ENTSO-E BIDDING ZONE CONFIGURATION TECHNICAL REPORT 2018

Regular Reporting on Bidding Zone Configuration
15 October 2018

European Network of Transmission System Operators for Electricity

ABOUT ENTSO-E

ENTSO-E, the European Network of Transmission System Operators for electricity, represents 43 electricity transmission system operators (TSOs) from 36 countries across Europe.

ENTSO-E was established and given legal mandates by the EU's Third Legislative Package for the Internal Energy Market in 2009, which aims to further liberalise the gas and electricity markets in the EU.

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EXECUTIVE SUMMARY

According to Commission Regulation (EU) 2015/1222 (CACM), bidding zones should be defined in a manner so as to ensure efficient congestion management and overall market efficiency. In order to monitor this, the Agency of the Cooperation of Energy regulators (ACER) is tasked with the periodical (every 3 years) assessment of the efficiency of current bidding zone configuration.

This Technical Report was prepared by ENTSO-E for years 2015 – 2017 upon the request of ACER, received 18 January 2018. Considering the fact that the assessment of the efficiency of bidding zone configurations is the task of ACER, this Technical Report serves only a fact-collection purpose and provides no recommendations in that regard. In parallel, ACER is mandated to prepare a Market Report, so that, based on both reports, ACER is able to assess the efficiency of bidding zones. If either the Market or Technical Report reveals inefficiencies in the bidding zone configuration, ACER may request that Transmission System Operators (TSOs) launch a review of an existing bidding zone configuration.

The previous Technical Report issued in January 2014 was prepared and issued before CACM entered into force, therefore this report is the first one issued under the CACM Regulation. Contrary to the previous pilot exercise covering only continental Europe, this Technical Report covers all the EU bidding zones.

The Technical Report consists of three main sections, each responding to major CACM requirements, i.e. Chapter 2 deals with congestions, Chapter 3 deals with flows not resulting from capacity allocation and Chapter 4 deals with congestion income and firmness costs.

An overview of **congestions** is presented for the following time stages: Capacity calculation for the purpose of day-ahead (DA) capacity allocation, D-1 (operational planning after DA market closure) and (close to) real-time. The location and frequency of congestions is also reported. Given that power flow patterns are not very stable and are heavily dependent on market and operational conditions, the location of congestions can vary. Moreover, congestions identified on certain transmission corridors do not necessarily result from single bottlenecks, but rather from constraints appearing on a number of lines. Hence, although one can observe a low frequency of congestion on particular lines across the corridor, the whole set of these lines constitutes a network congestion. These congested corridors are indicated as bubbles grouping grid element(s) to assist with the identification of congested parts of the network, complemented by TSOs' expert assessment.

In the timeframe 'Capacity calculation for the purpose of day-ahead capacity allocation', a relatively low number of congestions are reported, especially if compared to the D-1 timeframe. These reported congestions are generally on bidding zone borders or in their direct vicinity. This is due to the fact that in the capacity calculation timeframe, only the grid elements with relevant sensitivity to cross-border exchanges are considered.

In the timeframe 'D-1', the report identifies congested lines detected during the operational planning process, where TSOs check the DA market outcome for feasibility against the grid's technical capability. In principle, there should not be any costly remedial action, integrated in the data used as a basis for D-1 congestions detection. This is not always the case for some zones due to the different processes being applied. This should be taken into account when using the data shown in this report for the further analysis. In this timeframe, all grid elements are considered, irrespective of their cross-zonal relevance. Many lines with low frequency of congestions are reported, while high frequency congestions are reported for a relatively limited number of grid elements.

As far as the timeframe 'Real Time' is concerned, the collection of consistent data was especially challenging due to differences in TSO approaches to collecting and processing real-time operational data. In particular, some TSOs provided incident data from real-time systems, whilst others reported all congestions identified up to one hour before real time. Since both types of data refer to different situations, two sets of real time maps have been provided. The first set of maps shows congestions reported by TSOs using real-time system data, corresponding to actual security violations that occurred. These were usually the result of unexpected situations such as forced outages. The second set of maps shows congestions reported by TSOs using 'up to one hour before real time' data. These congestions result from changes to generation dispatch resulting from intra-day market activities, weather changes and/or forced outages (generation and/or transmission). In most cases, TSOs were able to manage these close-to-real-time congestions using operational congestion management procedures. Both sets of maps for this 'Real-Time' timeframe indicate the amount of operational challenges faced by TSOs very close to real-time.

With respect to the **future evolution of reported congestions**, TSOs' expert assessments have been provided in the report. It is to be underlined that TSOs have extensive investment plans in place to address the congestions identified in the short to medium and ten-year timeframe. It is also important to highlight that congestions, even with high frequency, do not automatically cause a loss of social welfare, as the congestion may be resolved by non-costly remedial actions such as topological changes, flow-control devices, etc.

This Technical Report also provides the information on **power flows not resulting from capacity allocation**. This assessment is done using the Power Transfer Distribution Factor (PTDF) indicator, which quantified the difference between measured physical flow on a given Bidding Zone border and 'allocated' commercial flow on that border obtained by approximating the allocated market flows stemming from cross-border transactions by PTDFs. This is the same approach as used by ACER for the Market Monitoring Report. The analysis yields no major differences in the evolution of total flows not resulting from capacity allocation over the last years. However, for some borders, the power flows not resulting from capacity allocation remain significant. Similar to the previous Technical Report issued in 2014, the highest magnitude of the indicator can be observed on borders between FR-DE, DE-PL, PL-CZ, CH-FR, CZ-AT, BE-FR, NL-BE, DE-NL, SK-HU, DE-CH and HU-SHB.

When it comes to **congestion rent**, it can be observed that it is concentrated in a relatively small number of countries. Congestion income collected by FR, GB and IT is considerably above other countries, followed by SE, DE and NL. One can observe a decline in the amount of collected congestion income, from 2.8 b€ in 2015 to 2.4 b€ in 2017.

When it comes to the **financial firmness** costs incurred by TSOs to ensure firmness of cross-border capacities, it is evident that these costs in all reported years are dominated by curtailments caused by emergency grid security or safety issues, with the exception of force majeure curtailment on the DE-DK border in 2017. Consequently, no trends can be identified. Overall, GR and IT had the highest financial firmness costs.

Analysis of **physical firmness** cost by country shows significant variation year on year. The highest costs are incurred by DE and GB. For PL, PT, ES and NL, physical firmness costs are also significant, though of a lower magnitude. Notably, in DE the costs for renewables curtailment compensation made up almost half of the total physical firmness and internal redispatch costs.

1 INTRODUCTION

1.1 BACKGROUND AND THE CURRENT BIDDING ZONE CONFIGURATION

The current and target model for the European Electricity Market is based on a zonal approach. In accordance with Article 2 of the Commission Regulation (EU) No 543/2013[1], a bidding zone is the largest geographical area within which market participants are able to exchange energy without capacity allocation. Cross-zonal electricity trades and exchanges are organised between these zones based on available transfer capacities calculated by TSOs. According to Commission Regulation (EU) 2015/1222 (CACM), bidding zones reflecting supply and demand distribution are a cornerstone of market-based electricity trading and are a prerequisite for reaching the full potential of capacity allocation methods including the flow based method. Bidding zones therefore should be defined in a manner to ensure efficient congestion management and overall market efficiency. In the current bidding zone configuration, there are multiple bidding zones in Italy and the Nordics, one bidding zone covering several countries (DE/AT/LU)[2] and bidding zones based on a historical context corresponding to Member States (see figure 1). CACM details how the efficiency of the current bidding zone configuration should be assessed.

1.2 CACM REQUIREMENTS

Article 34 of CACM requires an efficiency assessment by ACER of the current bidding zone configuration every three years. This process shall consist of:

- The Technical Report prepared every three years, according to Article 34 of CACM by ENTSO for electricity and sent to ACER; and
- A market report evaluating the impact of current bidding zone configuration on market efficiency, prepared by ACER.

The CACM requires that the Technical Report shall include at least:

- A list of structural and other major physical congestions, including location and frequency
- An analysis of the expected evolution or removal of physical congestions resulting from investment in networks or from significant changes in generation or in consumption patterns
- An analysis of the share of power flows that do not result from the capacity allocation mechanism, for each capacity calculation region (CCR), where appropriate
- Congestion income and firmness costs
- A scenario encompassing a ten year time-frame

In addition, ACER's letter requested that the Technical Report shall include:

- The time frame the congestions are seen in, e.g. real-time, intraday, day-ahead etc.
- That the evolution of the congestions should consider the short to mid-term time frames.

Subsequently, through discussion with ACER, it was agreed that

- The report shall not include intra-day congestion details.
- That ENTSO-E will focus on ACER's requirement to identify market relevant congestions.

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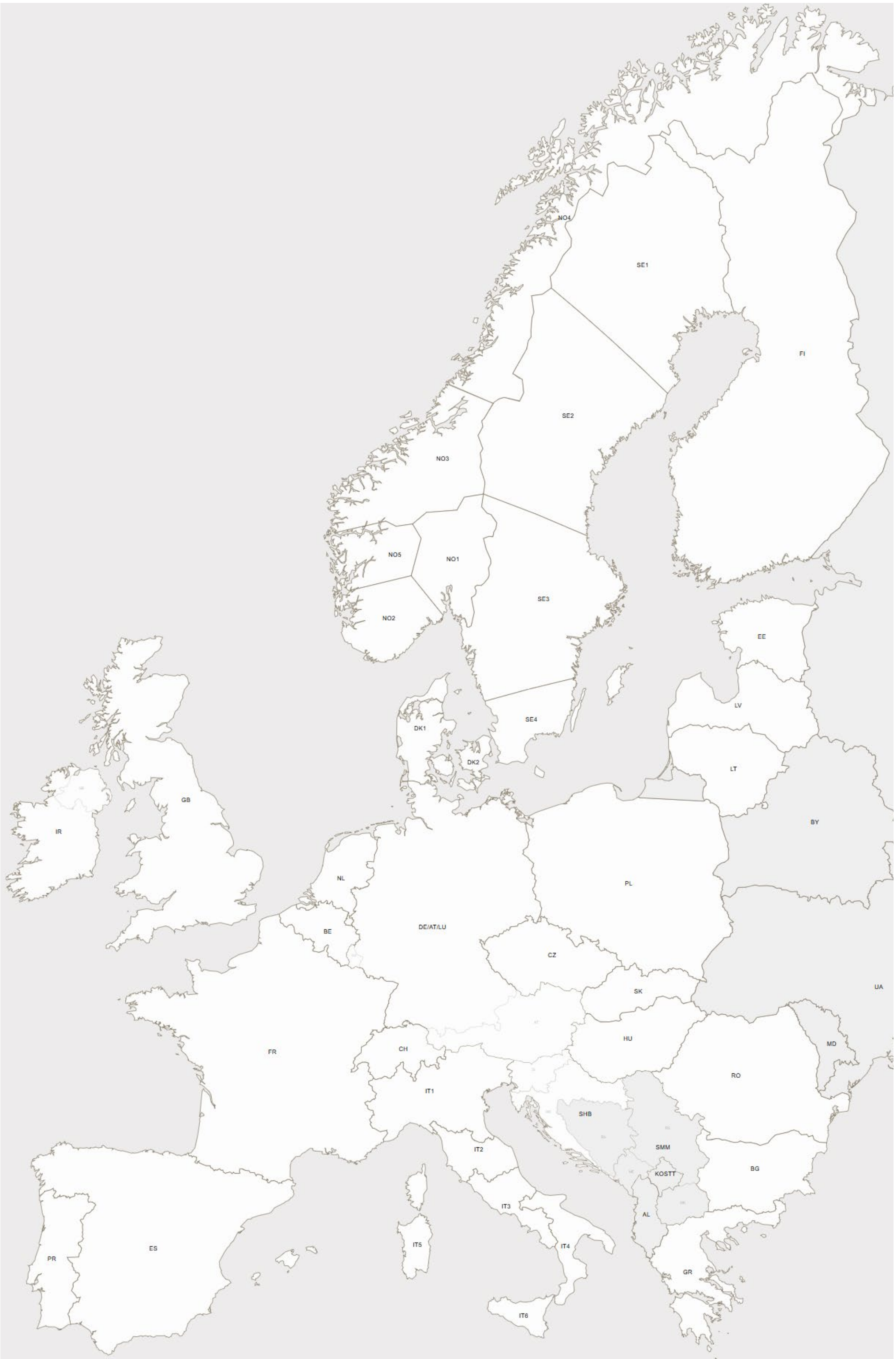
1 Commission Regulation (EU) No 543/2013 of 14 June 2013 on submission and publication of data in electricity markets and amending Annex I to Regulation (EC) No 714/2009 of the European Parliament and of the Council.

2 At the moment of drafting this Report.



According to the Annex 1 to ACER Decision No 06/2016 from 17 November 2016, the bidding zone border in between Germany and Austria is defined for Core CCR, however capacity allocation on this border shall be introduced in line with an implementation calendar agreed upon by the relevant regulatory authorities. According to the decision from BnetzA and E-Control, the allocation on the DE-AT border shall start as of October 2018.

For Italy, virtual bidding zones are not represented on the map

Figure 1: Bidding zone configuration

2 PRESENT CONGESTIONS AND THEIR FUTURE EVOLUTION

CACM requires a publication of structural congestions and major physical congestions, including their location and frequency. It also envisages an analysis of the expected evolution or removal of these congestions due to investments or changes in the generation or consumption pattern. This chapter seeks to address these requirements by first providing general background information on Capacity Calculation and methodological descriptions. Further congestions in 2015, 2016 and 2017 and their future evolution patterns are represented.

2.1 METHODOLOGY AND GENERAL DESCRIPTIONS

For the purpose of this Technical Report, the following has been investigated and analysed:

- Grid elements limiting cross-zonal capacity which appeared as active market constraints in the Day Ahead (DA) capacity allocation
- Grid elements which appeared to be congested during the short-term operational planning based on congestion forecasts in D-1 after the DA market but before the application of any remedial actions at this stage
- Alleviated and not alleviated congestions from the period up to one hour before time of operation.

All three processes are briefly described in the following chapters.

As explained in chapter 1.2 above and in accordance with CACM Regulation and the request from ACER, only structural congestions and major physical congestions are relevant in order to assess the bidding zone configuration. Even though CACM Regulation defines a structural congestion in Article 2, this definition does not give clear technical criteria in order to identify such congestions. The frequency of the congestion is quoted as a key factor, but in the course of the elaboration of the Technical Report, it appeared that the frequency of a single element is not sufficient to discriminate the congestions that are not structural. Indeed, sometimes a group of elements in the same area, with very low frequency if they are considered separately, can form one structural congestion.

It should be noted that the location of the limiting/congested element can change within the same congested area. In figure 2 there is a general flow from the generation group to the demand group. This is a simple power corridor which may easily be congested. If the underlying flow is high and approaching the capacity of the lines, the generators A and B will decide which line limits. If generator A runs, line 1 will be congested first. If generator B runs, line 2 will be congested first. If line 4 is on outage, line 3 will congest first. If line 3 is on outage, line 4 will congest first.

It is therefore appropriate to group the lines in the bubble and state that there is a congested area on the grid, in

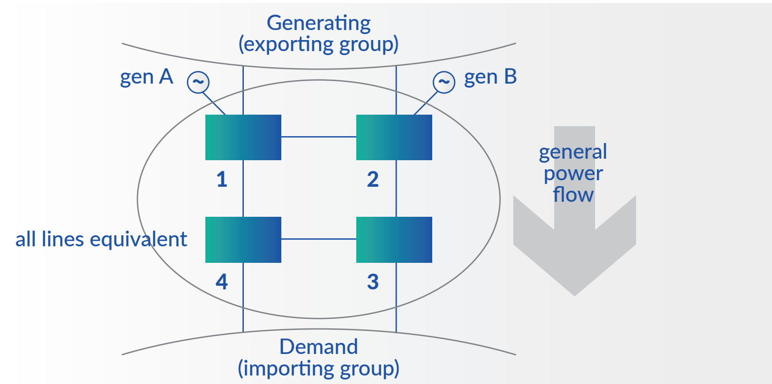


Figure 2: Example of congestion moving

this case the power corridor. However, no one element is the limiting factor at all times, nor is the location of the congestion fixed.

The frequency of congestion of the power corridor will be the sum of the cases where at least one of the elements may limit the corridor's power transfer.

Congestions in ES, SK, BG and CH are presented as bubbles (not line based) as they are considered 'sensitive critical infrastructure protection related information' according to the statements of CACM Regulation and their national law.

2.1.1 CAPACITY CALCULATION FOR THE PURPOSE OF DAY-AHEAD ALLOCATION

Within the capacity calculation process, TSOs calculate cross-zonal capacities which will be made available to the DA market, so that market participants can realize their cross-border transactions. Capacity calculation aims at computing the maximum available cross-zonal capacity while complying with underlying security standards (N-1 criterion) and respecting the operational security limits of each TSO (such as thermal limits, voltage limits, short-circuit current limits, frequency and dynamic stability limits). This is done for a given timeframe and bidding zone borders (including so called technical profiles, which encompass several bidding zone borders). The operational security limits cover permissible loading of grid elements[3], with their finite capabilities defined by their design and construction, as well as voltage and angular stability of the power system defined by the local structure and characteristics of the grid, where applicable. These aspects represent the limiting factors (constraints) when assessing cross-zonal transmission capacity. Grid elements constraining cross-zonal capacity are called critical network elements (CNEs). The CNEs limiting cross-zonal exchanges do not only appear on bidding zone borders, but within the grid of a bidding zone as well. Such elements are then recognised as internal lines with cross-border relevance as they are also affected by cross-border trading. Other congestions, fully internal to the BZ, are managed by the TSO via remedial actions, e.g. redispatching, topological changes etc. TSOs include remedial actions in the capacity calculation process in order to provide maximum cross-zonal capacity to market participants considering the secure operation of the system. This, together with reliability margin and applied risk policies, shall ensure that a sufficient amount of cross-zonal capacities are offered to the market whilst ensuring operational security. Before available capacities are provided to the market, they are also subject to mutual coordination between neighbouring TSOs.

The currently applied approaches in Europe for cross-zonal capacity calculations are either the net transmission capacity (NTC) approaches with different level of TSO coordination across Europe or the flow-based (FB) approach (currently FB has only been implemented in the Central Western Europe [CWE] area). In the NTC approach, the capacity to be given to the market is determined by the TSOs for each bidding zone border and direction, hence TSOs have to apply some splitting rules for distributing the available capacity amongst bidding zone borders. By doing so, TSOs assume the behaviour of market participants which in reality may be different. In the FB approach, TSOs determine flow-based parameters (comprised of available margins on CNEs associated with PTDF factors), and the market 'decides' within the allocation process how the available cross-zonal capacity is to be used.

For the purpose of this Technical Report, only the active market constraints are considered in this timeframe. For the regions using the FB approach, the active constraints are available from the FB computation while for the regions using the NTC approach, the active constraints have been computed ex-post for the purpose of this Report.

For the North Italy CCR, as the full price convergence is under 1% per year, all the limiting CNEs have been reported, without consideration of the cases where commercial exchanges were not congested during the allocation phase.

The active constraints are determined after the application of remedial actions, as per the agreed methodologies for capacity calculation.

3 Lines, transformers, breakers etc.

2.1.2 DAY-AHEAD OPERATIONAL PLANNING (D-1)

Day-ahead congestion forecasts (DACF) comprising results of the day-ahead allocation, represent the basis for the short-term operational planning process (e.g. DACF and Intra-Day Congestion Forecast [IDCF]). In particular, information resulting from the previous processes (cross-border as well as internal transactions), updated information about renewable energy sources (RES), updated load forecasts and unforeseen events are taken into account. In the cases of network elements with cross-border relevance, congestions which occur during these D-1 processes are mainly caused by deviations from forecasts such as unexpected changes in the grid topology or the generation or load pattern. The deviations may also be a consequence of inefficiencies of current configuration of the market (e.g. un-coordinated capacity calculation) resulting in unscheduled transit flows, loop flows, etc. During this phase, congested network elements which pose physical risks to system security are identified and costly or/and non-costly remedial actions for preventing or mitigating the forecasted security violations are determined.

For the purpose of this Technical Report, congested network elements are identified based on congestion forecasts in D-1 after the DA market (in the TSO-internal day-ahead operational security assessment or in the regional DACF-process) but before the application of any remedial actions at this stage (however the effect of remedial actions applied before the D-1 timeframe is taken into account). Due to local structural conditions of the network, several TSOs do not perform a DA security assessment[4]. In their case, congestions in the DA timeframe could not be evaluated.

2.1.3 REAL-TIME SYSTEM OPERATION

The aim of all previous congestion management procedures is to avoid congestions appearing close to real-time operation. Thus, these congestions should be less frequent compared to the previous timeframes such as DACF. However, in contrast to the previous stages, congestions appearing close to real-time system operation represent an immanent physical risk with a reduced scope of available remedial actions. They are generally caused by forecast errors, unscheduled flows and unexpected (unplanned) events.

For the purpose of this Technical Report, it was envisaged to collect alleviated and not alleviated congestions from the period as close to time of operation as possible, defined as up to one hour before real time. The effect of remedial actions applied in previous timeframes is inherently taken into account. During the data collection phase, it became apparent that some TSOs could not collect inclusive data up to one hour before real time or could not extract this data from their systems. These TSOs provided data on incidents that had been recorded as ICS[5] data. This means that for these TSOs, congestions seen within one hour of real time and which were resolved by control room actions, e.g. re-dispatch without a real time security breach, are not recorded.

The data collected by these two approaches is significantly different and therefore considered as not comparable. Consequently, for this report, two sets of real time maps are provided to visualise the data; one for ICS data and the second for data up to one hour before real time.

4 Baltic TSOs (AST, Elering, Litgrid) and Nordic TSOs (Statnett, Svenska Kraftnät, Fingrid, Energinet)

5 More precisely, the ICS events with ICS code ON1 (meaning N-1 violation) and ON2 (meaning N violation) are reported. ICS refers to the ENTSO-E 'Incident Classification Scale Methodology'

2.2. CONGESTED AREAS AND THEIR FUTURE EVOLUTION

In this section, congestions reported by TSOs are presented on maps for the different years and timeframes under investigation (a list of congestions is provided in Annex 1). Complying with CACM, in the current Technical Report, congestions are reflected only by their frequency i.e. percentage of hours per year where the congestion appeared. However, this is only one indicator for a congestion and therefore it should always be complemented by further indicators and be put into context by expert assessments. Further indicators could be the volume of the overload and the simultaneity of congested lines.

The frequency differences (more blue or more red lines) between the countries does not only depend on general grid topology (e.g. highly meshed, low meshed), but also on differences in capacity calculation/allocation, the demand behaviour or on-going maintenance works in the grid in the respective year.

Of note, not all congestions appear at the same time (the maps show full years). This means, that if, for example, there are three neighbouring grid elements that all impact cross-zonal capacity and these are 5% of the time congested each, these may lead to a maximum reduction of cross-zonal capacity of 15% of the time (in the case of total non-simultaneity). Furthermore, the frequency does not give any information about how much this congestion impacted the volume of cross-zonal capacity.

THE FOLLOWING MAPS AND SCALE SHOULD BE UNDERSTOOD AS FOLLOWS:

Colour scale from above 0 to above 35 represents the percentage of total hours of the year and reflects the range of congestion frequency for most of the reported lines. It means that lines with frequency above 35% are presented in dark red, the same colour as lines of exactly 35%.

Dot – transformer | substation | transmission line whose length is under 10 km

Coloured line/dot – congestion reported with a frequency corresponding to a number of hours per year

Grey line/dot – congestion reported and frequency not available

In the event that data is not available, the country is coloured in pink.

In the event that the concerned process is not performed, the country is coloured in light green.

In the event that data is not complete, the country is coloured in light blue.

Also important to note is that for double-circuit lines, only the circuit with higher frequency is displayed on the maps while the full list of congestions is provided in the table of congestions (Annex 1). The shape of the grid elements on the maps (straight lines) does not correspond to their real geographical layout; only the coordinates of the substations at both extremities are used.

2.2.1 CAPACITY CALCULATION FOR THE PURPOSE OF CAPACITY ALLOCATION

2015 – CAPACITY CALCULATION FOR THE PURPOSE OF DA ALLOCATION

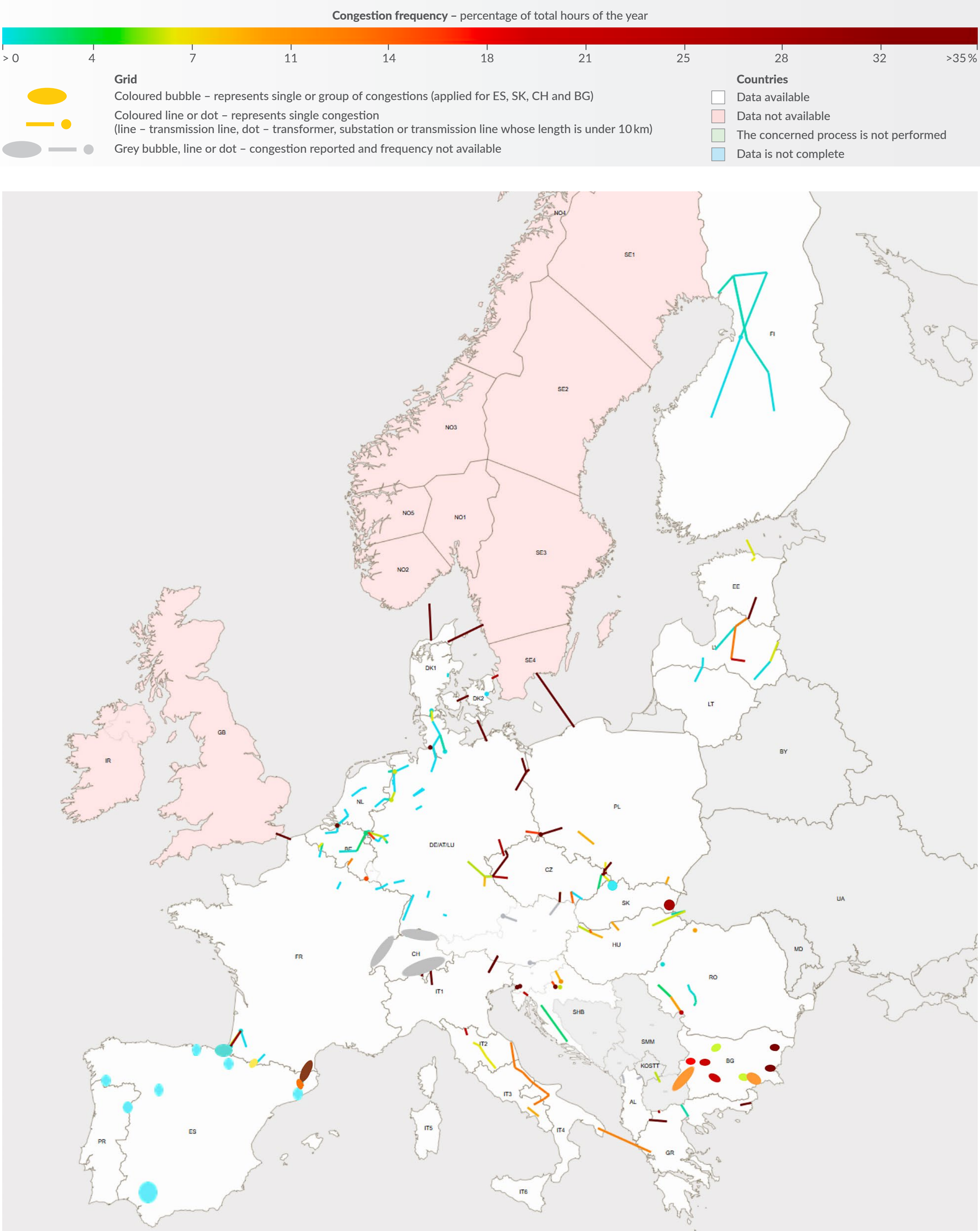


Figure 3: CCDA for 2015. Europe

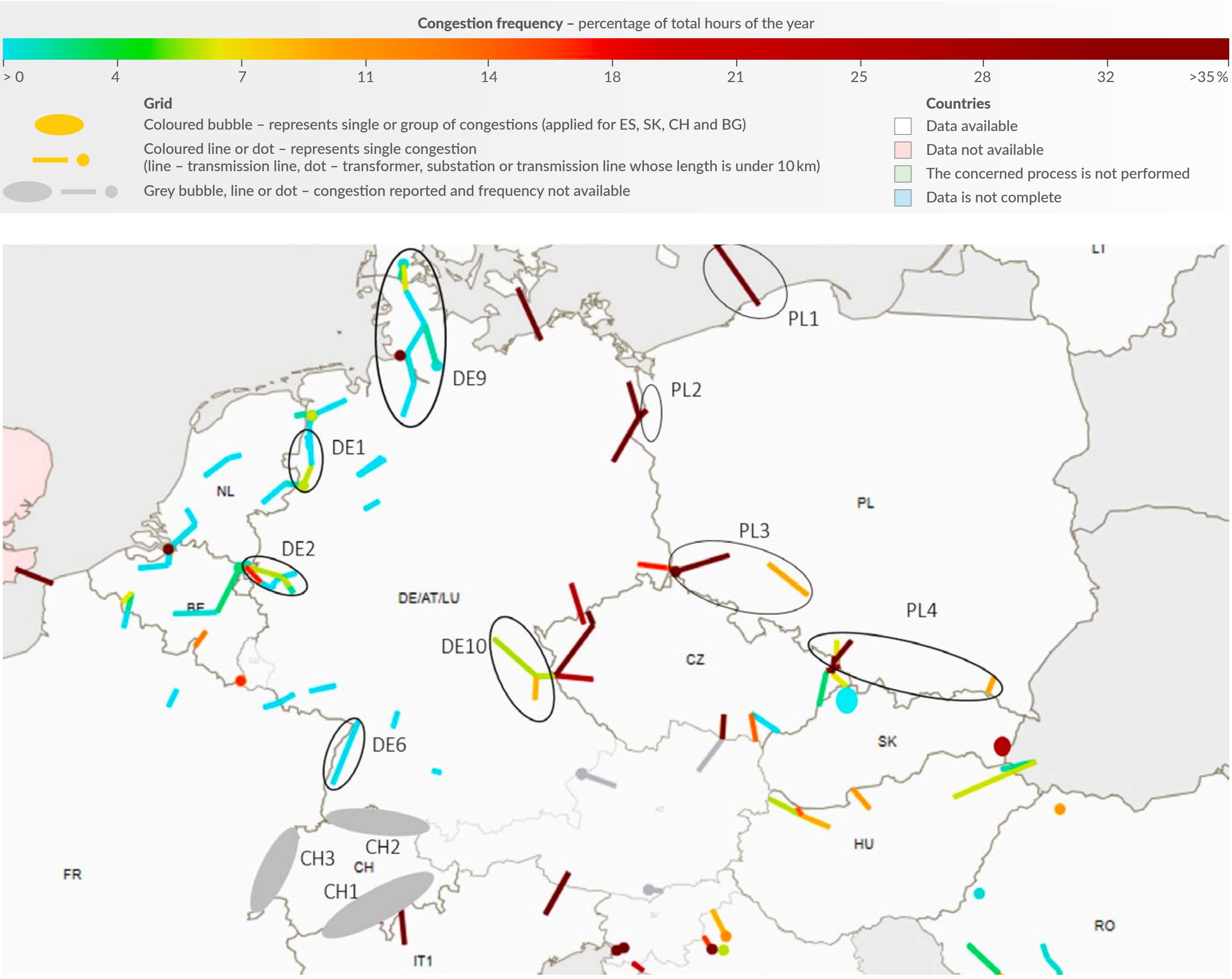


Figure 4: CCDA for 2015. Central Europe

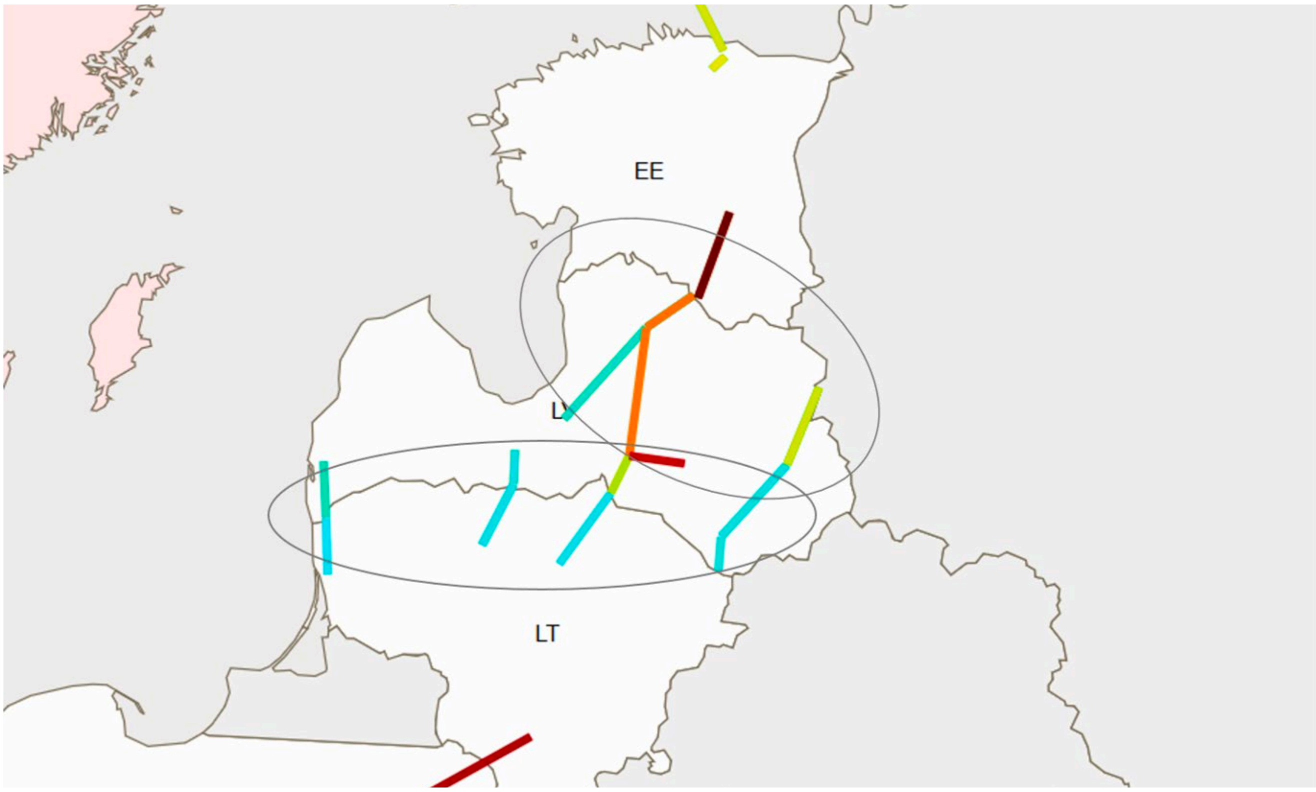
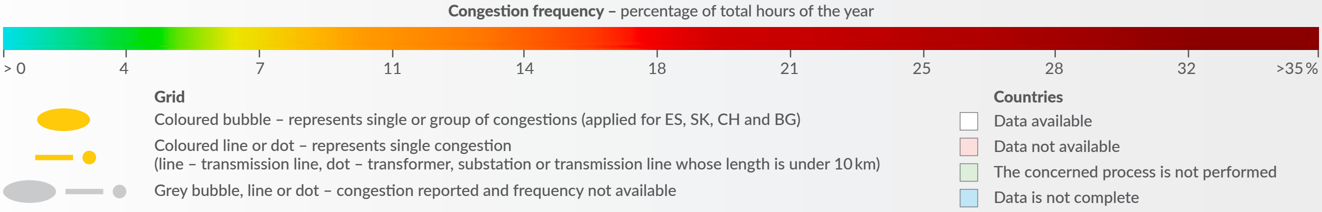


Figure 5: CCDA for 2015. Baltic countries



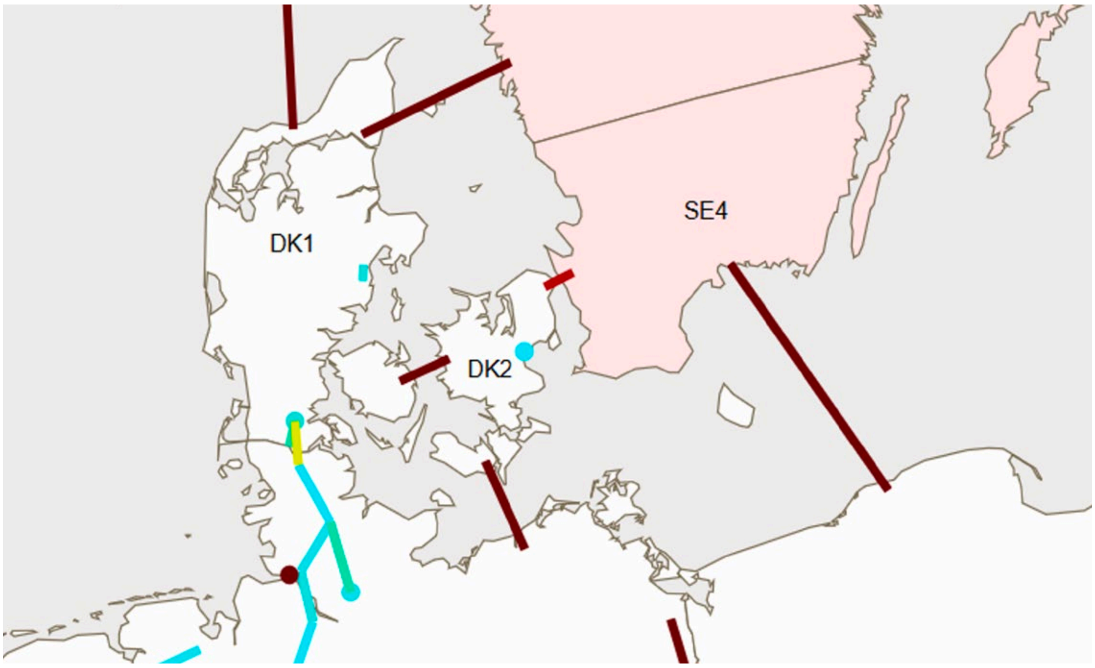


Figure 6: CCDA for 2015. Denmark/Sweden

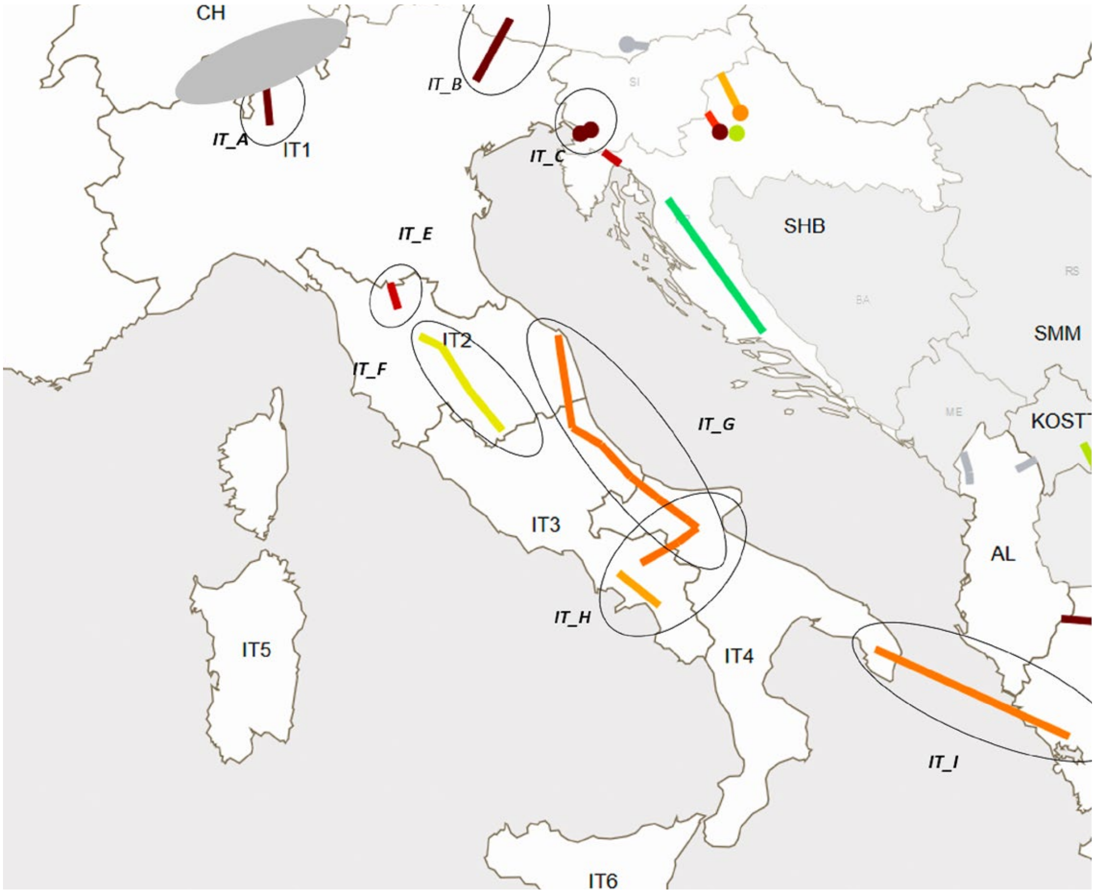


Figure 7: CCDA for 2015. Italy

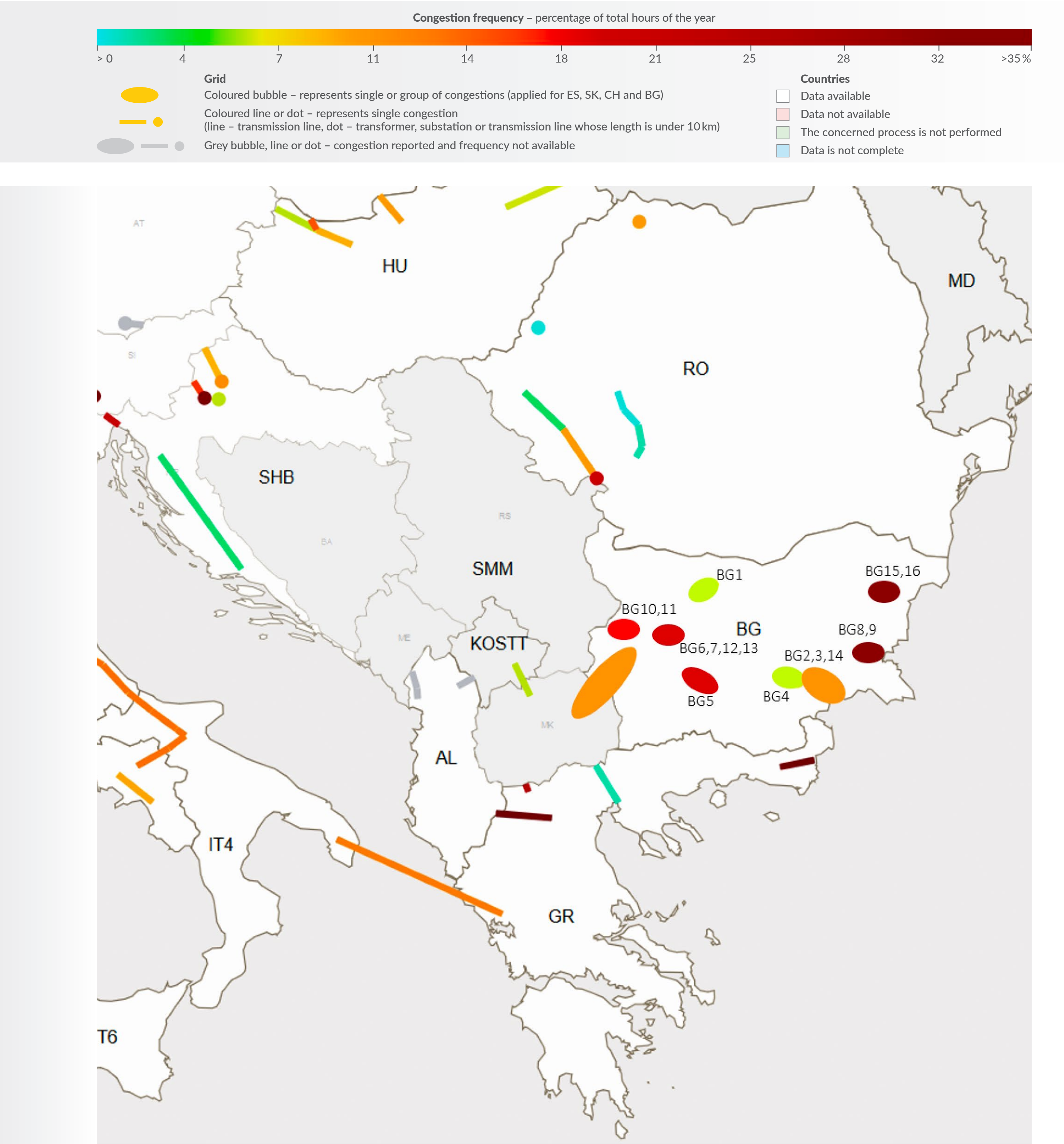


Figure 8: CCDA for 2015. Balkan countries

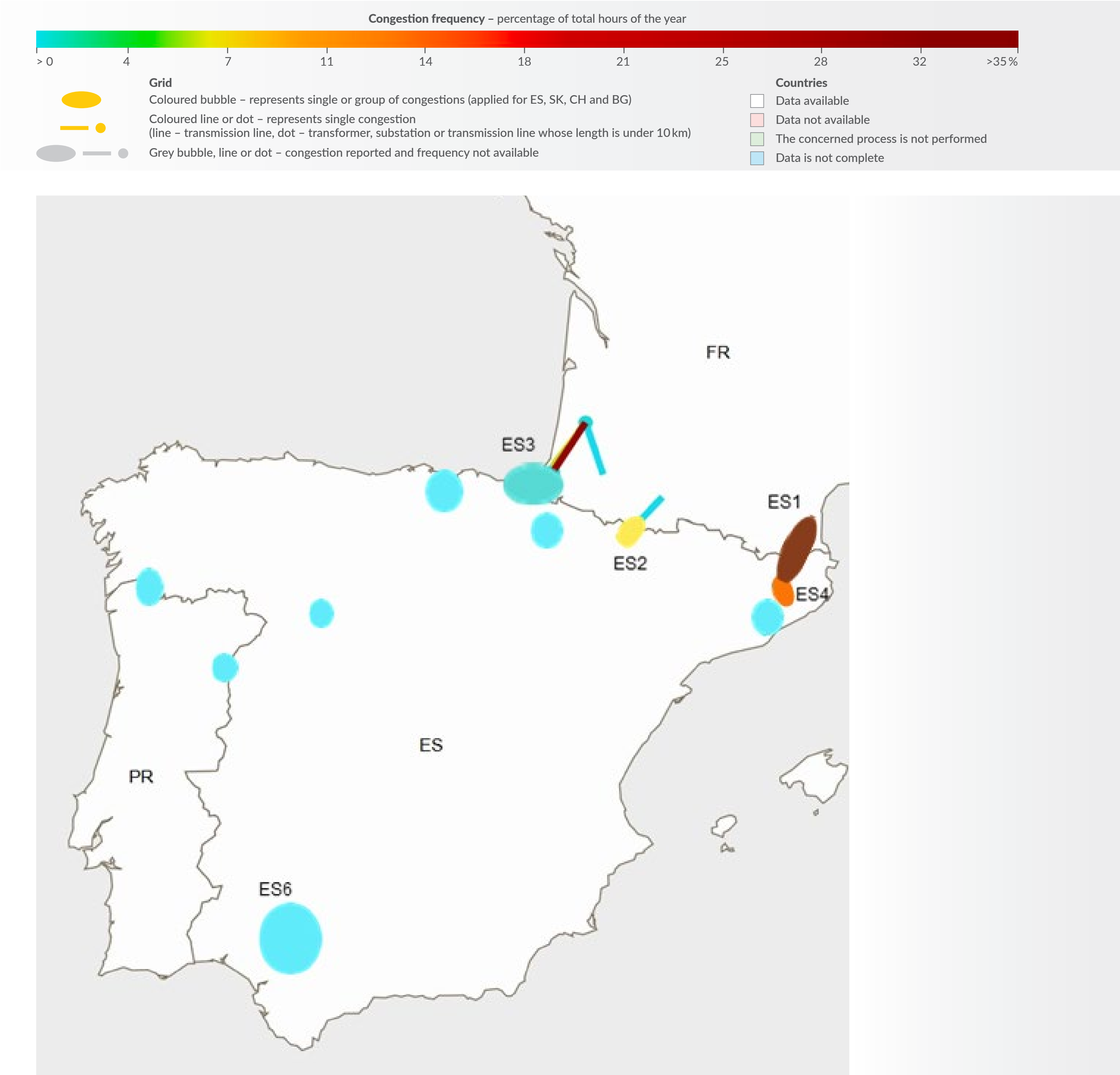


Figure 9: CCDA for 2015. Spain/Portugal

2016 – CAPACITY CALCULATION FOR THE PURPOSE OF DA ALLOCATION

Congestion frequency – percentage of total hours of the year

> 0 | 4 | 7 | 11 | 14 | 18 | 21 | 25 | 28 | 32 | >35 %

Grid

Coloured bubble – represents single or group of congestions (applied for ES, SK, CH and BG)

Coloured line or dot – represents single congestion
(line – transmission line, dot – transformer, substation or transmission line whose length is under 10 km)

Grey bubble, line or dot – congestion reported and frequency not available

Countries

Data available

Data not available

The concerned process is not performed

Data is not complete

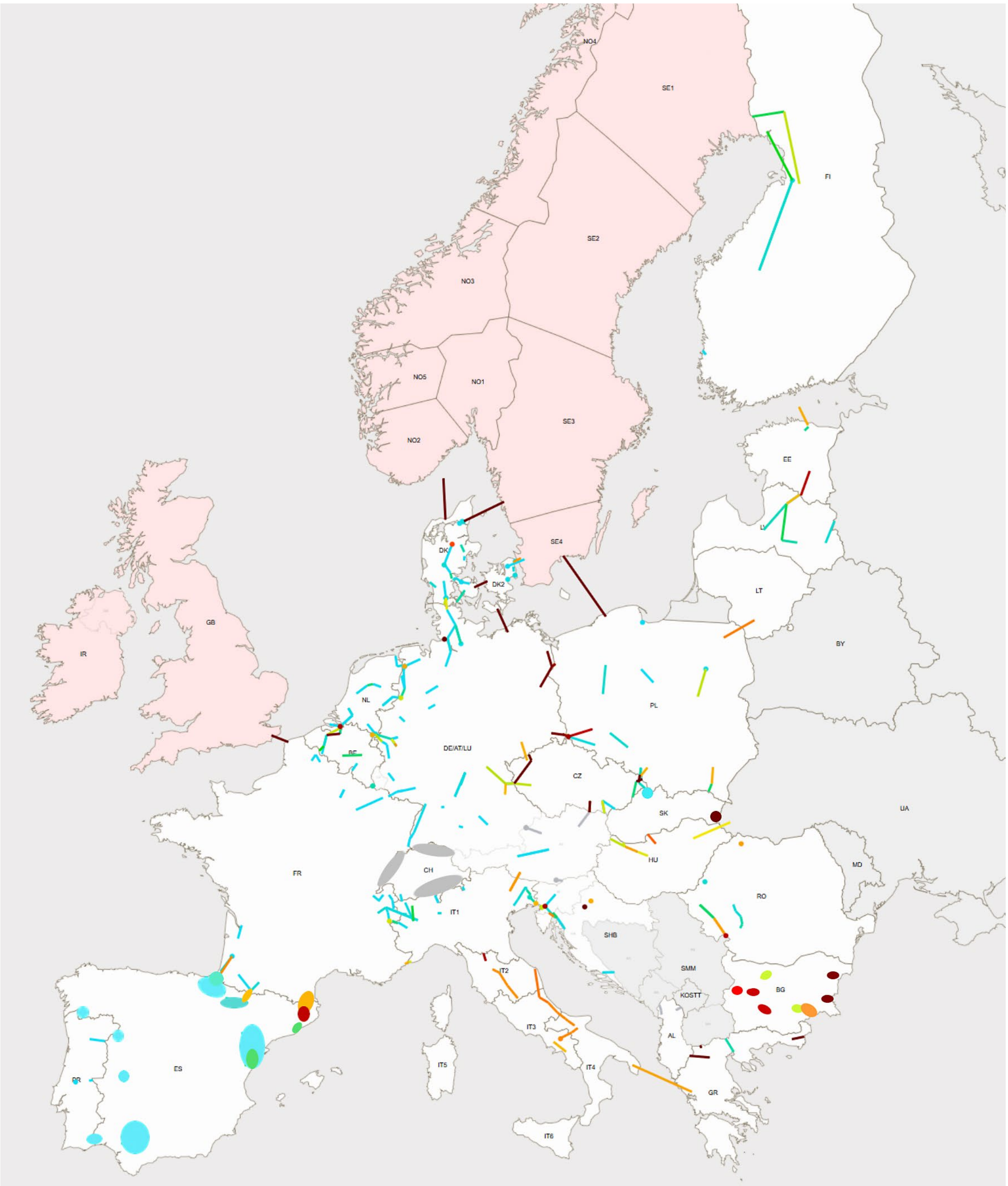


Figure 10: CCDA for 2016. Europe

Congestion frequency – percentage of total hours of the year

> 0 | 4 | 7 | 11 | 14 | 18 | 21 | 25 | 28 | 32 | >35 %

Grid

Coloured bubble – represents single or group of congestions (applied for ES, SK, CH and BG)

Coloured line or dot – represents single congestion
(line – transmission line, dot – transformer, substation or transmission line whose length is under 10 km)

Grey bubble, line or dot – congestion reported and frequency not available

Countries

Data available

Data not available

The concerned process is not performed

Data is not complete

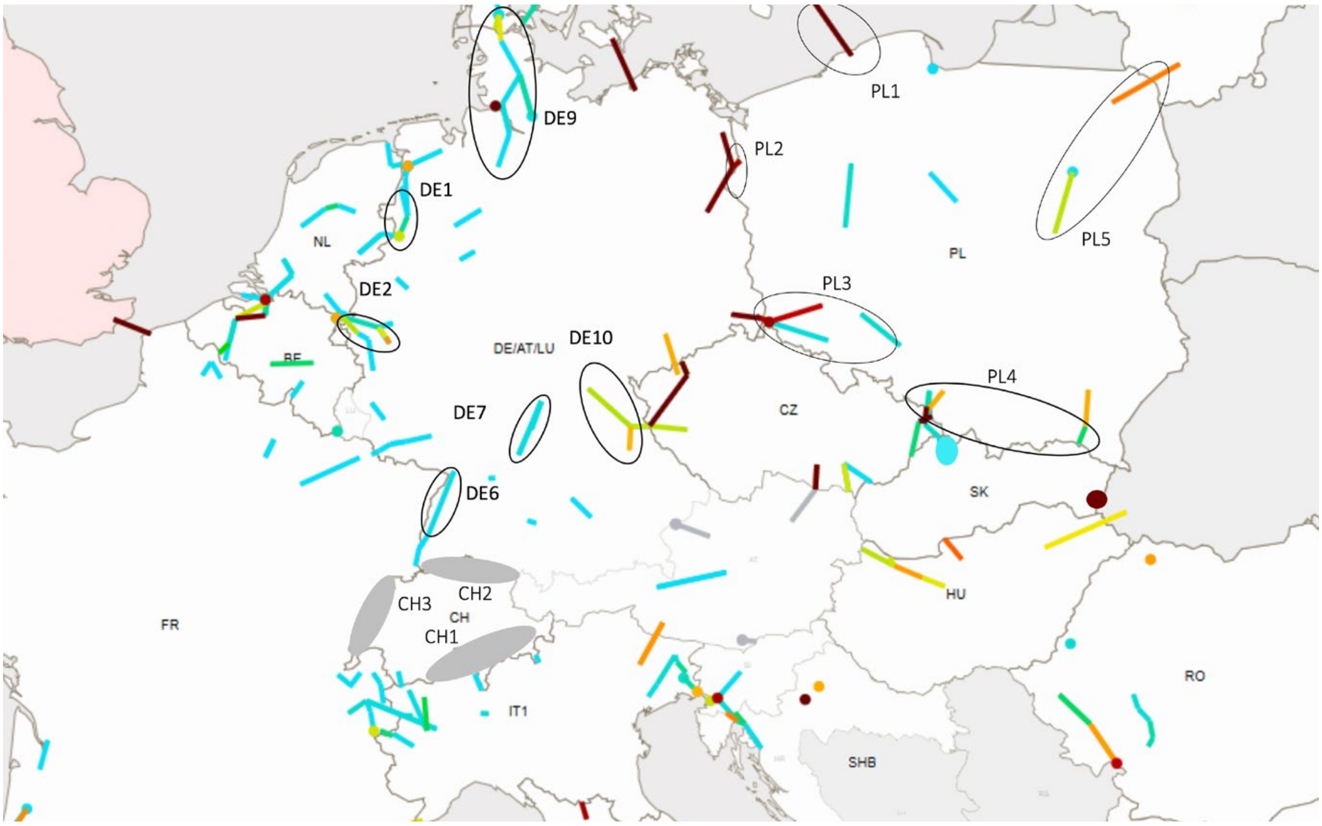


Figure 11: CCDA for 2016. Central Europe

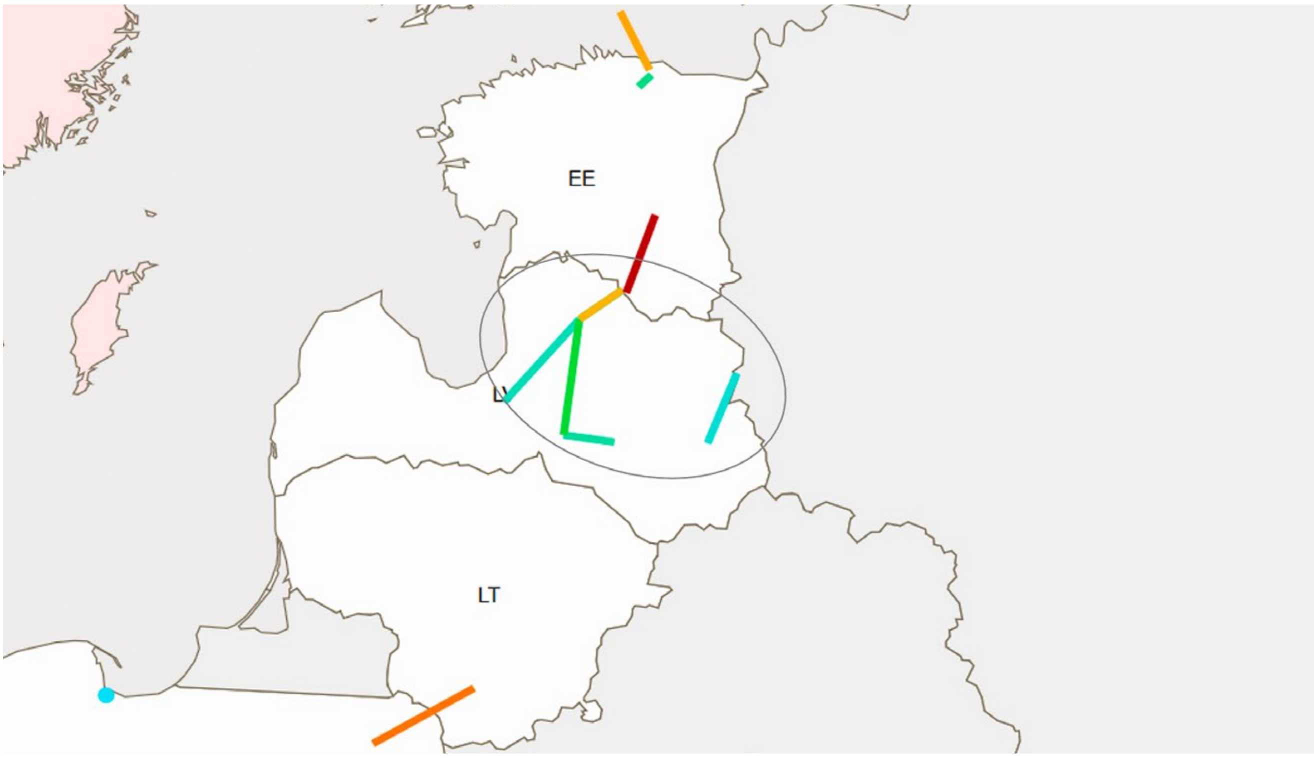


Figure 12: CCDA for 2016. Baltic countries

Congestion frequency – percentage of total hours of the year

> 0 | 4 | 7 | 11 | 14 | 18 | 21 | 25 | 28 | 32 | >35 %

Grid

Coloured bubble – represents single or group of congestions (applied for ES, SK, CH and BG)

Coloured line or dot – represents single congestion
(line – transmission line, dot – transformer, substation or transmission line whose length is under 10 km)

