Review of CEN's Root Cause Analysis Report of 25th February 2025 Chilean Power System Blackout

Legal notice

This document prepared by EPRI is an account of work contracted by Coordinador Eléctrico Nacional (CEN).

EPRI is an independent research organization and through this report, EPRI is offering objective, independent and fact-based outcome of its review of CEN's preliminary root cause analysis report and annex.

- EAF 089/2025: Desconexión forzada de la línea 2×500 kV Nueva Maitencillo – Nueva Pan de Azúcar; 25-02-2025, 15:16 horas and
- Anexos del EAF 089/2025

EPRI's role, as agreed with CEN, is not to conduct an investigation, but to review CEN's root cause analysis process and evaluating whether the conclusions and recommendations reached by CEN are consistent with the findings and align with industry best practice.

This report forms part of the agreed deliverables and presents technical comments and recommendations after reviewing the documents provided by CEN. These comments and recommendations are offered to assist CEN, inform CEN's ongoing investigation process, and support future efforts intended to limit the risk of similar significant power system events.

EPRI's technical review and general recommendations are not intended to judge the actions and performance of any parties involved in the blackout event but review the process and offer recommendations based on the expertise and experience of technical staff.

In some instances, indicated in the report, EPRI could not perform a review due to insufficient information.

EPRI
3420 Hillview Avenue, Palo Alto, California 94304-1338 USA
800.313.3774 ▪ 650.855.2121 ▪ askepri@epri.com ▪ www.epri.com

Executive summary

This interim report presents the findings of a review undertaken by EPRI, an independent research organization, into CEN's preliminary root cause analysis of the blackout event on 25th of February 2025 in Chile.

The document is divided into two main sections. The first section examines the parts of CEN's preliminary root cause analysis, addressing the system conditions prior to the blackout and the triggering event. The second section includes a review of the restoration process.

The event was triggered by an incident on the 500 kV transmission system.

Key facts:

- The inadvertent trip of the 2x 500 kV circuits between Nueva Maitencillo (NMAI) and Nueva Pan de Azúcar (NPAN) substations occurred. Troubleshooting activities were undertaken by the transmission asset owner to restore a communication channel to normal operation following an in-service failure. It is understood, with the communication channel out of service, that one of the four main protection functions automatically deactivated on each 500 kV circuit. The other main and backup protection functions remained active.
- The initial trip of the 2x 500 kV circuits between NMAI and NPAN was followed by subsequent trips on the 220 kV network running in parallel with the 500 kV network, which eventually led to separation of the system into two islands, North and South.
- Post separation, none of the two islands exhibited stable operation and ultimately collapsed leading to a total blackout.

Given the deadline for issuing the initial root cause analysis report into the 25th of February 2025 blackout, it is understood that at the time of writing, CEN is still collecting information from market participants and performing simulation analysis to understand the dynamic response of the power system during the event, and information continues to come to light.

As detailed in Section 4, EPRI's evaluation focused on:

- The structure of the report, with emphasis on keeping the report succinct with information presented in a clear, unambiguous, and logical manner.
- The inclusion of sufficient background information and context to clearly describe the operating state of the system before the event.
- Clear statements of the system operational security criteria and whether the grid was in compliance with these criteria prior to the event.
- The system defense plans which were in effect before the event as well as the overall system performance during and after the event.

- The design, implementation and performance of the protection and automatic reclosing.
- The operational liaison and communication between grid operator and representatives of the generator and grid asset owners.

This review recognizes the considerable effort invested by CEN in processing and analyzing vast amounts of data and information in a short window of time. The findings of this review are not intended to detract from the work carried out to date and are offered to guide potential refinements for future updates of the root cause analysis report. It should also be noted that EPRI is not deeply familiar with the governance process in Chile, and as such cannot assign specific recommendations and responsibilities for implementation but recognize that updates to relevant codes and governance may be appropriate based on the findings. With those provisos in mind, this report's key findings and observation include:

- There is a large amount of information presented in tabular format in the early sections of the report. While valuable, this information is not considered critical to understanding the initiating and propagation causes. This information could be summarized in the main body of the document and the full tables included in appendices.
- Important conclusions and categorical statements should be accompanied by clear and unambiguous supporting information such as time-dated measurements, time-dated logs, or references to paragraphs in standards, regulations, or other approved documentation or procedures.
- Information on the initial system conditions should be supplemented with more data regarding the levels of frequency and voltage reserves carried at the time.
- The operation security criteria should be further explained, especially the complexity around the N-2 (Severity 6 contingency type), the analysis conducted to derive operating limits and the defense plans in place to withstand N-2 extreme contingencies without experiencing a total blackout.
- Greater focus and increased scrutiny should be given to the UFLS philosophy and performance. High resolution plots of the frequency, annotated with activations of the UFLS stages, could be used to further explain the response of the system after the triggering event.
- The protection and control philosophy and application should be emphasized to enhance understanding of the sequence of events affecting the NMAI – NPAN 500 kV circuits.
- A more detailed account should be included of the operational liaison and communication, including the actions taken by the operators and field personnel and the alarms annunciated in the SCADA EMS of the companies involved.

