STRUCTURE OF DATA AND INFORMATION FOR PROTECTION, AUTOMATION, CONTROL AND OPERATION APPLICATIONS

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1 INTRODUCTION

The Brazilian electric energy industry model is based on competition among generation and distribution utilities within their respective segments, remuneration of transmission utilities depending on asset availability, an independent system operator and an electric energy trade chamber, which are independent institutions. Despite the successful experience with competition, all Brazilian electric energy industry segments agree that they must cooperate in many activities for their own benefit. Coherence in power grid measured data is an example of such cooperative work that shall be dealt with in the near future.

The Brazilian National Interconnected Power System is growing quite fast with the addition of large hydro plants, long distance HVDC links and AC transmission trunks. Back to back converter stations and power electronic equipment are being introduced in larger scale to provide more flexible AC transmission systems. At the same time distributed generation is increasing its share in the Brazilian energy matrix. All these issues impose a significant growth in terms of data and information figures and a challenge for their appropriate management and use.

The extensive – and proper – application of the IEC 61850 standard will be a natural consequence of so many new installations, as well as it will be the most suitable way to refurbish protection, automation and control devices and systems that have reached the end of their life cycles. Handling data will be much easier with the new standard, the same not being necessarily true for information acquired from this data. New kinds of data will stem from synchrophasor measurement systems, asset management systems, etc. These facts by themselves demand start planning how a reliable data structure shall be implemented and how and where this data should be converted to information.

Brazilian CIGRÉ Study Committee B5 – Protection and Automation (SC B5) is considering the possibility of creating a Working Group (WG) to deal with this subject, beginning to work within the substation environment. Later on, other Brazilian CIGRÉ SCs will be invited to contribute to the elaboration of a guide on data and information structures. This paper aims to get feedback from the international protection, automation and control community for the definition of the first steps of this work. An example on System Integrity Protection Schemes (SIPS) multi-utility application is presented to illustrate how things shall work under the proposed structure.

According to [1] and [2], it is expected the next ten years to be most fruitful for protection, automation and control engineering. Planning protection, automation and control systems in a national scale is neither usual nor easy, mostly in a large country like Brazil, while complying with electric energy regulating and trading rules.

Thanks to digital communication and distributed computing systems, there already is an opportunity to enhance and optimize the protection, automation and control process from bay level up to the highest level in the operational hierarchy. The highest control level in Brazil nowadays is the national control center but, in the future, there may be a South American control center or so, located anywhere. To reach such an important integrated power system control structure, it will be necessary to establish a continental strategic policy whose success will depend on getting the highest possible added value from all levels of operational hierarchy.

Obtaining information from data and deploying data or information at each level according to their attributions is one of the key ways to pave the path for effective power system evolution. Communication media shall only transport what is of exclusive need between two or among more operational hierarchy levels.

There shall be no more completely separated protection, automation and control systems from substation or power plant level up to the control center level. Duplicating tasks at different levels, as today is yet unavoidable, will not be necessary or justified, except for reliability reasons. A given task will be processed at the most cost effective level, as the result of technical/economic analysis.

The creation of a well-conceived and reliable data and information structure will lead to lower costs with better performance when dealing with protection, automation and control and the operational hierarchy in the near future.

2 DATA AND INFORMATION STRUCTURE (DIS)

The proposed structure depends on proper communication systems among all levels of the operational hierarchy. Communication issues will be discussed later with Brazilian SC D2 – Information Systems and Telecommunication. The data and information structure (DIS) shall provide inputs to all kinds of algorithms and software required for dealing with the classical power system conditions shown on Figure 1 [3]:

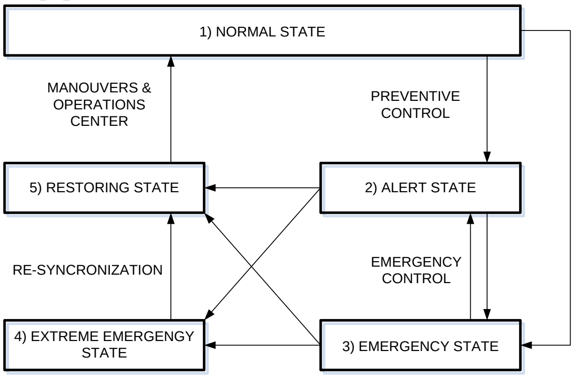


Figure 1 – Power System States: Fink and Carlsen Diagram [3]

DIS shall cope with classic and new protection, automation, control and operational macro-functions such as:

- Energy management;
- Supervisory, control and data acquisition;
- Substation/power plant automation;
- Site security and surveillance;
- Revenue measuring;
- Energy quality monitoring;
- Asset management;
- Synchrophasor measurement;
- Component protection;
- System integrity protection;
- Disturbance recording and analysis;
- Automatic restoration.

2.1 Protection, Automation and Control Hierarchy

The philosophy of the proposed data and information structure (DIS) is based on transforming data into information at the lowest possible level along the operational structure. The higher the hierarchical level, the higher the need for applying information based on more strict requirements. In other words: information may stem from the lowest level with inherent high added value and thus flow straight up to a higher or even to the highest level, or its added value may be growing progressively as it flows up along the operational hierarchy. DIS philosophy is also based on processing optimization and on checking coherence and consistency of data and information. DIS expected advantages are described on Table 1:

Table 1 – DIS Advantages

Hierarchical Levels	**Advantages**
At all levels	Distinct logging for data and information
	Logging of data that compose an information only flows up by request or automatically if some problem is found by checking applications
	Perspective of applying distributed processing along all operational hierarchy
	Optimized use of oscillography, sequence of events (SOE), energy quality registers, synchrophasor measurement systems and asset management systems
At the upper levels (control centers)	Processing capacity will be alleviated for Energy Management System (EMS) features
	More capable and faster Real-Time tools
	More user-friendly tools and systems
At the lower levels (station, bay & process)	Getting feedback from upper levels
	Protection and control with adaptive features
	Easier component protection and SIPS remote parameterization
	Easier station remote operation
	Better interaction between maintenance and operation staffs, mainly for unattended stations

One key issue when dealing with DIS: where to start the transformation of data into information? Should transformation start in the merging unit (MU) level? Although possible, processing some data in MU would mean to add new functions to it, in addition to merged signals. This is desirable only for those local functions, like signaling. As MUs are progressively being merged with primary equipment like current and voltage transformers, circuit breakers, etc., its concept will gradually be associated only to publish measured signals, leaving the decision functions to other IEDs. But, of course, the early transformation of these rough signals into processed information is desirable, reducing network traffic. So, if possible, this should be done on the first layer of IEDs. On the other hand, some standardization should be useful on this subject, as interoperability concerns might arise, with different kind of data being supplied by MUs from different vendors.

