Electric Power Systems

Edited by Michel Crappe

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Preface

This book, which deals with electric transmission systems, is the English translation of two books written in French and published in 2003 by Hermes Science Publications (*Commande et Régulation des Réseaux Electriques, Stabilité et Sauvegarde des Réseaux Electriques*) in the electrical engineering series of the Traité EGEM (series in electronics and electric engineering and micro-electronics). It consists of two parts, corresponding to the two books in question. The first deals with the control, regulation and security of large scale electric power networks and the second with the stability and safety of the systems. The two parts include 5 and 4 chapters respectively, written by renowned experts from the industrial world or from universities. Its aim is to present the state of the art in the concerned domains as well as future prospects, especially in the fields of research and development. It is aimed at specialists, scientists and people involved in research in the electricity sector; it presupposes thorough knowledge of the basic concepts of electrical engineering. It has not been possible to cover all the problems related to the subject in an exhaustive manner in a single book. The subjects discussed in this collective work are the result of a choice made by the editor and based on his experience in research and teaching.

If some repetitions have occurred, they show the different approaches and attitudes towards essential phenomena and have been deliberately maintained with a pedagogical aim in mind and to reinforce the perception of sensitive issues. Moreover, it also makes it possible for each chapter to be read independently of the others. Different solutions are sometimes suggested to resolve some problems, which proves that the field is wide open and a lot of research and development remains to be carried out.

Electricity is an energy carrier that is indispensable to human activities in developed countries, and is an essential factor in development for poorer countries. Electric transmission systems are key elements in ensuring a reliable supply of good

quality electric power. The introduction of new generation systems or management methods of electric power must, as a result, be the subject of in-depth study to ensure compatibility with sure and reliable functioning of transmission networks. The recent changes in electric transmission systems and new constraints in the electric power sector in Europe have particularly complicated matters. The new paradigm in the field of development and management of the electric power sector, due to the recent restructuring of the latter on the application of European Directives to organize the electricity market in Europe, appears if not explicitly then at least in a subtle manner in most of the chapters. At present, the setting up of the European market for electric power, concomitant with environmental constraints, is proving to be much more difficult than expected by its protagonists and is presenting numerous challenges, which can only be removed at the cost of significant efforts in research and development. Moreover, recent major blackouts that have occurred in Europe in a number of countries (Sweden, Denmark, Switzerland, Italy and Greece) and the blackout of 4 November 2006 have reminded us that the stability and the collapse of electric systems are problems that are very real and not purely academic. The blackout of 4 November is particular affected several millions of Europeans for several minutes to an hour, and moreover led 200 million people to be at risk of being deprived of electricity for several hours, even several days. The current situation therefore considerably reinforces the value of books on electric power transmission networks, such as this one.

In the first part, the book focuses on fundamental aspects of electric power systems, the evolution of European transmission networks in the face of new regulations, the impact of decentralized production, generation and transmission planning, quality of the electric power supply and finally advanced control methods.

The second part deals with voltage stability, transient stability, the defense plan, electromechanical aspects of digital simulation and finally power electronics to enhance controllability, stability and power transfer capability of large transmission networks. It naturally completes the first part.

If this book could guide the reader towards research and development in the field of electric power systems, it would amply fulfill its aim.

Sincere gratitude once again to the different authors and all the people who have contributed from near or far to the publication of these two books in French, especially Olivier Deblecker of the Faculté Polytechnique de Mons (Faculty of Engineering, Mons) for his help in the formatting of the different contributions. I especially thank the editor of ISTE/Hermes Science for having decided on the publication of the two books in English and for having ensured its translation.

Michel CRAPPE
Professor Emeritus of the Faculté Polytechnique de Mons
(Faculty of Engineering, Mons)

Chapter 1

General Aspects of the Control, Regulation and Security of the Energy Network in Alternating Current

1.1. Introduction

1.1.1. *History*

Though Edison managed to distribute electricity through direct current (at 110 V) for lighting for the first time in 1882 and the first long distance transmission was achieved in 1882 between Miesbach and Munich (57 km, 2,000 V), it soon became clear that long distance transmission needed a higher voltage if the volume of copper was to be kept low (Deprez in 1881) and thus should use alternating current and a transformer, whose principle was patented by Gaulard and Gibbs in 1881. Three phase generators have a simpler design concept and easier current breaking facility than that of direct current machines. In 1891, a power plant on the Neckar in Lauffen was linked to Frankfurt (a distance of 176 km) through a 15 kV alternating current line. Around 1920, with Europe standardizing its frequency at 50 Hz and suspended insulators coming into the picture, the voltage was raised to 132 kV. In the beginning, the distance between the hydroelectric power plants and the cities was the main reason for this long distance transmission. With the development of thermal power plants it became obvious that there existed a complementarity between these different modes of production giving rise to a better use of resources through interconnections within a country as well as between neighboring countries. As a result international connections

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Chapter written by Noël JANSSENS and Jacques TRECAT.

developed rapidly: in 1922 a 150 kV transmission linked France and Switzerland, Austria and Germany were connected through a 225 kV line in 1929, in 1935 the whole of eastern France was interconnected with Belgium, Switzerland and Germany, in 1985 a 380 kV transmission interlinked Western Europe, while the 1990s witnessed this link extending to Eastern Europe (Poland, Hungary, etc.) and the North African (Maghrebian) countries.

The advantages of such a synchronous network are to enable planned exchanges as well as to ensure solidarity between the different partners in case of generation outage while maintaining the impact on the frequency at a minimum.

Direct current is still used for traction (at voltages ranging from 500 to 3,000 V) but, presently, the alternating-direct conversion is carried out mainly in vehicles and the traction network develops using single-phase 25 kV and at 50 Hz.

It is necessary to mention that a reversal to direct current connections at high voltage becomes technically and economically interesting in the case of underwater connections for distances exceeding a few tens of kilometers (connection between France–Great Britain, Ireland–Scotland, etc.), in point to point overhead transmission links for distances exceeding a few hundred kilometers or even in interconnections between asynchronous power grids (some cases of links between Eastern and Central Europe before the 1995 synchronous interconnection or between grids having different frequencies (Japan)). These connections require converters using electronic components (thyristors, etc.).

1.1.2. *Network architecture*

The EHV (Extra High Voltage) international interconnection networks (400 kV, 225 kV) form a meshed grid to which the big power plants are connected (1,000 MW nuclear power plants, for example). This is completed by a (60 to 150 kV) subtransmission network often operated in subnetworks linked to the higher voltage level. To this network are connected lower capacity electric power plants and big industrial users. There is also a (20 kV to 400 V) distribution network for small and medium scale companies, businesses and the residential sector. This power distribution network is generally radial in structure but to ensure continuity of service it can possibly be looped in urban zones. Certain big cities have the possibility to mesh the network even at a low voltage. The meshed or looped network though costlier due to the complex control and protection systems provides a better continuity of service.

In general a large town is supplied using a 380 or 225 kV loop fed by the interconnected network. The step down substations connected to this loop transmit

power towards the subtransmission network using cables to enter the urban zone. To this subtransmission network are further connected the step down stations towards the distribution network (15-20 kV voltage) which are either looped or able to be looped and finally the single or three phase low voltage network of radial structure feeding the consumers.

It should be emphasized that in order to avoid producing a reverse sequence component that can cause additional heating of the alternators and electric motors, the three-phase loads have to be balanced. This balancing can be obtained by distributing the loads between the phases.

1.2. Power flow calculation and state estimation

1.2.1. *Introduction*

The power flow calculation (often also called “load flow”) is a fundamental tool both in operational control as well as in planning [BER 00, ERE 00, ESC 97]. This helps in determining the voltage at any point of the network and also the active and reactive power flowing through all the lines under a permanent (generally balanced) three-phase condition.

It is based on a model of the components of the network (transmission lines, transformers) and on the hypotheses of active and reactive power injection at the different nodes of the network.

On the contrary, the state estimation aims to provide a coherent, complete and reliable “snapshot” of the load flow results of the entire network based on the measurements and signaling carried out at the different points of the network. Using these remote measurements and remote signaling acquired in real time requires some filtering to take into account the transmission or measurement errors. The result thus obtained gives the voltages (magnitude and phase) at the nodes of the network that correspond “as far as possible” to the measurements.

1.2.2. *Modeling the components of the network*

Modeling the components of the network during balanced three-phase operation is based on the following hypotheses:

– symmetry of the elements that enable a positive sequence single-phase representation;

– magnetic influences between components are ignored;

– electric lines represented by an equivalent two-port circuit of localized constants;

– magnetic impedance of the transformers is ignored.

Using non-dimensional quantities (p.u.) makes it possible to simplify the representation of the transformers by reducing them to a simple series impedance (of magnetic flux dispersion).

It should be remembered that the use of non-dimensional quantities is based on a base three-phase power (S_{base}) and a base voltage between phases (U_{base}) that enable us to define a base impedance ($Z_{base} = U_{base}^2/S_{base}$) which helps in calculating the reduced impedances of the components. It should be remembered that one of the advantages of using the reduced impedances is having almost invariant orders of magnitude irrespective of the nominal power of the machines or the transformers. In addition, in the presence of transformers the ratio between the primary and the secondary side base voltages is a function of the nominal transformation ratio.

An electrical power transmission line between the nodes i and j will then be represented by a π-diagram (see Figure 1.1) having a series or longitudinal impedance: $\underline{z}_{ij} = r_{ij}+jx_{ij}$ (with r_{ij} and x_{ij} being respectively total resistance and total inductance of the line) and a shunt admittance $\underline{y}_{ij0} = (g_{ij0}+jb_{ij0})/2$ (g_{ij0} and b_{ij0} being respectively the positive sequence total conductance and total susceptance of the line).

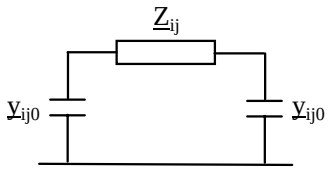

Figure 1.1. *Equivalent circuit diagram of an electrical line*

Transformer modeling will be carried out using an equivalent circuit diagram with an ideal transformer (see Figure 1.2(a)) or using a π-diagram (see Figure 1.2(b)) if the transformation ratio is complex (case of phase shifter transformers).

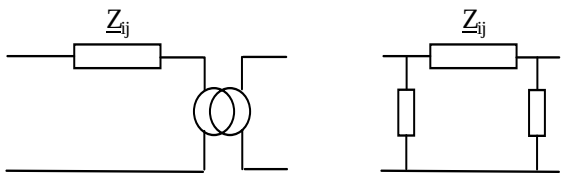

Figure 1.2. *Equivalent circuit diagrams of transformer: (a) with ideal transformer, (b) through a π-diagram*

1.2.3. *Power flow calculation*

The power flow calculation is based on the nodal equations $[\underline{I}] = [\underline{Y}]\,[\underline{V}]$, where $[\underline{I}]$ is the vector of the nodal current injected into the network, $[\underline{V}]$ the vector of the nodal voltages with respect to the neutral of the single-phase diagram and $[\underline{Y}]$ the matrix of the nodal admittances whose diagonal terms $\underline{Y}_{ii}$ are the sum of the admittances of the incident branches at node i and non-diagonal terms $\underline{Y}_{ij}$ the sum with changed sign of admittance of the branches between i and j.

According to the energy conservation laws the injected power in a node should be equal to the sum of the powers flowing in the incident branches in this node.

Under these conditions, the following complex equation can be written:

$$\underline{S}_i = (\sum_j \underline{Y}_{ij}\underline{V}_j)^*\underline{V}_i \qquad [1.1]$$

At each node four nodal quantities (P_i, Q_i, V_i, θ_i) shall be linked by two equations implying that two of these quantities have to be imposed in order to solve the system.

Based on the hypotheses made at the different nodes, they can be classified as:

– load nodes: characterized by the imposed active and reactive power, the unknowns will be the modulus and the phase of the nodal voltage;

– generator nodes: characterized by the imposed voltage modulus and an imposed active power, the unknowns will be the voltage phase and the injected reactive power;

– voltage controlled nodes: characterized by imposed voltage modulus and active and reactive (zero) power, the unknowns will be the voltage phase and the transformation ratio;

– slack node: used as a phase marker whose voltage modulus is also imposed, the unknowns will be the injected active and reactive power.

Equations [1.1] being non-linear, the iterative Newton-Raphson method is generally used in order to solve them. It should be remembered that based on an initial value of the unknowns, the vector of the variations is calculated by canceling the difference between the values imposed by the first member and the value calculated from the initial values using matrix reversal of the partial derivatives (Jacobian). The advantage of the polar form of these equations is to have one single equation for the generator nodes.

By assuming $\underline{V}_i = V_i\angle\theta_i$ and $\underline{Y}_{ij} = Y_{ij}\angle\gamma_{ij}$ and on separating the real and the imaginary part, equation [1.1] becomes:

$$P_i = V_i\sum_j Y_{ij}V_j\cos(\theta_i-\theta_j-\gamma_{ij}) \qquad [1.2]$$

$$Q_i = V_i\sum_j Y_{ij}V_j\sin(\theta_i-\theta_j-\gamma_{ij}) \qquad [1.3]$$

and from there:

$$P_i^{imp}-P_i = \sum_j ((\partial P_i/\partial V_j)\ \Delta V_j+(\partial P_i/\partial\theta_j)\ \Delta\theta_j) \qquad [1.4]$$

$$Q_i^{imp}-Q_i = \sum_j ((\partial Q_i/\partial V_j)\ \Delta V_j+(\partial Q_i/\partial\theta_j)\ \Delta\theta_j) \qquad [1.5]$$

The expressions of partial derivatives are obtained from equations [1.2] and [1.3]. A more efficient expression in terms of calculation time assumes $\Delta\theta_i$ and $\Delta V_i/V_i$ to be unknown. By denoting the Jacobian components as:

$$J_1 = [\partial P_i/\partial\theta_j],\ J_2 = [(\partial P_i/\partial V_j)\ Vj],\ J_3 = [\partial Q_i/\partial\theta_j],\ J_4 = [(\partial Q_i/\partial V_j)\ Vj] \qquad [1.6]$$

the following matrix system is obtained:

$$\begin{bmatrix}[\Delta P]\\ [\Delta Q]\end{bmatrix} = \begin{bmatrix} J_1 & J_2\\ J_3 & J_4\end{bmatrix}\begin{bmatrix}[\Delta\theta]\\ \left[\dfrac{\Delta V}{V}\right]\end{bmatrix} \qquad [1.7]$$

where [ΔP] and [ΔQ] respectively represent the differences between imposed and calculated active power at actual iteration at the generator and consumer nodes and the differences between imposed and calculated reactive power at the consumer nodes.

The size of the Jacobian matrix is twice the number of consumer nodes plus the number of generator nodes, the slack node being excluded from this calculation because the magnitude and phase of its voltage is known.

The structure of the Jacobian matrix is linked to the structure of the matrix of the nodal admittances of the network under review. Thus it is sparse. Obviously, techniques using this sparsity are used (decomposition in the LU form) and it is in fact the progress in these special big size sparse matrix reversal techniques that has enabled using this method efficiently.

Considering that phase shift and active power on the one hand and reactive power and voltage modulus on the other are interdependent, it appears that in general the elements of sub-matrices J_2 and J_3 can be ignored and therefore a decoupling into two independent systems is possible. Finally, the Jacobian elements are generally recalculated only during the first iterations and are kept constant afterwards. This helps in avoiding recalculation of the decomposition of this matrix.

In certain cases the problem can still be simplified by ignoring the real parts of the admittances (mainly safety studies), by considering the sine of the phase shifts to be their difference and assuming that the cosine of phase shifts will be one.

1.2.4. *State estimation*

In state estimation calculation, in addition to the parameters related to the electrical structures of the network, the following features are also available: telemetry of the active and reactive power flow in the electrical lines, telemetry of the active and reactive power injected at certain nodes (power balance), telemetry of the voltage modulus at certain nodes, remote signaling giving the logical state of the circuit breakers and the position of the on-load tap changers of the variable ratio transformers and sometimes even the current intensity in certain lines [DEB 87, ERE 00].

The state of a network of N nodes will be completely defined by the state vector $[x] = [V_1, V_2, \theta_2, V_3, \ldots, V_N, \theta_N]$ by taking the phase of node 1 as reference.

If the remote signaling is correct and the telemeasurements are affected only by low amplitude white noise, the state estimation methods will enable obtaining an “instantaneous” image very close to the real values which are inaccessible.

However, the telemetry can be altered by the presence of transmission errors. In such a case they should be identified and then eliminated or corrected to avoid getting incorrect values of [x]. While power flow calculation assumes that the data is devoid of errors and equal in number to that of the unknowns, state estimation implies a redundancy (use of more data than unknowns) which will enable taking into account the observation errors and giving a reliable solution despite the uncertainty over the values of the data. The control centers of the networks generally

use the method of least squares even though other algorithms based mainly on linear programming prove to be interesting during biased measurements.

Every measurement z_i differs from the exact value z_{it} of the measured quantity by an error ε_i, i.e.:

$$z_i = z_{it}+\varepsilon_i,\ i = 1, \ldots, m \qquad [1.8]$$

Using the hypotheses of a normal distribution for the density function of the random variable ε_I, of a zero average value E (ε_i) = 0, of a standard deviation σ_I, of an absence of correlation between measurements ($E(\varepsilon_j\varepsilon_i)$) = 0, $i \neq j$ and, considering that there are no topological or parametric error of the elements of the network, the vector of measurements [z] is given by the following equation:

$$[z] = [f([x])]+[\varepsilon] \qquad [1.9]$$

Therefore, the aim is to obtain an estimation $[\hat{y}]$ in such a way that the difference (known as residue) between the measured and the calculated values is minimal:

$$[r] = [z] - \left[f\left([\hat{y}]\right)\right] \qquad [1.10]$$

By using the weighted least squares, it is necessary to minimize:

$$J\left([\hat{y}]\right) = \sum \frac{\varepsilon_i^2}{\sigma_i^2} = \frac{\sum\left[z_i - f_i\left([\hat{y}]\right)\right]^2}{\sigma_i^2} \qquad [1.11]$$

By denoting the diagonal matrix of the covariant coefficients as [R], the optimum is obtained by canceling the gradient of equation [1.11]

$$\left|\nabla_x J(x)\right|_{x=\hat{y}} = [H(\hat{y})]^t[R]^{-1}[[z]-[f([\hat{y}])]] \qquad [1.12]$$

and the iterative Newton-Raphson method is used:

$$[\hat{y}_{k+1}] = [\hat{y}_k] + [[H]^t[R]^{-1}[H]]^{-1}[H]^t[r]^{-1}[[z]-[f([y_k]]] \qquad [1.13]$$

This solution implies that the gain matrix $[G] = [[H]^t[R]^{-1}[H]$ can be inverted, and therefore that there is a sufficient number of measurements corresponding to an observable network, i.e., there should be no subnetworks for which no

measurements are available. In fact, every Jacobian line is associated with a measurement which corresponds to a limited number of variables. This matrix will therefore be very sparse, as was the gain matrix. The same sparsity operation techniques will be used as in the case of power flow calculation.

In the same way, the active/reactive decoupling and maintaining the gain matrix at a constant value will provide a fast method of calculation. The details of these methods will not be discussed here but the reader can find useful references in the bibliography.

1.3. Planning and operation criteria

1.3.1. *Introduction*

Planning electrical systems involves developing evolution scenarios of the electrical energy requirement and choosing the infrastructure to meet those requirements such as installation and implementation of generation facilities, transmission, distribution and operation (dispatching, communication, etc.). Operating electrical systems also means using the existing facilities in the best possible manner keeping security and economy as the guiding principles.

Until recently, be it planning or operation, the procedure included all the components of the electrical systems within private or public sector companies that managed a particular geographical zone. From a techno-economic point of view a global optimum was aimed at. Electricity tariffs were fixed through a consensus between the public authorities and the people in charge of development and operation of the electrical system.

Since the deregulation of the electricity markets, it has become necessary to separate the different activities such as generation, transmission and distribution. As far as generation is concerned, several companies compete with each other in managing their own generator parks and in developing the commercial activity involved in buying and selling the electrical energy. Actually, a transmission network or a distribution network is a natural monopoly inside a given geographical zone, and it is not advisable to duplicate these infrastructures thereby increasing the cost of transmission of electrical energy. On the other hand, several companies can play the role of intermediaries between the consumer and the electricity supplier.

To ensure correct and reliable functioning of the electrical system the technical characteristics of the facilities and their mode of operation should satisfy a certain number of rules which form part of a “grid code” similar to the law of a country or a

region where it is applicable. The following sections detail some of the general aspects of these technical rules.

1.3.2. *Power generation units*

A power generation unit should function in a reliable manner, be involved in maintaining the voltage and frequency stability of the network and avoid disturbances which can jeopardize the correct functioning of the electrical system.

The reliability should be such that often turning to spinning reserves and cold reserves is avoided. Generally, using these reserves is more expensive than a planned generation program. Incidentally, the volume of these reserves, and therefore the cost of operation or of corresponding unavailability depends on the reliability of the entire generation unit in service.

As will be described in detail in section 1.4, frequency and the balance between generation and consumption are closely related. It is therefore essential that all the power generation units continue to function and maintain the synchronism within a certain frequency interval around the nominal frequency, for example, between 48 and 52 Hz for a 50 Hz network. It is also necessary that a sufficient number of units can adapt their production to the load in a rapid and flexible manner, by reacting to the variations of frequency or of a power set point coming from a central controller or a dispatcher. This involves imposing certain conditions on the adaptation speed of the power produced.

The voltage at every node of the network is the result of a set of elements: reference voltage of the generators, power flow on the transmission structures, compensation means of the reactive power: shunt or series condensers, inductances, synchronous compensators, static compensators with power electronics and other FACTS (flexible alternating current transmission systems). It is therefore necessary to impose on the generators a permissible range of production and absorption of reactive power as well as a range of permissible voltage at the terminals. A commonly used value for the $\cos\varphi_{nom}$ of the AC generator is 0.85 (gross output). From the point of view of the transmission system operator, the range will be expressed as a function of the maximum output capacity at the high voltage connection busbar of the generator. In order to ensure correct operational stability (particularly in case of a short circuit in the network) and to maintain an acceptable voltage range, the AC generator excitation will be controlled by a voltage regulator. Within this an over-excitation limit will prevent an excessive rotor current while still maintaining the reactive generation at its maximum permissible level; an under excitation limit will avoid getting dangerously close to the stability limit for insufficient synchronizing torque.

If asynchronous generators are used, a local compensation of reactive power should be foreseen while still ensuring rapid and automatic voltage control facilities which will be electrically close.

In the event of network failure which is normally eliminated by the protection within a certain prescribed time, a generator cannot lose the synchronism. Its design (mechanical inertia, rapidity and limit of over-excitation, fast action of the turbine valves, etc.) should ensure this “transient stability”.

The generation unit should also be equipped with protection devices which will separate it from the network in case of internal problems or external frequency and voltage conditions which exceed the permissible ranges. Such a separation is necessary in order to limit the possible damages to the generator and, for the electrical system, to limit the disturbances just to the tripping of this unit. In case of tripping due to external conditions a sufficient number of generators should be able to function in an isolated network with the help of their auxiliaries or in a local network despite the significant and sudden load reduction that follows, in order to be able to feed the network again once conditions allow it.

In case of black-out of the electrical system a certain number of units that are geographically scattered should be able to restart without an external source of electrical energy in order to restore the electrical system.

Certain characteristics of the generating units are imposed by the technical regulation in force. Others are optional and the corresponding services (such as contributing to the generation-consumption balance of the control area or the capacity to restart without an external source) either depend on a bilateral agreement with the transmission system operator or follow a call for tenders.

1.3.3. *Transmission network*

A transmission network is operated by a dispatching center or by a main dispatching center and several regional dispatching centers. A communication system sends back the signals (logical signals indicating the position of the circuit breakers, presence of an alarm, etc.) and the measurements (voltages, active and reactive powers in the electrical connections, etc.). These measurements, which are possibly recorded, are collected at the dispatching centers and are made available to the operators through screens. This system of collecting, storing and presenting data is often indicated by the acronym SCADA (supervisory control and data acquisition). This raw data can be processed and used by the software called EMS (energy management system) to describe a coherent state of the system (state estimator) and to carry out safety analysis. These functions have to be carried out

with a very high degree of reliability: independent emergency power supply, duplicating the data transmission paths and the data processing equipment, etc.

In general the transmission network is meshed. The power flow in each of the elements of the network (see section 1.2) can be calculated based on the inputs and the outputs of the electric power. This power flow cannot exceed the “thermal” capacity of the elements, particularly the maximum permissible continuous voltage and current whether it is to avoid accelerated aging or material deterioration or even, unacceptable deformation (sagging of the overhead lines). It is not enough to satisfy this criterion only in the reference case; it is also necessary to face current contingencies and unavailabilities. This is the reason why in the design, as well as in the operation of the electrical systems, care should be taken to respect the “N-1” criterion, i.e. when any element and only that element of the network trips, the new distribution of the power flow should still be acceptable. Special operating circumstances can lead to tolerating temporarily a mild overload of current knowing that remedial measures are available and can be put in place rapidly and in a simple way as a topological modification (opening or closing a coupling between busbars) or a modification in the output of certain generators. It should be possible to carry out these measures within a time frame lower than the thermal time constant of the elements subject to overload.

In case of incident, the short circuit current can lead to intense electrodynamic forces and significant heating. The speed of action of the protection system and the circuit breakers limits these forces and the input heat in time. For every level of voltage, the equipment is designed to withstand a given short circuit power (mechanical resistance of the materials, rated breaking power of circuit breakers). The short circuit power is defined as $\sqrt{3}$ times the line voltage before the short circuit multiplied by the current during a three phase short circuit. The IEC 909 standards describe the method of modeling the alternators to calculate the short circuit current by using the transient and subtransient reactance. During designing and operation care should be taken not to exceed a given maximum short circuit power at any busbar of the network. While the need for respecting the “N-1” criterion forces the meshing of the network as much as possible and mainly operating the substations with the coupling bars closed, respecting the short circuit load limit sometimes leads to keeping them open. New approaches based on probabilistic transmission planning are sometimes used, based on reliability evaluation [LI 07].

Apart from the constraints on the power flow in the elements of the network, care should also be taken to keep the voltage within a permissible range around the nominal voltage. Section 1.5 describes voltage regulation methods.

The short circuit load is also an indicator of the “solidity” of the electrical system. During rapid load variations, the voltage fluctuation will be inversely proportional to the short circuit power.

The design of automatic control systems should be such that disturbance is limited as far as possible when the electrical system breaks down. For example, in the case of a low voltage prolonging beyond a fixed time frame it is advisable to activate the circuit breakers in order to isolate the defective part of the network and to prepare its restoration. Even in case of loss of electrical supply, a certain maneuvering autonomy of the circuit breakers has to be retained so as to be able to configure the layout of the network to restore it. This can be achieved through energy reservoirs such as springs, compressed air, etc.

1.3.4. *Electrical power distribution system*

Electrical power distribution networks are either radial or are operated in subnetworks to avoid overloading by the power flow coming from the electric transmission system mainly when some of its links are out of service. In general a multiple (double or triple) supply is foreseen for industrial loads and low voltage networks either by using all the available electric power injections or only a part of them with the possibility to transfer on to another through an automatic control system in case one of them is tripped.

Until recently, nearly all the generators were of high nominal power and were connected to the electric transmission system and possibly to the sub-transmission network. Consequently, the power flow is directed from the electric transmission network to the distribution networks and from the highest voltage levels towards the lower levels within the distribution network. The protection plans take this into account. Since the proliferation of smaller generators (combined generation electricity/steam or electricity/heat, wind generators, photovoltaic cells, small hydraulic generators, etc.) which are connected to the distribution network, the above mentioned characteristics are changing. Under such circumstances the protection systems should be redesigned. Care should be taken not to exceed the limiting value of the short circuit power by imposing a decoupling transformer. This will limit the short circuit current through its leakage reactance and also the current in case of a single-phase fault through its windings coupling and its neutral coupling. In case of a fault leading to isolating the power distribution system the generators have to be automatically disconnected from the network, on the one hand to avoid being damaged and avoid creating violent transients during re-energizing, on the other hand to avoid danger to the personnel brought to repair the defect.

The generators and loads connected to the network should limit the voltage disturbances they generate: harmonics (introduced by the saturation of the ferromagnetic core and the non-linear devices mainly using power electronics), interharmonics, imbalance between the phases, flicker (rapidly oscillating voltage amplitude). The emission limits are described in the standards, such as the IEC 61000-3-n, n = 2 to 7 series of standards. If necessary attenuators should be used (passive or active filters, compensators). Similarly, user appliances should have a certain immunity to disturbances.

In case of a significant frequency reduction (of the order of 1 Hz), causing a disturbance capable of jeopardizing the operational safety of the network, automatic load shedding should be carried out by frequency relays. In general, a certain degree of the load shed is achieved based on the extent of frequency reduction. For big interconnected networks, local congestion problems are not necessarily linked to significant frequency variations. If a change of the grid topology or a generation redispatch cannot solve the problem, load shedding will be requested by the distributor. In certain situations voltammetric relays will be activated to avoid a voltage collapse.

1.4. Frequency and power adjustments

1.4.1. *Objectives and classification of the adjustments*

Alternative electrical power grids are designed for a nominal operating frequency. For technological and historical reasons, extended networks have a frequency of 60 Hz (North America, part of South America, part of Japan) or 50 Hz (rest of the world). The operating frequency should remain relatively close to the nominal frequency for the following reasons:

– in practice, certain applications are usable only within a fixed frequency range (machine tools, absence of flickering for incandescent lighting, etc.);

– dimensioning of the generating units and receiving devices takes into account the operating frequency. For rotating machines with speed linked to the frequency of the network, a frequency that is too high will result in a high centrifugal force incompatible with the equipment behavior. In the case of devices with a magnetic circuit, for a fixed voltage the flux is inversely proportional to the frequency. A very low frequency will entail excessive magnetic flux which in turn will enhance saturation, increase losses and create harmonic components;

– the design of the generators (turbines, alternators) and receiving devices consisting of rotating machines avoids the appearance of critical speeds around the nominal speed; however these exist outside this range.

Currently, almost all electrical energy generation is by alternators driven by a thermal (traditional or nuclear), gas or a hydropower turbine. These alternators carry out an electromechanical conversion of energy. The rotors of the turbo-alternator units which transmit the mechanical couple also have energy storage in the form of kinetic rotation energy.

If the electrical resisting torque of the alternators which is necessary for the electrical load of the network, including the transmission losses, is equal to the engine torque of the turbines, the system can be considered to be in equilibrium and its frequency corresponding to the rotation speed of the alternators is constant.

On the contrary, if the load increases, the resultant torque is negative and the frequency reduces; similarly, if the load reduces, the frequency increases. It is clear that the power balance and the frequency of the system are linked; setting the frequency and maintaining it around the reference frequency help in balancing generation and consumption of electricity.

Frequency and power adjustments have several objectives:

– ensure operational safety of the network: when the frequency moves away from the reference frequency caused by an imbalance. It is necessary to prevent a too significant frequency sweep in order not to disturb the functioning of the components of the system and, during major disturbances, avoid loss of generation or fragmentation of the network through correct functioning of the protection systems;

– respecting the balance between generation and consumption in every zone controlled by a dispatching center (for example on a nationwide scale), in the case of interconnected grids bound by contractual exchange programs;

– distributing the generation in an economical manner over all the units of every producer.

These three main objectives are to be considered on different time scales:

– the mechanical inertia backup of the rotors is equivalent to the consumption of the electrical system for a few seconds. To avoid a rapid breakdown of the frequency during a severe disturbance, such as the tripping of a big generation unit, it is necessary to envisage methods to reestablish the power equilibrium within seconds. This is achieved through primary regulation;

– the methods used for rapid frequency regulation should be easily deployable during malfunctions leading to sudden imbalances. It is thus necessary to envisage a power backup with a response time of a few minutes to follow the general generation – consumption pattern. This forms part of the secondary regulation;

– over a few tens of minutes, following the consumption trend or following the failure of power generation units, it is advisable to distribute the power generation of a unit economically taking into account the different constraints: permissible voltage and current on the transmission structures, emissions and environmental constraints (CO_2, NO_x, etc.). This objective is achieved using active power regulation of the working units and the decisions to stop and restart the generation units.

Turbo-alternator groups are equipped with regulators which control the opening of the inlet valves of the engine fluid. On the one hand these regulators make it possible to fix the level of the power produced through a local or remote control and on the other, to react to the variations of the rotation speed. The power set point supplied by the secondary or tertiary regulations, the feedback of the reaction speed forms the primary regulation.

1.4.2. *Primary regulation*

In the case of a sudden imbalance between power generation and consumption ΔP, it is preferable to control the allocation of the adjusted power generation. This can be performed through proportional speed controllers. In near static mode the modification of the power produced ΔP_{prod} will be proportional to the frequency deviation (with reference to the set value f_0) with a sign reversal:

$$\Delta P_{prod} = -K(f-f_0) = -K\Delta f \qquad [1.14]$$

Proportionality coefficient K is known as the regulating energy of the unit and is generally expressed in MW/Hz. An alternative formulation of this equation uses the speed droop σ, which is inversely proportional to K and brings into operation the relative variables:

$$\Delta P_{prod} = -(1/\sigma)\,(\Delta f/f_{nom})\,P_{nom} \qquad [1.15]$$

where P_{nom} is the nominal power of the turbo group. If the speed droop of the units participating in primary regulation is identical, these units will bring an identical contribution of relative value (with respect to their nominal power). To obtain a sufficient frequency quality without endangering the stability of the system, a speed droop of about 4 or 5% is chosen.

Generally the load of the electrical system depends on the frequency. In case of small deviations it can be assumed that the variation is proportional to the frequency deviation: $\Delta P_{load} = D\Delta f$. In relative magnitudes, the order of magnitude of D ranges from 1 to 2% of the load per percentage of frequency variation.

Using the above relations it can be easily shown that for an electrical system consisting of n controlling generators, after a sudden imbalance ΔP (positive for load loss, negative for generation loss), the quasi-static frequency deviation post-primary regulation is given by:

$$\Delta f = \frac{\Delta P}{\sum_{i=1}^{n} K_i + D} = \frac{\Delta P}{\sum_{i=1}^{n} \frac{1}{\sigma_i} \frac{P_{nom,i}}{f_{nom}} + D} \qquad [1.16]$$

The denominator of this expression is the coefficient of proportionality between the initial power imbalance and the final frequency deviation and is known as the regulating energy of the system.

For the Western European continental grid the rules in force require a total primary reserve of 3,000 MW (more or less) and a regulating energy of at least 18,000 MW/Hz. The primary reserve corresponds to the sum of the nominal powers of the two biggest generating units.

At time t_0 of the onset of the power imbalance, before the reaction to primary regulation, the modification of the kinetic rotation energy of the rotors compensates for this imbalance. The mechanical inertia of the rotors is often expressed in standardized variables. An often used notion is that of launching or transition T_a: it is the time (theoretical) interval necessary to reach the nominal rotation speed, starting from rest, by applying the nominal torque.

If there is only one generating unit, the initial frequency variation is then given by:

$$\left.\frac{df}{dt}\right|_{t_0} = \frac{f_{nom}}{T_a} \frac{\Delta P}{P_t} \qquad [1.17]$$

where P_t is the running power, which is also the nominal power of the unit. For a set of interconnected units, assuming a network reduced to a node, the denominator of the member on the right is the sum of products TaPt. For an extended network the propagation phenomenon of the electro-mechanical phenomena should be taken into account. The initial frequency variation will be more pronounced closer to the point of disturbance than in a remote location.

The transition time T_a is about 10 seconds. In the case of a generation loss corresponding to 5% of the running power for a 50 Hz grid, the initial reduction in

the frequency is 0.25 Hz/s. This shows that the primary regulation should rapidly adjust the generation to prevent the frequency from reaching inadmissible levels.

Another expression of the mechanical inertia of rotation in standardized variates uses inertia constant H, linked to the transition time through:

$$H = \frac{T_a \cos\varphi_{nom}}{2} \qquad [1.18]$$

The interference of the nominal power factor $\cos\varphi_{nom}$ is due to the fact that the inertia constant is expressed as a function of the apparent nominal power S_{nom}, the system base per unit used to describe the electrical parameters, whereas the transition time is connected to the nominal active power P_{nom}.

1.4.3. *Secondary regulation*

An interconnected electrical system consists of several control zones. Each one of these zones is managed by a local dispatching center on which other regional centers depend. The manager of a control zone should make sure that the balance between power generation and consumption of his zone is maintained considering the programmed power exchanges. For this, an automatic or manual control is designed to maintain this control deviation G around zero as given by:

$$G = (P_{exch}-P_{prog})+K_{sec}(f-f_0) \qquad [1.19]$$

where P_{exch} is the power exchange balance in the lines interconnecting the neighboring grids, P_{prog} is the programmed power exchange and K_{sec} is a coefficient having the dimensions of a regulating energy of the system (MW/Hz). If the coefficient K_{sec} is equal to the regulating energy of the system as defined in the primary regulation, then the control deviation G gives the power balance of the zone outside the action of the primary regulation. In fact, starting from a system in equilibrium at the reference frequency if an imbalance ΔP occurs in a given control zone its control deviation will be ΔP considering that term $K_{sec}(f-f_0)$ is equal to the contribution of this zone to the primary regulation reserve and term $(P_{exch}-P_{prog})$ is the contribution of the other control zones. Under the same conditions, the control deviation of the other zones will be zero because their power balance is equal to their contribution to the primary regulation reserve.

The secondary regulator has the control deviation G as its input signal and a power set point deviation as its output signal with respect to a reference level. This power set point is distributed amongst the generating units involved in the secondary regulation. The secondary regulator is generally of a proportional-plus-integral type.

Its integral nature helps in avoiding static error. For the Western European grid the recommended time constant is about 50 to 200 seconds. The proportional aspect produces a faster reaction. However, its involvement should be limited so as to avoid swings in the system.

In a certain number of electrical systems it is preferable to maintain the synchronous time such as the network frequency integral, close to the astronomical time. This is useful in devices where the time measurement uses the frequency of the electrical system (synchronous clocks). This objective can be achieved, for example in case of time deviation exceeding a certain threshold, by temporarily introducing a reference frequency f_0 which is slightly different from nominal frequency f_{nom}.

1.4.4. *Tertiary regulation*

Tertiary regulation aims at bringing into operation the generation facilities that enable us to cover the load over a few tens of minutes while the primary and secondary regulations compensate for the rapid fluctuations. In a situation where power exchanges are fixed, the objective is to produce the required power at a minimum cost taking into account a set of constraints: permissible transmission through transmission lines, environmental constraints such as pollutant emission or warming of river waters, etc.

In the absence of constraints and by ignoring the grid losses, it can be shown that the most economical distribution of power generation over a set of units in operation corresponds to the uniformity of their marginal costs of production. Taking into account the grid losses imposes penalty factors on the marginal costs which are related to the variation of losses in the electrical grid based on the distribution of power generation.

Generally, tertiary regulation can also bring into play the on/off status of the flexible generating units such as the hydraulic turbines or can even carry out short-term market transactions (spot market) in electrical systems with several operators.

Complex systems involving tens and even hundreds of generators and hundreds and thousands of transmission lines and transformers call for specialized desktop tools to locate the optimum operating point of the system. These calculation programs often referred to as optimum power flow, determine, using an iterative process, the value of the control variables such as the power set point of the generators in order to minimize an objective function, for example the combined operating cost taking into account the technical constraints of the system: admissible operating field of the generators, permissible current and voltage of the lines,

transformers and devices (circuit breakers, disconnectors), environmental constraints (pollutant emission, warming of waterways, etc.).

1.4.5. *Generating unit schedule*

The power requirement of the consumer is variable and corresponds to the economic and social activities with their day/night rhythm, working days/weekend, active season/vacation as well as the climatic conditions (temperature, clouds, wind). Safe and economical scheduling of generating units can be achieved by envisaging the required grid load as precisely as possible by referring to recent readings of similar periods, its general evolution and meteorological forecasts. Algorithmic methods developed in the past are based on the load cycles described above. More recently, calculation tools using artificial intelligence and particularly neuronal networks have been developed. Apart from the modulation of the power produced by the generators in operation, it is necessary to shut off certain generation units during low load periods and to start to meet the peak load. The unit commitment should take into account the operating cost of the units as well as their technical characteristics, for example, the on/off time with the associated costs.

There is lot of variation in the starting time of the generating units. Starting from rest, a turbo hydroelectric generating set can be synchronized at the network and supply electric power in a few minutes, a gas turbine requires a few tens of minutes, a traditional thermoelectric generating set takes a few hours and a nuclear power plant a few tens of hours (cold start). Starting and shutting generating units entail a certain cost linked to the energy used (fuel to start the turbo group), to the aging of the equipment (mechanical and thermal constraints) and to the manpower cost (starting teams).

Solving the unit commitment problem at a minimum cost is difficult as it involves continuous (the power modulation of the units in operation) and discontinuous (decisions regarding running or shutting the unit) variables knowing that there cannot be continuous transition between the two since there exists a minimum operating power of the generation units (to avoid cavitation problems of the hydro-electric generating sets and to ensure proper functioning of the boilers for the traditional thermoelectric generating sets). Dynamic programming and relaxation methods by Lagrange are amongst the calculation methods used. The algorithms used by the calculation programs are generally completed by heuristic rules taking into account the specificities of the generation unit under consideration. Often in practice several different solutions lead to very similar costs. In such a case it is the expertise of the operator that helps in choosing a judicious solution.

A particular domain concerns the hydrothermal coordination or hydrothermal optimization. The hydroelectric generating sets will be preferred to cover the peak loads and to rapidly balance the production and the demand. Using them is determined by the available energy based on the water input (river feeding a storage dam), taking into account the water level of the dam so that it stays within the permissible range. From this point of view, it is necessary to ensure coordination between the operations of the hydroelectric generating sets situated along the same river and along its tributaries.

In this context, the use of pumped-storage plants should be mentioned. During low electrical demand (mainly at night) when electricity is available at a low cost, water is pumped from a lower reservoir into a higher one. When there is a high demand this water flows in a reverse path going through a turbine. The overall efficiency of this pumped-storage operation is around 75%. The cost-effectiveness of the operation is that the marginal cost of the electrical energy used for pumping is lower than the marginal production cost of generation by other units at the time of turbining, multiplied by the overall efficiency of the operation.

1.4.6. *Load management*

Following serious disturbances (tripping several generating units and/or problems in transmission), a portion of the load can be shed in order to avoid a total or regional breakdown of the electrical system. This can be achieved rapidly by using automatic control systems (under frequency or voltage relays) or through the actions of the network control operator with certain customers. The supply agreements with these customers specify the technical and financial modalities of these interruptions (preferential tariff, notice period, maximum number and duration of the interruptions per time slot, etc.).

With the setting up of an open electricity market, there is the possibility that the cut in supply could be stretched to situations which are not necessarily due to serious disturbances but due to the availability of power supply and ruling rates.

1.5. Voltage regulation

The quality of the electrical energy supply is related mainly to the value and variation limits of the frequency and the voltage as well as the continuity of service [AGU 81, ERE 00].

As far as the voltage is concerned, it depends not only on the electromotive force of the generators (and thus on their excitation) but also on the behavior of the load,

the reactance and the grid capacity. The voltage value will be mainly influenced by the local reactive energy production and consumption. The voltage drops due to the flow of reactive energy in an inductive network will be responsible for the Joule losses of the network: the voltage control problem is mainly local. Under normal conditions, the two controls are separated: active power-frequency having a general effect on the network and voltage-reactive power having a local effect.

This separation helps in studying them separately and treating the specific problems in an independent manner.

1.5.1. *Case of short lines*

In the case of Western Europe where transmission lines of short length are common (a few tens of kilometers), it is possible to take the impedance dipole model (see Figure 1.3(a)) $\underline{Z} = R+jX$. If $\underline{V}_R$ and $\underline{V}_S$ can denote the phase voltages at the load side and the source side respectively, the vector diagram (see Figure 1.3(b)) marked with voltage V_R as origin of the phases for a current that is out of phase by an angle φ.

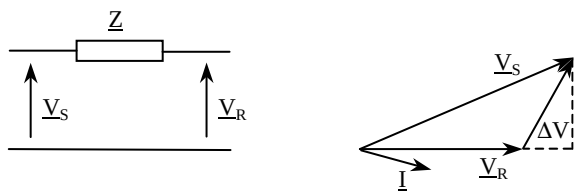

Figure 1.3. *(a) Short line, (b) vector diagram*

The complex voltage drop $\underline{\Delta V}$ consists of two parts: a longitudinal component ΔV, projection of the voltage drop on V_R and considered as the difference of the voltage moduli and a perpendicular component δV, considered to be the phase shift between the two voltages $\underline{V}_R$ and $\underline{V}_S$.

This leads to: $\Delta V = RI\cos\varphi + XI\sin\varphi$ and $\delta V = XI\cos\varphi - RI\sin\varphi$.

Introducing active power P and reactive power Q (per phase) at the receiver end leads to:

$$\Delta V = (RP+XQ)/VR \text{ and } \delta V = (XP-RQ)/V_R \qquad [1.20]$$

where, if R<<X, then:

$$\Delta V \cong XQ/V_R \text{ and } \delta V \cong XP/V_R \qquad [1.21]$$

Thus, it is clear that in order to limit the voltage drops the reactive power should not be transmitted. Minimizing the transmission of reactive energy also reduces the Joule losses given by the expression $3R\,(P^2+Q^2)/V_R^2$. All reactive power flow limits the possibilities of active transmission for the same heating of the conductors.

The same reasoning can be applied to the case of a network seen from a busbar and modeled by a Thévenin equivalent. In this case the Thévenin reactance is, in terms of non-dimensional quantities, the inverse of short circuit power S_{cc} at the node under review and V_S is the no-load (Thévenin) voltage at the node under review. Under normal circumstances, the ratio V_S/V_R is around one and the relative variation of voltage $\Delta V/V_R$ is such that $\Delta V/V_R \cong XQ/V_S^2 = Q/S_{cc}$ and the load voltage characteristic is given by:

$$V_R \cong V_S\,(1-Q/S_{cc}) \qquad [1.22]$$

The characteristic obtained is illustrated in Figure 1.4.

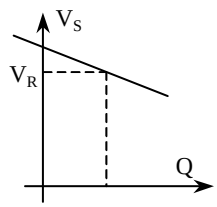

Figure 1.4. *Characteristic V_R depending on Q*

From this a first method of voltage control can be deduced through reactive power injection at the load level.

It can also be seen that a relation such as V = f(P,Q) implies that variation $dV = (\partial V/\partial P)dP+(\partial V/\partial Q)dQ$ is determined by sensitivity coefficients and, in particular, it will be coefficient $\partial Q/\partial V$ which will indicate the importance of the active power injection to be used to provoke a voltage variation. This coefficient is expressed as Mvar/kV, magnitude of a current, and the characteristic of the previous load shows that $\partial Q/\partial V_R = S_{cc}/V_S = I_{cc}$, three-phase short circuit current at the point under review. The higher the short circuit current at a point the less the advantage of regulating voltage through reactive power at that point.

1.5.2. *Case of the line with capacity*

Apart from the voltage drops in the transmission and distribution network caused by the consumption of reactive energy by industry, the networks themselves contribute towards supply or absorption of reactive energy. This will mainly be the case with long overhead power lines or underground cables. In these cases the effect of the capacities specific to these lines cannot be ignored.

The case of an ideal lossless line with distributed constants and of length L placed between two sources of voltage V_S and V_R having a phase shift of angle θ is considered. By denoting the inductance per unit length as l and the capacity per unit length as c, the characteristic impedance can be defined by $Z_0 = \sqrt{l/c}$ and the phase constant as $\beta = \omega\sqrt{l/c}$ (order of magnitude 10^{-3} rad/km). Given these conditions, it can be shown that the active power transmitted in R is given by:

$$P = V_S V_R \sin\theta/(Z_0 \sin(\beta L)) \qquad [1.23]$$

The reactive power in R is:

$$Q = V_R (V_S\cos\theta - V_R\cos\beta L)/(Z_0 \sin(\beta L)) \qquad [1.24]$$

If the line is electrically short, the sine can be considered as the angle and then the well known equation is arrived at:

$$P = (V_S V_R \sin\theta)/X \qquad [1.25]$$

with $X = \omega lL$ the total reactance of the line.

Similarly:

$$Q = (V_S V_R \cos\theta - V_R^2)/X \qquad [1.26]$$

These equations show that the active power circulation depends on the phase displacement between the voltages at every extremity of the line; a phase displacement of 90º marks the limit. This angle also corresponds to the stability limit of the alternators at the extremities. It is also clear that the transmitted reactive power is linked to the difference between the voltage moduli at the extremities and that, when the voltages are constant the active power cannot be controlled (by θ) without, at the same time, modifying the reactive power at the extremities.

If the voltages at the extremities of the line have the same modulus, the following equation is still obtained in the general case:

$$P = V_S^2 \sin\theta/(Z_0 \sin(\beta L)) = P_n \sin\theta/\sin(\beta L) \qquad [1.27]$$

by denoting $P_n = V_S^2/Z_0$, *the natural power or the characteristic power* of the line, with Z_0 characteristic impedance (around 300 ohms in overhead power lines, a few tens of ohms in underground cables).

It can be said that the natural power corresponds to an active power transmission when $\cos\varphi = 1$, there is just a phase displacement between the source and the load. All transmitted power higher than this power (case of overhead lines under heavy loads) corresponds to a consumption of reactive power by the line. If it is lower (case of underground cables of any rating: the thermal limit is always lower than this natural power) it indicates a reactive energy production by the line.

It is therefore clear that the lower the electrical length of the line the higher the ultimate power output. In this case heating will be the limiting factor.

For a length L equal to 1,500 km, the quarter wave line ($\sin(\beta L) = 1$) is encountered and it is then clear that the ultimate power is natural power.

These simple observations show the elements on which actions can be taken to adjust the transmitted active power:

– increase the voltage;

– reduce the electrical length of the line by reducing the inductance;

– modify the phase angle between the voltages at the ends.

Compensating the electrical length using series capacitors was common for a long time on long EHV lines. The degree of series compensation is k, the ratio of the series capacitive reactance to the reactance of the line is (X_c/X); it is generally limited to 60% to avoid hyposynchronous resonance phenomena.

In the case of a lossless line with identical voltage moduli at the ends, the active power is indicated by $P = V^2\sin\theta/((1-k)\ X)$ and the reactive power supplied by the series capacitor is $Q_c = 2V^2k\ (1-\cos\theta)/(X\ (1-k)^2)$.

The phase displacement modification is performed using phase shifting transformers (by introducing a series voltage perpendicular to the local voltage, see Figure 1.5, using a series transformer).

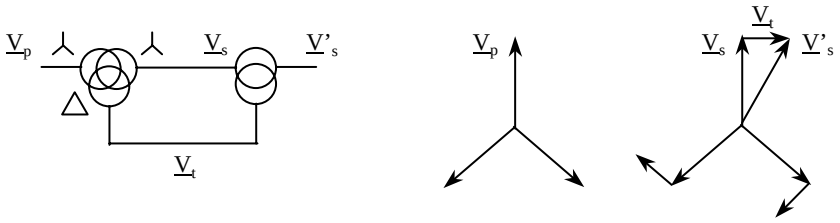

Figure 1.5. *Diagram of the principle of the phase shifting transformer*

In this case, if the total phase shifting is reduced by an angle σ, the power becomes $P = V^2\sin(\theta-\sigma)/X$.

It is clear that if in the above case the maximum transmissible power is not changed, it is bound to happen for a phase displacement between 90° and 90°+σ. The following equation gives the apparent capacity of the series transformer using the same hypotheses:

$$S = (4V^2/X)\sin((\theta-\sigma)/2)\sin(\sigma/2) \qquad [1.28]$$

Finally, introducing an ideal reactive power source in the middle of the line, for example, and maintaining the voltage modulus at the same point as at the extremities, enables us to consider two independent reactance lines X/2. The power is then given by: $P_s = (2V^2/X)\sin(\theta/2)$, doubling the maximum transmissible power.

The reactive power supplied by this source is: $Q_s = (4V^2/X)(1-\cos\theta)$, that is, 4 times the reactive power at the extremities of the line without compensation.

By taking the equations of the equivalent quadripole of the lossless line in sinusoidal mode:

$$V_S = V_R\cos(\beta L)+jZ_0I_R\sin(\beta L) \text{ and } Z_0I_S = jV_R\sin(\beta L)+Z_0I_R\cos(\beta L) \qquad [1.29]$$

and the following relation can be obtained after normalizing with the natural power and the voltage V_S:

$$V_R^4\cos^2(\beta L)+V_R^2(P_R\sin(4\beta L)\tan\varphi-1)+(\sin^2(\beta L)P_R^2)/(\cos^2\varphi) \qquad [1.30]$$

which enables us to trace V_R as a function of P for different power factors and for a given length (see Figure 1.6). Apart from the existence of a transmissible power limit, every power transmitted indicates two possible voltage values; only the higher value is stable.

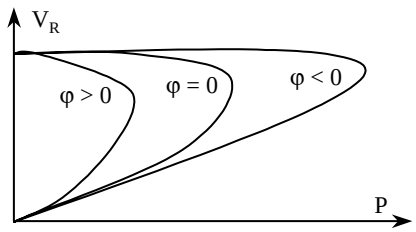

Figure 1.6. *Power limit as a function of φ*

If the resistance of the line is considered, it can be modeled by a scheme in nominal π where the transversal parameters are represented by a concentrated capacity C and a total longitudinal impedance $\underline{Z} = Z\angle\psi$ between the two sources with a phase displacement θ. This time, the maximum active power is obtained for a phase displacement θ = ψ, less than 90°, according to the following equations:

$$\underline{S}_S = (V_s^2/Z)\, e_j^{\psi} - (V_S V_R/Z)\, e_j^{(\psi-\theta)} \text{ and } \underline{S}_R = (V_R V_S/Z)\, e_j^{(\psi+\theta)} - (V_R^2/Z)\, e_j^{\psi} \qquad [1.31]$$

In a P-Q plane, these loci correspond to two circles centered respectively at V_S^2/Z and V_R^2/Z and of radius $V_R V_S/Z$. The impedance modification through a modification of the longitudinal impedance (series compensation) amounts to increasing the radius of the circle, all other parameters remaining constant.

1.5.3. *Traditional methods of reactive energy compensation and voltage regulation*

The methods will be different depending on the level of action: transmission or distribution.

In fact, in the first case, the network consists of important units, an electrical power grid with conductors having a weak resistance with respect to the reactance and as a result, a voltage drop linked to the reactive transmission. On the contrary, in distribution, there will often be a radial structure, a higher customer density, very few or no generators and a line resistance higher than the reactance. However, the current tendency of decentralizing generation by creating small units connected directly to the distribution network will lead to a modification of these conditions.

The objectives of regulation are different: in the electric transmission and subtransmission network, the aim is to maintain the voltage at the highest possible level to control the line losses while still remaining compatible with the equipment behavior whereas in distribution it is mandatory to keep the voltage close to its contract value to guarantee optimum use of customer equipment (voltage quality).

The decoupling between two levels is ensured by transformers equipped with adjustable taps under no load (medium voltage/low voltage or MV/LV) or under load (HV/MV) which avoid transmitting the voltage fluctuations from a network upstream to a network downstream.

In general, the compensation and control methods to be put into practice should face the periodic fluctuations connected to the daily development in power transmission but also to the sudden variations linked to the network malfunctions.

The devices used for compensating the reactive energy and maintaining the voltage are:

– fixed capacitors and inductances;

– synchronous compensators;

– static compensators (SVC or SVG);

– transformers with variable tappings (on load or no-load);

– generator sets.

Distribution and subtransmission network capacitors MV and compensators (synchronous or static) compensate for the reactive energy required by the HV loads and the LV distribution. The fast and refined adjustment of the reactive energy in HV and the voltage control are ensured by the generator sets (voltage control loops) and the capacitors of the transformer substations towards the subtransmission network.

In distribution, compensation of the reactance is carried out at the customer level through tariffs which penalize a bad cosφ, the voltage adjustment is achieved by the transformers at the level of the stations as indicated previously.

1.5.3.1. *Compensators and inductances*

The shunt capacitor banks can reach several megavars that can be split into steps of 2 to 4 Megavars or even 10 Megavars. They are used to improve the power factor at the inductive load level. Some of their disadvantages are:

– the reactive power reduces when the voltage reduces ($Q = \omega CV^2$) whereas it should increase;

– possibility of harmonic distortions through resonance with non-linear loads;

– voltage surges and overcurrents during switching-on.

The capacitor batteries are split into steps switched on or switched off through circuit breakers or nowadays, using thyristors (this eliminates equipment wear and increases the response speed), controlled by varmeter relays which measure the error between the set value and the power supplied. In order to avoid a very high current flow the thyristors have to be fired at the right moments: these shall be close to the time of the peak value voltage as long as the residual charge of the capacitors corresponds to a voltage value that is close and of the same polarity.

As mentioned above, the capacitor banks can be introduced in series with the conductors of a line so as to reduce its reactance. The voltage drop between the source and the load is also reduced as indicated in Figure 1.7. This type of compensation reduces the transmission angle θ and also acts on the active wheeling thereby increasing the transmissible power limit and the stability of the network.

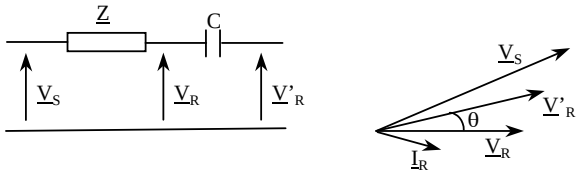

Figure 1.7. *Principle of series compensation*

Inductances are used to absorb the reactive power produced by the long lines at EHV under low load or by cable networks. They are generally connected to the transformer and their capacity can go from 50 Megavars (through a 3 windings transformer) to 400 Megavars in direct connection with EHV lines.

1.5.3.2. *Power generation units and synchronous compensators*

Power generation units are the sources of voltage of a network and can generate or consume reactive energy: a synchronous overexcited machine supplies reactive energy like a capacitor. During under excitation it absorbs reactive power like an inductance. Considering the electrical distance between generation and consumption centers, the units do not compensate for the loads but can meet the reactance requirements of the network. Figure 1.8 shows the operating limits of active and reactive power as well as a single-phase equivalent diagram of load. The impedance Z_d is an equivalent impedance which ultimately takes the regulators into account.

The supply of reactive power during over-excitation is limited by the maximum rotor current and during absorption by the stability of the synchronous machine. This limit can vary with the voltage regulators.

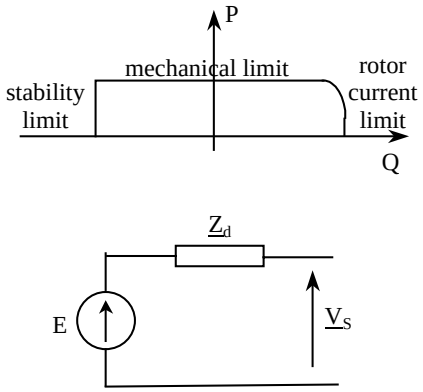

Figure 1.8. *Diagram of a synchronous alternator*

A synchronous compensator is a synchronous machine without load, designed especially for reactive power generation/absorption by adjusting the excitation. The limits are the same as for power plant units. Typical values range between 20 and 60 Megavars during supply and between 10 and 30 Megavars during absorption. More often they are connected to the tertiary windings of transformers. Their main advantage as against the capacitors or the passive inductances is their flexibility under all load conditions (continuous control) but they are expensive by way of investment as well as maintenance. At the moment this activity can be taken over by the alternators of the generation plants which are occasionally disconnected from their mechanical drive.

1.5.3.3. *Static compensators*

Power electronics have enabled, other than the direct current connections, the introduction of purely static compensators consisting of capacitor banks and inductances and controlled by thyristors mounted back to back. Thus there will be continuous control of the inductance by modifying the firing angle of the thyristors after paralleling a controllable inductance using thyristors (TCR: thyristor controlled reactor) and shunt capacitor banks also switched by thyristors. This is the principle of the static var condenser (SVC). Using autonomous static converters made from IGBT transistors or GTO thyristors enables to have a voltage source of phase variable with respect to the network and therefore using an adequate storage method, a true static generator (static var generator (SVG), such as STATCON). The control is continuous as in the case of a synchronous compensator but the response speed is much higher. The only disadvantage being the generation of harmonics which forces the use of filters. They are mainly used in maintaining the voltage at the fluctuating

industrial load levels (arc furnace, rolling mills, etc.) or in rebalancing the network in the presence of loads that are out of balance (TGV – high speed trains).

Their size varies with the type of application but ranges from -40/+60 Megavars to -75/+100 Megavars in the transmission network.

1.5.3.4. *Transformers with adjustable taps under load*

An on-load tap changer modifies the transformation ratio within a fixed range by increasing or decreasing the number of turns of a high voltage winding. Care should be taken not to interrupt the current or short circuit the turns during switching over. This can be done by temporarily introducing an inductance or resistance. The adjustment range is ±15% with 20 taps (scale between 1 and 2%). With respect to nominal control, a tap change corresponds to injecting an additional voltage at the point of insertion of the transformer which implies a modification of the sub transmission of reactive power in the concerned zone.

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Chapter 2

Evolution of European Electric Power Systems in the Face of New Constraints: Impact of Decentralized Generation

2.1. Introduction: a new paradigm

This chapter deals with the problems related to the recent development of electric networks and to the new constraints in the electrical energy sector in Europe. This evolution and the constraints, mainly the restructuring imposed by the deregulation of the electricity market, have literally led to a new paradigm in the management of the electrical sector, with significant impacts on the control, regulation and security of the electric networks. The development of a new type of production, called decentralized generation, based on cogeneration units, renewable energy systems or conventional power generation units set up by independent producers, is definitely going to impose new technical constraints. These constraints enter the electrical distribution networks with a certain acuteness which forces these networks to receive a major share of this new type of production while they have not been designed for it. New problems arise and they can be solved only at the cost of improvements in the existing networks and significant efforts in research and development in order to ensure a reliable and good quality supply of electrical energy to citizens and businesses. Creating a large European market for electrical energy by applying the principles of competition, as laid down in the Treaty of Rome, has turned out to be much more difficult than expected by its protagonists and presents several challenges, technical as well as organizational [CAP 06].

Chapter written by Michel CRAPPE.

2.2. Structure of modern electric transmission and distribution networks

Two types of electrical networks have to be considered: high voltage, generally more than 30 kV, transmission and subtransmission networks with a meshed structure on the one hand and low voltage, less than 30 kV, distribution networks with a radial structure on the other.

2.2.1. *Modern transmission networks*

Modern electrical transmission and subtransmission networks (see Chapter 1) consist of meshed circuits supplied with alternating current (50 Hz in Europe and 60 Hz in the USA) by large capacity generators with centralized production coordination and whose nominal power and location are planned on a countrywide scale. In addition, these units are controlled in a coordinated manner. These so-called dispatchable units participate in the generation of electrical energy as well as in controlling the frequency and voltage of the network by ensuring ancillary services. Until the recent liberalization of the electrical market, this type of power generation, known as conventional or centralized, was common practice. These meshed networks which are currently home to the main power generation, are characterized by a small number of users connected directly at high voltage as well as by the voltage drops linked to reactive power circulation (links with R<<X).

By recalling the expression of the voltage drop in a transmission line, we have:

$$\Delta V = RP/V+XQ/U \qquad [2.1]$$

The symbols used in this expression are defined in Chapter 1.

Meshing started in the 1950s and 1960s to pool the generation and transmission resources of electrical energy, to reduce the cost of energy by optimizing the production and to attenuate the fluctuations in the demand for electricity. In 1951, the UCPTE (Union for the Coordination of Production and Transmission of Electricity) was created to encourage and coordinate the electrical interconnection between the countries of continental Europe, and originally, to recover the waste from hydropower plants. The following section will illustrate the solidarity that exists between the partners of these big electrical meshed networks. Currently, meshing of the networks is carried out mainly in the case of voltages higher than 30 kV (36 kV, 70 kV, 150 kV, 220 kV, 380 kV in Belgium).

On July 1, 1999 the UCPTE became the UCTE (Union for the Coordination of Transmission of Electricity) to be in line with the European Directive 96/92/CE responsible for the electricity market in the European Union.

Electrically, the whole of Europe is grouped into four zones: UCTE, NORDEL (the four Scandinavian countries), ATSOI (Ireland and Northern Ireland) and UKTSOA. These four synchronous zones are interconnected by high voltage direct current links using mainly underwater cables. Today, the UCTE consolidates 23 countries, including 18 from the EU: Germany, Austria, Belgium, Bulgaria, Denmark (western part, Jutland and Funen), Spain, France, Greece, Hungary, Italy, Luxembourg, the Netherlands, Poland, Portugal, the Czech Republic, Romania, Slovakia, Slovenia; as well as Bosnia-Herzegovina; Croatia; FYROM; Serbia and Montenegro, and Switzerland. In addition to this, synchronous links exist with Albania, North Africa (Morocco, Algeria, Tunisia) and with Western Ukraine (island of Burshtyn). Connection with Turkey is under consideration and is expected to come through in 2008.

It can be expected that in the future, European coordination will link up more and more with UCTE for the technical management of the synchronization zone and with the ETSO (European Transmission System Operators created on July 1, 1999) for the harmonization of the market rules and the handling of the necessary data, in other words handling the legal and economic modalities of the international transmission of electricity. Currently, the ETSO consolidates the four European zones and consists of 32 members, all transmission network operators. Exchanges between the countries of the UCTE zone are through the 380 kV networks which form the backbone of the European network. The UCTE zone supplies electrical energy to around 450 million people to cover a total annual consumption which was 2,500 TWh in 2005. The physical electrical exchanges of electricity in the zone had reached 590 TWh in 2005 as against a total production of 2,535 TWh, that is 23.3%. Of this total production, 53.3% comes from traditional thermal units, while 31.3% came from nuclear-thermal, 11.6% from hydropower, 3.6% from renewable energy sources and finally 0.2% from sources not clearly identified. All detailed information and statistics are accessible on the UCTE website at http://www.ucte.org. Table 2.1 gives the net generation and physical exchanges of electrical energy in 2005 in the UCTE zone.

Energy required is the net generation (i.e. not including the energy of about 5% necessary to supply the auxiliary services of the power plants) of the different categories of producers of every country, increased or decreased by the import/export balances and deducting the energy used for the pumped-storage plants. For each country, the degree of openness is defined as the ratio of the sum of exports and imports to the energy required.

Country	Imports GWh	Exports GWh	Imports+exports GWh	Energy required TWh	Degree of opening %	Net power generation in TWh
Austria	23,090	19,773	42,863	63.2	67.82	63.8
Bosnia-Herzegovina	2,251	3,628	5,879	11.2	52.49	12.6
Belgium	14,188	8,022	22,210	87.2	25.47	82.3
Bulgaria	804	8,377	9,181	36.1	25.43	44.3
Switzerland	37,298	27,893	65,191	63.0	103.47	57.9
Serbia-Montenegro	8,563	7,819	16,382	41.6	39.38	41.4
Czech Republic	12,344	24,971	37,315	62.7	59.51	76.2
Germany	53,462	61,922	115,884	556.4	20.74	574.
Spain	10,071	10,271	20,342	252.8	8.05	255.8
France	5,705	66,229	71,934	482.4	14.91	545.9
Greece	5,682	1,838	6,491	52.9	12.27	50
Croatia	14,638	9,286	23,924	16.6	144.12	11.9
Hungary	15,635	9,411	24,907	39.3	63.38	33.1
Italy	50,039	1,103	51,142	330.4	15.48	289.6
Luxembourg	6,400	3,143	9,543	6.2	153.92	4.1
FYROM	2,395	72	2,467	8.1	30.46	6.5
The Netherlands	23,693	5,400	29,093	114.7	25.36	96.4
Poland	5,005	16,185	21,190	130.6	16.23	144
Portugal	9,477	2,806	12,283	49.9	24.62	43.6
Romania	1,606	4,520	6,126	51.9	11.8	54.8
Slovenia	9,285	9,539	18,824	12.8	147.06	13.2
Slovakia	8,568	11,290	19,858	26.3	75.51	29.2
UCTE			**589,708**	**2,496.1**	**23.63**	**2,534.5**
West Denmark*	7,367	7,984	15,315	21.3	71.9	21.9
Ukraine*	1,778	5,501	7,279	4.4	165.43	8.1

Table 2.1. *Net generation and physical exchanges of electrical energy in the UCTE network in 2005. Countries which are not in the European Union are in italics.*
** Associated members of the UCTE*

There are currently two large projects of interconnection with the UCTE network [CAP 06].

The MEDRING project

The idea of creating a large 400/500 kV ring around the Mediterranean has already been studied thoroughly (financed by EC) and several projects directed towards this objective have either been carried out or decided.

– Alternating current interconnection with Morocco, Algeria and Tunisia at 44 kV through underwater cables, commissioned in 1997.

– ELTAM Project: strengthening the Egypt–Libya–Tunisia–Algeria–Morocco interconnection financed by the AFESD. A common investment plan is approved.

– Eastern Mediterranean: Libya, Egypt, Jordan and Syria are already synchronized; the Mediterranean ring will be completed with the closing of the Tunisia–Libya interconnection (220 kV) and the connection of Turkey starting with the European side and then the Syrian side.

East–West interconnection (UCTE-UPS)

The biggest synchronous interconnection in history is on its way to completion. A political agreement was signed between the EC and Russia in 2002 to connect the (600 GW) UCTE grid to the (330 GW) UPS grid and thus create the world's biggest synchronous electrical system, going from Portugal to Siberia including North Africa.

Study of the synchronization conditions started in 2005 and should be completed in 2008.

This interconnection, besides being a technical challenge, should also respect the firm agreements with regards to the commercial and environmental rules in force in Russia.

Extending a synchronous zone beyond a certain size is less and less advantageous and is more and more inconvenient at the technical level. Thus, interconnection appears more and more as a means to export a liberal economic model, to implant the European market concept or to secure the supply of energy, and thus the whole decision sounds highly political. This strategy seems to have overridden technical considerations as the driving force for interconnection in Europe.

2.2.2. *Electrical distribution networks*

Electrical distribution networks operate at a voltage lower than 30 kV and have radial structures supplied by a limited number of source substations from the transmission and subtransmission network. They currently have hardly any generation units but supply a very large number of consumers. The voltage drops in the distribution networks are due to the active power circulation (R>>X) and the compensation of reactive power is mainly achieved at the consumer level because it is forced by pricing. Alternative supply is possible to tide over the faults and outages mainly through a second transformer in parallel, with a fast recovery, to supply part of the distribution network through another HV station. The distribution networks consist of passive electrical circuits in which the active and the reactive power fluxes flow from the high to the low voltages. These fluxes and voltages are determined by the loads. The protection systems and voltage control depend on this unidirectional character of exchange of energy. Soon, deregulation of the electricity market will lead to the development of distributed generation connected to a large extent to the distribution network. This is going to have significant impact more so because the distribution networks are not designed to host generation units. These networks will become active electrical circuits in which the power fluxes and voltages will be determined not only by the loads but also by the generators. Under certain circumstances the power fluxes can flow very well from the distribution network towards the transmission network. This can force a review of the protection plan and the voltage regulation. Added to that, the distribution networks will be the seat of problems concerning short circuit power, transient stability of the installed generation units, voltage stability and even frequency stability in the event of operation as islanded systems. These stability problems though common in transmission networks are new to the distribution networks. After defining decentralized generation in section 2.5 all the problems related to its integration will be analyzed in detail in section 2.6. Figure 2.1 resumes the meshed and radial structures of the transmission and distribution networks.

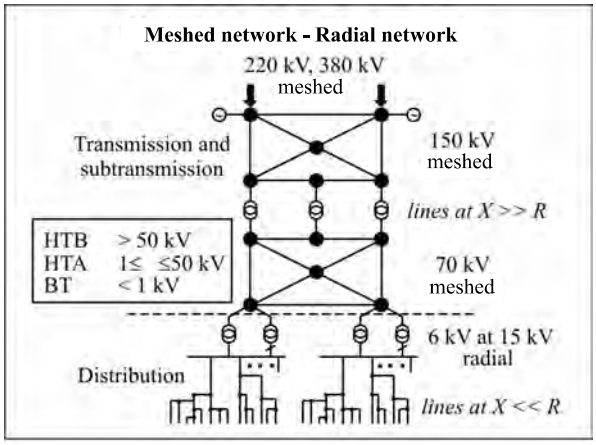

Figure 2.1. *Meshed and radial structures of the networks*

2.3. Recent development in the European networks and new constraints

In recent years, European electrical transmission networks have witnessed a considerable increase in interconnections calling for further increases in the near future and an increased opposition from ecologists to the construction of new structures (lines, power plants) in the zones where the population density is very high. Moreover, these networks are already being used close to their stability and security limits due to economic constraints. Under these conditions, unavoidable disturbances such as short circuits, temporary outages, line losses and consumption vagaries can at any time throw them outside their stability zone. These big networks with their increased power flows are becoming very complex to manage and coordinating their command and control systems is becoming problematic. It should be noted that, as it is, a power swing at 0.25 Hz following the tripping of a powerful generating unit in Spain would affect the UCTE network from Portugal to Poland. Fortunately, existing facilities help in damping this swing rapidly. The grids are also subjected to undesirable power loops between the interconnected zones leading to transmission lines overloading, stability problems and increase in the losses. The new constraints could be such that the conventional methods of controlling the networks (on-load tap changer transformers, phase-shifter transformers, switched series or shunt compensators, modifying the production set points and changing the network layout) might prove too slow and inadequate to handle the disturbances efficiently. It may be necessary to complement their action using power electronics FACTS type devices which have a fast response time (see Chapter 9 for details on FACTS). Network control using phasor measurements synchronized through satellites and spread over the entire network could become essential mainly to

dampen the power swings between interconnected zones. This advanced type of control will be dealt with in Chapter 5.

This already worrying situation is aggravated by the new constraints related to the European policy of deregulating the electricity market, reducing greenhouse gas emissions and using renewable energy sources.

2.3.1. *Deregulation of the electricity market in accordance with European directives*

Deregulation the electricity market in conformity with the European Directives CE 96–92, 2003/54/CE and EC 2005/89 related to the organization of the electricity market, constitutes, without any doubt, a constraint with major impacts on the structure and operation of the European networks. These Directives call for independent management, at least at the financial level, of the transmission activities related to generation and distribution of electrical energy. This means a radical transformation of the structures of the companies from a conventional vertical integration of activities, which is quite natural for scientific people, to an exploded structure with multiple actors. Most of the Member States have opted for a legal separation of activities by creating a separate legal entity to manage the transmission network. It is probably the most effective solution to guarantee separation of management. The liberalization is mainly in the area of production and modifies its organization in a significant way, in particular, development of an appreciable share of decentralized production by independent producers. The Directive allows two possibilities for setting up new power generating plants: through tender invitations or through authorization given by the government of the concerned State. Most of the Member States, such as France and Belgium have opted for the authorization procedure.

The backbone of the electrical system is the transmission network which for economic reasons cannot be duplicated. In every State the transmission network is managed by a single transmission system operator (TSO) appointed by the government concerned. This operator is responsible for the control of the system and the quality of the electrical energy supplied (frequency, voltage, stability). It should especially manage the power flows particularly during congestion. With exploded structures, this task will become more and more difficult in the future.

In every country, a national regulatory agency (Electricity Regulatory Commission (CRE) in France and CREG in Belgium) is in charge of consultation with the public authorities regarding the organization and operation of the electricity market as well as of general surveillance and control of application of rules and regulations related to the matter. The European Regulators Group for Electricity and Gas (ERGEG), set up by the European Commission on 11 November 2003 by

Decision 2003/796/EC, is an Advisory Group of independent national regulatory authorities to assist the Commission in consolidating the internal European Market for electricity and gas. Its members are the heads of the national energy regulatory authorities in the 27 Member States. In the USA an independent federal agency of the Department of Energy, the FERC (Federal Agency Regulatory Commission), regulates interstate trade in electrical energy. This agency was established in 1977 [PHI 99].

This revised structure has definitely led to a new paradigm in the organization and management of the electrical structure. The deregulation of the European market is being carried out gradually and in line with the various approaches in the different countries of the European Union (refer to the UCTE website: www.ucte.org). After deregulation, on 1 July 2007, EU countries opened their retail electricity and gas markets.

2.3.2. *Reducing greenhouse gas emissions in the generation of electrical energy*

First of all, it should be noted that 94% of the CO_2 emissions generated by human activities can be attributed to the energy sector. To be in line with the Kyoto Protocol, by 2010, the European Union should reduce the total greenhouse gas emissions on average by 8% against those of 1990. The efforts are spread out in the following manner: France and Finland just have to stabilize the emissions, other countries (Germany -21%, England -12.5%, Austria -13%, Belgium -7.5%, Denmark -21%, Italy -6.5%, Luxembourg -28%, Holland -6%) have to reduce them and finally certain countries (Greece +25%, Ireland +13%, Portugal +27%, Spain +15%, Sweden +4%) are eligible to increase their emissions. In the absence of reduction measures, there would be a global increase of 5% from 1990 to 2010 and 90% of this increase could be attributed to the transport of people and goods. This compulsion to reduce CO_2 emissions only has an indirect effect on the structure and operation of the electrical sector insofar as it amounts to giving more importance to production technologies particularly to the decentralized or dispersed production (combined heat and power generation, renewable energies and alternative energies). It should be noted that the contribution of the electrical sector to the total CO_2 emissions is not high, for instance in the case of Belgium it is 20%. Moreover, 35% of the electricity produced in the EU currently comes from nuclear sources which help enormously in reducing the emissions due to electricity generation and energy dependence. This explains the difficulty in striking a balance between abandoning nuclear power generation as decided by certain EU countries and the reduction of CO_2 emissions imposed by the Kyoto Protocol. Regarding nuclear energy, it should be noted that according to the International Agency for Energy and the Organization for Cooperation and Economic Development (*Uranium Red Book 2005*, IAE and OCED, Paris), at the present rate of consumption, the available uranium resources

with a short-term economic amortization, will cover a period of 80 years and 675 years respectively with the conventional known and total resources (including phosphates). However, all the resources contained in phosphates and sea water should last for tens of thousands of years. In addition to that, with rapid neutron techniques, the production would be roughly 50 times more than with thermal neutron techniques, according to the French Atomic Energy Commission. Finally, thorium, the available quantity of which on the Earth's crust is four times that of uranium, can be used as a fuel for nuclear fission [FRA 05]. Thus, it appears that it is not the availability of fuel that limits the future of nuclear energy but the problems related to the high cost of the power plants, handling of radioactive waste and above all the risk of accidents.

2.3.3. *Generation of electricity using renewable energy sources*

The White Paper by the European Commission COM(97)599 of November 1997 "Energy for the future: renewable energy sources" set as a target a 12% renewable content in the global energy consumption by 2010, including all sectors, and 22% for electricity. The present overall content is 6% (4% hydropower) and 14% for electricity. The Council of the European Union on March 9, 2007 set a target for 2020 at 20% of the global consumption. In terms of electricity, generation of energy from renewable sources will be largely decentralized and distributed. In the case of wind or solar energy, generation will be located where permitted by the weather.

In the case of renewable energy, the following points of the relevant directive are important:

– steps can be taken to organize the market forces so that a price support structure is set up for electricity generated from renewable resources, likewise the implementation of green certificates at consumer level with penalties depending on the consumption;

– a financing mechanism can be established to take care of the total or part of the net load from the above measures.

2.3.4. *Energy dependency of the European Union*

In the absence of appropriate actions (Green Paper by the European Commission) this dependency would reach an overall rate of 70% and 90% for petroleum products by 2030. Currently, 45% of petroleum imports come from the Middle East and 41% of natural gas imports come from Russia. These problems are dealt with in the Final Green Paper by the European Commission *Towards an Energy Policy for the European Commission* COM (94)659 of January 1995.

A lot of information is available on these questions in the report by the AMPERE Commission (Analysis of the Methods of Production of Electricity and Restructuring of the Energy Sector) published by the Belgian government [AMP 00][1]. This report which was handed over to the Secretary of State for Energy and Sustainable Development in November 2000 is accessible on the Internet at http://mineco.fgov.be/ampere.htm. Another interesting source of information is the study carried out by the Belgian producers of electricity ELECTRABEL and SPE "Knowledge on CO_2 emissions" as a part of their program "Rational Use of Energy". This study, started in 1999, was pursued until 2002. Important results are published in a special issue of the Review E by the Royal Belgian Society of Electricians [CO2 00]. Decisions on energy policy should be based on the results of such studies, which are scientifically proved and have a sound basis. Preparing future energy options is no doubt a major issue which might affect the stability of the European Union.

The most recent Green Paper (final COM 2006 105) of March 8, 2006 by the European Communities Commission, *A European Strategy for a Safe, Competitive and Sustainable Energy*, clearly talks about the energy realities facing Europe, the questions to be discussed and the actions that can be foreseen at the European level. It defines the three main objectives of a European energy policy: sustainability, competitiveness, security of supply, and suggests a certain number of concrete proposals to achieve these objectives.

2.4. The specific characteristics of electrical energy

The effects of recent development and the new constraints on the electrical power networks should be measured in terms of the specific characteristics of electrical energy. These characteristics are briefly dealt with in this section.

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1 The AMPERE Commission carried out the work as a part of the Royal Orders of April 19, October 18 and November 25, 1999 and in concurrence with the federal government of July 7, 1999. The Commission consisted of 16 members, all university professors and members of research institutes, selected based on their expertise in the different areas related to the generation of electricity. Considering the existing situation in Belgium, their objective was to draw up recommendations on the future choices concerning the generation of electricity taking into account the social, economic and environmental challenges of the 21st century. Observations were made over a period of 20 years on the technologies that could be commissioned and put into industrial use by 2020. The report consists of three parts:

– *conclusions, recommendations and executive summary* (basic information of the report);

– *comprehensive report* (conclusions of specialized study groups);

– *main report* (essential data and technical appendix which form the basis of the study).

