Report 3.2

Experiences from North American Disturbances and Recommendations for the Reliability Improvement of the Brazilian Interconnected System

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3.2.1 Introduction

Large interconnected electric power networks have developed and matured over the last three decades all over the world in a philosophically synchronized manner even when they were not physically connected. The development of the EHV technology provided the means for extensive interconnections over thousands of miles of physical distance and made it possible to exchange and transmit massive amounts of energy economically and efficiently. Moreover, such interconnections enhanced the flexibility in balancing the supply and demand which contributed handsomely to the availability and quality of the service. On the other hand, EHV networks made the physical long distances electrically short and made it possible for regional problems to propagate and cascade beyond their geographical boundaries to impact much wider service areas. The earlier problems in attempting to synchronize the French and the English systems in Europe, the north and south of the Western System of North America, and the 1965 Northeast blackout of North America are few of the cases which brought the complexity of interconnecting large systems to the forefront in early stages.

Transmission networks, are developed in bulk to serve the system needs into the future. The early years of operation usually have large operating margins which get smaller and smaller as the load grows and the equipment get older. In order to avoid or defer massive investment, system planners and operators have been getting more innovative in pushing the operating points closer to the design limit. As the systems operated under stressed conditions combined with new technologies and innovations, new limiting phenomena evolved and old ones came to the surface. We have seen massive turbine shafts braking when the idea of series capacitor compensation matured and provided more economic means of increasing system capabilities. We have also witnessed voltage collapse in large networks in Japan, France, Sweden, North America, and Brazil over the last 15 years when the value of dynamic reactive power was ignored in favor of investments in the real power generation. Fractional investments in transmission, in comparison to investments in generation to cope with load growth, over the last decade is a world wide phenomena. When added to the impact of near end of life of many of the original generation of the infrastructure, many parts of the world have recently experienced problems to various extents.

Four of the system disturbances reported in the previous section by Mr. Carson Taylor's report happened over a period of just over two years in the Western System of North America starting with an outcome of an earth quake in 1994 in California and ending with a cascaded system failure triggered by a contact between a transmission line and a tree in 1996. The impact of the latter disturbance was close to four times that of the earth quake and was noticeably larger than any of the recent history. That sequence of events sent a loud alarming message to the North American industry and resulted in a list of recommendations of close to 150 items in the Western Region alone ranging from short term fixes to long term reinforcement plans. While we learned from those incidents, it is neither realistic nor economic to respond in panic with massive and expensive plans and assume that problems of similar impact will not happen. In every case, the events uncovered inherent limits and provided grounds for innovations in the short and long term solutions. The former has always been key to restore confidence in the service until the more expensive and time consuming long term solutions are implemented.

The triggers and conclusion of the recent Brazilian Southeastern system collapse under investigation are not different in nature, apart from the specific details, from what have been witnessed in many parts of the world including North America as discussed in this report. It must not be taken as an indication of lack of effort or severe oversight on the part of those responsible for operating and maintaining the system. However, it must be used to uncover the unknown, assess the risk and minimize it progressively in time starting immediately, and revisit the planning philosophies for the future. We will try to tackle each of these issues in this report to the extent feasible within the given time frame. First, we will describe the North American experiences and perspectives related to major system disturbances, and then provide our assessment of the March 11th, 1999 Brazilian disturbance.

3.2.2 A North American Perspective - Scorecard

3.2.2.1 Major System Disturbances In North America

Other than the infamous 1965 Northeast Blackout, the disturbances reported in Mr. Carson Taylor’s section of the report were the only ones of significant system wide impact of a magnitude closer to that of the recent Brazilian disturbance. Therefore, we describe only the 1965 disturbance here. Apart from its historical significance, many of the lessons learnt from the incident and the corrective measures implemented are still applicable. As well, many of the institutional changes established in North America established to enhance the reliability of the electric power service are still in existence.

The conditions prior to the disturbance on Tuesday, November 9, 1965 was normal in every sense; the weather was mild and the loads were well below peak levels. At about 5:15 p.m., for no apparent reason, the interconnected power systems in the region started experiencing instability. Within a few minutes, there was a complete shutdown of the electric service to most of the American states of New York, Connecticut, Rhode Island, Massachusetts, Vermont; parts of New Jersey, New Hampshire, and Pennsylvania; and a major part of the Province of Ontario in Canada. Nearly 30 million people were without electric power supply ranging from several minutes to 13 hours.

The subsequent investigation of the incident revealed that the triggering event was the operation of a backup relay at Beck generating station in Ontario, Canada, which opened one of five 230 kV transmission lines connecting the generation of Beck to the Toronto-Hamilton load area. Prior to the opening of the line, these five lines carrying 1200 MW of Beck generation plus about 500 MW of import from New York State on two tie lines near Niagara Falls. The loading on each of the five lines was such it was slightly below the value that corresponded to the setting of the line back up relay. Possibly due to a small momentary change in system condition, the pick up setting of the relay appears to have been reached causing one of the lines to be opened. This, in turn, resulted in the sequential tripping of the other four parallel lines, causing isolation of Beck generation from the Ontario system on to the New York system. The resulting power surge of 1700 MW into New York led to cascading outages due to power system instability. After about 7 seconds from the opening of the first Beck line, the Northeastern system had split into separate areas or islands. The imbalances between generation and load within individual islands eventually resulted in a complete collapse of each of them.

The 1965 blackout changed the mindset of the electric utility industry as well as the public at large. As opposed to focusing primarily on achieving economies, the reliability of power supply became the overriding issue. The Northeast Power Coordinating Council (NPCC) was formed in January 1966 to improve coordination in planning and operation among the utilities in the region and enhance the reliability of the power supply. This was followed by formation of eight other regional reliability councils covering other regions of the United States and Canada. In 1968, the North American Electric Reliability Council (NERC) was formed, comprising the nine regional reliability councils, to promote the reliability of power supply in the electric utility systems in North America. Each of the regional reliability councils established detailed criteria and guidelines for the member systems with regard to power system planning and operation based on the circumstances and needs of the individual region, with NERC providing the overall coordination for all the regions.

