Pentalateral Energy Forum
Support Group 2

Generation Adequacy Assessment

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Contents

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Disclaimer:

It must be noted that the conclusions in this report are inseparable to the hypotheses described and can only be read in this reference framework. The hypotheses were gathered by the TSOs according to their best knowledge at the moment of the data collection and validated by ministries and regulators. The TSOs emphasise that the TSOs involved in this study are not responsible in case the hypotheses taken in this report or the estimations based on these hypotheses are not realised in the future.

Executive summary

This report provides the main findings of the second edition of the Pentalateral Generation Adequacy Assessment (PLEF GAA 2.0). The study was carried out by the Transmission System Operators of the seven countries cooperating in the Pentalateral Energy Forum (PLEF): Austria, Belgium, France, Germany, Luxembourg, the Netherlands and Switzerland (Penta countries/region).

The Pentalateral Energy Forum is the framework for regional cooperation in Central Western Europe (AT-BE-DE-FR-LU-NL-CH) towards improved electricity market integration and security of supply.

The first PLEF Generation Adequacy Assessment, issued in 2015 and based on the Political Declaration of the Pentalateral Energy Forum of 7 June 2013 in which the Ministers of Energy requested a Pentalateral Generation Adequacy Assessment, provided a first probabilistic analysis on electricity security of supply in Europe conducted from a regional perspective, thus making it possible to better assess generation adequacy jointly, on a regional scale covering the Penta countries. The know-how on methodology as developed by the Penta TSOs has later on been transferred and applied within the association of European electricity TSO's in ENTSO-E in the Midterm Adequacy Forecast (MAF).

This second Pentalateral Generation Adequacy Assessment focuses on two main aspects. The first goal is the development of state of the art methodologies, high quality data collection and enhanced adequacy modelling techniques and, by application of these methods, to obtain the second goal in order to provide a probabilistic adequacy assessment for the Penta Region on the horizons defined by the Ministries (short term: 2018/2019 and medium term: 2023/2024). These results provide decision-makers with a more holistic assessment of potential capacity scarcities in the Penta region.

Compared to the first assessment, important areas of improvement include better representation of the grid by using a Flow-Based (FB) approach and an improved model for taking into account flexibilities on the demand side. Also the climate database was extended from 14 to 34 years, now covering historical weather from 1982 to 2015.

The quantitative results from this study are generally consistent with those from the ENTSO-E MAF and from national studies. The differences are mainly because of different assumptions and data, the details can be found in the report. The sensitivity analyses enable different scenarios in a regional context. Some of these sensitivities, e.g. environmental, economic, as well as grid investment, demonstrate how these factors can have an important influence on regional generation adequacy.

The results for the first time horizon (2018/2019) show that France and Belgium are most prone to generation adequacy problems while similar observations can be made for the second time horizon (2023/2024) for these countries with slight issues (less than 3 LOLE/year) also observable for countries like the Netherlands and Germany. The economic viability evaluation of Demand Side Flexibility (DSF) provides an estimate of possible addition of available DSF in some of the PLEF countries for the analysis of their impact on generation adequacy. The results show that DSF has a clearly positive impact.

One of the main achievements of this study is the implementation of the FB approach at the regional level. The approach for FB-Market-Coupling (FB-MC) is a significant step towards more realistic modelling of operational planning in practice nowadays. Contrary to the constant NTC values defined for long-term planning, representative historical FB domains are chosen as basis and linked to expected climate and consumption conditions of each day for the winter 2018/19. Combined with the adjustable NTC values at the border between Germany and Switzerland based on the German wind production, this approach is a simple yet realistic representation of what is observed in everyday practice in the region. As this requires more detailed modelling and realistic inputs, at the moment, it is only possible to do this for the not-so-far future, i.e. FB approach for the 2018/2019 horizon only. With breakthroughs in the methodology and grid modelling it would be also possible to conduct FB approach for the longer time horizon, which could be facilitated via regional cooperation.

The step towards a more realistic modelling of operational planning in practice also means that the simulation results could better reflect the tight situations observed in practice leading to more realistic adequacy assessment of the region. Because of the aforementioned reasons, the FB and NTC approaches used for the same time horizon likely lead to different outcomes. FB approach should be target model, whenever possible, to reflect what is experienced in operational practice.

On the probabilistic approach, though it is quite developed the dependence of generation adequacy results on climatic conditions is key and despite the extension of the climate database to cover 34 historical years it is still not long enough to cover the necessary meteorological evolution. In this case, it might be beneficial to consult experts in this domain to evaluate or adjust the probability assigned to each climate year.

As some of the steps are pioneering and experimental in this study some of the results should be considered as indicative and evaluated together with those from the ENTSO-E MAF and the respective national studies, taking into account the differences in assumptions and data.

Contents

Index of figures and tables

1 Introduction

This report provides the main finding of the second edition of the Pentalateral Generation Adequacy Assessment (PLEF GAA 2.0). The study was carried out by the Transmission System Operators of the seven countries cooperating in the Pentalateral Energy Forum (PLEF): Austria, Belgium, France, Germany, Luxembourg, the Netherlands and Switzerland.

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In June 2015, the Penta ministers defined in their 2nd Political Declaration further milestones on security of supply, on market integration and on flexibility, including the aim for further improvements of the common methodology to assess security of supply on the regional level as developed by the TSOs and continue to publish regular bi-annual reports on the status of security of supply in the central western European region, starting in 2017.

The declaration was followed-up by a roadmap that was prepared together with the Penta TSOs defining the contents of the next adequacy study, taking into account important insights gained from the first study by the Penta TSOs on needs to further improve methodology of the assessments. After completion of the road map Penta TSO have intensively worked together to carry out the new study establishing an improved level in adequacy assessment.

This second Pentalateral Generation Adequacy Assessment focuses on two main aspects. The first goal is the development of state of the art methodologies, high quality data collection and enhanced adequacy modelling techniques and, by application of these methods, to obtain the second goal, in order to provide a regionally relevant adequacy assessment for the Penta Region on short (2018/2019) and medium term (2023/2024). These results provide decision-makers with a more holistic assessment of potential capacity scarcities in the Penta region.

Compared to the first assessment, important areas of improvement include i) better representation of the grid by using a flow-based approach and ii) an improved model for taking into account flexibilities on the demand side. Also the climate database was extended from 14 to 34 years, now covering historical weather from 1982 to 2015.

The present report starts with the executive summary. Chapter 2 provides a short description of the background and objective of the study. A description of the high level methodology is presented in chapter 3, while chapter 4 provides detailed descriptions of methodology, input data and modelling assumptions. Chapter 5, “Study framework”, provides an overview of the base case scenario’s and sensitivity analyses that were carried out for the two study horizons. The results of the analyses are reported in chapter 6. Conclusions and lessons learnt are provided in chapter 7. Chapter 8, the appendix, contains a “frequently asked questions and answers” list, as well as a description of the simulation tools employed in this study. Details on the FB modelling, NTC, the alignment of the tools on the results, a glossary and a TSO contact list can also be found in the appendix.

Comparability of Pan European, Regional and National studies

For consistent analyses and comparisons of the results methodological alignment between pan European, regional and national studies is important. This regional PLEG GAA study, ENTSO-E Pan-EU study (MAF) and various probabilistic national adequacy studies by TSO, currently share a similar approach.

By means of example, a non-exhaustive list of relevant studies is given below. Although not all studies in the list below use exactly the same approach, the methodological alignment between these studies and the PLEF GAA 2017 is significant:

- Elia Adequacy Study for Belgium: The need for strategic reserve for winter 2017-18 and outlook for 2019-20 and 2020-21[1]
- Elia Adequacy & Flexibility study for 2017-2027[2]
- RTE Bilan Prévisionnel 2016[3] and forthcoming edition 2017
- TenneT Rapport Monitoring leveringszekerheid 2016-2032[4]
- National Grid EMR Electricity Capacity Report of May 2017[5]
- ENTSO-E Mid Term Adequacy Forecast 2017[6], currently in consultation.

However, due to the different and complementary scope and usage of Pan-European, regional and national studies, some differences in the methodological assumptions and data might be considered between the above mentioned studies. Table 1 highlights some of the main differences observed between different adequacy assessments in Europe at present.

[1] http://www.elia.be/~/media/files/Elia/Products-and-services/Strategic-Reserve/171129_ELIA%20AR-Winter_UK.pdf

[2] http://www.elia.be/en/about-elia/newsroom/news/2016/20-04-2016-Adequacy-study-flexibility-Belgian-electricity-system

[3] http://www.rte-france.com/sites/default/files/bp2016_complet_vf.pdf

[4] https://www.tennet.eu/fileadmin/user_upload/Company/Publications/Technical_Publications/Dutch/Rapport_Monitoring_Leveringszekerheid_2017_web.pdf

[5] https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/116/Electricity%20Capacity%20Report%202017.pdf

[6] https://www.entsoe.eu/Documents/SDC%20documents/MAF/MAF_2017_report_for_consultation.pdf

Report	Time horizons	Geographical perimeter	Climate Dataase	DSR	Flow Based method
MAF 2017	2020, 2025	EU	ENTSO-E PECD	DSR input from TSOs	Not in 2017
PLEF 2017	2018/2019, 2023/2024	EU, but with focus on adequacy within PLEF region. MAF data provides the basis for setting up the model outside of the PLEF region	ENTSO-E PECD	DSR input from TSOs and additional use of flexibility tool	Usage of flow based approach from CWE TSOs, combined with RES-infeed dependent NTC approach for PLEF countries not within the CWE FB region
Probabilistic national studies by TSOs, comparable to MAF 2017	Different, up to 10 years ahead	Single unit resolution within focus perimeter relevant for the study. Dataset consistent with MAF for rest of the simulation perimeter	ENTSO-E PECD and Hydro specific databases for all climatic years[7]	Extensive consultation with market parties on national assumptions (e.g. DSR assumptions)	Flow based approach based on historical domains from the CWE FB tool implemented in some of them for several years now

Table 1 Features of regional and national analyses

The adequacy standard that has to be met are normally defined by each country, in case it is defined. For the moment, there is no such definition for the other PLEF countries (AT, CH, DE, LU) nor for the PLEF region.

PLEF Country	**Adequacy Standard**
BE	LOLE average of 3h/year & LOLE95 of 20 h[8]
FR	LOLE average of 3h/year[9]
NL	LOLE average of 4h/year[10]
AT, CH, DE, LU	n/a

Table 2 Existing Adequacy Standard in PLEF

[7] For its national study RTE uses a specific weather database provided by Meteo France which comprises 200 simulated years of the climate (temperatures, wind, solar radiation) over western Europe, and consistent with today's climate

[8] Belgian law 'Elektriciteitswet' of April 1999

[9] French law February and August 2004

[10] Dutch adequacy criteria in paragraph 4.2 of report Monitoring Security of Supply (in Dutch 'Rapport Monitoring Leveringszekerheid 2013-2029', www.tennet.eu) of Dutch TSO TenneT

2 General approach

The procedure implemented in this study can be divided into three major steps (see Figure 1): (I.), inputs are prepared, mainly covering electricity demand, renewables generation profiles, pre-installed power plant fleet, unscheduled generation unavailability and transmission capacities. (II.), constraints for the modelling of Flow-Based market coupling (FB Model) and capacities for Demand Side Flexibilities (DSF Model) are determined. (III.), generation adequacy indicators are computed utilising two Generation Adequacy models (GA Models).

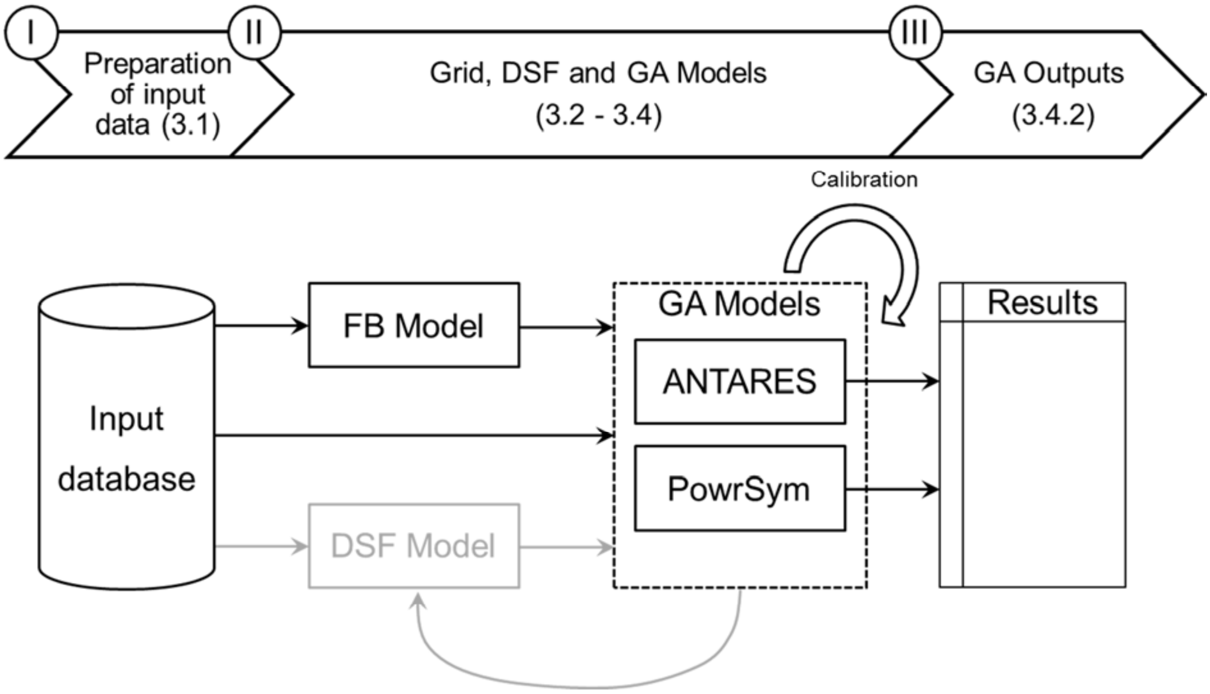


Figure 1 Process of study performance

According to Figure 1, in this study multiple tools and models are utilized. One reason for this is the further development of the adequacy assessment regarding the modelling of flow-based market coupling and demand side flexibilities. Moreover, in order to increase the level of quality and robustness of the presented results two system models (Antares and PowrSym) are used in parallel for determining market results and generation adequacy indicators. While both models use the same input data and follow the same approach with regard to probabilistic modelling there are differences for instance regarding the formulation of technical restrictions, which might lead to deviating results. However, as the results demonstrate, the two models converge well.

The enhanced modelling of flow-based market coupling requires a determination of commercial transaction constraints on the basis of relevant physical transmission constraints, which are described by the flow-based domains. The outputs of the capacity calculation process, in the form of historically observed flow-based domains, are then incorporated into the generation adequacy models. It is worth mentioning that planned reinforcements up to Winter 2018/19 have been considered in this assessment, in order to update the historical domains considered.

A further feature of the improved generation adequacy assessment concerns a determination of installed DSF capacities for the long-term time horizon, which are consistent with the assumed scenario framework of this study. According to Figure 1, the DSF model uses input data such as electricity demand, renewables generation profiles and installed power plant fleet. As cross border exchanges are only modelled in ANTARES and PowrSym there is a feedback loop from the generation adequacy models to the DSF model, which considers the exchange balances as exogenously given.

The three steps and underlying methodologies are described in more detail in the subsequent chapters. In chapter 3.1 the preparation of input data, e.g. the determination of temperature-sensitive load profiles, is briefly described. Chapter 3.2 gives an overview of the flow-based model and the derivation of the flow-based domains. A description of the DSF model is given in chapter 3.3. Both generation adequacy models and considered uncertainties are further detailed in chapter 3.4, where the description of the relevant outputs and indicators used for the generation adequacy analysis can also be found.

3 Methodology

3.1 Preparation of input data

The preparation of the PLEF input data is done through a standard data gathering process based on the one used also for the ENTSO-E MAF study, with the necessary updates by the PLEF TSOs concerning their national data. Attention is paid to adjust the data because of the different time horizons for the PLEF and the MAF studies. The scenario data have been presented and approved by the PLEF ministries.

3.1.1 Pan European Climate Database

Weather conditions are becoming a more and more important element in the European power system. Dependency on weather is present on both supply and demand side. Important weather-related supply side uncertainties concern the production of wind, solar PV and hydro power. On the demand side, in many countries the temperature has a major influence on demand.

In certain situations, the system may become more vulnerable, for example, when there is low availability of conventional power and simultaneously low feed-in from renewables (RES). All this combined with a cold wave in Europe can cause a significant reduction of the adequacy margin. Because of the space- and time correlated nature of these weather related parameters, a correct assessment of the adequacy risks in such situations places high demands on the method of simulation. For this reason ENTSO-E has improved the modelling of the weather dependent parameters by the development of a Pan European Climate database (PECD). This development started about 5 years ago within the framework Ten Year Network Development Plan (TYNDP) 2012.

This PLEF study uses the 2nd release of the Pan European Climate database (PECD 2.0). This database enables the creation of correlated chronological time series of weather-dependent parameters (electricity demand and renewables production) per market area in Europe based on historical weather over the period 1982-2015 (34 climate years). It also takes into account various available quantities of production from hydro power production depending on the rainfall (wet, average or dry year) in these years.

3.1.2 Load

The hourly load data are taken from the ENTSO-E MAF 2017[11]. The thermal sensitivity or temperature dependency of the hourly load is the same as the one applied for MAF using the Pan European Climate Database (PECD). The approach applied in the MAF report entails a sensitivity analysis of load and temperature, in order to consider the impact of heating and cooling on the consumption of electrical energy. On the basis of a cubical polynomial approximation synthetic hourly load profiles for each area are created. By this means seasonal and daily impacts of weather conditions, in particular temperature, as well as impacts of extreme events like cold spells in winter and heat waves in summer on the electrical load are considered. Because of the slightly different time horizons between the MAF and the PLEF studies the necessary interpolation/extrapolation is performed.

[11] Except for France, which has provided hourly load profiles by use of its own national methodology

3.1.3 Demand Side Response (DSR)

DSR is modelled as a virtual power plant in the generation adequacy models, with a maximum power and a strike price corresponding to the data collected, and may be allocated a limit in usage (daily limit on number of hours) to adapt to the type of usage at stake.

3.1.4 Wind and Solar

Similar to the ENTSO-E MAF study, the Pan European Climate Database (PECD) for wind and solar production for each country is applied. The extended database is based on existing global climate reanalysis models and contains hourly climate data for 34 years (1982 to 2015). The used climate data consider climatic spatial and temporal correlations and allow a consistent set of load, wind and solar production time series for the subsequent adequacy simulations. Onshore, offshore wind and solar photovoltaic load factor (percentage of production compared to installed capacity) time series are given for each market node and scaled to the respective future installed capacity.

With regard to the probabilistic assessment it should be noted that the extension of considered climate years causes a significant increase in the computational requirements in comparison to the last PLEF adequacy study. The additional efforts, however, significantly improve the range of possible weather patterns that are investigated.

3.1.5 Hydro

Modelling a hydro production system, especially one including storage and pump storage power plants is challenging due to its complexity and the presence of many stochastic variables, e.g. cascades of reservoir basins and unclearly defined marginal costs. Therefore some simplifications have to be made.

The data collection (using ENTSOE's templates) splits the hydro generation fleet in several categories, each having a set of specific constraints.

Run-of-river units of a given market node are merged in a single must-run unit with a predefined generation time-series of weekly energies provided by each TSO for different hydro conditions (dry, wet, average year). Theses time series are built based on historical data. The energy is converted in an hourly flat power profile.

Hydro reservoirs are subject to much more constraints and the generation profile results from an economic optimization. All annual reservoirs[12] of a given market node are merged in the data collection in a single reservoir. Based on the monthly starting and ending levels of this total-reservoir, and the monthly inflows provided by each TSO for annual storages, the model determines an energy credit to be optimally dispatched on a monthly basis. This monthly credit will then be distributed optimally into weekly credits. Hydro units are dispatched by the optimizer to reach a minimum system cost using all dispatchable units. In this way hydro dispatch is dependent on market price signals in the whole week, i.e. opportunistic costs, and limited by the pre-optimized weekly energy credit. For reservoir power plants min/max of generation capacities are additional optimization constraints.

Pure pumped storages are modelled with their efficiency rate (75%), and the pumping/generation is optimized by the model within limitation of capacities (use of max pumping and generation capaci-

[12] with a yearly management strategy

ties collected – MW). Basically the model seeks the best opportunity for pumping (when costs/prices are low) and for generation (when prices are high) in order to minimize overall costs of the system. Different types of pumped storage are described in the data collection that distinguishes daily pumped storage from weekly and yearly pumped storage. Modelling also makes this distinction. The energy (daily or weekly) produced should be balanced by the pumped energy with respect to the efficiency rate.

The consideration of hydrological conditions is enriched compared to the last PLEF adequacy assessment. The PLEF study uses new information made available by the Pan-European Market Data Base collected within current ENTSOE studies (MAF2017 and TYNDP2018). Indeed each Transmission System Operator not only delivers three hydrological data sets corresponding to dry, average, and wet conditions, but also allocates them to each year from the PECD. This allows a better consistency between all climatic variables (temperatures, wind, solar radiation and hydro conditions).

3.1.6 Thermal units and outages

Installed capacities for thermal units are based on ENTSO-E data, with the necessary updates by the PLEF TSOs for their national data. For thermal units, different categories are defined (coal, gas, etc.) in accordance with the definitions in the ENTSO-E market database. Each category has parameters defining the main technical and economical characteristics, like maximum power, fuel type, efficiency, fuel cost, operation and maintenance cost, etc.

Each thermal unit is given a rate of unavailability (forced outage and maintenance rate and durations) that is based on the type of the unit. When no specific data is proposed by the TSO, this information is taken from the PEMMDB of ENTSOE where default values based on historically observed unavailability are available.

The maintenance schedules used in PLEF are taken from the MAF study (adapted when differences exists on installed capacities for the PLEF region given the different time horizons studied); Such maintenance schedules result from an optimization which defines maintenance periods throughout the year. These optimizations respect the minimum maintenance level set for each season (winter/summer) by TSOs within the PEMMDB.

Maintenance plans determination in pan-European studies is clearly a field where modelling improvements could be implemented, to better translate not only the rationale of the maintenance from plant operators (maximize availability on peak period), but also the risks attached to maintenance (for example the risk of an extended duration of a maintenance due to unforeseen reasons). This would require an enhanced data collection and some complementary efforts in modelling.

On top of this maintenance, the simulators apply random draws to account for forced outages, thus producing different combinations of outages.

3.1.7 Outages of HVDC lines

In line with MAF, forced outages due to unexpected failures of HVDC links resulting in unavailability of these transmission links have been taken into account for selected High-Voltage Direct Current (HVDC) interconnections in the CWE perimeter. It has been considered that a forced outage of these links will occur with a chance of 6% for a period of 7 consecutive days (based on CIGRE data).

3.1.8 Fuel and CO_2-prices

The assumptions on fuel and CO_2 prices for this study were taken from the 2016 edition of the International Energy Agency (IEA) World Energy Outlook (WEO). The IEA WEO provides medium to long-term energy projections on a detailed sector-by-sector and region-by-region basis. It is known as a well-quoted source and is considered by policy decision makers. Since years ago it has been adapted as a source for the ENTSO-E TYNDP scenarios and was also used for the 2015 version of the PLEF Generation Adequacy Study.

The development of the energy sector and its markets is affected by many different uncertainties. The government policies of the different countries are a major driving force which is shaping the development of the energy sector. The WEO2016 makes detailed projections for three different scenarios: the "Current Policies Scenario", the "450 Scenario" and the "New Policies Scenario".

These three scenarios are based on different developments of future government policies. No changes in government policies are assumed for the "Current Policies Scenario", whereas the "450 Scenario" assumes that the greenhouse gases in the atmosphere are limited to 450 ppm[13] of CO_2. The idea behind the "450 Scenario" is to achieve the climate target and to limit the global temperature-increase to 2°Celsius. To evaluate the development of the energy sector under the assumption of today's policy ambitions the "New Policies Scenario" was defined. For this scenario the current state of the energy sector, recently announced commitments and likely future policy decisions are considered. The (Intended) Nationally Determined Contributions, which form the basis for the Paris Agreement[14], serve as a basis for this scenario.[15] [16]

For both horizons in this PLEF study the assumptions according to the WEO2016 "New Policies Scenario" are used for fuel and CO_2 prices. This IEA scenario is used as a baseline regarding future developments of the energy sector under the assumption that underlying trends like the energy demand remain unchanged. It projects fuel and CO_2 prices for the years 2020 and 2025. As these years are close to the chosen horizons of the PLEF-simulations, it was decided to apply the same assumptions for this study. The corresponding values are presented in Table 3 below:

Unit		Fuel type	2020	2025
€/GJ		OIL	12.1	14.6
€/GJ		GAS	6.1	7.4
€/GJ	29GJ/ton	Hard Coal	2.0	2.1
€/GJ	25GJ/ton	Hard Coal	2.3	2.5
€/GJ		Heavy Oil	12.7	15.3
€/GJ		Light Oil	15.5	18.7
€/GJ		Nuclear	0.5	0.5
€/GJ		Lignite	1.1	1.1
€/GJ		Oil Shale	2.3	2.3
€/tCO_2		CO_2 price	18.0	25.7

Table 3 EU fuel and CO2 prices of the IEA "New Policies Scenario" in the WEO2016

[13] parts per million
[14] http://unfccc.int/paris_agreement/items/9485.php
[15] http://www.worldenergyoutlook.org/media/weowebsite/2016/WEM_Documentation_WEO2016.pdf
[16] https://www.iea.org/publications/scenariosandprojections

In European power markets generation units are dispatched according to their marginal generation costs. Besides variable costs for maintenance, marginal costs are mainly determined by fuel and CO_2-prices. Accordingly, the merit order of generation units (without costs due to technical constraints), i.e. starting from the technology with the lowest cost, determines the cost minimal dispatch.

3.1.9 Perimeter

The perimeter covered in this study is shown in Figure 2 below. The blue highlighted countries represent the main focus area. The green highlighted countries are also considered in the models to improve the representation of the focus area.

Figure 2 Perimeter of the modelled countries in this study

3.1.10 Balancing Reserves

The total volume of balancing reserves has been provided by TSOs via the MAF 2017 data collection. A revision of these figures was performed within the CWE by PLEF TSOs. Reserves include both Frequency Containment Reserves (FCR) and Frequency Restoration Reserves (FRR). The figures and the approach on the modelling are listed in Table 4 . The amount in MW is either directly given or can be easily derived by multiplying the percentage with the total installed capacity of the corresponding category on the generation type for the PLEF countries.

These reserves are modelled in the following way:

- Reserves on hydro units – reduction of turbine capacity
- Reserves on thermal units – derating of the thermal capacity among the relevant categories

For Switzerland the balancing reserves are modelled as extra load, similar to the approach used in MAF 2017, instead of the reduction of hydro turbine capacity. This means that a fixed value is modelled for every hour, as it is not known in which hours these reserves will be needed for system operation. The purpose is to simulate a pessimistic scenario for a hydro country where energy constraints dominate those of installed capacity, assuming that no reserves for balancing can be used for generation adequacy purposes. This is also consistent with the approach used in the pan-European assessment in MAF.

An overview is provided below for the PLEF countries:

COUNTRY	AT
REDUCTION HYDRO [MW]	491
THERMAL REDUCTION %	1% in Gas units
COUNTRY	BE
REDUCTION HYDRO [MW]	
THERMAL REDUCTION %	Light Oil (100 % providing reserves) and 12 % in Gas units
COUNTRY	CH
EXTRA LOAD	868 MW
COUNTRY	DE
REDUCTION HYDRO [MW]	2658
THERMAL REDUCTION %	Hard Coal (3,8%), Gas Turbines (3,7%) and Oil Plants (33,7%)
COUNTRY	FR
REDUCTION HYDRO [MW]	500
THERMAL REDUCTION %	Nuclear (2%), Coal (2%) and Gas (2%) units
COUNTRY	NL
THERMAL REDUCTION %	Nuclear (5%), Coal (5%) and Gas (5%) units

(*) although not indicated here explicitly, similar approach has been adopted for the consideration of reserves in the whole simulated perimeter.

Table 4 Balancing reserves

3.1.11 System Adequacy Mechanisms

In some of the PLEF countries, different types of system adequacy mechanisms (SAM) are implemented. Some countries fully rely on the energy only market (EOM). Capacity mechanisms can target to safeguard the insurance of either generation adequacy or transmission adequacy.

To analyse whether the capacities contracted in the SAMs should be considered in the assessment, differentiation between mechanisms is made, which

a) ensure the availability of sufficient energy produced to cover the load (generation adequacy) by contracting resources in a decentralized capacity market (DCM) or strategic reserve (SR) and
b) ensure the availability of additional generation capacity in case of grid congestion (transmission adequacy). These capacities are then contracted in a grid reserve (GR) and need to fulfil certain

requirements by means of e.g. grid topology and ramp-up times, so that they have an effective impact to cure the grid congestion.

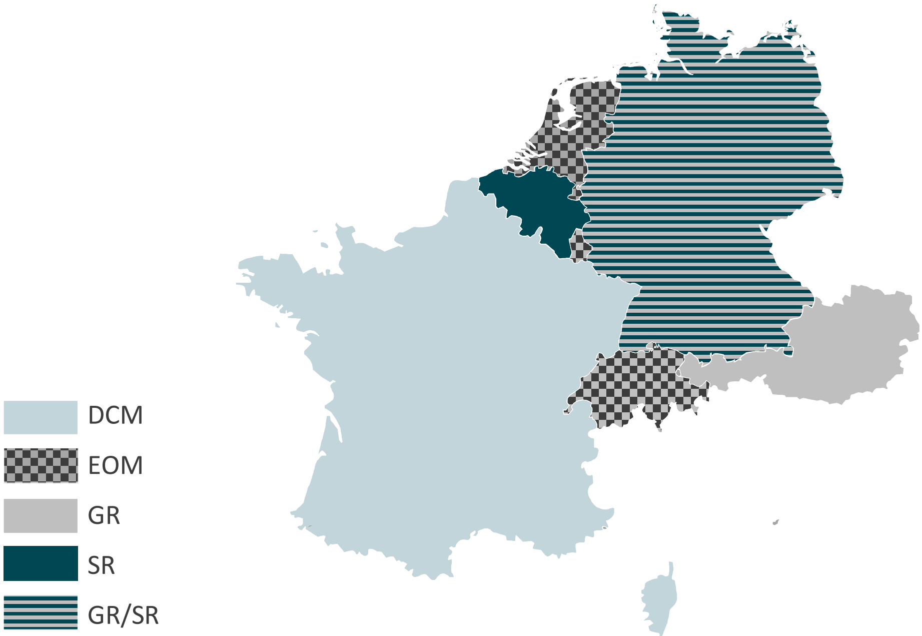


Figure 3 System adequacy mechanisms (in place or under development) in Central Western Europe

The described types of SAMs have predefined triggers and dispatch regimes, generally stated in the national energy laws.
Only SAMs that contributed to the assurance of the generation adequacy will be taken into consideration.
In the following, the SAMs implemented in the PLEF countries and to what extend the SAMs are considered when analysing generation adequacy in the countries of the region are described. According to the information and legal basis known at the point of time of the study the assumed capacity available in the two time horizons in incorporated.

