Emergency Voltage Stability Controls: an Overview

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***Abstract*—This paper provides an overview of emergency voltage stability controls in power systems. First, a brief review is made of voltage instability mechanisms, countermeasures, and system protection schemes. Next, the paper discusses various aspects of emergency controls, including generator voltage control, load tap changer modified control and load shedding, pointing out some important features and addressing research aspects. Load shedding is considered in some more detail, and applications to two real systems of, respectively, a response-based and an event-based load shedding scheme, are described.**

***Index Terms*—System Protection Schemes, Voltage Stability, undervoltage load shedding, emergency control.**

I. Introduction

THIS presentation focuses on the design and implementation of emergency controls to counteract voltage instability and save the power system from an imminent voltage collapse. Control actions considered include emergency coordinated control of generators, modified control of Load Tap Changers (LTC), and as a last resort load shedding.

In many power systems throughout the world, voltage instability is considered as a major risk of blackout, as important as thermal overloads and the associated risk of cascade line tripping. As these systems are forced by economic and environmental considerations to "walk closer to the edge" of such a catastrophic blackout, the need for effective means to identify an approaching critical condition, as well as to counteract an ongoing instability is becoming more evident every day.

A very useful tool, although not as widely used as it should be, in order to address the first problem (that of identifying the distance to the edge) is on-line security assessment. In the particular case of voltage stability problems the on-line Voltage Security Assessment (VSA) can be used at the control center as the "stick" that measures the distance to the edge at any specific point in time. A specific on-line VSA application is described in [1].

With the on-line VSA, security margins are continuously evaluated with respect to any number of contingencies. Using this information, appropriate preventive actions can be taken to restore sufficient margins, whenever needed. Preventive enhancement of security may lead the Transmission System Operator (TSO) to decrease the posted available transfer capabilities, to reschedule generation, to request some units to be kept in operation for voltage support and, in the last resort, to shed load. Of course, any of these actions has a non-negligible cost. Furthermore, in the prevailing open market environment, such decisions have to be taken in a transparent way. Hence, appropriate decision tools should support the TSO in taking these measures.

However, it would be extremely expensive, and most likely impossible, to protect a power system against any disturbance. As a trade-off between reliability and economy, power systems are usually operated in such a way that they can survive credible contingencies, i.e. incidents with a reasonable probability of occurrence, while for more severe incidents the TSO relies on corrective controls. The latter should take on the form of automatic emergency actions, through system protection schemes, aimed at preserving operation of the largest possible part of the system by isolating the part of the system responsible for the instability [2]. Corrective actions usually affect generators and/or loads, and hence are acceptable only in the presence of very severe disturbances.

Coming back to the "walking close to the edge" paradigm, when everything else fails and the edge is even slightly overstepped, the system should have a "safety net" that will avoid the widespread catastrophe of a free fall. Clearly "falling to the net" has a cost, but this is minimal with respect to that of a generalized blackout.

One important aspect regarding voltage stability and collapse should be discussed at this point. In assessing the security of an operating point, voltage level is generally not a good indicator. Indeed in modern power systems various controls hold voltages close to their nominal values even very close to the edge. Thus the special tool of on-line VSA is needed to quantify the distance to the edge in an easily measurable and meaningful quantity, such as load power in MW. This, as discussed above, is the "stick" that tells us how far the edge is. This information is also valuable, as will be seen, in order to arm a systems protection scheme against a possible collapse.

On the other hand, when the system enters an emergency situation, i.e. the edge is reached if not overstepped, low voltage of affected buses is the first indication of an approaching collapse. Since long-term voltage instability is initially a slow process the undervoltage information is extremely valuable

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and can be used to trigger the protection scheme that will form the safety net to save the collapsing system. This distinction is thus important: voltage level is a good indicator of an emergency situation, whereas in order to characterize the security of a normal operating point, further information is necessary.

In the next Section we briefly review voltage instability mechanisms, outline available corrective countermeasures and recall fundamentals about system protection schemes. Emergency control of generator voltages and LTCs are briefly discussed in Sections III and IV, respectively. A large part of the paper is devoted to load shedding, with general aspects discussed in Section V and two applications described in Section VI.

II. Voltage Instability and Countermeasures

Power system instability may take on the form of angle, frequency or voltage instability [3]. Voltage instability in particular results from the inability of the combined transmission and generation system to deliver the power requested by loads [4]. It is a dynamic phenomenon largely driven by the load response to voltage changes.

In a voltage unstable situation, the voltage drops caused by power transfers across the network are no longer in the order of a few percents (as in normal operating conditions), but undergo a dramatic, generally monotonic decline in the seconds or minutes following a disturbance. When this decrease is too pronounced, the system integrity is endangered mainly due to protecting devices that trip generation, transmission, or load equipment, not to mention the nuisance caused to customers by sustained voltage sags. This degradation process may eventually lead to a blackout in the form of a voltage collapse [5].

