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IEEE PSRC Working Group C4

Global Industry Experiences with System Integrity Protection Schemes (SIPS)

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1 Introduction

The electric power grid is the "pivot point" that balances generation and load. Maintaining the integrity of this pivot point is imperative for the effective operation of interconnected power systems. As such, the balance of power is only as reliable as the weakest pivot point in the system. System-wide disturbances in power systems are a growing issue for the power system industry [1], [2], [3], [4]. When a major disturbance occurs, protection and control actions are required to stop power system degradation, restore the system to a normal state, and minimize the impact of the disturbance [5], [6]. Control center operators must deal with a very complex situation and rely on heuristic solutions and policies. Local protection systems arrest the propagation of the fast-developing emergencies through automatic actions and are applied to address equipment specific or local system problems. Local protection systems are not intended for arresting large-scale power system problems, which may be caused by system disturbances.

The trend in power system planning has become tight operating margins, with less redundancy. At the same time, addition of renewable energy resources, interchange increases across large areas, and introduction of fast reactive control devices make the power system more complex to operate. The fundamental changes in the design and operation of the electric power system require that system-wide protection solutions be implemented to prevent disturbance propagation. As a result, automated schemes have been designed to detect one or more predetermined system conditions that would have a high probability of causing undesired stress on the power system.

Analysis of the NERC power transmission blackout data (Figure 1), shows probability vs. size of blackouts in the USA between 1984 and 1998. It is characterized by a power law [7] which makes the probability of large disturbances more likely than in the case of (commonly assumed) exponential distributions. In the case of exponential dependence, large blackouts become infrequent much faster than blackout costs increase. Hence, the risk of a large blackout (product of blackout probability and the associated cost) is very small. However, in the case of a power law dependence, as in Figure 1, the risk of large blackouts may become comparable to, or even larger than, the risk of small blackouts [7], [8]. Therefore, a common assumption that the risk of very large, devastating blackouts is negligibly small is no longer acceptable and can lead to very large and unexpected financial consequences, as the examples of large blackouts in the past decade have shown. Reduction of the risk of large system-wide disturbances and blackouts requires that system protection function be approached with the assistance of modern technologies in support of preserving system integrity under adverse conditions.

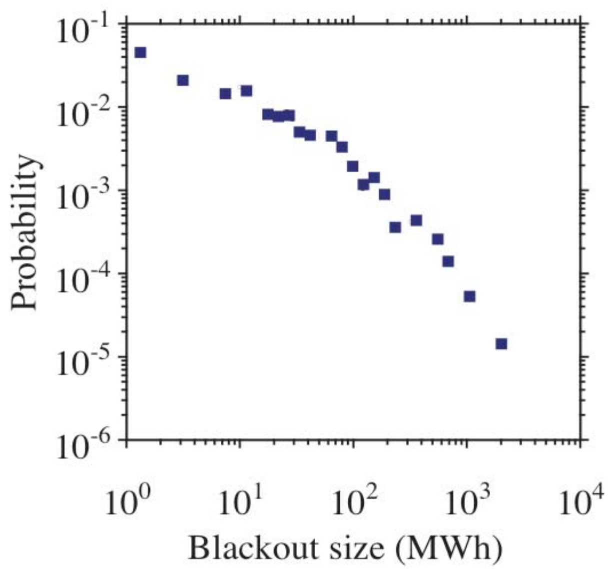


Figure 1 - North American Blackout Size Probability Distribution – Source NERC

These schemes, defined as system integrity protection schemes (SIPS), are installed to protect the integrity of the power system or strategic portions thereof, as opposed to conventional protection systems that are dedicated to a specific power system element. SIPS is a category of protection schemes designed to protect the integrity of the power system from system instability, to maintain overall system connectivity, and/or to avoid serious equipment damage during major events. The SIPS encompasses Special Protection Schemes (SPS), Remedial Action Schemes (RAS) and varieties of safety nets. These schemes provide reasonable countermeasures to slow and/or stop cascading outages caused by extreme contingencies, as well as additional schemes such as, but not limited to, Underfrequency (UF), Undervoltage (UV), out-of-step (OOS), etc.

Advanced detection and control strategies through the concept of system integrity protection schemes (SIPS) offer a cohesive management of the disturbances. With the increased availability of advanced computer, communication, and measurement technologies, more "intelligent" equipment can be used at the local level to improve the overall response. Traditional dependant contingency / event based systems could be enhanced to include power system response based algorithms with proper local supervisions for security.

In August of 1996, a seminal article [9] was published as a result of the activity of the joint Working Group of IEEE and CIGRE, the purpose of which was to investigate the special protection schemes (SPS) then in existence worldwide and to report about various aspects of their designs, functional specifications, reliability, cost and operating experience. The report encompassed over 100 schemes from all over the world and provided a wealth of information on the direction industry was taking in coping with ever-larger disturbances. The report also highlighted that IEEE and CIGRE were not the only groups of professional organizations that had shown concerns for the reliability of the SPS, and that several other organizations including Instrument Society of America (ISA) and International Electromechanical Commission (IEC) were actively involved in establishing standards for the future development of the devices manufactured to support system integrity type protection.

The results of the 1996 survey indicated that there was considerable interest in developing such Special Protection Systems (SPS). In fact, the survey indicated that such protection was widespread and no longer should be considered “special”. The acronym is now more properly termed System Integrity Protection Scheme (SIPS) or Remedial Action Scheme (RAS).

In 2005, the System Protection Subcommittee of the IEEE Power System Relaying Committee started an initiative to update the industry experiences on SIPS by creating and widely disseminating a new survey to attract as wide a response from the industry worldwide.

2 Survey Approach

The survey is intended to compile industry experiences with a category of protection schemes designed to protect the integrity of the power system; system stability, maintaining overall system connectivity, and/or to avoid serious equipment damage during major events. The survey is designed to provide guidance for future system implementers based on what exists today as well as operating practices and lessons learned. Our industry has long recognized system vulnerabilities, and is energized to promote grid reliability with SIPS being a key element. The responses to this survey will assist the industry in driving towards a more robust grid design.

The Power System Relaying Committee (PSRC) working group (WG) members requested that the survey questioner as well as the invitation for participation in the survey be expanded to include a global participation and suggested a comprehensive effort of IEEE, CIGRE, and EPRI representation in order to cover a worldwide base of responses. Once the request was approved, the survey was developed and a draft format was presented at IEEE informational meetings, conferences, and the CIGRE summer 2006 meeting to collect additional input on the form and to inform interested participants of the developments underway, and to request participation once the survey was released. Survey participants have access to the tabulated results of the responses and a copy of the collaborative report.

Since the survey participants are international, the topological structure of the power industry varies from one system to the next. For example, in some cases, the entire country is operated under a national power grid. In other cases, only the Grid Operators have participated on behalf of the entire grid. There are also many responses in a bundled or aggregate form since responses are representing a regional grid. Therefore, the total number of responses is not as meaningful as the total number of schemes reported, types of applications, operational experiences, and the technologies deployed. Care has been exercised not to have duplicate data entered.

The conclusions reflect that for the most part these schemes are accepted worldwide, are used in a variety of SIPS from manually operated system to very advanced and high speed schemes, all have a high degree of overall reliability, and good operational experiences. Many of the SIPS have annually or bi-annual operational history which assists in validity of the data.

Several examples of more complex schemes have been included by the survey participants as part of the report, which also emphasizes the wide acceptance of the SIPS.

2.1 Material Supplied to the Survey Participants

In addition to the questioner, the participants received supplementary material. Annex B is a copy of the survey. Annex C is the SIPS or RAS Application Definitions, a short review of methods to balance the operation of the power system and the main factors influencing the type of SIPS applied, that will prevent a loss of power system integrity. Annex C was provided in order to assist the respondents with the selection of the most appropriate types of SIPS actions, and to achieve consistency when tabulating the results.

2.2 Survey Data

Validity of Survey Data - This survey was sent to power companies, grid operators, and Independent System Operators worldwide. From the onset of the joint CIGRE / EPRI / IEEE working group formation, the working group volunteers developed an organizational structure with assigned roles to request the participation of various members, Regional Councils, CIGRE US, and CIGRE international, and individual power company points of contact. As described in the previous section, every effort was made in order to achieve consistency in survey responses amongst such diverse groups of global participants.

The representatives of more than 100 individual power companies and bundled power systems have been tabulated. Results are presented in graphical format with a summary interpretation. The responses are from a representative cross-section of utilities in terms of type of utility, size of a power company, municipalities, national grids, and provinces. The respondents also cover a broad geographical and Regional Council diversity within the North American Electric Reliability Corporation (NERC), as well as a significant number of CIGRE participants from different countries with completely different grid topologies. The survey responses show great consistency reflecting common practices across all segments of the industry.

The survey has two complementary parts, namely operational experiences and design practices. The two parts in the survey complement each other well with the information received from the industry. The operational experiences section demonstrates the performance of the existing schemes from discrete elements, to the telecommunication system availability and associated maintenance for telecommunication dependant schemes, to the operational performance and overall throughput timing for systems that have stringent performance requirements. The Engineering, Design, and Implementation section of the survey responses demonstrate how the SIPS have become an integral part of the technological advancements in power system manufacturing of multifunction protective devices, as well as the integration of advanced functions that at one time, would have been performed by discrete components. The survey results also highlight the need for better system monitoring, advanced tools, and advanced applications.

2.3 Missing Responses

Although several attempts have been made to contact different parts of the world, some power companies, parts of countries or the entire country in some cases have elected not to respond to our call for this survey. The working group members believe the election to not participate is not lack of communication rather the respective companies or individuals decision not to participate. Reasons for not participating are not known to the WG members.

2.4 Examination of Power Systems Conditions

Power systems are typically a network of interconnected elements with recognized limits. The power system operates normally while those limits are not violated and its overall security may be evaluated in terms of margins or indexes. The security evaluation is computed by different methods oriented to determine the system robustness for a future scenario. For instance, the analysis of contingencies has been a computational tool applied in control centers to complete studies for discovering overload levels, over-voltages, etc. [14]. With the knowledge of such margins, operators are able to control the power system through the on-line operation.

Figure 2 shows essential on-line conditions. The protection schemes respond immediately when power system passes from steady state to one of those conditions. The contingency becomes a non-expected event**.** Representative contingencies are the loss of generation or transmission components such as transmission lines or transformers.

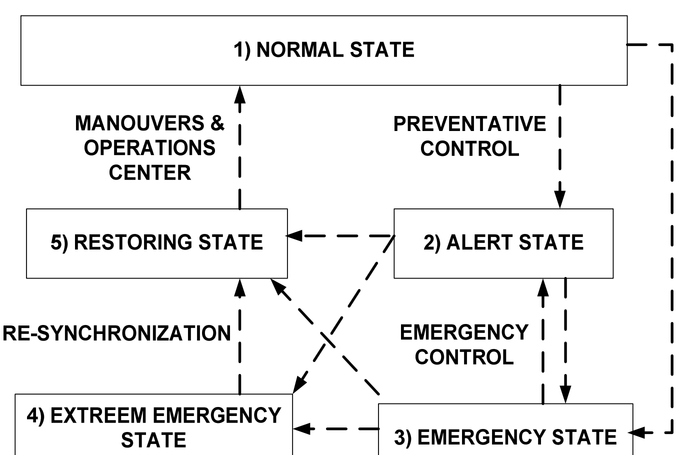


Figure 2 - On-line States in the Power System

Figure 3 is a sample representation of power system components operating harmoniously when system is normal and limits are not excessively exceeded..

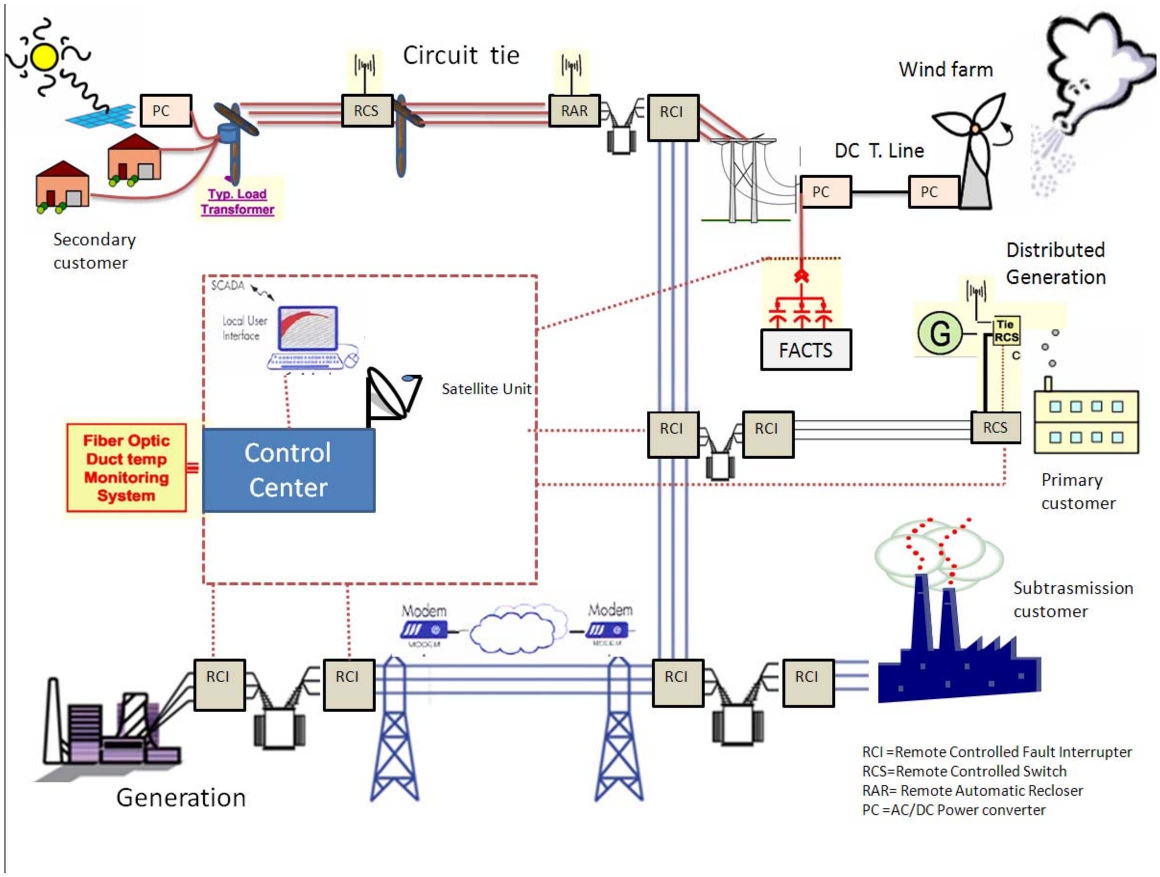


Figure 3 – Example Power System Components

Unlike conventional equipment protection that is applied to detect and operate for short circuits, SIPS are used to protect the electrical system. Most protection schemes are designed to respond immediately upon detection. System problems, on the other hand, occur in a few seconds, when branch currents are redistributed throughout the network and the bus voltages experience an alteration.

According to the operating rules, alert state is when the power system experiences a contingency and that does not present electric interruptions for firm customers. The solution involves implementations of protection schemes to ensure local disconnection. In this case, the disconnections of faulted elements generate a re-distribution of power flows without overloading other elements. Sometimes, manual action of operators (preventive controls) is required to maintain variables within an appropriate margin; for instance, they adjust reactive power by insertion or removal of shunt elements. Recurrent alert states are empirically solved from the experience of operators because they are familiar with simple contingencies.

The emergency state is established if the contingency develops into a cascading effect. The margin of reserve is reduced and the SCADA may reveal violations. Usually this condition takes place when the transmission system does not have an adequate amount of redundancy. For instance, a transmission line trip may overload another transmission line, and then the operator may need to react immediately to adjust the power on transmission system. Then the set of maneuvers (actions) by system operators is vital to avoid or mitigate the problem. Manual operator actions may not be fast enough to avoid further cascading outages, and automatic operations are necessary. Although there is a tendency to point at one or two significant events as the main reasons for triggering cascading outages, major blackouts are typically caused by a sequence of low-probability multiple contingencies with complex interactions. Low-probability sequential outages are not anticipated by system operators or may be fast developing for human interactions, thus rendering the power system more susceptible to wide-area blackouts. As the chain of events at various locations in the interconnected grid unfolds, operators are exposed to a flood of alarms and at times, incomplete information and may not be able to act quickly enough to mitigate the fast developing disturbances. The problem reveals a sequential operation of local and back-up protection schemes. In addition, a large number of alarms in the control center need to be prioritized to provide helpful information to the operators.

After a major disturbance occurs, the operators are focused on restoring the system to minimize the disturbance impact on the load. A restoration plan, including restoration scenarios, is very important to achieve the above goal. Modern restoration practices require proper modeling of protection scheme behavior during restoration.

More detailed description of disturbances, measures to prevent disturbance propagation, and restoration practices are described in the literature ([1], [15], [19], [20]). For example, CIGRE report 34.08 [19] discusses characteristics of severe system disturbances and describes measures applied by utilities against wide-spread blackouts, including SIPS against power system collapse and restoration policies applied at the time when that report was created. Reference [20] is a summary of comprehensive Technical Brochure C2.02.24 that provides a roadmap for the development of defense plans to mitigate extreme contingencies. Defense Plan was defined as a set of coordinated automated schemes that together can minimize the risk of impending disturbances cascading to widespread blackouts.

3 SIPS Components

3.1 *Definition*

The SIPS are installed to protect the integrity of the power system or its strategic portions. A SIPS is applied to the overall power system or a strategic part of it in order to preserve system stability, maintain overall system connectivity, and/or to avoid serious equipment damage during major events. Therefore, the SIPS may require multiple detection and actuation devices spread over a wide area and utilize communication facilities.

Within North America, NERC defines a Special Protection System (SPS) as an automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. A NERC defined SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS).

The SIPS encompasses SPS, Remedial Action Schemes (RAS), as well as additional schemes such as, but not limited to, Underfrequency (UF), undervoltage (UV), out-of-step (OOS), etc. These additional schemes are included in the scope of our interest since they are excluded from the conventional North American definition of SPS and RAS. A conventional protection scheme is dedicated to a specific piece of equipment (line, transformer, generator, bus bar, etc.), whereas a SIPS is applied to the overall power system or a strategic part of it. Therefore, SIPS may require multiple detection and actuation devices and communication facilities. The scheme architecture can be described by the physical location of the sensing, decision making, and control devices that make up the scheme and the extent of impact the SIPS has on the electrical system.

3.2 SIPS Architecture:

The SIPS Model explains the high level layout and configuration of the scheme, the overall system complexity, and the potential system/scheme interactions. The scheme architecture can be described by the physical location of the sensing, decision making, and control devices that make up the scheme and the extent of impact the SIPS has on the electrical system. SIPS Architecture also reflects the type of impact the scheme is intended for, Figure 4.

