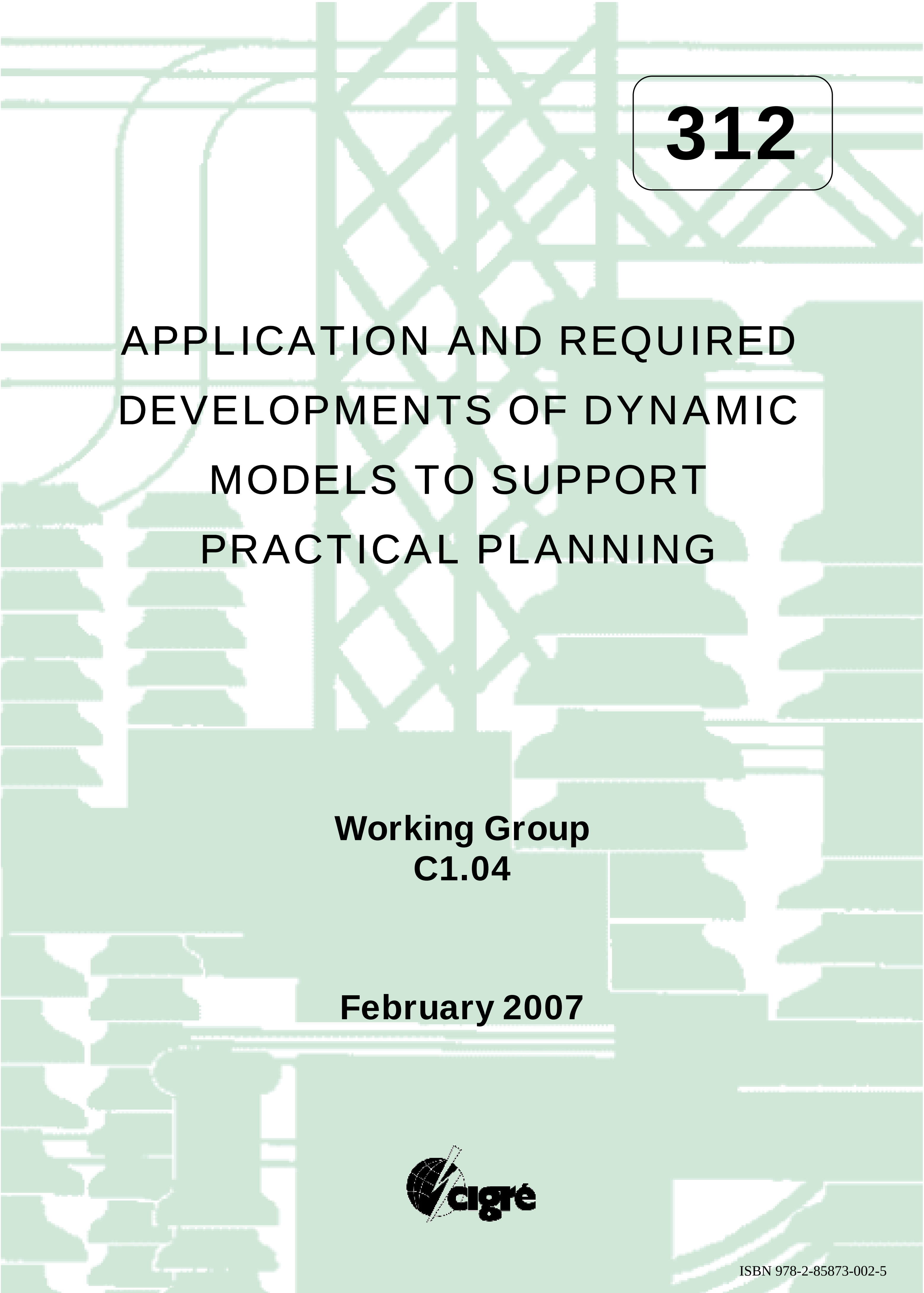

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APPLICATION AND REQUIRED DEVELOPMENTS OF DYNAMIC MODELS TO SUPPORT PRACTICAL PLANNING

Working Group
C1.04

February 2007

ISBN 978-2-85873-002-5

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EXECUTIVE SUMMARY

Nowadays analyses of the expected dynamic behaviour of power systems are playing an increasingly important role in the planning stage due to many factors, among which:

- tendency to exploit power systems closer to their technical limits;
- increased uncertainty in the generation expansion and, in many cases, lack of centralised control in the selection of the best location and size of new power plants;
- installation time of new power plants shorter than in the past and increasing diffusion of generation based on new technologies or renewable energy;
- need to accurately define the NTC (Net Transfer Capacity) between interconnected systems taking into account dynamic constraints;
- higher exploitation of interconnections to foster the commercial energy transactions;
- new devices for power transmission such as electronically controlled phase shifter transformers, HVDC links or FACTS devices.

Moreover, the worldwide process of unbundling between the various sectors of the electricity industry can contribute to a fragmentation of expertise, making even more difficult to handle and solve in the most appropriate way potential dynamic problems that can be envisaged at the planning stage.

For the above reasons Study Committee C1 (System Developments and Economics) of CIGRE decided to set up a Working Group dealing with the new dynamic issues to be considered in the planning process.

The aim of the WG activity has been to provide the planner useful indications of the main dynamic phenomena to be addressed in the planning stage as well as the dynamic models to be adopted with special emphasis on new generation technologies and network components. Detected deficiencies of dynamic models shall represent the input for further activities in the framework of CIGRE Working Groups.

Methodology

The methodology applied in the execution of the activities is based on the following steps:

- ✓ identification of the planner needs for dynamic analyses through a survey carried out among entities responsible for planning;
- ✓ identification of dynamic phenomena to be investigated;
- ✓ selection of reference case studies;
- ✓ recommendations on the most appropriate dynamic models and related parameters;
- ✓ identification of possible deficiencies and need for further developments

According to the above methodology, to identify the planner needs and the deficiencies related to the dynamic studies to be performed before starting the implementation of a new project, a questionnaire was prepared and circulated by each WG member. Moreover, to have a first view on new dynamic models, some consultancy companies involved in software development and selling have been contacted.

On the basis of the survey results, a clear definition of the dynamic phenomena to be addressed in the planning stage has been derived as well as the following case studies have been identified:

- *connection of a new generation centre to the grid*;
- *connection of large wind farms to the transmission grid in interconnected, weakly interconnected or isolated systems;*
- *dynamic analyses applied to large interconnected systems;*
- *subsynchronous resonance study.*

The above case studies can be used as reference for similar analyses, but, to facilitate the execution of dynamic studies, a presentation and discussion of some dynamic models has been included among the WG activities. Whenever possible, indications of the parameters to be adopted in relationships to the size and manufacturer of the generating units are provided.

Furthermore, problems of verification of parameters and tuning of adequate models are also addressed. As a matter of fact, in many contexts the dynamic behaviour of the existing equipment (either generators, associated controls or electronically controlled network devices) is not known with the detail requested for dynamic analyses. Then, specific actions should be undertaken to choose the most suitable models and correctly estimate parameters.

It is worth mentioning that the issue of correct modelling of the composite generation-transmission system with associated controls and automata as well as the estimation of the parameters to be used in the selected models is an area of investigation common to the planning and operation stage. Dynamic phenomena are also common to planning and operation, so one could argue *what are the real differences between dynamic analyses carried on at the planning stage*, from few years up to around 10 years ahead, *and those carried on at the operation stage*, from few months ahead to the on-line dynamic security.

Basically, at the operation stage the analyses shall account for the existing equipment and shall be consistent as much as possible with the real behaviour of the system. Incident reconstruction can often be a good opportunity to tune the models of the controls and the load "seen" from the transmission grid, provided that a sufficiently complete recording of the physical quantities is available. To this purpose, currently the technology of Wide Area Measurement or Monitoring, which is based on synchronised and high-resolution measurements, allows acquiring high-quality information for solving this task.

In the planning stage, a double requirement has to be fulfilled: on the one hand, an appropriate modelling of the existing equipment has to be set up; on the other hand, the planner shall identify the best control strategy and settings for the new installations and the overall system. In other words, the planner has the role of defining the "*target dynamic behaviour*" of the system, to be attained by adopting the control performances identified through the dynamic analyses. Obviously, this latter phase is further complicated by the fact that most of the investments in new generation are in the hands of private investors and needed information cannot be easily available to the planning responsible. This issue shall be suitably addressed in the connection rules foreseen in the grid codes. To this aim, a recent overview has been carried out within WG 2 of SC 1[1] dealing with models and data that shall be provided for the connection of generators to the grids and the conditions of confidentiality of the exchanged information. In summary, the planner has the responsibility to identify the "*minimum technical requirements*" to cope with the so-called "*credible contingencies*" and outline the emergency actions to be triggered at the occurrence of "*extreme contingencies*"; all that in order to overcome/minimise the limitations in the power transfers related to dynamic constraints. Having this "optimal" solution in mind, the planner shall monitor the evolution of the system, in close co-operation with the operation department, and suggest the actions to be taken on the control systems of the new generation units and/or network equipment before their commissioning

Survey on dynamic studies at the planning stage

To get the widest view on the needs and problems faced in dynamic analyses, a questionnaire was circulated to planner responsible operating in countries characterised by different degrees of market opening and very different characteristics of the power system under examination. In total, 44 answers, coming from all the continents, were collected out of which:

- 40 respondents from ISOs/TSOs/VIUs[2];

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[1] See: CIGRE ELECTRA magazine, n°. 224, February 226, pp. 44-45

[2] ISO: Independent System Operator; TSO: Transmission System Operator; VIU: Vertically Integrated Utility

- 4 respondents from consultants and software vendors.

Main outcomes from the survey are the following:

- ✓ ***Assessment of the dynamic behaviour of the generation-transmission system at planning stage -*** Almost all the respondents stated that dynamic analyses are executed at the planning stage and many of them apply dynamic analyses even in the mid-long term planning, but *in the large majority of cases dynamic analyses are carried out occasionally* to check specific situations where possible network reinforcements or other alternative measures (e.g.: installation of series capacitors or FACTS devices) are dictated by dynamic constraints. In the majority of cases, dynamic studies are carried out to check the impact into the system of the connection of new power plants or the construction of new lines, either internal or cross-border. Concerning connection of new power plants the common criterion adopted to decide whether dynamic analyses have to be executed or not is based on the size of the new plant and/or the voltage level. Survey results highlighted that growing importance is given to the examination of the dynamic impact of new wind farms connected not only directly on the transmission level, but also on the underlying distribution level. This latter aspect entails a further difficulty consisting of modelling the dynamic behaviour of "equivalent" wind farms seen from the transmission grid. Finally, dynamic analyses are also required by a series of other reasons related to the design of Special Protection Systems, installation of SVC, series compensations, HVDC links, FACTS devices and the preliminary design of load shedding policy.

- ✓ ***Which kinds of dynamic analyses in the planning process -*** While in the past only transient stability was examined, nowadays, also long term dynamics is investigated confirming the concern of planners for more complex interactions among control loops that could originate instability phenomena, which can be detected only several tens of seconds after the occurrence of a fault or manoeuvre.

- ✓ ***Dynamic models used and software tools -*** Despite the need to take into account complex dynamic phenomena, as above mentioned, according to the outcomes of the survey in most of the cases dynamic models suitable only for short-term dynamics (transient stability) are used. Slow control loops, like over-underexcitation current limiting circuits, AGC, SVR, which are essential to simulate long term dynamics spanning over tens of seconds are modelled only in a limited number of cases. Even more limited (about 20% of the respondents) is the number of planners that adopt dynamic models of wind farms or various forms of dispersed generation. As a matter of fact, one of the problems highlighted by the survey, is namely the difficulty in building models of wind farms (in many cases equivalent models) suitable for electro-mechanical transients with time domain simulation making use of a r.m.s. representation. Still more difficult turns out to be the selection of the parameters to be attributed to the wind turbine generators and related control systems. Similar problems have been highlighted for the dynamic load modelling: only in 22% of cases a dynamic model is used. Finally, dynamic equivalents to properly represent the response of neighbouring networks are used only in 25% of the cases. To this purpose, it is also worth mentioning that accuracy degree of external systems modelling shall be appropriate to the phenmena to be investigated, e.g.: for SSR study a three-phase modelling of the system is needed.

- ✓ ***Software tools -*** Concerning software tools in 77% of cases, planners make use of commercially available tools while in the remaining cases they use both in-house developed and commercially available software packages. From this point of view the role of software developers and vendors is crucial to offer to the planners adequate models and, especially, a library of associated parameters. This is particularly true for new kinds of generators (e.g.: wind generation) or electronically controlled devices, the technological evolution of which is rapid and requires close contacts with manufacturers.

Hence, the accuracy and the user friendliness of commercial software tools have a direct impact on the quality of planning analyses. It is worth mentioning that, whilst in the past there was a tendency to develop autonomously simulation programs, nowadays in-house developed software is rather an exception and only modules for some specific applications are developed directly by system operators.

✓ ***Needs identified by the planning responsible -*** As mentioned before, in a large majority of cases dynamic analyses are carried out only occasionally in planning stage. In some situations dynamic analyses are not carried out at all. The following main barriers preventing the execution of dynamic analyses have been identified:

- resource problems;
- lack of data;
- lack of experience.

Resource problems and lack of experience derive in some cases from the recent restructuring processes where the unbundling of former VIUs and the streamlining of the staff have increased the pressure on the remaining working teams to react more and more quickly to the numerous tasks attributed to system operators, especially in the planning stage (e.g.: requests for new generation connections, definition of interarea NTC, analyses of non-conventional solutions alternative to the construction of new lines to comply with strict environmental constraints). Lack of data is another common issue raised by planners when dealing with dynamic analyses. Particularly, information on new generating units and associated controls are not easily available. Furthermore, when executing dynamic analyses, respondents have highlighted the following problems as the most crucial (in order of priority):

- lack of models for wind farms;
- lack of models for new network equipment;
- lack of models for dispersed generation (equivalent dynamic models for transmission studies).
- lack of verified models (especially dynamic models) and data for loads;
- ensuring generator parameters are correct;
- open cycles and CC Gas Turbine models.

Recommendations for the execution of dynamic analyses

Because of the above recalled obstacles, the planner might not be able to optimise the dynamic behaviour of the system or is even discouraged from applying dynamic analyses. Then, an appropriate methodology helping to facilitate the execution of dynamic studies has been defined. Main issues to be addressed are:

- Which kind of models shall be adopted (*modelling*);
- How to discriminate dynamic phenomena triggered after the occurrence of a perturbation and in case of instability, how to detect the dominant phenomenon leading to instability (*discrimination of dynamic phenomena*).

✓ ***Modelling -*** For the execution of dynamic analyses, models shall fit with the phenomena to be investigated; consequently, different models shall be set up in the computational tools having different level of approximations. E.g.: investigation of the rotor angle stability facing large disturbances (i.e. a classical transient stability problem) requires time simulations covering an interval of few seconds. Then, an accurate modelling of the rotor e.m.f.s, AVRs and speed governors is essential, while slow dynamics loops (e.g.: secondary field current limiting circuit, boiler dynamics, supply systems dynamics, etc.) may be disregarded. In general, for the identification of the best control strategy and settings for the new installations, a modelling based on a "*two-stage procedure*" can be adopted:

1. **Use of reference models** to identify "*minimum technical requirements*" to cope with the so-called "*credible contingencies*" and outline the emergency actions to be triggered at the occurrence of "*extreme contingencies*";
2. **Use of complete dynamic models** in compliance with the available data (e.g.: for alternators, the dynamic order chosen shall be the maximum possible order, compatible with the available data set).

It is worth underlining that the tuning of the dynamic models for the existing components and control systems can be successfully obtained through a close interaction with the operation department, which it is expected to have validated models by means of on-the-field tests or reconstructions of events.

- ✓ ***Discrimination of different dynamic phenomena* -** An important task, especially in case of very large interconnected systems, consists in detecting, monitoring and understanding the nature of possible very slow transients occurring in the systems. Severe transients may arise as consequence of contingencies determining some weaknesses in the system structure. In such cases, electromechanical oscillations at very long period can interact with the primary and sometimes also the secondary frequency controls, causing slow frequency variations and consequently slow voltage phase variations. The slow voltage drops observable during the transients can be identified either as incipient voltage collapse or evolution of angle instability.

An exact understanding of the nature of this critical phenomenon is very important in order to adopt the most suitable countermeasures both in planning and in operation stage. These measures consist usually in the adoption of operation rules in conjunction with possible automatic control actions to guarantee the system security and alleviate emergency situations.

The difficult task of discriminating between angle instability and voltage instability can be accomplished by resorting to time simulation functions able to switch from a description of the system through a complete model taking into account simultaneously all the dynamics, fast and slow, and a simulation function utilising a reduced model neglecting the electromechanical transients. The model reduction is achieved by considering only one speed for all the machines of connected areas. Through this technique it is possible to separate, in case of slow dynamics, the transient angle instabilities from the voltage instabilities leading eventually to the voltage collapse.

Concluding remarks

From the analysis of the current practice, a number of issues shall be addressed to foster the execution of dynamic analyses in planning stage in order to make them a routine step instead of an occasional study as in some present situations.

At first, some *general models* shall be used by planners for defining the target dynamic behaviour of the future system. These models, though very simple and with a reduced number of associated parameters, allow an acceptable accuracy in time domain simulations. Since in the large majority of cases, planners tend to make use of commercial simulation tools, equipment manufactures and software vendors shall struggle to make *available libraries of models and "standard" parameters valid in a sufficiently wide range*. Sometimes, very detailed models of components of control systems may be useless for a "*system approach*". F.i. in case of wind farms, there's often no need for the modelling of each single aerogenerator, but it is sufficient an *equivalent model the whole wind farm* for the examination of the impact of wind generation into the transmission system.

In a more detailed stage of analysis, to enhance as much as possible the accuracy of dynamic analyses, especially in mid-term planning (3-5 years in advance), a close collaboration with the operation department is of utmost importance in order to *include in the dynamic models used in planning all the models of existing plants and controls already identified and validated during the system operation* including expected refurbishment and modifications.

A further issue is related to the examination of the dynamic behaviour of systems having configurations quite different from the present ones. This happens mainly when studying interconnections between two or more networks or when increasing cross-border capacities among existing interconnections through the construction of new lines or the installation of new devices either electromechanically or electronically controlled. In this phase, it is important to *discriminate among various transient phenomena* that may be coexisting after a perturbation and detect the prevailing one, which can lead to instability. To this purpose, use shall be made of *different dynamic models suitable for short and long-term time domain simulations*. Some software packages already allow it and are helpful, once detected the dominant transient phenomenon, to design the most appropriate measures for enhancing dynamic security margins.

A further issue, which shall not be neglected in planning, is related to *the influence of market mechanisms on the dynamic performance of the system*. Indeed, on the basis of market rules, many more generation dispatch scenarios may be formulated than in the past, leading to greater uncertainty in system dynamics. Then, it is up to the planner checking the compliance with static and dynamic security criteria considering stability against both large and small perturbations and supplying in advance indications to the investors in new power plants about possible constraints in the power generation.

Finally, as a completion of the unbundling process it is worth suggesting that all the *existing codes* (transmission grid codes, distribution codes, generators connection rules) *have to be carefully harmonised* since the current interfaces do not often fit accurately and this can jeopardize the future operation of the generation-transmission-distribution system.

GLOSSARY

AGC	: Automatic Generation Control
CCT	: Critical Clearing Time (referred also as CFCT: Critical Fault Clearing Time)
DFIG	: Double Fed Induction Generator
FACTS	: Flexible Alternative Current Transmission System
IG	: Induction Generator
IGCC	: Integrated Gasification Combined Cycle
ISO	: Independent System Operator
LFC	: Load Frequency Control
NTC	: Net Tranfer Capacity
PSS	: Power System Stabilizers
RES	: Renewable Energy Sources
S.O.	: System Operator
SSR	: Sub-synchronous resonance
SVR	: Secondary Voltage Regulation
TCSC	: Thyristor Controlled Series Capacitors
TRM	: Transmission Reliability Margin
TSO	: Transmission System Operator
TTC	: Total Tranfer Capacity
VIU	: Vertically Integrated Utility
VSC	: Voltage Source Converter
WEC	: Wind Energy Converter
WPP	: Wind Power Plant
WTG	: Wind Turbine Generators

1 INTRODUCTORY REMARKS

Nowadays analyses of the expected dynamic behaviour of power systems are playing an increasingly important role in the planning stage due to many factors, among which:

- tendency to exploit power systems closer to their technical limits
- increased uncertainty in the generation expansion and, in many cases, lack of centralised control in the selection of the best location and size of new power plants;
- installation time of new power plant (e.g combined cycle) shorter than in the past;
- increasing diffusion of generation based on new Technologies or Renewable Energy that requires a careful modelling of new types of generators and associated control systems (especially in case of non-dispatchable generation such as wind farms);
- need to accurately define the NTC (Net Transfer Capacity) between interconnected systems taking into account the dynamic constraints;
- higher exploitation of interconnections to foster commercial energy transactions with consequent need for accurate modelling of the protective devices, including special protection schemes, and for investigation of their behaviour in dynamic conditions;
- new devices for power transmission such as electronically controlled phase shifter transformers, HVDC links or FACTS devices.

Moreover, the worldwide process of unbundling between the various sectors of the electricity domain (generation, transmission, distribution, system-operation, system-planning, regulation, etc.) can contribute to a fragmentation of expertise, making even more difficult to handle and solve in the most appropriate way potential dynamic problems that can be envisaged at the planning stage.

For the above reasons Study Committee C1 (System Developments and Economics) of CIGRE (International Council of Large Electric Systems) decided to set up a Working Group dealing with the new dynamic issues to be dealt with in the planning process.

The aim of the WG activity is to provide the planner useful indications on the main dynamic phenomena to be addressed in the planning stage as well as the dynamic models to be adopted with special emphasis on the new generation technologies and network components. For a more effective support to the planning responsible, a series of case studies are presented, which can be taken as a reference in the execution of similar analyses. Moreover, references to documents already available in the scientific literature are provided, to enable the users to enter more deeply in the analysis of dynamic models.

Finally, the WG highlighted the new challenges and complexities to be taken into account when carrying on dynamic analyses at the planning stage as well as deficiencies of dynamic models. These latter will represent the input for further activities in the framework of CIGRE WG (e.g.: WG 6.01 “Power system security assessment”).

2 METHODOLOGY

The methodology applied in the execution of the activities is based on the steps shown in Fig. 2-1.

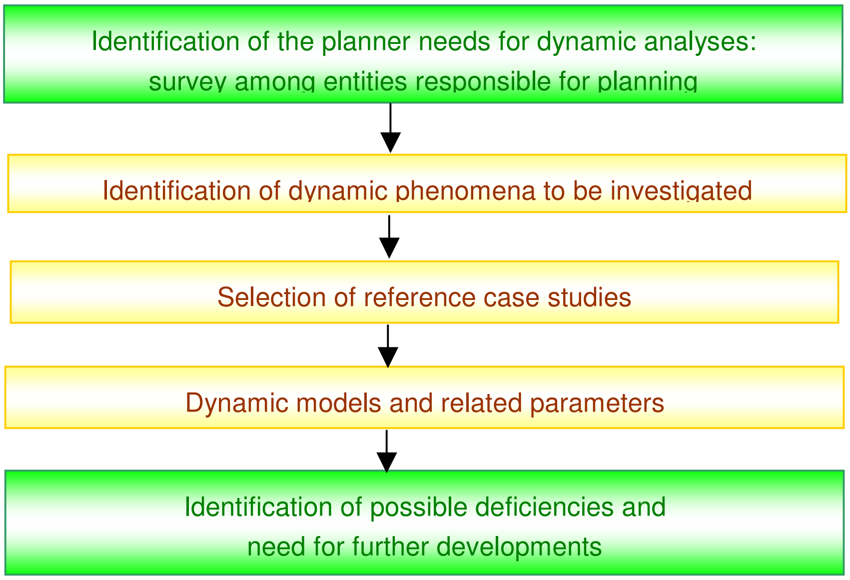

Fig. 2-1 – Steps followed in the execution of the activities

The first part of the WG activity has been devoted to find out from the planners what are their real needs and deficiencies related to the dynamic studies to be performed before starting the implementation of a new project. To this aim, a questionnaire was prepared and circulated by each WG member. A remarkable effort has been done to involve Entities responsible of transmission planning coming from different geographical areas and characterised by a different degree of market opening.

Moreover, to have a first view on new dynamic models already available, some consultancy companies involved in software development and marketing have been contacted.

The questionnaire, apart some general information on the respondent entities, addressed the following issues:

- Planning process adopted
- Responsibility for the definition of the planning criteria and rules
- Criteria applied for dynamic analyses
- Aspects or situations investigated in the dynamic analyses
- Dynamic phenomena examined in the studies
- Criteria for selection of the events to be simulated
- Dynamic models used
- Software Tools
- Validation of Dynamic Models
- Needs for further developments of dynamic models
- Obstacles preventing the execution of dynamic analyses at the planning stage.

The outcomes of the survey are presented in details in chapter 3. On the basis of the survey results, a clear definition of the dynamic phenomena to be addressed in the planning stage has been derived as well as a set of case studies has been identified. These latter deal with the following topics:

- *connection of a new generation centre to the grid.* In the past, within the vertically integrated electric company a joint generation-transmission planning used to be carried out. Nowadays, investments on new generation are left to private investors, who follow market indicators (e.g.: expected kWh price in a specific area, availability of supply infrastructures such as gas pipelines, integration of electricity production with other industrial processes such as in the case of IGCC plants, incentives for combined heat-power generation). Investors, looking at their own businesses, do not care of the overall optimisation of the generation-transmission system and, in many cases, several requests for connection of generation in the same area may be submitted to the S.O. These shall consequently struggle to accommodate in a fair way the additional injections of power, complying with the pre-established security criteria and minimising the investments in grid extensions. Pushing the system operation closer to its limit in some corridors call for accurate analyses of its behaviour in dynamic conditions. These have to be carried on at the planning stage before the commissioning of the new power plants;
- *connection of large wind farms to the transmission grid in interconnected systems, in isolated systems or in weakly interconnected systems*. Potential problems set by connection of wind generation are well known in the scientific literature; these are related to both operation and planning of electric systems. At the planning stage, three main categories of investment costs have to be addressed by the planners: grid extension costs, need for back up generation[3], additional balancing costs. Considering the intermittent nature of the wind generation, dynamic analyses have to be executed by the planner to identify at the best the necessary additional costs for the evacuation of the wind generation. Moreover, the amplitude of potential disturbances caused by the wind generation is quite different in relationship to the size of the system. Therefore, different study cases are illustrated derived from the Danish, Irish, Italian and Spanish experiences;
- *dynamic analyses applied to large interconnected systems.* We are all witnessing an on going worldwide trend in extending the size of power systems by interconnecting areas previously isolated each other. Decisions of interconnecting different regions, countries or even continents are surely driven by economic analyses on the profitability of energy exchanges backed up by political agreements among the concerned parties. However, the feasibility of realising interconnections creating power systems of very large size cannot disregard the investigation of their behavior in dynamic conditions. Indeed, dynamic constraints can lead to the adoption of alternative technical solutions (e.g.: asynchronous interconnection) with, in some cases, an additional burden in the investments, which could even lead to the non-profitability of the whole project. Moreover, as it will be described in section 4.1.3, very complex transients can be triggered in large systems causing the need for reviewing the setting or even the philosophy of control loops;
- *subsynchronous resonance study*. Long distance transmission of bulk power in AC requires adequate solutions. Among them, the installation of series compensation is one of the most popular. Different arrangements (e.g.: TCSC) can be adopted to warrant an optimised operation point with respect to the transmitted power as well as to warrant the system stability and avoid possible resonance. When dealing with a new project requiring series compensation special dynamic analyses have to be carried on as shown in 4.1.4.

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[3] In some cases, back up generation can be represented in equivalent way by a suitable reserve in cross-border interconnectors. However, this solution is normally criticised since it affects the NTC and, then, limits the trading possibility.

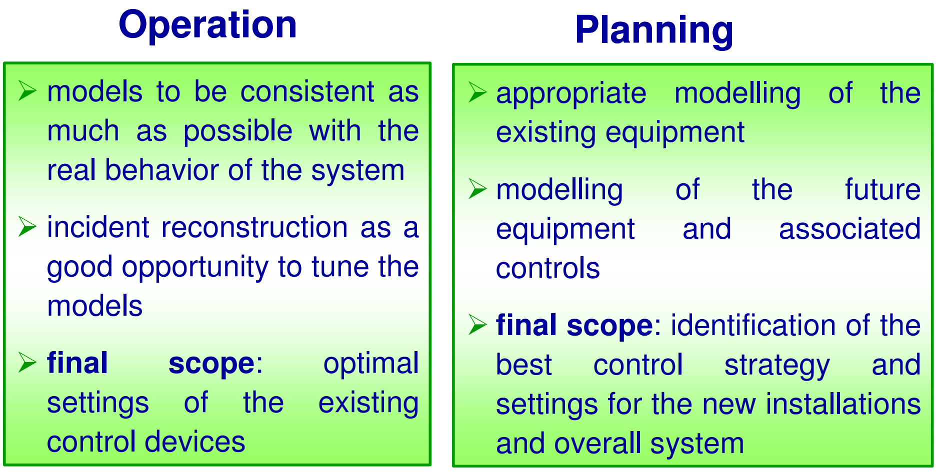
As mentioned, the study cases can be used as reference for similar analyses, but, to facilitate the execution of dynamic studies, a section dealing with the models has been introduced. This section addresses basically the models of wind farms seen from the transmission system and gas turbines either open or combined cycle. Whenever possible, indications on the parameters to be adopted related to the size and manufacturer of the generating units are provided.

Furthermore, problems of verification of parameters and tuning of adequate models are also addressed. As a matter of fact, for sound dynamic analyses on planning stage the adoption of adequate modelling and associated parameters is a mandatory pre-requisite. Unfortunately, in many contexts the dynamic behavior of the existing equipment (either generators, associated controls or network electronically controlled devices) is not known with the detail requested for dynamic analyses. Then, specific actions should be undertaken to choose the most suitable models and correctly estimate parameters. This issue is addressed in sect. 6. Moreover, aspects related to the modelling of load and embedded generation "seen" from the transmission system are also highlighted in order to suggest the planner the adoption of the most suitable solutions.

It is worth mentioning that the issue of correct modelling of the composite generation-transmission system with associated controls and automata as well as the estimation of the parameters to be used in the selected models is an area of investigation common to the planning and operational stage.

Dynamic phenomena are also common to the planning and operational stage, so one could argue *what are the real differences between dynamic analyses carried on at the planning stage*, from few years up to around 10 years ahead, *and those carried on at the operational stage*, from few months ahead (e.g.: to define the maintenance strategy in compliance with dynamic constraints) to the on-line dynamic security.

Basically, at the operational stage the analyses shall account for the existing equipment and be consistent as much as possible with the real behavior of the system (Fig. 2-2). To this purpose, incident reconstruction can often be a good opportunity to tune the models of the controls and the load "seen" from the transmission grid, provided that a sufficiently complete recording of the physical quantities is available [1].


Operation

- models to be consistent as much as possible with the real behavior of the system
- incident reconstruction as a good opportunity to tune the models
- **final scope**: optimal settings of the existing control devices

Planning

- appropriate modelling of the existing equipment
- modelling of the future equipment and associated controls
- **final scope**: identification of the best control strategy and settings for the new installations and overall system

Fig. 2-2 – Planning vs Operation Dynamic Analyses

In the planning stage, two requirements have to be fulfilled: on one hand, an adequate modelling of the existing equipment has to be set up, on the other hand the planner shall identify the best control strategy and settings for the new installations (e.g.: AVR equipped with PSS). Obviously, this latter phase is further complicated by the fact that most of the investments in new generation is in the hand of private investors and needed information cannot be easily available to the planner responsible. This issue shall be suitably addressed in the connection rules foreseen in the Grid Codes. To this purpose, a recent overview has been carried out within WG 2 of SC 1 dealing with models and data that shall be provided for the connection of generators to the grids and the conditions of confidentiality of the exchanged information [2]. In summary, the planner has the responsibility to identify the "*minimum technical requirements*" to cope with the so-called "*credible contingencies*" and outline the emergency actions to be triggered at the occurrence of "extreme contingencies"; all that in order to overcome/minimise the limitations in the power transfers related to dynamic constraints. Having this "optimal" solution in mind, the planner shall monitor the evolution of the system, in close co-operation with the operations department, and suggest the actions to be taken on the control systems of the new generation units and/or network equipment before their commissioning.

3 SURVEY ON DYNAMIC STUDIES AT THE PLANNING STAGE

To fit at the best the WG activities with the real needs of the planner responsible, a questionnaire was prepared and circulated by each WG members.

To get the widest view on the need and problems faced in dynamic analyses, the questionnaire was circulated to planner responsible operating in countries characterised by different degree of market opening and very different characteristics of the power system under examination. Furthermore, some consultants and software vendors were included in the survey to get a feedback on the available modelling of new type of generators and/or network components. In total, 44 answers, coming form all the continents, were collected out of which:

- 40 respondents from ISOs/TSOs/VIUs;
- 4 respondents from consultants and software vendors.

The breakdown of respondents (excluding consultants and software vendors) by geographical area and country is the following[4]:

- Europe (18 answers): Belgium, Italy, France, Spain (3), Greece, Slovenia, Switzerland, Serbia-Montenegro&Macedonia, Denmark (2), Sweden, Finland, England&Wales, Ireland, Russia, Baltic Republics (coordination centre);
- Africa (2 answers): Tunisia, South-Africa;
- Asia (14 answers): Turkey, Israel, Malaysia, Japan (11);
- America (2 answers): Brazil, Mexico;
- Oceania (3 answers): Australia (2), New Zealand.

Some additional informal replies were also received from other North African and South American countries.

3.1 Planning Process

Almost all the respondents declare that they outline a master plan with a time horizon in the range between 4 and 10 years ahead; in few cases (6 respondents), master plans cover a time horizons up to 15 years ahead and in 4 cases master plans spread over a time horizons up to 20 years or more. Plans are normally updated every year or, at the most, every 3-5 years.

Drawing master plans is a common factor independently from the degree of market opening and is normally carried out in unbundled systems by ISOs and TSOs. Differences, of course, emerge as for the implementation process of the proposed projects: this entails relationships with the entity in charge of approval of the development plans and the mechanisms for remunerating the investments. Two main solutions can normally be adopted:

- *Solution 1: "Grid seen as a natural monopoly"*
  - investment costs recovered through the transmission fees;
  - projects normally implemented by the system operator in charge of managing the grid;
- *Solution 2: "Market based transmission model"*
  - projects directly proposed by investors to ISO's/TSO's
  - investment cost remunerated through the assignment in a priority way of the transport capacity.

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[4] Figures in brackets mean that more than one answer was received from the specified country

In both the models an adequate regulatory framework shall be put in place to fulfil the expectations of the investors, while minimising the social impact related to transmission fees that should reflect the investment costs (solution 1) or, indirectly, related to increased generation price to cover the cost for the priority in transport capacity (solution 2).

It is worth noting that even in highly liberalised systems, master plans covers a quite long period in the future (10-15 years and even more) as it used to be in classical co-ordinated planning in VIUs. A frequent update of the master plans, in most cases every year, reveals necessary to account at the best for the uncertainty in network planning in deregulated systems.

Moreover, a quite classical decoupling of the planning process is kept in many cases. E.g. in Finland the following decoupling is kept by Fingrid:

- ✓ Master Plan : 30 years, updated every 3 years. No dynamic studies.
- ✓ Regional studies: 15 years, updated every 3 years. No dynamic studies
- ✓ Detailed investment plan: 5 years, updated twice a year. Dynamic studies included.

Finally, it is worth mentioning that in some areas (e.g. Peru, Chile), following the unbundling and the privatisation of the electricity sector, including most of transmission grid, no entity was given the responsibility for the coordination of planning. This has entailed increasingly complex problems being experienced by the system operators and in these last years the attitude towards a fully market driven network development has been revised recognising the need for a coordination of the grid development.

3.2 Responsibility for definition of planning criteria and rules

Normally, criteria and rules are defined and approved by the entity responsible for planning (29 answers), but in some cases planning criteria are approved by the Ministry of Energy (e.g.: Italy, Greece, Spain) or by the Regulatory Authority (e.g.: UK, Ireland, Russia, Turkey, Australia, New Zealand, South Africa). In few cases the planning criteria are approved by a “Co-ordinator Body” (e.g.: DC Baltija for Baltic Republics, ETRANS in Switzerland).

However, it is worth mentioning that, beyond the formal approval of planning criteria at the national level, in interconnected systems they are coordinated with the criteria adopted by the pool, which the country belongs to (e.g.: UCTE in central-western Europe, NORDEL in Nordic countries).

3.3 Assessment of the dynamic behaviour of the generation-transmission system at planning stage

Almost all the Respondents state that dynamic analyses are executed at the planning stage and many of them apply dynamic analyses even in the mid-long term planning, but in the large majority of cases dynamic analyses are carried out only occasionally to check specific situations where possible network reinforcements or other alternative measures (e.g.: installation of series capacitors or FACTS devices) are dictated by dynamic constraints. Fig. 3-1 shows that in the majority of cases, dynamic studies are carried out to check the impact into the system from the connection of new power plants or the construction of new lines, either internal or cross-border. Concerning connection of new power plants the common criterion adopted to decide whether dynamic analyses have to be executed or not is based on the size of the new plant and/or the voltage level. Of growing importance turns out to be the examination of the dynamic impact of new wind farms connected not only directly on the transmission level, but also on the underlying distribution level. This latter aspect entails a further difficulty of modelling the dynamic behaviour of “equivalent” wind farms seen from the transmission grid. Finally, dynamic analyses are also required by a series of specific reasons (classified in Fig. 3-1 as “Other reasons”); these are related to the design of Special Protection Systems, installation of

SVC, series compensations, HVDC links, FACTS devices and the preliminary design of load shedding policy.

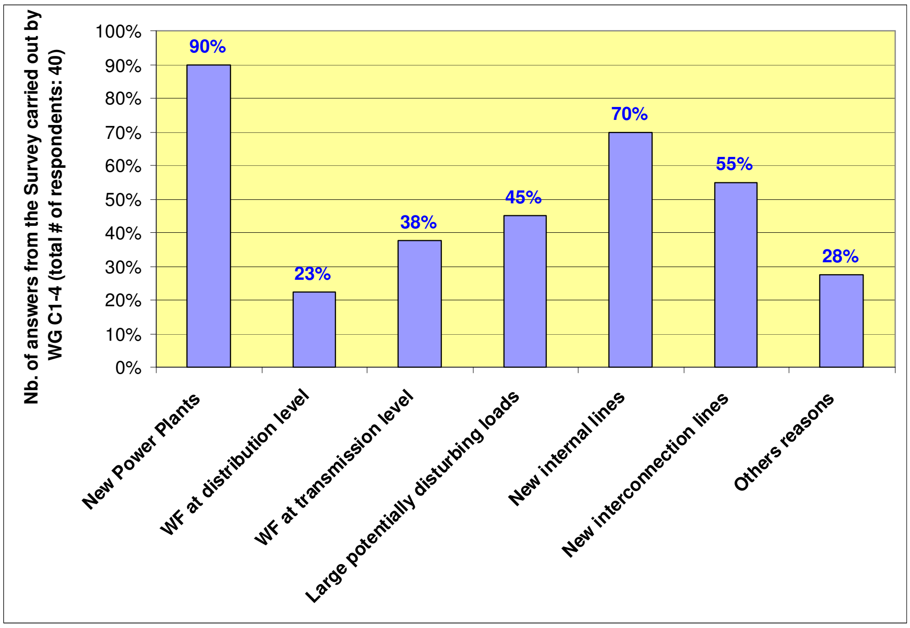

Fig. 3-1 – Main aspects investigated through dynamic analyses. Note: WF: Wind Farms

3.4 Which kinds of dynamic analyses in the planning process / for which purposes?

Modern power systems are characterised by a very large size spreading over large geographical areas. The trend of establishing new interconnections among formerly isolated systems and reinforcing the already existing interconnection corridors is going to increase the complexity of power systems. This tendency has been witnessed worldwide with a growing speed since the beginning of last decade [3], [5], [6], [8], [10], [11], [12]. Consequently, it is becoming more and more complex the understanding of the dynamic behaviour of the overall power system facing disturbances. As a matter of fact, following a perturbation many different dynamic phenomena can be triggered, often overlapped each other, and it is up to the expertise of the power system engineer discriminate the various phenomena and detect which is the most critical phenomenon for the system stability. Furthermore, when executing dynamic studies in planning stage, the planner shall be able to correctly anticipate the system behaviour accounting for the uncertainty in the future development of generation, demand and network. Lack of sufficiently accurate dynamic analyses, to be executed well in advance before the commissioning of the new infrastructure, can heavily jeopardise the expected revenue of the investment. E.g.: a generator may be forced to work with heavy limits with respect to its capability curve, a new interconnecting line may be forced to operate with very poor power flow limits to avoid interarea instability and, in some extreme cases, a new line may be kept switched off until adequate stabilising measures are undertaken.

The investigation of system stability is greatly facilitated by the classification of stability into appropriate categories [13]. The concept of stability of power system is related to the property of remaining in a state of operating equilibrium under normal operating conditions and to regain an acceptable state of equilibrium after being subjected to a disturbance [14]. As clearly highlighted in [15], the classification of power system stability is based on the following considerations [13]:

- *“the physical nature of the resulting mode of instability as indicated by the main system variable in which instability can be observed;*

- *the size of the disturbance considered, which influences the method of calculation and prediction of stability;*
- *the devices, processes and the time span that must be taken into consideration in order to assess stability".*

Fig. 3-2 shows the outcome of the survey carried out among planner responsible. As it can be seen, a wide spectrum of different dynamic phenomena are taken into account; while in the past only transient stability was examined, nowadays, also long term dynamics is investigated confirming the concern of planners for more complex interactions among control loops that could originate instability phenomena, which can be detected only several tens of seconds after the occurrence of a fault or manoeuvre.

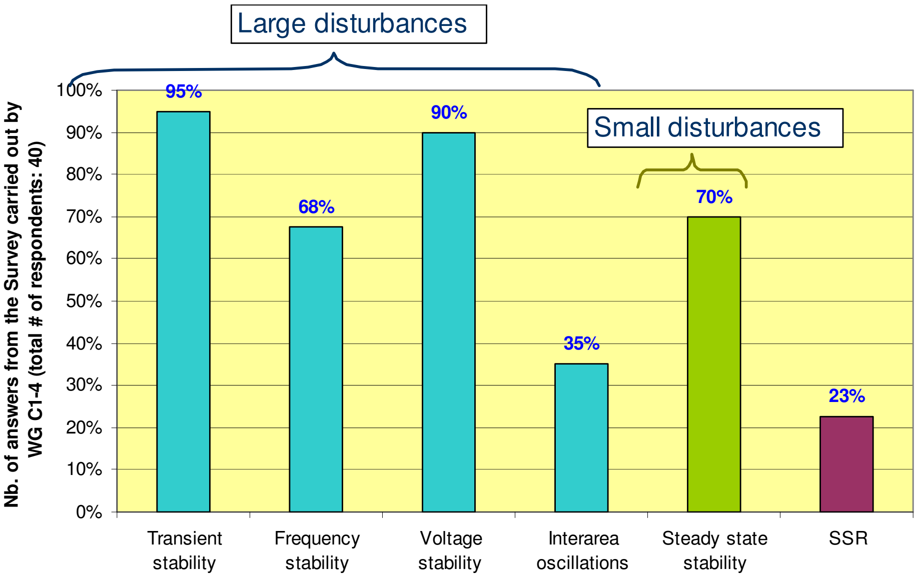

Fig. 3-2 – Dynamic phenomena examined in planning studies. Note: SSR: subsynchronous resonance

Tab. 3-1 summarizes the main analyses to be performed by the planner and for which purposes. For sake of completeness, static analyses have been included too.

ANALYSIS	WHICH CONDITION	FOR WHICH PURPOSE
STATIC ANALYSES		
Load flows	- Peak load - Off peak - Other "binding" conditions (f.i. situations characterised by unbalanced generation dispatching)	- Assessment of power flows, voltage profile, reactive power margins. - Identification in a deterministic way of security constraints; possible bottlenecks on power flows (overloads on lines or interconnecting transformers), violations on voltage limits or limits on generators' capability curves. - Assessment of steady state security: evaluation of security margins considering the pre-established planning criteria (e.g.: N-1 security criterion). - Definition of preliminary measures (e.g.: new shunt Var compensation, network reinforcements)
Short circuit	Maximum Pcc	Sizing of circuit breakers or network configuration
	Minimum Pcc	Assessment of voltage variations
Optimum Var Compensation	Normally, same conditions examined in the load flow computations	- Definition of the optimal location, size and preliminary control design of shunt Var compensation - Preliminary indication on the kind of devices to be installed: mechanically switchable or electronically controlled
Reliability analyses	Time span of one year	- Assessment of reliability indexes - Identification of possible network bottlenecks and related costs
DYNAMIC ANALYSES		
ROTOR ANGLE STABILITY		
Transient stability	Three-phase/unbalanced faults with successful/ unsuccessful reclosure at a predefined distance from the generator	- Assessment of Critical Fault Clearing Time (CFCT) and compliance of CFCT with the adopted stability criterion - Control and protection design
Steady state stability	Various conditions of interarea power transfers and active power dispatch	Assessment of system stability against small perturbations. Stability enhancement through appropriate location and tuning of PSS or other control loops associated to HVDC links or FACTS devices.
FREQUENCY AND VOLTAGE STABILITY		
Frequency stability	Tripping of large generators. Tripping of lines causing islanding of part of the system	- Assessment of frequency deviations - Checking of the compliance of load shedding scheme with the expected frequency deviations. - Checking of the generator stability facing maximum over/under-speed and tuning of relevant protection systems
Voltage stability	Tripping of large generators. Tripping of highly loaded lines or lines causing islanding of part of the system	- Assessment of reactive power margins of the generators or other Var compensation devices to cope with the new reactive power demand. - Redistribution of reactive power margins among generators and compensation devices and/or enhancement of margins
OTHER DYNAMIC ANALYSES		
Subsynchronous resonance (SSR)	Analysis required in presence of series compensation nearby thermal generation	Identification of measures to decouple identified resonance between network oscillation frequencies and the mechanical oscillation frequencies of the turbine-alternator system (e.g.: adoption of TCSC device and definition of the relevant control system, installation of protections able to automatically switch-off series compensation at the detection of undamped subsynchronous oscillations)
Electromagnetic transients (switching overvoltages, temporary overvoltages, lighting)	Lines & cables energisation (switching manoeuvres) and transformers energisations (in-rush currents). Lightning.	Definition of the Basic Insulation Level (BIL) of network components

Tab. 3-1 – Main analyses performed in power system planning

3.5 Dynamic models used and software tools

The survey carried on among the planner responsible has been aimed also at examining which dynamic models are adopted in planning studies and the software tools used for the simulations. Dynamic models have been classified in the following groups:

1. *Generators* (directly connected to the transmission grid): models of the synchronous machine, speed governors, frequency control, turbine controls, boiler controls and penstock dynamics, AVRs, over-underexcitation current limiting circuits dynamics, Special Protection Systems (SPS) and PSS
2. *System controls*: AGC, Secondary Voltage Regulators (SVR)
3. *HVDC links:* thyristor based converter, IGBT based converter
4. *Controlled network components (FACTS):* Controlled Series Compensation (CSC), phase shifting transformers (PHS transf.), Static Var Compensators (SVC), STATCOM and UPFC
5. *Wind farms:*
   - *Asynchronous generators:* direct grid connection, grid connection via DC link, dynamic slip control, Doubly Fed Induction Generator (DFIG);
   - *Synchronous generators:* direct grid connection, grid connection via DC link, grid connection via DC link gear-less
6. *Dispersed generation:* Small Hydro Turbines, Power electronics based Micro-Systems (PEMS) including fuel cells and micro.turbines, Photovoltaic Systems (PV), Superconducting Magnetic Energy Storage Systems (SMES), Battery Energy Storage Systems (BESS), Flywheels (FW)
7. *Load model*
   - *Static Model:* constant impedance, constant current, V-f dependent laws, other modelling depending of the nature of the equivalent load seen from the HV&EHV grid
   - *Dynamic model*
8. *Protections:* distance relays, overload relays, other protections (like overvoltage, pole slips, directional protections, load shedding relays, etc.), network automata (like changeres of topology)

Moreover, it has been asked whether dynamic equivalents are used when executing studies applied to large interconnected systems where detailed information on the whole system might not be available.
As it can be seen in
Fig. 3-3, in most of the cases dynamic models suitable only for short term dynamics (transient stability) are used. Slow control loops, like over-underexcitation current limiting circuits, AGC, SVR, which are essential to simulate mid-long term dynamics spanning over tens of seconds are modelled only in a limited number of cases. Even more limited is the number of planners that adopt dynamic models of wind farms or various forms of Dispersed Generation. As a matter of fact, one of the problems highlighted by the survey, is namely the difficulty in building models of wind farms (in many cases equivalent models) suitable for electro-mechanical transients with time domain simulation making use of a r.m.s. representation. Still more difficult turns out to be the selection of the parameters to be attributed to the wind turbine generators and related control systems. Similar problems have been highlighted for the dynamic load modelling: only in 22% of cases a dynamic model is used.

Finally, dynamic equivalents to properly represent the response of neighbouring networks are used only in 25% of the cases. To this purpose, it is also worth mentioning that the accuracy degree of external systems modelling shall be appropriate to the phenmena to be investigated, e.g.: for SSR study a three-phase modelling of the system is needed.

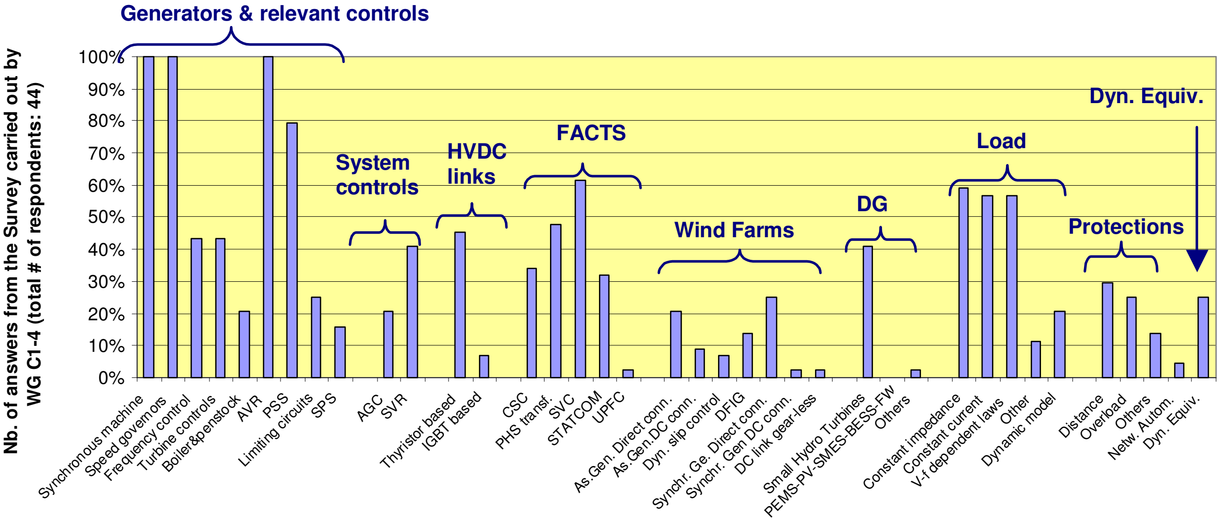

Fig. 3-3 – Dynamic models used in planning studies

Concerning software tools in 77% of cases, planners make use of commercially available tools while in the remaining cases they use both in-house developed and commercially available tools. From this point of view the role of software developers and vendors is crucial to offer planners adequate models and, especially, a library of associated parameters. This is particularly true for new kinds of generators (e.g.: wind generation) or electronically controlled devices, the technological evolution of which is rapid and requires close contacts with manufacturers. Hence, the accuracy and the user friendliness of commercial software tools have a direct impact on the quality of planning analyses. It is worth mentioning that, whist in the past there was a tendency to develop autonomously simulation programs, nowadays in-house developed software is rather an exception; only modules for some specific applications are developed directly by system operators and, usually, not directly in the planning department but from a dedicated research team that provides support to both planning and operation departments.