A. Short and Long-term Instability Mechanisms

The dynamics involved in voltage stability analysis refer to a wide variety of phenomena and controls that can be classified into:

- short-term dynamics of generators, turbines, governors, Automatic Voltage Regulators (AVRs), Static Var Compensators (SVCs), induction motors, HVDC links, etc. lasting typically from one to several seconds
- long-term dynamics of secondary frequency and voltage control, OverExcitation Limiters (OEL) of generators, LTCs, load self-restoration, etc. lasting typically several minutes, if not more.

In practice, the short and long-term dynamics are fairly well decoupled so that a distinction of short-term and long-term voltage stability is necessary.

When a power system is subject to a disturbance, the short-term dynamics are excited first. Over a period of a few seconds, the long-term variables do not respond yet and can be considered as constant parameters. The short-term time scale is the time frame of both angle instability (i.e. the loss of synchronism between generators) and of short-term voltage instability, which is linked to fast load recovery by induction motors and possibly HVDC systems. Another case of short-term instability may occur when, after a severe disturbance, frequency falls sharply due to generation-load imbalance that cannot be covered by the insufficient spinning reserve. In this case a short-term equilibrium cannot be obtained.

When an induction motor is subject to a voltage drop, its electromagnetic torque initially decreases as the square of voltage. As a result, the motor decelerates, i.e. the slip increases, until this increase (in the stable case) causes the electromagnetic torque to restore to the value of the mechanical one. The following are scenarios of short-term voltage instability caused by induction motors:

1. The outage of transmission equipment causes the maximum deliverable power to become smaller than the mechanical power of the motor load. Thus, the electromagnetic torque cannot be restored, the motor stalls, which causes the voltage to drop and a high current to flow in the armature.

2. A short-circuit near the motor causes the latter to decelerate. If the fault is not cleared fast enough, the motor is unable to reaccelerate and thus it stalls, with the same outcome as above.

In the first case, the system has no post-disturbance equilibrium, while in the second case the long-lasting fault makes it escape from the region of attraction of its post-disturbance equilibrium.

Let us now examine long-term voltage stability. To do so we assume that the system has survived the short-term period following the disturbance. From there on, it is driven by the long-term dynamics. Long-term voltage instability is associated with these slower dynamics. LTCs and OELs play an important role. A typical long-term instability scenario is as follows.

The triggering event is the outage of generation and/or transmission equipment reducing the maximum power deliverable to loads and causing transmission voltages to drop (although moderately at first) and generators to increase their excitation under AVR action. After some intentional delay time, LTCs start trying to restore the voltages of distribution networks by adjusting the ratios of the transformers feeding them. Bringing the distribution voltages back to the LTC setpoints (in practice, close to them, due to deadband effects) would mean restoring load powers to their pre-disturbance value. Tap changes and load power recovery depress voltages on the transmission side. This further draws on the reactive reserves and activates some OELs, which contribute to further reducing the maximum power deliverable to loads. If the latter becomes smaller than what the LTCs tend to restore, instability follows in the form of useless tap changes (that will eventually depress distribution voltages) and dramatic transmission voltage drops.

In this scenario the system loses its long-term equilibrium. In the best case, the process stops when LTCs hit their limits, yielding pseudo-stabilization. However, it is also possible that the long-term system degradation triggers instability of the short-term dynamics (assumed stable up to now). This may take on the form of:

- field current limited generators losing synchronism;

- motors stalling due to low voltage conditions;
- oscillatory angle instability due to OELs bypassing power system stabilizers.

Finally, the situation may be aggravated by protections:

- tripping lines due to thermal overload or zone-3 relay activation;
- tripping field current limited generators owing to low terminal voltage or armature thermal overload.

Long-term instability may also be driven by thermostatically controlled loads, which exhibit similar recovery behaviour.

B. Detection of emergency conditions

The test system shown in Fig. 1 will help illustrate some basic features of voltage instability and serve as an introduction to the problem of detecting an emergency condition. It consists of a remote system represented by a Thévenin equivalent, a double-circuit transmission line and a local generator feeding a motor load and a voltage-dependent LTC-controlled load.

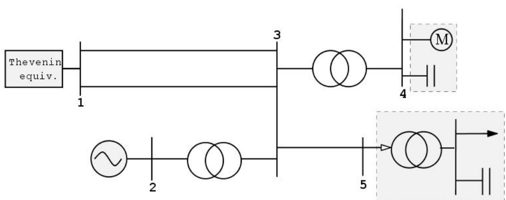

Fig.1. Illustrative test system

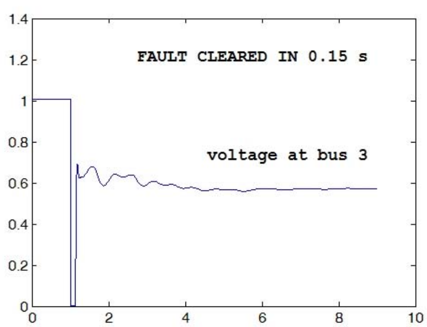

Fig. 2. Short-term instability due to slow fault clearing

In Fig. 2 a case of short-term instability in the form of motor stalling after a delayed short-circuit clearing is shown. Note the severely depressed voltage after the stalling of the motor.