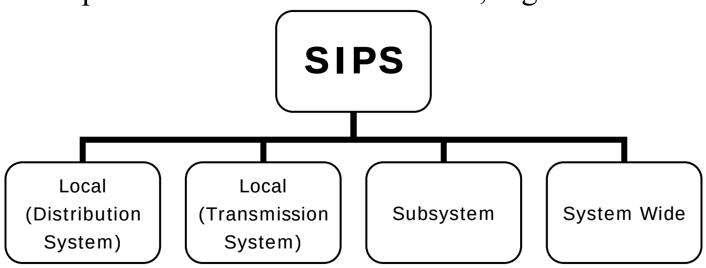


Figure 4 - SIPS Model [10]

i. Local

a. Distribution – For this type of SIPS, the architecture is simple. The equipment often have very limited or dedicated functions. All sensing, decision-making and control devices are typically located within one distribution substation. Operation of this type of SIPS generally affects only a very limited portion of the distribution system such as a radial feeder or small network.

b. Transmission – In this type of SIPS, all sensing, decision-making and control devices are typically located within one transmission substation. Operation of this type of SIPS generally affects only a single small power company, or portion of a larger utility, with limited impact on neighboring interconnected systems. This category includes SIPS with impact on generating facilities.

ii. Subsystem - SIPS of this type are more complex and involve sensing of multiple power system parameters and states. Information can be collected both locally and from remote locations. Decision-making and logic functions are performed at one location. Telecommunications facilities are generally needed both to collect information and to initiate remote corrective actions. The operation of SIPS of this type has a significant impact on an entire large utility or balancing authority area consisting of more than one utility, transmission system owner or generating facility.

iii. System wide - SIPS of this type are the most complex and involve multiple levels of arming and decision making and communications. These types of schemes collect local and telemetry data from multiple locations and can initiate multi-level corrective actions consistent with real-time power system requirements. These schemes typically have multi-level logic for different types and layers of power system contingencies or outage scenarios. Operation of a SIPS of this type has a significant impact on an entire interconnected system or a major portion thereof, comprising multiple balancing authority areas, possibly including international impacts.

3.3 SIPS Design Considerations:

Failure of the SIPS to operate when required, or its undesired or unintentional operation will have adverse impact on the power system. Therefore, design of the SIPS may involve redundancy or some backup functions, and depending on the operational security requirements may involve some form of voting, or vetoing [11].

3.4 SIPS Classification

Classification defines the scheme function in terms of purposes and operating times. One type of classification is on Flat and Hierarchical architecture.

a) **Flat Architecture-** In this classification, the measurement and operating elements of the SIPS are typically in the same location. The decision and corrective action may need a communication link to collect remote information and/or to initiate actions. Examples:
   - In an underfrequency load shedding scheme, the frequency is determined at a distribution station and the pre-selected circuit breakers are tripped.
   - In a generator rejection SIPS, central equipment (CE) collects remote information and conducts decision making, and initiates remote generator rejection to protect against transient instability [12].

b) **Hierarchical Architecture-** Several steps are involved in the corrective action of SIPS of this class. For example, local measurement, and / or a series of predetermined parameters at several locations are transmitted to multiple control locations. Depending on the intent of the scheme, immediate action can be taken and further analysis performed. The scheme purpose will drive the logic, design, and actions. Typical logic involves use of operating nomograms, state estimation and contingency analysis.

The primary difference between the two architectures in Figure 5 is in the necessity of providing information between the stations or between the measurement and switching devices in order to add control coordination from the higher and wider system view. A hierarchical scheme may involve multi-layers and will involve communication outside of the substation where as a flat scheme involves a single layer of decisions and actions. Note the typical operating time ranges for the hierarchical schemes in Figure 5.

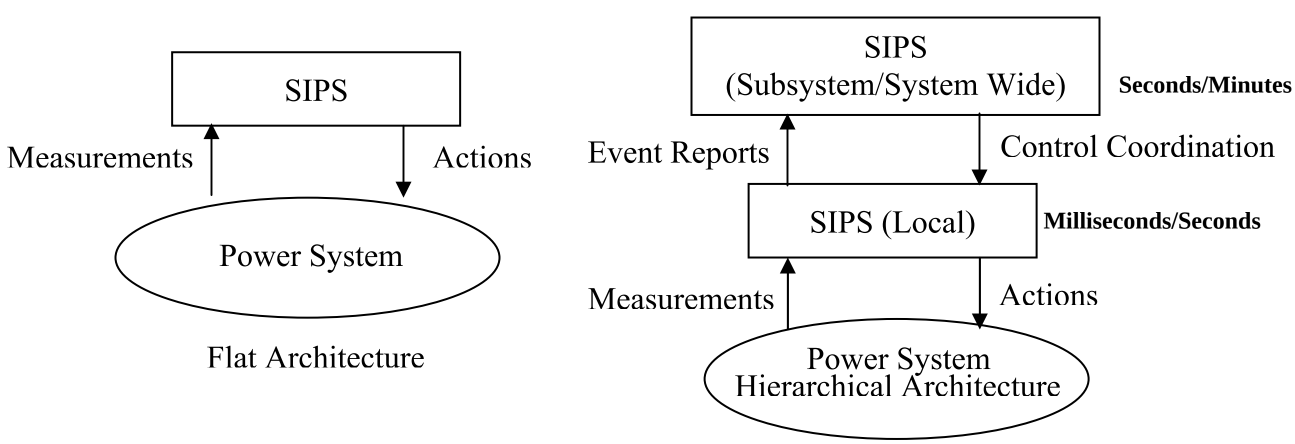


Figure 5 - Simplified Architecture of Flat and Hierarchical Schemes

In some schemes, action is immediate and must satisfy the purpose instantly, hence scheme logic may entail higher margins for actions taken. Other schemes may have a more adaptive nature, which employ monitoring the system response to the control action. This implementation requires communication. If the immediate action is not adequate to halt the progression of the outage, then additional analysis and action is required. For instance, SIPS that monitor transmission line congestion may immediately trip selected transmission elements (loads or generators) and continue monitoring the system condition to determine if further action is required. If the line loading is not relieved, tripping additional generation or load, either local or distributed, may be required. See SIPS Application Examples for samples of in-service schemes.

Another classification for SIPS is the concept of centralized and distributed architectures.

a) **Centralized –** All the information from remote stations and terminals are brought to one central location. Therefore, decision and corrective action of SIPS are implemented in the controller in one location. The function may be realized as a function of EMS, Logic Controllers installed in control center, or a Logic Controller installed in a substation. The decision and corrective action may need communication link to collect remote information and/or to initiate actions.

   Example - In a generator rejection SIPS, central equipment (CE) collect remote information and conducts decision making, and initiates remote generator rejection to protect against transient instability [12].

b) **Distributed –** Decision and corrective actions of SIPS are implemented in controllers installed in different locations. The system integrity protection function can be realized by coordinated operation & control of distributed controllers that have functions of decision & corrective action. The decision and corrective action may need a communication link to collect remote information and/or to initiate actions.

   Example - Underfrequency load shedding scheme

3.5 SIPS Applications

The types of SIPS applications may vary based on the topology of the power grid. The characteristics of the power system influencing the types of mitigation methods have been described in a number of literatures [13-16]. There may also be different views on the acceptability of the type of the application. For example, use of SIPS for generation shedding to balance grid performance may be viewed as unacceptable for certain levels of contingency in one network but a common practice in another interconnected grid. Consider power systems with limited transmission corridors where building a redundant and diverse interconnection outlet for a generating facility may not be physically practical or economically feasible to address a variety of technically possible outlet outages. In such conditions, and provided the application of SIPS is for protection of the interconnected facility, the generation facility may accept a certain level of risk so long as it can be demonstrated that such SIPS does not result in an unacceptable level of security to other parts of the grid.

The following is a list of power system mitigation methods and the main factors influencing the type of SIPS applied, that will prevent a loss of power system integrity. Names and / or the SIPS definitions may vary from one power system to the next or from one control area to the next. However, these schemes are intended to address power system constraints or when constraints could occur as result of increased transfer limits.

- Generator Rejection
- Load Rejection
- Under-Frequency Load Shedding
- Under-Voltage Load Shedding
- Adaptive Load Mitigation
- Out-of-Step Tripping
- Voltage Instability Advance Warning Scheme
- Angular Stability Advance Warning Scheme
- Overload Mitigation
- Congestion Mitigation
- System Separation
- Load and Generation Balancing
- Shunt Capacitor Switching
- Tap-Changer Control
- SVC/STATCOM Control
- Turbine Valve Control
- HVDC Controls
- Power System Stabilizer Control
- Discrete Excitation
- Dynamic Braking
- Generator Runback
- Bypassing Series Capacitor
- Black-Start or Gas-Turbine Start-Up
- AGC Actions
- Busbar Splitting

The main purpose of the listing is to provide a consistent method for responding to a series of questions that were asked in a form of a survey. The listing helps with the selection of the most appropriate types of SIPS actions and to provide a measure to appropriately categorize the types of applications from the survey responses.

3.6 SIPS Issues

Generally, disturbance propagation involves one or more power system phenomena/issues. SIPS applications in the previous section are used in the SIPS design to protect against following issues:

- Congestion

- Small-Disturbance Angle Instability
- Transient Instability
- Frequency Instability
- Voltage Instability
- Thermal Overloading

4 Structure of the Survey

The survey is divided into two parts: Part 1 identifies the "Purpose" of the scheme with subsections of "Type" and "Operational Experience" - For that part, a series of questions are repeated for each type of scheme which is reported.

Part 2 concerns engineering, design, implementation, technology, and other related sections such as cyber security considerations. This series of questions are asked only once. The respondents are asked to answer those questions based on most common practice in their companies.

The survey also asks respondents to identify the system integrity protection schemes that exist on their systems, the design and implementation, and the operation experience as applicable. Results of the survey are expected to assist the respondents in:

- The application, design, implementation, operation, and maintenance of new and next generation SIPS.
- Understanding feasible alternatives applied to extending transmission system ratings without adding new transmission facilities.
- Applicability of delayed enhancement of transmission networks to the respondent's system.
- Providing reasonable countermeasures to slow and/or stop cascading outages caused by extreme contingencies (safety net).

The survey is intended for power system professionals involved in the Planning, Design, and Operation of SIPS. The survey was distributed through CIGRE, IEEE, and EPRI.

5 Summary of Survey Results

5.1 Respondent Information and SIPS cost

Nearly one hundred and ten (110) responses from individual power companies, or bundled power systems have been tabulated. Since the survey participants are international, the topological structure of the power industry varies from one system to the next. Therefore, total number of responses is not as meaningful as the total number of schemes reported, types of applications, operational experiences, and the technologies deployed. Care has been exercised not to have duplicate data entered. The following types of entities have been included:

- Load Serving Entity
- Distribution Provider
- Transmission Owner / Provider
- Generation owner / Operator

- Reliability Authority
- Balancing Authority
- Other

Categories addressing cost considerations of particular type of SIPS are:

- $1-5M
- $5-10M
- $10-15M
- $15M plus

5.2 *Part 1: Purpose, Type and Operational Experience*

5.2.1 Purpose and Type

Respondents have indicated the number of functional SIPS (individual subsystems within single functional SIPS are part of the respective functional scheme, and are not counted independently). The numbers of SIPS performing similar types of functions have been grouped to indicate the total number of SIPS types. For each type of SIPS scheme, the number of schemes serving a similar purpose has been indicated, with the following purpose classifications:

- Essential
- Increased Security
- Increased power flow capability
- Important
- Normal

Figure 6 shows a summary of overall SIPS purpose classification. A total of 958 entries have been classified into five major categories as described in the survey. Note that almost all classifications are evenly distributed (with exception of "Important" which is at 8%). The approximate even distribution of classifications of SIPS highlights the important role of SIPS in grid reliability and how SIPS are integrated part of the grid development worldwide. This information is extracted from Annex B, Section A.

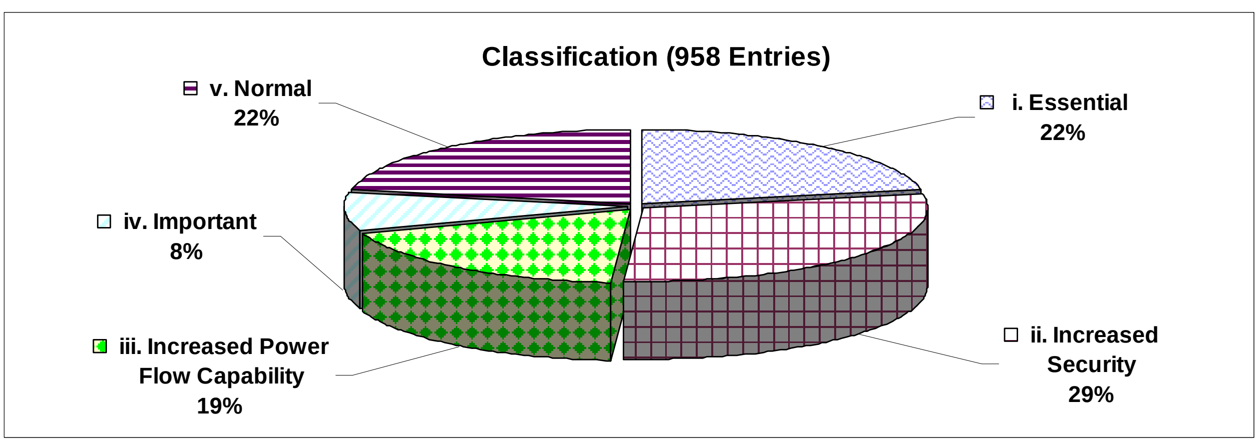


Figure 6 - SIPS Classification

It is clear from Figure 6 that the application of SIPS has become a component of a comprehensive total protection philosophy. The fact that 22% of the entries are applications to address "normal" system conditions demonstrates that SIPS are no longer applied solely for system security purposes. In fact, close examination of Figure 6 reveals SIPS applications can be viewed as two major categories:

1) **Normal Conditions** (49% with three components, 19% Increased Power Flow, 8% Important, plus 22% Normal) which in effect are system improvements considered part of normal conditions.

2) **System Security** (51% with two components, 22% Essential plus 29% for Increased Security) which at one time was the primary intent of SIPS.

Figure 7 shows the intent of the various types of SIPS. The information in Figure 7 correlates with the classifications in Figure 6, demonstrating that worldwide SIPS are integrated components of various aspects of grid operation. Close review of Figure 7 reveals that about 63% of the SIPS are applied for "System Security" (category 2 description associated with Figure 6) which is composed of Voltage instability (25%), transient instability (21%), and frequency instability (17%). The remaining 37% of the schemes are for "Normal" operating conditions composed of thermal overload (16%), Small disturbance angular instability (11%), and congestion management (10%).

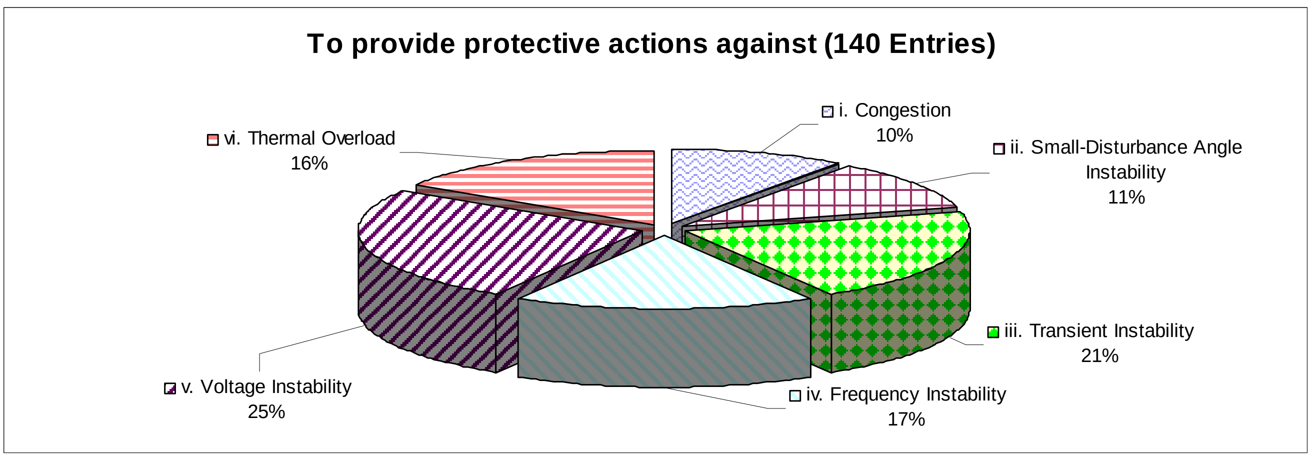


Figure 7 - SIPS Purpose

Table 1 shows the SIPS corrective actions in groups or categories. For example, Load Shedding category includes several types of measures involving rapid separation of load from the grid to maintain system integrity – Note that the "Load Shedding" category in Table 1 is a high speed automated system. The survey questioner explicitly highlighted that the manual load shedding is not part of the questions. The italic sequence numbers in Table 1 correspond to the survey section describing the corrective or protective action the respective scheme is designed to perform. Refer to Annex B for a copy of the survey.

Load Shedding	Generation Control - Slow Speed
ii. Load Rejection – (10%)	i. Generator Rejection – (8%)
iii. Under-Frequency Load Shedding – (8%)	xviii. Power System Stabilizer Control – (3%)
iv. Under-Voltage Load Shedding – (6%)	xix. Discrete Excitation – (1%)
v. Adaptive Load Mitigation – (2%)	xxi. Generator Runback – (3%)
ix. Overload Mitigation – (7%)	xxiv. AGC Actions – (4%)
System Stability	**Controls - Slow Speed**
vi. Out-of-Step Tripping – (7%)	xiv. Tap-Changer Control – (2%)
vii. Voltage Instability Advance Warning – (2%)	xvi. Turbine Valve Control – (1%)
viii. Angular Stability Advance Warning – (1%)	xxiii. Black-Start or Gas-Turbine Start-Up – (1%)
xi. System Separation – (7%)	
xx. Dynamic Braking – (1%)	**Congestion Mitigation**
	x. Congestion Mitigation – (3%)
Controls - High Speed Reactive Voltage Compensation	xii. Load and Generation Balancing – (3%)
xxii. Bypassing Series Capacitor – (2%)	xxv. Busbar Splitting – (2%)
xiii. Shunt Capacitor Switching – (5%)	
xv. SVC/STATCOM Control – (4%)	**Others**
xvii. HVDC Controls – (3%)	xxivi. Other, please specify – (5%)

Table 1 – SIPS Categories by Type of Corrective Actions and the Percentage of Application

Table 1 also shows the percentages for each type of corrective measure tabulated based on the responses received. From the 298 entries, only (8% or 24 schemes) are underfrequency load shedding, highlighting the fact that the survey responses are mainly focused on the SIPS with hierarchical structure. See Table 2 for each type of corrective measures and the respective percentage from survey responses.

Figures 8a and 8b show the types of corrective actions based on the categories listed in Table 1 in percentage and total number of schemes respectively. The fact that a good number of schemes apply to generator-turbines (21%) mirrors the results of the 1996 IEEE/CIGRE survey (21.6%) [9]. On the other hand, the percentage of system stability applications has increased from 11.8% (system separation 6.3% + out of step tripping 2.7% + dynamic braking 1.8%) in the 1996 report to 18% in this survey. Also, several new application categories have been added in recent years highlighting that protection philosophy has now been extended to include the total electric power system operating as a unified entity.