3.1.11.1 Austria

Austria implemented a grid reserve where generation capacity was contracted for redispatch measures in case of critical network congestion and was assumed with approximately 2,4 GW in both time horizons.

At the point of reporting the grid reserve aims to solve transmission issues and is not dispatched in order to cope with supply shortages. Therefore, the grid reserve was not incorporated into the base case.

3.1.11.2 Belgium

Strategic reserve contracted for the winters 2015, 2016 and 2017 is considered out of the market and is not part of the base case, neither in 2018/19 nor in 2023-24.

In Belgium strategic reserve could be activated when a risk of structural shortage is detected in the Belpex Day Ahead Market and/or in real-time. Structural shortage refers to a situation in which the total consumption level of Belgium, cannot be covered by the offer of installed production in the Belgium grid, excluding the contracted Balancing Reserves, including the importation possibilities and the energy available on the market (defined in Belgium's Electricity Act, art; 2,54°).

No strategic reserve capacity has been considered in the simulations.

3.1.11.3 France

In 2017 the capacity mechanism became operational in France. It is not explicitly modelled in this PLEF study, but is implicitly reflected in the input data. The generation units and DSF volumes in the dataset for France at both time-horizons are the best estimate values as foreseen by RTE given the existing units, the announcements made by their operator for the years to come and objectives set by the French Energy Transition Law at the point of time of the study. The announcements made by market parties integrate the existence of the French capacity mechanism for the next 10 years, based on the State Aid clearance published in 2016. The impact of the French capacity mechanism has therefore been estimated by market parties themselves and is reflected in the assumptions.

3.1.11.4 Germany

In Germany there are three different reserve mechanisms implemented by the revised German Energy Law (EnWG) in 2016, which aim to support different objectives. The EnWG offers two kinds of strategic reserves in order to deal with adequacy issues in Germany, the “Security Reserve” and “Capacity Reserve”.

The capacity of the Security Reserve will consist of lignite power plants. The amount of capacity in this reserve was built up from October 2016 onwards to a maximum amount of 2.7 GW in 2019/20. It will be faded out completely in October 2023 (0 GW). For 2018/19 it will amount to nearly 2 GW. The Security Reserve will not be incorporated in the base case of this study. An amount of 2 GW for the time horizon 2018/19 and 0 GW for the time horizon 2023/24 are included in the data collection for the sensitivity “*reserves contracted by TSOs*”.

The Capacity Reserve is foreseen to be tendered in mid-2018 for a time horizon of 5 years, and should be available as of winter 2018/19. At the point of time of data collection it is planned to contract 2 GW of Capacity Reserve by the German TSOs in 2018/19. The Capacity Reserve will not be incorporated in the base case of this study. An amount of 2 GW for the time horizon 2018/19 and 4 GW for the time horizon 2023/24 are assumed and added in the data collection for the sensitivity “*reserves contracted by TSOs*”.

The third element under the EnWG allows contracting of a grid reserve by the German TSOs. The Grid Reserve may be activated by TSOs primarily for redispatch in case of network congestions in Germany. The European Commission has approved this temporary measure until June 2020. At the point of time of this study, 6.8 GW of Grid Reserve were contracted by the German TSOs for the winter 2017/18. The power plants contracted may be located in or outside of Germany. No grid reserve has been contracted for the winter 2018/19 yet. However the national regulator (BNetzA) has already confirmed 3.7 GW as the needed amount for 2018/19. Due to the primary purpose of securing redispatch potential with regard to transmission adequacy, the capacities of the grid reserve are not incorporated in the base case, meaning that the respective capacities do not contribute to generation adequacy.

All three aforementioned reserves are not allowed to participate in the energy market. Therefore, the related generation capacities are not considered in the base case of this study.

3.1.11.5 Luxembourg

Luxembourg has an energy-only market. At this point of time there is no SAM installed.

3.1.11.6 Netherlands
The Netherlands have an energy-only market. At this point of time there is no SAM installed.

3.1.11.7 Switzerland
Switzerland has an energy-only market. At this point of time there is no SAM installed.

3.2 Grid modelling
Two approaches have been used in the PLEF study to model the interconnected grid. For the first time horizon, the modelling consists in a mixed approach which uses a flow-based representation for the CWE Flow Based Market Coupling (FBMC) area and "Net Transfer Capacity” model (NTC) for other borders. For the second time horizon, a full NTC approach is used for the whole perimeter. The paragraphs hereafter describe these two approaches.

3.2.1 Import/Export capacity for the NTC approach
The PLEF countries and their neighbouring countries are interconnected and modelled via market nodes. Due to the integration of national power markets and in order to model cross-border aspects of generation adequacy, a pan-European model is considered in this study. NTC-values are taken from the ENTSO-E data collection based on TSO expertise (bottom up data collection).

The NTC values are defined based on expert view between TSOs and mainly derived from available data of previous studies for ENTSO-E. One fixed value is chosen (for each direction when relevant) for the whole year. Every country involved in this study has also the option to define a so-called simultaneous import and export capacity, with the aim to e.g. capture operational constraints which might impact the import and export levels possible.

The chosen starting point are the bilaterally agreed transmission capacity for the MAF 2017 report 2020 and 2025 scenarios. The MAF 2017 NTC values were not published; the PLEF TSOs used them as a starting point because they are the most recent values for the entire European perimeter. Based on updated information on the commissioning of different grid investment projects the PLEF TSOs revised the values of the concerned borders for the use of this study. For the CWE area and relevant first neighbours, these transfer capacities from MAF have been revised and agreed between the respective TSOs to align the assumptions with the 2018/2019 and 2023/2024 time horizons (see Table 5). An overview of the projects providing the evolution of NTC between the 2018/2019 and 2023/2024 time horizons for the CWE area is provided in Table 5.

Border	Difference in NTC : 2023 – 2018	Comments
AT – CH	500	CH internal
AT – DE	1500	TYNDP16 Project 47 (St. Peter - Isar/Ottenhofen, St. Peter - Tauern, Westtirol - Zell/Ziller, Westtirol - Vöhringen/Leupolz), TYNDP16 Project 187 (St. Peter - Pleinting)
AT – ITn	300	Nauders - Glorenza
BE – DE	1000	ALEGRO Project
BE – FR	1000	Change in conductors Mastaing Avelgem
BE – GB	1000	NEMO Link

BE – NL	2000/1000*	Rilland; Brabo-projects
CH – FR	0/500*	Lake Geneva West
DE – NL	500	Meeden-Diele; Dutch internal reinforcement Ring (partly)
DE – NOs	1400	NordLink
DE – PL	1500	GerPol Improvements; GerPol Power Bridge I
FR – GB	2000	ELECLINK and IFA 2
FR – ITn	1000	Savoie Piemont
NL – DKw	700	COBRAcable
***direction dependent**		

Table 5 Evolution of net transfer capacities for scenarios 2018/19 and 2023/24 within CWE

3.2.2 CWE Flow-Based Model

For this adequacy assessment, an enhanced flow-based modelling approach is considered. In the following chapters the approach and calculation of flow-based domains is further detailed.

3.2.2.1 General Approach and Assumptions

Contrary to the NTC approach which is a bilateral approach border per border, the flow based method determines the exchanges potentials among a set of market zones, France, Belgium, Germany and the Netherlands in the case of this study.

On one hand, the NTC approach sets an interval in which commercial exchange may vary between two countries no matter what the exchanges with other countries are. On the other hand, the flow-based approach models the exchanges through domains which couple exchanges on all borders simultaneously for each hour. These domains reflect in detail the margins on the physical grid elements.

To enable computation, the method relies on simplifications; thus 12 typical days are selected. These 12 typical days reflect the diversity of the historical domains observed in the past. Correlations between the climate variables and the domains have been assessed in order to be used in the simulation scheme, and its climate database.

Combined with an adjustable NTC value at the DE-CH border, based on the level of the German wind production, this approach is a simple yet more realistic representation of what is observed in everyday practice in the region.

Nevertheless, it is important to note that this approach is based on historical FB domains, its validity thus spans the near future, before major changes in the grid and/or generation affect significantly the FB calculation. A “complete” operational flow-based calculation requires detailed modelling and realistic inputs (e.g. on generation unit localization) and can be reasonably applied only on a timeframe when input data are not so uncertain. Still within the operational framework here used, it has been possible to consider the effect of grid reinforcements foreseen for the first time horizon (see details in Table 5).

It should be noted that the FB model is built based on the current bidding zone configuration. Switzerland is coupled with other PLEF countries via the NTC approach. Both assumptions reflect the status quo.

What is a flow based domain?

The flow based approach enables closer modelling of actual grid constraints than NTC approach. For each hour of the year, the impact of energy exchanges on each critical line/element (also called 'branch') is calculated while taking into account the N-1 criteria. A critical 'branch' is a physical element of the grid, which has reached its maximum transmission capacity and therefore constrains the total flow of the system around it.

In typical situations, energy exchanges lead to many constraints. The 'limiting constraints' typically form a domain of possible maximum energy exchanges between the CWE countries (this is called the flow-based domain). For any given grid element, these constraints have the form

$$PTDF(A \rightarrow B) * Exchange(A \rightarrow B) + PTDF(A \rightarrow C) * Exchange(A \rightarrow C) + ... \leq RAM$$

In this equation A, B and C are market nodes within the FB area. 'PTDF' are the so-called Power Transfer Distribution Factors (PTDF) which allow to estimate the real flows that are to be expected in the different grid elements as a function of the commercial exchanges settled in the market between countries. 'Exchanges' are the above-mentioned commercial exchanges between these nodes and 'RAM' refers to Remaining Available Margin of the grid element under consideration. See further details in Appendix 8.3.

The graph below displays the projection of a flow-based domain along two axis, France and Germany net positions for a given time-step (15/07/2015 at hour 15).

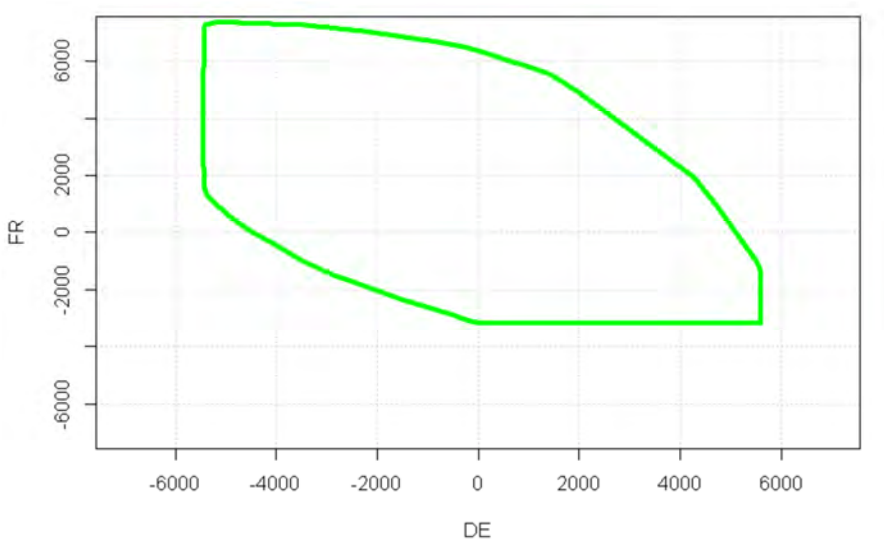


Figure 4 Example of projection of a flow-based domain on France and Germany axis (15/07/2015 at hour 15)

In the case presented above, the grid is able to bear safely all the net positions inside the green area. A positive value corresponds to an exporting net position while a negative value means an importing net position. However, as the third dimension of the flow-based domain is not depicted in this figure, it has to be reminded that some positions can only be reached under the condition that some other constraints are respected, for example in case of Figure 4 for the combined net position volume of Belgium, France, Germany and the Netherlands (for reference see also the 3D figures in Figure 9).

3.2.2.2 Calculation and Selection of Domains

Several flow-based domains are used for the Winter 2018/19 assessment. The following diagram illustrates the overall process of the probabilistic approach applied to the selection of flow-based domains in the simulations, including the creation and selection of the typical days:

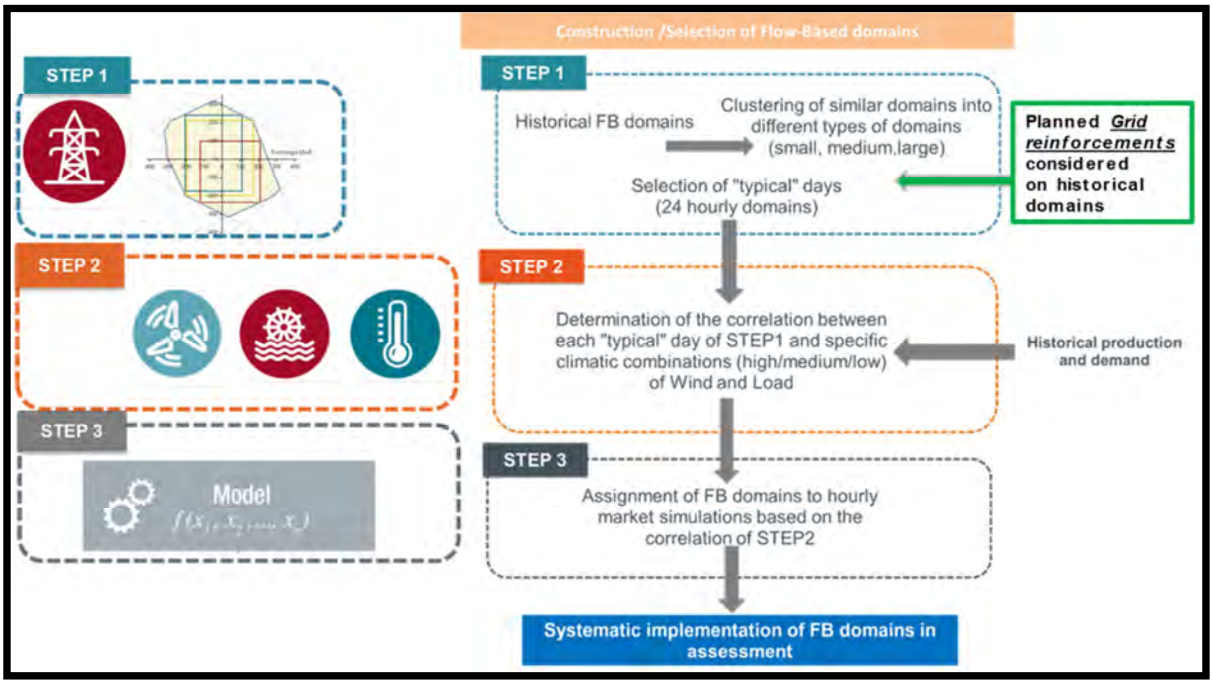


Figure 5 Illustration of the overall process of the probabilistic approach applied for FB domains selection

A clustering technique is applied to a set of historical flow-based domains to identify a few typical days which are used as input for the simulation tools.

One typical day consists of 24 individual domains (one for each hour of the day). Because of new investments, these domains have to be recomputed to take into account grid reinforcements (grid investment projects) that might enlarge the domain of possible exchanges (see Appendix 8.3). During the adequacy simulations, based on the climate conditions, the corresponding domains are drawn using a pre-defined correlation matrix. This approach is shown in Figure 5 and a more detailed explanation is given in the following paragraphs and in a dedicated document[17].

1) STEP 1

a) Typical day clustering

Within the framework of the co-development with Market Parties of a Standard Process to communicate about, and Assess the Impact of significant Changes (SPAIC) within the CWE flow-based consultation group, twelve typical days per year are defined on a regular basis by CWE TSOs. For this adequacy study, this approach is adapted. The domain calculations are performed by use of the same tool as currently used in Flow-Based Market Coupling (FBMC) operation for the CWE region[18]. While

[17] https://antares.rte-france.com/wp-content/uploads/2017/11/171024-Rte-Typical-Flow-Based-Days-Selection-1.pdf

[18] http://www.jao.eu/support/resourcecenter/overview?parameters=%7B%22IsCWEFBMC%22%3A%22True%22%7D

in operation the domains are updated every day based on forecast for the Day-Ahead Market Coupling, for this adequacy study the approach followed is based on so-called typical domains.

The 12 typical days found by this analysis can be split as follows: 4 typical days for winter (3 weekdays and 1 weekend), 4 typical days for summer (3 weekdays and 1 weekend) and 4 typical days for the inter-season (3 weekdays and 1 weekend). Regarding the robustness of the clustering-method, it was found that a similar number of historical domains was assigned to each cluster. This indicates that the clustering process provides sets of well differentiated flow-based domain types. As already stated above, each typical day consists of 24 domains (one for each hour).

The process to define the typical days is based on a statistical analysis of the geometrical shapes of available flow-based domains from historical records (Nov 1st 2016 – January 20th 2017). Historical days are therefore clustered in groups defined by the size of their 24 hourly domains, i.e. typically “large”, “medium” and “small” families/groups of domains are clustered.

Small domains correspond to situations with a highly congested network and therefore with small values for the maximum power exchanges possible between the different market areas considered by the given domain (related to the small area inside the domain). On the other hand, big domains correspond to situations with a less congested network and therefore relatively higher values of maximum possible power exchanges between the market nodes considered by the given domain (larger area). This is illustrated in Figure 6.

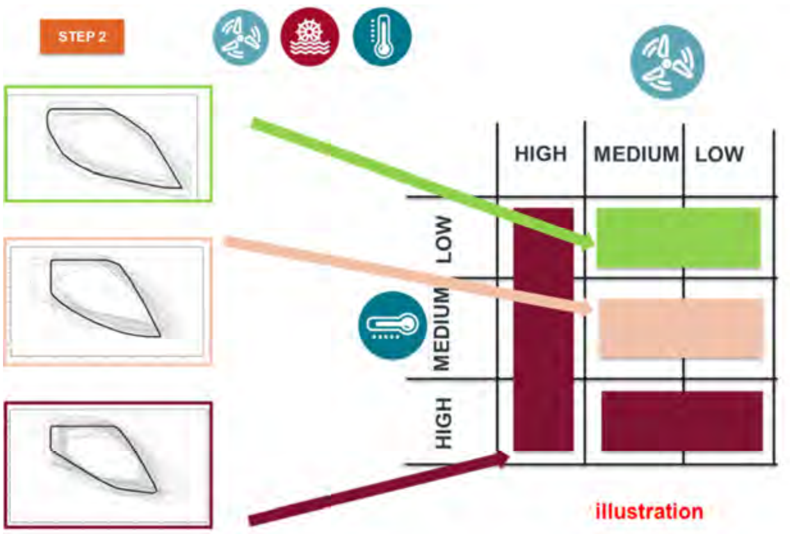


Figure 6 Process of domain selection

A typical day is thus the historical day within a given cluster for which the domains observed on that day provide a good representation of all the domains within each given cluster. Some clustering examples are provided in the following Figure 7. The following graphs illustrate the projection along 2 axis of the 4d (BE-DE-FR-NL) polyhedron on two axis (Net Position ⇔ balance of France and Germany).

Each clustered group consists of the grey domains with the black domain representing the typical day of each group.

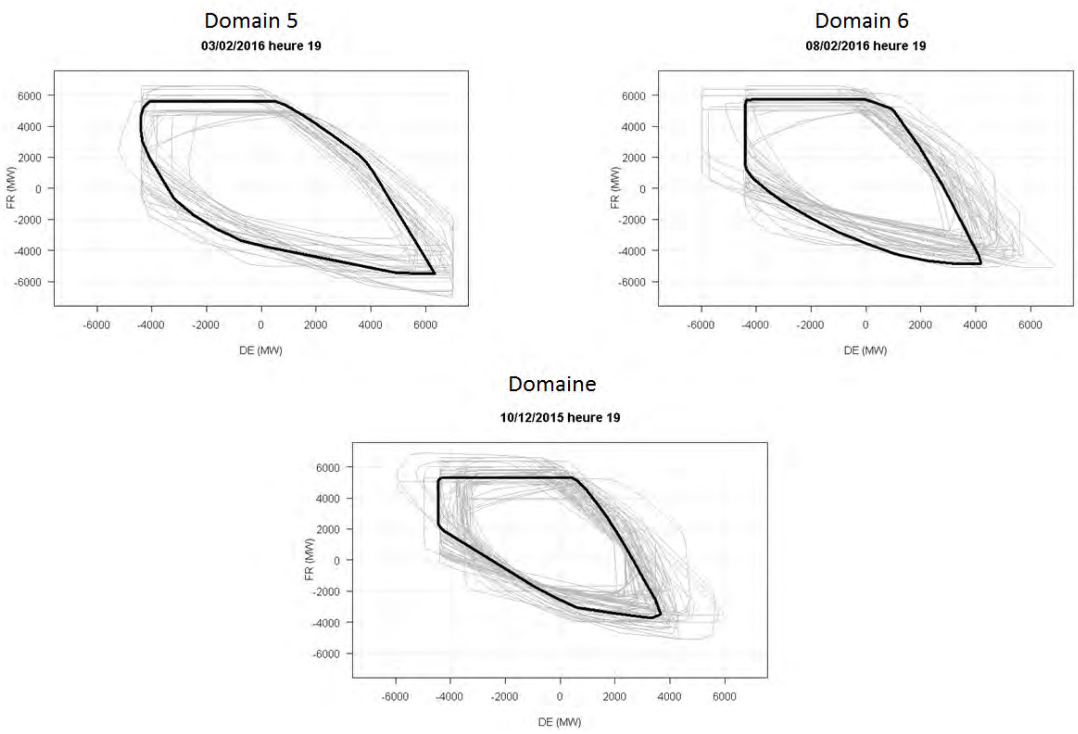


Figure 7 Examples for domain cluster representing the 3 typical working days in winter

b) Inclusion of reinforcements to update the grid to 2018/2019 horizon

The planned grid reinforcements to be commissioned until winter 2018/19 are taken into account in the calculation of the relevant flow-based domains. The changes or assumptions applied for the adequacy domains are:

- All new grid investments (new lines, change in conductors, new phase shift transformers, topology) applied in CWE grid
- No changes on production/load (Generation Shift Keys)
- Latest available LTA (Long-Term Allocations) inclusions are used for the re-computation of the typical day historical domains[19]
- The PST (Phase Shifting Transformers) tap positions are kept from the historical data and no new settings are applied.

A detailed overview of the grid reinforcements included can be found in Table 5 of this report.

Based on these grid reinforcements provided by the PLEF-grid expert group, a recalculation of the forecasted domains for 2018/2019 was performed on the selected typical days as mentioned above while keeping the historical parameters used in the flow based market coupling operational practice for the relevant typical days[20].

[19] see: http://jao.eu/news/messageboard/view?parameters=%7B%22NewsId%22%3A%222c3eacbc-76d7-4ec0-aee9-a7f600e00140%22%7D

[20] http://www.jao.eu/LicquidAction/Get/5f3bcaf1-5156-4c8c-b4b7-a4eb01062441?parameters=%7B%22NewsId%22%3A%222C3EACBC-76D7-4EC0-AEE9-A7F600E00140%22%7D

It should be noted that only the winter domains (4 x 24) were recalculated with grid reinforcement because for adequacy studies, winter period is the most critical one. For the other domains (8 x 24) unchanged historical domains have been used.

c) Resulting Domains

TSOs strive to increase domains in future and small domains will occur less frequent in future. This is illustrated in Figures 8 and 9. The consideration of grid reinforcements provides a larger flow-based volume.

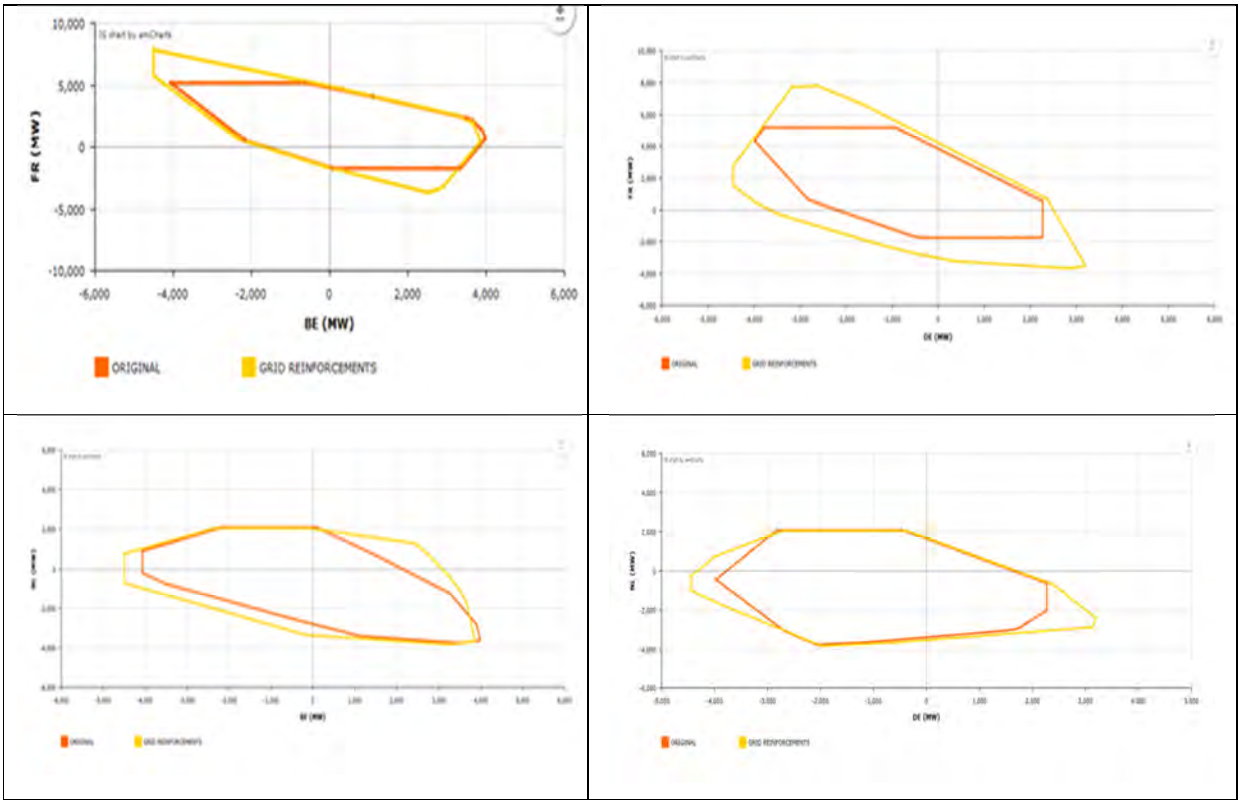


Figure 8 Effect of grid reinforcements - Typical day 10-12-2015 (Weekday) H19.
(Top Left) BE vs FR, (Top Right) DE vs FR (Bottom Left) BE vs NL, (Top Right) DE vs NL. Historical domains (Orange), PLEF domains (yellow)

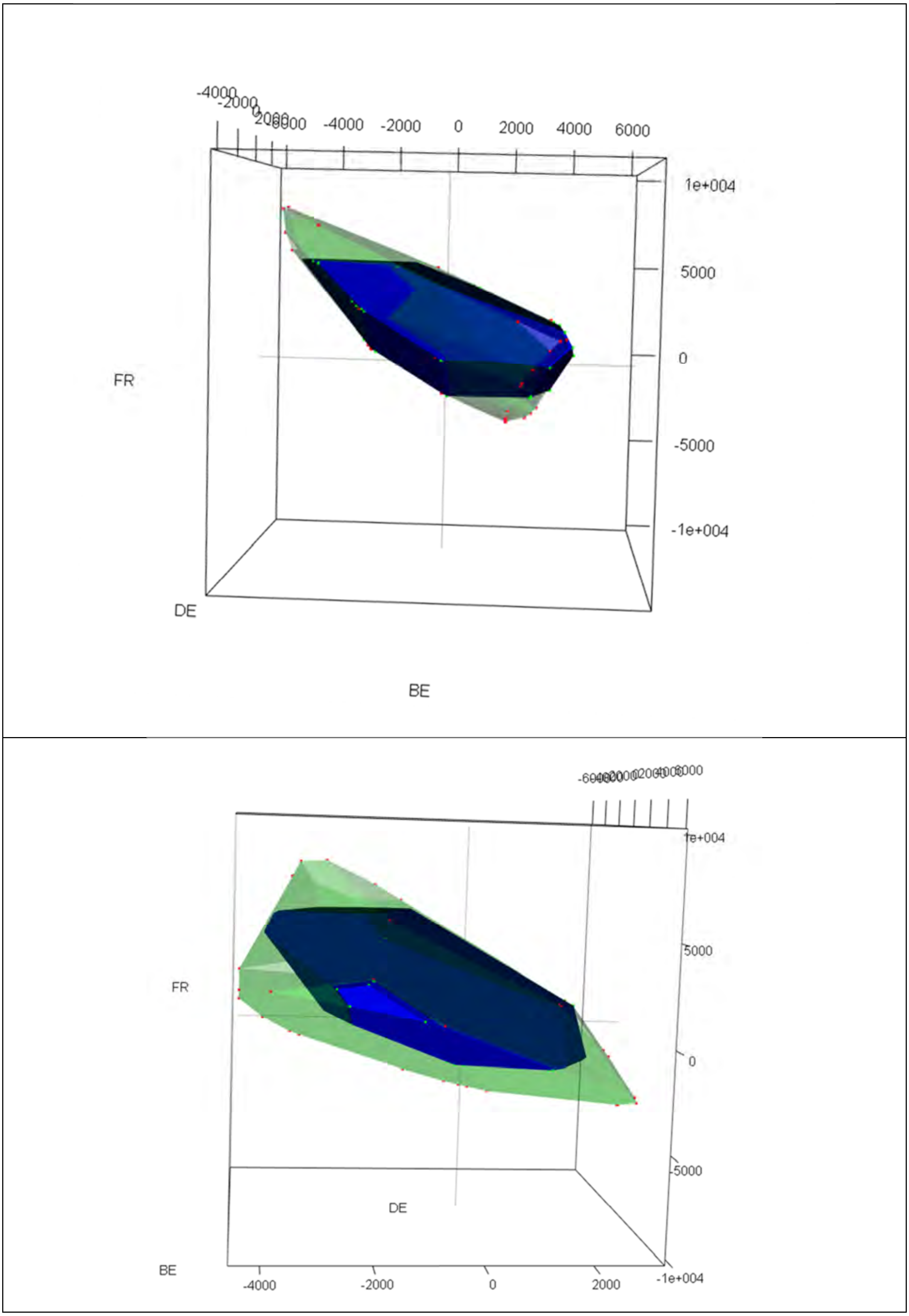


Figure 9 Effect of grid reinforcements - Typical day 10-12-2015 (Weekday) H19 (3D view). (Top Left) BE vs FR, (Bottom), DE vs FR. Historical FB volume (Blue), PLEF FB volume (Green)

2) STEP 2 – 3 Implementation in the market model simulations

Each domain is represented as a set of mathematical constraints (as shown above in terms of PTDFs, Exchanges and RAMs) given to the optimization problem that the market tool has to solve. The implementation of these constraints significantly increases the computation time of the simulations.

