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ELECTRIC POWER SYSTEM OPERATING STANDARDS A SEARCH FOR JUSTIFICATION

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Abstract This paper presents a discussion of System Operating Standards. The paper provides a context for why these standards were created, the current state of Standards, and the expected development of standards in a Market-oriented industry.

Traditionally standards were imposed by Governmental, Regulatory and Industry-supported Standards Reliability Organizations. These agencies have been driven by national, social, geographic and systemic needs. To date those needs have been addressed by the current set of standards that are more or less restrictive among the various operating systems.

This paper examinees the high-level Operating and Planning objectives (voltage, frequency, MWs and MVars) and projects whether and how those objectives will be addressed in the restructured market environment.

Key Words: Standards - System Operations - Reliability

1. INTRODUCTION

A dictionary's definition of the word Standard is as "**an acknowledged measure of comparison for quantities or qualitative value"** [1] In short, a performance level. Local/Regional Regulators set minimum performance standards for the individual entities they regulate. These standards are generally based on consumer needs. Standard Reliability organizations (entities setting multi-regional objectives – e.g. UCTE, NERC, et al) define standards of performance based on interconnected grid needs. Of necessity those needs span various time periods for Operations and Planning. Current international standards reflect differences in the systems that they apply to. However, as the electric power industry is restructured the basis for standards is being challenged and reviewed. This paper examines those differences and challenges.

Standards provide an important tool for managing the interaction of various parts of the power system to achieve efficient and reliable service delivery to consumers. They establish levels of performance

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throughout the power system that attempt to coordinate the behaviour of different parts of the power system to balance the needs of consumers with the needs of the industry in order to deliver efficient and reliable service. In a sense, they determine how risks and costs will be shared between consumers and the industry players.

When standards are needed to manage interaction between industry players whose parts of the power system directly connect, the detail of the standards can often be left to negotiation between the parties, provided there are accepted common high level objectives. When standards are needed to manage interaction between industry players whose facilities do not directly connect, or between industry players and consumers, there is a need for an independent body to set a standard for the overall benefit of the industry and its consumers.

Sometimes standards will benefit some parties more than others and the independent body needs a high level of power to impose what it considers to be the best decision. Usually, that high level of power comes from governments who wish to protect the interests of their citizens and their economies. For power systems involving multiple government jurisdictions, the governments themselves need to establish a process for setting standards, including some principles of fairness that will allow them to accept some adverse decisions in the interest of the industry and consumers at large.

2. Background

Reliability Performance standards are generally categorized as either Planning or Operating standards. Standards may also be categorized by WHEN they apply:

- Primary Control (automated reaction time frame)
- Secondary Control (respect for exchange programs and contingency replacement)
- Tertiary Control (capacity/energy replacement)
- Operational Planning (unit start-up based standards)
- Long Term Planning (construction time based standards)

Standards can also be categorized by WHAT they control: E.g. frequency or voltage.

In the restructured industry, more and more the question is WHY? Why is a standard's limit set at a given value? Why is the standard in place at all? To comply with tight performance standards may be expensive. To achieve small frequency excursions during disturbances requires much spinning reserves, and conservative transfer limits between congested areas may be quite expensive for the market agents. The restructuring of the industry has also separated those who may gain from less restrictive operation from those responsible for the system security. The need for justification of the applied standards and to find an appropriate balance between expected benefit and expected cost become more and more important. It is today more accepted to relax what has been used as firm defence lines towards unacceptable consequences for contingencies (N-1, N-2). To utilize emergency ratings after contingencies and to rely on the use of corrective actions, are now widely accepted. Still the technical performance standards are used, but new standards as commercial standards and other penalties for not complying to the standards are showing up. It is therefore important to review and adjust the existing standards to really fit the new competitive environment. Reviews of international standards have been conducted previously by CIGRE [2] for the purpose of identifying the standards. This paper will provide insight into the basis for the standard and be a first step in the work for justification.

3. Standard Development

A high-level review of selective standards is presented. The review includes standards from Asia, Australia, Europe, and North and South America.

