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European Network of
Transmission System Operators
for Electricity

TECHNICAL BACKGROUND AND RECOMMENDATIONS FOR DEFENCE PLANS IN THE CONTINENTAL EUROPE SYNCHRONOUS AREA

26.10.2010

PREPARED BY THE SUB GROUP
“SYSTEM PROTECTION AND DYNAMICS”
UNDER
- REGIONAL GROUP CONTINENTAL EUROPE -

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ABSTRACT

This report presents technical recommendations and rules for automatic actions to manage critical system conditions to prevent the Continental Europe Synchronous Area or parts of it from the loss of stability and cascading effects leading to a system blackout. Stability problems are classified and demonstrated by major incidents. The subsequent chapters focus on the analysis of line protection systems during abnormal system conditions, the analysis of defence plan procedures in the CE synchronous area as well as world wide and requirements to generators. Finally the technical recommendations for a Continental Europe-wide defence plan are presented.

List of abbreviations:

CE Synchronous Area - Continental Europe Synchronous Area

ENTSO-E - European Network of Transmission System Operators for Electricity

ENTSO-E RG CE - ENTSO-E Regional Group Continental Europe

UCTE - Union for the Coordination of the Transmission of Electricity

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1 INTRODUCTION

The synchronously interconnected power systems of Continental Europe ensure a high level of security of supply in the most efficient way. The physical characteristics of the CE Synchronous Area form a “Backbone of Security”, which implies significant mutual help among the interconnected TSOs in a natural way. However, the favourable overall physical coupling of the system implies at the same time the risk of adverse effects on adjacent areas or even on the whole system, especially in case of extreme contingencies. The consequences of partial or total blackouts in the highly industrialised countries are enormous and minimizing the probability of such events as much as possible is of utmost importance.

The CE Synchronous Area was due to fundamental changes during last decades. The implementation of market rules, the increasing generation by renewables and the geographical extension of the system by the connection of new countries created and is still creating new challenges. An inevitable consequence of this development is the operation of the system closer to its limits with reduced safety margins. This leads to more severe consequences for the security of the system in case of contingencies beyond the design criteria. These facts became evident during the recent incidents in the CE Synchronous Area. Consequently it is obvious that there is the need for implementation and harmonization of measures against extreme contingencies in order to mitigate the consequences for the operational condition of the power system itself and its grid users.

It should be noticed that the planning of transmission networks has been performed separately by each TSO in a decentralized manner. In this regard binding rules exist in the frame of the security package of the CE Synchronous Area (Operation Handbook of ENTSO-E Regional Group Continental Europe, etc.). Moreover, planning and operating guidelines are being harmonized in respective ENTSO-E RG CE Subgroups. Particularly, the most credible contingencies affecting generating units or transmission system elements must not lead to (severe) consequences (e.g. interruption of supply) for consumers. Thus the planning and operating rules ensure that the power system will remain viable if one system element (generating unit, transmission line) is lost (so called n-1 rule).

However, beyond such credible contingencies, a power system may also experience more severe disturbances, resulting from multiple and simultaneous outages. Depending on the system conditions such disturbances can lead to emergency conditions with the risk of dramatic consequences. In such a situation the power system has to be prevented from the loss of stability and cascading effects including partial or total system collapse (blackout) by specific defence plans. Defence plans have been developed, and updated continuously by individual countries or TSOs. These plans include a set of measures, mostly automatic, to ensure fast reaction to large disturbances in order to contain their spread within the smallest possible network. The aim of this report is to provide technical recommendations for automatic actions to manage critical system conditions to prevent the CE Synchronous Area or parts of it from the loss of stability and cascading effects leading to major blackouts.

A crucial factor to maintain power system stability is that the power system has to be treated as a whole, i.e. including generating units and distribution networks. Nowadays, because utilities are no longer vertically integrated, the TSOs are responsible for the overall system security. However, they don’t have the adequate legal position towards generating units and distribution networks to fulfil their obligations as some important measures against loss of stability have to be implemented at generation or distribution level. In order to create a legally binding force for the implementation of effective defence plans by TSOs the recommendations of this document form the basis for the future development of technical standards and for the harmonisation of national Grid Codes.

2 CLASSIFICATION OF STABILITY PHENOMENA

2.1 CONTEXT

Power system stability has been recognized as an important problem for secure system operation since the 1920s and several major black-outs caused by power system instability have illustrated the importance of this phenomenon.

The purpose of this chapter is to define and classify the instability phenomena and to illustrate this classification based on examples of black-outs or large disturbances on large scale transmission systems in order to point out the reality of such phenomena and the necessity of a harmonised Defence Plan within the CE Synchronous Area.

2.2 CLASSIFICATION OF STABILITY PROBLEMS ACCORDING TO CIGRE

According to CIGRE definition the, “power system stability can be defined as the ability of an electric power system, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a physical disturbance, with most system variables bounded so that practically the entire system remains intact“[1].

Based on proper planning criteria, most modern power systems are able to operate safely and in a stable fashion for single or multiple common mode contingencies.

However, power systems are subjected to a wide range of disturbances, small or large. Small load, generation or topology changes without any faults occur continually and the system must be able to adjust to these changing conditions and operate satisfactorily. It must also be able to survive numerous disturbances of severe nature, such as short-circuit on a transmission line or loss of a large amount of generators even if the large disturbance may lead to structural changes due to cascading events and the isolation of the faulted elements.

Due to the speed of instability phenomena engaged, the necessity exists for proper automatic control actions or operator interventions. In this context, the analysis of such situations and the design of effective countermeasures can be highly assisted by an appropriate classification of power system stability problems, based on the following considerations [2]:

- The physical nature of the resulting instability;
- The size of the disturbance considered;
- The devices, processes, and time span that must be taken into consideration, in order to judge stability, and
- The most appropriate method of calculation and prediction of stability.

Such a classification scheme is depicted in the following Figure 1 and, in the following paragraphs, a short description of each stability problem is provided in accordance with CIGRE definition.

It must be noticed that such a classification is important for understanding the underlying causes of the problem in order to develop appropriate design and operating procedures, during large disturbances or black-out, all these instability phenomena can appear simultaneously or successively in a very complex manner. This is particularly true in highly stressed systems and for cascading events; as systems fail one form of instability may ultimately lead to another form.

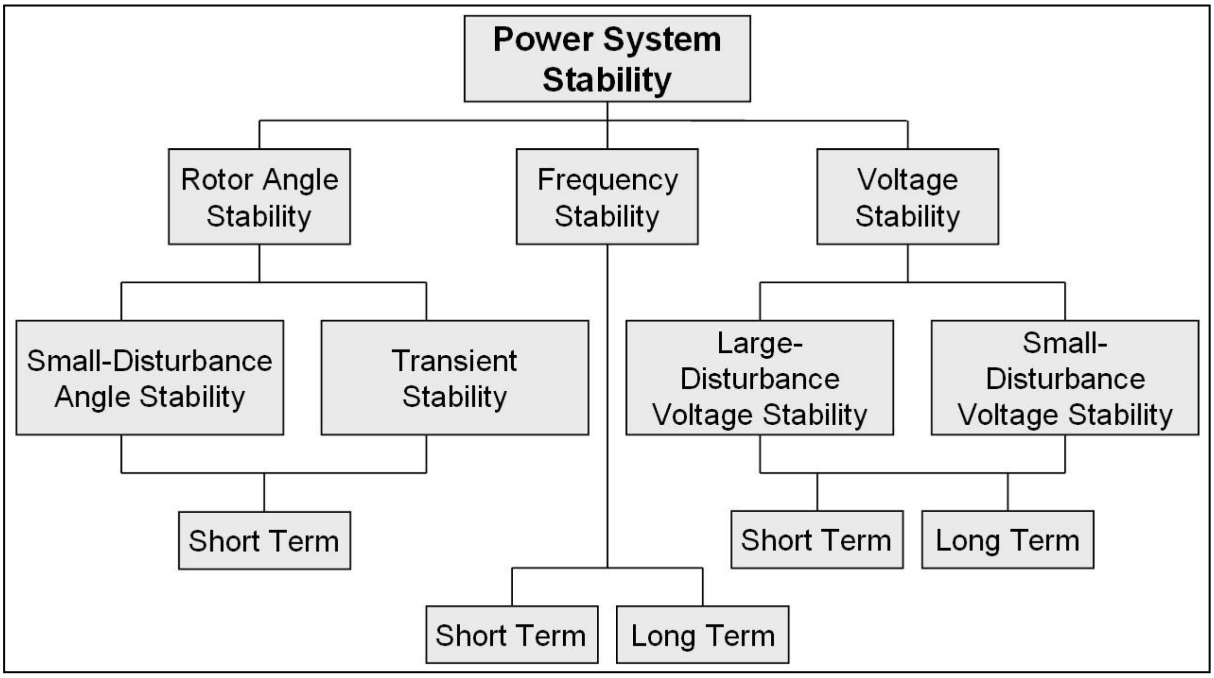


FIG. 2-1: CLASSIFICATION OF POWER SYSTEM STABILITY

2.2.1 ROTOR ANGLE STABILITY

Rotor angle stability refers to the ability of synchronous generators of an interconnected power system to remain in synchronism after a disturbance. It depends on the ability to maintain/restore equilibrium between electromagnetic torque and mechanical torque of each synchronous machine in the system and depends on the initial operating state of the system. Instability that may result occurs in the form of increasing angular swings of some generators leading to their loss of synchronism with other generators or aperiodical divergence of the angle between the machine (or the cluster) and the rest of the system.

The change in electromagnetic torque of a synchronous generator following a perturbation can be analyzed in two components, a synchronising torque component, in phase with rotor angle deviation, and a damping torque component, in phase with the speed deviation. System rotor angle stability necessitates the existence of both components. Lack of sufficient synchronising torque results in aperiodic or non-oscillatory instability, while lack of sufficient damping torque results in oscillatory instability.

Rotor angle stability problems can be divided in small-disturbance and transient stability sub-categories.

- **Small-disturbance (or small-signal) rotor angle stability**

For this sub-category of instability, a power system is considered stable if it is capable to maintain synchronism under small disturbances. The size of the disturbances (typically, white noise) allows the linearization of system equations for purposes of analysis. The stability problem is usually associated with insufficient damping of electromechanical oscillations.

Damping decreases if:

- Gain of exciter increases;
- The impedance seen from the plan increase;
- The Inertia of the unit is low;
- produced Active power increases
- The machine is underexcited

Small disturbance rotor angle stability problems may be either local or global.

The

⇨ Local problems concern a small part of the power system and are usually associated with rotor oscillations of a single power plant against the rest of the power system [0.8 → 2 Hz]. Such oscillations are called local plant mode oscillations.

⇨ Global problems are caused by the interaction among large groups of generators and have widespread effects. They involve oscillations of a group of generators in one area against a group of generators in another area. These oscillations are called inter-area mode oscillations [0.2→0.8 Hz].

- **Large-disturbance rotor angle stability or transient stability**

Transient rotor angle stability refers to the ability of the generators to maintain in synchronism after a severe disturbance (such as a short circuit on a transmission line or bus). Instability is usually in the form of aperiodic angular separation due to insufficient synchronising torque, manifesting as first swing instability. The time frame of interest in transient stability studies is usually 3 to 5 seconds following the disturbance and the resulting system response involves large excursions of generator angles and is influenced by the non-linear power-angle relationship. It may extend to 10-20 seconds for very large systems. Normally in large production pole, it is possible recognize a cluster of generators driven by a dominant machine this kind of phenomena can contrasted by:

- Fast valving protection adoption;
- As extreme solution, tripping the “dominant cluster generator” in way to decrease the local acceleration

As shown in Fig. 2-1, both types of rotor angle stability are classified as short –term phenomena.

2.2.2 FREQUENCY STABILITY

Frequency stability is related to the ability of a power system to reach and maintain a stable operating point (sustainable from generators) following a severe disturbance (resulting in a significant imbalance between production and consumption). Instability that may result occurs in the form of sustained frequency swings leading to tripping of generating units and/or loads or in an aperiodic transient.

In large interconnected power systems, this type of situation is most commonly associated with situations following splitting of systems into islands. Stability in this case is a question of whether or not each island will reach a state of stable operating equilibrium with minimum unintentional loss of load. It is determined by the overall response of the island as evidenced by its mean frequency, rather than relative motion of machines.

Frequency stability problems are associated with:

- inadequacies in regulation/control of power plants;
- poor coordination of control and protection equipment;
- unintentional protection trips leading to islands or high load-generation imbalance;
- out of step of plants;
- voltage instability;
- insufficient generation reserve respectively excessive power imbalance.

During frequency excursions, the time constants of the processes and devices participating will range from fraction of seconds (corresponding to the response of devices such as under-frequency relays and generator controls and protections) to several minutes, corresponding to the response of devices such as prime mover energy supply systems and load voltage regulators. In this sense, frequency stability may be a short-term or long-term phenomenon.

2.2.3 VOLTAGE STABILITY

Voltage stability refers to the ability of a power system to maintain acceptable voltages at all buses in the system under normal conditions and after a disturbance and depends on the ability of the system to supply the active and reactive load through the operating grid.

Instability that may result occurs in the form of a progressive fall or rise of voltages at some buses. A possible result of voltage instability is the loss of load in an area, or tripping of transmission lines and other elements by their protection systems leading to cascading outages. Another cause of instability can be the reaching of the limit in over or underexcitation; the first case is associated to voltage collapse phenomena. The second case typically arises when the impedance seen from the plant is approximately capacitive (i.e. during low load of the grid or after a large area load shedding); the reaching of underexcitation limit in the exciter drives the system to operate in an unstable point.

Loss of synchronism of some generators may result from these outages or from operating conditions leading to violation of field current limit.

Moreover, progressive drop in bus voltages is a phenomenon appearing due to rotor angle instability. As an example, the gradual loss of synchronism as rotor angles between two groups of machines approach or exceed 180° would result in very low voltages at intermediate points in the network, close to the electrical centre. The voltages near the electrical centre rapidly oscillate between high and low values.

A slow voltage collapse caused by load increasing, lack of reactive power and tap changer movements occurred during the incident on winter 1987 in France (Figure 2-4).

A fast voltage collapse caused by loss of angle stability occurred during the separation phase of Italy from UCTE (see Fig. 2-11).

The above issues show that a distinction between voltage and rotor angle instability is not always clear. However such a distinction is important for the understanding of the underlying causes of the problem and the development of appropriate design and operating procedures.

The driving force for voltage instability is usually the loads; in response to a disturbance, power consumed by the loads tends to be restored by the action of motor slip adjustment, distribution voltage regulators, tap-changing transformers, and thermostats. Restored loads increase the stress on the high voltage network by increasing the reactive power consumption and causing further voltage reduction. Voltage instability occurs when load dynamics attempt to restore power consumption beyond the capability of the transmission network and the connected generation.

As for the case of rotor angle stability a categorization to large and small disturbance voltage stability can be applied. In addition, because the time frame of interest for voltage stability problems may vary from a few seconds up to tens of minutes due to the fact that the dynamic of instability depends on high dynamic elements such as induction motors, electronically controlled loads, SVC, HVDC converters, voltage controller and limitations of generators so much as slower acting equipments as On Load Tap Changers, generator current limiters, thermostatically controlled loads or secondary voltage control, this phenomenon may be considered as a short-term or a long-term, according to Fig. 2-1.

2.3 DEMONSTRATION OF CLASSIFICATION BY MAJOR INCIDENTS

Taking into consideration the definitions and classification of different instability phenomena, the purpose of this chapter is to illustrate each one with recent large disturbances or black-outs which occurred on UCTE system or other large scale transmission systems.

The following figure presents the chosen incidents with their main corresponding instability phenomena:

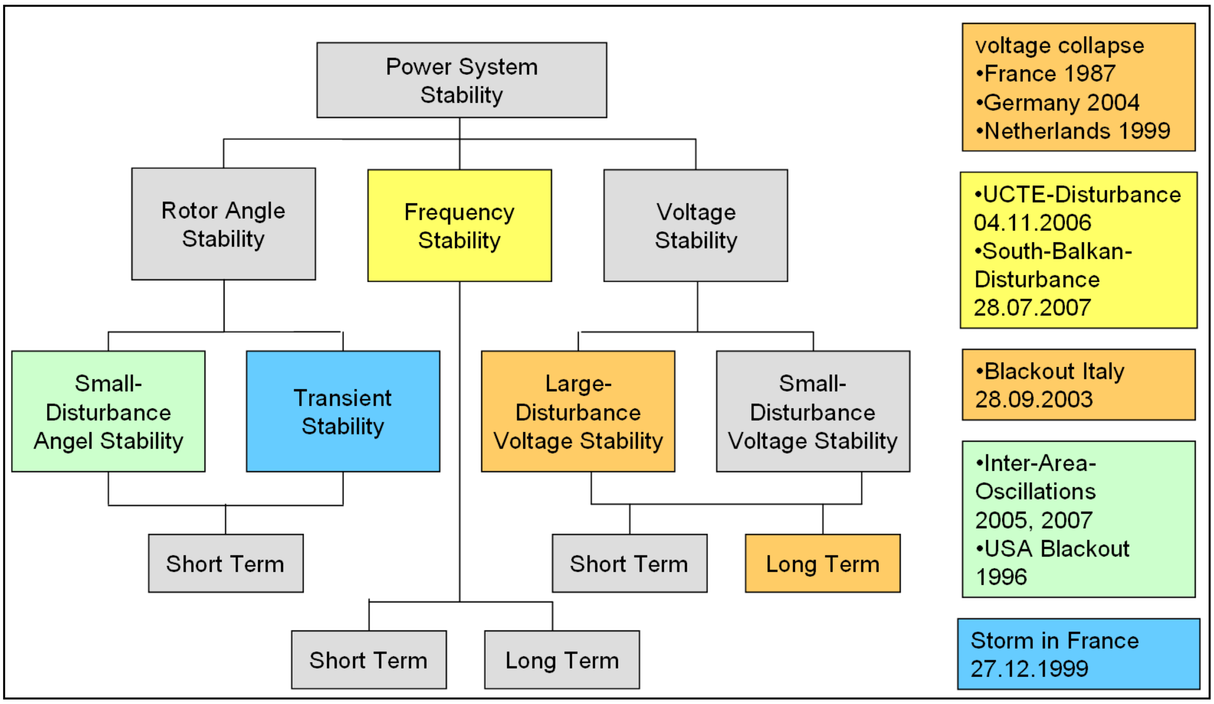


FIG. 2-2: ILLUSTRATION OF INSTABILITY PHENOMENA

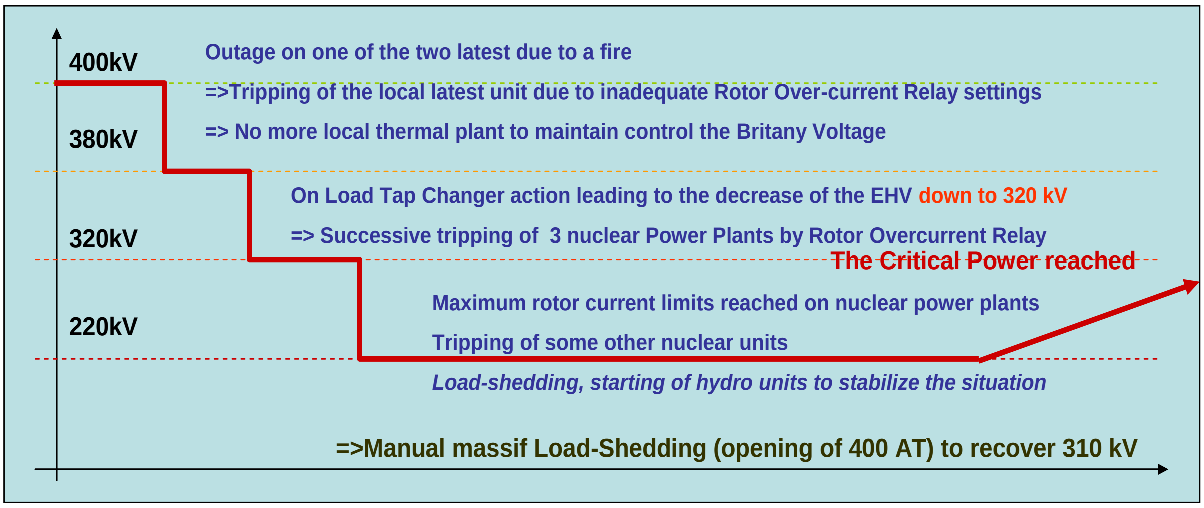
2.3.1 VOLTAGE COLLAPSE IN FRANCE 1987

This event which occurred in the West of France in year 1987 is a good example to illustrate the short-term and long-term dynamics involved in voltage instability phenomena leading to a voltage collapse.

Initial conditions:

- Brittany is an electric peninsula supplied:
    - Nuclear Power Plant quite far away from the load
    - Four 600 MW Coal/Fuel strategic power units near Nantes city necessary to maintain the voltage at the border of the peninsula
    - Gas Turbine necessary for peak load hours
- Outages on two of the four local thermal units inducing an stressed situation but in accordance with operating rules
- System heavily loaded in the west of France (very cold winter)

Sequence of event



Outage on one of the two latest due to a fire

=>Tripping of the local latest unit due to inadequate Rotor Over-current Relay settings

=> No more local thermal plant to maintain control the Britany Voltage

On Load Tap Changer action leading to the decrease of the EHV down to 320 kV

=> Successive tripping of 3 nuclear Power Plants by Rotor Overcurrent Relay

The Critical Power reached

Maximum rotor current limits reached on nuclear power plants

Tripping of some other nuclear units

Load-shedding, starting of hydro units to stabilize the situation

=>Manual massif Load-Shedding (opening of 400 AT) to recover 310 kV

FIG. 2-3: **SEQUENCE OF EVENT**

Analysis

- First instantaneous voltage drop due to the tripping of coal/fuel thermal units
- Large long-term voltage transient due to the tap changer movement which tried to maintain the voltage at the lower side of the transformers and decreasing drastically the EHV voltage
- Voltage drop increased by the tripping of other large units due to bad tuning of generator over-current protections
  - A large part of the west French grid under 300 kV
  - 2/3 of the French substations are under 275 kV
- Necessity to shed a large amount of load very quickly to avoid the spreading of collapse to the rest of France in less than 14 minutes

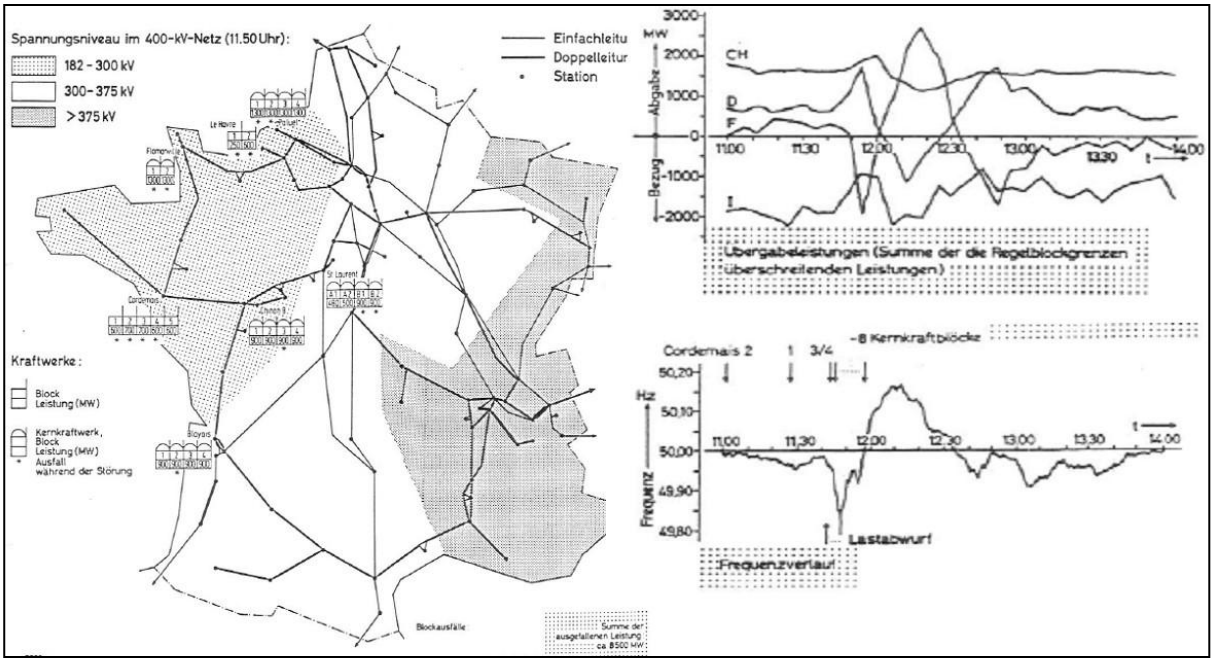


FIG. 2-4: MEASUREMENTS DURING THE VOLTAGE COLLAPSE

Synthetic analysis and RTE action plan

Such a disturbance pointed out the role of On Load Tap Changer in the dynamic of voltage collapse and the deep impact of additional adverse trippings of large power plants and the necessity to require dynamic performances and optimized internal protection systems;

It leads the TSO to take the necessary following countermeasures:

- Implementation of automatism to block the transformer On Load Tap Changers which are the "motor" of the voltage collapse;
- Implementation of a new "coordinated" secondary voltage control system with a more appropriated and faster time response;
- Optimisation of the generating units protection relays;
- Long Term Dynamic studies to anticipate the constraints :
- Systematic calculations of the limits of the system
- Optimisation of "static" robust criteria for the real time scada or static software
- Implementation of new compensation means to face the growth of consumption
- Reinforcement of the National CC /Regional CC coordination

2.3.2 BLACKOUT IN USA ON 10.08.1987

This incident is an example for an oscillatory instability (Small-Disturbance Angle Stability).

Inter-Area-Oscillations contributed to the severity of the incident which lead to the opening of tie-lines and therefore to the disconnection of the power system.