2.4.1. *Storage and production/consumption balance*

The most important characteristic is that the alternating current does not allow any storage except through conversions. However, converting large quantities cannot even be contemplated for another ten years due to prohibitive costs. Therefore, the production at present should continually compensate for the consumption and transmission losses over the entire interconnected network. Any imbalance will modify the frequency of the whole network, affect its stability and can lead to its breakdown. In the event of an imbalance (due to unexpected loss of an important generating unit) every partner of the interconnected network should, within 15 seconds, act automatically to restore the generation/consumption balance proportionally to their own installed capacity. These unexpected and automatic reactions of generating units are classified as *primary regulation* and they should be able to continue for 15 minutes, after which *secondary* and *tertiary regulation* should take over. Section 1.4 in Chapter 1 deals with these power regulations.

These regulations are part of what are commonly known as *ancillary services*, indispensable to ensure reliable functioning of the network. Figure 2.2 shows, for example, the power exchanges through primary regulation reserves in the UCTE network, as a reaction to the loss of 1,000 MW of power generation in France.

This shows the extent to which the regulation of an interconnected network is collective and the extent of solidarity that such a network can establish between partners.

It can be anticipated that storage of electrical energy is going to play a major role in the management of electrical networks. Section 2.7 mentions and compares the paths that can help in achieving this storage.

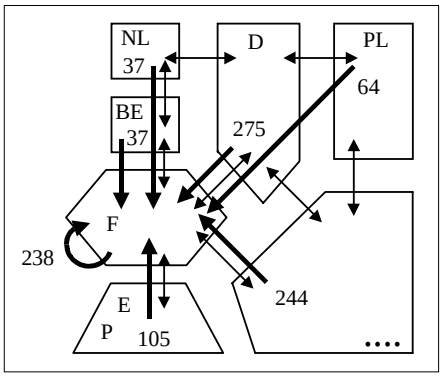

Figure 2.2. *Exchanges in the UCTE network, following a 1,000 W power generation loss in France*

2.4.2. *Laws of physics on flow of energy*

Another specific aspect is that the paths taken during the flow of electrical energy are determined by the laws of physics and not by the laws of market economy much to the dissatisfaction of economists. However, the current rules allow the economic actors to choose freely a “contractual path” between the source point and the consumption point for energy exchanges, ignoring the laws of physics. The result is a difference between “contractual paths” and “physical paths”, which gives rise to “unidentified” and thus “unprogrammed” fluxes across the network, causing congestions. Since the deregulation of the market, interconnection lines, at the Belgian borders, are regularly subjected to such “unidentified” fluxes that can go up to 7 times the programmed fluxes. Under these conditions, the transmission system operator is no longer in a position to guarantee operational security for the electrical system. The difficulty of the problem is illustrated in the example in Figure 2.3 where a 100 MW power flows from Germany towards Italy in the UCTE network.

Figure 2.3. *Flow of 100 MW power in the UCTE network from Germany to Italy*

Two other examples: power flow of 100 MW from Portugal to Germany, with 25% flowing through Belgium (Figure 2.4(a)) and power flow from France to Belgium (Figure 2.4(b)).

The two images in Figure 2.4(b) show the influence of placing the excess power generation of a country on the power distribution of the neighboring countries. Thus, in the case of importing power into Belgium from France, the fluxes which cross the Belgian borders in the South vary from 75% to 62% depending on whether the excess generation is on the West or on the East of France. The influence on the

networks of the neighboring countries is significant while it is just an exchange between two countries that share a common border.

These examples, obtained courtesy of ELIA, clearly show the complexity of the paths taken by the flow of power. It concerns steady-state conditions, with a given network layout and production distribution. In case of serious disturbances in the network such as the loss of a powerful generation unit, these flows are likely to be modified immediately and in a significant manner and lead to overloading certain connections. In order to manage the congestion problems of the electrical lines and to ensure network security, actions have to be taken rapidly at the European level. Care should be taken to avoid the international fluxes cornering the transmission capacities and thereby making them unavailable to the fluxes linked to the decentralized production to absorb the latter or to route the substitute energy when it falters.

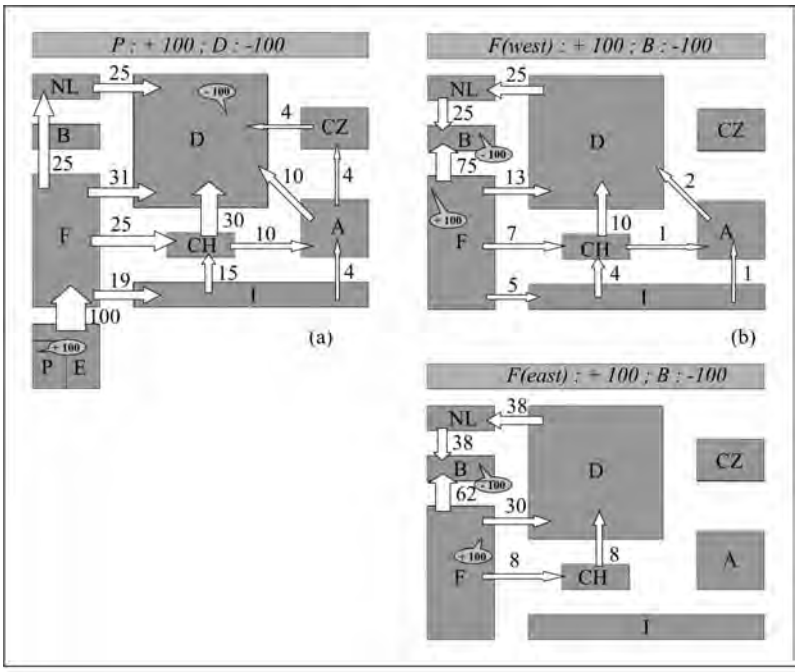

Figure 2.4. *Power flow in the UCTE network between Portugal and Germany (a) and between France and Belgium (b)*

A healthy management needs to abandon transmission contracts based on a contractual path, trace international exchanges through network operators, implement economical mechanisms allocating the transmission capacities and finally exchange information between operators regarding the network layout and the generation/consumption assessments at the border nodes [CRA 01].

2.4.3. *Strategic role of electrical energy*

It is always essential to consider the strategic role of utmost importance played by electrical energy in the operation and development of industrialized societies and not just brand it as another common consumer product. Most of our activities show our dependence on electricity and we only need to look around us to see the number of electrical and electronic devices that are used in day to day life. Society has today and will have for many more years to come, a weakness with respect to this energy vector. The accidents on the French electrical network during the strong winds of December 1999 only confirmed this weakness. Interruption in the supply of electricity completely paralyzes society with serious social, economic and human consequences.

2.4.4. *Voltage regulation in the electrical transmission and distribution networks*

It is imperative to maintain a voltage plan in the power transmission networks. While frequency control is an overall problem involving the entire interconnected network, voltage control is a local problem connected only to reactive energy. The strategy adopted to regulate the voltage plan in the transmission network is to maintain the voltage at the highest level possible to limit the line losses while at the same time remaining compatible with the correct material behavior. To achieve this control, compensation methods (capacitor banks, rotating or static compensators, FACTS) are used as close as possible to the zones where the reactive energy is required and the voltage amplitude value adjustment is carried out using generator field regulation and adjustable transformers. In short, the frequency control is closely connected to the frequency of the active power (coupling P, f) whereas the voltage control is linked closely to that of reactive power (coupling Q, V). Under normal conditions, there is decoupling between the two types of controls, which helps in studying and treating the problems independently.

In power distribution networks, it is imperative to keep the voltage close to the contractual value to ensure an optimum utilization of the devices connected. Since the structure and the regulation methods are very different in the transmission and distribution networks, a decoupling is necessary to solve the problems independently. This decoupling is ensured by using transformers equipped with on-

load (HV/MV) or unloaded (MV/LV) adjustable taps, which, as the case may be, modify their transformation ratio within a short or medium term so as not to transmit the voltage fluctuations from the upstream network to the downstream network. The on-load control comes into operation automatically within a minute. Two regulating modes are currently used: regulator with a fixed set point or regulator with voltage set point as a function of the current (compounding). In addition, the source substations are equipped with capacitor banks to compensate for the reactive power absorbed by the distribution network and to avoid its circulation in the subtransmission or transmission networks. See section 1.5, Chapter 1, for details on voltage regulation.

2.4.5. *Ancillary services*

A part of the generators should be able to participate not only in regulating the frequency but also the voltage by what we call ancillary services. At present, the decentralized power generation units do not provide ancillary services; there is a request to change such a policy as this type of generation will no longer be marginal and would be quite significant in the generation plant. It would thus be important to determine the capacity of every decentralized generation unit to provide ancillary services: reactive power regulation, voltage regulation, taking part in generation repartition, possibility to function autonomously and to provide a black start. To a large extent, the type of electrical generator used (asynchronous or synchronous) and the mode of connection with the network (direct connection or through an electronic converter) determine the capability of providing ancillary services [AMP 00]. The following section deals with this problem.

2.5. Decentralized power generation

2.5.1. *Definition*

As in the case of any new technology, standardizing definitions and terms used in the corresponding domains is always preceded by a state of confusion and redundancies used to refer to the same or very similar things. Decentralized power generation, also known as dispersed, spread or distributed power generation, does not seem to be an exception to this phenomenon.

A survey conducted at the CIRED (International Conference on Electricity Distribution) (CIRED report WG04) amongst 22 countries clearly showed the variety of definitions obtained for this type of generation. The definitions were based on either the voltage level, the drive motor, the installed power capacity or the centralized control possibility. This is why we believe in defining below the concept

in question by adopting the definition recommended by CIGRE (International Council on Large Electric Systems) (WG 37-23 report) [CIG 98].

While conventional power generation involves large capacity units connected to an HV network whose location and power require some planning and which have centralized controls ("dispatchable" units) to regulate frequency and voltage by ensuring ancillary services for reliable and economical functioning of the entire network, the decentralized generation is characterized by small, 50 to 100 MW, power generation units often connected to the distribution grid (<15 MW); which are neither planned like the centralized ones, nor coordinated.

Due to deregulation of the electricity market, decentralized power generation is developing in all countries on the basis of cogeneration units, renewable energy systems or traditional power generation installed by independent producers. Currently, in the USA, 35% of the electrical energy requirement in the industrial sector is already covered by self-generation. A recent study of the EPRI indicates that in the USA, more than 25% of the new power generation facilities that will be installed from now up to 2010 will be of the decentralized type. In Belgium, given the potential in renewable energy sources and cogeneration, the AMPERE Commission expects that, in 2020, the decentralized content of installed power generation units will be 25%, of which 1,500 MW will be from wind energy (1,000 MW in the North Sea and 500 MW offshore) [AMP 00, CRA 01]. With such a rate of penetration decentralized production will have a significant influence on the functioning of the transmission and distribution utilities and will entail serious problems. Countries such as Denmark and the Netherlands already have large plants with cogeneration units using renewable energy sources (windmills); once the rate of penetration exceeds 20%, utilities will encounter specific problems.

Some of the various reasons, both technical and economic, that justify the development of this type of power generation, are given below:

– currently available technology guarantees reliability for units from 100 kW to 150 MW;

– it is easier to find sites for reduced power generation;

– production can be carried out closer to the point of end use so as to reduce the transmission cost;

– natural gas, the energy vector often used in decentralized power generation, seems to be readily available in most consumer areas and also seems to offer price stability;

– gas fired power generation systems are constructed in a much shorter time and with lesser investment costs compared to the large traditional power plants;

– the higher energy efficiency of the cogeneration or combined cycle (gas and steam) systems enable us to reduce the cost of operation;

– government policies to promote clean technology in order to reduce CO_2 emissions and to promote renewable energy through subsidies and participation in price fixing lead to interesting economic conditions.

The fundamental characteristic of decentralized production is that in most of the cases it is driven by factors other than just the electricity demand – heat requirement in the case of cogeneration units and climatic conditions when it involves windmills. This results in uncertainties concerning geographical location, dynamics of development and activity levels and time of production, with consequences on the development, management and operation of the electrical networks. These networks should be in a position to absorb this decentralized production when it is active and also route the substitute power when the decentralized production is inactive. In certain cases the network structure can impose a limit on the power that it can receive at a given point from the decentralized units, as is explained below.

Due to the increase in the number of power generation units and the uncertainties involved in production, it would be advisable to:

– adopt a probabilistic approach for managing the network;

– foresee greater power flux flexibility between centralized and decentralized plants;

– transfer most of the ancillary services to the centralized units;

– review reactive energy compensation plans for voltage regulation;

– ensure a clean network infrastructure to guarantee stability (network backbone).

In addition, it is necessary to provide for the effects on the maintaining of maximum and minimum levels of short circuit power, functioning and selectivity of the protection systems, the voltage plan as well as the stability (see section 8.6).

2.5.2. *Decentralized power generation techniques in Europe, potential and costs*

As already discussed, decentralized production is based on three types of units: renewable energy, cogeneration and finally the traditional method of production. Considering their novel character, the first two types will be discussed. The case of Belgium will be taken for determining the potentials as a commission already set up by the government carried out this work in 2000 for 2020 [AMP 00]. However, a

new study report by a new government commission Energy 2030 set up by the Federal Ministry for Energy on November 2006 is now available. This report "Belgium's Energy Challenges Towards 2030" of June 2007 is accessible in English on the Internet at www.ce2030.be. It updates the problem of choices in Belgian energy policy taking into account the changes that have crept into the energy field. It also takes into account the increased pressure, definitely due to climatic changes, to reduce the greenhouse gas emissions exceeding the 7.5% imposed in Belgium by the Kyoto Protocol as compared to the levels of 1990; further reductions of about -15% and -30% may be imposed. The report talks about the increase in petrol and gas prices, possibilities of capturing and sequestering CO_2, the political decision to limit the life of nuclear power plants to 40 years so as to completely do away with nuclear energy between 2015 and 2025, and finally the deregulation of gas and electrical energy markets. According to this new study, the potential for renewable energy, in particular wind energy, is quite high (revised as being even higher by the AMPERE report); this will increase the share of decentralized power generation, as compared to the earlier study, in the different scenarios considered with special reference to the renewable energy sources (wind, solar, biomass) content in the installed power capacity going up to 53% depending on whether nuclear generation is retained or abandoned. This report CE 2030 might interest those who want to know about the policies in the energy sector and will provide them with a complete analysis of the scenarios studied. These different scenarios have been studied using the energy model PRIMES, established by the University of Athens (NTUA). The report particularly recommends the following: going back on the decision to walk away from nuclear power and to leave this option open, revising the policy of giving concessions to wind mills in the North Sea region, closely collaborating with the international studies in matters related to capturing and sequestering CO_2 upwards.

2.5.2.1. *Renewable energy sources*

With respect to power generation in Europe of the 15 countries, Table 2.2 below gives the renewable energy productions in 1995 and the projections for 2010 as given in the White Paper by the European Commission.

	Situation in 1995		**Projection for 2010**	
Type of energy	*TWh*	**% of the total**	*TWh*	**% of the total**
Wind	4	0.2	80	2.8
Hydropower Large units* Small units	307 270 37	13 11.4 1.6	355 300 55	12.4 10.5 1.9
Photovoltaic	0.03	-	3	0.1
Biomass	22.5	0.95	230	8
Geothermal	3.5	0.15	7	0.2
Total renewable	337	14.3	675	23.5
Total general	2366	100.0	2870	100.0

* Including pumped storage

Table 2.2. *Annual electricity generation using renewable energy sources in the Europe of the 15 countries, situation in 1995 and projection for 2010*

Due to its hydropower generation, the electrical sector, more than the other energy sectors, is already using renewable energy sources. In this context, the proportion of renewable energy sources used in the gross internal energy consumption of the 15 European Union countries in 1995 can be noted from the following: Austria (24.3%), Belgium (1.0%), Denmark (7.3%), Finland (21.3%), France (7.1%), Germany (1.8%), Greece (7.3%), Ireland (2.0%), Italy (5.5%), Luxembourg (1.4%), the Netherlands (1.4%), Portugal (15.7%), Spain (5.7%), Sweden (25.4%), UK (0.7%). These figures are taken from the White Paper. The current overall share of these sources for the EU is 6%.

Table 2.3 taken from the CIGRE WG 37-23 [CIG 98] report gives the estimates of the investment amounts and the cost price of kWh for the different energy sources.

Technology	*Power*	**Cost of capital (Euro/kW)**	**Total cost (Euro/kWh)**
Windmill (onshore)	15 MW	900-1,300	0.04-0.09
Windmill (offshore)	100 MW	1,500-2,000	0.05-0.12
Hydraulic turbine (low pressure)	5 MW	900-1,000	0.02-0.03
Conventional power generation (turbine)	5 MW	800-850	0.053-0.057
Conventional power generation (piston engine)	5 MW	500-750	0.03-0.0453
Photovoltaic*	5 MW	6,000-10,000	0.75-1
Fuel cell	5 MW	1,100-1,600	0.08-0.1
Micro-generator (piston engine)	50 kW	600-1,500	0.07-0.15
Micro-generator (turbine)	50 kW	~300	0.03-0.05
Micro-generator (fuel cell)	50 kW	~900	0.09-0.15

* These costs pertain to the generators connected to the network; they can go up to 1.5 Euro/kWh in the case of stand-alone systems [BAL 99]

Table 2.3. *Investment and electricity generation costs according to the CIGRE WG-37-23 report*

Table 2.4 gives the results of the study carried out as a part of the AMPERE Commission on the total costs in Belgium. Production costs (fuel, investment, operation) are given in column “Total 1” and external costs (CO_2, etc.) added to the production costs in column “Total 2”.

Euro/kWh	Cost, without fuel	Cost of fuel	Total 1	External costs	Total 2
Pulverized coal (SC)	0.019	0.015	0.034	0.024	0.058
IGCC	0.026	0.016	0.042	0.018	0.060
Gas turbine	0.046	0.032	0.078	0.015	0.093
TGV	0.011	0.021	0.032	0.010	0.042
Nuclear PWR (40 years)	0.022	0.009	0.031	0.0009	0.032
Windmill (near shore)	0.045	0.000	0.045	0.0010	0.046
Windmill (offshore)	0.058	0.000	0.058	0.0010	0.059
Windmill (onshore)	0.065	0.000	0.065	0.0010	0.066
Wood gasification + TGV	0.022	0.049	0.071	0.0089	0.080

SC: Supercritical pulverized coal fired station
IGCC: Combined cycle electric generating plant with coal integrated gasification
TGV: Gas/Steam Turbine or combined cycle electricity generating system
PWR: Pressurized water reactor

Table 2.4. *Production and external costs (AMPERE Commission in Belgium)*

Calculating the external costs or damages caused to human life and the environment is based on the methodology of the European project Externe E, completed by the studies carried out as apart of the CO_2 project by Belgian electricity producers [CO2 00]. The external effects are defined as the positive or negative manifestations of an economic agent which affects the activities of another economic agent and which are not taken into account by the market. The external costs are the monetary evaluation of the external effects. They are the total costs borne not by those who generate them but by a third party. This concept though ignored by economists for a long time, is gaining momentum as a result of the increasing pressures on the environment and the necessity to include it in political and economic strategies.

2.5.2.2. *Cogeneration or combined heat and power (CHP) generation*

2.5.2.2.1. Cogeneration

Generation of electricity through traditional means requires setting up of a thermodynamic cycle to produce mechanical energy. The operating fluid in this cycle is in contact with two heat reservoirs: one at a high temperature where heat is brought in and another at a low temperature from where heat is removed. The higher the difference between the temperatures, the higher the cycle efficiency. Mechanical energy production is necessarily accompanied by a heat discharge at the lower temperature of the cycle. This is how in thermal power plants 40 to 60% of the energy contained in the fuel is discharged into water courses or ambient air in the form of heat at low temperature.

In applications requiring thermal energy inputs at moderate temperature levels, the combined production of heat and electricity can be an interesting technique towards energy efficiency. A portion of the heat released at high temperature due to combustion is transformed into electrical energy and the rest is used to cover the heat requirements of the application. This technique is commonly known as cogeneration and can be recommended wherever possible and economically justified. The technical and economic optimization of a cogeneration unit is a delicate problem and calls for thorough study to evaluate the real saving of primary energy as compared to separate electricity generation and individual heating units. It is this energy conservation that describes a cogeneration unit most appropriately. It can vary between 0 and 20% and even show negative values. Designing a CHP unit should be based on the evolution of the heat and electricity requirements of the application over time. Operation under partial load which decreases the efficiency should be avoided. The annual operating time is also an important factor to be taken into account; if this time is limited as in the case of low power units used for heating in the domestic and tertiary sectors, it can affect the energy conservation adversely. In fact, it leads to keeping the old units that are low in efficiency and high in emissions in operating condition in the centralized plant in order to make up for the inactive period of the cogeneration units. In addition, as is clear from the following section, contribution of the cogeneration plants in reducing the CO_2 emissions is low.

The percentage of cogeneration in national production in 1999 in the different countries of Europe is: Denmark: 50%, the Netherlands: 40%, Finland: 35%, Austria: 25%, Italy: 17%, Spain: 15%, Portugal: 12.5%, Germany: 10%, Sweden: 7.5%, UK: 7.5%, Belgium: 5%, France: 3%, Greece: 2.5%, Ireland: 1.25%. There is still a lot of potential for cogeneration in several countries. This part of the chapter dealing with cogeneration is developed with a view to present objectively the advantages of this type of production towards conserving primary energy and

reducing CO_2 emissions. The European objective is to push the share of electricity produced by cogeneration up to 18% by 2010 [EUR 03].

According to the conclusions of the AMPERE Commission:

– in cogeneration, electricity production should be considered subsidiary or "incidental" compared to the production of heat;

– recourse to cogeneration implies a stable and continuous extraction of heat;

– promoting setting up of cogeneration units of low capacity and limited operating time should be avoided without thoroughly calculating the efficiency for the entire generation system.

Estimating the production of electricity by cogeneration beforehand depends mainly on the process used and can pose problems. However, it is possible to disconnect temporarily production of electricity and heat, by storing the latter for a maximum duration of 10 hours in the case of steam systems. This type of production guided by factors other than the electricity requirement does not generally form a part of primary or secondary power regulation.

The cogeneration units have greatly benefited from the progress made by gas turbines and combined cycles. Several classical production techniques are used in cogeneration; they are characterized by the ratio between the heat Q and the electricity produced E as well as by the nominal powers.

The prime movers used for cogeneration applications are of the following types:

– steam turbines (used for a long time by the autoproducers for cogeneration in the industry);

– gas turbines;

– piston engines (gas and diesel engines).

Some figures are as follows.

Ratio Q/E	Technologies	Nominal powers
3 to 4	Steam extraction steam turbines	50 kWe to 100 MWe and more
4 to 10	Back pressure steam turbines	
1 to 3	Gas turbines	100 kWe to 100 MWe
1.5	Piston engines, small gas engines	5 kWe to 4 MWe
0.5 to 1	Piston engines, big diesel engines	100 kWe to 60 MWe

Table 2.5. *Traditional technologies in cogeneration*

We would also mention cogeneration using the Stirling engine and fuel cell.

The Stirling engine, based on a thermodynamic cycle with efficiency similar to the Carnot cycle can be incorporated into a boiler to supply electric power and the residual heat is used for heating applications. Another alternative is to try to feed the Stirling cycle with heat from thermal solar collectors. The efficiency that can be achieved from the engines is very low at the moment; this seems to limit the potential for this technology for a long time to come.

Fuel cells, electrochemical systems that transform chemical energy directly into electricity are dealt with in the following section. The electrochemical reaction is exothermic and releases heat in the temperature range from 70°C to 1,000°C depending on the type of cell. Cells can therefore be an interesting option for cogeneration but since they are still in the development phase and their price is also high, their rate of penetration is difficult to foresee [AMP 00, BAL 99].

2.5.2.2.2. Energy advantage of cogeneration

In order to compare energy conversion in a cogeneration unit with a separate production of electrical energy in an electric power plant and heat in a boiler, the energy balances given in Figure 2.5 can be observed. These balances involve the following parameters:

– in the case of cogeneration α_E and α_Q represent respectively the electrical energy and the heat supplied in % with respect to the energy of the primary fuel used;

– in the case of separate production η_e and η_q represent the efficiency of the electric power plant and that of the boiler respectively as a percentage. The figure compares separate production with cogeneration of parameters $\eta_e = 55\%$, $\eta_Q = 90\%$, $\alpha_E = 35\%$ and $\alpha_Q = 50\%$.

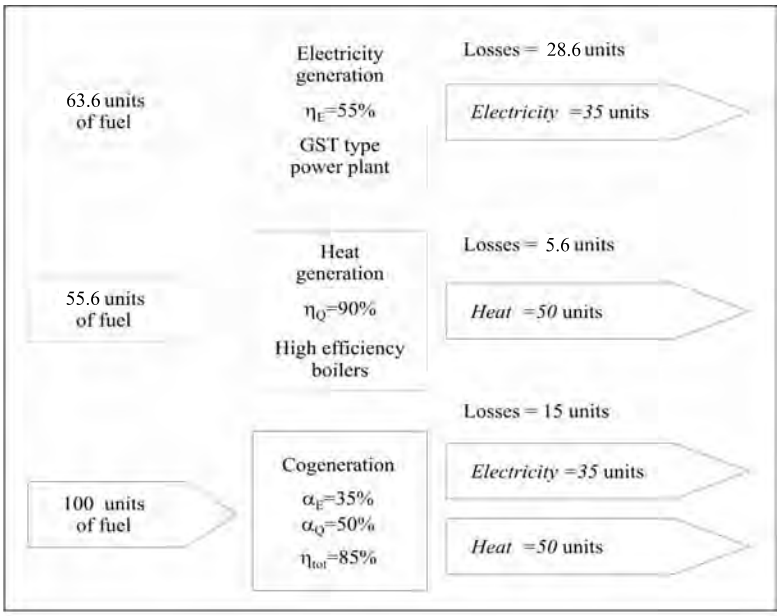

Figure 2.5. *Comparison between a cogeneration unit and separate production*

In a basic approach to cogeneration, sometimes the question of "overall efficiency" of the unit η_{tot} comes up. This efficiency is defined as a ratio of the sum of electrical and thermal powers to the primary input power.

This "overall efficiency" is expressed as:

$$\eta_{tot} = \alpha_E + \alpha_Q \qquad [2.2]$$

In thermodynamics such an expression is not acceptable as it is not correct to add thermal and electrical powers which are not equivalent. It is more appropriate to talk about the rate of energy utilization of fuel of the cogeneration unit.

The most correct method to characterize the performances of a cogeneration unit is to use the *exergetic efficiency*. Exergy is that part of energy that can be totally converted into any other form of energy – electrical energy, for example, is totally exergetic while heat always has a part that is non-convertible (anergy). These enable us to qualify the quality of energy by a factor which expresses the proportion of exergy; this factor is one in the case of electricity and is equal to the Carnot efficiency in the case of heat [MAT 00].

Exergetic efficiency is defined using the following equation:

$$\eta_{exe} = \alpha_{E+}\alpha_Q (1–T_0/T) \quad [2.3]$$

with T(°K): temperature at which heat is supplied and T_0(°K): ambient temperature.

Table 2.6, taken from [AMP 00], compares the exergetic efficiencies of cogeneration of parameters α_E = 35% and α_Q = 50% with those of a high efficiency boiler η_Q = 90% and of a combined cycle electrical power plant η_E = 55%, according to the temperature t at which heat is supplied and for an ambient temperature of 15°C.

t (°C)	Cogeneration	TGV (55%)	Boiler (90%)
15	35	55	0
50	40	55	10
100	46	55	21
200	55	55	35
300	60	55	45

Table 2.6. *Comparison of the exergetic efficiency of cogeneration with those of a high efficiency boiler and a combined gas/steam cycle power plant*

It can be noted that the exergetic efficiency of the cogeneration unit increases with the temperature of the heat supplied, that it achieves the efficiency of the GST electrical power plant only beyond a temperature of 200ºC of the heat supplied and that in the end the efficiency of the cogeneration unit is always higher than that of the boiler. It follows that the savings can be achieved only from the “heat” side.

Conservation of primary energy achieved through cogeneration as opposed to separate electricity and heat generation depends not only on the characteristics of the CHP units but also on those of the separate generation units. As an example, a rate of fuel utilization of 85% for the cogeneration, 90% for a separate heat generation using a high thermal efficient gas fired boiler (η_Q), Table 2.7 gives the value of the relative primary energy saving expressed as a percentage in relation to a separate generation unit, according to the efficiency η_e of the separate electricity generation plant, for different values of the α_E content as a percentage of electrical energy delivered by the cogeneration system.

η_e (%) / α_E (%)	**25**	**30**	**35**	**40**	**45**	**50**	**55**	**60**
25	40	33	28	23	18	14	11	8
30	45	38	32	27	22	17	14	10
35	49	42	36	30	25	20	16	12
40	52	45	39	33	28	23	19	14
45	55	49	42	36	31	26	21	16
50	58	51	45	39	33	28	23	18
55	61	54	48	41	36	30	25	20
60	63	56	50	44	38	32	27	22

Table 2.7. *Primary energy savings in cogeneration*

α_Q is given by the relation:

$$\alpha_Q = (0.85-\alpha_E) \qquad [2.4]$$

The relative saving in energy, also known as quality index is calculated by:

$$IQ = 1–1/(\alpha_E/\eta_e+\alpha_Q/\eta_Q) \qquad [2.5]$$

In the example given in Figure 2.5, the primary energy saving is 16% (19.2/119.2).

This table indicates that the possible saving of primary energy:

– reduces with the increase of efficiency η_e of the separate electricity generation (the scientifically correct reference to evaluate the saving in energy should be the power plant which offers the best efficiency using the same fuel as the CHP. In the case of gas, it is the gas/steam turbine power plant with an efficiency of 55%. For the CHP units using diesel, a traditional power plant using fuel with an efficiency of 40% to 45% is considered);

– increases with the electricity content α_E produced by CHP.

The impact of the CHP generation on CO_2 emissions will be analyzed in section 2.5.3.

2.5.2.3. *Fuel cells*

A fuel cell is an electrochemical device almost like a battery in which the chemical energy released due to the degradation of the fuel is directly converted into electrical energy and heat. The major advantages of such a structure are: high efficiency (even when partially loaded), low pollutant emissions, low noise (no rotating parts), variable generation of electricity and heat. There are different types of fuel cells:

– PEMFC: proton exchange membrane fuel cell;

– PAFC: phosphoric acid fuel cell;

– MCFC: molten carbonate fuel cell;

– SOFC: solid oxide fuel cell;

– AFC: alkaline fuel cell.

The last category was specially designed for domains related to space. Table 2.8 gives the characteristics of different fuel cells [CIG 01].

Type	**PEMFC**	**PAFC**	**MCFC**	**SOFC**
Electrolyte	Solid polymer	H_3PO_4	$LiCO_3/K_2CO_3$	ZrO_2 doped with Y
Temperature	80°C	200°C	650°C	1,000°C
Starting time	Seconds	3-10h	Few hours	Few hours
Power density	400 mW/cm^2	400 mW/cm^2	400 mW/cm^2	400 mW/cm^2
Fuel	Hydrogen	Hydrogen, natural gas, methanol, light oil	Hydrogen, natural gas, coal, gas, methanol, petroleum	Hydrogen, natural gas, coal, gas, methanol, petroleum
Efficiency	40-50%	40-50%	45-60%	50-60%

Table 2.8.*Characteristics of the fuel cells*

Net efficiencies of about 80% are theoretically possible. In the most traditional form of utilization, the PAFC has produced an efficiency of 40% at atmospheric pressure and 45% for systems under pressure. Incidentally, the efficiency levels are almost constantly between 30 and 100% of the output power. It should also be noted that the fuel cells have a low consumption when not in operation. Those that operate at a high temperature (MCFC and SOFC) represent advanced technical solutions. They are also used in CHP units due to the high operating temperature which helps

in reaching an efficiency of 75%. Additionally, using a solid electrolyte fuel cell avoids the protection necessary for corrosive liquid electrolytes.

New storage applications envisage using fuel cells in the power range varying from 5 MW to 500 MW for a duration ranging from a fraction of a second to 12 hours or more [MPS 00]. Such units are likely to be used to carry out black starts as well as to provide support in regulating voltage and frequency. A 40 kW fuel cell manufactured by United Technologies Corporation is capable of moving from zero output to full output in approximately 30 ms. An 11 MW prototype under development at the same manufacturer can provide changes of 1 MW/second between 30 and 100% of its maximum load. A 1 MW prototype developed in Japan for New Energy Development Organization can move from a power of 250 kW to 1,000 kW in 1 minute [CIG 01]. In addition, using a microturbine and a fuel cell simultaneously in power ranges between 250 kW and 2.5 MW as well as using fuel cells in CHP units (for heating big buildings) are probably going to be the systems that guarantee developments in the distribution networks. The European Commission looks to electricity and hydrogen as the two future energy vectors for Europe; these two energies can be converted from one to the other through electrochemical paths using fuel cells and electrolyzers [EUR 03]. The electrochemical path enables direct and reciprocal conversion of chemical energy into electrical energy without the intervention of heat or mechanical intermediary. To discover more on the prospect of hydrogen becoming an energy vector, references [VAN 05, BAC 06] can be used.

2.5.2.4. *Geothermal energy*

According to estimates, 1% of the heat contained in the top 10 km of the Earth's crust [OLI 99] is equivalent to 500 times the petroleum and natural gas reserves. Energy can be extracted straight from the water-table or through water injection. This latter technique is only at a trial stage. The commonly used hydrothermal sources are situated at relatively shallow levels, of about a few 100 meters up to 3,000 meters. It is the third most important renewable energy after hydropower and biomass to be used in the world with a generation of more than 6,000 MW spread over 21 countries [CIG 01].

Heat is either used directly or converted. The typical size of geothermal units varies from 5 to 50 MW. Development projects involving this type of production should be carefully studied as the level of output is not guaranteed within a time frame. The output can in fact reduce mainly due to problems in the bore well. Added to that, construction of a geothermal unit involves a relatively high investment cost. Europe's potential in geothermal energy is evaluated at 800 TWh per year using the HDR (hot dry rock) concept, with temperatures of 200°C to 250°C and a depth of 5,000 meters as long as the procedure is technically and economically viable.

However, the probability of the installed capacity in this type of production going beyond 2,700 MW and producing 24 TWh in the next few years is very low considering the costs and the financial risk [EUR 03].

2.5.2.5. *Microturbines*

These are the turbogenerator sets driven directly by high speed turbines (50,000-100,000 turns per minute) of capacity lower than 1 MW, most often in the range 25-100 kW. They are generally used in cogeneration units and burn different fuels. They are cleaner and quieter than the big turbines and require less of maintenance [BAR 99]. According to a study carried out by the Gas Research Institute [VAR 00], microturbines could supply around 8% of the supplementary power of 1 million MW expected by 2010 in the world. Their main advantage is that they do not require a huge infrastructure, but their cost is high (twice that of a diesel engine) although partially compensated by a high level of reliability (4,000 hours of operation without the need for major maintenance).

2.5.2.6. *Photovoltaic energy*

Photovoltaic generators are systems which convert solar energy directly into electrical energy. They consist of cells made of semi-conducting materials operating on the P-N junction principle and a majority of them are currently made (more than 85%) from crystalline silicium. The energy efficiency of these cells varies between 13 and 15%. However, using very expensive techniques related to micro-electronics it is possible to make cells with 25% efficiency. Generally the manufacturing cost of these cells is very high, which makes the photovoltaic technique the most expensive means of producing electrical energy of all the renewable energies. With depreciation over 20 years and an interest rate of 5%, the production costs per kWh vary between 0.37 and 0.62 Euros in Belgium for systems connected to the network. The production and cutting up of the basic material amount to more than 50% of the cost of producing the cells. In addition, the energy consumption in producing these cells is quite high. This explains the number of research activities that are being pursued to help bring down the cost. Thin film cells are being developed based on amorphous silicon, copper indium diselenide or cadmium sulfide for low power applications (feeding pocket calculators, watches, etc.). Prototypes using organic materials are under study. This latter path seems to be promising. By 2020, the cost per kWh of photovoltaic energy is expected to come down by a factor of 2 to 3; this, however, is not sufficient to ensure competitiveness and large scale development of this kind of power generation [DER 00, AMP 00, TER 93 and TER 96.

2.5.2.7. *Energy from the oceans*

There are only a few prototype units at the moment, but the results are encouraging. This type of production, allotted to units whose power is at least

10 MW, is seasonal and intermittent. The potential on the Atlantic coast of Europe is evaluated at 600 TWh per year. Research in this domain should concentrate on trying to reduce the cost and increase the reliability of the units as well as on the energy availability forecast in order to prove the relevancy of the concept [EUR 03].

2.5.2.8. *Hydropower energy*

This type of energy has the most significant prospects at the global level. Its exploitable potential in the world exceeds 14,000 TWh per year out of which 2,500 TWh are already in use. In fact, in Europe 11.6% of the 2,500 TWh of electricity produced per year are from hydropower. Also in Europe, small power plants whose output does not exceed 10 MW contribute about 40 TWh to the electricity generation and 50% of the sites that can still be used to set up small hydropower plants will be developed by 2015 [EUR 03]. Concerning the operation of electric networks, hydropower generation offers the following advantages: rapid start, precise and fast regulation of the power supplied.

2.5.2.9. *Biomass*

Biomass contributes about 5% of the energy supply of the European Union, mainly in cogeneration units of output ranging between 10 MW and 30 MW. With the development of new technologies this type of production offers many prospects for the future.

2.5.2.10. *Wind energy*

Without doubt, this energy is the one which has reached a high level of maturity and shows the highest degree of development in Europe. By the end of 2005, 40 GW of wind energy capacity was installed throughout the world of which 30 GW were in Europe; this gives an annual world production of 114 TWh and 84 TWh in Europe (considering a nominal production for 30% of the time). The resources in Europe are estimated at 1,000 TWh per year which corresponds to an installed capacity of 340 GW. 1,000 TWh represents more than the present nuclear production in the European Union which is 875 TWh (35% of 2,500 TWh).

However, implementing wind energy poses serious problems to the networks due to the intermittent nature of its production and the difficulty in forecasting active periods. This forces conventional units to increase their reserve capacity to provide substitute energy on the one hand and imposes restructuring of the transmission capacities to route this reserve energy or to absorb the wind energy during periods of activity on the other. In addition, it gives rise to unplanned power flows over the networks that can be a danger to certain parts of the interconnected network and possibly affect its stability. These problems call for thorough study if the proportion of wind energy capacity is to be increased in the generation plants and also if the

real cost of this method of electricity generation is to be determined [SWI 07]. At present, integrating wind energy in the transmission and distribution networks is far from sufficiently analyzed or controlled. The ETSO website (www.etso-net.org//renewables) gives an interesting study on wind integration in the networks (EWIS: European Wind Integration Study of February 2007).

2.5.2.11. *Installed power capacity and structure of electricity generation foreseen in Belgium by 2020*

The potential in renewable energies and in cogeneration units has been recently identified by the AMPERE Commission for Belgium with 2020 as their aim. This has made it possible to plan the construction of the power generation plants as well as the contribution of different sources in 2020. It may be interesting to go through the results of this evaluation as it forms a realistic vision of country regarding the contribution of renewable energy sources to electricity generation. The production by 2020 and the installed capacities in Belgium could be represented by the diagrams in Figures 2.6 and 2.7 pertaining to different types of power generation [CRA 01].

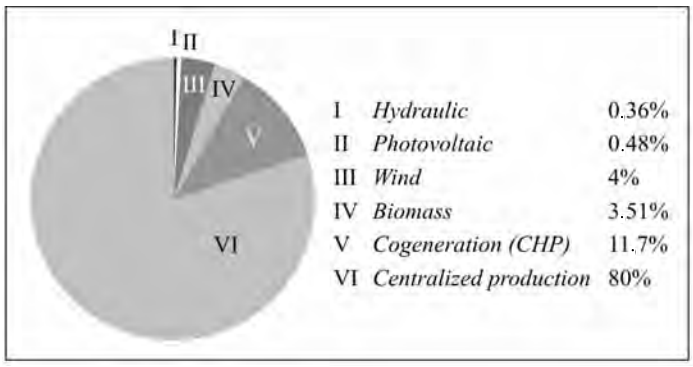

Figure 2.6. *Production in Belgium by 2020*

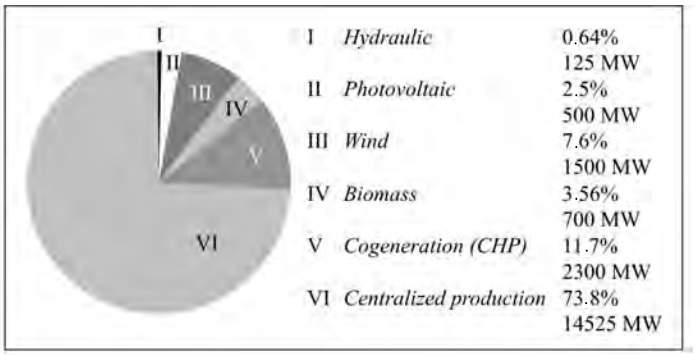

Figure 2.7. *Power generation plants in Belgium by 2020*

The total installed capacity and the annual production in 2020 would be 19.650 MW and 104 TWh respectively. These figures are obtained by updating the figures from 1999 (15,000 MW and 80 TWh) after taking into account an increase of 31% (+1.9% per year between 2000 and 2010 and +1.2% per year between 2010 and 2020) to cover the increase in consumption. Thus, in 2020 the decentralized content in the Belgian power generation plant could be 26.2%.

The potentials for decentralized generation are based on the following considerations [AMP 00, DER 00].

2.5.2.11.1. Hydropower

The potential for hydropower generation in Belgium is estimated at 125 MW of which 100 MW is already produced. This production will still be marginal as it will represent only 0.4% of the total in 2020. The installed capacity will represent 0.6% of the production plant. It is to be noted that this production depends on the period of the year and is available only for 3,000 hours per year.

2.5.2.11.2. Photovoltaic

The theoretical potential of this method is high, in principle 3,000 TWh/year considering the area of Belgium and using cells having 10% efficiency; but a more realistic estimate puts it at 10 to 20 TWh/year. With this new estimate, photovoltaic energy could ensure up to 20% of the production in 2020. However, the present cost of electricity generation using photovoltaic means is so high that in order to have a significant entry into the market, the cost has to be brought down drastically. With a production estimated at 0.5 TWh, i.e. 0.5% of the total electricity production, this method will still remain marginal in Belgium in 2020. The installed capacity would

then be about 500 MW, i.e. 2.5% of the production plant. This has been calculated on the basis of photovoltaic production at nominal power for 1,000 hours per year.

2.5.2.11.3. Offshore and onshore wind energy

In Belgium, installing windmills of 1,500 MW (500 MW onshore and 1,000 MW in the North Sea) by 2020 is technically viable provided there is a strong political will. The relatively high cost of electricity produced using wind energy (up to 2.5 times the cost of the kWh produced by a combined cycle gas/steam power plant) is partially compensated by the low external costs (no direct production of CO_2). In addition, these windmills would contribute towards achieving the objective fixed by the European Commission for the production of electricity from renewable energy sources. In 2020, this wind power of 1,500 MW would represent 7.6% of the total installed power capacity and would supply 4% of the net electricity generation. The wind farms in the North Sea would be spread over 124 km^2 between 10 and 30 km from the coast with a depth lower than 20 m.

Wind energy is inconstant and for a country such as Belgium, its average number of hours of availability per year according to location is:

– in the North Sea: 3,500;

– on the coast: 2,600;

– in the low lands (≤15 km from the coast): 1,800;

– in the interior of the country: 1,500.

2.5.2.11.4. Cogeneration

The potential market for cogeneration by 2020 is estimated between 1,700 and 2,300 MW, of which 1,100 MW are already operational. The installed capacity in cogeneration could reach 11.7% of the plant and ensure at the most up to 11.7% of the production by 2020 (considering a same rate of production as the conventional one, which at present is 80 TWh with 15,000 MW).

2.5.2.11.5. Biomass

The AMPERE Commission is of the opinion that the biomass option is essential even if its contribution in 2020 might not go beyond 4% of the total electricity generation. At present, 0.8% of this potential is already exploited. Burning waste which could cover 1.3% of the total electricity generation constitutes an interesting way to get rid of household waste by producing electricity. Based on the present conventional production (80 TWh for an installed capacity of 15,000 MW), power generation using biomass could correspond to a maximum installed capacity of about 750 MW, i.e. 3.8% of the installed capacity in 2020.

Contributions from other renewable (geothermal, tidal energy) and alternative (fuel cells) energy sources would remain very marginal by 2020.

2.5.2.11.6. Fuel cells

This method should play an important role in the future generation of electricity but not in the next few years as there are still problems to be solved (cost, fuel availability, life). In a similar manner to the conventional thermal power plants its production forecast is predictable, and considering its flexibility of production, it could contribute in an interesting way to the primary and secondary regulation in maintaining the production/load balance. It is necessary to make it clear that fuel cells have nothing to do with renewable energies as most of the hydrogen is from fossil fuels. Producing hydrogen from renewable sources is only conceivable in the long term.

2.5.3. *Decentralized power generation and CO_2 emissions, indirect emissions from so-called "zero emission" power plants*

Regarding reducing the greenhouse gas emissions due to energy conversion, reference has already been made to an important study conducted by the Belgian electricity producers, Electrabel and SPE, on the knowledge of equivalent emissions to CO_2, as a part of their URE program (rational use of energy). During the first two year phase, 14 scientific groups from Belgian universities and research centers analyzed the problems related to CO_2 emissions systematically. The result is the development of a coherent methodology that helps in associating primary energy consumption, emissions and external costs with the utilization of every energy vector in Belgium on the basis of the *complete life cycle* ("from cradle to grave", from source to discharge). Generation of electrical energy as well as the combined generation of electricity and heat (cogeneration) in conventional power plants along with new types of production that can be foreseen, particularly the renewable energy sources, were considered with added interest. To illustrate the advantage of this study [CO2 00] some of the major conclusions are restated in the following section.

Professor Ph. Mathieu of the University of Liège has evaluated the equivalent direct CO_2 emissions linked to the burning of fossil fuels in power plants. Typically, a coal fired power plant with flue cleaning device emits between 800 to 1,000 gCO_2/kWhe according to its efficiency and a gas turbine/steam turbine power plant emits half (400 g/kWhe). He has also given a method of allocating the CO_2 emissions corresponding to electricity and heat in cogeneration units based on the savings in fuel as compared to a separate production as well as on the heat exergy [MAT 00].

By this method, the CO_2 emission factors expressed in gCO_2/kWh can be calculated using the following equations where C_E, C_Q and C_I represent electricity, heat and primary fuel (natural gas) respectively:

$$C_I = \alpha_E C_E + \alpha_Q C_Q \quad [2.6]$$

$$C_E = C_I/\eta_e - (\alpha_E/\eta_e + \alpha_Q/\eta_e - 1) + C_I/\eta_{exe} \quad [2.7]$$

$$C_Q = C_I/\eta_Q - (\alpha_E/\eta_e + \alpha_Q/\eta_e - 1) + F_q C_I/\eta_{exe} \quad [2.8]$$

with:

$$F_q = 1 - T_0/T \quad [2.9]$$

in which T(°K) is the temperature of the heat supplied and T_0(°K) the ambient temperature.

η_{exe} is the exergetic efficiency of cogeneration given by relation [2.3] and $(\alpha_E/\eta_e + \alpha_Q/\eta_e - 1)$ is the saving in primary fuel.

In cogeneration with gas turbines the emissions are reduced by 14 to 15% compared to the separate generation. Moreover, when the turbine capacity is more than 10 MWe, emissions related to the generation of electricity and heat are respectively lower than those resulting from separate generation for the same quantities of electricity and heat. Below this capacity the emissions are almost identical and can even be higher. The higher the heat produced the lower the reduction. An evaluation of the impact of cogeneration on CO_2 emissions shows that this method of electricity generation is not a “miracle” solution for reducing CO_2 emissions; at the most it enables a reduction of about 1% of the total CO_2 emissions for Belgium and for the electrical sector of this country of about 4 to 5% per GW of the electrical type (GWe) installed in cogeneration.

At present, a detailed and general study of the impact of biomass on the environment is not available. Considering the renewable character of the bioorganic material, the CO_2 emission from the chimney is to a large extent neutral. Non-neutral CO_2 emissions are generally minimal: 10 $gCO_2/kWhe$ in the best case with cogeneration to 100 $gCO_2/kWhe$ in the case of short rotation cultivation of wood without cogeneration. It should be noted that 70% of the CO_2 emissions in the case of burning household waste are considered neutral because of their bioorganic character. Certain scenarios give a negative balance for CO_2 emissions mainly the drying of sewage sludge through fossil energy or manure digestion, without taking into account the possible methane emissions during storage [AMP 00].

The contribution of the capital goods to the emissions from fossil fuel power plants is negligible (<5%). On the contrary, in the case of the so-called "zero emission" generation systems, though direct emission due to combustion is zero, indirect emissions linked to construction, maintenance and dismantling have to be considered. This is the case with nuclear power plants, windmills, photovoltaic generators, hydroelectric power plants and power plants using biomass. Two different methods of analysis have been applied to study the life cycle of these power generation facilities:

– analysis of the process chain which calculates the total energy utilization and the corresponding emissions for all the materials used (steel, concrete, plastic, etc.);

– input/output analysis which divides a product according to its economic elements while the life cycle is defined as a set of economic activities.

This study conducted by K. Voorspools, E. Brouwers and W. D'Haeseleer has led to retaining the orders of magnitude of Table 2.9 linked to capital goods [VOO 00].

Type of construction	Duration of life (years)	Indirect emissions of CO_2 (gCO_2/kWhe)	Use of primary energy (kJprim/kWhe)	kJprim/kJe (%)
Nuclear	40	3	40	1.11
Wind power (coast)	20	9	120	3.33
Wind power (interior)	20	25	350	10.00
Photovoltaic 1996	20	130	3,000	83.33
Photovoltaic 2005	25	60	1,500	41.66
Pumped storage plant	40	8	110	3.06
Micro-hydraulic power plant	40	15	200	5.56
Wood gasification	15	15	260	7.14
Co-combustion of sludge	30	3	40	1.11

Table 2.9. *Indirect greenhouse gas emissions from "zero emission" power plants (construction, maintenance, demolition of plants, complete life cycle)*

2.5.4. *Decentralized production and ancillary services*

The present practice of leaving decentralized production out of ancillary systems may not last for a long time. With the development of this type of production its

participation will soon become necessary. In the case of every new system of production it will be necessary to consider its ability to ensure ancillary services: reactive power regulation, voltage regulation, participation in generation sharing (primary regulation, secondary regulation) and capacity to start without auxiliary voltage (autonomous working and black start).

2.5.4.1. *Types of generators and methods of connecting to the network*

The type of electric generator (asynchronous or synchronous) used in decentralized power generation and its method of connection to the network (direct connection or through an electronic converter) determine to a large extent the abilities of ensuring ancillary services. We should now point out that systems using conventional synchronous generators have well known classic characteristics and are capable of ensuring ancillary services without any difficulty and mainly in reactive power regulation. In the absence of any hard and fast rule and going by the final report (ELECTRA, no. 185 of August 1999) by a study team (working committees 11, 37, 38 and 39) formed during CIGRE (international conference on large electric systems) on *Characteristics of Decentralized Production*, the decentralized production facilities can be characterized by the type of generator or interface used. The following categories and their present field of application with certain encroachments between categories can be identified:

– systems with conventional alternators (synchronous machine): these systems are called conventional because of the synchronous generators used as in fossil fuel or nuclear thermal power plants and in hydropower plants. Biomass, geothermal energy, diesel, solar with a parabolic trough and tower, directly fired gas turbine, combined cycle gas turbine, wind;

– systems with asynchronous generators: solar reflector-engine, wind, wave;

– interface systems with power electronics converter: wind (with synchronous or asynchronous generators), photovoltaic, battery storage, superconducting magnetic coil storage, fuel cells.

2.5.4.2. *Generation forecast*

Generation forecasting should also be taken into account for the different sources. In the case of productions with certain vagaries, it is necessary to foresee substitute production as well as some additional margin in the transmission lines to enable modifications of power fluxes [JAN 00].

The unpredictable nature of the wind makes production forecasting difficult in the case of wind energy. Forecasting methods have yet to be developed; an inventory of the different methods of short-term prediction is given (0 to 36 hours) in [LAN 99].

Nuclear or conventional thermal power generation is highly predictable over days, weeks or even months.

Hydropower generation depends on hydrography, pluviometry as well as on the capacity of storage dams. The stored energy can cover a few days' to a few months' production. Forecast in the case of run-of-river power production can vary from a few hours to a few days.

Power generation using cogeneration facilities depends mainly on the industrial process which is involved.

Power generation using biomass can be considered conventional. The available energy depends on the storage capacity. The possibly seasonal character of the fuel, however, only allows prediction over weeks or months.

Power generation using fuel cells is predictable as with conventional thermal power plants.

Power generation using photovoltaic means is rather unpredictable depending on the region where it is set up.

2.5.4.3. *Regulation of power generation*

Adjusting power generation to load is a major problem in electrical networks. As it has already been seen this adjustment should be carried out using sources with available power reserves and with a possibility of regulating the power generation rapidly. The regulation has to be effective within seconds in the case of primary regulation of automatic action and within minutes in the case of secondary regulation. The latter intervenes to reestablish the balance in the regulation zone which caused the imbalance (see Chapter 1).

Conventional thermal power plants have the speed required in the case of these two types of regulation. Limitations are mainly at the boiler level.

Nuclear power plants have speed restrictions in regulating their production due to safety constraints.

Hydropower units tolerate large production variations after a few seconds.

Generally, cogeneration units being driven by heat requirement do not participate in primary or secondary regulations.

In the case of power generation using biomass or fuel cells, primary and secondary regulations are possible as in conventional thermal facilities, provided this was anticipated during the design.

Currently, windmills do not contribute towards production regulation. However, this situation is bound to change rapidly considering the more than significant role that this energy source is going to play in power generation plants. Recent models of windmills with variable speed, connected to the network through power electronics converters using pulse width modulation techniques can take part in primary regulation [RAI 02]. Obviously, this assumes that the aero-engine is operating at a capacity lower than the maximum corresponding to the wind conditions in order to reserve some power to be able to participate in regulation.

2.5.4.4. *Start-up time*

The start-up time necessary for different sources of electricity generation is an important characteristic for the management of a generation plant. These durations are briefly given in Table 2.10.

Types of sources	**Start-up time**
Conventional thermal units	Few hours
Nuclear power plants	20 to 30 hours
Combined cycle gas turbines	Few tens of minutes
Hydropower units	Few minutes
Windmills	Very short *
Fuel cells	Very short
Photovoltaic	Very short*
Cogeneration units	Undetermined**

* As long as the primary sources (wind, sun) are available.
** In principle, it is not possible to determine the duration of starting for a cogeneration unit as it is driven by an industrial process to supply heat, and the generation of electricity is linked to this process.

Table 2.10. *Start-up time of the different sources*

2.6. Specific problems in integrating decentralized production in the networks

2.6.1. *Connection conditions*

Incorporating renewable energy sources and, in a larger sense, decentralized generation in the electrical networks, though an interesting proposal from different angles, implies dealing with certain technical constraints in maintaining quality and reliability in the supply of electrical energy to citizens and companies. These constraints which have been forgotten to some extent are again becoming matters of concern and many studies are now being carried out. These problems can be solved only through research and development and modifications in the existing networks particularly the distribution networks which were not designed initially for this intake of production. Solving these problems depends on the rate of penetration of decentralized power generation.

In a free market setup, investment costs related to modifications and additional equipment necessary for integrating the decentralized production should logically be supported by this production. However, to enable development of renewable energy sources and cogeneration of quality, the CE/96/92 Directive has allowed certain measures to be put into place to ensure flow of a minimum volume of this type of production into the market at a minimum price. These measures can be accompanied by a method of financing the corresponding costs, which is handled by the Electricity Regulatory Commission (ERC).

In this perspective, it is important to analyze thoroughly and exhaustively the effects of integrating decentralized production in the networks in order to identify the problems to be solved and to evaluate the cost of investments necessary to carry out the modifications in the networks.

The following section will give a brief inventory of the technical constraints with a view to creating awareness of the problem related to the integration of decentralized production in the networks.

The methods and conditions of insertion in the high and low voltage networks differ from one country to another. They should be dependent on the rules (network codes) which specify the conditions for connection. These rules are laid down by the distribution and transmission system operators (DSO and TSO) and they should have the backing of the national authorities.

Analyses of recent incidents (Switzerland-Italy, incident of November 4, 2006 in Europe) already show the consequences of the behavior of the decentralized production on the stability of the entire electrical system (production, transmission and distribution). In most European countries, during the incident on November 4,

2006, this behavior was marked by the anarchic connections and reconnections of the wind energy power plants, and it could not be efficiently supplemented as the transmission system operators (TSOs) could not be informed in real time of the level of power admitted by the distribution networks from the generation point. During both the incidents, disconnection of the cogeneration plants was observed when there was a drop in frequency. This aggravated the production/consumption imbalance and hampered the defense plan through automatic load shedding in response to a voltage drop. With the expected increase in decentralized production which will be in a large share connected to the distribution networks, such problems will be aggravated.

It is important that the technical rules related to the connection of decentralized production units to distribution networks include binding requirements concerning: stability of the units during onset of frequency variations of the synchronous interconnection networks, information to be conveyed in real time to the transmission network operators on the actual activity of this type of production as well as on the role of the distribution network operators in maintaining the balance between production and consumption.

All these rules should be harmonized over the entire European network and those concerning transmission networks should be mandatory to ensure the best backup to the European electrical system.

Reports on the incident of November 4, 2006 established mainly by UCTE, and ERGEG (European Regulators Group for Electricity and Gas – Report 07-BAG-01-06 of February 6, 2007) are accessible on their websites.

2.6.2. *Influence on the design of the HV/MV stations*

This involves making sure that no structure (transformers, lines) is overloaded because of decentralized production. Safe functioning of the network has to be ensured whether or not the decentralized production is connected to the distribution network. As an example, even in the case where the local decentralized production is of the same order of magnitude as the consumption, the design of the link equipment in the high voltage network should be such that it can take care of the total consumption. This is to provide substitute energy in case of failure of the local production, or to absorb the energy generated by the decentralized production operating at full capacity with low local consumption (off peak hours).

This constraint can limit the decentralized production intake at a station.

2.6.3. *Influence on the protection of the distribution networks*

Proper functioning of the system requires that in the event of a failure at the MV terminal, the distributor has to ensure safety and clear the fault by opening the terminal circuit breaker. In the case of short-lived faults in the overhead lines, a short duration power-down (0.3 seconds) is sufficient to clear the fault and restore power quickly. Presence of a production cannot disturb the selectivity and sensitivity of the protection plan of the distribution network.

2.6.3.1. *Equipment behavior towards short circuit currents*

In the matter of protection, the contribution of decentralized generators in increasing the short circuit current in the network has to be taken into consideration. In the case of generators connected directly to the network this contribution is of about 5 to 7 times the nominal current of the machine. When it involves connection across an electronic converter this contribution can be brought to the nominal current level using the rapid control of the converter. However, with this last system working in isolated network after an incident, overcurrent protections would not function to clear the short circuit in the network. This problem would occur systematically in photovoltaic and fuel cell systems in an isolated network and therefore special protections have to be anticipated. In any case using standardized methods of calculation it is essential to make sure that the short circuit currents remain within the permitted values. Respecting these limits can in turn limit the power that can be connected to the network. However, a high short circuit power or, in other words, a weak short circuit impedance helps in attenuating the network disturbances and maintaining the voltage wave quality, both in amplitude and in harmonic content. Using current limiters such as supraconductor devices which are being developed nowadays [TIX 02], should help in achieving a balance between two contradictory requirements – high short circuit power and low short circuit current.

2.6.3.2. *Influence on the selectivity and sensitivity of protection*

The selectivity and sensitivity of protection can be disturbed due to the insertion of the decentralized production units in the distribution network.

2.6.3.2.1. Accidental tripping of a healthy circuit

As a simple example, the diagram in Figure 2.8 shows a load supplied through a substation of the network through link 2 and the connection to the substation through link 1 of a decentralized production unit. Each of these two links is protected by a circuit breaker against overcurrents (amperometrical protection) according to practice. In fact, opening a terminal circuit breaker should clear all faults arising from the MV terminal. In this extremely simple example, the circuit

breaker of line 1 can disconnect this line inadvertently in case of faults in line 2 because the generator current at the time of this fault can be higher than the protective threshold. This can happen provided the capacity of the decentralized production units is significant and if the fault is close to the station. The selectivity of the protection thus becomes faulty.

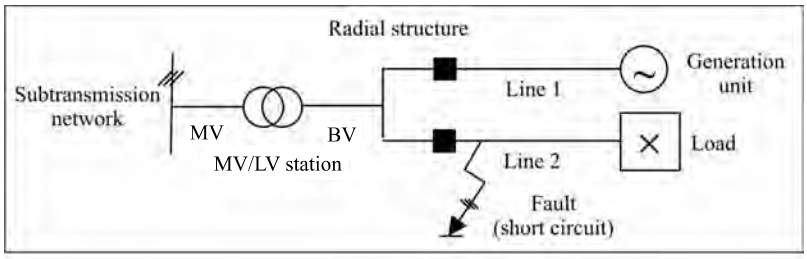

Figure 2.8. *Influence of the decentralized production on the selectivity of the distribution network protection*

Connecting a high power may need *directional current protection*, which should detect when the defect is upstream and not trip inadvertently.

Such protection based on phase difference measurements is currently under experiment.

2.6.3.2.2. Cutting off the protection of a faulty circuit

If the generator of the decentralized production is remote from the HV/MV station, a defect in a shunt close to the generator may not be detected in the first place by station protection. The default current at the station can then be clearly reduced in comparison to the case where the generator does not function. The station protection will clear the fault only after the intervention of the disconnect protection of the generator (see below). There will be a delay of 1 to 2 seconds from the temporization time of the disconnect protection in clearing the fault. To avoid this problem, the generator has to be connected in a more effective manner, probably with a dedicated terminal [JUS 97].

2.6.3.2.3. Disconnection protection

In case of a fault in the line connected to a decentralized generation unit, the latter has to be disconnected automatically and quickly in order not to maintain the fault under voltage.

This function is ensured by what is known as disconnection protection. Generally, it consists of a set of relays (homopolar voltage relays, vector jump

relays, etc.) and constitutes a relatively complex device [BRA 00]. Opening the circuit breaker at the terminal station disconnects the decentralized production units connected to this terminal even in the absence of a fault. Islanded operation is generally not allowed because it will lead to unacceptable frequency and voltage fluctuations. It should also be noted that the automatic changeover from the station supply (rapid restart) to another transformer supplied by another part of the HV network to ensure uninterrupted service in case of problems with the station supply, cannot adjust to the presence of the generators. Transient phenomena could appear, caused by voltage phase and frequency shifts between the generators and the new supply at the time of changeover. Such phenomena would provoke severe electrical and mechanical stresses, highly detrimental to the various pieces of equipment.

2.6.3.2.4. Neutral condition – ground faults

The power generation units are connected to the MV network through a transformer using star connection (generator side) and delta connection (network side), in such a way that the production group does not modify the homopolar current seen by the terminal station protection in case of line to ground fault. The presence of a production group does not interfere with the protection plan against ground faults. However, after opening the circuit breaker at the terminal station, the fault is maintained under voltage in neutral condition isolated by the power plant. Tripping of the latter should be ensured by the disconnection protection.

2.6.4. *Stability problems*

Stability, defined as the property of a system to stay in a state of equilibrium under normal conditions and to come back to an acceptable state of equilibrium following a disturbance in these conditions [KUN 97], is a major problem in electric power systems. It can be stated in different forms:

– the angular stability of synchronous machines connected to a network concerns their ability to keep running in synchronization with the network under normal operating conditions or following a disturbance. It is determined by the equilibrium of the electromagnetic and mechanical couples on the rotating mass of the groups. Any break in this equilibrium is transformed into oscillations of the rotors around their equilibrium position corresponding to the synchronous condition. These oscillations can entail loss of synchronism with the network and disconnection of certain machines. The following observations are made:

– the angular stability during minor disturbances accounts for the effect of normal fluctuations of low amplitudes of the electrical and mechanical quantities under synchronous operating condition of the network, due to load or generation

variations and to shunting. In this type of stability, the regulators which equip the generator and its driving machine play an important role,

– the transient stability examines the behavior after major disturbances such as short circuits. To control the protection the degree of severity of the disturbance beyond which coming back to synchronism is no longer guaranteed has to be determined (see Chapter 7),

– the voltage stability concerns the ability of the electrical system to maintain acceptable levels of voltage in the entire network during normal conditions as well as after weak or severe disturbances. This type of stability is determined by controlling the reactive power. It is considered to be the most disruptive problem in our networks as it can lead to voltage collapse (see Chapter 6),

– the frequency stability concerns the ability of the electrical system to maintain the frequency within the given limits following a break in the production/consumption balance. It is determined by the ability to restore this balance.

Until now stability problems affected only transmission networks while distribution networks were practically exempt from this problem due to their passive electrical circuits. However, with the insertion of a sizable volume of production in the distribution network, this situation will no longer be the same. The problems of angular stability, voltage stability and even frequency stability for operations in islanding conditions will have to be considered in future. In this regard it should be mentioned that the relatively long fault clearing time in distribution networks are not suited for maintaining the angular stability of the generation units. In addition, since it might be necessary not to disconnect the units systematically but to maintain them as far as possible in the network, the dissconnection protections have to be reviewed. Such a level of continuity of operation is observed when in cogeneration, the steam supply is critical for an industrial process [CIG 01].

2.6.5. *Influence on the voltage plan*

The presence of generators in the distribution network is definitely going to influence the voltage plan and the control of the regulation devices depending on the connecting method and the operating conditions. The effect of decentralized production on voltage regulation using compounding can mainly lead to a reduction of the voltage profiles in the terminals of a station and is certainly a problem to be examined along with the others. Decentralized production can generally be considered to be the cause of abnormal increase or decrease of voltage in the networks. In the future, centralized handling of the set values of voltage at the HV/MV substations as well as the supply of reactive power by the generators of decentralized generation, implementing the recent developments in

telecommunications and signal processing, could be the solution for voltage regulation. In addition, it might become essential to equip the HV/MV substations of future electrical networks with power electronics devices to control the reactive energy quickly. In the case of connection to the medium voltage network, the impedance of the network and the transformer of the HV/MV substation have an inductive character and the voltage amplitude in this case is influenced by the reactive power demand. The transformers of this station being at adjustable transformation ratio (transformers with adjustable on-load taps), serious incidents could occur due to lack of generation and reserves in the MV zone, inactive decentralized production for example.

In fact, any lack of generation is accompanied by a power demand across the transformer of the connecting station and to maintain the voltage in MV, transformer ratio has to be adapted. Routing the substitute electric power across the transformers of the connecting stations can lead to serious problems. Figure 2.9 shows a phasor diagram with the electrical quantities in question for a 20% impedance (network+transformer), adjusted to the nominal values of the transformer (S_N, U_N). It is clear from this diagram that there is a demand for additional reactive power on the network to ensure voltage maintenance. This may lead to a difficulty for the HV network to supply this increase (the generators being at the limit of their possibilities) and to a big accident resulting in a breakdown.

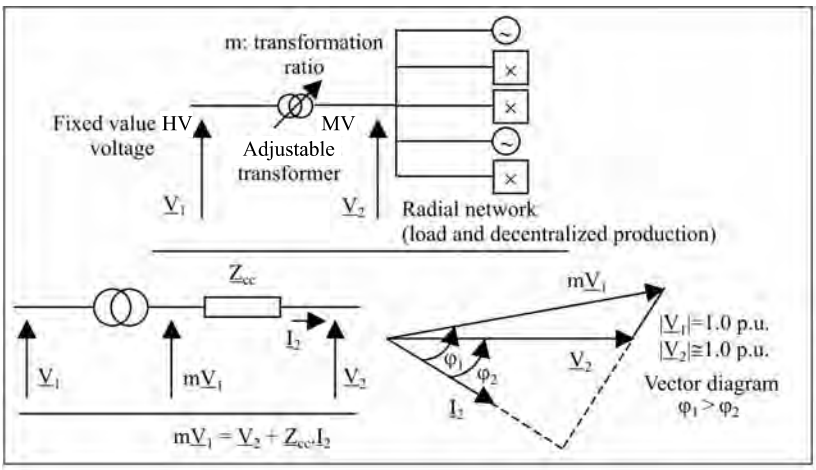

Figure 2.9. *Connection of decentralized production to the distribution network (MV), effects of supply from a substitute power*

The table below shows the behavior of such a system at different control taps of the transformer.

$\lvert \underline{V}_1 \rvert$	$m \lvert \underline{V}_1 \rvert$	$\lvert \underline{V}_2 \rvert$	$\cos\varphi_1$	Q_1 (reactive power required at the network)
1.0	1.0	0.93	0.887	0.462
1.0	1.05	0.96	0.879	0.500
1.0	1.10	1.006	0.872	0.539

Table 2.12. *Effects of transformer adjustment*

It has been observed that to recover 7.6% of the drop in voltage, the transformer ration has to be increased by 10% and that there is a 17% increase in the reactive power required.

There can be a significant reduction in power generation when factors other than power generation (for example, production of heat) guide the decentralized generation or when it is subjected to the vagaries of wind (wind energy production). Such a situation led to a complete blackout of the entire province of Utrecht in the Netherlands on June 23, 1997. This example is taken from a presentation by Professor R. Belmans from the Catholic University of Louvain in front of the AMPERE Commission. He has shown the need for a detailed study of the implications of integrating decentralized production on the functioning of the entire network.

2.6.6. *Impacts on transmission networks*

Other than the effects induced by production on the distribution networks, in matters related to exchanges between centralized and decentralized production, and reactive power management, the transmission networks will be subjected to the effects of the powerful cogeneration units and more of the offshore wind energy farms, for which many important projects are lined up. The intermittency in production using wind energy can cause significant unexpected power flows which can adversely affect the stability of the network [LUT 01]. Spinning reserves have to be kept ready to supply substitute power and the transmission lines need to have additional margins to allow for changes in the power flows. This is all the more worrying in an open market which is subjected to link congestion. Apart from this dynamic aspect it is important to evaluate from a static point of view the actual contribution of wind energy to a power generation system.

Belgium has carried out several studies to determine the effects of power generation using wind energy on the reliability index used commonly while planning power generation plants. These studies, using a statistical approach, help in determining an equivalent to wind power generation in conventional power generation according to the penetration level of the former. This equivalent is around 30% for the penetration levels expected. The above studies were carried out as a part of the "Knowledge of CO_2 emissions" project conducted by producers ELECTRABEL and SPE [RAI 01, RAI 02, MOR 01].

2.6.7. *Harmonic disturbances*

Apart from the effects on the amplitude of the voltage, it is necessary to examine the effects of decentralized production related to harmonic disturbances on the network that can affect the units connected and also the transmission systems of centralized remote control signals and tariff signals. Regarding electromagnetic compatibility, it is advisable to refer to the standards of the International Electrotechnical Commission, IEC Passive or active filters might be necessary to attenuate the disturbances [JUS 97].

It should be mentioned that the disturbances in the network depend on the short circuit power of the network at the point of connection (the weaker this power the greater the effect on the network) and also on the ratio X/R at the point of interconnection. During power output variations, the higher this ratio the lesser the effect on the network. The distribution networks to which the wind energy units are connected are characterized by R>X; voltage drops in these networks are mainly due to the circulation of active power and the disturbances that are due to wind power are quite significant. These disturbances, caused by variations in the wind velocity and the blades moving in front of the mast, should be limited to avoid flickering of the incandescent lamps; these flickerings are visible to the human eye in the frequency range of 2-20 Hz. This problem raises questions regarding installation of wind power units: the place of connection and the type of technology for the generator and the method of connecting it to the network. Connecting through an inverter can reduce voltage fluctuations substantially. Problems related to the quality of electric power supplied to users are discussed in Chapter 4.

2.7. New requirements in research and development

The evolution of European electrical systems, energy dependence and the new constraints due to the deregulation of the electricity market and environmental problems have given rise to new and numerous problems that can be solved only through sustained efforts in research and development both in the technical and

economic domains. The electrical industry is facing a new paradigm whose effects on the functioning and safety of electrical systems have yet to be analyzed. The hiatus between the purely anthropogenic conceptions of market laws and the realities of the physical world are unavoidable, particularly in the case of electrical energy with its specific characteristics that are bound by the laws of physics for their implementation. A Belgian study group from the Committee of the Academy for the Applications of Science (CAPAS) has very recently carried out an analysis to identify these hiatus. It has highlighted the visible and profound lack of knowledge on the functioning of the electrical systems that are going through a real change and the need to carry out research and development to find proper ways and means to resolve these issues. The entire analysis and results of this work team are given in the CAPAS report which can be referred to by the reader [CAP 06].

A lot of new equipment has to be developed to meet the various challenges, in particular, integrating the decentralized production in the distribution networks. Much of this new equipment will put into use the resources offered by power electronics. In this connection, it may be appropriate to mention that, currently, more than 50% of the electricity produced in the world is converted by power electronics devices and that European companies hold 40% of this important market. These companies are therefore in a position to face these new developments.

It would seem unduly confident to believe that we know all the requirements in research and development in a domain so complex and open. The suggestions given below are a personal vision of these requirements and results of the above mentioned study group; their only aim is to show the volume of work that remains to be done.

2.7.1. *Technical domain*

2.7.1.1. *Transmission network*

In the transmission network, extending the interconnection leads to increasingly vast and complex systems that pose specific problems related to controlling the production units and operating the networks.

Research work needs to be carried out on the following points:

– validation of dynamic models, mainly for slow power oscillations (<1 Hz);

– development of simulation and optimization algorithms for big systems;

– design and control of specific defense actions;

– phasor measurements synchronized through satellite on the entire interconnected network and improvement of the state acquisition techniques.

Amongst the investigation approaches with reference to the use of fast action electronics power controllers (FACTS) in the transmission networks, the following can be mentioned:

– optimized location in the network;

– concept of robust control algorithms;

– remote control with a high degree of automation;

– interactions between neighboring FACTS systems and with other control devices such as PSS (Power System Stabilizer).

The necessity of performing a thorough study of the impact of wind power production on the functioning of electrical systems, which has already been mentioned, should be recalled here.

In static studies, tools have to be developed to evaluate the contribution of inconstant sources such as wind energy to the planning of the power generation plants. Belgium has conducted studies based on the reliability indices commonly used in planning, as mentioned in section 2.6.6.

2.7.1.2. *Integrating decentralized production in distribution networks*

Problems related to integrating decentralized production in distribution networks open a vast field of applications and an important market for the development of new equipment such as the power electronics devices. Designing intelligent interfaces between decentralized production and the network is a promising domain which can be developed in the following directions:

– innovation in the design of converters and their control systems;

– systematic incorporation of the resources offered by modern telecommunications and data processing systems;

– new protection systems;

– automatic detection and clearing of faults;

– new structures for the distribution network.

Finally, mention should be made of the need for simulation tools to study dynamic behavior related to voltage and frequency stability, stability of power generation units and evaluation of harmonic disturbances, such as the flicker. To carry out these studies dynamic models of the new production facilities have to be

established, in particular, those of renewable energy sources as well as the ways to reduce a set of these units into an equivalent dynamic model. The models should represent every part of the system from the primary source to the connection to the network by including control and protection systems with different degrees of modeling based on the type of study to be performed.

It is probably the operation of the distribution networks that gives rise to so many and such varied questions:

– Which methodology should be adopted for the participation of decentralized production units in the ancillary services?

– How should the real time state acquisition be organized?

– How should the voltage of the distribution networks be handled?

– How should decentralized production be incorporated in the defense plans?

– Should decentralized production be regrouped locally in the form of micro networks or virtual power plants?

2.7.1.3. *Storage of electrical energy*

In the near future, storage of electrical energy is expected to play an important role in the management and operation of electric power systems. Different possibilities exist to investigate this subject:

– hydropower systems with two reservoirs also known as pumped storage units: they are characterized by an energy recovery efficiency of 75%, a natural limitation of available sites and a significant visual impact. They are meant for high volume storage with power capacities higher than 50 MW. They use synchronous machines which, during the pumping phase, act as motors similar to the loads that can absorb the excess production generated, from nuclear or wind power units, for example, and during the turbine phase behave as conventional synchronous generators;

– mechanical accumulation systems in the form of kinetic energy in flywheels or potential energy in compressed gas: these systems are proposed only for short duration storage for a few minutes for kinetic systems and 24 hours for compressed gas systems. Their strong point is their long life cycle. They are mainly considered voltage support devices for the network in case of quick power fluctuations;

– electrochemical accumulators: though expensive, this solution has the advantage of modularity and a high reaction speed. Lead acid batteries are those which are widely used nowadays. There are already a few dozen applications using batteries to compensate for the peak loads and to carry out specific operations. The largest one is a 10 MW capacity and 40 MWh energy system at Southern California Edison in Chino, USA. However, alternative solutions such as REDOX circulation-

based batteries are being developed. These are very promising because of their long life, low auto discharge and a possibility to withstand a full discharge. Their functioning is similar to that of the fuel cells i.e., they function as long as they have an electrolyte supply. These systems are likely to establish high capacity units such as the setting up of a 100 MWh project in the UK with a ground occupation of less than 0.5 ha [PRI 99]. The energy efficiency of the batteries is about 80%;

– supercapacities: energy is stored in direct current in the electrical field of these capacitances. Auto discharge of these at the rate of roughly 10% in 24 hours limits the storage duration. As in the case of electrochemical accumulators, they require power electronics for storing and recovering energy;

– superconducting magnetic coils: storing takes place in the form of magnetic energy. Power electronics systems are necessary to operate them. At the moment, these devices are very costly. Efficiency is high, around 90%, including losses due to cooling. In the long term, improvements are expected in supraconductivity at the temperature of liquid nitrogen. These systems are envisaged more as network management tools. Voltage stabilization and controlling voltage collapse can be achieved with the help of SMES (superconducting magnetic energy storage) [BUC 00]. Apart from being used as buffers with respect to the energy demand, the SMES can be of use in energy storage in the FACTS systems. To stabilize power swings in the transmission line 500 MW coils are under consideration;

– storing in hydrogen: hydrogen and oxygen are produced by the hydrolysis of water. The overall energy efficiency is about 60%, much lower than that of the electrochemical systems. Though very expensive, this system can in the long run be an economically justifiable alternative.

Table 2.12 compares the different systems based on the main characteristics.

	Hydro-power	Mechan.	Super-capacity	Supra-conduct. Mag.coils	Accu. P_b/P_bO_2	Accu. Redox-flow	Storing. in H_2
Efficiency	+	0	0	+	+	+	0
Auto discharge	+	--	-	+	0	+	+
Number of cycles	+	++	+	+	0	+	+
Full discharge	+	++	++	+	-	+	+
Environmental friendliness	0	++	++	+	-	0	++
Cost	++	+	0	--	0	+	--

++ = very good; + = good; 0 = medium; - = low to bad; -- = bad to very bad

Table 2.12. *Characteristics of electricity storage techniques*

To summarize, on a short-term basis lead acid batteries can be retained for capacities going up to a few tens of MW and hydropower systems with two reservoirs for higher capacities. On a medium term, REDOX accumulators are an interesting alternative and systems with hydrogen could be an economical solution on a long-term basis [AMP 00].

2.7.2. *Economics*

Until recently, electric power systems were developed in accordance with rules (called the regulation methods) and followed a business pattern consisting of companies with a vertical integration of production, transmission and distribution activities. In this context neither the electricity market structure nor its architecture was a source of concern. *Market architecture* includes organizational aspects: organizing the electricity market, organizations involved, rules, contracts etc. to ensure continuity and survivability while satisfying the economic needs of the stake holders (producers, transporters and consumers), whereas *market structure* involves physical and industrial aspects, number and size of the operators, degree of concentration of industries, capacities of the production facilities to meet the demands. Transition towards a competitive market on a European scale constitutes a major political and economic challenge not properly understood by the different actors and therefore poses numerous problems in the economic domain [CAP 06].

The main danger is that in the absence of stable and reliable economic signals during this transition phase the investments suffer due to a wait and see policy; as a result, ensuring a reliable and economically competitive operation of the big but still segmented European network with a lack of coherence and uniformity in the rules which are essentially still national, becomes difficult. There are innumerable problems to tackle and the list below is by no means exhaustive: development of new transmission facilities, methods of allocating the existing capacities, deployment of ancillary services, reserve capacities in generation, decision to invest in generation and transmission, network congestion management, economically unjustified exorbitant costs, dangers of a break in the supply, role of national controllers, the possibility of having one European controller, market architecture specific to decentralized production. It is futile to believe, as some people do, that the big European market is going to direct itself spontaneously towards an adequate structure having its own rules.

2.8. Conclusion: a challenge and an opportunity for development for the electrical sector

The main challenge imposed on the electrical sector in Europe is to find a solution to the problems arising from the development of the electric networks and the new constraints and maintaining at the same time, a trouble-free uninterrupted quality power supply to citizens and companies. Integration problems in the so-called decentralized production networks are particularly important and they are felt more acutely in the distribution networks which are not designed to receive such production. It is essential that research and development anticipate the effects of the mutation experienced by the electrical sector and help in reducing the disadvantages and increasing the advantages of this mutation. This challenge is also a boon for European companies because of the importance of the market that follows and the leadership position that it offers to these companies.

