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University/Company GoalArt	Department
Address Scheelevägen 17, 223 70 Lund	
Project Manager Jan Eric Larsson	
Other project participants Per Andersson	
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Preface

During the last ten years, power grids have been equipped with a new measurement tool, so-called Phasor Measurement Units or Synchrophasors. These units provide measurement data with at least two orders of magnitude higher frequency than previous systems, and enables direct measurement of phase angle deviations. It seems obvious that this data would be integrated in the control room environment immediately. However, during conferences and customer meetings, we have observed that this is not so. The synchrophasor data ends up in the back office and is used for post mortem analyses, while the operators still use the old SCADA data for their on-line monitoring in real-time.

This project was born out of an inspiration to investigate why synchrophasor data is not integrated into SCADA/EMS systems, and to outline how this could be done.

We would like to thank Olof Samuelsson and Morten Hemmingsson from Industrial Electrical Engineering and Automation, at Lund University. They have helped us with basic knowledge about power grids, grid phenomena, synchrophasors, and a lot of practical knowledge about synchrophasor measurements and data. They have also been very inspirational, and it has been a pleasure to work with them.

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Box 310 • 631 04 Eskilstuna • Besöksadress Kungsgatan 43
Telefon 016-544 20 00 • Telefax 016-544 20 99
registrator@energimyndigheten.se
www.energimyndigheten.se
Org.nr 202100-5000

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Summary

The control systems used in today's control rooms are called SCADA/EMS systems. They receive, store, and present real-time data from sub-stations in the grid (SCADA), and use a model to calculate flows in the grid and the effects of the largest potential outages (EMS). These systems handle analog and discrete data with a sampling frequency of a few seconds.

During the last ten years, larger power companies have installed a new technology called phasor measurement units (PMU). Lately, the term synchrophasor has become more popular. These units measure signals in the sub-stations with a sampling frequency of milliseconds. This makes it possible to observe real-time phenomena of new kinds, such as wave forms, rapid oscillations, and real (as opposed to calculated) phase angles. These data in turn, makes it possible to detect and diagnose a whole new class of problems in power grids.

The situation today, concerning synchrophasors, is that operators in the control room still use the SCADA/EMS systems for monitoring in real time. PMU data may be available on screen, but without algorithmic support or integration to other parts of the SCADA system. Larger power grids often have connected synchrophasors, but data from these are not normally used in real time, but mainly

for analysis of fault situations later on, when you try to find out what really happened, (so-called post mortem analysis).

There are several reasons why synchrophasor data are not used in real time in control rooms. Today's SCADA systems are not able to receive, manage, or present data with the amount and frequency provided by synchrophasors. Control room algorithms, methods, and routines are not designed to use synchrophasor data. The consequence is that these data are not used in real time, which would probably be the largest value of the new technology.

In this project, we have investigated the possibilities of making synchrophasor data available to operators in real time, so that these data can be used intelligently, integrated with other real-time systems, and presented in real-time to operators in the control room.

We outline how synchrophasor data can be analyzed by a signature identifier algorithm, which captures aspects of the fast synchrophasor data and turns these into slower SCADA data, which can be fed to the existing SCADA/EMS system.

This makes it possible to create new control room tools, for example, a vulnerability indicator that combines analysis of global phase angle differences with alarm data from out-of-service generators, lines, and equipment, and transformer tap changer positions, a local stability analysis that monitors phase angle differences over single lines, and a swing detector that can perform a root cause analysis on oscillations that propagate through the grid.

We also show how synchrophasor data can capture phenomena that are too quick to be seen in SCADA data, and how these data can be used to provide more correct root cause analysis in real time.

We present synchrophasor data from lightning strikes and show that these data contain much more detailed information that old-style SCADA data, and it is even possible to separate rapid, multiple lightning strikes from each other.

Finally, we propose a new monitoring algorithm, which uses a grid analysis to detect points and regions of congestion, locally and dynamically, and then can use either SCADA data or synchrophasor data, or both in combination, to assess the danger that the congestion poses to the grid, locally and globally.

We believe that a technical solution for integration of synchrophasor data in real time in control rooms is not only valuable for operators. We think it is necessary in order to utilize the installed synchrophasor units as much as possible and to drive the smart grid of the future.

Sammanfattning

De styrsystem som används i dagens kontrollrum för kraftnät kallas för SCADA/EMS. De innehåller dels insamling, lagring och presentation av realtidsdata från stationer i nätet (SCADA), dels en modell med vilken man beräknar bland annat flödena i nätet och inverkan av de största potentiella bortfallen

(EMS). Dessa system hanterar analoga och diskreta data med en samplingsfrekvens runt någon sekund.

Under de senaste tiotals åren har större kraftnät installerat en ny teknologi som kallas phasor measurement units (PMU). Dessa enheter mäter signaler i stationerna med en samplingsfrekvens på någon millisekund. Detta gör det möjligt att studera realtidsfenomen av ett helt nytt slag, bland annat vågformer, snabba svängningar, och verkliga, momentana (i stället för beräknade) fasvinklar. Dessa data gör det möjligt att upptäcka och diagnosticera en helt ny klass av problem i kraftnätet.

Läget i dag, när det gäller PMU-enheter, är att operatörerna i kontrollrummet fortfarande använder de befintliga SCADA/EMS-systemen för driftövervakning i realtid. PMU-data kan finnas på skärm, men då utan stöd av algoritmer eller koppling till andra delar av SCADA-systemet. I större kraftnät finns ofta PMU-enheter inkopplade, men data från dessa används normalt inte i realtid, utan huvudsakligen för analys av felsituationer i efterhand, då man försöker ta reda på vad som egentligen hände, (så kallad post mortem analysis).

Skälen till att PMU-data inte används i kontrollrummet i realtid är flera. Dagens SCADA-system förmår inte ta emot, hantera eller presentera data med den omfattning och med den frekvens som kommer från PMU-enheterna. Kontrollrummets algoritmer, metoder och rutiner är inte gjorda för att använda PMU-data. Följden är att PMU-data inte används i realtid, vilket antagligen vore det största värdet hos den nya tekniken.