In Fig. 3 a typical case of long-term voltage instability is shown. After the loss of one of the two circuits of the transmission line, the local generator gets overexcited. After its OEL is activated at t=50 s, the load restoration process through LTC action becomes eventually unstable and the distribution voltage cannot be restored. As the instability evolves for about 3 minutes the voltages suddenly collapse and synchronism is lost between the local generator and the remote system.

Clearly in this case there is enough time to take appropriate countermeasures after the disturbance, but the time margin should not be overestimated because this could lead to a blackout. Note that the gradual drop of the transmission voltage can serve as an indicator of the emergency condition. Note also that the reactive reserve of the local generator is immediately exhausted in this case, but this is not a sufficient indication of voltage instability.

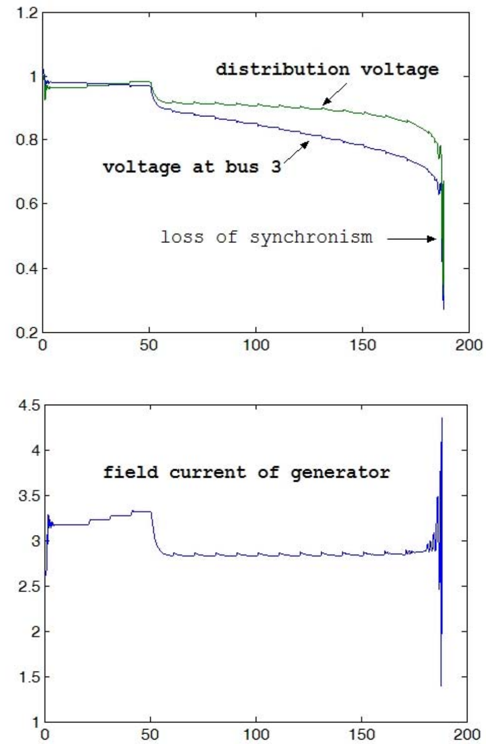

Fig. 3. Long-term voltage instability leading to loss of synchronism

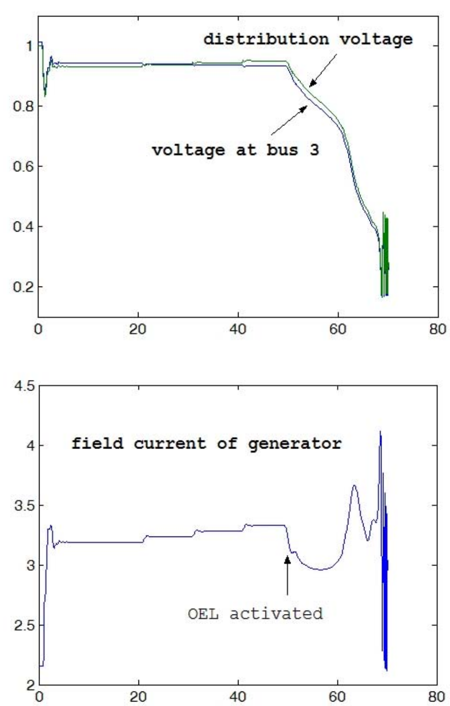

Fig. 4. Long-term voltage instability with a higher proportion of motor load

The variant shown in Fig. 4 corresponds to a higher proportion of motor load represented by the equivalent induction motor. In this case, when the OEL enforces the limitation at t=50 s, voltages fall more abruptly than in the previous case and the induction motor stalls. This in turn further depresses voltages causing the local generator to lose synchronism shortly after the motor has stopped completely absorbing the high reactive starting current. Note that some motors may trip in this case, but for those with only thermal protection this may take a few minutes. In any case motor protection is not modelled in this simple system.

This is a much more difficult case to protect against, as time limitations are very strict. Most probably transmission voltage can still be used as a triggering signal for load shedding, but a much faster action (within a few seconds) has to be taken to restore a stable operating point. Alternatively, the indication of generator overexcitation (negative reactive power reserve) could be used to speed up this action, for instance by allowing undervoltage load shedding to act with a shorter delay [6].

It should be noted, however, that the design of a protection scheme is very much system-dependent. For instance, in the system with lower percentage of motor load (Fig. 3) generation overexcitation is not an indication for urgent load shedding. As is well known for voltage stability in general, load behaviour has also a strong impact on the design choices.

C. Types of emergency controls

Several options exist for emergency controls that will protect the system against voltage collapse. In the following we classify emergency controls according to their cost that includes also the nuisance caused to consumers whose service is disrupted.

Reactive shunt element switching and special generator voltage controls have no negative impact on consumers or other operational cost and will be normally the first to be utilized, if available.

