Review of the Iberian Peninsula incident investigation

Observations and technical comments

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EXECUTIVE SUMMARY

Overview

This technical note distills the principal observations from EPRI's technical review of the April 28, 2025, blackout in the Iberian Peninsula power system. The analysis in this technical note is based on available data specified below and aims solely to inform future risk mitigation. EPRI does not assign blame or offer conclusions regarding what did or did not occur. EPRI's role is limited to analyzing technical data and presenting unbiased findings based on its independent R&D activities.

Purpose, Approach and Disclaimer:

- The objective of EPRI's review is to help minimize the likelihood of future blackouts by identifying actionable lessons learned.

- This EPRI technical note was prepared by EPRI as an account of technical research carried out by EPRI under separate contracts for Iberdrola Energía Sostenible España and Endesa S.A. This technical note reflects the results of EPRI's independent scientific research assessments made based on objective technical criteria, and using data made available to EPRI by those project funders, as well as certain publicly available information.

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KEY OBSERVATIONS

1. Systemic Voltage Control Issues

- During stressed operating conditions, marked by large amplitude oscillations and degraded voltage performance, a voltage runaway developed leading to unacceptable overvoltage conditions followed by total blackout.
- The Spanish system has faced persistent overvoltage challenges, with voltage limits repeatedly exceeded and frequent disconnections of generation and demand due to overvoltage protection. Disconnection of generation and loads in response to overvoltage conditions during steady state operation are symptoms of a systemic voltage control issue.
- The voltage control process relies heavily on static reactive power compensation devices, and synchronous generators; with limited network-based reactive power compensation dynamic resources (e.g., synchronous condensers and FACTS devices).
- Automatic switching of static devices is not widely implemented, reducing the system's ability to respond quickly to voltage excursions.

- Throughout the morning of April 28, the grid experienced several sustained oscillation events, voltages rising into the emergency operating range, and large and rapid voltage fluctuations. Fast and large fluctuations in voltage are an indicator of ineffective voltage control, a precursor to voltage instability. Across the morning, voltages at multiple transmission grid locations across Spain rose above normal operating range and into the emergency operating range.
- From the measurements and recordings, one can observe the significant oversensitivity of the voltage in response to
  - changes in generation power output,
  - changes in power transfers with neighbouring countries, and
  - actions taken by the operators.

2. Generator and Resource Configuration

- At the time of the event, only certain synchronous generators were required to operate in voltage control mode; based on Spanish regulations, special regime generators (renewable, co-generation, energy from waste) operated in power factor control.
- On April 28, a record low (for recent years) number of large synchronous generators with voltage control capability were online, reducing dynamic reactive power support.
- As published by the system operator in the Transmission network development plan for the 2021-2026 period, a minimum number of synchronous generators must be maintained in service at all times to ensure safe and secure operation. It is unclear whether this was a requirement met on the day.

3. Oscillations and Frequency Control

- The system experienced significant oscillations. It can be observed that on the morning of April 28th multiple successive oscillations occurred, so it can be concluded that the actions taken to mitigate them addressed the immediate symptoms without resolving the underlying root-cause.
- Not all large generators are equipped with power system stabilizers, limiting the ability to damp oscillations.
- Top-of-the-hour market schedule changes have historically contributed to oscillatory events and operation with reduced damping and frequency response margins.
- The damping ratio estimated with Prony analysis method for the time windows selected during the oscillations was close to zero, indicating the relative ineffectiveness of the mitigation plan.

4. Collector Substations and Protection

- Many renewable resources are connected through third-party collector substations, which were disconnected by overvoltage protection during the cascade.
- Fast voltage changes on the 400 kV side led to overvoltage on the 220 kV side, triggering protection and disconnections.

5. Planning and Simulation

- Day-ahead and real-time simulation analysis are used to plan for voltage performance and oscillation mitigation. The effectiveness of such analysis depends on accurate models and timely reassessment.
- A generator was declared unavailable on the night prior to the event and remained unreplaced by the event day. On the event day, the number of voltage-controlling scheduled units was the lowest recorded in 2025.

6. Operator Tools and Proficiency

- Typically, operator situational awareness is supported by automated decision-making tools (e.g., real-time contingency analysis and dynamic security assessment solutions) that run automatically either on a regular schedule (e.g., every 5 or 10 minutes) or when triggered by an event or by the operator. Implementation of rapid switching actions can outpace these tools' feedback.
- It has not been documented in reports which tools are available in the Spanish TSO control room, how these tools performed and how could be adapted, in response to this event, to provide enhanced performance in identifying similar risks.
- Operator proficiency and training standards vary across Europe; there is no collective requirement for simulator-based or standardized training and certification, unlike other critical sectors.

7. Remedial Actions and System Defense

- More than one hundred manual switching actions that impact the voltage control process – mainly of shunt reactors and transmission circuits – were implemented during the morning. This can impair situational awareness and lead to unexpected consequences.
- In general, switching back into service of transmission circuits tends to be less effective for inter-area oscillations damping than starting up synchronous machines with power system stabilizers tuned at the specific frequency of oscillation.
- There is no discussion in the public report about why hydro power plants were not brought online (or why they would not be suitable) to increase damping in response to the oscillations. Only CCGTs were discussed, but their startup times limited their value to provide immediate support. Hydro power plants are often used on other grids to help damp oscillations.
- Automatic schemes for reactive power compensation (ARS) are effective but not widely deployed in Spain.
- Low Frequency Demand Disconnection (LFDD) schemes may be less effective in systems with impaired voltage performance, sometimes exacerbating overvoltage conditions.

8. General Principles for Incident Investigation

- Investigations should focus on unbiased fact assessment, root cause analysis, and identification of contributing factors, with the sole aim of preventing recurrence.

- Independence, unrestricted access to evidence, and clear protocols for handling sensitive information are prerequisites for effective investigations.

Conclusion

The April 28, 2025, blackout in the Iberian Peninsula was the result of a confluence of systemic voltage control limitations, insufficient dynamic resources, operational practices, and market-driven dispatch patterns. The observations emphasize the need for:

- Enhanced voltage control capability and automation,
- Improved operator training and situational awareness tools,
- Clearer standards and compliance mechanisms,
- Robust, unbiased investigation frameworks.
- These lessons are broadly applicable to power systems undergoing similar transitions to higher shares of inverter-based resources and market-driven operations.

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1. INTRODUCTION

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This is an EPRI technical note. It is intended as an informal report of continuing research, a meeting, or a topical study. It is not a final EPRI technical report.

The scope of the review summarized in this technical note is intentionally limited to aspects relevant to the incident until the collapse of the power system. The restoration activities conducted immediately after the collapse of the power system are not covered here and may be subject to a separate review.

EPRI did not conduct an investigation, but rather objectively analyzed and examined the information provided to us for technical review. Hence, this note includes technical comments and observations after reviewing the materials available:

- Versión no confidencial del informe del comité para el análisis de las circunstancias que concurrieron en la crisis de electricidad del 28 de abril de 2025 – Gobierno de España, Consejo de Seguridad Nacional
- Blackout in Spanish Peninsular Electrical System the 28th of April 2025 (18/06/2025) – Red electrica
- Grid Incident in Spain and Portugal on 28 April 2025, ICS Investigation Expert Panel, Factual Report (3 October 2025)
- PMU data provided by Iberdrola, from 74 nodes in the Spanish system covering measurements from 11:00 to the collapse

- SCADA measurements from across the Spanish transmission grid and power plant terminals as provided by Iberdrola
- Audio recordings of liaison between TSO and DSO, and generator control rooms
- Operational practices for generator control between TSO and Iberdrola and Endesa power plants

These comments and observations are offered to assist and inform those involved in the investigation process, and support future efforts intended to limit the risk of similar significant power system events.

EPRI's analysis and general observations are not intended to judge the actions and performance of any parties involved in the blackout event but review the data and offer recommendations based on the expertise and experience of EPRI technical staff. Certain sections of this report are focused on general principles related to issues relevant to the event and provided here for broader context, whereas others explicitly address the event itself. Summary of the incident that impacted the Iberian Peninsula on 28th April 2025.

During the morning of April 28th, the Spanish power system was stressed due to widespread and sustained overvoltages and large amplitude power system oscillations.

Throughout the morning, real-time operators implemented numerous remedial actions to mitigate power system oscillations and abnormally high and low voltages. These remedial actions included re-connection of transmission circuits used for voltage control and connection and disconnection of shunt reactors.

The total loss of supply of the Iberian Peninsula occurred shortly after 12:33. The collapse of the system was initiated by voltage runaway that led to a widespread overvoltage condition leading to activation of power plant protection systems. In the interim factual report, the initial voltage runaway has been linked to withstand and ride-through capability of resources connected to the distribution grid, failure of power plants to ride-through high-voltages, and under-delivery of reactive power from synchronous generators, although these are disputed in the context of the condition and configuration of the grid immediately prior. The role of the corrective actions implemented by the TSO and how the operating conditions of the system may have contributed to the voltage runaway is expected to be addressed as part of the detailed analysis in the final report.

Transmission grid protection systems did not play a substantial role in the cascade tripping, although activation of the low frequency demand disconnection (LFDD) system defense scheme may have exacerbated the overvoltage conditions.

The Spanish power system has experienced challenges with overvoltage conditions for the past few years, most notably during the weeks before the blackout.

Observation 1: The collapse of the power system occurred during a stressed operating condition that involved both large amplitude oscillations and degraded voltage performance.

2. CHARACTERISTICS OF THE SPANISH POWER SYSTEM

This section highlights some key aspects about the Spanish power system, its characteristics, operating practices, regulations, and recent changes as well as broader discussion of various issues related to power system operations. These help provide context for the events of April 28.

Interconnection

The Spanish Power System is a heavily meshed network with a 400 kV backbone grid and extensive 220 kV networks around large urban areas. Relative to the size of the power system, it could be considered that the Iberian Peninsula is weakly interconnected via France to the rest of the power system of Continental Europe. In this case, weak is defined in terms of interconnection capacity as well as the length or impedance of the lines which interconnect the main nodes of the grids. This issue has been widely recognized in the past and additional interconnectors are in both development and planning.

Voltage control

At the time of the incident, only the synchronous generators of nuclear, coal-fired, hydroelectric and CCGT (combined cycle gas turbine) power stations were required to operate in voltage control mode.
These generators are required to control the voltage at the transmission grid side of their generator step-up transformers to a target issued by the system operator. The system operator can instruct changes in real-time to modify the reference target voltage or the reactive power output of the generating units.

Special regime generation, including renewables (both inverter interfaced like wind and solar, and solar thermal using synchronous generators), co-generation and energy from waste, were required to operate in power factor control mode and thus do not actively regulate grid voltage. This is an unusual practice internationally, with almost all power systems with high penetrations of renewables having ended this practice between ten and twenty years ago. While it may not be optimal, it is feasible to operate the grid with renewable plants in constant power factor control mode. This approach requires procuring sufficient dynamic reactive power from alternative sources. There are no public reports which provide clarity about this practice.

The voltage control process is heavily reliant on the use of static reactive power compensation devices (shunt reactors and shunt capacitors), switching of transmission circuits, reactive power capability of the HVDC converters and the reactive power range of synchronous generators operating in voltage control mode. The information available suggests that transformer units in transmission and distribution systems are equipped with on-load tap changers. Some of these on-load tap changers are controlled manually by the relevant system operator, while others are in automatic control. The large majority of the static reactive power compensation devices were not equipped with automatic switching in response to elevated voltage conditions, for example automatically switching shunt reactors into service.

At the time of the incident, the Spanish power system did not have transmission-connected synchronous condensers, static var compensators (SVC), or large transmission-connected battery energy storage system (BESS) installations to provide dynamic reactive power capabilities, while it had one 220 kV connected STATCOM and two VSC HVDC symmetrical monopoles in the North of the country. Thus, synchronous generators are the only source of dynamic reactive power on the Spanish grid which can provide fast-acting or automatic response to abnormal voltage conditions in the Central and Southern parts of the system.

Typically, pumped storage hydroelectric schemes are designed with units that have capability to operate in synchronous condenser mode. It is unclear which units in Spain have such capability and whether these are available and utilized in this operating mode. If such capability is available, it could present a valuable source of dynamic reactive power, especially during scenarios with large solar and wind output when there are fewer conventional power plants online.

Internal regulations and standards related to voltage limits have been interpreted for ENTSO-E by the energy regulator in Spain, CNMC, to allow continuous operation up to 435 kV. This is higher than neighboring countries, and most European power systems in general, where an upper operating limit of 420 kV for their equipment and plant is applied. There is thus a discontinuity in voltage ratings at the Spanish border which needs to be managed by the relevant TSOs: busbars on the Spanish side can be operated up to 435 kV, while busbars just the other side of the border must remain below 420 kV.

The Spanish standards require large transmission connected synchronous generators to offer a minimum reactive power range of 15% of the nominal net active power, 0.989 leading and 0.989 lagging. On the absorption side, the majority of power systems request a minimum of 33% of the nominal active power, in other words 0.95 leading. This 0.95 leading requirement is consistent with the European Network Code – Requirements for Generators (RfG). In Spain, the voltage control service provided by generators is considered to be adequate if it complies with requirements for 75% of the 5-minute sampled values over each hour. In other words, it is allowed for each unit not to comply with the voltage control requirement up to 25 % of the time per hour.

The regulations and standards do not currently define concepts like insufficient voltage performance margins and the oversensitivity of system voltage. These notions are important for power systems transitioning from synchronous machine dominated operations to high penetration of inverter-based resources. If such performance requirements are clearly defined and implemented, it would support planning of power system configurations that are not conducive to degraded voltage performance, and it would help in real-time with identification of early signs of degradation in voltage control performance and application of prompt corrective actions. Defining only voltage magnitude limits becomes insufficient in power systems that are experiencing complex power system dynamics influenced by markets with short intervals (see next subsection) and high penetration of inverter-based resources.

Prior to the disturbance, the public-domain regulations and standards did not include detailed performance requirements for transmission grid voltage in terms of pre- or post-contingency voltage limits, reactive power reserve requirements, limits on rapid voltage changes, notifications, or reporting.

In the past several years, there have been instances of voltage exceeding the limits, sometimes leading to disconnection of generation or loads under protective actions. Exceedances of voltage limits are a critical events as they risk damage to both grid assets and grid customer and power plant assets. Limited information has been shared in the public domain about these events, the causes, or the mitigation actions. Reports reference discussions between the transmission system operator and distribution grid owners with respect to coordinating response to sustained elevated transmission grid voltage conditions. Actions referenced included blocking tap-changing on distribution transformers; tapping transformers to lower distribution voltage profile during such conditions can result in the transmission grid voltage being further increased.

In summary, voltage control is implemented in Spain by:

1) The TSO who manually-switch shunt reactors and shunt capacitors to regulate grid voltage. Switching out transmission lines has also become a common strategy for managing elevated voltage conditions during short (overnight) or long-term (weeks or months) periods. Transmission grid and distribution transformers are equipped with on-load tap changers. Depending on their role and position in the system, these are controlled manually or operated in automatic mode.
2) Power plant owners who regulate their grid-connection voltage within a required range.

It can be noted that Spain is almost unique as one of the very few power systems with a high proportion of inverter-based resources that requires those plants to operate with constant power factor.

Observation 2: To ensure compliance with standards is maintained and normalization of deviance is avoided, robust processes for regulatory reporting of voltage limits exceedances are typically implemented. Disconnection of generation and loads in response to overvoltage conditions during steady state operation are symptoms of a systemic voltage control issue.

Balancing Power

At the time of the event, the Spanish power system did not impose a uniform, system-wide limit on how quickly power plants could change active power output. While generators are required to be technically capable of limiting the active-power ramp rate, the applicable standards do not define a single mandatory ramp-rate value applicable to all plants. Instead, any specific ramp-rate restriction may be imposed by the TSO on a case-by-case basis through individual connection agreements or operational instructions. In other interconnected power systems, ramp-rate limits vary and are often explicitly defined for particular plant types or individual generating units.

For example, in Denmark[1] ramp rate limits of between 1% and 20% of the nameplate capacity per minute are imposed on each generator group, while other power systems such as Great Britain[2], limit active power ramping to a certain MW per minute values based on the total change in output.

The electricity market in Continental Europe has undergone changes in recent years, most notably the change in market intervals from 60-minute intervals to 15-minute intervals in 2025. For Spain, these 15-minute intervals have been implemented in the intra-day market from March 2025. This is a feature of Continental European markets that is not found elsewhere, in power systems with similar characteristics. There are examples of markets with shorter than 15-minute market intervals, in US and Australia, however these are centrally dispatched and/or using locational marginal pricing.

With changing market intervals, there are associated changes in security assessments and resource needs due to the expected increase in volatility. These changes are usually identified during comprehensive grid impact studies completed during the market design process to ensure that grid reliability is not compromised. There is no information in the investigation reports related to the assessment of control room capability, processes and power system performance before implementation of 15-minute intra-day intervals.

On the day of the incident, the power system was operated with limited downward active power regulation capability. The nuclear power plants online had limited flexibility, while many or most of coal-fired and CCGT units were operating close to their technical minimum active power export limits. During oscillations, the standard mitigation plan included taking actions to reduce active power export to neighboring power systems. Most conventional power plants were already operating close to their technical active power output minimum and were critical for controlling the voltage. The reduction in active power output was implemented on renewables generation. As the renewable generation operated in power factor control mode

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[1] Energinet. Regulations for Grid Connection of New Facilities—RFG—APPENDIX 1—REQUIREMENTS

[2] Grid Code documents | National Energy System Operator

(between 0.98 inductive and unity), reducing active power output also reduced reactive power absorption. Thus, reducing renewable generator output would impact grid voltage both by the change in active power flow across the grid and the reduction in reactive power absorption.