3.1 Asia

3.1.1 Japan

In Japan, ten vertically integrated private power companies (utilities) have been taking responsibilities for supplying electric power to customers in their own control areas. The operations covering the boundaries of different control areas have been considered as supplementary subjects. Each power company, therefore, has its own rules for planning and operations. Thus, in Japan, the operating standards and planning standards differ from company to company, although the differences are not major ones. Their individual standards depend on their area and /or system characteristics. The fundamental concept for all the utilities is to use (N-1) criterion, but some more than (N-1) contingencies are taken into account in order to prevent largescale blackouts.

At present, in Japan, the government and private power entities are discussing the future directions of electric power deregulation. In particular, the so-called "neutral organization regarding transmission business" is scheduled for establishment in 2004 to make sure the fairness and transparencies of the electric power business, as the number of newcomers will be increased in the future. The neutral organization is scheduled to make common and standard rules for the following: System configuration, System access, System operation and System information disclosure.

These rules will be based on the present utilities' rules and will release the information to all transmission users, while the utilities are scheduled to recheck and revise their own rules in accordance with the rules the neutral organization makes, and they will release the information to all the transmission users.

3.1.2 Korea

The Korea Electricity Commission (KOREC) is a regulator of the Korean Electricity Market. The KOREC has published the standards for power system reliability and power quality. The KOREC make decisions based on the consulting of a Reliability Panel consisting of market participants, regulator, experts, etc. The standards state criterias to maintain system stability for contingencies, generation reserve for frequency control, and basic technical requirements of generator to network connection.

The Korea Power Coperation (KEPCO), as a single transmission network provider, should reinforce the network to meet the standards. The Korea Power Exchange (KPX) shall operate the power system according to the standards and market rules.

The KOREC updates continuously the standards considering the market structure to increase the public benefit and market competion.

3.2 Australia [3]

The power system in the eastern states of Australia, covering Queensland, New South Wales, the Australian Capital Territory, Victoria and South Australia is interconnected and operates as a common “National Electricity Market”, formed by the participating state governments in 1998 by enacting common legislation. Tasmania will join the National Electricity Market in May 2005.

In general, transmission networks, major power stations and major industrial loads are regulated by a “National Electricity Code” (the Code) which was prepared by the state governments and approved by a national government authority responsible for competition regulation. Compliance with the Code is a condition of registration in the National Electricity Market. A government body, the “National Electricity Code Administrator” (NECA) manages amendments to the Code. State government regulatory bodies regulate distribution networks and interaction with general consumers.

The Code contains the standards for power system security, from both an operations and a planning perspective. It also contains provisions for some standards to be prepared by the “Reliability Panel” which was established by NECA. These include the standards for power system frequency, and for power system reliability.

The Code also contains provisions for some standards to be prepared by the “National Electricity Market Management Company Limited” (NEMMCO) in its roles as market and system operator, following a process of consultation with the industry. These include ancillary services specifications and data communication standards.

A recent review of the Code resulted in significant changes to the standards for connection to the transmission networks, which came into effect on 16 November 2003. It established three levels of standards in the Code: system standards, which set overall power system performance objectives; access standards for plant connecting to networks; and plant standards (such as IEC standards). In general, access standards set the limits for negotiation between connecting parties, usually with a power system security or supply quality objective. The Reliability Panel can set plant standards.

The structure of the National Electricity Market has recently been reviewed and changes are expected on 1 July 2004, when new government bodies will replace NECA. The new structure is expected to improve the efficiency of the Code change process, and hence the process for setting and amending standards.

3.3 Europe

3.3.1 UCTE (Union for the Co-ordination of Electricity Transmission) [4-7]

The Union for the Co-ordination of Electricity Generation and Transmission (UCPTE) was established in 1951 at the instigation of the Organization for European Economic Co-operation. Its original role was to contribute to the development of economic activity through the improved exploitation of energy resources associated with the interconnection of electricity systems – in particular, related to surplus hydroelectric power. By setting common operational rules and by organizing the international co-operation between the electricity system operators, the UCPTE assumed an increasing responsibility in the secure operation of the European interconnected electric system.

