Continental Europe Synchronous Area Separation on 8 January 2021

Interim Report

Publication date: 26 February 2021

European Network of
Transmission System Operators
for Electricity

About ENTSO-E

ENTSO-E, the European Network of Transmission System Operators for Electricity, represents 42 electricity transmission system operators (TSOs) from 35 countries across Europe. ENTSO-E was registered in European law in 2009 and given legal mandates since then.

Disclaimer

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EXECUTIVE SUMMARY

On Friday, 8 January 2021 at 14:05 CET, the Continental Europe Synchronous Area was separated into two areas (the North-West area and the South-East area) due to cascaded trips of several transmission network elements. Immediately after the incident occurred, European TSOs started to resolve it and resynchronised the continental Europe power system at 15:08 CET. Due to the fast and coordinated approach, no major loss of load or damages were observed in the power system.

In the immediate aftermath of the system separation, European TSOs in close collaboration through the ENTSO-E body decided to start a joint process to collect all relevant facts regarding the incident. This process was launched with the clear mission to deliver these facts to national and European authorities, ENTSO-E members as well as to any interested audience in a transparent and complete way. This interim report presents the first collection of the gathered facts, while the incident is still under further investigation. The report is structured in the following parts, which are briefly summarised below.

System conditions before the system separation

The overall pan-European flow pattern on the afternoon of 8 January 2021 reflected a special load situation. This situation was caused, on the one hand, by warm weather in the Balkan Peninsula as well as the Orthodox Christmas holiday on 6 and 7 January, leading to an overall lower demand than usual in some of these countries. On the other hand, countries in central Europe saw colder weather and corresponding higher loads. This pan-European flow pattern was forecasted with the existing security procedures like Day-Ahead-Congestion-Forecast (DACF) or Intra-Day-Congestion-Forecast (IDCF) as well as in (n-1) simulations.

The overall pan-European flow pattern was complemented by additional local flows, leading to an increase of flows (compared to market schedules; this is relatively normal) within the Croatian transmission system, especially near the substation Ernestinovo. This substation is equipped with two busbars, linked by a busbar coupler, which carried a relatively high power flow coming from the power infeed of two transmission lines on one busbar at the time of the incident.

The production by conventional power plants and renewable energy sources in the region of the system separation corresponded well to the scheduled production, and there was no unplanned unavailability of production units. There were no planned maintenance works or unplanned outages, so the grid topology was mapped correctly in the network models used for congestion forecasts in DACF and IDCF.

Impact on market

To understand further impacts on the market, comparisons of the commercial and cross-border physical flows from the South-East area to the North-West area and day-ahead prices for these areas have been compiled for 7 and 8 January 2021. Data trends indicate neither that the market was interrupted, nor that prices fluctuated, both at the time of the incident and afterwards. In addition to this, TSOs from the affected South-East area highlighted that no market activities were suspended at the time of the incident.

Sequence of events

At 14:04:25, the initial event took place with the trip of the busbar coupler in the substation Ernestinovo, triggered by overcurrent protection. Prior to that incident, an additional increase of power flows had been observed in Ernestinovo at the change of the hour. The initial tripping of the busbar coupler in Ernestinovo led initially to the redirecting of the busbar coupler flow through the 400/110 kV transformers in Ernestinovo which subsequently tripped as well, and then subsequently to a shift in power flows to neighbouring transmission lines, causing a further trip of the Serbian transmission line Novi Sad – Subotica also due to overload protection. The tripping of the busbar coupler was not identified as an ordinary contingency pursuant to the methodology for coordinating operational security analysis.

The summarised flow pattern from South-East to North-West as well as the tripping of the busbar coupler in Ernestinovo brought the power system to the verge of angular instability, and the second trip instantly triggered the instability. Accordingly, both events were then followed by a sequence of further cascading disconnections of all transmission lines from the border between Romania and Ukraine down to the Mediterranean Sea in the Dalmatian region within 20 seconds due to transmission system protection.

As a consequence of the cascading disconnections, the system was separated into two synchronous areas where the South-East area yielded a surplus of generation and thus an increasing frequency, while the North-West area saw a surplus of load and thus a decreasing frequency (see figure 1). In both areas the system protection schemes and frequency containment reserves reacted rapidly and as expected, ensuring that the power system avoided any additional major damage and outages.

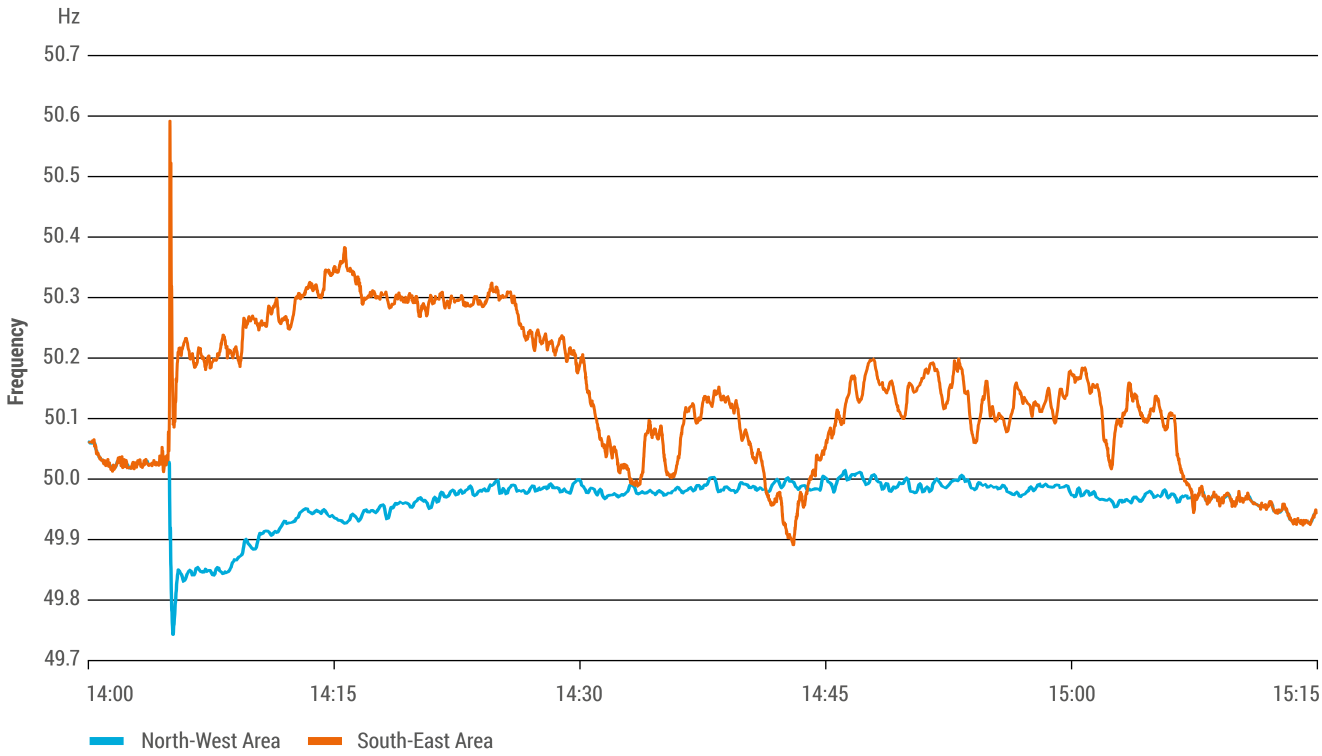

Figure 1: Frequency development during the incident

System status and automatic defence actions in individual areas

Due to the significant frequency deviation, all generation units which underwent primary control either decreased (South-East area) or increased (North-West area) their power generation accordingly. In addition, by exceeding the 200-mHz frequency limit, a high number of generation units changed their control mode and contributed according to the process of frequency stabilisation by either activating additional reserves in the North-West area or decreasing their generation further in the South-East area.

Additional support in frequency stabilisation was gained through 1.7 GW of automatic interruptible load in France and Italy, which were disconnected according to their contractual duties. Furthermore, through frequency support over HVDC links, the North-West area received 535 MW of automatic supportive power from the Nordic synchronous area and 60 MW from Great Britain. Due to the high frequency transients, it has been reported that a certain number of generation units and domestic loads were disconnected in both areas.

Manual countermeasures and system stabilisation in individual areas

During the incident, the TSOs which were impacted most by the event activated several system states in the ENTSO-E Awareness System (EAS). This allowed all TSOs in Europe to be aware of the seriousness of the ongoing incident. Furthermore, both the North and South coordination centres set alarms for frequency deviations according to the consequences in their coordination zones.

According to the established procedures, EMS (Serbia) acted as frequency leader in the South-East separated area, to coordinate the return of the system to 50 Hz. Amprion (Germany) acted in the same manner as the frequency leader in the North-West area due to its role as Synchronous Area Monitor (SAM). This allowed the resynchronisation to take place as quickly as possible. Each separated area subsequently took appropriate control actions, mostly on the production side, to balance its area.

Resynchronisation process

After stabilising both areas with automatic defence actions as well as manual countermeasures, the resynchronisation process started with HOPS (Croatia) acting as the resynchronisation leader. Moreover, resynchronisation actions were performed by the further affected TSOs, namely EMS, NOSBiH (Bosnia and Hercegovina) and Transelectrica (Romania). The actions which allowed the resynchronisation can be grouped into the following phases: preparatory actions and resynchronisation sequences.

During the preparatory actions, EMS, HOPS, and NOSBiH agreed to form three strong reconnection points, which could then be used for the resynchronisation sequence. The resynchronisation process was further supported by a relief of the load flow situation through an increase of power flow on the DC Link Monita between CGES (Montenegro) and Terna (Italy), which changed its flow in the direction of Montenegro to Italy from 100 MW to 600 MW.

The resynchronisation sequences started with the reconnection of the busbar coupler in Ernestinovo, which was equipped with a synchro-check device and was thus able to reconnect the two separated areas. Further reconnections were then performed on the other disconnected transmission lines in a coordinated manner.

Communication of coordination centres/SAM and between TSOs

The TSOs Amprion and Swissgrid (Switzerland) in their role as SAM in Continental Europe are responsible for the procedures and coordinated countermeasures in case of steady state frequency deviations. During the event, Amprion was responsible for launching extraordinary frequency procedures and coordinating countermeasures. During the large frequency deviations, both coordination centres informed all TSOs via the EAS and launched an extraordinary procedure for frequency deviations to coordinate countermeasures in a fast and effective manner to stabilise the system.

One step of this procedure was a telephone conference among Amprion, Swissgrid, RTE (France), Terna and REE (Spain), which was initiated at 14:12 CET, shortly after the frequency drop. In the telephone conference, the situation was evaluated, and the TSOs were informed about countermeasures which had already been activated. Additionally, the SAM made several phone calls to affected TSOs to gather information, monitor progress and coordinate measures all over Continental Europe. The TSOs of the North-West and South-East areas intensively coordinated the actions for resynchronisation in order to reach one synchronous area in Continental Europe as fast as possible.

Classification of the incident based on the Incident Classifiction Scale (ICS) methodology

Regarding the valid legal framework, i.e. the System Operation Guideline (SO GL), a check has been performed regarding the classification of the incident according to the ICS methodology. According to the analysis, the incident fulfils criterions ON2 (N-state violation), T2 (incidents on transmission network elements), RS2 (separation from the grid) and F2 (incidents leading to frequency degradation). According to the methodology, the most critical criterion is F2.

For incidents of this scale, a detailed report must be prepared by an expert panel composed of representatives from TSOs affected by the incident, relevant RSC(s), a representative of subgroup ICS, regulatory authorities and ACER upon request. The ICS report must contain an explanation of the reasons for the incident based on the investigation according to article 15(5) of SO GL. TSOs affected by the incident must inform their national regulatory authorities before the investigation is launched.

According to the inherent interest, to clarify the reasons for the incident and, in due mission, to provide transparent and complete facts regarding the incident, ENTSO-E will inform NRAs and ACER about the upcoming investigation in due time before it is launched.

1 INTRODUCTION

Background

On 8 January 2021 at 14:05 CET, the Continental Synchronous Area in Europe was separated into two areas (the North-West area and the South-East area) due to the tripping of several transmission network elements. The system separation resulted in a deficit of power in the North-West area and a surplus of power in the South-East area, leading in turn to a frequency decrease in the North-West area and a frequency increase in the South-East area. The automatic response and the coordinated actions taken by the TSOs in Continental Europe ensured that the situation was quickly restored close to normal operation. Resynchronisation of the North-West and South-East areas was achieved at 15:08 CET.

Continental Europe System Separation Task Force

In the immediate aftermath of the system separation, European TSOs, in close collaboration through the ENTSO-E body, decided to start a joint process to collect all relevant facts regarding the incident. This process was launched through the composition of an ENTSO-E Task Force with the clear mission to deliver these facts to national and European authorities, ENTSO-E members as well as to any interested audience in a transparent and complete way.

The Task Force, composed of the European TSOs, has been coordinating all relevant ENTSO-E bodies in analysing the event and is responsible for the development of the current interim report and for supporting with facts the communication with external stakeholders. This interim report thus presents the first collection of the gathered facts, while the incident is still under further investigation.

The investigation has classified the event according to the ICS Methodology[1] as a Scale 2 event, and therefore a relevant investigation expert panel is expected to be launched soon. The Task Force will assist the development of work within this expert panel and use the Interim Report and the knowledge acquired while creating it as a good basis on which to build.

Structure of the Interim Report

The Interim Report is structured as follows: the second chapter presents the facts that have been gathered regarding the evolution of system conditions during the event. This includes the system conditions before the separation, the impact of the market and sequence of events. The chapter is complemented by an overview of system status and automatic defence actions as well as the manual countermeasures and system stabilisation, for both of the two separated areas. The third chapter focuses on the resynchronisation process, while the fourth chapter reflects the communication between the coordination centres and synchronous area monitors and the TSOs. The assessment of the incident based on the ICS Methodology is summed up in the fifth chapter, while the Interim Report concludes with the sixth chapter, presenting the next steps.

Sources of data and information

The analysis presented in this report is based on information that was sent by all continental Europe TSOs and more detailed information by the most affected TSOs. An important source of information comprised recordings from Wide Area Monitoring (WAM) systems, which have delivered by their accurate and precise time stamping valuable measurements for aligning all the events into the right order. Another important source of information were measurements from transient recorders or digital protection devices with precise GPS time stamps.

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1 **ICS Methodology 2020**

2 EVOLUTION OF THE SYSTEM CONDITIONS DURING THE EVENT

2.1 System conditions before the system separation

2.1.1 System conditions in continental Europe

This section analyses the system conditions in continental Europe shortly before and at the time of the incident. The focus is on the development of flows from day-ahead market schedules and intra-day market schedules to the measured flows.

The overall Pan-European flow pattern on the afternoon of 8 January 2021 reflected a special load situation. This situation was caused, on the one hand, by warm weather in the Balkan Peninsula as well as the Orthodox Christmas holiday on 6 and 7 January, leading to an overall lower demand than usual in some of these countries. On the other hand, countries in central Europe saw colder weather and corresponding higher loads.

The differences in the actual market schedules for the two timestamps, 13:45–14:00 and 14:00–14:15 (Source: Vulcanus/Verification Platform), are shown in figure 2. Higher differences are shown for the values between DE–FR, DE–NL, NL–BE, BE–FR and FR–ES. However, these are not unusual in terms of their magnitude and in comparison to the size of the market areas. Furthermore, in the area of the system split, there are rather small changes in the actual market schedules between the two timestamps considered.

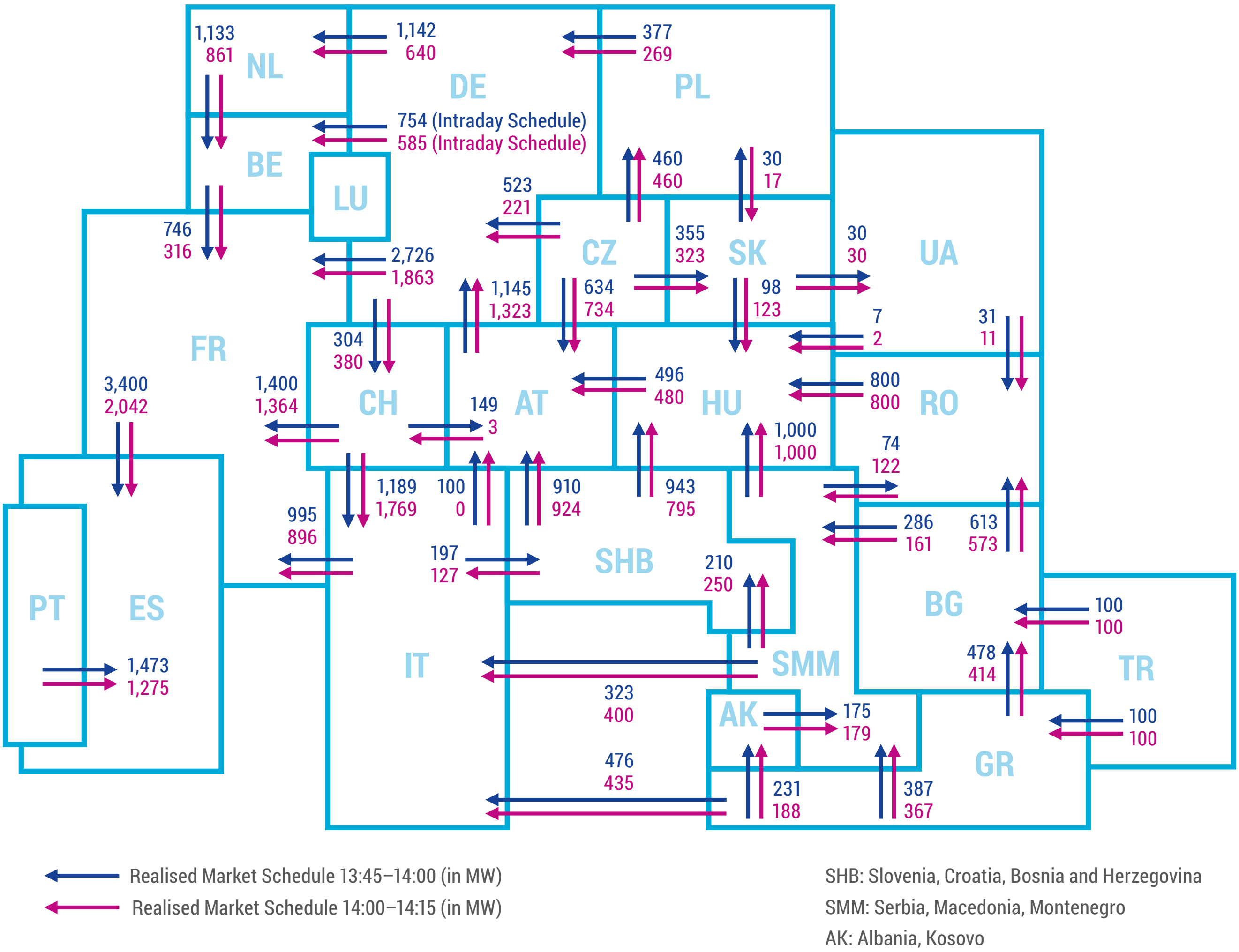


Figure 2: Comparison of actual market schedules

The difference between the day-ahead market schedules and the actual market schedules for the timestamp 13:45–14:00 (Source: Vulcanus/Verification Platform) is shown in figure 3. This timestamp is used here because it is also used in the following comparison of the actual market schedules and the measured power flows (see figure 4). Since the measured power flows each represent the mean value of the timestamp under consideration, the timestamp 14:00–14:15 cannot be used to evaluate the system conditions before the system separation. Overall, the differences between the day-ahead schedules and the actual schedules are rather small. Larger differences are found for ES–PT and CZ–PL. In the area of the system split, all differences can be classified as rather small.