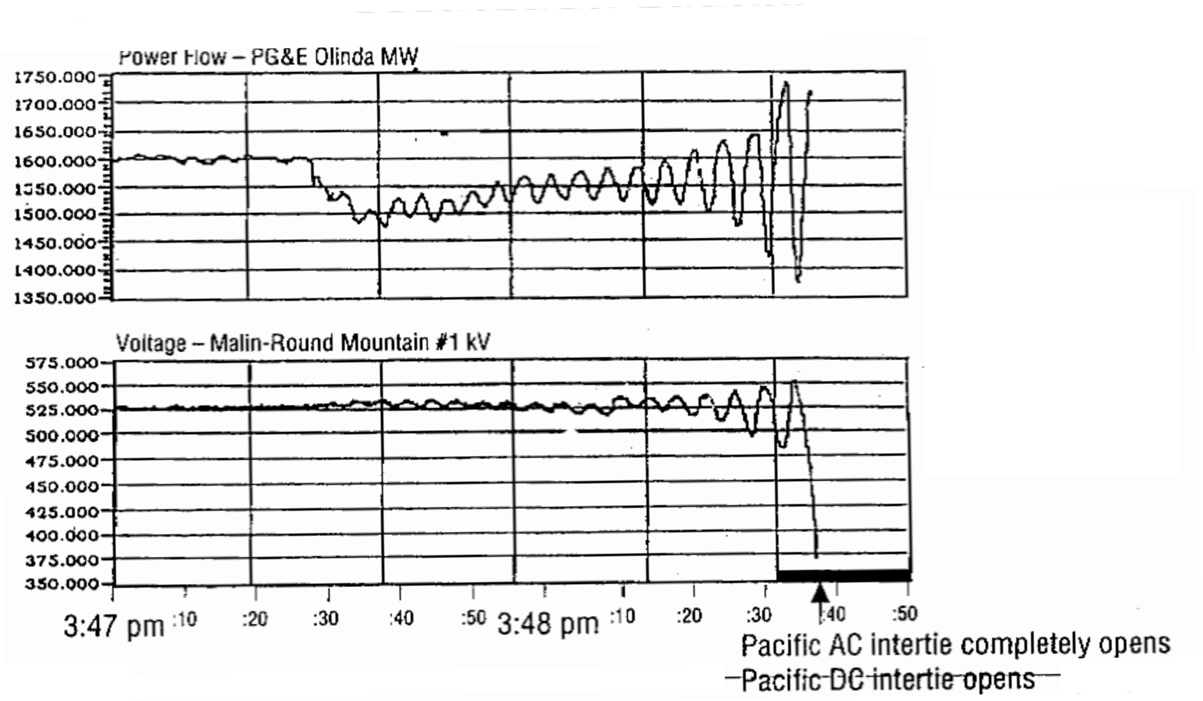


FIG. 2-5: OSCILLATORY MODE WITH NEGATIVE DAMPING LEADING TO THE OPENING OF TIE-LINES

2.3.3 VOLTAGE COLLAPSE IN NETHERLANDS 1997

On June 23rd, 1997 a voltage collapse occurred in the 150 kV-distribution grid in the area Flevoland-Gelderland-Utrecht in the Netherlands.

After the outage of three generation units within three minutes the HV/MV transformers were overloaded and the remaining units were no longer able to top up the shortage of reactive power sufficiently, however load was disconnected manually. After the failure of further power plants due to the decreasing voltage, the Province of Utrecht was shut down completely in order to maintain the supply of the other areas.

34 minutes later it was started to restore the lost generation units and following the electricity supply was completely restored after about four and a half hours.

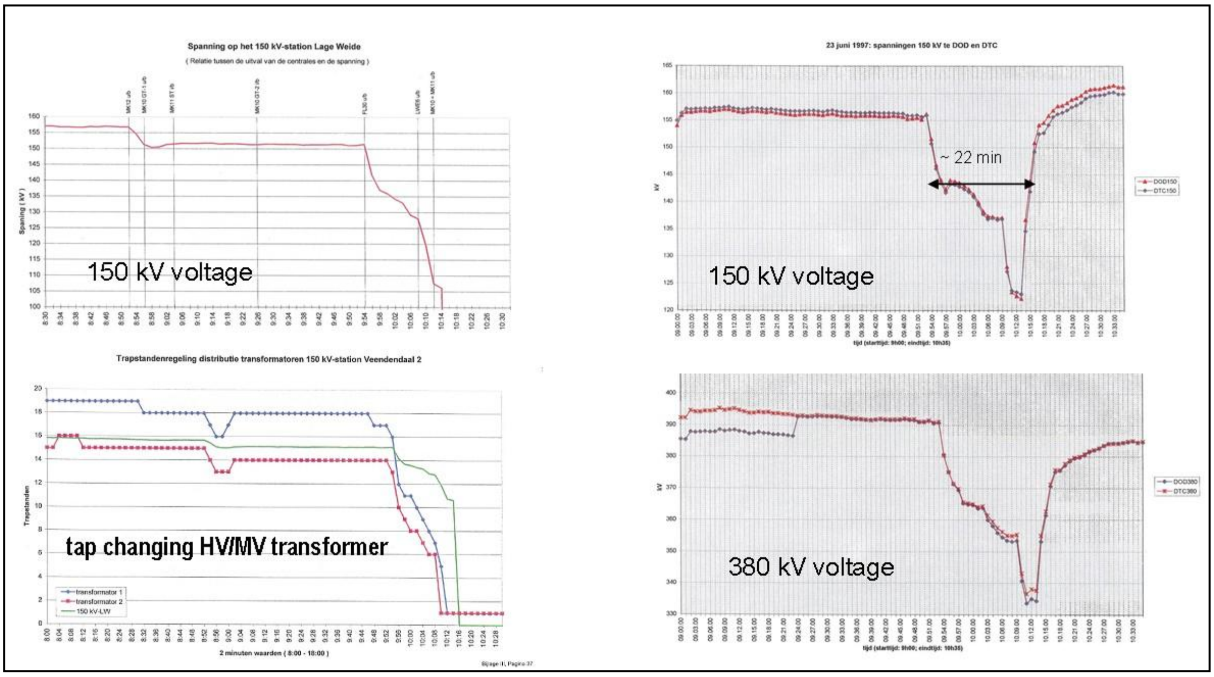


FIG. 2-6 VOLTAGES AND TAP CHANGING OF HV/MV TRANSFORMERS

This incident demonstrates that in case of the shortage of reactive power automatic load tap changing leads to an additional voltage drop and therefore causes the risk of a voltage collapse.

2.3.4 SOUTH-WEST OF FRANCE DISTURBANCE-1999 STORM

This example is a clear illustration of the notion of maximum transfer capacity (from electrotechnical point of view) of a weak grid leading to the loss of synchronism of an area. It presents also the French issue to avoid a spreading of instability phenomena.

Initial situation

At time of event (27-12-1999), the situation of the French national grid was heavily impacted by a strong storm which destroyed some lines and towers. Then, the system was not sufficiently meshed to ensure a normal synchronisation between the different areas.

The south-west of France and Spain in particular was weakly linked to the rest of France only through:

- One 400 kV OHL from Bordeaux (Braud) to West part of French grid;
- Three 400 kV OHL from Carcassone (Gaudière) to the Centre and the South-East of France,
- On 400 kV OHL from Perpignan (Baixas) to Spain,

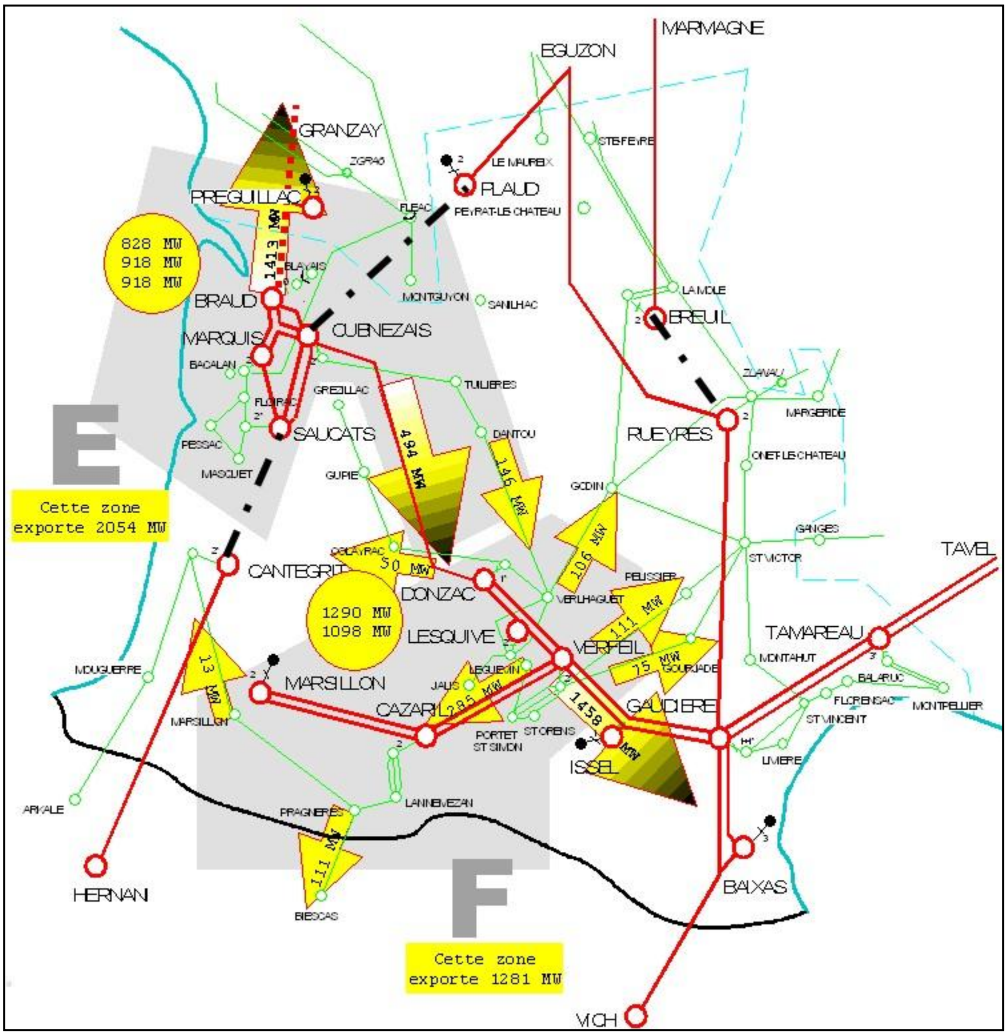


FIG. 2-7: INITIAL SITUATION BEFORE FAULT[1]

Moreover, the South-West of France was in an export situation to the rest of UCTE grid and the nuclear power plant of Bayais (near Bordeaux) and Golfech (Near Toulouse) were at full power.

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[1] The "E" and "F" grey areas are RTE defence plan synchronous areas at the border of which out-of-step relays are installed to avoid the spread of loss of synchronism. Dotted lines represent OHL destroyed by the storm.

Sequence of events

⇨ Fault on the most loaded and synchronising OHL of the Blayais NPP

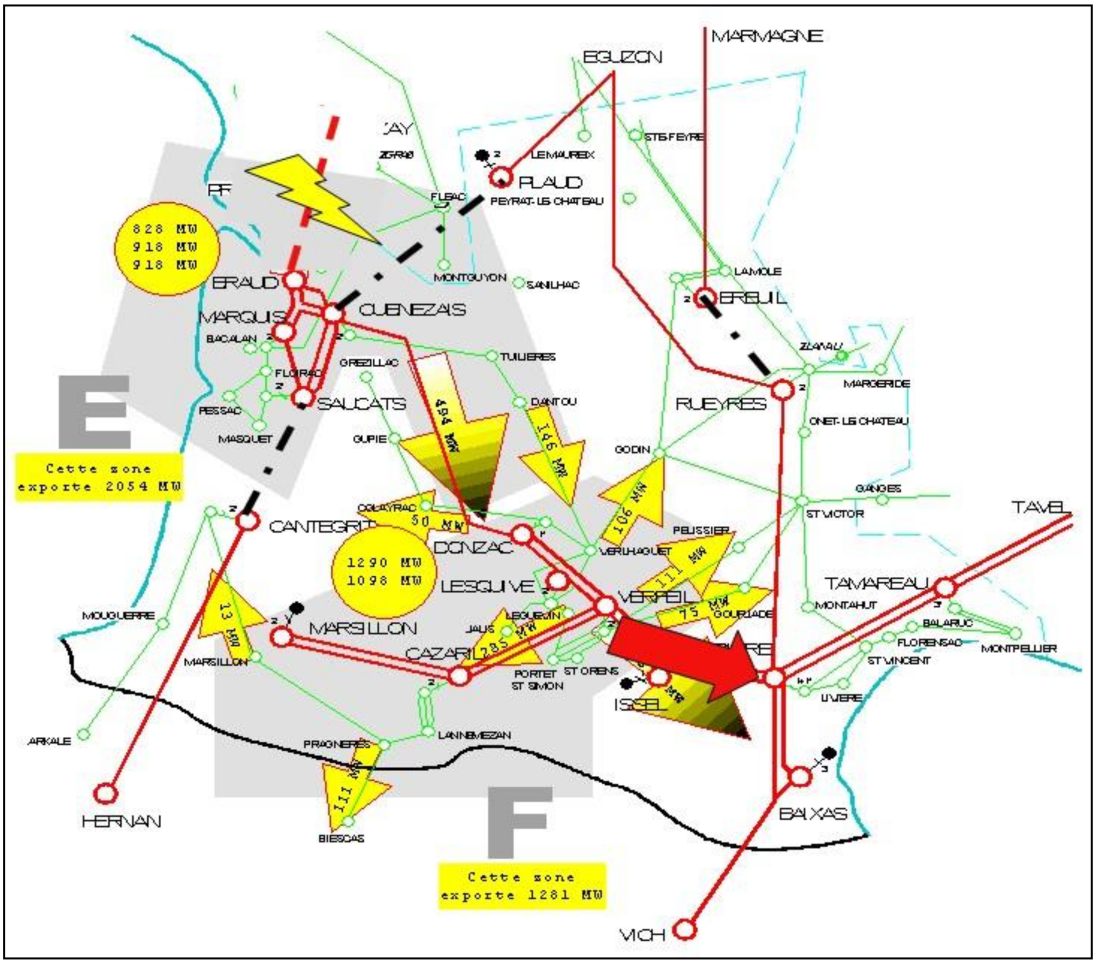

FIG. 2-8: FAULT LEADING TO THE EXCEEDING OF THE MAXIMUM TRANSFER CAPACITY[2]

⇨ Maximum Transfer Capacity reached on the remaining OHL following the fault and fast voltage collapse within 2 seconds due to the fact that the power can't be evacuated from this area;

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[2] The "E" and "F" grey areas are RTE defence plan synchronous areas at the border of which out-of-step relays are installed to avoid the spread of loss of synchronism.

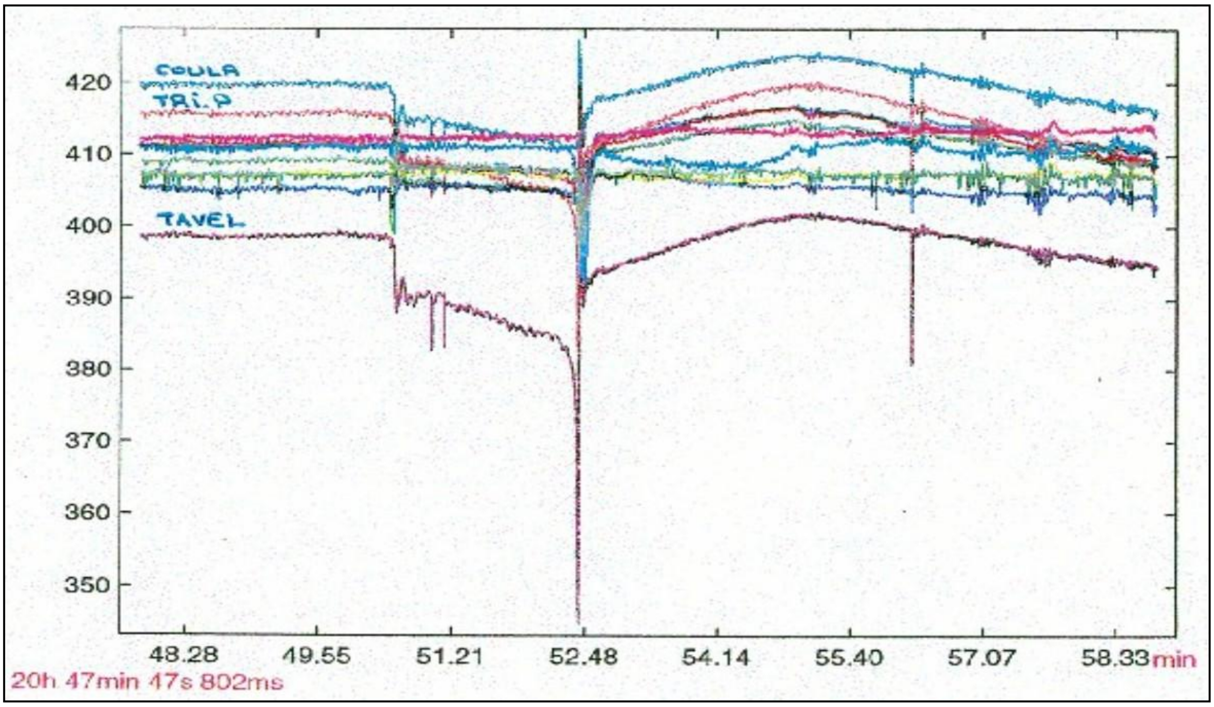


FIG. 2-9: VOLTAGE AT SEVERAL BUSSES DURING THE TRANSIENT AFTER FAULT

- ⇨ Large power oscillations and adverse tripping of 2 nuclear power plants of the area;
- ⇨ Correct activation of out-of-step relays (French Defence Plan) separating the system in 3 areas within 2 minutes (South-West of France, Spain and UCTE) and avoiding the spreading of the loss of synchronism;
- ⇨ Situation stabilized.

Analysis of the incident

Compared to frequency instability or long-term voltage collapse, the transient instability phenomena can be extremely fast with dramatic consequences, and, the solutions to face such incident are not obvious and depending of the philosophy of the protection system used to ensure a good coordination with the defence plan.

Thanks to the implementation of the French Defence Plan and dedicated to disconnect from the rest of the grid the area losing their synchronism, the spread of the loss of synchronism was avoided.

2.3.5 BLACKOUT IN ITALY 28.09.2003

Black-out sequence of events

The following map presents the OHL connecting Italy to the UCTE Grid with the corresponding sequence of events.

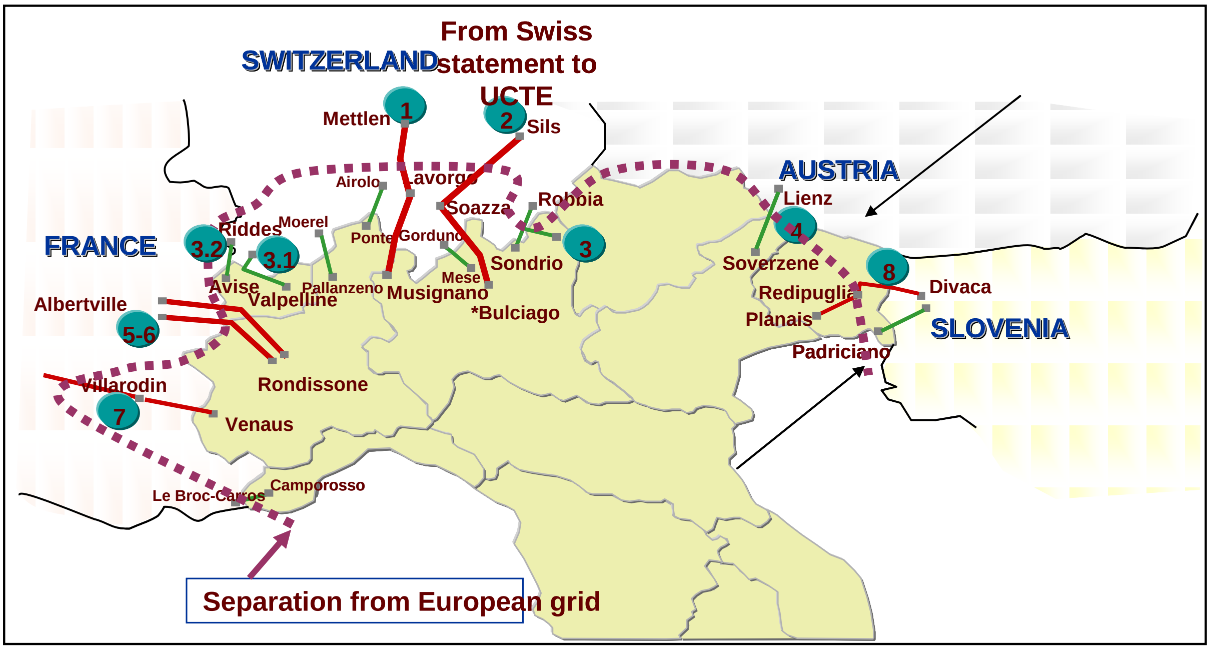


FIG. 2-10: SEQUENCE OF EVENTS LEADING THE BLACK-OUT OF ITALY

Italy was in an importing situation the sequence of event was the following ones:

- At 03:01 there was the tripping of Mettlen-Lavorgo 400kV (internal line in Switzerland serial to Lavorgo-Musignano Italy-Switzerland tie line);
- At 03:25 there was a second trip of Soazza Sils 400 kV (internal line in Switzerland serial to Bulciago Soazza Italy-Switzerland tie line);
- Cascading phenomena started and transient voltage instability occurred immediately inducing the tripping of other interconnection lines between (or serial) Italy and successively Switzerland, Austria, France and Slovenia. .
- Italy disconnected from the rest of UCTE system about 10 seconds after the Soazza - Sils trip;

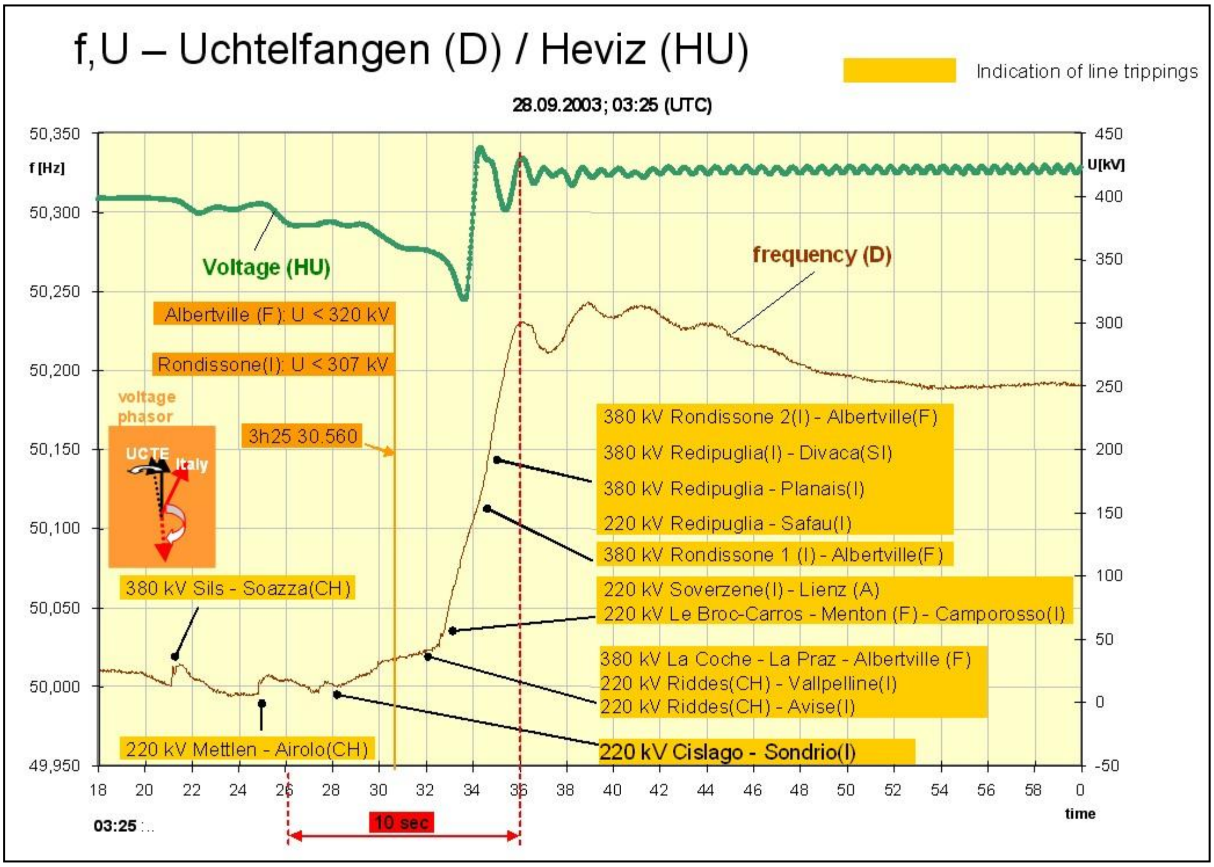


FIG. 2-11: FAST TRANSIENT VOLTAGE COLLAPSE BEFORE ITALY DISCONNECTION FROM THE REST OF UCTE

After the disconnection of Italy from the rest of the grid, there was a severe unbalance between Consumption and Generation leading to a fast decrease of frequency and action of Italian under-frequency-load-shedding

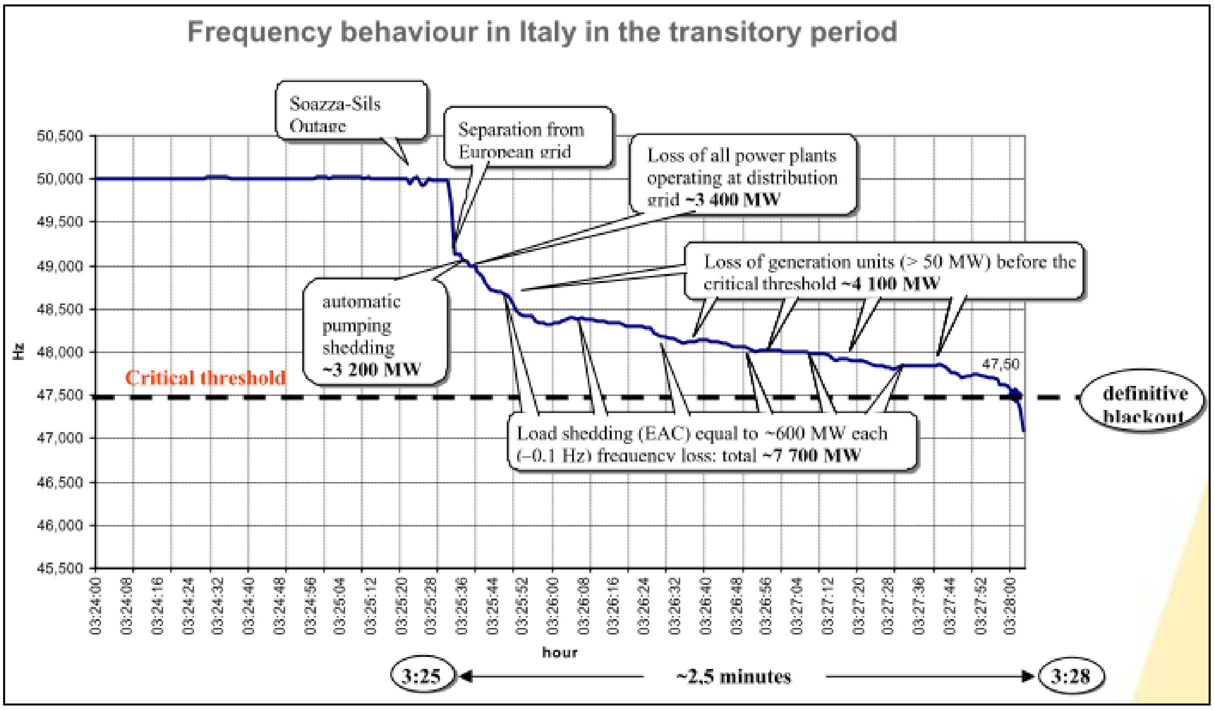


FIG. 2-12: FREQUENCY COLLAPSE IN ITALY

The under-frequency-load-shedding was correctly activated step by step for a total (including pumping storage plants automatic trip) of ~10900 MW during the frequency transient before black out, many generating units were disconnected at the time (power plants operating at distribution grid and main units on transmission grid (~7500 MW) due to: local strong transients, block/trips of thermal process regulation system, tripping of generator protections (under-frequency, minimum impedance, over voltage…).