During periods of low and negative pricing as observed on the morning of the incident, some renewable generators responded to market signals by rapidly reducing or increasing their output. When the price went negative, in some cases renewables power plants across the country would reduce their output for “economic curtailment” leading to large net reductions. When the price turned positive again at a later market interval, they would raise their output again. This rapid change in active power was observed to impact power flow across the grid and, due to the resulting reduction in reactive power absorption, impacted the voltage profile.

An increasing frequency of events has been observed in which renewable generation, primarily wind and solar, rapidly reduces power output in response to market price signals. In parallel, European power systems are experiencing a growing number of hours with negative wholesale electricity prices[3]. For example, on 1st of April 2025, the French power system experienced an approximately 9 GW reduction in power output, primarily from solar and wind, over a 30 minute period.

For power systems that operate with renewable generation in voltage control mode, these fast power output variations are mainly an issue of balancing and frequency control, whereas in the Spanish case the challenge manifested as a voltage control issue. In modern power systems, the consequences of such large and fast power variations need to be well understood to determine whether prevention or mitigation solutions are required to maintain safe and secure operations.

The power systems in Continental Europe have been experiencing frequency variations around the top of the hour – mainly during the ramping periods in the morning and the evening. These frequency deviations are generally observed within a time window of ten minutes around the top of the hour, corresponding with the time intervals for cross border schedule changes.

During these scenarios, the primary frequency reserves are utilized, which was observed to lead to a decrease in damping of frequency oscillations, due to low availability of primary frequency reserves, causing the damping of inter-area oscillations to also be reduced.

In summary,

- Intra-day market intervals in Spain have reduced from 60-minute intervals to 15-minute intervals.

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[3] https://assets.rte-france.com/analyse-et-donnees/2025-10/Electricity%20review%201st%20semester%202025.pdf

- There were no ramp rate limits in Spain in contrast to other comparable countries in Europe.
- Downward active power regulation was limited in Spain as many or most conventional units were operating at or near their minimum technical output.
- During the morning leading up to the blackout, renewable power plant output was sensitive to market prices especially when they swung below or above zero. Grid voltage and oscillation damping were also sensitive in the time period around market intervals.

Observation 3: Top of the hour planned changes in market positions have been observed to cause challenges with oscillations and erosion of frequency response margins for several years, placing the power system in a vulnerable operating condition. When the voltage performance is degraded, with high voltage sensitivity to the changes in power flows on transmission corridors and the response from resources in power factor control mode, the power system operation is also at risk from voltage limit exceedances.

Oscillations

Power systems can be exposed to natural and forced oscillations. While mitigation of natural oscillations involves changes in the system conditions, like reducing power transfers and changes of grid topology, mitigation of forced oscillations usually involve detection and removal of the source of oscillations.

In Spain, not all large generators have power system stabilizers that can help mitigate oscillations.

The Iberian Peninsula is at the edge of the Continental European grid and has been previously subjected to large amplitude oscillations. These oscillations have been studied in great detail to identify root causes and mitigating plans.

Power systems can naturally experience periods of low frequency oscillations as they continually adjust to new operating conditions based on ever present load and generation changes. Typically, the oscillations are of imperceptible amplitudes and last for short periods. With the introduction of shorter market intervals, larger imbalance conditions have been observed at specific times during the day which align with periods when generators are starting to change output to meet new operating points. Oscillations of perceptible amplitudes which can be sustained or growing could be triggered by these changes in generation and load.

Transmission line outages associated with maintenance and voltage control can result in an increased in impedance between major nodes of the power system. This reduces the synchronizing torque between synchronous generators and the overall system capability to withstand disturbances. The increase in electrical distance between generators impacts their oscillations damping effectiveness. Switching lines back into service can improve damping, but not all lines are equally valuable in this regard. Switching lines on the main corridors between groups of power plants and part of the oscillation path tend to have the greatest impact on damping. Tangential lines or lines which connect power plants via a more circuitous route tend to have less impact on damping. In general, switching back into service of transmission circuits tends to be less effective for inter-area oscillations damping than starting up synchronous machines with power system stabilizers tuned at the specific frequency.

An inter-area oscillations damping mitigation plan was established in the past to provide an agreed strategy for responding to oscillations involving synchronous generators in the Iberian Peninsula.

During the December 2016 event, the remedial actions involved prompt reduction in power transfers between Spain and France. Follow-up analysis informed the decision to change operating mode of the France-Spain HVDC from AC emulation to constant power transfer during oscillations.

From the information available, it is unclear whether starting up conventional power plants with synchronous generators equipped with power system stabilizers is a remedial action considered in the oscillations damping protocol. Similarly, from the information available to date, it is not clear whether analysis was conducted to determine the effectiveness of switching back into service transmission circuits as a method for damping inter-area oscillations or how this outcome informed the oscillations damping protocol – what circuits to be switched, how effectiveness of actions is verified, how many circuits to be returned.

On the morning of the blackout, the grid voltage was very sensitive to changes; in particular, switching lines into service to reduce damping tended to raise grid voltage.

> Observation 4: It is important to determine the type of oscillations experienced in order to select and apply suitable remedial actions, effective for the specific type of oscillations. Protocols intended for damping natural oscillations may be ineffective in dealing with forced oscillations.

Collector Substations

Many renewable installations in Spain are connected to the 400 kV grid via third party infrastructure. The aggregation of renewable generators can be in the range of hundreds of megawatts typically connecting through a chain of 400/220 kV and 220/medium voltage transformers with on-load tap changers, as demonstrated in Figure 2-1. The interface with the system operator is on the 400 kV side.

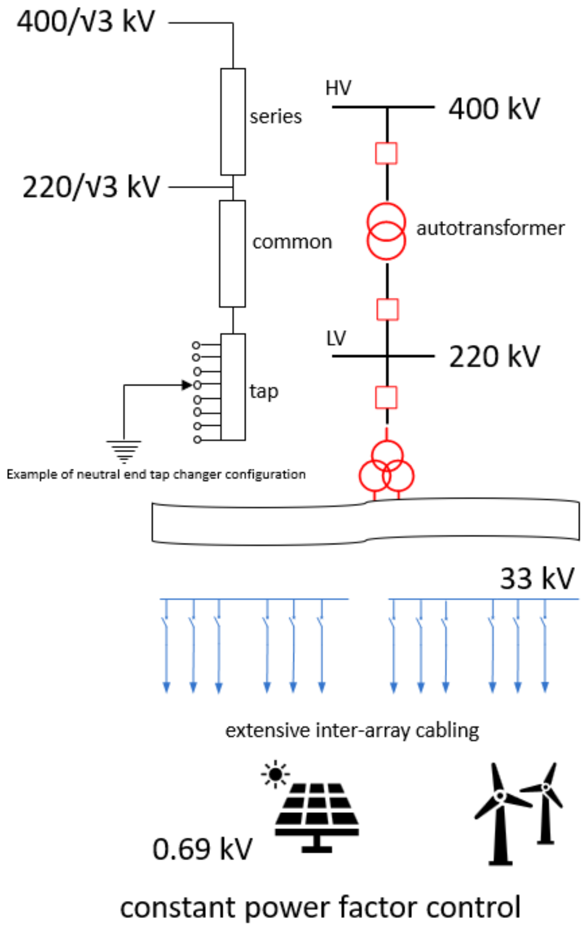

Figure 2-1 Collector substation example

It has been identified in the various reports that several of these generation resources, connecting to the 400 kV network through this type of arrangement, participated in the initial stage of the cascade leading to the total collapse of the Spanish power system by disconnecting on overvoltage protection functions on third party controlled assets.

High-resolution event measurements were not available for many of the devices that tripped in the early part of the event. Some of the information available is conflicting and some relies on SCADA measurements which may give misleading indications of what happened. From the information available to date, the disconnections of these generation resources during the first event was most likely related to the high rate of change of voltage on the 400 kV side, while the magnitude of the voltage at the 400 kV side was still within limits, causing elevated or high voltage conditions on the 220 kV side.

High rates of change of voltage, some exceeding 15 kV in 30 seconds, could have been beyond the typical limitations introduced by inherent mechanical restrictions and settings implemented in transformer automatic voltage control schemes.

The voltage control strategy at these collector substations is not always coordinated. The individual power plants are required to operate in power factor control mode, so they cannot take actions to directly control the collector network voltage without additional assets such as STATCOMs.

Typical automatic tap changing is designed for continuous regulation of the voltage on the lower voltage side of the transformer. This involves continuous measurement of the voltage and triggering a change in tap position when the voltage deviates outside a preset bandwidth. Standard designs involve time delays and deadbands to prevent excessive tap changing or hunting behavior. For example, time delays for the first tap change may be longer than subsequent tap changes, which may cause automatic tap changing to be slower than the fast variations in voltage observed on the 400 kV side. Typical time delays before the first tap change range from 10 to 60 seconds, so these can provide some control actions for voltage changes over the course of minutes, but little benefit to changes over shorter periods. In general, time delays can be set to be bypassed for extreme voltage conditions measured and initiate rapid tap changing.

3. POWER SYSTEM PERFORMANCE PRIOR TO 28TH APRIL 2025

In the week prior to the blackout incident, the Spanish power system experienced two noteworthy events which manifested in fast changes in voltage magnitude around the top of the hour, coinciding with changes in power transfers with the neighboring countries. These are reviewed in this section[4].

22nd of April, 19:00

A fast increase in voltage developed just before 19:00 which peaked about three minutes after, reaching voltage magnitudes above 435 kV and even above 440 kV at nodes in the Southwest of Spain, registering a high rate of change, around 20 kV in less than two minutes, as seen in the voltage plots in Figure 3-1 below. This sudden increase in voltage coincided with changes in power transfers with Portugal and France, reduction in active power output from solar generation and reduction in pumped storage demand. Transmission connected market participants were disconnected on protective actions during the high voltage condition. No comprehensive report has been published on the event, so no conclusions can be drawn apart from identifying rapid voltage changes as a known risk.

24th of April, 18:00

A similar event occurred on the 24th around 18:00, however at this time the fast rate of change in voltage had a downward trend that manifested in around 20 kV change in voltage in less than two minutes at nodes in Southwest, as observed in the voltage plots in Figure 3-2. Again, no comprehensive report on the event has been published, so limited conclusions can be drawn apart from rapid voltage changes being a known risk.

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[4] Readers are also encourage to review reports issued by the Spanish Government and ENTSO-E, from which the information here is taken:
https://www.lamoncloa.gob.es/consejodeministros/resumenes/Documents/2025/Informe-no-confidencial-Comite-de-analisis-28A.pdf

https://www.entsoe.eu/news/2025/10/03/28-april-blackout-in-spain-and-portugal-expert-panel-releases-comprehensive-factual-report/

Observation 5: During these two days, the power system configuration and mode of operation—including network topology, generation dispatch, and availability of fast-acting voltage control resources—could not prevent rapid, uncontrolled voltage fluctuations.

From the information available in the investigation reports, it is unclear whether these incidents were considered to pose high risk to power system management and what measures were implemented after these incidents on 22nd and 24th to prevent such situations from placing the power system at risk.

Power system operation refers to the continuous management and decision-making processes needed to generate, transmit, and deliver electricity while balancing supply and demand, keeping system frequency and voltage within prescribed limits, and maintaining the reliability and security of the electrical grid. These principles are challenged, when during steady state scenarios, without faults or unplanned events, voltage drifts rapidly outside limits, which can then cause undesired generation and demand disconnections.

Voltage Issues in previous years

From the information made available in the public domain, it can be inferred that the Spanish power system has faced significant challenges with voltage performance in recent years. The challenges manifested not only in consistent exceedances of voltage limits, but also in frequent disconnections of generation and demand facilities on overvoltage protective actions.

This can be considered as an unusual system performance when compared with other similar power systems. Widespread overvoltage issues are very rare; when overvoltages occur, they tend to be isolated to specific local conditions such as the end of long lines or following the tripping of multiple assets. Spain operates with a voltage limit of 435 kV on its 400 kV grid, which is higher than the 420 kV limit used in some other grids where similarly frequent overvoltage events have not been reported. A notable exception was the blackout in North Macedonia in May 2025, which occurred due to high voltage conditions during the night causing grid transformer overvoltage protection to trip.

It is unclear what reporting process is in place to announce the challenges to bodies responsible with ensuring that system performance requirements are maintained to a level that does not threaten safe and secure operation or integrity of assets. The information in the public domain is relatively limited. Prompt reporting, analysis and application of corrective actions is critical for maintaining secure system operations.

Other similar power systems have implemented the requirement for inverter based resources to operate in voltage control mode, in some cases for decades, and supplemented the resources that can actively support voltage control process with FACTS devices like STATCOM and SVC as well as with synchronous condensers Several comparable grids with high proportions of inverter-based resources have deployed synchronous condensers and/or STATCOMs to provide dynamic reactive power, including Germany, Great Britain, Italy, Australia, Texas, and California. This represents one approach to addressing dynamic reactive power requirements in systems with significant inverter-based generation.

Observation 6: As highlighted by recent system events in Iberia and North Macedonia where challenges related to voltage control capability led to widespread implications, a mechanism for evaluation of voltage control capability of areas forming the European synchronous system may be necessary to ensure a satisfactory level of power system voltage performance is maintained to limit the risk of similar events.

4. DAY AHEAD PLANNING

Voltage control

Simulation analysis is conducted at the day ahead stage to determine the power system configuration necessary to maintain adequate voltage performance. If the power system voltage performance is deemed to be insufficient, solutions are devised which may involve dispatching out of merit generation resources with voltage control capability.

This type of simulation analysis requires the use of network models that accurately represent the response and behaviour of the power system. This may include precise models of the generation controls, transformer tap changers, protection and control of inverter based resources, voltage dependency of the loads, and aggregated control and protection response of energy sources connected to the distribution grid. The outcome of the analysis includes the voltage profile anticipated to be achieved throughout the day for a given network topology, planned transfers with neighboring system, demand forecast and generation dispatch. Any material changes in these input assumptions may require a reassessment of the previous analysis' outcomes.

In power systems that rely on switching many transmission lines for voltage control purposes, combinations of network topologies are analyzed to consider different configurations informed by what transmission lines are expected to be returned to service. The investigation reports do not include any information regarding the network topology and generation dispatch studied at the day ahead stage and which of the transmission lines used for voltage control were considered to be returned to service during the day. Returning more voltage control transmission lines than had been studied at day ahead stage, without balancing these actions with reactive power compensation resources with absorption capability, can significantly impact the voltage profile of the power system.

Modern power systems have the capability to reassess the adequacy of voltage control at 4 hours ahead and even closer to real-time to include higher certainty input assumptions. This real-time capability can support assessment of impact and effectiveness of control actions when system configuration differs from planning assumptions.

On the previous day, the analysis performed by the Spanish system operator defined the number and location of generator resources required for voltage control purposes. One out of the two generators designated to operate in the Southwest of the system redeclared its capability on the night of the 27th of April. A replacement was not scheduled by the Spanish system operator, leading to operations on the morning and afternoon of the 28th of April with the lowest number of transmission connected large synchronous generators with voltage control capability connected that was recorded in 2025. There are no details regarding the process that informed the decision to operate with less units than initially scheduled.

Observation 7: In the Spanish power system, the largest contribution to dynamic reactive power compensation is provided by synchronous generators. On the day of the event, a record low (for the year) number of transmission connected large synchronous generators designated to control the voltage were online.

Oscillations

Some transmission system operators use small-signal stability and damping analysis at planning stage and few in real-time. This type of simulation analysis is conducted to verify the power system performance during oscillations given the expected configuration of the power system, demand levels and power transfers. It considers the response of the power system when subjected to the known natural modes of oscillations and to any potential forced oscillations. As part of the analysis the power system configuration and generation dispatch is evaluated to assess whether it is adequate to limit any oscillations below dangerous levels and offer sufficient means to suppress any oscillations that may threaten safe and secure operations, which may include sufficient generators with power system stabilizers in service on the main direction of the oscillation path, adequate active power reduction volumes of generation that doesn't automatically changes reactive power output as a result, system strength that limits the amplitude of the oscillations to a benign level that offers the real-time operators the necessary time to carry out any investigation required to identify and isolate any plant that may be cause of forced oscillations.

As part of this simulation analysis, remedial actions are typically also devised, their effectiveness validated and their impact on the power system's safe and secure operation evaluated. For instance, if the remedial actions include rapidly switching many transmission circuits in service along with many shunt reactors, the impact of these actions is evaluated to ensure it does not lead to unintended consequences.

Observation 8: In power systems that could be exposed to oscillations, whether due to their location within a given synchronous area, their configuration or their operating philosophy, improving capability and processes around oscillation analysis may help enhance system resilience. Day-ahead, intra-day and real-time analysis to assess the impact of oscillations can be used to identify system configurations and operating conditions vulnerable to severe abnormal operations.

5. DEGRADED VOLTAGE PERFORMANCE ON THE 28TH OF APRIL

Insufficient voltage performance of the system manifests through uncontrolled, large and rapid changes in the voltage magnitude. Oversensitivity of the voltage to changes in generation active power output and changes in dominant active power flows across critical transmission corridors is another symptom of degraded voltage performance of a power system.

It can be observed, comparing voltage control philosophy in Spain with other regions, that several factors may be important contributors to voltage performance. These include the operation in power factor control of a large part of the resources in the generation mix, lack of reactive power compensation devices with dynamic voltage control capability and the method of voltage control applied on the generators required to operate in voltage control mode and follow a target reference at the high voltage side of their generator step-up transformers.

