Electricity Coordinating Center Ltd.
V. Stepe 412, 11040 Belgrade 33,
Serbia
www.ekc-ltd.com

Training on Coordinated Capacity Calculation in Electricity

Energy Community Secretariat
Vienna
13.02.2019

Zoran Vujasinović,
Electricity Coordinating Center (EKC)

Topics

- Introduction and basic terms
- Requirements of related Guidelines regarding CCC
- Status of the CCC processes in WB6
- Main findings of EnCS & EKC project "Implementation of a Regional CCC in the WB6"
- Methodology of capacity calculation
- Examples

This course targets in-depth discussion of the coordinated capacity calculation methodology developed under the WB6 initiative as well as knowledge gaining from the developments on other CCRs and in particular in the 10th CCR regarding coordinated capacity calculation. Dwelling into the processes of TSOs in performing capacity calculation and national regulatory authorities in assessing, monitoring and understand the impact will be the key objective.

Introduction

- Calculation and market based allocation of scarce cross-border transmission capacity in SEE region;
  - Activity in force for ≈15 years in SEE, upon unbundling of electricity sector
  - Driven by the obligation to allocate the transmission capacity to third parties in transparent and market based manner
- Strong cooperation is present, due to strong interdependency among national networks and the need to coordinate data, calculation and allocation
- Based on the Net Transfer Capacity (NTC) methodology
- So far organised on the basis of ENTSO-E recommendations and good practice
- After approving the relevant Guidelines (CACM, FCA), required to be further harmonised and improved
  - Directly applicable to EU TSOs
  - WB6: Non-EU TSOs (will) have the obligation to follow the Guidelines as well, through the Energy Community Treaty

Reminder

Methodologies: NTC-based / Flow-Based

NTC (ATC)-based capacity calculation:

Single constraint per each border, for commercial transactions; for the group of transmission elements between the two systems

Flow-based capacity calculation (PTDF/RAM):

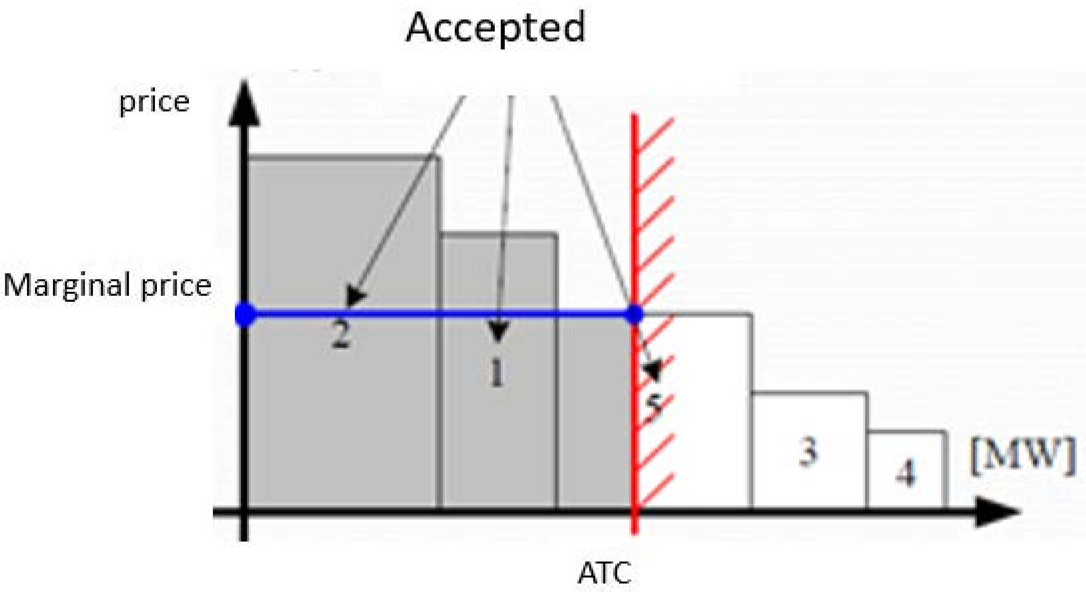
- Set of physical constraints (RAM) at each observed transmission element.
- Influence of commercial transactions to the flows, given by sensitivity factors (PTDF)

Reminder

Explicit auctions of capacity

- **Explicit auction of capacity: auctioning only capacity, electricity trade goes separately (afterwards)**

ATC is the portion of NTC available at current auctions, remaining after Already Allocated Capacity (AAC)
ATC=NTC-AAC



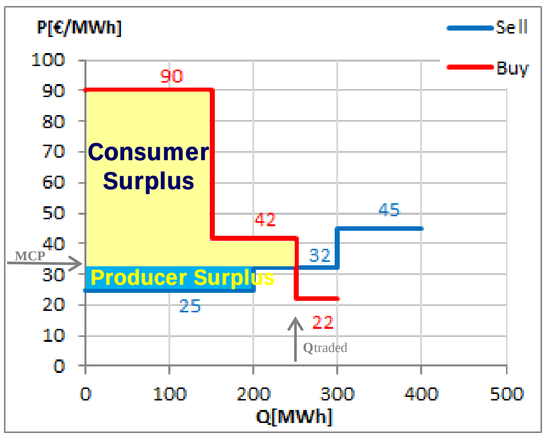
- **Implicit auction (market coupling): capacity is implicitly allocated along with the electricity trade, over power exchange trading algorithm →**

Implicit auctions of capacity: Market Coupling

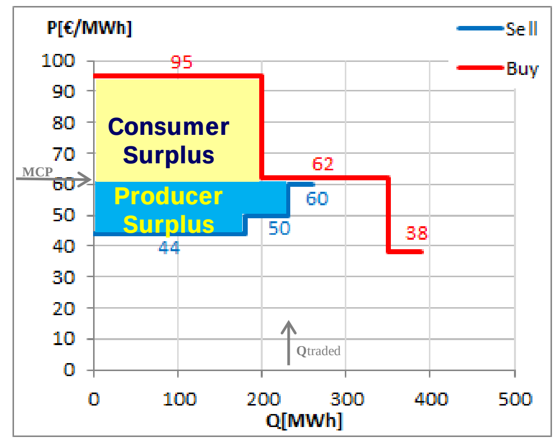
- Matching the buy and sell curves of coupled markets jointly, according to the overall merit order, with respecting the transmission constraints.
- Transmission constraints: ATC-based, or Flow-based (PTDF/RAM)
- The overall aim: to maximize the total welfare

Example: Two areas, coupled over ATC

Area 1 (before coupling)

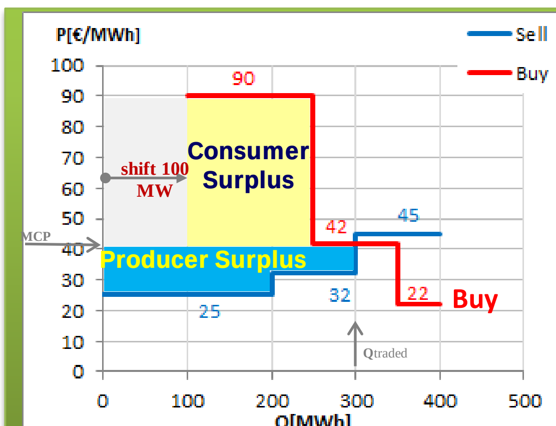


ATC = 0 MW

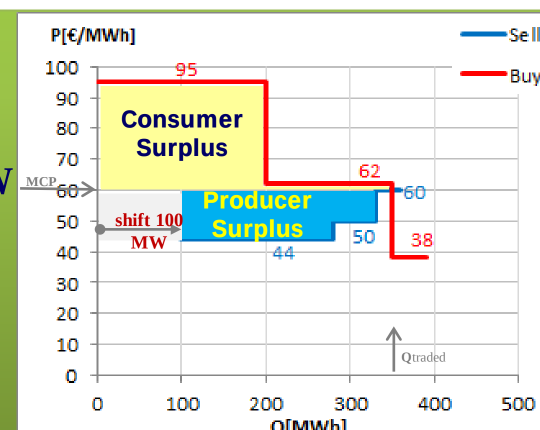


Area 2 (before coupling)

Area 1 (after coupling)