The adverse trippings of all these generating units counter the UFLS action and finally led to a black out.

This Black-out has been an illustration of the complexity and succession of different instability phenomena:

- Cascading OHL tripping due to transient overload;
- Fast voltage instability and collapse caused by loss of angle stability;
- Power/consumption unbalance combined with generation trips after disconnection of Italy from the rest of the grid, has caused a frequency instability transient.

It shows also the necessity to ensure that the generating units (on distribution and transmission system) will be maintained connected to the grid as longer as possible to give time to the UFLS to be efficient.

2.3.6 VOLTAGE COLLAPSE ON 220-KV-LINE DURING RADIAL SUPPLY OF 110-KV-GRID IN GERMANY, 02.09.2004

On 02.09.2004 a voltage collapse occurred in Germany on the 220/110 kV grid with the following sequence of events:

- Decrease 220-kV-voltage due to the increase of load and continuous automatic tap changer action (110/10 kV-tap-changers)
- Increase of 220-kV-current leading to the tripping of 220-kV-line due to exceeding the trigger criteria of the line protection (overcurrent)

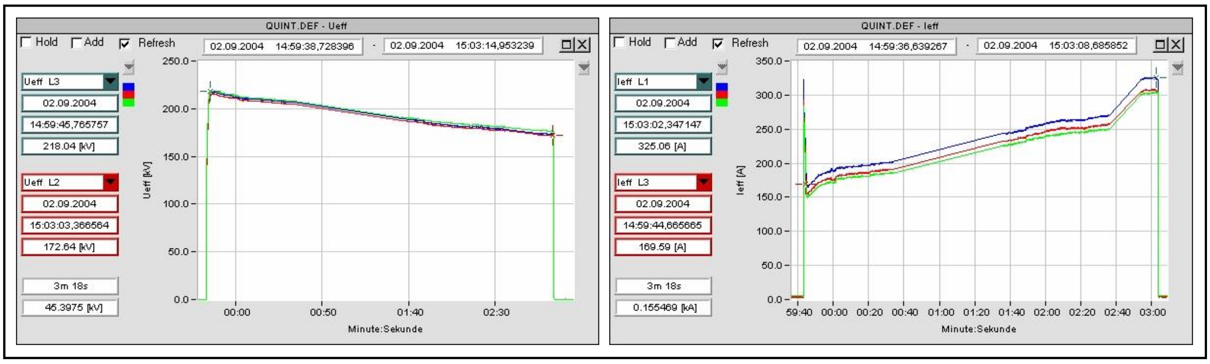


FIG. 2-13: VOLTAGE AND CURRENT ON THE 220KV NETWORK

As for the French voltage collapse, this example illustrate the fact that the long-term dynamic phenomena are mainly due to the OLTC movements and that a specific control strategy (e.g. blocking of OLTC) is necessary to avoid voltage instability.

2.3.7 VOLTAGE COLLAPSE IN POLAND 2006

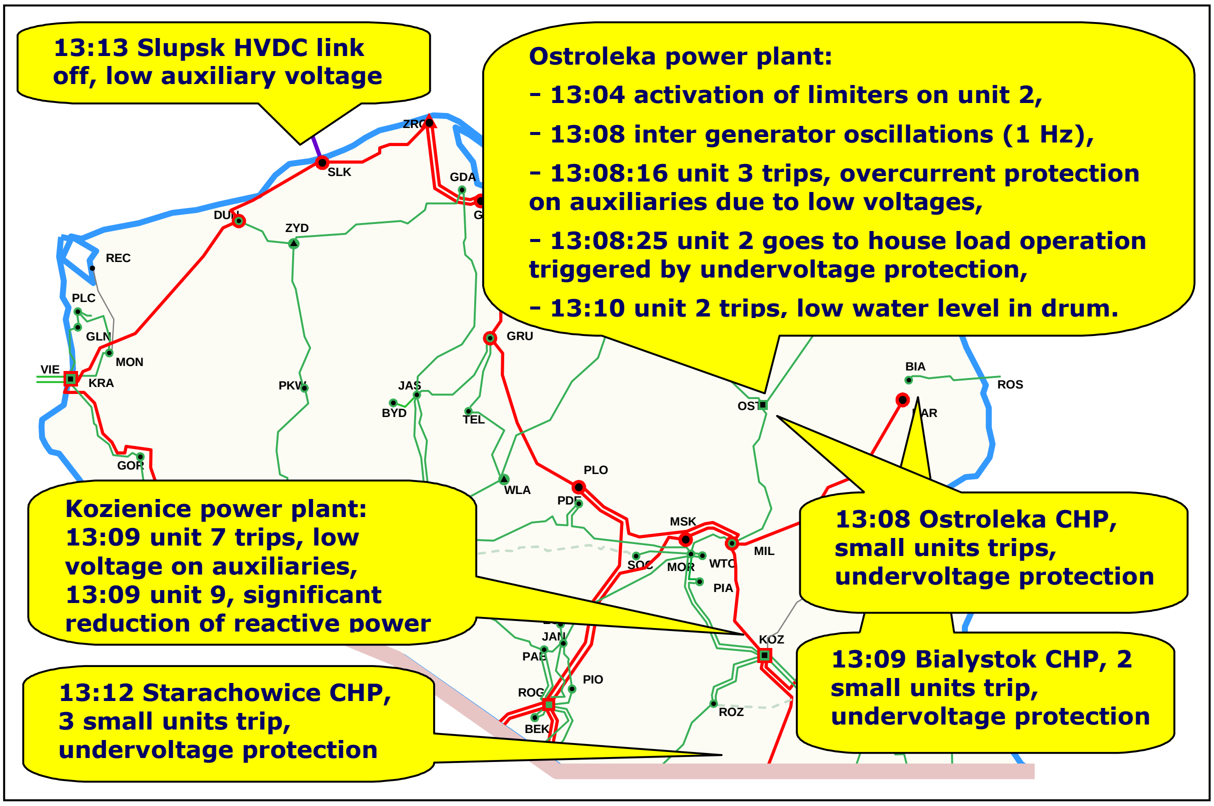
During the incident in Poland on June 26th, 2006 occurred a voltage collapse which was extended over a large geographical area

During that time Poland was affected by extraordinary summer weather conditions.

An unexpected increase of demand for reactive power was not compensated at the distribution level.

During the whole incident the active automatic on load tap changers of transmission to distribution network transformers maintained the voltage level in the 110 kV network within limits but consequently out of limits in transmission network. The condition of reactive power balance was aggravated also by significant forced reduction of available generation capacity during that morning and forced outages of units. Due to the very deep declining of the voltage level further units (by generator protection) and the HVDC connection with Swedish system (due to low auxiliary voltage) were lost.

The course of events is shown in Fig. 2-14 and Fig. 2-15.



13:13 Slupsk HVDC link off, low auxiliary voltage

Ostroleka power plant:
- 13:04 activation of limiters on unit 2,
- 13:08 inter generator oscillations (1 Hz),
- 13:08:16 unit 3 trips, overcurrent protection on auxiliaries due to low voltages,
- 13:08:25 unit 2 goes to house load operation triggered by undervoltage protection,
- 13:10 unit 2 trips, low water level in drum.

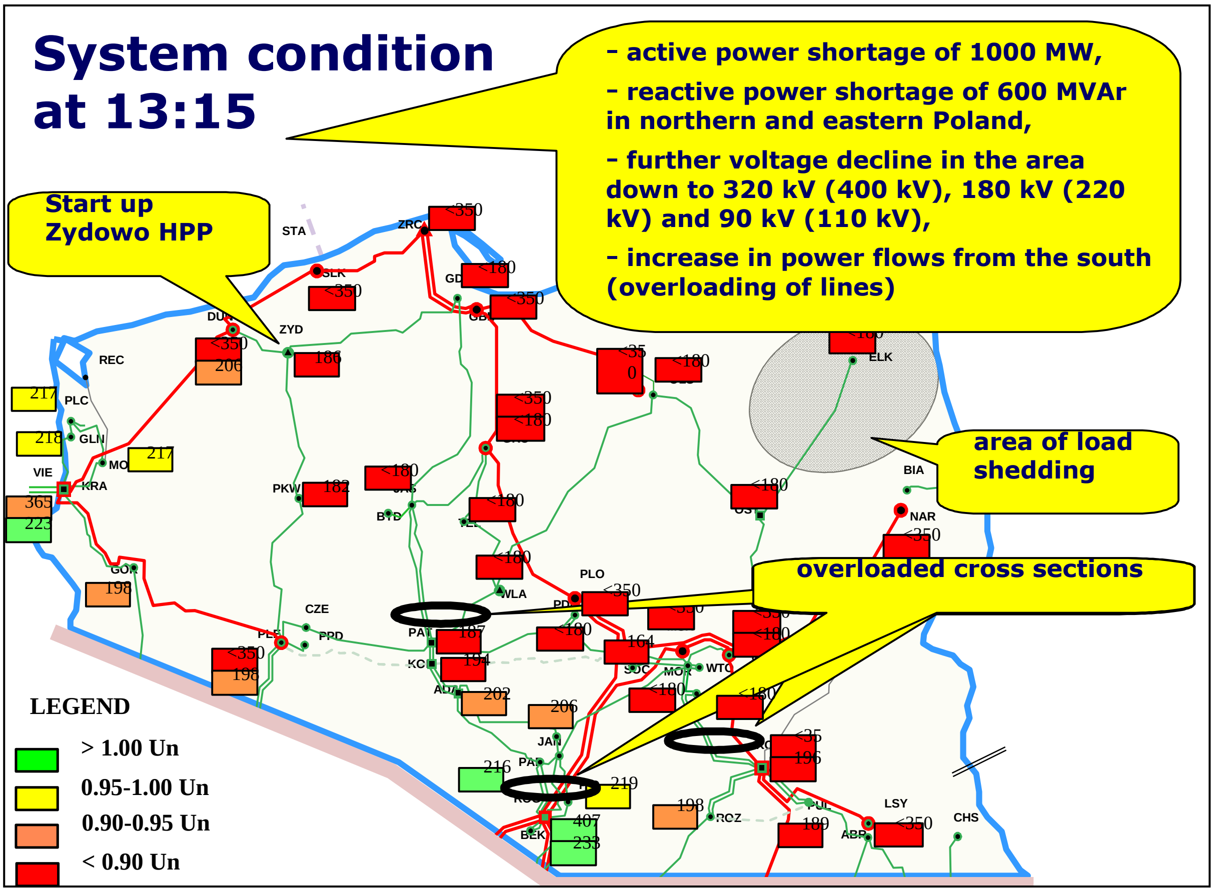
Kozienice power plant: 13:09 unit 7 trips, low voltage on auxiliaries, 13:09 unit 9, significant reduction of reactive power

13:08 Ostroleka CHP, small units trips, undervoltage protection

13:09 Bialystok CHP, 2 small units trip, undervoltage protection

13:12 Starachowice CHP, 3 small units trip, undervoltage protection

FIG. 2-14: VOLTAGE COLLAPSE IN POLAND 2006 – COURSE OF EVENTS



System condition at 13:15

- active power shortage of 1000 MW,
- reactive power shortage of 600 MVAr in northern and eastern Poland,
- further voltage decline in the area down to 320 kV (400 kV), 180 kV (220 kV) and 90 kV (110 kV),
- increase in power flows from the south (overloading of lines)

Start up Zydowo HPP

area of load shedding

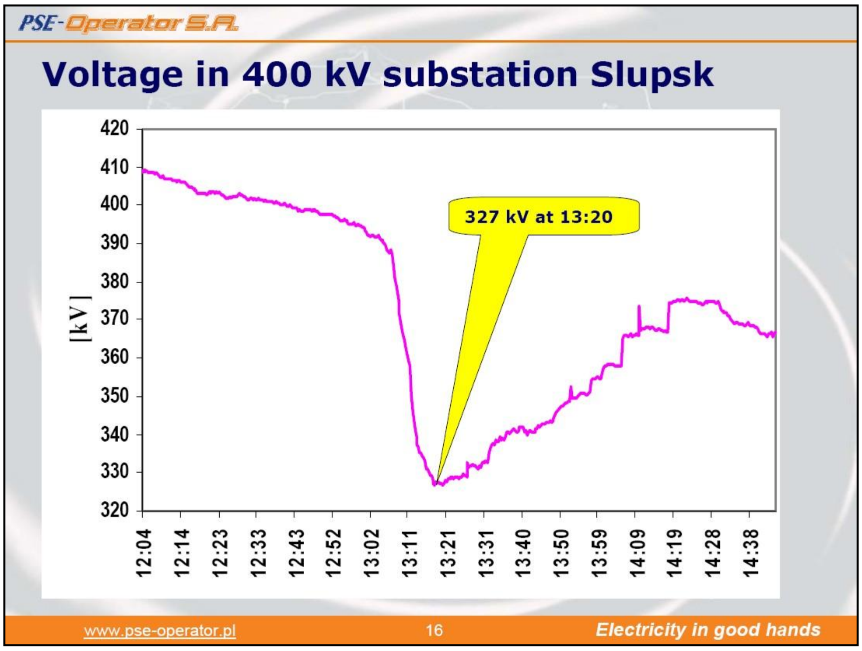
overloaded cross sections

LEGEND

🟩 > 1.00 Un
🟨 0.95-1.00 Un
🟧 0.90-0.95 Un
🟥 < 0.90 Un

FIG. 2-15: SYSTEM CONDITION OF THE NORTHERN PART OF THE POLISH SYSTEM JUST AFTER EVENTS

The voltage course in a 400 kV substation is shown in Fig. 2-16.



PSE-Operator S.A.

Voltage in 400 kV substation Slupsk

327 kV at 13:20

www.pse-operator.pl 16 *Electricity in good hands*

FIG. 2-16: VOLTAGE COLLAPSE IN POLAND 2006 – 400 KV VOLTAGE COURSE

After the events the following remedial actions were undertaken:

- start up of hydro unit in HPP Zydowo to recover auxiliary voltage in Slupsk HVDC substation and resume operation of HVDC link (back from 14:31),
- load shedding (13:58 – 16:04, ca 110 MW) to recover auxiliary voltage in Ostroleka substation and start up tripped units (unit 3 back at 15:27, unit 2 at 17:37),
- switching on some lines off for maintenance,
- units normally non dispatchable by TSO ordered to increase generation to improve local active and reactive power balances
- emergency power deliveries from neighbouring TSOs to balance the system.

The post mortem analysis of this incident, except of mentioned, revealed others adverse factors influencing on voltage conditions shows:

- lack of sufficient and properly located reactive power sources in the northern part of the system,
- limited range of generator’s capabilities made available to TSO (limiters set in excessive way),
- lack of adaptation of generating units to operate under lower network voltage:
  - many unit transformers have no on-load tap changers,
  - many unit transformers have too high rated upper voltage,
  - range of voltage control in auxiliaries is too small.
- limited possibilities for TSOs to analyse situation on the whole system, including 110 kV subtransmission network because of lack of TSO access to on line data from distribution network,
- lack of on-line reporting to TSO dispatchers about overloading of units,
- late recognition of emergency state by TSO dispatchers - required remedial actions wasn’t undertaken in due time.

This incident shows that the northeast part of the Polish power system is vulnerable to voltage stability problems because of small margin for secure operation. To restore required margin and to avoid similar further incidents, there where installed new reactive power sources (bank capacitors) in designated substation of the transmission network. Owing to limited TSO possibilities to analyse the whole system (including 110 kV network), a system monitoring of this part of the system with alarm function in case of voltage stability problem is under preparation. Furthermore other aspects concerning reactive power balance should be also taken under consideration in future in case of such incidents:

- decreasing active power production in generating for increasing reactive power reserves,
- compensating higher reactive power demand at distribution network immediately by switching on shunt capacitors,
- increasing availability of reactive power production up to full capabilities of units,
- reporting (on line) to TSO about all threats to generating units.

2.3.8 UCTE-DISTURBANCE 04.11.2006

The disturbance on November 4th, 2006 is one of the most severe incidents in the last decade within UCTE and is relative to cascading overload phenomena leading to a splitting of the UCTE grid and large frequency deviations.

Synopsis of event

- At 9:38 pm, E.ON Netz opened the Conneforde-Diele 380 kV double line over the Ems River (boat from the shipyard). This corridor participated to the link between Germany and Netherlands which were being crossed by high East-West energy flows;
- As expected, the power flow was redistributed to other more southern located lines and at 10:07, 380 kV lines between RWE Transportnetz Strom and E.ON Netz are overloaded and a necessary topological action was performed by E.ON (Landesbergen substation).

  Unfortunately, this action led to the overload of the 380 kV Landesbergen-Wehrendorf and its tripping and other cascading tripping up to the final separation of the entire UCTE grid in three parts.

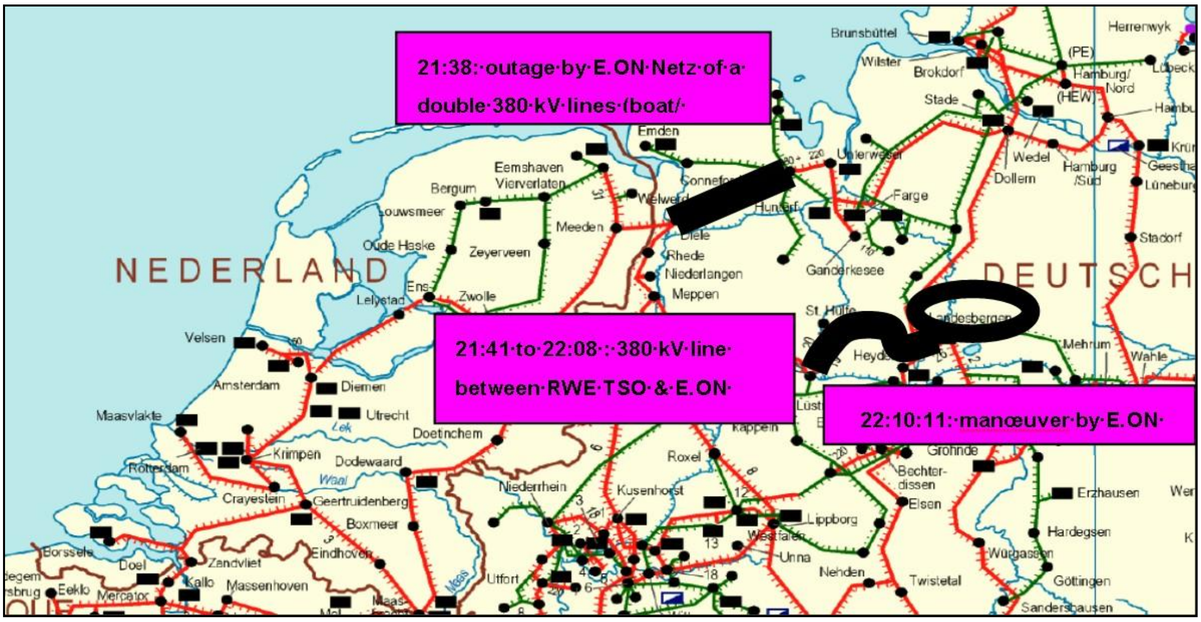


FIG. 2-17: FIRST EVENTS INITIATING THE CASCADING TRIPPINGS

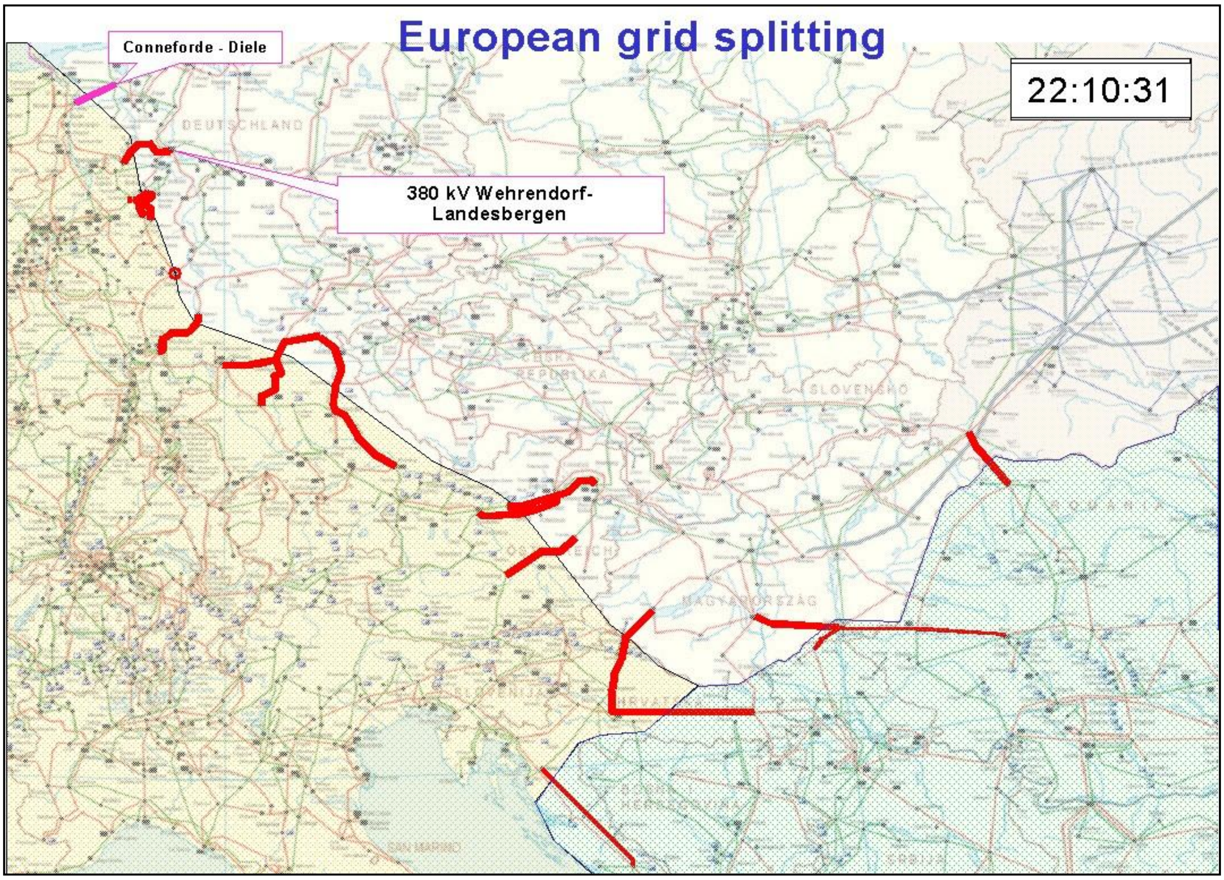


FIG. 2-18: CASCADING TRIPPINGS OF OHL AND SEPARATION OF UCTE SYSTEM IN 3 AREAS

The countries in the Western area (Spain, Portugal, France, Italy, Belgium, Luxembourg, Netherlands, Switzerland and parts of Croatia, Austria and Germany) was in power deficiency situation of about 9 GW. That led to a frequency drop down to about 49 Hz stopped by automatic load-shedding and by tripping of pumping storage units.

The countries in the South-Eastern area (Macedonia, Montenegro, Greece, Bosnia and Herzegovina, Serbia, Albania, Bulgaria, Romania and parts of Croatia and Hungary) encountered a slighter deficiency of power which led to a frequency drop to about 49,7 Hz and were not seriously affected by the disturbance.

The countries in the North-Eastern area (Czech Republic, Poland, Slovakia, Ukraine and part of Hungary, Austria and Germany) encountered a surplus of generation. The value of frequency was over 50,5 Hz in most of the cases and it peaked at 51,4 Hz.

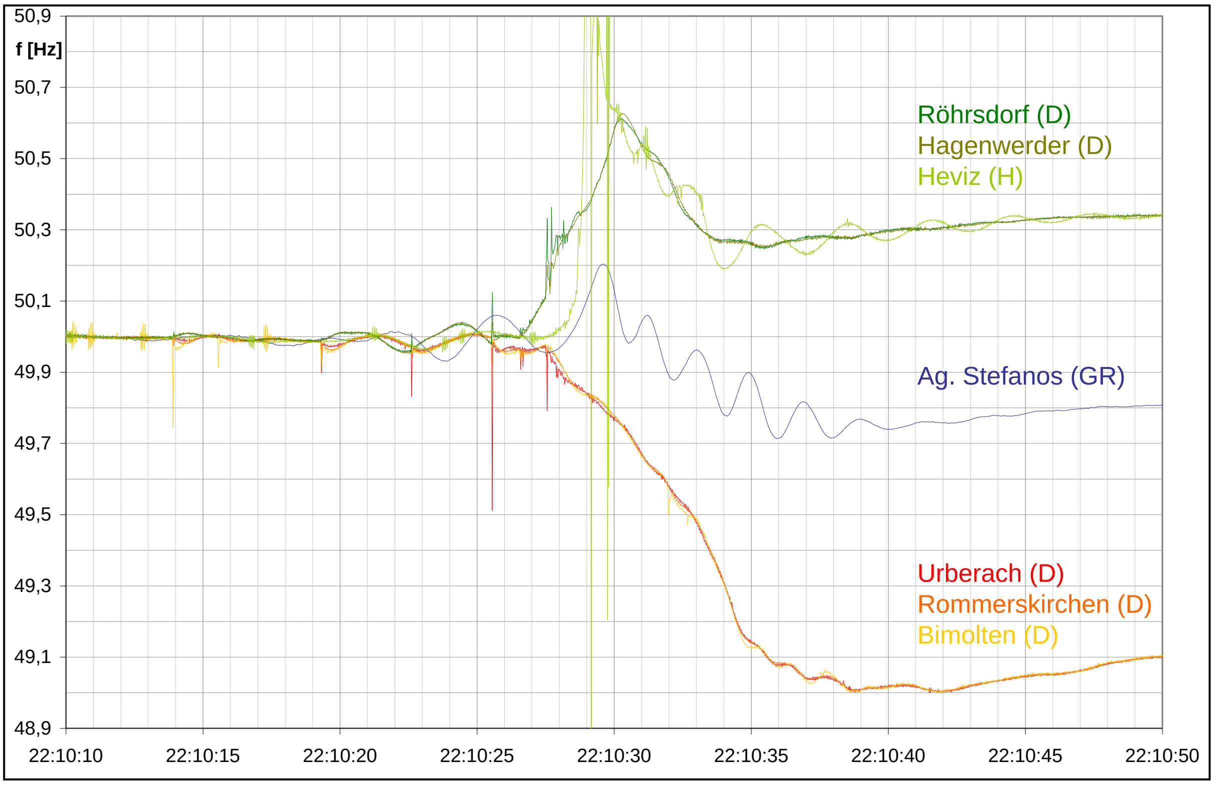


FIG. 2-19: FREQUENCY DEVIATIONS IN THE 3 AREAS FOLLOWING THE SEPARATION

In the Western area, the tripping of small and/or distributed generation units due to under-frequency increased the initiate power/consumption unbalance. Automatic tripping and uncontrolled reconnection of these units may influence in critical situations in such a way that it was impossible to perform a clear analyse in real-time concerning this distributed generation.

