CALCULATING CAPACITIES FOR CROSS-BORDER EXCHANGES: COMMON METHOD APPLIED BY RTE FOR VARIOUS FORECAST TIMEFRAMES

PLURIANNUAL, ANNUAL, MONTHLY, WEEKLY, D-2 and D-1

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OBJECT OF THE DOCUMENT

Under Article 5 of European Community Regulation n° 1228/2003/EC (which will be replaced in 2011 by the European Community Regulation n° 714/2009/EC) of the European Parliament and of the Council of June 26, 2003 on conditions for access to the network for cross-border exchanges in electricity, and Article 30-I of French Decree n°2006-1731 of December 23, 2006 amended, approving the standard concession specifications for the public electricity transmission system, RTE is required to publish the method used to calculate total transfer cross-border capacities and security margins.

This document sets out the rules on calculating capacities and security margins applied by the public electricity transmission system operator to the electrical interconnections, in order to ensure network security based on the electrical and physical characteristics of its constituent installations and based on the production and consumption forecast on substations of the network.

These rules were approved by the French energy regulator, CRE, in a deliberation dated June XX, 2010.

INTRODUCTION

To ensure that all capacity calculations are consistent through time, a harmonized method of calculating cross-border exchange capacities has been adopted for the various timeframes studied, ranging from intraday right up to pluriannual level. This method, and its practical application for calculating capacities on the borders with the East Block (Belgium, Germany, Switzerland and Italy), Spain and England, are set out in the following chapters.

1. PREAMBLE – DEFINITIONS AND NOTIONS ON INFLUENCING FACTORS

1.1. DEFINITIONS

Some of the terms and phrases commonly used in reference to capacity calculation are explained below. These definitions are in line with the documentation published by ENTSO-E[1] along with definitions taken from Article 9 of the concession specifications for the French public electricity transmission system:

AAC (*Already Allocated Capacity*): the total amount of allocated transmission rights depending on the allocation method.

[1] *"Definitions of Transfer Capacities in liberalized Electricity Markets"* – final report, April 2001.

Allocation: process of selling transmission rights on interconnections.

ATC (*Available Transmission Capacity*): the part of NTC that remains available, after each phase of the allocation procedure, for further commercial activity. ATC is given by the following equation: *ATC = NTC- AAC.*

Commercial exchange: energy transaction between two separate hubs via the electricity transmission system. This commercial exchange is broken down into physical flows across transmission system installations.

Congestion (on an installation): situation where physical flows via an installation exceed the Maximum Tolerable Load.

Countertrading: involves setting up a complementary energy exchange between two hubs, with the aim of reducing the load on a installation that is under stress, either on our own network or on an interconnection installation. To carry out this exchange, each TSO will activate balancing offers available on their respective hubs, according to economic precedence.

Critical branch: internal installations within the RTE network and/or cross-border installations liable to be subject to load stress[2] under normal conditions or after a simulation of losses suffered by network installations[3], and on which the load flows transiting are notably affected by exchanges via interconnections. The list of critical branches is therefore subject to change.

CWE (Central Western Europe): regional initiative launched by the regulators, with the ultimate objective of creating a single European market for electricity. This initiative includes Belgium, France, Germany, the Netherlands and Luxembourg.

D-2CF (Day - 2 Congestion Forecast): set of data constituting the best estimate available, two days ahead of time, of the grid status (generation, demand, network availability, topology, etc.) in each country.

DACF (*Day Ahead Congestion Forecast*): set of data constituting the best estimate available, one day ahead of time, of the grid status (generation, demand, network availability, topology, etc.) in each country.

Deviations: differences between the sum of scheduled commercial programmes and the sum of actual physical flows.

East Block: all of the borders on the eastern side of France, i.e. the borders with Belgium, Germany, Switzerland and Italy.

Full grid: represents a situation where all transmission system installations present are under load.

[2] A critical branch is deemed to be under stress if the load on the branch is greater than or equal to the maximum permitted load.

[3] This involves simulating transmission via critical branches in a network configuration in fallback mode, with an additional installation disconnected (i.e. high voltage line, transformer, etc.)

ITL ("Intraday Transfer Limit"): NTC calculated on a day-ahead basis for the intraday timeframe on the France-England border.

Load-Frequency Control: control system used to manage frequency effectively (involving all generation units) across France.

Maximum Permanently Tolerable Flow: Maximum flow possible across a network installation without compromising current network reliability and security rules.

Netting: taking into account nominations on an interconnection, in both directions, in order to offer market players all the capacity actually available and thereby optimize use of the interconnection concerned.

Network installation: element forming part of the electricity transmission system, which may be a power line, a bus-bar in a substation, a transformer, phase-shifter transformer, etc.

NTC (*Net Transfer Capacity*): the maximum exchange programme (in MW) between two control areas compatible with security standards applicable in both areas[4] and taking into account technical uncertainties regarding future network conditions.
NTC is defined as follows: NTC = TTC – TRM[5].

Off-peak times: represent the period of the day during which national electricity demand is at its lowest. These off-peak times cover the period from 00:00 to 07:00 in capacity calculations.

Peak times: represent the period of the day during which national electricity demand is at its highest. These peak times cover the period from 07:00 to 24:00 in capacity calculations.

Physical capacity: the maximum load an installation is physically able to withstand.

Physical flows: flows of energy transiting network installations

Physical margin: difference between the physical flow across a network installation and the maximum permanently tolerable flow.

Redispatching: involves modifying the local generation plan (within a hub) in order to reduce the load on a network installation that is under stress, or on an interconnection installation.

Topology: situation at a given time of all installations constituting the electric network.

TRM (*Transmission Reliability Margin*): the security margin that copes with uncertainties on the computed TTC values[6] arising from:

[4] These rules are set out in ENTSO-E Policy 3: http://www.entsoe.eu/fileadmin/user_upload/_library/publications/ce/oh/Policy3_final.pdf and in RTE's "Power System Reliability Handbook", specifically Article 2.3: http://www.rte-france.com/uploads/media/pdf_zip/publications-annuelles/memento_surete_2004_complet.pdf

[5] See definition of TRM below.

[6] See definition of TTC below

- deviations of physical flows due to the physical functioning of load-frequency control mechanisms,
- emergency exchanges between TSOs (TSO-TSO contract) to cope with unexpected imbalance situations in real time,
- Inaccuracies, e.g. in data collection and measurements.

TSO: Transmission System Operator

TSO-TSO Contract (emergency backup contract): contract with a neighbouring TSO allowing TSOs to pool a reserve of energy to deal with any contingencies that may affect the transmission network.

TTC (*Total Transfer Capacity*): the maximum exchange programme (in MW) between two areas compatible with operational security standards applicable to each system (i.e. GridCodes), if future network conditions, generation and load patterns were perfectly known in advance.

