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# Substation and Control Centers



## matching modern substations and control centers

### Before going back in time – briefly

When SCADA systems started to be implemented in Control Centers, most of the substations were protected and controlled by electromechanical devices and some substations had static (electronic) devices. This meant that all substation secondary systems were based on one kind of analogue technology. Except for remote measurements, that required one transducer for each specific quantity (f, V, I, P and Q), these devices were only able to communicate data by plain binary means: electrical contacts. The word then was data! What else could substation protection and control devices send up but data? Raw data only!

By that time, it was common that substation and control center operators had different readings for the same electrical quantity, because of the use of distinct transducers, sometimes with different accuracy classes. What to say about energy and power demand measurements for billing purposes? In Brazil, and probably all around the world, they still remain without any direct relation with f, V, I, P and Q measurements used by the operators.

Another typical condition of those days was that SCADA systems had to pick up their data (measurements and status of breakers and switches) within existing substations, which should be minimally “disturbed” by the introduction of extra transducers and auxiliary relays to cope with the SCADA needs. These transducers and auxiliary relays had to be wired to existing devices and to the remote terminal unit (RTU), so minimal “disturbance” meant minimum wiring. Even with all possible care, many accidental trips occurred, as usual when dealing with substations in service.

*Could logic checks, at least, be done at the substation level?* Of course, yes. But such logic checks demanded more wiring, which imposed more accidental tripping risks, so they were not even considered. On the other hand, logic checks could be implemented in new substations without risks of accidental tripping, *but why should they be implemented?* Control centers had processing capacity, control centers demanded all data, and control centers could do more through SCADA systems! In fact, SCADA systems quickly evolved with new and fascinating facilities: one of them was the state estimator,

required by the unavailability of RTUs in all substations. The absence of local logic tests led the state estimators to be complemented by topological estimators. Even though, a plain inconsistency of a switch secondary contacts was enough to impose some complicated problems for the state estimation. It must be bared in mind that busbar static protections could do such kind of check since the sixties. But the devices could not “talk” among themselves and share information, despite some of them already being able to transform raw data into information with great added value.

Sequence of events (SOE) became a must, despite having no time synchronism among substations, the task of analyzing a disturbance was so demanding that any tip was most welcome. Disturbance analysis engineers were (and still are) so skilled that they could time synchronize manually the majority of the available data and transform the whole thing into information that supported a detailed report about the events in the power system.

### Still back in time – more briefly, but under specialists’ view point

The prevalent conditions in substation and control centers were quite clear during the dawn of SCADA systems: no processing capability was available at the substation level and control centers were inherently built with processing capacity and human-machine-interface. Clearly, the two teams of specialists –control center people and substation visionaries – had different problems to cope with. The difference in the immediate needs put the two teams apart. No competition between them, but no common goal, except for the time synchronization among RTUs: a demand of control center specialists to be solved by substation and communication specialists.

This situation is beginning to change because:

- With overall accuracy requirements becoming more stringent, control centers alone will never be capable of dealing completely with the lack or inconsistency of power system data;
- power system protection and control improvement implies in adaptability
- synchrophasor measurement systems are the key for adaptability and they “are born” in substations, but they need a common point (the control center) to be processed and fed back to the protection systems
- wide area control and protection systems promote inherently integrative tasks between the two specialist communities

To sum up, synchrophasor measurement systems and wide area control and protection systems are important and challenging for both substation and control center people. But why should the two communities stick to them, now when substation PAC systems can already be much more useful for control centers?

*The question above shall be rephrased this way: why not start to do deeper use of substation processing capabilities and send no more data to the control centers, but information with great added value? This would leave*

Improving power system control requires a new way of thinking by substation and control center specialists.

the control center processing capability to be used for even more “noble” tasks.

#### It can be done right away

Digital technology evolved so fast that PAC systems are effectively available at the bay and substation levels. Since the implementation of the first coordinated systems, one may say that the word system is properly applied to the substation secondary environment. Nevertheless, there were still limitations concerning intra-substation communication, mainly when products from different vendors had to be integrated in the same PAC system. Any substation planned to be built in more than one stage – the majority – could easily have fair PAC digital systems provided by distinct manufacturers. From the control center viewpoint, there could be many PAC systems provided by as many vendors, once there were substation data concentrators that could handle all the distinct communication protocols out of the RTUs and send to the upper level all the data. Only raw data, because there was no new stimulation for local processing, except for special means. It doesn't mean that the first PAC digital systems were not able to solve a significant share of existing problems, such as time synchronization. They solved it and did more, for instance:

- substation SOE started to be fully associated to voltage and current wave shape recording, both simplifying disturbance analysis and showing many not yet explained issues concerning protection and power system behaviors

- recording devices (subsystems) were available to the monitoring of long term (systemic) disturbances, showing that there was a lot more to be explained about the power grid performance

- decentralized busbar and breaker-failure protection could easily identify the substation configuration by monitoring the switch secondary contact consistency.

Nowadays, there are no more limitations stemming from substation communication, thanks to IEC61850 standard. It allows all vendors to use the same communication protocol while preserving their proprietary algorithms. More than that, IEC61850 imposes a new way of conceiving and

thinking about PAC substation systems with positive consequences over a number of issues. Perhaps the less discussed one would be local data processing to check all substation data (measurements and status), transforming them into information and sending messages with added value to control centers. This necessarily includes SOE and other similar issues.

Comparison of measurements and status data improves the identification of incorrect measurements, providing correct quantities to the control center. In a near future it will be all part of a self-healing process of the PAC system.

Any inconsistency and measurement problem will immediately generate local or remote alarm. The word remotely means not only that the remote operator will be warned, surely, but that the state estimator will acknowledge any problem that could not be solved at the substation level.

The procedures will bring the following benefits:

- less data traffic through the communication channels between substation and control center;

- state estimators would have to deal only with the lack of a whole substation (defective communication or PAC system), which is a low probability occurrence;

- whenever a substation event or measurement could be solved at the local level, the state estimator will be warned;

- same accuracy class for each quantity measurement within a substation (easy to be standardized within all the substations connected to the control center);

- same measurement for all users (local and remote operators, as well as electric energy trading personnel);

- local alarm processing, simplifying SOE traffic and sending to the control center only the information pertinent to its attributions according to the electric industry model;

- all raw data will be stored at local historic repositories and will be available by request from the upper level.

There are practically no technical challenges in achieving the benefits above. A lot more can be done, but a wider integration between substation and control center specialists. A new way of thinking shall be imposed to both groups for the sake of operators and real-time engineers.

#### Biography

**Jorge Miguel Ordacgi Filho** is a Professional Electrical Engineer who graduated from Universidade Federal Fluminense. During his career as a protection engineer (1974 – 1998) with FURNAS Centrais Elétricas, Itaipu Hydro and ELETROBRÁS he worked on settings calculations, analysis, transmission line protection (up to 500 kV) and power plants. He later joined the Brazilian ISO managing the implementation of special protection systems and was involved with Control Center Automation Systems, SCADA, etc. 1975 - 1992 he taught Power System Protection at Universidade Veiga de Almeida in Rio. Jorge is the Brazilian Member of CIGRÉ SC B5 - Protection and Automation.

## 1 IED Panels



## 2 ONS control center