In synthesis, at the end of the automatic response of the system when the fall of the frequency ceased, the following indicative power balance held:

- ~9 GW of import from Eastern area non longer available
- ~11 GW of generation lost when the frequency reached 49,5 Hz
- ~17 GW of shed load and pumped storage
- ~3 GW from primary regulation of generators and load self reduction

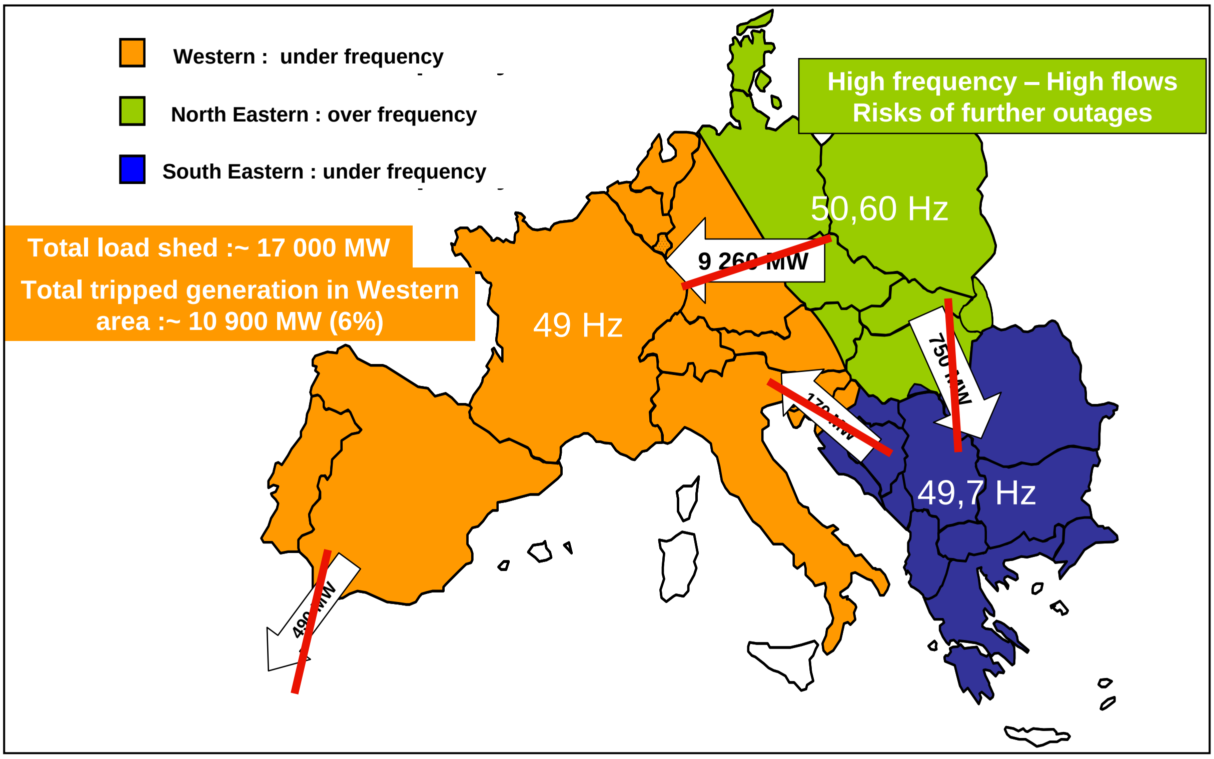


FIG. 2-20: SEPARATION OF UCTE GRID IN 3 PARTS WITH DIFFERENT CONSUMPTION/GENERATION UNBALANCES

Concerning stability issues, the analysis of the dynamic behaviour of the Western area was full of learning:

- ⇨ It proved the necessity of an efficient Under-Frequency Load-Shedding scheme to avoid a black-out;
- ⇨ Nevertheless, if the automatic UFLS was sufficient to stabilize the frequency, the ratio of load-shedding during the disturbance differed from one TSO to another for different reasons (UFLS settings, materials,…). There is a clear need of harmonisation of ENTSO-E RG CE rules for this issue.

Distributed generation units were not monitored or controlled appropriately by TSOs. The uncoordinated behaviour during the disturbances worsened the consequences and introduced a risk for more severe instability. Moreover, it appeared clearly that strong requirements are necessary concerning decentralized generation in order to be maintained on the grid as longer as possible during the UFLS activation.

2.3.9 DENMARK ISLANDING - 29.05.2007

This disturbance is relative to the small-disturbance Angle Stability (oscillatory instability).

Initial State

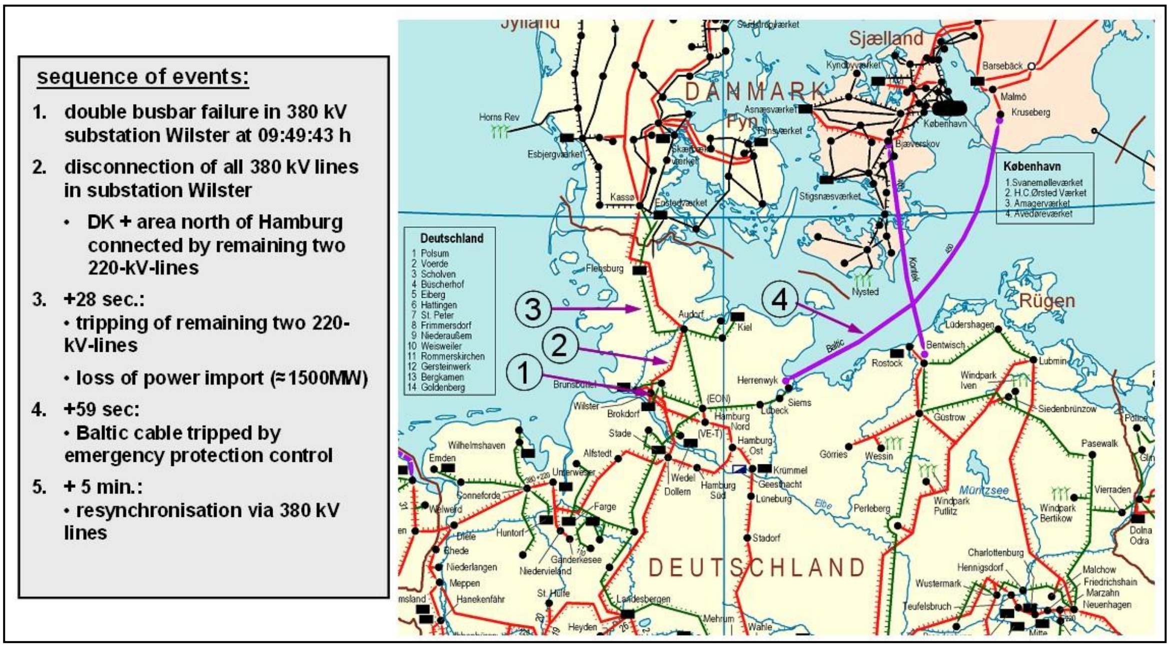
Denmark and Germany are connected through two 380 kV OHL, two 220 kV OHL and also through the HVDC Baltic cable.

Before incident, 1500 MW was being exported from Denmark to Germany.

Sequence of events

- ⇨ Double busbar failure in 380 kV Wilster substation (Germany) at 09:49:43 due to the explosion of a current transformer.
- ⇨ Disconnection of all 380 kV lines in substation Wilster and in particular the both 380 kV lines to Audorf. It means that Denmark and the north of Hamburg area are only connected by remaining two 220 kV lines.

  Due to the weak remaining link between Denmark and Germany and the exportation from Denmark, large power oscillations occurred with a negative damping.
- ⇨ + 28 sec.:
  - ○ tripping of remaining two 220 kV lines by overload during the oscillating phenomena
  - ○ increasing of frequency until 51 Hz due to islanding of West-Denmark;
  - ○ loss of power import for UCTE system (about 1500 MW)
- ⇨ + 59 sec.: Baltic Cable tripped by emergency protection control leading to the loss of globally 2200 MW of importation for UCTE system (resulting frequency at 49,95 Hz) and to quite high frequency phenomena in Denmark controlled in particular thanks to an automatic adjustment of import from HVDC links from Sweden and Norway;
- ⇨ + 5 min.: resynchronisation via 380 kV lines



sequence of events:

1. double busbar failure in 380 kV substation Wilster at 09:49:43 h
2. disconnection of all 380 kV lines in substation Wilster
   - DK + area north of Hamburg connected by remaining two 220-kV-lines
3. +28 sec.:
   - tripping of remaining two 220-kV-lines
   - loss of power import (≈1500MW)
4. +59 sec:
   - Baltic cable tripped by emergency protection control
5. + 5 min.:
   - resynchronisation via 380 kV lines

FIG. 2-21: SEQUENCE OF EVENTS

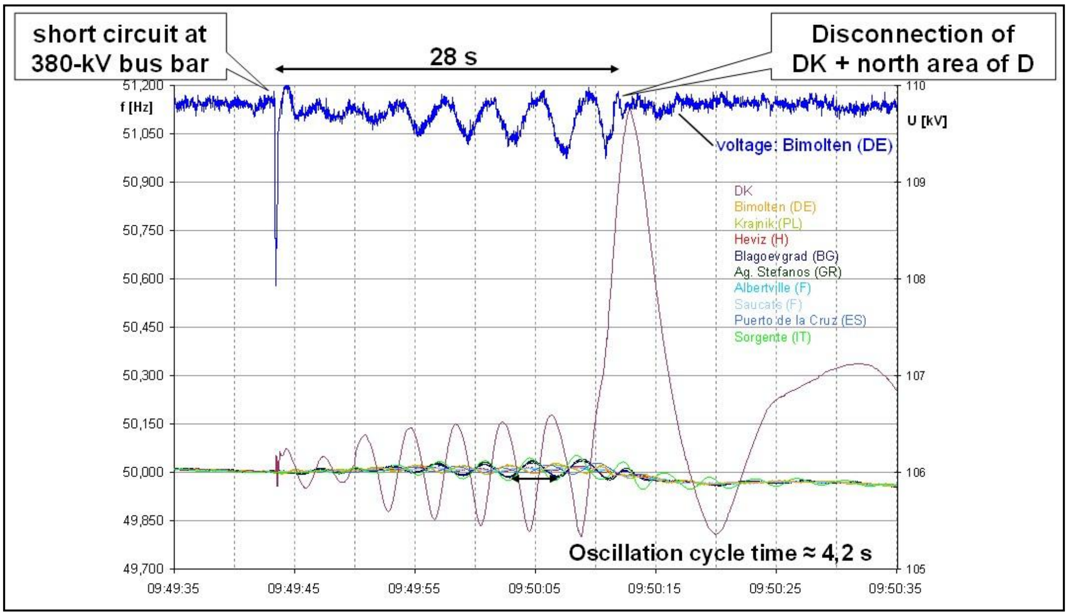


FIG. 2-22: RESULTING POWER OSCILLATIONS

Analysis and conclusions

This event point out the complexity of such disturbances with a cascade of different kind of phenomena:

- ⇨ Cascade of over-load leading to the tripping of OHL
- ⇨ Occurrence of oscillatory modes with negative damping contributing to the tripping of the last 220 kV tie-lines between Denmark and Germany
  It can be noticed that this tripping was efficient to avoid a spreading of this instability even if it led to an islanding of Denmark;
- ⇨ Over-frequency phenomena in Denmark controlled by prime over regulation and interesting automatic adaptation of flux on HVDC links between Denmark and Sweden/Norway

2.3.10 SOUTH-BALKAN-DISTURBANCE 24.07.2007

The event on July 24th, 2007 constitutes the most severe disturbance in the history of the South East Europe (SEE) region after the connection of the SEE region to the rest of UCTE system (after 10 October 2004)

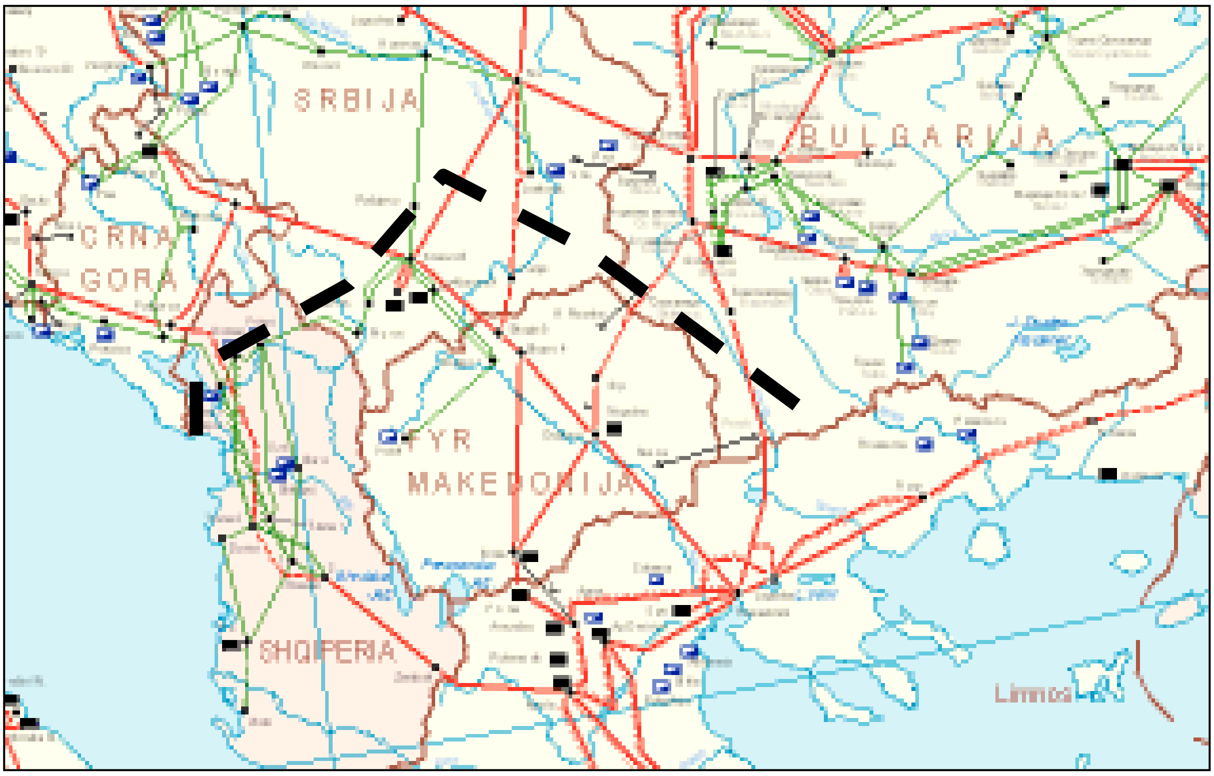


FIG. 2-23: DISCONNECTION OF BALKAN FROM THE REST OF UCTE GRID

Synopsis of the events:

- In the initial state, the Balkan area was in a import situation but (N-1) secure – Albanian system was importing more than 50% of its own consumption;
- Almost simultaneously tripping (4 seconds difference) of the lines Kosovo B -Nis and Kosovo B - Ribarevina due to fault. The result was that the SEE region was divided into two islands: One with the rest UCTE and one with Greece, FYROM, Albania and the part of Serbia (area of Kosovo);
- Tripping of the line Podgorica-VauDejes due to overload;
- Tripping of the line Blagoevgrad-Thessaloniki due to overload.

The frequency in the power systems of Greece, FYROM, Albania and part of Serbia (area of Kosovo), which operated in an island mode, dropped down to 48.713Hz.

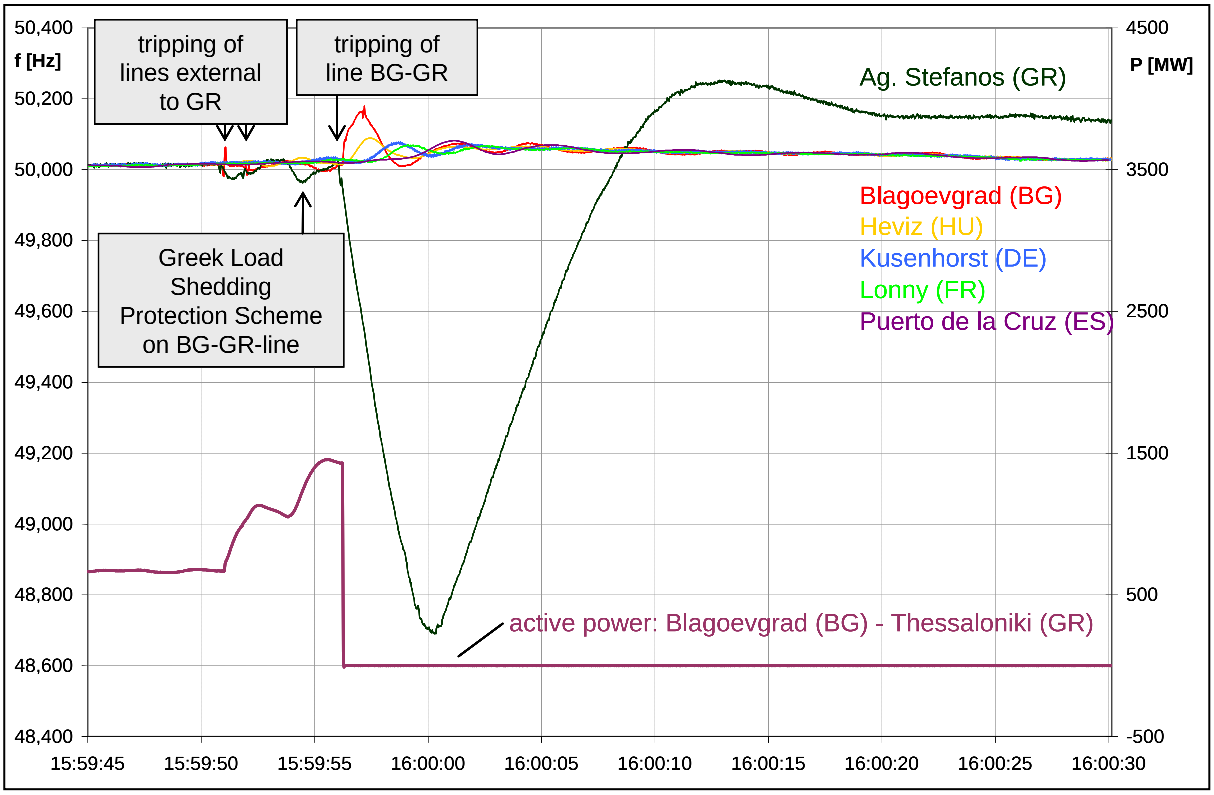


FIG. 2-24: FREQUENCY DEVIATION FOLLOWING DISCONNECTION FROM UCTE

- ⇨ Opening of the tie lines between Greece-Albania, Greece-FYROM
- ⇨ Final black out in Albania, FYROM and in the Kosovo area.

This curve shows the dynamic of a frequency instability just after the disconnection from the rest of the UCTE grid and the necessity to shed load automatically to restore a frequency near 50 Hz.

At 48,7 Hz, it can be noticed the strong effect of the disconnection of Greece from the rest of Balkan system which presented a large generation/consumption unbalance. This automatic action led to the final black out of Albania, FYROM and in part of Serbia (Kosovo area), but permitted to Greece to return to a stable situation before a quick system restoration. The resynchronization of the two power systems (UCTE network) and the Greek system took place almost 10 minutes after the disturbance, while there was a difference of 165 mHz between the two systems. Without such an automatic disconnection, Greece could also encounter a black-out.

Analysis and potential improvements to avoid such an incident in the future:

Even if the double tripping of 400kV was an event not supervised (statistic occurrence) and the situation secure with regard to N-1 rule, this black-out permitted to point-out that the countries concerned do not have the same level of defence barriers (in particular under-frequency-load shedding scheme).

Some countries presented a to large generation/consumption unbalance to be supported by the other. That led Greece to install under-frequency protections on the tie-lines to protect their own grid and to permit a faster restoration.

The potential identified improvements could be the following ones:

Better harmonization of defence plans in the area in particular concerning Under Frequency Load Schedding (UFLS). Each individual ULFS must take into account the particularity of each country in particular for countries in strong import situation;

Following this harmonization, analyze of the pertinence of the under-frequency protections on tie-lines with regard to solidarity if each country participates to the same effort;

Development of the 400kV line Mogilla-Stip-Dubrovo and the second 400kV line between Bulgaria and Greece, the line Maritsa-N. Santa. These two lines are expected to solve the problem with the high influence of the Kosovo B substation at the SEE region.

2.3.11 INTER-AREA-OSCILLATIONS IN THE CE SYNCHRONOUS AREA

During 2005 to 2007 inter-area oscillations of 0,2 to 0,25 Hz with a quite low damping were observed repeatedly:

- 2005-05-01
- 2005-05-20
- 2005-06-26
- 2005-08-21
- 2005-10-16
- 2005-12-15
- 2007-04-01

The following curves show inter-area oscillations of 0,2 Hz observed on the 1st of May 2005.

The low damped mode of 0,2 to 0,25 Hz is called East/West CE mode as the western countries (Spain) oscillated in an opposite way compared to the eastern countries (Greece, Bulgaria, Romania).

This example points out that inter-area oscillations must be supervised and analysed in order to identify and prevent the potential causes of negative damping.

The causes of such changes in the damping of the concerning mode were not clearly identified for the observed incidents in 2005 to 2007.

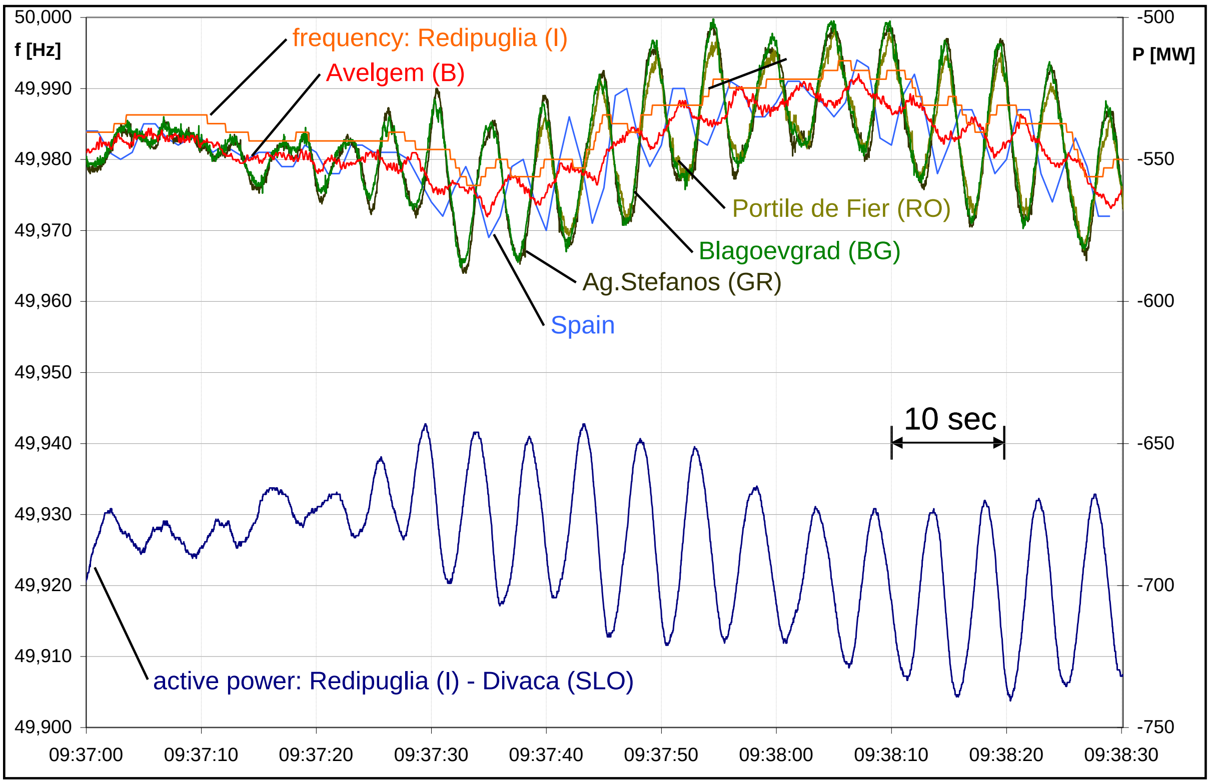


FIG. 2-25: CE INTER-AREA OSCILLATION MODE WITH LOW DAMPING

2.3.12 MORE EXHAUSTIVE LIST OF LARGE DISTURBANCES

The previous illustration of large disturbances is relative to those discussed in the Power System Stability Expert working group meetings. Nevertheless, this description is not exhaustive and many other black-outs or large disturbances occurred in the world which can briefly list in the following table with a classification according to the instability phenomena engaged.

Location	date	Frequency Stability	Voltage Stability	Transient Stability	Small-Signal Stability
Black-out in France	19/12/1978	X	X	X	
France-Spain incident	10/08/1981			X	
France-Spain incident	30/12/1981			X	
Voltage Collapse in France	12/01/1987		X		
Black-out in USA	10/08/1987			X	X
Voltage Collapse in Netherlands	X1999		X		
1999 Storm in the South-West of France	21/06/1999	o		o	
Black-out of the southern part of Portugal	09/05/2000	X	X		
Black-out USA-Canada	14/08/2003	X	X		
Black-Out in Scandinavian countries	23/09/2003		X		
Black-out in Italy	28/09/2003	X	X	X	
Black-out in the southern part of Greece	12/07/2004		X		
Rhineland/Palatinate/Luxembourg incident	02/09/2004		X		X
CE inter-area oscillations	01/05/2005				X
Voltage collapse in Poland	26/0672006		X		
4th of November UCTE incident	04/11/2006	o			
Denmark Islanding	29/05/2007	o			o
South-Balkans Disturbance	24/07/2007	X,o*			

o: system collapse could be prevented by activation of DP and/or by adequate behaviour of generation units

X: system collapse (partly), DP not available / not sufficient

* partial Blackout after system splitting

2.3.13 CONCLUSIONS DRAWN FROM MAJOR INCIDENTS

The above described incidents lead to the following conclusions:

Black-outs or large disturbances are caused by a sequence of low-probability events, not planned by the network designers and not expected by operators, on a stressed system operated marginally or following unanticipated contingencies.

The power system is faced with cascading sequences leading to overload-equipment, voltage instability, transient or small-signal instability and to frequency instability in case of system separation or large amount of tripped generation. The instability phenomena can occur successively or simultaneously in a very complex manner.

Based on the power system prevailing conditions (equipment availability, operating reserve, performance requirements for generators, distributors and protection systems), the system may cause quickly parts to island or lose synchronism with risk of complete black-outs if no fast and dedicated actions (load-shedding, generation rejection, system separation) are proactively taken.

Automatic well-coordinated and dedicated Defence Plans are needed to minimize the risk of impending disturbances cascading to wide-spread black-outs.

Finally, the consequences and the unfolding of the disturbances have a deep impact on the condition of restoration which must be taken into consideration as an entire part of the Defence Plan.

3 ANALYSIS OF LINE PROTECTION SYSTEM IN ABNORMAL SYSTEM CONDITIONS - RELAY PERFORMANCE DURING SYSTEM DISTURBANCES

3.1 SUMMARY

The recent wide-area electrical disturbances have clearly demonstrated the vulnerability of the interconnected power system when operated outside its intended design limits. Recent disturbances have shown that protective relay systems are very often involved in major wide area perturbations, sometimes preventing further propagation or sometimes triggering the disturbances by their maloperation and contributing to the spread of the disturbance.