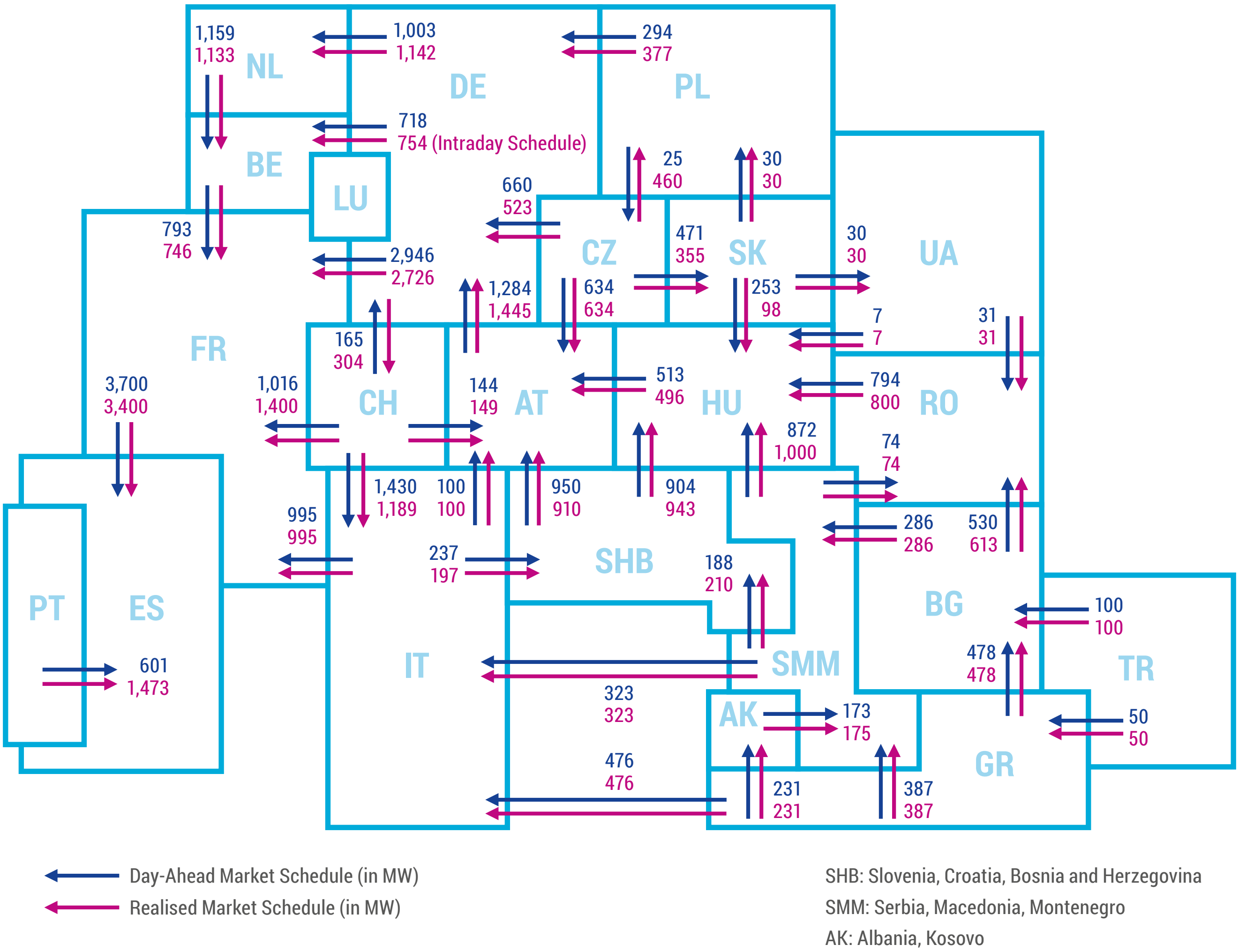
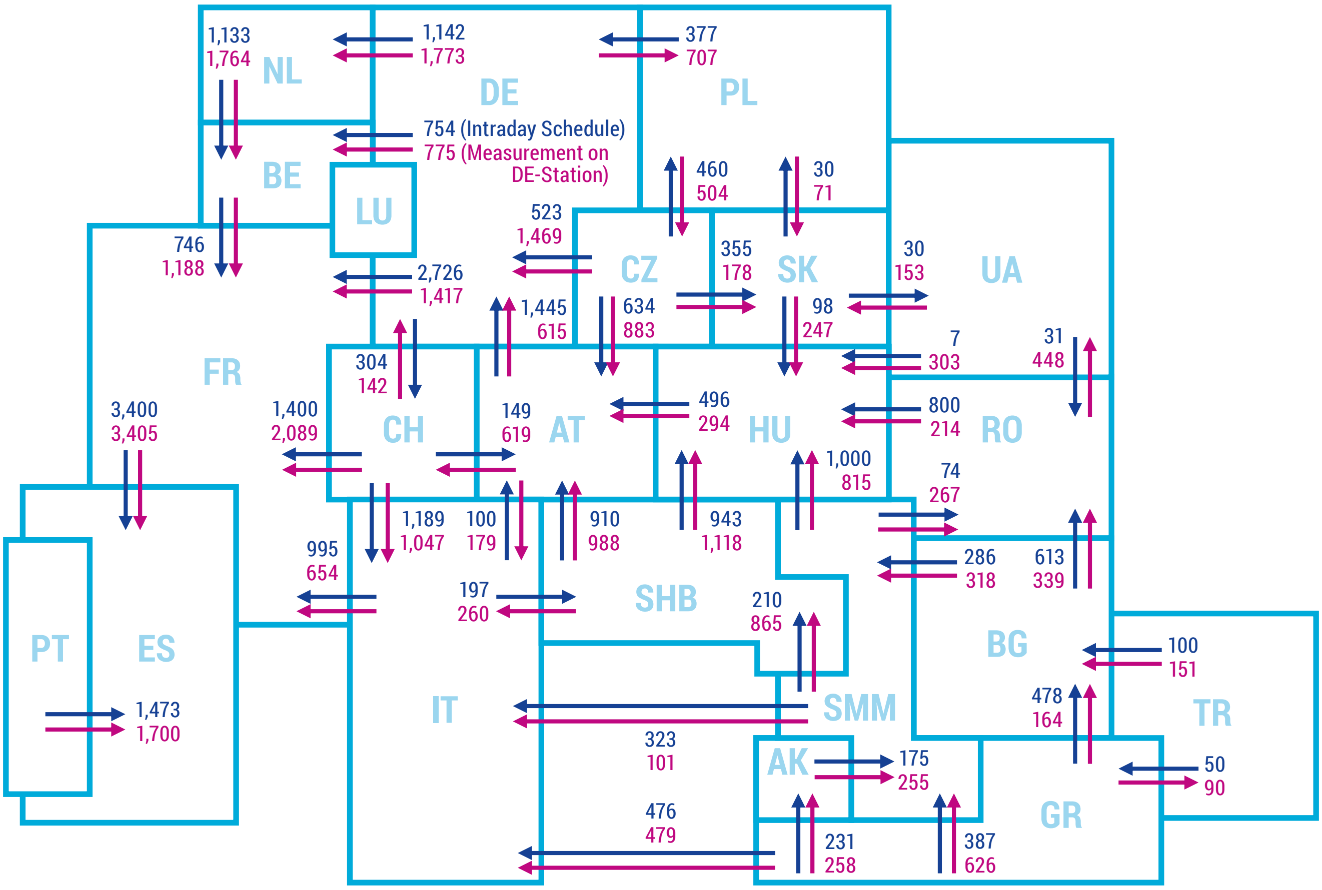


Figure 3: Comparison of day-ahead and actual schedules

The difference between the actual market schedules and the measured power flows for the timestamp 13:45–14:00 (Source: Vulcanus/Verification Platform) is shown in figure 4. The power flows in a meshed AC-grid are the result of actual state of generation (output and localisation), consumption (profiles and localisation), and transmission network (topology and technical parameters). It is not unusual that in a highly meshed AC-grid that physical flows significantly differ from the scheduled exchange programs. Flows in DC connections can be fully controlled. Changes in flows in DC connections from scheduled to actual flows can be activated for operational optimisation.

Overall, there are differences between the actual market schedules and the measured power flows. These deviations occur regularly in the network of continental Europe. The relevance for the deviations resulting in the area of system separation is still under investigation.



Realised Market Schedule 13:45–14:00 (in MW)
Measured Power Flow 13:45–14:00 (in MW)

SHB: Slovenia, Croatia, Bosnia and Herzegovina
SMM: Serbia, Macedonia, Montenegro
AK: Albania, Kosovo

Figure 4: Comparison of actual schedules and measured power flows

To understand the system conditions before the system split, a more detailed analysis is performed at the interconnectors between the affected countries in South East Europe (Serbia, Croatia, Romania) and Central West Europe (Slovenia, Hungary). The analysis of the flow towards West Central Europe is performed by looking into the scheduled and total market flows in the hours 13:00–14:00, 14:00–15:00 and 15:00–16:00, both on 7 and 8 January. The day before the system separation is considered in order to give a comparison.

Table 1 and table 2 provide information on the scheduled day-ahead market flows and the total market flows (Source: ENTSO-E Transparency Platform). The net values are considered in each case (i.e., RS > HU corresponds to the difference between RS > HU and H U> RS). For both 7 and 8 January, exports of comparable magnitude from the South East European countries to Central West Europe can be seen. On both days the total market flows are slightly higher than the scheduled day-ahead flows. The biggest difference between the 7 and 8 January is the shift of a part of the exports from HR > SI to HR > HU.

Scheduled Day Ahead Flow (MW)					
Date	**Time**	**RS > HU**	**BZN|RO > BZN|HU**	**HR > SI**	**HR > HU**
7 January	13:00–14:00	956	800	274	662
	14:00–15:00	960	800	323	701
	15:00–16:00	975	800	330	728
8 January	13:00–14:00	872	794	315	904
	14:00–15:00	875	800	434	819
	15:00–16:00	895	800	411	881

Table 1: Scheduled Day Ahead Market Flows (net values)

Total Flow (MW)					
Date	**Time**	**RS > HU**	**BZN|RO > BZN|HU**	**HR > SI**	**HR > HU**
7 January	13:00–14:00	1,000	799	676	581
	14:00–15:00	1,000	790	628	658
	15:00–16:00	1,000	800	592	733
8 January	13:00–14:00	1,000	800	365	943
	14:00–15:00	1,000	800	598	795
	15:00–16:00	1,000	800	606	857

Table 2: Total Market Flows (net values)

Summative Flows (MW)				
Date	**Time**	**Day Ahead**	**Total**	**Delta**
7 January	13:00–14:00	2,692	3,056	364
	14:00–15:00	2,784	3,076	292
	15:00–16:00	2,833	3,125	292
8 January	13:00–14:00	2,885	3,108	223
	14:00–15:00	2,928	3,193	265
	15:00–16:00	2,987	3,263	276

Table 3: Summative Market Flows (net values)

Flows (MW)						
Date	**Typ**	**RS > HU**	**BZN|RO > BZN|HU**	**HR > SI**	**HR > HU**	**Sum**
7 January 13:00–14:00	Total Market Flow	1,000	799	676	581	**3,056**
	CB Physical Flow	757	223	869	814	**2,663**
	Delta	**-243**	**-576**	**193**	**233**	**-393**
8 January 13:00–14:00	Total Market Flow	1,000	800	365	943	**3,108**
	CB Physical Flow	788	251	819	1095	**2,953**
	Delta	**-212**	**-549**	**454**	**152**	**-155**

Table 4: Total Market Flows and CB Physical Flows from South East Europe to Central West Europe (net values)

Table 3 shows the summative market flows from South East Europe to Central West Europe. Focusing on 8 January (Source: ENTSO-E Transparency Platform), there was a scheduled day-ahead export of 2784 MW from South East Europe to Central West Europe at 14:00–15:00. The resulting total market flow is slightly higher at 3076 MW. The comparison with 7 January shows that the flows on 8 January were slightly larger overall. In contrast, for 7 January, there is a larger delta between the total market flows and the scheduled day-ahead flows.

In a final step, the total market flows are compared with the cross-border physical flows. For this purpose, table 4 shows a comparison for the timestamp 13:00–14:00 for both 7 and 8 January (Source: ENTSO-E Transparency Platform). Similar correlations can be seen for the two days under consideration. The physical flows are slightly lower than the total market flows. At the same time, a shift of part of the market flows from RS > HU and RO > HU to physical flows of HR > SI and HR > HU can be observed.

2.1.2 System conditions in Croatia, Serbia and Romania and with neighbouring countries

2.1.2.1 System conditions in Croatia/HOPS

HOPS is operating the 400 kV, 220 kV and 110 kV transmission network in Croatia. This transmission network as well as the interconnection to neighbouring countries is depicted in figure 5.

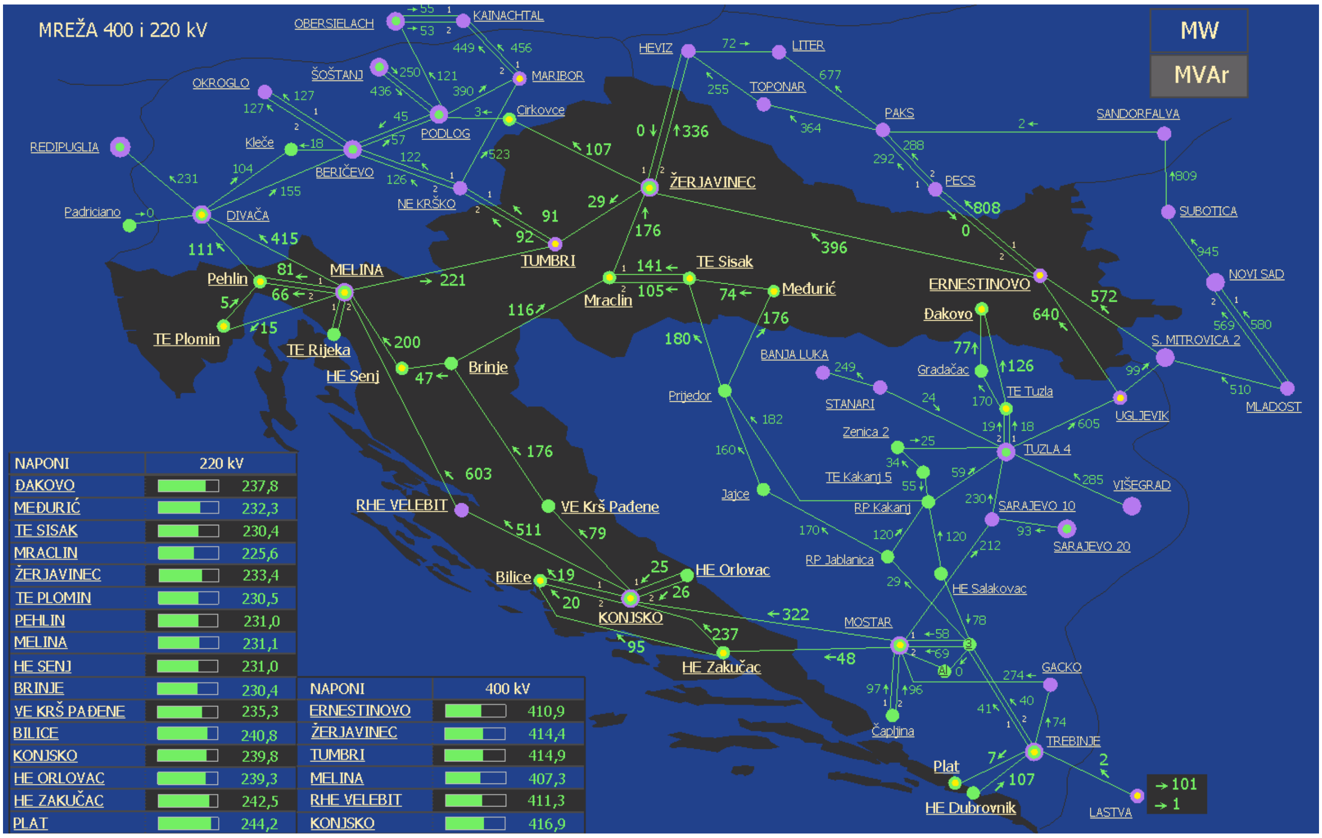


Figure 5: 400 kV and 220 kV Transmission Network of HOPS

The transmission network of HOPS is connected to the neighbouring countries by the following lines:

- NOSBiH – two 400 kV, six 220 kV and eleven 110 kV tie lines,
- MAVIR (Hungary) – four 400 kV tie lines,
- EMS – one 400 kV and two 110 kV tie lines,
- ELES (Slovenia) – three 400 kV, two 220 kV and three 110 kV tie lines.

Calculated NTC values

The net transfer capacities (NTCs) at all borders are calculated in bilateral coordination with the neighbouring TSOs in accordance with the former MLA Operation Handbook. For the calculation of NTCs the ENTSO-E seasonal network models are used and adapted to the relevant month. The NTCs are calculated by each TSO of the respective border. The NTC values are compared and the smaller value is chosen as the final value. At the borders with Hungary, Serbia and Bosnia and Herzegovina, the values are calculated on a monthly basis, which means that the most unfavourable situation for that month is taken into account. At the border with Slovenia, values are calculated on a daily basis. HOPS also takes into account the specific layout/shape of the Croatian power system in the calculations, especially the location of the substation (SS) Ernestinovo, which is directly connected to three substations in the surrounding three countries, namely SS Pecs (MAVIR), SS Mitrovica (EMS) and SS Ugljevik (NOSBiH). This means that cross-border flows are highly interdependent at SS Ernestinovo.

The bilaterally agreed upon NTC values for the whole day of 8 January 2021 are:

- HR » BA 1000 MW; BA » HR 1000 MW
- HR » HU 1000 MW; HU » HR 1200 MW
- HR » RS 500 MW; RS » HR 600 MW
- HR » SI 1500 MW; SI » HR 1500 MW

The calculated NTC values as shown above also take into account the scheduled/planned outages as described further on.

Market schedules

The market schedules were a reflection of a general trend in continental Europe: cheaper energy from a place of lower demand in the east (warm weather in the Balkan Peninsula, Orthodox Christmas) was sold to a place of higher demand in the west (cold wave, especially in the Iberian Peninsula).

The net exchange values for Croatia for 8 January 2021 can be found in table 5. The market schedules show high imports to Croatia from Bosnia and Herzegovina and Serbia beginning at 08:00 in the morning. The net exchange during this time is close or even equal to the full NTC value. Furthermore, Croatia exports energy to Slovenia and Hungary during this time.

Hour	BA > HR	SI > HR	HU > HR	RS > HR
00:00–01:00	755	-374	-591	-20
01:00–02:00	838	-470	-755	-16
02:00–03:00	845	-719	-724	122
03:00–04:00	845	-828	-707	102
04:00–05:00	832	-751	-762	108
05:00–06:00	804	-653	-739	123
06:00–07:00	618	-395	-655	224
07:00–08:00	965	-394	-743	215
08:00–09:00	983	-516	-771	512
09:00–10:00	979	-515	-715	538
10:00–11:00	980	-574	-695	537
11:00–12:00	979	-502	-697	522
12:00–13:00	1,000	-481	-688	492
13:00–14:00	1,000	-365	-943	524
14:00–15:00	1,000	-598	-795	600
15:00–16:00	1,000	-606	-857	591
16:00–17:00	1,000	-636	-791	560
17:00–18:00	1,000	-628	-616	416
18:00–19:00	1,000	-616	-660	411
19:00–20:00	989	-637	-648	414
20:00–21:00	716	-653	-349	362
21:00–22:00	638	-820	-63	337
22:00–23:00	564	-815	-108	290
23:00–24:00	544	-848	-280	322

Table 5: Net exchange values of Croatia (in MW)

Production of power plants (running) and renewables (forecast and actual)

The actual production of power plants corresponds to the scheduled production in Croatia. In the hour from 13:00–14:00, before the system separation, the scheduled and actual productions are the following (in MW):

Type of Power Plant	Scheduled	Realised
Hydro power plants (HPPs)	1,470	1,428
Thermal power plants (TPPs)	462	463
Wind power plants (WPPs)	225	288
All other power plants	129	127
SUM	**2,286**	**2,306**

Table 6: Planned and actual production in Croatia

In the hour from 14:00–15:00, during the system separation, the scheduled productions are almost the same (in MW):

Type of Power Plant	Scheduled
Hydro power plants (HPPs)	1,420
Thermal power plants (TPPs)	462
Wind power plants (WPPs)	224
All other power plants	126
SUM	**2,232**

Table 7: Scheduled production in Croatia

There are no power plants directly connected to SS Ernestinovo. One power plant in the vicinity is connected to the 110 kV network at SS Osijek 2. Nevertheless, this power plant was not in operation during the time of the system separation. During the time of the system separation, about 30 MW of distributed energy resources were in operation in the proximity of SS Ernestinovo and operated at constant production (with mainly biomass or gas as the primary energy source).

Power plants not in operation/disconnected from the grid

Furthermore, no outage or malfunction of any power plant was reported before the incident.

Consumption

The planned consumption in Croatia was very close to the actual consumption. The values for the hours of interest are the following (in MW):

Hour	Planned	Realised
13:00–14:00	2,500	2,519
14:00–15:00	2,438	2,432

Table 8: Planned and actual consumption in Croatia

Scheduled/planned outages of grid elements

All outages of transmission lines were taken into account during the planning phase the day before. The following transmission lines were out of service:

- 400 kV Ernestinovo (HR)–Pecs (HU) 2: line was out of service as of 5 January 2021 due a technical circuit breaker failure in SS Ernestinovo,
- 400 kV Žerjavinec (HR)–Heviz (HU) 1: line was switched-off as a corrective measure for voltage reduction as the flow on this line was below the natural load of the line, so it was producing reactive power.

Due to the collective annual leave during the Christmas and New Year holidays, no maintenance work on transmission assets was foreseen in the work plan, and therefore no other lines were out of service.

Grid topology

The topology in SS Ernestinovo just before the system separation can be seen in figure 6.