ATC = 100 MW →

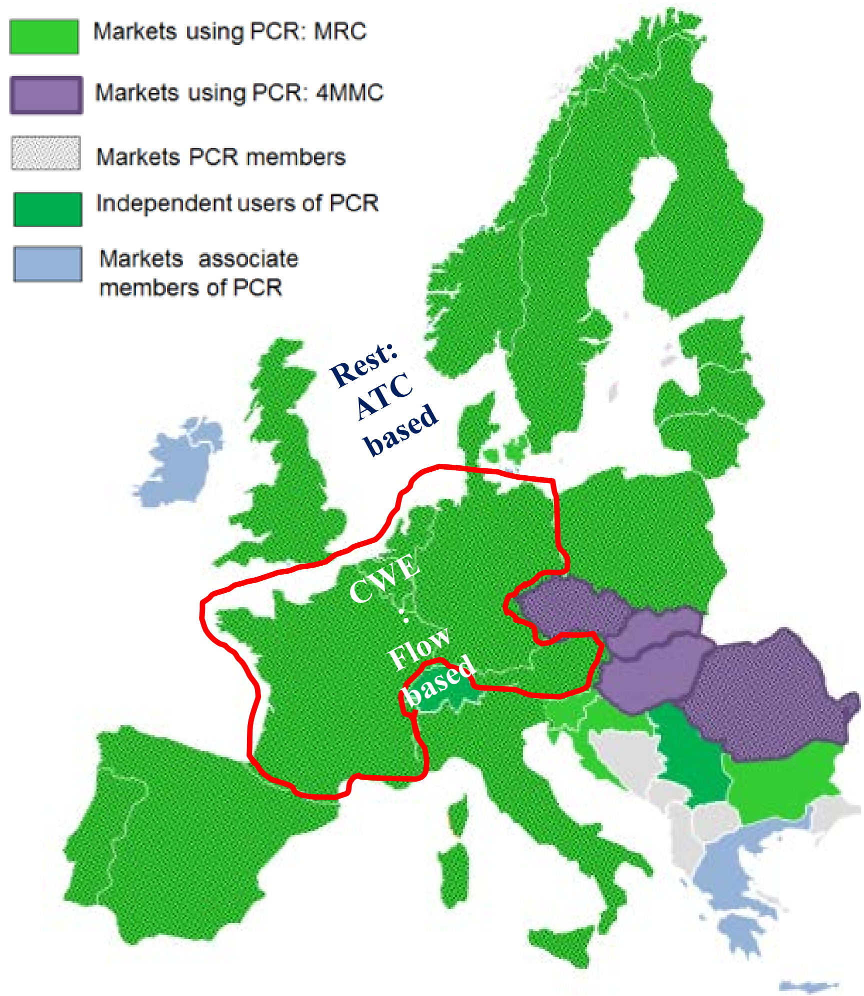


Area 2 (after coupling)

Reminder

Market Coupling: Multi-Regional Coupling (MRC)

- **Marked in red: CWE Flow-based participants (DE+LU, AT, FR, BE, NL)**
  - **Austria (AT) since Oct 2018 separate bidding zone**
- **MRC: single Day-ahead Market Coupling alogrithm (green area)**
  - **Hibrid Flow-based (CWE) and ATC-based (rest)**
  - **Plan to have Flow-based at entire CORE region (CWE+CEE)**
- **In perspective for D-1 level:**
  - **FB entire Continental Europe**
  - **FB Scandinavia (independently)**



Guidelines: FCA

Forward Capacity Allocation

- In force in EU since September 2016
- Defines the requirements on calculation and allocation of transmission capacities on “forward” time horizons: year-ahead, day-ahead typically
- Allows the application of NTC-based or Flow-based capacity definitions
  - Recognises the need for defining “scenarios”, coping with different forecasted network states
  - Still mostly relies on NTC-based principles
- Defines explicit auctions of transmission rights as the allocation method
- Requires single, pan-European allocation platform

- In most of the propositions (methodology, modelling, Bidding Zones…), FCA refers to CACM Guidelines →

Guidelines: CACM GL
Capacity Allocation & Congestion Management

- In force in EU since July 2015
- Defines the requirements on calculation and allocation of transmission capacities on day-ahead and intra-day time horizons
- Allows the application of NTC-based or Flow-based capacity definitions
  - Flow-based where network is strongly interdependent, and where the region is “mature enough“ to apply flow-based market coupling
  - Defines Capacity Calculation Regions (CCR): network areas for which the common capacity calculation methodology is required
- Day ahead: Requires implicit capacity allocation, through Market Coupling
  - Target: in the single Market Coupling procedure for the whole Europe (MRC)
  - $\Rightarrow$ Hybrid of NTC-based and Flow-based Market Coupling
- Requires 24-hours capacity calculation, at standardised Common Grid Models
- Requires periodical assessment of suitability of Bidding Zones
  - Bidding Zone: network area which it can be treated as copper plate for capacity allocation (without internal transmission constraints)

Capacity Calculation Regions (CCR)

CACM GL defines Capacity Calculation Regions (CCR): network areas with the common capacity calculation methodology

CCR 1	**Nordic**
CCR 2	**Hansa**
CCR 3	**Core (CWE+CEE)**
CCR 4	**Italy North (NBI)**
CCR 5	**Greece-Italy (GRIT)**
CCR 6	**South-West Europe (SWE)**
CCR 7	**Ireland and United Kingdom (IU)**
CCR 8	**Channel**
CCR 9	**Baltic**
CCR 10	**South-east Europe (SEE)**

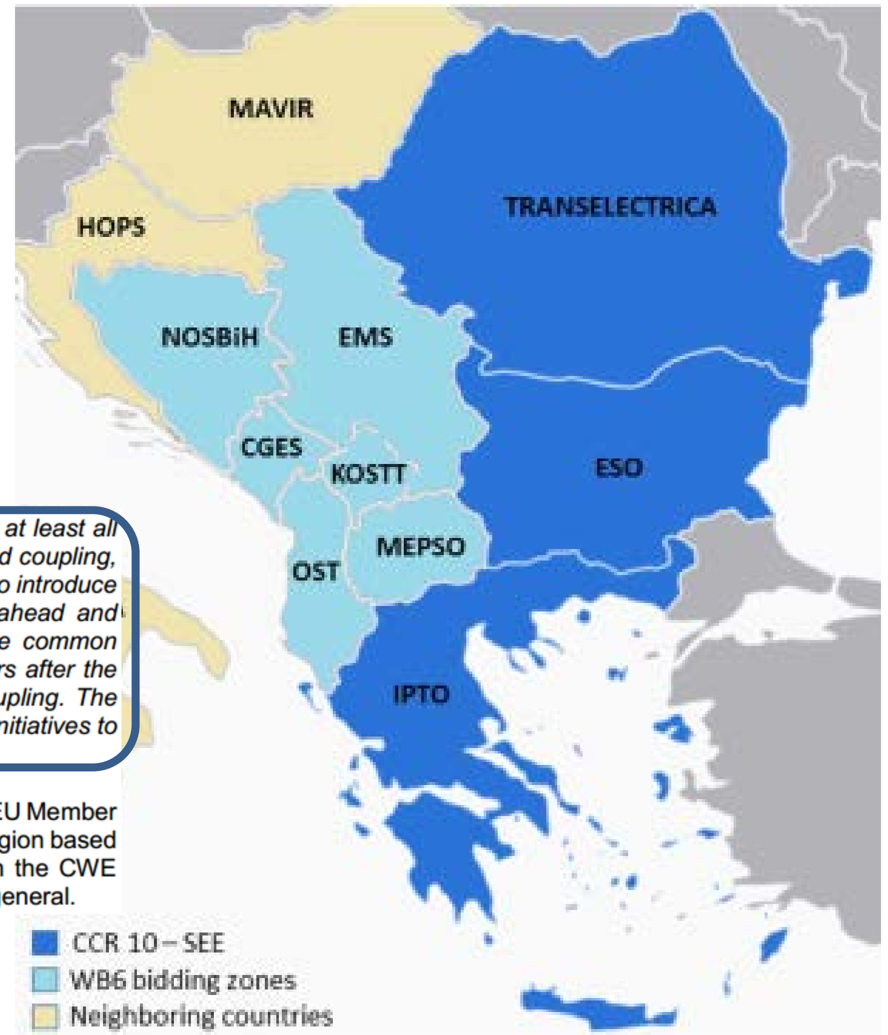
SEE: CCR 10 shadow

- SEE: CCR 10 shadow – under recognition, as an extension of CCR 10 (RO, BG, GR)
- Its definition and calculation methodology, subject to EnCS/EKC Study RCCC
- CCR 10 shadow supposed to include:
  - CCR 10,
  - WB6 TSOs
  - borders to HOPS, MAVIR, TERNA (hvdc)

Methodology:

keep on with NTC-based, until all EnC parties join the NTC-based Market Coupling.

Then, go for Flow-based.



