Chapter 8

# STABILITY CONTROLS WITH INDUSTRY RESTRUCTURING

Industry restructuring from a highly centralized hierarchical and possibly state-owned system to a new model characterized by competition in generation with guaranteed access to transmission has many impacts on power system stability.

Unlike the case of other industries such as communications and transportation where overloads result merely in telephone busy signals, or gridlock at toll plazas, power consumption is instantaneous. Power must be supplied the moment a switch is turned on. Inadequacies in the generation/transmission plant can result in system collapse with unacceptable consequences.

The dynamic performance of power systems, that is the ability of maintaining reliable and stable supply within tolerable limits of voltage and frequency, is a function of the joint characteristics of generation, transmission, control and protection, and loads.

In the traditional approach of integrated planning of bulk electric systems by a centralized company or agency, the decision process on generation, transmission, distribution, and control additions was well structured. The aim was an optimum allocation of investment in the various segments so as to achieve a prescribed level of reliability at minimum cost.

In Brazil for example, the plans of generation additions were established almost independently, with mere estimates on transmission feasibility. This was due to the high relative cost of generation. Transmission planning then proceeded to accommodate an already established generation master plan.

The recent abundance of natural gas and the rapid progress of combustion turbine and combined-cycle technology has drastically changed the economics of generation. Concurrently, the worldwide trend to deregulation has opened the power generation industry to independent producers. The restructuring of the power industry requires establishing requirements for new generation equipment and controls, and requires administering the required ancillary services in the new operating environment.

So while competition will force the evolution of the most economic generation additions, there will still be some aspects of dynamic characteristics requiring cooperation dictated by the effects on overall system performance. Stability control, including the equitable allocation of associated costs, is one such issue.

## 8.1 Some Examples of New Scenarios

### 8.1.1 The Brazilian electric system

The predominantly hydro Brazilian system spans large geographical distances and has most of its generation remote from load centers. Unfavorable hydrological conditions frequently call for high power transfers between regions, even during light load conditions. Stability problems are therefore naturally aggravated during these conditions.

Up to now, the allocation of costs of stability controls has been decided jointly by the GCPS and GCOI, the national coordinating pools for planning and operation of the Brazilian power system, whose decisions are mandatory. The stability controls considered include control of system oscillations (PSS), generation dropping, underfrequency load shedding, dynamic voltage controls, HVDC controls, controlled islanding, and automatic switching of shunt compensation.

In the old system structure stability problems were detected and resolved by GCOI/GCPS. The introduction of IPPs, cogeneration, and an ISO (Independent System Operator) changes this picture. Attributing responsibility for a given stability problem and distributing the costs of candidate solutions are very complex issues with opposing opinions. There is therefore need to investigate these aspects in order to establish guide-lines, responsibilities, and associated costs for stability controls in a competitive environment.

The Brazilian electric system has an installed capacity of 56,000 MW which is predominantly hydro (95%), has 150,000 km of transmission lines of voltage levels from 138-kV to 765-kV. The energy production is of the order of 309 TWh, with 97% being from hydro. There are about 40 million consumers, with 32.5 million being residential consumers. The energy consumption per capita is 1,954 kWh/year for residential consumers.

Other Brazilian system characteristics are:

- Large capacity hydro power plants remote from the load centers.
- Large hydroelectric dams, having up to 5 years storage capacity for good regulation of variable inflows.
- Hydro units of large capacity: Itaipu (700 MW), G. Munhoz (418 MW), Itumbiara (380 MW), etc.
- Long transmission lines, sometimes presenting bottlenecks in some transmission corridors.
- Frequent operating conditions with heavy energy transfers, even during light load, due to hydroelectric generation coordination for optimal water usage.
- High load growth (6% per year, during 1996/1997).
- Delays in construction of high capital investment power plants, with consequent need for urgent generation expansion.

During unfavorable hydrological conditions, the transfer of large blocks of energy between generating subsystems having hydrological diversity is carried out mainly during light load conditions. In some parts of the system, it’s common to have reversals in the power flow of some transmission lines and transformers. In a few cases involving highly unfavorable hydrological conditions, the system has operated with violations of the existing criteria of transient stability. Note that in these cases the system must still meet the criteria for small-signal stability to avoid spontaneous oscillations.

As stated before, there are two coordinating bodies for the expansion planning and operation of the interconnected systems, which are composed of managers from Eletrobras and all the other Brazilian utilities—the GCPS (Coordinating Group of System Planning) and GCOI (Coordinating Group for Interconnected Operation). These two groups perform stability studies, and establish recommendations concerning the required control actions for system stabilization.

**New scenarios for the Brazilian electric system.** The last Ten-Year Plan, released every year by GCPS, estimates that the rise in electrical energy demand in the period 1997–2006 will call for the installation of an additional 3200 MW of generation every year. Two immediate questions appear: a) How will the transmission system evolve? and b) What will be the expansion process for this additionally needed generation?

Taking into account the ongoing restructuring process of the Brazilian electrical industry, the government stimulus to private investors, and the highly developed technology for combustion turbines, it's possible to envision the following scenario:

- Significant increase in thermal generation, mainly gas turbines. It's expected that in the next ten years gas turbines will represent 10% of the total installed capacity.
- Implementation of several international interconnections, initially with Argentina, Uruguay and Bolivia, through long distance or back-to-back HVDC links.
- Utilization of alternative energy sources: Wind power and solar generation, biomass (sugarcane leftovers), mainly in the northeastern part of the country.
- Significant rise in distributed generation.
- Operation of the existing system closer to its maximum limits.

The above scenario is very likely because:

- The country needs to increase its generation capacity in the immediate and near future, so as to prevent severe power shortages.
- The newly implemented legislation regarding IPPs and the open access created favorable conditions for these new agents. The reduced construction period for gas turbine power stations is ideal for rapidly commissioning the needed additional generation. Another advantage is that gas turbines can be located close to the load centers, therefore minimizing high investments in long distance transmission.
- The technology development of combustion-turbine driven power plants makes the combined-cycle power plant one of the most efficient forms of power generation, offering very-competitive energy prices. These power plants cause low environmental impact, with negligible levels of audible noise, atmospheric pollution and emission of liquid or solid waste. The turbine has acoustic insulation, the natural gas has very low levels of sulfur, and the burners can meet the most severe environmental legislation. The gas supply to these power plants is guaranteed by Petrobras (newly-discovered

gas fields as well as imported gas), together with the gas pipelines Bolivia–Brazil and Argentina–Brazil. There will also be gas pipelines within the Brazil to distribute gas.