1 Scope of review and methodology

1. EPRI have performed an independent, non-biased technical review of CEN's root cause analysis and conclusions. General recommendations included are based on international best practice and experience. The review is not intended to judge the actions and performance of any parties involved in the blackout event.
2. EPRI's review is limited to the information which was available at the time of writing. To ensure the review and any recommendations are relevant and accurate, the report could be revised when the additional information becomes available.
3. The review was undertaken for CEN, the system operator, and was targeted at the report[1] and the annexes[2] published by CEN. During the review process, EPRI participated in online meetings with key subject matter experts from CEN. The review, analysis, conclusions and recommendations presented in this report have been produced in response to the information made available to EPRI by CEN at the time. All market participants are mandated by national regulations to provide CEN with data and information to support investigation. At the time of writing, it is understood that not all information and data required, nor output of simulation analysis, is available for conducting a comprehensive investigation. It is understood that CEN will issue a final report at a later date which will include review of complete information and data from market participants along with simulation analysis performed by CEN.
4. This review is concerned with the preliminary root cause analysis and restoration report published by CEN. Once CEN releases its final investigation report, this may be the focus of a separate review.
5. The review is structured into two parts; the first part of the review is aimed at the prevailing system conditions before the blackout and the triggering event, whilst the second part is concerned with the restoration and auditing process.

   The first part of the report includes Sections 1 to 5. Section 1 describes the scope of the review, and the methodology applied, Section 2 deals with the prevailing system conditions, and the sequence of events leading to the total blackout is discussed in Section3. Section 4 details EPRI's findings on report presentation, system security, protection performance, automatic reclosing and operational communication. Finally, the conclusions reached, and

[1] EAF 089/2025: Desconexión forzada de la línea 2×500 kV Nueva Maitencillo – Nueva Pan de Azúcar; 25-02-2025, 15:16 horas

[2] Anexos del EAF 089/2025

recommendations made are presented in Section 5. The second part is formed of Section 6 which includes findings related to system operation after the triggering event and during the restoration efforts, and Section 7 captures the conclusions and recommendations related to restoration.

6. The process evaluation criteria considered the requirements and format for investigation as laid out in the NTSyCS, TITLE 6-7 STUDY FOR ANALYSIS OF FAILURES[3]. In addition, EPRI also considered industry best practice such as the application of guidelines by NERC[4][5] in North America and ENTSO-E [6][7][8]in Europe; while these don't directly apply here, they are used to provide an overview and comparison of approaches taken elsewhere.
7. Key items of investigation in the NTSySC process include the following:
    a) A detailed description of the disturbance.
    b) A description of the affected equipment.
    c) The chronology of events and the description of the causes of the events.
    d) The description of system defense plans and actions taken to prevent transition from abnormal operations to blackout.
    e) The estimate of energy not supplied.
    f) A description of the actions taken to normalize the service.
    g) The analysis of protection actions.
    h) Details of all the information used in the evaluation of the failure.
    i) The description of the configurations in the moments before and after the failure.
    j) An analysis of the causes of the failure and the operation of the protection and control devices.
    k) An analysis of the actions and instructions of the Coordinator and the actions of the corresponding Control Centers.

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[3] NORMA TÉCNICA DE SEGURIDAD Y CALIDAD DE SERVICIO, Enero 2025

[4] NERC Attributes of a Quality Event Analysis Report, January 2015

[5] NERC Electric Reliability Organization Event Analysis Process Version 5.0

[6] ENTSO-E Proposal for Regional Coordination Centre Post Operation and Post-Disturbances Analysis and Reporting Methodology

[7] ENTSO-E System Operation Guideline (SOGL)

[8] ENTSO-E INCIDENTS CLASSIFICATION SCALE METHODOLOGY

l) A recommendation regarding the installations for which the Coordinator should request an Audit.
m) The Coordinator's conclusions resulting from the investigation regarding the facts that led to the failure, detailing the actions of the personnel and the equipment involved in the failure, or regarding the operation of a particular element, as appropriate.

8. Blackout investigation reporting requires the synthesis and clear presentation of information from multiple sources. It is essential that such information is communicated in a straightforward and unambiguous manner. Statements and conclusions should be supported by clear evidence. While this is often the case, there are instances—described in detail later in this report—in which additional information, explanation and reference to relevant regulations could be included to substantiate the conclusions drawn.
   The operation and the performance of the power system leading to the collapse and during restoration should be evaluated with respect to relevant standards, regulations, procedures, and industry norms.
9. Unless specifically identified in the statement, the conclusions and recommendations in this review report are directed to all stakeholders with their relevant responsibilities and not intended to assign any specific responsibility to any one entity.
10. Throughout this report, EPRI have noted instances where additional information would enhance understanding of the root cause analysis. These observations are intended to highlight information gaps that may need to be addressed by relevant stakeholders/market participants who hold or control such information. This should not be interpreted as criticism directed at any specific entity, but rather as identification of areas where collaborative effort may be required to achieve full transparency and comprehension.
    EPRI acknowledges that the responsibility for gathering and presenting information in the root cause analysis report remains with CEN, within the constraints of what was provided by the stakeholders and was reasonably accessible within the time allowed. EPRI also notes that the initial report was required in a very short period of time compared to the approach observed elsewhere; for example similar events in Europe or the US often do not have reports for several weeks or months.
    It falls outside the scope of our review to adjudicate on the information exchange, hence EPRI make no determination of what information was or should have been requested nor on what information was provided. The intent of identifying these information gaps is ultimately to improve the quality and completeness of understanding for all stakeholders.
11. In addition to the documents provided, to aid understanding, EPRI requested the following information:
    a) Documentation on protection and control functional designs and design philosophy including redundancy, maintenance procedures, and reliability.