The mention to merging units is related to the future. But right now, all control centers belonging to the Brazilian Independent System Operator (ISO) receive a huge amount of data and depend on the conventional process through Supervisory, Control and Data Acquisition (SCADA), configurators, topological estimator and state estimator to feed the real time advanced tools within the Energy Management System (EMS). Despite the efforts of the infrastructure team, one could say that many improvements are needed at those control centers' level and below. The ISO is providing for its national and regional control centers a modern net of EMS [4]. Most utilities have also modern control centers. On the other hand, something shall be done at the substation and power plant level to enable the ease production of information, as well as more interaction among all levels of the operational hierarchy.

Presently, large amounts of data flow upwards even to the Brazilian national control center. On the other hand, information flow is small and not too many commands flow downwards. For instance, the only command that stems from independent system operator is Automatic Generation Control (AGC) signals, which flow from the ISO regional control centers down to the power plants that take part in AGC. Another issue is that present regulation does not state that utilities must exchange data or information for their own and system wide benefits: the exchange usually results from bilateral negotiations. That is why implementing DIS will not be a technical effort only: regulation shall evolve, so all segments of Brazilian electric energy industry shall be granted with benefits.

Of course, data or information flow depends on adequate communication system and the evolution towards this requirement is taking place in a fair pace. For instance, what to say about adaptive features implementation for protection, monitoring and control? DIS is expected to enable that data, information and commands to flow up, down and horizontally within the operational hierarchy ruled by cost-effective solutions and obeying regulation. Figure 2 shows data x information relative requirements along operational hierarchy:

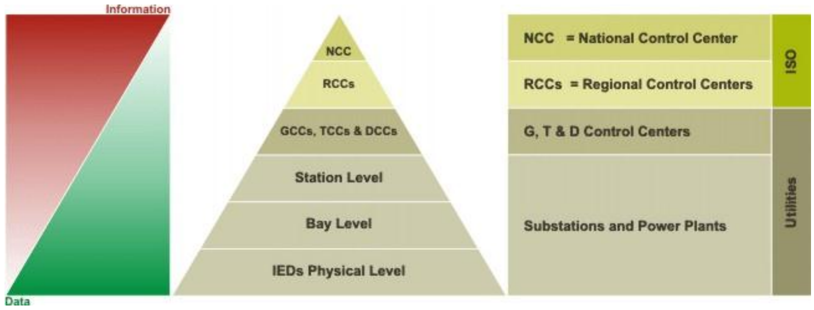


Figure 2 – Data and Information Relative Requirements

2.2 Application of Synchrophasor Measurement and Asset Management Systems

Besides conventional data sources, Asset Management Systems and Synchrophasor Measurement Systems are getting more and more interest in Brazil. Asset Management Systems (AMS) are considered as related to the utilities, but its dissemination is still small within the National Interconnected Power System. Synchrophasor Measurement Systems (SMS) are focused by the Brazilian Independent System Operator (ISO) and utilities, as described below.

The interest on synchronized measurement in Brazil emerged in the 1990s due to the difficulty to assess the system dynamic performance during wide-area disturbances, but only in 2000, the ISO started the effort to deploy a large-scale SMS for the National Interconnected Power System (NIPS). The main motivation for deploying such synchrophasor system is to increase NIPS' reliability and operating efficiency by using this technology for dynamic disturbance recording, real-time monitoring and state estimation enhancement.

The system may also be used for other applications in the future, such as wide-area control and protection, once sufficient experience is gained. The Brazilian SMS deployment plan consists of three main stages: a top-down system design approach, a strict equipment certification test process and a phased deployment plan.

The system specification was concluded and eight selected phasor measurement units were submitted to tests, aiming at certification to be applied in the Brazilian synchrophasor measurement systems. As all tested phasor measurement units were not able to be certified (according to the IEEE C37.118-2005 standard), the vendors are expected to improve their devices and retest them. Phasor measurement units' certification is needed to ensure a globally consistent synchrophasor measurement system performance and is a fundamental stage to allow starting the deployment of such system in Brazil [5].

Another important Synchrophasor Measurement System initiative in Brazil came from the Santa Catarina Federal University (UFSC). The project started in 2001 as a research carried out jointly by UFSC and a Brazilian utility. In 2003, the project got financial support from the Brazilian government which allowed the deployment of a prototype synchrophasor measurement system. This first system measures the distribution low voltage in nine university's laboratories, communicating with a phasor data concentrator at UFSC over the public Internet. This system allowed the recording of national interconnected power system dynamic performance during the latest power system major disturbances. Currently, another project from UFSC have installed Phasor Measurement Units (PMUs) on three 500 kV substations in the South of Brazil [6].

From this early experience with SMS, it is expected that a huge amount of synchrophasor data will be generated and transmitted to the upper hierarchical levels. How this data will be processed and integrated to the Energy Management System application has been a concern, addressed during the system specification development. The ongoing revision of IEEE C37.118, will include synchrophasor data transmission using IEC 61850 protocol and is expected to facilitate the integration of Synchrophasor Measurement Systems with other protection, automation and control systems and applications.

The present expectations on Asset Management Systems (AMS) are that utilities shall transform their data into information and be responsible for taking care of the respective assets accordingly. A utility shall use AMS information to more effectively justify that the asset must be out of service for any kind of maintenance and to decide when it shall be replaced, if so, bearing in mind the regulation on this matter.

Despite the Brazilian Synchrophasor Measurement System initial application being restricted to disturbance analysis and input for state estimators by independent system operator, time will show that SMS will ease the application of Wide Area Monitoring, Protection and Control Schemes (WAMPACS) and will allow component protection systems and system integrity protection schemes to enhance their adaptive features. Then more information and commands will flow downward.

2.3 Transforming Data into Information

Data or information (D/I) shall be established according to their traditional features and application requirements: necessity, resolution, accuracy, latency, processing time, time synchronization, etc. [7]. The transformation of data into information must be performed in a simple and reliable way. The station environment provided by IEC 61850 standard is particularly adequate for this task.

