF) and ICT companies developed strategies for how to apply the developed tools, devices, system solutions and infrastructures to improve the integration of renewable energy resources into the electricity system. The project has prepared the appropriate system solutions to achieve such ambitious targets accompanied by improvements of the power quality and the energy efficiency.

9.3.3 DSR Projects in the USA

The Obama administration has implemented national programs to double the energy efficiency in the USA by 2030. Several national and state programs have been started to increase the energy efficiency, which also includes the optimum use of the available power system generation and transmission capacity by shifting the energy demand to avoid expensive load peaks. The U.S. Department of Energy distinguishes between different kinds of Demand Side Response (DSR—see also Sect. 6.4.3) and how they can be used for power system operation and planning. Figure 9.16 shows the time scale beginning with the planning steps and ending with energy efficiency achievements on the long term. For monthly down to

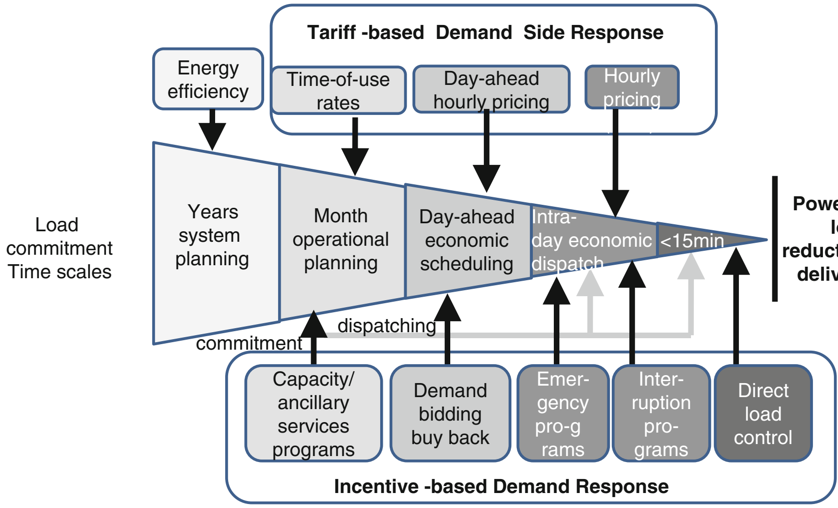


Fig. 9.16 Role of demand side response in power system operation and planning [29]

real-time operation, tariff and incentive based methods can be applied to adapt the load behavior to a certain extent. Tariff-based DSR focuses on the adaptation of tariffs to influence the consumption behavior due to different tariff zones during the day. In this case the reaction of the consumers to the tariff change (tariff elasticity) must be known to consider this for planning and operational tasks. The structure of these tariffs can be limited to one high and one low tariff, but hourly prices are also possible.

On the other hand, incentive-based DSR is taken into account if the tariff elasticity is not completely known. This model distinguishes between capacity and ancillary services programs for mainly large scale consumers (industry) and direct load control, which can also be implemented in the residential area. The payment is coordinated with the current market prices in combination with some sort of fixed compensation for the DSR provision.

The U.S. electricity market liberalization started in 1982 based on the Public Utilities Regulatory Policies Act of 1978 [30]. This process was mainly enforced by the national regulator (FERC) and led to the early design of market mechanisms to improve power system efficiency and stability. For that reason, Demand Side Response Programs were already implemented before the year 2000 due to proper market conditions, i.e. capacity markets, and great effort to lower the power system loading by shifting the peak load to times of low demand. A broad analysis in 2008 showed that about 53 % of all U.S. power utilities offered a time-of-use tariff (compare Fig. 9.17 for Arizona) and 43 % operated by using a peak-shaving program [31]. Other programs address commercial and industrial customers and are mainly interested in reliable energy supply and minimizing costs. To avoid