I projektet har vi undersökt förutsättningarna för att göra PMU-data tillgängliga för operatörerna i realtid, under samma förutsättningar som för data som i dag kommer via SCADA-systemet.

Vi har beskrivit hur PMU-data kan analyseras av en identifieringsalgoritm, som fångar aspekter hos snabba PMU-data och omvandlar dessa till långsammare SCADA-data, som kan skickas vidare in i det befintliga SCADA/EMS-systemet.

Detta gör det möjligt att skapa nya verktyg i kontrollrummet, till exempel en sårbarhetsindikator som kombinerar analys av globala fasvinkelskillnader med larmdata från stillastående generatorer, bortkopplade ledningar och lindningskopplare nära ändlägen; en lokal stabilitetsanalys som övervakar fasvinklar för enskilda ledningar; samt en svängningsdetektor som kan utföra en rotfelsanalys på svängningar som sprider sig i nätet.

Vi visar också hur PMU-data kan fånga fenomen som är för snabba för att synas i SCADA-data, och hur dessa data kan användas för att tillhandhålla mer korrekt rotfelsanalys i realtid.

Vi presenterar PMU-data från blixtnedslag och visar att dessa data innehåller mycket mer detaljerad information än gammaldags SCADA-data. Det verkar till och med möjligt att separera flera närliggande blixtnedslag från varandra.

Tills sist föreslår vi en ny övervakningsalgoritm, som använder sig av en nätverksanalys för att detektera punkter och regioner med överbelastning, lokalt och dynamiskt, och som sedan kan använda SCADA-data eller PMU-data eller

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bådadera i kombination, för att avgöra hur stor fara överbelastningen utgör för kraftnätet, lokalt och globalt.

Vi tror att en teknisk lösning för integration av PMU-data i realtid i kontrollrummet inte bara vore värdefull för operatörerna. Vi tror att det är en nödvändighet för att få ut det mesta ur installerade PMU-enheter och för att driva framtidens intelligenta elnät.

Introduction

The control systems used in today's control rooms are called SCADA/EMS systems. They receive, store, and present real-time data from sub-stations in the grid (SCADA), and use a model to calculate flows in the grid and the effects of the largest potential outages (EMS). These systems handle analog and discrete data with a sampling frequency of a few seconds. Essentially, the technology behind today's SCADA/EMS systems was first developed during the sixties, when mainframe computers became available to solve the load flow calculations needed for state estimation and contingency analysis, Stagg and El-Abiad, (1968).

During the last ten years, larger power companies have installed a new technology called phasor measurement units (PMU). Lately, the term synchrophasor has become more popular. These units measure signals in the sub-stations with a sampling frequency of a few milliseconds. This makes it possible to observe real-time phenomena of new kinds, such as wave forms, rapid oscillations, and real (as opposed to calculated) phase angles. The synchrophasor technology that has been installed during the last years is based on a new generation of hardware and software, and has a completely different performance.

For several different reasons, SCADA/EMS and synchrophasors have not yet been successfully integrated. The aim of our project has been to investigate why this is, and to outline a possible way of actually enabling this integration.

The State Estimator View

Since the sixties, the classical way of managing power grids in control centers has been centered around load flow calculation and state estimation. When main frame computers became available, it also became possible to perform power flow calculations for power grids. In essence, the idea is that the power grid itself (with generators, lines, transformers, busbars, and loads) is represented in a matrix, selected analog values (voltages and power flows) and the breaker positions are used as input, and a matrix-based algorithm solves Kirchoff's laws in all points of the grid. The result is a picture of the voltages and power flows of a power grid at a certain moment in time.

This is managed by a SCADA/EMS system. The SCADA part of the system receives analog and discrete signals, and discrete alarm information. Typically, the sampling rate of SCADA data has been around two seconds, with alarms being received when they arrive, with a similar transfer delay of no more than around two seconds.

Based on the collected SCADA data, the EMS part of the system performs the load flow calculations and produces a state estimation for voltages and power flows in the grid. Today, this is done every 15 minutes or more frequently. For example, the estimator at HOPS presents a new solution every 60 seconds.

The state estimation can then be used as a basis for monitoring and control of the grid. Algorithms can look at the actual flows and compare them to the maximum ratings of the equipment, to detect overloads and other problems.

Another standard algorithm, the contingency analysis, has a static list of the 100 to 1 000 most critical grid faults, and performs a load flow analysis on the grid state to see what would happen when each of these faults occur. The grid is operated with enough extra resources (for example, spinning reserves) to guarantee that there will be no outage even if the largest of the critical faults listed as contingencies would occur. This is called the "N-1" criterion.

In some sense, it is fair to say that the "state estimator" view of the grid has dominated the thinking of most of the routines, tools, and algorithms in power grid control rooms since the sixties.

The Synchrophasor View

A phasor measurement unit (PMU), also known as a synchrophasor, is a modern measurement unit placed in a sub-station. It can measure voltages, power flows, and currents, just as an old SCADA RTU, but it reads values with a sampling speed of around 1 000 Hz, performs calculations on the values, and delivers output data in speeds from 20 to 50 Hz (that is, over 100 times faster than an old-fashioned RTU system). Each synchrophasor is connected to global time via GPS, and can time stamp its data accurately. This allows a synchrophasor system to deliver phase angle differences between two different locations in the grid in real time.

For short lines that overload, the limit is usually decided by thermal overload. However, for medium long power lines (from 80 to 300 km), the transmission capability is usually limited by the voltage drop limit, and for longer lines (over 300 km), by steady-state stability, Glover and Sarma (2002). In the two latter cases, deviating phase angles between the line ends provide a very good early warning of line overload, Adelson, et al., (2009), NASPI (2016), NERC (2016). The same is true for groups of long power lines. Deviations in phase angles can be seen more easily before actual voltage drops or beginning instabilities. Thus, one of the obvious uses for synchrophasors is to monitor phase angle differences between different regions in large power grids.

In some sense, the "synchrophasor" view of the grid is to look at phase angle deviations between regions in large grids, especially long and narrow grids with generation in one end and load in the other, such as, for example, the Swedish national grid or the Long Island power grid, Adelson, et al., (2009).

