LOSS OF SYNCHRONISM DETECTION,
A STRATEGIC FUNCTION FOR POWER SYSTEM PROTECTION

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SUMMARY

Maintaining power system reliability in a deregulated market environment is a day-by-day challenge for electrical utilities throughout the world. Stability and thermal limits, voltage collapse and loop flows are usual constraints that system planners and operators have to deal with. Recent cascading failures in several power systems worldwide require adequate analysis, research and development efforts to determine conditions and triggering events, to develop preventive transmission planning solutions, operating procedures and automatic protection systems. In this context, loss-of-synchronism detection is considered a strategic function to protect a power system against severe contingencies and cascading failures.

A major North-American power utility, Hydro-Québec operates a modern, extensive and complex power system that requires efficient and innovative automatic protection schemes. Its transmission system is currently protected by a series of coordinated special protection schemes (SPSs) that have been developed over the last twenty years. These SPSs require continuous adaptation and innovation, however, because of the increasing capacity and complexity of the transmission system. While new major hydraulic and wind power plants are integrated, the addition of transmission lines is strictly limited by economic and environmental considerations.

In this context, research and development teams at Hydro-Québec and Areva T&D are jointly developing two novel relays, RPS and DLI, for loss-of-synchronism detection in transmission substations and power plants. These protection devices have been designed to improve present SPS performance and provide new system protection alternatives. They are able to anticipate loss of synchronism using local variables only and are based on fuzzy-logic multi-criteria algorithms. Since they are generic, these novel protection relays are applicable to other large power systems prone to transient and dynamic instabilities.

The main characteristics and performance of these two new relays as well as their application on the Hydro-Québec transmission system are presented in this paper.

KEYWORDS
Power system protection, remedial action schemes, loss-of-synchronism detection, fuzzy-logic based protection, defence plans.

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1. INTRODUCTION

Modern power systems are commonly designed and operated to withstand most likely to occur contingencies. For such N-1 type events, classical relays are suitable to protect each individual piece of equipment while maintaining continuous operation of the whole system. These protections are considered the first defence line of a power network.

On the other end, severe or extreme events involving simultaneous or cascaded contingencies (type N-2, N-3...) require system level protections such as massive generator tripping, load shedding or ultimately coordinated system separation to preserve system stability or to prevent serious damages of transmission and generation equipments. These remedial actions are performed by Special Protection Schemes (SPS) and are considered the system second and third defence lines.

Electrical integrity of Hydro-Québec power system when subjected to extreme contingencies actually relies on a series of such Special Protection Schemes [1-2] that were developed and implemented during the last twenty years. Due to the evolution of the transmission system in terms of its capacity and complexity, these SPS still require continuous adaptation and innovation to allow the integration of large production plants while maintaining the number of transmission circuits as low as possible for economic and environmental reasons. For Hydro-Québec, adapting and innovating its system defence means improving its actual SPS performances in the short term as well as bringing new system protection concepts to meet medium and long-term requirements.

In terms of their detection principles, SPS may be classified in two different categories. Event-based systems are detecting the causes of a disturbance while response-based systems are rather reacting to its effects. Fast topology detection schemes, as presented in [3], are considered event-based SPS while RPS and DLI described here correspond to response-based protection relays.

The paper is organized in the following manner. An overview of Hydro-Québec actual defence plan is first introduced in section 2 focusing on the five major SPS actually in use. The challenge of loss of synchronism detection in transmission and generation installations is then presented in section 3. Section 4 is devoted to the description of the two resulting RPS and DLI protection relays, their detection principles, fuzzy-logic based algorithms, hardware and software architectures and characteristics. Their response-based performances are then illustrated in section 5 using sample power system conditions simulated on Hydro-Québec transmission system. The last section brings back the key ideas of the paper and summarizes the R&D activities being conducted or planned by Hydro-Québec and Areva T&D engineers in this field of power system defence and protection.