3.6 Needs identified by the planning responsible and obstacles in the execution of dynamic analyses

As mentioned before, in a large majority of cases dynamic analyses are carried out only occasionally in planning stage. In some situations dynamic analyses are not carried out at all. The following main barriers preventing the execution of dynamic analyses have been identified:

- ✓ resource problems;
- ✓ lack of data;
- ✓ lack of experience.

Resource problems and lack of experience derive in some cases from the recent restructuring processes where the unbundling of former VIUs and the streamlining of the staff have increased the pressure on the remaining working teams to react more and more quickly to the numerous tasks attributed to system operators, especially in the planning stage (e.g.: requests for new generation connections, definition of interarea NTC, analyses of non-conventional solutions alternative to the construction of new lines to comply with strict environmental constraints). One respondent stated explicitly "*The availability of expert resources is an ongoing major limitation to dynamic analyses*". Lack of data is another common issue raised by planners when dealing with dynamic analyses. Particularly, information on new generating units and associated controls are not easily available, as discussed here below.

Furthermore, when executing dynamic analyses, respondents have highlighted the following problems as the most crucial:

- ✓ lack of models for wind farms;
- ✓ lack of models for new network equipment;
- ✓ lack of models for Dispersed Generation (equivalent dynamic models for transmission studies).
- ✓ lack of verified models for loads; difficulty in collection of load data and information on motor load (dynamic model of the load);
- ✓ ensuring generator parameters are correct. Problem of identification of generator models and associated controls (AVR and governors);
- ✓ open cycles and CC Gas Turbine models.

4 CASE STUDIES

To facilitate the complex task of examining the system behaviour in presence of different dynamic phenomena often coexisting and overlapped, a series of case studies has been selected, each one dealing with different issues of dynamic analyses to be applied at the planning stage. The presentation of case studies shall represent a support for the planner aiming at providing the methodology to be followed in the various cases as well as the most critical problems to be overcome.

4.1 Selected Case Studies

The following case studies have been collected and described in this technical report:

Connection of new generation units:

- connection of a new generation centre to the transmission grid (example taken from a practical case related to the power system of Italy);

Connection of wind farms:

- connection of wind farms in isolated systems (methodology proposed by Ireland)
- connection of wind farms in interconnected systems (methodology proposed by Spain)
- connection of off-shore wind farms (presentation of the experience of West Denmark and Germany)

Interconnection among large power systems:

- dynamic analyses applied to the investigation of the feasibility of synchronous interconnection between TESIS[5] and UPS/IPS[6] (practical case proposed by Belgium, who was member of the international study team)

Steady-state stability (SSS) study:

- SSS analysis applied to SAPP (experience proposed by South-Africa).

Sub-synchronous resonance (SSR) study:

- SSR analysis applied to SAPP (experience proposed by South-Africa).

4.1.1 Connection of a new generation centre to the transmission grid

In unbundled environments the location of new generating units is not centrally planned as it used to be in the past, but it is driven mainly by market signals and external factors such as availability of primary energy resources (e.g.: gas pipelines, LNG). Moreover, commissioning of new power plants is mainly in the hands of private investors who decide when making the request for connection to the grid as well as the size of the power plants. The S.O. shall struggle to accommodate the evacuation of the additional injection without jeopardising the system security and minimising the needs for further network reinforcements, which are normally difficult to be achieved due to a generalized opposition of the affected population and, on the other hand, they have an adverse impact on the transmission fees to recover the investment costs.

Feasibility studies for the connection of mid-large size power plants (in the order of many 100 MW) are carried on with two completely different perspectives:

- the investor perspective;
- the S.O. perspective.

In the first case the following aspects are normally investigated:

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[5] TESIS: Trans-European Synchronously Interconnected System composed by UCTE and former-CENTREL

[6] UPS/IPS: UPS. Unified Power System: interconnected power system of the Russian Federation. IPS: Interconnected Power System composed by UPS and the power systems of the CIS countries with the exception of Armenia and Turkmenistan.

- analysis of the mid-long term electricity prices in the area where the new generator will be located to evaluate the expected yearly revenues. To this purpose, market simulators are normally used [16];
- amount of power that can be generated in compliance with possible network constraints. Normally, only static analyses aimed at checking potential overloads are carried out;
- connection costs;
- environmental impact study;
- procedure for the application of connection according to the rules of the Grid Code.

The perspective of the S.O. is quite different, being basically addressed to the assessment of the impact of the new power plant into the grid. Apart the classical static security assessment, dynamic studies are more and more essential considering that the proposed location cannot be the "optimal" one for the grid. Additionally, limitations of the generation raised during the operation of the power plant will surely cause complaints from the plant owner, who, in some extreme cases, could claim remuneration for the suffered loss of revenue.

As an example, it is possible to consider the following situation where the connection of a new combined cycle plant rated 940 MVA has been proposed in the extreme south of Italy. In the region, the transmission grid is characterised by only one 400 kV corridor from Sicily towards the main load centres in the region of Naples (Fig. 4-1). The power flow is normally conveyed from south to the region of Naples and the additional injection will load the existing corridor close to their limits. Consequently, a set of dynamic analyses had to be performed aimed at assessing the CCT of three-phase solid faults in the 400 kV line both at the northern and the southern side of the new power plant. Moreover, different condition of power exchanges between Sicily and the mainland had to be considered. Once the CCT have been evaluated, the values had to be compared with the typical intervention times of the distance protections. The study demonstrated that the lowest CCTs is recorded at the occurrence of three phase faults in the line north of the new power plant with a condition of power import towards Sicily[7]. In this situation, values of CCTs in the range between 190 ms (summer scenario) and 250 ms (winter scenario) have been evaluated. These values are below the intervention time of the second zone of distance protections (300 ms). Consequently, the most appropriate measures have been identified to preserve the stability of the new generating units, acting both on the excitation current and the generated power. It turned out that the most effective measure was the reduction of the active power generation down to 90% of the rated value in the winter scenario and 75% of the rated value in the summer scenario, whenever Sicily is in import conditions.

The above constraints are limiting the total yearly amount of generated energy by the new power plant with a direct impact on the revenues expected by the investor. It is up to the S.O. to clearly define the dynamic constraints that are affecting the productivity of a power plant and inform the concerned investors <u>before</u> the commissioning of the new plant.

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[7] The situation of Sicily in importing conditions is not common, but cannot be excluded "a priori".

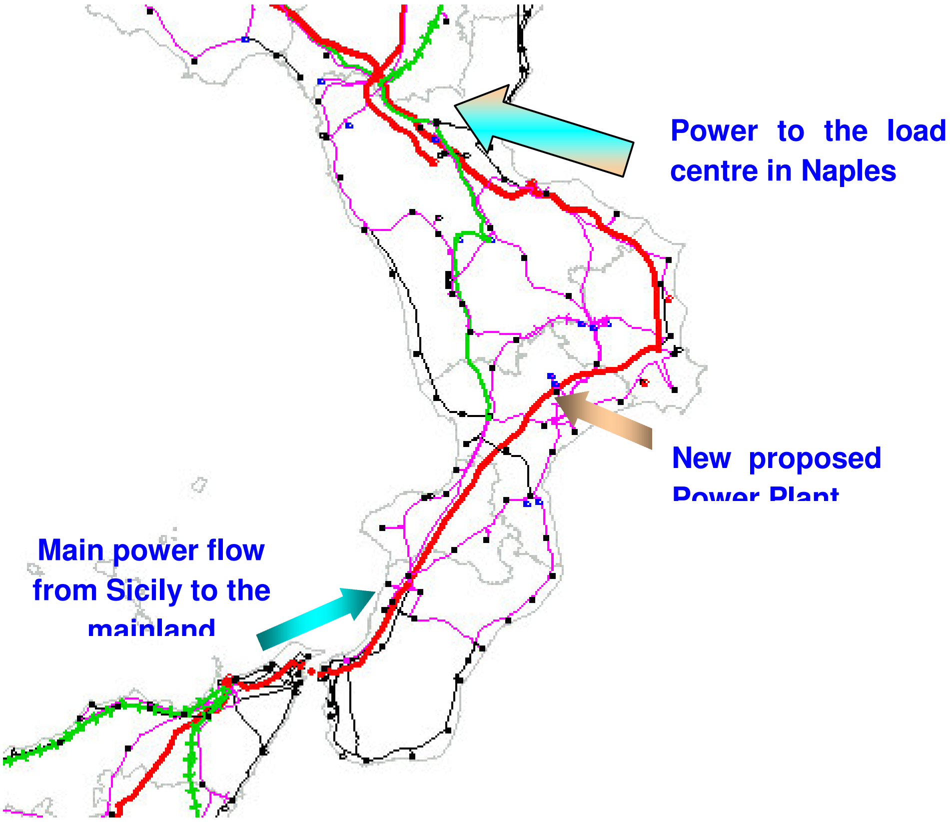

Fig. 4-1 – Scheme of the transmission system in south Italy

In addition, the examination of the electromechanical stability of the new units shall be checked also in islanding conditions, which can be created as a consequence of a fault cascade. In this latter situation, further dynamic analyses have to be carried on dealing with frequency transients in order to ensure that over/under-frequency trends will not cause, respectively, disconnection of units or the attainment of the first threshold for load shedding.

Fig. 4-2 shows in a highly synthetic way the process followed for the identification of possible constraints and related remedial actions.

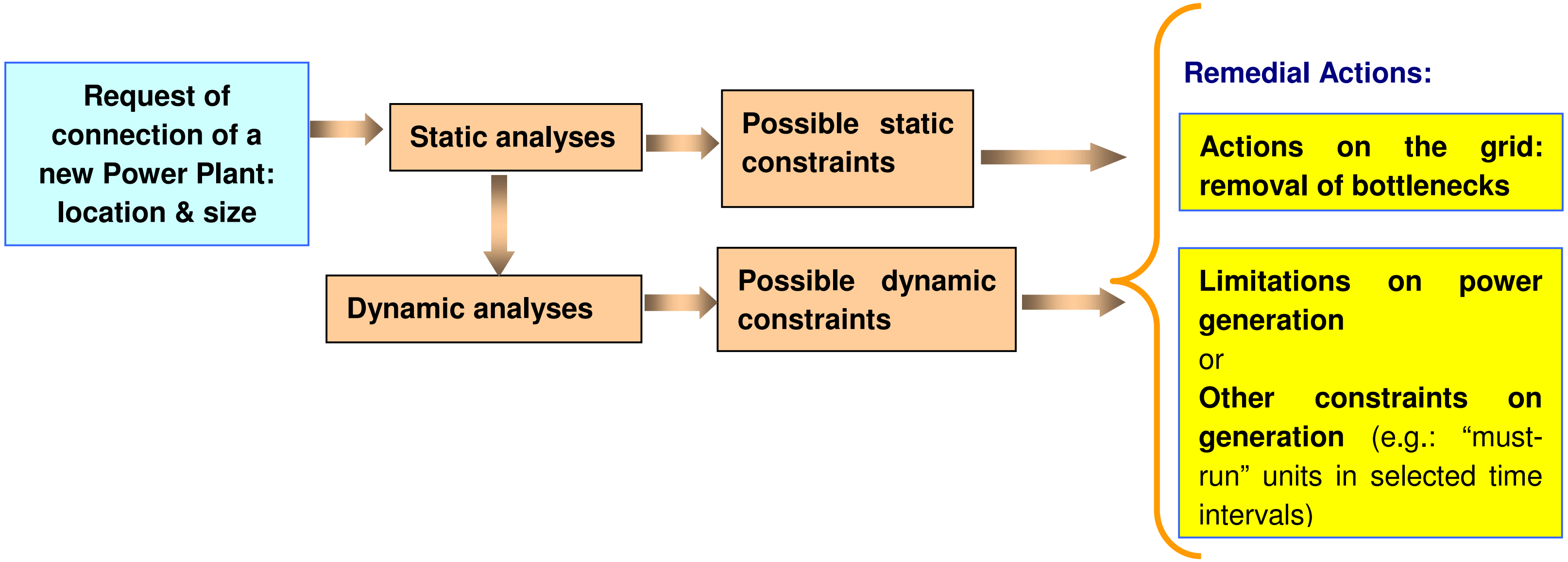

Fig. 4-2 – Flow to be followed for the examination of the impact of a new power plant into the grid

4.1.2 *Connection of large wind farms*

The impact of wind generation on the dynamic behaviour of a system is closely related to the ratio between the penetration level of wind generation and the “equivalent” generation capacity. In isolated systems the “equivalent” generation capacity is simply the sum of the committed generators selected after the unit commitment phase. In interconnected systems, the evaluation of the “equivalent” generation is more complex requiring to correctly take into account the support that can be derived from the neighbouring systems considering their inertia and spinning reserve as well as the limits in the tie-lines. Moreover, the support deriving form the neighbouring systems is different depending on the type of interconnection. Both DC and AC links can be of great help to evacuate the power in excess (e.g.: high wind generation in condition of low demand) or face sudden production shortfall related to an unforeseen decrease of wind generation. On the other hand, the contribution of DC links to frequency stability in case of sudden disconnection of generators is very poor not being able to give the inertia support of the connected system. In general, the need to keep a margin on tie-lines to smooth surplus or shortfall of power production reduces the possibility of energy trading with the consequent reduction of the ATC[8]. Then, this solution shall be carefully investigated due to a possible heavy impact on electricity prices, especially in importing areas weakly interconnected.

In the examined study cases, the following situations have been considered:

- Windfarms in isolated systems;
- Windfarms in meshed systems poorly interconnected with neighbouring countries
- Windfarms in highly meshed systems
- Experiences of off-shore windfarms.

4.1.2.1 Windfarms in isolated systems

Isolated systems are often small poorly meshed networks that require the system operator to consider different aspects when implementing generation compared to heavily interconnected systems. These aspects may not be of a dynamic related perspective but will play an important part when analysing the total behaviour of the system.

Issues to take into consideration are level of network meshing, spinning reserve requirements and the access to fast responding hydro generation or storage devices (e.g.: pumping storage units, wind-gas combination, wind-hydrogen production or actions on demand to make it more flexible in relationship to the generation availability). Other topics to look at is how to predict the wind forecast and the economic and environmental impacts of wind generation compared to conventional generation i.e. conventional generation has an operating minimum and during low system demand it is essential to be able to bring these units back to allow wind generation. However, wind generation can not provide spinning reserve, so conventional units may have to be declared ‘must-run’ during these occasions. Depending on the wind penetration, restrictions on how much wind the system can take at certain times may have to be put in place. To this purpose, probabilistic procedures based on non-sequential Monte Carlo model with full network representation and DC load-flow calculation have

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[8] ATC: Available Transmission Capacity evaluated, according to the ETSO definitions, as ATC=NTC-AAC with:
NTC: Net Transfer Capacity
AAC: Already Allocated Capacity

been developed and presented in [17]. Through a suitable modelling of wind-generator production P versus wind intensity Vv (*Fig. 4-3*), the randomness of wind intensity Vv, the correlation of wind intensity among various windfarms and all the other random events associated to the conventional generation and the grid, it is possible to define the optimal amount of wind penetration in relationship to a minimum threshold of wind energy, which has to be cut-off.

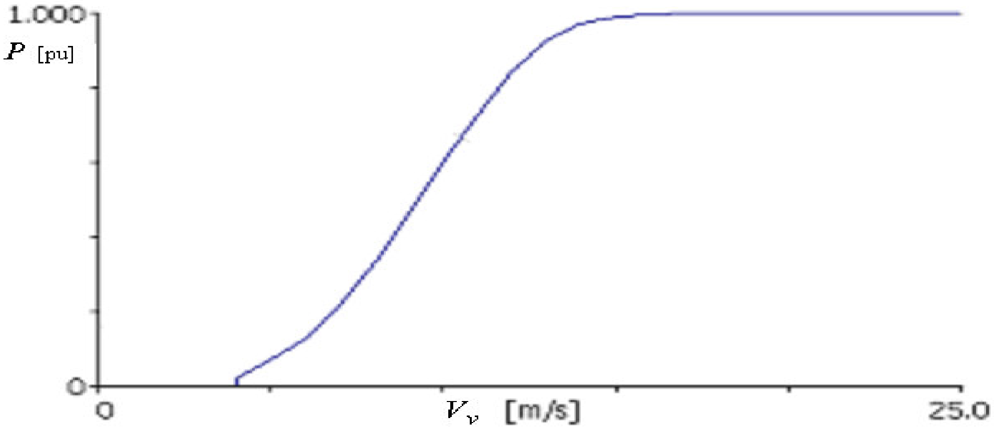


Fig. 4-3 Example of wind-generator production P versus wind intensity V_v

Following the discussion above, it is clear that not only dynamic issues may have to be investigated in isolated system. All issues should be considered in parallel with the dynamic analysis of the wind generation as these may affect the outcome of the simulations.

The inclusion of wind generation, which in its nature is intermittent, has a greater impact in an isolated system with respect to meshed systems as, for a same size, it will have a higher percentage of the overall generation mix. With a high penetration of wind generation in the isolated system the windfarms ability to ride through faults and provide voltage control may have a greater impact on security, reliability and operation of the system.

The actual simulations carried out for windfarms connecting into an isolated system are in theory no different to the simulations carried out for highly interconnected systems, but as outlined above there are other issues that may have to be taken into consideration.

Methodology of simulation

Depending on what is intended to be simulated different approaches may have to be considered with different methodologies and different simulating software as a result. The type of technology for wind turbines is important, as this will have an impact on which simulations to carry out.

On the market today there is a wide range of different types of technologies for wind turbines available, stretching from simple induction machines to machines connected via a fully rated converter.

All these technologies have different impacts on stability of the network especially in combination with all the control features in a windfarm. In some cases, they draw reactive power from the system directly after the fault, as in the case of asynchronous generators. The amount of post-fault reactive power absorption depends on the adopted technology and also on reactive compensation devices that can be installed in the windfarm. The impact of a single windfarm connecting to the system from a synchronous stability point of view is very marginal if it has any impact at all. However, with high wind penetration this may become an issue as a deficit in reactive power may in theory have an impact on the angular stability.

What recalled above has a close relationship with the Grid Code in each country respectively and many countries in Europe have developed a special section of the Grid Code concerning windfarms as a complement to deal with issues that only concerns windfarms.

The simulations have to capture the above concerns in a way so that the utility is able to understand the impact of a single windfarm connected to the grid or the impact of the total installed capacity of wind. As mentioned earlier the windfarms ability to ride through faults and its capability of voltage control and voltage recovery after fault should be investigated. In addition, the impact that windfarms has on the synchronous stability of conventional units should also be closely monitored.

Dynamic models for WTG

Dynamic models of wind turbines and their control systems have recently become available from the wind turbine manufacturers. Depending on what software calculation program the utility is using to carry out the dynamic simulations, in commonly used software programs these models should be available with clear and transparent documentation, which shall include block diagrams of controls.

To represent the actual response of the windfarm all the features of the windfarm needs to be represented. The level of accuracy of the model can and should vary depending on the purpose of the simulation. A transmission system operator and the manufacture of the turbine will always have different requirements on what features should be represented. The models available today represent some or most of the following features:

- The generator (DFIG, IG, WEC)
- Generator controls
- Reactive compensation devices
- Wind Model
- Rotor/Hub connection via a flexible shaft to the generator (2-mass representation)
- Aerodynamics energy conversion
- Blade pitch angle control
- Under/Over voltage relays
- Under/Over frequency relays

All models need to be populated with appropriate parameters. The models are only available in a compiled format, which means that the source code is not available. This means that any parameters relating to the models, which represent a particular windfarm, are submitted by the developer in conjunctions with the manufacturer.

The developer of the windfarm is responsible for the settings applied and for compliance with the appropriate Grid Codes. The settings will vary between windfarms depending on connection method and location in the network. Settings that would typically vary are voltage and frequency relay settings and the mode of control, which could typically be power factor, voltage or reactive power.

The industry is currently discussing the criteria for validation of these dynamic models, but due to lack of data available the validation of these models could span out over a number of years. Validation of these dynamic models is vital, as the confidence gained in the models behaviour is underpinned by the quality of the measurement data received.

4.1.2.2 Windfarms in meshed systems poorly interconnected with neighbouring countries: the Spanish case

4.1.2.2.1 Introductory Remarks

In Spain, wind power development depends on particular promoters and regional governments. In areas with few connection requests, regional governments favour direct links between investors in windfarms and the electrical company. In areas with great wind resources and development, regional governments usually call electrical companies for planning the infrastructures necessary to evacuate the energy, most times including reinforcements to maximize the available wind capacity.

The studies include both, nodes from the distribution systems and nodes from the transmission system as a solution for increasing the network capacity to acquire high amounts of wind power. Even wind farms formerly connected to the distribution system might change the final connection point to a transmission node to make room for more wind generation.

The studies performed one by one, according to the request reception, are not the main matter of the methodology explained.

In this document, the methodology applied to large scale wind development is described. The network is divided in electrical zones while maintaining administrative borders into account, to inform regional governments. A study is carried out about the wind power penetration capacity on each zone

The following points are addressed in the study:

1. Short circuit power capacity and static network analysis
2. Transient stability
3. National limits regarding system security

Through the study of these features, the available capacity is verified in the local area, the regional network and the wide national system requirements. For example, while the limit based on short circuit power capacity is related with voltage variations in the connecting point, static network analysis takes into account the regional network capacity. Transient stability studies involve wide areas, even national scope studies in scenarios where a large-scale wind integration has to be checked against limiting behaviours under perturbation, such as voltage dips travelling far through the network. In these cases, the objective is to avoid the disconnection of wind farms in cascade for minimum voltage protection that will result in not admissible network conditions.

Other national limits involve a number of considerations that are not addressed in this document. For example, in Spain there is a national wind production limit depending on the total demand, related with power-frequency regulation. In very light load conditions, this limit is already overcome and enforced with orders to disconnect wind generation units.

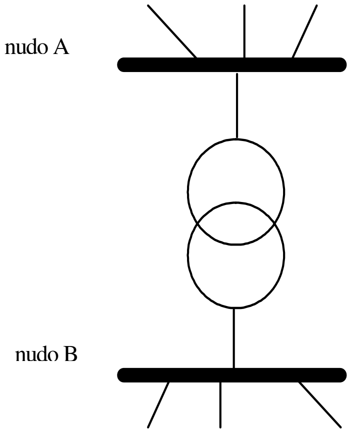
4.1.2.2.2 Short circuit power capacity and static network analysis

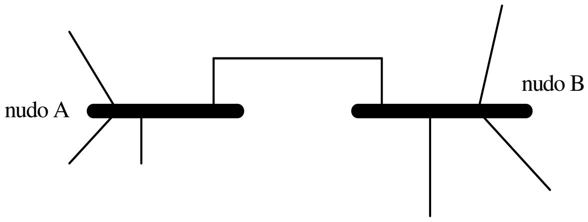
4.1.2.2.2.1 Short circuit power limitation

Short circuit power limitations are related with voltage variations due to the wind fluctuations and possible disconnection of a number of wind machines.

Maximum nodal wind power installation capacity is settled by Spanish regulations in a 5% of three phase short circuit power. This limitation is currently studied under the following assumptions:

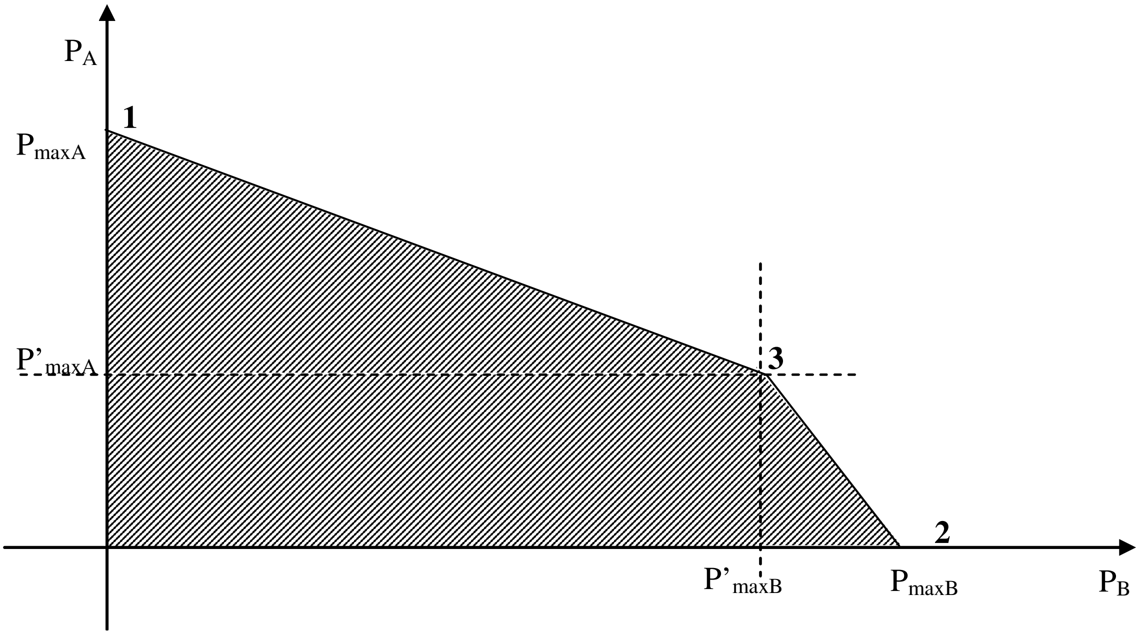
- The limit corresponds to the maximum simultaneous production. Installed wind energy is usually diminished by a simultaneous coefficient of 80%, which means that installed power will be 25% over the real available capacity.
- The three-phase short circuit power is statistically studied: the value used is the one, which is overcome 50% times during the year (percentil-50).
- The nodes electrically connected by transformers or lines but not strongly linked to the rest of the network are studied together so a global short circuit capacity is given depending on where the wind power will connect (see figure). The typical configuration where a joint study is necessary includes the transmission axis, with two or more nodes connected by a single line. Only the short circuit power provided by the ends is taken into account, to avoid that every new substation has to be modelled as a new node with the same capacity than the one aside.





The figure might correspond for example to a 400/132 kV transformer. The X-axis (Point B) will be the installable wind power in the 400 kV side and the Y-axis (point A) will be the 132 kV side. There are three singular points:

1. Pmax A. Maximum installable wind power if all the wind-farms are connected in the 132 kV side.
2. Pmax B. Maximum installable wind power if all the wind-farms are connected in the 400 kV side.
3. Optimum. A high percentage of wind power is connected in the EHV transmission side (400 kV in the example) and the rest in the HV transmission (132 kV in the example) side.



4.1.2.2.3 Network analysis.

A case study for different time horizons is generated with different hypothesis regarding:

- Demand scenarios.
- Network developing alternatives.
- Wind power penetration scenarios according to regional wind power plans and resources (wind level in the specific area).

The approved security proceedings regarding contingency analysis, voltage limits under perturbed conditions and so on are used to verify the maximum wind power installation for each scenario.

In case there is a network element limiting the possible wind power installations in an area with important wind resources, an alternative will be given, which should be included in the network planning procedures and supported by the regional government and the wind promoters (might pay for its construction as network reinforcement at the end).

The more restrictive scenario can even be improved through automatic disconnection of wind power in case of overloads in very specified elements following a contingency. This method is only used for small amounts of installed power in a local connection, since the main objective is to avoid general disconnection of wind farms in wide areas under perturbations.

4.1.2.2.4 Transient Stability

Short circuits in the electrical network cause variations and unbalances on main magnitudes (e.g.: voltages, power flows) and in the connectivity (due to the intervention of protective schemes). In some severe cases, short-circuits can trigger disconnection of generating units or significant loads.

The studies carried out in this context are intended for checking if the new wind generation forecast in the area compromises the transient stability of the area and the whole power system.

4.1.2.2.4.1 Methodology

The main goal is to extract transient stability indicators to verify the effect of the future wind farms in the network.

One indicator calculated is the critical timing for fault elimination (CCT) in the transmission network nodes in the general area, and in particular in the most conflictive ones.

The maximum production concentration in the area is also studied and the impact in transient stability.

By these means, it is easy to compare the situation with and without wind generation in the system and find out the limiting conditions.

4.1.2.2.4.2 Critical fault elimination timing

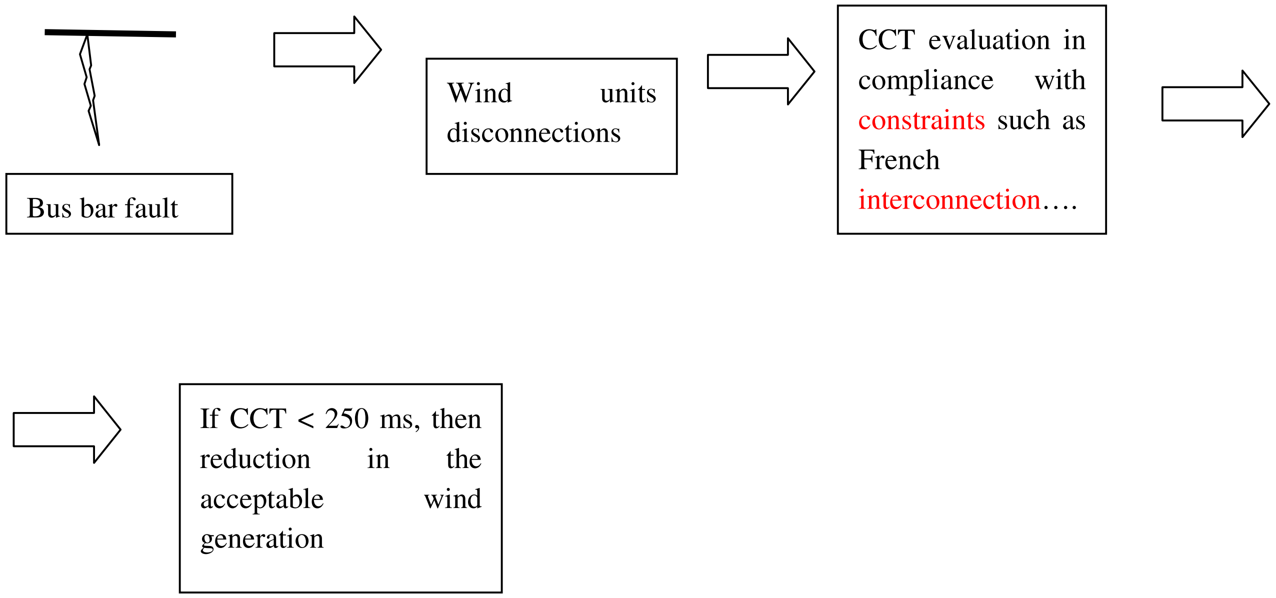
The objective is to identify the fault elimination conditions (time and selectivity) in the connecting point and the wind farm substation to avoid severe consequences on the peninsular power system. That means, once the wind generation is connected, to guarantee:

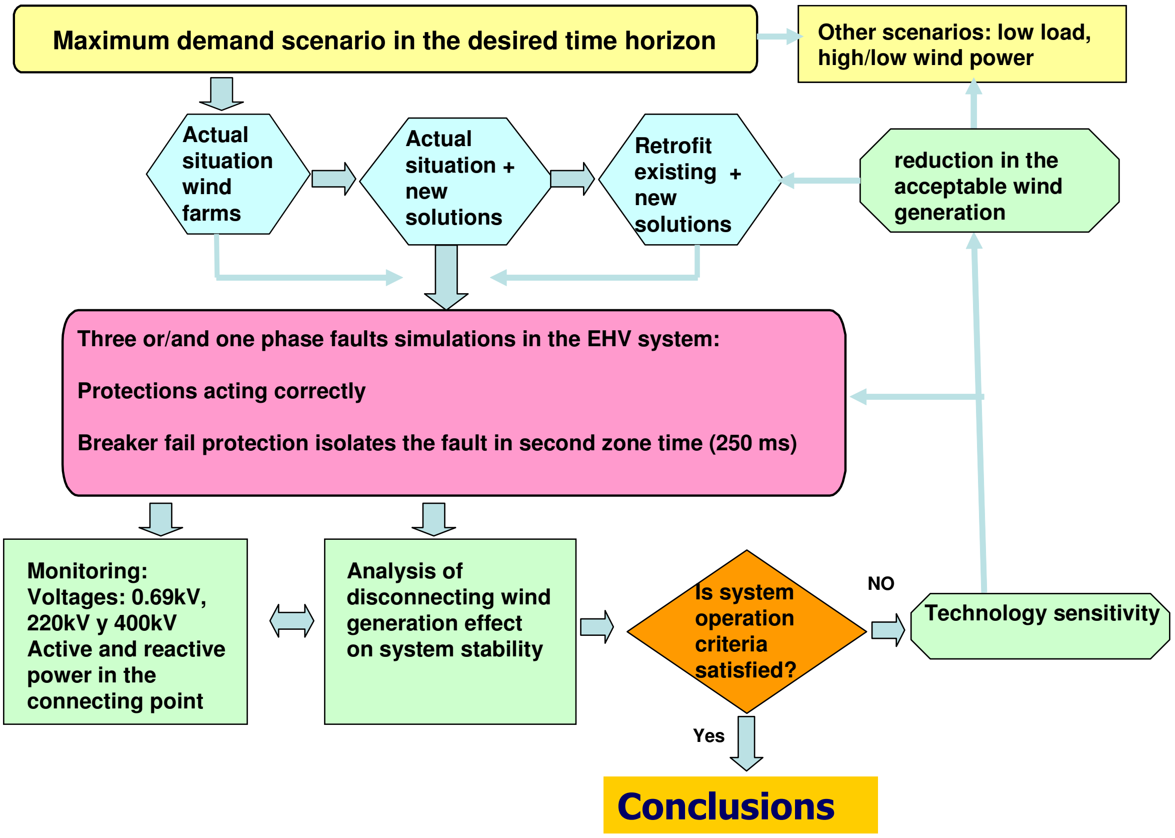
- Generator units stable functioning
- Quality and continuity of supply

In the critical timing calculations, a busbar fault duration is not considered admissible depending on the following phenomena:

- French interconnection loss due to the synchronous-relay system activation (DRS) installed in the lines.
- Significant supply disconnections
- Generating unit disconnection over 1100 MW (maximum generating unit in the system).
- In a branch, protection scheme activation due to apparent impedance inside the trigger relay characteristics (connected branches without internal fault).

If critical time is under 250 ms (minimum fault elimination time for break-opening failure protection) for any of the reasons above, maximum production must be limited. Then, a complementary process is followed: the fault permanency is fixed in 250 ms and the production is reduced until the result is within acceptable limits.

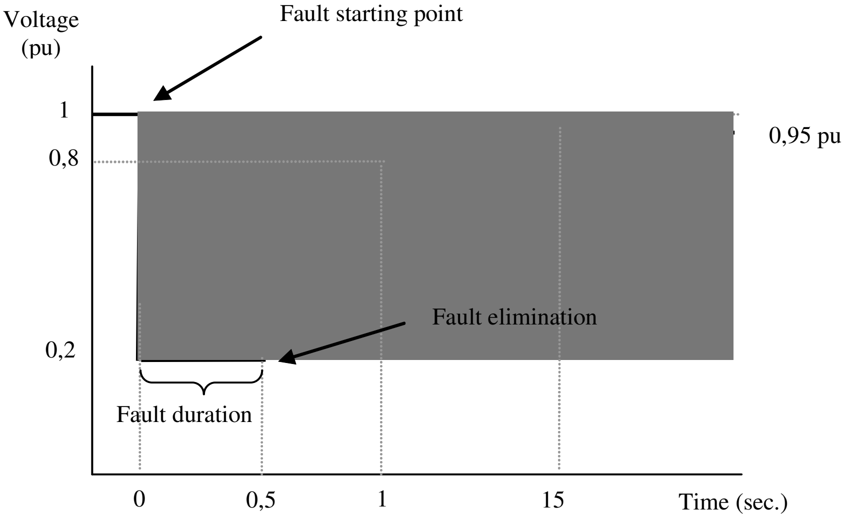

Bus bar fault
Wind units disconnections
CCT evaluation in compliance with constraints such as French interconnection….
If CCT < 250 ms, then reduction in the acceptable wind generation


Maximum demand scenario in the desired time horizon
Other scenarios: low load, high/low wind power
Actual situation wind farms
Actual situation + new solutions
Retrofit existing + new solutions
reduction in the acceptable wind generation
Three or/and one phase faults simulations in the EHV system:
Protections acting correctly
Breaker fail protection isolates the fault in second zone time (250 ms)
Monitoring: Voltages: 0.69kV, 220kV y 400kV Active and reactive power in the connecting point
Analysis of disconnecting wind generation effect on system stability
Is system operation criteria satisfied?
NO
Technology sensitivity
Yes
Conclusions

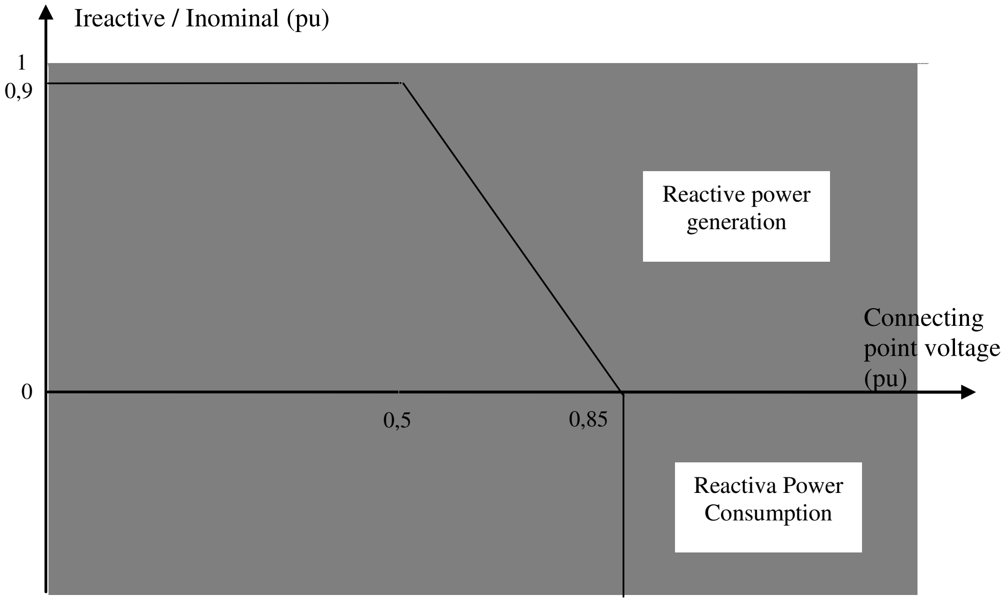
4.1.2.2.5 Regulation under discussion (P.O. 12.3)

4.1.2.2.5.1 Behaviour under short circuit conditions

- Design or control measures will allow generators to avoid instantaneous disconnection during voltage dips associated with short circuits correctly eliminated by the protective scheme in the power system. The wind farm will stand one-two or three phase voltage dips with the values and duration shown in the figure below.



- It is not admissible to absorb active or reactive power at the connecting point level during the fault and voltage recovery period. Machines should generate the maximum current possible (trying to maintain nominal current or the pre-fault current). The current distribution between active and reactive components will fulfil the limits established by the figure below. For voltages under 0.85 p.u. in the connecting point, the generator will have to generate reactive power.



- A 40 ms delay from the fault initial time is allowed to achieve the performance shown in the figure. This behaviour must be guaranteed by a technical centre qualified by the Administrative Office.

4.1.2.2.5.2 Primary regulation

- Wind farms will be able to lower generation against frequency rise and to increase load if wind speed is over the corresponding to the nominal power (maximum 5% over a 5 minutes period, while wind allows). If the wind generator is working at partial load, it only has to fulfil the requirement to reduce generation.
- In exceptional conditions at the System Operator request, the wind farms will be able to operate under corresponding power for partial load, to have primary regulation to raise against frequency drops as indicated in the Operational Procedure regarding complementary services to the network.

4.1.2.2.6 Case study description and models

The study horizon is settled around 4 years in advance. Depending on the area, a summer or winter peak-demand will be selected.

The topology includes detailed Spanish and Portuguese networks with the respective dynamic models of generators, voltage regulators, speed governors and stabilisers. Also, user-developed models are used for main power plants, thermal and nuclear.

A detailed model from the French network is added and an equivalent from the rest of European network.

Loads use the general model IZ (constant current for active power and constant impedance for reactive power).

Besides, the following models are used:

- General minimum voltage protection model in generation bus bars with typical values of 0,75 p.u. in 800 ms.
- General overspeed protection model adjusted to 115%.
- General synchronous relay model in the branch ends

To model wind generation, a difference is established between actual and future wind farms.

4.1.2.2.7 Existing wind farms.

Two technologies are used: asynchronous (squirrel-cage inductor machines) and doubly-fed inductor machines.

Spanish technical regulation dates from 1985. It states that wind farms should disconnect instantaneously from the network for voltages under 85%. The rule was established when wind penetration was low, so without the knowledge on its behaviour under disturbed circumstances, it was better to disconnect them. In the actual scenario with a high penetration, the rule will provoke that a high amount of wind units will disconnect with far and correctly eliminated faults.

The assumption of instantaneous minimum voltage relays will prevent the integration of high scale wind power from the transient stability view point. Thus, the following assumptions are made:

- Asynchronous wind generators: minimum voltage relay adjusted to 85% of nominal voltage with 300 ms delay to avoid disconnection with fault eliminated correctly in 100 ms.
- Doubly fed inductor machines. The models simulate well the behaviour of the machines in situations with voltages over its own minimum voltage protection, tuned at 90% nominal value (the relay triggers instantaneously). Consequently, they might disconnect immediately with faults correctly eliminated in far nodes on the network if the voltage dip is enough.

4.1.2.2.8 Future wind farms.

The technology used for future wind farms has a direct impact on the power system stability due to the different behaviour under perturbations. Therefore, the amount of allowed wind power installed will depend on the machine technology used.

In the study there are three hypotheses:

1. **Realistic.** Under voltage dips, the future wind farm will behave as an asynchronous generator (squirrel-cage) with a strong reactive power transient consumption (its only reactive power compensated for normal operation). This behaviour, in areas with great wind farm density, will delay the voltage recovery so the minimum voltage relays timing might be reached and cause the wind farms disconnection. This modelling will include the wind farms with:
   - Asynchronous machines
   - Doubly-fed machines that, during the voltage dip, shift to asynchronous behaviour for auto-protection and to avoid disconnection. This is the least favourable case because this technology might avoid the undesired transient reactive power consumption; however, while the new models and control designs are not developed, the actual schemes will be used.
2. **Optimistic.** The future wind farm will continue connected to the work during a voltage dip (see figure). That means, the wind farm will remain connected with a 20% of nominal voltage during 500 ms, and 1 second for voltages 80% of nominal and without reactive power consumption during voltage recovery. This modelling will include the wind farms with:
   - Synchronous with stator converters. It behaves as a constant current source and has an acceptable behaviour under short-circuits.

- Either new technologies or improvements in services machines that fulfil the requirements mentioned.

3. **Optimistic with adequacy**. Both, future wind farms and actual wind farms will stand the voltage dip described in the future regulation. This is the Optimistic hypothesis including also the actual wind farms. Adequacy is the process to improve the wind machines already installed to the technical requirements for the future wind machines. This hypothesis accounts for the special effort from promoters and manufacturers to develop new technologies with a better behaviour under short-circuits.

4.1.2.3 *Windfarms in meshed systems: the German case*

Germany is witnessing an impressive development of RES and, namely, wind generation. Till 2010, the share of electric power generation from renewable sources shall rise to at least 12.5% and, by 2020, to at least 20%. Additional major increase of capacity can be achieved by 2050. Wind power will contribute substantially to accomplishing these goals. This huge development of RES is not fully driven by market mechanisms, but it is basically supported by the Federal Government, which is committed to strongly reduce CO_2 emissions. The target set by the German Government consists of a reduction in CO_2 emissions from the current 859 million tons per year to 846 million tons over the period 2008-2012 [18]. In energy generation and industry, CO_2 emissions will have to drop from the current 503 million tons per year to 495 million tons by the year 2008-2012. Obviously, one important way to achieve this target is an increased use of RES and, particularly, wind energy. The present and perspective development of wind energy in Germany is shown in Tab. 4-1. As it can be seen, in the next years a substantial amount of new wind installations will be off-shore, especially in the North Sea [19].

Ta velopment of installed wind capacity in Germany up to 2020 in GW

	Installed wind capacity in Germany, in GW				
Year	**2003**	**2007**	**2010**	**2015**	**2020**
Onshore	14.5	21.8	24.4	26.2	27.9
North Sea	0	0.4	4.4	8.4/8.1	18.7
Baltic Sea	0	0.2	1.0	1.4/1.7	1.7
Total	14.5	22.4	29.8	36.0	48.2

Ta velopment of wind energy (W.E.) production up to 2015 in GWh

	Wind-power feed-in, in GWh			
Year	**2003**	**2007**	**2010**	**2015**
W.E. onshore	23,500	34,900	40,300	44,700
W.E. offshore	0	1,900	18,000	32,500
Total	23,500	36,800	58,300	77,200

Tab. 4-1 – Expected wind power development in Germany. Source: DENA - "Planning of the Grid Integration of Wind Energy in Germany Onshore and Offshore up to the Year 2020".

To investigate the impact on the transmission grid caused by the development of new wind generation, the German Energy Agency has commissioned the study "*Planning of the Grid Integration of Wind Energy in Germany Onshore and Offshore up to the Year 2020*" (DENA grid study). The goal of this study is to enable fundamental and long-term energy-economy planning, supported by as many stakeholders as possible. The first part of this study (Part I) was issued in February 2005 and dealt with the investigation of the impact of new wind farms into the Germany transmission grid up to the year 2015 with a 20% proportion of renewable energy in the total power supply. The general results of the above-mentioned study can be found in the DENA report; in our analysis we like to address the technical solutions that can be adopted to integrate large off-shore wind farms with the transmission grid on the land taking into account the dynamic performances to be achieved and the related dynamic models.

In general, for distances between wind farms and feeder nodes on land of up to 150 km, high-voltage AC transmission concepts employing suitable submarine cables have been preferred. Since the transmission capacity of a three-conductor submarine cable is limited to between 240 and 360 MVA (referring to a voltage level up to 170 kV), the number of cable routes to land to carry the 18.7 GW of power projected for 2020 in the North Sea would be between 70 and 100. Indeed, due to the alternating current, three-phase cables are able to give off capacitive charging power. The charging current puts a burden on the effective cable cross-section in addition to the active power transmitted and must be taken into consideration when choosing cable cross-sections. Depending on the reactive power conditions at the wind farm central station and at the grid connection node, it is advisable to plan corresponding power factor correction (PFC) systems in parallel with the cable. For extreme lengths of offshore and onshore cables, it is advisable to additionally plan a compensation facility at the point where the submarine cable joins the shore, thus improving cost-effectiveness.

A possible solution to avoid such a large number of cable corridors could consists of a system configuration (Fig. 4-4), which incorporates 4 collecting stations out at sea and transmits the power via high-capacity conductors such as gas-insulated tubular conductors (GIL). However, this solution turns out to be extremely expensive: the cost of GIL rated 2000 MVA, including civil works, is indeed 10-12 times bigger than that of an overhead line having the same capacity. As an example, GIL installed at PALEXPO in Geneva has a cost of about 6.5 M€ for a length of about 500m. Moreover, there are no experiences so far of GIL connections exceeding a length of few kilometres.

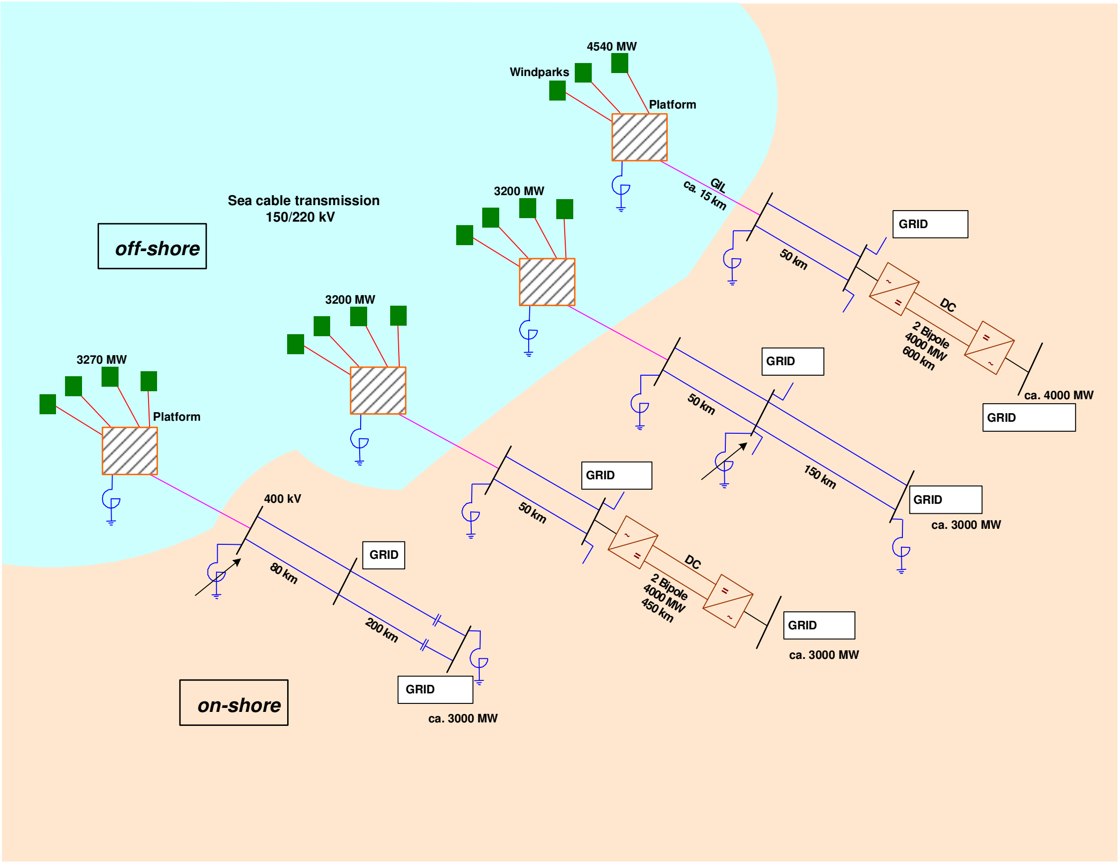


Fig. 4-4 – Connection of large off-shore wind farms to the transmission grid on the land

An appealing alternative solution consists of adopting HVDC connection from a hub platform on the sea to the connecting substation on the land. Two technologies are nowadays available: thyristor based or IGBT based. HVDC with thyristor technology or HVDC with IGBT technology (VSC: voltage source converter) consist of two header stations (the rectifier and the inverter station) as well as one pair of single-conductor cables for forward or return transport of the current. Indeed, considering current environmental compatibility and magnetic declination aspects, authorities are not prepared to approve single-pole transmission systems with one cable route and returning of the current via underground/submarine electrodes. Contrary to three-phase cables, the high-voltage DC transmission system with cables is capable of effective and stable transmission over several hundreds of kilometres. One crucial factor is that no capacitive charging currents at all put a stress on DC-cables. Furthermore, a DC connection does not transmit any short-circuit currents from the shore to the medium-voltage distribution level in the wind farm, thus making grid connection of the WPPs more cost-effective at the medium-voltage level.