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Chapter 3

Planning Methods for Generation and Transmission of Electrical Energy

3.1. Introduction

Following widespread deregulation of the electrical sector, generation and transmission network planning is in a transition phase with the emergence of new thinking resulting in new methods. While it is a bit premature to describe the above planning in great detail, it is probably the right moment to explain the objectives behind this planning with special reference to the new challenges that come up and the approach to deal with them.

This chapter will first describe how the planning of generation facilities and the transmission network works in a regulated system by highlighting the objectives and the criteria to be respected. It will then analyze the changes brought about by the deregulation of the electrical sector and the technological evolutions mainly at the level of generation of electricity. All these changes whether they are economic, organizational, technological or societal, modify the planning framework and should therefore be taken into account in one way or another.

Since the planning methods are still in the developmental stage, they will not be discussed in detail. Moreover, the related software is mainly developed by the different utilities and is not yet freely available in the market. Therefore, the explanations will focus more on reasoning, objectives and criteria rather than on details regarding flow charts and mathematical processes.

Chapter written by Jean-Marie DELINCÉ.

3.1.1. *Generation functions*

To plan a function, it is first necessary to have a clear idea of the objective and the framework of the plan. In the regulated system, until now the main objective of electrical energy generation has been to meet the electrical requirements of a country or a well defined geographical territory attributed to a given utility in the most economical manner. This corresponds to the responsibility of supplying electrical energy. To do this it is necessary to estimate the evolution in electricity consumption over sufficiently long periods, keeping in mind the time required to construct new generation units. This should be followed by an estimate of the developments in generation facilities as well as of the fuels used. All this planning is strongly connected to the energy policy of a country and is thus influenced by the choices of the political powers.

It is also necessary to be aware of the important role played by the type of power generation. Thus, if the generation is essentially thermal, the main objective is to ensure covering the load capacity considering that the fuel reserves are normally sufficient. Whereas in the case of hydropower generation plants, the problem has to be analyzed from the energy angle, given the limited water reserves, covering the total electrical energy consumption down through the year can become a difficult task.

3.1.2. *Functions of a transmission network*

A transmission network has totally different functions but nevertheless is strongly influenced by choices at the generation level. In fact, the main purpose of the transmission network is to ensure reliable uninterrupted supply of electrical energy to the consumers.

As the power plants are subjected to outages and incidents, the network has come into the picture to establish connections between the units and to ensure backup operation. Moreover, since the scale effect induced the generation of larger and larger units for several decades, the network has taken up the transmission to route the high volume energy generation towards a particular location closer to the customers who are, in general, spread over a given territory.

Along with the scale effect of generation, there is also the possibility of operating energy sources like big hydraulic sites or lignite deposits delocalized with respect to consumption.

Later, this network has taken up functions that established interconnections between neighboring systems that have led to the large entities that we know today,

such as the Western European interconnected grid (the UCTE grid), the Scandinavian grid (NORDEL), the North American grids, etc. These interconnections have helped in increasing the security of supply by pooling the available power reserves and by letting the power plants grow bigger and bigger. In addition, the different countries, utilities and even systems have the opportunity to have common investments in generation. Finally these interconnections create the possibility to achieve synergies between different systems and to benefit from the different characteristics specific to each generation system such as thermal generation on the one hand and hydropower on the other. For example, the creation of the European interconnected grid has eliminated wastage in hydropower generation through diversion. In fact when a system cannot consume all the energy produced by a hydraulic plant (as in the case of melting of snow in the Alpine region), the grid gives it the possibility of selling excess energy to other systems using thermal power where the generation groups can be reduced or even stopped to allow importation of electricity.

As a result of the deregulation of the electrical sector, the transmission network should also fulfill its role as a facilitator of the electricity market and help actors in the market to carry out their transactions in the best possible way. In this regard, it should be realized that the network fulfills this function only for commercial transactions, which ultimately gives rise to physical fluxes. One of the major difficulties of the new environment is to clearly distinguish between the market with all its commercial transactions that give rise to financial fluxes and the electrical system with committed generation units, the transmission network and the connected clients that cause physical fluxes in the network. The market has an impact on the network only when it causes physical fluxes.

An interesting way to express the change in the function of the transmission network in the deregulated sector is to talk of its vertical and horizontal functions. Under a regulated system, the design of the network had helped in the development of the vertical function, i.e., supplying loads connected to lower voltage levels from a majority of the generation machines connected to the higher levels of voltage. Due to deregulation of the markets, the accent is more on the horizontal function of the interconnection network at the highest voltage level. This should enable a transaction between any nodes of the interconnected network beyond political boundaries. This is clearly what every actor of the market wishes.

3.2. Planning in integrated systems and in a regulated market

In order to be clear, it is perhaps useful to define the regulated market concept. In a regulated market, generation, transmission and distribution of the electrical energy are attributed for a very long period to one or several utilities. Through supervision

of a controlling agency set up by the government, the utilities, which may be public or private, are guaranteed adequate compensation for investments and payments towards operation and maintenance of the electrical system through tariffs applied to the electrical energy. In return, these companies have an obligation to supply electricity to all clients. Most of the time, they are integrated vertically, that is, they cover generation, transmission and distribution. Generally, a separation, if it exists, is between generation-transmission and distribution.

Planning within this framework is carried out in two stages: first, planning of generation facilities considering the long delays in construction and then planning of the transmission network, which depends on the location of the power plants.

3.2.1. *Generation planning*

Generation planning in general involves planning the centralized generation facilities having a reasonable size and with an operation controlled by centralized dispatching. All small generation units such as micro-hydro power plants, small cogeneration units, diesel units, isolated wind power units, etc. are not included in the planning in a detailed manner. This has to be analyzed on the basis of the size of the system under review. For a country such as France, not including a 0.5 MW wind power unit does not affect the planning, whereas for an isolated Greek island it may be important.

The generation planning process of a system should have well defined basic hypotheses. The public authorities should therefore specify their energy policy options:

– Will generation facilities situated exclusively in the country cover the total electricity consumption? Otherwise how much of the need can be covered by imports from other countries?

– What are the authorized primary energy vectors? Is there a willingness to diversify the primary energy sources and vectors?

An important element to fix is the planning study timescale. In fact to make correct economic choices it is essential that the duration of the study takes into account the construction time of the new units and the duration of their operation. Thus, if it takes 10 years to construct a generation unit whose operating period is 20 years, the generation plan should have an outlook of at least 20 years.

3.2.1.1. *Evolution of the electrical energy requirement*

The electrical energy requirement is the first step in planning. This exercise is not easy as it has to stretch over a relatively long timescale. The development pattern of the requirement gives the first indication.

In the case of a thermal generation plant, the peak demand is a primary factor. However, to carry out a realistic forecast of the consumption trend, it is advisable to extrapolate the annual energy consumption and then derive a peak load from the average peak utilization. In fact an annual peak load is strongly influenced by chance occurrences such as a cold weather spell, a particularly cloudy day, etc. Results of statistical regressions carried out on these points are not very coherent. On the other hand working on the annual energies smoothes out random phenomena and more coherent results are obtained.

This statistical evolution of the requirement does not take into account all the underlying trends and causes significant errors when there is a trend break. Following the various oil crises of the 1970s there was a clear break in the electricity consumption trend bringing down the annual growth rate from around 7% to 1% in most Western European countries. The reverse trend is also possible in a country with a substantial economic growth. It is therefore essential that the study on the evolution of the requirement is based on economic trends at the level of the geographical entity under consideration.

In spite of these studies it is better not to focus on one single rate of increase given for the entire projected period. One possibility is to carry out the studies with different hypotheses of evolution while still staying within realistic values and to determine the possible results with respect to the retained rates.

Independent of the evolution of the total quantity of electrical energy consumed, the load curve should also be studied. This curve evolves throughout the year and presents characteristics typical to the system studied. Thus when a load duration curve is established (all the energies consumed every quarter of an hour and classified in descending order over the year) it can be observed that the peak load occurs only during a given quarter of an hour but for the majority of time the power requirement is much lower. Therefore, the minimum value of the load curve throughout the year is between 30 and 50% of the peak consumption.

In an electrical system with a strong penetration of electrical storage heating, there is an increase in consumption during winter nights and intermediate seasons. This influences the load duration curve by increasing the minimum load and making the curve flatter. Similarly, for countries such as Germany and France, large scale air conditioning of offices and residences increases the consumption in summer with

the possibility that in certain sub-networks the peak load occurs in summer during very hot periods whereas in these countries the peak load is normally during cold and dull winter months.

3.2.1.2. *Change in fuel prices*

Another important parameter in generation planning is the forecast of the evolution of fuel particularly in a predominantly thermal electrical system. This evolution is difficult to foresee particularly for highly volatile fuels such as petroleum and natural gas. That is why it is safer to envisage different scenarios with high and low assumptions of price evolution for highly volatile fuels.

3.2.1.3. *Evolution of generation units*

The cost of electric power generation consists of three big items:

– Investment in the unit. Depending on the type of plant, this item varies substantially. Two extreme cases are: nuclear with a very high investment cost (about 2,500 Euro/kW installed) on the one hand and the combined cycle gas turbine (CCGT) where the investment is very low (about 500 Euro/kW installed). The investment in the generation unit should take into account the costs related to connection to the network. The more the capacity of the unit, the higher the connection voltage and the higher the costs. For this, as a first approximation, the standard costs have to be envisaged according to the size of the unit.

– The fuel cost to be matched to the kWh produced: the efficiency of the group is thus incorporated. This efficiency can vary about 30% for the nuclear plants to a value higher than 50% for the latest CCGT groups.

– The cost of operation which includes the cost of personnel who run the unit as well as maintenance costs. This item should also include all payable taxes and in particular, deductions made as a part of the environmental policy: tax on CO_2 emissions, waste heat discharge, waste water discharge.

Judicious choices to build new units can be made only after thoroughly analyzing all the possibilities offered by the present and future markets in the field of generation of electricity by taking into account the three items that form the cost of generation. Along with these economic aspects it is necessary to have a clear idea of the technical possibilities of the different generation facilities: evacuation of the residual heat, rampup and rampdown rates, stopping and restarting characteristics and constraints, minimum stable generation, heat rate variation on the basis of the generation level, reliability, availability (based on the requirements of maintenance periods and overhauling), etc. These different technical and economic aspects enable us to define the most appropriate classes of units to cover the basic load (high use of

the units, about 8,000 h/year), units of medium utilization (about 5,000 h/year) and peak load and emergency power plants (used for less than 1,000 h/year).

In addition, it is equally necessary to understand clearly other phenomena that can influence generation requirements. Thus, promoting renewable energies and/or cogeneration can lead to installing in the planning timescale a series of small units that can reduce the need for large centralized generation. Similarly technological developments can disturb historical trends. A large-scale installation of fuel cells could also in the end reduce the need for centralized generation. As long as these trends are not confirmed or reversed, the only solution that seems feasible consists of having different scenarios where extreme but realistic hypotheses for the envisaged trends are retained.

In an electrical system with many different types of machines the level of participation of the different units during peak load has to be defined properly. The windmills participate only in a limited manner in the peak load: participation of on-shore wind energy units is around 25 to 30% whereas it is 35 to 40% for off-shore units. Similarly, for cogeneration units it is necessary to keep in mind that their generation is driven by an industrial process. The same is the case with hydropower groups, at least the run-of-river power plants whose peak load participation can be clearly lower than their nominal capacity. Considering the significant share of this type of generation and the unpredictability of their generation it is essential to calculate the necessary reserve power. This can be taken into account by lower availability than for thermal plants.

In a predominantly hydropower system, the generation plant planner should analyze his plant not on the basis of peak load but according to the annual energy. He has to assume the hydropower conditions of the annual energy generation of every hydropower power plant.

3.2.1.4. *Generation planning*

Once all these data and hypotheses are collected, planning new generation facilities to cover the fixed target has to be considered. The electrical network is not included in this planning. This boils down to a single electrical node.

Considering the uncertainties discussed above, it is not possible to retain just one scenario. Therefore, different hypotheses have to be combined to derive a series of scenarios: evolution of electricity consumption, evolution of fuel prices and evolution of the need for centralized generation.

In the case of a predominantly thermal power system, it was already stated that the peak load coverage has to be planned. On the basis of the peak loads foreseen for

every year of the planning period under consideration, it is necessary to analyze how the peak load is covered by the existing generation facilities by taking into account the decommissionings that can be decided during the study timescale. Every existing group has to be included with its reliability and availability.

To determine the annual shortfall in power, different methods of varying complexity exist. The first consists of simply fixing the system reserve margin with respect to the peak load and from there deriving the necessary capacity. Other methods use a probabilistic criterion. Basically there are three: the probability of not covering the peak load either at that specific moment or right through the year using more or less detailed models; the expected value of the lost load expressed either in terms of the number of days or number of hours per year when there will be a shortfall in generation; finally, the expected value of unsupplied energy which includes the number of hours of generation failure and also the extent of power failure.

All these probabilistic methods should be based on more or less detailed load models. Thus, the year can only be divided into four periods with a load curve for working days and for holidays or it can be represented by a detailed hourly load curve for each week. To have realistic results it is better to use only the statistics on the random availability of the groups and to simulate a planning of the programmed non-availability of the generating units (overhauls and programmed stops). The probabilistic methods are based on analytical methods which in turn are based on binomial distribution or on drawing lots of a large number of possible situations on the basis of the statistics on the availability of the groups using the Monte Carlo method and from there deriving the mean values and standard deviations. This type of simulation can face difficulties if there are powerful pumped-storage power plants of high storage capacity. Nevertheless they have to be correctly represented to optimize the economic coverage of the load.

Special attention must also be paid to generation overcapacity periods. When a generation system consists of many units with few adjustment possibilities and whose generation is not regulated by the electricity demand, there can be low load periods when adjusting the generation against the demand becomes difficult resulting in excess generation. This phenomenon is common during low demand in summer in systems where the number of nuclear units is significant or in countries where the decentralized generation share (cogeneration, wind energy, etc.) is so high that the generation stays committed even when the load is low. It is necessary to estimate the volume of these overcapacity periods and find a way to deal with this surplus generation by storage in the pumped-storage plants, exchange with countries using hydropower generation, other ways of reducing the generation, etc.

Once the shortfall of power is determined year by year on the study timescale, the possibilities to take care of this shortfall should be analyzed using new generation groups. A judicious choice requires considering the market realities, the energy policy of the country and the possible sites. Simulating the generation system's projected operation enables us to calculate the cost of operation of this system on the study timescale based on different hypotheses of evolution of the load, fuel prices, investment costs of the possible various new units (size, type, fuel) in conjunction with the existing power plants. It is therefore necessary to simulate a unit commitment of the generation system according to the availability and the economic order of the power plants. A reference scenario can be determined based on the results of the different scenarios and the choice criteria retained. However, in the event of the study timescale being long it may be useful to look into the decisions that should be taken immediately and those that can be delayed. This element is very important because we can also look into the scenarios that offer maximum flexibility by enabling us to take the most appropriate decisions at a time when the information is least affected by uncertainties. It is possible to find an optimum solution for a set of hypotheses retained. However, the assumptions made are always based on more or less precise forecasts. To get an idea of the quality of the solutions obtained a sensitivity study can be carried out. Another way is to establish different sets of highly contradicting hypotheses, to determine the optimum solutions for each of them and then to look for the deoptimization introduced by a non-optimal solution with respect to the retained hypotheses. This amounts to retaining the solution which offers the lowest deoptimization taking into account the realistic variation spectrum of the hypotheses. Different mathematical methods of varying sophistication are used in this type of research for robustness and/or maximum flexibility with respect to possible evolutions.

3.2.2. *Transmission network planning*

Transmission network planning in a regulated market can be performed only after establishing the generation planning and knowing the generation system (with the existing and new power plants) which will be available for every year of the study timescale. In conventional methods, network planning is done at peak load which, depending on the systems, can occur at different times. In the countries of Northern Europe, peak load is generally during cold and dull (cloudy sky) winter months, whereas in California it is during the warm spells in summer with intensive operation of air conditioners.

3.2.2.1. *Load vectors*

In order to plan a network it is not enough to just have a peak load to be covered as in the case of generation planning, but it is necessary to have an exact

representation of the loads at every node of the network to be studied at the time of the peak. Ideally this load vector should be synchronous, i.e., at every node the load at the time of the peak load and not the maximum recorded load should be given. If actual readings are not available, certain assumptions have to be made on the presence of the loads at the peak depending on the knowledge of the type of load. If only the overall peak load and the maximum load per node are available, then the sum of the maximum loads has to be calculated and brought back to the recorded peak load to finally derive a synchronizing factor to apply to every maximum load at every node.

This load vector has to be prepared for every year of the study outlook. The peak load of the system is given by the assumptions made at the time of planning the generation facilities. In addition, it is necessary to make assumptions on the evolution of the loads at the different nodes of the network. If the growth rate of every node of the network is available it is possible to extrapolate the maximum loads year by year. To bring the sum of the maximum loads to the peak load retained for the year under review the synchronizing factors have to be used again. It is not necessary to look for high accuracy depending on the type of planning study carried out. If it is a medium term planning study to determine the major developments in the interconnecting network, it is not necessary to envisage the evolution of every particular node of the network: in fact this network is mainly influenced by the location of the generation facilities and the high load concentrations. It would be sufficient to have the general evolution trends per region and make plausible assumptions on the differential assumptions between regions. On the other hand, if the planning concerns a local network, it is necessary to have a detailed representation of the loads and their node by node evolution.

In the load representation, the reactive part should definitely not be forgotten. Normally there are not many indications on the reactive behavior of the loads and a very simple assumption is made to keep the $\cos\varphi$ constant, knowing very well that this assumption is false. In fact it is sufficient to analyze the values in winter when the loads are mainly resistive and the $\cos\varphi$ is high, whereas in summer, when air conditioning is common, the loads show lower $\cos\varphi$.

3.2.2.2. *Electrical and topological network data*

Calculating the load flow requires an electrical and topological databank of all the elements in the network. From the electrical point of view, its resistance, inductance and capacitance have to be known. In the case of transformers it is essential to know the transformation ratio and the adjustment range under load at the different taps. In addition, the nominal capacity of every element should be known to be able to apply the criteria. It is then necessary to carry out calculations keeping in mind the manner in which the elements are connected between themselves and

even more so the connection of the elements on the different busbars in the substations operated with separate busbars (topology of the substations).

For every substation it is necessary to know the short circuit power for which it was designed and the interrupting capacity of all the circuit breakers in the network.

In addition to this data on the network, data related to the generation machines such as their nominal power, transient and subtransient inductances and working ranges in the active power-reactive power curve as a function of the voltage (capability curves). If the calculations on transient and static stability have to be carried out, then the volume of data necessary would be much greater.

This data is generally available for the existing elements. As a part of the studies on network development, some new elements have to be introduced for which data is not readily available. The usual method of integrating this data consists of having a catalog of standard values for unit elements: transformers of known nominal power, values per unit length of the impedances of overhead and underground links. These values are then taken for studies keeping in mind the estimated lengths of new links to be added.

3.2.2.3. *Planning criteria*

The criteria to be respected should be fixed before starting to plan the networks. These criteria help in approaching the reliability and the desired availability of the networks. Essentially, the criteria relate to the thermal design of the network, to the voltage stability of the system, to the static and dynamic stability of the power generation groups. In addition, it is necessary to verify that the short circuit powers at the different nodes do not exceed the capacities of the units.

Traditionally, the N-1 criterion is the most commonly used basic criterion in thermal design. This means that the network has to be designed in such a way that the loss of any element of the network does not in any way overload any other element in the network and at the time of peak load. Normally the network elements under consideration are all electrical links in the topological sense of the term; they are limited by the circuit breakers activated by the protection and form links between two electrical nodes: lines, cables and transformers. The busbars are not normally considered part of the elements of the network whose loss should be supported without any overload. Certain countries wish to take positive action against power transmission tower contingencies on the overhead lines and also study the loss of two or more three-phase circuits in the same overhead line. Certain variations of this criterion are also possible when actions have to be taken at the time of loss of a network element before analyzing the consequences: thus, it is possible to accept and simulate the operation of certain protections (special protection

schemes) or certain automatic controls that enable us to limit the consequences of the loss of a given element. These examples show that to compare different network planning methods, in addition to knowing that the (N-1) criterion is used, the detailed way in which it is used should also be analyzed. Everything finally amounts to determining the limits of network development. In fact, developing a network that can resist a very unlikely contingency is expensive. If a particular event is unlikely to occur it is better to envisage defense measures (load shedding, redispatching generation facilities, etc.) to face it rather than invest in additional facilities.

Considering the low availability level of the generation groups as compared to the network elements, in addition to the N-1 criterion a second N-2 criterion is also applied to the generation groups; according to this criterion, loss of a generation group along with any other network element should be analyzed at peak load. Normally for such contingencies limited overloads of 110% of the nominal power of the equipment are accepted.

The problem of voltage stability of an electrical system is also complex due to the fact that the load flow calculations do not converge just before voltage collapse. As a result, the traditional calculation methods are incapable of simulating correctly the voltage collapse. Nowadays, simulation models for voltage collapse exist and they can calculate the safety margin with reference to the collapse but since they are still highly computer intensive, they are used only to complete the planning process in verifying special critical situations. To overcome this difficulty, the traditional method fixes high and low voltage limits at every node of the network and makes sure that they are not exceeded for every contingency studied in N-1 and N-2 (in conjunction with the generation groups).

The static stability of the groups should be studied in relation to the characteristics of the alternators, their control, the step-up transformers and the connection to the network. Situations relating to the contingency should also be considered where the impedance of the alternator connection to the network can vary strongly and influence the static stability of the group in a decisive manner.

Regarding the dynamic stability of the group, the operating time of the network protections should be fixed and the capacity of the groups to resist three-phase faults at the terminals without disconnecting and resulting in tripping should be analyzed. In conventional calculations only the time for clearing the fault at the first stage of the protections is retained without provision for protection failure. In a well protected network this time for clearing a three face fault is about 150 msec and if the protection failure is included it increases to 300 to 350 msec; most of the groups cannot sustain such fault clearing times.

Short circuit power calculations are generally carried out for three-phase power and the results are available in the load flow calculation programs. With these results, it is necessary to ensure that at every node the calculated values do not exceed the design values of the elements and, in particular, the disconnecting capacity of the circuit breakers. It may be worthwhile studying the different network and generation plant topologies.

Regarding the single-phase short circuit power, its value is determined by the way the network is grounded. In high and very high voltage networks the grounding method is exclusively direct. However, the number of groundings should not be too high as this might lead to a single-phase short circuit current higher than the three-phase value. In such a case, care has to be taken that the network elements are properly designed to handle these values. Moreover, the number of groundings should be sufficient to ensure an efficient grounding in all the network configurations under operation. This explains why calculating the single-phase short circuit power at every node of the network is carried out, though less frequently than the power flow calculations, after verifying that the ratio between the single-phase and three-phase Scc is between 1 and 0.5.

3.2.2.4. *Calculation methods*

In order to carry out studies on thermal design and voltage stability of the system, calculations are made using load flow calculation programs; this type of calculation can be performed in two different ways: for direct current and for alternating current. The direct current methods are faster compared to the alternating current methods which involve finding a solution through successive iterations given the coupling of the differential equations in active power – electrical angle and those in reactive power – voltage. In addition, these alternating current methods can cause convergence problems during strained situations in the network. On the other hand, the direct current methods are inconvenient as they do not take into account the reactive state of the network and they only allow the thermal design. It may be interesting to carry out an initial set of studies in direct current to perform a rapid selection of the network reinforcements to be analyzed. Once this is done, the interesting results can then be examined with the help of an alternating current model which enables us to solve voltage problems.

Most load flow calculation programs also give the values of the three-phase short circuit power at every node of the network studied. For single-phase short circuit power normally an appropriate calculation program is necessary. The major problem in this type of calculation is the access to all the data as per the Fortescue components (symmetrical components): direct, inverse and homopolar. Mainly it is necessary to do away with all the transformer neutral groundings as well as the homopolar values of all the links. These values are particularly difficult to determine

for overhead lines with several circuits in parallel due to the electromagnetic coupling between the different circuits.

For calculating the voltage stability there are programs which are capable of studying the margin at the time of voltage collapse of a network. The difficulty is to define the acceptable criteria. This notion of collapse margin, though it enables a relative classification of a series of situations of the network, does not enable specifying the acceptable and unacceptable situations.

The static and dynamic stabilities of power generation units require detailed information on the electrical characteristics of the alternators as well as on the voltage and power regulations of the units. This data is then processed with the help of specific programs which model the behavior of the units in the time range from milliseconds to a second. From these simulations it is possible to derive conditions under which the machines lose stability as well as the fault clearing time for a three-phase fault at the machine terminals.

3.2.2.5. *Planning process*

Any network study should start from the definition of the load vector and the matched power generation system. There is no major difficulty in going about the planning of the integrated structure in this way. Once the generation system is fixed, network planning consists of verifying the extent of response of the network to all the criteria considered at the peak load. When the network does not respond to the criteria, network reinforcement solutions have to be found to make it respond in the most economical way possible. It is here that the expertise of the planners comes into effect. In fact, there are no scientific or mathematical methods of finding solutions. An exhaustive study of all possible network reinforcements leads to a combinatorial explosion of variants. At this stage it is not possible to evaluate in detail all the solutions imagined. The planner chooses amongst the variants on the basis of the cost scales of the new elements of the network. Ideally, these cost scales should represent the average cost of realization of these reinforcements at the time of requirement.

Furthermore, it is impossible to respond to all the criteria at the same time. That is why it is judicious to solve the thermal overloads in the first place followed by tackling the problem of voltage stability, then studying the cases where the three-phase power is too high and finally taking up the study of the stability of the groups. Nevertheless, all these problems are not completely independent of each other and a certain looping of the problems and their solutions is necessary to arrive at a totally optimal solution.

Normally, thermal overload problems can be solved by reinforcing the network using new connections or new transformers. If the problems are due to improper flux distributions on the more or less parallel connections, a rebalancing of the fluxes has to be attempted. This can be obtained through changes in the topology on the busbars at important nodes. In extreme cases inserting induction coils or phase shifting transformers may prove necessary. When the network has both overhead and underground connections at the same time, it may be difficult to find solutions given the significant impedance difference per unit length between these two types of connections. It is then necessary to find ways to avoid parallel operation of the overhead and underground connections.

Voltage problems can also be solved using new connections or new transformers. Nevertheless, in many cases this type of problem can be solved by installing capacitor banks as close as possible to the loads having a low $\cos\varphi$. In more difficult cases installing a reactive energy compensation system of the power electronics type (static var compensator (SVC)) could be useful.

The high value of short circuit powers generally results from a dense meshing of the network. In case it is not possible or it is too expensive to increase the capacity of the equipment to resist the high short circuit power, attempts have to be made to unmesh the networks. From an electrical point of view, this can sometimes be obtained by choosing a layout that would increase the electrical distance between the sources. Often the only solution is to unmesh the networks and create separate sub-networks. Normally this amounts to installing additional transformers at the high voltage level.

When the groups are not statically stable, two levels of remedy are possible: the impedance at the terminals of the group can be reduced by strengthening the connection between the group and the network. Considering its cost, this solution is not always possible. Sometimes it is possible to intervene at the control level of the generation groups and improve the stability through appropriate sophistication and parameterization.

The dynamic stability of the groups can be improved by taking action at the network protection level and by clearing the faults in a time lower than the critical time of the machines. However, even here there are limits, particularly if the fault clearing time has to be guaranteed even when there is a protection or a circuit breaker failure. Another method is to foresee sophisticated controls at the level of the machine controls through a judicious choice of parameters. Even this solution is not without limits, particularly for small power machines where the control costs become an important item.

Since the life of a network is quite substantial and the return on investments takes a long time, it is wise to carry out network planning studies over a sufficiently long time, about 10 to 15 years. These studies enable us to establish a structure and framework of the general network and should be done without entering into too many details. Thus, the necessary reinforcements and detailed solutions for networks of lower voltage can also be looked into even in a shorter time frame. Nevertheless, the suggested short time reinforcements form a part of a long-term vision and will therefore still be of interest.

With peak load planning, only one operating point of an electrical system is studied in detail. Furthermore, this operating point is purely theoretical and does not arise in practice: the committed generation plant is different, the network topology is not complete due to outages for maintenance or works or due to contingencies, and the consumption load is not at its maximum. The constraints that arise in the operation of the electrical power system are most of the time due to outages of network components and due to a different commitment of the power plants. That is why it can be useful to study in detail another operating point of the system with low consumption load but where certain generation plant configurations and certain particularly constraining outages are taken into account. Normally, for these operating points, suitable criteria should be fixed to analyze the situations. A regional electrical study has to be carried out to see the impact of the absence of the most important generation unit in a complete network and under all simple contingencies. In the case of a network of the highest voltage, it is also possible to study the impact of the outage of every network component in a healthy network and during all simple contingencies. For this analysis changing the commitment of the available power plants can be accepted.

As all these studies are highly time and resource intensive the general tendency is to limit the number of operating points and the variants studied. The only way out is to use automatic methods generating a large number of operating points and to use the results obtained from statistical analyses. These methods will be dealt with later in this chapter.

3.2.2.6. *Planning international interconnections*

Planning international interconnections is based on the savings to be achieved on the basis of synergy between systems. These savings are at the level of load synchronism and economies of scale with respect to generation units that are too powerful for an isolated system but are possible when two or more systems are involved. They are also generated by pooling up the running or cold reserves in the generation plants of two or more interconnected systems.

To perform this type of economic research it is better to reduce the network of every system to a limited number of nodes and to simulate many operating points of the two systems to be interconnected by simulating as best as possible the generation systems and the loads to be fed on both sides of the proposed interconnection. It is then possible to estimate the required transfers between systems to optimize the operation of the two generation systems taken as a whole. From there a realizable saving per interconnection can be derived with reference to a separate operation of the two generation systems and thus the economic interest in carrying out the interconnection or not.

3.3. Generation planning in a deregulated market

In an open market all the conventional activities that go with the electrical sector are split into various activities: generation, transmission network management, management of distribution networks and supply. Generation and supply are totally deregulated and are therefore controlled by market laws, i.e., by the laws of supply and demand. On the other hand, network management activities cannot be deregulated as it is not possible to create competition in these areas and thus they are a natural monopoly.

To prevent the market from becoming totally anarchic the political authorities retain certain rights within the framework of power generation. Certain countries have a development plan for the generation system and organize competitions through tenders for the new generation facilities. Others give more freedom to the producers retaining just the basic traditional rights of giving licenses to build and operate power plants as with any other industry. Sometimes the government issues an indicative generation plan defining the energy policy: needs in terms of new generation facilities, types of fuel to be used in power generation with defined goals for distributed power generation, renewable energy sources, etc.

However, since the generation is governed by market laws, investors and users of generation facilities adopt their reasoning based on economics. They have to calculate their generation costs, market share and returns to calculate the profitability of their activities or the return on investments. In this evaluation a major role is played by the organization of the electricity market. In fact, if the market is exclusively organized on the basis of a spot market, the sale price is fixed for every hour according to the supply and demand equilibrium at that particular hour. In such a case the producers have to face significant uncertainties regarding their returns. On the other hand, if the market is based on bilateral transactions and/or on a market that allows long-term transactions (futures, forwards, etc.), the producers can obtain a client portfolio and be sure, at least in the short term, of their returns.

Given this data, the manufacturers opt for investments with minimum risk. This explains the current exclusive development in the combined cycle (CCGT) gas fired power plants. These highly efficient units (recent units exceed 50%) can be built quickly (the normal time frame is 24 months) at a relatively low investment cost, can be operated with fewer people and use a fuel which, though expensive, is widely found in European countries at least. In the absence of strong political will (influencing the laws of the market), investments in other generation facilities are not going to be easy. Thus, nuclear technology has almost been abandoned in all European countries given its investment cost and strong opposition from a large percentage of the population. Similarly, coal-fired plants are also decreasing in number due to their low efficiency, high cost of environmental protection and the need to have more operating personnel.

In Europe, as part of the sustainable development, quality cogeneration and renewable energies are given importance. However, the potential for cogeneration is limited by economic considerations of profitability of the various projects. There is stiff competition between large CCGT type units and small cogeneration projects. Similarly, the profitability of projects using renewable energies can only be guaranteed by subsidy systems. One of these systems is the introduction of green certificates which force a producer to have a combination of generation facilities with a fixed share from renewable energy sources. This system enables a producer who does not himself own these facilities to reserve them from another producer who might have a surplus of these facilities; this is achieved through a tradable permit scheme. Technologies that can be included in renewable energies are: hydropower, wind power and photovoltaic power. Europe's hydropower capacity is already fully utilized and as such no new major capacities can be expected. Photovoltaic power does not show much sign of development for the near future. That leaves only wind power that can be developed in a significant manner in the years to come. However, high power units will be installed off-shore facing the coasts in huge farms that are unthinkable on-shore anyway in European countries where the population density is quite high.

Another development that needs a close follow-up in the years to come is that of distributed generation as opposed to high power centralized generation. In fact, advances in technology have made it possible for small units to be installed almost everywhere: there are gas microturbines, gas engines and also fuel cells. Since all these generations can be coupled with heat generation in the form of hot water, applications enabling rational utilization of energy are numerous. Though these techniques have yet to prove their economic efficiency and be reliable and non-polluting, they offer high development potential in the event of success.

The current experience of the electricity markets is far too insufficient to draw any concrete conclusions on its ability to meet the demand. In fact, in most cases the

electricity sector was deregulated in a system with excess generation capacity. This resulted in a general lowering of electricity prices which did not encourage any investment. Furthermore, we must bear in mind that electricity storage facilities are limited and the transmission network is not capable of routing an infinite amount of energy from one point to the other; as a result the price of electricity in the stock markets is extremely volatile. These different elements could give rise to a cyclic generation behavior with booms and busts. Considering the long time frames in the construction of new generation facilities, these periods could stretch over several years. The electricity market also has the peculiarity that the demand is often unaware of the real-time price fluctuation in electricity and that the market laws based on equilibrium between supply and demand cannot be expressed clearly. It is therefore essential that the demand pattern changes which should lead to a demand side management that is much more elaborate than that known now. The generation facilities can then be used in a more economical manner and the producers can work with more stable prices. However, whether there will still remain a structural problem regarding the generation capacity to cover extreme peak loads is a point to consider. In fact, at present there are generation plants consisting of peak hour units that work only for a few hours in the year (<1,000 hr). They are used to cover infrequent peak loads and are activated during generation outages. It is not obvious if the electricity market will come forward to encourage producers to invest in these generation facilities.

One final point should be mentioned in relation to electricity generation even if it does not directly concern a generation unit. Different experiments are in progress to use the fuel cell technique as a means of storing electricity. The pilot units are already large in size and have a significant capacity (peak power: 18 MW with a storage capacity of 90 MWh). Once again, it is necessary to wait for the results to fix the profitability, cost, reliability and environmental cost. However, this development could revolutionize the generation market by enabling storage of electricity. By partially going away from the binding constant equilibrium between generation and demand it would be possible to use the generation facilities in a better way, particularly those whose generation depends on external factors (cogeneration, wind power, photovoltaic, run-of-river hydropower facility, etc.) and reduce the price volatility of electricity in the stock markets.

The above-mentioned aspects prove sufficiently that in the years to come the electricity generation market will see a lot of important developments that are not really foreseeable today. However, it is difficult to talk about the planning of generation facilities in the strict sense of the word.

3.4. Establishing a development plan of the transmission network

As far as the transmission network is concerned, this activity is still regulated and controlled by an organization appointed by the public authorities. This organization regulates the transmission tariffs and checks on the efficiency of the network operators in their tasks which include operation, maintenance and network development with a view to facilitate the electricity market without in any way jeopardizing the reliability and security of the system.

This means that the network development has to be approved by the regulator as it is he who allows the network operator to invest. These investments have to be financed as any other investment, partially through the owner's equity funds, partially through loan funds. All these funds result in financial costs (interests on debts, repayments on borrowings) or entail dividends to the shareholder. To access the capital markets the network operator should have a healthy financial structure. This structure can be guaranteed only through an appropriate fund inflow structure that can cover the investment costs.

As network developments take a longtime and they are amortized over long periods the regulator generally asks the network operator to submit development plans for a sufficiently long period: 7 to 10 years.

3.4.1. *Reasons for investment*

3.4.1.1. *Network development*

A development plan of the network is guided by different driving forces. The first is certainly the network reinforcement necessary to meet the load increase which has to be studied with respect to the nodes of the transmission network and not with reference to the level of the load of the end user.

Along with the load, the development in generation should also be taken into account. The network structure is largely influenced by the decommissioning of units as well as construction of new ones.

3.4.1.2. *Improvement in availability or reliability*

A second driving force for investment in the network is the improvement in the network availability and reliability at specific points. In the new environment this activity has to be guided by correct measurements of the actual value at the different nodes of the network and by the expected value by the network users.

Investments of this nature can be of different types: improvement in protection to increase selectivity and rapidity, installation of more intelligent automatisms of better performance, change in the high voltage structures of the stations, overhead ground wire equipment to reduce sensitivity to lightning strikes, etc.

3.4.1.3. *Investments towards replacement*

The European high voltage networks were developed after the Second World War, between 1950 and 1975. Today the equipment has reached a certain age and investments are necessary to replace those materials which have become obsolete or just worn.

There can be different scenarios. In the case of certain protection equipment, failures are more and more frequent (reliability curve goes up in the shape of a bathtub at the end of its life). For other materials it is no longer possible to find spare parts and maintenance is almost impossible. In certain equipment such as transformers, insulation gets old and leads to breakdowns that can no longer be repaired economically. In overhead lines, armored cables and conductors have to be replaced as they wear out under the influence of atmospheric conditions and vibrations. Similarly, high voltage station structures might require major and costly maintenance.

3.4.1.4. *External forces*

Other influences and constraints can impose major investment. Thus it may be necessary to replace materials due to toughening of legislation on the environment. A simple example is that of an obligation to eliminate isolated equipment with PCB containing liquids (Askarel). Similarly, legislation on the use of asbestos leads to replacement costs. Toughening of legislation on noise entails costly modifications to reduce disturbance from transformers. In other cases, labor protection laws can force the review of high voltage station structures. Finally, during major infrastructural work, new motorways, new railway tracks, port installations, etc., the overhead lines have to be raised or displaced.

3.4.2. *Constraints and uncertainties*

Aside from investment motivation, there are many constraints and uncertainties which strongly influence the decisions related to network development.

3.4.2.1. *Generation system*

One of the uncertainties concerns the evolution of the generation system. In a deregulated electricity sector, the network operator is no longer aware of the

intentions of the producers. The latter can decide to decommission existing units for economic reasons at very short notice: grid regulations normally insist on a six month notice period. Furthermore, even if the producer does not decommission a unit, nothing prevents him from stopping it. If the network operator is obliged to force the commitment of a unit for the security of the system he is forced to give compensation to the producer, which can be heavy.

The same problem comes up with respect to new units. In fact, the producer is not obliged to announce his intentions and can construct a new generation facility as soon as he receives the necessary licenses and authorizations. At present, while a CCGT machine can be constructed in less than 2 years, most of the network reinforcements cannot be carried out in such a short time. If the network operator has no means of knowing in advance where the new generation facilities are going to be installed, he will not be in a position to develop the network in such a way as to incorporate these new facilities in an efficient manner.

Another uncertainty that affects the development of electric power generation is not caused by deregulation but is related to technological and societal developments. In fact, it is difficult to envisage the type of development that decentralized and distributed generation will go through.

In particular, producing electricity from wind energy involves making assumptions on the participation of this generation in covering the load. According to studies and surveys carried out in Denmark, the contribution of windmills to the peak load is only 30% of the installed capacity of these facilities. Their annual utilization time is around 3,000 hours. These values are somewhat higher for off-shore wind farms. Similarly, cogeneration is driven by an industrial process and not by the need for electricity. As a result, assumptions also have to be made regarding their generation by studying in detail the industrial process that drives them.

As long as these facilities constitute only a small fraction of the generation system, precise evaluations are not necessary. The moment their share in the generation system increases, it would be preferable to specify the operating conditions to simulate the electrical system behavior in a better way.

Another element consists of predicting the behavior of the actors in the generation market. Whereas in a regulated market often intentions were to ensure a certain electrical self-sufficiency of a country through national power generation plants capable of meeting a major part of the national load, the situation is not quite the same in a free market. Thus, based on the opportunities offered by the transborder electricity markets, producers will either commit or stop their generation facilities. For a given country this might lead to unusual export and import patterns.

It is very difficult to foresee the evolution of the European electricity market and the possible behavior of the producers.

3.4.2.2. *Loads*

It is equally difficult to forecast the evolution of the loads. Assuming that deregulation of the electricity market creates more awareness regarding the real-time price of electricity amongst consumers, they will try to change their behavior so as to be able to benefit from the most interesting prices. This will definitely modify the shape of the load curves and could even lead to it becoming flat and thus to a slower increase of the peak load.

As has been already mentioned, evolution of the generation facilities could lead to the development of small distributed generation such as fuel cells, microturbines, small wind power units, small hydropower turbines, etc. According to growth, load increase at the nodes of the transmission network will be slowed down and in extreme cases could even become negative. In addition, other elements mentioned in the planning of the network in a regulated market are also applicable.

In many countries, the political will favors measures that help in rational utilization of energy. Some even imagine being able to reduce the total energy consumption. However, it should be noted that savings in primary energy often entails an increase in the consumption of electricity to the disadvantage of other vectors. In any case the impact of these measures has to be analyzed carefully in order to determine a plausible evolution of consumption.

3.4.2.3. *Wheeling*

Following the deregulation of the market, a change in the wheeling through the interconnection network should be expected particularly in the case of the networks situated in a relatively central manner in a big interconnected network. At the European network level, both Belgium and Switzerland are affected by this phenomenon. As the actors in the market try to benefit from every opportunity, there are fluxes that appear between regions with excess power and low generation costs towards regions with deficit power at high generation costs or a high selling price of electricity. These wheelings are observed more mid-season or during summer when over-capacities are the most significant. However, for the sake of network development, structural wheelings have to be identified while opportunity wheelings have to be ignored. In fact, it is not possible to justify investment in the grid on the basis of wheelings that are totally random or are for limited periods. Thus, structural fluxes are fluxes justified by the elements that will be maintained for a certain time such as the exchanges between predominantly hydropower regions and predominantly thermal regions, such as the exchanges based on seasonal or day-night complementarities, differences in the peak load moments, etc. On the contrary,

occasional fluxes are those due to brief imperfection of the market, non-availability of an important power plant, difference in regulation between countries, etc.

The main problem in forecasting wheelings is their high variability. Unless the economic and technical causes that provoke them are determined, it is very difficult to know how they are going to evolve over a period of 5 to 10 years.

3.4.3. *Planning criteria*

3.4.3.1. *Deterministic criteria*

Evolution of the network can be determined using the same deterministic criteria as for planning which were mentioned as part of the regulated sector. Nevertheless, the conditions in which the network should be developed are not so well determined and call for a much broader way of working. This will be explained in the following sections.

3.4.3.2. *Probabilistic criteria*

Considering the environment which is very uncertain and the increasing pressure to focus more on the reliability and availability of the network, a probabilistic approach for the development of the network seems to be essential. In fact, the traditional method of planning looks into only one point of the operation of the electrical system, mainly at peak load with a complete network. In actual operation the network is rarely complete. Moreover, the load and the committed generation system vary a lot over the course of the year when the imports, exports and international wheelings go through the vagaries of the electricity market. The difficult situations of the electrical system no longer occur at the peak load but in specific configurations of load, generation system and network outages. Quantifying this type of problem requires a large number of operating point simulations that represent the different conditions of the electrical system over the course of the year. Techniques used are Monte Carlo random draws where the operating points are composed of loads distributed according to the known load duration curve, by random generation systems keeping in mind the existing units and those foreseen and their availability, wheelings superimposed on import or export conditions resulting from the load and the committed generation system. For these different calculated operating points the system security conditions have to be analyzed by superimposing contingencies generated randomly, based on the reliability and availability distributions of all the network components. This gives rise to some operating points where all the load can be fed without overloading the network, and others which are more or less overloaded, and yet others where the supply is lost. For example, it is thus possible to calculate, using statistical tools, the methods and distribution of overloads and losses of supply over a year. In order to study a large

number of operating points (thousands of them), it is necessary to computerize the calculations of the operating points. One main difficulty is that the load flow calculations do not always converge and thus it becomes necessary to determine a stable operating point. One way out of this problem is to carry out calculations only on active power. This enables us to identify all the problems related to overload in the system without touching the problems of voltage stability. In case of calculation in active or reactive powers, it is essential to include an optimization program (optimal power flow (OPF)) in the load flow calculation; in this program the optimization function has to be chosen correctly: optimizing the voltage plans with reactive generation margin equalization on all the generation units, minimizing network losses, etc. These methods help in bringing out the availability and reliability values of the electrical system at every node of the network.

These methods can also be applied to determine the volumes of auxiliary services that the network operator needs to meet his obligations. In fact, using operating point simulations, it is possible to bring out places that are prone to congestion or security problems related to voltage stability or network component overload. For these operating points, the network operator is obliged to change the commitment of the generation park (redispatch). If the operator knows the volumes that might be required, it is possible to develop a network development strategy that can help in reducing them in a more economical manner.

However, it is necessary to be aware of the fact that using these probabilistic methods has to solve the problems related to calibration of the design criteria. They are therefore used more to compare solutions between themselves and give them an order of preference rather than take them as absolute.

However, attempts were made to determine volumes of unsupplied energy using probabilistic models. In spite of the attraction that this notion offers, it still requires modeling of the load recovery procedures after a contingency. If it involves minor contingencies, it is possible to simulate them as the network is reconstituted by automatisms. The difficulty increases when these simulations have to be carried out based on human actions which vary from operator reactions in the load dispatching centers of the network to the in-the-field interventions of the workers with problems of reaching them by phone and traveling from one place to another.

3.4.3.3. *Economic criteria*

Another change in the deregulated market may relate to the study of a development plan from an economic point of view. Normally in an integrated company the network development was taken up on the basis of minimum investment costs incorporated over a sufficiently long timescale. Investments in the

network were smaller compared to that of generation facilities; thus, their impact on the income and expenditure of the entire company was low.

As soon as the network operator is an independent company or maintains separate accounts, this company should ensure its economic viability. This requires establishing business plans spread over a sufficiently long period and incorporating all the aspects of a commercial company: income according to the tariffs, operating costs, investments with depreciation and the financial costs that they generate, etc. In addition, as the regulator should monitor the tariffs and at the same time ensure viability of the network operator/operators, he wants to have a long-term view of the evolutions to foresee tariff evolutions and avoid saw-toothed modifications according to the annual level of investments. In fact, for a network operator, the impact of the investments on the income and expenditure account is rather high.

It would be far fetched to try to analyze every investment project individually and calculate a return on investment (ROI) or a net present value. In fact, it is generally not possible to determine correctly the increase in the income or reduction in the expenses to attribute to a well defined project. This is not true for certain projects which enable us to reduce the volume of auxiliary services that the network operator is led to buy.

A method which is already used is to calculate the unsupplied energy despite the difficulties mentioned. In fact, by using the cost of this unsupplied energy it is possible to justify investments in the network that enable us to reduce the volume. As a part of the economic analysis at the network operator's level, this technique has the major disadvantage that the cost of unsupplied energy is a societal cost that is not supported by the operator but by society in general. As such its reduction does not amount to a reduction of expenses for the operator.

In the same way, in the different categories of investment already mentioned, those generated due to external causes such as environment, land use planning and other legislation can never be justified.

All the above mentioned elements clearly show that finding economic justification for a development plan is very difficult. The regulator and the network operator should come to an agreement regarding the criteria to be fulfilled by the network and guarantee appropriate compensation for investment incurred due to the application of these criteria. In addition, depending on the case, economic reasons can or cannot always justify investments generated due to other causes. Thus, in the case of renewals, considering only the total cost of the equipment integrated over the remaining period of life can justify it.

3.4.4. *Elaboration of the development plan*

In all deregulated systems, the regulator asks the network operator to draw up a network development plan over a medium term timescale (5 to 10 years). Given the considerable investment in the network, this plan is absolutely essential to be able to plan the financial evolution of the operator and thus forecast the evolution in the electricity transmission tariff.

Ideally, this plan should take care of all the investment required by the increase in demand, development of the generation system, replacement of materials and equipment and also that imposed by external causes (legislation changes, displacement of installations, etc.). A simple enumeration shows the difficulty in proposing a permanent and well defined solution.

Another important aspect of the development plan consists of proposing a suitable balance between investment expenditures (CAPEX) and operating expenditures (OPEX). In fact, for a certain number of ancillary services, the network operator can either buy them from the producers or make investments to provide them. Thus, the voltage plan support can be ensured by buying the reactive energy from the producers but that can also be guaranteed at least partially by installing capacitor banks or even SVCs providing reactive energy. In the same way, network congestion can be cleared by redispatching the generation system or by strengthening the network where the links are overloaded.

There should be a clear distinction between investment charged to all the network users and investment charged to a particular user (private connection). Depending on regulation, these notions can be different from one network to the other.

Considering all the elements discussed above, it is clear that a development plan has to be prepared in a random environment. It is therefore important to study the robustness and flexibility of a plan with respect to foreseeable constraints rather than determine an optimal solution for a set of given assumptions.

The aim of the following sections is to show a possible solution to handle the problems already listed. As the developments are quite recent there is no single established methodology yet. Perhaps in a few years current developments will lead to a more defined method.

3.4.4.1. *Integrating the environment*

Right from the time of drawing up the plan, the constraints related to the environment and land use planning have to be taken into account. In fact, Western

societies are so concerned about these constraints that ignoring them might lead to complications which in most cases can amount to denial of authorization or unending delays in getting authorization after going through numerous legal and administrative remedies and procedures.

Therefore, while preparing a network development plan it will be essential to measure the impact on the environment and attempt to balance the impact as far as possible. This would mean that the new links should be compensated, at least partially, by a reduction of the existing links of the network. If these compensations have to be convincing, they have to be located as close as possible to the new links planned. In order to objectivize this kind of procedure, it may be useful to rely on a methodology of measuring the environmental impact. This method should be a proven and acceptable method without someone or other raising questions if the results do not suit them. It should be able to evaluate different impacts such as visual (overhead lines), acoustic (transformer noise), real risks (fire, ground pollution, etc.) and possible risks (electromagnetic fields), etc.

3.4.4.2. *Limits: thermal and static, dynamic and voltage stability*

The network operator, under financial pressure, will try to use his assets judiciously and approach the operating limits without in any way exceeding them. Thus, the overhead and underground links, as well as transformers, all have potential reserve capacities. In fact their nominal values are based on relatively conservative hypotheses. Through a more accurate knowledge of the real operating conditions, the acceptable load values can be raised substantially in most of the cases. This is particularly true during real-time operation. However, while planning, these values can be increased by taking into account the peak time, shape of the load curve and meteorological conditions prevailing at that particular moment.

Once the thermal limits of the network are overcome, detailed studies can be carried out on problems related to the voltage stability and the extreme cases of static and dynamic stability of the power generation groups.

Development of the decentralized generation facilities possibly shows a higher sensitivity to dynamic stability. Generally these machines have low inertia and for reasons related to cost, are equipped with less sophisticated controls and are connected at lower voltage levels. Care should therefore be taken during a three-phase fault to ensure that there is no massive loss in decentralized generation that can stress the transmission network and even entail system collapse. This can call for improvements in the electrical protections in the lower voltage networks so as to limit risks of long duration three-phase faults.

Similarly, technical requirements of the transmission network should be precise when it comes to specifications with respect to the producers. In order to reduce the investment costs related to sophisticated controls required to maintain the static and dynamic stability of the machines, the producers try to compromise by simplifying these controls. This explains the need for a grid regulation that can bind the producers to invest wherever necessary.

3.4.4.3. *Creative approach: new equipment*

Since a large number of data brings out increasing uncertainties, the network development has to be studied from a different angle to bring in innovations. New high performance equipment using power electronics, FACTS (flexible alternating current transmission systems), can bring in solutions to problems unsolved until now.

Certain equipment can help in managing the active power fluxes and influence the flow distributions between links. Similarly, others can be used as SVCs for reactive power and can replace conventional generation facilities. Some of the equipment can be made to compensate for power quality disturbances: flicker, harmonics and interharmonics, imbalance between phases.

Independent of this equipment using power electronics, certain manufacturers have produced equipment using conventional elements that help in modifying the phase in a node and in limiting short circuit input from one node to the other.

One of the oldest techniques consists of interconnecting networks through one or more direct current links (HVDC). These connections enable us to have complete control over the fluxes and not to bring in the short circuit power. Recent developments have managed to carry out these connections at a much lower cost compared to that in the past.

All this equipment does not increase the intrinsic capacity of the network but enables it to use its existing capacity more efficiently and thus delay investment in new links. Its disadvantage is that it is costly and introduces new problems in the network operations: it has to be well integrated in the protection plans, normally it generates harmonic disturbances that should be properly assessed and compensated, its control function should be determined in relation to other equipment in the network to avoid interactions between controls and undesirable phenomena.

Since the problems encountered in the networks can shift from one point to another, the equipment used should be designed so that it can be easily moved as the needs change.

In addition, studies related to all the possibilities of the control system for the entire network should be carried out so as to ensure an efficient utilization of these possibilities. Thus, a centralized voltage control can create voltage plan conditions that make the networks robust with respect to contingencies that could introduce voltage instabilities. A correct knowledge of transformer heating and of the connections in relation to the load state and the meteorological conditions enable correct loading of these elements without exceeding the thermal design levels. When such a control is installed in the network it is normal to take it into account in the network development studies by adapting the planning criteria.

3.4.4.4. *Scenario development*

Considering the uncertainties over the evolution of the parameters influencing network development, it is no longer possible to define a deterministic development. It is therefore essential to establish a series of highly contrasting scenarios that will take up the most probable parameter evolutions in the study outlook. Thus, the network developments necessary in each scenario can be studied to meet the fixed criteria. From all the solutions obtained it is necessary to find the development that can satisfy all the scenarios foreseen in the most flexible and robust manner. In this investigation, choices made for the initial years have to be good because they are not reversible whereas in the distant future, it is possible to wait to have more information that will enable us to make a more judicious choice. The main criterion is to retain a network development with maximum adaptability, measured by a least-regret method, to all the scenarios forecast (robustness) and which can also push to a distant future the decisions that can lead to a well defined path (flexibility). This means that the chosen development should be flexible enough to shift the direction if a particular parameter is found to evolve in a specific direction.

3.4.4.5. *Multicriteria analysis*

When a development plan has to include several objectives from energy, ecological and economic categories, it becomes difficult to find a reasonable balance. Such problems can be solved by using multicriteria decision support techniques. The main objective of these methods is to assist a decision maker confronted with complex problems involving multiple objectives, criteria and points of view. In this context, to decide does not mean to find the perfect solution to a problem. It involves imagining compromises and getting the arbitration accepted in case of conflicts. Generally no one answer will be acceptable to all the actors; arbitration cannot eliminate certain high-handedness, a compromise cannot prevent certain power plays. The multicriteria decision support aims at reducing this aspect and making it acceptable. It has no intention of deciding in the place of the decision maker. At best, these procedures provide guidelines, ideally accompanied by information on the structure of the problem.

3.5. Final observations

All the developments presented in the previous sections aim at highlighting the increasing complexity of network development. This complexity is not entirely due to the deregulation of the electricity markets. However, this deregulation has made certain design parameters more uncertain and thereby increased the difficulty in finding a development that satisfies the expectation of all the actors. In addition, the increasing reticence of the public with respect to network extensions force the planners to show more and more clearly that the reinforcements envisaged are really necessary and correspond to the user requirements in reliability and availability of electric supply. It appears that the years to come will witness a high level of development in new methodologies and methods that will favor economic analysis of the investments to be made as well as their technical justification without forgetting to include the environmental dimension and land use management. Finally the decision process has to become more and more transparent in order to convince the regulator, the public authorities and behind them the general public of the need for the proposed developments and of the quality of the choices made.

3.6. Bibliography

It is quite difficult to give bibliographical references for every theme developed. However, CIGRÉ (International Council on Large Electric Systems) was a rich source of information along with all the work carried out by the previous study committees 37 and 38 or now the study committee C1: reports of the Paris sessions in all even years, the symposiums organized by these committees and technical brochures from the various working groups organized within these committees.

Chapter 4

Power Quality

4.1. Introduction

The problems related to the quality of electricity supply concerns all the actors present: network operators, network users (producers or consumers of electricity) or various intervening parties (suppliers of electricity or services).

As a part of the work on “operation, control and security of the networks”, the problems are going to be handled from the point of view of the network operator who is in charge of setting up the facilities that will enable us to control the quality at the interfaces between the network and the outside world (network users, neighboring networks) while respecting the technical requirements in the tariff structure and the contracts.

4.1.1. *Disturbances and power quality*

The operation, even the integrity, of certain electrical and electronic equipment has always been affected by “disturbances” [DEV 90]. These disturbances can enter the sensitive equipment through different paths:

– electricity supply: general problem studied here;

– input and output of signals, grounding, radiation, etc.: more localized compatibility problems on industrial sites.

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The electricity supply consists of a three-phase system of voltage waves that are characterized by frequency, amplitude, sinusoidal waveform and symmetry of the three-phase system. A perfect supply does not exist and the above four characteristics are affected by “disturbances” even if they are limited to levels which do not interfere with the sensitive equipment.

In 1985, a European Directive “pertaining to the approximation of the provisions of the Member States on the responsibility towards defective products” [DUE 85] clearly stipulated that “electricity is also a product”. Since then everybody has been talking about the “quality of the electricity product”, even if the concept if often debated: since it is difficult to store electricity, production has to follow consumption in real time. The voltage coming out of the power plants is of excellent quality and the entire system contributes to consolidate this quality (amplitude and frequency stability, short circuit power, etc.). However, it is subjected to several changes during transmission mainly under the influence of the disturbance facilities of the clientele or of the contingencies. As a result, electricity poses problems that are of a different nature as compared to other industrial products.

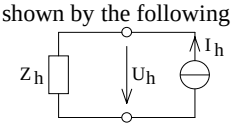
The present trend is to talk about “power quality” or “electromagnetic compatibility” whereas earlier the terms used were “disturbances” and “interference” [ROB 97].

4.1.2. *Quality of electricity supply and electromagnetic compatibility (EMC)*

4.1.2.1. *Quality of electricity supply*

According to IEEE [IEE 96], “power quality problem” implies any variation in the supply of electric power that causes malfunctioning or damage to user equipment such as: voltage dips, transient voltage surge, harmonic distortion, electrical noise. However, all these phenomena mainly affect the voltage supplied to the user. If the latter does not use any disturbance load, the current will still probably be deformed due to the characteristics of the supplied voltage[1]. This

1 On the other hand, if the client uses disturbance loads, these will first disturb the current which then results in a voltage disturbance (because the impedance of the system is not zero) and which in turn results in a degradation of the supply to other customers. This can be illustrated by observing the basic mechanism of the harmonic generation. Assuming that there is no harmonic voltage in the network before connecting the (non-linear) distorting load of the customer, the situation can be shown by the following schematic drawing:



explains why some consider that the quality of electricity supply reduces with the voltage quality ("power quality = voltage quality") [DUG 96].

In a larger sense, the expression "power quality" also includes the concept of "voltage continuity" (or "reliability of the supply"). Obviously we can only talk about the "voltage quality" when there is a voltage. In case of voltage interruption ("short" or "long" depending on whether the duration is less or more than 3 min), the point to be discussed is about voltage continuity (reliability of supply): a supply can be reliable only when the number of annual interruptions is small and their average duration is low[2]. The following equation corresponds to the most appropriate interpretation:

$$\text{power quality} = \text{continuity} + \text{voltage quality} \qquad [4.1]$$

4.1.2.2. *Electromagnetic compatibility (EMC)*

In an attempt to clarify the concepts the commonly used expression "electromagnetic compatibility" (EMC) cannot be overlooked. Where does it stand with respect to power quality? The IEC defines the EMC as the capacity of a device, a piece of equipment or a system to function in its electromagnetic environment without itself causing intolerable electromagnetic disturbances for everything that is found in its environment [IEC 90]. It is therefore a wider concept covering disturbances that enter through the input/output of the equipment in addition to its electricity supply, radiated disturbances in addition to conducted disturbances, HF phenomena (>9 kHz) in addition to LF phenomena (<9 kHz). The fact that EMC is used in two different senses results in a certain ambiguity:

– for standardization, EMC is used in a wider sense: it involves ensuring compatibility by coordinating immunity levels of sensitive equipment with the

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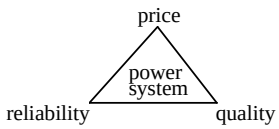
Even though the initial supply was through a purely sinusoidal voltage, this load absorbs a distorted current (fundamental + harmonics) and is responsible for the circulation of harmonic currents in the network. It behaves as a source of harmonic currents. According to Ohm's law, harmonic voltages then appear at the load for every row h of harmonic: $U_h = Z_h \cdot I_h$.

2 In a general way, the reliability concept is often equated to the quality concept. A distinction, if and when it is made, is not always in the basic sense adopted here (for example, "reliability" can refer to all of the "voltage dip and interruption" phenomena). Here "electricity product" can be compared to any industrial product: other than the service, the three main characteristics for the client are price, quality and wait time (more than zero for electricity when there is an interruption).



emission levels of disturbance equipment; this covers all the phenomena and it is also the philosophy of the committees 77 for IEC and 210 for CENELEC (European Committee for Electrotechnical Standardization);

– in common parlance, EMC and power quality are supposed to cover two distinct domains implementing different analysis and compensation techniques with certain overlapping (EMC is concerned with the disturbances at high frequency or entering through the ground terminals, the input/output of signals or that are radiated; power quality is concerned with disturbances at low frequencies entering through the electricity supply).

The present chapter deals only with power quality. It should not however be forgotten that the network operator's responsibility does not stop with ensuring the quality of electricity supply at the points of interface between the network users and the neighboring networks. He should also be concerned with the repercussions of and towards the networks of a third party (telecommunication networks, electric traction, underground buried cables, etc.), without forgetting the environment in the large sense.

4.2. Degradation of the voltage quality – disturbance phenomena

Disturbances that degrade the voltage quality can arise from:

– faults in the electrical network or in the customers' facilities: short circuit in a station, overhead lines, underground cables, etc.; these faults can be attributed to various reasons: atmospheric (lightning, frost, strong winds, etc.), materials (aging of the insulating units, etc.) or human (wrong actions, work by a third party, etc.);

– disturbance facilities: arc furnace, welding machines, speed changers and all applications using power electronics, televisions, fluorescent lighting, starting or switching of the equipment, etc.

The main phenomena that can affect the voltage quality whenever it is present are briefly described below.

4.2.1. *Frequency variations*

Frequency variations are very low (less than 1%) in the synchronous European grid and do not in general jeopardize electrical or electronic equipment.

The situation in a small isolated network may be different. Certain industrial processes require very precise control of the motor speeds and can have problems in case of supply from a badly designed stand-by group.

4.2.2. *Slow component of voltage variations*

The RMS value of voltage varies continuously due to modifications of the loads fed by the network. The network operators design and operate the system in such a manner that the variation range remains confined to the contractual limits.

Regular equipment can withstand smooth voltage variations in a range of at least ±10% of the nominal voltage without any inconvenience.

4.2.3. *Voltage fluctuations – flicker*

Rapid voltage variations whether they are repetitive or random, are caused by rapid variations of power absorbed or produced by equipment such as welding machines, light-arc furnaces, windmills, etc.

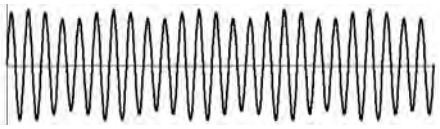


Figure 4.1. *Voltage fluctuation*

These voltage fluctuations can cause flickering of the lighting which is disturbing for the client, even if the individual variations do not exceed a few tenths of a percent. Other applications of electricity are not normally affected by these phenomena as long as the variation amplitude remains lower than 10%.

4.2.4. *Voltage dips*

Voltage dips are due to short circuits that arise in the general network or in customers' facilities. Only voltage drops of more than 10% are considered here (lower amplitudes belong to the category of "voltage fluctuations"). Their duration can vary from 10 ms to several seconds depending on the location of the short circuit and the functioning of the protection parts (the faults are generally cleared in 0.1-0.2 s in HV, 0.2 s to a few seconds in MV). Short circuits are random events: they can result from atmospheric phenomena (lightning, frost, strong winds etc.), malfunction of equipment or accidents.

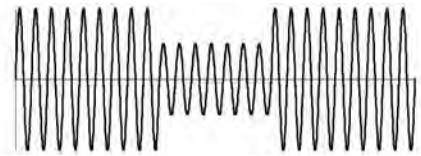


Figure 4.2. *Voltage dips*

Voltage dips can cause tripping of equipment when their depth and duration exceed certain limits (depending on particular load sensitivity). The consequences may be extremely expensive (restarting time can be several hours or even days, loss of computer data, damage to products and even to production equipment, etc.).

4.2.5. *Transients*

The strongest but fortunately the least frequent voltage surges for the client are due to lightning. Their amplitude can reach several kV in the overhead LV networks. In addition, such transients can be transmitted even to the underground LV networks.

More frequent transient voltage surges are produced in the customers' units for example, during tripping of LV equipment. Their energy content is lower than that of lightning voltage surges but their amplitude can go beyond 1 kV in LV with steep fronts (rise time of the order of 1 ns, i.e., 10^{-9} s); this can be dangerous to the electronic circuits.

Voltage surges can cause serious damage which can be overcome using voltage surge protection devices. There can also be other transient phenomena that cause annoying malfunctions without involving high amplitude voltage surge.

Some examples of transients arising out of diverse sources are given below.

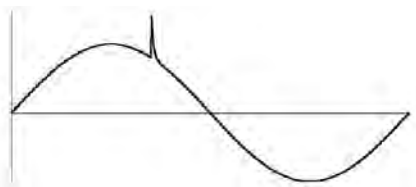


Figure 4.3. *Transient voltage surge due to the tripping of LV equipment*

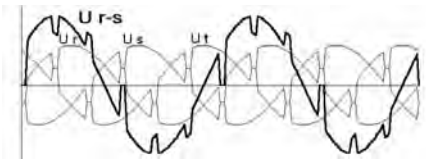


Figure 4.4. *Commutation notches due to a three phase*[3] *rectifier (in addition their recurrence causes a permanent distortion)*

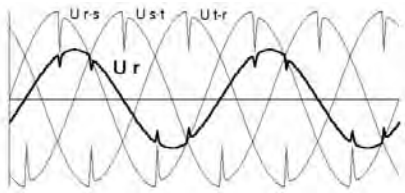


Figure 4.5. *Commutation notches due to a three phase controller (in addition their recurrence causes a permanent distortion)*

NOTE.– Commutation notches due to electronic rectifiers or controllers are not really transients in the conventional sense. The waveforms of Figures 4.4 and 4.5 are recurring types and could be described (using the Fourier transform) as a series of harmonics. However, it is the stiffness of the notches of the sine curve that may cause trouble; these notches can therefore be considered as recurring transients.

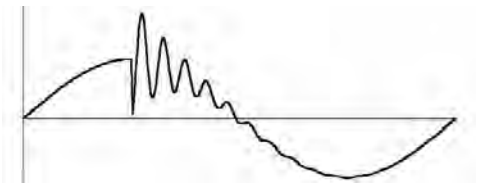


Figure 4.6. *Dampened transient oscillation due to switching on of a capacitor bank*

Development of power and control-command electronics has significantly increased the sensitivity to transients. For example, in the past, the MV capacitor banks were often switched on directly and did not pose any problem; now, the high sensitivity of the speed changers of asynchronous motors forces us to take special precautions (series reactance, pre-insertion resistance, controlled switching on, etc.).

3 Idealized oscillogram (in practice, every sudden variation causes an oscillation of the circuit and the sine curve indicates six dampened oscillations).

4.2.6. *Harmonics and interharmonics*

Harmonics are components whose frequency is a multiple of the fundamental frequency (50 Hz), which causes a distortion of the sinusoidal waveform. They are mainly due to the non-linear equipment such as electronic converters or controllers, arc furnaces, etc. Their amplitude can be amplified by the resonance phenomena mainly when the capacitor banks are not installed with necessary precautions.

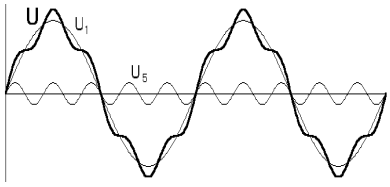


Figure 4.7. *Distortion caused by only one harmonic (h = 5)*

High levels of harmonics can cause excessive heating of certain equipment, for example, capacitors or rotary machines, and can disturb the operation of the electronic systems. In office buildings with a large number of computers and fluorescent lighting, neutral overload through homopolar harmonic currents (mainly h3) has become common (RMS value of current higher than the phase currents whereas the copper section is low). Other less frequent phenomena have also been observed such as damage to the circuit breakers (increase of dv/dt).

Components whose frequency is not an integral multiple of the fundamental are encountered less frequently but they are not rare. They are called interharmonics. They are mostly due to facilities producing rapidly changing harmonics such as arc furnaces, cyclo-converters, speed changers used in certain conditions ("modulation" of the harmonics gives rise to "lateral bands" at intermediate frequencies); presence of harmonic filters can aggravate the phenomenon considerably (amplification of intermediate frequencies; instability phenomenon in converters, etc.).

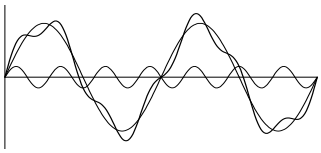


Figure 4.8. *Distortion caused by a single interharmonics (h = 3.5)*

Interharmonics cause variations in the peak value of the sine curve and shifting of the point where it crosses zero; in this respect they are more bothersome than the ordinary harmonics and justify imposition of more severe limitations.

4.2.7. *Unbalance*

Network dissymmetries only cause low levels of voltage unbalance (generally limited to a few tenths of percent). Whereas, certain single phase loads (particularly, railway traction in alternating current) cause significant unbalanced currents and thus a significant voltage unbalance.

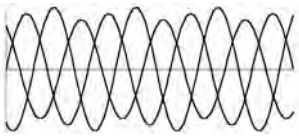


Figure 4.9. *Voltage unbalance*

The main problem with unbalance is that it causes additional heating of the three phase rotating machines.

4.2.8. *Overall view of the disturbance phenomena*

Table 4.1 summarizes the above phenomena and gives some indications on the usable remedies if required.

Type of disturbance	Origin	Consequences	Possible solutions
Long interruption	Short circuit, overload, untimely tripping, (maintenance)	Equipment shutdown, generation losses, damage	Stand-by supply (network), uninterruptible power supply (UPS)
Voltage dips and short interruption	Short circuit, (switching on a big motor)	Equipment shutdown, generation losses, damage	Network conditioner, design of sensitive equipment, un-interruptible power supply (UPS)
Rapid fluctuation (flicker)	Fluctuating facilities (light-arc furnaces, welding, frequent starting motors, windmills, etc.)	Flickering of lighting	Synchronous compensator, reactive power static var compensator, active conditioner, series capacitor

Harmonics	Non-linear facilities (power electronics, electric arcs, etc.)	Thermal effects (motors, capacitors, neutral conductors, etc.), dielectric effects (aging of the insulator) or almost instantaneous effects (automatic machines)	Active or passive filtering, anti-harmonic choke, derating of the equipment
Interharmonics	Non-linear and fluctuating facilities (arc furnaces, welding machines, windmills), frequency changers, centralized remote control	Flickering of fluorescent lighting, malfunctioning of automatic machines, mechanical damage to rotating machines	Active or passive filtering, damping of filters, anti-harmonics choke, design of sensitive equipment
Unbalance	Unbalanced facilities (railway traction, etc.)	Heating of rotating machines, vibrations, malfunctioning of protection system	Balancing device, network conditioner
Voltage surge	Short circuit, commutations, lightning	Tripping, danger to people and materials	Galvanic separation, overvoltage protection, controlled switching on, pre-insertion resistance

Table 4.1. *Overall view of the main disturbance phenomena, with special reference to preventive or remedial measures*

4.3. Basic concepts of standardization

To ensure compatibility between all the disturbance facilities and all the sensitive facilities fed by the network, emission limits should be imposed on the former and sufficient immunity levels should be provided for the latter. At all the supply points of the facilities connected to the networks, the effective disturbance levels can be higher than the individual emission limits but should remain lower than the individual immunity levels: the concept of “compatibility level” is introduced naturally.

In 1981, the study group from CIGRE (International Council on Large Electric Systems) and CIRED (International Conference on Electricity Distribution) CC02 (CIGRE 36.05/CIRED 2), published the first international report [MEY 81] which stipulated “existing values in the network” for the harmonics: for different voltage levels, a “low value” was given for every harmonic row (value often encountered in the vicinity of the important disturbance facilities and associated with a low interference probability) and a “high value” (value rarely exceeded in the networks, corresponding to a high degree of probability of producing interference). Nine years later, the IEC stipulated for the first time the compatibility levels for low voltage [IEC 90] which corresponded almost totally to the “high values” of the report [MEY 81].

In the meantime, it became clear that the significance of the “compatibility level” concept cannot be the same in medium and high voltage as in low voltage. In LV, the sensitive facilities connected to it can have interference if the stipulated values are exceeded. For medium and high voltage, a “target level of compatibility” concept was introduced [MIR 88] to convey the fact that overshooting these levels did not directly involve a risk of interference; the aim was to coordinate between the different voltage levels with a view to respect, in the end, the compatibility levels in low voltage. These “target levels” are called “planning levels” by the IEC [IEC 96, IEC 96].

The CENELEC published EN 50160 [CEN 99] standards that stipulate the “voltage characteristics” with a view to define the characteristics of the “electricity product” [DUE 85].

It is important to clarify the relationship between these various concepts.

Compatibility levels. These are the reference values (Publications IEC 1000-2-1 and 1000-2-2 [IEC 90]) for coordinating emission and immunity of equipment that are either a part of or are supplied by a network to ensure electromagnetic compatibility in the entire system. They correspond to a 95% non-overshooting probability for the entire system considering a distribution in space and in time. However, there is some tolerance in this as a network operator cannot ensure control of all the network points at all times. Actual levels of disturbances have to be evaluated for the entire network to compare with the compatibility levels even though it is hardly realistic; as such there is no evaluation method that is defined with reference to the compatibility levels. Thus, it is obvious that they are more reference values than operational limits.

Voltage characteristics. The European standard EN 50160 [CEN 99] gives the main voltage characteristics at the supply points of the client in the low and medium voltage public network systems under normal operating conditions. These are almost guaranteed limits (at least for certain parameters), covering all the points of a network. These limits are equal to or are slightly higher than the compatibility levels. The method of evaluation of the real characteristic at a point of the network (to be compared with the specified characteristic) is based on time-dependent statistics: for example, for a harmonic voltage, the measurement period is one week and 95% of the average quadratic values (RMS) on successive 10 min periods should not exceed the specified limit.

Planning levels. These levels are used while evaluating the impact of a disturbance facility on the network (refer to the IEC 61000-3-6 [IEC 96], 61000-3-7 and 61000-3-13 publications). The planning levels are specified by the network operator for all voltage levels and can be considered internal quality objectives.

Generally they are equal to or lower than the compatibility levels. Only indicative values can be given in the international recommendations as the target levels vary with the network structure and circumstances. As in the case of voltage characteristics, the method of estimating a real disturbance level (to be compared at the planning level) is based on time-dependent statistics; since its aim is to characterize as close as possible the disturbance capacity of the phenomenon, it provides higher results which when compared to the lower limits show that the requirements are clearly more severe for the network.

Figures 4.10 and 4.11 illustrate the basic concepts described above and highlight the most important relations between them.

In an extended system (see Figure 4.10), interferences are unavoidable on certain occasions and as such, there is an overlap between the distributions of the disturbance and immunity levels. The voltage characteristics can be equal or higher than the compatibility level; they are specified in the European standards EN 50160. The planning levels can be equal or lower than the compatibility levels; they are specified by the network operator on the basis of the technical reports IEC 61000-3-6, 61000-3-7 and 61000-3-13. The immunity test levels are specified in the appropriate standards or agreed on between users and manufacturers.

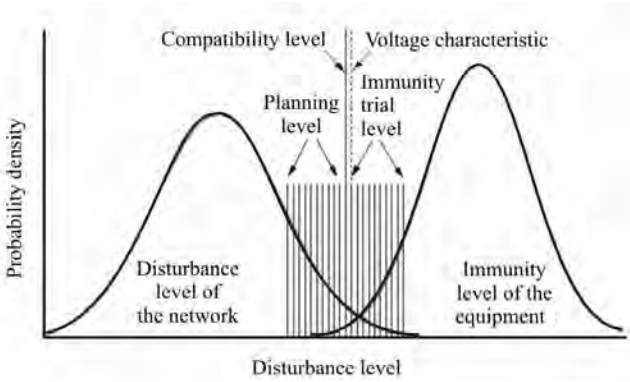


Figure 4.10. *Illustration of the basic standardization concepts in power quality using time/place dependent statistics concerning the entire system*

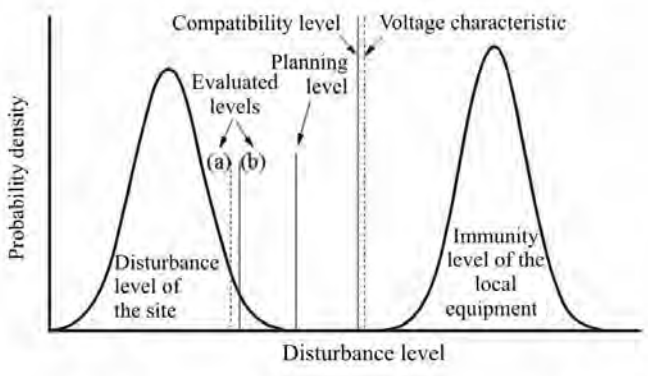


Figure 4.11. *Illustration of the basic standardization concepts in power quality using time-dependent statistics concerning a site of the system where the real level (a) is estimated with a view to compare with the voltage characteristic and the real level (b) is estimated with a view to compare with the planning level*

In most of the points of the network (Figure 4.11 is only an illustrative example), there is no or very little overlapping between the distribution levels of immunity and disturbance; the influences are therefore minor and equipment continues to function satisfactorily (the electromagnetic compatibility is ensured).

4.4. Quality indices

Reverting to the definition of power quality, two main aspects should be considered: voltage continuity and quality. These two can be linked to the two general aspects characterizing product supply and services [LUN 93]:

– the product or service should be provided within the specified time frame;

– the product or service should be of good quality (the desired quality).

A third aspect of the quality of service involves providing information or advice to the different types of customers; the European Regulators call this the "commercial quality" [EEC 01].

4.4.1. *Voltage continuity*

Various expressions such as "reliability of supply" which are not so specific are frequently used to refer to voltage continuity. This continuity results from the behavior of the entire system of generation-transmission-distribution which should

simultaneously satisfy the good performance conditions, both static ("system adequacy") and dynamic ("system security").

The adequacy concept requires the availability of equipment that enables us to satisfy the consumer requirement at any time. The security refers to the capacity of the system to face the dynamic process that appears during transition from one stable state to the other (for example, during the loss of a big generation unit). Normally, the projected indices are based only on the adequacy (for example, the LOLE – "loss of load expectancy"), whereas the post performance statistics refer to the overall reliability of the system (adequacy + security).

Two main sets of indices enable us to characterize the voltage continuity: 1) "system" indices and 2) "interface point" (connecting point with the neighboring network or with a generation or consumption unit) indices.

For customers of the network, the "interface point" basic indices are the failure rates (number of interruptions per year), the average duration of an interruption (minutes per interruption) and the annual outage (min/year) at the connection point [ALL 00] (the third index being the product of the first two). The "system" indices provide more general information that enable us to characterize a set or a subset of the system.

For example, the IEEE has defined a series of indices of both types:

– system average interruption frequency index:

SAIFI = (interruptions/customer.year) = (Σ interrupt.)/(Σ customers);

– customer average interruption frequency index:

CAIFI = (Σ interrupt. x affected customers)/(Σ affected customers);

– system average interruption duration index:

SAIDI = (minutes/customer.year) = (Σ duration x affected customers)/(Σ customers);

– customer average interruption duration index:

CAIDI = (minutes/interruption);

– average service availability index:

ASAI = (8760 – SAIDI/60)/8760;

– average energy not supplied:

AENS = (kWh/customer.year).

In addition to the average indices, the current trend is to use indices with reference to customers who are not properly serviced [VAN 01] [CEE 01] such as:

– maximum individual customer interruption frequency:

MICIF (interruptions/customer.year);

– maximum individual customer interruption duration:

MICID (minutes/customer.year).

In the European distribution system, quite often the recommendation followed is [STA 97] by UNIPEDE[4] where the three "system" indices are related to the three "interface point" basic indices:

– "interruption frequency" = average number of interruptions per customer per year (= SAIFI);

– "interruption duration" = average duration of interruptions (min/interruption) (= CAIDI);

– "supply unavailability") = average number of minutes without supply per customer and per year (min/customer.year) (= SAIDI);

where the third index is the product of the first two.

It should be highlighted that only long interruptions of more than 3 min should be considered. Interruptions of less than 3 min duration are considered to be a voltage quality problem (and not a continuity problem) similar to the "voltage dips and short interruptions".

It is interesting to note that unavailability of supply depends on the type of the distribution network (urban or rural, etc.) and can be related to the load density. For example, the curve in Figure 4.12 shows the results obtained for a few tens of distribution networks. With bi-logarithmic coordinates, this curve becomes a straight line which merges practically with Zollenkopf's law, established in Germany more than 30 years ago [DUS 97, ROB 97].