Generation rescheduling, as well as fast unit start-up, do not affect the consumers, but they have a definite impact on the market and thus are controls with a cost, albeit relatively low.

Emergency controls on LTCs on the other hand have no direct cost, but they do impact, even if indirectly, the load power consumed, as well as the quality of power delivered to consumers due to unrestored distribution voltages. They are thus also classified as intermediate cost countermeasures.

Finally load shedding is the ultimate countermeasure to save an unstable system, but is only a last resort to be used only when there is no other alternative to stop an approaching collapse.

D. System protection schemes

As already mentioned, a System Protection Scheme (SPS) is a protection system designed to detect abnormal system conditions and take predetermined, corrective actions (other than the isolation of faulted elements) to preserve as far as possible system integrity and regain acceptable system performances [2].

Apart from this fundamental difference, both equipment and system protections share some common design requirements:

- *dependability*: the protection acts when needed;
- *security*: the protection does not act when not needed;
- *reliability*: it is both dependable and secure;
- *selectivity*: the size of the action fits the severity of the disturbance;
- *robustness*: the protection can face a wide range of scenarios that could be encountered.

In recent years, several types of SPS have been proposed and/or implemented. They can be classified according to the following four criteria [2, 10]:

- *decentralized vs. wide-area*. A decentralized SPS uses local measurements (for instance collected in the same substation) and acts on local devices (for instance located in the same substation). On the other hand, a wide-area SPS collects data from several (distant) locations and/or acts on devices located in several (distant) places of the system;
- *response-based vs. event-based*. A response-based SPS relies on measurements of electric quantities (such as voltage, frequency, etc.) through which the consequences of system misoperation can be observed. On the contrary, an event-based SPS operates upon the recognition of a particular combination of events;
- *rule-based vs. algorithmic decision*. A rule-based SPS relies on "if ... then ..." rules (e.g. comparison of measurements with thresholds, etc.) while an algorithmic decision-based SPS relies on a more involved analysis of a model of the system;
- *closed-loop vs. open-loop*. An SPS works in closed-loop when it is able to act several times, each action relying on the measured result of the previously taken actions.

Decentralized SPS are more reliable, since they do not rely on an extensive telecommunication system. On the other hand, they may lack the system view needed to coordinate various, competing controls.

Event-based are expected to be faster than response-based SPS, which have to wait for the system response to a specific event before acting. They are appropriate in cases where the threatening disturbances can be clearly identified (see for instance Section VI.B). However, response-based SPS are more robust, since they work by observing the consequences of disturbances without attempting to identify them.

A similar conclusion holds for algorithmic SPS: since they rely on a model of the system, they are in principle better prepared to face unforeseen disturbances and adapt their action to the severity of the situation. On the other hand, the more detailed the model, the lower the robustness with respect to modelling and real-time data inaccuracies, and the higher the dependency upon the real-time information system. Rule-based SPS are comparatively simpler, although the embedded rules have to be properly tuned (see Section VI.A).

When the counteracted phenomena make it possible, closed-loop SPS combine selectivity and dependability: since they are allowed to operate as many times as needed, they automatically adapt their action to the severity of the disturbance. Furthermore, this increases the SPS robustness against the inevitable uncertainties in system behaviour. This is particularly important in voltage instability, where loads plays a central role while their composition changes with time and their behaviour under large voltage drops may not be known accurately.

III. Emergency controls of generator voltages

It is well known that the maximum power that a source can deliver to a load increases with the square of the source voltage. Hence, an increase in generator voltages may contribute to stabilizing a system, provided that the maximum power is made larger than the power that loads attempt to restore [4].

In the same spirit, although more relevant to planning than emergency control, the regulation of high-side voltages of generator step-up transformers (through either compensation of their leakage reactance, or an additional loop in the AVR) is effective as it regulates voltages closer to the loads. However, the range of admissible generator voltages is limited, which in turn limits the increase in deliverable power, especially if generators already operate above nominal voltage. This type of control thus appears better suited to low but stable voltage situations, or as a welcome complement to other emergency controls.

When several generators control a voltage weak area, coordination is mandatory to avoid unwanted interactions. The latter, for instance, may lead one generator to produce reactive power that is absorbed by a neighbouring generator, with a limited improvement of voltages at load buses and a risk of switching the sending generator under limit. Generator voltages have to be increased in unison.

Such a coordinated control is precisely the objective of the secondary voltage control used in France and Italy [7]. Simply stated, the latter adjusts generator voltages to regulate the voltages at “pilot nodes”, while making the reactive power production of each generator proportional to its capability.

To our knowledge, secondary voltage control has been mainly designed for normal operation (where indeed it greatly simplifies operators’ tasks). It is basically a long-term control, with a time constant of one minute, similar to that of LTCs, with which it interacts in case of large disturbances. To be more effective in emergency conditions, the response should be made faster upon detection of abnormal conditions.