From Figures 1 and 2, one may identify how the macro-functions shall interact with the power system states and then infer what, why, where, which, (by) whom and how much D/I shall be handled. Table 2 is a rough proposition to be debated to provide feedback for the Working Group that will be created within Brazilian CIGRÉ SC B5:

Table 2 – Power System in Normal State

Macro Functions →	SSSS	SCS SAS	RMS	EQMS AMS	SMS	CPS+SIPS	DRS	ARS
National Control Center								
Regional Control Centers		⇓⇑			⇓⇑	**Adaptive Features**		
G/T/D CCs	⇑		⇑		⇔			
Station Level				⇑		⇓		
Bay Level								
IED Physical Level		Measurement Uniqueness				Idem		Idem
DIS Hierarchy ↑ / **Macro Function States →**	**Active**		**Monitoring & Measuring**			Stand by		

Legend:

- G/T/D CCs – Generation, transmission and distribution utilities' control centers;
- SCADA – Supervisory, Control and Data Acquisition system;
- EMS – Energy Management System;
- SCS – Supervision and Control System (SCADA+EMS);
- SAS – Substation/Power Plant Automation System;
- SSSS – Site Security and Surveillance System;
- RMS – Revenue Measuring Systems;
- EQMS – Energy Quality Monitoring System;
- AMS – Asset Monitoring System;
- SMS – Synchrophasor Measurement System;
- CPS – Component Protection System;
- SIPS – System Integrity Protection Scheme;
- DRS – Disturbance Recording and Analyzing System;
- ARS – Automatic Restoring System.

Table 2 clearly depicts that macro-functions related to power system steady state shall share the same D/I and those related to temporary power system conditions shall share another set of the same D/I, while the output of digital instrument transformers is under fine tuning to match IEC 61850 station environment [8].

SCS, SAS, RMS, EQMS, AMS and ARS shall share the same analog quantities since the lowest level in which they coexist. Presently, there have been many cases stemming from different Brazilian electric energy industry segments that are users of mainly RMS, EQMS and asset management systems, in which the same quantity is registered with different results. Monitoring voltage limits is a good example: Independent System Operator SCS, the SASs of small transmission utility and electric energy trade chamber RMS historic subsystems are likely to show three different voltage values for the same time-tag.

If a Synchrophasor Measurement System is available, because of its best accuracy in measuring frequency, voltage and current, its output would be the best option to be sent up as information and to input them in the other systems quoted in this paragraph. Defining the bay status since the IED physical level and using such kind of information at station level for checks will relief the processing systems of higher hierarchy.

Possibly an RMS in Brazil will benefit a lot from CIGRÉ WG B5.41 – Investigation of possibilities to improve metering systems for billing purposes in substations.

Reinforcing DIS advantages, SCS, SAS, Asset Management Systems and Synchrophasor Measurement Systems will more easily allow CPS and SIPS to be granted with sophisticated adaptive features. This means that information with very high added value will flow downward even to bay level. Such a perspective shall allow SIPS to benefit from being armed by more specific power system conditions, to have more numerous and more tuned triggering possibilities and even to be reconfigured, as exemplified by Table 3:

Table 3 – SIPS' Hypothetical Arming and Triggering Conditions

<table>
<tr><th rowspan="2"></th><th colspan="2">ARMING CONDITIONS</th><th colspan="2" rowspan="2">ARM AS</th></tr>
<tr><th>STATUS</th><th>MEASUREMENTS</th></tr>
<tr><td rowspan="6">SIPS # X</td><td>TLs Branca-Azul & Branca-Verde In Service</td><td rowspan="3">0.8 (Branca-Azul) + 0.6(Branca-Verde) + (Branca Gen.) > 1,800MW
AND
(Verde SE Voltage) < 0.95 pu</td><td colspan="2">#1 TRIGGERING & ACTIONS</td></tr>
<tr><td>SVC at Verde SE In Service</td><td rowspan="2">#1 Trigger Conditions</td><td rowspan="2">#1 Actions</td></tr>
<tr><td>Branca Power Plant With 5 Generators In Service</td></tr>
<tr><td>TLs Branca-Azul & Branca-Verde In Service</td><td rowspan="3">(Branca-Azul) + 0.9(Branca-Verde) + (Branca Gen.) > 1,200MW
AND
(Verde SE Voltage) < 0.9 pu</td><td colspan="2">#2 TRIGGERING & ACTIONS</td></tr>
<tr><td>SVC at Verde SE Out of Service</td><td rowspan="2">#2 Trigger Conditions</td><td rowspan="2">#2 Actions</td></tr>
<tr><td>Branca Power Plant With 3 Generators In Service</td></tr>
</table>

The authors suggest that data transformation into information means shall be named "Information Creating Box" (ICB). An ICB does not have to be standard neither for all hierarchical levels nor for all information kinds. ICBs shall be implemented according to the information quality requirements by the simplest and fastest way, which implies in smaller costs. Data and information consistency checks may take place at different hierarchical levels.

Such a proposition is meant to allow the Independent System Operator, electric energy trade chamber and utilities to implement their ICBs freely, but in a fashion that assures that transit and checks between two or more hierarchical levels may take place without any difficulties. Thus DIS and ICBs will be drivers to foster wider and faster adoption of IEC 61850 in Brazil. And so, ICBs inside DIS shall provide inputs for all kinds of algorithms and software required for dealing with the classical conditions shown on Figure 1.

Digital and analog (D/A) data sets shall be transformed into information to cope with present and future requirements for distributed control. The same applies to data and information sets required to create information with higher and higher added value.

Regardless of producing information by means of logic equations, by the use of algebraic operators or through sophisticated algorithms, the philosophy behind ICB will be clearly defined. This is the point in which the Independent System Operator, electric energy trade chamber and utilities shall start enlarging their cooperative work. So, which data set is needed to produce a certain class of information shall be previously defined. The same applies to information classes that depend not only on data sets, but other information as well. The task will start by broadcasting a questionnaire, so the Independent System Operator, electric energy trade chamber and utilities shall evaluate what their present practices are, their progress on the use of IEC 61850, etc.

At least in the Brazilian SC B5 guide about DIS and probably through a more formal work leaded by the Independent System Operator, a number of ICBs will be analyzed and classified according to their pros and cons.