The 4 typical days for winter (3 weekdays and 1 weekend) provide representative domains used as proxies for the relevant domains expected during next Winter 2018/19. Such simplification implies that these available 24 x 4 hourly domains still need to be assigned to each hourly simulation of the interconnected power system for next winter, each hour presenting different expected climatic, generation and demand situations during next winter.

A systematic correlation approach based on analysis of hourly climate data was performed in order to define such assignment. The following climatic parameters were analysed:

- Observed wind production.
- Observed temperature and temperature sensitive load.

For example for the "3 weekdays in winter" clusters, a probability matrix was calculated as a function of daily energy ranges (high/medium/low) of wind and load. As such each combination provides a 3-fold (P_A : P_B : P_C) representativeness-weight or probability. The probability for each typical day to be chosen within the Monte Carlo approach is presented below in Figure 10. As it can be seen, the probability to have the small domains (typical day 7) is 100% when it is very windy and cold. These situations, relevant for adequacy, are thus linked with high wind in-feeds in Germany and high demand in France.

		Load		
		low	medium	high
Wind	low	0,1	0,2	0,2
	medium	0,4	0,2	0,1
	high	0,3	0,4	0

		Load		
		low	medium	high
Wind	low	0,4	0,3	0,5
	medium	0,2	0,4	0,6
	high	0,1	0,1	0

		Load		
		low	medium	high
Wind	low	0,5	0,4	0,4
	medium	0,4	0,4	0,4
	high	0,6	0,6	1

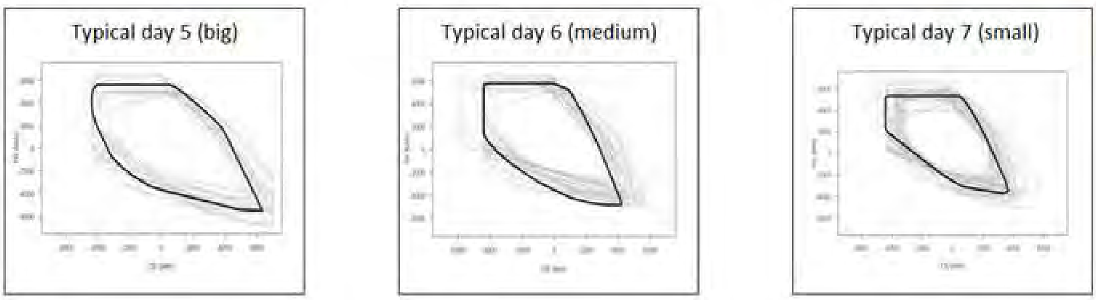


Figure 10 Illustration of correlation between 'historical' domains and climatic conditions

3.2.3 NTC vs. FB Model

For the first time horizon in this study, a flow-based as well as an NTC approach is used to model the transmission capacities. Both approaches differ significantly from each other.

The long term planning NTC values provide a good, yet simplified, representation for the long term horizon (1+ year ahead). These NTC values might differ from actual capacities encountered in operational time frame. In this sense, the flow-based modelling provides a more accurate representation of what is observed in the operational time frame. The flow-based values indicate a more correct picture of the physically available transmission capacities since these values also consider the exchanges between other countries and take a more “short term” grid situation better into account.

Deviations of transmission capabilities under the flow based approach from the fixed NTC values can therefore go in both directions. On the one hand, due to synergies across several borders, capacities can increase under flow based while, on the other hand, usually in times of scarcity and tight grid situations, capacities are lower than the respective NTC values.

Moreover, in case LOLE is not equal to zero in the CWE region, a so called „adequacy patch“ is applied on top of the results of the generation adequacy simulations. In case of shortage (ENS>0), the goal of this adequacy patch is to achieve a “fair” way of effort sharing by moving away from the optimal solution at CWE perimeter to a solidarity solution.

Without the activation of the adequacy patch the algorithm searches for the global optimal solution (minimization of system costs in the CWE region) which could lead to the fact that under CWE FB-MC countries with ENS can still export. With the adequacy patch countries facing adequacy problems can reduce their export and might even import to reduce ENS, thus possibly increasing ENS in other countries (with or without existing ENS). The adequacy patch is applied only when at least one country in CWE has ENS. It redistributes ENS among the contributing countries in CWE.

As a consequence both approaches are likely to lead to different results for the first time horizon, and a comparison should always consider these methodological differences. As the flow-based methodology is more accurate and closer to reality of grid operation, this should be the preferred approach when possible.

3.2.4 Wind-Dependent Transmission Capacity

Another step to closer simulate transmission system operation consists in modelling the wind-dependent NTC at the German borders. This is only applied to the Swiss-German border because the other borders are modelled using the aforementioned flow-based domains. It should be noted that these considerations are only applied to the first time horizon.

The wind-dependent NTC values are based on the so-called C-function, which limits the amount of export from Germany to Switzerland in case of high wind production in Germany during the operational planning phase. In order to link this with the probabilistic drawing of the flow-based domains, the values are mapped as shown in Table 6 below. It should be noted that the current NTC-values for the year 2017/2018 are used for this study. The forecasted values for the year 2018/2019 show an increasing trend of the NTC values. The current, while smaller, values support a pessimistic assumption of the import capacity for Switzerland from Germany.

Domain	NTC DE- CH	NTC CH -DE
Small domain (high wind)	800 MW	4000 MW
Medium domain (medium wind)	1400 MW	
Large domain (low wind)	2000 MW	
Weekend	2000 MW	

Table 6 NTC values DE-CH and vice versa according to domain

3.3 Demand Side Flexibility Model

Most power systems in Europe are currently characterized by low price elasticity (inflexibility) of electricity demand, which is why generation units follow the electricity demand to balance the system at all points in time. For this reason most generation adequacy assessments focus on the supply side and evaluate the risk of a supply shortage, i.e. electricity demand exceeding available generation capacity.

From an economic point of view consumers might be willing to pay to avoid a supply disruption andto shift their consumption in order to help the system in scarcity situations. While there might be an obvious benefit of demand side flexibility with regard to security of supply, the development of demand side flexibilities is mainly encouraged by the increasing share of variable RES. This is because, in a system with a high share of non-dispatchable generation, i.e. from wind and solar photovoltaic power, elasticity of electricity demand will have to increase in order to continuously balance the system in the future.

In this context, several options like storages, demand side management or flexibilisation of must-run generation units are discussed. All possible options are associated with different technical and economic factors leading to constraints with regard to the deployment and utilisation. For example, in the case of demand side flexibilities in the industrial sector technical constraints might be imposed by restrictions due to chemical or thermal processes. Economic factors are mainly related to technology costs and competition between existing and new technologies.

In this regard it has to be noted that results of existing studies on the expected penetration of demand side flexibilities are based on scenarios, i.e. fuel prices, generation mix or geographical scope, deviating from the assumed scenario framework of this study. Accordingly, one of the main questions is how technologies and the penetration of flexibilities will develop under the considered scenario framework and relevant time horizon of this study. Only then it will be possible to evaluate a realistic contribution of demand side flexibilities to security of supply.

To answer this question, electricity market models can be used to show how markets and the operation of thermal generation units and flexibilities may be impacted by a given scenario. Accordingly, this adequacy assessment entails an enhanced modelling of demand side flexibilities including an evaluation of the economic profitability using the flexibility model "AmpFlex" developed by Amprion. A brief description of the model is given in the following.

The flexibility model is used to determine a combination of flexibilities, i.e. installed capacities, for which it is economically sensible to participate in the electricity market within a certain framework of economic and technical assumptions. The model is a dispatch model based on cost minimization. It is formulated as a linear problem with an hourly resolution. Assuming a competitive situation with adequate anticipation by market participants, dispatch of generation units and flexibilities is determined simultaneously through optimization in the flexibility model. This leads to an operation of cost efficient generation units and flexibilities to cover the residual demand, i.e. total system load minus infeed from variable RES. The model is implemented in Matlab and uses the CPLEX Solver.

The key variables of the model are dispatch of generation units, operation of flexibilities and pumping quantities. Moreover, shedding of load in case of scarcity situations is considered at the technical price limit of the electricity market. Total costs include operating and start-up costs. Due to the focus of the adequacy assessment on the Day-Ahead market and in order to simplify the model, a detailed modelling of heat demand and reserve requirements for the provision of balancing services is not implemented. Hence, associated must-run electricity generation is modelled exogenously, as well as cross-border exchanges.

Besides the operation of generation units and flexibilities the revenues gained on the electricity market are a major output of the model. Based on a comparison of these revenues with annual investment, fixed and variable costs[21], it can be evaluated if the assumed combination of flexibilities is economically profitable (makes economically sense) and is therefore likely to be developed under the assumed scenario framework. It has to be noted that the model framework assumes a competitive energy-only market with a high cost for load curtailment (i.e. Value of Lost Load: VoLL, for more details see Appendix 8.2.3) and no capacity remuneration, as for instance in place in France.

The DSF Model differentiates between physical storages like hydro and virtual storages like demand side flexibility. The activation and dispatch of hydro storages is determined by the water value, which depends on the efficiency of hydro units and corresponding opportunity costs between the considered time steps. Based on the marginal costs of the system (or electricity prices) these opportunity costs are determined endogenously in the model. For virtual storages like demand side flexibility the activation depends on the opportunity costs between consuming electricity or shifting the load. In contrast to physical storages however the opportunity costs are not determined by the efficiency, but by the willingness-to-pay of end consumers. Accordingly, in the simulations a willingness to pay of 40 Euro/MWh for DSF household (300 Euro/MWh for DSF Industry & Business) is assumed. This means end consumers would be willing to shift their load if price spreads between two time steps exceed 40 Euro/MWh (300 Euro/MWh). This threshold can be interpreted as activation costs of DSF.

In order to integrate the flexibility model into the adequacy assessment it is coupled with one of the generation adequacy models used in this study (ANTARES). This approach is shown in Figure 11. Both models use the same input data with regard to electricity demand, installed generation capacities, fuel and CO2-prices, infeed from variable RES and must-run generation (see chapter 3 and 4). Cross-border exchanges and operation of switchable loads contracted by TSOs are taken from the base case of the ANTARES simulation. In order to approximate the optimal installed capacity of demand side flexibilities per country an iterative approach is implemented as depicted in Figure 11 (see feedback loop between steps 5 and 3). In the case that the profitability of demand side flexibilities con-

[21] The difference between revenues and costs is also called marginal return or contribution margin. In case the revenues exceed the costs (contribution margin > 0) the respective flexibility is assumed to be profitable under the assumed scenario framework.

verges (no significant change in step 3 after feedback loop) the respective iteration determines the final result with regard to the installed capacity of demand side flexibilities. A more detailed description of the model and formulation of the objective function and side constraints can be found in the Appendix 8.2.3.

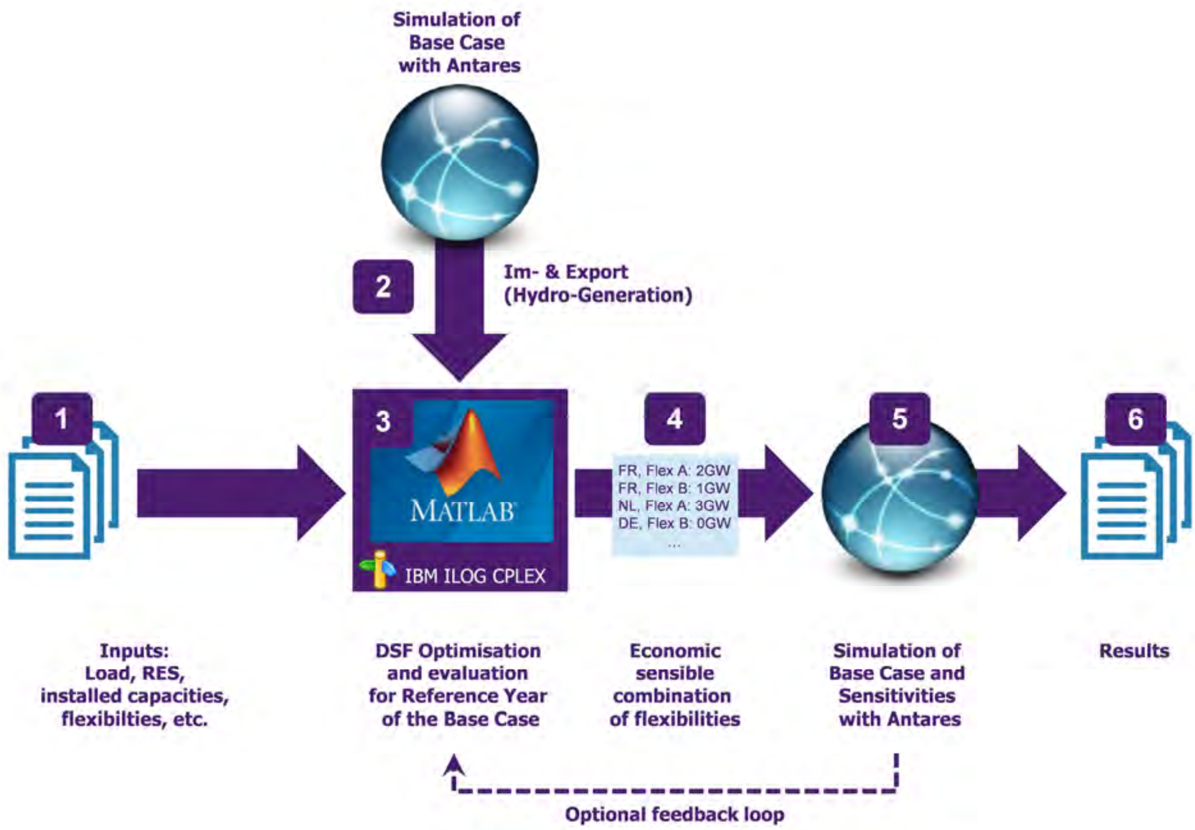


Figure 11 Iterative approach to approximate the optimal installed capacity of demand side flexibilities per country

According to the approach shown in Figure 11 the combination of flexibilities is obtained in step 4. The installed capacities of demand side flexibilities are considered in the subsequent generation adequacy simulation. With regard to the modelling of flexibilities in this study it has to be noted that the focus is on the day-ahead market, meaning that potential revenues from the participation on intraday or balancing markets are not modelled.

3.4 Generation Adequacy Models

The methodology used to assess the security of supply relies on the use of two advanced tools : ANTARES and Powrsym.

Both tools use a probabilistic approach where future supply and demand levels are compared by simulating the operations of the European power system on an hourly basis over a full year. These simulations take into account the main contingencies susceptible of threatening security of supply, including outdoor temperatures (which result in load variations, principally due to the use of heating in winter), unscheduled outages of nuclear and fossil-fired generation units and HVDC links, variable amount of water resources, wind and photovoltaic power production.

A set of time series, loads on the demand side and available capacity of units generating supply reflecting various possible outcomes are created for each of the phenomena considered. These time series are then combined in a sufficient number to give statistically representative results regarding shortages (risk of demand not being met due to a lack of generation) and annual energy balances (output of different units and exchanges with neighbouring systems).

A summary of the methodology is shown in the following Figure 12.

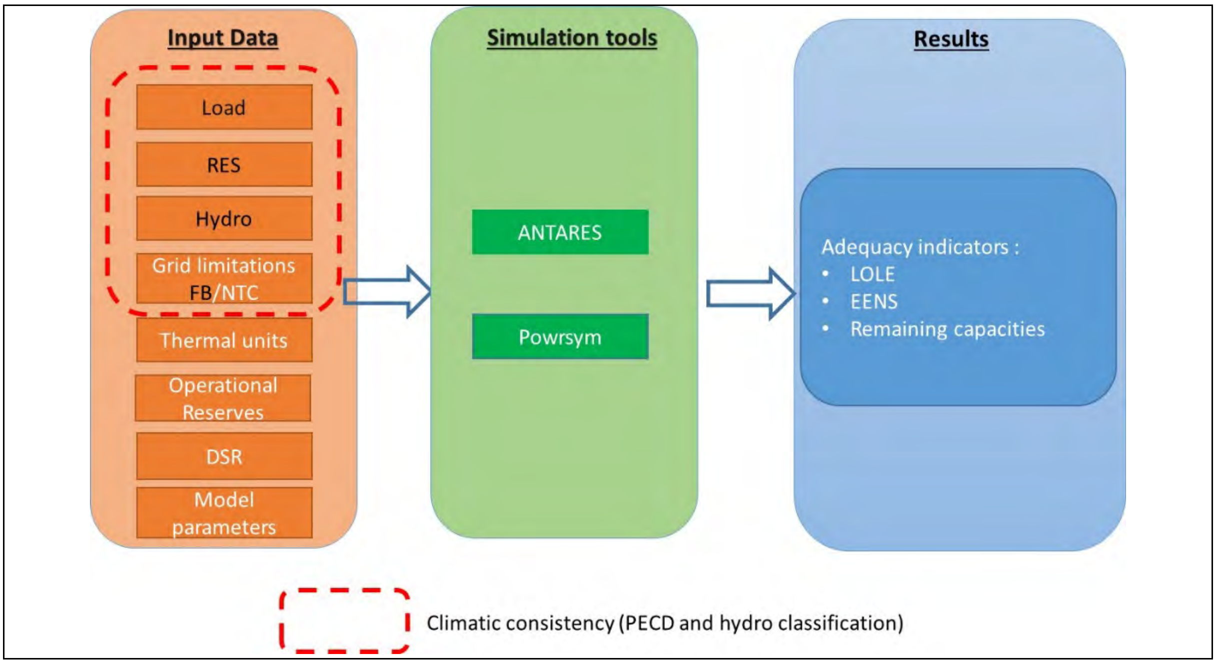


Figure 12 Methodology of combining various possible outcomes to achieve statistically representable results

The following paragraphs provide the rationale behind the PLEF simulation tools, the definition of the adequacy indicators computed, the principle of the Monte Carlo approach and its convergence. Finally, the benefits brought by the usage of two tools to conduct this study are presented.

3.4.1 Advanced tools

In this chapter, only a general description of the tools employed for the PLEF adequacy analyses is given. For the specific features of each individual tool please refer to the Appendix, where a more detailed description for Antares and Powrsym can be found.
Both PLEF adequacy tools are built upon a market simulation engine. Such market simulation engine is built upon the assumption of a pure and perfect market.

Simulators solve an optimization problem with an hourly resolution

Both tools calculate the marginal costs as part of the outcome of a system-wide costs minimization problem. Such mathematical problem, also known as “Optimal Unit Commitment and Economic Dispatch” is often formulated as a large-scale Mixed-Integer Linear-Programming (MILP) problem. In other words, the program attempts to find the least-cost solution while respecting all operational constraints (e.g. ramping, minimum up/down time, transfer capacity limits, etc.). In order to avoid infeasible solutions very often the constraints are modelled as “soft” constraints, which means that they could be violated, but at the expense of a high penalty, i.e. high costs. Most mathematical solvers nowadays are capable of solving large-scale LP problems with little computation time. However, with the presence of integer variables it is still common in commercial tools to solve the overall problem by applying a combination of heuristics and LP.

In the regional study for PLEF, the size of the problem, i.e. the number of variables and constraints could be huge, i.e. thousands of each of them. The size increases with the optimization time horizon and the resolution. For the PLEF study the optimization horizon is a week and the resolution is hourly, i.e. given the constraints and boundary conditions the total system costs are minimized for each week on an hourly basis. The latter means that the results such as generation output of the thermal and hydro plants, marginal costs, etc. are given per hour. This setting of the parameters is a common practice for the market simulations which are conducted for ENTSO-E TYNDP.

Simulators compute NTC and Flow based constraints

These tools also have the functionality to include the network constraints to a different degree. Nowadays the most common modelling approach for pan-European or regional studies is based on NTC-Market Coupling. This means that the network constraints between the market nodes are modelled as limits on the hourly commercial exchanges at the border. This approach is used in this study for the second time horizon.

For the first time horizon the Flow-Based Market Coupling described in chapter 3.2 is applied. Theses domains are considered in the model as additional linear constraints to the optimization problem. The mapping between the domains and the climatic condition results from random draws respecting a probability matrix built from historical analysis (see chapter 3.2.2.2).

Adequacy assessment relies on probabilistic simulations - Monte Carlo approach

The market simulation tools can be used for adequacy analysis purposes. The two tools used within this study utilise a Monte-Carlo approach which is considered to be the “state-of-the-art technique” to represent probabilistic variables such as climate data and unplanned outages in electricity market models.

This involves a large number of simulations with random draws (combinations) on the stochastic variables (e.g. climate data, load, hydrological conditions, forced outages, etc.) in order to work out a representative probability distribution curve of the required outputs (e.g. ENS, LOLE). In order to reduce the time required for this big number of simulations, some tools also have a “quick-run” feature which reduces convergence time significantly for each run through the simplification of the optimization problem (e.g. removing integer variables, i.e. the on/off decisions, the ramping constraints, etc.).

3.4.2 Adequacy indicators and relevant model outputs

Generally in generation adequacy analyses it can be distinguished between deterministic and probabilistic approaches. The system risk, i.e. the probability of a shortage of supply to cover the demand, is subject to the interaction of random factors like unavailability of generation facilities, customer load demand, system behaviour and the fluctuations of feed-in from renewable energy sources (RES). The main disadvantage of deterministic techniques is that they neglect the probability of occurrence, which is why the system risks cannot fully be determined using deterministic criteria. Due to the increased uncertainty introduced by the significant expansion of RES, probabilistic criteria have become increasingly important.

In most generation adequacy studies, the Loss of Load Expectation (LOLE also called Loss of Load Duration - LOLD) is used as an indicator amongst others for the measurement of generation adequacy. While this indicator quantifies the expected duration of shortfall, it does not contain any information about the extent in terms of unsupplied energy. Consequently in this study, a set of criteria as defined in the following is considered. These are often defined on an annual scale and can be measured both at national and regional level.

The LOLE and ENS indicators are the same as the ones measured in the MAF and their definition is taken from the MAF report.

- **Loss Of Load Expectation**[22] (h/y):

LOLE is the number of hours in a given period (year) in which the available generation plus import cannot cover the load in an area or region.

$$\mathrm{LOLE} = \frac{1}{N}\sum_{j \in S} LLD_j \qquad (1)$$

Where, LLD_j is the loss of load duration of the system state j ($j \in S$) associated with the loss of load event of the j^{th}-Monte-Carlo simulation and where N is the number of Monte-Carlo simulations considered. It should be noted *LOLE* can only be reported as an integer of hours because of the hourly resolution of the simulation outputs. *LOLE* does not indicate the severity of the deficiency or the duration of the loss of load within that hour.

The proposed indicator above is quantified by probabilistic modelling of the available flexible resources. Normally there is a tolerated maximum level of the duration of shortfall (e.g. 3 hours in 1 year) defined by each country for the monitoring of security of supply. Accordingly, exceeding this threshold (see Table 2) would mean a violation of the envisaged system security level and corresponding measures would have to be defined and applied. LOLE describes the duration of encountering loss of load but not the severity. Consequently, consider further criteria describing the extent of a shortfall are considered.

- **Energy Not Supplied or Unserved Energy (ENS)** [MWh/y]:

ENS is the energy not supplied due to the demand exceeding the available generating and import capacity.

$$\mathrm{ENS} = \frac{1}{N}\sum_{j \in S} ENS_j \qquad (2)$$

Where ENS_j is the energy not supplied of the system state j ($j \in S$) associated with a loss of load event of the j^{th}-Monte-Carlo simulation and where N is the number of Monte-Carlo simulations considered[23]. Additional indices to measure, for example, frequency and duration of the *ENS* or the power system flexibility, can be considered in the future.

[22] When reported for a single Monte-Carlo simulation as the sum of all the hourly contributions with ENS, this quantity refers to the number of *hours (events)* within one year for which ENS occurs/is observed and this quantity should be referred to as *Lost of Load Event*. The quantity calculated in Eq. (1) refers to the *average over the whole MC ensemble of Events* and it therefore provides the statistical measure of the expectation of the number hours with ENS over that ensemble.

[23] ENS is often referred in the literature as *Expected* Energy Non-Served EENS. Although we skip the *Expected* from our nomenclature definition, the ENS reported here should be understood and an Expectation or Forecast value and **not** as actual ENS observed in historical statistics of actual power systems behaviour.

Other indicators may be computed such as:

- **Relative ENS per country (RENS)**

$$RENS\,[-] = \frac{ENS\ per\ country\ [GWh]}{\text{Average annual consumption per country [GWh]}} \qquad (3)$$

- **Remaining capacities/Margins**

The above criteria indicate the duration, likelihood and extent of shortfalls for every PLEF country or even for the PLEF region in case there are adequacy problems. For countries where the load does not exceed the available generation capacity no adequacy problem would be identified and all indicators would be equal to zero. However, it would be of interest to evaluate the amount of surplus or how far a country is to the border of being inadequate. For this purpose margin indicators are computed.

The hourly simulations performed with the two models used in this study enable the computation of two different margin indicators for a country for a given hour (time stamp). The first margin indicator considers the country as isolated, the second margin indicator takes into account the interconnections, namely the export/import.

The indicators described here echo the work of the Regional Security Coordinator (RSC) CORESO within the Short and Medium term Adequacy project (SMTA[24]) and the ENTSO-E Seasonal Outlook Reports. This project aims at identifying high risk situations for security of supply. Once identified, these situations can then be further analysed in a detailed network study.

To compute these two margins, the available supply needs to be assessed, which corresponds to the sum of available power from dispatchable (hydro and thermal) and non-dispatchable generation (e.g. wind, solar photovoltaic, run of river generation). The available generation capacity is then compared against the load.

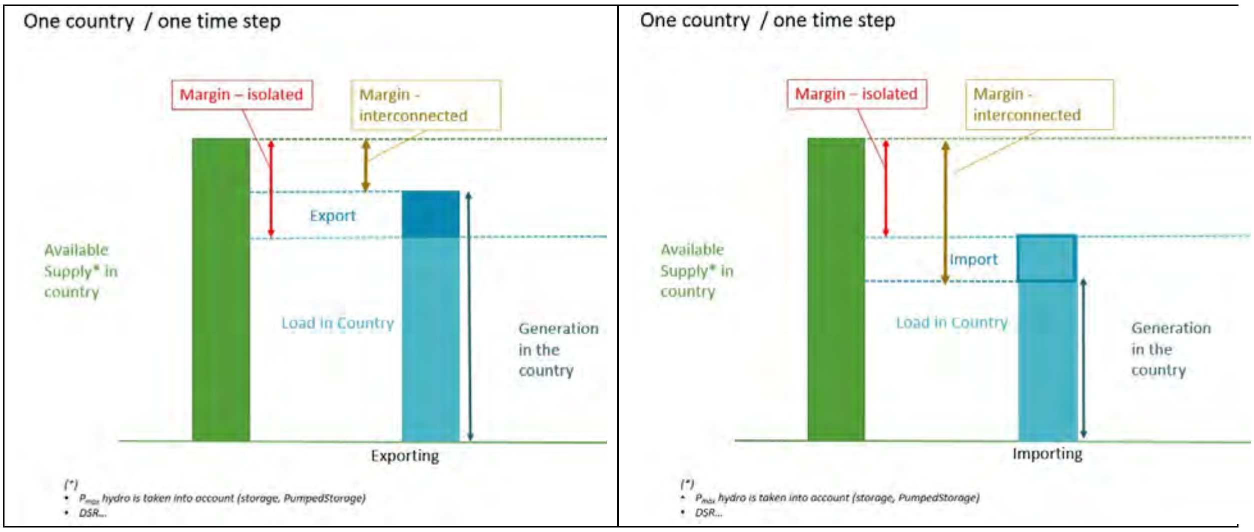


Figure 13 Different configurations for the margin indicators

[24] More detailed information available at: https://www.coreso.eu/services/short-and-medium-term-adequacy-smta

Figure 13 illustrates different configurations for the margin indicators. On the left side the situation of an exporting country, on the right side the situation of an importing country is shown.

In some cases, load might be so high, that both margins become negative. This corresponds to situations with load curtailment or unsupplied energy and is depicted in Figure 14.