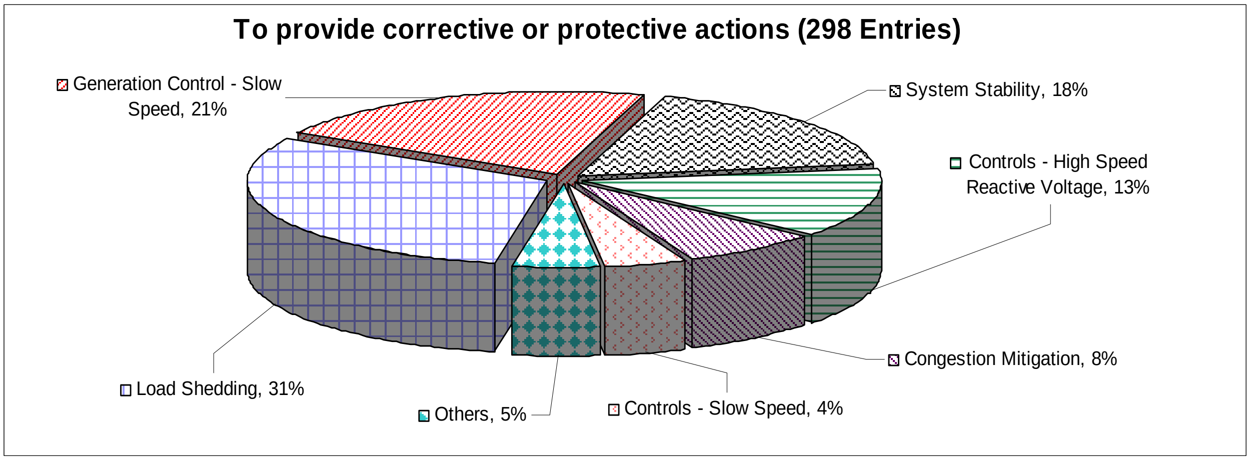


Figure 8a – Percentage of SIPS Corrective Actions Based on Categories Identified in Table 1

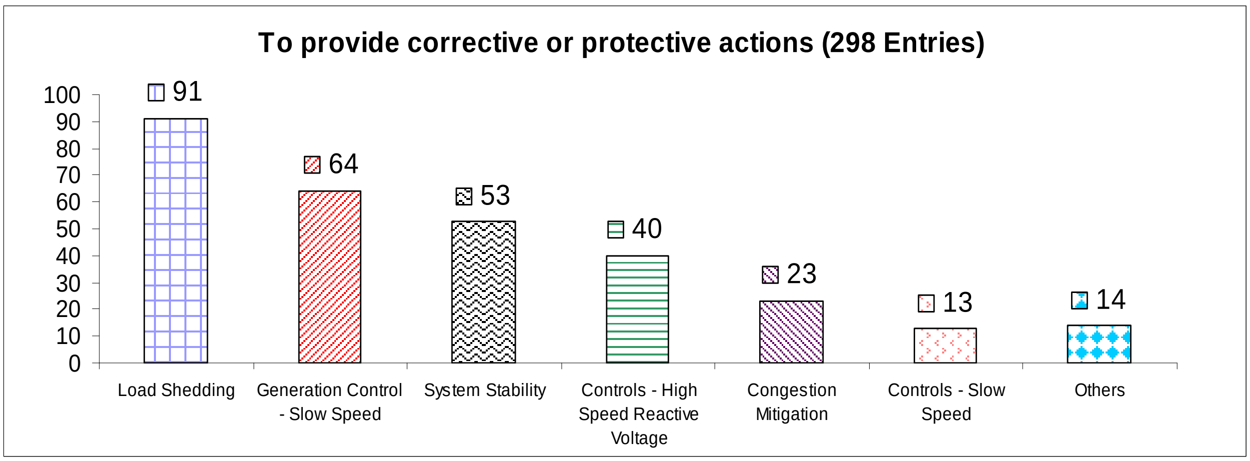


Figure 8b – Number of SIPS Corrective Actions Based on Categories Identified in Table 1

5.2.2 SIPS Performance

SIPS applications by nature raise an issue concerning dependability and security. A failure to operate when required does not alleviate the problem. Such in-action can result in an increase in system stress - very possibly leading to a total blackout. On the other hand, incorrect operation will remove system elements when system integrity does not require it possibly increasing the system stress. Figure 9 is a plot of the functional performance of SIPS showing that 66% of the respondents have experienced a performance of 99% or better reflecting the dependability. For the purpose of this report, the performance indicators are not affected as a result of a few local schemes, such as underfrequency load shedding.

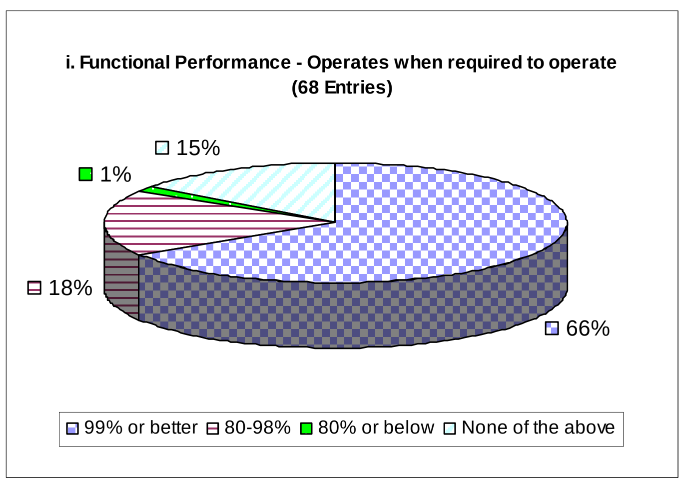


Figure 9 - SIPS Performance

Since SIPS in many cases are communication-dependant schemes, it is important to evaluate the performance of the communications equipment associated with these schemes. Figure 10 shows the performance of communication based SIPS with 65% of the respondents to have indicated performance of 99% or better. Note, some schemes are not communication based (25%) and none of the respondents have observed communication performance of the 80% or below.

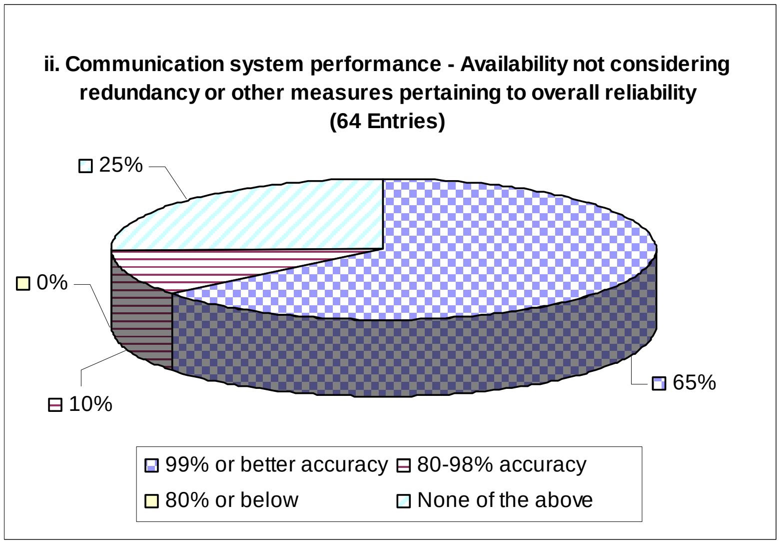


Figure 10 – Telecommunication Performance of SIPS

Figure 11 shows number of successful operations for the five classifications of SIPS described earlier (Essential, Increase Security, Increased Power Flow Capability, Important, and Normal). Based on the responses, 39% of the schemes operate once a year and 47% of the schemes have never operated. The infrequent operational experience of these schemes highlights the importance of testing, verification of set points, and routine verification of coordination of the schemes with both conventional protection as well as other SIPS in the area.

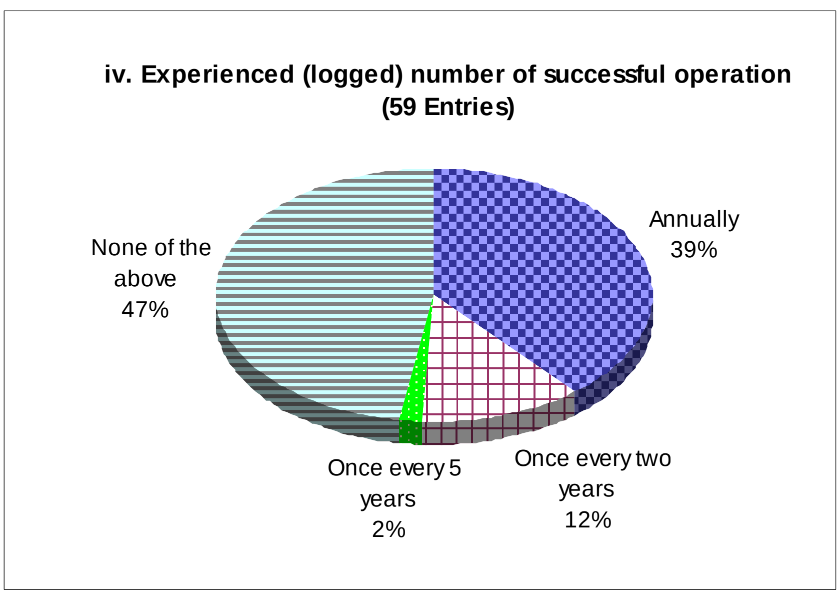


Figure 11. Number of successful Operations

A good majority of the respondents noted that the criterion used in the design is a combination of purpose of the schemes and also based on the measures set forth within the reliability coordinators in the area where asset owner operates the systems. For example, hardware and telecommunication aspects of the design may need to conform to a regional reliability group.

5.3 Part 2: Engineering, Design, and Implementation

Part 2 is of this survey describes the main methodologies adopted in the scheme design in terms of preliminary studies, technology assessment, design standards, redundancy etc. Design issues were considered next. In general, the overall design can be broken down into the following components, namely:

- System Study
- Solution Development
- Design and Implementation
- Commissioning / Periodic Testing
- Training & Documentation

In this section, the specific responses and comments are listed next to the selections in parenthesis.

5.3.1 System Study

In order to design a wide area monitoring and prevention scheme, accurate system studies need to be completed to identify the ensemble of contingency scenarios and / or the type of a response based system, to define the parameters required for proper implementation. Some of the critical items include:

- Understanding the requirements and the intent of the application – (different requirements result in different solutions)
- Types of studies to be performed – Planning and Operating studies, followed by on-going system studies including protection coordination studies
- Evaluating multiple solutions – Studying alternatives and performing contingency analysis
- On-going dialog with all entities involved – Internal and external (Regional).
- Identifying monitoring locations and set points – overload conditions, undervoltage, underfrequency, phasor measurement
- Arming conditions and levels – Determining whether the scheme arming should be power system condition based or outage/contingency based
- Contingency identification
- Identify islanding points if applicable
- Voltage or phase angle stability
- System restoration process; Cold Load Pickup considerations .
- Wide area monitoring and intelligent dispatch
- Reliability and dependability levels – Redundancy, Voting, Fail safe, etc.

System studies identify limitations or restrictions. The limitations may be thermal, voltage, or angular instability related limits wherein the latter items are of significantly more concern than thermal capacity limits. It should be noted, however, that relaxing non-thermal limits in a cost-effective fashion can be very challenging in a deregulated environment. Finally, all the above criteria need to be evaluated within the range of existing reliability council standards.

Survey Responses to System Study Related Questions:

- System Studies Done Prior to Deploying the SIPS. To properly apply a SIPS, extensive studies are performed to provide a thorough understanding of the performance of the power system under various credible contingencies, and to determine the required corrective action to mitigate any severe consequences of those contingencies that could lead to system collapse or damage. These studies require modeling the system in sufficient detail to accurately simulate the actual responses to the contingencies.
    - Planning criteria - Survey respondents have described their planning criteria, which is a key element in identifying the level of performance required of their SIPS
        - seasonal performance variations (2)
        - single contingency (6)
        - double contingency (10)
        - single contingency followed by breaker failure (5)
        - extreme contingencies (7)
        - other (9), Study includes impact of breaker failure protection
    - Types of planning studies
        - steady state (12)
        - dynamic (4)
        - transient stability (11)
        - other (9), Study includes transient simulations for faults
    - Real-time operational studies (12)
    - Protection and control coordination studies - Respondents reported on whether they have attempt to coordinate SIPS with conventional protection schemes:
        - Yes (23)
        - No (5)
        - Other (4), Comments explaining the levels of studies and types:
            - Simple SIPS - applications and coordination impact is minimal.
            - Coordination studies are performed only for transformer overload mitigation.
            - Perform coordination studies for certain types of schemes, for example essential and important.
    - Coordination with other Protection and Control systems (30) responses have been received with following breakdown based on the respondents applications:
        - Coordinated with other SIPS (7)
        - Coordinated with local protection (11)

        - Coordinated between themselves (i.e., UVLS vs. SIPS) (12)

      Some respondents have indicated that their applications in some cases involve primary and back-up (as opposed to Primary 1, Primary 2, or Set "A" / Set B" type of applications). When designed as Primary / backup, there is coordination between the two systems. Others have responded that coordination studies are done at the planning stages with all core teams involved. In other cases, a Regional Committee verifies coordination amongst different schemes to avoid cascading events.

- The survey asked what types of technologies were used in the SIPS
        - Electromechanical (1)
        - Solid State (1)
        - Microprocessor (13)
        - Custom designed product (2)
        - Other (8) – Majority of the comments reflects that the majority of schemes they have been applying in recent years are numerically based systems. Some have indicated that they have many schemes that involve a combination of solid state, microprocessor, and tone communication – Other schemes have evolved over time and they include a combination of all of the above.
        - PMU (2) – The PMU based schemes are simple applications of PMU such as Blackstart, or confirmation of two systems measurements in a redundant systems applied to very large generation sources. Respondents have designed the systems to be available for more adaptive systems (responsed based) as more experiences are gained.
        - Combination of above (13)
        - Time synchronization techniques (3)
        - Future trends or functions that should be considered (1)
        - Rationale for combining different vintage hardware
            - System expanded (3)
            - Obsolescence (blank – No responses)
            - Combination of above two (15)
- Are there specific standards used in the design and application of?
    - Yes, as it pertains to consistency in application philosophy (12)
        - Use devices of different vendors as part of the redundancy (2)
    - No (14)
        - Reasons:
            - Planning and operational aspects of different schemes require different hardware (1)

- Different SIPS have been deployed over many years and technology has changed (4)
- Application specific – each situation is unique and no common concept or standard exists (2)
- Other (5)

5.3.2 Hardware Description and Outage Detection

The primary data used in a SIPS are line flows and line outages. Line flows involve the measurement of the Watts and Vars on the lines in the area of the scheme. Newer schemes may consider the collection of Synchrophasor data, which involves not only the synchronized measurements themselves but also the Time Stamps associated with the measurements.

Line Outage detection can take several forms – depending on the level of security required in the scheme. In the simple case, monitoring of the breaker auxiliary contacts can be used. It should be noted, however, that this mechanism could be insecure from two different vantage points. First of all, the breaker auxiliary switch mechanism can fail – especially during routine breaker testing yielding incorrect outage information. Secondly, coupling of the breaker auxiliary contact wiring from other control signals in a cableway can result in transients that "appear" to look like a breaker open signal. These types of transients can be detected through the use of input-circuit debounce. The coupling transients, however, can contain enough energy to last for over 20ms thereby adding significant delay to the SIPS scheme.

A more secure mechanism for outage detection can be implemented by using a combination of information – specifically by implementing the logic that includes breaker is Open AND the current on the line is Zero. Most digital relays today can perform a Zero-current check in ½ of a cycle thereby resulting in faster and more secure outage detection. Local practice, such as the use of a Line Maintenance switch, also needs to be incorporated in the outage detection logic. Other implementations may involve a confirmation of under power condition from remote terminal for added security. Note that when under power is used, the "outage detection" logic design may also need to address loss of potential conditions.

When speed of detection is paramount, a third mechanism can be employed which is the monitoring of the breaker trip signals as wired from the protective relays. By tapping into the trip buses of the breakers, typically as much as 40ms can be saved in outage detection time. As tripping can sometimes occur on a single pole basis, the detection logic needs to be able to differentiate between a single pole trip and a 3 pole trip and to act according to the needs of the scheme. Note that, based on the scheme requirements, not only would the primary relay trips be monitored but also the Breaker Failure trip outputs.

In general, the function of outage detection should be implemented through the use of "protection class" hardware, that is, hardware that is designed for the substation environment. Typical environmental requirements include an extended temperature range (-20 to +55°C), the ability to tolerate 95% non-condensing humidity, the ability to withstand high common mode voltages across all terminals, and the ability to withstand fast and oscillatory electrical transients. In addition, the detection device must be able to quickly perform the logic required to confirm a line outage per the criteria stated above.

It is important that events throughout the SIPS be available and time-coordinated so that a post-mortem of an SIPS operation can be analyzed. Most IEDs today have the ability to time stamp events based on Universal Time Coordinated (UTC) through an IRIG-B input as typically provided by the Global Positioning System (GPS). Time stamping to the nearest millisecond is the minimum time accuracy requirement. Many IEDs, when they read the IRIG-B clock signal, will internally maintain time accuracy to the nearest microsecond – which is required for synchrophasor measurements.