TTF (Technical Task Force): working group set up following the Italian blackout of 2003, and which includes the transmission system operators from Italy and neighbouring countries (France, Switzerland, Austria, Slovenia). The working group aims to introduce procedures and information exchanges that will help to improve the security of supply in Italy, and in particular the organization of activities relating to the management of installations with an influence on load flows close to Italy's borders, notably

- planning withdrawals of installations from the networks
- calculating capacities on the Italian interconnectors...

1.2. INFLUENCING FACTOR

The influencing factor of an exchange (or a generating facility) on a given critical branch represents the impact of an additional volume of exchanges in a given direction (or a variation in generation), on the critical branch concerned. This coefficient is expressed as a percentage. Thus, if an exchange from country A to country B has an influencing factor of +10% on a line, this means that 100 MW of exchanges from country A to country B will increase the load on the line concerned by 10 MW.

The influencing factors of a commercial exchange across an installation will vary over time, depending on the generation plan and network topology. Consequently, these are variable over time and are systematically recalculated based on estimated base cases (topology, generation, etc.). These base cases are explained in chapter "3. GENERAL METHOD – Calculations for the different timeframes".

2.GENERAL METHOD - PRINCIPLES

2.1. BASIC PRINCIPLES

The basic principles applied when calculating capacities for (commercial) exchanges in electrical energy are as follows:

- evaluating remaining physical margins on transmission system installations, under full grid conditions or after simulating the loss of an installation. For this, an initial situation must first be defined, and is referred to as the "base case".
- distributing these physical margins evenly across the borders influencing loads on one of the network installations.

Commercial capacities on each border are then calculated by the distribution of physical margins and the application of influencing factors for exchanges on critical branches, as explained in article "2.4. Calculating TTCs, NTCs and ATCs". Consequently, these commercial capacities depend heavily on the network scenarios, whether:

- the distribution of generation
- the distribution of demand
- the network topology
- exchanges estimated on the borders.

These capacities made available to market players take into account the TRM. The TRM values are determined for each border and are the same for all timeframes (from pluriannual up to intraday), as explained in article "2.2. Principle for determining TRMs.

2.2. PRINCIPLE FOR DETERMINING TRMS

Determining the TRM on the East Block borders

For the purpose of calculating the NTC on all borders with countries in the East Block, RTE defines a valid TRM in both directions, the objectives of which are to:

- protect against the consequences of deviations in the event a unit in another country or in France goes down for whatever reason (primary frequency control application).
- allow at least one TSO-TSO contract to be signed for imports and exports.

To satisfy these two objectives, the total TRM defined by RTE for the East Block has been set at 600 MW. This volume, which is to be broken down between France's various borders with countries in the zone, is based on the following two coverage assumptions:

- RTE itself covers 50% of deviations[7] on the East Block borders, i.e. 300 MW.
- RTE signs an average TSO-TSO contract, i.e. for 300 MW to provide the remaining coverage[8].

In order to determine how this TRM is distributed across the borders with East Block countries, RTE takes into account the degree of sensitivity of each border to the application of load-frequency control mechanisms.

[7] This 50% level for coverage of control imbalances is acceptable, notably due to the existence of the second TRM component concerning the activation of TSO-TSO contracts.

[8] For information, RTE has TSO-TSO contracts with Belgium (250 MW), Germany (150 MW), Switzerland (400 MW) and Italy (300 MW).

From this standpoint, it is preferable to set aside a bigger margin on the border with Belgium, given that exchanges with that country are more sensitive to load-frequency control. Belgium has units with a high unitary value (1000 MW), the loss of which would increase the capacity imported into Belgium by an almost equivalent volume. This increase would fall entirely on Belgium's two borders (with France and the Netherlands), therefore representing a rise of approximately 500 MW per border.
The situation is rather different for the borders with Germany, Switzerland and Italy. These countries have multiple interconnections with numerous countries, which serves to limit load-flow variations on France's borders due to load-frequency control.

The TRM of 600 MW is therefore split between the borders with countries in the East Block in the following way:

- 250 MW on the border with Belgium
- 150 MW on the border with Germany
- 100 MW on the borders with Switzerland and Italy.

Determining the TRM on the border with England
The TRM determined for the interconnection with England is nil, as the link consists solely of a direct current line on which load-frequency control has no impact.

Determining the TRM on the border with Spain
For the border with Spain, the TRM is also determined according to the ENTSO-E definition. Consequently, since there is no mutual backup agreement on this border, only physical deviations (from programmed commercial exchanges) detected and caused by load-frequency control are taken into account. Due to its nature as an electric peninsula, on which load-flows are independent of existing exchanges on all other borders, the vast majority of deviations on the border need to be covered by a margin.
A specific method has therefore been adopted, in order to ensure 90% coverage for any deviations detected. This coverage does not extend to extreme cases of imbalances on physical deviations. However, RTE accepts this risk, for the following reasons:

- load-frequency deviations are short-lasting,
- deviations from exchanges on this interconnection do not necessarily lead to an increase in those exchanges,
- the capacity available for the market is not necessarily fully used by market players

The TRM calculated for the France-Spain border is therefore 200 MW.

2.3. PRINCIPLE FOR DETERMINING INFLUENCING FACTORS

The influencing factors of a commercial exchange across an installation will vary over time, depending on the generation plan and network topology. They are therefore not set in stone, but calculated from the base cases (topology, generation, etc.) used for each calculation timeframe.

These base cases represent the best available estimates[9], at the point in time when the capacities are determined, of the status of the electricity transmission system. So, to determine the influencing factor of a commercial exchange via an installation, RTE simulates an

[9] Most realistic estimate based on data available at the time of the calculation.

increase/decrease in generation on both sides of the border concerned, to simulate a complementary commercial exchange. This increase/decrease is applied as follows:

- in France: in proportion to the primary reserve of units in operation
- in each neighbouring country: in proportion to the units brought on stream

This method of determining influencing factors provides a realistic estimate of actual influencing factors on the network[10]. Validation of the results is performed as a second step of the capacity calculation method as defined in the article "2.4. Calculating TTCs, NTCs and ATCs".

2.4. CALCULATING TTCS, NTCS AND ATCS

RTE uses the general method explained in this article to calculate capacities on France's borders. However, the specificities of each interconnection may lead RTE and the neighbouring TSOs to apply methods which differ substantially from those set out in chapter " 4. METHOD ADOPTED – Situation on each border "

Method of calculating TTCs, NTCs and ATCs

By applying the basic principle of capacity calculation, as explained in article " 2.1. Basic principles ", it is possible to determine available capacities on all interconnections. The various stages in the calculation process are given in this article, along with a numeric application. The way this principle is applied on the different borders is set out in chapter " 4. METHOD ADOPTED – Situation on each border " of this document.

So, as a general rule, for each network configuration[11] *i* considered (either under full grid conditions, or after simulating an installation outage), the total physical margin available on a critical branch *k* is determined as follows: Ki .

The physical margin to be attributed to a country *p* is therefore given by $Ki, p = Ki/n$ where n_i is the number of countries influencing the critical branch *k* after a fault.

For the network configuration *i* under consideration, the additional capacity attributed to country *p* is thus $ComplementaryCapacity_{i,p} = Ki, p / Ci, p$ with Ci, p the influencing factor with country *p* on critical branch *k* under network configuration *i*.

