WG European Market Design & System Operation

June 20th 2019

09:30 – 12:30

Agenda

European Market Design

1. Intraday design on Nemo Link – 30 min
2. EPEX SPOT: decoupling on 7/06 – 45 min
3. CEP 70%: state of play for Belgium and in EU – 30 min
4. CORE: long-term capacity calculation and splitting rules – 30 min

System Operation

5. Update regarding emergency & restoration – 30 min

Intraday design on Nemo Link

Introduction of an ID explicit product on the BE-GB border

Elia and Nemo Link are working together to introduce an intraday product on the BE-GB border before the end of the year. Elia and Nemo Link aim for a swift implementation.

- For sake of simplicity and given the uncertainty on the Brexit, the implementation of the ID product is based on explicit ID auctions hosted by JAO
- Project partners include Elia, Nemo Link and NGESO. Hence, development at NGESO might impact the implementation timeline
- Pragmatic approach is chosen (i.e. go-live as soon as possible), potential improvements to the product design might be shifted to a later date

Please note that the information shown in this presentation is work in progress and subject to change

Explicit vs Implicit allocation on the BE-GB Bidding zone border

Elia fully recognizes that the target solution on the BE-GB border is implicit allocation via XBID (in case GB remains in the IEM). The choice for explicit allocation is driven by:

- Explicit allocation is considered the “safe” choice in an uncertain Brexit context. Even in case GB leaves the IEM, explicit allocation can continue. Indications of the EC are that this will probably not be the case for implicit allocation as part of XBID
- Introduction of the BE-GB border in XBID would create dependencies with other borders (concept of waves) and the losses functionality in XBID.

➔ Explicit allocation ensure a relatively fast implementation of an ID product on the BE-GB border, without excluding the move to implicit allocation at a later stage. Explicit allocation is thus an early implementation of the target solution.

The product design is a compromise between a pragmatic approach, allowing a fast implementation, and the needs of the market

The design of the ID explicit product is driven by the following elements:

1. Auctions are to be hosted by JAO and existing functionality and timings are preferred. Some discussions with JAO are still ongoing and these might impact the final product design.
2. Elia wants to perform an ID capacity calculation based on the same operational processes as in CWE. The timing for the provision of capacity is thus driven by existing processes (for Elia).
3. An IT limitation of NGESO prevents a Cross Zonal Gate Closure Time of 60 minutes (cf. Art 59 of CACM – deadline of 1/1/2021).

Further characteristics of the ID explicit product

The proposed ID product is characterized by:

- Use It Or Lose It product, no resales between auctions
- 60’ MTU as pragmatic solution and alignment with other ICs, an MTU of 30’ will be discussed in the future.

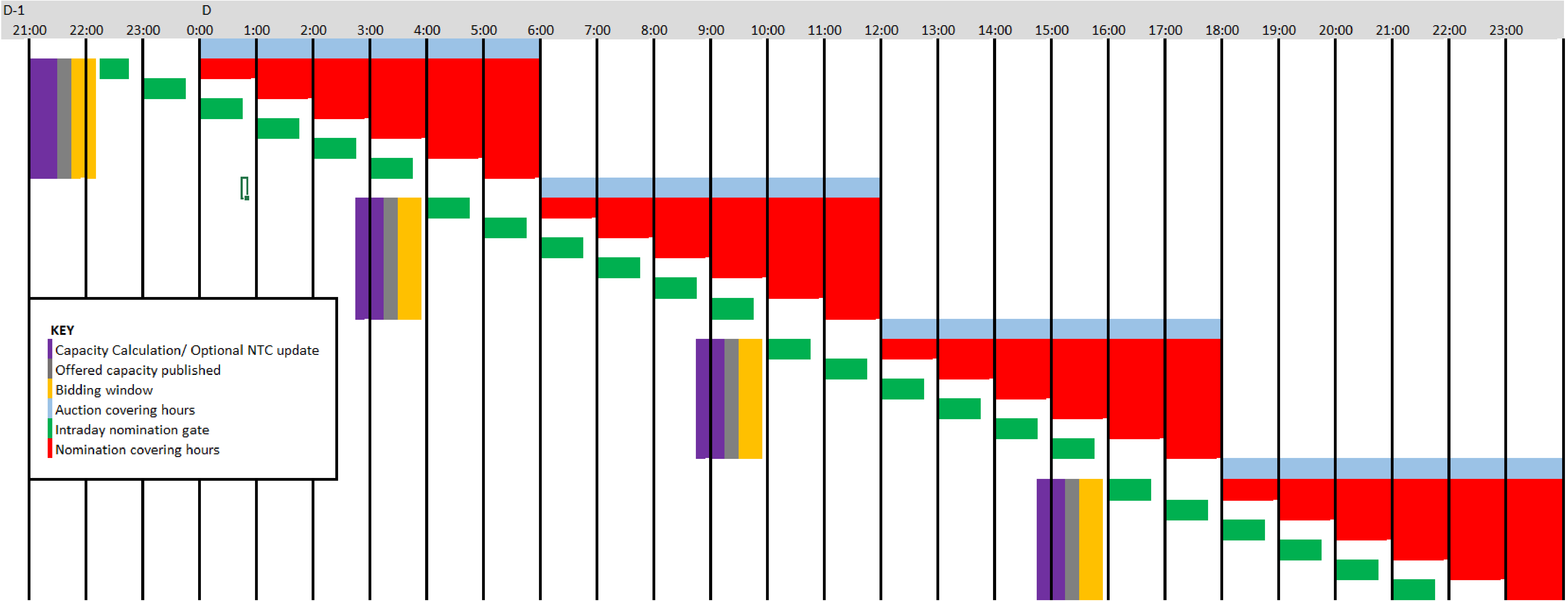
Key principles of the auction design

- 4 auctions, each auction covering 6 hours (thus non-overlapping auctions)
- Hourly bidding possible
- Auctions hosted by JAO