With the exception of special-regime generation, which includes renewable units required to operate in power factor control mode, the voltage control strategy of conventional generation in Spain varies by technology. For example, combined-cycle gas turbine (CCGT) plants employ automatic voltage control to track a target set at the high-voltage side of the generator step-up transformer. In contrast, nuclear power plants (NPPs) regulate voltage through the automatic voltage regulator (AVR) at the generator terminals, while adherence to the 400 kV side target relies on manual operator intervention. These differences in control philosophy influence steady-state voltage performance.

This voltage management philosophy is suitable when there is an abundance of resources controlling the voltage, but can become less effective or ineffective in certain regions for system configurations that involve resources with dynamic voltage control capability that are few and far between. With only a limited number of generators automatically controlling the voltage, the voltage targets required adapting, and reactive power instructions need issuing in real time, to ensure the scarce resource is utilized effectively to assist with voltage control beyond the pilot node that is being controlled. It becomes necessary to dispatch out-of-merit generators to provide sufficient dynamic reactive power for each region, but this can result in over-reliance on the performance of individual power plants instead of spreading risk across multiple units.

Throughout the morning of April 28, the grid experienced several sustained oscillation events, voltages rising into the emergency operating range, and large and rapid voltage fluctuations.

From the measurements and recordings, one can observe the significant oversensitivity of the voltage in response to

1) changes in generation power output,

2) changes in power transfers with neighbouring countries, and

3) actions taken by the operators.

Across the morning, voltages at multiple transmission grid locations across Spain rose above normal operating range and into the emergency operating range. This is indicative of a grid at the edge of controllability or a grid operated with a high degree of uncertainty.

Fast and large fluctuations in voltage, like the ones the system experienced between 10:30 and 11:15, are an indicator of ineffective voltage control, a precursor to voltage instability.

Disconnection of generation and loads in response to overvoltage conditions during steady state operation are symptoms of a systemic voltage control issue

Modern power systems have many stakeholders and use many different technologies and vendors. To ensure that equipment is designed and operated to the expected performance levels, it is important that requirements and standards are clear and unambiguous. The fact that the ENTSO-E expert panel required clarification and support with interpretation of significant performance requirements in Spain, highlights the challenges that can exist (see section 2.6.1 of the ENTSO-E interim report).

The advantages of implementing clear and structured grid codes and security of supply standards include clarity provided by a single reference document which eliminates confusion about which rules apply, definitions and performance requirements interconnect logically to avoid contradiction between different technical areas. Frequent stakeholder engagement in open fora and periodic systematic updates of codes and standards are important for power systems to accommodate emerging technologies that lead to changes in power system operation and the dynamics during abnormal conditions.

While voltage control capability has been typically considered to be a local aspect, recent significant events highlighted that insufficient voltage control performance margins in one area have the potential to lead to widespread implications. Defining clear requirements and enforcing compliance at European level may act to limit the risk of similar events.

The complexity of synchronous operation between nearby areas that follow different limits must be reviewed to fully understand the implications on all parties affected. For example, the interaction between a power system allowed to operate continuously at 435 kV voltage level interconnected with areas that consider 420 kV as a limit with only short time limited exceedances allowed under emergency conditions, should be evaluated.

Notwithstanding the limitations around the network based dynamic reactive power compensation devices, like FACTS and synchronous condensers, relative to other power systems operating with high penetration of inverter-based resources, the Spanish power system benefits from an abundance of hydroelectric resources. With around 20 GW of installed capacity, the large transmission connected units participate in the voltage control process and have power system stabilizers. Many of these large hydro units were in operation and desynchronized in the morning of April 28th. It is not clear, from the available information, whether attempts were made to bring them back online between 11:06 and 12:32, especially after the large and fast changes in voltage of approximately 45 kV in 5 minutes led to disconnection of transmission connected demand on overvoltage protection functions or after the large amplitude oscillations ensued.

As observed on the ENTSO-E Electricity Market Transparency Platform, hydro units were available for service, after desynchronized in response to market signals, many of these fast starting units were utilized during the restoration process .Some of the pumped storage hydroelectric units are designed to operate in synchronous condenser mode.

There is no discussion in the public reports about why hydro power plants were not brought online (or why they would not be suitable) to increase damping in response to the oscillations and improve the voltage performance. Only CCGTs were discussed, but their startup times limited their value to provide immediate support. Hydro power plants are often used on other grids to help damp oscillations.

Under stressed operating conditions, when the reactive power reserves and the voltage control capability are limited, the system operator has the capability to request blocking the operation of tap changers on transformers at the interface with the distribution systems, to prevent the difficult operating conditions being exacerbated by transformers tapping to remedy voltage issues on the distribution system. On the day of the event, blocking of transformer tap changer operation was not requested or at least this action was not documented in the technical reports.

Use of decision making support tools and operator proficiency

Experienced operators can often anticipate when the power system may be at risk of degraded voltage performance. Apart from detecting unusual power system configurations like network topology or generation pattern and dispatch (like lower than usual number of generators with fast acting automatic voltage control capability), seasoned operators can also often identify when the voltage profile or controllability is diverging from the advice provided by the day ahead planning team.

The operators can also identify more subtle early signs like the unusual response of the power system following planned switching actions like reactive power compensation plant switching or transmission voltage control circuit switching. Observing the natural behavior of the power system in response to daily load variations can also be used to detect if the power system is starting to operate in a stressed condition.

Real-time operators generally use the output of decision-making support tools on dedicated displays as part of their consoles and videowall. These may include, but are not restricted to:

- voltage trends from pilot nodes – large voltage variations than usual are sign of voltage control issues
- reactive power trends from critical generators – identify whether their response or output is not as expected
- voltage trend overlaid on previous days with similar characteristics – divergence could act as an alert

- voltage control notifications annunciated – more than usual could be a sign of voltage control challenges

Observation 9: Across the world, operators using consoles and large displays or videowalls for team level situational awareness, that include voltage trends and real-time reactive power output of critical resources, are better placed to identify early signs of voltage performance degradation.

As part of the operational liaison, the real-time operators responsible for voltage control can also be alerted by real-time operators from distribution control centers and from power stations. These operators can also often identify when something is unusual based on the volume of voltage control related alarms annunciated or behaviour of their generators.

Most importantly, control centers of system operators are equipped with simulation analysis tools for power system risk management. These tools are used to anticipate where the power system is trending or flag if the current power system configuration is conducive to degraded operating conditions or violations. Examples of such tools include the real-time contingency analysis of the SCADA EMS, dynamic security assessment tools and wide area monitoring systems that can trigger alerts to notify the real-time operators of existing or impending risk.

The feature of the 2023 blackout in Brazil was the challenge of accurately modeling of inverter-based resources in real-time decision-support tools. The models available created a situation where the system operator was unaware that they were operating the grid with certain risks. A 500 kV line tripped due to a protection relay issue and this single event triggered cascade tripping of nearby lines ultimately resulting in the loss of supply to approximately 30 million people. The investigation report detailed the modelling challenges and how the system operator worked to review and improve their models as well as developing advanced risk-mitigation strategies.

In February 2025, the voltage sag during a prolonged distribution fault in Sri Lanka lead to widespread tripping of distribution-connected solar PV inverters by anti-islanding protection. This lead to a country-wide blackout of 22 million people. The investigative report detailed how the grid owner went door-to-door to collect event logs from thousands of inverters to determine the root-cause of tripping. This information was used to improve real-time models and increase the ability of the system operator to calculate and mitigate the associated risks. These two cases illustrate the hidden risks of operating complex grids with advanced technologies and how post-event model validation and verification can be used to substantially mitigate these risks.

The most important risk of operations with degraded voltage performance is when the deterioration in the voltage control capability extends to the loss of control over the voltage. It can be considered that real-time operators are no longer in control when the voltage changes at a high rate in response to steady state operating conditions or planned actions.

The performance and insights from decision-support and real-time monitoring tools during the April 28th event have not been discussed in much detail in the public reports. This is not unusual in public reports as the focus is more often on the sequence-of-events, power plant-performance, and protection & control performance, but is included in reports examining cases such as the above where such system played a contributing role to the ability of the system operator to see and mitigate risks.

6. OSCILLATIONS ON THE 28TH OF APRIL

Oscillations

The Iberian power system is at the edge of the Continental Europe synchronous area. Inter-area oscillations have been a feature of the grid for many years. The last notable incident happened in December 2016 when oscillations developed in response to the unplanned disconnection of a tie-line between Spain and France. At the time, the oscillations were promptly suppressed by operator actions to reduce the active power transfer between Spain and France.

Subsequent simulation-based analysis performed by the Spanish and French system operators resulted in an enhanced oscillations mitigation strategy. This strategy focuses on multiple actions, including reduction of power transfer between Spain and France and switching the France – Spain HVDC link from ac line emulation to constant power control mode.

Switching transmission lines into service is also part of the protocol, in Spain, for damping inter-area oscillations. Dispatching of additional fast-starting synchronous generators with power system stabilizers was not used as a method for damping oscillations on the day.

Damping of Oscillations

During the morning of April 28th, when the first oscillations ensued, the real-time operators at the French TSO informed the European Regional Coordination Centre, however no immediate remedial actions were taken as a result (see ENTSO-E factual report page 241).

> Observation 10: Control centers equipped with adequate tools that can detect early signs of stressed operations are better placed to coordinate or take early action and prevent minor issues from becoming widespread events.

Although the use of appropriately tuned power system stabilizers is the most effective way to damp natural oscillations, the contribution from individual units is limited. The collective action of multiple units with power system stabilizers in conjunction with additional actions like reducing active power transfers is required in order to deliver prompt damping and suppress natural inter-area oscillations.

In the recent trends observed in power systems operating with high penetration of inverter-based resources, synchronous generators are more frequently operated at their minimum active power output technical limits. The levels of damping provided, and the effectiveness of power system stabilizers tends to be significantly lower when synchronous generators are operating at minimum technical output compared to normal rated output. This can have a substantial impact on overall system damping.

Operating synchronous generators in their under-excited region, absorbing reactive power to manage high voltage conditions, reduces the damping torque which in turn impacts the small signal stability of the system.

Low-amplitude oscillations were detected in the early morning of April 28th, between 05:45 and 10:00, but these were not severe enough to justify significant operator actions. The market schedule resulted in 15 combined cycle gas turbine units and multiple large hydro units being de-synchronized in this time. The location of these CCGT units is presented in Figure 6-1. From the information available in the investigation reports, it is unclear whether these initial oscillations were considered as early signs of stressed operations and acted upon by the system operators in Spain.

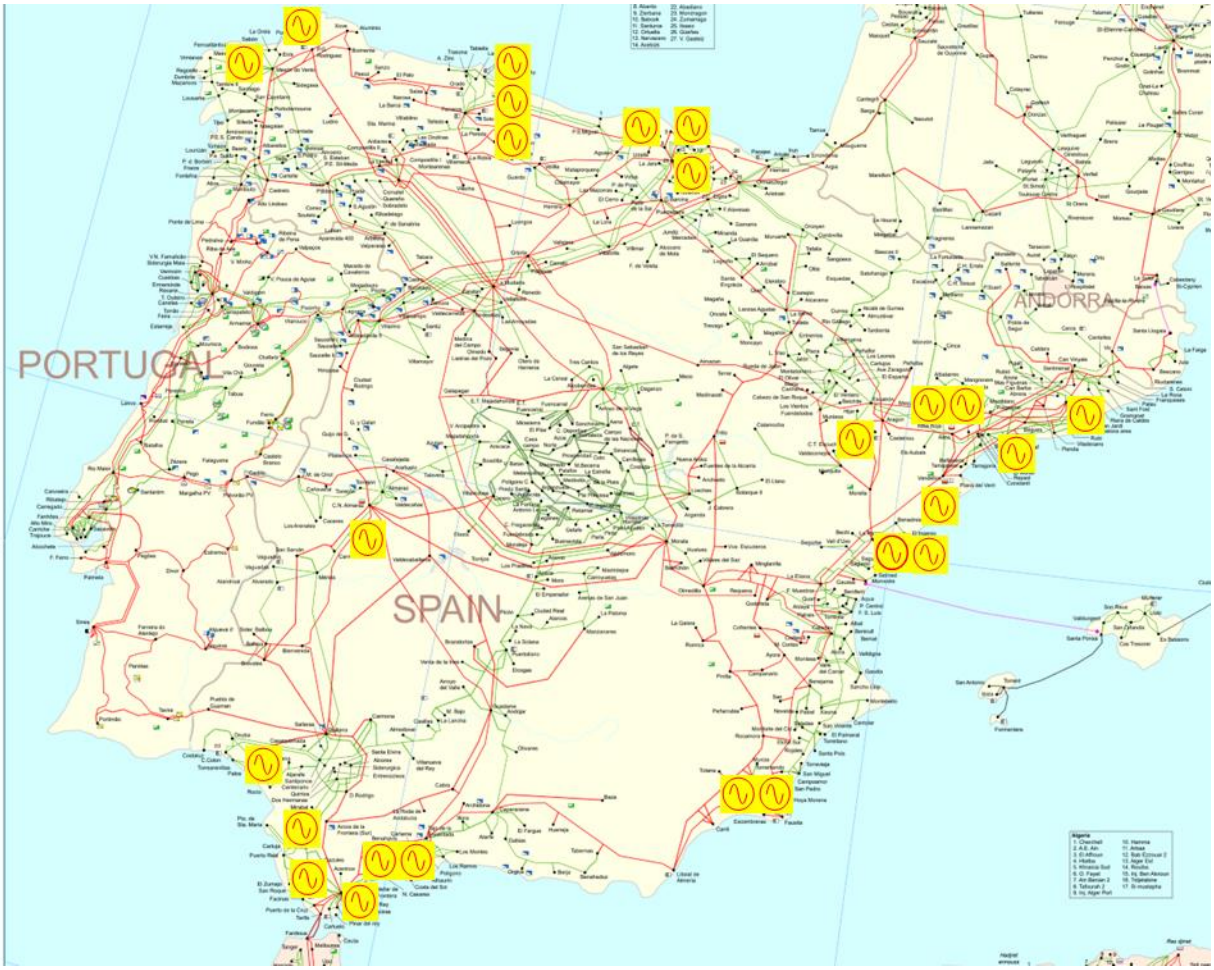

Figure 6-1 Map showing the location of the 15 CCGT units de-synchronized between 08:00 and 10:00[5][6]

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[5] Grid Map

[6] Electricity Market Transparency

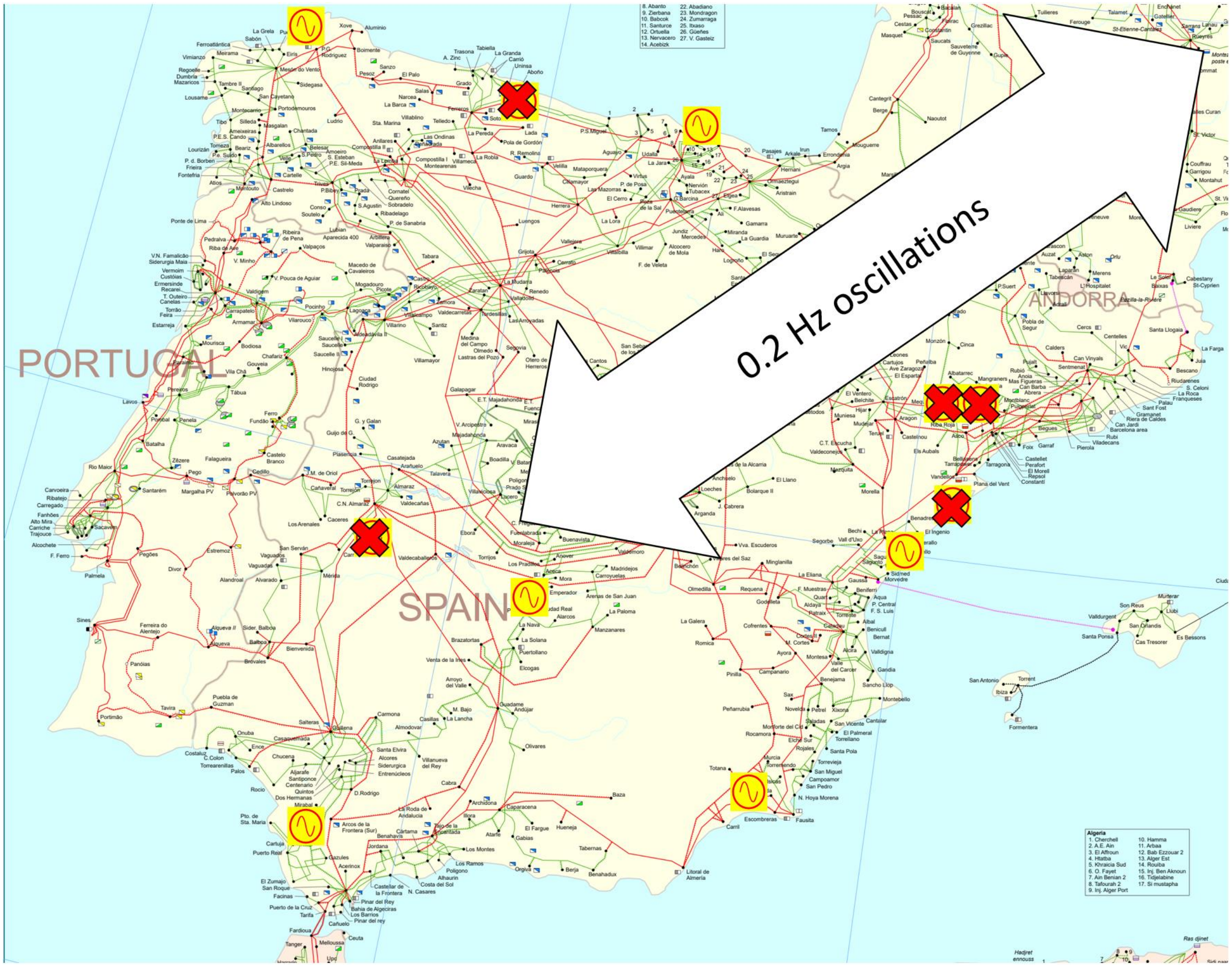

Figure 6-2 Map of Iberian peninsula showing units with PSS[7]

Observation 11: Defining and maintaining a minimum number of generating units with power system stabilizers in service may limit the risk of similar incidents.

