# A4 – Appendix 4: Coordinated Operational Planning

### *Chapters*

**A. ENTSO-E RG CE network calculations**

**B. NTC Capacity Assessment**

**C. Flow-Based Capacity Assessment**

### *History of Changes*

v 2.4. draft reviewed policy, to RG CE Plenary, 4.10.2010, comments from external consultation

v 2.3. draft reviewed policy, to WG O&S, 8.02.2010, comments from internal consultation

v.2.2 draft reviewed policy, to WG O&S, 26.08.2008, after comments from WG OS

v.2.1 draft reviewed policy, to WG O&S, 1.09.2008

v.2.0 final policy, approved by the UCTE Steering Committee on 03.05.2006

# A. ENTSO-E RG CE network calculations

## *ENTSO-E RG CE Network Data Sets*

The need to compute the behaviour of the meshed European electric network requires that each TSO provides a network data set that describes the model of each network including the generation and load data. This data set is given in the CIM-format.

There are three types of data sets:

- Forecast – used in the DACF procedure or flow-based allocation procedure,
- Snapshot – information retrieved from the real-time system, describing the real situation at a specific moment in time,
- Reference – full description of the network for future winter and summer situations with expected exchange scenarios.

These data sets provide a useful database that enables various types of studies, such as:

- expansion of the ENTSO-E continental European network,
- computation of the NTC values.

**Forecast data sets.** These so called DACF data sets are used to forecast possible congestion in the day ahead procedure. The DACF data sets are generated after the gate closure of the market and their export/import balances have to match with the exchanges provided in the VULCANUS system. The two days ahead system situation is represented by the D-2CF data sets. These models are used in the allocation procedure in the daily cycles. The model comprises the changes of topology for the predicted day. The detailed description of both data sets can be found further on in this document. For the purpose of intraday congestion forecasts, the plan is to use the IDCF models, which can be based on the snapshots and adopted system situation.

**Snapshot data sets.** Each TSO retrieves from their Energy Management System (EMS) the real-time data needed for this task. Normally the network data is obtained from the state estimator functionality. It is recommended to provide the snapshot after a power flow computation. The network equipment that is out for maintenance is marked as out of operation. In order to enable merging of the data, TSOs have to use the same timestamp for the snapshot data sets.

**Reference data sets.** These data sets are forecasted not for the day ahead (as used in the DACF), but for the medium term. The medium term forecast is made for the next summer or winter to provide a good base to compute the NTC. For the reference data sets all the network and generation data must be provided, including the minimum and maximum limits of active and reactive power (MW, Mvar) for each generator/plant. All the network elements are considered to be in operation. Next to the reference data sets, the short circuit model is produced. The first one is provided every 5 years or on request and describes the input data for short circuit calculations.