3.2.2.2 Experiences From Recent North American Disturbances

The North American Electric Reliability Council (NERC) requires detailed reports on disturbances of actual or potential impact of a specified level. Those reports are usually compiled in the form of annual reports. In addition to the 1965 Northeastern Blackout and the disturbances of the Western system reported in Mr. Carson Taylor's report, numerous other events resulting in smaller localized regional impact of few thousand MW have occurred in North America. The limited impacts of these events were a blessing, but they were always analyzed and produced valuable lessons. For the purpose of this investigation, the NERC disturbance reports since 1994 were reviewed. The conclusions and recommendations of those reports are categorized and summarized below:

1. System Protection

Automatic protection schemes isolate faulted lines or other system elements to minimize the risk to the rest of the system. The outcome of these schemes with their relays, underlying control strategies, and communication systems are to confine electric system problems to the affected equipment. Some common factors contributed to extending the impact of the reported disturbances beyond the faulted equipment:

i) Inadequate relay scheme maintenance programs or procedures

ii) Improper relay coordination of step-distance impedance relays

iii) Inadequate system modeling that does not adequately reflect the impact of neighboring systems when determining system limits and relay settings

iv) Uncoordinated protection systems between adjacent control areas

v) Generation protection not coordinated with other remedial measure such as under frequency load shedding

vi) Insufficient balance of supply and demand in the post fault electric islands

The common recommendations addressing the system protection issues were summarized as follows:

i) Continue to examine and maintain the critical protection systems that have potential for wide impact

ii) Coordinate critical protection systems among all neighboring control areas

iii) Generator protection should leave room to remedial measures such as under frequency load shedding to act before tripping. Earlier generator tripping usually complicate the problem further and amplify the deficit

iv) More attention should be given to under frequency load shedding relay operation and setting to ensure proper relay operation under extreme conditions and reasonable supply and demand balance.

2. Communications

The need for timely and adequate communications among control areas during disturbances continues to arise during the analysis of disturbances. In addition, prior to system restoration, communications between control areas are necessary to establish the state of the transmission system and the key equipment for restoration. The common recommendations of the reports to address the communications issues are summarized below.

Each control area should:

i) Review its emergency operations plans to ensure that they include adequate communications with other control areas before, during, and after emergency

ii) Be able to determine the configuration of the system following separation from the interconnection

iii) Regularly review the operating guides related to system security, particularly the portion devoted to dissemination of information to other control areas within the regional council.

3. Planning

It was recognized in some cases that the system planners and operators do not work closely in installing new facilities or modifying existing ones. More importantly the need to continually review system disturbances to ensure that system operators could handle future events was recognized. The following recommendations were made:

i) Review system modeling regularly with the planners and operators to reflect any changes and operating practices

ii) Review every disturbance with the operators and planners to learn valuable lessons

iii) Review operating nomograms regularly to reflect changes in design or philosophy.

4. Operator Training

The operators are like fire fighters, they must always be trained for the fire before it comes, not on the job. It is often neglected that the odd and severe conditions do not happen very often within the life of an operator and experience for the big events can only be gained from training. The following recommendations were made:

i) Operators should be familiar with critical equipment like remedial action schemes and control equipment like phase shifting transformers

ii) Operators should often be trained to think under pressure and how to restore the system

iii) Always examine the operator training programs to make sure they reflect more stressed operating conditions and various configuration during restoration

iv) Training should be ensured in the use of communication facilities, and procedural conduct

The above list of issues and recommendations are global to most of the disturbances experienced in various parts of the world. The hundreds of thousands of small elements impacting the behavior of the power systems make it difficult to always be on top of every deficiency in a given element at a given time, yet it is not an excuse to declare defeat and ignore it. The question is that of a reasonable balance and minimizing risk and impact realizing that it is impossible to eliminate all together. Like the lessons we learned from incidents in the other parts of the world, we should try to learn from the Brazilian case to assess the risk, and adjust that balance in view of what we know today.

3.2.2.3 Special Protection Schemes - Application and Experience

Special Protection Schemes (SPS), sometimes referred to as Remedial Action Schemes (RAS) or Emergency Controls, are a form of protection and control measures that is primarily implemented to control the overall system response and protect it against catastrophic failure beyond the direct action of individual equipment protection.

Many North American systems have wide implementation of such schemes with positive results of many years of experience. Such schemes are mostly implemented to protect the system against events of low probability/high impact nature (e.g. multiple outages of two or more transmission lines, part or all of a critical substation, ..etc.) in the long term planning process. However, in some limited cases, SPS were implemented to protect against some events of more frequent nature (e.g. single contingency outages) when the system reinforcement is either not feasible within the required time frame or economically prohibited. Moreover, equipment maintenance modes in the operating time frame may leave the system in conditions by which the next single contingency is of equivalent impact to multiple contingencies in the planning time frame. In these cases, SPS usually play a major role in maintaining a reasonable comfort zone for the system operators.

Under-frequency load shedding protection may be categorized as SPS to some extent by virtue of its action and impact but its general application in just about every system leaves doubt about describing it as “Special”. Therefore, for the purpose of this discussion, we will exclude the under-frequency load shedding protection.

Most of the SPS applied in many parts of the world were the result of creative thinking. The most important ingredients of a successful SPS are simplicity, reliability, and cost. Simplicity reflects on how complex the triggering signal is (in nature and number). For example, one can simply implement a triggering scheme to protect against multiple contingencies by detecting all possible combinations of multiple outages that could have impact. This would result in a costly less reliable SPS. Instead, one can detect the minimum cut sets of contingencies leading to the potential risk or trigger based local measurements of variables reflecting the impact rather than the cause. Apart from the indirect impact of the degree of complexity of the triggering signals on the SPS performance, its reliability is directly dependent on the hardware, redundancy and design philosophy of the schemes.

Some North American reliability councils, like the Western System Coordinating Council (WSCC) and the Northeast Power Coordination Council (NPCC), have implemented strict rules, criteria, and review process to govern the design philosophy of SPS. Every SPS has to be reviewed by a group of specialists from the region before approval for implementation.

The following are key issues that must be addressed in developing SPS [1]:

- Detection - What measurement and calculations are required to detect and identify an emergency condition?
- Control action - Which controlled elements should respond and how?
- Coordination - What is the degree of coordination required and to what extent can local or decentralized control be used?
- Timing - How quickly must the action be initiated and how long should it last?
- Degree of automation and adaptiveness - Is operator intervention required?
- Effect on equipment and system - Is the control action subjecting the element being controlled and other elements to an unacceptable level of stress?

Particularly critical is the issue of the necessary degree of coordination. A local detector and control is far more economical and reliable than a centralized scheme. Unfortunately, a decentralized control action may not be adequate in many cases. The operator often plays a key role in coordinating related information from diverse sources and developing corrective strategies to restore the system to a more secure state of operation.

The highly nonlinear and time varying nature of power systems makes it difficult to develop fully automatic controls capable of adapting to changing system characteristics. Operator assistance may be required for many emergency controls to ensure that they act only when required.