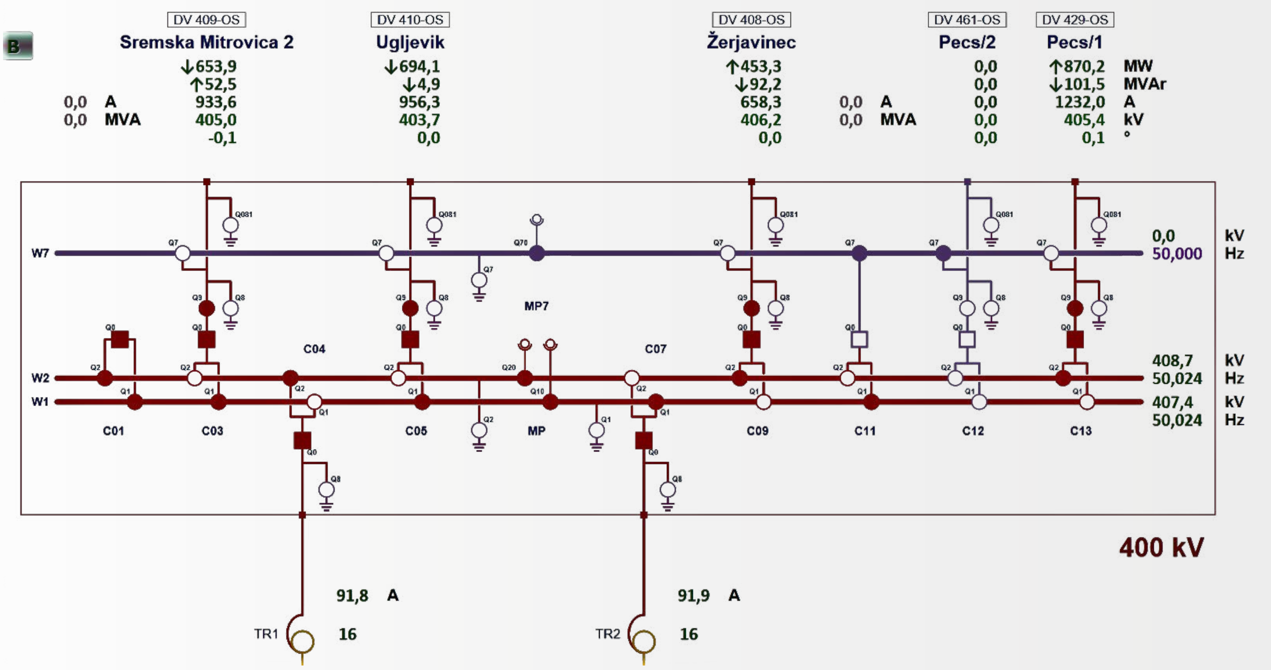


Figure 6. Topology in SS Ernestinovo just before the system separation

Power Flow (MW)	Busbar coupler	Ernestinovo – Žerjavinec	Đakovo – Gradačac	Đakovo – Tuzla	Ernestinovo – Ugljevik	Ernestinovo – S. Mitrovica	Ernestinovo – Pecs 1	Ernestinovo – Pecs 2	Žerjavinec – Heviz 1	Žerjavinec – Heviz 2
IDCF 13:00–14:00	1,076	344	-94	-132	-568	-510	730	0	0	345
IDCF 14:00–15:00	1,078	355	-96	-135	-563	-516	723	0	0	350
IDCF 13:00–14:00	1,076	344	-94	-132	-568	-510	730	0	0	345
RTSN at 13:30	1,180	409	-83	-129	-619	-604	779	0	0	306

Table 9: Comparison of forecasted and realised flows near SS Ernestinovo (in MW)

Current (A)	Busbar coupler	Ernestinovo – Žerjavinec	Đakovo – Gradačac	Đakovo – Tuzla	Ernestinovo – Ugljevik	Ernestinovo – S. Mitrovica	Ernestinovo – Pecs 1	Ernestinovo – Pecs 2	Žerjavinec – Heviz 1	Žerjavinec – Heviz 2
IDCF 13:00–14:00	1,517	485	-133	-186	-801	-719	1,029	0	0	486
IDCF 14:00–15:00	1,520	500	-135	-190	-794	-727	1,019	0	0	493
IDCF 13:00–14:00	1,517	485	-133	-186	-801	-719	1,029	0	0	486
RTSN at 13:30	1,664	577	-117	-182	-873	-852	1,098	0	0	431

Table 10: Comparison of forecasted and realised currents near SS Ernestinovo (in A)

The topology chosen in SS Ernestinovo always follows the rule that both 400/110kV transformers (TR1 and TR2) are not connected to the same busbar. Furthermore, both 400 kV tie-lines between Ernestinovo and Pecs (no. 1 and no. 2) are not connected to the same busbar. This rule is followed in order not to change the topology in SS Ernestinovo too often and to avoid an additional reduction of the lifetime of transmission assets. Thus the topology was not changed when the line Ernestinovo (HR)–Pecs (HU) 2 was taken out of service on 5 January 2021.

Power flows on grid elements in different time frames (Day-Ahead, Intraday, Real-Time)

The power flows in the HOPS network are predicted beginning on the day before the delivery using the DACF process. Furthermore, the power flows are updated and checked regularly by the IDCF with newer data available. During real-time operation, an n-1 contingency calculation is performed every minute using the SCADA system of HOPS. The result is a list of n-1 violations.

In table 9 the forecasted IDCF values of the hours from 13:00–14:00 and 14:00–15:00 for the most important transmission network elements that affect the flows in SS Ernestinovo are compared (see figure 5 for the location of transmission network elements). In addition, the value of the real-time snapshot (RTSN) made at 13:30 is depicted in the table and compared to the IDCF values.

It can be concluded that the match between the IDCF values of the power flows and the actual flow for 13:30 was relatively good and only led to a mismatch on the flow of the busbar couple of about 100 MW. From the comparison of IDCF values it can also be seen that the power flow was not predicted to change significantly from the hour 13:00–14:00 to the hour 14:00–15:00.

Furthermore, in table 10 the same values are shown in amperes. The values in amperes are used for the following description of facts.

From table 10 it can be concluded that the mismatch of the actual power flow on the busbar coupler compared to the forecasted value was about 150 A at the time of 13:30.

During the IDCF as well as during real time operation n-1 contingency simulations are performed. The tripping of the busbar coupler was not identified as an ordinary contingency pursuant to the methodology for coordinating operational security analysis. Therefore, the tripping of the busbar coupler was not included as a possible event in the n-1 contingency simulations in DACF, IDCF or in real time.

Furthermore, the power flow value on the busbar coupler for the case of a trip of a transmission line had to be calculated manually in the IDCF by considering the power flow on the transmission lines and the transformers at the SS of Ernestinovo. Neglecting the power flow on the transformers TR1 and TR2, the power flow of the busbar coupler would correspond to the sum of the power flow on the lines of Ernestinovo (HR)–Pecs (HU) 2 and Ernestinovo (HR)–Žerjavinec (HR).

The manual calculation of the power flow on the busbar coupler for the case of a trip of a transmission line was performed with the IDCF data set for the hour 13:00–14:00. The trip of the 400 kV line from Novi Sad – Subotica (see figure 5) led to the worst case loading of the busbar coupler. In case of a trip, the expected power flow on the busbar coupler resulted in a power flow of 1,370 MW and a current of 1,930 A, respectively. The value was still within the permitted limits.

Power flow on the busbar coupler and the surrounding grid elements in real-time

The SCADA system of HOPS has alarm settings that warn the operators in case a trip of a transmission network element occurs or the power flow on a transmission network element is beyond a certain threshold. This threshold can be reached either by an overcurrent (overload) in the n-state or a predicted n-1 violation (the value for the busbar couple in the n-1 state due to a trip of another transmission network element had to be calculated manually as described above).

The threshold corresponds to the rated current that the weakest part of the high voltage equipment in some bay can transfer permanently. This means that the limit can come from, for example, the maximum current that can be transmitted by a transmission line, but it can also come from the maximum current that can be transmitted by a metering current transformer in the transmission line bay. In the case of the busbar coupler in SS Ernestinovo, the metering current transformer was the limiting element. The rated current of this metering current transformer is 1,600 A. Considering the protection setting (the current should not be larger than 130 %) the maximum power flow for the protection of the busbar coupler was set to 2,080 A.

If the value exceeds 2,080 A for 5 seconds, the circuit breaker of the busbar is opened in order to protect the metering current transformer. The timer is reset once the value again falls below 1,976 A.

The SCADA system of HOPS has two alarms for an overcurrent for the busbar coupler. The first alarm is reached when the current reaches a value of 96 % of the rated value of the metering current transformer. Thus the first alarm occurs at a current of 1,536 A. The second alarm occurs when the current is 120 % of the current transformer setting. Thus the second alarm occurs at a value of 1,920 A.

During the hour 12:00–13:00, roughly 50 alarms occurred, because the current through the busbar coupler was oscillating around the value of 1,536 A. The last alarm occurred at 12:56:57, because after this the current did not fall below the value of 1,536 A. During the hour 13:00–14:00 the current of the busbar coupler stayed at around 1,700 A and was relatively stable. In the ongoing analysis of the incident the alarm handling will also be further investigated.

In figure 7 the power flow through the transmission network elements connected at SS Ernestinovo for the period 14:00–14:10 are depicted. The limits for the transmission lines is 2,000 A, whereas the limit for the busbar coupler is 2,080 A. From the figure it can be observed that the current through the busbar coupler is constantly increasing in the time after 14:00.

At 14:00:59 the current of the busbar coupler reached the value of 1931 A (note: at 14:00:00 the current was 1736 A). Thus the second threshold of 1,920 A was met and an alarm occurred. At 14:01:06 the power flow value fell again under 1,920 A and fluctuated between 1,830 A and 1,920 A. At 14:04:16 the value again exceeded the threshold of 1,920 A. At 14:04:21 the current through the busbar coupler reached a value of 1,989 A.

The timing of the described measurements corresponds to the location at SS Ernestinovo. The measurements are then sent to the SCADA system of HOPS. Due to the local communication concentrator unit in the substation the data is submitted only periodically, meaning every 4 seconds, to the SCADA system. Just in case the measured value changes instantly more than 10 %, the value is delivered directly (this was not the case in this situation). The value may fluctuate within the 4 seconds, but the last measured value will always be sent. Furthermore, the SCADA system trends is only refreshed every ten seconds, so that the operator can only see updates every ten seconds, no matter if the value is already available in the SCADA system.

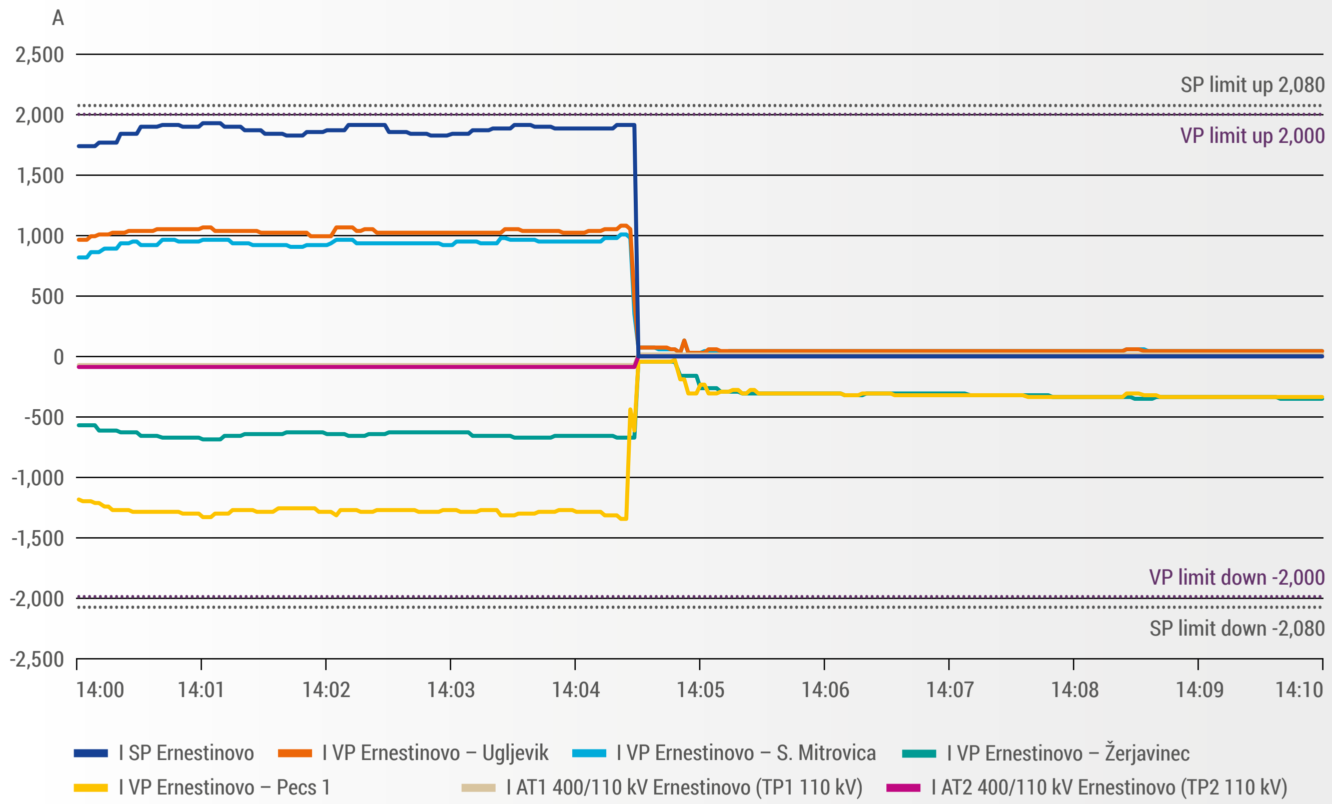


Figure 7: Currents of transmission network elements in SS Ernestinovo between 14:00 and 14:10
(SP W12 corresponds to the flow through the busbar coupler)

Because of the refreshing rate of the SCADA system, the operators could not see the last value of 1,989 A. The last reported where the busbar coupler was still closed was at 14:04:16 with a value of 1,922 A.

Furthermore, the relay, which opens the circuit breaker of the busbar coupler, uses different measurement equipment than that used for the SCADA system. The relay, which also gets the measured value almost instantly, noticed a current above 2,080 A at 14:04:20.907. Beginning from this time, the timer started to count as long as the value stayed above 1,976 A. As after 5 seconds the measurement of the relay recorded a value of 2,007 A, the circuit breaker of the busbar coupler opened at 14:04:26.

The trip of the busbar coupler led to a shift of the flows, i.e. the current through the busbar coupler was now flowing through the transformers TR1 and TR2. Those two transformers were interconnected via the underlying 110 kV busbars and were therefore still connected to the two 400 kV busbars in SS Ernestinovo. Due to the resulting overcurrent both transformers TR1 and TR2 tripped at 14:04:28 and led to a complete separation of the two busbars in SS Ernestinovo.

Furthermore, it should be highlighted that the second alarm for the high current on the busbar coupler at 14:00:59 led to a limited time to take necessary actions in the control centres to determine and activate remedial actions (i.e. change the topology in SS Ernestinovo). Unfortunately, the time was then too short in order to determine necessary remedial actions in time. Further, the difference between the actual measured value of the relay as well as the delay in the reporting of measurements to the SCADA system gave the impression that the current through the busbar coupler was about 1,920 A at the time of tripping, and the urgency of the required action was not properly assessed.

2.1.2.2 System conditions in Serbia/EMS

Calculated NTC values

EMS's control area is connected to the neighbouring areas with the following lines:

- NOSBiH – one 400 kV, one 220 kV and two 110 kV tie lines,
- MAVIR – one 400 kV tie line,
- HOPS – one 400 kV and two 110k V tie lines,
- Transelectrica – one 400 kV and three 110 kV tie lines,
- ESO EAD (Bulgaria) – one 400 kV and two 110 kV tie lines,
- MEPSO (North Macedonia) – one 400 kV tie line,
- CGES – two 220 kV and one 110 kV tie lines.

NTC on all borders is calculated in bilateral coordination with neighbouring TSOs in accordance with the former MLA Operation Handbook, using a seasonal model adapted to the relevant month and taking the smaller value that each of the TSOs calculates.

In addition, in the calculations, EMS takes into account the specific position of TS Sremska Mitrovica 2, which is directly connected to two other control areas: SS Ernestinovo (HOPS) and SS Ugljevik (NOSBiH).

The bilaterally agreed upon values for the whole day of 8 January 2021 are as follows:

- RS » HR 600 MW; HR » RS 500 MW
- RS » HU 800 MW; HU » RS 700 MW
- RS » RO 800 MW; RO » RS 800 MW
- RS » BG 300 MW; BG » RS 350 MW
- RS » MK 300 MW; MK » RS 250 MW
- RS » ME 300 MW; ME » RS 200 MW
- RS » BA 600 MW; BA » RS 500 MW

Market schedules

Market schedules reflected a general trend in continental Europe to obtain cheaper energy from a place of lower demand in the east (this day had warm weather in the Balkan Peninsula and it was the first day after Orthodox Christmas) sold at a place of higher demand in the west. Therefore, market schedules were mainly from the east to the west, and net exchange values for 8 January 2021 are provided in table 11.

Hour	Net Exchange EMS – NOS BIH	Net Exchange EMS – ESO EAD	Net Exchange EMS – HOPS	Net Exchange EMS – MAVIR	Net Exchange EMS – CGES	Net Exchange EMS – MEPSO	Net Exchange EMS – TRANSELECTRICA
01	-301	40	-20	614	-114	-40	201
02	-332	40	-16	613	-99	-73	240
03	-313	104	122	722	-114	-155	217
04	-306	122	102	748	-157	-135	209
05	-290	39	108	803	-157	-115	218
06	-290	65	123	648	-132	-129	281
07	-338	25	224	685	-36	-165	161
08	-288	-64	215	769	-142	-210	301
09	-386	35	512	840	-185	-210	192
10	-389	-177	538	943	-180	-225	208
11	-388	-239	537	926	-144	-197	151
12	-387	-206	522	949	-148	-232	148
13	-312	-187	492	989	-84	-235	33
14	-307	-231	524	1,000	-85	-228	74
15	-246	-97	600	1,000	-86	-212	-122
16	-304	-155	591	1,000	-90	-201	-9
17	-376	-162	560	1,000	-134	-198	-3
18	-377	-190	416	986	-184	-196	110
19	-397	-142	411	835	-186	-5	51
20	-417	-99	414	784	-186	10	73
21	-334	-77	362	661	-98	-46	127
22	-278	-55	337	605	-56	33	-36
23	-294	-59	290	555	48	-6	-51
24	-331	-49	322	436	163	0	-73
TOTAL (MWh)	**-7,981**	**-1,719**	**8,286**	**19,111**	**-2,586**	**-3,170**	**2,701**

Table 11: Net exchange values at EMS' borders (in MW)

Production of power plants (running) and renewables (forecast and actual)

The production of power plants in Serbia went mostly according to plan (slightly higher wind generation infeed), and in the hour before the separation (the hour from 13:00-14:00 on 8 January), the following are the scheduled and actual productions:

- HPPs: scheduled 2,040 MW, actual 2,060 MW,
- TPPs: scheduled 2,835 MW, actual 3,076 MW,
- WPPs: scheduled 60 MW, actual 106 MW,

In sum, the scheduled production was 4,935 MW, and the actual was 5,242 MW.

In the hour from 14:00–15:00:

- HPPs: scheduled 2,077 MW, actual 1,512 MW,
- TPPs: scheduled 3,065 MW, actual 2,913 MW,
- WPPs: scheduled 73 MW, actual 159 MW,

In sum, the scheduled production was 5,215 MW, and the actual was 4,584 MW.

Power plants not in operation/disconnected from the grid

Production units that were not available include: TPP Kolubara (four generators), TPP Morava (one generator) and TPP-HPP Novi Sad (one generator), for a total of 360 MW.

Consumption

Consumption was very accurately forecasted, so in the hour from 13:00–14:00, the planned consumption was 4,420 MW while the actual consumption was 4,496 MW. The planned consumption for the hour from 14:00–15:00 was 4,382 MW and the actual was 4,595 MW.

Scheduled/Planned outages of grid elements

All outages were taken into account during the planning phase, and only one 110 kV line was switched off:

- Overhead line (OHL) 110 kV SS Majdanpek 1 – SS Majdanpek 2: line was switched off due to a circuit breaker failure in SS Majdanpek 1.

Grid topology

Due to the Christmas and New Year holidays, the scope of planned works in the grid was small. No maintenance work was foreseen in the weekly work plan, only 110 kV from SS Majdanpek 1 – SS Majdanpek 2 was switched off due to a circuit breaker failure in SS Majdanpek 1.