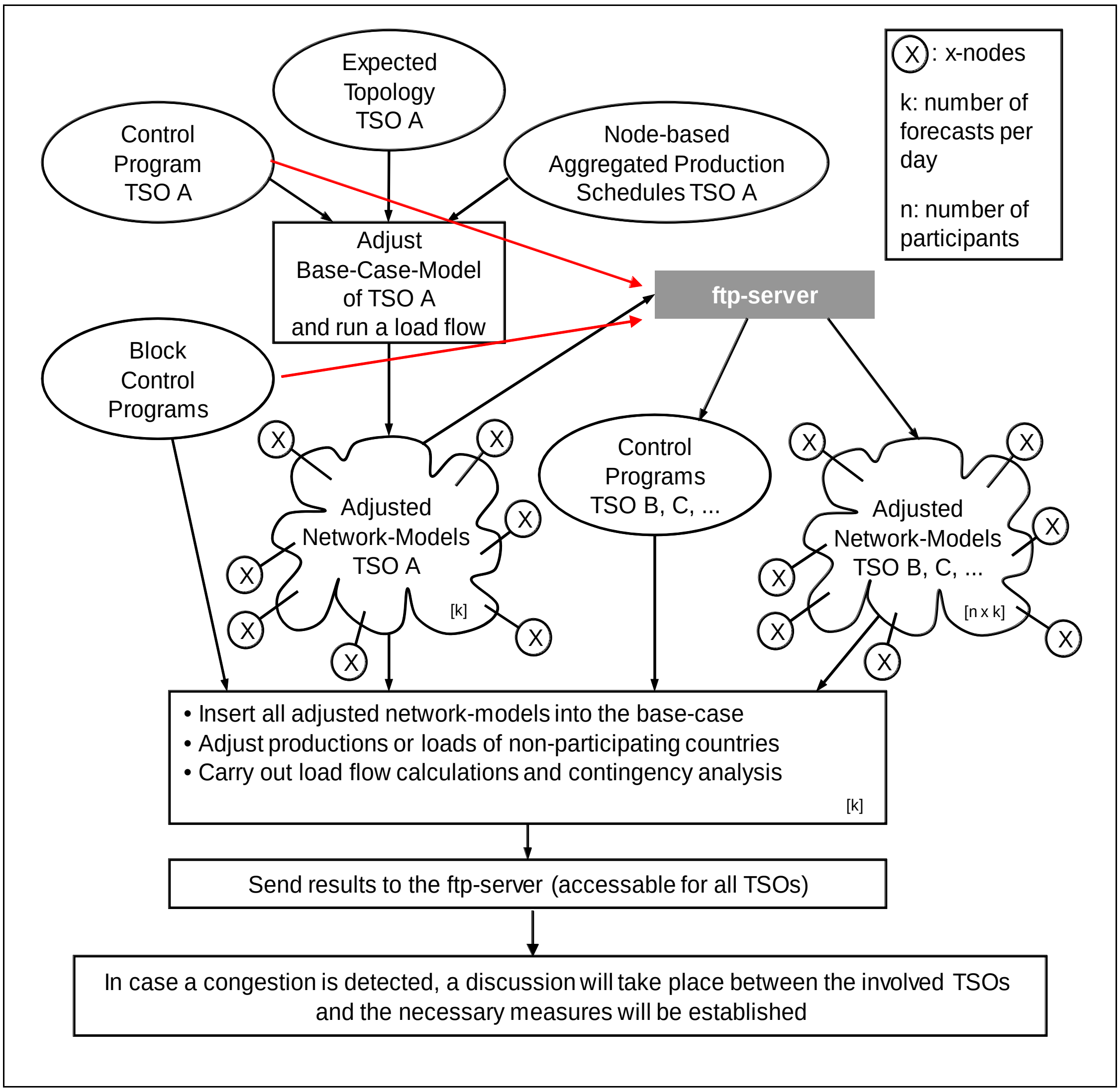
## *DACF procedure*

The different steps of the modular short-term load flow forecast and security analysis are as follows:

- Based on a data set of its own network each TSO collects the forecast data for the agreed timestamps (production schedules from the 750-/380-/220-kV-power plant operators, topology, import/export programs etc.) and adjusts a suitable selected load flow data set in the following way:
    - Extract the part of the data set representing their own network by cutting all TIE LINES in their electrical center (half the line parameters) and adding a fictitious node (starting with the character “X” in its name).
    - Replace the injections (generation) in the own network by the available node-based aggregated production schedules (considering the export/import situation) and adapt the network topology, tap position, etc., according to the expected state of the forecast time of the following day.
    - Adjust the loads in their own region based on a convenient estimated load distribution, taking into account the production in the distribution system, so that the sum of the production minus the losses minus the sum of the loads equals the control program (i.e. the sum of the scheduled power exchanges including generation of power plants operating in VIRTUAL TIE LINE mode).
    - Determine enough possibilities of realistic Mvar production in their own network to allow the load flow to reach a suitable voltage level.
    - Adjust the injection (load or generation) in the fictitious X-nodes to match the exchange program according to roughly estimated TIE LINE flows. These adjusted flows have no influence on the results obtained after the composition of the total interconnected system, because their sole purpose is to allow a stand-alone plausibility check of the TSO’s network.
    - Carry out a stand-alone load flow calculation of the TSO load flow data set to check the proper participation of the slack bus (only used for compensating the network losses) and the plausibility of the result (MW, Mvar, voltage).
- To exchange the control programs, the VULCANUS system is used, once its flaws (e.g. VIRTUAL TIE LINES of jointly owned power plants) are corrected. Each TSO takes the last available load flow DACF data set.
- After having collected the complete load flow data sets of all other TSOs, all these data sets have to be merged (reference will be given) by connecting the “X-nodes” and setting the X-node injections to zero.
- Adjust the production or even load in TSOs' load flow data set for which the time stamp is not available (or even group of TSOs) linearly or using other information so that the sum of the production minus the losses minus the sum of the loads equals the control program.
- Perform a security analysis (⏩P3-A) on the merged DACF data sets.