The DC cables of the forward and return conductors are laid jointly. Losses of the cables, heat development and the anticipated magnetic fields are clearly less than in the case of three-phase cables. The dimensions and weight of the DC cables are also clearly less than in the case of three-phase cables, and so laying is clearly easier and more cost-effective.

In comparison with conventional phase-commutated thyristor technology with a current-source DC link, voltage DC link converters with IGBT are able to operate on a "passive" network in an insular mode, and are thus able to build up the network voltage and frequency in the wind farm network. In comparison with classic high-voltage DC transmission (pulsating limit of thyristor converters), transmission under a low load of the wind farm with power outputs of less than 10% of the farm's rated output is also ensured. Therefore, there is no need for separated three-phase cable transmission for auxiliaries' service and low-load operation of the wind farm. From today's point of view and depending on the concept, the power output of such an IGBT-based voltage DC link converter with a DC voltage of +/- 150 kV is between 250 MW and 350 MW per system. It can be estimated that future converters will have a power output of about 500 MW.

Systems for high wind farm power outputs

Both transmission technologies (AC and DC) presented above have to be compared in terms of their technical or economic advantages or their feasibility limits. For the high power density values of up to several thousand MW at sea, the medium-voltage systems must first be grouped with unit capacities of about 250 MW at 33 kV up to a maximum of 4000 A. Such unit capacities can be put together in the form of conventional switching elements in a stationary arrangement and at the medium-voltage level (to cope with the event of a fault). Conversion by means of suitable unit transformers to a higher voltage level is then necessary. With the aforementioned cable and converter power values (depending on AC or DC system limits and transmission length), approximately 160 MW to about 250 MW can be expediently obtained from a 33 kV wind farm.

Solution variants for high-voltage transmission

For a wind park located about 75 km off-shore two alternatives have been assessed. The park consists of a maximum of 78 generators of 3.6 MW (phase I) and a maximum of 88 generators of 5 MW in phase II.

In consideration of the wind farm examined, HVAC and HVDC-VSC alternatives were taken into account.

a) HVAC alternative (cable length – 75 km):

➢ Phase I	Infeed on the platform via a three-winding transformer, 250/125/125 MVA, 150/33/33 kV, 1200 mm2 cable, 3-phase
➢ Phase II	Infeed on the platform via two three-winding transformers, 210/105/105 MVA, 150/33/ 33 kV, 2x630 mm2 cable, 3-phase

Taking the thermal transmission capabilities of the cables into account, the number of WPPs to be connected was optimized.

b) HVDC-VSC alternative:

- Phase I Infeed on the platform via one HVDC-VSC DC transmission system
- Phase II Infeed on the platform via one HVDC-VSC DC transmission system

		HV AC Alternative		HV DC Alternative	
		Phase I	Phase II	Phase I	Phase II
No. of WM		75	88	78	56
Total		163		134	
Nominal power	MW	270	440	280.8	280
Generation WM	MW	244.4	400	254.6	256
Windmill service	MW	5.25	7.04	5.46	4.48
Losses internal grid	MW	2.2	4	2.2	2.6
Power infeed platform	MW	237	389	247	249
Losses HV Equipment	MW	9.6	16.6	15.8	16
Power infeed grid	MW	227	372	231	233
Total losses+auxilliaries	MW	17.1	27.6	23.5	23.1

Tab. 4-2– Comparison of alternatives for connection of off-shore wind farms

The results are summarized in Tab. 4-2. Note that, two WPPs out of the total WPPs installed, were always considered to be "under inspection" and an average wind utilization factor of 0.93 was assumed (this explains the difference between the Nominal Power and the Generation from Wind Machine shown in Tab. 4-2).

Demand to meet the system reliability standards

With this wind energy's continuing popularity and growth it has become a requirement by the German transmission grid operators for wind turbines to comply with transmission reliability standards similar to those demanded to thermal generators [20], [21].

Apart from local impact, wind power also has a number of system-wide impacts because it affects

- power system dynamic and stability
- reactive power control and voltage control
- frequency control and load following/dispatch of conventional units

Three main aspects shall be fulfilled by wind generators:

- no excitation of power oscillations after grid disturbances
- in feed of reactive power during and after system faults
- maintaining system stability, minimize grid disruption

Today wind turbines have single response to fault situations in the grid which result in instantaneous voltage drops. They trip off-line to protect their function until the grid recovers. The immediate loss of generation can impact system stability and lead to cascaded tripping of some thousand MW wind power. Even more important a trip of the whole North Sea system can in future result in high amount of lost generation and, consequently, this is calling for a new reserve and support strategy for the Central-Western European interconnected power pool (UCTE).

Fig. 4-5 and *Fig. 4-6* depict the demand for conventional generators and wind generator as function of system voltage (grid code demand [20]). The wind generator has to feed reactive power during grid disruption, keeping the wind farm on-line and generating power through a fault event. An electronic control system has to be designed to deliver ride-through capability at or below 15 % grid voltage for up to 500 ms. In addition, beyond coping with the initial disturbance, the wind generator has to remain engaged until the fault is cleared, providing support to bring the system back to normal operating conditions. Wind manufacturer started to change the converter circuits of the DFIGs (see *Fig. 4-7*) to follow the demand. Using so-called "crowbar SCR" to control the converter voltage for low voltage without tripping the converter.

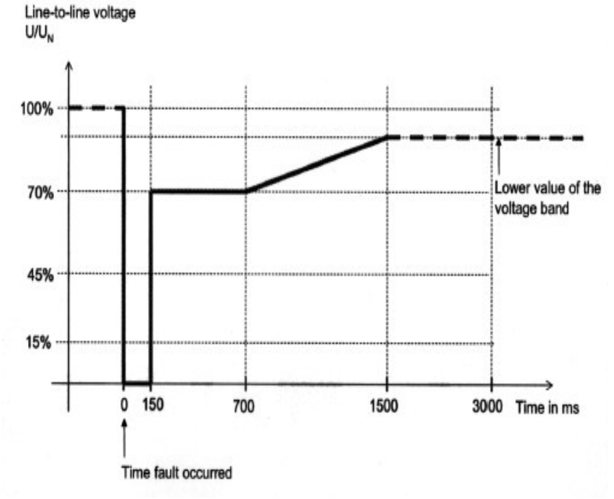


Fig. 4-5 –Voltage limit curve of a network fault for generators with high symmetrical short circuit current component (large thermal plant)

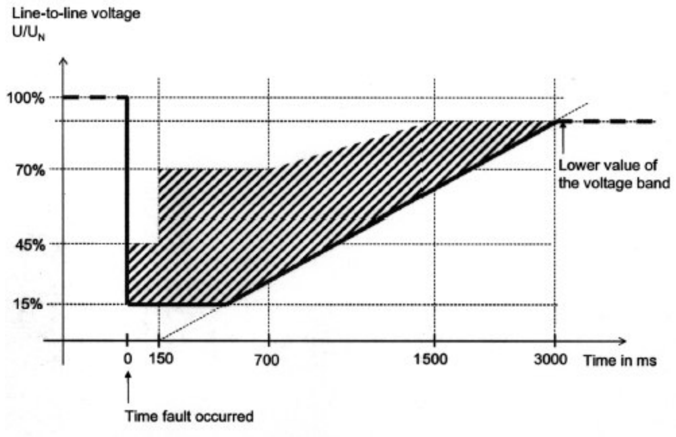


Fig. 4-6 –Voltage limit curve of a network fault for low symmetrical short circuit current component of a generator (wind generator)

A crowbar[9] device limits the energy delivered to the protected circuit by abruptly changing from a

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[9] When mentioning the crowbar device we refer to a device, which is electronically controlled and not mechanically switched like in the classical old applications.

high impedance state to a low impedance state in response to an elevated voltage level. Having been subjected to a sufficient voltage level the crowbar begins to conduct. While conducting, the voltage across the crowbar remains quite low and, thus, the majority of the transient power is dissipated in the circuit’s resistive elements and not in the protected circuit or the crowbar itself.

This allows the crowbar to be able to withstand and protect loads from higher voltage and/or higher current levels for a greater duration of time than clamping devices (Zener Diode, MOV). In comparison new converter design using thyristor/IGBT-converters allows fulfilling the grid demand, too.

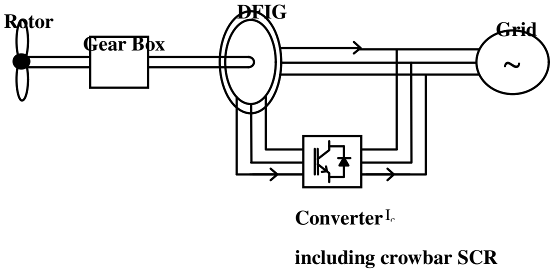

Fig. 4-7 – Basic structure of a DFIG

Simulation of the North Sea wind park grid

To prove the grid demand a simulation model of a typical DFIG was developed. The new wind generator model was established in the simulation system NETOMAC[10]. The DFIG model is based on an agreed model between wind manufacturers, transmission grid operators and wind farm operators in Germany. The basic mathematical model(s) are described in [22] and [23].
The whole North Sea wind park system for 2010 was topologically modeled and interconnected to a reduced transmission grid model. The wind parks have been modeled by equivalent DFIGs of a size of some 10 MW (100 equivalent DFIGs in total).

Fig. 4-8 shows a typical 3-phase fault in the grid with 150 ms duration and 15 % residual voltage. The crowbar circuit is fired and prevents the wind park to trip.

Fig. 4-9 shows a 3-phase short circuit at the interconnection point of a wind park on the 380 kV level with 45 % residual voltage.

For the other wind parks with shorter interconnecting cables the crowbar is active for fault on all fault levels (depending on the fault distance to the interconnection point). The crowbar is active for about 150 ms during the 350 ms fault. Without crowbar 3-phase faults result in loss of several wind parks with far-reaching consequences for the grid operation.

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[10] NETOMAC is a power system simulator developed and in use at Siemens AG

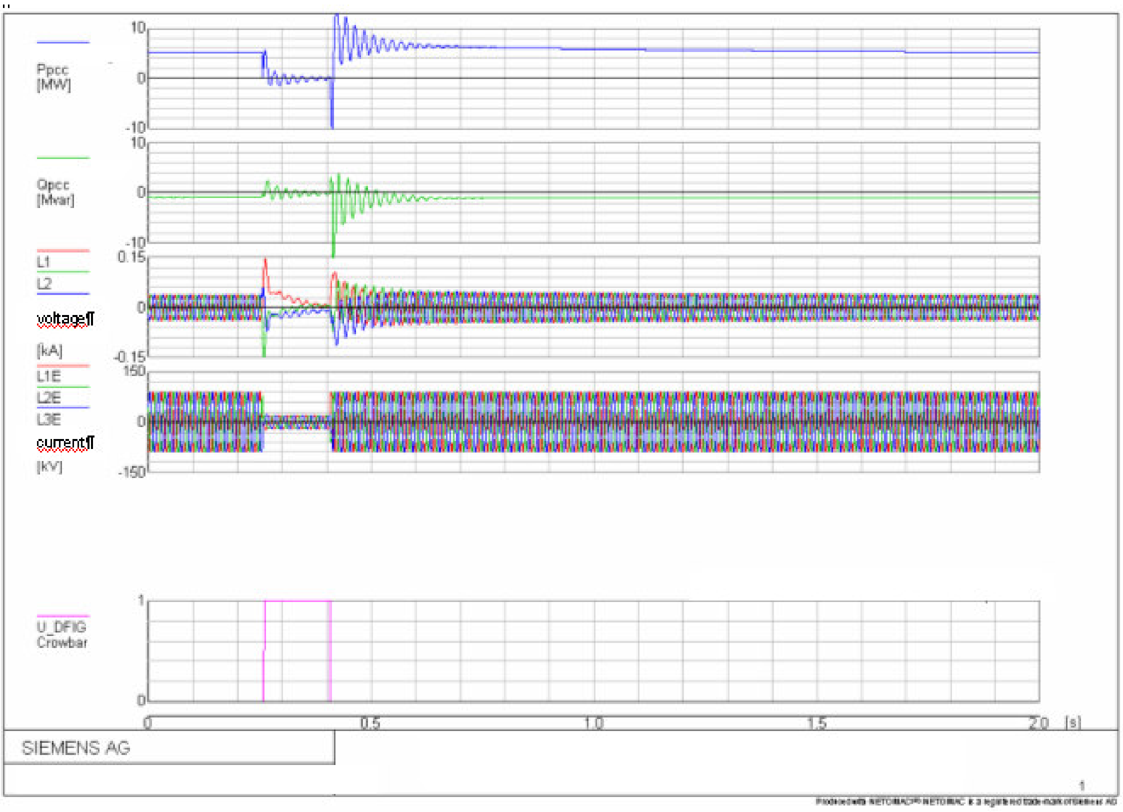

Fig. 4-8 – 3-phase short circuit at the wind park connection point for 150 ms, 15 % residual voltage crowbar resistor active

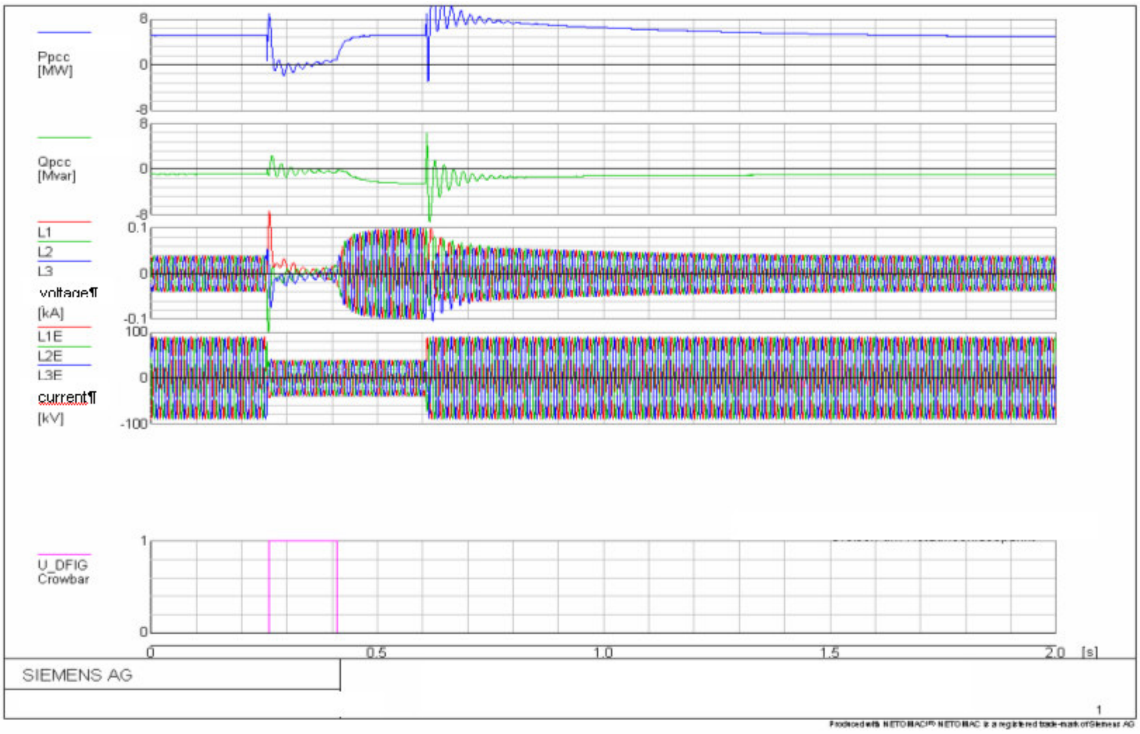

Fig. 4-9 – 3-phase short circuit at wind park connection point on 380 kV level for 350 ms with 45 % residual voltage, crowbar active during 150 ms

Conclusion

The transmission technologies and their essential components for the conveying of high power output levels (with three-phase or also with DC current) from the sea to the shore are state of the art, and have proven themselves throughout many years of service in onshore and offshore electricity supply, and also in the area of oil and gas supply (to some extent offshore).

The further development and application of proven technologies for three-phase AC and DC transmission (for new transmission concepts and routes) shall progress in a context of detailed studies and simulation of the new transmission task. In this case, the transmission routes must be minimized and chosen so as to ensure stable and reliable power transmission over long distances through the sea, across the mudflats and to some extent onshore, as far as the connection nodes of the consumer grids. Particularly important reveal to be the dynamic behaviour of wind farms at the occurrence of perturbations on the transmission grid. Adoption of technology with ride-fault capability, as above recalled, will become essential especially in case of off-shore wind farms, the large size of which is likely to have a non negligible impact on the transient behaviour of the overall generation-transmission system.

Finally, the interaction of high-power offshore wind generating plants and power supply networks must not in any way jeopardize supply reliability, and must likewise not lead to a burden on (or overloading of) onshore parts of the public electricity supply grid. In addition to this requirement, adequate network capacities and power quality for forwarding power to distant conurbations must be ensured.

4.1.2.4 *Connection of large off-shore wind farms: the Danish case*

The western Danish power system with a significant amount of wind power in the power grid represents the case of the AC/DC interconnected system. The transmission system of Western Denmark is operated by the Danish TSO Energinet.dk. The transmission system is operated at 400 kV and 150 kV. To the south, the western Danish power system is connected to Germany, the UCTE synchronous area, via 400 kV, 220 kV and 150 kV AC-lines. To the north, the western Danish power system is connected to Norway and Sweden, the Nordel synchronous area, via five High Voltage Direct Current (HVDC) links. Fig. 4-10 shows the map of the transmission system of Western Denmark. Tab. 4-3- gives the key counts of the power generation and the power consumption in Western Denmark.

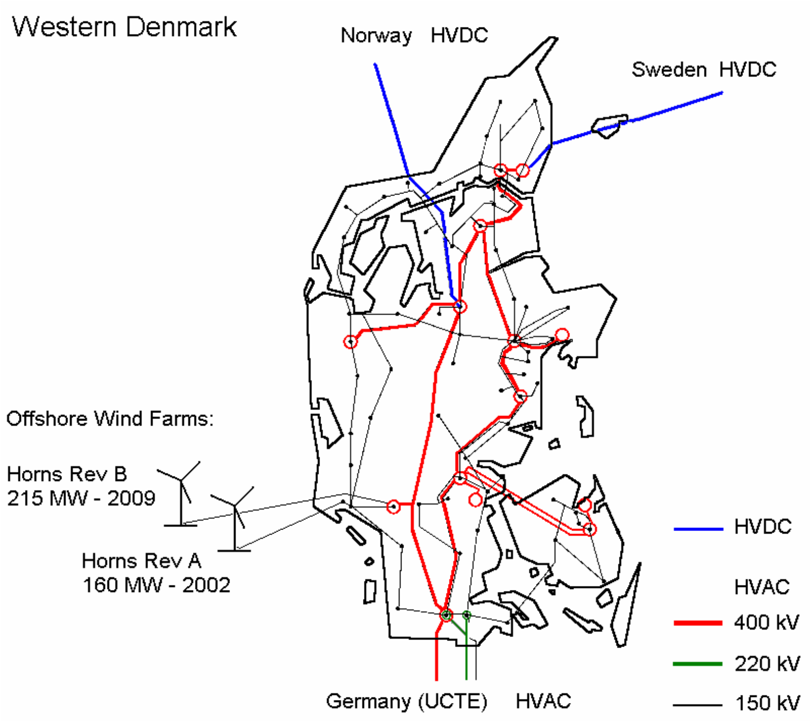

Fig. 4-10: Power system of Western Denmark by the year 2009 with two large offshore wind farms.

An offshore windfarm of 160 MW of rated power is commissioned at Horns Rev A (HRA). This offshore windfarm is AC-connected to the 150 kV on-land transmission system, at the substation Karlsgaarde. The construction of the second offshore windfarm, Horns Rev B (HRB), with a rated power of 215 MW, will take place by the year 2009. The offshore windfarm HRB will be commissioned just 5 km from the existing windfarm HRA and connected to the 150 kV transmission system, presumably, at the substation Endrup.

	MW	GWh
Central power plants	3,516	12,951
Local CHP units	1,593	6,839
Local wind turbines	2,379	4,875
Offshore windfarm Horns Rev A	160	
Consumption		21,246
Maximum load	3,639	
Minimum load	1,281	
Capacity export to UCTE	1,200	
Capacity import from UCTE	800	
Capacity export to Nordel	1,440	
Capacity import from Nordel	1,460	

Tab. 4-3- Key figures of the power system of Western Denmark [24].

The Danish TSO has performed preliminary investigations of short-term voltage stability with regard to the grid connection of the second offshore windfarms at Horns Rev. The Danish TSO applies the simulation tool Powerfactory from the manufacturer DigSilent, Gomaringen, Germany.

4.1.2.4.1 Response of Horns Rev A

The offshore windfarm HRA contains eighty V80 2 MW variable-speed wind turbines equipped with doubly-fed induction generators from the Danish manufacturer Vestas Wind Systems. This model is developed by the Danish TSO and in cooperation with the wind turbine manufacturer Vestas Wind Systems. The model is developed for internal use of the Danish TSO.

Validation of the transmission system model, including the Horns Rev A windfarm, is made from events in the system and involves all the grid equipment connected in the vicinity of the event location. The most typical events are single-phase short-circuit faults. The following presentation gives an example on validation of part of the western Danish transmission system around the on-land connection point of the Horns Rev A windfarm at the substation Karlsgaarde. The event is a single-phase short-circuit fault at the 150 kV transmission line between the substations Herning and Sdr. Felding, Fig. 4-11.

At the moment of the event, the windfarm produced 89 MW. The Esbjerg power plant with the power rating of 400 MW and the Herning combined heat-power unit with the power rating of 90 MW were also in operation at that moment. The validated part of the Danish transmission system is marked in Fig. 4-11(a). The Danish TSO monitored the voltage and the current in 3 phases at the substation Karlsgaarde which are plotted in Fig. 4-11(b). Then, the Danish TSO performed computations with the use of the complete transmission system model including the central power plants, consumption, the local wind turbines, the local CHP units and the dynamic model of the Horns Rev A windfarm. The simulation results are plotted in Fig. 4-11(c). The measured and the simulation figures are in good agreement.

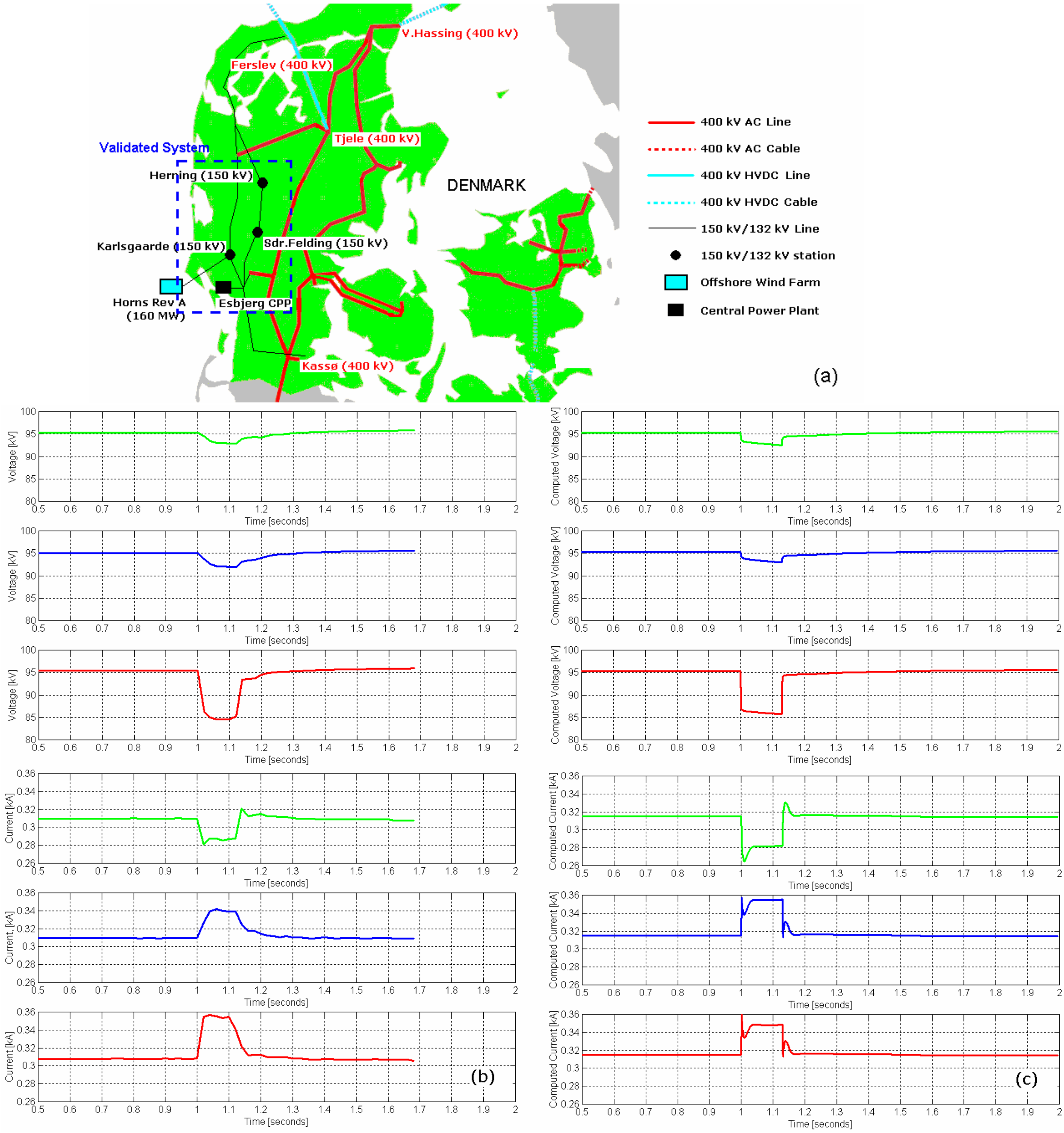

Fig. 4-11: Validation of part of the Danish transmission system at the substation Karlsgaarde, the on-land connection point of the Horns Rev A windfarm: (a) - validated system, (b) - measured with 20 ms time constant voltage and current, (c) - simulated voltage and current in the substation Karlsgaarde..

4.1.2.4.2 Expected response of Horns Rev B

Preliminary stability investigations performed by the Danish TSO have clarified the issues with regard to reliable and secure operation of the Danish power system with the two offshore windfarms at Horns Rev. At the moment of the preliminary stability investigations performed by the Danish TSO, the wind technology to be applied at the second offshore windfarm at Horns Rev was not decided yet. Therefore the Danish TSO performed the stability investigations with the use of generic models based on the two most applied wind turbine concepts in Denmark.

4.1.2.4.2.1 Wind turbine concepts of Horns Rev B

The concept of fixed-speed wind turbines consists of an induction generator with a short-circuited rotor circuit, a shaft system, a three-bladed rotor with a blade-angle control. The induction generators are excited from the power grid. Therefore reactive compensation of such generators is required. To provide dynamic reactive power control of such fixed-speed wind turbines, dynamic reactive compensation is to be applied.

The concept of variable-speed wind turbines consists of a doubly-fed induction generator, a frequency converter allowing an independent control of active and reactive power of the generator, a shaft system, a three-bladed rotor with a pitch control. The doubly-fed induction generators are (self-) excited by the power electronics converters through the rotor circuit. Therefore, no additional reactive compensation is required.

Other wind turbine concepts, e.g. applying full-rating converters, are also considered as possible for the offshore windfarm HRB. The results of investigations are not discussed in this presentation.

In stability investigations of the Danish TSO, the offshore windfarms at Horns Rev are initialised at rated operation to represent the worst case for maintaining of short-term voltage stability.

4.1.2.4.2.2 Fixed-speed wind turbines

Fixed-speed wind turbines are modelled using the induction generator model of the simulation tool Powerfactory. The shaft system is represented by a two-mass model [24]. The rotor aerodynamics are represented using $C_P(\lambda,\beta)$ characteristics with the power coefficient C_P, the tip-speed ratio λ and the blade angle β. The blade-angle control, active-stall, is modelled in a generic way, and consists of a proportional-integral (PI) controller and a pitch servo [26].

When wind turbines are in normal operation, the regular blade-angle control is used to optimise the power output of the wind turbines. The blade-angle control shifts the control mode to control the generator rotor speed when abnormal overspeeding of the wind turbine is registered [26]. Excessive overspeeding may cause instability of such fixed-speed wind turbines, voltage instability in the grid and, then, protective disconnection of the wind turbines [26].

Fig. 4-12 shows selected simulation results when the offshore windfarm HRB contains the fixed-speed wind turbines. Preliminary stability investigations of the Danish TSO showed that the blade-angle control applied at excessive overspeeding may stabilise operation of the offshore windfarm at Horns Rev.

4.1.2.4.2.3 Variable-speed wind turbines

The variable-speed wind turbines are modelled using the doubly-fed induction generator model of the simulation tool Powerfactory. The frequency converter is a back-to-back AC/DC/AC converter connecting the rotor circuit of the generator to the power grid [27]. The frequency converter is modelled with representation of the rotor and grid-side voltage-sourced converters connected through a DC-link with a capacitor. Through the frequency converter, the rotor circuit exchanges the active power with the power grid.

The frequency converter control is arranged in a generic way as in Ref. [27]. The rotor converter control provides an independent control of active and reactive power of the doubly-fed induction generator. The generator, then, is excited through the rotor circuit. In normal operation, the generator can be reactive neutral or set to exchange an amount of reactive power with the power grid, for example, for voltage support. The grid-side converter control is arranged with an independent control of DC-link voltage and reactive current. The grid-side converter is reactive neutral with the power grid in normal operation.

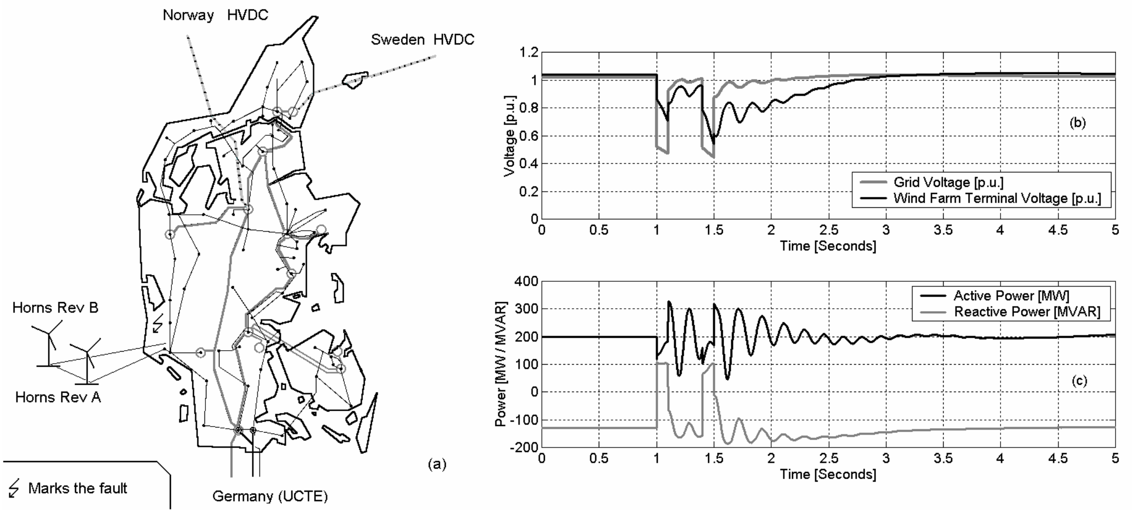

Fig. 4-12: Offshore windfarm HRB with fixed-speed wind turbines: (a) - location of the fault, (b) - grid voltage in the 150 kV system and terminal voltage of the windfarm, (c) - active and reactive power of the windfarm generator.

The shaft system is represented with the use of the two-mass model. The rotor aerodynamics are represented with the use of $C_P(\lambda,\beta)$ characteristics with the power coefficient C_P, the tip-speed ratio λ

and the blade angle β. The pitch control contains a PI controller and a pitch servo. When the wind turbine is in normal operation, the variable-speed operation and the pitch control are applied to optimise the power output of the wind turbine. In normal operation of the power grid, the variable-speed operation is controlled by means of the rotor voltage vector control with the use of the frequency converter control.

When the power grid is subject to a short-circuit fault, the frequency converter may block, e.g. stops switching and trips [27]. In such a situation, the converter controllability (with regard to reactive power) is lost. The rotor circuit, then, is short-circuited through a crowbar with a finite impedance. The wind turbines must ride through the fault using the crowbar protection [27], [28]. When the grid operation re-establishes, the crowbar is removed, and the frequency converter restarts [27], [28]. Operation of the offshore wind farm HRB with the use of crowbar protection is shown in Fig. 4-13. During operation with the crowbar, the generator operates as an induction generator, which requires excitation from the power grid. Hence, the wind turbines absorb reactive power from the grid so long as operation using the crowbar is continued. The pitch control is relevant at excessive overspeeding of the turbines at operation using the crowbar.

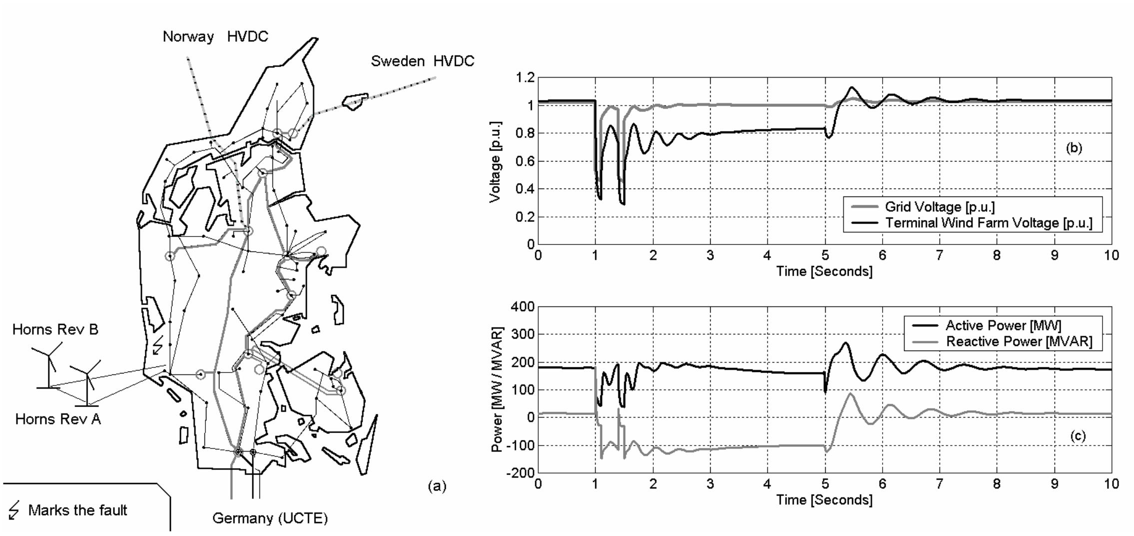

Fig. 4-13: Offshore windfarm HRB with variable-speed wind turbines: (a) - location of the fault, (b) - grid voltage in the 150 kV system and terminal voltage of the windfarm, (c) - active and reactive power of the windfarm generator. Converter blocks at 1 second and re-starts at 5 seconds of the simulation time.

4.1.2.4.3 Risk of disconnection

The blade-angle control applied at excessive overspeeding of fixed-speed wind turbines is a relatively slow control. When the blade-angle control is insufficient to prevent such excessive overspeeding, disconnection of the offshore windfarm HRB may occur. Fig. 4-14 illustrates such a case with a severe event in the transmission system resulting in disconnection of the offshore windfarm HRB (the case of fixed-speed wind turbines). When the windfarm is tripped, the grid voltage re-establishes.

Protective disconnection of variable-speed wind turbines applying the crowbar protection may also occur, for example, when the frequency converters do not restart due to excessive voltage fluctuations or current transients appearing at the moment of restart [27]. After several unsuccessful restart attempts, the converters may block and trip permanently and order the wind turbines to disconnect. To accurate prediction of such current transients, the generator model must be the fully-transient (5th order) model, e.g. with representation of the stator flux and current dynamics [27].

If the offshore windfarm HRB disconnects during a short-circuit fault, this may lead to a power loss of max. 215 MW in the Western Danish power system, which is relatively a small power system. Therefore, such disconnections must be avoided. According to the Grid Code of the Danish TSO, demonstration of the fault-ride-through capability of large (offshore) windfarms rests with wind turbine manufacturers and windfarm owners. The fault-ride-through capability must be demonstrated by tests and simulations. The Danish TSO requires also delivery of block-diagrams describing the wind turbine model and the fault-ride-through solution.

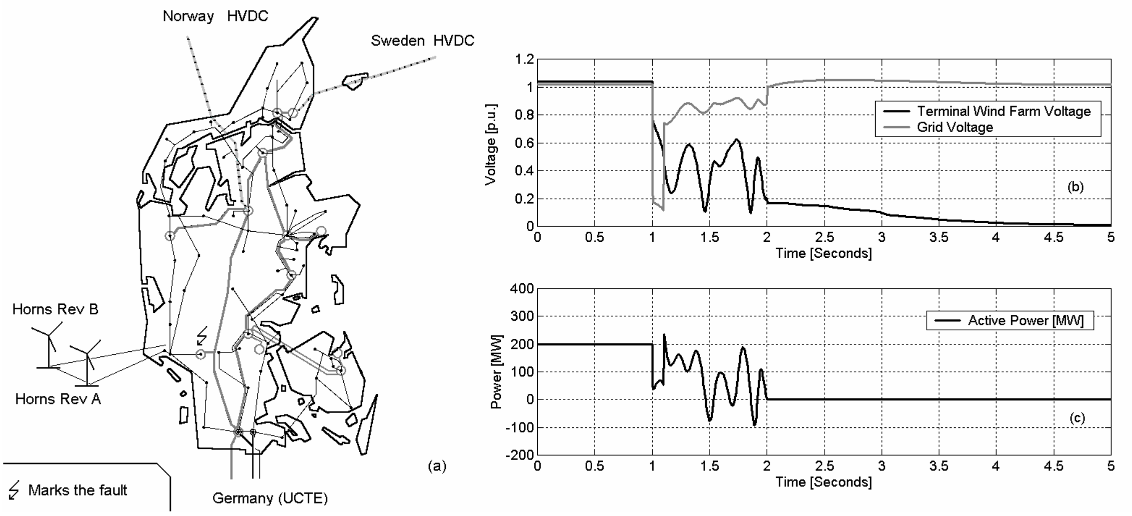

Fig. 4-14: Offshore windfarm HRB with fixed-speed wind turbines: (a) - location of the fault, (b) - grid voltage in the 150 kV system and terminal voltage of the windfarm, (c) - active power of the windfarm generator. Case of a severe event resulting in disconnection of the offshore windfarm HRB (at 2 seconds of the simulation time).

4.1.2.4.4 Conclusion

The Western Danish transmission system represents a case of a strongly interconnected power system with a significant amount of grid-connected wind power. The first offshore windfarm at Horns Rev, HRA, was commissioned in the year 2002. This large offshore windfarm is equipped with a fault-ride-through solution of the manufacturer Vestas Wind Systems. The construction of the second offshore wind farm at Horns Rev, HRB, is announced, and, in total, 375 MW offshore wind power will be commissioned at Horns Rev by the year 2009. The offshore wind power commissioned at Horns Rev may cover 10% of the maximum peak load of the western Danish power system.

The Danish TSO develops and updates dynamic models of electricity-producing wind turbines of different concepts to meet the requirements for reliable and secure operation of the Danish power system with increasing wind power. The dynamic models of electricity-producing wind turbines are validated from the measurements, when possible.

The Danish TSO has performed preliminary stability investigations for the western Danish power system with two offshore windfarms at Horns Rev, for two most common concepts in Denmark, e.g. fixed-speed wind turbines with induction generators and variable-speed wind turbines with doubly-fed induction generators. The Danish investigations predict voltage re-establishment. However, power loss due to disconnection of some wind turbines can be present. Therefore immediate power reserves can be required to compensate for this power loss.

4.1.3 Dynamic analyses applied to an interconnection study

4.1.3.1 Dynamic analyses applied to the investigation of the feasibility of synchronous interconnection between TESIS and UPS/IPS

4.1.3.1.1 Context of the study

Up to now, launching dynamic studies in the frame of network planning has not been frequent, and has usually been limited to the analysis of the impact of new generation plants. For studying the interconnection of two systems, several aspects are usually examined:

- benefits in terms of avoided reserve capacity and related savings on investments;
- benefits in terms of optimised generation system and related savings in fuel (this usually includes a specific study on the local fuels available for the long term);
- benefits linked to the aggregation of the demand curves of both systems, namely the non-simultaneity of the peaks;
- costs of the various options envisaged for the interconnection lines;
- acceptability of the new normal regimes and N-1 situations (failures or unavailabilities);
- acceptability of the new short-circuit levels:

It is worth mentioning that interconnecting two systems may significantly change their control characteristics and, therefore, may significantly modify their dynamic behaviour. For this reason, this reference study addresses the two following aspects:

- the dynamic behaviour after small or moderate disturbances like the loss of a generation unit (dynamic stability);
- the transient behaviour, i.e. after a short-circuit (transient stability).

Moreover, a third aspect is considered consisting of the assessment of the static context that favours an acceptable dynamic behaviour:

- the influence of the interconnection on the margins regarding voltage issues (reactive power reserve, AVR and OLTC settings).

As it plays a role in determining the dynamic behaviour, this last issue has in fact been studied first.

The presentation of this reference study is based on the feasibility study TACIS EREG 9601, carried out by the consortium EDF (France) -CEZ (Czech R.)-IVO (Finland)-RWE (Germany)-TRACTEBEL Engineering (Belgium) with VNIIE (Russia), of which the tasks related to the network analysis have been performed by the team TRACTEBEL Engineering-CEZ-VNIEE. The approach has been applied to study the AC interconnection between the UCTE system (Western and Central Europe), referred also as TESIS, and the UPS system (Russia, Ukraine, Belarus, Moldova and interconnected countries).

Because of its specific assumptions[11], this study is not to be compared with the ongoing UCTE study on the same subject. However, the approach proposed here is general enough to be applied to all other cases of AC interconnections.

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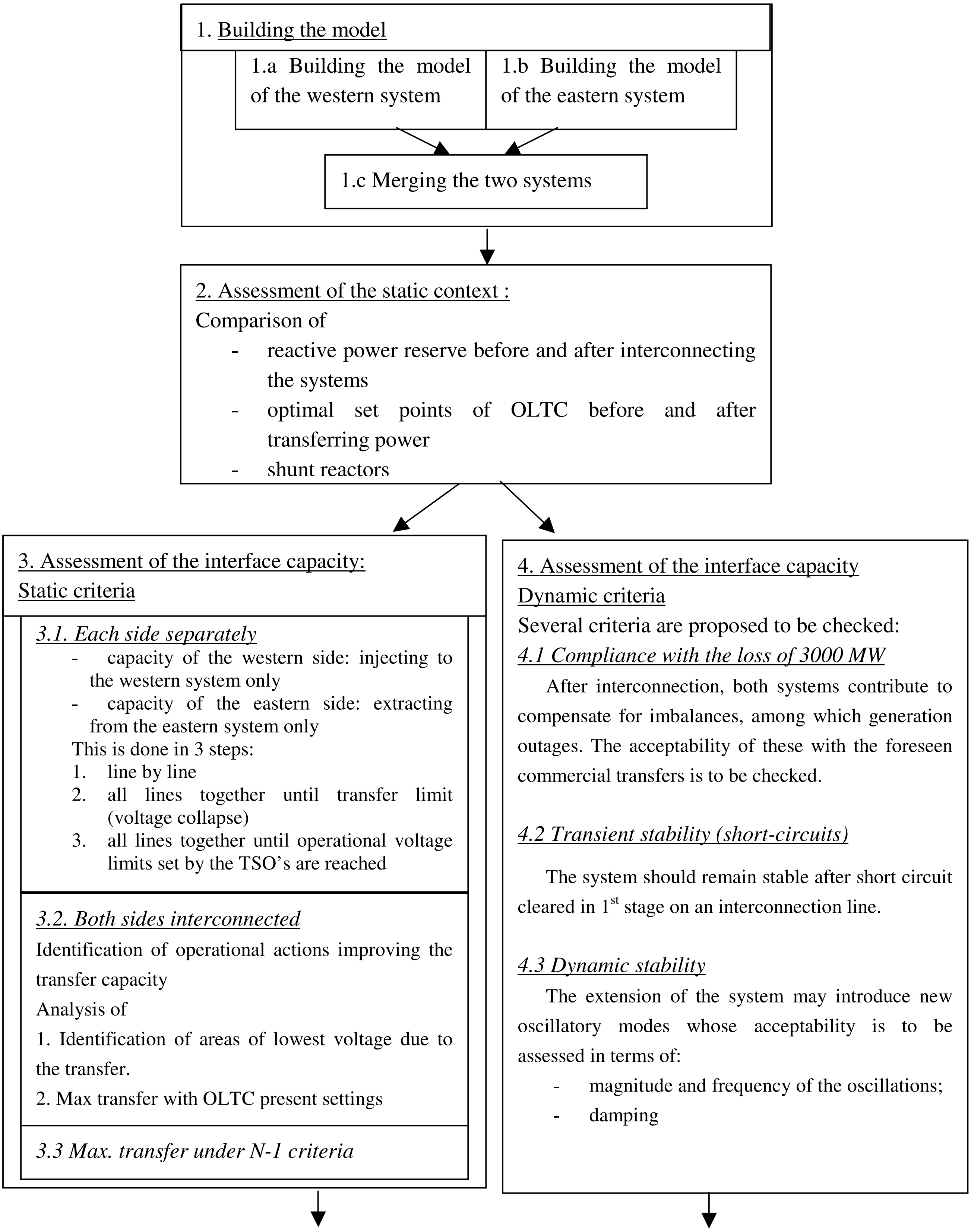
[11] Like the future lines planned in Ukraine and Russia, see further in the text.

4.1.3.1.2 General methodology of the study

The methodology adopted is made of 5 steps :



1. Building the model

1.a Building the model of the western system

1.b Building the model of the eastern system

1.c Merging the two systems

2. Assessment of the static context :

Comparison of

- reactive power reserve before and after interconnecting the systems
- optimal set points of OLTC before and after transferring power
- shunt reactors

3. Assessment of the interface capacity: Static criteria

3.1. Each side separately

- capacity of the western side: injecting to the western system only
- capacity of the eastern side: extracting from the eastern system only

This is done in 3 steps:

1. line by line
2. all lines together until transfer limit (voltage collapse)
3. all lines together until operational voltage limits set by the TSO's are reached

3.2. Both sides interconnected

Identification of operational actions improving the transfer capacity

Analysis of

1. Identification of areas of lowest voltage due to the transfer.
2. Max transfer with OLTC present settings

3.3 Max. transfer under N-1 criteria

4. Assessment of the interface capacity Dynamic criteria

Several criteria are proposed to be checked:

4.1 Compliance with the loss of 3000 MW

After interconnection, both systems contribute to compensate for imbalances, among which generation outages. The acceptability of these with the foreseen commercial transfers is to be checked.

4.2 Transient stability (short-circuits)

The system should remain stable after short circuit cleared in 1st stage on an interconnection line.

4.3 Dynamic stability

The extension of the system may introduce new oscillatory modes whose acceptability is to be assessed in terms of:

- magnitude and frequency of the oscillations;
- damping

4.1.3.1.3 Application of the methodology

4.1.3.1.3.1 Step 1: building the models

The network models are those collected by TREACTEBEL Engineering, RWE and EDF during and before the study. It resulted in a model with the following number of nodes:

WEST(UCTE):	1262	**EAST (UPS):**	930
Hungary (HU)	41	Estonia (EE)	45
Czech R. (CZ)	100	Latvia (LV)	55
Poland (PL)	607	Lithuania (LT)	43
Slovak R. (SK)	44	Belarus (BY)	104
Romania (RO)	340	Ukraine (UA)	218
Bulgaria (BG)	35	Russia Centre	181
Yugoslavia (YU)	18	Russia Siberia	21
Croatia (HR)	7	Khazakstan	8
Bosnia (BH)	6	Russia Ural	25
Slovenia (SI)	10	Russia Volga	60
Austria (AT)	42	Russia North W.	25
Greece (GR)	1	Russia Caucasus	93
Italy (IT)	1	Russia Kalilingrad	26
France (FR)	2	Moldova (MD)	26
Germany (DE)	8	Total Russia: 439	

Tab. 4-4 -Key figures of the power system model

The main assumptions are:

- ✓ Lines that were planned in 1998 for 2005 are in the model (their construction has been postponed):

Ukraine: Kmelnitskaya- Dniestrovskaya	750 kV
Ukraine: Dniestrovskaya- Primovskaya	750 kV
Ukraine: Primovskaya- Kakhovskaya	750 kV
Ukraine: Kakhovskaya- Zaporojie	750 kV
Ukraine: Yujnodonbaskaya- Donbass	750 kV
Russia : Shakti- Frolova	500 kV

- ✓ All transfers here are from East to West.
- ✓ In terms of dynamic models, no accurate modelling has been made available by the TSO's. Therefore, all generation nodes generating more than 100 MW have been fitted with one generation unit with a simple voltage regulator and a composite frequency controller made of:
  - o One simple hydro turbine controller
  - o One simple steam turbine controller

- ✓ The ratio for the hydro and for the steam controllers have been set from the hydro and thermal generation levels as available in UCTE reports at the time of the study.
- ✓ All machines have been fitted with the same parameters, except the above ratio hydro/thermal generation
- ✓ The model is built for high load conditions.

Then, the model is completed by a selection of generators to be used for creating the cross-border transfers. For the present study, two sets have been defined:

- o one for short distance transfers (Poland, Hungary, Romania – Western Russia and Ukraine)
- o one for long distance transfers (Germany, Austria and Italy – Central Russia, Ural and Siberia).

The software used have been:

- ✓ PSS/E for OPF and N-1 computations
- ✓ EUROSTAG for dynamic studies and assessments of the Q reserves[12]

4.1.3.1.3.2 Step 2: Assessment of the static context

Comparison of the reactive power reserve before and after interconnecting the systems

This step aims at drawing a comparison among the reactive reserves of each TSO:

- before interconnection;
- after interconnection but without power interchange;
- after interconnection and with various values of power interchange.