At IED physical layer, programmable logics and algebraic operators are already available for transforming data into information. All the possible checks shall be performed at this very level.

At station level, programmable logics and algebraic operators are also available and it will be likely to occur that the ICB for certain information shall require data and other information from the same or different levels. If required by each case, data and information coming from bay level shall be checked and all possible checks shall be performed with the new information. What would be faster, less expensive, more reliable, etc.: shall ICBs use logical blocks and algebraic operators or a local state estimator? Hopefully this issue shall be debated from now on.

Thanks to IEC 61850 inter-station features, it will be possible to perform more checks and to create new and more reliable ICBs. The information added values and their costs shall be compared to the same ones required for implementing the respective ICBs at the next higher level.

The goal (dream?) is providing all utilities control centers with top quality D/I, allowing that SCADA & EMS do not depend on network configurators, topological state estimators and – why not? – state estimators! Once dreaming is inexpensive, a dynamic state estimator at the Independent System Operator regional control centers, which are the larger info users, would be most welcome. Anyhow, dreaming or not, D/I shall be properly provided to all control centers. Generation, transmission and distribution utilities' control centers shall effectively intercommunicate and be provided by all D/I required for the use of their full capabilities and duties.

About the Independent System Operator national and regional control centers there are good news: their Supervision and Control Systems (SCS=SCADA+EMS) are about to become a real net. Practically all utilities modernized their SCSs, so the three higher hierarchical levels demand the best possible D/I from the lower levels. In this sense, D/I shall be organized according to the main groups of macro-functions.

2.4 Data and Information (D/I) Consistency and Coherence

Within data and information structure (DIS) context, these words shall be understood as:

- <u>Consistency</u> is related to use data or information sets only after they have been checked and then have the same level of quality – the <u>required quality level</u> for the specific application;
- <u>Coherence</u> is related to the application of the <u>same data or information</u> for all functions, for operator display and public broadcasting.

Here again logical blocks and algebraic operators or a local state estimator shall be considered as tools for consistency checks which shall be part of the information creation box input (ICB), so D/I may be handled as they flow upward along the operational hierarchy. For example, active power values measured in the bays linked by any busbar configuration may be algebraically added and considered valid if the result is less than a previously established threshold. The threshold value definition will be a consequence of the accuracy of equipment, devices and systems in service to treat active power measurements at the station level.

Coherence tests shall be part of the ICB output, in order to choose the best available information when redundancy occurs. In this case, probably state estimators at station level will be the adequate tool to be applied.

2.5 Redundancy and Security Issues for Data and Information

Redundant data and information (D/I) shall be seen as a blessing, but only the best of each class within its respective hierarchical level of application shall be effectively used. Wherever redundant D/I are inherently available (then at no cost) or the availability is quite cheap, a quality ranking shall be created. This procedure assures that the second D/I in the row will be considered in case of absence of the best one. Probably the easiest way to create quality rankings would be during the consistency and coherence checks. Anyhow, other alternatives shall be analyzed when ICBs are being put forward, bearing in mind the characteristics stated on topic 2.2 above.

For example, everyone feels annoyed when sees a display of a busbar arrangement with four sections, which are interconnected and four different voltage readings are displayed. Sending voltages upwards as mere data from substation level (SL) implies in unnecessary increase of communication traffic and keeping the display of four voltages at all upper levels. Frequently, it is not difficult to choose the best measurement at any possible level, but except for SL, all the choice requires more data, etc. Choosing the most adequate voltage at the substation level, sending it upwards as information is much more rational. So, Supervision and Control Systems, Substation/Power Plant Automation Systems, Revenue Measuring Systems and Energy Quality Monitoring Systems, will not be susceptible to conflictive input data, once they will be receiving the same analog value as coherent and consisted information.

Cyber security features shall follow the basic characteristics specified for the new net of supervisory and control systems (Global Energy Management System) that the Brazilian ISO is providing for its national and regional control centers [4]:

- Firewalls, intrusion prevention systems, tokens and security monitoring;
- Preparation under demand of vaccines against specific virus;
- Anti-virus, anti-spam and uniform resource locator (URL) filter supported by cyber security experts.

Cyber security concerns are neither uniformly known nor equally practiced by all hierarchical levels and utilities, so these features shall be weighted and emphasized as per the following items:

- Security management control;
- Program for increasing conscience of personnel with access to critical assets;
- Networks shall be segmented at control center levels;
- Perimeter electronic security:
  - Traffic control by Firewalls and intrusion prevention systems,
  - Authentication and authorization control;
- Personnel access control (physical security);
- Digital system management control:
  - Hardening,
  - Security updates,
  - Protection and combat systems against malicious codes,
  - Auditing,
  - Invasion periodical testing;
- Incident response plan;
- Critical asset recovery plan.

2.6 Sharing Data and Information (D/I)

All devices and systems along the operational hierarchy shall be suitable for dealing with both data and information.

Transforming data into information at any level below the Independent System Operator regional control centers will indeed bring back the discussion on the disadvantages (dangers?) of sending calculated values to the Independent System Operator regional centers. This issue is part of a more updated and future proof way of dealing with protection, automation and control all along the operational hierarchy: the protection, automation, control and communication specialists shall work so closely in the near future, that their technical profiles shall become much more similar than today. Presently there still is nearly a technical abyss between specialists on the station and below levels and the specialists on control centers. This is the natural consequence of being impossible to apply computing facilities at the harsh station level electromagnetic interference environment of, say thirty years ago, while the control centers of those times were being granted with more and more processing capacity.

Brazilian Independent System Operator is giving a nice example by creating a net among all its control centers, so most of the propositions of this paper will be spontaneously accomplished. Such an example will ease establishing what D/I shall be exchanged among stations and utilities' control centers, in terms of technical concerns. IEC 61850 is expected to guide its users to enhance the use of more compatible technical solutions among all Brazilian electric energy industry segments.

From now on, protection, automation and control shall be understood as the common infrastructure for establishing trade and competition within a secure environment. This paper was written precisely to stimulate the enlargement of cooperative work and D/I sharing for the benefit of all Brazilian electric energy industry segments. Competition will not be restricted; on the contrary, it will take place without endangering national interconnected power system electrical security.