b) Documentation on operational liaison and practice including the communication protocols between the system operator and the transmission asset owner regarding unplanned unavailability of protection functions and power system operation with depleted or degraded protection functions on critical transmission assets, including actions to be taken when the transmission asset remains in service with protection depletion.
c) Information on the alarms associated with the communications channels and the protection functions annunciated on the day in the SCADA EMS of the system operator and the transmission asset owner.
d) Voice recordings of the operational communication conducted by the system operator and transmission asset owner from their control rooms, between themselves and those involving protection specialists conducting the remedial activities.
e) Procedure(s) for troubleshooting protection and communication channel failure whilst ensuring the risk of maloperation is controlled.
f) Sequence of actions involved in the troubleshooting activities carried out to remedy the unavailability of the differential protection functions.
g) Design philosophy of the system defense plans and outcome of the regular effectiveness testing of such plans and schemes.

PART I

2 Prevailing power system conditions on 25th of February 2025

12. Transmission Grid Status
    a. The Chilean power transmission system is characterized by long, high-capacity, series-compensated 500 kV transmission corridors, with lower-capacity 220 kV transmission running in parallel. The 500 kV transmission backbone is formed of double circuits running on the same tower. As identified in simulation analysis[9], such configurations could be conducive to overloading and system instability for contingencies involving the loss of 500 kV double circuits carrying high power transfers, unless special automatic remedial action schemes (RAS) are in place to assist.
    b. On 25th of February 2025, at the time when the event occurred, there was an additional 220 kV path between NMAI and NPAN operating in parallel with the 500 kV backbone. The system conditions, before the triggering event, involved approximately 1800 MW power flow on the 500 kV NMAI – NPAN transmission corridor, from the North to the South.
13. Generation Status/System Reserves
    a. The generation mix exhibited a high proportion of inverter-based resources (IBR) on transmission grid, particularly in the Northern part of the grid, and a high proportion of distributed energy resources (DER), especially in the Southern part of the grid.
    b. The report should include detailed information regarding the generator frequency response reserves, and the quantity and location of dynamic reactive power reserves carried at the time.
14. Chilean Transmission Grid Operational Security Standards [10]
    a. The grid is operated to ensure that:
        i. N-1 contingencies do not result in violations of frequency, voltage and thermal rating of assets[11]

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[9] ESTUDIO DE PLAN DE DEFENSA CONTRA CONTINGENCIAS Informe Final, Noviembre 2020

[10] NORMA TÉCNICA DE SEGURIDAD Y CALIDAD DE SERVICIO Enero 2025

[11] Articles 5-31 and 5-32 of NORMA TÉCNICA DE SEGURIDAD Y CALIDAD DE SERVICIO Enero 2025

ii. N-2 contingencies do not result in total blackout[12][13]

b. EPRI understands that security against consequences of N-2 contingencies relies on operation of system defense plans, special protection schemes (SPS) or RAS and the response of generation resources.
c. EPRI understands that the power system performance during N-2 contingencies is verified regularly by CEN through offline simulation analysis. It is not clear if the outcome of the N-2 analysis informs the limits at which the power system is planned and operated in real-time.
d. CEN does not currently have the capability to conduct contingency analysis in real-time environment to understand the consequences of N-2 contingencies, considering the generation and load pattern, network topology and power flows experienced in real-time as inputs for the analysis.

[12] Article 5-33 of NORMA TÉCNICA DE SEGURIDAD Y CALIDAD DE SERVICIO Enero 2025

[13] Article 1-7 item 3 of NORMA TÉCNICA DE SEGURIDAD Y CALIDAD DE SERVICIO Enero 2025

3Sequence of events

15. From information available to date, the inadvertent operation of protection relays on the 500 kV double circuit between NMAI and NPAN led to separation of the North and South areas of the power system. No faults, disturbances, or other abnormal power system conditions had occurred immediately prior to the relay operation.
16. The protection operation occurred during troubleshooting activities, related to a communication channel failure, performed by the transmission asset owner for this transmission corridor. The communication channel failure occurred earlier in the day and resulted in differential protection functions on both circuits of the 500 kV NMAI – NPAN line becoming inoperative. Each NMAI – NPAN 500 kV circuit still had double distance and one remaining differential protection functions in service.
17. There is no indication to suggest the reason for the communication channel/multiplexer module failure was due to external party interference or cybersecurity considerations.
18. The protection devices automatically triggered high-speed automatic reclosing for both 500 kV circuits between NMAI and NPAN, which would have re-established a strong electrical link between North and South regions of the grid. Automatic reclosing did not complete as voltage and/or frequency differences across the open circuit breakers exceeded the limits configured in the controller.
19. The collective response of generators, transmission assets, system defense plans and SPS was not sufficient to re-stabilize the grids. It is understood that CEN's detailed review is underway to establish whether the collective and individual response was as expected.
20. The response of the collective resources in the Southern electrical island could not stabilize the grid and customers lost supply within approximately 5 seconds. The Northern electrical island continued to operate for approximately 4-minutes before it too lost stability and customers lost supply.