As published by the system operator in the Transmission network development plan for the 2021-2026 period[8] a minimum number of synchronous generators must be maintained in service at all times to ensure safe and secure operation. It is unclear what scenarios, and contingency cases have been used to determine the minimum number of units required to be online and how these compared with the system conditions experienced on April 28th. These aspects could warrant further assessment to understand if the number, location, type and power output of the generation units with Power System Stabilizers was sufficient to comply

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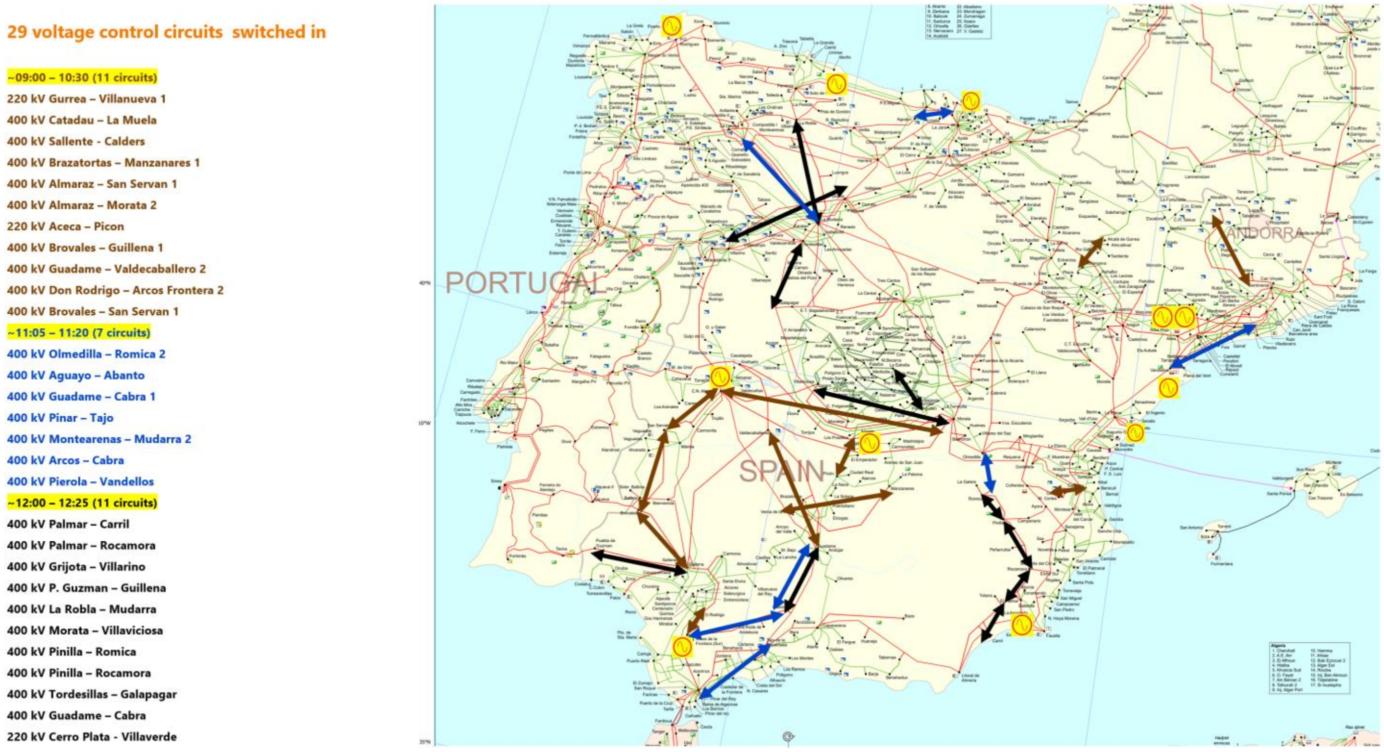
[7] Grid Map

[8]

with the planning studies conducted to determine the limits for stable operation. The six synchronous machines with Power System Stabilizers are shown in Figure 6-2.

Damping ratios and Level of Damping on the 28th of April



29 voltage control circuits switched in

~09:00 – 10:30 (11 circuits)
220 kV Gurrea – Villanueva 1
400 kV Catadau – La Muela
400 kV Sallente - Calders
400 kV Brazatortas – Manzanares 1
400 kV Almaraz – San Servan 1
400 kV Almaraz – Morata 2
220 kV Aceca – Picon
400 kV Brovales – Guillena 1
400 kV Guadame – Valdecaballero 2
400 kV Don Rodrigo – Arcos Frontera 2
400 kV Brovales – San Servan 1
~11:05 – 11:20 (7 circuits)
400 kV Olmedilla – Romica 2
400 kV Aguayo – Abanto
400 kV Guadame – Cabra 1
400 kV Pinar – Tajo
400 kV Montearenas – Mudarra 2
400 kV Arcos – Cabra
400 kV Pierola – Vandellos
~12:00 – 12:25 (11 circuits)
400 kV Palmar – Carril
400 kV Palmar – Rocamora
400 kV Grijota – Villarino
400 kV P. Guzman – Guillena
400 kV La Robla – Mudarra
400 kV Morata – Villaviciosa
400 kV Pinilla – Romica
400 kV Pinilla – Rocamora
400 kV Tordesillas – Galapagar
400 kV Guadame – Cabra
220 kV Cerro Plata - Villaverde

Figure 6-4 Map of Iberian peninsula with transmission circuits switched in service for oscillations' mitigation overlaid[9][10]

Many power systems worldwide are operated to maintain, in real-time, the damping ratios for problematic oscillation frequencies above 5%. This is industry good practice and mentioned in the Spanish standards. Analysis, carried out as part of this study, of the time windows around 11:02, 11:23, 12:04 and 12:19 estimate the damping ratios were at or below 1%.

Multiple transmission circuits were switched back to service after the 11:05 oscillation in an effort to improve system damping. The information currently available is insufficient to determine how the damping ratios evolved throughout the day in response to various deliberate actions or unexpected events. This information should be available for retrieval in the WAMS recordings of the system operator; alternatively, it could be estimated from ambient data from PMU recordings prior to 11:00. PMU recordings, covering time window from 11:00 to

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[9] Grid Map

[10] 28 April 2025 Blackout

the collapse, provided by the TSO to the industry and made available for review by Iberdrola, are insufficient to analyze the initial oscillations and how the system performance was impacted by the multiple conventional units de-synchronizing in response to market signals during early morning.

WAMS records can show whether lowering the impedance on the oscillation path by switching back to service transmission circuits delivered the expected impact on the damping levels. In highly meshed power systems with multiple parallel transmission corridors it is typically difficult to achieve significant changes in impedance. The list and location of the transmission lines returned to service between 09:00 and 12:25 is seen in Figure 6-4.

It can be observed that on the morning of April 28th multiple successive oscillations occurred, so it can be concluded that the actions taken to mitigate them addressed the immediate symptoms without resolving the underlying root-cause.

In general, switching back into service of transmission circuits tends to be less effective for inter-area oscillations damping than starting up synchronous machines with power system stabilizers tuned at the specific frequency.

As part of the analysis performed by EPRI on the PMU data provided by Iberdrola, the damping ratio, estimated with Prony analysis method, for the time windows selected during the oscillations was close to zero, indicating the relative ineffectiveness of the mitigation plan.

> Observation 12: Wide area management systems (WAMS) that estimate the damping ratio of the system can be used to verify the effectiveness of corrective actions implemented in real-time to damp oscillations.

Power plants, interfaced by power electronics or synchronous machines, can initiate or participate in oscillations. Examples of power plants initiating oscillations could include anything from scenarios of inadvertent switching of PSS out of service on synchronous machines, unwanted response from IBR controllers tuned for different power system conditions than those experienced in real-time or erroneous or suboptimal inverter firmware updates. Power plants can also participate in power system oscillations that are initiated by other elements of the power system that are remote from their point of connection. If the system conditions at the point of connection are disturbed by oscillations, the power plant can participate by providing positive damping and support the suppression of the oscillatory behaviour experienced at the point of connection or introduce negative damping in which case the power plant could act to exacerbate the existing oscillatory condition.

The ENTSO-E interim report presents the behavior and response of the HVDC link and an inverter-based resource in the Southwest. A cause and effect relationship is not yet presented in the interim report. Well synchronized high resolution monitoring installed at plant level may be necessary to support this type of investigation.

Observation 13: Many synchronous areas that operate with high penetration of inverter-based resources mandate installation of high resolution dynamic monitoring at the connection point. Such practices aid in real-time with identification of rogue controllers, compliance monitoring and support effective post-even investigations.

Oscillations are not uncommon, and the power systems are operated in a prudent manner that allows real-time operators to investigate the cause, localize the rogue plant in case of forced oscillations, determine and implement effective remedial actions. In order for operators to be successful in performing this sequence of actions there are several prerequisites:

- The power system mode of operation is not conducive to large amplitude oscillations that could threaten the safe and secure operation e.g., large magnitude oscillations could cause low voltage conditions and trigger widespread disconnection of IBR due to multiple FRT activations, similarly overvoltage or undervoltage conditions can trigger protection operation on power plants or network assets.
- In order for operators to quickly identify oscillations and take appropriate mitigation actions they need appropriate monitoring systems. The sophistication and complexity of the monitoring system depends on the severity of the oscillations and system-specific risk considerations. Typically, however, the monitoring systems use synchrophasor data and should be capable of continuously monitoring and alarming across multiple oscillation frequency ranges and damping thresholds at strategic location on the grid. It is common to use multiple alarm thresholds to trigger on large-magnitude oscillations as well as prolonged, lower-magnitude oscillations. Other criteria can be informative – for example, the presence of harmonics (e.g. 0.4 and 0.6 Hz oscillations in addition to the 0.2 Hz oscillation, as shown in the examples in Figure 6-3 and Figure 6-4) can indicate forced oscillations while a single oscillation of 0.2 Hz alone usually indicates natural oscillation. Forced oscillations with frequencies resonating with known natural oscillations modes can be misleading for operators.
- As synchrophasors usually (but not always) monitor bus voltages and transmission lines flows, they may not be able to precisely identify the source of forced oscillations. It can be challenging to identify the source of forced oscillations in real-time, but some preparatory work can help. For example, while generator SCADA data may have slow sampling rates, oscillations in real or reactive power output can often be seen in SCADA data as irregular, frequent step changes up and down. While SCADA cannot capture the true shape and magnitude of the oscillation, the development of appropriate templates or analytics can make it possible to detect the step-changes and identify participating units. This can help inform operators' decision-making process.
- When oscillations are identified, operators should have a clearly documented and well-practiced action-plan. For inter-area oscillations this plan may involve multiple system operators sharing information up to fully coordinating their response. The action plan should detail how the oscillation should be classified in terms of severity, the remedial actions appropriate to each severity level, the expected outcome and timeline for each action, any risk-factors, and escalatory procedure should actions fail.

- It can also be beneficial to pre-assign expert staff or teams within the organization to immediately begin investigating the oscillations by evaluating the measured data, running simulations to identify optimal remedial actions, and identifying other potential risks. By preparing these experts with the right tools and templates these experts can help provide valuable technical insights to operators and help accelerate and improve their decision-making process.
- Operators need to be provided with adequate training on how to identify and deal with different types of oscillations and how to manage the potential impact of the remedial actions on the overall power system operation.

Some practices and software adopted in real-time operations by system operators around the world follow. Note that the tools, technologies, and procedures are particular to individual grid and each grid's requirements depends on their specific risk profile. These are highlighted as relevant to the events in Spain, but should not be interpreted as being systems which could have prevented the events of April 28th:

- Small—signal stability assessment tools are used by some system operators to identify potential oscillations risks in the day-ahead and real-time environments. This enables them to change operational plans to prevent the oscillations occurring or to put in place appropriate remedial action plans
- Use of forced oscillation localization tools to identify the regional source of the oscillation or the individual generator units forcing the oscillation

Availability of data from dynamic system monitoring and recording devices is a fundamental prerequisite for conducting investigations into significant system events like blackouts. It is common for modern power systems to have an extensive network of dynamic monitoring and recording devices. Typical requirements for deployment of such devices are generally included in the Grid Code generation connection requirements and connection agreements. It is understood that in Spain the PMU are deployed on important transmission circuits, not at generating sites. Without PMU data from the point of connection of generation resources, it becomes more challenging to establish the source of oscillations.

To estimate the location of plants with rogue controllers that may be introducing unwanted oscillations, power system operators can utilize purposefully designed tools to support decision making.

Forced Oscillation Localization Tool (FOLT) developed by EPRI and University of Tennessee (Figure 6-5) has been used in this case to analyse the data from the 74 PMU channels provided. The PMU are configured with a 50 Hz sampling rate (one sample every 20 milliseconds). Data channels included positive sequence voltage and current with magnitude and angle, active and reactive power, frequency, and rate-of-change-of-frequency (ROCOF).

The tool utilizes three different methods to localize the source of oscillations:

1. Dissipating Potential
2. Oscillation Magnitude
3. Oscillation Mode Angle

As shown in Figure 6-6, based on the angle difference and magnitude ratio between frequency and voltage measurements, the tool estimates the source type. For cases in which the oscillation magnitude in frequency is larger than voltage magnitude and the oscillation mode angle of frequency is leading the voltage, it is estimated to be an active power control issue (e.g., governor). Alternatively, for a case where the oscillation magnitude of frequency is smaller than the voltage magnitude and the oscillation mode angle of frequency is lagging the voltage, a reactive power control issue (e.g., exciter) is estimated to be the cause.

The results presented in this report should be considered indicative, as the tool is proficient in localizing forced oscillations and at this stage it isn't known with high degree of certainty whether the oscillations experienced on the day were of natural or forced nature.

In this case, the source of oscillation was estimated to be closest to PMU installed in 220 kV substation in Merida area.

Without PMU data from the point of connection of generators, the source location should be interpreted loosely, as is only indicative of the area of the system that scored highest on the different methods of localization utilized, with the weighting factors applied.

The intent is to highlight solutions that may be employed by power system operators to aid with identification of sources of oscillations.

Analysis can be conducted by power system operators to identify power system configurations which may be conducive to propagating initial benign oscillations and triggering unwanted response from other plants. One option may be to introduce small modulations in active and reactive power output of plants and observe the response of the system and protection and control of other devices connected to the system to evaluate the level of risk such oscillations may impose, gauge the time available to implement mitigation actions and devise effective corrective solutions.