2.7 Selection of Data or Information (D/I) According to the Application

Topic 2.2 (Table 2) states that at least two categories of D/I will coexist for some time: those related to the power system operation and steady state measurement systems and those related to component protection and power system integrity. Synchrophasor Measurement Systems probably will belong to both categories, once they are very accurate and time synchronized with great precision, thus being useful for various kinds of applications.

Data and information management facilities will play a very important role on this matter. Data and Information Structure (DIS) implementation is not expected to pose new parameter management problems when information is created at the lowest possible hierarchical level and sent upwards. On the other hand, remote parameterization of component protection systems and system integrity protection schemes requires a lot of care. The implementation of adaptive features to those macro-functions will be an even more complex task.

D/I selection shall be performed in a way that does not raise too many discussions among the different kinds of today's specialists. The natural way for selecting D/I stems from the duties of station up to national control center levels. These duties are clearly defined by official documents, such as Grid Procedures, that exist under the Regulating Agency strict supervision and are pretty stable on the definition of duties for all Brazilian electric energy industry segments.

Blending the lawful duties with technical and economical expertise, D/I selection may be focused on each application requirements. The concern here is the same for all DIS implementation: when the real work shall start? Brazilian SC B5 DIS WG will produce a guide on the subject and then… what to do? An attractive option would be studying the most important multi-utility SIPS to determine what, why, where, which, (by) whom and how much they shall evolve.

3 STRUCTURE ANALYSIS UNDER IEC 61850 VIEWPOINT

The standard IEC 61850 (Communication Networks and Systems for Power Utility Automation) has already proved its capability to extensively model almost every conceivable need of substation automation systems. This range is being expanded to many automation areas like condition monitoring, functional testing, etc., after being successfully extended to hydro power, wind power, and distributed energy resources [9]. The use of this standard allows the full implementation of the concepts of Model Based Automation (MBA), as shown on Figure 3:

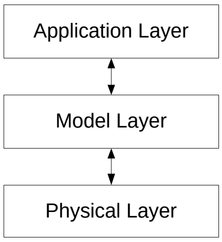


Figure 3 – Model Based Automation Architecture

In this architecture, an automation solution is divided in three layers: the physical layer, at the controlled process, where electrical automation signals are collected or injected on the primary process equipment; the model layer, where standard software blocks mirror the behavior of all equipment from the physical layer, while serving as a gateway to and from upper layers; and the upper application layer, where again standard blocks of data and software implement the desired automation and protection functions.

This MBA architecture, with its model layer and standard building blocks, allows the complete abstraction of the application layer from the physical aspects of the controlled process. This feature offers many advantages over conventional hardware-oriented automation systems, making possible the implementation of location-free and multi-supplier interoperable solutions.

3.1 Matching the Structure to the Present Version of IEC 61850

IEC 61850 supports the implementation of MBA architecture for automation systems by using standardized blocks of data and software classes known as Logical Nodes. At the Model Layer, specific Logical Nodes are available to model almost all common electromechanical equipment used in power systems like circuit breakers (XCBR), current transformers (TCTR), power transformers (YPTR), etc. Using these modules it is possible to build a complete model of the primary controlled process, in substations or power plants, so that all automation and protection functions can be deployed using real-time data conveyed by these models. As depicted in Figure 4, the models are used to convey information to and from the Physical Layer, while receiving and transmitting data to the upper Application Layer.

As far as data is concerned, a Logical Node can be seen as a software class, with structured data for Settings, Controls, Measured and Status information about a specific modeled behavior. This view is shown in Figure 4, as a UML package diagram for a Logical Node:

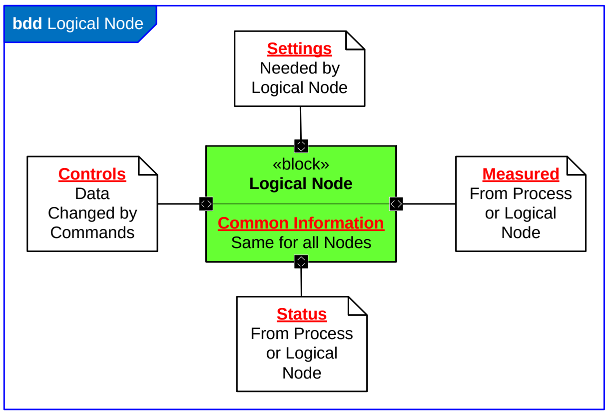


Figure 4 – Logical Node Structured Data

Settings and Control data allow commands and behavior to be defined from an upper application layer to select a desired behavior from the LN or its modeled process. Measured and status data allow monitored data to be collected and exchanged among logical nodes on the same layer or to and from upper layers. Logical Nodes defined on IEC 61850 are also used at the application layer to build automation, protection and monitoring functions. All major functions typically found on substation and power system automation can be built using specialized Logical Nodes, like the differential protection (PDIF), human machine interface (IHMI), etc.

An input-output view of a Logical Node and its connection to a controlled process and other LN can be depicted as a package of four building blocks, as shown in Figure 5. These blocks unveil the possible roles a LN can play in an automation system, in conveying input-output data among other LN, while serving as a communication channel to the controlled process and other automation layers for settings, controls, measured and status data.

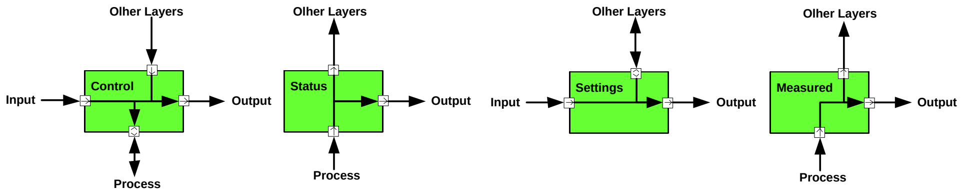


Figure 5 – Logical Node Input-Output Functions

3.2 What is missing in IEC 61850 to assure the Structure Full Implementation

Although conceptually correct and almost universally accepted nowadays as the logical evolution of all power system automation, IEC 61850 has faced several difficulties to its full application. The first relates to its huge size, in trying to cover all possible automation needs. This makes it difficult to digest from a first reading, mainly from practicing field engineers. Many optional aspects of the standard have caused misinterpretation from different suppliers and integrators, resulting in loss of interoperability, the main focus of the standard. Lack of a digital version makes also difficult to maintain the standard, and its uniform and interoperable implementation from tool makers. These difficulties are currently being addressed by IEC TC57, so they are expected to be solved in a near future with a fully digital version of the standard.