4 EPRI Review Findings

Report Format

21. CEN’s report presents detailed information from a wide range of sources. There are several long tables with insightful data essential to the detailed understanding of the system state and sequence of events. While valuable, this data is not essential to describing the background to the event or how the event propagated to a blackout. It is common for such data to be included as Appendices rather than in the main body of the report. Examples of such cases include the information presented in a tabular format from page 3/398 to 151/398.
22. Specific conclusions and categorical statements should be accompanied by supporting information to substantiate the statements. The supporting information might include measurements or procedural logs alongside relevant references to Grid Code requirements, regulations, or approved procedures. For example, the paragraph in page 154/398 related to the asset owner not informing CDC about the troubleshooting actions performed could be linked to the relevant regulations (Decree Supreme DS 125, Art. 88) that govern the communication process between Transmission Asset Owners/Market Participants and CDC prior to taking any such actions.

Operating Reserve and Grid Performance

23. Information was not presented in the report regarding the primary frequency operating reserve which was available immediately prior to the initiating event. Neither was information about the location or distribution of these reserves available. As a result, EPRI were unable to evaluate the adequacy of reserves or the potential role they might have played in the propagation of the event.
24. Detailed information is included regarding generation and transmission asset protection operation.
25. Information was not presented in the report regarding the performance of generation resources or transmission assets during the event; as indicated earlier this may be due to information not yet being provided at the time of the report. As a result, EPRI were unable to evaluate the grid performance against the requirements set out in the relevant technical standards. It is understood that comprehensive system performance evaluation is ongoing. The outcome should be included in a future update to CEN’s investigation reports.

System Security and Performance

26. Section 7 in CEN's report, related to prevailing system conditions, shows that prior to the event, the system was operating in a stable manner and N-1 secure.
27. The security of the Chilean grid against N-2 contingencies is regularly evaluated. An evaluation of how the system was operated at the time relative to the recommended operating limits of the latest offline study [14][15] was not presented in the report.
28. During certain system conditions involving high power transfers, the Chilean power system relies on the correct operation of multiple system defense plans to avoid total blackout following specific N-2 contingencies. Not all system defense plans identified as required by studies, were fully implemented at the time of the event.
29. It is an industry-wide challenge to employ real-time contingency analysis modules of modern SCADA EMS to accurately model the dynamic response of power plants and power plant controllers to severe events such as an N-2 contingencies. As a result, it can be difficult for operators to maintain enhanced situational awareness.

Under-frequency Load-Shedding (UFLS) Performance

30. There was insufficient data presented in the report to evaluate the response or performance of the Chilean UFLS defense scheme.
31. It is expected to see a verification of the response of the UFLS compliance with the technical performance requirements following frequency and voltage deviations. Without having detailed information to understand the philosophy and design of the UFLS, the total load selected to UFLS is estimated to be low, in comparison to other power systems. For example, ERCOT in Texas has a minimum of 45% of total load selected to UFLS and Great Britain has 60%, without dependency on high ROCOF.
32. Regarding the UFLS response during the event, an evaluation of the design of the scheme should be carried out to determine if the total load selected was sufficient to ensure high probability of successfully stabilizing islands post-separation event.

[14] ESTUDIO DE PLAN DE DEFENSA CONTRA CONTINGENCIAS Informe Final, Noviembre 2020

[15] Estudio para el Diseño de detalle del PDCE de la zona norte del SEN, Anexo 2 - Parte 1: Simulaciones dinámicas, 7 mar. 19

33. High resolution frequency plots, annotated at times when UFLS stages activated, should be included in the report to highlight the performance of the scheme.

Protection Design, Performance and Operation

34. From the information provided in the report, it is not possible to determine the exact troubleshooting activities and sequence of actions that led to the protection inadvertent operation. EPRI's understanding, based on information available to date, is that the troubleshooting activities were performed on the only multiplexer in the NMAI 500kV substation. The multiplexer was active and serving multiple communication channels in operation and relays associated with multiple on load primary circuits.
35. There was insufficient evidence provided in the report to assess whether the established processes and procedures were adhered to during any corrective actions which were taken to resolve the protection communications outage.
36. The report does not refer to particular protection design specifications, relay configuration or protection application philosophy and whether these were followed in the design and implementation of the protection and control at NMAI and NPAN, especially considering the level of redundancy that may be mandated to limit common point of failure scenarios.
37. Most modern differential protection functions are designed to automatically block and avoid spurious tripping following the loss or disturbance to communication channels. Based on the information made available in the report, it is insufficient for EPRI to understand what troubleshooting activities were performed or which precautions were taken to minimize the risk of spurious tripping by the transmission asset owner.
38. The report did not include complete information on the process followed on the day by the transmission asset owner, when attempting to return to service differential protection after remedying the communication channel failure.

Automatic Reclosing Design and Performance

39. The report did not include an assessment of the performance of the automatic reclosing.
40. The report did not include relay logs and event records to allow evaluation of the performance of the automatic reclosing. Furthermore, information was not available on the synchronizing and synchronizing check schemes or whether these performed in accordance with their settings or not.

Operational Liaison and Communications

41. The report did not include a comprehensive assessment of the operational liaison and communication between the system operator and transmission companies.

42. From the information made available, it is understood that the transmission asset owner did not inform CDC about their intention to remedy the issue and return to service the protection communication channel.
43. EPRI understands that the initial failure of the communication channels correctly triggered the differential protection function to block. According to information provided, this occurred at or before 10:30. The report does not include any reference to assessment of the situation at this stage. The first communication that transmission asset owner initiated to inform the system operator about the unavailability of protection functions on 500 kV NMAI – NPAN circuits was around 13:35. No information is included in the report regarding SCADA EMS alarms, associated with the NMAI and NPAN substations, that may have been annunciated at CEN's and control rooms of asset owners.
44. The report does not scrutinize the discussion between the system operator and transmission asset owner operators. The discussion was expected to cover the consequences of protection depletion and the next steps to be taken to address the main protection communication channel failure. Effective operational communication is not just about transmitting information; it's about ensuring that critical information is received, understood, and acted upon appropriately in the complex environment of power system operations.