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Combining SCADA and Synchrophasors

From 2005 to 2015, several national initiatives allowed power grid utilities to increase the number of synchrophasors in their grids substantially. Today, synchrophasor data is available in most TSO and ISO control rooms. However, this data is not integrated with the SCADA/EMS system, and not used in real-time monitoring and control of the grid. The operators are still using the SCADA/EMS system, while synchrophasor data is mostly used for post mortem analysis in the back office.

There seems to be two quite different reasons for this state of affairs. The first is that today's SCADA/EMS systems have been designed for a data rate of around two seconds. They cannot easily handle data at 20 Hz speed. This is not because of performance limitations of modern computers. Rather, we guess that the underlying reason is that a standard SCADA/EMS system can afford to perform a large number of tasks for each arriving SCADA sample, such as storing them in a database and updating a large number of algorithms. Modern computers can easily manage to receive data at a rate of 20 HZ and to quite a large amount of calculations on this data, which we tested in the Chapter "A Simple Performance Experiment," see below. We can conclude that one reason for the difficulty of using synchrophasor data in a SCADA/EMS system is the software design assumptions made when the SCADA systems were implemented. We believe that synchrophasor data can be received by a signature identifier algorithm, which produces discrete property signals in the standard SCADA rate. These signals can then be integrated in the SCADA/EMS system and used for monitoring and diagnosis.

The other reason for why it is difficult to integrate synchrophasor data into a SCADA/EMS system is of a very different nature. In the "state estimator" view of the grid, each grid object (generators, lines, busbars, loads) has its own set of measurement values, such as voltage, active power flow, and current. In this view, we are used to think about local values for each grid component. In the "synchrophasor" view of the grid, we tend to talk about phase angle differences between regions of the grid (this because there are not synchrophasors at every busbar in the grid). Since SCADA/EMS systems are designed with the state estimator view as a basis, there is no obvious place where synchrophasor data can be plugged in into the existing SCADA data structure.

Some power grid companies have implemented wide-area monitoring based on SCADA data. This often done by defining fixed regions and comparing the regions to each other. For example, the Swedish National Grid (SvK), has defined four regions, and one of the most important ways of managing the global health of the Swedish grid is to monitor the power flows between those regions.

We propose that much of the problems can be solved by defining regions and integrating SCADA and synchrophasor data based on this. Ideally, it would be possible to use power flows to detect and define regions dynamically, and we also propose a new algorithm to do this.

Translating Synchrophasor Data to SCADA Data

It is often stated that today's SCADA/EMS systems cannot receive measurement data at the rates produced by synchrophasors. At the same time, modern computers can send, receive, and manage large amounts of data in real-time, for example, when showing films over the Internet.

Our conclusion is that it is not the performance of modern computers and communication networks that sets the limits for receiving synchrophasor data. Instead it is the internal software design of the SCADA/EMS systems. They were designed with the assumption of a data rate of one sample in one to two seconds only. Thus, our guess is that for each received data item, a typical SCADA/EMS system performs one or several database accesses, and updates a number of algorithms. This means that it would be possible to overcome the problem by redesigning a SCADA/EMS system from scratch.

However, building a new SCADA/EMS system is a major undertaking. Such a project would need thousands of man-hours, and pose large problems in managing backward compatibility with both software modules, algorithms, and user demands. For practical reasons, we will be living with today's SCADA/EMS systems for a long while into the future.

A PMU to SCADA Signature Identifier

In order to make synchrophasor data available in the SCADA world, we propose a solution, where a separate algorithm receives the synchrophasor data (at the rate of 20 to 50 Hz), and performs calculations that produce discrete flags with values that are limited to the typical SCADA rate (around 0.5 Hz), see Figure 1.

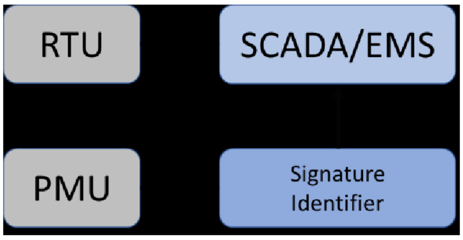

Figure 1. A separate signature identifier turns PMU data into SCADA data.

The signature identifier can calculate a number of properties and store them in flags, and these flags can then be used as SCADA signals. Some examples are as follows:

Increase	The synchrophasor signal has been slowly increasing over the last second (or other time period). The rate of change could also be reported.
Positive Jump	The signal has made a positive delta change. The size of the change could also be reported.
Spike	The signal has made a quick spike.

Outlier	The signal contains positive, negative, or mixed outliers. Outliers are random measurement points that do not agree well with the rest of the signal.
Quick peak	The signal has made a peak or drop and returned, during a single SCADA interval. The magnitude and length of the peak could also be reported.
Oscillation	The signal oscillates with a detectable frequency. Here the signature identifier would also report the frequency and amplitude of the oscillation.
Chaotic	The signal is oscillating or swinging but no regularity can be detected.

This is a set of examples of signal properties that can easily be calculated by a signature identifier. The results are remembered for each SCADA interval and the SCADA/EMS system can save the flag signals. This enables both operators and algorithms to detect such things as, for example, that a bus bar experienced a voltage drop that was too quick to appear in the SCADA data, that the power flow on a line is fluctuating rapidly and randomly, or that power is swinging back and forth with a steady frequency.

A Simple Performance Experiment

In order to verify the calculation performance of a signature identifier, we made a small implementation for a single signal. We used a power flow signal measured by a synchrophasor in the Croatian grid. We received it from HOPS during the project, see Figure 2. For this text, the signal was stored as values in a text file. The signal shows the active power flow over the 220 kV power line Konjsko-Brinje (HOPS's synchrophasors are connected to the 220 kV level) during a trip of a generator on the 110 kV level.

We implemented a program in C running under Windows on a standard 2.7 GHz laptop, and let it read 100 000 000 values, and performed a calculation for a positive jump. The calculation uses a sliding window of six values to avoid outlier disturbances, and easily detects the single jump in the signal (from around zero to 20 MW flow).

This experiment showed that it is possible to perform over 2 000 000 read operations per second and over 500 000 000 calculations per second. The file read operations were done one by one, so it would be possible to speed this up further by one or several orders of magnitude.