The first generation of secondary voltage control relies on reactive power control loops in power plants and a centralized PI controller to regulate the pilot node, with no model of the system. On the other hand, the second generation, in operation in the Western region of France, uses a sensitivity model of the power system (built from SCADA information) and computes generator voltage changes by solving a succession of quadratic programming problems. In fact, this control scheme can be seen as a special implementation of the *Model Predictive Control* (MPC), in so far as it relies on the multi-step optimization of a quadratic voltage-reactive power objective, embedding new measurements of pilot node voltages and generator reactive powers at each time step.

MPC (or MPC-like) approaches have been proposed by several researchers to control generator voltages, shunt compensation and load shedding in emergency conditions [29-32]. This interesting research work is well beyond the emergency schemes used in today’s practice and is not considered further in this paper. A discussion of some strengths and limitations of this approach is offered in [33].

IV. Emergency control of LTCs

Automatic LTCs on bulk power delivery transformers constitute a prime source of load restoration and are thus a driving force for voltage instability. Several emergency LTC control measures are in use or have been proposed in the literature for containing voltage instability:

- *tap blocking* is the simplest countermeasure involving emergency LTC control. It consists simply of deactivating the control mechanism that is normally restoring the secondary (distribution side) voltage of the power delivery transformer. In this way load restoration is cancelled, or, in the worst case, delayed;
- *voltage setpoint reduction* consists of lowering the reference voltage and associated deadband of the distribution side voltage. The LTC is left to control this voltage in the normal way;
- *tap locking* is the action of assigning a specific tap position, where the LTC will move and then lock;
- *tap reversing* consists in changing the control logic, so that the LTC is controlling the transmission side voltage instead of the distribution side.

The above actions are able to efficiently stop the system degradation, especially if LTC control is the only source of load power restoration. However, LTCs are relatively slow devices, unable to quickly correct a situation with severe voltage drops caused by an initial disturbance. Hence, they can be used to counteract disturbances with moderate impact or in conjunction with other countermeasures.

Tap blocking basically “freezes” the system in its current state. By the time it is applied, voltages may already have dropped significantly, and the system is left with these low voltages. This measure is better suited to delay the daily load pick-up by keeping distribution voltages unregulated, when for instance the available stability margin is smaller than the expected load peak.

Distribution voltage setpoint reduction is more efficient, since it produces a distributed load power reduction that corrects transmission voltages. Of course, the load sensitivity to voltage has to be large enough.

Tap locking forces LTCs to operate even more in favour of transmission voltages, but requires choosing target positions, which may change with operating conditions.

Tap reversing is the most effective of all LTC emergency measures. Ref. [9] reports on detailed simulations of a large system, in which the LTC logic is modified so as to revert the tap movements once the voltage at a monitored transmission bus falls below some threshold. A deadband on this voltage allows the system to settle down in between the normal and reverse logic modes. In order to control a large number of LTCs, the latter are divided into clusters, each with its own monitored voltage. Ref. [9] also considers the control of two levels of LTCs in cascade, with proper coordination of the respective threshold voltages used at both levels.

When other factors of load recovery (e.g. thermostatic loads) are present, the above LTC controls only offer a temporary relief. Their relative merits on a longer time-scale are compared in [5,8] for a small system including load self-restoration. Again, tap reversing appears as the most effective. technique, provided that LTCs do not hit their limit. Obviously, none of the LTC emergency controls is able to restore long-term system equilibrium in the presence of load self-restoration. This requires direct load shedding.

Among the above controls, tap blocking, voltage setpoint reduction, and tap locking are more easily implemented, since they are supported by most of the existing LTC controller hardware. These techniques, or combinations of them, are used in some countries. On the other hand, tap reversing would require further developments, in particular a modification of the tap changing logic as well as the transmission of remote voltage measurements. Its cost may become prohibitive, if many transformers are involved.

V. LOAD SHEDDING

While used in the last resort, load shedding is well known to be an effective countermeasure against voltage instability [11] especially when the system undergoes an initial voltage drop that is too pronounced to be corrected by generator voltages (due to the limited range of allowed voltages) or LTCs (due to their relatively slow movements and also limited control range).

The time, location and amount are three important and closely related aspects of load shedding against voltage instability [4] that we discuss before dealing with rule-based SPS.

A. Time, location and amount aspects

From the discussion of Section II, it is clear that the time available for load shedding is limited by the necessity:

1. to avoid reaching the catastrophic collapse that can take on the form of generator loss of synchronism or motor stalling. This leaves little time in the case of long-term instability involving a sudden voltage drop after OEL activation (as in Fig. 4) and even less in the case of short-term instability (as in Fig. 2);
2. to stop system degradation due to undervoltage tripping of field current limited generators or the line opening by protection;
3. to limit customer nuisance caused by sustained low voltages. This may lead to acting fast even in the case of long-term voltage instability, if the disturbance is harmful enough.

As far as long-term voltage instability is concerned, if none of the above factors is limiting, one can show that there is maximum delay beyond which shedding later requires shedding more [4]. This is a matter of system attraction to the newly restored long-term equilibrium.