Survey Responses to Hardware Description and Outage Detection:

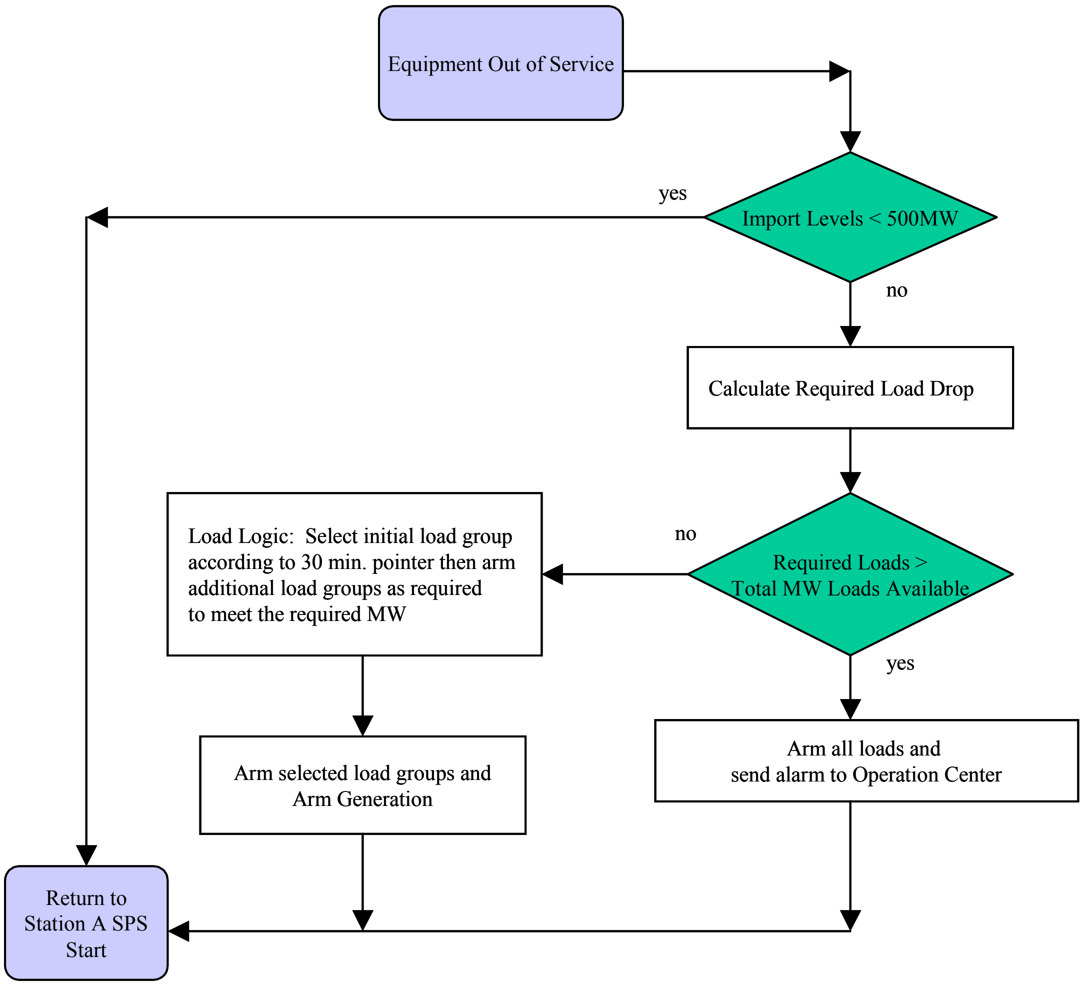
- Outage detection Method
    - Breaker auxiliary contacts (3)
    - Breaker status and undercurrent (4)
    - Voltage (1)
    - Both voltage and current (2)
    - Trip output from protective relays (5)
    - SCADA based architecture?
        - No (13)
        - Yes (4)
    - Open-ended line detection (1)
    - Manual opening (1)
    - Other (11), Respondents have provided more detailed description, for example different schemes have deployed combination of breaker aux. contact and current / voltage supervision. Also, provisions for breaker maintenance feature is built-in to the scheme.
- Does the scheme use programmable logic controllers (PLC)?
    - No (15)
    - Yes (14)
        - Central controller (8)
        - If redundant PLCs, are they in one location:
            - Yes (14)
            - No (6)
        - How many redundant PLCs?
            - One – (8)
            - Two – (9)
            - More – (1)
        - Triple redundant modular (TMR) controller?
            - Yes (2)
            - No (5)

5.3.3 Scheme Architecture

Once the design and application planning aspects of the SIPS have been defined, many questions arise regarding the implementation such as:

- Identification of the functional and technical requirements (evaluation of monitoring, isolation of transmission equipment, breaker failure application, redundancy, etc.)
- Selection of the technology to meet the functional requirements of the SIPS technically and economically, such as high speed secure communication between the SIPS devices and programmable solutions to protect the system against severe contingencies
- Identification of the areas that may need new technology developments
- System diagnostics.
- Flexibility/Upgradeability to meet the future expansions or requirements of designed SPS
- Description of scheme operation and well prepared Maintenance plans / Intelligent or Automatic Maintenance Testing
- Communication system design and failure detection systems. For example, routing of primary system communication failure on the alternate communication medium when dual schemes are applied.
- Simplicity of the implemented solution over the life cycle of the project and as new operators, maintenance specialists, and engineers take responsibility for expansion or operation.
- Cost effectiveness for implementation.
- Provisions for alternate location for manual arming
- Breaker failure operation and automatic restoration – Should breaker failure be incorporated as part of the design and whether automatic restoration should be considered for parts of the scheme operation

Given the defined contingencies, a method of conveying the actions for a given contingency is required. One technique is to migrate the monitored quantities and subsequent state transitions in a flowchart. Figure 12 illustrates such a flowchart for a situation where remedial action is required for a particular piece of equipment being out of service. Once the outage is detected, updated power flow measurements are used to determine whether any arming is needed. If the measured line flows are less than the value from the study (500MW in this example), stable system operation can be expected. However, when line flows exceed the limits identified by system studies, the system is automatically armed for a pre-calculated load-shed upon detection of the next defined contingency. In this example, the amount of load shed needed is compared against that available and then an optimal load-shed decision is selected.



Another key consideration is the availability aspect of the overall system. As a SIPS is typically a system stabilizing scheme, failure to operate can result in the collapse of a section of the power system. To achieve high availability, most SIPS are implemented in a redundant manner, which is, redundant measurement equipment, redundant communications, redundant controllers, and redundant mitigation. Having redundancy results in the fact that multiple data sources are fed to multiple controllers – all making decisions. Given that one of the data sources is corrupt, an incorrect decision can be made. To address this issue, functions such as input data conditioning/evaluation, voting, and vetoing can be used.

Input data conditioning involves the process of comparing data from the multiple data sources and checking the inputs for consistency. Consistency algorithms can be created based on expected values, values from other ends of the line, and value tracking. At a minimum, the system operator can be alarmed during a data consistency failure. At a maximum, the consistency algorithm has to decide if the SIPS will be allowed to operate.

When there are multiple controllers in the SIPS, it is possible that different decisions may have been made by different controllers. There are two strategies for dealing with the multiple-decision issue:

Voting – the mitigation device, upon receiving multiple commands, can choose to Vote on the received commands. Typically a 2 out of 3 scheme is used but other combinations are possible

Vetoing – in the case where there are only two controllers an incorrect decision can have disastrous consequences, the one controller can, if it disagrees with the decision, "veto" the decision of the first controller

Most SIPS today are event bases, that is, the system reacts in a pre-programmed manner upon the detection of pre-determined operation criteria. While this technique is effective, it is not adaptive to changing system conditions. As SIPS controllers evolve, they will be able to migrate to a more response-based approach, that is, the system will dynamically determine the best course of action based upon evolving system conditions.

Survey Responses to Hardware Description and Outage Detection:

- Objective: decision making
    - Predetermined, based on off-line simulation (17)
    - Response-based, using fast system assessment techniques (4)
    - Intelligent system with self-reconfiguration capability (3)
- Redundancy needs/implementation - Both telecommunication and hardware
    - Completely redundant (14)
    - Partially redundant (8)
        - Reasons for parts that aren't redundant
            - Not possible (2)
            - Too costly – blank
            - No impact on reliability (1)
            - Other (1), No comment provided
    - Dual – completely duplicate (1)
    - Dual – partially duplicate (2)
    - Describe criteria for determining redundancy (No comments provided in this section)
- Criteria for consideration of redundancy
    - Interconnection between different system (owners) requirements (5)
    - Interconnection between different countries' requirements – blank
    - Regulatory, or International Oversight Compliance
        - NERC and/or Regional Council (10)
        - UCTE (1)
        - ESCJ (1)
        - Other (7)

- Does the scheme use voting?
    - No (25)
    - Yes (5)
        - 2 out of 2 w/maintenance and fail-safe mode (blank)
        - 2 out of 3 (1)
        - 3 out of 4 (blank)
        - Other (4), example includes schemes that are combination of a Out-of-Step protection complementing the RAS.
- Is the scheme:
    - Response based event control (1)
    - Condition based (13)
    - Both (10)
    - Other (4), combination of response based and condition based
- Does the scheme initiate breaker failure?
    - Yes (15)
    - No (10)
        - If no, how is failed breaker handled?
        - Failed breaker condition not possible (1)
        - Scheme does not address breaker failure (10)

- Performance requirements:
    - Throughput timing: entire scheme
        - Below 50 msec (2)
        - Below 60 msec (0)
        - Below 70 msec (2)
        - Below 80 msec (1)
        - Below 90 msec (1)
        - Below 100 msec (3)
        - Below 110 msec (blank)
        - Between 110 – 150 msec (2)
        - Between 150 – 200 msec (7)
        - Greater than 200 msec (11)
        - Not time sensitive (blank)

Comments provided in this section reflect that timing is a direct function of scheme purpose and "type" as described in the survey. For Type I - below 50ms; Type II - below 100ms; Type IV - varies from 5 to 30 seconds

- Throughput timing of the controller
  - Below 30 msec (11)
  - Below 50 msec (4)
  - Below 75 msec (blank)
  - Below 100 msec (4)
  - Greater than 100 msec (3)

5.3.4 Data acquisition, System Restoration and related tools - Describe the data acquired by the scheme and the measurement methodologies.

As application of wide area monitoring often involves extreme contingencies, such schemes are not expected to operate frequently. Therefore, significant importance should be placed on effective and fast power system restoration after major disturbances Power system restoration needs to be executed with well-defined procedures that require overall coordination within the restoring area, as well as with the neighboring electrical networks. In general, the operated breakers should be blocked from automatic reclose. Intelligent restoration recommendations and mechanisms should be provided to the operating personnel as the generation, frequency and/or voltage recover.

Survey Responses to Data Acquisition, Restoration, and Measurement Methodology:

- Measured Quantities
  - Voltage
    - Polarity sensitive (17)
    - Not polarity sensitive (3)
  - Current
    - Polarity sensitive (14)
    - Not polarity sensitive (8)
  - Power output of generators
    - Percentage sensitivity (3)
    - Time delay to calculate (2)
    - Range (3)
    - Delta f / delta t (1)
    - Other (4), Conductor Temperature, wind speed, outdoor temprature
- Time synchronization requirements
  - Accuracy (9)
  - Specified synchronization requirement (blank)

        - Other (8)
    - Use of SMART SIPS / Intelligent SIPS
        - Does the SIPS automatically adjust
            - Load (4)
            - Generation (3)
            - Both (8)
        - Does the SIPS include on-line power system assessment?
            - Optimal power flow (2)
            - Transient stability assessment (3)
            - Voltage stability assessment (2)
            - Other (7), See next section on State Estimator
        - Are State Estimator values interlinked with the scheme?
            - Yes (5)
            - No (14)
    - Does activation of the scheme block automatic reclosing?
        - Yes (11)
        - No (11)
        - Not applicable (5)
    - Does the scheme activation block any operator initiated SCADA restoration?
        - Yes (5)
        - No (22)
        - Not Applicable (3)
    - Restoration Issues and Planned Mechanisms
        - Restoration part of the design of the scheme (3)
        - Restoration facilitated by scheme data (blank)
        - Restoration facilitated by EMS data only (blank)
        - Restoration handled by operating and dispatching instructions only (9)
        - Performed through EMS and instructions (2)
        - Other (1), No comment is provided

6 SIPS Application Examples

As part of responses received, a series of application examples were provided by the respondents describing specific applications and levels of complexity associated with different schemes. Examples are described in this section.

6.1.1 Overload Mitigation

Figure 13 shows an overload scheme applied to meshed bulk power system. When a single line suddenly becomes unavailable during peak periods, the remaining line would overload. The line outage detection scheme would detect the stressed system conditions and execute corrective actions. The corrective actions include balance of load and generation flows and may include automatic generation run back at the source side, and increasing generations and/or shedding loads and pumped storage generators at the remote end to balance the system before equipment are damaged.

For adaptive load mitigation schemes, the system may be partially adjusted by initially activating pump load separation for example, followed by a second computation of system conditions before executing further actions. For such adaptive schemes, the corrective actions continue to be executed until the congestions are mitigated and system is relieved. More intelligent application like Optimal Power Flow to the control center would be possible to calculate the amount of appropriate control actions.

The arming of such schemes will determine the mode of operation for the scheme and whether the system adjustments need to be immediate or the conditions support gradual balancing of load and generation.

Communication networks utilized may be a combination of audio-tone or digital connectivity so long as it meets the overall throughput requirements. The level of redundancy is based on the scheme criticality, the possibility for other mitigation measures such as operator ramp down reaction time, or the likelihood of a condition for which the scheme performance is critical.

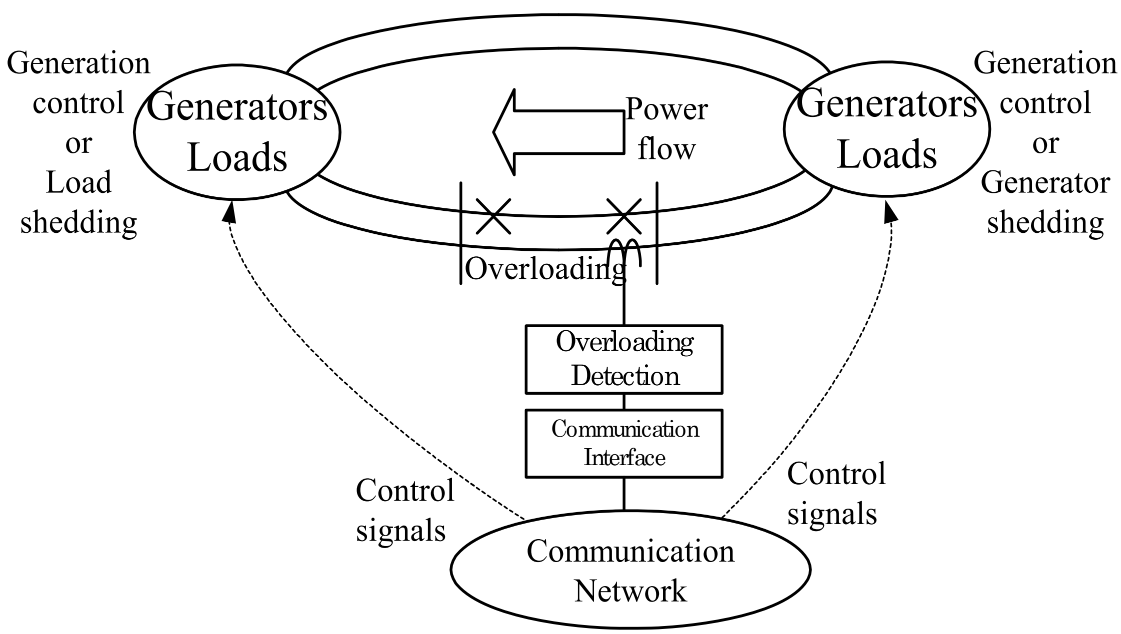


Figure 13 – Example of Overload Scheme

6.1.2 System Separation Scheme against Small-Disturbance Angle Instability

The SIPS described in Figure 14 is implemented to initiate a system separation against small-disturbance angle instability caused by very severe but rare contingencies. The SIPS is based on the observation of phase angle difference between substations, and separates the subsystem including the western generator group from major grid in case of instability to be detected.

The SPS is a fully redundant system composed of two identical relaying systems for the purpose of separating two 275kV power systems. Each system has a Central Equipment (CE) installed in a 500kV substation near western generation centers, three Remote Terminal Units (RTU) installed in three substations located near northeastern, southeastern and northern generation centers, and one RTU installed in a 275kV substation near western generation centers. CE and RTU are connected as star topology through a microwave synchronized communication channel.

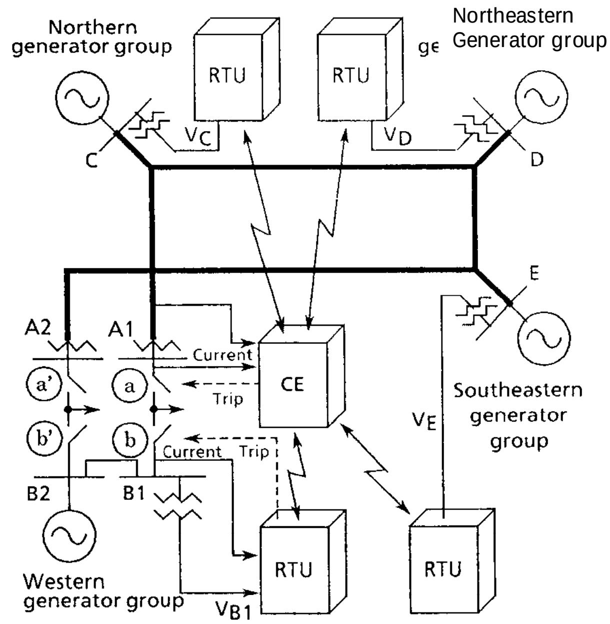


Figure 14 - System Configuration

The RTU simultaneously samples busbar voltages at 600 Hz, and the samples are transmitted to the CE. CE calculates in real time the phase differences between W-NE, W-SE and W-N. When two out of three phase difference values, predicted at 200ms in the future, exceed the pre-determined threshold value, the CE detects the loss of synchronism of western generation centers from main grid, and initiates the western system separation based on the tripping signal from CE.

6.1.3 Load Rejection and Shunt Capacitor Switching against Frequency Instability after System Separation

In power system supplying the urban load center described in Figure 15, 275kV/154kV and 275kV/66kV substations are supplied from the main grid through radial operated networks composed of a 275 kV double-circuit overhead trans- mission line and triple circuit underground cables. Each network has adjacent networks that can be connected by switching normally opened circuit breakers. Some of these networks include generation plants whose capacity is much smaller than load demands and others include no generation plants.

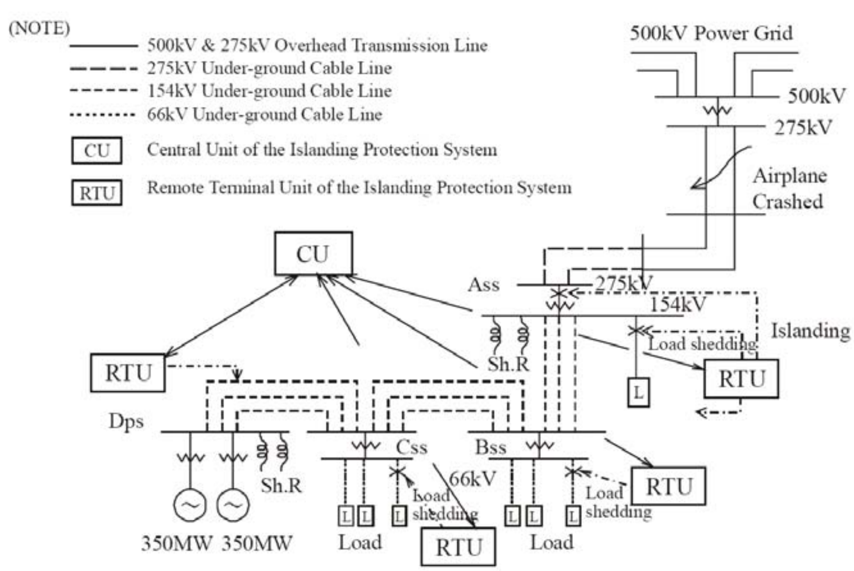


Figure 15 - System Configuration

In case of loss of double circuit line supplying a power system including generation plants, the power system is separated from main grid under extremely overloaded condition. Severe power imbalance may result in under voltage as well as under frequency situation. Saving a heavy overloaded system only by underfrequency load shedding programs would be very difficult. A SIPS is needed to save the separated power system securely, which initiates intentional islanding at the point where heavy imbalance of active power exists is a much better approach. The SIPS also initiates balancing control for both active and reactive power by load shedding and shunt reactor switching. If only active power balancing control is done, over voltage is expected after load shedding because of the large amount of cable charging and reduction of reactive power consumption. Load shedding effect being diminished with voltage sensitive characteristics in overvoltage condition may introduce the failure to arrest frequency decay. The SPS is a fully redundant system that has a central unit (CU) and several RTU's. Each RTU acquires required information data like power flow at intentionally separated point and submits them to the CU. The CU cyclically computes the amount of load shedding and reactive power control based on the received information data from the RTU. A fiber optic network is used for the communication channel between CU and RTU. The RTU's are connected to CU in a star topology.