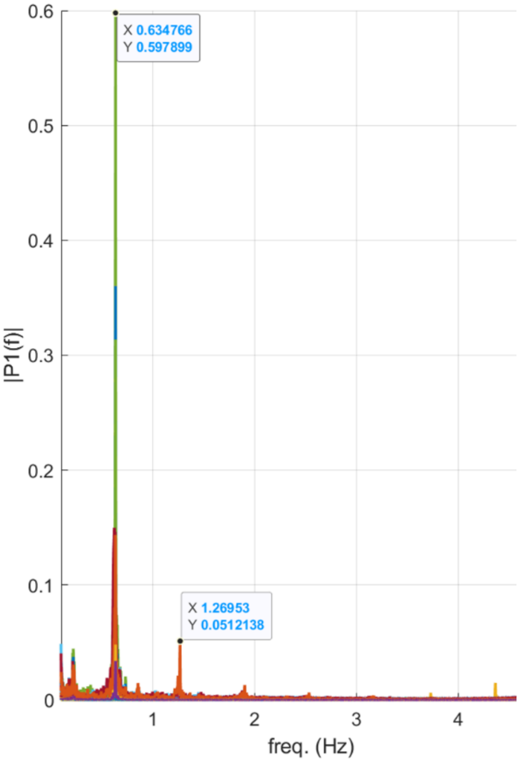


Figure 6-3 Example of second harmonic present during oscillations around 12:03

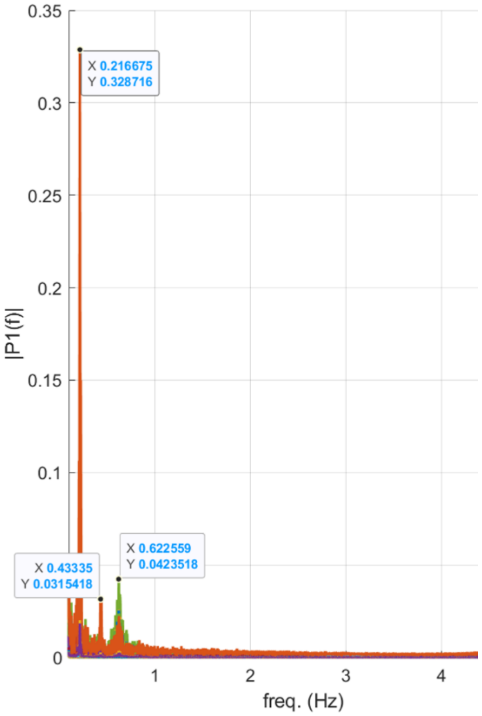
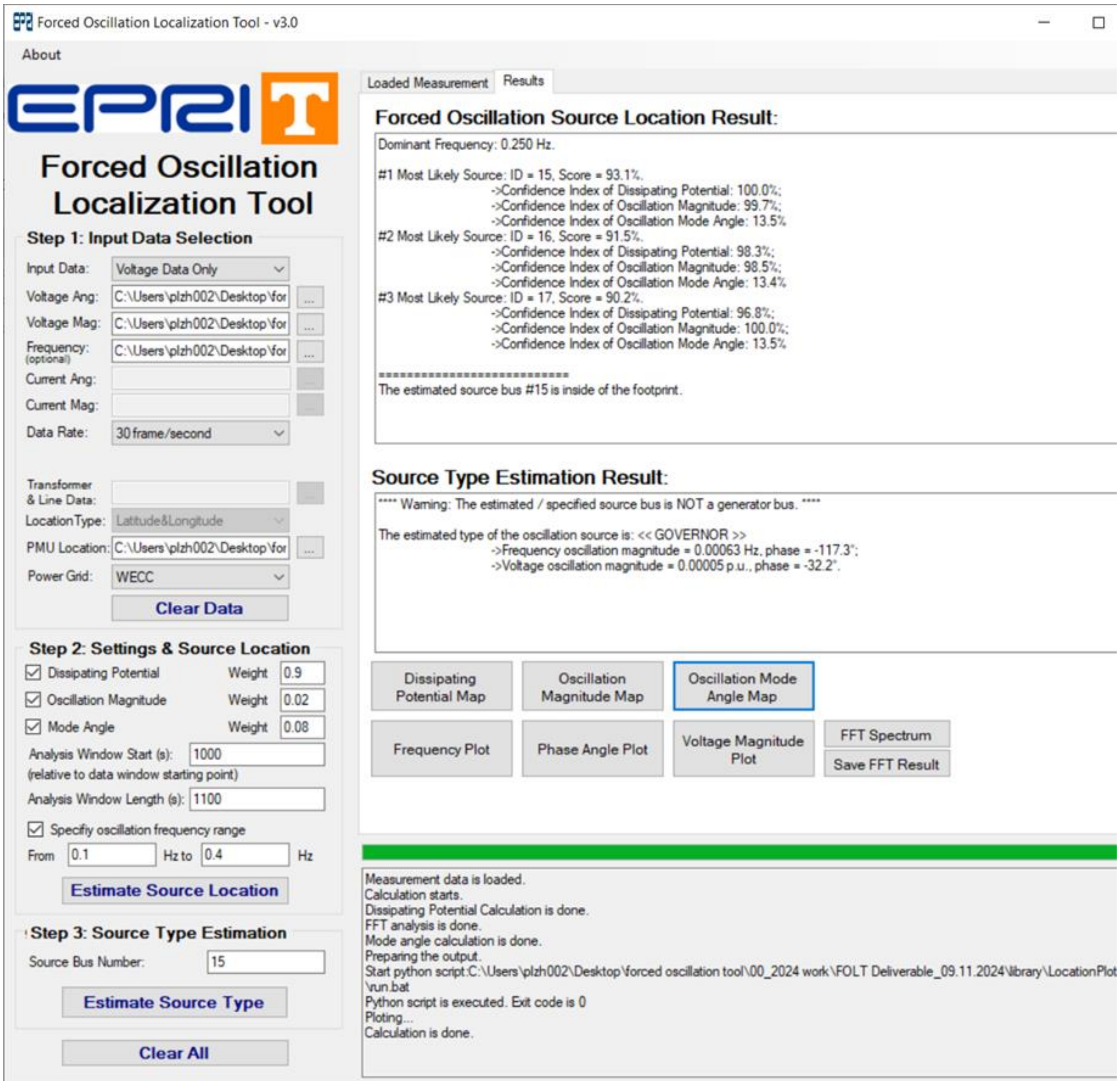


Figure 6-4 Example of second harmonic present during oscillations around 12:19



Step 1: Input Data Selection

Input Data: Voltage Data Only
Voltage Ang: C:\Users\plzh002\Desktop\for
Voltage Mag: C:\Users\plzh002\Desktop\for
Frequency: (optional) C:\Users\plzh002\Desktop\for
Current Ang:
Current Mag:
Data Rate: 30 frame/second
Transformer & Line Data:
Location Type: Latitude&Longitude
PMU Location: C:\Users\plzh002\Desktop\for
Power Grid: WECC

Step 2: Settings & Source Location

☑ Dissipating Potential Weight 0.9
☑ Oscillation Magnitude Weight 0.02
☑ Mode Angle Weight 0.08
Analysis Window Start (s): 1000
(relative to data window starting point)
Analysis Window Length (s): 1100
☑ Specfiy oscillation frequency range
From 0.1 Hz to 0.4 Hz

Step 3: Source Type Estimation

Source Bus Number: 15

Forced Oscillation Source Location Result:

```
Dominant Frequency: 0.250 Hz.

#1 Most Likely Source: ID = 15, Score = 93.1%.
                    ->Confidence Index of Dissipating Potential: 100.0%;
                    ->Confidence Index of Oscillation Magnitude: 99.7%;
                    ->Confidence Index of Oscillation Mode Angle: 13.5%
#2 Most Likely Source: ID = 16, Score = 91.5%.
                    ->Confidence Index of Dissipating Potential: 98.3%;
                    ->Confidence Index of Oscillation Magnitude: 98.5%;
                    ->Confidence Index of Oscillation Mode Angle: 13.4%
#3 Most Likely Source: ID = 17, Score = 90.2%.
                    ->Confidence Index of Dissipating Potential: 96.8%;
                    ->Confidence Index of Oscillation Magnitude: 100.0%;
                    ->Confidence Index of Oscillation Mode Angle: 13.5%

==========================
The estimated source bus #15 is inside of the footprint.
```

Source Type Estimation Result:

```
**** Warning: The estimated / specified source bus is NOT a generator bus. ****

The estimated type of the oscillation source is: << GOVERNOR >>
                    ->Frequency oscillation magnitude = 0.00063 Hz, phase = -117.3°;
                    ->Voltage oscillation magnitude = 0.00005 p.u., phase = -32.2°.
```

```
Measurement data is loaded.
Calculation starts.
Dissipating Potential Calculation is done.
FFT analysis is done.
Mode angle calculation is done.
Preparing the output.
Start python script:C:\Users\plzh002\Desktop\forced oscillation tool\00_2024 work\FOLT Deliverable_09.11.2024\library\LocationPlot
\run.bat
Python script is executed. Exit code is 0
Ploting...
Calculation is done.
```

Figure 6-5 Forced Oscillation Localization Tool[11]

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[11] Forced Oscillation Localization Tool (FOLT) v2025

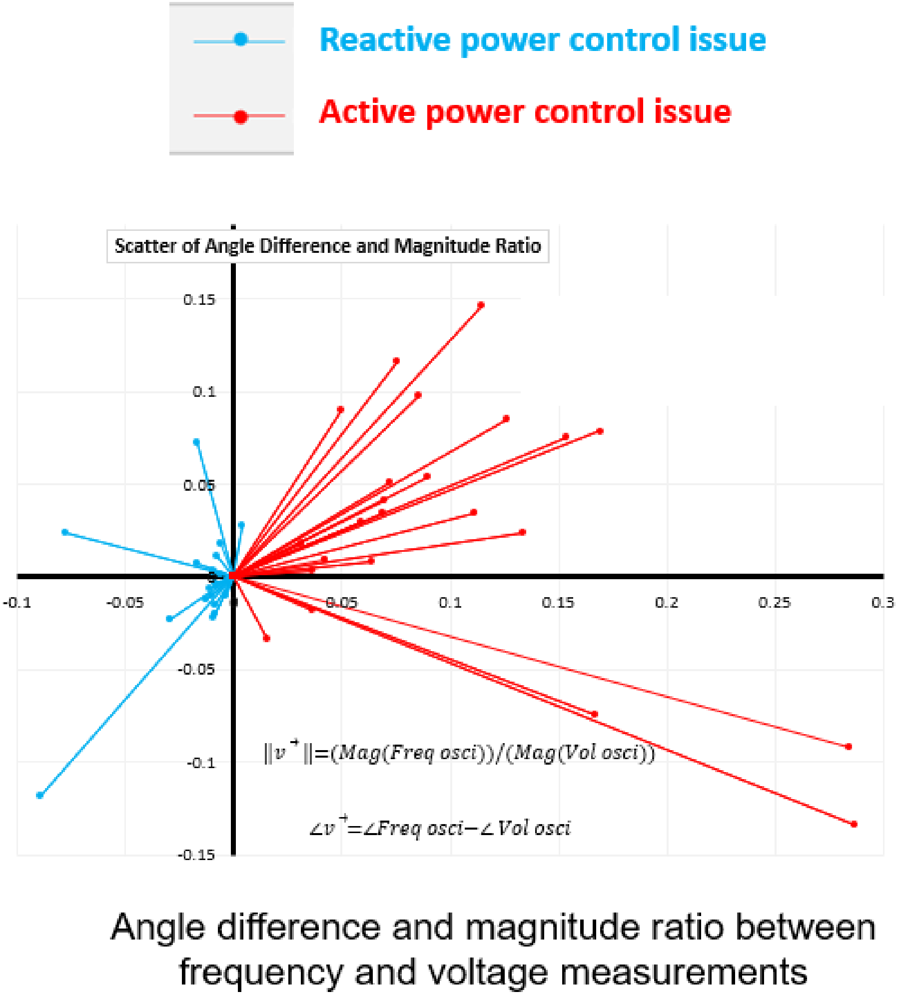


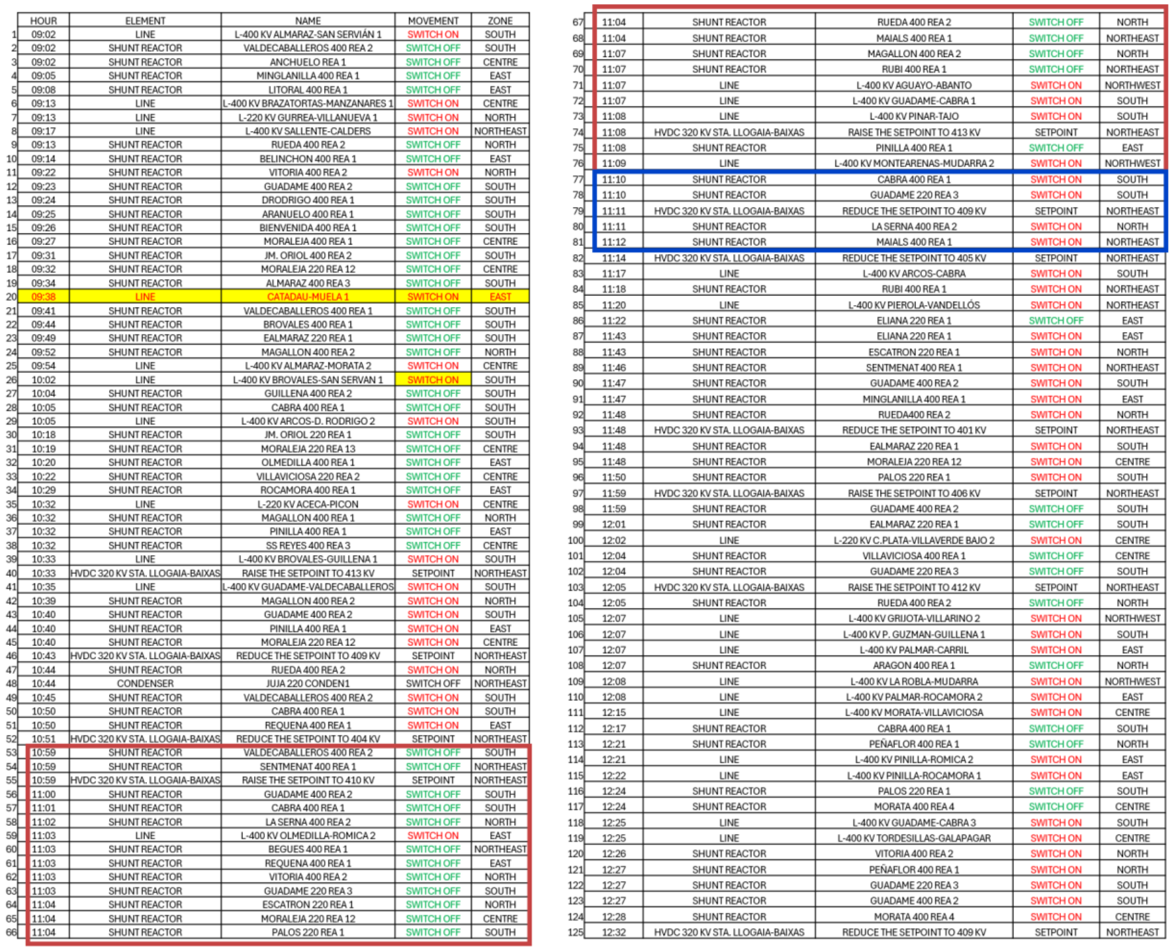
Figure 6-6 Active power or reactive power controller issue

Observation 14: Operation of the power system in a configuration that provides sufficient operating margin allows operators time necessary to detect, identify the type of abnormal operation and implement effective corrective actions to return system operation to normal.

7. CONTROL AND REMEDIAL ACTIONS IMPLEMENTED ON THE 28TH OF APRIL

Prevailing system conditions

Due to limitations in voltage control capability, the Spanish power system uses a large number of voltage control circuits compared to similar power systems. This impacts the configuration of the system and its response and behavior during complex stressed operations like those present during oscillations. Planning the system's operation is also becoming difficult when there is a need to consider multiple combinations of configurations that include various levels of voltage control circuits in and out of service. In real-time, this may pose challenges for the operators having to switch multiple circuits in a short period of time whilst fully understanding the consequences of these switching actions.