Protective relay elements are designed to respond to overcurrents, over- or undervoltages, over- or underfrequency, and underimpedance. These abnormal system conditions will cause many types of relay systems to operate during major system disturbances. The relays most likely to operate during disturbances are:

- Distance relay elements (first or higher zones)
- Backup distance relay elements (first and higher zones)
- Instantaneous directional and nondirectional overcurrent relays
- Diferential line relay
- Under- and overvoltage relays
- Underfrequency relays
- Loss-of-field relays
- Volts/Hz overexcitation relays
- Generator backup relays
- Voltage restraint overcurrent relays
- Voltage controlled overcurrent relays

Some of these relays are generator protection or load shedding relays. This document will focus on the relays functions usually found on transmission systems. We analyze the roots causes why transmission network relay systems are most prone to operate during stressed system conditions. The stressed conditions for which the behaviour of the relays has been analyzed are those that, typically, could potentially jeopardize the system security: undervoltage situations, heavy dynamic line loadings, power swings, and abnormal frequency conditions.

As for the different relay technology found on transmission systems (e.g. electromechanical, static & numerical) the conclusions of this document apply to all of them. However, the actual trend is to install numerical relays, and the performance of these technology relays during abnormal frequency is of special interest and it is covered in the last sections of this document.

Finally as a sort summary the following table shows, for each of the system stressed condition analyzed, which elements are prone to maloperate. The check mark means that the relay element is prone to maloperate.

	Distance Protection	**Overcurrent Protection**	**Differential Protection**
Undervoltage	✓	✓	✘
Line Loading	✓	✓	✘
Power Swing	✓	✓	✘
Frequency aberration	✓	✓	✓

3.2 RELAY PERFORMANCE *DURING UNDERVOLTAGE*

This section analyzes the behaviour of transmission system relays during situations of undervoltages caused typically by voltage stability problems.

The immediate impact of a voltage stability problem on a network will be a reduction of the phase voltage magnitudes at the local substation buses. This reduction of magnitude is a three-phase phenomenon (all three phases should be equally affected) and the rate-of-change of the voltage should normally be a slow value (corresponding to voltage reduction occurring in time frames of a few seconds to a few hours). Sudden changes in voltage magnitudes occurring in a few cycles are to be considered as exceptional but should not be discounted.

Voltage instability can occur in heavily loaded systems when the available reactive power from capacitors, generators, synchronous condensers, line charging, and static VAR compensators falls below or does not greatly exceed the system reactive losses and load. Typically, voltage instability can occur following the loss of several equipment outages, or when the system is heavily loaded following a lesser system disturbance. Reactive reserves are quickly exhausted when the system lacks the required reactive power and system voltages start to decline.

Distinguishing features of voltage instability and voltage collapse are:

- ✓ Low system voltage profile
- ✓ Heavy reactive power flows
- ✓ No substantial frequency change
- ✓ Inadequate reactive support
- ✓ Heavily loaded power systems

In these situations unwanted tripping of relays could lead to a wide area disturbance.

3.2.1 DISTANCE PROTECTION

A distance element basically computes the ratio of a voltage over a current to measure impedance. When the ratio gets low enough, due to the reduction in the voltage magnitude, to enter the applied impedance characteristic, the relay issues a tripping signal, so low voltage contributes to line tripping by distance protection.

When a voltage stability problem occurs on a network with the expected reduction of the voltage magnitudes and increase of the load current at the same time, the possibility exists that the impedance measured by the distance relays could infringe into the element characteristic and the voltage instability could then be the cause for the tripping of the line.

This situation is the same as the one occurring during an out-of-step condition when the distance element will trip not because of a phase fault but because the computed impedance infringing into the element characteristic. In general terms the apparent impedance $\overline{Z}_r$ seen

$$\overline{Z}_r = \frac{U^2 \cdot (P + jQ)}{P^2 + Q^2}$$

by a distance relay corresponds to:

where $\overline{U}$ is the line to line voltage and P and Q are the injected active and reactive power at the location of the relay.

In case $\overline{Z}_r$ remains within the area of one of the predefined zones of operation during a time exceeding the setting of the timer associated with the zone, the relay will operate. It follows from the equation that these events may cause distance relays to mal-trip as a depressed voltage, and generally high values of P and Q make the value of $\overline{Z}_r$ low enough to be in the tripping characteristic of the distance relay. This behaviour is undesirable since it will aggravate the status of the power system in an already severe situation.

Undesirable relay operations due to voltage instability will mainly be initiated by the zone with the longest reach. Normally this is the zone used for remote back-up protection which usually is zone 3.

3.2.2 OVERCURRENT PROTECTION

In some transient scenarios low voltage levels can result in high load currents above the pick-up of the overcurrent relays. If the time exceeds the time setting delay, it can cause an undesirable trip

3.2.3 DIFFERENTIAL PROTECTION

Line current differential and phase comparison relaying systems, applied for transmission line protection, are immune to voltage instability, because of their principle of operation, current going into an apparatus must be equal the current leaving the device when there is not fault.

3.3 RELAY PERFORMANCE WITH DYNAMIC LINE LOADING

3.3.1 DISTANCE PROTECTION

The effect of load on the operation of distance relays is well known and studied. It may lead to under or over-reaching of the distance characteristic.

This is especially true in the case of long transmission lines, multiterminal lines and the Zone 3 elements that have to provide backup protection for lines outgoing from substations where those lines are connected This system topology leads to a very high zone 3 reach to provide back-up to the primary protection of the lines that could then encroach on the line load, leading to line tripping

Tripping heavy loaded lines is quite dangerous during wide area disturbances and will result in quick deterioration of the system and a possible blackout.

As an exampled during the 14 August 2003 the Sammis-Start 345 kV line tripped as a consequence of zone 3 tripping. Fig. 3-1 shows the apparent impedance inside Zone 3 seen by the distance relay of that line clearly inside the tripping area of zone 3.

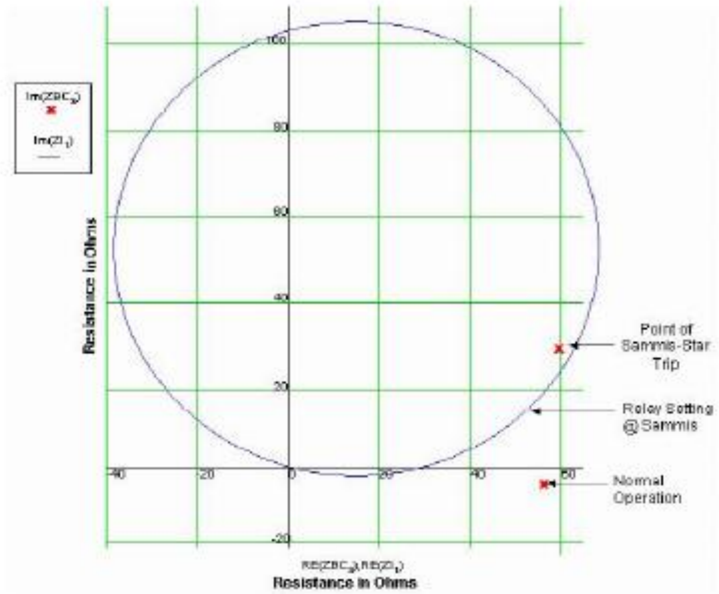


FIG. 3-1: **ZONE 3 DISTANCE RELAY OPERATION ON THE 345 KV SAMMIS-STAR TRANSMISSION LINE**

Low voltage levels, combined with high load currents, and in some cases very high reactive flows result in the tripping of time delayed distance elements. The relay operates as designed and set.

3.3.2 OVERCURRENT PROTECTION

Since phase overcurrent protection has limited use at the transmission or bulk level of the power system, high balanced current should not result in protection operation. However, in real life the system is quite often not balanced. Un-transposed transmission lines may have a difference in the impedance of the individual phases in the range of up to 10 %. As a result, the high current during dynamic loading or system oscillations may create sufficient zero sequence current that will lead to the operation of a backup ground overcurrent element of a multifunctional protection relay. A ground pilot element could also operate to trip for example in a DCB (Directional Comparison Blocking) scheme if the blocking signal is interrupted and sufficient unbalance current exists.

Over-current protection is sometimes installed on transformers to provide back up protection to transformer differential relay. Over current relays also provide some degree of thermal protection to the transformer and back up protection to the relays protecting equipment connected to the transformer. Over-current relays are set to pick up around 130% to 200% of the rating of the transformer. System contingencies leading up to the overloading of the transformers beyond the over-current relay pick up setting will result in tripping the transformer. Some users have chosen to provide redundant differential protection instead of providing over-current back up to avoid tripping due to overloads.

3.3.3 DIFFERENTIAL PROTECTION

Differential protection is exchanging current information from the both ends of the protected elements. The operating current and restrain current are expressed as:

Operating Current = | I1 + I2|; restrain current = (|I1| + |I2|)/2

During an overload, the current load is high but equal at both ends, so line current differential relaying systems are immune to high load currents.

3.4 RELAY PERFORMANCE DURING POWER SWINGS

3.4.1 DISTANCE PROTECTION

Power swings can, for example, cause the load impedance, which under steady state conditions is not within the relay's operating characteristic, to enter into the distance relay-operating characteristic.

The impedance trajectory during a power swing will cross any relay characteristic that covers the line, provided the electrical centre falls inside the line. Phase distance relays respond to positive-sequence quantities. The positive-sequence impedance measured at a line terminal during a power swing condition varies as a function of the phase angle separation, δ, between the two equivalent system source voltages.

Zone 1 distance-relay elements with no intentional time delay are the distance elements most prone to operate during a power swing, if the power swing blocking (PSB) relay function is not enabled.

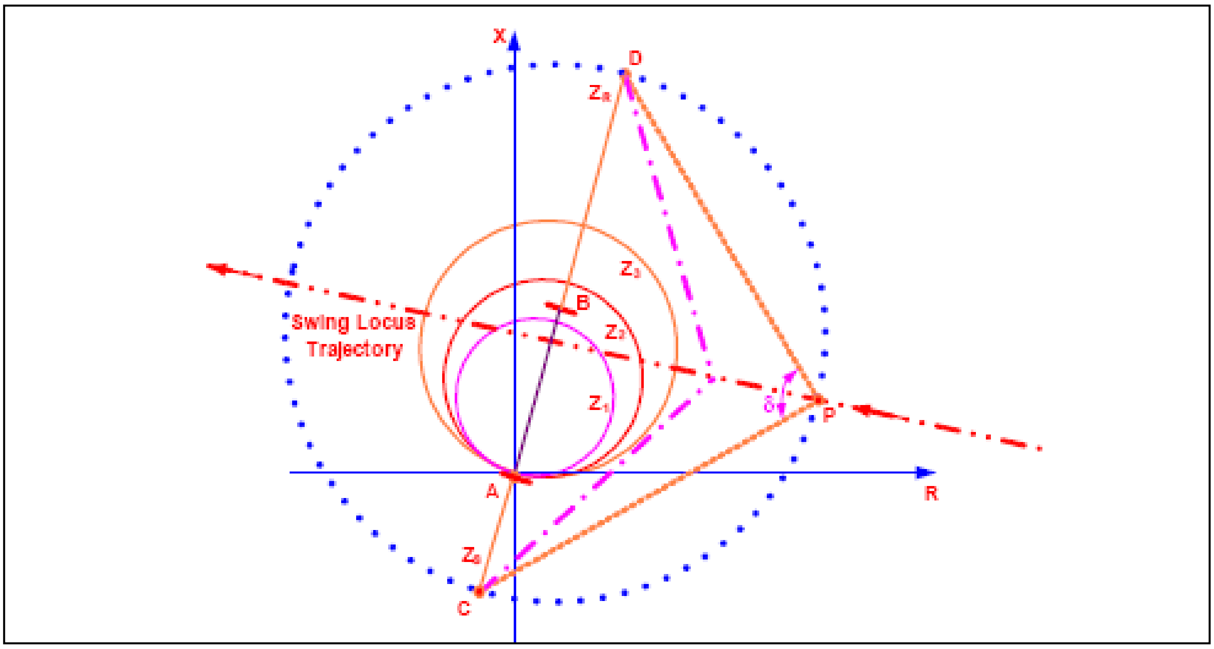


FIG. 3-2: SWING LOCUS TRAJECTORY WHEN THE MAGNITUDE OF ES/ER = 1.0

As we can see in the Fig. 3-2 the swing locus passes through the zone 1 tripping zone and because usually it is no time delay the protections will trip the protected element as if any real short-circuit happening.

Backup zone step-distance relay elements will not typically operate during a swing, depending on their time-delay setting and the time it takes for the swing impedance locus to traverse through the relay characteristic.

3.4.2 OVERCURRENT PROTECTION

When power swings reach certain amplitudes (e.g.due to unsufficient damping) they can generate high currents during part of the swing cycle that may impact the performance of phase directional or nondirectional instantaneous overcurrent relays. Instantaneous phase overcurrent relays will operate during those power swings if the line current during the swing exceeds the pickup setting of the relay.

Likewise, directional instantaneous overcurrent relays operate if the swing current exceeds the pickup setting of the relay and the polarizing and operating signals have the proper phase relationship during the swing. Time-overcurrent relays will probably not operate but this will depend on the swing current magnitude and the time delay settings of the relay.

3.4.3 DIFFERENTIAL PROTECTION

Modern numerical line current differential and phase comparison relaying systems, applied for transmission line protection, are immune to stable and unstable power swings, because of their principle of operation.

3.5 RELAY PERFORMANCE *DURING POWER SYSTEM ABNORMAL FREQUENCY CONDITIONS*

This is a critical issued for the numerical relays that are actually being installing in most of the power systems. The numerical relays track system frequency to calculate the current, voltage, and impedance phasors. Under abnormal frequency situations, phasor errors calculations could lead to unwanted operation of the relays based on this technology. Without getting into the detail, the performance of these relays during a frequency excursions depens on:

- ✓ The type of filtering
- ✓ If the relay has frequency tracking or not
- ✓ The measurement and tracking speed
- ✓ And type of polarizing memory.

3.5.1 DISTANCE PROTECTION

Frequency variations in the power system with respect to nominal frequency produce errors in Fourier filter (DFT) calculations as the samples used no longer equal exactly a integer multiple of the system frequency

However, the tendency of a distance relay to misoperate for a frequency variation is not predominantly caused by phasor calculation errors as they are relatively minor even for a comparatively large frequency deviation. The main cause for undesired tripping is due to the way memory polarization is utilized, as will be discussed below.

Distance relays algorithms generally employ a memorized voltage taken several cycles before the fault inception in order to ensure correct operation for the following conditions:

- ✓ Faults with low voltage at the relay terminal, where the polarizing voltage is below the signal threshold required for accurate voltage measurement.
- ✓ Faults with voltage inversion on series compensated lines.
- ✓ Faults in applications with capacitive voltage transformers (CCVT's) that may generate significant transients, especially for low voltage faults.

The memory time required for the polarizing voltage depend on the type of fault and the system characteristics:

1. Faults with low voltage at the relay terminal, where the polarizing voltage is below the signal threshold required for accurate voltage measurement.

In general, low- or zero-voltage faults occur for faults very close to the relay terminal where there is little line impedance between the relay and the fault location. Close-in faults are located within the relay Zone 1 reach. As Zone 1 trips instantaneously, the polarization memory time required is very short. Typically 2 - 3 cycles' memory is sufficient.

However, in applications with high source-to-line impedance ratio (SIR) the voltage may drop to a very low value also for external faults, beyond the remote line terminal in Zone 2 or even Zone 3. The distance units should remain asserted until the corresponding timer has timed out and it may be necessary to increase polarization memory time up to Zone 2 or Zone 3 time delays.

2. Faults in applications with capacitive voltage transformers (CCVT's) that may generate significant transients, especially for low voltage faults.

For applications with CCVT's, the voltage polarization memory time should be long enough to last during the subsidence of any transient produced.

The use of longer polarization times presents a serious problem for distance protection in the presence of frequency excursions. A change in frequency will cause a phase angle shift between the frozen memory voltage phasor and the actual voltage phasor. This shift is especially detrimental for distance relay Mho characteristics.

The Mho characteristic is formed by comparison of the angle between an operating quantity and a polarizing quantity:

$$\begin{aligned} OP &= I \cdot Z_n - V \\ POL &= V_M \end{aligned} \tag{1}$$

where

I = the fault current for the impedance measuring unit

V = the fault voltage for the impedance measuring unit

V_M = the polarizing memory voltage

Z_n = Zone n reach setting

The mho characteristic operates when the angle between the operating quantity and the polarizing quantity is less than 90 degrees:

$$\left| \angle OP - \angle POL \right| \leq 90° \tag{2}$$

Fig. 3-3 is showing the phasors and the resulting mho operating characteristic in an impedance plane.

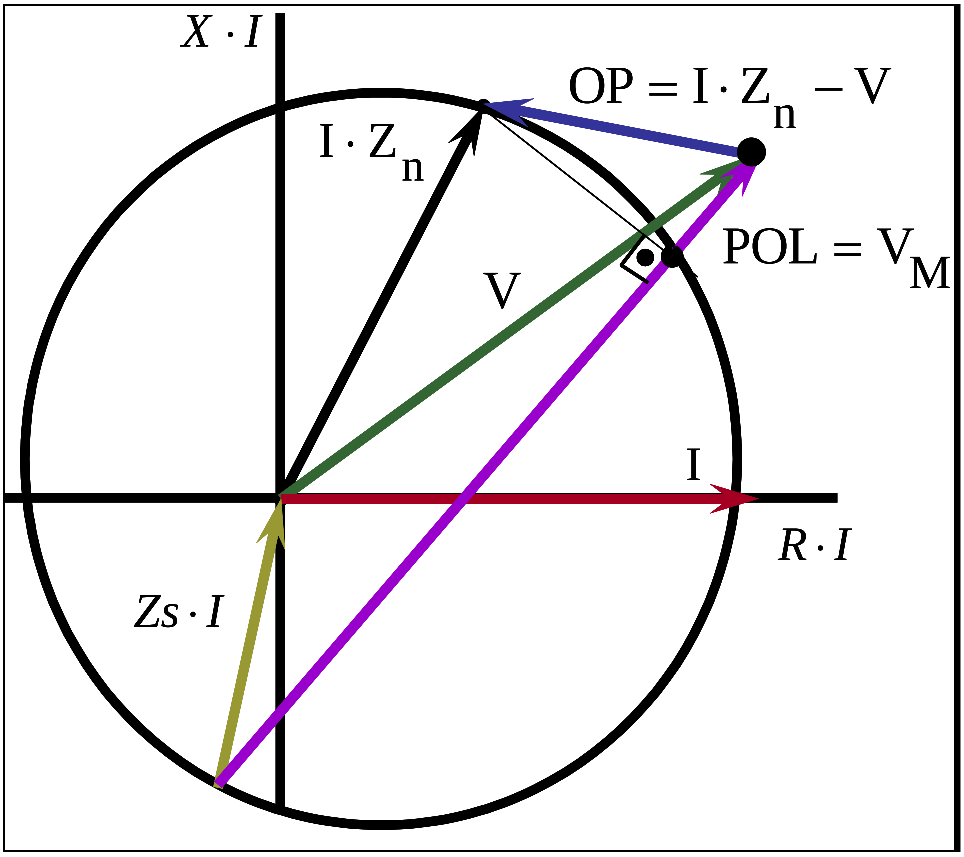


FIG. 3-3: MHO CHARACTERISTIC AND EFFECT OF POLARIZING MAGNITUDE

The mho elements tend to overreach for decreased frequency and underreach for increased frequency.

It is important to note that the tendency for a false operation by the mho characteristic does not only occur while the frequency varies with time but also for any discrete change, because in both cases there is a shift between the polarizing and operating phasors, although the shift is constant in the latter case, instead of varying with time.

For distance relay quadrilateral characteristic, the use of memory voltage is not as prone to cause misoperations during frequency excursions as for the mho elements. The reason for this is that the memory voltage is used for directional measurement only, and not for reach. It is possible that a large frequency variation could cause loss-of-directionality of the quadrilateral characteristic, but undesired tripping would still not occur as the apparent impedance would be outside the set reactive and resistive reach. However it could result in a missed trip for a forward fault or a trip for a reverse fault if the directional element makes an erroneous decision.

3.5.2 OVERCURRENT PROTECTION

Overcurrent elements calculated the current phasor and compare with a threshold to make a protection decision. In most of the application the overcurrent has a time delay to coordinate with other protections devices. The typical errors for phasor magnitudes are between 1% and 11% depending on the magnitude of frequency excursions and the tracking algorithms. Therefore if frequency ramps quickly (10 Hz/s) error could be around 7% and one should increase settings thresholds of overcurrent to prevent misoperations.

> Overreaching of overcurrent elements is proportional to the difference between the input and the relay tracking frequencies

3.5.3 DIFFERENTIAL PROTECTION

Differential protection is a pilot protection and therefore is exchanging current information from the both ends of the protected elements. The operating current and restrain current are expressed as:

$$\text{Operating Current} = |\, I1 + I2|; \quad \text{restrain current} = (|I1| + |I2|)/2$$

For external faults the currents at both ends are equal. Both currents are the same phasor with opposite polarity. When the relay calculated the phasor sum the phase shifts and magnitude oscillations cancel itself, so the operating current is a perfect zero (disregarding the small charging current). Because the restraining current is an average of phasor magnitudes, the magnitude of oscillations of an individual phasor pass directly to the restraint current.

For zero fault resistance internal faults both the operating current and the restrain current oscillate with similar magnitudes errors. In general terms, the differential element is secure again external faults regardless of system frequency, and it is dependable for internal faults without resistance and could reduce its sensitivity for high resistance faults.

Differential protections with frequency tracking capability may track frequency in symmetrical or asymmetrical manner. Differential protection devices must stay in synchronism with each other and should stay in synchronism with the power system for accurate phasor measurements. Devices track the system frequency in either a symmetrical or asymmetrical manner to adjust the sampling process or compensate the raw phasors. A symmetrical scheme uses an equivalent average frequency between all devices and an asymmetrical scheme uses local frequency measurement at a given device. The symmetrical schemes are immune to off-nominal frequency problems, because all devices use the same tracking frequency. In case of asymmetrical schemes, the tracking frequencies may differ considerably between devices because each device uses frequency derived locally and may respond differently to their local input signals.

Differential protections measure currents in the phase-segregated or mixed-mode. Phase-segregated differential schemes are immune to errors caused by off-nominal frequencies, opposite to mixed-mode because of occurrence of spurious negative-sequence currents in response to off-nominal frequencies, which can jeopardize security of the line differential scheme. The mixed-mode system is really not widely used on high voltage level (except for short coupling lines without requirements of single-phase auto recloser).

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[8] Out-of-Step Protection Fundamentals and Advancements. Demetrios A. Tziouvaras, Schweitzer Engineering Laboratories, Inc., Vacaville, CA USA and Daqing Hou, Schweitzer Engineering Laboratories, Inc., Boise, ID USA, 2003

[9] Adapting Protection to Frequency Changes. R. Cimadevilla, R.Quintanilla and S. Ward 32nd Annual Western Protective Relay Conference

4 ANALYSIS OF DEFENCE PLAN PROCEDURES

4.1 DEFENCE PLANS IN THE CONTEXT OF SYSTEM STATES

In general power systems are planned, built and operated to withstand a predefined set of credible contingencies. In this regard a credible contingency is a contingency or a fault which has been specifically foreseen in the planning and operation of the system, and against which specific measures have been taken to ensure that no serious consequences would follow its occurrence [1]. In particular the power system functions in terms of customer supply and scheduled power transits should not be affected within given limits by the predefined credible contingencies. To this aim the so called n-1 rule is common practise in most large power systems worldwide. The n-1 rule ensures that the power system is always operated in a robust condition with sufficient safety margins in order to withstand single failures followed by the loss of one system element (transmission line, transformer, generating unit etc.). Under these circumstances the power system is considered to be in the "normal" state (Fig. 4-1).

If the system parameters are still within admissible ranges but the system does not any more meet the criteria given for a secure state (e.g. no more n-1 secure), the system is considered to be in an alert state (or endangered state). Typically the system might reach this state after a (n-1) contingency. This state requires application of remedial actions without any delay in order to come back to the secure state (i.e. to comply again with the n-1 rule).

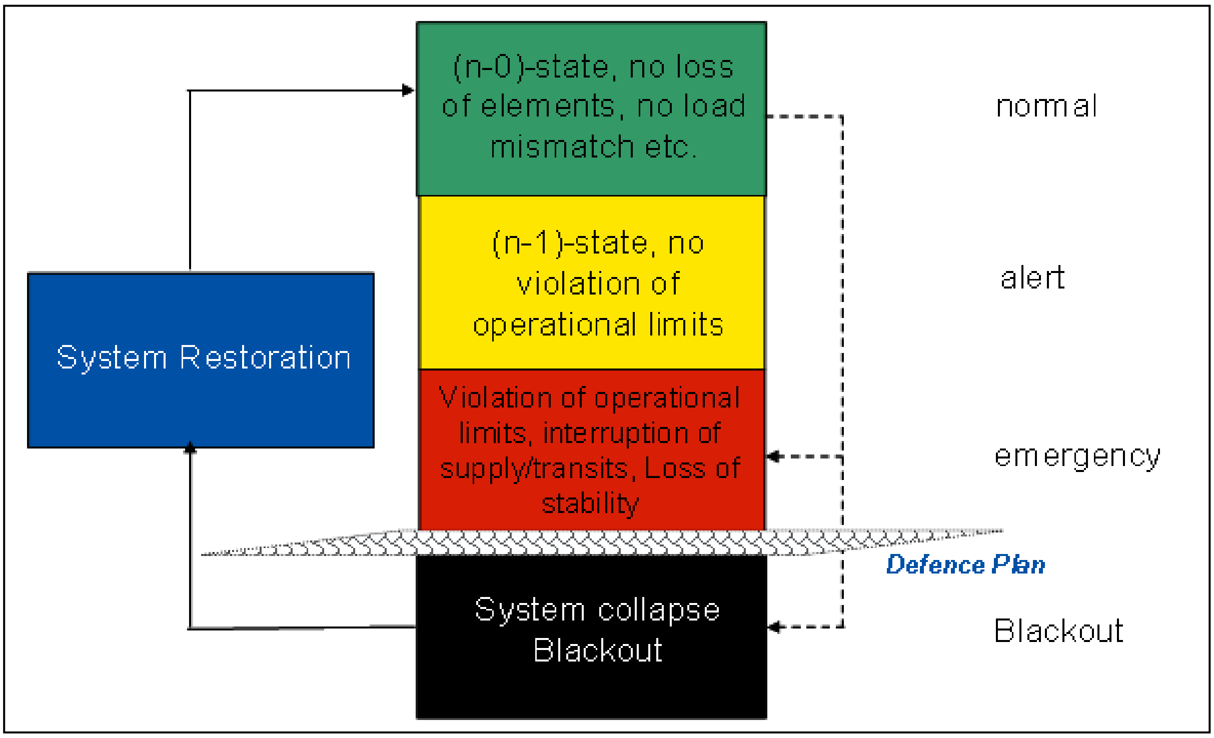

FIG. 4-1: SYSTEM STATES ACCORDING TO [3]

Power Systems can also be subjected to contingencies, which exceed in severity the predefined credible contingencies. These non-credible or extreme contingencies are rare and often result from exceptional technical malfunctions, force majeure conditions or human errors. Extreme contingencies are with respect to their causes and consequences variegated and thus not specifically defined in the design and planning policies of most utilities. As consequence of extreme or unforeseen contingencies the system parameters could violate the admissible operational limits and hence the system is considered to be in an emergency state (a disturbed state). A system being in emergency state might not be able to fulfil its function with respect to consumer supply and power transits, but is not blacked out. However, there is the risk of system collapse mainly due to the loss of stability. Therefore relevant actions must be taken immediately to bring back the system into acceptable conditions.