This calculation is performed for all network configurations, or for each outage simulation.

For country *p*, the resulting $ComplementaryCapacity_p$ is equal, under <u>all of the network configurations *i* considered</u>[12] <u>and on all critical branches *k* of the network</u>, to the minimum of the $ComplementaryCapacity_{i,p}$:

$ComplementaryCapacity_p = Min\left(ComplementaryCapacity_{i,p}; i\right).$

[10] Actual influencing factors vary for each additional MW exchanged, depending on the new units brought on stream, developments in the topology, etc. They are particularly difficult to calculate for a low gain.

[11] This network configuration includes all of the hypotheses needed to determine loads on network installations: generation (location, volume generated, etc.), demand (location, volume consumed), network topology, commercial exchanges, etc.

[12] Simulation of installation outages on the French network (line, generation unit, etc.)

$ComplementaryCapacity_p$ therefore satisfies all the critical branches, after simulation of all faults on the network[13].
TTCp = $ComplementaryCapacity_p$ + all commercial exchanges[14] included in the network configuration under consideration.

For country p, the NTC of this country A referred to as NTCp is calculated as follows:
NTCp = TTCp – TRMp.

For country p, the ATC of this country A referred to as ATCp is calculated as follows:
ATCp = NTCp – AACp.[15]

These TTCp values are validated, as explained below, by means of an analysis of the French network's status, either under full network conditions and or after simulating an installation outage, in order to ensure that:

- loads on French network installations, following allocation of the ATCs calculated, are acceptable,
- voltage restrictions in French substations are complied with.

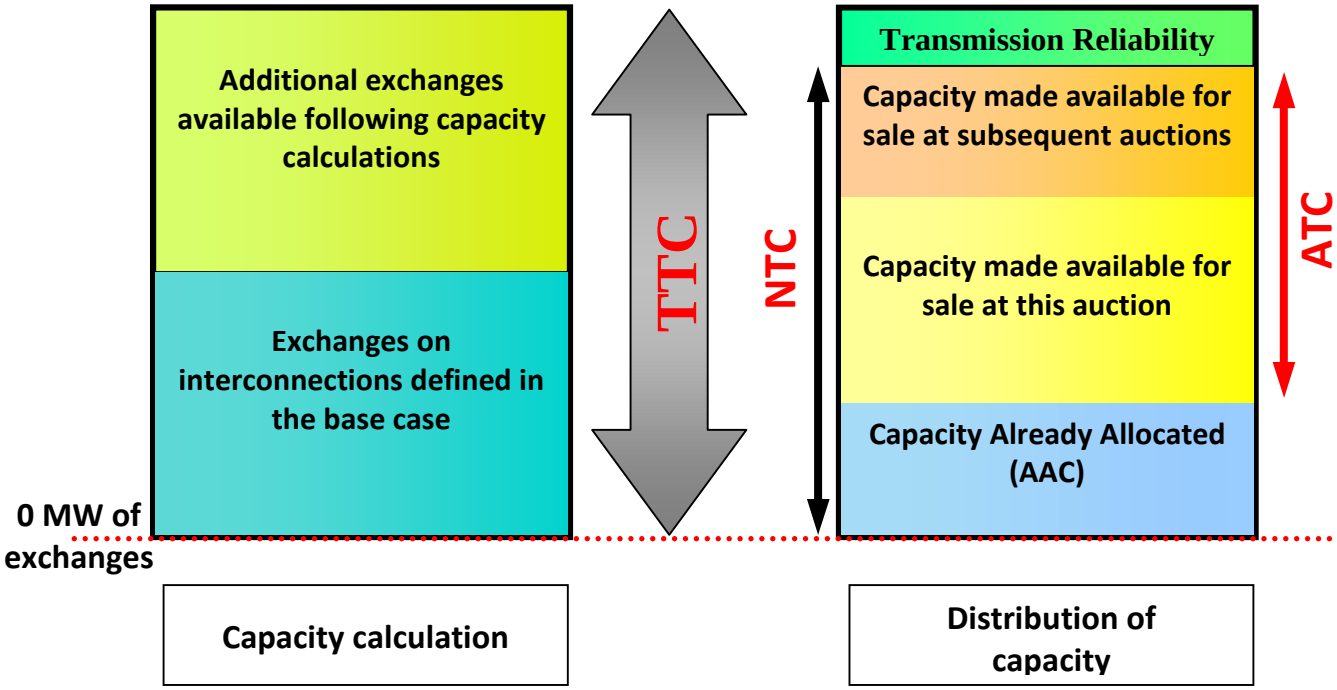
Validation of results
The model described above has limits a main limit linked to uncertainties for the modelling of variations in exchanges[16] between countries (as defined in article " 2.3. Principle for determining influencing factors). The second limit of the methods is not to consider the active / reactive flow in the determination of influencing factors. Thus, the results obtained need to be analyzed by network engineers through simulation of load-flows on the network.
The analysis are performed taking into account

- the engineers' expertise in view of the situation being considered, mainly related to the the exchanges taken into account for the base case and by consequence to the generation plan.
- the result of a load-flow calculation, for active and reactive power, which reflects the voltage issues which were previously disregarded by the method used to share physical margins.

This analysis enables, through a new calculation of capacities following the procedure listed above, to adapt the final results to the new constraints detected. This computation can either increase the capacity (available margin on all critical branches) or reduction of capacity (too important constraint on a critical branch)

[13] RTE works to optimize this method by implementing an iterative capacity calculation. After each capacity calculation, RTE therefore defines the remaining physical margins on each installation on the French network (taking into account the ATCs calculated), and re-applies the above method until there is no longer any physical margin remaining on the critical branch.
[14] These exchanges are detailed in chapter " 4. METHOD ADOPTED – Situation on each border ".
[15] If the ATCp values calculated are negative, RTE will apply corrective measures such as redispatching or countertrading, either alone or in conjunction with the neighbouring TSO, in order to avoid exceeding the Maximum Tolerable Flows on network installations.
[16] These uncertainties are linked to the hypotheses adopted, which can have very different import / export values for calculating capacities when it comes to definitions: of generation plans, substation topology, etc.

This capacity calculation method enables us to define the additional exchanges available following capacity calculations and which are splitted as :



Example of numeric application

To demonstrate a numeric application of this method, we have used the example of calculating intraday capacities on borders with the East Block, with a critical branch *k* and based on network configuration *i*. Only France's three borders with Belgium, Germany and Switzerland have an intraday mechanism. All the critical branches limiting capacities on these interconnections are influenced by these three borders. Consequently, the physical margins available on the critical branches will be distributed evenly[17] on the three borders.

Let's take the critical branch *k* as a power line under a load of 1500 MW and with a maximum tolerable flow of 1680 MW.

The physical margin available on this critical branch *k* is obviously 1680 - 1500 = 180 MW.