	HOUR	ELEMENT	NAME	MOVEMENT	ZONE
1	09:02	LINE	L-400 KV ALMARAZ-SAN SERVIÁN 1	SWITCH ON	SOUTH
2	09:02	SHUNT REACTOR	VALDECABALLEROS 400 REA 2	SWITCH OFF	SOUTH
3	09:02	SHUNT REACTOR	ANCHUELO REA 1	SWITCH OFF	CENTRE
4	09:05	SHUNT REACTOR	MINGLANILLA 400 REA 1	SWITCH OFF	EAST
5	09:08	SHUNT REACTOR	LITORAL 400 REA 1	SWITCH OFF	EAST
6	09:13	LINE	L-400 KV BRAZATORTAS-MANZANARES 1	SWITCH ON	CENTRE
7	09:13	LINE	L-220 KV GURREA-VILLANUEVA 1	SWITCH ON	NORTH
8	09:17	LINE	L-400 KV SALLENTE-CALDERS	SWITCH ON	NORTHEAST
9	09:13	SHUNT REACTOR	RUEDA 400 REA 2	SWITCH OFF	NORTH
10	09:14	SHUNT REACTOR	BELINCHON 400 REA 1	SWITCH OFF	EAST
11	09:22	SHUNT REACTOR	VITORIA 400 REA 2	SWITCH ON	NORTH
12	09:23	SHUNT REACTOR	GUADAME 400 REA 2	SWITCH OFF	SOUTH
13	09:24	SHUNT REACTOR	DRODRIGO 400 REA 1	SWITCH OFF	SOUTH
14	09:25	SHUNT REACTOR	ARANUELO 400 REA 1	SWITCH OFF	SOUTH
15	09:26	SHUNT REACTOR	BIENVENIDA 400 REA 1	SWITCH OFF	SOUTH
16	09:27	SHUNT REACTOR	MORALEJA 400 REA 1	SWITCH OFF	CENTRE
17	09:31	SHUNT REACTOR	JM. ORIOL 400 REA 2	SWITCH OFF	SOUTH
18	09:32	SHUNT REACTOR	MORALEJA 220 REA 12	SWITCH OFF	CENTRE
19	09:34	SHUNT REACTOR	ALMARAZ 400 REA 3	SWITCH OFF	SOUTH
20	09:38	LINE	CATADAU-MUELA 1	SWITCH ON	EAST
21	09:41	SHUNT REACTOR	VALDECABALLEROS 400 REA 1	SWITCH OFF	SOUTH
22	09:44	SHUNT REACTOR	BROVALES 400 REA 1	SWITCH OFF	SOUTH
23	09:49	SHUNT REACTOR	EALMARAZ 220 REA 1	SWITCH OFF	SOUTH
24	09:52	SHUNT REACTOR	MAGALLON 400 REA 2	SWITCH OFF	NORTH
25	09:54	LINE	L-400 KV ALMARAZ-MORATA 2	SWITCH ON	CENTRE
26	10:02	LINE	L-400 KV BROVALES-SAN SERVAN 1	SWITCH ON	SOUTH
27	10:04	SHUNT REACTOR	GUILLENA 400 REA 2	SWITCH OFF	SOUTH
28	10:05	SHUNT REACTOR	CABRA 400 REA 1	SWITCH OFF	SOUTH
29	10:05	LINE	L-400 KV ARCOS-D. RODRIGO 2	SWITCH ON	SOUTH
30	10:18	SHUNT REACTOR	JM. ORIOL 220 REA 1	SWITCH OFF	SOUTH
31	10:19	SHUNT REACTOR	MORALEJA 220 REA 13	SWITCH OFF	CENTRE
32	10:20	SHUNT REACTOR	OLMEDILLA 400 REA 1	SWITCH OFF	EAST
33	10:22	SHUNT REACTOR	VILLAVICIOSA 220 REA 2	SWITCH OFF	CENTRE
34	10:29	SHUNT REACTOR	ROCAMORA 400 REA 1	SWITCH OFF	EAST
35	10:32	LINE	L-220 KV ACECA-PICON	SWITCH ON	CENTRE
36	10:32	SHUNT REACTOR	MAGALLON 400 REA 1	SWITCH OFF	NORTH
37	10:32	SHUNT REACTOR	PINILLA 400 REA 1	SWITCH OFF	EAST
38	10:32	SHUNT REACTOR	SS REYES 400 REA 3	SWITCH OFF	CENTRE
39	10:33	LINE	L-400 KV BROVALES-GUILLENA 1	SWITCH ON	SOUTH
40	10:33	HVDC 320 KV STA. LLOGAIA-BAIXAS	RAISE THE SETPOINT TO 413 KV	SETPOINT	NORTHEAST
41	10:35	LINE	L-400 KV GUADAME-VALDECABALLEROS	SWITCH ON	SOUTH
42	10:39	SHUNT REACTOR	MAGALLON 400 REA 2	SWITCH ON	NORTH
43	10:40	SHUNT REACTOR	GUADAME 400 REA 2	SWITCH ON	SOUTH
44	10:40	SHUNT REACTOR	PINILLA 400 REA 1	SWITCH ON	EAST
45	10:40	SHUNT REACTOR	MORALEJA 220 REA 12	SWITCH ON	CENTRE
46	10:43	HVDC 320 KV STA. LLOGAIA-BAIXAS	REDUCE THE SETPOINT TO 409 KV	SETPOINT	NORTHEAST
47	10:44	SHUNT REACTOR	RUEDA 400 REA 2	SWITCH ON	NORTH
48	10:44	CONDENSER	JUJA 220 CONDEN1	SWITCH OFF	NORTHEAST
49	10:45	SHUNT REACTOR	VALDECABALLEROS 400 REA 2	SWITCH ON	SOUTH
50	10:50	SHUNT REACTOR	CABRA 400 REA 1	SWITCH ON	SOUTH
51	10:50	SHUNT REACTOR	REQUENA 400 REA 1	SWITCH ON	EAST
52	10:51	HVDC 320 KV STA. LLOGAIA-BAIXAS	REDUCE THE SETPOINT TO 404 KV	SETPOINT	NORTHEAST
53	10:59	SHUNT REACTOR	VALDECABALLEROS 400 REA 2	SWITCH OFF	SOUTH
54	10:59	SHUNT REACTOR	SENTMENAT 400 REA 1	SWITCH OFF	NORTHEAST
55	10:59	HVDC 320 KV STA. LLOGAIA-BAIXAS	RAISE THE SETPOINT TO 410 KV	SETPOINT	NORTHEAST
56	11:00	SHUNT REACTOR	GUADAME 400 REA 2	SWITCH OFF	SOUTH
57	11:01	SHUNT REACTOR	CABRA 400 REA 1	SWITCH OFF	SOUTH
58	11:02	SHUNT REACTOR	LA SERNA 400 REA 2	SWITCH OFF	NORTH
59	11:03	LINE	L-400 KV OLMEDILLA-ROMICA 2	SWITCH ON	EAST
60	11:03	SHUNT REACTOR	BEGUES 400 REA 1	SWITCH OFF	NORTHEAST
61	11:03	SHUNT REACTOR	REQUENA 400 REA 1	SWITCH OFF	EAST
62	11:03	SHUNT REACTOR	VITORIA 400 REA 2	SWITCH OFF	NORTH
63	11:03	SHUNT REACTOR	GUADAME 220 REA 3	SWITCH OFF	SOUTH
64	11:04	SHUNT REACTOR	ESCATRON 220 REA 1	SWITCH OFF	NORTH
65	11:04	SHUNT REACTOR	MORALEJA 220 REA 12	SWITCH OFF	CENTRE
66	11:04	SHUNT REACTOR	PALOS 220 REA 1	SWITCH OFF	SOUTH
67	11:04	SHUNT REACTOR	RUEDA 400 REA 2	SWITCH OFF	NORTH
68	11:04	SHUNT REACTOR	MAIALS 400 REA 1	SWITCH OFF	NORTHEAST
69	11:07	SHUNT REACTOR	MAGALLON 400 REA 2	SWITCH OFF	NORTH
70	11:07	SHUNT REACTOR	RUBI 400 REA 1	SWITCH OFF	NORTHEAST
71	11:07	LINE	L-400 KV AGUAYO-ABANTO	SWITCH ON	NORTHWEST
72	11:07	LINE	L-400 KV GUADAME-CABRA 1	SWITCH ON	SOUTH
73	11:08	LINE	L-400 KV PINAR-TAJO	SWITCH ON	SOUTH
74	11:08	HVDC 320 KV STA. LLOGAIA-BAIXAS	RAISE THE SETPOINT TO 413 KV	SETPOINT	NORTHEAST
75	11:08	SHUNT REACTOR	PINILLA 400 REA 1	SWITCH OFF	EAST
76	11:09	LINE	L-400 KV MONTEARENAS-MUDARRA 2	SWITCH ON	NORTHWEST
77	11:10	SHUNT REACTOR	CABRA 400 REA 1	SWITCH ON	SOUTH
78	11:10	SHUNT REACTOR	GUADAME 220 REA 3	SWITCH ON	SOUTH
79	11:11	HVDC 320 KV STA. LLOGAIA-BAIXAS	REDUCE THE SETPOINT TO 409 KV	SETPOINT	NORTHEAST
80	11:11	SHUNT REACTOR	LA SERNA 400 REA 2	SWITCH ON	NORTH
81	11:12	SHUNT REACTOR	MAIALS 400 REA 1	SWITCH ON	NORTHEAST
82	11:14	HVDC 320 KV STA. LLOGAIA-BAIXAS	REDUCE THE SETPOINT TO 405 KV	SETPOINT	NORTHEAST
83	11:17	LINE	L-400 KV ARCOS-CABRA	SWITCH ON	SOUTH
84	11:18	SHUNT REACTOR	RUBI 400 REA 1	SWITCH ON	NORTHEAST
85	11:20	LINE	L-400 KV PIEROLA-VANDELLÓS	SWITCH ON	NORTHEAST
86	11:22	SHUNT REACTOR	ELIANA 220 REA 1	SWITCH OFF	EAST
87	11:43	SHUNT REACTOR	ELIANA 220 REA 1	SWITCH ON	EAST
88	11:43	SHUNT REACTOR	ESCATRON 220 REA 1	SWITCH ON	NORTH
89	11:46	SHUNT REACTOR	SENTMENAT 400 REA 1	SWITCH ON	NORTHEAST
90	11:47	SHUNT REACTOR	GUADAME 400 REA 2	SWITCH ON	SOUTH
91	11:47	SHUNT REACTOR	MINGLANILLA 400 REA 1	SWITCH ON	EAST
92	11:48	SHUNT REACTOR	RUEDA400 REA 2	SWITCH ON	NORTH
93	11:48	HVDC 320 KV STA. LLOGAIA-BAIXAS	REDUCE THE SETPOINT TO 401 KV	SETPOINT	NORTHEAST
94	11:48	SHUNT REACTOR	EALMARAZ 220 REA 1	SWITCH ON	SOUTH
95	11:48	SHUNT REACTOR	MORALEJA 220 REA 12	SWITCH ON	CENTRE
96	11:50	SHUNT REACTOR	PALOS 220 REA 1	SWITCH ON	SOUTH
97	11:59	HVDC 320 KV STA. LLOGAIA-BAIXAS	RAISE THE SETPOINT TO 406 KV	SETPOINT	NORTHEAST
98	11:59	SHUNT REACTOR	GUADAME 400 REA 2	SWITCH OFF	SOUTH
99	12:01	SHUNT REACTOR	EALMARAZ 220 REA 1	SWITCH OFF	SOUTH
100	12:02	LINE	L-220 KV C.PLATA-VILLAVERDE BAJO 2	SWITCH ON	CENTRE
101	12:04	SHUNT REACTOR	VILLAVICIOSA 400 REA 1	SWITCH OFF	CENTRE
102	12:04	SHUNT REACTOR	GUADAME 220 REA 3	SWITCH OFF	SOUTH
103	12:05	HVDC 320 KV STA. LLOGAIA-BAIXAS	RAISE THE SETPOINT TO 412 KV	SETPOINT	NORTHEAST
104	12:05	SHUNT REACTOR	RUEDA 400 REA 2	SWITCH OFF	NORTH
105	12:07	LINE	L-400 KV GRIJOTA-VILLARINO 2	SWITCH ON	NORTHWEST
106	12:07	LINE	L-400 KV P. GUZMAN-GUILLENA 1	SWITCH ON	SOUTH
107	12:07	LINE	L-400 KV PALMAR-CARRIL	SWITCH ON	EAST
108	12:07	SHUNT REACTOR	ARAGON 400 REA 1	SWITCH OFF	NORTH
109	12:08	LINE	L-400 KV LA ROBLA-MUDARRA	SWITCH ON	NORTHWEST
110	12:08	LINE	L-400 KV PALMAR-ROCAMORA 2	SWITCH ON	EAST
111	12:15	LINE	L-400 KV MORATA-VILLAVICIOSA	SWITCH ON	CENTRE
112	12:17	SHUNT REACTOR	CABRA 400 REA 1	SWITCH OFF	SOUTH
113	12:21	SHUNT REACTOR	PEÑAFLOR 400 REA 1	SWITCH OFF	NORTH
114	12:21	LINE	L-400 KV PINILLA-ROMICA 2	SWITCH ON	EAST
115	12:22	LINE	L-400 KV PINILLA-ROCAMORA 1	SWITCH ON	EAST
116	12:24	SHUNT REACTOR	PALOS 220 REA 1	SWITCH OFF	SOUTH
117	12:24	SHUNT REACTOR	MORATA 400 REA 4	SWITCH OFF	CENTRE
118	12:25	LINE	L-400 KV GUADAME-CABRA 3	SWITCH ON	SOUTH
119	12:25	LINE	L-400 KV TORDESILLAS-GALAPAGAR	SWITCH ON	CENTRE
120	12:26	SHUNT REACTOR	VITORIA 400 REA 2	SWITCH ON	NORTH
121	12:27	SHUNT REACTOR	PEÑAFLOR 400 REA 1	SWITCH ON	NORTH
122	12:27	SHUNT REACTOR	GUADAME 220 REA 3	SWITCH ON	SOUTH
123	12:27	SHUNT REACTOR	GUADAME 400 REA 2	SWITCH ON	SOUTH
124	12:28	SHUNT REACTOR	MORATA 400 REA 4	SWITCH ON	CENTRE
125	12:32	HVDC 320 KV STA. LLOGAIA-BAIXAS	REDUCE THE SETPOINT TO 409 KV	SETPOINT	NORTHEAST

Figure 7-1 List of actions with an impact on voltage control[12] adapted from ENTSO-E factual report

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[12] 28 April 2025 Blackout

Due to the limitations experienced with the dynamic voltage control capability, reliance on the reactive power range and voltage control from a few synchronous generators, the operators resorted to multiple instances of switching of static reactive power compensation devices, mainly shunt reactors, as shown in Figure 7-1.

> Observation 15: In the system configuration with many transmission circuits switched out for voltage control and a relatively low number of widely dispersed synchronous generators dynamically controlling the voltage, caution must be exercised. While switching out transmission circuits reduces the reactive power gain, the effectiveness of the voltage control resources is also reduced as the electrical distance is increased.

Throughout the day there are a few notable instances that draw attention to the challenges that were experienced while operating the system. A few examples include:

- 400 kV shunt reactors switched out of service and back into service less than 10 minutes later
- One 400 kV shunt reactor in the South being switched 6 times in 3 hours period
- 17 shunt reactors switched out of service; 5 voltage control lines switched in service and 2 HVDC voltage setpoint changes in 10 minutes

Whilst the very frequent switching of shunt reactors is generally an asset management concern, in this case the switching of static reactive power compensation devices in lieu of resources of dynamic reactive compensation had a significant impact in the later stages of the collapse when a large number of shunt reactors in the South were disconnected during the overvoltage condition.

Fast switching of elements that impact the voltage performance of the system, like transmission lines and shunt reactors is not common practice due to the impact on the capability to understand the consequences of these rapidly implemented switching actions. The understanding of the consequences of such changes in system configuration and operating points is typically informed by analysis tools that run periodically.

Operators can choose to take multiple switching actions in quick succession to resolve system issues such as abnormal voltages. In emergency conditions this can be unavoidable, but the rapid change in system operating state can result in a reduction or loss of risk-awareness. Under normal operating conditions, if certain actions are unplanned, the real-time operators can run offline analysis to understand the consequences and effectiveness of their actions before implementation. Under stressed emergency operations, there may not be sufficient time, and operators may rely on tools like Real-Time Contingency Analysis or Dynamic Security Assessment tools to understand if any credible contingencies could lead to violation of operating limits. Real-time contingency analysis and dynamic stability assessment tools tend to run on some periodic basis such as every five or ten or fifteen minutes and report an updated list of credible risks of abnormal voltages, overloads, or instability to the operator. When multiple switching actions are taken in a short period, the system will have moved away from the operating state studied at the previous interval and the next report may take a few minutes to come through. This can result in the grid being in a high-risk state unbeknownst to the operator. There is a necessary trade-off in decision-making between speed and security.

A delayed feedback, in response to the fast switching actions implemented in the transmission system, arrives from the impact at the distribution level. Complex loads may take time to adjust their operating point to the new system conditions. In a similar manner the impact from distribution transformers changing tap positions will also be delayed and not be immediately obvious to the transmission real-time operators. For these reasons, it is common practice to allow time between switching actions to evaluate the impact and effectiveness of the corrective actions taken, to ensure these don't have unintended consequences.

Decision making support tools

Decision making support tools referenced in the previous section can be utilized to assess the effectiveness and identify unwanted consequences of remedial actions implemented or to be implemented. Essentially, checking the effectiveness of switching certain transmission circuits may have on increasing the damping levels of the power system or evaluating the impact of returning transmission voltage control circuits may have on the overall voltage profile. These decision making support tools are becoming increasingly important for maintaining situational awareness in complex power systems with reduced correlation between cause and effect.

> Observation 16: Typical contingency analysis tools are limited to simulation of power system physical faults. In modern power systems that operate a myriad of devices with protection and control that are challenging to accurately represent in analysis tools, new types of contingencies may be devised to improve situational awareness. One example would be to deliberately introduce oscillations in simulation tools to observe the response of the system. If oscillations are observed to lead to unacceptable conditions, due to the spread of the impact or the severity of amplitude, the operators can decide to change the system configuration to achieve a defensive posture.

On the 28th of April, the remedial actions implemented in response to the oscillations detected throughout the day included the reduction of power transfers with neighboring power systems by reducing the output of renewable generation. Likewise, many transmission voltage control circuits have been returned to service. Both these sets of actions acted to impact the voltage profile and the voltage control capability of the Spanish power system.

At this stage of the investigation and given the information available, it is unclear why these actions were not taken in conjunction with dispatching fast starting synchronous generators with power system stabilizers and voltage control capability. Equally, it is not known what voltage related alerts have been annunciated when and after these remedial actions were implemented. More broadly, it is not known if the control center tools accurately predicted the consequences of oscillation mitigation (the rapid voltage rises) or how operators can learn from this event to improve response to emergency conditions and ensure they have the necessary information available to them to make the best decisions. Furthermore, it is not known to what extent the characteristics and protection and control of distribution-connected power plants is considered in real-time contingency analysis or dynamic stability assessment tools or whether the consequences of rapid voltage changes or elevated voltages on the distribution grid were known. Internationally, some system operators ignore them or simply treat them as negative loads with no protection or control response, while others have modeled these devices in great detail for ten years or more. A key component of event analysis is identifying – with the benefits of hindsight –which risks could have been identified and using that information to develop improved risk identification, calibration, and management procedures and tools.

There is no information in the investigation reports related to the output from decision-making support tools like real-time contingency analysis or dynamic security assessment solutions. It is not clear whether these tools would have flagged any potential exceedances of limits and how such information was used to inform operational decisions.

Observation 17: Implementation of multiple manual switching actions of static reactive power compensation devices is an ineffective way to attempt to manage fast changing dynamic phenomena.

Operator proficiency

The operator proficiency is a key prerequisite for safe and secure power system operations. Operator proficiency alongside loss of situational awareness have been identified as causal factors or root causes in recent significant system events.

Observation 18: Having operators of all areas that form part of a larger synchronous system trained and certified to a set standard can establish common baseline of operator competency and prevent inconsistent training.

Although operator conduct and proficiency in any of the areas of the synchronous European system has the potential to trigger widespread consequences, in Europe, there isn’t currently a collective requirement that sets a common standard for training, certification and authorization of operators. When it comes to standards for improving and maintaining operator proficiency, the electricity industry currently lags other mission critical sectors like civil nuclear, aviation or air traffic control. For example, operator training is conducted at inconsistent standards with some TSOs relying exclusively on on-the-job training whilst others may be using dispatch training simulators that are unable to replicate the power system dynamics encountered in operations of modern and complex systems. For instance, in the civil nuclear sector there are international standards that mandate the performance requirements and accuracy of the simulators for operator training. Similarly, North American power system operators are regularly evaluated and certified at a common set of standards to ensure proficiency of operators is a defined level.

Observation 19: Operators have been experiencing novel power system dynamics that are challenging to replicate in typical training simulator environment. Defining the system dynamics required to be replicated in training simulators can support with uplifting of the operator training capability. Effective training regimes involve simulator environments that can replicate system dynamics with high degree of realism. Standards can be introduced to define performance requirements for training simulators, like the level of completeness and degree of accuracy of system dynamics replicated.