This comparison can be displayed in a comparison table, which normally shows an improvement (increase) of the reserve after interconnection since the (unloaded) interconnection lines provide reactive power.
The reserve can be expressed in percent of the total reactive capacity of each TSO, like in Tab. 4-5.
When transferring 4.7 GW, on the contrary, some 21 power plants of the model get their Q reserve reduced below 25 %.

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[12] At the time of the study, the version with linear analysis (eigenvalues) was not yet available. For that reason, the damping factors evaluated in step 4.3 have been identified from time domain simulations and not from eigenvalues.

Qreserve area [%]	Separated	Interconnected (no power interchange)
Eastern UCTE:		
Poland	58.7	60
Slovakia	64.1	*63.4*
Hungary	76.3	88.9
Romania	69.8	71.9
Bulgaria	63.1	*46.8*
Czechia	56.1	59.3
Yugoslavia	58.4	58.6
Croatia	89.7	*87.4*
Bosnia	58.4	59.7
Slovenia	96.2	*91.4*
Greece	25.7	*24.7*
Western UPS:		
Estonia	69.7	73.8
Latvia	80	85.6
Lithuania	66.7	67
Belarus	46.2	53.7
Ukraine	36.8	45
Moldavia	33.6	Fixed
Russia	61.3	65.6

Tab. 4-5 -The reserve expressed in percent of the total reactive capacity of each TSO

Optimal set points of OLTC before and after transferring power

The use of regulating transformers fitted with On Load Tap Changers can improve the voltage levels and consequently can increase the transfer capacity. The identification of suitable OLTC settings is typically performed using an OPF with an objective function assigned to maximize the reactive power reserve.

For the system studied here, the optimal set points of OLTC does not change significantly when closing the interconnection lines. But when loading the cross-border lines, the optimal set points of OLTC appear to significantly increase in PL and SK (p.u. transformer ratios from 0.94 up to 1.04), and to decrease in HU, RO and BG (p.u. ratios from 1 down to 0.85 for some transformers).

Optimal set points of shunt compensation before and after transferring power

In the same way, the OPF results would indicate the optimal use of shunt capacitors
For the system studied here, shunt reactors proved not to be much influenced by the interconnection.
A similar comparison could be done in terms of loss levels, espacially comparing transfers on short distances and transfers on long distances.

During periods whithout cross-border flows, the loss levels normally turns out to be reduced.

In the present study, the loss reduction due to the presence of the existing interconnection lines is about 51 MW as shown in the following table.

Active power losses [MW]	UPS [separ.] MW	UCTE [separ.] MW	BASE CASE [interconn.] MW	Red. due to intercon. MW
UCTE	-	900	936	-36
UPS	2084	-	1997	87
Total			2933	51

Tab. 4-6 -loss reduction due to the presence of the existing interconnection lines

Compliance to the N-1 criteria

In order to ensure that overloads do not spread in case of N-1 contingencies, the proposed approach also identifies the maximal transfer such that the N-1 criteria is satisfied. Since this is a rather classic criteria, results are not presented here.

4.1.3.1.3.3 Step 3: Assessment of the interface capacity, without disturbances

3.1. Each side separately

1. Line by line: this computation allows evaluating the impact of internal constraints of the systems on the whole interface capacity. The capacity obtained by that way is the highest estimate for the interface capacity (high over-estimation). Because of that it does not have much interest unless generators were installed at both ends of these lines.

2. All lines together with one-side network models until transfer limit is reached (voltage collapse).
This capacity limit is found using a progressive loading (load ramp) on selected loads or countries.

3. All lines together with one-side network models, until an operational voltage limit is reached.
For the present study, the following results have been found, using a low voltage limit of 0.9 pu:

	Inj. to West (MW)	Extr. from East (MW)
1. Sum of all individual line thermal capacities	15,560	15,560
2. All lines together up to V collapse transfer limit	15,382	11,070
3. All lines together up to V > 0.9	11,400	9,730

Tab. 4-7

3.2. Both sides interconnected

1. Max transfer with OLTC present settings

Increasing the generation in the east and decreasing in the west leads to results where one line may reach its thermal limit well before the others. In order to increase the transfer beyond that level, one has either to plan a phase control device (phase shifter or FACTS), or to operate the weak link in radial mode. Higher transfer limits can then be computed.

2. Identification of areas of lowest voltage due to the transfer.

Weak areas have been identified in step 2 here above and optimised OLTC settings have been computed.

Tab. 4-8

With initial OLTC settings	West- East together
All lines in parallel Transfer up to voltage collapse	8,827 MW
Operating PL-BY line in radial mode Transfer up to voltage collapse	10,300 MW
Operating PL-BY line in radial mode Transfer up to V= 0.9	~7,900 MW

3. Max transfer with adapted OLTC settings
With these settings higher transfer capacities are obtained, and can be almost 10 % higher as shown in the following table.

Tab. 4-9

With OLTC settings optimised for the transfer, PL-BY line in radial mode	West- East together
Transfer up to voltage collapse	11 200 MW
Transfer up to V>0.9	8 800 MW

4.1.3.1.3.4 Step 4: Assessment of the interface , dynamic criteria

4.1 Compliance to UCTE criteria for load-frequency regulation during a standard outage

A sudden loss of about 3000 MW generation is to be simulated dynamically on plants of both sides of the interface, in compliance with the operation rules adopted in UCTE.

From a static point of view, it is to be pointed out that the load-frequency control of both sides are "superimposed" to each other, forming an "aggregated" load-frequency control of the whole system. On the opposite, the standard disturbances of both sides (which is assumed to be 3000 MW in each side) are not to be superimposed or aggregated. Hence, the standard disturbance after interconnection is not 6000 MW but remains 3000 MW, and this results in a better frequency control after interconnection than before.

In the present case, simulations have been carried out for 3000 MW outages in FR, ES, IT, DE, PT, UA and RU, and none of the cases led to any instability. Although this result is to be considered within the approximation of the model[13], it not surprising from a static perspective since both systems already can cope with the sudden loss of 3000 MW of generation.

The acceptability of the contributions of each system to the global load-frequency control can be expressed in the following way:

- in case of a standard event in the system A, can the interconnection withstand the flows coming from the action of the primary load-frequency control of system B (and viceversa) ?

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[13] since it uses simple regulator models and does not represent the possible action of the UPS automata at such high loading values

- if yes, what is the maximal commercial flow (Net Transfer Capacity) of the interface, knowing that a Transfer Reliability Margin should cover for the functioning of the primary load-frequency control?

The UPS system includes internal "controlled sections" with automata that may activate redispatching generated power or shedding load if the flow overpass a threshold. It is of interest for its operators to know if a standard generation outage in UCTE (3000 MW) would trigger or not these automata, considering the envisaged transfer levels. The answer to that question should be analysed using the specific characteristics (thresholds) of these automata. These thresholds and the envisaged transfer levels are presented in Tab. 4-10.

Name of section	Thresh. (MW) N max ->	Thresh. (MW) N max <-	Base case (MW)	Transfer Level (MW)	Marg (MW)	Acceptable
1. Ural to West	2200	-3000	217	-1265	3465	yes
2. Centre to East	5000	-5500	-1169	-2637	2863	yes
3. North West to Centre	1800	-1500	-240	-1403	97	yes
4. North West to Baltics	1000	-1000	-45	323	677	yes
5. Centre to Belarus	1500	-1000	649	1823	-323	no but (°)
6. Ukraine to Central Russia	2200	-3000	-1140	-4026	-1026	no but (°)
7. Ukraine+C. Russia- Cauc. N.	1750	*-1750*	140	-1638	112	yes
8. InterUkraine (West to Cent U.)	6200	*-6200*	1237	-2707	3493	yes
9. Merging (6)+(7) technical limits	6000	-6000	1000	-5664	336	yes

Tab. 4-10 -Transfer levels across sections and margins after the loss of 3000 MW of generation in Western Europe

(°) the team responsible for assessing the compatibility of the above transfer level ensured that the controlled sections and their automata would in fact allow the envisaged transfer. However, a more detailed study of the section behaviour is deemed advisable in order to check that these sections do not hamper the transfer.

4.2 Transient stability

The objective is here to assess the dynamic behaviour in case of three phase short-circuit for increasing values of the cross-border transfer. The stability of the system is then simulated for the most constraining short circuits.

Depending on the assumption on the good detection of the fault by the protections, durations of 150 ms, 240 ms or 300 ms can be considered. Here, a normal elimination of the fault is considered (1st stage), represented by a short-circuit duration of 150 ms.

In the present system, the most constraining locations are the interconnection lines themselves (i.e. each of the 750 kV lines, any side) and the model led to indicate a transfer capacity for transient stability between 7000 and 8000 MW, supposing all lines are available after the short circuit.

Tab. 4-11

Case of short-circuit on line	**Transfer far from interface** RU->UCTE 7000 MW	**Transfer far from interface** RU->UCTE 8000 MW
PL-UR 750 kV, PL side	stable	unstable
PL-UR 750 kV, UR side	stable	unstable
HU-UR 750 kV, HU side	stable	stable
HU-UR 750 kV, UR side	stable	stable
RO-UR 750 kV, RO side	stable	stable
RO-UR 750 kV, UR side	stable	stable
Summary: transfer level that satisfies all the above constraints	7000 MW is acceptable *(from stability point of view)*	8000 MW is not acceptable

4.3.a Dynamic stability (in terms of inter-area oscillations)

The objective is to observe the differences between the oscillatory behaviour before and after interconnection. For this purpose, a moderate entity event is applied, namely the loss of a 1000 MW generation unit.

In the frame of the present study, simulations have been performed for outages in four areas: ES, PL, RU (western part), RU (eastern part). In terms of modelling and having no access to more detailed representation of the generator's dynamics, a same turbine-governor model has been used for the whole system (670 generators), with a parameter indicating the percentage of hydropower within the total generated power.

Outages in UCTE

- *Outage in Spain:*

After interconnection, and during the transient period (from 5th to 20th second), the frequency behaviour appears to have larger oscillations than before interconnection, but frequency becomes almost constant after the 40th second. The frequency in Italy follows a new oscillatory mode and the frequency behaviour elsewhere (Germany, Poland...) remains almost unaffected.

- *Outage in Poland:*

In the interconnected system, frequency oscillations appear to be much smaller than in the UCTE system alone. The interconnection has here a positive impact on the frequency behaviour.

Outages in UPS

- *Outage in Western Russia:*

In the UPS system alone, a low damping oscillatory mode appears, with Siberian units clearly oscillating against those of all other UPS regions.

In the interconnected system, this oscillating mode disappears completely after the 30th the second, which proves a positive impact of the interconnection on the UPS frequency behaviour.

- *Outage in Eastern Russia:*

In the UPS system alone, the Siberian units oscillate with a low damping, in phase with the frequency in the Ural, and both Siberian and Ural groups of units are in opposition with the other areas.

In case of the interconnected system, the oscillations vanish after some 40-50 sec, showing a better damping. However, all Russian regions except Siberia during the first 30 seconds show oscillations much larger than in isolated case. In the interconnected case, the whole Russia oscillates around Ukraine, and against Western Europe.

4.3.b Damping

The damping is represented by a damping constant D_i of the inter-area oscillation, where frequency deviations are modelled:

$$Df(t) = Ao \,.\, e^{-D_i.t} \cos(\omega_i.t)$$

But why an oscillatory analysis? Because:

- It is important for the concerned power utilities to set-up and to maintain a dynamic model of their system: such model often provides information both on the oscillatory behaviour (small disturbances) and large disturbances, so that proper actions or equipment can be designed for facing particular events.
- oscillations reduce the life span of mechanical components.
- oscillations, even small, may be close to a stability limit if the damping is very weak. Consequently, it is normally suggested to keep a margin with respect to instability, i.e. with respect to the case of sustained oscillations ($D_i = 0$). Table 9 shows the criterion suggested for the acceptability of damping.

Tab. 4-12

Class	Damping const. D_i	Evaluation	Acceptability
I	>0.1 1/s	decreasing	sufficient
II	~0.05 1/s	decreasing	critical
III	0.05>Di > 0	slowly decreasing	Danger because data inaccuracies
IV	0	undamped	stability violation
V	< 0	increasing	Stability violation

The model includes 4000 nodes and 670 generators spread between Spain and Siberia. If the global behaviour is approximated by the main oscillatory mode:

$$Df(t) = Df_{fin} + A_o.e^{-Di.t}.\sin(\omega_o.t)$$, then

D_i can be measured from simulated curves:

$$Di = \frac{1}{2.\Pi}\ln(\frac{A_{i+1}}{A_i})$$

Tab. 4-13

Outage:	in Spain - UCTE alone	in Spain	in Poland	in Central Russia	in Eastern Russia
Main period W (s)	4.1	4.2	2.4	6	10
Main period E (s)	-	12.8	12.8	10	10
Damping D_i before interconn. (1/s)	0.1	0.13	0.11	0.11	0.06
D_i after interconnection (1/s)	-	0.22	0.22	0.31	0.13
Assessment: interconnection is	-	favourable		favourable	favourable

The above values are related to simulations with weak transfer between UCTE and UPS. Other simulations with large transfers up to 7000 MW have led to similar values and conclusions. However, without involving all the TSO of the concerned countries, the model has been kept simple and an update with a more detailed dynamic model would be worth for confirming the results.

4.1.3.1.3.5 Step 5: Screening the transfer capacities on all the criteria

Once maximum transfer capacities have been found for the various criteria, the capacity complying with all criteria can be declared, i.e.: the Total Transfer Capacity (TTC) as per the ETSO definition. The ETSO definitions also consider a security reserve called Transmission Reliability Margin (TRM) to be substracted from the TTC to obtain the Net Transfer Capacity (NTC). The approach proposed here allows minimsing the uncertainty and, then, the TRM with a consequent maximation of the NTC to be offered on the market.

4.1.3.1.4 Conclusions

This study case presented an approach consisting in analysing step by step static and dynamic criterias in the frame of AC interconnections, particularly in the case of very large systems evaluating in detail their interface capacity according to the following steps, which can be adopted in general for similar studies:

Static criterias:

- ✓ influence of the interconnection on the reactive power reserves, on the optimal set points of regulating transformers and on optimal set points of shunt Var compensation devices
- ✓ assessment of the interface capacity up to voltage collapse (absolute limite) and up to voltage operational limits (taken here at 0.9 pu);
- ✓ interface capacity in N-1 (strict N-1, i.e. without or before any dispatcher actions).

Dynamic criterias:

- ✓ dynamic behaviour of the interconnected system during a standard power imbalance event;
- ✓ risk for the cross-border transfers to trigger specific protections of a system (namely the automatas of the cross-sections in UPS);
- ✓ changes in transient stability due to the interconnection;

- ✓ changes in dynamic stability due to the interconnection, and particularly the damping factor of the inter-area oscillations.

Screening these criteria allows to find the acceptable Total Transfer Capacity. If the approach is applied in depth and with detailed models, its should allow reducing the Transmission Reliability Margin, thereby bringing the Net Transfer Capacity to the highest acceptable values.

In the present case, the approach has been applied to the AC interconnection of the UCTE and UPS systems and showed that within the approximation of the model used, there is a technical feasibility for transfers of several thousands of MW through the interface. Therefore, the results presented here to illustrate the approach also confirm the interest of more detailed models, as currently undertaken on the interconnection of UPS and UCTE.

The proposed approach is deemed appropriate for interconnecting systems prone to show new oscillatory modes after interconnection, namely systems which are very large compared to the capacity of the interconnection and systems of different types of dynamic controls.

4.1.4 Subsynchronous resonance study

The presentation of this reference study is based on the study TSI\EL\03\007, carried out by TSI. The approach has been applied to study the study of the effect on the Subsynchronous Resonance (SSR) stability of the Eskom network of a proposed network expansion plan to strengthening of the high voltage Eastern Cape network.

From an SSR perspective, the power stations that were considered as potentially affected were Koeberg, Kendal, Majuba and Tutuka. Early frequency scan results showed that the impedance's seen by Kendal, Majuba and Tutuka were dominated by the local loads in their area and were not affected by series compensation in the Cape Network. The bulk of the study thus reduced to investigating the SSR stability of the Koeberg generators in the new strengthened network.

The approach taken to this study was to first use frequency scanning to gain an understanding of the nature of the SSR problem and to identify cases where there was possible SSR concern. These cases would be the minimum set included in a more detailed eigenvalue study.

Presented in this study is the generator torsional mechanical data for the generators at the above power stations. Even though initial study results showed that Kendal, Majuba and Tutuka were not affected by series compensation in the Cape and hence their torsional mechanical parameters were not required, they were presented here for the sake of completeness.

4.1.4.1 System data

4.1.4.1.1 Network Data

Network data included light and peak load conditions with a variable number of units on-line at Koeberg Power Station. For these studies, multiple generating units at a power station were lumped into single equivalent units.

4.1.4.1.2 Dynamic Data

The dynamic data file was supplied by Sarica Swart of Eskom Transmission Expansion Planning.

4.1.4.1.2.1 Generator Torsional Data

This section presents the Generator Torsional data which was used in the SSR study.
For each applicable generator, the data presented is for a lumped parameter multi-inertia shaft system. The data is listed as lumped inertia constants (units - kg.m2) and torsional stiffnesses of interconnecting shafts (units - Nm.rad-1 x 106).

For eigenvalue studies the torsional data is required in per-unit with the inertias specified as an inertia constant, H. Based on the machine ratings and a frequency base of 50 Hz the per-unit values of inertia constant (H) and torsional stiffnesses are calculated and presented together with the physical data in Tab. 4-14 to Tab. 4-19.

4.1.4.1.2.2 *Koeberg Torsional Data*

The Koeberg torsional data was obtained from previous consulting and research work done by Dr Jennings while at the University of Natal. The data is presented in Tab. 4-14 below.

Koeberg Mechanical Data					
Inertia			Torsional Stiffness		
Section	Lumped Inertia [kg.m2]	Inertia Constant (H) [per-unit]	Section	Torsional Stiffness [Nm.rad-1 106]	Torsional Stiffness [per-unit]
HP	3432	0.158	HP – LP1	36.3	10.63
LP1	12991	0.598	LP1 – LP2	86.5	25.34
LP2	12882	0.593	LP2 – LP3	79.9	23.42
LP3	13577	0.625	LP3 – GEN	91.9	26.93
GEN	14641	0.674	GEN – EXC	240.7	70.53
EXC	739	0.034			

Tab. 4-14 - Koeberg Torsional Mechanical Data

4.1.4.1.2.3 *Tutuka Torsional Data*

From a torsional perspective, Units 1-3 of Tutuka are different from Units 4-6 as they have a different exciter. The data for units 1-3 are presented in Tab. 4-15 while the data for units 4-6 are presented in Tab. 4-16 [4-1].

Tutuka Units 1-3 Mechanical Data					
Inertia			Torsional Stiffness		
Section	Lumped Inertia [kg.m2]	Inertia Constant (H) [per-unit]	Section	Torsional Stiffness [Nm.rad-1 106]	Torsional Stiffness [per-unit]
HP	1104	0.0817	HP – IP	121	57.0
IP	2448	0.1812	IP – IP	2427	1143.8
IP	2614	0.1935	IP – LP1	261	123.0
LP1	8772	0.6494	LP1 – LP1	5558	2619.4
LP1	9079	0.6721	LP1 – LP2	228	107.5
LP2	8787	0.6505	LP2 – LP2	5542	2611.9
LP2	9079	0.6721	LP2 – GEN	149	70.2
GEN	10851	0.8033	GEN – EXC	39.5	18.6
EXC	1081	0.08			

Tab. 4-15- Tutuka Units 1-3 Mechanical Data

Tutuka Units 4-6 Mechanical Data					
Inertia			Torsional Stiffness		
Section	Lumped Inertia [kg.m2]	Inertia Constant (H) [per-unit]	Section	Torsional Stiffness [Nm.rad-1 106]	Torsional Stiffness [per-unit]
HP	1104	0.0817	HP – IP	121	57.0
IP	2448	0.1812	IP – IP	2427	1143.8
IP	2614	0.1935	IP – LP1	261	123.0
LP1	8772	0.6494	LP1 – LP1	5558	2619.4
LP1	9079	0.6721	LP1 – LP2	228	107.5
LP2	8787	0.6505	LP2 – LP2	5542	2611.9
LP2	9079	0.6721	LP2 – GEN	149	70.2
GEN	10851	0.8033	GEN – EXC	37.0	17.4
EXC	1075	0.0796			

Tab. 4-16 - Tutuka Units 4-6 Mechanical Data

4.1.4.1.2.4 Majuba Torsional Data

From a torsional perspective, Units 1-3 of Majuba are different from Units 4-6. The data for units 1-3 are presented in Tab. 4-17, while the data for units 4-6 are presented in Tab. 4-18.

Majuba Units 1-3 Mechanical Data					
Inertia			Torsional Stiffness		
Section	Lumped Inertia [kg.m2]	Inertia Constant (H) [per-unit]	Section	Torsional Stiffness [Nm.rad-1 106]	Torsional Stiffness [per-unit]
HP	1074	0.0726	HP – IP	117	50.4
IP	2333	0.1577	IP – IP	2431	1046.2
IP	2501	0.1691	IP – LP1	243	104.6
LP1	4487	0.3033	LP1 – LP1	2446	1052.6
LP1	4447	0.3006	LP1 – LP2	200	86.1
LP2	4502	0.3043	LP2 – LP2	2435	1047.9
LP2	4447	0.3006	LP2 – GEN	142	61.1
GEN	10851	0.7335	GEN – EXC	37.0	15.9
EXC	1075	0.0727			

Tab. 4-17 - Majuba Units 1-3 Mechanical Data

Majuba Units 4-6 Mechanical Data					
Inertia			Torsional Stiffness		
Section	Lumped Inertia [kg.m2]	Inertia Constant (H) [per-unit]	Section	Torsional Stiffness [Nm.rad-1 106]	Torsional Stiffness [per-unit]
HP	1074	0.0669	HP – IP	117	46.4
IP	2333	0.1454	IP – IP	2431	964.3
IP	2501	0.1558	IP – LP1	257	101.9
LP1	9019	0.5620	LP1 – LP1	5646	2239.6
LP1	8983	0.5597	LP1 – LP2	226	89.6
LP2	9019	0.5620	LP2 – LP2	5646	2239.6
LP2	8983	0.5597	LP2 – GEN	150	59.5
GEN	10851	0.6761	GEN – EXC	37.0	14.7
EXC	1075	0.067			

Tab. 4-18 Majuba Units 4-6 Mechanical Data

4.1.4.1.2.5 Kendal Torsional Data

Kendal Torsional Data was supplied by Eskom Transmission. No verification of this data was done by Eskom. The physical values of lumped inertia and torsional stiffness are presented in Tab. 4-19. However, the per-unit values presented in Tab. 4-19 were calculated for the purpose of this study from the physical values that were supplied and are not the same as the per-unit values supplied. In the case of the torsional stiffnesses, the reason for the difference appears to be that the supplied per-unit values were calculated using a machine rating of 850 MVA rather than 810 MVA. In the case of Inertia Constant, there is a factor of 2 difference between the supplied values and those calculated in this study. It is difficult to determine the reason for this difference as the data supplied did not indicate the method used to calculate the per-unit values. These differences were not material since the frequency scan results presented later in the report show that there is no possibility of SSR at Kendal and hence the accuracy of the mechanical model is not important. Should the frequency scans have shown possibility of SSR problems, then it would have been necessary to validate the accuracy of the Kendal mechanical model.

Kendal Mechanical Data					
Inertia			Torsional Stiffness		
Section	Lumped Inertia [kg.m2]	Inertia Constant (H) [per-unit]	Section	Torsional Stiffness [Nm.rad-1 106]	Torsional Stiffness [per-unit]
HP	1248	0.0760	HP – IP	164.9	63.96
IP	4720	0.2876	IP – LP1	246.3	95.53
LP1	14106	0.8594	LP1 – LP2	200.9	77.92
LP2	14106	0.7140	LP2 – GEN	128.5	47.90
GEN	11720	0.0361	GEN – EXC	103.4	40.10
EXC	593				

Tab. 4-19 - Kendal Mechanical Data

4.1.4.1.2.6 Torsional Frequencies

The torsional natural frequencies of the generators presented in the previous sections calculated from the mechanical parameters presented in those sections and are shown in Tab. 4-20. Only the sub-synchronous frequencies are shown as the super-synchronous frequencies are not of relevance in this study.

Unit	Mode Frequency (Hz)			
	1	2	3	4
Koeberg	6.68	12.37	15.84	17.47
Kendal	15.64	27.58	39.28	
Tutuka 1-3	16.17	26.64	32.95	37.31
Tutuka 4-6	16.16	26.52	32.11	37.30
Majuba 1-3	16.62	29.87	33.51	44.02
Majuba 4-6	16.18	26.52	32.17	37.32

Tab. 4-20 - Torsional Subsynchronous Frequencies

4.1.4.1.2.7 Torsional Interaction Susceptibility (TIS) Values

A useful parameter calculated from the torsional mechanical data is the Torsional Interaction Susceptibility (TIS), which gives an indication of how susceptible a mode is to SSR [4-2]. This value is shown in Tab. 4-21 for the generators listed in the previous sections. A higher value indicates that a mode is more strongly coupled to the electrical system and is thus more susceptible to SSR. For comparative purposes the TIS values for the first 4 torsional modes of the IEEE First Benchmark Model generator are 36, 3, 9 and 12.

Unit	Torsional Interaction Susceptance			
	1	2	3	4
Koeberg	63.1	28.0	48.6	0.3
Kendal	63.2	8.1	0.1	
Tutuka 1-3	46.4	5.3	10.2	0.4
Tutuka 4-6	46.2	4.4	11.3	0.3
Majuba 1-3	45.9	0.2	11.7	0.5
Majuba 4-6	54.5	5.4	13.6	0.4

Tab. 4-21 - TIS Values for Subsynchronous Modes

4.1.4.2 METHODS OF ANALYSIS

Two methods were used in the study to determine if there was a possibility of SSR. These were Frequency Scanning and Eigenvalue Analysis.

4.1.4.2.1 Frequency Scanning

The purpose of frequency scanning is to provide a broad overview of the characteristics of the network at sub-synchronous frequencies. The main advantage of this is to identify cases where SSR is not a concern and thereby reduce the number of cases needed to be studied using eigenvalue analysis. In essence, frequency scan studies are good at indicating where SSR is not going to be a problem but in cases where frequency scans indicate SSR is a possibility, the result should be considered as confirmation that further more accurate studies (eigenvalue analysis) are needed.

The method of analysis is to look into the network from a point inside the airgap of a generator and calculate the impedance seen by the generator. The mechanical torsional system of the generator interacts with the electrical network at frequencies called the complementary mechanical frequencies of 50Hz ± fm (where fm = the mechanical torsional frequency). Therefore there are potential SSR problems where electrical resonances identified in the frequency scan coincide with the complementary mechanical frequencies. It should be noted that a match between an electrical resonance and a complimentary mechanical frequency does not imply a definite SSR problem; it merely indicates that the potential for SSR exists. Whether an SSR problem will occur depends on the degree of interaction between the electrical and mechanical resonances and this should be ascertained by further eigenvalue studies.

In this report the frequency scans were calculated using the Digsilent Software Package using the full network model as supplied by Eskom Transmission Expansion Planning and imported into Digsilent format by TSI, SAPSSI.

4.1.4.2.2 Eigenvalue Analysis

This method of analysis is well proven for SSR and gives immediate and clear information on the state of each turbogenerator torsional mode.

In this report the system eigenvalues were calculated using the Multi-Area Small Signal Stability program (MASS) which forms part of the EPRI Power System Analysis Package (PSAPAC). This program has a feature that allows the modelling of the multi-inertia shaft systems of turbo-generators as well as the modelling of the dynamics of transmission system voltages and currents. The modelling of both of these elements is essential for accurate SSR studies. One drawback of modelling the ac network dynamics is that it greatly increases the size of the system model and the system order can easily become too large for the eigenvalue solving routines. The MASS program thus allows the user to specify only parts of the network for detailed modelling. While this enables the network size problem to be overcome it requires judicious selection of which network components to select and which to omit in the detailed model.

4.1.4.3 FREQUENCY SCAN RESULTS

4.1.4.3.1 Interaction between Generating Stations

The purpose of the frequency scans performed in this section are to investigate the effect of the numbers of units on-line at the study power stations (Koeberg, Majuba, Tutuka and Kendal) on the frequency characteristics of the network impedance seen by the other study power stations. This result is necessary to determine whether the number of units on-line at a station needs to be included in the list of contingencies for eigenvalue analysis.

A base case was chosen as 2005 peak load with 1 unit on-line at Koeberg, 5 units on-line at Tutuka, 4 units on-line at Kendal and 5 units on-line at Majuba. This is referred to in the legend of the various figures as 1Ko_5Tu_4Ke_5Ma. For each generating station, 3 additional frequency scans were performed with different combinations of units on-line at the other 3 stations.

4.1.4.3.1.1 Koeberg Frequency Scan

Figures 1 shows the frequency scans from Koeberg with the combination of units on-line as indicated in the legend. The reasons why the curves are not drawn in the same figure is because the curves do not have the same x-axis data. However, it is clear that the network impedance characteristic seen by Koeberg is not effected by the number of units on-line at Tutuka, Majuba or Kendal.

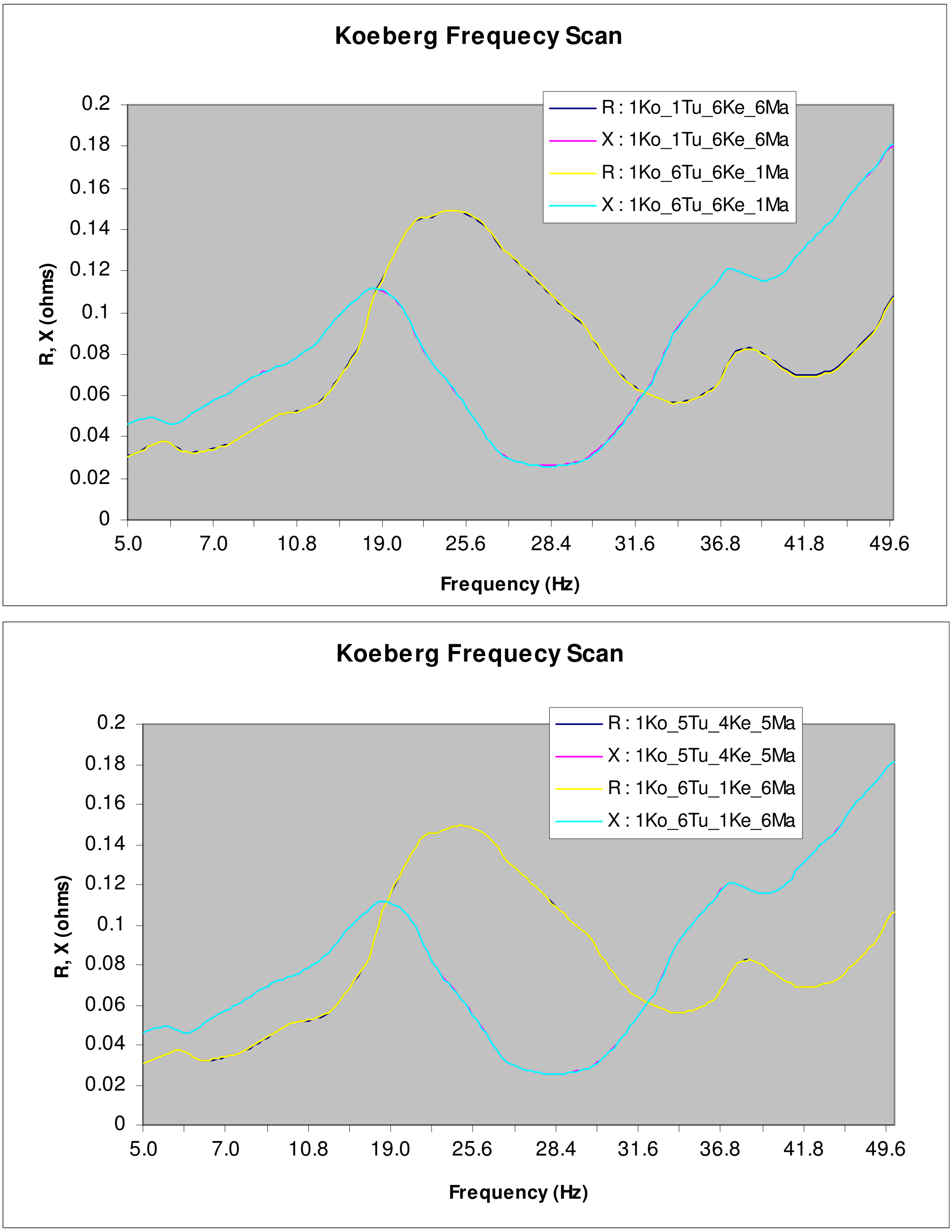


Fig. 4-15 Koeberg Frequency Scan With Variable Numbers of Units at Other Stations

The frequency scan in Fig. 4-15 shows that there is a reactance minimum at 28.3 Hz and another (smaller) one at 39.8 Hz. The 28.3 Hz electrical resonance is far from the complementary mechanical frequencies for Koeberg (at 34.2 Hz, 37.6 Hz and 43.3 Hz) indicating no chance of SSR due to this electrical mode. However the 39.8 Hz electrical resonance is right in the danger zone (34 Hz to 44 Hz) for interaction with the Koeberg mechanical modes. For the network condition considered in Fig. 4-15, the 39.8 Hz electrical mode is sufficiently far from the mode 2 complementary frequency of 37.6 Hz for there to be little likelihood of SSR, however it is close enough to warrant further studies of network outages that may shift this electrical resonance.

4.1.4.3.1.2 Tutuka, Majuba and Kendal Frequency Scans

Fig. 4-16, Fig. 4-17 and Fig. 4-18 show the frequency scans from Tutuka, Majuba and Kendal with the combinations of units on-line as indicated in the legend. The results in these frequency scans are very different to those for Koeberg and are somewhat expected. They show that in some cases the number of units on-line does effect the network reactance seen by another station, but more importantly though, they show that these three stations do not see any network resonances caused by series compensation. Instead the network reactance behaves largely like an inductive reactance. This is mainly due to the presence of the large load fairly close to these three stations and this load dominates the impedance seen by these three stations. These results shows that the series compensation in the transmission lines south of Beta to the Cape will not induce SSR at these three stations.

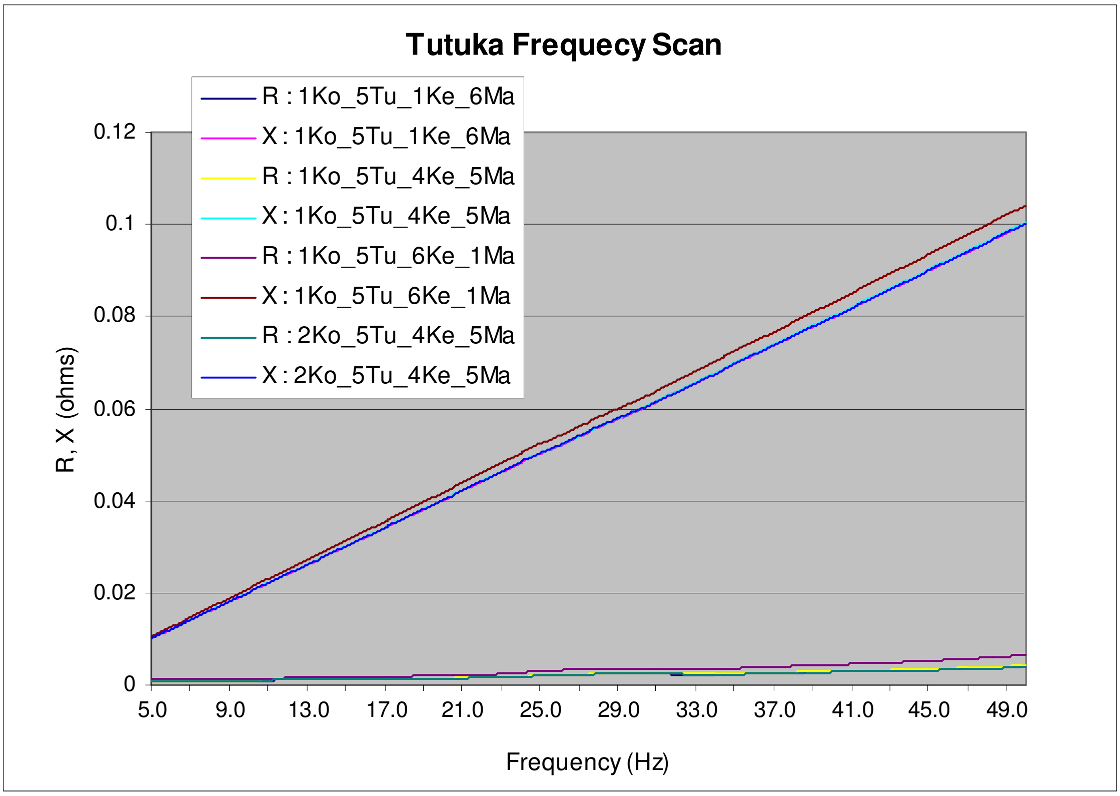


Fig. 4-16. Tutuka Frequency Scan With Variable Numbers of Units at Other Stations

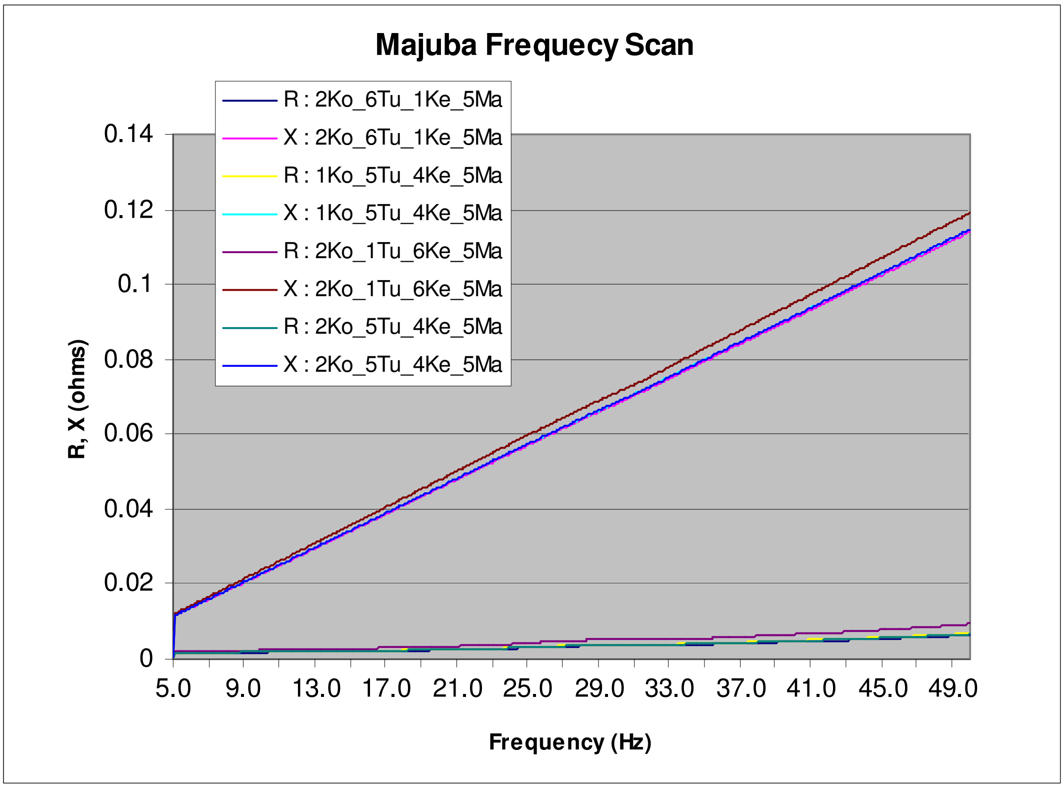


Fig. 4-17 Majuba Frequency Scan With Variable Numbers of Units at Other Stations

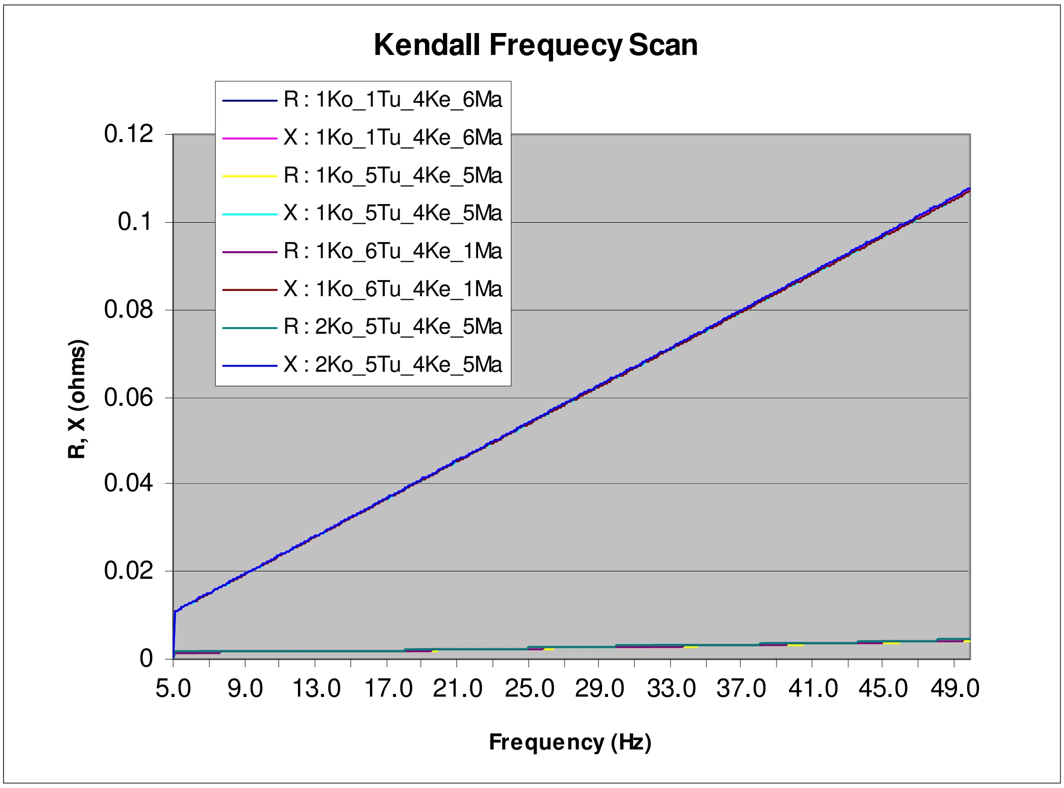


Fig. 4-18 Kendal Frequency Scan With Variable Numbers of Units at Other Stations

4.1.4.4 Comparison of 2003 Network and 2005 Network

The frequency scans of the previous section have shown that the proximity of the generators in the Central Region to the large load in that area make them impervious to SSR due to series compensation in the Cape areas. However the frequency scans in Fig. 4-15 for Koeberg power station show that this power station does in fact see series resonances due to the compensation in the Cape transmission system and thus could be susceptible to SSR.

As a starting point prior to investigating the possibility of SSR at Koeberg for the strengthened 2005 network, it is useful to consider the current Eskom network of 2003. The SSR stability of Koeberg in this network was studied and was deemed safe and indeed Koeberg has been operating satisfactorily with no SSR incidents. It is thus useful to compare this current network with the proposed 2005 network to see how the proposed network changes affect the network reactance (electrical resonances) seen by Koeberg. This is done in Fig. 4-19 where the network reactance seen by Koeberg for both the present and 2005 networks is shown and is one of the most insightful graphs in this report.

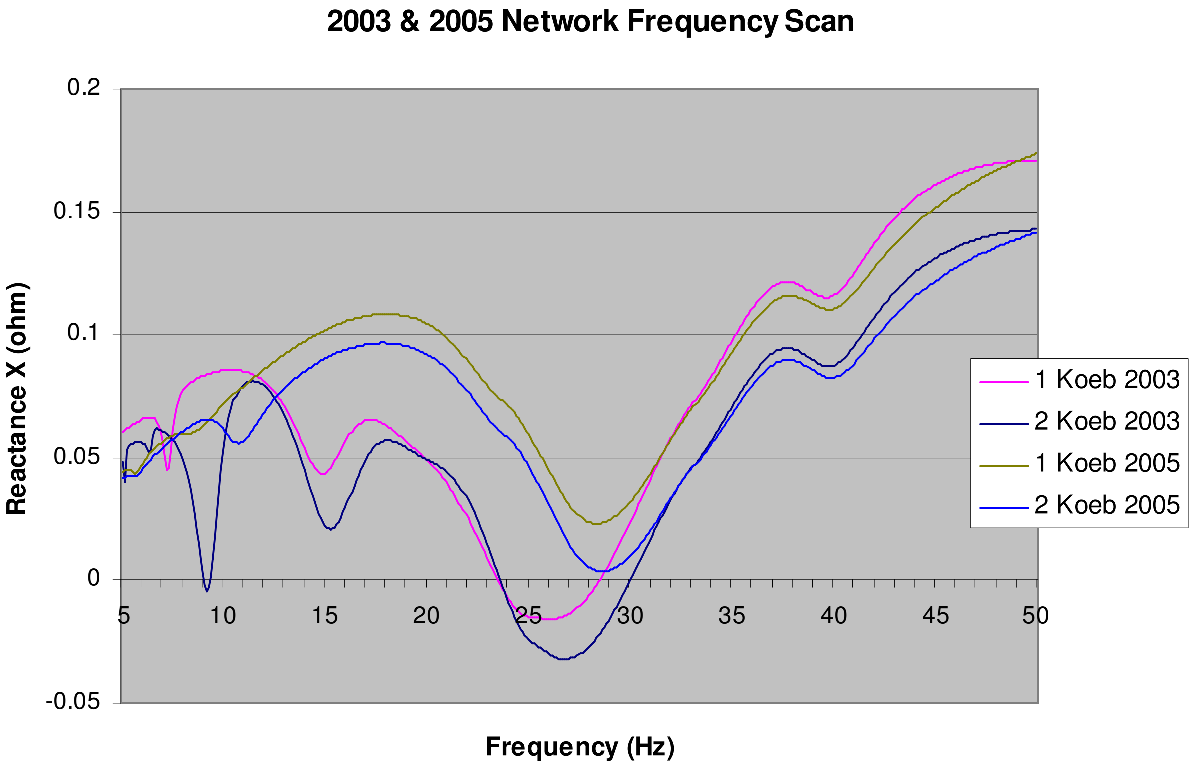


Fig. 4-19 Network Reactance Seen From Koeberg for Present Network (Year 2003) and Year 2005 Network.

This figure shows that the 2005 frequency scans are shifted upwards compared to the 2003 scans indicating a more stable system in terms of induction generator effect. However the most significant information shown is that the network strengthening measures have affected the reactance seen by Koeberg mainly between 5 Hz and 30 Hz. The electrical resonances seen by Koeberg around 8 Hz and 15 Hz are largely reduced or eliminated in the 2005 network. In the frequency range 34 Hz to 44 Hz where the Koeberg mechanical modes interact with the electrical system, there is very little difference in the reactance seen by Koeberg between the 2003 and 2005 networks. This single result is significant and gives one confidence to expect the SSR stability of the 2005 system to be similar to that of the current 2003 system.

One further observation on a negative note is that the major electrical resonance at around 27 Hz in the 2003 network has shifted to around 29 Hz in the 2005 network. It has thus moved closer to the mechanical mode 3 complimentary frequency of 34.2 Hz. While this difference in frequency between this electrical resonance and the mechanical complimentary frequency is large in terms of SSR interaction and indicates no likelihood of SSR interaction, it is necessary to confirm that no system outage causes this electrical resonance to move too close to 34.2 Hz.

4.1.4.5 Contingency Studies

The following is a list of network conditions or contingencies supplied by Eskom transmission to be considered in the study.

765kV line and transformer contingencies

3. Alpha 765/400kV transformer
4. Alpha-Beta 765kV line
5. Beta 765/400kV transformer
6. Beta-Hydra 765kV line and transformer (transformer feeder bay)

400kV single line contingencies

7. Beta-Luckhoff-Hydra 400kV line
8. Beta-Luckhoff-Hydra 400kV line series cap bypass
9. Perseus-Luckhoff-Hydra 400kV line
10. Perseus-Luckhoff-Hydra 400kV line series cap bypass
11. Hydra-series cap-Poseidon 400kV line
12. Hydra-series cap-Poseidon 400kV line series cap bypass
13. Beta-series cap-Delphi 400kV line
14. Beta-series cap-Delphi 400kV line series cap bypass
15. Poseidon-Delphi 400kV line
16. Delphi-Neptune 400 kV line
17. Poseidon-Grassridge 400kV line or Poseidon-Grassridge_ext 400kV line
18. Grassridge-Grassridge_ext 400 kV link
19. Hydra-Kronos-Aries 400kV line
20. Hydra-Victoria-Droërivier 400kV line
21. Hydra-Droërivier 400kV line

Transformers

22. Grassridge or Grassridge_ext 400/132 kV transformer
23. Grassridge 220/132 kV transformers

Shunt devices

24. Grassridge 400kV and 132kV shunt capacitors / reactor
25. Grassridge or Grassridge_ext 400 kV SVC
26. Chatty 132kV
27. Hydra 400kV shunt capacitors / reactors
28. Perseus 400kV shunt capacitors / reactors
29. Delphi 400kV shunt capacitors / reactors

132kV lines

30. Grassridge-Grassridge_ext 132 kV link
31. Grassridge-Smelter 132kV line or Grassridge_ext-Smelter 132kV line
32. Grassridge-Chatty 132kV line
33. Grassridge_ext-Coega 132kV line

Other lines

34. Tutuka-Alpha 400 kV line
35. Alpha-Kendal 400 kV line

36. Perseus-Grootvlei 400 kV line
37. Perseus-Theseus 400 kV line
38. Perseus-Leander 400 kV line
39. Perseus-Mercury 400 kV line (future)
40. Droërivier-Komsberg-Muldersvlei 400 kV line
41. Droërivier-Komsberg-Bacchus 400 kV line
42. Poseidon-Grassridge 220 kV traction line
43. Poseidon-Grassridge 220 kV direct line (replaced by 400kV line with PAS)

They were to be considered with different numbers of units on line at Koeberg and with Tutuka / Majuba units as required for peak load and light load conditions. It was shown earlier that the number of units online at stations in the Central Region had no effect on the network impedance characteristic seem by Koeberg so it is not relevant to include this as a variable in the study.

The methodology followed here for the frequency scans was to start with a base case of system healthy at peak load with one Koeberg unit on line. A frequency scan was performed for all relevant contingencies and the reactance was plotted to determine the position of electrical resonances. This was then repeated with 2 Koeberg units online for certain selected contingencies.

It should be noted that subsynchronous resonance occurs at a lower frequency to the standard 50 Hz power flow and as such is largely independent of what occurs at the 50 Hz level. So whereas power flows are critical in standard stability studies, they play a very minor role in determining whether there is a potential for SSR and in fact, can almost be considered as two separate systems superimposed on each other. Hence it is only necessary to do studies at a single power level (chosen as peak load here) and only if there is marginal SSR stability is it then worthwhile to consider the effects of small changes in network configuration due to power flow levels. Power flows from a generator are only relevant when there is some destabilization of the mechanical modes due to SSR and the amount of mechanical damping present (dependant on turbine steam flows) will determine ultimate stability or instability.