## *DACF visualisation*

The defined DACF procedure is visualised in the following figure.



# B. NTC Capacity Assessment

## *Guideline for NTC determination*

## Definitions

NTC (net transfer capacity)

NTC = BCE + ΔE – TRM

where:

BCE: Base Case Exchange (scheduled exchange)

ΔE: Maximum shift of generation that can be assigned to control areas involved in the interconnection preventing any violation of the N-1 SECURITY PRINCIPLE.

TRM: Transmission Reliability Margin

ATC: Available Transfer Capacity

ATC = NTC – AAC

where:

AAC: Already Allocated Capacity

**Reference Base Case Preparation**

The input data sets (winter, summer) are the ENTSO-E RG CE reference cases based on the ENTSO-E RG CE snapshot that have to obey the following rules:

- For all generation nodes that are to be considered for the NTC determination, the minimal and maximal output power must be indicated. Generators out of operation in the base case must also be included, with their corresponding limits, so that they could be switched on if necessary during NTC determination.
- In cases where a node of the transmission network is linked by a transformer to a lower voltage radial network with load and generation, the load and the generation can be summed up separately and indicated in the node of the transmission network (thus the aggregated generation of the lower voltage network can be used for the NTC determination). In this case the summed minimum and the maximum of the generation power must be indicated. In the case of meshed underlying networks, that procedure is not admissible; such networks have to be explicitly modelled.
- Pump storage stations that also have to be considered for the NTC determination can be defined by the indication of the minimal and maximal power limits.

**Definition of Generation Shift Method**

Generators that take part in the NTC determination must be characterised by their minimal and maximal power limits. It is possible to choose a limited number of generators to perform NTC calculation manually, especially when there are many generators.

The Generation Shift Method deals with the way the global exchange shift is shared between the different generation units.

The chosen generators are used for the NTC determination in the following way: in the area of one TSO (generators i=1,n) the generators' active power is increased and in the area of the other TSO (generators j=1,m) the generators' active power is decreased by the same value simultaneously.

That shift can be accomplished as follows:

**Method A:**

All chosen injections are modified proportionally to the remaining available generation capacity.

$$\boxed{P_{new}^{inc} = P_i + \Delta E \cdot \frac{P_i^{max} - P_i}{\sum_n (P_i^{max} - P_i)}}$$

$$\boxed{P_{new}^{dec} = P_i + \Delta E \cdot \frac{P_i^{min} - P_i}{\sum_n (P_i^{min} - P_i)}}$$

where:

$P_i$ : Actual active power generation (MW)

$P_{new}^{inc}$ : New increased injection, in next iteration it will be $P_i$

$P_{new}^{dec}$ : New decreased injection, in next iteration it will be $P_i$

$\Delta E$ : Shift generation, negative for increasing and positive for decreasing

$P_i^{max}$ : Maximum permissible generation (MW)

$P_i^{min}$ : Minimum permissible generation (MW)

additional condition: $|\Delta E| \le |\sum(Pmax - Pi)|$

additional condition: $|\Delta E| \le |\sum(Pmin - Pi)|$

Advantage: generation over-utilisation is impossible and generation capacities are reached simultaneously. It is also ensured that the evacuating lines are not overloaded because their capacity was based on the maximal power evacuation.

That method should be used by TSOs in the normal case, because it respects the physical limits while operating the transmission grid. The last value of $\Delta E^{max}$ is determined when all generators or any network element reaches its operation limits.

**Method B:**

This method can be used in emergency cases if the indications of the generation limits are missing or as a further calculation after the capacities used in method A have all been reached.

All chosen injections are modified proportionally to the current generation:

$$\boxed{P_{new}^{dec} = P_i + \Delta E \cdot \frac{P_i}{\sum_n (P_i)}}$$

$$\boxed{P_{new}^{inc} = P_i + \Delta E \cdot \frac{P_i}{\sum_n (P_i)}}$$

Remark: delta E has got a different sign (see also method C)!