CACM, Article 20.4 referred to above, indicates the following: *"No later than six months after at least all South East Europe Energy Community Contracting Parties participate in the single day-ahead coupling, the TSOs from at least Croatia, Romania, Bulgaria and Greece shall jointly submit a proposal to introduce a common capacity calculation methodology using the flow-based approach for the day-ahead and intraday market time-frame. The proposal shall provide for an implementation date of the common capacity calculation methodology using the flow-based approach of no longer than two years after the participation of all SEE Energy Community Contracting Parties in the single day-ahead coupling. The TSOs from Member States which have borders with other regions are encouraged to join the initiatives to implement a common flow-based capacity calculation methodology with these regions."*

The Article 20.4 of CACM refers to the flow-based methodology, nevertheless it infers that the EU Member States will couple the markets with the Energy Community Contracting Parties from the SEE region based on the NTC approach for capacity calculation. This is fully in line with the experience from the CWE experience and seem to be in line with the views of the stakeholders from the SEE region in general.

EnCS&EKC RCCC project

- **Main goal: facilitating the application of Regional Coordinated Capacity Calculation in Shadow CCR 10 region on D-2 level**
  - Assessment of the readiness of the TSOs
  - Assessment and development of the methodology
  - Governance process
    - + Recognizing the Bidding Zones
    - + Recognizing the Coordinated Capacity Calculator(s)
  - Capacity building

The main deliverable: Methodology for Coordinated Capacity Calculation in Shadow CCR 10 (NTC-based)

NTC: main definitions

Base Case Exchange (BCE):

Initial commercial exchange at the border, already inlcuded in the network model simulation

Total Transfer Capacity (TTC):

Maximum exchange program between two areas, compatible with operational security standards applicable at each system

TTC = BCE + ΔEmax

Transmission Reliability Margin (TRM):

Security margin that deals with uncertainties on the computed TTC values (modelling&forecasting, load-frequency deviations)

Net Transfer Capacity (NTC):

Maximum exchange program between two areas compatible with security standards applicable at each system, taking into account the technical uncertainties on future network conditions

NTC = TTC – TRM

Already Allocated Capacity (AAC): Already allocated transmission rights (at previous auctions)

Available Transmission Capacity (ATC): part of NTC that remains available, after previous auctions, for present auction round

ATC = NTC- AAC

Direction A→B

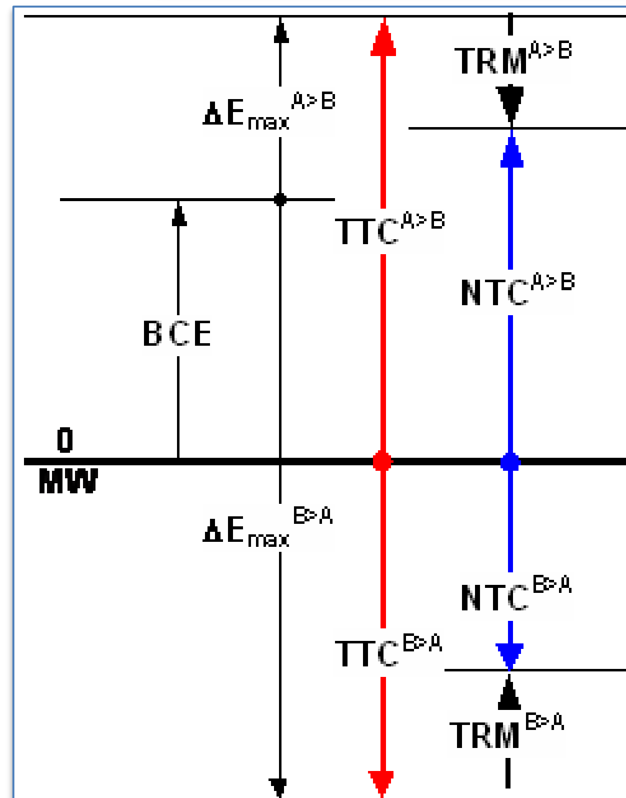
$$TTC^{A\to B} = BCE^{A\to B} + \Delta E_{max}^{A\to B}$$

$$NTC^{A\to B} = TTC^{A\to B} - TRM^{A\to B}$$

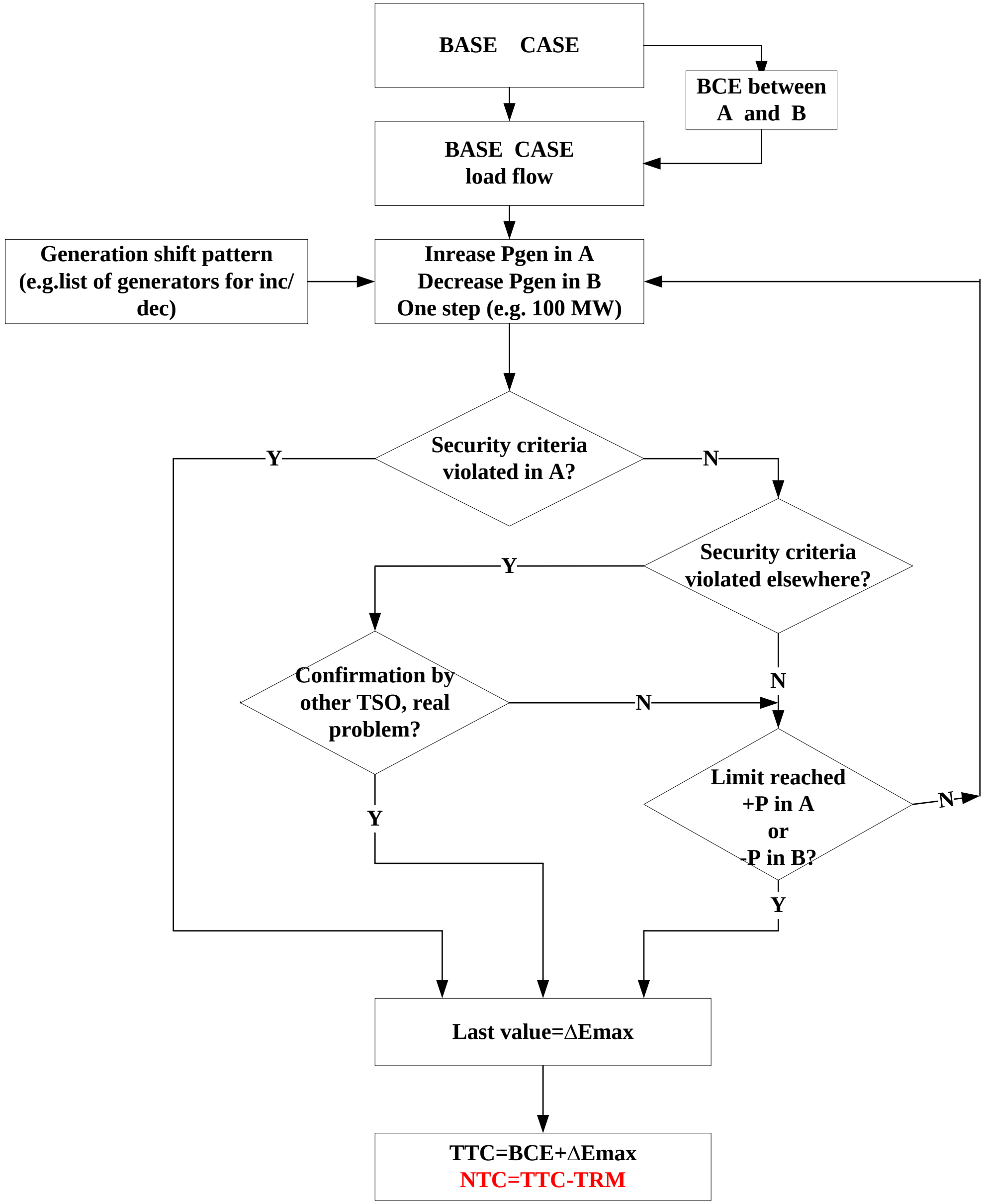
Direction B→A

$$TTC^{B\to A} = BCE^{B\to A} + \Delta E_{max}^{B\to A}$$

$$NTC^{B\to A} = TTC^{B\to A} - TRM^{A\to B}$$



NTC (TTC): calculation methodology



CCC methodology

- **CCC Methodology for Shadow CCR 10 is based on NTC approach.**
- **Following main aspects are specified:**

- Exchange of IGMs and CGMs
- Base Case Exchange values
- Critical Network Element & Contingency + Remedial Actions
- Operational Security Limits
- Generation/Load Shift Keys
- Composite NTC
- Transmission Reliability Margins

Exchange of IGMs and CGMs

- **Two-days-ahead Individual Grid Models (D-2 IGMs) are the main input for day ahead capacity calculation.**
- **TSOs are obliged to create their D-2 IGMs on daily basis for all 24 hours using the best available forecasts of production and consumption, as well as their net positions.**
- **In order to produce IGMs with net positions that sum to zero on Continental Europe level, TSOs should use *balanced net positions*.**
- **Common Grid Model Alignment (CGMA) is a process used for alignment of net positions of modelled areas, and HVDC flows on the level of Continental Europe.**
- **CGMA process: referring to the scenarios for which market schedules are not available (D-2, … month-ahead, year ahead).**

Base Case Exchange values

- BCE values are related to the best forecast of commercial exchanges at the time frame considered (as a “starting“ modelled cross-border exchange).
- In meshed system, BCE values are regularly different from base case physical cross-border flow (NTF), due to loop flows.
- BCE, many options to define it. Finally adopted:
  - BCE≡NTF (in transition process)
  - BCE taken from Common Grid Model Alignment (CGMA) process (if / when considered credible)

Critical Network Elements&Contingency, Remedial Actions

- **Critical Network Element (CNE), "Critical Branch":**

network element (either within a bidding zone or between bidding zones) impacted by cross-border trades.