5 Conclusions and Recommendations

Report Format

45. From a formatting perspective, it is recommended to strive to keep the report succinct and flow with the timeline of the event. Large tables of data should be considered for relocation in the appendix at the end and the information that they might provide summarized in the body of the report. It is understood that the format of the report and the content included in the report are informed by NTSyCS requirements.
46. The frequency and voltage plots presented throughout the report would benefit from additional context. It is good practice to annotate the plots with events that had an important impact on changing the frequency and voltage trends.

Reserve and Response

47. Taking into account the characteristics of the Chilean power system, which make it prone to system separation, apart from implementing minimum inertia floors, consideration should be given to evaluating dynamic reactive power support and voltage performance from all power plants and Flexible AC Transmission Systems (FACTS) in each potential island. Likewise, when determining the amount of frequency response and the number of generation resources operating with their governors in a mode that supports the power system during frequency deviations, the risk of separation and the maximum imbalance that can occur should be considered alongside the largest credible generation contingency.

System Security and Performance

48. The system defense plans, for the power system to survive N-2 contingencies, should be evaluated against design criteria and expected performance parameters.
49. The performance of generating resources in response to frequency and voltage deviations should be evaluated against relevant national codes and standards.
50. The performance of transmission protection and control assets should be evaluated against their existing configuration. Review of the existing setting practices should be conducted against global industry best practice, to maximize power system reliability and resilience.
51. The performance of transmission assets that are relied upon to deliver dynamic reactive compensation and support voltage control process during contingencies should also be evaluated.
52. It is recommended that the assumptions, operating limits, and operating scenarios used for the regular offline N-2 analysis are all evaluated. It is recommended that operating procedures are evaluated to determine whether it is clear to operators how to identify situations when the power system is in an operating state which may not be secure against an N-2 event.

53. It is recommended that the capability of the analysis tools used for Real-Time Contingency Analysis (RTCA) are evaluated for suitability to the current and future grid operations.
54. The information available to date indicates that the Northern island collapsed following disconnection of multiple plant in response to voltage deviations. The frequency remained within range, without warranting activation of protection. The main reason for the collapse could be related to the inability to control the voltage in the island. It is uncommon for power systems operating with high penetration of inverter-based resources to not implement and use the provision of fast voltage control from these devices. As part of the investigation process, the role of inverter-based resource operating in reactive power control mode, rather than voltage control mode should be evaluated.
55. To ensure that lessons are learned and the risk of similar events happening in the future is limited, a thorough investigation should be conducted of all aspects that had an impact leading into the blackout and if these being different would have averted the consequences. Examples include:
    a) Design and planning considerations:
        i. Resilient and redundant configuration of multiplexers mandated by protection design and philosophy document including schematic diagram of configuration.
        ii. Clear responsibility over the design, philosophy, implementation, testing and monitoring of UFLS.
        iii. Review of the philosophy for determining the amount of frequency response to be carried in real-time.
        iv. Power system risk management policy should be reviewed to determine acceptability of operation with high power transfers across the 500 kV backbone when defense plans, against contingencies that can lead to system separation, are not fully implemented and tested. As presented in the table included in page 301/398.
        v. Review of the system defense plans that involve fast automatic disconnection of generation resources to manage frequency deviations, when these generation resources may have a role in the voltage control process too.
        vi. Review of the synchronization and check synchronization policy. The settings recommended should ensure there are high chances of successful automatic reclosing whilst observing the potential impact on other equipment and plant like shafts of synchronous generation units.
        vii. Protection setting coordination review with emphasis on maintaining system integrity over protecting assets more than is necessary or

reasonable. For instance, assets should not be disconnected on overvoltage protection action in milliseconds time if tested according to standards at higher voltages for minutes or hours.

viii. Development of a robust process for determining the power transfer limits on the 500 kV network and capability to assess these limits in real-time as operating system conditions change.

b) Real-time operation:

i. Review and determine if the existing regulations on the process of troubleshooting primary and secondary equipment (DS 125, Art. 88 and NTSyCS *Annex Requisitos Técnicos Mínimos de Instalaciones que se Interconectan al SI, Art. 25*) require updating to further highlight that no intervention on equipment that is in service shall take place without prior agreement from the system operator.

ii. Development of policy clearly stating the considerations for situations when protection is unavailable. At minimum, this should include actions to be taken, and the maximum time operation is allowed to continue with degraded protection.

iii. Update of operational procedures to reinforce the requirement to promptly interrogate and investigate alarms annunciated in SCADA EMS, and the need to ask probing questions as part of the operational liaison process

UFLS Performance

56. The frequency plots presented imply that the Southern island collapsed due to low frequency. Further investigation should focus on the levels of frequency response carried at the time and the amount of load selected to UFLS. The UFLS has 15% of the total load selected to disconnect for low frequency conditions, with another 10% contingent on both low frequency conditions and fast rate of change of frequency (RoCoF), which may cause the latter to not activate in scenarios when the frequency decline is not rapid.
57. Considering the characteristics of the Chilean power system with higher loads in the South and bearing in mind the increased risk of separation, it is recommended that the response of the UFLS scheme is reviewed in terms of quantity of load shed, location of selected load, timing of each stage, and the adequacy of the UFLS scheme for arresting the decline in frequency during major system disturbances.
58. A thorough evaluation of the UFLS changes proposed and implemented following the 2020 review is recommended.
59. Similar to the last line of defense provided by UFLS, steps should be in place to assist during abnormal frequency conditions. For example, solutions used by other system operators

include the requirement for generating resources to operate in Limited Frequency Sensitive Mode and automatically respond by changing their active power output when frequency exceeds certain thresholds, even when these generating resources are not selected to provide primary frequency response.