Power flows on grid elements in different time frames (Day-Ahead, intraday, Real-Time)

Table 12 shows the data on power flows for the most important elements that affect the flows in TS Ernestinovo. They are displayed in order: DACF data as sent by HOPS, data from the merged, common day-ahead model, data from the common IDCF model, and real-time data as seen by the dispatcher.

	Line S.Mitrovica – Ugljevik	Line S.Mitrovica – Ernestinovo	Line S.Mitrovica – Mladost	Line Subotica 3 – Novi Sad	Line Subotica 3 – Sandorfalva	Line Subotica 3 – Sombor 3	Line Djerdap 1 – TPP Kostolac A	Line Djerdap 1 – Bor 2	Line Djerdap 1 – Portile de Fier
DACF 13 h	37.50	429.70	-534.00	-598.00	450.70	53.00	521.00	593.00	-89.00
IDCF 13 h	40.20	460.00	-560.20	-614.30	482.50	49.40	513.80	594.10	-81.80
SCADA 13 h	-98.04	597.33	-515.82	-910.78	784.41	36.08	427.19	356.27	288.06
DACF 14 h	28.00	421.50	-512.60	-574.50	438.70	51.80	491.90	589.00	-52.70
IDCF 14 h	30.50	459.50	-543.50	-601.40	478.20	46.50	484.10	591.40	-47.20
SCADA 14 h	-98.85	603.86	-526.95	-932.16	821.98	31.94	375.38	333.19	273.41

Table 12: Power flows that affect SS Ernestinovo (in MW)

	Line S.Mitrovica – Ugljevik	Line S.Mitrovica – Ernestinovo	Line S.Mitrovica – Mladost	Line Subotica 3 – Novi Sad	Line Subotica 3 – Sandorfalva	Line Subotica 3 – Sombor 3	Line Djerdap 1 – TPP Kostolac A	Line Djerdap 1 – Bor 2	Line Djerdap 1 – Portile de Fier
ΔPmax	349.2	745.6	511.4	1,198.5	1,447.6	179.3	395.6	583.7	894.3

Table 13: Maximum power values in transmission lines connected to EMS substations (in MW)

Figures 8, 9 and 10 show the power flows through the individual elements connected to busbars in SS Sremska Mitrovica 2, SS Subotica 3 and SS Đerdap 1 for the period 13:00–14:15. A sudden change in flows at 14:00 can be noticed. The maximum power values according to these figures can be seen in table 13 (values are in MW).

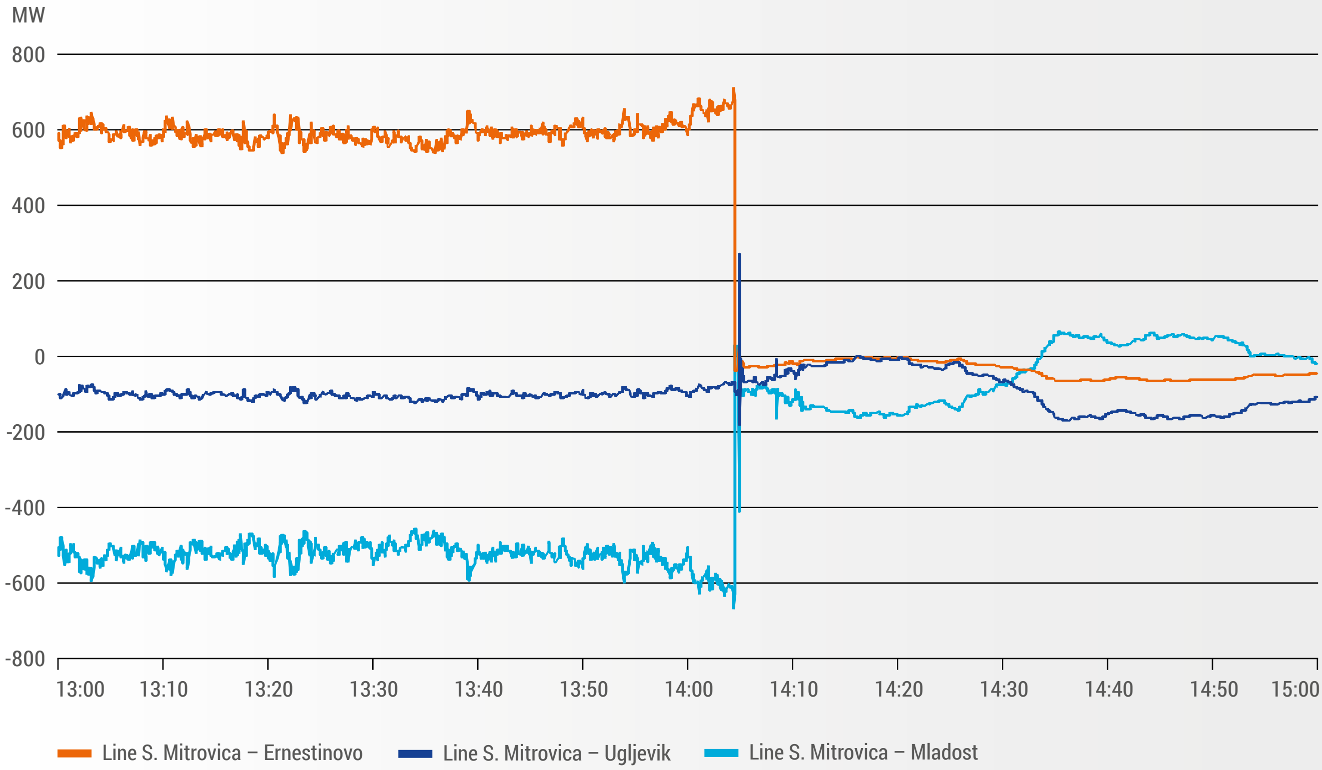


Figure 8: Power flows through the individual elements connected to busbars in SS Sremska Mitrovica 2

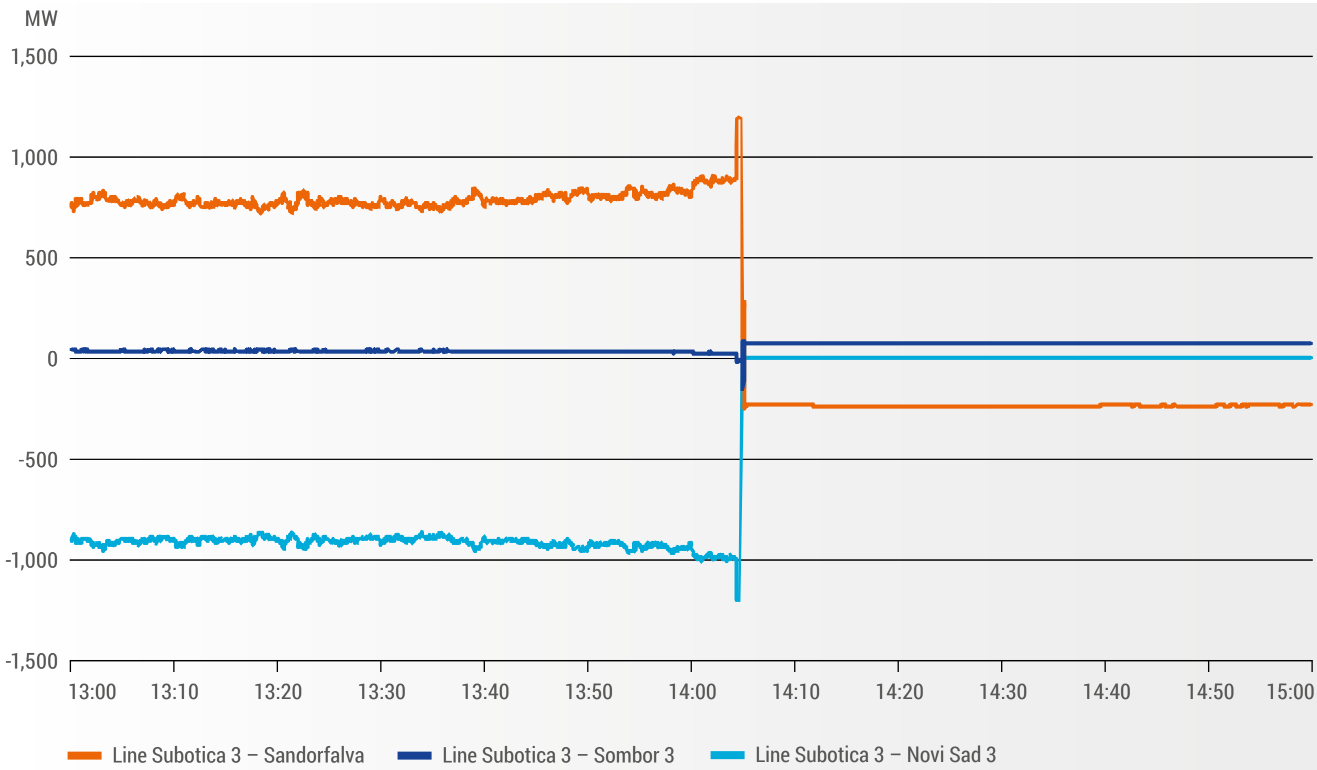


Figure 9: Power flows through the individual elements connected to busbars in SS Subotica

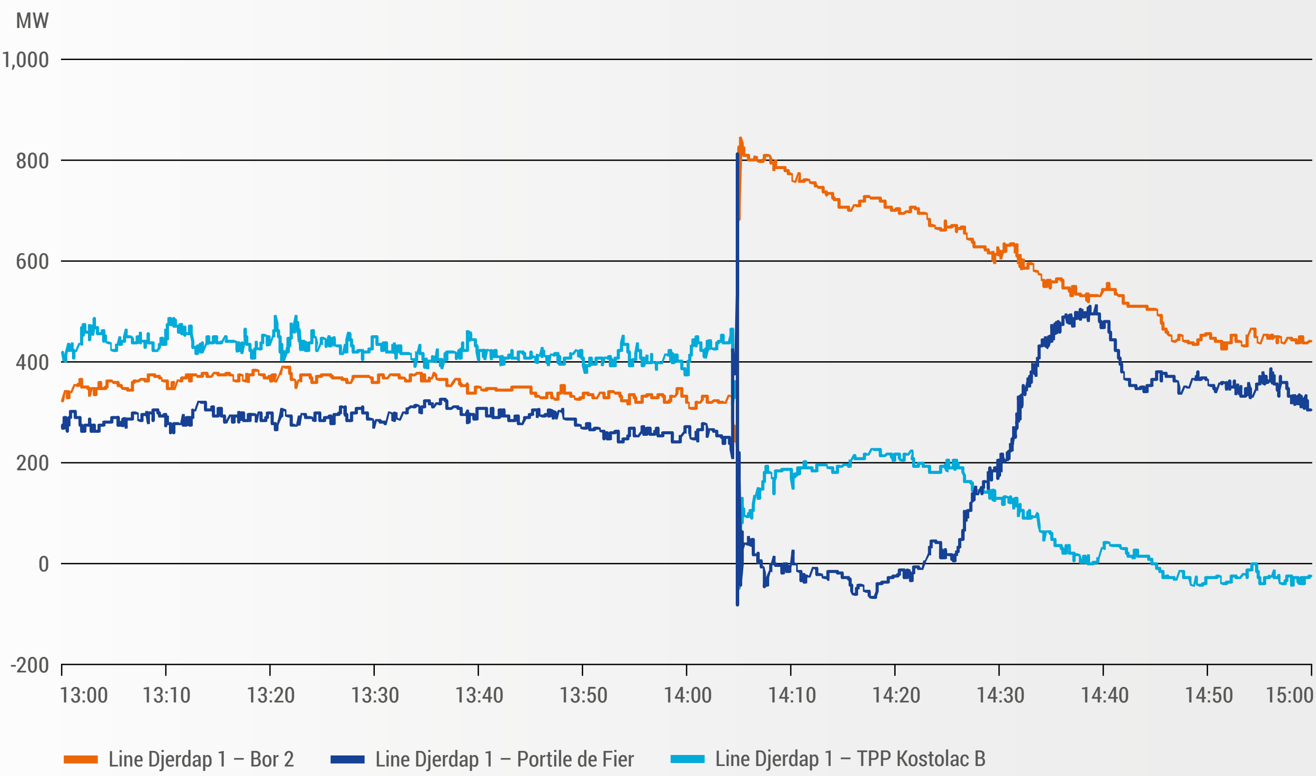


Figure 10: Power flows through the individual elements connected to busbars in SS Đerdap 1

2.1.2.3 System conditions in Romania/Transelectrica

Calculated NTC values

Transelectrica' control area is connected to the neighbouring areas with the following lines:

- MAVIR – two 400 kV tie lines,
- EMS – one 400 kV tie line and three 110 kV tie lines (usually disconnected and operated in radial topology only),
- ESO – EAD – four 400 kV tie lines (usually, only three lines in operation and one circuit not energised),
- Western Power System – of Ukrenergo (Ukraine) – one 400 kV tie line.

The NTC at all borders is calculated in bilateral coordination with neighbouring TSOs in accordance with the former MLA Operation Handbook, using the seasonal model adapted to relevant month and taking the smaller value that each of the TSOs calculates.

At the borders with Hungary, Serbia, Ukraine and Bulgaria, the values are calculated on a monthly basis, which means that the most unfavourable situation for that month is considered.

Bilaterally agreed values of the NTC for the whole day 8 January 2021 were as follows:

- RO » HU 800 MW, HU » RO 1,000 MW
- RO » RS 800 MW, RS » RO 800 MW
- RO » BG 1,000 MW, BG » RO 1,000 MW
- RO » UA 200 MW, UA » RO 400 MW

Market schedules

Market schedules were more a result of long term scheduled imports compensated by day ahead and intraday scheduled exports entailed by Romanian wind generation, than a consequence of the general trend depicted by the commercial power stream from the Balkan Peninsula to the North-West systems of Continental Europe interconnection. Within hours 14 and 15 the Romanian power system was fairly balanced, the net exchange really low and the actual rate of NTC use moderate. The exchange values on Transelectrica borders for 8 January 2021 may be found in Table 14.

Hour	Net Exchange RO – HU	Net Exchange RO – RS	Net Exchange RO – BG	Net Exchange RO – UA	Total Net Exchange
01	800	-201	33	-37	599
02	800	-240	4	-38	530
03	788	-217	-15	-38	522
04	759	-209	-81	-38	435
05	793	-218	-152	-38	388
06	450	-281	-132	-37	4
07	31	-161	-162	-34	-324
08	99	-301	-467	-27	-694
09	36	-192	-803	-18	-976
10	114	-208	-734	-26	-851
11	276	-151	-764	-35	-672
12	511	-148	-807	-34	-476
13	623	-33	-810	-33	-251
14	800	-74	-613	-31	84
15	800	122	-573	-11	340
16	800	9	-430	-2	379
17	732	3	-829	0	-92
18	738	-110	-753	0	-123
19	748	-51	-739	0	-39
20	701	-73	-507	0	122
21	760	-127	-272	-6	357
22	787	36	-81	-19	725
23	786	51	-88	-31	722
24	788	73	-11	-34	820

Table 14: Net exchange values at Transelectrica' borders (in MW)

Production of power plants (running) and renewables (forecast and actual)

The realised production of Romanian classical power plants was lower than planned due to higher wind generation than expected. In the hour before the separation (14 hour CET on 8 January) there were the following scheduled and realised productions:

- Nuclear power plant (NPP):
  scheduled 1,390 MW, realisation 1,360 MW,
- Hydro power plants (HPPs):
  scheduled 3,337 MW, realisation 2,974 MW,
- Thermal power plants (TPPs):
  scheduled 2,996 MW, realisation 2,644 MW,
- Wind power plants (WPPs):
  scheduled 1,118 MW, realisation 1,535 MW,
- Photovoltaic power plants (PV PPs):
  scheduled 20 MW, realisation 29 MW,
- All other power plants:
  scheduled 61 MW, realisation 78 MW,

in total: 8,922 MW scheduled and 8,620 MW realisation.

Hour	Total Net Exchange	Scheduled WPP	Realisation WPP
01	599	205	266
02	530	144	67
03	522	105	9
04	435	80	1
05	388	67	1
06	4	67	12
07	-324	71	41
08	-694	100	101
09	-976	174	163
10	-851	301	312
11	-672	431	411
12	-476	574	756
13	-251	816	1,034
14	84	961	1,376
15	340	1,118	1,575
16	379	1,235	1,706
17	-92	1,339	1,815
18	-123	1,374	1,906
19	-39	1,328	1,905
20	122	1,252	1,794
21	357	1,164	1,828
22	725	1,107	1,741
23	722	1,020	1,660
24	820	977	1,656

Table 15: WPPs production on 8 January 2021 (scheduled, realisation) and total net exchange (in MW)

Power plants not in operation/disconnected from the grid

The following production units were not available on 8 January 2021 (out of service for maintenance works): one unit at TPP București Sud and one unit at TPP Ișalnița - in total an amount of 415 MW. Some others production units were out of operation for long term works and are not relevant for this incident.

Consumption

The planned consumption in the 14 hour (13:00–14:00) was 8,320 MW whereas the realised consumption was 8,619 MW. The planned consumption for the 15 hour was 8,260 MW and for realisation was 8,050 MW.

Scheduled/Planned outages of grid elements

One outage was considered during the planning phase the day before: 400 MVA, 400/220 kV autotransformer in Porțile de Fier substation, due to the refurbishment works (replacement of 400 MVA unit with another one of 500 MVA).

Grid topology

On 8 January 2021, there was no relevant change in Transelectrica grid topology prior to the occurrence of the incident at 14:05 CET.

Power flows on grid elements in different time frames (day-ahead, intraday, real-time)

The Romanian transmission grid faced relatively medium to high power flows from the South-East region of the Romanian system (where most of the wind farms are located) to the North-West region.

The following tables show the data on power flows for the most relevant elements for the event reconstruction, i.e. all the elements which were tripped after the tripping of the line Subotica–Novi Sad (table 16) and tie-lines (table 17). They are displayed in order: day ahead congestion forecast, intraday congestion forecast and real-time data as monitored by dispatchers on the SCADA system.