This delay may be used to activate other emergency controls and hence decrease the amount of load shedding. An illustration is given in Fig. 5. This figure, relative to the real system considered in Section VI.A, shows the influence of the shedding delay τ on the minimal amount of load $P^{\min}$ that has to shed, in a single step, in order to save the system. For the (long-term instability) scenario of concern, the best time to shed is 15 to 20 seconds (or 35 to 40 seconds) after the disturbance. This delay allows automatic devices to switch shunt compensation and hence to increase the network transmission capability, thereby reducing the necessary amount of load to be shed. Shedding earlier resets the shunt compensation switching devices by increasing the transmission voltages that they monitor.

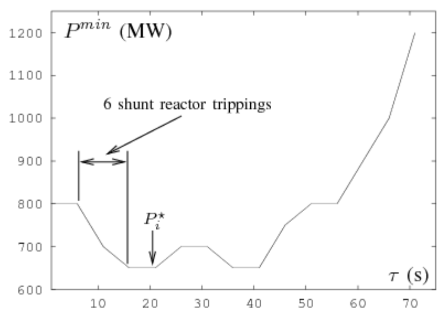

Fig. 5. Minimal load shedding as a function of shedding delay

As far as frequency instability is of concern, the shedding location does not play an important role; what matters is to restore the overall generation-load balance of the system (or the island after a network split). On the contrary, when voltage instability is of concern, the shedding location matters a lot: shedding at a less appropriate place requires shedding more.

In practice, of course, the region prone to voltage instability is known beforehand owing to some structural weakness of the system. However, within this region, the best location for load shedding may vary with the disturbance (and the associated instability mode). This was illustrated e.g. in [53] through simulations of a real system with a rather meshed structure.

There are proven sensitivity or eigenvalue analysis techniques to identify which parameters it is most effective to change in order to increase a load power margin [13-15]; this can be straightforwardly applied to load shedding. Sensitivity analysis can be coupled to time simulation in order to find the best corrective actions in a post-disturbance unstable situation as well [16]. More recently Ref. [17] proposed a unified while simple sensitivity analysis encompassing unstable as well as low but stable voltage situations. It involves the sensitivities of the transmission voltage experiencing the largest drop, which can be easily computed.

Incidentally, when undervoltage tripping of limited generators is a concern (see requirement 2), the loads to shed are those most effective in restoring generation voltages. In this case, sensitivity analysis should be redirected to generator bus voltages (with the field current limits in effect).

Once a ranking of loads has been set up, the minimal amount of power to shed can be easily determined, e.g. through a binary search on this single parameter [18].

While they perform very well in off-line simulations, the above mentioned computations could hardly be embedded in a protection scheme. This would require extensive real-time information of the type considered in the research work on Model Predictive Control already mentioned in Section III.

A possibly sub-optimal but by far simpler (and hence more reliable) technique consists in shedding first where voltages drop the most. Even if it may lead to shedding some more load, this criterion makes sense in terms of nuisance to customers caused by sustained low voltage.

B. Design of load shedding rules

Load shedding schemes are typically rule-based and rely on a measured voltage V used in rules of the type [19]:

$$\textit{if } V < V^{th} \textit{ during } \tau \textit{ seconds, shed } \Delta P \textit{ MW} \qquad (1)$$

Clearly, the threshold V^{th} must be:

- low enough so that no load is shed in acceptable post-disturbance situations. This involves normally all N-1 contingencies; whether load may be shed following harmless N-k contingencies is a matter of criteria;
- high enough to avoid shedding too late.

Similarly, in long-term instability cases, the delay τ must be:

- long enough to prevent reaction on a nearby fault, leaving time for protections to act and voltage to recover to normal values;
- short enough for already mentioned reasons.

It has been mentioned in Section II.D that a closed-loop SPS is desirable to face modelling uncertainties and adjust to the severity of the disturbance. A closed-loop design is obtained by allowing the above rule to be applied several times until V recovers above V^{th}, thereby compensating for the fact that the load shedding amount is not known a priori.

Post-disturbance voltage is an appropriate input signal for the above purpose. Indeed, voltages have practically no inertia and the effect of acting on some component is felt almost instantaneously, at least in some neighbourhood, thereby allowing the next action to be taken without prohibitive delays[1].

In fact, this signal is so "volatile" that the delay τ must be left in between successive sheddings to avoid excessive action (that could eventually lead to overvoltages). Even better, τ can obey an "inverse-time" characteristic in which the smaller the voltage drop below the threshold, the larger τ.

The scheme can further adjust to the disturbance severity by linking the load shedding step ΔP to the average voltage drop, i.e. by taking [19]:

$$\Delta P = K.\Delta V^{av} \qquad \text{subject to} \quad \Delta P^{\min} \le \Delta P \le \Delta P^{\max} \quad (2)$$

where ΔV^{av} is the average voltage drop:

$$\Delta V^{av} = \frac{1}{\tau}\int_{t_o}^{t_o+\tau} (V^{th} - V)\, dt \qquad (3)$$

and t_O is the time where V drops below V^{th}, or the last time the rule has triggered load shedding.