For these three borders and under the network configuration *i*, exchanges on the interconnections have respective influencing factors on this critical branch of 5% (Belgium), 10% (Germany) and 20% (Switzerland).

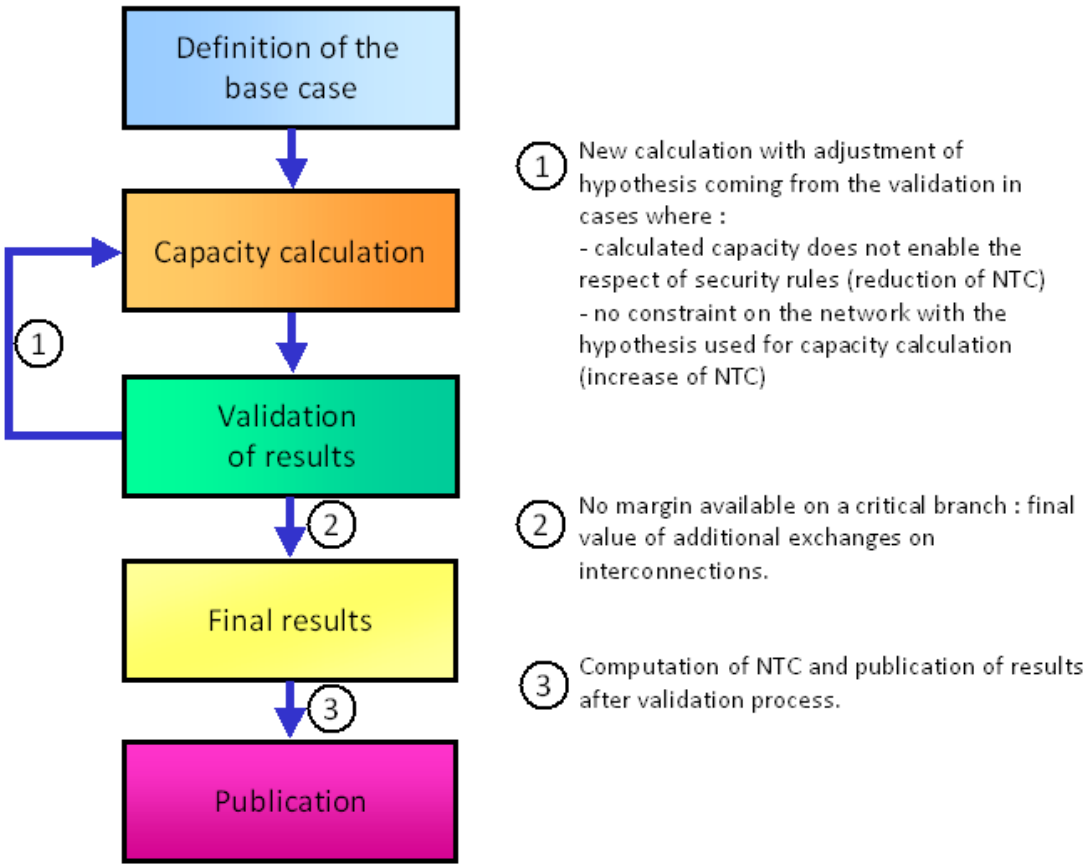
The additional capacity available on each interconnection as calculated for the configuration here is therefore:

- $ComplementaryCapacity_{i,1} = {(180/3)}/{0.05} = 1200MW$
- $ComplementaryCapacity_{i,2} = {(180/3)}/{0.1} = 600MW$
- $ComplementaryCapacity_{i,3} = {(180/3)}/{0.2} = 300MW$

[17] Even distribution between borders by applying the formula: Ki,p =Ki/n

So, we can see that the greater the influence of the border on the critical branch concerned, the less additional capacity it is attributed. Based on these additional capacity values, we can determine the TTC, NTC and ATC values for the different borders, as defined above.

2.5. SUMMARY SCHEME DEFINING THE STAGES OF THE CAPACITY CALCULATION METHOD



3. GENERAL METHOD – CALCULATIONS FOR THE DIFFERENT TIMEFRAMES

3.1. PLURIANNUAL

Pluriannual NTCs are calculated for two forecast scenarios for peak times (demand peak) in future years (one for the summer and another for the winter[18]).

Base case selection:
The calculations are performed under assumed full grid conditions, using the most recent status of the European network (a winter or summer forecast file describing the European electricity transmission system[19] and contains information provided to TSOs by generators concerning the distribution of generation), into which France is merged (best estimate of the expected network status in pluriannual studies). The commercial exchanges and corresponding balances assumed for each country, are those decided jointly at meetings with neighbouring TSOs.

Topology[20]:
For this study timeframe, the file used assumes full grid conditions and the NTC study is performed with a constant topology. No substation plan is adopted specifically to optimize the NTCs calculated, as the effectiveness of these measurements depends on operating conditions encountered in real time, and which may differ significantly from the base case situation studied for this timeframe.

Tools used:
Calculations are performed using active / reactive network study tools.

Coordination
Coordination takes place in two stages.

- The first involves the exchange of data between TSOs, upstream from the capacity calculations: a base case is exchanged (with all members of ENTSO-E), which takes into account network developments.
- The second involves pooling the NTC values (one for the summer and one for the winter in both directions) calculated by each TSO individually on their shared border, and only publishing those values which respect the security of their respective transmission networks.

Display:
The NTC values (one for the summer and one for the winter, in both directions) are calculated on each border by the system operators (RTE and the neighbouring TSO) and are published on the ENTSO-E website along with those of the other countries. These values are given as an indication only.

[18] The summer covers the period from May 10 to September 20, and winter covers the period from November 11 to April 19.
[19] 400kV and 225kV transmission network with a description of all the technical specifications of its constituent installations (resistance, semi-inductance, Sci, etc.)
[20] Any network topology considered complies with structural constraints, notably those linked to Short Circuit Current in substations.

3.2. ANNUAL, MONTHLY AND WEEKLY

Base case selection:

The base case is chosen from a series of files representing actual operating situations observed in real time, at a given point in time, for RTE's entire 400 kV and 225 kV network and for a part of the adjacent networks. The base case selected is the one deemed to be most appropriate for the study to be carried out. This network "snapshot" is updated to reflect planned outages of installations for scheduled maintenance work, and hypotheses for the availability of generation units.

In this file, commercial exchanges are adapted to take into account the level of commercial exchanges guarantees at earlier timeframes (Belgium, Germany and Spain) or to match the capacity coordinated with the neighbouring TSO (Switzerland and Italy), or highly likely exchanges (England) over the timeframe considered.

Topology:

The network topology depends on the generation plan, installation outages, losses and the various loads expected on lines (plan optimization). This topology will be refined as the study timeframe approaches.

Tools used:

Calculations are performed using active / reactive network study tools.

Coordination

Coordination takes place in two stages.