Network elements	DACF 13:00	IDCF 13:00	SCADA 13:00	DACF 14:00	IDCF 14:00	SCADA 14:00
220 kV OHL Paroșeni – Târgu Jiu Nord	248	257	276	244	255	316
220 kV OHL Timișoara – Reșița ck.1	268	274	281	268	275	279
220 kV OHL Timișoara – Reșița ck.2	268	274	278	268	275	276
400 kV OHL Mintia – Sibiu Sud	267	277	290	268	279	328
400 kV OHL Iernut – Gădălin	496	515	569	510	534	565
400 kV OHL Iernut – Sibiu Sud	692	714	787	702	729	801
400 MVA, 400/220 kV AT Roșiori SS	86	82	82	78	71	88
220 kV OHL Iernut – Câmpia Turzii	106	109	97	109	112	117
220 kV OHL Fântânele – Ungheni	6	9	16	12	17	23

Table 16: Forecasted and realised flows on the network elements that tripped at 14:05 CET (in MW)

Tie lines	DACF 13:00	IDCF 13:00	SCADA 13:00	DACF 14:00	IDCF 14:00	SCADA 14:00
400 kV OHL Roșiori – Mukacevo	394	423	492	424	463	460
400 kV OHL Arad – Sandorfalva	-86	-85	-7	-75	-76	-55
400 kV OHL Nădab – Bekescaba	236	242	301	248	260	262
400 kV OHL Porțile de Fier – Djerdap	-183	-210	-273	-138	-178	-268
400 kV OHL Țânțăreni – Kozloduy ck.1	-316	-364	-591	-262	-308	-578
400 kV OHL Țânțăreni – Kozloduy ck.2	0	0	0	0	0	0
400 kV OHL Rahman – Dobrudja	54	35	79	105	86	112
400 kV OHL Varna – Stupina	61	41	126	116	96	150

Table 17: Forecasted and realised flows on the tie lines (in MW)

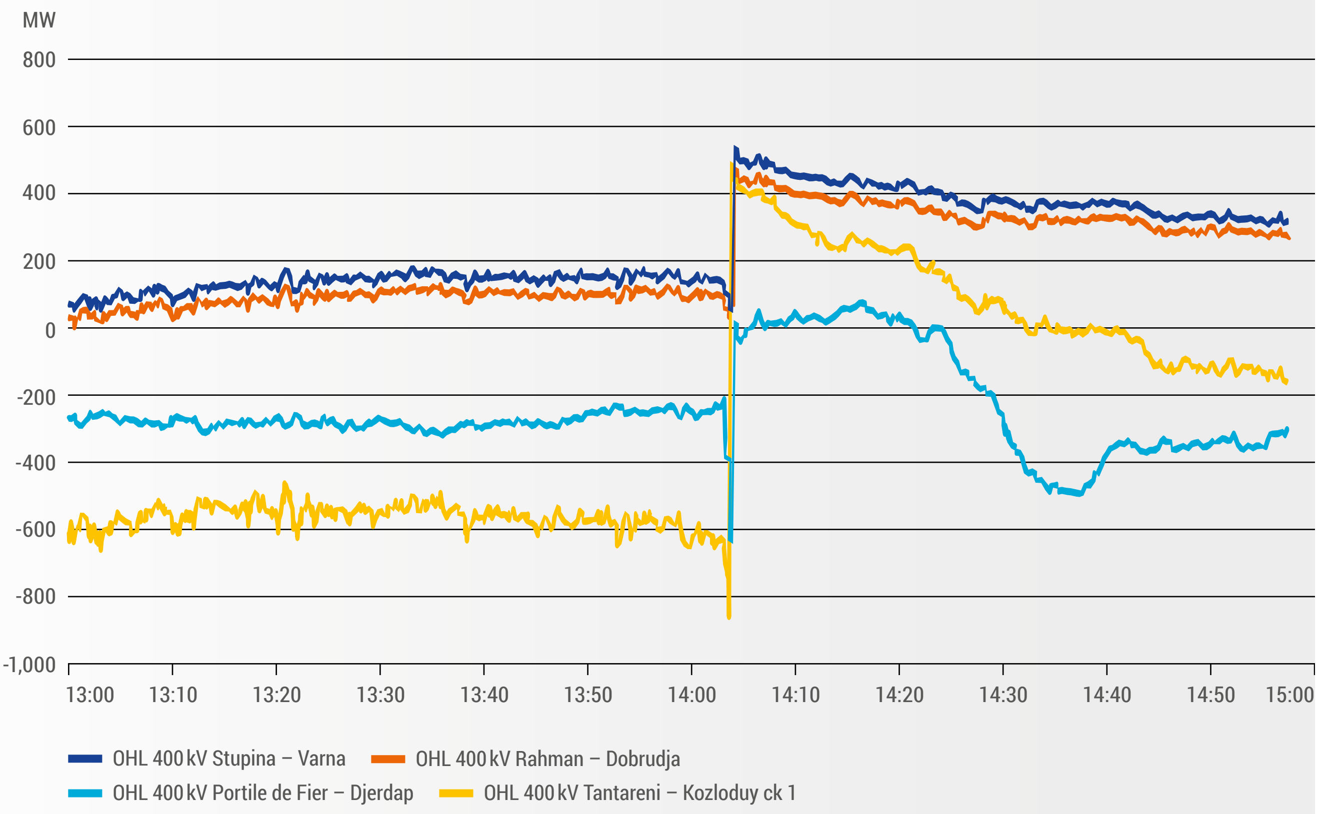


Figure 11: Power flows through the Romanian tie-lines within the South-East split area

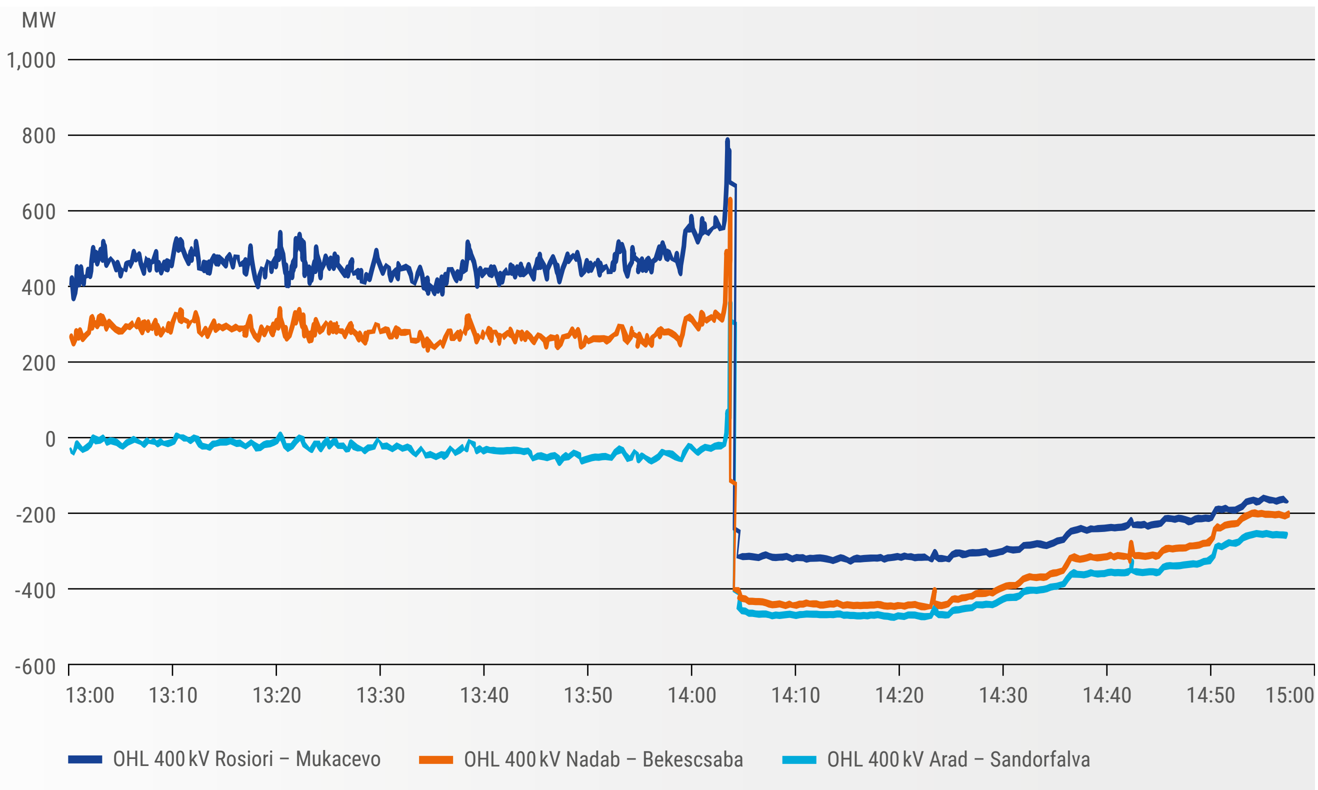


Figure 12: Power flows through the Romanian tie-lines within the North-West area

Figure 11 and 12 display the active power flows on the tie lines in the South-East area and in the North-West area respectively during the incident.

2.2 Impact of market

Day-ahead prices have been briefly analysed for 7 and 8 January 2021 to understand whether: (1) the market was interrupted, and whether (2) prices fluctuated or not. Data trends indicate that the market was not interrupted, nor did the prices fluctuate, either at the time of the incident or afterwards. In addition, TSOs from the affected South East European countries (Serbia, Bosnia and Herzegovina, Romania, and Croatia) highlighted that no market activities were suspended at the time of the incident.

2.3 Sequence of events

The sequence of events was reconstructed based on WAMs measurements and on protection device recordings which both possess precise GPS time stamps. The results can be found in table 18. Furthermore, the related separation could be reproduced with the help of a dynamic model setup, starting from the individual model snapshots delivered by all continental European (CE) TSOs.

No	TSO	delta/s	trip time	substation 1	substation 2	voltage/kV	Comments
1	HOPS	0	14:04:25.9	Ernestinovo		400	busbar coupler overload protection
2	EMS	23	14:04:48.9	Subotica	Novi Sad	400	overload protection 20 s 2nd zone
3	TRANS	26	14:04:51.9	Paroşeni	Târgu Jiu Nord	220	distance prot. starting zone 2.4 s
4a	TRANS	27.9	14:04:53.8	Reşiţa	Timişoara	220	dist. prot. 0.4 s
4b	TRANS	27.9	14:04:53.8	Reşiţa	Timişoara	220	dist. prot. 0.4 s, breaker L1 failure
5	NOS BiH	28.2	14:04:54.1	Prijedor	Međurić	220	dist. prot. out-of-step protection
6	NOS BiH	28.2	14:04:54.1	Prijedor	Sisak	220	dist. prot. out-of-step protection
7	HOPS	28.3	14:04:54.2	Melina	Velebit	400	dist. prot. zone 3
8	TRANS	28.3	14:04:54.2	Mintia	Sibiu	400	distance prot. power swing cond.
9	HOPS	28.5	14:04:54.4	Brinje	Padene	220	dist. prot. zone 1
10	TRANS	28.6	14:04:54.5	Gădălin	Iernut	400	distance prot. power swing cond. zone 2 0.4 s
11	TRANS	28.7	14:04:54.6	Sibiu Sud	Iernut	400	dist. prot. zone 3 reverse 0.6 s
12	TRANS	28.7	14:04:54.6	Transf 400/220	Roşiori	400/220	dist. prot. power swing cond.
13	TRANS	42.6	14:05:08.5	Iernut	Câmpia Turzii	220	dist. prot. zone 2 power swing conditions
14	TRANS	42.7	14:05:08.6	Fântânele	Ungheni	220	dist. prot. zone 2 power swing conditions

Table 18: Sequence of events

The tripping of the first two elements (see sequence #1 and #2, the first 23 seconds), occurred in a situation of extremely high power flows of around 6.3 GW from the South-East area of the (CE) power system towards the North-West area. The flow of 6.3 GW results by summing up the individual active power flows at 14:00 over the fifteen transmission system elements which tripped. The initial tripping of the busbar coupler in Ernestinovo led initially to the redirecting of the busbar coupler flow through the 400/110 kV transformers in Ernestinovo which subsequently tripped as well, and then following that, to a shift in power flows to neighbouring transmission lines. In the course of the incident, the CE power system was subsequently split up in a cascading manner into two areas over an additional time frame of approximately 20 seconds.

It should be noted that this sequence of events reflects only the separations of transmission lines in the extra high voltage transmission system. In the parallel operated so-called sub-transmission system, around 15 additional lines at the 110 kV voltage level tripped and are not included in this table. They were disconnected automatically by their dedicated protection systems due to their operation in parallel with the transmission system.

Figure 13: Geographical location of main tripped transmission system elements

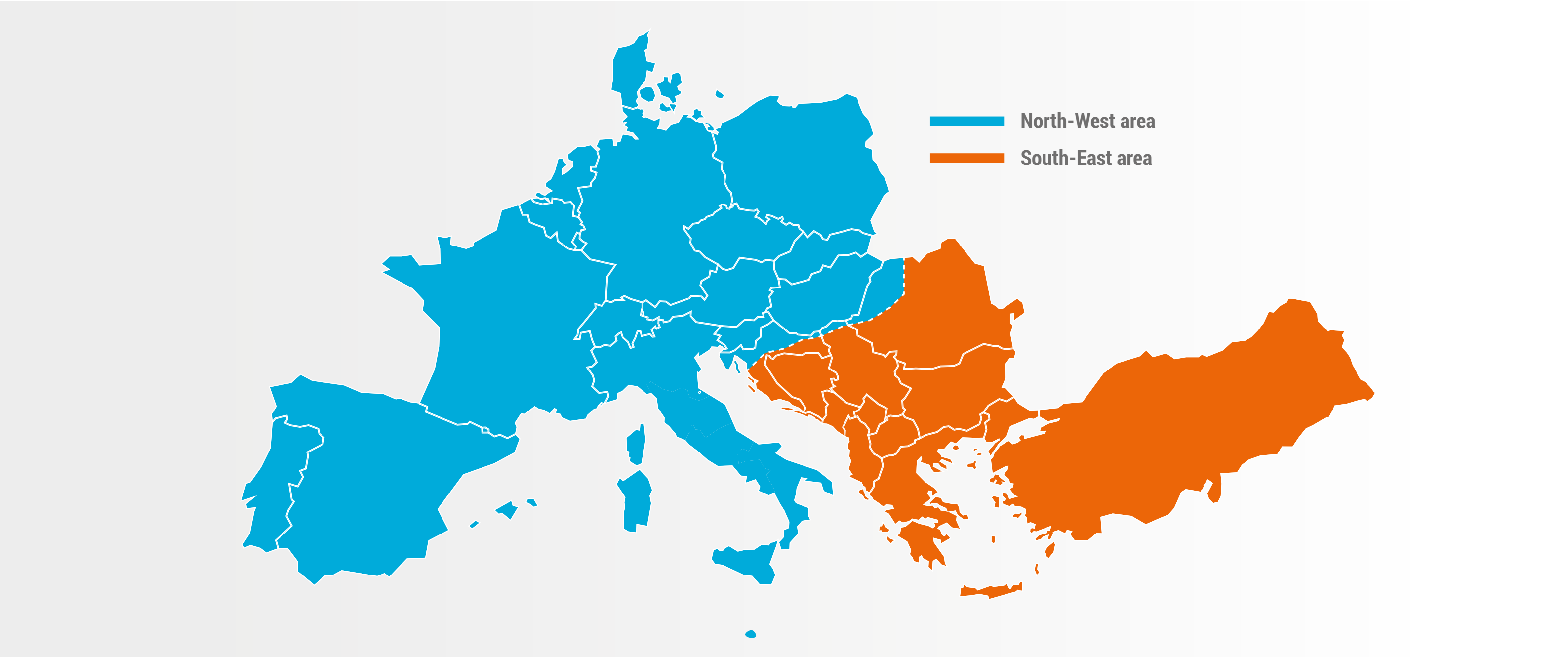


Figure 14: Resulting two synchronous areas after the system split

The exact locations of the tripped elements in the high voltage transmission system are depicted in figure 13.

It can be clearly seen that the resulting separation line crosses at least four European transmission system operators, namely HOPS, NOS BiH (Bosnia and Herzegovina), EMS and Transelectrica. As a result of the cascade, the CE power system was divided into two main areas. The corresponding resulting separation line is presented in figure 14.

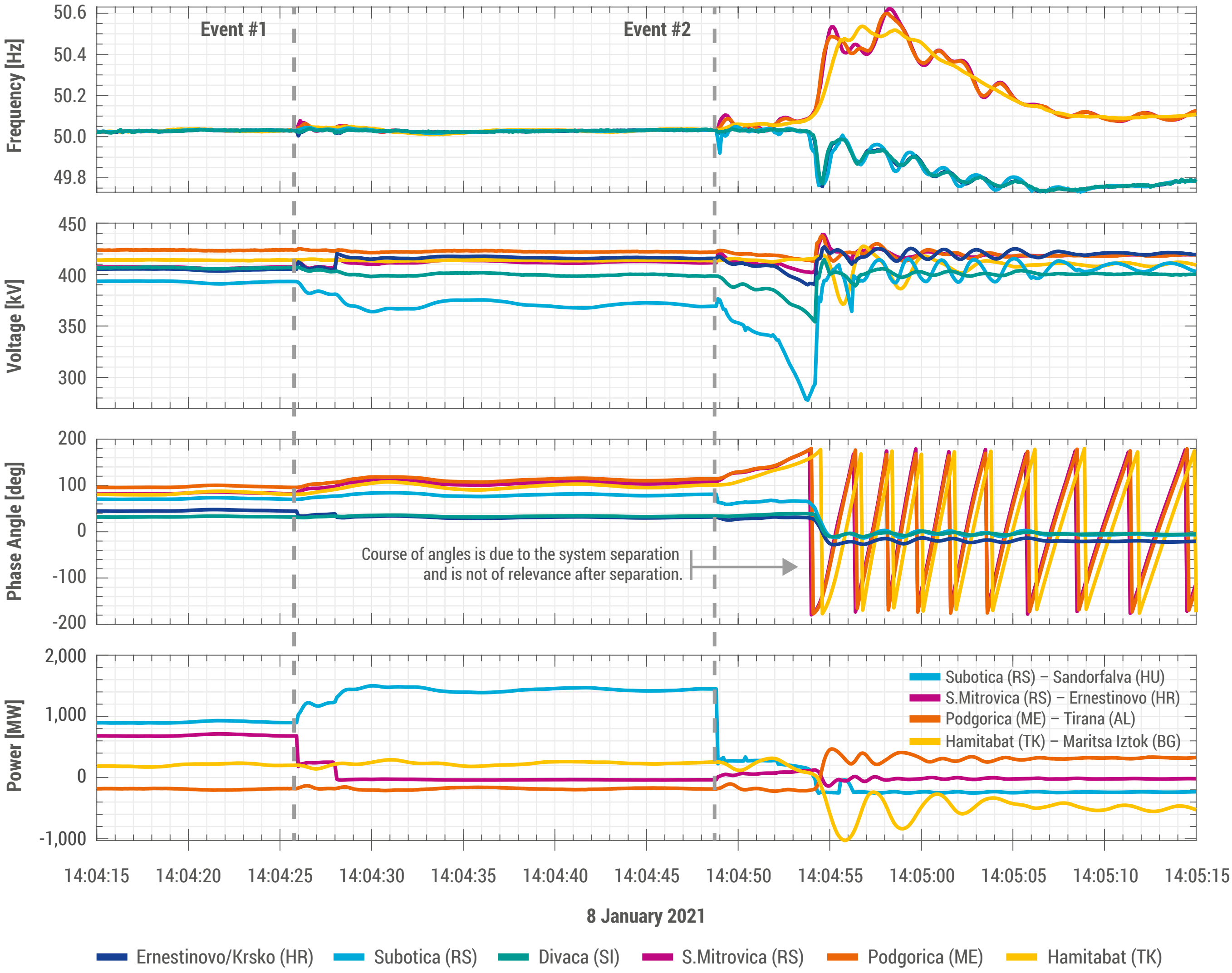


Figure 15: Frequencies, voltages, voltage phase angle difference and active power of selected transmission lines (reference for voltage phase angle difference is Lavorgo (CH) substation)

The phasor measurement unit (PMU) recordings included in figure15 explain how the separation took place. The colours of the graphs are related to the corresponding colours of the separated areas. By analysing the selected recordings in detail, it can be stated that:

- Based on the high east-west power flow, the phase angle differences show that before the first event the system was already operating close to the point of angular instability with voltage phase angle differences of close to 90 degrees between Western Europe (Switzerland) and Eastern Europe. After the separation of the two areas due to the asynchronous operation, a permanent voltage phase angle difference shift between the corresponding substations can be observed.

- The frequencies show that the opening of the busbar coupler in Ernestinovo substation at 14:04:25.9 (event #1) already had a visible impact on the overall system stability. The small oscillation stabilised before the overload of the second element.

- After the trip of the second element #2, namely the Subotica-Novi Sad transmission line at 14:04:48.9, the entire system reached the so-called "point of no return" and the two areas started to separate from each other due to angular instability.

- The separation phenomena were characterised by:

  - A very fast voltage collapse at all substations close to the line of separation,
  - Rapid increase of the voltage phase angle difference between the two areas, and
  - A gradual difference in the frequencies of the two areas – the frequency was increasing in the South-East area and decreasing in the North-West area.

This transient drove the system into two separate synchronous areas in which the South-East area was in overproduction and the North-West area suffered a power deficit. The effect of the unbalance is depicted in the frequency trends that show an overshoot in the South-East area and an underfrequency transient in the North-West area of the system. The very fast stabilisation of the system frequencies in both areas was achieved thanks the activation of several system protection schemes in both areas.

It should be noted that the classical transmission system protection devices separated the CE system into two areas by tripping line by line, thereby saving the system from more instabilities and related serious damage.

2.3.1 Activated system protection schemes

South-East area

The internal special protection scheme in Turkey in the Marmara region prevented an overload of the important Badirma-Bursa corridor by shedding 975 MW of power generation, which had fed power to the Turkish system over this corridor. A special protection scheme on the tie-lines that connect Turkey with Bulgaria and Greece was not activated and additional splitting of the network was avoided. The frequency in the South-East area increased with a RoCoF of 300 mHz/s and reached a maximum value of 50.6 Hz.

North-West area

After the electrical separation, the frequency decayed very fast, with a RoCoF of 60 mHz/s, and reached its minimum at 49.74 Hz. Here a further frequency decrease was stopped by the activation of the frequency-dependent French defence system (1,300 MW reacting at 49.82 Hz) and the frequency-dependent Italian defence plan (400 MW reacting at 49.75 Hz). Both systems disconnected industrial loads regulated by dedicated contract agreements.

The details of further automatic defence systems, such as the activation of frequency containment reserves or emergency control power delivered for example by the neighbouring DC-connected synchronous areas, which have also significantly helped to stabilise the two areas, are described in the next chapter.

2.4 System status and automatic defence actions in individual areas

2.4.1 Activation of frequency containment reserves

Due to the significant frequency deviation, all generation units which participated in the primary control either decreased (South-East) or increased (North-West) their power generation accordingly. In addition, by exceeding the 200 mHz limit, a high number of generation units changed their control mode to emergency control and contributed accordingly to the process of frequency stabilisation by either activating additional reserves in the North-West area or decreasing their generation in the South-East area. As an example, the following picture shows the almost perfect activation on 8 January of the Frequency Containment Reserve (FCR) of one provider in Austria. In the first graph it is visible how the active power output of the unit followed the frequency change. In the second graph each dot represents one working point of the unit. It is easy to conclude that the unit followed the agreed upon droop settings.