Grey bubble, line or dot – congestion reported and frequency not available

Countries

Data available

Data not available

The concerned process is not performed

Data is not complete

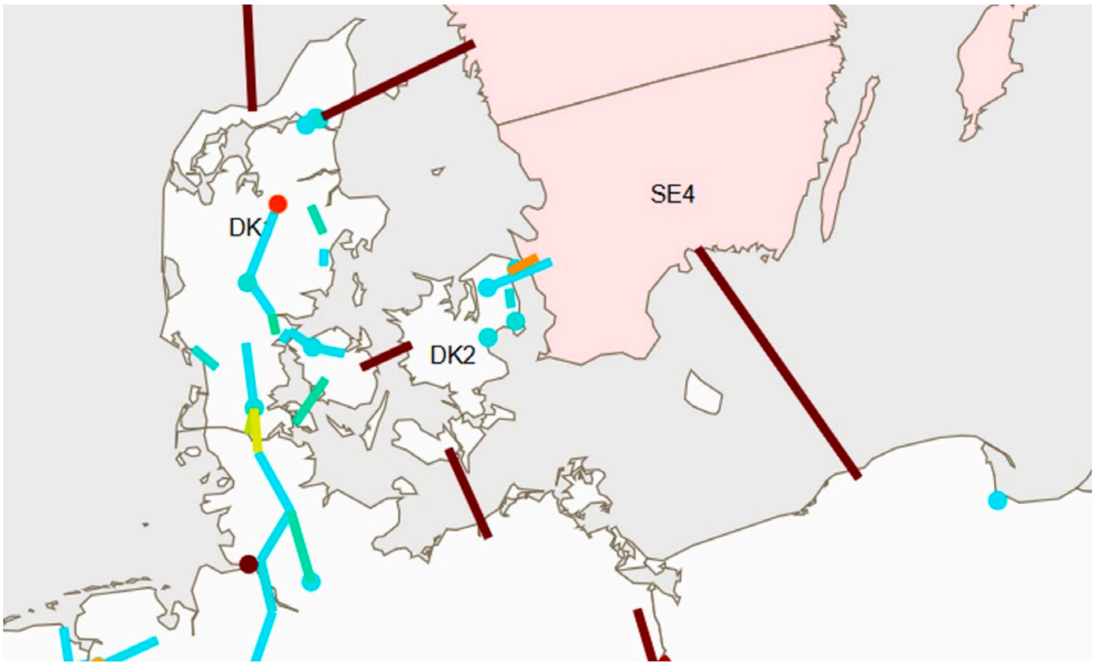


Figure 13: CCDA for 2016. Denmark/Sweden

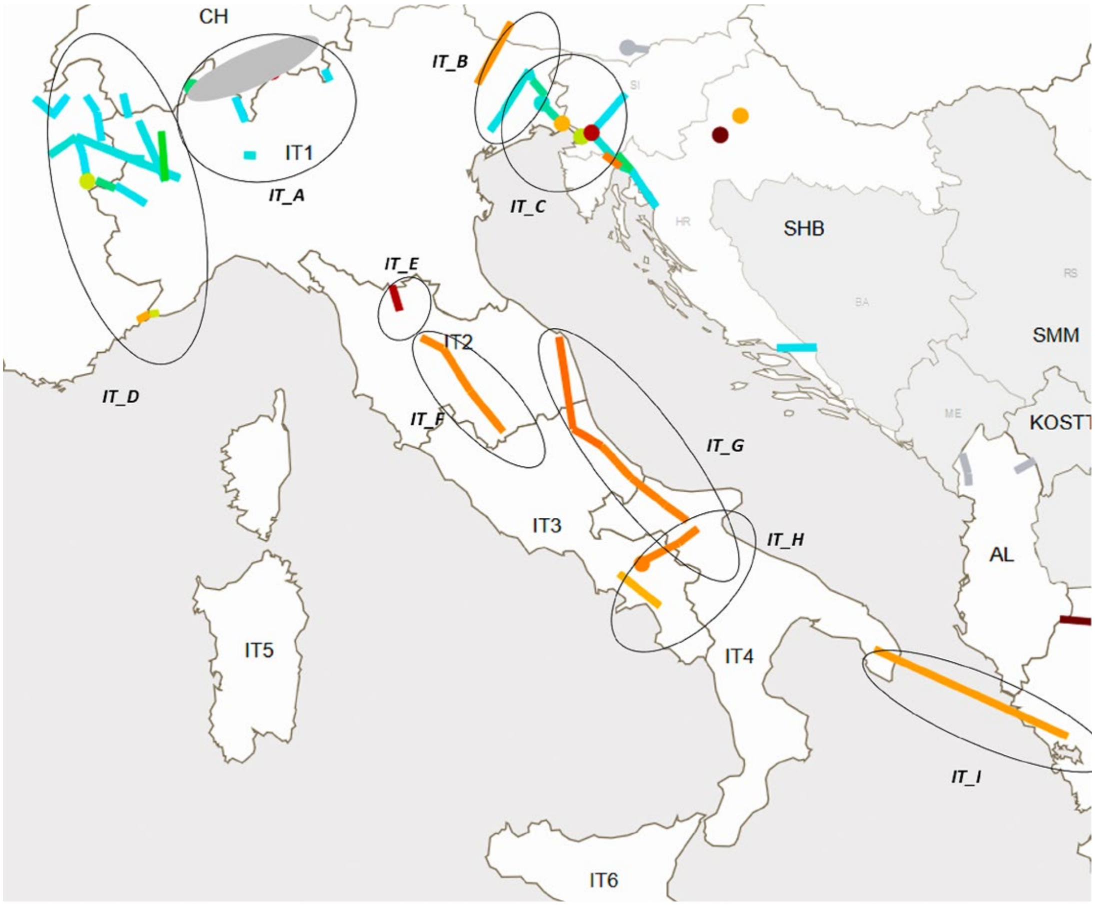


Figure 14: CCDA for 2016. Italy

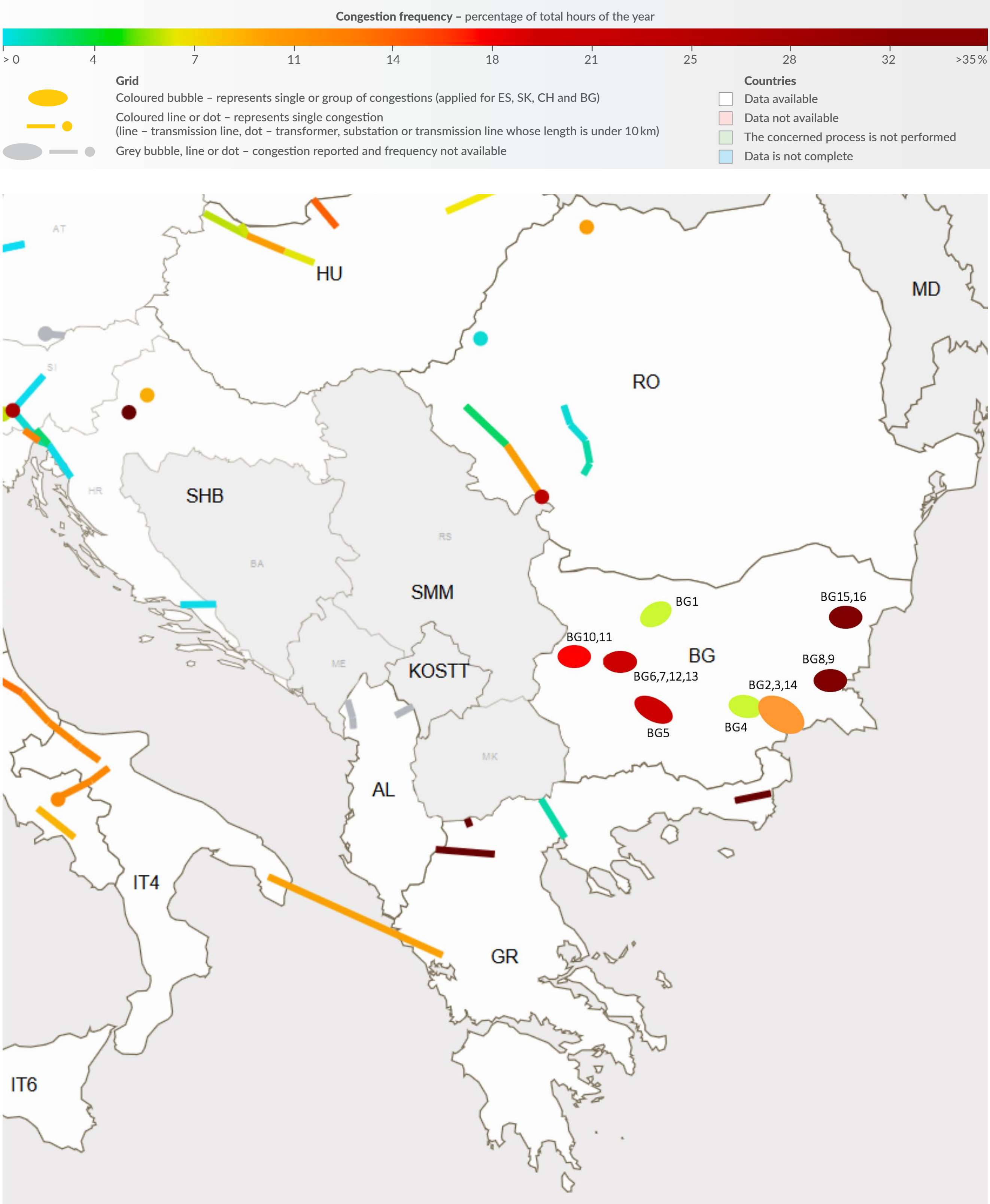


Figure 15: CCDA for 2016. Balkan countries

Congestion frequency – percentage of total hours of the year

> 0 | 4 | 7 | 11 | 14 | 18 | 21 | 25 | 28 | 32 | >35 %

Grid

Coloured bubble – represents single or group of congestions (applied for ES, SK, CH and BG)

Coloured line or dot – represents single congestion
(line – transmission line, dot – transformer, substation or transmission line whose length is under 10 km)

Grey bubble, line or dot – congestion reported and frequency not available

Countries

Data available

Data not available

The concerned process is not performed

Data is not complete

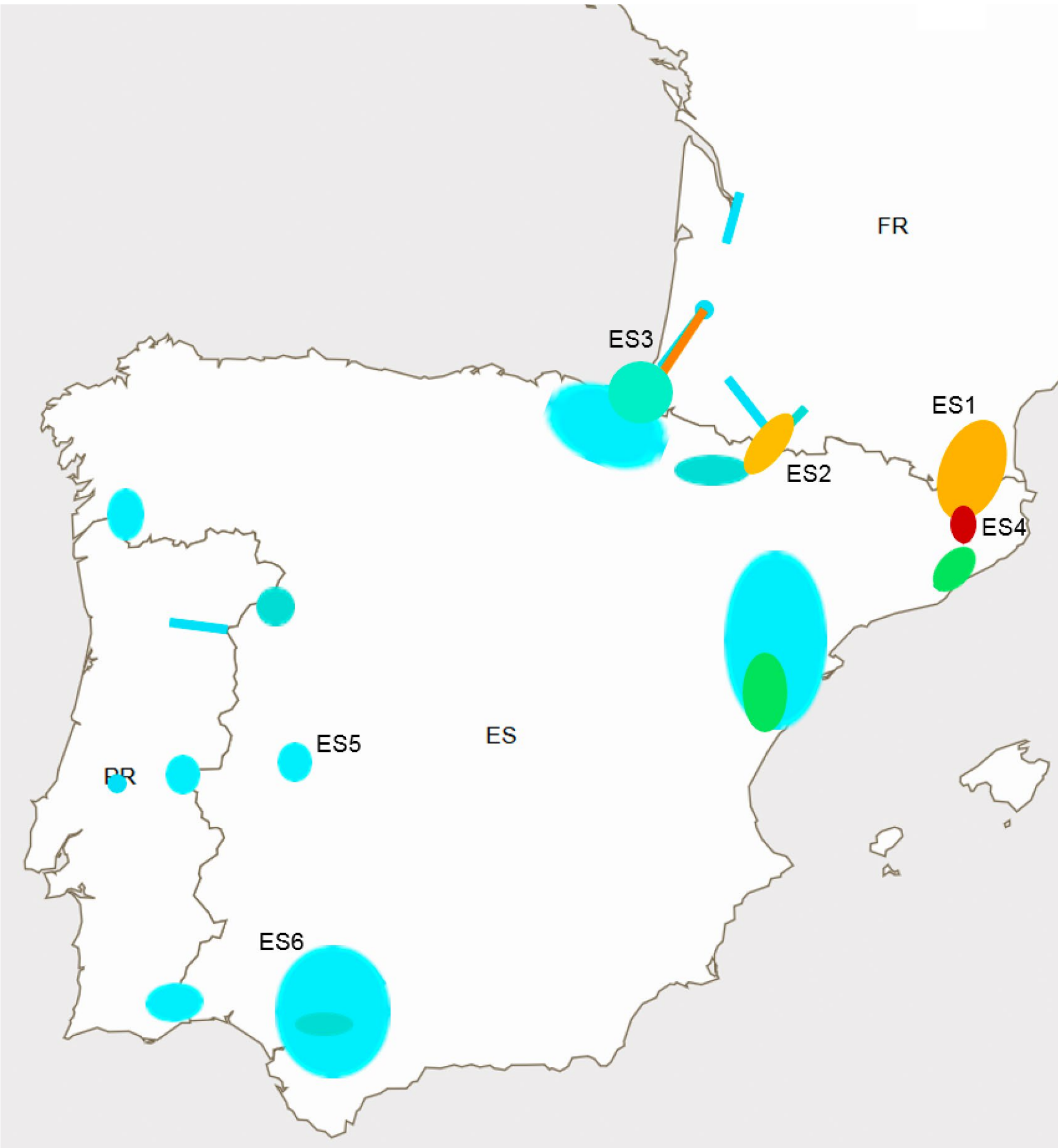


Figure 16: CCDA for 2016. Spain/Portugal

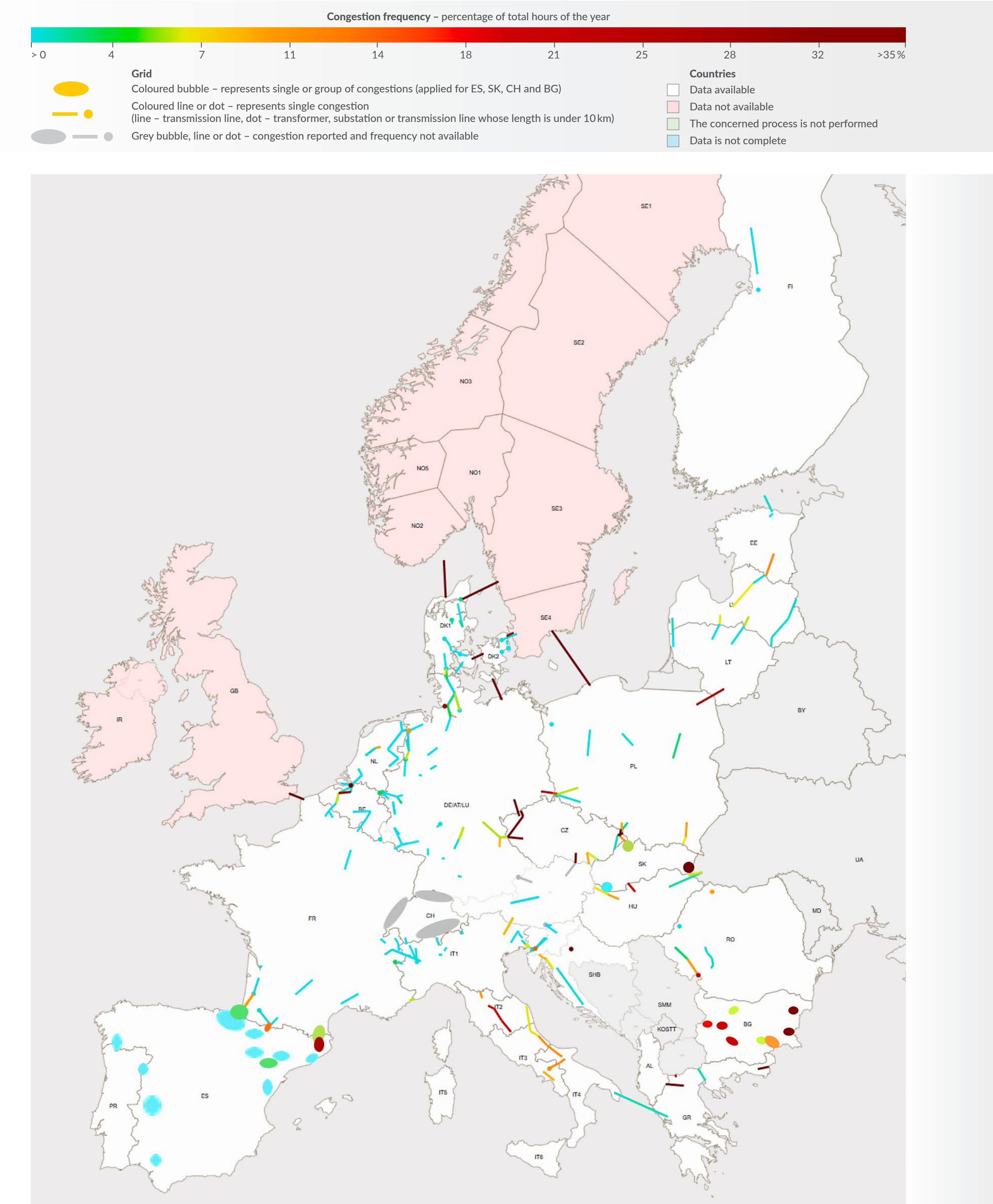


Figure 17: CCDA for 2017. Europe

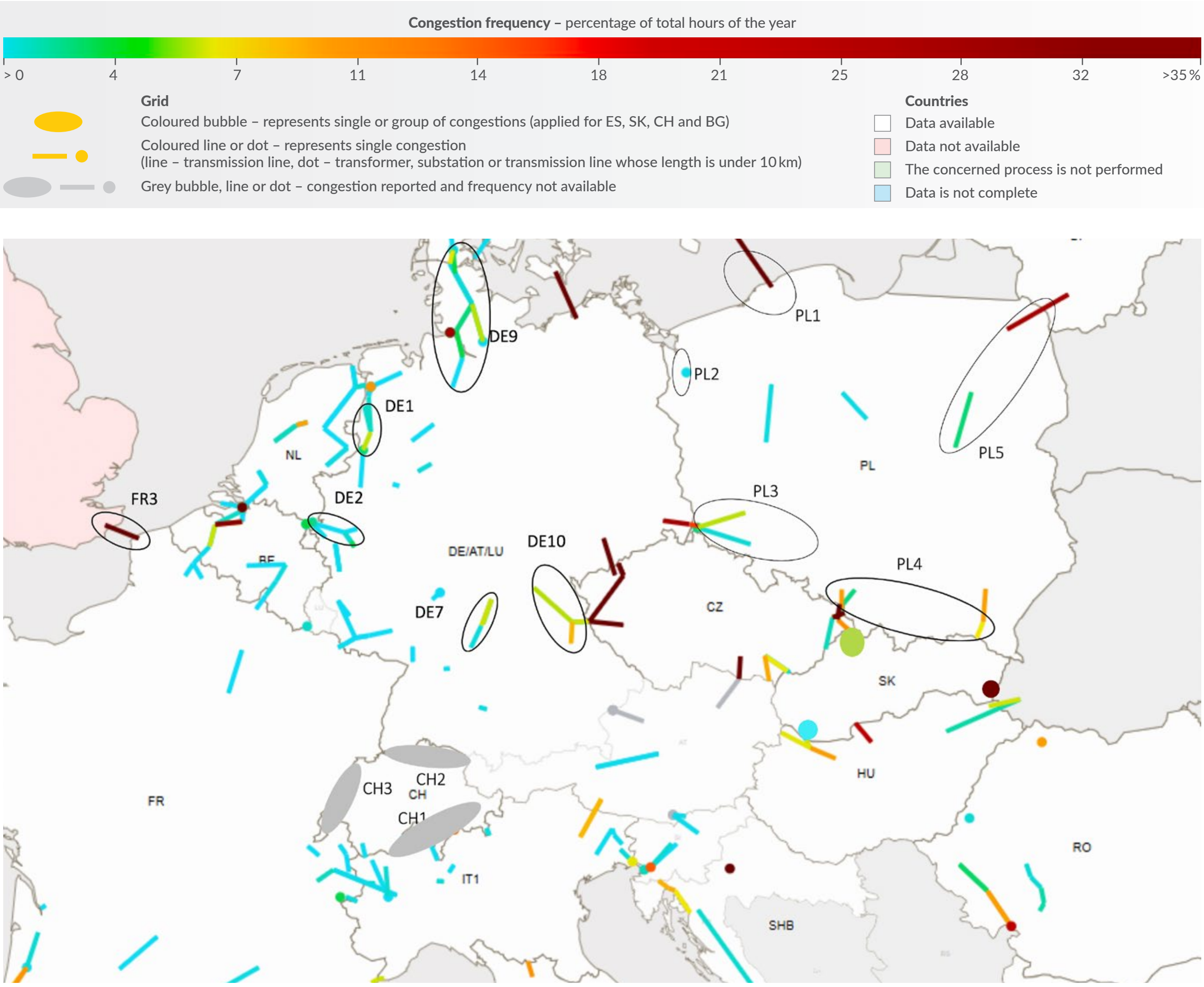


Figure 18: CCDA for 2017. Central Europe

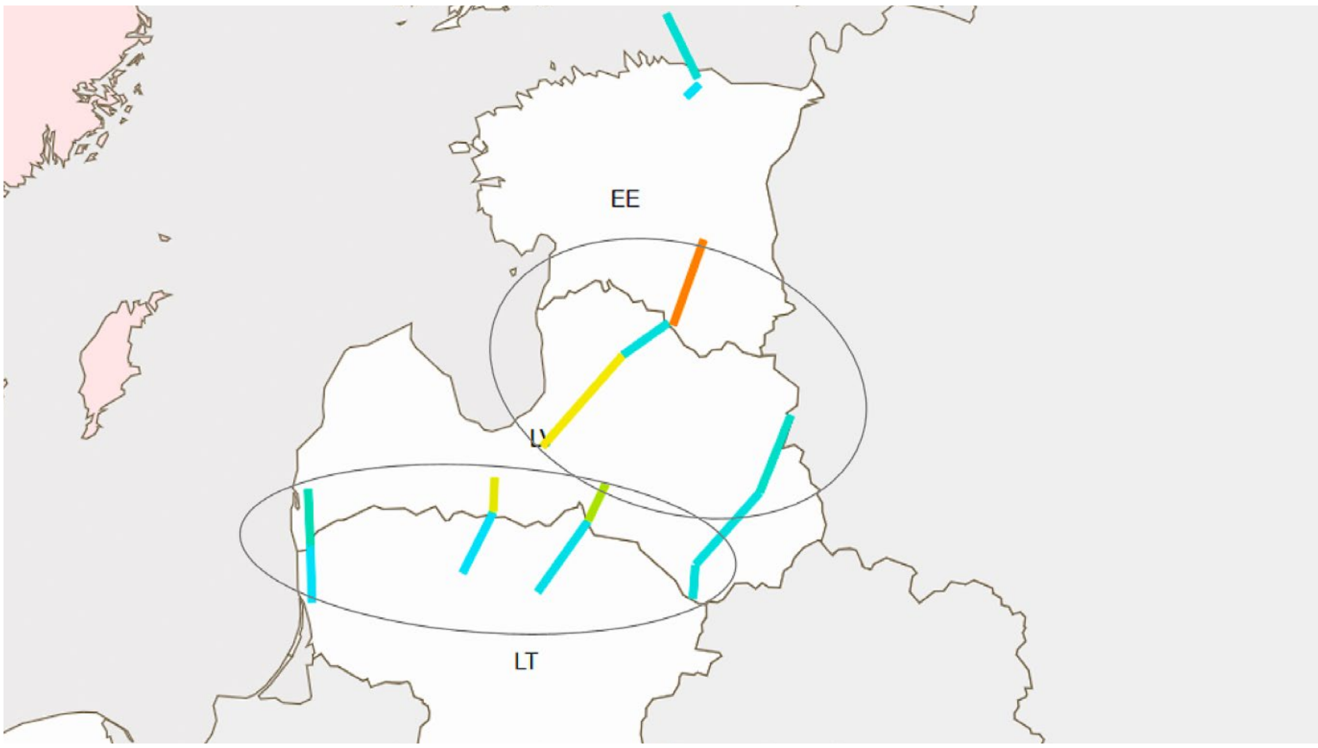


Figure 19: CCDA for 2017. Baltic countries

Congestion frequency – percentage of total hours of the year

> 0 | 4 | 7 | 11 | 14 | 18 | 21 | 25 | 28 | 32 | >35 %

Grid

Coloured bubble – represents single or group of congestions (applied for ES, SK, CH and BG)

Coloured line or dot – represents single congestion
(line – transmission line, dot – transformer, substation or transmission line whose length is under 10 km)

Grey bubble, line or dot – congestion reported and frequency not available

Countries

Data available

Data not available

The concerned process is not performed

Data is not complete

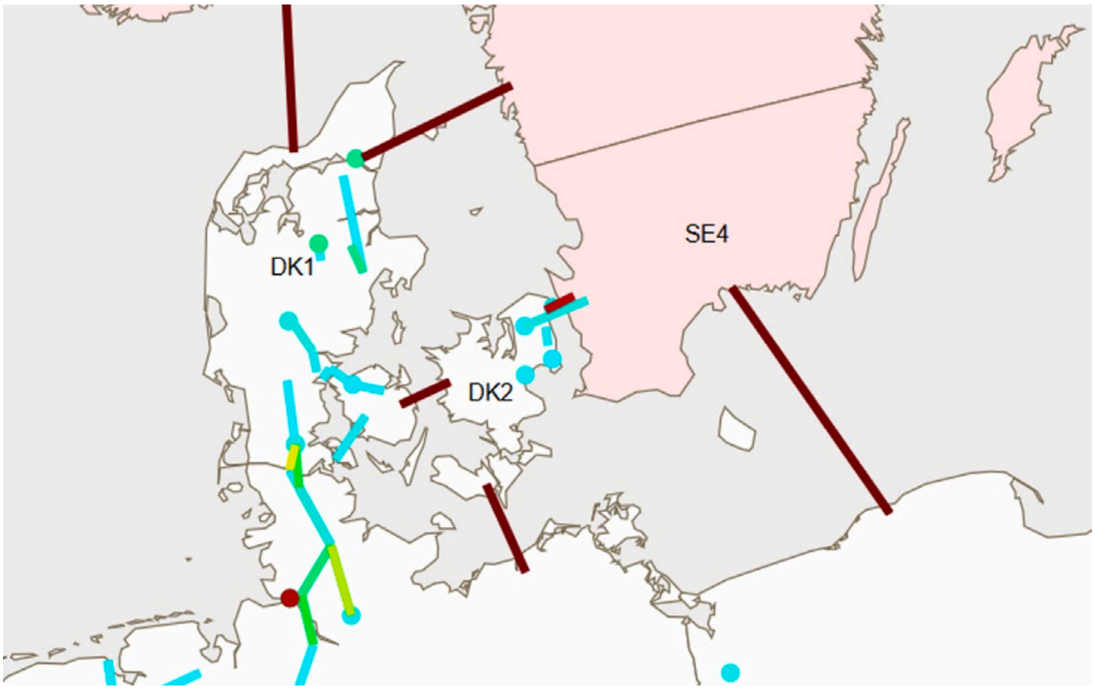


Figure 20: CCDA for 2017. Denmark/Sweden

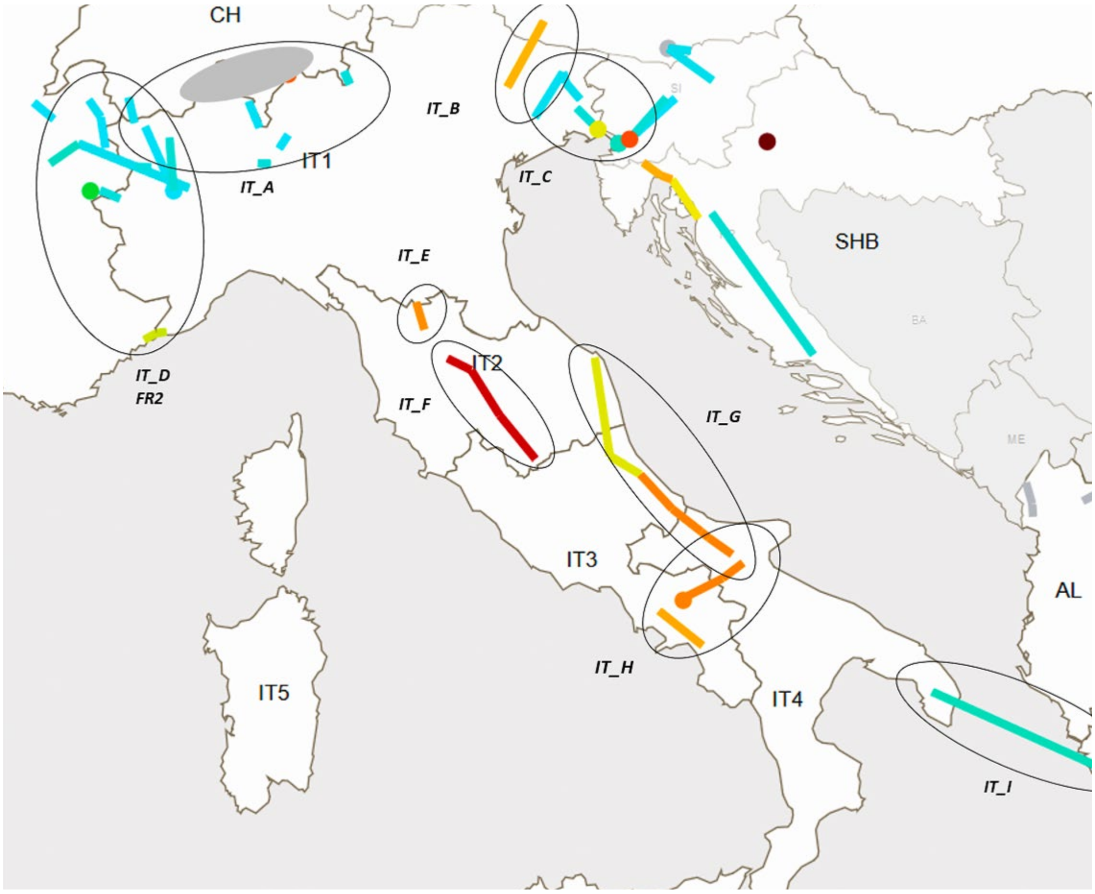


Figure 21: CCDA for 2017. Italy

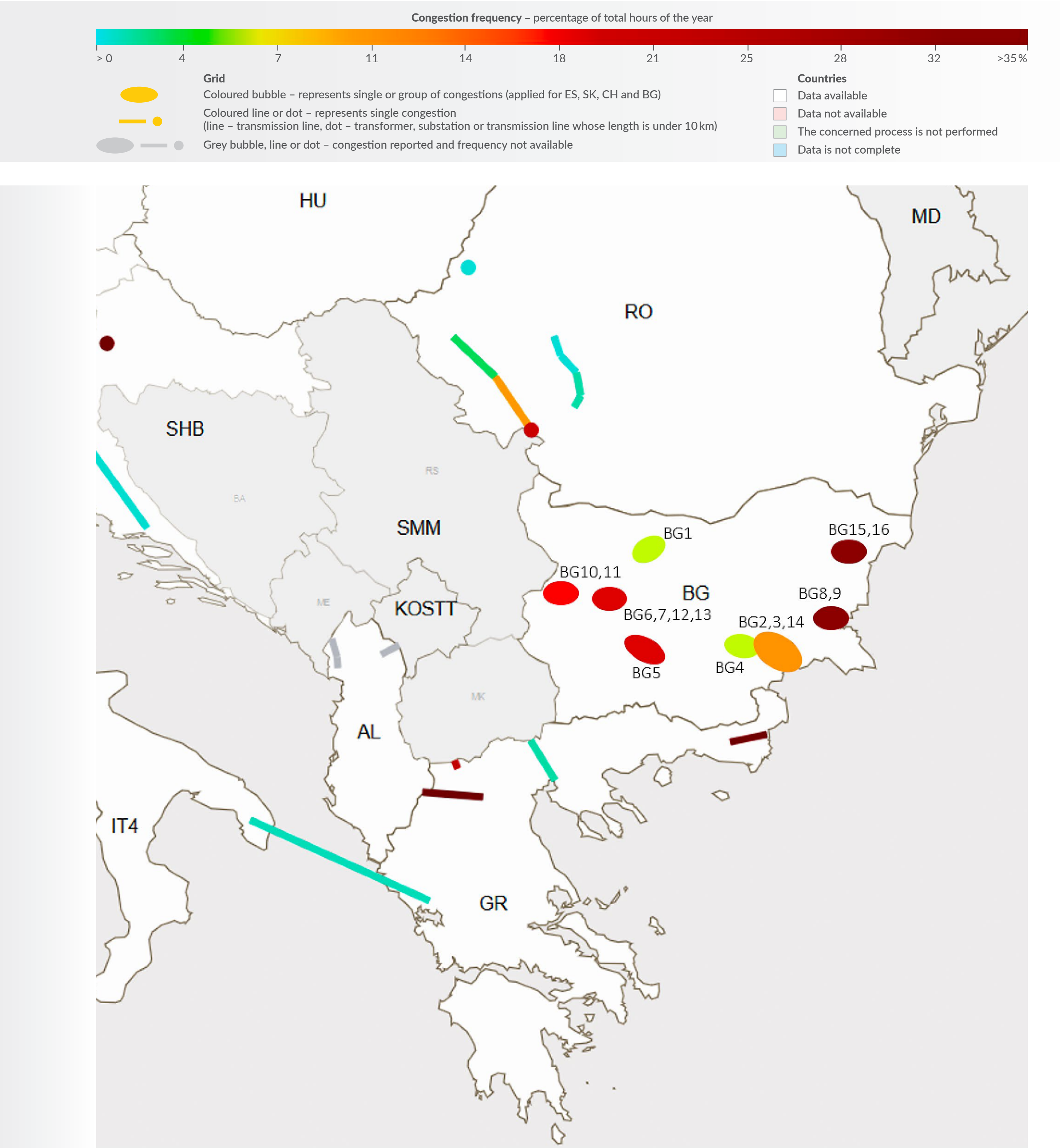


Figure 22: CCDA for 2017. Balkan countries

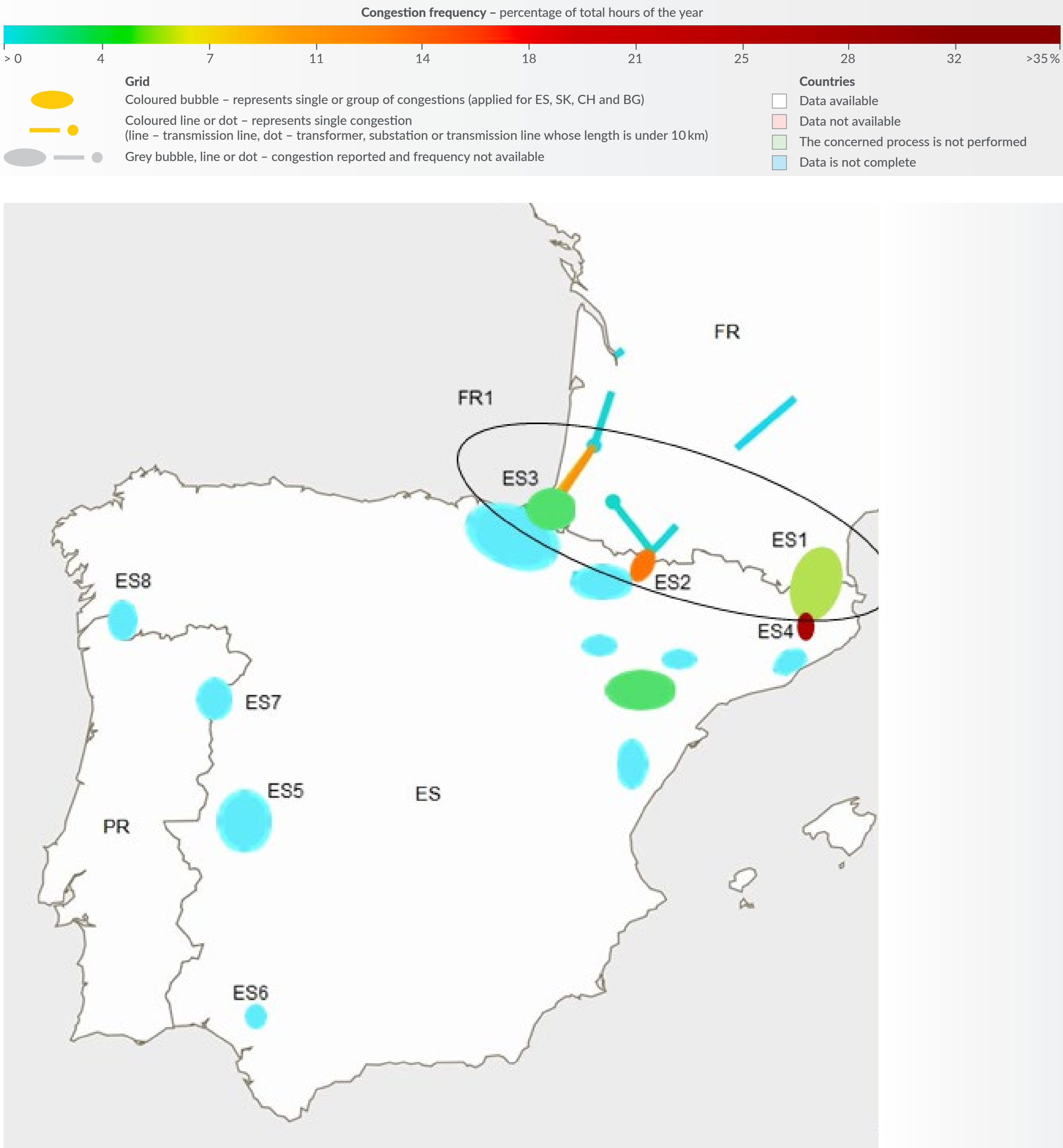


Figure 23: CCDA for 2017. Spain/Portugal

2.2.2 EXPERT ASSESSMENT OF CONGESTIONS FOR CAPACITY CALCULATION FOR THE PURPOSE OF CAPACITY ALLOCATION

The primary objective of Section 2 is to report on where congestions have occurred in the grid over the reported years 2015, 2016 and 2017. In this sub section, each TSO provides an expert assessment of how these congestions have evolved over the reported years for the stage 'capacity calculation for the purpose of capacity allocation'. This includes an expert assessment of the causes of the congestions and the interdependencies of congested lines.

AUSTRIA

For the given period of time, APG's Capacity Allocation at the borders between Austria and its neighbours (except Italy) is based on past and real-time situations as well as expectations for the next two days (maintenance, planned disconnections due to grid reinforcements, wind-, PV- and hydro power infeed).

In February 2016, a coordinated D-2 capacity calculation process was implemented in the CCR North Italy, which maximises the cross-zonal import-capacities at the North Italian border, but requires improvement for the coordination of non-costly remedial actions. The frequency of congestions in 2015 was estimated by a yearly capacity calculation process on TERNA side.

For the years in scope, most of the reasons for limiting cross-zonal capacity in Austria are either cross-border elements or situations on network elements due to planned disconnections because of grid reinforcements.

BELGIUM

Regarding the capacity calculation for the purpose of DA allocation (CCDA) framework and for all the years in scope, the main elements limiting cross-zonal capacity in Belgium (active market constraints for the DA market coupling process) were located at the Belgian borders: both North (NL-BE) and South (BE-FR). After DA market coupling, within the D-1 operational planning stage, these congestions are usually reduced due to the application of topological measures and preventive remedial actions.

CZECH REPUBLIC

For the given period of time, no congestions on internal network elements of bidding zone Czech Republic have been recorded. The constraining network elements appeared only on bidding zone borders, respectively on borders where cross border allocation does exist (ČEPS – TTG, ČEPS – 50Hertz, ČEPS – APG, etc). Predominantly, the cross border line of voltage level of 400 kV shall be considered as actively constraining the cross-border capacity. This concerns all borders between the Czech Republic and neighbouring systems except the border between ČEPS and PSE, where cross border lines of 200 kV voltage level also appeared as constraining in time. The deployment of constraining elements has been stable over time.

DENMARK

In Denmark there are generally no significant congestions internally in the bidding zones as is also evident from the maps presented in Chapter 2. Energinet have historically been proactive in ensuring that the transmission grid internally has been developed continuously along with the commissioning of new interconnectors and with the introduction of the quite significant amounts of renewable generation found in Denmark.

CCDA timeframe:
In the capacity calculation phase, there are no lines or transformers which, in all of the reported three years from 2015 – 2017, have been congested to a point where it influences capacity calculation in more than 53 hours during any given year.

For some lines or transformers they are limiting for up to 2 % of the time in one year but not in other years. This is normally due to periods with planned outages of other grid elements for maintenance of the grid or the construction of new grid elements.

There is only one case, in 2016, where a 400/150 kV transformer in Tjele limited the Danish capacity calculation on bidding zone borders for more than 3 % of the time.

The maps also show significant congestions on the cross-border lines to neighbouring countries, indicating that they are in fact the bottlenecks of the electricity system.

ESTONIA

For the given period, the capacity was constrained according to the common capacity calculation rules in the Baltics. Elering does its utmost to provide maximum capacity to the market. According to the methodology, the capacity was reduced due to restrictions on maximum power flow on the interconnection between Estonia and Latvia. Elering reported the interconnection as the current weakest line in the interconnection that would most likely be overloaded in the event of the most serious N-1 occurrence. That line is situated on the cross-border.

The connection between Finland and Estonia was limited mostly due to technical limits of the HVDC links. On a few occasions, the limitations were due to maintenance works inside the Estonian power system that warranted the limiting of export capacity towards Finland.

FINLAND

In December 2016 three new lines came into operation to reinforce cut P1 connection (i.e. the internal north-south connection). The three lines Tuovila – Hirvisuo, Hirvisuo – Jylkkä and Jylkkä – Pikkarala combined to form a north-south connection along the west coast of Finland. The commissioning of these lines allowed for an increase in P1 capacity and outages of P1 lines no longer resulted in capacity reductions in 2017. In addition to the P1 reinforcements, significant investments have been made to reinforce the grid in Northern Finland. The construction and maintenance work necessitated planned outages and capacity reductions on several lines in Northern Finland during 2015 and 2016.

FRANCE

Exceptional power system conditions and situations of planned outages are taken into account in the frequency levels.

The area FR1 can be qualified as structurally congested. RTE and REE committed themselves to a high level of grid investments with several projects already commissioned, such as the HVDC Baixas-Santa Llogaia in 2015 and the PST of Arkale in 2017. The Biscay Gulf project, whose commissioning is planned in 2025, should almost double the cross-zonal capacity between France and Spain.

It should be noted that since the commissioning of the PST of Arkale, some congestions located in the western part of the border have been transferred to the central part (Pragnères 225 kV) due to the PST optimisation. This configuration maximises the cross-zonal capacities in such cases.

Some French internal elements are monitored by REE according to their risk policy and limited the cross-zonal capacity in REE capacity calculations and not in RTE capacity calculations. Therefore, the frequencies of those elements are the result of the sum of the cases where they are considered as active constraints by RTE and by REE. Concerning the cross-border elements, only the higher frequency between RTE and REE is visible on the maps. Frequencies per TSO are available in Appendix 1.

The active constraints in the area FR2 appeared in 2016, following the go-live of the coordinated CCDA, which maximises the total Italian import capacities (from the North Italian TSOs to Italy) with more accuracy concerning the limiting critical network elements. A few active constraints can be noted, which are created by the PST optimisation. A new HVDC line between France and Italy (the 'Savoie-Piémont' project) is currently under construction in order to increase the cross-zonal capacity of the North Italian border, and whose commissioning is planned in 2019.

The French-British border is crossed by DC interconnections only (area FR3). There is no capacity calculation for this border, i.e. the full physical transmission capacity of the DC cables is always given to the market. Therefore, the frequency of the active constraint corresponds to the price divergence between France and Great Britain, adjusted for losses. Several projects of new DC interconnections are on-going, the most advanced being Ecleclink and IFA 2, both planned for 2020.

The occurrence of all the other active constraints in France is very low (under 1%) and usually corresponds to situations of planned outages. Therefore, no other active constraint in France can be qualified either as structural or as major. Nevertheless, RTE maintains its investment in the whole territory in anticipation of potential future structural congestions.

GERMANY

Germany is a key exchange country. Due to its central location in the European electricity system, it is an important transit country. Moreover, Germany is one of the biggest exporters, especially when renewable infeed is high in the northern part. Most of the congestion in the German grid appears in this situation, when Germany exports electricity.

50Hertz

In the CCDA framework and for all years in scope, the main elements limiting cross-border capacity in Germany were the lines located at the German borders and the respective feeding lines: The KONTEK DC-link to Denmark, the lines on the Polish border (*Krajnik – Vierraden* and feeding lines as well as *Hagenwerder – Mikułowa* and feeding lines) and the interconnector to the Czech Republic (*Röhrsdorf – Hradec*).

In 2017 it can be seen that the red lines on the German – Polish interconnector *Krajnik – Vierraden* disappear. This is due to construction work (upgrading of the line and the installation of PSTs) for which the interconnector has been switched of.

Amprion

Of note, the cold spell in the beginning of 2017 was an exceptionally critical situation during which Germany exported large amounts of electricity in order to alleviate energy scarcities in other bidding zones. Several capacity-increasing measures, e.g. removal of the Final Adjustment Value (FAV) and the introduction of winter limits, were taken by Amprion to make this possible, causing an unusually high pressure on the grid. When analysing the data, this should be considered.

Congested area DE 2 [DE – NL] (2015 – 2017)

Congestions in this area predominantly appear when there is a high infeed of base load power plants, i.e. mainly lignite power plants, and at the same time Germany exports electricity. The concerned grid elements are the 380 kV cross-border lines *Rommerskirchen – Paffendorf – Oberzier – Siersdorf – Maasbracht (TTN)* and the upstream internal 380 kV lines *Rommerskirchen – Brauweiler – Knapsack – Sechtem*. For the observed years, a clear downward trend in the frequency of congestions is noticeable. This is at least partly due to the capacity-increasing measures which Amprion has taken, e.g. removal of the FAV and introduction of winter limits and dynamic line rating. Evidence that congestions have therefore shifted closer to real time is visible in the D-1 stage.

Congested area DE 1 [AMP – TTG] (2015 – 2017)

Congestions in this area predominantly appear when there is a high wind infeed in the North of Germany and at the same time Germany exports electricity. The grid elements concerned are the 380 kV lines *Gronau – Hanekenfähr – Meppen – Niederlangen (TTG) – Dörpen/West (TTG)* and the transformer at Gronau. For the observed years, there is no clear trend in the frequency of congestions noticeable. This is at least partly due to a higher wind infeed in 2017 compared to 2016 which has offset the capacity-increasing measures which Amprion has taken, e.g. removal of the FAV and the introduction of winter limits and dynamic line rating. Without these measures, the congestions in this area would have most likely increased. Evidence that congestions shifted closer to real time is visible in the D-1 stage.

General remarks concerning the capacity calculation and allocation stage:

It can be seen that due to the introduction of the 20 % minRAM which is applied in the CWE region from April 2018 onwards, almost no internal lines of Amprion are actively limiting the DA market anymore. Consequently, cross-border lines, e.g. the *Ensdorf – Vigy* line to France, are more often the limiting element.

TenneT GER

Congested area DE 9

The cluster includes the 380 kV lines *Kassoe – Jardelund – Audorf – Wilster*, *Wilster – Büttel – Brunsbüttel – Brunsbüttel* (949, TTG/50Hertz), *Wilster – Dollern – Sottrum* and the 220 kV lines *Kassoe/Ensted – Flensburg – Audorf – Hamburg Nord – Hamburg Nord* (50Hertz). In D-2, (capacity calculation stage, D2CF) all elements that are relevant for cross-border capacity calculation are monitored (contingency list according to the ENTSO-E Operational Handbook). To remedy the major grid constraints in this cluster, the grid development included two important constructions of 380 kV lines: *Audorf – Hamburg Nord*, *Audorf – Kummerfeld – Hamburg Nord* as well as *Brunsbüttel – Brunsbüttel* (951, TTG/50Hertz) – *Hamburg Nord* (50Hertz). These construction measures were on-going in the considered time period and were finalised at the end of 2017. Note that the construction in this period led to temporary restrictions in this cluster. Furthermore, even the enforcement of the grid element Brunsbüttel (949, TTG/50Hertz) did not eliminate the constraints in this cluster entirely (i.e. Brunsbüttel (949, TTG/50Hertz) has vanished from the map). The constraints are only transferred to the subsequent grid elements in the system (yellow marked lines in the map) depending on their contribution to the congestion. Therefore, the currently yellow marked lines will turn into orange/red marked lines depending on further grid development.

Frequencies were only available for 2016 and 2017. For 2015, the same frequencies have been assumed as applicable for 2016.

Congested area DE 10

This cluster includes the 380 kV lines *Redwitz – Etzenricht – Schwandorf* and the interconnectors *Etzenricht – Hradec* and *Etzenricht – Prestice*. In the years 2016 and 2017, this cluster was improved by the enforcement of the 380 kV line *Redwitz – Remptendorf*, the newly constructed 380 kV line *Redwitz – Altenfeld* and the extension of the connection between *Altenfeld – Vieselbach* in the control area of 50Hertz. Note that the construction in this period led to temporary restrictions in this cluster. Furthermore, even the enforcement of the grid element *Redwitz – Remptendorf* did not eliminate the constraints in this cluster entirely (i.e. *Redwitz – Remptendorf* has vanished from the map). The constraints are only transferred to the subsequent grid elements in the system (yellow marked lines in the map) depending on their contribution to the congestion. Therefore, the currently yellow marked lines will turn into orange/red marked lines depending on the further grid development. In D-2 (capacity calculation stage, D2CF) all elements (especially the cross-border lines) that are relevant for cross-border capacity calculation are monitored (contingency list according to ENTSO-E Operational Handbook). NTC values at the ČEPS – TenneT – D border are determined in close coordination with the ČEPS – 50Hertz profile. Additionally, the impact of the ČEPS – APG border is taken into account by ČEPS in the event of topology changes, i.e. PST implementations and modifications. Due to mutual interdependencies between the ČEPS – TenneT-D and ČEPS – 50Hertz profiles via the ČEPS grid (substation Hradec and Kadane etc.) the level of unscheduled flows at the ČEPS – 50Hertz border has to be taken into account from ČEPS' point of view when the NTC between ČEPS and TenneT-D is assessed.

Frequencies were only available for 2017. For 2015 and 2016, the same frequencies have been assumed as applicable for 2017.

TransnetBW

Congested area DE7

The line 380 kV Grafenrheinfeld – Stalldorf rt was structurally damaged from winter 16/17 until end of October 2017 and therefore a lower thermal limit had to be applied throughout the majority of 2017. Consequently, the line limited the DA market more frequently. Since this corridor is heavily impacted by north to south flows it will be further upgraded in the future (see the 'Future Developments' section).

Studies performed by CWE TSOs show that due to the 20 % minRAM which is applied in the CWE region from April 2018 onwards, no lines of TransnetBW will actively limit the DA market in the future.

Congested area DE6

The line Daxlanden-Eichstetten showed constraints in the years 2015 and 2016. Since the loading of the grid in this area is expected to increase in the future, it is foreseen that several lines in this area will be upgraded (see 'Future Developments' section).

GREECE

The Greece – Italy border is a DC interconnection. The full physical transmission capacity of the DC cable is always given to the market.

For the AC interconnections, the status per year is as follows:

2015

For the total amount of Greek imports, the critical element is mainly the tie line between Greece and Turkey, while one tie line between IPTO and MEPSO also has a relative considerable share. Other lines that were the critical elements were from neighbouring grids (between MEPSO – KOSTT, MEPSO – ESO); the latter ones appeared in maintenance periods.

For the total amount of Greek exports, the main critical element is the tie line between Greece and Albania; additionally, a tie line between IPTO – MEPSO also has a relative considerable share.

2016

For the total amount of Greek imports, the main critical element is the tie line between Greece and Turkey, while one tie line between IPTO and MEPSO also has a relative considerable share, higher than in 2015 since there was in operation a new tie line between MEPSO – EMS.

For the total amount of Greek exports, the main critical element is the tie line between Greece and Albania, additionally a tie line between IPTO – MEPSO also has a relative considerable share.

2017

For the total amount of Greek imports, the main critical element is the tie line between Greece and Turkey, with an increased share compared to 2015/2016 due to the increased Turkish exports at that period, while one tie line between IPTO and MEPSO also has a relative considerable share.

For the total amount of Greek exports, the main critical element is the tie line between Greece and Albania, additionally a tie line between IPTO – MEPSO also has a relative considerable share.

HUNGARY

The congestions of the Hungarian system in this timeframe are concentrated in the northern part of the network. This congestion area consists of cross-border lines and those directly connected internal lines at the Austrian, Slovak and Ukrainian border. In a broader sense, this area is part of the so-called Central Eastern European profile, which is a structural bottleneck between the northern and central parts of Central Eastern Europe. This profile consists of the tie-lines between Czech Republic and Austria, Slovakia and Hungary and, Slovakia and Ukraine. In Hungary, constraints of this profile limit market exchanges mainly on the Austrian-Hungarian and Slovak-Hungarian borders, and are in that way the main active market constraints in the country. When the market exchanges are limited, mostly the two cross-border lines to Slovakia and the 220 kV circuits in the western part of Hungary (one line, partly double-circuit running over several substations form the centre of the country over the border towards Austria) set the limits. Other lines limit less frequently, usually in maintenance situations when one or several lines are not available in the area. The constraints have been relatively stable in the 2015-2017 time period; no constraints have gained or lost importance in a significant manner.

ITALY

Active critical branches in the Italian Power System are presented for all existing bidding zone borders, including internal Italian Bidding Zones[6].

At the Northern Italian borders (Cluster IT_A, IT_B, IT_C, IT_D) data from the yearly capacity calculation process have been used for 2015 (and this led to very high frequencies), while data from the CCDA process (activated in February 2016) have been considered for 2016 and 2017.

The frequencies of critical branches activation is:

- Decreased on the border between IT1 (Italy North) and IT2 (Italy Central North) (cluster IT_E) in 2017 (11 %) compared to the previous years (20 % in 2015 and 25 % in 2016) and on the border between Italy and Greece (cluster IT_I) (2 % in 2017 versus 13 % in 2015 and 10 % in 2016);
- Increased on the border between IT2 (Italy Central North) and IT3 (Italy Central South) (cluster IT_F and IT_G), from 6 % to 19 %;
- Stable on the border between IT3 (Italy Central South) and IT4 (Italy South) (cluster IT_H), between 12 % and 14 %.

Cross-zonal capacity between Continental Italy and the main islands (IT5 Sardinia, IT6 Sicily) is not displayed in the maps since dynamic and voltage issues are typically limiting the capacities on these borders.

LATVIA

In the area of Latvia in the CCDA timeframe there were few OH lines which were limiting cross-zonal capacity between the bidding zones EE-LV and LV-LT during the observed period of time.

In 2015, the main limitations have been recognised between bidding zones Latvia and Estonia, and there were three cross-border lines which have an impact on capacity limitations and four internal lines which reduced the market capacity for certain hours and in different circumstances. In 2015 only one cross-border line has been identified which limited the cross-zonal capacity between bidding zones Latvia and Lithuania. This kind of limitation is rather small and insignificant because it occurred for only a few hours in the year. All these limitations have been recorded as 'system security' because the Baltic States are still operating in synchronous mode with IPS/UPS power system and there are no harmonised rules for wholesale power exchanges between the EU and Russia/Belarus.

In 2016, the hours with cross-zonal capacity limitations on the EE – LV were reduced due to a reduction of power exchanges from north to south within Baltic States. In 2016, a new link was established from Lithuania to Sweden (NordBalt) with a capacity of 700 MW and it reduced the power flow from Finland and Estonia to Lithuania via Latvia. The new link reduced the congestions on all cross-borders in area of Latvia. Some insignificant capacity limitations on cross-border EE – LV remained. In 2016, no capacity limitations were recorded between the Latvia and Lithuania bidding zones.

In 2017, the congestions between bidding zones did not increase and there were few cross-border lines which were influencing the power exchanges between bidding zones. The capacity limitations on cross-borders were small (less than 10 % for each line in 2017) and all those limitations have been recognised as system security. The system security issue is very important as the Baltic States' power systems are operating in synchronous mode with IPS/UPS.

6 Critical branches for internal borders have been identified according to the outcomes of the yearly capacity calculation process. Hence, the effect of planned outages on the critical branches selection is only partially taken into account

LITHUANIA

Internal grid elements of the Lithuanian power system rarely limit cross-border capacities between Lithuania and the neighbouring systems. During the time period from 2015 until 2017 only a few cross-border lines were identified as the elements reducing capacity between Lithuania and Latvia biding zones. However, these limitations were not significant and have occurred less than 1% of time in 2015 and 2017. In 2016, there were no limitations at all.

Regarding the interconnection between Lithuania and Poland, during 2017 there were some capacity constraints in the direction from Lithuania to Poland. These limitations were not frequent (occurring 3.8% of time) and they are no longer expected, since the new 330 kV double circuit transmission line Alytus-Kruonis is already in operation.

NETHERLANDS

In the CCDA framework, the import for the Netherlands was very seldom restrictive as an external constraint. Next to the interconnectors *Meeden – Diele* and *Maasbracht – Rommerskirchen*, the following internal lines were restrictive: *Lelystad – Ens*, *Krimpen – Geertruidenberg* and *Diemen – Lelystad*. No congestions appeared on the DC-cables BritNed and Norned.

In specific line outage situations, a reduction of the monthly long term transmission rights is used.

NORWAY

The Norwegian control area today consists of five bidding zones. The configuration of bidding zones have changed many times after multiple bidding zones were implemented in Norway more than 25 years ago. The reason for the changes is to ensure that we reflect structural, physical bottlenecks in the grid in the best possible way. Statnett still has a process to reassess bidding zone configuration to ensure the efficient handling of congestions.

Statnett monitors about 300 cuts in normal operation, plus approximately 100 more per week depending on outages in Norway. The most significant of these can be found on the bidding zone borders. Today, Statnett has an expert assessment-based process for capacity allocation, and does not keep a detailed record of internal or cross-border CNEs that reduce transmission capacity in a format that suits this report. Statnett expects to have such a process in operation when the FB market algorithm is planned to be implemented in 2020.

In general, when all grid elements are in operation, internal bottlenecks rarely reduce trading capacity, apart from some periods in winter where high consumption in Oslo reduces the possible transit flow from NO2 and NO5 through NO1 to SE3.

During a period from 2013-2022 with increased investment in new grid and upgrades of the existing grid, Statnett has reached the investment peak in 2018. The following list contains completed, ongoing or planned significant grid investment projects that are expected to increase transmission capacity during 2018:

- Voltage upgrade of 300 kV *Namsos – Nedre Røssåga* to 420 kV in NO4, completed 2017
- New line 420 kV *Ørskog – Sogndal*, completed in 2016, creates a new corridor between NO5 and NO3.
- Voltage upgrade of 300 kV *Klæbu – Namsos* til 420 kV in NO3, completed in 2017
- Inner Oslo fjord-cables will increase transmission capacity from NO1 to SE3 in periods of high consumption in Oslo during winter, to be completed 2018.

POLAND

Active constraints in Poland visible in the timeframe of capacity calculation for the purpose of DA allocation can be grouped into five clusters.

The cluster PL1 represents transmission limitations related to the DC cable between Poland and Sweden. This cable was initially built as an alternative means of supplying energy to Northern Poland instead of a generation unit. Hence, there are some limitations of exports towards Sweden. Investments related to the build-up of the off-shore grid in Poland should eliminate these limitations in the near future.

The cluster PL2 – especially for 2015 and 2016 – and clusters PL3 and PL4 – for all three years – represent structural congestions relevant for power exchange on Polish synchronous borders i.e. PL–DE, PL–CZ and PL–SK. The presented active constraints concern cross-border lines and lines directly connected to border substations, and hence they are highly influenced by unscheduled flows. It is already apparent that in 2017 the active constraints are of lower frequency compared to 2016 and 2015. This is a consequence of PST installation in Mikułowa substation and temporary disconnection of the 220kV *Krajnik–Vierraden* interconnection. Although these active constraints will most likely remain on the Polish synchronous border in near future, they will be mitigated to a certain extent by splitting the DEAT bidding zone, PST installation in Vierraden substation, upgrading the *Krajnik–Vierraden* interconnector from 220kV to 400kV and grid investments at the Polish side around Mikułowa substation, i.e. 400kV *Mikułowa–Czarna* in 2022, 400kV *Czarna–Polkowice* in 2019, 400kV *Mikułowa–Czarna–Pasikurowice* in 2022 and 400kV *Mikułowa–Świebodzice* in 2023.

The cluster PL5 represent active constraints related to interconnection between Poland and Lithuania. It must be noted that the limitation displayed on the maps mainly represents the back-to-back converter station connecting two asynchronous systems. Additionally, since the LitPol project is not yet fully finalised and some grid investments foreseen in the Poland–Lithuania project plan are still ongoing, some active constraints in that area limit export capacities in the direction from Poland to Lithuania. These are expected to be mitigated as soon as the foreseen lines are built e.g. 400kV *Ostrołęka–Stanisławów* in 2023.

Any other constraints apart from the ones grouped under the aforementioned clusters cannot be deemed as structural congestions. The frequency of those constraints is relatively low, e.g. 220kV Pila *Krzewina–Plewiska* is active just 0.5% of all hours in 2017 and grid investments are expected to solve those constraints in near future, e.g. a new double circuit line 400kV-Pila *Krzewina–Plewiska* in 2021.

PORTUGAL

Portugal and Spain have a single market and this market was split due to insufficient capacity in the following percentage of time in the last three years:

2015 → 2% of the time

2016 → 8% of the time

2017 → 7% of the time

Most of the congestions were related with tie-lines (cluster ES7 and ES8) and the Portuguese Generation Shift Key, namely because the Portuguese system did not have more generation to increase or decrease.

Some minor internal congestions close to the Douro and the Tejo interconnections did not exceed 0.1% of the time.

SLOVAKIA

As the maps show, there are no internal lines congested in the capacity calculation process. All the congested lines are only cross-border: three lines in total. The main reason for their congestion is the overloading caused by high transfer from the northern part of Europe (north of Germany) with high production to the southern part of Europe (Hungary, Balkan states) with a higher load. Most of the transfer is transmitted by three interconnectors on the SK–HU and SK–UA profile. The congested line between Slovakia and the Czech Republic is mainly congested because of high transfer flow from north to south through the Slovak transmission system which is combined with the planned outages of interconnectors on the PL–SK profile.

SLOVENIA

The frequent constraints in 2015 are due to the yearly process of capacity calculation, while constraints in 2016 and 2017 are more realistic and are a result of the coordinated CCDA, which maximises the cross-zonal capacities at the North Italian border with more accuracy concerning the limiting CNEs. A few active constraints can be noted around Divaca substation, which are for most of the time intentionally created by the PST located in the substation with the purpose to maximise overall IN CCR cross-zonal capacities.

SPAIN

There are no relevant active market constraints of the Spain-Portugal border as this border is rarely congested because of the high number of hours with price convergence. In general, for 2015, 2016 and 2017, REE active market constraints of the Spain-Portugal border do not usually exceed 1 % of the time. The observed congestions by REE are mostly placed on the tie-lines (clusters ES7 and ES8) or close to them (cluster ES5) and at 220 kV Western Andalucía (cluster ES6).

In 2015, 2016 and 2017, the Spain-Portugal border showed congestions at 220 kV Western Andalucía (cluster ES6), mainly due to import flows from Southern Portugal and low thermal capacity of 220 kV lines at Western Andalucía. These REE active market constraints are not relevant congestions and only in 2016 did the frequency of one line reach 2 % of the time. Due to the commissioning of some planned network element upgrades in 2018, congestions are expected to be further reduced.

In 2015, 2016 and 2017, the observed congestions by REE on the Spain-Portugal border are also placed on the tie-lines (clusters ES7 and ES8) or close to them (cluster ES5). These REE active market constraints of the Spain-Portugal border are not relevant congestions as they do not exceed 1 % of the time. From the REE side, the commissioning of a new Spain-Portugal interconnection and also some internal lines for 2023 will solve all the detected congestions.

The rest of the REE active market constraints for the Spain-Portugal border in 2015 are caused by REE network element outages and do not exceed 0.1 % of the time. Likewise, in 2016, the REE active market constraint at Duero Area is also the result of a long lasting network element outage with import flows from Portugal.

There are more active market constraints on the Spain-France border than on the Spain – Portugal border and as a result the Spain-France border is usually congested. In general, the REE active market constraints of this border are mostly placed on the tie-lines (clusters ES1, ES2 and ES3) or close to them (clusters ES4 and FR_1). The main reason for the congestions on the Spain – France border is the high import flows from France to Spain. Some REE active market constraints of the Spain-France border in this area reach frequency values between 20 % and 27 % of the time. Therefore, this area can be qualified as structurally congested.

In 2015, the observed congestions by REE for the Spain-France border are mostly placed on the East 400 kV interconnection line (cluster ES1) and on the 380 kV French line, continuation of the West 400 kV interconnection line (cluster FR_1). After the commissioning of the new HVDC link between Spain and France, the frequency of these active market constraints was reduced to less than 10 % of the time in 2016 while the rest of the interconnection lines kept similar values of frequency (clusters ES2 and ES3). In 2017, after the commissioning of the Arkale PST, the frequency of these active market constraints has been further reduced, except for the West 220 kV interconnection line (cluster ES3) and the 220 kV French line (cluster FR_1), continuation of West 220 kV interconnection line. This situation and the observed congestions by REE on the West 220 kV interconnection line and on the 220 kV French line are expected to remain until the commissioning of a new HVDC link between Spain and France that will increase the cross-border capacity between these countries.

In the capacity calculation stage, sometimes the REE active market constraints of the Spain – France border are RTE internal elements, as these network elements are considered as REE critical elements, due to the possibility of cascade tripping of the ES – FR tie lines.

In 2015, 2016 and 2017, the observed congestions by REE for the Spain-France border are also placed on a 220 kV line of the Gerona area, close to the Spain – France border (cluster ES4). This is mainly due to the import flows from France and its low thermal capacity during the summer period. From 2015 to 2017, this REE active market constraint increased its frequency from 15 % to 21 % of the time due to higher import flows from France to Spain. However, after the commissioning of the Arkale PST, a reduction in the frequency of this congestion is occurring. In order to solve this congestion, a development plan is scheduled by REE for 2020, so the congestion will be reduced as a result of the commissioning.

There are no additional relevant congestions of the Spain-France border. The rest of the REE active market constraints of this border are in the REE control area and are caused by REE network element outages or unusual operational situations related to RES or demand. In general, these REE active market constraints of the Spain-France border do not exceed 1 % of the time and only in some cases do they reach 3 % of the time.

SWEDEN

The data on specific grid elements is missing due to information security limitations.

Sweden is currently divided into four bidding zones. The bidding zones are based on known structural bottlenecks in the grid.

The West-Coast-Corridor is a known internal and structural bottleneck. Svenska kraftnät gives as much capacity as possible to the market with consideration of operational security in the Swedish grid. Svenska kraftnät therefore needs to maintain operational security on the West-Coast-Corridor.

The West-Coast-Corridor is made up of a few transmission lines on the Swedish West coast that get heavily loaded in situations with northbound flows, which differs from the other cuts in the transmission grid. This is the reason why the flow on the West-Coast-Corridor cannot be handled in an efficient manner with bidding zones, nor can it be handled by countertrade due to the lack of efficient balancing reserves in the area. In this situation, Svenska kraftnät applies a method whereby the capacity on the impacted interconnections is limited pro-rata with respect to their maximum capacity. In this way, the available capacity is distributed as transparently and fairly as possible. This exemption to the management of the other Swedish cuts has been granted by the EU Commission in Svenska kraftnäts commitment to introduce bidding zones and reinforce the West-Coast-Corridor.

Svenska kraftnät is working on reinforcing the grid in the Gothenburg region and has applied for a permit to build a new transmission line between Skogssäter and Stenkullen, which will increase the transmission capacity. In addition to building new transmission lines, Svenska krafnät will implement FB in the coming years and perform a review of the existing bidding zone configuration to further reduce the bottlenecks.

Revenues from internal Swedish congestion rents are earmarked for investments to reduce structural bottlenecks at the borders between the four bidding zones. A project is currently ongoing to increase the capacity on SE3-SE4 by two new HVDC links. Projects to increase SE2-SE3 capacity are planned, and further measures are being investigated.

SWITZERLAND

Congested area CH 1 (CH – IT)

Following the go-live of the coordinated CCDA in 2016, which maximises the cross-zonal capacities at the North Italian border, limiting CNEs are determined more accurately. The Italian-Swiss border is the only Northern Italian border that has no PST installed. Therefore, the possibility of controlling the power flows on the Swiss border is lower compared to the other borders. Thus, it is the most congested of the Northern Italian borders in the CCDA process.

Congested area CH 2 (DE/AT-CH)

The grid in Northern Switzerland is highly meshed and the appearance of congestions is dependent on maintenance activities in the area of the bidding zone border. Maintenance activities can lead to a decrease in the available cross-zonal capacity, especially in the planning phase. The occurrence of congestions in this area is influenced by national and also regional characteristics. In the winter period, the cross-zonal capacity is mainly limited by the PSTs in the Northern Swiss grid or the 380kV transit lines.

Congested area CH 3 (FR-CH)

The main reason for the congestions on the Swiss-French border is the high export situation from France. This is often dependent on weather conditions, as France has a high level of production but less demand in the event of early but warm winters. Main congestion in 2015 and 2016 was located on tielines between Switzerland and France, which was solved after a refurbishment in 2017.