60. A recent trend has been observed amongst power systems operating with high penetration of DER involving reduction in the effectiveness of the UFLS. Some of the solutions employed to limit the risk of degraded performance of UFLS include monitoring of reverse power flows across distribution feeders selected to the UFLS and presenting real-time operators with information on the difference between expected load to be shed based on the design and implementation of the scheme and the actual amount of load that would be shed based on real-time system conditions.

Protection Design, Performance and Operation

61. Multiplexers serve as the telecommunications backbone of modern substation protection and control systems, ensuring reliable, secure, and efficient transmission of critical data between devices within a substation and between different substations in the power network. It is not possible to achieve high levels of redundancy and resilience with designs that involve only one multiplexer per substation. It is best practice for transmission utilities to employ two multiplexer units per substation and include the requirement in the protection and control design philosophy.
62. It is often that protection engineers of transmission asset owners rely on support from the OEM of the equipment for troubleshooting. The remit and the responsibility of OEM support personnel should be clearly understood when implementing their recommendations related to their device, which is part of a complex power system configuration, they are not fully familiar with. The transmission asset owner personnel performing the troubleshooting should ensure the actions recommended by OEM support personnel will not have unintended consequences.
63. Since differential protection operation is dependent on the communication channels between the ends being healthy, it is industry good practice that transmission utilities have procedures that deal with situations when communication channels fail. These procedures provide advice in the form of actions to be taken by real-time operators and field protection personnel to avoid inadvertent operation of differential protection in the absence of genuine faults.
64. Precautions should be taken during troubleshooting to limit the risk of unintended consequences; these precautions may involve but not limited to the following:

a) Temporarily blocking the tripping outputs of the differential protection through trip links or by setting the protection function to test mode whilst maintaining alarming capability.
b) Supervise the restoration of the communication channels by performing the resynchronization under controlled conditions as opposed to allowing automatic restoration.
c) Introduce a phased approach involving the restoration of the communication channel initially, verifying stable data exchange, followed by the re-enabling of the protection function only after the stability was confirmed.

65. Resynchronization of differential protection after a communication channel loss typically involves a sequence of steps. The following generic steps based on industry best practice associated with protection return of service following communication channel issues can be recommended:
    a) Ensuring the communication network or fiber optic is physically restored and stable.
    b) Check the relays' event logs to confirm the nature of the communication failure.
    c) Reset the communication interfaces to clear any error states and allow re-establishing of differential protection without risk of maloperation.
    d) Perform manual resynchronization.
    e) Verify synchronization status to check communication indicates normal operation and data exchange between line ends is functioning correctly.
    f) Restoring the protection to normal operation by re-enabling the differential protection function that was temporarily manually disabled
66. Overvoltage protection settings should be scrutinized as they could be too restrictive at 1.15 per unit and with 100 millisecond timer. Some of the distance protection operation should also be verified against the power swing blocking and out of step tripping settings policy.
67. One of the essential characteristics of power systems that can withstand and recover from severely abnormal operating conditions involving multiple contingencies is a good balance between protecting the assets and plants and preserving the integrity of the overall power system. Network and generation protection coordination should be conducted or reviewed to ensure important system elements are not disconnected prematurely during abnormal system operating conditions.
68. In power system operating with high penetration of DER, the use of anti-islanding protection based on RoCoF and Vector Shift methods is problematic. The anti-islanding methods have been observed to inadvertently operate during transmission faults rather than for genuine islanding conditions, adding to the combined loss of generation output. Mitigation options employed by other system operators involve alternative solutions, like intertripping, which are less likely to misoperate for incidents in the transmission network whilst remaining

sensitive to genuine islanding scenarios. Prior to such alternative solutions being implemented, the risk and the impact of DER's loss of mains protection schemes misoperating can be included in simulation studies and contingency analysis.

Automatic Reclosing Design and Performance

69. It is important to investigate if a successful automatic reclosure of a 500 kV circuit could have stopped the propagation of the event. This should be reviewed in the future.
70. Without having insights into the analysis that informed synchronization relay settings, the 20° voltage phase angle setting is considered to be restrictive compared to other power systems and in general for 500 kV corridors intended to carry high power transfers.
71. Power systems with unnecessarily stringent voltage phase angle difference settings for automatic reclosing and protection settings intended for promptly tripping transmission assets and generating resources for conditions that are within their withstand capabilities, are less likely to avoid total collapse.