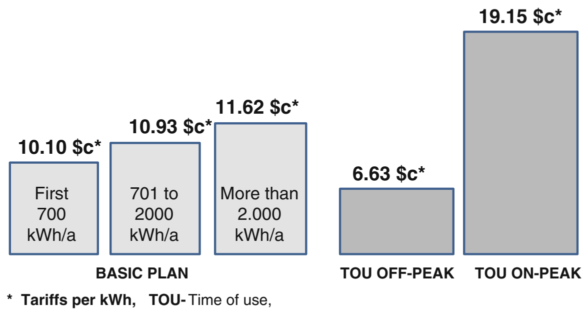


Fig. 9.17 Salt River Project in Central Arizona Basic Plan and Time of Use tariffs comparisons [33]

expensive peak loads, utilities offer explicit measures to inform the customer about peak load situations. They will be rewarded for reducing the consumption during this time. The Colorado Springs Utility, for example, designed a Peak Demand Rebate program for medium and large business consumers focusing on on-peak summer demand reduction, whereby consumers were rewarded with $400/kW (minimum reduction of 20 kW) [32].

A prominent example for a large scale Demand Side Response program can be seen in California, which is one of the leading U.S. states in terms of environmental protection.

In the California statewide Pricing Pilot (July 2003–December 2004) households could decide between their standard rate and the following three new tariff designs:

- Time-of-Use (ToU)
- ToU plus fixed Critical Peak Period (CPP-F)
- ToU plus variable Critical Peak Period (CPP-V).

Some results of the consumers' behavior who used ToU with CPP-F are summarized in Fig. 9.18. CPP-F, meaning a price five times the standard tariff, was announced the day-ahead. The price was valid during a typical peak load time (2–7 p.m.). The application was limited to 15 Critical Peak periods per year. Depending on the climate zone (zone 1 being the coldest) the highest peak load reduction during critical market conditions (critical week days) was 15.8 % in Zone 4, because the most relevant flexible loads were air conditioning systems which are mostly used in the warmest zone. The average reduction of all participating customers yielded 13.1 %.

As can be seen, the majority of the U.S. electricity supply companies have introduced various efficient DSR programs supporting energy saving and load shifting. The consumers' energy efficiency may be enhanced if dynamic tariffs with a significant spread are applied.

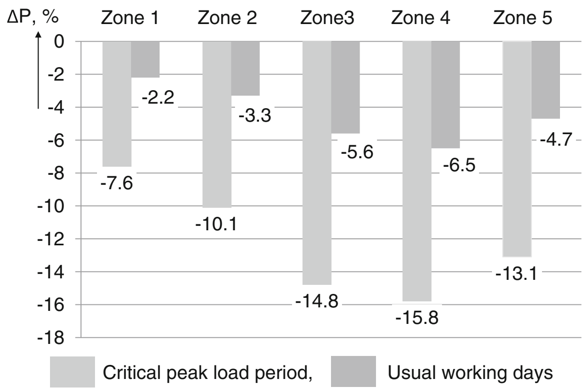


Fig. 9.18 Peak load reduction by applying the CPP-F tariff in California [34]

9.3.4 *The South Korean Smart Grid Test-Bed on Jeju Island*

The South Korean government is strongly committed to reduce the CO_2 emissions by 4 % compared to the level of 2005 [35]. Consequently, a 30 % reduction of the emissions is expected if this target is transferred to the predicted level of 2020. In this sense, South Korea is a model for other countries in the Pacific region. Strategic programs have been established to decrease the emissions of fossil fuel combustion and to develop renewable power generation.

In this context, South Korea started a national Smart Grid project to support the large scale integration of renewable energy sources into the electric power system operation in an efficient, comprehensive and environmentally friendly way. Moreover, the government voted on a Smart Grid Act, which went into effect in November 2011.

The national Smart Grid program is split into three stages:

1. Construction, installation and operation of a Smart Grid test-bed (2013),
2. Expansion of the approved solutions into metropolitan areas ($\sim$2020),
3. Completion of the nationwide Smart Grid ($\sim$2030).

In the first stage, it was decided to build a Smart Grid test-bed on Jeju Island.

Jeju Island was selected in June 2009 as the optimum area because of the available potential of renewable energy sources (RES) and of the opportunity to install and operate the test-bed for various technologies and innovative solutions in a closed territory. Jeju Island, which is located at the southern tip of the Korean peninsula, covers an area of 185 km^2 and has a population of approx. 577,000. The island is synchronously isolated from the continent and connected to mainland by a High Voltage DC-link (HVDC) of 150 MW installed capacity. A second HVDC link with 200 MW transmission capacity was completed in March 2013. The main island network consists of a 154 kV double system loop.