4 UNIPEDE merged with EURELECTRIC in 1999; the name of the new entity is EURELECTRIC.

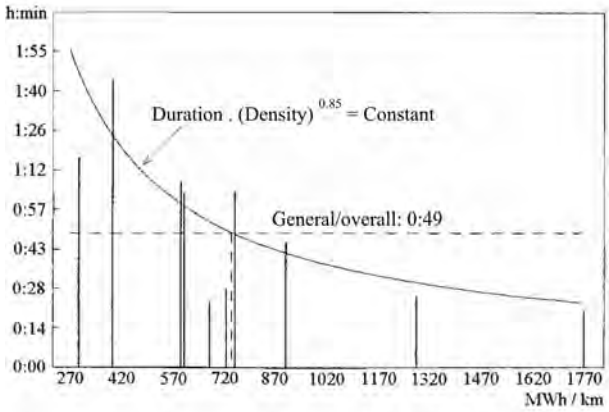


Figure 4.12. *Unavailability of supply (min/customer per year), related to the load density (MWh per km of MV network) for ten distribution zones*

In the case of transmission networks, UNIPEDE has indicated other "system" indices [LUN 93, SVE 97]:

– "average interruption time" or AIT = 8760·60·ENS/AD (min/year), where ENS = "energy not supplied" following interruptions (MWh/year) – excluding network losses – and AD = annual energy demand (MWh/year) – excluding network losses;

– "severity index", SI = 10^5·ENS/AD (pu);

– "system minutes", SM = 60·ENS/PL (min/year), where PL = "peak load" (MW).

UNIPEDE has recommended using AIT. The SI and SM indices can be derived: knowing one of the three indices enables us to determine the other two (SI = AIT/5.256; SM = AIT·AL/PL, where AL = "average load of the year" in MW, that is, AL = AD/8760).

The "interface point" indices can also be used for transmission networks. The "performance statistics at the supply point" in New Zealand give an example of this [TRA 99].

Figure 4.13 shows an example of the AIT statistics. The concerned systems are split into three parts: 1) production system, 2) large transmission network (≥220 kV), 3) regional transmission network (40 kV≤U_N<220 kV). For every interruption and forced load reduction, the ENS has been attributed to one of the three sub-systems.

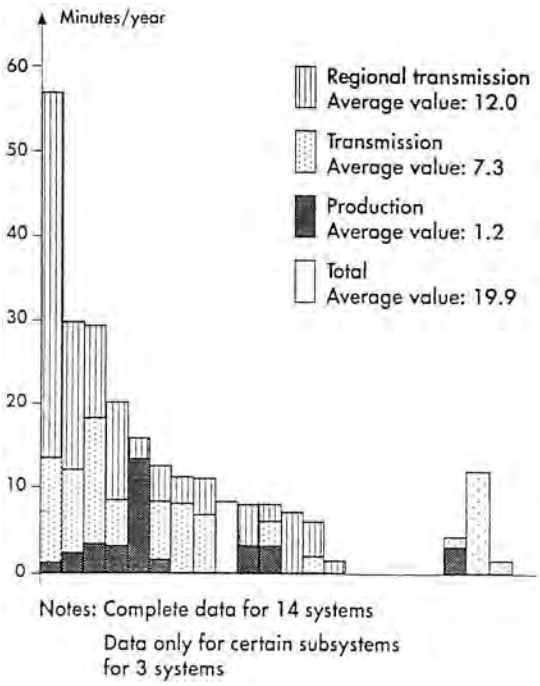


Figure 4.13. *Statistics on AIT of 17 UNIPEDE member countries for the period 1982–1991*

4.4.2. *Voltage quality*

Voltage has four main characteristics: frequency, amplitude, waveform and symmetry.

4.4.2.1. *Frequency*

For the synchronous European grid, the EN 50160 standard stipulates that the average value of the fundamental frequency measured over 10 s, should be in the range of 50 Hz ±1% during 99.5% of the year and 50 Hz +4%/-6% during the whole time.

Maintaining this level of quality is the common responsibility of all the operators of the networks concerned (regulating zone); they should take part in the primary and secondary regulations in conformity with rules of the game by the UCTE[5] [UCP 98, UCP 99].

5 UCTE has been the new name for UCPTE since 1999 (the "P" has disappeared because the producers are no longer involved in the organization).

4.4.2.2. *Amplitude*

The network operator should maintain the voltage amplitude within a span of the order of ±10% around its nominal value. However, even with a perfect regulation several types of disturbance can degrade the quality: 1) voltage dips and short interruptions, 2) rapid voltage changes (flicker), 3) temporary or transient voltage surges. More frequent problems are due to the first two categories (major difficulty in providing protection) and require defining of the quality indices.

The voltage dips and short interruptions are caused by contingencies. In Europe they are frequently characterized by a table called UNIPEDE or "Disdip" (from the name of the UNIPEDE working group that proposed it) [DAV 90] (see Table 4.2) where the annual number of events is mentioned for every depth/duration category.

Duration / Depth	10 ms ≤Δt <100 ms	100 ms ≤Δt <500 ms	500 ms ≤Δt <1 s	1 s ≤Δt <3 s	3 s ≤Δt <20 s	20 s ≤Δt <60 s
10≤ΔU/U<30%						
30≤ΔU/U<60%						
60≤ΔU/U<100%						
100%						

Table 4.2. *UNIPEDE table giving statistics on voltage dips and short interruptions*

Duration is the time during which the voltage is lower than its nominal value by more than 10%. A complex voltage dip is characterized by its maximum depth and its total duration. When the duration and the depth are different for every phase, the maximum depth and the longest duration are noted.

As the years go by this table has undergone several modifications [GUT 96], but the basic principles have remained unchanged. However, characterization of the unbalanced three face voltage dips can be better expressed using new concepts such as "characteristic amplitude", "characteristic jump of the phase angle" and "PN factor" [ARR 00].

Voltage fluctuations (succession of rapid changes), or flicker, are caused by commutation or operation of the so-called fluctuating facilities. Europe uses two types of quality indices: the indices defined in the European standards EN 50160

[CEN 99] to be compared with the voltage characteristics, and the indices defined in the IEC 61000-3-7 [IEC 96] publication, to be compared with the planning levels.

The two sets of indices and their target values cover very different requirements [ROB 98]: voltage characteristics define the pollution levels which should not be exceeded at the connecting points so as to avoid disturbances of sensitive facilities; planning levels are the pollution levels that are used by the network operators to share the emission limits between all the disturbance facilities.

Both EN 50160 and IEC 61000-3-7 use the international flicker meter (defined in the IEC 61000-4-15 publication) that provides a short term severity index Pst for successive 10 min periods and a long term severity index Plt for successive 2 hour periods. However, the quality indices are different:

– EN 50160: for every one week period, the $Plt_{95\%}$ percentile is the quality index to be compared to the voltage characteristic;

– IEC 61000-3-7: for every minimum period of one week, the $Pst_{95\%}$, $Pst_{99\%}$ and $Plt_{95\%}$ percentiles are the quality indices to be compared to their respective planning levels.

4.4.2.3. *Waveform*

As in the case of flicker, two sets of quality indices are used for the harmonics [ECS 99, IEC 96]:

– EN 50160: for every one week period, the 95 percentile of the 10 min mean quadratic values of every individual harmonic voltage (U_{hSh95}) is the quality index compared to the corresponding voltage characteristic;

– IEC 61000-3-6: for every minimum period of one week;

– the 95 percentile of the 10 min mean quadratic values of every individual harmonic voltage (U_{hSh95});

– maximum value over the entire period of the daily 99 percentiles of U_{hvs}, i.e. $U_{hvs99DM}$;

are the quality indices to be compared to their respective planning levels.

Table 4.3 gives an example of measurements at a 10 kV interface point between transmission and distribution networks.

	EN 50160		CEI 61000-3-6		
h	U_{hSh95}	V. Charact.	U_{hSh95}	$U_{hvs99DM}$	Plann. Levels*
3	0.5	5.0	0.5	2.8	4.0
5	3.0	6.0	3.0	6.2	5.0
7	1.7	5.0	1.7	2.3	4.0
11	0.5	3.5	0.5	0.7	3.0
13	0.2	3.0	0.2	0.4	2.5

Table 4.3. *Example of evaluation of harmonic levels using quality indices EN 50160 and IEC 61000-3-6, and comparison of the results with the voltage characteristics and the planning levels respectively. *The planning levels have to be multiplied by 1.5-2.0 in order to be compared with* U_{hvsMDM}

4.4.2.4. *Symmetry*

Two sets of quality indices are used for the negative sequence voltage component U_-, in relation to the positive sequence voltage component U_+, i.e. U_-/U_+ or u_-:

– EN 50160: for every one week period, the 95 percentile of the 10 min mean quadratic values of u_- is the quality index to be compared to the corresponding voltage characteristic;

– IEC 61000-3-13: for every period of minimum one week:

– the 95 percentile of the 10 min mean quadratic values of u_-,

– the maximum value over the entire period of the daily 99 percentiles of u_{-vs}, i.e. $u_{-vs99DM}$,

are the quality indices to be compared to their respective planning levels.

4.5. Evaluation of quality

4.5.1. *Voltage continuity*

It has been seen that the most used quality indices for voltage continuity are the global indices (SAIFI, CAIDI and SAIDI in distribution, AIT in transmission). They do not require any special measuring instruments, just good reporting and validation procedures. Every time a contingency gives rise to an interruption in supply, reliable data on the duration of interruption and on the amplitude of the power cut should be available.

4.5.2. *Voltage quality*

In general, all measuring instruments should conform to the international standards (IEC 61000-4-7 for harmonics and interharmonics, IEC 61000-4-15 for flicker, IEC 61000-4-30 for the quality of electricity supply in general). The precision and resolution of the measurements should be sufficient with regard to the target values to which the quality indices will be compared. The precision of the measuring transformers is a delicate point when it comes to harmonics and unbalance. There is still much to accomplish in this domain.

4.5.2.1. *Frequency*

The quality of the synchronous European grid being excellent the frequency is not a major issue for users.

However, every regulating zone has to contribute towards this quality and the network operator is bound to make sure that his contribution share in the primary and secondary regulation of the frequency is respected. To ensure this he has to record the power and frequency variations at the connecting points of the regulating production groups (to verify if the producers respect their commitment towards providing ancillary services) and the points of interface between the neighboring regulating zones (to verify if the regulating zone under his responsibility respects his share in the above commitment). The measuring systems to be used are not of the type used for "quality of electricity supply" but the requirements in terms of rapidity, synchronism and precision are more than those of the usual systems (SCADA).

4.5.2.2. *Amplitude, waveform and symmetry*

The present trend is to install quality recorders at all the outlet points of the transmission network, i.e., at the points of interface with the (HV) industrial consumers and the (MV) distribution networks. This is of interest to parties – the network operator and his customers. Large numbers of recording devices that meet the technical specifications and at the same time are not very expensive need to be installed.

These devices should have communication facilities to enable centralized data processing. They should also be capable of carrying out local processing to avoid transferring a large volume of data ("it is information and not data that is required"). Two main types of local processing are: 1) recording data in reaction to certain specific events (exceeding the thresholds) and 2) calculating main quality indices.

For example, in the case of voltage dips, the device should be capable of providing a sufficient description of every event (date and hour, voltage evolution profile at every phase) as well as prepare a UNIPEDE table.

In the case of flicker, harmonics and unbalance the problem is slightly different. The quality indices EN 50160 are considered sufficient for the requirements of the customers and the number of quality recorders available in the European market can supply them. However, since the network operator also needs the quality indices IEC 61000-3-6/7/13, an instrument capable of providing both the sets of quality indices becomes essential. Very few manufacturers are ready to meet this demand.

This shows the necessity of choosing proper quality indices that should be followed in future. The fact that the IEC 61000-3-6/7/13 publications defined the quality indices to mainly determine the emission limits was not properly understood. It is however obvious that:

– it is necessary to define the maximum overall levels of pollution before dividing them between individual polluters in the form of emission limits;

– these maximum levels are not operational if the existing levels cannot be compared to them;

– well defined quality indices are necessary to estimate the existing levels;

– EN 50160 type of quality indices are not suitable for this purpose; they give a good overall evaluation of quality, but they do not follow the phenomena closely enough to limit the emissions efficiently.

This explains why the IEC 61000-3-6/7/13 publications defined the quality indices and the target values even though that was not their primary objective.

4.6. Connection of the disturbance facilities

4.6.1. *Definition of the emission level of a disturbance facility*

Be it voltage fluctuation (flicker), (inter) harmonics or unbalance, the emission level of a disturbance facility is the value of the corresponding quality index that could be attributed to this facility had it been the only source of disturbance in the network (it is interesting to note that a quality index is in reality an index of disturbance).

4.6.2. *Concept of short circuit power*

The concept of short circuit power though fundamental, widely used and well known seems to be difficult to figure out.

4.6.2.1. *Standard short circuit power*

The IEC 909 [IEC 88] standard is taken as the reference standard for this aspect. It is based on the calculation of the initial short circuit current (I''_{sc}) in the unloaded network (neither passive loads nor shunt condensers). To calculate I''_{sc}, Thévenin's theorem is applied to the unloaded network with a voltage source equal to cU_n (where U_n is the nominal voltage). The IEC specifies two standard values for the factor c. The "maximum value" should be used to determine the ability of the materials to retain their specifications during short circuits. It is fixed at 1.1 for HV networks. The "minimum value" should be used for other requirements, for example, to determine the impact of the fluctuating facilities in terms of flicker levels. It is fixed at 1.0 for HV networks.

The short circuit power (IEC standard) is thus defined by:

$$S''_{sc} = \sqrt{3} \cdot U_n \cdot I''_{sc} \qquad [4.2]$$

(it can be observed that the voltage used to calculate current I''_{sc} is cU_n, but the voltage used to derive S''_{sc} is simply U_n).

4.6.2.2. *Effective short circuit power*

A second approximation can be recommended when it comes to closely following reality as in the case of evaluating the possibility of connecting a significant fluctuating load for which the standard short circuit power would not be sufficient. The short circuit power is then calculated by taking into account the real operating voltage and the shunt elements of the network.

Under normal operating conditions (see Figure 4.14) the network is loaded. It can be assumed that the operating voltage is equal to the nominal voltage at the point where the short circuit power has to be determined. For the voltage to be equal to U_n at this point, the source of the electromotive force of Thévenin's equivalent diagram should be equal to μU_n (with $\mu>1$, assuming that the loads are mainly inductive). The short circuit current is multiplied by the same factor and so is the short circuit power. Moreover, if the operating voltage is higher than U_n, which is common at the supply point of the industrial loads, the increase in the short circuit power is even more significant, i.e. $S_{sc.eff} = S''_{sc} \cdot \mu \cdot (U_{ex}/U_n)^2$.

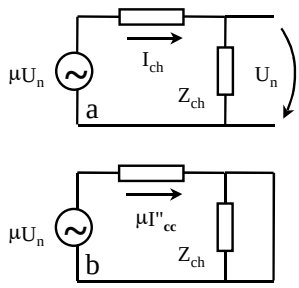


Figure 4.14. *Increase in the short circuit current in a loaded network at a point where the voltage is equal to U_n (μ>1); a) initial conditions in a loaded network, b) short circuit conditions*

It is this short circuit power corresponding to the loaded network and to the real operating voltage that is called "effective".

4.6.2.3. *Apparent short circuit power*

In the previous analysis the loads are considered linear elements, i.e., elements whose impedance remains constant depending on the voltage. However, real loads often have a different behavior with their reactive power consumption drifting significantly from the voltage by a quadratic function. This can generally be represented by:

$$\frac{Q}{Q_o} = \left(\frac{U}{U_o} \right)^{\alpha} \qquad [4.3]$$

Depending on the type of load, the α exponents falling between 0.5 and 18 can be found in the literature.

This load behavior can influence the voltage fluctuations caused by reactive power fluctuations in a significant manner. This is already true in the case of voltage elevation that provokes a simple switching on of the capacitor banks: the proportional increase in reactive power consumption of the loads is generally more than the square of the voltage; this is followed by a higher voltage drop in the equivalent impedance of the network and finally a lower voltage rise than expected.

The result is that the short circuit power of the network seems higher than its standardized value and even higher than its effective value. It is this higher value that is known as "apparent short circuit power". It should be noted that the conventional method of evaluating the short circuit power by successively switching

on and switching off a capacitor bank provides a means for assessing this apparent short circuit power.

To be more precise, the apparent short circuit power is often about 10 to 20% higher than the effective short circuit power which itself is 10 to 20% higher than the standardized short circuit power.

4.6.2.4. *Contractual short circuit power*

Whatever the method adopted to evaluate the short circuit power (standardized, effective or apparent), it is certain that its value is not a fixed characteristic of the network (low or high load periods, adjusting the pattern to suit the maintenance operations or contingencies, evolution of the system over the years, etc.). When discussing the connection of a disturbance facility at the project stage, it is important to define the network conditions based on which the facility has to be designed.

The network operator should therefore take the responsibility to define a "contractual short circuit power". This is not a minimum guaranteed value but a value to which the emission level of disturbance of the facility should be brought before comparing it to the emission limit. Of course, this does not mean anything if the short circuit power evaluation method is not properly defined as well as the evaluation and transposition method of the emission level of the facility.

4.6.3. *Determining the emission limits of a disturbance facility*

The IEC 61000-3-6 [IEC 96] publications on disturbance facilities, 61000-3-7 on fluctuating facilities and 61000-3-13 on unbalanced facilities describe the three stage procedure to fix the emission limits of a disturbance facility.

The basic principle is that the acceptability of a disturbance facility depends on the agreed power of the user, the power of the material causing disturbances and the network characteristics. The aim is to limit injection from all the facilities of individual users at levels that do not cause voltage pollution exceeding the planning level.

4.6.3.1. *Stage 1: simplified evaluation of emission limits*

Most of the facilities are either not disturbing or cause weak disturbances that do not require any specific study to determine their emission limits.

It is for the network operator to determine the conditions under which a facility can be accepted in Stage 1. If these conditions are not fulfilled, the conditions of acceptance in Stage 2 should be determined.

The conditions of Stage 1 can be specified in various manners. For example, a limit to the Si/Ssc ratio between the capacity of the facility and the short circuit power of the network can be defined. This approach is inconvenient in that it requires defining the value of Ssc, which, as has been seen, requires a thorough study.

Another approach consists of defining, for every voltage level, a standard short circuit power (generally: a standard impedance value, at 50 Hz and other frequencies), that enables us to define standard emission limits irrespective of the connection point.

4.6.3.2. *Stage 2: emission limits taking into account the effective characteristics of the network*

If a facility does not fulfill the Stage 1 criteria, specific characteristics of the disturbance pieces of equipment as well as their share in the overall pollution of the network should be evaluated. This can be derived from the planning levels and is divided between the individual users depending on their contracted load with respect to the total available power of the network. To allocate the pollution quota in the intermediate voltage networks, it is imperative to take into account levels of disturbance due to networks of higher voltage.

The principle of this approach is that if the network is under full load and if all the users inject at the rate of their individual limit, the total disturbance level is equal to the planning level. The limits of Stage 2 therefore represent the quota allotted to each user without restriction.

4.6.3.3. *Stage 3: accepting higher emission levels on a precarious basis*

In certain cases, a user may wish to emit disturbances that exceed basic limits authorized in Stage 2. The network operator thus carries out a thorough study of the facility to be connected or modified as well as the present and future characteristics of the network with a view to determine the special conditions that can allow the connection.

The emission limits that are approved are only allowed on a conditional and provisional basis. If the network conditions become less favorable or if other users wish to use their individual quota of pollution, the limits can be brought back to the Stage 2 level.

4.6.4. *Verification of the emission limits after commissioning*

4.6.4.1. *Harmonics*

The problem is very complex. Since the sources are multiple, the voltage and current harmonics of a customer are not necessarily only due to his own distorting facilities. Moreover, since the planning levels and the emission limits are defined in statistical terms, emission levels cannot be determined only by a spot measurement before and after the switching on of a disturbance facility.

There are methods where the voltage and the supply current to a customer are recorded over several days and the variations in the measured harmonics are used on the basis of their origin (at the customer's site or in the network) to finally derive emission level statistics that can be directly compared with the fixed limit [YAN 96]. These methods also provide the harmonic impedance of the network and the impedance of the customer's facility.

However, these methods require very precise measurements and are particularly sensitive to phase angle errors. Errors can be introduced by the data processing algorithms ("spectral leakage", "sample skewing", etc.) and even more by measuring transformers.

Since these methods are not yet sufficiently mature to be introduced in the contracts, pragmatic but less sophisticated simplified approaches are generally used. For example, harmonic voltages are measured for a week at the common coupling points in the absence of disturbance facility and then for another week with the facility. For harmonic row h and percentile p, the following equation can be written [IEC 96]:

$$\mathrm{Ehp} = \sqrt[\alpha]{\mathrm{Uhp}_2^{\alpha} - \mathrm{Uhp}_1^{\alpha}} \qquad [4.4]$$

where

– Ehp = emission level

– Uhp_1 = harmonic voltage without disturbance facility

– Uhp_2 = harmonic voltage with disturbance facility

– α = exponent of the law of addition (1 for $h<5$, 1.4 for $5 \leq h \leq 10$, 2 for $h>10$)

As this estimate could prove pessimistic (due to external influences and exponents higher than 1 in the law of addition), it is completed by a harmonic current measurement of the facility. However, this second estimate can also be pessimistic (more so if the facility contains filters: the current is important but

corresponds to cleaning up and not pollution of the network) and only the smallest of the two emission level evaluations is retained.

4.6.4.2. *Flicker*

Several simplified methods have been developed based on the assumption that the term R·ΔP is negligible as against the term X·ΔQ in the approximate equation:

$$\frac{\Delta U}{U} \cong \frac{R \cdot \Delta P + X \cdot \Delta Q}{U^2} \qquad [4.5]$$

With the progress achieved in reducing the reactive power variations (supplying fluctuating facilities through sophisticated converters, using active conditioners, etc.), the above assumption is less and less valid.

The only known method that seems to give correct results is the method that records voltage waves (at the PCC) and current (of the fluctuating facility) [COU 01]. Using digital simulation, the recorded current is then fed to the network model with contract impedance and the fluctuating voltage generator, whose phase angle is at all times equal to that of the recorded voltage, is determined (the phase shift between voltage and current should be retained to respect the respective importance of active and reactive power variations). The digital simulation of the flicker meter provides the flicker level that would be produced by the facility if it was the only source of flicker and if the network impedance was that of the contract (which satisfies the definition of the emission level).

4.7. Controlling power quality

Once the quality indices are defined and the measurement and evaluation facilities are available, it is possible to define quality objectives and to verify if they are satisfied. The tendency seems to be to make the network operators pay the penalty for not meeting the required objectives [ALL 00, VAN 01]; some could even support the idea of paying compensation for any interruption in supply. On the other hand, there is a tendency to want to reduce the transmission and distribution cost, which could amount to avoiding excessive quality standards. It is therefore not sufficient to be able to evaluate the existing levels of quality. There is a growing need to control them.

4.7.1. *Voltage continuity*

The competitive electricity market entails lots of changes. The sequence generation – transmission – distribution is no longer valid because [ALL 00]:

– the power generation is divided amongst several independent producers who compete with each other;

– the distributed power generation often connected to the distribution systems plays an important role.

The transmission network planning follows mainly a deterministic approach (N-1 criterion, etc.). However, the present trend seems to give more importance to the obligation to perform rather than to the obligation of means.

The design of the system is obviously not the only factor that influences the final voltage continuity level (reliability of supply). Other important factors are the component reliability, selectivity of protection, maintenance and operation procedures. Costs also play a decisive role, particularly the interruption costs, in achieving the optimum described by the well known curve in Figure 4.15.

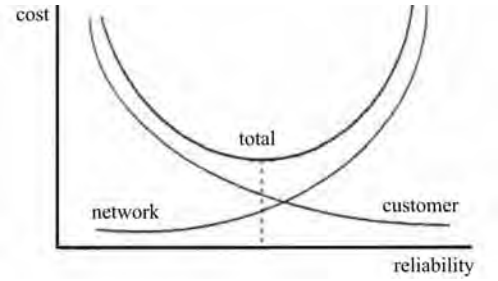


Figure 4.15. *General cost of voltage continuity*

Efforts are being made to have a better control of the voltage continuity (supply reliability). For example:

– there are attempts to bridge the two approaches – deterministic and probabilistic – for planning and operation of the systems rather than consider them as mutually exclusive branches of an alternative [ALL 00];

– trials are underway to establish links between objectives of voltage continuity and reliability specifications of electrical equipment; for example, EDF (Electricity of France) uses two complementary methods [DES 00]:

- a top-down approach, known as “allotting probabilistic objectives”, which deduces the reliability specifications of station equipment from the voltage continuity objectives,

- an ascending approach calculating the reliability of the HV stations from the reliability of the components thus enabling a comparison between diverse architectures.

4.7.2. *Voltage quality*

4.7.2.1. *Frequency*

It is known that the responsibility of the transmission system operator (TSO) is to monitor the participation of his regulating zone in the primary and secondary frequency regulation of the synchronous European grid. This involves specifying exactly the contribution of the active producers in the regulating zone (the corresponding "ancillary services" can, for example, be bought by the TSO from some of the producers).

4.7.2.2. *Amplitude (from the point of view of voltage dips and short interruptions)*

As in the case of long interruptions, the voltage dips and short interruptions are influenced by the design of the system, component reliability, selectivity of protections and maintenance and operation procedures. Good simulation software can be very useful in several respects:

– as complementary tools for permanent monitoring (of course it requires many years before statistically significant data can be collected and in the meantime the system can develop) mainly to provide adequate information for users;

– as a decision support system to choose from various possibilities for the network development, equipment and procedures;

– as support for evaluating the financial costs involved in certain specific contractual clauses or general quality commitments.

4.7.2.3. *Amplitude (from the point of view of rapid fluctuations), waveform and symmetry*

These quality aspects have a common point: the disturbance phenomena (flicker, harmonics, unbalance) originate from the normal functioning of the so-called disturbance facilities. The quality should therefore be controlled through specification (and control) of adequate emission limits for these facilities.

4.8. Quality in a competitive market – role of the regulators

In a competitive market, the electricity quality no longer depends on the suppliers of electricity but on the network operators (transmission and distribution network). Depending on the established tariff structures, certain network operators could think of reducing their development and operational costs at the expense of quality.

To face this risk, certain regulators develop quality standards. The Council of European Energy Regulators has published a comprehensive report on how this

domain currently stands (the countries concerned are Spain, Italy, Norway, the Netherlands, Portugal and the UK) [EEC 01]. This report covers the three aspects of service quality: commercial quality, continuity of supply and voltage quality (the last two constitute what is known as “power quality”).

Generally two types of quality standards can be observed:

– the guaranteed standards that concern individual customers and imply an indemnity payment in case of non-fulfillment (automatic payment or on complaint from the customer);

– the general standards that concern a network in its totality or in a specified zone and in certain cases imply a link between performances and tariffs.

From the technical aspect of quality, it is not surprising that priority is given to the continuity of supply. For this, there are currently four types of standards:

– standards concerning individual customers (for example, duration of interruption limited to four hours);

– standards concerning the worst serviced customers (for example, limiting the percentage of customers for whom the annual outage exceeds a certain value and limiting the value attained);

– standards relating to the annual evolution of quality (for example, the difference between the anticipated and the observed interruption costs can influence the tariffs of the following year [LAN 01]);

– average standards (for example, limiting the annual outage time – SAIDI in distribution, AIT in transmission).

Up to now there have not been many requirements of the regulators with respect to voltage quality. This quality is referred to in the EN 50160 [CEN 99 – European Committee for Standardization] standards. However, the intention is to deal exhaustively with the question at a later stage.

It is necessary to highlight the difficulty that always appears while fixing the quality standards – or simply compare the performances of different networks or during different periods: how to deal with the external factors that are independent of the will of the network operator:

– situations beyond control;

– influence of third party;

– meteorological, climatic and geographical conditions;

– load density, etc.

Generally, the objective looked for is neither to improve the quality nor to maintain it at its present level. The aim is rather to arrive at the optimum quality, the one that corresponds to the socio-economic optimum. As indicated in Figure 11.15, this signifies that the intention is to reduce the total cost of network development and operation on the one hand and the costs supported by the customers due to quality defects on the other. The standards related to the annual evolution of quality aim directly at this objective.

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Chapter 5

Applications of Synchronized Phasor Measurements to Large Interconnected Electric Power Systems

5.1. Introduction

Maintaining the security of the large interconnected power systems requires a thorough knowledge of the network behavior as well as a conception of its development. Recent developments in certain measuring technologies related to electric power systems enable us to obtain real-time voltages (magnitude and phase), currents (magnitude and phase) and the frequency of the power system in a synchronized manner. This information is very useful for the network operators as it provides a good picture of the system and makes it possible to follow its evolution during operation. Thus, it becomes possible to have a better control over the various electrical quantities and to have more advanced functions for protection, fault detection, low-frequency oscillation damping, etc.

A precise knowledge of voltages (magnitude and phase) and currents (magnitude and phase) at every point of the network enables us to evaluate the stability or the stability margins of this network without much difficulty. These quantities are also used for state estimation of the network, load distribution calculations and fault detection and location. Real-time measurement and availability of these quantities enable the operators of large power systems to efficiently handle dangerous situations that can alter the security of a part or all of the power system.

Chapter written by Nouredine HADJSAID, Didier GEORGES and Aaron F. SNYDER.

This chapter focuses on the use of synchronized measurements and their applications to electric power systems, primarily increasing their power flow capacities and improving their stability. The first part of this chapter consists of a general presentation of the concepts related to *synchronized phasor measurements* or *SPM*. This will be followed by a presentation of the possible applications using this type of information and the devices that were used in each application. The last part describes the results obtained after simulating the improvement in damping of the low-frequency power oscillations of the interconnected power systems using synchronized measurements.

5.2. Synchronized measurements

The measurement and communication systems used commonly in power systems do not automatically provide any precise knowledge of the state of a large interconnected electric power system. Often, parameters that are required and should be known are accessible only after several exhaustive calculations of the state of the network. These calculations are quite intensive depending on the problem under study, the size of the network or the complexity of the modeling method used. The computing time can therefore be prohibitive in certain cases causing certain impact on the knowledge or control of the security of the system in real time.

The real-time utilization principle of this information in the electrical power systems can be illustrated by the drawing in Figure 5.1, which represents a simplified model of an interconnection line between two subnetworks A and B.

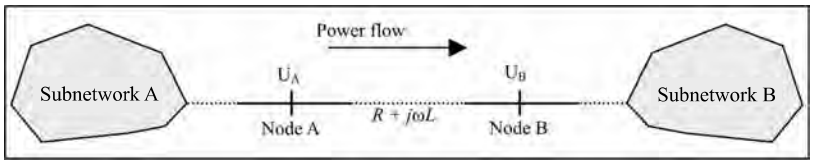

Figure 5.1. *Transmission line model for power transfers*

with:

– $X_{line} = j\omega L$: line impedance (resistance is not considered),

– U_A, U_B: voltages at nodes A and B respectively,

– Φ_A, Φ_B: phase angles of voltages U_A and U_B respectively.

The power transfer in the line between nodes A and B can be expressed through:

$$P_{Wheeling} = \frac{U_A U_B}{X_{line}} \sin(\Phi_A - \Phi_B) \qquad [5.1]$$

The phase angles can be obtained through calculation (of load distribution) or through measurement using suitable devices. The notion of a "phasor" can thus be defined as a complex quantity in polar form (see Figure 5.2).

In recent years certain devices have been developed to measure electrical quantities in a synchronized manner [MAC 93]. These devices, which use the American military's Global Positioning System satellites or GPS, are capable of providing measurements (U, I, Φ, ε, etc.) with a precision of a few microseconds. Thus, a quantity such as the phase angle of the voltage at a node can be expressed with an error less than 0.018 degrees at 50 Hz. This precision satisfies the precision necessary for certain network calculations.

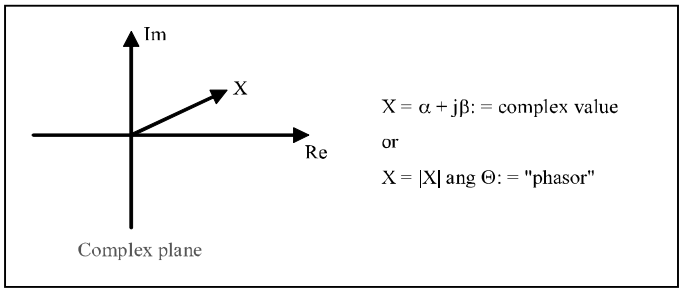

Figure 5.2. *Notion of a "phasor"*

A summary of these applications and the corresponding precision required is given in Table 5.1.

Application	Required precision
State estimator	≤0.1 degrees
Stability supervision, control	≤1 degree
Fault detection	≤0.1 degrees
"Adaptive relaying"	≤0.1 degrees
Analog pre-filtering stability	≤0.1 degrees

Table 5.1. *Summary of network applications for the SPMs and required precisions [WOR 94]*

5.3. Applications of synchronized measurements

The SPM applications (Figure 5.3) can be divided into four main sections: state estimation, protection, supervision and network control. These sections are neither mutually exclusive nor exhaustive. In fact, a measurement given by a device for the state estimator can also be used for a machine control loop or FACTS (*flexible AC transmission system*) device or for protection systems.

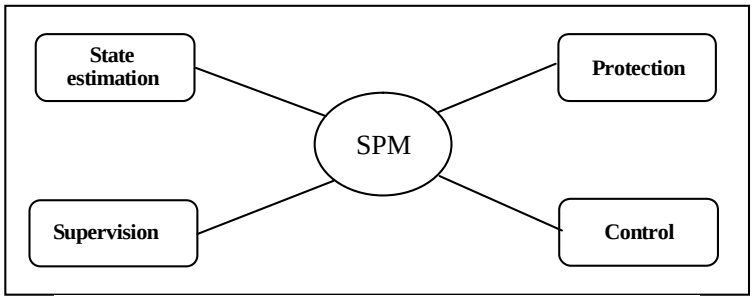

Figure 5.3. *Synchronized phase measurement (SPM) application domains*

5.3.1. *State estimation*

State estimation (Figure 5.4) includes two types of estimations: static, or conventional, estimation and dynamic estimation.

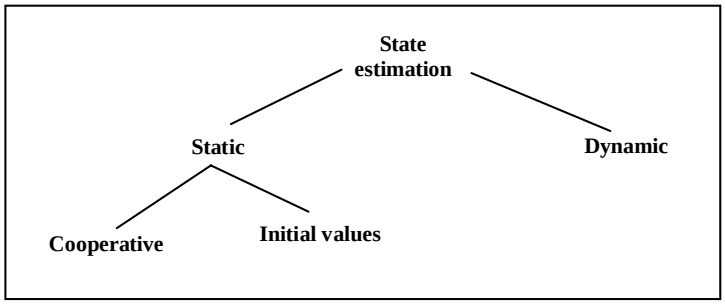

Figure 5.4. *State estimation*

A state estimator receives information from the network (measuring devices) in a sampled manner. The corrected electrical state of the power system is then calculated based on this information. However, not all the quantities obtained are measured at the same moment nor are they received by the corresponding

calculation software program level at the same instant. It is therefore clear that calculating the state of the power system can take a very long time, particularly in the case of large power systems.

If, however, these electrical parameters can be obtained in a synchronized manner (using suitable measuring devices) then the "conventional" state estimation needs redefining. In fact, if all the quantities necessary for determining the state of the power system can be measured and used at the same time then "estimation" is no longer necessary since it is possible to "determine" the state of the power system at the time of synchronization provided all the necessary measurements are available and are precise. While a worthy goal, this "determination" cannot always be realized because all of the measurements are not always available (e.g., the network is not fully equipped with measuring devices using synchronization). In addition, often these measurements are affected by various errors (e.g., errors of measurement, transmission, instrument transformer saturation, etc.).

However, assuming that the electrical parameters are synchronized and are transmitted in real time to the control or telecontrol center, it is possible to get a real-time state of the power system. In addition, this state gives information on the dynamics and evolution of the system [PHA 93, BUR 94a].

In all cases, using synchronized measurements, even if there are not many, can improve the precision of the existing "conventional" state estimator.

5.3.2. *Network supervision*

There are two main branches of supervision and surveillance applications of an electric power system (Figure 5.5): events and stability.

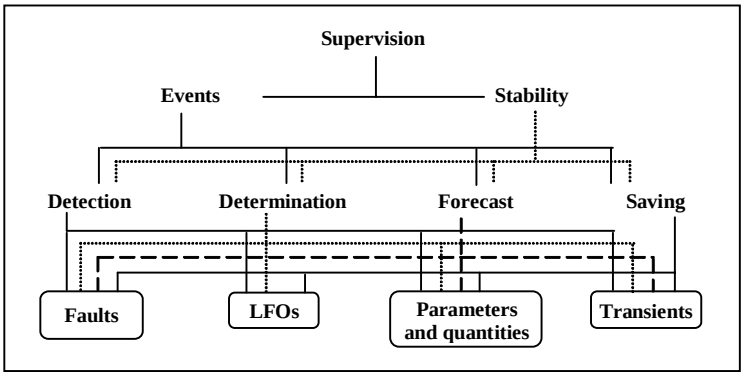

Figure 5.5. *Electrical network supervision*

It can be seen that all the sub-branches are interconnected except low-frequency oscillation (LFO) forecast. In fact, it is not easy to foresee these oscillations as their existence does not depend on the use of a supervising device, whereas it is possible to detect, determine, anticipate and store the network data based on events such as line faults. As shown in the chart in Figure 5.5 the same work can be carried out for studies related to the stability of the system.

5.3.3. *Power system protection*

The main advantage of using synchronized measurements is that they help in improving the already installed protection systems in the networks. It is a part of the aspects related to synchronization and speed of the measuring devices. In opposition to the currently installed systems that take one second for the actions of the operators, it takes just a few milliseconds using synchronized measurements.

The second advantage is the possibility of using adaptive protection. Instead of determining the fixed recovery actions following a large number of stability simulations, the circuit breakers are activated in real time depending on the parts of the network to be restored. While the aim of this concept was to address the various faults that occur in the network [PHA 91], it also enables us to envisage other applications such as forecast-correction algorithms incorporating the synchronized values [OHU 90] and [MAT 95]. Other applications, except those related to fault detection and location, are shown in Figure 5.6.

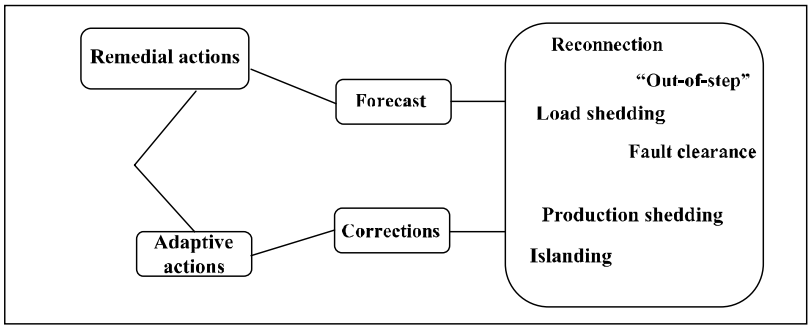

Figure 5.6. *Electric network protection*

5.3.4. *Power system control*

The application of synchronized measurements to the field of power system control (see Figure 5.7) and regulation seems quite promising [ROS 88, SMI 94,

SNY 97]. In fact, in an interconnected power system all the control systems have a local feedback loop. In case of serious events in the network, these control loops do not take into account the system as a whole. However, this "overall" vision is necessary to avoid fault propagation or system collapse. Moreover, FACTS devices are also equally likely to use synchronized signals while coordinating their operations in the network.

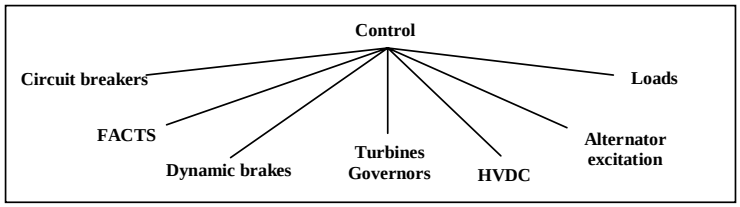

Figure 5.7. *Power system control*

5.4. Application of synchronized measurements to damp power oscillations

In this section the low frequency power oscillation problem will be discussed. Then the theory and use of the power system stabilizer, or PSS, controller in the power systems is provided. After presenting the theory, a control methodology for this type of controller will be given in detail. Results of the application of the controller on a test system will also be presented and discussed.

5.4.1. *Power oscillations*

For a very long time, power oscillations have been the cause of major damaging problems for the power systems. Increases in the size of the networks and their interconnection have lead to a situation that, though economically beneficial, encourages fault propagation and gives rise to these oscillations.

The automatic voltage regulators, or AVRs, installed on the generators connected to the network make it possible to maintain the stator voltage as constant. They also contribute towards maintaining the stability of every machine and enable us to increase the maximum power that can be transmitted. However, due to extension of the networks, increase in power exchanges as a result of deregulation of the electrical energy markets, and also due to severe operating conditions, these regulators seem much less efficient in maintaining stability.

The most commonly used solution is the application of a second feedback loop on the generator in the form of a supplementary signal injected at the voltage

reference input of the AVR. By choosing an appropriate machine that is best suited to be equipped with a power system stabilizer, it is possible to maintain the stability of the interconnected power system for a wider range of operating points compared to simple voltage regulation; this is achieved through a judicious use of advanced tuning methods for the PSS controllers [IEE 94].

On the other hand, controllers that have synchronized measurements (SPM) as input signals are capable of providing more significant stability margins. This type of result is shown further below through a study on a 4-machine test system.

Small-signal or small disturbance analysis method was applied to the 4-machine test system of Figure 5.8 to highlight power oscillations and their damping by the controllers. While calculating the oscillation profile (through modal analysis) of this network, three electromechanical modes appear. These modes are shown in Table 5.2.

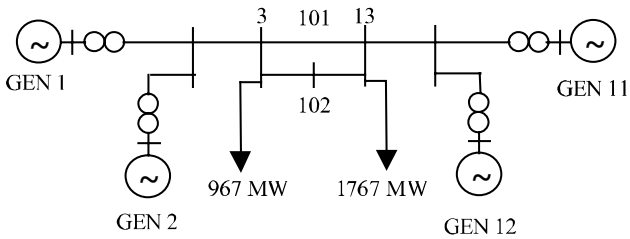

Figure 5.8. *4-machine test system [KUN 94]*

Mode	Eigenvalue	Frequency (Hz)	Damping rate
1	-0.5997 ± j 7.0365	1.1199	0.0849
2	-0.6060 ± j 7.2470	1.1534	0.0833
3	0.0296 ± j 4.1785	0.6650	-0.0071

Table 5.2. *Electromechanical modes of the 4-machine test system of Figure 5.8*

Mode	Machine	PF: speed	PF: angle
1	1	0.0038	0.0043
	2	0.0040	0.0056
	12	0.0040	0.0054
	11	0.0029	0.0043
2	1	0.0182	0.0012
	2	0.0149	0.0012
	12	0.0139	0.0010
	11	0.0183	0.0017
3	1	0.0564	0.1020
	2	0.0976	0.1289
	12	0.0756	0.0782
	11	0.0343	0.0677

Table 5.3. *Participation factors of the 4-machine test system of Figure 5.8*

The oscillation modes, their frequency of oscillation as well as their damping factors are given in Table 5.2. The form of these three modes indicates the existence of local and inter-area types of modes. The first part of the mode classification consists of studying their participation factors (denoted as "PF") which are summarized in Table 5.3. To identify the modes of interest, mainly those that are the inter-area type (the most critical), the mode forms based on the matrix of the right eigenvectors found in Table 5.4 are studied. Upon observing the value of the participation factors as well as the mode form, two "local modes" (modes 1 and 2) connected to two machines of the same area and an inter-area mode (mode 3) between the machines of the two regions can be noticed. The choice of location of the controller is now indicated: the site where the participation factor of the machine for inter-area oscillations is the greatest. By these factors it can be seen that it is machine 2 that participates the most in the critical oscillation mode, then machines 1, 12 and 11. Incidentally, the mode coupling relates to a machine in every area and it is the maximum for machines 2 and 12. This result is normal due to the inter-area oscillation mode.

Mode	Machine	Mode form
1	1	0.1017 ± j 0.4662
	2	-0.1263 ± j 0.5001
	12	-0.0287 ± j 0.0187
	11	0.0545 ± j 0.0544
2	1	-0.0372 ± j 0.0412
	2	0.0283 ± j 0.0921
	12	-0.1951 ± j 0.4770
	11	0.2045 ± j 0.4235
3	1	-0.0712 ± j 0.4106
	2	-0.1099 ± j 0.2961
	12	0.0799 ± j 0.3526
	11	0.1108 ± j 0.3912

Table 5.4. *Mode forms for the 4-machine test system of Figure 5.8*

Machine	Factor	Order
1	3.1413	4
2	4.0747	2
12	4.5083	1
11	3.2869	3

Table 5.5. *Controllability factors for a controller in the 4-machine test system of Figure 5.8*

Another useful calculation is the controllability factor. By calculating these factors in open loop, there is an indication of the effect of a control signal *j* on a mode *i* of oscillation. For the system represented in Figure 5.8, the factors obtained for a controller on one of the machines as well as their classification are given in Table 5.5. A second calculation useful for classification is that of observability linked to mode *i* through machine *j*. The observability factors and their classifications for input signals of a controller are given in Table 5.6 where “Pelectrical” refers to the electrical power signal, “Pmechanical” refers to the mechanical power signal and “Pacceleration” refers to the acceleration power signal.

	Factor	per	input	signal	
Machine	**Pelectrical**	**Pmechanical**	**Pacceleration**	**Speed**	**Order**
1	0.2022	0.0404	0.2426	0.0035	3
2	0.1200	0.0266	0.1466	0.0023	4
12	0.2835	0.0601	0.3436	0.0052	2
11	0.3008	0.0660	0.3669	0.0057	1

Table 5.6. *Observability factors for a local controller*

Finally, Tables 5.7 and 5.8 show the observability factors for an input signal that contains a local and a remote signal (resulting from the synchronized measurements – SPM). The results in Table 5.7 show that these factors are higher for remote signals than for local signals.

Machine (loc-rem)	Pacceleration	Speed	Order
11-1/1-11	0.6041	0.0091	1
11-2/2-11	0.5133	0.0080	3
12-1/1-12	0.5823	0.0086	2
12-2/2-12	0.4901	0.0075	4
11-12/12-11	0.0266	0.0005	6
1-2/2-1	0.1045	0.0013	5

Table 5.7. *Observability factors for a "remote" controller*

5.4.2. *Theory of PSS controllers*

The large interconnected power systems are regularly the host of spontaneous, low-frequency power oscillations which are linked to the dynamic stability of those systems. These oscillations can limit the power flow on the interconnected lines between regions of power generation and consumption and even cause instability of the entire power system. The first solution to this problem was to apply damper windings on machines and turbines. Unfortunately, when the power systems started operating close to their stability limits, the weakness of the synchronizing torque available to damp these oscillations was found to be causing system instability.

To avoid this second problem, voltage regulators are installed on the generators. This improved the steady-state stability, but the transient stability still remained a damaging problem for the power system. Also, with the interconnected systems becoming larger and larger with greater amounts of power flowing across these interconnections (mainly the VHV lines), an increasingly nefarious instability factor was added compared to earlier situations.

The complete structure of a machine (generator/alternator) with the "AVR" and "PSS" controllers is given in Figure 5.9. The most important control parameters of the machine are specified: mechanical torque *Cmech*, mechanical power *Pmech*, speed, excitation voltage *Uexc*, electrical power *Pelec*, and output voltage *Uout*.

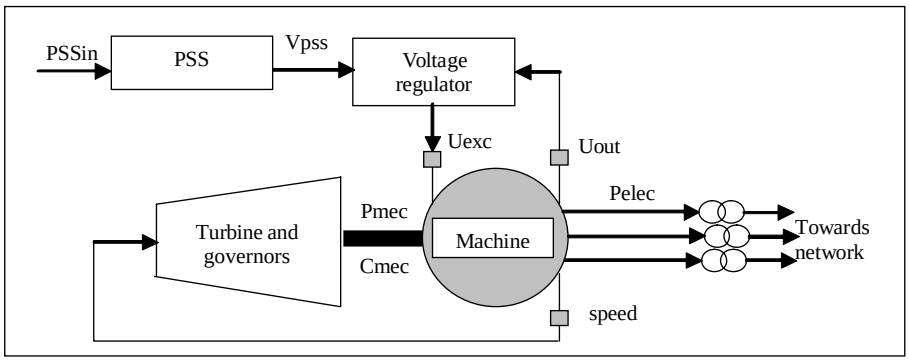

Figure 5.9. *Overall structure of a machine connected to the network*

5.4.3. *Controller tuning by residue compensation*

The main task of a "PSS" controller is to provide a damping torque in phase with the oscillation mode in the network, or, in the case of a local oscillation, in phase with the concerned machine. Figure 5.10 shows the principle of a feedback loop structure which acts on the voltage regulator of the machine in order to damp these oscillations. This IEEE [IEE 94] type structure is "conventional", consisting of a gain and a phase correction. This compensation is represented by the lead-lag blocks that contain the quantities *T1-T4*. The PSS gain *Ks* and the high-pass filter (block *Tw*) are also represented. The input signal is chosen from among the useful electromechanical parameters such as those shown in Figure 5.9. To avoid a very slow response from the controller, the "PSS" does not act on the speed governor of the machine. Instead, the output signal from the "PSS" is injected into the voltage regulator of the machine, where it acts on the excitation voltage. This approach enables us to compensate the oscillation phase irrespective of its control.

The tuning of a "PSS" consists of finding a good phase compensation which remains valid for the widest range of possible operating points of the network. This tuning has to be efficient and robust. A large number of tuning methods for the "PSS" controllers have been proposed and applied in the electric power systems throughout the world. Each one of these methods has its own phase compensation determination irrespective of the machine and its network configuration.

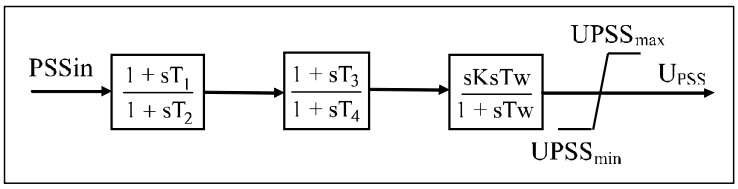

Figure 5.10. *Structure of a "conventional" PSS controller*

There is a major disadvantage: most of the methods are developed and tested on the model of a network consisting of a machine connected to an "infinite bus". This type of design is necessary due to the significant number of differential equations that are used to model a network. These equations are impossible to handle without the use of digital computing, in particular for large power systems. Once the infinite-bus tuning approach has been completed for a single controller, it may then be extended to the entire power system. However, a second disadvantage appears: the "PSS" acts only on the signals of its own machine. This controller does not have an "overall" vision of the network. In order to further distinguish it from a controller using remote quantities it is called a local feedback controller (LFC).

In the same manner, a PSS controller with inputs from remote measurements (synchronized measurements or SPM) will be called a remote feedback controller (RFC).

A typical tuning of a controller is possible from small-signal analysis. The network, represented as a state-space realization, is constructed using desired input and output quantities for the controller. After calculating the matrices of the state-space realization **A**, **B** and **C**, the controllability and observability factors are calculated. Each factor is described by its own signal:

– controllability: $B_{i,\Delta Vpss}$

– observability: $C_{i,\ \Delta Pssin}$

The sensitivity R_i of an eigenvalue λ_i with respect to the input and output signals of a controller can be described as follows:

$$Ri = \frac{\partial \lambda_i}{\partial q} = B_{i,\Delta Vpss} * C_{i,\Delta Pssin} \qquad [5.2]$$

This sensitivity is called the residue (Ri) of the eigenvalue λi. This factor is represented in Figure 5.11.

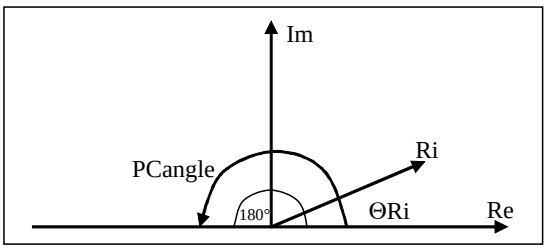

Figure 5.11. *Eigenvalue residue*

The sensitivity factor Ri, its phase angle ΘRi and the phase angle compensation PCangle situated in the complex plane are clearly indicated.

The control problem involves finding the compensation necessary to create the trajectory angle of an eigenvalue equal to 180º by varying the lead-lag values and then finding a gain that can maximize the effect of the controller at a given moment.

Parameter	RFC	PSS-LFC
K	15	11.2947
T1	0.1	0.1432
T2	2.0	2.1511
T3	0.2	10.0
T4	3.0	10.0
Tw	15	30

Table 5.8. *Controller tunings*

For the 4-machine test system, this approach yields the control presented in Table 5.9. Another method based on the AVR/PSS coordination was applied to the 4-machine test system and its adjustment was optimized (see Table 5.9). The critical mode, i.e., the unstable mode in the beginning becomes stable at the nominal operating point with these adjustments.

Other design techniques using advanced concepts such as LQG controller synthesis [BOU 97] or linear robust control synthesis by LMI (linear matrix inequalities) approaches were also successfully applied; however, they will not be dealt with in detail here.

It should however be noted that the linear controller synthesis using the LMI approach amounts to solving a convex optimization problem. This type of approach can be highly flexible in considering the control objectives: the energy deployed can thus be minimized and the disturbances that can act on the system can be attenuated (robustness objective), while still considering the constraints, for example, of locating the poles in closed loop (control of damping) or still taking into account the uncertainties on the model of the system [AMM 00].

Incidentally, it is equally possible to take into account the effect of the lags induced by the synchronized measurements during synthesis of the controller [SNY 99]. The controllers thus obtained, however, have the disadvantage of being of a high order (typically corresponding to the number of state variables of the network considered). Fortunately, using reduced model techniques these controllers can be simplified *a priori* (if the network model is reduced) or *a posteriori* (if the controller model is reduced).

It can also be noted that other approaches based on non-linear automation techniques (approaches using input/output linearization or using Lyapunov functions) have been the subject of research for several years. The potential advantage with these approaches is that they are capable of considering the entire non-linear phenomena that can be modeled; this is not possible with small signal analysis.

However, there are still no non-linear controller synthesis methods available today that offer the flexibility of the linear controller approach (LMI in particular) particularly in considering the robustness objectives. Moreover, the absence of frequency analysis tools constitutes a major handicap for the non-linear approach. Finally, implementing these controllers requires redesigning the real-time control-command architecture of the networks.

5.4.4. *Results*

The tuning of a controller employing remote signals (RFC) can be accomplished in the same manner as that of a conventional controller (LFC, PSS). After the tuning parameters are obtained, the optimum gain for the controller irrespective of its position and its tuning can be found through studies related to the system eigenvalues. A RFC controller with two inputs was tuned and placed in the test system on machine 12. The structure of this controller is shown in Figure 5.12 (see also Figure 5.8).

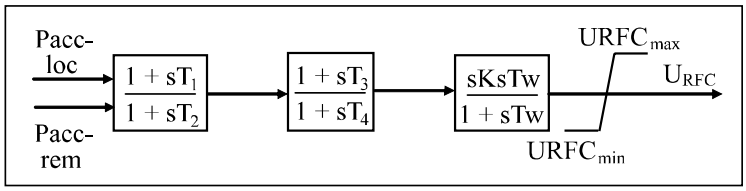

Figure 5.12. *Double input RFC controller*

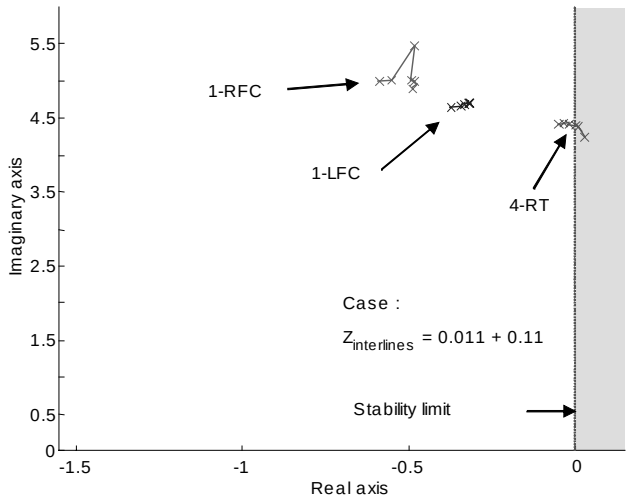

Figure 5.13. *Eigenvalues for nominal case, all the controllers*

Once the LFC and RFC controllers are parameterized, the continuation power flow method [NAY 95, NAY 96] was applied to study the robustness with respect to the power flow capacity in the 4-machine test system. The following figures contain the results of the test system with three types of controllers: only voltage regulators

(4-RT), only one LFC controller (1-LFC) situated on machine 12 and only one RFC controller (1-RFC) placed on machine 12 using measurements from generators 12 and 1.

5.4.4.1. *Steady state analysis*

This part of the chapter describes the first continuation power flow method analysis of every controller at the nominal operating point (Pwheeling = 381MW) for the interconnection lines at Z interlines = 100% (nominal impedance). Figures 5.13 and 5.14 show the migration of eigenvalues and damping factors of the three controllers.

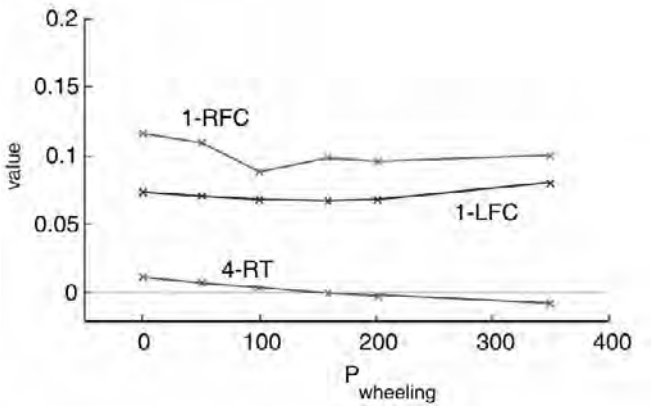

Figure 5.14. *Damping factor migration for the nominal case for all the controllers*

5.4.4.2. *Dynamic analysis*

The second analysis represents the performance of every controller following a short circuit arising at an arbitrary point in the network. The following figures contain plots of the parameters specific to this type of analysis: the electrical power of the machine where the controller is placed, the speed of the same machine and the wheeling power in the interconnection lines (Figures 5.15, 5.16 and 5.17). Every curve clearly indicates the response of the 1-RFC and 1-LFC controllers and it can be noted that the RFC controller offers better performance than the LFC controller.

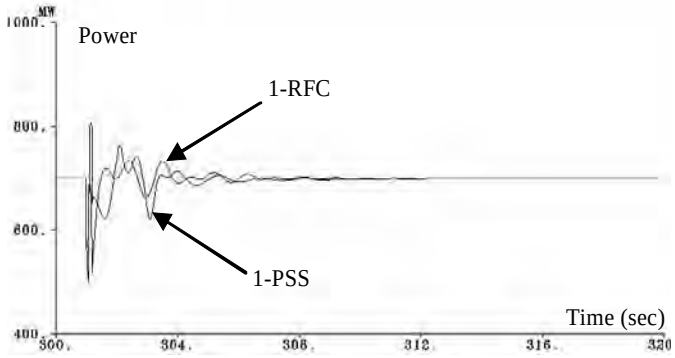

Figure 5.15. *RFC against PSS, Pelec of machine 12 at Pwheeling = 500 MW*

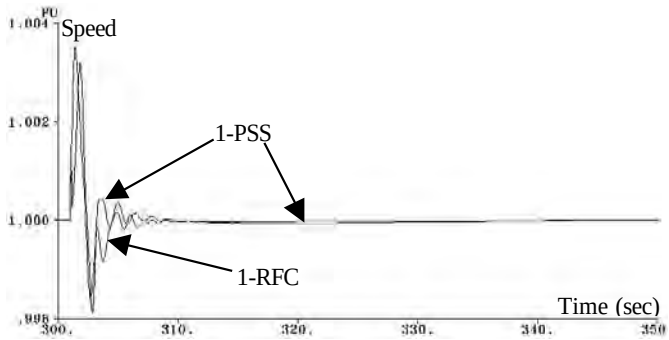

Figure 5.16. *RFC against PSS, speed of machine 12 at Pwheeling = 500 MW*

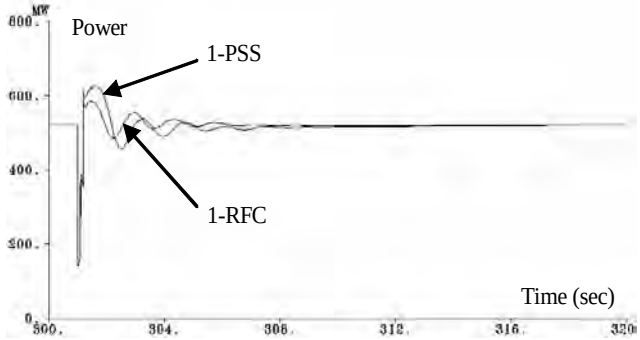

Figure 5.17. *RFC against PSS, wheeling capacity at Pwheeling = 500 MW*

5.5. Conclusion

To conclude, it has been shown that synchronized measurements, and in particular synchronized phasor measurements, provide important information for control, calculation and stability improvements for a large interconnected power system. In particular, with synchronized input signals, the controllers placed in an optimum manner are better for the dynamic stability of the system than the controllers using local parameters. These controllers are designed to increase the wheeling capacity in large power systems by maintaining the stability with enhanced damping of the very low-frequency power oscillations.

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5.7. Appendices

A. *Controller design*

For the study carried out here, a state-space realization is used to model the associated network and controllers. This representation uses differential equations which form the basis of a small-signal study wherein the system is linearized around a given operating point.

These equations are written in the following state-space realization form [KUN 94]:

$$\begin{cases} \dot{x} = Ax + Bu \\ y = Cx + Du \end{cases} \qquad [A1]$$

where x is the state vector, u is the input variable vector, y is the output variable vector, A is the state variable matrix, B is the input variable matrix, C is the output variable matrix and D is the matrix that defines the dependence of the input variables with respect to the output variables. This representation can be replaced by an input/output representation defined by a transfer function matrix using the Laplace transform. In this case, the network represented by *P(s)* is linked to the controller *K(s)* through selected outputs y and input variables u where:

$$P = \begin{bmatrix} A & B \\ C & D \end{bmatrix} \text{ and } u = -K.\,y \qquad [A2]$$

Eigenvalues λ_i of matrix A are the solutions of det $(A-\lambda_i I) = 0$ which makes it possible to define the oscillation mode of the system as follows [KUN 94]:

$$\lambda_i = \sigma_i \pm j\omega_i \qquad [A3]$$

The frequency and damping factor of every oscillation mode can thus be defined as:

$$\text{frequency: } f_i = \omega_i / 2\pi \qquad [A4]$$

$$\text{damping factor: } \zeta_i = -\sigma_i / \sqrt{\sigma_i^2 + \zeta_i^2} \qquad [A5]$$

If damping factor $\zeta_i>0$, the oscillation corresponding to the i*th* eigenvalue is damped, and if $\zeta i<0$ the oscillation corresponding to the i*th* eigenvalue is undamped. In addition, the nature of an oscillatory mode *i* (particularly if it is a local mode or an inter-area mode) can be determined based on the study of column vectors of the

right modal matrix, and more readily using a graphic representation in the complex plane of these different values.

The introduction of a controller amounts to transforming the open loop system into a closed loop system. This results in a shift of eigenvalues λ_i. The aim is to position the eigenvalues, particularly those related to the inter-area mode, in a zone of the complex plane that guarantees the system stability (that is $\sigma_i<0$), and therefore to increase the associated damping factor for the largest number of possible operating points of the power system.

B. *Glossary of the abbreviations used*

AVR automatic voltage regulator

FACTS flexible alternating current transmission system: FACTS "devices" are power electronic devices used to improve the stability of the power system

GPS global positioning system satellites: system of American satellites which send synchronization signals

LFC local feedback controller: controller that uses only a local input signal (typical "PSS" controller)

PMU phasor measurement unit: a device that measures voltage and current phasors (and frequency) with a synchronized clock using GPS satellites

PSS power system stabilizer: control device that compensates electromechanical oscillations of a machine

RFC remote feedback controller: controller that contains at least one remote input signal which can be measured by a PMU

SPM synchronized phasor measurements: synchronized measurements of voltage (magnitude and angle) or current (magnitude and angle) calculated by a PMU

Chapter 6

Voltage Instability

6.1. Introduction

Power transmission through an electric transmission network is accompanied by drops in voltage between production points and consumers. In normal operating conditions, the drop in voltage is about a few percent of the nominal voltage. One of the issues faced by planners and operators is ensuring that the voltage at the different busbars of the network remains under any conditions within the prescribed limits, especially in conditions of high load and/or following certain likely fault conditions. In some circumstances, however, in the seconds or minutes following the appearance of a disturbance, voltage can decrease in a catastrophic manner, to the point that power cannot be correctly transmitted to the consumers and the stability of the system can be put at risk. The mechanism that underlines this dramatic drop of voltages is *voltage instability* and the resulting problem, *voltage collapse*.

In simple terms, voltage instability is due to the behavior of the loads, which tend to recover the power consumption over and above that which can be supplied by the combined transmission and generation systems.

In a number of networks in the world, voltage instability is considered a major source of failure, at least as important as thermal overloads on equipment (and the associated risk of cascade trippings) or angular instability (loss of synchronism between generators), which have been known for a longer time. Several factors contribute to this state of affairs:

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– as we know, the construction of new electric lines is becoming more and more difficult, often delayed and sometimes impossible;

– the concentration of production in larger and larger power stations has decreased the number of points where voltage is maintained in the network and has increased the transmission distances of electricity between power stations and consumers. Certainly, the emergence of decentralized generation is going to reverse this tendency, by bringing the producers closer to the consumers. However, these new power sources will have to provide additional services such as voltage regulation and availability of reactive power reserves;

– heavy use of shunt capacitors to maintain the voltage profile makes it possible to transmit greater quantities of power but moves the instability point closer to the normal operating range;

– voltage instability is often triggered by the loss of transmission and/or production equipment, fault conditions whose occurrence is relatively highly probable (as compared for example to that of a three-phase short circuit, considered in angular transient stability);

– finally, the deregulation of the electricity market has led to power grids being made to work closer to their physical capacity, for economic reasons. It is thus necessary to evaluate these capacity limits even more than in the past, especially with relation to the risk of voltage instability.

The considerable number of power outages suffered and the fear of other major failures have motivated significant research in the field of analysis of voltage stability and security during the past 15 years. Among the vast range of publications, the following can be cited as an introduction (but certainly not in an exhaustive manner): some early international publications [WEE 68], [ZAB 69], [NAG 75], [LAC 78], [LAC 79], [BAR 80], [TAM 83], [BOR 84], [CAL 86], [KES 86], [CLA 87], [HAM 89], a set of five workshops wholly [FIN 88], [FIN 91], [FIN 94] or partially [FIN 98], [FIN 01] devoted to this question, reports of several work groups CIGRE [CIG 88], [CIG 93], [CIG 94a], [CIG 94b], [CIG 98] and IEEE [IEE 90], [IEE 93], [IEE 96], [IEE 00], a chapter in the reference book [KUN 94] and two monographies [TAY 94], [VAN 98].

The aim of this chapter is to describe voltage instability phenomena, and indicate the measures taken to avoid them and to go over the calculation methods used. It borrows rather largely from references [VAN 98] in which the interested reader will find more details.

6.2. Voltage instability phenomena

6.2.1. *Maximum deliverable power for a load*

The most important source of instability in a power grid is without doubt the transmission of bulk power over great distances. Voltage stability particularly concerns how electric power is brought to large consumption centers.

Let us consider the basic system with two nodes in Figure 6.1, in which a synchronous machine feeds a load through a line. For reasons of simplicity, we show this through a reactance series X and the generator with a voltage source E.

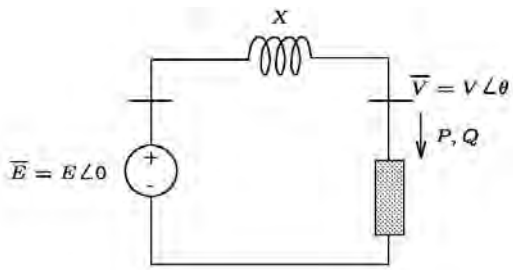

Figure 6.1. *Simple generator-load system*

In the steady-state sinusoidal regime, the operation of the system is described by the power flow equations [KUN 94], [VAN 98]:

$$P = -\frac{EV}{X}\sin\theta \qquad [6.1]$$

$$Q = -\frac{V^2}{X} + \frac{EV}{X}\cos\theta \qquad [6.2]$$

where P (resp. Q) is the active (resp. reactive) power consumed by the load, V the voltage at the node where it is connected and θ the phase angle between the two nodes (see Figure 6.1). By resolving [6.1] and [6.2] with respect to V, we easily obtain:

$$V = \sqrt{\frac{E^2}{2} - QX \pm \sqrt{\frac{E^4}{4} - X^2P^2 - XE^2Q}} \qquad [6.3]$$

Figure 6.2 shows the variation of voltage *V* with power *P* and *Q* (in fact, equivalent dimensionless quantities). Under normal conditions, the point representing the operation of the system is situated on the upper part of this surface *V(P,Q)*. Operation on the lower part, characterized by a very high current and very low voltage, is generally not acceptable.

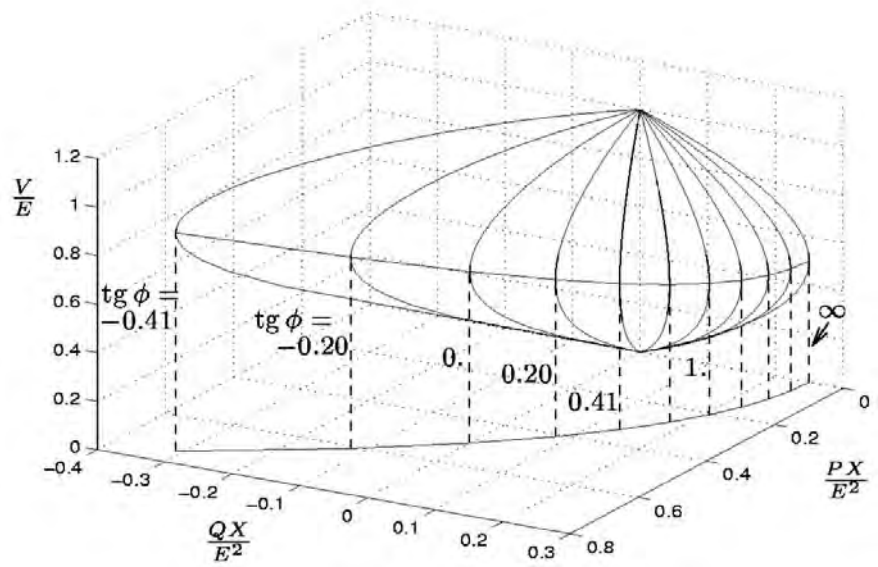

Figure 6.2. *Voltage load based on active and reactive power consumed*

This diagram confirms the existence of maximum deliverable power for the load, well known in circuit theory. More precisely, all points located on the "equator" of the surface *V(P,Q)* (where the expression under the square root in [6.3] vanishes) correspond to maximum power. The projection of this limiting curve on plane *(P,Q)* is a parabola. The latter limits the area in which the operation of the system is possible.

6.2.2. *PV and QV curves*

By cutting the surface of Figure 6.2 by vertical planes $Q = P.tg\phi$ we obtain the curves in Figure 6.3, which give the evolution of voltage with the power consumed, when the load is operating at a constant power factor. These curves, usually called *PV curves*, are widely used in a number of explanations as well as in industrial applications. *QV* curves are defined in the same manner.

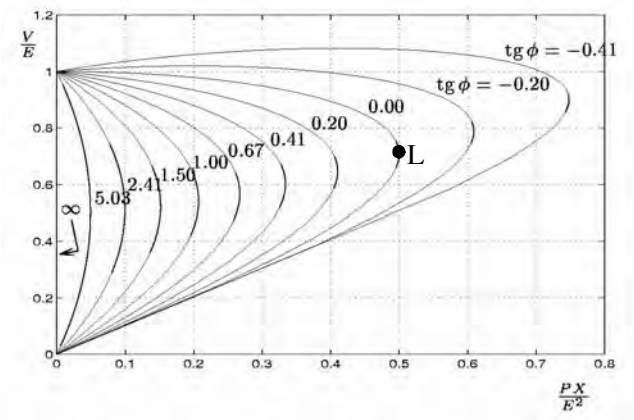

Figure 6.3. *PV curves at constant power factor (referred to by the value of tgϕ)*

Note incidentally that the above results remain unchanged if the direction of active power P is reversed. Thus, there is a maximum value of power that a generator can transmit to the rest of the system, without controlling its voltage and consuming reactive power (an induction machine, for example).

Voltage instability results from an attempt to operate beyond the maximum deliverable power. This can happen due to a significant increase in the load or, in a more realistic manner, due to an outage which decreases the maximum deliverable power, as is the case in the example detailed here below.

6.2.3. *Long-term voltage instability illustrated through a simple example*

The following example, taken from [VAN 98], is related to the system in Figure 6.4. In the latter, busbar 3 is the supply point of a distribution network. The load at this node can represent a large number of consumers fed through a medium voltage (MV) network. We show this aggregate through an exponential model (widely used in large-scale system stability studies):

$$P = P_O \left(\frac{V_3}{V_o}\right)^{\alpha} \qquad Q = Q_O \left(\frac{V_3}{V_o}\right)^{\beta} \qquad [6.4]$$

where V_o is the reference voltage and P_o (resp. Q_o) is the active power (resp. reactive) consumed at this voltage. The load is compensated through shunt

capacitors. Busbar 3 receives its power from a transformer equipped with a *load tap changer*, a device making it possible to adjust the transformer ratio *r* without interrupting the current. This adjustment is performed in discrete steps, one step corresponding to movement from one tap position to the next on the transformer. This load tap changer is equipped with a controller which adjusts *r* so as to maintain the distribution voltage within fixed limits $[V_o\text{-}\varepsilon\ V_o+\varepsilon]$ despite voltage fluctuations in the transmission network [CIG 93], [KUN 94], [TAY 94], [VAN 98]. For the sake of simplicity, the voltage setting V_o of the load tap changer is taken as the reference voltage in model [6.4].

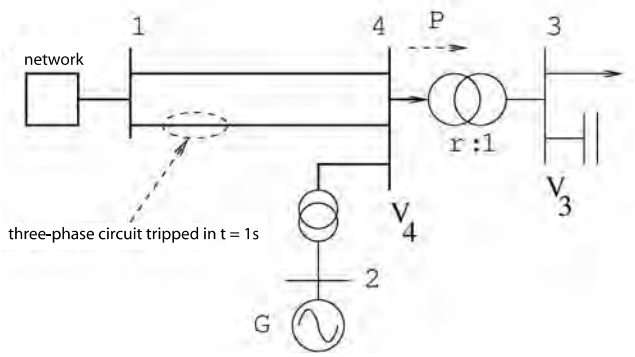

Figure 6.4. *Single-line system diagram in the example*

A major part of the power comes from bus 1 through a relatively long double-circuit transmission line. The remainder is supplied locally by a synchronous machine connected to bus 2. The latter is equipped with a voltage regulator that is meant to maintain the voltage at bus 2 (almost) constant, and a rotor current limiter whose role is to prevent the excitation current from exceeding a thermal limit . This limiter can be activated when the voltage regulation at bus 2 requires a lot of reactive power to be produced, and hence greatly overexcites the machine [CIG 93], [KUN 94], [TAY 94], [VAN 98].

Details are given following two scenarios of voltage instability due to tripping, in $t = 1$ s, of one of the two circuits between buses 1 and 4.

6.2.3.1. *First scenario*

The evolution of the system is shown in Figures 6.5a-c. The system first undergoes electromechanical oscillations due to the rotor movement of the generator. The *short-term* dynamics of the generator being stable, these transients are damped rapidly. A short-term equilibrium is thus achieved in about $t = 10$ s, voltage V_4 being established at around 0.96 pu (see Figure 6.5a).

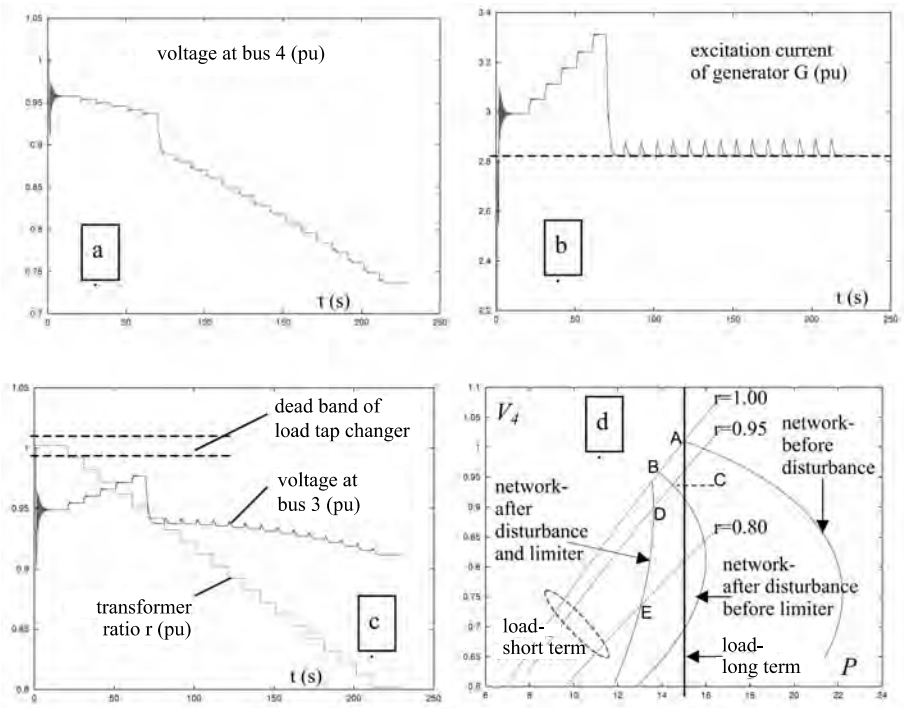

Figure 6.5. *Example, 1st scenario: time evolutions and PV curves*

The system response during the minutes that follow is a typical example of *long-term* dynamics, driven by the load tap changer and the rotor current limiter. The load tap changer acts after an initial intentional delay of 20 s and subsequently every 10 s. These modifications lead to a decrease of voltage V_4.

The functioning of the rotor limiter appears clearly in Figure 6.5b, where the evolution of the rotor current of G is seen. After the disturbance, the current reaches approximately 3 pu, a value that is distinctly higher than the thermal limit shown by the dotted line. The device has an inverse-time characteristic: it tolerates lighter overloads during longer periods. Due to this delay, the limiter is activated at $t = 70$ s. Before this instant, the voltage regulator controls the voltage at bus 2 and gives rise to a higher and higher excitation current, in response to the first tappings of the load tap changer. There is a correspondingly higher generation of reactive power by the machine. After $t = 70$ s, each attempt to increase the excitation current is corrected by the limiter. With its excitation being maintained (nearly) constant, the generator behaves like a constant e.m.f. behind to saturated synchronous reactance. Its terminal voltage is no longer regulated and V_4 undergoes a significant drop.

This drop continues, still under the effect of the tap changer, until V_4 reaches 0.75 pu. The final "stabilization" is due to the tap changer reaching its last position. As no other dynamics intervene, the system remains at this level of voltage which is completely unacceptable.

Figure 6.5c shows the evolution of distribution voltage V_3 and transformer ratio r. Before the action of the rotor current limiter, each tapping has the desired effect, which is the return of V_3 towards its set point value (the middle of the deadband shown in Figure 6.5c). On the contrary, after the generator field current limit is enforced, the changes in r have an effect which is at first negligible, and then opposite.

A more detailed analysis of the phenomenon is provided by PV curves in Figure 6.5d that shows the relation between transmission voltage V_4 and power P entering the transformer (see Figure 6.4). All these curves have been plotted based on the consideration that the short-term dynamics are at equilibrium. Depending on whether P is considered as the power supplied by the network or supplied to the load, we obtain:

– network characteristics, of the type in Figure 6.3. Figure 6.5d shows three of them, whose significance is explained later on;

– *short-term characteristics of the load*. These are obtained on the basis of model [6.4] and by expressing V_3 as function of V_4 and r. Each of the curves is related to a different value of r (1.00, 0.95 and 0.80, respectively).

The initial operating point of the system is A, intersection of the network characteristic "before disturbance" and the load characteristic relative to r = 1.00, the initial value of the transformation ratio. After the tripping of the line but before the activation of the overexcitation limiter, the network characteristic becomes the curve marked "after disturbance – before limiter". After damping of electromechanical transients and before r begins to vary, the system thus settles at the short-term equilibrium point B. In the moments that follow, the functioning of the load tap changer modifies the load characteristic; the short-term equilibrium is modified correspondingly. It is located in C (r = 0.95) at the time when the rotor current limiter enters into action. Under the effect of the latter, the network characteristic becomes the curve marked "after disturbance and limiter"; the equilibrium point is at D. Under the effect of the tap changer, it goes down further along the network characteristic, until it reaches E, the point corresponding to the tap changer having reached its limit.

The vertical line in Figure 6.5d is the *long-term load characteristic.* Due to the presence of the load tap changer, the long-term equilibrium of the system is characterized by $V_3 = V_o$ (the deadband $\pm\varepsilon$ of the tap changer is not considered here)

i.e., based on [6.4], $P = P_o$. In other terms, in the presence of a load tap changer, the load behaves at constant power in the long term.