In half a century, the geographical scope of the Union has been extended from the 8 original countries (Belgium, Germany, France, Italy, Luxemburg, the Netherlands, Austria and Switzerland) to 20 countries, first in the South (Spain, Portugal, Greece, Yugoslavia), then in the East (Czech Republic, Hungary, Poland and Slovak Republic) co-operating in CENTREL

The introduction of the Internal Electricity Market (IEM) in the European Union triggered a process of fundamental change. The Transmission System Operators have the task to facilitate the market by ensuring domestic and cross-border network access without jeopardizing the global security of the whole synchronous system.

In April 1999 the name of the organization was changed to “Union for the Co-ordination of Electricity Transmission (UCTE)” which confirmed the main object of the association as the body in charge of the synchronous interconnection coordination of all Transmission System Operators of the UCTE area.

The Association pursues scientific aims and shall have the following purposes with regard to the Synchronous Area :

- to study and to co-ordinate the rules for operation of the UCTE Synchronous Area and its interfaces with neighbouring Transmission systems;
- to study and to assess interconnected systems regarding reliability and adequacy;
- to study and to monitor the geographic extension of the Synchronous Area;
- to study and to co-ordinate mutual technical and operational assistance between Transmission System Operators; and
- to contribute to the dissemination of expertise and information, including statistics, relating to the interconnected system.

The prime objective of UCTE [5] is to provide secure operation of international interconnections in the electricity transmission system of the synchronous area. Main missions of UCTE are:

- Technical and operational co-ordination of interconnection in the UCTE synchronous area;
- Monitoring and control of the short-term reliability of the system with regard to load, frequency control, stability, etc.;
- Medium-term adequacy between generation and load (3-year power balance forecast); and
- Study and monitor the development of the synchronous area.

Development of Reliability standards [6] is one of the challenges for UCTE. To maintain the security of the electric system at its previous and present high level implies a.o. modifications of operational standards made necessary by the development of the electricity market and the emergence of new types of actors (such as traders). These challenges comprise:

- to develop binding and transparent reliability standards, for which a legal framework of enforceability must be worked out.
  In this respect, a UCTE Operation Handbook is under development. It summarizes and updates all relevant existing UCTE rules and recommendations and transforms them into a stringent set of policies, which are intended to serve as a basis for the binding reliability standards.
- to further develop co-ordination on operational level between involved TSOs regarding cross-border congestion management and cross-border grid access.
- to co-ordinate congestion management using UCTE technical tools and ETSO market principles.
- to enhance communication towards market players regarding the adequacy issue.

3.3.2 NORDEL [8-9]

Nordel is a body for co-operation between the transmission system operators in the Nordic countries.

The Nordic electricity system has a long tradition for co-operation and co-ordination in operation and planning. This was earlier based on Nordel recommendations, and is now based on a common Nordic system operation agreement between the Nordic TSO's [8].

The primary objective for Nordel is to facilitate an efficient and harmonised Nordic electricity market. There are three main activity areas for Nordel: System planning, market development and system operation.

In Nordel's By-Laws it is stated that Nordel shall contribute to technical co-ordination and to the determination of recommendations, not least in the following spheres:

- system expansion and transmission planning criteria
- system operations, reliability of operations, reliability of supply and exchange of information
- principles for pricing transmission and system services.

The first common grid dimensioning rules were introduced already in 1972. These have substantially helped the development of the current system. Rules were originally meant for planning of the Nordic main grid, but should also help to support the operation of the grid.

All TSO's have undersigned the system operation agreement which objective is to make use of the advantages of an interconnected operation of the Nordic power system. The TSO's shall thus jointly maintain the coherent operation of the Nordic power system with a satisfactory level of security and quality. In the system operation agreement reliability principles, operating terms, ancillary service principles and other operational principles are agreed upon, and it forms part of a Nordic Operation Code.