- Another important factor is the co-generator with Petrobras as the biggest. Considering the various oil fields and refineries owned by Petrobras where the gas is currently being burned, it's estimated that as much as 10,000 MW can be generated.
- The north–south interconnection, commissioned February 1999, interconnecting the north/northeast system to the larger south/southeast/centerwest system. It's a 500-kV circuit, 1,000 km long, which will bring a gain of 600 MW of guaranteed energy by making optimal use of the hydrological diversity between the river basins involved. This interconnection together with those with Argentina will cause some areas of the system to operate close to their maximum transmission capacity. As described in Chapter 7, this interconnection has TCSCs for enhancing stability [8-6].

The scenario calls for the solution of an important structural problem: How to stimulate private agents to build hydro plants? There is still a considerable hydro potential to be explored in Brazil that is economically feasible. This requires, however, an intensive capital investment, and private agents prefer investments that can be recovered in shorter periods. Undoubtedly, the solution for this problem is to form partnerships between private investors and Eletrobras, so as to ensure that investments that are sound for the whole system will actually be made. In this case, long distance transmission with the need for stabilization actions will be required.

In addition to the above factors and uncertainties that have a major impact on the overall system dynamic performance, there are the effects of major changes in the generation scenarios over the next two to three years. A significant amount of gas-fired generation will be operating close to the major load centers.

All of the above factors point to continued importance of the phenomena of system stability and increasing dependence on control actions. The problem in the new competitive generation framework is how to establish costs, both first costs and operating costs for controls and how to allocate them among the various parties.

### 8.1.2 The Nordel power system

The Nordel power system comprises the interconnected power systems of Norway, Sweden, Finland, and part of Denmark. The other part of the Denmark, which is interconnected with the UCPTE system, has strong connections to Nordel through several HVDC links. The Nordel system has undergone major changes during the last decade due to restructuring. The aim of this section is to give a brief overview of the changes, and to describe possible impacts with respect to stability control.

The Nordic power systems are characterized by a mix of hydro and thermal generation. While Norway has almost 100% hydro generation, Finland has mainly thermal generation and Sweden has an even mix of thermal and hydro generation. The Danish system is unique with a high penetration of wind energy and co-generation from independent producers (see next section).

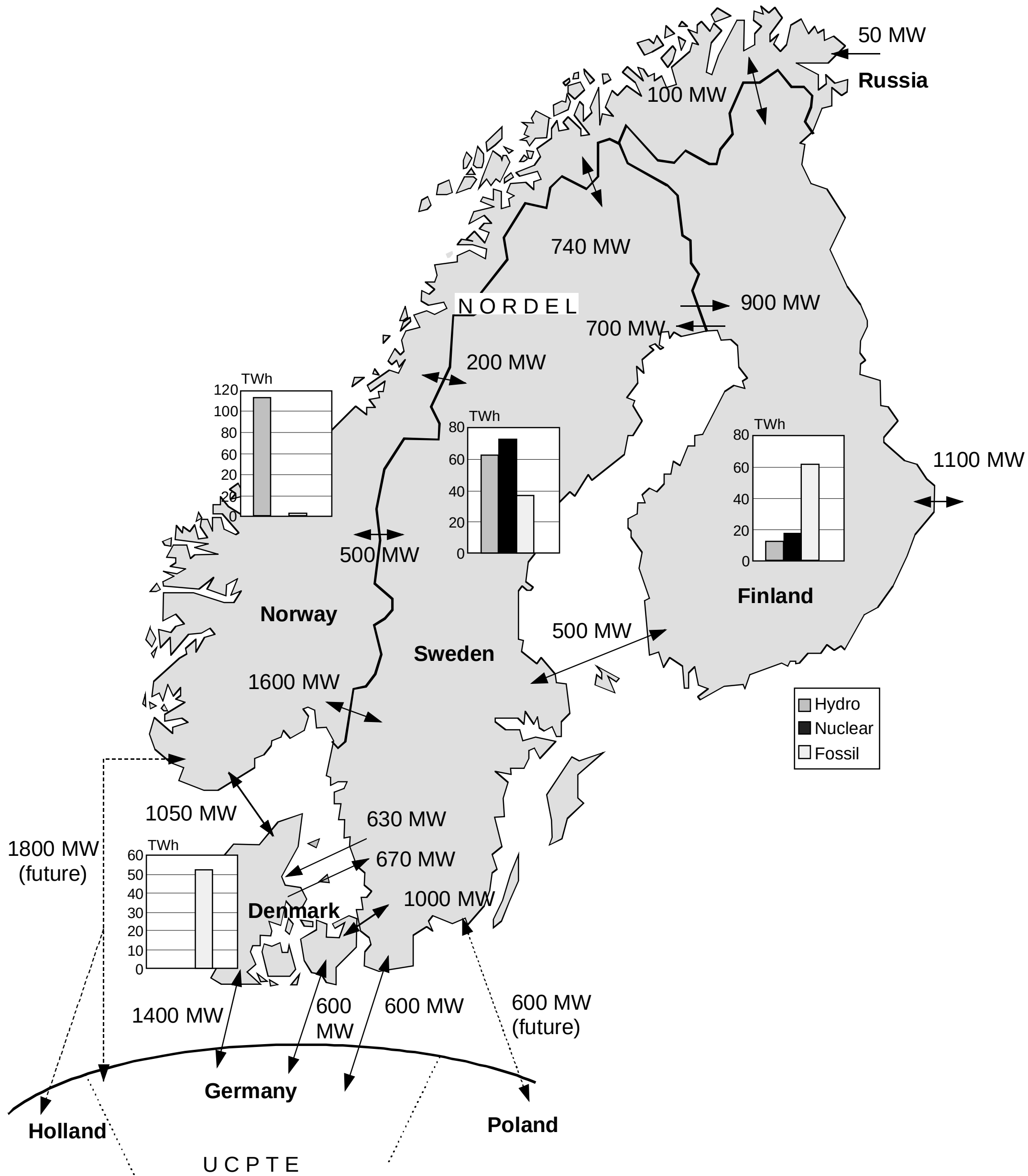


Fig. 8-1. Generation and transmission capacities in the Nordic Countries.