The nature of the instability then appears quite clearly: under the effect of the disturbance, the maximum power that the network and generators can deliver has been reduced to the point of becoming lower than the power that the load tap changer tends to recover.

In more mathematical terms: the system is unstable due to the loss of its long-term equilibrium, the long-term load characteristic not intersecting with the final characteristic of the network.

6.2.3.2. *Second scenario*

The second scenario differs from the first by the initial production of generator G. The time response of the system to the same disturbance is given in Figures 6.6a and b.

The initial behavior of the system is similar to that of the earlier scenario, with a rotor current limitation at t = 100 s. In the mean time, here, the progressive drop in voltage under the effect of the load tap changer finally leads to a loss of synchronism (angular instability), as the evolution of the rotor angle in Figure 6.6b shows. The resulting pole slipping is responsible for the voltage oscillation visible in Figure 6.6a. In reality, a similar situation would result in the machine tripping by the relay for loss of synchronism, which would further aggravate the situation.

PV curves related to this scenario are given in Figure 6.6c. As in the case of Figure 6.5d, the short-term equilibrium point follows path AB (loss of the line), BC (functioning of the load tap changer), CD (G switching under rotor current limit). Here again, the disappearance of the long-term equilibrium is seen in the final configuration of the system. In the mean time, the difference increases with relation to the previous case in that when r goes from 0.83 to 0.82 pu, there is no more intersection between the *short-term* load characteristic and that of the network. This shows that the system also loses its short-term equilibrium point, which translates into the loss of synchronism mentioned above.

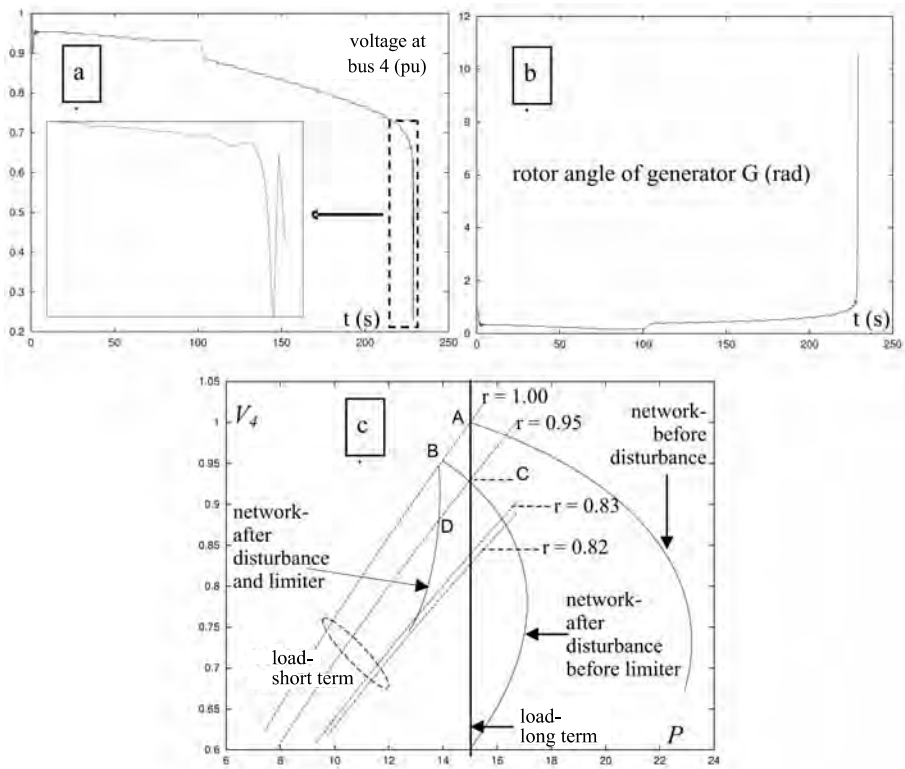

Figure 6.6. *Example, 2nd scenario: time evolutions and PV curves*

6.2.4. *Load restoration*

The above example shows a typical situation where the "cause" of the instability is the load tap changer, which tries to recover the voltage at the load terminals – and thus the power consumed by it – at its value before the disturbance. Two other load restoration mechanisms are described hereafter.

6.2.4.1. *Induction motors [HAM 89], [KUN 94], [TAY 94], [VAN 98]*

Induction motors are present in a number of industrial and commercial appliances. If voltage V at the terminals of a motor drops, active power P consumed by the latter decreases immediately as the square of the voltage (constant admittance behavior) and then returns to approximately its value before disturbance in a time interval of about one second. In fact, a motor with a constant mechanical torque and negligible stator resistance would recover its active power consumption. In a real

motor, there is low dependence of P with respect to V in steady state. The corresponding variation of reactive power Q is slightly more complex: as and when V is reduced, Q decreases, goes through a minimum and then increases up to the point of the motor stalling. In large industrial three-phase motors, the stalling voltage is about 0.7 pu but in smaller size equipment, or in heavily loaded motors, this critical voltage is higher. Load restoration by motors plays a significant role in networks having their peak load during the summer and feeding a significant part of air conditioning [DEU 97].

6.2.4.2. *Thermostats [CLA 87], [KAR 92], [KUN 94], [TAY 94], [VAN 98]*

Another type of restorative load is electric heating controlled by a thermostat. As we know, the latter controls start-stop cycles in such a way that the energy produced maintains the temperature close to a set point value. Following a drop in voltage, the power produced by resistance reduces quadratically. The thermostat should then let the resistance remain in function for a longer time to obtain the same amount of heat. If the average behavior of a large number of devices of this type is considered, the prolonged connection time appears, as seen from the network, like the recovery of power to its value before disturbance. This does not hold true for significant drops in voltage as, when thermostats are permanently in operation, the total load behaves like a simple resistor. It has also been observed that (older) bi-metal thermostats were themselves affected by variations in voltage, making power recovery faster than that which can be expected from the thermal inertia of the buildings. This type of behavior evidently plays a role in networks with their peak loads in the winter, having a significant part of electric heating. It is especially significant when the load tap changers, that are usually faster, do not recover the distribution voltage, e.g. because they have reached their limit or have been blocked.

6.2.4.3. *Generic models of restorative loads [KAR 92], [KAR 94], [XU 94]*

The load seen from the busbar feeding a distribution network is an aggregate of multiple individual loads, lines and MV cables, MV/LV transformers, compensation capacitors, etc. The modeling of such an aggregate is a critical issue. In effect, even if specific data for each device taken individually can be obtained, it remains to determine the composition of the total load, construct the resulting model, and especially, keep it up to date (based on the season, the time of day, etc.).

Several companies have proceeded in taking measurements by noting the evolution of power consumed within the minutes that follow a voltage drop (for example [KAR 92], [XU 97]). Such an evolution is outlined in Figure 6.7. The recovery of power can arise from the action of thermostats, tap changers situated downstream (and not explicitly modeled), voltage regulators, automatic switching of capacitors and indeed the response of the demand to the reduction of initial power.

This type of behavior can be represented by the generic load model [VAN 98]:

$$P = z_P P_O \left(\frac{V}{V_O}\right)^{\alpha} \quad \text{where } z_P \text{ obeys :} \quad T_P \frac{d}{dt} z_P = \left(\frac{V}{V_O}\right)^{a} - z_P \left(\frac{V}{V_O}\right)^{\alpha} \quad [6.5]$$

$$\text{with :} \quad z_P^{\min} < z_P < z_P^{\max}$$

In a way, the load obeys a model of the type in [6.4] where the superscript goes from the short-term value α to the long-term value a. These two parameters are deduced from variations in initial and final power (see Figure 6.7) by:

$$\alpha \cong \frac{\Delta P_t / P_O}{\Delta V / V_O} \qquad a \cong \frac{\Delta P_S / P_O}{\Delta V / V_O}$$

while T_P can be obtained by adjusting, according to the method of least squares, the time response of the model (dotted line curve in Figure 6.7) on the evolution measured. Similar relations are applied to reactive power.

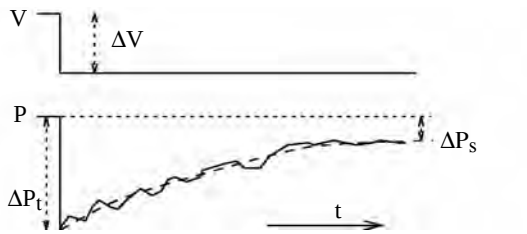

Figure 6.7. *Response of power consumed to a voltage drop*

6.2.5. *Classification of instabilities*

One of the complexities of voltage instability is related to the fact that it can develop in different time scales, according to the components involved. We conclude this section with a classification of the mechanisms of instability, based on the division of the system into a “fast” and a “slow” part [VAN 96], [VAN 98].

In the study of stability (angular, frequency or voltage stability), it is considered that the network has an instantaneous response, according to quasi-sinusoidal approximation [KUN 94]. It is thus described using algebraic equations of the type:

$$\mathbf{0} = \mathbf{g}\,(\mathbf{y}, \mathbf{x}, \mathbf{z_c}, \mathbf{z_d}) \qquad [6.6]$$

obtained by applying Kirchhoff's first law at each node. The components of $\boldsymbol{y}$ are usually projections of voltage phasors onto two orthogonal axes rotating at a known speed. The other variables that intervene in [6.6] are defined here below.

Short term dynamics take place in a time interval of at most 10 to 20 seconds after a disturbance. They come from the generators and their regulators, turbines, synchronous and static compensators, motors and, where applicable, the high voltage direct current (HVDC) links. They are described formally by:

$$\frac{d}{dt}\mathbf{x} = \mathbf{f}\,(\mathbf{y}, \mathbf{x}, \mathbf{z_c}, \mathbf{z_d}) \qquad [6.7]$$

Long term dynamics typically extend over several minutes after disturbance. They are represented by:

$$\mathbf{z_d}(k+1) = \mathbf{h_d}(\mathbf{x}, \mathbf{y}, \mathbf{z_c}, \mathbf{z_d}) \qquad [6.8]$$

$$\frac{d}{dt}\mathbf{z_c} = \mathbf{h_c}(\mathbf{x}, \mathbf{y}, \mathbf{z_c}, \mathbf{z_d}) \qquad [6.9]$$

The discrete-time equation [6.8] is related to events such as switching of shunt compensation, tapping by load tap changers, switching of a generator under rotor current limit, changes in set point values imposed by the secondary regulation of voltage or frequency. Continuous-time equation [6.9], on the other hand, corresponds to regulations (for example, PI control inside secondary regulations) or to load models of the type in [6.5].

There is some time decoupling between short and long term dynamics, which makes it possible to break down the mechanisms of instability as follows.

When a disturbance is applied to the system (short circuit, line tripping, etc.), the short term dynamics are excited first. In this time range, variables $\mathbf{z_c}$ and $\mathbf{z_d}$ do not have the time to change and can be treated as constant parameters in equation [6.7]. It is the time scale of angular instability (loss of synchronism between generators). It is also that of *short-term voltage instability*, related to the response of motors, or HVDC systems.

In this time range, it is sometimes difficult (if not meaningless) to divide between angular and voltage instabilities. However, a case of "pure" short-term voltage instability related to the behavior of induction motors is as follows [TAY

94]. With reference to Figure 6.1 and assuming that the load consists of such a motor:

– following a tripping of the line, *X* increases and the maximum deliverable power for the load drops. If it becomes less than the power that the motor tries to recover, the latter stalls and the voltage at its terminals collapses. In this case, the system loses its short term equilibrium point;

– a short circuit in the vicinity of the motor leads to deceleration of the latter. If the fault is not eliminated rapidly, the motor is incapable of reacceleration; here again, it stalls and the voltage at its terminals collapses. In this case, the long lasting fault takes the system out of the region of attraction of the post-disturbance equilibrium point.

Let us now suppose that the system has survived this period governed by short term dynamics. It is currently driven by long-term dynamics [6.8]-[6.9], which can be the cause of *long-term voltage instability*. This was the case in the example in section 6.2.3, where the instability resulted from the loss of long-term equilibrium of the system.

The long term evolution of $\mathbf{z_c}$ and $\mathbf{z_d}$ can be seen as a slow variation of parameters occurring in the model of the fast subsystem [6.7]-[6.8]. In a number of cases, short-term dynamics respond in a stable manner to these variations. In these conditions, the analysis of the system is considerably simplified if the *quasi steady-state approximation of long-term dynamics* is adopted [VAN 98], which involves the replacement of differential equations [6.7] by the corresponding equilibrium equation:

$$\mathbf{0} = \mathbf{f}\,(\mathbf{y}, \mathbf{x}, \mathbf{z_c}, \mathbf{z_d}) \qquad [6.10]$$

In the example in Figure 6.5, this approximation is valid for the entire evolution of the system. However, it is possible that the variations of $\mathbf{z_c}$ and $\mathbf{z_d}$ finally induce instability of short-term dynamics. This is the case in the example in Figure 6.6, where generator G ends up with a loss of synchronism. In this scenario, the instability of long-term dynamics is the cause, and that of short-term dynamics is the effect. In the same category, the stalling of motors or the onset of unstable rotor oscillations is found.

Naturally, the evolution of a real system can be more complex, due to, for example, the tripping of overloaded lines (the current increasing following the drop in voltage) or rotor-current limited generators whose terminal voltage goes too low.

6.3. Countermeasures for voltage instability

Often stimulated by real-life incidents, a certain number of countermeasures have been developed, which are summarized here below.

It is clear that the most efficient measure is the construction of new transmission lines and/or the installation of new power stations close to centers of consumption. However, in a number of cases where political and/or environmental constraints prevent such remedial steps, other solutions must be considered.

6.3.1. *Compensation*

Shunt compensation is the traditional means of providing reactive power required to maintain a good voltage profile. Capacitor banks are placed near the loads to improve their power factor and in subtransmission networks to compensate reactive losses. However, excessive compensation presents the disadvantage of bringing critical voltage (corresponding to the maximum deliverable power) to normal values, as shown by the curves with negative $tg\phi$ in Figure 6.3.

Series compensation is a very effective means of reducing impedance in long transmission lines and the drops in voltage that accompany them. However, this type of equipment is costly, makes protection more complex and can be the source of subsynchronous resonance. The possibility of a long-lasting bypassing of capacitors must also be taken into account.

6.3.2. *Automatic devices and regulators*

Certain devices that facilitate the maintenance of voltage after a “normal” disturbance can also help stabilize it in case of an emergency.

Shunt compensation can be engaged automatically, for example in response to a sufficiently long drop in voltage. The speed of the action is essential to counter short-term voltage instability [IEE 96], [VAN 98]. To this effect, it may become necessary to resort to static compensators, clearly more costly but faster [HAM 89]. In cases of long-term instability, the compensation engaged mechanically may suffice. In extra high voltage (EHV) networks operating below surge impedance loading, shunt reactances used to avoid over-voltage can be tripped to counter voltage instability [BER 96].

Voltage control is in the most part, carried out by regulators that equip synchronous machines. As seen in the simple example in Figure 6.1, higher source

voltage makes it possible for more power to be transmitted for the load. In areas closer to power stations, tighter voltage regulation can be obtained by compensating the voltage drop in the step-up transformer. Alternatively, load tap changing of the ratio of this transformer makes it possible to vary the network voltage more widely while maintaining the stator voltage close to its nominal value.

On the other hand, the heating of the rotor and stator windings limits the voltage regulation capacity of synchronous machines rather strictly. These limits, usually presented to operators in the form of *capability curves* [CAL 86], must be checked with relation to the real settings of the limiters. Even though operating rules vary considerably from one system to another, reactive power reserves must be evaluated and maintained at an adequate level [TAY 98]. Along the same lines, the engagement of shunt compensation by operators also aims to release *dynamic reserves of reactive power*, i.e., quantities of reactive power that can be supplied rapidly by generators and compensators, in response to a disturbance.

The effect of voltage regulators is local in nature; following a disturbance, the voltage at the nodes that are at a distance from the generators can become unacceptable. Moreover, a large part of the additional reactive power being produced by generators that are closest to the disturbance, post-disturbance reserves can be unequally distributed. This situation must be corrected by adjusting the regulator settings. Although this correction is carried out manually in most countries, a closed loop control, called *secondary voltage control*, was implemented, in France [VU 96] then Italy. The objective is to control the generators located in the same region in a coordinated manner, so that the voltages at some “pilot nodes” are maintained close to their settings and each generator produces reactive power pro rata of its capacity. The time constant of this control is about one minute, i.e. around the response time of the load tap changers.

This control increases the maximum deliverable power for the load. In response to a load increase, secondary voltage control maintains the voltage constant during a longer time but leads to a final more abrupt drop, because all the reactive reserves tend to be depleted at the same time. The constant character of the pilot node voltage can also mask a weak situation.

To our knowledge, secondary control has never been provided with an operating mode suitable for emergency situations, where a more rapid rise in voltage of generators is required. The possibility offered by the secondary control to control the generators in a coordinated manner would clearly be an asset in emergency situations.

6.3.3. *Operation planning*

Preventive analysis of voltage security is indispensable to operation planning. Significant progress has been made in the methods of analysis, as shown in section 6.4.

In operation planning, a major decision concerns the commitment of production groups so as to ensure sufficient security margins in the system. The opening up of the electricity market has considerably changed the context in which such decisions are made. For a given set of transactions along a transmission network, security margins need to be evaluated, congestion identified and market-based decisions adjusted accordingly.

6.3.4. *Real time*

The analysis of voltage security, made possible by the increase in computational power, has appeared among the real-time functions available to control support systems. In this context, preventive actions must be taken if the security margins are found to be insufficient. These actions can involve generation rescheduling (for example, from cheaper but remote generation units to units which are more costly but closer to the centers of consumption) and/or starting up of fast units (gas turbines, hydropower stations). In certain cases, load shedding can be done preventively, especially if the contracts negotiated with consumers contain a clause related to interruption.

6.3.5. *System protection schemes*

Evidently, the deregulation of the electricity market is going to lead to the operation of networks closer to their capacity limits. In this context, it is probable that security margins may be ensured for only the most likely disturbances, whereas more severe disruptions will be countered by *system protection schemes*, i.e., automatic devices whose role it is to avoid or contain the development of instability[1]. Such remedial measures are justified by the fact that operating the system in such a way as to withstand severe disturbances would be very expensive, with regard to the weak probability of these disturbances occurring.

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1 Unlike equipment protection, whose role is to take out of service a component to prevent it from damage from operating outside its expected limits.

Even if system protection schemes can integrate and coordinate various means, action on the load is the ultimate measure against voltage instability. It can be practiced indirectly, through the load tap changers, or directly, through load shedding.

6.3.5.1. *Action on load tap changers*

The example in section 6.2.3 has emphasized the role of tap changers in long-term voltage instability. In emergency mode, the load tap changers can be blocked, can be brought down to a determined position or their voltage settings can be reduced (typical variation: -5%). All these techniques exploit load sensitivity to voltage.

A number of networks are equipped with more than one level of load tap changers, for example between EHV and HV, on the one hand, HV and MV on the other. In this case, emergency actions need to be coordinated. In principle, it is sufficient to maintain MV distribution voltages at low levels (to take advantage of load sensitivity for voltage) and HV voltages of subtransmission networks as high as possible, so as to reduce reactive losses in these networks and draw maximum benefit from the shunt capacitors that are connected at this level.

It must be noted that if the blocking of tap changers makes it possible to stop degradation of operating conditions, it is hindered by other mechanisms of load recovery. Furthermore, in the case of certain loads (for example induction motors compensated by shunt capacitors), it is preferable to let the load tap changer operate, as an increase in voltage reduces the net consumption of reactive power [TAY 94]. Finally, it may be difficult to set up a centralized control system, given the large number of transformers feeding distribution networks.

6.3.5.2. *Load shedding*

Shedding an appropriate volume of load, at a suitable place and in a sufficiently short period of time is a very effective way of stopping voltage instability [TAY 94], [DEU 97].

Short-term voltage instability due to motors requires rapid shedding: the response time should not typically exceed 1.5 s, in order to avoid stalling of induction motors. One form of automatic load shedding consists of tripping the motors that cause instability, to save the rest of the system. The criterion for disconnection should be the drop in voltage rather than the increase in the current absorbed, as this is also produced on the starting of the motor. Industrial high power motors are generally equipped with such protection but this is not the case for small motors used for example, in air conditioners (the latter can continue to operate even after stalling, consuming a higher current and collapsing the voltage).

The shedding of load to counter long term voltage instability must take into account various factors (some are illustrated in the example in section 6.2.3) [VAN 98]:

– the primary objective is to return the system to a long-term equilibrium point. With reference to Figures 6.5d and 6.6c, following load shedding, the long term characteristic of the load moves to the left. For sufficient load shedding, the network and the load characteristics intersect again, their intersection defining the new operating point of the system;

– the example in section 6.2.3.2 shows that load shedding must take place before reaching the point of "no-return" where short-term dynamics become unstable;

– moreover, load shedding must take place sufficiently quickly so that the system is attracted by the new long-term equilibrium point so created [XU 94]; in the opposite case, voltage continues to drop. It can be shown that beyond a certain level, the more the increase in load shedding time, the more is needed to be shed to stabilize the system (and the higher the voltage surge) [MOO 99];

– in other cases, load shedding should avoid the tripping of lines by overcurrent or distance protections or that of generators under rotor current limit by under-voltage protections;

– the place where power (active and reactive) is cut off is greatly significant. A method combining time simulation and eigenvector analysis [MOO 99] makes it possible to identify the most appropriate busbars. The greater the distance of load shedding from this location, the higher the quantity to be shed to save the system. In this respect, the situation is very different from under-frequency load shedding where only the maintenance of an overall active power balance is essential.

These different aspects must be taken into account in designing system protection schemes involving load shedding [VAN 02]. They are usually based on the abnormal decrease of voltage in some busbars of the transmission network, and possibly on the increase in reactive production of generators close to the area to be protected. In consideration of the serious consequences of load interruption, the smallest quantity needs to be shed that is still compatible with the constraints mentioned above, which depends on the disturbance suffered. The threshold voltage must be sufficiently low to avoid load shedding when it is not necessary and sufficiently high so as not to unduly delay the load shedding. In systems that are really limited by voltage instability, it may be necessary to shed a few seconds after the occurrence of a disturbance (which contradicts the idea that long-term instability leaves more time to act). Whatever the case, even less severe scenarios give little time for an operator to react, and automatic schemes are to be preferred.

Finally, let us mention that a rapid variation of power flowing through HVDC links can also counter long-term voltage instability, especially when the inverter is located in a voltage sensitive area [TAY 94].

6.4. Analysis methods of voltage stability and security

Here below, without going into the analytical details, four types of methods used to analyze scenarios of voltage instability and evaluate corresponding security margins are mentioned. Even though these methods concern real time planning, the emphasis is on the latter.

6.4.1. *Contingency analysis*

Contingency consists of determining the system response to likely disturbances. A system is considered secure if it can tolerate a set of contingencies.

The disturbances considered for long-term voltage instability are the loss of transmission or generation equipments, the sequence of events leading to the tripping not being of significance. According to the well known “N-1” criterion, the system must respond correctly to the loss of any single element. More severe disturbances may be considered, such as busbar faults leading to disconnection of all the equipments connected to a bar. If there is a risk of short-term voltage instability, the response to short circuits must also be considered.

Automatic devices were mentioned earlier on, which can help in stabilizing the system after disturbance. However, it is widely accepted that the system should withstand any disturbance of the N-1 type without the help of any devices interfering with the recovery of power for the loads. Thus, switching of shunt compensation or secondary control is accepted but not the blocking of tap changers, nor load shedding, which has an impact on consumers. The reaction of the operator, considered too slow, is usually not taken into account.

6.4.1.1. *Post-contingency power flow*

As indicated in section 6.2.3, one of the main causes of instability is the loss of the long term equilibrium point. Static methods of analysis focus on the existence of such a point; they are based on algebraic equations derived from conditions of long-term equilibrium of model [6.6]-[6.9].

The most widely used algebraic model is the standard set of power flow equations. This is partly due to the fact that power flow software is very widespread

and also used for the analysis of static security. However, some precautionary measures are important:

– loads represented at constant power. This hypothesis is justified for loads whose voltage is controlled by tap changers, if the dead bands of the latter are ignored. However, in the absence of this tap changer or if it has reached its limit, the long term behavior of the load must be considered;

– generators represented as constant voltage or constant reactive power. Under the control of the voltage regulator, a generator sees its terminal voltage decrease slightly as and when its reactive production increases. Under rotor current limit (and even more, stator current limit), the reactive production varies with the voltage. Finally, the maximum reactive power that can be generated must be updated when changing the active power production;

– instead of being left to a slack-bus, any imbalance of active power must be distributed according to the frequency control settings.

The models used in load flow can be refined but, a more appealing solution is the quasi steady-state simulation described in the next section.

The simplest analysis of a disturbance is to calculate the post-disturbance (long-term) equilibrium point using a power flow software. In unstable cases where such a point does not exist, the solving algorithm (usually the Newton-Raphson method) fails converging, which can be interpreted as the indication of instability.

However, this approach presents two deficiencies: (i) the divergence can result from a purely numerical problem, not directly related to physical instability. This is particularly true when the power flow calculation involves a large number of adjustments or when a significant number of generators switch under reactive power limit; (ii) in cases of real instability, in the absence of any solution, the method does not provide information on the localization of the problem and the remedial measures to be applied.

6.4.1.2. *Full time simulation*

A static approach, like post-contingency power flow, obviously has its limitations. For example, it cannot take into account post-disturbance controls which depend on the time evolution of the system, nor detect situations where the system has a post-disturbance equilibrium point but is not attracted by the latter. These cases can be studied through time simulation. The latter, in addition to other advantages presents: better interpretation of the results (for example the time sequence of events), the possibility of obtaining information on corrective actions, pedagogical advantages, etc.

The simulation of short-term voltage instabilities involves the numerical integration of equations [6.6], [6.7]. The model is close to the one used for the analysis of angular stability, but particular attention must be paid to load modeling. On the other hand, the simulation of long-term voltage instabilities requires the numerical integration of the complete model [6.6]-[6.9]. The latter is *stiff*, i.e. certain phenomena are very rapid (e.g. subtransient dynamics) compared with the time interval on which the system is analyzed (for example around ten minutes). Three approaches are used to simulate such a system:

– adopting for the entire simulation the small integration step required to reproduce the fastest dynamics. Although simple to apply (and also widely used!), this method is slow and produces a huge volume of outputs;

– lengthening the integration step after the period when short-term instability could occur, so as to later filter out the insignificant fast transients. Reverting to a smaller integration step can be also considered;

– using a variable step integration method. The latter is adapted automatically to the behavior of the system: short when the fast transients are excited, and longer when only slow dynamics drive the system [DEU 93].

In the last two cases, the increase of the integration steps requires a stable integration method, on penalty of amplifying the errors introduced by the integration scheme. Implicit methods are to be preferred from this point of view.

In spite of the increase in computational power, full time simulation remains heavy in terms of computing time, data maintenance and processing of outputs. It is not very appropriate for true real-time applications.

6.4.1.3. *Long-term quasi steady-state simulation*

To accelerate the calculations of long-term voltage stability, the possibility of filtering insignificant short-term dynamics, has been mentioned earlier. Taking the idea of filtering further, we arrive at the quasi steady-state (QSS) approximation of long-term dynamics, which consists of replacing the short-term dynamics [6.7] by their equilibrium equations [6.10] (see section 6.2.5).

Formally, equation [6.10] comes from equilibrium conditions of [6.7]; in practice, however, a reduced set of equibrium equations and $\boldsymbol{x}$ variables are considered. For example, three equations suffice to represent a synchronous generator, taking into account its saturation, and the steady-state effects of its voltage regulator and speed governor [VAN 98].

A QSS simulation involves: (i) the solution to equations [6.6] and [6.10], under constant $\mathbf{z}_c$, when $\mathbf{z}_d$ changes according to [6.8]; (ii) the time integration of [6.6],

[6.9] and [6.10] under constant $\mathbf{z_d}$ (see Figure 6.8). The time step is typically between 1 and 10 s, according to the type of system. Short-term dynamics being considered marginal, it would be irrelevant to identify the precise moment when each discrete transition [6.8] (for example a change in tap changer position) occurs; in time and place, the different discrete components are analyzed in a "synchronous" manner at each time step and undergo a transition as soon as the internal timing is exceeded.

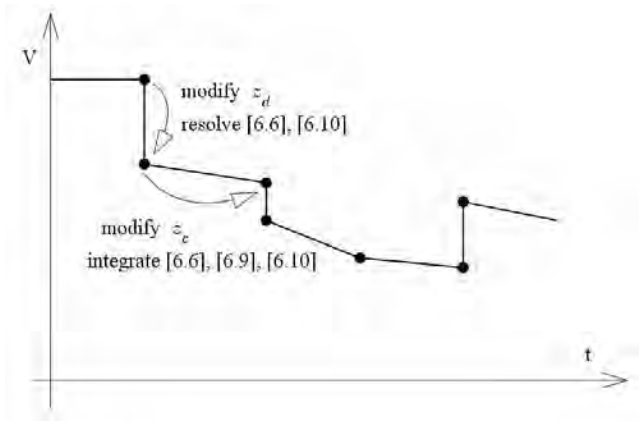

Figure 6.8. *Quasi steady-state simulation*

Equations [6.6] and [6.10] are solved with respect to **x** and **y**, using the Newton method with a Jacobian matrix updated and factorized as rarely as possible: for example, after switching of machines under rotor current limit but not after the change in taps by load tap changers, except if the convergence worsens. Continuous differential equations [6.9] are integrated using the Trapezoidal Rule. A partitioned scheme is used, in order to use the same Jacobian for time integration and for solving the discrete changes. A partitioned scheme is acceptable as the integration step is low compared to the time constants of the phenomena modeled by the equations.

QSS simulation offers a suitable compromise between the effectiveness of static methods and the advantages of time simulation. The limitations are as follows:

– for severe disturbances, there is a risk of not detecting short-term instability. To handle these cases, one solution is to couple the detailed and QSS time simulations: the first to check that the system survives short-term transients, the second to analyze the long-term evolution of the system rapidly [LOU 01];

– QSS simulation does not restitute the final evolution of the system when instability of the long-term dynamics induces instability in short-term dynamics, as given in the example in section 6.2.3.2. For instance, in the case of Figure 6.6a, QSS simulation stops when voltage V_4 reaches 0.77 pu and declares the loss of short-term equilibrium. In the context of voltage security analysis, the final simulation of this instability has limited interest, the system clearly being unstable in the long-term.

QSS simulation has been validated with respect to full time simulation. In the research reported in [VAN 97], it has proved to be around 1,000 times faster than full simulation with fixed step integration and is satisfactory in terms of precision for the calculation of security limits. This approach is also well suited to real-time applications.

6.4.2. *Determination of loadability limits*

Contingency analysis focuses on one operation point. It can also be useful to determine up to what level the system can be "stressed" without becoming unstable. Stress consists of variations, supposedly slow but having great amplitude, of some parameters. In practice, it corresponds to a load increase and/or modifications in generation that weaken the system by increasing power transfer in certain corridors and/or by depleting reactive power reserves. Usually the stress is distributed to many busses according to certain participation factors. This corresponds to variations in the parameters of the type:

$$\mathbf{p} = \mathbf{p}^O + S\ \mathbf{d} \qquad [6.11]$$

where scalar S is the level of stress and vector **d** is its "direction".

A *loadability limit* corresponds to the maximum value of S so that the system remains stable. In the very simple case in Figure 6.1, for example, for a direction of load increase defined by $tg\phi = 0$, the limit corresponds to point L located at the tip of the corresponding curve PV in Figure 6.3.

Here again, static methods are based on equilibrium equations of the system (typically power flow equations), that we write in its compact form:

$$\boldsymbol{\varphi}\ (\mathbf{u},\ \mathbf{p}) = \boldsymbol{\varphi}\ (\mathbf{u}, \mathbf{p}^O + S\ \mathbf{d}) = \mathbf{0} \qquad [6.12]$$

where **u** is a state vector and **φ** and **u** are n-dimensional vectors.

6.4.2.1. *Continuation methods (for example [AJJ 92], [VAN 98])*

A continuation method consists of tracing the solution **u** of equations [6.12] with respect to changes in parameter *S*. For this, [6.12] is considered to be a set of *n* equations with *n+1* variables. The continuation parameter is the variable that is fixed when solving these equations. Far from the sought limit, the continuation parameter is S and [6.12] is resolved for increasing values of *S*, by using a predictor-corrector scheme. When the loadability limit is approached or exceeded, the resolution algorithm (typically, Newton's method) diverges. Then a component of **u** is taken as the continuation parameter and [6.12] is resolved with respect to *S* and the other components of **u**.

In practice, continuation methods are used to automatically trace PV curves. Only a short portion of the lower part of these curves is determined. The component of **u** taken as the continuation variable is, for example, the lowest voltage magnitude. The reactive limits of generators are enforced while progressing along the curves.

6.4.2.2. *Optimization methods (e.g. [VAN 91], [IRI 97], [VAN 98])*

The loadability limit can be obtained more directly as the solution to the constrained optimization problem:

$$\max\ S$$

$$\text{with} \quad \boldsymbol{\varphi}\ (\mathbf{u}, \mathbf{p}^{O} + S\ \mathbf{d}) = \mathbf{0} \qquad [6.13]$$

$$\text{and} \quad \mathbf{h}\ (\mathbf{u}, \mathbf{p}^{O} + S\ \mathbf{d}) \leq \mathbf{0}$$

where the inequalities in [6.13] deal with the reactive production capacity of generators. Newton's method with heuristics to identify the binding constraints as well as the interior point method have been successfully applied to this problem.

In certain cases, the limit can be obtained as the solution for an *optimal load flow* with a more "traditional" objective (for example, minimizing the operating costs with very cheap generators in the sending area and very expensive ones in the receiving area).

6.4.2.3. *Time simulation and sensitivity analysis (e.g. [VAN 95], [VAN 98])*

This method consists of simulating the system response to loads increasing linearly in time and calculating at regular intervals sensitivities, whose change in sign indicates exceeding the loadability limit. The sensitivity of total reactive production to the various loads, for example, tends towards infinity then changes sign. QSS simulation allows for quick calculations.

6.4.2.4. *QV curves (e.g. [ELE 88], [VAN 98])*

A QV curve gives the loadability limit that corresponds to the increase in reactive consumption at a single node of the network. It can be obtained through an ordinary power flow program, by connecting a dummy synchronous capacitor to the node in question whose reactive production is recorded as and when change is made in the voltage setting. The procedure must be repeated from node to node. The technique is simple but the thus obtained loadability limit corresponds to a very artificial loading of the system.

6.4.3. *Determination of secure operation limits*

The analysis of disturbances and stress may be combined for a realistic analysis of security margins. From this point of view, the following can be distinguished:

– *post-disturbance loadability limits*, which indicate how much further the system can be stressed *after* a disturbance. This notion is closely related to the fact that contingencies consist of permanent equipment outages. These limits can be calculated by applying one of the methods in section 6.4.2 to the system in its post-contingency configuration;

– *secure operation limits*, which indicate how much further the system can be stressed, in its current configuration, before one of the specified contingencies leads to unacceptable post-disturbance evolution. Such a limit is easier to interpret in that it refers to parameters that an operator can observe (for example, the system load) or control (for example, a transaction implying a modification in the generation scheme).

In the calculation of a secure operation limit, there is a clear difference between:

– pre-disturbance configuration, where the reaction of operators or controllers to the stress applied on the system can be taken into account (for example shunt compensation switching, adjustment of generator voltages or transformer ratios, etc.);

– post-disturbance configuration, where only automatic devices reacting to the disturbance are considered.

The procedure used in the ASTRE[2] software is described briefly [VAN 95], [VAN 97], [VAN 98], [VAN 00], in view of its application in real time.

A simple and robust method to determine a secure operation limit with respect to one contingency is *binary* research (or *dichotomous*). It consists of constructing an interval $[S_l\ S_u]$ of stress values S such that S_l corresponds to a stable post-incident evolution, S_u to an unstable evolution and the difference $S_u - S_l$ is less than a tolerance Δ. The search begins with $S_u = S_{max}$, a value beyond which we are not interested in knowing the security limit, and $S_l = 0$, unless a better lower limit is available. At each stage, the interval is divided into two equal parts; if the midpoint corresponds to stable behavior (resp. unstable), it is taken as the new lower limit (resp. upper). The process is shown in Figure 6.9a, where the dotted arrows indicate the passage of one stress level to the next.

When calculating the secure operation limit with respect to the most severe among several contingencies, it is more effective to resort to *simultaneous binary study*, as shown in Figure 6.9b. At each stress level tested, all the remaining contingencies are simulated. If at least one of them is unstable, all the stable ones can be ignored since their security limits are higher than the current stress. The procedure thus continues with only unstable incidents and converges progressively towards the limit of the most constraining one. For the others, it nevertheless provides a lower bound on the security limit; the lower this limit, the more accurate the bound.

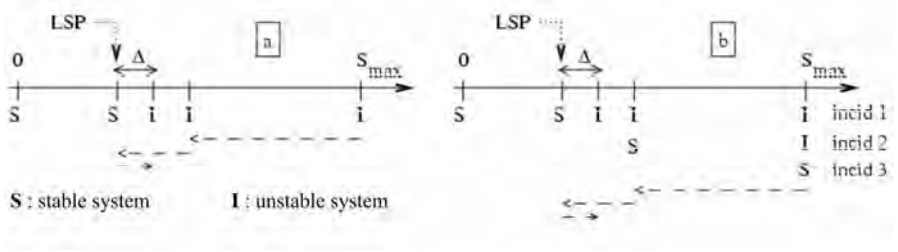

Figure 6.9. *Binary research: (a) simple; (b) simultaneous*

2 Acronym for *Analyse de la Stabilité de Tension des Réseaux Electriques* (analysis of voltage stability of electric networks). This software was developed at the University of Liège and is currently used by RTE (French transmission system operator), Hydro-Québec (TransEnergie dept.) and ELIA (Belgian transmission system operator). It is also used by HTSO at the Greek national control center as the result of the OMASES project (2001-2003), financed by the European Union, aiming to develop a platform for dynamic security assessment in real time.

The calculation of secure operation limits is carried out in ASTRE by three executable programs communicating through a shared (RAM) memory [VAN 00]: (i) a power flow calculation generates the pre-disturbance stressed operating points; (ii) a QSS simulator analyzes the post-disturbance time evolution of the system; (iii) a third module drives the other two according to the binary research logic described above.

By way of example, Figure 6.10 shows the evolution of voltage at a 400-kV bus of the French network, following a severe disturbance, and for four levels of pre-disturbance stress: 0, 0.08 S_{max}, 0.10 S_{max} and S_{max}. The two intermediary values correspond to the marginally stable and unstable cases of the binary search. The incident is applied at $t = 10$ s. The time step of this QSS simulation is 10 s. The bus in question being a pilot node of secondary voltage control, its voltage has the same pre-disturbance value for the first three stress levels (reactive reserves are depleted at stress S_{max}) and it returns close to this value in stable cases (even if very slowly in the marginal case).

Figure 6.11 shows similar curves related to the Hydro-Quebec network. The incident is applied at $t = 1$ s. The time step of the QSS simulation is 1 s. The voltage jumps are caused by the automatic tripping of shunt reactances connected to the 735-kV network. The number of these automatic devices, the voltage and timing of their tripping considerably influence the behavior of the system. During the setting of these parameters, the ASTRE software was extensively used to analyze a very large number of possible scenarios.

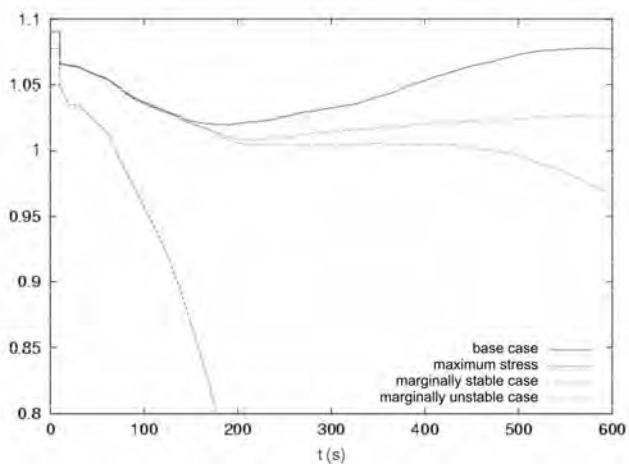

Figure 6.10. *Evolution of voltage (in pu) for 4 stress levels of a binary search; RTE system*

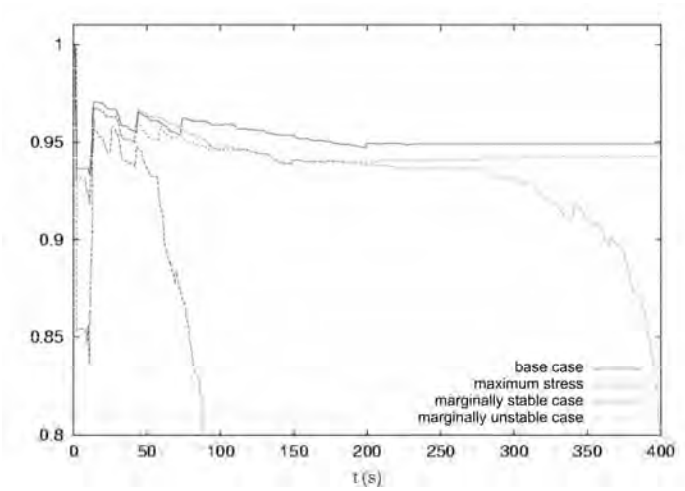

Figure 6.11. *Evolution of voltage (in pu) for 4 stress levels of a binary search; Hydro-Quebec system*

Faced with the large number of incidents to be considered in practice, *contingency filtering* is essential in real-time applications. The objective is to quickly identify a sub-set of potentially dangerous disturbances (i.e. having low secure operation limits) *for the direction of stress considered*, and to only calculate the security limits of the latter. Simultaneous binary research already filters incidents in the sense that those with a limit greater than S_{max} are eliminated at the first stage of the procedure. However, this still requires the simulation of all the incidents. In systems where stability is not greatly dependent on automatic devices acting after the disturbance, post-disturbance power flow calculations can be used for filtering purposes. The system having been stressed at S_{max}, the disturbances declared as potentially dangerous are those which lead to either a divergence of the power flow algorithm, or voltage drops greater than a certain threshold. The choice of this threshold is a compromise between the risk of false alarms (that lead to having to simulate too many disturbances) and of not identifying a dangerous problem, the second aspect naturally taking precedence over the first.

6.4.4. *Preventive control*

When the security margins with respect to certain disturbances are very low (and even more if the system responds in an unacceptable manner to a disturbance, even without any stress being applied to it), it is useful to determine the best preventive actions to be taken to recover acceptable security margins. A detailed description of

this question is outside the scope of the present chapter. Let us simply mention that for every dangerous (or potentially dangerous) incident it is possible to construct a linearized relation of the type [CAP 02]:

$$\sum_{j=1}^{p} S_{ij} \Delta u_j - c_i \leq 0 \qquad [6.14]$$

where Δu_j is the variation of the j-th control variable. Relations [6.14] can be incorporated into inequality constraints of an optimal power flow, meant to determine the preventive controls which optimize an economic or technical criterion. Coefficients S_{ij} can be determined on the basis of eigenvector analysis [DOB 92], [GRE 97] coupled, for example, with QSS simulation [VAN 95], [MOO 99]. Interested readers are invited to refer to [CAP 02] for more details.

6.5. Conclusion

Voltage stability is an important aspect of the stability and security of large electric power networks. During the past 15 years, significant progress has been made in the comprehension of the mechanisms of instability, in the implementation of countermeasures and the development of digital methods to analyze these phenomena.

Various aspects of the problem deserve the attention of researchers and electric power companies:

– load modeling. Load aggregates seen from the supply points of the distribution networks shall without doubt remain the least known components of electric power networks. More effort must be made to improve and validate the model of this part of the system which is at the heart of voltage instability;

– faced with uncertainties in the model, especially that of the load, it is necessary to develop different approaches, static or others, that make it possible to better curb the limitations of the system;

– voltage security analysis should be more systematically incorporated in real-time control center applications. Methods offering a good compromise between precision and speed are already available;

– without doubt more and more networks are going to be equipped with system protection schemes intended to counter more severe disturbance than those considered in preventive security assessment. These emergency controls must be designed in a closed-loop manner so as to cope with the uncertainties of the model.

Methods are needed to optimize and update the parameters of these system protection schemes, based on a vast set of scenarios;

– over and above the "traditional" system protection scheme generally using a small number of local measurements (for reliability purposes), a wide-area protection system collecting a larger set of measurements and relying on the real-time analysis of a system model can be imagined. By its very nature, long-term voltage instability (possibly coupled with emergency control of load tap changers) leaves time for a computer to identify the problem and determine the most effective corrective action in real-time;

– it is desirable to develop quicker methods of analysis for short-term voltage instability, for systems subject to this type of problem;

– finally, the increasing use of distributed generation sources raises the issue of secondary control services for voltage and supply of reactive power.

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Chapter 7

Transient Stability: Assessment and Control

7.1. Introduction

Transient stability is a phenomenon related to the very existence of interconnected electric networks. It is an especially difficult issue due to its intrinsic characteristics (governed by highly non-linear integro-differential equations that are generally bulky; very fast time evolution), it becomes even more problematic in the context of the deregulation of the electric energy sector. In fact, among the implications of this deregulation, we find on the one hand, the significant increase in the size of networks controlled from the same dispatching centre, and the operation of these networks increasingly closer to their security limits, if not at their very limits, on the other. The direct consequences of this current situation are the necessity to assess stability even faster than in the past and to develop control tools, i.e. stabilization tools, where necessary. There is especially a pressing need for emergency control methods, which aim to stabilize the network *after* the appearance of a dangerous disturbance.

The conventional time domain transient stability method, the only one to be currently used, is not capable of responding to such requirements. It cannot provide effective control tools in preventive mode, and even more so, in corrective mode. However, even as an analysis tool, it is intrinsically limited by the absence of adequate stability margins. It is this latter aspect that initially led to the development of “non-conventional” methods. Two types are distinguished: “direct” methods and “automatic learning” methods. The latter made a tentative appearance towards the beginning of the 1970s and came back into force in the 1980s, after an eclipse of

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nearly two decades. As for direct methods, they were sporadically initiated in the 1950s and 1960s, before their explosion since the 1970s. The fascination observed since the first works on the subject continues even today, although it is tempered with the appearance of "hybrid" direct-temporal methods, in the 1980s, developed in response to the difficulties encountered by "pure" direct methods. It is a method of this type that will be the subject of this chapter, the SIME method. As will be discussed later, the time domain method becomes an indispensable accessory, at least for the "preventive SIME" variant.

However, before going into the details of the subject, we shall outline a brief history of direct methods and the reasons that have led to the development of SIME. This outline will be preceded by a discussion about the status of transient stability in the general context of security, and the changes introduced by the liberalization of the electricity sector.

7.2. Transient stability

7.2.1. *Problem statement*

In general terms, the *security* of an electric power system can be defined as the robustness of its operation in normal operating conditions as well as during disturbances. Security thus covers a large range of phenomena that can be subdivided, generally, into "static" and "dynamic". Power system stability deals with dynamic phenomena.

Power system stability can be defined as the system aptitude to remain stable under normal operating conditions and recover an acceptable equilibrium after being subjected to disturbances. Stability is a multifaceted issue, which depends on a large number of parameters, such as the speed of evolution of phenomena, the severity of the disturbances in play, or the physical nature of the instability that can result from it. We are thus led to distinguish between "small" and "large" disturbances. By "large" disturbances, we mean significant modifications in the network (short circuit at busbars, opening of a line carrying significant amount of power, loss of a generator, etc.), for which its behavior must be studied on the basis of dynamic non-linear equations. System stability in the face of large disturbances is subdivided, in turn, into "*voltage stability*" and "*transient stability*". Legitimized for several decades, the latter term in fact refers to angular phenomena that are non-linear and cannot be linearized.

To be more precise, the *transient stability* of an electric system is its aptitude to ensure synchronous operation of its generators when it is subjected to significant disturbances. The occurrence of such disturbances can lead to large excursions of

rotor angles of some machines and, if corrective actions fail, even to the loss of synchronism, which generally develops in a few seconds if not in fractions of a second.

In the matter of system security, the non-linear nature of transient stability phenomena, their fast evolution and disastrous practical implications make it one of the most important domains and at the same time the most difficult to assess and even more so, to control.

This chapter is devoted to the study of transient stability, i.e., the assessment of the severity of large disturbances and the control (stabilization) of electric systems subjected to disturbances that are considered dangerous.

7.2.2. *Operating procedures*

The foundations of power system security and the definition of different operating procedures were established by Dr. Dy-Liacco in a thesis in 1968 [DYL 68]. They are still valid today with small differences due to the deregulation of the electricity sector. In it, preventive, emergency (or corrective) and restoration procedures are distinguished. We shall consider the preventive procedures below, and then indicate the specificities of emergency procedures in comparison.

Modifications brought about by the deregulation of the electricity sector are finally discussed in section 7.2.3.

7.2.2.1. *Preventive procedures: operating environment (Table 7.1)*

In the matter of control in preventive mode, the study of power systems is based on their common generic needs, in addition to specific needs corresponding to different network topologies, operation strategies, etc. Traditionally, they are classified into three categories, corresponding to three application domains. They are identified in Table 7.1.

As suggested in this table, the study of preventive procedures aims to assess network stability and – if necessary – to determine appropriate actions for stabilization, on the basis of a prediction of operating conditions and the simulation of credible disturbances, that are considered dangerous. Let us note that even in the framework of real time operation that covers a range in the order of an hour or 1/2 hour, it is not possible to determine optimal stabilization actions due to uncertainties about the future operation of the system and, more so, the random nature of the occurrence of likely events. Also, the operator could feel reluctant to apply

preventive control actions in anticipation of a disturbance, which, in most of the cases, may not occur, considering that such actions are too costly.

An alternative to real time control in preventive mode can be provided by the corrective mode.

Application (allowed time)	**Essential needs**		**Essential characteristics**	**Needs**
	Speed	**Precision**		
Planning (months to decades)	Desired	± Important	Very large number of cases	• Contingency filtering • Sensitivity
Operational planning	Critical	Important		• Margins • Sensitivity
Real-time operation (minutes)	Crucial	Desired		Real time* • Contingency filtering • Sensitivity • Control (stabilization)

* The absence of appropriate techniques can lead to operating the system with unnecessarily large and uneconomical stability margins.

Table 7.1. *Context of application and corresponding needs. Adapted from [PAV 93]*

7.2.2.2. *Corrective mode*

The corrective mode aims to assess the status of the system and the corrective action considered necessary *after* a disturbance has actually occurred, i.e., on the basis of *real* network operation and events. These conditions raise uncertainties about the preventive mode. Even if corrective action is generally more expensive than preventive action (stabilization measurements being even higher when taken later), they are easily accepted as indispensable to the survival of the system.

In short, the corrective mode would be likely to provide an optimal solution to real time system control. It remains to be seen whether appropriate techniques for transient stability exist, and whether they are satisfactory. In fact, the evolution speed of transient phenomena imposes particularly stringent applicability conditions on corrective methods.

An easier solution to this difficult problem could be provided by a combination of techniques from preventive and corrective modes. For example, corrective action could be determined *before* the appearance of the disturbance but applied *after* its occurrence. Obviously, such combinations can only be suboptimal. Conceptually,

the optimal approach would have to call upon real time corrective control and in a closed loop. The feasibility of such control is examined in section 7.7.

7.2.3. *Deregulation of the electricity sector*

7.2.3.1. *Current status*

Throughout the world, deregulation of the electricity sector is increasing. By and large, it implies abandoning vertical organization, where generation, transmission and distribution are operated as one single entity, in favor of horizontal organization, where these three activities become independent, at least from the administrative point of view.

It is generally admitted that the transmission system, whose stability is under study, should remain a monopoly, because of its physical characteristics and the advantages of centralized control. This creates a new function of the "transmission system operator" (TSO).

The main role of the TSO is to make access possible for all producers and consumers of electricity in a non-discriminatory manner [ILI 98]. At the same time, among his numerous duties, the operator is responsible for network security. In fact, this activity, today called "congestion management" (a term borrowed from economists), existed well before deregulation. It consisted of ensuring the system operation without exceeding limits of any kind and at minimal cost. In reality, only static (thermal and voltage) limits were generally taken into account.

7.2.3.2. *New challenges*

The essential difference with respect to the situation before deregulation is that minimization of operation cost has now been replaced by the maximization of profitability of the electricity market. At the same time, even if static limits are almost always the only ones to be taken into consideration, the need to include dynamic limits (of voltage and/or transient stability, according to the system specificities) becomes increasingly pressing.

Whatever the case, transient stability assessment becomes a more and more difficult task, because of new demands in addition to the difficulties that have already been mentioned. Among these, three have been outlined below. For more information the reader may refer to [SHE 99, KUN 98], for example:

– Long distance transactions of electric power between producers and consumers often cause problems to networks not involved in these transactions, but which transfer part of this power. To identify and control the issues of resulting congestion

management, the operator would need to analyze systems that are much larger than his own.

– The very significant increase in the size of networks to be processed is thus one of the indirect consequences of deregulation.

– In new types of electricity markets, a number of services that were traditionally the responsibility of different production sites now have to be operated and run profitably by the operator, often in real time.

– The traditional "unit commitment" has now been replaced by transactions which determine the production profile for the day or the hour ahead. The type of these transactions thus directly influences congestion management; the operator would then need to interact closely with the market so as to ensure system security.

The increased needs in the power system operation under liberalization is leading to new ways of using the operations of the existing controls, to study new ones and conveniently coordinating the entire set of all the operations. These are the greatest challenges for the TSO.

7.3. Transient stability assessment methods: brief history

7.3.1. *Conventional time domain approach: strengths and weaknesses*

Problems related to the dynamic behavior of electric power systems appeared at the same time as the interconnection of synchronous machines. This is how transient stability was studied in the 1920s through analytical techniques, such as the equal area criterion which is still used. The advent of digital computers in the 1960s enabled a surge of time domain methods and their intensive use.

These methods assess the robustness of the system to withstand large disturbances[1] by determining its evolution in time through a step-by-step resolution of all the integro-differential non-linear equations that govern transient stability phenomena. The assessment comprises two phases: the phase during the fault and the phase after the elimination of the fault. Often:

– either we try to find out if the system has lost synchronism for a given fault clearing time, t_e ;

1 As mentioned already, a "large disturbance" is meant to be a significant modification to the network, such as single-, two- or three-phase short circuits at generator busbars, transformers or large consumption centers, generally eliminated by opening of lines; the loss of an important generator; opening of an important interconnecting line, etc. Later on, the terms "disturbance", "contingency" or "fault" will be used interchangeably.

– or we assess one of the two following stability limits: the critical clearing time (CCT) for a given level of power, or the power limit for a given clearing time.

Power limits are more popular in the USA, critical clearing times in Europe. Moreover, being an easier calculation, CCT often helps, for example, to filter and rank contingencies.

In the light of the above considerations, let us now examine the following question: can the time domain approach meet the requirements from section 7.2.2. In addition, more generally, what are its strengths and weaknesses?

To answer these questions, some essential characteristics are identified below.

The time domain approach:

– provides important information on transient phenomena, particularly on the behavior of their salient parameters and the time evolution of the system;

– can comply with any kind of system modeling (from the most detailed to the simplest) and any kind of stability scenario (type of contingency, sequence of events);

– can describe any type of instability (local or inter-area modes, with multiple oscillations, etc.);

– can reach the required degree of precision, based on the hypothesis of sound modeling and correct parameter values of the system.

On the other hand, the time domain approach:

– is not well adapted for fast filtering of contingencies;

– does not provide stability margins that can tell us “how far” the system is from instability and, consequently, the tools to calculate sensitivities;

– does not provide effective control tools, i.e. for stabilization of unstable scenarios.

In short, the time domain approach is incapable of meeting the needs identified in section 7.2.2 and particularly those related to control, whether it is preventive or – *a fortiori* – corrective.

However, the time domain approach serves as a reference for any transient stability analysis. As we shall see later, it is also the basic tool for non-conventional methods.

In conclusion, it must be noted that the spectacular progress made at every turn in the field of computer technology has contributed to making time domain methods much faster than in the beginning: simulations requiring one hour of CPU time barely a decade later do not need more than a few seconds. Thus, time simulations are becoming "faster than real time". However, the weaknesses mentioned earlier still remain valid.

7.3.2. *Direct approaches: a brief history*

The disadvantages of time domain methods mentioned have led to the development of non-conventional methods, particularly direct methods based on Lyapunov's stability criterion and on the construction of functions of the same name.

The very first works date back to 1947 [MAG 47] and 1958 [AYL 58], even if they do not apply the Lyapunov general theory to the letter but are based on the concept of energy, which is a special case. The first publications using the Lyapunov criterion, so to speak, appeared in 1966 [EL-A 66], [GLE 66]. They were followed by an extraordinary number of publications that increased extraordinarily during the course of time.

In brief, the application of the Lyapunov criterion (or of the second method) to transient stability of electric power systems consists of: (i) constructing the Lyapunov function for the system, $V(\mathbf{x})$, where $\mathbf{x}$ is the state vector; (ii) evaluating the limit value, V_{lim}, i.e. the value taken by the Lyapunov function on the stability domain boundary; (iii) calculating the margin $\eta = V_{lim} - V(\mathbf{x_e})$ where $\mathbf{x_e}$ is the value of the state vector of the system entering its post-fault configuration, and deciding that the system is stable if $\eta > 0$.

The fascination for the application of the Lyapunov criterion to power systems is due to a number of reasons, and particularly the following two: (i) the calculation time that the methods gain by eliminating the "post-fault" simulation stage which is – by far – the most laborious; (ii) the possibility of defining stability margins that give information on the distance to the instability and that are likely to pave the way for a number of applications (filtering of contingencies, sensitivity studies, control techniques, etc.).

At the same time, the initial enthusiasm was rapidly tempered due to two major difficulties:

(i) One is related to the construction of Lyapunov functions for detailed models of the power system.

(ii) The other difficulty concerns the calculation of the stability domain boundary in an effective and pragmatic manner. More precisely, this calculation proves to be extremely heavy, with direct methods losing an essential advantage as compared to time domain methods. In addition, Lyapunov theorems being essentially conservative (they provide sufficient but not necessary conditions for stability[2]), it would be necessary to find a *pragmatic* definition of the stability domain, which eliminates this conservatism and makes the stability assessment reliable.

Among the different countermeasures proposed to overcome the first difficulty, a hybrid solution seems to have finally prevailed. This solution consists of using a time domain program and detailed system modeling to calculate the values of variables (δ, ω) and "injecting" them into the Lyapunov function that is constructed for the simplified system modeling, considering that the only dynamic variables are (δ, ω). From the theoretical point of view, this approach ceases to fulfill the applicability conditions of the Lyapunov stability criteria; however, from the practical viewpoint, it gives satisfactory results. Initiated towards the mid-1970s, this approach is now widely used. It is to be noted however that this approach requires a correction (in "kinetic" and "potential" parts of the Lyapunov function) which, in turn, requires the knowledge of "critical machines" (i.e. machines responsible for the loss of synchronism); when in fact, the method is not capable of identifying critical machines.

A good definition of the practical stability domain was an even more difficult issue to cope with. One of the solutions proposed towards the mid-eighties consisted of replacing the multimachine system by a single machine equivalent. Rahimi and Schaffer on the one hand [RAH 87] and Xue *et al*. on the other [XUE 86], [XUE 88] were the first to propose such an approach, independently of each other. The idea is simple: for a single machine system, the stability domain can be defined precisely with the help of either the Lyapunov stability criterion or equal area criterion[3]. Without going into the details, let us say that the implementation of the Xue approach, named EEAC (extended equal-area criterion), also requires the knowledge of critical machines. However, their identification is in essence easier with the "single machine" approach. Let us note finally that the EEAC, such as it was conceived initially, overrules the necessity of using a time domain stability program

2 More precisely, Lyapunov's method stipulates that a system that is inside the stability domain is stable; but its instability is not guaranteed if it is outside this domain. This practical property is not to be confused with the theorem according to which the necessary and sufficient condition for a system to remain stable is that it possesses a "Lyapunov function". This theorem, which is very important from the theoretical point of view, of course, is not of great help from the practical viewpoint.

3 For the remainder, it is easily shown that the two criteria coincide in the case of simplified modeling of the system.

at the cost, nevertheless, of simplification of the multimachine system modeling and of its time evolution.

While wishing to preserve the essential advantages of time domain methods and EEAC, we arrived at the SIME method, towards the early 1990s. In short, SIME (single-machine equivalent) transforms the trajectories of the multimachine system into that of an equivalent OMIB (one-machine infinite bus) system, whose parameters are calculated by a time domain program and refreshed at each time step of it.

This hybrid method is the basis of transient stability assessment and control, which was developed subsequently.

7.3.3. *Note on automatic learning approaches*

The other category of non-conventional methods of transient stability assessment is machine learning. It is to be noted that the pattern recognition method, which is a part of this, was initiated almost at the same time as direct approaches [GUP 76]. However, their real growth was seen nearly two decades later. One of the reasons is that these methods took up a lot of computer memory, and had to wait for significant progress to be made for computers to meet their scope.

The process in the automatic or machine learning methods (more precisely supervised machine learning) differs fundamentally from that in direct methods. By and large, machine learning is based on a set of pre-analyzed cases in order to deduce the properties of cases unknown in the study. From the calculation point of view, the construction of the database is rather heavy as it generally comprises a very large number of pre-analyzed cases. On the other hand, its use to extract information on the case for study can be extraordinarily fast.

Another basic difference is that machine learning can process several physical problems at once (for example, transient stability and voltage stability), unlike direct methods.

As often, the work of an engineer consists of choosing, with full knowledge of the facts, from the vast range of available methods in order to extract and, if possible, combine the advantages of several methods.

Any reader interested in machine learning methods may refer to specialized books such as [WEH 98], [WEH 00].

7.4. The SIME method

7.4.1. *Origins*

As mentioned earlier, SIME is a hybrid method resulting from the combination of two transient stability methods, i.e. the time-domain method applied to the multimachine system under study, and the equal area criterion applied to a one-machine equivalent that will henceforth be called OMIB. This combination provides two types of essential information on transient stability i.e.: critical machines (the machines responsible for the possible loss of synchronism) and stability margin.

For that matter, for a given unstable scenario, defined by the pre-fault system operating point and the considered contingency (type, localization, sequence of events), the SIME method controls the time domain program; once the system enters the post-fault phase, SIME starts selecting data at each step of the program to construct from the multimachine system an OMIB candidate, to which it applies the equal area criterion. The process stops once the criterion detects the instability conditions [7.8] (see below). At this point, SIME identifies critical machines, declares that the OMIB candidate is the real OMIB, and calculates the corresponding instability margin.

By refreshing the OMIB parameters at each step of the time domain program, SIME retains the precision of this program as well as its aptitude to process the desired modeling and stability scenario. At the same time, by using OMIB and the equal area criterion, the method considerably widens the possibilities of the time domain program through the following aspects: (i) fast stability analysis; (ii) filtering of “harmless” contingencies and ranking – assessment of “harmful” contingencies; (iii) sensitivity analysis; (iv) control, i.e. stabilization; (v) descriptions and multi-faceted physical interpretations provided by the OMIB and the equal area criterion. The last two possibilities carry a great deal of importance as it will become clear later.

The identification of the appropriate OMIB and obtaining basic information (critical machines and margins) are described in section 7.4.2. Section 7.4.3 introduces the distinction between preventive SIME and emergency SIME.

Section 7.5 summarizes different descriptions of transient phenomena provided by SIME and illustrates them on real systems.

Section 7.6 presents preventive SIME with some details, while section 7.7 outlines the origins of emergency SIME.

7.4.2. *Formulation*

7.4.2.1. *Basic principle*

The SIME method is based on the two following propositions.

PROPOSITION 1. As complex as it may be, transient instability is triggered when the system machines are irrevocably split into two groups, leading to the loss of synchronism.

PROPOSITION 2. By replacing the trajectory of each of the two groups of machines with that of an equivalent machine, then the trajectory of the two equivalent machines with that of single machine system (OMIB) and on applying the equal area criterion, SIME replaces the study of multimachine system dynamics with that of OMIB via the equal area criterion.

7.4.2.2. *Parameters and dynamic equation of the OMIB*

The parameters of the OMIB angle, speed, inertia coefficient, mechanical power, electric power and accelerating power are identified respectively by $\delta, \omega, M, P_m, P_e, P_a$. At any given moment, these parameters are calculated on the basis of the system machine parameters. Thus, the angle of the OMIB is calculated based on the rotor angles of the machines by

$$\delta(t) = \delta_C(t) - \delta_N(t) \qquad [7.1]$$

where index C is related to critical machines and index N to non-critical machines and where

$$M_C = \sum_{k \in C} M_k \;\; ; \;\; M_N = \sum_{j \in N} M_j \;\; ; \;\; M = \frac{M_C M_N}{M_C + M_N} \; . \qquad [7.2]$$

M is the inertia coefficient of the OMIB.

The speed of the OMIB is defined in a similar manner by

$$\omega(t) = \omega_C(t) - \omega_N(t) \; . \qquad [7.3]$$

At the same time, mechanical power of the OMIB is defined by

$$P(t) = M \left(M_C^{-1} \sum_{k \in C} P_{mk}(t) - M_C^{-1} \sum_{j \in N} P_{mj}(t) \right) . \qquad [7.4]$$

The electric power of the OMIB receives a similar expression. As for accelerating power of the OMIB, it is defined by

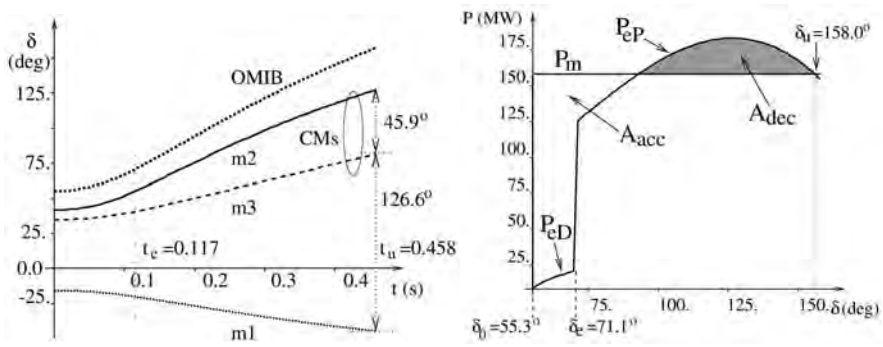
$$P_a(t) = P_m(t) - P_e(t) \ . \qquad [7.5]$$

Finally, with the above notations, the dynamics of the OMIB obeys

$$M\ddot{\delta} = P_m(t) - P_e(t) = P_a(t) \ . \qquad [7.6]$$

It has to be emphasized that parameters P_m , P_e , P_a are obtained on the basis of the parameters of the multimachine system, which take into account all the system and machine regulations and call upon Park's equations. From then on, no other simplifying hypothesis (other than the ones used by the time program) is involved in the trajectory of the OMIB. Furthermore, these different parameters are refreshed at every time step of the time domain program.

By way of illustration, Figure 4.1a describes the trajectories of a system with 3 machines (m_1, m_2, m_3) and that of the OMIB. Let us note that the OMIB trajectory is more advanced here than that of the most advanced machine, m_2 . At the same time, Figure 7.1b translates the equal area criterion described hereafter.



(a)

Time evolution of the machines and OMIB

Number of critical machines: 2

Number of non-critical machines: 1

(b)

Representation $P-\delta$ of OMIB

Parameters resulting from the equal area criterion δ_e = 71.1°,

δ_u = 158.0° ; t_u = 0.458s

Figure 7.1. *Representations of a 3-machine system and equivalent OMIB. Contingency no. 2; t_e =117 ms. SIME is coupled with a time domain program written in MATLAB [CHO 97], [MAT 99], adapted from [PAV 00]*

7.4.2.3. *Equal area criteria*

From a general point of view, the equal area criterion stipulates that the stability/instability of the dynamic system governed by an equation of the [7.6] type depends on the sign of margin η defined by

$$\eta = A_{dec} - A_{acc} \qquad [7.7]$$

where A_{dec} (respectively A_{acc}) represents the decelerating area (respectively accelerating) (see Figure 7.1b): the system will be stable if η is positive, unstable if η is negative, the boundary between stability and instability taking place for $\eta = 0$.

Relation [7.7] that translates the equal area criterion covers expressions that are especially easy to calculate, as summarized in the following part.

Instability criteria and the corresponding margin

An unstable trajectory of the OMIB reaches the unstable angle δ_u at moment t_u where

$$P_a(t_u) = 0 \; ; \; \dot{P}_a(t_u) = \left.\frac{dP_a}{dt}\right|_{t=t_u} > 0 \qquad [7.8]$$

with $\omega > 0$ for $t > t_0$ (see Figure 7.1b).

The conditions in [7.8] are the "stop conditions" imposed by SIME on the time domain program. In fact, they mark the beginning of the system irrevocable loss of synchronism; all later calculation is thus of no use, except for a specific search.

In $t = t_u$, margin η defined by [7.7] takes a closed form expression that is extremely easy to calculate:

$$\eta_u = -\frac{1}{2} M \omega_u^2 \; . \qquad [7.9]$$

Stability criteria and the corresponding margin

A stable OMIB trajectory reaches its "return angle" δ_r $(\delta_r < \delta_u)$ at moment t_r where the angle of OMIB reaches its maximum value then decreases:

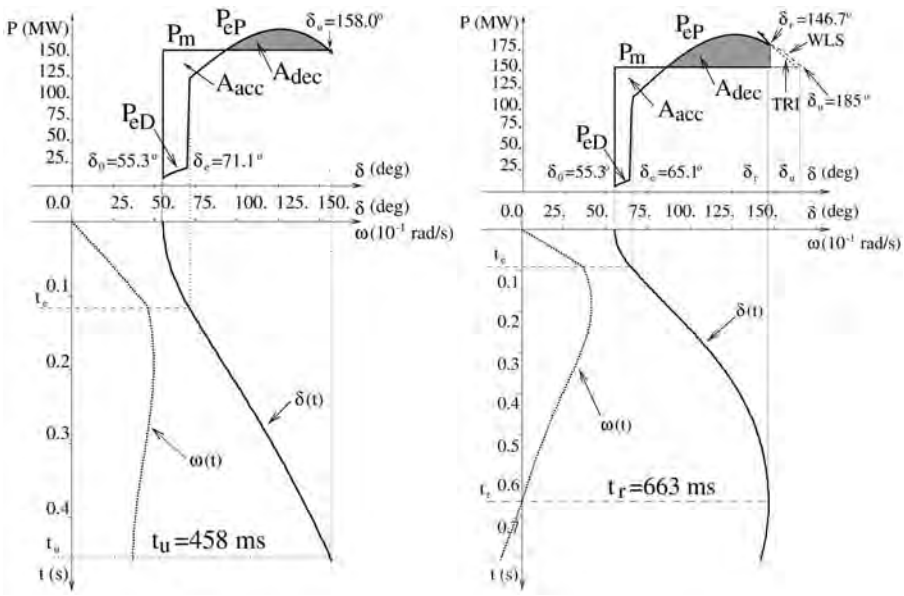
$$\omega(t_r) = 0 \text{ with } P_a(t_r) < 0 \; . \qquad [7.10]$$

The conditions in [7.10] are the "stop conditions" imposed by SIME on the time domain program. In fact, they show that the system is stable – at least with relation to the considered oscillation; any later calculation proves to be of no use if the following oscillations are not taken into account.

In $t = t_r$, margin η is expressed by (see Figure 7.2b)

$$\eta_{st} = \int_{\delta_r}^{\delta_u} |P_a| \, d\delta . \qquad [7.11]$$

It is to be noted that, contrary to the unstable margin [7.9], the stable margin [7.11] can only be calculated approximately. In fact, neither angle δ_u nor trajectory $P_a(\delta_u > \delta > \delta_r)$ is known since, in fact, the OMIB trajectory "returns" i.e., the angle of the OMIB ceases to increase from $\delta = \delta_r$.



(a) t_e = 117 ms *(b) t_e = 92 ms*

Figure 7.2. *Time and $P-\delta$ representations for the OMIB of the 3- machine system. Contingency no. 2. Adapted from [PAV 00]*

Two approximations are proposed in [PAV 00]. Without going into the details, we shall identify them as "triangle approximation" (TRI in Figure 7.2b), where

$$\eta_{st} \cong \frac{1}{2} P_a (\delta_u - \delta_r)$$

and "least squares approximation" (weighted or not), where the curve $P_a(\delta_u > \delta > \delta_r)$ is extrapolated on the basis of $P_a(\delta_u < \delta < \delta_r)$ (shown by WLS in Figure 7.2b).

7.4.2.4. *Identification of the OMIB*

This identification is based on Proposition 1 in section 7.4.2.1. It is obtained in the following manner:

(i) at every calculation step starting from t_e (time where the multimachine system enters its final configuration, SIME ranks the machines in decreasing order of their rotor angles, then considers the first (for example, 10) "electric distances or intervals"[4] between adjacent machines, ranked in decreasing order;

(ii) each of these "intervals" divides the machines into two groups, located on either side of it. SIME calculates the corresponding "OMIB candidate" and applies test [7.8] to it;

(iii) if one of the "OMIB candidates" fulfills the conditions in [7.8], it is considered the "real OMIB" (or OMIB in short); critical machines (and non-critical ones) are respectively those in groups above and below the interval. SIME calculates the corresponding margin [7.9] and stops the time domain program;

(iv) if not, SIME decides the continuation of the time domain program, proceeds to the calculation of the next step and repeats stages (i) and (ii) until it finds conditions [7.8], and executes step (iii).

Figure 7.1 has schematically described the above process.

NOTE.–Let us remember that the identification of the OMIB can be carried out only on an unstable trajectory. By continuation, we consider that the OMIB of the unstable trajectory identified earlier is still valid for a stable trajectory which is near enough to it (for example, obtained for a relatively close clearing time).

4 For example, in Figure 7.1a, the two electric distances noted in t_u are d_1 = 126.6° (between machines m_3 and m_1) and d_2 = 45.9° between machines m_2 and m_3. Distance d_1 divides the three machines between (m_2, m_3) and m_1; Distance d_2 divides them into m_2 and (m_3, m_1). As suggested in the diagram, the calculation leads to choosing distance d_1 to define the group of critical (m_2, m_3) and non-critical machines (m_1).

7.4.2.5. *Notations*

Hereafter, we summarize the different notations introduced so far, related to the OMIB parameters and corresponding quantities.

P_e	:	electric power
P_m	:	mechanical power
P_a	:	accelerating power
M	:	inertia coefficient
t_e	:	clearing time of the disturbance
t_u	:	instability time, i.e. time where the OMIB reaches its unstable angle and loses synchronism; $\delta_u = \delta(t_u)$.
d_i	:	angular deviation between the ith critical machine and the most advanced non-critical machine
Index D		is related to the configuration during-fault
Index P		is related to the configuration after the fault (post-fault)
η	:	stability margin
η/M	:	stability margin normalized by the inertia coefficient
δ	:	angle of the OMIB
ω	:	speed of the OMIB

7.4.3. *Preventive SIME vs emergency SIME*

Like any security function in preventive mode, preventive SIME aims to detect situations that could lead to the loss of synchronism of the system, if they were to occur. Preventive SIME thus simulates dangerous disturbances to evaluate their degree of danger and propose, when necessary, control methods capable of stabilizing the system, by adequately modifying the operating point of the pre-fault system.

The preventive SIME method thus uses a time domain program to carry out the simulations. Figure 7.3 sketches the principle of coupling SIME with the desired time domain program (MATLAB, EUROSTAG, ETMSP, PSS/E, ST-600, etc.). The preventive SIME method will be the subject of section 7.6.

Emergency SIME, on the other hand, aims to “save” a situation that has been rendered fragile by the occurrence of a disturbance. In fact, when a disturbance actually occurs, SIME evaluates its severity and, where necessary, triggers control devices that are capable of stabilizing the system in time, i.e., before loss of synchronism takes place. Section 7.7 will specify the differences of emergency

SIME compared to preventive SIME. In particular, we shall see that one basic difference is that the "emergency closed loop" SIME uses measurements retrieved from production sites instead of simulation data provided by a time domain program.

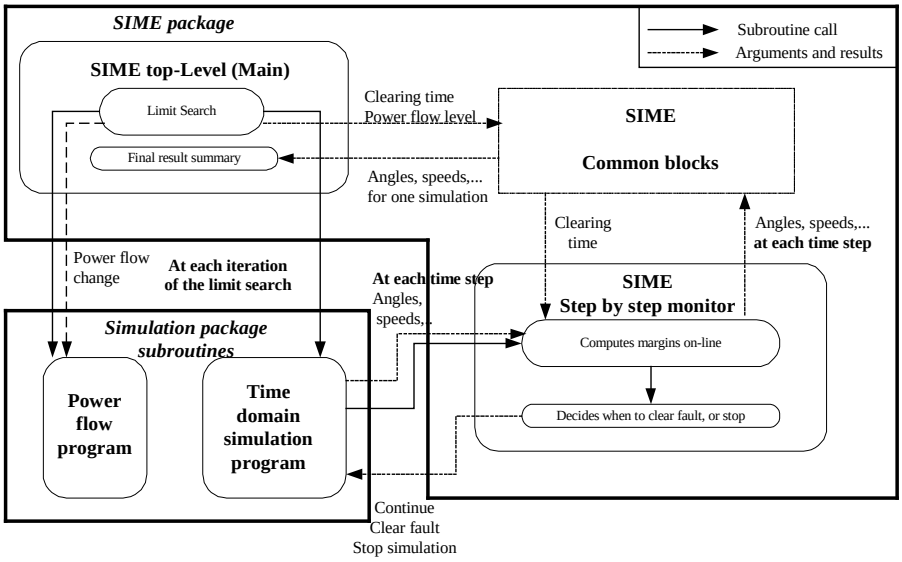


Figure 7.3. *Coupling of SIME with a transient stability time domain program. Diagram of the principle. Adapted from [ERN 98c]*

7.5. Different descriptions of transient stability phenomena

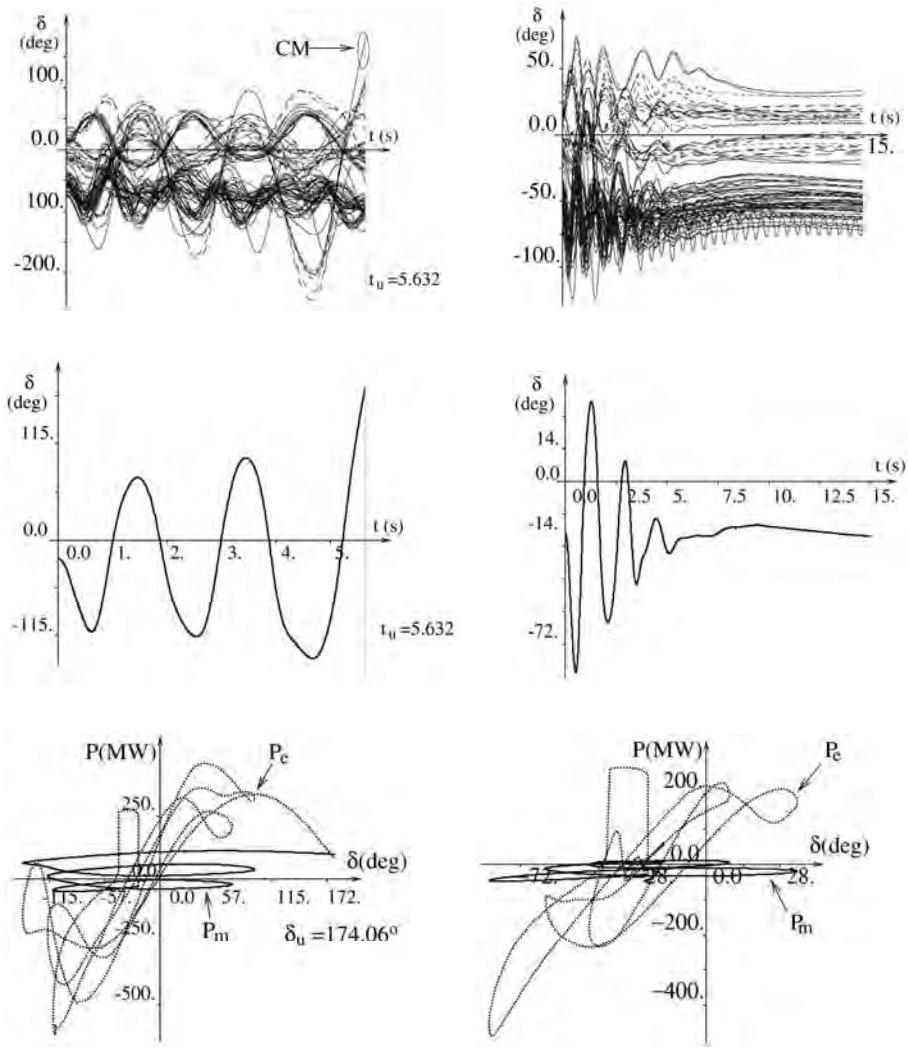
Thanks to its "adherence" to both the time domain and direct methods, SIME provides a wide range of descriptions of transient phenomena and especially the following descriptions:

1. time evolution of rotor angles of the multimachine system;
2. time evolution of the OMIB;
3. $P-\delta$ curves of the OMIB;
4. phase plane of the OMIB.