If the CU detects system separation by voltage angle difference and/or voltage magnitude, CU issues the control signal to RTU. The RTU which receive the signal perform the predetermined control procedure in very fast manner (on the order of 500ms).

The separation of particular power systems can be detected by the differences of voltage magnitude or phase angle away from those of the main grid. The SPS has also RTU installed outside possible islands for the purpose of measuring the voltage phasor as reference.

6.1.4 Undervoltage load shedding as wide-area protection scheme

Figure 16 describes an example of Undervoltage Load Shedding Scheme as wide area protection scheme. UVLS is composed of Monitoring and Judging units (MJ) installed at four 500kV substations and load-shedding units (LS) installed at several 275 or 154/66 kV substations. Each MJ unit is connected via microwave communication channel, and the LS units are connected to a MJ unit as star topology via microwave. Long-term voltage collapse is designed to monitor the 500kV network. In this application, the 275kV or lower voltages are regulated by automatic tap changers on 500/275 or 154 transformers. The MJ units monitor the 500kV busbar voltages.

For the purpose of security, the SPS uses 3-out-of-4 decision-making logic by the MJ units. The SPS does not use any SCADA information. The MJ units detect slow types of voltage collapse (ten seconds to minutes order) by using unusual continuous $\Delta V/\Delta t$ value obtained with the

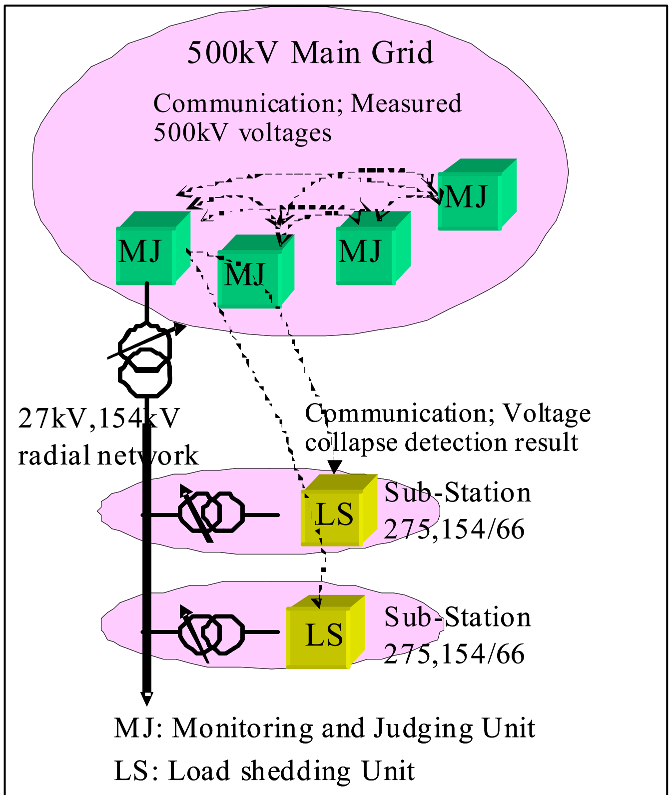


Figure 16- System Configuration

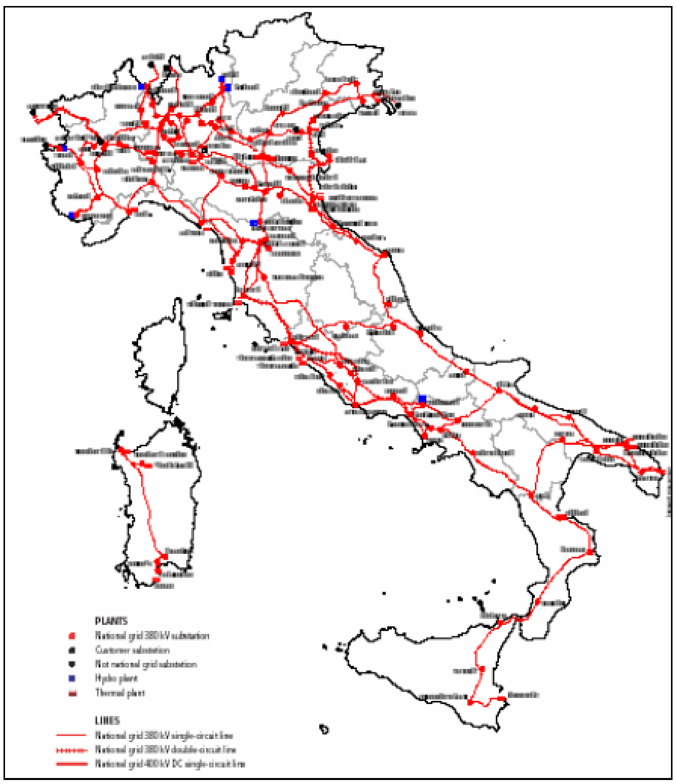
least square route value calculation technique for twenty sets of voltage values. The settings are determined so that the SPS never pick up normal voltage dip based on actual measurements. Fast voltage collapse can be also detected by ΔV/Δt calculation with one second of data window.

The SPS can be categorized as feedback control, which means that feeders continue to be shed until recovery from undervoltage condition is detected.

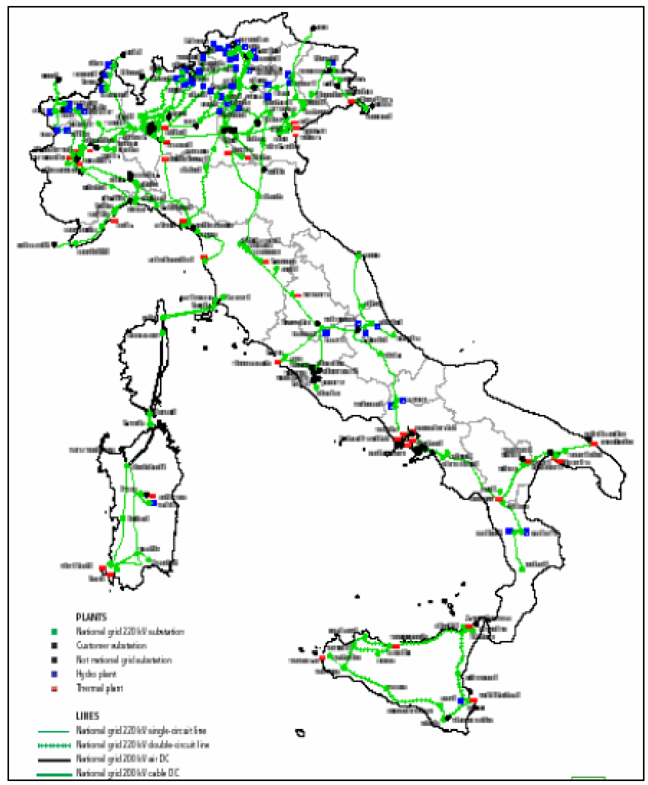
6.1.5 Primary and Secondary Countermeasures to Maintain Synchronization of a Multi-country Grid

A general view of the Italian transmission system is depicted in Figure 17. The Italian power system is at the border of the UCTE synchronous area and its interconnection lines are concentrated in the north of Italy including the following 400kV alternating current (AC) lines:

- Three lines interconnected with France
- Four lines with Switzerland
- One line with Slovenia



380kV System



230kV System

Figure 17 - Italian 380 kV and 220 kV Transmission Systems

There are also additional 220kV AC lines with France, Switzerland, Slovenia and Austria. The interconnection with Greece is through submarine direct current (DC) cable. The two main islands in Italy are connected via 400 kV AC system, via cable (Sicilia, with a planned increase in 2010 of two additional cable links), and via DC links (Sardegna, with the existing SACOI system and in 2009 the new SAPEI system).

The Italian power system is characterized by a significantly longitudinal structure that may generate constrained cut-sets (cut-planes). Preventing cascading outages is very important in this situation. This implies a particular attention in avoiding too large power flows on specific interconnected lines ("the critical sections"). An outage on more than one of the transmission lines of a critical section may seriously jeopardize system security because of overloads on the remaining lines with transient protection tripping and voltage collapse. An additional problem can arise due to this particular structure of the system: transient stability or high frequency transient phenomena due to imbalance between load and generation in big production poles in case of mini-islands due to cascading trips.

In order to contrast these events, the following automatic or manual primary and secondary schemes are activated when the Italian system is connected to UCTE network to maintain overall grid synchronization.

1. Automatic Control of Critical Sections
2. Generation plants teletripping
3. Power swing blocking relay
4. Manual load shedding

Countermeasures 1, 2 ,and 4 are integrated into a central system that periodically acquires power system parameters such as current, voltage, active and reactive power values and status information of circuit breakers status and disconnects switches from the monitored substations/power plants and perform calculations based on predefined logics rules determined via off line dynamic studies. Based on predefined power system conditions, the central system remotely prepares (arms) the peripheral devices, in the grid sections potentially exposed to static or dynamic risks, with the corrective control actions needed to face the related critical contingency. The armament is calculated and implemented upon each significant variation occurring of the power system's operating condition.

To configure the proper action at the devices in the field, some time is needed. Once the shedding action on the field devices is armed, if an event occurs, noticeable through a protection tripping, the event detector sends the information to all the possible recipients, using a multicast transmission method, the latest to avoid the saturation of the telecommunication channels. Upon receipt of the information that a specific event has occurred, only the devices previously armed for that event will execute the shedding action, Figure 18. In spite of the fact that an amount of time is needed to configure the system, if a critical event occurs, it can be tackled by few hundreds of milliseconds (200-400 ms) in average.

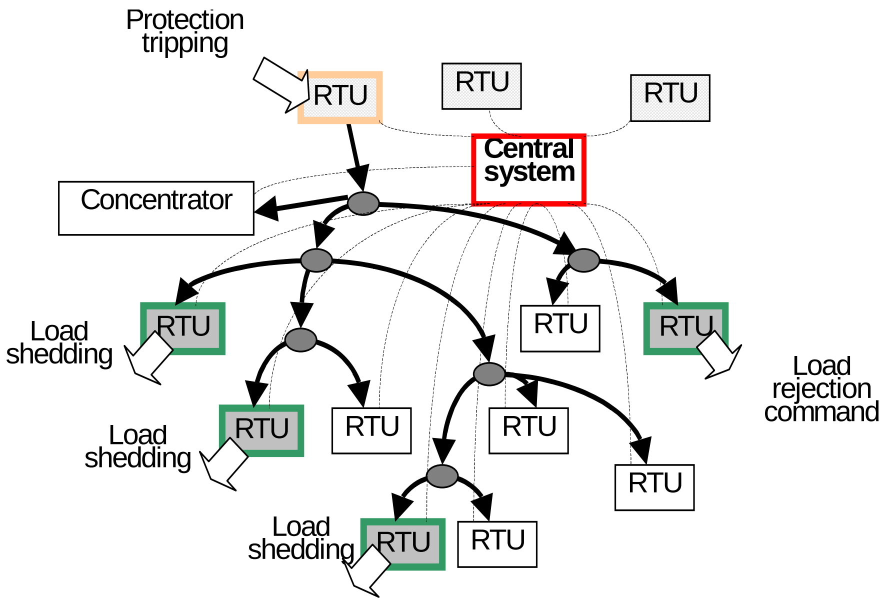


Figure 18: Flow of actions following the detection of an occurred critical event

With reference to the loads, some relevant industrial consumers (Figure 19), which have subscribed power interruptible contracts, can be disconnected by either preventive control or corrective remedial action; the amount of this particular category is 3000 MW.

Some other residential and industrial loads, due to their particular position and demanded power, can be shed by TERNA operators only in emergency conditions, even without specific contracts; this category is 25 % of the Italian peak load (the maximum load recorded in 2007 was 56,822 MW).

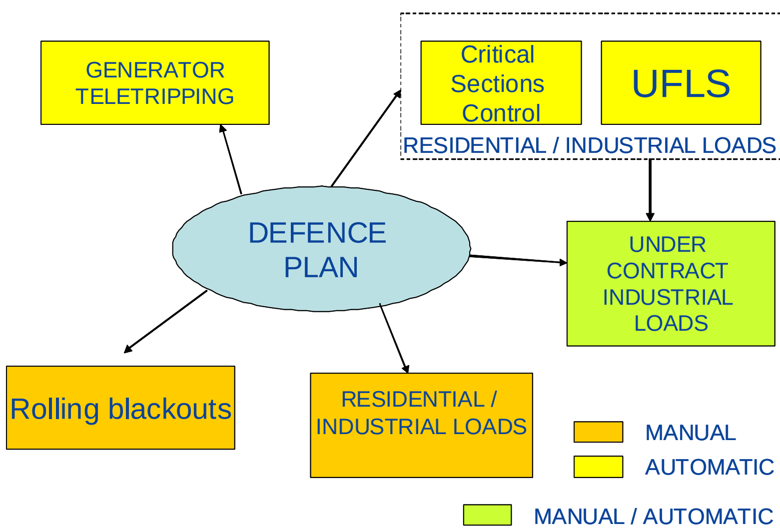


Figure 19: Target loads/power plants of the Defense System

An example of the tele-tripping of power units is the Sicilia interconnection with the South of Italy: in case of the tripping of the submarine 400 kV cable, the islanded Sicilian network (if previously was exporting power), can reach frequencies critical for the stability of the system.

Then, an appropriate set of generators are be automatically rejected in order to save the system. The remedial actions in case of disconnect from UCTE or severe UCTE contingencies are:

1. Underfrequency relays[1]
2. Tele-Tripping of power units
3. Automatic islanding of some parts of the system

Referring to the under-frequency load shedding plan, it's based on more than 1300 relays installed in the Italian grid; general criteria is to avoid:

- A minimum frequency under 47.5 Hz (50 Hz System)
- A critical stress to the power plants during the transient and at steady state

Load shedding plan start at 49.0 Hz down to the last step, located at 48.1 Hz; the total number of steps it's equal to 8. At the first four steps, down to 49.1 Hz, measurements of frequency and frequency gradient are utilized, combined with a logical AND.

6.1.6 High-Speed Control Scheme to Prevent Instability of Major Generating

Unintended loss of a major power plant can cause substantial strain on the remaining generating resources and lead to local system instability and/or generate oscillations with impact to the overall bulk power system. One such situation occurs when severe disturbances occur on transmission line exits from the power plant, Figure 20. Based the disturbance severity, the typical results are intensive swings or loss of plant synchronism which will lead to the loss of the entire generation complex either by out-of-step protection, or unit shutdown by protective devices reacting to voltage dips at auxiliary buses; e.g: Reactor Cooling Pump (RCP) undervoltage protection. SIPS as a high-speed emergency control solution can complement the generator out-of-step protection. By quickly detecting the destabilizing conditions, preemptive actions can be taken to preserve the plant and minimize the extent of the disturbance and subsequent effect on the power grid.

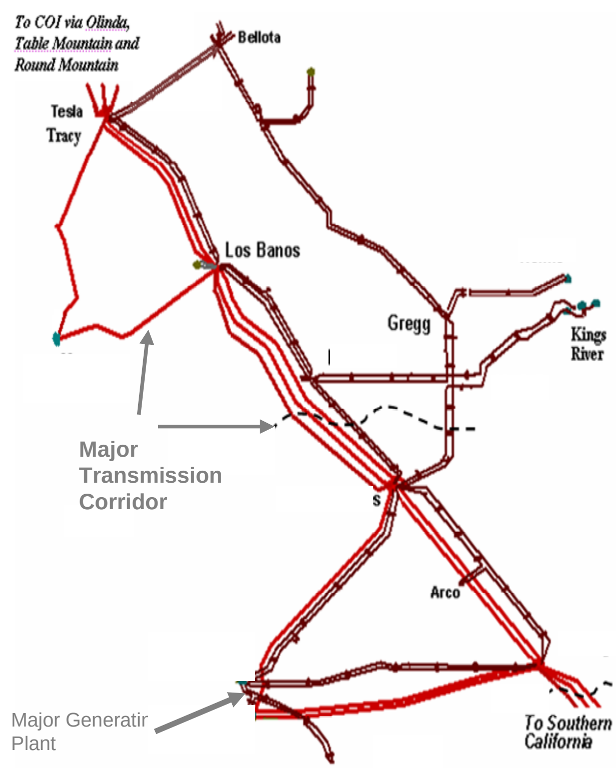


Figure 20 - Major Generation Plant with Surrounding Transmission System – Impact of Unit Output rating changes

[1] At present, studies about UVLS and additional islanding schemes are under evaluation

In this SIPS application, the control strategy is based on transient stability analysis for various types of 500kV transmission line faults, including delayed faults caused by complete and partial breaker failures. Different types of faults and transmission outlet line outage conditions for various system and plant initial conditions are managed by the scheme. Such SIPS can improve the availability of the generation supply and allow the power company to meet the Regional reliability criteria. The scheme also offers added advantages for scheduled transmission line outages by allowing full power operation with a line out of service.

At the 500kV Voltage level, the plant is connected to two diverse substations through three 500kV transmission lines. Two of the three lines are on a common right of way, and the third line is connected to a different 500 kV substation through a diverse path, Figure 21.

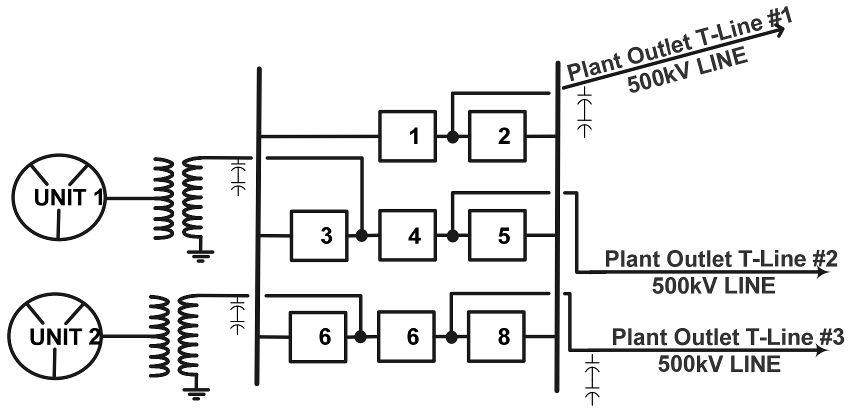


Figure 21 - Power Plant Electrical System with Control Voltage Sensing Points

Detailed unit stability studies and operating experience have not revealed any plant stability problems with all three 500 kV line outlets in service or following a loss of a single 500 kV component (a line or a unit). However, at certain plant output levels; a single line loss in a two-line scheme (type 1 event); double line outages (type 2 event), and breaker failure-caused delayed single line loss may lead to synchronous swings or to a loss of synchronism between the plant generators and the interconnected bulk power system.