- **Critical Network Element and Contingency (CNEC), "Critical Branch/Outage"**

represents a set of CNE and specific operational situation for which CNE shall be monitored during capacity calculation. Operational situation can be "N" state, or contingency case (N-1, N-2…).

- **Remedial Actions (RA): Preventive/Curative/Special protection Scheme (SPS)**

all measures applied in due time by TSOs (individually within their biding zone or coordinated if they impact multiple grids) to relieve overloads on certain CNEs, i.e. to keep system in secure state and to maximize cross-border capacities.

  - **Non-costly measures (topological actions, PST taps, controlling reactive flows…)**
  - **Costly measures (redispatching, counter trading, curtaliments…)**

Non-costly RA typically to be used in NTC calculation

Operational security limits

- Line rating – Permanent Admissible Transmission Loading (PATL) or
- Transformer rating

$$I_{max} = \frac{S_{nom}}{\sqrt{3} \cdot V_1}$$

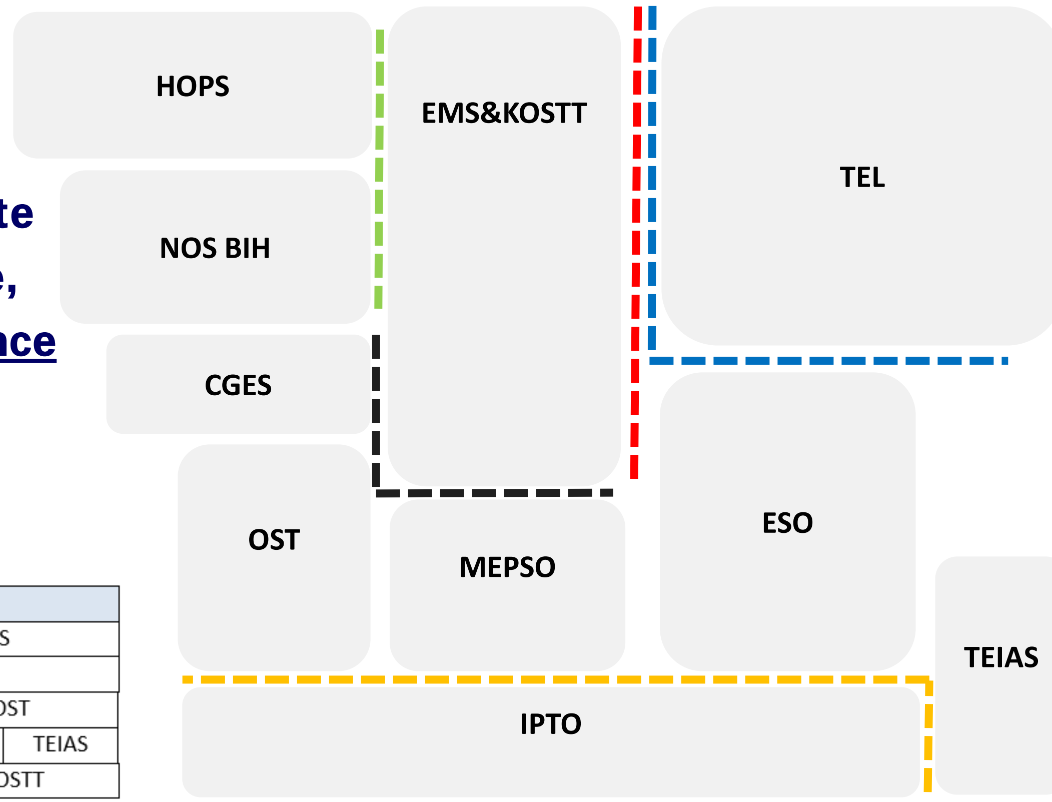
- For IGMs described through CGMES format PATL and TATL (Temporary Admissible Transmission Loading) can be defined
- Since thermal current limits are dependent on weather conditions, Imax is usually changed on the seasonal level or more often.

Generation&load shift keys

- Generation/load shift keys (GLSKs): method of altering net position of a given bidding zone by estimated specific injection increases or decreases
- According to the current NTC calculation practice in SEE region, the most common generation/load shift key methods are:
  - Proportionally to generation reserve (respecting Pmin-Pmax)
  - Proportionally to base case engagement of plants
  - Using fixed coefficients per plants
  - Merit Order List
- Default method for CCR 10 Shadow is: proportionally to generation reserve, using all generation units

Composite NTC

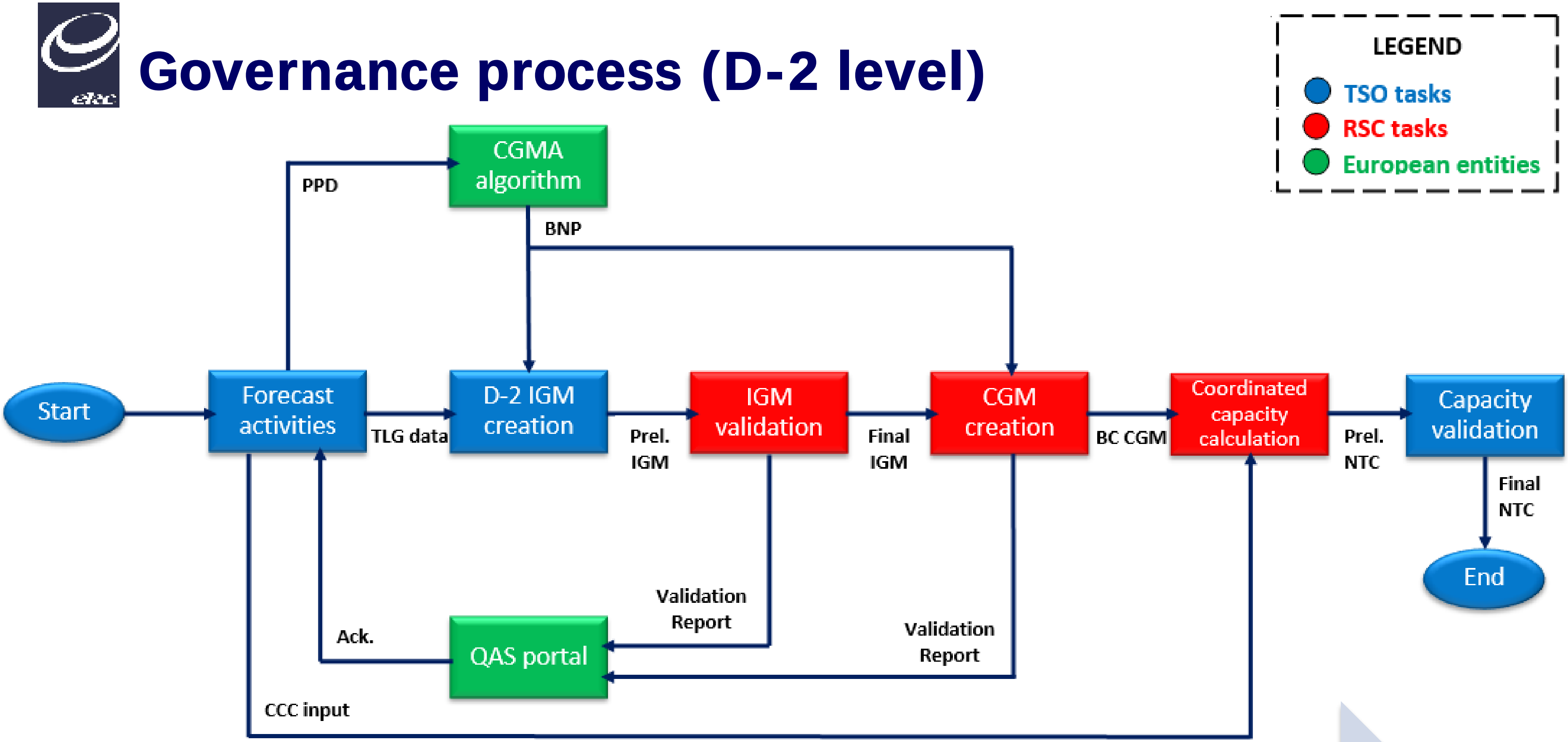
- **For each border/direction, composite or bilateral calculation is to be done, based on its <u>network interdependence</u>**
- **Initial borders with composite NTC:**