2.2.3 D-1 TIMEFRAME

2015 – D-1

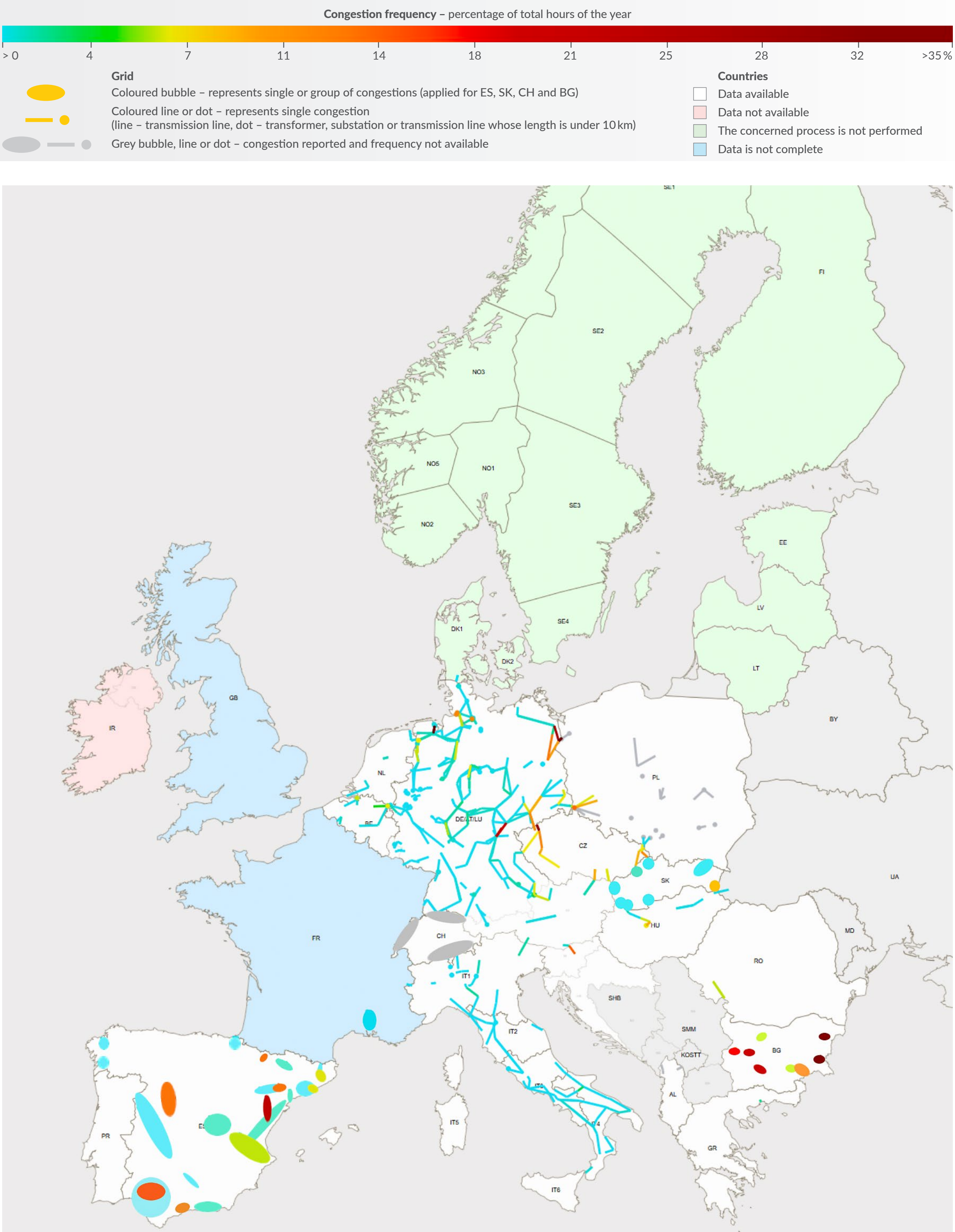


Figure 24: D-1 for 2015. Europe

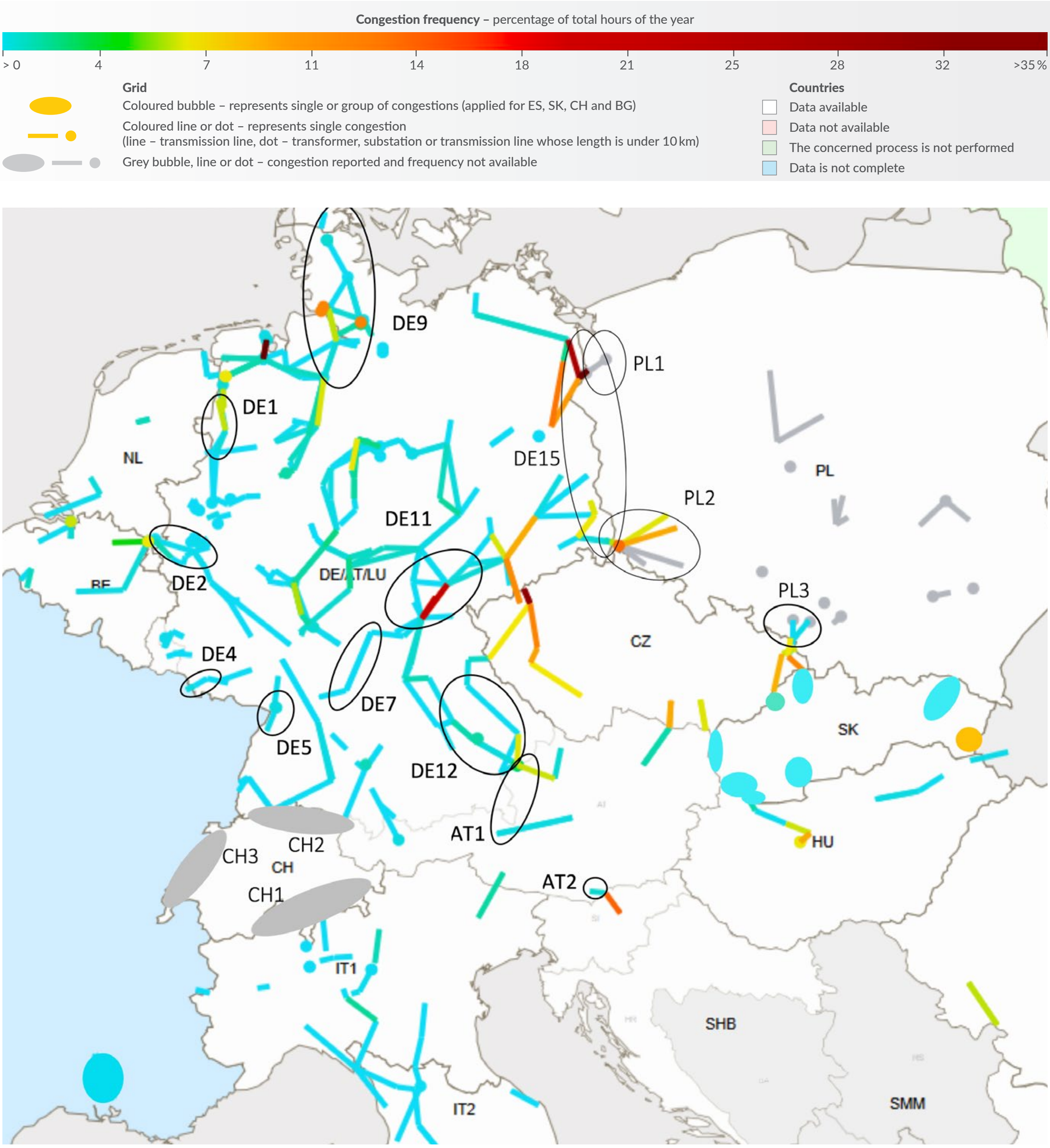


Figure 25: D-1 for 2015. Central Europe

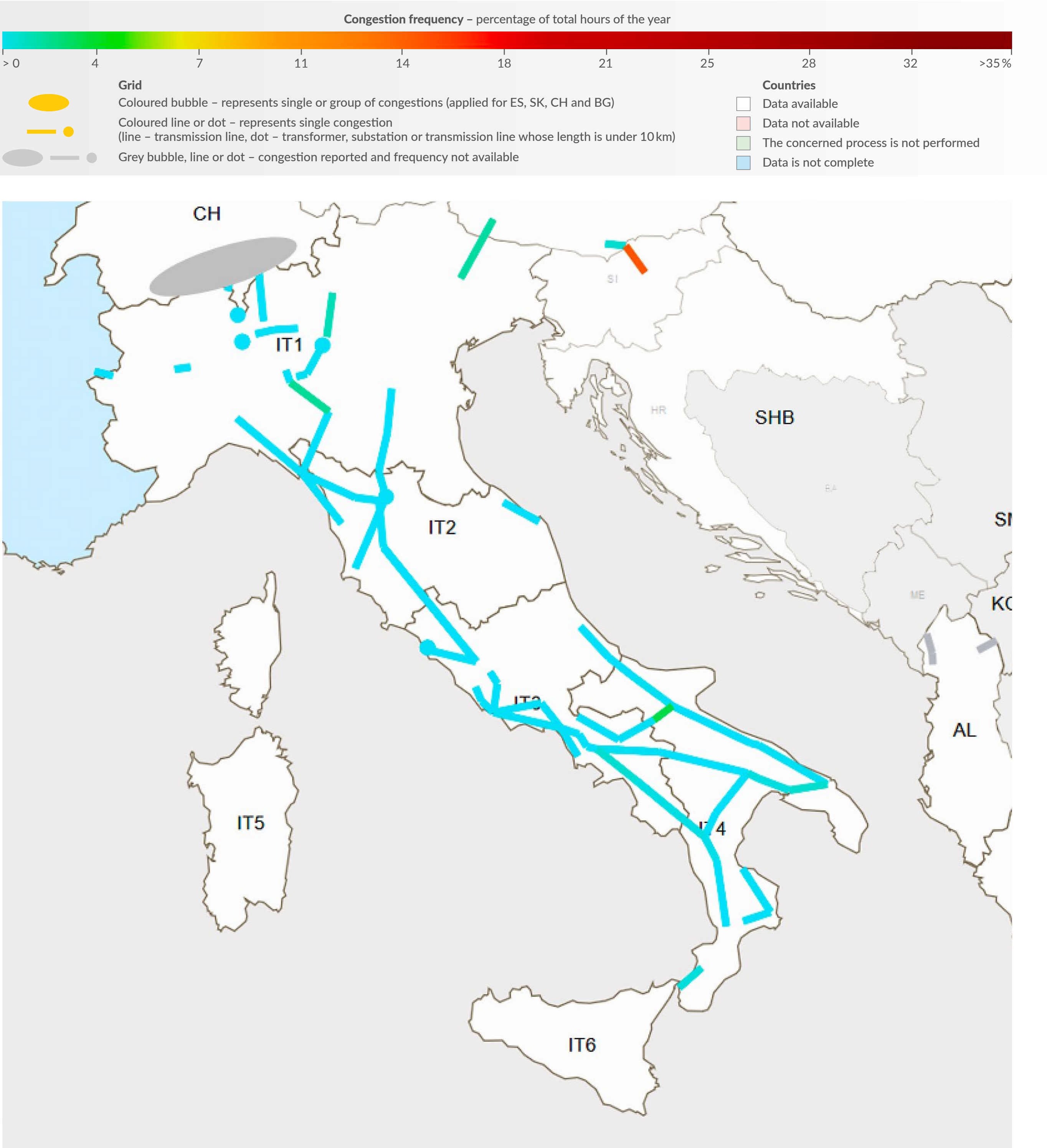


Figure 26: D-1 for 2015. Italy

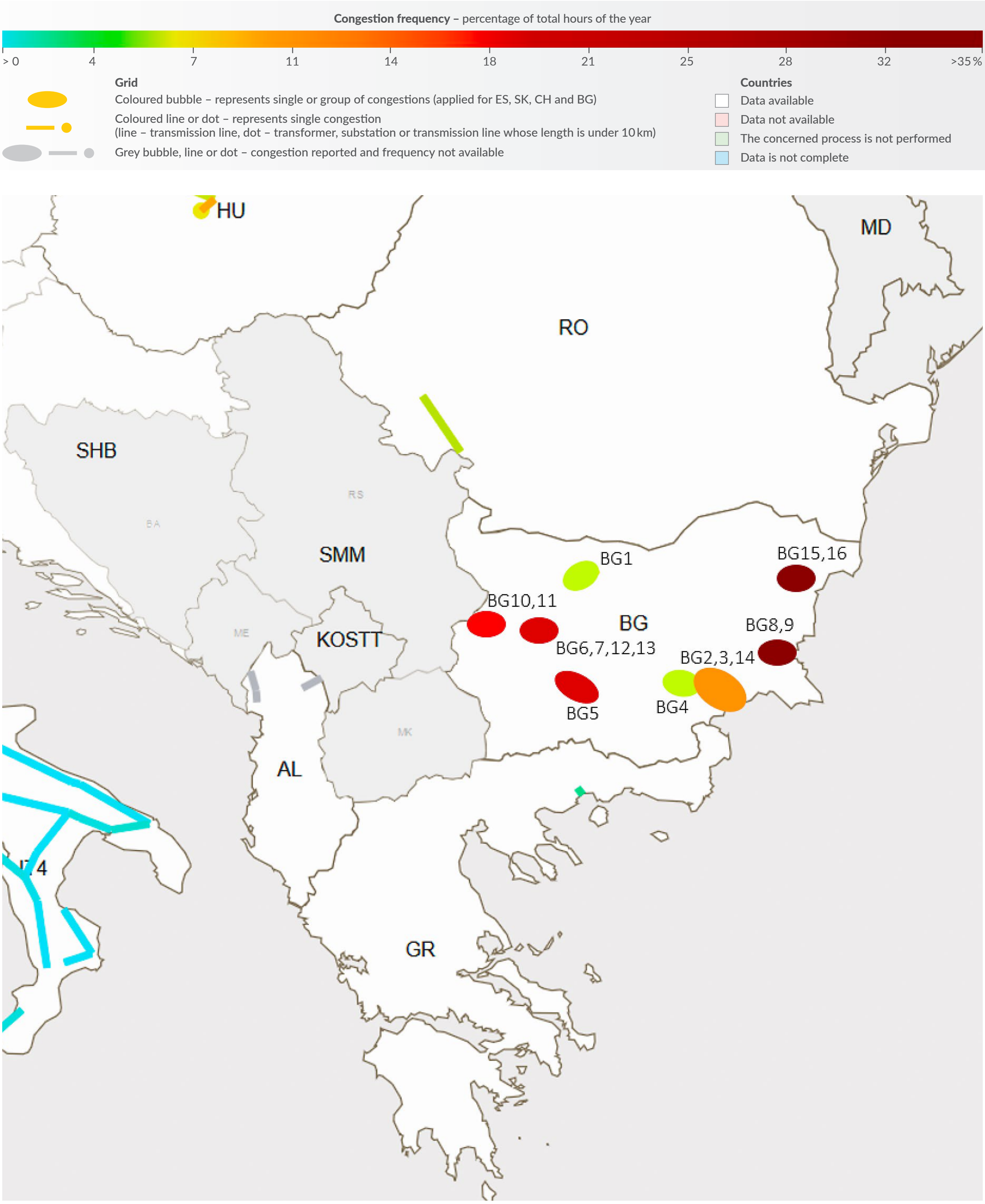


Figure 27: D-1 for 2015. Balkan countries

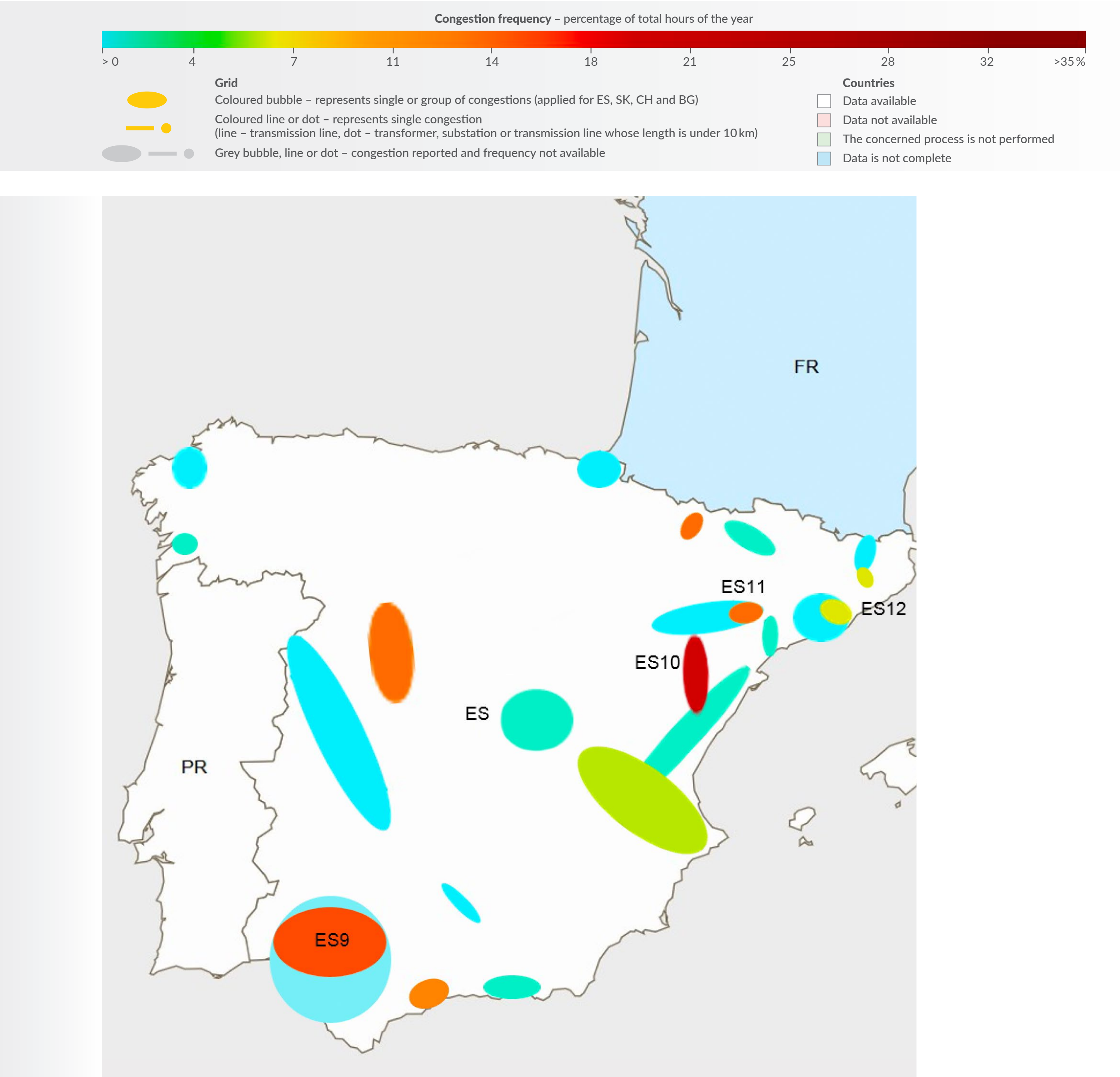


Figure 28: D-1 for 2015. Spain/Portugal

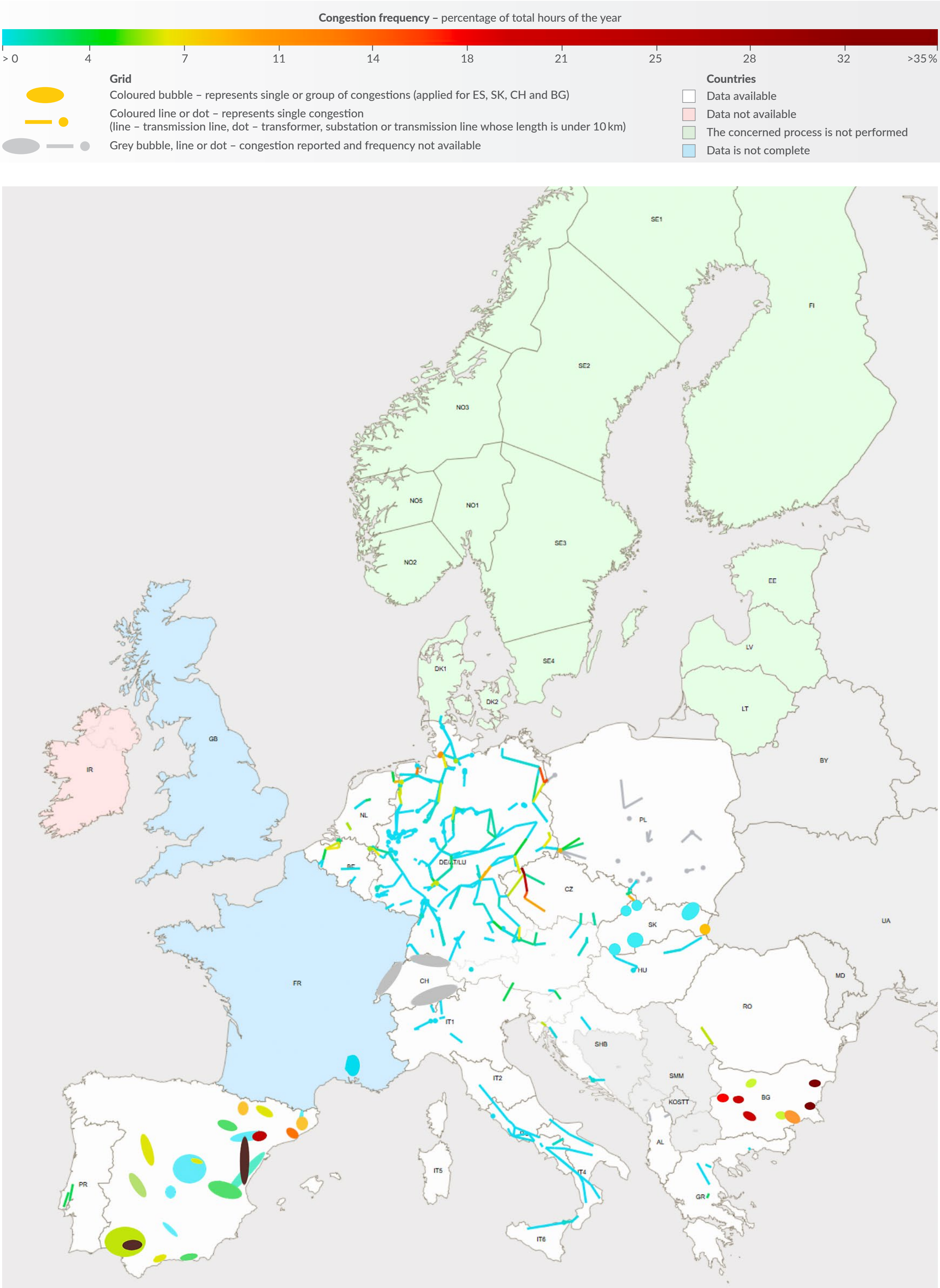


Figure 29: D-1 for 2016. Europe

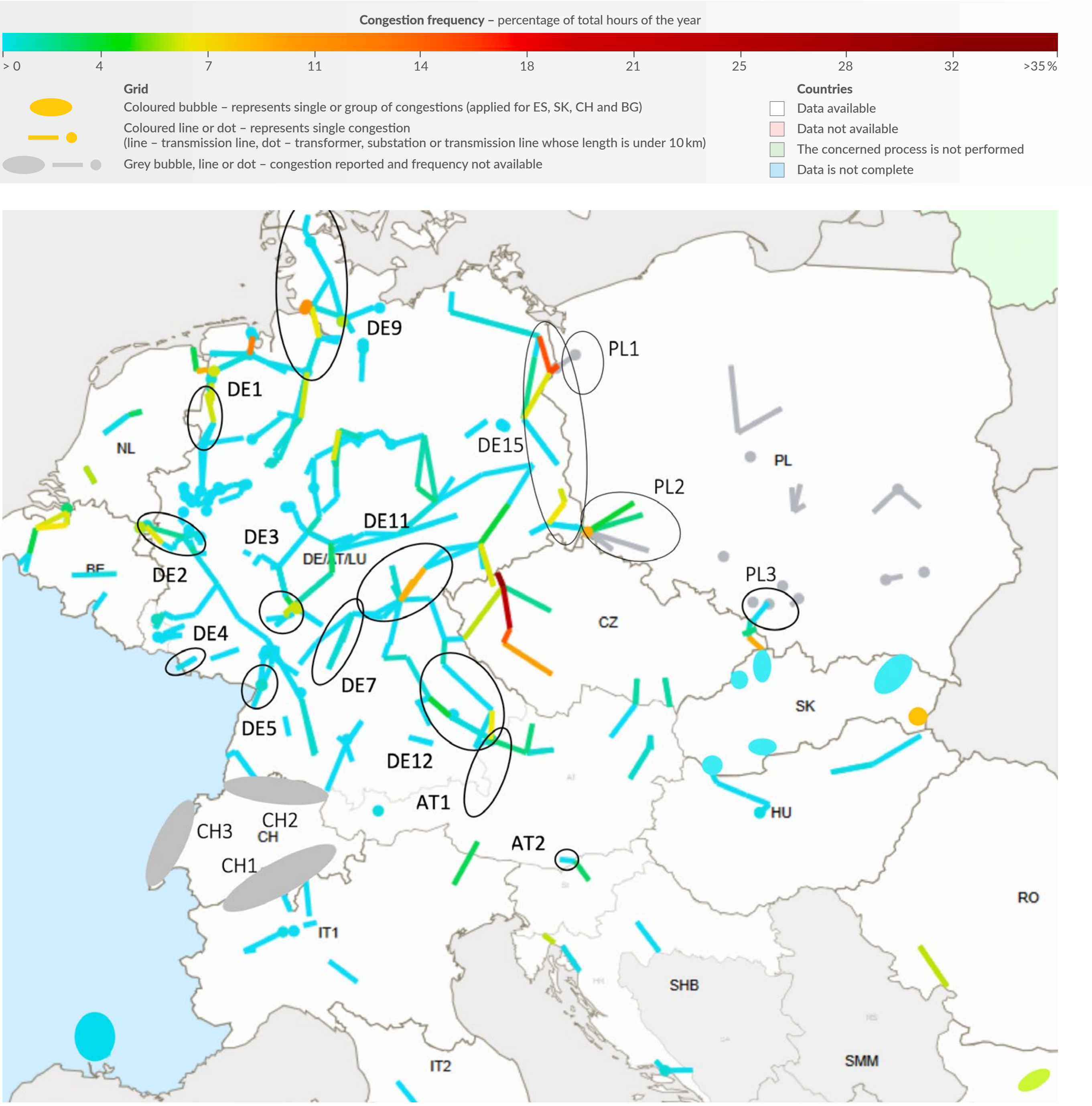


Figure 30: D-1 for 2016. Central Europe

Figure 31: D-1 for 2016. Italy

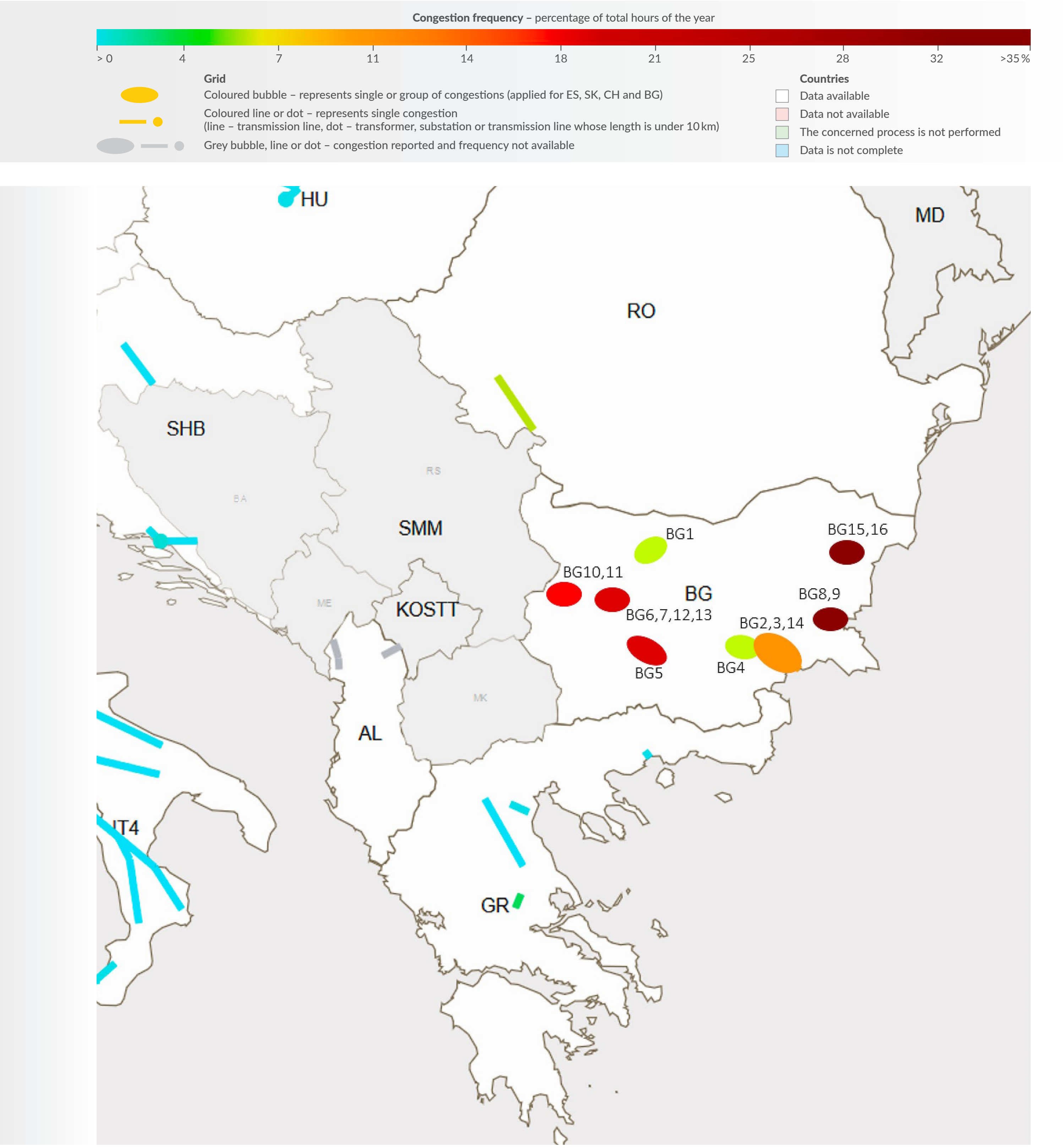


Figure 32: D-1 for 2016. Balkan countries

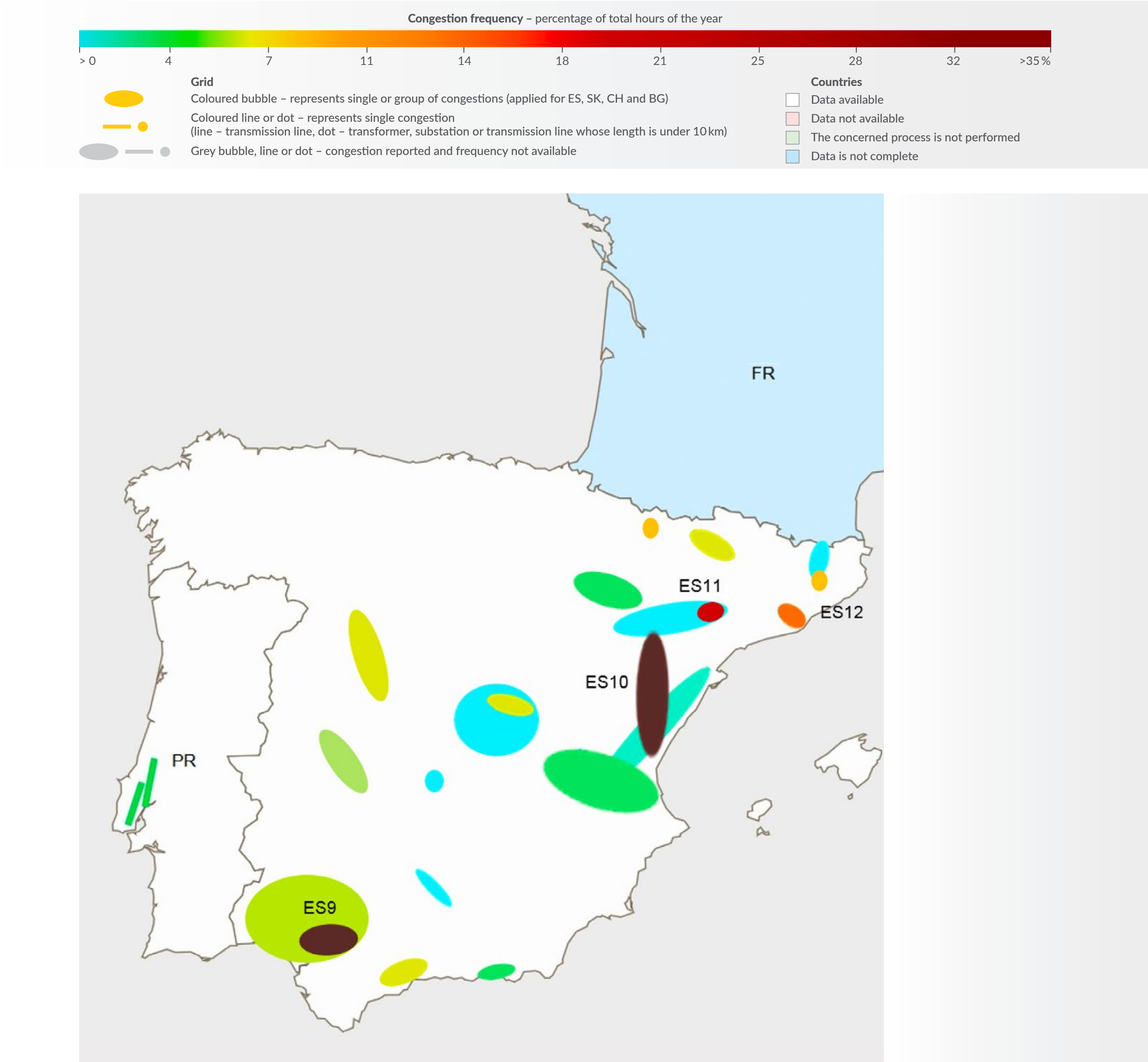


Figure 33: D-1 for 2016. Spain/Portugal

2017 – D-1

Congestion frequency – percentage of total hours of the year

> 0 | 4 | 7 | 11 | 14 | 18 | 21 | 25 | 28 | 32 | >35 %

Grid

Coloured bubble – represents single or group of congestions (applied for ES, SK, CH and BG)

Coloured line or dot – represents single congestion
(line – transmission line, dot – transformer, substation or transmission line whose length is under 10 km)

Grey bubble, line or dot – congestion reported and frequency not available

Countries

Data available

Data not available

The concerned process is not performed

Data is not complete

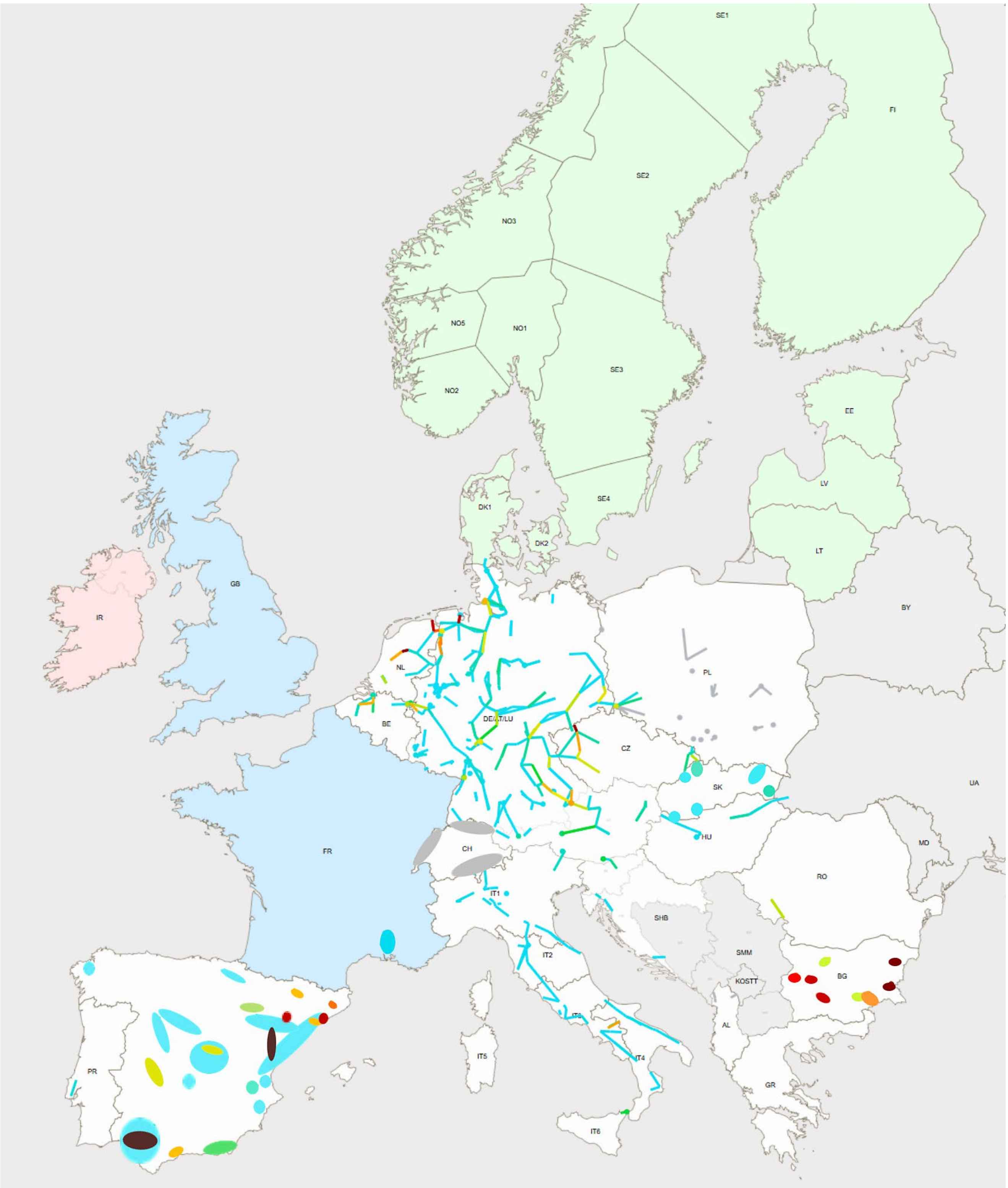


Figure 34: D-1 for 2017. Europe

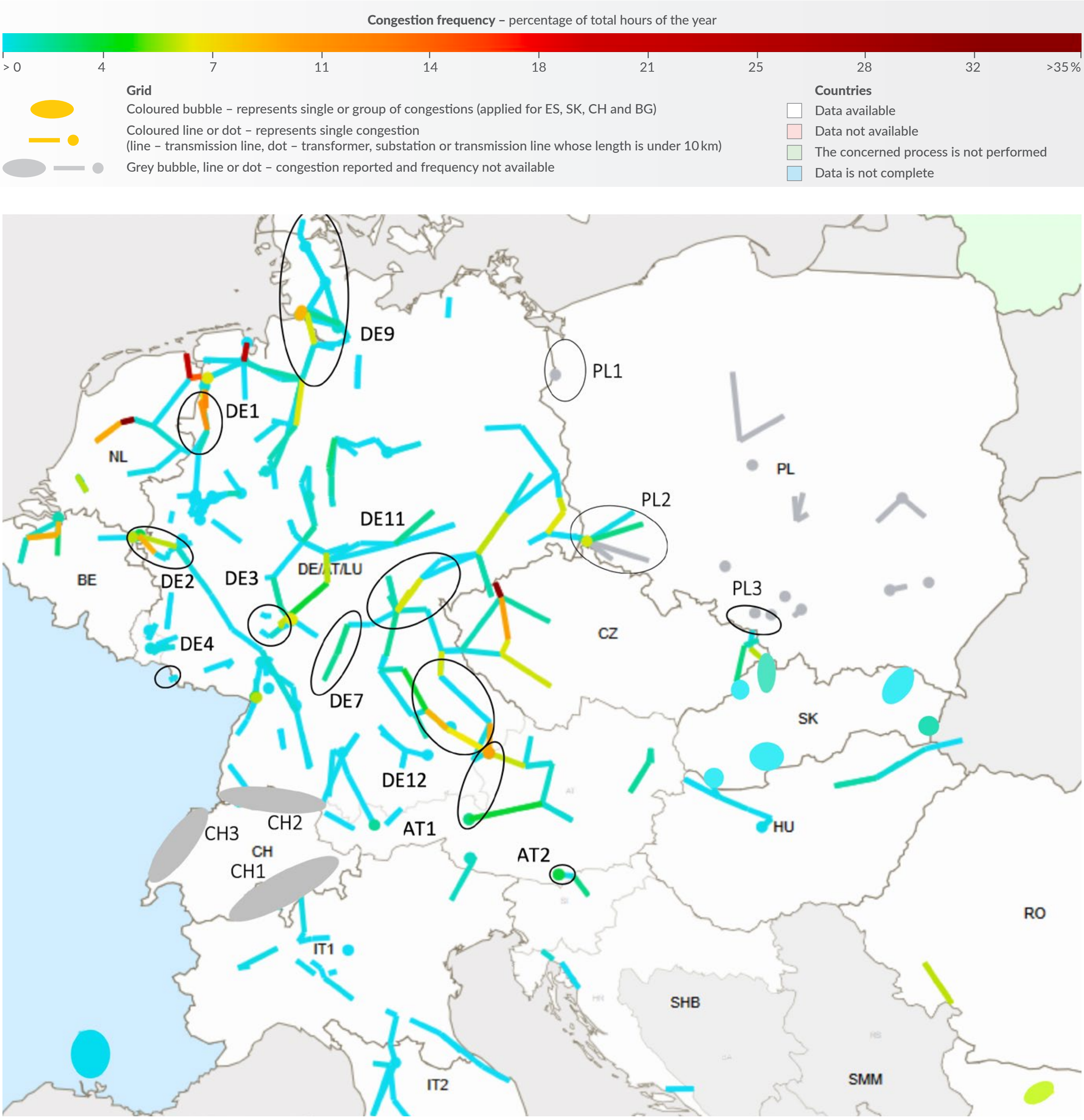


Figure 35: D-1 for 2017. Central Europe

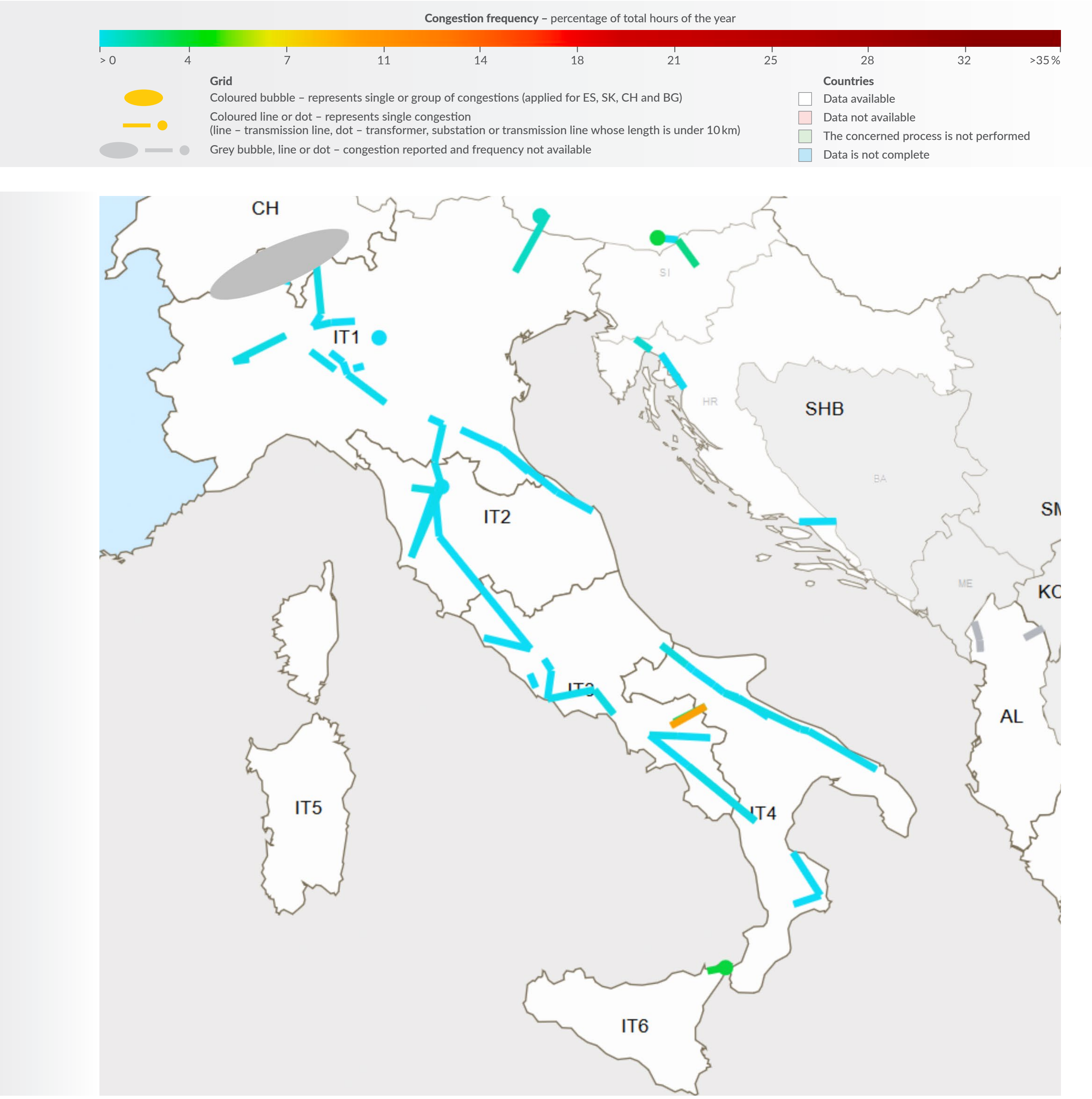


Figure 36: D-1 for 2017. Italy

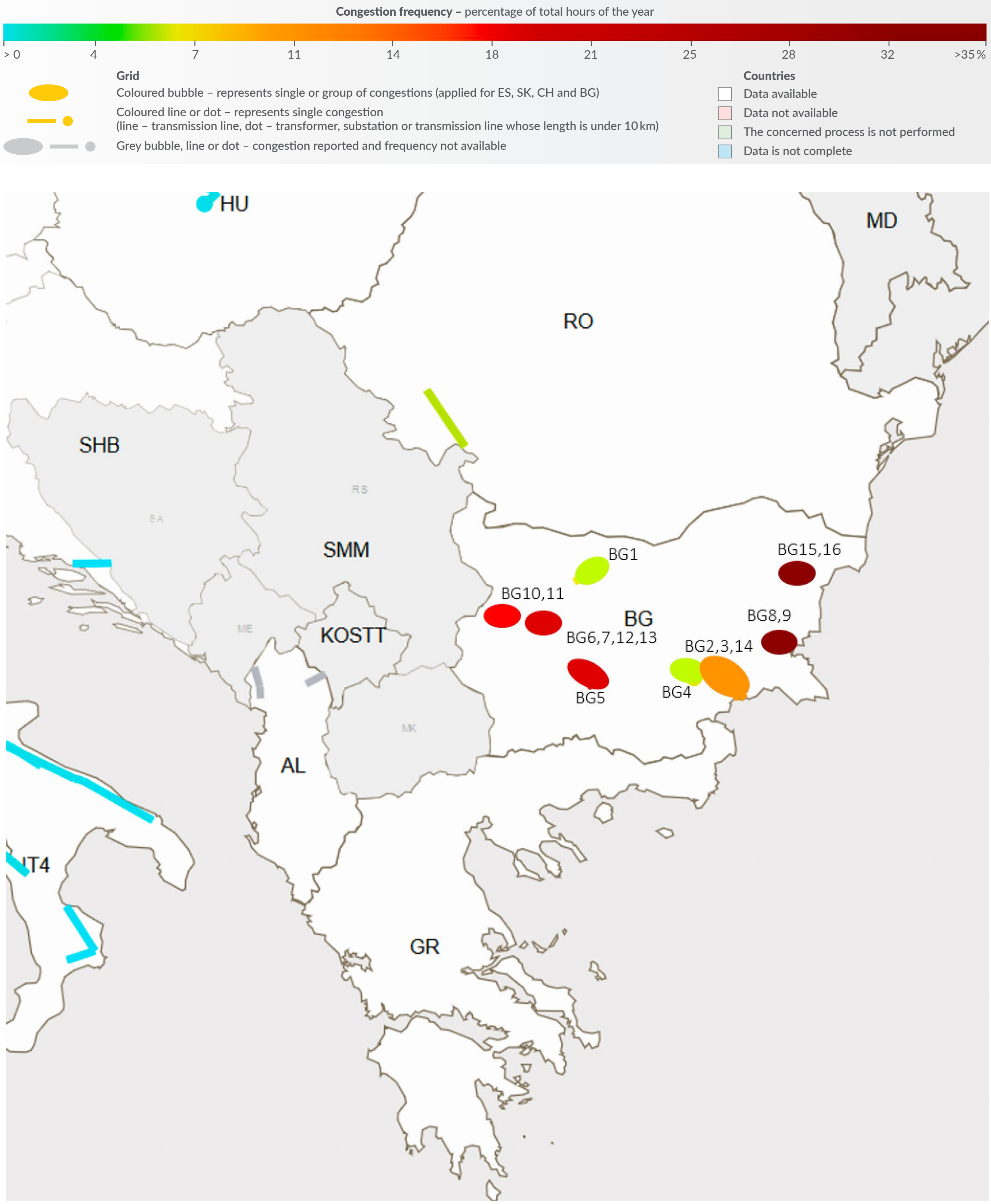


Figure 37: D-1 for 2017. Balkan countries

Congestion frequency – percentage of total hours of the year

> 0 | 4 | 7 | 11 | 14 | 18 | 21 | 25 | 28 | 32 | >35 %

Grid

Coloured bubble – represents single or group of congestions (applied for ES, SK, CH and BG)

Coloured line or dot – represents single congestion
(line – transmission line, dot – transformer, substation or transmission line whose length is under 10 km)

Grey bubble, line or dot – congestion reported and frequency not available

Countries

Data available

Data not available

The concerned process is not performed

Data is not complete

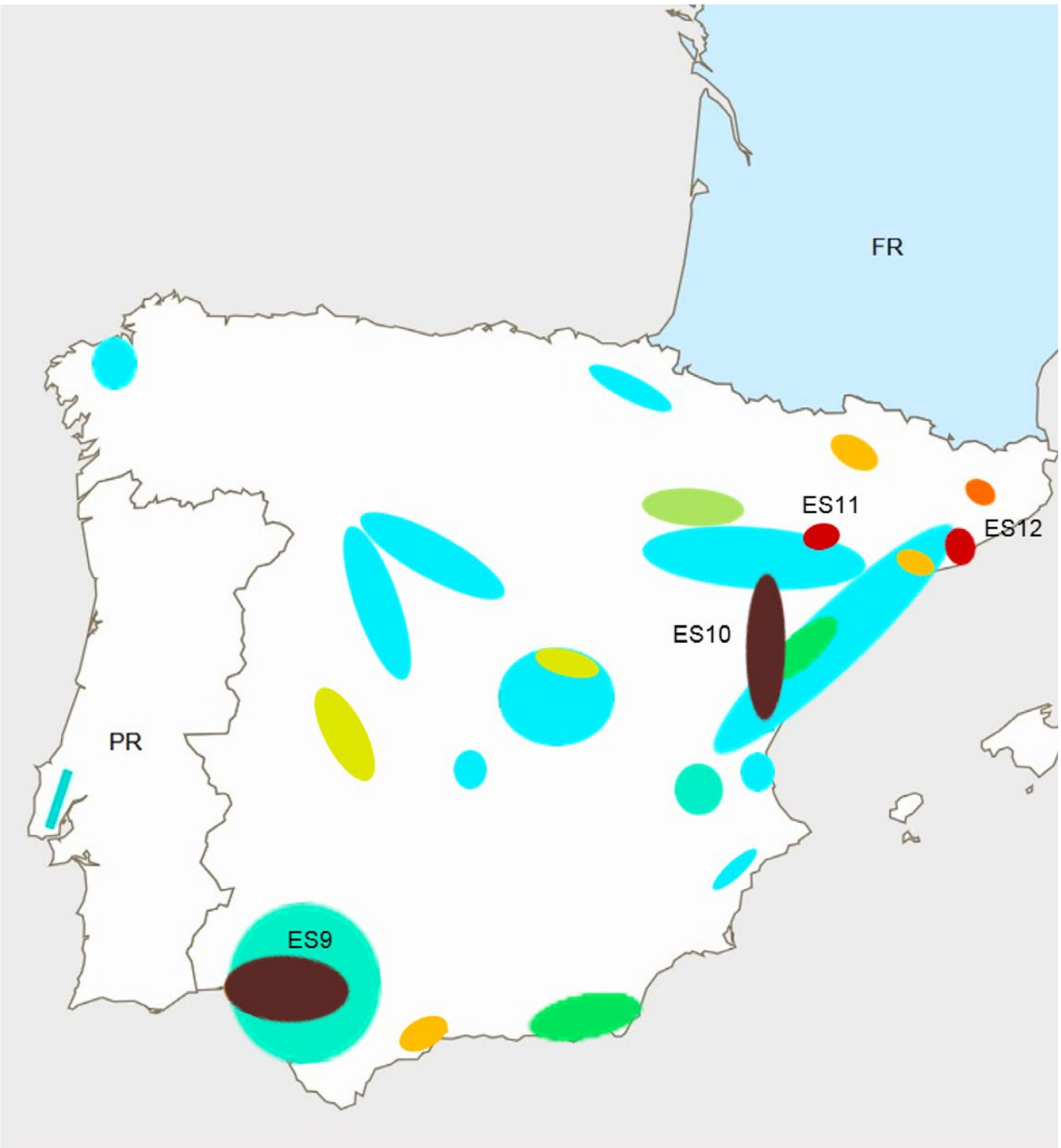


Figure 38: D-1 for 2017. Spain/Portugal

2.2.4 EXPERT ASSESSMENT OF CONGESTIONS FOR D-1 TIMEFRAME

The primary objective of Section 2 is to report where congestions have occurred in the grid over the reported years 2015, 2016 and 2017. In this sub section, each TSO provides an expert assessment of how these congestions have evolved over the reported years for the D-1 stage. This includes an expert assessment of the causes of the congestions and the interdependencies of congested lines.

AUSTRIA

Congestions in area AT1 are currently relieved by PST tapping, special switching states in Germany and Austria and thermal rating, as well as redispatch. To relieve congestions in the area of St. Peter, two new 380-kV-double circuit OHL *St. Peter – National Border* (2021: Isar/Ottenhofen/DE) and *St. Peter – National Border* (2024: Pleinting/DE) are planned. Furthermore, a reconstruction of the existing 220-kV-line *St. Peter – Hausruck – Ernsthofen* is ongoing and will be finished in 2021. To relieve congestions in the area of Tauern, in 2022 a new internal double circuit 380-kV-line connecting the substations Salzburg and Tauern is planned to be constructed (replacement of existing 220-kV-lines on optimised routes). The congestions in area AT2 appeared in 2015 to 2017 during DACF. To remedy the constraints, special switching states and redispatch are applied. In 2018, a third 380/220-kV-transformer was erected in Obersielach to relieve the congestions. The occurance of other congestions are either very low or not stable between 2015 and 2017. Accordingly, they are not significant for the consideration of this report.

BELGIUM

After DA market coupling, within the D-1 operational planning stage, the CCDA phase foreseen congestions at the North (NL – BE) and South (BE – FR) borders are usually significantly reduced due to the application of topological measures and preventive remedial actions.

CZECH REPUBLIC

In this stage, on top of those congestions reported in the CCDA stage, several other congestions on internal network elements are reported. This particularly concerns those located in transiting paths from Germany to Austria, (i.e. lines from border substation Hradec u Kadane) in the south direction. Topological measures, such as reconfiguration or multilateral redispatching within the TSC cooperation framework, were applied to mitigate these congestions. After putting the PST between ČEPS and 50Hertz in July 2017, the level of congestions reported on internal network elements in transiting path from Germany (50Hertz) to the Sout east had decreased.

DENMARK

D-1 timeframe after market allocation but before use of remedial actions: In Denmark, there is no structured congestion management process for this timeframe. The market result from the allocation phase is directly useable as long as there are no unplanned outages in the grid between the time where capacity is given to the market and real-time. The use of bidding zones to handle significant congestions ensures that the market outcome can be directly applied regardless of the schedules that market participants submit to the TSO.

ESTONIA

There is no congestion management process established in the D-1 stage.

FINLAND

D-1 timeframe after market allocation but before use of remedial actions: In Finland there is no structured congestion management process for this timeframe. The market result from the allocation phase is directly useable as long as there is no unplanned outages in the grid between the time where capacity is given to the market and real time. The use of bidding zones to handle significant congestions ensure that the market outcome can be directly applied regardless of the schedules market participants submit to the TSO.

FRANCE

Only the D-1 congestions that effectively triggered a costly remedial action are reported here. They are linked to a single contingency (N-1 REALTOR – TAVEL 400 kV), and their occurrence is very low (0.23 % of the time in total in 2017), so they cannot be considered either as structural or as major physical congestions.

GERMANY

Germany is a key exchange country. Due to its central location in the European electricity system, it is an important transit country. Moreover, Germany is one of the biggest exporters, especially when renewable infeed is high in the northern part. Most of the congestion in the German grid appears in this situation, when Germany exports electricity.

As described in chapter 2.1, the collected D-1 data includes preventive remedial actions which are planned before gate closure time of the DA market. However, remedial actions planned after the DA market are excluded. The reason for the inclusion is that remedial actions are part of the DA schedules, which result from the preventive planning process (week-ahead planning process).

50Hertz

Congested Area DE 15 [PSE, 50Hertz]

The observed congestions are similar in the planning and operational phases. The data are based on grid models from the common TSC DA process (DACF). As preparation for the operational phase, bilateral or multilateral remedial actions may be needed to fulfil the security criteria for the profile between PSE and 50Hertz.

In 2015 and in the first half of 2016 before the commission of phase shifters in Mikułowa and the subsequent disconnection of the 220 kV *Krajnik – Vierraden*, relevant congested tie-lines were: 220 kV *Krajnik – Vierraden* and 400 kV *Hagenwerder – Mikułowa*. The internal congestions were 220 kV line *Bertikow – Neuenhagen*, 220 kV line *Neuenhagen – Vierraden*, 400 kV *Mikułowa – Czarna* line and the 400/220 kV transformers in Mikułowa. Other congested lines are the 220 kV *Mikułowa – Świebodzice* line, the 220 kV *Mikułowa – Cieplice*, line and the AT2 400 MVA autotransformer in Krajnik.

The congestions listed above were caused by physical flows from 50Hertz to PSE. These flows were correlated with periods of high generation in the 50Hertz area. In the planning stage, the transmission capacity offered to the market was limited as unscheduled flows had to be taken into account. Unscheduled flows, composed of loop and transit flows, are influenced by various factors including volatile injections and commercial schedules from northern to southern parts of Europe.

The congestions in the operational phase were eliminated by remedial actions (including bilateral and multilateral actions).

With the installation of phase shifters in Mikułowa and the subsequent disconnection of the 220 kV *Krajnik – Vierraden*, remedial actions could get reduced to the very minimum. In 2018, two of four phase shifters were commissioned in Vierraden and the tie-line was upgraded from 220 kV to 400 kV. It is currently expected that only in exceptional situations are remedial actions needed.

Congested Area DE 11 [TTG, 50Hertz]

This cluster includes the 380 kV lines *Redwitz – Remptendorf* (50Hertz), *Redwitz – Altenfeld* (50Hertz), *Kriegenbrunn – Redwitz*, *Etzenricht – Mechlenreuth – Redwitz*. D-1 congestions (DACF process) are alleviated in D-1 or by remedial actions in the operational phase.

Amprion

Notably, the cold spell in the beginning of 2017 was an exceptionally critical situation during which Germany exported large amounts of electricity in order to alleviate energy scarcities in other bidding zones. Several capacity-increasing measures, e. g. removal of the FAV and introduction of winter limits, were taken by Amprion to make this possible, causing unusually high pressure on the grid. When analysing the data, this should be taken into account.

Congested area DE 2 [DE – NL] (2015 – 2017)

For a general description of this cluster, please refer to the description of the capacity calculation and allocation stage. For the observed years, a clear upward trend in the frequency of congestions is noticeable. At least partly due to the capacity-increasing measures which Amprion has taken, e. g. removal of the FAV and introduction of winter limits and dynamic line rating, congestions shifted closer to real-time and therefore more frequently appeared in the D-1 stage.

Congested area DE 1 [AMP – TTG] (2015 – 2017)

For a general description of this cluster, please refer to the description of the capacity calculation and allocation stage. For the observed years, a clear upward trend in the frequency of congestions is noticeable. At least partly due to the capacity-increasing measures which Amprion has taken, e. g. removal of the FAV and introduction of winter limits and dynamic line rating, congestions shifted closer to real-time and therefore more frequently appeared in the D-1 stage.

Congested area DE 3 [AMP – TTG] (2016 – 2017)

Congestions in this area predominantly appear when there is high wind infeed in the north of Germany and at the same time Germany exports electricity. The grid elements concerned are the 380 kV lines *Pfungstadt – Urberach – Dettingen – Großkrotzenburg* (TTG). Considerably more congestions have appeared since 2016, when several power plants in this area were decommissioned or moved out of the market into the German grid reserve. The increase in frequency is also partly due to the capacity-increasing measures which Amprion has taken, e. g. removal of the FAV and the introduction of winter limits and dynamic line rating, which shifted congestions closer to real-time to the D-1 stage.

Congested area DE 4 [DE – FR] (2015 – 2017)

Congestions in this area are of a more temporary nature and predominantly appear when there is high nuclear infeed in France and at the same time Germany imports electricity. This is especially the case in the summer period, when the demand in France is low. However, during the cold spell in the beginning of 2017, large amounts of electricity were exported from Germany, so the typical direction of the congestion turned from Germany to France. The grid elements concerned are the 380 kV cross-border lines *Ensdorf – Vigy* (FR). For the observed years, there is no clear trend in the frequency of congestions noticeable. Due to the temporary nature of the congestion, the frequency is rather low. When congestions appeared, however, they were rather critical.

TenneT GER

Congested area DE 9

For a general description of this cluster DE9, please refer to the D-2 (capacity calculation stage) description. D-1 congestions (DACF process) are alleviated in D-1 or by remedial actions in the operational phase. The installation of the new PST at Kassoe has improved the situation in D-1 and real-time. Since July 2017, ENDK and TenneT have applied the MinCap procedure (guaranteed minimum capacity at the German–Danish interconnector), which is currently implemented with a volume of 700 MW in both directions. A further increase of the guaranteed minimum capacity is under evaluation by the European Commission.

Congested area DE 11

This cluster includes the 380 kV lines *Raitersaich – Kriegenbrunn – Würgau – Redwitz – Remptendorf* (50Hertz), *Redwitz – Altenfeld* (50Hertz) and *Eltmann – Oberhaid – Redwitz – Mechlenreuth*. D-1 congestions (DACF process) are alleviated in D-1 or by remedial actions in the operational phase.

Congested area DE 12

This cluster includes the 220 kV lines *Pleinting – St. Peter*, *Pleinting – Pirach – St. Peter* and *Altheim – Simbach – St. Peter*. The grid enforcement from 220 kV to 380 kV is planned for 2021 (*St. Peter – Isar/Ottenhofen*) and 2024 (*St. Peter – Pleinting*). However, in the meantime dynamic line rating has been applied on these lines, which led to significant reductions of congestions in this area.

TransnetBW

Congested area DE 7

The line 380-kV-Grafenrheinfeld – Stalldorf rt was structurally damaged from winter 16/17 until end of October 2017 and therefore a lower thermal limit had to be applied throughout the majority of 2017. Consequently, the line appeared in D-1 more frequently. Since this corridor is heavily impacted by north to south flows, it will be further upgraded in the future (see 'Future Developments' section).

Congested area DE 5

The line *Daxlanden-Maximiliansau* sw showed constraints in the years 2016 and 2017. Since the loading of the grid in this area is expected to increase in the future, it is foreseen that several lines in this area will be upgraded (see 'Future Developments' section).

GREECE

The D-1 congestions that were corrected by costly remedial actions are reported here (generation redispatching was used in all cases). They are linked to single contingencies in which their occurrences are very low (in total less than 2.5 % for all cases in 2015/2016).

HUNGARY

Based on the situation in the capacity calculation timeframe, congestions can be expected in the northern part of the Hungarian power system. As the market reaches the limits set by network constraints in the region, unscheduled flows and loop flows can cause overloads. In the north-western part of the Hungarian network, where the tie-lines to Austria and Slovakia are concentrated and interdependent, these flows cause overloads in several situations. Overloads in this region have been relatively stable in the 2015 – 2017 time period and were observed less than 1 % of the time. Managing these overloads was mainly possible by conservative bilateral offered capacities on these borders, as difference between scheduled exchange and real-time flow on SK – HU border occasionally reaches maximum values of 1,000 MW, which is caused by hardly predictable transit flows.