Earlier Nordel gave recommendations, but now as an agreement the former recommendations are binding. The system operation agreement has also been approved by the regulators in the different countries.

A common Nordic Grid Code is being developed. In addition to the Operation Code the Grid Code will consist of a Planning Code and a Connection Code.

3.3.3 United Kingdom [10]

Before liberalization in 1990 which created a separate transmission and operating company (National Grid) and several private generating companies the supergrid system in England and Wales and over 95% of the total generation was owned and operated by the Central Electricity Generating Board (CEGB). The Operating Standards at this time were defined in a CEGB Operational Memorandum.
In 1990 this document was used along with several others to form the basis of The Grid Code and the Operational Standards.

At privatization and as required by the transmission licence, National Grid implemented the Grid Code, which is designed to permit the development, maintenance and operation of an efficient, co-ordinated and economical system for the transmission of electricity. National Grid and users of its transmission system are required to comply with the Grid Code. The Grid Code covers all technical aspects relating to connections to and the operation and use of the transmission system and electrical plant connected to it or to a distribution system.

In 1992 the Regulator requested National Grid to review the System Security and Quality of Supply Standard to reflect the new industry structure, but to maintain the principles of the existing standards. National Grid prepared a revised standard, which combined six standards into a single document in consultation with the authorized electricity operators and the document was approved by the regulator in October 2000.

3.4 North America [11-12]

The North American Electric Reliability Council (NERC) in its preamble to its Operating Standards and Policies states the basis for its standards as follows:

"All CONTROL AREAS share the benefits of interconnected systems operation and, by their participation in NERC, they recognize the need to operate in a manner that will promote reliability in interconnected operation and not burden other interconnected CONTROL AREAS.

All CONTROL AREAS shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency. Multiple outages of a credible nature shall also be examined and, when practical, the CONTROL AREAS shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from these multiple outages".

The ***Operating Standards*** are based on the premise that all control areas share the benefits of interconnected systems operation and, by their participation in NERC, they recognize the need to operate in a manner that will promote reliability in interconnected operation and not burden other entities within their interconnection. The ***Planning Standards*** define the reliability of the interconnected bulk electric system in terms of its ability to supply the aggregate electrical demand and energy requirements of their customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements; and its ability to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

NERC's standards and Policies were based on the traditional vertically integrated Control Areas. Control Areas that included generation, transmission and load responsibilities. With restructuring, that assumption was challenged. NERC's voluntary Standards were also challenged. NERC responded by creating a new Standards-making Process [12] that focused on Reliability. The objective of the new process is to eliminate Market-impairing Guidelines and focus on 'measurable', 'technically-defensible' 'consensus-based' mandatory Reliabilty Standards that are applied on the basis of which entity is 'responsible' for a reliability function (as opposed to writing standards for a particular corporate structure).

The very definition of the term 'reliability' is being reviewed. Should the focus of standards be on maintaining the integrity of the bulk power transmission system (to ensure that Market activity can proceed)? Should the focus be on ensuring that the transmission system is stable and that uncontrolled cascading outages will not occur? Or is reliability defined in terms of avoiding any activity that will impair the flow of energy on another operating system? This debate is underway, and the outcome will determine the role of system operations in a market-oriented industry in North America.

3.5 South America (Brazil) [13]

The main Agents that have responsibilities with Operating Standards are:

- The Brazilian Electricity Regulatory Agency (ANEEL) is responsible for regulating and inspecting the production, transmission, distribution and sale of electricity.
- The Brazilian National System Operator (ONS) is responsible for managing, coordinating and controlling the interconnected system operation.

The Brazilian System Operating Standards can be characterized in terms of quality, security and reliability. These standards are defined in the Grid Procedures, under responsibility and coordination of ONS and participation of the Generation, Transmission and Distribution Companies, and must be approved by the regulator (ANEEL).