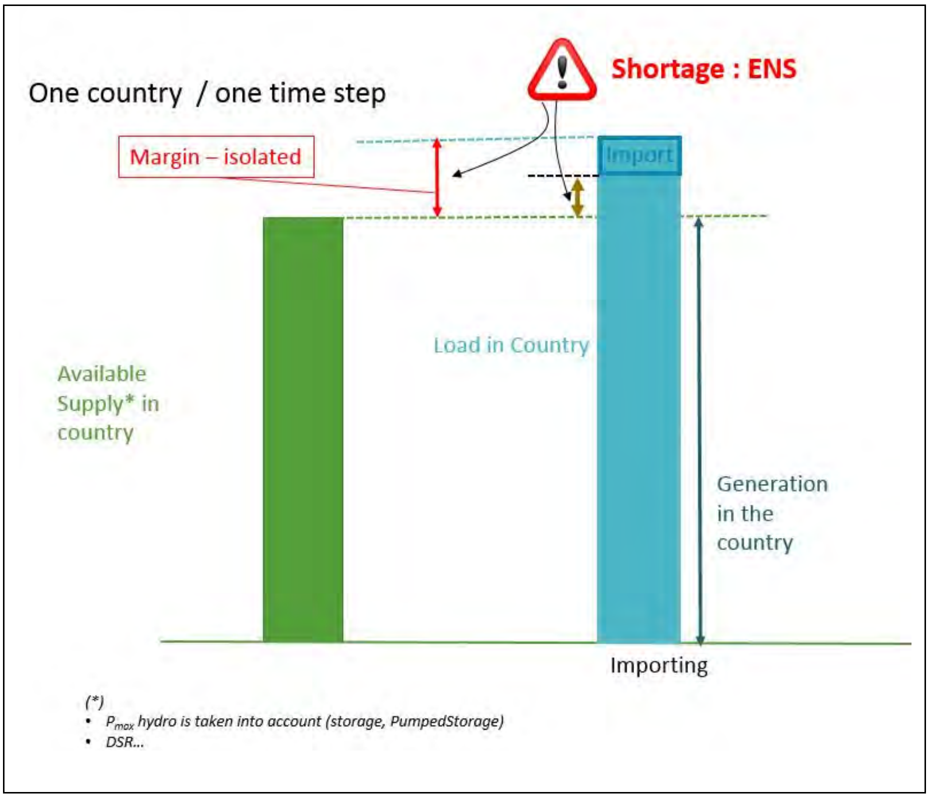
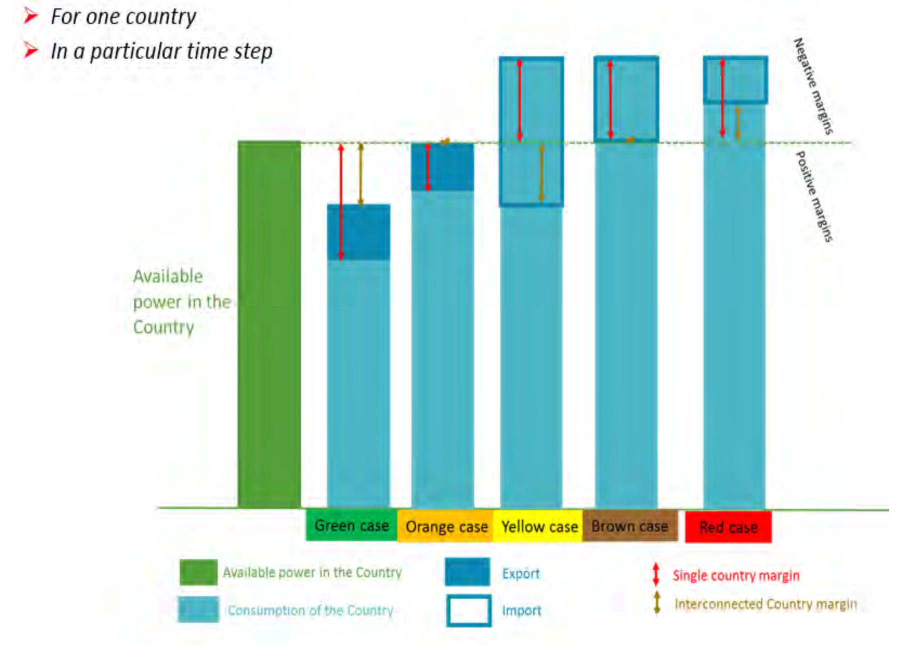


Figure 14 Example for situations with load curtailment or unsupplied Energy

When both margins ("interconnected" and "isolated") are negative, imports cannot remove all the ENS this country would face if it would be isolated.

Five different settings can be derived from the two margins to illustrate the situation of a country. This is shown and explained in Figure 15 below.



Red case: There is load curtailment in the country even with the interconnectors support.

Brown case: The country has no curtailment but 0 MW margin while interconnected, the supports provided by the interconnector is essential.

Yellow case: The country has positive margins (provided by interconnector), but would be short if no interconnectors.

Orange case: The country has 0 margin when interconnected but would have a positive margin without interconnectors.

Green case: The country has positive margins even without interconnectors

Figure 15 Five different status settings to illustrate the situation of the a country

These margin indicators complement the adequacy analysis, and are of interest especially when no LOLE appears in simulation, as they enable assessing the gap between secure and unsecure situations.

3.4.3 Monte Carlo scheme - Convergence

To properly assess Security of supply (SoS), both tools simulate a large number of years.

Figure 16 presents the rationale behind the construction of the simulated years. Basically the 34 climate years (1982-2015) from the PECD are combined with random outages based on the specified technical parameters of the types of thermal plants and HVDC links. For the FB approach, wind and load are among the drivers for the shape and the size of the FB domains (small, medium or large). A mapping of the relevant FB domains is made to be consistent with the climatic condition of each simulated year based on a predefined probability matrix.

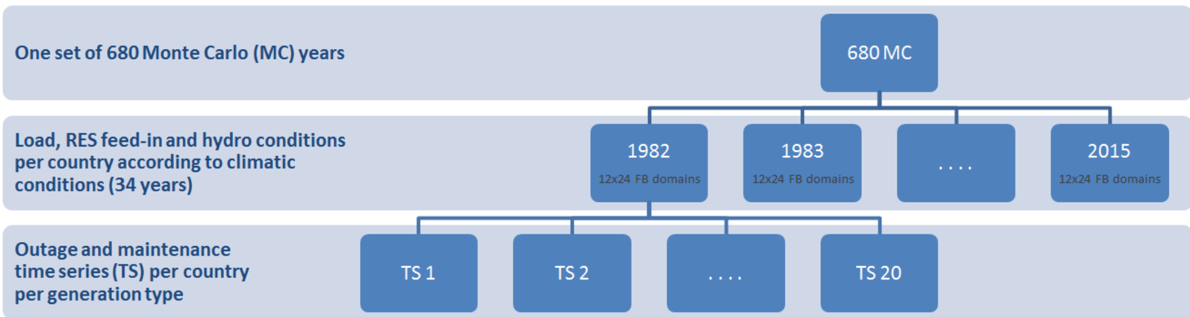


Figure 16 Rationale behind the construction of simulated years, based on 34 climate years and 20 scenarios for thermal availability

In such a Monte Carlo approach, a large number of simulations is necessary to reach an acceptable convergence of results. Each climate year is assumed to have the same probability of occurrence.

Figure 17 illustrates the convergence of the adequacy indicator Loss of Load Expectation (LOLE). The graph on the left hand side displays the moving average of LOLE while increasing the number of

Monte Carlo years; this value clearly stabilises after a couple of hundred simulations. On the right hand side, the estimated error[25] is displayed. After 600 simulated MC years the LOLE can be estimated within a confidence interval of ± 1h.

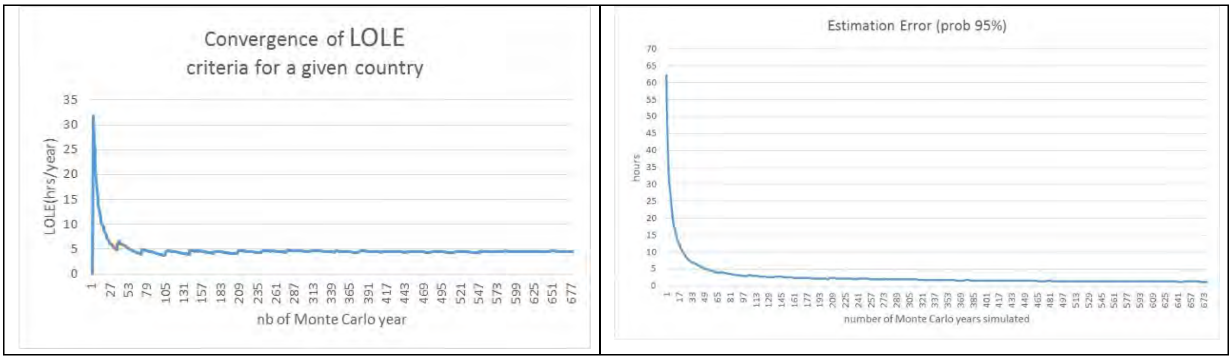


Figure 17 Convergence of the adequacy indicators Loss of Load Expectation (LOLE)

3.4.4 Benefits from using two simulators

For this study two different models (system simulators) were used in parallel. The aim of the use of different models is to produce consolidated, representative and reliable results. The process is shown in Figure 18. The comparison of the results was done for all climatic years according to the following procedure:

- Preparation of aggregated output data of the models
- Visualization of the output data in form of comparison charts
- Discussions and analyses within the PLEF TSO group
- Specification of actions regarding model or data improvement

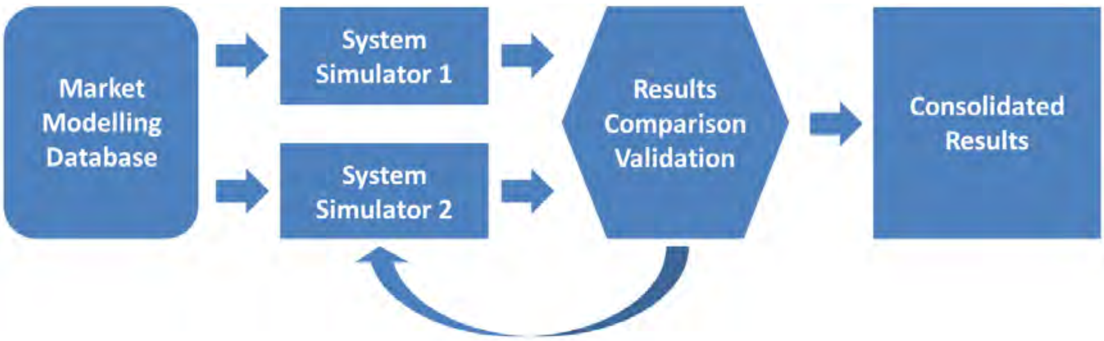


Figure 18 Process of using two simulations in parallel

Although the use of multiple models and the output comparison is a lengthy and time consuming procedure, the following major advantages are connected to it.

[25] The error defined here corresponds to $|\varepsilon_n| \leq 1.96\frac{\sigma}{\sqrt{n}}$ where n is the number of Monte Carlo years, and σ the standard deviation of the LOLE. The confidence interval for the computed LOLE with N Monte Carlo years (i. e. $\overline{X}_N$) is given as $\left[\overline{X}_N - 1.96\frac{\sigma N}{\sqrt{N}}, \overline{X}_N + 1.96\frac{\sigma N}{\sqrt{N}}\right]$

Input data quality: Owing to the fact that multiple models are used the input data are checked multiple times independently. This way, errors in the input data will be detected more likely and can be corrected. This leads to a consistent set of input data with high quality.

Synchronization of input data: Some of the input data are also part of the aggregated output data of the models (e.g. PV feed-in, load per country). This way possible input data differences (between the different models) can be detected and corrected. The synchronization of the input data is the basis for the comparison of the actual results and also helps to gain a common understanding of the input data.

Comparison of results: The identification of differences in the results of the models, enables a discussion about e.g. how the models work and how the modelling (e.g. of hydro power plants, biofuel units) is done.

This study has shown a very good convergence of the results computed by both models.

4 Input data and assumptions

The template for data collection and thus the perimeter of the input data of the PLEF study is based on the MAF 2017 process. The data of the PLEF region were gathered from its countries for the relevant time horizons. The final data was frozen at June 2017.
For all other countries (called "rest of the world" or ROW) the MAF 2017 data of the "Best estimate"(BE)-scenario for the time horizons 2020 and 2025 were interpolated and extrapolated for the relevant time horizons 2018/2019 and 2023/2024 respectively. Please find some more details about the country specifics in the following paragraphs.

4.1 Country specifics

4.1.1 Austria

The installed operational capacities for Austria quoted in the Figure 19 are based on the values published by E-Control (Austria's NRA) and represent the values for the base case scenario. The capacities kept for the Austrian "Grid reserve" are not included in the base case scenario of this study. These capacities of 2.4 GW are mainly gas power plants together with one hard coal power plant.

Furthermore the installed operational capacities of Austria still contain the (pumped) storage power plants of the "Kraftwerksgruppe Obere Ill-Lünersee" (capacity: approx. 1.7 GW) as well as the power plant „Obervermuntwerk II" (360 MW) which will be put into operation in 2018. Although these power plants are all located in Austria, they are electrically connected to the German control block. Since the decision to include them in the Austrian dataset was made at the beginning of this study, these power plants are considered for the Austrian control block. In case these power plants would be considered in the German dataset instead, this might lead to higher "LOLE" and "EENS" values in Austria and lower values for Germany.

Within all relevant time horizons all new power plant projects have been considered as long as grid access was officially applied for. The increase of wind and solar power capacities was calculated based on assumptions of the „Best estimate scenario" of the MAF 2017.

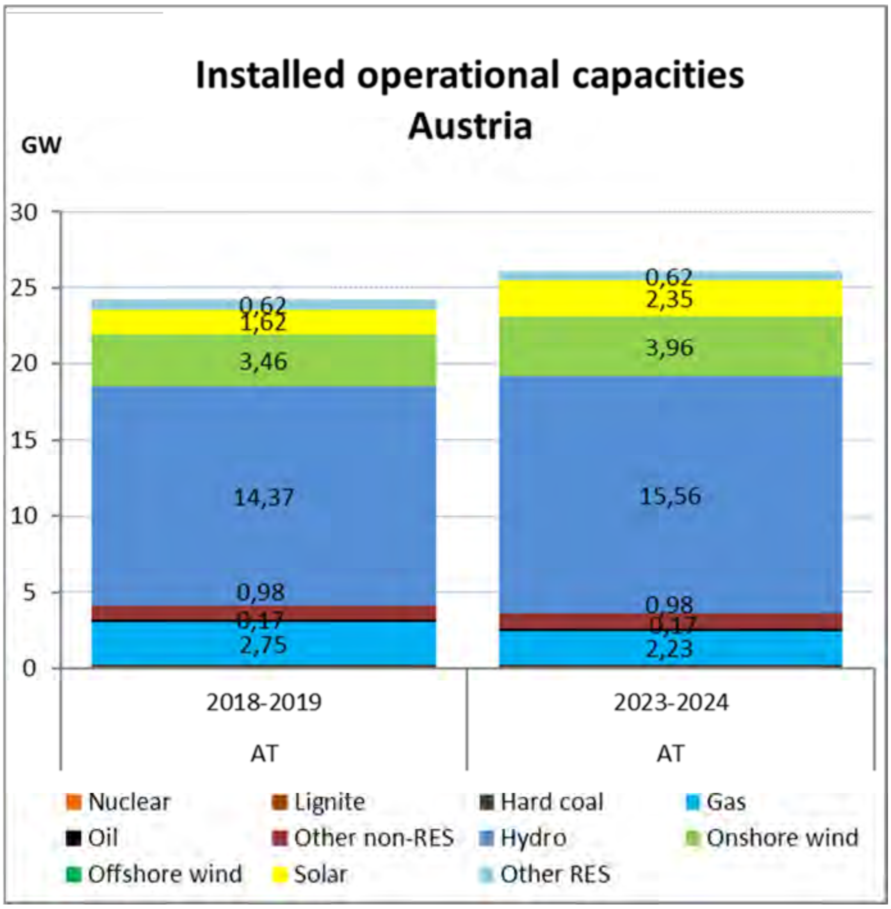


Figure 19 Generation mix (operational capacities) of Austria base case 18/19 and 23/24

Concerning the scenario „Units at risk of being mothballed or decommissioned, because of economic reasons“ it has been assumed for the time horizon 2023/2024 that no hard coal unit will be in operation anymore and older gas power plants (in sum: 645 MW) will be decommissioned as well.

An annual increase of the load of 0.56 % until 2020, respectively in average of 0.4 % until 2025 has been taken into account (Source: MONITORING REPORT Versorgungssicherheit 2015-2025 of E-Control). For the Austrian load time series the values of the “Best Estimate” scenarios of the MAF 2017 for the time horizons 2020 and 2025 were interpolated and extrapolated respectively for the relevant time horizons 2018/2019 and 2023/2024. These time series also consider the extra load of additional electric vehicles, heat pumps, hybrid heat pumps and other additional loads.

The NTC values were taken from the MAF 2017 and were adjusted for the relevant time horizons. For the border between Germany and Austria it has been bilaterally agreed on 5000 MW for 2018/2019 and 6500 MW for 2023/2024 as NTC values had to be delivered for this report before the new agreement on 4.900 MW has been achieved between Germany and Austria.

4.1.2 Belgium

Elia - beyond its active involvement in the regional PLEF GAA study - currently publishes every year an adequacy assessment covering the next 3 winters. Last year, at the request of the Minister of Energy, Elia published an adequacy study covering 10 years. The Adequacy Study for Belgium is a recurrent document delivered to the Minister and the Federal Public Service every year for the 15th of November.

The edition covering winter 2017/18, 2018/19 and 2019/20 was published in December 2016. This study evaluated the need of strategic reserve capacity as defined by the law based on the most recent forecasts of production and demand in Belgium and neighboring countries. The next yearly update of this study was published in December 2017 and covers one additional winter (2020-21).

The Adequacy & Flexibility study for 2017-2027 was requested by the Minister of Energy to Elia in order to assess the adequacy and flexibility requirements of the Belgian system for the next 10 years. The study was published on April 2016[26] and an addendum to the study was published in September 2016.

Load and annual demand forecast provided for 2018 and 2023
The demand forecast provided for 2018 and 2023 assumes a stable demand (excluding additional electrification of heat and transport and additional baseload) as described in the base case scenario of the AdeqFlex2017-27 study. Additional contribution to the demand from EV and heat pumps was considered based on external studies (e.g. global EV Outlook 2016). Concerning additional baseload, Elia takes into account information reported by its national grid users. This results in a slightly higher demand growth than the base case scenario of the AdeqFlex2017-27 study.

For 2018, the DSR assumptions are described in the Market Response study performed during 2017 within the preparations of the SR18-21 report. For 2023 the DSR assumptions are the same as those described in AdeqFlex2017-27 study.

Net generating capacity forecast provided for 2018 and 2023
The hypotheses for Belgium in terms of RES, Nuclear, CHP, biomass, pump storage, were taken into account from the SR17-20 study. A best estimate in terms of installed gas capacity was made for 2018 and 2023 based on decommissioning figures, technical lifetime as well as indications of the target for Belgium's structural block needed to ensure adequacy from the AdeqFlex2017-27 study. Strategic reserves contracted for the winters 2015, 2016 are considered out of the market and are not part of the base case data submitted for PLEF. Regarding mothballing assumptions, some technologies of the generation park might be exposed to mothballing due to unfavorable economic conditions.

For 2018
The generation capacity is in line with the national studies SR17-20 and to be published SR18-21.

For 2023
By the end of 2025, a complete nuclear phase-out is planned in Belgium according to the law. In order to assess the effect of such phase-out, a reduction of 2 GW nuclear generation capacity is considered in 2023 with respect to 2018.

All existing biomass and gas units were considered as part of the production park. Furthermore new OGCT units were considered, in order to increase the thermal capacity of Belgium and to ensure adequacy (but there is no guarantee that such capacity will be available in 2023, nor that new capacity will be built).

[26] *http://www.elia.be/en/about-elia/newsroom/news/2016/20-04-2016-Adequacy-study-flexibility-Belgian-electricity-system*

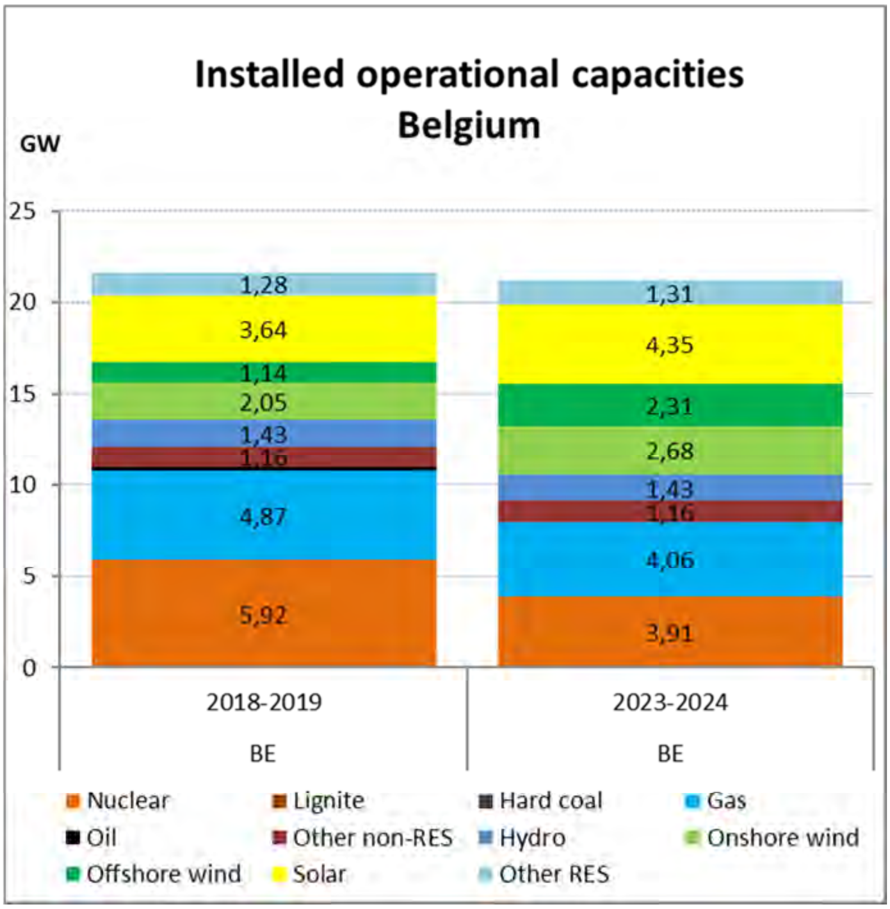


Figure 20 Generation mix (operational capacities) of Belgium base case 18/19 and 23/24

4.1.3 France

Assumption used for load and generation within the PLEF and the MAF studies are mainly inspired by the French energy-transition-bill named “Loi de la transition énergétique pour la croissance verte”.[27]

Over the past several years, RTE has observed a stabilization of power demand in France, mainly due to energy efficiency measures and moderate economic growth. These efficiency measures will be further developed in the coming years, such that power demand is likely to stabilize or decrease in spite of sustained demographic growth. Peak power demand should follow a similar decreasing trend. Since 2015, the new legal framework supports new tools to optimize energy consumption in the country and set ambitious targets aiming at reducing the multi-energy consumption.

Net generating capacity encompasses a decrease of the nuclear power fleet in the mid of 20’s to achieve a mix of production composed of 50 % of nuclear energy at the end of the decade. At the horizon of 2030, this bill fixes the objective to complete this mix of production by 40 % of renewables mainly driven by the development of wind and solar technologies. In addition to this deep transformation, coal power plants are expected to shut down at the horizon of 2023.

[27] https://www.legifrance.gouv.fr/affichTexte.do?cidTexte=JORFTEXT000031044385&categorieLien=id
http://www.developpement-durable.gouv.fr/programmation-pluriannuelle-energie

The base case 2023/2024 for France proposes a reduction of 8 GW of the nuclear installed capacity in comparison with the first time horizon and an installed capacity of 1.6 GW of coal (2.9 GW in 2018/2019). A sensitivity-analysis is made on the second time horizon with a complete closure of all coal plants. The installed capacities used per technology are summarized in Figure 21.

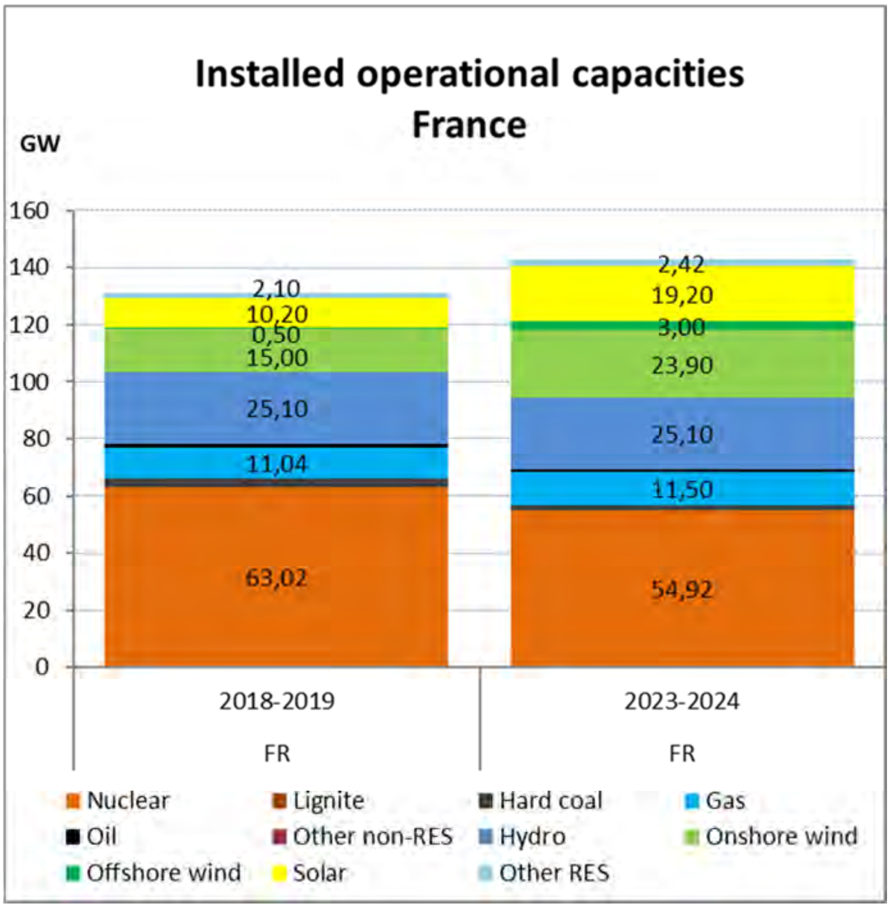


Figure 21 Generation mix (operational capacities) of France base case 18/19 and 23/24

This is consistent with the various combinations of installed capacities for nuclear and coal for mid-term horizons (2022 and after) tested in the latest edition of the French adequacy study (Bilan pré-visionnel 2017).

Regarding Demand Side Response, the base case comprises a capacity of 3 GW in 2018/2019 and 5 GW in 2023/2024 of switchable loads with a limit of 5 hours usage per day.

4.1.4 Germany

The assumed thermal capacities for Germany correspond to the expected development at the time of the data collection. The latest information about mothballing, decommissioning as well as the commissioning of new power plants is considered. The development and the foreseen schedule for the phase out of nuclear power plants are also reflected in the data collection. Especially the phase-out of nuclear capacities in combination with the provision of capacity and security reserve lead to a strong decrease of the overall thermal capacity by 2023/24.

In the light of the Bundestag election in September 2017 and the ongoing negotiations in particular regarding a coal phase out, the future development of firm generation capacity remains a significant uncertainty.

RES development corresponds to the political targets. It is assumed that the installed PV-capacity as well as the installed wind-capacity will increase from 2018/19 to 2023/24. For Run-of-River (RoR) power plants the installed capacity remains constant. Table 7 gives an overview of the installed RES capacities for Germany.

	2018/19	2023/24
PV	45.0 GW	53.8 GW
Wind-Onshore	48.8 GW	54.7 GW
Wind-Offshore	5.6 GW	9.3 GW
RoR	4.3 GW	4.3 GW
Other RES	7.6 GW	8.1 GW

Table 7 RES capacities in Germany

The installed capacity of Hydro-Pumped-Storage-Power-Plants also remains nearly constant over the analysed time horizons.

A detailed description of the different reserves in Germany can be found in chapter 3.1.11.4. As the reserves are not participating in the electricity market the total power plant capacity in Germany was reduced. The corresponding values are shown in Table 8.

<table>
<tr><th></th><th>2018/19</th><th>2023/24</th></tr>
<tr><td>Capacity reserve</td><td>2 GW</td><td rowspan="2">4.0 GW</td></tr>
<tr><td>Grid reserve</td><td>3.7 GW</td></tr>
<tr><td>Security reserve</td><td>2 GW</td><td>0 GW</td></tr>
</table>

Table 8 Assumed reserves in Germany

Nevertheless “Switchable Loads” which are operated by the German TSOs are considered in all analysed scenarios. A capacity of one GW is assumed for both time horizons. Further flexibilities are determined endogenously using the DSF model “AmpFlex” as shown in chapter 3.3.

It is assumed that the overall load will decrease slightly from 2018/19 to 2023/24 due to trends in increasing energy efficiency according to political targets. This effect is diminished by an increased consumption of electric vehicles (EV) and heat pumps (HP).