Other internal overloads are concentrated in the 220 kV network around two big power plants in the central and eastern region of the country. Overloads have been caused by the generation pattern and special maintenance cases and long-lasting outages in the 220 kV network, which caused higher violation frequencies for several elements in single years.

In the above mentioned cases, there were topological measures available to decrease the loading of the affected lines.

Hungary participated in multilateral redispatch several times, but none of them was activated because of an overload in the Hungarian network. Internal redispatch was not activated in the D-1 timeframe for transmission line congestions.

ITALY

In D-1 timeframe, congestion level in the Italian Power System shows a decreasing trend in the three years under assessment and all the elements show quite a low degree of congestion.

Most of the congestions detected in D-1 stage are linked to:

- Cross-border flows, between internal bidding zones, expected to exceed the NTC value. This expectation is related to the application of improved load and RES infeed forecasts in D-1 stage from Terna side;
- Local congestions inside bidding zones and close to metropolitan areas;
- Different load and generation distribution compared to the capacity calculation process, especially at the Northern Italian Border.

Over the three years under assessment, only the 380 kV connection between Benevento and Troia substations (at the border between IT3 and IT4) reached a frequency of expected congestion level in D-1 stage of about 10 % (in 2017).

LATVIA

The D-1 process is not established.

LITHUANIA

There is no congestion management process established in the D-1 stage.

LUXEMBOURG

In 2015, 2016 and 2017, a limited number of congestions have been reported on the cross-border lines with Germany in the D-1 time frame. These limited number of congestions did not have any impact on the market as Luxembourg is part of the DE/AT/LU bidding zone and until October 2017 had no interconnection with another country.

Since October 2017, a new interconnection IC BeDeLux between Belgium and Luxembourg has been in operation. In a first phase, the operation is limited to a technical trial phase of one year. During this first phase, no commercialisation of potential additional capacities on the BE–LU border is foreseen. The aim of the technical trial phase is to gain experience regarding the actual operation of the new PST (main grid element of the IC BeDeLux) according to the approved operating principles. In a second step, based on the findings of the technical trial phase, a decision will be taken on the potential commercialisation. In case of a positive assessment, a possible commercialisation could be expected by Q1 2020.

NETHERLANDS

Within the D-1 operational planning timeframe, the detected congestions, as mentioned in paragraph 2.2.2., are solved in a preventive way with both topological measures and internal redispatch. These measures result in a n-1 operational planning.

NORWAY

The D-1 process does not exist in Norway today.

POLAND

In the D-1 timeframe, the indicated congestions in Poland are grouped into three clusters.

Clusters PL1, PL2 and PL3 – mainly for 2015 and 2016 – represent D-1 congestions which are visible during the DACF. The presented congestions are highly influenced by unscheduled flows from DE and further towards CZ and SK. It is already visible that in 2017 the congestions are of lower frequency compared to 2016 and 2015, mainly due to PST installation in Mikułowa substation and temporary disconnection of 220 kV *Krajnik – Vierraden* line. Although these congestions will most likely remain on the Polish synchronous border in near future, they will be mitigated to a certain extent by splitting the DEAT bidding zone, the PST installation in Vierraden substation, upgrading the *Krajnik – Vierraden* interconnector from 220 kV to 400 kV and grid investments at the Polish side around Mikułowa substation, i. e. 400 kV *Mikułowa – Czarna* in 2022, 400 kV *Czarna-Polkowice* in 2019, 400 kV *Mikułowa – Czarna – Pasikurowice* in 2022 and 400 kV *Mikułowa – Swiebodzice* in 2023.

Other network constraints in the D-1 timeframe apart from the ones grouped under the aforementioned clusters are of a rather internal character. In Poland, network constraints are managed within the Integrated Scheduling Process (ISP) run by TSO. The ISP process is bid-based security constraint unit commitment and economic dispatch, where balancing, reserve procurement and congestion management are co-optimised within one integrated process run by TSO just immediately after the DA market closure. Since the commitment and operational set-points of all centrally controlled generation units in Poland (all units above a certain size) are determined by PSE within the abovementioned ISP, thereby obtaining a technically feasible operational plan for the following day, these congestions do not materialise during the D-1 DACF process. Thus, PSE is unable to indicate the frequency of those network constraints. The provided list is expert-based and indicated in grey colour. This includes not only 220 kV and 400 kV lines, but also transformers and transmission-relevant 110 kV lines (indicated as grey dots). These network constraints cannot be considered as structural as their location frequently changes depending on power system operating conditions. In order to mitigate these network constraints, PSE is implementing adequate solutions covering both grid investments and market-based solutions i. e. further improvement of the ISP process including the implementation of a new balancing market with full network model and locational pricing.

PORTUGAL

The congestions are based on technical analysis in D-1 after the DA market is closed. The most significant congestions that occurred in the last three years occurred in the 400 kV corridors close to Lisbon and are usually associated with REN network outages.

Additionally, some important voltage issues occurred in 2015, which required some generation in the south of Portugal that was put in service; this problem was overcome by installing reactors.

SLOVAKIA

There are more congested lines in the Slovak transmission system in the D-1 stage compared to the Capacity Calculation stage. Most of the lines are cross-border lines and the main cause of the congestion is very high transfer flows from the northern part of Europe with high production to the southern part of Europe with a higher load. As for the congested lines HU/SK profile and SK/UA profile, most of the transferred electricity is transmitted by three interconnectors on the SK – HU and SK – UA profile. There is one more internal line which was congested in 2015 which is an adjacent line to the interconnector on the HU – SK profile. Congested lines between the Czech Republic and Slovakia are congested as well because of high transfer flows from north to south combined with the planned outages of interconnectors between the PL – SK profile, CZ – SK profile and CZ – AT profile. The last two lines that are registered as congested are on the PL – SK border. Their congestion is caused by high flows from north to south through the Slovak transmission system combined with the planned outage of the interconnector on the PL – SK profile. As there are only two lines connecting Poland and Slovakia, if one line is out of service the other one can be overloaded in case of contingency.

SLOVENIA

The D-1 congestion in IN CCR is typically handled by PST Divaca and therefore virtually non-existent. The congestion on 220 kV grid between SI-AT is stable, with a tendency to be less limiting due to the application of effective topological remedial actions.

SPAIN

The REE data of the congestions during the short-term operational planning are partially estimated. These congestions are based on analyses in D-1 after the DA market. From the REE side, many observed congestions in D-1 do not appear in the CCDA stage since they are not included in the critical elements that are monitored, because they do not present any relevant sensitivity to cross-border exchanges.

In 2015, 2016 and 2017, the congestions in D-1 with the highest frequencies after the DA market are placed at 220-kV Western Andalucía (cluster ES9) and the 400-kV transmission corridor between Aragón area and Levante area (cluster ES10). These congestions reach frequencies up to 60 % of the time. For 2018, uprates or automatisms are expected to be commissioned in order to reduce the frequency of these congestions.

The congestions of a few lines at the 220-kV Western Andalucía (cluster ES9) are mainly due to the low thermal capacity of 220-kV lines at Western Andalucía during the summer period. These congestions are managed by REE with non-costly topological measures and redispatching. In order to solve these congestions, a development plan is expected for 2018, so congestions will be reduced as a result of the commissioning of uprates.

The congestions on the 400-kV transmission corridor between the Aragón area and Levante area (cluster ES10) are mainly due to the low thermal capacity of the lines during the summer period. These congestions are managed by REE with non-costly topological measures and redispatching. For 2018, part of the energy redispatched will be reduced, with the installation of run-backs automatisms on the affected units. Before 2021, a development plan is scheduled by REE, so congestions will be reduced more as a result of the commissioning of new network elements.

From 2015 to 2017, most of the observed congestions by REE are reduced due to the commissioning of uprates or new network elements. Only the frequencies of a few congestions placed at the northeast side of Spain have increased (clusters ES11 and ES12) during the summer period due to low thermal capacity of 220-kV lines and higher demand in the Cataluña area. These congestions are managed by REE with non-costly topological measures and redispatching. In order to ensure a future reduction of congestions for these areas, there will be network solutions commissioned before December 2020.

In general, the rest of the observed congestions by REE are mostly placed in the REE control area and are caused by unusual operational situations related to RES or demand. These congestions do not exceed 5 %. These congestions are managed by REE with non-costly topological measures and redispaching.

SWEDEN

The day-ahead forecast process does not exist in Sweden.

SWITZERLAND

Congested area CH 1 (CH – IT)

The constraints on the IT-CH border are mainly the same in D-1 as in the CCDA timeframe. Congested elements are either 380 kV internal and tielines in case of high Italian import.

Congested area CH 2 (DE/AT – CH)

The constraints on the DE/AT – CH border are the same in the D-1 as in the CCDA timeframe. Dependent on the scenario, the main congested elements are the PSTs and 380 kV transit lines. The situation worsened due to the introduction of the CWE Market coupling, which induces high unscheduled flows inside the Swiss system

Congested area CH 3 (FR – CH)

The constraints on the FR-CH border are the same in the D-1 as in the CCDA timeframe.

2.2.5 REAL-TIME

For the real-time stage, it is especially challenging to provide comparable data, since congestion management approaches as well as the data processing and reporting differ among TSOs. Therefore, for real-time, two different sets of maps are shown.

One set of maps display all the TSOs which used ICS reports as their source [7]. These TSOs typically have very few congestions since ICS reports only include the most critical of congestions, when redispatch is no longer available and neighbouring TSOs might be affected.

The other set of maps present all the TSOs which provided data up to one hour before real time. However, even for these TSOs, sources differ and the resulting reported congestions are not necessarily comparable. Further details can be found in the individual TSO descriptions below.

7 RTE reported ICS data completed with the violations reported in accordance with the French classification scale (Evènements Système Significatifs – ESS).

2.2.5.1 REAL-TIME MAPS OF THE TSOs WHICH USED UP TO 1 HOUR REAL-TIME DATA

2015 – Real-time up to one hour

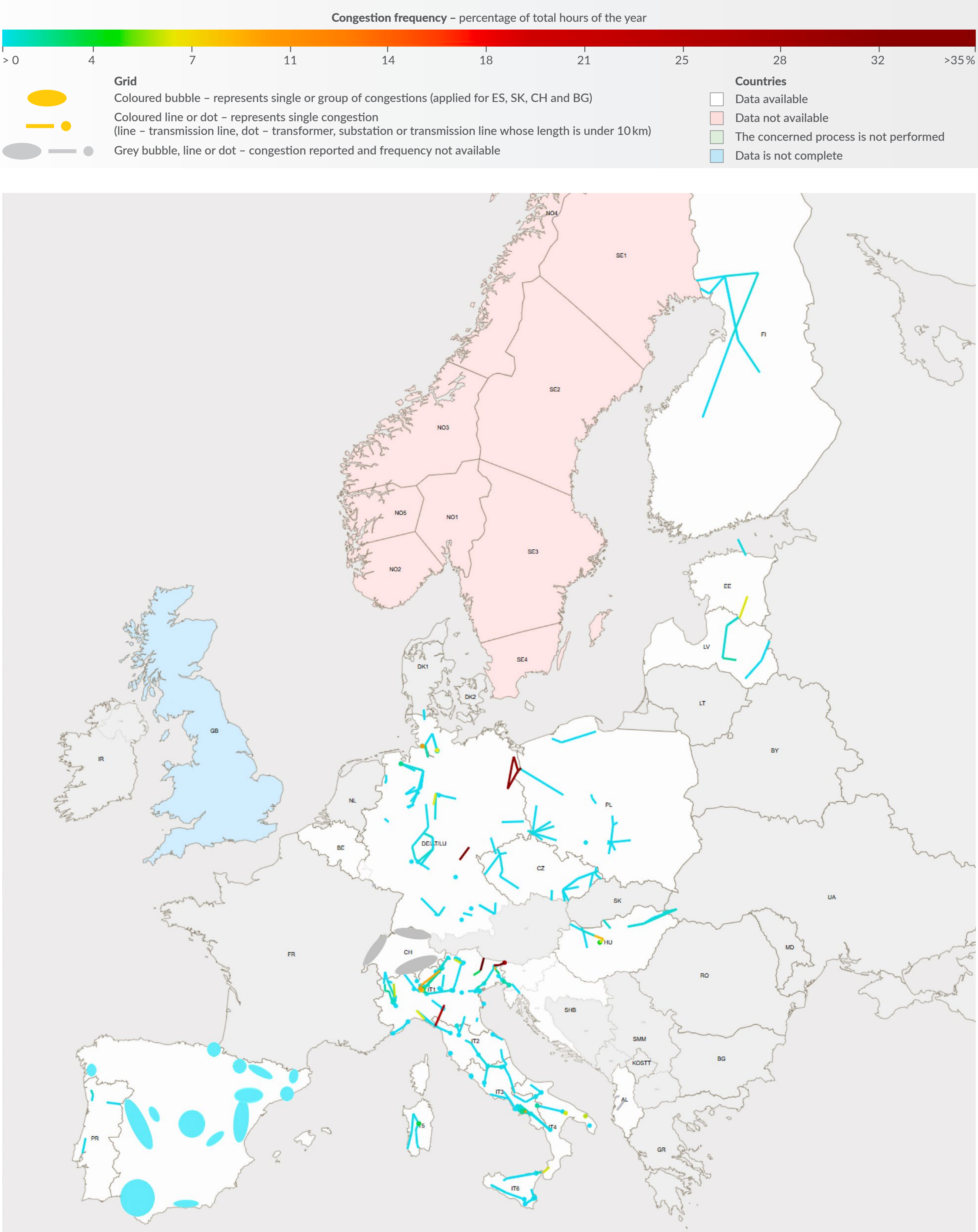


Figure 39: Real-time (up to one hour) for 2015. Europe

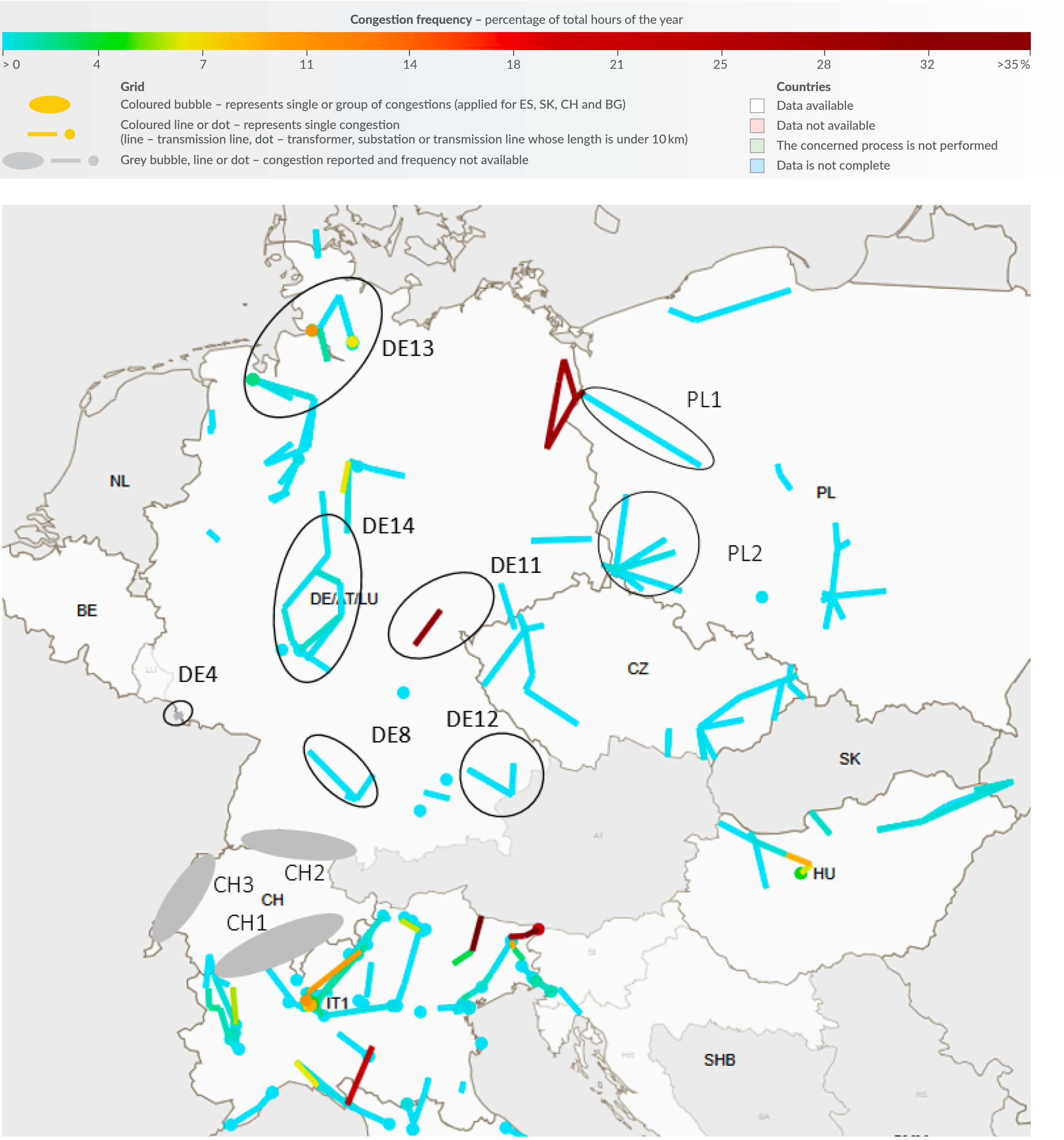


Figure 40: Real-time (up to one hour) for 2015. Central Europe

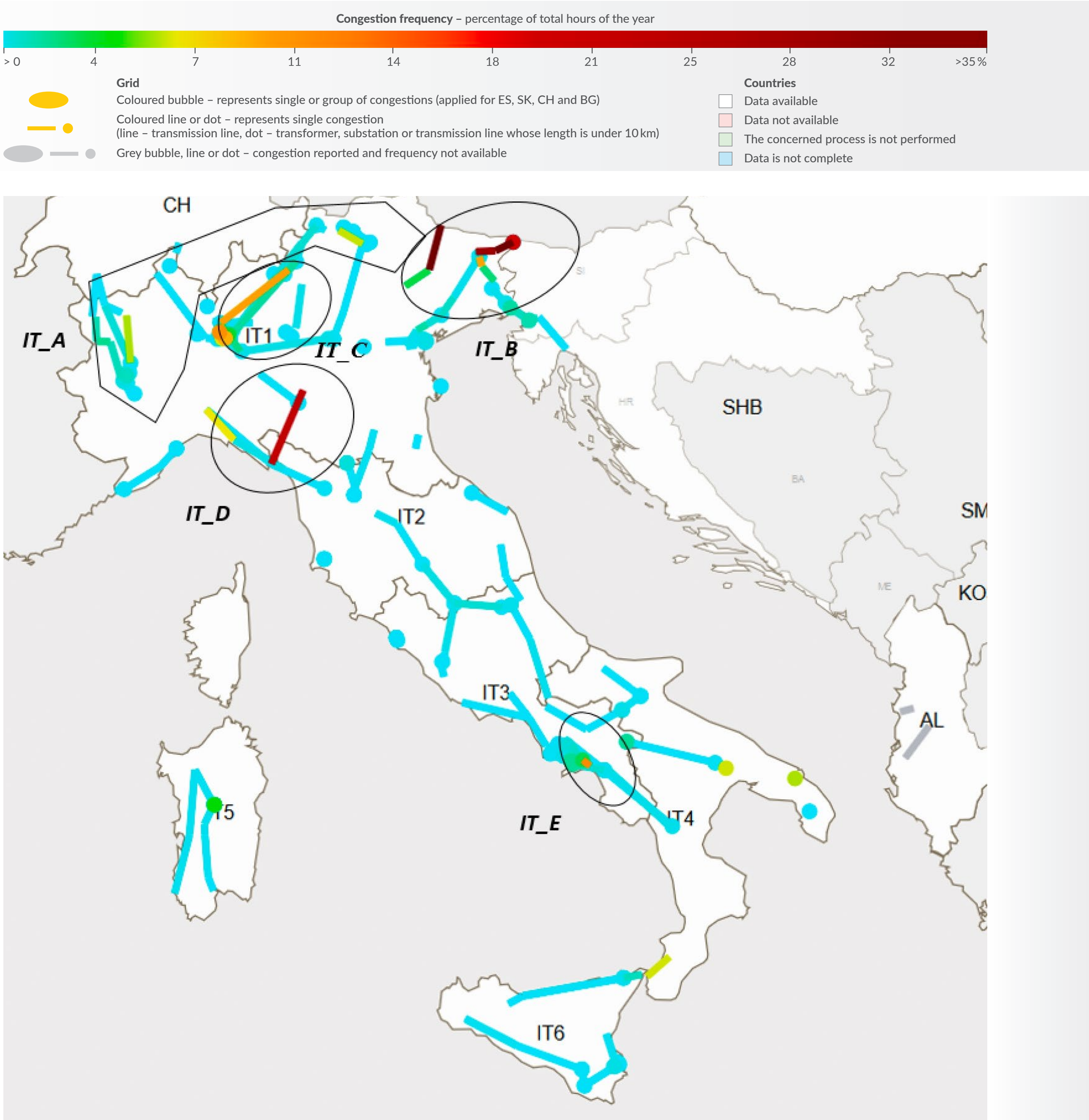


Figure 41: Real-time (up to one hour) for 2015. Italy

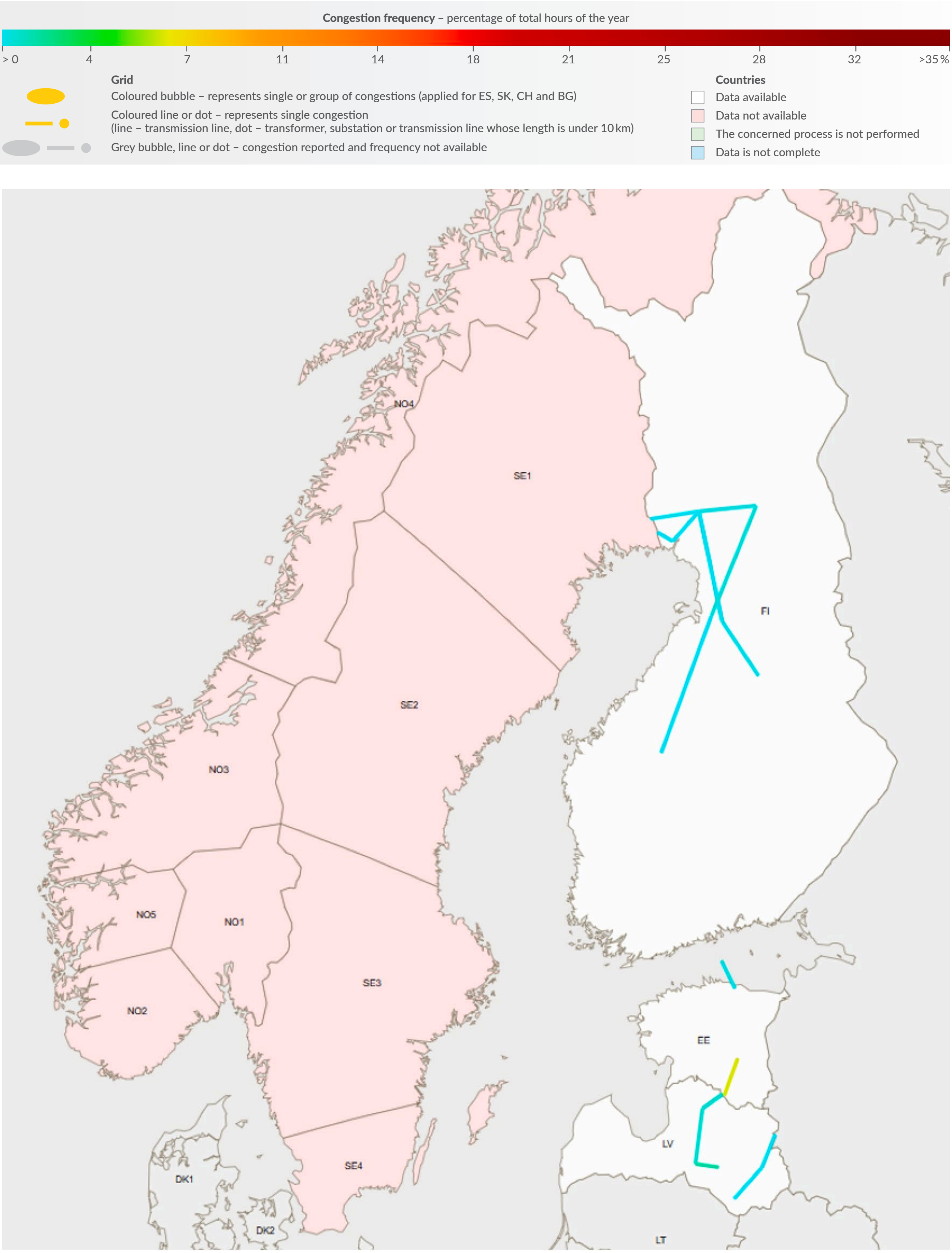


Figure 42: Real-time (up to one hour) for 2015. Nordic and Baltic countries

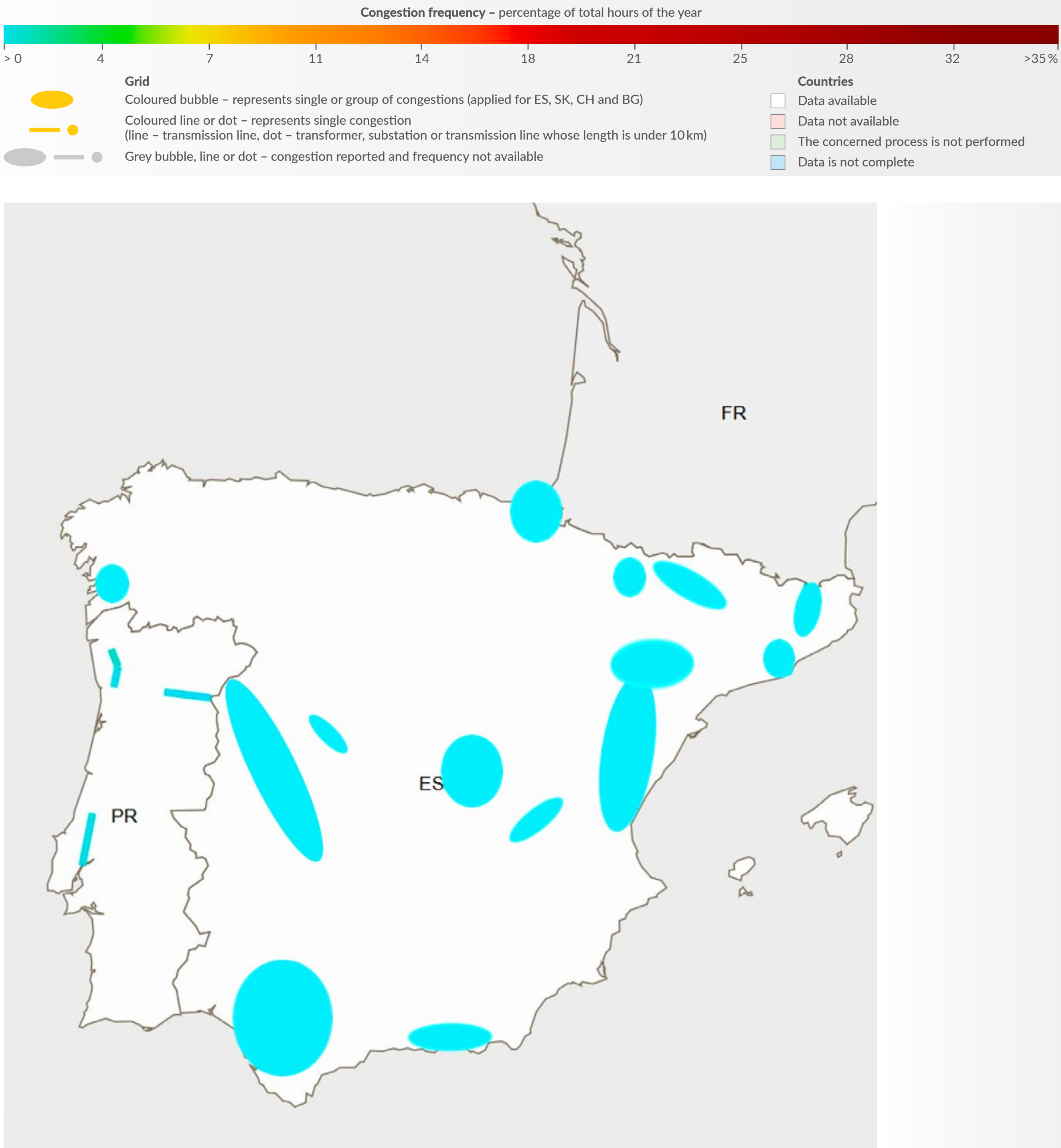


Figure 43: Real-time (up to one hour) for 2015. Spain/Portugal

2016 – Real-time up to one hour

Congestion frequency – percentage of total hours of the year

> 0 | 4 | 7 | 11 | 14 | 18 | 21 | 25 | 28 | 32 | >35 %

Grid

Coloured bubble – represents single or group of congestions (applied for ES, SK, CH and BG)

Coloured line or dot – represents single congestion
(line – transmission line, dot – transformer, substation or transmission line whose length is under 10 km)

Grey bubble, line or dot – congestion reported and frequency not available

Countries

Data available

Data not available

The concerned process is not performed

Data is not complete

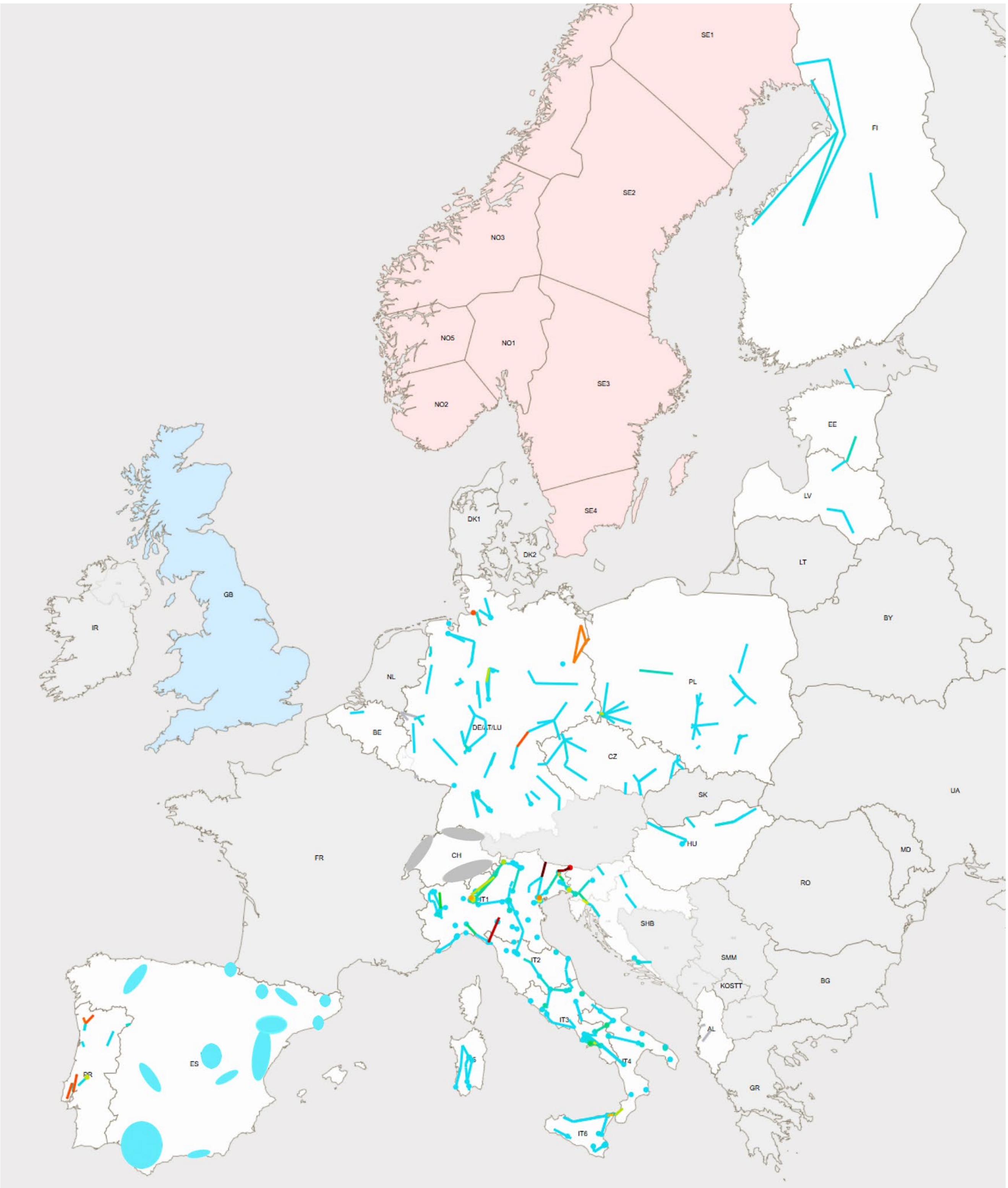


Figure 44: Real-time (up to one hour) for 2016. Europe

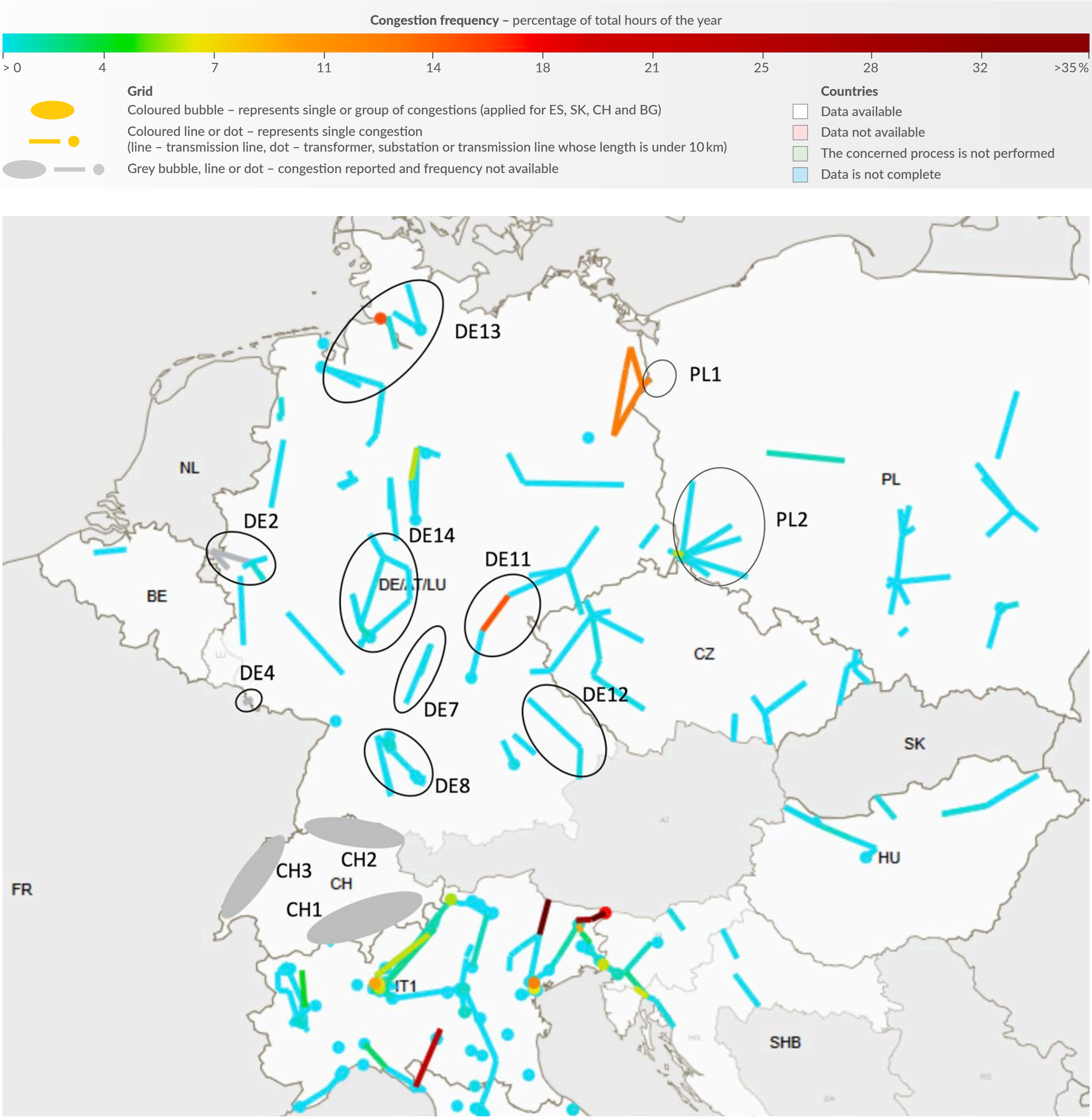


Figure 45: Real-time (up to one hour) for 2016. Central Europe

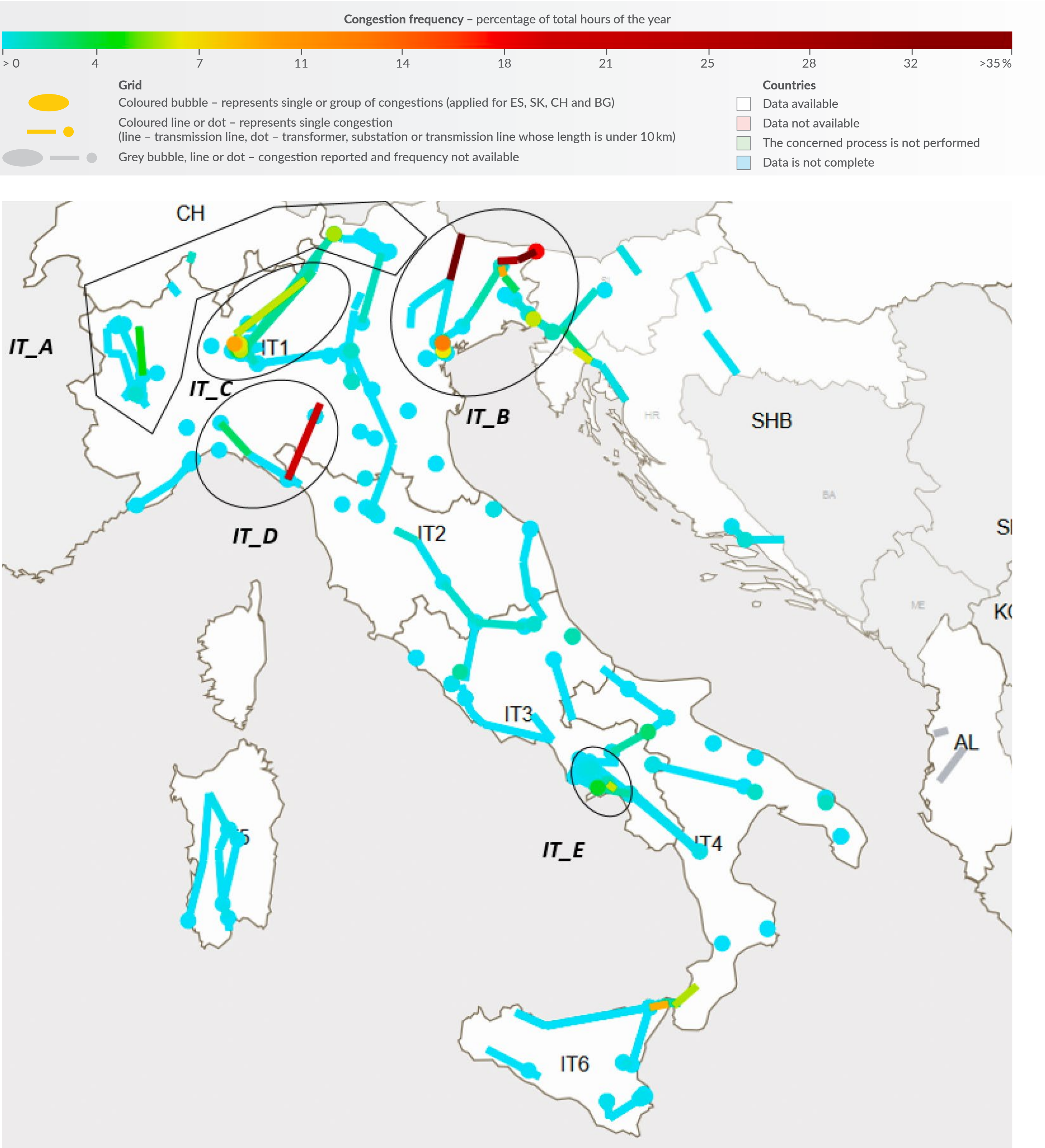


Figure 46: Real-time (up to one hour) for 2016. Italy

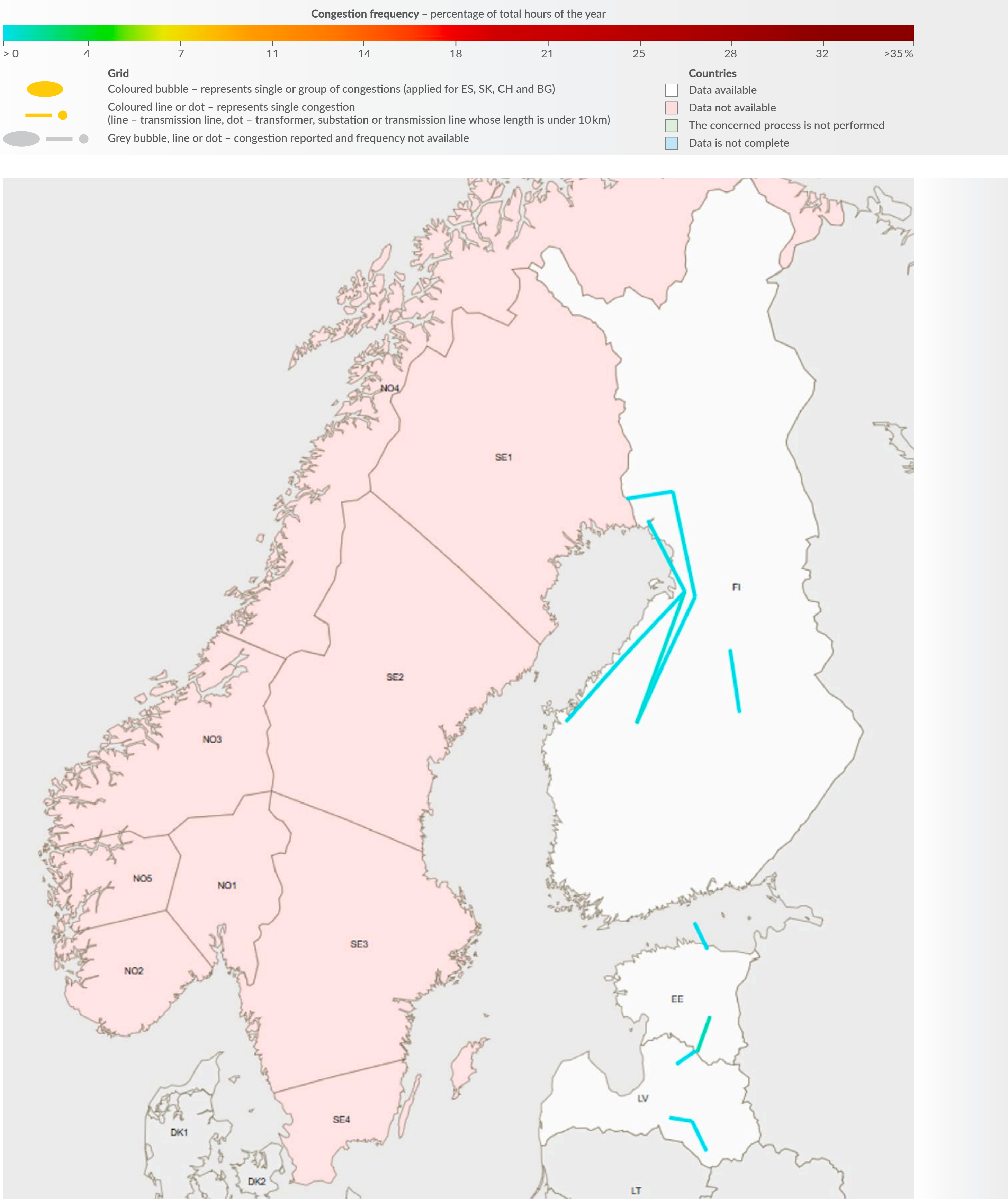


Figure 47: Real-time (up to one hour) for 2016. Nordic and Baltic countries

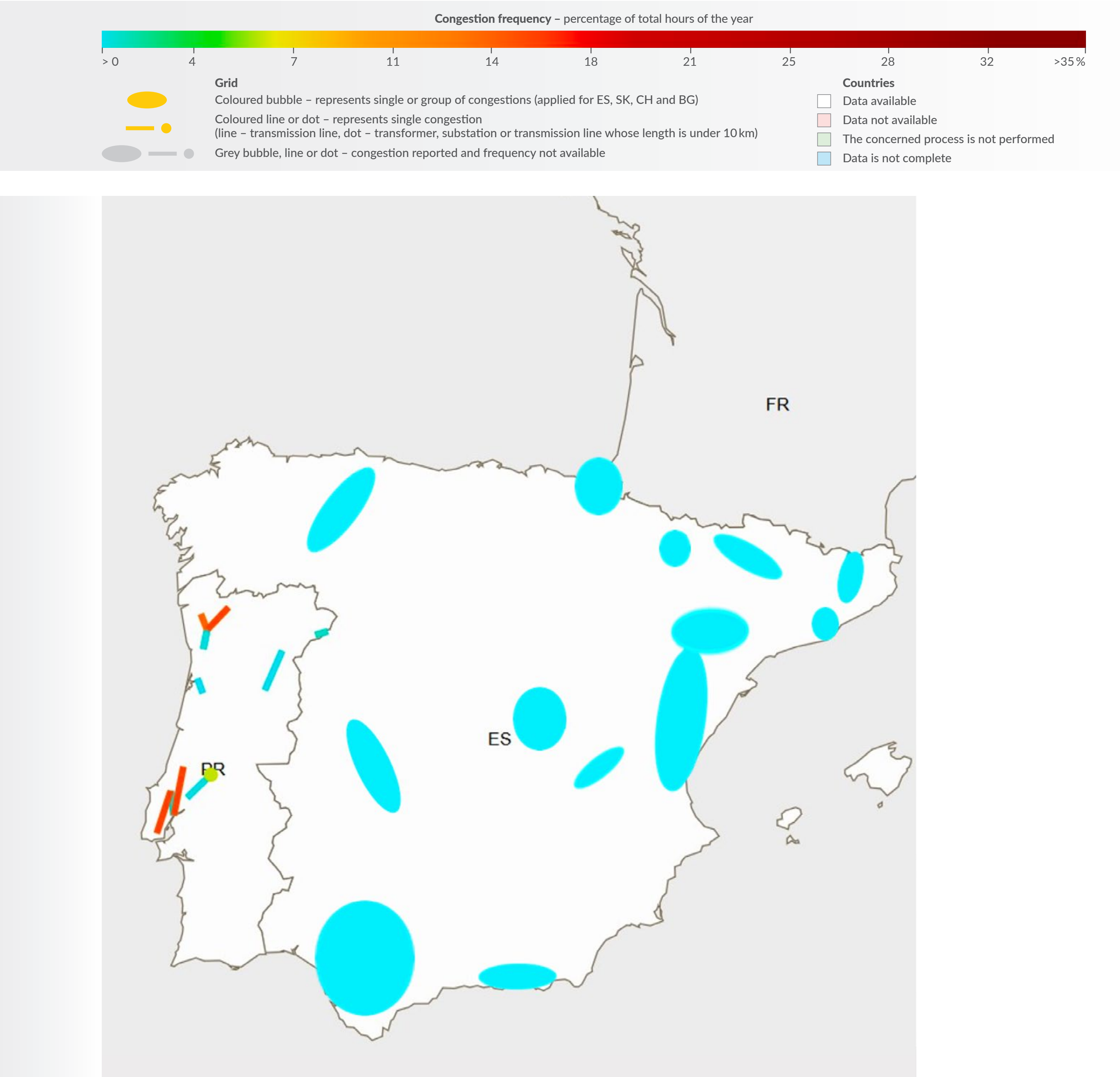


Figure 48: Real-time (up to one hour) for 2016. Spain/Portugal

2017 – Real-time up to one hour

Congestion frequency – percentage of total hours of the year

> 0 | 4 | 7 | 11 | 14 | 18 | 21 | 25 | 28 | 32 | >35 %

Grid

Coloured bubble – represents single or group of congestions (applied for ES, SK, CH and BG)

Coloured line or dot – represents single congestion
(line – transmission line, dot – transformer, substation or transmission line whose length is under 10 km)

Grey bubble, line or dot – congestion reported and frequency not available

Countries

Data available

Data not available

The concerned process is not performed

Data is not complete

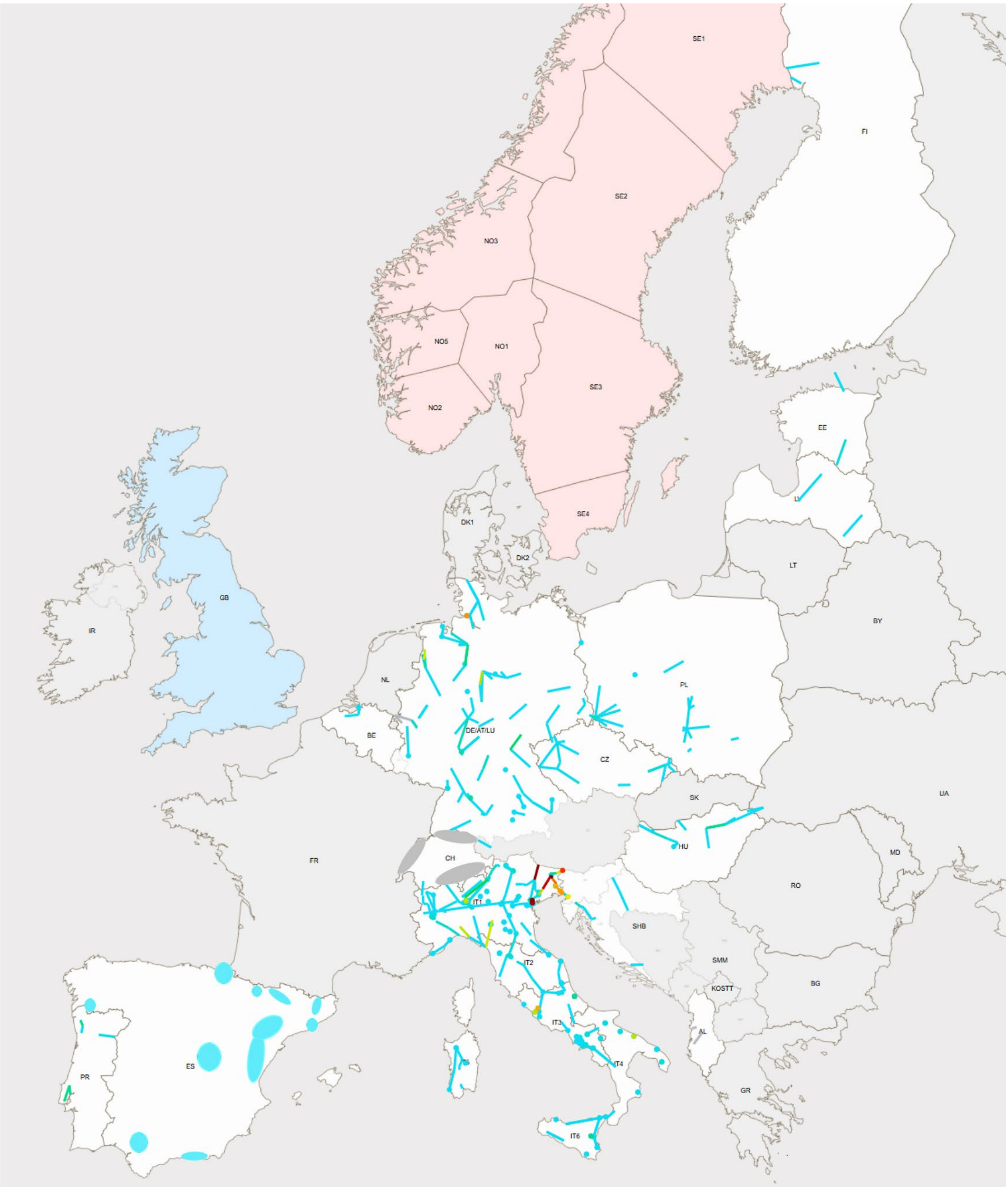


Figure 49: Real-time (up to one hour) for 2017. Europe

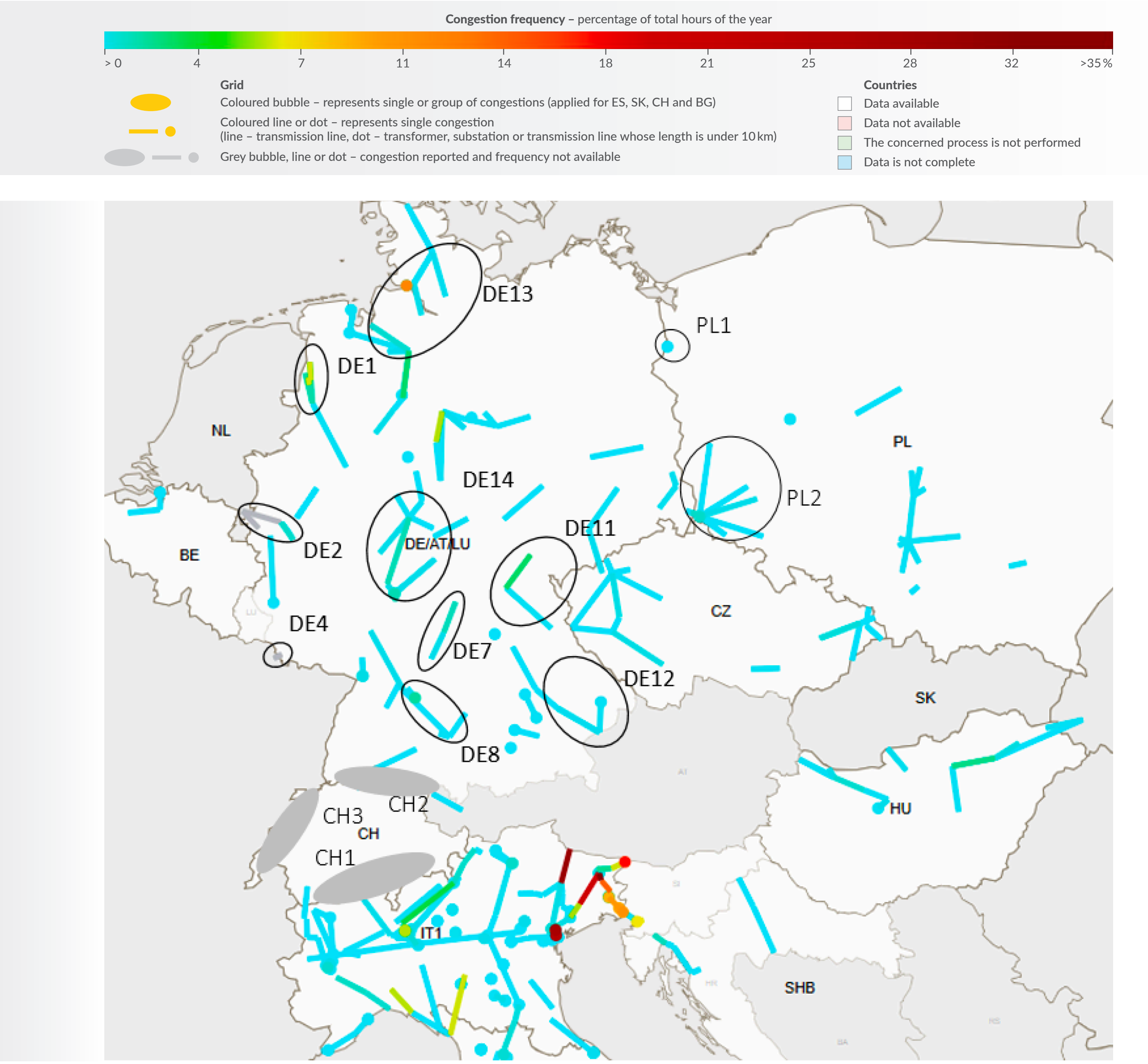


Figure 50: Real-time (up to one hour) for 2017. Central Europe

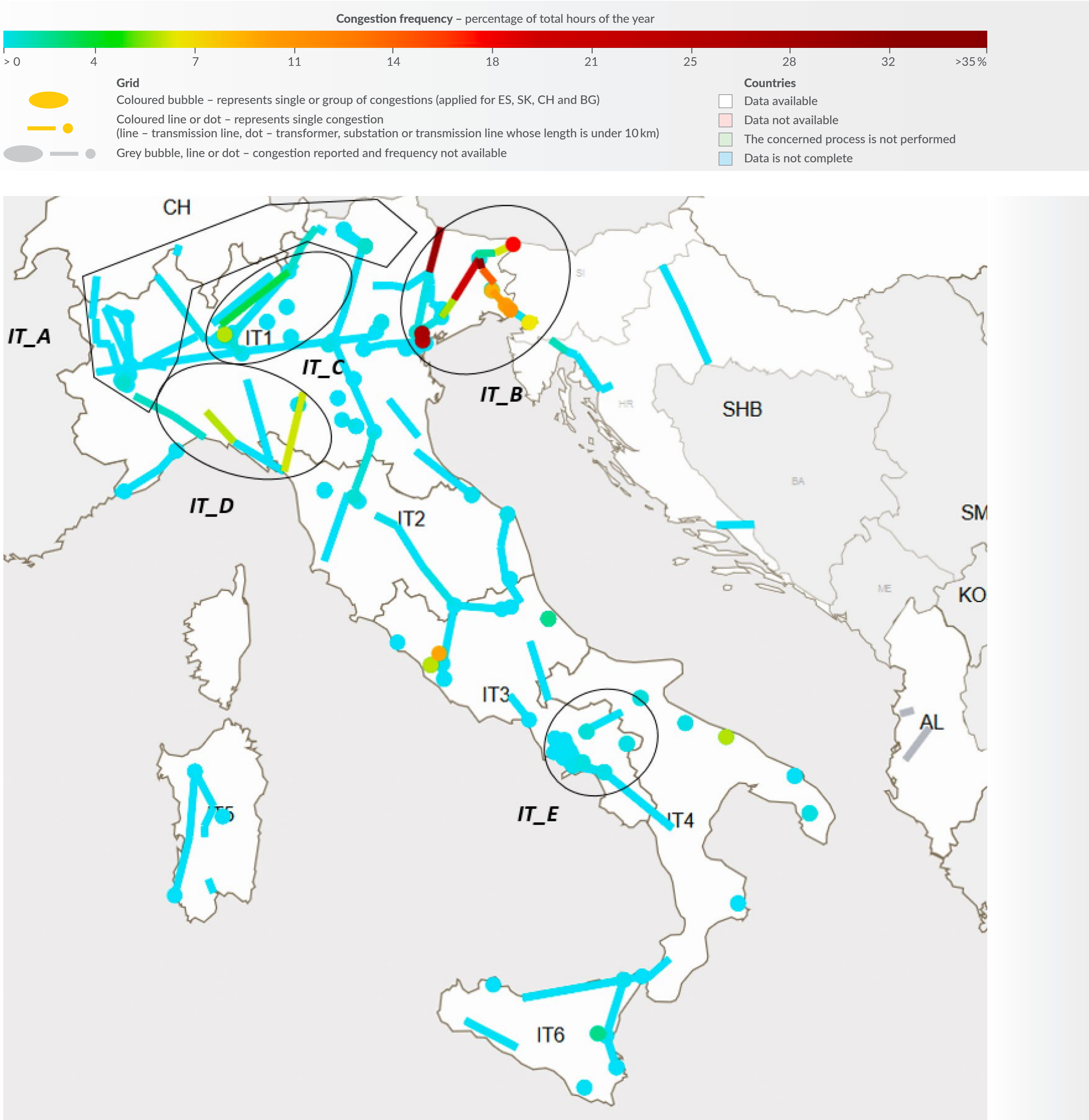


Figure 51: Real-time (up to one hour) for 2017. Italy

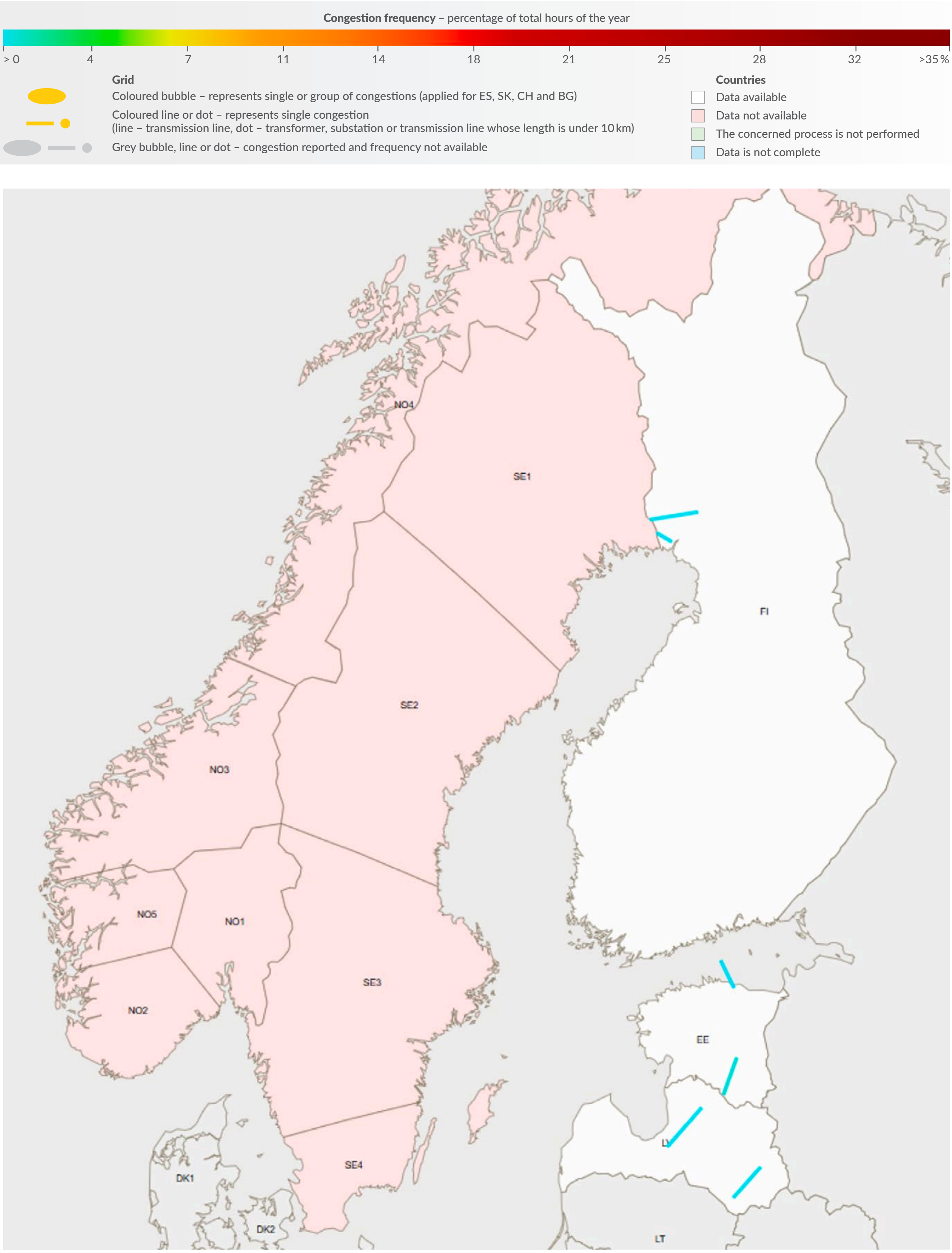


Figure 52: Real-time (up to one hour) for 2016. Nordic and Baltic countries

Congestion frequency – percentage of total hours of the year

> 0 | 4 | 7 | 11 | 14 | 18 | 21 | 25 | 28 | 32 | >35 %

Grid

Coloured bubble – represents single or group of congestions (applied for ES, SK, CH and BG)

Coloured line or dot – represents single congestion
(line – transmission line, dot – transformer, substation or transmission line whose length is under 10 km)