- The first involves the exchange of data, upstream from the capacity calculations.
  - Annual: base cases exchanges (with neighbouring countries) for weeks identified as potential stress periods (with scheduled outages of installations and generation units impacting on interconnection capacities).
  - Monthly:
    - Files are exchanged (with neighbouring countries, excluding Spain) containing information on the network topology and generation programmes, for each week of the month.
    - Base cases exchanged with Spain.
  - Weekly:
    - Information files exchanged, containing hypotheses for network topology and generation unit outages, on all borders excluding Spain. Capacities are calculated by each TSO, incorporating the "worst case" hypotheses (i.e. those where the network is subject to the greatest stress), provided by each TSO.
    - Weekly base cases exchanged with Spain.
    - All exchanges concern two situations (peak and off-peak times[21])

[21] The distinction between peak and off-peak times is necessary due to substantial disparities in demand levels and generation plans (e.g. in pumped storage hydro-electric plants, water is pumped to the higher level during off-peak times at night and released back through the turbines during the day) between the daytime peak and the night-time trough. For Spain, the calculation is done by exchanging peak and off-peak forecast weekly files.

- The second stage involves pooling the NTC values calculated by each TSO individually, and publishing only those values which enable the TSOs to guarantee the security of their transmission systems.

Display:

- Annual: a weekly NTC value for each border and direction. (including two capacity calculation scenarios – import and export)[22]
- Monthly: at least one capacity value for each direction on each border[23] and an indication of the critical branch limiting the NTC.
- Weekly: NTCs displayed for each day[24] (one value for peak times and one value for off-peak times) and each border for the coming week, on the RTE website.

3.3. D-2

The aim of capacity calculations performed on D-2 is to determine the capacity that can be made available to market players for the daily timeframe, via explicit auctions or market coupling arrangements.

Base case selection:

The base case is selected from among the data available on operating network situations. The choice is made in such a way as to ensure the closest possible match with the day to be studied, based on forecast parameters for demand (taking into account economic demand response), the generation plan and scheduled installation outages. These calculation hypotheses are updated to take account of information obtained by RTE over the course of the day

A night-time off-peak and a daytime peak situation is chosen (or even an evening peak in winter) for the studied. These elements are incorporated into files known as D-2CFs for the D-2 timeframe. Wind generation estimates are incorporated into the base situations for calculating capacities

Topology

The network topology depends on the generation plan, installation outages, losses and the various loads expected on lines (plan optimization).

Based on the study files, the TTC values are calculated[25] taking into account RTE's security rules, for each border and each direction. A peak time value and an off-peak value are calculated, then applied to all hourly intervals throughout the day.

[22] Displayed at end of February for the current year, on the RTE website An initial forecast of minimum NTCs for the coming year is published in November/December (one value for each direction on each border)

[23] Displayed one week before the month concerned, on the RTE website.

In the case of Spain, RTE displays two values (peak and off-peak times) for each day and each direction.

In the case of England, Italy and Switzerland, RTE displays one value for each week and each direction.

[24] Displayed on Thursday evening, in daily steps, for the coming week, for all France's borders, on the RTE website.

[25] In the specific case of the Spanish interconnection, given the parameters influencing the values calculated for the weekly timeframes, D-2 studies are only performed in the event of a significant deviation from the hypotheses adopted for that timeframe (outages caused by damage or unscheduled decommissioning of installations, altered generation plan, major demand deviations in South-Western France (the Aquitaine, Midi Pyrénees and Languedoc-Roussillon regions) which have a substantial impact on this calculation.

Tools used
The calculations are performed with an algorithm applying the capacity calculation method explained in article " 2.4. Calculating TTCs, NTCs and ATCs ", then checked and validated using active / reactive network study tools.

Coordination
Coordination takes place in two stages.

- The first involves the exchange of data, upstream from the capacity calculations, and during which the data contained in the D-2CF files are exchanged with neighbouring TSOs.
- The second stage involves pooling the NTC values calculated by each TSO individually, and publishing only those values which enable the TSOs to guarantee the security of their transmission systems.

Improved coordination alongside the introduction of CWE market coupling
As soon as market coupling arrangements are launched for Centre West Europe, coordination between TSOs will be improved for the region (with capacity calculations for all borders shared by France, Belgium, Germany and the Netherlands).
Once the capacities have been calculated by RTE (keeping the first level of coordination explained above) and pooled with the corresponding TSO, the following steps are carried out in conjunction with the other TSOs:

- These data (D-2CF and NTCs calculated by RTE) are sent to the CWE TSOs' shared system
- NTCs calculated for each TSO are sent back by the shared system
- a D-2CF file is created for the entire zone (called a "*merge*" file) by the TSOs' shared system
- a network analysis is carried out by each TSO in order to test whether stresses[26] appear on the network with the NTCs provided using the "*merge*" file
- the results are sent to the shared system ("*flags*"):
  - "*green flag*" if there are no difficulties, which means there is no change to the capacities initially calculated,
  - "*red flag*" if stresses are detected, resulting in coordinated reduction of capacities

Display (on the RTE website):

- on D-2: NTCs displayed are updated for each border and each direction for day D on the RTE website.

3.4. D-1

The purpose of the calculations carried out on D-1 are to:

- determine the impact of exchanges nominated at interconnections on French network installations
- determine the capacity to be made available to market players within the intraday timeframe.

Base case selection:
The calculation hypotheses used on D-2 are updated to take account of information obtained by RTE over the course of the day:

This practice is also applied to D-1 calculations.
[26] The low flow over one or more critical branches exceeds the maximum permissible flow.

- exchanges nominated for the next day[27],
- demand forecast for the next day,
- the generation plan resulting from the call programmes of the various generators, as disclosed at 16:00 on D-1 (16:30 after the launch of CWE market coupling)
- forecast information from other TSOs via the exchange of DACF files.

For this timeframe, at least two study files are created to calculate capacities:

- one file representing the off-peak demand period. This file is generally created by RTE, taking into account the demand estimated at 03:30.
- a second file representing the peak demand period. This file is created by RTE, taking into account the demand estimate depending on the times of the year:
  - either around 08:00 (demand peak in the morning in spring in summer)
  - or around 19:00 (demand peak in the evening in autumn and winter)

Based on these study files, capacities are calculated taking into account RTE's security rules, for each day, border and direction, and using the various exchange hypotheses. (4 calculation scenarios). For each base case, one capacity value is determined for imports, and another for exports.

If congestion appears, RTE deals with it in priority by adjusting the network topology, and then by adjusting the generation plan, taking into account its effectiveness and in line with economic precedence. If resolving the congestion requires adjustments to be made to generation, the ATC in the direction concerned, made available for the intraday timeframe, is nil for the period during which it needs to be reduced.

Topology

The network topology is updated to reflect the latest information available on the generation plan and hypotheses for energy exchanges via interconnections. Note that the latest network events (installation outage, works completed early, etc.) are also taken into account in the topology used, in the base case, for the purposes of calculating capacities.

Tools used

The calculations are performed with an algorithm applying the capacity calculation method explained in article " 2.4. Calculating TTCs, NTCs and ATCs ", then checked and validated using active / reactive network study tools.

Coordination

Coordination takes place in two stages.