No.	Area 1	Area 2
1*	EMS&KOSTT	NOS BiH, HOPS
2*	TRANSELECTRICA, ESO	EMS&KOSTT
3*	EMS&KOSTT	CGES, MEPSO, OST
4**	ADMIE	OST, MEPSO, ESO, TEIAS
5**	TRANSELECTRICA	ESO, EMS&KOSTT

- **Splitting of composite NTC per bilateral borders:**
  - **Static coefficient: proportionally to Imax of tie lines;**
  - **Dynamic coefficient: proportionally to Δ(border flow) during NTC calculation;**
  - **Fixed ratio: common agreement on a ratio, by all involved TSOs**

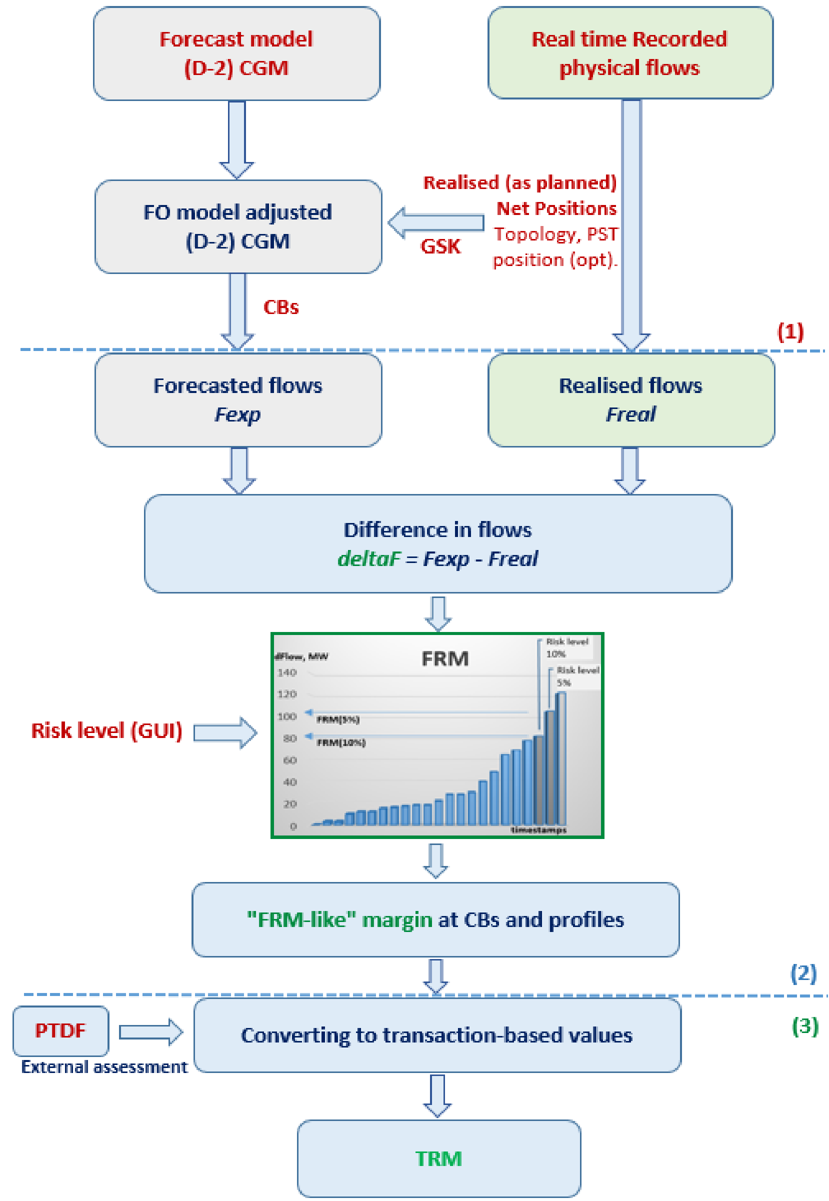
Governance process (D-2 level)



- **CGMA** – Balanced Net Positions – D-2 17:05
- **TSO** – Delivery of D2CF IGMs – D-2 19:00
- **MA** – Creating D2CF CGMs – D-2 19:00-20:00
- **Calculator** – Performing NTC Calc. – D-2 20:00-D-1 07:00
- **TSO** – Final NTC values – D-1 08:00

Transmission Reliability Margin

- Reliability Margin covers uncertainties in the period between the capacity calculation and real time and flow deviations due to load-frequency control
  - TRM at NTC-based
  - FRM at flow-based
- TRM assessment still empirical in many TSOs
- CACM requires clear RM methodology; also a task within RCCC project
  - offline process; to be reviewed on at least yearly basis
  - to be based on historical data
  - with statistical analysis



Methodology proposed for CCR Shadow 10:

- *Comparison of realized flows and D-2 forecasted flows (from adjusted D-2 models)*
- *Statistical analysis (risk level 5%)*
- *Obtaining border-wise flow deviation (≈FRM)*
- *Converting to TRM, by sensitivity factor (PTDF)*

TRM calculation example

Area 1->Area 2				
time-stamp	Pexp Expected flow	Preal Realised flow	Δflow	Δflow (≥0)
t1	598	610	12	**12**
t2	611	621	10	**10**
t3	596	614	18	**18**
t4	603	528	-75	
t5	598	518	-80	
t6	651	651	0	**0**
t7	646	626	-20	
t8	653	683	30	**30**
t9	648	697	49	**49**
t10	651	666	15	**15**
t11	628	613	-15	
t12	631	622	-9	
t13	596	701	105	**105**
t14	603	725	122	**122**
t15	598	531	-67	
t16	648	676	28	**28**
t17	651	679	28	**28**
t18	636	676	40	**40**
t19	653	669	16	**16**
t20	598	663	65	**65**
t21	611	595	-16	
t22	616	694	78	**78**
t23	613	695	82	**82**
t24	608	611	3	**3**
t25	611	633	22	**22**
t26	656	629	-27	
t27	663	616	-47	
t28	661	649	-12	
t29	658	675	17	**17**
t30	661	673	12	**12**
t31	591	568	-23	
t32	593	552	-41	
t33	596	665	69	**69**
t34	591	566	-25	
t35	593	567	-26	
t36	576	539	-37	
t37	571	557	-14	
t38	543	481	-62	
t39	543	561	18	**18**
t40	546	549	3	**3**

	No.	timestamp	Δflow (≥0) ascending
	n1	t6	**0**
	n2	t24	**3**
	n3	t40	**3**
	n4	t2	**10**
	n5	t1	**12**
	n6	t30	**12**
	n7	t10	**15**
	n8	t19	**16**
	n9	t29	**17**
	n10	t3	**18**
	n11	t39	**18**
	n12	t25	**22**
	n13	t16	**28**
	n14	t17	**28**
	n15	t8	**30**
	n16	t18	**40**
	n17	t9	**49**
	n18	t20	**65**
	n19	t33	**69**
90%	n20	t22	**78**
95%	**n21**	**t23**	**82**
	n22	t13	**105**
100%	n23	t14	**122**

- Observing expected and realised flows over some border/direction; can be composite profile as well.
- E.g. 40 timestamps, with flow in “positive“ direction
- Out of those 40, the 23 have “positive” flow deviation (contributing to cross border flow ⇒ potentially endangering security)
- They are sorted in ascending order
- If e.g. 95% of percentiles is to be taken into account (“Risk level 5%”)
- **Resulting border-wise FRM value is 82 MW**

- If typical “sensitivity factor” PTDF on lines between TSOs A and B for transaction A-B is 75%
- TRM = FRM/PTDF = 82/0.75 = 109 MW
- **Resulting TRM value is 109 MW**