Some of the emergency control methods are “heroic” in nature and they may impose significant stress on equipment. Their design should attempt to minimize the duty on equipment, and their application has to be based on a careful assessment of benefits and costs.

Here we describe some of the SPS that have been utilized by utilities serving the Canadian Provinces of British Columbia and Ontario.

3.2.2.3.1 SPS Applications in British Columbia

BC Hydro has an extensive menu of SPS implemented for many years ranging from few to decades with very positive experience record. BC Hydro's experience should be particularly important in this case because of its close relevance to the hydraulic base nature of the Brazilian resources and the nature of the system limiting phenomena (e.g. transient and voltage stability). Some of the most effective SPS applied in BC Hydro are described below:

Generation Shedding

Sometime, referred to as "Generation Dropping", generation shedding is a scheme by which a pre-determined amount of generation is tripped upon the detection of a set of specific critical circuit outages to retain the integrity of the rest of the system. The amount and location of the generators to be dropped are usually based on extensive studies which determine the characteristics of the system and the most effective action required. The scheme is implemented by arming a course of action in anticipation of the possible scenarios which have potential of exposing the system to unacceptable risks. The impact of periodic tripping of generators on hydraulic turbines is virtually nil. On the other hand, the wide implementation of this particular scheme on thermal facilities is not as popular except under very special circumstances because of the more complex process of load rejection and loading of thermal turbines. The majority of generation shedding applications are to maintain transient stability and, therefore, have to be very fast (few cycles). The minor applications to overcome voltage stability problems can be slower if needed.

BC Hydro has wide application of generation shedding schemes in all the major generating facilities. For many years of operation, BC Hydro implemented generation shedding schemes for single contingencies where the economics and the value added by additional major transmission facilities were very difficult to justify. The system wide scheme is armed by the system operator based on computer tools which determine for him the amount and location required. Once the operator approves the recommendation and the arming scheme, it is implemented in real time waiting for the triggering signals to occur. Upon the detection of the triggering signals, the designated generators trip in about 80 ms.

The triggering signal is the line breaker status for line faults, transmitted by dual communication channels for redundancy. Relay operation signal is also possible but was found less reliable than breaker status. Moreover, under some conditions, the system might be vulnerable on a simple line tripping without any relay action. Accordingly, the BC Hydro triggering signals are breaker status.

It should be noted that generation shedding by itself could hurt more than help if the system cannot overcome the resulting generation deficiency created by the SPS. Generation shedding will only be effective if the amount of spinning reserve in the receiving area is capable of providing the deficit or if the amount of generation shed is countered by shedding of a load block. BC Hydro is connected strongly to the rest of the Western system and has an operating and reserve sharing agreement which make load shedding unnecessary to counter the generation shedding.

High Speed Line Tripping and Reclosing

High speed tripping of faulted lines is very much an old and well established and applied technology but reclosing is not necessarily as widely applied. Although the planning criteria is usually based on the assumption of reclosing on a permanent fault after tripping, over 90% of the line faults are temporary (mostly caused by lightning) in nature. This result in recovery of the system integrity in less than or around one second in the vast majority of line faults. Moreover, since most of transmission line faults are single line to ground, tripping single phase and reclosing could significantly enhance the system security under a wider variety of operating scenarios.

Implementation of three phase reclosing for existing facilities is usually a modest effort exercise. Single phase tripping and reclosing, however, is much more demanding in the implementation effort than its three phase counterpart. Should reclosing be unsuccessful in the odd occasions, it has its negative mechanical impact on the power system facilities especially the generators. The impact is trivial on a hydraulic turbine/generator complex compared to its thermal counterpart. The application in systems based on the former in much more popular than the latter.

BC Hydro has extensive successful experience in both single and three phase tripping and reclosing on all 500 kV aerial lines and some lower voltage where it adds value. Three phase reclosing is done within 750 ms and single phase is done in 1.5 seconds following the initial fault clearing.

Under Voltage Load Shedding (UVLS)

An effective remedial action against voltage collapse is UVLS. Analogous to generation shedding for transient stability, UVLS is achieved by tripping a pre-determined amount of load in the region susceptible to voltage collapse upon the detection of voltage level below a preset value at a set of central load points. In order to make the scheme robust and avoid unnecessary tripping of load, the proper schemes are usually equipped with time elements and supervised by key indications of voltage instability such as local generator or synchronous condenser reactive power output. Since this scheme involves a harsh action of load shedding, it is usually implemented to protect against multiple contingencies or unforeseen events. Applications to protect against single contingency events should only be done as a temporary measure until more comprehensive solutions are developed and implemented.

BC Hydro has successfully implemented a multiple contingency UVLS in the major load centres. Because of its close relevance and potential application in Brazil, a full description of the methodology and the scheme is attached (paper by S.C. Pai).

Switchable Reactive Support Devices

In their traditional applications, these devices are neither special nor protection. Because of the slow nature of the voltage collapse mechanism of power systems, switchable shunt capacitors can provide good part or all of the necessary dynamic support needed to save the system from collapse. The same type of signals used to trigger the UVLS scheme can be used to switch shunt capacitors automatically. Depending on the system characteristics, switching time anywhere between 10 and 30 seconds is sufficient. Careful studies of this application could provide a very reliable and economic alternative to more expensive dynamic VAR devices like static VAR compensators and synchronous condensers. The most important factor in determining the feasibility of this application for voltage stability purpose is the characteristics of the load. The time required for the studies, testing, and installation is about one year.

BC Hydro has implemented intelligent schemes for switching shunt capacitors to protect against voltage collapse. The savings achieved by such application are significant.

Dynamic Braking Resistors

This application is extremely effective and suitable for enhancing the transient stability performance of the power system of hydro based systems like Brazil. Braking resistors are literally electrical braking devices which limit the generators overspeed during disturbances and, hence, keep their relative position closer to synchronous. The resistors are massive heating elements installed close to a generating plant or central to a group of them. Upon the detection of indicative quantities to machine acceleration, a pre-specified block of resistors is switched for a period of time enough to absorb the kinetic energy induced by the disturbance within the design limits of the resistor itself. The full operation of the braking resistor (on and off) is completed within the first swing of the power system.