Fig. 8-1 shows the total annual generation in the Nordic countries, and the transmission capacities between the countries and to the European continent.

**Restructuring in the Nordic power systems.** The restructuring started in 1991 with deregulation of the Norwegian electricity market. Sweden followed in 1996, and Finland joined the common Nordic market in 1998.

Restructuring, in general, deals with the following issues:

- Unbundling of services.
- Deregulation within trade of electrical energy.

- Dis-aggregation of utilities. Economically and functionally separate units are established within power generation, transmission and distribution, power markets and retail sales.

In the Norwegian case, the major arguments for restructuring of the electricity market have been to:

- Avoid excessive investment.
- Improve selection of investment projects.
- Create incentives for cost reduction.
- Create equity among consumers.
- Achieve reasonable geographical variations.

The main actors in the Norwegian (and Nordic) power market are:

*Regulator*. The Regulator of the Norwegian power industry is the governmental body "The Norwegian Water Resources and Energy Directorate" (NVE). The Regulator grants regional concessions and concessions for trade in electrical energy and has an important role in supervision of the monopoly operations in transmission and distribution.

*Market Operator*. The Market Operator is responsible for the market clearing process in what is called the organised markets. The operator of the common Norwegian/Swedish/ Finish market is Nord Pool. Nord Pool is also open to market participants without physical access to the Nordel grid. See Nord Pool's web site [8-17].

*System Operator*. The main grid company, Statnett SF, has the system operator responsibility in Norway. Similarly, there are independent system operators in Sweden and Finland, Svenska Kraftnät and Fingrid, respectively [8-17]. These companies are also the main transmission grid owners in their respective countries.

*Market Participants*. The Market Participants are buyers and sellers in the market, and include generators, distributors, industry, and traders/brokers.

*Network Owners*. The Network Owners have by regulation been given the responsibility for generating and distributing metering and settlement data, and keeping continuous track of the information so that equal opportunities are given to all the competitors.

The report *Deregulation of the Nordic Power Market, Implementation and Experiences 1991–1997* [8-18], issued by SINTEF Energy Research, Statnett, Nord Pool and the Norwegian Electric Federation, provides further information.

*Retail Sales*. Retail sales are yet another service made possible through deregulation, but is only indirectly related to the power exchange. Retail sales mean that the individual electricity consumers are free to choose from which power company they buy their energy, totally independent of which network owner (distribution grid) they are connected to.

**Changes in system operation from restructuring.** There are some major changes from system restructuring that affect system operation and control. These relate to changes in objectives, responsibilities and ownership, as well as to new services and ways to operate the system.

*Changes in responsibilities and ownership.* This has to do with the unbundling of services that defines the responsibilities and tasks of the different entities. There is a mix of power producers, which are mainly economically motivated. Their main control objectives relate to control and optimization of their own energy resources and market obligations. System responsibilities, such as stability control, contribution to active reserves/frequency control, and reactive reserves/voltage control become secondary objectives.

*Increasing focus on cost efficiency.* This relates to both operation and to changing attitudes toward investments in new generation and transmission capacity. A result is that fewer new lines are being built, and the systems are operated closer to their capacity limits. New controls rather than new transmission lines will increasingly solve transmission congestion.

*Changes in operating patterns*. Deregulation of energy markets and increasing competition among the power producers lead to larger and more frequent changes in power flow patterns.

New services are introduced to deal with the changes discussed above. Monitoring and controlling system stability, system reserves, transfer limits, etc., which are the main responsibilities of the system operator, is to a large extent based on ancillary services.

*Ancillary services* are fundamental services needed in order to maintain acceptable power quality and power system security. The system operator will normally contract or require the individual power producers to provide some system services. The services may range from primary frequency and voltage control, including stabilizing control, provision of active and reactive reserves and system protection (load shedding or generator tripping) schemes. Ancillary services can be organized as firm requirements (e.g., primary controls), possibly with fixed economic compensation, as contracted services (bilateral contracts between the system operator and a power producer) or as market-based services. Secondary controls for congestion management or power balancing may also be defined as ancillary services, but organized in the Scandinavian countries through separate markets.

**Impact on system stability and control.** The changes from restructuring may impact power system stability and system controls.

Experience indicates that deregulation has caused decreasing investments in new transmission and generation capacity, and thus the existing systems will be operated closer to their capacity limits. Increased utilization means less reserves and more transmission congestion. Thus the need for stability controls will also increase. Larger and more frequent changes in power flow patterns will increase the need for coordinated and more robust control solutions.

Well-functioning system (or ancillary) services are crucial in the restructured environment. In order to become less dependent on ancillary services provided by generators, it is likely that system operators will show increasing interest in deploying power electronic devices for congestion management (power flow control) and stability control. Development and application of new energy storage devices for fast-acting reserves may also become more attractive in the future.

Another way of handling transmission congestion is to rely more heavily on special protection schemes. Thus there is a need for robust and coordinated design in order to avoid adverse interaction between protection systems and other controls.

In order to monitor and coordinate the increasing control applications, there is a need for improved EMS tools at the system -control centers. On-line tools for voltage stability and transient stability assessments will become increasingly important.

In summary, the major impact on the technical side from system restructuring is an increasing dependence on controls in order to cope with the increasing competition among power producers and the increasing utilization of existing transmission grids. This dependence on both existing and partly new control devices will require sophisticated design as well as improved tools for on-line system operation.

Power system security and power quality may be regarded as collective benefits. In deregulated systems the system operator is given the overall responsibility for maintaining the security and quality criteria. Having one such independent entity may also prove advantageous regarding the technical possibilities of providing coordinated controls.

### 8.1.3 The Danish electric system

Large variations in power transfers in transmission networks of large interconnected systems must be expected in the future. One part of the power variations will come from controlled power plants delivering power to remote consumers or power companies on short-term conditions. For this type of power variations, the system can at least have a short time warning, and the system operation can be adjusted to be able to handle the power transfer.