Nominations

- 45’ nomination gate (H-2 until H-1.15).
- Due to the timing of the auction, the first nomination gate will be shorter (30’). During each nomination gate, nominations for the remaining hours will be possible.
- Nominations on RNP

Graphical overview of the auction and nominations



Implementation timeline

Elia and Nemo Link aim for a go-live before the end of the year. The implementation timeline is partly driven by the regulatory track

- Product design needs to be finalized by end of June, followed by a 1 month consultation. Probably both IEM and non-IEM rules will be consulted.
- Submission to NRAs by end of July, an approval period of 3 months is considered (Ofgem requirement)

External factors might impact the go-live

- Big dependency on IT implementation of NGESO.
- Dependency on JAO for auction design
- Impact Brexit (possible that go-live gets delayed when legal framework is uncertain)

EPEX SPOT: decoupling on 7/06

Incident of 7 June 2019

part of eex group

Incident description and root causes

On 7 June 2019 EPEX faced an incident that decoupled the EPEX CWE and GB markets from the rest of the European market. There were two parts to the incident:

Part 1: Events leading to the decoupling of the market

- 11h39: An erroneous order was submitted by a member unintentionally. This order type is not allowed on EPEX markets. The result was an ETS server lock, followed by the deactivation of the order and a restart of the servers, and then the reopening of the order books.
- 12h41: The same error was made again by the same member. This led to another ETS server lock and the application of the same sequence of actions as the first time.
- 12h 49: As time had run out in the normal PCR processes, partial decoupling was declared.

Incident description and root causes

Part 2: Issues during the local EPEX auctions

Once Partial Decoupling is declared, EPEX runs local auctions in each market and capacity is allocated explicitly via shadow auctions run by the Joint Auction Office (JAO).

EPEX encountered a second issue during these local auctions, where the calculation and publication of erroneous prices led to a later cancellation and rerun of the local auctions:

- 13h00: Order books opened for local auctions
- 13h22: Order books closed
- 13h41: Publication of first erroneous prices (reason: the price calculation was made on the basis of only a small proportion of the order book, due to an issue stemming from the earlier server restarts)
- 14h07: Cancellation of the results of first local auctions and reopening of the order books
- 14h35: Order book closure and calculation of market results based on complete order books
- 15h38: Publication of final market results
- 15h49: Results sent to ECC which in turn validated all transactions. All nominations and payments completed and settled correctly.

Incident description and root causes

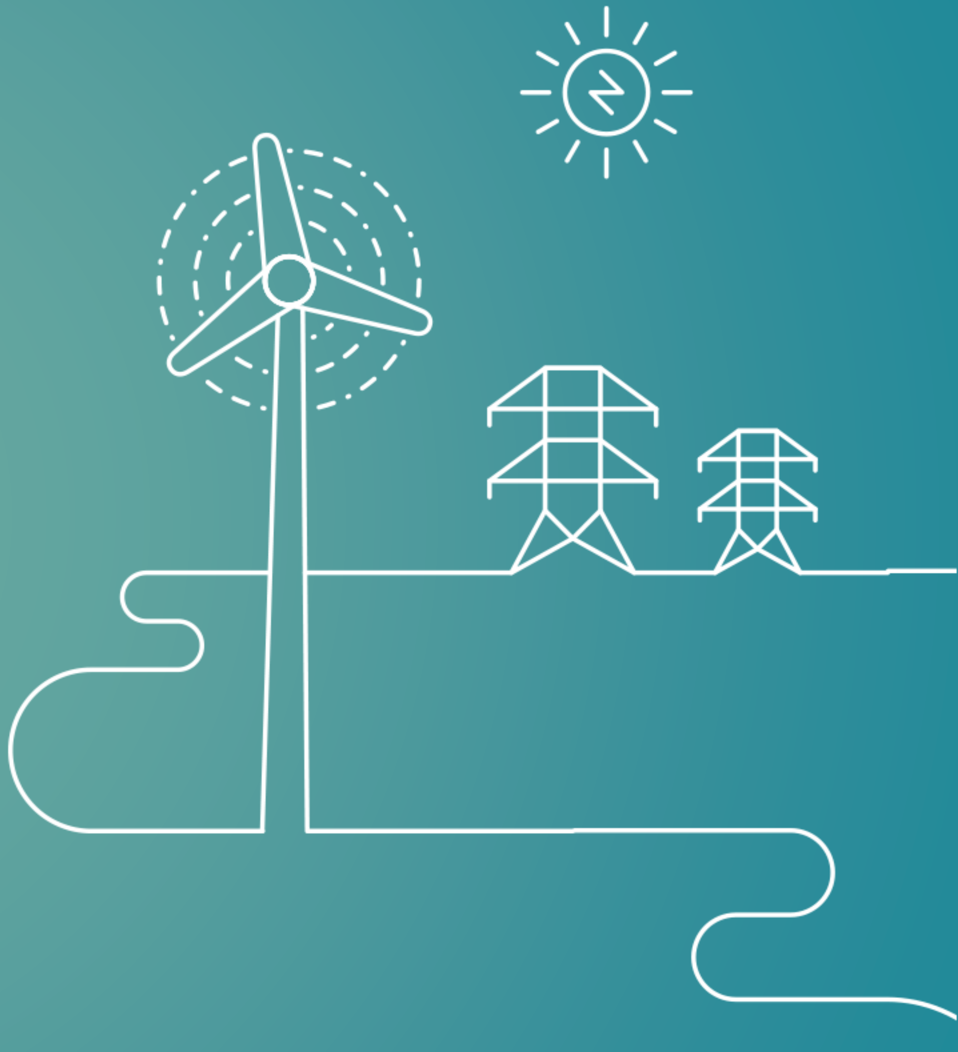
Reasons behind the publication of the erroneous results:

- The erroneous market prices had been calculated based on a non-complete and much reduced order book
- This issue led to many member orders not being filled
- The core IT issue behind this related to a lack of synchronization of two modules in the ETS trading system during the restarts of the servers, in the first part of the incident
- EPEX did check the prices using one of its two tools before publication
  - The first check was all clear. It checks that prices make sense given the order book used for the price calculation.
  - The second check could not be run because of the workaround solutions in place, due to the first part of the incident. This second tool is used to verify order book completeness and volumes.
- There is also significant time pressure given the related gate closure times for nomination schedules, and as our operators need to take very rapid decisions based on incomplete and sometimes conflicting information

Corrective measures

- For part 1 of the incident, the deployment in production of a patched system on 7/6 at 19h30 has permanently solved the root cause
- For part 2 of the incident, procedures have already been updated to include additional manual checks of the auction results and to clarify the processes during a decoupling situation
- Further corrective measures are also to come for part 2 of the incident, as it is more complex in nature and includes wider impacts than just EPEX:
  - Review and improve the EPEX communication process *during* incidents
  - Study further the consistency of the partial decoupling procedure and the second auction procedure
  - Study the timings and interactions between EPEX and its stakeholders during a decoupling incident
  - Put in place regular training session with market participants

CEP 70%: state of play for Belgium and in EU



Legal context

New regulation internal electricity market

- Adopted by the European Council on May 22nd
- Entry into force: Jul 4th 2019
- Applicable as from 1.1.2020
- New philosophy bidding zones and capacity calculation: **build (grid) – split (bidding zone) – pay (redispatch)**

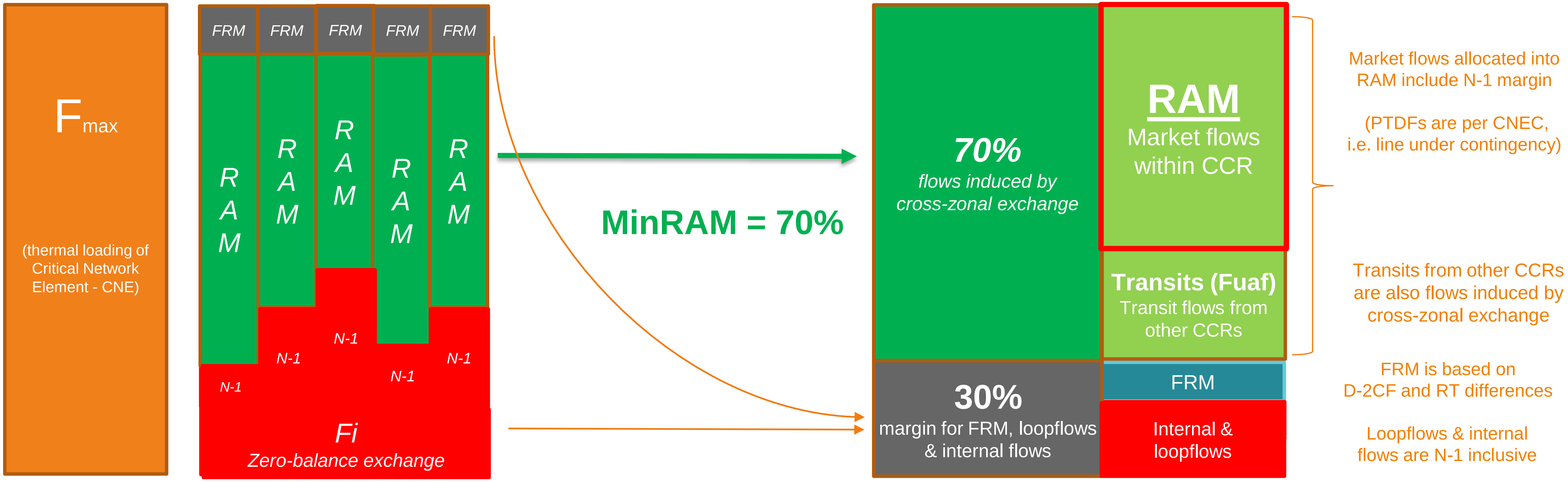
CEP Art 16(8) defines a **minimum threshold for capacity** provided to the market of **70%** of the thermal capacity

If 70% is not possible on 1.1.2020

- Member States have the possibility to develop **action plans** with a concrete timetable and a linear trajectory to reduce congestions and reach the 70% by end 2025. Associated RDCT costs to reach action plan targets to be borne by the Member States implementing the action plan.
- **Derogations** are also possible at request of the TSO, strictly limited to maintaining operational security and limited in time (1-2 years, not excluding renewal). This is an **NRA led process**, with CCR wide NRA consultation (and ACER involvement in case of disagreement).