BC Hydro has a 3-block 600 MW braking resistor at the terminal station of the G.M. Shrum (GMS) generating station in Northern British Columbia. Bonneville Power Administration (BPA) has a 1400 MW block of braking resistors at a central location to the major generating plants in Oregon State. BC Hydro's scheme triggers upon the detection of a preset amount of accelerating power at GMS while BPA's scheme is triggered by the same signal but supervised by a voltage dip indicator. Both companies have more than 25 years of good experience with the application of braking resistors to maintain transient stability. BC Hydro will not hesitate to recommend them for similar applications and will apply them again wherever needed. Both BC Hydro and BPA use the braking resistors also to limit over frequency of the system under islanded conditions.

3.2.2.3.2 SPS Application in Ontario

Several forms of SPS have been used in Ontario since 1965 to enhance system security: Generation tripping, generation ramping, controlled system separation, reactors/capacitors switching, load shedding, and transient excitation. Application of most of these have been straightforward and routine. Here we describe three unique schemes that required special consideration and coordination.

Scheme for Prevention of Voltage Collapse

This scheme was implemented in the early 1980s to cope with extended delays in obtaining approval to build 500 kV transmission lines in eastern Ontario, requiring the Ottawa area load to be supplied largely by 230 kV transmission. Under heavy load conditions, loss of a critical 230 kV circuit could lead to voltage collapse of the Ottawa area. To prevent this, a coordinated scheme consisting of the following controls was put in use:

- Fast auto reclosure of major 230 kV circuits
- Automatic load rejection
- Automatic switching of shunt capacitors
- Automatic blocking of transformer ULTCs

The fast auto line reclosure is used as a first measure for preventing voltage collapse. It provides for reclosing of major 230 kV circuits in 0.9 s to 1.3 s. If reclosure is successful, voltage recovers and other preventative measures will not be triggered. If, on the other hand, reclosure is unsuccessful, load rejection may be triggered depending on how low the voltage drops, followed by capacitor switching and possibly, ULTC blocking as described below.

The automatic load shedding provides for tripping of up to 750 MW of load, comprising nine blocks of loads which may be individually selected by the operator from an attended master station. It trips the load if local station voltage drops below a preset value for a minimum time period (1.5s).

A total of 36 capacitor banks in 17 transformer stations have been equipped with automatic switching (on/off) features dependent on voltage and time. The capacitors are switched in staggered blocks with settings ranging from 1.8 s to 8.0 s so that only the required amount of compensation is switched.

Facilities for automatic blocking of under load tap changing (ULTC) have been provided at 14 transformer stations. The ULTCs are blocked when the load voltages drop below a preset value for a specified time, and unblocked when the voltages recover.

The voltage collapse prevention scheme was designed by carrying out power flow and transient/midterm stability time domain studies for different load levels. Since voltage stability is sensitive to load characteristics, load models used in these studies were based on measured characteristics at two transformer stations in the Ottawa area, one supplying predominantly commercial loads and the other predominantly residential loads.

It has not been necessary to arm this scheme since the building of 500 kV lines in Eastern Ontario in the early 1990s. However, it is still available for use under emergency conditions.

Bruce Generation/Load Rejection Scheme

This scheme was implemented in the 1980s to maintain transient (angle) stability of the Bruce Nuclear Power Development complex located on the east shore of Lake Huron in Ontario [2].

Initially, a two-unit generation rejection scheme was implemented. As the generation capacity in the Bruce complex increased, this was later replaced by a four-unit generation/1500 MW load rejection scheme.

Two-Unit Rejection Scheme. In 1980, the Bruce complex had a total generation of 3200 MW, with four 750 MW units at Bruce GS-A and one 200 MW unti at Douglas Point GS. It was connected to the Ontario Bulk Electricity system by three 230 kV double circuit lines and one 500 kV double circuit line. A planned second 500 kV double circuit line could not be built until the late 1980s due to a prolonged approval process. A two-unit rejection scheme was implemented to maintain transient stability for loss of both circuits of the 500 kV line. This provided for rejection depending on the output of the station.

The generating units are designed so that after tripping they continue to run, supplying unit auxiliaries. For a temporary fault, the units are brought back on-line quickly, following the reclosure of the lines.

The two-unit rejection scheme was an extension of the trip circuits from various remote and local protections. Selection of the generators for tripping for different circuit faults was carried out manually under the direction of the System Control Centre.

Four-Unit Generation/1500 MW Load Rejection Scheme. Four 750 MW nuclear units were added to the complex at Bruce GS-B between 1983 and 1987, increasing the total generation capacity of the complex to 6200 MW. Until the second 500 kV line was built, additional measures were required to maintain transient stability. After a careful evaluation of all alternatives and an assessment of costs/benefits, a four-unit (3000 MW) rejection scheme was adopted. When units are tripped at Bruce, the loss of generation is made up by power flows from throughout the interconnections to neighbouring utilities, costumer load had to be rejected so that net loss of generations would not exceed 1500 MW. Signals from the Bruce complex would be automatically transmitted to load rejection stations using mainly microwave facilities. Loads at about thirty transformer stations throughout southern Ontario were chosen as possible candidates for rejection. This generation/load rejection scheme permitted up to six Bruce-A and Bruce-B to be fully loaded. The number of generating units and the amount of customer load rejected depended on the local Bruce generation, the number of transmission circuits in service and the contingency. The following factors were given consideration in the selection of the scheme:

a) The cost of displacing locked-in nuclear energy with fossil-fueled generation. This was estimated to be in order of one million dollars per day.

b) The estimated frequency of double circuit 500 kV outages: 0.3 to 0.5 per year.

c) The possible adverse effects on generating units with regard to risk of turbine-generator-runaway, increased forced and maintenance outage rates, additional wear and tear, and cumulative loss of component life. These were carefully evaluated and judged to be acceptable.

This scheme is still in service, but with addition of the second 500 kV line it is used only under emergency conditions. The scheme is computer based and operates by monitoring post-contingency system configuration (i.e., by checking which breakers have operated) rather than protective relaying. The system has been duplicated to improve reliability and permit routine testing. It is managed by the SCADA system at the System Control

Centre. Selections are made through supervisory control equipment linking the System Control Centre to the Bruce Complex.

Transient Excitation Boosting

Significant improvements in transient stability can be achieved through rapid temporary increase of excitation of generating units. Supplementary excitation control, commonly referred to as power system stabilizer (PSS), provides a convenient means of damping system oscillations. A high initial response excitation with a high ceiling voltage and a fast acting automatic voltage regulator, supplemented by a PSS, is by far the most effective and economical method of enhancing the overall system stability.