Another part of the power variations will come from uncontrolled power plants such as wind generation. It will be most easy to include a large amount of wind power in a system if the natural changes in the power production is allowed to spread freely over a large area. The probability that all the wind production will change rapidly in an equal way is smaller the larger the system is. By allowing the power variations to spread freely over the entire system less demands will be put on the control of the controllable power plants in order to maintain a local power balance. Besides, wind power and hydro power combines very well, and a free exchange of power between hydro areas and wind areas is desirable even when located far from each other.

In Denmark 800 MW of wind power was installed in 1997, out of a total capacity of 10,000 MW.

Both the desire for larger power transfers and the increased uncertainty of the power changes create a need for advanced angle stability control.

## 8.2 Coordinated Planning and Operation in a Competitive Environment

Organizational and administrative issues under the new competitive environment can only be resolved successfully following recognition of technical factors that make interconnected operation possible. We raise issues for discussion without advocating particular administrative and financial approaches.

### 8.2.1 Assuring compatibility of equivalent dynamic characteristics

In the traditional vertically-integrated power company, the overall system reliability is the responsibility of one entity, whether state or investor owned. In this environment the acceptable characteristics of generation, transmission, control and protection evolved naturally to fairly uniform patterns among various utilities, as dictated by techno-economic considerations. There would be no tendency to under invest in one segment (generation, transmission, or controls) causing a disproportionate impact on reliability. In this scenario the cooperative approach to accepting one's share of investment, dictated by dynamic considerations, was natural for mutually beneficial interconnected operation.

Where necessary, organizations such as NERC, NPCC, WSCC, ERCOT etc. in the USA, UNIPED in Europe and GCOI/GCPS in Brazil issued recommendations on practices to be followed by all members of such power pools. Examples are in the area of primary frequency control (droop settings and spinning reserve) and automatic generation control (area control error reversals per hour etc.).

For interconnected systems using long distance transmission, the problem of poor damping of inter-machine and inter-area electromechanical oscillations presents a serious reliability problem. The techno-economic solution is to distribute control effort (PSS in this context) over most generators. Members of interconnected systems owning both transmission and generation follow voluntarily the guidelines set by coordinating councils (e.g., in the WSCC every unit over 75 MVA is to be equipped with a PSS).

Since this problem of damping can also be abated by adding transmission, one can appreciate the problem of enforcement of the most techno-economic solution. This solution is usually borne by the generation segment, where independent producers have no perceived stake in transmission.

This dilemma extends to other system reliability aspects such as transient stability, load shedding, and generator dropping.

Distributed generation in systems linked by EHV and UHV transmission can present major challenges in system and protection design. Load rejection and system separation, with overspeeding generators connected to excessive line charging, could lead to very high overvoltages and widespread damage to system and consumer equipment.

It's not merely stability that must be addressed. The entire system design must be by a highly trained team considering all relevant parts of the system regardless of ownership.

Reference 8-4 describes how the evolution of system structures can affect the necessity for stabilization and its location. Loading, with its effect on angle separation and relative inertia between sending and receiving areas, play an important role.

In systems with widespread transmission and significant interchange over long distance, the problem of oscillatory instability can dictate the need for stabilizing action under normal operating conditions. In other systems the problem arises only following contingencies. Since the nature of the system structure following multiple contingencies is almost unpredictable, units that normally are not participating in oscillation damping action can become important.

The effectiveness of PSS in providing damping is not only a function of their application on generating units, but also a function of the PSS and other excitation equipment control tuning. System-wide dependence on PSS for adequate damping performance will require more formal inspections and testing by the regional transmission organization (ISO or independent transmission company) of the restructured power industry.

## 8.3 The Impact of IPP Thermal Generation on System Dynamic Performance

### 8.3.1 Beneficial aspects of IPPs

New thermal-based IPPs will bring many benefits to the interconnected system:

- Being close to the load centers they will bring better voltage control and smaller loading of transmission lines, with consequent reduction in transmission system losses.
- Improvements in voltage stability, because of a larger reactive power support near the load centers.
- Improvements in electromechanical stability, due to smaller line loading and added dynamic voltage support. The damping of interarea oscillations will also tend to improve as a function of the smaller phase angle differences.
- Extra flexibility in planning equipment and transmission line outages.
- In Brazil, the availability of more thermal generation will allow an effective hydro-thermal coordination.
- Alleviation of the problem of ever-increasing transmission distances to bring power to the load centers.
- The better dynamic voltage control will yield a more reliable operation of transmission line distance protection, with a significant reduction in undesired tripping. This decreases the risk of system separation, frequency decay, and load shedding.

### 8.3.2 Detrimental aspects

IPPs, when compared with state owned or regulated generating companies, are oriented towards a higher and faster return on investment. Their motto is to maximize power production and reduce their costs. What could be the consequences? Some of the functions carried out for free in today’s environment (voltage support, frequency regulation, dynamic response, transient overload capability, etc.) are classified in the new environment as “ancillary service,” whose provision will have an associated cost. Some of these aspects are further elaborated in tables in section 8.3.4.

Offsetting some of the positive aspects of IPPs listed in §8.3.1 is the need for assuring redundancy in the case of unplanned outages of such facilities. Such outages result in loss of both power production and voltage support—which must be provided by alternate facilities.

### 8.3.3 Problem issues with new IPPs

Tables 8-1 and 8-2 list system design and operation considerations for the restructured industry. These issues generally involve dynamic aspects of the plant interacting with the power system. In the vertically-integrated traditional utility (or power pool made up of such utilities), the planning and design process is usually undertaken by owner representatives participating in joint interconnected system studies with access to the entire database. Reliability criteria are followed and the design process considers all logical cost-effective alternatives, whether they involve generation, transmission, protection or control.

In the restructured environment the technical approach should be the same since the mere fact of separate ownership of generation versus transmission does not change the underlying laws of physics which govern the reliability of overall system performance. The challenge is to develop an organizational structure to execute the necessary system studies and enforce the design requirements among the separate parties. As competitors, the parties have a natural tendency to hold back on free exchange of information. IPPs are concerned with the generation process and normally would not have the expertise to determine complex control and protection requirements dictated by the overall system.