Grey bubble, line or dot – congestion reported and frequency not available

Countries

Data available

Data not available

The concerned process is not performed

Data is not complete

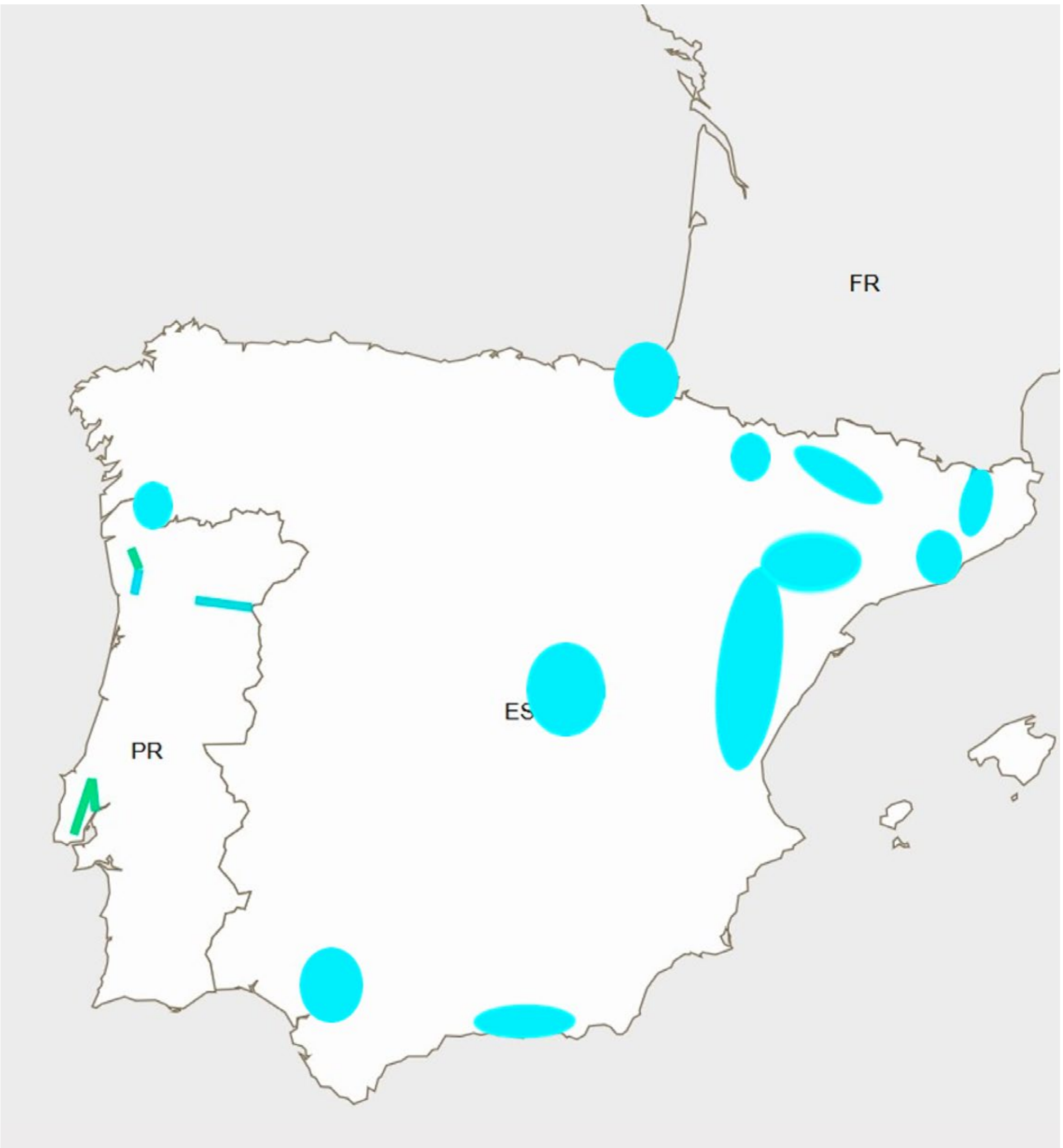


Figure 53: Real-time (up to one hour) for 2016. Spain/Portugal

2.2.5.2 REAL-TIME MAPS OF THE TSOs WHICH USED ICS DATA

2015 – Real-time (ICS)

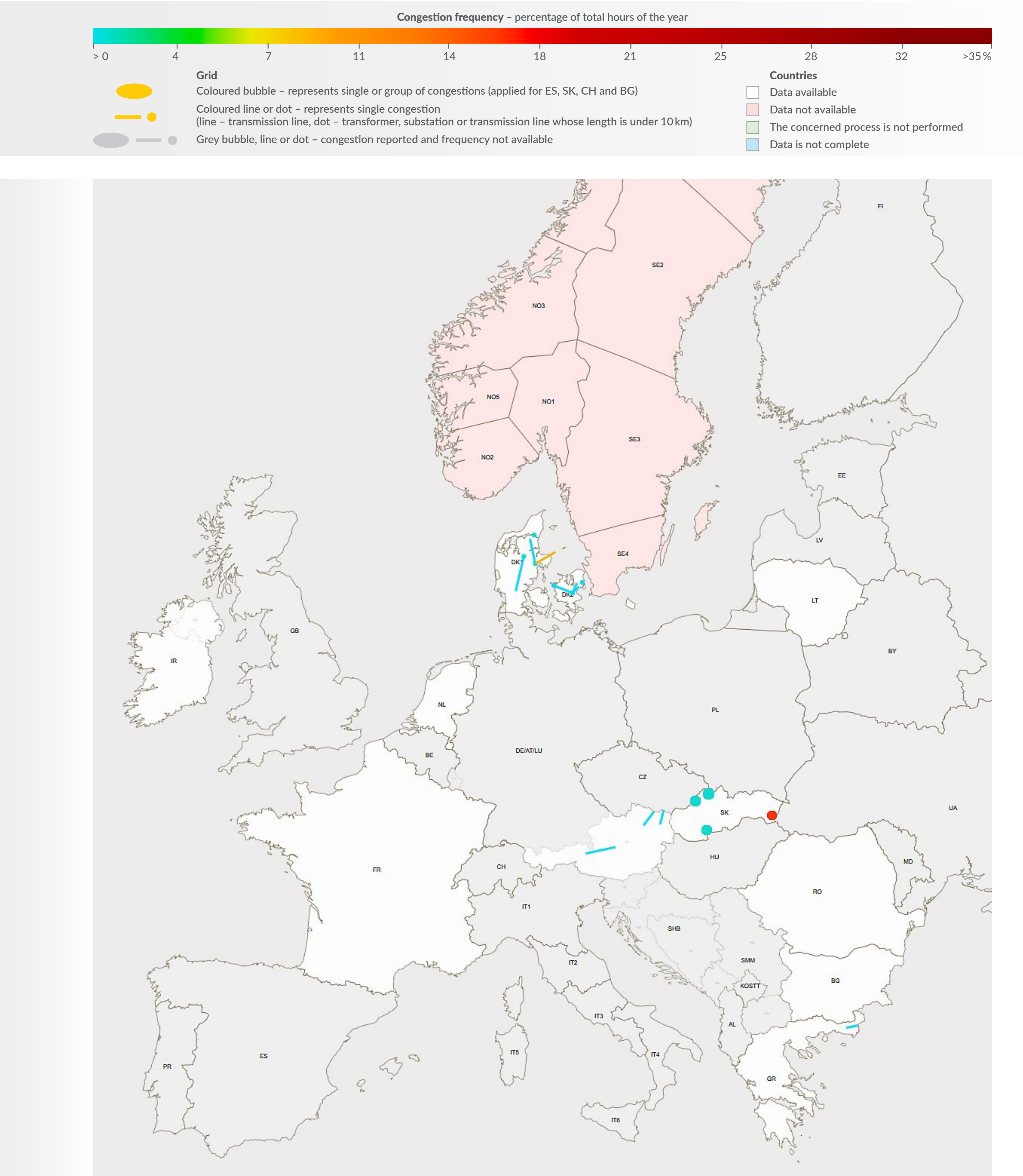


Figure 54: Real-time (ICS) for 2015. Europe

Congestion frequency – percentage of total hours of the year

> 0 | 4 | 7 | 11 | 14 | 18 | 21 | 25 | 28 | 32 | >35 %

Grid

Coloured bubble – represents single or group of congestions (applied for ES, SK, CH and BG)

Coloured line or dot – represents single congestion
(line – transmission line, dot – transformer, substation or transmission line whose length is under 10 km)

Grey bubble, line or dot – congestion reported and frequency not available

Countries

Data available

Data not available

The concerned process is not performed

Data is not complete

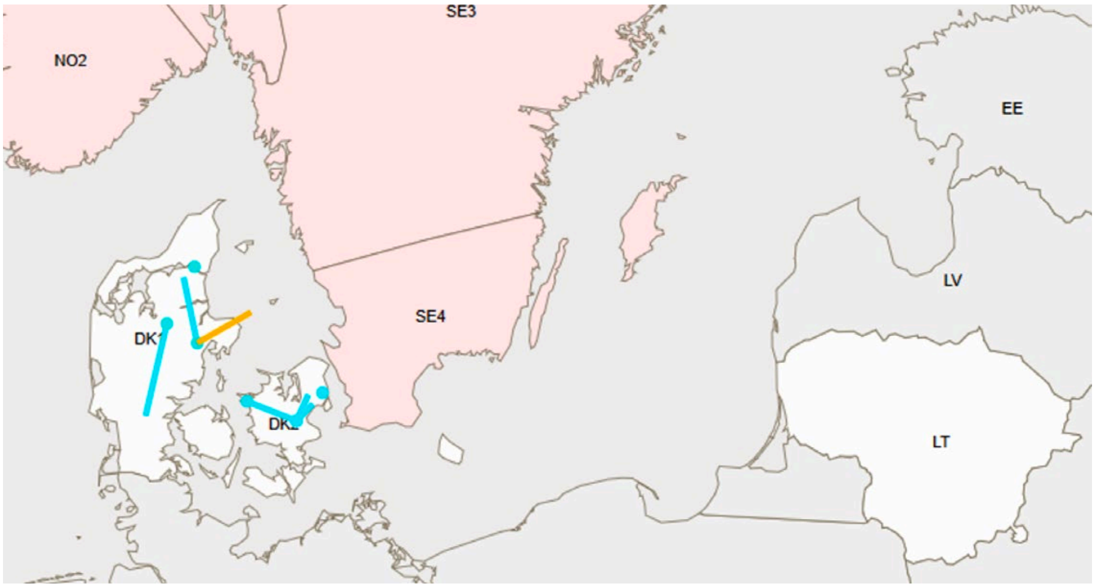


Figure 55: Real-time (ICS) for 2015. Denmark/Lithuania

Figure 56: Real-time (ICS) for 2015. France, Ireland, Netherlands

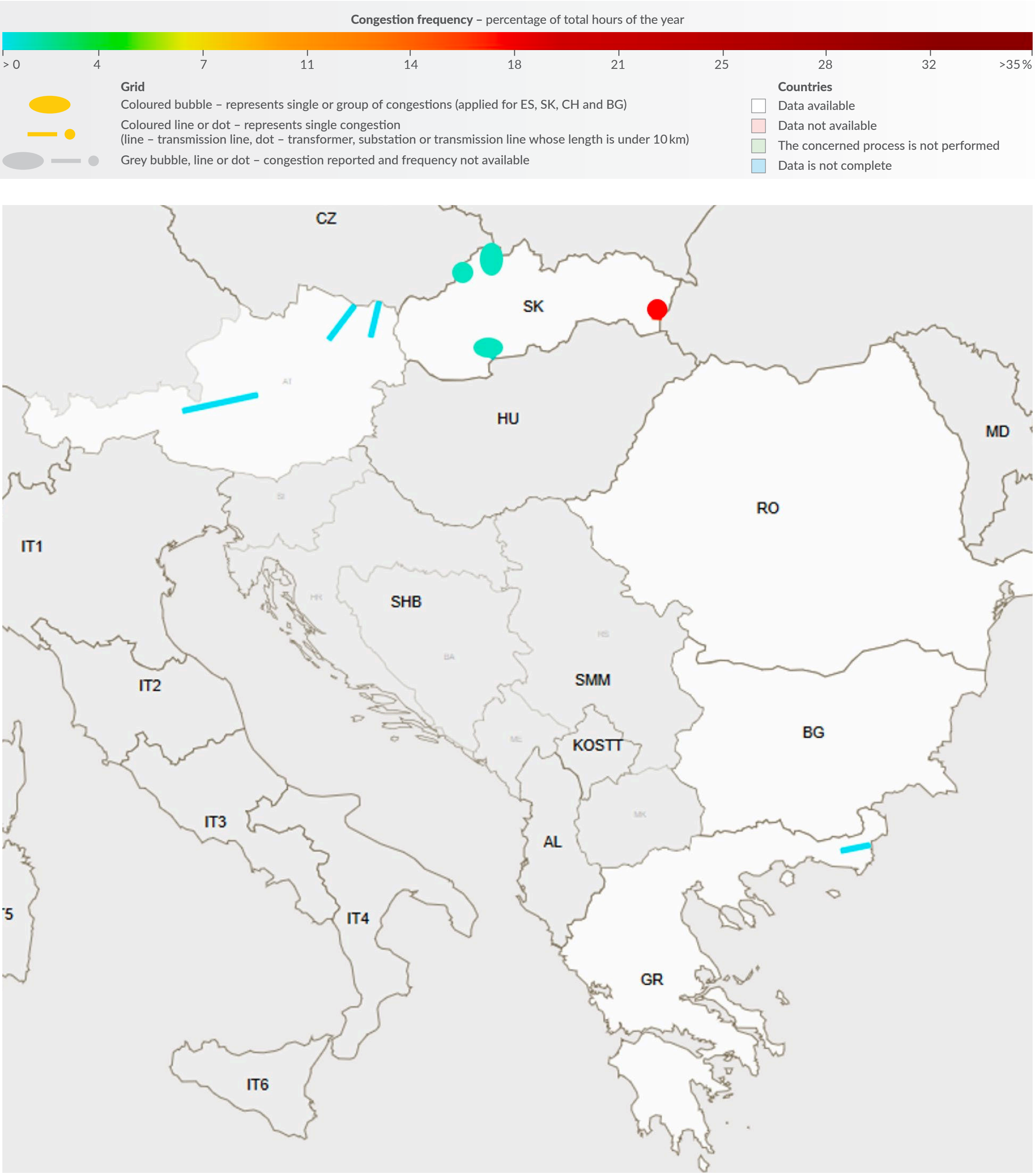


Figure 57: Real-time (ICS) for 2015. Balkan countries

2016 – Real-time (ICS)

Congestion frequency – percentage of total hours of the year

> 0 | 4 | 7 | 11 | 14 | 18 | 21 | 25 | 28 | 32 | >35 %

Grid

Coloured bubble – represents single or group of congestions (applied for ES, SK, CH and BG)

Coloured line or dot – represents single congestion
(line – transmission line, dot – transformer, substation or transmission line whose length is under 10 km)

Grey bubble, line or dot – congestion reported and frequency not available

Countries

Data available

Data not available

The concerned process is not performed

Data is not complete

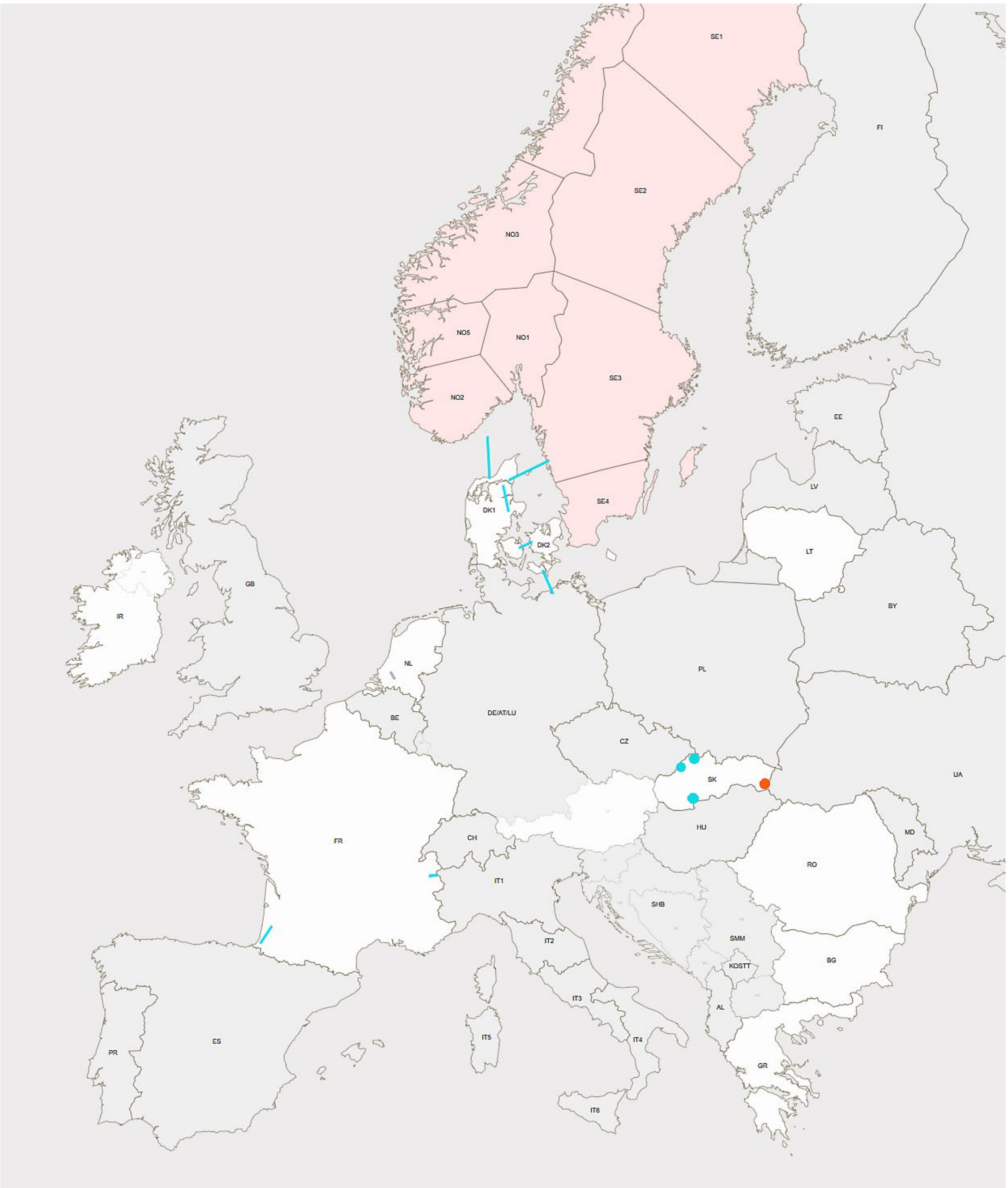
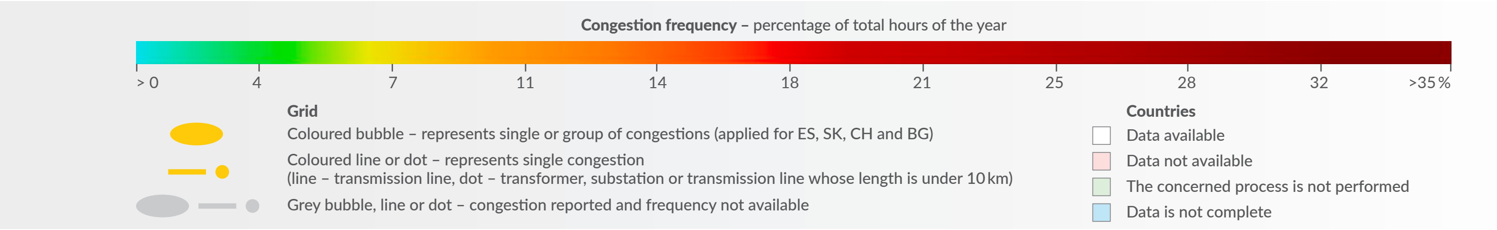


Figure 58: Real-time (ICS) for 2016. Europe



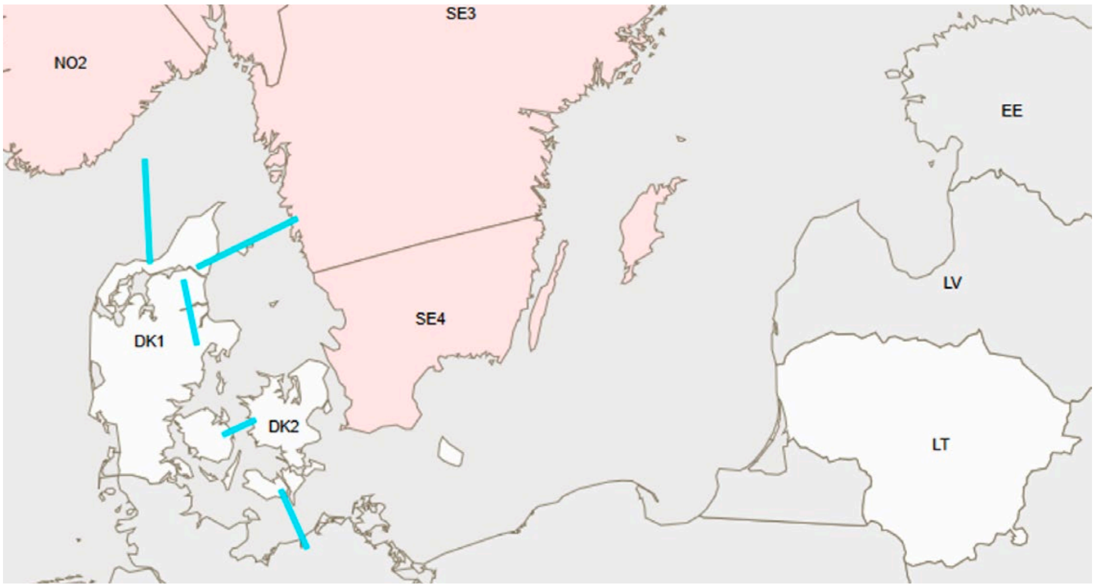


Figure 59: Real-time (ICS) for 2016. Denmark/Lithuania

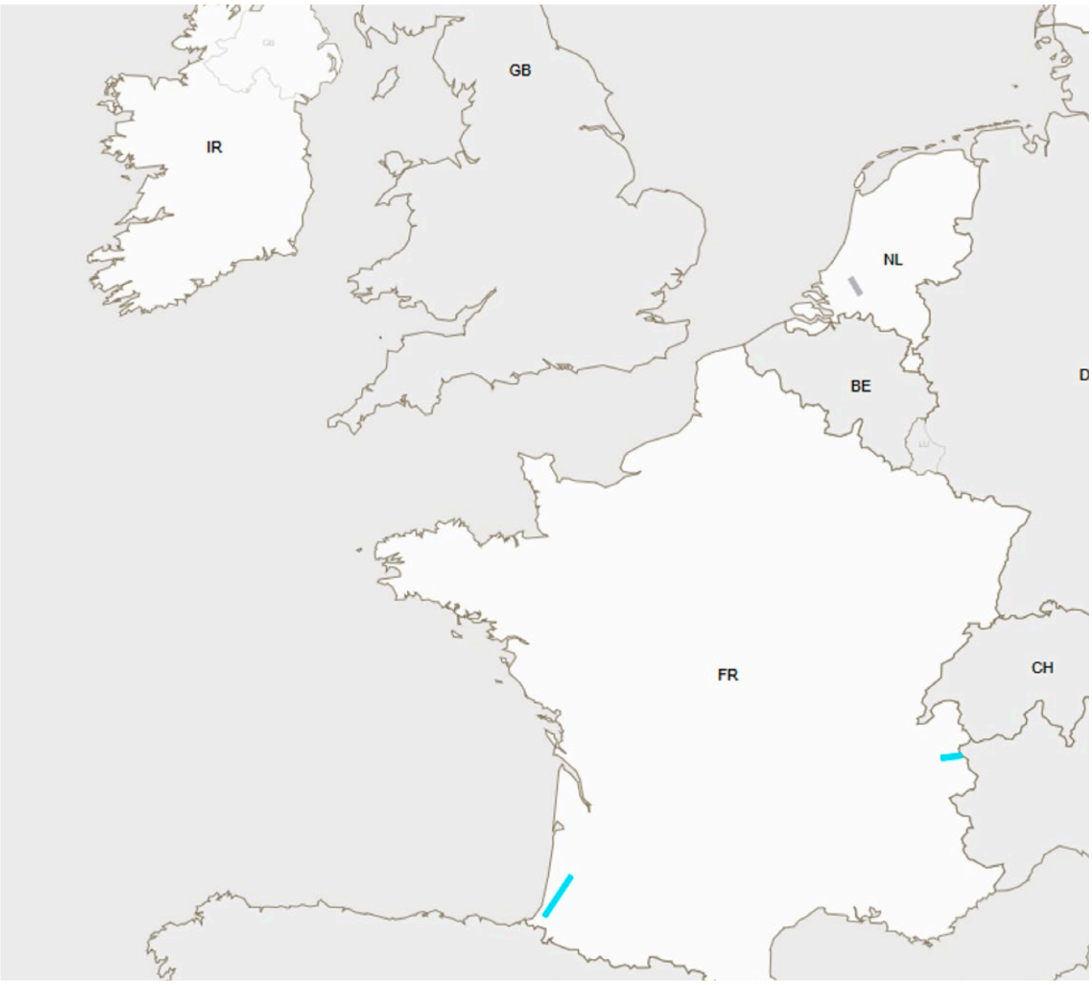


Figure 60: Real-time (ICS) for 2016. France, Ireland, Netherlands

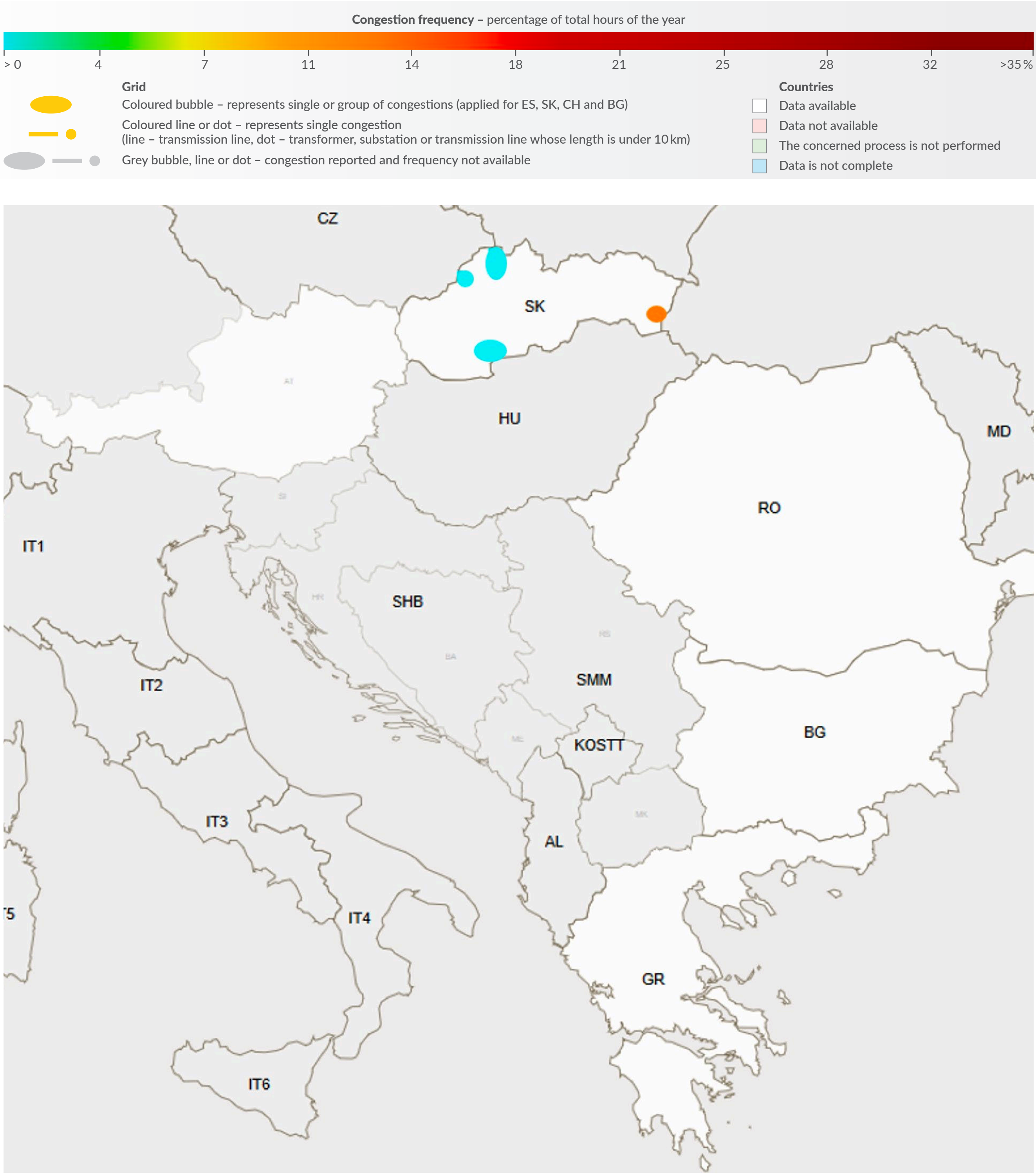


Figure 61: Real-time (ICS) for 2016. Balkan countries

2017 – Real-time (ICS)

Congestion frequency – percentage of total hours of the year

> 0 | 4 | 7 | 11 | 14 | 18 | 21 | 25 | 28 | 32 | >35 %

Grid

Coloured bubble – represents single or group of congestions (applied for ES, SK, CH and BG)

Coloured line or dot – represents single congestion
(line – transmission line, dot – transformer, substation or transmission line whose length is under 10 km)

Grey bubble, line or dot – congestion reported and frequency not available

Countries

Data available

Data not available

The concerned process is not performed

Data is not complete

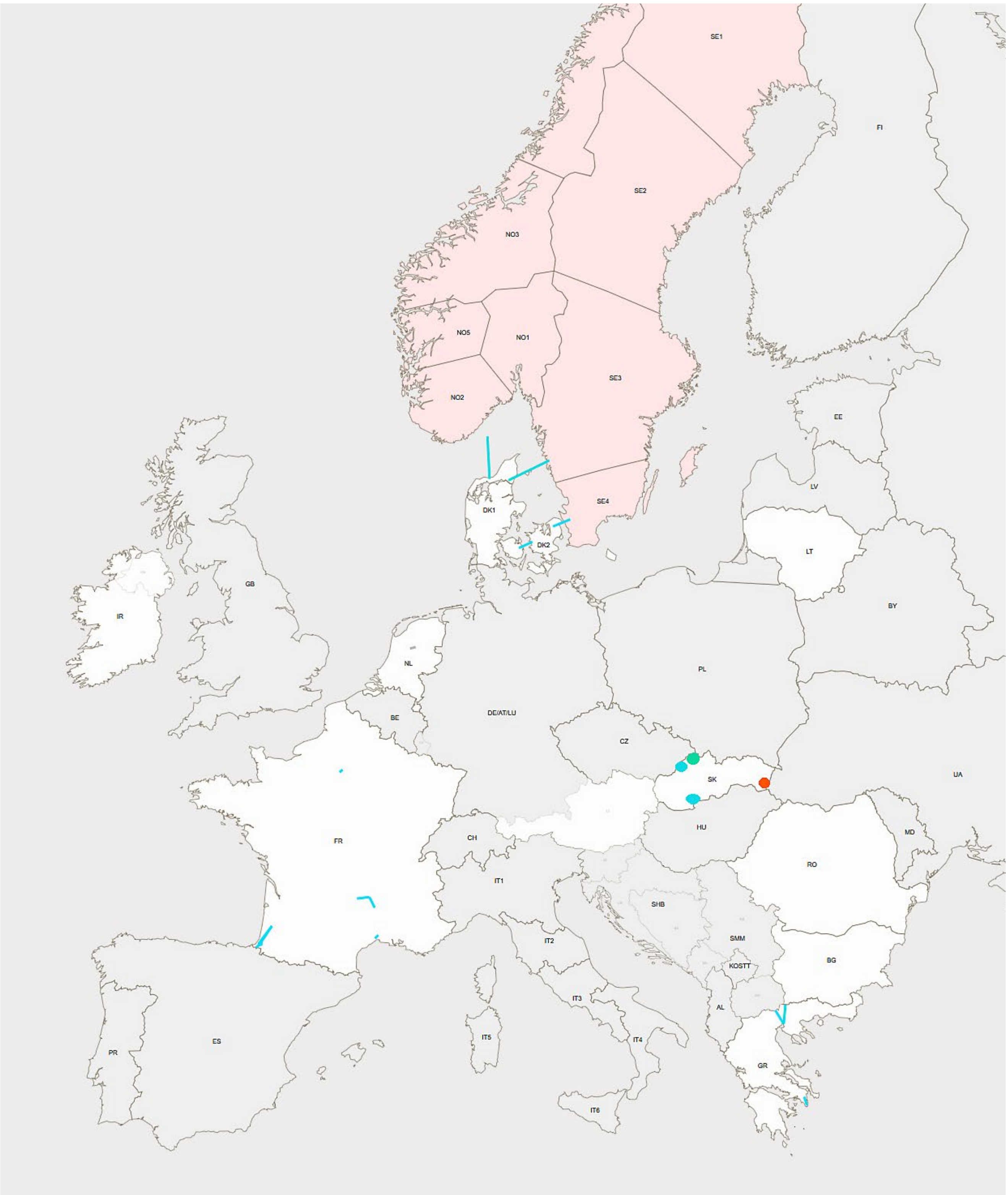
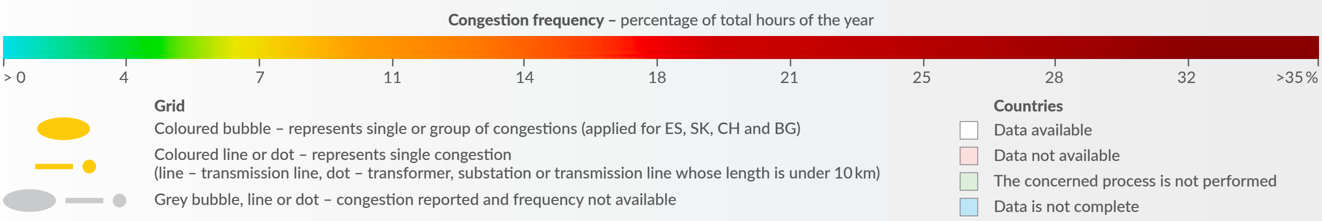


Figure 62: Real-time (ICS) for 2017. Europe



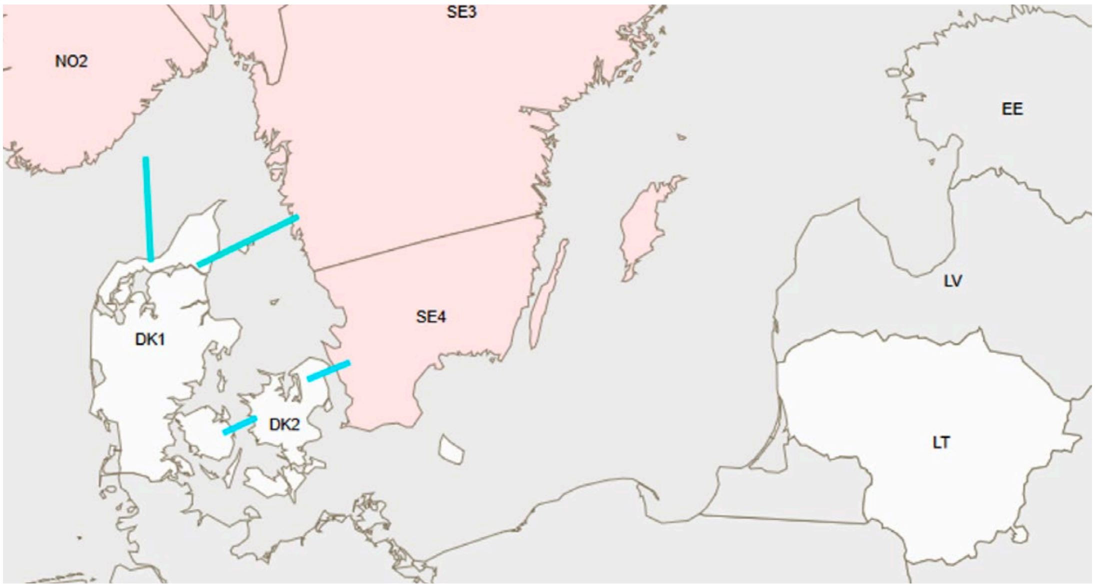


Figure 63: Real-time (ICS) for 2017. Denmark/Lithuania

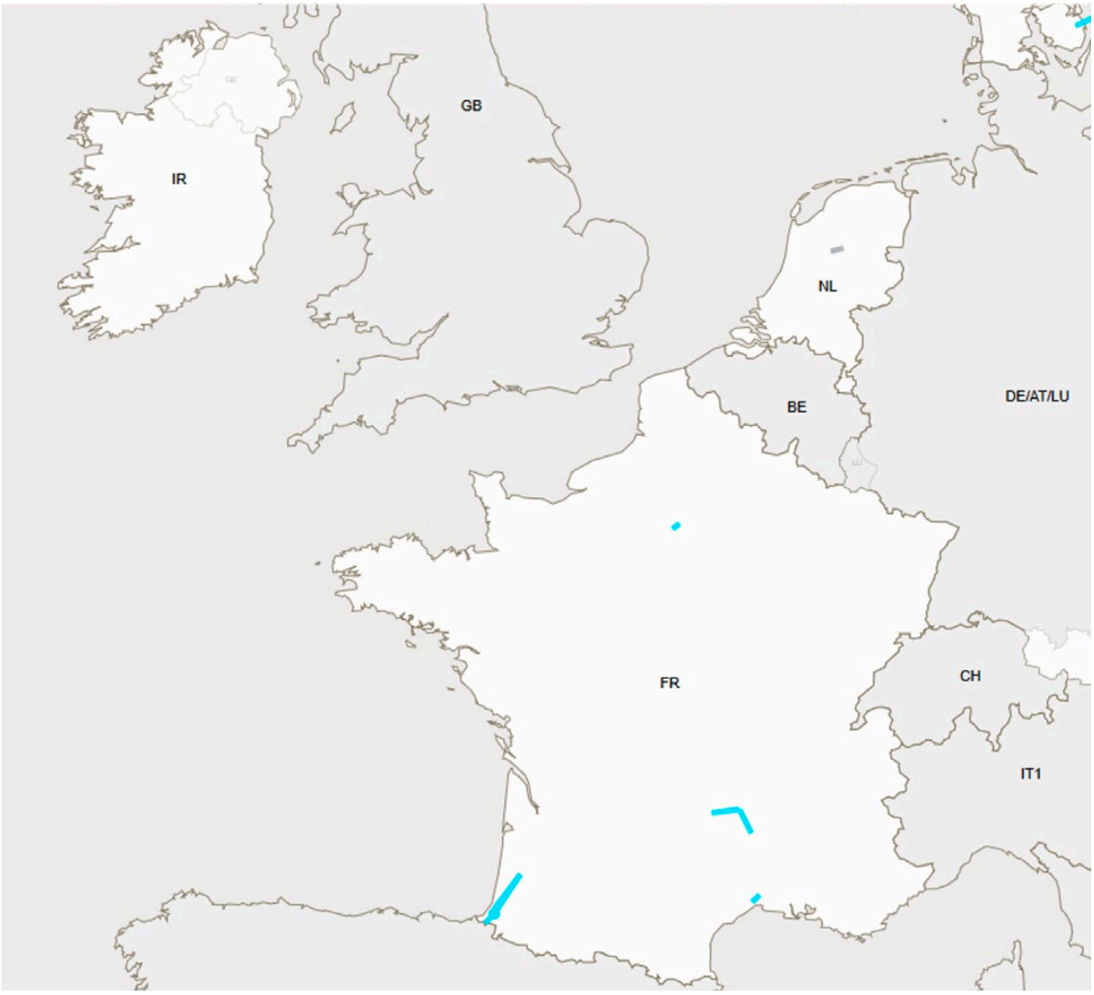


Figure 64: Real-time (ICS) for 2017. France, Ireland, Netherlands

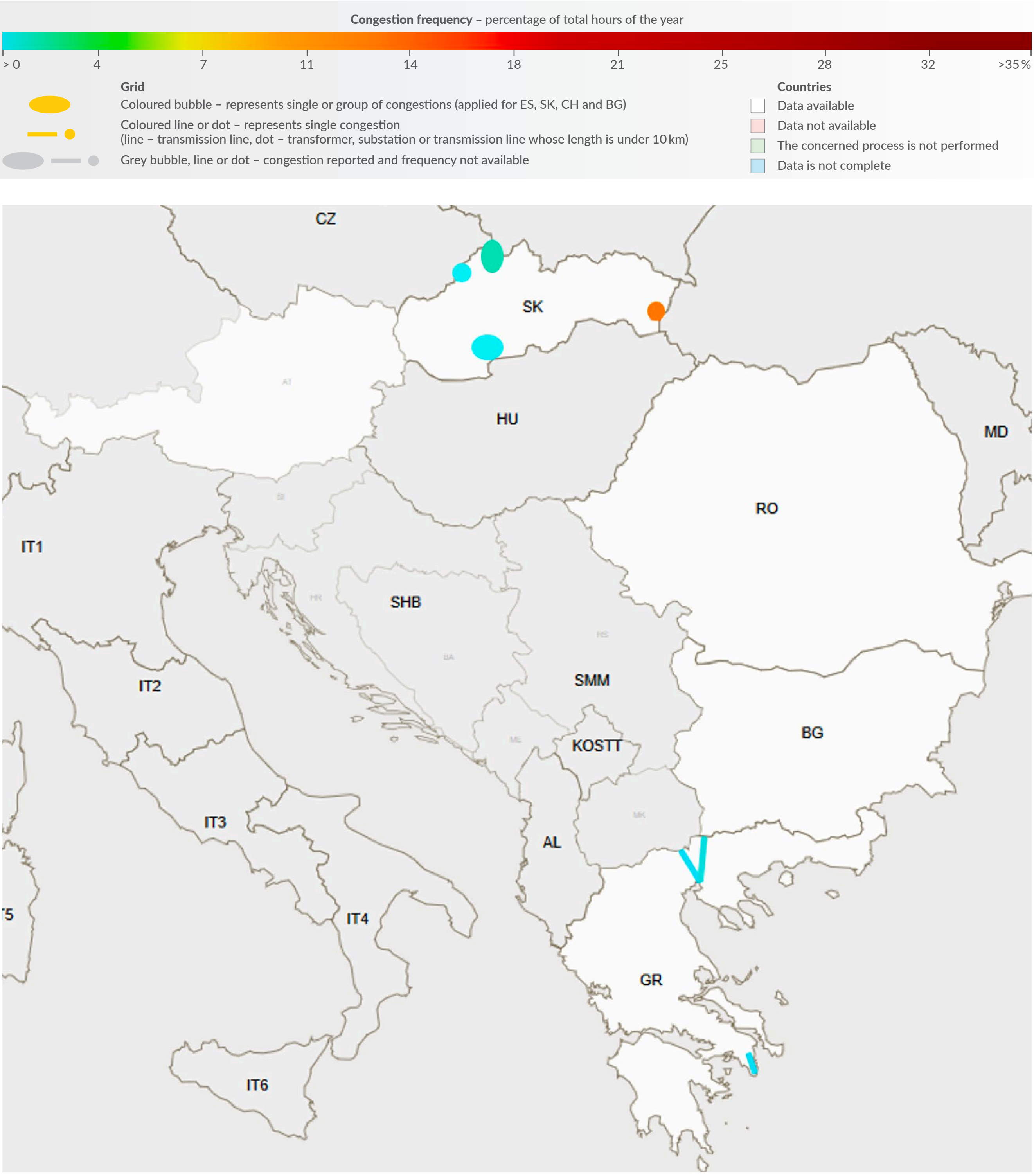


Figure 65: Real-time (ICS) for 2015. Balkan countries

2.2.6 EXPERT ASSESSMENT OF CONGESTIONS FOR REAL-TIME

The primary objective of Section 2 is to report where congestions have occurred in the grid over the reported years 2015, 2016 and 2017. In this sub section, each TSO provides an expert assessment of how these congestions have evolved over the reported years for the real-time stage. This includes an expert assessment of the causes of the congestions and the interdependencies of congested lines.

AUSTRIA

For the real-time timeframe, APG reported violations in accordance with the ICS. Only in 2015 did N-1 violations occur with a very rare frequency (0.04 % – 0.11 %). Accordingly, they are not significant for the consideration of this report.

BELGIUM

During 2015, the Belgian Bidding Zone did not experience any potential N-1 security violation close to real time system operation (up to one hour before operation, maximum). In 2016, the line *Mercator – Horta* suffered a potential N-1 violation of around 79 minutes. This latter violation was due to high North→South market and loop flows crossing the Belgian grid combined with the presence of maintenance works at the parallel lines. This situation was completely solved with additional tap changes on the PSTs to reduce the loop flows and with the opening of a coupler at the Avelgem substation.

During 2017, three network elements suffered potential N-1 security violations close to real time system operation. These were: the *Doel – Mercator* line (26 minutes), the Zandvliet PST (26 minutes too) and the *Mercator – Horta* line (1h 45 minutes). The case of *Doel – Mercator* was due to high North→South market and loop flows crossing the Belgian grid and was completely solved by applying additional tap changes on the PSTs to reduce the loop flows, and the opening of a coupler at the Avelgem substation. For the event of the PST Zandvliet, the cause was related to high North→South market and loop flows crossing the Belgian grid combined with limitations in one of the PSTs located in Zandvliet; this was completely solved with additional tap changes on the PSTs to reduce the loop flows and several topological measures in Mercator, Horta and Avelgem. The last case of *Mercator – Horta* was also caused by a high North→South market and loop flows crossing the Belgian grid, this time combined with maintenance works at the parallel lines; the remedy consisted of additional tap changes on the PSTs to reduce the loop flows, and the opening of a coupler at the Horta and Avelgem substations.

CZECH REPUBLIC

Besides congestions which appeared in previous stages, several further congestions on internal lines were experienced close to the real-time and real time operation. The occurrences are, however, far below 1 % of time. This rest of the congestions are mostly transient ones before measures became effective. Topological measures such as reconfiguration or multilateral redispatching within the TSC cooperation framework were applied to mitigate these congestions. After putting the PST between ČEPS and 50Hertz in July 2017, the level of congestions reported on internal network elements in transiting path from Germany (50Hertz) had decreased. The majority of these congestions were caused by unexpected high power flows from the northern direction (either from 50Hertz or PSE) during planned maintenance periods. Few congestions resulted as a consequence of redispatching outside of the Czech republic.

DENMARK

Energinet have only reported ICS data for the real-time timeframe. In general, as with the CCDA stage, there are no internal congestions in the Danish bidding zones when all grid elements are in operation. This means that most of the congestion management during real-time is to handle faults in the grid.

ESTONIA

Real-time congestions occurred only when there were either unexpected outages on the lines that limit the interconnection capacity between Estonia and Latvia or were due to excess power flows caused by third countries.

FINLAND

Transmission capacity reductions during the operational hour have been necessitated primarily by increased, above-forecast wind generation or temperatures that are higher than the seasonal norm. The timing of maintenance is important, particularly when multiple lines are being serviced, but the timing cannot always be optimised.

FRANCE

RTE reported ICS data completed with the violations reported in accordance with the French classification scale (Evènements Système Significatifs – ESS). Such violations are very rare and are solved in a few minutes. Therefore, they are not relevant for the consideration of this Technical Report and cannot be considered either as structural or as major physical congestions.

GERMANY

For the real-time stage, German TSOs derived congestions from redispatch measures performed to mainly solve n-1 violations and identified up to one hour before real time. Consequently, considerably more congestions are shown than if just ICS data or another less extensive source had been used.

Germany is a key exchange country. Due to its central location in the European electricity system, it is an important transit country. Moreover, Germany is one of the biggest exporters, especially when renewable infeed is high in the northern part. Most of the congestion in the German grid appears in this situation, when Germany exports electricity.

50Hertz

From 2015 to 2017, the general level of congestions was reduced significantly. This is due to two reasons already described in the D-1 section:

- the disconnection of the 220 kV *Krajnik – Vierraden* (affecting congested area DE15 [DE-PL])
- the successive commissioning of two additional circuits between *Altenfeld – Redwitz* (affecting congested area DE11 [TTG-50Hertz])

The congestions visible in 2017 were congestions which only occurred for a small number of hours (see also data in annex 1). Reasons for most were again twofold:

- the installation of PSTs in Mikułowa and Hradec led to a shifting of flows and a more intense use of lines. The shifting occurred generally towards the western direction. This causes some congestions on different lines (on a very low level).
- Additionally, the high amount of construction work in the 50Hertz grid (due to upgrading of lines and transformer stations) also led to some temporary congestions.

Amprion

Congested area DE 2 [DE – NL] (2016 – 2017)

For a general description of this cluster, please refer to the description of the capacity calculation and allocation stage. Due to a well-functioning congestion management system, congestions observed in the real-time stage are generally much less frequent than in the previous stages. For the observed years, no clear trend in the frequency of congestions is noticeable, but only the years 2016 and 2017 are of any note.

Congested area DE 1 [AMP – TTG] (2017)

For a general description of this cluster, please refer to the description of the capacity calculation and allocation stage. Due to a well-functioning congestion management system, congestions observed in the real-time stage are generally much less frequent than in the previous stages. Only in 2017, the inter-TSO 380 kV lines *Haneken-*

fähr – Meppen – Niederlangen (TTG) – Dörpen/West (TTG) showed a highly increased frequency of congestions. The criticality of these lines in real time is due to the priority of wind infeed. According to German energy law, RES may only be curtailed close to real-time. The exceptional high wind infeed in 2017 thus explains the sharp increase in the frequency of congestions in real time.

Congested area DE4 [DE-FR] (2015-2016)

For a general description of this cluster, please refer to the description of the D-1 stage. Due to a well-functioning congestion management system, congestions observed in the real-time stage are generally much less frequent than in the previous stages. For the observed years, there is no clear trend noticeable.

TenneT GER

Congested area DE 13

The region covered by bubble DE13 is dominated by high RES feed-in, in particular on- and offshore wind. For a general description of the right side of the cluster, please refer to the D-2 (capacity calculation stage) and D-1 (operational planning) description. In the left side of the cluster, there are the 380 kV lines *Diele – Dörpen West – Hanekenfähr*, *Diele – Dörpen West – Niederlangen – Meppen*, *Diele – ConnefordeOst* and the 220 kV lines *Conneforde – Maade*, *Conneforde – Sottrum*, *Huntorf – Bockland – Sottrum*. On the line *Conneforde – Maade* is a special protection scheme called emergency power control (EPC) applied, i. e. operation in n-0.

Congestions within this area can often only be cured by a reduction of RES. This remedial action has a short activation time and has to be activated as measure of last resort.

Congested area DE 14

This cluster represents the power hub over which the north-south and east-west load flows pass. In this cluster there are the 380 kV lines *Borken – Karben*, *Gießen Nord – Karben*, *Borken – Mecklar*, *Großkrotzenburg – Karben* which developed to the power hub for Germany. This resulted in the retrofitting and expansion of this region. As result of these measures, this hub has emerged as a congestion region.

Congested area DE 12

The region covered by bubble DE12 is dominated by high and increasing RES feed-in (mostly PV) as well as high and currently unlimited north-south transits between Germany and Austria. This cluster includes the 220 kV lines *Pleinting – St. Peter*, *Pleinting – Pirach – St. Peter* and *Altheim – Simbach – St. Peter*. The grid enforcement from 220 kV to 380 kV is planned for 2021 (*St. Peter – Isar/Ottenhofen*) and 2024 (*St. Peter – Pleinting*). However, in the meantime, dynamic line rating has been applied on these lines, which led to significant reductions of congestions in this area.

Congested area DE 11

This cluster includes the 380 kV lines *Raitersaich – Kriegenbrunn – Würgau – Redwitz – Remptendorf* (50Hertz), *Redwitz – Altenfeld* (50Hertz) and *Eltmann – Oberhaid – Redwitz – Mechlenreuth*.

TransnetBW

Congested area DE 7

The line 380-kV-Grafenrheinfeld-Stalldorf rt was structurally damaged from winter 16/17 until end of October 2017 and therefore a lower thermal limit had to be applied throughout the majority of 2017. Consequently, the line appeared in RT more frequently. Since this corridor is heavily impacted by north to south flows it will be further upgraded in the future (see 'Future Developments' section).

Congested area DE 8

The cluster includes substations 380-kV-Wendlingen, 380-kV-Endersbach and 380-kV-Altbach which are reported due to voltage violations, which have a very local effect and appear in the summer season because of low load.

GREECE

Greece reported ICS data. The violations were very rare and primarily refer to increased voltage levels at specific nodes due to low demand; the problems were solved locally by applying reactive compensation measures. Additionally, the tripping of individual tie lines caused either by faults or by large system disturbances (in the case of the Greece – Turkey tie line due to the blackout in Turkey in 2015) did not cause any problems in system operation since the system remained N-1 secured.

HUNGARY

The real-time congestions presented for the Hungarian network cover violations of the 100 % thermal limit in the real-time contingency analysis of the SCADA system. This corresponds to the permanent admissible thermal limit of the elements. According to the security policy laid down in the Grid Code, overloads in the N-1 case do not necessarily mean the violation of the system security as far as the temporary admissible thermal limit is not exceeded and topological measures are available to decrease the loading of the overloaded lines. These measures are considered as curative actions, which means they are activated only if the contingency situation really occurs. The temporary limits for the transmission network were not exceeded in real time and curative measures were always available to mitigate the violations of the permanent limit in the 2015 – 2017 time period. There was a single situation in 2015 when the contingency case actually occurred and the restoration of the N-1 security was not possible without redispatch.

Real-time violations are in correlation with the congestions identified in the D-1 timeframe, which means, that forecasts are generally in line with real-time experience. There were several violations that only appeared in real-time but they had a very limited frequency, only a few hours per year.

ITALY

Real-time congestion level for elements in the Italian Power System is derived from an online system security assessment (taking into account N-1 security criterion) performed on state estimation results.

The main congested areas in the last three years (at least one element with a frequency higher than 10 %) are the following:

- Cluster IT_A: congestions on Italy – Switzerland border. They are induced by unbalanced flows at the Northern Italian Border and they are typically solved using PSTs on other borders or, in the worst cases, applying countertrading measures.
- Cluster IT_B: congestions close to the Austria – Italy and Slovenia – Italy border. They appear when high import flows are observed from the eastern countries. These congestions can be solved by managing PSTs' tap positions and they are also mitigated by proper special protection schemes at the border.
- Cluster IT_C: congestions close to the Milan metropolitan area. They are typically solved by applying proper topological schemes.
- Cluster IT_D: congestions on the 220 kV grid close to the IT1-IT2 border. They are observed when high flows on this border appear simultaneously to high load conditions in this area. They are solved by applying proper topological schemes. As IT1-IT2 frequency of congestions decreased in 2017, even these real-time congestions had a lower impact in this year.
- Cluster IT_E: congestions on the 220 kV grid of Campania region close to the IT4-IT3 border. They are observed when high flows on this border appear (especially with high production in Calabria region – e.g. virtual Bidding Zone of 'Rossano') simultaneously with high load conditions in this area. They are solved by applying proper topological schemes and they are also mitigated by proper special protection schemes.

LATVIA

In the real-time during the assessed time period from 2015 till 2017, only a few congestions have been identified; they were rather small and each occurred less than 2 % of the time in the particular year. In 2015, there were more countertrades fixed compared to 2016 and 2017 and this was due to the higher need for power exchanges from north to south within Baltic States. For the real-time congestions on cross-border EE-LV, Latvian and Estonian TSOs have applied countertrade measures. The countertrades have been applied only on cross-border EE-LV and none on cross-border LV-LT as in the past the overloads in real-time were not recorded there.

LITHUANIA

No real time congestions identified in the Lithuanian grid during the time period from 2015 until 2017.

NETHERLANDS

In the intraday and real time timeframe, the occurring congestions (e.g. the ones that are mentioned in paragraph 2.2.2.) are solved with topological measures, internal redispatch and, if necessary, cross-border redispatch.

NORWAY

As for the capacity calculation for the purpose of the capacity allocation phase, Statnett does not keep detailed data of real time congestions. As capacities are determined according to the CCDA congestions, for corridors fully utilised by the market, one would expect to see these congestions in real time as well in cases where bidding zones have significant imbalances.

In addition, due to Norway's high degree of distributed hydro production in radial grid structures, we often redispatch to relieve bottlenecks that cannot be handled by separate bidding zones, due to the expected market competition conditions. The costs of these remedial actions are reflected in chapter 4.3 for Norway.

POLAND

In the real-time timeframe, the presented congestions are grouped into two clusters in order to explain the nature of the network congestions experienced over the three reported years in Poland. For the real-time timeframe, PSE has reported network constraints identified up to one hour before real time operation i.e. in time when all congestion forecast processes such as DACF or IDCF are finalised and dispatchers are managing remaining congestions based on on-line grid analyses using EMS systems.

Clusters PL1 and PL2 represent congestions which are highly influenced by unscheduled flows from DE towards south direction to CZ and SK and usually result from dynamic changes of those unscheduled flows. In the near future, this would be mitigated to a certain extent by splitting the DEAT bidding zone, PST installation in Vierraden substation, switching Krajnik-Vierraden interconnector from 220 kV to 400 kV and grid investments at Polish side around Mikułowa substation i.e. 400 kV *Mikułowa – Czarna* in 2022, 400 kV *Czarna – Polkowice* in 2019, 400 kV *Mikułowa – Czarna – Pasikurowice* in 2022 and 400 kV *Mikułowa – Świebodzice* in 2023.

Other network constraints identified up to one hour before real time of operation apart from the ones grouped under the aforementioned clusters usually result from unexpected events. These network constraints should not be deemed as structural as their location frequently changes depending on the power system operating conditions and near to real-time outages/events. It must be underlined that the occurrence of these congestions stems from the fact that, in central-dispatch systems, the operation of generation units determined under ISP leads to transmission and generation resources being used to the fullest possible extent (as under optimal power flow problem) to minimise the overall energy supply costs for all consumers. Therefore, any unexpected events in real-time frame may require some adaptation measures on the TSO side. In order to mitigate those network constraints, PSE is implementing adequate solutions covering both grid investments and market-based solutions i.e. further improvement of the ISP, including the implementation of a new balancing market with full network model and locational pricing.

PORTUGAL

Real-time level of congestions for elements in the Portuguese power system came from the online system assessment performed by the state estimator, taking into consideration the n-1 security criterion.

The most significant congestions are associated with REN outages and generation profiles different from those initially foreseen. To solve these congestions, some different curative and preventive remedial actions were taken.

SLOVAKIA

In the main, all congestions reported during real-time operation were caused by high unplanned flows on all three borders – CZ – SK, HU – SK and SK – UA. In addition, there were several cases when an unplanned turn-off of the lines occurred, which made the congestion even more serious. As SEPS is not using costly remedial actions, these congestions were solved by the changing of the topology. Mostly, the reconfiguration in transformer station was performed or the related connecting line was turned off. For the congested lines on the HU – SK profile and SK – UA profile, the congestions were also solved by activating the RAAS – EAS system. The highest frequency of congestion of 15 % of hours per year was registered on the line on SK – UA profile. The rest of congestions occurred with a frequency of 2 % and less of hours per year.

SLOVENIA

There are no frequent congestions in real time operation. Some congestions close to IN CCR area are present; however this is due to near-maximum optimised PST operation in line with coordinated CCDA. Due to the nature of this congestion, effective remedial action (PST adjusting) is always available. Congestion on the SI – AT CORE CCR border is handled by topological remedial actions.

SPAIN

There are no relevant congestions from real-time operation (maximum one hour before real-time) and there no incidents reported by REE in ICS for these three years. In general, the congestions from real-time operation do not exceed 1 % of the time and are caused by unexpected events or operational situations. In the main, these congestions are managed on the REE side by redispaching. Therefore, they cannot be considered as structural congestions.

SWEDEN

The data on specific grid elements is missing due to information security limitations.

SWITZERLAND

Congested area CH 1 (CH – IT)

The constraints on the IT – CH border are mainly the same in real-time as in the D-1 timeframe. Congested elements are either 380 kV internal and tielines in case of high Italian import.

Congested area CH 2 (DE/AT – CH)

The constraints on the DE/AT – CH border are the same in real-time as in the D-1 timeframe. Dependent on the scenario, the main congested elements are the PSTs and 380 kV transit lines. The situation worsened due to the introduction of the CWE Market coupling, which induces high unscheduled flows inside the Swiss system

Congested area CH 3 (FR – CH)

The constraints on the FR – CH border are the same in the real-time as in the D-1 timeframe.

2.2.7 D-1 AND REAL-TIME TIMEFRAME FOR GREAT BRITAIN

The National Grid System Operator manages congestion in Great Britain by creating internal zones separated by transmission 'boundaries'. These boundaries intersect the transmission system across critical routes where bulk power transfer is limited or expected to be limited in the future, which may result in congestion.

For long term system planning, National Grid uses approximately 40 boundaries as described in the Electricity Ten-Year Statement (ETYS)[8]. In operational timescales, a more specific set of boundaries are required; at present, the number of operational boundaries stands at over 200. Since the of number of transmission boundaries is so large, it was assumed that National Grid would report the three most congested boundaries each year between 2015 and 2017 in this report.

National Grid manages congestion using a full system optimiser tool called EBS (energy balancing system). This system is used for both D-1 and real-time congestion forecasting and solves congestions on multiple boundaries simultaneously. As a result, many system operator (SO) actions taken cannot be only attributed to congestions in a single part of the network. To counter this, National Grid's performance review team analyses the actions taken at D-1 and real-time the following day and attributes actions to their corresponding boundaries. It is this data that has been used to generate the congestion maps.

Figure 66: D-1 and real-time for 2015. Great Britain

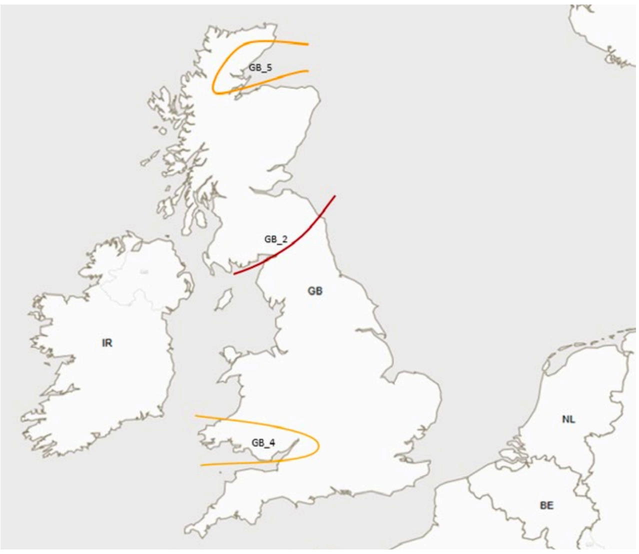


Figure 67: D-1 and real-time for 2016. Great Britain

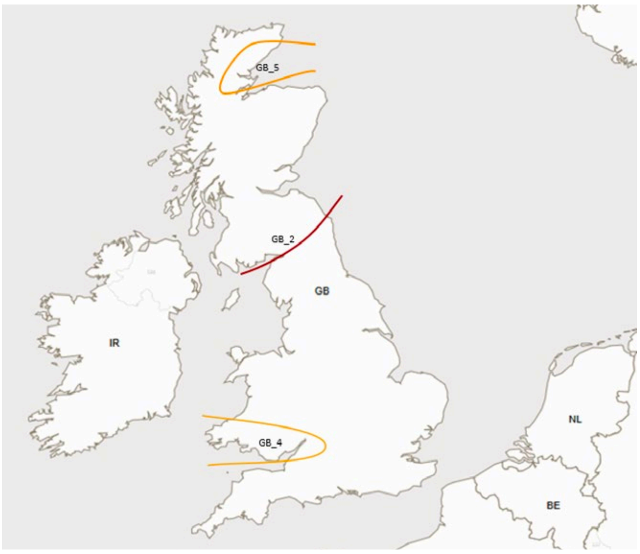


Figure 67: D-1 and real-time for 2017. Great Britain

Congestion frequency – percentage of total hours of the year

> 0 | 4 | 7 | 11 | 14 | 18 | 21 | 25 | 28 | 32 | >35 %

Grid

Coloured bubble – represents single or group of congestions (applied for ES, SK, CH and BG)

Coloured line or dot – represents single congestion
(line – transmission line, dot – transformer, substation or transmission line whose length is under 10 km)

Grey bubble, line or dot – congestion reported and frequency not available

Countries

Data available

Data not available

The concerned process is not performed

Data is not complete

8 https://www.nationalgrid.com/sites/default/files/documents/14843_NG_ETYS_2017_AllChapters_A01_INT.pdf

2.2.8 EXPERT ASSESSMENT OF CONGESTIONS FOR D-1 AND REAL-TIME TIMEFRAME FOR GREAT BRITAIN

It should be noted that the GB transmission system is interconnected with other European countries through a few offshore HVDC links; however, the GB system is operated in such a way that the cross-border flows are not constrained on the HVDC interconnectors in real-time. Therefore, the congestion spend is mostly incurred on internal boundaries. The three most congested boundaries in Year 2015, 2016 and 2017 are described as follows with commentaries of associated reinforcements.

GB_2 SCOTEX

This boundary crosses the border between Scotland and England. Scotland has a lot of connected wind generation which results in some congestion. A combination of connect and manage[9] schemes and difficult reinforcements in the region has made the SCOTEX boundary an active constraint with an intact system and outages further exacerbate the problem.

A new western HVDC link[10] between Scotland and England & Wales that provides additional capacity across this boundary is due to be commissioned by 2018 and will help alleviate congestions on this boundary. Once fully operational, the reinforcement will remove a large portion of the SCOTEX congestion spend.

GB_3 VEMIDLANDS & GB_4 VSWALES

VEMIDLANDS and VSWALES are congested due to similar causes – high voltages. The areas encompassed by the two boundaries have a lack of reactive absorption measures with the increasing level of renewable penetration and lower transmission demand. With fewer units of synchronous plant that could provide voltage support operating in merit, additional congestion spend is incurred on those two boundaries, especially overnight. This, however, should be completely eliminated when relevant reactive compensation schemes are completed.

GB_5 SHEDEX & GB_1 SSENWEX9

These two boundaries represent local congestion seen in the north of Scotland; the cause of these constraints are very similar to the SCOTEX boundary but on a smaller scale.