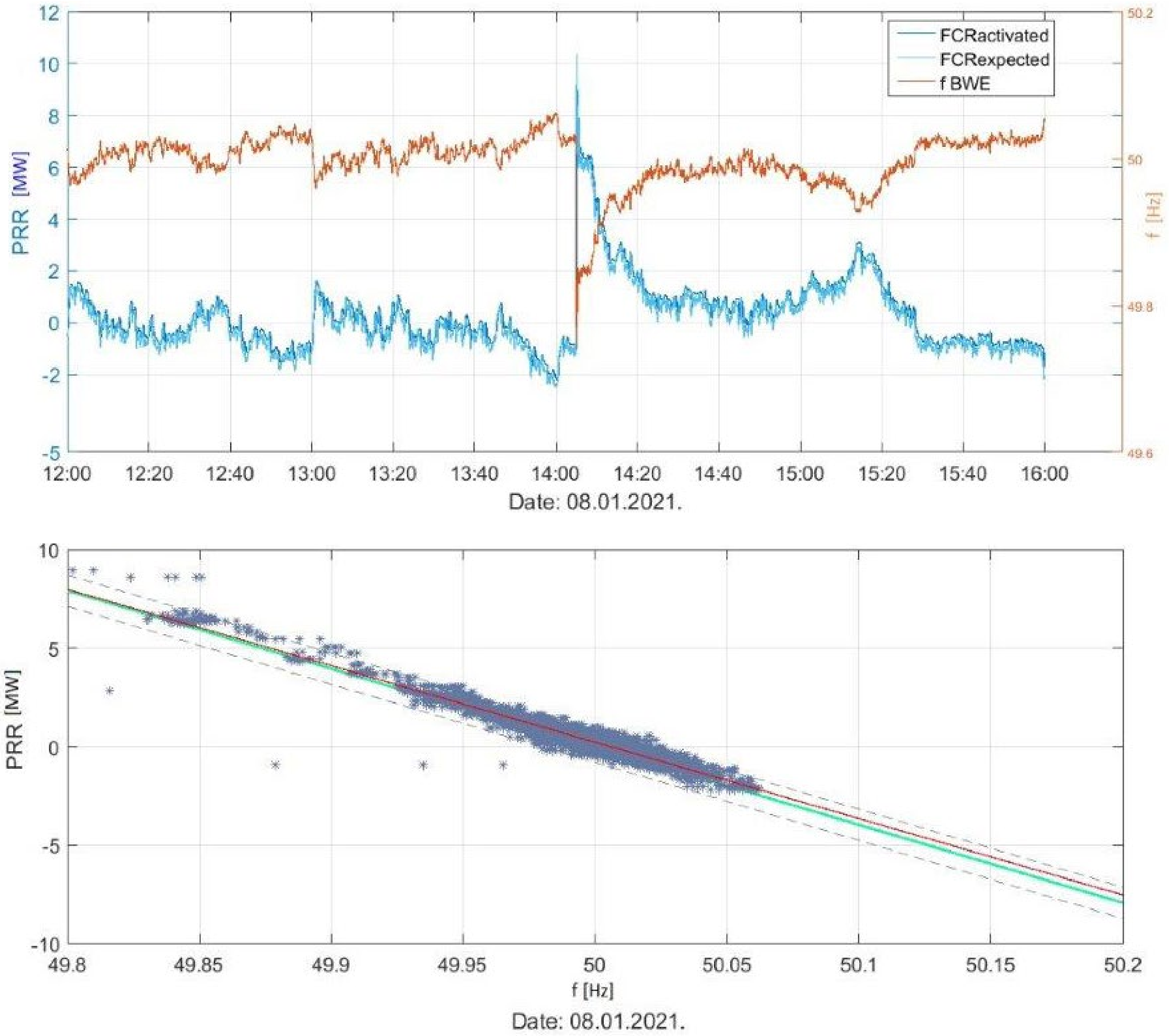


Figure 16: Activation of FCR – Provider in Austria

2.4.2 Activation of automatic Frequency Restoration Reserves

North-West area

Almost all LFC controllers in the North-West area remained in operation during the incident and helped the restoration of frequency. Some TSOs manually switched off LFC in order to additionally help frequency restoration. The triggering criteria for LFC controller freezing was not met (SAFA Annex 5 C-4) – the frequency drop was too short.

South-East area

There was no influence of automatic Frequency Restoration Reserves (aFRR), since the large number of TSO LFC controllers were switched off manually or automatically ended in Frozen Control Mode in accordance with SAFA Annex 5 C-4.

2.4.3. IGCC status

In the control areas which are part of the IGCC cooperation any occurring imbalances are netted within the possible limits. Therefore, the IGCC process avoids the activation of aFRR due to the netting process.

Theoretically a separation of the IGCC area could lead to a netting between two physically disconnected areas. Therefore, the imbalance would persist and no aFRR would be activated in both areas, even though this would be necessary.

The whole IGCC area was within the North-West area, except Croatia, which was partly separated due to the system separation. The impact of the separation of the part of Croatia on the rest of the IGCC area is still under investigation.

2.4.4 Supportive interruptible load

1.7 GW of automatic interruptible load in France and Italy were disconnected. In the following graph the disconnection of interruptible load in France is shown. The interruptible load in Italy was allowed to reconnect at 14:47 CET and in France at 14:48 CET.

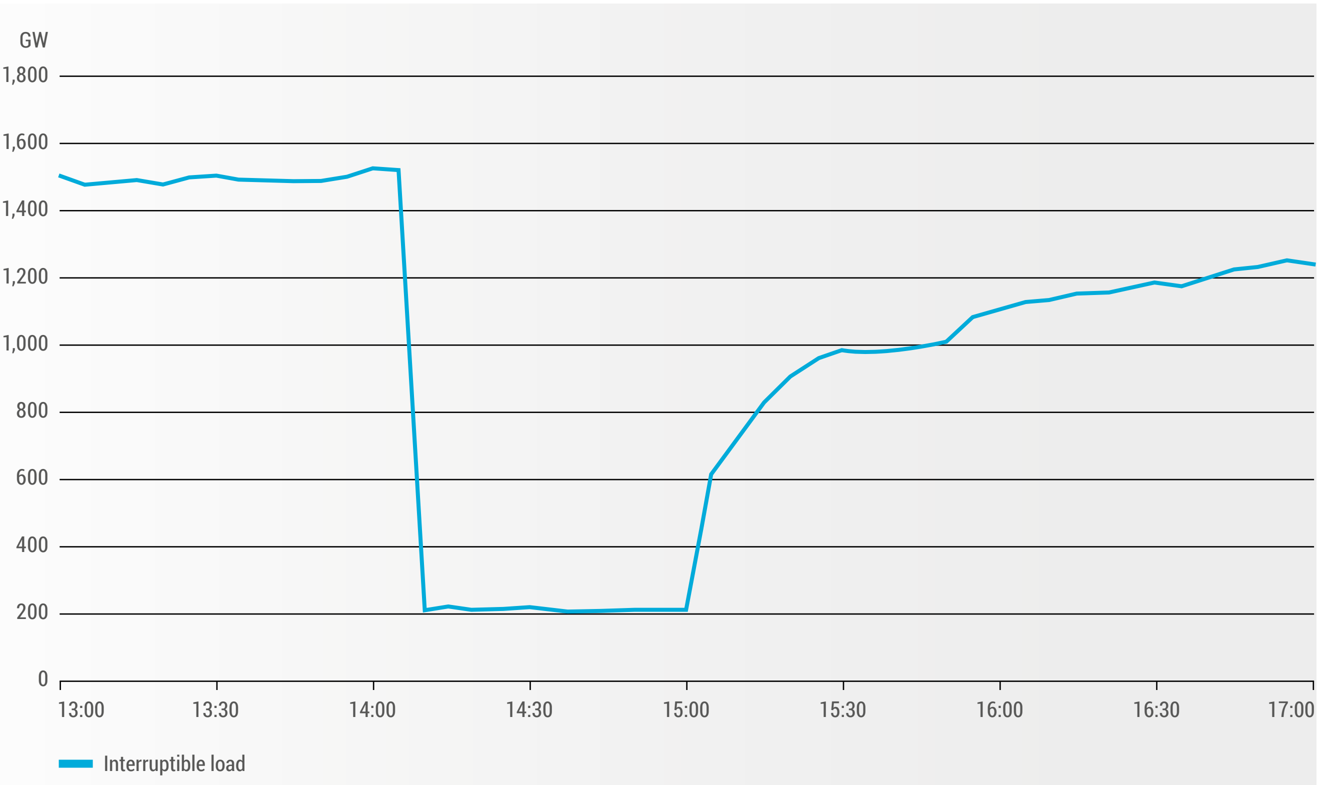


Figure 17: Interruptible service load activation in France

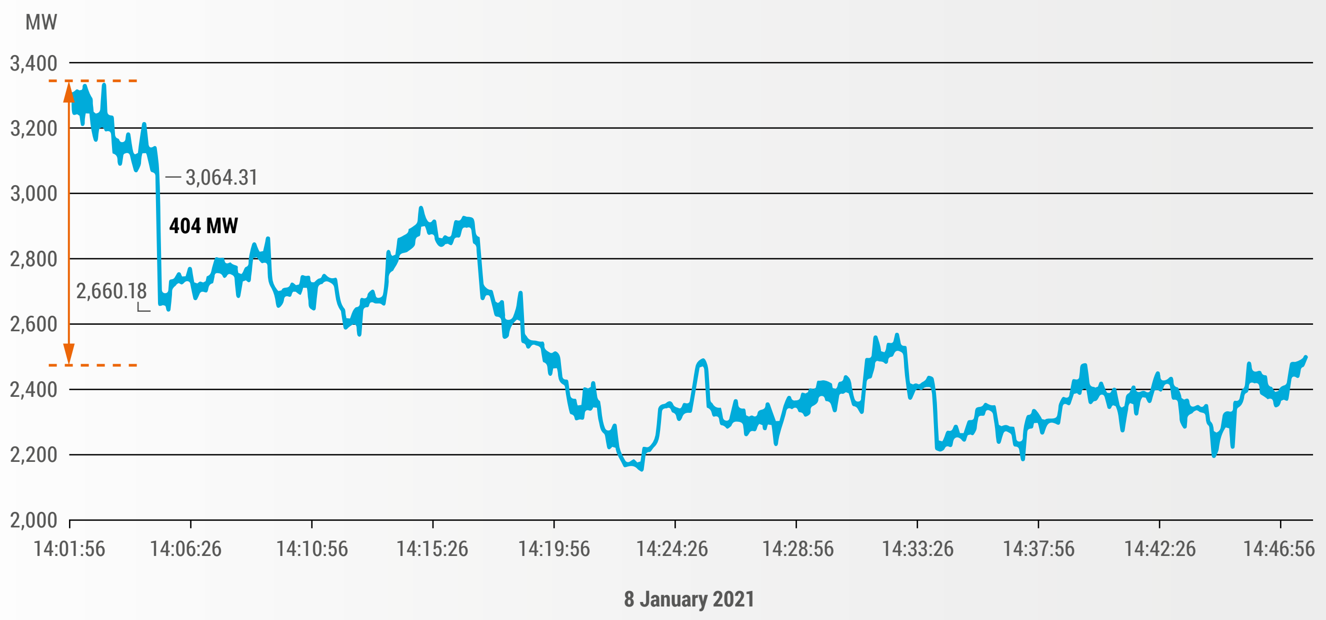


Figure 18: Interruptible service load activation in Italy

2.4.5 Disconnection of generation units or loads close to the separation line

Due to the high transients of voltage and frequency, a significant number of generation units and industrial or domestic loads were disconnected in both areas.

South-East area

Due to extreme voltage and frequency variations close to the separation line, approximately 1 GW of generation connected to the transmission system and 60 MW connected to the distribution system were disconnected. The total load tripped in the South-East area was 233 MW; mainly connected to substations close to the separation line and therefore tripped because of the high transients.

North-West area

Due to the close proximity to the separation line and because of the related high transients in voltage and frequency, 348 MW of generation tripped.

The total load disconnected in this area was 70 MW, while 36 MW was located close to the separation line and disconnected due to extreme transients. The other 34 MW tripped due to incorrect protection device settings.

2.4.6 Disconnection of non-conforming generation units or transmission elements

South-East area

Because of the over-frequency (in excess of 300 mHz), about 833 MW of non-conforming dispersed generation connected to the transmission system and 687 MW embedded in the distribution system tripped.

North-West area

Unfortunately, several automatic disconnections took place, even very far from the system separation line, based only on the system frequency deviations which were in both areas outside the normal operation range of +/- 200 mHz. Due to incorrect protection settings, another 296 MW of generation tripped far from the separation line and only based on the resulting 250 mHz frequency drop. Distributed generation with non-conforming disconnection settings (49.8 Hz) with a total of 295 MW tripped.

The loss of the HVDC link between Santa Llogaia (Spain) and Baixas (France) occurred due to an erroneous protection parametrisation of the auxiliary sources for a frequency threshold of 49.75 Hz. Coordinated countertrading between France and Spain was necessary to cope with the loss of interconnection capacity.

2.4.7 Support from other synchronous areas

Thanks to the frequency support over HVDC links, the North-West area received 535 MW of automatic supportive power from the Nordic synchronous area and 60 MW from Great Britain. The Nordic area helped from three directions: Skagerak (NO–DKW) with 270 MW, Kontiscan (SE–DKW) with 215 MW and Kontek (DKE–50Hz) with 50 MW. Figure 19 shows the change of power on the NEMO cable between the UK and Belgium.

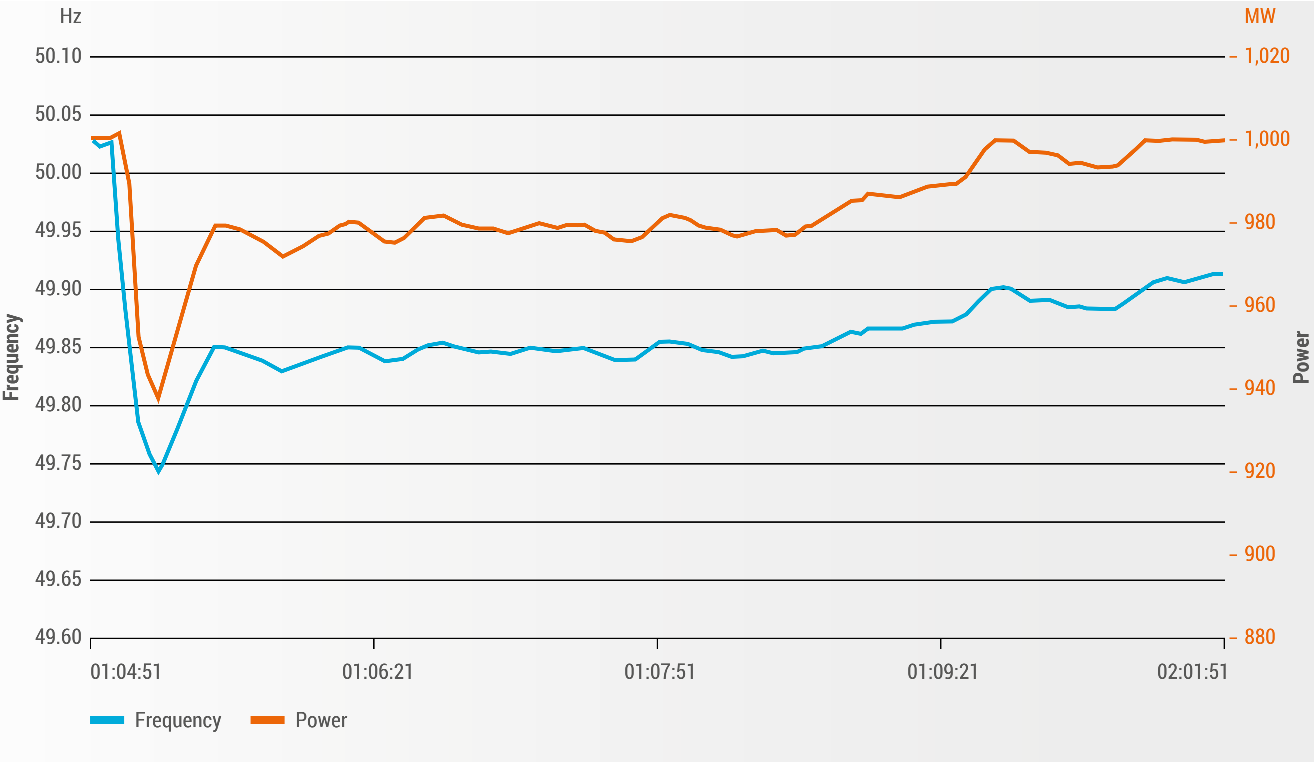


Figure 19: Frequency in the North-West area and active power on the NEMO HVDC link between the UK and Belgium

2.5 Manual countermeasures and system stabilisation in individual areas

During and following the event, several system states were activated by affected TSOs, which allowed all TSOs in Europe to become aware of the seriousness of the event (see table 19). In addition, the coordination centres set the alarms for frequency deviations, where CC North set the alarm for confirmation of the frequency deviation in North West Europe and CC South set the alarm for the frequency deviation in South-East Europe.

TSO	Country	Type of Alarm	Message(s) set	Reason
CC North	North & West Europe	alert (yellow)	• Frequency Degradation	• FRQ |df| > 100 mHz for t > 5 min
CC South	South-East Europe	emergency (red)	• Frequency Degradation	• FRQ |df| > 200 mHz
APG	Austria	alert (yellow)	• Frequency Degradation	• According to the EAS rules and methodology
ELES	Slovenia	alert (yellow)	• Frequency Degradation	• The frequency degradation which occurred after the system split. Other incidents were not detected at that time.
EMS	Serbia	emergency (red)	• Critical Event	• One of the criteria for activation of the message EMERGENCY is "system split – at least one asynchronous system involving more than 1 TSO"
HOPS	Croatia	alert (yellow)	• Flow Constraint • Voltage Constraint • Short-circuit Current Constraint	• Because of N-1 violation, flow constraint and frequency deviation • Very important to mention is that due to stressed situation NCC dispatchers did not have enough time to think about properly message EAS set
NOS	Bosnia Herzegovina	emergency (red)	• Frequency Degradation • Loss of Tools/Facilities • N Violation	• Frequency higher than 200 mHz • Video wall and workstation in dispatcher centre was disconnected • There is at least one violation (frequency) of a TSO's security limits with consequences on neighbouring TSOs, even after effects of Remedial Actions
OST	Albania	alert (yellow)	• Frequency Degradation	• The Dispatchers sent the message due to the first notification in SCADA System for over frequency. In OST power system we did not observe any other event following the frequency alarm
RTE	France	emergency (red)	• Frequency Degradation • Critical Event	• RTE activated the contracted industrial load disconnection service and were long by 3,500 MW on a voluntary basis to support the frequency of the North-Western Island. • RTE lost the HVDC with REE on frequency excursion.
Trans-electrica	Romania	emergency (red)	• Critical Event	• Based on the very complex impact and phenomena within the system (high frequency deviation + overloads & trips + voltage oscillations and power swings + split of the network + load & generation loss and real emergency situation, more than one condition from the emergency state definition was obtained

Table 19: EAS alarms in CE

According to the established procedures, EMS then acted as frequency leader in the separated South-East area to coordinate the return of the system to 50 Hz. This allowed the resynchronisation to take place as soon as possible. Amprion acted in the same manner as the frequency leader in the North-West area due to its role as SAM.

Each area subsequently took appropriate actions on its control means, mostly on the production side, to create a balanced area. The full details of these actions is still being collected during the current data collection phase. The following paragraph thus shows the information which is available at this stage.

2.5.1 North-West area and neighbouring synchronous areas

Frequency management

The Coordination Centres Amprion and Swissgrid in their role as SAM detected the frequency drop and the long lasting frequency deviation in the North-West Area. They informed all TSOs via the Frequency State traffic lights in EAS. Although the criteria for stage 2 of the "Extraordinary procedure for frequency monitoring and countermeasures in case of large steady-state frequency deviations" were not reached, Amprion as the frequency monitor in odd months, initiated the telephone conference between Swissgrid, RTE, Terna, REE and Amprion at 14:12 CET proactively. In the conference the situation was analysed and assessed. Information about incidents and already activated automatic measures were shared. Because the frequency in the North-West area was recovering and automatic measures such as FCR, aFRR and contractual load shedding in France and Italy appeared sufficient, the TSO came to the agreement that no further action was required to stabilise the frequency in the North-West area. The coordination centres decided to focus their investigations on the reasons for the system separation and to call the TSOs from the South-East area for more coordination. Furthermore, the Coordination Centre monitored the frequency in the North-West Area. They coordinated the successive withdrawal of measures and the return to normal state in the North-West Area. More details can be found in chapter 4.