The full integration of IEC 61850 in a system-wide hierarchical data structure, covering the full range of automation applications in power systems, from bay and process level at substations, to inter substations, inter-area and wide-area applications like Synchrophasor Measurement Systems and System Integrity Protection Schemes (SIPS) needs further development to assure harmonization with existing SCADA standards like CIM (Common Information Model) and other power system protocols.

4 PRACTICAL EXAMPLE – SIPS

In fact, the acronym SIPS (System Integrity Protection Scheme) is not yet used in Brazil for mere conservative reasons. The acronym SPS (Special Protection Scheme) remains as the preferred one. In this example SPS will be used for the brief description of what is in service. Later on SIPS will be the acronym applied to mean the future, for instance, the inclusion of Synchrophasor Measurement Systems, Asset Management Systems and, of course, the application and information structure.

4.1 Sample SPS Outlook

The most important SPS in the country was chosen for this example: the one related to 765 kV South-Southeast Interconnection, which has a remarkably good performance record. It has been referred to in many seminars and in Protection, Automation and Control World Magazine [10]. Besides the Independent System Operator there are three utilities directly involved with this scheme: Itaipu Binacional, Furnas and Eletrosul.

The scheme is based upon Remote Terminal Units (RTUs) and the communication media available by the time of its energization – mid nineties. The RTUs were upgraded to cope with protection electromagnetic interference requirements – they must not only withstand electromagnetic transients, but they must also keep on processing, sending and receiving data. The hardware and software date from mid nineties and they are about to be replaced by up-to-date equipment.

The 765 kV South-Southeast Interconnection is responsible for transporting the electric energy produced at Itaipu 60 Hz plant (7,000 MW). The energy produced at Itaipu 50 Hz plant (7,000 MW) minus the energy demanded by Paraguay is transported by a ±600 kV high voltage direct current (HVDC) link. Paraguay became the largest electric energy exporter in the Americas, thus the major part of Itaipu 50 Hz generation flows to Brazil. Both the 765 kV and the HVDC link head to the same Brazilian geo-electric region: the largest load in the country – São Paulo metropolitan area.

This SPS aims to identify transmission component losses and/or transformer overloads in order to guarantee compatibility between Itaipu generation and transmission capacity immediately after disturbances along the 765 kV transmission corridor, which is described in Figure 6:

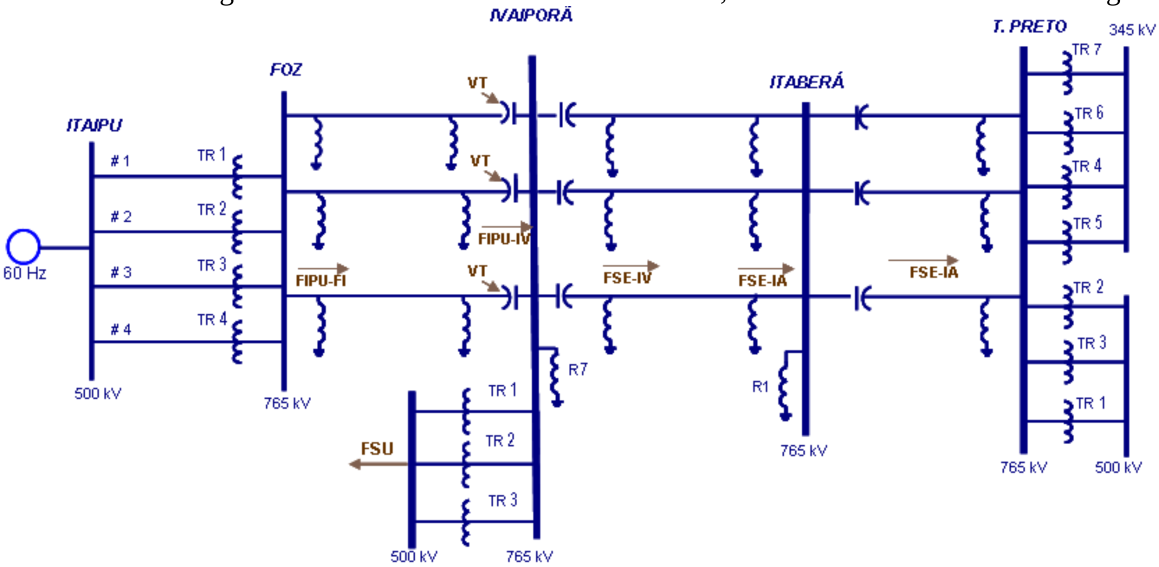


Figure 6 – S-SE 765 kV Interconnection

There are RTUs at Foz, Ivaiporã, Itaberá and T. Preto substations to collect data and send them to Itaipu 60 Hz Hydro Plant (7,000 MW), where there are two RTUs to handle local and remote data, to process data and to take the decision on sending the triggering orders according to the 765 kV corridor hazardous conditions. According to the topology of the corridor shown on Figure 6, the power flows (FIPU-FI, FIPU-IV, FSU, FSE-IV and FSE-IA), the voltage at the line side of the Ivaiporã series capacitors (VT) and the number of generators in service, generation shedding at Itaipu takes place tripping 1 to 4 generating units.

The dual RTUs installed at Itaipu are also programmed to perform a permanent interchange among the generators in service to select the four units to be tripped. Human intervention to exclude any generator from the shedding list is easily possible. The SPS operating time is around 200 ms, which is suitable for present National Interconnected Power System (NIPS) stability requirements. To achieve this operating time, the RTUs at the substations gather binary and analog data and send them to the dual RTUs installed at Itaipu, where all the processing is performed. The same binary and analog data are gathered by other devices to be sent to the substation level and above.

Depending on NIPS operation conditions and on the amount of shed generation at Itaipu 60 Hz plant, the HVDC link raises its power order according to the capability of Itaipu 50 Hz machines in increasing their generation. If the maximum power that the HVDC link is not enough, there are five stages of under-frequency based load shedding.