Because of the high plant inertia and small system impedance, these swings would potentially result in widespread voltage dips with magnitudes and durations outside the guidelines defined by the Planning Standards in the Region. These swings may also cause operation of plant protective devices, such as out-of-step and/or reactor cooling pump undervoltage protection which ultimately result in outage of two units (DUO), as opposed to losing only one unit. Loss of a large generation source (entire plant) at once may also cause a definite strain on the remaining generating resources in the system. From the plant perspective, the most undesirable consequence is switching to the alternative power supply of the plant auxiliary loads. Therefore, automatically armed and activated SIPS can provide stable operation following one of the previously described severe disturbances.

From the system perspective, the DUO at peak output could impose a significant stress on the interconnected bulk power system and increase dependence on the adequate performance of protecting and regulating devices throughout the system. Any failure or misoperation may result in a cascading affect, e.g. with possible collapse and separation at critical tie locations.

Studies have determined that – tripping one generator – is the only effective option amongst the considered alternatives to achieve first swing suppression over the entire range of plant operation. Option considered, but not analyzed in detail, is building another 160 kilometer

500kV outlet. Based on existing transmission line outlets, Figure 21, studies have determined that for line faults with significant 500 kV voltage dips, very high speed SIPS are required. System studies have shown that SIPS would have to correctly identify the condition and issue the appropriate plant trip signal within 100 milliseconds (msec) following the disturbance initiation. High speed performance relies on SIPS initiation by redundant pilot transmission line protection for each of the plant outlets. A high-speed SIPS will also maintain system stability for disturbances which are aggravated by line faults. In some no-fault cases, delayed generator tripping can be an effective solution to prevent poorly damped oscillations which may occur if only one 500 kV line remains in service. Figure 22 illustrates generator trip effectiveness in the described situations, [11].

- Category 1: Two lines are tripped / or opened within a "short" (10 seconds) period of time
- Category 2: One line has been out (greater that 10 seconds) and there is either a protective trip or an outage on a second line
- Category 3: A Breaker Failure occurs with an accompanying "severe" undervoltage condition

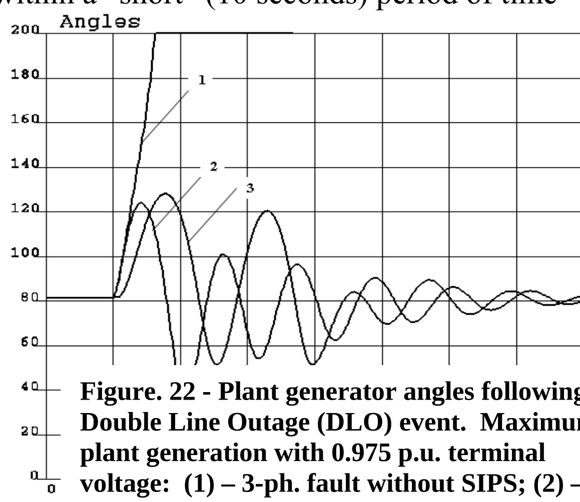


Figure. 22 - Plant generator angles following a Double Line Outage (DLO) event. Maximum plant generation with 0.975 p.u. terminal voltage: (1) – 3-ph. fault without SIPS; (2) – 3-ph. fault and immediate generator trip; (3) – no fault and 3 second delayed generator trip.

The scheme uses latest technological developments and standards including the IEC 61850, it has redundant systems and has vetoing incorporated when redundant systems do not agree or when a system is out for maintenance.

6.1.7 Remedial Action Scheme for Addition of Generation

Description

The addition of generation in eastern Arizona precipitated the need to provide added infrastructure on the transmission system to maintain the reliability of interconnection and the region and transport the power to Phoenix metropolitan area, Figure 23. Schedule constraints did not allow for installation of addition transmission paths prior to the installation of the added generation, however, series capacitors were added with a Remedial Action Scheme (RAS) to facilitate the added generation. The series capacitors increased the capability of the transmission line but the loss of the compensated line during periods of heavy load can cause thermal, stability, and generator problems.

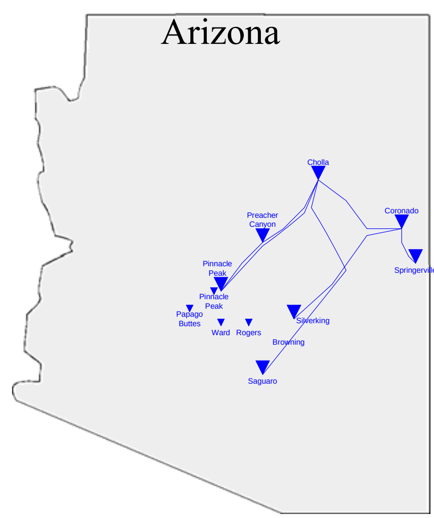


Figure 23 – SIPS Application for Maintaining Grid Reliability in Eastern Arizona Transmission Grid as a result of Interconnection of Large Generation Facilities

The added generation is approximately 500 kilometers away from the load centers and various transmission lines, shunt capacitors, and series capacitors are dispersed throughout Eastern and Central Arizona.

Studies

Studies have indicated that loss of the series compensated lines during heavy flows would cause over loads on adjacent transmission elements and voltage dip and recovery issues at various load busses in the region beyond the limits approved by the Regional Standards for single contingency (N-1) and double contingency (N-2) events. The solution to prevent violation of the requirements is to insert shunt capacitors, utilize high speed reclosing, and trip generation if necessary. Some addition studies have been performed concerning the following issues:

1. Voltage transients due to fast insertion of shunt capacitors
2. The impact of high speed reclosing on generator turbines
3. Various forced outages of transmission lines for maintenance etc.

Operation

The scheme monitors the flow and status of the generation and the transmission systems in the region. Arming values have been derived from system studies with consideration for variable automatic arming for various power system conditions. If a fault occurs on the series compensated line the scheme will take the appropriate action by inserting shunt capacitors in the Phoenix area and/or bypassing the series capacitors. If high speed reclosing fails then generation will be tripped.

The scheme has three main functions. RAS 1 is used to mitigate for N-1single contingencies. This RAS had 9 sub functions to account for the various initial lines out of service and single contingencies that needed to be monitored. RAS 2 is used to mitigate for N-2 double contingencies that impact the transmission system and the reliability of the region. RAS 3 is used to mitigate for N-2 double contingencies that impacted the generators in the area.

Table 2 shows a sample arming, trigger condition, and the action that is developed for all the contingencies for which the schemes is designed for.

	ARMING Condition		Trigger Condition	Action – Solution
	Line Status	**Flow**		
RAS 2	CO-SI in Service Series Capacitors in CHO-PR in service CHO-PP in service	CHO-PR +14.9% of CO-SI > 566	CO-SI Trip CHO-SAG Trip	FLT + 12 cycles: Insert Shunt Capacitor FLT + 12 cycles: Insert Shunt Capacitor FLT + 1.0 second: Trip Unit if line still open FLT + 1.5 seconds: Insert Shunt Capacitor if line still open FLT + 1.5 seconds: Insert Shunt Capacitor if line still open

Table 2 – Sample Arming and Action Conditions for the Addition of Generation SIPS (RAS)

Design

Designs of Remedial Action Schemes that impact the region require that the scheme function at a very high reliability. This requires the scheme to incorporate redundancy in the design. The equipment installed monitors transmission loading and status of shunt capacitors and lines to determine the appropriate mitigation measures to be taken. The entire decision and action process has to be very fast over a wide geographic area and over various owners systems.

To increase dependability of the scheme, two redundant schemes were developed. Redundancy was used to mitigate any credible common mode failures between the two schemes. Some concept's applied included two DC supplies, multiple auxiliary relays, two different AC current and AC voltage courses, multiple relays. Equipment needed to be installed at all applicable substations and connected through multiple high speed communication systems that were owned, operated and maintained by multiple owners. The communication system utilizes digital microwave and fiber optics installed on the static wires above the transmission lines. Two separate paths for communication were established. Multiple current and voltage sensing sources were used and all tripping was implemented through multiple paths. All equipment was monitored for failure and status and extensive operator alarms and controls were installed.

Ethernet communication between devices has been implemented that utilized 61850 communication protocols including GOOSE messaging. Point to point communication over G.703 has also been used.

6.1.8 Arizona – California Intertie Remedial Action Scheme

Description

The addition of large generation in the state of Arizona, USA, required that mitigation be implemented to maintain the reliability of interconnection and the Region. The generation output was increased however the loss of this generation could cause transmission system far away to overload and exceed facility ratings. Several transmission lines on the border of Oregon and California would be impacted by this added generation. A Remedial Action Scheme (RAS), or SIPS, was installed to facilitate the added generation and provide for safe operation of the Region when this generation is suddenly lost. The added generation is approximately 1700 kilometer away from the area in the Region that would be thermally impacted due to the interconnected grid, and about 160 kilometers from the load centers in the Phoenix metro area, Figure 24.

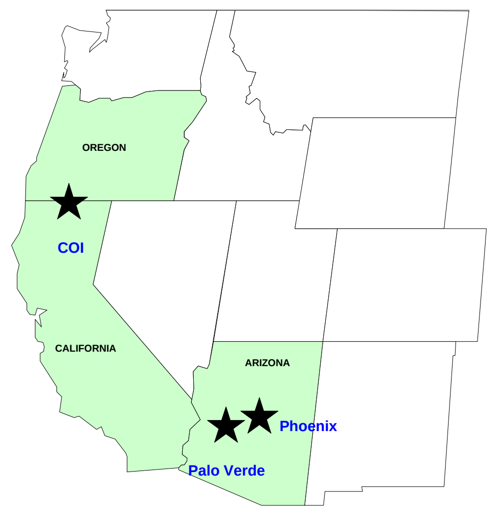


Figure 24 – SIPS Application for Maintaining Grid Reliability in Arizona

Studies

Studies have shown that sudden loss of more than 2500MW of generation could cause overload in the Northern Part of the interconnected region, some 1700 kilometers away during heavy flows in a particular flow direction. The loss of generation in Arizona would cause the lines to exceed the ratings and if this overload is not mitigated rapidly, then the transmission lines would need to be removed from service. This condition in turn would cause other facilities to overload and possible cascading throughout the region. Studies have determined that the removal of load in Arizona would mitigate the overload of the interconnected grid. However, the overload of grid occurs faster than generation can be manually adjusted. Therefore a high speed load shedding scheme would need to be implemented. The electrical region has requirements that facility ratings must not be exceeded for N-1 single contingencies or credible N-2 double contingency events. The solution to prevent violation of the requirements is to trip enough load in the Phoenix area to prevent the overload of the interconnected grid. Since the added generation was 120MW then the loss of generation must be followed by the tripping of 120MW of load. A thermal SIPS (or RAS) with load shedding capability would allow safe operation of the grid when a sudden loss of more than 2500MW of generation occurs.

Operation

The scheme monitors the total generation output and load available in the Phoenix Metro area. The RAS will arm when generation is above 2500 MW. Distribution substations throughout the Phoenix metro area are monitored for enough load to trip for the loss of generation. Load varies with ambient temperature and the scheme will adjust to make sure that enough load is always available but will only trip the appropriate amount of load. The scheme is constantly adjusting the amount of load that is armed to trip. Large contiguous blocks of load could not be tripped so only small blocks of load across the metro area were included. This required the scheme to monitor load at 14 different substations through the metro area and adjust the amount continuously. If the system is armed and the generation is lost, then at least 120MW of load will be shed within a second.

Design

Designs of Remedial Action Schemes that impact the region require that the scheme function at a very high reliability. This requires the scheme to incorporate redundancy in the design. The equipment installed monitors generation output and the load across the Phoenix metro area. This has to be accomplished over a wide geographic area and over various owners systems.

To increase dependability of the scheme, two redundant schemes have been developed. Redundancy has been used to mitigate any credible common mode failures between the two schemes. The design has two DC supplies, multiple auxiliary relays, two different AC current and AC voltage courses, multiple relays. Equipment needed to be installed at all applicable substations and connected through multiple high speed communication systems that were owned, operated and maintained by multiple owners. The communication system utilizes digital microwave and fiber optics installed on the static wires above the transmission lines. Two separate paths for communication were established. Multiple current and voltage sensing sources were used and all tripping was implemented through multiple paths. All equipment was monitored for failure and status and extensive operator alarms and controls were installed.

Ethernet communication between devices has been implemented that utilize IEC 61850 communication protocols including the early version of GOOSE messaging. Point-to-point communication over G.703 is also used.

7 Conclusions

In August 1996 issue of IEEE Transactions on Power Systems, an article [9] was published as a result of a joint CIGRE/IEEE study titled “Industry Experience with Special Protection Schemes”. The article attracted a great deal of attention, as wide-area protection and system integrity protection systems were only beginning to make inroads into utility practices. The geographical coverage of the report spanned the globe, the number of reported special protection schemes was 111, and the range of issues reported was very wide (from functional breakdown, design considerations, cost and reliability to testing and various other considerations). The complexity of the system integrity protection schemes has greatly increased since the time of the first report, and IEEE PES Power System Relaying Committee undertook an effort in 2005 to collect and update the information from around the globe with collaborations from CIGRE and EPRI.

This new (IEEE / CIGRE / EPRI) survey has corroborated the findings in the earlier report and has identified many new areas where SIPS are applied. The IEEE / CIGRE / EPRI provides valuable information to the industry practitioners and researchers alike about the trends and experiences in system integrity protection schemes. It answers many questions about current industry practices, regional differences in system protection philosophy and experience with such designs. This document describes some of the critical design considerations and applications of latest technology for SIPS. Several examples of more complex applications have been provided. The report also covers many of the industry practices and approaches to using new technologies for monitoring, communication and control in a never ending quest to further reduce the risk of large power system blackouts.

8 Acknowledgment

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Annex B Survey

A complete copy of the survey is included in this section.

A. SIPS Type and Systems

Brief description of scheme type (from the list, Appendix C)

Indicate the number of functional SIPS (individual subsystems of a single functional SIPS are part of the respective functional scheme and should not be counted independently). Then, group together the number of SIPS performing similar types of functions per Appendix I and indicate the total number of SIPS types.

For each type of SIPS, indicate the number of schemes on your system serving a similar purpose
Total Number of SIPS =
Number of Types SIPS performing similar purpose =

Purpose - Categorize your present installed SIPS for (check all that apply). For each category scheme indicate how many of the SIPS (Total Number of Systems) meet the purposes below.

a. Essential (prevent cascading outages) – Number of schemes
b. Increased Security (minimize area affected by undesirable conditions) - Number of schemes
c. Increased Power Flow Capability(improve available transfer capability) - To extend transmission system rating without adding new transmission facilities or to delay enhancement of transmission networks - Number of schemes
d. Important (avoid difficult operating conditions) - Number of schemes
e. To provide reasonable countermeasures to slow and stop cascading outages caused by extreme contingencies (Safety Net)
f. To increase generation output and maintain stability
g. Normal (A better functioning of the network) - Number of schemes
    1. Describe
h. Other (Please Describe)

B. Main Scheme Functionalities

Objective: Describe the main scheme functionalities and the potential benefits for the power system.

I. Please identify power system issues that your SIPS was designed to address (Intended objective).
    a. To provide protective actions against
        i. Congestion
        ii. Small-Disturbance Angle Instability
        iii. Transient Instability
        iv. Frequency Instability
        v. Voltage Instability
        vi. Thermal Overloading

b. To provide corrective or protective actions such as
   i. Generator Rejection
   ii. Load Rejection
   iii. Under-Frequency Load Shedding
   iv. Under-Voltage Load Shedding
   v. Adaptive Load Mitigation
   vi. Out-of-Step Tripping
   vii. Voltage Instability Advance Warning Scheme
   viii. Angular Stability Advance Warning Scheme
   ix. Overload Mitigation
   x. Congestion Mitigation
   xi. System Separation
   xii. Load and Generation Balancing
   xiii. Capacitor Switching
   xiv. Tap-Changer Control
   xv. SVC/STATCOM Control
   xvi. Turbine Valve Control
   xvii. HVDC Controls
   xviii. Power System Stabilizer Control
   xix. Discrete Excitation
   xx. Dynamic Braking
   xxi. Generator Runback
   xxii. Bypassing Series Capacitor
   xxiii. Black-Start or Gas-Turbine Start-Up
   xxiv. AGC Actions
   xxv. Busbar Splitting
   xxivi Other, please specify

C. Operational Experience Per Type of SIPS

iv. Please describe the scheme performance history for this type of SIPS
   a. Total number of scheme-years of operational experience for this type of SIPS upon which the following questions are based.
   b. Functional Dependability
      1. Total number of correct operations of SIPS of this type (scheme operated correctly when required to operate)
      2. Total number of failures to operate of SIPS of this type (scheme failed to operate when required)
   c. Functional Security
      1. Total number of incorrect or unnecessary operations of SIPS of this type (scheme operated incorrectly or spuriously due to protection or scheme logic failure, etc.)
   d. Communication system performance – Availability not considering redundancy or other measures pertaining to overall reliability (99% or better accuracy, 80-98% accuracy, 80% or below)

   e. Do you have methods to measure reliability of the SIPS performance?
      1. Describe in brief

v. Operator acceptance

1. Describe in brief

vi. Describe the design and implementation review process.

1. Please describe the design review process for the particular SIPS you are reporting and if there is an external review committee for conceptual approval.

D. Engineering, Design, and Implementation Considerations

Objective: Describe the main methodologies adopted in the scheme design in terms of preliminary studies, technologies assessment, design standards, redundancy etc.

II. What design issues were considered and applied, in implementation of the SIPS being reported here?

i. Types of System Studies

i. Describe the planning criteria

i. Seasonal performance variations

ii. Single

iii. Double

iv. A single contingency followed by a breaker failure

v. Extreme contingencies

vi. Other, please specify

ii. Types of planning studies

1. Steady State
2. Dynamic
3. Transient Stability, Transient simulations
4. Other, Please specify

iii. Real-time operational studies

b. Please comment

iv. Protection and control coordination studies

j. Please provide some information on coordination with other Protection and Control systems

i. Coordination with other SIPS

ii. Coordination with local protection

iii. Are your SIPS coordinated between themselves? Describe, example: UVLS vs. SIPS

k. Types of protective relaying technology used:

i. Electromechanical

ii. Solid State

iii. Microprocessor

iv. Custom designed product

v. Other, please specify

vi. PMU

vii. Combination of above
viii. Protocols (ModBus, DNP 3.0, IEC 61850, Vendor specific, others)
ix. Time synchronization techniques, etc.
x. Describe any future trend or functions that should be considered
xi. What is the rationale for combining different vintage hardware?
   1. System expanded
   2. Obsolescence
   3. Combination of 1 & 2

l. Do you have standards for SIPS applications (as it pertains to consistency in application philosophy)?
   i. Yes
      a. Do you use devices of different vendors as part of the redundancy?
      b. Are there multiple Standards specific to application
      c. Are older systems changed to meet new standards

   ii. No – Please indicate reasons
      a. Planning and operational aspects of different schemes require different hardware
      b. Devices that can meet the requirements not readily available
      c. Different SIPS have been deployed over many years and technology has changed
      d. Lack of good network connectivity
      e. Application specific – Each situations is unique and no common concept or standard can be established
      f. All of the above
      g. Other, please specify

III. Hardware Description and Outage Detection

m. Please describe the substation devices
   i. Outage detection Method
      a. Does the scheme rely only on breaker aux. contacts
      b. Does the scheme use combination of breaker status and undercurrent?
      c. Is voltage used for outage detection?
      d. Are both voltage and current used for outage detection?
      e. Tripping output from protective relays for the equipment.
      f. Does the scheme have provisions for breaker when in maintenance?
      g. Is the scheme a SCADA based architecture?
         1. No
         2. Yes – Please describe
      h. Does the scheme automatically identify open ended line?
      i. Does the scheme automatically identify manual opening of the line
      j. Other, please specify

   ii. Does the scheme use programmable logic controllers
      a. No
      b. Yes, if yes
         I. Does the scheme use a central controller?