The main objective of the interconnected system operation is assuring the security, reliability and quality performance standards. In operational terms this objective means both obtaining adequate frequency and voltage levels and supporting contingencies up to a specified severity level, such as N-1. For higher severity level contingencies, power system defense plans, including both system protection schemes and special equipment, are defined in the operational planning phase with the objective of preventing blackouts and reducing the impacts on the power system to a minimum. These actions result in better quality, increasing of continuity and minimization of loss of load, giving benefits for all consumers.

The main objectives of the operating standards are to define the following aspects:

- The criteria that must be observed in the access and use of the Basic Transmission Grid (230 kV and above).
- The criteria and performance indicators that must be observed in the transmission expansion planning and operational planning phases, as well as in operational scheduling and real time operation.
- The criteria that must be observed in the design of power plants.

Nowadays in the restructured environment, there is increasing consumer demand for better quality and continuity (security and reliability) of the electric energy supplied. On the other hand, consumers also demand a reduction in the tariffs and prices of electric energy consumption. These demands work in opposite directions. Consumers will ultimately be provided with the electric energy quality and continuity they can afford to pay. This may be a simple technical and economic question, but it is a complex political problem.

As for the electric energy players, there has been a tendency to use the resources available to the maximum and operate closer to power system limits. This is why system operating standards have become major challenges, which involve governments, regulators, system operators, G/T/D companies, market players and consumers.

4. Standard Comparison

4.1 Frequency

Restructuring has caused many Standards Making Organizations to reconsider and justify their Standards. The fundamental objectives of why standards even exist are being reviewed.

In NORDEL the objective is to “make use of the advantages of interconnected operation… [and] maintain … a satisfactory level of security and quality” [8].

In North America, the justifications for the North American Electric Reliability Council’s current frequency-based control performance standards are being challenged. The frequency-based concept of Time Error Correction as a reliability standard is also being challenged.

In a major portion of Europe, the Union for the Coordination of Transmission of Electricity (UCTE) is looking at TSOs to “keep the lights on” and “to make the market happen.” UCTE’s primary goal is to maintain security – UCPTE’s goal was to develop effective use of energy resources.

The Reliability Panel of Australia’s National Electricity Code Administrator in 2000 undertook a review of its standards to “review the potential for inclusion of direct economic criteria in the standards to reflect the market environment in which the standards operate” [3]. Australia’s National Electric Code also states that “Variations in frequency … can cause equipment to malfunction. Wider variations can lead to equipment damage. The task of setting frequency standards is largely a matter of making a trade-off between quality, security and cost. However, none of the service impacts and costs is sufficiently known [3].

Frequency is the one common measure linking all members of a synchronous electric power system, and an accepted indicator of an control area’s ability to balance resources and demand as well as to manage disturbances. The universality of that measure would lead to the presumption that frequency standards for different systems would be relatively consistent. Differences can be rationalized by the relative size of the largest generation loss relative to the size of the interconnection. Large highly-meshed interconnections realize the benefit of sharing contingency losses over many sources; smaller interconnections must share the response over fewer sources. One would expect that the larger systems would be able to withstand larger frequency deviations than smaller interconnections. The limited set of data available form the responses to the questionnaire [see Table 1 below] indicates just the opposite approach. Frequency deviation limits on larger systems tend to be much smaller than frequency deviation limits on smaller systems. Differences can also be rationalized on the basis of the type of generation units. To avoid turbine damage, large thermal units generally must be disconnected if the grid frequency falls to 2,5 Hz below scheduled frequency. The more robust hydro units can operate to about 5,0 Hz below schedule.

The fact that small systems that ‘experience’ wider deviations have wider frequency deviation limits than do the larger systems that experience smaller deviations seems to point to observed system conditions being the real justification for frequency limits rather than actual reliability concerns.

Time Frames

Internationally, frequency standards all recognize the need to address differing time frames. Three accepted time frames are generally referenced as Primary Control, Secondary Control and Tertiary Control.