These different types of descriptions are illustrated hereafter based on simulations on two real networks, i.e.:

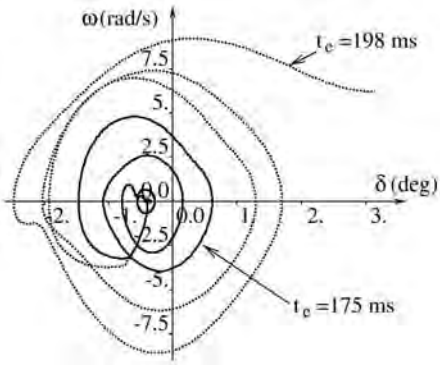
– on the Hydro-Quebec network; SIME is coupled with the time domain program ST-600 (Figures 7.4 and 7.5);

– on test network A of EPRI; SIME is coupled with the time domain program ETMSP (Figures 7.6 and 7.7).



(a) t_e = 198 ms **(b)** t_e = 175 ms

Figure 7.4. *Three typical representations of back- and multi-swing phenomena simulated on the Hydro-Quebec system for two clearing times: one larger and one smaller than CCT*



CCT(SIME) = 175.5 ms; CCT(ST-600) = 176 ms. Adapted from [PAV 00]

Figure 7.5. *Phase plane of the OMIB. Representation of back- and multi-swing phenomena of Figures 7.4. Adapted from [PAV 00]*

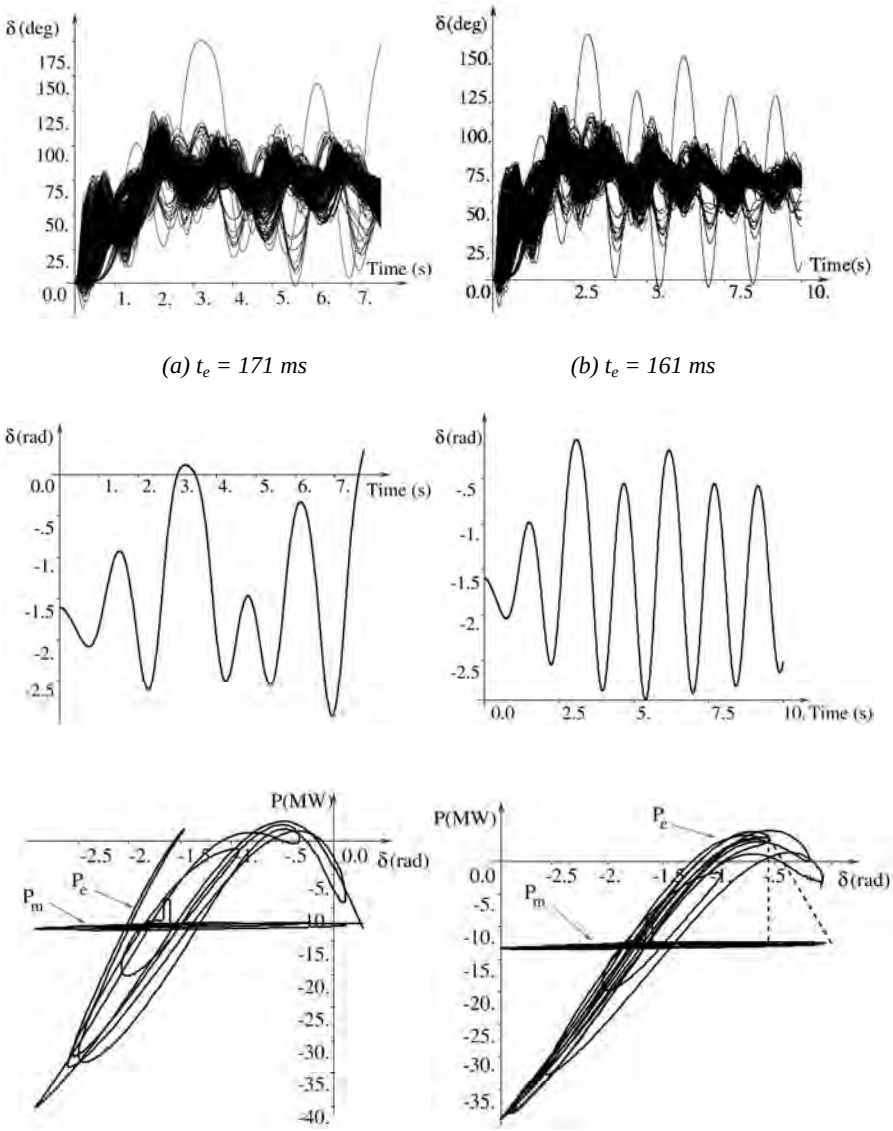
The Hydro-Quebec system is modeled by 86 machines and uses a little more than 2,000 dynamic state variables.

It is to be noted in Figure 7.4 that the time evolution of the OMIB provides a clearer description than the time evolution of the system machines, especially of the system damping. In the same figure, $P-\delta$ curves describe the phenomenon of "return" ("back-swings"; beginning of the transient movement in deceleration). A clearer description of this phenomenon is given by the curves in Figure 7.5, where we see, indeed, that the start of the trajectory indicates a negative acceleration of the OMIB.

Let us note that the latter figure provides a reduction rate of the dynamic state variables of more than 2,000/2, that is, more than 1,000; in spite of this, or rather thanks to this, the phenomena, which are rather complex, are clearly described by the different representations of the OMIB in Figures 7.4 and 7.5.

Thus, SIME is able to substantially reduce the problem dimensions. The advantages that can be drawn from this are significant.

We find the same type of behavior in Figures 7.6 and 7.7 from simulations on the EPRI test system A [EPR 95]. In particular, the existence of "back-swings" is indicated in Figure 7.7. Despite a reduction rate of more than 1,500, this figure is especially clear and meaningful.



(a) t_e = 171 ms *(b) t_e = 161 ms*

Figure 7.6. *Three representations - type of back-multi-swing phenomena simulated on test system A of EPRI (627 machines).*
CCT(SIME) = CCT(ETMSP) = 168 ms. Adapted from [PAV 00]

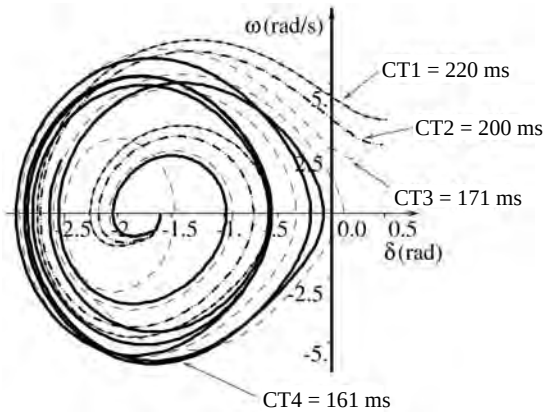


Figure 7.7. *Phase plane of OMIB. Representation of back- multi-swing phenomena of Figures 7.6. Adapted from [PAV 00]*

Similarly, Figure 7.6 related to the time evolution of the OMIB clearly shows that *multi-swing* phenomena are involved: damped (Figure 7.6b), or leading to a loss of synchronism (Figure 7.6a). In the latter case, it is necessary not to stop the simulation after the first oscillation, at the risk of missing the detection of the loss of synchronism (which takes place at close to 7.5 s).

NOTE.– The quality of SIME's diagnostic can be evaluated by comparing CCT of different contingencies provided by SIME and the ad hoc[5] time domain program, used alone. The principle of CCT calculation by SIME is described below (section 7.6.1). In the meantime, the legends in Figures 7.4 and 7.6 show a very good concordance of the two methods.

7.6. The preventive SIME method

As mentioned earlier, at the basis of any SIME-based stability calculation (analysis, sensitivity and control) is the determination of critical machines and stability margins. The equal area criterion added to this information, is especially rich in interpretation and valuable suggestions. Furthermore, the different investigations are largely facilitated by a remarkable property that has been verified, whatever the size of the electric system or stability scenarios in question, i.e., the (quasi-)linear variation of the stability margin with the severity of the considered disturbance.

5 I.e., coupled with SIME.

Figures 7.8 and 7.9 show this observation in two very different cases: that of an academic 3-machine system and the EPRI 627-machine system.

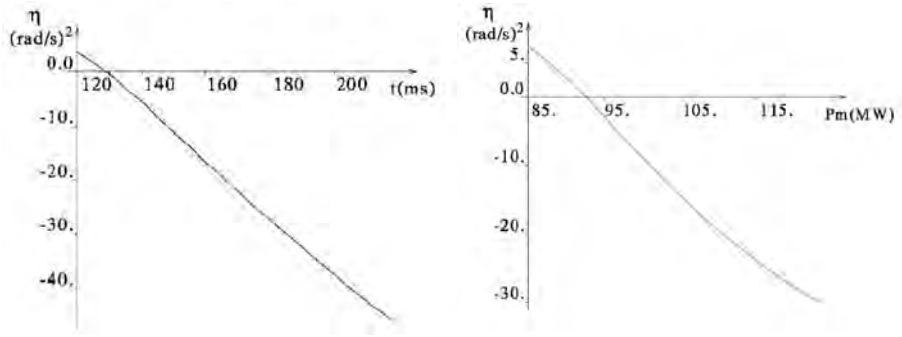


Figure 7.8. *Variation of the stability margin with the disturbance clearing time and the OMIB mechanical power. 3-machine system. Adapted from [PAV 00]*

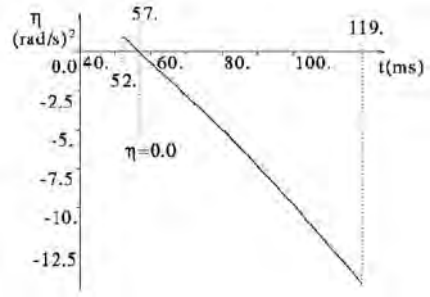


Figure 7.9. *Variation of the stability margin with the disturbance clearing time and the OMIB mechanical power. 627-machine system. Adapted from [PAV 00]*

Below, different types of possible applications of the preventive SIME are shown in brief. For more detail, the reader may refer to [PAV 00].

7.6.1. *Stability limits*

Two types of stability limits are considered: CCT and power limit. Their calculation follows the same process, summarized as follows:

(i) the stability limit corresponds to a zero margin;

(ii) the variation of the margin with the disturbance clearing time or the power level is quasi-linear; from which comes the idea of extrapolating (or interpolating) successive margins linearly;

(iii) SIME essentially uses unstable scenarios (see section 7.4.2.); from which comes the necessity to proceed from "right to left", i.e. to consider scenarios that are less and less unstable;

(iv) so as not to miss the detection of instabilities with possible multiple oscillations, i.e. unstable oscillatory phenomena (as, for example, those in Figure 7.4a), it is necessary to pursue the simulation for the entire integration period (5, 10 or 15 seconds according to the system and its modeling). This leads to the calculation of a stable margin (positive) unless a multi-swing instability appears. In the latter case, the simulations must continue until a stable simulation is found.

Let us point out, nevertheless, an essential difference between the calculation of a CCT and that of a power limit: for a given operating point, the first provides a single solution; however, for a given clearing time, the calculation of the power limit can have an undetermined number of solutions, depending on the manner in which the power of the system during the margin cancellation process is modified.

Figure 7.10 gives a schematic description of the search for a CCT through successive linear extrapolations (or interpolations): a first extrapolation related to margins $\eta(0)$ and $\eta(1)$ provides a value close to CCT, $t_e(2)$. The margin, $\eta(2)$ calculated in $t_e(2)$ being in fact non-zero, is then interpolated with $\eta(1)$, providing a second close to CCT, $t_e(3)$. Finally, the extrapolation between $\eta(1)$ and $\eta(3)$ provides a precise value for the CCT.

On the other hand, Figure 7.11 gives a schematic description of the search for power limit, P_L, in the specific case where we try to maintain the total power constant (that is the load) of the system. The cancellation of the negative margin ("stabilization") is obtained by moving a part of the generation from critical machines to non-critical machines. This process of stabilization is elaborated in section 7.6.3.

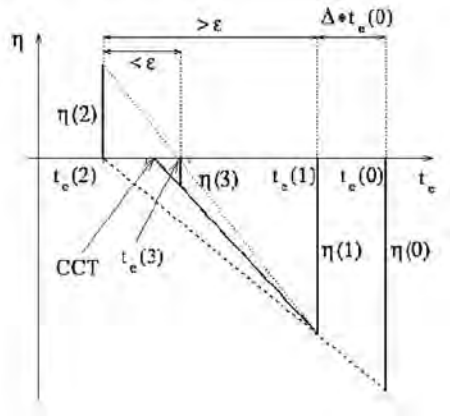


Figure 7.10. *Schematic description of the search for a CCT. Adapted from [PAV 00]*

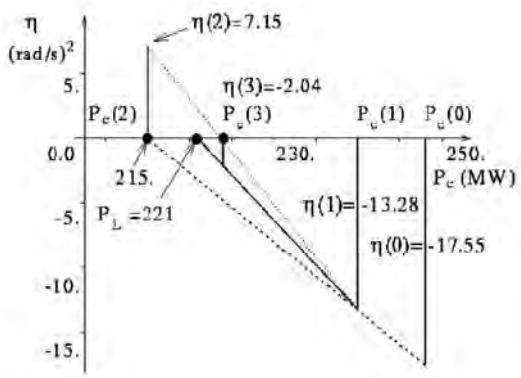


Figure 7.11. *Schematic description of the search for a power limit. Adapted from [PAV 00]*

7.6.2. *FILTRA: generic software for contingency filtering*

A good contingency filter should:

(i) eliminate "harmless" contingencies in a reliable manner, i.e. without eliminating any "harmful" contingencies, and as fast as possible;

(ii) rank the "potentially harmful" contingencies;

(iii) identify and evaluate really dangerous contingencies, i.e. those that would lead to the system loss of synchronism.

The implementation of filtering software depends greatly on the system in question, its modeling and the number of contingencies to be filtered. The diagram in Figure 7.12 seems to be particularly well suited in cases where the number of contingencies to be filtered is relatively high.

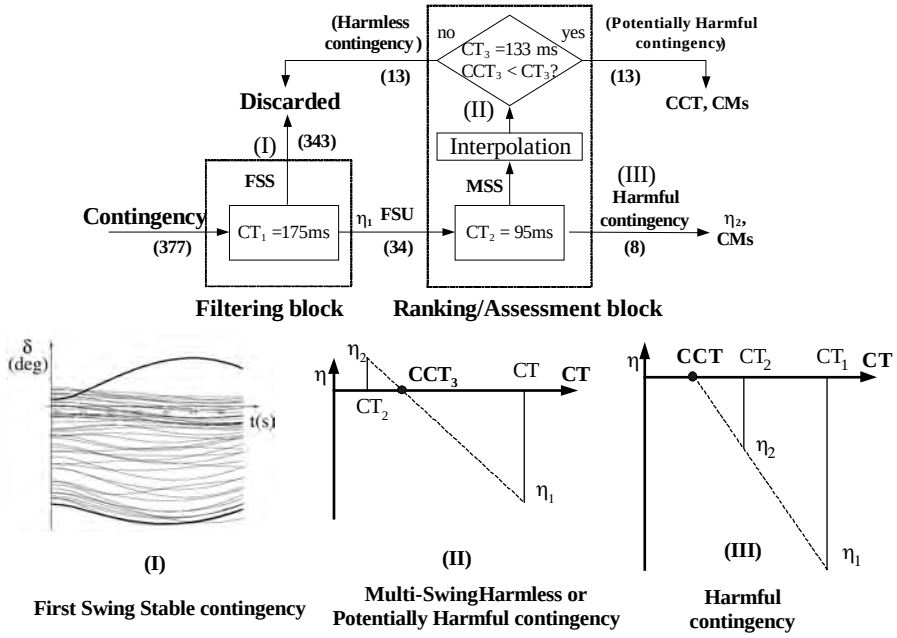


Figure 7.12. *A construction of FILTRA. Schematic description of the different classes of contingencies. The numeric values in parenthesis correspond to a simulation carried out on the Hydro-Quebec system and indicate the number of contingencies classified in each of the categories. Adapted from [PAV 00]*

Without going into the details, let us note that a contingency is declared to be:

– "first-swing stable" (FSS) if it simultaneously obeys a criterion based on the multimachine system and a criterion based on the OMIB. Let us note that to identify – and eliminate – FSS contingencies, a clearing time of contingencies, CT_1, is selected which is greater than the reaction time of protections[6];

6 It should be noted that the threshold values CT_1 and CT_2 can vary depending on the contingencies in question.

– "first-swing unstable" (FSU) if the contingency is not FSS. All the FSU contingencies detected are sent to the second block of FILTRA to be ranked further and analyzed. This second block uses a second time step for clearing, CT_2, close to the reaction period for protection. In the diagram, CT_2 = 95 ms.

For any contingency detected to be FSU, the time domain simulation is followed either until the instability conditions [7.8] are found, or on the maximum simulation period. In the first case, it is declared to be "harmful" (single- or multi-swing unstable), in the second case "potentially harmful" or "harmless". More precisely, a contingency is declared to be:

– "harmful" if it is unstable (has a negative margin, $\eta_2 < 0$) for CT_2. For such a contingency, the CCT is approximately evaluated by extrapolation of margins η_1, η_2 (see Figure 7.12(III));

– "potentially harmful" if it has a positive η_2 margin and if its CCT (evaluated by interpolation of margins η_1, η_2) is less than the threshold value CT_3;

– "harmless" if it has a positive η_2 margin and its CCT_3 is greater than the threshold value CT_3.

Let us note that:

– the approximate calculation providing CCT_3 is useful only to rank "multi-swing stable" (MSS) contingencies;

– contingencies declared to be "harmful" and "potentially harmful" are accompanied by two types of information automatically obtained during the earlier search which are the margin (negative) and critical machines[7]. They have great significance in the stabilization stage described hereafter.

7.6.3. *Stabilization of contingencies ("control")*

The control (i.e. the stabilization) of contingencies declared to be dangerous ("harmful") and possibly "potentially harmful" use the general process according to which:

– stabilizing a contingency amounts to canceling its margin, which is initially negative;

– canceling the negative margin amounts to increasing the decelerating area and/or decreasing the accelerating area. This can be done by reducing the mechanical power of the OMIB. In turn, this reduction can be achieved by moving

7 Although it has the least significance, this information is also provided for contingencies screened as "harmless".

one part of the generation of critical machines to non-critical machines[8] whose generation has to be increased for the same quantity (when neglecting losses). In fact it is easily shown that:

$$\Delta P_{OMIB} = \Delta P_C = -\Delta P_N \qquad [7.12]$$

where ΔP_C (respectively ΔP_N) represents the variation of generation of critical machines (respectively non-critical). As a result:

– to evaluate the approximate quantity of generation to be moved, proceed to the calculation suggested in Figure 7.13;

– to determine on which machines the generation has to be reduced, identify the critical machines. In addition, to distribute this total decrease of generation on different critical machines (when there are many), we can either take into account the considerations specific to the electricity market and/or feasibility, or proceed to a reduction proportional to the "degree of criticality" of critical machines. The first possibility can be treated by the use of an "optimal power flow" (OPF) algorithm, the second by using the rule given below:

– to reduce the generation proportionally to the "degree of criticality" of different critical machines, the rule of proportionality to be used is

$$\frac{P_{Ci}}{P_{Ck}} = \frac{d_i * M_i}{d_k * M_k} \qquad [7.13]$$

where d_i represents the angle deviation ("advance") of the *i*th critical machine with respect to a reference (for example, the most advanced non-critical machine), this deviation being evaluated in t_u .

Concerning the increase in generation, ΔP_N , to be distributed over non-critical machines, several solutions can be envisaged. For example, we can call upon an OPF which, in addition, can take into account other objective functions, for example ensuring maximum power transmission on a corridor (interconnection lines).

The above rules are fine-tuned by successive iterations (generally two or three in number). They can be applied to stabilize either each dangerous contingency *separately*, or all (or a sub-set of) dangerous contingencies *simultaneously* (the

8 Let us note that this operation is not necessarily sufficient to stabilize a scenario; it is possible that, in addition, some generation (and thus load) rejection becomes indispensable. Also, let us note that for "back-swing" instabilities, the generation transfer should be operated from non-critical machines to critical machines.

number of iterations does not increase in the case of simultaneous stabilization). The example in the next section shows the steps to be followed.

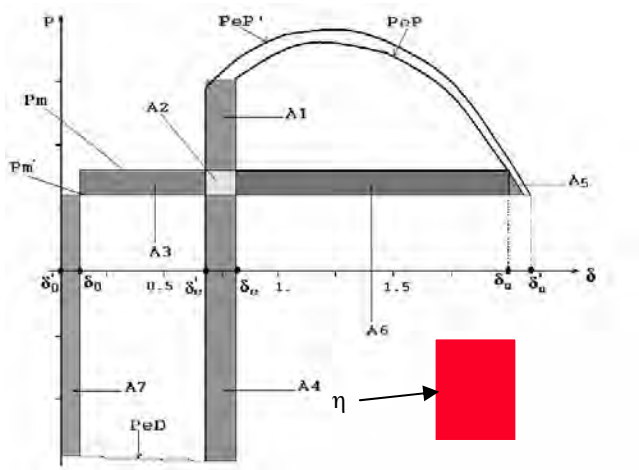


Figure 7.13. *Compensation diagram used to approximately assess the OMIB power variation necessary to stabilize the system. Contingency no. 672 of the Brazilian system.* t_e *= 167 ms;* η *= 14.7;* P_{OMIB} *= 324 MW;* P_C *= 1,050 MW. Adapted from [ERN 98a]*

7.6.4. *Transient stability assessment and control: integrated software and example of application*

By integrating the FILTRA and "control" functions, we obtain the integrated software represented in Figure 7.14. Below we show this software in one specific application aiming to determine maximum power flow that can be supported by the entire set of interconnections linking the south-eastern – west-central region and the southern region of the Brazilian system without violating the transient stability constraints.

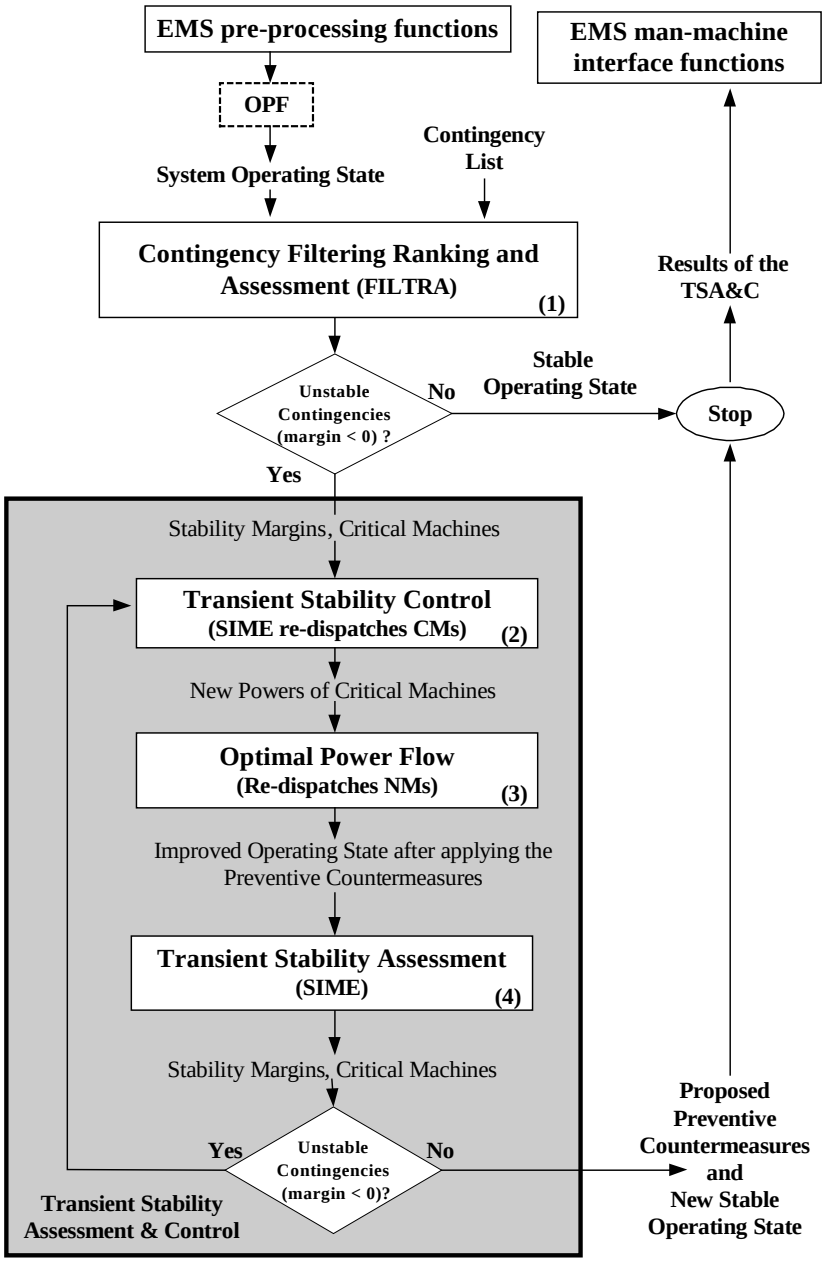


Figure 7.14. *Integrated software for transient stability assessment and control in the preventive mode. Adapted from [PAV 00]*

At the first stage, a list of 850 *a priori* "interesting" contingencies for this corridor is submitted to the FILTRA[9] function, which eliminates 832 of them and sends 18 contingencies to the second block. This block decides that among these 18 contingencies, 6 are "harmless", 6 "potentially harmful" and 6 "harmful". These last contingencies are sent to the "stabilization" stage so as to modify the operating point in order to simultaneously stabilize them.

The "simultaneous stabilization of contingencies" stage is summarized in Table 7.2. Columns 2 to 4 provided by FILTRA do not require any specific explanation. Column 5 shows the type of instability: +n for n-swing up-swing instability, -n for n-swing back-swing instability. Column 6 specifies the power variation to apply to the critical machines. This variation has been calculated by the compensation scheme in Figure 7.13, for instabilities of the "first-swing" type, and taken as equal to 10% of the total power generated by the critical machines for instabilities with multi-swings for which the compensation scheme is no longer valid. Let us recall that for "back-swings" the power variation of critical machines is an increase and not a reduction.

Finally, column 7 provides three types of information: the identification of critical machines and, for each of them, in parenthesis, the distance d_i defined in [7.13] and the modification of the generation power, evaluated according to [7.13].

It has to be mentioned, and this is easy to conceive physically, that certain contingencies have some critical machines in common. It is on this observation that the significance of simultaneous contingency stabilization depends. For example, column 7 shows that the power generated by machine 187 should be reduced to approximately 215 MW to stabilize contingency 263, and 55 MW to stabilize contingency 239. It is thus necessary to reduce its power by 215 MW. To stabilize all the contingencies at once, the values adopted for each of the 13 critical machines are indicated in bold print; their sum is 911 MW.

This reduction is compensated by an equal increase, when neglecting losses, of power of non-critical machines (of which there are 43). The distribution of the increase in power on the latter is determined by an OPF whose objective function is to ensure maximum power transmission on the corridor in question. The OPF thus provides the new operating point: iteration no. 1 can begin. The calculation consists of simulating different contingencies, still using the same clearing time, 167 ms. Table 7.2 shows that following iteration no. 1 only contingency 159 is still slightly unstable, while the other contingencies have been "over-stabilized". In particular, to

9 The first block of the scheme used for this purpose differs from that in Figure 7.12. On the other hand, the structure of the second block is identical to that in Figure 7.12; but the threshold values are different: CT_2 = 167 ms, CT_3 = 180 ms.

correct the over-stabilization of contingency 167, a new iteration is calculated, on the basis of the operating point provided by the OPF.

1	2	3	4	5	6	7
Base Case						
Cont. no.	η_2	t_u (MIP) (ms)	CCT (ms)	Swing	ΔP_C (MW)	CM_i (d_i (°) , ΔP_{Ci} (MW))
263	-9.30	390		+1	-333	187(92,-**215**), 186(82,-**55**), 179(55,-**63**)
140	-2.46	605		+1	-185	16(75,-185)
112	-2.99	580	125	+1	-252	16(64,-**252**)
239	-3.49	550	142 141 156	+1	-297	181(105,-**115**), 184(95,-**22**), 182(83,-**46**), 292(79,-**7**), 187(65,-55-, 186(61,-15), 179(57,24), 291(42,-**2**), 290(41,-**6**), 293(34,-**5**)
159	-82.31	2,805		-3	+16	2706(-13,+**16**)
167	-0.33	2,020		+2	-139	21(76,-**139**)
Iteration 1						
263	1.53	(4,000)	--	--	+47	187(--,+30), 186(--,+8), 179(--,+9)
112	1.49	(4,000)	--	--	+84	16(--,+84)
239	3.01	(4,000)	--	--	+248	181(--,+97), 184(--,+18), 182(--,+38), 292(--,+6), 187(--,+46), 186(--,+13), 179(--,+20), 29(--,+1), 290(--,+5), 293(--,+14)
159	37.79	(4,000)	--	--	-5	2706(--,+5)
167	9.76	(4,000)	--	--	+134	21(--,+134)
Iteration 2						
167	5.84	(4,000)	--	--	+4	21(--,+4)

Table 7.2. *Simultaneous stabilization of all dangerous contingencies. Adapted from [BET 99]*

Let us note that following the stabilization of the dangerous (*harmful*) contingencies, a test must be applied to contingencies initially detected as "potentially harmful" so as to verify that they have not been destabilized.

From the point of view of the operator, the most important information is:

– the representation (for example in the form of a histogram) of power of critical machines "before" and "after" stabilization;

– the value of maximum power that can be transmitted through the corridor.

Table 7.3 provides general and detailed information (for each of the interconnection lines), concerning maximum power "before" and "after" stabilization. It suggests that to meet transient stability constraints we must reduce the power transmitted through the corridor by 77 MW (3.545-3.468) as compared to maximum power; this is a relatively small reduction (about 2%). This remark also holds valid for the reduction of power generated by critical machines.

Let us note that among the different transient phenomena encountered in this real-world application example, some are of the "local mode" type, others of the "inter-area mode" type. Figures 7.15 and 7.16 give an example of each of these modes.

1	2	3	4	5	6	7	8	9
Line	Amount of power (MW)							
	765 kV	**230 k**			**138 kV**			**Total**
	110-109	222-2559	202-2622	303-2946	303-2946	337-2608	337-2837	
Initial	2,368	178.0	158.0	129.5	342.0	248.5	121	**3,545**
Final	2,184	257.6	206.8	145.6	326.8	235.8	111.8	**3,468**

Table 7.3. *Modification of power flow. Adapted from [BET 99]*

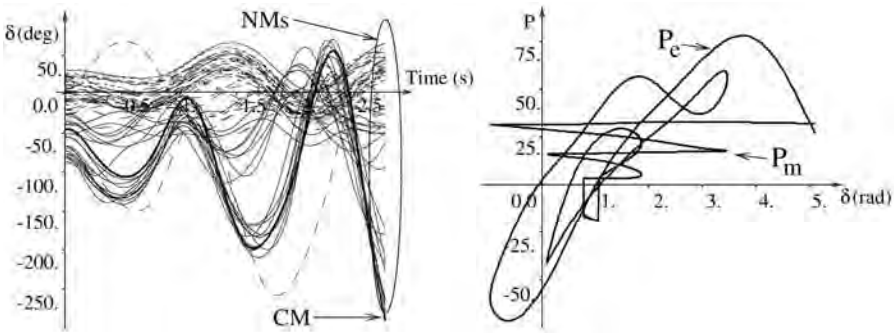


Figure 7.15. *Loss of synchronism in "back- multi-swing mode". South-southeast Brazilian power system, 56 machines, 1185 nodes. Contingency no. 159;* t_e *= 167 ms. Operating conditions of the base case. Adapted from [BET 99]*

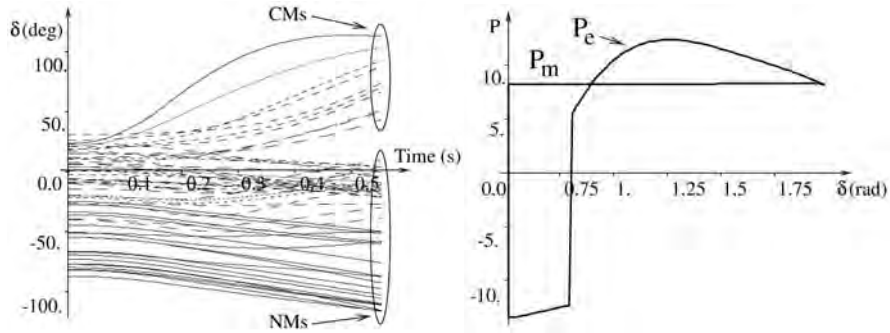


Figure 7.16. *Loss of synchronism in "first-swing" inter-area mode. South-southeast Brazilian power system, 56 machines, 1185 nodes. Contingency no. 239;* t_e *= 167 ms. Operating conditions of the base case. Adapted from [BET 99]*

7.6.5. *Current status of the preventive SIME*

Thanks to a very significant number of simulations conducted on a number of networks with multi-form characteristics, this software has achieved the desired degree of maturity and robustness for its practical use. An intermediate stage was passed through tests that have been conducted within the framework of the European project OMASES [OMA 01].

7.7. Emergency SIME method

7.7.1. *Aims*

The emergency SIME method has the following aims:

– to predict in real time and *after* a large disturbance has occurred, if this disturbance is likely to cause the system loss of synchronism;

– if yes, to evaluate the degree of severity (margin) and the moment when the loss of synchronism will become irrevocable;

– knowing the degree of severity, to evaluate the type and importance of the control action to be executed to check the extreme case of loss of synchronism;

– to continue to process SIME to determine if the control action is sufficient or if it is necessary to take additional action.

In short, the ultimate aim of emergency SIME is the implementation of corrective control techniques in real time and closed loop.

The information used to achieve this particularly ambitious aim is provided by measurements collected in real time at production sites.

It is to be noted that the disturbance to be stabilized is supposed to be completely unknown; only its effects are reflected in the processed measurements.

It is also to be noted that the time domain simulation would not be suitable here even if it were faster than real time. Finally, note that the method is free from any uncertainty linked to the system modeling and knowledge of its parameters, since it relies on real-time measurements, which are supposed to reflect the physical reality.

7.7.2. *Origins*

The above description suggests that the method has to *predict* the possible loss of synchronism and trigger means of stabilization capable of acting in a time interval less than the "time to instability", also determined in a predictive way. Also, the method has to predict if the control carried out has been adequate to check the loss of synchronism, on the basis of measurements *that still do not take into account the effects of this control*.

This facility of providing a fast predictive diagnosis is the prerogative of OMIB, as appears from the following considerations.

Figure 7.17 summarizes the organization of the different tasks of emergency SIME, briefly described below.

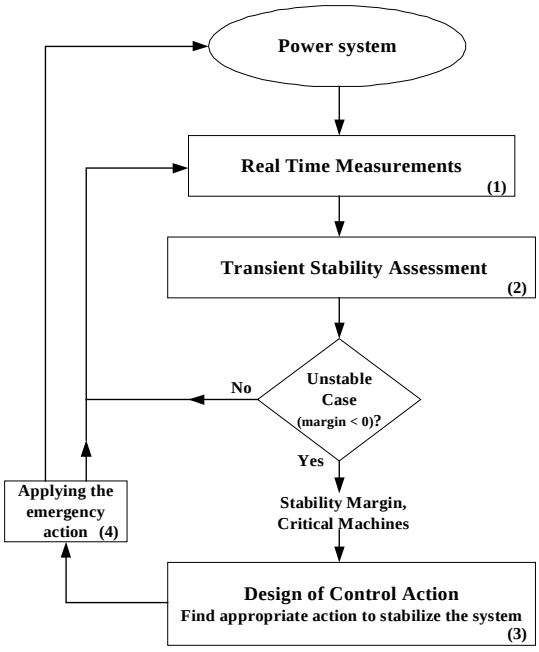


Figure 7.17. *Organization of corrective assessment and control software in real time and in closed loop. Adapted from [ERN 00a]*

(i) Prediction of the OMIB structure. This prediction is based on real time measurement sets acquired at regular time intervals, t_i , *after elimination* of the disturbance (i.e. after the system enters into its final configuration). The set of measurements is updated every Δt (for example, every 20 ms). The prediction begins at moment $t_i + 2\Delta\text{t}$, and uses the first three sets received in t_i , $t_i + \Delta\text{t}$, $t_i + 2\Delta\text{t}$.

By using a Taylor series based on these three sets of measurements, the rotor angles of the machines in the system can be predicted in the range of, for example, 100 ms. This prediction makes it possible to identify the OMIB candidates, in accordance with section 7.4.2.4.

(ii) Prediction of the curve $P_a - \delta$ of OMIB candidates, based on

$$P_a(\delta) = a\delta^2 + b\delta + c\,, \qquad [7.14]$$

by resolving for a, b, c for the three times t_i , $t_i + \Delta\text{t}$, $t_i + 2\Delta\text{t}$.

(iii) Prediction of instability, by resolving

$$P_a(\delta_u) = a\delta_u^2 + b\delta_u + c = 0$$

for δ_u and by trying to determine if both instability conditions [7.8] are verified.

If not, repeat steps (i) to (iii), based on the new sets of measurements.

If yes, consider the OMIB candidate that fulfills these conditions like the real OMIB, and calculate in a sequence:

– the unstable margin

$$\eta_u = -\int_{\delta_i}^{\delta_u} P_a \, d\delta - \frac{1}{2} M\omega_i^2 \qquad [7.15]$$

– the time to instability

$$t_u = t_i + \int_{\delta_i}^{\delta_u} \frac{d\delta}{\sqrt{\frac{2}{M}\int_{\delta_i}^{\delta} - P_a \, d\delta - \omega_i^2}} \, . \qquad [7.16]$$

(iv) Validation test. This test is based on the observation that the value of the calculated margin based on [7.15] should be the same whatever moment it is calculated, as it corresponds to the same scenario. The above calculations should thus be repeated at successive intervals Δt until a value for the (quasi-)constant margin is obtained, unless the time to instability is very short. In fact, in the latter case, to avoid loss of synchronism, the stabilization of the system will be carried out immediately, even if this stabilization is not optimal.

(v) Corrective control. The only corrective control identified so far is generation tripping. The decisions to be taken in this case concern the identification of critical machines and the assessment of the number of critical machines to be tripped. This number depends on the size of the negative margin that needs to be canceled in such a way as to make the decelerating area at least equal to the accelerating area (see Figure 7.1b).

Without going into the details, let us say that the calculation should take into account the time period between the moment when the action is decided and the moment when it is carried out. In addition, the effect of this action must be predicted on the basis of measurements received *before* this action takes effect. This calculation is developed in [PAV 00].

7.7.3. *Estimation of time taken by the different tasks*

With the possibilities offered by current technology, the time periods involved by the different tasks for a complete cycle of corrective control are, at first approximation, as follows:

1. data (measurements) acquisition at generation sites and their transmission to the control center dedicated for emergency SIME: 50 ms;

2. use of data at the control center (blocks (2) and (3) in Figure 7.17) for the *predictive* SIME (prediction of the OMIB, its curve $P_a - \delta$, margin and instability time): virtually negligible duration as compared to that of other tasks;

3. transmission of the control command from the control center to generation sites to be controlled: 50 ms;

4. execution of the control command: 50 ms.

The above approximate evaluation thus requires a total time duration of 150 ms. To this duration the duration for necessary measurements sets acquisition for a correct evaluation of margins is added, after the disturbance elimination: between 3 x 20 and 10 x 20 ms, i.e. 60 to 200 ms. In other words, an emergency control cycle requires between 310 and 450 ms from the appearance of a disturbance. For this cycle to be effective, the time to instability should be less than this cycle.

7.7.4. *Illustration*

The emergency SIME method using generation tripping as control has been tested on four different networks. The tests are based on contingency simulations provided by a step-by-step stability program; data sets are collected every 20 ms.

Simulations have been carried out on the following systems:

– Hydro-Quebec system modeled by 92 machines: the contingency was chosen in a manner so as to affect the eastern corridor of the network and it dealt with saving the Churchill Falls site by rejecting up to 4 hydraulic machines [ZHA 97b];

– Brazilian system, modeled by 65 machines: it dealt with saving the production site of Itaipu by tripping up to 5 hydraulic machines, out of 8 in normal operation [ERN 98b];

– test system C of EPRI with 88 machines, by rejecting thermal production [ERN 00b];

– WSCC American system, also by rejecting thermal production [ERN 00a].

The results of simulations obtained with emergency SIME have been tested and fully validated by purely time domain simulations.

As an illustration, we briefly describe below the results obtained with the WSCC network. The time domain program coupled with SIME is ETMSP.

This network was modeled by 29 machines generating close to 60,000 MW. The disturbance in question is a three-phase short circuit, eliminated by opening a line. This disturbance was selected arbitrarily among various dangerous disturbances identified in the network. It is to be noted that the clearing time for obtaining these different "dangerous" disturbances is 150 ms.

In the absence of any stabilization, the preventive SIME provides a negative margin of -2.8 (rad/s)^2, time to instability, t_u = 480 ms, and the corresponding angle and speed of the OMIB: δ_u = 1.75 rad and ω_u = 2.36 rad/sec. In addition, the software identifies two critical machines of 843 MW each.

Stabilization by emergency SIME. The simulation results obtained are summarized in Table 7.4. The columns of this table provide the following information:

– Column 1: time for acquisition of the last measurement set

– Column 2: predicted margin of the system without control

– Column 3: time for the predicted instability

– Column 4: predicted margin of the controlled (stabilized) system.

1	**2**	**3**	**4**
Time (ms)	Margin before corrective action (rad/s^2)	Time of instability (ms)	Margin after corrective action (rad/s^2)
290	-3.54	458	--
310	-3.35	464	0.903
330	-3.27	466	1.208
350	-3.16	469	1.487
370	-3.05	473	1.902
390	-2.97	475	2.025
410	-2.90	478	2.541
430	-2.83	481	2.827
450	-2.81	480	2.835

Table 7.4. *Evolution of phases of predictive evaluation and corrective control. Adapted from [ERN 00a]*

The disturbance having been eliminated at 150 ms, the first results of the prediction (started at 210 ms) indicate that the system is stable. However, at 290 ms, the margin becomes negative and the corresponding time to instability is 458 ms. Critical machines are identified. To be precise, the history of events has evolved as follows:

– in $t = 0$, a three-phase short circuit is applied;

– in $t = 150$ ms, the short circuit is eliminated by opening a line;

– in $t = 290$ ms, a loss of synchronism is predicted in the range $t_u = 458$ ms;

– in $t = 310$ ms, the rejection of a critical machine is decided, given the relatively short time to instability;

– at 150 ms later, i.e. t = 460 ms, the machine is effectively eliminated; the system recovers synchronous operation.

Table 7.4 provides some additional details. First of all, let us note that the value of the negative margin and the time to instability vary slightly during the course of the simulations. Then, the positive margin reproduced in column 4 is a *predicted* margin. It reflects the degree of stability of the system after the rejection of a critical machine. Let us also note that the margin provided in column 2 will only become really positive in t = 460 ms + 3 x 20 = 520 ms (i.e. following the acquisition of 3 sets of measurements collected after the execution of the control). It is also fortunate that the time to instability is in reality more than 460 ms, contrary to the first prediction (458 ms); in fact, if this prediction was precise, the system would lose synchronism before the execution of the control (which takes place at 460 ms).

Finally, let us note that the predicted margin comes close to the real margin (the one provided by preventive SIME (-2.8 (rad/s)^2) only at the end of the simulations (towards 430 ms).

7.7.5. *Note on corrective control in open loop*

The execution time of the control in closed loop can prove to be excessive when it is a question of stabilizing particularly violent contingencies. Technical literature in fact mentions cases where, to avoid loss of synchronism, action must be taken in 100 or 200 ms following the appearance of a disturbance.

In similar cases, we have to resort to predefined corrective measures based on simulations conducted off-line (with preventive SIME) and activated in real time after the detection of a situation close to the one that is simulated. In addition to avoiding catastrophic degradation of the network, this control is less costly as its

importance varies inversely to its application time [PAV 00]. In compensation, the emergency conditions to which this control is applied will not be identical to simulated conditions.

A more satisfactory solution could be found in the judicious combination of control in open loop and another in closed loop: the first would be executed in the shortest time period possible, but in a relatively discrete manner given the fact that the second (emergency SIME in closed loop) would be able to reinforce the first action if necessary.

7.7.6. *Conclusion*

Unlike preventive SIME, emergency SIME has not yet reached full maturity. One of the reasons for this is that focus was initially on the development of preventive SIME. On the other hand, emergency SIME requires the implementation of up-to-date technological equipment, which is only now becoming available.

In spite of this, emergency SIME in closed loop has until now provided very promising results. It can thus be considered as an interesting alternative to open loop control techniques (where the control is predetermined on the basis of simulations conducted off-line and applied in real time), when the stability scenarios “seem close” to those in the simulations.

However, many aspects deserve wider exploration, such as:

– performance of the PMU for the measurements acquisition;

– performance in telecommunications for transmission of measurements;

– implementation of stabilization actions other than the rejection of production;

– advantages and disadvantages of centralized control as compared to decentralized control (close to site(s) to be protected);

– advantages and disadvantages of complete control (i.e. using data from all the production sites) as compared to incomplete control (using data from certain target sites).

Without doubt, a generic solution to the problem of corrective control in real time will be provided through a combination of an open loop and closed loop approach.

In any event, rapid technological progress and the increasing probability of encountering emergency situations augur a great future for these types of methods.

Simulations conducted at present within the framework of a European project provide a significant test bank of the potentialities of this software [EXA 01].

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Chapter 8

Security of Large Electric Power Systems – Defense Plans – Numerical Simulation of Electromechanical Transients

8.1. Introduction

Continuity of supply is without doubt the primary concern of the designer and operator of electric power systems. To reach a high level of performance, until recently, electricians enjoyed all the necessary facilities: rigorous development planning, integrated management of production and networks, investment capabilities in accordance with technical objectives based on mutual agreement between different components of the utility. This favorable situation made it possible to maintain network operation a good distance away from their physical limits, without having to think about what would happen if these limits were transgressed. The major but rare incidents have often revealed the risk presented by certain degradation mechanisms of operation that had escaped the attention of operators.

Deregulation of the electricity market has greatly modified the control conditions of network operation security. In fact, open access to the network, contracts for supply agreed between the producer and consumer makes the operating conditions more and more unpredictable; the search for maximum economic efficiency leads to

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the desire to use the interconnection capacities far beyond their established limits, etc.

All these evolutions lead to the operation of networks closer to their physical or stability limits and increase the risk of transgressing these limits accidentally. There is therefore a need for more precise knowledge of these limits and understanding of what happens beyond them, so as to develop countermeasures, system protections which could, where appropriate, contain the incidents and prevent a widespread collapse of the system.

The importance of the role of modeling and tools for dynamic simulation in the acquisition of knowledge and understanding of phenomena is considered. The simple observation of actually experienced cases that one hopes would be rare, is obviously a very limited method.

The dynamic model of the system, which is a veritable encyclopaedia of modeling of the system components, itself becomes the main source of knowledge of systemic phenomena.

It will therefore be no surprise that in this chapter, the modeling and methods of simulation are of paramount importance, but the real guide to the problem will be the knowledge of physical phenomena and mechanisms that can lead to major faults. This knowledge will be systematically applied to the analysis of incidents as well as to their preventive and corrective control. It will be verified using the examples presented that this control is not a mere matter of applying rules, but the result of an elaborate thought process to be followed in each case.

8.2. Degradation mechanisms of network operation

8.2.1. *The system*

In the existing conditions of technology, electricity cannot be stored on a large scale. Practically all the available means of accumulation depend on a conversion into another form of energy. The reconversion into the electricity vector does not generally allow a sufficiently fast transformation to cope with loss of load-generation equilibrium as a result of an incident in the network.

The only energy reserve that can be mobilized easily and instantaneously is available in the form of kinetic energy in rotating sets, mainly alternators and their driving machine. The range of variation allowed for the “normal” frequency setting is low, in the order of ±1 Hz. Considering the inertia constant of the network, this

reserve only represents, in the ½ control band, for example from 50 to 49 Hz, the load consumption during 0.2 s.

The maintenance of network frequency, other than the emergency measures taken if the frequency goes below 49 Hz (or an equivalent threshold for networks operating at 60 Hz), thus depends on the response capacity of the conversion process of energy involved in the production units in general and in those that participate in frequency control in particular.

These processes present time periods of change in the system and variation rate limits of the variables that are related to it: temperature, flow, pressure, etc. These constraints have to be studied and taken into account for the operation of the system. They are generally related to the type of unit in question. For example the size of the drop, the presence or not of a surge tank for hydroelectric plants or the use of solid, liquid or gaseous fuels for thermal plants, the type of boiler, the schedule for settings, etc.

This limited capacity of the electric system to restore load-generation equilibrium following a sudden variation is one of the reasons that have led to interconnection. For a determined variable, for example the loss of a generation set, a reduction of impact on the system is obtained by the increase in its size.

Interconnection has thus made the use of very large power stations possible and thus, benefits from the effect of size. This was the only way to obtain efficiency and acceptable pollution levels with fossil fuels other than natural gas, which was not available for the production of electricity until recently.

An interconnected network must link the power stations in a sufficiently robust manner to implement mutual support necessary for system security. Other than the thermal behavior of lines, the network will always present an exchange capacity limit, a maximum transferable power, resulting from the close coupling between active power transmission and voltage behavior.

Another particularity is a result of the electromechanical conversion of energy almost exclusively by rotating machines: the system is the seat of undamped oscillatory phenomena.

Interconnection also implies that a substantial part of the installations are spread out over vast areas. This leads to exceptional vulnerability for an industrial installation, due to the impossibility of effectively protecting the structures from natural disturbances, or even any malicious acts.

The variables that can affect the system are internal or external in nature. The internal causes of fault are related to different materials: influence of aging, errors in designing or setting, defective work or even human error. Rigorous design or maintenance of installations can reduce the frequency of occurrence of these phenomena.

External causes are more diverse. By definition they cannot be controlled. Only their effects can be controlled. Among the most frequent, inclement weather such as storms, gales, snowfall, hail storms, etc., for which constructive measures have to be taken depending on the local circumstances and available historic information.

The risks of accidental damage of structures are evaluated based on the places and particular layout conditions, the norms and rules to be followed. The risk of sabotage, rarely mentioned, must also be included in certain circumstances.

Defects in elements of the electric power transmission and distribution system often involve defective insulation. The consecutive transient behavior is characterized by currents whose amplitude greatly exceeds the values seen in steady state. This essential characteristic distinguishes electricity from other energy vectors and constitutes both an advantage and a disadvantage.

The advantage is making the detection of an incident possible and thus providing criteria enabling the effective isolation of the defective element. The disadvantage is a significant hazard for the survival of the material which is exposed to severe constraints during the fault phase, but also a risk for people. Moreover, it is this latter aspect that is mainly considered in regulations related to the protection of electric power systems.

The primary objectives of a protection plan are thus the security of people and the limitation of constraints imposed on the material. Tripping needs to be ensured, if possible only for the element in question, in a minimum amount of time. It is here a question of time ranging from a few tens of milliseconds to a little over a few seconds in the worst cases.

Two fundamental principles are used, “unit” protection and redundancy. “Unit” protection is based on absolute criteria making it possible to detect the faulty element rapidly, for example differential protection, distance protection with remote tripping, etc. Redundancy is made up of two distinct measures. On the one hand, “unit” protection is doubled by preferential use of different operational principles; on the other hand “non-unit” protections for distance and overcurrent for example, enable, in an emergency, the protection of elements upstream by timed tripping of the element on which they are installed.

"Unit" protection also ensures tripping, generally timed, of an element if its operating point leaves the acceptable operating range.

8.2.2. *Continuity of supply*

The continuity of supply in case of risks affecting the system can only be ensured if a certain number of conditions are respected in terms of structure, on the one hand, and organization, on the other.

The structure of an EHV-HV system is based on meshing, ensuring that at least two distinct paths make it possible to reach each station. Then the implementation of specific procedures as much during the development of the infrastructure as the operation of the system ensures the maintenance of margins.

These procedures verify that the unserviceability and normative faults will not lead the system beyond certain limits, maintaining a "sufficient" margin with relation to collapse. These limits and procedures are established on the basis of past experience. They are often questioned after a serious incident has affected the system to which they apply.

Having margins available assumes certain overinvestment in production and transmission means, lack of optimization of the operation point in the system. Preventative security comes with a cost. The definition of development criteria or system operation, in the context considered here, i.e., the risks against which the system must remain within its acceptable working range can thus be heavy as a result, in terms of cost to indiscriminately cover any events whose probability of occurring can be very different.

Moreover, the probabilistic approach is recommended at present, which tends to accept risks whose probability of occurrence is rather low. This implies however, that specific measures are taken to cope with these faults that are no longer covered by preventative security.

Among the deterministic criteria for security, the best known is without doubt the "N-1" criterion. It stipulates among other things that in state "N", i.e., when all the system elements are in operation, the operating conditions respond to the operative standards, and this for different suitable standard states: for example at peak load, or low load etc. In addition, it implies that for any type of incident leading to the retirement of one and only one element, the system operating point remains within the acceptable range. The latter is then declared as "N-1" secure.

However, the system can be subjected to the risk where the scope far exceeds the incident or normative incidents maintained as “N-1”, “N-2”, etc. In these conditions, the system state could go far beyond the usual accepted limits. A nomenclature of characteristic states has been suggested:

– *secure*, the network is “N-1” secure and the operation margins are respected;

– *vulnerable*, the network is no longer “N-1” secure, or the operation margins are no longer verified;

– *alert*, the network is still viable, but the probability of defense actions being necessary is high;

– *emergency*, the network is not viable but the security can be recovered without resorting to defense actions, by a change in configuration, for example;

– *defence*, the network is not viable and defence measures are indispensable;

– *collapse*, the network is off power; all sources are stopped or disconnected.

The development of incidents involving large electric networks, particularly serious incidents, is essentially dominated by the activation of relays and automatic devices tripping production groups, opening the line or transformer circuit breakers, cutting off load supply, separating the busbars, modifying the set points of compensation systems and on-load tap changers of transformers.

The operation of these automatic devices that create discontinuity in the network, is itself defined by values of certain variables (voltage, currents, apparent impedance), that have existed in the evolution states of the network.

Network behavior in case of incidents can be represented by formalism similar to Petri networks. It refers to directional graphs made up of two types of nodes. One type represents the states, the other represents the transitions. The “state” and “transition” nodes are linked through branches going from a “state” to a “transition” or from a “transition” to a “state”.

The following diagram synthetically shows all the listed “states” and a set of generic “transitions”, some going in the direction of the degradation of system operation, others imposing a system recovery, generally at the cost of reduction of the supplied load.

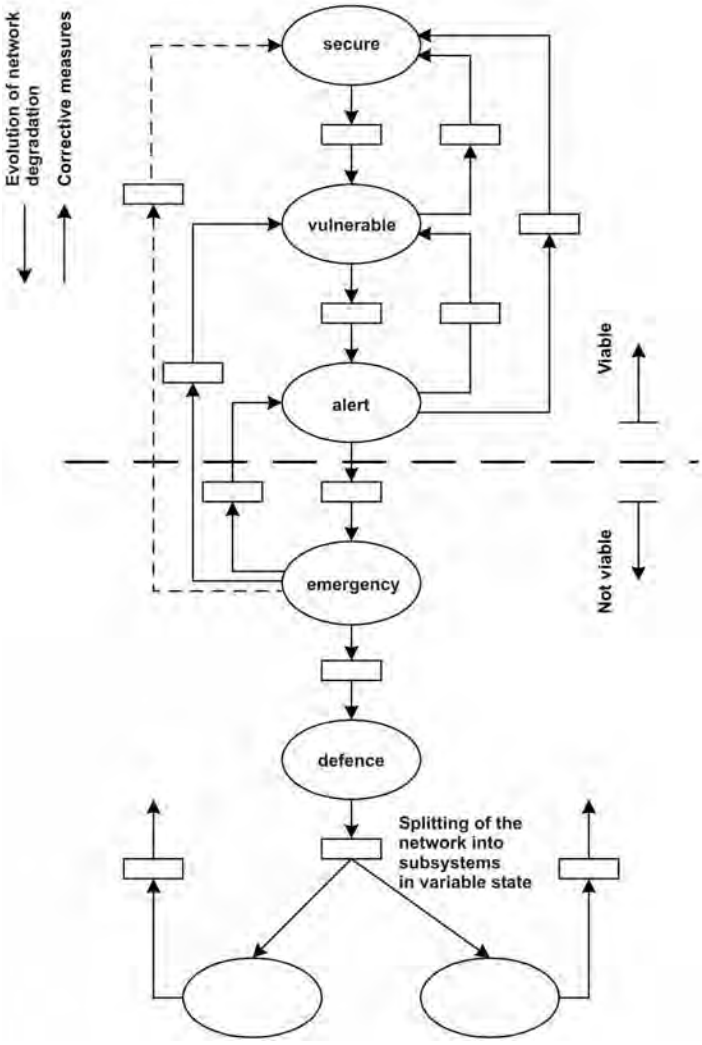

Figure 8.1. *Petri-like network related to the system states*

A normative incident affecting a system in “secure” state constitutes a “transition” that leaves the system in this state; the “transition” in fact loops on to “the state”. For such an incident, there are no consequences perceived by the customers.

For a disturbance that is beyond these criteria, different types of transitions are possible. In the case of more serious disturbances, the initial incident will cause progressive degradation of system operation until partial or total collapse.

This degradation process is characterized by the succession of states and transitions from one state to another (usually intervening after the events) and setting the "mechanisms" in motion. Events can affect the topology (the network so to speak, tripping of a unit for example) or the state (defined mainly by loads and production, an unexpected increase of load for example) of the system.

8.2.3. *Degradation mechanisms*

Degradation mechanisms represent the system reactions when there is a rupture of generation-load equilibrium, transgression of network transmission capacity limits or loss of damping capacity of system disturbances, in a progressive manner (evolution of the state), or abruptly (transition). In practice, during serious incidents, many of these mechanisms are involved successively, and even simultaneously.

8.2.3.1. *Cascade tripping*

Cascade tripping due to overload is a regular cause of serious incidents affecting interconnected networks. Can we consider it a basic degradation mechanism as such? Or should it be seen as a factor that favors the spreading of the incident?

Thermal limits generally allow some time for action of a few minutes, or even around ten minutes, making the intervention of the dispatcher possible. If it refers to a stability limit, the deployment of countermeasures has to intervene too quickly to be executed by the operators and thus depends on automatic devices.

If cascade tripping occurs as often in the description of serious incidents, it is because few systems are currently equipped with specific protection in this respect. Countermeasures imply implementing remote action at one single time in networks that may belong to different utilities. They are difficult to design for general use as they depend on the precise moment in time.

8.2.3.2. *Development of undamped oscillations*

The development of diverging rotor oscillations is in fact a special case of angle stability loss (see here below). The phenomenon develops in a quasi-stationary state, often spreads over several minutes and usually ends in a loss of synchronism, unless a system non-linearity limits the oscillation amplitude which is maintained, or an adequate countermeasure brings the system back within its static stability limit.

In interconnected systems, the main risks come into this domain from low frequency oscillatory modes, of about 0.1 to 0.5 Hz: interzone oscillations.

These modes are inevitable and directly related to laws of mechanical movement of alternator rotors. In a given system, the oscillation frequency is relatively invariant; it is the damping that needs to be controlled. This depends on the system as a whole, especially on the operation point and details of installation of different control loops, but also the characteristics of the loads.

The amplitude of power transfer plays an important role as well as the weakening of the interconnected network following trippings in links. Both can give rise to the appearance of interzonal oscillations.

The most spectacular recent incident having led to the appearance of diverging oscillations hit the WSCC network on 10 August 1996. The successive loss of two links in an interval of a few minutes, the first due to a fault, the second following a faulty setting of protections, caused the appearance of increasing oscillations ending after 6 to 7 minutes through trippings on rupture of synchronism, and the collapse of a large part of the West American network.

The data acquisition system previously set up in this system, sensitive to interzonal oscillations has brought to light the adverse role played by additional control loops installed on the HVDC link of the Pacific Intertie which amplified the phenomenon that they were meant to contain.

8.2.3.3. *Loss of angular stability*

The most well known form of loss of angular stability is seen in the case of a short circuit in the network. The protection system is normally developed so that production units maintain a stable operation in case of “normative” faults, for example a three-phase short circuit nearby, eliminated by tripping of the unit in question in base time, possibly in backup. In weak networks, the conditions maintained are often less severe (for example, the normative fault is single phase).

The loss of angular stability due to short circuit will thus not intervene in principle unless the operating conditions are degraded, low voltage for example, if the incident is more serious than the reference incident considered during the design phase of the protection system, or again in case of faults in one or the other protection scheme.

It is important to remember that often serious incidents having a short circuit as the cause and leading to loss of synchronism occur due to false maneuvers related to works in substations, where protection has been blocked to avoid untimely tripping.

Finally, it will be noted that the loss of synchronism can also result from a variation of the impedance of the link of a machine to the network, consequential to the tripping of a line, or to an increase in the internal angle of the machine following a reduction in excitation.

8.2.3.4. *Loss of frequency stability*

Frequency instability is a result of a significant imbalance between production and consumption and especially the inability of the production to adapt fast enough to reestablish this equilibrium. This instability is generally seen by a decrease in frequency. Cases of frequency increase may occur, although more rarely, mainly in networks characterized by a significant part of hydropower generation.

Two cases are presented hereafter. The first concerns an isolated network of moderate power, the second an interconnected network, in order to show why frequency instability in large interconnected systems can only occur after their break up into islands.

The isolated system is made up of a public network presenting a peak load variant of 800 MW at the minimum point of the load, to 2,000 MW at the peak. An aluminum electrolysis production plant of 1,200 MW, operating through auto-generation, is interconnected with it (the interconnection capacity corresponds to around 20% of the power of the site). The primary frequency control is mainly established on the industrial site by electrolysis control according to a criterion with two thresholds making it possible to cover the “normative” incident, i.e., the loss of the largest sized group on the site.

The public network which “benefits” from this control by the load presents a significant spinning reserve from conventional units without reheat related to a sea water desalination plant. This reserve can be rapidly released by opening of turbine inlet valves and operation of the stored energy reserve in the boilers. However, this is depleted rapidly and does not constitute a primary reserve in the real sense of the term.

A common mode incident is taking place in the gas plants supplying a power station comprising of several units, that trip in cascade. Load shedding is triggered first at the industrial site; the first thresholds of the load shedding plan of the public network are activated later. At this moment, the link with the industrial site trips. The public network collapses in frequency, for lack of sufficient load shedding.

Simulations have shown that in the absence of this tripping, the situation would not have been secured. The frequency collapse would simply be involved later, after the depletion of the reserve in classic thermal groups.

The second incident considered took place in France on 19 December 1978, at around 8 am. At this moment the network is in a state classified as “vulnerable”, it is largely an importer (it is the initial phase of nuclear power production deployment after the first oil shock). Hydropower generation is abnormally weak, a large number of unavailable power plants affect the Parisian region, and the weather is cold.

The load increases faster than the expected limit. The secondary frequency control stops having reached its limit, indicating that all the expected reserves have been put on line. The emergency start up of the hydropower units still available intervenes. At the same time voltage is degraded in the Parisian region, it affects the supply of the auxiliaries of some power stations, leading to a reduction in their production. 15 minutes after the beginning of the alert, the first overload appears. If nothing is done, this line will trip in 20 minutes.

What would have happened if the network, instead of being interconnected with the West European system, had been isolated? The frequency would have decreased and the load shedding plan would have automatically reestablished the situation. What happened in December 1978? After 20 minutes, the overload protection tripped, the degradation of the system state was then abruptly accelerated ending in a substantially widespread voltage collapse.

In a large interconnected system, the lack of reserve does not lead to frequency problems, but to problems of power transfer which often translates into voltage collapse.

8.2.3.5. *Loss of voltage stability*

Voltage instability, like frequency instability can occur through an increase or decrease. The risk of instability due to overvoltage concerns situations with weak load, in large widespread networks or networks equipped heavily with cable links. The immediate consequences are more critical than for voltage collapse. In particular, for production groups where the reactive power absorption limit constitutes not only the thermal limit but also the stability limit.

The previous point has already introduced some characteristics of a typical voltage collapse sequence in an interconnected system. Two other examples will be briefly discussed.

Voltage collapse in northern Belgium in August 1982. All the ingredients are found. At the initial stage, the network is vulnerable, a single 380 kV line supplies the north of the country, due to delay in the commissioning of the northern loop of the 380 kV network and the consignment for work of the interconnection to France. The incident triggering the degradation process is the loss of Doel 3 unit in test

when it produces 500 MW and as many Mvar. After the Doel 3 tripping, the two neighboring groups, Doel 1 and 2 are in reactive power overload. A few tens of seconds later, their voltage regulation "interprets" this situation as an automatic regulator fault, which is substituted with the manual regulator. This, at the time, is not equipped with a shock proof transition device. Its operating point corresponds in fact to the last synchronization of the group. Given their active load these machines thus greatly absorb reactive power.

Regional groups, which have their rotor overloaded, reduce their reactive production, under the effect of their voltage regulation reaching its limit or due to intervention of the personnel on duty. The system voltage decreases progressively. Four minutes thirty seconds after the initial incident, the Doel 1 and 2 groups trip through the impedance relays, activated due to the loss of synchronism. A few seconds later, the only 380 kV line connecting the region to the interconnected European network trips, the degradation follows leading to an almost complete collapse, with the exception of a sector of a few peripheral areas supplied through the south of the country.

A second incident that is worth noting occurred on 12 January 1987 in the EDF network. Its cause, an unusual common mode. The incident starts at 11:30 by the tripping of a unit in the Cordemais power station due to an electric fault. Two units are stopped due to damage. The weather is very cold, the demand is high.

After the incident, the voltage remains sufficient, 405 kV at Cordemais. One of the two remaining units is tripped by the dispatcher on duty, due to fire. The last unit trips due to a very high excitation current. It is in fact the lack of coordination between the over excitation limiter and the relay setting. From normal, the situation has become vulnerable, but the voltage at this time is acceptable.

However, the distribution voltage is too low. The on-load tap changers on transformers will progressively recover this voltage, thus the load. Production units in the periphery of the Brittany region progressively increase their reactive generation. Three minutes twenty five seconds after the tripping of the last group at Cordemais, one nuclear power unit of 900 MW trips due to a very high excitation current.

Thus, in less than three minutes 6 more units will trip, all due to the same criterion. The situation is stabilized in the mean time as, given the drop in voltage and the transformer tap changers progressively reaching their setting limits, the load "is reduced". Finally, the stabilization of the state is achieved thanks to remotely controlled load shedding.

A system error in the coordination of relay settings and over excitation limiters needs to be considered as the main factor leading to the spread of the incident. The motor of the collapse is attributed to the on-load tap changers on the distribution transformers and to the restoration of consumption they have made possible (modification of the state).

8.2.4. *Unfavorable factors causing spread of the incident*

The systematic analysis of incidents effectively confirms that the collapse of large interconnected networks is a result of at least one of the mechanisms described in section 8.2.3.

The unfavorable factors can be pointed out. They concern the system state before the incident, the nature of incident initially affecting the system and certain "motors" likely to favor the spreading of the system disturbance. In case of the latter, a distinction can be made between "motors" that cause the evolution of states and those that cause transitions.

8.2.4.1. *System state before the incident*

Where the topology of the system is concerned, we note that peripheral areas are more sensitive to major incidents, and longitudinal networks are particularly exposed to the risk of voltage collapse. The presence of important substations on the energy transmission axis introduces a particularly sensitive area. The structural weakening of the network consecutive to the unavailability of units can be a source of additional difficulties in case of an incident, even if on the basis of the nomenclature, the network remains "secure".

It is the application of a load and production dispatch for the particular network structure that will finally indicate whether the system respects the operation rules or not. However, there is no simple indicator that makes it possible to judge the available margin. The analysis of incidents indicates that bulk transmission on the lines along a corridor is a risk factor. So also are situations with high load, especially if they correspond to low availability in terms of reserve. The examination of the voltage profile in the system is an indicator. An abnormally low or high voltage map is a sign that calls for prudence.

It is implicitly known that the quality of control policies, their effective implementation in the system, the resulting margins of the different control devices, on equipment, especially those linked to the interconnection, are just as responsible for operation security.

The policy for voltage control must not only be clearly established, but implemented as completely as possible. It is often admitted, wrongly so, that the secondary control of voltage can be achieved without any major disadvantages through manual action by the dispatcher. This is effectively possible in a normal situation, but what happens when it is close to the margin, when the situation, although normal, is tense and on the verge of the development of a major incident?

Auxiliary control functions are introduced to maintain the equipment within their acceptable working range and thus avoid tripping by "unit" protection. Thus on synchronous machines, over or under excitation limiters maintain the operating point for as long as possible inside the capacity curve, at the cost of the effective participation of the group in voltage control, in a manner so as to avoid tripping due to overload or instability.

A large number of units operating at the "limit" constitute a degradation index of the system state even if this state remains "secure".

8.2.4.2. *Events triggering the incident*

At the source of any serious incident is an accidental event. This can affect the system locally, such as the tripping of a unit. It is often the case of classic insulation faults, possibly multiple, in the same mode; or simply unwanted trippings. This type of disturbance can cause a change in the system state through a transition.

Other more general events will directly affect the state without any local cause being identified absolutely as a triggering factor. Among these events, the increase in load exceeding the expected limits is without doubt the most frequent.

8.2.4.3. *Particular factors*

When an incident affects an element in the network, the protection system trips it, and if the network was in a "secure" state, its return to stable operation is normally assured. For an initially simple incident to turn into a major incident it is necessary that a series of malfunctions takes place, such as a faulty protection setting, refusal of a disconnector to open or the initial operating point not ensuring an adequate operation margin, etc.

The extension of the incident can also occur through different mechanisms directly affecting the state, the appearance of static instabilities, lack of equilibrium between production and consumption as a result of the splitting of the network, voltage instabilities due to the absence of reserves or the automatic operation of on-load tap changers on distribution transformers, inadequate load shedding, or again the reaction speed of operators not adapted to the dynamics of the incident.

8.3. Defense action and the notion of a defense plan

The analysis of supply continuity has introduced the enumeration of characteristic standard states. Incidents affecting the system can lead it towards more degraded states. Defense action makes it possible to bring the system back to less degraded states.

Restoring the system state essentially signifies preserving network integrity, i.e. maintaining the maximum units of the transmission and interconnected network in service as far as possible, bringing the main variables, voltage, frequency and load of links back to their respective ranges, so as to avoid additional trippings; but also maintaining production units and ensuring their availability, whether or not they are connected to the system. This restoration has a price: load shedding, isolation of the areas of occurrence of the initial incident or victims of consecutive disturbances.

A few methods have already been mentioned in the description of degradation mechanisms. They will be systematically developed hereafter. Generally, defense measures ensure the detection of abnormal situations on the one hand and the implementation of generally pre-established automatic action on the other, making it possible to maintain network integrity, in acceptable performing conditions.

In the current state of technology, and according to the convention of protection or control, implementation relies preferably on local measures and criteria, at least in the case of the ultimate criterion of triggering the process of countermeasures. These conditions are in fact considered as being the basis of the robustness. However, today the tendency is to promote the use of system information from regions that are probably a long distance away, by taking advantage of the high speed information transfer channels that criss-cross the networks.

For each mechanism it is possible to define defense actions, and for each of them establish a list of methods likely to check the development of the degradation process of the system state. These methods must be implemented in a more or less radical manner according to the process in which they are applied.

8.3.1. *Frequency instability*

8.3.1.1. *Increase in frequency*

Increases in frequency can intervene in the event of accidental isolation of an area of heavy export. They are the result of insufficient performance of speed controls in production units, because the valve system is inherently slow or the construction constraints of the installation must be respected.

These difficulties are seen mainly in networks heavily equipped with hydroelectric units. It can be more acute in case of mixed generation plants, as over speed constraints are stricter for thermal units, especially of large size (mechanical constraints in blades in low pressure stages).

A tripping or islanding scheme of groups on the basis of frequency resolves the problem in an effective manner. Frequency thresholds must be in stages, the timing must be homogenous and reduced to the maximum. The order of tripping of groups must integrate constraints related to the over speed limits of each unit and those related to frequency control capacity following an incident by groups still in operation.

8.3.1.2. *Decrease in frequency*

The available methods to counter frequency decrease are more diversified. Most often they affect the load. There is occasion to distinguish slow decrease in frequency, for which some action on the generation is possible, and fast decreases for which the only corrective action through load shedding is likely to check the process.

Slow decrease in frequency

Slow decreases in frequency can be corrected by automatic actions on generation, or on the load, generally on the basis of simple frequency criteria. The different thresholds must be adequately coordinated if we aim for an action proportionate to the cause. The following list gives a brief idea of the possible methods:

– timed tripping of interruptible load;

– stopping of pumps in the pumping stations;

– automatic closure of operating procedures in thermal unit overload (in combustion turbines by operating in superheating, classic thermal units by acting on the feed water heaters and extractions);

– automatic start of peak units.

Fast decrease in frequency

If the imbalance between production and consumption is significant, the decrease in frequency is such that corrective measures must intervene rapidly. Only load shedding is capable of checking the phenomenon. In extreme cases, classic schemes based on the frequency criterion can prove to be insufficient, because they are too slow. It is thus necessary to introduce massive initial load shedding. According to

the circumstances, this can be made up of preventative load shedding or based on a mixed criterion of frequency and frequency derivative.

The main characteristics of these schemes are briefly summarized below:

– Load shedding based on the frequency criterion must intervene in a determined frequency band by common agreement between the different system operators. The geographic distribution must also be as uniform as possible. This is in order to avoid power transfers following the implementation of the plan, but also to dispose of a sufficient proportion of loads shed everywhere, necessary in the case of splitting of the system into islands. It can be shown that timing is not desirable, and that if it is introduced to carry out a final correction in case of under-frequency in the steady state, it is necessary to coordinate instantaneous and timed tripping in a succession of decreasing frequency thresholds.

– Load shedding based on a mixed criterion of frequency and frequency derivative is very useful through the large scale and fast action that it enables. It has the reputation of not being controlled given the variations in system parameters during the course of time. It can be shown [JAN 96] that the approach is possible and robust. In order to guarantee optimal load shedding (asymptotic frequency in the post incident system in the region of 50 Hz), it is necessary to envisage load shedding based on the frequency derivative criterion less than that which would be theoretically required and to complete it with a conventional plan based on a frequency threshold criterion.

– In the case of networks with a simple interconnection structure, as in an industrial site for example, it is possible to implement a preventative load shedding scheme triggered simultaneously to decoupling with the external network. Ideally, this initial load shedding must be completed with a conventional plan.

8.3.1.3. *Note*

The frequency measured at a point in the interconnected network provides, with some local oscillations, information about the state of equilibrium between production-consumption in the system. This explains the sound operation in general of load shedding plans based on the frequency criterion.

The quantity of load likely to be shed must be as high as possible, so as to guarantee system safety in the most critical cases. However, a significant reduction of load inevitably causes problems of voltage surge. These can only be controlled by acting on compensation methods in a coordinated manner. It is not common to invest in covering these problems. As a result, the proportion of load that can be shed is often limited to around 50%.

8.3.2. *Voltage instability*

Phenomena affecting voltage are first of all local phenomena. The voltage level in the system is not as representative of the state of reactive imbalance of the system as frequency is, in the case of imbalance of active power. This explains that automatic load shedding plans in case of decrease in voltage must be less common as it demands more investigations as to their establishment.

8.3.2.1. *Increase in voltage*

Preventative measures must be set up to adapt the system operating point and avoid the system becoming capacitive: coordinated adaptation of voltage settings of the groups, change in transformer tappings of production units.

Slow increase in voltage

At the mid-term we can act by adapting the system operating point by automatic action, controlled by the voltage, to respectively retire or continue the supply of inductances and shunt capacitors.

Fast increase in voltage

This type of loss of voltage stability is rare but extremely dangerous as there is no way to check it. The system state degradation necessarily causes acceleration of the process, the tripping of production units due to loss of voltage or angular stability, aggravating the situation.

8.3.2.2. *Decrease in voltage*

The methods available to counter voltage decrease are greater in number. The majority of actions concern load tripping.

Slow decrease in voltage

At the mid-term we can act by adapting the system operating point by automatic action, controlled by voltage, to respectively retire or continue the supply of inductances and shunt capacitors.

Blocking the on-load tap changers on distribution transformers or reduction of the voltage setting in medium voltage, makes it possible to benefit from a “soft”, homogenous reduction of the load, by allowing load sensitivity to take voltage into account. This reduction can only be transient, in the presence of thermostatic type loads.

Voltage collapse

In case of more rapid degradation, automatic load shedding must be envisaged. Its implementation is less frequent than load shedding due to under-frequency, the local voltage criterion not being as pertinent as the frequency criterion.

8.3.3. *Loss of synchronism*

If loss of synchronism occurs, it can affect the whole area. In this case, plant islanding makes it possible to avoid the possible spreading of the phenomenon to other areas of the system. The measures to be taken must be extremely fast. Implementing effective protection poses problems of principle and setting.

Plant islanding, the tripping of interconnecting lines, are extreme measures that make it possible to stop the disturbance from spreading into the system. The implementation of effective strategies implies determining the area to be isolated, as well as indispensable additional measures. In the current state of technology, such areas are pre-established, on the basis of structural criteria, or “offline” studies. This actually limits their implementation in typified cases for which the area in question is explicitly designed. A “dynamic online” approach of the definition of areas to be isolated is difficult to envisage today, as much due to the range of methods as the means.

Alternatively, the problem can be treated at an individual level for each generator, usually equipped with a relay for loss of synchronism. In case of concurrent application, it is considered necessary to coordinate the two systems so that the systemic protection always intervenes before the tripping of the units.

Networks that heavily export hydroelectric power run the risk of loss of synchronism in the case of a three-phase fault, because on the one hand, these groups present a weak inertia and on the other, it is not always possible to rapidly reduce generation due to constraints related to water hammer. The addition of brake resistors makes it possible to offset this lack of control action, by limiting the acceleration of groups.

8.3.4. *Cascade tripping*

In the case of a cascade tripping risk, the means of control are less frequent at present, even though useful methods have existed or exist even now. These protections of the whole system are distributed in it and act in a coordinated manner

by using several signals, of which some come from sensors located in other substations that may be a great distance away.

Some interconnections in areas with weak load density do not respond to the "N-1" security criterion, for economic reasons. Maximum transferable power results from a static stability limit. Ensuring sufficient robustness for such an interconnection calls for the implementation of special measures.

Such a strategy has been deployed in the UPS network, the interconnected network which supplied the former USSR from Lake Baikal to the East European countries. This network was, and still remains, albeit reduced in its extent in the West, made up of a set of subnetworks operated according to the "N-1" rule, but with weak interconnections between them. These interconnections are long, and ensure security in "N", with a margin related to the static stability limit. In case of a loss of an element in the interconnection, the loss of stability is certain except if the transit is brought back sufficiently fast to an adequate limit. This generally implies the tripping of production at the exporting end of the network and load shedding in the importing part (the implementation is in fact more complex and takes into account the inertia criteria, angular stability limits being involved).

8.3.5. *Notion of defense plan*

Setting up a set of coordinated countermeasures described here above, out of which some possibly play a part in emergency control, constitute a defense plan, or a safeguard plan. This can also be limited to a particular aspect, for example a defense plan against loss of synchronism.

8.4. The extended electromechanical model

8.4.1. *Definition, validity domain*

The simulation of unstable behavior and scenarios combining different degradation mechanisms requires an advanced modeling of the system, capable of precisely reproducing states that are far from normal operating conditions.

The extended electromechanical model of an electric system covers a range of frequencies from 0 to 10 Hz. In terms of physical phenomena, it goes from rotor transients in alternators particularly significant for loss of synchronism phenomena to quasi steady-state phenomena (evolution of the state of the network in normal operating conditions).

Parallel to the size of its frequency domain, the extended electromechanical model covers the most extreme system states, so as to make the investigation of unstable behavior possible.

Towards higher frequencies, the model makes a hypothesis of the phasor representation of electric quantities (voltage, currents, flow), at the basic frequency (no representation of harmonics). Wave propagation phenomena are thus absent.

Towards lower frequencies, the extended electromechanical model represents the full return to equilibrium after disturbance, whatever the behavior of the network. It is thus capable of treating bifurcations, undamped oscillations, etc. that can appear in complex scenarios.

Lines and cables are represented according to the conventional model in PI used in load flow calculations.

Transformers are represented in detail: saturation of magnetic circuits, tap changer (including its dynamics), overload protection, etc.

Finally, imbalanced systems (single phase short circuits, opening of a phase, etc.) are generally treated by the Fortescue symmetrical components.

Electric generators are represented according to the well known Park equations. The rotation speed of the machine is explicitly taken into account in the calculation of flux and magnetic saturation can be modeled in both axes so as to precisely define the position of the rotor with relation to the rotating field and correctly represent the operating limiting loop and the ceiling of the excitation system.

The aim of modeling the prime mover of the alternator as well as its excitation system is to provide the correct time evolution of the mechanical torque and excitation voltage applied to the alternator, without needing to represent the exact operation of the entire power station for the same. However, the complexity of the coordination of regulations is such that it is often necessary to develop a model based on the description of physical operation of the entire installation to correctly detect any change in the control mode or the operation of an internal protection that can have serious effects on the operation of the whole system.

We shall retain that the main time constants of the physical process are often reproduced with sufficient precision with a simplified model whose parameters have a clear physical definition. On the other hand, operation thresholds and limits, of great significance for the simulation of large disturbances, require more complex non-linear models and modeling of auxiliary controller loops.