II. If redundant controllers, are the controllers in one location?
    a. Yes
    b. No
III. How many redundant controllers does the scheme use?
    a. One
    b. Two
    c. More – Please specify
IV. Does the scheme use a triple redundant modular (TMR) type controller?
    a. Yes
    b. No
    c. Other type of controller (Please describe)

IV. Scheme Architecture

Objective: Describe the scheme architecture in terms of control paradigms, automatic features, critical functions etc.

n. Please provide information on decision making:
- i. Predetermined, based on off-line simulation
- ii. Response based, using fast system assessment technique
- iii. Intelligent system with self reconfiguration capability
- iv. Other, please describe

o. Redundancy needs/implementation - Both telecommunication and hardware
- i. Completely **redundant**
- ii. Partially **redundant**
    1. Please describe typical portions that are not redundant and why
        a. Not possible
        b. Too costly
        c. No impact to reliability
        d. Other – Please describe
- iii. Dual - Completely **duplicate**
- iv. Dual - Partially **duplicate**
- v. Describe criteria for determining redundancy
- vi. Describe limitations to achieve redundancy

Redundant – There are 2 systems (A and B) and there are no credible common mode failures between systems. No single point of failure that can impact both of redundant systems A and B.

Dual or Duplicate – There are credible common mode failures relative to redundant scheme – example, communication route may be same, or both systems pickup same auxiliary isolation devices, or common breaker trip coil (absence of breaker failure scheme).

p. Redundancy philosophy
- i. Describe criteria for consideration of redundancy
    1. Interconnection between different system (owners) requirements
    2. Interconnection between different countries' requirements

3. Regulatory, or International Oversight Compliance in terms of reliability and performance requirements.
    a. NERC and / or Affiliated Regional Reliability Organization (RRO)
    b. UCTE – European Union for the Coordination of Electricity Transmission
    c. ESCJ - Electric Power System Council of Japan
    d. Other - Specify

q. Does the scheme use voting
   i. No
   ii. Yes, if yes, is the scheme
      1. 2 out of 2 with maintenance and fail safe mode
      2. 2 out of 3
      3. 3 out of 4
      4. Other (please specify)

r. Is the scheme
   i. Response based event control
   ii. Condition Based Scheme
   iii. Both
   iv. Other (please specify)

s. Does the scheme initiate Breaker Failure
   i. Yes
      1. Does initiation follow the same philosophy as conventional breaker failure initiation? Please describe if otherwise.
   ii. No
      1. Please describe how a failed breaker is arrested for a system swing that may cause excessive currents
      2. Failed breaker condition not possible - Each breaker in the scheme has two independently operated trip coils?
      3. Scheme does not address breaker failure condition

t. Please describe performance requirements of the SIPS
   i. Throughput timing of the entire scheme
      1. What is the required or expected timing of the overall scheme in milliseconds?
         a. Below 50 Milliseconds
         b. Below 60 milliseconds
         c. Below 70 milliseconds
         d. Below 80 milliseconds
         e. Below 90 milliseconds
         f. Below 100 milliseconds
         g. Below 110 milliseconds
         h. Between 110 – 150 milliseconds
         i. Between 150 – 200 milliseconds
         j. Greater than 200 milliseconds – Please specify time
         k. Not time sensitive

2. What is the typical timing of the overall scheme in milliseconds?
    a. Below 50 Milliseconds
    b. Below 60 milliseconds
    c. Below 70 milliseconds
    d. Below 80 milliseconds
    e. Below 90 milliseconds
    f. Below 100 milliseconds
    g. Below 110 milliseconds
    h. Between 110 – 150 milliseconds
    i. Between 150 – 200 milliseconds
    j. Greater than 200 milliseconds – Please specify time
    k. Not time sensitive

ii. Throughput timing of the controller
    a. Below 30 Milliseconds
    b. Below 50 milliseconds
    c. Below 75 milliseconds
    d. Below 100 milliseconds
    e. Greater than 100 milliseconds

V. Data acquisition and related tools

Objective: Describe the data acquired by the scheme and the measurement methodologies adopted.

u. Measured Quantities
  i. Flow (P, Q, both)
    1. Polarity sensitive
    2. Not polarity sensitive
  ii. Current
    1. Polarity sensitive
    2. Not polarity sensitive
  iii. Power Outputs at generators (P, Q, both)
  iv. Frequency
    1. Percentage sensitivity
    2. Time delay to calculate
    3. Range
    4. $\Delta f/\Delta t$
  v. Voltage
    1. Level
    2. $\Delta V/\Delta t$
  vi. Others; e.g. Conductor Temperature – Please specify

v. Is time synchronization used?
  i. no
  ii. yes
    1. Accuracy
    2. What is the specified synchronization a requirement for scheme operation
    3. Other, please specify

w. Do you have a SMART SIPS / Intelligent SIPS
   i. No
   ii. Yes, Does the SIPS automatically adjust?
      1. Load
      2. Generation
      3. Both
   iii. Yes, On-line power system assessment
      1. Optimal Power Flow
      2. Transient Stability Assessment
      3. Voltage Stability Assessment
      4. Other, please specify
      5. Are state estimator values interlinked with the scheme?
         a. Yes - Please describe
         b. No – If not, do you plan to interlink in the future?

x. Does the scheme activation block any automatic reclosing?
   i. Yes
      1. Lockout requiring inspection or SCADA intervention (reset)
   ii. No
   iii. Not Applicable

y. Does the scheme activation block any operator initiated SCADA restoration?
   i. Yes
   ii. No
   iii. Not Applicable

z. Restoration Issues and Planned Mechanisms
      1. Is restoration part of the design of the scheme?
      2. Is restoration facilitated by scheme data?
      3. Is restoration facilitated by EMS data only?
      4. Restoration is handled by operating and dispatching instructions only
      5. Performed through 3 & 4
      6. Other, Please specify

E. Communication, Networking, and Data Exchange

Objective: Describe the scheme communication architecture in terms of technologies adopted, data exchange performances, remedial actions against communication failures, Ethernet and other networking, etc.

aa. Please provide some information on architecture of the communication
   i. Redundant
   ii. Duplicate
   iii. Mostly redundant, small portion duplicate
   iv. Other, please specify

bb. Please provide some information on the communication medium
   i. Microwave
   ii. Dedicated Fiber
   iii. Multiplexed Fiber

1. Describe nature of data stream, communications protocol, or utility-managed LAN/WAN communications stack used for SIPS.

iv. Leased wideband networking data circuits (WAN with MPLS, Frame Relay, or other networking stack carrying SIPS and other data traffic)
v. Leased voice bandwidth (analog tone or modem) telephone circuits
vi. Power line carrier
vii. Combination of microwave and fiber
    1. Approximate percentage of microwave
    2. Approximate percentage of fiber
viii. Combination of microwave, fiber, leased phone circuits, and other
ix. Other (please describe)

cc. Do you make use of multi-protocol systems within a given hardware?
  i. No
  ii. Yes
    1. Which protocols (see below for Ethernet questions separately)
      a. Describe application in brief for each scheme (For example, Analog, Status, Alarms)
  iii. Does the scheme use Ethernet messaging for:
    1. Analog values
    2. Status
    3. Trip commands

dd. Does the Ethernet messaging occur in between substations or confined to a location – If Ethernet not used, skip to ff.
  i. Yes, in between substations or systems
  ii. Only within the substation
  iii. Both
  iv. No Ethernet messaging applied

ee. Are the Performance and timing requirements affected by use of Ethernet?
  i. Not impacted
  ii. Yes, and performance is improved
  iii. No change in performance

ff. Are there any Ethernet interfacing devices (hubs, switches, routers, bridges, etc.)?
  i. No
  ii. Yes
    1. Please list or describe devices through which SIPS messages may pass, and their physical locations:
      a. Connecting communicating devices within a substation or control location
      b. Interfacing control location or substation LAN to a wide area communications facility – utility owned
      c. Same as b,. but interfacing to a leased communications service
      d. Interconnecting otherwise-separated LANs or WANs for SIPS
      e. Other – Please describe
    2. Characterize the nature of the networking environment between or among communicating SIPS locations:
      a. LAN within a utility-owned secured physical area only

b. A single virtual LAN operating over a wide area with utility data communications among locations and assigned network bandwidth or channels.
c. LANs at physical locations, connected by a WAN
d. (c.) with virtual LAN connection using 801.2 VLAN and/or using router programmed association of locations.
e. LANs and/or WANs that are separated by bridged interconnection(s).

gg. Does the scheme share Ethernet with other network traffic?
- i. Dedicated to the SIPS application
- ii. Part of a protection and control network
- iii. Part of the corporate network

hh. Describe cyber security implementation and protection features in use or planned

ii. How is communication failure measured in terms of reliability index and availability?
- i. Partial failures are considered
  1. Please describe briefly
- ii. Only complete failures are considered
- iii. Who in the organization is responsible for checking or tracking? Check all that apply
  1. Protection Engineering
  2. Maintenance
  3. Operation
  4. Telecommunication
- iv. Describe what tools are used for tracking

jj. Would scheme operate with a communication channel failure?
1. Yes
2. Covered by the alternate SIPS
3. No
4. Other (please specify)

kk. Please describe Control Area Visibility
- i. Is there any SIPS related information interchange with neighboring control areas or interconnected power companies?
  1. No
  2. Yes, If Yes, select as many as apply
     a. Flow (P, Q, both)
     b. Power Outputs at generators(P, Q, both)
     c. Frequency
     d. Voltage
     e. Other (please specify)

VI. Arming methodology

ll. Automatic
mm. Manual
nn. Override options
oo. Other (please describe)

VII. Implementation issues

pp. Please describe the choice of Hardware
qq. Is the scheme multifunctional?
rr. Is the scheme Centralized or Distributed?

Types of tools

ss. Is there an event reconstruction and playback system capability as part of the overall scheme (note – this question is not for discrete components at the measurement terminals)?

tt. Describe event records and access to the information:
  i. Available to different disciplines within the organization
  ii. Available to operating personnel only
  iii. Other (please describe)

F. Testing Considerations

uu. Describe the procedure (if any) for design testing – Examples, Actual system events, transient simulation tools (i.e:, PTI model, EMTDC, EMTP, etc.)
vv. Is there a System Study Validation procedure? Event records, Real Time Digital Simulator, etc.
ww. Is Periodic testing done on the scheme?
  i. No
  ii. Yes
    1. Is testing based on overall system testing or component testing, or both
  iii. Is scheme design set up for automatic tests
    1. Can the entire scheme be tested automatically for the intended purpose, after isolation switches are open?
      a. No
      b. Yes
        i. Partially Automated - Describe
        ii. Completely Automated

    2. Does the scheme testing have capability to load a predefined set of test cases (based on system studies)?

    3. If applicable, does the scheme have provisions for using real-time power flow conditions in connection with simulated outages desired for scheme performance?

  iv. Are Test results (Pass / Fail) automatically generated after each test?
  v. Is testing set up for manual simulation tests?
  vi. Can system testing be automated (Minimal personnel interaction)?
  vii. Does system testing incorporate automatic measurements for throughput timing?
    5. What is the frequency of testing and maintenance?
    6. Are there any other comments on testing?

G. SIPS Cost Considerations

VIII. Approximate cost:

Please indicate the approximate cost for the particular type of SIPS you are reporting,

1. $1-5M
2. $5-10M
3. $10-15M
4. $15M plus

H. Respondent 's System Information

Objective: Describe the system in which the SIPS is installed, including the number and voltage level of substations and lines, extent of connectivity to neighboring systems, membership in regional or national interconnected systems or reliability organizations, etc.

IX. Respondent Affiliation (see Appendix III for information about NERC Reliability Functions)

Describe your organization. Choose one of the following:

1. Load Serving Entity
2. Distribution Provider
3. Transmission Owner / Provider

Respondent 's System Information (Cont'd)

4. Generation owner / Operator
5. Reliability Authority
6. Balancing Authority
7. Other (please specify)

Describe your organization's primary function (planning, protection, operations, maintenance, telecommunications, etc.)

System Ownership: Choose one from the following:

i. Federal or National Government
ii. State Government
iii. Provincial Government
iv. Municipal Government
v. Investor Owned
vi. Cooperative
vii. Other (please specify)

What is the generation capacity of your organization in MW?

For systems that are transmission or integrated companies, please specify the generation capacity that is interconnected with your system (if known). Choose from the following:

i. 0-1000 MW
ii. 1000-5000 MW
iii. 5000-10,000 MW
iv. 10000 – 20000 MW
v. Over 20,000 MW

What are the transmission voltages of your power company in kV? Check each that apply

i. 0-100 kV
ii. 100-200 kV
iii. 200-300 kV
iv. 300-499 kV
v. 500 kV and above

What is the predominant voltage which the scheme are applied in kV?

i. 0-100 kV
ii. 100-200 kV
iii. 200-300 kV
iv. 300-499 kV
v. 500 kV and above

What percentages of the schemes applied are for transmission system integrity?

i. Below 10%
ii. Between 10% - 25%
iii. Between 25% - 50%
iv. Between 50%-75%
v. Between 75%-100%

What percentages of the schemes applied are for safety net against extreme contingencies?

i. Below 10%
ii. Between 10% - 25%
iii. Between 25% - 50%
iv. Between 50%-75%
v. Between 7%5-100%

What percentages of the schemes applied are for increasing transmission capacity?

i. Below 10%
ii. Between 10% - 25%
iii. Between 25% - 50%
iv. Between 50%-75%
v. Between 7%5-100%

What is the peak load of your power company in MW?

i. 0-1000 MW
ii. 1000-5000 MW
iii. 5000-10,000 MW
iv. 10,000-20,000 MW
v. Over 20,000 MW

Have the numbers or types of SIPS in your power company increased in last decade compared to prior years?

i. No
ii. Yes
    1. If yes, please briefly describe types of changes and reasons

Please give us your contact information, for clarifications on responses.

ii. Name, Phone Number, Function in your company
    1. Name
    2. Phone Number
    3. E-mail address
    4. Function in your company

I. *Assistance in completing the survey*

The following individuals are available to assist in interpreting the questions if clarification is needed.

X. Survey Help

Scope clarification / general question – contact

Vahid Madani – IEEE
Miroslav Begovic - IEEE
Javier Amantegui - CIGRE
Pei Zhang - EPRI

Technical Issues – Contact

DAC-phuoc Bui – Canada (French Speaking)
Andre dos Santos – Portugal
Stan Horowitz - USA
Bogdan Kasztenny - Canada
Shinichi Imai - Tokyo
Jon Sykes - USA
Rich Young - USA
Eric Udren - USA
Alfredo Vaccaro - Italy

Annex C SIPS or RAS Application Definitions

The following is a list and a short review of methods to balance the operation of the power system and the main factors influencing the type of SIPS applied, that will prevent a loss of power system integrity.

Names and / or the SIPS (RAS) definitions may vary from one power system to the next, or from one control area to the next. However, these schemes are intended to address power system constraints or when constraints could occur as result of increased transfer limits. The main purpose of this section is to aid the respondents with the selection of the most appropriate types of SIPS actions and for the WG members to use as a measure to appropriately categorize the types of applications in the summary report.

1. Generator Rejection
2. Load Rejection
3. Under-Frequency Load Shedding
4. Under-Voltage Load Shedding
5. Adaptive Load Mitigation
6. Out-of-Step Tripping
7. Voltage Instability Advance Warning Scheme
8. Angular Stability Advance Warning Scheme
9. Overload Mitigation
10. Congestion Mitigation
11. System Separation
12. Load and Generation Balancing
13. Shunt Capacitor Switching
14. Tap-Changer Control
15. SVC/STATCOM Control
16. Turbine Valve Control
17. HVDC Controls
18. Power System Stabilizer Control
19. Discrete Excitation
20. Dynamic Braking
21. Generator Runback
22. Bypassing Series Capacitor
23. Black-Start or Gas-Turbine Start-Up
24. AGC Actions
25. Busbar Splitting

The mitigation measures are described below.

Generation rejection

Generation rejection schemes involve tripping of one or more generating units. The practice of generator tripping is used on all kinds of units but especially on hydro-generator units.

Generation rejection improves transient stability by reducing the accelerating torque on the machines that remain in service after a disturbance.

Generation rejection can also be used to reduce power transfers on certain parts of a transmission system and thus solve overload or voltage stability problems.

Load rejection

Load rejection schemes involve supply voltage drop and / or even load shedding.

Congestion Mitigation – Refer to Load and Generation mitigation definitions

Load and Generation Balancing – No definition needed

Dynamic Braking

Another method of balancing the grid where the path used for heavy power transfers may suddenly be interrupted.

Generator runback schemes

Similar to the generator rejection with the possibility of stepping down the generator output in a timely steps.

Turbine fast valving

An alternative to generation rejection when a slower reduction in generator output is acceptable. Turbine fast valving is applied to thermal units and involves closing and reopening of steam valves in order to reduce the accelerating power of generators that remain connected to the network after a severe transmission fault.

Automatic Generation Control (AGC)

Not necessarily an SIPS --The main objectives of automatic generation control (AGC) are to regulate frequency to the specified value (e.g. 60 Hz) and maintain the interchange power between areas at their scheduled values.

Fast unit and pumping storage unit start-up

Not necessarily an SIPS - Power support by fast unit (e.g. gas turbine) or pump storage start-up could be used at low frequencies or when there is a high risk of voltage collapse caused by inadequate generation. SIPS that initiate gas turbine or pump storage start-up are very efficient in recovering from the stressed situations.

The gas turbine start-up process takes several minutes and consequently provides a solution to long-term critical situations. In long-term voltage stability, tap changer blocking could be used to give enough time to start the gas turbine.

Underfrequency load shedding

The underfrequency load shedding (UFLS) schemes are applied to preserve the security of both the generation and transmission system during disturbances that result in major reduction in system frequency. Such schemes minimize the risk of total system collapse, maximize the reliability of the overall network and protect system equipment from damage.