Activation of production

Several TSOs applied measures (manual or automatic) regarding power generation units:

- CEPS: Defence service providing units (i.e. the majority of transmission-connected units and some distribution-connected type D units) switched to proportional speed control at 14:05:03–14:05:05. Their active power output followed the frequency.
- Amprion: Several hydropower plants synchronised between 14:05 and 14:07 for frequency restoration.
- CEPS returned units to active power control at their scheduled active power output between 14:29 and 14:39.
- Elia performed incremental bids to make sure that the system imbalance was positive.
- RTE delayed a late request for disconnection of one nuclear unit (Saint Alban), started all the French gas/oil turbines (800 MW) and pushed up some hydrogeneration to boost its balance upward by 3,500 MW for one hour.
- Terna supported the quick restoration of normal frequency values in continental Europe.
- APG (Austria) activated reserves manually to stabilise the frequency. Altogether 564 MW contributed (ordered at 14:06 CET, activated at 14:15 CET).
- Transelectrica: After the system separation at 14:05 CET, an amount of 739 MW of reserves were activated in the North-West area to restore the frequency:
  - 141 MW of the production units (three HPP units) that tripped at 14:05 and have been restarted after the incident (the rest of 207.2 MW out of 348.2 MW that were tripped in the North-West area could not be restarted);
  - 598 MW of other production units that were not in operation but were started after the two areas separated.

Reconnection of load

Interruptible load was allowed to reconnect at 14:47 CET in Italy and at 14:48 CET in France. A total load of 27.9 MW was successfully resupplied between 14:28–16:00 CET in the Romanian power system. Furthermore, there were some consumers which remained connected to the grid but affected in their business due to the significant changes in operational parameters.

Countertrading/measures in the market

Furthermore, the following measures regarding market activities were applied by the TSOs:

- RTE and REE reported at 14:12 h that coordinated countertrading, approx. 1,400 MW, was activated to avoid overloading 400 kV line Vic-Baixas after the loss of the HVDC link. For that:
  - REE increased production
  - RTE decreased production

2.5.2 South-East area and neighbouring synchronous areas

Activation of production

The following TSOs applied countermeasures regarding the power generation units in their area:

- EMS: At 14:38 HPP Djerdap reduced power by 300 MW (endangered security of the power system); at 15:05 HPP Djerdap reduced power by 175 MW (endangered security of the power system),
- NOSBiH excluded production manually in the amount of 350 MW (14:26 CET: -58 MW, 14:41 CET: -145 MW, 14:54 CET: -135 MW),
- IPTO (Greece) called EMS at 14:16 CET. Due to the fact that the frequency was higher than maximum steady-state frequency deviation, dispatchers agreed that the production of power plants in their control areas should be reduced in a coordinated manner,
- After the call with IPTO, EMS also asked ESO EAD, Transelectrica and TEIAS (Turkey) to reduce the production of power plants in the separated island with over-frequency, and
- HOPS prepared the network for resynchronisation by switching on more generation units (increase of rotating reserve), but the total amount of production reduction was about 300 MW at the time of resynchronisation.
- Transelectrica: Reserves of 1,288 MW were activated in the downward direction in the South-East area to restore the frequency.

Actions on grid topology and reconnection of grid elements

EMS reconnected the 100kV OHLs that were tripped during the event.

Reconnection of load

A total load of 162.9 MW was successfully resupplied between 14:21–16:30 CET by Transelectrica. Furthermore, there were some consumers which remained connected to the grid but had their business affected because of the significant changes in operational parameters.

Measures on the market

After taking note that the loads on the transmission lines Ernestinovo – Ugljevik and Ernestinovo – S. Mitrovica 2 were almost the same as before the disturbance, in coordination with CGES and Terna, the program on the Monita DC-link was changed in order to improve the stabilisation of the system after resynchronisation.

3 RESYNCHRONISATION PROCESS

3.1 Preconditions for system resynchronisation

Thanks to the EAS, TSOs received information a short time after the disturbance that the Continental Synchronous Area had separated into two areas (Figure 20).

The control areas with an overfrequency are highlighted in red. A separate island with the TSOs HOPS, Transelectrica, NOSBIH, EMS, ESO, MEPSO, OST and IPTO can be identified (as can be observed from the frequencies, the colouring of OST is not correct in the figure because of an issue in the data handling failure in EAS).

More detailed information was available to the TSOs through WAMS (Figure 21) and SCADA/EMS.

Figure 20: EAS overview of the Continental Europe Synchronous Area

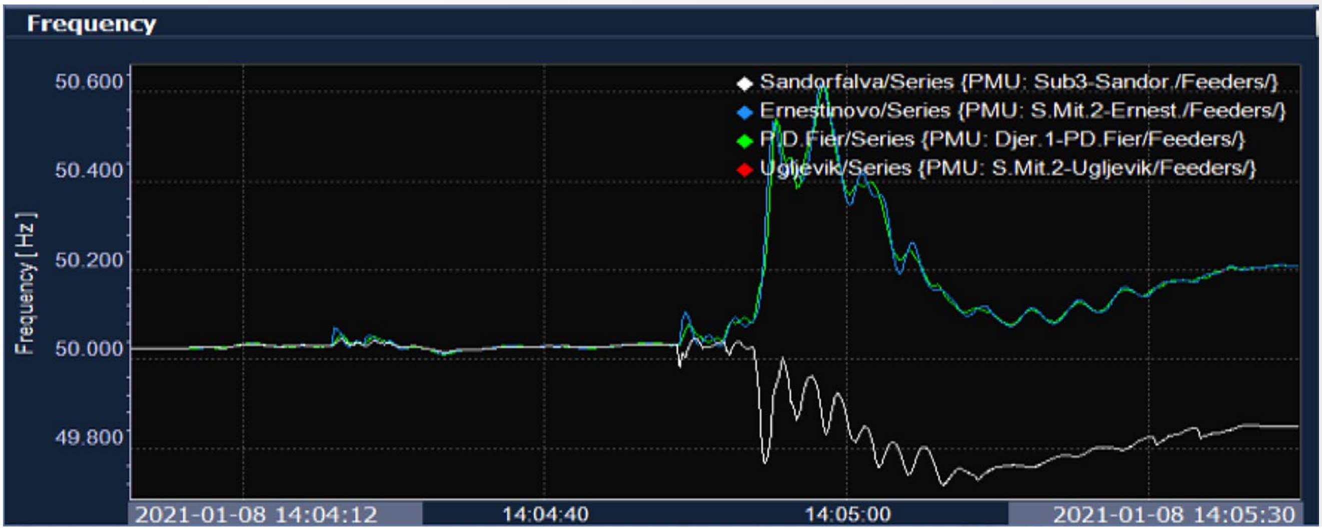


Figure 21: Frequency recording for Continental Synchronous Area at the moment of separation

The TSOs of the South-East area (EMS, HOPS, NOSBiH, MAVIR, ESO EAD, IPTO and Transelectrica) had a phone call with a briefing about every TSO system state. Affected TSOs (EMS, HOPS, NOSBiH, and Transelectrica) exchanged information about tripped elements in their networks in order to determine the line where the two parts of the Continental Synchronous Area had separated.

After the system separation, the South-East area had a high frequency, which was stabilised between 50.2 Hz and 50.3 Hz. The system operation of Transelectrica was largely influenced (significant challenges in both transmission and distribution grids, especially because the grid had to be operated for the two separated areas), and Transelectrica could not comply with the resynchronisation leader condition. Consequently, frequency regulation was done with the coordination of EMS with all the other TSOs in the South-East area. EMS agreed with ESO EAD, IPTO, HOPS, NOSBiH and Transelectrica to reduce the production of their power plants (Transelectrica did this just in the higher frequency part of the grid). Furthermore, EMS asked ESO EAD if they could call TEIAS to also decrease their production. TEIAS agreed and reduced their production.

The North-West area had a low frequency, which was stabilised around 49.96 Hz. Resynchronisation actions were performed in the networks of HOPS in Croatia, EMS in Serbia, NOSBiH in Bosnia and Hercegovina and Transelectrica in Romania.

The actions which allowed the resynchronisation can be grouped into the following phases:

› Preparatory actions

› Resynchronisation sequences

3.2 Preparatory actions

EMS, HOPS, and NOSBiH agreed during a conference call to the plan for resynchronisation as follows:

› To wait until the frequency difference between the areas is less than 100 mHz and shows a decreasing trend,

› To make three strong reconnection points connect in a short time,

› The first reconnection point would be a busbar coupler 400 kV in SS Ernestinovo (the busbar coupler in Ernestinovo has a synchro-check device and is more or less in the middle of the split line),

› The second reconnection point would be OHL 400 kV Novi Sad 3 – Subotica 3 (which is more or less in the middle of the split line, as well, providing a second strong connection in relatively small area),

› The third reconnection point would be OHL 400 kV Konjsko – Velebit (last tripped 400 kV connection in HOPS),

› To connect other the tripped OHLs in Transelectrica, HOPS, NOSBiH and EMS.

3.3 Resynchronisation sequences

To ensure the success of the resynchronisation plan, EMS and HOPS kept an open line during the resynchronisation sequences of the first three points. Thereafter, one EMS dispatcher was on the line with the HOPS dispatcher, the second EMS dispatcher was in communication with SS Novi Sad 3, and the third was on the line with the Transelectrica dispatcher. The resynchronisation sequences are listed below:

1. The busbar coupler 400kV in Ernestinovo (HR) was switched on at 15:07:25,
2. Immediately after confirmation that the first step was successful, OHL 400 kV Novi Sad 3 (RS) – Subotica 3 (RS) was switched on at 15:08:20,
3. Immediately after confirmation that the second step was successful, OHL 400 kV Konjsko (HR) – Velebit (HR) was switched on at 15:09:38,
4. Transelectrica was informed that EMS, NOS BIH and HOPS had made reconnections, so the internal line connection in Transelectrica could be started,
5. Transelectrica switched on OHL 400 kV Sibiu Sud – Mintia at 15:10, and afterward, OHLs 400 kV Iernut – Sibiu Sud & 400 kV Iernut – Gădălin at 15:12,
6. HOPS and NOSBiH switched on other tripped lines:
   - 220 kV Brinje (HR) – Pađene (HR) switched on at 15:12
   - 220 kV Sisak (HR) – Prijedor (BA) switched on at 15:14
   - 220 kV Međurić (HR) – Prijedor (BA) switched on at 15:15,
7. Transelectrica proceeded to reconnect the rest of the tripped lines and transformers:
   - 220 kV Iernut – Baia Mare 3 at 15:16
   - 220 kV Iernut – Câmpia Turzii at 15:17
   - 220 kV Târgu Jiu Nord – Paroșeni at 15:17
   - 220 kV Reșița – Timișoara 1 at 15:19
   - AT 400 MVA – 400/220 kV Roșiori at 15:23,
8. EMS and HOPS proceeded to reconnect the tripped 110 kV OHLs.

Around 15:50 on the transmission lines, large loads of 400kV Ernestinovo – Ugljevik and 400 kV Sremska Mitrovica 2 – Ernestinovo were observed, which were almost the same as before the disturbance. The level of the DC Link Monita was then changed in the CGES – Terna direction from 100 MW to 600 MW at 16:10 in coordination with Balcan TSOs and TERNA.

After this coordinated action, there was a change in power flow on the tie-lines between EMS – HOPS and EMS – NOSBiH: 400 kV Sremska Mitrovica 2 – Ernestinovo (from approximately 700 MW to 600 MW) and NOSBiH – HOPS 400 kV Ugljevik – Enestinovo (from approximately 740 MW to 630 MW).

The frequency in continental Europe during the resynchronisation process based on the WAMS measurement of frequencies in the split areas (each measurement point with exact GPS time stamp, 50 msec resolution) is presented in figure 22 (frequency recording for North–West and South-East areas during resynchronisation at two points).

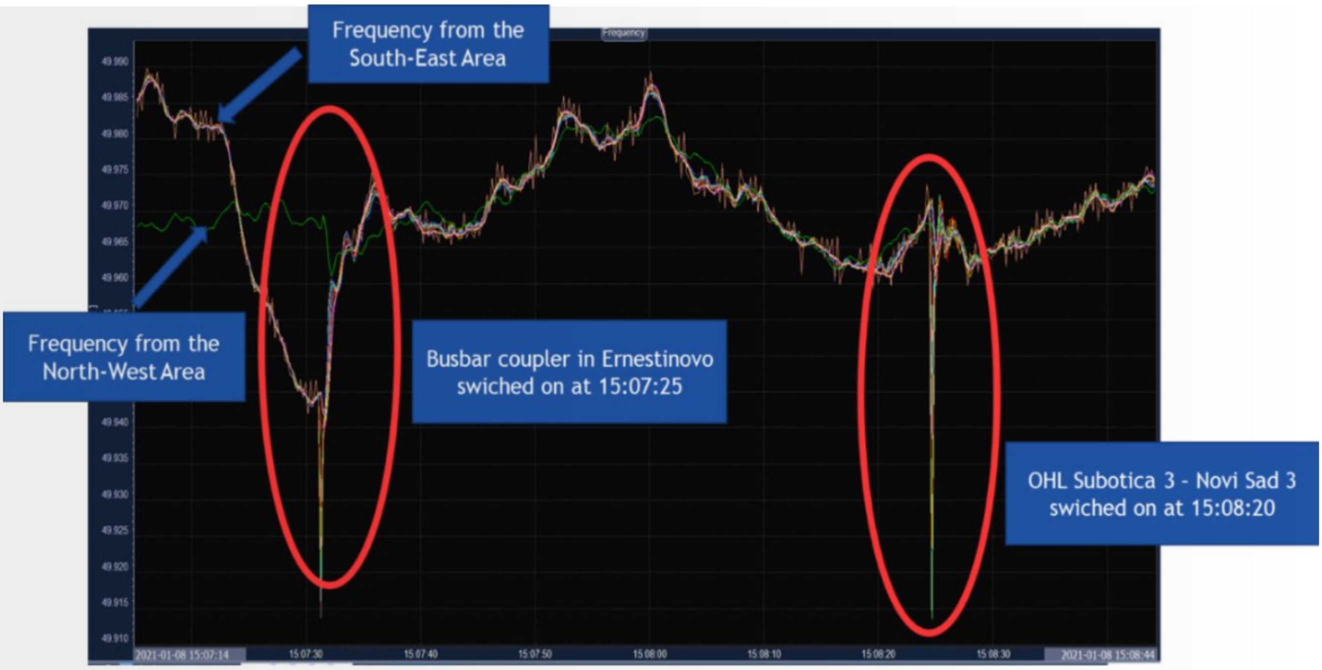


Figure 22: Frequency recording for North-West and South-East areas during resynchronisation at two points

4 COMMUNICATION OF COORDINATION CENTERS/ SAM AND BETWEEN TSOs

4.1 Between North and South Coordination Centres and the affected TSOs

8 January, 14:05 CET:
The system separation caused large steady-state frequency deviations within the two disconnected islands of the Continental Synchronous Area. In the North-West area the frequency dropped from 50.02 Hz to 49.74 Hz, while the frequency in the South-East area jumped to 50.6 Hz. The frequency deviations were detected by the local LFC-systems of the coordination centres (CC) Amprion (CC North) and Swissgrid (CC South). For CC South the "Emergency State" and the predefined message "Frequency deviation | Δf | > 200 mHz" was set automatically in the EAS.

8 January, 14:06 CET:
During a phone call between the coordination centres, the frequency drop was verified and the first common analyses were started based on information from EAS. At this moment the frequency deviation in the North-West area had decreased to 160 mHz under-frequency. EAS provided the following indications:

- High ACE value of IPTO – (Change from +50 MW » -1,950 MW)
- High ACE value of REE » -1,267 MW
- Temporary high ACE sum-values for CC North and CC South

Based on this information, the coordination centres called REE and IPTO to ask for more information. REE reported the disconnection of HVDC interconnectors between RTE and REE.

Additionally, Terna informed Swissgrid via phone that the contractual load had been automatically disconnected.

8 January, 14:10 CET:
The trigger for Stage 1 of the CE Extraordinary Procedure was reached (Frequency deviation |Δf| > 100mHz for a time period t > 5min). For CC North the "Alert State" and the predefined message "Frequency deviation | Δf | > 100 mHz for t > 5 min" was set automatically in EAS.

Due to the results of the common analysis and the critical nature of the situation, the CCs decided to launch Stage 2 of the CE Extraordinary Procedure proactively.

8 January, 14:12 CET:
Amprion, as the responsible frequency monitor in odd months, activated the "extraordinary procedure" (50/100 mHz-procedure) Stage 2 phone conference with the involved TSOs (Amprion, Swissgrid, RTE, Terna, and REE).

The TSOs shared the following available information:

- Amprion reported the frequency drop, the trigger for the CE extraordinary procedure and results of the first short analysis,
- RTE and Terna reported a contractual load shedding of 1,300 MW in France and contractual load shedding in Italy,
- REE confirmed HVDC disconnection between RTE and REE,
- RTE and REE reported that coordinated countertrading, approx. 1,400 MW, was activated to avoid overloading the 400 kV line Vic-Baixas after the loss of the HVDC link between Santa Llogaia (Spain) and Baixas (France). For that:
  - REE increased production
  - RTE decreased production

During the call, the CCs detected the probable system separation on the EAS frequency map. A separate island with the TSOs HOPS, Transelectrica, NOSBIH, EMS, ESO, MEPSO, OST and IPTO was indicated.

Due to the fact that the frequency deviation in the North-West area was decreased by primary control FCR and other automatic measures like contractual load shedding and aFRR activation to less than 50 mHz and was still recovering, the 5 TSOs decided that at that moment no further measures were necessary to stabilize the frequency in the North-West area.

The coordination centres decided to focus their investigations on the reasons for the system separation and to call the TSOs from the South-East area.

In parallel, APG called Amprion grid engineer and informed that APG activated reserves and modified LFC to support the frequency.

8 January, 14:29 CET – 14:35 CET:

Swissgrid called IPTO. The TSO confirmed the grid separation of the South-East area. At this time, the cause was estimated to be in the grid of Transelectrica.

Amprion called Transelectrica. Due to the fact that the split went through the grid of Transelectrica, the control centre of the TSO was very busy troubleshooting and the responsible dispatchers were not able to answer the call. Hence a call back was agreed.

Swissgrid called EMS. The TSO also confirmed the system separation in the area of Serbia and Romania and reported production shedding due to over-frequency.

The coordination centres kept in touch and shared all relevant information via phone.

8 January, approx. 14:40 CET:

In a phone call between Amprion and APG, Amprion reported the system split and the results of the 50/100 mHz-procedure phone conference.

8 January, 14:43 CET – 14:51 CET:

The coordination centres had several phone calls together and with Terna and RTE. The high ACE of RTE (approximately 3500 MW), due to compensation measures for HVDC tripping and due to contractual load shedding and the upcoming hour schedule change in France, was discussed. As the frequency had recovered and was very close to 50 Hz, the CCs agreed that RTE and Terna should start reconnecting the disconnected contractual load in 300 MW steps and that RTE should adjust the production in coordination with REE, which was adapted due to the tripping of the HVDC connection. The coordination centres would monitor the development of the frequency and contact the TSOs in case of degradation.

8 January, 14:51 CET – 15:06 CET:

The coordination centres tried to get more information about the system separation and the activities in the South-East area. In addition, they wanted to push the reconnection of the HVDC links between RTE and REE and to insure that production adjustments at RTE and REE did not lead to errors in load frequency control.

Amprion called ESO and Transelectrica. ESO provided further information about the system separation. The cause was estimated by ESO operators in Romania.

Swissgrid called REE to ask for the status of the HVDC interconnection and ensured that REE and RTE were aware that the production adjustment had to be considered in the balance calculations. REE informed Swissgrid that the reconnection of the HVDC interconnectors was planned shortly. Swissgrid gave REE the task of pushing the reconnection of the HVDC interconnector forward and going back to the initial production plan with RTE as soon as possible.

8 January, 15:08 CET:
The coordination centres got in touch and monitored the resynchronisation of the South-East area with the North-West area in EAS and their local LFC Systems. After the successful resynchronisation the CCs decided to contact the control areas with the highest ACE values (imbalances) in EAS (RTE, EMS and ELES) and to initiate the return to the original production plans and exchange programs.

8 January, 15:11 CET – 15:23 CET:
Swissgrid had several phone calls with TSOs in the CC-South area (RTE, EMS and ELES). In the calls, information about resynchronisation was shared, and Swissgrid gave the TSOs the task of recovering the lost production, reducing imbalances and returning to original production plans and exchange programs. RTE was also requested to proceed with the reconnection of the HVDC interconnectors.

8 January, 15:27 CET – 15:31 CET:
Amprion had phone calls with MAVIR and Transelectrica and attempted to get more detailed information about the system separation, the resynchronisation and the current situation in the grid of the TSOs. Transelectrica deployed actions and measures to supply the lost load and recover the right generation schedule.

8 January, 15:47 CET:
Swissgrid again contacted RTE to ask for the status of the HVDC interconnectors and current production. RTE reported that they had returned to their original production plan, but the process of reconnecting the HVDC interconnector with REE was still ongoing. Amprion contacted APG and asked them to deactivate mFRR which was activated from APG to support the frequency.