Operator's instinct forms an important part of the response during emergency operations, especially for seasoned operators that have developed mental models that allow them to make confident decisions in stressful situations with scarce information. These mental models have been developed based on many years of experience operating synchronous machine dominated systems. Today, elements that are beyond the visibility and experience of transmission operators, like dynamics of distribution systems and behavior of controllers from inverter-based resources have started to play a more dominant role in the response of transmission systems during emergency operations. Power system dynamics are changing as they are becoming more brittle, which impacts the way in which they fail too, moving away from the cases when operators had multiple early signs and had sufficient time to address the issues to a more 'break before leak' type of failure. Since existing dispatch training simulators are not able to replicate these complex dynamics, the power system may need to be operated with larger operating margins until the decision making tools and training capability is enhanced to provide operators control and expertise over the system they are operating.

Observation 20: Operators may need training on new mental models and operational practices to effectively navigate abnormal situations and emergencies in power systems with high penetration of inverter-based resources. Past experience with conventional systems, while valuable, provides an incomplete foundation for these evolving system dynamics.

In response to the concerns and voltage challenges presented by the distribution and generation operators, the transmission operators planned to continue using the switching of static reactive power compensation devices to deal with a fast evolving dynamic situation. Even after the overvoltage conditions experienced around 10:30, which resulted in transmission connected load disconnecting on overvoltage protection, the transmission operators did not enact a defensive posture or move to put the grid in a more conversative operating mode. This is a typical mitigation action implemented by system operators globally to improve the system strength, damping and the voltage system performance by bringing online fast starting synchronous units, usually hydro units with fast acting voltage control and power system stabilizers.

The normalization of deviance, in simple terms is a concept that refers to operators' reducing their sensitivity to certain system behavior, even when they observe significant violations of operating limits when these violations have been experienced in the past and did not result in significant issues.

Another trend observed in recent significant events around the world is the operators not feeling empowered to change the generation pattern and dispatch dictated by signals from market outcomes.

On the day of the event, even when the system was operating in a stressed condition, subjected to large amplitude oscillations, the emergency actions were taken in order of competitiveness rather than effectiveness, as noted by REE in their report.

A review of collective human factors should explore and understand the impact on real-time operations from pressure to operating the power system in a cost efficient manner. Likewise, the impact of any direct and implied political directions and regulatory policies on interfering with operator decision making and ultimately with the safe and secure real-time operations of the system should be reviewed.

Situational Awareness

Situational awareness refers to the ability to monitor an environment, perceive threats, evaluate risks, and decide to take action, based on the information that is available to the person at a point in time.

There has been a rapid increase in the complexity of many power systems around the world in the last ten to fifteen years. It has been observed during significant recent events around the world that established protocols or remedial actions that used to work are no longer effective or have the same degree of outcome. The legacy control room tools, protocols and training are gradually becoming inadequate for the challenges of modern power system operators that have started to impose difficulties even on most seasoned power system operators.

Experienced operators can often anticipate when the power system may be at risk of heading in an area of operation that involves degraded voltage performance. Apart from detecting unusual power system configurations like network topology or generation pattern and dispatch (like lower than usual number of generators with fast acting automatic voltage control capability), seasoned operators can also often identify when the voltage profile is diverging from the advice provided by the day ahead planning team.

The operators can also identify more subtle early signs such as the unusual response of the power system following planned switching actions like reactive power compensation plant switching or transmission voltage control circuit switching. Observing the natural behavior of the power system in response to daily load variations can also be used to detect if the power system is starting to operate in a stressed condition.

Real-time operators generally use the output of decision making support tools on dedicated displays as part of their consoles and videowall. These may include, but are not restricted to:

- voltage trends from pilot nodes – large voltage variations than usual are sign of voltage control issues
- reactive power trends from critical generators – identify whether their response or output is not as expected
- voltage trend overlaid on previous days with similar characteristics – divergence could act as an alert
- voltage control notifications annunciated – more than usual could be a sign of voltage control challenges

The ENTSO-E interim report compares the reactive power output of synchronous generators in different areas of the Spanish power system relative to an expected reference (Figures 2-84 to 2-86 of that report). It is unclear whether the calculated reactive power references considered the reactive power limitations or the mode of voltage control operation of the nuclear units or other existing limitations of the synchronous generators operating on the day. Assuming the reference values are correct, as discussed in the previous paragraph, discrepancies between expected and actual reactive power output are an important parameter monitored by system operators in real-time. It is unclear if the discrepancies highlighted in the reactive power plots have been identified on the day and whether the system operators contacted the power plants to inquire about the differences, to directly instruct changes in setpoints or Mvar outputs or replace the reactive power range capability of any power plants deemed non-compliant by starting additional generation resources in the relevant areas.

To evaluate the voltage control performance of the synchronous generators on the day, their individual circumstances and limitations need to be understood, for example any derogations and the specific voltage control process that is implemented at nuclear power plants in Spain.

Most importantly, control centers of system operators are equipped with simulation analysis tools for power system risk management. These tools are used to anticipate where the power system is trending or flag if the current power system configuration is conducive to degraded operating conditions or violations. Examples of such tools include the real-time contingency analysis of the SCADA EMS, dynamic security assessment tools and wide area monitoring systems that can trigger alerts to notify the real-time operators of existing or impending risk.

Based on a review of the audio recordings of the operational liaison between the transmission system operator and the distribution network operator in the Southwest, as made available by Endesa, the recordings indicate that the transmission operators were aware of developing operational issues in the southern region. Specifically, the operators referred during the recorded exchanges to a shortage of generation resources with voltage control capability in the South and discussed this condition as a contributing factor to the operational difficulties being experienced.

The recordings further show that the market merit order was cited by the operators as a limiting factor in securing additional generation support in the southern region. However, the recordings do not contain any explicit discussion or explanation as to whether the operators considered, or believed themselves authorized, to initiate generation outside the merit order to address the situation.

Human factors refers to how people interact with systems, procedures, and environments, with the aim of designing operations that account for human capabilities and limitations to improve safety, performance, and reliability. Situational awareness and human factors are tightly interlinked, particularly in complex, time-critical operational environments such as power system control rooms.

Situational awareness is shaped and constrained by human factors, including organizational culture, procedures, training, workload, and decision-making authority.
Even when operators have adequate situational awareness, human factors can influence how that awareness is translated into timely action.

Procedural constraints and market rules may limit perceived freedom to act, even if operators recognize a situation when an intervention is required, for technical reasons, to remedy the abnormal operation.

Authority and role clarity can affect whether operators feel empowered to deviate from standard practices and take decisions that have a cost associated as part of market operation. Risk perception and accountability concerns may bias decisions toward compliance with established frameworks (e.g. market merit order) over discretionary operational interventions.

Conversely, strong human-factor design with clear decision authority given to the operators, well-defined emergency procedures, effective communication, and a culture that supports justified remedial actions irrespective of the market implications, can enhance situational awareness by enabling operators not only to recognize emerging problems but also to act decisively upon them.

In practice, system performance depends not only on whether operators understand what is happening, but on whether the human and organizational context allows that understanding to be converted into timely and effective operational decisions.

Observation 21: The operators using consoles and large displays or videowalls for team level situational awareness, that include voltage trends and real-time reactive power output of critical resources, are better placed to identify early signs of voltage performance degradation.

Observation 22: Prudent operations are characterized by planning the system with sufficient operating margins. Sources with adequate dynamic reactive power range, strategically located to handle system vulnerabilities are required to ensure a healthy voltage control capability. In real-time, remedial actions that involve large number of manual interventions with low effectiveness are an inefficient method to deal with fast developing situations.

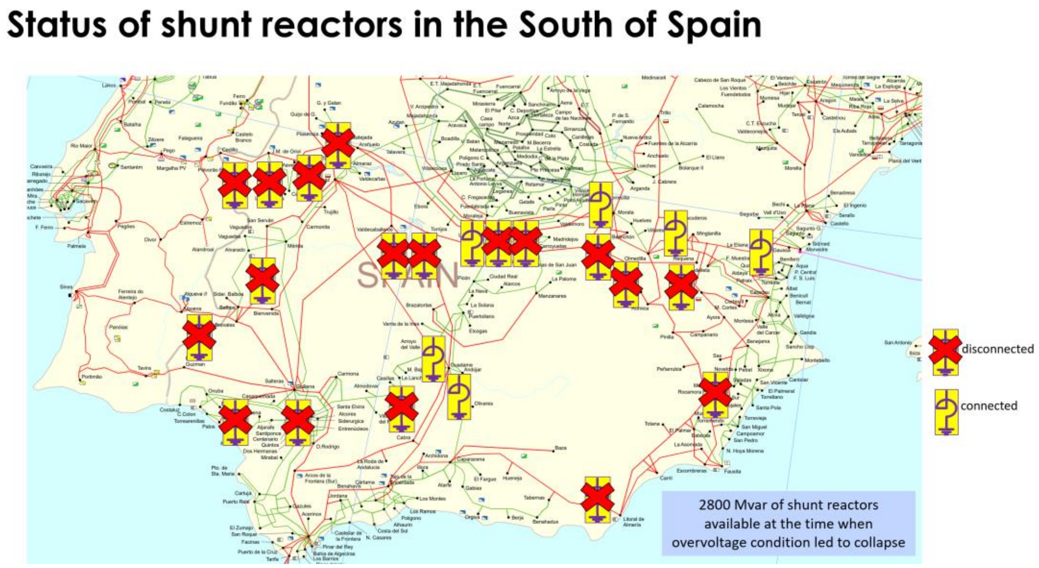
8. SYSTEM DEFENSE PLANS

Here, potential system defense plan approaches are reviewed, without specific reference to the Iberian event. These solutions and strategies are presented to share insights and experience from other grids.

Automatic Switching of Static Reactive Power Compensation Plant

Automatic switching of static reactive power compensation plant schemes (ARS) is a control strategy which is commonly used by transmission system operators worldwide. RTE in France utilize such schemes on approximately 50% of their static reactive power compensation equipment[13]. It is often employed in conjunction with other fast acting dynamic sources of voltage control. At their core, these schemes use local controllers to automatically switch shunt capacitors and reactors in a coordinated response to high and low voltage conditions. The design of such automatic switching systems requires careful sizing and distribution of the static reactive power compensation devices to avoid excessive switching or abnormal voltages.

Figure 8-1 below, shows the number and location of shunt reactors available to absorb reactive power and lower the voltage profile, at the time when the power system was experiencing overvoltage conditions.



2800 Mvar of shunt reactors available at the time when overvoltage condition led to collapse

Figure 8-1 Status of shunt reactors In Central and Southern Spain before the blackout[14][15]

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[13] High Voltage –Sharing of events concerning the Iberian blackout and challenges for RTE, December 2025

[14] 28 April 2025 Blackout

[15] Grid Map

A key concern at design stage is to ensure the automatic switching does not result in sustained undervoltages or overvoltages during either normal system conditions or stressed conditions. The application of such automatic schemes has proved to be useful during recent significant system events, for example, in Sweden in 2022 a prolonged, 7-second fault on a 220 kV side of a 400/220 kV transformer resulted in 35 reactive power compensation devices switching automatically in quick succession. While there were brief undervoltages and overvoltages, the swift and coordinated actions of the scheme helped to prevent system collapse, generator instability, and loss of customer load.

Observation 23: Automatic switching schemes for reactive power compensation plant are an efficient defense method during emergency operations for power systems that operate with a large fleet of such static devices.

Low Frequency Demand Disconnection (LFDD)

Low frequency demand disconnection is a well-establish and universally-applied system defense scheme. It involves the staged disconnection of blocks of load when frequency falls below certain thresholds for certain periods of time. Some regions – particularly smaller islands – also use rate of change of frequency to accelerate tripping to avoid rapid frequency collapse.

Internationally, there has been a trend in the last five years of decreasing performance from low frequency demand disconnection schemes during major underfrequency events. This has taken the form of LFDD under-delivering relative to expectations, resulting in less load being disconnected than expected. Various explanations are provided ranging from changes in load patterns to penetration of DER and failure of DER to ride-through rapid frequency changes.

The adequacy of such schemes, expected to act as a safety net, should be reviewed to ensure they maintain high probability of success in delivering the expected results, when considering fast changes in power system operations and dynamics. Several system operators have already redesigned their LFDD schemes to be more adaptive, while many more are at the study or engineering design stage. Monitoring substations and load with LFDD is also an extremely valuable strategy. Historically, many system operators only verified the available LFDD annually or every few years and primarily focused on LFDD available during the peak grid demand period. Practices are changing, however, with system operators more regularly reviewing how much LFDD is available and some even started displaying the available and expected LFDD in their real-time control centers. By reviewing or monitoring the demand at LFDD locations, the system operator can determine how much load would actually trip at each frequency threshold and compare against the minimum required to secure the system.

Observation 24: For power systems that operate with insufficient voltage control capability and are challenged by overvoltage conditions, the LFDD become less effective and tend to exacerbate the overvoltage condition accelerating the collapse.

System Separation Schemes

Protection functions on tie-lines have been generally successful in limiting the spread of abnormal conditions to healthy parts of the European grid. They tend to be triggered only when a loss of synchronism is detected and the grids are already experiencing unstable power swings, in which case separation is essential to prevent uncontrolled cascade tripping. There has been an industry trend away from tripping tie-lines and interconnectors unless absolutely necessary in preference to keeping the grids synchronized and sharing resources during major disturbances.

System Integrity Protection Schemes

System Integrity Protection schemes (SIPS), Special Protection Schemes (SPS), and Remedial Action Schemes (RAS) are different names for similar strategies. While certain regions have very specific definitions SIPS, SPS, and RAS, others use the terms inter-changeably. In general, they are control and protection schemes which activate to mitigate or prevent overloading, abnormal voltages, instability, oscillations, and other undesirable or degraded system conditions. A common example is automatic run-back or tripping of a generator in response to line overloading, but very sophisticated wide-area schemes have been deployed using synchrophasors to control power plants and batteries in response to instability and oscillations.

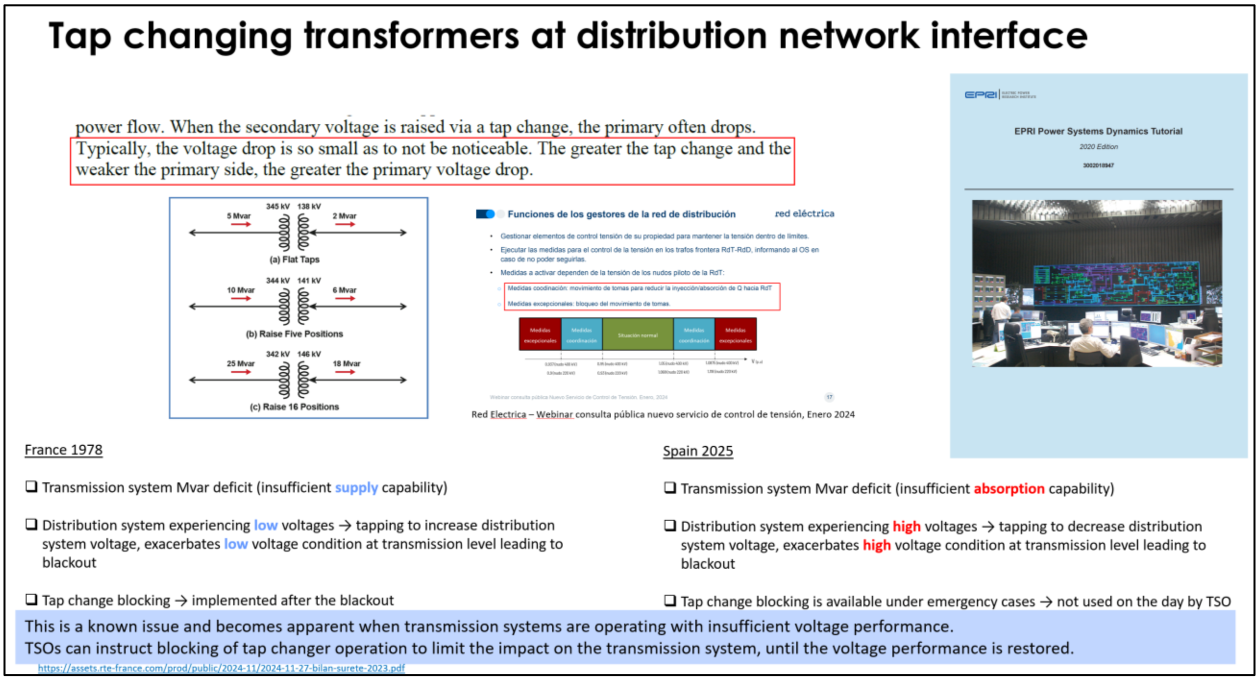
Overvoltage conditions can be challenging to resolve automatically, and the preferred solution is almost always the addition or more shunt reactors, STATCOMs, SVCs, synchronous condensers, or leveraging a nearby power plant. SIPS can provide certain solutions if shorter-term solutions are required. If shunt reactors or capacitors are near the at-risk location, then it may be possible to switch them automatically (as used in the ARS approach discussed above). A SIPS (or local controller) could take a coordinated action to re-dispatch power plants or issue new reactive power setpoints to power plants. Tripping load will tend to exacerbate the overvoltage, while tripping power plants will also tend to exacerbate the overvoltage, so neither of those options are viable. Large battery energy storage systems (BESS) have been integrated into SIPS in the past and could provide a potential solution for overvoltage conditions if located at the right location by triggering the BESS to enter full charging mode and/or reactive power setpoint.