The conclusion is that computer or algorithm performance is no limit for a signature identifier as described above. The reason for why a standard SCAD/EMS system cannot operate at synchrophasor speed is to be found in the software design and the number of complex tasks performed for each SCADA value.

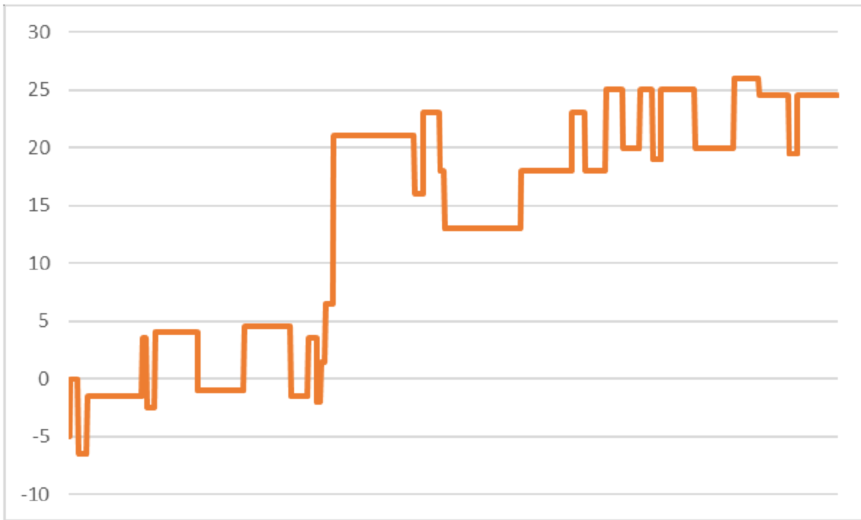

Figure 2. A synchrophasor power flow signal from the Konjsko-Brinje power line.

Synchrophasor Disturbance Footprints

Lightning strikes and short-circuits are common reasons for tripping of power lines. If the automatic reclosing does not work, the result is a line outage, which easily can develop into a more complicated fault situation.

In SCADA data, a lightning strike is seen as a trip signal (from a protection relay) and low voltages and flows (if the line trips). Normally, there is no special information about the nature of the fault, except that there was an under-voltage and/or too high flow.

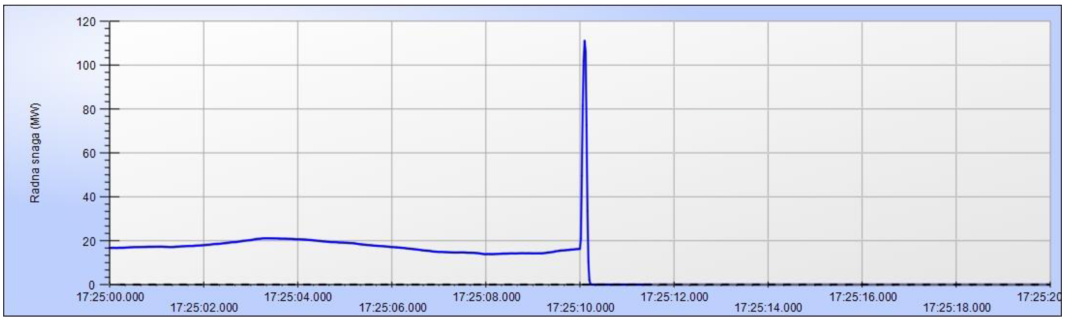

Figure 3. Power flow during a lightning strike in the Konjsko-Brinje power line.

Using synchrophasor data from HOPS, we studied some signals during lightning strikes. The power flow during a typical lightning strike can be seen in Figure 3.

It seems that a typical lightning strike is characterized by a tall but narrow spike in active power, just as one would expect. Similar, large spikes can be seen in reactive power and frequency. In this case, it seems that the line trips and the power flow goes to zero after the lightning strike.

In Figure 4, we can see the active power flow during what we believe is a dual lightning strike in the Konjsko-RHE Velebit power line. The two strikes are separated by about 0.5 seconds and are easy to distinguish in the graph. The guess from HOPS is that the first strike tripped one phase. After the second strike, the power flow goes to zero, which indicates that the entire line tripped.

Figure 4. Dual lightning strikes in the Konjsko-RHE Velebit power line

In Figure 5, we see the frequency disturbances during the same dual lightning strike. The frequency varies almost chaotically for a second, and then there is no clear measurement to be observed.

Figure 5. Frequency during the dual lightning strike in Konjsko-RHE Velebit.

As can be seen from these examples, the synchrophasor data is much more precise than old-style SCADA data. In fact, it is possible to see details in how the signals behave during a fault.

Our observation is only that it may be possible to use a signature identifier to extract several more precise properties of faults. The dual lightning strike in Figure 7 hints that even rapid, multiple lightning strikes can be detected and separated.

It would be interesting to compare a number of different types of faults, and investigate if they are detectable and distinguishable, by looking at the typical behavior (or “footprints”) of the synchrophasor variables. If so, it may be possible to create a catalog of typical footprints for different types of disturbances. If there are distinguishable footprints, they could presumably be detected by the signature identifier solution described above.

Knowledge-Based Root Cause Analysis

GoalArt has a unique technology that can point out the real faults in complex fault situations, at the moment the information arrives, which reduces the fault diagnosis time and the risk of erroneous conclusions and actions. GoalArt's technology is commercially installed at the Swedish National Grid (SvK) and the Croatian TSO (HOPS). An evaluation performed by HOPS during 2015 shows that GoalArt's technology reduces the amount of alarms with over 98 % both in daily operations and during incidents, without removing important alarms. Thus, this technology is a solution for the information overload problem in fault situations.

Synchrophasor-Based Algorithms

Based on a synchrophasor data signature identifier, it is possible to implement several algorithms for monitoring and diagnosis of power grids. In the following, we will outline three such algorithms, and describe how they could work and what value they would provide in a control room.

A Global Vulnerability Indicator

The idea behind a vulnerability indicator is to monitor data from the entire grid, and to detect situations where the grid state is starting to deviate from normal, and moving towards potentially dangerous situations, where there is a risk of outages.