2. HYDRO-QUÉBEC DEFENSE PLAN: AN OVERVIEW

In the 1990s, Hydro-Québec devoted substantial efforts to analyzing the reliability of its transmission system. This analysis led to more stringent design criteria and establishment of an extensive program to strengthen the existing infrastructure. The most attractive solution for satisfying these new criteria was to add series compensation, shunt reactors and SPSs. In this context, five main SPSs were implemented [1-2]:

**RPTC (Based on events detected by topology changes):**
A generation-rejection, load-shedding and remote reactor-tripping scheme designed to detect topology changes such as loss of lines or bypass of series-compensated capacitor banks in 15 strategic 735-kV stations: Up to 5,000 MW of generation rejections at four different sites and remote shedding of up to 3,500 MW of load and 1,500 MVar of shunt capacitors.

**UFLS (Based on frequency response):**
Under-frequency load-shedding scheme with access to more than 13,000 MW of load in 150 distribution substations

**MAIS (Based on voltage and frequency responses):**
Automatic shunt reactor switching systems for voltage control with access to 15,000 MVar in 22 735-kV substations

**UVLS (Based on voltage response):**
Under-voltage load-shedding system with access to 2,500 MW of load, mainly found in in Montreal area 735-kV substations
SPSR (Based on events detected by topology changes and on voltage, frequency and angles response):

All measures deployed for protecting strategic power equipments in case of system separation. Following such a separation, severe temporary overvoltages (TOVs) due to the Ferranti effect appear on long unloaded lines still connected to the generators. Strategic equipment must be protected against these overvoltages to ensure that system restoration can be achieved in a reasonable time. When system separation occurs, unloaded lines are rapidly removed from service by overvoltage protections and the level of these overvoltages is limited by special surge arresters.

Hydro-Québec needs RPS relays to improve one of the SPSR’s functions, which consists in detecting severe power oscillations or imminent loss of synchronism as seen from a transmission line in order to switch on special surge arrestors. The RPSs will replace and improve the performance of a static relay.

On the other hand, the DLI is a totally new function dedicated to power plant instability detection that has been developed to complement RPTC remedial actions in two different ways. First, being a response-based relay, the DLI will provide permissive conditions to current RPTC generation rejection and load shedding sub-systems to improve the security of this event-based SPS. It will also be required to initiate its own generation-rejection actions to increase the maximum limit currently allowed for the RPTC (5,000 MW). System studies have in fact demonstrated that additional rejection capacities will be needed in the future as the next major hydroelectric generation plants are integrated.

3. LOSS OF SYNCHRONISM DETECTION: THE CHALLENGE

In general, occurrence of extreme contingencies in a power system may lead to voltage, frequency or angular instabilities. Voltage instabilities are related to the incapacity of the system to provide sufficient reactive power at one or several buses. Excessive voltage drops or collapses will then occur and propagate to the whole system if no remedial actions are undertaken. Angular or frequency instabilities are related more to the incapacity of the system to provide appropriate real power flows between generation areas or between generation and load areas to maintain system equilibrium. Such instabilities may lead to either under/overfrequency situations or loss-of-synchronism conditions.

In the first case, the frequency will be the same for the whole system but out of the normal range, while in the second case, area or sub-system frequencies will differ and induce loss-of-synchronism conditions characterized by periodic zero voltage (or virtual faults) located at a dividing line also called cut-set line. Anticipation of such loss of synchronism in combination with fast remedial actions may allow system stability to be maintained. However, since modern networks are generally not designed to sustain more than one virtual fault or out-of-phase event, a pre-planned scheme to split the network into viable islands or to go through the separation and de-energize the system without damaging the strategic power equipment are the two remaining options.

In a given power system, the location of the cut-set lines will depend on both the transmission grid topology and the geographical locations of generators and loads. To illustrate this concept, the cut-set lines of Hydro-Québec’s present bulk network are shown on the left in Figure 5. This power system, with its Y-shaped transmission grid, three major remote generation complexes (James Bay, Churchill Falls and Manic-Outardes) and concentration of load areas in the south, has four natural cut-set lines and is prone to separation in three different ways:

- Churchill Falls power plant (5,500 MW) versus the rest of the grid: cut-set line **A**
- Both Churchill Falls and Manic-Outardes generation complex (11,000 MW) on the eastern transmission corridor versus the rest of the grid: cut-set line **B**
- James Bay complex (13,000 MW) versus the rest of the grid: cut-set lines **C** and **D** depending on the post-event topology of the transmission corridors.