The *Caithness – Morray* DC link reinforcement is expected to reduce the congestion in this area to a certain degree. As a result of the reinforcement work required, there has been a large number of outages in this area over the last three to four years; these are also contributing factors to the congestion spend on these boundaries. The majority of the reinforcement works, which included building three new substations, are on track to be delivered within this financial year.

GB_6 VESTUARY

This boundary saw higher constraints than usual in 2017 due to long plant outages; the plants in question are base load and provide constant voltage support. In the absence of this generation, ancillary services had to be procured from alternative providers, increasing the congestion spend in this area. In addition, plant in the region tends to be marginal at times of high renewable output, resulting in National Grid SO dispatch actions to maintain complaint voltage levels.

To mitigate the voltage limitation and lower the congestion spend on this boundary, several new shunt reactors were commissioned in the area in late 2017/18. National Grid SO and TO are also collaborating to bring back online another large shunt reactor which has been out of service on a long-term fault. At present, outages to facilitate this are difficult to secure but conversations are ongoing.

9 https://www.nationalgrid.com/sites/default/files/documents/Complete%20CUSC%20-%20%201%20April%202018.pdf

10 http://www.westernhvdclink.co.uk/

2.2.9 EXPERT ASSESSMENT OF FUTURE EVOLUTION OF CONGESTIONS

Grid reinforcement and expansion may relieve, completely remove or shift an existing congestion to other locations in the grid. Another important driver of congestions is the development of generation and demand patterns. Changes in these patterns may also relieve or worsen existing congestions or create new ones. Thus, the assessment of congestions' evolution for the future horizon is subject to uncertainties. Furthermore, congestions can move on hourly resolution that cannot be reflected in the bidding zone configuration.

In this subsection, each TSO provides a brief assessment of how investment plans by TSOs are expected to impact the identified congestions over the next 10 years. This future assessment also considers anticipated changes to generation and demand patterns.

ALBANIA

2021 OHL Tirana2-KosovaB will enter Koman S/s; in doing so, simulations in this time frame show that all congestions on borders AL – RS and AL – ME will be relieved.

2023 OHL Tirana2-KosovaB will enter Koman S/s; in doing so, simulations in this time frame show that all congestions on borders AL – RS and AL – ME will be relieved.

2028 OHL Tirana2-KosovaB will enter Koman S/s; in doing so, simulations in this time frame show that all congestions on borders AL – RS and AL – ME will be relieved.

AUSTRIA

2021 **380/220-kV-Transformer Obersielach:**
The NDP project 13-1 foresees the erection of a third 380/220-kV-Transformer in Obersielach to reduce the congestion of the existing transformers. Expected Commissioning Date: 2018

380/220-kV-Transformer Lienz:
The NDP project 15-3 foresees the erection of a third 380/220-kV-Transformer in Lienz to reduce the congestion of the existing transformers. Expected Commissioning Date: 2020

220-kV-line St. Peter – Ernsthofen:
Reconstruction of the existing 220-kV-line *St. Peter – Hausruck – Ernsthofen* (NDP project 14-2).
Due to optimised operation, the expected effect of this project is to reduce the congestions on the 220-kV-line- *St. Peter – (Aschach) – Hausruck – (Sattledt) – Ernsthofen*. Expected commissioning date: 2021

220-kV-line St. Peter - Simbach (TTG) / Pleinting (TTG) / Pirach (TTG) / Altheim (TTG):
380/220-kV-Transformer St. Peter:
New 380 kV double circuit OHL *St. Peter – National Border* (Isar/Ottenhofen/DE) and *St. Peter – National Border* (Pleinting/DE) (NDP project 11-7). This project is also part of the German NDP and TYNDP (Ten-Year Network Development Plan) 2016 (Project 47; Investment 212 and Project 187; Investment: 997). The expected effect is that the congestions *'St. Peter – Simbach/Altheim'* and *'St. Peter – Pleinting/Pirach'* will be relieved.
Expected Commissioning Date St. Peter – Isar/Ottenhofen: 2021
Expected Commissioning Date St. Peter – Pleinting: 2024

220-kV-line Lienz – Soverzene (TERNA):
Erection of additional cross border line AT – IT: *Nauders – Glorenza*
The NDP project 11-12 / TYNDP 2016 Project 26; Investment 614 foresees a new 220 kV interconnector between the substations Nauders (AT) and Glorenza (IT). The expected effect of this project is to increase the security of supply and the interconnection capacity Austria – Italy. Moreover, the congestion *'Lienz – Soverzene (IT)'* will be relieved. Expected Commissioning Date: 2021

Another Project is the reinforcement of the existing 220 kV interconnection line 'Lienz – Soverzene' with a high temperature conductor. The expected effect is to increase the interconnection capacity to Italy and the congestions 'Lienz – Soverzene' will be relieved. Expected Commissioning Date: 2024

220-kV-line Bisamberg - (Kledering) - Wien - Ternitz
Due to the erection of the APG-Weinviertelleitung (NDP Project 11-8), the interaction with the windinfeed will be done via 380 kV (Austria internal transformation), and will therefore affect the powerful 380 kV systems around Vienna. The direct sensitivity to the given 220 kV line will be significantly reduced and therefore the flows will be lower. Expected Commissioning Date: 2021

2023 **220-kV-line Tauern – Weißenbach**
380/220-kV-Transformer Tauern
380/220-kV-Transformer St. Peter
220-kV-double line *Salzburg – Tauern* 231A/232A completion of the 380 kV line *St. Peter – Tauern* (NDP 11-10). This contains a new internal double circuit 380 kV-line connecting the substations Salzburg and Tauern (replacement of existing 220-kV-lines on optimised routes). This project supports the interaction between the RES in northern Europe (mainly DE) with the pump storage in the Austrian Alps. This project is also part of TYNDP 2016 (Project 47; Investment: 216). The expected effect is that the congested 220-kV-line *'Tauern – Weißenbach'* and the congested transformers in St. Peter and Tauern will be relieved. After the commissioning of the NEP project 11-10, the 380/220-kV-transformers in Tauern will be decommissioned. Expected Commissioning Date: 2022

Moreover, the congestions on the line 'Tauern – Weißenbach' will reduced by an operational optimisation of the line (new conductors). Expected commissioning date: 2025

380/220-kV-Transformer Westtirol
The TYNDP 2016 Project 47; Investment 219 foresees an upgrade of the existing 220 kV-line *Westtirol – Zell – Ziller* (NDP project 14-3) and the erection of additional 380/220 kV-Transformers (NDP project 11-9). The expected effect is the improved connection to the 380 kV ring and the related increase of the security of supply. Moreover, the west-east connection will be enforced and transformer congestion in Westtirol will be relieved.
Expected Commissioning Date – second 380/220-kV-Transformer West Tirol: 2023
Expected Commissioning Date – line upgrade West Tirol – Zell/Ziller: 2024

2028 **220-kV-line Obersielach – Podlog (ELES)**
Errection of a 600-MVA-PST in Obersielach or Hessenberg to control the flows on the 220-kV-lines in southeast Austria. Expected Commissioning Date: 2025
In the TYNDP 2018, a long term reinforcement of the line was identified and included to the project list.

220-kV-line Ernsthofen – Weißenbach
An operational optimisation (change of the conductors) has taken place already. To complete optimisation, measures in the respective substations have to be taken in the next few years (see NDP 2017 P.37f).
Expected Commissioning Date: < 2025

BELGIUM

2021 The projects mentioned below should solve the congestions by the time given:

- 220.513 *Aubange – Moulaine* & 220.514 *Aubange – Moulaine*: Installation of PSTs because of increasing flows (certain);
- 380.73 *Mercator – Horta* & 380.74 *Mercator – Horta*: Installation of HTLS because of increasing flows (certain);
- 380.25 *Zandvliet – Doel* & 380.26 *Zandvliet – Doel*: Project 'Brabo' Phase II will create a parallel line *Zandvliet – Lillo*, alleviating *Zandvliet – Doel* (certain);
- 380.29 *Zandvliet – Borsele* & 380.30 *Zandvliet – Geertruidenberg*: (Project in the Netherlands will introduce a substation in Rilland between Borssele and Geertruidenberg. The lines 29 & 30 will become lines connecting *Zandvliet – Rilland*);
- 380.73 Doel – Horta: (Line no longer exists as such; split in *Doel – Mercator* 53 and *Horta – Mercator* 73).

2023 The projects below are expected during this period:

- 380.101 *Horta - Avelgem* & 380.102 *Horta – Avelgem*: Installation of HTLS because of increasing flows (certain);
- 380.79 *Avelgem – Mastaing*: Installation of HTLS because of increasing flows (certain);
- 380.80 *Avelgem – Avelin*: Installation of HTLS because of increasing flows (certain);
- 380.29 *Zandvliet – Borsele* & 380.30 *Zandvliet – Geertruidenberg*: Upgrade of the lines *Borssele – Zandvliet* to HTLS, and installation of a total of four PSTs (from the existing two) (certain);
- PST-Zandvliet: Upgrade of the lines *Borssele – Zandvliet* to HTLS, and installation of a total of four PSTs (from the existing two) (certain);
- 380.51 *Doel – Mercator* & 52 & 53 & 54: Project 'Brabo' Phase III will create a parallel line *Lillo – Mercator*, alleviating *Doel – Mercator* (certain);
- 380.23 *Meerhout – Van Eyck*: Second circuit on the existing towers *Massenhoven – Meerhout – VanEyck*, in HTLS, and upgrade of the existing circuit to HTLS (certain);
- 380.19 Achene – Lonny & 380.10 *Gramme – Achêne*: Installation of PST on axis *Lonny – Achêne – Gramme* being studied as a short-term option before 2025, when, due to the closure of the nuclear power plants in Tihange, a higher loading of this line is expected. (highly likely);
- 380.27 *Van Eyck – Maasbracht* & 380.28 *Van Eyck – Maasbracht*: Upgrade of the lines *Borssele – Zandvliet* to HTLS, and installation of a total of four PSTs (from the existing two) will allow a shift of flow from Van-Eyck to Zandvliet;
- PST Van Eyck: Upgrade of the lines *Borssele – Zandvliet* to HTLS, and installation of a total of four PSTs (from the existing two) will allow a shift of flow from VanEyck to Zandvliet.

2028 Scenarios 2030 and beyond show a re-appearance of some congestions, and some new congestions, leading to the grid reinforcements mentioned below that are under study:

- 220.513 *Aubange – Moulaine* & 220.514 *Aubange – Moulaine*: Further reinforcement of the border FR – BE is being studied;
- 380.73 *Mercator – Horta* & 380.74 *Mercator – Horta*: New overloads are likely to occur in the long-term, due to increased offshore wind and increased flows from France and Great Britain. A project to build a new corridor *Avelgem – 'Centre of the country'*, creating a parallel path for *Avelgem – Horta – Mercator*, is being started;
- 380.101 *Horta – Avelgem* & 380.102 *Horta – Avelgem*: New overloads are likely to occur in the long-term, due to increased offshore wind and increased flows from France and Great Britain. A project to build a new corridor Avelgem-centre of the country, creating a parallel path for *Avelgem – Horta – Mercator*, is being started;
- 380.79 *Avelgem – Mastaing*: Further reinforcement of the border FR – BE is being studied;

- 380.80 *Avelgem – Avelin*: Further reinforcement of the border FR – BE is being studied;
- 380.19 *Achene – Lonny* & 380.10 *Gramme – Achêne*: Other options are being investigated to reinforce the border FR-BE. HTLS upgrade of the link *Lonny-Achêne-Gramme* is an option;
- 380.27 Van *Eyck – Maasbracht* & 380.28 *Van Eyck – Maasbracht*: A possible reinforcement *VanEyck – Maasbracht* with HTLS and installation of a total of four PSTs (from the existing two) is being studied for the long term;
- PST Van Eyck: A possible reinforcement *VanEyck-Maasbracht* with HTLS and installation of a total of four PSTs (from the existing two) is being studied for the long term;
- 380.11 *Van Eyck – Gramme*: A HTLS upgrade of most of the remaining 380 kV grid is being planned. This includes *VanEyck-Gramme*;
- 380.31 *Gramme – Courcelles*: A HTLS upgrade of most of the remaining 380 kV grid is being planned. This includes *Gramme-Courcelles*;
- 380.35 *Bruegel – Mercator*: A HTLS upgrade of most of the remaining 380 kV grid is being planned. This includes *Bruegel – Mercator*.

BULGARIA

2021 Implementation of the already planned projects which are included in the last ENTSO-E TYNDP regional investment plan for the South-East Europe (SEE) region.

2023 Implementation of the already planned projects which are included in the last ENTSO-E TYNDP regional investment plan for the SEE region.

2028 Implementation of the already planned projects which are included in the last ENTSO-E TYNDP regional investment plan for the SEE region.

CROATIA

2021 220 kV OHL *Senj – Melina* is nominated for ampacity increased by replacement of ACSR conductors with HTLS conductors 220 kV OHL *Zakucac – Konjsko* ampacity increased by replacement of ACSR conductors with HTLS conductors

2023 –

2028 220 kV OHL *Zakucac – Mostar* ampacity increased by replacement of ACSR conductors with HTLS conductors 220 kV OHL *Pehlin – Divaca* ampacity increased by replacement of ACSR conductors with HTLS conductors

CZECH REPUBLIC

2021 Border SK: modernisation of the tie-line V424 (*Sokolnice – SK*)

Border PL: modernisation of the internal line V460 (*Albrechtice – Nošovice*)

Border 50Hertz, TenneT DE and AT: no changes

2023 Border 50Hertz: switching off of the tie-lines V445 and V446 (*Hradec East – Röhrsdorf*) (2022)

Border SK: modernisation of the tie-line V424 (*Sokolnice – SK*) (2022)

Border PL: switching off of the tie-lines V443 and V444 (*Albrechtice – Dobrzen* and *Nošovice – Wielopole*)

Border TenneT DE and AT: no changes

2028 Border 50Hertz: switching off of the tie-lines V445 and V446 (*Hradec East – Röhrsdorf*) (27-28), switching off of the internal line V430 (*Hradec East – Röhrsdorf*) (27-28) and switching off of the internal line V431 (*Chrást – Přeštice*) (24, 26-27)

Border TenneT DE: switching off of the internal line V432 (*Kočín – Přeštice*) (26-28)

Border AT, SK and PL: no changes

DENMARK

2021 Reinvestments in the transmission grid

In Denmark, a significant number of reinvestments will be carried out over the coming years. Some of the more significant ones are mentioned here. For further details, the plans are available on Energinet's homepage[11].

- Reinvestment in the 132 kV cable network in Copenhagen
- Reinvestment programme for 132 kV and 150 kV substations
- Reinvestment in 150/60 kV and 132/50 kV transformers
- Reinvestment in the 400 – 150 kV combined overhead line between substations Kassø and Malling
- Reinvestment in the 400 kV overhead line between substations Fraugde and Landerupgård
- Reinvestment in the 400 kV GIS substation at Asnæs Power Station
- Asnæs Power Station and the transformer project comprising reinvestment in transformers in the Danish transmission grid.
- Reinvestment in 150 kV overhead lines (*Bredebro – Kassø*, *Klim Fjordholme – Mosbæk*, *Ensted – Sønderborg*)
- Replacement of the GIS substation at Amager Power Station
- Reinvestment in 132 kV overhead lines (substations Stasevang and Teglstrupgård, *Statoil Syd – Kirkeskovgård – Torslunde*, *Stasevang – Teglstrupgård*)
- Substation Vester Hassing: Reinvestment in automation.

Expansion of the transmission grid

Due to significant changes in the load and generation portfolio in Denmark as well as the introduction of new interconnectors to Holland and Great Britain, there are significant expansions of the internal AC grid planned in the future. A selection of the most important are listed here, but further details can be found on Energinet's homepage .

- Measures to be taken to secure the supply of Copenhagen (including reinvestment in two 132 kV cables).
- Establishment of a sufficient grid structure for the incorporation of wind power and/or interconnectors. The final solutions are defined in the planning projects and may, among other things, include the establishment of a new 400 kV connection in Jutland, possibly between substations Revsing and Landerupgård, an extra 400 kV circuit in Jutland between substations Idomlund and Tjele on the existing towers as well as a new 400 kV connection on Zealand between substations Bjæverskov and Hovegård.
- Establishment of new 150/60 kV transformers at substations Stovstrup and Idomlund.
- Other, smaller projects: Upgrade of the operating voltage of the 60 kV cable to the island of Læsø, securing the reactive balance in substation Tjele; connection of the electric boiler in substation Grønnegården and optimised utilisation of existing and new installations, as well as the connection of future consumers to a new 400 kV high-voltage substation at substation Kassø North.
- Furthermore, a planning project is examining a number of potential solutions for ensuring sufficient power on Zealand, cf. Energinet's Report on security of electricity supply 2017. The solution space examined in the project, among other things, includes operational initiatives, strategic spare capacity and various interconnectors to Zealand from e. g. Western Denmark, Poland, Germany or Sweden. The final solution alternative and time of establishment have not been decided and are not included in the complete overview. Once a solution has been decided, it will be incorporated into the analysis assumptions and form part of a planning foundation in future reinvestment and development plans.

11 https://energinet.dk/Anlaeg-og-projekter/Netplanlaegning

2023 The Danish grid is generally dimensioned to ensure that no internal congestions occur during normal operation. Energinet does not have a detailed plan of projects that will be realised from 2023 onwards, but system development needs will continuously be addressed as they are identified with a reasonable amount of certainty.

The colour indicates how often an element is loaded more than 100 %. There are also plans in place to handle a number of these overloadings. These include the use of dynamic line rating as well as new reinforcements being planned when more is known about the development of the generation portfolio and the location of loads, both of which are changing significantly in Denmark over the coming 10 years.

2028 Some expansion projects are planned for the timeframe in 2023 and onwards. In connection to the construction of new 400 kV lines between Denmark West and Germany, a 400 kV line from Endrup to Idumlund will be constructed. Both are in order to ensure the better distribution of flows internally in Denmark, but also to ensure that the wind power being built on the west coast of Denmark can be collected and distributed to the consumption centres in the region.

The Danish grid is generally dimensioned to ensure that no internal congestions occur during normal operation. Energinet does not have a detailed plan of which projects will be realised from 2023 and onwards, except for reinvestment, but system development needs will continuously be addressed as they are identified with a reasonably amount of certainty. The political system in Denmark is highly focused on increasing the wind infeed into the Danish transmission system, thus it is expected that significant investments will be needed over the coming years.

ESTONIA

2021 The number of congestions on EE – LV cross-border is expected to decrease due to investments in increasing capacity to this cross-border by building a new line connecting the two control areas. Also, the operation of NordBalt HVDC link has decreased power flows from north to south, which also has had an effect since March 2016 and is expected to also have an effect in the future.

Of the short to mid-term effects, the most influential is the building of the third connection between Estonia and Latvia, expected to be completed in 2020. Also, seasonal effects and maintenance plans play substantial roles.

2023 The number of congestions on the EE – LV cross-border is expected to decrease due to investments in increasing capacity to this cross-border by building a new line connecting the two control areas. Also, the operation of the NordBalt HVDC link has decreased power flows from north to south, which has also had an effect since March 2016 and is expected to also have an effect in the future.

Of the short to mid-term effects, the most influential is the building of the third connection between Estonia and Latvia, expected to be completed in 2020. Also, seasonal effects and maintenance plans play substantial roles.

In 2023, there will be line reconstruction that will give additional capacity between EE – LV control areas.

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Of the short to mid-term effects, the most influential is the building of the third connection between Estonia and Latvia which is expected to be completed in 2020. Also, seasonal effects and maintenance plans play substantial roles.

In 2023, 2024 and 2025 there will be reconstruction works on several lines that will give additional capacity between EE – LV control areas.

In the long term, in 2030, Baltics are expected to desynchronise from Russia. This will change the loading of the elements substantially.

FINLAND

2021 The available import capacity via alternating current connections from northern Sweden to northern Finland (SE1-FI) will decrease by 300 megawatts in connection with the commissioning of the Olkiluoto 3 nuclear power plant unit.

2023 By the end of 2022 the new AC line to P1 cut will be commissioned.

2028 By the end of 2024, the new AC line to P0 cut will be commissioned. By end 2025, we expect a third 400 kV AC line to be commissioned between Finland and Sweden (SE1-FI) giving an additional capacity of 800/900 MW depending on the direction. The Fenno-Skan 1 (SE3-FI) direct current connection will reach the end of its service life in the late 2020s, and Fingrid and Svenska kraftnät have investigated a replacement of the connection in its current location or in the Kvarken area. A capacity of 800 MW is planned for the replacement connection (SE2-FI), which would increase the existing market capacity by 400 MW.

FRANCE

Three areas of structural or major physical congestions have been identified: the borders between France and England, France and Spain, and France and Italy. As presented in chapter 2.2.2, several grid investments are ongoing in these areas in order to increase the available cross-zonal capacities.

Furthermore, RTE keeps investing in the whole territory in anticipation of potential future structural congestions.

GERMANY

50Hertz

2028 In the ten year time frame, congestions are expected to remain on the cross-border lines to Poland and the Czech Republic.

Different internal projects (new lines as well as reinforcements): The commissioning of internal grid reinforcements according to the German Grid development plan and the EnLAG will further reduce significantly congestions in the control area of 50Hertz and are under monitoring from the national regulator.

No major inner congestions are expected to remain due to the planned grid extensions, load flow controlling devices and the HVDC connecting 50Hertz and TenneT.

All investments are approved by the German Regulator in the framework of the national grid development plan (Netzentwicklungsplan) and some are additionally part of the German Bundesbedarfsplan or EnLAG. There is a risk of delay of investments, since the best-case scenario is assumed.

A new HVDC- interconnector to Sweden is planned to be commissioned in this time horizon according to the TYNDP 2018.

Amprion

Amprion uses a combination of targeted investment measures to alleviate current and envisaged future congestions in the grid. For the congested areas identified in this report, the following grid reinforcements and expansions have been planned. All of them were approved by the German NRA in the framework of the national grid development plan (Netzentwicklungsplan; project numbers are given below in parentheses)[12]. These investments are foreseen as solving all identified internal congestions in the future.

Congested area DE2 [DE – NL]

- New cross-border DC line and converter Alegro (*Oberzier – Lixhe*; P65) to be commissioned in 2021
- New cross-border DC line 2nd Interconnector (*DE – BE*; P313) to be commissioned in 2028
- New internal DC line and converter Ultranet (*Osterath – Philippsburg*; DC2) to be commissioned in 2023
- Multiple internal projects, e. g. reinforcement of AC line *Oberzier – BE* (Hambach P200)

12 Some investments are additionally part of the German Bundesbedarfsplan or EnLAG.

Congested area DE1 [AMP – TTG]

– AC line reinforcement Doettinchem-Niederrhein (AMP-013) to be commissioned in 2018

– New internal DC line and converter A-Nord (*Emden/Ost – Osterath*; DC1) to be commissioned in 2025

– Multiple internal projects, e. g. new AC line *Dörpen/West – Niederrhein* (AMP-009)

Congested area DE3 [AMP – TTG]

– Internal projects, e. g. reinforcement of AC line *Großkrotzenburg – Urberach* (P161) and *Karben – Kriftel* (P316)

Congested area DE4 [DE – FR]

– Reinforcement of the cross-border line Vigy (P170) and installation of a PST (P314)

TenneT DE

2021 Border DK: cross-border grid extension (*Audorf – Kassö*) and internal grid extension to decrease load flows on critical elements (*Audorf – Dollern*)

Border NL: cross-border grid extension (*Meeden – Diele*)

Border CZ: no changes

Border AT: cross-border grid extension (*Isar – St. Peter*)

Germany: additional investments to reduce congestions and redispatch
(according to German Grid Development Plan)

All investments approved by German Regulator in the framework of national grid development plan (Netzentwicklungsplan) and part of German Bundesbedarfsplan. Risk of delay of investments.

→ evolution to be seen in comparison to status quo

2023 Border DK: cross-border grid extension (*Audorf – Kassö*, *Niebüll – Endrup*) and internal grid extension to decrease load flows on critical elements (*Audorf – Dollern*)

Border NL: cross-border grid extenstion (*Meeden – Diele*) and internal grid extension to decrease load flows on critical elements

Border CZ: internal grid extension to decrease load flows on critical elements (reduction of loop flows)

Border AT: cross-border grid extension (*Isar – St. Peter*, *Pleinting – St.Peter*)

Germany: additional investments to reduce congestions and redispatch
(according to German Grid Development Plan)

All investments approved by German Regulator in the framework of a national grid development plan (Netzentwicklungsplan) and part of German Bundesbedarfsplan. Risk of delay of investments.

→ evolution to be seen in comparison to status quo

2028 Border DK: cross-border grid extenstion (*Audorf – Kassö*, *Niebüll – Endrup*) and internal grid extension to decrease load flows on critical elements (*Audorf – Dollern*)

Border NL: cross-border grid extension (*Meeden – Diele*) and internal grid extension to decrease load flows on critical elements

Border CZ: internal grid extension to decrease load flows on critical elements (reduction of loop flows, DC 5)

Border AT: cross border grid extenstion (*Isar – St. Peter*, *Pleinting – St.Peter*)

Germany: additional investments to reduce congestions and redispatch
(according to German Grid Development Plan)

All investments approved by German Regulator in the framework of national grid development plan (Netzentwicklungsplan) and part of German Bundesbedarfsplan. Risk of delay of investments.

→ evolution to be seen in comparison to status quo

TransnetBW

The long-term development of congestions is analysed in the German 'Netzentwicklungsplan' and in mid-term in the German 'Systemanalysen'. What we observe is a very positive effect of grid expansion measures that alleviate today's and tomorrow's congestions, as described earlier in this document.

Explicit increase in interconnector capacity:

Border FR: *Eichstetten – Muhlbach*

Implicit increase in transfer capacity to AT, CH and FR due to grid extensions (some major projects):

DC: SuedLink (*Brunsbüttel – Großgartach*)
Ultranet (*Osterath – Philippsburg*)

AC: *Grafenrheinfeld – Großgartach*
Weinheim – Daxlanden
Daxlanden – Eichstetten

GREAT BRITAIN

To reduce future congestion in the GB transmission system, National Grid utilises long-term optimisation to identify the best way to reinforce the network during system planning. The costs of congestion are quantified by total constraint costs incurred on approximately 40 boundaries as listed in the ETYS.

National Grid SO is obligated to publish the ETYS on an annual basis to identify the future system needs in bulk power transfers of different boundaries. The required transfer for each boundary is then fed back to the TOs or other relevant parties for them to propose network reinforcement options to meet the identified future system needs. A range of network reinforcements, including both build and reduced-build options, are then submitted to National Grid SO to assess for their cost and benefit.

The assessment and selection process is known as the Network Options Assessment (NOA) where benefits in boundary constraint savings in future years delivered by the options are considered against their total capital expenditures. The process is conducted under different Future Energy Scenarios[13] followed by a least-worst regret analysis to mitigate the risk that investments of certain options are inefficiently driven by certain energy backgrounds which is highly uncertain in the distant future.National Grid SO publishes the NOA report each January, recommending to the TOs and relevant parties its best view into the future of which options should be invested in over the coming years to achieve an optimal balance between reinforcing and constraining the network. This process seeks to optimise the delivery dates of the TO reinforcements, should the investments be delivered early, there is a risk of inefficient capital spend; and should the options being delivered late, we will see additional congestion costs. In NOA 2017/18[14], National Grid SO has recommended a total investment of £ 21.57m for year 2018/19 across 22 different reinforcement projects with a total capital expenditure worth £ 3.24bn.

It is important to note that while the investment recommendations are given by National Grid SO, the TOs and other relevant parties will ultimately be responsible for ensuring reinforcements are delivered in time to meet system needs. For projects with large infrastructure investments, the TOs must also pass the Strategic Wider Work[15] submission to the GB regulator (Ofgem) for approval and to determine the project's final specifications and commissioning date.

Whilst the current NOA focuses on bulk power transfers, National Grid SO has also published its Network Development Roadmap Consultation for the coming years in 2018, committing to include other system needs such as regional reactive requirements in its future NOA. It also aims to expand the NOA to include wider market participants for providing whole system solutions to better optimise congestions on those boundaries.

The following section summaries the future reinforcements of the three most congested boundaries as presented in Section 2.2.7. Please refer to the NOA Methodology[16] for more details about how the NOA is conducted and the NOA report19 for National Grid SO's full investment recommendations.

13 http://fes.nationalgrid.com/fes-document/

14 https://www.nationalgrid.com/sites/default/files/documents/Network-Options-Assessment-2017-18.pdf

15 https://www.ofgem.gov.uk/electricity/transmission-networks/critical-investments/strategic-wider-works

16 https://www.nationalgrid.com/sites/default/files/documents/NOA%20methodology%20FINAL%203.1%2026July2017.pdf

2021 SCOTEX:
The Western Link HVDC Bootstrap was commissioned in December 2017 to alleviate SCOTEX congestions. Full capability of the link is expected in late 2018 when up to 2250 MW of power will flow on the link across the Scotex boundary between Hunterston, Scotland and Deeside, England. While the cable is rated at 2250 MW, the final boundary capability increase is yet to be confirmed as there may be remaining stability limits on SCOTEX. The link will provide considerable additional transfer capability and significantly alleviate congestion. Further reinforcement of SCOTEX is planned in 2021 through circuit reconfiguration in the North East and super grid transformer replacements in the North West, which will provide additional transfer capability.

SSENWEX9 & SHEDEX:
A DC link reinforcement in this area is expected to be completed later this year and it is forecast that this will relieve congestions to an acceptable level. No further reinforcement is expected ahead of 2021.

VEMIDLANDS & VSWALES:
At present, the forecast congestions in the future years for these boundaries is low and therefore no further reinforcement is planned. Our NOA expansion project will consider voltage assessment in these areas and may recommend additional investment if it is economic to do so.

VESTUARY:
Additional reactive compensation is due to commission in this region late 2018 which should help relieve the voltage congestions presently seen.

2023 SCOTEX:
Further reinforcement on SCOTEX is planned in 2023 through the planned commissioning of series reactors and substation reconfigurations in the North East.

SSENWEX & SHEDEX:
By 2023, further onshore reinforcements are proposed to increase the thermal capability of the east coast of Scotland, along with new substations and PSTs to alleviate future congestion caused by increasing renewable generation connection to the region.

VEMIDLANDS & VSWALES:
At present, the forecast congestion in future years for these boundaries is low and therefore no further reinforcement is planned. Our NOA expansion project will consider voltage assessment in these areas and may recommend additional investment if it is economic to do so.

VESTUARY:
No additional reinforcement is planned ahead of 2023 for this boundary.

2028 SCOTEX:
Thermal reinforcement of this boundary is planned in 2025 and 2026; it is also planned to compliment this work with the commissioning of two 2GW Eastern HVDC subsea links from Scotland to England, in 2027 and 2028. These reinforcements are forecast to provide significant additional capability to the SCOTEX boundary. Due to the complexity and large scale of two HVDC links, they are proceeding as planned via a joint strategic wider work submission by the GB TOs (National Grid, SPT, and SHE Transmission) where the definitive specification and commissioning date of the first Eastern HVDC link will be decided.

SSENWEX & SHEDEX:
Additional thermal reinforcement of the east coast onshore network of Scotland is planned in 2026, this work involves uprating some circuits to operate at a higher voltage level, increasing the export capability of the region.

VEMIDLANDS and VSWALES:
At present, the forecast congestions in the future years for these boundaries is low and therefore no further reinforcement is planned. Our NOA expansion project will consider voltage assessment in these areas and may recommend additional investment if it is economic to do so.

VESTUARY:
Thermal reinforcement in the form of reconductoring is expected to be commissioned in 2025 and new transmission circuits are proposed for 2027. The new circuits are also subject to the SWW process and are currently progressing as planned, with an outcome expected in 2019.

GREECE

2021 All investments approved by the Greek Regulator in the framework of the TYNDP

Information of the already planned projects are included in the last ENTSO-E TYNDP regional investment plan for the SEE region.

Tie lines:
The flow of the tie line GR – AL is expected to be reduced (considering the same level of exchanges) with the operation of the 400 kV line *Tirana – Kosovo* as well as with the commissioning of the new 400 kV interconnection line *Bitola (MK) – Elbasan (AL)* in 2020 according to the ENTSO-E TYNDP 2018 list of projects.

2023 All investments approved by the Greek Regulator in the framework of the TYNDP.

Information of the already planned projects are included in the last ENTSO-E TYNDP regional investment plan for the SEE region.

Tie lines:

1. The operation of the new 400 kV tie line among GR – BG, the line *Maritsa – N Santa* will relieve the loading of the line *Nea Santa (GR) – Babaeski (TR)*, considering the same level of exchanges.
2. As also mentioned for 2021, the flow of the tie line GR – AL is expected to be reduced (considering the same level of exchanges) with the operation of the 400 kV line *Tirana – Kosovo* as well as with the commissioning of the new 400 kV interconnection line *Bitola (MK) – Elbasan (AL)* according to the ENTSO-E TYNDP 2018 list of projects.
3. A new connection among the Israel – Cyprus – Crete – Greek mainland with a DC connection of 1,000 MW could also be developed.

2028 All investments approved by the Greek Regulator in the framework of the TYNDP.

Information of the already planned projects are included in the last ENTSO-E TYNDP regional investment plan for the SEE region.

Tie lines:

1. As also mentioned for 2023, the operation of the new 400 kV tie line among GR – BG, the line *Maritsa – N Santa*, will relieve the loading of the line *Nea Santa (GR) – Babaeski (TR)*, considering the same level of exchanges. As also mentioned for 2021 and 2023, the flow of the tie line GR – AL is expected to be reduced (considering the same level of exchanges) with the operation of the 400 kV line *Tirana – Kosovo* as well as with the commissioning of the new 400 kV interconnection line *Bitola (MK) – Elbasan (AL)* according to the ENTSO-E TYNDP 2018 list of projects.
2. As also mentioned for 2023, a new connection among the Israel – Cyprus – Crete – Greek mainland with a DC cable of 1,000 MW could be developed. It may be feasible by then that the rating of the connection could be increased by up to 2,000 MW (using two DC cables of 1,000 MW each).

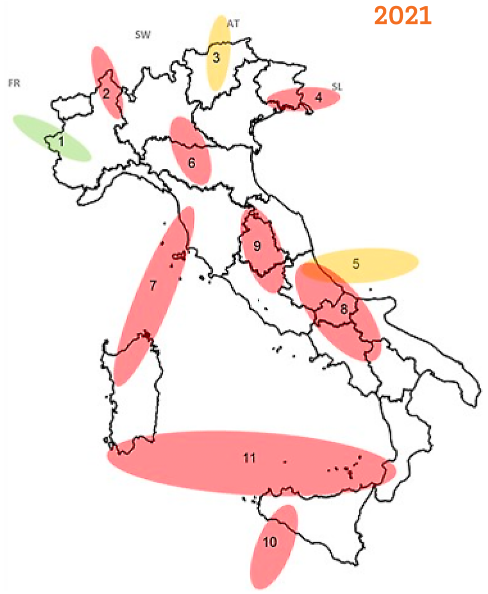
HUNGARY

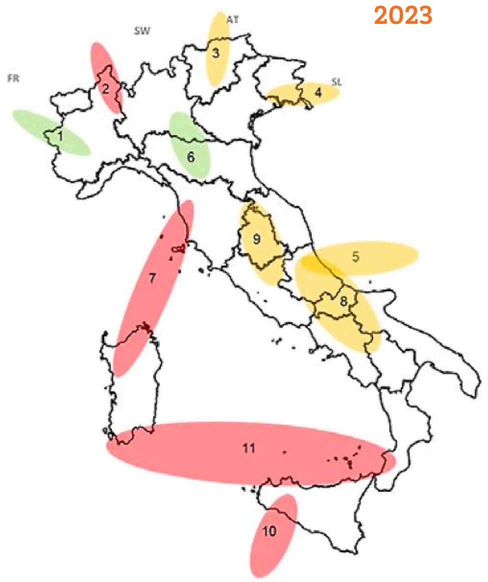
Considering the scenarios of the Hungarian national NDP and the TYNDP, no remaining congestions are forecasted on transmission level in any timeframe. This is mainly due to the planned three new transmission 400 kV lines on the SK – HU border until 2020. These will ease the situation on the AT – HU border as well, due to the interdependency of both borders. In case of extreme load-flows, these two borders are still expected to remain the most limiting ones.

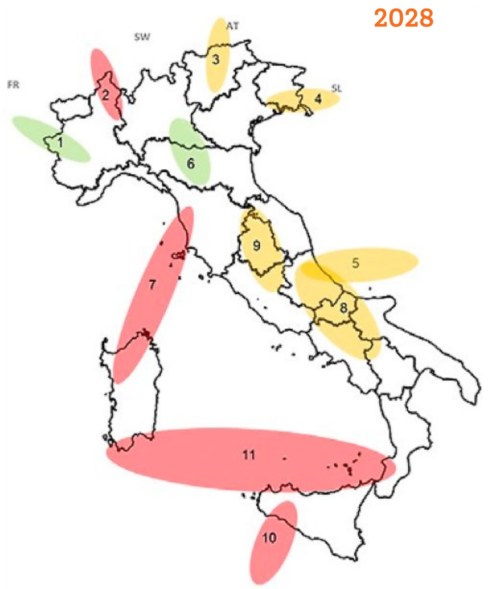
In addition, the new 750/400 kV substation in Szabolcsbáka (commissioning in 2019) and the re-arrangement of existing transmission lines in the area will help the situation in Eastern Hungary.

Investments in the time period 2021 – 2028 will not have a significant influence on the presented congestions which will be already eased by the grid reinforcement on the SK – HU border until 2021. In 2021, the commissioning of the new tie-line between Hungary and Slovenia is expected. With this line, a new bidding zone border will be introduced. The main gain of this connection will be the improvement of market connections between Slovenia, Croatia and Hungary. Other investments in this period are mainly related to improving the connection between the transmission and distribution system.

ITALY







By 2021, an increase of the available transmission capacity at the Northern Italian Border is expected due to the new HVDC link *Piossasco – Grande'lle* (on the France – Italy border, area 1) and to the enhancement of the interconnection with Austria (area 3, new 132 kV tie line *Prati di Vizze – Steinach* and 220 kV underground cable from Nauders to Glorenza). In addition, the first 600 MW HVDC interconnection line between Italy and Montenegro (area 5) is expected to be commissioned.

By 2023, a further increase of the available transmission capacity at the Northern Italian Border is expected due to the new HVDC link *Salgareda – Divaca* and to some 132 kV Merchant lines on the same border (cluster 4). Internal investments are also foreseen:

- A new 400 kV OHL line from Calenzano to Colunga (replacing the existing 220 kV one) will increase transmission capacity between Italy North (IT1) and Italy Central North (IT2), also relieving the observed congestions in recent years (area 6).
- Works for optimisation of the existing 220 kV backbones Villavalle to S.Barbara and Villanova to Candia will relieve congestions in this area, increasing transmission capacity between Italy Central South (IT3) and Italy Central North (IT2) (area 9). A new HVDC link between Villanova (or Villavalle) and Fano (or Portotolle) is also planned to increase the transmission capacity on the relevant network critical section and will improve the stability of voltage and frequency in this network portions.
- A new 400 kV line between Deliceto and Bisaccia will increase transmission capacity between Italy South (IT4) and Italy Central South (IT3), also relieving the observed congestions in recent years (area 8).

By 2028, a further increase in the available transmission capacity at the Northern Italian Border is expected due to the new HVDC link *Pallanzeno – Airolo* (on the Switzerland – Italy border, area 2). By this year:

- the repowering of existing HVDC link between the Italy Mainland, Corsica and Sardinia island will also enhance the interconnection between Sardinia and Continental Italy (area 7);
- A new HVDC link is also planned between Italy and Tunisia (area 10).

LATVIA

2021 Up to 2020, three new investments have to be commissioned:

1) EE-LV 3rd interconnection;

2) *Riga CHP2 – Riga HPP* in 2020; and

3) Kurzemes Ring project in 2019 (these are shown on the map below).

After the commissionning of these three investments, the overloads and congestions on cross-borders EE-LV and LT-LV will be reduced/removed or appear very rare. The TSO assumption is that after 2020, with the commissioning of these three investments, the overloads on one particular element in area of Latvia will be removed.

2023 During 2023, two existing overhead lines on cross-border EE-LV will be reconstructed to increase the capacity for internal cross-border within the area of Baltic States. The reconstruction is planned to ensure the security of supply in case of desynchronisation from the IPS/UPS power system in 2025.

2028 Starting from 2025, it is planned that Baltic States will desynchronise from the IPS/UPS power system and operate in synchronous mode with Continental Europe. According to the case of synchronisation with Continental Europe, this is relevant to strengthening the internal grid in Baltic States and many internal reinforcements are planned. Regarding the Latvia and Estonia cross-border, there are planned existing line reconstruction works which have to be done up to 2025; therefore, in 2028 no congestions and overloads are forecasted.

LITHUANIA

2021 Until 2021 new transmission lines will be commissioned:

1. 330 kV double circuit transmission line *Alytus – Kruonis*.
   This line will ensure transmission capacity from the LitPol Link interconnection.
2. Reconstruction of 330 kV transmission line Lietuvos E-Vilnius to double circuit.
   This new line is required to ensure security of supply to the Vilnius region.

2023 N/A

2028 Due to preparation for synchronisation with CEN and desynchronisation with the IPS/UPS power system, few 330 kV transmission network development projects are under consideration:

1. Reconstruction of 330 kV transmission line *Klaipėda – Bitėnai* to doublecircuit;
2. Reconstruction of 330 kV transmission line *Bitėnai – Jurbarkas* to doublecircuit;
3. Construction of new 330 kV transmission line *Jurbarkas – (KHAE-Sovietsk)*.
4. An additional line in Vilnius region *Vilnius – Vilnia – Neris*.
5. Construction of new 330 kV Mūša switchyard in Northern part of Lithuania.

LUXEMBOURG

2021 Upgrade of the lines Heisdorf – Bauler to HTLS

2023 Future expected increase of vertical load of Luxembourg with additional transit flows may limit the exchanges on the different borders DE – LU and BE – LU.

2028 A new infrastructure project between Germany and Luxembourg (IC DeLux) is currently being developed (TYNDP 2018). The project comprises the construction of two new 380-kV-substations in Germany (Aach) and Luxembourg (Bofferdange). The new substations will be connected via a new AC-link to allow a higher cross-border capacity between Germany and Luxembourg. This new infrastructure will reduce possible future congestions due to future load increase of Luxembourg on the DE – LU border. The commissioning date of the project is expected in 2026.

NETHERLANDS

2021	Border NO:	no new developments scheduled
	Border DK:	cross-border grid extension (HVDC connection, project COBRAcable). Capacity 700 MW, expected in-service date: 2019
	Border GB:	no new developments scheduled
	Border DE:	– reinforcement phase shifter capacity at interconnector *Meeden – Diele*. Expected in service date: 2020
		– upgrade transport capacity 380 kV connections *Lelystad – Ens*, *Diemen – Lelystad*, *Geertruidenberg-Krimpen*
		– in-service date new interconnector *Doetinchem – Niederrhein*: 2018
	Border BE:	– realisation of new 380 kV station Rilland, and reconfiguration of single circuits *Zandvliet – Borssele* and *Zandvliet – Geertruidenberg* to double circuit *Zandvliet – Rilland*
2023	Border NO:	no new developments scheduled
	Border DK:	no new developments scheduled
	Border GB:	no new developments scheduled
	Border DE:	– upgrade transport capacity 380 kV connections *Ens – Zwolle*, *Eindhoven – Maasbracht*
		– upgrade 380 kV substation Maasbracht
	Border BE:	– upgrade transport capacity 380 kV connections *Ens – Zwolle*, *Eindhoven – Maasbracht*
		– upgrade transport capacity overhead lines *Zandvliet (B) – Rilland*
		– upgrade 380 kV substation Maasbracht
2028	Border NO:	no new developments scheduled
	Border DK:	no new developments scheduled
	Border GB:	– study ongoing feasibility of 'wind connector': HVDC interconnector with offshore wind connection node halfway (offshore location IJmuiden Ver / East Anglia)
	Border DE:	– upgrade transport capacity 380 kV connection Zwolle – Hengelo
	Border BE:	– realisation 380 kV grid extension *Rilland – Tilburg*

NORWAY

2021 NordLink, HVDC-interconnector to Germany of 1,400 MW, to be completed in early 2020

NSL, HVDC-interconnector to Great Britain of 1,400 MW, to be completed late 2021

Western corridor in NO2 is a voltage upgrade project to upgrade lines and stations from 300 to 420 kV and build new 420 kV lines and stations to handle new HVDC interconnectors NordLink and NSL, to be completed in 2021

2023 Voltage upgrade of 300 kV *Sogndal – Aurland* to 420 kV

2028 Possible grid reinforcements from northern Norway to middle Norway and Sweden (uncertain)

New 420 kV lines *Surna – Aura* and *Åfjord – Snilldal* to handle investments in renewable energy in middle Norway.

POLAND

The network constraints in Poland, indicated in this technical report, will be reduced or completely eliminated within a scenario encompassing a ten year time-frame. In order to mitigate those network constraints, PSE is implementing adequate solutions covering both grid investments and market-based solutions, i.e. further improvement of the ISP[17] including implementation of a new balancing market with full network model and locational pricing.

Below the main investments are presented, which are attributed to three selected periods ending on 2021, 2023 or 2028.

2021 Development plans until 2021 expect the following new investments:

1. Installation of phase shifters in Vierraden substation on Krajnik-Vierraden the DE – PL tie-line;
2. Reconfiguration of Krajnik substation (change the operating voltage of the tie-lines *Krajnik – Vierraden* from 220 kV in to the 400 kV);
3. Construction of new 400 kV lines: *Krajnik – Baczyna*, *Czarna – Polkowice*, *Piła Krzewina – Plewiska*, *Jasiniec – Pątnów*, *Jasiniec – Grudziądz*, *Piła – Krzewina – Bydgoszcz*, *Żydowo Kierzkowo – Słupsk*, *Gdańsk Przyjaźń – Żydowo Kierzkowo*, *Grudziądz Węgrowo – Pelplin – Gdańsk Przyjaźń*, *Kozienice – Ujrzanów*, *Kozienice – Miłosna*.
4. Modernisation of 220 kV lines: *Kozienice – Rozki*, *Janow – Zgierz – Adamow* (I stage), *Joachimow – Łagisza/Wrzosowa*.

2023 Implementation of the following development projects:

1. Reinforcements of 400 kV grid between Mikułowa, Czarna and Pasikurowice,
2. Construction of the new line 400 kV *Mikułowa – Swiebodzice*.

The above investments eliminate constraints on the *Mikułowa – Czarna* line and will reduce the load of the 400/200 kV transformer in Mikułowa substation.

3. Modernisation of 220 kV lines: *Janow – Zgierz – Adamow* (II stage), *Janow – Rogowiec*, *Rogowiec – Piotrkow*, *Rogowiec – Pabianice*, *Joachimow – Losnice*.

2028 The following development targets will occur:

1. Reinforcement of the chain 400 kV lines from Krajnik to Olsztyn Matki, Northern part of Poland.
2. Construction of new 400 kV lines: *Baczyna – Plewiska*, *Dunowo – Zydowo Kierzkowo*, *Piła Krzewina – Zydowo Kierzkowo*, *Kozienice – Ołtarzew*, *Puławy Azoty – Kozienice – Lublin Systemowa*, *Puławy Azoty – Kozienice – Ostrowiec*.
3. Reconstruction of the 400 kV line *Pasikurowice – Dobrzen – Trebaczew – Joachimow*.
4. Modernisation of the 400 kV lines: *Grudziądz Węgrowo – Płock*, *Gdańsk Błonia – Olsztyn Matki*, *Zarnowiec – Gdańsk/Gdańsk Przyjaźń – Gdańsk Błonia*, *Rogowiec – Płock*, *Rogowiec – Oltarzew*.
5. Modernisation of 220 kV lines: *Joachimow – Rogowiec*, *Joachimow – Huta Częstochowa*.

17 The ISP process is a bid-based security constraint unit commitment and economic dispatch, where balancing, reserve procurement and congestion management are co-optimised within one integrated process run by TSO just immediately after the DA market closure.

PORTUGAL

2021 There are some internal reinforcements foreseen in the northwest Portugal region in order to solve some internal constraints caused by the increase of installed power in this area. Although these reinforcements could be put into operation in 2019, there are still some pending issues related with some local opposition.

On the other hand, it is expected that the future new interconnection between Portugal and Spain in the northwest part of Portugal, foreseen to 2021, will solve the current angle deviation restrictions that occur in that area. This reinforcement will increase the NTC with Spain to higher values, mainly in the Spain to Portugal direction, and so achieve the MIBEL objective of an NTC for the commercial purpose of at least 3,000 MW in both directions (ES → PT and PT → ES).

2023 In the northern region of Portugal, there is already a high volume of hydro power plants installed and a significant amount of new hydro power plants are foreseen to appear between 2022 and 2024. Therefore, in wet conditions some constraints could occur in the internal Portuguese network and in the northeast Portugal-Spain interconnection. However, these constraints shouldn't affect the market operation too much as it is expected that, at least, the commercial NTC will be higher than the MIBEL target of 3,000 MW.

With the foreseen huge increase in solar power plants in the south of the Iberia peninsula, some constraints could appear in the south interconnection lines between both countries and/or internal network of each country. These reinforcements should be analysed, in joint Portuguese and Spanish TSO studies, taking into account the effective installation of those solar power plants.

ROMANIA

2021 We expect to finalise the 400 kV OHL Nadab-Oradea Sud within 1-2 years (it is almost ready, except some towers to be placed on an area with ownership problems).

The 400 kV OHL *Resita (RO) – Pancevo (RS)* double circuit and new 400 kV OHL *Portile de Fier – Resita* single circuit (internal RO line) are under construction. These are PCI projects.

2023 We do not expect significant changes between 2021 and 2023

2028 The OHL 220 kV *Resita – Timisoara – Sacalaz* (internal RO corridor) will be upgraded to 400 kV. This is a PCI project.

SLOVAKIA

2021 The congestion on the HU – SK and UA – SK profile will be partially solved by the commissioning of the new double 400 kV cross-border line between SK and HU and new single 400 kV cross-border line between SK and HU by the end of 2020. This will increase transmission capacity on the profile by approximately 100 % in the export direction and by 50 % in the import direction. The likeliness of removal of congestions on HU-SK and SK-UA profiles close to 100 % in the event no obstacles for commissioning of new lines happen. Also, SEPS is expecting to increase the PATL on the cross-border line on the SK – UA profile by 400 A in the mid-summer of 2018. During 2021, the 200 kV line between SK and CZ will be decommissioned, which will cause the decrease of the TC on this profile by 10 % in both directions.

2023 Reconstruction of the 400 kV cross-border line between SK and CZ which should be done by 2025 will improve the situation caused by decommissioning of the 200 kV line between SK and CZ performed in 2021. The capacity on this profile will be increased on the current level. The results of the market and network simulations showed a decrease of the import flows on the SK – CZ, due to the fact that the balance of the Slovak power system will change from import to export by the commissioning of the new generation unit. In cases of high transit or loop flows through the Slovak transmission system, the remaining 200 kV cross-border line on SK – CZ profile has been indicated in the network calculations as an element that will be high loaded or even congested, in case of 400 kV cross-border line outage. The likeliness of such congestion has been evaluated based on the high transit flows occurrence in the Slovak transmission system in current operation, which is approximately 5 % of the year.

2028 The last 200 kV cross-border line on the SK – CZ profile will be decommissioned in 2025 and PATL of the 400 kV cross-border line on the SK – CZ profile will be increased approximately to 2,000 A in 2026. This action will increase the TC on the SK – CZ profile to the current level again. The results of the market and network simulations showed a decrease of the import flows on the SK – CZ due to the fact that the balance of the Slovak power system will change from import to export by the commissioning of the new generation unit.

SPAIN

2021 Most of the congestions still remain in 2021, as network solutions are not commissioned by December 2020. Even so, some congestions disappear as a result of the commissioning of some uprates of some lines.

2023 In the ES – PT border, the commissioning of a new ES – PT interconnection and some internal lines solve all the congestions detected.

In the ES – FR border, congestions still remain as network reinforcements are not expected to be commissioned by December 2022.

However, it is considered that long term horizons with new interconnections will have new limiting elements to the NTC in different lines to those reported here. This is the framework of the TYNDP.

2028 In the ES – FR border, the commissioning of new ES – FR interconnections and some internal lines solve almost all the congestions detected.

There is one remaining line whose congestion percentage is very low. In addition, it is not detected in long term horizon studies.

However, it is considered that long-term horizons with new interconnections will have new limiting elements to the NTC in different lines to those reported here. This is the framework of the TYNDP.

SWEDEN

Sweden has a power surplus, which is expected to remain during the next decade. Following the decommissioning of nuclear plants in the south of Sweden, increasing volumes of wind power are expected to be installed in the north. This will lead to increasing export to Finland and through Sweden to the continental market. The following improvements are planned:

Border	Capacity	Year	Reason
SE3 – SE4	+ 2,600 MW	2018 – 2019	New HVDCs
SE2 – SE3	+ 800 MW	2022 – 2023	Various improvements
SE1 – FI	+ 500/900 MW	2025	New AC line
SE4 – DE	+ 700 MW	2026	New HVDC
SE2 – FI	+ 800 MW	2029	New HVDC
SE3 – FI	– 400 MW	2029	Old HVDC decommissioned when SE2-FI commissioned

SWITZERLAND

The realisation of the Strategic Grid 2025 should enable the elimination of current congestions and accommodate the new large pump storage devices (Nant de Drance and Linth-Limmern). Furthermore, the interconnector 'Italy – Switzerland' is a PCI (label 2.15.1 in the 3rd PCI list published in 2017). The following list of investments should eliminate current and future congestions and is based on the TYNDP 2018 package (https://tyndp.entsoe.eu/tyndp2018/):

2021 Investment 1284 *Pradella* – *La Punt*: Reinforcement of the existing route

Investment 1261 A: *Bickigen* – *Chippis*: Optimisation of the existing route by voltage conversion to 380 kV

Investment 1261 B: *Chamoson* – *Chippis*: Reinforcement by construction of a 380 kV route and new 380/220 kV transformer in Chippis

2023 –

2028 Investment 1259 *Beznau* – *Mettlen*: Optimisation of the existing route by voltage conversion to 380 kV, partial reinforcement

Investment 1287 *Bassecourt* – *Mühleberg*: Reinforcement of the existing route by voltage conversion to 380 kV including a new 380/220 kV transformer in Mühleberg

Investment 642 *All'Acqua (CH)* – *Pallanzeno (CH)* – *Baggio (IT)*; New interconnector project between Italy and Switzerland

Investment 1285 Magadino: Connection of the *Avegno* – *Gorduno* line to the Magadino substation and new 380/220 kV transformer in Magadino

Investment 1286 *Chippis* – *Lavorgo*: Reinforcement by construction of a new 380 kV route including a new 380/220 kV transformer in Mörel

2.3 CONCLUSIONS

This chapter gives an overview of congestions for the following time stages: Capacity calculation for the purpose of DA capacity allocation, D-1 (operational planning after DA market closure) and (close to) real-time. The location and frequency of congestions is also reported. Given that power flow patterns are not very stable and are heavily dependent on market and operational conditions, the location of congestions can vary. Moreover, congestions identified on certain transmission corridors do not necessarily result from single bottlenecks, but rather from constraints appearing on a number of lines. Hence, although one can observe a low frequency of congestion on particular lines across the corridor, the whole set of these lines constitutes a network congestion. These congested corridors are indicated as bubbles grouping grid element(s) to assist with the identification of congested parts of the network, complemented with TSOs' expert assessment.

In the timeframe **'Capacity calculation for the purpose of day-ahead capacity allocation'**, a relatively low number of congestions are reported, especially if compared to the D-1 timeframe. These reported congestions are generally on bidding zone borders or in their direct vicinity. This is due to the fact that in the capacity calculation timeframe, only the grid elements with relevant sensitivity to cross-border exchanges are considered.

The reported congestions in this timeframe have quite high frequency rates. This is most noticeable on the bidding zone borders that use NTC approaches. For the borders where FBA is applied, there are congestions of lower frequency but for a higher number of grid elements.

The same general congestion patterns are seen for each reported year, save for some cases when constraints were alleviated by investments.

In the timeframe **'D-1'**, the report identifies congested lines detected during the operational planning process, where TSOs check the DA market outcome for feasibility against the grid's technical capability. In this timeframe, all grid elements are considered, irrespective of their cross-zonal relevance. Many lines with low frequency of congestions are reported, while high frequency congestions are reported for a relatively limited number of grid elements.

As far as the timeframe **'Real-Time'** is concerned, the collection of consistent data was quite challenging due to differences in TSO approaches to collecting and processing real-time operational data. In particular, some TSOs provided incident data from real-time systems, whilst others reported all congestions identified up to one hour before real time. Since both types of data refer to different situations, two sets of real time maps have been provided. The first set of maps shows congestions reported by TSOs using real-time system data, corresponding to actual security violations that occurred. These were usually the result of unexpected situations such as forced outages. The second set of maps show congestions reported by TSOs using 'up to one hour before real time' data. These congestion result from changes to generation dispatch resulting from intra-day market activities, weather changes and/or forced outages (generation and/or transmission). In most cases, TSOs were able to manage these close-to-real-time congestions using operational congestion management procedures. Both sets of maps for this 'Real-Time' timeframe indicate the amount of operational challenges faced by TSOs very close to real-time.

With respect to the **future evolution of reported congestions**, TSOs' expert assessments have been provided in the report. It is to be underlined that TSOs have extensive investment plans in place to address the congestions identified in the short to medium timeframe.

Finally, it is important to highlight that congestions, even with high frequency, do not automatically cause a loss of social welfare, as the congestion may be resolved by non-costly remedial actions, such as topological changes, flow-control devices, etc. For congestions that cannot be resolved using non-costly measures, these can potentially affect social welfare due to their impact on cross-border capacities (congestion on cross-border relevant lines identified during cross-border capacity calculation process and active during the allocation phase) or the need to apply costly remedial measures that are paid for in transmission tariffs by all grid users (congestion identified during D-1 and real-time stages).

3 POWER FLOWS NOT RESULTING FROM CAPACITY ALLOCATION

Within this chapter, an assessment of flows not resulting from capacity allocation is carried out based on the PTDF Flow Indicator.

In section 3.1, the calculation methodologies and general descriptions are provided. Section 3.2 gives an overview of the data used. In section 3.3, results are presented and commented.

3.1 METHODOLOGY

This chapter provides a description of the PTDF Flow Indicator. The consideration of power flows not resulting from capacity allocation is complex and different indicators are possible. For this report, the same PTDF indicator as calculated for the MMR report is used and is described in this section. This PTDF indicator is widely accepted as being one approximation to loop flows.

This indicator is based on the capacity allocation model of the internal zonal electricity market in Europe, assuming that:

– Market transactions within each bidding zone are not limited (deemed as a copper-plate)
– Market transactions between all bidding zones are limited through cross-zonal capacity calculation and allocation procedures.

Flows not resulting from capacity allocation are computed as the difference between the measured physical flow and the computed flows at the bidding zone borders (In most cases the bidding zone border and member state border are the same thing. However, for the CZ borders with AT and DE, the borders are calculated on a member state basis, DE and AT being in the same bidding zone for the reported years)[18] from the net positions of each bidding zone for each hour of the year.

The equation is as follows:

$$\text{PTDF Flow deviation}_b\,(h) = PF_b\,(h) - CF_b\,(h)$$

$PF_b\,(h)$: Measured cross-border physical flow over given bidding zone border (b).

$CF_b\,(h)$: Calculated flow induced by all cross-border exchanges between all European bidding zones, i.e. estimation of export/import and transit flows.

In order to compare the measured cross-border physical flows $PF_b\,(h)$ and calculated flows $CF_b\,(h)$, the net position per bidding zone will have to be transformed (via PTDF) into cross-border flows resulting from capacity allocation. This transformation takes into account the electric properties of the transmission grid from a common grid model.

The indicator calculates average PTDF Flow deviations per border, providing a comparison between the cross-border flows that are the result of the capacity allocation process and the measured physical flows on cross-border tie-lines.

18 Currently there is no CZ – (DE+AT) bidding zone border. The cross border allocation does exist for yearly, monthly, DA and intra-day timeframes on CZ – AT, CZ – DE(50HzT) and CZ – DE (TTG) cross-border interfaces.

Hence, the indicator focuses on loop flows (which are a subset of unscheduled flows) and neither evaluates who is responsible for the PTDF Flow deviations nor if the identified PTDF Flow deviations induces security issues.

$$CF_h = \left(\sum_{l=1}^{L=number\ of\ BZ\ border} \begin{bmatrix} 1 & \cdots & k \\ \vdots & \ddots & \vdots \\ L & \cdots & . \end{bmatrix} \cdot \begin{bmatrix} 1 \\ \vdots \\ k \end{bmatrix} \right)$$

Sum of the flows created by all exchanges between bidding zones in the synchronous area at all bidding zone borders

PTDF matrix (resolution)

Net positions of the relevant bidding zones

For each hour, the flows resulting from capacity allocation will be computed using a power transfer distribution factor (PTDF) matrix and the net positions of the relevant bidding zones from the synchronous area.

The measured hourly physical flow minus the above vector $CF_b(h)$ will be the indicator for each hour.

The PTDF indicator is not computed for some areas of Continental Europe which are radially structured (e.g. internal Italian bidding zones borders, ES – PT border).

In fact, in a radially structured network (e.g. Figure 9):

- Physical measured flow on a given border can be computed from an energy balance of the radial part:

$$PF_{C \to B}(h) = NP_{RT,C}(h) + NP_{RT,D}(h)\ \forall h$$

Where:

$PF_{i \to j}(h)$ is the measured physical flow from Bidding Zone i to Bidding Zone j

$NP_{RT,z}$ is the net position (in real-time) of the Bidding Zone z

- PTDF coefficients are equal to –1, 0 or 1:

$$PTDF_A^{C \to B} = 0$$
$$PTDF_B^{C \to B} = 0$$
$$PTDF_C^{C \to B} = 1$$
$$PTDF_D^{C \to B} = 1$$

Where:

$PTDF_b^l$ is the sensitivity of the link l to a variation of the net position of the Bidding Zone b

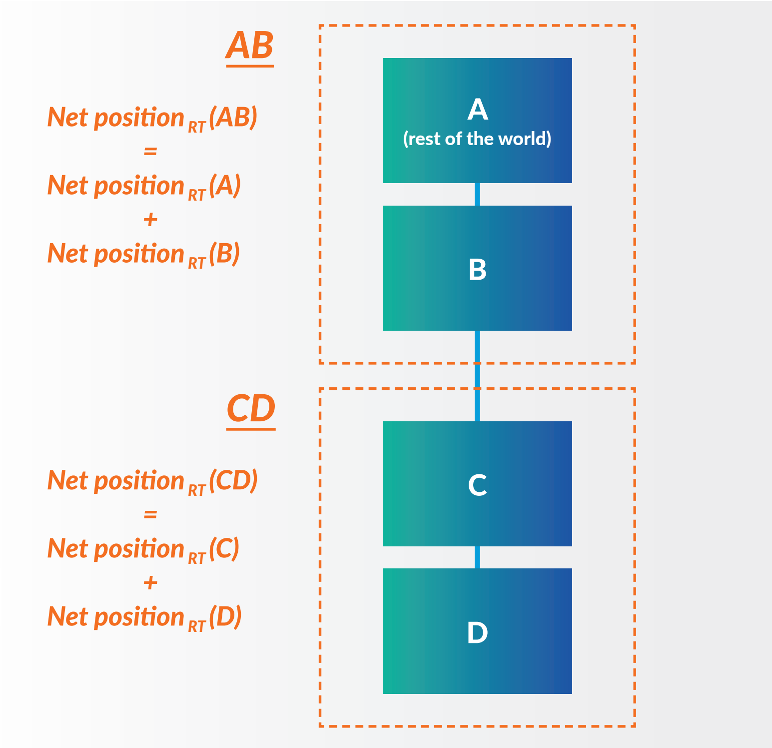


Figure 69: Radially structured network

Consequently, calculated flow induced by all cross-border commercial exchanges between all European bidding zones $(CF_{C\rightarrow B}(h))$ is equal to:

$$CF_{C\rightarrow B}(h) = PTDF_C^{C\rightarrow B} \times NP_C(h) + PTDF_D^{C\rightarrow B} \times NP_D(h) = NP_C(h) + NP_D(h) \; \forall \, h$$

And hence:

$$\begin{aligned} PTDF\ Flow\ Deviation_{C\rightarrow B}(h) &= PF_{C\rightarrow B}(h) - CF_{C\rightarrow B}(h) \\ &= [\,NP_{RT,C}(h) + NP_{RT,D}(h)\,] - [\,NP_C(h) + NP_D(h)\,] \\ &= [\,NP_{RT,C}(h) - NP_C(h)\,] + [\,NP_{RT,D}(h) - NP_D(h)\,] \end{aligned}$$

The difference between the hourly real-time net position and the hourly realised net position (control program) is equal to the hourly bidding zone imbalance $(IMB_D(h))$:

$$PTDF\ Flow\ Deviation_{C\rightarrow B}(h) = IMB_C(h) + IMB_C(h)$$

Since it is out of the scope of this report to assess system imbalances and it is also reasonable to assume that the average yearly value of system imbalance is equal to zero for each bidding zone, the PTDF indicator can be assumed negligible for the bidding zones border in a radially structured part of the system.

This conclusion is also supported by the very low values obtained from the computation for the FR–ES border (less than 20 MW in each year).

3.2 DATA SOURCES

This chapter provides a description of the data used for the calculation of the PTDF indicator used in this Technical Report. For each relevant category of input data (actual vs computed information), the data source is detailed for the three main synchronous areas (SAs) considered in this report (Continental Europe, Baltic and Nordic SAs).