Undervoltage load shedding

Similar to UFLS, undervoltage load shedding schemes (UVLS) provide means of preventing system collapse during severe, and possibly prolonged, voltage deficiency conditions. Power systems with heavy loading on transmission facilities and limited reactive power control can be vulnerable to voltage instability. In extreme situations, load shedding when voltage collapse is imminent may preserve system stability.

UVLS may be a localized system, voltage measurements are at the substation where load is shed, or include voltage information from other parts of the system.

Remote load shedding

Remote load shedding schemes are designed to operate after severe contingencies affecting the system's transmission capacity (e.g. loss of several transmission lines). This kind of extreme contingencies endanger transient, dynamic or short-term voltage stability.

Shunt equipment Switching - Automatic shunt switching (shunt reactor/capacitor tripping or closing)

SIPS are widely used to control the voltage levels in a substation. This is achieved by automatic switching of shunt reactors and capacitor banks.

Thermal Limitations:

- Over Load Mitigation Schemes

Overload schemes are applied to protect equipment from excessive overloading, beyond their emergency ratings. When emergency rating of the equipment remaining in-service is exceeded following an outage on some of the parallel equipment. Typical applications include multiple parallel transmission lines, being part of the same system, or multiple parallel transformers serving the same load.

In the case of line thermal scheme, when a single line suddenly becomes unavailable during peak periods, the remaining line, or lines, become overloaded. The line outage detection scheme would detect the stressed system conditions and execute corrective actions. The corrective actions include balance of load and generation flows and may include automatic generation run back at the source side, and increasing generations and / or shedding loads & pumped storage generators at the remote end to balance the system before equipment are damaged.

Since thermal rating of equipment is generally a function of time and magnitude of the excessive exposure, thermal schemes are time delayed.

- Adaptive Load Mitigation Schemes

For adaptive load mitigation schemes, the system may be partially adjusted by initially activating pump load separation for example, followed by a second computation of system conditions before executing further actions. For such adaptive schemes, the corrective actions continue to be executed until the congestions are mitigated and system is relieved. More intelligent application like Optimal Power Flow (refer to Chapter 2) to the control center would be possible to calculate the amount of appropriate control actions.

The arming of such schemes will determine the mode of operation for the scheme and whether the system adjustments need to be immediate or the conditions support gradual balancing of load and generation.

These schemes may rely on substation load, where monitoring elements of the scheme are located, or communication based systems.

System separation

Wide-area schemes provide system protection during unplanned or unpredicted sequence of outages by proactively taking actions to prevent the system from cascading into unplanned islands. For example, when a system is stressed and system and equipment are removed without sufficient levels of adjustment or when faults occur, the chain of events starts. Wide-area schemes provide mechanisms for fast automatic actions (e.g. load shedding, system separation).

The loss of power system integrity caused by multiple contingencies can be characterized by one or more of the following phenomena:

- Transient angle instability;
- Frequency instability;
- Voltage instability;
- Small signal angle instability;
- Cascading Outage

Transient angle instability

Transient stability of a power system describes the ability of all the generators to maintain synchronism when subjected to a severe disturbance such as a heavy current fault, loss of major generation or loss of a large block of load. The system response will involve large excursions in generator angles and significant changes in real and reactive power flow, bus voltages and other system variables.

The main consequences are major disturbances for customers (voltage dips, frequency deviations) and/or major transients (real power, voltage, frequency, etc.) on the generating units and power system.

To prevent loss of synchronism, rapid and massive actions based on the direct detection of the contingency are often required. Some of the commonly known actions include:

- Generation rejection and fast valving
- Dynamic braking
- Reactor switching near generation
- High speed load shedding schemes

Frequency instability

Frequency stability is defined as the ability of a power system to maintain the system frequency within an acceptable range during normal operating conditions or following a major disturbance. If, despite the control actions taken to maintain the network integrity, network separation occurs, it is important to limit frequency excursions.

The frequency drop may be deep so that under frequency relays will disconnect thermal units from the network, increasing the power deficit.

Some of the common UF actions include:

- Underfrequency load shedding to reverse a frequency drop
- Overfrequency tripping of generation (hydro type)
- UF relays tripping of interconnection lines

Voltage instability

Voltage stability involves the ability to maintain steady acceptable voltages at all buses under normal conditions and after being subjected to a disturbance. Voltage instability results from the attempt of loads to be restored above the maximum power that the combined generation and transmission system can deliver to them.

Voltage instability may be caused by a single or multiple contingencies. With respect to long-term voltage stability, the main concern is the loss of transmission facilities (mainly in between generation and load centers) or the tripping of generators (mainly those located close to the loads and supporting the voltages of the latter). For short-term voltage instability, the slow clearing of a fault may cause an induction motor dominated load (e.g. air conditioning) to become unstable.

Some of the commonly considered actions are:

- Shunt capacitor (on-line) and shunt reactor switching (off-line)
- Emergency control of LTCs: blocking, return to a pre-defined position, decrease
- Modulation of HVDC power
- Fast unit start-up
- Fast increase of generator voltages (through AVR setpoints).
- Load shedding as needed to stabilize voltage

Small signal angle instability

Small signal stability is defined as the ability of the power system to maintain synchronism when subjected to a small disturbance. Different modes of power systems oscillation, complexity of power system and its interconnected components, can attribute to the angular instability.

Frequency oscillation range is generally in the order of 0.1 to 2.0 Hz for small disturbances. Un-damped electromechanical modes can be of a local type with frequency range of 0.7 to 2.0 Hz, or of inter-area oscillation mode with frequency range of 0.1 to 0.7 Hz.

Counter-measures used include:

- Generator excitation control
- PSS - power system stabilizer
- Secondary voltage controls – STATCOM, SVC, and HVDC.

Out of Step Tripping

1) Cascading Outage (Stability / Cascading prevention schemes)

Cascading refers to an uncontrolled sequence of outages of power system components such as transmission lines, transformers, generators, etc. triggered by an incident at a single location. The sequence of low-probability disturbances is generally not planned by the system designers and is not expected by system operators. In some situations, a severe transmission system disturbance can initiate major oscillations in real and reactive power flows and instability in voltage levels.

Cascading outages affect power system tie lines or multiple control areas and will be particularly problematic when one region is importing power and another is exporting.

NERC Definition of Cascading: See Appendix III
Cascading is the uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption, which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies.

2) Overload cascading

The following types of actions are used by some utilities to counteract cascaded line tripping:

- Outage detection schemes on critical tie locations
- Power swing blocking of distance relays
- Undervoltage load shedding
- Gas turbine start-up

Definition of Some Unique Terms

TMR - Triple Modular Redundant (TMR)

A terminology associated with control systems that have three system processor elements working together and having capability to revert to two system processor elements or one in the presence of one or two faulty components respectively. These systems are fault (component) failure tolerant and have capability to run in 3-2-1 mode based on the equipment configuration.

For example, a **3-2-1 "**Three system processor elements" working together and having capability to revert to two system processor elements working in the presence of a single fault, reverting to one system processor elements working in the presence of two faulty components.

The entire designs of such systems are fully redundant and operating in parallel.

Redundant – No common mode failures between systems A (primary) and B (alternate) - No single point of failure that can impact both of redundant systems A and B?

Duplicate – There are some common mode failures relative to redundant scheme – example, communication route may be same, or both systems pickup same auxiliary isolation devices, or common breaker trip coil (absence of breaker failure scheme).

Centralized – See description within the survey

Distributed – See description within the survey

Annex D – Additional information received with the Responses

D.1 Communication, Networking, and Data Exchange

Considering the significance of the information passed over the communication channels, a robust communication channel is required. Today's technology allows robust communication network which offer:

- Path Redundancy
- Low error-rate communication channel
- Low latency
- High Availability
- High security
- Deterministic

The choice of a particular communication technology will be based on the scheme performance requirements in conjunction with the scheme data requirements. Some standard communication channels include the IEEE C37.94 Standard for communication over multiple DS0 synchronous channels and Ethernet. The C37.94 standard allows multiple DS0 channels to be aggregated to provide higher bandwidth data paths.

To achieve high communication availability and subsequently high scheme availability, communication redundancy with alternate path routing is the ideal for which to strive. The requirement for alternate communication paths also falls out of the architectural redundancy requirements described above. Path redundancy can be achieved with technologies such as the fiber rings (SONET, SDH) and Ethernet rings. Path redundancy can also be achieved through the use of alternate media, for example, one copper/fiber path and one radio or satellite path.

Low error rate communications can be achieved through fiber channels or low-noise copper channels. At a minimum, a copper communication channel with a Bit Error Rate (BER) of less that 10^{-4} is required. With a BER of 10^{-4} and a communication pack size of 200 bits, the probability of a lost packet is 1 out of 50. The probability of getting two bad packets in a row is 1/2500 that would delay operation of the system by 16ms.

More important than low noise is high data security, that is, if there is an error in a packet of data, the device must have a high probability of being able to detect bit errors in the message. This function is typically accomplished through the addition of a Cyclical Redundancy Code (CRC) – an error detecting methodology - along with the message. The probability of the CRC to detect an error is a function of its size. For smaller packet sizes, a 16-bit CRC is capable of detecting all bit error combinations up to 3 bits.

Although the probability of getting 4 errors in one message at a bit error rate of 10^{-4} is about once every 200 years, the real issue is related to burst errors. A burst error is when many bits (more than 5) are changed due to some event on the communication system. With a 16-bit

CRC, the probability of NOT detecting a burst error is 1 out of 65,536. Although these are good odds, the communication industry tends to err on the conservative side and pushes the size of the CRC to 32 bits. With a 32-bit CRC (as used on all Ethernet communications), the probability of NOT detecting a burst error is 1 out of 4,294,967,296 – somewhat better odds.

Desirable in a communication system is the ability to monitor not only lost packets but also the rate of lost packets. When high rate of errors are detected, maintenance crews can quickly be dispatched to search out the source of the communication errors. In conjunction with error detection is the need to detect lost communications in general. The end users could also benefit from cost effective test tools that would help validate noise / error detection and system response during lab and commission testing.

Another desirable feature is the ability of the communication link to provide end to end timing – that is, how long it takes a message to travel from "Station A" to "Station B". Detection of communication delays outside the expected ranges again allows for quick crew dispatch, identification, and solution of the problem.

Of particular concern today is the need for communication security or cyber security. The primary concern is that "routable protocols" such as DNP, Modbus, 870-5 T104, and IEC 61850 Client/Server be secured from outside interference. Security with these protocols is typically achieved through the use of external gateway/firewall/encryption devices. A secondary strategy to achieve cyber security is to use non-routable protocols such as the IEC GOOSE and standard or proprietary point-to-point communication methodologies.

The traditional SIPS scheme collects data that is to be used for only the collecting scheme. As today's power systems become more congested, it is clear that multiple SIPS will be needed for multiple system contingencies. As such, there is a trend to "share" collected information between multiple schemes and thereby minimize the collection and, subsequently, mitigation hardware in the field. This type of SIPS has been called a "Central" SIPS where multiple SIPS can be executed with shared data from the field devices in a SIPS region of performance. Such an architecture can save not only money, from a field device installation perspective, but also time to install as a new scheme can quickly be brought on line through the sharing of existing infrastructure.

- Architecture of the communication
- Communication medium and protocols
- Information about shared communication (with other applications)
- Impact of communication failure on reliability index and availability
- Cyber security implementation and protection features
- Operability of the scheme with a communication channel failure
- Control area visibility

D.2 Arming methodology

One design parameter that sets these schemes apart is the "arming" and "disarming" levels in response to system conditions. For example, a watchdog type of scheme may be required. Some SIPS are armed automatically based on flow and power system condition, or preprogrammed contingencies in the case of the condition based SIPS, a by the system control center computers, while others require human operator action or approval, and some are armed all the time. Manual arming is generally tied to alarm systems to alert operating staff to verify condition and activate / arm for the next level of contingency. Refer to SISPS Application Examples section of this report for more information.

Common factors in arming determination include:

- Levels
- Use of operating Nomograms
- Set points for the thresholds
- Methods
    - Automatic / Dynamic
    - Manual

For adaptive load mitigation schemes using more intelligent application like Optimal Power Flow to the control center would be possible to calculate the amount of appropriate control actions. The arming of such schemes will determine the mode of operation for the scheme and whether the system adjustments need to be immediate or the conditions support gradual balancing of load and generation.

D.3 Implementation issues

A SIPS may be called upon to act for multiple contingencies and operating conditions. As such, a given scheme will contain multiple functions – all operating on the same set of mitigation devices. Such multiplicity results in a more complicated controller design, more extensive testing, and the involvement of multiple utility disciplines throughout the implementation phase of the project.

As a result of the multi-functionality requirements, the SIPS architect must decide whether to implement a centralized or a distributed system. The centralized architecture – having a central location for all data to be collected and controls issued – has the benefit of being able to implement multiple functions from one or two central location as well as the capability to make operational changes – saving on implementation costs but adding complexity to the overall scheme.

The Distributed architecture spreads the intelligence and control of the SIPS throughout the operating range of the scheme, or between the central controller and the field devices in the case of combined centralized and distributed systems. The benefit of this design is modularity and that a single node failure does not take down the entire SIPS. Scheme modularity lends itself to simpler architecture, the scheme logic is much simpler to test, and the various components are easy to isolate for test and maintenance. Also, different bus configurations may require special attention during abnormal switching and the distributed architecture easily facilitates the reconfigured bus. For example, in a Main / Aux. or a double bus single breaker configuration where substitute breaker is used, the substitute breaker position, or when power flow may change polarity as a result of switching, can be incorporated into the local (field) devices part of the SIPS. Other benefits include restoration for use of response based systems. For example, frequency or angle measurements may be part of requirements for restoring a section of the system.

As mentioned earlier, the ability to aggregate and view events from the entire system is extremely desirable. Events tell the story of the operation. Even in non-operational situations, the arming and disarming of the system is evidenced in the event record. Again, having all events on a common 1ms accuracy time base is mandatory.

A related feature is the ability to play-back a scenario. This would entail simulating measurements throughout the system, making an arming decision, and then executing an operation (with the outputs blocked). Such a testing mechanism yields the next best overall test (next to "natural testing" when the system truly does operate).

- Multi-functionality of the scheme
- Design: centralized or distributed architecture
- Availability of event reconstruction or system playback capability
- Description of event records and their availability within the organization

D.4 Testing Considerations

The ultimate success of the implementation solution depends on a proper testing plan. A proper test plan should include the lab testing, field-testing, study validation, and automatic and manual periodic testing.

D.5 Lab Testing

Lab testing is designed to validate the overall scheme in a controlled environment. Lab tests permit controlled inputs from numerous sources with frequent checks of the output at every stage of the testing process. The lab tests ensure that the desired results are accomplished in the lab environment in contrast to costly and time-consuming field debugging.

For example, in a group of three SPS devices, a lab test could be simulated to check wide area communications (fiber/copper), average message delivery and return time, unreturned messages count and CRC failure count (under simulated noise conditions), and back-up communication switching timings.

It is advisable to create a detailed test plan as part of the overall implementation. A combination of the Logical Architecture, Logic Design, and the Physical Architecture could be used in preparation of the test plan.

D.6 Field Testing and Commissioning

Field commissioning tests should be carried out to check the performance of the special protection scheme against the real world abnormal system conditions. The telemetry data and the dynamics of various power system configurations such as breaker close and bypass contacts, changing the selectivity of the current transformer inputs, the total trip timing over the implemented communications between devices and the central control station, and the possible scenarios of unavailability of devices at the time of execution of a command signal in a given station all need to be tested. In general, every input point and every logic condition needs to be validated against expected results. Additionally, the effect of DC transients on Line Outage need to be tested thoroughly in the field before putting the scheme into service.

D.7 Scheme Validation

A critical consideration in implementing wide area monitoring and control schemes is the development of automated test scenarios. Such test cases could be prepared based on the type and the intended application of the scheme, and should include provisions for ease of updating case studies as system conditions change.

For schemes that involve transmission constraints and stability limits, data from the state estimator can be used to determine different pre-outage flows within the power grid. The pre-outage flows are loaded into the controller as pre-contingency conditions. The controller, or simulator portion of the controller, would then be programmed for various outage, underfrequency, and / or undervoltage status scenarios to perform overall system performance evaluation.

State Estimator data could also be used to develop case scenarios representing future flows and load patterns for further system performance evaluations or to make adjustments where necessary.

D.8 Periodic Testing

A proper test plan to simulate line outage on the monitored transmission/distribution lines in the respective substations and tripping of the lines should be conducted on a periodic basis to test the contingency plans and as a learning curve for the better understanding of the SIPS. This test is often conducted without stopping any inputs – only actual trip outputs, or other actions such as capacitor insertion are blocked. For example, while simulating, a line outage, the monitored station should generate a trip output for the required load shed. The overall design need to incorporate the capability of isolating the trip signal but yet validating that it was issues. Devices such as latching and lockout relays can be installed for this purpose.

- Testing procedure
- Periodicity of testing
- Maintenance issues

Annex E – Survey Participation Invitation Letters

Separate invitation letters have been sent out to members of CIGRE and IEEE to announce and encourage participation – Below is a sample sent to the CIGRE Study Committee (SC) B5 members.

Dear Colleagues:

CIGRE Study Committees B5 (Protection and Automation) and the IEEE Power System relaying Committee (PSRC) Working Group C4 invite you to participate in the survey of the "Global Industry Experiences with System Protection Integrity Schemes" (SIPS).

For the past 18 months, many technical experts representing IEEE PES, CIGRE Study Committees B5, C2 (System Operation and Control), and EPRI Grid Operation and Planning Program have actively volunteered their time and knowledge in the development of a comprehensive survey that would benefit our industry. Please refer to the presentation summary or the Survey for a complete list of working group members.

The survey is designed to provide guidance for future implementers of these systems based on what exists today, operating practices, and lessons learned. The survey is in two parts: Part 1 identifies the "Purpose" of the scheme with subsections of "Type" and "Operational Experience". Part 2 is about the Engineering, Design, and Implementation aspects of the Asset owner's practices. Please use the comment field to elaborate exceptions or when additional comments are needed.

As you are completing the survey, please take a moment to look over the "Procedures and Cautions" section at the beginning of the survey. Also, save your responses frequently and before exiting. The HTML format survey does not prompt the user to save when exiting. To save your work, you must choose "File->Save As". Do Not Change the filename when saving the HTML file. Use same file name as when you first opened the file. To change the filename, you must save and exit the file, then use Microsoft Explore.

The survey, a brief overview presentation of the survey, and other related documents are located at http://my.epri.com/portal/server.pt?Highlight_id=global_industry_experiences_with_system_integrity_protection_schemes_da_342184.html. The survey could also be accessed through the IEEE PSRC site at http://www.pes-psrc.org/c/, select "What's New" tab.

The organizing committees appreciate your participation and responses by March 19, 2007. Survey participants will receive tabulated results of the responses.

If you are not directly involved with the survey content, please forward this letter containing the survey link to your colleagues interested in this area. You can also add names to the survey distribution list by contacting Vahid Madani at (vxm6@pge.com) or Javier Amantegui at (javier.amantegui@iberdrola.es).

Thank you for your support. We look forward to your responses.

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