In such a context, it is understandable that loss-of-synchronism detection may be suitable in both transmission and generation installations. This is why, as mentioned earlier, two different applications were considered in the Hydro-Québec defence plan, one involving the RPS relay in transmission substations and the other using the DLI in power plants. First, however, an overview of conventional approaches used for such detection is relevant in order to understand the Areva T&D and Hydro-Québec R&D team’s motivation to work on these new developments. Let us consider the simplified system of Figure 1. Two machines, represented by voltage sources $E_A \angle \theta$ and $E_B \angle \phi$ behind transient
impedances $Z_A$ and $Z_B$, transfer power through a transmission line of impedance $Z_L$. For $E_A = E_B$ and $\theta = 45^\circ$, the apparent impedance as seen from relay $R$ corresponds to point $P$. During a power swing, initial generator speeds $\omega_A$ and $\omega_B$ are changing and the apparent impedance is moving along the PQ line (if $E_A$ remains equal to $E_B$) from right to left when $\omega_A > \omega_B$ and left to right when $\omega_A < \omega_B$.

The slip rate between the two generators is a function of the accelerating torques and inertias of the machines. The power swing leads to instability when the angle $\theta$ exceeds $180^\circ$ and a virtual fault, located at the electrical centre of the system, occurs. As shown in Figure 1, this electrical centre is located either on the PQ line when $E_A = E_B$ or on generator A or B side when $E_A / E_B < 1$ or $> 1$. In either case, the challenge is to predict the occurrence of instability to provide fast enough remedial action.

Classical approaches make use of auxiliary relays in the $R$, $X$ plane in combination with timers. The right portion of Figure 1 illustrates this principle with two mho relays (outer and inner zones) and an angle impedance relay. $Z_{initial}$ is the pre-disturbance apparent impedance seen by relay $R$, located at one end of the transmission line. While a fault will cause an instantaneous movement of apparent impedance $Z_{app}$ from the load area to the line impedance $Z_L$, a power swing will cause $Z_{app}$ to move at a measurable rate and will be detected if the sequential pickup of the outer and inner mho units takes more than a predetermined time. It may be considered unstable when the angle impedance unit picks up and stable when $Z_{app}$ returns in the load area. Typically, this scheme will trip upon unstable swings and block for stable ones.

When tripping is required, excessive breaker stresses will be reduced if the two systems to be separated are not too close to $180^\circ$. It is therefore highly desirable either to anticipate the unstable swing or to delay the trip signal after the pole slip. However, anticipating the instability can rarely be done with such a scheme because the $Z_{app}$ trajectory is hard to predict for all conditions prevailing in a real system while tripping on a stable swing is not desirable. On the other hand, with a delayed trip signal, the magnitude and duration of voltage excursions will be more severe and will decrease the chances of island survival. Moreover, there is a possibility that heavy transfer or post-contingency conditions will bring the apparent impedance inside the outer zone for a time and make the power swing detection ineffective.

These difficulties have been invoked as justification for developing more sophisticated schemes for predicting the dynamic behaviour of power swings. New protection principles based on locally measured variables such as $U\cos\phi$ [4], line power and current [5] and $R$-Rdot [6] have been developed and used to improve the performance of loss-of-synchronism detection. Other schemes based on wide-area measurements consisting in measuring the angle shift between the sub-networks using phasor-measurement units are promising since a direct measurement of this quantity makes no assumption about the impedance of the tie-lines between the monitored sub-networks. However, this technology is
still at an early stage. As an example, a device was tested for detecting the loss of synchronism between Florida Power and Georgia Power based on wide-area measurement of the angle shift between the two grids [7]. Even if the results were encouraging, the need for significant improvement before reaching a practical use was acknowledged.