8 January, 16:15 CET:

Amprion as responsible frequency monitor activated the "extraordinary procedure" (50/100 mHz-procedure) Stage 2 phone conference with the involved TSOs (Amprion, Swissgrid, RTE, Terna, and REE). The conference was used to report the current status of the CE transmission system. The CCs reported on the successful resynchronisation, relayed that the situation had relaxed and that all TSOs were back in their normal state. The TSOs confirmed the normalised status. RTE and REE reported that the HVDC interconnector between France and Spain was still out of service but that the reconnection process was ongoing. Amprion distributed a final report to the involved TSOs.

In the afternoon, Amprion sent a management information report via email to the ENTSO-E bodies RG CE Plenary, SOC and CSO SG.

4.2 Between affected TSOs in the South-East area and the border region

Information has only been provided by HOPS and EMS, while Transelectrica is still collecting data to be provided.

8 January, 14:05 CET:
The operators of EMS observed a tripping of two overhead lines between two 400 kV/110 kV substations due to overcurrent protection and an outage of a power plant (400 MW). The Wide Area Monitoring System (WAMS) indicated a high frequency deviation and islanding alarms were displayed. WAMS frequency measurements for two 400 kV/110 kV substations deviated from other frequency measurements in the EMS grid.

At the same time, in the control room of HOPS, investigations began after the tripping of several elements in the grid of HOPS.

8 January, 14:08 CET – 14:15 CET:
EMS called HOPS: Both TSOs confirmed a system separation. By considering data from SCADA/EMS, WAMS and EAS, the points of separation were assumed to be in the grids of the TSOs HOPS, EMS, Transelectrica and NOS BIH.

After the call, HOPS informed NOS BIH and ELES while EMS called MAVIR to inform them about the system separation and that two EMS substations were only supplied by the grid of MAVIR.

ESO EAD informed EMS that the cause of the grid separation was estimated to be in the Romanian TSO (due to the outage of eight power lines in the grid of Transelectrica).

EMS called Transelectrica. The control centre of Transelectrica was unable to answer because they were extremely busy with the sudden situation in their grid.

8 January, 14:16 CET – 14:48 CET:

Swissgrid called EMS. EMS confirmed the system separation, and that Romania reported on the production shedding due to over-frequency.

IPTO called EMS. Due to the fact that the frequency was higher than maximum steady-state frequency deviation, dispatchers agreed that they should coordinate to reduce the production of power plants in their control areas.

After the call with IPTO, EMS also asked ESO EAD, Transelectrica and TEIAS to continue to reduce the production of power plants in the separated island with over-frequency.

The power system operators (IPTO, ESO, HOPS, Transelectrica, CGES, NOSBiH) kept in touch and shared all relevant information.

In alignment with NOSBiH and EMS, HOPS shared a resynchronisation strategy in which, after a successful attempt, EMS would make a reconnection to MAVIR, and, along with NOSBiH, would try to align the frequency to meet resynchronisation parameters.

8 January, 14:55 CET – 15:04 CET:

The power system operators agreed that the reconnection of grid separation should be done by switching on the 400 kV busbar coupler in SS Ernestinovo (HOPS), when the frequencies in both islands had approximated and were stable.

8 January, 15:06 CET:

When conditions were met (the frequencies of the two islands approached each other), HOPS switched on the busbar coupler in SS Ernestinovo, and immediately afterwards EMS switched on the 400 kV OHL, and the connections with MAVIR were restored. Then, the South-East area reconnected with the North-West area. After a successful reconnection in substation Ernestinovo, HOPS relayed news of the successful reconnection to EMS and initiated the immediate reconnection of OHL 400 kV Velebit – Konjsko.

At the same time, EMS informed Transelectrica of the reconnections. Transelectrica started reconnecting transmission lines in their grid. After the resynchronisation and stabilisation of the system, the power system operators increased the production of the power plants in their grid to bring ACE values into desirable limits.

Afterwards, HOPS agreed with NOSBiH that the reconnection was stable enough to continue with the 220 kV reconnection of 220 OHL interconnectors in substation Prijedor (NOSBiH).

Due to high flow perseverance in a northern direction, the OHL interconnector with MAVIR (Ernestinovo – Pecs 2) was switched on with MAVIR alignment.

Swissgrid (CC-South) called EMS. EMS shared information about the successful resynchronisation. Swissgrid assigned EMS to recover the lost production, reduce imbalances and return to the original production plans and exchange programs.

8 January, 14:15 CET – 16:10 CET:

During the event, EMS, HOPS and NOSBiH had three conference calls for information and coordination:

First call, around 14:20 CET:

- Frequency regulation of all TSOs in the South East area in coordination with EMS,
- Reconnection of three points in the shortest possible time (busbar coupler 400kV in SS Ernestinovo, OHL 400 kV SS N. Sad 3 – SS Subotica 3, and OHL 400 kV SS Konjsko – SS Velebit).

Second call, around 15:15 CET:

- Confirmed successful resynchronisation.

Third call, around 15:50 CET:

- After taking note that the loads on the transmission lines Ernestinovo – Ugljevik and Ernestinovo – S. Mitrovica 2 were almost the same as before the disturbance, in coordination with CGES and Terna, the program on the Monita DC-link was changed in order to improve the stabilisation of the system after resynchronisation.

5 CLASSIFICATION OF THE INCIDENT BASED ON THE ICS METHODOLOGY

Regarding the valid legal framework, i.e. the System Operation Guideline (SO GL), a check has been performed regarding the classification of the incident according to the Incident Classification Scale (ICS) methodology. The following analysis was performed based on the sequence of events that are known so far.

5.1 Analysis of the incident

The event started with flows that were higher than had been foreseen in the grid models. This higher flow resulted in an N-state overload on the busbar coupler of Ernestinovo. This is an ON2 according to the ICS classification. The reason for this classification is that there was at least one wide area deviation from operational security limits after the activation of curative remedial action(s) in N situation.

The overloaded busbar tripped, and thereafter several other network elements also tripped. This is a T2 according to the ICS classification. This criterion was reached because there was at least one wide area deviation from operational security limits after the activation of curative remedial action(s) in N situation. There were also wide area consequences on the regional or synchronous area level, resulting in the need to activate at least one measure of the system defence plan.

The cascading of several line trips led to the system split. This is an RS2 according to the ICS classification. This criterion was reached because the separation from the grid involved more than one TSO and because at least one of the split synchronised regions had a load larger than 5% of the total load before the incident.

The splitting of the grid led to a region with over frequency and a region with under frequency. In the region with under frequency, the deviation of more than 200 mHz lasted less than 30 seconds. In the over frequency region, the deviation of more than 200 mHz lasted more than 30 seconds. This is an F2 according to the ICS classification. The criterion for an F2 was reached because there was an incident leading to frequency degradation (200 mHz for more than 30 seconds).

Regarding the voltage deviations, only OV1 (scale 1 violation of standards on voltage) were reported.

As a consequence of the events, the only loss of load reported so far was in the area of Transelectrica. The loss of load was about 190.8 MW, which was more than 1 % and less than 10 % of the load in the TSO's control area, resulting in an L1 (scale 1 incident on load).

5.2 Classification of the incidents

The priority of each criterion is shown in table 20 with a number from 1 to 27, where 1 marks the criterion with highest priority and 27 marks the criterion with lowest priority. When an incident meets several criteria, the incident is classified according to the criterion that has the highest priority; however, information regarding all sub criteria are also collected.

Scale 0 Noteworthy incident	Scale 1 Significant incident	Scale 2 Extensive incident	Scale 3 Major incident / 1TSO
Priority/Short definition (Criterion short code)	Priority/Short definition (Criterion short code)	Priority/Short definition (Criterion short code)	Priority/Short definition (Criterion short code)
#20 Incidents on load (L0)	**#11** Incidents on load (L1)	**#2** Incidents on load (L2)	**#1** Blackout (OB3)
#21 Incidents leading to frequency degradation (F0)	**#12** Incidents leading to frequency degradation (F1)	**#3** Incidents leading to frequency degradation (F2)	
#22 Incidents on transmission network elements (T0)	**#13** Incidents on transmission network elements (T1)	**#4** Incidents on transmission network elements (T2)	
#23 Incidents on power generating facilities (G0)	**#14** Incidents on power generating facilities (G1)	**#5** Incidents on power generating facilities (G2)	
	#15 N-1 violation (ON1)	**#6** N violation (ON2)	
#24 Separation from the grid (RS0)	**#16** Separation from the grid (RS1)	**#7** Separation from the grid (RS2)	
#25 Violation of standards on voltage (OV0)	**#17** Violation of standards on voltage (OV1)	**#8** Violation of standards on voltage (OV2)	
#26 Reduction of reserve capacity (RRC0)	**#18** Reduction of reserve capacity (RRC1)	**#9** Reduction of reserve capacity (RRC2)	
#27 Loss of tools and facilities (LT0)	**#19** Loss of tools and facilities (LT1)	**#10** Loss of tools and facilities (LT2)	

Table 20: Classification of incidents according to ICS methodology

The highest criterion from ICS is in this incident is an F2, and thus an expert panel for a scale 2 investigation will be launched for this event.

For incidents of scale 2 and 3, a detailed report must be prepared by an expert panel composed of representatives from TSOs affected by the incident, a leader of the expert panel from a TSO not affected by the incident, relevant RSC(s), a representative of SG ICS, the regulatory authorities and ACER upon request. The ICS annual report must contain the explanations of the reasons for incidents of scale 2 and scale 3 based on the investigation of the incidents according to article 15(5) of SO GL. TSOs affected by the scale 2 and scale 3 incidents must inform their national regulatory authorities before the investigation is launched according to article 15(5) of SO GL. The ENTSO-E secretariat will inform NRAs and ACER about the upcoming investigation in due time, before it is launched and not later than one week in advance of the first meeting of the expert panel.

Each TSO must report the incidents on scale 2 and 3 classified in accordance with the criteria of ICS in the reporting tool by the end of the month following the month in which the incident began, at the latest. As the incident happened on 8 January 2021, the affected TSOs have to classify the events during this incident according to the ICS Methodology before 28 February.

6 NEXT STEPS

As described in chapter 5, the incident on 8 January 2021 can be classified as a scale 2 incident according to the ICS methodology. For a scale 2 incident, a detailed report must be prepared by an expert panel. The report will present a factual description of the incident as well as an evaluation of the incident.

The data provided in this report will serve as a basis for the factual description of the incident by the expert panel. As indicated in the individual chapters of this report, some data about the incident is still being collected. This is mainly data which is not centrally stored and for which several external parties need to be contacted for the data collection. Additional data and information, deemed necessary for the investigation, might be identified by the expert panel during its investigation.

The report as prepared by the expert panel will also comprise an evaluation of the incident in order to identify recommendations, if necessary. This analysis and evaluation will comprise at least the following:

- An analysis of the causes of the incident,
- An evaluation of the activated remedial actions and measures from the system defence plan,
- An evaluation of the actions of TSO operations of the transmission system,
- A description of the functioning of the network element(s),
- Conclusions and explanations of the reasons for the incident, and
- Recommendations based on the conclusions of the investigation.

The expert panel will be comprised of representatives of affected and non-affected TSOs as well as representatives of the RSC and of the ICS methodology. Furthermore, NRAs and ACER will be invited to the expert panel.

It is currently planned that the expert panel will start its investigation in the first week of March 2021. This allows sufficient time to collect all relevant data for the analysis within ENTSO-E. The investigation performed by the expert panel will be summarised in a final report, which will be published on the ENTSO-E public website, planned for summer 2021.

In order to understand the root causes of the incident and to evaluate the incident as soon as possible, the TSOs have already prepared as a next step an analysis based on the following questions:

- What are the root causes that led to the incident, and why could the incident not be avoided?
- What other critical factors during the disturbance need to be considered?
- Which existing defence measures worked well in order to prevent the power system from further disturbances?

In order to answer these questions, steady state as well as dynamic simulations might need to be performed. In this respect it will also be considered whether the responsibilities of the European legislation, for example those given by the SO GL, the Emergency and Restoration Network Code (ER NC) or the Synchronous Area Framework (SAFA), have not been fulfilled and led to the cause of the incident.

This analysis, which is currently being performed, will improve the efficiency and rapidity of the investigation by the expert panel. Thus, an evaluation of the incident and the formulation of recommendations, if deemed necessary, can be conducted as soon as possible in order to prevent comparable causes from leading to such an incident again in the future.

ANNEXES

List of TSOs (alphabetical order)

Company	Country (abbreviation)
50Hertz	Germany (DE)
Amprion	Germany (DE)
APG	Austria (AT)
ČEPS	Czech Republic (CZ)
CGES	Montenegro (ME)
Creos Luxembourg	Luxembourg (LU)
ELES	Slovenia (SI)
Elia	Belgium (BE)
EMS	Serbia (RS)
Energinet	Denmark (DK)
ESO EAD	Bulgaria (BG)
Fingrid	Finland (FI)
HOPS	Croatia (HR)
IPTO	Greece (GR)
MAVIR	Hungary (HU)
MEPSO	North Macedonia (MK)
National Grid ESO	Great Britain (GB)
NOS BiH	Bosnia and Herzegovina (BA)
OST	Albania (AL)
PSE	Poland (PL)
REE	Spain (ES)
REN	Portugal (PT)
RTE	France (FR)
SEPS	Slovakia (SK)
Statnett	Norway (NO)
Svenska Kraftnät	Sweden (SE)
Swissgrid	Switzerland (CH)
TenneT DE	Germany (DE)
TenneT TSO B.V.	The Netherlands (NL)
Terna	Italy (IT)
Transelectrica	Romania (RO)
TransnetBW	Germany (DE)
TEIAS	Turkey (TR)
VUEN	Austria (AT)

List of abbreviations

A	Ampere(s)
ACE	Area Control Error
ACER	Agency for the Cooperation of Energy Regulators
aFRR	Automatic Frequency Restoration Reserves
CC	Coordination Centre
CE	Continental Europe
CET	Central European Time
DACF	Day-Ahead-Congestion-Forecast
DC	Direct Current
EAS	ENTSO-E Awareness System
ENTSO-E	European Network of Transmission System Operators for Electricity
ER NC	Emergency and Restoration Network Code
FCR	Frequency Containment Reserves
GPS	Global Positioning System
GW	Gigawatt
HPPs	Hydro power plants
HVDC	High Voltage Direct Current
ICS	Incident Classification Scale
IDCF	Intra-day Congestion Forecast
IGCC	International Grid Control Cooperation
LFC	Load Frequency Controller
mHz	Milihertz
MLA (Operation Handbook)	Multilateral Agreement (Operation Handbook)
MVA	Megavolt ampere
MW	Megawatt
NPPs	Nuclear Power Plants
NRA	National Regulatory Authority
NTC	Net Transfer Capacity
OHL	Overhead Line
PMU	Phasor Measurement Unit
PV PPs	Photovoltaic Power Plants
RoCoF	Rate of Change of Frequency
RSC	Regional Security Coordinator
SAFA	Synchronous Area Framework Agreement
SAM	Synchronous Area Monitor
SCADA	Supervisory control and data acquisition
SOGL	System Operation Guideline
SS	Substation
TPPs	Thermal power plants
TSO	Transmission System Operator
kV	Kilovolt(s)
WAMS	Wide Area Measurement System
WPPs	Wind Power Plants

Frequency Monitoring and Application of the Extraordinary Frequency Procedure by the Synchronous Area Monitor

General description of the CE Extraordinary Procedure and dedicated traffic lights in EAS

Two procedures are in place in RG CE to avoid serious system disturbances, and especially large frequency deviations with the risk of the uncoordinated disconnection of generation or load. The aim of the procedure is to coordinate countermeasures in case of steady-state frequency deviations between the Coordination Centres and TSOs in a fast and effective manner in order to keep the steady-state frequency between 49.9 Hz and 50.1 Hz.

The "Extraordinary procedure for frequency monitoring and countermeasures in case of large steady-state frequency deviations" (50/100 mHz-Procedure) is triggered when the following criteria are fulfilled:

Stage 1

- system frequency of 50.05 Hz or 49.95 Hz is exceeded for a time interval longer than 15 minutes
- system frequency of 50.1 Hz or 49.9 Hz is exceeded for a time interval longer than 5 minutes
- action: contact and discussion of measures between the dedicated Coordination Centre and the impacting TSOs

Stage 2 (Activation of five TSOs Telco)

- system frequency of 50.05 Hz or 49.95 Hz is exceeded for a time interval longer than 20 minutes
- system frequency of 50.1 Hz or 49.9 Hz is exceeded for a time interval longer than 10 minutes
- action: Telephone Conference and discussion of measures by Amprion, Swissgrid, REE, RTE and Terna

On 10 January 2019 a huge frequency deviation of 192 mHz under frequency was caused by the convergence of a long lasting steady-state frequency deviation due to a frozen measurement in LFC-System of one TSO and a high Deterministic Frequency Deviation (DFD) during the evening peak-load at the hourly schedule transition. After this event the Coordination Centres decided with confirmation of SOC Subgroup CSO to establish a second procedure the "Procedure for frequency monitoring and countermeasures in case of long-lasting steady-state frequency deviations" (6s-Procedure/LLFD-Procedure). The aim of this procedure is to detect long lasting frequency deviations (LLFDs) at an early stage based on grid time deviations to prevent the occurrence of critical frequency deviations.

Since 2020 "Frequency States" Traffic-Lights dedicated to the 50/100 mHz-Procedure and the LLFD-Procedure were implemented in the EAS. This Traffic-Lights should inform all CE TSOs in case of frequency deviations. The Frequency States are triggered automatically via the local LFCs of the Coordination Centres in case of large steady-state frequency deviations and manually by operators of the Coordination Centres in case of long lasting steady state frequency deviations.

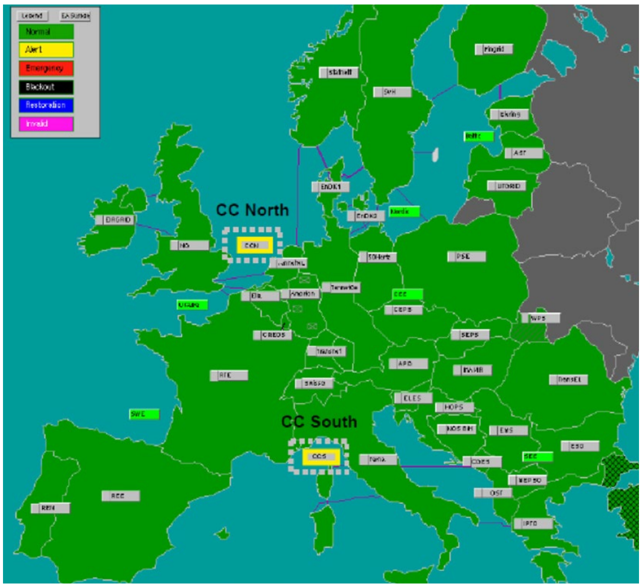


Figure 23: EAS frequency state traffic lights with status "yellow"

Application of the CE Extraordinary Procedure on 8 January 2021

On 8 January 2021 at 14:10 CET the trigger for Stage 1 of the CE Extraordinary Procedure was reached (Frequency deviation $|\Delta f| > 100$ mHz for a time period $t > 5$ min). This was signalised in EAS by an "Alert State" for the Frequency Traffic-Light. Due to the fact that 5 minutes before a frequency drop down to 49.74 Hz occurred, the actual cause of the incident was not clear at this time and the incident seemed to have a huge impact with more need for coordination, the Coordination Centres in their role as Synchronous Area Monitor (SAM) decided to launch the Stage 2 telephone conference of the CE Extraordinary Procedure proactively, although the criteria for Stage 2 was not reached in the North-West Area of the System Separation.

The conference call was used for:

1) gathering information:

- about the frequency drop, the trigger for the CE Extraordinary Procedure and current results of the first short analysis of the CCs in EAS.
- about contractual load shedding in France (RTE) and in Italy (Terna)
- about the tripping of HVDC links between France (RTE) and Spain (REE) and the resulting adaption of production in France and Spain.

2) analysing the situation:

- During the call the CCs detected the probable System Separation in the EAS frequency map. A separate island with the TSOs HOPS, Transelectrica, NOSBIH, EMS, ESO, MEPSO, OST and IPTO was indicated.

3) coordinating necessary countermeasures:

- Due to the fact that the frequency deviation in the North-West Area was decreased by Primary Control FCR and automatic measures to less than 50 mHz and was still recovering, the 5 TSOs decided that at this moment no further measures were necessary to stabilize the frequency in the North-West Area.
- The Coordination Centres decided to focus their investigations
  - on the reasons for the System Separation and a possible resynchronization of the South-East Area,
  - on the monitoring of the frequency in the North-West-Area
  - and on the coordination of measures to bring the North-West-Area back to normal operation

This report was produced by the ENTSO-E Task Force – Continental Europe System Separation 08 January 2021.

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