- The first involves the exchange of data, upstream from the capacity calculations, and during which the TSOs swap DACF files covering all the information in their possession, at dawn on the day concerned.
- The second stage involves pooling the NTC values calculated by each TSO individually, and publishing only those values which enable the TSOs to guarantee the security of their transmission systems.

Display (on the RTE website):

[27] Netting is applied to define these exchanges.

- on D-1: intraday NTCs and ATCs (for the next day) updated following daily nominations.

3.5. SUMMARY TABLE OF HYPOTHESES ADOPTED FOR CALCULATING CAPACITIES OVER THE DIFFERENT TIMEFRAMES

Timeframes	Annual	Monthly	Weekly	D-2	D-1 (for intraday)
French transmission network	Calendar of annual scheduled outages	Calendar of monthly scheduled outages	Calendar of weekly scheduled outages	Addition of network events / outages caused by damage and update of scheduled outage calendar	Addition of network events / outages caused by damage and update of scheduled outage calendar
Neighbouring TSO network	Calendar of annual scheduled outages	Calendar of monthly scheduled outages	Calendar of weekly scheduled outages	D-2CF for CWE + DACF excl. CWE	Data consolidated by DACF
Off-take forecast (consumption by node)	Normal temperatures	Normal temperatures	Forecast temperatures	Forecast temperatures	Forecast temperatures
Exchanges taken into account	Base case	Base case	Base case	Exchanges nominated at earlier timeframes[28][29]	Daily nominations
Generation forecast (by node)	Base case [30](based on a *merit order*)			Use of generators' re-updated running programmes[31], as seen from D-1	Generators' running programmes

All uncertainties on hypotheses

Timeframes	Annual	Monthly	Weekly	D-2	D-1 (only Ger-Be-Swi and Spa[32])
French transmission system	Network with partial knowledge of schedule outage dates and with contingencies not taken into account		Network with almost definitive knowledge of scheduled outages but with contingencies potentially occurring in real time not taken into account		
Neighbouring TSO network	Partial positioning of scheduled outages and contingencies not taken into account		Almost definitive positioning of schedule outages excluding contingencies		

[28] Nominated exchanges taken into account: Monday for calculations on Wednesday, Tuesday for calculations on Thursday, Wednesday for calculations on Friday, the previous weekend for calculations over the coming weekend, Friday for calculations on Monday and Tuesday.

[29] If, on a date prior to the calculation of capacities (D-2), RTE has knowledge of a capacity level for the deadline D coming from a neighbouring system operator, the exchange hypotheses may be adjusted accordingly.

[30] Base case for generation: Generation plans are establishes on the basis of information from generators (mainly availabilities), which is used to determine a merit order based on previous experience (Real Time economic signals).

[31] Re-updating involves taking into account any generation units outages which are known on D-2.

[32] This re-updating process is only applied in the case of Spain if there are significant changes to the hypotheses initially established for the previous timeframe.

Timeframes	Annual	Monthly	Weekly	D-2	D-1 (only Ger-Be-Swi and Spa[32)]
Off-take forecast (consumption by node)	Unknown deviations from normal temperatures. Uncertainties on the level of demand by industrial consumers (crisis period notably)		Improvement in demand forecasting with improvements to meteorological estimates and estimates of demand by industrial consumers (records from previous week)		
Generation forecast (by node)	Unit availability not definitively fixed. Units started up unknown (merit order created on the basis of RTE's previous experience). Latter have significant impacts on results.		Better estimates and knowledge of availability, but generation programmes not known accurately (merit order created on the basis of RTE's previous experience). Latter have significant impacts on results.		Generators' running programmes
Unavailability considered	The unavailability defined in "Policy 3" of the ENTSO-E Operation Handbook are considered[33].				

[33] As a result, events with unforeseeable consequences (meteorological events, strikes, etc.) are not studied.

4. METHOD ADOPTED – SITUATION ON EACH BORDER

4.1. BASE CASE – EXCHANGE HYPOTHESES FOR CALCULATING EXPORT CAPACITIES

Export capacities are calculated from the base case. The cross-border exchange hypotheses for that base case are detailed in the diagram below.

From these base cases, capacities are calculated for various timeframes (from annual to D-1), taking into account hypotheses for network topology, demand and internal and external generation, as defined in article " 3.5.Summary table ".

These base cases, defined for each timeframe, are used to take account hypotheses regarding the exchanges that will be nominated. So, in the case of exports, the following hypotheses are adopted for each country:

- For Italy, the export value given by the TTF (Technical Task Force) is adopted, since it is assumed that all the capacity on this border will be nominated, in line with previously observed behaviour in the Italian market. For the D-2 calculation, this hypothesis is adjusted to take account of the actual nominations observed on the previous day or days.
- For England, for medium term timeframes[34], we assume 1500 MW of imports (the 1500 MW export scenario is also considered, but results in much lower system stress) on the France-England interconnection. For short term timeframes[35], this hypothesis is adjusted to take account of the actual nominations observed on the previous day or days.
- For Spain, for timeframes from medium term to D-2, an export value of 800 MW of exchanges is assumed. For short term timeframes, the exchanges nominated on the previous day(s) are taken into account.
- For Switzerland, upstream from D-2, a value of 3000 / 3200 MW is assumed[36] consistent with the capacity coordinated[37] which includes a part of obligations linked to the existence of long term contracts. For short term timeframes, this hypothesis is adjusted to take account of the actual nominations observed on the previous day or days.
- For Belgium and Germany, the capacities guaranteed for earlier timeframes are used[38]. For short term timeframes, this hypothesis is adjusted to take account of the actual nominations observed on the previous day or days.

- For the D-1 calculation used to determine intraday capacity, on all the interconnections, the flows nominated on D-1, taking into account Netting, are defined as a base reference for updating capacity calculations.