In this method, the generation limits are not considered; this can lead to an over-utilisation and thus to unrealistic NTC results. The method B indicates a theoretical NTC value of the transmission grid without taking the physical limits of production into consideration.

**Method C:**

The chosen injections are modified proportionally according to a merit order with indications of the ranking after each injection taking the maximal and minimal production into account.

**Generation Shift Computation□ ($\Delta E_{max}$)**

After the generations and the shift method for the NTC determination have been chosen, ΔE is increased iteratively until a relevant constraint is violated.

**Shift Limitation due to Security Constraints**

After each iteration step, the N-1 SECURITY PRINCIPLE must be checked in one's own transmission network; each TSO must decide which elements are to be considered in the n-1 security analysis. It is advisable to take into account some elements in neighbouring systems as well as in one's own grid.

At any rate, the detailed security aspects must be exchanged between the neighbouring TSOs (⏩P3-A).

**Handling of transformer taps, reactive power and losses**

During the NTC determination, the transformer taps and the reactive injections of PQ nodes and HVDC-lines settings are not changed. The change of losses caused by the load flow shift is compensated in the slack node.

# C. Flow-Based Capacity Assessment

## *Definitions*

Critical branch – a branch that is significantly influenced by the cross-border allocation and that is at risk of being constrained due to network security reasons.

Border connection – a single tie line or an aggregated representation of multiple tie lines connecting two neighbouring TSOs.

The difference between critical branches and border connections is illustrated in fig. 1.

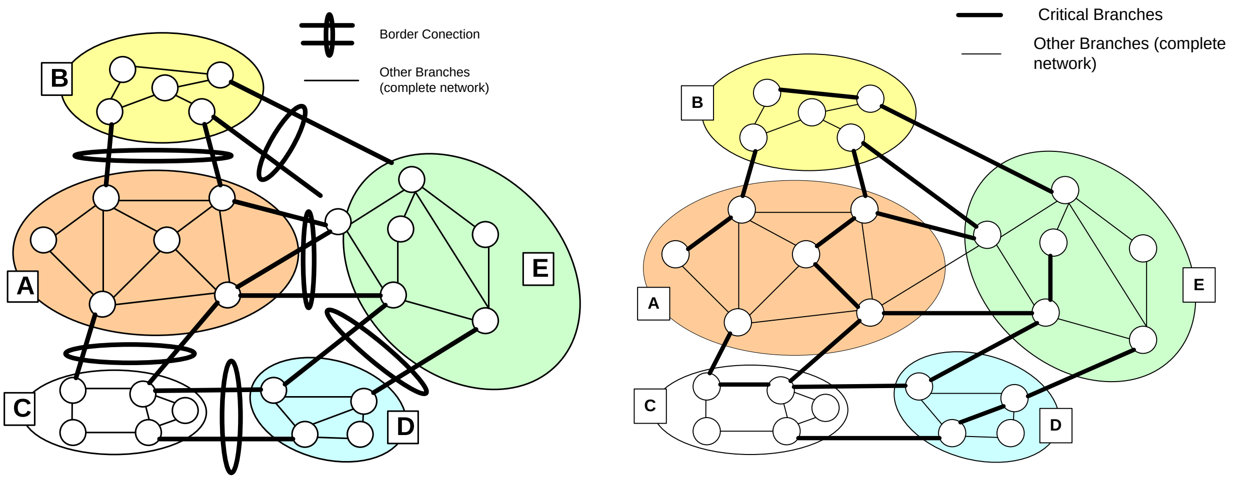



Fig. 1: Critical Branches and Border Connections.

Fref' - an estimate of the flow that is already present on the critical branch or border connection prior to the allocation

Fmax – the maximum allowed flow on a critical branch or border connection. In the case of a critical branch, this is a physical quantity of the branch; it can be the setting of a protective relay that limits the power flow or the thermal limit of the equipment.