<u>Primary</u>

Primary Control (Governor response) is designed to arrest frequency decay. In short, to prevent the frequency from going down to a value that would result in Under-frequency Relay Operations before the System Operators have time to react. UCTE states that the objective of Primary Control is to ”maintain balance using governors and stabilize system frequency…without concern to exchanges.” What is the basis for the current Primary Control standards? Generally, the Primary Control Standards require response within 15 - 60 seconds. The questionnaire results show that the allowable Contingency Frequency deviation limit is 200 – 500 mHz which in turn is 2 – 6 times the deviation required to reach the reported frequency relay operating limits (even when including operation at the lower Normal Limit). Is the margin between the normal deviation and the relay limits justified?

Table I Frequency Standards comparison

	Set Point (Hz)	Normal - Secondary - Limits (+ / -)	Contingency - Primary - Limits (+ / -)	Load Shedding Limit	Largest Loss (MW)	Frequency Response Characteristic (MW / Hz)	Time Error Limit
Region							
Europe							
NORDEL	50.0	100 mHz	500 mHz	-1300 mHz	1200	6,000	30 seconds
UCTE (First zone)	50.0	20 mHz	180 mHz	- 800 mHz	3,000	18,000	20 seconds
UK	50.0	200 mHz	500 mHz	-1200 mHz	1,320		10 seconds
Asia							
Japan							
Tokyo	50.0	100 mHz	200 mHz	-1200 mHz	1,600		10 seconds
Chugoko	60.0	100 mHz	200 mHz	-1200 mHz	*** ***		10 seconds
Kansai	60.0	100 mHz	200 mHz	-1300 mHz	1,180		10 seconds
Chubu	60.0	100 mHz	200 mHz	- 900 mHz	3,650		10 seconds
Korea	60.0	100 mHz	200 mHz	- 500 mHz	2,000		*** ***
Americas							
No America							
East	60.0	20 mHz		- 700 mHz	2,100	35,000 63,000 (FBS)	10 seconds
West	60.0	20 mHz		- 900 mHz		5,000 19,600 (FBS)	2 seconds
Brazil	60.0	100 mHz	500 mHz	-3000 mHz	720		
Australia							
NEMMCO	50.0	150 mHz	- 500 mHz 1000 mHz	-3000 mHz			15 seconds

Secondary / Tertiary

Secondary control limits (both Manual and Automatic) is designed to reset the Primary Control Response (after the Primary Control has been exhausted) as well as to balance supply and demand. Secondary control response is generally designed to keep the control area in some "normal" operating range that will "allow efficient and predictable operation of generation, networks and equipment and predicable [contingency] excursions" [*9*]. UCTE states that Secondary control maintains balance ..taking into account Exchange programs.." [5]. Internationally, this range is between 20 and 200 mHz. A study in South Africa stated that a tolerance of + / - 500 mHz is used as a tolerance for major-end use equipment. This would suggest that the imposed standards are tighter than needed by the consumer.

The general response requirement time for Secondary Control service is 10 minutes. The 10 minute requirement is a 'specified' value and generally not a 'justified" value (at least in most Standard documents received). The concept of Secondary Control is that it is supplied by 'operating' units, and unless those units are relieved of their obligation, then the system would not be able to response to a second contingency event. Hence the need for a Tertiary Control (Replacement) obligation to provide energy from previously off-line units to reset the Secondary response. Since these units are providing backup there is no specific frequency limit associated with them. There is however a time requirement – generally 30 minutes to 2 hours.

The NORDEL notes that "Due to the limited size of the system compared with for instance UCTE, the instantaneous disturbance reserve has to be activated faster than in the UCTE system…." [8]. It is also possible to find this situation inside huge systems, like UCTE, when there are not well-connected areas, like the Iberian Peninsula, where it is needed to react faster than the general recommendation for the whole area.

Again the issue is what is the justification for the time requirements being used in today's standards. These standards result in control areas carrying sufficient reserves to meet these times. Market forces are right to ask the question because of the money that can be saved by constructing slower less responsive resources. If the service is not really needed, then why should the consumer pay for the higher cost response imposed by these standards? If there is an order of magnitude difference between the highest and lowest allowable frequency deviations and another 2,5 times the largest deviation being justified by the consumer, it is appropriate that the question be asked.