For the special case of cogeneration installations, a thermodynamic model may be necessary to take into account the effects of disturbances affecting the thermal part on the conditions of steam at the turbine inlets and outlets. A model taking into account flow evolutions in a qualitative manner is generally adequate. Temperature control for steam towards customers and levels in the boiler steam drum for example will often be assumed to be correctly established and will not usually be represented.

Static and dynamic behavior of the load is of great importance in many scenarios.

Particular attention is accorded to asynchronous motors. In addition to transient systems of the machine itself, the mechanical load as well as its fluctuations will be duly modeled when there is special consideration of security of supply to large industrial sites. In factories as well as at the domestic consumer level, the large number of low power motors which cannot be reasonably modeled individually, will be aggregated on the basis of adequate uniformity of their characteristics and those of the related load.

Significant loads of a particular type often have to be modeled specifically: electrolysis, rolling mill, paper machine, etc.

Real behavior of systems subjected to large scale disturbances is obviously greatly influenced by the operation of different types of protection relays. If the expected operation of selective protection is often included in the definition of simulated scenarios (thus without effective modeling of relays), complex scenarios with relay cascading operation require modeling of the relays. Thus, the extended electromechanical model generally includes protection against overload, impedance, loss of synchronism, over- and under-voltage or frequency, load shedding plans, eventually load recovery, etc. We remember that internal protection in production units can also play a decisive role.

8.4.2. *Numerical simulation*

The extended electromechanical model covers traditional domains of transient stability and long term stability and even quasi-stationary evolution of networks. Ordinarily, each of these domains is associated with a specific model of the network that will then be resolved by a dedicated program.

The major disadvantage of this approach is the inability of the long term or quasi-steady-state model to detect fast instabilities (often related to rotor oscillation) that could develop along a “slow” trajectory, if it is possibly not by non convergence of a mathematical singularity of a model that neglects certain physical phenomena.

The global discussion of the extended electromechanical model has obvious methodological advantages and considerable precision. It is also indispensable to the simulation of complex scenarios of system collapse, where fast and slow phenomena work together. If it has only been practiced in recent times, it was because of having to wait at the same time, for mastery of algorithms with variable steps and the power of more recent computers to be available.

8.4.3. *Mathematic properties*

The mathematical formulation of the model of components described in section 8.4.1 is not discussed here. Many examples can be found in other books.

The constitution of a global model leads to an algebro-differential system with the characteristics and requirements, as follows:

– the size of the system is large. It easily reaches thousands, or even tens of thousands of variables. However, the vacuity of the system remains high;

– the system is stiff, i.e., presents time constants very different from one another;

– the system is oscillating and poorly damped;

– the system is highly non-linear;

– discontinuities of algebraic variables and of derivatives of differential variables are many in number.

To resolve such a system, the integration algorithm must respond to the following specifications:

– to ensure numerical stability and correct simulation of oscillation damping, an implicit “A-stable” method is necessary;

– to be able to ensure the required numerical precision and the desired calculation speed at the same time, a variable integration step is necessary;

– the solution of algebraic and differential equations must be simultaneous to ensure sufficient robustness in extreme operating conditions.

8.4.4. *Algorithmic properties*

The numerical methods described here correspond to the complete industrial implementation of the extended electromechanical model used in the EUROSTAG program [STU 89], [AST 93].

8.4.4.1. *The algebro-differential system to be resolved*

The extended electromechanical model leads to the formulation of a non-linear algebro-differential system (DAE): [8.1], [8.2], [8.3]:

$$\dot{y}_i = f_i(y,t) \qquad i = 1, ..., k \qquad [8.1]$$

$$0 = g_j(y,t) \qquad j = 1, ..., m \qquad [8.2]$$

$$y(0) = y_0 \qquad [8.3]$$

where y is the vector for state variables, having $(k+m)$ components. Algebraic equations [8.2] essentially come from the network representation and differential equations [8.1] essentially come from production units. $y\ (0)$ defines the initial operating point of system [8.3].

8.4.4.2. *The Gear-Hindmarsh algorithm [BYR 75]*

Let us assume that we know, in time t_n, the vector for state variables $y(t_n)$. Let us also suppose that we know the value of its successive derivatives with relation to time up to the order q (q being the order of the integration method). Our aim is to construct an approximation y_{n+1} of the exact solution $y(t_{n+1})$ of system [8.1], [8.2], [8.3].

Nordsieck vector

At each time step, we conserve the value of each state variable $y(t)$ and its q successive time derivatives $y^{(q)}(t)$ in a vector called the Nordsieck vector, $\vec{y}(t)$, which has the following form:

$$\vec{y}(t) = \left(y(t), h\, y^{(1)}(t), \frac{h^2}{2!} y^{(2)}(t), ..., \frac{h^q}{q!} y^{(q)}(t) \right)^T$$

where h is the time step.

The Nordsieck vector is especially well adapted to a change in time step, as the new vector is obtained by multiplication of the earlier by a diagonal matrix:

$$\vec{y}(t + \alpha h) = D\, \vec{y}(t + h)$$

where

$$D = \begin{pmatrix} 1 & & & & \\ & \alpha & & & \\ & & . & & \\ & & & . & \\ & & & & \alpha^q \end{pmatrix}$$

and α is the relation between the duration of the two consecutive time steps.

It is also adapted for a change in method order: the suppression of a line and a column in the case of reduction in the order, and the addition of a line and column in case of an increase in the order.

Phases of prediction and correction

The algorithm is divided into two phases.

The prediction phase: on the basis of Taylor's formula developed until order *q*, in time t_n, the following values can be calculated:

$$\underline{y}_{n+1}, \underline{y}^{(1)}_{n+1}, \underline{y}^{(2)}_{n+1}, \ldots, \underline{y}^{(q)}_{n+1}$$

which are the prediction values of the state vector y and its successive derivatives q in time t_{n+1}.

We can write, with Nordsieck's notation, the following relation between the vectors:

$$\underline{\vec{y}}_{n+1} = A\,\vec{y}_n$$

where:

$\vec{y}_{n+1}$ is the Nordsieck vector predicted in time t_{n+1}

$\vec{y}_n$ is the Nordsieck vector calculated in time t_n.

A is Pascal's higher triangular matrix defined by:

$$A(i,j)=\begin{cases} 0 & for\ i>j \\ \dfrac{j!}{(j-i)!i!} & for\ i\le j \end{cases}$$

The correction phase: in some hypotheses we can show that the Nordsieck vector $\vec{y}_{n+1}$ in time t_{n+1} can be deduced from its predicted value by applying the following formula:

$$\vec{y}_{n+1}=\underline{\vec{y}}_{n+1}+\vec{l}\left(y_{n+1}-\underline{y}_{n+1}\right) \qquad [8.4]$$

where:

$$\vec{l}=\left(l_0,...,l_q\right)^T$$

$\vec{l}$ is a coefficient vector, depending on the integration method used, and its order q.

Based on [8.1], [8.2], [8.3] and [8.4], the search for y_{n+1} can be obtained by resolving the following system [8.5] and [8.6]:

$$\mathrm{h_n}\dot{y}_{n+1}+l_1\left(y_{n+1}-\underline{y}_{n+1}\right)-h_n f\left(y_{n+1},t_{n+1}\right)=0 \qquad [8.5]$$

$$g(y_{n+1},t_{n+1})=0 \qquad [8.6]$$

This system is resolved by the Newton method consisting of the search for the correction vector $\Delta y_{n+1}=y_{n+1}-\underline{y}_{n+1}$ which satisfies the non-linear system [8.7], [8.8].

$$h_n\ \underline{\dot{y}}_{n+1}+l_1\ \Delta y_{n+1}-h_n\ f(\underline{y}_{n+1}+\Delta y_{n+1},t_{n+1})=0 \qquad [8.7]$$

$$g(\underline{y}_{n+1}+\Delta y_{n+1},t_{n+1})=0 \qquad [8.8]$$

Time step variation and the order of the method

The truncation error (or method error) is a local measure of precision of the method used. This error is defined by:

$$E_{n+1} = \left| y\left(t_{n+1}\right) - y_{n+1} \right|$$

where $y(t_{n+1})$ is the real solution in time t_{n+1} and y_{n+1} is the solution calculated in time t_{n+1} when the latter is obtained on the basis of real solution $y\left(t_n\right), y^{(1)}\left(t_n\right), ..., y^{(q)}\left(t_n\right)$ in time t_n.

This truncation error can be written for a method of order *q*:

$$E_{n+1} = \left| K_q h^{q+1} y^{(q+1)}\left(t_{n+1}\right) \right| + o\left(h^{q+2}\right)$$

where K_q is a specific numeric constant for the method and its order.

An estimation of this truncation error can be deduced from [8.4].

$$E_{n+1} = K_q l_q \; q! \left\| \Delta y_{n+1} \right\| \qquad [8.9]$$

where $\|\Delta y_{n+1}\|$ is a weighted norm of the correction vector Δy_{n+1} calculated by resolving the non-linear system [8.7], [8.8].

E_{n+1} is compared to a precision threshold (*TOL*), chosen by the user.

The error norm thus obtained is used to validate the current integration step. In addition this approach provides the prediction of the new time step h_{new} giving the required precision.

Thus, according to [8.9]:

$$h_{new} = h_{old} \left[\frac{TOL}{K_q} \, l_q \; q! \left\| \Delta y \right\| \right]^{\frac{l}{q}} \qquad [8.10]$$

Moreover, an analog formula in [8.9] gives an approximation of the truncation error obtained with a method in the order *(q-1)* and order *(q+1)* and thus makes it possible to choose the new order.

8.4.4.3. *ADAMS-BDF mixed method*

The properties of numerical stability

The algorithm described above is adapted to the resolution of stiff problems (see section 8.4.3), i.e., having greatly dispersed eigenvalues λ.

Two numerical stability conditions are required to get good simulation of phenomena, with raised calculation speed, i.e., with the greatest possible calculation step:

– A good simulation of stable phenomena, even with a time step higher than the lowest time constant, implies a stability domain that includes the *totality* of half complex plan $Re(\lambda) < 0$. This property is called *"A-stability"*.

– However, to ensure the correct detection of unstable cases, the stability domain must be strictly *restricted* to a half complex plan. We thus say that the method is *"symmetrically A-stable"*.

An upgraded method: the mixed Adams-BDF method

The Adams methods and BDF (backward differentiation formula) method are in accordance with the general architecture of the algorithm that we have just seen (see section 8.3.3.2).

In order 2, the Adams method is often called the trapezoidal method:

$$y_{n+1} = y_n + \frac{1}{2} h_n \dot{y}_n + \frac{1}{2} h_n \dot{y}_{n+1} \qquad \text{[Adams]}$$

Its stability domain is "symmetrically A-stable"; the algorithm is thus a good candidate for the simulation of the extended electromechanical model. It provides an effective and sure instrument for the detection of unstable modes.

However, time steps that are too short are chosen by the algorithm which leads to very high calculation time, due to higher Newton's corrections of algebraic variables.

The expression of the implicit BDF method of order 2 is written:

$$y_{n+1} = -\frac{1}{3} y_{n-1} + \frac{4}{3} y_{n+1} + \frac{2}{3} h_n \dot{y}_{n+1} \qquad \text{[BDF]}$$

The A-stable BDF method is not strictly symmetrically A-stable and thus presents a risk of over damping of oscillations of weak amplitude. On the other hand, these performances are excellent in terms of calculation time.

It is the combination of the Adams method for variables from the differential part and BDF for the algebraic part that have provided the solution and a remarkable compromise between the loss of precision of the simulated damping, which is not measurable most of the time, and calculation speed.

In practice, the variations in the step length from 1 to 100,000 during the course of the same simulation are frequently observed, variations dictated by only maintaining precision of simulation and thus a correct reflection of the real physical behavior of the system.

8.4.4.4. *Processing discontinuities*

Discontinuities in the mathematical model are generated by the network after short circuits, opening of lines, etc. In power stations, it is the changes in relays, saturation of regulators, etc. that cause discontinuities.

These discontinuities correspond to function discontinuities f_i and g_j of the system [8.1], [8.2], [8.3].

Each time a discontinuity is encountered, the integration algorithm would have to be initialized again in order to again resolve the system [8.1], [8.2], [8.3] possibly with new initial conditions. However, this systematic reinitialization would be very costly in “CPU” time.

The idea is thus to avoid or simplify these reinitializations as much as possible.

We make the distinction between discontinuities directly affecting algebraic variables and those affecting functions f_i [8.1].

A discontinuity in an algebraic variable is often a major discontinuity: a short circuit for example, or opening of a line greatly modifies the physical behavior of the production-transmission system. As a consequence, this type of event always implies a complete reinitialization of the algorithm, with an evaluation of a new Jacobian matrix for system [8.7], [8.8]. However, we know that some network discontinuities of less importance (change in the transformer tapping, for example) do not require the reevaluation of the Jacobian matrix.

A discontinuity in a process associated with a production unit occurs very frequently: we distinguish between one degree and two degree discontinuities. The

first category concerns the gradient of functions f_i or g_j, two degree discontinuities concern functions f_i or g_j themselves. One degree discontinuities are treated by a selective correction of the Jacobian system matrix.

When a variable is subjected to a two degree discontinuity, its prediction can no longer be made by Taylor development (the derivatives are not known). To resolve the problem, a mathematical system is constructed corresponding to the physical sub-system that is subjected to the discontinuity. This smaller sized system then undergoes a so-called local integration procedure, with reinitialization, between times t_n and t_{n+1}, which makes it possible to recreate a prediction of derivatives and variables in t_{n+1}.

The values obtained are then introduced in the set of values calculated by the normal prediction procedure. The correction stage can then begin with a better chance of success.

8.5. Examples of defense action study

8.5.1. *Methodological considerations*

At this stage the reader is aware of the discussions of the required facts concerning physical phenomena, system modeling and mathematical simulation tools to be able to appreciate the lessons drawn from the complex simulation studies. He will find here below three examples implementing the described means and concepts and relating to defense plans.

The establishment of defense plans is based on a set of simulations that have the following aims:

– the study of complex scenarios which are capable of representing the circumstances that prevail during major incidents;

– the detailed analysis of system operation without taking countermeasures into account;

– the verification of the operation of the new scheme and determination of the effectiveness of the considered defense measure.

The evaluation of effectiveness will be as precise and valid as the entire test will be wide and diversified, especially to make the detection of possible malfunctions, the latter being less probable in highly typified scenarios.

The following examples respectively concern the establishment of a load shedding scheme in case of voltage collapse, the study of relay settings of system splitting in case of loss of synchronism and finally the islanding plan of an industrial site in case of serious disturbances affecting the supply network.

Each of these examples makes it possible to illustrate some methodological particularities. The entire set gives quite a complete view of this type of study. An important part of the discussion concerns the modeling effort which was necessary to achieve the objective.

We shall note that the conditions of implementation of defense measures, peculiar to the studied systems and the context of operation, play an important role in designing the plan.

8.5.2. *Load shedding due to voltage criteria [DEU 97]*

8.5.2.1. *Context*

A network in the Middle East, in the early 1990s, is characterized by a high increase in load, due, among other things, to a decrease in electricity prices. The distribution company faces difficulties in coping with this increase, particularly as resources are lacking, given the reduction in sale prices.

The region is characterized by a significant variation in load between peak and minimum load conditions. This is the result of extensive use of air conditioning. The biggest part is mainly made up of “window units”, not equipped with sophisticated protection.

Delays in investments in distribution stations are such that a number of substations present load rates close to 100%, in normal operation.

8.5.2.2. *Brief description of the incident type to guard against*

A short circuit on the busbars of an important 400 kV substation in the region is eliminated late, by backup protections, after about 800 ms. Work was carried out in the substation and local protections are not in service.

A widespread voltage collapse takes place. Significant currents circulate in the high voltage cable network. These are progressively tripped by overcurrent backup protections.

This cable tripping implies a considerable slowing down of the establishment of system restoration procedure, since it is necessary to verify the exact causes of tripping for each cable.

8.5.2.3. *Analysis summary*

The loading of medium voltage transformers being high, the source impedance is relatively high and likely to lead to unusual voltage drops. The initial short circuit is sufficiently long to cause motor blockage. These motors cannot restart after elimination of the fault given the low level of voltage. They are not tripped either given the absence of under-voltage protection. The incident is extensive, the fault having touched very high voltage.

Figures 8.2 and 8.3 present the results of a simulation carried out *a posteriori*, which confirms the development of events.

The system operated in 5 independent 110 kV zones, interconnected by the 400 kV, totals a load of 2,700 MW. A short circuit of 100 ms affects zone 2 in T_0 = 1 s. This short circuit, correctly eliminated by the tripping of the cable in question, causes the blockage of air conditioners in the area (curve 2 in Figure 8.2). The current in certain cables exceeds the backup threshold set at 200%, 2 s. The third and fourth curves in Figure 8.2 show the crossing of overcurrent threshold and tripping of two cables in T_0+2 and 4 s. Finally, the substation experiences blackout in T_0+6 s, as can be seen in the first curve in Figure 8.2.

Figure 8.3 shows some information related to zone 1 which has been affected by the incident occurring in zone 2. The operating conditions of the system cause an “export” of the disturbance, air conditioner motors are blocked progressively. In a similar manner, backup cable and transformer protection, set at 1.4 s in this case, accentuate the degradation of the system state. In fact, the tripping of a feeder or a transformer leads to load shedding which reestablishes voltage and thus increases the current in the neighboring feeders which in turn trip due to overload. In the case under consideration, the substation experiences overvoltage after a series of successive trippings (first curve in Figure 8.3).

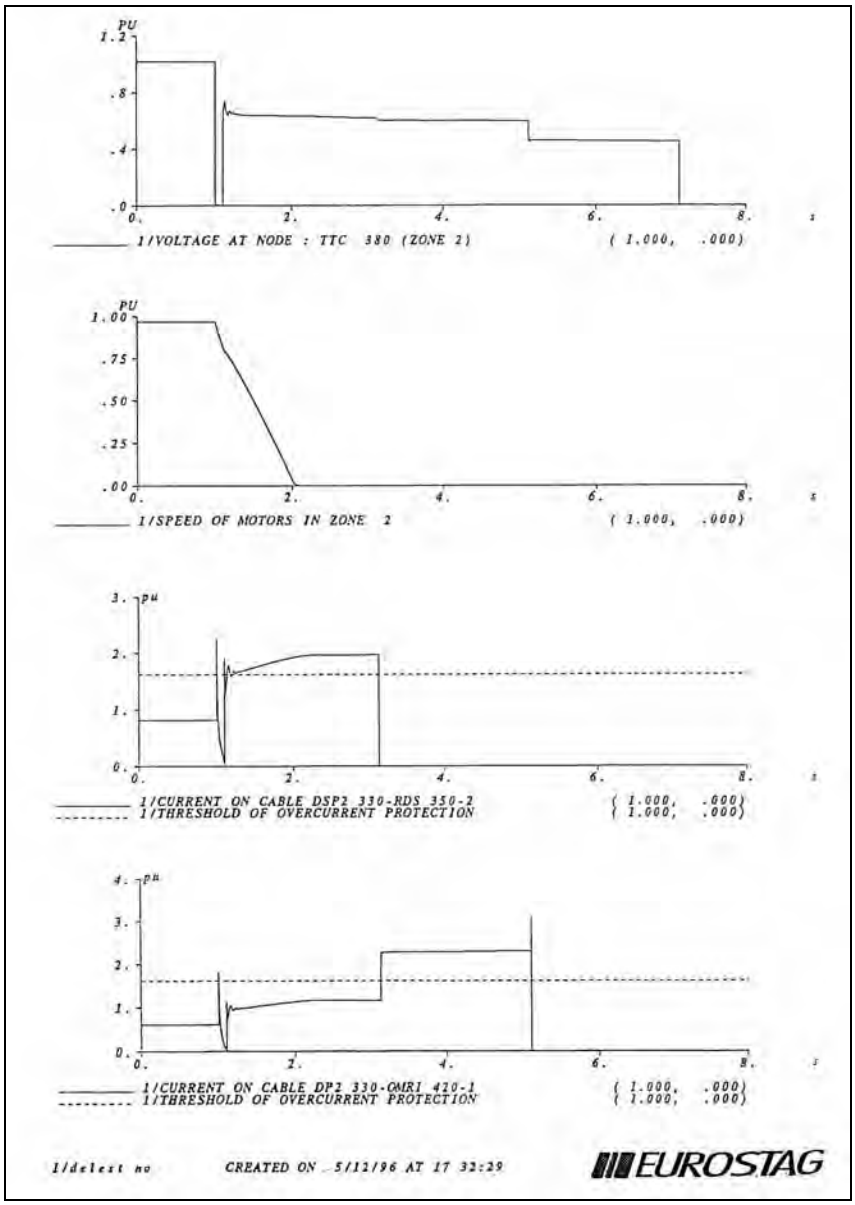

Figure 8.2. *Simulation of a short circuit affecting zone 2*

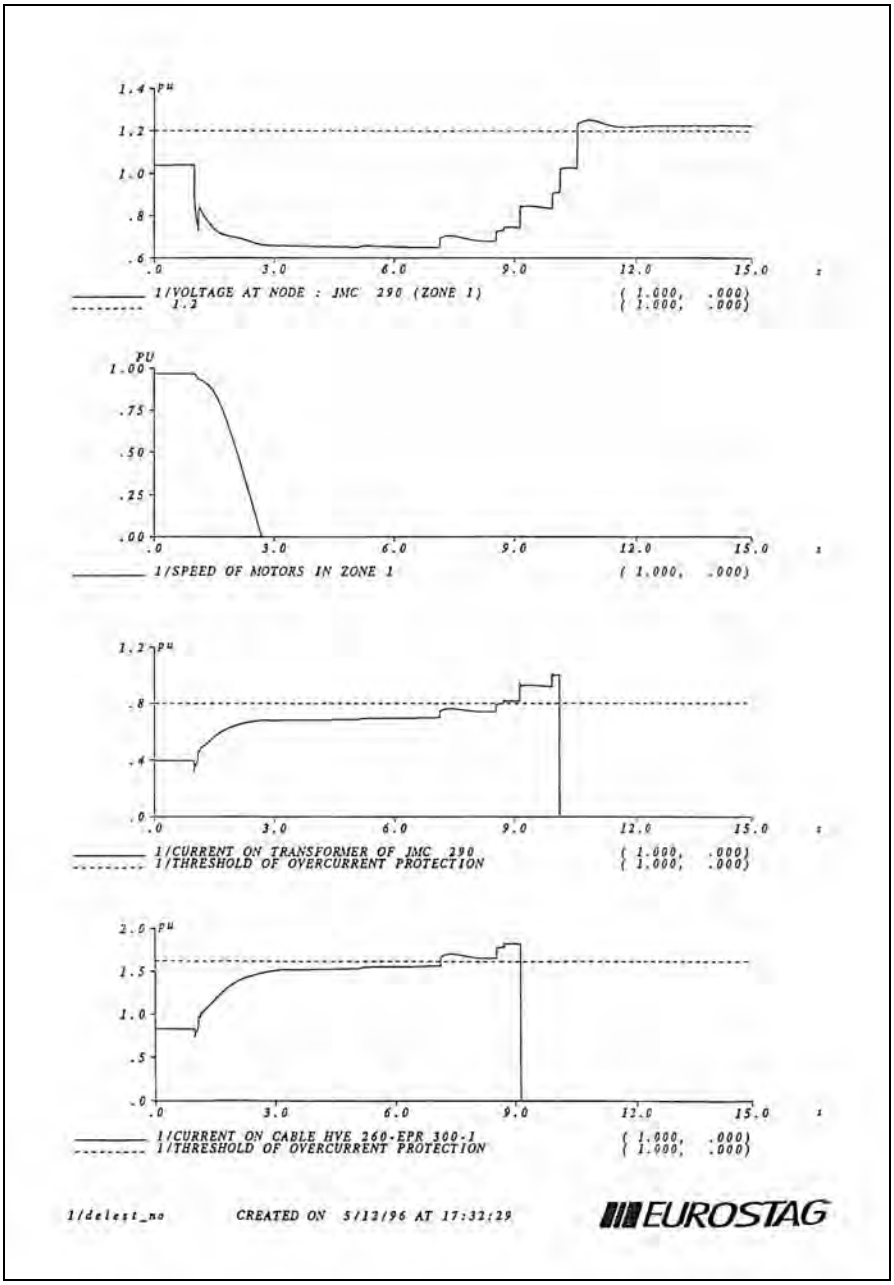

Figure 8.3. *"Export" of the incident affecting zone 2 to zone 1*

8.5.2.4. *Modeling*

In the given circumstances, the main objective of the load shedding plan consists of limiting the extension of the incident avoiding backup tripping of cables. This allows the acceleration of the restoration procedure of the system. As the backup tripping intervenes beyond a time period of two seconds after the start of the incident, the plan must intervene during this short period of time. The system model must thus be correct up to this moment, but not necessarily beyond it.

Recordings using numerical fault recorders, carried out in a number of stations, were available and covered several tens of seconds. These recordings mainly concerned the frequency, voltage and current, often in a single phase.

The development of the model took place in different stages during which modeling was progressively refined, mainly to ensure good concordance with quantities measured during the incident.

The main steps of the work were as follows:

– a first model of the system was established by translating the data of an existing model into adequate formalism. It took into account conditions close to those prevalent during the incident. It mainly comprised load subtransmission data, but also production units, with their voltage and speed regulations;

– a model of an air conditioner developed on the basis of laboratory measurements, used to conduct investigations related to voltage instability, were selected [WIL 92]. On this basis, a model for equivalent load was established. It included a representation of series impedance of the distribution network in medium and low voltage;

– the first simulation of the incident on the basis of this first model was carried out. The behavior was tested against the recordings. For this first approach, measurements taken a great distance from the areas in question were retained. These were measurements of voltage and frequency for an important power station;

– the comparison showed significant discord between responses for voltage and frequency. The first action to be taken concerned models for voltage regulation, which were reviewed in detail. Conventional models of static exciters or brushless exciters were selected and set up. Their parameters were adapted to take into account the available information. Generic limiters of over and under excitation were introduced, taking into account the capacity curves of groups and normal operating principles of these types of limiters;

– after these modifications, the response of the system frequency given by the model was not always in accordance with the measurement. It appeared, even though the voltage was more or less respected during the initial phase of the

incident, that the active power consumed by the motors of “blocked” air conditioners did not reflect the reality. The parameters of equivalent motors were then updated, especially those related to stalling conditions. This later led to the development of specialized tools for optimization [MER 98];

– this last modification made it possible to make the response of the model consistent with the measurement up to the moment of the first tripping of cables. This was completely compatible with the objectives. The load shedding plan should have in fact intervened beyond the tripping time of the main and backup protections, i.e., around 1 second after the detection of the fault, but before the final backup tripping of cables;

– verifications of details were able to be carried out considering the recordings of currents in some substations with radial supply. Some diversity could be identified. Industrial type substations in particular presented the least sensitivity to voltage collapse, all other things being equal. A reduced proportion of loads presenting a load torque independent of speed in these zones would explain this phenomenon;

– the load shedding plan is likely to impose massive reductions of load. This leads to a certain risk of voltage increase and justifies *a posteriori* the necessity of modeling the under excitation loops of voltage regulation in production units. This overvoltage can be reabsorbed only by fast action on shunt compensation. The system model was thus adapted to include coordinated switching on of shunt inductance in the load shedding plan.

The comparison of frequencies (Figure 8.4) and voltage (Figure 8.5) measured and simulated in a generation site far from the incident area attest to the quality of the modeling. The perceptible deviation beyond 6 s in frequency results from the trippings intervening in the system, causing a reduction in the supplied load.

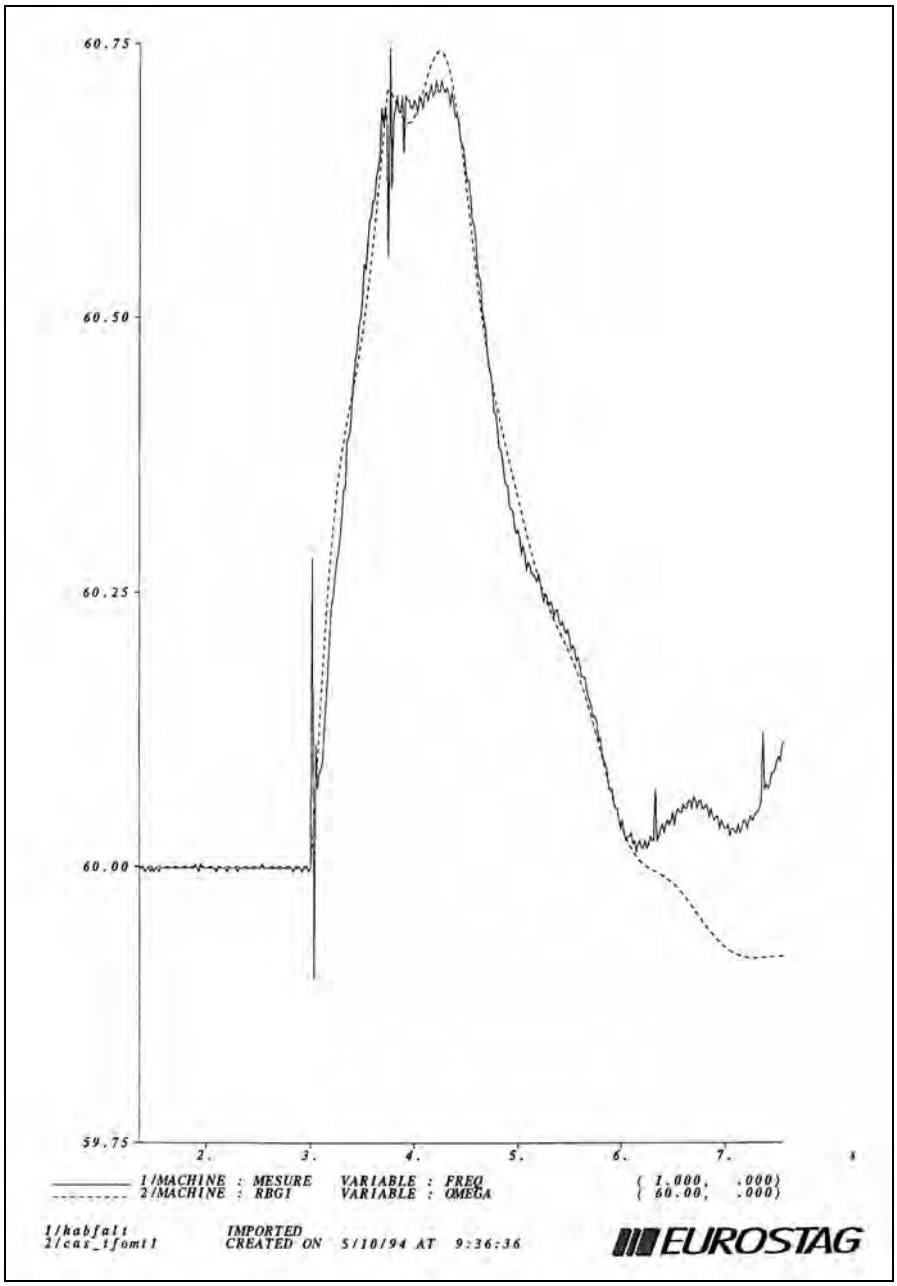

Figure 8.4. *Comparison of measured and simulated frequencies*

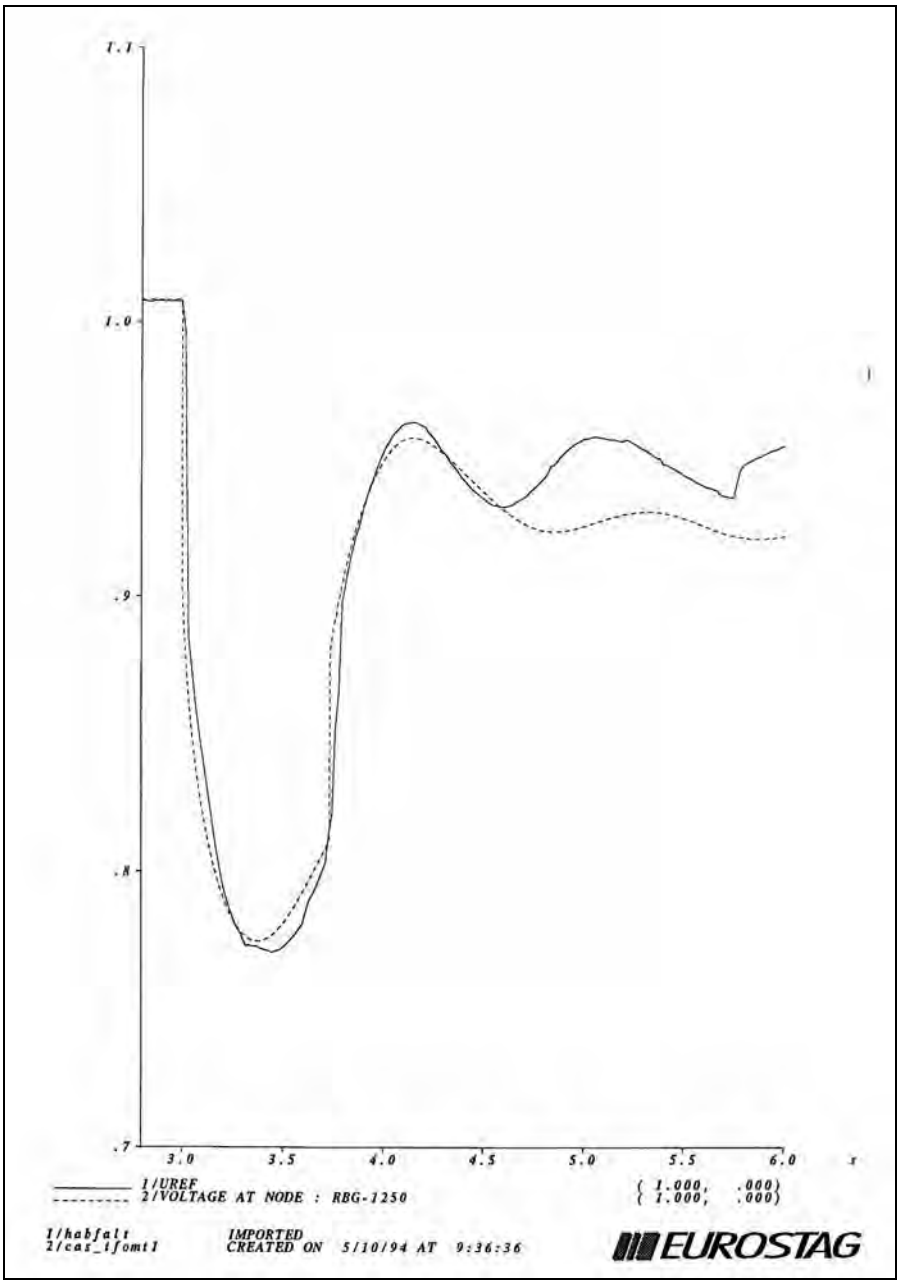

Figure 8.5. *Comparison of measured and simulated voltage*

8.5.2.5. *Proposed protection scheme*

Contrary to load shedding in case of frequency decrease, for which the evolution of local frequency represents the state of imbalance quite correctly between production and consumption, the evolution of local voltage is not a clear reflection of the imbalance in reactive power.

The proportion of load to be shed in case of under-voltage must thus be based on a criterion enabling more robustness. Systemic analysis indicated that the proportion of load to be shed in a substation depended closely on the level of loading of HV-MV transformers. Below a certain level, load shedding is not necessary, and further it must be proportional to the preincident load. In the proposed scheme, this load is determined by the sum of transformer currents in the station.

Finally, the switching on of shunt inductance is synchronized with load shedding; the decision depends on the load criterion at the station. This "feed-forward" type action, rather than a "feedback" switching depending on voltage criteria, makes it possible to avoid transient overvoltage consecutive to load shedding.

Figure 8.6 shows by a dotted line the voltage response of the system in case of load shedding. The risk of overvoltage in the steady state is apparent. The dashed line curve indicates the system response if switching on shunt inductances installed in medium and high voltage in a feedback voltage control scheme is included. To avoid exceeding the maximum voltage in the transient system, a coordinated implementation of load shedding and switching on of shunt inductances was simulated. The corresponding response is given by the bold line curve.

Figure 8.7 shows one of the consequences of coordinated switching on of shunt inductances. Overvoltage having been controlled, motor acceleration is less intense, the return time to steady state is increased and the currents are higher. We note, on the dotted curve, that the current threshold of backup protection is briefly crossed, without consequence.

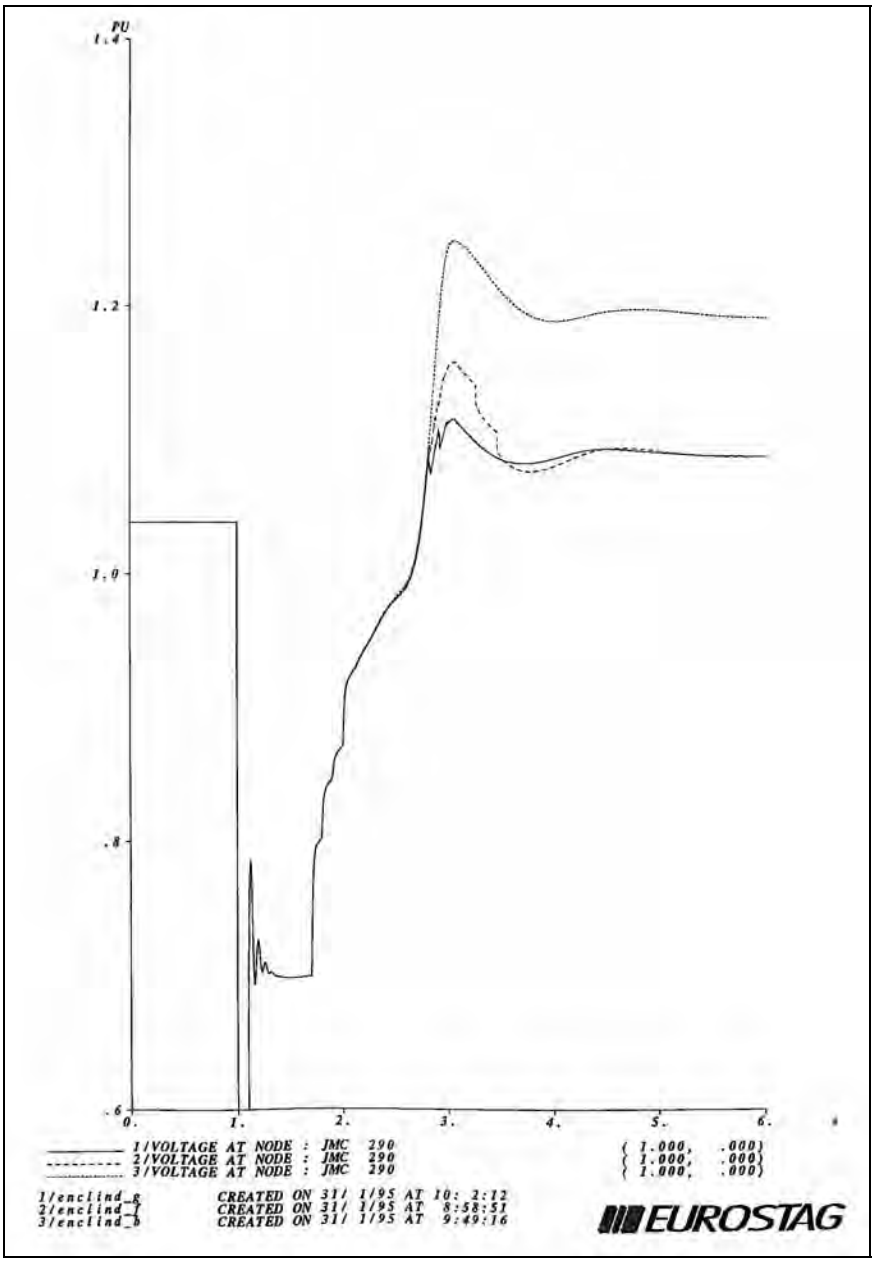

Figure 8.6. *Comparison of responses of different implementations of load shedding plan*

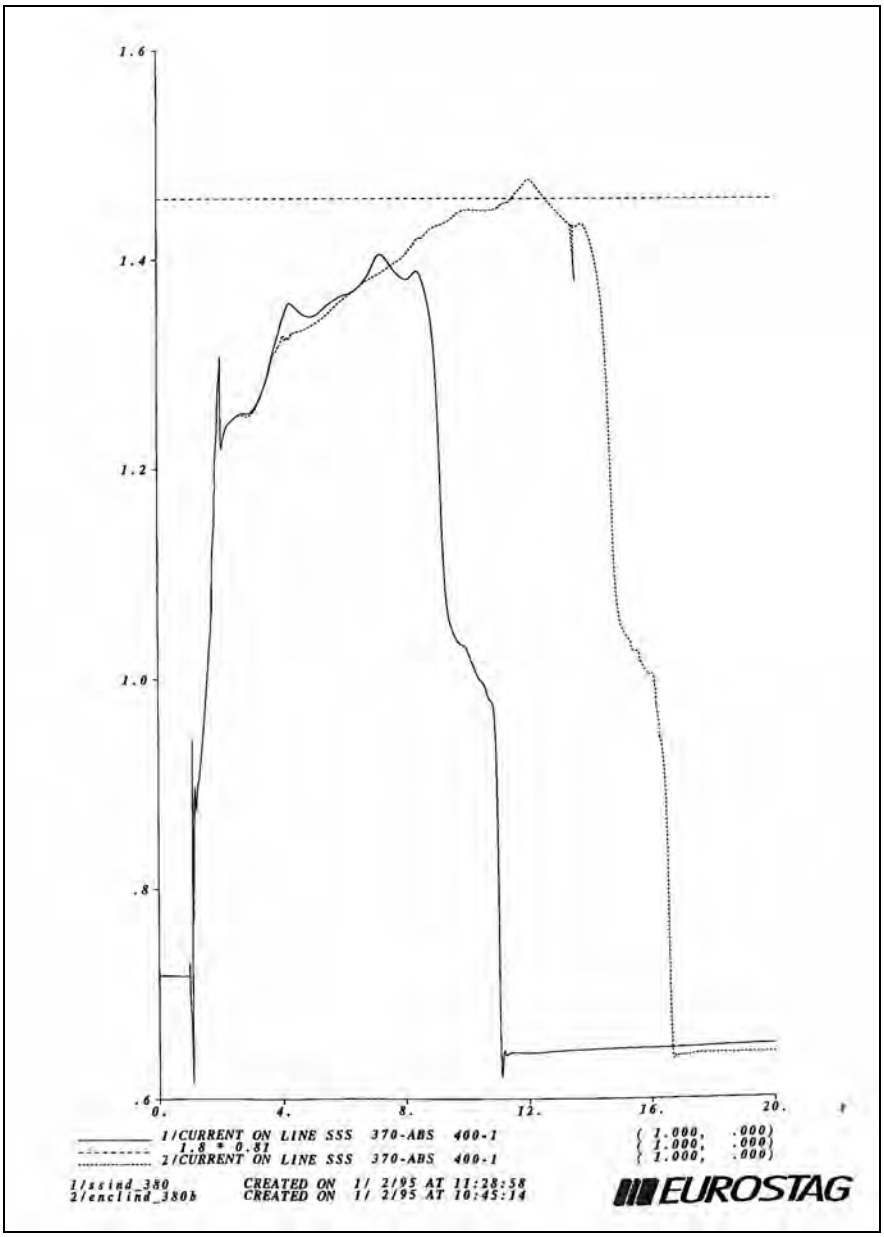

Figure 8.7. *Influence of coordinated closing of shunt inductance on the evolution of line currents*

8.5.3. *Islanding plan in case of loss of synchronism*

8.5.3.1. *Context*

One of the sections of the EDF (now RTE) defense plan concerns automatic islanding of areas losing synchronism. In the initial version, loss of synchronism is detected locally by a specific "DRS" relay (decoupling in case of loss of synchronism), installed according to predetermined splitting boundaries. Alternatively, EDF studied a new implementation based on a centralized approach in real time [COU 92]. This plan is not in service at present.

Initially, the setting up of such relays was carried out through a scheme equivalent to a very simplified network (assimilation of two interconnected areas). This simplified approach was not capable of providing a satisfactory plan, after the great change that the French network underwent in the 1980s. The increase of system meshing does not in fact make it possible, to bring back the network as seen by any "DRS" relay, to two equivalent interacting areas. The system response must be studied in its totality.

8.5.3.2. *Modeling*

Efforts in modeling dealt with two very different aspects: the precise representation of DRS relays and a detailed system model.

The development of a correct and reliable model of a relay not only meant in depth analysis of operation principles, but also details of implementation of the industrial product.

The system model had to correctly take into account the behavior of production units in transient system in terms of their out of step operation. It will be noted however, that the behavior of areas isolated by the opening of "DRS" was not to be taken into consideration here, as it involved the establishment of a load shedding plan due to under-frequency.

The possible interaction between DRS and protection against loss of synchronism installed on generators had to be examined thoroughly. In the case of the French network, the loss of synchronism relays installed in groups intervene only after more than three electrical rotations, or beyond the maximum expected for the setting of the "DRS".

8.5.3.3. *Methodology*

The final aim of the study was to define the best settings, knowing that it is not a question of an optimal solution for defense measures, only a robust solution.

The splitting boundaries of the system are pre-established. The model thus includes “DRS” at the two ends of the lines crossing these boundaries. In the modeling, the relays can be activated or not.

To establish a strategy of system splitting, we have to necessarily start with a study of its behavior after the loss of synchronism.

On the basis of an initial representative state of an average situation, a number of variants equal to the number of areas in the system are defined. Each variant corresponds to a production plan that maximizes the export of the area in question, total consumption remaining identical. Simultaneously the link between the area under study and the remaining system is weakened by the voluntary tripping of one or two elements.

Prolonged simulations of short circuits are then carried out, inducing a loss of synchronism. The deactivated relay response makes it possible to see the “free” reaction and especially the amount of electric pole slipping detected, the other parameters of the relay being fixed (amplitude of voltage thresholds, number of electrical cycles per voltage beating, etc.).

The comparison of all the cases makes it possible to deduce a first set of settings, in particular the amount of electrical pole slipping detected to activate the tripping, normally 1 or 2.

The same set of cases is then replayed, with the relays being activated. The opening of a line by DRS apparently greatly modifies the resulting transient system. Often an accentuation of loss of synchronism takes place, which leads to the successive opening of “DRS” in the area due to a type of propagation.

Following this stage, a series of cases did not prove satisfactory. Some modifications of placement or settings resolved one or two difficult issues.

Finally, the defense plan setting being achieved, it was useful to test the device on all the base cases used in the design, completed by a set of special scenarios for this purpose, including other operating points.

The effectiveness of an islanding plan in case of loss of synchronism is not 100%. In 70 to 80% of cases, for example, the detection will be correct. The remaining 20% will either be badly timed trippings, or non-tripping. These often correspond to “deteriorated” situations, for which the generating sets recover synchronism during the transients, often due to closing the inlet valves resulting from the initial loss of synchronism.

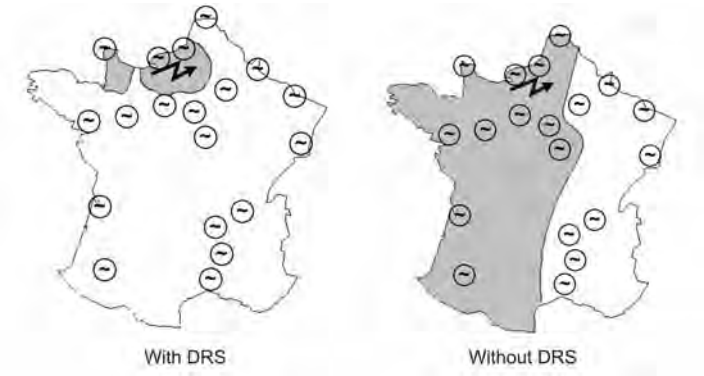

Figure 8.8. *Consequence of loss of synchronism with and without DRS*

Figure 8.8 shows the consequences of a loss of synchronism consecutive to a prolonged three-phase short circuit affecting an important 400 kV substation in the Northwest of the French network. In the absence of a defense plan against loss of synchronism, the western half of the French network loses stability with respect to the European network, taking Spain and Portugal along with it. The establishment of a judiciously tuned DRS makes it possible to localize the loss of synchronism to a subsystem of smaller size.

8.5.4. *Industrial networks*

Important factories having the capacity to produce electricity locally are generally linked to the public network on which they depend to accomplish the generation-load equilibrium of their system, especially during random or programmed unavailability of their production units.

Operation security of industrial networks depends on the perfect control of electromechanical transients caused by incidents affecting the internal or public network or by tripping of local production units. Moreover, this control is indispensable to the design and settings of protection systems and primary regulation of the groups. It is also the basis of the definition of operating rules and their correct application [KAR 00].

8.5.4.1. *Specificity of modeling*

Modeling of industrial networks is different from that of public networks in their detail of load representation. The massive use of aeroderivative combustion turbines in cogeneration installations makes the model even more complex [KAR 01]. These units are characterized by high efficiency, but exhibit weak inertia and appearance of unexpected behavior in the transient state, in fact reflecting the complexity of the control scheme: control of burners, air flow control by inlet guide vanes, air bleed circuit, controllable stator blades, etc. In the most difficult cases, modeling of such units must depend on a calculation program provided by the constructor. This code is then included in the dynamic simulation program of the electric power system.

More than ever, it is useful to provide for the verification of behavior of models developed for each subset, on the basis of recordings taken during tests or incidents.

In general, the preparation of a model requires the following steps:

– statement of the main characteristics of existing local generation, particularly the alternator and its speed and voltage regulators and their parameters, for example in the form of block diagrams, including the limiting loops;

– establishment of the composition, electric and mechanical characteristics, and power associated with loads driven by asynchronous motors, connected in medium and low voltage, without forgetting the necessary consideration of the response of contactor switches;

– distribution of factory loads into categories: able to be shed or not, sensitive, to be secured, for example for safety requirements;

– inventories of particular loads, their nature and corresponding power;

– modeling of the network itself. The aim is to at least enable the development of a synthetic model of the rotating load distributed in medium and low voltage networks;

– statement of the logic, localizations and settings of the present or projected automatic devices leading to load shedding due to frequency or voltage criteria, and in the latter case the criteria and parameters of the automatic load recovery scheme;

– examination of the logic, the settings and localizations of the islanding protection with respect to the external supply network;

– examination of principle diagrams of steam circuits, study of various interactions between steam production and electricity.

All this information is integrated into the base model of the site. This will possibly be enriched during simulations so as to identify critical behavior in a more precise manner.

8.5.4.2. *Types of investigation*

Different investigations may be required based on the specific problems of the site in question. A non-exhaustive list is proposed below.

Critical clearing time of a fault

The determination of critical clearing time of a fault is carried out for short circuits affecting public or factory networks. The comparison to base time and backup of protection plans of external networks and the factory makes it possible to judge the decision to be taken, for example resorting to preventative islanding to prevent the possible tripping of groups by loss of synchronism relays, etc. The notion of stability is not limited to the loss of synchronism of synchronous machines; it must also include phenomena for the blockage or stalling of asynchronous motors.

Load shedding plans

For cases of islanding, it is necessary to establish a load shedding plan in case of under-frequency. It is generally made up of two complementary sections. The first acts in anticipation ("feed-forward") being based on the initial pre-calculated, imbalance of power, and the second acts in counter-reaction ("feedback") following the effective evolution of frequency. This second section can be integrated into the load shedding plan aiming to protect the network and secure the load essential to the factory (final security of the site).

The nature of industrial load and the loading rate of elements constituting the network, make these systems sensitive to voltage instability during the recovery after faults that have been correctly eliminated. This can justify the development or verification of the correct operation of a load shedding plan based on the voltage criterion. This can include a procedure to automatically restore the load when the system is stabilized.

Stability following large disturbances

In sites equipped with cogeneration installations, interactions between the steam and electricity networks can be significant in case of large disturbances. The developed model must make it possible to indicate the ability of the adopted control scheme to maintain acceptable operation.

The study of stability of an industrial system, interconnected with the public network, verifies that the site remains stable following an electric fault eliminated by main or backup protections. The investigation assumes the consideration of automatic shedding and progressive restoration of the driving load of the factory, which will be activated if necessary. This type of investigation shows in which conditions islanding of an industrial network becomes necessary.

In the case where disconnection from the public network is necessary, it is required to determine the conditions to be respected to preserve the stability of the factory network. The simulation, following a fault eliminated by main or backup protections, takes into account the separation of the site network by opening the switching devices meant for this purpose. Operations of automata for load shedding action and load progressive restoration must be included in the modeling.

If the isolated operation of the network is envisaged, the study of this type of operation can involve different domains, briefly listed here below:

– frequency stability in case of tripping of the production unit;

– frequency stability in case of tripping of a significant load;

– consequences of a fault, of the short circuit type, affecting the site, especially the evaluation of the risk of loss of synchronism if there are many synchronous generators on the site;

– evaluation of the load shedding-restoration system response in these specific conditions;

– study of the protection scheme and relay settings;

– etc.

Development of an automatic islanding device

The development of an automatic islanding device is usually based on knowledge acquired during the development of points mentioned earlier. The analysis of simulated cases makes it possible to propose a scheme, in case of disturbances in the public network (long duration fault, slow decrease of frequency, voltage, etc.), to ensure islanding of the factory network. In particular, such a protection system must anticipate the shut down of the factory before the loss of synchronism of production units, their return to house load or tripping.

The capacity to restart the factory in isolation can be verified as well as the correct recovery operation after the fault. The activation of automatic devices for load reconnection, leads to a more or less progressive increase in power. The study of voltage and frequency evolution of the system indicates the margins with respect

to thresholds of automatic load shedding operations. This makes it possible to analyze the capacity of combustion turbines to be restarted in isolation respecting their constraints.

The optimization of the start sequence of the driving load must respond to different constraints related to voltage thresholds of load shedding relays, operating thresholds of contactors and current thresholds of cable protections. An industrial network is connected to the public transmission network. The driving load is started in “waves”. The curves in Figure 8.9 give the evolution of voltage and current on a link and the rise in motor speed representing each wave. The time curve for voltage shows the margins available for the relays and contactor switches.

The start of the driving load in the isolated network introduces severe constraints as much at the production level and frequency control as excitation and voltage control. Figure 8.10 shows in the first curve that the initial frequency is set above 51.5 Hz at the start so as to conserve the maximum margin with respect to under-frequency load shedding thresholds. The second curve shows the evolution of power delivered by the generator. These two curves recall the significance of having a generating set with sufficient inertia. Constraints related to the excitation which reaches its limit during the start of each wave are illustrated by the last curve in the figure. During the start of the first waves, the reduction in voltage at the terminals does not make it possible to reach the excitation limit.

8.6. Future prospects

Some recently proposed systemic protections suggest great prospects [HEY 01, LIU 00]. They obviously refer to current technical possibilities in terms of measurement, transfer and processing of information.

In terms of principles, these new protections correspond to a paradigm shift in terms of operational security. In fact, the increasing issue is replacing the traditional passive approach, based on preventive security, for example the “N-i” criteria, with an active approach. Because of this, electric system operation and security are becoming dependant on remote automatic actions, even for “simple” incidents.

It is paradoxical to think that, simultaneously, the last developments in terms of nuclear production propose passive core cooling system implementations that rely on fundamental principles such as gravity, natural convection, etc. In this sensitive field, the passive approach to security has replaced the traditional active approach!

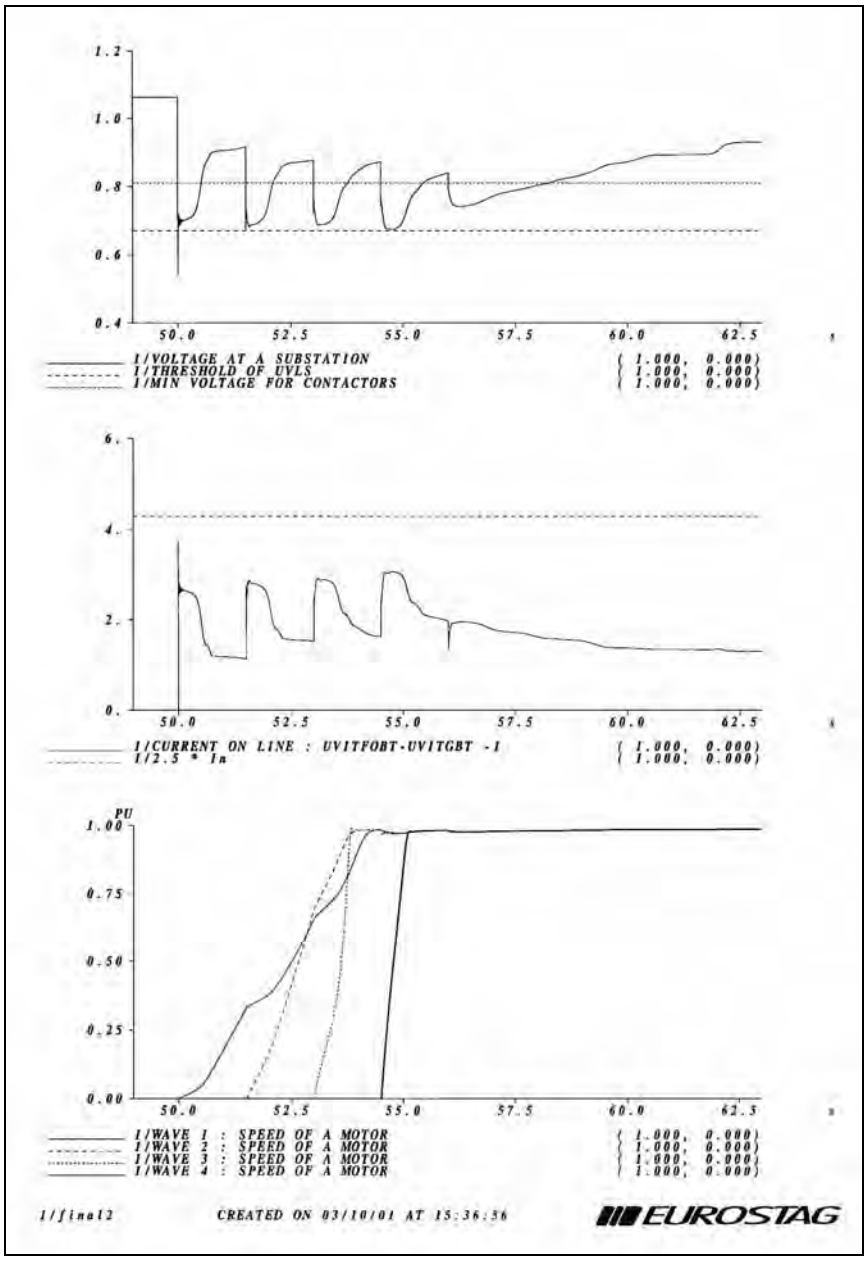

Figure 8.9. *Start in waves of the driving load for an industrial site operating in an interconnected network*

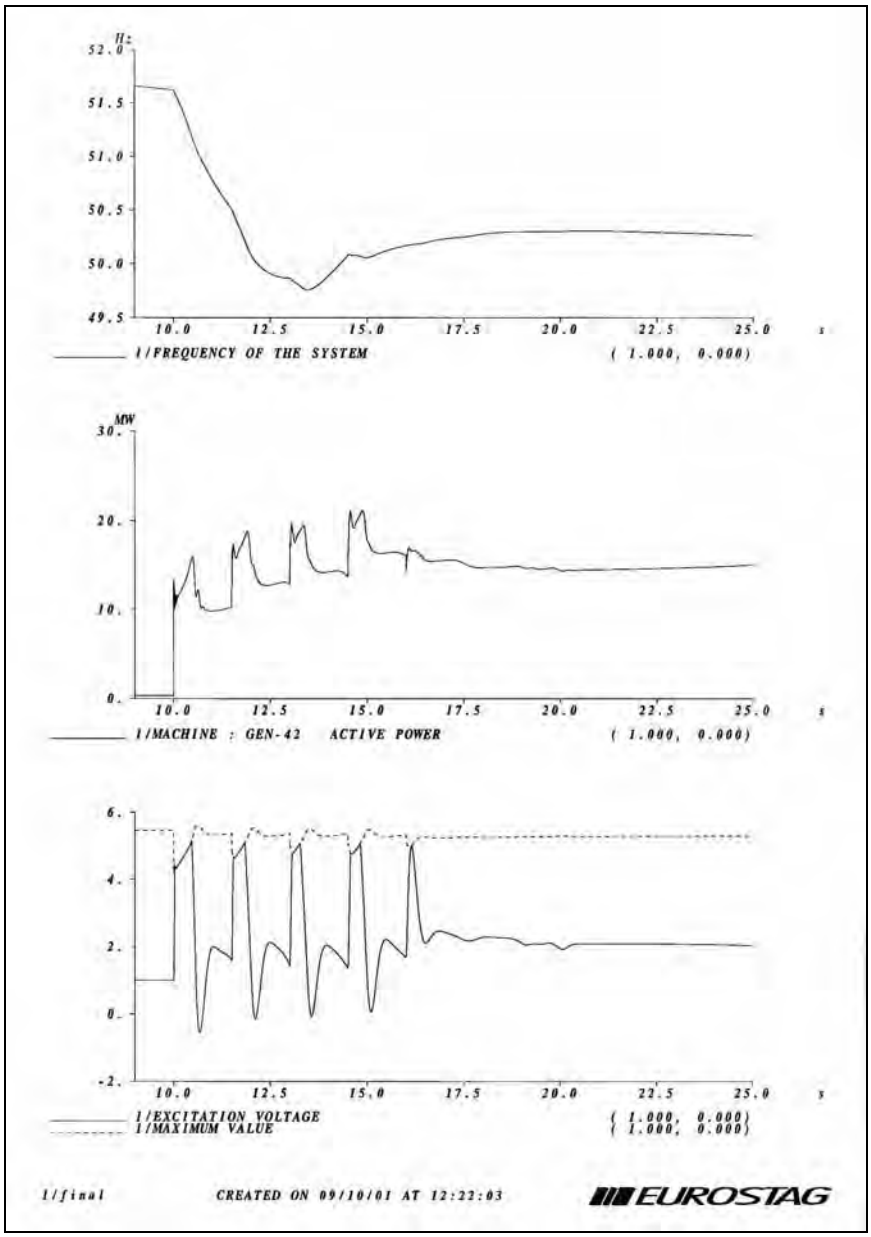

Figure 8.10. *Start in waves of the driving load in an isolated network*

If the advantage to be gained from a lessening of electric system development and operation criteria can be significant in some circumstances, accepting the concomitant risks can only be justified with knowledge of their cause. Their correct evaluation mainly comes from the simulation field.

8.6.1. *Evolution of simulation tools*

Simulation software will need to evolve to allow for large system operation simulation in a disrupted environment by including detailed modeling of new measurement and defense devices. Reflection should be made to systemic protection schema modeling in simulation tools, including data transfer.

The increase in power exchanges between interconnected networks leads to the simulation of larger systems that are no longer limited to the borders of a state. This obviously implies considerable data exchange between neighboring networks.

In parallel, simulation tools will also have to consider the introduction and evolution of devices for system control in quasi steady-state. In fact, as was previously indicated, the integral application of control policies is one of the options open to the operator for guaranteeing operational security. The best evaluation of margins involves simulation of states totally compliant with operating rules.

The increase in computer power makes it possible to meet these new requirements. Algorithmic progress remains vital for the introduction of more detailed local modeling (not relying on the representation of variables in the form of phasors) for a critical zone within a system represented by its extended electro-mechanical model. This new step would be necessary for the precise consideration of power electronics switching events.

Since using the slow phasor output of a digital fault recorder provides an electro-mechanical response of the system, it is probably the best modeling “certification” method. In order to be efficient, such an approach requires synchronizing the different fault recorders-of the interconnected system, which is technically possible, and the will of the different system operators to collaborate in terms of security.

8.6.2. *Real-time curative action*

We have seen that defense actions are the subject of development corresponding to detailed dynamic simulations to subsequently be generated on the field by simple criteria.

The increase of calculation power, paired with progress in communication methods, makes it possible to develop curative action based on the analysis of established trajectories in real-time. The “central point” algorithm developed by EDF is an example [COU 91].

In the intended implementation, which has not gone beyond the prototype stage, network fragmentation boundaries remain predetermined. Loss of synchronism detection is based on the measurement of the voltage phase at different points in the network. Trip orders to circuit-breaker in order to isolate the out-of-synchronism region are sent from a “central point” where the different measurements are processed. Preventive and coordinated load shedding can be activated in the healthy zone to improve chances of success in the operation.

Reaction speed must be high, since loss of synchronism occurs in a split second. For other slower events, it is possible to consider “closed loop” actions, for example, load shedding in the case of voltage collapse. This generally develops over minutes. It would then be possible to determine with proper measures and from dispatching, locations and quantities of loads to shed to avoid voltage collapse.

8.6.3. *Load actions*

The implementation of most defense counter measures involves action on the load in order to restore the balance between production and consumption. Today, the action usually goes through the opening of medium voltage feeder circuit-breakers used in the load shedding plan.

A direct action on the load would enable us to reach this same objective with the advantage of being able to sustain client “energization” as long as segregation can be achieved between vital and “sheddable” domestic loads.

The question of the link ensuring communication between the dispatching center and ultimate load still remains open today. The nature of implementations liable to be developed will depend on the capacity of this link. It is not certain that real-time actions are possible. Breakdown in two phases, as is traditionally done, may then apply.

The evaluation of the total sheddable load per *feeder* would regularly be accomplished from dispatching. The proportion of load to shed would be established and corresponding amounts would be sent to a device installed at the user's location. In the case of crossing a locally determined threshold, the actual trigger would occur at HV-MV stations or at dispatching, based on a telecommunication circuit performance. Trigger chain parameters, and specifically the threshold, would also be remotely set up.

8.6.4. *Decentralized production*

The increasingly wide development of decentralized production introduces constraints but also new possibilities in terms of system control and security.

Decentralized production takes the place of centralized production which, if no arrangement is made, will have to maintain all system services with limited running capacity. Over time, it will be necessary to consider the involvement of decentralized groups in system control. Currently, in the most advanced networks in this field, measures have already been taken in this regard. Electric and thermal productions have been dispatched in cogeneration units with the introduction of thermal storage.

Other solutions are being studied. They mainly concern quasi steady-state operation. Their implementation must take into consideration all conditions prevalent in the system in a precise manner to benefit from new advantages linked to decentralized production, without disrupting the action of current measures, for example, system control in case of emergency.

The contribution to voltage control perfectly illustrates this question. In fact, today there are control procedures against voltage collapse based on the temporary reduction of distribution voltage by action on HV/MV transformer settings. This action makes it possible to decrease the loading without using load shedding. This practice could be jeopardized by inadequate decentralized production reaction.

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Chapter 9

System Control by Power Electronics or Flexible Alternating Current Transmission Systems

9.1. Introduction: direct current links and FACTS

In a book on monitoring, control and security of electric power systems, a chapter has to be devoted to the possibilities offered by devices that use power electronics resources. These devices, of which some are already in use and others are at experimentation or project stages, are together classified under the general name of FACTS, an acronym for flexible alternating current transmission systems. They were created through a study initiated towards the end of the 1980s by EPRI (Electric Power Research Institute) in the USA in a rush of effort to develop high voltage direct current links which had widely demonstrated the reliability of power electronic devices in high voltage power systems. These links, over distances of about 1,000 km of overhead lines and 50 km of underwater cables or connecting back to back asynchronous systems or systems with different control modes, use alternating current/direct current conversion systems with thyristors for hundreds to several thousands of megawatts of power. At present, all over the world, there are about 100 direct current links for a total transmission capacity of 70,000 MW, or 140,000 MW in conversion capacity, with voltage higher than 500 kV. In addition, there are new large projects, like the Three Gorges-Changzhou project of 7,200 MW -500 kV in China. Today, a new generation of direct current links is being developed, using converters with fully controllable components for turn-on as well as for turn-off (GTO, IGBT, and IGCT). This new type of link makes the creation of

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Chapter written by Michel CRAPPE and Stéphanie DUPUIS.

applications of several tens to several hundreds of MW of power possible. The first link of this type was installed in 1998 in Sweden to connect a wind turbine farm of 50 MW on the island of Gotland over a distance of 70 km to an important network substation. A 180 MW link was then installed in Australia. A link for 330 MW of power in 138 kV through 40 km of underwater cable between Connecticut and Long Island in the USA was made operational in May 2002. A project for 225 MW through underwater cable between Finland and Estonia can also be mentioned [SMI 00].

Currently, these new direct current links systematically use voltage-sourced converters (VSC) with pulse width modulation (PWM) achieved with IGBTs (insulated gate bipolar transistor) as components. The latter have seen significant development in the past few years, now reaching limits of 6.5 kV in voltage and 2.5 kA in current. These converters provide a number of advantages as compared with conventional line commutated thyristor converters.. In fact, they do not require installation of costly harmonics filters, or reactive energy source, or information exchange between the two converters of the link. Making it possible to generate voltage of adjustable frequency and amplitude and phase, they constitute real static sources, capable of providing or absorbing as much active as reactive power.

These new direct current links are possible for the following applications:

– links between smaller dispersed units (wind turbine machines, stream plants, etc.) and the linking of all these units to the main system;

– supply to rapidly expanding centers;

– supply to users a long distance away from the main network.

The aim of FACTS is to improve transit control in links and to increase the transmission capabilities of the network, by operating the existing infrastructures and new resources at the maximum level, by using power electronic devices that carry out conversion or switching operations, in the range of a few tens to a few hundred megawatts. It is important to note that if FACTS devices make it possible to increase transmission capabilities, they do not constitute substitutes for lines as such and inevitably lead to a reduction in available reserves in case of an incident and, as a result, to a certain weakening of the system. The increase in transfer capabilities is carried out by bringing stability limits closer to the thermal limits of links. The direct current links mentioned earlier, while constituting real lines, are also considered in the range of systems that are likely to increase the flexibility of electric power transfer. We direct the reader to the abundant specialized literature that discusses direct current links and in this book, we focus on new systems, i.e., FACTS.

Deregulation of the electricity market should lead to a significant increase in the exchanges of electric power through the networks. The exchanges are conditioned by transmission capabilities, which are vital for the smooth functioning of a deregulated market. Furthermore, large networks with increased power transfers become very complex to manage and the coordination of control and regulation systems can pose a problem. Conventional control methods, on-load tap changing transformers, phase shifting transformers, passive elements switched by circuit breakers for series or parallel compensation, setting modifications for active and reactive power production of generators, and changes in the topology of the network, run the risk of being too slow and insufficient to respond effectively to the operational needs of power systems. It may be noted that the modification of the transmission angle through the phase shifting transformer requires several seconds per degree. It will thus be necessary, in certain cases, to complete the action of conventional control means by using FACTS devices with high response speed. These devices in reality are only fast actuators and it is essential to extract all their possible benefits by using sophisticated regulation and control strategies especially with remote control in order to coordinate and optimize the operation of FACTS. This implies the implementation of fast means of communication adapted for high speed large data transmission systems. Chapter 5 summarizes the problem of control through long distance signals (remote control).

The pioneers in the field of FACTS are, unquestionably, Narain G. Hingorani and Laszlo Gyugyi. We strongly recommend reading their book *Understanding FACTS*, published by IEEE Press [HIN 00], which presents the concepts and technology of FACTS systems. It may be noted that the first shunt type static var compensators (SVC) were installed in Nebraska in 1974 and in Minnesota in 1975, and it was in 1984 that the first converter connected in series was installed in California.

Up to the present time, almost all the installations have been in the United States and Japan. With the evolution of European networks, the use of FACTS systems could be important in Europe in the near future, and it is after all judicious to consider the possibilities of their implementation in network development planning. The evolution and the new constraints in the network are described in detail in Chapter 2.

9.2. General concepts of power transfer control

9.2.1. *Introduction*

These concepts have been described in Chapter 1 to which we revert for more details. In the current chapter, we take up only the fundamental principles

implemented by FACTS. To do this, it is sufficient to use expressions describing the exchange of power between two points A and B of the network linked through a pure inductance link X.

9.2.2. *Power transmission through reactance*

In the single phase diagram in Figure 9.1, the voltage at nodes A and B are respectively $\underline{V}_a = V_a\angle\delta_a$ and $\underline{V}_b = V_b\angle\delta_b$, V_i being the rms (root-mean-square) value and δ_i the voltage phase with relation to a common reference.

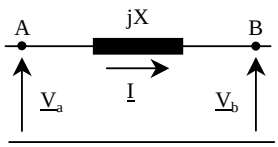


Figure 9.1. *Single phase diagram of power exchange between two points linked by pure reactance X*

We recall that this single phase diagram also represents power exchanges in a three-phase system, in this case voltages are between phase and neutral, also qualified by neutral voltage and the current is the line current. The following expressions are directly usable in a three-phase system, provided that the voltage and power are expressed in reduced quantities. With normal quantities, these expressions give the power per phase and it is thus necessary to multiply the results by 3 to obtain the total power.

The positive direction selected for the current being free, in the case of the figure it is taken from A towards B.

$P_a = V_aV_b \sin(\delta_a - \delta_b)/X$, active power supplied by A and received by B [9.1]

$Q_a = V_a[V_a–V_b\cos(\delta_a - \delta_b)]/X$, reactive power supplied by A [9.2]

$Q_b = -V_b[V_b–V_a\cos(\delta_a - \delta_b)]/X$, reactive power received by B [9.3]

$\underline{I} = (\underline{V}_a-\underline{V}_b)/X$, current from A to B [9.4]

$Q_a = Q_b+XI^2$ [9.5]

Expression [9.1] indicates the parameters by which it is possible to modify the active power transmitted, i.e. the reactance of link X, the voltages V_a and V_b and

finally the transmission angle $\delta = \delta_a - \delta_b$. It has to be pointed out that the direction of active power transfer is only determined by the phase shift related to the voltage at the extremities of the link (from A to B if $\delta_a > \delta_b$ and from B to A if $\delta_a < \delta_b$) and does not depend in any way on the related value of these voltages.

In transmission lines, the voltage drop for nominal current is commonly about 1% per 10 km, which signifies a drop of 20% for a 200 km line. In Europe, the average distance between the big cities is in the order of 200 to 300 km and the average distance between the interconnecting stations is 100 to 150 km.

In the part following this section we shall adopt, by way of example, the following numerical values, expressed in reduced quantities, $V_a = V_b = 1.0$; $X = 0.2$ (200 km link). With these values, the transmission angle is 11.54° for the transfer of nominal power P = 1.0. It has to be pointed out that the hypothesis of equality of voltage amplitudes at the extremities of the link implies that the reactive power of the line is supplied in equal parts by the two extremities. We already knew, in Chapter 1, that voltage maintenance requires the supply of reactive power.

Figure 9.2 shows the evolution of active and reactive power based on the transmission angle for these numerical values. We can see the maximum value of active power that can be transmitted, as well as reactive power to be used at each extremity to ensure voltage maintenance. Only the parts of these characteristics corresponding to a transmission angle between 0° and 90° represent stable operation and, for reasons of operating stability of alternators, the transmission angles are generally limited to values of about 30° to 40°.

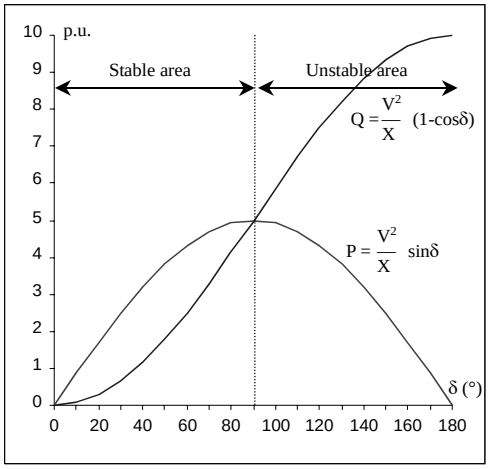


Figure 9.2. *Variation of active and reactive power with transmission angle, for a link with reactance (see Figure 9.1 with $V_a = V_b = 1.0$; $X = 0.2$)*

Figure 9.3 shows the relative positions of phasors, still in the case where voltage is equal at the extremities. A more realistic situation, in which reactive energy must be supplied by node B to the network downstream of this point, is represented in Figure 9.4. It is stipulated that this case implies a voltage drop between A and B and thus once more shows the influence of reactive power transfer on the voltage level and the necessity for compensation of the reactive power at the location where it is summoned. In the vector diagrams presented, the transmission angle has been systematically exaggerated (>11.54°) for diagram clarity.

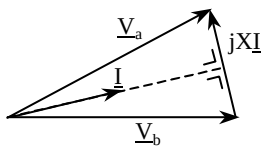


Figure 9.3. *Vector diagram for $V_a = V_b$*

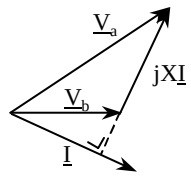


Figure 9.4. *Vector diagram for $V_a \neq V_b$*

9.2.3. *Modification of reactance in link X*

The active power transmitted can be controlled, for given voltages (amplitudes and phases) at the extremities of the links, through modification of inductance X.

This modification can be brought about through the introduction of reactance in series with the link. According to the inductive ($\Delta X>0$) or capacitive ($\Delta X<0$) character, it is possible to reduce or increase power. This modification can be carried out through passive elements, units of inductances or capacitances, triggered with the help of mechanical or electronic switches or by a thyristor-controlled electronic device. The latter system, known as a thyristor-controlled series reactance (TCSR), makes continuous control possible in the range of control settings, it will be described in section 9.8. This system also makes it possible to damp power oscillation between areas through its fast control.

Compensation of reactance of the line by series capacitors can induce various oscillatory phenomena with frequencies lower than the network frequency, called subsynchronous oscillations, which are seen especially in the oscillatory exchanges of energy between electric systems and rotating masses of generation groups. The eigenfrequencies of mechanical systems (alternator + driving machine) are generally situated between 4 and 40 Hz, with damping expressed in time constants between 2.5 and 10 seconds. These interactions are translated especially by the torsional torques on the shafts of generation groups, leading to fatigue phenomena, that are capable of causing fissures or even rupture. See specialized material for more in-depth discussion of this issue.

The frequency of electric resonance is given by the following relation:

$$1/\omega' C = \omega' L = (\omega'/\omega)X \qquad [9.6]$$

with ω' as the resonance angular frequency and ω the network angular frequency. By introducing the factor for compensation k according to $1/\omega C = kX$, the reactance compensated for the frequency of the network becomes $(1-k)X$ and the angular frequency of resonance is expressed by $\omega' = \omega\sqrt{k}$.

As $0 \leq k \leq 1$, resonance frequencies are less than the network frequency, from which the term subsynchronous comes. In practice, the compensation factor does not generally exceed 40% to limit the risk of subsynchronous resonance.

The steady-state effect of the compensation system can be very well appreciated based on equation [9.1]. Any reduction of X is translated, with constant values for voltage and transmission angle, by increases in current and active and reactive power proportional to $1/(1-k)$.

In principle, series type compensations must only be designed for a relatively small fraction of power that can be transmitted by links. For example, for a compensation of 25% for a link whose reactance is 20% (200 km), a device designed for 9% of the power of the line is sufficient. Such compensation increases the transfer capability of the link by 33%. For a 400 kV line whose nominal current is 2,000 A, a device of 41 MVA per phase is sufficient. This calculation takes into consideration the increase in current in the compensated line (I = 1.33). However, in practice, in order to tolerate possible overcurrent, all devices installed in series must be designed to tolerate 100% overcurrent.

If the mechanically controlled capacitor banks make it possible to adapt power transfer to network conditions, the number of switchings is however limited due to the wear and tear of mechanical devices. Furthermore, such compensation systems with low response speed do not make it possible to avoid subsynchronous resonance

phenomena mentioned above. On the other hand, power electronic versions, other than being able to modify the degree of compensation as often as required by network conditions without any problems of wear and tear, thanks to their high response speed, can also contribute to the damping of subsynchronous oscillations and low frequency power oscillations (typically from a few tenths of a hertz to a few hertz) occurring in the network after certain incidents or maneuvers. These latter oscillations, known as electromechanical oscillations, are related to the dynamic equilibrium of the rotating masses in generation units (see section 9.5). In practice, an economical solution consists of linking a capacitor bank, either fixed or adjustable through mechanical switches, with a power electronic system in series to ensure fast control and preserve network stability.

9.2.4. *Modification of voltage and the segmentation method*

The modification of voltage amplitude of one or other extremity of the link modifies the power transmitted. However, in practice voltage needs to be maintained within a narrow range to operate the materials within their design limits. This greatly reduces the margin for maneuver through voltage modification.

On the other hand, to maintain a constant voltage at points in the network is a useful method implemented especially in the principle of segmentation which consists of dividing a long line into several sections at the extremities where shunt type compensation systems maintain the voltage. This in fact results in the reduction of reactance in relation [9.1] and thus in the increase in transmittable power. The division into N parts of a link makes it possible to multiply the active power that can be transmitted by N. The restriction of this segmentation principle is economic in nature, due to the cost of compensation devices, which are intended to supply the reactive power necessary to maintain the voltage.

To maintain a constant voltage at the extremity of a line supplying radial load is another application that makes it possible to avoid voltage collapse at the load terminals. This voltage regulation makes it possible to prevent the maximum transmittable power from being based on the power factor of the load but be determined by relation [9.1].

To maintain a constant voltage by shunt compensation requires devices whose design is determined by relations [9.2] and [9.3].

9.2.5. *Modification of the transmission angle*

The modification of the transmission angle is carried out by the injection of a voltage. The voltage is injected through a transformer connected in series in the link as described in section 9.4.1. In the case of a phase shifting transformer, this voltage is injected at the receiving node in quadrature with the voltage at this node (Figure 9.5a). In the case of advanced electronic series compensators (ASC), this voltage can have any phase, especially in quadrature with the current in the link (Figure 9.5b).