The foregoing considerations point to the logic of a strong independent and competent organization to not only be in charge of system operation, but also of licensing future system additions in generation, transmission, control or protection.

Issues listed in the tables show the need to establish methods and procedures for requiring certain design features in IPP installations. These include providing ancillary services—for instance reactive power support, primary speed control, supplementary damping control (PSS) etc. Little has been done so far to develop such methodology, which should include allocation of costs to those agents not contributing their share of ancillary services.

If this is not done in the planning process, IPP additions may impact the adequacy of transmission networks. The resulting additional reinforcements needed in transmission would be reflected in transmission costs, which would have to be borne by all consumers.

**Table 8-1. Protection, System Voltage/Frequency Control, and Stability Aspects**

| Issue | Traditional Approaches | Problem issues with new IPPs |
|---|---|---|
| Protection settings | Settings take into account the plant equipment's and power system requirements | - Concerned only with plant equipment security.<br>- Larger possibility of plant tripping during disturbances.<br>- For disturbances that cause generation deficits, plant tripping will increase the magnitude of frequency dips. In this case it will be necessary to increase the total load shedding. In extreme cases it could lead to a system collapse.<br>- For disturbances that cause overvoltage, plant tripping can aggravate the voltage profile, increasing the chances of reaching transmission lines protection settings. The tripping of transmission lines could lead to a system collapse<br>- For disturbances that cause large absorption of reactive power by the generators controlling voltage profile, settings of minimum excitation limits can cause plant tripping. With increasing numbers of IPP plants, this can lead to larger system overvoltage and equipment tripping (or damage). |
| Generator power factor | Generators with low rated power factor (0.9) can be used. This can avoid network reinforcements. | Without consideration of system requirements during contingencies, the tendency would be to order less costly, higher rated power factor machines. The deficiency of reactive power reserve could require move expensive alternative equipment in transmission. |
| Short-time overload capability of generator excitation equipment | Exciters are able to produce up to 200% of rated reactive power for approximately 20 seconds. This improves system dynamic performance. | - Lower capacity excitation systems and conservative setting of limiters. This reduces IPP costs. The limiter actuation might be increased to protect excitation and generator windings against failure due to high voltage stress. This can lead to voltage control problems and even collapse.<br>- System requirements could be enhanced with greater MVAr reserves in generators. |
| Operation of generators as synchronous condensers | This characteristic is used during light load conditions in order to provide better voltage profile control, to maintain short-circuit level and to avoid transmission line opening to mitigate sustained over voltage during light load. | This expedient would require installation of clutches representing additional costs. |
| Excitation equipment, power system stabilizers and governors | Are fully utilized to improve the power system dynamic performance, being considered the most appropriate and economic means. | Application of higher cost machines with improved excitation systems (high initial response yielding move effective action from PSS) would not be normally adopted without some hard rules to define compensation of costs. |
| Participation in Special Protection Schemes (SPS) | The design and implementation of Special Protection Schemes (Emergency Control Schemes) are analyzed by all parties involved. The SPS is installed considering the best location, i.e., it can be installed in any plant. | The IPP may not accept to participate in any SPS. This non-acceptance may jeopardize system reliability and require system reinforcements. |

**Table 8-2. Operating Aspects**

| Issue | Traditional Approaches | Problem issues with new IPPs |
|---|---|---|
| Minimum number of units in operation | The number of units in each plant is determined to guarantee a minimum value of system inertia and reserve. | - IPP could consider that they have no obligation to do that, and maintain the number of machines in operation in order to obtain the maximum productivity of the plant.<br>- This could affect voltage control, system stability and increased frequency dips. |
| Generating unit operation with minor failures | When minor failures occur, the utilities may agree to keep the generating units in operation until system conditions evolve to level at which unit disconnection will not jeopardize the overall system reliability. | The IPP could consider that they have no obligation with system reliability requirements, the main objective being to protect their own equipment. |
| Information exchange and data availability | - To provide a more reliable and secure operation, abundant information is made available on current limitations/ unavailability of equipment and power flow constraints.<br>- Traditionally all the data are available including data from disturbances (oscillograms, plant operator reports, etc.,) for post operation analysis. | - The IPP could consider having no obligation to inform the others on what is occurring to his plant.<br>- This intentional withholding of information is detrimental to overall system reliability.<br>- The IPP could have inadequate data acquisition and recording equipment. |
| Black-start capability | The operational planning of the interconnected system determines the restoration planning with its various parallel subsystems.<br>-Every subsystem has at least one power station with black-start capability. | - IPPs, for cost reduction, may rely on remote power station cranking rather than install black-start capability.<br>- As a consequence, the system restoration time may be increased. |

### 8.3.4 Conclusions related to IPPs

1. Careful planning and design studies should establish the proper integration of IPPs into the interconnected system, including special requirements in equipment, and control and protection. The proliferation of IPPs, with their rapid installation cycle, can have detrimental impacts to system dynamic performance, which may not be fully compensated in the transmission network at reasonable cost.

2. Although transmission network investments will rise, the overall system reliability could be somewhat degraded in the future.

3. The eventual lack of control actions and the consequent rise in transmission prices can result in loss of economic efficiency in power production.

4. Many efforts have been noted to develop methods and tools for some of the ancillary services. So far, however, very little has been done concerning control action cost allocation. This should be considered a priority issue in order to ensure economic efficiency.

5. The transition period from the cooperative model to the competitive one will cause some additional risks, which are not fully assessed.
6. One way to minimize the detrimental impacts and additional risks, is ensure that selling ancillary services can be good business. Something should done, so as to make generation fulfill its natural or traditional ancillary functions. Finding other control alternatives in the transmission network (like FACTS) is always more expensive.
7. The Independent System Operator (ISO) concept is good, but that organization should have added functions in long term operational planning and, particularly, licensing and inspection of new facilities to ensure that they meet system requirements.

## 8.4 Other Issues Related to Power System Performance in the New Utility Environment

### 8.4.1 Reliability aspects

The forces of market deregulation have encouraged a widespread decline in planning resources, and have undercut the planning process itself. Unrealistic models provide a common point of failure for the entire decision making process whereby the power system is planned and operated. Compounding this, the system sometimes operates under conditions that planning cannot anticipate.