A properly tuned PSS is effective in damping both local plant modes and interarea modes of oscillations. Under large disturbance conditions, the PSS generally contributes positively to first swing transient stability. However, in situations with dominant local as well as interarea swing modes, the normal PSS response can reduce the excitation after the peak of the first local mode swing, but much before the highest peak of the composite swing is reached. Significant improvements in transient stability for such situations can be achieved by keeping the excitation at ceiling until the highest point of the swing is reached. A discontinuous excitation control scheme referred to as *transient stability excitation control* (TSEC) has been developed and applied at Ontario Hydro for this purpose [3,4].

Principle of TSEC Operation. The discontinuous excitation control uses a signal proportional to the change in generator rotor angle. The angle signal prevents premature reversal of field voltage and hence maintains generator terminal voltage near the maximum allowable value of about 1.15 u over the entire positive swing of the rotor angle. The angle signal if used continuously results in oscillatory; therefore, it is used only during a transient period of about two seconds following a disturbance.

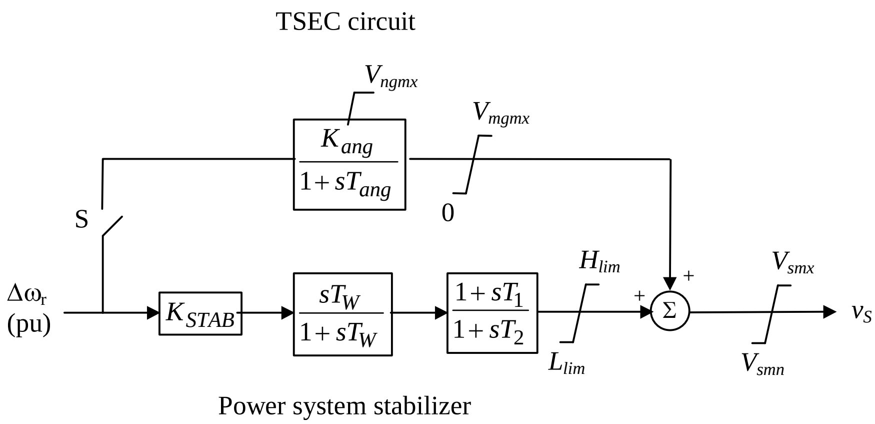

Fig. 1. Block Diagram of TSEC Scheme

TSEC Implementation. Figure 1 shows a block diagram of the discontinuous excitation control scheme. The TSEC circuitry is integrated with the PSS circuitry. The angle signal is derived by integrating the speed signal. The TSEC block shown in the figure is an integrator with a washout; the value o T_{ang} is such that, in the frequency range of interest, the output of the block is proportional to the angular deviation. The relay contact (S) is closed if the generator terminal voltage drop exceeds a preset value, exciter output voltage is at positive ceiling, and the speed increase is above a preset value. The relay contact is opened when either the speed drops below a threshold value or the exciter output comes out of saturation: the TSEC output signal then decays exponentially.

With TSEC, a fast acting terminal voltage limiter (TVL) is required to prevent the generator terminal voltage from exceeding the allowable maximum value, typically 1.15 pu of rated voltage. The development of a sufficiently fast acting limiter without amplifying the shaft torsional components of the terminal voltage signal presented a challenge. This challenge was met by implementing a dual voltage limiter with a combination of fast bang-bang type control and a slow continuos control [5].

The TSEC and TVL settings should be coordinated with other overexcitation protection and control functions. They must also be coordinated with transformer differential protection.

Effect of TSEC on Power System Performance. The effectiveness of TSEC in improving transient stability is illustrated in Figure 2. The figure shows the responses with and without TSEC of a fueled power plant consisting of two 500 MW units having bus-fed thyristor exciters with PSS. The disturbance considered is a three-phase fault on a major transmission line close to the plant, cleared in 60 ms. As seen from the rotor angle plots, the generators at this plant exhibit a dominant low frequency interarea swing without TSEC. Clearly, the system transient stability is very significantly improved by TSEC. As an indication of the degree of stability, the critical fault-clearing time was determined for the two cases and was found to be 62.5 ms without TSEC, and 117.5 ms with TSEC.

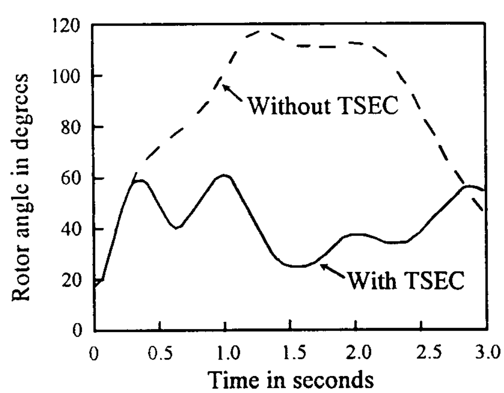

Fig. 2. Effect of TSEC on Transient Stability

When TSEC is applied to several generating stations in an area, bus voltages in the entire are raised. This increases the power consumed by voltage dependant loads, thereby contributing to further enhancement of transient stability.

The initial version of TSEC was applied in 1974 to the Lennox GS in eastern Ontario, which consisted of four 500 MW oil-fired units. An improved version of TSEC was applied from the mid to late 1980s to the generating units at three major plants in southwestern Ontario: Nanticke GS (eight 500 MW coal-fired units) and Bruce GS-A and Bruce GS-B (four 750 MW nuclear units each). These applications have contributed to a significant increase in the power transfer capability of the system.

Compared to other forms of emergency control, such as fast-valving and generator tripping, TSEC imposes very little duty on equipment. It is also fully automatic; that is, it does not have to be armed and disarmed by the operator. In effect it is a nonlinear adaptive control based on local measurements.

3.2.3 The Brazilian Perspective - An Evaluation

The 11th of March, 1999 event was explained by Mr. Antonio Carvalho. It is our understanding that a single line to ground (phase B) fault was triggered at the Bauru substation as a result of what appeared to be a lightning stroke causing a bus insulator flashover. The bus configuration of Bauru is such that the fault was cleared by opening 5-440 kV lines and a transformer bank. Four of the five lines represent a major one of the four corridors supplying the São Paulo area from Jupiá and I. Solteira generating plants. The fifth line, to Assis, represents a second of the four corridors. Thus, a major part of the supply corridors to São Paulo was lost in clearing the fault at Bauru.