An extreme option would be to employ SIPS to strategically de-energize the part of the grid experiencing the overvoltage to save the rest of the grid. This could be achieved by deliberately islanding the affected area or tripping certain long lines which are contributing significant capacitive vars. This is a very risky strategy as well as being challenging to design, which is why dynamic reactive power sources like STATCOMs, and synchronous condensers are almost always the preferred long-term solution.

Blocking of tap changers' operation

These schemes were developed in response to voltage instability events in the past. The issue was that the transmission grid would experience a degraded or low voltage condition and distribution transformers would then begin tapping in order to boost the distribution grid voltage, but this would bring the transmission grid voltage down further and accelerate voltage collapse. Such dynamics were observed during the 1978 blackout in France. A similar risk exists during elevated transmission grid voltage conditions, where distribution transformer could tap in order to bring down the distribution voltage but inadvertently raise the transmission grid voltage further. The solution is to automatically or manually block tap changing should such an event occur.

Figure 8-2 includes references to the voltage effect when tapping, examples of implementation of tap changer blocking and the approach in Spain.



Tap changing transformers at distribution network interface

power flow. When the secondary voltage is raised via a tap change, the primary often drops. Typically, the voltage drop is so small as to not be noticeable. The greater the tap change and the weaker the primary side, the greater the primary voltage drop.

Funciones de los gestores de la red de distribución red eléctrica

- Gestionar elementos de control tensión de su propiedad para mantener la tensión dentro de límites.
- Ejecutar las medidas para el control de la tensión en los trafos frontera RdT-RdD, informando al OS en caso de no poder seguirlas.
- Medidas a activar dependen de la tensión de los nudos piloto de la RdT:
  - Medidas coodinación: movimiento de tomas para reducir la inyección/absorción de Q hacia RdT
  - Medidas excepcionales: bloqueo del movimiento de tomas.

Webinar consulta pública Nuevo Servicio de Control de Tensión. Enero, 2024 17

Red Electrica – Webinar consulta pública nuevo servicio de control de tensión, Enero 2024

EPRI Power Systems Dynamics Tutorial

2020 Edition

3002018947

France 1978

- ❑ Transmission system Mvar deficit (insufficient **supply** capability)
- ❑ Distribution system experiencing **low** voltages → tapping to increase distribution system voltage, exacerbates **low** voltage condition at transmission level leading to blackout
- ❑ Tap change blocking → implemented after the blackout

Spain 2025

- ❑ Transmission system Mvar deficit (insufficient **absorption** capability)
- ❑ Distribution system experiencing **high** voltages → tapping to decrease distribution system voltage, exacerbates **high** voltage condition at transmission level leading to blackout
- ❑ Tap change blocking is available under emergency cases → not used on the day by TSO

This is a known issue and becomes apparent when transmission systems are operating with insufficient voltage performance.
TSOs can instruct blocking of tap changer operation to limit the impact on the transmission system, until the voltage performance is restored.

https://assets.rte-france.com/prod/public/2024-11/2024-11-27-bilan-surete-2023.pdf

Figure 8-2 Impact on tap changing on transmission voltage profiles and control actions[16][17][18]

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[16] https://assets.rte-france.com/prod/public/2024-11/2024-11-27-bilan-surete-2023.pdf

[17] Red electrica – webinar consulta pública nuevo servicio de control de tensión, Enero 2024

[18] EPRI Power Systems Dynamics Tutorial: 2020 Edition

Observation 25: When transmission systems are operated with reduced voltage performance margins, the impact from the distribution systems, through the response and behaviour of distributed energy resources, tap changers of distribution transformers and the voltage dependency of loads, is more significant.

9. PRINCIPLES OF INCIDENT INVESTIGATIONS

This section, while not focused specifically on the Iberian event, lays out principles that are important for any blackout investigation. They do not explicitly address how the investigation to this blackout is carried out or attempt to pass judgement on this investigation, but are provided here for general reader context.
Other critical infrastructure sectors, like civil nuclear and aviation, have standards, recommended practices and reference manuals for investigation and analysis of events. Examples include materials from International Atomic Energy Agency and International Civil Aviation Organization.

Objective and credibility of investigations

As a general guidance for investigations, the only objective of any blackout investigation should be the prevention of other blackouts. This objective supersedes all other considerations and establishes the primary mission of the investigation.

The fundamental principle governing any blackout investigation must be the identification of the real root cause to prevent future blackout through implementation of recommendations and lessons learned. If the root cause is accurately determined and effective mitigation actions and defensive mechanisms are implemented, the probability of a similar event occurring is reduced.

The purpose of a blackout investigation should not be to apportion blame or liability. The investigation process should maintain strict separation from any blame assignment or liability determination, as these concerns can compromise the integrity and the effectiveness of the fact-finding mission.

The credibility of any blackout investigation fundamentally depends on independence of the investigators. Depending on the event, Transmission System Operators (TSO) involved in the event, associations representing TSO and market participants, regulatory bodies that approve regulations and standards, government agencies that set the energy plans and directions cannot typically serve as primary or sole investigators due to inherent conflicts of interest, when these organizations may have operational decisions, regulatory positions or political considerations that could bias their assessment of events. This is why it is more common to form a multi-party investigative committee where the evidence can be evaluated in a transparent and unbiased manner, objective conclusions drawn, and recommendations proposed.

Focus of the investigation

Unbiased fact assessment

Conducting an unbiased fact assessment forms the cornerstone of any credible blackout investigation. When investigators approach the evidence with preconceived notions about root causes or culpability, they risk overlooking critical contributing factors, and ultimately arrive at incomplete or incorrect conclusions. An unbiased approach ensures that all data, whether from SCADA systems, operator logs, relay records, or witness statements, receives equal scrutiny regardless of whether it supports or challenges initial hypotheses. This investigative integrity is essential because power system failures typically involve complex cascading effects where the triggering and exacerbating events may differ significantly from what initial observations may have suggested.

Blackout investigations are particularly vulnerable to organizational pressures but also to cognitive biases that can compromise fact-finding. Various bodies involved or affected by the blackout, may have institutional interests in attributing failures to certain individual factors rather than systemic design flaws or policy inadequacies.
Confirmation bias can lead investigators to selectively emphasize evidence supporting predetermined narratives while dismissing contradictory data. Hindsight bias could also create the illusion that the sequence of events was predictable and preventable, potentially leading to unfair blame assignment.
An unbiased fact assessment methodology explicitly counteracts these tendencies by establishing protocols that separate data collection from interpretation, utilize diverse and varied perspectives, and systematically document all evidence regardless of its implications.

Root Cause Analysis

The complexity of modern interconnected power systems means that blackouts rarely have single causes. Instead, they result from combinations of equipment failures, protection system responses, operational decisions, market conditions, and human factors interacting in unexpected ways. Only through unbiased fact assessment can investigators identify the actual causal chain rather than stopping at superficial or politically convenient explanations.
For example, what initially appears as operator error may, upon objective examination, reveal inadequate situational awareness tools, unclear procedures, or systemic training deficiencies. What seems like equipment failure might actually expose design vulnerabilities, maintenance inadequacies, or inappropriate application of technology. Without bias-free investigation, these deeper systemic issues remain hidden, preventing the development of effective corrective actions.

Root causes represent the fundamental underlying reasons why a blackout occurred, the essential factors that, if eliminated or corrected, would have prevented the event entirely.

In power system failures, root causes typically address systemic issues such as inadequate design standards, flawed protection coordination philosophies, insufficient operational procedures, lack of situational awareness capabilities, organizational cultures that tolerate deviations from standards, inadequate investment in infrastructure modernization, or regulatory frameworks that don't incentivize reliability appropriately.

A root cause answers the question "Why did this system or process allow the failure to occur?" rather than simply "What failed?" For example, in a blackout triggered by relay misoperation, the root cause might not be the specific relay malfunction but rather the absence of comprehensive relay testing protocols, inadequate coordination studies, or missing redundancy in protection schemes.

Individual errors or specific non-compliant behavior often appear as contributing factors in the causal chain, and investigations that stop at this level may lead to punitive actions on those deemed responsible. However, deeper analysis frequently reveals root causes in systemic issues: inadequate procedures that set up operators for failure, insufficient training programs, poor human-machine interface design, or organizational pressures that compromise safe and secure operation.

Identification of Contributing Factors

Contributing factors are the multiple conditions, decisions, and events that combined to enable or accelerate the blackout sequence, even though individually they might not have caused a complete system collapse. These factors create vulnerability, reduce safety margins, or amplify the consequences of initiating events.

Contributing factors often include equipment being out of service for maintenance, higher-than-expected loading due to weather conditions, communication failures between control centers, incomplete system models used in planning studies, operator error during critical decision, or cascading effects from seemingly minor initial disturbances. While each contributing factor alone might be manageable within normal system resilience, their confluence creates conditions where the root cause can manifest as an actual blackout. The relationship between root causes and contributing factors forms a causal chain where contributing factors act as intermediate links connecting root causes to the observable event. In a scenario where vegetation contact causes a line trip: the immediate physical cause is tree to conductor contact, contributing factors might include deferred maintenance schedules, faster than predicted vegetation growth due to weather, and lack of adequate clearance monitoring technology, while the root cause could be inadequate vegetation management program funding or risk assessment methodologies. Understanding this hierarchy is essential because addressing only the immediate cause (clearing that specific tree) or individual contributing factors (adjusting that maintenance cycle) without correcting root causes leaves the system vulnerable to similar failures through different pathways.

Development of Preventive Measures

The findings of blackout investigations inform significant policy decisions, capital investments, regulatory reforms, and sometimes legal proceedings with high cost implications. The affected companies, regulators, policymakers, and the public will only accept and act upon investigation conclusions if they trust the process was fair and thorough.

An unbiased fact assessment methodology, transparently documented and independently verifiable, can establish this credibility.

When investigations are perceived as predetermined or influenced by political considerations, the resulting recommendations face resistance, implementation delays, and ongoing disputes that undermine grid reliability improvements. Conversely, investigations recognized for their objectivity may create consensus around necessary changes and motivate collective action to prevent recurrence.

Perhaps most importantly, after a blackout, the industry should learn not just from what failed, but from what nearly failed and what performed correctly under stress. Without preconceptions investigators can identify latent vulnerabilities, recognize when operating limits were violated, and understand which defensive systems or operational interventions would have been effective in preventing the outcome. This comprehensive understanding enables the industry to strengthen grid resilience to avoid similar events.

Effective blackout investigations must thoroughly document both contributing factors and root causes because they inform different types of corrective actions.

Contributing factors often point toward tactical, near-term improvements: updating specific procedures, adjusting operational limits, enhancing training on particular scenarios, or modifying maintenance schedules. These interventions can quickly reduce the probability of similar events.

Root causes, however, demand strategic, systemic changes: redesigning protection philosophies, implementing new technologies for situational awareness, restructuring organizational accountability, or revising industry standards.

Addressing root causes typically yields broader, longer-lasting improvements but requires greater time, investment, and organizational commitment. Mitigating contributing factors provides more immediate risk reduction and may be essential for preventing near-term recurrence, but without root cause correction, new contributing factors will inevitably emerge.

Investigations that identify only contributing factors may achieve short-term improvements but fail to address fundamental vulnerabilities, while those focusing exclusively on abstract root causes without documenting specific contributing factors may propose theoretically sound but impractical solutions disconnected from operational realities.

Access to information and evidence

The requirement for unrestricted access acknowledges that organizational self-interest, competitive concerns, liability fears, and regulatory apprehension often create barriers to information sharing. Companies may be reluctant to provide evidence that could reveal standards violations, inadequate maintenance practices, or operational errors that expose them to penalties or litigation. Real-time operators might hesitate to disclose communications or decisions that could be second-guessed or criticized.

Without clear legal authority and confidentiality protections that override these concerns, investigations become protracted negotiations over information access, during which evidence degrades, and organizational positions harden, ultimately producing incomplete analyses that fail to identify systemic vulnerabilities.

Investigators must be authorized to have immediate and unrestricted access to any evidence in the form of:

- Audio and video recordings
- Operator logs
- SCADA EMS, RTCA, MMS, DSA, WAMS records
- PMU, DFR and relay logs and settings
- System models used in the operational planning and real-time environment

For digital evidence, timestamps, data integrity, and protection from modification are essential for establishing accurate event chronology.

Investigators must also have access to staff involved in the blackout. Interviewing of relevant staff is necessary to understand what they saw, heard and know of the events that led to the blackout.

Access to internal documentations is also important for investigators to understand the broad context. These materials may include:

- Operating principles and manuals
- Risk register and controls in place to manage risk
- Training records
- Safety database records
- Reporting of system security violations and mitigations
- Historic data
- Audit reports

Effective investigation authorization must provide both immediate post-event access and ongoing retrospective access as analysis progresses. Initial evidence collection captures the immediate system state and perishable data, but detailed analysis often reveals additional information needs, such as previous instances of similar but less severe disturbances, engineering studies conducted during system planning, or training records for involved personnel. Investigators must have continued authority to request and obtain such retrospective information without repeated negotiations or delays. Additionally, access authorization should enable investigators to conduct follow-up interviews, request clarifications, and obtain additional data extracts as their understanding evolves and new questions emerge, supporting the iterative analysis process essential for complex technical investigations.

Prerequisites of enabling effective investigation

The fundamental requirements are the clear and mandatory need to record relevant information during disturbances and provision of this information for post-event analysis and investigation process. These requirements should be included in legally binding standards and compliance with these requirements enforced by regulatory authorities.
While unrestricted access is essential for investigation effectiveness, it must be balanced with legitimate protections for critical infrastructure security, personal privacy, and commercial confidentiality.

Investigation frameworks should establish clear protocols for handling sensitive information, including secure data storage, limited distribution, redaction of non-essential identifying information in public reports, and penalties for unauthorized disclosure.

Security-sensitive information about control system vulnerabilities, physical protection measures, or cyber defense capabilities requires protection from public release while still being available to cleared investigators.

Regulatory frameworks should explicitly empower designated investigation bodies to compel information delivery, conduct site inspections, interview personnel, and obtain expert technical assistance as needed. Penalties for non-compliance, evidence spoliation, or obstruction should be sufficient to deter resistance while being proportionate and focused on ensuring cooperation rather than punishment.
Effective mechanisms may be necessary when voluntary cooperation is not forthcoming.

However, the most effective investigation regimes combine clear legal authority with industry recognition that thorough, unbiased investigation serves collective interests in grid reliability, creating a culture where evidence access is viewed as a shared responsibility rather than an adversarial imposition.

Preservation of recordings to minimize the loss of information is equally important.

Detailed requirements regarding information recording may involve, but not restricted to:

- When to trigger data recording
- To what resolution
- For how long to record
- How long to keep the recordings
- Avoid data overwriting for complex disturbances
- Avoid measurement data clipping due to insufficient measurement range

Investigation activities

The main activities include:

- Processing, analysis and time synchronization of data from various sources to develop an accurate timeline for the events. To aid interpretation, the sequence of events can be annotated of frequency and voltage plots.
- Determine latent system conditions and initiating events
- Identify and examine contributing factors and the root cause of the event

Conditions prior to the blackout

The following should be collected and analyzed:

System and market characteristics

Understating of the generation mix, the levels of redundancy in the network, typical power flows, protection philosophy, market intervals

System design and security criteria

Review of codes and standards that set system operation limits, performance requirements like withstand and fault-ride through, contingency cases for the power system to be secured against, levels of frequency and voltage reserves etc.

System Operation roles and division of responsibilities

Understanding the dynamics, exchange of information and communication between various roles or teams within the control room operations and support functions.

System defense plans

Understanding the performance of protection and control devices during the event. Understanding the design principles, implementation and testing of adequacy and effectiveness of schemes like UFLS, loss of synchronism protection or automatic reactive power device switching.

Training, maintenance and testing policies

Review of materials related to:

- Operator proficiency, training and authorization
- Emergency operations and restoration testing regimes
- Process for evaluating compliance with performance requirements

Situational Awareness

Tools to support real-time operators in understanding the system conditions, level of stress, response and behaviour etc. Validating and verifying the grid models and tools in the hours leading up to the event – could the models accurately replicate the event, was the event identified as a credible risk, how was risk management in the hours preceding the event.

Approach of the organization towards safe and secure operations

‘Better safe than sorry’ approach that involves operation with vast operating and stability margins versus ‘sailing close to the wind’ which would involve acceptance of larger risks to achieve cost efficient operations. One approach adopts conservative operating practices, maintaining substantial operating and stability margins to minimise risk. In contrast, a more aggressive strategy deliberately operates closer to system limits, accepting increased risk exposure in exchange for improved cost efficiency.

Week to day-ahead planning stage

- Planned workload and the human resource assigned to deliver the workload
- Handover process between day-ahead planning team and the real-time time
- Process for significant changes in input assumptions occurring after the day-ahead plan was issued
- Delivery of the system model with expected system conditions, as anticipated at day-ahead stage
- Voltage profiles to be achieved and remedial actions devised in response of contingencies and violations of system limits

Prevailing system conditions in real-time

- Largest credible loss of infeed and outfeed, frequency reserves, voltage control capability, market schedules, power system limitations, relevant operator actions leading up to the event
- Outputs of RTCA, DSA and WAMS from the start of the shift to the event

- Generation pattern – location, output, temporary limitations or derogations
- Location of main load centers
- Operating principles and protocols
- Workload relative to the resources available
- Audio recordings
- Operator logs may capture control room internal communications not captured by audio recordings
- SCADA records: network topology, switchgear changes in status, alarms annunciated, changes in power flows between various stages of the event, activation of protection functions and system defense plans, implementation of manual remedial actions, changes in frequency and voltage profiles across the network
- RTCA and DSA: outputs from runs prior to the event unfolding
- PMU/WAMS and DFR: allow for more detailed investigation given the higher resolution