In order to cope with and to minimize the impact of these rare but extreme contingencies, i.e. in particular to prevent a total system collapse, Defence Plans have been developed and implemented by several utilities. These plans include a set of coordinated and mostly automatic measures (System Protection Schemes3) to ensure fast reaction to large disturbances and to avoid their propagation through the system. A Defence Plan is thus designed to initiate the final attempt at stabilizing the power system when a wide spread collapse is imminent [2]. Individual SPS such as load shedding, generation rejection or system splitting are then regarded as coordinated elements used within a Defence plan.

A blackout state is characterized by almost total absence of voltage in a certain area of the transmission system as a consequence of tripping of generating units due to abnormal variation of voltage and/or frequency, which occurred during the emergency state. Once the system enters the blackout state the restoration plan shall be activated as soon as possible.

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[3] In the literature further notations for the term System Protection Scheme circulate, e.g. Special Protection Scheme (SPS), System Integrity Protection Scheme (SIPS), Remedial Action Scheme (RAS), Emergency Control Action (ECA). Independent of the respective notation all these schemes are used when the focus for the protection is on the power system supply capability rather than on a specific equipment.

4.2 DEFENCE PLANS IN THE CONTEXT *OF STABILITY PHENOMENA*

The risk of system collapse results from the possible loss of stability after extreme or unforeseen contingencies. Therefore individual SPS used within a defence plan are generally designed as tailored automatic measures to detect and to contain specific system conditions, in particular hazardous power system phenomena like different types of power system instability:

- *Rotor Angle Instability*
- *Frequency Instability*
- *Voltage Instability*

In this context the containment of such conditions means to keep them under control in a way that the post-disturbance phenomena are diminished and voltages, currents and frequencies are kept within their acceptable limits, which is a precondition to reach a stable operating point. To reach a stable operating point in turn is a precondition to ensure that the generation units keep on running. In the end the challenge of avoiding total system blackouts is more or less the challenge of keeping the generating units running, which also requires a robust behaviour of generating units which is compliant with the respective grid codes (Fig. 4-2).

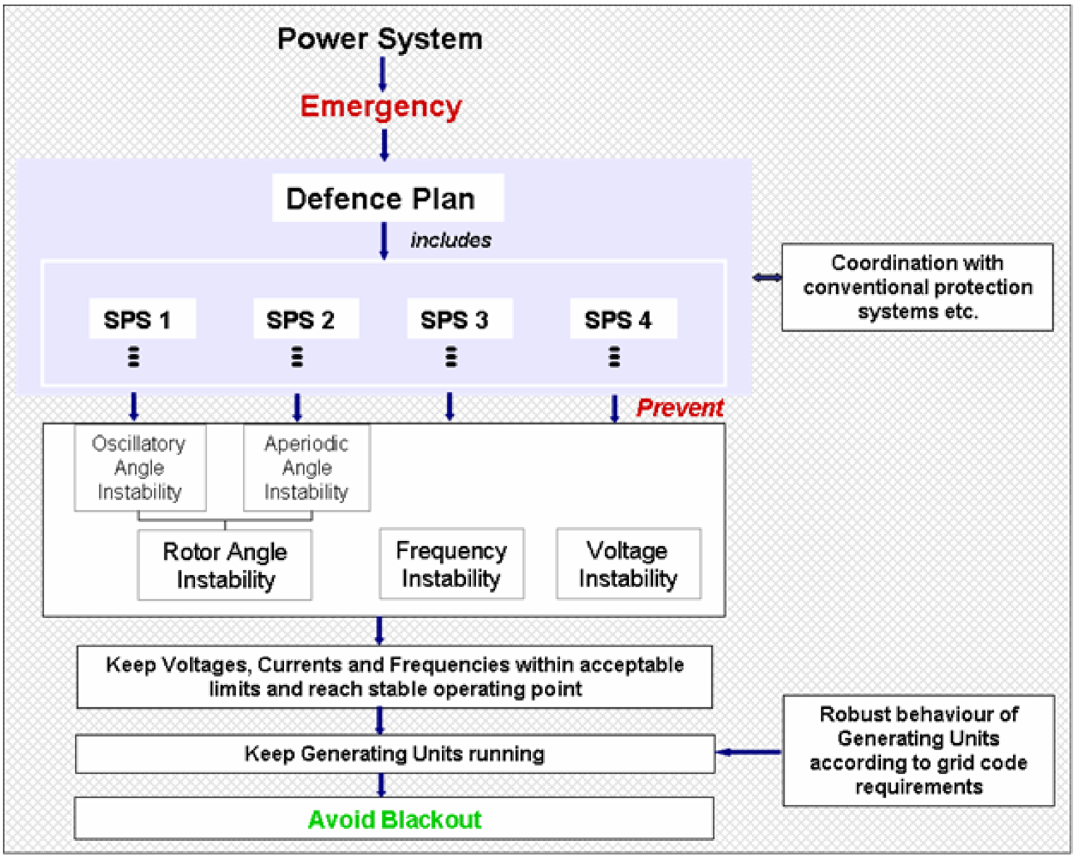


FIG. 4-2: A SET OF COORDINATED SPS IS CONSIDERED AS DEFENCE PLAN

In densely meshed power systems with dispersed generation and load patterns a disturbance usually passes all system states (see Fig. 4-1) before emerging as a blackout. This provides a certain time frame to react before the emergency state is reached and to measure and to assess relevant system parameter that can be used as input for the SPS. These so called response based SPS have the advantage that they are efficient also for events that are not explicitly identified, which is important as there is an innumerable combination of possible contingencies that could strike the grid.

If the SPS action is not based on the power system response but on an event itself the SPS is called event based. Event based SPS can be used for a limited number of critical events, that are easy to identify and which require quick remedial actions. Especially in weak and highly loaded systems in case of specific scenarios already single failures could bring the system from the normal state to an emergency state or even – if no defence plan is implemented – to the blackout state (Fig. 4-1 dashed line). In such a case remedial actions have to be triggered immediately after the event is detected. Even though the measured system quantities do not yet reveal the loss of stability it is known beforehand that the consequences of the event would be critical for the system stability and security. As the CE Synchronous Area is operated according to the n-1 rule a single failure does not endanger its stability and consequently response based SPS should be used within the Defence Plan.

4.3 REVIEW *OF* DEFENCE PLANS *IN THE* CE SYNCHRONOUS AREA *AND WORLD WIDE*

4.3.1 DESCRIPTION OF THE APPLIED PROCEDURE

Currently, as regards the Continental Europe Synchronous Area, specific individual countermeasures for extreme contingencies and/or more sophisticated defence plans are applied on national or TSO’s level (within each Control Area) without CE wide harmonization. Therefore at first an inventory was conducted to provide an overview of the practices applied by all the ENTSO-E RG CE members. The inventory and the corresponding results are not made public within this report. Fig. 4-3 shows the TSOs that contributed to the inventory.

Defence plans in use outside of the CE Synchronous Area have been investigated by means of literature research. The results are given in the Annex.

Country	TSO	
Albania	OST	🟩
Austria	APG	🟩
Bosnia-Herzegovina		🟥
Belgium	Elia	🟩
Bulgaria	ESO	🟩
Croatia	HEP-TSO	🟩
Czech Republic	CEPS	🟩
Denmark_West	Energinet.dk	🟩
France	RTE	🟩
Germany		⬜
	EnBW Transportnetze	🟩
	E.ON Netz	🟩
	RWE TSO	🟩
	VE-T	🟩
Greece	HTSO	🟩
Hungary	MAVIR	🟩
Italy	TERNA	🟩
Luxembourg		🟥
F.Y.R of Macadonia	MEPSO	🟩
Montenegro	EPCG	🟩
Netherlands	Tennet	🟩
Poland	PSE-Operator	🟩
Portugal		🟥
Romania	Tel-Transelectrica	🟩
Serbia	JP-EMS Serbia	🟩
Slovak Republic	SEPS	🟩
Slovenia	ELES	🟩
Spain	REE	🟩
Switzerland	swissgrid	🟩

FIG. 4-3 : COUNTRIES / TSOS THAT CONTRIBUTED TO THE INVENTORY

4.3.2 KEY FUNCTIONS OF THE EXISTING DEFENCE PLANS

4.3.2.1 MEASURES TO MANAGE FREQUENCY INSTABILITY PHENOMENA

In general Under-Frequency Load Shedding (UFLS) is utilized to overcome the risk of frequency instability phenomena (recommendations for the CE Synchronous Area: see chapter 6).

4.3.2.2 MEASURES TO MANAGE VOLTAGE INSTABILITY PHENOMENA

Most of the measures that are implemented by utilities to overcome the risk of voltage instability can be categorized according to the scheme shown in Fig. 4-4.

Thereby sophisticated planning policies and specified preventive operation procedures precede the activation of the actual defence plan.

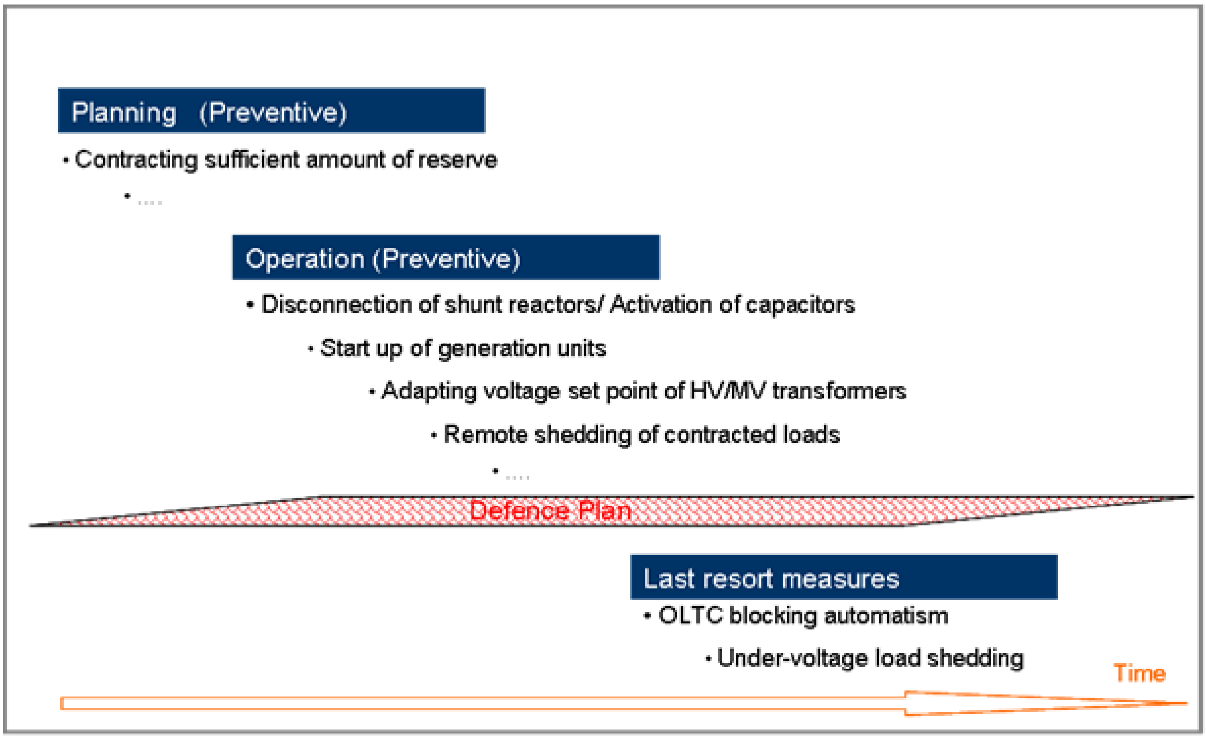


FIG. 4-4: MEASURES TO OVERCOME THE RISK OF VOLTAGE INSTABILITY PHENOMENA

However, if the operational measures are insufficient to prevent the further degradation of the voltage last resort measures like the blocking of On-Load Tap Changers (OLTC) and Under-Voltage Load Shedding (UVLS) can be initiated to preserve the system integrity. The technical concepts behind these schemes (e.g. the methodology to identify critical voltage conditions and thresholds for blocking OLTC and UVLS) are currently not harmonized within the CE Synchronous Area and can differ between the TSOs. (recommendations for the CE Synchronous Area: see chapter 6).

4.3.2.3 MEASURES TO MANAGE ROTOR ANGLE INSTABILITY PHENOMENA

With respect to its manifestation rotor angle instability can be subdivided into

- *Aperiodic or non-oscillatory angle instability*
- *Oscillatory angle instability*

and further into small-signal and transient stability sub-categories when focusing on its causes.

Aperiodic or non-oscillatory instability results from a lack of sufficient synchronizing torque and could affect both single generating units and entire power system areas. The latter case is referred to as wide area asynchronism, i.e. coherent generating groups slip with respect to each other.

To contain either the transient stability of single generating units or the transient stability of coherent generating groups some utilities have implemented or require fast valving. With appropriate trigger criterions fast valving could aid the overall system stability by reducing the transmitted power after fault clearing, which is of particular importance when the transmission corridor is weakened after fault clearing. Strictly speaking fast valving is not an "emergency defence measure" in the actual sense unless the trigger for its activation is a measured system response that reveals the system to be in the emergency state. But undoubted it could support the overall system security and should be required where necessary (see also chapter 5).

In order to initiate (controlled) system separation in case of asynchronism some utilities have implemented Out-of-Step Protection on predefined tie lines whereas others rely on the distance protection to separate the system at its natural points, i.e. at the location of electrical centre.

Fig. 4-5 Fig. 4-5shows measures to overcome the risk of rotor angle instability.

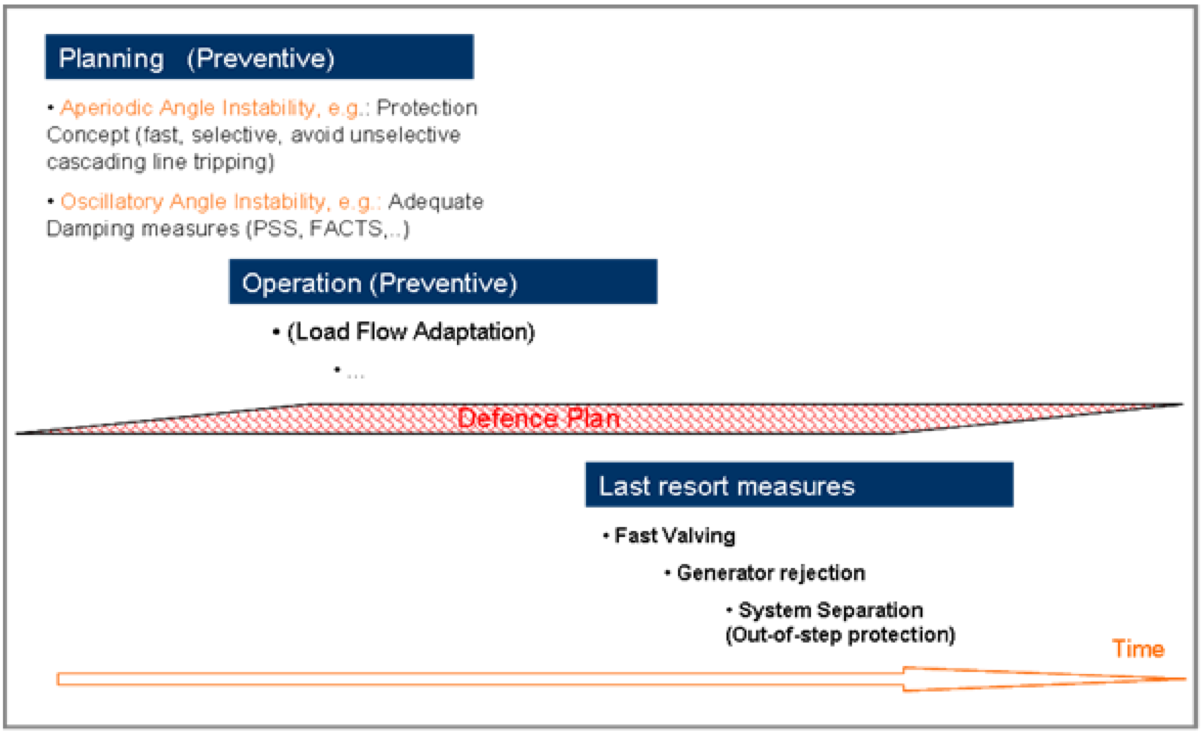


FIG. 4-5: MEASURES TO OVERCOME THE RISK OF ROTOR ANGLE INSTABILITY PHENOMENA

An important factor in case of aperiodic angle instability is its evolution with respect to time:

- A fast (pole) slipping is often caused by a heavy transient disturbance (e.g. delayed fault clearing). As classical impedance based Out-of-Step protection detects the out-of-step condition not till the first pole slip has occurred a voltage collapse occurs when the phasors of the concerned areas move towards phase opposition. Depending on the exact voltage profile generating units that behave in a robust manner according to grid code requirements are able to resist such a condition if it passes by fast enough.
- A slow (pole) slipping that comes along with a decreasing voltage over several seconds could be the result of a new operating point that is not small signal stable, e.g. a weakened transmission corridor that is not able to transmit the required

power (see chapter 2, Italian Blackout). The resulting fluctuations of voltage, currents and frequency could last for a longer time period before out-step-relays operate. Though also depending on the exact voltage profile generating units are – in comparison with fast pole slipping – much more prone to disconnect from the grid.

In contrary to aperiodic instability oscillatory instability results from a lack of sufficient damping torque. It could affect both single generating units (local oscillations) and entire power system areas (inter-area oscillations). The power system itself (generating units, loads) comprises an inherent natural damping. The occurrence of un-damped oscillation is related to the action of control devices, in particular (fast) automatic voltage regulators, within the power plants. Therefore countermeasures to manage oscillatory instability are mainly concentrated on prevention by installing additional damping devices (Power System Stabilizer, FACTS,…) (see Fig. 4-5Fig. 4-5) In the case of an un-damped oscillation, depending on the oscillation amplitude, unintended operation of protection devices could result and trip lines or power plants. In the worst case an out-of-step condition likewise to aperiodic instability could result. (recommendations for the CE Synchronous Area: see chapter 6).

[1] U.G. Knight “Power System in Emergencies”, Wiley

[2] CIGRE Task Force C2.02.24, “Defence plan against extreme contingencies”, Technical Brochure, April 2007

[3] UCTE Masterplan for managing wide disturbances- Basic considerations and action plan, February 2008

5 REQUIREMENTS TO GENERATORS

5.1 INTRODUCTION

The course of disturbances during emergency conditions depends in a high degree on the performance of the generation units: On the one hand generation units are the main source of actions supporting system stability mainly by means of governor and excitation control. On the other hand generation units themselves might be affected by voltage and frequency variations during disturbed grid conditions and therefore they must be robust enough to withstand them. Consequently, especially during emergency conditions the dynamic response of generating units is a crucial factor for preserving and re-establishing the system security and integrity.

In this context the whole generation process has to be considered like boiler, turbine, generator, excitation and governor control, auxiliary, protection levels, etc. Against the background of the TSO’s responsibility for the system security a close cooperation of generators and TSOs is necessary in order to define appropriate grid requirements and to ensure sufficient performance of generation units.

The UCTE document “Requirements to Generators” (UCTE AD-HOC Group, final Version September 2008) /1/ describes all important elements in this context. With respect to frequency stability phenomena detailed and sufficient specifications are given. However, the Expert Group on Power System Stability highlighted that with respect to the loss of rotor angle or voltage stability the aspired behaviour of generation units should be specified more precisely. Currently the ENTSO-E Pilot Code “Requirements for Grid Connection Applicable to all Generators” is under development and discussion /2/. This network code will cover in detail the technical requirements for generators that are necessary for the security and stability of the power system.

The risk that emanates from the loss of rotor angle stability is mainly based on the decreasing voltage in the proximity of the electrical centre. Therefore both phenomena the loss of voltage stability as well as the loss of rotor angle instability necessitate to set precise requirements on generators that focus on exceptional voltage conditions.

The uncontrolled tripping of generating units due to a decreased grid voltage leads to the further deterioration of voltage support, uncontrolled power flows redistribution with overload risks and finally to cascading outages (lines, further power plants) and system collapse. For this reason it is indispensable that generation units are robust with respect to exceptional voltage conditions and behave in compliance with the requirements that are specified in the next paragraphs.

Thereby the requirements that should be met by the generation units are derived both from simulation studies (realistic events have been used to demonstrate slow and fast voltage decreases) and the measured grid voltage behaviour

5.2 CLASSIFICATION OF VOLTAGE DROPS

Voltage drops can be classified according to their evolution over time:

- Short term voltage drops in the range of 100 ms up to several seconds, e.g.
  - A voltage drop during a short circuit in the grid near generating units and after fault clearing (transient stability) → chapter 5.3.1
  - A voltage collapse during the loss of wide area rotor angle stability (asynchronous operation) → chapter 5.3.2
- Long term voltage drops in the range of seconds/minutes to hours, e.g.
  - low quasi-steady state grid voltages and slow voltage collapse → chapter 5.3.3

5.3 REQUIREMENTS TO GENERATORS WITH RESPECT TO THE DIFFERENT VOLTAGE DROP CHARACTERISTICS

5.3.1 SHORT TERM VOLTAGE DROP DURING SHORT CIRCUIT

Fig. 5-1 shows the simulation of the voltage behaviour in the grid and at the generator terminals during and after a 3-phase short circuit, which occurs very close to the grid connection point of the generation unit.

This simulation illustrates that a 3-phase short circuit always causes an

- initial voltage drop (<=150ms)
- a subsequent voltage drop in the shape of a saddle after fault clearing. This voltage drop results from the advanced internal rotor angle and its exact shape depends on the initial generator operating point, the short circuit duration and the short-circuit power of the grid to which the concerned generating units are connected. Moreover the voltage drop depends also on the type of excitation, the automatic voltage regulator and the governor of the unit including fast valving.

Based on the principle physical behaviour the voltage profile curve shown in Figure 5-2 has been derived.

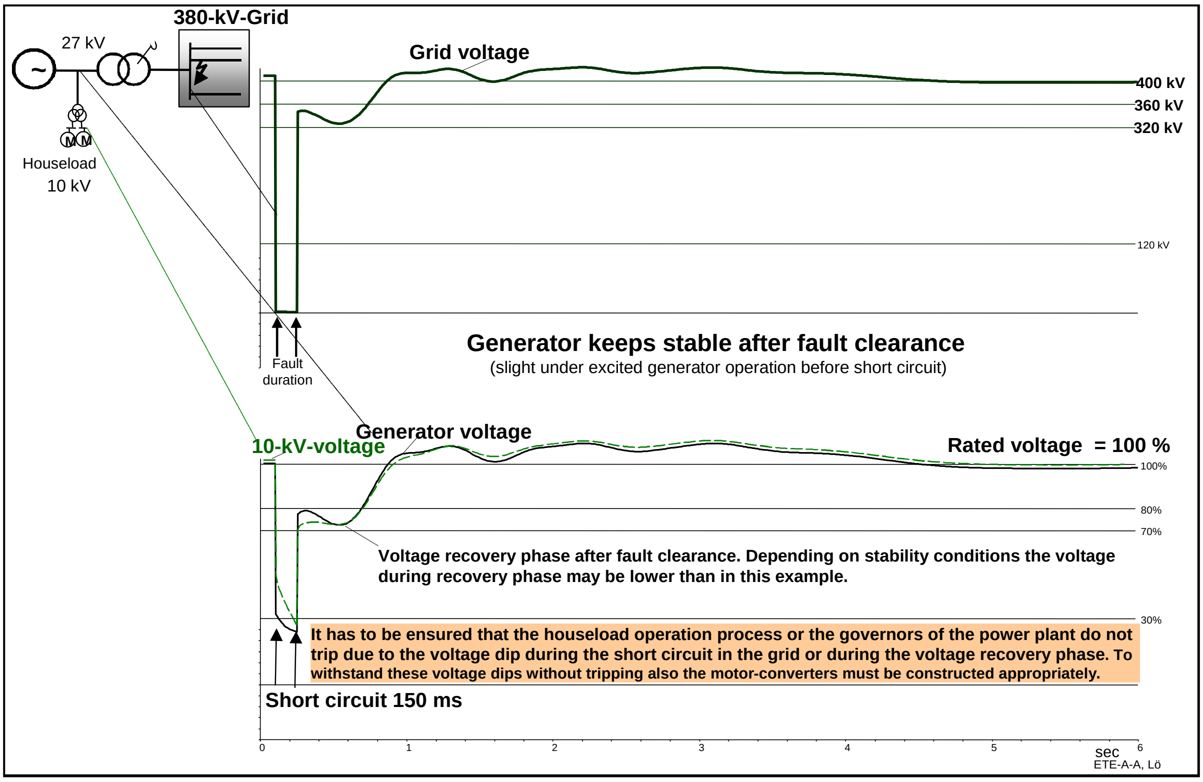


FIG. 5-1: SIMULATION OF A VOLTAGE DROP AT GENERATOR TERMINALS AND AUXILIARY SUPPLY AFTER A SHORT CIRCUIT IN THE GRID

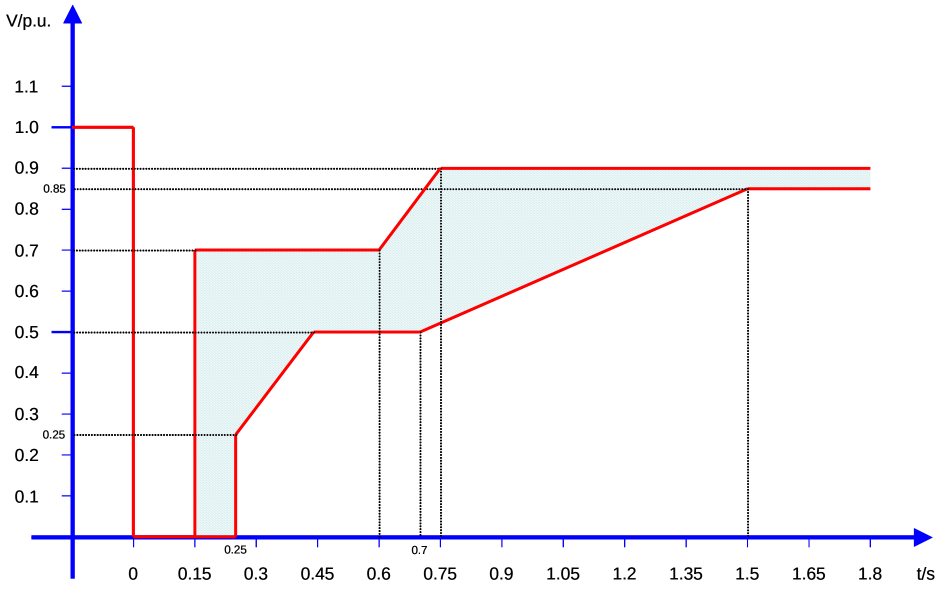


FIG. 5-2: BOUNDARIES OF A VOLTAGE-AGAINST-TIME-PROFILE (RED LINES) AT THE PCC (HV-SIDE) FOR SYNCHRONOUS GENERATING UNITS CONNECTED AT VOLTAGE LEVELS AT 110 KV OR ABOVE /2/

Figure 5.2 shows the boundaries of a voltage-against-time profile (red lines) at the PCC (HV-side) for Synchronous Generating units connected at voltage levels at 110 kV or above. The inner red line represents the minimum requirement which can be extended to the shaded area on TSO request, e.g. in case of specific grid characteristics or operation principles.