Table 4 summarizes how seventeen special protection main sub schemes operate:

Table 4 – Special Protection Main Sub Schemes

Emergency Conditions		Actions
1	Foz autotransformers overload	1 or 2 generator shedding
2	Loss of 1 line Itaberá-T.Preto	1 up to 3 generator shedding
3	Loss of 1 line Ivaiporã-Itaberá	1 up to 3 generator shedding
4	⇓ Full load rejection at T.Preto ⇓	Tripping of 3 lines Itaberá-T.Preto
5	$\Delta f/\Delta t$ > reference at Itaipu	Tripping of 3 lines Foz-Ivaiporã
6	Loss of one line Foz-Ivaiporã	1 or 2 generator shedding
7	Ivaiporã autotransformers overload	1 up to 3 generator shedding
8	Loss of 3 lines Foz-Ivaiporã	Tripping all lines Itaipu-Foz & all Itaipu 500 kV breakers
9	Loss of 3 lines Ivaiporã- Itaberá or Itaberá-T.Preto	Generator shedding as needed to keep power flow to South
10	T.Preto autotransformers overload	1 up to 3 generator shedding & tripping 1 or 2 lines between T.Preto and loads

Emergency Conditions		Actions
11	VT < reference	Tripping of 330 MVAR reactor at Ivaiporã
12	Maximum excitation at Itaipu generators, FIPU-FOZ > reference, VT < reference or Ivaiporã remote terminal unit out of service	1 generator shedding
13	Loss of two series lines (same breaker and a half bay) between Ivaiporã and T.Preto or loss of line #2 Itaberá-T.Preto and T.Preto autotransformer #4	1 up to 3 generator shedding
14	Loss of two series lines (same breaker and a half bay) Foz-Itaberá	1 up to 3 generator shedding
15	Loss of two parallel lines Ivaiporã-Itaberá or Itaberá-T.Preto	1 up to 4 generator shedding
16	Loss of one autotransformer at Ivaiuporã	1 generator shedding
17	Loss of 500 kV S-SE interconnection (2 lines)	1 up to 3 generator shedding

4.2 Inclusion of Synchrophasor Measurement Systems and Asset Management Systems

A synchrophasor based System Integrity Protection Scheme (SIPS) will be strongly dependent on the Synchrophasor Measurement Systems (SMS) architecture. The system architecture will define the data latency over the network. Depending on the achievable data latency some protection and control functions might not be applied. It is possible, although probably more costly, to use an independent synchrophasor architecture for the protection and control applications, but this solution also includes some latency to the whole system performance. So, it is estimated that only SIPS with response times ranging from 200 to 500ms will be viable through synchrophasor measurement systems.

In the beginning, SMS probably will be used in SIPS for arming functions, like today Supervisory, Control and Data Acquisition system's measurements have been used abroad. Considering the better accuracy of SMS, some gains might be obtained for heavy loaded transmission corridors, allowing the transfer of more power without direct impact on system reliability. Anyway, SMS will improve the adequacy of model for simulations and accurate determination of the power system real limits; so, it may be possible to identify extra gains for SIPS application.

A Synchrophasor Measurement System is best used when it covers the whole operational hierarchy with bidirectional information flow, as shown in Table 2.

The Asset Management Systems (AMS) application in Brazil is a decision of the utilities, because Brazilian electric energy industry model was conceived in a way that utilities are free to take care of their assets. In case of asset failures that endanger local, regional or system wide energy or electric operation, severe fines are applied to the asset owner. Table 2 classifies AMS in the same category of Energy Quality Measurement Systems: their outputs do not reach the Independent System Operator Regional Control Centers (RCCs). At the utilities' control center level, the proposed data and information structure shall offer means for producing information that will flow upwards to RCCs through SCADA. The scheme presented above would benefit by receiving information on the recent thermal performance of the autotransformers, then allowing them to withstand larger overloads, working as a self-adaptive scheme.

4.3 SIPS' Evolution Requirements to Get Full Benefit of the Proposed Data and Information Structure

Reference [11] proposes that System Integrity Protection Scheme SIPS requirements, specifications, design, etc. shall be done in order to get maximum benefits from IEC 61850 standard and Wide Area Monitoring, Protection and Control Schemes (WAMPACS) to reach the Global SIPS concept [12] highlighted below. Table 3 depicts a general example of a SIPS that may perform two distinct sets of actions (triggering thresholds and tripping, etc.) according to two different arming conditions (power system conditions). Both arming conditions and sets of actions shall be easily parameterized, preferably by remote human machine interfaces, to cope with seasonal or scheduling particular operation conditions.

Even under the Global SIPS concept, it is clear that reconfiguration by automatic change of sets of actions is more restricted than the parameterization change. To deal with Global SIPS is a complete engineering task, encompassing planning, specification, designing, commissioning, maintenance, etc. This way of working will be quite a change in Brazil, concerning power system simulations, which will have to be done as per the usual chronology, but linked to engineering typical activities and milestones:

- Long-term simulations will allow SIPS' conception (sketching and outlining) under protection, automation and control engineering viewpoint (1), defining:
    - SIPS' basic actions,
    - Desirable reconfiguration possibilities,
    - Desirable re-parameterization possibilities,
    - SIPS' design planning;
- Mid-term simulations will define:
    - All SIPS' sets of actions (triggering thresholds and tripping, etc.) and parameterizations,
    - The sets of actions that may be remotely reconfigured and the necessary hardware, software, secondary system and the resources at the higher hierarchical levels to accomplish such reconfiguration,
    - Same as above for remote re-parameterization,
    - Coordination requirements among all SIPS covered by the global concept and other "stand alone" SIPS,
    - SIPS' specification and design and, later on,
    - SIPS' commissioning and testing;
- Short-term simulations, will define:
    - If the coordination needed by expected power system operation conditions among all SIPS are fully achieved by the available reconfiguration re-parameterization facilities,
    - SIPS' configurations that best suit the expected power system operation conditions (2),
    - Changes or enhancements in SIPS' parameterization to cope with the expected power system operation conditions;
- Scheduling simulations, will define:
    - SIPS' remote parameterization changes to cope with daily expected power system operation conditions.

(1) SIPS based on IEC 61850 standard shall be designed bearing in mind that test facilities are a must [12]. The test facilities shall allow the widest possible range of checks along the whole chain of SIPS shared or exclusive systems, devices and primary equipment.