3.2.1 ACTUAL DATA

As described in chapter 3.1, the computation of the PTDF indicator requires the following hourly series of actual data:

- **Measured Physical Flow**

  These values represent the metered aggregated load flows at the border between two control blocks. They are uploaded approximately at the end of the following week.

- **Control Programs (Net Position)**

  Realised control programs (net positions) are the sum of the realized scheduled exchanges of each block. The realized control program takes into account the long term nominations, DA exchanges, ID exchanges and potential remedial actions, and may include balancing exchanges.

Data sources for the three SAs previously mentioned:

- **Continental Europe**

  Actual data source for Continental Europe is the 'ENTSO-E Verification Platform – Vulcanus'.

  Vulcanus is a web IT platform used by TSOs to store and visualise matched data on control area[19] and control block level[20], amongst others Day Ahead Control Programs and schedules, Intraday Control Programs and schedules, Realized Control Programs and schedules, and Measured Physical Flow. The data suppliers (who collect data from the relevant TSOs) are Amprion for the northern part of Continental Europe, Swissgrid for the southern part of Continental Europe and REE. Data on measured physical flows, net positions and scheduled exchanges was taken from the Vulcanus database.

  Data is stored primarily in an hourly resolution; however, for some TSOs data is also available in a ¼ hour resolution.

- **Baltic and Nordic Areas**

  Data for Baltic and Nordic synchronous areas have been provided, only for 2017, by relevant TSOs using their internal databases. Since a structured process for common PTDF computation is not yet implemented in these areas, PTDFs have been computed by relevant TSOs for the scope of this assessment using prototypal tools.

19 A CONTROL AREA is a coherent part of the UCTE INTERCONNECTED SYSTEM (usually coincident with the territory of a company, a country or a geographical area, physically demarcated by the position of points for measurement of the interchanged power and energy to the remaining interconnected network), operated by a single TSO, with physical loads and controllable generation units connected within the CONTROL AREA. A CONTROL AREA may be a coherent part of a CONTROL BLOCK that has its own subordinate control in the hierarchy of SECONDARY CONTROL. Source: Continental Europe Operation Handbook

20 A CONTROL BLOCK comprises one or more CONTROL AREAS, working together in the SECONDARY CONTROL function with respect to the other CONTROL BLOCKS of the SYNCHRONOUS AREA it belongs to. Source: Continental Europe Operation Handbook

3.2.2 COMPUTATION OF THE PTDF MATRIX

A power transfer distribution factor (PTDF) is an influence (sensitivity) factor in the modification of the generation or load on the active power flow of a given element of the grid (or a zone). The PTDF matrix is based on a DC load flow approach. More detailed information on the CWE flow based methodology is available on the JAO website[21].

The PTDF matrix (resolution per bidding zone) has been computed, separately for each of the three main SAs, from a common reference grid model (CGM) and a generation shift key (GSK).

For Continental Europe, several CGM files for each year were considered and the correspondent PTDF matrix was applied, in the PTDF indicator computation, for a two-month period in 2016 and 2017. In 2015 only three PTDF matrices were calculated (Table 2). The same approach and the same snapshot have been also considered for 2017 in the Baltic area.

Interval			CGM
1/1/2015	→	31/3/2015	Reference Case* model for 21 January 2015 10:30 CET
1/4/2015	→	30/9/2015	Reference Case model for 15 July 2015 10:30 CET
1/10/2015	→	31/12/2015	Reference Case model for 20 January 2016 10:30 CET
1/1/2016	→	29/2/2016	DACF model for 20 January 2016, 10:30 CET
1/3/2016	→	30/4/2016	DACF model for 16 March 2016, 10:30 CET
1/5/2016	→	30/6/2016	DACF model for 18 May 2016, 10:30 CET
1/7/2016	→	31/8/2016	DACF model for 20 July 2016, 10:30 CET
1/9/2016	→	31/10/2016	DACF model for 21 September 2016, 10:30 CET
1/11/2016	→	31/12/2016	DACF model for 16 November 2016, 10:30 CET
1/1/2017	→	28/2/2017	DACF model for 18 January 2017, 10:30 CET
1/3/2017	→	30/4/2017	DACF model for 15 March 2017, 10:30 CET
1/5/2017	→	30/6/2017	DACF model for 17 May 2017, 10:30 CET
1/7/2017	→	31/8/2017	DACF model for 19 July 2017, 10:30 CET
1/9/2017	→	31/10/2017	DACF model for 20 September 2017, 10:30CET
1/11/2017	→	31/12/2017	DACF model for 15 November 2017, 10:30 CET

* A Reference Case is a common grid model representing standard topology scheme for the Continental Europe area.

Table 1: CGM and intervals used

For the Nordic area assessment, available PTDFs are referred only to 2017 winter snapshots (due to the above mentioned absence of a structured process for their computation). The following table presents a summary of the considered snapshots and how they have been applied in the assessment:

Interval			CGM
1/1/2017	→	8/1/2017	Grid model for 8 January 2017, 13:00 CET
9/1/2017	→	22/1/2017	Grid model for 15 January 2017, 13:00 CET
23/1/2017	→	31/1/2017	Grid model for 29 January 2017, 13:00 CET
1/2/2017	→	5/2/2017	Grid model for 5 February 2017, 13:00 CET
6/2/2017	→	19/2/2017	Grid model for 12 February 2017, 13:00 CET
20/2/2017	→	31/12/2017	Grid model for 5 February 2017, 13:00 CE

Table 2: CGM and intervals used, Nordic area

21 http://www.jao.eu/support/resourcecenter/overview?parameters=%7B%22IsCWEFBMCRelevantDocumentation%22%3A%22True%22%7D

It is not possible to perfectly represent the grid topology over the entire year with just a few snapshots some aspects will not be taken into account with this approach (e. g. maintenances, modification of topology, new lines, generation and load pattern, load variation).

Different rules are used in Europe for the determination of GSK (e. g. merit order, linear GSK). For the indicator, the computation of the GSK has to be standardised in order to ensure the comparability of the PTDFs. For this Technical Report, a GSK with a pro-rata of all generation units connected to the grid model has been chosen. Non-linear phenomena, e. g. constraints on maximal generation unit power infeed, are not taken into account. For example, a bidding zone produces 2,000 MW and a power plant in the bidding zone produces 100 MW. If the bidding zone production is increased by 30 MW, the power plant production will be increased by 1.5 MW (100/2,000 × 30 = 1.5).

The generation of a bidding zone is increased by 100 MW. If the load of a line increases by 5 MW, the PTDF of the bidding zone on the given line will be 0.05. This computation is made for each tie-line and each bidding zone. However, the results are not given per each tie-line but aggregated for each border between bidding zones.

The PTDF matrix is computed on the bidding zone level but in the Vulcanus database, the resolution may be different. The net position for the Austrian – German – Luxembourg bidding zone is not directly available. The Vulcanus database provides one net position for Germany – Luxembourg – Denmark West and another net position for Austria. For the computation of the matrix, the generation units are increased for all four areas at the same time. It is also not possible to compute the allocated flows between the Austrian – German – Luxembourg bidding zone[22] and the Denmark West bidding zone.

The shape of the PTDF matrix is the following for *k* bidding zones and *n* borders:

$$\begin{array}{cc}
 & \begin{array}{ccc} \textit{BZ A} & \textit{BZ B} & \textit{BZ k} \end{array} \\
\begin{array}{c} \textit{Border AB} \\ \textit{Border AC} \\ \dots \\ \dots \\ \textit{Border n} \end{array} &
\begin{bmatrix}
PTDF_{\text{BZ A on border AB}} & PTDF_{\text{BZ B on border AB}} & PTDF_{\text{BZ k on border AB}} \\
PTDF_{\text{BZ A on border AC}} & PTDF_{\text{BZ B on border AC}} & PTDF_{\text{BZ k on border AC}} \\
 & & \\
 & & \\
PTDF_{\text{BZ A on border n}} & PTDF_{\text{BZ B on border n}} & PTDF_{\text{BZ k on border n}}
\end{bmatrix}
\end{array}$$

22 Allocated and not allocated flows are not calculated on the border between Germany and Austria as this is considered as a border within a bidding zone where cross border allocation does not exist (however information about physical flows and commercial exchanges are available in Vulcanus).

3.3 ANALYSIS OF THE INDICATORS

Schedules are a TSO tool for planning system operation after market closure and before real-time. Schedules are agreed plans from generation and consumption units as well as internal and external commercial exchanges and exchanges between TSOs. Schedules provide the necessary information for the TSO to operate and balance the system, as well as carry out security analysis.

All schedules in a scheduling area should sum up to zero within a time period to keep the system in balance. If no faults occur, both consumption and production will be equal to the prognosis. This enables the TSO to balance its system in real-time with a minimum level of reserves for balancing, compared to the extensive level of reserves necessary if no schedules are available[23].

In this sense, the Load Frequency Control (although the LFC works on the control area level) ensures that the sum of all differences between commercial and physical flows over all borders of a bidding zone and the respective control area is very close to zero. From the bidding zone perspective, control system differences between schedules and physical flow at one border net off differences at other borders (netting effect).

In the ideal case of two isolated systems with a single AC interconnection, the physical flow will also always be equal to the schedule. However, in a meshed network and when looking at individual borders of a bidding zone, differences between schedules and physical flows can be observed.

3.3.1 RESULTS OF THE PTDF FLOW INDICATOR FOR THE YEARS 2015, 2016 AND 2017

The advantages and limitations of the PTDF Flow indicator are shown in Table 4. This is followed by a graphical representation of the indicator for the years 2015, 2016 and 2017.

Advantages	Limitations
– The physics of the flows are taken into account by translating commercial exchanges into physical flows between bidding zones. – Linkage with the enduring capacity allocation process in Europe (FB market coupling) is ensured by using allocated flow (sum of export, import and transit) as an input for calculation	– Errors between forecasted flows and realized flows are included in the values (emphasised by the fact that only six CGMs are currently used for the computation) – Assumptions on pro-rata GSK do not consider merit order and/or cross border portfolio optimisation; no maximum generation per generator is considered when applying prorata GSK – Data availability of net position (for aggregation of countries see also subsection 3.2.2) – Measured physical flows include both market and non-market transactions (internal, bilateral, multilateral redispatch, primary and secondary reserve power) with some transactions not being scheduled (e. g. primary and secondary reserve).

Table 3: Advantages and limitations of the PTDF flow indicator

Based on the given input data set and necessary assumptions and limitations taken, the PTDF indicator estimates the size of loop flows but also includes uncertainties related to the PTDF matrixes adopted for the computation. Its average value naturally cannot provide (total) absolute value of the flows not resulting from capacity allocation.

23 Source: Supporting Document for the Network Code on Operational Planning and Scheduling, Chapter 5.7, Page: 44

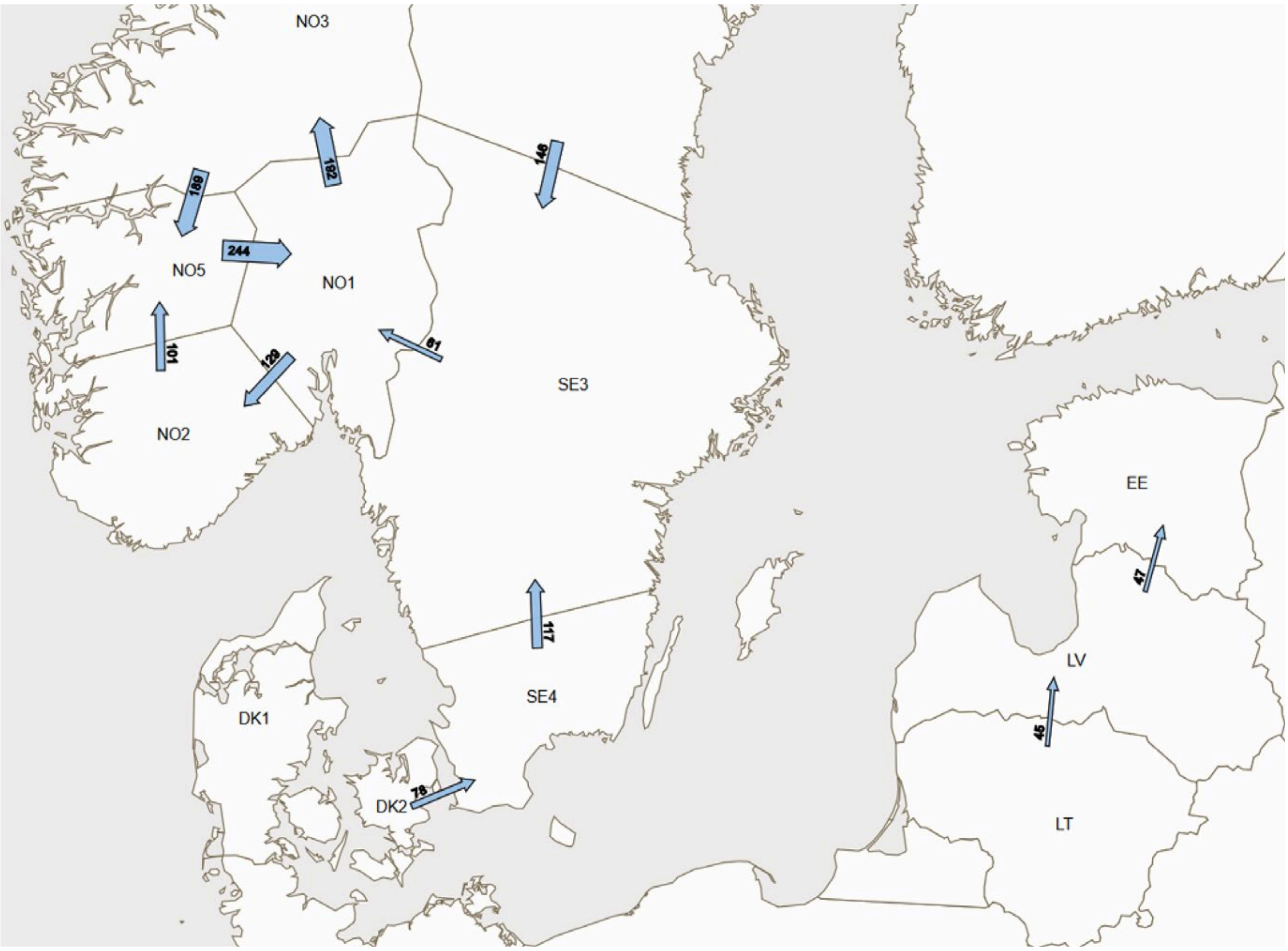


Figure 70: Average PTDF Flow Indicator for 2017 (in MW). CCR: Baltic and part of Nordic. Data available only for 2017

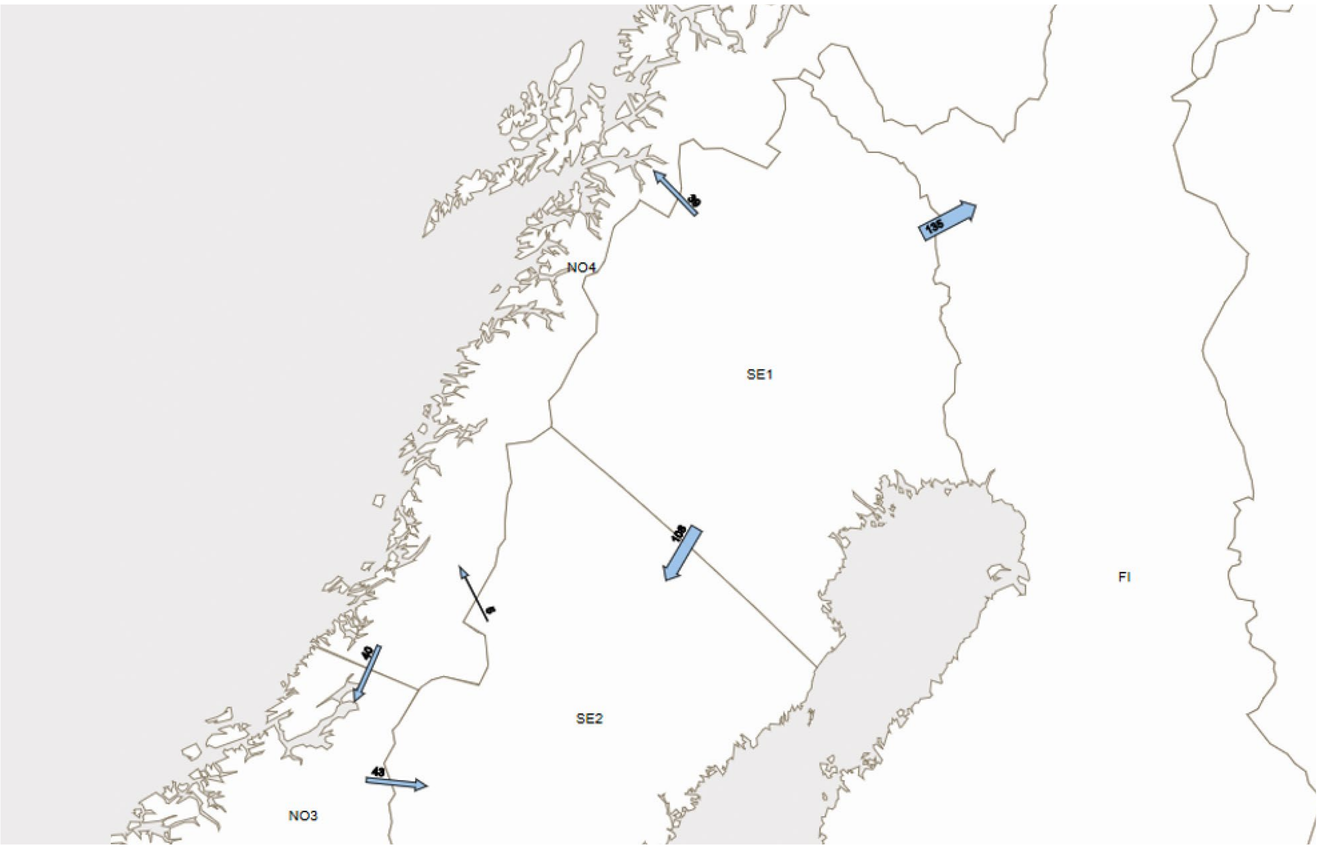


Figure 71: Average PTDF Flow Indicator for 2017 (in MW). CCR: part of Nordic. Data available only for 2017

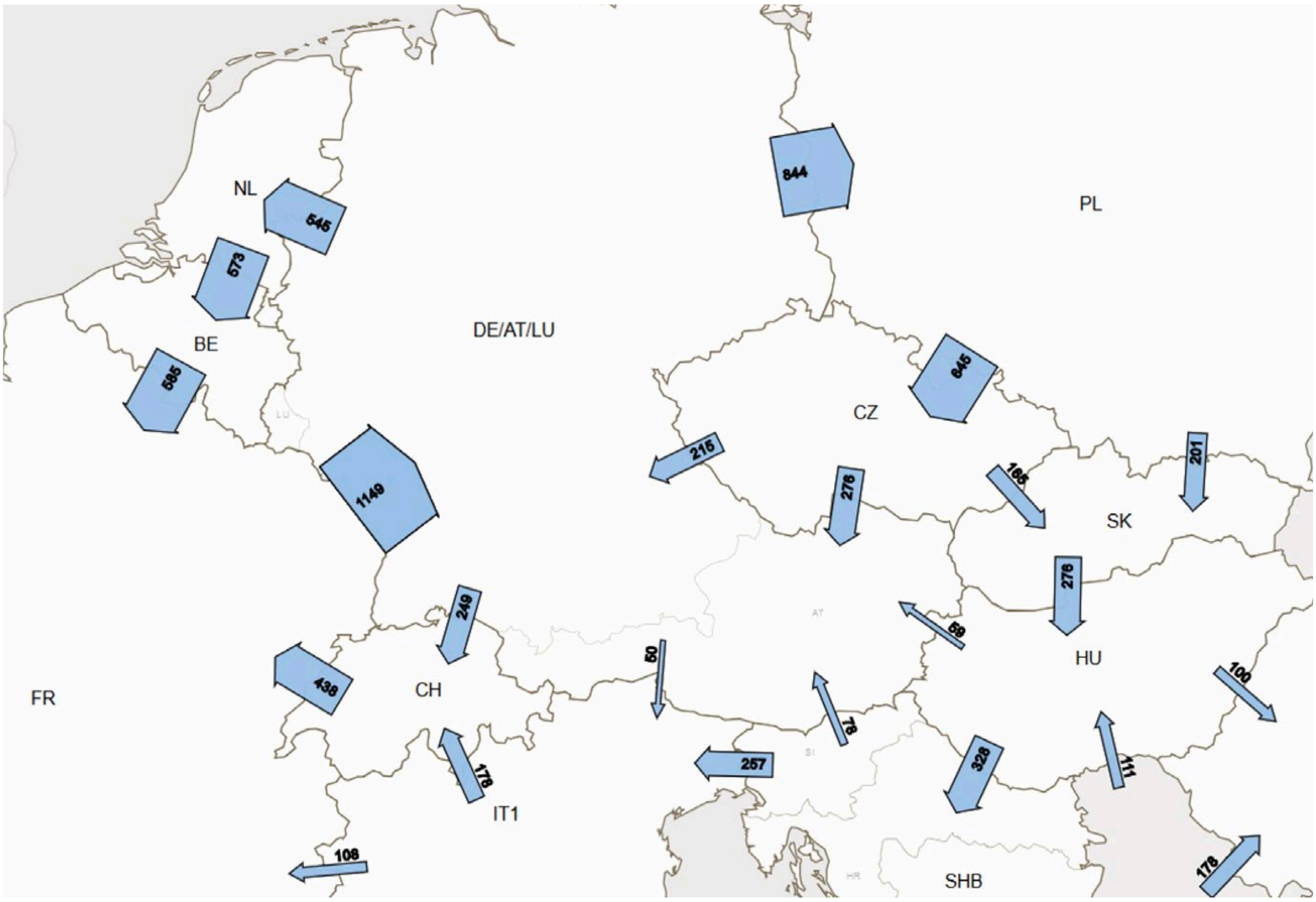


Figure 72: Average PTDF Flow Indicator for 2015 (in MW). CCR: Core and Italy North

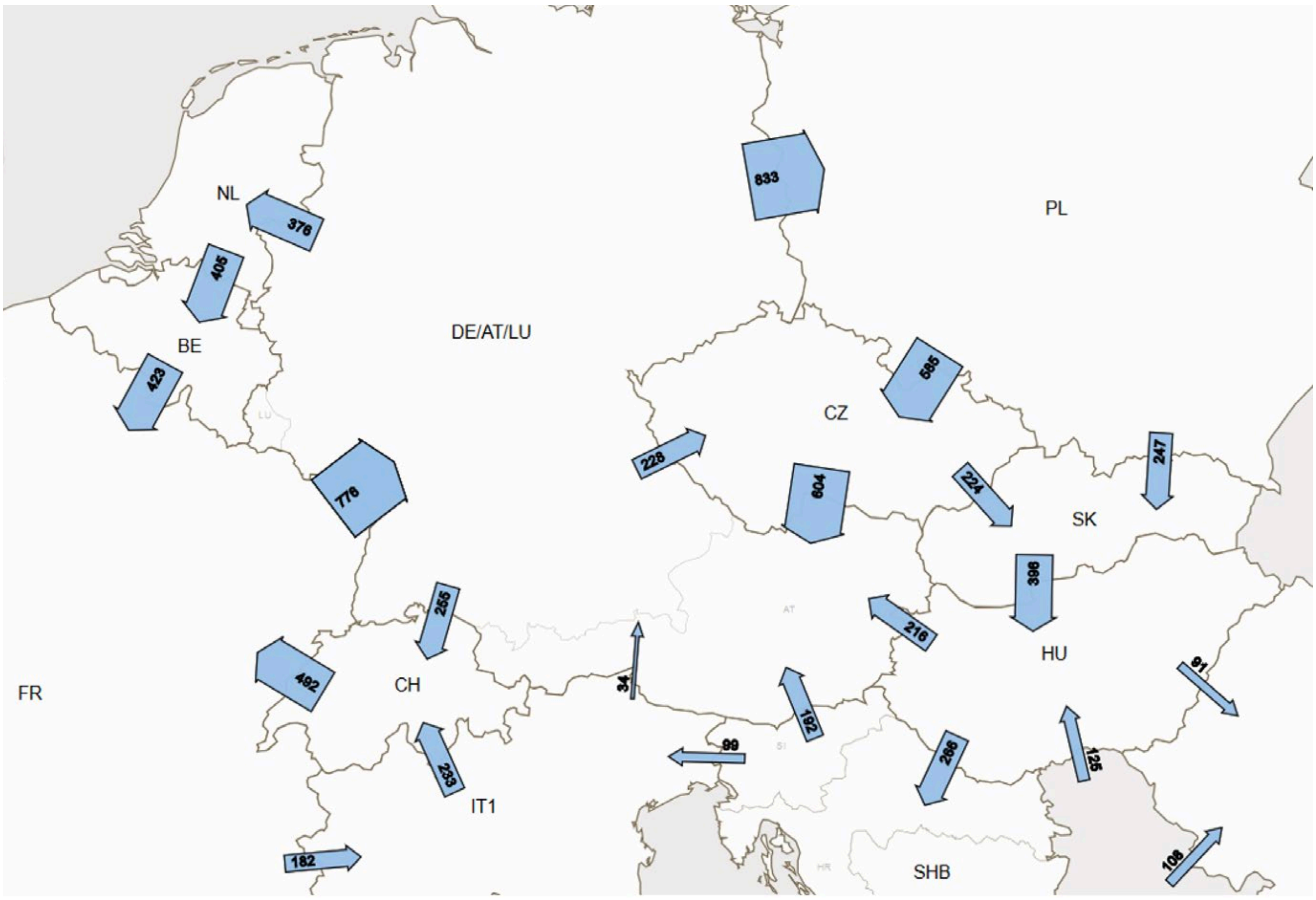


Figure 73: Average PTDF Flow Indicator for 2016 (in MW). CCR: Core and Italy North

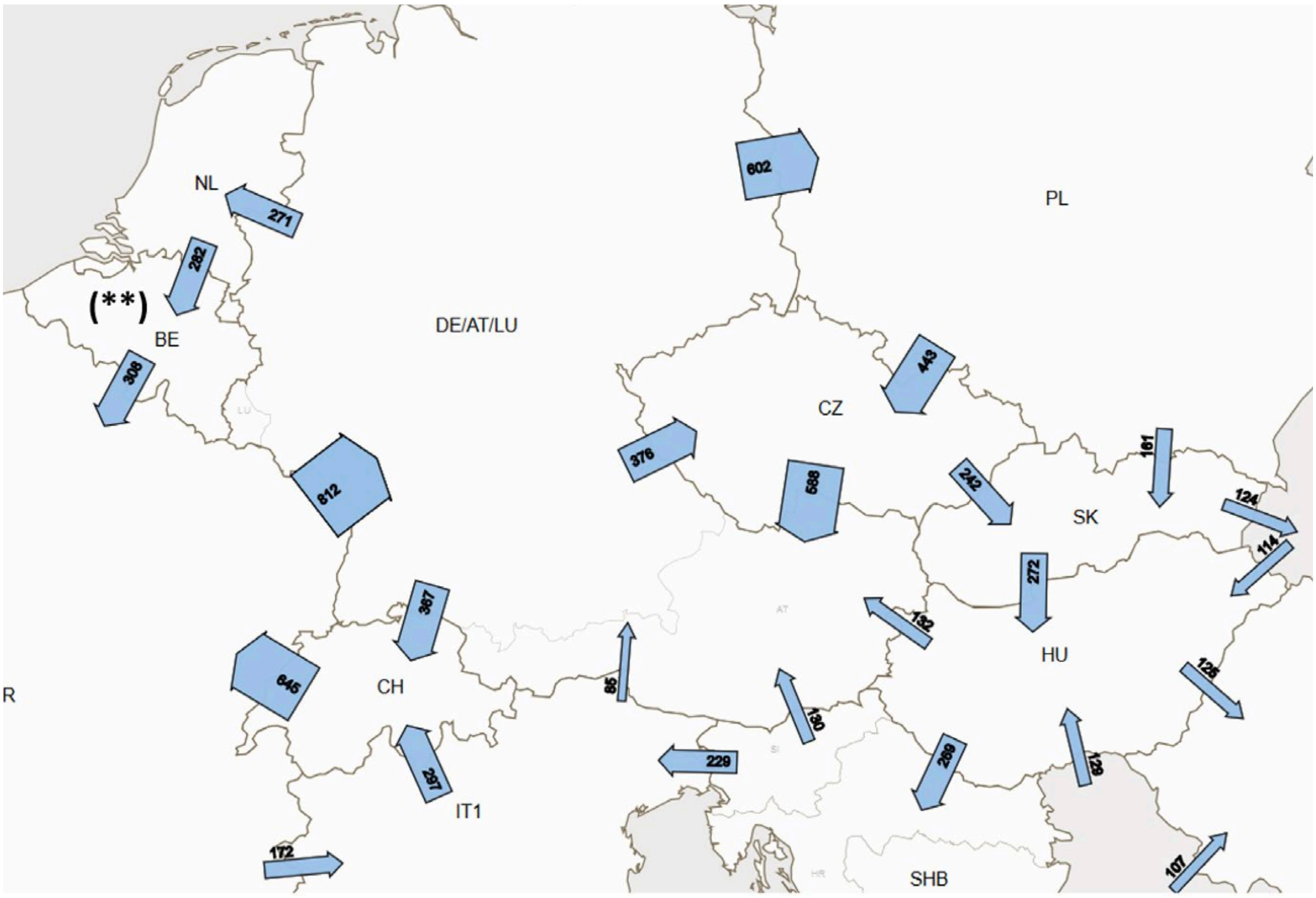


Figure 74: Average PTDF Flow Indicator for 2017 (in MW). CCR: Core and Italy North (CH – FR, CH – IT, CH – DE/AT/LU, UA – SK, UA – HU and UA – RO bidding zone borders are not part of these CCRs). SI – HR border is missing due to lack of data.

* Data for UA – SK, UA – HU and UA – RO borders available only for 2017

** The results of this indicator are complemented by an additional one used by Elia System Operator NV to measure Loop Flows at the Belgian borders, the results for this have been published in the internet (http://www.elia.be/en/grid-data/interconnections/Loopflows) since 2017. The method of Elia uses the actual CWE FB parameters, D2CF data and leads to higher average estimations. The main reasons for the discrepancy and more details on the Elia method are provided within the Expert Assessment of this Section.

*** The lower level of loop flows on the DE-PL border in 2017 mainly results from temporary (but for the whole 2017) disconnection of 220 kV Krajnik-Vierraden (PL – DE) interconnector.

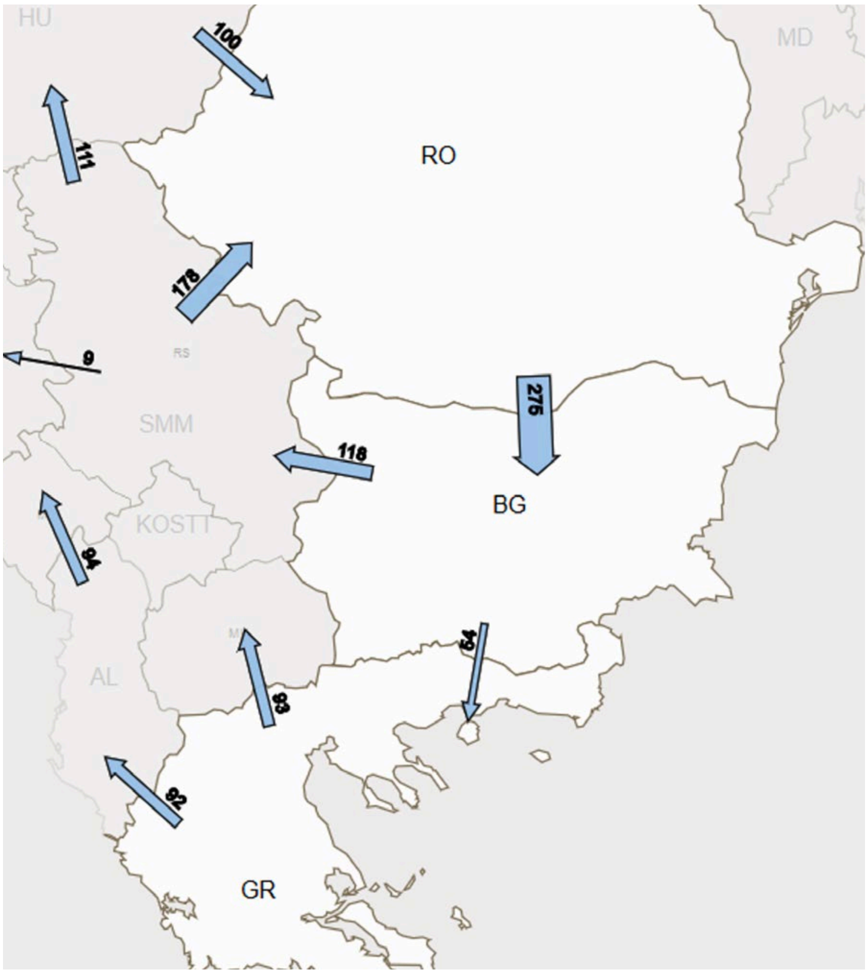


Figure 75: Average PTDF Flow Indicator for 2015 (in MW). CCR: South-east Europe (SEE)

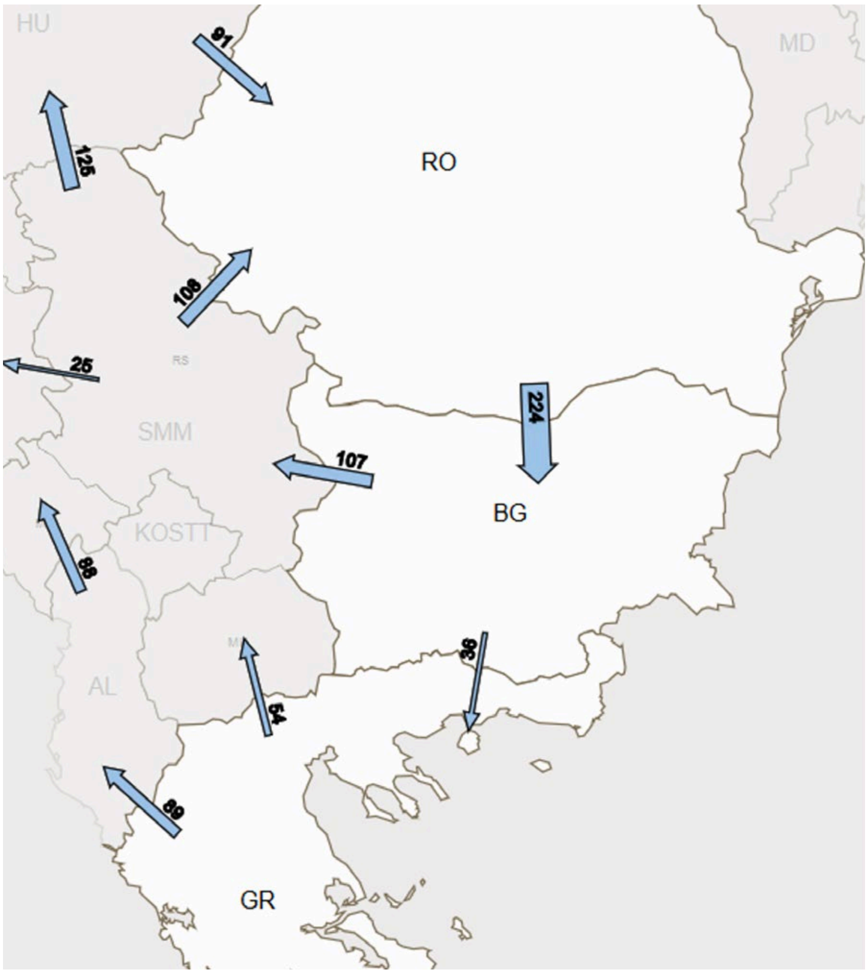


Figure 76: Average PTDF Flow Indicator for 2016 (in MW). CCR: South-east Europe (SEE)7

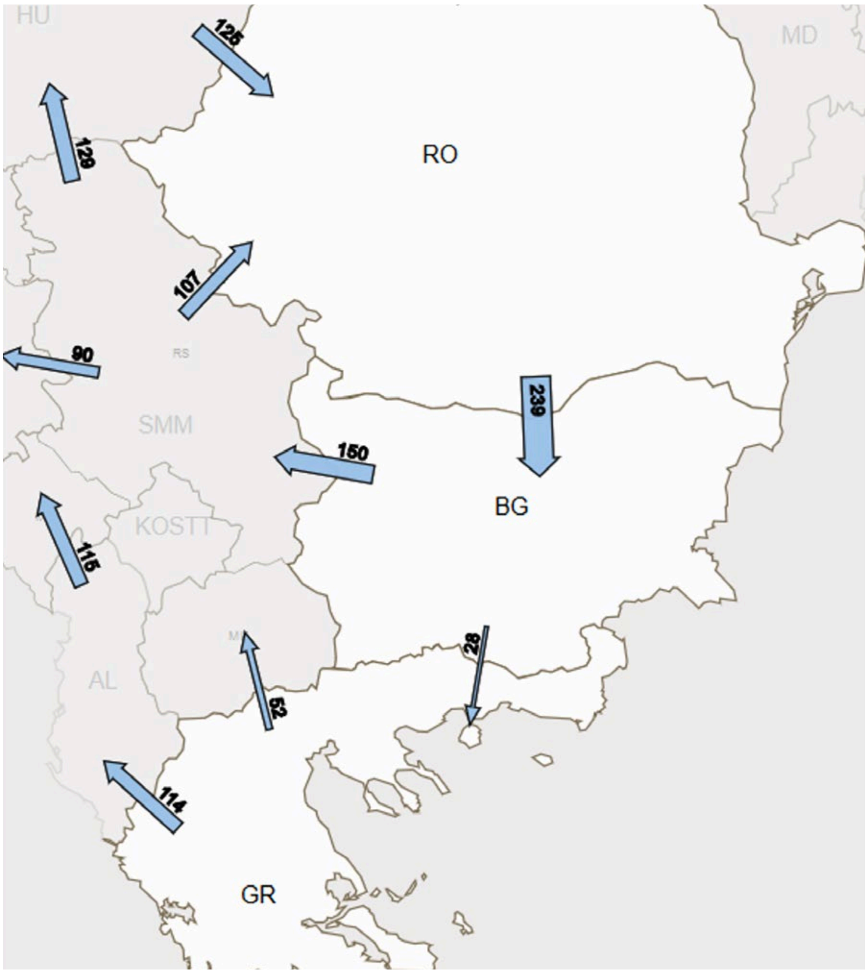
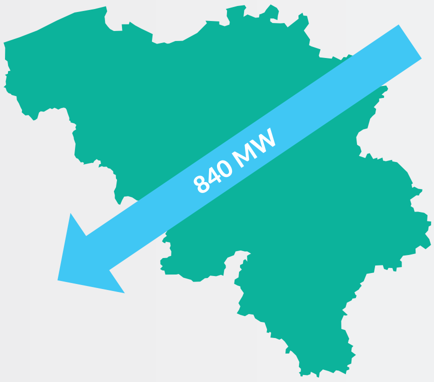


Figure 77: Average PTDF Flow Indicator for 2017 (in MW). CCR: South-east Europe (SEE)

3.3.2 EXPERT ASSESSMENT ON THE PTDF FLOW INDICATOR

Complementary to the information provided in this report, it should be highlighted that Belgian system operator Elia publishes the estimated level of loop flows crossing Belgium since 2017 on their own website[24]. For the case of 2017, Elia has calculated an average loop flow of 840MW crossing Belgium in the North→South direction. The direction North→South was indeed the predominant one for every month of 2017 on average, with a visible seasonality effect of higher loopflows during winter.

Average Yearly Loop Flows Crossing Belgium (North → South) in 2017



Average Monthly Loop Flows Crossing Belgium (North → South) in 2017

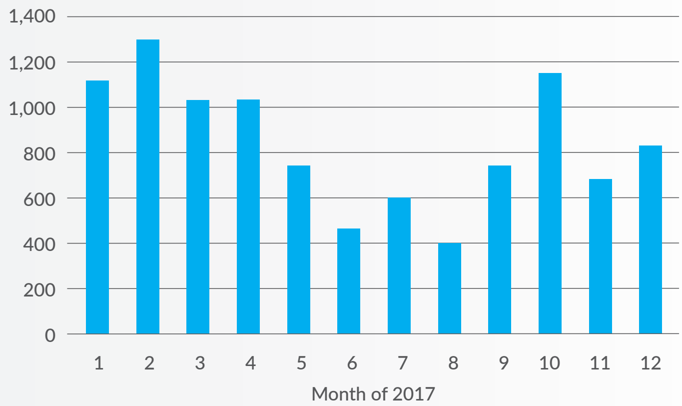


Figure 78: Loop flows in Belgium

These levels of loop flows calculated by Elia are significantly higher than the ones estimated by the PTDF Indicator in this Study, for the following reasons:

- The calculation of this Report compares the final measured physical flows at the borders with what was expected to be observed using PTDFs and the final real-time net hub positions. The calculation of Elia is built in a different manner and uses D-2 data
- This Report uses simplified PTDFs based on a limited number of timestamps and the GSKs were calculated pro-rata. In contrast, Elia calculations use real CWE FB parameters with hourly granularity
- The Belgian-(Luxembourg + Germany) bidding zones AC border is not included in the calculation that was elaborated on for this Technical Report

24 http://www.elia.be/en/grid-data/interconnections/Loopflows

3.4 CONCLUSIONS

The PTDF Indicator used to quantify power flows not resulting from capacity allocation is the same as the one used by ACER for the Market Monitoring Report. The current methodology used to compute these indicators has, however, some limitations, e. g. only six sets of topologies are used to calculate PTDFs for the years 2016 and 2017.

Figure 79 below provides an overview of these flows across all relevant bidding zone borders for 2015, 2016, 2017. Averages[25] and maximum values are shown. In this graph, borders are ordered according to a descending average value.

Figure 79: PTDF Flow Indicator from 2015 to 2017 for border (in MW)

Figure 80 shows the evolution, as summed totals, of the following values over all borders[26] :

- PTDF Indicator (flows not resulting from capacity allocation)
- Absolute values of the yearly average allocated flows
- Absolute values of the yearly average physical flows

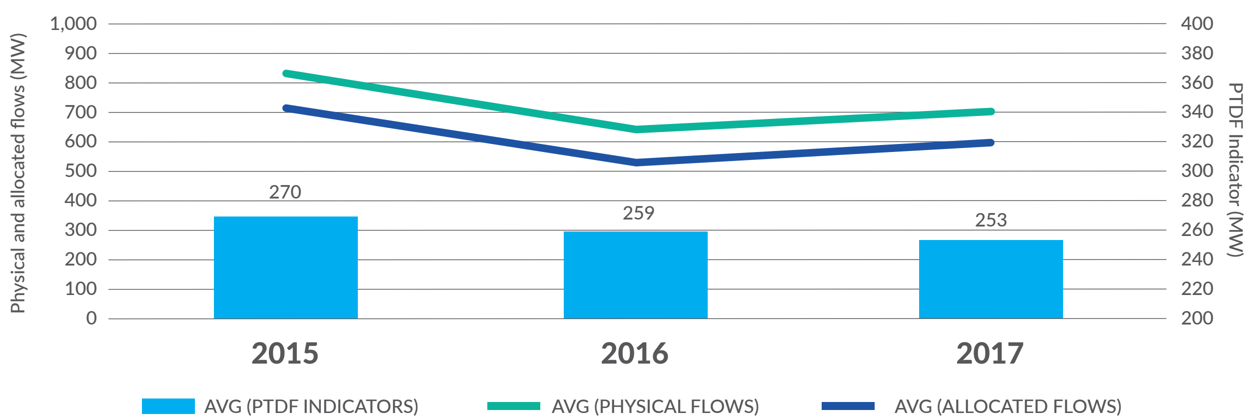


Figure 80: Average values of indicators among all borders). All borders for which 2015, 2016 and 2017 are available have been considered in the average

25 Average and maximum values for Baltic and Nordic synchronous areas correspond to the 2017 PTDF Flow indicator. All borders for which 2015, 2016 and 2017 are available have been considered in the average

26 PTDF Flow Indicator from 2015 to 2017 for border (in MW)

It can be seen from the above figures that the overall amount of the PTDF flow indicator is rather stable over the three analysed years. Looking at the borders with the highest average value of flows not resulting from capacity allocation across the three years under investigation, the following key elements can be observed:

→ The highest value of the PTDF flow indicator has been observed on the FR-DE border in 2015 (1,149 MW). On this border, a decreasing trend can be observed in the successive years, but the absolute value of the PTDF flow indicator still remains the highest among all borders in 2017.

→ High values of the PTDF flow indicator are observed also on the border between Germany and Poland, as well as on the border between Poland and Czech Republic. Also, on these borders a decreasing trend can be observed from 2015 till 2017. On the contrary, increasing trend can be observed on the CZ – AT-border and on the DE – CZ border, where the direction of the PTDF flow indicator changed after 2015.

→ The status of the DE – AT border in the existing DE/AT/LU bidding zone makes the reporting of flows not resulting from capacity allocation technically complex. Currently, DE/AT/LU is a single bidding zone. For other borders, capacity is allocated between bidding zones. However, borders DE-CZ (respectively, 50Hertz – ČEPS and TTG – ČEPS) and AT – CZ are allocated separately and PTDF indicators are calculated for these country borders even though there is no DE – AT capacity allocation process. However, as there was no capacity allocation process on the DE – AT border in the years 2015 – 2017, the effect of these cross-border exchanges is reflected in a common DEAT net position[27].

→ High value for the PTDF flow indicator is identified on the CH – FR border, with a peak observed in 2017.

→ Significant values of PTDF flow indicator representing power flows that do not result from capacity allocation can be observed on the axis Germany – Netherlands – Belgium – France (direction North to South). Although the general level of these flows decreases from 2015 to 2017 considerably, their value remains above the 2017 average for all borders.

→ The obtained values of the PTDF indicator for Belgium differ from the level of loop flows estimated by the Belgian system operator Elia. For 2017, Elia has calculated an average loop flow of 840 MW crossing Belgium in the North-South direction. One important reason for these differences is that the calculations contained in this report are based on differences between the final measured physical flows at the borders with what was expected to be observed using PTDFs and the final real-time net hub positions (with limited number of PTDFs calculated using pro rata GSK). The calculation of Elia uses real CWE D-2 data with hourly granularity.

→ A north to south loop of flows not resulting from capacity allocation can be observed on the border between HU – SK and HU – SHB.

For the remaining borders, e.g. most of the Nordic and Baltic region, the PTDF flow indicator provides results in the lower range.

27 Cross-border allocation on the bidding zone border between Austria and Germany (see Decision of ACER on CCR from 11/2016) is expected to start as of 1 October 2018.

4 CONGESTION INCOME AND FIRMNESS COSTS

Congestion income indicates how much market participants value the possibility for cross-border trade, how interconnections are used and where capacity might be increased. The firmness costs are distinguished between financial and physical firmness costs. Congestion income and firmness costs have relevance with regard to bidding zones as they indicate to some extent the internal and cross-border congestions.

4.1 CONGESTION INCOME

Congestion income refer to the revenues received as a result of capacity allocation[28] (long-term, day-ahead and/or intraday; explicit or implicit) and the revenues are shared between involved TSOs, according to the CID methodology which has to facilitate the efficient long-term operation and development of the electricity transmission system and the efficient operation of the electricity market of the Union, comply with the general principles of congestion management provided in the Article 16 of Regulation (EC) No 714/2009, allow for reasonable financial planning, be compatible across time-frames and establish arrangements to share congestion income deriving from transmission assets owned by parties other than TSOs.

The total yearly income was acquired on a country level for 2015, 2016 and 2017 and the revenues are presented in the graphs below. The income was gathered on a country and on a border level for those borders where capacity allocation mechanisms exist. For the few countries (Italy, Norway, Sweden, Denmark) which have more than one bidding zone, the internal congestion income are represented at the top of bar.

The congestion income received on a specific border does not explicitly describe the situation regarding the congestion on that border. Indeed, the income depends on many factors:

- → development of prices in the individual countries (this is dependent on load/demand/RES infeed/generation park/weather conditions and can change from year to year)
- → price difference between countries (is it more or less interesting to trade with country A than with country B?)
- → amount of capacity made available to the market → this impacts the prices but also determines the volume that can be traded (so a lower volume, but due to reduced capacity maybe a higher willingness of traders to pay more)
- → grid investments (may lead to more cross-zonal capacity on a specific border to be offered to the market and may lead to lower prices)
- → method of capacity allocation (implicit vs explicit, where implicit leads to higher price convergence and thus to lower price difference)
- → the number of borders a country has to other borders (the more borders you have the more congestion income you may receive, so high income does not automatically mean that a country is more congested than another country)
- → new interconnectors (not yet existing borders, like new HVDC lines) may lead to new congestion income and thus to more total congestion income (so more cross-zonal capacity does not automatically lead to reduced congestion income)

A short analysis goes with each graph. This analysis is completed by an assessment done by the TSOs at the end of the section.

28 In accordance with article 2.16 of the CACM Regulation

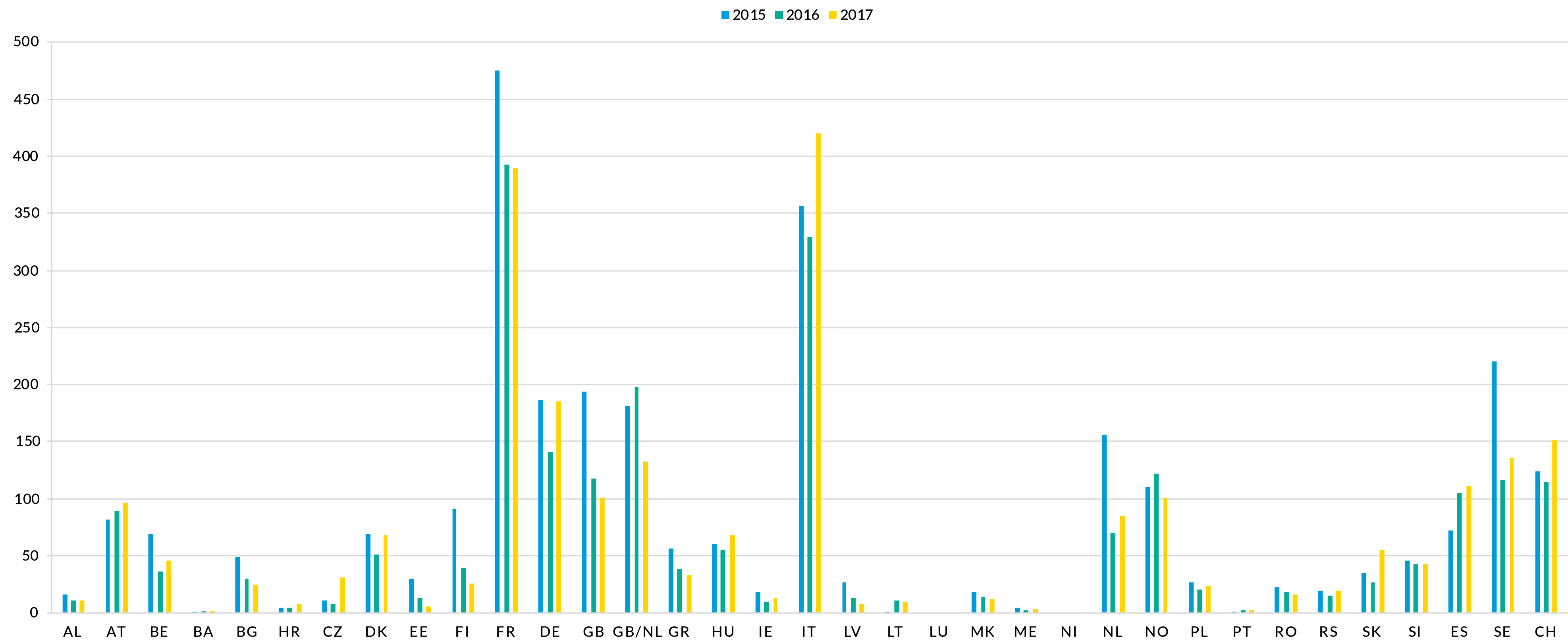


Figure 81: Congestion Income for the years 2015 – 2017 (mln EUR)

From the graph above it can be seen that very high congestion revenues were received in France, Italy, Great Britain, Germany, Sweden and Switzerland. In most of these countries, the congestion revenues are decreasing.

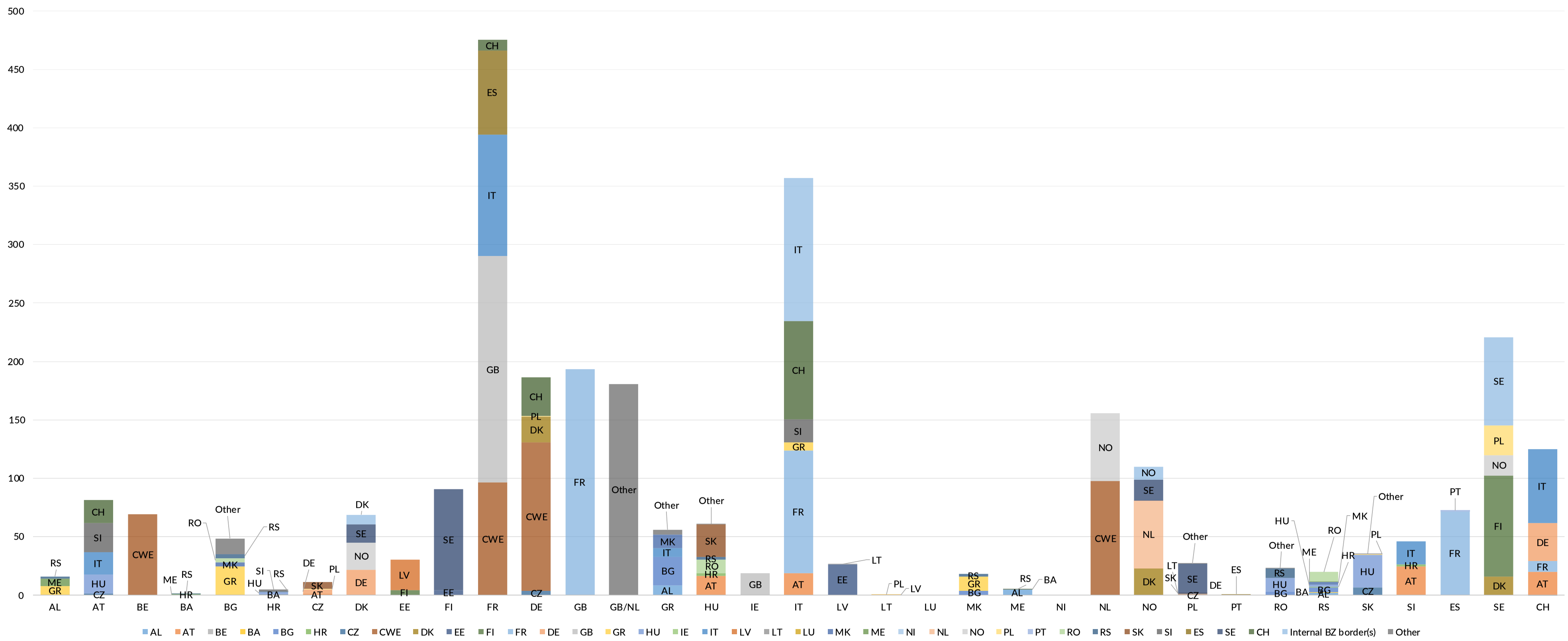


Figure 82: Congestion Income 2015 (mln EUR)

As can be seen from the graph for 2015, FR, GB and IT are receiving the major amounts of congestion income from the capacity allocation process far above other countries such as SE, DE and NL. In countries IT, GB as well as SE, major parts are also composed by internal congestions. Congestion incomes for CWE countries include revenues from the FB DA allocation and long-term allocation. As the revenues from FB DA allocation cannot be split per border, only a total value of congestion income for all the CWE borders can be displayed for the concerned countries.

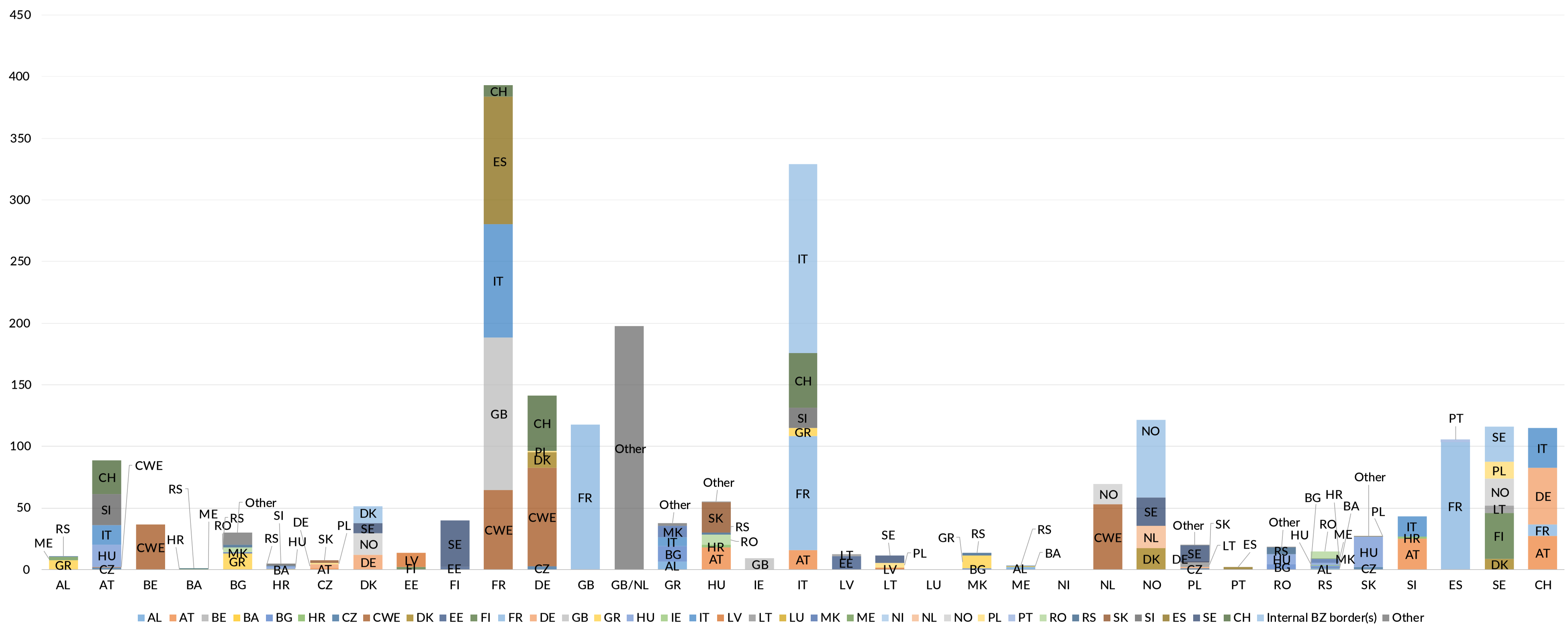


Figure 83: Congestion Income 2016 (mln EUR)

As can be seen from the graph for 2016, FR, GB and IT are still having the major amounts of congestions income from the capacity allocation process far above other countries such as SE, DE and NO.

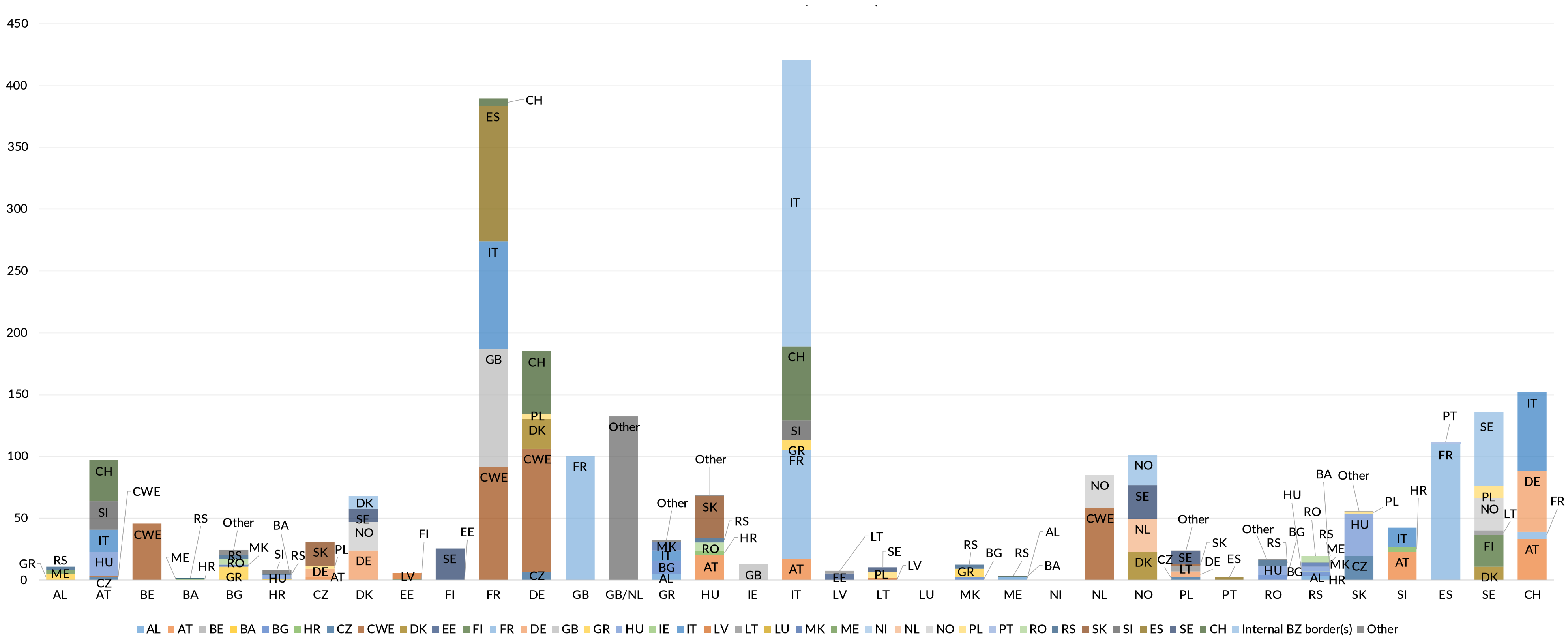


Figure 84: Congestion Income 2017 (mln EUR)

As can be seen from the graph for 2017, FR, GB and IT are still having the major amounts of congestion income from the capacity allocation process far above other countries such as SE, DE and NO.

4.1.1 SUMMARY AND COMMENTS FROM TSOs FOR CONGESTION INCOME

The Congestion income sub-chapter is prepared according to the requirements stated in the Article 34 of the CACM Regulation. The Congestion income revenues part present the total yearly incomes on a country level for three different years and on a border level for those borders where capacity allocation mechanisms exist.

For the countries which have more than one bidding zone, the internal congestion revenues are presented separately, adding those on the top of all other revenues per cross-border. The congestion income revenues fluctuate from year to year and there is no clear trend. The congestion income received on a specific cross-border does not explicitly describe the situation directly regarding the congestion on that cross-border because the income is dependent on many factors within and around particular bidding zone. The impacting factors could be different in each case and specific ones are not possible to highlight. The specific comments about congestion incomes for some countries are briefly provided below.

AUSTRIA

Since 2016 APG is part of the CWE CCR. Thus, APG receives a fixed part of 3.5 % of external flow part DE – AT.

BELGIUM

Since the CWE FB Go-Live date (20 May 2015 with first delivery date on 21 May) congestion income allocation is performed according to the Capacity Calculation Region formulas for the purpose.

BULGARIA

For the period 2015 – 2017, the majority of congestion income is on the Bulgarian-Greek border, while there is a significant decrease on the Bulgarian-Turkish border.

ESTONIA

The EE–LV cross-border is the most congested cross-border within the Baltic States. The sum received has been reduced due to the commissioning of the NordBalt HVDC cable between Lithuania and Sweden.

FINLAND

Congestion income is primarily generated from exchanges on the interconnectors linking the Finnish and Swedish power markets. The amount of congestion income is heavily dependent upon the availability of hydropower generation in Norway and Sweden (which in turn is dependent on the amount of rainfall in any given year). A high availability of hydropower such as in 2015 increases price differentials between the Finnish and Swedish power markets and consequently drives higher congestion revenues. The number of hours of price differentials between Finland and Sweden is expected to decrease once the Olkiluoto 3 nuclear unit enters commercial operation and the new interconnector between Finland and Sweden is commissioned.

FRANCE

After a spike in 2015, the French congestion income decreased to reach 390 M€ in 2017. It is balanced between all the borders, except with Switzerland, due to the historical long-term contracts that give priority and free access to the capacity.

GREECE

For the Greek borders with TERNA, ESO, MEPSO and OST, the majority of the congestion income is at the border with ESO (GR-BG border) for all years, while the shares of the other borders are close depending on the year under consideration.

HUNGARY

Congestion income was relatively stable over the years. Mainly the Austrian, Slovak and Romanian border contributed to the total income.

LATVIA

In the area of Latvia, the congestion income is collected on the cross-border EE – LV and very rarely and in small part on the cross-border LV – LT. As EE – LV is the weakest cross-section within the Baltic States, the congestion income occurred mainly on this cross-border and the price difference between two bidding zones remains. Since 2016, when NordBalt HVDC cable with a capacity of 700 MW between SE – LT has been in operation, the amount of congestion income on cross-section EE – LV has been reduced and Latvian TSO is looking forward to strengthening and increasing the capacity on cross-border EE – LV to eliminate congestion revenues.