4.1.4.5.1 Contingencies - 1 Unit at Koeberg

Fig. 4-20 through Fig. 4-26 show the frequency scans for the different contingencies. It is clear that in almost all cases, in the critical zone of 34 Hz to 44 Hz, while there may be some slight movement of the frequency scan curves, their shape is largely unaltered. As expected, it is seen in Fig. 4-23 and Fig. 4-24 that 132kV line outages and shunt devices have very little effect on the whole reactance spectrum seen from Koeberg. This lends credence to the view that load levels have little influence on altering the probability of SSR.

Two notable exceptions do occur where the network reactance characteristic in the critical zone does change markedly. The first is Contingency 19, the outage of the Hydra-Kronos-Aries 400 kV line and this is shown in Fig. 4-22. Most notably, the series resonance at 39 Hz disappears as this is due to the compensation in the Aurora-Hydra Western transmission circuit. This contingency thus leads to a more stable SSR system in terms of the 39 Hz mode.

The second contingency that causes an appreciable change to the network reactance characteristic in the critical zone is contingency 40. This is the outage of Droerivier-Komsberg-Muldersvlei 400 kV line and is shown in Fig. 4-26. This large change is due to the fact that the line is close to Koeberg and is key in linking Koeberg to the compensated network in the Southern Cape. This contingency causes a more prominent electrical resonance at 38.8 Hz and this is in close proximity to the mechanical mode 2 complimentary frequency. While this proximity indicates a possibility for SSR, whether SSR will occur or not depends on the strength of interaction between the electrical and mechanical modes and this is checked by eigenvalue analysis. From an intuitive perspective, one would expect this to probably not lead to SSR as the network characteristic in the critical zone of 34 Hz to 44 Hz is similar to what exists today, and this is in fact confirmed by the eigenvalue studies later in this report.

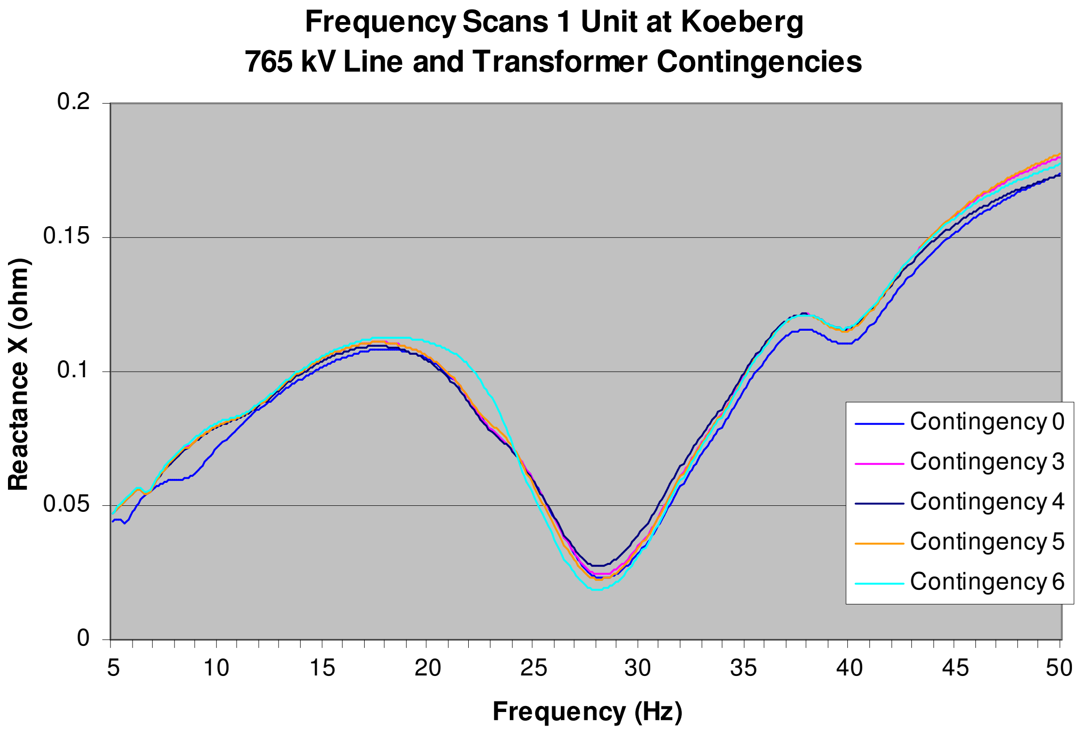


Fig. 4-20 1 Koeberg Unit – 765kV Line and Transformer Contingencies

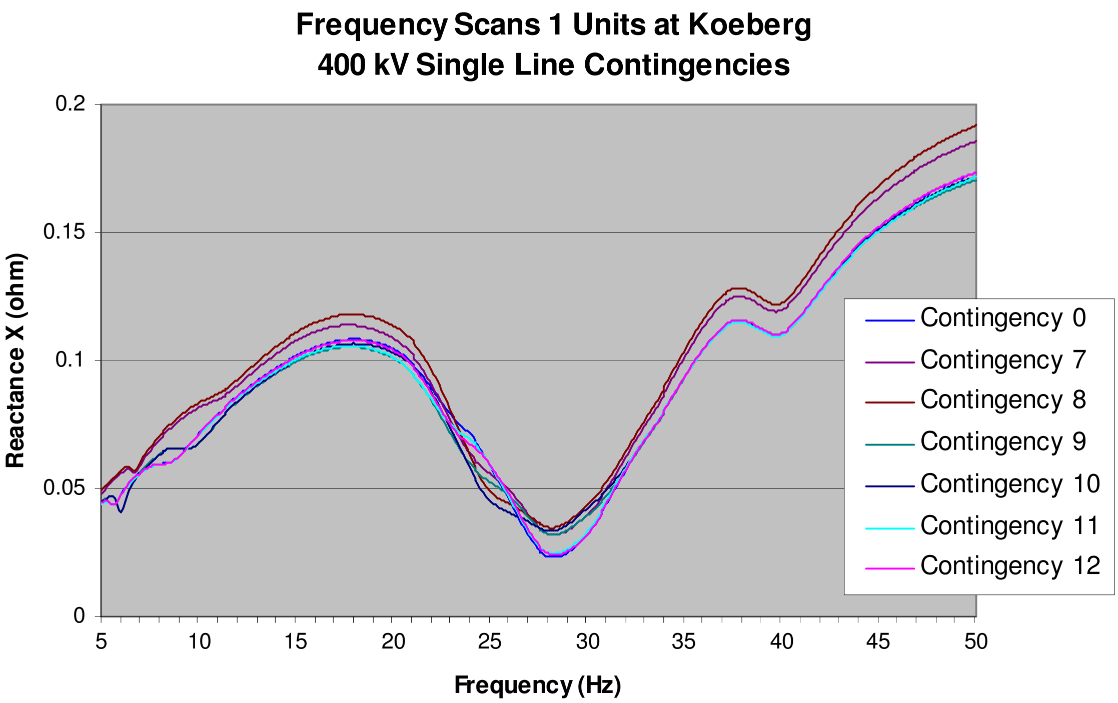


Fig. 4-21 1 Koeberg Unit – 400kV Single Line Contingencies

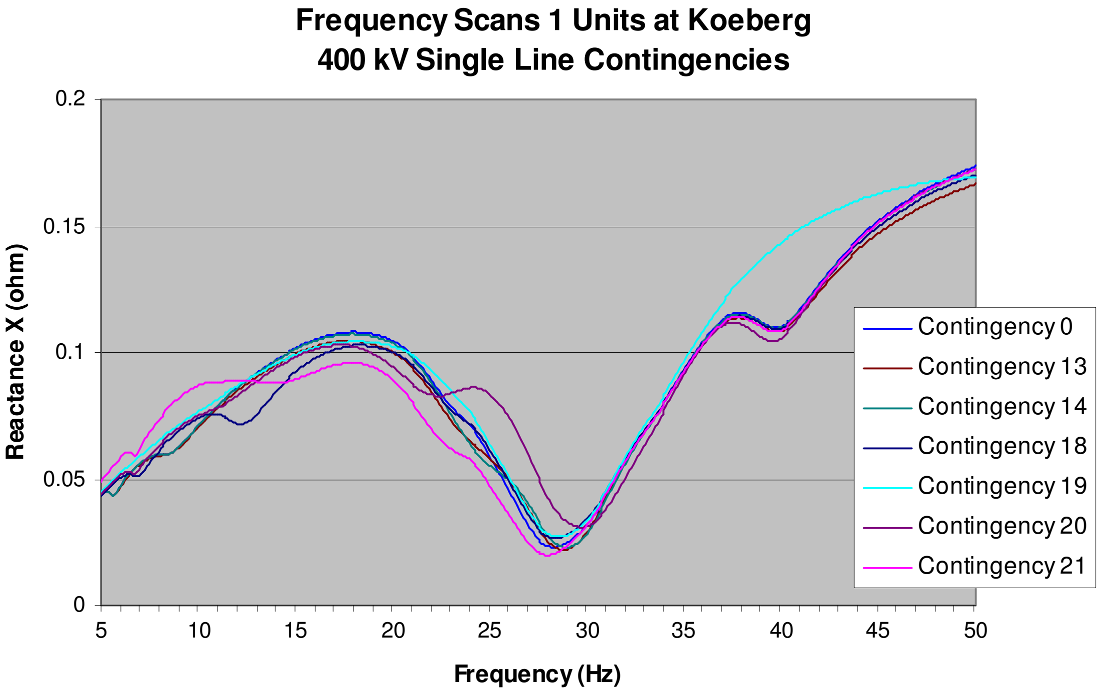


Fig. 4-22 1 Koeberg Unit – 400kV Single Line Contingencies (continued)

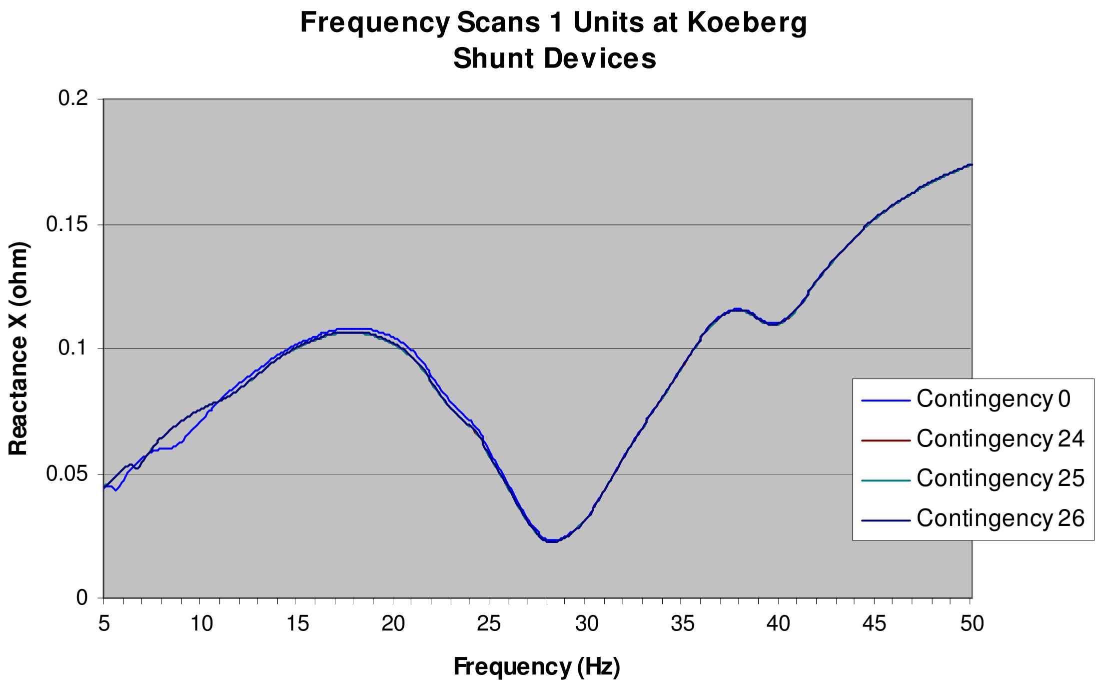


Fig. 4-23 1 Koeberg Unit – Shunt Device Contingencies

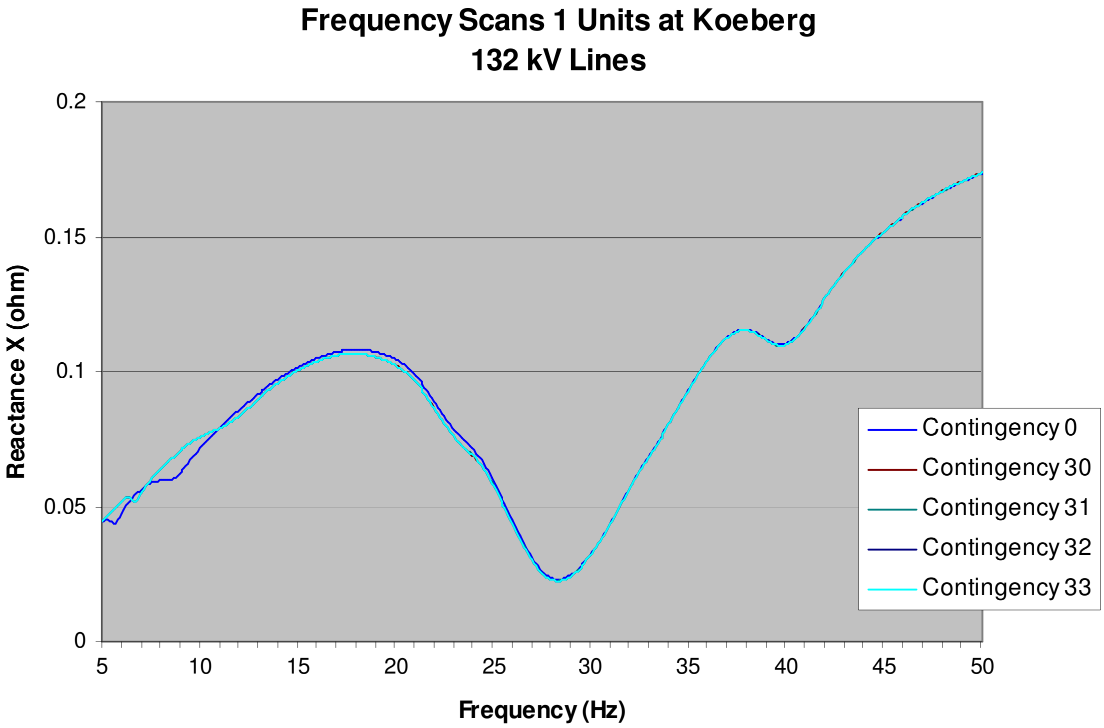


Fig. 4-24 1 Koeberg Unit – 132 kV Line Contingencies

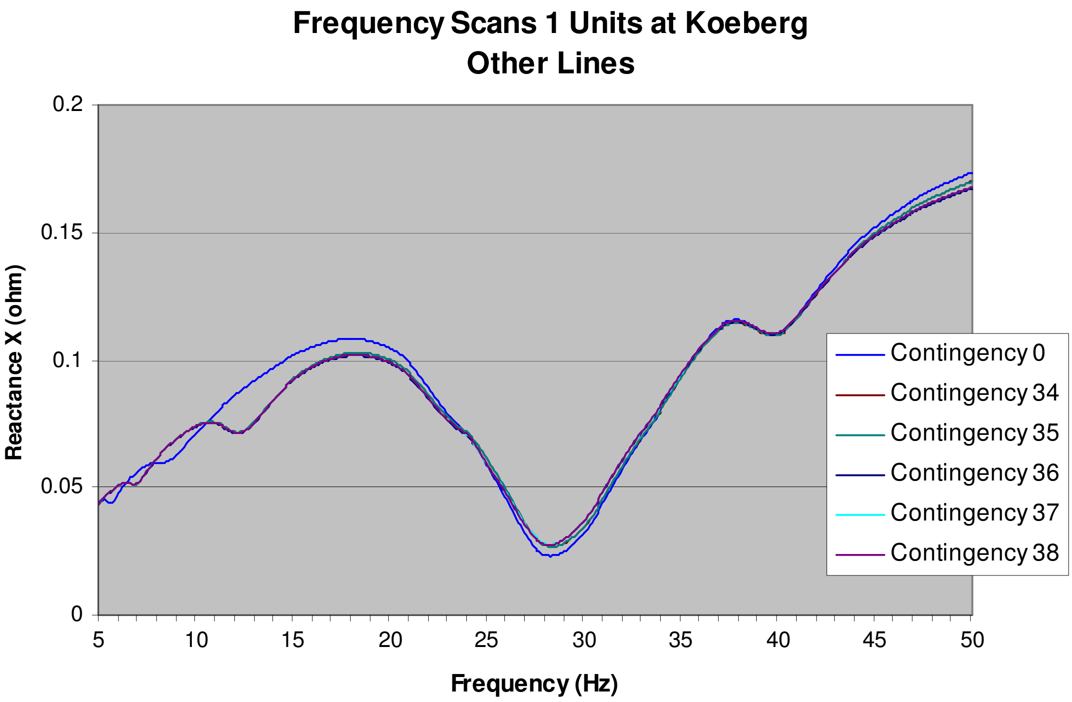


Fig. 4-25 1 Koeberg Unit - Other Line Contingencies

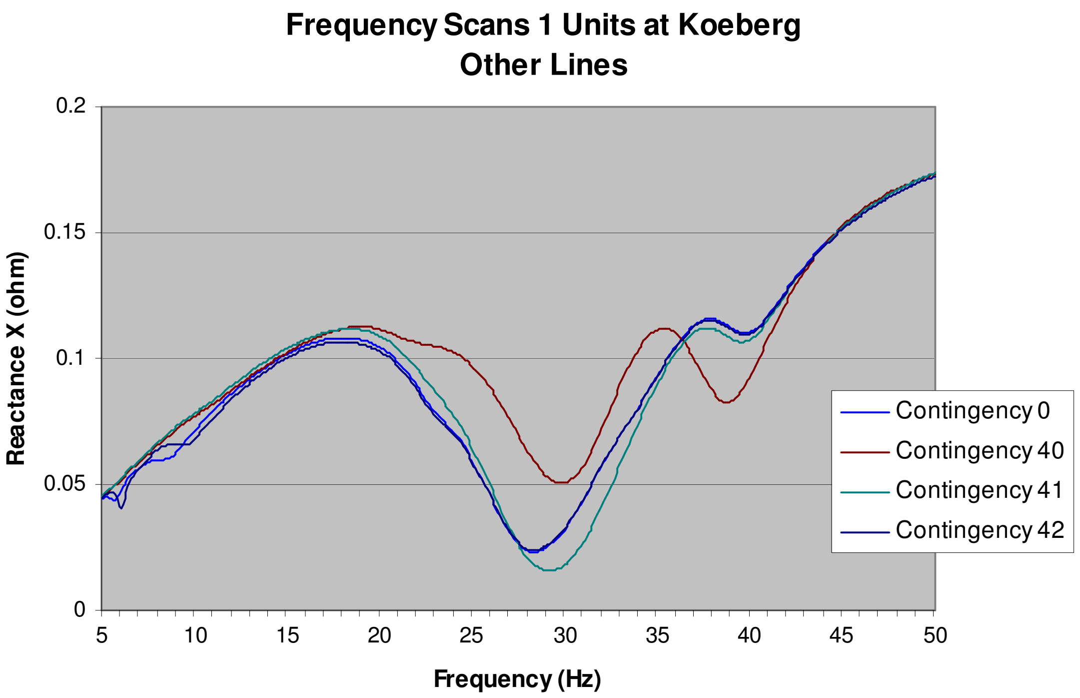


Fig. 4-26 1 Koeberg Unit - Other Line Contingencies (continued)

4.1.4.5.2 Contingencies - 2 Units at Koeberg

Fig. 4-26 and Fig. 4-27 show the frequency scans for selected contingencies for 2 Koeberg units on line. The reactance curves are slightly lower than for 1 Koeberg units as would be expected following the results of Fig. 4-19. In general, the comments made in section 4.1.4.5 for a single Koeberg unit on line are applicable here.

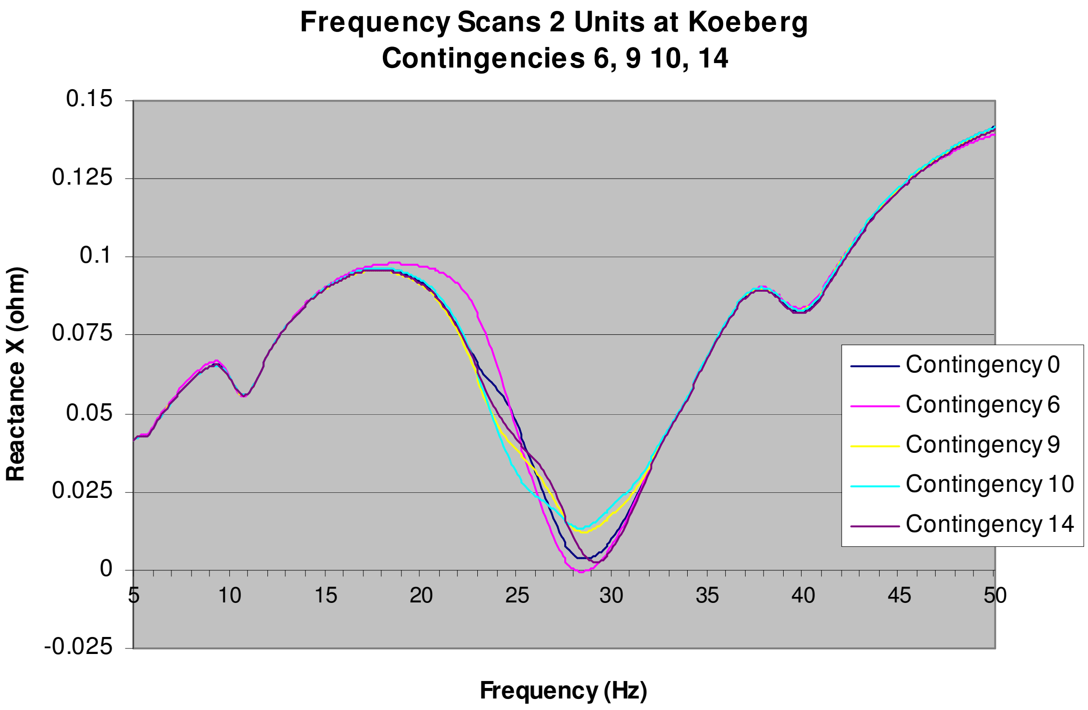


Fig. 4-27 2 Koeberg Units – Selected Contingencies

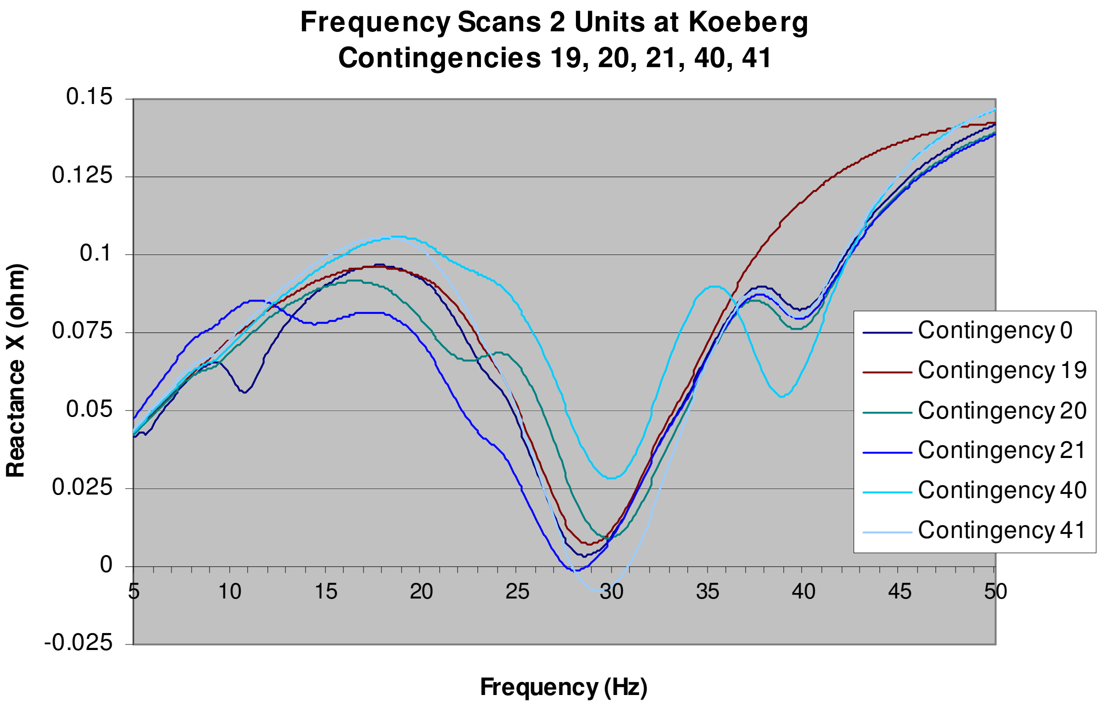


Fig. 4-28 2 Koeberg Units - Selected Contingencies (continued)

4.1.4.6 EIGENVALUE RESULTS

The frequency scan results in the previous section have indicated that there is little likelihood of SSR in the proposed 2005 network for the base case and all studied contingencies. The exceptions are contingencies 19 and 40 where there is appreciable change in the network frequency as seen from Koeberg in the critical frequency zone. This dictates a more detailed analysis being required of at least these two contingencies and this is achieved through eigenvalue calculations.

For the eigenvalue calculations all excitation systems were removed from the generator dynamic models since these do not have much influence on the damping of SSR modes. Moreover, while the Koeberg generators were represented with their full detailed model, all other generators were represented by infinite busses. This typically leads to less damping of the torsional modes and is suitable for a first pass calculation. Should any results show a condition of instability, then further calculations with more detailed generator representation would be necessary. In this particular study as it turned out, this was not necessary.

For the sake of completeness the system eigenvalues were calculated for all contingencies and for both 1 and 2 units online at Koeberg. The results for a single Koeberg unit online appear in Fig. 4-29 while those for 2 units on line appear in Fig. 4-30. Only the eigenvalues for Koeberg mechanical modes 1, 2 and 3 are shown as these are the eigenvalues of interest. The eigenvalues are calculated with the mechanical damping at Koeberg set to zero. This means that the real parts of the eigenvalues for the mechanical modes are due to the electrical damping contribution. A positive value for the real part of the eigenvalue would indicate a negative damping contribution from the electrical network due to SSR and would be a cause for concern.

The results show that contingencies 19 and 40 are indeed largely different, in terms of SSR damping of the mechanical modes, to the rest of the cases particularly for 2 units at Koeberg. However for the base case and all contingencies studied the electrical damping contribution is positive (corresponding to a negative real part of the eigenvalue) and there is thus no indication of any adverse SSR interaction.

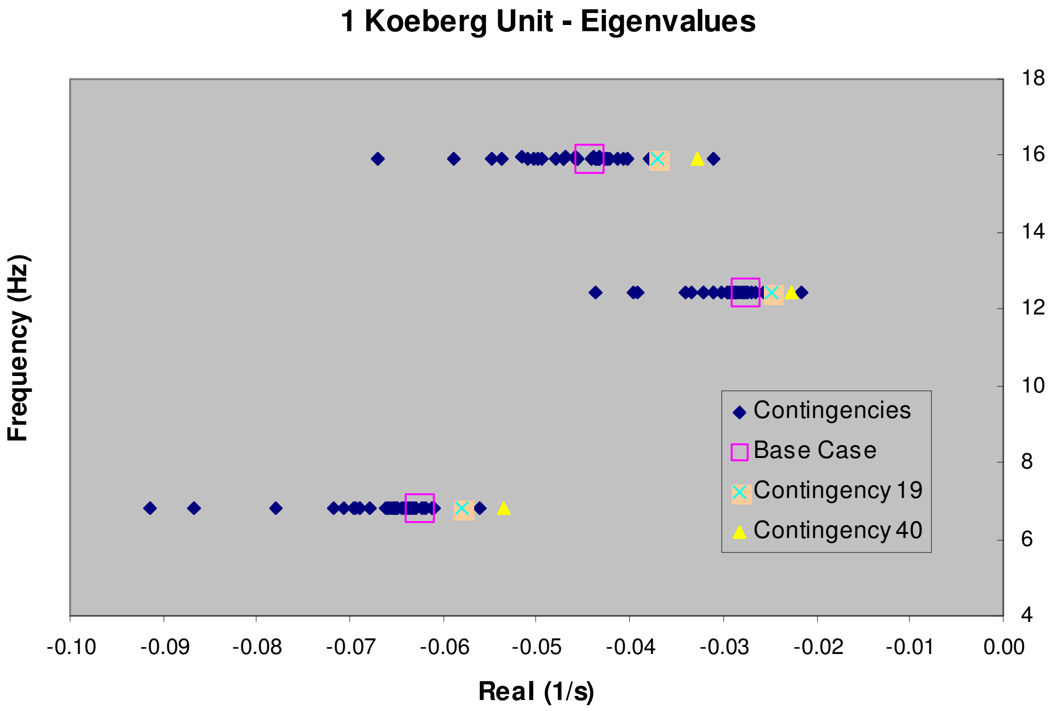


Fig. 4-29 1 Koeberg Unit - Eigenvalues

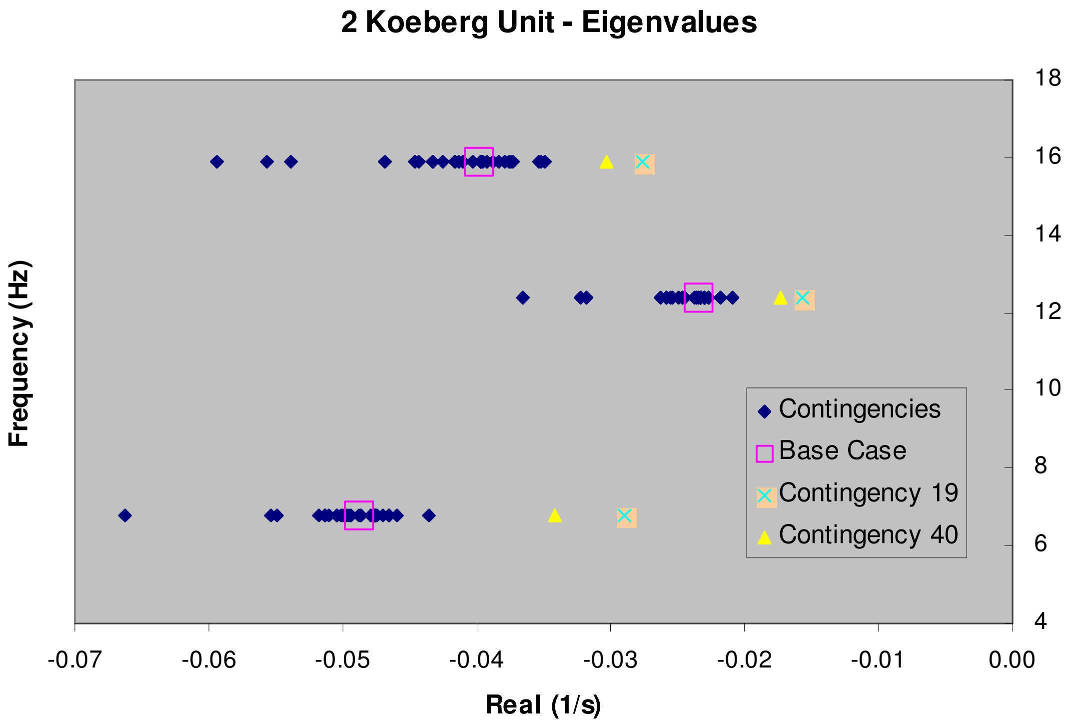


Fig. 4-30 2 Koeberg Units - Eigenvalues

4.1.4.7 CONCLUSION

This study has investigated the effect of network strengthening proposals for the Cape transmission network, including the addition of series compensation, on the SSR stability of Eskom generation. The method of analysis was to first gain an overall understanding of the potential for SSR at various power stations and to identify conditions requiring detail analysis by doing frequency scan studies. Thereafter more detailed eigenvalue analysis studies were performed. The frequency scan studies have shown the following:

- The network impedances as seen from Tutuka, Majuba and Kendal are dominated by the large shunt loads near to these machines and they will not be affected by series compensation in transmission lines in the Cape Network.
- In the frequency range 34 Hz to 44 Hz where the Koeberg mechanical modes interact with the electrical system there is very little difference in the network reactance seen by Koeberg between the present network and the proposed new network.
- The network strengthening measures have affected the reactance seen by Koeberg mainly between 5 Hz and 30 Hz.
- 132kV line outages and shunt devices have very little effect on the network reactance seen by the Koeberg generators.
- Of the contingencies studied only two caused any appreciable change to the network reactance seen by Koeberg in the critical zone of 34 Hz to 44 Hz. These were Contingency 19, the outage of the Hydra-Kronos-Aries 400 kV line and Contingency 40, the outage of the Droerivier-Komsberg-Muldersvlei 400 kV line.

Eigenvalue results have shown that for the base case and all contingencies studied the electrical damping contribution is positive (corresponding to a negative real part of the eigenvalue) and there is thus no indication of any adverse SSR interaction.

4.1.4.8 RECOMMENDATIONS

While the eigenvalue studies have shown that there is not threat of SSR, there is some appreciable change to the network impedance as seen by Koeberg in the 34 Hz to 44 Hz zone for two of the studies contingencies. Due to the severe consequences of SSR, we recommend that it would be prudent to do some transient simulation studies for Contingencies 19 and 40 in order to confirm eigenvalue results.

4.1.4.9 REFERENCES

[4-1] G D Jennings, “Richards Bay Subsynchronous Resonance Study”, Study for Eskom Technology Group, Contract Number : 2TB 000706, Jan 1999.

[4-2] G D Jennings and R G Harley, "New index parameter for rapid evaluation of turbo-generator subsynchronous resonance susceptibility", Electric Power Systems Research Journal, Elsevier, Switzerland, Vol 37, 1996, pp 173-179.

4.1.5 *Steady-state stability (or Small Signal Stability) study*

The aim of this study case is the presentation of a general methodology, which can be adopted for Small Signal Stability studies, together with a detailed example of application to the South African Power Pool (SAPP). Investigation of system stability against small perturbations is of utmost importance when planning interconnections among systems as already pointed out in the example above described relevant to the AC interconnection between TESIS and UPS/IPS systems (see step 4 of the methodology). This section addresses specifically this dynamic phenomenon more in depth.

4.1.5.1 Methodology:

The methodology for undertaking Small Signal Stability studies can be summarised in the following steps:

- Develop appropriate network base case files (load flow and validated dynamics data) in the file format for use in the Power Systems Analysis Package (PSAPAC) Small Signal Stability Program (SSSP) format. The PSS/E base case files developed can be converted to the appropriate PSAPAC file format.
- Develop a list of credible contingencies for the network based on transient & voltage collapse results and the analysis of historical fault events.
- Perform an eigenvalue scan to identify and correct bad or suspicious data.
- Set up an initial small signal stability minimum damping criteria for local and inter-area modes.
- Perform pre-contingency eigenvalue scans on the base cases in order to:
    - Classify the types of oscillatory modes in terms of local, inter-area and control modes on the system.
    - Identify the troublesome modes on the system i.e. oscillatory modes, which do not meet the minimum damping criteria.
- Perform detailed eigenvalue analysis (eigenvectors, participation factors, and frequency responses) on the modes identified above.
- Verify the existence of the oscillatory mode by performing non-linear time domain studies at different operating conditions.
- Determine the cause of insufficient damping and correct the problem via:
    - Correcting bad or suspicious data
    - Determining generation or transmission transfer limits
    - Tuning of existing controllers, e.g., exciters, governors, PSSs or SVCs
    - Adding supplementary controllers such as PSS
    - Adding additional transmission equipment, e.g., lines or FACTS devices
- Verify the improvement in damping by running non-linear time domain studies for the solutions identified above.
- Repeat analysis for the post-contingency cases based on the credible contingency list.
- Review the minimum damping criteria to ensure that the small signal performance of the system is acceptable for future planning scenarios.

- Rank the solutions developed for the pre- and post-contingency cases based on the system damping improvement.

4.1.5.2 Interpretation of Results:

The results of a small signal stability study are generally analysed in two separate domains viz.

- Frequency domain where the system eigenvalues, eigenvectors, damping and participation factors are analysed.
- Time domain where standard time domain plots from a transient stability simulation are analysed.

The frequency of a mode of oscillation in a power system is dependant on the following:

- system strength, that is the number, size and loading of transmission lines (many high voltage lines that are lightly loaded is a strong system). The stronger the system the higher the natural frequency.
- generator inertia, based on its size and geometry. Hydro units have a larger inertia per MVA than a thermal unit. The larger the inertia, the lower the natural frequency.
- generator power output (real and reactive). The loading of the generator can be related to its power or torque angle (rotor angle). As the loading increases, the angle increases. The higher the angle, the lower the natural frequency.

The following classification of the various oscillation modes is also possible:

Local Problems:

- Local plant modes: where a single generator or plant oscillates against the rest of the system (from 0.7 to 2 Hz). These are the most common in modern power systems.
- Interplant or machine modes: where generators close to each oscillate against each other. The frequencies of the modes can be up to 3 Hz. These are usually well damped.

Global Problems:

- Inter-area modes: where a group of generators in one area oscillates against a group in another area. The system is clearly split via an interconnection. The frequencies range from 0.1 to 0.3 Hz.
- Intra-area modes: where sub-groups of generators in an area (that is meshed) oscillate against each other. The frequencies of the modes range from 0.4 to 0.7 Hz.

Results of the small signal analysis should be compared to the time domain results using Fourier or Prony analysis. This will allow the engineer to calculate the frequency content and damping of time-domain signals.

4.1.5.3 Typical ESKOM Case Studies

A global case study is presented which represents a realistic ESKOM/SAPP case with minor modifications. The following data is contained in the case:

- 1049 buses;
- 60 generators;
- 12 SVCs; and
- No HVDC Links.

The study objective of the small signal stability study is the following:

- Find low frequency oscillatory modes using PEALS eigenvalue SCAN MODE in SSSP.
- Compute detailed mode characteristics for the weakly damped modes.
- Apply a PSS to improve the damping of a local mode oscillation.

The following damping criteria have been adopted for the study:

- Local modes should have a minimum damping of 10%.
- Inter-area modes should have a minimum damping of 5%.

The following data files were developed for use in PSAPAC SSSP.

pf.raw	Powerflow data in PSS/e v23.4 format
dynamics.dat	Dynamic data in PSS/e format
exc.dat	Ruacana exciter data in PSAPAC format
udpss.dat	Kariba North PSS in PSAPAC format

<u>Step 1: An eigenvalue scan is firstly performed in SSSP to identify the low frequency modes</u>

- SSSP is used to scan modes between 0.2Hz and 1.0 Hz. This is the range where small signal stability problems are likely to occur.
- 6 modes exist in the system in this frequency range. They are shown below in Tab.4-22.

Mode #	Real Part of Eigenvalue	Imaginary Part of Eigenvalue	Frequency [Hz]	Damping [%]
1	-0.632	±1.470	0.235	39.3
2	-0.754	±2.104	0.339	33.7
3	**-0.123**	**±2.580**	**0.411**	**4.75**
4	-1.772	±3.680	0.586	43.4
5	**-0.048**	**±4.469**	**0.711**	**1.07**
6	**-0.119**	**±4.914**	**0.782**	**2.43**

Tab. 4-22. Case Study Eigenvalue Scan Results

Tab. 4-22 indicates that modes 3, 5 & 6 do not meet the minimum damping criteria.

Step 2: Compute the detailed mode characteristics for the weakly damped modes

- Focus on the three weakly damped modes at 0.41Hz, 0.71 Hz and 0.78Hz.
- Use PEALS circle mode of SSSP to compute the details of these modes.
- Examine the mode shapes & participation factors to understand these modes.

Mode 1: 0.41Hz

The mode shape (or right eigenvector) is firstly computed in SSSP PEALS to characterise the oscillation mode. The right eigenvector is shown graphically in Fig. 4-31 below.

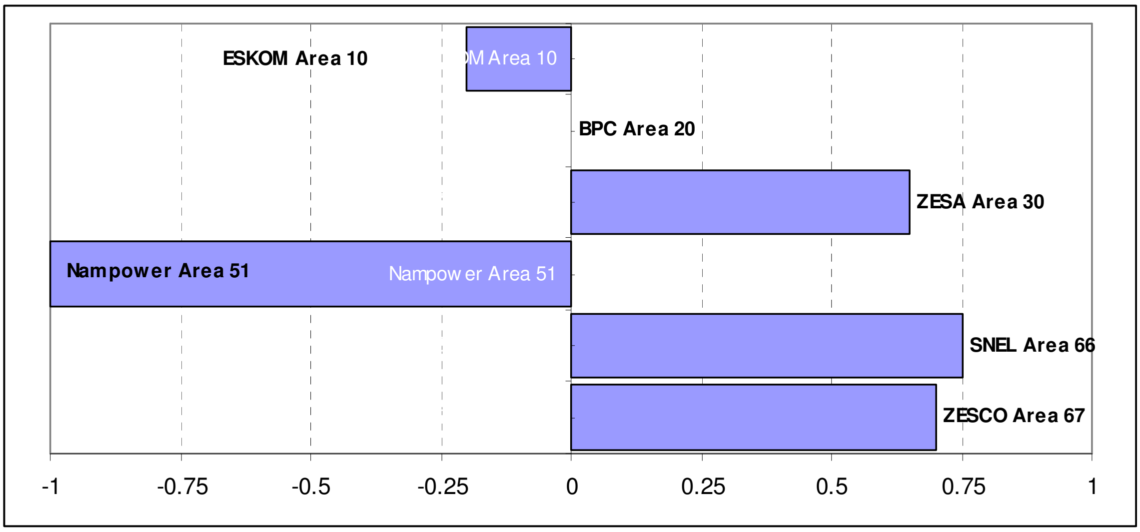


Fig. 4-31: Mode Shape for 0.41Hz Mode

The mode shape and frequency of oscillation indicates that it is an inter-area mode. It shows that the ZESA, ZESCO & SNEL control areas swing against the ESKOM & NAMPOWER control areas. The oscillation is weakly observable in the BPC control area.

The dominant participation factors are then calculated to determine the controllability of the mode. The results are shown in Fig. 4-32.

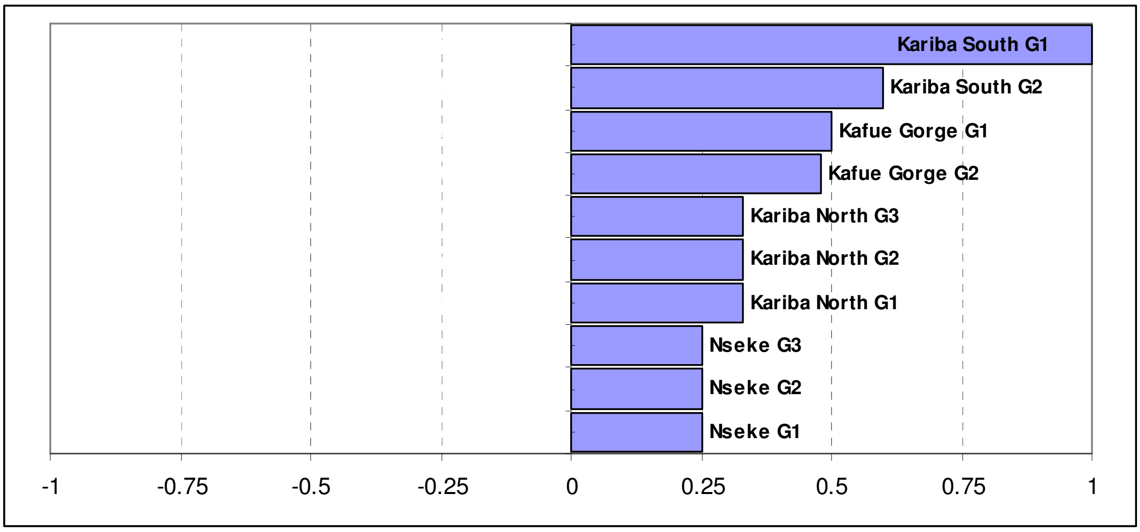


Fig. 4-32: Dominant Participation Factors for 0.41Hz Mode

Fig. 4-32 indicates that the inter-area mode can best be controlled at the Kariba South and Kafue Gorge Units in Areas 30 (ZESA) and 67 (ZESCO). The mode is not controllable in the ESKOM system. The mode shape is also shown graphically in Fig. 4-33 below:

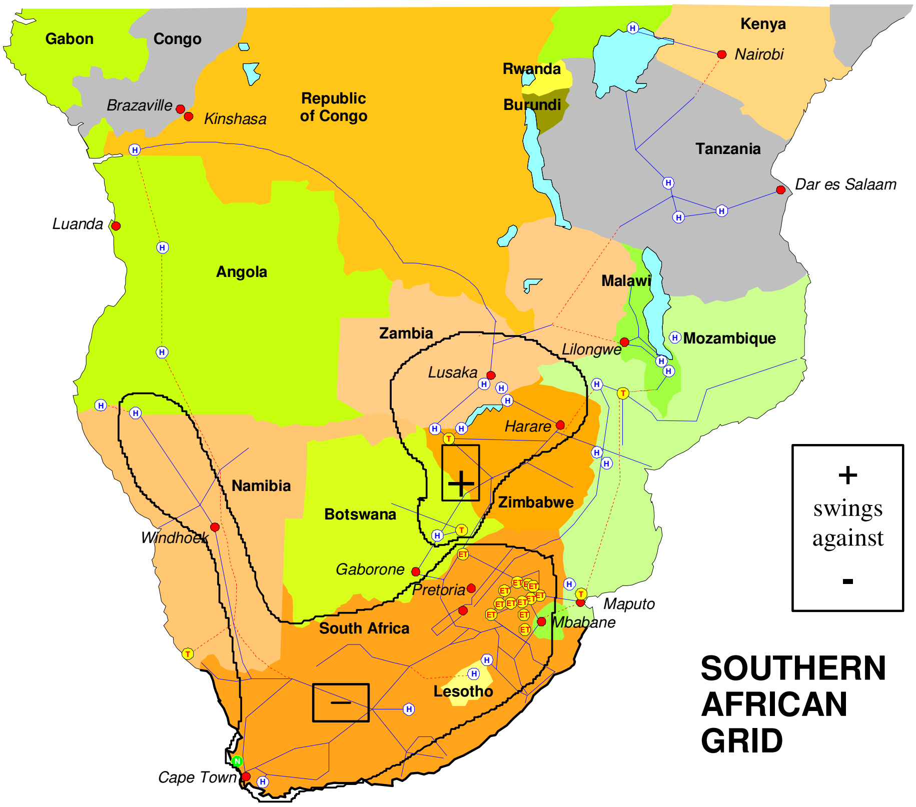


Fig. 4-33: Geographical Representation of the SAPP 0.41Hz Mode Shape

The above mode has been verified by measurements of tie-line oscillations on the Matimba - Insukamini 400kV interconnector.

Mode 2: 0.71Hz

The mode shape is firstly computed in SSSP PEALS and is shown in *Fig. 4-34*.

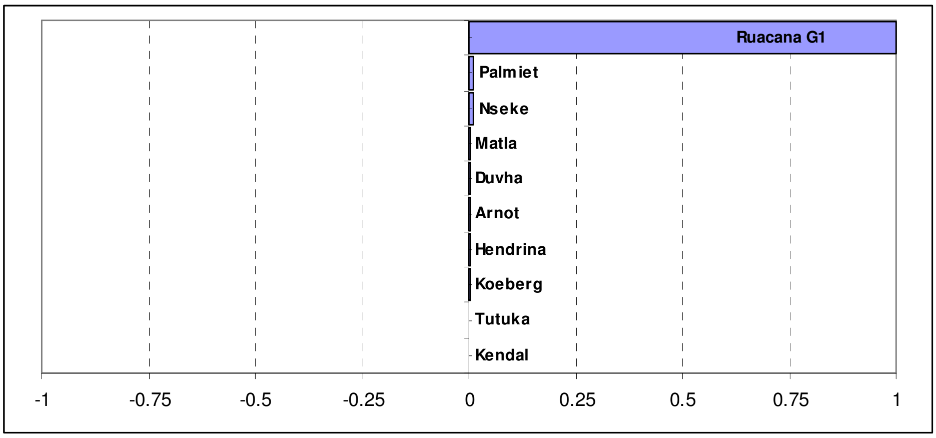


Fig. 4-34: Mode Shape for 0.71Hz Mode

The mode shape indicates that only the Ruacana units are swinging against the rest of the network (which is at standstill). The frequency and mode shape thus indicate that is a local mode.

Fig. 4-35 below shows the participation factors for the 0.71Hz mode.

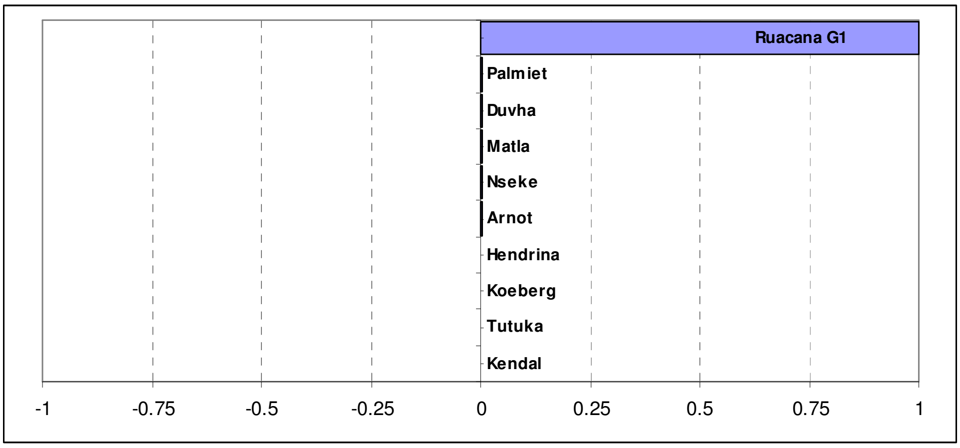


Fig. 4-35: Participation Factors for 0.71Hz Mode

Fig. 4-35 clearly indicates that the mode can only be controlled at the Ruacana power station. This can best be done with the application of a PSS.

Mode 3: 0.78Hz

The mode shape is firstly computed in SSSP PEALS and is shown in *Fig. 4-36*.