C. Distributed undervoltage load shedding

Reference [20] proposes a distributed implementation of undervoltage load shedding aimed at:

- adjusting the amount of load dropped to the severity of the situation;
- adjusting its location to the disturbance location;
- facing uncertainties in system response.

To this purpose, the region prone to voltage instability is divided into several load areas. Each of them is provided with a controller monitoring the measured local voltage, operating in closed-loop, and reacting with variable delay and variable amplitude, as outlined in the previous section. The various controllers are implicitly coordinated by the network voltages themselves, and cooperate without resorting to a dedicated communication network, which adds to the simplicity.

D. Additional input signals

We have stressed in Section II.C that generator reactive reserve (or an indication of excessive field currents) might be a useful input signal to complement voltage in some cases. This idea was used in the SPS described in [21].

Similarly, in order to meet the second requirement in Section V.A, it might be appropriate to involve generator voltages in the SPS rules, the objective being to keep them above the undervoltage tripping thresholds.

On the way from rule-based to algorithmic decisions, another approach consists in trying to detect a condition that corresponds to the system becoming unstable, instead of observing the consequences of this instability. Such an indicator is expected to provide an earlier emergency signal before voltage has dropped significantly.

Identifying the so-called critical point where the system crosses maximum load power is an easy task in off-line simulations using sensitivity analysis coupled with time simulation [12, 16]. It is, however, a much more challenging task when only real-time measurements are available.

The Voltage Instability Predictor of Ref. [23] is aimed at detecting the above critical point. It consists of detecting at several buses a condition in which the magnitude of the load impedance becomes equal to that of the Thévenin equivalent impedance seen from the bus of concern. This is easily shown to correspond to maximum load power in a simple two-bus system [23, 4]. The Thévenin impedance has to be estimated in a least-square sense from measurements sampled over a time window that should be wide enough for the operating conditions to change, but narrow enough to satisfy the constant Thévenin impedance assumption. We believe that several issues need be addressed concerning the application of this method, for instance:

- the detectability of a system-wide instability by monitoring the system from a single bus;

[1] due to its slow dynamics (dictated by rotating masses inertia, speed governors and turbines), frequency is comparatively a less convenient input signal, and other forms of closed-loop control have to be used in the case of underfrequency load shedding.

- the robustness of the technique when applied over the time interval that follows a severe disturbance (instead of during a smooth load increase);
- its capability to provide an early alarm compared to low voltage detection.

Some of these points are addressed in recent works [24, 25].

VI. EXAMPLES OF LOAD SHEDDING SCHEMES

A. Response-based SPS: Hydro-Québec system

With its long transmission corridors between the hydro generation areas in the North and the main load centers in the South part of the province, the Hydro-Québec system is exposed to angle, frequency and voltage stability problems.

Besides static var compensators and synchronous condensers, the automatic shunt reactor switching devices – named MAIS – play an important role in voltage control. These devices, in operation since early 1997, are now available in twenty-two 735-kV substations and control a large part of the total 25,500 Mvar shunt compensation. Each MAIS device relies on the local voltage, the coordination between substations being performed through the switching delays. While fast-acting MAIS can improve transient angle stability, slower MAIS significantly contribute to voltage stability. MAIS devices react to voltage drops but also prevent overvoltages by reconnecting shunt reactors when needed.

In order to upgrade the reliability of its transmission system, H-Q has developed over the recent years an extensive defence plan against major disturbances. Besides traditional underfrequency load shedding measures, an extensive generation rejection and remote load shedding scheme, named RPTC, has been installed to face transient angle stability problems. The last step of this deployment was the undervoltage load shedding scheme named TDST, which is now in operation.

While RPTC is event-based (due to the speed of angle instability phenomena), TDST is response-based, relying on five transmission voltages measured in the Montreal area. More precisely, local voltages are measured (with a sampling rate of 0.1 s) in five 735-kV substations equipped with MAIS devices and validated through the data acquisition chains of the latter. The average $\overline{V}$ of these local voltages is then considered, provided that 3 values out of the 5 received are valid [22].

The protection relies on $\overline{V}$ not only to allow bad data rejection but also to better identify dangerous disturbances. Indeed, while an N-1 contingency (for which no load shedding is allowed) can affect one of the local voltages, it has little effect on the average $\overline{V}$. Conversely, a significant drop of $\overline{V}$ is an indication that an N-2 or more severe disturbance has occurred.

TDST can act in a pre-defined load basin, of which it is allowed to shed at most a certain percentage. The remote load shedding controller present in RPTC knows which distribution circuit breakers can be opened.