Market deregulation and utility restructuring are, through a variety of mechanisms, making it impossible to predict system vulnerabilities as accurately or as promptly as the increasingly volatile market demands. Controller-based options for reinforcing the power system can be very attractive. For a control system to be fully competitive in this respect, however, its functional reliability must somehow be established early in the planning process.

It’s rarely possible to do this within the conventional framework used for new transmission lines or for new power plants. It’ll always be necessary to trade the benefits promised by a control system against the inevitable risks associated with closing a high-power loop around system dynamics that are not fully understood. If the risks are perceived as too high, or if the functional reliability is perceived as inadequate, then system reinforcements though enhanced control will be displaced by less technically demanding means.

Reliability is just one intangible emerging in the new power system. Others include information security, regulatory changes, business survival, and the directions in which a particular regional transmission organization (RTO) evolves.

### 8.4.2 Implications of equipment ownership

As many electric power systems move toward deregulation, there is much focus on the economic issues associated with the new competitive operating environment; details of energy trading and pricing have been in the forefront. However, the ability to operate in such an environment with an acceptable degree of security and reliability, and indeed to be economically competitive, requires significant attention to the methods and strategies of power system control.

In the new environment, the power system comprises corporate entities having diverse roles, equipment, and business interests. There are independent generating entities, transmission entities, distribution entities and brokering entities. The physical functioning of the integrated power system, however, remains the same as before. Therefore, the responsibility for control of individual equipment should not follow ownership; instead it should be vested with RTO. The specification and design of these controls should be part of overall system planning and design carried out by an independent entity. Otherwise, system security and economy will be sacrificed, defeating the very purpose of restructuring the industry.

In particular, it's essential to recognize the critical role played by generator controls in maintaining system stability and controlling voltages and frequency. It should be mandatory for the generators to be fitted with fast-acting excitation system, AVR, and speed governing systems. In many cases, PSS should be mandatory.

The PSS should be designed and tuned so as to contribute to the enhancement of overall system stability, including damping of local as well as interarea modes of oscillation.

There should be no difficulty in motivating power plant owners to install controls that enhance the operability and stability of the generators. For those controls that are provided to meet the overall power system requirements there should be proper financial incentives.

### 8.4.3 AGC in the new environment

With deregulation comes the redefinition of system control areas. Both the introduction of new control areas and the consolidation of existing controls areas impact the way traditional control issues are handled. Traditionally, frequency control, achieved through the matching of generation to load, has been one of the functions of control areas using some form of automatic generation control (AGC). Although the extent to which frequency control is required is debatable, some control is required to prevent the instabilities and other adverse effects associated with excessively low or high frequencies. The control of frequency to tight tolerances is arguably associated with improved power quality which may be expected by some customers, but that is not strictly a requirement for successful interconnected operation.

In a deregulated environment it's not clear who will be responsible for any level of frequency control. AGC requires spinning reserve that can be valued as an ancillary service. While it's possible that certain parties will be prepared to provide such services for a price, what is not clear is the extent to which this will occur. The first issue of maintaining the frequency of a large system within limits required for secure operation is a natural byproduct of near matching of the load and generation which should take place under free energy trading.

The second issue of maintaining tight frequency control for power quality concerns should be based on value and price to consumers.

### 8.4.4 Modeling/data requirements — a bigger challenge

Equally important as the analysis method is the model used to represent the power system. It's essential the model represent sufficient detail and accuracy to properly reproduce all important system dynamics. While this has led to the use of very large system models (for example, North American Eastern Interconnection is often represented by more than 26,000 buses), analytical tools are available to handle such systems. Good dynamic reduction methods are also available which can be applied to reduce large models to more manageable sizes while retaining the key system dynamics.

Perhaps a bigger challenge is the availability of model data for various equipment, including generators and the associated controls, protective systems, and system loads. While phenomenal advancements have been made in terms of analytical techniques and computational tools, data acquisition has not kept pace with the requirements. Many utilities use "typical data" for modeling much of the equipment. For control and protection, the data is often not representative of the actual settings and, in many cases, the condition of the equipment. More effort is needed towards the acquisition and verification of model data. This is being increasingly recognized by the industry, particularly in the aftermath of major system disturbances. For example the two disturbances that occurred in 1996 on the western North American system have motivated the WSCC to mandate field measurement and model derivation for all generation units (unit, exciter, PSS, governor, and protection) greater than 10 MVA. Once good models are obtained (that is, they match the field response), then it's necessary to use this information to optimally tune the system. Once optimized, it's essential that field adjustments are not permitted without prior study of the impacts.

### 8.4.5 On-line dynamic security assessment and real-time monitoring and control

In the new power sector the system conditions are extremely unpredictable and the volume of transactions that may have to be examined may be huge. The traditional approach to deploying preventive and emergency controls based on off-line security analysis studies which generate a set of tables indicating stability limits and control measures may not be satisfactory.

In the new structure, tools are necessary, such as on-line transient stability assessment and voltage stability assessment. These are described in Chapter 5.

In order to make these new tools useful, it's necessary obtain reliable on-line input data.

It's necessary adopt real-time system monitoring and control. An example of such a scheme is a wide-area measurement system (WAMS) being developed by Bonneville Power Administration western North American. The WAMS use synchronized phasor measurements and portable power system monitors to centralize information at control centers.

### 8.4.6 Alternatives for pricing of stability controls in a deregulated industry

The shift to a market-based structure necessitates the unbundling of services by stripping out non-energy costs and identifying ancillary services that have costs and value. The following is based on procedures of the Northeast Power Coordinating Council in North America [8.3].

With the re-regulation of the electric power industry one important question appears: Will proper market signals in combination with commonly accepted "best practices" foster competition and preserve or even enhance the reliability of the system? This represents a difficult challenge with respect to the interface between the market driven generation sector and the regulated transmission system that may be under the control of an Independent System Operator (ISO). However, the prudent use of Special Protection Systems (SPS) and Dynamic Control Systems (DCS) can play a vital role in enhancing both competition and system reliability provided that proper market signals are implemented.