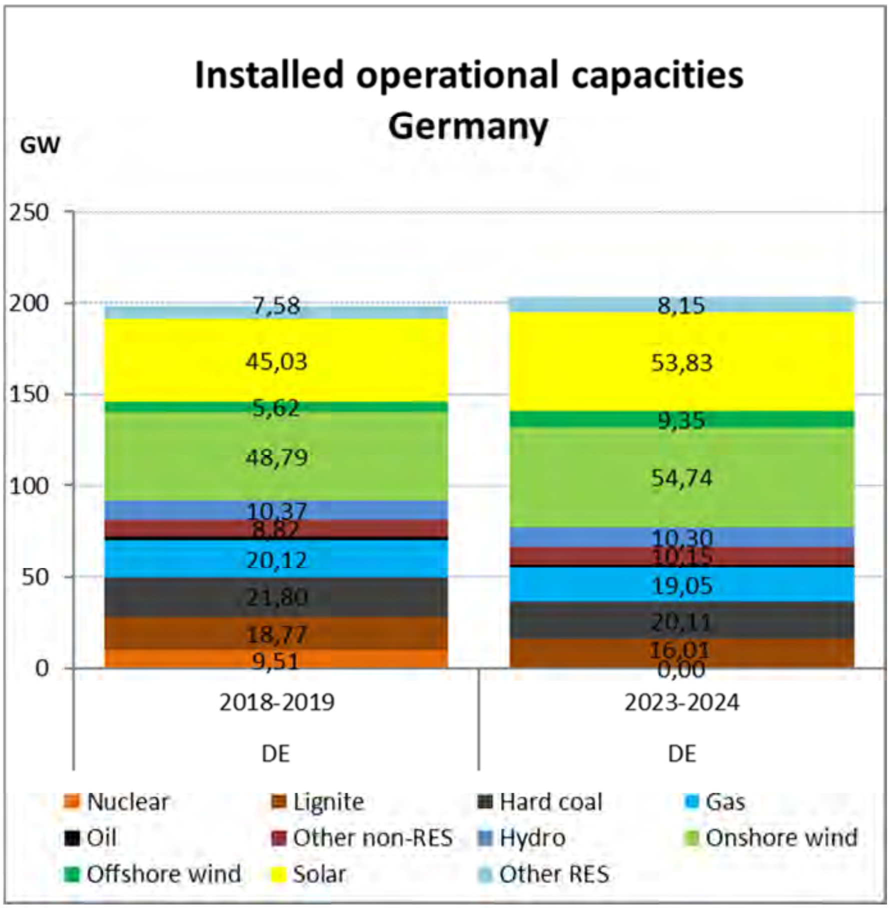


Figure 22 Generation mix (operational capacities) of Germany base case 18/19 and 23/24

4.1.5 Luxembourg

The assumptions used for the load and capacity forecast for Luxembourg in the present PLEF report are in line with the MAF 2017/TYNDP 2018.

Load and annual demand forecast

The demand forecast provided for 2018/19 and 2023/24 assumes a stable load and demand increase due to a steady increase of the population from currently 564,000 inhabitants to 1,100,000 inhabitants until 2050. First benefits related to energy efficiency measures can be noticed and should affect positively the further load increase due to new housing development and building renovations. Nevertheless a trend to use more electricity for heating (heat pumps) and mobility (electric vehicles and electric buses) can be observed.

A load increase is also considered to account for the additional demand of contracted IT data-centers or new IT data-centers to be built in the coming years. The forecast reflects the situation at the time of the data collection.

For both time horizons no additional DSF capacities are considered.

Net generating capacity forecast

It is assumed that the installed PV-capacity as well as the installed wind-capacity will increase from 2018/19 to 2023/24 according the national RES targets. The all other installed capacity is supposed to remain constant.

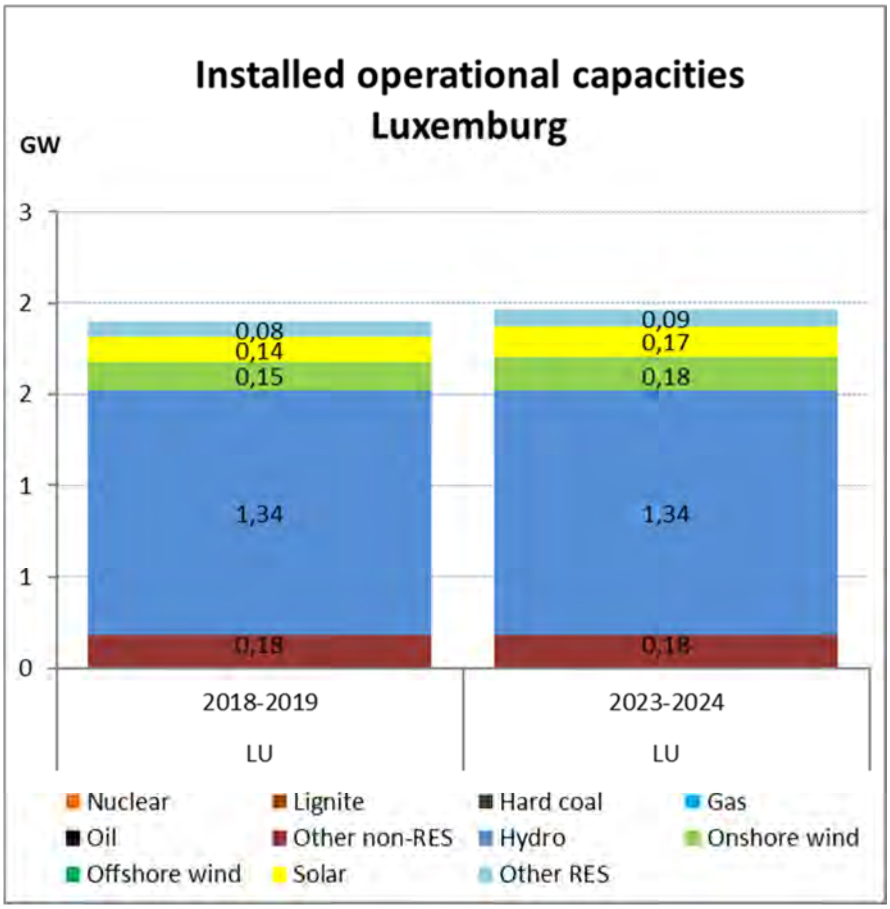


Figure 23 Generation mix (operational capacities) of Luxemburg base case 18/19 and 23/24

4.1.6 Switzerland

The Swiss Federal Office of Energy (SFOE) provided the data for the generation scenarios in Switzerland. They are equal to the data used in the national System Adequacy Analysis published by SFOE on 26th October 2017 and are based on the Swiss Energy Strategy 2050. The generation from renewable sources increases as estimated except for wind production where recent observations show a slower increase than assumed by the strategy. For electricity production based on nuclear fuel, the SFOE anticipates the phase out of the three oldest production units until 2023. The increase in hydro production is assumed to be moderate since most of the planned units are already built and in operation, including the recently built pump storage plants which have been in operation since 2017.

The probabilistic hourly load data as well as the weekly hydro energy data are taken from the MAF database while the NTC values are provided by Swissgrid network planning experts according to the projected commission of different reinforcement projects. The load and hydro data provided by Swissgrid are based on the assumptions given and published in MAF.

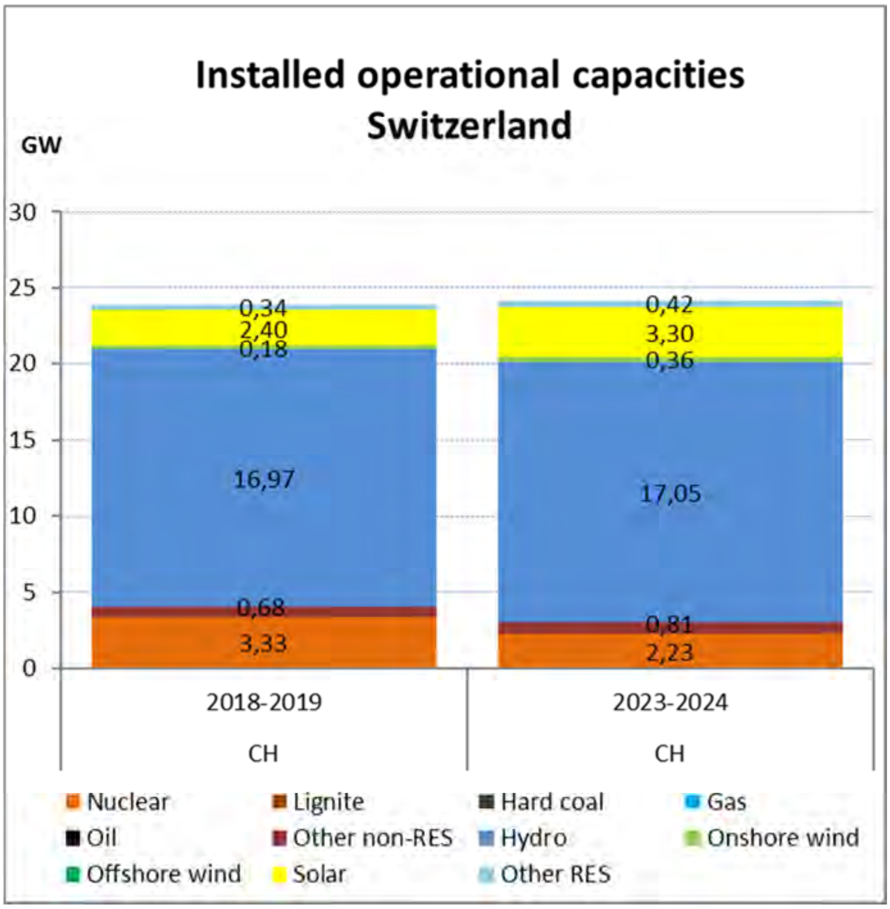


Figure 24 Generation mix (operational capacities) of Switzerland base case 18/19 and 23/24

4.1.7 The Netherlands

Besides the regional PLEF adequacy study, TenneT carries out national adequacy studies on annual base as a statutory duty to inform Minister of Economic Affairs of the Netherlands. Main goal of the national report is to provide insight into expected short and midterm development of the adequacy in the Netherlands and, if necessary, advice the Minister on measures to safeguard the security of supply. In addition, the report aims to inform the market.

The overall methodological approach of the national and this regional PLEF study are in line with each other. The supply and demand data for the PLEF study are based on current information available during the period of data gathering.

Because of the different time slots for data gathering for national studies and the PLEF study, the input data is not 100% aligned. Due to the de-motballing of some gas fired power plants, the overall installed operational capacity in the Netherlands is a bit higher in the national study for both time horizons. However, these differences do not have a big impact on the results or the conclusion of this PLEF study. The Dutch national adequacy study was published in November 2017.

Total electricity consumption in the Netherlands has fluctuated around 115 TWh in recent years and for the next years no major increase of total power demand is expected.

In the upcoming years the supply side in the Netherlands shows a decrease in installed operational thermal generation capacities. This decrease is mainly due to several plans for decommissioning and mothballing of thermal production capacity. However, the current trend of decreasing operational thermal power is less strong compared to earlier outlooks. This is mainly caused by the de-mothballing of some power plant in 2017.

Most recent national adequacy report can be found online[28].

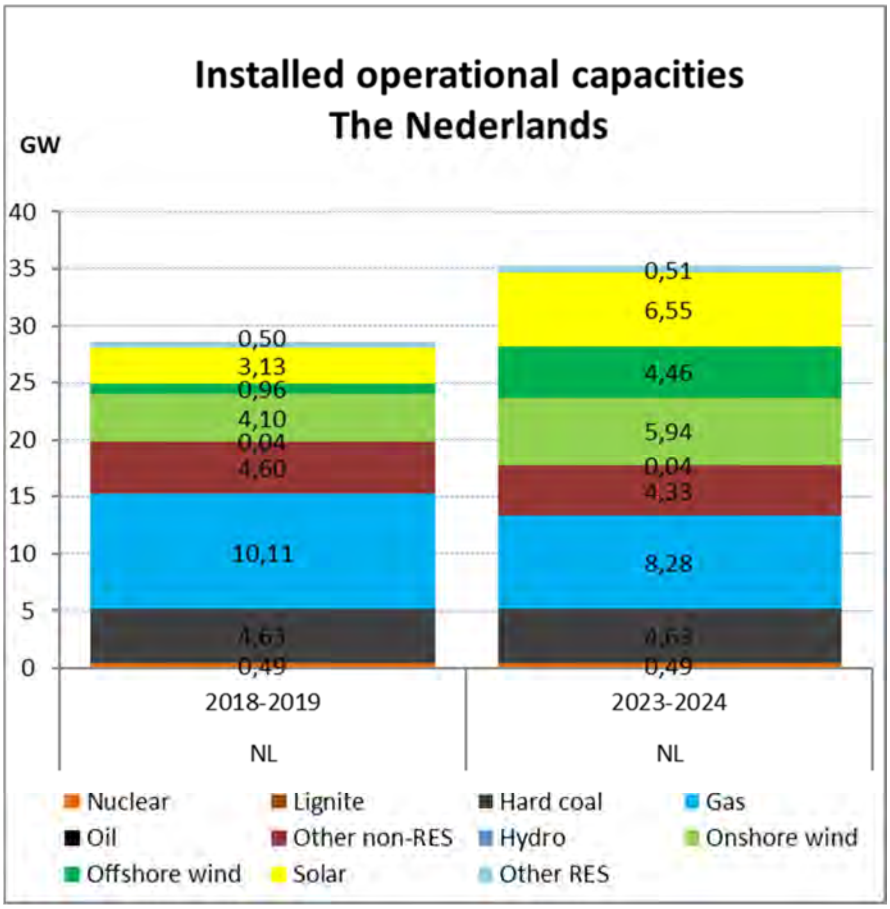


Figure 25 Generation mix (operational capacities) of The Netherlands base case 18/19 and 23/24

4.2 ROW data

Installed capacities

The installed capacities of the ROW countries for both time horizons (2018/2019 and 2023/2024) are linear interpolated from the input data for the "Best estimate" scenarios for the time horizons 2020 and 2025 of the MAF 2017. In the following graph you can see the evolution of the installed capacities of some selected countries within the years 2018 and 2025.

[28] https://www.tennet.eu/fileadmin/user_upload/Company/Publications/Technical_Publications/Dutch/Rapport_Monitoring_Leveringszekerheid_2017_web.pdf

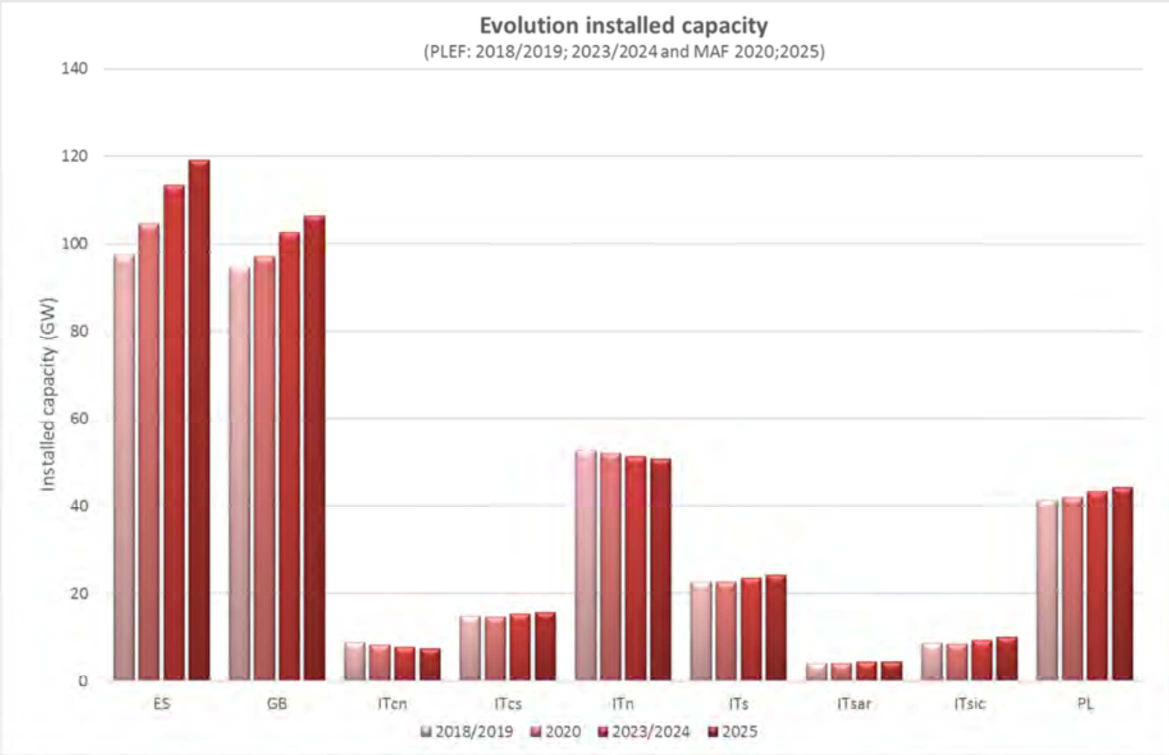


Figure 26 Evolution of the installed capacity of the row countries

Load

The load time series of the ROW countries for both time horizons (2018/2019 and 2023/2024) are linear interpolated from the time series for 2020 and 2025 calculated by TF Senora for the MAF 2017. These time series already include the load concerning additional electric vehicle, heat pumps, hybrid heat pumps and other additional loads. In the following graph you can see the evolution of the load of some selected countries within the years 2018 and 2025.

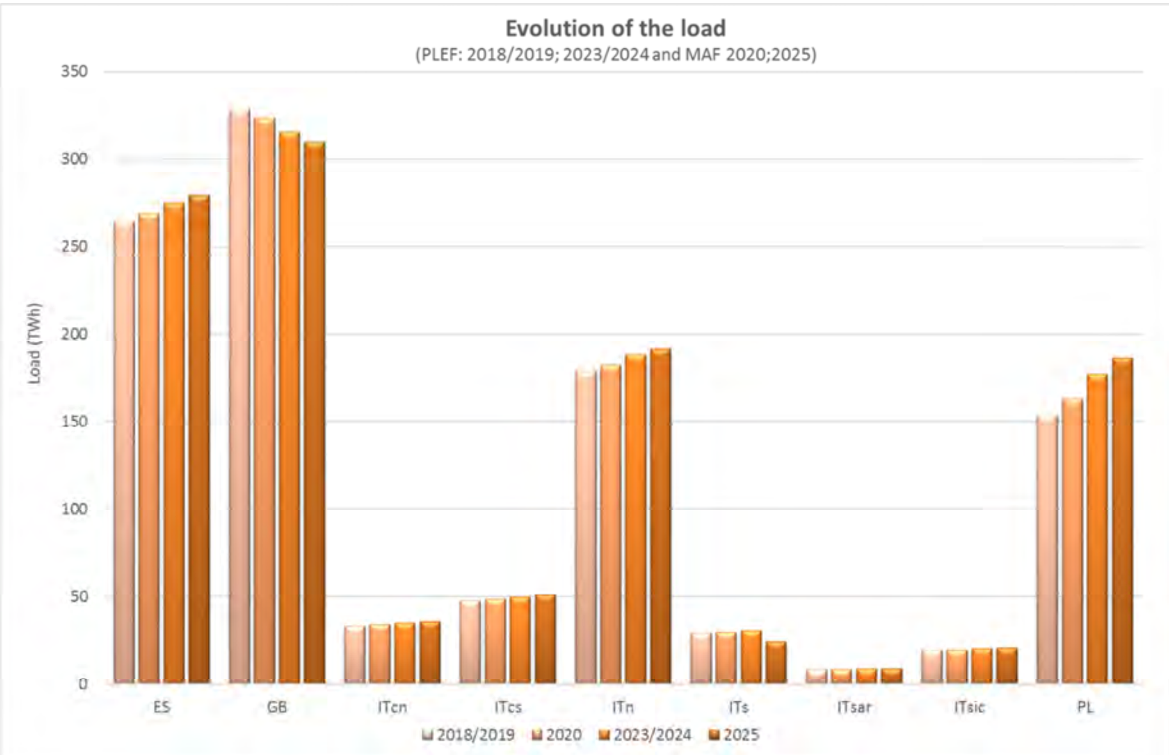


Figure 27 Evolution of the load of the row countries

5 Study framework

In order to give a clear picture of the expectations on this adequacy study it should be stated that this study will model the electric power system using predefined situations described in the base case scenario and in different sensitivities. The commissioning and de-commissioning of generation capacities are given exogenously for each of these scenarios. This adequacy assessment study will model how the production resulting from the given installed capacities will meet the forecasted demand but should not lead to statements on whether or not the market works properly or investments will be made in the assumed way in the near future. This stems especially from the fact that a central optimized dispatch is simulated – not a bottom up market – and the available generation capacity is given exogenously. Targeted market modelling exercises are more suitable to derive information such as optimal installed capacity of generation facilities.

PLEF time horizons

The following years have been identified to give a complete overview of the adequacy situation in the short-term and mid-term time horizon in the countries of the Pentalateral Energy Forum (what is referred to as "PLEF" in the report):

- 01.10.2018 – 30.09.2019 – short-term analysis
- 01.10.2023 – 30.09.2024 – mid-term analysis.

For the "short" term time horizon, there is less uncertainty in all areas affecting the input parameters of the study: demand, grid and market model. Nevertheless uncertainties on the supply-side can be quite important due to the economical context of security of supply. The goal of this study is to give the best possible assessment of the adequacy situation in the Penta Region in the upcoming years.
The 2023/2024 time horizon has much more uncertainties and consequently a much wider range of possible futures, which is also true for assumptions based on political targets.

As the base case for each of the time horizons is utilizing the most recent information available at the TSOs regarding e.g. the commissioning, decommissioning and mothballing of power plants, changes or drivers for changes in the power system are addressed in the different sensitivities. Amongst others this could be additional flexibilities acting on the energy market or new capacity regimes both increasing the installed capacity of the base case. But also decreasing effects like e.g. additional outages are covered.
For both time horizons the treatment of the different system adequacy mechanisms is described in chapter 3.1.11.

5.1 Base Case

Scenario for short-term analysis: PLEF Scenario 2018/19

For the short-term adequacy assessment (10/2018 – 09/2019) the base case scenario is based on conservative assumptions as approved by the Ministries during scenario definition phase of this study. For the PLEF countries an individual data collection has been conducted by the PLEF TSOs containing the latest available information.

For countries outside of the PLEF area (ROW countries) assumptions are based on the ENTSO-E MAF study interpolated for the relevant time horizon.

This bottom up approach is taking into account only confirmed additional investments in generation to maintain the current level of supply. Only the commissioning of new power plants which are considered as confirmed according to the information available to the TSOs are taken into account. The same approach is taken for the decommissioning of existing power plants. Corrections with respect to closure and temporary shutdown of generation assets were taken into account where possible.

The installed capacity of renewables is taken into account on the basis of the "best estimation" of the TSOs as in the most cases the commissioning of renewables is not confirmed in an early stage. Also load forecasts are the best national estimates available to the TSOs under normal climatic conditions. A general description on load modelling is given in chapter 3.1.2.

Flexibilities like for example switchable loads which are operated by the TSOs are also taken into account in the base case of this study.

Scenario for mid-term analysis: PLEF Scenario 2023/24
For the mid-term adequacy assessment (10/2023 – 09/2024) a second base case scenario has been defined. This scenario is based on the same approach as the short term scenario.

Harmonization of data for scenarios
In order to improve the quality of the assessment, all scenarios make use of:

- a common approach of RES (solar and wind) availability based on historical climate data,
- correlated and synchronized hydro data for specific hydrological conditions ("normal", "dry" and "wet" years) for Switzerland, Austria and France, and
- temperature-sensitivity of load with a common approach by using time series of temperature from the ENTSO-E climate database (correlated to the solar and wind time series).

For both the short and mid-term scenario the fuel and CO_2 prices are based on the "New Policies Scenario" used in the 2016 edition of the IEA World Energy Outlook report. More description is given in chapter 3.1.8.

5.2 Sensitivities

In framework of this study also additional sensitivities were analysed. These sensitivities are derived from the base case scenarios and consider probable changes or drivers for changes in the power system that could occur in the different countries. The sensitivities can be classified as "positive" or "negative" ones. In case of a negative sensitivity, generation capacity is reduced compared to the base case and vice versa. Some of the "worst" cases which could happen in terms of adequacy are described below.

The following "negative" sensitivities were analysed:

- **Decommissioning of power plants due to economic reasons**
  A high penetration of RES and moments of high RES in-feed can lead low price-levels on the energy market. This impacts the commercial viability of thermal power plants, especially of those with a high marginal price. As a consequence power plants might be decommissioned due to low number of full load hours and in turn low profitability.

The thermal capacity which is assumed to go offline in this sensitivity is shown in Table 9. This sensitivity is only applied to the countries where the national generation adequacy criteria are met in the base case. Nevertheless the impact on the region is analysed.

- **Decommissioning of power plants due to environmental reasons**
  For each country in the PLEF area, TSOs have, in consultation with the national Ministries, identified capacities that are included in the base case, but could be at risk of being decommissioned on midterm because of environmental constraints, e.g. targets on decarbonization. The resulting, mainly coal fired, generating capacities that were identified are summarized in Table 9.

- **Sensitivity on reduced availability of nuclear power plants**
  Sensitivity cases for reduced availability of nuclear power plant have been carried out for both the first and second study horizons. The reduction of the French nuclear plants is based on the actual reduction of nuclear availability that occurred in 2016-2017. The reduction in Switzerland was based on the assumption that the older nuclear plant(s) could undergo maintenance for an extended period.

Country	**Reduction of installed capacity (MW)**			
	Economic sensitivity	**Environmental sensitivity**	**Reduced availability of Nuclear Power**	
	2023/24	**2023/24**	**2018/19**	**2023/24**
AT	891	404		
BE	1709	0	1000	
CH	0	0	365	1010
DE	1895	0		
FR	0	1740	5000	5000
LU	0	0		
NL	881	1250		
Total	5376	3394	6365	6010

Table 9 Reduction of installed capacity per sensitivity in MW

In addition to the "negative" sensitivities, the following "positive" sensitivities were analysed.

- **Sensitivity on additional Flexibilities**
  This sensitivity addresses the contribution of flexibilities like storages, demand side management or flexibilisation of must-run generation units to generation adequacy. While most generation adequacy assessments focus on the supply side, there might be an obvious benefit of demand side flexibility with regard to security of supply. All possible flexibility options are associated with different technical and economic factors leading to constraints with regard to the deployment and future utilisation. Accordingly on the basis of an electricity market model economic viable combinations of flexibilities are determined and considered in the subsequent generation adequacy simulation.

- **Sensitivity on Grid**
  Finally a sensitivity was carried out to assess the impact of the grid projects on adequacy levels in the PLEF countries. In this sensitivity the adequacy in 2023/24 was assessed with reduced grid, by not taking into account the grid projects between 2018 and 2023 (Table 6 in chapter 3.2.1).

An overview of all study cases carried out is shown in Table 10.

Case		Horizon 2018/19	Horizon 2023/24
base case		X	X
Economic sensitivity	Neg		X
Environmental sensitivity	Neg		X
Sensitivity on nuclear availability	Neg	X	X
Sensitivity on Grid	Neg		X
DSF sensitivity	Pos		X

Table 10 Overview of all simulated sensitivities

6 Results of the adequacy assessment

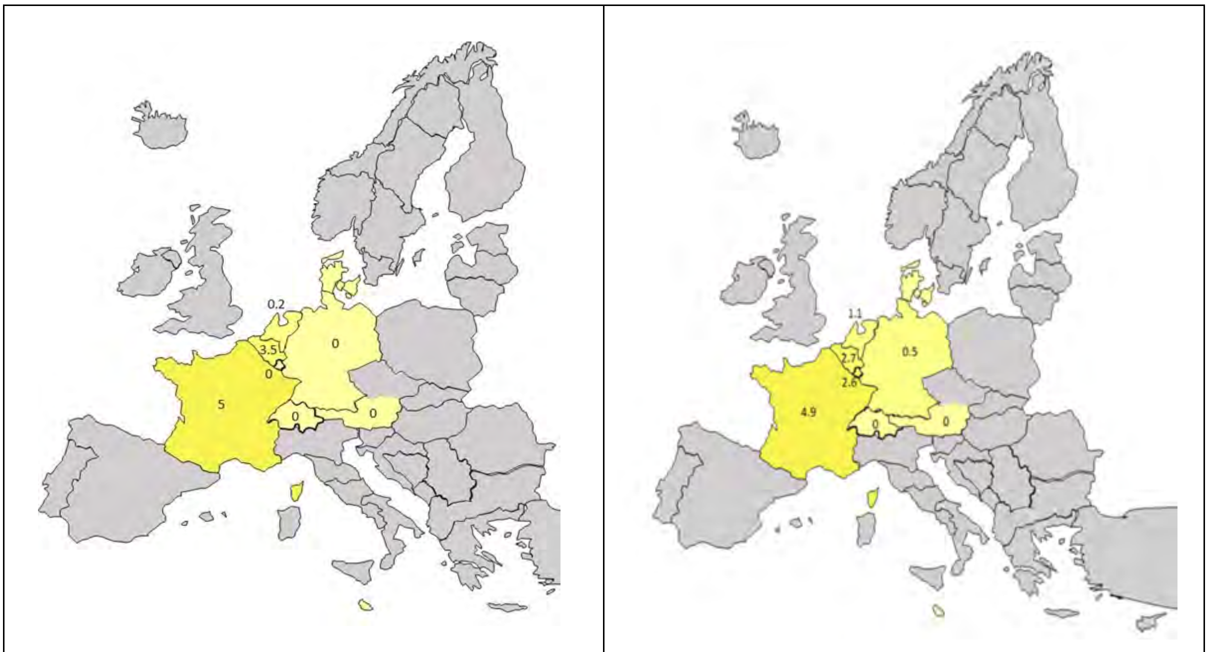
6.1 Results summary base case

6.1.1 Synthetic indicators

In the base case of the two studied horizons, adequacy indicators show very contrasting situations in the PLEF region. All results shown in this chapter are average figures over all the Monte-Carlo years. While Austria and Switzerland do not encounter any risk of curtailment for both horizons, simulations underline a tighter situation in France and Belgium (and the loads of Luxemburg directly connected to these two countries). Nevertheless, France and Belgium's adequacy indicators do not significantly deviate from national standards (max. LOLE of 3hrs/year). The situation does not worsen in the second time horizon.

In Germany and the Netherlands, the adequacy indicators show no specific risk in 2018/2019, but the situations tightens a bit in the second time horizon.