The load shedding controller relies on the following:

- 3 rules, each allowed to act once:

R_1 *: if* $\overline{V} < 0.94$ *pu for 11 seconds, shed 400 MW*

R_2 *: if* $\overline{V} < 0.92$ *pu for 9 seconds, shed 400 MW*

R_3 *: if* $\overline{V} < 0.90$ *pu for 6 seconds, shed 700 MW*

- R_4: a rule of the type given by (1)-(3) with $\tau = 3$ s, $V^{th} = 0.95$ pu, $\Delta P^{\min} = 100$ MW, $\Delta P^{\max} = 250$ MW and $K = 6{,}500$ MW/pu. This rule cannot act before R_1, R_2 or R_3 has been activated but it can act several times, in closed-loop mode, with a maximum of 1000 MW of load shed.

The main purpose of R_1, R_2 and R_3 is to react to a severe voltage drop and make the voltage promptly recover. These rules are "concurrent" in the sense that any of them can be applied irrespective of the others. However, each rule may be triggered only once.

The role of R_4 is the final stabilization of the system. With V^{th} set to the high value of 0.95 pu, there could be a risk of undue load shedding following large system transients. On the basis of simulations, it is possible to tune the protection parameters to avoid such false operation; however, the uncertainty affecting the simulation models must be considered as well. Therefore, to increase the protection security, it was decided to condition the application of R_4 to the previous triggering of R_1, R_2 or R_3. Further details on the SPS design and its optimisation can be found in [19, 22].

An example of simulated response to a double line tripping is given in Fig. 6. Although $\overline{V}$ falls below the thresholds of R_1 and R_2 just after the disturbance, advantage is taken of the MAIS devices, which make $\overline{V}$ recover above 0.94 pu, and hence reset the rules. However, the voltage decrease resumes, causing R_1 to shed 400 MW. From there on, R_4 sheds 3 blocks of 100 MW, and $\overline{V}$ stabilizes above 0.95 pu. The minimal load shedding was 650 MW in this case.

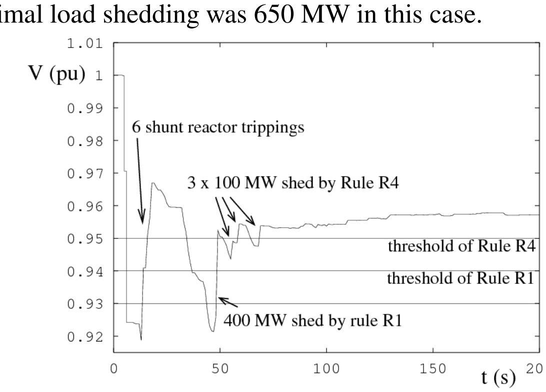

Fig. 6. Example of undervoltage load shedding in Hydro-Québec system

B. Event-based SPS: Hellenic system

The Hellenic Interconnected System is prone to voltage instability incidents since 1996, when the summer peak started to dominate due to increasing air-conditioning use in the south part of the system and in particular in the Athens metropolitan area. These culminated in the July 2004 blackout of the south system [26]. Following this a number of major system upgrades were performed to restore the security of the system. On top of these the Hellenic Transmission Operator (HTSO) decided to install an on-line Voltage Security Assessment (VSA) tool in continuing operation at the National control center [1]. The VSA reports for 2005-06 were quite encouraging [27] as secure operational margins were generally comfortable. However, for certain specific and very severe contingencies security margins may be drastically reduced in the near future.

The contingencies under investigation are:

1. The tripping of a double-circuit line serving radially a power station of nominally 950 MW near Athens, and
2. The combined loss of two 300 MW units in the southern peninsula of Peloponnese.

At the last stage of the 2004 blackout, a manual load shedding action was attempted, but was unsuccessful, since there was not time left for it to be performed. This led to the conclusion that for each of the above two contingencies an automatic load shedding scheme should be designed. The details of these schemes are presented in [28]. Some basic design characteristics are outlined below.

Due to the long history of low voltages in the system undervoltage was not deemed a sufficient indicator for load shedding. It was thus decided to select two separate event-driven load-shedding schemes that would recognize the above contingencies and act accordingly for shedding pre-specified loads.

On the other hand, voltages as low as 0.88 pu at generator buses were seen from the blackout experience to cause disconnection of units due to auxiliary loss, leading to a cascade of generator trippings. This information was used to tune the amount of load shedding for each of the above schemes. Thus the minimum amount to be shed was calculated so that no generator voltage falls below the tripping threshold. In this calculation the voltage sensitivities to load rejection discussed in Section V.A were used.

The final amount of shedding was determined examining also available feeders for automatic disconnection. The feeders marked for the underfrequency protection system (used also to avoid overloading of the interconnection lines to the neighbouring countries to the North) were used for this purpose. The amount of load shedding was tested by simulation and proved effective.

Furthermore, to avoid unwanted operation of the load shedding schemes it was decided that they are armed centrally from the National control center using the information provided by the on-line VSA application, as well as operator judgment. Thus, each load shedding scheme is armed centrally, but it is triggered by local detection of the corresponding contingency.

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