Operational Liaison and Communications

72. It is uncommon for troubleshooting activities to be conducted on secondary equipment that is active and serves primary equipment that is in service without explicit agreement from the system operator. To gain better understanding of this situation the alarms annunciated in SCADA EMS of the system operator and transmission asset owner along with the audio recordings and transcripts of communication between transmission asset owner personnel, and system operator and transmission asset owner should be analyzed.
73. Real-time operators should have information made available to them in a timely and detailed manner to understand the potential risk and consequences of the protection depletion and the activities carried out to remedy the failure.
74. Ensuring compliance with regulatory standards, national grid codes and safety protocols is a fundamental aspect of the role undertaken by real-time operators and specialist field staff. A thorough understanding and commitment to compliance is essential. Those involved in system operations should have the discipline to consistently follow established protocols. This is generally maintained and reminded through a regular and robust training regime.
75. Effective communication is crucial. Operators coordinate with field personnel, neighboring control areas, generation facilities, and other stakeholders to ensure seamless grid operation. They should convey complex technical information clearly and concisely, especially during critical situations and when under pressure.
76. Amongst the multiple operator and specialist staff traits and topics to be trained and tested, the most relevant ones for this event are compliance and communication.

77. Having a rigorous process of training and authorization for those directly involved in transmission system operation is critical and a foundation for maintaining safe and secure operations.
78. It is good practice for operators to be trained and encouraged to develop a questioning attitude, fostering an environment where they feel comfortable seeking clarification and raising concerns.
79. Operators should always exhibit an inquisitive approach and prompt the interlocutor with additional questions to build clear understanding of what is being done and what the consequences of actions might be. In situations when protection depletion is discussed, it is good practice for the operators with responsibility over the operation of the system to have the protection and automation schedule related to the circuits impacted available, and methodically go through what is faulted and affected, what protection functions remain unaffected, what are the implications of the protection depletion and continued operation in degraded configuration and finally what is being done to resolve the situation.

PART II

The second part of the review is concerned with the sections from CEN's root cause analysis report related to the moments after the system separation, the total system collapse and the restoration process. Lastly, the review covers CEN's conclusions, recommendations, auditing requested and post-event remedial actions to be implemented.

6EPRI Review Findings

80. The report should include the initial actions taken by CEN post system separation. These are expected to include a swift assessment of the system conditions and actions intended to stabilize any clusters of the system that haven't collapsed. The timeline presented in the report suggests the operators were enacting the restoration procedure whilst the North island was not yet collapsed; this could be explained further.
81. From the restoration curve included in the report, it is uncertain what the expected restoration performance was compared to how it progressed in real-time.
82. It is understood that following the system collapse, the transmission owner of the NMAI – NPAN 500 kV circuits, implemented a temporary mitigation solution aimed to prevent potential subsequent inadvertent operations of the protection, without prior communication and agreement from CEN.
83. CEN processed large volumes of data in a short window of time to establish whether plant and equipment response and behavior during the collapse and subsequent restoration was as expected and aligned with requirements set by code and standards. Firm conclusions require in depth analysis of vast amounts of information, in the form of outputs from digital fault recorders, data captured by phasor measurement units, alarms from SCADA EMS, audio recordings of operational communication, simulation studies and interview notes. The existing requirements for submitting the investigation report within 15 days may be too stringent for systemwide events like total blackout considering the amount of data that needs to be analyzed. As a comparative example, in Europe, the system operators are allowed 3 months for information gathering and 6 months from the event to submit a comprehensive investigation report.
84. Some coordinated entities experienced total loss of SCADA, voice communication and localized loss of control to some Remote Terminal Units (RTU) in substations. These issues hindered the restoration process. The transmission asset owner that has an important role in multiple restoration plans, suffered total loss of SCADA EMS and communication for several hours.
85. It is understood that in some cases, generators of relatively low rated power attempted to energize large clusters of high voltage network and failed several times. It is not clear from

the report whether the network configuration was aligned with the restoration plan, or it was decided to attempt to restart the island without knowing the precise network topology at the time, due to lack of visibility and control. From the information provided in the report, it is not clear why these generators tripped multiple times and what was decided in between attempts, to minimize the risk of disconnecting again.

86. Multiple generators tripped on activation of protection functions for loss of excitation, over-excitation, over-voltage, under-voltage, over-frequency, under-frequency, reverse power. There is insufficient information to ascertain how the restoration in these area was managed and coordinated to limit the risk of such setbacks. No information is presented on the mode of operation of these generators and how the frequency and voltage reserves were being managed to limit the risk of collapsing the island during development.
87. Some generators with important roles in the restoration plans encountered issues with starting up their generation units. In some cases, it is understood the communication process with CDC was not prompt and efficient.
88. There is no information to suggest whether the restoration plans have been regularly tested beyond simulation studies, especially for the areas where initial restoration attempts have been unsuccessful. If this is not currently the practice, it is recommended to be so in the future.
89. Some generators tripped during the restoration process and operators were unable to provide a reason and sufficient information to CDC to inform their decision making process. This may have created an extra burden on the CDC operators.
90. In some cases, generator failures to energize the initial network clusters and the collapse of restoration islands are related to overvoltage conditions. The reason for the overvoltage conditions is unclear, whether the recommended restoration sequence, as per the plan, was followed or alternative sequences had to be devised in an emergency on the day. It is not clear in what mode the generators were operating, such as automatic voltage regulator (AVR) being active or not. In some instances, CDC instructs generators to control the voltage within the island, however it is unclear whether this refers to changing voltage setpoints on the AVR or changing to voltage control mode.
91. There was one case in which a generator disconnected in response to the energization of a transmission circuit when absorbing excessive reactive power. The restart time, following disconnection, was stated by the generation operator to be six hours. Such lengthy periods between successive attempts are not suitable for blackstart resources relied upon during power system restoration and should be reviewed.
92. System transients associated with energization of the 500 kV network sections during the preliminary stages of restoration led to unintended disconnection of generation and demand that was restored at the time. It is unclear whether this step was required at this

stage and whether the system was in a state that could accommodate energization of 500 kV network elements.