Technical context: 70% in flow-based day-ahead

- At least 70% of thermal capacity is to be made available for *flows induced by cross-zonal exchanges*
- Up to 30% of thermal capacity can be reserved for FRM, loopflows and internal flows
- *“Taking into account contingencies”*: N-1 intrinsically embedded in flow-based, the contingencies are thus inside 30% and 70%



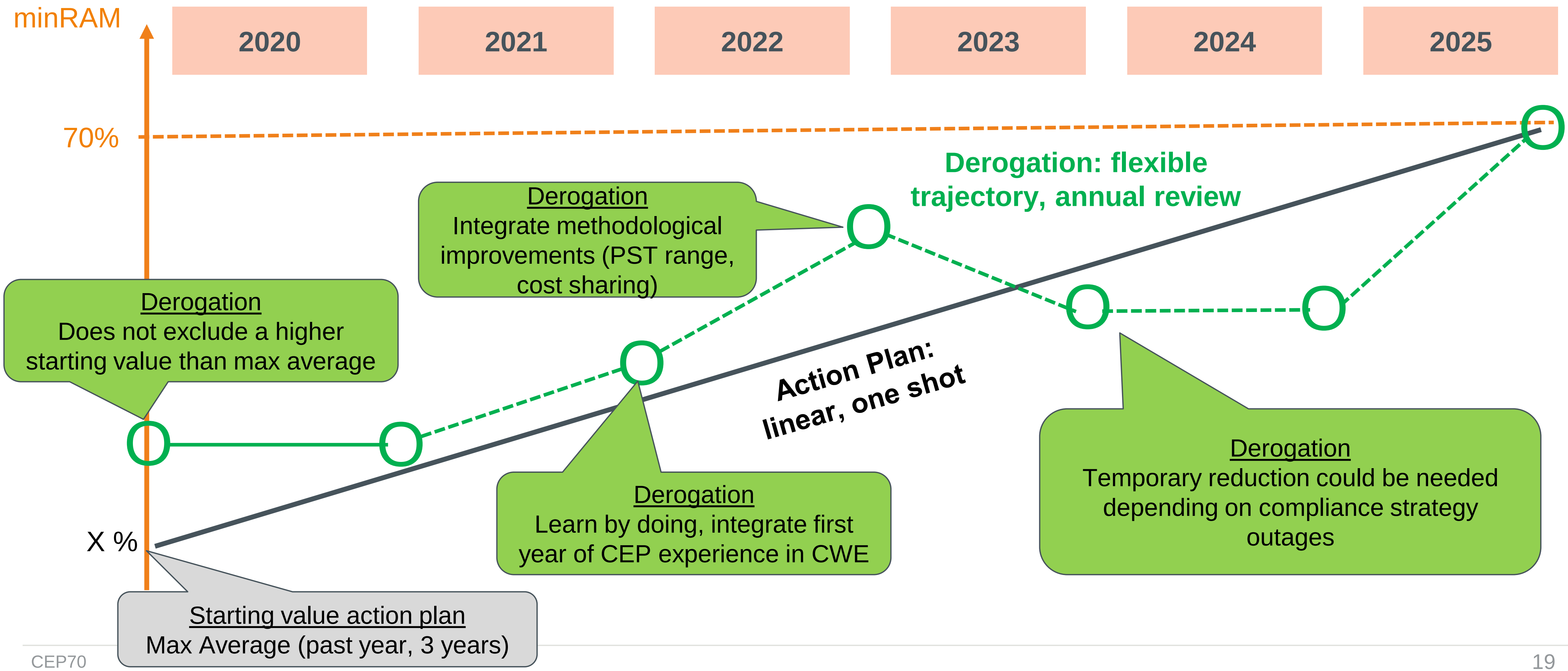
Thermal capacity of a line:

$F_{max} = \sqrt{3} \cdot I_{max} \cdot U \cdot cos(\varphi)$

Base Case (zero-balance exch.) including N-1

Sequence of derogations can develop into a flexible trajectory

For illustration purpose only



Probable approach for Belgium

EC sees three groups of Member States

1. Member States that clearly have structural congestions impacting the neighboring countries ➔ action plan
2. Member States with limited congestion and existing plans to reach the 70% ➔ left open how to be formalized
3. Member States with no congestions and that will reach the 70% in case the pollution in the network has been removed ➔ derogation

The situation in Belgium is a combination of the group 2 and 3 rationale. In addition, a solution is needed to manage outages as acknowledged in EU compliance discussion

1. Impact of other Member States: loopflows ➔ derogation
2. Long-duration outages required for HTLS upgrade internal grid ➔ derogation
3. Ad hoc cases leading temporarily to limited congestion ➔ manage through compliance monitoring in 2020 and re-evaluate
4. Short-duration outages cf. maintenance ➔ compliance monitoring

Derogation: Elia would opt for 1 year cycles in line with “learn by doing” mindset

EU compliance discussion

- The Commission and Member States invited ACER and NRAs to engage in technical discussions with ENTSO-E/TSOs on the concrete interpretation and implementation of the 70%
- Hence ACER initiated two work streams – one amongst NRAs and one with TSOs & NRAs – to tackle the key questions
  - How to calculate the compliance of TSOs/MSs with Article 16(8) of Recast Electricity Regulation
  - Who will calculate existing compliance and which data is needed?
  - Are TSOs able to comply as of 1 January 2020? If not, will TSOs ask for action plans or derogations? If TSOs ask for action plans or derogations, how to calculate the starting point?
- European Commission in supporting role

State of play EU compliance discussion

Source: ACER slides Infrastructure Forum Jun 17

- ACER/NRAs, in collaboration with TSOs, are developing two guidelines for a joint understanding of the calculation principles:
  - ✓ *Guideline for* ***fulfillment monitoring – first step***
  - ✓ *Guideline for* ***compliance assessment – second step***

- Fulfillment monitoring of 70% cross border capacity will be the **base for NRAs/MSs works** on:
  - ✓ ***Compliance assessment*** *where NRAs can consider efficiency, price differentials or exempted hours threshold when evaluating the overall year compliance*
  - ✓ ***Enforcement decisions****:*
    - *National* ***action plans*** *approved by MSs*
    - ***Derogations*** *or temporary exemptions approved by NRAs of CCR (or ACER if no agreement)*