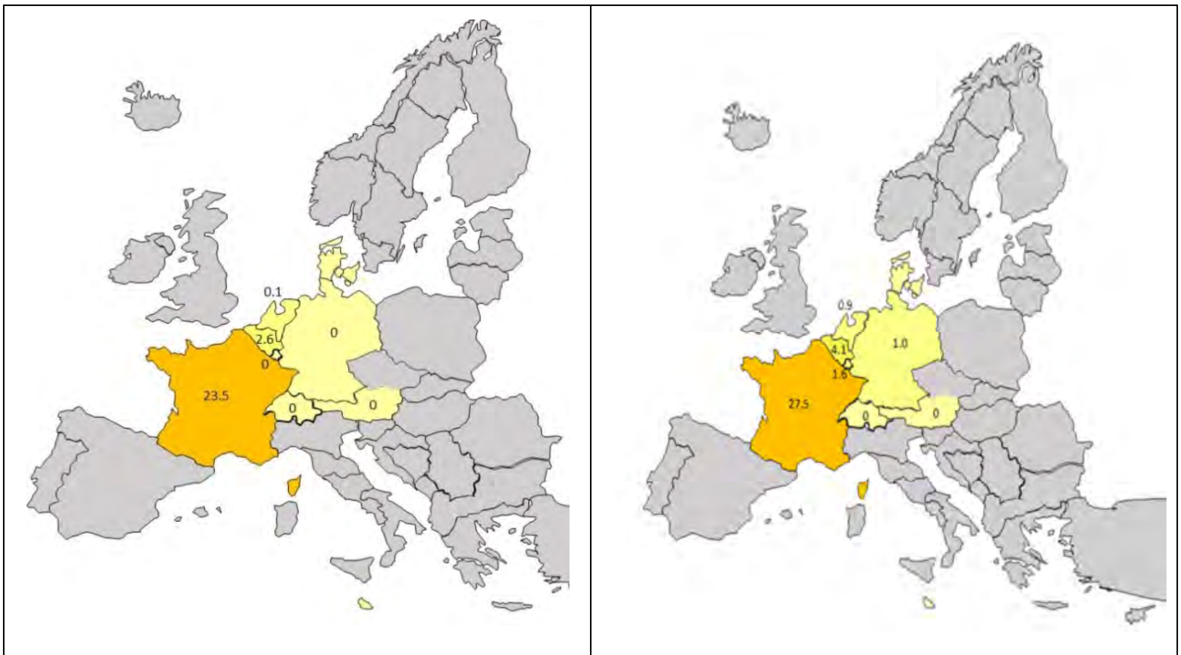
The maps hereafter display the level of Loss of Load Expectations for the two time slots studied.



2018/2019 (flow-based) | 2023/2024 (NTC)

Figure 28 LOLE levels in the base-case (hrs/year)

Regarding volumes of expected energy not served (ENS), they increase in the second time horizon in all countries but Switzerland and Austria.



2018/2019 (flow-based) | 2023/2024 (NTC)

Figure 29 Expected Energy Not Served in the base-case (GWh/year)

6.1.2 Detailed results

Behind the synthetic indicators obtained over all the Monte Carlo years simulated (combinations simulated = climatic conditions * outages on plants and HVDC), it is worth underlining that the risk of curtailment is not evenly distributed throughout the year, or among all climate years used (PECD 1982-2015). This paragraph aims at giving some more insight on the detailed results from the probabilistic simulations performed to assess the adequacy indicators and a better understanding of the phenomena at stake.

The detailed analysis that follows focuses very often on the second time horizon, but observations made still hold for the first time horizon.

1) Monthly and hourly analysis of the risks

The risk within the PLEF region is concentrated in winter and more specifically in January, and November for both time horizons (see Figure 30). In January the load level is the main driver, whereas in November problems may occur because of an early cold spell happening on a system where some units are still in maintenance, or wind generation is limited.

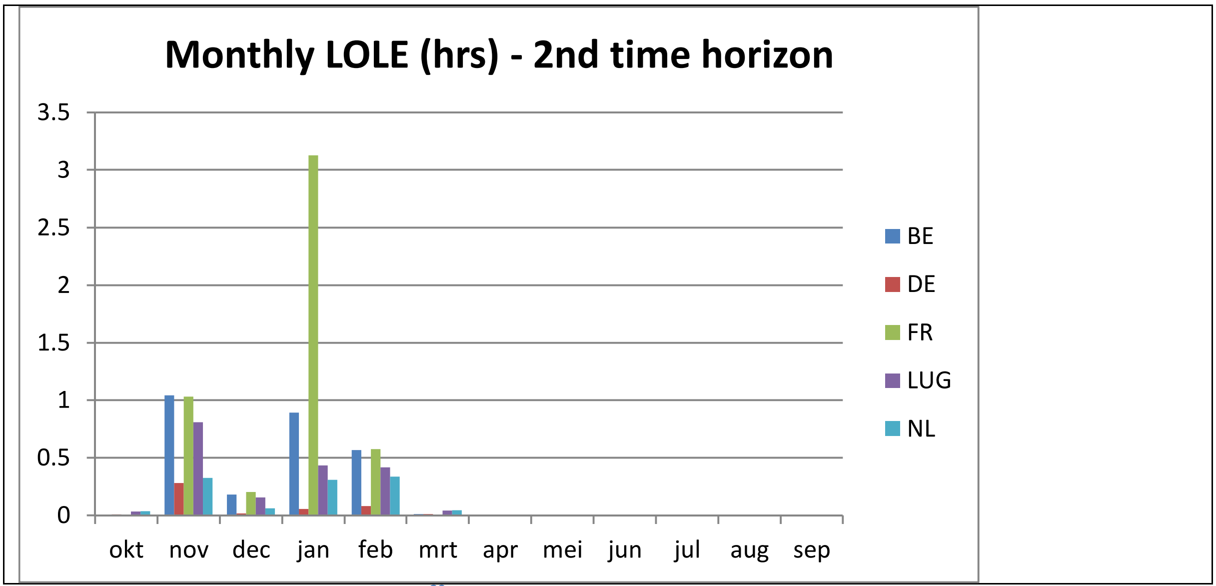


Figure 30 Monthly LOLE 2nd time horizon[29].

2) Sensitivity of the results to climate years

Figure 31 hereafter presents the contribution of each climate year to the overall indicator LOLE for Belgium, Germany, France, Luxemburg and the Netherlands for the second time horizon. It shows that a few years concentrate the risk of security of supply among which 3 prove to be more challenging for the region: 1985, 1987 and 1998.

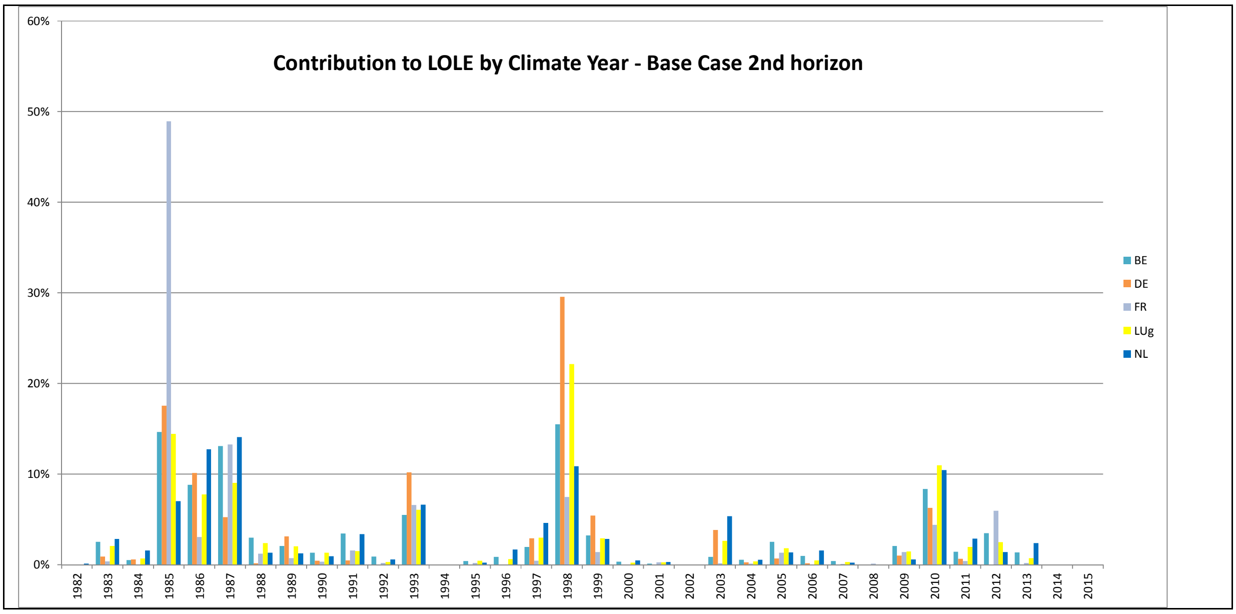


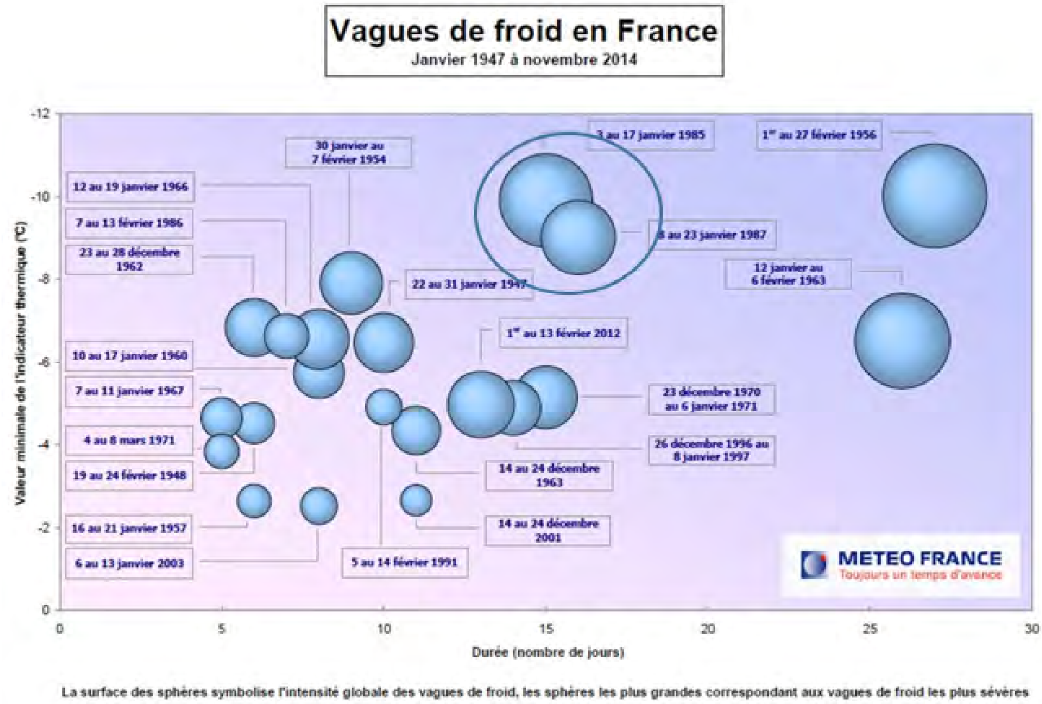
Figure 31 Contribution of each climate year to the overall indicator LOLE for the 2nd time horizons

3) Sensitivity to temperatures

Two years concentrate most of the risk, especially for France, namely 1985 (50% of the French LOLE comes from this specific year) and to a lesser extent 1987. The explanation behind this is mainly related to the temperatures experienced in these two years.

[29] "LUg", "LUG" and "LU" in the report are used synonymously to refer to Luxemburg in public grid

This graph in Figure 32 produced by Meteo France[30] shows how severe, from a French standpoint but might also be extrapolated to the whole PLEF region, these two years have been.

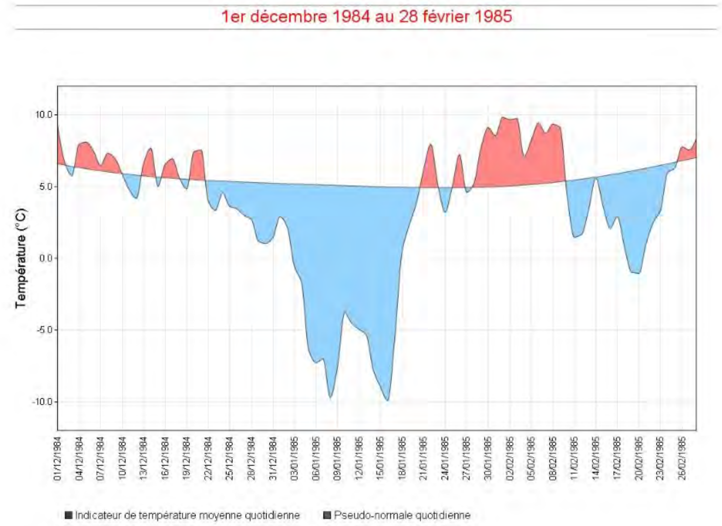


Each blue circle illustrates the severity of the cold spell (duration * magnitude °C)

Figure 32 Consideration of coldspell in 1985 and 1987

In 1985 and 1987 a two week-long cold spell hit Western Europe in January with extremely cold temperatures up to 15 degrees below normal conditions as shown in the subsequent Figure 33 (graph also taken from Meteo France). Given the sensitivity of the region to temperature, especially in France (approx. +2.5 GW load/°C), this translates in very stressful episodes for the security of supply. Such situations provide the so-called 'stress test' situations for the region, which are useful to e.g. test its resilience. It should be noted however that the probability of occurrence of these extreme situations is expected to be low.

[30] http://www.meteofrance.fr/prevoir-le-temps/meteo-et-sante/grands-froids#



Blue areas show temperatures below normal conditions.

Figure 33 1985 temperatures in France between December 1st 1984 and February 28th 1985

Temperatures alone are not solely responsible for tight security of supply situations. Thus combination with other climatic data (such as wind) could further aggravate the situation.

4) Wind generation in Germany

The year 1998 proves to be also very challenging (especially for Germany, Belgium, Netherlands, and Luxemburg). Most of the difficult situations are encountered in November. This corresponds to a situation where wind generation reaches its lowest level with 40% less production than in average. As shown in the Figure 34, the wind generation in Germany in November shows a significant drop in the second half of the month with an infeed reduced by 20 GW compared to the average generation over all climatic years. Year 1998 is also the 3rd coldest year of the database for the month of November, which leads to a high level of load in the region (intense cold spell 3rd week of November). Coupled with a low availability of thermal units this leads to high loss of load expectations.

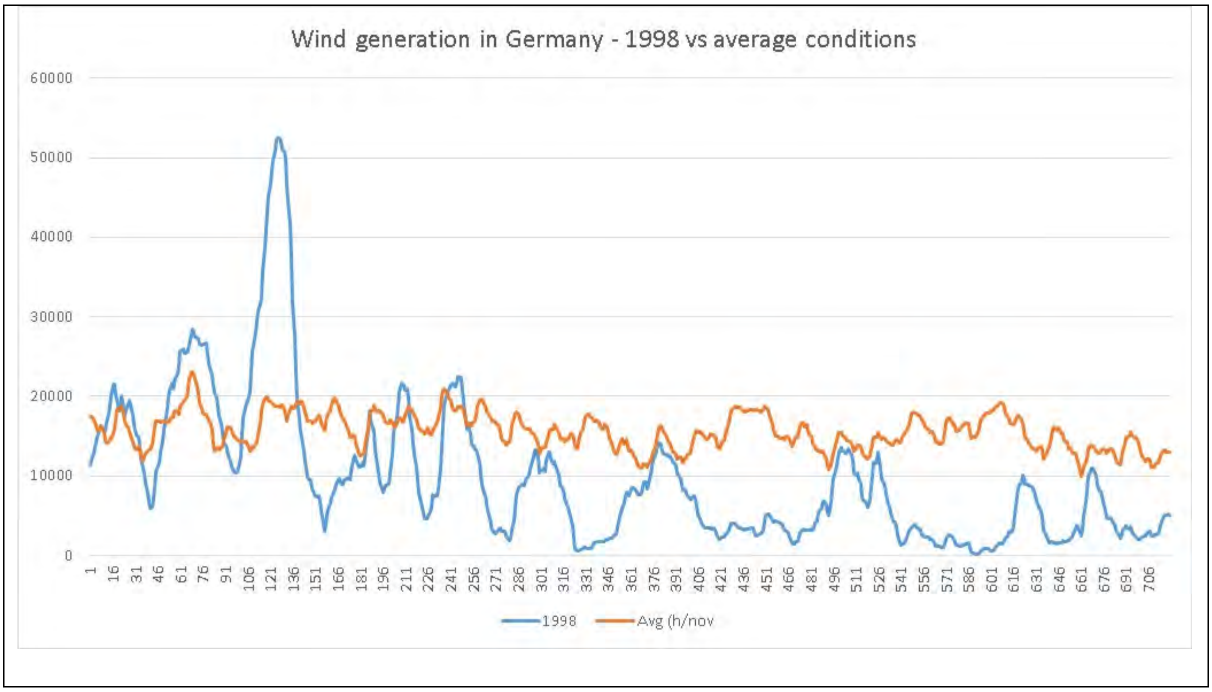
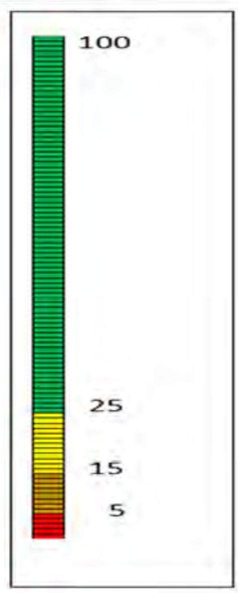


Figure 34 Hourly wind generation in MWh

5) Margins analysis – illustration for the 3rd week of January for the second time horizon

A detailed analysis has been performed to illustrate the level of the margins for the 3rd week of January, which proves to be one of the most challenging in terms of security of supply.

Regarding margin indicators defined in chapter 3.4.2, "margin status" graphs as shown and explained in Figure 35 can be computed.



"Red case": There is load curtailment in the country even with the interconnectors support.

"Brown case": The country has no curtailment but 0 MW margin while interconnected, the supports provided by the interconnector is essential.

"Yellow case": The country has positive margins (provided by interconnector), but would be short if no interconnectors

"Orange case": The country has 0 margin when interconnected but would have a positive margin without interconnectors

"Green case": The country has margin even without interconnectors

In the example on the left for a given hour a 5% probability to be in „red case" and a 75% probability to be in „ green case" can be observed.

Figure 35 Hourly pattern of the margin status for the interconnected situation

The graphs in Figure 36 and in Figure 37 show the hourly pattern along the 3rd week of January of the margin status for the interconnected situation within each PLEF country. Two groups of countries can clearly be derived from the graphs. On one hand Austria and Switzerland who have no risk of curtailment, but use all their margins to support neighbours when all other PLEF countries are short (morning and evening peak).

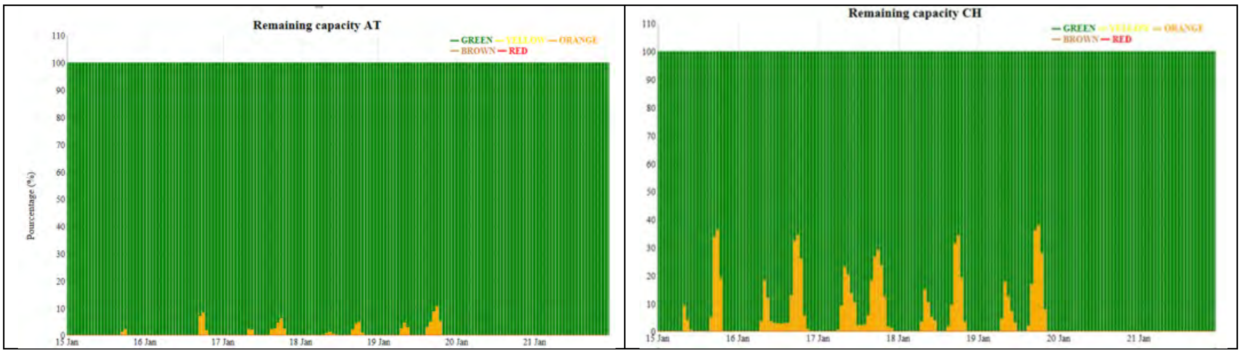


Figure 36 Status of Austria and Switzerland

On the other hand, all other countries face tight situations (yellow, brown or red cases) especially during working days (Figure 36 and Figure 37 start on a Monday) at morning and evening peak where for France, Belgium and to a lesser extent the Netherlands and Germany, load curtailment might occur.

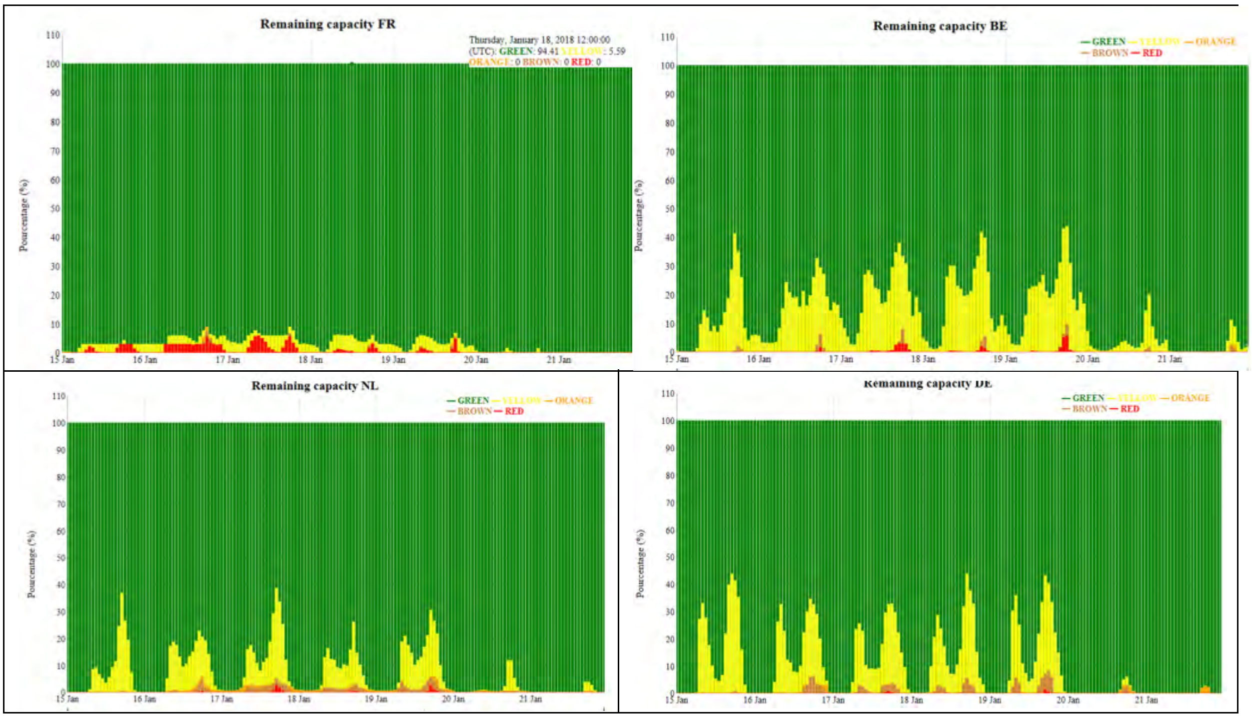


Figure 37 Status of France, Belgium, Germany and Netherlands

The subsequent graphs present the remaining capacities (MW) in an isolated or interconnected situation for the different countries. The four graphs below illustrate the contrasting situations for France and Switzerland (each grey curve corresponds to one Monte Carlo year). The two graphs side by side display the remaining capacity in the isolated (left) ,and the interconnected situation(right). Each grey curve account for one out of the 680 Monte Carlo year simulated (Monte Carlo year = a climatic year coupled with outages on plants and grid). Each grey curve is one Monte Carlo year (680 grey curves), red curve represents 1st percentile, blue 10th percentile and green the median.

France faces negative remaining capacities during working days for a couple of simulated years, which corresponds to climatic years 1985 and 1987. In the interconnected case (graph on the right) the situation clearly improves.

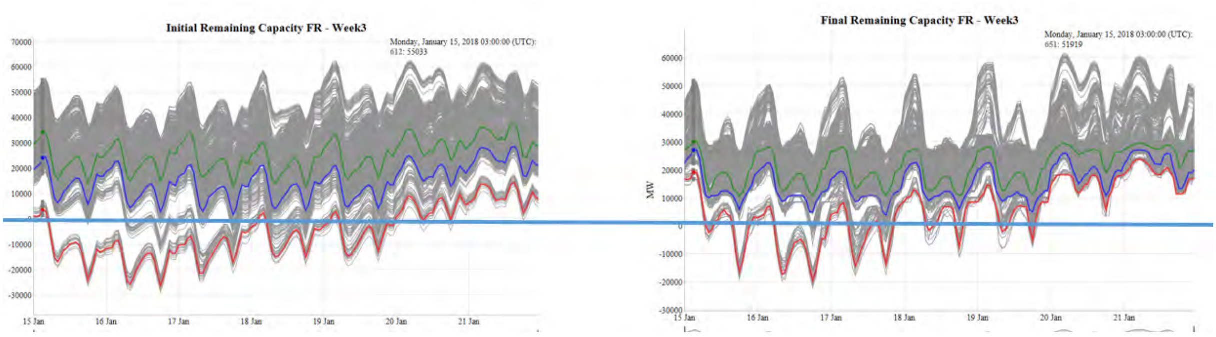


Figure 38 Remaining capacity France

The remaining capacities for Switzerland, when assessed in an isolated configuration, show positive values (above 2 GW). It should be noted that in the capacity methodology the energy constraints should also be taken into account in order not to provide over-optimistic values, which is not the case in this example.

When assessed with the interconnectors (graph on the right), the remaining capacities drop to 0 at peaking hours (Switzerland exports to neighbours, supports) and do not get negative. The graph on the right hand side also illustrates, that Switzerland margins in the interconnected situations are at their maximum at night and during the week end when the system is long and Switzerland imports (hydro storage).

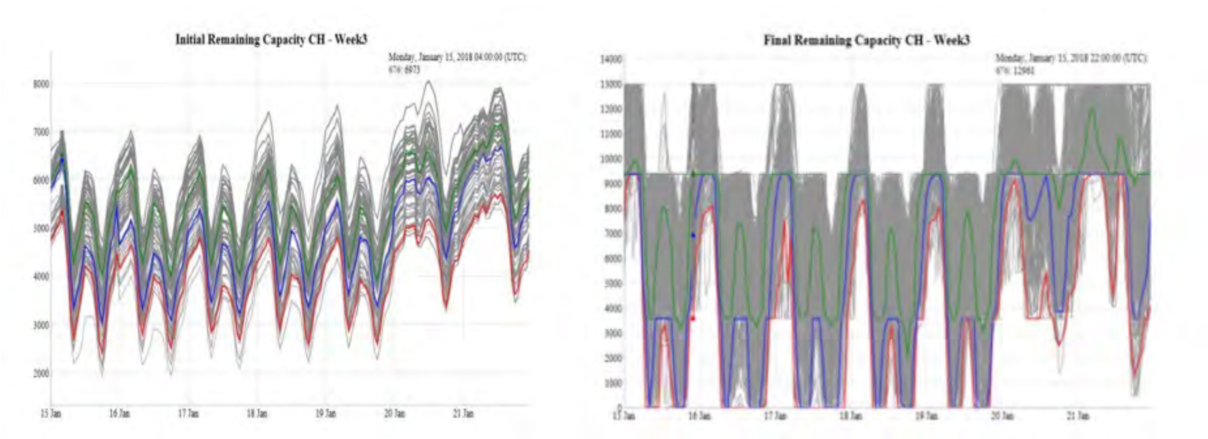


Figure 39 Remaining capacity Switzerland

The phenomenon depicted above applies for other countries within PLEF region as well, as illustrated in Figure 40 below.