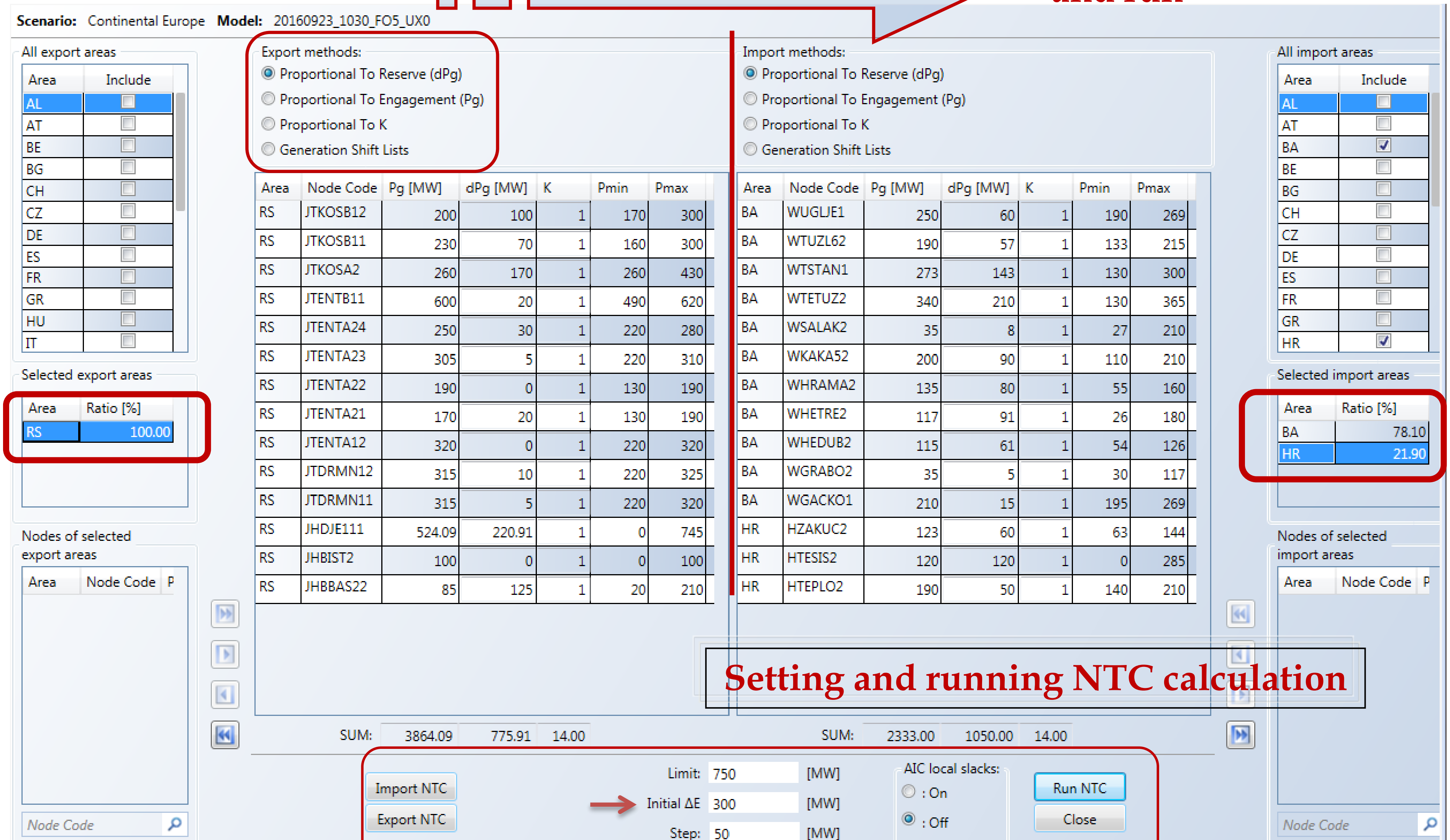
NTC (TTC) calculation example: Serbia → Croatia&BiH

1. Selecting the simulation network model
2. Defining Base Case Exchange
3. Defining n-1 contingency and monitoring lists
4. Run the calculation...

NTC calculation

Generation shift

Calculation setup and run



Area	Ratio [%]
RS	100.00

Area	Node Code	Pg [MW]	dPg [MW]	K	Pmin	Pmax
RS	JTKOSB12	200	100	1	170	300
RS	JTKOSB11	230	70	1	160	300
RS	JTKOSA2	260	170	1	260	430
RS	JTENTB11	600	20	1	490	620
RS	JTENTA24	250	30	1	220	280
RS	JTENTA23	305	5	1	220	310
RS	JTENTA22	190	0	1	130	190
RS	JTENTA21	170	20	1	130	190
RS	JTENTA12	320	0	1	220	320
RS	JTDRMN12	315	10	1	220	325
RS	JTDRMN11	315	5	1	220	320
RS	JHDJE111	524.09	220.91	1	0	745
RS	JHBIST2	100	0	1	0	100
RS	JHBBAS22	85	125	1	20	210

Area	Node Code	Pg [MW]	dPg [MW]	K	Pmin	Pmax
BA	WUGLJE1	250	60	1	190	269
BA	WTUZL62	190	57	1	133	215
BA	WTSTAN1	273	143	1	130	300
BA	WTETUZ2	340	210	1	130	365
BA	WSALAK2	35	8	1	27	210
BA	WKAKA52	200	90	1	110	210
BA	WHRAMA2	135	80	1	55	160
BA	WHETRE2	117	91	1	26	180
BA	WHEDUB2	115	61	1	54	126
BA	WGRABO2	35	5	1	30	117
BA	WGACKO1	210	15	1	195	269
HR	HZAKUC2	123	60	1	63	144
HR	HTESIS2	120	120	1	0	285
HR	HTEPLO2	190	50	1	140	210

Area	Ratio [%]
BA	78.10
HR	21.90

Setting and running NTC calculation

NTC calculation results

Critical step: **650** MW; accepted step: **600** MW

BCE= 563 MW
ΔEmax= **600** MW
TTC=1113 MW
TRM= 100 MW
NTC= 1013 MW

Summary by steps (11)

Export	Step	DEmax	Outages	Overloaded	Loading max [%]
☐	3	400	93	1	100.3
☐	4	450	93	1	101.9
☐	5	500	93	1	103.6
☐	6	550	93	1	105.3
☐	7	600	93	1	107.0
☑	8	650	93	2	108.7
☐	9	700	93	4	110.4
☐	10	750	93	4	112.1

Export areas

Name
RS

Import areas

Name
BA
HR

Calculated parameters

NTC	1113.2	[MW]	TTC	1213.2	[MW]
NTF	563.24	[MW]	TTF	870.95	[MW]
BCE	563.2	[MW]	TRM	100.0	[MW]
DEmax	650.0	[MW]	DFmax	307.71	[MW]
PTDFbase	100.0077	[%]	PTDFmax	71.78965	[%]

Outages (2/93)

ID	Name	Overload	DIV
5	Outage 5	1	
50	Outage 50	1	

☑ Overloaded&diverging only

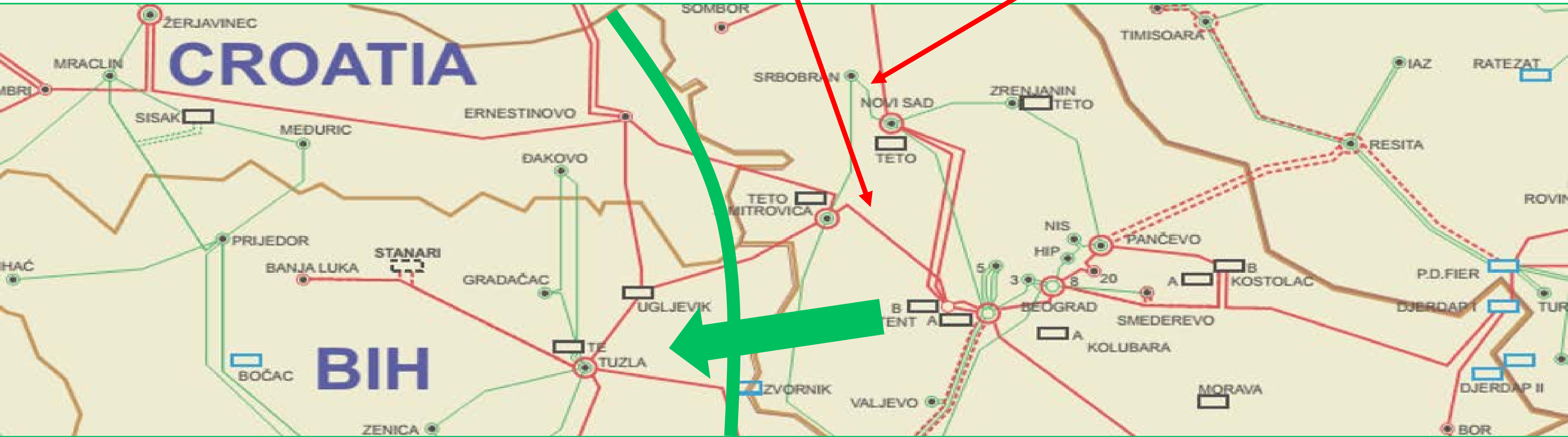
Contingency elements (1)