Fulfillment would be applied on every CNEC and every MTU => output

- Non-fulfilment hours per country
- Available margins per CNEC
- Shadow prices

Ongoing alignment

- **Balance between fulfillment monitoring and compliance assessment**
- **Transit flows: uncertainties related to forecast non-CWE / non-CORE exchanges**
- **Exchanges with third countries**

Next steps

Interpretative planning, subject to further alignment between involved parties

National track

- Confirm derogation approach with CREG & FOD – towards summer
- Develop the content of the derogation, likely with “rule-book” – towards Sep/Oct

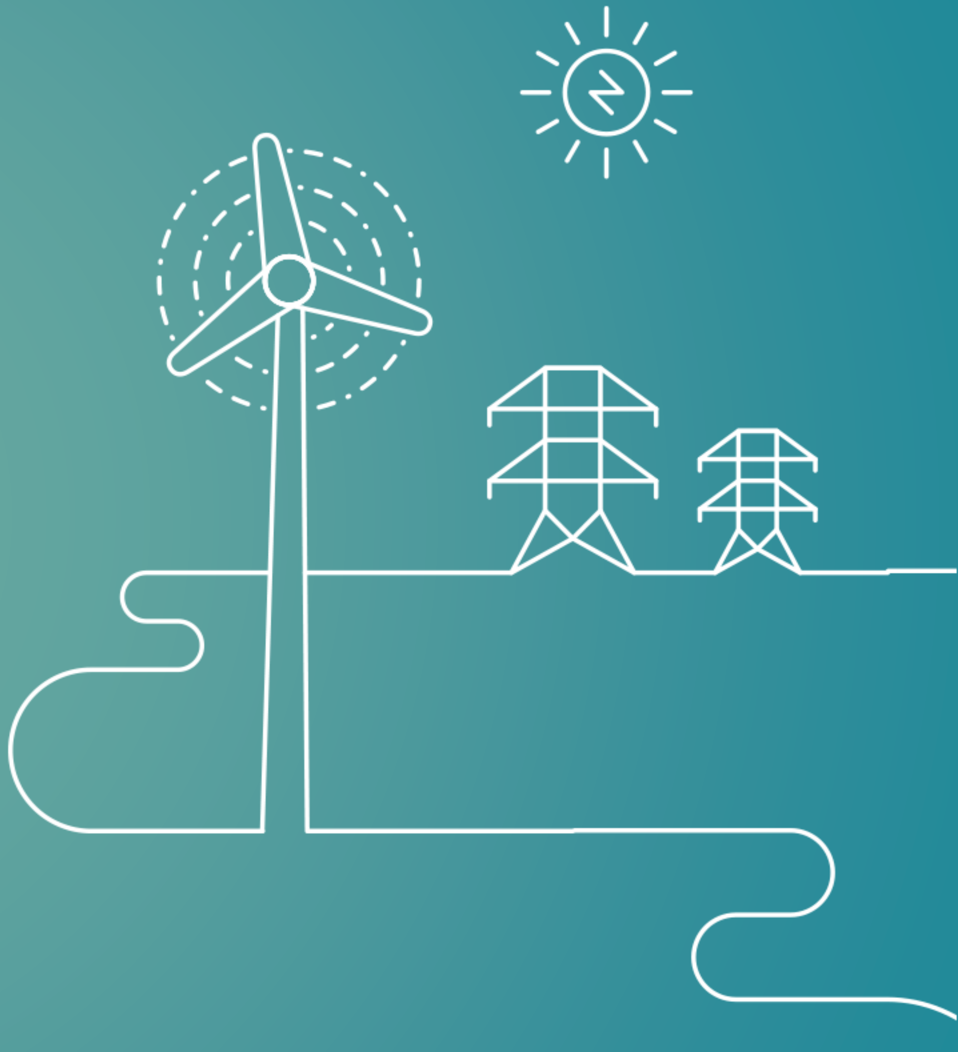
EU track

- **ACER fulfilment monitoring methodology** (July 2019)
- **Results** of fulfillment monitoring (September/Oct 2019)
- Guideline for **compliance assessment** (2nd half of 2019)
- Indications by MS/NRAs on **action plan or derogation**
- After summer: next ECBC meeting to monitor progress – *to be confirmed*

CWE / CORE track

- Guidance from NRAs & ACER on transit flows – *coming weeks*
- CWE: start IT implementation, followed by impact assessment – *by end 2019*
- CORE: work out derogation process and template – *towards Sep/Oct*
- CORE: hand in derogation – *Sep/Oct*
- CORE: approval of derogation – *the earlier the better cf. link with CWE implementation*

CORE: long-term capacity calculation and splitting rules



Current state of play

Calculation

1. No common calculation method among TSOs
2. No common capacity calculator, instead TSOs assess their NTCs individually
3. Final values are harmonized within CWE area
4. Timings aligned within CWE together with JAO

Splitting

1. Different splitting rules on each bidding-zone-border within CWE area

Legal Requirements

EU requirements -> FCA regulation (EU regulation 2016/1719 – guideline on Forward Capacity Allocation)

- **Objectives:**
  - recital 4: […] ensure that capacity calculation is reliable and that **optimal capacity** is made available to the market […]
- **Requirements:**
  - Art. 9: […] **long-term cross-zonal capacity is calculated** for each forward capacity allocation and at least on annual and monthly time frames.
  - Art. 10.1: […] a **common coordinated capacity calculation methodology** for long-term time frames within the respective region.
  - Art. 10.2 + 5: approach used […] shall be either a **CNTC approach** (default) or a FB approach (conditioned)
  - Art. 10.4: […] applying a **security analysis based on multiple scenarios** (default) […] or a statistical approach (conditioned) […]