At the present time, since the wide-area technology is still developing and generally requires an expansive and failure-prone telecommunication infrastructure, the RPS and DLI relays have been designed to be fully local devices, their decision being based on a multi-criteria approach which complements the weakness and strength of many local variables to ensure self-tuned loss-of-synchronism relays with improved reliability and security.

4. FUNCTIONAL DESCRIPTION OF RPS AND DLI RELAYS

As shown in Figure 2, the RPS and DLI are two fuzzy-logic-based relays of the same family. Their hardware and software structures are very similar. While the RPS essentially supervises a transmission line to detect either severe power swings or, ultimately, loss-of-synchronism conditions, the DLI has the same functional capabilities but is fitted with a special transducer for accurately measuring the rotating speed of the plant generators. This additional feature is required to detect power plant instability with adequate pre-emption time. The six main functions found in RPS and DLI relays are initialization-setting, voltage and current acquisition and positive-sequence phasor computation, decisional-variable computation, fuzzy-logic algorithms, output and auxiliary functions.

Function 1: Initialization and setting

Four categories of parameters are required to set these relays:

<table>
<thead>
<tr>
<th>Function 1: Initialization and setting</th>
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<tbody>
<tr>
<td>1) RPS and DLI: Power System Parameter:</td>
<td>Power system nominal frequency (50 or 60Hz)</td>
</tr>
<tr>
<td>2) RPS and DLI: RPS Line Parameters:</td>
<td>Nominal ( \phi ) voltage (kV), Nominal Surge Impedance Loading Power (MVA)</td>
</tr>
<tr>
<td>PT and CT ratios, Line length (km), Line impedance parameters</td>
<td></td>
</tr>
<tr>
<td>3) RPS only: Arrester Parameters:</td>
<td>PT and CT ratios</td>
</tr>
<tr>
<td>4) RPS and DLI: Fuzzy logic Parameters:</td>
<td>9 parameters to tune the fuzzy logic algorithm sensitivity</td>
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Function 2: Acquisition - Computation of direct sequence phasors - Line model

Acquisition: Voltage and current signals are first processed with a 400 Hz anti-alias filter and then sampled at a rate of 1920 samples/s (32 samples * 60 Hz) for both 50 Hz and 60 Hz power systems.

Computation of direct-sequence phasors: A specially designed Kalman filter extracts the voltage and current positive-sequence phasors used as the primary variables in these applications. Kalman filtering was used instead of the widely spread discrete Fourier transform for several reasons. At first, it can be easily self-tuned at fundamental frequency without any hardware modification. This allows distortion-free tracking of fundamental quantities, even in the presence of large frequency offset, more effective rejection of harmonics or even pre-selected resonant non-harmonic frequencies, a characteristic that is not feasible with the DFT. This feature is very welcome in Hydro-Québec’s series-compensated network characterized as it is by many sub-synchronous electromagnetic phenomena.

Line model: A transmission line model is needed to compute the remote voltage and current phasors \( V_r \) and \( I_r \), given the local phasors \( V_s \) and \( I_s \). These sets are then used to derive decisional variables (function 3) such as line angle and frequency shifts, local and remote \( U_{	ext{cos}} \) and their derivatives. A quadrupolar line model (A, B, C, D) is used for this purpose. Such a model allows for projection of remote end phasors with very simple algebraic relationships that can be repeated to cascade several line sections as found with series-compensated lines.
**Function 3**: Computation of decisional variables

Both relays have the same basic set of 12 decisional variables, called RPS variables that are derived from phasors $V_s$, $I_s$, $V_r$ and $I_r$. The DLI is augmented by another three decisional variables derived from its speed transducer. All these variables are computed at a rate of 4 samples/cycle.

RPS decisional variables: They are used to track and anticipate the stable or unstable evolution of power swings across the transmission line. The line is used here as a "sensor" of the power system dynamics. Three angular variables, one concavity index [8], two voltage and six $U \cos \phi$ variables are preprocessed with a view to feeding the fuzzy-logic algorithm.