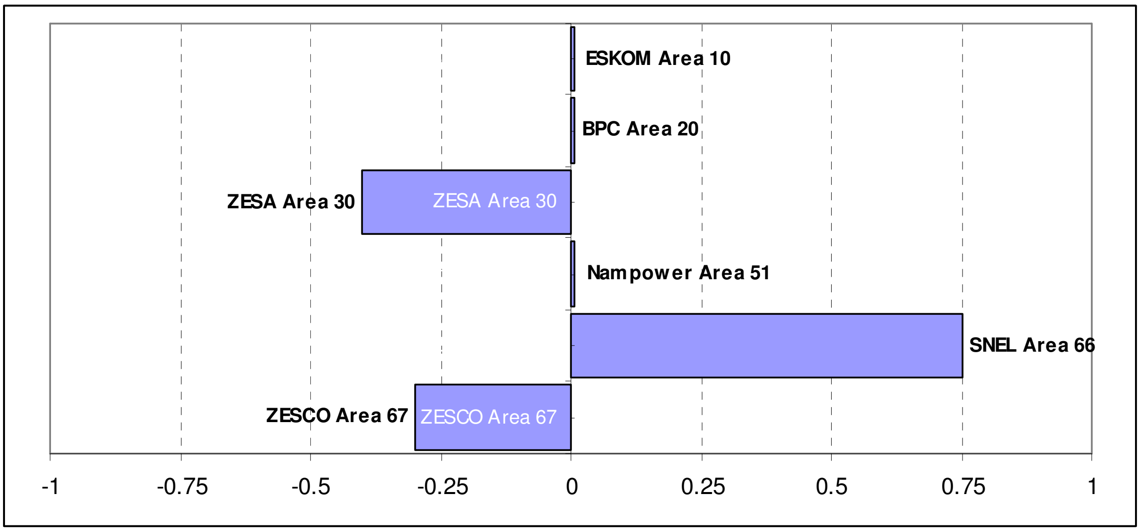


Fig. 4-36: Mode Shape for 0.78Hz Mode

The mode shape indicates that the SNEL control area swings against the ZESA and ZESCO control areas. The oscillation is not observable in the ESKOM, NAMPOWER and BPC control areas. This can be classified as an inter-area mode.

Fig. 4-37 below shows the participation factors for the 0.78Hz mode.

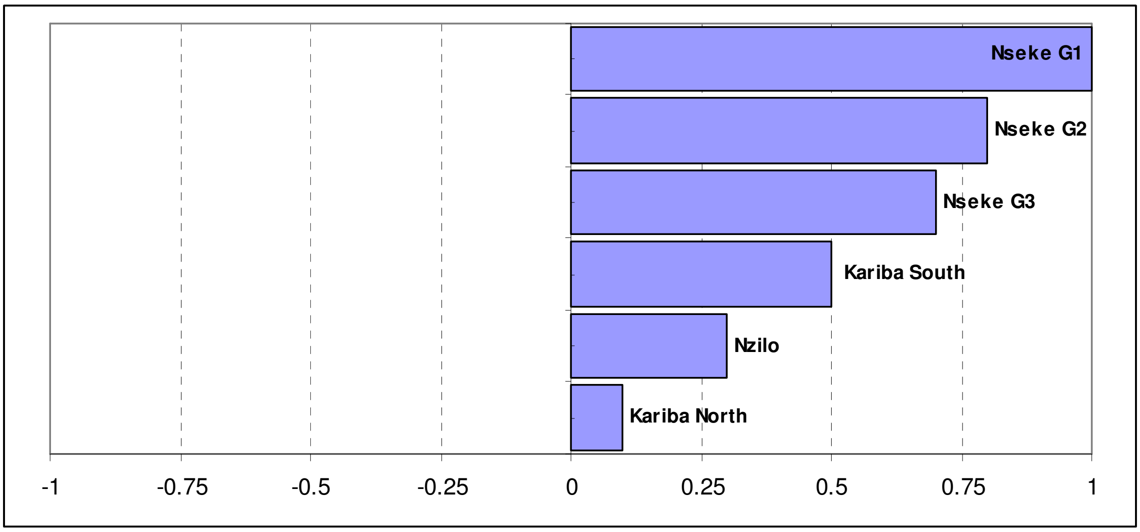


Fig. 4-37: Participation Factors for 0.78Hz Mode

Fig. 4-37 indicates the mode can be best controlled at the Nseke plant in the SNEL control area. The mode shape is shown geographically in Fig. 4-38.

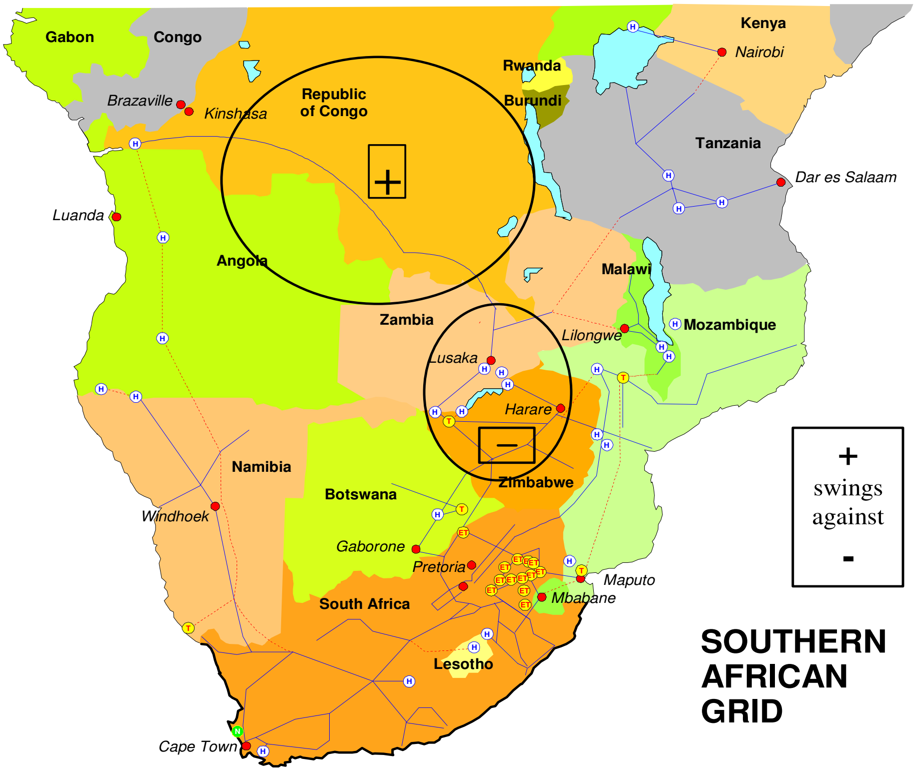


Fig. 4-38: Geographical Representation of the SAPP 0.41Hz Mode Shape

Step 3: Verify the existence of the mode by performing a frequency response from the machine voltage regulator summing junction input to generator speed and/or electrical power outputs

- The frequency response is calculated in SSSP PEALS for the Ruacana generator with the voltage regulator summing junction as the input and the generator speed and electrical power as the output.

The frequency response calculation for the Ruacana generator is shown in *Fig. 4-39*.

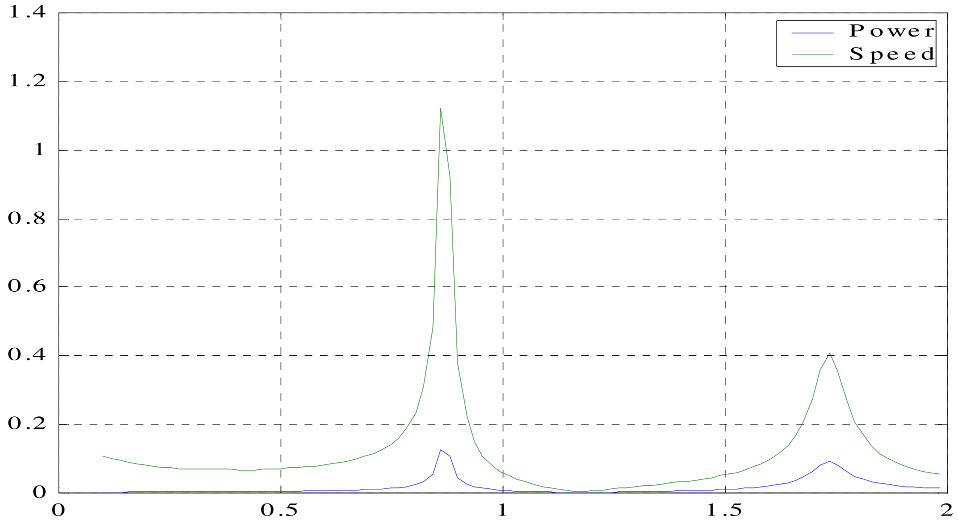


Fig. 4-39: Frequency Response for Ruacana Unit

The local mode at 0.71Hz is clearly evident. *Fig. 4-39* indicates that the 0.71Hz local mode is more observable in the rotor speed than in the electrical power. The rotor speed is thus a more suitable signal to use as the PSS input.

Step 4: Verify the existence of the mode by a non-linear time domain simulation in PSS/e Dynamics. The mode oscillation frequency should be observable in the generator electrical power and speed

- A time domain simulation is run to verify that the Ruacana oscillation frequency is present. The verification of the oscillation is shown in *Fig. 4-40*. Prony analysis can be utilised in PSSPLT to confirm the existence of a particular mode if multiple oscillation frequencies are present.

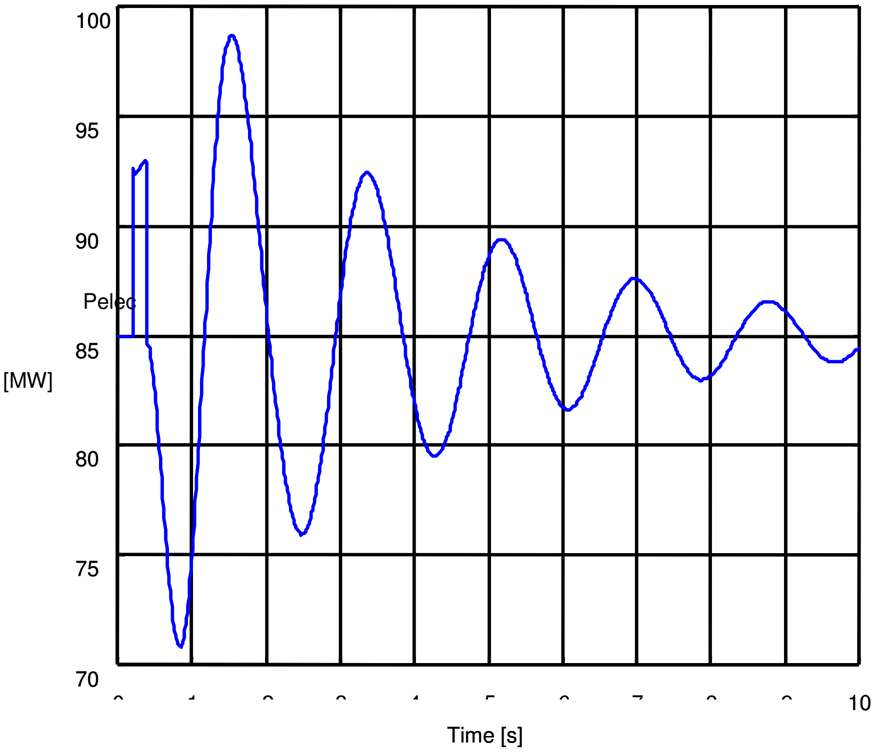


Fig. 4-40: Ruacana Electrical Power Response

Step 5: Correct the problem of insufficient damping by adding a supplementary control device such as a PSS.

- A simple speed based PSS was designed to improve the damping of the local mode oscillation.

Step 6: Verify the improvement in damping of the mode by a non-linear time domain simulation in PSS/e Dynamics. The improvement in damping should be observable in the generator electrical power and speed.

- A time domain simulation is run to verify that the application of a PSS will improve the mode damping. The verification of the improvement is shown in *Fig. 4-41*. Prony analysis can also be utilised in PSSPLT to confirm the mode damping has been improved.

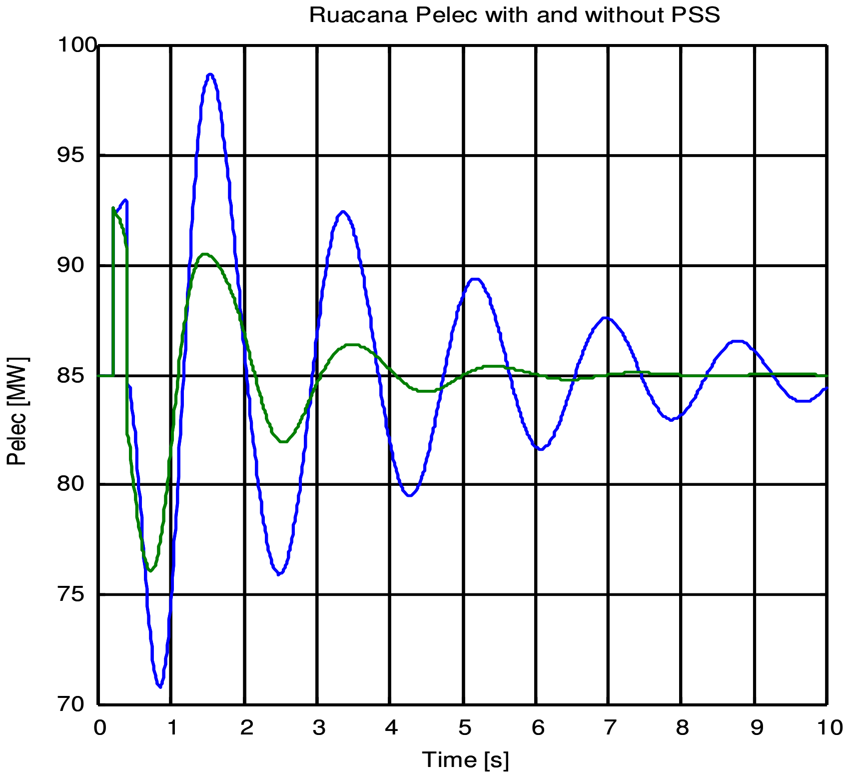


Fig. 4-41: Ruacana Electrical Power Response with and without PSS

Fig. 4-41 clearly indicates that a PSS has improved the damping of the local mode oscillation.

5 RECOMMENDATIONS FOR THE EXECUTION OF DYNAMIC ANALYSES

From the survey carried out by the WG members, it comes out that the planner is often discouraged from applying dynamic analyses because of the obstacles above recalled (see par. 3.6). Then, an appropriate methodology helping to facilitate the execution of dynamic studies has been defined. Main issues to be addressed are:

- ✓ How to discriminate dynamic phenomena triggered after the occurrence of a perturbation and in case of instability, how to detect the dominant phenomenon leading to instability (discrimination of dynamic phenomena);
- ✓ Which kind of models shall be adopted, according to the dynamic phenomena to be investigated (modelling).

5.1 Discrimination of different dynamic phenomena

5.1.1 Investigating system behaviour facing different dynamic phenomena

Modern power systems are characterised by a very large size spreading over large geographical areas. The trend of establishing new interconnections among formerly isolated systems and reinforcing the already existing interconnection corridors is going to increase the complexity of power systems. This tendency has been witnessed worldwide with a growing speed since the beginning of last decade [3], [4], [5], [6], [7], [8], [9], [10], [11], [12]. Consequently, it is becoming more and more complex the understanding of the dynamic behaviour of the overall power system facing disturbances. As a matter of fact, following a perturbation many different dynamic phenomena can be triggered, often overlapped each other, and it is up to the experience of the power system engineer discriminate the various phenomena and detect which is the most critical phenomenon for the system stability. Furthermore, when executing dynamic studies in planning stage, the planner shall be able to correctly anticipate the system behaviour accounting for the uncertainty in the future development of generation, demand and network. Lack of sufficiently accurate dynamic analyses, to be executed well in advance before the commissioning of the new infrastructure, can heavily jeopardise the expected revenue of the investment. E.g.: a generator may be forced to work with heavy limits with respect to its capability curve, a new interconnecting line may be forced to operate with very poor power flow limits to avoid interarea instability and, in some extreme cases, a new line may be kept switched off until adequate stabilising measures are undertaken[14].

The investigation of system stability is greatly facilitated by the classification of stability into categories [13]. The concept of stability of power system is related to the property of remaining in a state of operating equilibrium under normal operating conditions and to regain an acceptable state of equilibrium after having been subject to a disturbance [14]. As clearly highlighted in [15], the classification of power system stability is based on the following considerations [13]:

- "*the physical nature of the resulting mode of instability as indicated by the main system variable in which instability can be observed;*
- *the size of the disturbance considered, which influences the method of calculation and prediction of stability;*

---

[14] F.i.: the new interconnecting 220 kV lines between Tunisia and Libya, though erected since the year 2002, are not currently (year 2005) in operation, until the potential interarea instability problems are deeply investigated and, whenever necessary, appropriate measures are undertaken.

- *the devices, processes and the time span that must be taken into consideration in order to assess stability".*

A synthetic view of the classification of power system stability problem is provided in Fig. 5-1.

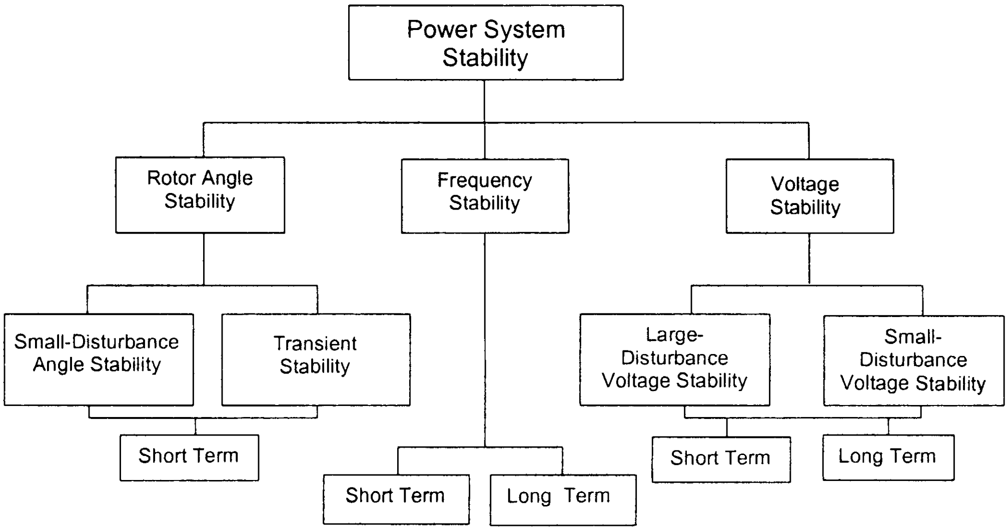


Fig. 5-1 Classification of Power System Stability [15]

5.1.2 Understanding the nature of transients

An important task, especially in case of very large interconnected systems, consists in detecting, monitoring and understanding the nature of possible very slow transients occurring in the systems. Severe transients may arise as consequence of contingencies determining some weaknesses in the system structure. In such cases, electromechanical oscillations at very long period can interact with the primary and sometimes also the secondary frequency controls, causing slow frequency variations and consequently slow voltage phase variations. The slow voltage drops observable during the transients can be identified either as incipient voltage collapse or evolution of angle instability.

An exact understanding of the nature of this critical phenomenon is very important in order to adopt the most suitable countermeasures both in planning and in operation stage. These measures consist usually in the adoption of operation rules in conjunction with possible automatic control actions to guarantee the system security and alleviate emergency situations.

The difficult task of discriminating between angle instability and voltage instability may be accomplished by resorting to time simulation functions able to switch from a description of the system through a complete model taking into account simultaneously all the dynamics, fast and slow, and a simulation function utilising a reduced model neglecting the electromechanical transients [38]. The model reduction is achieved by considering only one speed for all the machines of connected areas. Through this technique it is possible to separate, in case of slow dynamics, the transient angle instabilities from the voltage instabilities leading eventually to the voltage collapse.

More precisely, the criterion suggested is to pass from the STD (short term dynamics) simulation to the LTD (long term dynamic simulation), as the last one takes into account only mean frequency transients, neglecting loss of synchronism among machines (Fig. 5-2). If a post-contingency equilibrium point is found, taking into account only the slow dynamics, possible instabilities are to re-conduct to transient angle instabilities.

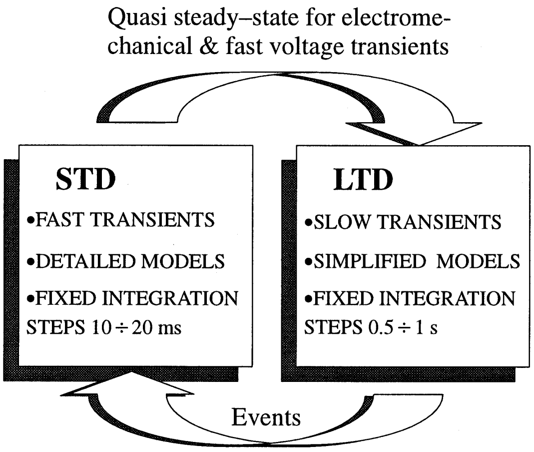


Fig. 5-2 – Short Term and Long Term simulation modes to detect different causes of system instability [1]

5.2 Modelling

For the execution of dynamic analyses, models shall fit with the phenomena to be investigated; consequently, different models shall be set up in the computational tools having different level of approximations. E.g.: investigation of the rotor angle stability facing large disturbances, i.e. a classical transient stability problem, requires time simulations covering an interval of few seconds. Then, an accurate modelling of the rotor e.m.f.s, AVRs and speed governors is essential, while slow dynamics loops (e.g.: secondary field current limiting circuit, boiler dynamics, supply systems dynamics, etc.) may be disregarded. In general, for the identification of the best control strategy and settings for the new installations, a modelling based on a "*two-stage procedure*" can be adopted:

3. **Use of reference models** to identify "*minimum technical requirements*" to cope with the so-called "*credible contingencies*" and outline the emergency actions to be triggered at the occurrence of "*extreme contingencies*";
4. **Use of complete dynamic models** in compliance with the available data (e.g.: for alternators, the dynamic order chosen is the maximum possible order, compatible with the available data set).

As an example, for the modelling of frequency control and supply systems, the general block scheme, valid both for thermal and hydro units, shown in Fig. 5-3 can be adopted, where:

- $k = 20$ p.u./p.u.; $T2 = 3s$; $T1 = 10s$ for steam and hydro units;
- $k = 20$ p.u./p.u.; $T2 = 0s$; $T1 = 0.45s$ for turbogas units.

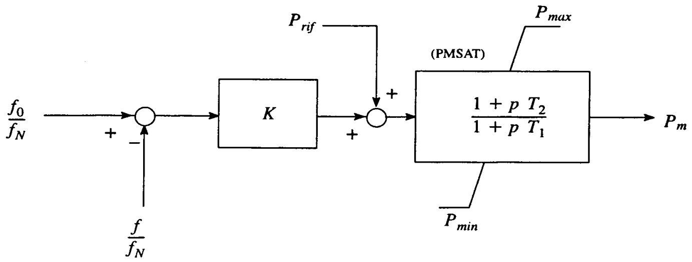


Fig. 5-3 – General block diagram for frequency control

A comprehensive transfer function of "canonical" type as simple as that shown in Fig. 5-3 can efficiently replace a complete model like that shown in Fig. 5-4, related to modelling of a thermal unit with oleodynamic turbine regulator.

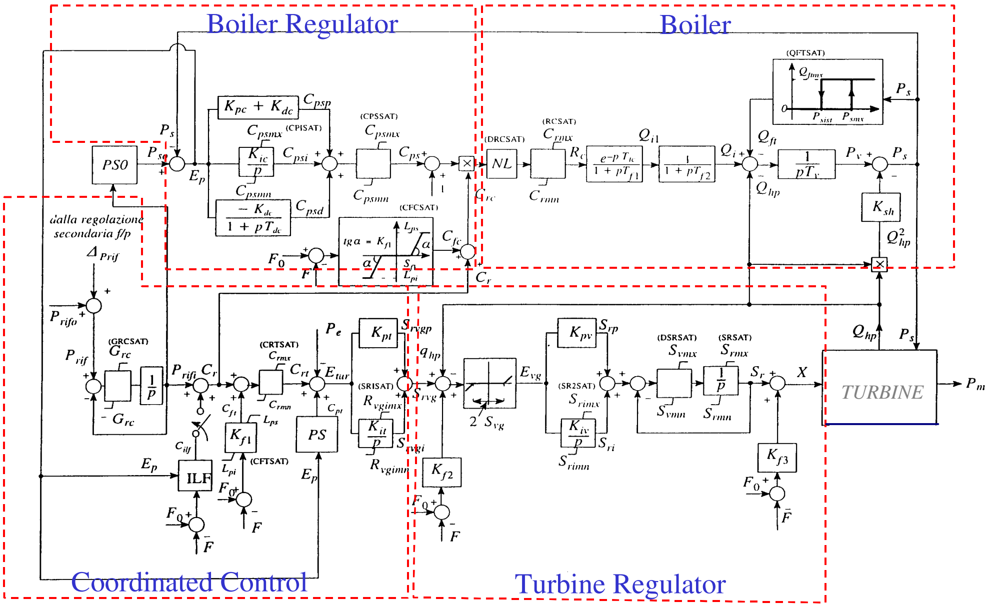


Fig. 5-4 –Block diagram for frequency control and supply system of thermal unit with oleodynamic turbine regulator [1]

Similarly, for aerogenerators one can start from a general model as shown in Fig. 5-5 and Tab. 5-1, which includes the description of the various components such as:

1) the aerodynamic rotor model,
2) the blade-angle control (pitch or active-stall), if any,
3) the shaft system model,
4) the converter model and control, if any,
5) wind speed,

and which is valid for each type of turbine (fixed-speed wind turbine, wind turbine with variable-slip generators, variable-speed wind turbines). Then, further simplifications are introduced according to the analyses under examination. E.g.: in transient stability studies, wind speed variations are not relevant; hence, in such studies one may assume a constant wind speed. On the contrary, the blade pitch angle control and the speed control may have an impact on the machine stability (similarly to fast valving impact on thermal power plant stability) and should not be neglected.

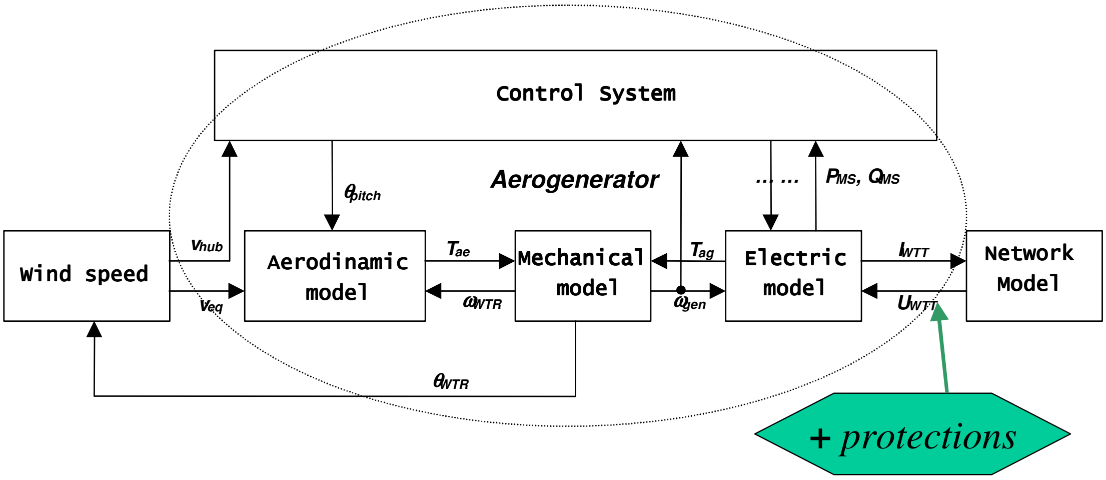


Fig. 5-5 –General model of an aerogenerator with related control systems.

Symbol	Meaning
v_{hub}	Wind speed (*hub*)
v_{eq}	Equivalent wind speed
V	Wind speed
θ_{WTR}	Wind Turbine Rotor angle
ω_{WTR}	Wind Turbine Rotor speed
θ_{pitch}	Blade Pitch angle
T_{ae}	Aerodynamic torque
T_e	Electrical Torque
ω_{gen}	Generator speed
P_{MS}	Active power (*Main Switch*)
Q_{MS}	Reactive power supplied to the grid
U_{WTT}	Voltage at Wind Turbine Terminals
I_{WTT}	Machine current

Tab. 5-1 List of symbols used in Fig. 5-5

- Also the load modelling can be quite easily solved in a first stage analysis, by adopting a canonical formulation, which turns out to be accurate in a wide number of situations (see sect. 6.5).

The following chapter addresses more in detail modelling issues for specific generator and network components according to the priority and needs identified in the survey among the planner responsible.

When examining the system behaviour with the use of complete dynamic models (step 2 of the methodology), it is worth mentioning that the tuning of the dynamic models for the existing components and control systems can be successfully obtained through a close interaction with the operational department, which it is expected to have validated models by means of on-the-field tests or reconstructions of events.

6 MODELS

Modelling of the composite “generation-transmission” system is already presented and discussed in many documents available in the scientific literature. On the basis of the outcomes of the survey carried out in the first part of the work, the WG activity addressed the modelling of new forms of generation and network equipment electronically controlled.

More in detail, the technical report includes the following sections:

- reference models for wind farms;
- reference models for gas turbines;
- network equipment electronically controlled;
- load models.

6.1 Reference models for wind farms: the Danish experience

This section addresses reference models of wind farms taken from the Danish experience and, in particular, from the experience of ELTRA who has a solid background on dynamic modelling of electricity-producing wind turbines. The *Danish TSO focuses first and foremost on modelling of induction generator based wind turbines*. Among such concepts are:

1) Fixed-speed wind turbines equipped with conventional induction generators [25]. Fixed-speed wind turbines can be either fixed-pitch or with active-stall control. These wind turbines operate at an almost fixed slip that is in the range of 2% in rated operation. The induction generators do not control the reactive power, but they are magnetised from the power grid. In other words, they do absorb the reactive power from the grid to produce and supply the active power to the power grid. Then, they are normally reactive power compensated with the use of capacitor banks.

2) Pitch-controlled wind turbines with variable-slip induction generators [31]. The control of variable-slip induction generators is arranged with the use of a power electronics converter connected in series to the rotor circuit. Operation of the power electronics converter corresponds to addition of an external rotor resistance to the rotor circuit impedance. The switching frequency of the power electronics converter switches is relatively large and allows almost continuous control of the external rotor resistance. The external rotor resistance can be varied in the range from zero to the maximum value allowing the slip variation in the range up to 10% in rated operation. The variable-slip induction generators absorb reactive power from the grid for magnetisation and this is reactive compensated with the use of capacitor banks.

3) Variable-speed, pitch-controlled wind turbines equipped with doubly-fed induction generators (DFIG) and frequency converters [32]. The frequency converter of the DFIG is a back-to-back, AC/DC/AC converter providing connection between the rotor circuit and the power grid. In this way, the rotor circuit exchanges the active power with the power grid. The frequency converter contains the rotor voltage-sourced converter (VSC) and the grid-side VSC connected through a DC-link. The rotor VSC control is arranged with independent

control of the active power and the reactive power. Then, the DFIG is magnetised from the rotor circuit with the use of the rotor VSC. The DFIG can be either reactive neutral or set to control the reactive power exchange with the grid within a given range. The active power of the DFIG is optimised with the use of variable-speed operation of the rotor. The generator rotor speed is controlled by the rotor voltage-source induced by the rotor VSC. The generator rotor speed is in the range from -50% to +15% with regard to the synchronous speed (zero-slip with regard to the electrical grid frequency). The grid-side VSC control is arranged with independent control of the DC-link voltage and the reactive current of the VSC. Normally, the reactive current of the grid-side VSC is set at zero.

For each type of turbine (fixed-speed wind turbine, wind turbine with variable-slip generators, variable-speed wind turbines) a general model (Fig. 6-1) is provided together with the description of the various components such as:

1) The aerodynamic rotor model.
2) The blade-angle control (pitch or active-stall), if any.
3) The shaft system model.
4) The converter model and control, if any.

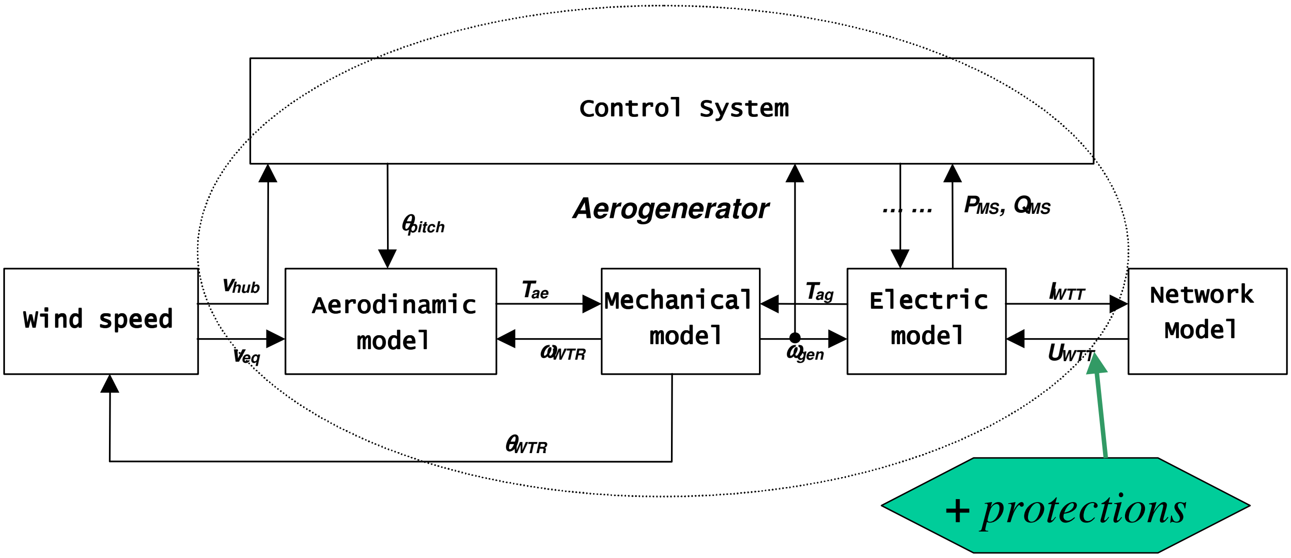


Fig. 6-1 – General model of a wind generator

6.1.1 Reference models for wind farms

In the following sections the dynamic modelling of the most common wind generators in use in Denmark are presented. They refer to:

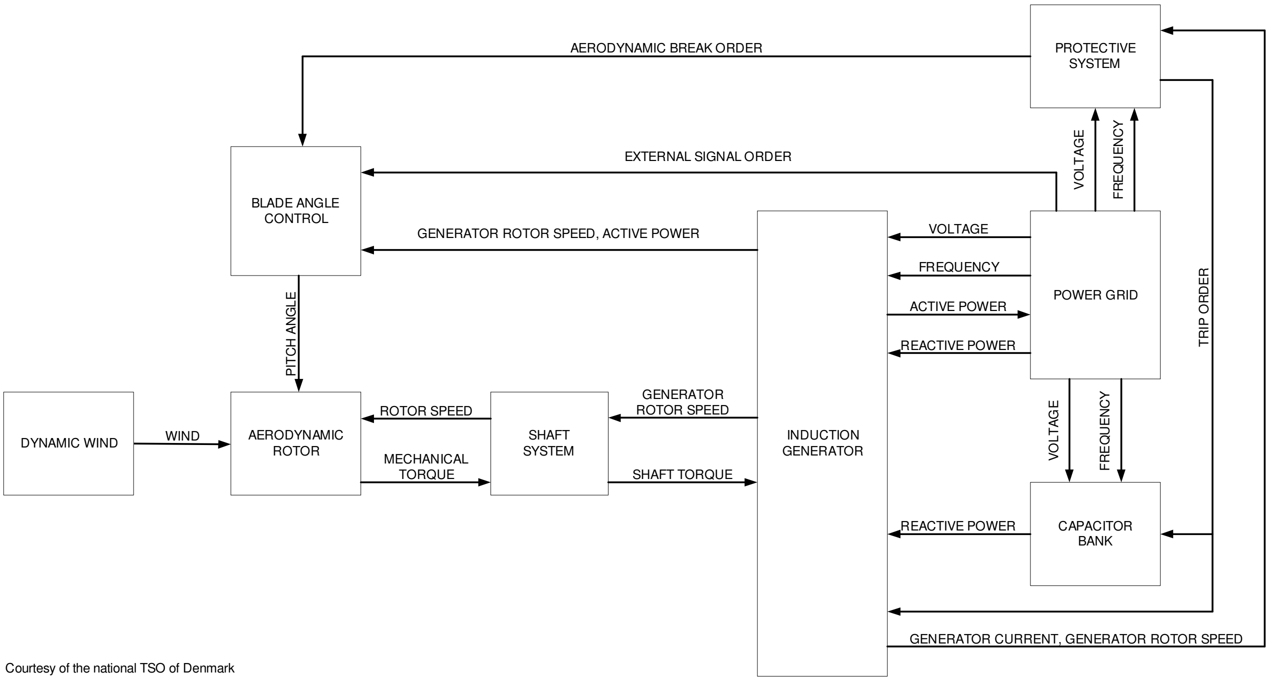
1) Fixed-speed wind turbines equipped with conventional induction generators;

2) Pitch-controlled wind turbines with variable-slip induction generators;

3) Variable-speed, pitch-controlled wind turbines equipped with doubly-fed induction generators (DFIG) and frequency converters.

6.1.1.1 Fixed-speed wind turbines

The generic model of fixed-speed wind turbines equipped with induction generators with short-circuited rotor circuit is given in Fig. 6-2.



Courtesy of the national TSO of Denmark

Fig. 6-2: Generic model of fixed-speed wind turbines with representation of all the necessary components.

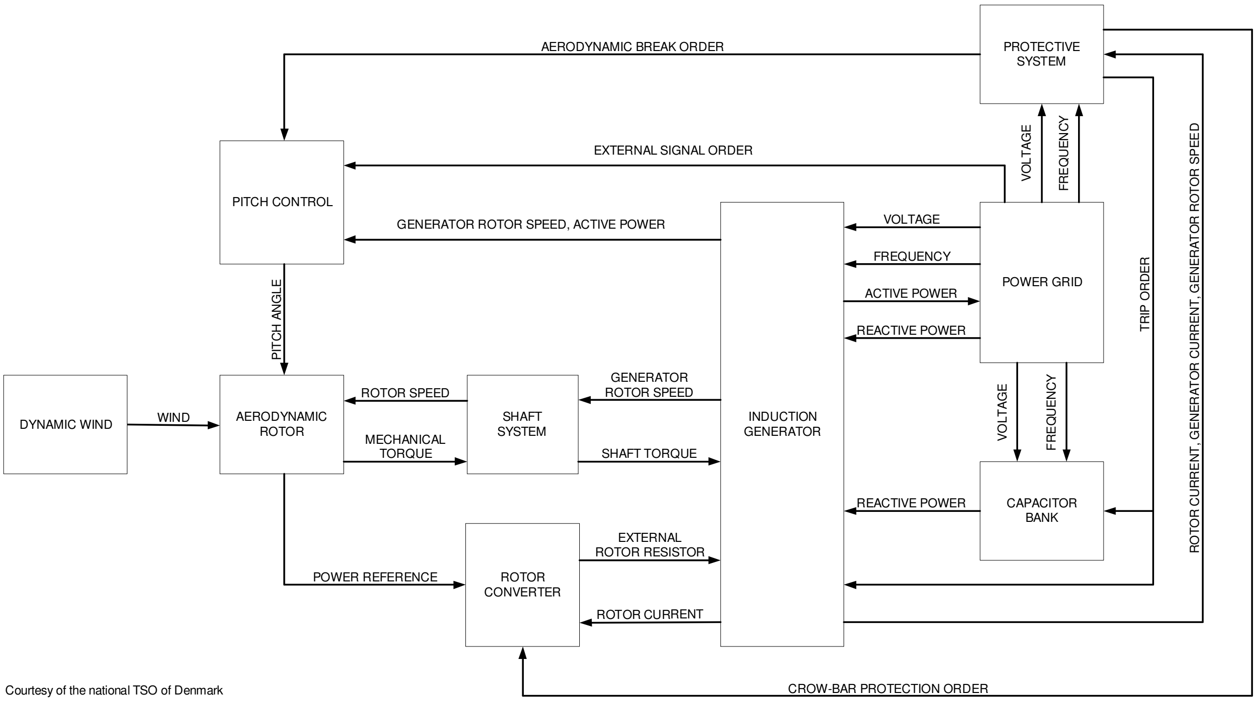
The generic model of fixed-speed wind turbines consists of components such as:

1) The dynamic wind model (if any wind fluctuations are required in the investigations);
2) The aerodynamic rotor model;
3) The shaft system model;
4) The induction generator model and its capacitor bank model;
5) The protective system model;
6) The blade-angle control (active-stall control), if any;
7) The external power system that may order the ancillary services from the wind farm if, required;
8) Reactive compensation.

This concept is applied in the Danish offshore wind farm at Rødsand/Nysted with the rated power capacity of 165 MW.

6.1.1.2 Wind turbines with variable-slip generators

The generic model of pitch-controlled wind turbines equipped with variable-slip generators is presented in Fig. 6-3. This model contains the rotor converter representation where the rotor converter is connected in series to the rotor circuit of the generator. The converter interface operates as the external rotor resistance continuously regulated by the rotor converter control.



Courtesy of the national TSO of Denmark

Fig. 6-3 -: Generic model of pitch-controlled wind turbines with variable-slip generators with representation of all the necessary components.

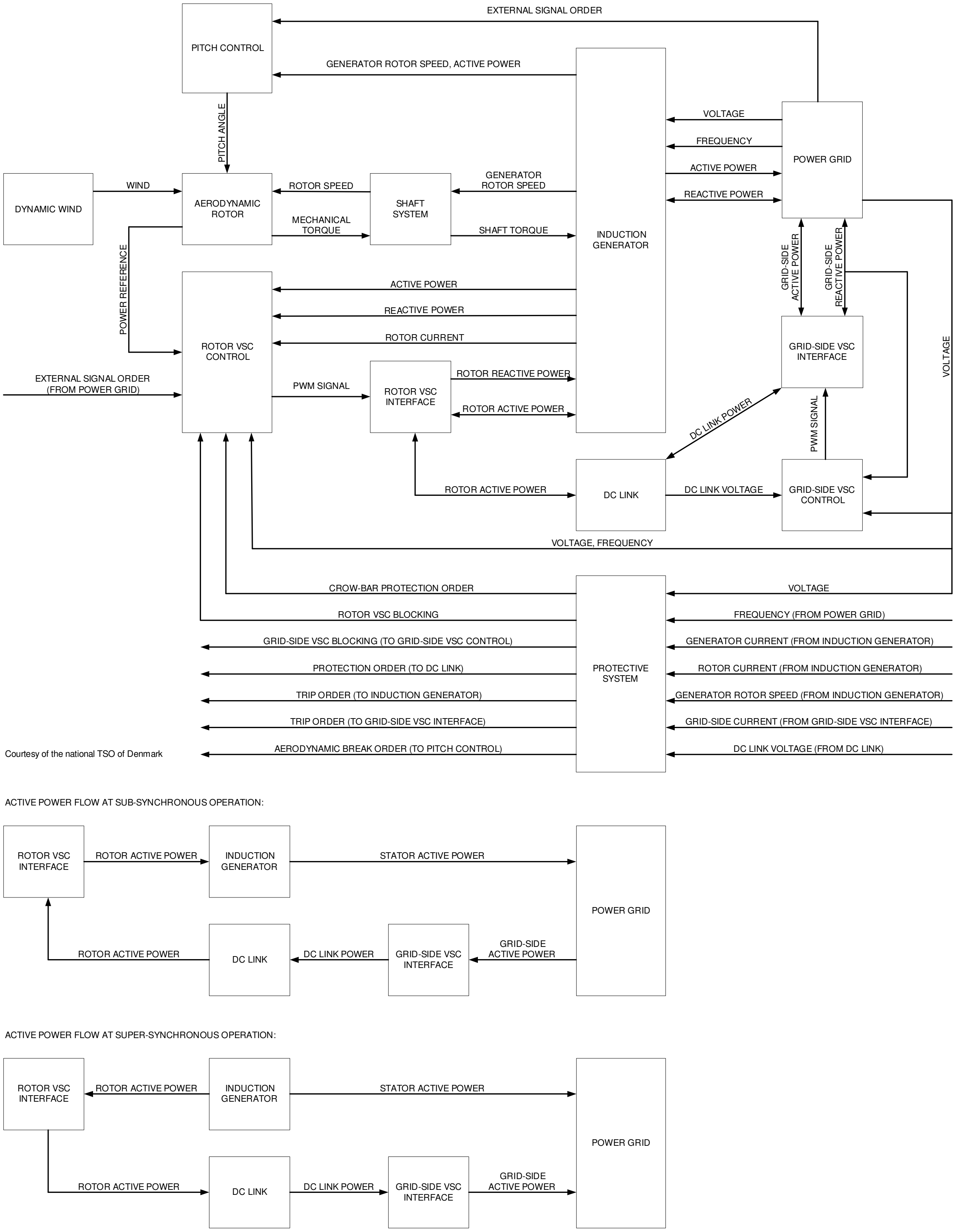
The generic model of pitch controlled wind turbines with variable-slip generators contains the components such as:

1) The dynamic wind model (if any wind fluctuations are required in the investigations).
2) The aerodynamic rotor model.
3) The shaft system model.
4) The induction generator model and its capacitor bank model. The rotor circuit is with an external rotor resistance adjusted by the rotor converter.
5) The rotor converter model, including the interface and the control.
6) The protective system model with the use of the crowbar protection when required.
7) The pitch control.
8) The external power system that may order the ancillary services from the wind farm, if required.

When the dynamic control of the external rotor resistance is not relevant for the target of the investigations, the variable-slip generator can be modelled as a conventional induction generator with enlarged rotor resistance. The value of the rotor resistance is enlarged to get a reasonable slip value of the generator in normal operation.

6.1.1.3 Variable-speed wind turbines

Fig. 6-4 presents the generic model of variable-speed, pitch-controlled wind turbines equipped with doubly-fed induction generators (DFIG) and partial-load frequency converters.



Courtesy of the national TSO of Denmark

Fig. 6-4: Generic model of variable-speed, pitch-controlled wind turbines with doubly-fed induction generators with representation of all the necessary components. The power flow in the doubly-fed induction generator is shown according to the generator rotor speed.

The generic model of variable-speed, pitch controlled wind turbines equipped with DFIG and partial-load frequency converters contains the following components:

1) The dynamic wind model (if any wind fluctuations are required in the investigations).
2) The aerodynamic rotor model.
3) The shaft system model.
4) The induction generator model with accessible rotor circuit. In the rotor circuit, the rotor VSC induces and controls the rotor voltage of a given magnitude and a given phase angle.
5) The rotor VSC model, including the interface and the control.
6) The grid-side VSC model, including the interface and the control.
7) The DC link model.
8) The protective system model with the use of the crowbar protection when required.
9) The pitch control.
10) The external power system that may order the ancillary services from the wind farm, if required.

This concept is applied in the Danish offshore wind farm at Horns Rev with the rated power capacity of 160 MW.

6.1.1.4 Components of dynamic wind turbine models

Though the wind turbine concepts seem to be very different to each other, there are components in the wind turbine construction that can be represented in a general way.

The most known and well-described component of the electricity-producing wind turbines is naturally the induction generator. The induction generator models may be of different order, but usually either the transient fifth-order model or the reduced third-order model is applied. Such induction generator models are recently the text-book stuff and the part of all the existing simulation tools applied for investigations of power system stability.

On the other hand, the aerodynamics of the rotor, the mechanical shaft system and the wind turbine control are relatively new issues within the electrical power supply. Therefore, this presentation focuses on the general description of the components below:

1) The aerodynamic rotor model.
2) The blade-angle control (pitch or active-stall), if any.
3) The shaft system model.
4) The converter model and control, if any.

This description must provide the common relations applied for implementation of such models into the existing simulation tools and for computations together with the given dynamic models of induction generators.

6.1.1.4.1 Aerodynamic rotor model

The three-bladed rotor converts the wind power, P_W, into the mechanical torque of the low-speed shaft, T_M. In the aerodynamic rotor model, the computation of the mechanical torque, T_M, from the incoming wind, W, is made with the use of the $C_P(\lambda,\beta)$ characteristics according to:

$$\begin{aligned} T_M &= \frac{P_M}{\omega_M}, \\ P_M &= P_W \cdot C_P(\lambda, \beta), \\ P_W &= \frac{1}{2} \cdot \rho_{AIR} \cdot \pi R^2 \cdot W^3. \end{aligned} \tag{4.1}$$

Here P_M denotes the mechanical power and ω_M is the speed of the rotor, C_P denotes the power coefficient of the rotor, λ is the tip-speed ratio, β is the pitch angle of the blades, ρ_{AIR} is the standardised air density and R is the rotor radius. The $C_P(\lambda,\beta)$ characteristics of the rotor may be received from the wind turbine manufacturer. The tip-speed ratio is defined as:

$$\lambda = \frac{\omega_M \cdot R}{W}. \tag{4.2}$$

The pitch angle, β, is dynamically adjusted by the pitch or the active-stall control system of the rotor. When the wind turbines are fixed-pitch, the pitch angle does not change during dynamic operation of the rotor. Then, there will only be a single $C_P(\lambda)$ characteristic of the rotor representing the rotor aerodynamics.

The use of the $C_P(\lambda,\beta)$ characteristics corresponds to representing the aerodynamic rotor in equilibrium at any time. The use of the $C_P(\lambda,\beta)$ characteristics predicts the mechanical torque of the rotor, T_M, without loss of accuracy in the case of the active-stall control and in the case of the pitch control with relatively slow changes of the pitch angle [33].

In the case of the pitch control with relatively fast changes of the pitch angle, there are notable overshoots in the physical behaviour of the mechanical torque caused by transition between the states of equilibrium for the rotor. In this case, the use of the $C_P(\lambda,\beta)$ characteristics does not predict accurate behaviour of the mechanical torque of the rotor, T_M, [33].