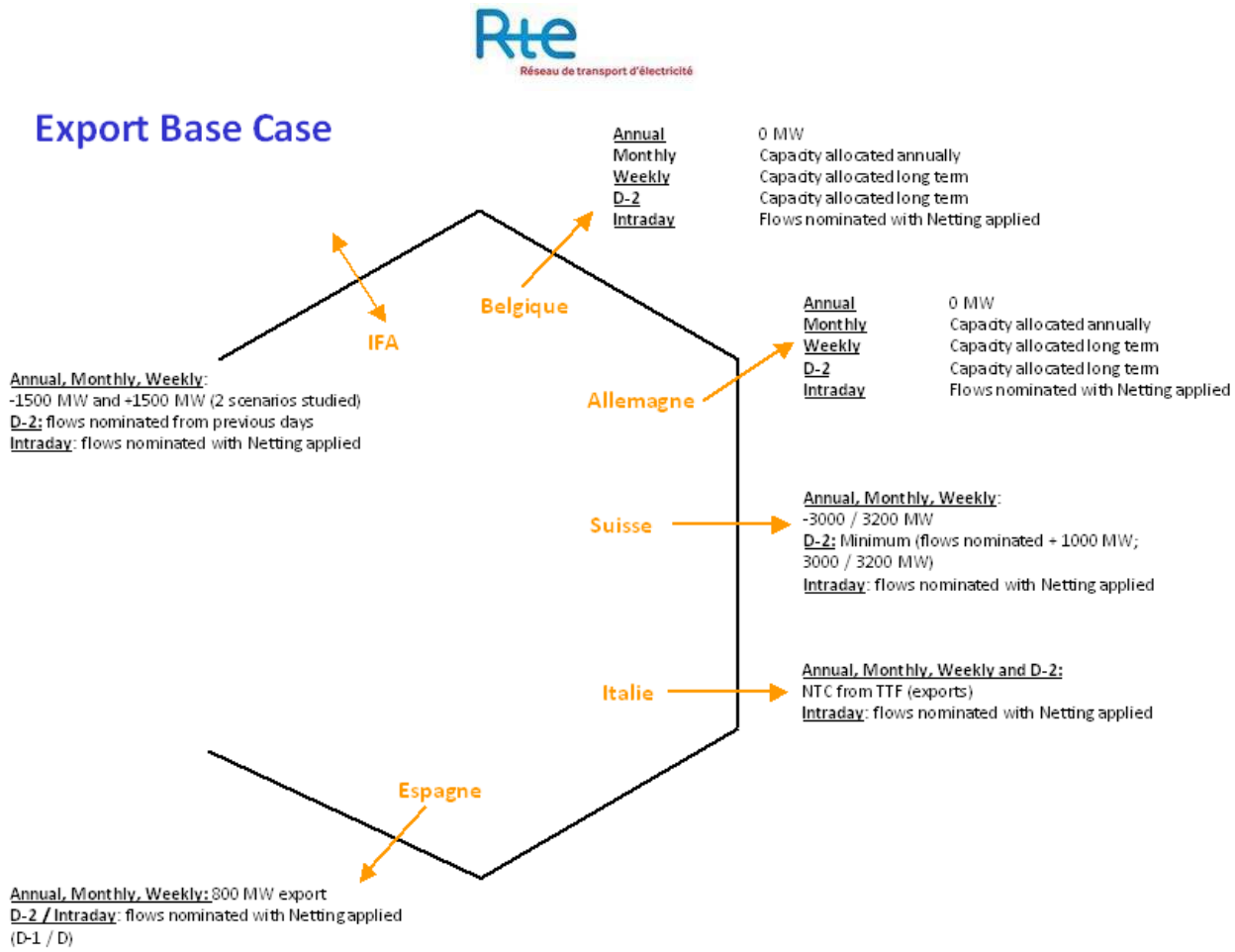
[34] The medium term timeframe covers all capacity calculations prior to the weekly calculation (inclusive)

[35] The short term timeframe covers all capacity calculations after the D-2 calculation (inclusive)

[36] These values are valid for the current year but may change in future years.

[37] Capacities established in bilateral Swiss-French meetings

[38] Capacities allocated at previous timeframes



4.2. DETERMINING CAPACITIES OVER DIFFERENT TIMEFRAMES – EXPORT

In the case of Italy, the TTF (Technical Task Force) determines a total capacity value for all Italy's borders. This capacity value, calculated for the annual timeframe using network studies on shared files, is then distributed between Italy's various borders. It may therefore be offered to market players for all timeframes, except in the case of scheduled and / or unscheduled outages.
There is no new capacity calculation[39] with Italy (except during works): only the value determined by this TTF is valid. This hypothesis is based mainly on the high level of interconnection capacity utilisation (for exports), dictated by the operation of the Italian electricity market[40].

In the case of England, at timeframes earlier than D-1, the NTC is only limited by the line's physical capacity. For intraday exchanges, checks are carried out to ensure that using the line to its full construction capacity will not endanger network reliability. If the check reveals there could be a danger, a new NTC (ITL) is calculated, using a base hypothesis consisting of actual nominations on all the other borders on D-1.
The principle defined in article " 2.4. Calculating TTCs, NTCs " therefore applies, only taking into account a single country influencing capacities on this border.

[39] This capacity is therefore deemed to be feasible.
[40] Due to the unique characteristics of the Italian market, capacities are calculated at an earlier stage between the TSOs affected.

In calculations of capacity on the France-Spain border, the entirety of the available margin is allocated to cross-border exchanges between France and Spain, as no other countries have any influence on these exchanges. The NTC is therefore calculated independently of all other borders.
The principle defined in article " 2.4. Calculating TTCs, NTCs " therefore applies for all timeframes (from pluriannual to D-1), taking into account a single country influencing capacities on this border.

In the case of Switzerland, capacities calculated annually are guaranteed up to the daily timeframe. The values taken into account for 2010 are 3000 MW in summer and 3200 MW in winter. These values are guaranteed because capacity is reserved for long term contracts, under which nominations are made daily. For intraday exchanges, capacities are determine by the method explained above in article " 2.4. Calculating TTCs, NTCs ".

In the case of Belgium and Germany, capacities are calculated by applying the method explained in article " 2.4. Calculating TTCs, NTCs ".
On both of these borders, it is assumed that at timeframes earlier than D-1, the countries influencing the critical branches on these borders are solely Germany and Belgium. capacities on the borders with Switzerland and Italy being pre-defined as explained above.
On the other hand, for intraday exchanges, capacities are distributed between Germany, Belgium and Switzerland after nomination under long term contracts on the France - Switzerland interconnection. The three borders are processed simultaneously. The physical margin is thus split into three and distributed evenly on these borders.
Once the margin has been distributed on each border, the ATC specific to each border is calculated accurately, by dividing the physical margin by the influencing factor of exchanges on each border on the critical branch concerned. The resulting ATCs are then coordinated[41] with those determined by the neighbouring TSOs, to obtain the final capacities assumed on the interconnections.

<table>
<tr><th></th><th>England</th><th colspan="2">Germany</th><th>Belgium</th><th>Switzerland</th><th>Spain</th><th>Italy</th></tr>
<tr><td>Annual</td><td rowspan="4">E[42] (physical capacity), in case of works</td><td colspan="3">E</td><td>E</td><td>E</td><td>E (TTF) + works</td></tr>
<tr><td>Monthly</td><td colspan="3">E</td><td rowspan="3"></td><td>E</td><td rowspan="3">E in case of works</td></tr>
<tr><td>Weekly</td><td colspan="3">E</td><td>E</td></tr>
<tr><td>D-2</td><td colspan="3">E</td><td>E</td></tr>
<tr><td>D-1 for intraday</td><td>E (Intraday Transfer Limits)</td><td colspan="4">E</td><td>E</td><td></td></tr>
</table>

Summary table of export capacity calculation timeframes.

[41] This coordination involves keeping the maximum capacities accepted simultaneously by both TSOs. Also, in the case of CWE, this coordination involves pooling the capacity values calculated by each TSO, and reducing them, as necessary, in a coordinated manner as explained in article " 3.3. D-2 ", detailing the calculation method applied for CWE for the D-2 timeframe.
[42] E: indicates that a calculation is performed to determine export capacities.