Speed decisional variables: As previously mentioned, this second set is dedicated to the DLI. These variables are derived from a specially designed speed transducer, required to anticipate instabilities when out of phase conditions do not occur on the RPS transmission line. Depending on the event, virtual faults may in fact appear on a remote line, not in the range of the RPS line detector. The basic principle of the speed detector is shown on figure 3. $V_{abc}$ and $I_{abc}$ correspond to the $V_{plant}$ and $I_{plant}$ of figures 2 and 4.
These input signals are first converted to positive-sequence voltage and current phasors $V_p$, $I_p$ and electrical power $P_e$ by the previously introduced Kalman filter. A first block computes the low-frequency portion of the speed transducer $\omega_L$ from the frequency deviation of the machine’s internal voltage phasor. Its high-frequency counterpart $\omega_H$ is obtained from a second block by integrating the electrical power in the rotor dynamics equation. Three decisional variables are extracted from this transducer to follow the dynamic behavior of the machine.

**Function 4:** Fuzzy logic algorithm

Many of the decisional variables mentioned above could individually provide a good indication of system stability. However, given the wide range of operating conditions found in large power systems, the performance of single-variable-based algorithms is limited because none of them may be considered perfect in this respect. The solutions proposed here are multi-criteria algorithms that take full advantage of the strength of all these variables by considering them all together to assess the stability condition. Fuzzy-logic algorithms with their inherent properties of combining multiple inputs in multi-rule schemes were found suitable for the present applications. The RPS and DLI fuzzy-logic algorithms proceed in three distinct steps:

1) **Fuzzyfication** of the 12 decisional variables for the RPS (15 for the DLI): It consists in transforming the crisp variables provided by function 3 into categories easily described by linguistic spellings of the common language such as **Normal**, **Small**, **Large**, **Very Large**. These terms correspond to classes that are specified by membership functions. Specifying the various linguistic parameters is a tedious task, generally based on a careful analysis of the physical principles in interaction with the huge database developed over the years by Hydro-Québec system engineers.

2) **Fuzzy logic inference** on these features, using 12 rules or criteria for the RPS (17 for the DLI): These rules may be classified in 4 categories:
   a) Rules based on large angle shifts allowing detection of virtual faults on the RPS line.
   b) Instabilities not resulting in out-of-phase situations on the RPS line (virtual fault on another line further along the corridor). In these cases, the angle shift tends to be equal to zero, both phasors, $V_s$ and $V_r$, being on the same side of the virtual fault.
   c) Security rules for situations where the relay should not trip because the system is stable
   d) DLI specific rules related to its speed decisional variables.

3) **Crisp detection signal:** An output stage is used to filter and validate the fuzzy logic decision signal

**Function 5:** Output functions

As shown in Figure 2, the RPS and DLI relays provide two types of outputs, the main detection signal $DS$ and the application-specific signals ($21P$ for the RPS and $DG1-DG12$ for the DLI). $DS$ is essentially the fuzzy-logic output once processed by a Programmable Scheme Logic (PSL), a generic tool of the target platform [9] used to customize applications. Since both relays are planned for system protection functions, interfacing them with external devices is mandatory. For this reason, the two relays provide spare digital inputs and outputs for interconnecting external logical signals with the internal ones.

**RPS specific function:** Hydro-Québec requirement for the RPS is the control of SMOSA (Switched Metal-Oxide Surge Arrester) in the SPSR scheme [2]. Upon detection of a potential system separation, these arresters are locally switched on by the RPS. Since their rated voltages are too low to be permanently connected, they are switched on for short periods of time and a low impedance protection $21P$ is provided to protect them in case of internal impedance degradation. In this application, the RPS settings are relatively sensitive in order to detect severe power swings as well as loss-of-synchronism conditions.

**DLI specific function:** The DLI is used either to issue permissive conditions for existing SPS or as a new SPS with its own generator-dropping remedial actions. In the first case, it is tuned in a more sensitive way to detect all disturbances severe enough to be considered power systems 'events'. In the second case, it is tuned to detect loss of synchronism and programmed to perform generator rejections. Monitoring of generator on-off states ($D1-D12$ inputs) and active powers ($P1-P12$ inputs) is then required, as illustrated in Figure 2. Figure 4 shows how RPS and DLI relays are connected in substations and plants. The five Hydro-Québec 735-kV substations where RPS relays are required and a future possible application (a long term development scenario for the Gull's Island power project) of the DLI as an SPS are pinpointed in Figure 5.
Figure 4: Hydro-Québec applications: RPS in a substation and DLI in a major power plant.