**Performance requirements.** In all cases of SPS, the design and operation must be consistent with all criteria, including protection criteria. Depending upon the type of SPS, varying degrees of functional redundancy may be required to ensure reliable operation. For example, Type I (SPS with potential for interarea impact, initiated by normal conditions) may require two independent protection schemes while a Type III (SPS with potential for local impact only) may require only one set of system protection. In addition, for loss of an element without a fault or due to a single line to ground fault cleared in normal time, the failure of an SPS circuit breaker is considered as part of the normal criteria. Thus there are situations where excess generation may be armed for rejection to ensure that sufficient generation is successfully tripped for a critical fault.

The design and operation of the DCS must be approved by the ISO. Once approved, procedures must ensure that the DCS performs as intended. Note that the NERC Standards require the generator owners to provide accurate and timely steady state and dynamic data for their generating units [8-8]. Modeling should be consistent with industry standards, such as IEEE models. In order to ensure the proper modeling of excitation equipment (also other machine and governor parameters), the ISO could conduct audits (similar to machine parameter measurement R&D projects) as required. In addition, event reconstruction by simulating actual system events and comparing the results with the actual machine performance could identify units with suspect parameters. It's necessary that any changes to the control parameters be communicated to the ISO.

DCS are subject to reliability standards that ensure dependability and security. For Type I DCS (whose incorrect operation or failure to operate following a normal criteria contingency would have interarea or interregional consequences), design requirements specify that the DCS should perform its intended function for specified Bulk Power System (BPS) contingencies while itself experiencing a single undetected failure. This means that vital subsystems should either have a functional redundancy or sufficient self-diagnostics so that there would be reduced dependency on the DCS in setting transmission system limits. All Type I and Type II DCS (installed for the purpose of mitigating the interarea impact of extreme contingency) are designed so that a critical failure of the DCS itself does not cause unacceptable BPS behavior. Similar to protection system criteria, owners of DCSs have obligations to perform both maintenance and monitoring functions.

**Justification for SPS or DCS.** The implementation of a SPS or DCS is dependent upon the system conditions that justify their use. We discuss two main categories of SPS use: reliability and economy.

*Reliability*. An approach to defining reliability is to recognize that the SPS or DCS is providing greater resiliency to the operation of the network when the device is not required in the setting of normal limits on the system. For all DCS and those SPS required for stability, the devices are in effect providing greater stability margin to the system for a particular set of contingencies. An alternate approach to reliability does not account for the additional robustness of the system, but rather defines reliability as the requirement that the implementation of a DCS or SPS cannot reduce the operating limits of the network. (If there is a reduction, then there are economic penalties.)

If the system is operating in an insecure state (for either normal or extreme contingency criteria) and the arming of an SPS or DCS would return the system to a more secure state, the SPS or DCS becomes essential to maintaining reliability. For example, immediately upon the loss of one or more transmission facilities, the interface flows may violate the permissible normal criteria transfer limit. For this scenario, a Type I SPS could restore the transfer limit.

*Economy*. The economic use of an SPS or DCS applies when the device is required to increase the normal transfer limit of the system. In this case, the use an existing SPS or DCS as well as the planning of a future SPS or DCS would be driven by the transmission tariff structure.

In the future it may be possible to attribute an improved loss of load probability to particular SPS or DCS. This could then be weighed against the value that the load places on enhanced reliability of service. It is judged that this will present not only technical challenges, but will no doubt be complicated by the regulatory process required to approve this methodology.

**Payment Schedules for SPS and DCS**. Several options exist for the payment schedules for the arming of existing SPS and DCS, as well as for the implementation of future devices. Some options:

*Don't Pay*. In the Don't Pay scenario, it's assumed that all existing SPS and DCS continue to function in a secure manner, but there is no special payment made for their use. Future system additions could be addressed through rules such as a requirement that all future generators are required to have high performance excitation systems that include power system stabilizers (PSS). The Don't Pay method could also require payment from the SPS or DCS providers if they failed to preserve existing system transfer limits.

It's not clear if the Don't Pay option will cause any degradation in the reliability of the system with respect to the implementation of SPS and DCS. In the short term the primary focus of generator providers will be on issues that are more economically lucrative. It's also well recognized by market participants that the great experiment in the deregulation of the electric power industry could come to an abrupt end if there were many interruptions of load. In the long term, the robustness of the network could improve if price signals locate new generation closer to the load and overall system transfers are reduced. This scenario would of course reduce dependency on SPS and DCS.

*Embedded Cost.* This method recognizes the benefits of SPS and DCS and seeks to make the provider cost neutral, but without necessarily accounting for lost opportunity costs. We discuss the possible use of an Embedded Cost method, first for SPS and then DCS.

The payment for arming a SPS would include paying for the installation and maintenance of the protection system as part of the Transmission Service Charge (TSC) or Transmission Uplift Charge (TUC). For Type I SPS the ISO and all market participants (the generator, transmission owner, and the load) are the beneficiaries of the reliability aspects of the SPS. However, the generator is not compensated for any additional transmission capability that may be available as the result of arming or installing the SPS. For Type II SPS the system has an extra degree of security against extreme contingencies. However, the generator, transmission facility, or load providing this service is placed at risk. In the event that either Type I or Type II SPS is triggered and works as designed for an actual contingency or has an undesired trip (within reason), payment shall be as follows:

GR (generation rejection or reduction)—The unit must be made "whole" otherwise the unit would not be willing to provide the extra measure of security. Therefore, back-up power is supplied free of charge to the generator if it is rejected. (It's assumed that only a limited number of false trips due to the SPS would be tolerated.) If this power is from the economy (perhaps the Location Based Marginal Pricing or LBMP) market, then the differences between the economy market and the rejected generator's price is provided from the TCT (Transmission Cross-Tripping).

TCT (Transmission Cross-Tripping)—No payment. The ISO has responsibility for system reliability and the TCT provides an extra level of security.

LR (load rejection)—No payment. SPS is in the same class as underfrequency load shedding. Eventually there may be reliability-based rates and the load which is placed at risk might get a discount.

For Type III SPS (with potential for local impact only)—the local area is the beneficiary of the SPS. Local arrangements could be made to compensate the involved parties.