Load Shedding

The Load Shedding Limit is not an operating limit per se. This limit is generally used to indicate when generators should disconnect to prevent damage. In UCTE, load shedding is used to stabilise the system when primary control is exhausted. The lower limit of load shedding is above the level of generation disconnection. In Brazil, load shedding is used to stabilise the system when primary and secondary control is exhausted and to avoid thermal and hydro generation disconnection. The Australian NECA notes "If a disturbance is so severe that the frequency reaches [the load shed limit] it is better to allow collapse and then rebuild." Should these relay limits form the basis for frequency standards? Indeed, what is the role of load carrying obligations in a Market-based environment? The load shedding level and generation tripping level are different because load is shed in the hope of avoiding generation tripping (and system collapse). For example, in the Australian National Electricity Market, load shedding starts at 49.0 Hz and generation tripping is at 47.0 Hz (with some exceptions).

4.2 Voltage

Voltage conditions in a high voltage grid are directly related to the reactive power balance at the system nodes. Depending on their operational state, all generators, loads and system components (lines, transformers) can be defined as either reactive power consumers or producers. The network by itself produces or absorbs reactive power depending on the load level through the line and on types of wire - overhead or under-grounded cables. To compensate for an excessive consumption of reactive power, TSOs have to be sure that dedicated producers will feed enough quantity into networks in addition to this produced by other devices installed in the networks or in consumer installations.

Unlike active power, reactive power cannot be transmitted over long distances, since the transmission of reactive power generates an additional demand for reactive power in the system components, thereby causing voltage drops. In order to obtain an acceptable voltage level, reactive power generation and consumption have to be situated as close to each other as possible to avoid excessive reactive power transmission. This reactive power can nevertheless be produced in their control area or at the vicinity in those of neighbouring TSOs.

Voltage control has a more local or regional impact than the frequency control. Therefore each TSO has more freedom to define its own strategies, except for the voltage levels of tie-lines to other regions. This is also a finding from the questionnaire used in this work. The accepted variations around the nominal voltages were quite different for the different utilities. The voltage profile in a system will of course depend on the structure (how meshed the system is) and the amount of power transit. A system with significant power transfer between generation and load areas will in general experience large differences in voltage levels while systems with more local supply that can help keeping a more flat profile.

The comparison will be organized according to these aspects:

- Upper and lower limit in normal operating conditions
- Limits under disturbances
- Acceptable time for recovery
- Minimum voltages for load tripping
- Reactive reserve requirements

Normal operating conditions

There were totally ten responses to the survey. Four of these were from Japan.

It appears that in most of the transmission networks, the voltages are kept within +- 5% of nominal values. However, in Japan quite tight voltage limits were used since all these utilities had less than

+- 2.5% deviation and one utility used +- 1%. The other responses were from PJM, Korea, Brazil, UCTE, Nordic countries and UK. It appeared that though the goal was +-5% as normal operating range, it was possible to go beyond these limits and approach +-10% at least for shorter time periods.

Limits under disturbances

The responses of this item varied quite a lot. Acceptable limits depend on the security criteria used. In the responses from Japan, there were two N-1 and two N-2 criterions applied for the system operations. Only one of the responses indicated any limits under disturbances and the limit was in this case indicated to be +-10%. Korea used an N-2 criteria. No voltage limits were given, but the voltages had to be above the point of collapse after an N-2 contingency.

Brazil accepted +-5% deviation in the Basic Transmission Grid (230kV and above) and +5%/-10% deviation in the Primary Distribution Grid (below 230kV and up to 1kV) for N-2 disturbances while +-10% could be accepted during restoration at all busbars. In UK +-12% deviation was accepted for an N-2 disturbance while +-6% was the limit for N-1 cases. In Nordic countries, voltages below 370kV for the 400 kV grid, was considered unstable. If the voltage in several stations dropped below 380kV, the disturbance was considered to be severe.