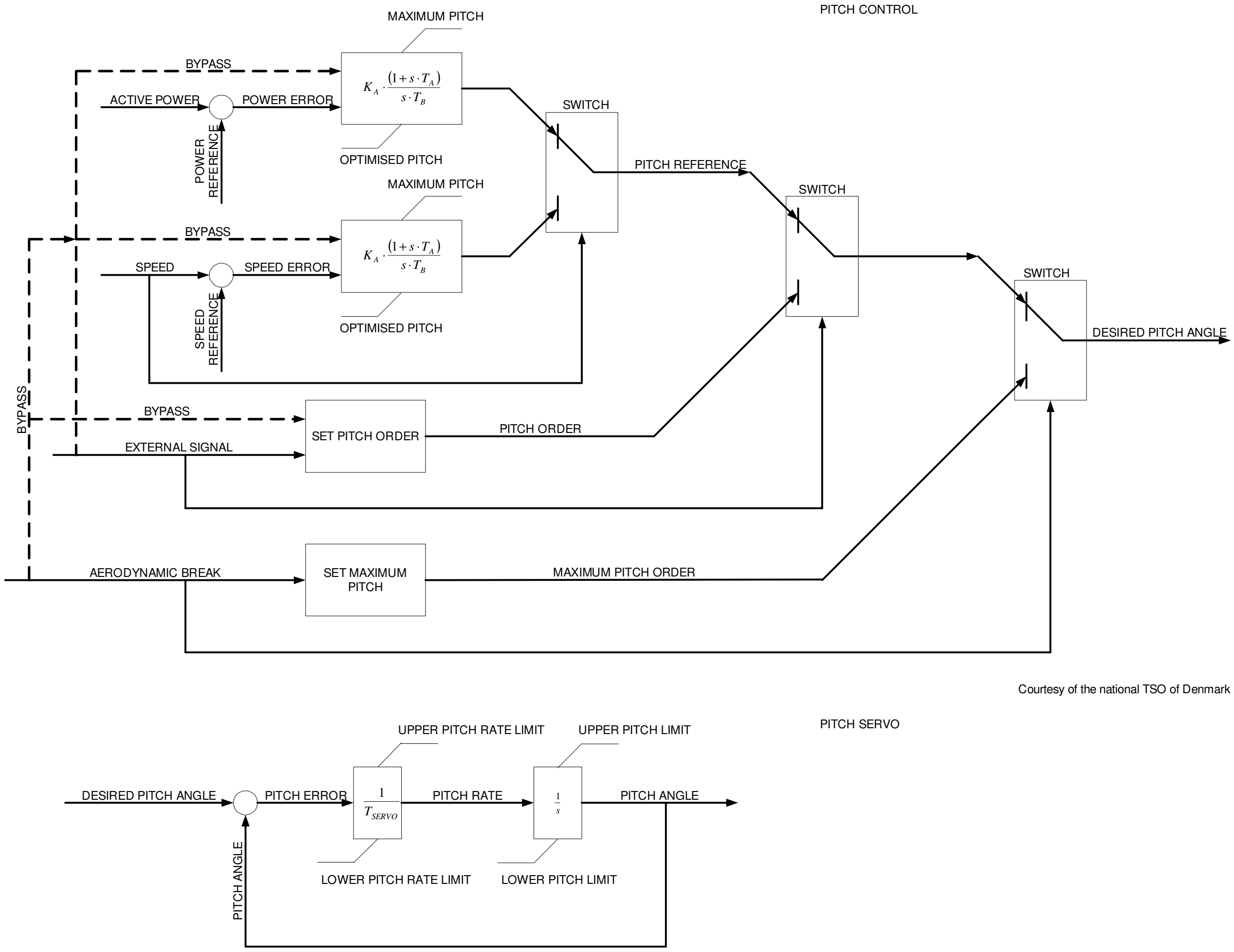
6.1.1.4.2 Blade-angle control model

The blade-angle control has two general targets. When the wind speed is below the rated wind, the blade-angle control is set to optimise the mechanical power of the rotor. When the wind speed is above the rated wind, the blade-angle control is applied to keep the rotor in the rated operation.

Usually, the fixed-speed wind turbines are equipped with active-stall control or fixed-pitched. The active-stall control implies that the pitch angle, β, is controlled in the negative range of the pitch angles. In this control mode, the blade is turned to increase the angle of attack so stall occurs. When stall occurs, the shaft power, P_M, is reduced.

The variable-speed wind turbines are equipped with pitch control. The pitch control implies that the pitch angle is controlled in the positive range of the pitch angles. The blade angle is turned to decrease the angle of attack so the shaft power, P_M, is reduced.

The generic model of the blade-angle control is present in Fig. 6-5, in the case of the pitch control. The control system itself consists of the regular control that is set to keep the desired active power, P_E, according to the power reference, P_{REF}, set by the incoming wind, W. The regular control must also prevent excessive overspeeding. When the generator rotor speed exceeds a given limit, the control mode is changed to control the generator rotor speed, ω_G. The regular control is arranged as a simple proportional-integral controller [33].



Courtesy of the national TSO of Denmark

Fig. 6-5: Generic model of the pitch control and the pitch servo.

The regular control can be disabled and the blade-angle control can be controlled by a signal from the external system. This control mode may be present for the large wind farm according to the specific requirements of the national Grid Code. For example, the national Grid Code may require that the mechanical power of the large wind farm is reduced to 20% of the rated power in less than 2 seconds. The order given by the external system can be cancelled. Then, the regular control is restarted.

Another option of the use of this control is participation of the large wind farm to control the grid frequency with the use of the blade-angle control. In this case, the external signal contains the grid frequency deviation and the blade-angle control must then adjust the pitch angle to minimise this frequency deviation. This control is applicable to minimise the positive as well as the negative frequency deviations in strong wind, e.g. when the wind turbines can produce more power than their factual operational point. When the wind turbines are in optimised operation, only the positive frequency deviations (the factual grid frequency exceeds the desired grid frequency) can be minimised.

The blade-angle control is also applied to aerodynamic break of the rotor. This function must stop the wind turbine when tripped from the grid. Once given, the order to stop cannot be cancelled.

6.1.1.4.3 Shaft system model

The shaft system of the wind turbines equipped with induction generators consists of the low-speed shaft of the rotor and the high-speed shaft of the generator rotor coupled together through the gearbox. Obviously, this is a two-speed system with a slowly rotating rotor and a rapidly rotating generator rotor. In modern wind turbines, the rated rotor speed, ω_M, may be in the range of 15 rev./min., whereas the rated generator rotor speed, ω_R, may be 1500 rev./min. for the generator with 2 pole-pairs (N_{PP}) connected to the power grid with the fixed frequency of 50 Hz. The gearbox ratio, N_{GB}, is then 100 and the total ratio between the rotor speed, ω_M, and the electrical system speed, ω_E, becomes $N_{GB} \cdot N_{PP} = 200$.

This implies that the coupling between the rotor and the generator becomes soft [25]. As explained in Ref. [25], the term of the soft coupling implies that the shaft torsion oscillations may be distributed to the electromagnetic field of the induction generator. The electromagnetic field of the induction generator may therefore show oscillating behaviour with a notable magnitude and a frequency that is the natural frequency of the shaft torsion oscillations. In other words, the shaft torsion oscillations become present in all the electrical parameters of the induction generator such as the active and the reactive power, the grid voltage, the generator rotor speed, etc.

Such shaft torsion oscillations are the phenomenon of electromechanical interaction between the wind turbines and the power grid. The typical range of the natural frequencies of the shaft torsion oscillations is a few Hz that is close to the natural frequencies of conventional power plants and other power equipment and control of the grid.

Specifically for the fixed-speed wind turbines equipped with induction generators [25], the shaft torsion oscillations and the oscillations of the electromagnetic field lead to more acceleration of the generator rotor, more absorption of the reactive power and then slower voltage re-establishment.

Therefore the model of the shaft system of grid-connected wind turbines must represent such shaft torsion oscillations excited by the grid faults. Since the model is applied in investigations of power system stability, all the parameters of the shaft system model must be written and parameterised with regard to the rated electrical system speed. The shaft system model is essentially the two-mass model [25] according to:

$$\begin{bmatrix} 2H_M & 2H_G & \omega_0 \end{bmatrix} \cdot \frac{d}{dt} \begin{bmatrix} \omega_M \\ \omega_G \\ \theta_S \end{bmatrix} = \begin{bmatrix} -D_M & 0 & -K_S \\ 0 & -D_G & K_S \\ 1 & -1 & 0 \end{bmatrix} \cdot \begin{bmatrix} \omega_M \\ \omega_G \\ \theta_S \end{bmatrix} + \begin{bmatrix} T_M \\ -T_E \\ 0 \end{bmatrix}. \qquad (4.3)$$

In the state equation system (4.3), H_M and H_G are the inertia constants of the rotor, respectively, of the generator rotor in seconds, K_S is the shaft system stiffness in p.u./el.rad., ω_0 is the rated electrical system speed that is the rated frequency multiplied by 2π, ω_M and ω_G are the rotor speed and the generator rotor speed in p.u. with regard to the rated electrical system speed, respectively, and θ_S is the shaft torsion twist in el.rad.

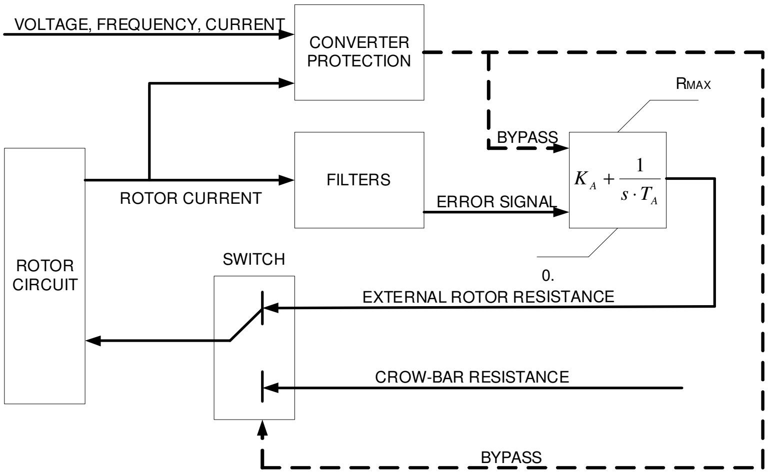
6.1.1.4.4 Converter control models

The converters applied with variable-slip generators and with doubly-fed induction generators are pulse-wide-modulation (PMW) converters. The PWM is controlled by the switching dynamics of the IGBT switches. The switching frequency can be in the range of several kHz that produces almost continuous signals when taking into account that the characteristic time constants of the most rapid, relevant processes of the generator dynamics and the power grid dynamics are in the range from tens to hundreds of milliseconds. Therefore, the switching dynamics of the PWM converters are neglected when the models are applied in investigations of power system stability.

A distinction is made between the converter control applied with the variable-slip generators and the converter control of the back-to-back frequency converter applied with doubly-fed induction generators.

6.1.1.4.4.1 Converter control for variable-slip generators

The reduced generic control system of the rotor converter applied with the variable-slip generators is shown in Fig. 6-5. The converter receives the measured rotor current, I_R. The measured rotor current is then sent through the filters including the band-pass filter that cuts off the stationary contributions. The filters produce the filtered error signal of the rotor current, I_{ERR}, containing the relevant contributions that must be attenuated by the converter control. According to Ref. [26], among such relevant contributions is the shaft torsion mode. The filtered error signal, I_{ERR}, is the input of the proportional-integral controller that produces the additional value to the rotor resistance. In the terms of the generic converter control, the whole converter operation corresponds to the addition of the external rotor resistance, R_{EXT}, to the rotor circuit impedance [26]. The use of the IGBT switches allows variation of the external rotor resistance from zero to the chosen upper limit R_{MAX}.



Courtesy of the national TSO of Denmark

Fig. 6-6: Reduced generic model of the converter control of variable-slip generators. This variant is with crowbar protection.

The IGBT switches of the rotor converter are power electronics devices, which are sensitive to and must be protected from thermal and electrical overloads. Therefore the converter may block when the operation of the generator or the converter approaches the conditions, which may cause such overloads. The converter may block due to excessive current transients, excessive fluctuations of the grid voltage and the grid frequency.

When the converter blocks, then it stops switching and trips. The rotor circuit will be short-circuited through the crowbar. Principally, the converter can be restarted when the normal operation conditions are re-established. Under the restart procedure, the crowbar is removed and the converter starts switching again.

6.1.1.4.4.2 Rotor VSC control for DFIG

The control of the back-to-back frequency converters to be applied together with DFIG is more complex than the control of converters of the variable-slip generators. Fig. 6-7 presents part of the rotor VSC control. The converter control is arranged with the use of the (α,β)- reference frame with the α- axis following the grid voltage vector, U_S, and the β- axis displaced by the angle of π/2 to the α-axis. With the use of this reference frame, the converter control is arranged with independent control of the active, P_E, and the reactive power, Q_E.

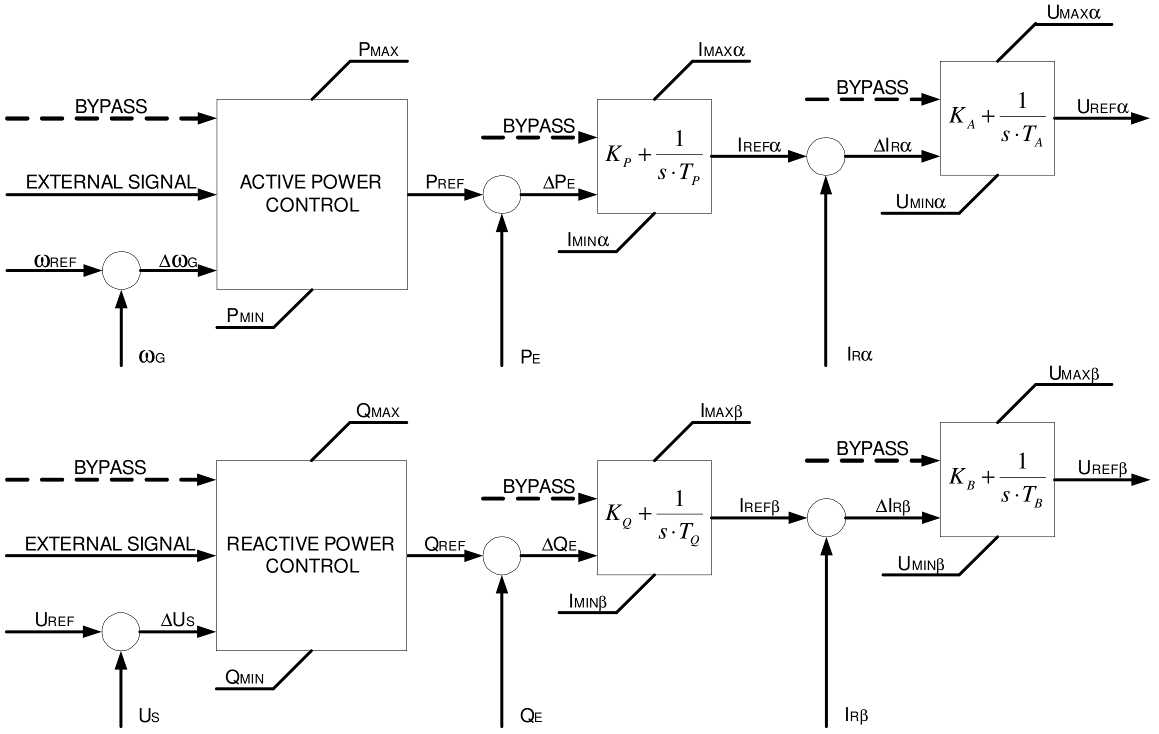


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Fig. 6-7: Part of generic control of the rotor VSC. Crowbar protection is not shown.

The rotor VSC control is realised with the use of the cascade system consisting of the two proportional-integral controllers in series in the two control loops. The input of the cascade system is the active power error and the reactive power error according to their respective references. The first proportional-integral controllers generate the rotor current references in the (α,β)- reference frame. The second proportional-integral controllers generate the rotor voltage references in the (α,β)-reference frame from the respective rotor current errors in the (α,β)- reference frame. When the switching dynamics of the VSC are disregarded, the induced voltage in the rotor circuit is given by the rotor voltage references computed by the VSC control system.

The active power reference sent to the VSC control can be computed in several ways. In normal grid operation, the active power reference can be computed from the generator rotor speed deviation. This control helps also to damp possible torsion oscillations [27].

The active power reference can also be set by the external system or by the grid frequency deviation sent to the control from the external system. In this case, the large wind farm is ordered to contribute to the power balance control or to the frequency control in the power grid.

The reactive power reference sent to the VSC control can be generated from the grid voltage deviation. In this case, the large wind farm is set to control voltage in the given node of the power grid. However, the reactive power control will often serve the goal of the power factor improvement. Notice that the external system can also send an order of the reactive power to the large wind farm.

The rotor VSC is controlled by switching of the IGBT switches. As already discussed, such IGBT switches must be protected against thermal and electrical overloads. When a short-circuit fault occurs in the vicinity of the wind turbine terminals, the grid voltage drop may excite the rotor current transients. When such rotor current transients become excessive, the rotor VSC may stop switching and trip. This converter action may cause disconnection of the wind turbine.

One of many possible ways to improve the fault-ride-through capability of such wind turbines is to bypass the converter control and to apply the crowbar protection [27]. In this case, the rotor VSC is tripped and the rotor circuit is short-circuited through a crowbar. The resistance of the crowbar may be in the range of 20 of the rotor winding resistance [27]. So long as the power grid is in abnormal operation, the crowbar is applied to the rotor circuit.

When the voltage and the frequency in the power grid are re-established, the rotor VSC is restarted and the crowbar is removed. At this stage, it is important to ensure that the converter restarting with removing of the crowbar does not again excite excessive current transients, which may lead to the converter blocking. When the rotor current transients become excessive again and again at the moments of the converter restarting, the converter may after several restarting attempts block permanently and the wind turbines disconnect [27].

6.1.1.4.4.3 Grid-side VSC control for DFIG

The power capacity of the grid-side VSC is in the range of 25% of the rated power capacity of the generator. The controllability of the grid-side VSC is also restricted with regard to the reactive power control. Detailed representation of this VSC and its control in investigations of power system stability seems to be of less relevance [34].

Usually, the grid-side VSC is set to exchange to active power between the rotor circuit and the power grid and to keep the reactive power at zero. Therefore, this VSC can very simplified be represented as shown in Fig. 6-8. This is simply an ideal link with a fixed DC voltage exchanging all the active power between the rotor circuit and the power grid.

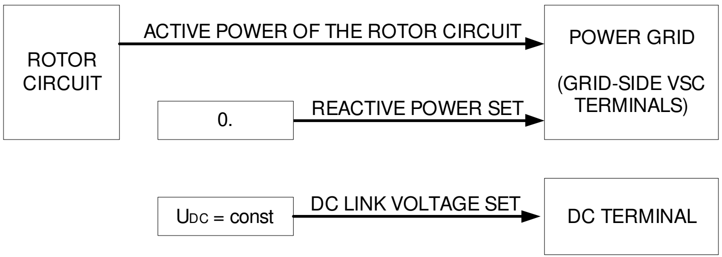

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Fig. 6-8: Simplified model of the grid-side VSC in investigations of power system stability. The model assumption is a fixed voltage of the DC link. The active power flow is for super-synchronous operation mode of DFIG.

Notice that this simplified representation is based on the assumption of the fixed voltage of the DC link. This assumption is broken when the grid voltage and then the DC link voltage fluctuates as the result of a short-circuit fault in the power grid. When fluctuating behaviour of the DC link voltage may not be disregarded, the more detailed models of the grid-side VSC and its control are required. The idealised model of the DC link is shown in Fig. 6-9 The model equations of the idealised, lossless DC link are [27]:

$$\begin{aligned} & C \cdot \frac{dU_{DC}}{dt} = I_{DC}, \\ & I_{DC} = J_1 - J_2, \\ & J_1 = \frac{P_R}{U_{DC}}, \; J_2 = \frac{P_{VSC}}{U_{DC}}. \end{aligned} \tag{4.4}$$

Here C denotes the DC link capacitance, U_{DC} is the voltage across and I_{DC} is the current through the capacitance, J_1 and J_2 are the currents injected into the DC link from the rotor circuit, respectively, from the grid-side VSC. The signs of the injected currents, J_1 and J_2, can be derived from Fig. 6-9 when considering what is the charging and the discharging current.

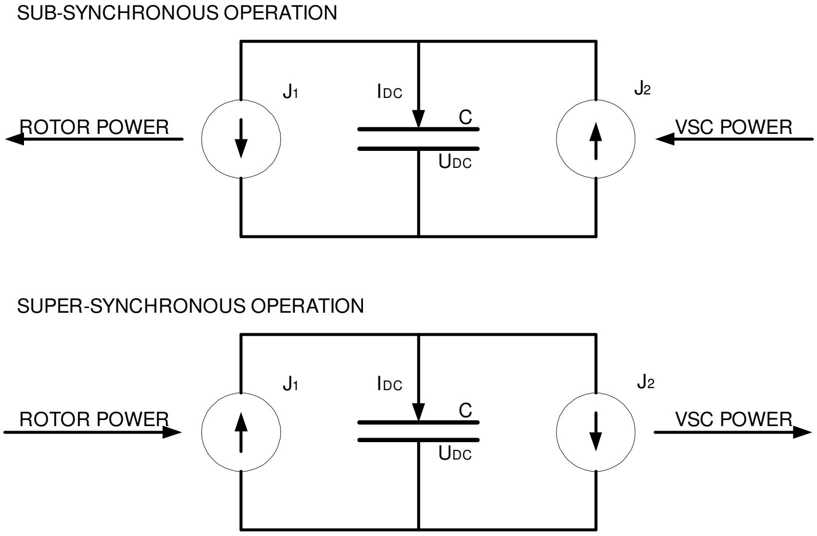

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Fig. 6-9: Idealised, lossless DC link representation.

The generic control of the grid-side VSC is similar to the control of a Statcom with few exceptions. The grid-side VSC is arranged with independent control of the DC link voltage, U_{DC}, and of the reactive current component, $I_{\mathrm{G}\beta}$. The control system is again realised with the use of the cascade system as shown in Fig. 6-10.

Normally, the grid-side VSC is set to be reactive neutral with the power grid. Therefore, the reference of the reactive current component is normally set at zero. However this VSC can be set to control the reactive power or the power factor. In this case, the reference of the reactive current component of this VSC can be controlled by the terminal voltage.

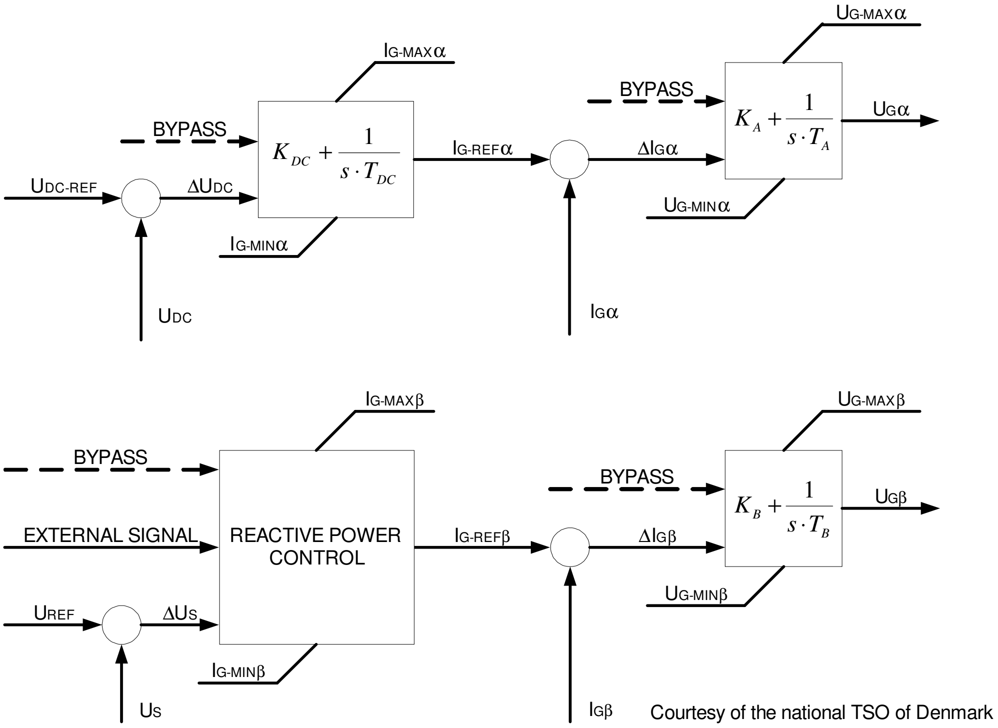

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Fig. 6-10: Reduced generic control of the grid-side VSC.

The external system may order an amount of the reactive power from the wind farm and the grid-side VSC can be set to supply some part of this reactive power demand. Notify that this control is possible because the control of the grid-side VSC is similar to the control of STACOMs. On the other hand, the power capacity of the grid-side VSC is limited. Therefore its controllability with regard to the voltage and the reactive power control is also limited.

The grid-side VSC is controlled by switching of the IGBT switches. This VSC must be protected from thermal and electrical overloads in the same way as already discussed for the case of the rotor VSC. The grid-side converter may block by excessive current transients in the converter terminals and by excessive fluctuations of the DC link voltage that may be caused by a voltage drop at a short-circuit fault in the power grid.

Blocking and restarting of the grid-side VSC must be coordinated with the protection and restarting of the rotor VSC. When the crowbar protection of the rotor VSC is applied, the grid-side VSC may either block or be in operation. When the grid-side VSC is in operation, it may be set to supply an amount of the reactive power to the grid that contributes to the grid voltage re-establishment [27].

6.2 Other reference models for wind farms

6.2.1 Wind farm modelling and aggregation issues

As seen from the point of view of grid study, the objective is to model the dynamic behaviour of the electric power generated by wind farms and sometimes by local electrical networks including wind farms.

A wind farm includes several wind turbines connected to the transmission grid through a local network. The detailed modelling of a wind farm requires the knowledge of the local network structure and characteristics (line length and impedance).
Depending on the availability of data regarding the structure of the local network, several wind farm models are possible:

- A detailed local network describing all or most of wind turbines and the network connecting them up to the grid,
- A simplified local network including a single equivalent machine connected to the grid through an equivalent line (or not) and a step-up transformer (or not).

6.2.1.1 Studied phenomena and modelling

Depending on the studied phenomena, more attention will be given to the different model parts.

Regarding transient stability studies, the wind speed variations are not relevant, as mentioned in par. 5.2: in such studies one may assume a constant wind speed.

The blade pitch angle control and the speed control may have an impact on the machine stability (similarly to fast valving impact on thermal power plant stability). A constant torque model is classically used when data are not available. This hypothesis is more conservative than the constant wind speed.

Regarding the mechanical model a detail multi-mass drive train model is not crucial, but the overall inertia value is a key parameter.

The electromechanical and electrical parts (generator and the associated controls, DC converters and their controls, protections etc…) are key components, which demand a high care for modelling.

For long-term stability studies (voltage or frequency collapse for instance) a simplified injection model may be sufficient if the voltage and current protections are modelled.

The models presented in the following only deal with the electromechanical and electrical parts of wind turbines.

6.2.1.2 Modelling approaches

In the perspective of generator modelling, several approaches are possible:

- detailed models of a specific machine and controls provided by the manufacturer,
- generic models according to the technology with standard parameters which may be enriched by specific controls and parameters,
- simplified equivalent models.

6.2.2 Detailed models

Detailed models are dedicated to a specific machine manufacturer and type, they must be provided either by the manufacturer or available in the dynamic simulation tool model library.

Detailed models are suited to studies for which the manufacturer and wind turbine types are identified. Then, either the detailed model is provided by the manufacturer and must be implemented in a simulation tool or the model is included in a simulation tool model library.

In planning studies the specific machine type and manufacturer are often not identified what limits the use of detailed models.

6.2.3 Generic generator models by technology

The generic model approach takes advantage of the classification of wind turbines into various generation technologies available today when the specific data are not available. They may, therefore, require appropriate modifications in order to represent a specific wind turbine generator proposed by a manufacturer.

More specifically, the following models are detailed here below:

- Induction generator without power electronics
- Induction wind turbine generator with dynamic slip control
- Doubly-fed induction wind turbine generator
- Synchronous or induction generator connected through a back-to-back converter

The models presented hereafter use components such as induction machines (Park representation), control loops and injectors. They do not include lines and step-up transformers.

6.2.3.1 An induction wind turbine generator without power electronics

A simple induction model without controls can be used to represent this technology. The reactive power is usually provided by capacitor banks.
The protections (voltage, current and speed) should be implemented.

6.2.3.2 *An induction wind turbine generator with dynamic slip control*

The model of an induction wind turbine generator with dynamic slip control uses an induction machine with opened rotor circuit model. In this type of machines, power is extracted from the rotor and consumed in a varying resistance R, and the rotor power is no more injected to the grid at the machine terminal.

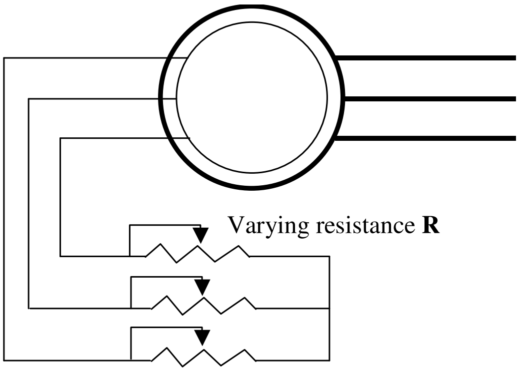

Fig. 6-11 : induction machine with dynamic slip control. Note: varying resistance is normally represented by PWM control

The value of resistance R results from a speed control loop implying a proportional-Integral (PI) corrector :

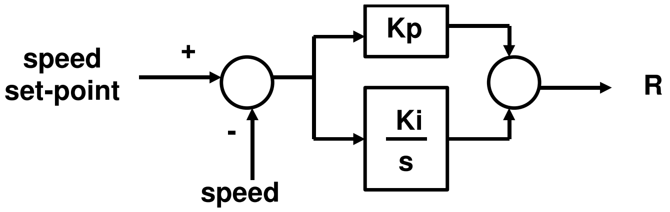

Fig. 6-12 : speed control loop

6.2.3.3 *A doubly-fed induction wind turbine generator*

Doubly Fed Induction Generators (DFIG) are induction machines with slip ring rotors fed by bi-directional frequency converters.

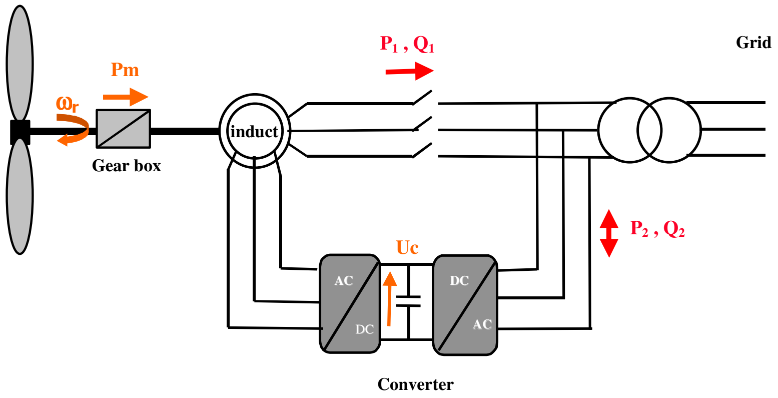

Fig. 6-13 : Doubly-fed Induction generator principle

The proposed DFIG generic model includes the following functions:

- an induction machine with opened rotor circuit,
- a speed and reactive power control through rotor voltage,
- a converter model controlling the active power provided to or extracted from the machine rotor and the grid voltage
- a crowbar protection

A general overview of a doubly-fed induction wind turbine is provided in the figure here below.

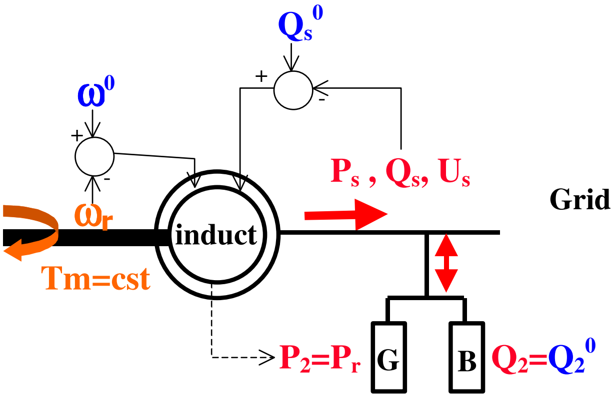

Fig. 6-14: a proposed one-line generic model for a doubly-fed induction wind turbine

Tm : mechanical torque
ω_r : rotor speed
ω^0 : rotor speed set-point
Ps : stator active power
Qs : stator reactive power
Qs^0 : stator reactive power set-point
Us : stator voltage
Pr : rotor active power
Qr : rotor reactive power
G : converter model conductance
B : converter model susceptance
P2 : converter active power injection to the grid
Q2 : converter reactive power injection to the grid
$Q2^0$: converter reactive power injection set-point

The induction machine model is standard and can be found in the technical literature. The stator flux variation with respect to time is typically neglected in stability programs.

In the model here exposed the mechanical torque is set constant but a pitch control loop can be added.

The induction machine controls:

The output of the regulator is the rotor voltage Vr in the form of its Vrd et Vrq components on the direct and quadrature axes (D-Q axes). The D-Q reference frame is rotating at the synchronous speed with Q-axis 90° ahead of D-axis.

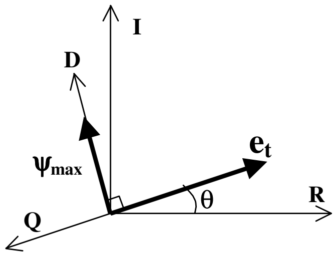

Fig. 6-15 : reference frame used

D-axis coincides with the maximum of the stator flux ψ_{max}, which means that the terminal voltage e_t is located on Q-axis.
The computation of the rotor voltage Vr (Vrd, Vrq) results from an inner control loop on the rotor current components (Ird, Irq). A proportional-integral (PI) correction is used on the error signals between the rotor current components and reference currents. The Irq reference current is determined by the speed control and the Ird reference current derives from the stator reactive power control.

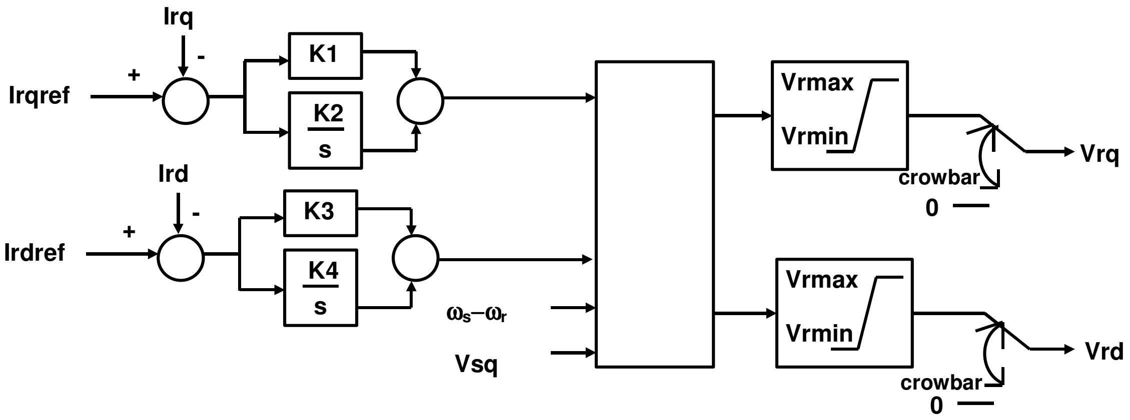

Fig. 6-16 : control structure of the doubly-fed induction machine

The **crowbar** is an under-voltage protection, which short-circuits the rotor windings if the grid voltage goes below pre-defined threshold.

The speed (ωr) regulation controls the set-point of the Q-axis component of the rotor current (Irqref) since the electrical torque (Te) is proportional to Irq ($Te = \frac{LM}{LM + L1} I_{rq}$ with LM : mutual inductance of the induction machine, L1 stator leakage reactance) :

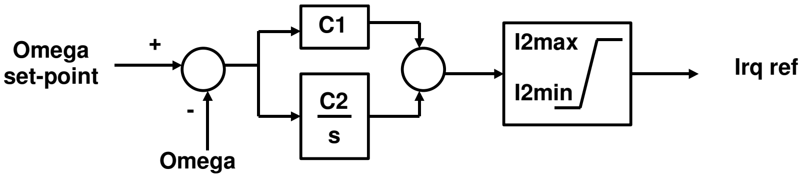

Fig. 6-17: speed control loop

The stator reactive power (Qs) regulation controls the set-point of the D-axis component of the rotor current (Irdref) :

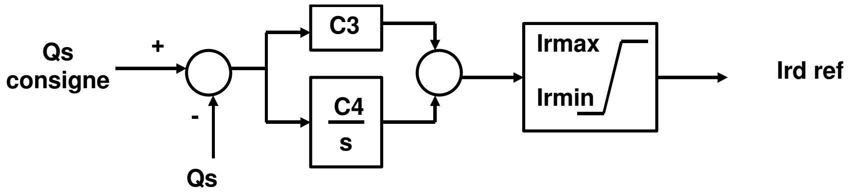

Fig. 6-18: voltage control loop

The converter is modelled by an injector (here a variable admittance G+jB) connected to the stator : the G conductance is given by the rotor active power P2 (absorbed or produced) and the B susceptance is computed to output the converter reactive power set-point Q_2^0. The converter controls are assumed to be instantaneous. The **crowbar** is an under-voltage protection, which short-circuits the converter if the grid voltage goes below pre-defined threshold.

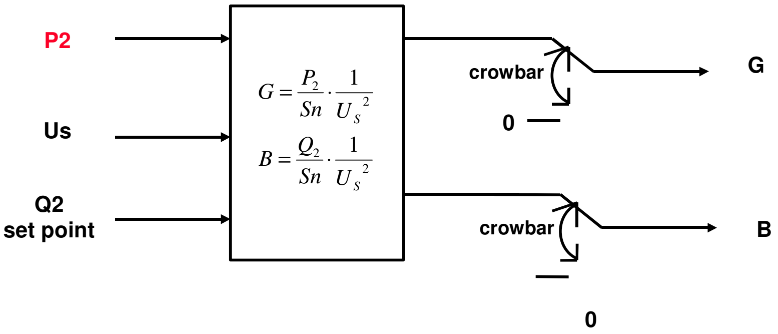

Fig. 6-19: converter model

6.2.3.4 A synchronous or induction generator connected through a back-to-back converter

The model hereafter represents in a simplified way the whole system composed of a back-to-back converter and a wind turbine generator (whatever technology involved i.e. synchronous or induction machines). More specifically, the wind turbine generator and the converter are modelled altogether by a single injector with appropriate control loops.

The following functions are represented in the model:

- a generator speed control with mechanical inertia representation;
- a voltage/reactive power control;
- protections (voltage, speed, current).

6.2.4 Simplified models

Those models are suited for long-term stability studies; they model the wind farms by power injections (PQ). The active power can be independent from the power system but may vary with respect to time to represent the wind variation on a several minute period of time. The reactive power can be either constant or variable depending on a voltage control loop. The current and voltage protections should be represented.

6.3 Reference models for gas turbines

Similarly to the procedure adopted for the modelling of wind turbines and generators, a general model like that shown in Fig. 6-20 has been suggested. In the control model one of the most important loop, which shouldn't be disregarded, deals with the limitation of the power output rate of change (e.g.: 5% of max output per second), which can affect the dynamic performance of the system.

Starting from the general model shown in *Fig. 6-20*, a procedure for adjusting the parameters has been proposed starting from the plate data and, specifically, from the output rating. As a matter of fact, even though an accurate model is available, very often it is of little (or even no use) for the planner, lacking information on parameters to be used.

In the analysed context we have foreseen a situation when one doesn't have any information about the constructor and the model of a certain gas turbine, but one only knows its output rating.

The analysis of the features of some of the most common gas turbine models can be helpful for the determination of significant data and of general adjustment rules. Some of the aforementioned features are shown in the table below.

constructor and model	**Output Rating MW**	**pressure ratio**	**heat rate kJ/kWh**	**air/exhaust gas flow kg/s**	**Exhaust temperature °C**
GE PG9351FA	255.6	17.0:1	9757.0	624.0	609.0
GE PG9231EC	169.1	14.0:1	10309.5	508.0	556.1
GE PG9171E	126.1	12.6:1	10653.0	418.0	543.0
Siemens V94.2A	182.3	13.8:1	10232.5	519.8	567.2
Siemens V94.3A	265.9	17.0:1	9323.4	655.9	584.4
Mitsubishi M701	144.1	14.0:1	10346.4	440.9	542.2
Mitsubishi M701F	270.3	17.0:1	9418.3	650.9	586.1
Mitsubishi M701G	334.0	21.0:1	9101.9	737.1	587.2
ALSTOM GT 13 E2	165.1	14.6:1	10082.7	532.1	524.0
ALSTOM GT 26	263.0	32.0:1	9726.3	607.4	615.0
Ansaldo V64.3	63.0	16.1:1	10223.0	191.9	531.0
GE PG6581B	42.1	12.2:1	11227.0	141.1	548.0
GE PG6591C	42.3	19.0:1	9930.0	117.0	574.0
GE LM2500PK (*)	29.3	22.8:1	10152.0	89.0	488.0
GE LM2500PH (*)	26.5	18.2:1	9148.0	76.0	497.0
GE LM2500PE (*)	22.8	18.9:1	10556.0	72.0	513.0
GE LM2000 (*)	17.6	15.6:1	10129.0	63.0	474.0
GE MS5001	26.8	10.5:1	12687.0	276.1	483.0

(*) Aero-derivative gas turbines

Table 5-1 - Ratings of some gas turbine models

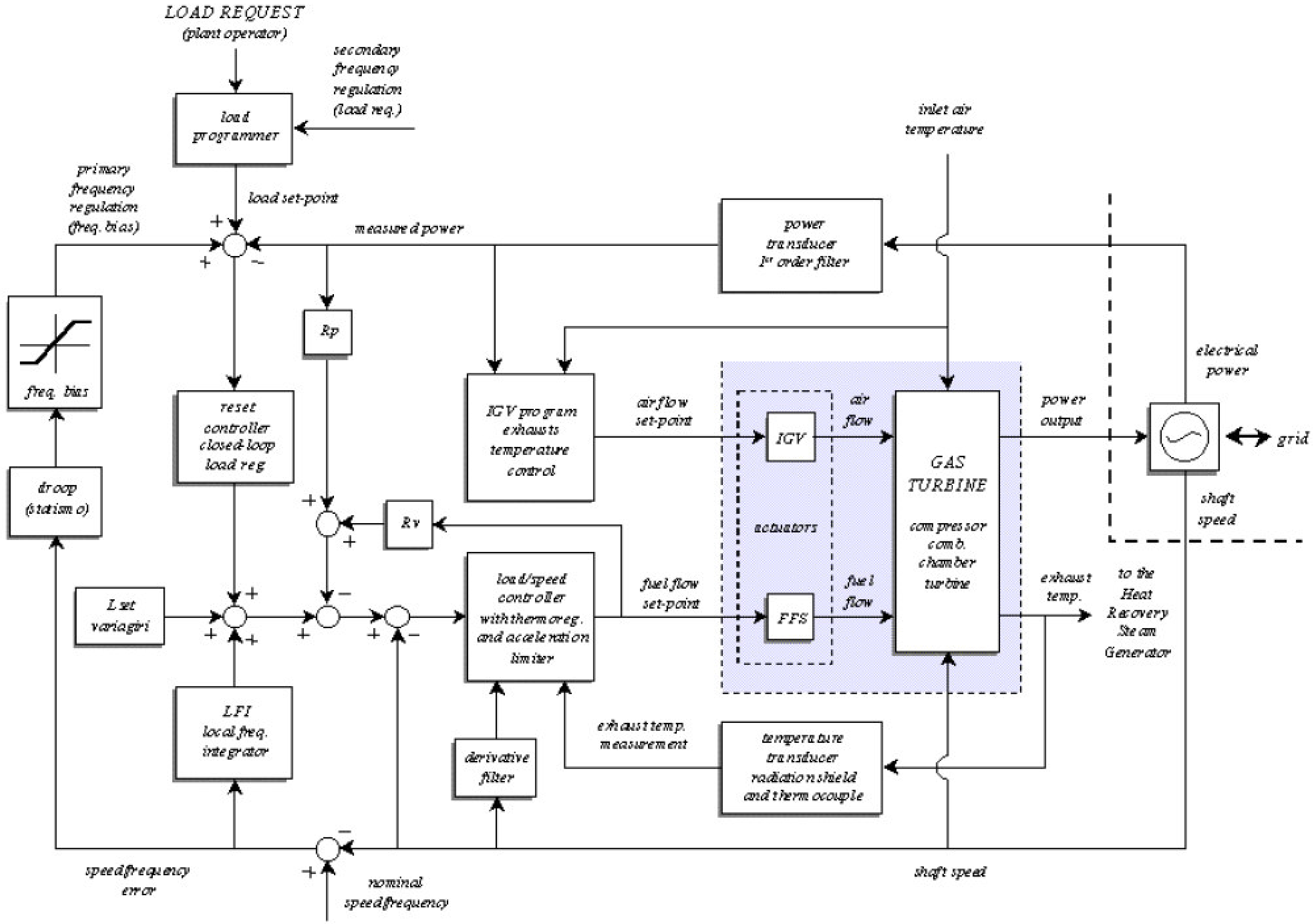

Fig. 6-20 General block diagram of a gas turbine

The characteristic features of the analyzed gas turbines have been graphically visualized in the following diagrams.

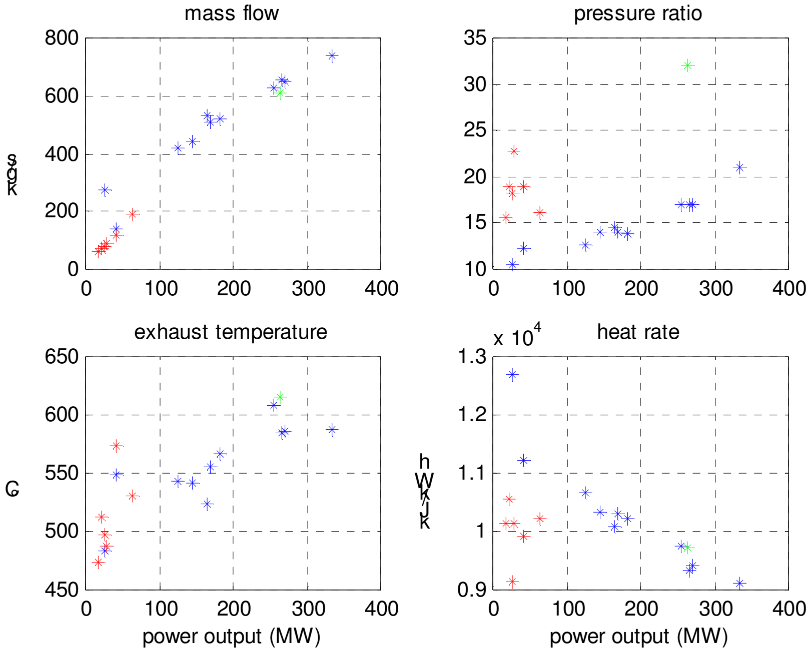

Fig. 6-21 - Graphic comparison of the ratings of some typical gas turbine models. The data relevant to some aero-derivative or small rating gas turbines are red; the data relevant to the model ALSTOM GT 26 , which is different from the average because of a particularly high pressure ratio, are green.

An approximate trend of the considered characteristic data has been identified by means of the Least Square Method (a first order approximation has been adopted). However, we have excluded some specific data from the set adopted for the identification. These excluded data are relevant to aero-derivative gas turbines, to some small rating models (for which it's difficult to find a common trend) and, at last, to the gas turbine ALSTOM GT 26 (which is characterized by a pressure ratio equal to 32 – about twice as high as the average). Therefore we can refer the effectiveness of the proposed analysis to the case of typical heavy-duty gas turbine models characterized by medium-high output ratings.

The results of the performed analysis are shown in the following diagrams.

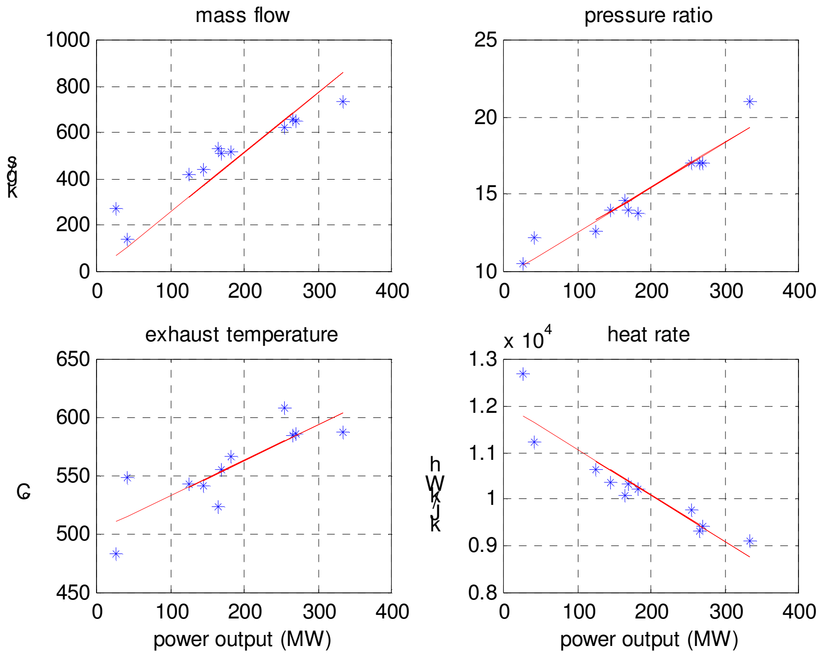

Fig. 6-22 – Identification of an approximate trend of the gas turbine ratings (heavy-duty, 50 Hz) on the basis of the output rating.

One can notice that the air/exhaust gas flow shows a very pronounced dependence on the output rating. A similar trend, even if less pronounced, characterizes the exhaust temperature and the heat rate. Also the identification of a typical trend for the pressure ratio seems to give good results: however, it is worth reminding that we have excluded small rating models from the identification; these models are often characterized by higher pressure ratio values with respect to the identified trend, in relation to their own output rating.

More details on models and relevant parameters of gas turbines can be found in [29].

6.4 Network equipment electronically controlled, DG and storage devices

Network equipment electronically controlled is classified as follows:

- HVDC/BtB (High Voltage DC transmission / Back to Back)
- FACTS (Flexible AC Transmission Systems)
- Phase shifting transformers.

Moreover, also DG (Dispersed Generation) and Storage devices are considered in this section, since they are based on power electronics and related control systems.

In this section, a brief description of typical systems and references for the models are provided as well as recent trends and required developments.

This report doesn't include the detailed modelling of the above equipment, since they are available in the scientific literature. Thus, a recall to technical documents is made in order to easily retrieve the needed models.

6.4.1 HVDC/BtB

By continuous developments in the second half of the past century, conventional HVDC/BtB became a mature and reliable technology [6.1][15]. Systems installed in the early days come near their end of life. By replacing mercury arc valves with thyristor valves, the reliability and availability are improved and, at the same time, it may allows higher ratings than the existing poles [6.2][6.3].

HVDC has an excellent behavior to convey power to the required location in the system. In addition it is very effectively used to increase stability limits in AC systems and damp oscillations. Fig. 6-23 illustrates the basic design of an HVDC link and the equivalent controllable element for the network. Network coupling by means of HVDC allows coupling of networks with different basic frequency (e.g. 50 Hz and 60 Hz) and different control philosophies. Power fluctuations between systems coupled by HVDC are alleviated if power fluctuations caused by voltage changes is prevented. It is thus possible to control active power independently of reactive power. This method is successfully adopted for the control of active power to parallel AC systems. By using HVDC links with additional control signals (e.g.: signals related to active power oscillations), network power fluctuations can be damped; this can be achieved by feeding in modulated power via an HVDC link interconnecting the two areas subject to poorly damped interarea oscillations.