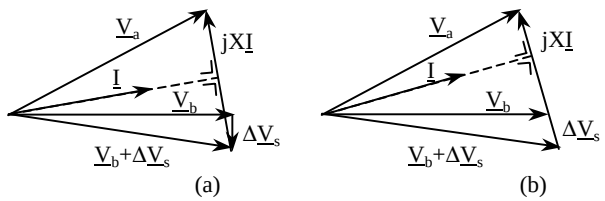


Figure 9.5. *Influence of injection of additional voltage $\underline{\Delta V}_s$ to one of the extremities of the link (a: $\underline{\Delta V}_s$ in quadrature with $\underline{V}_b$; b: $\underline{\Delta V}_s$ in quadrature with I)*

9.2.6. *Comparison of three methods in a simple case*

Performances related to the three methods in terms of modification of active power transit are compared while considering the case of a 25% increase in transit of active power, based on an initial situation defined by the following reduced values: P = 1.0, X = 0.2, $V_a = V_b = 1.0$.

One parameter is modified at a time, the others being maintained at their initial value. The results are given in the table below, in which the first line gives the initial conditions, the second line concerns the modification of reactance X, the third line is related to the modification in voltage amplitude V_a and the last line deals with the modification of the transmission angle δ. All the quantities are expressed in reduced values, with the exception of the transmission angle expressed in degrees.

X	P	Q_a	Q_b	V_a	V_b	δ	I
0.20	1.00	0.101	-0.101	1.00	1.00	11.54	1.00
0.16	1.25	0.126	-0.126	1.00	1.00	11.54	1.26
0.20	1.25	1.689	1.124	1.25	1.00	11.54	1.68
0.20	1.25	0.159	-0.159	1.00	1.00	14.48	1.26

Table 9.1. *Comparison of modification methods of power transfer*

It is the method by modification of reactance X which seems the most effective in modifying the transit, it is also the least costly. We realize that the modification of voltage changes reactive power and the current excessively and thus does not constitute a solution to modify active power transfer. On the other hand, as far as maintenance of the voltage plan is concerned, it is the compensation of reactive power that constitutes the most appropriate means of action.

9.3. Control of power transits in the networks

This section gives examples of installing transit control in the networks.

9.3.1. *Circulation of power in a meshed network: power loop concept*

Let us consider the simple system in Figure 9.6 with two self-sufficient zones A and B, each having a source and a load, but interconnected to make up a mesh.

This very simple meshed network makes it possible to show the concept of power loop and to assess the methods to modify the transits. The voltage is imposed at the generator nodes, 400 kV in the example, and the active and reactive power are imposed at the load nodes.

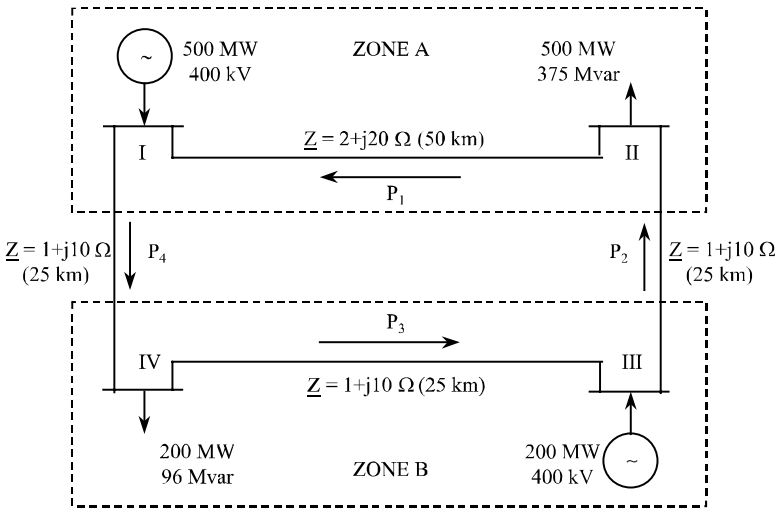


Figure 9.6. *Basic meshed network*

9.3.1.1. *Simplified method of calculation of transit: direct current model*

A simplified method of calculation enables an estimation of power transfers P_1, P_2, P_3 and P_4. This method, called the direct current model, is based on the hypotheses that the voltage has the same amplitude at each node of the network and the links are represented by their reactance. This leads us to only consider active power transfer. The model is ruled by the power conservation equations in each node and by the equation which translates the equality of the algebraic sum of the transmission angles to zero, in the entire mesh ($\sum P_i.X_i = 0$).

$$\begin{aligned} P_4-P_1 &= 500 \text{ MW} \\ P_2-P_1 &= 500 \text{ MW} \\ P_2-P_3 &= 200 \text{ MW} \\ P_4-P_3 &= 200 \text{ MW} \end{aligned} \qquad [9.7]$$

$$20P_1+10P_2+10P_3+10P_4 = 0 \qquad [9.8]$$

The results of the calculations are: $P_2 = P_4 = 240$ MW; $P_3 = 40$ MW and $P_1 = -260$ MW. They give rise to the circulation of 240 MW between the two zones, called the power loop. Such a circulation can lead to overload on the interconnection lines.

We can conclude that the power transfers in a meshed network depend on impedances of links and their interconnection and not on their owner or business contracts exchanged between the partners connected by these links. The transfers of electricity in a meshed network are governed by laws of physics and not of the market. This physical constraint can be the source of problems in a free market [CRA 03].

9.3.1.2. *Method of iterative calculation of load flow*

The calculations made by the Newton–Raphson iterative method have given the following results very close to those of the simplified method. The given active and reactive power are respectively supplied or received depending on whether it is a generating or receiving node.

Node	P (MW)	Q (Mvar)	U (kV)
I Generator	502.1 259.5 towards II 242.6 towards IV	160.8 123.7 towards II 37.1 towards IV	400
II Load	500 258.5 from I 241.5 from III	375 113.4 from I 261.6 from III	394
III Generator	200 242.2 towards II -42.2 towards IV	332.8 269.8 towards II 63.0 towards IV	400
IV Load	200 242.3 from I -42.3 from IV	96 33.4 from I 62.6 from III	399

Table 9.2. *Power transfer calculated by iterative process*

9.3.1.3. *Influence of impedance modification of one of the network links by series compensation (capacitor bank or power electronics device)*

By taking the same conditions as in the earlier section but with a compensation of 40% for the line where the impedance is the highest, we bring the reactance to 60% of the initial value (X = (6/10)20 = 12 Ω). This compensation modifies the transfers and especially the circulation power as shown in the table below.

Node	P (MW)	Q (Mvar)	U (kV)
I Generator	502.2 312.1 towards II 190.1 towards IV	199.8 158.7 towards II 41.1 towards IV	400
II Load	500 310.7 from I 189.3 from III	375 149.5 from I 225.5 from III	394
III Generator	200 189.9 towards II 10.1 towards IV	288.5 231.4 towards II 57.4 towards IV	400
IV Load	200 189.9 from I 10.1 from III	96 38.8 from I 57.2 from III	399

Table 9.3. *Influence of series compensation of link impedance*

9.3.1.4. *Influence of transmission angle modification of one of the links*

Still with the same conditions as section 9.3.1.2, we examine the influence on transits with a reduction of 5° of the transmission angle of the I-IV link. The phase shifter is placed at node IV. The results are given in the following table.

Node	P (MW)	Q (Mvar)	U (kV)
I Generator	504.2 512.9 towards II -8.7 towards IV	122.4 115.2 towards II 7.2 towards IV	400
II Load	500 509.6 from I -9.6 from III	375 80.6 from I 294.4 from III	393
III Generator	200 -9.0 towards II 209.0 towards IV	392.1 300.0 towards II 92.1 towards IV	400
IV Load	200 -8.7 from I 208.7 from III	96 7.2 from I 88.9 from III	397

Table 9.4. *Influence of transmission angle modification of a link*

The last two sections show, through a simple example, the possibilities of modifying the transits and especially circulation power and, where necessary, bringing back the transits below the allowed thermal limits. In the example, the placement of compensators was chosen arbitrarily. We can show that the location of one or more compensators in a network has an impact on their design for a determined effect [DUP 01]. The optimal location of compensators is definitely an issue that requires study.

9.3.2. *Modification of transits on parallel lines of a corridor*

Another simple example lies in the control of power transfer repartition between parallel lines with different impedances in a corridor linking two areas, for power exchanged between these two areas. Without control, power transfer is shared between the different lines, due to their impedance. This can lead to an overload in the link which presents the weakest impedance or to the incorrect operation of other links. A typical case is of an overhead line in parallel with a cable. This control can be carried out by compensation of reactance or modification of the transmission angle.

9.4. Classification of control systems according to the connection mode in the network

The control systems can be classified according to their connection mode to the network, in series, shunt or by series-series or series-shunt combinations.

9.4.1. *Series type controller*

These control systems are implemented by an insertion of impedance or of a variable voltage source in series in a link. The principle of the action of a series controller is always reduced on the injection of voltage in series in the link, since the product of the impedance inserted multiplied by the current represents an injection of voltage. Thus, from the functional point of view, all series controllers will be modeled by a voltage source. If this voltage is in quadrature with the current, the controller must supply or absorb only reactive power. If this is not the case, the controller also puts active power into action. In practice these controllers are realized by different ways: either by capacitors or inductances varying in steps switched mechanically or by electronic switches with thyristors (Figure 9.7a), or through a variable impedance in a continuous manner using a controller with thyristors (Figure 9.7b), or finally through injection of series voltage with the help of a transformer. This voltage is either constructed by a transformer connected to the network in the conventional case of an on-load phase shifting transformer with mechanical switches or with thyristors (Figure 9.8), or carried out through electronic path with the help of a converter (Figure 9.9). In the following part, only systems with controllers and electronic converters will be described in greater detail, the other systems being conventional.

We must remember however that in the case of a phase shifting transformer the voltage in quadrature of each phase is developed by tappings through an auxiliary transformer of one part, adjustable in steps, of voltage at the terminals of the two other phases.

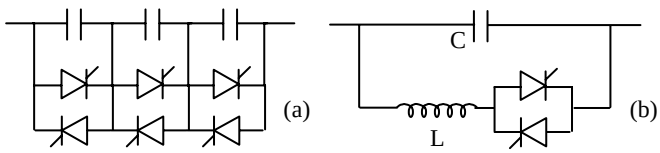


Figure 9.7. *Series compensation (a: capacitors with electronic switches, b: system with controller)*

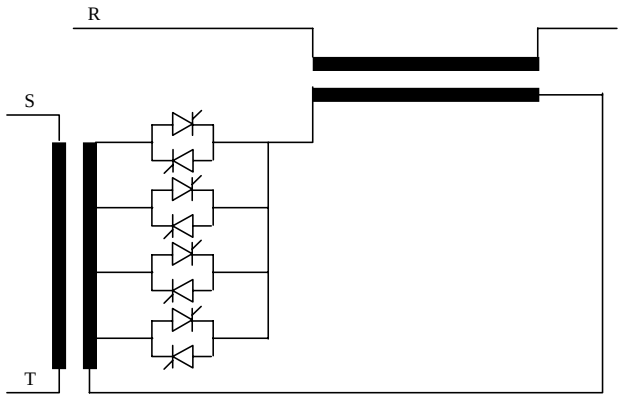


Figure 9.8. *Phase shifting transformer with electronic switch*

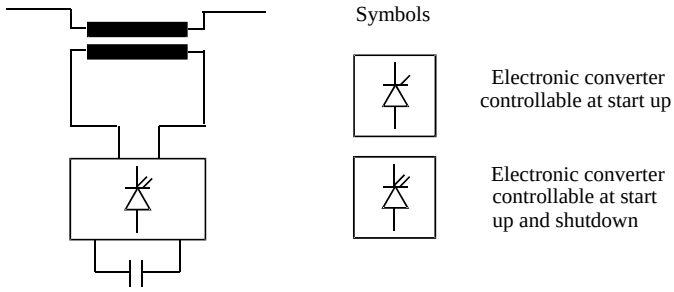


Figure 9.9. *Series compensator with electronic converter*

9.4.2. *Parallel or shunt type controller*

In this case variable impedance or source are still in question but connected in parallel in the link. The action principle is reduced this time on the injection of a current in the link at the connecting point of the controller. All shunt controllers will thus, from a functional point of view, be modeled by a variable current source. As long as the injected current remains in quadrature with the voltage at the point of injection, the controlling device supplies or absorbs only reactive power. In practice, we find the same systems as for series compensation: adjustable inductances and capacitors, varying impedance by a controller (widely used system and commonly known as SVC) and variable voltage sources established by electronic converters. A step down transformer is generally used for the connection of shunt controllers. Only electronic type systems will be described in greater detail.

Contrary to series compensation, which acts specifically on the link in which it is inserted, shunt compensation acts on the node to which it is connected and thus on the entire set of links that are connected to the node.

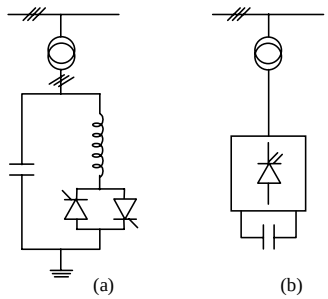


Figure 9.10. *(a) Reactive power static compensator with controller, (b) static compensator with converter*

9.4.3. *Compensators of series-series and series-shunt types*

These types of compensation with a combination of compensators only concern controllers using electronic converters. They are proposed by Laszlo Gyugyi and consist of two categories: that which proceeds from coordination of the control of several compensators and that with active power exchange between compensators through a direct current link. In this last category we find an association of series compensators from several lines known as an interline power flow controller, represented in Figure 9.11 and the bringing together in a single device of a shunt compensator and a series compensator connected by a direct current link. This last system known as UPFC (unified power flow controller) or universal power regulator is in the diagram in Figure 9.12. It constitutes a very effective system and is already in use (see section 9.8).

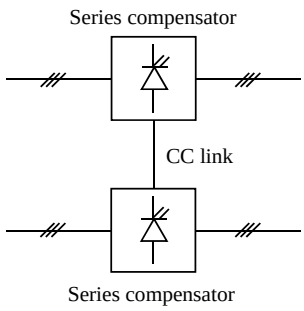


Figure 9.11. *Interline power flow controller (IPFC)*

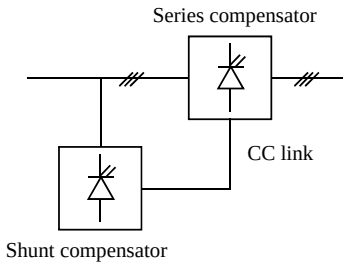


Figure 9.12. *Unified power flow controller (UPFC)*

9.5. Improvement of alternator transient stability

9.5.1. *Introduction to transient stability*

In section 9.2, we have already shown that the links were never at the maximum transferable power corresponding to a 90° transmission angle but at a weaker power corresponding to transmission angles of about 30° to 40°. This limitation is carried out, in case of serious disturbances in the network, to preserve the synchronous operation, called transient stability, of alternators connected to the network. During a fault in the network, the alternators have the tendency to be accelerated under the effect of the imbalance between the driving mechanical torque, practically constant in the duration of the phenomena in question, and the electromechanical torque related to the electric power supplied to the network, which is reduced almost instantaneously under the effect of the fault. In reality, these imbalances lead to oscillations around the synchronous operation of frequencies typically of about a few tenths to a few hertz. These oscillations can lead to losses of synchronism. It is therefore important to reserve a margin of transferable power to decelerate the alternators after a fault, and to allow them to regain stable operation in synchronism after a few oscillations.

The determination of the degree of severity of a fault beyond which synchronism is lost is a major problem in the control of electric power systems. The study of dynamic behavior of power systems after a large disturbance is called transient stability, and is the subject of Chapter 7. The disturbances generally result from incidents in the network such as short circuits.

The value of electromechanical torque applied to the alternator shafts in transients depends on the laws of magnetic flux and current variations, and can only be determined by the integration of the complete system of dynamic equations of the machines, called two-axis equations or Park's equations. Furthermore, following a

disturbance in the network, all the generators are affected to various degrees and there is an interaction between them through the links of the network. The dynamic behavior of the latter can be determined by numerical calculation with the help of specialized software such as EUROSTAG which is discussed in Chapter 8. This conventional time domain method of assessing transient stability does not however make it possible to elaborate the control tools in preventive mode, let alone in corrective mode. This is why "non-conventional" methods of analysis of transient stability have been developed. These methods are the subject of Chapter 7. However to physically interpret the phenomena, we can always consider that transient behavior of a machine in the network remains similar to that of a mass suspended by a spring and build a simplified model. This approach, described in the next section, enables the assessment of the FACTS effect on transient stability by idealizing their control. Any device capable of modifying active power exchange in the network makes it possible to improve transient stability in as much as it reacts faster than the speed of electromechanical oscillation of alternators, i.e., in a tenth of a second. FACTS can very easily respond to this requirement and are useful means to improve transient stability. Even though the method of qualitative study of the effects of control devices on transient stability constitutes an investigation tool generally used in the first instance, in practice, we must insist upon the necessity in all cases to proceed in the second instance to study, taking into account the real behavior of machines and regulating laws for controlling devices.

The study to be carried out is of two types, corresponding to different frequency domains. The first, in which FACTS are modeled in the form of synthetic functions, has the aim to study the effects on the dynamic behavior of the network and establish control strategies. This type of study is based on the hypothesis of the so-called first harmonics or quasi-stationary states and essentially treats power exchanges. Fundamental to the regulation and control of networks, it is the main subject of Chapters 7 and 8.

The second type of study aims to examine the internal operation of FACTS, at the component level and their control, to evaluate in particular the constraints on these components. It takes into consideration the entire set of harmonics. It concerns a constructor's approach more than a user's and particularly uses software such as ATP, EMTDC, MATLAB/SIMULINK, SIMSEN, SIMPLORER and others.

9.5.2. *Simplified study of transient stability by area criterion*

We consider a single generator connected to a very stiff network, also called infinite, for which it can be supposed that the voltage is constant in amplitude and in phase. In practice, this hypothesis is based on a network consisting of a large number of machines whose sum of power is very significant compared to the power

of one of them. In this respect, it can be noted that the loss of 3,000 MW in the European UCTE network in normal operation can only result in one frequency variation of about 180 mHz or 0.36% with relation to 50 Hz and in a transient conditions this variation cannot exceed 800 mHz. By adopting traditional simplifying hypotheses in transient stability, called quasi-stationary states or first harmonics, the electric model of the synchronous machine can be reduced to a simple dipole made up of the serialization of an electromotive force with a so-called transient reactance using IEC terminology. These elements are denoted E' and X' and lead to the diagram with phasors in Figure 9.13.

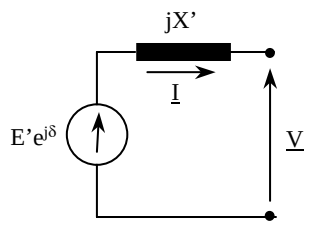


Figure 9.13. *Simplified model of a synchronous machine in transients*

The electromotive force $\underline{E}'$ is determined by the relation:

$$\underline{E}' = \underline{V} + jX'\underline{I} \qquad [9.9]$$

in which $\underline{V}$ and $\underline{I}$ are the voltage at the generator terminals and the current flowing out the generator respectively.

Angle δ between the voltage and the electromotive force, or the internal angle, is equivalent to the transmission angle in that it determines the exchange of power between the machine and the network. Physically, it is at a constant near the angle between the magnetic axis of the alternator rotor and a synchronous signal synchronized with the network operating at synchronism. For more details on this modeling, the reader may consult books that specifically deal with transient stability of power systems.

In the case where the generator is connected to network voltage $\underline{V}_r$ through reactance X_e, the earlier equation is generalized:

$$\underline{E}' = \underline{V}_r + j(X' + X_e)\underline{I} \qquad [9.10]$$

The supply of active and reactive power by the generator is governed by expressions of the type in [9.1] and [9.2] and especially for active power it is expressed by:

$$P = (E'Vr/(X'+X_e))\sin\delta \qquad [9.11]$$

with angle δ between $\underline{V}_r$ and $\underline{E}'$.

We assume furthermore that the magnetic flow in the excitation circuit of the machine is maintained at its initial value before the appearance of the disturbance during the entire transient operation, which is translated by the constancy in amplitude of the transient electromotive force E'.

We shall finally suppose that the mechanical driving torque remains constant despite the fact that it can be reduced through fast control, especially by fast valving in the case of steam turbines.

Finally, it is assumed that the variations of angular rotation speed of the machine are negligible in comparison with synchronous speed:

$$d\theta/dt = \omega + d\delta/dt \cong \omega \qquad [9.12]$$

with angle θ referring to the position of the rotor with relation to a fixed reference and ω synchronous speed.

The equation of equilibrium for the rotating masses is written:

$$Md^2\theta/dt^2 = Md^2\delta/dt^2 = C_{acc} \qquad [9.13]$$

where M is the acceleration constant defined by $M = 1/p^2(PD^2/4)\omega/S$ in the case where torque and angle are respectively in reduced quantity and in radians. S represents the apparent nominal power, p the number of pairs of generator poles and $PD^2/4$ the inertia moment of the generator (alternator + driving machine).

C_{acc}, acceleration torque in reduced quantity, is the difference between the mechanical driving torque and the electric torque.

The product $C_{acc}d\delta/dt$ represents the instantaneous acceleration power and kinetic energy accumulated during the course of the acceleration is expressed by the integral $\int C_{acc}d\delta$.

The electrical torque is calculated by relation [9.11] as, in reduced value, we can assimilate the torque with the power since the speed is assumed constant. The kinetic energy accumulated during the acceleration or deceleration is measured

simply by the corresponding areas in the diagram expressing the torque based on the angle δ (see Figure 9.14).

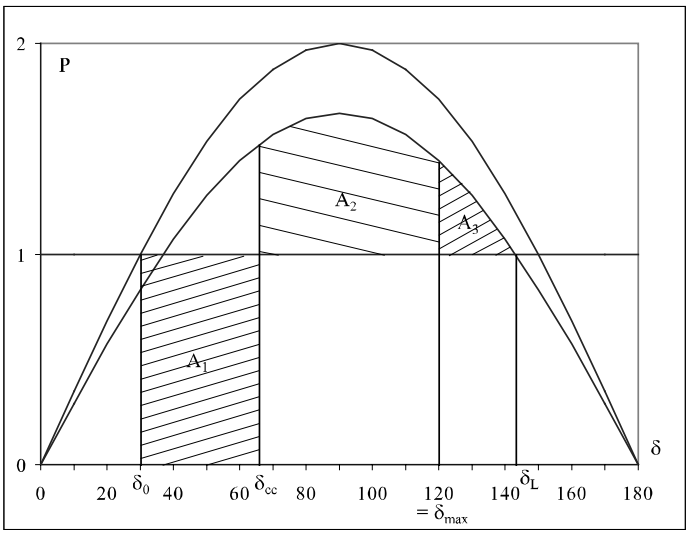


Figure 9.14. *Criterion of areas and stability margin*

The so-called area criterion consists of verifying that area A_1 corresponding to the acceleration period between the moment of the appearance of fault at internal angle δ_o and the moment of its elimination at internal angle δ_{cc} is less than the area during which the machine can decelerate. If this is the case, the stability is considered as assured, i.e., that the machine will regain synchronous operation. Implicitly, this amounts to saying that the stability is assured once the angle of the machine goes past a maximum and the area criterion is sometimes also called the criterion of the first oscillation (first swing stability). In practice, however, the loss of synchronism generally occurs after several oscillations. We have considered it useful to develop this section because this simplified theory and area criterion are very effective tools to understand the phenomena under consideration, even though they only constitute a quantitative approach that is often far from reality.

9.5.3. *Study of an application case*

Let us consider, for the sake of application, the case of an alternator connected to an infinite network, through a transformer and two lines in parallel, as in Figure 9.15. The parameters of this example are (in reduced quantities): $X' = 0.3$, $X_T = 0.1$, $X_{L1} = X_{L2} = 0.2$ and we have conditions where $E' = V_r = 1.0$ and where the alternator

supplies unit power to the network. The E' = V_r hypothesis has been adopted in order to obtain, for reasons of symmetry, simple expressions to describe power exchange and evaluate the effects of different systems of compensation in transient stability.

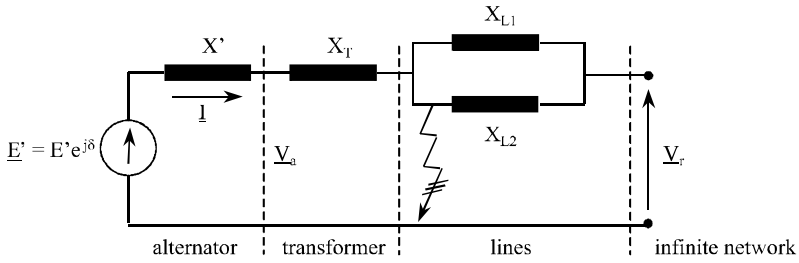


Figure 9.15. *Single phase diagram in transient of an alternator connected to the network*

Let us suppose a fault that consists of the appearance of a three-phase short circuit at the terminals of line 2 at the alternator side, followed by the elimination of this line after some time. The operating conditions before the fault make it possible to calculate the phase of E' with relation to system voltage, it is $\delta_0 = 30°$, as well as the magnitude of the voltage V_a at the alternator terminals and its phase with relation to the network, respectively 0.967 and 11.93°. The current supplied by the alternator has amplitude of 1.035 and is deviated by 15° ahead of V_r. These quantities are represented in the vector diagram in Figure 9.16 let us note that the electromotive force E' and the voltage V_r each supplies reactive power of 0.268 to cover the reactive power of 0.536 ($0.5I^2$) consumed by the entire set of reactance in the circuit.

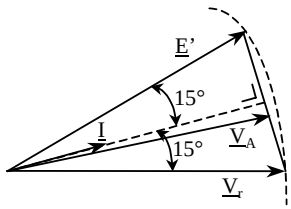


Figure 9.16. *Vector diagram related to the system operation before the fault in the circuit in Figure 9.15*

Figure 9.14 shows the application of area criterion in this case of fault. Area A_1 represents the kinetic energy stored during the short circuit.

Once line 2 is eliminated, the alternator can deliver energy to the network once again and is subjected to deceleration torque. Angle δ_{max} represents the maximum value reached by angle δ, characterized by the equality of areas A_1 and A_2. This equality of areas signifies that all additional kinetic energy accumulated during the acceleration period has been completely absorbed by the braking. Area A_3 represents what is agreed upon as the stability margin. The critical clearing time of the fault is defined as leading to a zero stability margin, in which case δ_{max} reached is the limit angle δ_L.

In the case of the diagram, a launching time of 10 seconds has been taken for the generator and a clearing time for line 2 of 0.2 seconds after the appearance of the fault has been selected. This leads to an angle δ_{cc} of 66° at the moment of elimination of line 2. The braking time sees a reduction of voltage in the link, an increase in current and reactive power supplied by the network based on angle δ.

The exchange of electric power obeys the two following laws respectively for normal operation and during braking time:

$$P = 2\sin\delta \qquad [9.14]$$

$$P = 1.667\sin\delta \qquad [9.15]$$

9.5.4. *Improvement of transient stability by ideal shunt compensation*

In the case of the application in the earlier section, let us examine the effect of an ideal shunt type compensator located between the alternator and the transformer i.e., in the middle of the link after the elimination of line 2. This compensator is supposed to rigorously maintain voltage V_a constant at the nominal value at the connecting point.

The transferable electric power after the elimination of line 2 now obeys the relation:

$$P = 2(V^2/X)\sin(\delta/2) \qquad [9.16]$$

For the example in question, we obtain:

$$P = 3.333\sin(\delta/2) \qquad [9.17]$$

This compensation mode amounts in fact to a reduction of half the value of the reactance of the link and participates in the “segmentation” principle that has been discussed earlier.

The increase in active power able to be transmitted during the braking time requires the supply of significant reactive power by the compensator, given by the following relation:

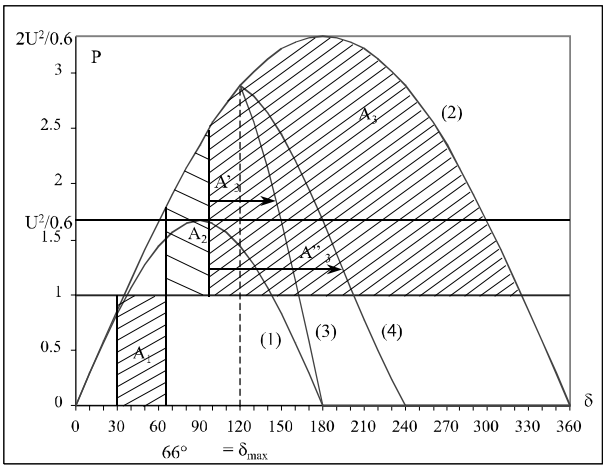
$$Q = 4(V^2/X)(1-\cos(\delta/2)) \qquad [9.18]$$

In the case under consideration:

$$Q = 6.667(1-\cos(\delta/2)) \qquad [9.19]$$

The value of this reactive power can reach eight times the maximum active power that can be transmitted by the uncompensated link and is four times this power when the active power transmitted by the compensated link is maximal ($2V^2/X$ for $\delta/2$ equal to 90°).

During the braking time, the law of transmittable electric power with compensation based on angle δ is taken up in Figure 9.17, which also shows the increase in stability margin A_3. Such a system requires a compensator with significant reactive power, up to 3.33 in the considered case. This sort of investment is not realistic from an economic point of view. Furthermore, the necessary capacitor to supply such reactive power can lead to phenomena of subsynchronous resonance. In practice, the compensators have limited action which reduces their effect on transient stability (see the following sections).



(1) without compensation (3) compensation with limitation (δ_{max} = 120°), type SVC
(2) ideal compensation (4) compensation with limitation (δ_{max} = 120°), type SVG

Figure 9.17. *Improvement of transient stability by shunt compensator*

Figure 9.18 presents a diagram of a compensated system as well as a vector diagram.

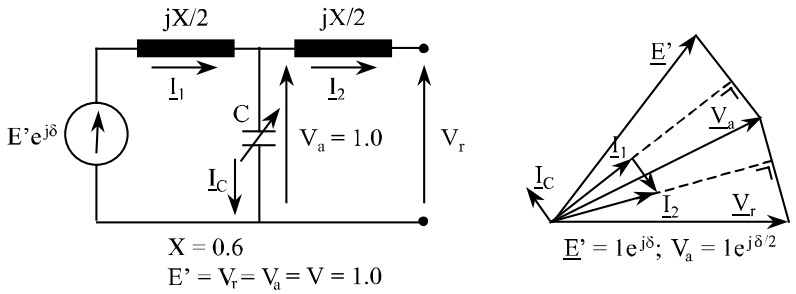


Figure 9.18. *Diagram with shunt compensator and corresponding vectorial diagram*

9.5.5. *SVC type shunt compensator*

As compensation is limited for both economic and security reasons, the real compensators are characterized by a maximum capacity C_{max} on the basis of which they no longer regulate voltage at the connecting point. They are then working on the circuit as a capacitance of a constant value. In this case the transferable active power obeys the following relation:

$$P = (V^2/X)[1/(1-\omega C_{max}X/4)]\sin\delta \qquad [9.20]$$

This expression is deduced easily from the Thévenin diagram of the circuit with fixed compensation, given in Figure 9.19.

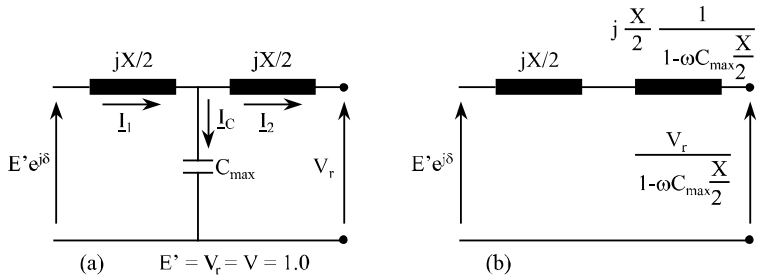


Figure 9.19. *Circuit with fixed compensation of SVC type and corresponding Thévenin diagram*

At the regulation limit, the value of C_{max} corresponds to a value of δ that we denote by δ_M and we can write:

$$Q_{max} = 4(V^2/X)(1-\cos(\delta_M/2)) = \omega C_{max} V^2 \quad [9.21]$$

From this we deduce the law of C_{max} based on δ_M as well as another expression of active power:

$$1/\omega C_{max} = X/(4(1-\cos(\delta_M/2))) \quad [9.22]$$

$$P = (V^2/X)\sin\delta/\cos(\delta_M/2) \quad [9.23]$$

The table below is related to relation [9.22], the value of Q_{max} being the same as that of the maximum current of the compensator.

δ_M (°)	Q_{max} (p.u.)	$1/\omega C_{max}$ (p.u.)
66	1.08	0.93
90	1.95	0.51
100	2.38	0.42
120	3.33	0.30
140	4.94	0.20

Table 9.5. *Design of the compensator on the basis of the limiting angle of action δ_M*

Figure 9.17 shows the evolution of the power transmitted in the application example discussed with a regulation limit corresponding to an angle of 120°, as well as the corresponding stability margin A'_3. We observe a very great reduction of this margin in relation to that with the ideal compensator.

In operation beyond the regulation limit, the voltage at the connecting point of the compensator decreases rapidly. Still considering the application, characterized by voltage at the extremities of the link with the same amplitude ($E = V_r = V$) and with the compensator connected in the middle of the link such that the latter only exchanges reactive power with the link, the voltage $\underline{V}_a$ at the connecting point has a phase shift equal to half of the transmission angle δ. We thus obtain the expressions $\underline{V}_a = V_a e^{j\delta/2}$ and $\underline{I}_c = I_c e^{j(\delta/2+\pi/2)}$ for the voltage at the connecting point of the compensator and the current absorbed by it respectively.

The amplitude of V_a, in the limiting period of the compensator, is determined very simply with the help of the relation:

$$P = (2VV_a\sin(\delta/2))/X \qquad [9.24]$$

in which P is the active power transmitted by the link given by [9.23].

By way of example, in the case of an SVC with δ_{max} of 120°, voltage $\underline{V}_a$ falls to 52% for a 150° transmission angle.

9.5.6. *Shunt compensation with SVG (static var generator) compensator*

This system acts like a real synchronous rotating compensator. It is like the previous system subjected to a limitation. This limitation is on the compensator current which cannot exceed a maximum value I_{cmax}.

Within this limit, the system behaves like an ideal compensator and the transmittable power by the link is clear from [9.16] while its current is given by [9.25] here below.

$$I_c = (4V/X)(1-\cos(\delta/2)) \qquad [9.25]$$

At the current limit, we observe:

$$I_{cmax} = (4V/X)(1-\cos(\delta_M/2)) \qquad [9.26]$$

δ_M being the phase angle for which the compensator reaches its limit in the current. Beyond this limit, the compensator acts as a constant current source, responding to the expression:

$$\underline{I}_c = I_{cmax}\, e^{j(\delta/2+\pi/2)} \qquad [9.27]$$

in the hypothesis adopted where the compensator only exchanges reactive power with the link. The system is thus represented by the diagrams in Figure 9.20.

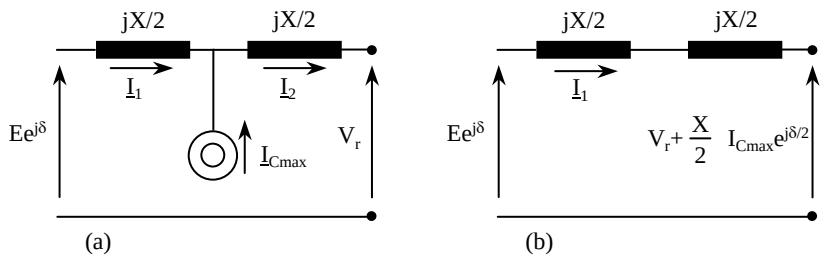


Figure 9.20. *SVG in current limitation, general diagram and Thévenin diagram*

From the Thévenin diagram, we easily deduce expression [9.28] for the power transmitted by the link when the compensator operates within limitation.

$$P = (V^2/X)\sin\delta+(VI_{cmax}/2)\sin\delta/2 \qquad [9.28]$$

Figure 9.17 shows the evolution of this power for a current limit corresponding to an angle δ_M of 120°, as well as the corresponding stability margin A''_3 for the same application case as earlier.

This type of compensator is clearly more effective than the SVC in that, for the same compensator power, it clearly improves the stability margin more. For a 150° transmission angle the transmitted power is 2.44 as against 1.67 for the SVC with the same limitation δ_M = 120°. The voltage at the compensator is 0.76 as against 0.52, the value calculated by relation [9.24] as in the case of the SVC.

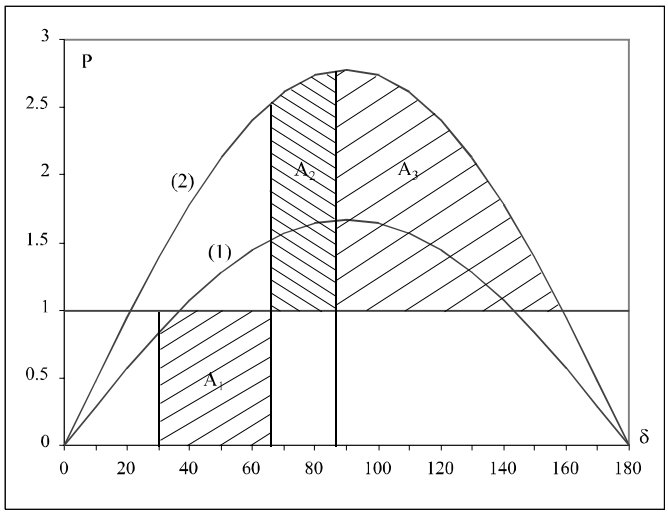
Relation [9.28] makes it possible to determine the transmission angle corresponding to zero power transmitted, as well as zero voltage at the compensator terminals. This angle is equal to 240° in the application under consideration.

9.5.7. *Series type compensation by modification of link reactance*

In the case of series compensation of link reactance, the expression for power that can be transmitted is given by:

$$P = (V^2/(1-k)X)\sin\delta \qquad [9.29]$$

with $0 \leq k \leq 1$, k being the compensation factor which, in practice, is limited to a value of about 0.4 to avoid subsynchronous resonance phenomena, which increases the transferable power to a maximum of 67%. The corresponding curves and the stability margin are given in Figure 9.21, still for the same application.



(1) without compensation, $P = (V^2/X)\sin\delta$ (2) with compensation (k = 0.4), $P = (V^2/(1-k)X)\sin\delta$

Figure 9.21. *Series compensation by modification of link reactance (k = 0.4)*

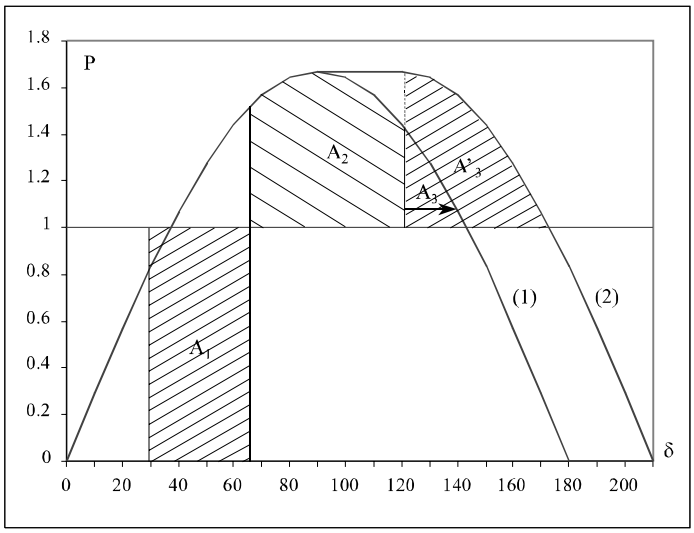
Such compensation in the considered case, X = 0.6 and k = 0.4, requires a design for the series compensator at $\Delta X I_{max}^2$ or, in our case, 3.71; the maximum current being 3.93.

9.5.8. *Series type compensation by modification of the transmission angle*

This modification operates with the help of a device that carries out an ideal phase shift of angle α, in such a way that the transferable power becomes:

$$P = (V^2/X)\sin(\delta-\alpha) \qquad [9.30]$$

The control of the phase shift makes it particularly possible to maintain the transferable power at its maximum value without compensation in a maximum range twice its maximum value of possible shift $2\alpha_{max}$. Figure 9.22 shows the application of this principle in our case of application with an ideal shift of $-30° \leq \alpha \leq 30°$.



(1) without compensation, $P = (V^2/X)\sin\delta$ (2) with compensation ($\alpha_{max} = 30°$), $P = (V^2/X)\sin(\delta-\alpha)$

Figure 9.22. *Compensation by ideal variation of the transmission angle (±30°)*

Such compensation only improves the stability margin relatively slightly. Furthermore, this compensation system implies an exchange of active and reactive power with the link at the same time, even in the ideal case under consideration. The application of this type of compensation concerns mainly the management of power transits to especially eliminate power loops.

9.6. Damping of oscillations

FACTS enabling the rapid modification of torque equilibrium acting on the shafts of the electric energy generator units, by modification of electric power exchanged between the nodes of the network, it is understood that they can play a role in the damping of oscillations (electromechanical oscillations and subsynchronous oscillations). Furthermore, such a role has been proved in the past by fast action on high voltage direct current links, predecessors of FACTS.

9.7. Maintaining the voltage plan

To maintain the amplitude of the voltage between certain limits is a major issue in the control of electric power systems where spectacular voltage collapses have highlighted its importance in the matter of security. As we have shown earlier,

reactive power compensation systems can contribute very effectively to voltage regulation. Such systems are already largely used for this purpose in many power systems in the world.

In the future, in a deregulated market, recourse to compensators and particularly to FACTS type compensators could be imposed in a more systematic manner. In fact, in this kind of market, the transmission system operator (TSO), responsible for maintaining voltage, no longer has direct control on generation units and thus on the supply of reactive power. It may prove to be more advantageous for the transmission system operator to invest in means of reactive energy generation itself rather than paying for the production of this energy by independent producers, especially since the compensators are capable of being moved within the network in response to modifications in the operating conditions, as is already the practice in England (see section 9.8).

9.8. Classification and existing applications of FACTS

There is a whole range of possible devices designated by acronyms that are a little confusing in nature. We present a glossary of these acronyms at the end of the section in an attempt at clarification. Certain devices are in service at present in normal operating conditions or in pilot applications, others are at the project stage. For a detailed description of the systems, we refer to specialized books such as [HIN 90], [HIN 00], [SON 99] and [LED 92].

We shall limit ourselves in this book, to briefly discussing the main systems used at present and dividing them into two categories, those that use the traditional thyristor as a power electronics component and those that use so-called fully controllable switching on and off components such as GTO (gate turn off thyristor), IGBT (insulated gate bipolar transistor) and IGCT (insulated gate commuted thyristor). The last component will, in all probability, succeed the GTO.

For each of the mentioned systems, we shall give existing applications across the world with their main characteristics, their location and operations.

9.8.1. *Classic systems with thyristors*

These systems comprise two classes.

9.8.1.1. *Hybrid systems*

This class, qualified by mixed or hybrid systems, is made up of conventional control systems (transformers with controllable tappings, phase shifting

transformers, capacitor banks) in which mechanical switches are replaced by electronic switches using the thyristor as the switching element. These systems have already been mentioned in earlier sections.

Let us point out, however, concerning hybrid phase shifting transformers, that a transformer of 1,500 MVA has been in operation for about 15 years in the 380 kV German electric power system. It makes it possible to avoid congestion in power transit of around 1,000 MW from the western part mainly to the southern part of the system but also to the northern part. The solution of a transformer was preferred to that of an HVDC station due to its lower cost [CIG 01].

Other transformers are installed in the German network: two phase shifting transformers of 220 kV, 300 MVA to connect the Obrigheim power station to the rest of the network and a transformer of 30 MVA.

Recently, capacitor banks in steps turned on or off by thyristor controlled switches placed in shunt have seen significant development to carry out series type compensation. They are known as TSSC (thyristor switched series capacitor) and are represented in Figure 9.23.

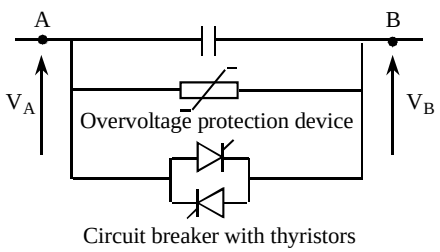


Figure 9.23. *Diagram of the TSSC principle*

Powerful installations of this type have been in operation in the USA, especially at the Kanawha River substation of the American Electric Power (AEP) network, since 1991 [CIG 97]. This installation, controlled manually from a control center, carries out the compensation on a 345 kV line from 0 to 60%, in steps of 10%, to prevent overload of this line and the parallel line of 138 kV in case of loss of a main 765 kV line. This 788 MVA and 2,500 A system consists of three fixed capacitors of 7, 14 and 21 Ω and a switching system with photothyristors placed in parallel on the 7 Ω capacitor.

9.8.1.2. *Systems with AC controllers*

This class uses a controller in alternating current to carry out varying reactance, controlled by thyristors, connected to a capacitor bank switched by thyristors.

Control of reactance is carried out through modification of the moment of turning on the thyristors. The capacitors are switched on by the operation of thyristors in ideal control switches, with turning off at the current passing zero and switching on at the voltage passing zero.

This structure is the basis of the following systems used in practice:

– the SVC to be placed in shunt in the circuit to be compensated;

– the TCSC (thyristor controlled series capacitor) also known as the ASC (advanced series compensator).

These last two systems are the subject of the two following sections given their importance.

9.8.1.3. *Static var compensator (SVC)*

The schematic diagram of an SVC is represented in Figure 9.24. These systems are now almost always made up of three separate inductances, cabled in delta connection and controlled independently by a current variator with thyristors, to enable a rebalancing of the network through differentiated action in each of the phases. A three-phase capacitor bank that can be controlled in steps, placed in shunt, completes the device.

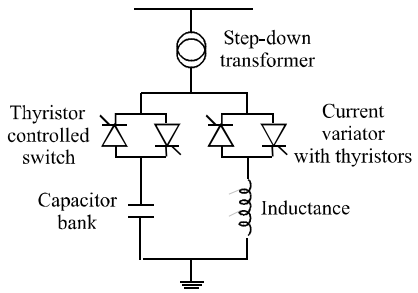


Figure 9.24. *Flow diagram of an SVC*

More than 200 SVC are in operation around the world in electric power systems of from 10 to 765 kV. The oldest date back to the 1970s. The main function of an SVC is to support the voltage, but it can also be used to reduce the phenomenon of

flicker in the presence of fluctuating loads (mills, light-arc furnaces, etc.), damp power oscillations and increase power transfer (through these two actions, it improves the static and transient stability margin) and reduce subsynchronous oscillations. The capacity of an SVC can vary from -300 to 800 Mvar in a continuous or discrete manner. The Hydro-Quebec network was one of the first to be equipped with this type of compensator in a long distance line.

Standardized SVC are present in the National Grid Company (NGC) system in England; they have a capacity of -75 to 150 Mvar obtained by a TSC of 110 MVA, a TCR of 115 Mvar and filters of 40 Mvar [REN 95]. Among the standardized SVC, there are two SVC, installed in 1992 at the Harker substation in the north of the English electric power system, whose specific aim is to increase static and transient stability margins in order to satisfy the planning standards in the case of an increase in power transfer from Scotland to England. The control mode of SVC is designed so as to make the total capacity of the SVC available for the improvement of transient stability.

There is also, at the heart of NGC, SVC that can be relocated, made up of transportable cabins containing valves with thyristors, control and protection systems as well as auxiliary sources of power. As far as reactance, capacitors and secondary transformers are concerned, they can be mounted outside on platforms that are easy to relocate. The NGC has developed two types of specifications to standardize the SVC that can be relocated. The first type enables a capacitive compensation rate of up to 60 Mvar, inductive compensation not being necessary for this type of SVC. The complete relocation from one site to another does not take more than three months and can occur up to 8 times in a lifespan of 40 years. The second specification enables capacitive compensation between 150 and 225 Mvar for electric systems of 400 kV and 275 kV. Complete relocation is possible in 6 months [DAV 95].

One of the most powerful SVC in the world is located at Forbes in the Manitoba-Minnesota transmission system in the USA [CIG 01]. Its commissioning has made it possible to increase by an amount of 200 MW the capacity of the transmission system. It consists of two TSR and three TSC. The capacity of the SVC can vary from 149 Mvar in continuous mode to 450 Mvar for 10 seconds every 30 minutes for inductive compensation and from 110 Mvar in continuous mode to 400 Mvar for 10 seconds every 30 minutes for capacitive compensation at 500 kV. Two capacitor banks, of 300 Mvar at 500 kV, switched mechanically and controlled by the same control system as the SVC, make it possible to carry the total reactive power at 1,000 Mvar for capacitive compensation.

The regulation characteristic generally adopted for SVC is shown in Figure 9.25. It is based on the measurement of the network voltage. The main disadvantage of

these devices is in their behavior outside the regulation zone where they act like constant reactance and present a compensation power proportional to the square of the voltage.

Furthermore, the current absorbed by the inductances is rich in odd harmonics. These harmonics are usually eliminated with the help of LC filters and the delta connection of the compensator makes it already possible to eliminate homopolar third order harmonics.

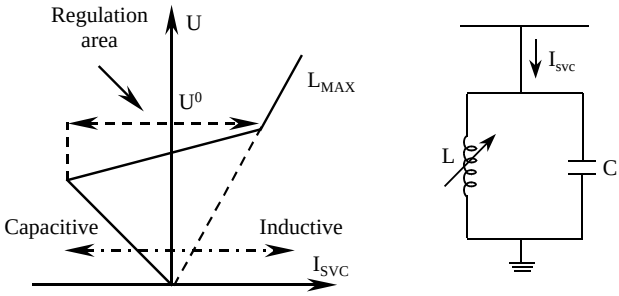


Figure 9.25. *Control characteristic of an SVC*

9.8.1.4. *Series compensator with parallel resonance circuit (TCSC or ASC)*

This system uses capacitors with fixed values placed in shunt with inductances controlled by a current variator with thyristors, so as to make the control continuous for capacitive or inductive compensation respectively beyond and within the resonance frequency. The flow diagram of such a system and its control characteristic are represented in Figure 9.26.

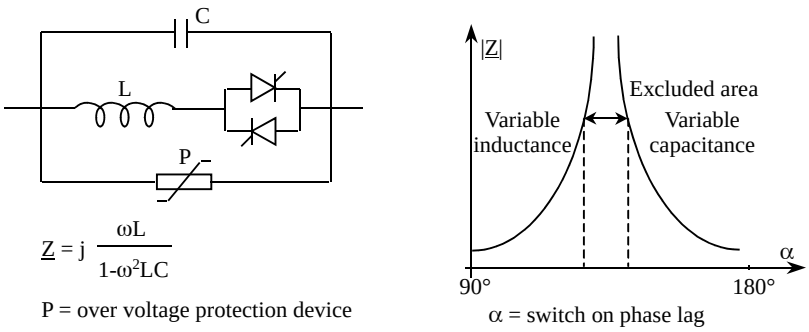


Figure 9.26. *Flow diagram of the series compensator with parallel resonance circuit and control characteristic (ASC or TCSC)*

At present in existing installations, only the part of varying capacitance is generally used. Control most often consists of slow control of power flow in cascade with fast control, for example of frequency deviation between interconnected areas to damp power oscillations [MPA 95].

TCSC has been used since 1993 at the Kayenta station of the Western Area Power Administration system in the USA in order to overcome a major congestion problem in the HV transmission system [CIG 97]. It makes an increase of 33% power possible in the 320 km at 230 kV line in which it is installed (from 300 to 400 MW). It supports the voltage at the station; it ensures flexible and continuous control of the level of line compensation and limits the fault current. This TCSC can help against subsynchronous oscillations. It is made up of two series capacitor banks of 165 Mvar and 100 A with a single phase impedance at 60 Hz of 55 Ω. One of the banks is controlled to carry out fixed series compensation of 55 Ω while the second is subdivided into a fixed segment of 40 Ω and a controllable segment of 15 Ω.

The TCSC, installed in 1993 at the Slatt substation of the 500 kV Bonneville Power Administration system in USA [CIG 97], is used for improving the transient stability through the power transit control of the line in which it is installed and for damping of subsynchronous oscillations. It has a capacity of 202 MVA and 2,900 A and it is made up of six identical modules of thyristor controlled capacitors of 1.33 Ω. Each module can operate according to three different states:

– bypassed capacitor: inductive state by total conduction of the valve with thyristors;

– capacitor installed without current in the valve with thyristors: capacitive state fixed at its nominal value;

– capacitor installed with current in the valve with thyristors: capacitive state that can be controlled in continuous manner.

The TCSC at Stöde in Sweden was installed in 1998 to obtain the desired level of compensation in a long 400 kV line linking the northern part of Sweden to the central part where the load is situated and thus prevent a risk of subsynchronous resonance [CIG 97]. It comprises a fixed section and a thyristor controlled section with a local controller using variables such as line currents or the capacitor voltage. The installation does not require human presence at the site and the control center is situated 400 km away from the site.

Two TCSCs have been present since 1999 in the interconnecting systems of the south-south-east and north-north-east networks in Brazil also consisting of a 1,020 km line of 500 kV and fixed series compensation of 54% divided into 6 banks to increase power transfer up to 1,300 MW [CIG 97]. Each TCSC procures 6% of series compensation in steady-state. Their presence is justified by the existence of

weakly damped low frequency oscillations. The TCSC have proved their ability to damp these oscillations whatever the situation, including those where there is a weak power transfer (<200 MW).

9.8.2. *Systems with fully controllable elements*

These systems use the resources offered by fully controllable power electronic components, making it possible to get sources of voltage or current whose amplitude and phase can be controlled.

The IGBT has seen significant development in the past 10 years. At present, it reaches limits of 6.5 kV in voltage and 2.5 kA in current. In the future, the IGCT could become the main component for high voltage power and replace the GTO [JAE 97].

Currently, for economic and performance reasons, the systems used in practice invariably use alternating current/direct current converters with a forced switching called voltage-sourced converters or VSC. In this type of converter, DC voltage has a fixed polarity and reversal of the direction of power transfer takes place with reversal of polarity of the direct current. The switching is organized according to the modulation technique of pulse width, called PWM (Pulse Width Modulation), so as to reduce the harmonics generated by the converters.

Figure 9.27 shows the flow diagram of a single phase voltage-sourced converter. We shall note the presence of a diode placed in antiparallel in each controllable element so as to ensure the bidirectionality of the current.

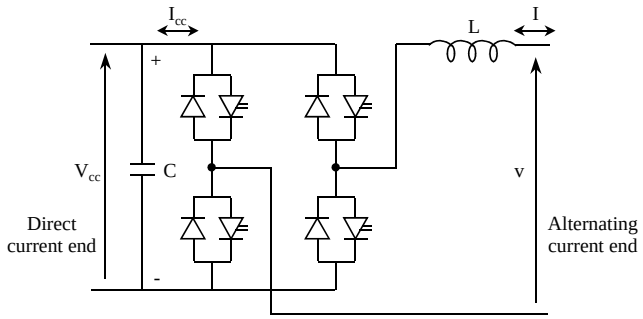


Figure 9.27. *Flow diagram of a single phase voltage-sourced converter*

In the following part, we shall use the symbol in Figure 9.28 to show a voltage-sourced converter.

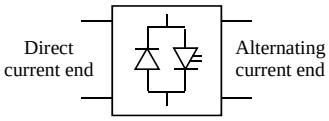


Figure 9.28. *Symbol of a voltage-sourced converter*

These converters that deliver alternating voltage with variable phase and amplitude can be placed in series or in shunt in a power system according to control requirements. The shunt compensation system is known under the names SVG and STATCOM. The series compensation system is called ASC. Another system called unified power flow controller or UPFC combines shunt compensation and series compensation (section 9.4.3). Finally, structures with two converters make it possible to carry out either series compensation, or shunt compensation, or a combination of these two types of compensation in different lines of the same corridor. They are called CSC for convertible static converter. An example of application of this structure is given in section 9.8.2.3.

9.8.2.1. *Advanced static compensator for reactive power (SVG or STATCOM)*

This carries out shunt type compensation, by acting like a real static synchronous compensator. It is made up of an AC/DC self-commutated converter, connected at the direct current side to an energy storage unit, a capacitor in the version called STATCOM, Figure 9.29.

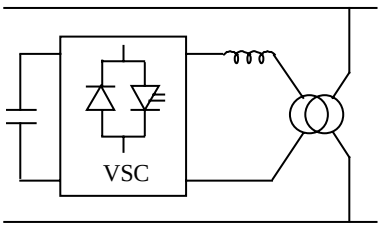


Figure 9.29. *Flow diagram of a STATCOM or SVG, reactive power static compensator*

The voltage at the alternating current side is in phase with that of the network so that there is only exchange of reactive power with the latter. The setting of the current and the direction of the reactive power exchanged is controlled by the value of the converter voltage. The operating principle is shown in Figure 9.30.

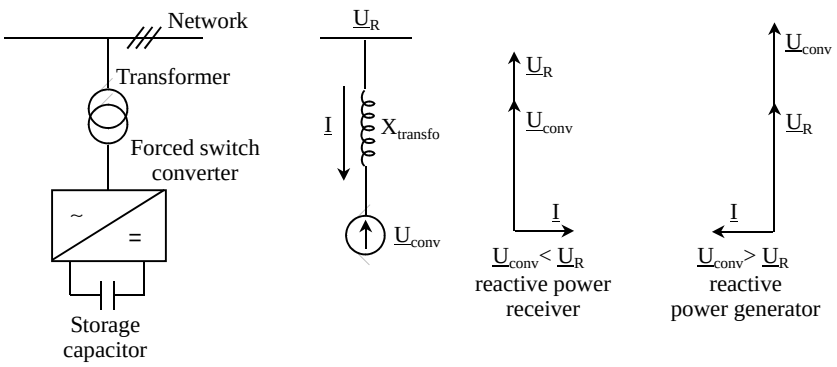


Figure 9.30. *Operating principle of the advanced shunt static compensator, STATCOM*

This system could also supply active power to the network and be of help by covering peak consumption, for example, and even become a real back up generator. For this, it is necessary to use a power storage unit, an electrochemical accumulator (battery) or a superconducting magnetic coil (SMES system for superconducting magnetic energy storage). In the future, such systems could be envisaged in networks with decentralized production to mitigate production vagaries.

These new devices have as their main advantages:

– reduction in the size and cost of fixed components;

– possibility of unlimited control of voltage as against the SVC. The maximum current exchanged is independent of voltage and maximum reactive power varies like the voltage. In classic SVC type compensators, this power varying as the square of the voltage, the system becomes completely ineffective in case of deep voltage drops;

– reduction in harmonics by using pulse width modulation techniques called PWM to organize the converter switching;

– high response speed, of about 10 times that of an SVC.

Several STATCOM installations are present in the Japanese networks for 22, 33, 66 and 154 kV. They ensure voltage control operations, compensation of fast variations in reactive load and control of power oscillations.

A STATCOM of ±100 Mvar has been installed at the Sullivan substation of the Tennessee Valley Authority (TVA) electric system in the USA since 1995 [EDR 00]. It is made up of a voltage-sourced converter with 2 levels at 48 pulses that combine eight three-phase bridges with 6 pulses with nominal power of 12.5 MVA

each. A step down transformer makes it possible for the converter to be installed in the 161 kV transmission line. The STATCOM set is held in a classic building with land area allowance of 27.4×15.2 m. A mechanically switched capacitor bank with a capacity of 84 Mvar makes it possible to extend the operation range of the STATCOM up to 184 Mvar in capacitive mode. This capacitor bank is controlled directly by the STATCOM in an emergency. The regulation of voltage at the 161 kV node by the STATCOM leads to reduced usage of the 1,200 MVA on-load tap changing transformer linking the 161 kV and 500 kV networks of the TVA and thus reduces the risk of an outage, the cost of which is estimated at one million dollars, for this transformer. Without the STATCOM, the TVA utility should have taken recourse to the installation of another transformer at the substation or the construction of a new 161 kV line, two expensive alternatives.

A STATCOM installation was designed for localization at the East Claydon substation of the 400 kV NGC network in England so as to supply additional compensation in the south [CIG 01]. The design was carried out in a manner as to be able to relocate the STATCOM to other substations of 400 or 275 kV networks. The complete installation comprises a STATCOM with a total capacity of 150 Mvar (75 Mvar in inductive and in capacitive), a TSC of 127 Mvar to supply additional power in case of a demand higher than the capacity of the STATCOM and a harmonics filter of 23 Mvar to prevent the installation from increasing the level of harmonic distortion already existing in the network. The STATCOM solution was preferred to an SVC due to less occupied volume and better performance in case of low voltage level.

Such a system can also be installed in series in a line to constitute a series type compensator, which enables the establishment of series voltage in the line. This is called ASC or SSSC (static synchronous series compensator). Its flow diagram is presented in Figure 9.31.

The voltage generated by the converter is in quadrature with the line current. If the system does not have an energy storage element, it acts like an angle shifter.

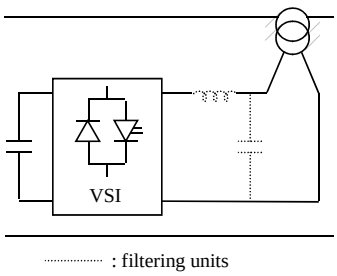


Figure 9.31. *Flow diagram of a series compensator with converter, ASC or SSSC*

9.8.2.2. *Unified power flow controller (UPFC)*

This is the most sophisticated FACTS system, proposed by Laszlo Gyugyi [GYU 91]. It consists, as shown in Figure 9.32, of two synchronous sources coupled with the network through transformers, one placed in parallel and the other in series, obtained by static converters having a storage capacity in common. The series voltage source is completely controllable in amplitude and phase. This converter draws its energy from the intermediate DC circuit, this latter being itself fed by the shunt converter that supplies active power absorbed by the converter and the losses and can, moreover, control the reactive power at point A.

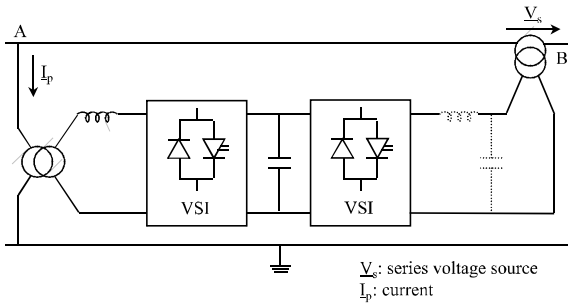


Figure 9.32. *Flow diagram of the unified power flow controller, UPFC*

The three-phase voltage converters each make it possible to independently control two quantities: currents i_1 and i_2 for converter 1 controlled in current, voltages v_1 and v_2 for converter 2 controlled in voltage. Each of these quantities that can be controlled constitutes one degree of freedom that can be used for system control. Thus, the three basic parameters of power transmission of a system namely, voltage, line impedance and phase shift can be independently or simultaneously controlled. The fourth degree of freedom is related to the maintenance of constant voltage at the capacitor terminals, in the absence of a DC source. The UPFC functionally carries out the combination of a static synchronous compensator (STATCOM) and a static series compensator. According to the control mode selected, we could have [LO 98]:

– either direct control of voltage by addition (or subtraction) of voltage in phase with the shunt node voltage and thus action mainly on reactive power;

– or a shunt compensator, by acting only on the voltage of the shunt converter to absorb or generate reactive power at the shunt node and maintain the voltage constant there;

– or a series compensator by inclusion of series voltage in quadrature with the current of the link and with a value such that only the voltage at extremity B is modified and thus mainly the reactive power at this node;

– or a phase shifter, if the series voltage is in magnitude and phase such that while maintaining the same magnitude of the voltage in B it reduces the phase shift of this latter voltage with relation to node A. The action will thus take place essentially on the active power through the line;

– or multiple function control, making it possible to control active and reactive power flow through the line.

The converters are traditionally of the PWM type with multiple levels to reduce the quantity of harmonics injected in the network, even though some research tends to show the advantage of the PAM (pulse amplitude modulation) type [THE 97].

A UPFC of 2×160 MVA has been in existence, since 1998, in a strengthening system made up of a high capacity double line, of the 138 kV AEP transmission system in the USA [EDR 00]. The role of the UPFC is to supply dynamic support for voltage at the Inez substation as well as an independent control of active and reactive power transits of the new high capacity link (an increase of more than 100 MW is possible in the power transfer). The aim is the optimization of the use of existing installations, the minimization of need for new equipments and the availability of transmission capability sufficient for future increases in load. The two converters, 3 levels with 48 pulses, can function independently of each other thus making three different operation modes possible:

– operation in normal UPFC mode;

– operation in STATCOM mode for the shunt converter and in mode static synchronous series compensator (SSSC) for the series converter;

– operation in STATCOM mode with a capacity of ±320 Mvar by connecting the two converters to the transformer of the shunt insertion.

9.8.2.3. *Convertible static compensator (CSC)*

An installation project at the Marcy substation of the New York system, of a CSC with a 200 MVA capacity has been under study since 1999 for the New York Power Authority (NYPA) [EDR 00]. This CSC, in operation since July 2004, plays for the first time the role of a STATCOM and, in the mid-term, it will act like a series compensation device. The objective is to increase the power transfer capability from 30 to 40% while ensuring transmission system reliability and power quality. The limits imposed on power transfer by voltage problems and power oscillations will thus be eliminated, the bottle neck situation will be removed and the transmission system losses will be reduced. In addition to the two operation modes already mentioned, three other modes are possible for CSC, as shown in Figure 9.33:

– operation as STATCOM with a capacity of ±200 Mvar;

– operation as ASC with a capacity of ±200 Mvar;

– operation as STATCOM with a capacity of ±100 Mvar and as ASC with a capacity of ±100 Mvar;

– operation as UPFC made up of two converters with a capacity of ±100 Mvar;

– operation as IPFC made up of two converters with a capacity of ±100 Mvar.

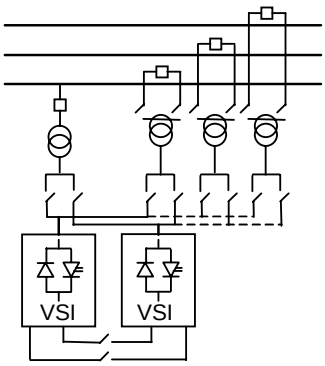


Figure 9.33. *Flow diagram of CSC at the Marcy substation*

9.8.3. *Glossary*

– CSC: convertible static compensator

– GTO: gate turn off thyristor

– HVDC: high voltage direct current

– IGBT: insulated gate bipolar transistor

– IGCT: integrated gate commuted thyristor

– IPC: interphase power controller

– MSC: mechanically switched capacitor

– MSSC: mechanically switched series capacitor

– PST: phase shifting transformer

– SC: series capacitor

– SSSC: static synchronous series compensator

– STATCOM: static synchronous compensator

– SVC: static var compensator

– SVG: static var generator

– TCBR: thyristor controlled braking resistor

– TCPST: thyristor controlled phase-shifting transformer

– TCSC: thyristor controlled series capacitor

– TSSC: thyristor switched series capacitor

– UPFC: unified power flow controller

– VSC: voltage source converter

9.9. Control and protection of FACTS

FACTS make up very fast actuators with relation to the phenomena which they are meant to act upon, thus their control laws play an essential role in their installation.

Given their potentials, these systems are used to simultaneously fulfill several functions: the main operations at low response speed such as the control of power transits in normal conditions, fast action operations in the improvement of transient stability, maintaining the voltage plan and damping of oscillations. Well coordinated control strategies, multiple functions and multiple variables, are to be established to use the full potential of FACTS.

Three aspects are to be considered in FACTS control:

– slow system control in steady-state for which the control settings will be obtained on the basis of the area control, coordinating especially different FACTS actions present in the area to prevent incoherent operation (resonance or chaos phenomena) [CLA 94]. An approach based on a learning system such as artificial neural networks [LO 98] can be effectively considered given the complexity of the problem to be resolved;

– fast control including coordination with other more conventional regulators such as PSS (power system stabilizer) [PAS 97] and AVR (automatic voltage regulator);

– coordination of the control laws of the different functions that each FACTS device must ensure so as to control the interactions [WAN 01].

Chapter 5 deals with this issue of control, especially with the use of control signals coming from distant sites to those where FACTS are installed (remote control).

A hierarchical control strategy seems obvious for FACTS devices. An example of such control is given in Figure 9.34 [DUP 97]. This strategy is inspired by the work of J.P. Hautier [HAU 95].

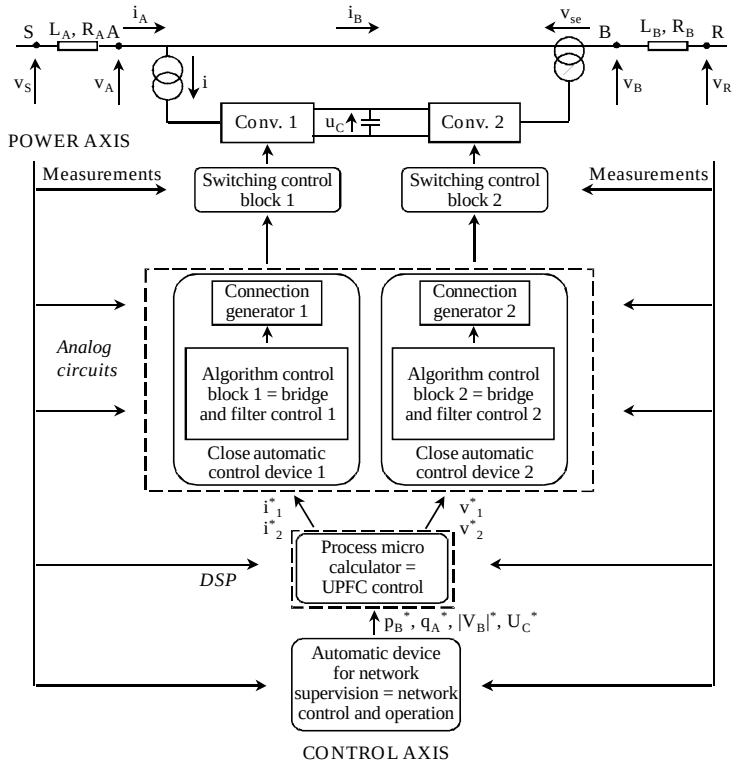


Figure 9.34. *General diagram of hierarchical control of a UPFC*

As far as protection is concerned, it is necessary to consider not only the protection of the equipment itself, especially converters, but also lines in which this equipment is installed. In particular, so-called classic distance protection based on impedance measurements (see Chapter 5) should take into account the apparent likely changes in these measurements due to FACTS systems (for example, by compensation of series impedance). They could have to be abandoned in favor of differential protection comparing the current at the extremities of the line and requiring a secure and fast telecommunications system between the line extremities. Incorrect operation of a protection can also counter the possibilities of FACTS [IEE 92].

9.10. Modeling and numerical simulation

The installation of FACTS in electric power systems most often requires study through numerical simulation so as to prepare for this installation. To do this, FACTS devices need to be modeled in the same way as the power systems in which they are installed.

The modeling of FACTS can present different levels of complexity depending on the objective of the numerical simulation. If the effects produced by the installation of a FACTS device in an electric power system are to be studied, the FACTS device will be modeled by a black box, representing the general operation of FACTS, with the input and output interfering with the network. On the other hand, if the numerical simulation is with the aim of designing the FACTS device by determining its constraints, the internal behavior of FACTS should be taken into account in the modeling.

This section deals with the modeling of a single FACTS device: the unified power flow controller or UPFC, considered the FACTS device with the most capabilities. Several models of UPFC used in the literature are presented by giving details on their structure, their control modes and the applications for which they are intended.

9.10.1. *UPFC modeled by two voltage sources*

The UPFC can be modeled by two voltages sources, one in series, and the other in parallel, as shown in Figure 9.35.

This type of model is used to find the apparent impedance of the UPFC seen through a protection relay of the line in which it is installed [DAS 00]. This makes it possible to study the influence of the UPFC and its localization in the fault detection method in a corridor with two lines linking two areas.

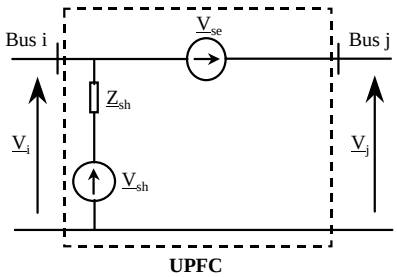


Figure 9.35. *Model of two voltage sources*

9.10.2. *UPFC modeled by a series voltage source and a shunt current source*

Figure 9.36 shows the model of the UPFC made up of a series voltage source and a shunt current source. The two sources can be coupled so as to establish a sequential approach with the aim of state estimation of power systems comprising FACTS devices and direct current links [QIF 00].

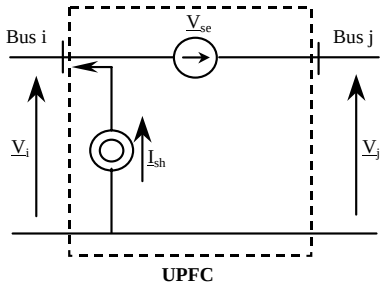


Figure 9.36. *Model of series voltage source and shunt current source*

The series voltage source can be selected to model the voltage introduced in the transmission line and the shunt current source can be divided into two parts: one modeling the compensation of shunt reactive power and the other modeling active power exchanged with the network. This type of model makes it possible to obtain load-flow equations, i.e. active and reactive power at the two nodes of the UPFC, which must be introduced into the resolution algorithm for load-flow so as to obtain the available active power margin for each branch of the test network selected for this paper [FAN 00].

This type of model can be selected as the control model for the UPFC [PAD 99]. The current and voltage sources are divided into real and imaginary parts:

$$\underline{I}_{sh} = I_{shp} + jI_{shq} \qquad [9.31]$$

$$\underline{V}_{se} = V_{sep} + jV_{seq} \qquad [9.32]$$

I_{shp} controls the DC voltage of the UPFC and I_{shq} controls the voltage of the shunt connection node. V_{sep} is intended to control the series voltage at the node whereas V_{seq} regulates the active power of the line. This control model is associated with a second model showing the UPFC in the network and made up of two coupled current sources whose settings are calculated based on $\underline{I}_{sh}$ and $\underline{V}_{se}$. These two related models make it possible to study the influence of the UPFC on the transient stability, damping of power oscillations being carried out by the control of the voltage introduced in series in the steady-state and during disturbances.

A variant of the model is obtained by adding impedance representing the reactive part of shunt compensation. This impedance is one of the three control parameters with the amplitude and phase of the voltage source. The shunt current source represents, for this type of model, the active part of the shunt compensation so as to obtain correct physical behavior of the UPFC. The article, [MIH 96], shows the capability of the UPFC to improve dynamic stability of a power system.

9.10.3. *UPFC modeled by two current sources*

The UPFC is modeled by two shunt current injectors coupled as shown in Figure 9.37.

The settings of the injected currents are calculated on the basis of variables of control of the UPFC, i.e., series and shunt voltage at the output of the two converters and on the voltages at the connection nodes of the two injectors. These current settings will depend on the objectives to be fulfilled by the UPFC since the control variables of the UPFC are the result of four regulation loops in the model which control the DC voltage of the UPFC and three parameters of the network: the voltage at the node of shunt connection, active and reactive power at the node of the series connection. This model is thus especially meant for the study of the effects on the network due to the presence of the UPFC. It is implemented in the Eurostag software [DUP 99]. This latter is a short and long term dynamic simulation software, which makes the hypothesis of the first harmonics (Chapter 8). The studies conducted with this model particularly show the capability of the UPFC to control a network with a low voltage level and the importance of the position of the UPFC at the heart of the network and also in its installation line.

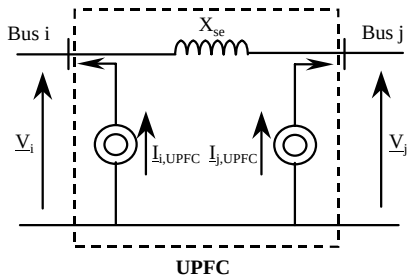


Figure 9.37. *Model of two current sources*

A UPFC model made up of two coupled current sources is also used in the PSASP software [LO 00]. It was selected for better modeling of the UPFC in the study of simulation of transient states. It also enables better representation of control

variables of the UPFC. A control strategy of general damping using the method of energy transient functions is associated with this model. The model makes it possible to study the effectiveness of the UPFC to damp low frequency electromechanical power oscillations.

A variant of this type of model consists of introducing one of the series current sources in the network [MA 00]. A centralized global control diagram using a hierarchical structure with three levels is meant to supervise several UPFC represented by this model so as to carry out regulation in real time.

9.10.4. *UPFC modeled by two power injections*

The model made up of two injections of power, shown in Figure 9.38, can be divided into rectangular components to carry out a study of power transit [SON 00]. Two control modes can be related to this model:

– open loop control when the control parameters of the UPFC are given and when the impact of the UPFC on the system is observed under different conditions;

– closed loop control in the case of control of the transit through a line and the voltage at node i by the UPFC.

Several UPFCs modeled in this way have shown, for simulations of a real network, their capabilities to balance the power transmissions and support the voltage profile.

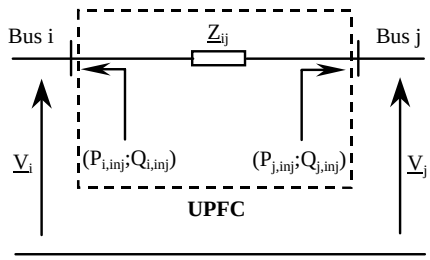


Figure 9.38. *Model of two injections of power*

The orthogonal components (P_{Iinj},Q_{Iinj}) and (P_{Jinj},Q_{Jinj}) of the pair of power injections in the model can be taken as control parameters. P_{Iinj} and P_{Jinj} control the active power of the line. Q_{Iinj} controls the voltage at the shunt connection node and Q_{Jinj} controls the series voltage and reactive power of the line. A local controller, driven by an algorithm of optimal power transit, enables the UPFC to satisfy the given settings by a central controller. The influence of the injection of reactive

power at node J on voltage at the series node, the reactive power of the line and the nominal power of the UPFC can be determined with this type of model [SON 00].

A model of active and reactive power injection can be derived from a model with two current injectors [SRE 00]. This model takes into account the dynamics of the direct current link of the UPFC and enables the introduction of equations governing the dynamic operation mode of the UPFC in the linear state matrix of the system. Two control modes are available for this model:

– the series converter controls the active power transit and the shunt converter regulates the voltage of the direct current link as well as the voltage of the shunt connection node;

– the series converter controls active power transit and the power of the direct current link while the voltages of the shunt connection node and the direct current link capacitor are controlled by the shunt converter.

This model makes it possible to assess transient stability, especially the damping of oscillations of the rotor angle of generators in a test network comprising two UPFC. The simulation carried out with the first control mode shows that the increase of the value of the capacitor of the direct current link favors the damping of oscillations.

9.10.5. *Internal models of the UPFC*

A mathematic model of the UPFC, based on a transformation of a three-phase system to a stationary orthogonal system or into a rotating reference frame, enables the study of the operation mode of the UPFC and the determination of its dimensions [PAP 00]. It shows the dependence between the operations of the series converter and the changes in the quantities of the shunt branch. It enables the study of characteristics, in steady-state, of UPFC operations with constant or variable DC voltage. Methods of designing control algorithms can be obtained with this model.

A state space model of the UPFC where only the low frequency part is taken into account after decomposition by Fourier analysis has been developed. The model must make it possible to construct a robust $H\infty$ controller to regulate the currents of the two converters of the UPFC subjected to disturbances in the electric system and unstructured variations in parameters. This $H\infty$ controller will make it possible to ensure UPFC operation security for a large number of operating conditions [VIL 00].

9.11. Future prospects

There is no doubt that FACTS will play a more and more important role in the future to resolve the problems of voltage quality, damping of oscillations, transfer repartition and management of power congestion, and finally stability. It is important to note that if these systems make it possible to extend transmission capabilities, they do not constitute substitutes for lines as such and, in this application, lead to a reduction of available reserves in case of an incident and thus to a certain weakening of the network. Temporary use required by particular circumstances can prove to be useful and be carried out by mobile devices.

Furthermore, power electronics systems easily accept complex control algorithms and are thus capable of carrying out several functions simultaneously (transit control and damping of oscillations for example).

For the generalized use of FACTS becoming a reality, there are still studies to be conducted, especially related to optimal location, protection, control strategies especially with remote control and a large degree of automation, the interaction between neighboring FACTS and with other control systems such as PSS.

If decentralized production is to play an important part, long distance transmissions could be reduced, but the necessity of transit repartition between interconnected areas and the exchanges between centralized and decentralized production would continue. Moreover, we can then also think of the use of FACTS systems in the distribution network (<30 kV) to compensate, for example, for the production risks related to renewable energy (wind, photovoltaic, etc.) and for voltage control and power quality. FACTS systems are thus well placed for development in the future, whatever the production scenario.

Applications of these systems are finally being considered in railway networks. A study of a fast compensator of voltage drops in substations has been the subject of a project in Europe, DGVII, at the initiative of SNCF with other European railway partners, universities and constructors [CRA 99], [CRA 01].

However, these power electronics systems are at present very costly, about 4 to 10 times that of traditional control equipment according to available data [CIG 01]. Conventional equipment costs specific amounts of about 10 EUR/kVA. The power electronics devices are as yet only installed where technical constraints make it necessary or if they are economically justifiable alternatives for power system reinforcements. However, there are indications that the prices could decrease with development in the field of power electronics and the increase of applications in a deregulated market.

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