Preliminary studies done by the investigation team show that the system would have survived the disturbance if it was not for a critical loading condition on the short line between Jupiá, T.Irmãos and I. Solteira. The line subsequently tripped when triggered by zone 3 relay. This, in turn, caused a serious split in the 440 kV ring which weakened the system significantly and immediately caused transient stability problems. One can go through the sequence of events to critique how hell broke loose after instability took place. While those details should be very important to those analyzing the protection and control operation for auditing and checking purposes, we find that the lack of coordinated time records among the affected entities will make this exercise lengthy. For the purpose of this report, the authors will concentrate on the triggering event and the issues leading to the initiation of the instability phenomena for the purpose of minimizing the risk in the future rather than studying the behavior in the system while collapsing.

Apart from the deficiency in the Bauru substation arrangement which will be addressed later, the protective relaying scheme acted as it was designed to do. According to Mr. Osvaldo Shiraishi, the Bauru bus fault clearing was achieved by the operation of the zone 2 relays of the far end of the five lines connected to the bus with a transfer trip signal to the Bauru's end. In the absence of bus differential protection at Bauru, as expected, the directional characteristics of the fault current due to the bus fault prevents zone 1 protection from operating instantly. Zone 2 fault clearing time is 400 ms. This clearing time may appear excessive for 440 kV voltage class. The single phase to ground type of the faults is usually a blessing because of its lower impact on system stability, as verified by the preliminary studies, when cleared in such a long time. However, the studies team conducted additional studies based on our request to reproduce the simulation results but triggered with a three phase fault instead of a single phase fault. The results still showed stable behavior if it was not for the subsequent tripping of the Jupiá-T.Irmãos-I.Solteira line.

It appears that faults at the main grid tend to accelerate the system generators in close synchronism which get disturbed if a subsequent set of faults (e.g. Jupiá-T.Irmãos-I.Solteira) affect the system connectivity severely.

3.2.3.1 Review of the Incident

The review of the incident and the status of the system based on the information provided by the investigation team will be addressed under four main sections:

- The triggering event
- The remedial measures
- Restoration
- General Observations

The Triggering Event

The question here is why the event was initiated and how it escalated to the unacceptable level with the intention of minimizing similar future risks.

A good starting point is the impact of lightning strikes on transmission lines and substations. Transmission lines and electric installations are usually protected against high voltage surges resulting from lightning or switching activities to various extents. The protection is done using voltage limiting devices or shielding measures to either divert the surge currents to ground or limit its impact to the design limit. These measures are never fool-proof but, rather, the degree of protection provides a risk minimization measure. Thus, regardless of how much one is willing to invest in those measures, there will often be those strikes that pass through the shielding equipment and surpass the voltage limiting characteristics of the surge limiting devices. Thus it is not surprising to experience substation equipment flashover due to lightning. However, it is also important to investigate the triggering mechanism and review the coordination process whenever a flashover takes place.

The investigation team informed us that shortly after the day of the disturbance, the condition and the characteristics of the problem insulator and the surge arrester were tested and found to be up to the expected standards. We were also informed that the 440 kV transmission lines around Bauru substation are double shielded for the full length of the lines. Accordingly, we can only assume that either the lightning strike was of the direction and magnitude that surpassed the capabilities of both the shield and the protective device or the lightning strike directly hit the substation insulator. While the probability of this happening should be very small, we have to keep in mind that this is the first time it happened in the history of this particular substation.

Acknowledging that a prompt action has been taken to investigate the characteristics of the insulator and the surge arrester, we recommend a further analysis to determine if additional shielding measures are required, for substations located in regions of high isochronic levels.

Given that the evolution of the triggering lightning strike is legitimate, the fault clearing by tripping five critical lines must be addressed. Bauru substation bus has two section/single bus/single breaker configuration. The faulted bus section connects five critical 440 kV transmission lines supplying major load centres of the South East. This configuration has the following deficiencies:

- The single bus/single breaker configuration is economic but among the least reliable. Clearing bus faults similar to the trigger of this event or breaker failure events result in clearing large number of circuits. It should be noted that although the probability of this type of events is low, they do happen with high impact which usually justifies the incremental investment. The service class and significance of the 440 kV system warrants a significantly better bus configuration than that which exists at Bauru.
- The way the circuits are allocated to each of the two bus sections leaves lot of room for improvement. Double circuit lines to the same destinations are connected to the same bus section which make the supply points more severely vulnerable to bus faults.

The investigation team shared with us the result of their analysis of the configuration of about 80 substations in the system. The method of analysis is sound and is based on classification of all the substations according to the risk of multiple line outages versus the impact on the system. The results were classified into three categories: high, medium, and low risk. About 80% of the substations fall in the low risk category. A quick review of some of those in this category indicates that the vast majority of the Brazilian substations measure among the best of substation designs. Bauru and I. Solteira are the only two substations classified as high risk high impact, while Cabreúva and Jupiá were classified as medium risk high impact. The remaining 11 substations fell in the medium risk/medium impact category: they deserve some attention but not immediately. We commend the team for their approach which provided an excellent decision making framework.

The team identified possible rearrangement of Bauru bus configuration through simple switching actions by which the critical circuits would be split between the two sections in such a way that a bus section fault would result in a much less impact on the system. For example, double circuits to the same destination would be allocated to two separate bus sections. We were advised that these re-arrangements will require a thorough review of the protective relaying schemes of the substation and the rating of buswork elements including the circuit breakers and switches. This review is currently underway and is expected to be presented within the next few days. It should be noted that the full substation could still be lost for a failure of the sectionalizing breaker. However, the latter event is of a significantly less probability than all previously described events including the one under investigation. Should the protection coordination issues get addressed, the re-arrangement is expected to be implemented immediately. The reliability impact of a similar fault in the future is expected to be enhanced significantly but flexibility of operation would be somewhat compromised. Should it be desired to maintain the same level of operating flexibility as at present, the re-arrangement of the various circuits between the two bus sections should be done by re-arranging the physical terminals of the connection points instead of switching.

I.Solteira suffers from deficiencies similar to those of Bauru, with added challenges of being a generating station. Re-arranging the points of connection including the generators among multiple sections of a single bus result in large variety of load flow between the bus sections which makes the protection coordination significantly more challenging than for Bauru. This is also under significant investigation by the team at the moment but expected to take more mental effort than Bauru.

Cabreúva and Jupiá substations configuration suffers from the same risk of the single bus arrangement but of lower impact than Bauru and I.Solteira. Therefore, the priority order of the former two is lower than that for the latter in the investigation.

We recommend and support a speedy action plan to re-arrange the critical circuits among the bus sections of single bus substations. The plan should start with the protective relaying review to accommodate the necessary changes then follow with implementation using the available switching flexibility in each of the substations to minimize the risk of exposure to another failure within the short time frame. We also recommend a follow up action plan to achieve the same arrangement through physical manipulation of the line terminals at the substation to recover the historical operating flexibility of the substations as a short term plan. The risk should be further addressed in a longer term strategy to bring the security level of the weak substations to the same standards as for the rest of the system.