The Jeju Smart Grid test-bed aims to become the world's first "all-inclusive" test bed as well as the world's largest Smart Grid community in which testing of

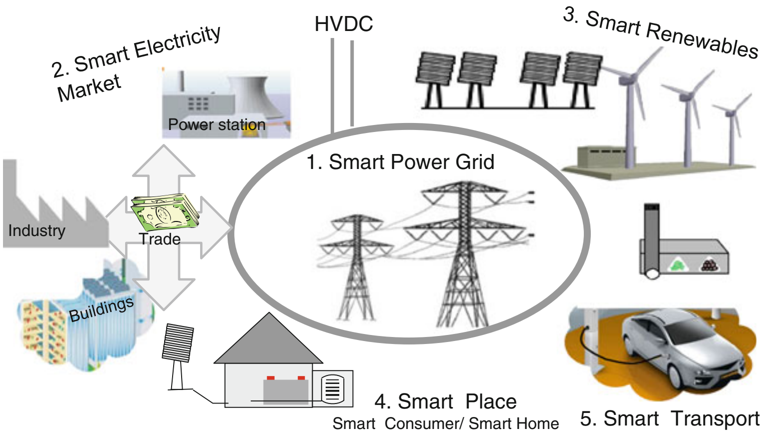


Fig. 9.19 The five domains of the Jeju Smart grid test-bed

the most advanced electric network technologies and research results will occur, and business models will be developed [36]. The test-bed was scheduled from December 2009 until May 2013. The erection of the infrastructure was completed within the first 18 months. The following 2 years were foreseen to test the integrated operation of the Smart Grid functions.

The project is focussed on five domains as presented in Fig. 9.19:

The objectives of the Smart Power Grid domain are directed at establishing Smart Transmission and Smart Distribution functions by introducing digital substation automation and SCADA systems that are supported by advanced information and communication technologies (ICT).

The core of this domain is based on the establishment of the advanced digital Jeju network control center. The control center includes the real time system monitoring including the power generation, the power flows and the network topology and the schedule management. A town with 3,000 households has been selected as the Smart Grid Test-bed. Two substations, each with two busbars, feed the smart distribution network, the operation of which will be optimized in relation to the other domains. The network is enhanced by self-healing features to shorten the interruption time after faults [35].

The Smart Market domain offers various tariffs to the consumers and introduces smart energy trading instruments. The long-term target is to introduce real time pricing systems nationwide. The new market and information management is embedded in the control centre functions and is split into day-ahead and intraday market activities [37].

The Smart Renewable domain is focused on the growing utilization of distributed RES and energy storage facilities and the energy management in the framework of micro-grids. A consortium of three enterprises is involved to test the energy management with 4.5 MW wind power plants, 2.45 MW h storage capabilities and 100 kW of installed solar power. In general, the intention of South Korea is to operate 1,126 MW wind power plants in 2016 [37].

The objective of Smart Place domain consists of the introduction of smart energy management systems based on smart meter services, inhouse displays, communication systems (e.g. power line carrier) and distributed energy resources integrated in the home automation systems. Over 2,000 consumers are participating in the tests which are executed by a consortium of four partners [37].

Smart Transport aims to establish the infrastructure for the charging of electric vehicles and to incorporate the electric vehicle management in the context with the other test-bed domains. The responsible consortium of three partners has to establish and operate 100 slow and 28 fast charging stations [37].

After establishing the Smart Grid infrastructure, phase 2 was started to gain operational experience. Phase 2 is focused on the development and investigation of business models, on the analysis of best practice experience, the extension of the capabilities and their aggregation into virtual power plants.

The technical and market related investigations are accompanied by the work of five information centers and experience halls which are open to the public.

In general, the Jeju Island Smart Grid test-bed provides the opportunity to put the three pillars of Smart Distribution into practice (see Chap. 6) in the form of a real distribution system operation over a longer period of time.

This project is directed at increasing the energy efficiency and enhancing the electric network infrastructure by allowing the large scale integration of renewable energy sources. As a result, new technologies will be developed and brought to maturity. The investigation of the interactions between the Smart Markets and the Smart Grid operations will also generate new knowledge regarding how this context may create benefits and how it should be supported by regulatory and legislative rules.

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