A standard monitoring approach in power grids is to use so-called contingency analysis. This is based on a list of pre-defined faults (such as generator and line trips, and bus bars isolations). At regular time intervals, each fault is superimposed on the current grid state and a state estimator performs a load flow calculation. If this calculation yields values that are too close to preset limits, the algorithm will warn of a possible vulnerability to the fault that was tested.

Contingency analysis is a good method for providing continuous monitoring of power grids, but it is not perfect. Among the weaknesses are the following:

- The method only detects dangers based on a fixed, pre-defined list of faults. These faults are tested one by one. However, if there is a fault in the real grid, that is not in the list, or if there is a combination of independent faults, the contingency analysis will be unpredictable. It may simply miss dangerous situations.
- The calculation of all the contingencies is time-consuming. Typically, a new result is available every 10 to 15 minutes. If fault develops more rapidly, the contingency analysis may not detect it until too late.
- The state estimator depends on selected measured values from the grid. If these values are not available (because of a faulty sensor or a repair action), or if the grid state enters into a disturbed situation, the estimator may not be able to perform the load flow calculation ("it cannot solve"), and suddenly, no results are available. This was the case, for example, before the North

American blackout on August 14, 2003, see US-Canada System Outage Task Force, (2004).

For these reasons, it would be valuable to develop different, complementary methods for grid monitoring and diagnosis. The global vulnerability indicator described below is one such attempt.

We propose to collect the following data on-line in real-time, from the SCADA system and from the synchrophasors (via signature identifiers).

- Global phase angle differences between selected geographically distant stations in the grid.
- Phase angle differences over selected main stretches of long lines important for the bulk of the transmission in the grid.
- The number of large generators and important transmission lines and transformers that are currently tripped or out-of-service.
- The total MW sum of the same generators, lines, and transformers that are out of service.
- Tap changer positions of major transformers in the grid.

These numbers can be presented in a set of bar graphs, and the vulnerability indicator could also calculate a weighted sum of them. If either one of the measurements or the weighted sum become too high, the operators receive a warning. For example, the bar graphs may change color from blue to red. This makes it very easy to get a quick, visual overview of the grid state, see Figure 6.

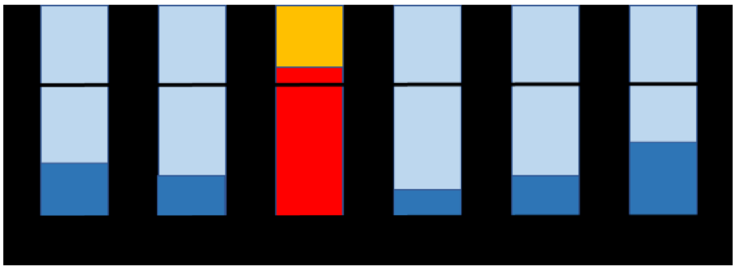

Figure 6. Possible display design for a vulnerability indicator.

In this example, we assume that there is a main phase angle difference measured between the northern part of the grid (with most of the generation) and the southern part (with most of the load), called NS. In addition, the two most important stretches of transmission lines are called LN1 and LN2. The number of tripped units are called Units and their MW total is MW. Finally, the sum of the tap changer positions is called TAP.

In the example, the situation is acceptable, except that LN2 displays an unusually large phase angle difference, which should be looked into.

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A Local Stability Analysis for Power Lines

Classically, line overload problems have been classified into three different types, Glover and Sarma, (2002).

1. For short power lines, up to 80 km, an overload primarily gives thermal problems. If the elastic limit is passed, the line may be unable to resume its previous length when it cools again.
2. For medium length power lines, up to 300 km, the main load is determined by the voltage drop limit. As the line becomes increasingly loaded, it behaves more and more as an inductive element, and this may lead to a voltage drop and eventually to a line trip.
3. For longer lines, over 300 km, the main load is often determined by the synchronous stability over the line. If the phase angle difference between the generation at one end and the load at the other end becomes too large, the line may not be able to maintain synchronicity between its ends.

The first case above is seldom a problem in practice, while the next two are among the typical serious problems in power grids, and they have to be monitored carefully as soon as the grid is heavily loaded.

Problem 2 and 3 have very similar symptoms. The phase angle difference across the line will increase, and the voltages at the load bus bar will drop. It has been concluded elsewhere, Adelson, et al., (2009), that phase angle difference is a better measure for early detection of voltage problems than looking at the voltage itself. This is simply because the general look of so-called PV curves, Adelson, et al., (2009), Glover and Sarma (2002). In the beginning of an voltage drop or synchronicity problem, the phase angle difference starts to change more quickly than the voltage drop, and the latter can be very small at first.

An obvious use of synchrophasors is to measure the phase angle difference between selected distant points in the grid, and/or over some of the long transmission lines that handle larger parts of the total transmission. As the number of synchrophasors increase in the grid, it is possible that the situation in the future may be that all major, long lines have synchrophasors at both ends. In this situation, the operators will have good monitoring and early warning concerning overload and voltage problems. Early line overloads can be connected to GoalArt's diagnostic system, and will increase the diagnostic precision in the analysis.

A Swing Detector

One recurring problem in large power grids is that of power oscillations. When the power grid is large and have large generation and load centers far apart, power can travel back and forth with a regular frequency. This may simply be due to bad damping by the control systems. For example, the NORDEL grid had such oscillations for several years, until HVDC lines made it more stable. The frequencies were around 0.25 to 0.5 Hz, Eliasson (1990).

The Swedish national grid has observed oscillations between physical generator characteristics and inductive and capacitive compensators. These had frequencies around 16 Hz, Samuelsson (2017).

There is an ENTSO-e Regional subgroup on System Protection and Dynamics, which looks into power swings in the central European grid, Rubeša (2017).

Power oscillations are not easy to observe in SCADA data, and faster oscillations cannot be observed at all. Therefore, power oscillations have not been part of the standard monitoring in power grid control rooms.

It is straight-forward to use the signature identifier solution for synchrophasor data to detect oscillations at any frequency below 10 Hz (or 25 Hz, depending on PMU settings). In this way, oscillation data could be made available in the SCADA system in the control room.

Oscillations could also be useful in root cause analysis. In transmission paths where the oscillations in power flow are high, they can be used to explain spurious overloads and consequential problems of these.