LITHUANIA

In Lithuania, congestion income is generated from exchanges on cross-borders between LV – LT, PL – LT and SE – LT. The smallest part on congestion income comes from the cross-border between LV – LT and has taken only 1 % of all Lithuania congestion income in 2018. Major congestion income of Lithuania comes from cross-border connections 500 MW LitPol Link and 700 MW NordBalt – from the beginning of 2018 it was 43 % and 55 % accordingly of all Lithuania congestion income. Even though LitPol Link capacity is lower by 200 MW than NordBalt, the congestion revenue on both connections is on the same level. The main reason for this is a higher price difference between Poland and Lithuania power markets than Sweden and Lithuania.

PORTUGAL

Congestion income in the PT-ES border is low since the level of price convergence in that border has been above 90 % in a three-year study.

SPAIN

Spain experienced higher congestion incomes in 2016 and 2017 than in 2015. This is primarily a result of the commissioning of a new interconnector between France and Spain in October 2015 that almost doubled the cross-zonal capacity between these two countries. Regarding the distribution of the Spanish Congestion Income between borders, around 98 % is generated in the FR-ES border due to the big price difference in both DA markets. This is a clear indicator of the lack of cross-zonal capacity between France and Spain. On the other hand, congestion income in the PT-ES border is low since the level of price convergence in that border has been above 90 % in a three-year study.

SWEDEN

The explanation for Sweden's fairly high congestion revenues are high power exchange from/to neighbouring countries and the fact that Sweden is divided in four bidding zones according to structural bottlenecks, which generate internal congestion revenues.

4.2 FIRMNESS COSTS

According to CACM Regulation, 'firmness' means a guarantee that cross-zonal capacity rights will remain unchanged and that a compensation is paid if they are nevertheless changed. For the purpose of this report it was assumed that firmness costs are related not only to cross-zonal aspects but also to internal redispatch actions taken by TSOs.

Furthermore, financial and physical firmness costs were distinguished between:

- **Financial firmness costs**
  If there is curtailment of assigned cross-zonal capacity rights, compensation is paid. Different compensation cases and rules are defined in the European regions.
- **Physical firmness costs**
  As redispatch measures are taken to accommodate a secure flow resulting from all transactions in a bidding zone, it is not always possible to make a clear distinction between measures taken for the firmness of cross-border capacity or internal capacity. While it is not possible, all redispatch costs are included in the figures for physical firmness. Possible types: internal redispatch, cross-border redispatch, counter trading, other defined by TSO.

4.2.1 FINANCIAL FIRMNESS COSTS

The comparability of financial firmness costs are affected by the differences in the detailed auction rules. The detailed auction rules for Member States of EU have been set in harmonised allocation rules for long-term transmission rights in accordance with Article 51 of Commission Regulation (EU) 2016/1719 establishing a guideline on Forwards Capacity Allocation in 2016 (hereafter referred to as 'HAR')[29]. The HAR takes into account the general principles, goals and other methodologies set out in the Regulation (EU) 2016/1719 and these Allocation Rules, also including the related regional and/or border specific annexes, contain the terms and conditions for the allocation of Long Term Transmission Rights on Bidding Zone borders in the European Union.

The HAR contains:

- At least harmonised definitions and scope of applications,
- The description of the allocation process/procedure for long-term transmission rights, including the minimum requirements for participation, financial matters, type of products offered in explicit auctions, nomination rules, curtailment and compensation rule, rules for market participants in case they are transferring their long-term transmission rights, the use-it-or-sell-it principle, rules as regards force majeure and liability,
- regional or bidding zone border specific requirements with regard (but not limited) to the description of the type of long-term transmission rights which are offered on each bidding zone border within the capacity calculation region,
- the type of long-term transmission rights remuneration regime to be applied on each bidding zone border within the capacity calculation region according to the allocation in the DA time frame,
- the implementation of alternative coordinated regional fallback solutions,
- the regional compensation rules defining regional firmness regimes.

HAR contributes to the efficient long-term operation and development of the electricity transmission system and electricity sector in the EU, as they optimise allocation of long-term capacity, reflecting congestion on all EU borders in an efficient way.

The different compensation cases and the associated compensation rules differentiate, for example, between 'force majeure', emergency situations/safety of power system or other costs for financial firmness. The related financial firmness costs were delivered on a TSO level for 2015, 2016 and 2017 and they are represented as total financial firmness costs, firmness costs by border and financial firmness costs by reason for curtailment. All graphs are available below.

Please note that financial firmness costs are usually shared between the involved TSOs, but not always to a 50/50 principle. The costs that country A had to pay for border A/B needs to be added to the costs that country B had to pay for border A/B in case of curtailment. Costs are reported on a TSO basis.

A short analysis goes with each graph. This analysis is completed by an assessment done by TSOs at the end of the section.

29 https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/ANNEXES_HAR_DECISION/Annex%20I_171002.pdf

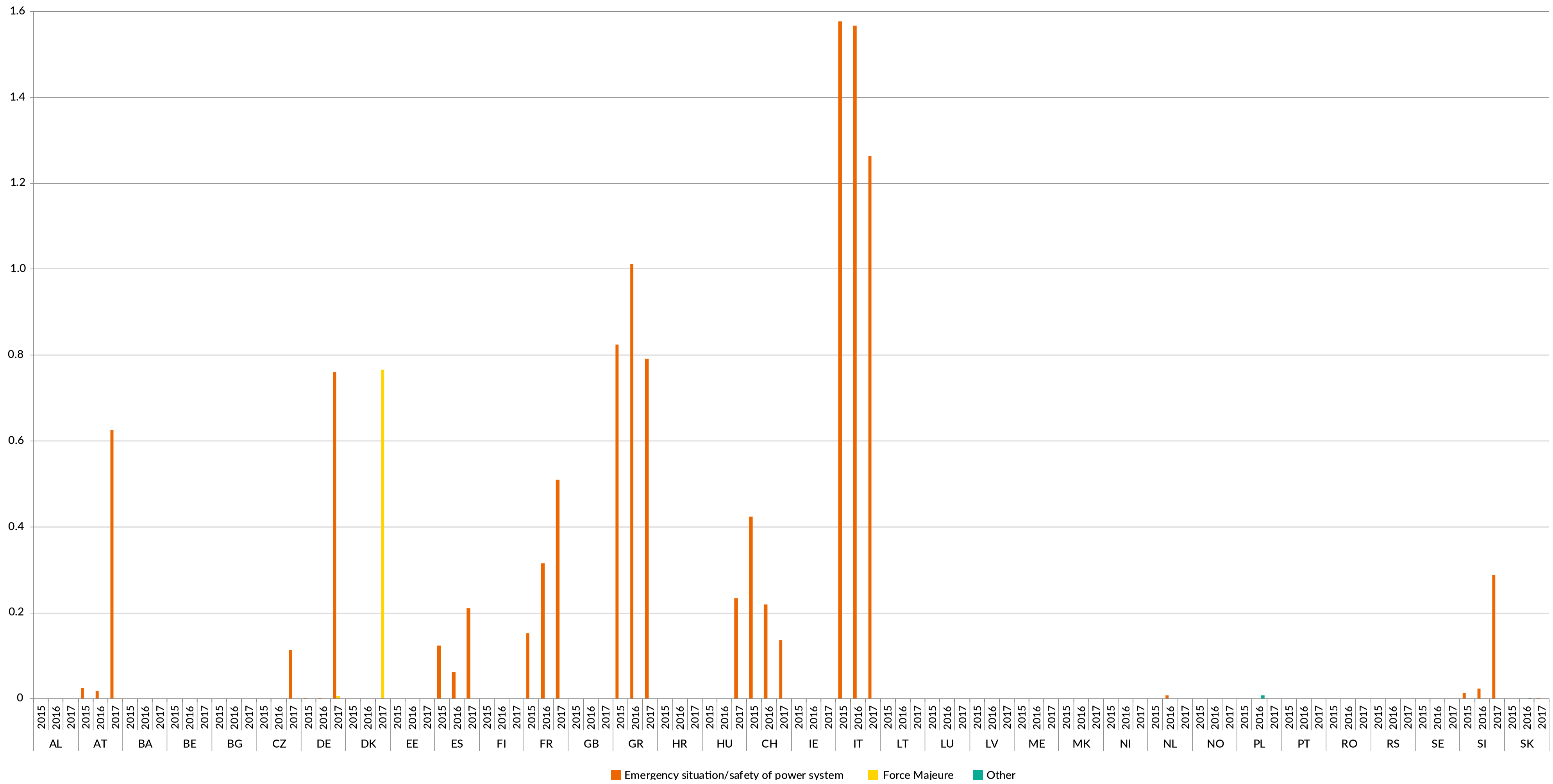


Figure 85: Total financial firmness costs for the years 2015 – 2017 (mln EUR)

As can be seen from the graph above, most of the costs paid in order to ensure the financial firmness of cross-border capacity in the years 2015-2017 are due to curtailments caused by emergency situations or safety of the power systems. Only in 2017 was there a force majeure issue in Denmark. There is no clear trend recognisable when comparing years. Over the three years, Greece and Italy had the highest financial firmness costs.

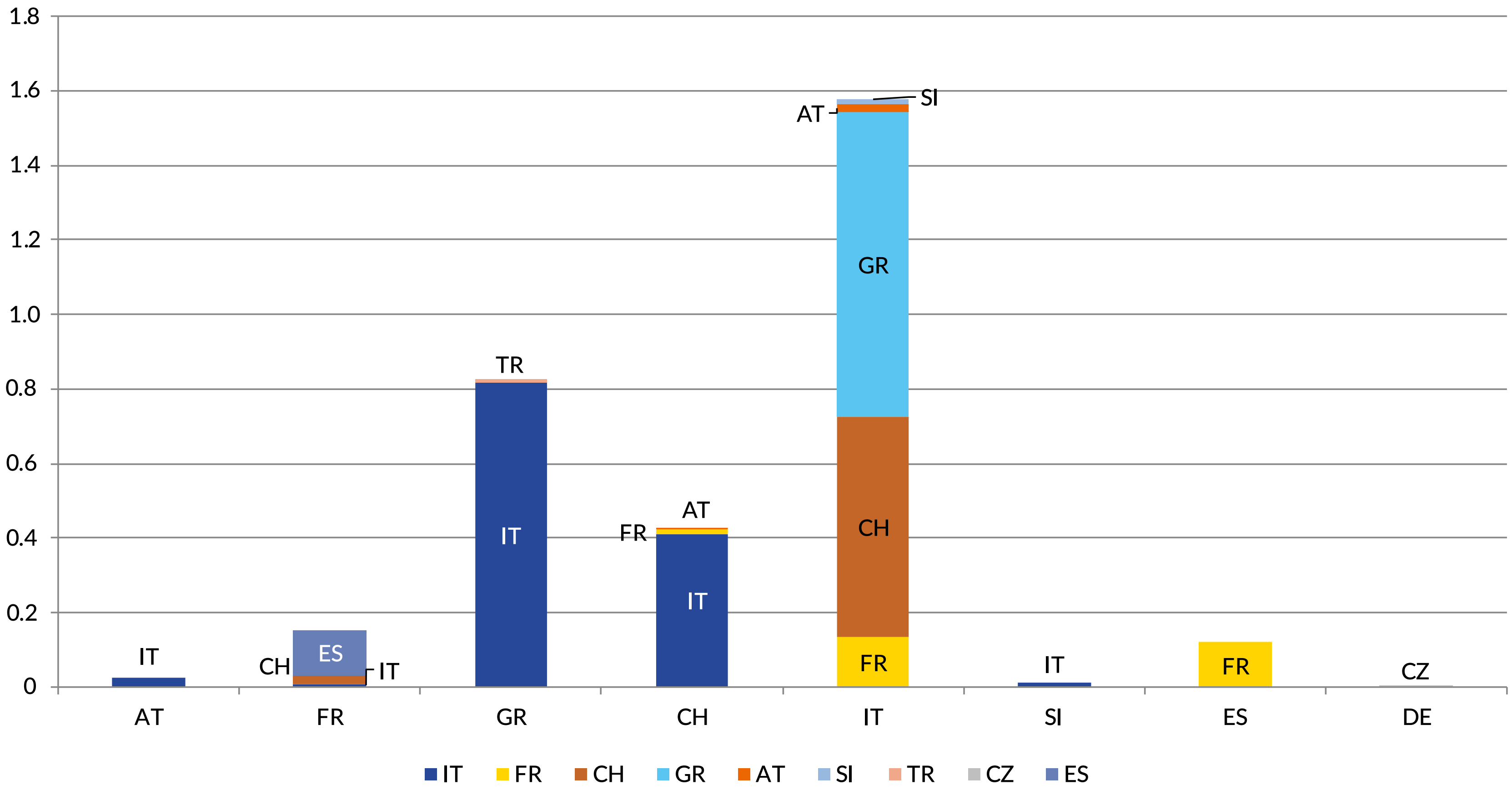


Figure 86: Financial firmness costs by border, 2015 (mln EUR)

The detailed representation of total financial firmness costs by border has been shown only for the countries which have applied the financial firmness in 2015. It is observed that the highest volume of financial firmness has been applied for cross-borders with Italy. The highest financial firmness costs are on cross-borders IT–GR and IT–CH. The rest of the financial firmness costs are rather small and insignificant.

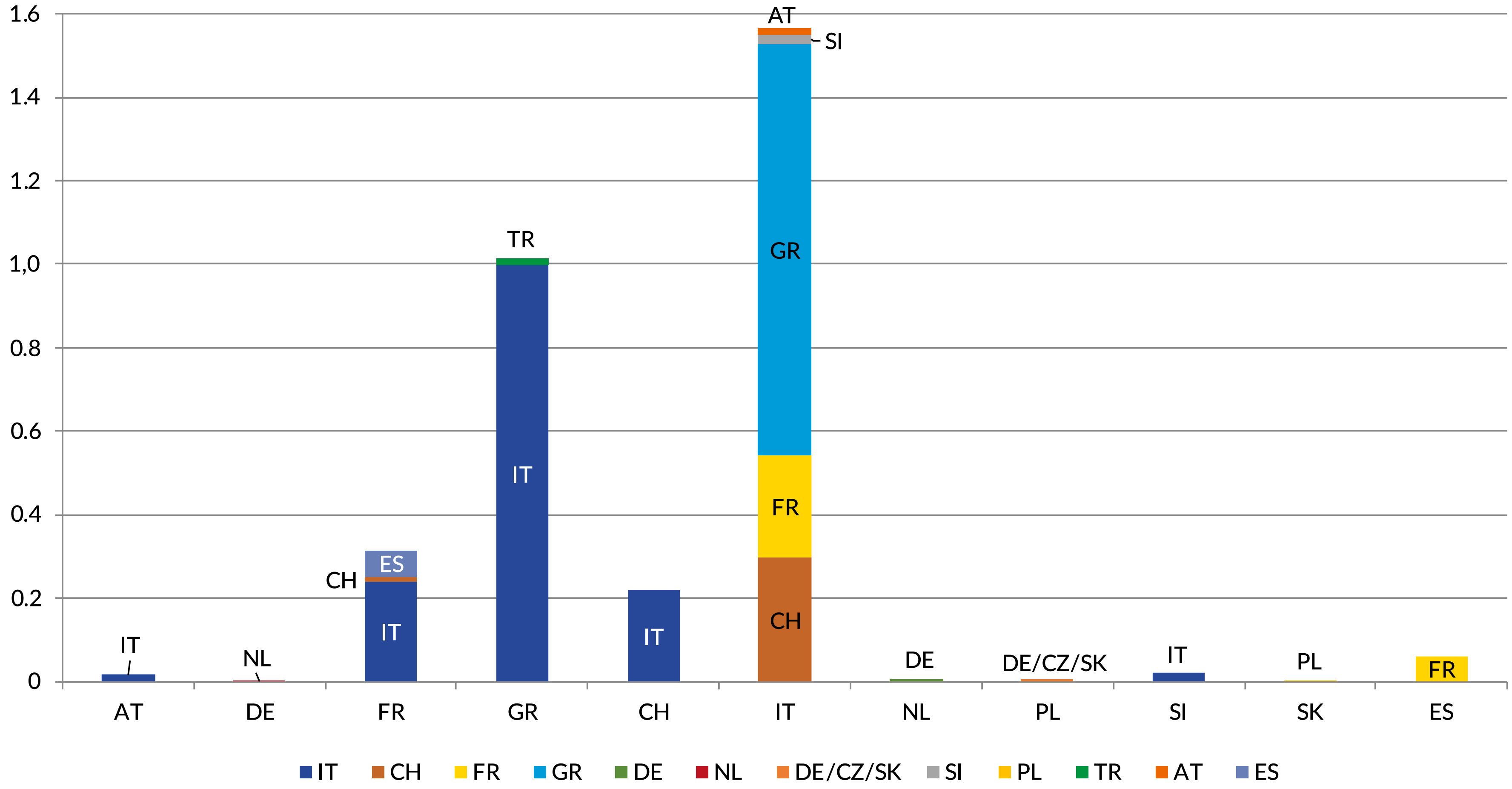


Figure 87: Financial firmness costs by border, 2016 (mln EUR)

The detailed representation of total financial firmness costs by border has been shown only for the countries which have applied the financial firmness in 2016. The highest financial firmness costs are on the cross-borders IT – GR and IT – CH and for the rest of the countries, the financial firmness costs are rather small and insignificant.

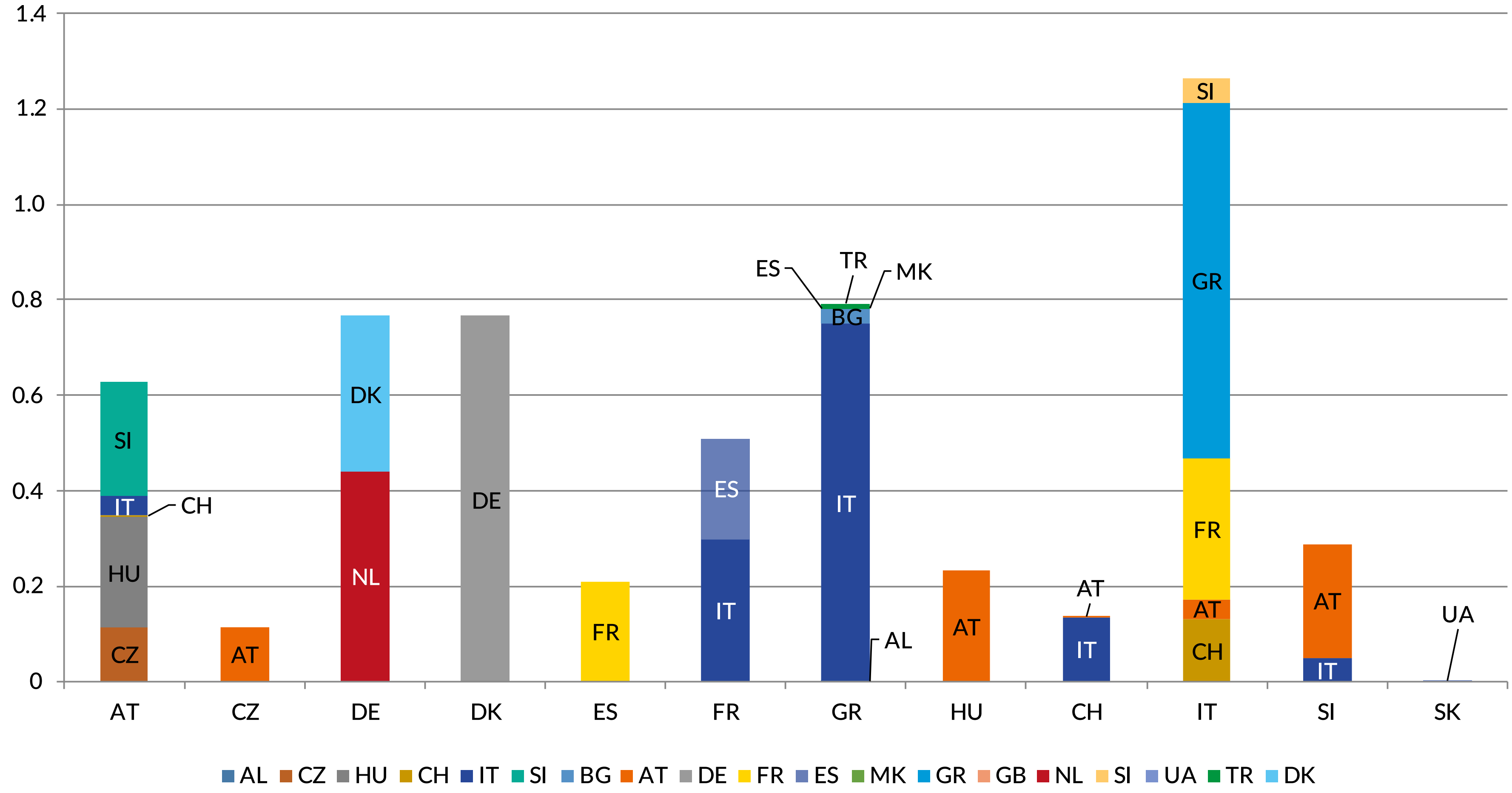


Figure 88: Financial firmness costs by border, 2017 (mln EUR)

The detailed representation of total financial firmness costs by border has been shown only for the countries which have applied the financial firmness in 2017. In 2017 the financial firmness costs are reducing in general and Italy is still a leading country keeping very high financial firmness costs on different cross-sections. The highest figures have been observed on cross-sections IT – GR, DK – DE, HU – AT and AT – SI. The rest of the financial firmness costs are rather small and insignificant compared to others.

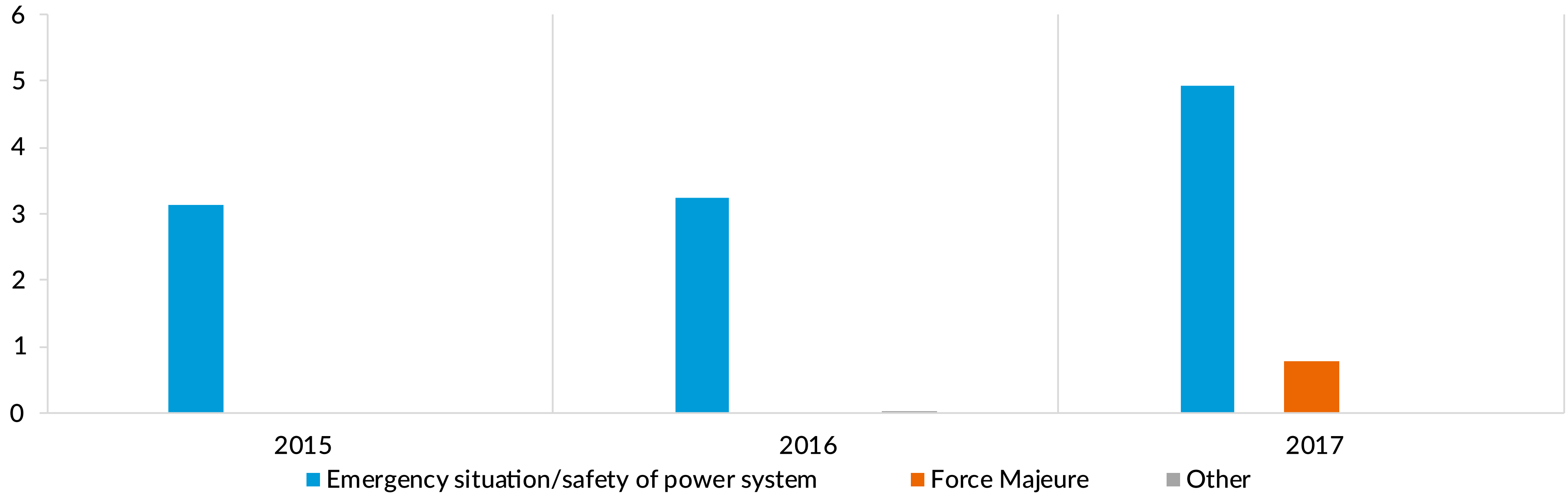


Figure 89: Financial firmness costs by reason for curtailment (mln EUR)

As can be seen from the graph above, most of the costs paid in order to ensure the financial firmness of cross-zonal capacity are due to curtailments caused by emergency situations or safety of the power systems. Only in 2017 have there been costs associated to curtailments due to force majeure. The highest financial firmness costs are registered in 2016.

4.2.2 SUMMARY AND COMMENTS FROM TSOs FOR FINANCIAL FIRMNESS COST

The financial firmness costs sub-chapter is prepared according to the requirement stated in Article 34 of CACM. The financial firmness costs are affected by detailed auction rules set in HAR for long-term transmission rights in accordance with Article 51 of Commission Regulation (EU) 2016/1719 establishing a guideline on Forward Capacity Allocation in 2016. The HAR contributes to the efficient long-term operation and development of the electricity transmission and electricity sector in the EU. The financial firmness was delivered for three years as total amounts and they differentiate between force majeure, emergency situations/safety of power system and others. However, they are presented for three years by costs per cross-border as well as by reason for curtailment.

AUSTRIA

In 2017, JAO cancelled a one day ahead auction at the CEE borders of Austria due to technical problems. The resulting costs were classified as firmness costs by APG. This led to higher firmness costs compared to the two years before.

BELGIUM

During 2015, Belgium applied for Financial Firmness the Rules for Capacity Allocation by Explicit Auctions Version 2.0, as from then on (2016 and following years), Belgium applies the most updated version of the HAR. Please note that there have been no curtailments during the period 2015 – 2017 at the Belgian borders. Consequently, there have been no financial firmness costs or volumes.

BULGARIA

For the period 2015 – 2017, ESO did not apply curtailment to any border and respectively did not pay compensation to market participants.

DENMARK

It is worth noting that the reason for the financial firmness cost on DE – DK, which in reality only covers the Kontek connection between Energinet and 50Hertz, is different between Denmark and Germany in that a third party owns 1/3 of the connection. The share of cost that is to be covered by the third party is firstly covered by Energinet and thereafter transferred to the third party.

FRANCE

Financial firmness costs in France represent small amounts in comparison with the high amounts of congestion income. The costs incurred following unplanned outages of the DC interconnectors between France and Great Britain are not taken into account.

GREECE

For the Greek borders, almost all the financial firmness cost and the relative volumes are with the DC cable with Italy (almost 99 % for 2015/2016 and around 95 % for 2017); this is due to the tripping of the cable and the curtailment of cross-border exchanges which follow.

HUNGARY

Hungary had a curtailment once in 2017 when the capacity on the AT – HU border was reduced. There has been no other case registered in the time period 2015 – 2017.

ITALY

From 2015 till 2017, the highest values of financial firmness costs and volumes occurred on the IT – GR border. Since the interconnection between Italy and Greece is composed by only one HVDC cable, planned and unplanned outages of the link required the application of curtailment measures to ensure system security.

LITHUANIA

NA to Lithuania: there were no explicit capacity auctions and no LTTR offered on any of the Lithuanian borders throughout 2015 – 2017, hence no financial firmness costs applied to Lithuanian cross-borders.

SPAIN

During 2015, REE applied HAR 2.0 but only for the FR – ES border, as from 2016 REE is applying HAR for both borders. In the three year study period, REE has only applied curtailments in the FR – ES border. The curtailed volume is very small in comparison with the total offered capacity (less than 1 %) and it was only applied due to the safety of the power system. The curtailed capacity has been compensated at positive market spread. This amount is deducted from congestion income.

SWEDEN

Sweden does not apply financial firmness.

4.3 PHYSICAL FIRMNESS COSTS

In this Technical Report, physical firmness costs cover both internal and cross-border remedial actions done by TSOs.

Physical firmness costs are related to measures done by TSO(s) that guarantee unchanged cross-zonal capacity rights. This can be achieved by remedial actions such as topological changes or by changing the generation and/or load pattern (redispatch and countertrade).

In addition to guaranteeing unchanged cross-zonal capacity rights, there may also be measures needed in order to solve internal congestions within a bidding zone. For this report, this is considered as part of physical firmness costs.

Each TSO delivered the costs for 2015, 2016 and 2017. Cost categories for internal redispatch, cross-border redispatch and counter trading were given. Additional types of costs could be added by the TSOs if applicable and they are included under the category 'Other'. TSOs reported for renewable curtailment and the activation of grid reserve in this category.

A cross-border redispatch means redispatch measures activated across zones including multilateral redispatch. Internal redispatch means redispatch measures activated within the Bidding Zone. Please note that an internal redispatch is not only used for internal congestions but can also be used to alleviate cross-border congestions (e.g. in a meshed grid the elements considered for capacity calculation is not only the 'interconnector' itself but eventually some more surrounding grid elements that can be congested and would impact the cross-zonal capacity). On the other hand, a cross-border redispatch can also help in case of an internal congestion with cross-border relevance.

It has to be noted that the comparison of the delivered costs can only be indicative. There are substantial differences between the different countries (see comments from TSOs).

Among other points, this relates to:

- the categorisation of measures as physical firmness measures
- the interdependency on other grid management measures (e.g. congestion management, voltage control, balancing)
- the trigger for the measures (e.g. local vs. regional congestion)
- the monitoring of measures and related costs
- regulatory, system dispatch and market arrangements for the determination of redispatch costs
- the availability of power plants and the respective cost structure and availability of alternatives to the TSOs (e.g. topology measures)

The costs shown in the figures below represent the sum of the costs for cross-border redispatch measures (redispatch measures activated across zones including multilateral redispatch), countertrading and internal redispatch measures (redispatch measures activated within a zone with netted costs of increased generation and revenue from decreased generation). A short analysis goes with each graph. This analysis is completed by an assessment done by TSOs at the end of the section.

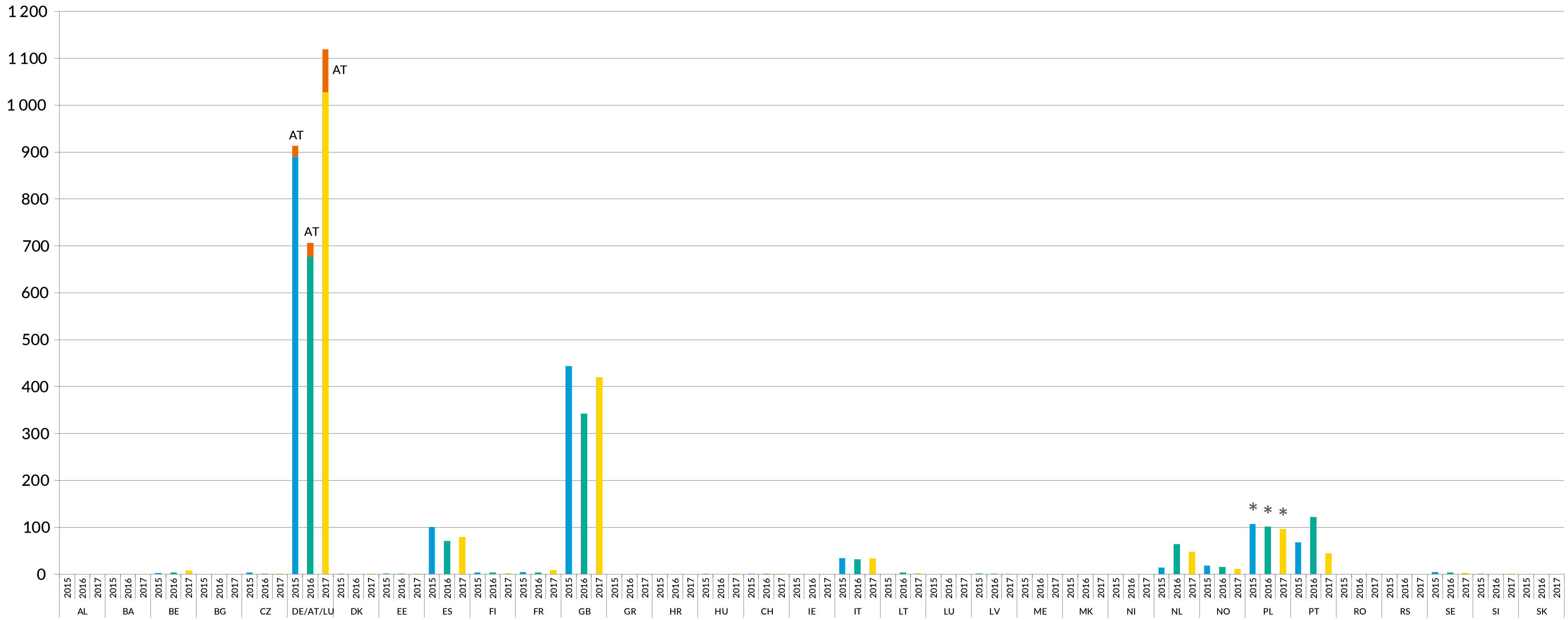


Figure 90: Total physical firmness costs for the years 2015 – 2017 (mln EUR)

As the graph shows, the highest physical firmness costs belong to the DE/AT/LU bidding zone which is then followed by Great Britain. Physical firmness costs for Poland[30], Portugal, Spain and Netherlands are relevant but of lower magnitude.

30 * Due to the fact that PSE applies ISP, cost and volume reported by PSE cover the whole ISP i. e. not only congestion management and thus reported cost and volume should be deemed as strongly overestimated. For a more detailed explanation, see s. 4.3.1.

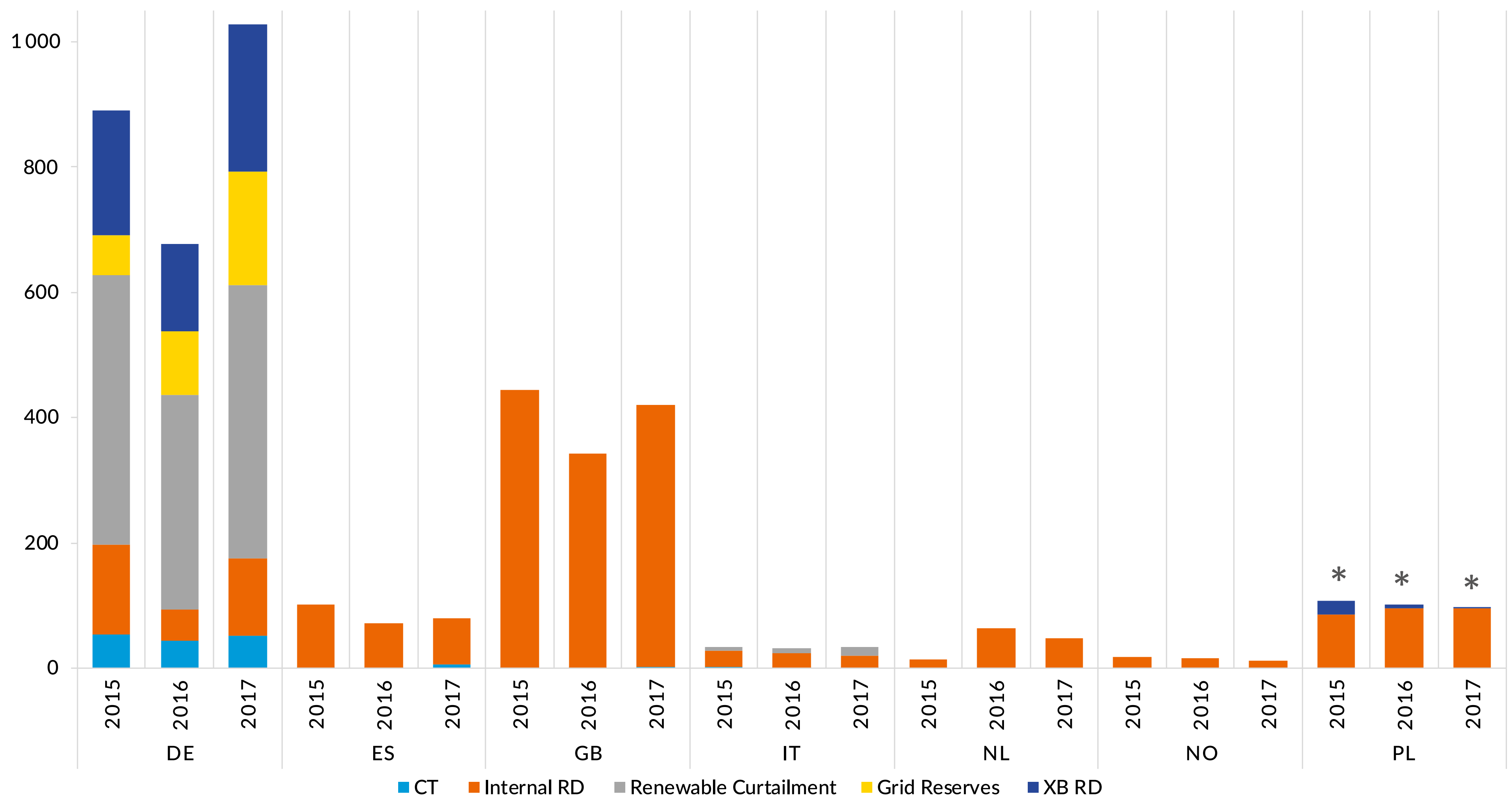


Figure 91: Physical firmness costs by measures applied, mln EUR (1/2)

This graph shows the countries which have reported highest physical firmness costs over the years 2015, 2016 and 2017 (over 10 m€). Most of the costs paid in order to ensure the physical firmness are due to internal redispatches, except for DE and AT. In general there is a big dispersion in the values over the years, no statistically significant tendencies are observed. The country which has registered highest physical firmness costs, regardless of its demand, is DE. This is mainly due to Renewable Curtailment compensation.[31]

31 * Due to the fact that PSE applies ISP, cost and volume reported by PSE cover the whole ISP i. e. not only congestion management and thus reported cost and volume should be deemed as strongly overestimated. For a more detailed explanation, see s. 4.3.1.

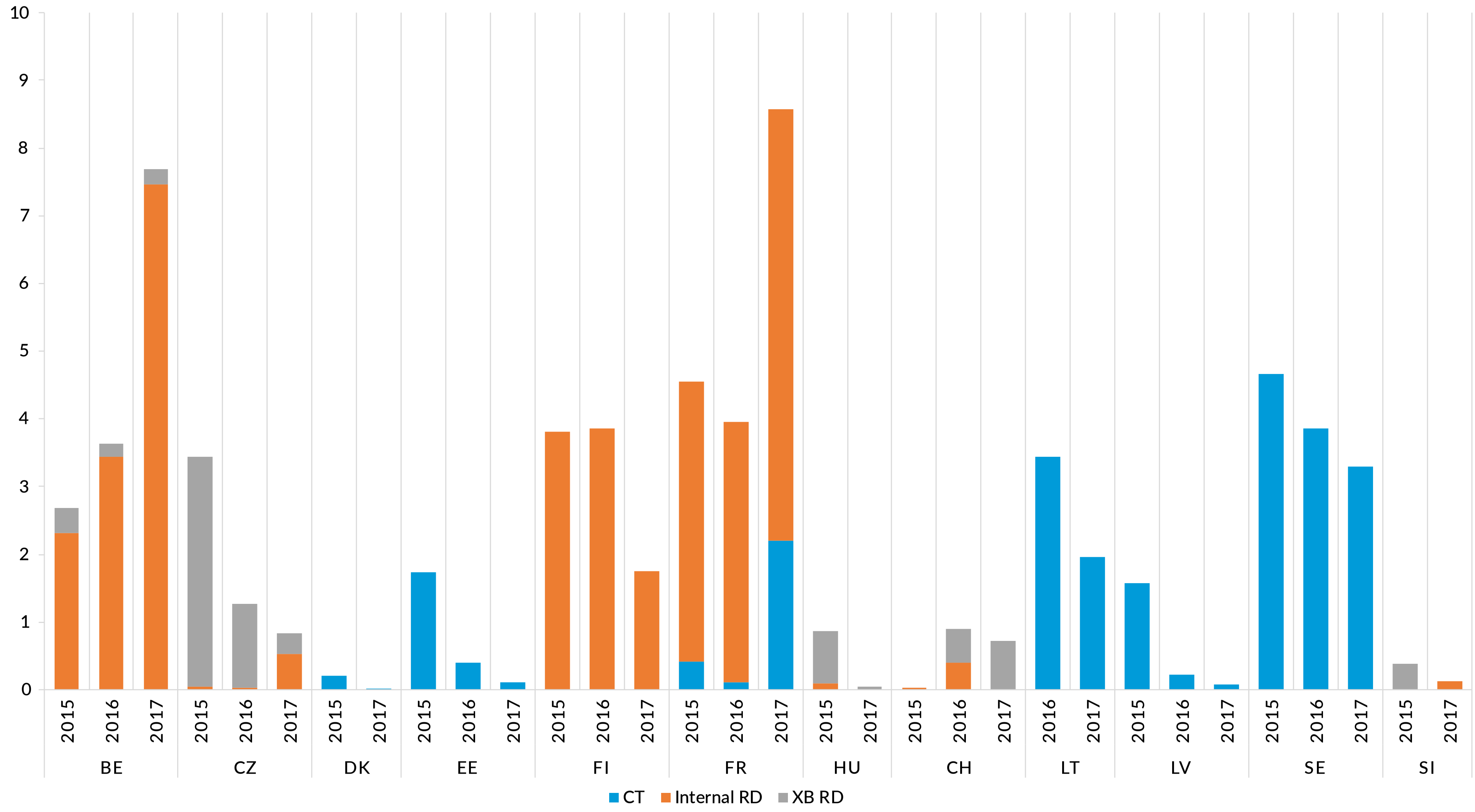


Figure 92: Physical firmness costs by measures applied, mln EUR (2/2)

This graph shows the countries which have reported lowest physical firmness costs over the years 2015, 2016 and 2017 (below 10 m€). There is a big dispersion in the measures applied by the TSOs in order to ensure physical firmness. Most of the costs paid by FR, BE and FI are due to internal redispatches while for DK, EE, LI, LV and SE are due to Countertrading. There is also a big dispersion in the values over the years; no statistically significant tendencies are observed. The country which has registered lowest physical firmness costs, regardless of its demand, is DK.

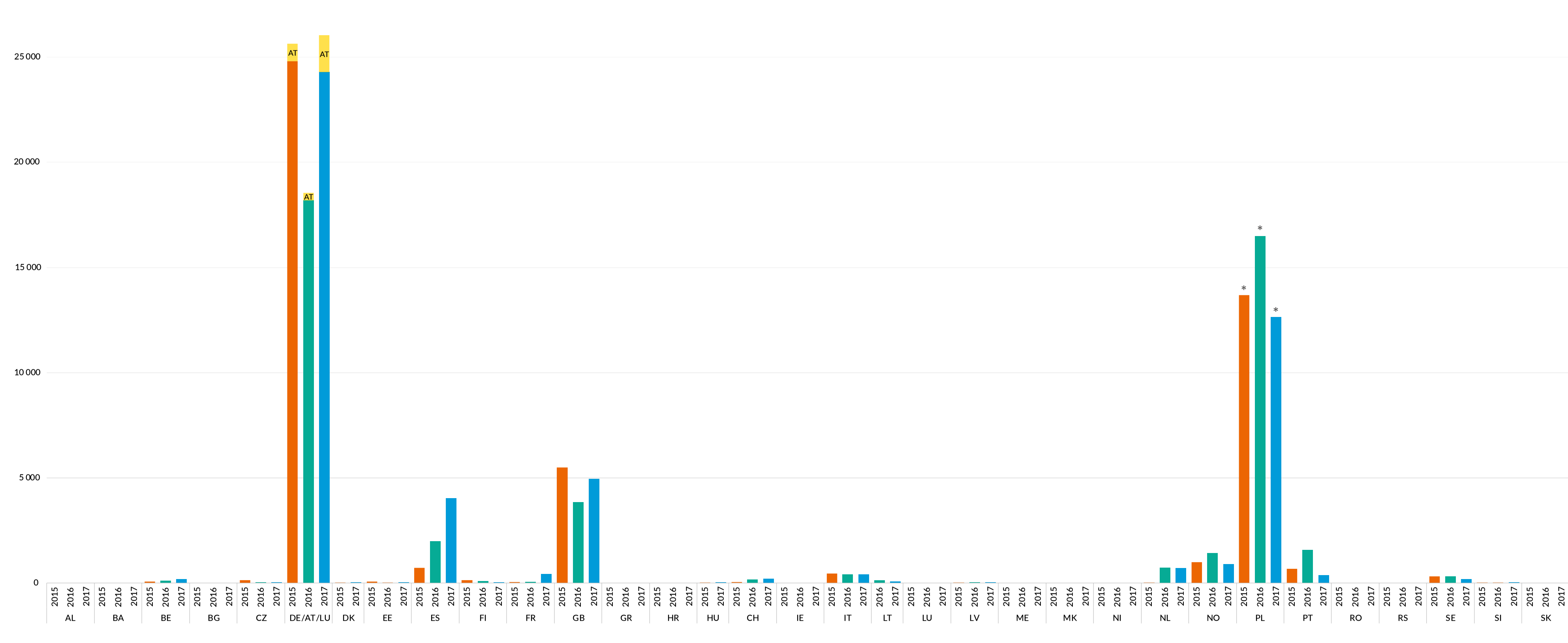


Figure 93: Total volume of measures applied for the years 2015 – 2017 (GWh)

DE/AT/LU bidding zone and Poland[32] show the largest total volume of measures applied in all three years, followed by Great Britain.

The total volume across all other zones and years was up to 1.6 TWh.

32 * Due to the fact that PSE applies ISP, cost and volume reported by PSE cover the whole ISP i. e. not only congestion management and thus reported cost and volume should be deemed as strongly overestimated. For a more detailed explanation, see s. 4.3.1.

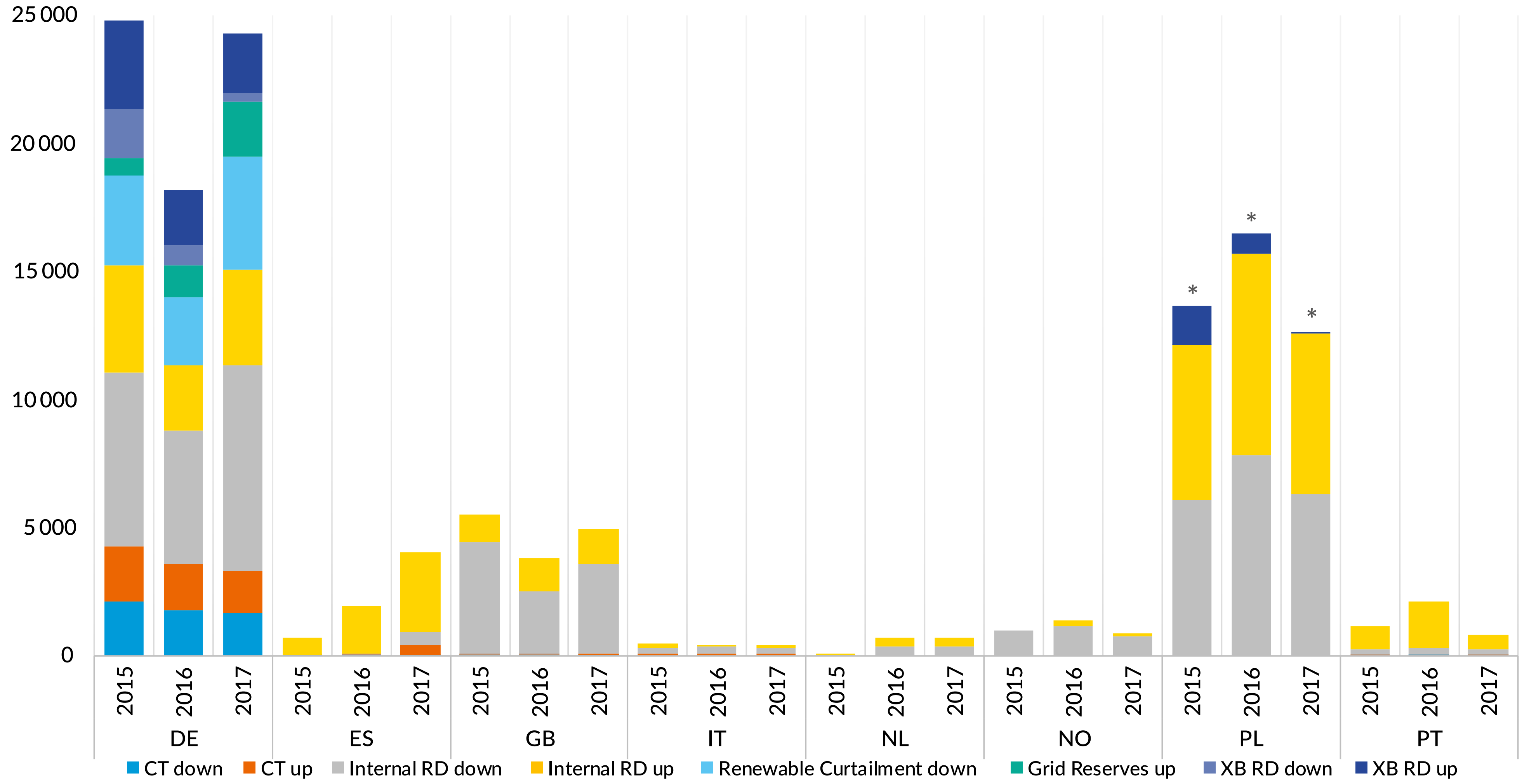


Figure 94: Total volume of measures applied, GWH (1/2)

The Figure shows evolution of (total) volumes of activated remedial actions for different categories. By far the highest total volume can be observed in the case of Germany (on the level of 20 TWh/year or more), followed by Poland[33] (around 15 TWh/year).

33 * Due to the fact that PSE applies ISP, cost and volume reported by PSE cover the whole ISP i. e. not only congestion management and thus reported cost and volume should be deemed as strongly overestimated. For a more detailed explanation, see s. 4.3.1.

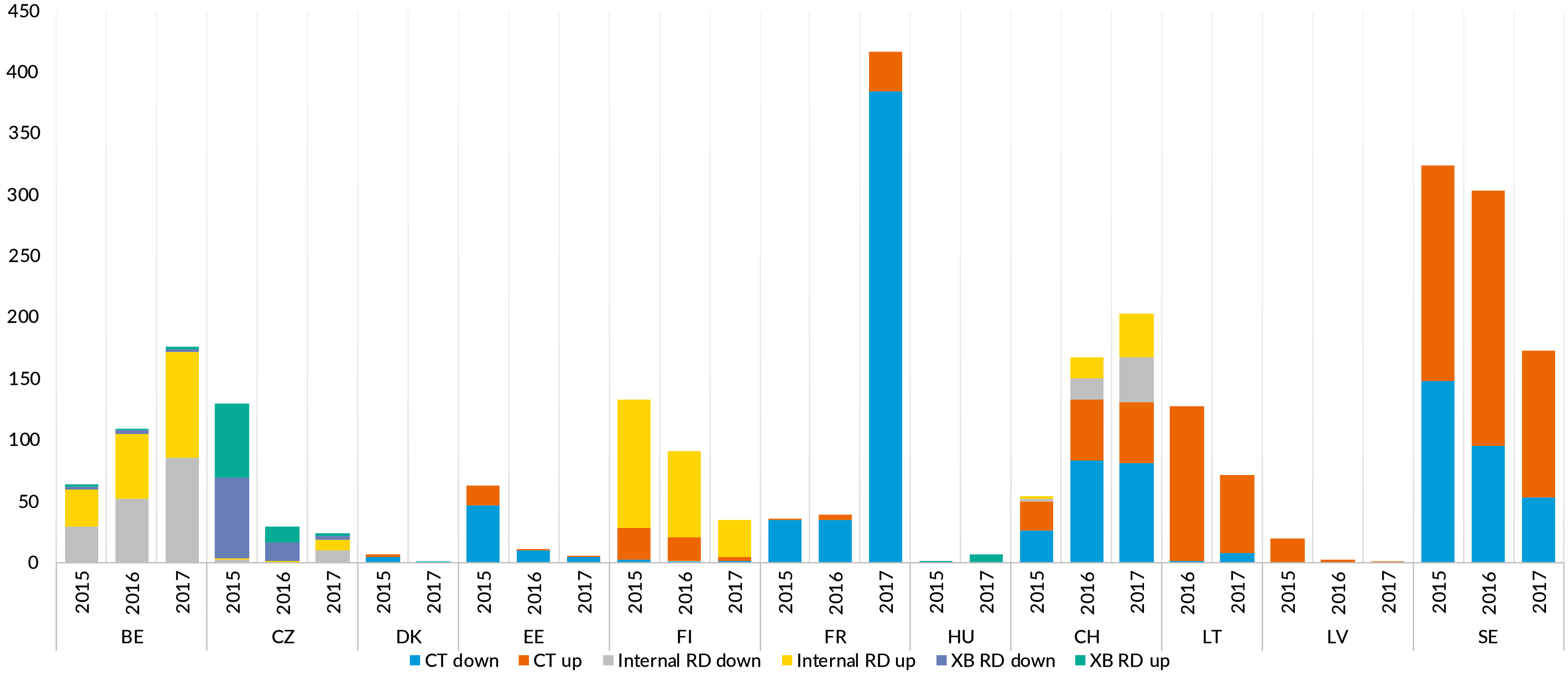


Figure 95: Total volume of measures applied (2/2)

The Figure shows evolution of (total) volumes of activated remedial actions for different categories less 500 GWh/year. A spike of the volume of countertrading can be observed in France in 2017 (cca 400 GWh), this represents 8× values from 2015 and 2016. A decreasing tendency can be observed in Sweden towards around 150 GWh in 2017.

At the same time, increasing trends may be indicated for Belgium (from cca 60 GWh in 2015 to 180 GWh in 2017) and Switzerland (an increase from cca 50 Wh to 200 GWh in 2017).

4.3.1 SUMMARY AND COMMENTS FROM TSOs FOR PHYSICAL FIRMNESS COSTS AND VOLUMES

The physical firmness costs in the report have been distinguished between internal and cross-border remedial actions to accommodate a secure flow resulting from all transactions in a bidding zone and guarantee unchanged cross-zonal capacity rights. Each TSO delivered the cost categories for 2015, 2016 and 2017 ordered by internal redispatch, cross-border redispatch, counter trading and additional type of costs under the category 'Other', which includes renewable curtailment and the activation of grid reserves. It is important to keep in mind that the comparison of the delivered costs can only be indicative because there are differences between the different countries. In addition to the total physical firmness costs in the report, the physical firmness costs by measures applied are presented. This part is split in two parts and the values are reported for countries with high physical costs and low physical costs comparatively. The costs for physical firmness are being linked to the volumes of measures applied and in the report the total volumes of measures applied is given. Additionally, the detailed amount of volumes per category are presented on a country by country basis. The comments from TSOs about physical firmness costs are briefly presented below.

AUSTRIA

The costs for redispatching in Austria increased from 2015 to 2017. For all years in scope, a big part of the costs were caused by cross-border redispatch. Costs for internal redispatch increased during the period 2015 – 2017. For the period under consideration, most of the redispatch volume was used for the up regulation of cross-border redispatch.

BELGIUM

During the period 2015 – 2017, total redispatch costs in Belgium increased from around 2.7 M€ per year to 7.7M€, which still remains a relatively low figure when compared to the costs of other bidding zones. Within these total cost figures, cross-border redispatch rarely represents more than 250 – 300 K€ per year. There is no counter-trading performed at the Belgian bidding zone borders. Internal redispatch volumes have increased from around 59 GWh in 2015 (half for up-regulation and half for down regulation, roughly) to 171 GWh in 2017 (also rather symmetrical). Cross-border redispatch volumes do not usually exceed 3 GWh per year (and, save exceptions, are also of a rather symmetrical pattern).

BULGARIA

For the period 2015 – 2017, ESO did not perform cross-border re-dispatching with neighbouring TSOs. The coordinated methodology for re-dispatching in SEE region has not been developed by now. ESO used non-costly remedial actions for solving internal congestions.

ESTONIA

Counter-trading costs have gone down due to the EE – LV cross-border being less congested. During later years, the outages of HVDC links have been less problematic.

FINLAND

During 2015 – 16, countertrade costs were above average due to several challenging transmission line construction projects on the west coast of Finland and numerous technical disruptions on HVDC interconnectors. During 2017, HVDC interconnector performance improved due to less technical faults. This resulted in countertrade costs returning to their annual average.

During 2015 and 2016, internal countertrade costs were a result of the construction of new transmission lines on the west coast of Finland. Generating units in this region were deployed to maintain secure grid operation. In 2017, internal countertrade were primarily a result of outages caused by transmission line projects in southern Finland.

FRANCE

The low values of firmness costs incurred in France result from the high availability of topological remedial actions due to a regular investment in the grid and its maintenance. Countertrading activations are concentrated at the FR – ES border.

GERMANY

Total German physical firmness and internal redispatch costs amounted to 890 M€ in 2015, 677 M€ in 2016 and 1 B€ in 2017 [34]. These figures summarise all costly remedial actions for the management of transmission congestions within Germany and at its borders. Different forms of internal and cross-border redispatching and countertrading were applied. These also include the activation of the German grid reserve and renewables curtailment compensation (EisMan) as reported to the German NRA on a quarterly basis. Notably, the costs for renewables curtailment compensation made up almost half of the total physical firmness and internal redispatch costs.

The increase in costs in 2017 can be explained partly by a particularly high wind infeed in 2017, but also by the capacity-increasing measures which Amprion has undertaken, e. g. removal of the FAV and introduction of winter limits and dynamic line rating.

The physical firmness and internal redispatch costs of Germany have to be considered in the context of the DE/AT/LU bidding zone. At least a part of the costs is due to the unlimited trade between Austria and Germany. How these costs will develop in the future, after the bidding zone split between Austria and Germany has been introduced in October 2018, is therefore hard to predict.

GREAT BRITAIN

Total physical firmness costs incurred across GB were between 340 M€ and 440 M€ per year during 2015 – 2017. This is considered high when compared to the majority of the other bidding zones. However, it should be noted that the physical firmness costs in GB were almost fully contributed by internal redispatch actions. This is mainly because the cross-border flows between GB and other bidding zones were usually not constrained when the GB system is balanced, therefore very little physical firmness cost is incurred on cross-border redispatches. The other reason for high internal congestion in GB is that GB market participants are under the Connect and Manage arrangements rather than Invest and Connect arrangements. The goal of Connect and Manage is to facilitate the connections of market participants as soon as possible whilst maintaining the balance of capital investments and congestion costs for the benefit of the GB consumers.

HUNGARY

In Hungary, redispatch was only applied in a few cases in the time period 2015 – 2017. There was one case in 2015 when internal redispatch was activated due to a disturbance on a 400 kV tie-line. The outage itself could be managed but the restoration of the N-1 security was not possible without redispatch. In other cases, internal redispatch was activated because of distribution system security violations in a few special maintenance cases. The latter cases do not have cross-border relevance.

Hungary participated in the Multilateral Remedial Action (MRA) agreement among the members of the TSC security cooperation until the cost ceiling approved by the Hungarian National Regulatory Authority had been reached in 2015. Hungary rejoined the agreement in 2017. There have been several activations in both 2015 and 2017 based on this agreement. Hungary contributed to the costs of these actions in accordance with the MRA cost sharing agreement. Frequency and volume of the activations was significantly reduced in 2017 due to some investment and available topological measures (including PSTs) of the partner TSOs.

ITALY

Physical firmness costs for Italy also include an estimation of the costs incurred for solving congestions in the Italian Power System: since Italy adopts a central dispatching approach, where all the system constraints (e.g. reserve, balancing, congestions etc.) are solved all together in an SCOPF algorithm (in order to minimise system costs), costs and volumes cannot be associated ex-post to a single constraint in a straightforward way.

34 The value in 2017 is preliminary and only includes the TSOs' costs and not the DSOs' costs for renewables curtailment (EisMan).

LATVIA

Regarding physical firmness costs, AST has experienced some costs from the counter-trades on cross-border EE-LV. This cross-border is the weakest cross-section in the area of the Baltic States, therefore some counter-trades were activated. In 2015 and 2016, the amount of counter-trades and the costs were higher due to high energy flows from Estonia towards Lithuania. In 2016, a new link between Lithuania and Sweden (NordBalt 700 MW) was established and due to this, the flows on cross-border EE-LV significantly reduced. However there have been some counter-trades but the overall amount of overloads reduced. To eliminate all overloads, congestions and price differences on the cross-border EE-LV, Latvian and Estonian TSOs has developed the new interconnector between Estonia and Latvia (called the 3rd Estonia – Latvia Interconnector) which is included in the Estonian and Latvian National Transmission system development plans, Pan-European TYNDPs and 3rd version of Projects of Common Interest. The interconnector has to be in operation in 2020.

NORWAY

Physical firmness and internal congestion costs come from real time redispatch to handle internal bottlenecks in radial grids with distributed hydro production.

POLAND

In Poland, network constraints are managed within ISP run by the TSO. The ISP process is bid-based security constraint unit commitment and economic dispatch, where balancing, reserve procurement and congestion management are co-optimised within one integrated process run by the TSO immediately after the DA market closure.

Due to the co-optimisation applied in the ISP process, it is not possible to calculate separate redispatching costs or redispatching volume as in self-dispatch systems. In the ISP network, constraints are identified and managed within one process that is integrated with balancing and reserves procurement. There is no sequential process with identification of overload and next manual decision to do congestion management. Therefore, any action taken by the TSO cannot be unambiguously assigned to any specific overload or even category of actions such as: balancing or congestion management.

Consequently, the reported cost and volume cover the whole ISP, i.e. not only congestion management, and thus reported cost and volume should be deemed to be strongly overestimated.

PORTUGAL

The internal redispatch costs resulted from particular characteristics of the Portuguese electric system that frequently motivates the mobilisation of thermal units to establish the regulation reserve.

SLOVAKIA

SEPS does not use costly remedial actions for relieving congestion.

SPAIN

The cost of internal redispatch in the Spanish Electrical System has decreased in 2016 and 2017 in comparison with 2015. In the future, the cost of internal redispatch will be reduced with the installation of run-backs automatisms on the affected units. There had not been cross-border redispatch at any year and countertrading activations are mainly executed at the FR-ES border.

SWEDEN

The cost for countertrading also includes the cost for internal redispatch and cross-border redispatch.

4.4 CONCLUSIONS

Chapter 4 provides information on collected congestion income and the costs incurred to ensure firmness of cross-border and internal capacities.

When it comes to **congestion rent**, it can be observed that it is concentrated in a relatively small number of countries. Congestion income collected by France, Great Britain and Italy is considerably above other countries, followed by Sweden, Germany and the Netherlands. One can observe a decline in the amount of collected congestion income, from 2.8 b€ in 2015 to 2.4 b€ in 2017.

When it comes to the **financial firmness costs** incurred by TSOs to ensure firmness of cross-border capacities, it can be seen that these costs in all reported years are dominated by curtailments caused by emergency grid security or safety issues, with the exception of force majeure curtailment on the DE – DK border in 2017. Consequently, no trends can be identified. Overall, GR and IT had the highest financial firmness costs.

Analysis of **physical firmness** cost by country shows significant variation year on year. The highest costs are incurred by DE and GB. For PL, PT, ES and NL, physical firmness costs are also significant, though of a lower magnitude. Notably, in DE the costs for renewables curtailment compensation made up almost half of the total physical firmness and internal redispatch costs.

Total firmness costs are mainly driven by the physical firmness costs, as the physical and financial firmness costs have different magnitudes.

ABBREVIATIONS

Acronym	Definition
ACER	Agency for the Cooperation of Energy Regulators
AL	Albania
AT	Austria
BA	Bosnia and Herzegovina
BE	Belgium
BG	Bulgaria
CACM	COMMISSION REGULATION (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management
CCDA	Capacity calculation for the purpose of day-ahead allocation
CCR	Capacity calculation region
CGM	Common reference Grid Model
CH	Switzerland
CNE	Critical Network Element
CORE	Capacity calculation region in Central Europe*
CSE	Continental South East
CWE	Central Western Europe
CZ	Czech Republic
D-1	One day prior to real time
DA	Day Ahead
DACF	Day Ahead Congestion Forecast
DC	Direct Current

Acronym	Definition
DE	Germany
DK	Denmark
EE	Estonia
ENTSO-E	European Network of Transmission System Operators for Electricity
ES	Spain
ETYS	Electricity Ten Year Statement
FAV	Final Adjustment Value
FB	Flow Based
FI	Finland
FR	France
GB	Great Britain
GR	Greece
GSK	Generation Shift Key
HAR	Harmonised Allocation Rules
HR	Croatia
HU	Hungary
HVDC	High-Voltage Direct Current
ICS	Incidents Classification Scale
IDCF	Intra Day Congestion Forecast
IE	Ireland
IN CCR	Italy North Capacity Calculation Region
ISP	Integrated Scheduling Process

* https://www.entsoe.eu/network_codes/cacm/implementation/core/

Acronym	Definition
IT	Italy
LFC	Load Frequency Control
LU	Luxembourg
LV	Latvia
ME	Montenegro
MK	The Former Yugoslav Republic of Macedonia
NI	Northern Ireland
NL	Netherlands
NO	Norway
NOA	Network Options Assessment
NRA	National Regulatory Authorities
NTC	Net Transfer Capacity
OHL	Overhead Line
PL	Poland
PST	Phase Shifting Transformers
PT	Portugal
PTDF	Power Transfer Distribution Factor
RES	Renewable Energy Sources
RO	Romania
RS	Serbia
SA	Synchronous area
SE	Sweden

Acronym	Definition
SEE	South-East Europe
SHB	Control block of Slovenia, Croatia and Bosnia
SI	Slovenia
SK	Slovakia
SO	System Operator
TSO	Transmission System Operator
TTG	TenneT Germany
TYNDP	Ten-Year Network Development Plan

European Network of
Transmission System Operators
for Electricity