Remark: At present this profile is harmonized within ENTSO-E and discussed with concerned stakeholders (manufacturers etc.).

Requirements related to short term voltage drops

- The generating units must resist a transient voltage drop above the given voltage profiles for grid and generator terminal respectively according to Figure 5-2, i.e.
    - The transient stability of the generating units must be given.
    - It has to be ensured that the houseload operation process is affected neither by the voltage drop during the short circuit nor by the voltage recovery phase after fault clearing. To withstand the voltage drops by the generation unit in some cases additional specifications for the dimension of the motor-converters and the electrical feeders are necessary.

These requirements are valid for generating units with houseload connected to the low voltage side of the step up transformer (generator side) and also for generating units with houseload connected directly to the extra high voltage grid.

5.3.2 VOLTAGE COLLAPSE DUE TO LOSS OF WIDE AREA ANGLE STABILITY

During wide area asynchronism adjacent grid areas are slipping against each other, which cause high voltage drops in more or less extended grid areas. Fig. 5-3 illustrates the voltage behaviour at the “electrical centre”, which becomes temporarily zero, when rotating voltage phasors reach phase opposition.

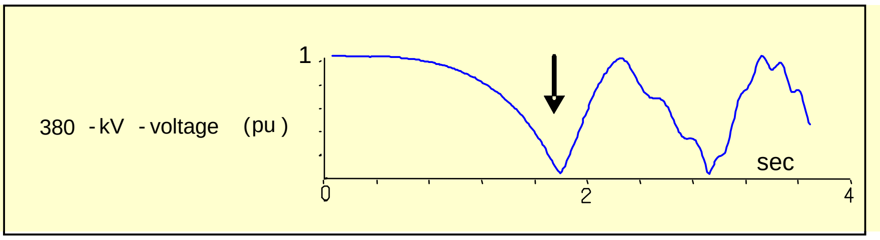
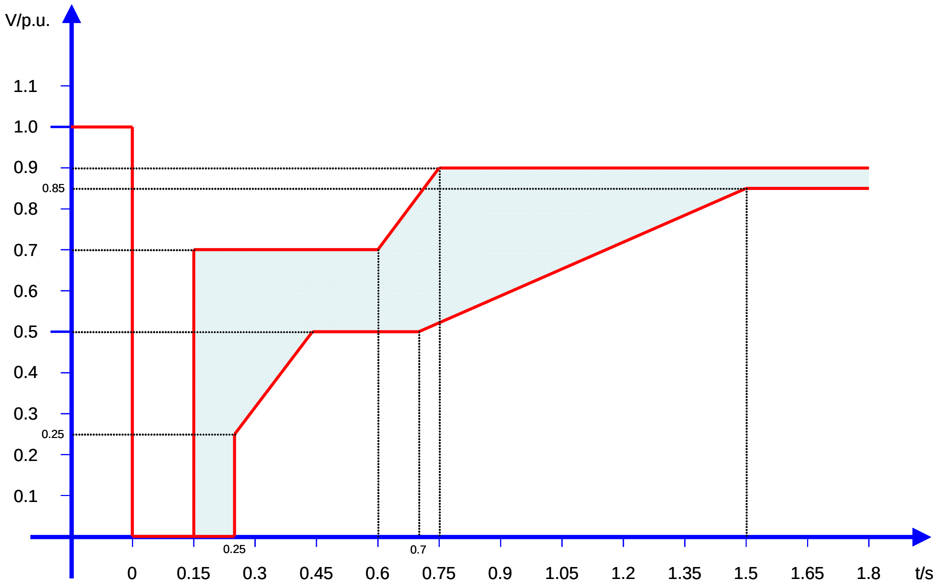


FIG. 5-3: SIMULATION OF THE GRID VOLTAGE DURING WIDE AREA ASYNCHRONISM

The duration and the deepness of the voltage drop in the surrounding grid area depend on its topology, the location and operation mode of generation units (counteracting the voltage drop in their proximity) and the rate of the pole slipping.

Requirements related to voltage collapse due to loss of wide area angle instability

According to the results of a number of transient stability studies, which were performed for different CE grid areas, it can be concluded that

- WIDE AREA ASYNCHRONISM GENERALLY OCCURS AFTER MULTIPLE CONTINGENCIES THAT LEAD TO A WEAK CONNECTION OF TWO ORE MORE GENERATION CENTRES. IN SUCH CASES THE ELECTRICAL CENTRE, I.E. THE LOCATION OF THE MOST CRITICAL VOLTAGE DROP, REMAINS SOMEWHERE ON THE TRANSMISSION CORRIDOR THAT CONNECTS THE COHERENT GENERATION GROUPS. THE GENERATION UNITS THEMSELVES, PROVIDED THAT THEY BEHAVE ACCORDING TO THE GRID REQUIREMENTS, SUPPORT THE VOLTAGE BY REACTIVE POWER INFEED AND “PUSH AWAY” THE ELECTRICAL CENTRE UNTIL AS THEIR OWN REACTIVE CAPABILITIES ARE NOT REACHED (ROTOR CURRENT, STATOR VOLTAGE LIMITS…). THEREFORE IN THE PROXIMITY OF MAJOR GENERATION UNITS (NOMINAL POWER FEW HUNDRED MW) THE VOLTAGE DOES MOST LIKELY NOT FALL BELOW THE VOLTAGE PROFILES SHOWN IN
-
- 

- **FIG. 5-2**, SO THAT THE REQUIREMENTS GIVEN IN PARAGRAPH 5.3.1 ARE ALSO SUFFICIENT TO SUSTAIN THE OPERATION OF IMPORTANT GENERATION UNITS DURING LOSS OF WIDE AREA ANGLE STABILITY.

- Smaller generation units, in particular those ones closer to the electrical centre, are most likely not strong enough to counteract the short term voltage collapse. But the risk of their tripping is at least to some extent tolerable. In this regard special attention has to be drawn on large numbers of small renewable generation units in certain grid areas, which out of the scope of this document.

5.3.3 LOW QUASI-STEADY STATE GRID VOLTAGES AND SLOW VOLTAGE COLLAPSE

In chapter 2 several incidents with slow voltage decrease in the transmission grid are described. As a general rule the minimum voltage in the EHV systems grid does not reach a stable operating point below 80% - 85% of nominal voltage, as typically in such conditions line protection will be activated due to their settings of impedance triggering criteria, and consequently transmission lines are opened. The voltage near important generation units is assumed to be not less than 340 kV.

Requirements related to low quasi-steady voltages

At the quasi-steady state grid voltage at the high voltage side of step-up transformers above 340 kV (U_n = 380 kV (400 kV)) and 190 kV (U_n = 220 kV (225 kV)) the unit must not be disconnected from the grid. In case of lower quasi-steady state grid voltages a disconnection of generating units from the grid is only admissible, if this is necessary for successful tripping on house load (auxiliary supply).

This requirement is minimal and standard. Each TSO may require more constraining performances depending on the particularity of its own system. When grid voltage decreases the generating units have to increase automatically reactive (overexcited) power (using the full output diagram) into the grid.

Each generating unit is obliged to control generator voltage automatically. In case of decreasing voltage level in the grid the generator voltage controller increases the excitation automatically and the generator must reinforce grid voltage automatically. Constant cos(φ)- regulation or constant Q- regulation must be avoided. If voltage is controlled at the grid voltage level, the voltage range is determined by the TSO. Step up transformers with on load tap changer are advantageous during low grid voltage level, because an adaptation to a lower ratio (U_{THV} /U_{TLV}) discharges the generator and could avoid problems due to over current-limiters and/or over excitation-limiters.

It is essential for the power system that the generation units support the voltage in the described manner during low quasi-steady states grid voltages. Otherwise such conditions would cause the risk of a slow voltage collapse.

5.4 *TRANSIENT STABILITY* AND *STEADY STATE STABILITY REQUIREMENTS*

In addition to the given requirements in /1/, the following remark should be added.

Fast valving of turbines shall be requested by TSO, if it is necessary to preserve the transient stability (three phase short circuits near to the generation unit).

The whole dynamic behaviour of the generator is tested by the TSO (excitation system, PSS, governor system, inertia) in an environment representative of the grid to which it is connected.

Power System Stabilizers should be implemented on all generation units beyond a predefined size (e.g. 100 MVA) and tuned both for local modes (also in case of weak grid connection of the generator) and inter-area modes if the necessity is expressed by the concerned TSO.

Over–excitation capabilities are also favourable with regard to stability issues.

5.5 COORDINATION WITH *DEFENCE PLAN*

As general rule it has to be ensured that the generation units do not trip before the defence plan action is active. This has to be considered when the Defence Plan and the corresponding thresholds are determined.

Coordination of generator protection, unit control and regulation with the defence plan and with the normal protection system and network protection is necessary. On this background the requirements to generators given in /1/ should be specified more precisely. Following fields for the need of more precise requirements to generators were identified:

- robustness against transient voltage deviations,
- over-frequency behaviour,
- frequency range for synchronisation.

/1/ “Requirements to Generators” (UCTE AD-HOC Group, final Version September 2008) Technical paper: Definition of a set of requirements to Generating Units

/2/ “Requirements for Grid Connection Applicable to all Generators”, Working Draft October 2010

6 RECOMMENDATIONS FOR THE CE SYNCHRONOUS AREA DEFENCE PLAN

6.1 FREQUENCY INSTABILITY

In a highly meshed power system like the CE Synchronous Area frequency instability phenomena are a matter of concern when it comes to system splitting. Especially when the system is separated along highly loaded transmission corridors the remaining isolated areas suffer a high amount of sudden surplus or a power deficit.

In the latter case it is of utmost importance to stabilize the frequency above the disconnection threshold for generating units (47.5 Hz).This is achieved by adequate Under Frequency Load Shedding (UFLS) Schemes.

Although past incidents revealed a sufficient operation of load shedding schemes in the CE Synchronous Area there is need for binding rules and modifications. This is motivated by

- The principle of solidarity which necessitates an improved harmonisation of UFLS
- The regulatory framework (Operation Handbook of ENTSO-E Regional Group Continental Europe, DSOs)
- The technical development of load shedding relays
- The clarification of relevant system dynamics and requirements

Against the background that the concept must work robust in a wide range of scenarios and taking into account the existing load shedding schemes the following rules are recommended (see also Figure 1):

- Load shedding of customer consumption is allowed at 49,2 Hz and mandatory at 49,0 Hz and a stepwise 50 % of the nominal load should be operated under load shedding relays in the range 49.0 to 48.0 Hz.
- At 49,0 Hz at least 5% of total consumption should be shed, which should be complemented for each individual TSO according to the loss of generation at this stage induced by the frequency drop due to non compliance with grid requirements.
- Below 49.0 Hz, the stepwise load shedding plan should be complemented by an individual mitigation of the loss of generation. TSOs should adapt their own load shedding plan in order to compensate the additional loss of generation.
- Frequency steps should be smaller than or equal to 200 mHz (depending on number of steps and characteristic of load shedding relays).
- in each step of UFLS not more than 10% of the load shall be disconnected (depending on the number of steps and characteristic of load shedding relays)
- Maximum disconnection delay should be 350 ms including breakers operation time. No intentional time delay should be added.
- Frequency measurements for load shedding devices should be maintained at a maximum inaccuracy of 100 mHz.

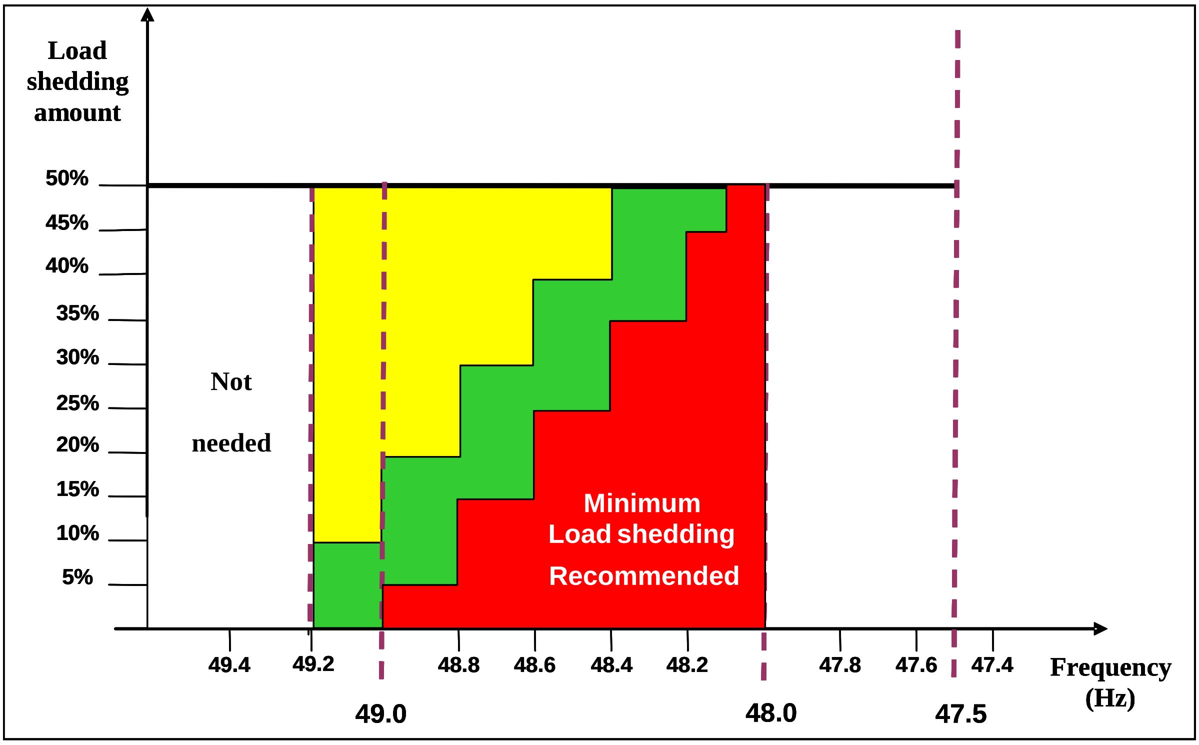


FIG. 6-1: RECOMMENDATIONS ON UFLS

Besides the aforementioned binding rules the following options for individual solutions are accepted:

- Based on the reference case for primary control in the CE Synchronous Area (3GW outage: f > 49.2 Hz) pumps can be automatically disconnected according to the subsequent scheme
    - f = 49.2 …. 49.8 Hz: with delay (0…10s)
    - f < 49.2 Hz: without delay
- The derivative of the frequency in the frequency range f > 49.2 Hz can be utilized. It is not recommended in the range f < 49.2 Hz because it requires more measuring time (4-5 cycles) and is more sensitive to oscillations.

6.2 *VOLTAGE* INSTABILITY

- To manage voltage instability phenomena the blocking of On Load Tap Changers (OLTC) and Under-Voltage Load Shedding (UVLS) should be defined respectively developed as standard for the CE Synchronous Area.
- Regarding its technical specifications the standard needs to be flexible as it has to reflect regional conditions.
- Implementation:
    - The decision for the implementation should remain within the individual TSOs, i.e. each TSO is requested to assess if its control area is prone to voltage instability phenomena and in which extent the overall system security and other grid users could be affected
    - Based on the TSO assessment and under reference to the created standard the implementation of OLTC blocking and UVLS should be binding for DSOs
    - If the decision for the implementation is taken it is recommended to utilize always both OLTC blocking <u>and</u> UFLS in a coordinated way.

6.3 *ROTOR* ANGLE *INSTABILITY*

6.3.1 APERIODIC ANGLE INSTABILITY

The analysis of defence plans world wide including the CE Synchronous Area has revealed that the implemented measures against aperiodic angle instability are in the majority of cases tailored solutions for specific power system configurations, e.g. dedicated generating and load centres connected via weak transmission corridors. Under such circumstances it is possible to predefine criteria for system separation by offline studies.

In practise even algorithms for a predictive out–of–step detection are implemented to ensure that the system separation is initiated in due time. Though the Expert Group couldn't identify a direct application for predictive out–of–step for the CE Synchronous Area it is recommended to pursue at least the research and development in this direction.

As the power system of the CE Synchronous Area is highly meshed in most of its areas the risk of loss of synchronism is limited to multiple contingencies and consequently might occur along hardly predictable corridors. If defence plan actions can not avoid a loss of stability, defence plan actions should permit a system splitting.

Therefore it is recommended that the individual TSOs are responsible to implement effective countermeasures that suppress the hazardous effects of loss of synchronism and their propagation through the power system. To this aim

a) sophisticated and tailored solutions, e.g. based on research and manifold power system studies, can be implemented for the TSO or a TSO overlapping area (in the latter case agreed between the TSOs that are affected). In order to support utilities in developing and implementing optimized solutions the Expert Group on Power System Stability will set up a guideline including the most relevant information regarding

a. the identification of endangered network areas
b. the procedure to define actions to avoid the spread of a loss of synchronism (dependent on operation philosophy)
c. necessary reaction times dependent on the physical phenomena
d. requirements on measurements
e. Solution structures

b) a straightforward approach is applied in the case approach a) is not followed.

Straightforward solution:

1. *Conventional Distance Protection:*

As the loss of synchronism is accompanied by low voltages and high currents in the proximity of the electrical centre the distance protection can serve as “Natural System Protection”, which automatically opens the lines that coincide with the electrical centre. This is in particular a pragmatic approach in cases where the power system configuration makes it difficult to predefine the scenarios and corresponding separation corridors.

In order to manage conditions where the electrical centre is in a transformer or a generator or to manage protection failures it should be ensured that at least cross-border lines are opened

2. *Out-of-Step Relays/function:*

The increasing loading of transmission lines requires optimised performance for the Distance Protection might deteriorate a stressed network condition in order to avoid unintended tripping of highly loaded lines. The out of step relays/function should open the lines where the electrical centre is located un-delayed after the second pole slip

Thus, distance protection maloperation like it may occur during stable power swings (see chapter 3) can be avoided

The distance protection shall be utilised exclusively for “real” electrical faults (short circuits). To this aim selected zones in case of oscillations are blocked (power swing blocking). In such cases Out-of-Step Relays/Function have to be implemented/activated.

Generally system separation should only be used as a last resort to avoid a system collapse, if other operational or preceding system protection schemes (e.g. generator rejection, preventive fast valving) did not operate effectively or cannot avoid the loss of stability. However, if dynamic studies and researches of TSOs reveal that severe contingencies may lead to a loss of synchronism the TSO should implement emergency control actions aiming to avoid aperiodic instability. Moreover the TSO shall implement measures to enhance stability and the robustness of the power system like adjustment of PSS settings and fast valving for generators

6.3.2 OSCILLATORY ANGLE INSTABILITY

In the worst case Oscillatory Instability results in the loss of synchronism, i.e. for oscillatory instability the same recommendations as for aperiodic instability apply.

Power System Stabilizer (PSS) should be implemented on generating units if the necessity is expressed by the concerned TSO. The settings have to be agreed between the responsible TSO and the power station operator.

6.4 CONCLUDING *REMARKS*

The derived recommendations for the CE Synchronous Area defence plan are aimed to manage the effects resulting from extreme contingencies, i.e. to keep them under control, in a way that the decisive electrical quantities (frequency, voltages, currents) remain within the acceptable limits, which is a precondition to reach a stable operating point.

To reach a stable operating point in turn is a precondition to ensure that the generation units keep on running, which in the end is the challenge of avoiding total system blackouts. This is the reason why a robust behaviour of generating units which is compliant with the respective grid codes (see chapter 5) is so essential for the power system as a whole and therefore required by the TSOs.

The line protection has different major effects during emergency conditions and stability problems. Previous incidents show that unintended operation of line protection - in spite of correct technical behaviour according to their design and settings - might have both negative and positive effects on the course of the disturbance: During a critical situation unintended and uncontrolled tripping of lines, which are free from electrical failures, might deteriorate the situation due to the resulting weakening of the grid. On the other hand such unintended line tripping might serve as a system protection, when a stability problem and its propagation through the system is eliminated (e.g. Denmark incident, see chapter 2). Consequently it is more and more important to ensure high performance of line protection with respect to their original function (fault clearing) and at the same time to implement System Protection Schemes to protect the system against loss of stability.

ANNEX - DEFENCE PLANS OUTSIDE OF THE CE SYNCHRONOUS AREA – LITERATURE RESEARCH

WIDE AREA PROTECTION AGAINST VOLTAGE COLLAPSE IN SWEDEN (NORDIC SYSTEM) [1]

The synchronous Nordel system comprises the power systems in Finland, Norway, Sweden and the part of Denmark east of the Great Belt. AC-links are used for power exchange within the synchronous area and HVDC-links are used for power exchange with systems outside the synchronous area. A map of the entire Nordel system is shown in Figure 1.

The Swedish power system is a longitudinal one with the main part of the generation in the north (hydro units) and the load centres in the middle and south. Nuclear stations are located close to the southern load centres. A number of critical cut-sets, or bottle necks, are identified along the transmission corridor, where power transfer capacity is limited. In the bottle neck number 4 (BN4), power transfer limitation is posed by voltage stability considerations emerging in a post fault situation following a dimensioning fault.

In order to cope with this issue a wide area protection (WAP) scheme has been designed and implemented. This scheme utilises as analogue inputs voltage measurements in six 400kV substations and digital inputs the current limiters from two large turbo generators located in the south. Shunt reactors at the 400kV level and shunt capacitors at the 130kV system, south of BN4 are controlled by this protection scheme. Additionally, gas turbines in the southern Sweden can be started up automatically, HVDC power can be requested from Germany (through the 600MW HVDC link connecting the southern Sweden and Germany) and an automatic request can be sent in Denmark for maximum support. Load shedding is also a control capability of the protection system. The entire protection scheme is implemented in the Swedish TSO SCADA system. A schematic diagram is shown in Figure 6.

For the disconnection of a 400kV shunt reactor, the WAP system necessitates a warning indication in the six out of eight input signals (six voltage and two reactive power). Additional requirements include that the reactor must be connected and also that the reactor control system is in operation. In order to avoid hunting situations, disconnecting from the WAP system is not allowed within five minutes after a disconnect order. All WAP system control actions are similar. For disconnecting high priority loads an additional safety measure is implemented by the requirement of a local low voltage condition, outside the SCADA system, in order to activate the load shedding.

Figure 1. Nordel transmission system.

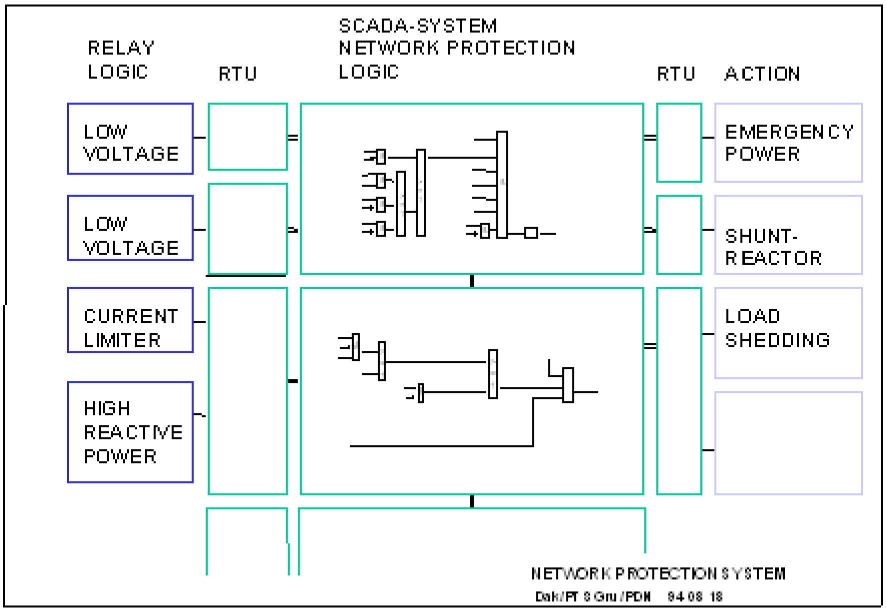


Figure 2. System protection scheme block diagram.

Basic Principles Of the Hydro-Quebec-Defence-Plan [2]

The Hydro-Québec system for the year 2000 is shown in Fig. 3. The total production is approximately 37,000 MW. The transmission system comprises eleven 735 kV lines with series compensation, thirty seven 735 kV substations, a ±450 kV multi-terminal DC line 1200 km long and dynamic shunt compensation facilities comprising eleven static and nine synchronous compensators.

The Hydro-Québec system has a number of characteristics that make stability and voltage control important issues in the design of its transmission system. Among the most important of these characteristics are the following:

- There is no synchronous link with neighbouring systems.
- The great distances between generation and load.
- The use of a 735 kV transmission system that is very extensive (more than 11,000 km of 735kV lines) but has a relatively limited number of lines located in two main axes.

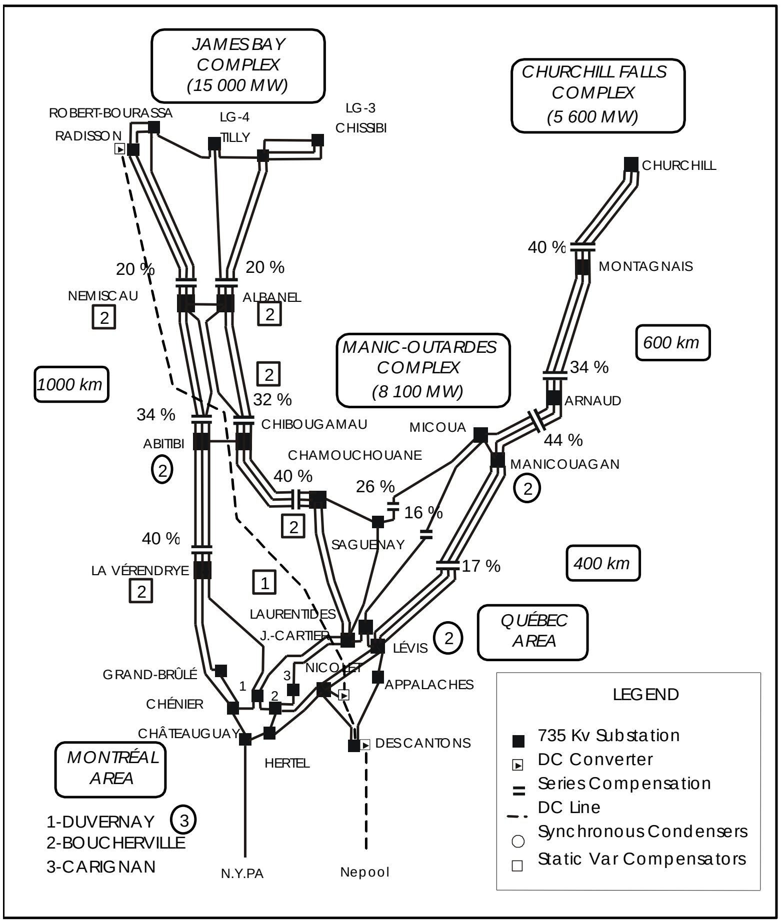


Figure 3. The Hydro-Québec transmission system.