GoalArt's root cause analysis algorithm basically classifies all voltages and power flows as either too low, normal, or too high. However, it also has the options of using the characterizations data-not-available and random-too-high-or-too-low. Oscillations could be connected as the latter, and would increase the diagnostic precision. In practice, oscillations with large amplitudes may lead to overload of lines and transformers, and tripping of protective equipment. These effects would be possible to include in a root cause analysis, once the oscillations can be detected and measured.

Random and Chaotic Disturbances

The 1996 Western Interconnection blackout in Canada and the USA was preceded by problems that caused fast oscillations, that first increased more or less exponentially and then lost their regularity, NERC (2002). One of the two originating faults of the 2003 NORDEL blackout occurred in a sub-station on the West coast of Sweden. Here GoalArt has observed rapid disturbances in the flows of power lines preceding the blackout.

Rapid and unregular variations in voltages and flows are typically a strong indicator that something is going wrong. Normally, these variations cannot be observed using SCADA data, but only by fault recorders in post mortem analysis.

Again, these important disturbances could be identified by a signature identifier solution, and would be very useful for monitoring and diagnosis. First, the SCADA system should alarm all such disturbances. Secondly, they can be used in root cause analysis.

As described above, GoalArt's root cause analysis algorithm classifies voltages and power flows as either too low, normal, or too high, but it can also use data to classify a signal as data-not-available and random-too-high-or-too-low. Oscillations and rapid, non-regular disturbances should be connected as the latter, and would increase the diagnostic precision, especially in chaotic situations with large disturbances in the grid.

Rapid, chaotic disturbances can be caused by other faults and they may propagate through the grid and, in turn, cause consequential problems, such as trips and outages. Once they can be detected and measured, they can be included in the root cause analysis algorithm.

Synchrophasor Data in Root Cause Analysis

GoalArt's main product is a system and an algorithm for finding original root cause alarms (that is, the alarm nearest to the starting point of a problem), in complex fault situations. This algorithm uses a network model, for example, described in CIM, Common Information Model, CIM User Group (2017), and receives its knowledge of the current situation by reading alarm and event data and analog data from the SCADA system in real time, GoalArt (2012).

It should be noted that this root cause analysis is a very efficient alarm rate reduction tool. In complex fault situations, there may be hundreds of alarms in a few seconds. Operators typically cannot handle this amount of information as quickly as needed, and alarm systems usually become unusable in critical situations. With the GoalArt algorithm, the number of alarms remains at recommended levels (around one alarm per ten minutes), even during alarm cascades and outages. Currently, this is the only product with this kind of performance, which has been shown by evaluations in commercial operation, Baranovic, et al., (2014). The GoalArt system enables the operators to retain their understanding of complex, developing faults situations, that is to maintain situational awareness.

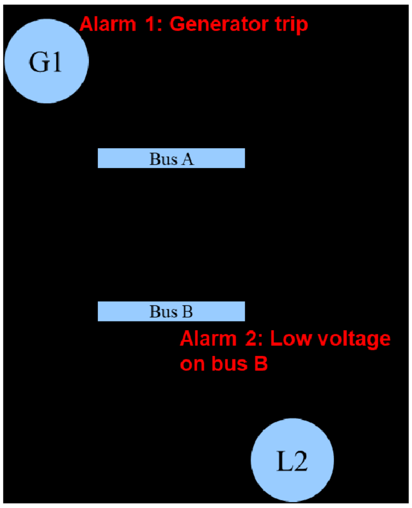

Figure 7. Example of a consequence propagation chain.

The root cause analysis algorithm works by tracking incoming alarms and other fault indications, and "connecting" them by use of the grid model. This is best explained by a simple example, see Figure 7.

In the example, we assume that a generator G1 trips. This leads to a zero MW flow out from the generator. In turn, this leads to a voltage drop at Bus A, an active power flow drop over the transmission line between Bus A and Bus B, a voltage drop at Bus B, and a drop of active power to the Load L2.

By using the physical connection structure and incoming alarm information, the algorithm can conclude that all the alarms are caused by the generator trip. The low fault from G1 is the root cause, and all the other alarms are consequences. A single alarm explains the fault situation.

However, it is not enough to receive all available alarms from the grid. Typically, a transmission line has no configured alarm for a low power flow, since this is not necessarily a fault. A zero or near zero flow may occur during the varying modes of transmission during a day, and is called a “floating” line.

The GoalArt algorithm needs to know that the active power flow over the line drops, in order to connect the events at Bus A with the events at Bus B. Because of this, the GoalArt system reads analog values from lines and transformers, and performs so-called “delta” calculations on them, in order to produce internal events that can be used in the root cause analysis algorithm. This is the exact same type of calculation that is needed for the positive/negative “jump” calculation described earlier in this document.

In a project with a commercial customer, GoalArt observed problems based on the sampling period of SCADA data. In the project, GoalArt received a CIM model and historical SCADA data for a number of events. The goal of the project was to test and evaluate GoalArt’s root cause analysis algorithm using historical scenarios.

Figure 8. A section of a power grid.

Several of the events contained transmission line trips caused by lightning strikes, and other contained generator trips caused by internal faults. Most of the scenarios had a large number of consequential faults.

We observed that several trips caused large but quick dips in voltages. The voltage disturbances spread over anything from a few to over twenty stations, and lasted from one to five seconds. In several cases, after a few seconds, the grid managed to return the voltages to normal again, often in a new operational state. In some cases, when loads were tripped, the quick voltage changes were in the form of rapid peaks instead.

However, in one scenario, we observed no voltage changes, see Figure 8. In this particular case, the transformer T1 tripped (due to a lightning strike). This was followed by several effects on the 138 kV level, which are not interesting for the example. However, four capacitors on the 25 kV level also tripped. If there had been a voltage peak on the 25 kV bus, the algorithm would be able to explain the four trips by the main fault. But there was no change in voltage on the bus.

Our educated guess about this case is that there was in fact a rapid voltage peak or spike on the 25 kV bus, which in turn tripped the capacitors. But the peak most probably started and ended within a single SCADA sample period (two seconds at this customer). Thus, the algorithm did not detect any high voltage on the bus and could not see that the capacitor trips were consequences of the transformer trip.