FRM (flow reliability margin) - the FRM specifies a flow reliability margin per critical branch or border connection. This figure is not obtained from the underlying grid model nor is it a physical quantity of the line; the FRM is based on operational experience with the grid model/flow-based procedure. The FRM covers the uncertainty that stems from the grid forecast, and the error due to the linear representation of the grid. Inevitably, the FRM reduces the available space on the critical branches because a part of the free space must be reserved to cope with these uncertainties. For the models used for the long-term capacity assessment the margin should be bigger than for the daily one.

PTDF (Power Transfer Distribution Factor) - The PTDFs describe what physical flow on a given critical branch or border connection would be provoked by a requested commercial exchange between two countries or two control areas (or ‘hubs’). These two hubs do not necessarily need to be directly connected. Simply said, the PTDFs translate a commercial transaction between two hubs into the expected physical flows over the entire network. The PTDF matrix is computed from an underlying grid model that is adequate to the current allocation process.

## *Principles*

The flow-based method relies on a linearization of the network describing the relation between net positions or bilateral commercial exchanges and flows in the network in a specific region. Only the flows on the critical branches, or aggregated flows on border connections, are monitored for this purpose, both under N and N-k conditions.

In a flow-based allocation mechanism, the additional flows induced on the critical branches or border connections by commercial transactions should not increase the existing flows (Fref') above the maximum allowed flow corrected with its flow reliability margin (Fmax-FRM) for those elements. So, the flow-based allocation mechanism yields the following modelling:

$$[PTDF]x[T] \leq [F_{\max}] - \lfloor F_{ref}{}' \rfloor - [FRM]$$

As the Fref' represents the flow prior to the allocation, the transaction matrix *T* consists of net positions or bilateral commercial transactions involved in the allocation mechanism only.

Grid model

A Common Grid Model (CGM) is used for the calculation of the power flows needed for the Flow Based Capacity Assessment (FBCA). The state of the system is forecasted for the adequate time period. It represents the region as detailed as the forecast period allows. The neighbouring areas to the region are modelled as accurately as needed. Each TSO from the region delivers its model with the same identical parameters as specified in the DACF procedure. The only difference is the concerned day of forecast.

The models of the TSOs surrounding the region used for the FBCA could be updated according to the best knowledge as follows:

- A full model of TSOs surrounding the region,

- Important changes of the network topology,

- Important changes of exchange programs (e.g. proper choice of reference days in case of bank holidays).

## *Coordination*

The regions and the surrounding TSOs should find the solution in delivering similar types of data. In particular, neighbouring regions which introduced the FBCA should harmonise their models and the time schedules.

The FBCA process should be realised in the specific region. If possible, regions can coordinate exchanged data which is suitable for the processes (e.g.: models).

The core element of coordination is a standard calendar that defines how input data for the D-2CF data set have to be identified, with the global goal of providing a balanced ENTSO-E data set before the merging of D-2CF files.

Table 1: Standard calendar

| Day D-2 (day of file creation) | Estimated Topology | Estimated Load Prog. | Estimated Gen. Prog. | Estimated Wind Prog. | Exch. Prog. | D-2CF Dataset Day D |
|---|---|---|---|---|---|---|
| Sun | Tue | Tue | Tue | Tue | Mon | Tue |
| Mon | Wed | Wed | Wed | Wed | Tue | Wed |
| Tue | Thu | Thu | Thu | Thu | Wed | Thu |
| Wed | Fri | Fri | Fri | Fri | Thu | Fri |
| Thu | Sat | Sat | Sat | Sat | Sat week before | Sat |
| Fri | Sun | Sun | Sun | Sun | Sun week before | Sun |
| Sat | Mon | Mon | Mon | Mon | Fri week before | Mon |

The important information connected with the calendar is the transparent identification of the adequate exchange programme, while the other D-2CF data (load, topology etc.) are under full control of the individual TSOs. Nevertheless, any deviation from the standard calendar should be coordinated on a regional level.

## *Additional comments*

Depending on the forecast period, the updated data should be as precise as possible.

All delivered models for the adequate period are merged.

The regions could exchange the models.

A nominated transaction can be allowed only if it satisfies the above-mentioned set of inequalities.

The purpose of the allocation method is precisely to find a combination of the transactions which fulfil the security criteria of the interconnected systems.

The allocation can be made in the different time periods (i.e.: daily, monthly, yearly).