CIM ID	Node 1	Node 2	Node 3
_4baab4a7-480d-59b8-4f76-a9cee9a12	JRPMLA12	JSMIT211	

Details of the overloaded elements (1)

CIM ID	Name	Loading [%]
_384903c9-c40b-8af2-afde-412a2f6	JNSAD322 JSRBOB2	108.7

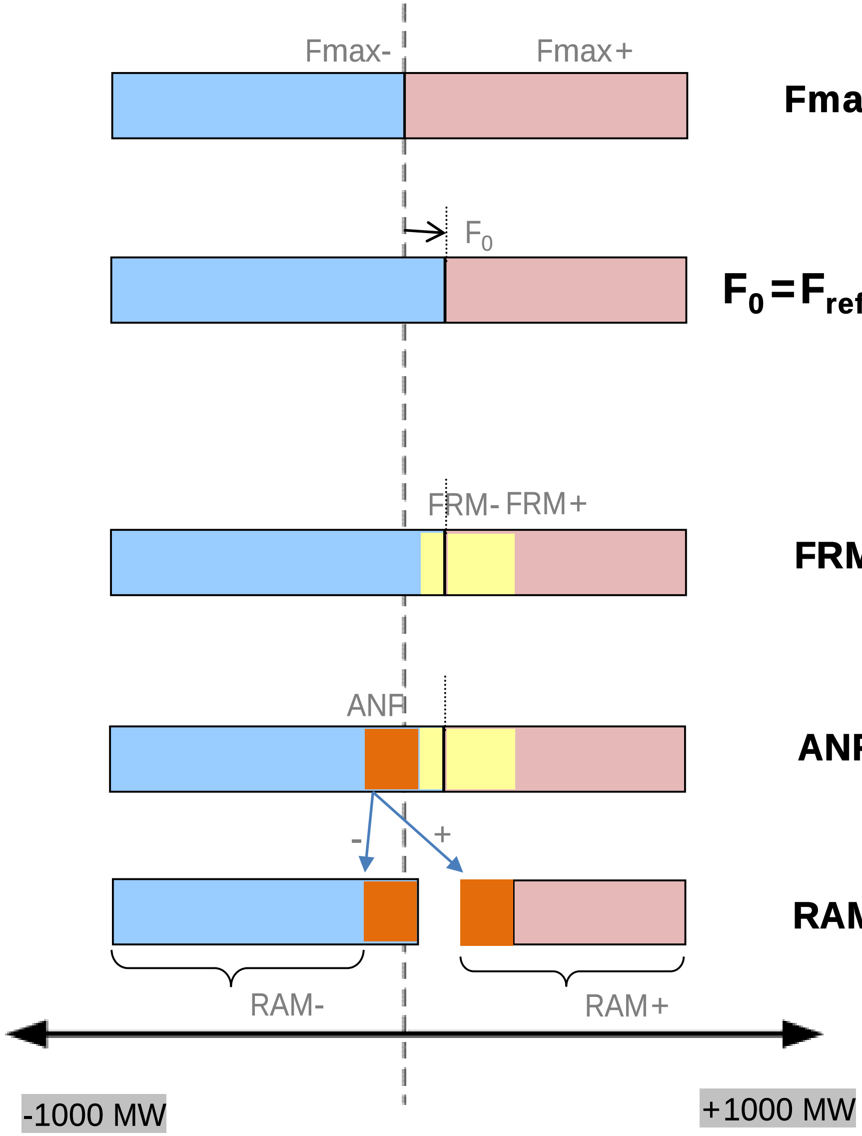
Export results | Export models | Close



Flow-Based capacity calculation

Flow-based calculation: definitions

Simplified calculation example, for one CNEC (Critical Branch/Critical Outage)



Fmax

Maximum Flow: Full capacity of element
Fmax= √3*U*Imax*cosΦ (MW)

$\mathbf{F_0=F_{ref}-F_{NP}}$

$\mathbf{F_0}$: Base Flow (loop & outside flows).
$\mathbf{F_{ref}}$: Load flow (calculated AC or DC) on the CB, for certain CO;
NP (i.e. BCE): exchanges among participating areas, in network model ($\mathbf{F_{NP}}$=BCE*PTDF)

FRM

Flow Reliability Margin: margin, containing modelling mismatches, uncertainties of flows by outside areas, influence of LF Control

ANF

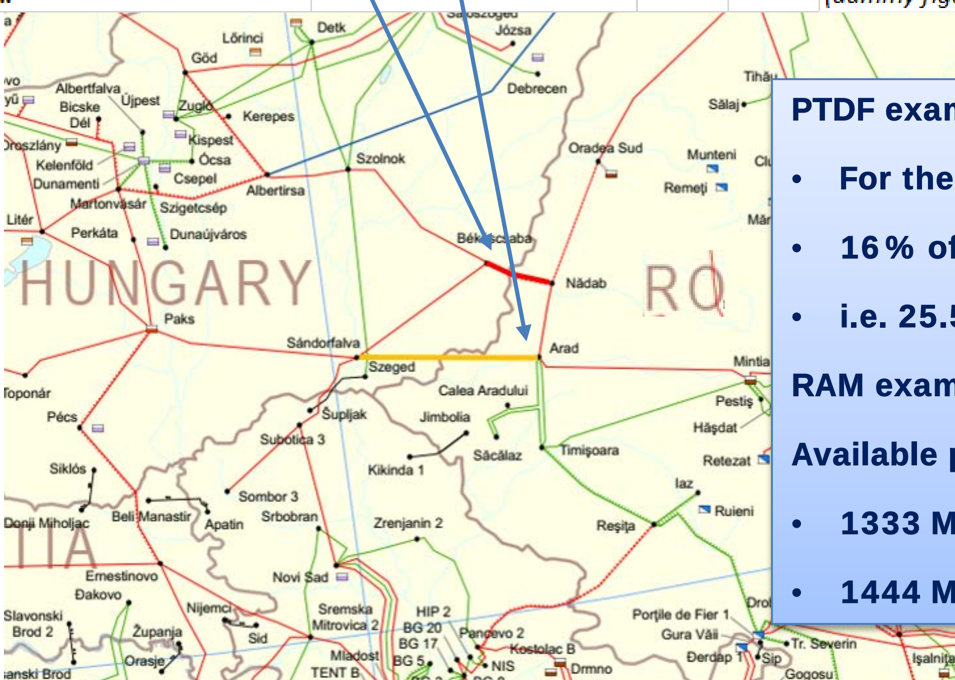
Already Nominated Flow: flow due to Long-term nominations
ANF= YMnominations * PTDF; $F_{ref}'=F_0+ANF$

RAM

Remaining Available Margin

Flow-based capacity calculation: example

# PTDF/RAM, hour 01				RAM		PTDF							
critical_branch	critical_outage	from	to	RAM+	RAM-	AL>BA	AL>BE	AL>BG		RO>HU	BA>AL	BA>BE	
XWI_GY21 OWIEN 21 1	(base case)	HU	AT	296	150	0.1%	2.1%	-0.2%	...	-0.6%	-0.1%	2.0%	...
XWI_GY21 OWIEN 21 1	OSARA 11 OZURND11 1	HU	AT	293	153	0.1%	2.5%	-0.3%	...	-0.8%	-0.1%	2.4%	...
XBE_NA11 MBEKO 11 1	(base case)	RO	HU	1333	1444	3.3%	8.3%	-4.6%	...	16.0%	-3.3%	5.0%	...
XBE_NA11 MBEKO 11 1	XSA_AR11 MSAFA 11 1	RO	HU	1372	1398	5.5%	10.1%	-8.1%		25.5%	-5.5%	4.7%	...
XBE_NA11 MBEKO 11 1	MBEKO 11 MSAFA 11 1	RO	HU	1231	1539	2.7%	10.6%	-3.3%	...	14.2%	-2.7%	7.9%	...
XBE_NA11 MBEKO 11 1	MAISA 11 MSZOL 11 1	RO	HU	1222	1448	2.5%	4.8%	-3.8%	...	12.9%	-2.5%	2.3%	...
XSA_AR11 MSAFA 11 1	(base case)	RO	HU	1184	1033	3.0%	2.5%	-4.9%		13.3%	-3.0%	-0.5%	...
XSA_AR11 MSAFA 11 1	MBEKO 11 MSAFA 11 1	RO	HU	1258	959	3.6%	0.6%	-6.0%		14.8%	-3.6%	-3.0%	...
XSA_AR11 MSAFA 11 1	XBE_NA11 MBEKO 11 1	RO	HU	1135	1082	5.4%	8.5%	-8.2%		24.8%	-5.4%	3.1%	...
XSA_AR11 MSAFA 11 1	XPF_DJ11 JHDJE111 1	RO	HU	1158	1059	3.2%	1.6%	-7.6%		17.9%	-3.2%	-1.6%	...
LBERIC2 LKLECE2 1	(base case)	SI	SI	399	399	0.1%	0.5%	-0.3%	...	-0.4%	-0.1%	0.4%	...
...				*(dummy figures)*									



PTDF example:

- **For the 100 MW commercial transaction between RO->HU,**
- **16% of it would flow over CB Nadab-Bekescaba (in base case),**
- **i.e. 25.5%, in case of Outage of CO CO Arad-Sandorfalva**

RAM example:

Available physical capacity at CB Nadab-Bekescaba, in base case:

- **1333 MW in forward direction**
- **1444 MW in reverse direction ...**

Thank you for your attention!