The effect of this is that the capacitor trips are presented as independent root causes themselves, rather than as consequences of the transformer trip. This is not disastrous for the algorithm, but it does give less diagnostic resolution.

We have observed this type of phenomenon in different situations, and we draw the conclusions that for relatively strong grids, that can compensate for changes rapidly, a lot of problems are not seen because of the slow SCADA sampling rate (this is particularly true for power swings and fast irregular disturbances).

The diagnostic power of the GoalArt system and other, similar algorithms, could be much improved by combining SCADA and synchrophasor data, using the signature identifier solution described previously.

Defining Regions for Angle Deviations

One of the obvious uses for synchrophasor data in monitoring is to look at phase angle differences over large transmission areas, especially when a grid covers a region with mainly generation, a long geographical transmission, and another region with mainly loads. This is a quite common occurrence. Examples of this can be found in the Croatian and Swedish power grids, see Figure 9.

In such cases, the grid globally behaves approximately like a long transmission line. In case of an overload, there may be a voltage drop and/or problems with synchronicity, which both may lead to outages.

This is quite true for the Swedish grid, which hydro power generation in the north and most of the load in the south. The problems also occur in the south-east part of the Croatian grid. However, the problems in Croatia are less pronounced, since the grid is quite well supported by neighboring grids in Bosnia, Hungary, and Serbia.

In cases with long grids with generation in one end and load in the other, it is quite obvious that there should be synchrophasors located in the physically remote corners of the grid. For Croatia, it makes sense to place synchrophasors in the western, northern, northeastern, and southeastern corners. In Sweden, the SvK grid is split into four regions, and power flows between those areas are monitored today. It would make sense to place synchrophasors in each region.

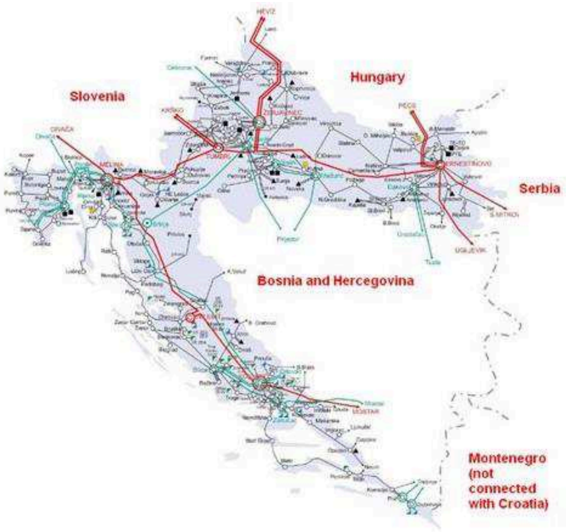

Figure 9. Overview grid maps for HOPS and SvK.

This quite simplistic strategy of locating synchrophasors based on geography and the main transmission needs, offers a first good step in using synchrophasor data to monitor the global stability of a grid.

Another well-known example of a "long" grid is the Long Island grid, Adelson, et al., (2009), and yet another one is the transmission power grid of Turkey.

An Algorithm for Dynamical Detection of Congestion

There are several different methods for monitoring power grids. Some of these methods are very clearly geared towards a detailed, local view. Among these are:

- Sub-station monitoring via SCADA alarms from equipment, breakers, etc.
- Special monitoring of equipment functions.
- Most SCADA alarms and analog signals.
- State estimation and contingency analysis, focusing on a fixed set of measurements and potential faults.

On the other hand, we have a number of methods that have a clearly global view of the grid. Among these are:

- Phase angle difference monitoring between regions.
- Power flow monitoring between areas (as done at SvK in Sweden).
- The use of frequency as a simple measure of total generation balance.

However, there are few methods that combine both the local, detailed view and the global grid view.

There is a strong, theoretical argument for use of redundancy in monitoring and diagnosis. A single method, and single model, or a single channel for measurement data, pose risks that the monitoring will be incomplete or fail.

During the project, while discussing the possibility of combining different methods for monitoring and diagnosis, we discovered the possibility of a new type of monitoring. This is not yet a new method. Instead, the ideas are presented here in the form of a few examples, to suggest what could be developed.

GoalArt's algorithm for root cause analysis uses knowledge of the physical connection structure of the grid. It propagates consequence information along the grid data structure in its memory. An idea in the same direction has lead us to propose a new algorithm for monitoring and diagnosis.

The basic idea of the algorithm is to use the combined knowledge of the physical connection paths in the grid, and the actual power flows along this path, to detect overloaded points or regions dynamically.

Figure 10. A node with only a single inflow.

First, consider a single node in the grid, with a number of connections. This node can be, for example, a bus bar, a voltage level, or a sub-station, see Figure 10. The node in the example has six connections. For each, the power flow direction has been shown with an arrow.

The first step in the algorithm is to look at each node and identify those nodes for which the following conditions hold:

- There is a single inflow among the connections.
- The inflow is near to the transfer capacity.

In this way, we can find points in the grid, which pose a danger, in the sense that should the flow demand in these points suddenly increase, or should the single line in question trip, the node will no longer have an adequate power supply, and voltages and flows would change drastically in the vicinity of the node, potentially causing an outage. A simple monitoring method based on SCADA values, would be to check how near the single inflow is to the maximum capacity of the corresponding line or transformer.

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Obviously, the example is simplified. In a real case, there may be un-modeled connections and unmeasured flows. A practical implementation would have to handle such problems.

A generalization of the first example is to create a graph-search algorithm that identifies groups or nearby connections, which all share the same flow direction, see Figure 11.

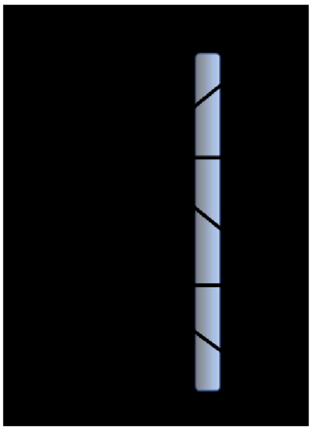

Figure 11. An area with flows in one direction only.

In Figure 11, we see a case where five connections have the same flow direction, based on current flow values and directions, as measured by the SCADA system (or synchrophasors).