The Protective Measures

In this section, we will address the protective measures which were activated in response to the triggering event and suggest those of potential benefit to the Brazilian system based on our experience.

As mentioned earlier, the bus fault at Bauru was cleared by tripping five lines by distance protection (zone 2) because of the lack of differential protection at Bauru. The line protection has three zones: Zone 1 covers 80% of the line length and has instantaneous tripping time. Zone 2 covers 120% of the line length and tripping time of 400 ms. Lastly zone 3 covers 150% of the line length and has 1 second tripping time. Power swing initiated operation are blocked for zone 1 and permitted in the other two. Automatic reclosing is permitted only for single phase faults within zone 1.

All five line protection have operated appropriately as expected.

The T.Irmãos to I.Solteira line is of about 40 km length and tripped on zone 3. The line rating was far below capacity when it tripped. At least two of the major disturbances in North America in recent history involved zone 3 line relay tripping. Therefore, zone 3 relay settings have been reviewed and many have been revised. According to Mr. Osvaldo Shiraishi from CESP the setting of zone 3 of the Jupiá-T.Irmãos-I.Solteira line was tested, revised and implemented.

This, together with the revision underway to the circuit re-arrangement at Bauru, will help to ensure that the 11^{th} of March, 1999 sequence of events will not repeat.

As discussed earlier, we have focused on the actions associated with the events leading to the total system shut-down. As the system reached the unstable condition, on its way to collapse, thousands of equipment, protective devices, and control devices have reacted according to their characteristics and settings. It is virtually impossible to fully assess the appropriateness of their response without global synchronous timing and data logging system. Such a global system would not necessarily have saved the system from collapsing on the 11th of March but would have provided invaluable information about the performance of the critical protection and control schemes which, in turn, would have helped assessing and improving their performance. Such systems also collect information continuously under the daily and frequent events which help monitoring and enhancing the performance of the critical elements for bigger and more serious events like the one of the 11th of March.

Thus, we strongly recommend developing and implementing a plan to install a global synchronous time coordination and data logging system to monitor and document the performance of the interconnected system on a continuous basis.

Restoration

Mr. Paulo Cesar Fernandez described the comprehensive Brazilian system restoration plan in detail. The plan was developed under the guidance of the Central Coordinating Group many years ago after the experience of two system collapses in the 1980's. The plan is detailed and specific as to the restoration activities done independently within the various regions and the coordination at the integrated system level. We understand that the restoration strategy is based on extensive analysis of the system behavior during restoration based on steady state, electromechanical dynamic, and electromagnetic transient analysis. We understand that routine review of the plan by the operating staff is done on a regular basis.

Through the course of discussions with the staff involved in restoration, we have determined that there was no hesitation or confusion among the operating staff in initiating and executing the restoration strategy.

Our assessment is that the Brazilian restoration strategy is very comprehensive and measures up to any of the best international practices in restoration.

In general, restoration strategies after system wide collapses make certain assumptions as to the condition and availability of the network facilities. Seldom does it ever happen anywhere in the world that the post-disturbance system condition and availability are the same as the pre-disturbance. More worth noting is the fact that some of the facilities critical to the restoration process may be out of service for maintenance or otherwise.

The Brazilian restoration process of the 11th of March was no exception. The process was delayed primarily due to the unavailability of the minimum number (5) of generators required to initiate restoration from Marimbondo generating station. Some of the generators were out of service prior to the disturbance and exciter breakers of two of the generators failed to energize. It is not known as to whether the failures of the exciter breakers were a result of excessive duties experienced by those facilities during the disturbance. However, it is reasonable to assume that it is probably the case, given the age of those facilities and their performance prior to the disturbance. Moreover, when trying to energize, insertion resistors of CESP/Araraquara-I.Solteira line breaker failed.

Insertion resistors were applied in circuit breaker technology some years ago to limit the magnitude of the surges associated with line energizing. The industry experience with such equipment was rather poor and have been abandoned by many utilities. The delay caused by these particular difficulties consumed an additional half hour in the restoration process.

The operating staff successfully followed an alternate route to restore the service to Rio de Janeiro from Furnas generating station through the 345 kV network, but was further complicated by a transformer overload which interrupted the service again for about another hour.

The Eletropaulo representatives expressed concern about the priority given to their strategically important load in the under-frequency load shedding scheme. They have not objected to participating in a load shedding strategy to save the system under severe disturbances but would like to see better selectivity of the type and location of the load to be shed in their system. They also stated that it is important to count on H.Borden generating facility as an alternative for supplying priority load in São Paulo City. This generating facility could provide a smoother and faster restoration process. Furnas operating staff indicated that, because of environmental problems, operating this plant needs special governmental permits regardless of the form of the agreement among the distribution companies which may prohibit their abilities to do so under the urgent conditions of restoration. The discussions generated some ideas which Eletropaulo will consider and pursue.

In spite of the challenges described above, the entire system was restored within four hours with large bulks of the system load starting to be restored in half an hour.

It is our view that four hours of restoration time for such a massive volume of geographically sparse load and facilities in spite of the difficulties experienced by the operating staff is a remarkable achievement. The leadership in developing the restoration strategy and the effort and skills of the operating staff who executed it on March 11th deserve recognition.

Not withstanding the above, we recommend reviewing the condition of the facilities critical to the restoration process such as the Marimbondo facilities to ensure top condition at all times. We further emphasize the need to monitor the condition of those facilities now and in the future. The availability of such equipment is of vital national importance and must be clarified in a contractual form.

Insertion breaker resistors proved to be unreliable and should be phased out if possible. This will require a review of the system response to switching actions and may have to be substituted by other means of surge suppression.