PJM reported to have 15 minutes to correct voltage magnitudes if they fell into the normal low region, i.e. 1.0 pu on 500 kV and 0.95 pu on lower voltages. If voltages fell into the emergency low levels, 5 minutes were allowed to correct.

Acceptable time for recovery

UK reported a required recovery time to be less than 15 minutes. PJM had 15 minutes to correct when voltages dropped to normal low ie 1.0 pu on 500 kV and 0.95 pu on lower voltages. If voltages drop to emergency levels, 5 minutes were allowed to correct. The others had no specified requirements for voltages or as soon as possible as a guideline.

Minimum voltages for load tripping

In the responses from Japan, only one company had installed relays disconnecting loads at low voltages. The relays operated at voltages below -10% of nominal values. In Korea, load tripping took place by special protection schemes, but no voltage limits were indicated in the response.

In UCTE, the TSOs take corrective action, including load reduction, load shedding necessary to prevent voltage collapse with insufficient reserves. In Finland only electric boilers have relays that disconnect them at 105 kV voltage (at 110 kV voltage level). In Norway more extensive protection schemes are used for disconnecting load. In UK there are no relays on supergrid transformers, but most industrial drives and motors have low voltage protection, which operates at -20% voltage drops.

In Brazil the relays tripped load when the voltages dropped below 0.9 pu. In the response from PJM, load tripping started when the voltages on the 500 kV network dropped below 5% of nominal value. At the lower voltage levels, load tripping started when the voltage dropped below 0.9 pu.

Reactive reserves

Finland, Korea and PJM reported that certain margins for the reactive reserves had to be present. In Finland, there had to be enough reactive reserve located so, that the power system can be restored to normal operating conditions after a dimensioning fault. This was done by reserving the entire reactive power production capacity of the generators connected to the 400 kV grid as instantaneous disturbance reserve end 50% of the capacity of generators connected to the 220, and 110 kV network. This had to be activated in 5 seconds. Korea calculated the reserve requirements on system studies. As indicated above, N-2 contingencies were used in the evaluations. The others indicated that the voltage level was the main criteria, but certainly system studies are conducted to verify the margins against the security criteria. (N-1, N-2).

5. Conclusions

Earlier energy was one product with all aspects included. In a market environment the product has been separated into energy and a number of ancillary services. Prior to restructuring all aspects of energy production, transmission and distribution applied to one type corporate entity (the control area), and standards could be easily tailored to those entities. With the onset of restructuring it is no longer a matter of a set of bundled standards that are applied to one entity, now those responsibilities are distributed. That requires distribution of the accompanying standards. And that requires identification of responsibilities – beginning with the responsibility to serve load as well as the responsibility to build facilities. In the new market environment voluntary compliance and peer pressure is no longer sufficient to achieve operation within standards. When developing performance standards they need to be objective and measurable. The standards must be developed in an open, inclusive, balanced and fair manner.

Restructuring implies competition, and competition implies profit motivation. Entities cannot make money if they are assigned responsibilities better served by other entities. Standards are the measure of comparison of comparable entities. The restructured environment has created new entities. Entities not envisioned by traditional measures. The old control areas are rebelling against unfair or outdated standards. The new Market entities are questioning why standards apply to them.

The fundamental justification for frequency (and Time Error) standards is still developing. The assumptions of equipment damage and timing requirements require more review by the Standard Making Organizations. The reported divergent standards indicate that the limits and system requirements need more review. The Standard Makers are rightly challenged by the restructured industry to go beyond historic experience and come up with up-to-date new world rationalization for frequency-based standards.

The applied standards for voltage levels and excursion during disturbances are quite different between the systems. There may be several reasons for this. One obvious reason is that the voltage and reactive power relation has more local/regional impact and therefore permits more local standards even in interconnected systems. However, the system structure and the amount of power exchanges between control areas are of importance. It also seems that in the restructured systems larger deviations between nominal and actual voltage levels have been experienced.

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