Legal Requirements

→ Core LT CCM will be a Scenario based NTC calculation

Additionally FCA request a Common Coordinated Capacity Calculation Methodology (Art. 10.1) by:

- Using a common grid model (Art. 18)
- Using common scenarios (Art. 19)
- Using a common calculation methodology (Art. 10.2)
- Using a coordinated calculator (Art. 21.2)
- Using a cross-zonal validation (Art 15)

Scenario = Forecasted status of power system for a given time frame (CACM Art. 2.4)

~ a representative picture of the grid situation at one certain timestamp containing planned outages, expected grid topology, production park, renewables, …

→ One NTC value for each border and for each direction is calculated for each selected timestamp

CORE region

CORE borders = 17

NTC possible combinations = $2^{CORE\ borders} = 131k$

LT CCM: likely corners

- Corner = a set of combinations of bilateral exchanges

-The Core CCR consists of 17 bidding zone borders, leading to 131.072 possible corners.

This means that in the existing Core CCR there are 131.072 ways of combining the NTCs.
→ Simultaneous feasibility of all those combinations might lead to very restricted NTC values due to unlikely combinations.

→ LT CCM will calculate NTC values for Likely combinations only

Open point: “threshold” on the number of likely corners to be considered

LT CCM: open parameters

Base Case Quality

Every calculation algorithm with (nearly) overloaded CNEC will lead to (nearly) 0 NTC

→ The use of a maximum loading threshold on CNEC in base case (Core 0-balanced incl planned outages) before starting the NTC calculation is crucial. The way to achieve it is not defined:

- Coordinated RA?
- MinRAM?

CNEC

- CNEC selection threshold for long-term capacity calculation is still to be determined
  - Same than DA or different?

Distribution of the RAM

“Top-Down” or “Bottom-Up” – see next slide

LT CCM: 2 algorithms still on table to distribute the RAM

“Bottom-Up”

- The “Bottom-Up” approach only considers positive contributors

- RAM of CNEC is shared without border prioritization between positive contributors (equal share approach). As a consequence, in the “Bottom-Up” approach even bidding zone borders that are electrically further to the CNEC obtain the equal share of available RAM for capacity allocation

“Top-Down”

- “Top-Down” approach considers both negative and positive contributors (i.e. the approach allows to take into account NTCs that reduces the load on a CNEC while checking the grid security);

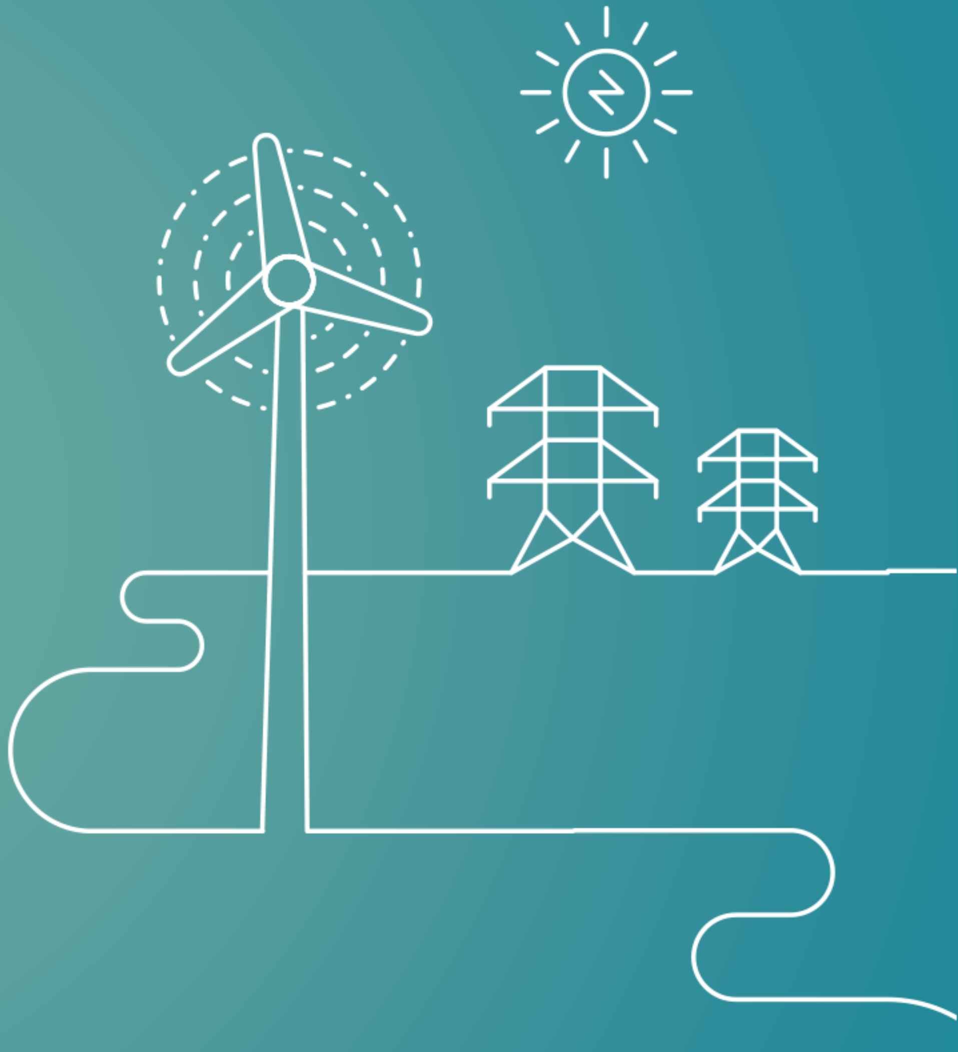
- “Top-Down” approach distributes the RAM of a CNEC using a PTDF share. As a consequence in the “Top-Down” approach the biggest portion of the available RAM is allocated to the bidding zone borders that are electrically closer (high PTDF) to the CNEC;