A proposal for the payment of the DCS is dependent upon several factors, including whether the control is excitation equipment or governor related, the type, and the inherent transmission rate structure.

Excitation equipment tuning and supplementary controls, such as power system stabilizers, are essential to the stability performance of the system. They are considered as part of the "Voltage Support and Control" Ancillary Service and the payment for this category of DCS is thus highly dependent upon the transmission rate structure.

Transmission tariffs for Voltage Support and Control are often “embedded” or cost based rates. For this scenario, the generator is paid for a portion or the full capital and operating cost of the DCS.

Excitation equipment improvements, such as replacement with solid state systems and/or the addition of PSS could result in greater system resiliency, particularly with respect to extreme contingencies. In other instances, the modification to the excitation system may not be capital intensive and could require simply changing a gain. In either case it’s suggested that the embedded cost method would pay the generator for all or part of the excitation equipment modification. It’s recognized that the generator would not realize any additional benefits from increases in transfer limits.

Turbine governor DCS fall into several categories. Those that provide frequency response and regulation services usually impact the long-term dynamics of the network and are commonly addressed by transmission tariffs. It would be a difficult task to economically quantify the differences between the control performance (AGC) response and the DCS turbine governor response. Other DCS, such as fast valving, impact the short-term dynamics and can be handled similar to a SPS.

*Market-Based Rates*. The proper price signals would establish an economical incentive for providing SPS and DCS services. It’s interesting that generators on the downside of, and loads on the upside of, a congested transmission interface might be reluctant to make system improvements resulting in higher transmission operating limits. This is because the higher limits would result in the generator receiving a lower LBMP and the load paying a higher LBMP price. The generator could proceed with the improvement by making financial arrangements with other market participants. However, the question of how the ISO would arrange for system improvements justified by improved system resiliency needs to be determined based upon the particular ISO definition or reliability. We now discuss possible Market-Based Rate methodologies for SPS and DCS.

For a Type I SPS resulting in higher system transfer levels, there is a cost saving to customers. However, the SPS comes at a cost to the owner of SPS, possibly including a lost opportunity cost, as would be the case for the rejection of generating units. The SPS holder could theoretically claim an allocation of transmission that could be handled in any number of different ways. The transmission allocation could be defined as the increase in transfer capability across a congested interface. In this case, the Transmission Provider could offer a payment based upon a percentage of the expected increases in wheeling revenue. An interesting approach to determining the value of and location of the transmission allocation could be the auction of incrementally feasible Transmission Congestion Contracts (TCCs) as suggested in some Locational Based Marginal Pricing (LBMP) methods. The auction could be conducted similar to proposals for the conversion of “traditional” transmission rights into TCCs. Alternatively, it may be possible for the SPS holder to utilize a more direct bid based methodology that avoids the complication of a special TCC auction as suggested by some LBMP systems. The following alternative bid based system could be used:

GR—Since generation rejection schemes allow for higher economy transfers by placing units at risk, the benefiting entities should pay the machines for accepting a possibly lower capacity factor. Other costs to the machine include possible penalties for backup supply (assuming a bilateral contract) and physical costs, such as possible loss of life of the machine from additional trips. The generator would need to weigh these costs against possible lost opportunity costs due to the lower transmission interface capability that would result from disarming the SPS. It's suggested that the following procedure be invoked:

The ISO determines transfer limits with and without the SPS activated.

The generation unit (through a power exchange) accepts or rejects bids from other generating units or load serving entities for the activation of the SPS.

TCT—Presumably higher system transfer limits would result in greater transmission revenues. Therefore, the owner of the TCT is reimbursed for the costs of the SPS through the Transmission Uplift Charge.

LR—Load rejection is the dual of generation rejection and could be handled a similar way as follows:

The ISO determines transfer limits with and without the SPS activated.

The Load (possibly through a power exchange) accepts or rejects bids from other generating units or load serving entities for the activation of the SPS.

Type I SPS do not increase transfer limits and Type II SPS are reliability based and do not have an economy market at this time. In the future, it's conceivable that loads may wish to pay for higher levels of reliability. At that time a power exchange could be used as a mechanism for bidding for the activation of the SPS. It's envisioned that alternative approach would be an ISO calculation of the probability of the contingency events necessitating the SPS action. This could be weighed against the cost of the service interruption. Based upon this economic determination, a decision could be made on whether or not to pay the reliability-based rate for the SPS.

Type III SPS is a local issue where it is difficult to generalize reliability versus economy method of compensation.

For the case where the transmission system is stability limited, the application of a single DCS could increase the transfer capability of the system. Similar to the methods described in the SPS section, increased transmission capability could be allocated to the owner of the DCS. This method is applicable to new or improved DCS as well as for DCS that can be armed or disarmed by operators or a defined set of system conditions. The transmission allocation problem becomes more complex for the case where multiple DCS are coordinated to increase transfer limits. Here the individual owners of the DCS could come to some business solution, possible based upon techniques that are used for tuning DCS and Dynamic Security Analysis.

Total payment for DCS used to enhance the reliability of the network would be determined similar to the method used for SPS. However, the allocation of the payment would be more complicated and possibly require advanced analyses that determine the individual contributions of the DCS

**Market Power**. In all cases where the owner of an SPS or DCS is paid there is the issue of market power. It will be necessary to prevent anti-competitive actions by generators and loads by constant observation and possible dispute resolution by regulatory authorities.

### 8.4.7 Large scale stability controls and legal liabilities

Legal liability with stability controls may be a concern when the nature and role of the RTO (Independent System Operator or Independent Transmission Company) is not well established [8-14–16]. Key points are:

- Redefinition of electricity as a market product may well expose all providers to legal liabilities from which they are now immune.
- Large-scale stability control (LSSC) faces many technical challenges that make it very difficult to assure reliable LSSC performance. Only the RTO(s) will have the infrastructure and other assets needed to monitor LSSC performance effectively. LSSC, marketed as an ancillary service, could be a magnet for lawsuits. An RTO should be held harmless for duties performed according to sound engineering practice,
- LSSC actions that are initiated after system failure is clearly underway face less legal exposure. This would favor a shift in emphasis, toward greater acceptance of system failures but with LSSC action to make the failures "graceful" and to facilitate prompt restoration of electrical services.

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