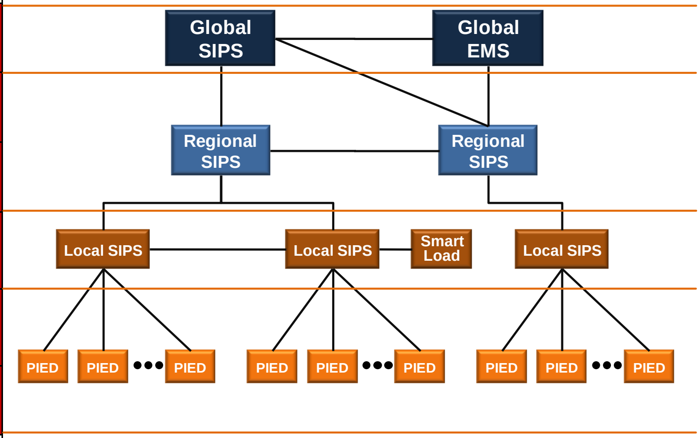
(2) If an exceptional configuration not covered by SIPS' automatic means or a specific configuration to cope with some temporary special conditions are necessary, short-term simulations will "trigger" the personnel responsible for implementing the necessary changes.

Lots of previous work will be required to achieve the Global SIPS and the associated Global EMS concepts – please see Figure 7 below. Within the plethora of activities encompassed under the huge effort necessary to accomplish such an advance, the communication systems shall be treated as priority #1. Once national interconnected power system is under fast expansion, the new transmission lines are installed with optical and other communication means, a significant part of enhancing communication systems is already undergone.

4.4 Application of the Proposed Data and Information Structure (DIS)

System integrity protection schemes (SIPS) shall be conceived and implemented in Brazil in a way to achieve the global concept [12] highlighted in Figure 7, which mixes such a concept with the envisaged DIS shown on Table 2 under a large disturbance condition:

Macro Functions →	SCS	SAS	SMS	CPS	SIPS
NCC	⇓		⇓		⇓
RCCs	⇓⇑ ⇔		⇑⇓ ⇔		⇓⇑ ⇔
G/T/D CCs	⇓⇑ ⇔		⇓⇑ ⇔		⇓⇑ ⇔
Station Level	⇓⇑ ⇔	⇓⇑ ⇔	⇓⇑ ⇔	⇔	⇓⇑ ⇔
BayLevel	⇓⇑ ⇔	⇓⇑ ⇔	⇓⇑ ⇔	⇓⇑ ⇔	⇓⇑ ⇔
IED Ph. Level	⇑	⇑	⇑	⇓⇑	⇓
DIS Hierarchy ↑ / Macro Functions' State →	Active				



Legend:
- NCC – National Control Center;
- RCCs – Regional Control Centers;
- G/T/D CCs – Generation, Transmission and Distribution utilities' control centers;
- SCADA – Supervisory, Control and Cata Acquisition system;
- EMS – Energy management system;
- SCS – Supervision and Control System (SCADA+EMS);
- SAS – Substation/Power Plant Automation System;
- SMS – Synchrophasor Measurement System;
- CPS – Component Protection System;
- SIPS – System Integrity Protection Scheme;
- PIED – Protection Intelligent Electronic Device.

Figure 7 – DIS in Disturbance Conditions Applied to the Simplified Diagram of a Global SIPS

A hierarchical SIPS philosophy and the data and information structure proposed in this article, which is also hierarchical, will suit each other quite well, **if** adequate planning is previously made for both. This mutually beneficial implementation will take place easier by the comprehensive application of the IEC 61850 standard intra and inter substations and power plants, as well as upwards to the control centers. IEC 61850 Edition 2, encompassing wider use of the standard, is being finalized [13]. There is also a Brazilian CIGRÉ SC B5 initiative to give the first steps on hierarchical SIPS implementation [11].

The full implementation of the proposed data and information structure to the SPS related to 765 kV South-Southeast Interconnection depends on the substitution of the RTUs, which are at the end of their life-cycle, by other devices and systems compliant with IEC 61850. The criteria and ideas described in [11] shall be taken into account when upgrading this scheme, as well as to all other important schemes in national interconnected system.

For the moment, the great benefit brought by the proposed data and information structure (DIS) would be providing data coherence between the scheme and the other supervision and control functions from the substation level up to national control center level. In a glance, applying DIS to the sample SPS would provide remote information such as:

- Bay and busbar status;
- Analysis of discrepancy in switch secondary contacts, defining bay and busbar status by giving privilege to SIPS security or dependability as previously defined;

- Same analog quantities as those used for supervision and control, substation automation, revenue measurement, asset management and automatic restoring systems, avoiding discussions on eventual reading or logging differences;
- Application of component protection tripping signal instead of waiting for the operation of circuit breakers.

By the mere improvement of communication systems between substation (or power plant) and control centers, more benefits could be added with ease:

- Bringing down the information made available at the control centers by DIS, for instance, topology, voltage and frequency of strategic substations and power plants located elsewhere within south and south-east systems;
- Implementation of a Synchrophasor Measurement System with the adequate architecture to provide voltage and frequency control, angular and voltage stability information from south or south-east systems, as well as from national interconnected system as a whole;
- The kind of information quoted above plus those stemming from Asset Management Systems, as they go being put into service by the utilities, will improve arming capabilities and perhaps allow the introduction of adaptive features.

Deeper improvements would be enhancing the arming concept to allow reconfiguration, the perspective of reducing the dependence on conventional out-of-step tripping functions, reduction of generation at Itaipu 60 Hz, instead of tripping generating units, etc. In fact, DIS application will benefit from the adoption of IEC 61850 standard, so mixing DIS philosophy with the standard full capabilities much better results will be achieved.

5 CONCLUSION

This paper presented the philosophy behind a Data and Information Structure (DIS) for power system protection, automation, control and real-time operation aiming to benefit from the IEC 61850 standard full capabilities and to support the future requirements of a multi-layer hierarchical country-wide power system control structure. DIS will provide the creation of high added value information from the lowest possible level of the operational hierarchy, alleviating communication media and offering better flexibility for implementing protection, automation and control macro-functions, thus improving their performances. Once technological evolutions do not take place at the same time in a power system, deciding the most appropriate moment to start DIS implementation is effectively a tricky concern.

Brazilian CIGRÉ SC B5 – Protection and Automation will create Working Groups to produce guides on:

- DIS philosophy and envisaged requirements;
- Hierarchical SIPS implementation.

The expectation is to present the Working Group deliverables at 44th CIGRÉ Paris Session in August 2012.

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