93. Large autotransformer units at Kimal substation tripped several times during energization attempts. Energization of such large units multiple times during the restoration efforts introduces significant challenges and risks, like severe voltage dips or overvoltage conditions when the transmission network restored exhibits low order resonances which can be excited by the low order harmonic currents present in the inrush current. It is good practice to limit the number of such actions.
94. There were unsuccessful attempts to support restoration efforts from SADI via 345 kV interconnection. This is not an established recovery plan as part of the restoration of the Cordillera area.
95. During the restoration sequence, a generation unit was switched out of service due to being out of economic merit order. The switching sequences for restoration of each area are presented in chronological order and tabular format. It isn't clear in these tables when the normal operation of the electricity market was resumed.
96. There has been a case where the transmission operator energized a circuit without coordination with CDC which consequently required de-energization, highlighting the need for clear communication protocols.
97. There have been situations where circuit breakers could not be closed, potentially due to interlocking or specific settings (e.g., dead bar charge/dead line charge) making them unsuitable for restoration. This may have led the operators to find alternative solutions that have not been tested and hence introduce further risks and delays.
98. CEN delegates the leading role for conducting restoration in specific areas to local Transmission System Operators. There has been a case of a coordinated entity being unaware of their responsibilities and decision making authority during the restoration process.

7 Conclusions and Recommendations

99. The promptness and effectiveness of the response post-event should be evaluated against a restoration standard. Such a restoration standard is expected to include the amount of load to be restored in each zone and area relative to an established timeline.
100. It is considered that the restoration process performed well under difficult circumstances, like critical SCADA EMS and voice communication being unavailable. Not all areas have been

impacted by the loss of SCADA EMS and voice communication, their delayed restoration is understood to have been affected by the lack of resources with required capability. Restoration performance in these areas should be reviewed and plans adapted to yield improved restoration times. This can be delivered through requiring or incentivizing deployment of new resources or upgrade of existing resources to develop restoration capabilities, network investment and adapting restoration plans.

101. Detailed restoration plans are in place for each area and zone of the power system to act as contingency planning to be undertaken in situations involving a total failure of the power system. These restoration plans have been enacted as planned, but without a standard that sets the expectations and targets, it is not known whether these performed as expected.

102. The restoration plans provide multiple alternatives that account for the unavailability of resources and network assets. It is not detailed in the report how these plans are defined and validated. For instance, in the case of transformers that tripped on energization and generators that tripped when attempting network energization, it is not known if suitable simulation analysis or live testing was conducted to assess protection adequacy and capability of the generators to restart the cluster of network assigned to them.

103. To expedite decision making process on the day, the restoration plans could be further developed to include clear guidelines for the network configuration, generation pattern and system strength levels necessary for energization of 500 kV network to have high probability of success whilst limiting the impact and risks on existing stable islands.

104. To limit the risk of collapsing the island during initial stages of the restoration, the restoration plans should also include the reactive power capability of the generators relative to their active power output. The no-load reactive power gain of the transmission circuits that form part of the initial restoration sequence should also be included in the restoration plan for the specific voltage levels required to be achieved and maintained during the early stages of the restoration.

105. The restoration plans should include the minimum number of attempts each generator resource should achieve and an estimation of the time to be achieved between each attempt.

106. Apart from the expected start-up times for the generators designated as blackstart resources, the restoration plans should also include information about the capability of these units to operate at full speed no load (FSNL) and their technical minimum active power limits. This information could be used by the real-time operators with responsibility for organizing the restoration process to improve overall coordination and preparation of load blocks.

107. A restoration standard should also include the requirement for a certain number of restoration resources necessary to deliver a high probability of achieving prompt restoration. It should also include the need for regular physical testing.

108. Integration of support from neighboring SADI power system in the restoration plans should be explored for potential inclusion in plans in the future. In general, following a total blackout, the blackstart support from unaffected neighboring power systems is one of the fastest options to initiate the restoration process.
109. Chilean power system has specific challenges introduced by the distances between key electrical nodes in a network that is stretched across approximately 4000 km. Enhanced resiliency is necessary to ensure attributes that are critical during restoration. As a minimum these include switchgear telecontrol, measurements, equipment status indications and voice communication to remain fully available despite loss of main supplies. The high level of reliability and resilience required by these key functions must be confirmed regularly by live exercises, as part of a rigorous testing regime.
110. Restoration drills should be conducted with all entities expected to play an important role during the process to ensure the roles and responsibilities are well understood and practiced.
111. The generators playing key roles in the restoration process should have clear instructions on the operating modes, voltage setpoints at generator terminals and tap positions of generator step-up transformers during the initial stages of the restoration and how these need to be adapted as the restoration process progresses and the island is developed.
112. When restoration paths are devised, they should be tested against protection and control drawings/schedules to confirm switchgear can be operated as required and not unnecessarily prevented by configurations and settings unsuitable for restoration scenarios.
113. To achieve a transparent and comprehensive root cause analysis of the event, the auditing process should encompass all entities directly involved.

Acronyms

UFLS – Under Frequency Load Shedding	EDAC – Esquema de Desconexión Automática de Carga