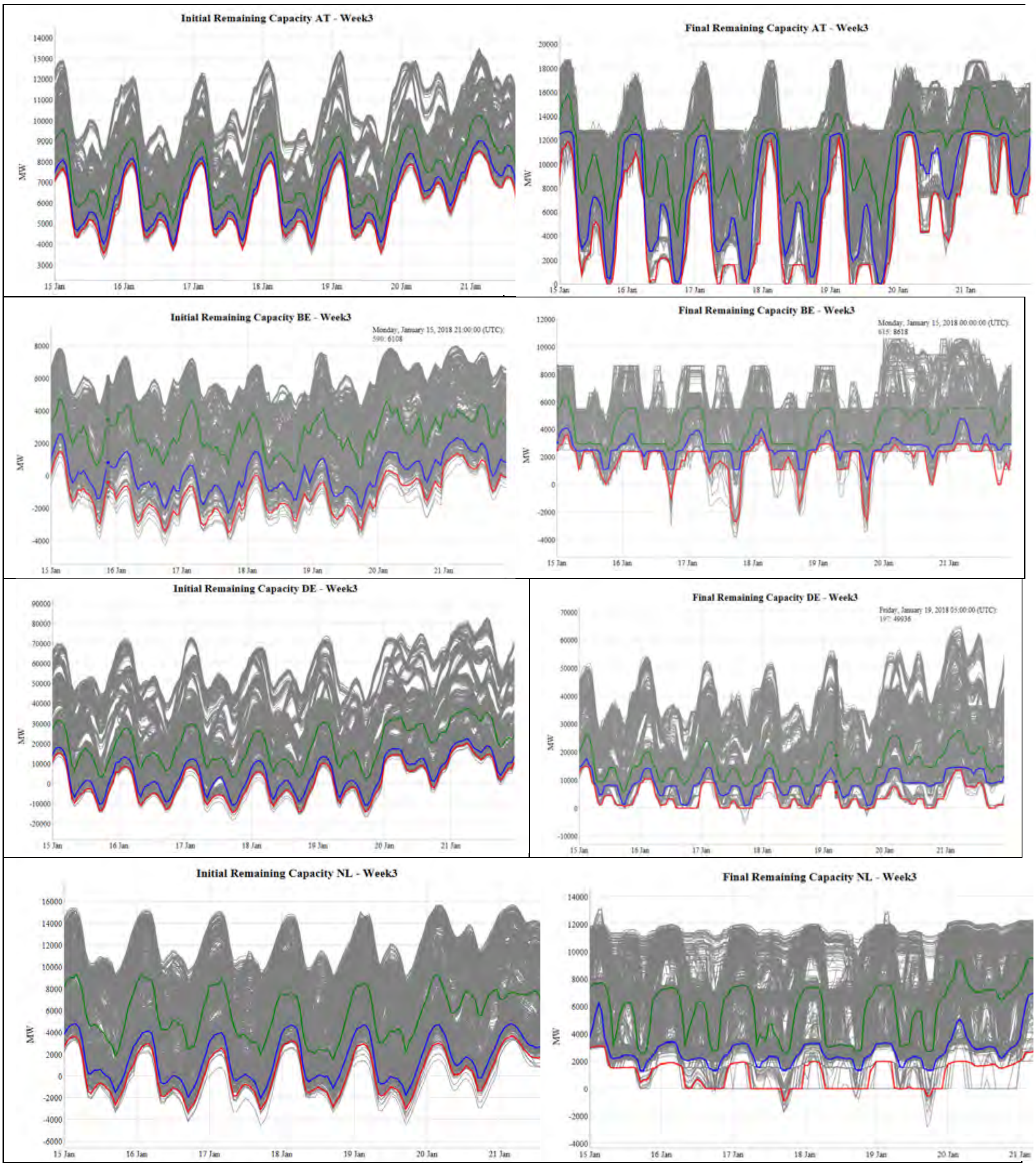


Figure 40 Remaining capacity Austria, Belgium, Germany and Netherlands

6.1.3 Flow Based Results vs. NTC Results

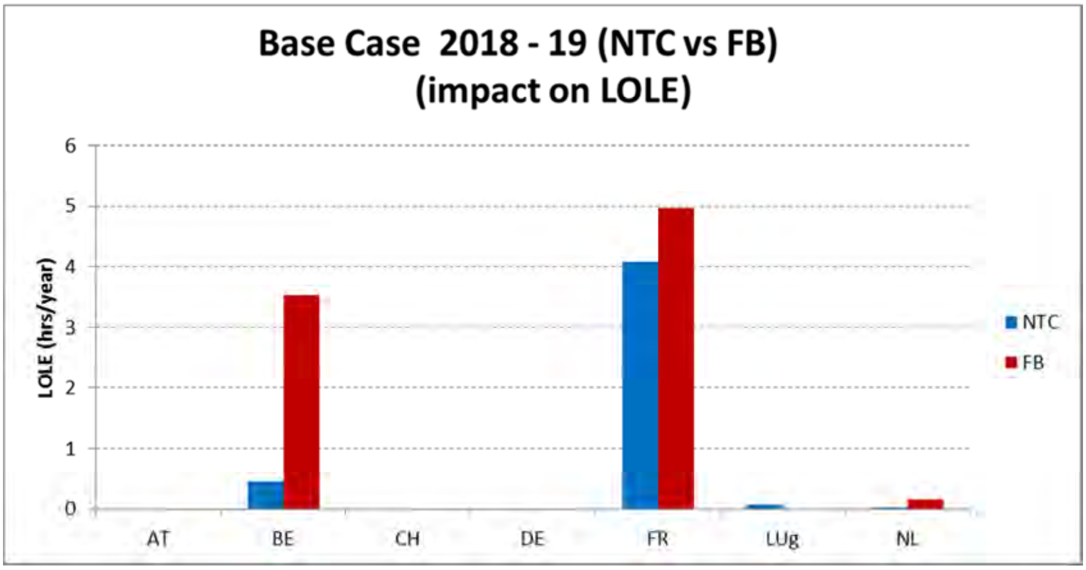


Figure 41 Comparison of NTC and flow-based results (impact on LOLE)

The approach for FB-MC is a significant step towards more realistic modelling of operational planning in practice nowadays. Contrary to the constant NTC values defined for long-term planning, representative historical FB domains are chosen as basis and linked to expected climate and consumption conditions of each day for the winter 2018/19. Combined with the adjustable NTC values at the border between Germany and Switzerland based on the German wind production, this approach is a simple yet realistic representation of what is observed in everyday practice in the region. As this requires more detailed modelling and realistic inputs, at the moment, it is only possible to do this for the not-so-far future, i.e. FB approach for the 2018/19 horizon only. With breakthroughs in the methodology and grid modelling it would be also possible to conduct FB approach for the longer time horizon, which could be facilitated via regional cooperation.

The step towards a more realistic modelling of operational planning in practice also means that the simulation results could better reflect the tight situations observed in practice leading to more realistic adequacy assessment of the region. Because of the aforementioned reasons, the FB and NTC approaches used for the same time horizon likely lead to different outcomes. FB approach should be target model, whenever possible, to reflect what is in practice.

6.2 Results summary Sensitivity Analysis

6.2.1 Impact of Economic Sensitivity for 2023/24

In the economic sensitivity case defined in chapter 5.2, around 5.5 GW of installed capacities in thermal units are removed from Austria, Belgium, Germany and the Netherlands. The histogram in Figure 42 presents the effect on the LOLE indicator of this withdrawal compared to the base case.

LOLE increases significantly in all countries; it more than doubles Belgium, Germany, Luxemburg and the Netherlands. In France, where no capacity was removed, the effect is a bit lower. Austria and Switzerland remain at their level in the base case (no LOLE).

This sensitivity illustrates the risk of synchronous mothballing or closure of several units within the region.

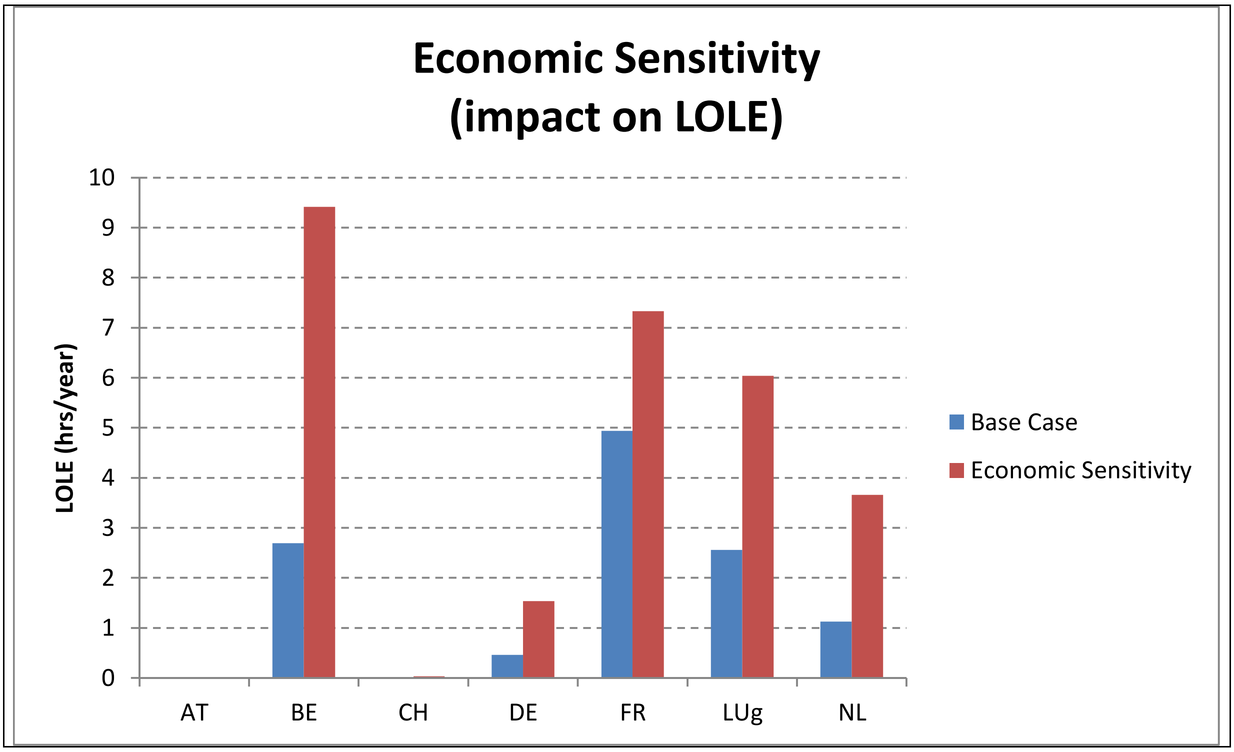


Figure 42 Impact of economic sensitivity on LOLE

6.2.2 Impact of Environmental sensitivity for 2023/24

In this sensitivity, coal units are shut down in Austria, the Netherlands and France for a total of approximately 3 GW. The effects are presented in the following graphs which display the LOLE for the base case and the sensitivity case. It shows that all countries but Switzerland and Austria would see their LOLE increase. While Germany's situation slightly worsens, the main effects are observable in Belgium, France, Luxemburg and the Netherlands.

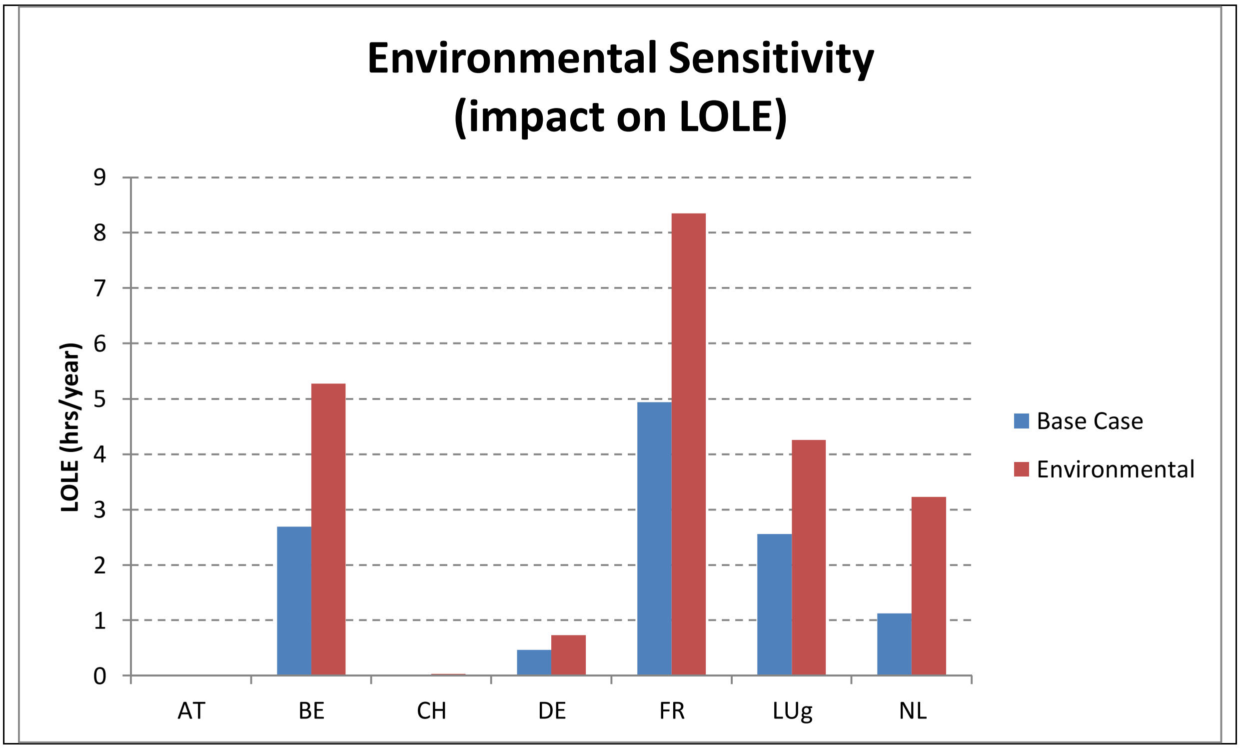


Figure 43 Impact of environmental sensitivity on LOLE

6.2.3 Impact of Long term unavailability of nuclear for 2018/19 and 2023/24

In the case of lower availability of nuclear units in France (according to winter 2016-2017), Belgium and Switzerland, the security of supply would be aggravated in France and Belgium with a LOLE reaching at least 10 hrs/year as illustrated in Figure 44; in the meantime the other countries of the region would not see their LOLE affected.

For Belgium, the same storyline has been further analyzed in detailed by the recently published national adequacy study of Elia[31]. For this nuclear unavailability sensitivity, the national study by Elia has identified the volume of strategic reserve needed to ensure that the national standard (LOLE < 3 hrs/year and LOLEP95 < 20 hrs/year) is respected.

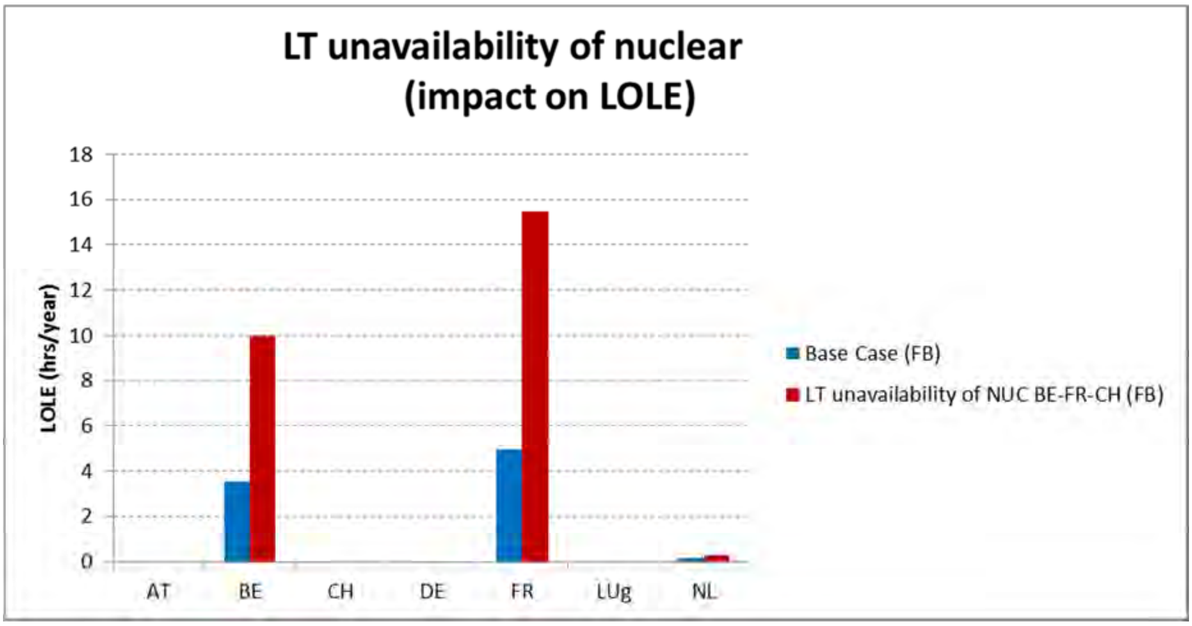


Figure 44 Impact of LT unavailability of nuclear on LOLE (first time horizon)

In the second time horizon a low availability of nuclear units would endanger security of supply in all countries except Austria as shown in Figure 45.

[31] Elia national study – Adequacy study for Belgium: The need for strategic reserve for winter 2018-19 and outlook for 2019-20, 2020-21.

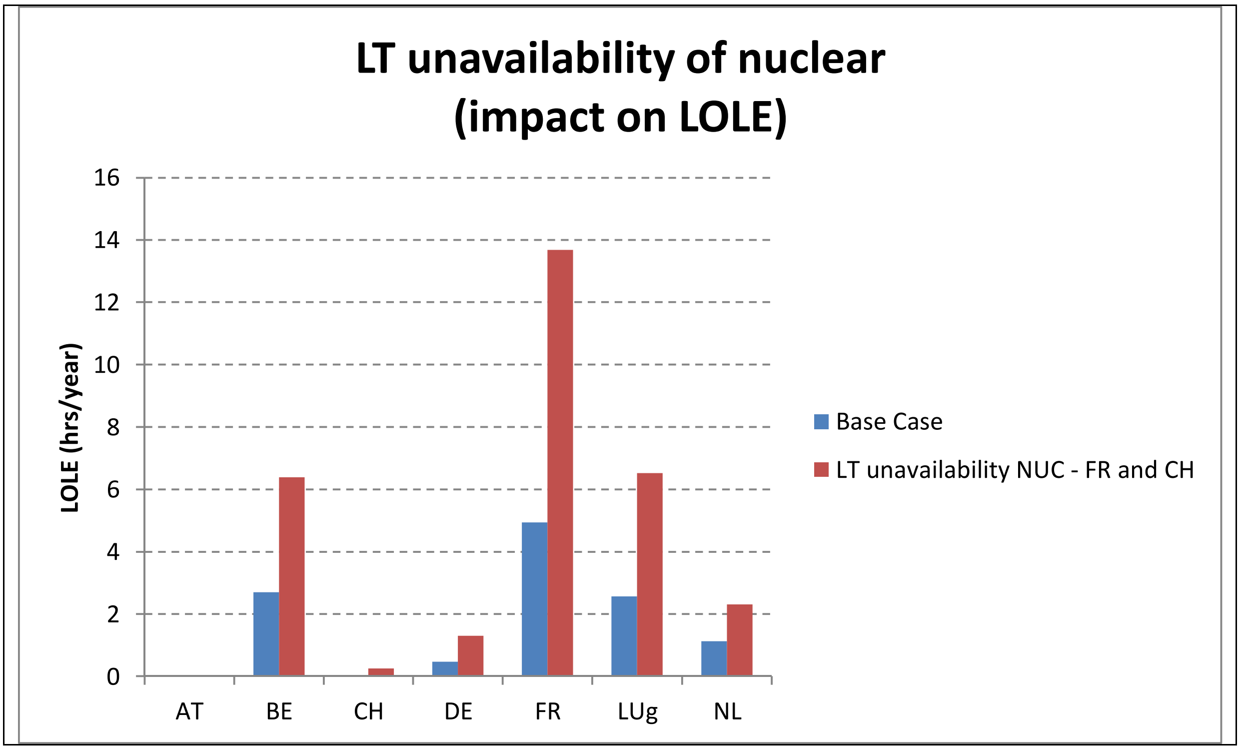


Figure 45 Impact of LT unavailability of nuclear on LOLE (second time horizon)

6.2.4 Impact of Interconnectors projects on 2nd time horizon

The grid projects (Table 5) listed for the Grid Sensitivity clearly improve the level of security of supply within the region, and more specifically in Belgium and France as shown in Figure 46. Without them, the LOLE from these two countries would exceed 10 hrs/year, which is roughly two to three times more LOLE than in the base case,. This result points out the key role played by interconnection projects, which not only enhance market integration but also increase the security of supply.

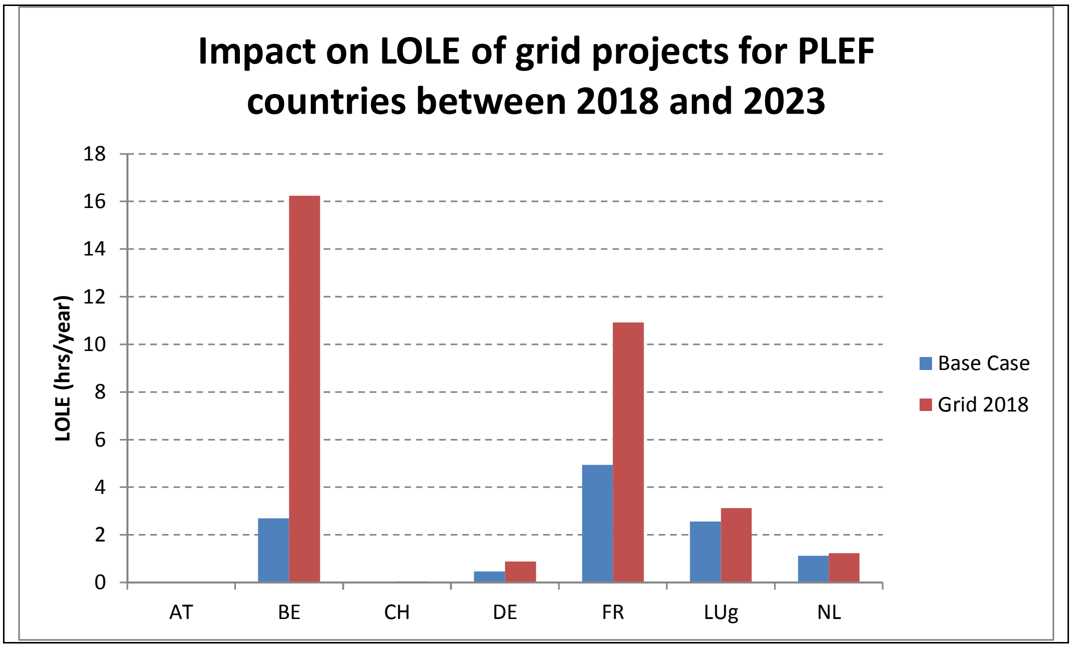


Figure 46 Impact of grid projects on LOLE

6.2.5 Impact of Demand Side Flexibility

On the basis of the input data gathered according to chapter 4 and the relevant outputs of Antares from the base case (exchange balance, hydro generation and operation of switchable loads), the economic sensible combinations of flexibilities for France, Germany, the Netherlands and Switzerland are determined using the DSF model "AmpFlex". The underlying assumptions regarding activation costs, shifting duration and fixed costs can be found in the appendix. Moreover, it has to be noted that the climate year used for the DSF simulation is 2013 which is considered as an average year in the context of generation adequacy.

	Base Case	DSF sensitivity			
Country	**Sum**	**DSF Ind & Business**	**DSF Household**	**Flexible Biomass**	**Sum**
	Assumed Capacity [MW]	Installed Capacity** [MW]	Installed Capacity** [MW]	Max. potential [MW]	**Max. potential [MW]**
France	5,000	6,000	1,500	-	**7,500 (+2,500)**
Germany	1,000*	-	-	1,636	**2,636* (+1,636)**
Netherlands	-	375	275	-	**650 (+650)**
Switzerland	-	-	-	-	**-**
Austria* **	-	-	-	-	-
Belgium* **	1,096	-	-	-	**1,596 (+500)**
Luxemburg* **	-	-	-	-	-

* including 1,000 MW switchable loads contracted by TSOs

** For DSF Installed Capacity equals Max. potential

*** Capacities/potential is given exogenously

Table 11 Distribution of DSF sensitivity per country

The model results reveal a considerable DSF potential for France and the Netherlands. Compared to the base case additional potential for DSF of 2,500 MW and 650 MW is found (see right column in Table 11). In Germany and Switzerland, however, DSF is not profitable under the considered scenario framework. The results can be explained by two main factors: First, the profitability of DSF is driven by the revenues gained in hours with scarcity, i.e. high load and low available generation capacity. In such hours prices are determined by the cost for load curtailment (i.e. Value of Lost Load) as defined in the appendix. Second, in countries with a high share of flexible hydro generation, i.e. Switzerland, there is no need for further flexibility from an economic point of view. In particular for Switzerland several simulations have been performed assuming different capacities for DSF household. In all cases DSF household was activated in the model. However, due to the high share of flexible hydro generation in Switzerland the utilization and full load hours of DSF household are very low. As a consequence the revenues gained on the electricity market are not sufficient to cover the annual investment costs of the respective flexibilities. That is why in the subsequent adequacy simulations zero DSF capacity is considered for Switzerland. For Germany it has to be noted that besides existing pumped storages additional flexibility can be provided by flexible biomass plants[32]. However, it has to be noted that this does not mean that the potential for DSF is not there in Switzerland or Germany. It rather means that it is not activated since market prices are not sufficiently high. If prices - in

[32] A flexibilisation of biomass plants with combined heat and power (CHP) entails an installation of a heat storage, so that heat supply obligations can be covered by the heat storage while increasing the generation of electricity at the same time. Biogas units can be made flexible through installation of gas storage.

the calculated scenarios or even in other market environments – would reflect a need for flexibility to ensure security of supply, one can certainly expect that more DSF capacities would enter the market.

For Belgium and Austria the DSF capacities are given exogenously without validation by the DSF model. For Belgium on the basis of a market parties consultation and the MAF report an installed DSF capacity of 1.596 MW is assumed. For Austria and Luxemburg installed DSF capacities of 0 MW are assumed, as likewise in Switzerland flexibility might be provided by existing hydro generation units (see grey values in Table 11).

The obtained capacities for DSF and flexible biomass are the basis for the DSF sensitivity as further elaborated in the following.

For all countries the incorporation of DSF leads to improvements with regard to the occurrence of supply shortages. The highest decrease of LOLE is found for Belgium (from 2.5 to 0.9 hrs/year). For France the LOLE of 4.5 hrs/year is decreased to 3.3 hrs/year. The results regarding the LOLE indicate that DSF provides an opportunity to guarantee the defined level of security of supply.

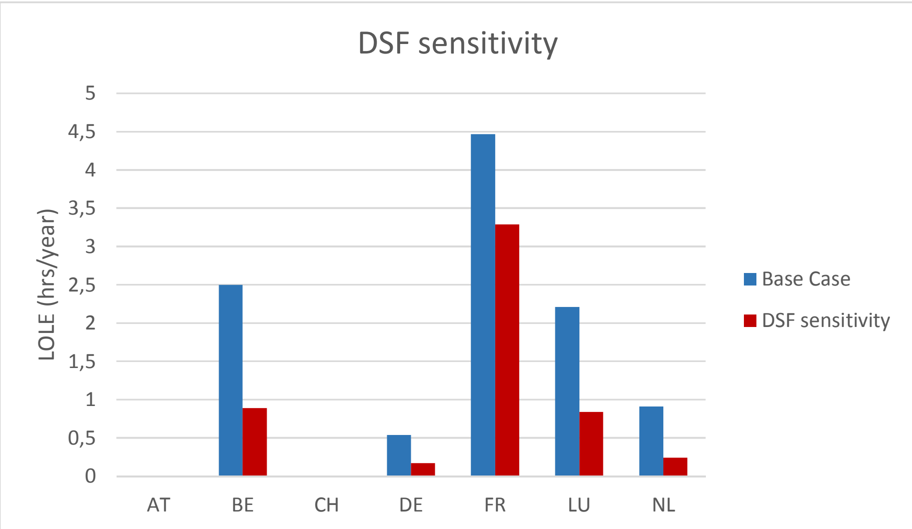


Figure 47 Impact of DSF sensitivity on LOLE

Further insights can be gained by an analysis of the Energy not Served (ENS), which indicates the magnitude of load that might be lost when demand exceeds the available generation capacity. According to the base case the highest ENS is found for France, whereby the incorporation of DSF allows a considerable reduction of lost load in most PLEF countries. Accordingly the highest absolute improvement is found for France followed by Belgium, where the sum of avoided compulsory load curtailment amounts to 8,7 GWh/year.

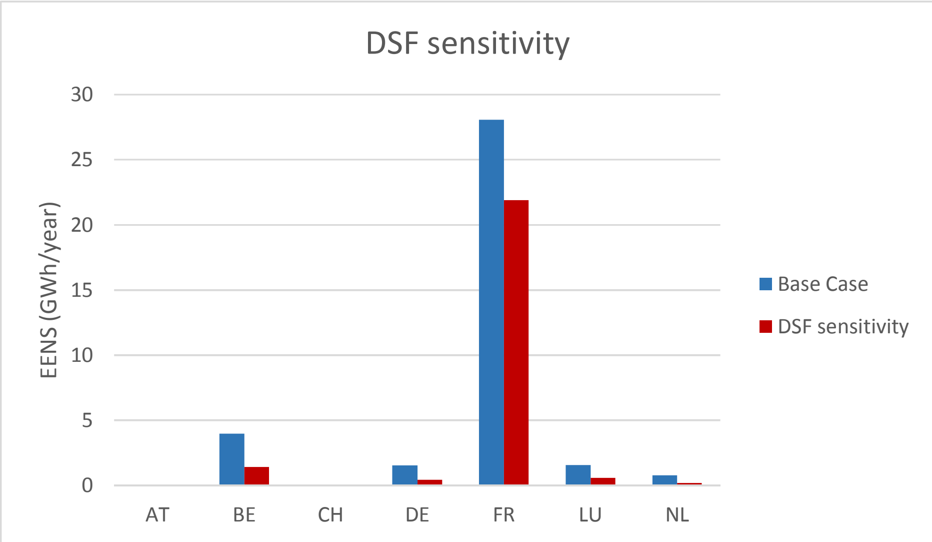


Figure 48 Impact of DSF sensitivity on ENS

To summarize, the incorporation of DSF leads to a considerable improvement of generation adequacy in France, Belgium, Germany, Luxemburg and the Netherlands.

6.3 TSO Comments on results

PLEF GAA STUDY & NATIONAL STUDIES BY BELGIUM AND FRANCE

The PLEF GAA provides results for winter 18/19 and winter 23/24. This first time horizon is also addressed in two national reports which have been recently published by the Belgian (Elia) and French (RTE) Transmission System Operators, i.e.:

1. Elia national study – **Adequacy study for Belgium: The need for strategic reserve for winter 2018/19 and outlook for 2019/20, 2020/21.**
2. RTE national study – **Bilan prévisionnel de l'équilibre offre-demande d'électricité en France 2017.**

These national studies are currently used by the corresponding national authorities of France and Belgium to decide on solutions necessary to ensure security of supply at national level.

The risk of shortage in the base case for winter 2018/19 is higher in the PLEF study in comparison to the above mentioned national studies as a consequence of different assumptions in the 'base case'. Indeed, in the 'base case' of the Elia study, which uses the RTE national study as input, neighbouring countries are found to be adequate. It is thus assumed that, in the 'base case', neighbouring countries will take the necessary actions to remain adequate (when taking into account energy exchanges and within their national criteria). As a result, for winter 2018/19, RTE and Elia foresee that in the 'base-case scenario' considered in their respective national adequacy reports that: i) France should be at its standard of LOLE = 3h and ii) Belgium should be at its standards of LOLE < 3h and LOLEP95 < 20h.

The PLEF GAA study considers in addition a different assumption for the 'base case'. The occurrence of a very extreme and unlikely situation is assumed. Such situation causes that several countries can be outside their adequacy criteria simultaneously. This case provides a so-called 'stress test' situation for the region, to e.g. test its resilience. The solutions identified in the above national studies should contribute as well to solving the adequacy situation identified in the PLEF 'base case'.