Therefore Hydro-Québec decided to deploy a defence plan against extreme contingencies. Much effort has focused on increasing the system's ability to withstand extreme contingencies. The considered contingencies and the level of system performance required for each one as described in table 1.

The philosophy adopted by Hydro-Québec for protection against extreme contingencies - 'Defence Plan against extreme contingencies'- is that a general power failure must not be the consequence of a situation that could reasonably have been avoided. The defence plan consists of the automatic measures required to preserve the stability of the power system and maintain acceptable voltage levels after extreme contingencies. It is the ultimate protection to prevent the complete collapse of the Hydro-Québec system following an event of this type.

Extreme contingencies	Performance requirements
Single line to ground fault (SLGF) with loss of two series or two parallel 735 kV line.	**A**
SLGF with loss of one or two parallel 735 kV lines and bypass of remaining series capacitor in the same corridor.	**B**
Ac-dc event: Loss of a bipolar dc line caused by a fault with loss of a 735 kV line.	**B**
SLGF with loss of all line in a corridor:	
In Churchill-Manic section of HQ power system	**B**
Elsewhere	**C**
Loss of all 735 kV lines emanating from a substation.	**C**
Partial or total loss of generation unit at a station.	**C**
Loss of a major load centre.	**C**
Three phase fault with delayed clearing.	**C**
Unintended operation of a SPS.	**D**

Table 1: Performance requirements for extreme contingencies

A: stable, service continuity, SPS with limited actions

B: stable, all SPS allowed

C: stable at least at 75% power transfer level, all SPS allowed

D: stable, local SPS allowed

The objective of the Hydro-Québec defence plan is to preserve the integrity of the electric system by using automatic measures that are simple, reliable and safe for the system and provide the most extensive possible coverage against all possible extreme contingencies.

The defence plan against extreme contingencies is based on the use of the following automatic measures:

- Generation rejection and remote load shedding covering extreme contingencies involving the loss of several 735 kV lines in fifteen substations.
- 735 kV shunt reactors automatic switching system whose main purpose is to control voltage on the system after an extreme contingency. MAIS is installed in twenty-two 735-kV substations. Only voltage is used as a selective variable to guide the automatic switching of shunt reactors after an extreme contingency.
- Undervoltage load shedding system. This is a redundant scheme located at two different operating centres and always armed. Measurements from five 750kV substations in the Montreal area are used as input signals. Load shedding is based on voltage decline and duration while at a second level additional load may be shed based on a 3-second voltage integral calculation.
- Underfrequency load shedding system (UFLS) to restore the generation-load equilibrium and distributed in about 150 distribution substations. In order this scheme to be effective and fast, a combination of frequency thresholds and gradients is used. In addition, in order to avoid excessive voltage variations during load shedding, simultaneous tripping of shunt capacitors at the distribution level is implemented.

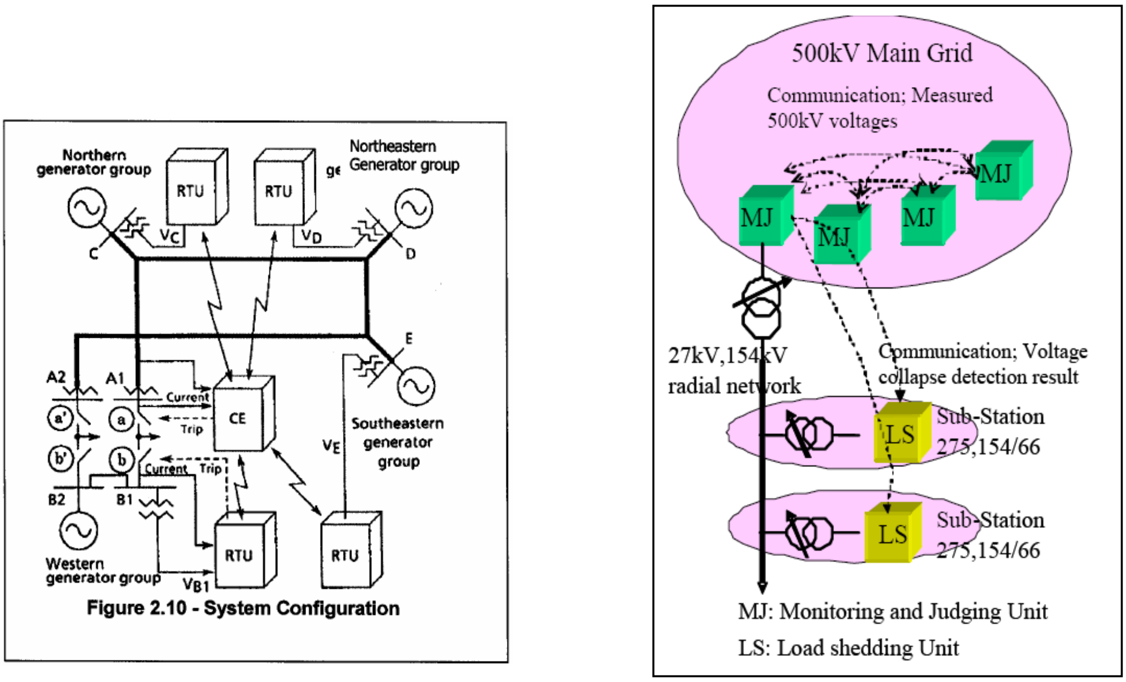
BASIC PRINCIPLES OF TEPCOS DEFENCE PLAN (JAPAN) [3]

The part of the Japanese electrical power system operated by the Tokyo Electric Power Company (TEPCO), is composed of three major generating centres located in northern, north-eastern and south-eastern areas and load centres concentrated in Tokyo and the surrounding area particularly in the west. The backbone of Tepcos power system is a 500kV transmission system that interconnects generation and load centres. The area of Tokyo is connected to the main transmission system via a 275kV radial transmission network in which a number of 275 kV/154 kV and 275 kV/165 kV substations are connected. A number of generation plants also exist in this area. A schematic diagram of TEPCOs power system is shown in Figure 4.

The main system protection schemes (SPS) included in TEPCOs defence plan are:

- A predictive out of step protection system
- An islanding protection system with active and reactive balancing control for the Tokyo metropolitan area
- A wide area protection scheme for under-voltage load shedding

The first SPS was build by Toshiba and installed in 1989 in order to cope with slow unstable oscillations (~ 0.5 Hz) that can develop under some contingency conditions between the western part and the other regions of TEPCOs power system. This scheme utilises as input signals busbar voltage waveform measurements, acquired by four remote terminal units (RTU) with a 600Hz sampling rate. The measurements are transmitted to central equipment (CE) located close to the western area, via a microwave network. Using these measurements, an algorithm embedded in CE calculates in real-time the phase difference between W-NE, W-S and W-N regions.



(a) **(b)**

Figure 4. Out of protection scheme (a) and UVLS scheme (b).

Then the algorithm provides a prediction of these phase angle differences 200ms ahead using extrapolation. In case that a predetermined threshold is exceeded, an out of step condition is predicted and CE orders the separation of the western area and the initiation of load shedding.

Tokyo metropolitan area is connected to the 500kV transmission network via a 275kV double circuit line. The loss of this line in the case of large power flows from the upstream network would create an extremely unbalanced situation. As a result, survival of the created island utilising only under-frequency load shedding would be very difficult. In order to cope with this situation, a specific purpose SPS has been designed. This SPS utilises several RTUs connected in a star topology to a central unit (CU) via a microwave network. RTUs transmit continuously information such as power flows to CU which calculates the necessary amount of load shedding, in order to achieve active power balancing, and shunt reactor switching in case of splitting. The second action aims at the achievement of reactive power balancing and is necessary due to the extended cable network existing in the area. Separation of the Tokyo metropolitan area is detected by voltage angle difference from the main grid and/or voltage magnitude. If such a case occurs CE issues control signals to the RTUs in order to perform necessary control actions. The RTU that receives the signal performs the predetermined control action in a very fast manner (in the order of 500ms).

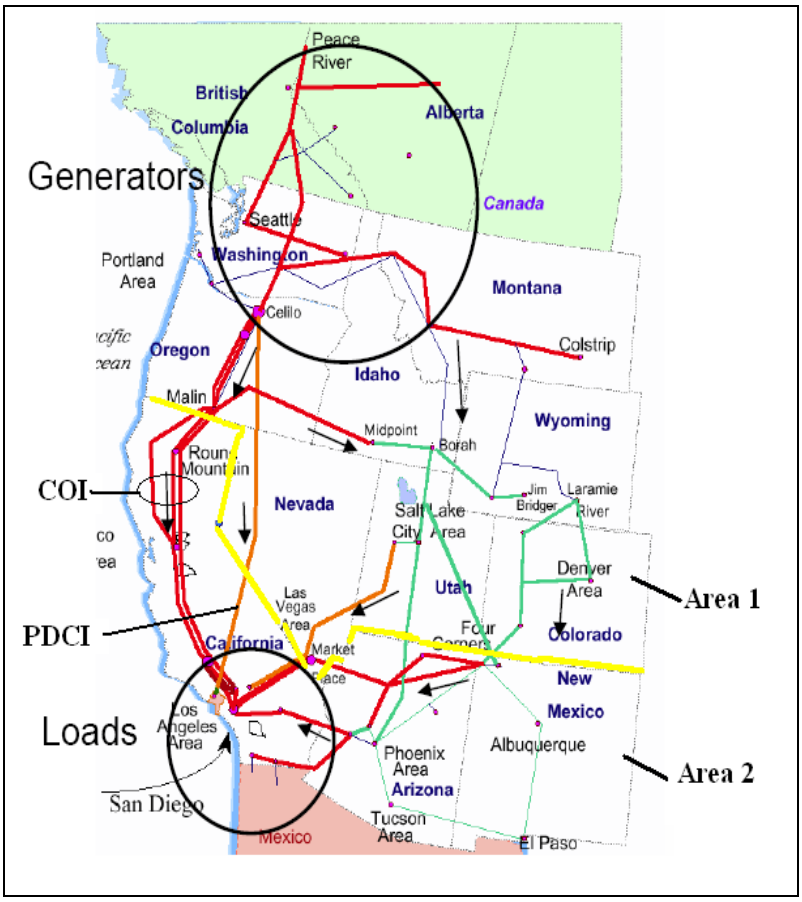
In the past, TEPCO experienced long term voltage instability (in the order of one to ten minutes) due to rapid demand increase. One of the measures implemented to cope with this situation was the design and installation of a wide area protection scheme for under-voltage load shedding (Figure 4b). The components comprising this scheme are four monitoring and judging units (MJ) installed at four 500kV substations and load shedding units (LS) installed at several 275 or 154/66 kV substations. All these units communicate via a microwave network. In MJ units an algorithm is implemented for the detection of slow voltage collapse (ten seconds to minutes order). This algorithm detects unusual continuous Δv/Δt values utilising the least square root value calculation technique for twenty sets of voltage values. Fast voltage collapse can be also detected by selecting a one second time frame. For security reasons the SPS scheme uses 3 out of 4 decision making logic. This scheme can be considered as a closed loop control since feeders continue to shed until recovery from under-voltage is detected.

WECC AREA, CALIFORNIA –OREGON INTERTIE WIDE AREA PROTECTION SCHEME

[4], [5]

The interconnected transmission system of the Western Electricity Coordination Council (WECC) extends from Canada to Mexico and includes the Canadian provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of the 14 states west of the Rocky Mountains. In this system large amounts of power are transferred by the Pacific north-west that has abundant hydroelectric resources and the south-west where considerable coal-fired and nuclear resources exist, to the large load centres of southern and northern California. A major corridor in this system is the California-Oregon AC intertie (COI) which consists of three 500kV transmission lines and the Pacific DC intertie (PDCI) shown in Figure 5. The north-south transfer capability of COI is 4,800 MW and 3,100 MW for the PDCI.

Figure 5. WECC system

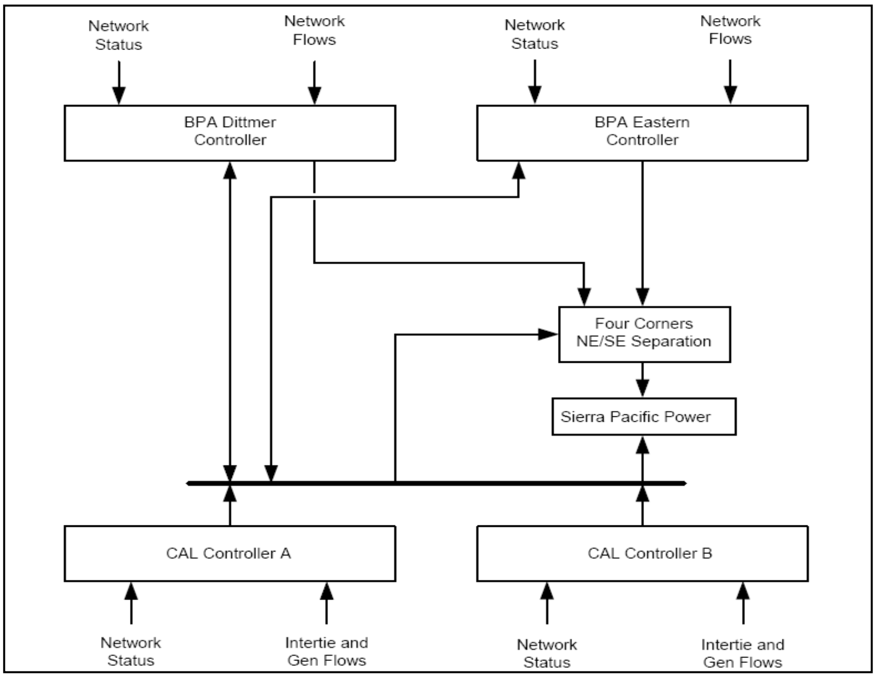


Outages on either COI or PDCI during high load conditions may have adverse effects on the rest of the system and especially on lower capacity power paths from the Pacific north-west to California. In fact planning studies have shown that single-, double-, three line loss on COI or bipolar PDCI line loss in stressed operating conditions can cause instability, cascading effects, WECC system separation and islanding.

In order to cope with this situation, two Wide Area Protection Schemes (WAPS) have been designed in the Pacific NW and northern California to detect 500kV outages and initiate appropriate remedial actions. The first of them is operated by Boneville Power Administration (BPA). A schematic diagram of these two schemes is shown in Figure 6. Each of them consists of two identical systems, for reliability purposes. These schemes supervise the status of 500kV lines in their areas, power flow levels and the output of two major generating units in central California. Depending on the situation appropriate remedial actions are initiated controlled by these centres. These actions include combinations of the following:

- Tripping generation in the Pacific NW and Canada or in northern California.
- Tripping adequate pump loads in California.
- Suspension of automatic generation control in the Pacific NW.
- Insertion or removal of mechanically switched capacitors or shunt reactors
- Bypass series capacitors
- Transmission of transfer trip signals to separate the WECC system in two islands
- Application of a dynamic breaking resistor at a Pacific NW generating site.

Figure 6. WECC wide area protection system controllers.



For the transmission of signals a microwave network is used. In case of a complete loss of COI, an islanding of the WECC system is initiated that separates the WECC system in two islands. These two islands include the areas in the two sides of the yellow line in Figure 5. Islanding control logic in implemented on the Four Corners substation in New Mexico. Input signals are transfer trip signals sent from the two WAPS controllers. If these signals indicate a COI separation, approximately seven lines are opened in New Mexico, Arizona and Nevada to create northern and southern islands. Other actions that may be taken by the WAPS controllers to preserve the stability of the two islands are the shedding of water irrigation pump load in Area 2 and the insertion of a dynamic brake resistor in Area 1.

This dynamic brake has been built by BPA and has a rating of 1400 MW. Its main task is the stabilisation of the large concentration of hydro units in the Grand Coulee and Chief Joseph Dams. It consists of three single-phase resistors created from several hundred feet of wire strung on towers. This brake is activated in order to reduce the acceleration of hydro units after an opening of line breakers due to a fault in a high power export situation. A similar device with a rating of 600 MW has been installed in the Shrum hydro power station located in Northern British Columbia by the BC Hydro.

BUENOS AIRES' DEFENCE PLAN DESIGN PRINCIPLES [3], [6]

A general view of the Argentinean power system is depicted in Figure 7. The generation portfolio includes thermal units (53%), hydraulic units (40%) and nuclear units (7%). The main hydraulic power stations are in the Trancomahue region in the southwest part of Argentina with an in installed capacity of 4.485 MW. Other important hydro power stations are the Salto Grande plant in the eastern region and the Yacyreta plant in the northeast region with a total capacity of 5290 MW. The main load centre is in the Buenos Aires region reaching 70% of the total load. Radial connections, extending to several hundreds of kilometres, are used to transfer power from the main hydro power stations to Buenos Aires load centre. Automatic generation disconnection implemented in hydro power stations, switching of shunt reactors and under-frequency load shedding schemes utilizing frequency gradient are used to maintain the stability of the transmission system in case of severe contingencies in these corridors.

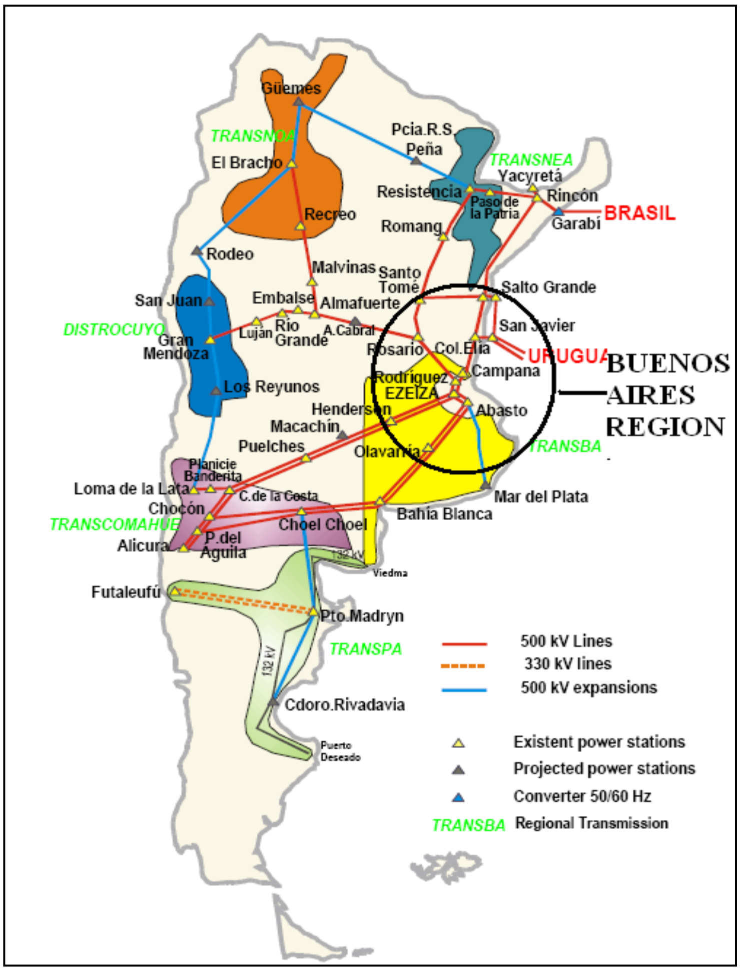


Fig 7. Argentinean Transmission system.

The interface of the Buenos Aires region to the main power system consists of three 500/220kV substations in Abasto, Ezeiza and Rodriguez. In the region thermal generation also exists with a capacity of 5786 MW. The scope of the defence plan design for this area was to avoid a collapse of its power system in case of low probability events in the upstream network, taking into account its structure described above [3]. The chosen solution utilises a scheme structured in three hierarchical levels. At the first level, monitoring of quantities such as voltage and frequency, in the three border substations, allows an early detection of conditions necessitating the splitting from the main power system. In case that the created island cannot reach a stable operation point, the second level is energized causing a further splitting in smaller subsystems. If any of these new islands cannot stabilise their operation, the third level is initiated creating smaller islands including power plants and local generation. The entire scheme will cooperate with existing load shedding schemes based on frequency and voltage thresholds. For the implementation of this defence plan a redundant network of dedicated PLCs will be used. These devices will be installed in the three border substations (first level), nine substations in the inner network (second level) and 36 substations at the distribution level (third level).

BRAZILIAN DEFENCE PLAN CHARACTERISTICS [7], [8]

The Brazilian power system is dominated by hydro power generation. In fact 97% of the consumed energy is generated by hydraulic plants. Complementary hydrological characteristics of the different sites allow the utilisation of the transmission system for energy optimisation. In order to achieve this, generation from areas that are in a wet period is increased while water in areas that are in a dry period is stored. Such an operation is feasible due to the electrical interconnection of the main basins (Figure 8). Although this way of operation improves the energy efficiency of the Brazilian power system, it necessitates the transfer of large amounts of energy over very long distances through a rather sparse network. This fact implies that in case of extreme contingencies a high risk exists for the development of frequency and voltage deviations, accompanied by power oscillations that may lead to cascading outages and finally system collapse.

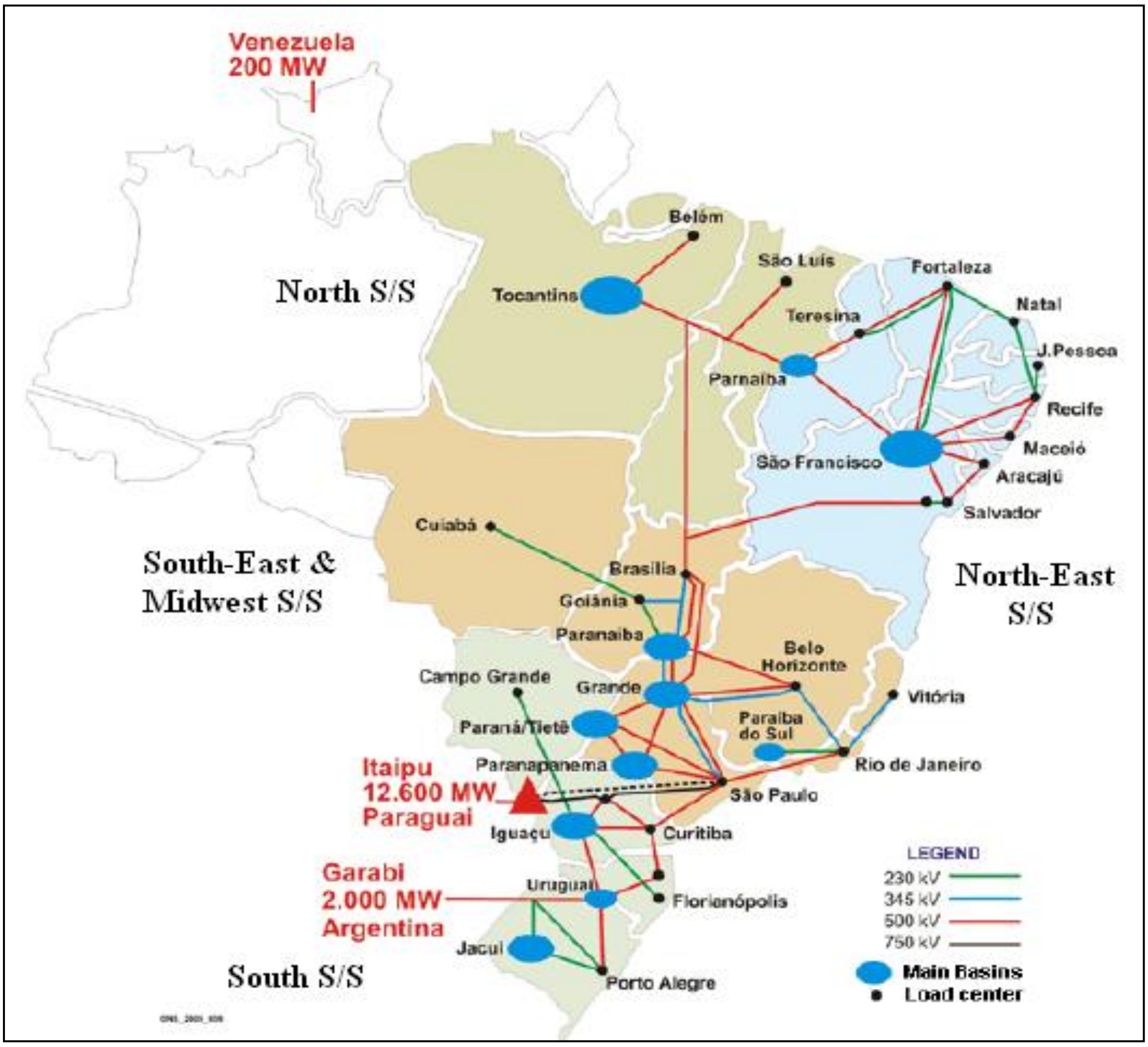


Figure 8. Brazilian transmission system.

In order to cope with this situation the Brazilian ISO has developed a defence plan that makes extensive use of SPS. In the year 2005 133 such schemes were in operation. In the following paragraphs, some of them are briefly presented.

The Brazilian power system is roughly divided into four subsystems, corresponding to the country's main regions which are the South, South-East/Midwest, North and North-East. As can be also seen by Figure 8, these four subsystems are weakly interconnected and the main structural transmission constraints lie on the tie lines between them. In order to avoid spreading of disturbances between regions, out of step protection is implemented in the interconnection lines. Based on previous experience and extensive planning studies, fast tripping (in the way in) leads to the splitting of the Brazilian system to stable regional islands.

The major part of the load is located in the South-East/Midwest region In order to cope with the associated generation deficits that could be caused by the tripping of South-East/Midwest subsystem interconnection lines an under-frequency load shedding scheme is in operation in this area. This scheme is comprised of five steps with 7% of load shed in each one of them. The decision logic is solely based on frequency measurements. A second under-frequency load shedding scheme is in operation in the North-east region. This region is characterised by an increasing market demand. In this case the load shedding decision is based on the frequency gradient.

The sparse structure of the Brazilian power system together with the large distances between generation and load creates increased risks for the developed of transient and small signal instabilities. Among the utilised measures, hydro generation rejection is used in order to alleviate the relevant transmission constraints. An implementation example concerns the Itaipu hydro power station. The South and Southeast system are interconnected by two 750 kV and three 230 kV transmission lines. The outage of one 750 kV transmission line will provoke the system instability, with South – Southeast system separation. An appropriated number of generator units tripping in Itaipu, following the 750 kV transmission line tripping (as function of power transfer) allow the system to maintain its stability. Generation rejection in Itaipu power station is also used to control over-frequency situations in the South region and avoid voltage collapse in the 765kV transmission system.

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