Once identified, the group of connections make up a dynamically defined “cut,” between two regions, much like the static cuts between the four regions in the Swedish power grid. The difference here is that the regions and cuts are detected dynamically, based on currently available connections (breaker states), and the size and direction of the current power flows.

Once the regions and cuts are identified, the algorithm can perform monitoring in two different ways.

- It can look at how loaded the lines in the cut are, and how near each line is to its maximum capacity. If the total sum of the load is near the total maximum capacity, we have detected a dangerous region of congestion.

- It can look for the nearest synchrophasors on each side of the cut. If a suitable pair of synchrophasors are found, the phase angle difference between them can be used as a good indicator of how dangerous the load of the flow through the cut actually is.

This is a very brief outline of the ideas behind the new algorithm. If this would be possible to develop and implement, we would have a monitoring algorithm that would combine the detailed view of the typical SCADA alarm system with a more global monitoring based on cuts and synchrophasor data. This algorithm would be local in that it would detect points of congestion more precisely than any of the "global" algorithms mentioned above, but it would be global in that it would detect any regions and cuts that appeared dynamically because of the current flow state in the grid.

Finally, it would look at all locations in the grid and would not miss any congestion problem, no matter how small or large. In this way, it would increase the reliability of monitoring that otherwise only uses contingency analysis.

We propose to develop, implement, and test such an algorithm is a separate research and development project.

Project Overview

The project was born out of a very practical question. Why is it that synchrophasor data is not integrated into SCADA/EMS systems? Interestingly enough, to a large extent, the project has been a theoretical study, based on contacts and discussions with an electrical power university department, a major power grid operator, and selected vendors and suppliers in the synchrophasor and SCADA/EMS business.

The project has been performed by Per Andersson and Jan Eric Larsson at GoalArt. We have had lengthy discussions with Professor Olof Samuelsson and Morten Hemmingsson at the Department of Industrial Electrical Engineering and Automation (IEA) at Lund University, and we have arranged several "mini seminars" together. We are very grateful that we could tap into their much greater and deeper knowledge of power grids in general and synchrophasors in particular.

However, one thing made our cooperation with IEA extra valuable. For several years they have been part of a university network of early PMU users. In fact, six different organizations have their own synchrophasors and exchange data, on a pure research basis. This means that IEA had a large experience, a good set of suggestions, and also lots of hands-on knowledge of synchrophasors. During the project, we have had some ten different discussion meetings at IEA and GoalArt, and we have shared a large number of articles and references.

Our other partners in the project have been Igor Ivanković, Renata Rubeša, and Marko Rekić from the Croatian National Grid (HOPS). They quickly volunteered to be the main industrial partner, and willingly shared both data on the synchrophasor in the HOPS grid, as well as data from, among other things, smaller incidents in the grid as measured by their synchrophasors. We also received a set of synchrophasor data from several lightning strikes and a ground fault in the HOPS grid. We spent a visit at HOPS on September 18, 2017, where we had very fruitful discussions and feedback on the project results.

While attending the Electric Power Grid Control Center Conference (EPCC) 14 in Wieslock, Germany, we had a meeting with representatives of General Electric (previously Areva/Ahlstom). This is the commercial vendor that has the most mature product for inclusion of synchrophasor data in their SCADA/EMS system. They helped us to validate that currently, the available tools simply show phase angles geographically across the grid, but contain no advanced analysis and are not connected to other parts of the SCADA/EMS system.

In order to verify that hardware and software performance is not an obstacle to integrating synchrophasor data in a SCADA/EMS system via the proposed signature identifier solution, GoalArt made a small test implementation of a signature identifier using a single filter to detect one property of the SCADA data we received from HOPS. As expected, performance is not the reason for the lack of integration.

Results

Since this project is mainly a theoretical study, we have elected to describe the problems and our findings in a running text. For the reader's convenience, the results are again summarized here.

- Computer hardware and software performance is no obstacle to receiving synchrophasor data at the speeds of 20 – 50 Hz. Instead, we propose that it is the inherent design choices in today's SCADA/EMS systems that limit their ability to receive and store synchrophasor data.
- We believe that today's SCADA/EMS systems will not easily be redesigned to receive synchrophasor data. There is such a large amount of design and development in these systems, that they can only be modernized at a slow pace. However, we propose a separate software module, a so-called signature identifier, which uses standard algorithms to analyze synchrophasor data and produce new signals, consisting of "flags," which identify important aspects of the synchrophasor data, but can be produced at SCADA data rate.
- We have provided a number of examples of interesting properties that can be calculated by a signature identifier.
- We investigated synchrophasor data from lightning strikes and saw that the information contains much more detail than ordinary SCADA data. Even rapid, multiple lightning strikes can be identified and separated from each other. It may be interesting to study different types of faults and see if they can be detected and identified by tuning a signature identifier.
- Given that we can have access to both synchrophasor data and signature identifier data, we have proposed three algorithms for monitoring and diagnosis in real-time in the control room. These are a vulnerability indicator, and local stability detector, and a swing detector.
- We have shown an example where synchrophasor data will allow root cause analysis to arrive at a more correct result by observing fast properties of signals, which may not be visible in ordinary, slow SCADA signals.
- Finally, we have proposed a new algorithm that detects points or regions of congestion dynamically, and then uses SCADA data and/or synchrophasor

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data to detect dangerous overload situations. This algorithm will perform a task similar to today's contingency analysis, but in a different way. One advantage is that it will look at the entire grid and all potential problems, and not be limited to a fixed set of faults, like standard contingency analysis.

- An obvious continuation of this project is to design and develop the newly proposed algorithm for monitoring and diagnosis of congestion. This would be an excellent topic for a separate project.

Discussion

The modern society has become increasingly dependent on a reliable supply of electric power, and more and more vulnerable to problems and outages. Today's main way of guaranteeing an uninterrupted and reliable power flow, is for power utilities and transmission system operators to monitor the operation of their power grids.

The results of the project are aimed at improving the speed and accuracy of the monitoring of power grids. Since synchrophasors are already installed in relatively large numbers in most transmission grids, it would be very good if their data could be used as efficiently as possible. We hope that the ideas proposed in this report will help to accomplish that.

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