LT CCM: splitting rules

Goal of the splitting rule is to split capacity between allocation timeframes

- 50% Yearly - 50% Monthly is proposed
- TSOs dismissed the 100% - 0% approach following all Core NRAs guidance that it is not seen as compliant with FCA

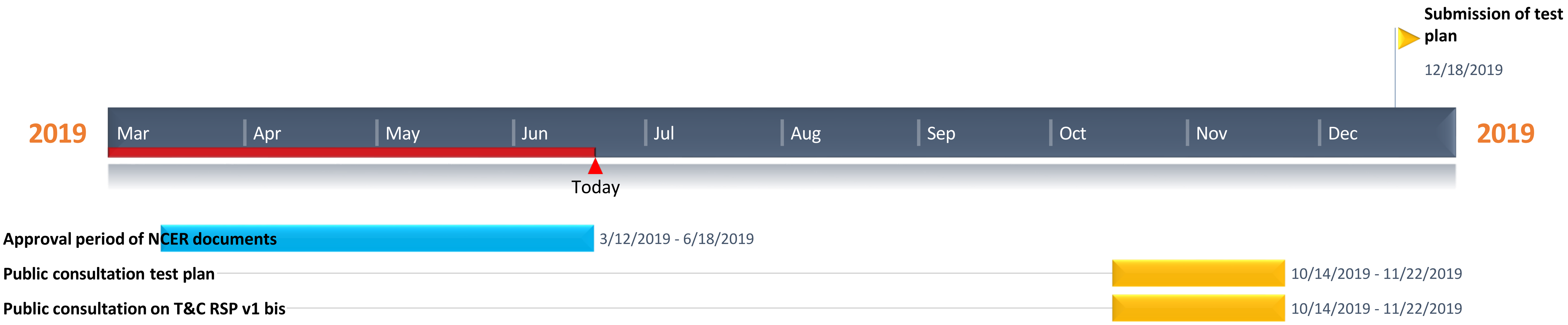
Update regarding emergency & restoration



Agenda

1. Process overview and timeline
2. Feedback on NCER documents submitted in December 2018 by Elia
3. Communication requirements imposed by NCER
4. Test plan pursuant NCER

1. Process overview and proposition for timeline



2. Feedback on NCER docs submitted in December 2018 by Elia

NCER document	To be appoved by	Status	
Terms & Conditions for Restoration Service Providers	Creg	Refused	New version to be submitted
Rules for suspension and restoration of market activities and rules imbalance settlement during market suspension	Creg	Pending	
List of SGUs identified for defense and restoration plan	Minister	Pending	
List of High priority SGUs for defense and restoration plan	Minister	Pending	
Restoration Plan	Minister	Pending	
System Defense Plan	Minister	Pending	

Terms & Conditions for Restoration Service Providers

- The CREG did not approve T&C RSP v1 for the following main reasons:
  - General Terms and Conditions and force majeur to be reviewed and re-consulted
  - Some technical remarks on fuel requirements
  - Clarify conditions to participate (CIPU units) and/or aggregation modalities
- Elia will draft a new **version 1 bis**, taken into account the remarks of the Creg
  - Version 1 bis will include the **present design** for black start units
  - Contract period based on T&C RSP v1 bis: 1/1/2021 – 31/12/2023
  - A new public consultation will be organized (Oct – Nov 19)
  - Submission of final document to Creg in December 2019
- T&C RSP v2 will include target design and is to be developed in the coming years.

List of SGU and high priority SGU identified for defense and restoration plan

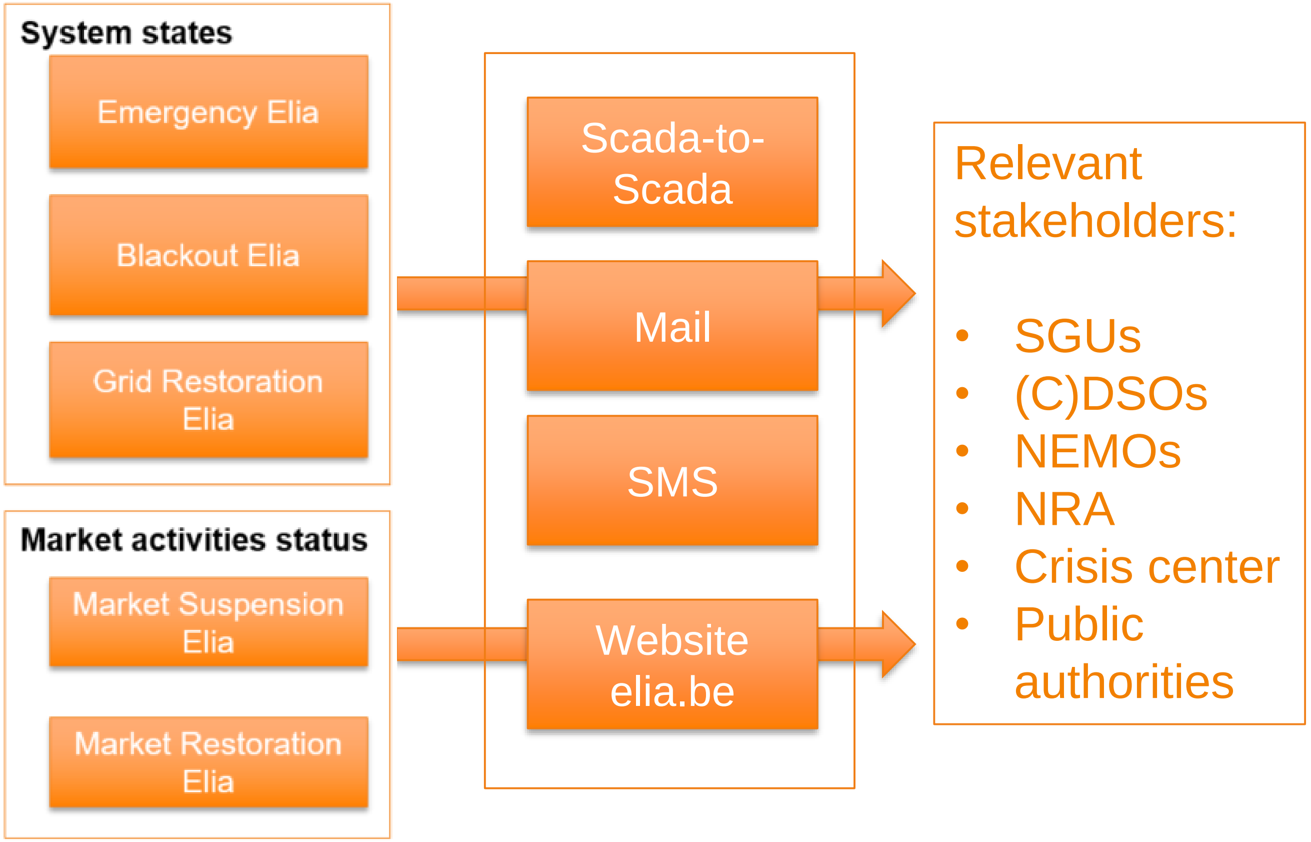
- Lists of individual identified SGUs were added in annex of the Defense and Restoration plans and submitted to the Minister of Energy for approval.
- No feedback from Minister of Energy so far.
- Notification letters to inform individual SGUs (according to NCER art 12.3 / 24.3) are waiting to be sent after approval.