Facing outstanding advantages offered by HVDC links or BtB systems, potential risks induced by these devices shall be accurately addressed by planner. Particularly, the execution of a screening study on possible subsynchronous resonance is recommended; indeed, HVDC links/BtB systems interact with thermal units nearly the converter stations with a potential risk of torsional vibrations on turbine-generator shaft. Specifications for any new HVDC system where there is a potential risk for torsional interaction with turbine generators should contain provisions for screening studies to determine if detailed subsynchronous resonance analysis and possible subsynchronous damping control loops are required. Typically, only turbine generator units located near a *rectifier converter* station and having a *weak connection with the main AC system* could be affected by subsynchronous resonances. This is due to the common current control regulator bandwidth for HVDC converter station that is in the range of 10Hz to 30 Hz, hence including possible torsional mode of vibrations for large thermal turbine generators.

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[15] Note: references on "network equipment electronically controlled, DG and storage devices" are listed in sect. 6.4.6

The screening study can be based on the IEC 60919-3 technical specification "*Performance of high-voltage direct current (HVDC) systems – Part 3: Dynamic conditions*", with reference to the following formula:

$$UIF_i = (S_{HVDC}/S_i)\,(1-(SC_i/SC_{tot}))^2$$

where:

UIF_i = Unit Interaction Factor of i_{th} generating unit.

S_{HVDC} or S_i = HVDC (excluding AC filters) or i_{th} generating unit rating in MVA

SC_i = Short circuit level at HVDC commutating bus excluding ith unit

SC_{tot} =Short circuit level at HVDC commutating bus including ith unit

As a result of extensive studies the IEC document suggests that an interaction factor lower than **0.1** will not have a significant interaction, without any need of more detailed studies.
The formula suggests that the more critical conditions are relevant to the system off-peak conditions, where the out of service of one generation unit causes a higher UIF. Moreover in the formula it is considered the apparent power of the HVDC link without taking into account AC filters.

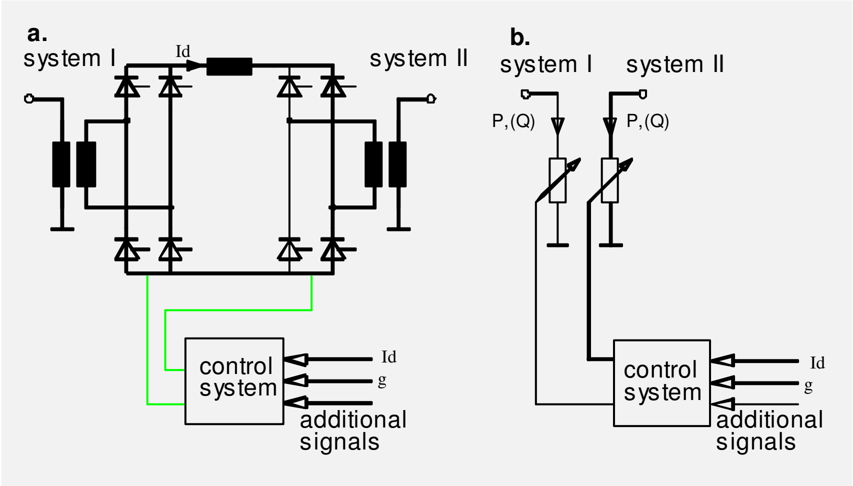

Fig. 6-23 a. Schematic circuit of HVDC, b. Equivalent controlled grid-element

When representing HVDC systems in software tools for power system analysis, the model described in [6.4] is proposed for system planning studies. Reference [6.5] describes basic theory and control of an HVDC system, while reference [6.6] specifically addresses how incorporating HVDC links in power system analysis and dynamic models.

Recently, application of VSC (Voltage Source Converter) DC transmission systems is progressing. VSC based HVDC technology enters in the second generation and it shows benefits related to the use of reactive power/AC voltage control to support relatively weak AC networks [6.7][6.8]. A dynamic model for a VSC DC transmission is shown in [6.9], that is used for power system planning and analysis.

6.4.2 FACTS

The fast development of power electronics in the last two decades enables the development of a number of different equipment used in AC systems. This equipment is often referred to as FACTS (Flexible AC Trans-mission System). The idea of FACTS is explained in Fig. 6-24. The active power transmitted between the systems is defined by the equation shown in figure where “U1” and “U2” are the voltages at both ends of the transmission line, “X” is the equivalent impedance of the line and “δ1-δ2” is the phase angle difference between both systems. From the equation, it can be seen that the transmitted power can be influenced by three parameters: voltage, impedance and phase angle difference. FACTS devices can influence one or more of these parameters: from SVC up to Controlled Series Compensation, Phase Shifting Transformer or Unified Power Flow Controller (UPFC) there is a wide range of application possibilities. HVDC links can also be included in the wider category of FACTS devices, since they have the ability of controlling active power through power electronics.

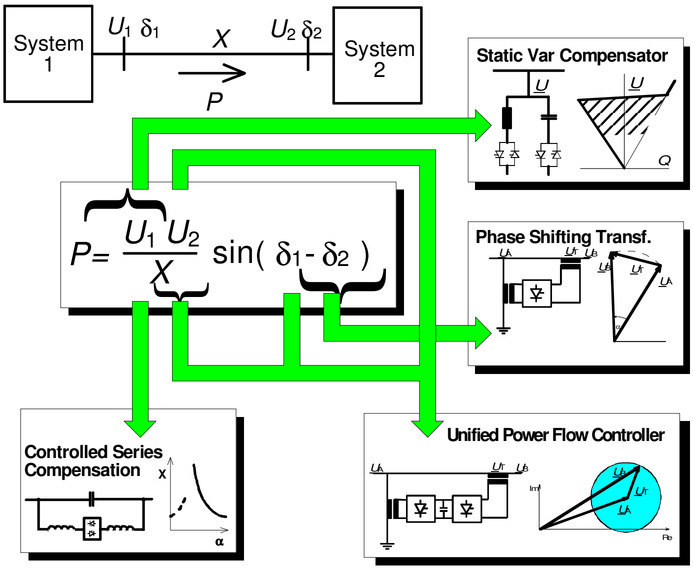

Fig. 6-24 Power flow control and stability improvement in AC systems

Fig. 6-25 illustrates main technical features of the most common FACTS devices, which are already in operation or will be used in AC systems in the future. Three squares boxes in the scheme of Fig. 6-25 means an excellent behavior of the device, which is basically developed to cope with the control/phenomenon referred in the columns of the scheme; two squares means the device is suited to control the magnitudes or enhance stability facing the phenomena referred in the columns; one square means the device can contribute to the magnitude control or stability enhancement if it is installed in the system for other reasons.

	load control	voltage control	transient stability	oscillation damping
HVDC	❑❑❑	❑⬚	❑❑	❑❑❑
SVC	❑	❑❑❑	❑	❑❑
TCSC	❑❑	❑	❑❑❑	❑❑
TCPAR	❑❑❑	❑❑	❑	❑❑
UPFC	❑❑❑	❑❑⬚	❑❑❑	❑❑❑

Fig. 6-25 Main technical features of some FACTS devices

In the following a short recall of the basic characteristics of the most popular FACTS devices are recalled. For each category of devices references to most appropriate dynamic models are provided.

6.4.2.1 Static Var Compensator (SVC)

Static Var compensator (SVC) is a controllable network. Fig. 6-26 depicts the basic SVC configuration. This network element is primarily employed for voltage and reactive power control. When employed in the network as a controllable shunt element the following additional tasks can be performed:

- ✓ Improving stability in transient condition;
- ✓ Damping of active power fluctuations by modulation of the reactive power fed into the network;
- ✓ Increase of the transmission capability of network links;
- ✓ Damping of subsynchronous resonances.

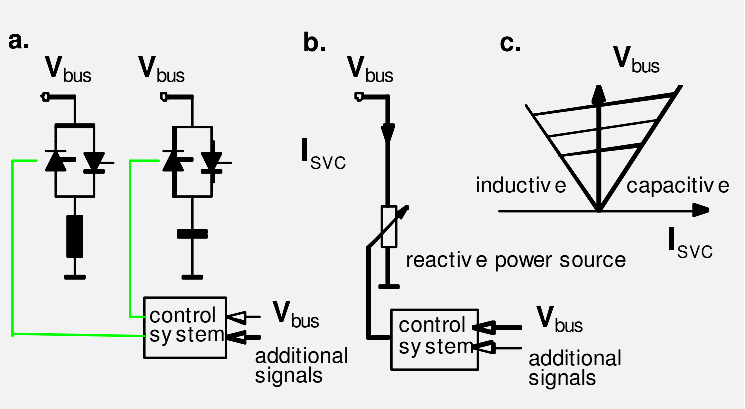

Fig. 6-26 Static Var Compensator (SVC)

a. Schematic circuit, b. Equivalent controlled grid-element, c. Characteristic of an SVC

The voltage in the system can be changed in a narrow range due operating voltage limits and in relationship to the rating of the SVC. Therefore, the SVC influences only reactive power flow in the system during steady state condition. Using a fast control, however, the SVC can also produce small changes in the active power flow by voltage modulation. Such changes in the active power flow can counteract power oscillations in the system and increase the stability limit.

6.4.2.2 Static Synchronous Compensator (STATCOM)

The STATCOM is a further development of SVC. On the secondary side of the transformer (Fig. 6-27-a), a GTO-based inverter is connected. Using a voltage-sourced inverter that converts the DC voltage at its input terminals into a three-phase set of output voltages the STATCOM can produce inductive and capacitive reactive power. When the voltage source is greater than the transmission line voltage, leading reactive current is drawn from the transmission line and the equipment appears as a capacitor. When the voltage source is smaller than the transmission line voltage, lagging reactive current is drawn. The advantage of this solution is the compactness of the design and infeeding reactive power current into the system independently of the operating voltage. This can be also seen in the operating diagram given in Fig. 6-27-c. In addition, comparing to the SVC, the STATCOM does not need large capacitor banks. Disadvantages of the STATCOM currently are higher losses and the problem to build GTO-based inverters for high ratings.

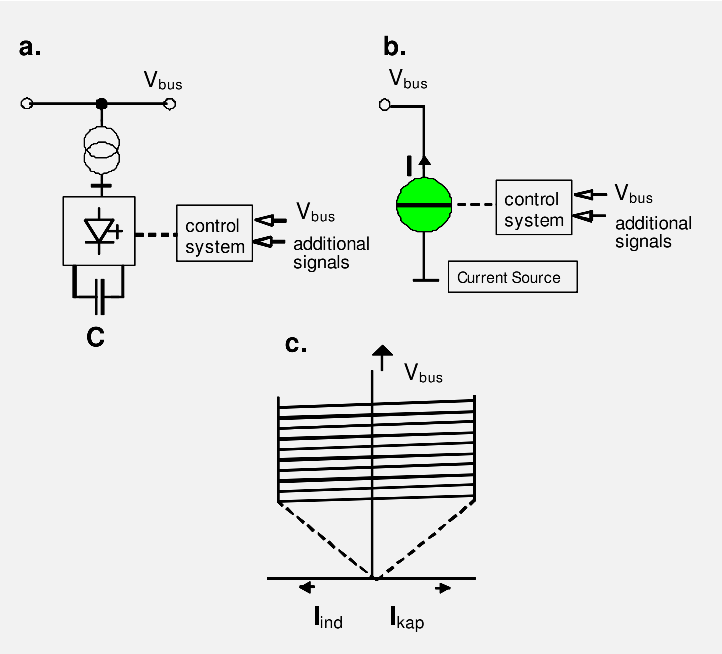

Fig. 6-27 Static Synchronous Compensator (STATCOM)

a. Schematic circuit, b. Equivalent controlled grid-element, c. Operating diagram

6.4.2.3 Thyristor Controlled Series Compensator (TCSC)

Load flow in a network is determined by the impedance relationships. The line impedance can be changed by series compensation. This technique has been used for decades to increase the capability of transmission lines. The degree of the compensation is, however, constant or only slowly changeable by mechanical switching in large steps. Thyristor controlled series compensation (TCSC) makes it possible to control the line impedance fast and continuously. It allows an effective increase of power transmission capacity at any given phase-angle displacement across the line. Nowadays, TCSC with supplement controller signals such as active power change in the transmission line is also recognized as an important damping source. Fig. 6-28 depicts the TCSC schematic circuit and the basic mode of operation as a network element.

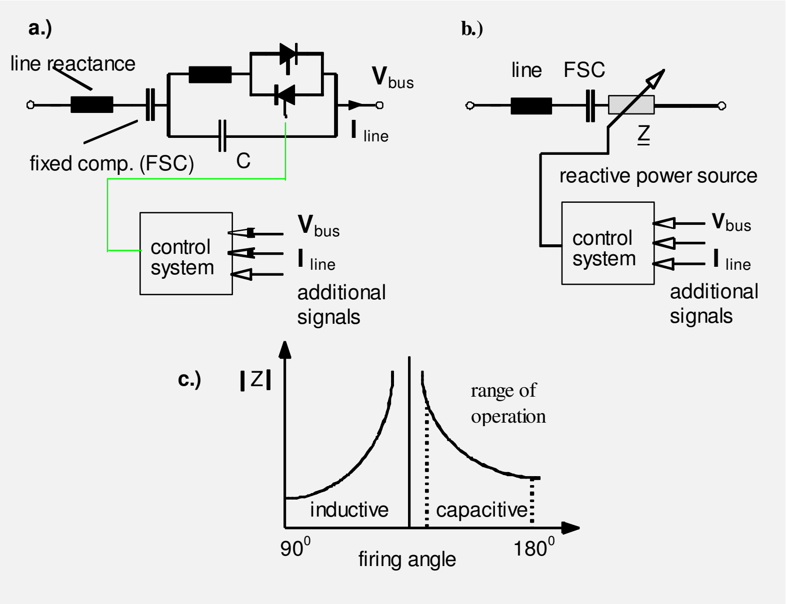

Fig. 6-28 Thyristor controlled series compensation (TCSC)

a. Schematic circuit, b. Equivalent controlled grid-element, c. Operating diagram

Hierarchical control of an interconnected power system with TCSCs distributed in the transmission lines allows implementation of complex and optimized load distribution structures, which automatically maintain, for example, an optimal voltage profile or which minimize the transmission power losses in the overall system.

6.4.2.4 Unified Power Flow Controller (UPFC)

The Unified Power Flow Controller (UPFC) is expected to be one of the most effective FACTS devices using GTO-technology. UPFC combines main features of STATCOM and TCSC with additional fast active power flow control and can control independently more parameters: amplitude and angle of the voltage in longitudinal direction and reactive power consumption controlling the line to ground voltage. As shown in Fig. 6-29, two GTO-converters are connected between the shunt and the series transformer. In the same figure the UPFC conceptual modelling for stability assessment in simulation programs is given. The operating diagram is shown in the upper part of the figure.

As I t can be seen, inverter 2 can insert a voltage Ut of the variable amplitude and angle, into the series winding of the transformer. The reactive power to provide this additional voltage is produced by the inverter 2 itself. The corresponding active power, however, is transmitted from the shunt transformer through the two converters. The converter 1 can, in addition, control voltage at the terminal of the UPFC by its reactive power control.

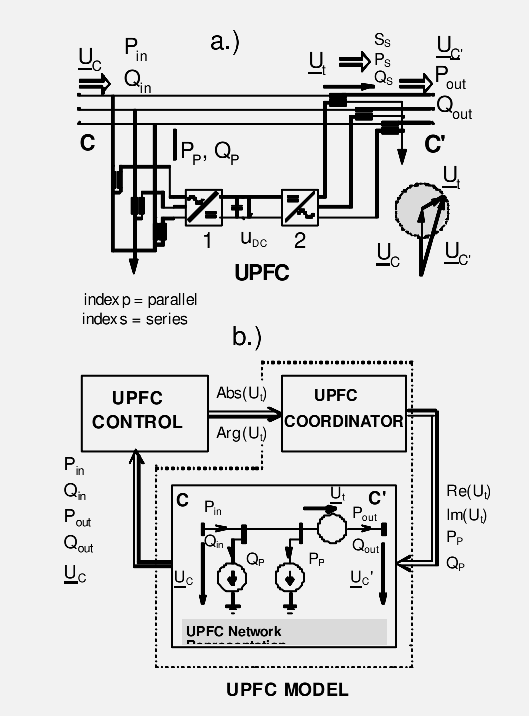

Fig. 6-29 Unified Power Flow Controller (UPFC)

a. Schematic circuit, b. Equivalent controlled grid-element

6.4.2.5 References for FACTS modelling

For more detailed information, basic concepts of FACTS and models of specific FACTS controllers including SVC, STATCOM, TCSC, SSSC, UPFC, IPFC (Interphase Power Flow Controllers), electronically controlled PHS transformers and special controllers with a detailed comparison of their performances are included in [6.10]. Major FACTS applications used in the United States are also included. Reference [6.11] also provides a comprehensive guide to FACTS, covering all the major aspects in research and development of FACTS. Reference [6.9] focuses on modelling in load flow and stability studies. The document covers the following systems: SVC, STATCOM, BESS (Battery Energy Storage), SMES (Superconducting Magnetic Energy Storage), TCSC, SSSC, TCPAR (Thyristor Controlled Phase Angle Regulators), UPFC, HVDC. A survey on existing tools and practices on FACTS is given before the descriptions of the various FACTS device models in the subsequent sections.

6.4.3 Phase shifting transformer

Reference [6.14] briefly shows fundamentals and equivalent circuit of a phase shifting transformer.

Recently, the use of Rotary Phase-Shifting Transformers (RPST) that have ability to control load flow in a transmission system and interconnect different power grids asynchronously is investigated [6.15][6.16] and variable frequency transformers (VFT) are already available for commercial use [6.17]. A very recent application of VFT is related to the US-Mexico interconnection where a 100 MW VFT is presently under construction in the Laredo region (Texas) and is scheduled for commercial application in early 2007 [6.18].

6.4.4 *DG and Storage*

Several new generation and storage technologies have the potential to significantly impact power system performance. Some of these new technologies are well suited for distributed generation and storage applications. Reference [6.12] explains main characteristics of various new generation and storage technologies including a variety of energy sources, as listed below:

- ✓ Wind Energy Conversion System (WEC)
- ✓ Small Hydro Turbines (HP)
- ✓ Micro Turbines
- ✓ Fuel Cells (FC)
- ✓ Biomass Systems (BMS)
- ✓ Photovoltaic Systems (PV)
- ✓ Solar Thermal (STH)
- ✓ Geothermal (GTH)
- ✓ Superconducting Magnetic Energy Storage （SMES)
- ✓ Battery Energy Storage (BESS)
- ✓ Flywheels (FWH)

The above generation and storage technologies can have an impact on transient stability and long-term dynamics of power systems.

Reference [6.13] also describes models of the major micro-generation sources and their power electronic interfaces.

6.4.5 ***Required developments***

Required developments can be classified as:

- ✓ New models for individual devices;
- ✓ New dynamic models for the aggregate of a large number of devices.

If a new type (configuration, control feature) of device is proposed and applied, a new model to represent its dynamic characteristics is required. Moreover, there are a large variety of different system configurations and control schemes. So, software packages are required to provide a feature to easily build up user-defined models and interface them to the power system models.

Several new generation and storage technologies have the potential to significantly impact power system performance. Most of these new technologies are well suited for distributed generation and storage applications and are connected at the distribution level. Nonetheless, if a large number of DGs and storages are installed, they may affect load flow and stability of a transmission system. But they have not been designed to support system stability during power system disturbances. Reference [6.19] and [6.20] consider influence of synchronous generators and/or induction generators. When ratio of DG units connected via electronic power converters becomes higher, there is no clear guideline how they are modelled within a dynamic study of a transmission system. Indeed, there is a gap between the individual models [6.12][6.13] and model of the aggregate of a large number of DGs. So, it is important to develop appropriate equivalent (aggregate) models.

Furthermore, such DG units may stop by protection relay during or a short period after the system faults. So, the modelling of such characteristics is required for the aggregated DGs units to simulate accurately they behaviour during perturbations.

The output power of some DGs that use renewable energy such as photovoltaic systems and WECS (Wind Energy Conversion System) cannot be controlled and anticipated accurately. Moreover, their output varies instant by instant. A guideline to reflect such characteristics for dynamic simulation of a transmission system is required.

6.4.6 References for modelling of network equipment electronically controlled

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6.5 Modelling of the Load “seen” from the Transmission Grid

Based on the nature of dynamic studies and the phenomena to be analyzed, two different types of generic load models have to be used:

a) small disturbance load models used for maximum frequency and voltage deviations of about 5% and 10% respectively. For this type of study if the system load in the region of interest is mainly a non-industrial load, the percentage of induction machines should not exceed about 20% of the whole load.
b) when investigating large disturbances, a different load model shall be used. F.i.: if the problems to be investigated deal with faults or slow voltage decays, typical phenomena known as voltage collapse, a load model able to represent an induction machine behaviour is absolutely necessary. In such situations of too low voltage (more than 20% under rated value) induction machines will start to stall and, therefore, absorb extensive quantities of reactive power, consequently leading to a higher voltage drop.

The parameters of the generic load models are partly well documented in several references [36], [41] and [42]. In this context a distinction of the load behavior is done by defining manly three typical loads:

- industrial
- commercial
- domestic.

Several parameter sets for static and dynamic voltage dependence of the active and reactive power demand are given [42].

Based on the fact that the load composition on a single substation feeder could change a lot during one day, week or year, corresponding studies should consider this variation by a corresponding set of base cases.

Also for load parameter specific identification procedures could be applied. Therefore, the active and reactive power of typical feeders should be monitored together with the voltage and frequency. Special trigger events as voltage or frequency drop are subsequently used in order to start the measurement acquisition.

However, depending on the size of the system and the number of loads connected it is recommended to start the study with an investigation of the nature of the highest loads within the area of interest. Special protections schemes on the load side or compensation devices as well distributed generation could affect the load behavior of that system substantially. More information on load modeling for dynamic studies can be found in [30], [35] and [36].

7 VERIFICATION AND IDENTIFICATION OF PARAMETERS

The analysis has specifically addressed the verification of parameters of units and associated controls for power generation. The South African and Swiss experiences are have been gathered and here below it is presented the suggested methodology to be applied for the identification and verification of parameters to be used in the modelling of generating units and associated controls.

An extensive presentation of the procedure fore verification and identification of parameters is available in "*System parameter estimation tool*" developed at ESKOM RSD [39]; in this report a summary of key issues are recalled.

7.1 Plant modelling: overview of control loops for fossil-fired units

Fig. 7-1 provides an overview of the turbine-generator control loops for a typical fossil-fired unit.

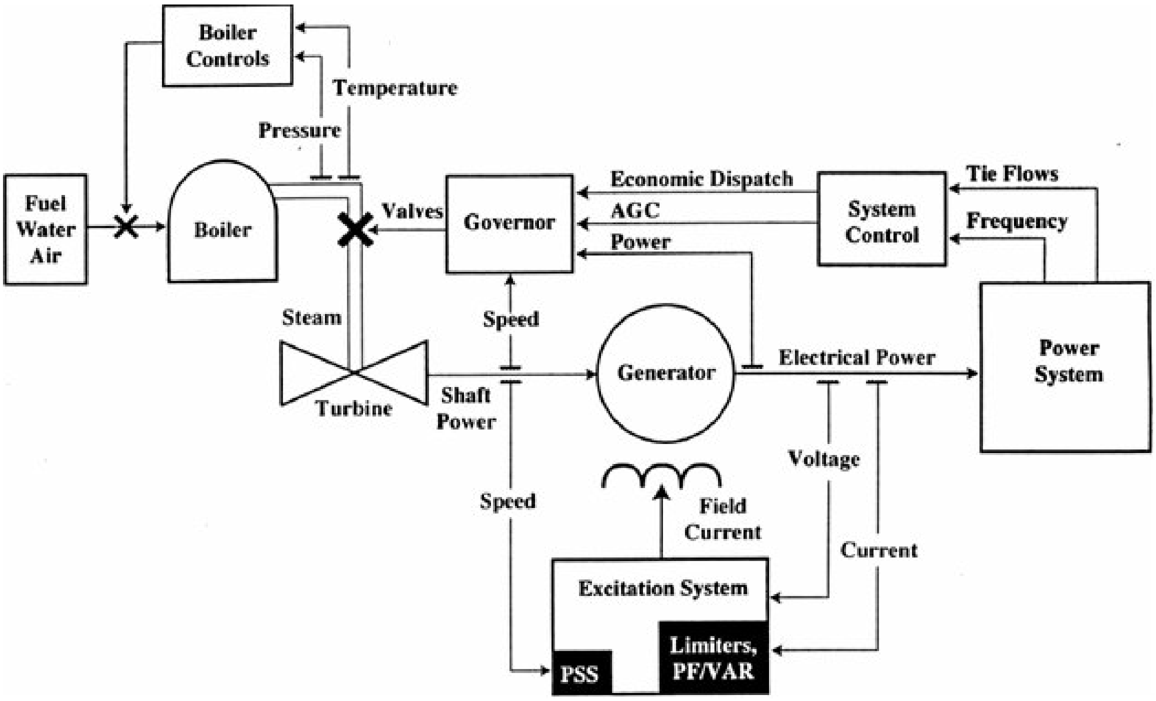

Fig. 7-1: Generator Control Loops Overview Diagram

These controls allow the power system to meet the continually changing customer load requirements by adjusting the active and reactive outputs of the generators. The major control loops can be summarized as follows:

- Power System Generation Dispatch includes automatic generation control systems (AGC) for the maintenance of overall system frequency and tie-line interchanges and manual operator controls such as economic dispatch.

- Prime Mover Energy Supply System for fossil-fired units (shown) includes fuel supply and boiler control loops, while for hydroelectric machines, penstock and conduit systems will participate in the dynamic behaviour.
- Turbine Controls include the governor (speed control loop) as well as supplementary controls, which are active during full or partial load rejections.
- Excitation System includes the amplification stage(s), automatic voltage regulator (AVR) function, excitation limiters and supplementary controls such as power system stabilizers (PSS), and outer control loops (e.g. power factor or reactive power regulators).

Included within these control loops are the turbine and synchronous generator. Clearly, the modelling of these components can have a significant impact on the accuracy of the representation of each of the major control loops.

The need to represent each of these components and control loops, and the type of model required, is established by determining the type of simulations which are to be performed, and the types of operating conditions to be represented.

7.2 Verification of parameters of units and associated controls for power generation: key parameters analysis

In order to determine which pieces of equipment must be modelled in detail, the type of simulations, which will be performed, must be defined. This involves establishing the time frame and the system conditions, which are to be simulated (e.g. interconnected and/or islanded operation). The latter is often specified as a range of voltages and frequencies for which the models must be valid.

The following table provides guidelines for equipment modelling for different stability study types. The table is read as follows:

- "✓" indicates that a dynamic model is needed
- "**X**" indicates that a dynamic model is not needed
- "**?**" indicates that a dynamic model may be included depending on special conditions or simulations goals.

	STUDY TYPE					
EQUIPMENT	**SSR**	**Transient**	**Small-Signal**	**Islanded Operation**	**Long-Term Dynamics**	**Voltage Stability**
Time Frame	**< 1s**	**< 10s**	**< 20s**	**10s - mins**	**mins**	**1s-mins**
Generator	✓	✓	✓	✓	✓	✓
Shaft System	✓	X	?	X	X	X
Excitation System						
AVR	?	✓	✓	✓	✓	✓
Stabilizer	?	✓	✓	?	?	✓
Limiters	X	?	X	?	✓	✓
PF/VAR	X	X	X	?	✓	✓
Turbine Control						
Speed Governor	X	X	?	✓	✓	X
Overspeed Control	X	X	X	✓	✓	X
AGC	X	X	X	X	?	X
Prime Mover	X	X	X	?	✓	X
Loads	X	X	?	✓	✓	✓

Tab. 7-1 - Equipment Modelling Requirements

The specific parameters associated with each model for the equipment listed in Tab. 7-1 was analyzed to determine which parameters are required for specific stability studies. The following table lists the important parameters of a generation plant, which need to be validated for various stability studies. The parameters are classified in three different classes viz.:

- Class 1 Parameters: These parameters are essential for any stability study. Validated parameters must be obtained.
- Class 2 Parameters: The accuracy of these parameters has a noticeable effect on the accuracy of interconnected power system stability studies. It is highly desirable that the values of these parameters are validated.
- Class 3 Parameters: These parameters are useful but not essential. If values are not provided or obtainable, standard default values may be used in interconnected power system stability studies

					Excitation Controls & Protection		Governor Limits	
Class	**Generator**	**Exciter**	**PSS**	**Governor**	**Limits**	**Trips**	**Hydro**	**Steam**
• 1	• Xd Xq • H • Tdo’ • S(1.0) • S(1.2)	• Maximum Efd • Ka • Static/Rotating Power Source • Vrmax • Time Constant • Xcomp • Ke Tf Tb Tc etc • Se (DC Exciter)	• Kpss • Type of Input • Dominant Time Constant	• R (droop) • Qnl – flow at no load speed • Gain At • K1 – K6 • Pmax • Intentional Deadband • Maximum Velocity	• OEL Type/Setting • UEL Type/Setting • V/Hz • Power Factor Control Status • Stator Current Limit	• Loss of Field • IPP Interface • Over/Under Freq. • Over/Under Voltage • Over Current Excitation • Over current V/Hz	• Tunnels • Tanks • Motoring • Water Depression	• Boiler Modes • Load Limiters
2	• Xd” Xq” • Xd’ Xq’ • Tdo” Tqo” • Xl	• Se, Efdmax (Brushless)		• Tw Kp • R Ki • Tr • T1 – T4 (Steam.Turbine Model)				
3	• Ra • Xo Ro			• D				

Tab. 7-2 - Key Parameters

The influence of Key Parameters can be summarised as follows:

DYNAMIC PHENOMENA	IMPORTANT PARAMETERS
Transient Stability	Inertia & Exciter
Small Signal Stability	Exciter & PSS
Voltage Stability & Control	Reactive Limits, Control & Protection
Frequency Stability & Control	Inertia & Governor

In the report the tests necessary to be carried on for the identification of the parameters are described. As a matter of fact, this activity is in common also with the operation analyses, whenever the system operator wants to be reasonably sure that the model he/she is using fit adequately with the real system.

7.3 Hydro plants: parameter verification of units and associated controls

Based on the fact that in dynamic calculations the highest dynamic impact is determined by the behavior of the generating units, their correct dynamic representation is of crucial importance. The dynamic response of the generating units is caused by the interaction of:

- Generator
- Turbine dynamics
- Turbine controller (governor)
- AVR (automatic voltage controller)

and, depending of the type of turbine, of:

- Boiler dynamics (steam units)
- Penstock dynamics (hydro units)

In the following only aspects related to the modeling of hydro power plant systems will be considered [40].

One of the main problems during the set-up process for dynamic models is the acquisition of accurate parameters. According to our experience the most accurate but also most time- and cost- intensive method of parameter acquisition is to perform dedicated system tests for parameter identification.

Therefore, the following actions have to be done:

a) review of all available documentation about the hydraulic system (penstock, surge chamber, turbine configuration)

b) preparation of measurement points for pressure, flow, valve positions for all main hydraulic elements in the chain from the upper to lower reservoir
c) perform typical tests while recording in high resolution (e.g. 100 msec) hydraulic, mechanic and electric quantities
d) parameter identification after dividing the whole scheme in small peaces, where input and output values have been measured

Finally, comparisons between the measurement test and simulation results have to prove the model quality.

By including valve characteristic measurements as well as efficiency measurements for the complete operation range of the generating unit and all units for one common penstock respectively, models valid for the whole operation range of power plants can be obtained.

The special system tests consists in step-by-step changes of the operation point of the plant by changing from interconnected operation into operation in a small island of 10-20% of the plant rated power. The tests start with zero exchange power and should be extended to islanding with 5% load steps up to 50% power excess or 5% power deficit for the balance between power exchange on the interface and load of the available island. The resulting step response for hydraulic, mechanic and electric quantities represents the input for the detailed parameter identification process.

The main two parameters for the penstock are the water starting time T_w and the wave traveling time T_L, which both can be calculated from the geometrical data of the hydraulic scheme. However, the exact values are given by the identification process.

For all the other parameters e.g. valve opening and closing speed, governor gain etc. exact values can only be extracted after detailed identification procedures.

8 CONCLUDING REMARKS

From the analysis of the current practice, a number of issues shall be addressed to foster the execution of dynamic studies in planning stage in order to make them a routine step instead of an occasional study as in some present situations.

General dynamic models

At first, some *general models* can be used by planners for defining the target dynamic behaviour of the future system. These models, though very simple and with a reduced number of associated parameters, allow an acceptable accuracy in time domain simulations. Since in the large majority of cases, planners tend to make use of commercial simulation tools, equipment manufacturers and software vendors shall struggle to make *available library of models and "standard" parameters valid in a sufficiently wide range*. Sometimes, very detailed models of components of control systems may be useless for a "*system approach*". F.i. in case of wind farms, there's often no need for the modelling of each single aerogenerator, but it is sufficient an *equivalent model the whole wind farm* for the examination of the impact of wind generation into the transmission system.

Interactions between planning and operation

In a more detailed stage of analysis, to enhance as much as possible the accuracy of dynamic studies, especially in mid-term planning (3-5 years in advance), a close collaboration with the operation department is of utmost importance in order to *include in the dynamic models used in planning all the models of existing plants and controls already identified and validated during the system operation* including expected refurbishment and modifications.

Discrimination among different transient phenomena

A further issue is related to the examination of the dynamic behaviour of systems having configurations quite different from the present ones. This happens mainly when studying interconnections between two or more networks or when increasing cross-border capacities among existing interconnections through the construction of new lines or the installation of new devices either electromechanically or electronically controlled. In this phase, it is important to *discriminate among various transient phenomena* that may be coexisting after a perturbation and detect the prevailing one, which can lead to instability. To this purpose, use shall be made of *different dynamic models suitable for short and long-term time domain simulations*. Some software packages already allow it and are helpful, once detected the dominant transient phenomenon, to design the most appropriate measures for enhancing dynamic security margins.

Influence of market mechanisms

Moreover, an additional aspect, which shall not be neglected in planning, is related to *the influence of market mechanisms on the dynamic performance of the system*. Indeed, on the basis of market rules, many more generation dispatch scenarios may be formulated than in the past, leading to greater uncertainty in system dynamics. In principle, it is the market that determines the set of generators to be dispatched and, on the basis of the expected set of dispatched generators, it is up to the planner checking the compliance with static and dynamic security considering stability against both large and small perturbations.

Criteria to deal with uncertainty

Higher uncertainty in future configurations of the generation-transmission system leads, as a consequence, to the need for examining a huge number of different situations. Then, some criteria have to be adopted to reduce the number of simulations while keeping a sufficient degree of accuracy. Several alternatives can be proposed each of them offering pros and cons such as:

a. *Simulation of the disturbance events on all possible future system variants*:
    - Pros: thorough analysis;
    - Cons: high computational effort; need for some criteria in the post-processing of the results, especially in presence of conflicting requirements to enhance system stability;

b. *Simulation of the disturbance events only on the most constraining variants*
    - Pros: ensure warranty of system stability against the most critical situations;
    - Cons: risk of overestimating the costs of measures to be adopted either in terms of new control devices / network equipment or limitation of power flows.

c. *Simulation of the disturbance events only on variants which have the higher probability of occurring:*
    - Pros: fair compromise between computational effort and accuracy;
    - Cons: uncertainty is shifted from the number of future possible configurations to the variants which are estimated on the basis of the experience of the planner as those having the higher probability of occurrence;

d. *Application of some kind of probabilistic generation of cases followed by dynamic analyses:*
    - Pros: possibility of examining the dynamic behaviour of the system in presence of a high number of different configurations even considering some configurations that cannot be easily envisaged by the planner;
    - Cons: need for dedicated software able to automatically generate configurations, execute dynamic simulations and store the results needed for post-processing.

9 NEED FOR FUTURE DEVELOPMENTS

To facilitate the dynamic studies at planning stage, making them a routine step in the planning process, a series of issues deserve to be further developed possibly in collaboration with other SC of CIGRE and, namely, SC C4 (modelling issues), C 2 (for aspects common to operation and planning) and C 6 (impact of the DG in transmission).

Priority shall be given to the following:

- *consolidation of wind farms modelling*. Models shall be able to give an equivalent representation of the behaviour of the whole wind farm or of selected aggregations. Wind generations are often characterised by fast electronic controls and suitable simplifications shall be provided for electromechanical and slow dynamics. These may consist in formulating algebraic relations across some “fast” control loops to enable r.m.s time domain simulation. Moreover, the availability in software packages of library containing wind farm models classified by typical technology and with relevant reference parameters would be highly beneficial for planners;
- *modelling of Distributed Generation (DG)*. Priority shall be given to find out models able to correctly represent the impact of DG in the transmission system. Hence, suitable “equivalent” models shall be provided, considering that this form of generation is not directly connected to the transmission system, but its functioning can affect in a non negligible way the flows across the interfaces transmission-distribution;
- *system stability in presence of RES.* An important point, which shall still be investigated, is relevant to the *effect on the oscillatory (in)stability and frequency control from large-scale penetration of renewable and distributed generation.* As a matter of fact, usually, attention is paid to the modelling facing large perturbations, but the effect on system damping or primary frequency regulation from renewable and distributed generation is often neglected [37]. Presently, power system oscillations tend to be damped basically by large power plants equipped with power system stabilizers and in some cases SVCs, while the effect on damping from large-scale penetration of renewable and distributed generation is not deeply investigated. As in some operating conditions this new form of generation displaces a remarkable amount of conventional power plants, it is essential to know in advance whether the damping and frequency regulation provided by large numbers of smaller machine will have a similar effect to damping and regulation provided by larger plants;
- *overlapping of different control loops*. In large and stretched synchronous interconnected systems, very slow transients may arise at the occurrence of perturbations. As a consequence, while the primary frequency control is still working, because of the interaction with the slowest electromechanical modes of the network, the LFC action (or secondary frequency control) starts to be no more negligible. The latter control loop acts normally with slower time constants, in the order of some tenth of seconds. The combination of the effects of electromechanical oscillations, primary frequency control loop and LFC causes still slower transients for the system. For such a reason, in order to detect possible instabilities, the time domain simulations have to be prolonged at least up to about 100 s or more. Moreover, for such extended networks, it is not possible to assume the hypothesis of the same frequency for the entire system, even in case of long term dynamics. The consequence is a response function of the frequency error that depends upon the proximity to the disturbance, and a different speed transient for each country for a long time.

Then, when examining the dynamic behaviour of large interconnected systems, the validity of the decoupling among different control loops (typically primary and secondary frequency control) has to be carefully checked and a re-design of control loops has to be considered.

- *Hybrid AC/DC corridors*. Use of DC links is more and more common for a series of reasons (e.g.: increase of inter-area transfer capacity). In some situations DC links may be used to: decouple the overall system; reduce the risk of interarea oscillations, reduce investment costs while maintaining the same transport capacity (enhancement of transfer capacity); make easier the reclosure procedures with asynchronous islands; etc. All the above situations require the set up of a detailed study methodology to define the sizing of the DC link, its control characteristics before its commissioning and to solve possible drawbacks caused by the operation of DC links such as SSR, which might originate from the frequency of current regulator.

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APPENDIX 1 - TERMS OF REFERENCE OF SC1 WORKING GROUP 04

CIGRÉ SC C1, " SYSTEM DEVELOPMENT AND ECONOMICS "

WG: C1-4	**Convenor : Bruno Cova (Italy)** **Secretary: Federico Silvestro (Italy)**

TITLE: " APPLICATION AND REQUIRED DEVELOPMENTS OF DYNAMIC MODELS TO SUPPORT PRACTICAL PLANNING "

BACKGROUND

Nowadays *analyses of the expected dynamic behaviour of power systems* are playing an increasingly important role in the *planning stage* due to many factors, among which:

- tendency to exploit power systems closer to their technical limits
- increased uncertainty in the generation expansion and, in many cases, lack of centralised control in the selection of the best location and size of new power plants;
- installation time of new power plant (e.g combined cycle) shorter than in the past
- need to accurately define the NTC (Net Transfer Capacity) between interconnected systems taking into account the dynamic constraints.
- increasing diffusion of *generation based on New Technologies or Renewable Energy* that requires a careful modelling of new types of generators and associated control systems (especially in case of non-dispatchable generation such as wind farms).
- higher exploitation of interconnections to foster the commercial energy transactions (with consequent need of accurate *modelling of the protective devices , including special protection schemes*- and of investigation of their behaviour in dynamic conditions).

In the past, an extensive activity on dynamic modelling of generation and network components has been carried out, among others, in SC-38. Scope of the activity of this new WG is the selection of the most appropriate models and their fitting in the *practical planning procedures*, taking into account the deep changes occurred in the recent years and the new technologies now available.

SCOPE

To provide the planner with a guideline pointing out the most appropriate and update dynamic models to support "practical planning".

The work will be mainly addressed to the dynamic models to be applied to the new technologies utilised in power generation as well as in network components (e.g.: new types of generators, power electronic equipment, higher level of network automation and protection allowing increased power transfer in security conditions).

The steps proposed to achieve the above-mentioned target are:

1. **Examination of the most recent dynamic models to be applied for the new technologies utilised in:**
    a) units and associated controls for power generation . Special attention has to be paid to the power production from renewable, especially from wind, that is likely to remarkably increase in the near future;

b) network components. The examination will mainly be addressed to the new components based on power electronics and the new issues related to the network automation.

During this phase the WG members will also provide the reference of the software tools, which have the possibility of simulating the new types of controls and network components.

2. Review of the dynamic analyses presently carried out at the planning stage.

- Procedures presently applied by TSO, ISO or vertically integrated electric companies concerning the dynamic analyses at the planning stage;
- Standards or rules applied by countries operated in pool (e.g.: UCTE, NORDEL, COMELEC, MASHREK, etc.) or isolated, as for the acceptable dynamic disturbances

3. Proposal of the most appropriate dynamic models to be used for a "practical planning":

a) dynamic models for renewable applied to the planning of:
  - isolated systems (e.g.: Ireland, Iceland, etc.).
  - weakly interconnected systems with AC (e.g.: Egypt) or DC tie-lines (e.g.: Sardinia);
  - strong interconnected systems (e.g.: Denmark).

b) dynamic analysis for planning new interconnections

c) dynamic analysis for exploiting at a higher level the existing interconnections (e.g.: sections Italy-"rest of Europe", France-Spain, Spain-Portugal)

Deliverables and time schedule

Installation of the WG C1-4	January 2003
Beginning of the work	September 2003
Intermediate Report (see points 1 and 2 of the WG Scope)	April 2005
Final Report (see point 3 of the WG Scope)	April 2006

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Approval by TC Chairman : **Date :**

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APPENDIX 3. QUESTIONNAIRE PREPARED BY WG 04 OF SC 1 AND CIRCULATED TO PLANNING RESPONSIBLE

QUESTIONNAIRE

1. General Information

a) General information from the Entity asked to reply the questionnaire.

Entity name: …………………….
Country: …………………….

Is your Entity a:

- Independent System Operator ☐
- Transmission System Operator ☐
- Vertically Integrated Utility ☐
- Regulatory Body ☐
- Ministerial Body ☐
- Other (please specify) ☐

Please, tick as appropriate.

What is the degree of "market opening" (threshold of eligibility)?
(please provide a breakdown per region if necessary)

General information on the size of the system object of planning studies:

Installed Power: ……. MW
Production ……. TWh referred to the year ……
Consumption ……. TWh referred to the year ……
Voltage levels of the transmission system [kV]:…………
Length of lines (possibly split by voltage level): ………..

Number of substations ….
Transformation capacity ….. MVA
Interconnections with neighbouring systems?
Yes ☐ No ☐
If yes, how many interconnections?……. At which voltage level? ……..

b) Planning process adopted

Do you carry on dynamic analyses at the planning stage?
Yes ☐ No ☐

If no, do you think they shall be carried out or extended to other situations in the future?

Yes ☐ No ☐

For which needs?

☐

Please, go to the question 2.9

(should the dynamic studies executed by other dept. e.g. "operational Dept", please forward the "questionnaire" to them).

What is the time horizon of your planning studies ?

- Master Plan : years, updated every ….. years.

Does it include dynamic studies ?

Yes ☐ No ☐

- Regional studies: years, updated every ….. years.

Do they include dynamic studies?

Yes ☐ No ☐

2. DYNAMIC ANALYSES IN THE PLANNING PROCESS

Which criteria do you apply for dynamic analyses?

If you have a document describing the criteria you apply for dynamic analyses, you can include it to the questionnaire. Otherwise, as an example, you find here below a list of possible conditions to be fulfilled in dynamic studies

a) security conditions

- N-1 security, defined as compliance with thermal ratings with (i.e. after) or without (i.e. before) any dispatcher action :

  With ☐ Without ☐

- N-1 and N-2 security for double circuits on the same electric tower defined as compliance with thermal ratings with (i.e. after) or without (i.e. before) any dispatcher action :

  With ☐ Without ☐

- Other (please detail: N-k at power plants larger than …. MW, N-m at main substations) ….

b) Voltage

- limits in normal state (pre-fault condition: please provide the acceptable range in %): ……
- limits in alarm state (post-fault condition: please provide the acceptable range in %): …….

c) frequency
  - bandwidth in normal conditions: …….
  - bandwidth in post-fault conditions: …….

d) loading conditions in N-1 conditions
  - maximum overload for overhead lines and duration (please detail in minutes the durations considered and in % the related temporary overloads accepted): ......

  - maximum overload for transformers and duration (please detail in minutes the durations considered and in % the related temporary overloads accepted): ......

e) acceptable faults (please, describe the kind of faults, sequence and timing for the manoeuvres) e.g.: single phase fault / single pole opening after ….ms / unsuccessful reclosure at …ms / permanent three-phase opening
……

Which procedures do you have for dynamic studies?
Please, describe them.

How often dynamic analyses are carried out?
If occasionally, please give us an example. When the study was carried out? What kind of study?

2.1 Which aspects or situations do you investigate?

Connection of a new power plant with size greater than ……MW at voltage level …. kV (*please, specify the power and voltage thresholds)* ☐
Connection of wind farms to the distributions level (please detail: what is the required delay for reclosing or resynchronisation after a short-circuit: …. ms) ☐
Connection of wind farms to the transmission level ☐
Large potentially disturbing loads e.g.: steel plants with EAF ☐
New internal lines ☐

New interconnection lines ☐
Other (please specify) ☐

2.2 Which dynamic phenomena are studied?

a) large disturbances

Phenomena:

Transient stability ☐
Frequency dynamics ☐
Voltage instability ☐
Interarea oscillations ☐
Other (please specify: redispatching against overload cascades , interruptible loads,…) ☐

b) small disturbances

Steady state stability ☐

c) Subsynchronous resonance

SSR ☐

Perturbations. Which perturbations are simulated ?

1. Generator trip

test for all generators ☐
test for generators above a fixed threshold ☐ Threshold [MW]

2. Line faults.

Single faults (N-1 security)

Single circuit – three phase fault – no autoreclosing ☐
Single circuit – three phase fault with successful/unsuccessful autoreclosing ☐
Single circuit – single phase fault – no autoreclosing ☐
Single circuit – single phase fault – successful / unsuccessful autoreclosing ☐
Other (please, specify) ☐

Multiple faults (N-m security)

Tripping of all the circuits on the same electric tower ☐
Line + generator trip ☐
Other (please, specify) ☐

3. Fluctuations of non-dispatchable generation ☐

4. HVDC links: faults at the terminals, faults nearby the terminals (commutation failures) ☐

5. Islanding ☐

2.3 Criteria for selection of the events to be simulated

How do you select (or identify) the events to be simulated ?

- by expert judgement ☐
- by screening cases not compliant with a criterion, as per static calculations (contingency analysis: systematic N-k, ...). ☐
- by selecting outages of all branches loaded higher than a threshold ☐
- other selection criteria: please specify

☐

2.4 Responsible for the definition of the planning criteria and rules

Approved by the Entity responsible for the planning ☐
Approved by the Regulatory Authority ☐
Approved by the Ministry of Energy ☐
Approved by the "co-ordinator" Body (in interconnected systems) ☐
Other (please, specify) ☐

2.5 Dynamic models used

- Generators (directly connected to the transmission grid):
  - Synchronous machine ☐
  - Speed governors ☐
  - Frequency control ☐
  - Turbine controls ☐

Boiler controls, penstock dynamics ☐
AVRs ☐
Limiting circuit dynamics ☐
Automaton for redispatching: “complex” protection schemes ☐
PSS ☐
Other (please, specify) ☐

- System controls:
  AGC ☐
  Secondary Voltage Regulators ☐
  Other (please, specify) ☐

- HVDC links:
  Thyristor based: converter controls ☐
  IGBT based: converter controls ☐
  Other (please, specify) ☐

- Controlled network components (FACTS):
  Controlled Series Compensation (TCSC, TPSC) ☐
  LIC (Line Impedance Control: series capacitors) ☐
  Phase Shifting Transformers, Phase Angle ☐
  Regulators, Quadrature Boosting Transformers ☐
  SVC (Static Var Compensator) ☐
  STATCOM ☐
  UPFC ☐
  Other (please, specify) ☐

- Wind farms:

Modelling of wind turbine generators with their generator and protection system representation only ☐

Modelling of the relating control system too ☐

Asynchronous generators

Direct grid connection ☐
Grid connection via DC link ☐
Dynamic slip control ☐
Doubly fed Induction Generator ☐

Synchronous Generators

Direct grid connection ☐
Grid connection via DC link ☐

Grid connection via DC link gear-less ☐

Other models/ controls

Please specify: … ☐

- Dispersed generation:
  - Small Hydro Turbines ☐
  - Power electronics based Micro-Systems (fuel cells, micro-turbines) ☐
  - Photovoltaic Systems ☐
  - Superconducting Magnetic Energy Storage Systems ☐
  - Battery Energy Storage Systems ☐
  - Flywheels ☐
  - Others, please specify:… ☐

- Load model

Static Model

Constant impedance ☐
Constant current ☐
V-f dependent laws ☐
Other (please, specify): …. ☐

Dynamic model

Dynamic model ☐
If "yes", please, describe shortly which dynamic model(s) is (are) used

- Protections: distance protection ☐
- Protections: overload protections ☐
- Protections: others (please specify) ☐

- Network automata (like changeres of topology …) ☐

- Dynamic equivalents:
  Do you use dynamic equivalents in large-scale system studies? ☐

2.6 Validation of Dynamic Models

About the synthesis and validation of model parameters, are the models based on test measurements?

Yes ☐ No ☐

If yes, please, specify for which components.

2.7 Software Tools

In-house developed ☐
Commercially available ☐

If you use commercially available software, could you, please, indicate its name and the distributor?

Main characteristics of the tools (if more than one, please duplicate the following two tables and fill them in):

simulated phenomena

electromagnetic transients ☐
electro-mechanical transients ☐
long term stability (frequency dynamics, interarea oscillations, slow voltage instabilities) ☐
Steady state stability ☐
Subsynchronous Resonance ☐

Controls

built-in libraries ☐
models developed by the manufacturer ☐
models developed by the software provider ☐
user developed models ☐

2.8 Needs for further developments of dynamic models

Lack of models for new network equipment ☐

Lack of models for wind farms ☐

Lack of models for Dispersed Generation to be considered in power system dynamic studies ☐

Lack of information on new generating units ☐

Others, please specify: ☐

2.9 What prevents you from carrying out dynamic analyses at the planning stage?

Unavailability of software tools ☐

Resource problems ☐

Lack of data ☐

Lack of experience ☐