4.3. BASE CASE - IMPORT

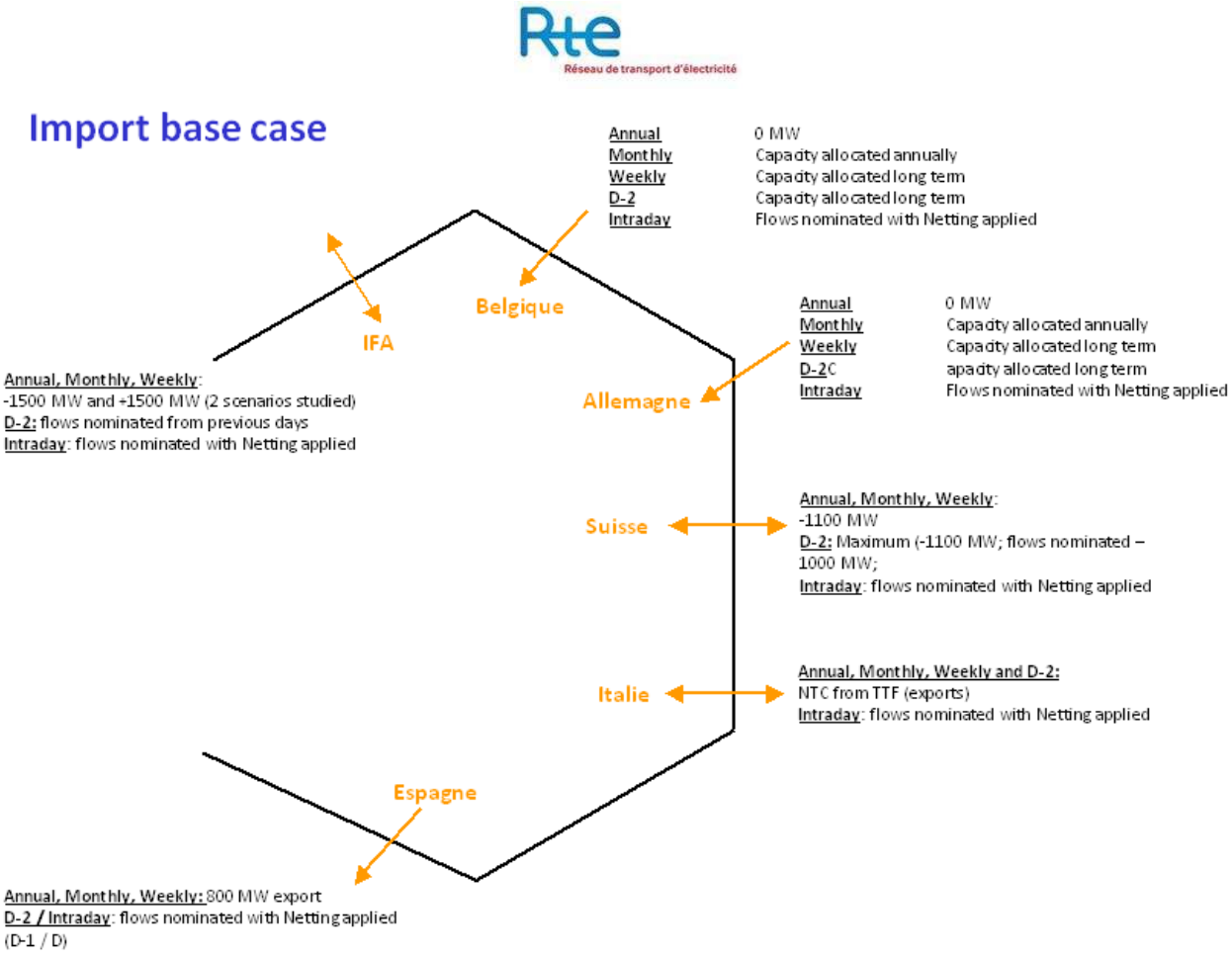
Import capacities are calculated from the base case set out, for 2010, in the graph below.
From these base cases, capacities are calculated for various timeframes (from annual to D-1), taking into account hypotheses for network topology, demand and internal and external generation, as defined in article " 3.5.Summary table ".

This import base case, defined for each timeframe, is used to take account of hypotheses regarding the exchanges that will be nominated. In the case of imports, the following hypotheses are therefore adopted for each country (for all timeframes other than intraday):

- For Italy, the import value adopted is the one given by the TTF (Technical Task Force). For the D-2 calculation, this hypothesis is adjusted to take account of the actual nominations observed on the previous day or days.
- For England, for medium term timeframes, we assume 1500 MW of imports on the France-England interconnection, i.e. 1500 MW of exports depending on the faults studied. For short term timeframes, this hypothesis is adjusted to take account of the actual nominations observed on the previous day or days.
- For Spain, the value of 800 MW is used, as for the export calculation. Note that this decision in no way affects the final outcome, as capacities on this interconnection are calculated completely independently of calculations on other interconnections.
- For Switzerland, we assume a value of 1100 MW[43] consistent with long term contract values. For intraday exchanges, the flows nominated and netted are used as a base reference for updating capacity calculations.
- For Belgium and Germany, the capacities guaranteed for earlier timeframes are used[44]. For short term timeframes, this hypothesis is adjusted to take account of the actual nominations observed on the previous day or days

- For the D-1 calculation used to determine intraday capacity, on all the interconnections, the flows nominated on D-1, taking into account Netting, are defined as a base reference for updating capacity calculations.

[43] These values are valid for the current year but may change in future years.
[44] Capacities allocated at previous timeframes



4.4. DETERMINING CAPACITIES OVER DIFFERENT TIMEFRAMES – IMPORT

Capacities on the France-England, France-Italy and France-Spain interconnections are calculated in the same way for both imports and exports, as explained in article " 4.2. Determining capacities over different timeframes – Export ".

In the case of Belgium, Germany and Switzerland, capacities are calculated by distributing margins evenly between the borders and using influencing factors to determine the interconnection capacities defined in article " 2.4. Calculating TTCs, NTCs ".
The three borders are thus processed simultaneously. The physical margin available on the lines is therefore divided into three and split evenly between the borders. There is no priority given to one particular border for the intraday timeframe.
Once the margin has been distributed on each border, the ATC specific to each border is calculated accurately, by dividing the physical margin by the influencing factor of exchanges on each border on the critical branch concerned. The resulting ATCs are then coordinated[45] with those determined by the neighbouring TSOs, to obtain the final capacities assumed on the interconnections.

[45] This coordination involves keeping the maximum capacities accepted simultaneously by both TSOs.

	England	Germany	Belgium	Switzerland	Spain	Italy
Annual	I[46] (physical capacity), in case of works	I			I	I (TTF) + works
Monthly		I			I	
Weekly		I			I	
D-2		I			I	
D-1 for intraday	I (Intraday Transfer Limits)	I			I	

Summary table of import capacity calculation timeframes

[46] I: indicates that a calculation is performed to determine import capacities.