Defense plan and restoration plan

- No feedback from Minister of Energy so far.
- Old “Rescue code” and “Reconstruction code” according to old FTR remain in operation until approval by Minister of Energy.
- Elia cannot impose implementation measures and deadlines to SGUs, DSOs, … as long as plans are not approved

3. Notifications related to the system states and the market activities

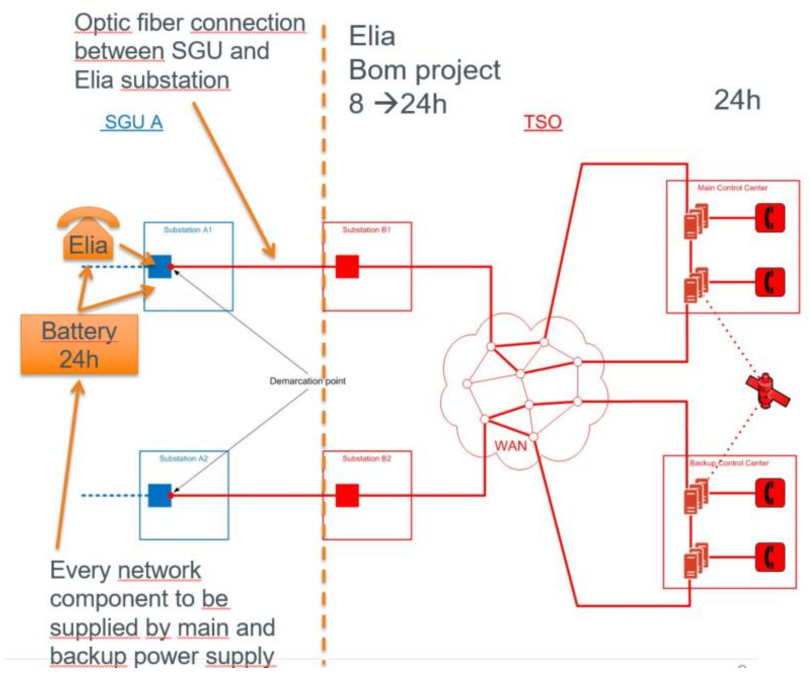
- Requirement NCER art 39 and 40
- Approval of plans needed before stakeholders can be informed about implementation measures
- Elia started internal preparation, however, deadline for implementation 18/12/2019 as mentioned in NCER will become challenging/impossible.
- Information to stakeholders on how to register for receiving the notifications will be communicated in Q1 2020.



Communication systems NCER Art 41

Blackout proof voice communication system with at least 24 hours autonomy to be implemented by 31/12/2022

Already available in black start units, important large power plants, some large demand facilities and CDS, rail infra company, all DSOs, national crisis center.



Further planning:

- June – Sept 19: inventory of missing SGUs
- Oct 19: Internal approval of roll out plan 2019 – 2022
- Individual SGUs will be contacted via our customer relations department.
- New standard under development for new SGU connections to Elia grid.

4. Test plan

- A test plan has to be defined by 18/12/2019 pursuant to NCER
- **Test plan** in accordance with NCER art 43 to 49 to assess the proper functioning of all equipment and capabilities considered in the SDP and RP
- The test plan should be defined in consultation with DSOs, SGUs identified in the SDP and in the RP, DSPs & RSPs
- The test plan shall include the **periodicity and conditions of the tests**, following the minimum requirements outlined in Articles 44 to 47

The test plan should follow the methodology lay down in:

- Regulation 2016/631 : RfG
- Regulation 2016/1338 : DCC
- Regulation 2016/1447 : HVDC
- The national laws if the SGU is not subject to the above mentioned regulations

First draft: Sept 19

↓

Public consultation Oct-Nov 19

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Test plan submission to minister of energy for approval Dec 19