General Observations

The conclusions made in the preceding part of this report are specific to the topics and issues related to the March 11th event. Through the course of the discussion with the members of the investigation team, we have come across the following important observations. Although these are not directly tied to the event under investigation, they could matter to other events in the future:

1. The transmission system has few weak pockets which need immediate attention. Fortunately, these can be covered by remedial measures in the immediate to short time frame until a more rigorous fix is done.
2. We notice the long distances of EHV transmission lines from the resources to the load centres accompanied by poor voltage regulation in major points of the South and Southeast. These characteristics lend themselves very nicely to series compensation. Series compensation technology is economic, effective, and reliable. The cost of a typical 500 kV series capacitor bank is about $10M. Series compensation is fully self regulated and can make the electric distance two to three times shorter. The installation period is typically a year and half. The type of compensation provided by series compensation will enhance the system capability against both voltage and angle instability.
3. The Southeast to South transmission system is weak. The loss of any one of six sections of the 500 kV transmission corridor cause severe under voltage. A remedial action scheme is in place to shed a block of load in the South and two generators at Itaipu. A much more significant amount of load has to be shed if the two parallel circuits of any of the three sections are lost. The load shedding on the first contingency concerns us more than the double contingency because of its high probability of occurrence.
4. While a number of SPS involving generation shedding are currently in place, there is room for utilizing the network more effectively by implementing additional SPS in the immediate and short term. Should this become the case, it is important to have a higher level of spinning reserve allocated strategically around the system to compensate for the amount lost in the SPS without impacting the generation-load balance. The nameplate capacity of the Brazilian system compared to the current peak demand indicates about 18% resource planning margin which is among the highest and suggests a high level of reserve comfort. Yet, it is our understanding that the availability of many of the old plants is becoming more limited by delay in modest refurbishment.
5. The new South to North interconnection provided up to 1000 MW of exchange between the two major regions. It appears, however, that the interconnection could be tripped very often due to loss of synchronism between the two regions in response to even modest disturbances in the South and Southeast. Some of those disturbances may trigger generation shedding of up to 1500 MW at Itaipu which when combined with the loss of the Northern intertie could result in loss of up to 2500 MW of generation for modest disturbances. Beside emphasizing the point made in item 4, above, there must be solutions to stabilize the Northern system.
6. Considering the current strategy of dispatching the generating plant in a competitive environment, it is very important to be specific in the sales agreement to obligate the buyers to respond to the instructions of the system operators under emergency regardless of the economics.
7. The operators of the various regions and the ISO are evolving into a different market, different players, and more stressed system rapidly. It is very important to expose

them to a thorough training strategy and certification process to ensure maintaining their competence.

8. There appears to be a perception among some of the people we interviewed that the number of remedial measures at Itaipu is excessive. We do not believe that such a number (14) is excessive.

9. The fragmentation of the historical industry structure into many generation and distribution companies, the transfer of major system responsibilities to the ISO, and the evolution of many new players demand a legislated ministerial course of action to manage the reliability of the integrated system. Reliability Management Systems (RMS) is the hottest topic currently under review and restructuring in North America. The RMS includes three distinct process:

   i) Standards development (Planning and Operating) through a consensus of stakeholder self regulating body with an independent governance (not the ISO). Limits on frequency deviation and Area Control Error (ACE), operating reserve availability, and appropriate settings of generator AVR's and power system stabilizers are examples of necessary operating standards.

   ii) Enforcement of the standards through sanctions against the violators.

   iii) Compliance monitoring through control area operators, security coordinators, and ISO's.

10. We were informed that some of the critical synchronous condensers located at the load centres operate close to their limits under normal operating conditions. This indicates that the system is normally deficient of dynamic voltage support facilities and should be immediately investigated. It is necessary to make sure that all possible static shunt compensating devices are utilized effectively to free up the dynamic support reserve of the synchronous condensers while plans are developed to install additional shunt capacitors in at those locations.

3.2.4 Recommendations

The following is a summary of our recommendations for implementing various measures to improve the overall system reliability. We have attempted to categorize them in terms of target implementation time frames based on the urgency of the required measure and the expected lead time required. It should be noted that regardless of the implementation time frame specified, an implementation plan for all recommendations should be initiated as soon as possible.

Measures to be implemented immediately

1. Rearrange the bus configurations at Bauru, I.Solteira, Cabreúva, and Jupiá through switching changes so as to minimize the impact of bus faults on the system security. It should be noted that the feasibility of such rearrangement has to be checked from protection modification requirement and operating flexibility.

2. Review the application of Zone 3 and other backup distance protection on EHV and the upper end of the HV networks throughout the system, and where appropriate

replace them with improved relaying. In system stability studies, model Zone 3 and backup protection.

3. Initiate the development of a Reliability Management System including the development of compliance national standards to govern the quality of operation, planning, and data reporting processes.
4. Explore and determine feasible local SPS which can be implemented immediately to improve system security under multiple contingencies (e.g. generation shedding at I.Solteira and Jupiá).
5. Review the condition of the facilities critical to the restoration process immediately and fix whatever is possible on the spot.

Measures to be implemented in the short time frame (few months to a year)

6. Rearrange the substations identified in item 1, above, further to improve the operating flexibility by making changes to the physical terminals of the connection points and revising the protective relaying philosophy.
7. Determine all feasible SPS and begin implementing them in priority order. The implementation should be according to a well structured emergency security and control strategy.
8. Investigate overload on the key interface transformers in the system (e.g. 500/440 kV transformer at Água Vermelha) and determine the necessary short and long term solutions.
9. If feasible, implement over-excitation limiting devices on the critical synchronous condensers and generators which play major role in maintaining voltage stability.
10. Implement a legislated Reliability Management System.

Measures to be implemented in the medium time frame (one to two years)

11. Improve reactive power compensation in the South and Southeastern systems by installing series and/or shunt capacitors.
12. Implement a system wide emergency control plan based on wide applications of SPS. While this plan should be implemented to prevent system collapse following multiple contingencies, it may be called upon to respond to lower contingency levels until a permanent fix is implemented.
13. Improve the stability of the North and Northeast systems by proper analysis and installation of stabilizing measures.
14. Modernize the excitation systems of the critical power plants at or close to the load centres especially H. Borden, L.C. Barreto, and P. Colômbia.
15. Implement computational tools to enhance the ability of the system operators to assess the system capability in or near real time.

16. Implement a system wide time synchronous monitoring and data logging system to capture valuable information for assessing the system performance on a continuous basis.

17. Implement an operator training and certification strategy.

Long Term Measures (beyond two years)

18. The load growth is expected to consume most of the remaining margins within the next few years. SPS could serve securing the system on temporary basis but network reinforcements using hard measures must be planned and implemented. In particular, consideration should be given to:

    - An EHV line between Itaberá and Campinas to form a 750/500 kV ring around São Paulo.
    - Strengthening the interconnection between the Southeastern and South Systems.
    - Strengthening the transmission within the Southeastern system to remove the critical bottlenecks, reduce the burden on the SPS, and improve the performance of the North-South interconnection.
    - Insertion breaker resistors proved to be unreliable and should be phased out if possible. This will require a review of the system response to switching actions and may have to be substituted by other means of surge suppression.

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