**Function 6:** Auxiliary functions: RPS and DLI are implemented on a modern digital relay platform [9] that offers a set of auxiliary functions for user interfacing, communication, programmable scheme logic, self-verification, event logging and disturbance recording. These features are helpful for installing, operating and maintaining these strategic relays.

Figure 5: Present Hydro-Québec grid and its natural cut-set lines (A to D) and RPS substations (Left) - A possible DLI application in a future long-term scenario involving the Gull’s Island complex (Right)
5. RPS AND DLI PERFORMANCES: SOME RESULTS

The RPS-DLI algorithm was extensively validated on Hydro-Québec network with EMTP and stability simulations and on Anderson test system, as described in [10], with Matlab-SimPowerSystems simulation tool. More than 300 test cases were selected for each relay to verify their reliability, security and speed.

- **Reliability:** To trip on unstable cases (100% for both RPS and DLI)
- **Security:** Not to trip on stable cases (100% for both RPS and DLI)
- **Speed:** RPS average pre-emption time > 10 cycles before out-of-phase condition. DLI detection was fast enough to avoid loss of synchronism of Churchill-Gull complex in all extreme contingencies considered in Hydro-Québec system studies.

Sample test cases are shown in Figure 6 for EMTP simulations on the Hydro-Québec system. The first two sets of curves are for an unstable and a stable case on the RPS (Figure 6a). As can be seen, a pre-emption time of 35 cycles before loss of synchronism is obtained even if the angle shift DTH is still less than 20° thanks to other variables such as the Vscosφ signal. On the other hand, the stable case, similar in terms of Vscosφ and Ps signals around 0.8 s, is correctly analyzed by the RPS due to other variables such as the angle shift. In this case, it is a power reversal situation rather than an out-of-phase condition. Figure 6b clearly demonstrates the positive effect of fast generator dropping at the Gull's Island power plant by the DLI. Even with major RPTC remedial actions (4,000 MW rejected at Churchill Falls and 3,500 MW of load shed in Montreal) the system would not be stable on an extreme contingency involving the loss of three Montagnais-Arnaud lines.

![Figure 6a: Unstable (left) and stable (right) cases with RPS](image)

![Figure 6b: Effect of fast DLI remedial action in Gull's Island power plant](image)
With its ability to anticipate unstable power swings, the DLI complements the RPTC actions with an additional 1,500 MW of generation rejection in order to maintain a large enough synchronizing torque to keep the power plant connected and the whole system stable. The right-hand curves are for comparing the power plant speed deviation of the DLI transducer with the theoretical transient response provided by EMTP. As may be noticed, the transducer accuracy is more than satisfactory.

6. CONCLUSION

Recent cascading failures in power systems scattered throughout the world call for analysis, research and development efforts in order to determine the conditions and triggering events, and devise preventive transmission planning solutions, operating procedures and automatic protection systems. In this context, loss-of-synchronism detection is considered one of the strategic functions required to protect a power system against severe contingencies and cascading failures. With its extensive complex power system, Hydro-Québec obviously needs efficient automatic protection schemes and for that purpose, has recently developed two novel relays, RPS and DLI, in a joint R&D project with Areva T&D. These relays are intended to provide efficient solutions to the loss-of-synchronism problems affecting Hydro-Québec’s present and future system.

These two relays are now at their final stage of development. As was done in the same partnership activities for the earlier open-line detector relay project [3], it is planned to conduct extensive functional tests on pre-industrial units on IREQ’s Hypersim real-time simulator in 2006 and homologation and field tests on final units in 2007. Simulator tests will be done on two power system models, the Anderson test system [10] previously used in the development phase, and a reduced 300-bus version of Hydro-Québec’s main grid. Field tests will be conducted in one of the target substations (Figure 5) for the RPS and in a major power plant of the Bay James complex for the DLI.

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