Electricity Coordinating Center Ltd. Belgrade

Vojvode Stepe 412, 11000 Beograd

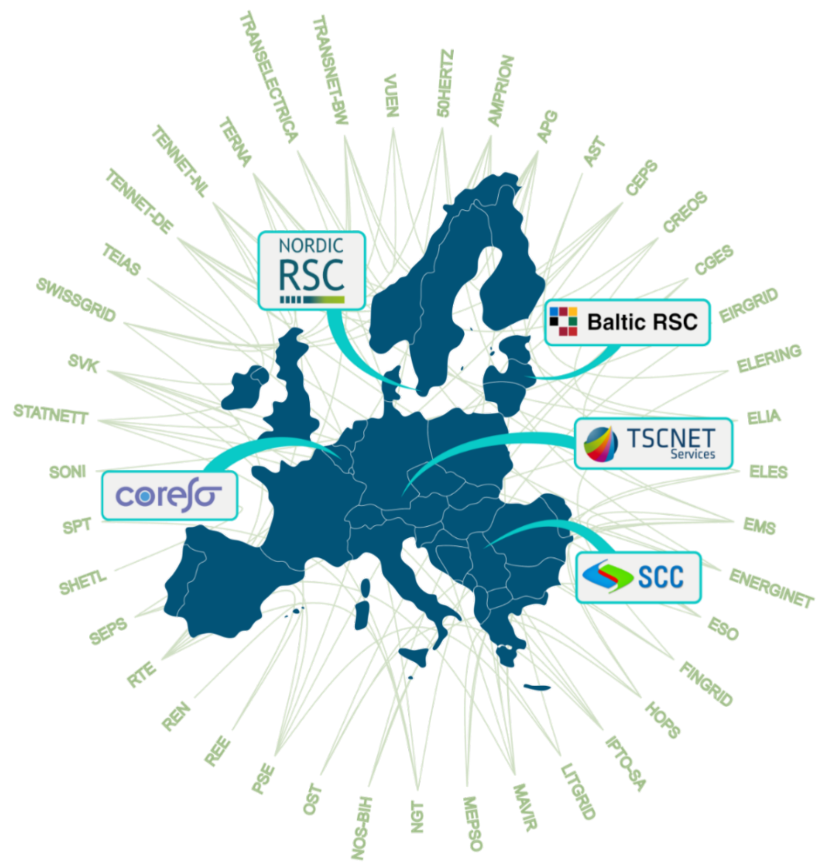
E-mail: zoran.vujasinovic@ekc-ltd.com

Web: www.ekc-ltd.com

Backup slides…

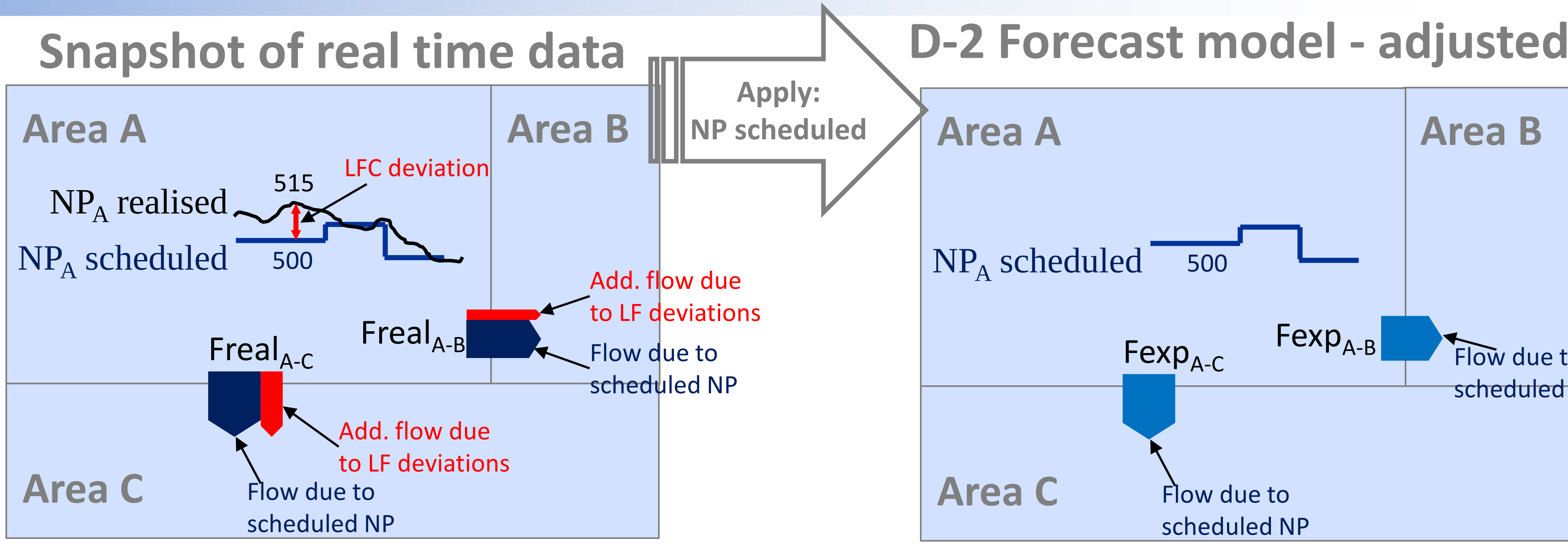
Coordinated Capacity Calculator, in perspective

No.	Bidding Zone 1	RSC 1	Bidding Zone 2	RSC 2	Expected Capacity Calculator
1	EMS&KOSTT	SCC	ESO	SCC	SCC
2	EMS&KOSTT	SCC	MEPSO	SCC	SCC
3	EMS&KOSTT	SCC	OST	SCC	SCC
4	EMS&KOSTT	SCC	CGES	SCC	SCC
5	EMS&KOSTT	SCC	NOS BIH	SCC	SCC
6	MEPSO	SCC	ESO	SCC	SCC
8	CGES	SCC	NOS BIH	SCC	SCC
9	CGES	SCC	OST	SCC	SCC
10	ESO	SCC	IPTO	SCC	SCC
11	IPTO	SCC	OST	SCC	SCC
12	MEPSO	SCC	IPTO	SCC	SCC
13	EMS&KOSTT	SCC	Transelectrica	TSCNET	SCC/TSCNET?
14	EMS&KOSTT	SCC	HOPS	TSCNET	SCC/TSCNET?
15	EMS&KOSTT	SCC	MAVIR	TSCNET	SCC/TSCNET?
16	NOS BIH	SCC	HOPS	TSCNET	SCC/TSCNET?
17	Transelectrica	TSCNET	ESO	SCC	SCC/TSCNET?
18	CGES	SCC	TERNA	CORESO	SCC/CORESO?



- Required to designate coordinated capacity calculator, per each border
- Borders between service users of different RSCs require further coordination and sharing of tasks among RSCs

TRM: How flow deviations due to LFControl are considered?



By applying scheduled and not realised Net Position from D to D-2, intentionally the difference among resulting cross-border flows is increased for the influence of LFC deviation.

Comparison of **Frealised** vs **Fexpected**

Intentionally the “LFC component” of Fexpected is omitted, and thus it is included in difference, and in Reliability Margin

E.g. Country A for the timestamp hh:30, has:
planned Net Position = 500 MW, and realised Net Position = 515 MW (this 15 MW difference is due to the operation of LFC)
Real time recorded CB flows (Freal) actually correspond to the "515 MW" situation

⇒ if adjustment of Net Position of D2CF model would be done:
  - ⇒ to exact 515 MW, then comparison Freal vs. Fexpected, inlcudes only inaccuracies component
  - ⇒ to 500 MW („before“ LFC), then comparisons Freal vs Fexpected includes both inaccuracies and deviations