Load thermal sensitivity for France is an important driver of adequacy problems in winter mainly for France as well as for Belgium, and to the lesser extent also for the countries within the CWE. Assumptions regarding temperature sensitivity of load are therefore important for defining such 'stress – test' situations. The PLEF GAA considers temperature-dependent load in line with the Pan-European ENTSO-E study MAF 2017. Historical temperature records 1982 – 2015 are considered. The inclusion of these historically observed situations introduces observed cold spells with a large regional impact (e.g. very cold winter of year 1985). These historical cold spells situations are considered in the PLEF GAA simulation in a way in which its effect is clearly visible in the results. However it should be noted that the probability of occurrence of these extreme situations is very low, significantly lower than the '1-out-20' (also referred as P95 percentile) criteria monitored in the Elia national study.

PLEF GAA STUDY & NATIONAL SITUATION FOR GERMANY

For the first time horizon, LOLE is equal to zero for Germany. For the second time horizon the situation is deteriorating and a LOLE of 0,5 h/year is resulting from the simulations. This corresponds to a ENS of 1,0 GWh/year.

The current German Energy Law and the Capacity Reserve Ordinance form the legal basis for the establishment of a capacity reserve (a type of strategic reserve) mechanism for the purpose of safeguarding the security of supply in Germany. At the point in time of data collection it is intended to tender 2 GW by mid of 2018 and to build up this reserve to 4 GW by 2023/24. The Capacity Reserve will be sufficient to reduce the resulting LOLE for the second time horizon to zero. If there will be a forecasted demand excess that cannot be covered by market capacities, the Capacity Reserve might be dispatched based on TSO request, to provide additional energy without significantly impacting the energy market.

Due to the government election in autumn 2017 there are intensive discussions emerging concerning a coal phase-out in Germany or at least diminishing proportion of coal-fired power plants of the generation park available. When completing the study, no robust information on the plans of the new government were available, so no additional sensitivities regarding this aspect could be conducted. As soon as more detailed information is available an additional modelling of a sensitivity concerning a further phase-out of coal would be beneficial, since there might be major implications not only on the security of supply in Germany but also on the neighbouring countries.

7 Conclusions and Lessons learnt

The quantitative results from this study are generally consistent with those from the ENTSO-E MAF and from national studies. The differences are mainly because of different assumptions and data, the details can be found in the report. The sensitivity analyses enable different scenarios in a regional context. Some of these sensitivities, e.g. environmental, economic, as well as grid investment, demonstrate how these factors can have an important influence on regional generation adequacy.

The results for the first time horizon (2018/2019) show that France and Belgium are most prone to generation adequacy problems while similar observations can be made for the second time horizon (2023/2024) for these countries with slight issues (less than 3 LOLE/year) also observable for countries like the Netherlands and Germany. The economic viability evaluation of Demand Side Flexibility (DSF) provides an estimate of possible addition of available DSF in some of the PLEF countries for the analysis of their impact on generation adequacy. The results show that DSF has a clearly positive impact.

One of the main achievements of this study is the implementation of the FB approach at the regional level. The approach for FB-MC is a significant step towards more realistic modelling of operational planning in practice nowadays. Contrary to the constant NTC values defined for long-term planning, representative historical FB domains are chosen as basis and linked to expected climate and consumption conditions of each day for the next winter 18/19. Combined with the adjustable NTC values at the border between Germany and Switzerland based on the German wind production, this approach is a simple yet realistic representation of what is observed in everyday practice in the region. FB approach should be the target model, whenever possible, to reflect what is in practice. As this requires more detailed modelling and realistic inputs, at the moment, it is only possible to do this for the not-so-far future, i.e. FB approach for the 2018/2019 horizon only. With breakthroughs in the methodology and grid modelling it would be also possible to conduct FB approach for the longer time horizon, which could be facilitated via regional cooperation.

The step towards a more realistic modelling of operational planning in practice also means that the simulation results could better reflect the tight situations observed in practice leading to more realistic adequacy assessment of the region. Because of the aforementioned reasons, the FB and NTC approaches used for the same time horizon likely lead to different outcomes.

One of the challenges that remains is the long-term representation of the FB approach. The current approach is based on historical domains adapted to accommodate the planned grid reinforcements for the first time horizon. The generation and load pattern, which is a key to the determination of the domains, is assumed to be unchanged. This would be challenged when applied for a longer future horizon. As FB is the target model according the European Network Code it is important that long-term adequacy assessments can take this into account. This would also imply a prediction of how the FB methodology as well as region will develop in the future which entails political considerations and uncertainties.

On the probabilistic approach, though it is quite developed the dependence of generation adequacy results on climatic conditions is key and despite the extension of the climate database to cover 34 historical years it is still not long enough to cover the necessary meteorological evolution. In this case, it might be beneficial to consult experts in this domain to evaluate or adjust the probability assigned to each climate year.

Moreover, in their original format some of the data sources which are used in this study might refer to different time horizons than the ones analysed in this study. As a consequence these data are adjusted to comply with the analysed time horizons. This is a complex step in the data preparation process, which is also prone to errors in the underlying assumptions of the study.

With quite a few hydro countries in the PLEF region a proper hydro-modelling is imperative. Despite the use of different hydrological years, outages for hydro power plants are not considered. In combination with a “perfect foresight” model, this leads to an optimistic dispatch of the hydro power plants.

Maintenance and outages of the thermal power plants are drawn according to the given technical parameters. A more realistic availability of the thermal power plants could be implemented if this information is available at the plant level and collected on a more refined time step (monthly values for maintenance would be an improvement).

The Grid sensitivity performed in the study highlights the key role played by planned interconnection projects, which not only enhance market integration but also improve the security of supply. Furthermore, probabilistic approaches such as the ones used in this GAA are key to assess security of supply contribution of future interconnectors. A method based on probabilistic assessments is currently being assessed within the framework of the ENTSO-E CBA.

As some of the steps are pioneering and experimental in this study, some of the results should be considered as indicative and evaluated together with those from the ENTSO-E MAF and the respective national studies, taking into account the differences in assumptions and data.

8 Appendix

8.1 Frequently asked questions & answers

- **What is the difference between national assessment, ENTSO-E assessment, etc.?**
  Currently Pan-EU adequacy studies (MAF), Regional (PLEF GAA) and some national studies by TSO share the same probabilistic methodology. This methodological alignment enables consistent analyses and facilitates comparison between the results of these different studies. Due to the different and complementary scope and usage of Pan-European, regional and national studies, still some differences in the methodological assumptions and data might need to be considered among them.
  Pan-European and regional assessments sharing a common methodology aim at ensuring greater consistency not only between these and national assessments but also consistency of any proposed solutions which might arise at a regional or Pan-EU level, to deal with adequacy problems.
  National studies are needed so countries can perform detailed analysis regarding the implementation of measures to ensure security of supply at national level. Therefore national studies focus on exploring specific national sensitivities and specificities, beyond the scope of the European and regional assessments. Consistent and complementary of national studies with the European and regional assessments is important when used for implementation of measures to ensure SoS.

- **What is the diff. between market simulations for network planning and adequacy assessment?**
  Traditionally the market simulation tools were used mainly for network planning purposes. The optimal unit commitment and dispatch tools can also be employed to conduct generation adequacy analyses under more conservative assumptions of the input parameters, e.g. installed capacity, outages, etc. More importantly, till now market simulations for network planning are mostly deterministic, meaning that an average/normal scenario would be sufficient for transmission investment decisions. Even though this is also being evolved and continuously improved, probabilistic analyses for network planning are restricted in number, especially when compared with adequacy studies, for which the “worst” case (e.g. high load combined with dry year and low wind conditions) must be considered with their possible outcome and the associated probability of occurrence. Because of this reason, hundreds, if not thousands, of simulations are required.

- **Why do the simulations in this assessment cover only the Day-ahead market? Are TSO activities in the Intraday-market or in Real-time considered?**
  Certainly the model here used does not cover all aspect of the real market and system behavior. Still this methodology allows the development of a model able to capture all the key features and risks regarding adequacy at the regional level power system, which is the main objective of the study. We believe that it is most important to capture periods of structural shortage at the Day-Ahead market level. This is where the fundamental signals shortage, relevant to generation adequacy should be captured.
  The effect of imbalances due to force outages occurring close to real time and the effect of forecasting errors of load, wind, solar production is accounted in a simplified way in the PLEF assessment by consideration of operational reserves requirements as an extra constraint to the modelling. This modelling while simplified, is deemed sufficient for the type of generation adequacy assessment performed here.
  Further detailed modelling of these aspects (the effect of imbalances due to force outages occurring close to real time and the effect of forecasting errors) is considered outside of the

scope of the PLEF GAA since these imbalances are typically covered by the intraday and mainly balancing markets and even more important are not observed systematically in the Day-Ahead market during several days of a week, i.e. not providing any systematic signal of shortage during this point of time of the Day-Ahead market clearing.

- **Are grid constraints within the market nodes considered?**
  In this study the current bidding zone configuration for the first horizon together with the FB approach is used. FB approach itself includes critical branches, so internal congestions are addressed implicitly in the model. As this requires more detailed modelling and realistic inputs, at the moment, it is only possible to do this for the not-so-far future, i.e. FB approach for the 2018/2019 horizon only. With breakthroughs in the methodology and grid modelling it would be also possible to conduct FB approach for the longer time horizon, which could be facilitated via regional cooperation.

- **Which set of historic climatic years was used is this study? What is the probability of occurrence of the historic years?**
  For this study the historic climatic years 1982 – 2015 were used, and they were included with equal weighting in the Monte Carlo approach. In the "Conclusions and Lessons learnt" chapter of the report, it is recommended to work on improvements in this area. An evaluation of the likelihood of extreme events, for example, should be considered.

- **Will the dataset used for this study be fully disclosed?**
  No, the level of detail of information in the PLEF area in the report is the level of disclosure that TSOs can give, taking into account confidentiality issues with market players.
  In the report data is provided on a country-by-country basis as well as transport capacities within the PLEF area.
  In general PLEF TSOs cannot publish detailed data for countries outside the PLEF area.
  Outage information (forced outages and maintenance) is based on historical statistics but there is still room for further improvement in this area.
  PLEF TSOs welcome engagements by market participants in order to facilitate e.g. economical / technical data needed to improve the accuracy of the forecasts used in the simulations performed. It is very important to have good visibility, e.g. on decommissioning, mothballing figures in order to setup the relevant generation scenarios.

- **Was Demand-Side-Flexibility (DSF) considered during this study and was the impact of DSF on adequacy evaluated?**
  In order to assume appropriate DSF capacities an evaluation from an economic perspective was carried out using the “AmpFlex” model. Additional DSF capacities were considered for some of the PLEF countries in the subsequent adequacy modelling and their impact on adequacy is quantified in the DSF-sensitivity. A detailed description of this model including relevant input parameters is given in the appendix of the report.

- **What are the desired LOLE values on a national basis?**
  The national criteria are described briefly in Table 2 of the introduction.

- **What kind of additional simulations were carried out besides the base case, and which potential developments are reflected in these additional simulations?**
  To quantify consequences of uncertainties on the outcomes of the analysis a number of sensitivity variants have been considered in addition to the base case analyses with alternative

assumptions regarding parameters that are uncertain and at the same time have a major influence on the outcomes of the study in term of adequacy levels. The following sensitivities were analysed:

- more generation capacity (mostly gas fired) is mothballed or decommissioned because of economic reason (economic sensitivity),
- more generation capacity (mostly coal fired) is shut down because of environmental reason (environmental sensitivity),
- a lower availability of nuclear capacity,
- a delay of interconnector projects,
- extra DSF potential

The results of these analyses are summarized in chapter 6.2

8.2 Detailed Model descriptions

8.2.1 ANTARES

ANTARES - A New Tool for generation Adequacy Reporting of Electric Systems – is a sequential Monte-Carlo multi-area adequacy and market simulator developed by RTE. Antares has been tailored around the following specific core requirements:

a) Representation of large interconnected power systems by simplified equivalent models (at least one node per country, at most #500 nodes for all Europe)
b) Sequential simulation throughout a year with a one hour time-step
c) For every kind of 8760-hour time-series handled in the simulation (fossil-fuel plants available capacity, wind power, load, etc.), use of either historical/forecasted time-series or of stochastic Antares-generated time-series
d) Regarding hydro power, definition of local heuristic water management strategies at the monthly/annual scales. Explicit economic optimization comes into play only at the hourly and daily scales (no attempt at dynamic stochastic programming)
e) Regarding intermittent generation, development of ***new stochastic models*** that reproduce correctly the main features of the physical processes (power levels statistical distribution, correlations through time and space)

At core, each Monte-Carlo (MC) year of simulation calls for two different kinds of modelling, the first one being devoted to the setting up of a ***“MC scenario”*** made up from comprehensive sets of assumptions regarding all technical and meteorological parameters (time-series of fossil fuel fleet availability, of hydro inflows, of wind power generation, etc.), while the second modelling deals with the economic response expected from the system when facing this scenario.

The latter involves necessarily a layer of market modelling which, ultimately, can be expressed under the form of a tractable ***optimization problem***.

The former “scenario builder” was designed with a concern for openness, that is to say make it possible to use different ***data pools***, from “ready-made” time-series[33] to entirely “Antares-generated” time-series[34]

The figure below describes the general pattern that characterizes Antares simulations.

[33] In the case of the PLEF study, the climate dependant time series are provided to the model (PECD2.0).

[34] For availability of thermal plants

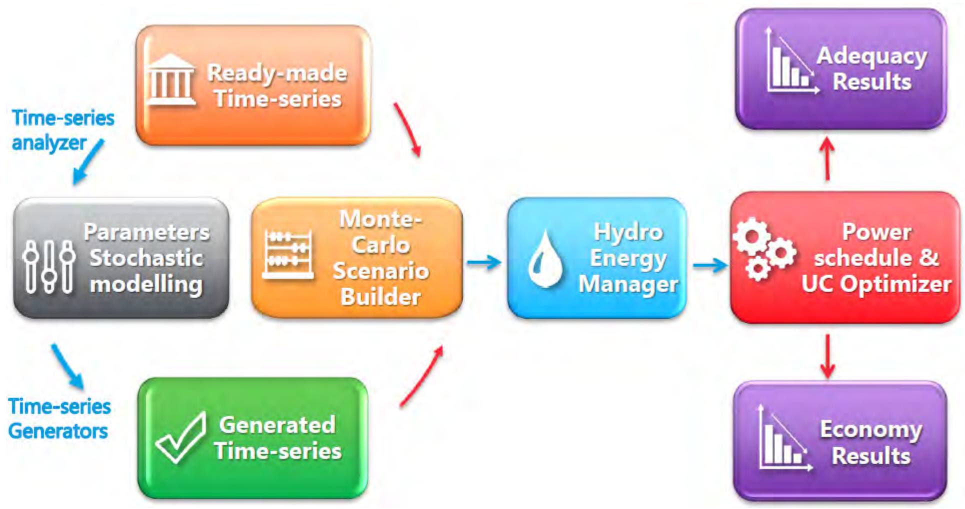


Figure 49 Characterization of Antares simulations

Time-series analysis and generation

When ready-made time-series are not available or too scarce (e.g. only a handful of wind power time-series) for carrying out proper MC simulations, the built-in Antares time-series generators aim at filling out the gap. The different kinds of physical phenomena to model call for as many generators:

- The daily thermal fleet availability generator relies on the animation of a most classical three-state Markov chain for each plant (available, planned outage, forced outage)
- The monthly hydro energies generator is based on the assumption that, at the monthly time scale, the energies generated in each area of the system can be approximated by Log Normal variables whose spatial correlations are about the same as those of the annual rainfalls.
- The hourly wind power generator is based on a model [5] in which each area's generation, once detrended from diurnal and seasonal patterns, is approximated by a stationary stochastic process.

The different processes are eventually simulated with proper restitution of their expected correlations through time and space. The identification of the parameters that characterize at best the stochastic processes to simulate can be made outside Antares but this can also be achieved internally by a built-in historical time-series analyzer.

Economy simulations

When simulating the economic behaviour of the system in a "regular" scenario (in that sense that generation can meet all the demand), it is clear enough that the operating costs of the plants disseminated throughout the system bear heavily on the results of the competition to serve the load. As known, the most simple way to model the underlying market rationale is to assume that competition and information are both perfect, in which ideal case the system's equilibrium would be reached when the overall operating cost of the dispatched units is minimal.

Altogether different is the issue of the time-frame to use for the economic optimization: realism dictates that optimization should neither attempt to go much further than one week (letting aside the specific case of the management of hydro resources) nor be as short-sighted as a one-hour snapshot.

Put together, these assumptions lead, for economic simulations, to the formulation of a ***daily/weekly linear program***, whose solution could be found using the standard simplex algorithm[35].

For each area of the system, the main outcomes of economy simulations are the estimates at different time scales (hourly, daily, weekly, monthly, annual) and through different standpoints (expectation, standard deviations, extreme values) of the main economic variables:

- Area-related variables: operating cost, marginal price, GHG emissions, power balance, power generated from each fleet, unsupplied energy, spilled energy.
- Interconnection-related variables: power flow, congestion frequency, congestion rent (flow multiplied by the difference between upstream and downstream prices), congestion marginal value (CMV - decrease of the overall optimal operating cost brought by 1MW additional transmission capacity).

Grid modelling

The tool offers different features which, combined together, give a versatile framework for the representation of the grid behaviour.

- Interconnectors (actual components or equivalent inter-regional corridors) may be given hourly transfer/transmission asymmetric capacities, defined with a one-hour time step.
- Asymmetric hurdle costs (cost of transit for 1MW) may be defined for each interconnector, again with a one-hour time-step.

An arbitrary number of either equality, two-side bounded or one-side bounded linear constraints may be defined on a set of hourly power flows, daily energy flows or weekly energy flows.

This feature enables the modelling of Flow based constraints as presented in chapter 3.2.2 is described in further details in a dedicated document[36].

In parts of the system where no such constraints are defined, power is deemed to circulate freely (with respect to the capacities defined in (a)). In other parts, the resulting behaviour depends on the constraints definition. A typical choice consists in obtaining DC flows by using either PTDF-based or impedance-based hourly linear constraints. Note that the latter is a usually more efficient way to model the grid because it is much sparser than the former. Other constraints may be defined to serve quite different purposes, such as, for instance, the modelling of pumped-storage power plants operated on a daily or weekly cycle.

[35] Yet, since a very large number of weekly simulations are carried out in a row (52 for each MC year, several hundreds of MC years for a session) and considering the fact that many features of the problems to solve may be transposed from one week to the next (e.g. grid topology), it proved very efficient to implement in Antares a variant of the ***dual-simplex algorithm*** instead of the standard algorithm.

[36] https://antares.rte-france.com/wp-content/uploads/2017/11/171024-Rte-Modelling-of-Flow-Based-Domains-in-Antares-for-Adequacy-Studies.pdf

8.2.2 PowrSym

PowrSym is a probabilistic Monte Carlo tool developed by Operation Simulation Associates, Inc., used to model the operation of large interconnected electricity production and transmission systems[37]. The supply may consist of power and heat production units, wind, solar and (pumped) hydro resources. The simulation uses an equal incremental cost computation method to optimally dispatch hydro, thermal and other resources, subject to grid constraints. In principle, PowrSym can model an unlimited number of grid nodes and generation stations. In current practice PowrSym models have been built for up to 1000 grid nodes and 5000 generating stations with 100 or more generating units per station. The base optimizing periods are weeks or months, with the possibility to use different time steps, e.g. one hour or 10 minutes.

Input Data

The input for PowrSym consists of two parts: time series data, and description of generator and grid characteristics. Time series data include loads, solar resources, wind resources, and certain other data[38]. System characteristics such as generating unit data and grid constraints are not time series but may change by week or season. Input data is prepared using database facilities and/or spreadsheets. While a large amount of data is required to set up a base case, it is very easy to make data changes for various scenarios of the base case.

Planned Maintenance Schedule

PowrSym may accept a planned maintenance schedule as input, or may use an internal maintenance scheduling algorithm to scheduled required planned maintenance optimally, or a combination of two. The planned maintenance scheduler produces an output file for use in other models or to maintain consistency across study scenarios.

Treatment of uncertainties by using Monte Carlo Scenarios and Climate Dependent Time Series

PowrSym uses a Monte Carlo simulator to include the effects of uncertainties on generating unit availability, transmission link capacity, and variants in loads and hydro, solar and wind availability. These may be used in combination with pre-defined climate dependent time series. In flow-based grid mode, Monte Carlo draws are used to select the flow-based equations by date. A specified number of scenarios, driven by random number selection, are selected for simulation.

Spinning and Operating Reserve

PowrSym features a detailed model of spinning and operating reserve with a variety of specification methods and constraints on the reserve contributions of individual generating units. Spinning Reserve Requirements must be met by un-dispatched capacity of on-line generating units. Operating reserve includes spinning reserve plus off-line quick-start generating units. Operating and spinning reserve requirements may be specified for any combination of system, transarea, and control areas Reserve requirements maybe specified as a constant amount, a percent of load, the largest on-line unit, or some combination of these amounts.

[37] The PowrSym tool also includes an detailed module to model supplies, transport and storage of different fuels

[38] PowrSym also has many options to model various types of demand side flexibilities

The contribution of each generating unit to reserves can also be controlled. A non-firm unit does not contribute to reserves, a firm unit does. A quick-start unit contributes to operating reserves while off-line. An upper bound may be placed on a unit's contribution thus limiting its contribution when partially dispatched during low load periods. A lower bound may be placed on a unit's contribution to reserves effectively preventing the unit from being fully dispatched unless reserve constraints must be violated. A summary report of spinning reserve violations is produced.

Hydro Scheduling

PowrSym respects the reservoir constraints of each hydro station. Reservoir constraints are specified as maximum level, minimum level, hourly inflow, and required levels at the beginning and ending of the simulation period (week or month). The model will allocate water and pumping across the simulation period, respecting reservoir levels and system requirements. The PowrSym hydro prescheduler will schedule the hydro generation and pumping across the period to levelize the loads in the area where the hydro is located. This pre-schedule may be left in place for the thermal optimization or the hydro thermal optimization may reschedule the hydro in a cost-optimal manner. For adequacy studies, PowrSym will skip the computationally intensive hydro-thermal optimization for periods where unserved energy is below a specified level.

Hydro Thermal Optimization

The hydro thermal optimization schedules the hydro and the thermal resources across the period (week or month) to minimize production costs and unserved energy in the system. The thermal optimization creates a marginal cost curve for each hour of the period. The hydro generation and pumping is then scheduled against the array of hourly marginal cost curves to minimize total system costs, by using the so-called value of energy (water) method. This generally finds a more optimal hydro schedule than the pre-schedule going against only the loads, but is computationally intensive.

Final Optimization

PowrSym optimizes the unit commitment and dispatch of the thermal units using the method of equal incremental cost. The marginal cost for each hour is determined and units with operating cost less than the system marginal cost can be expected to be at full output during the hour. Units with higher marginal cost may be either offline or partially dispatched. The equal incremental cost theory applies not just to generating units, but also to interaction between the system areas subject to the grid constraints. For example, two interconnected areas will have the same marginal cost unless the link between the areas is at capacity. The grid model may be one or some combination of three methods. The three grid methods used are the NTC method, the PTDF method, and the Flow-Based method. The model respects the power curve, heat rate curve, ramp rates, minimum up times, and minimum down times of the generating units. Generating unit costs include fuel cost, operation and maintenance cost, and emissions-related costs. Wind and solar stations may be treated as either must-take stations or optionally curtailment can be allowed when necessary to meet minimum loads. The thermal optimization includes a robust operating and spinning reserve model.

Grid Model

PowrSym includes three distinct grid models which may be used individually or in combination allowing different models for different areas of a large system. The Net Transfer Capability (NTC) model allows free flows between the areas limited only by link capacities, wheeling charges, hurdle costs, and link losses. The Power Transfer Distribution Factor (PTDF) model utilizes transfer factors between each area and the defined centre area. Internally the logic expands the transfer factors array to define the factors for exchange between each area and each other area. The third model is an implementation of the flow based market coupling method used in CWE and uses constraint equations based on the net positions of selected areas to further bound the NTC model based on the flow-based model.

The grid model has three methods for the priority of scheduling flows. The first method schedules power flows incrementally from the surplus areas to the areas with the largest unserved energy in each hour. This method will tend to levelized unserved energy across the areas and results in minimum total unserved energy for the system. The second method is the opposite of the first, it schedules power flows incrementally from the surplus areas to the areas with the least unserved energy. The second method tends to concentrate the unserved energy in a few areas and minimizes loss of load hours but generally results in an increase of both system unserved energy and costs. The standard method combines the first method with some cost factors in an attempt to minimize total system costs.

Combined Heat and Power Stations (CHP)

While the district and industrial heat requirements are often represented simply as minimum generation requirements on selected stations, PowrSym offers a fully integrated and optimized CHP model. In CHP mode, a time series of hourly heat loads are specified for each defined heat area and both CHP and heat boiler stations are assigned to each area. The heat rate functions for each CHP station are functions of both the electrical and heat loading of the station. The CHP model is fully integrated into the hydro-thermal-grid optimization resulting in a global optimum for serving both the electrical and heat loads. The PowrSym output reports include costs, fuel consumption and emissions associated with heat production.

CWE flow based calculations in PowrSym

PowrSym is able to incorporate the mechanism of the Flow-based Market Coupling as applied in the CWE FB market coupling in the Monte-Carlo economic dispatch optimisation.

- **Selection of the Flow-based domains**

On forehand each day of the reference year 2018/2019 is categorised based on the season, day of the week, French load, German wind generation, and German solar PV generation. Based on this category a set of flow based domains and the chances for a specific domains are determined for each day. During the (Monte-Carlo) simulations one of the pre-selected domains is chosen with a weighted draw.

- **FB domains in PowrSym**

A Flow-based domains consist of 24 lists of constrains, one for each hour, which reflects the physical network limitations. The constrains in one list describe together the space for exchange between the four CWE zones. In the simulations with Flow Base domains the tool selects for each hour a corresponding list and optimize the flow with the given space or exchange. This in contrary to the non-

Flow Based calculations which is uses fixed values for the interconnector capacities. The Flow-Based domains might both be less restricting and more restricting depending than the fixed interconnector capacities depending on the used Flow-based domains and the direction and magnitude of the market power flows.

Reporting

PowrSym produces detailed output reports by hour, day, week, month, and year. Output results include system reliability measures such as ENS and LOLE, emissions totals, fuel costs, fuel consumption, and other cost factors. Output reports include files designed for input into database and spreadsheet models allowing flexibility in the preparation of charts and graphics.

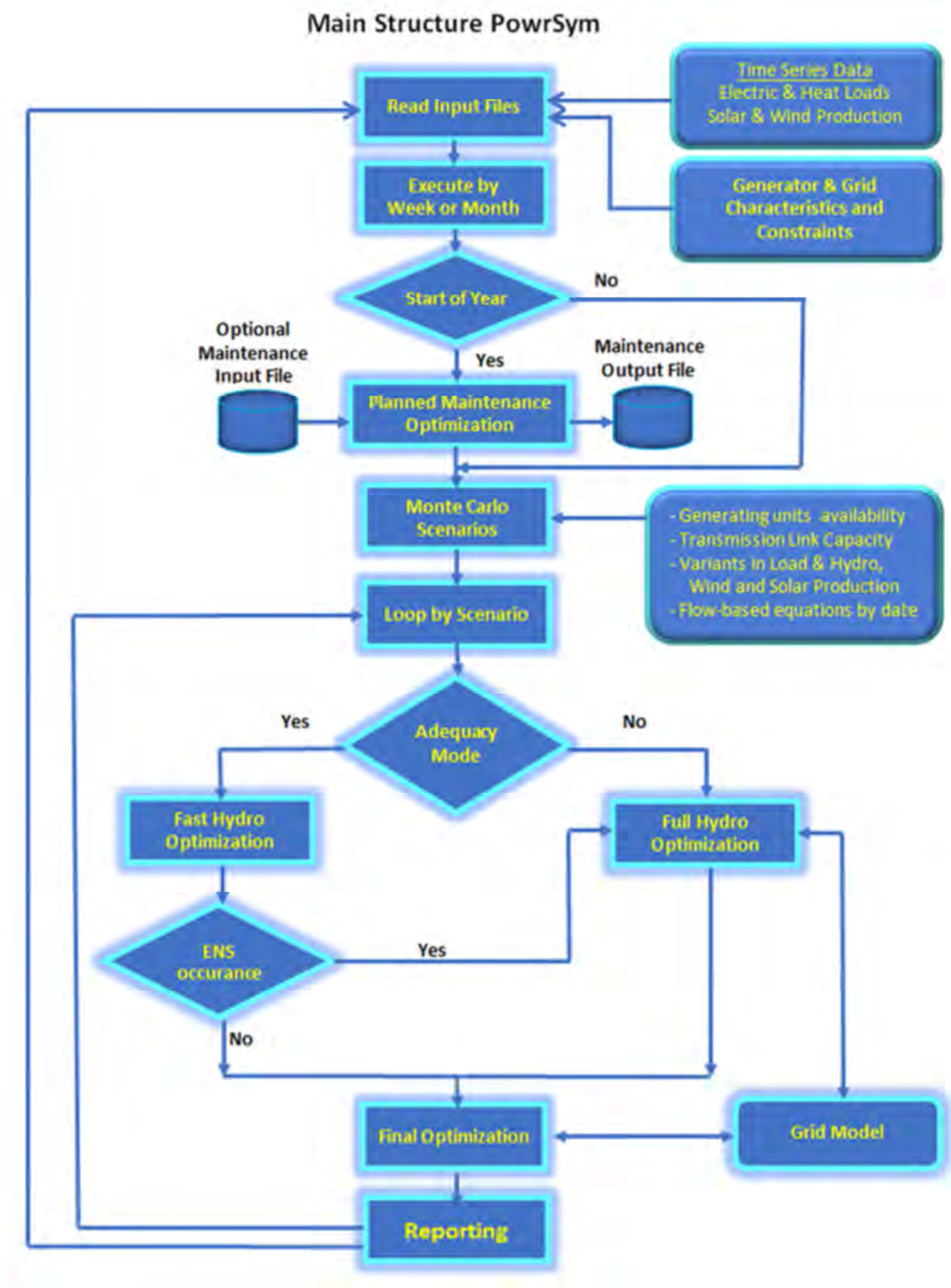


Figure 50 Main structure of PowrSym

8.2.3 AmpFlex

The flexibility model was developed by Amprion and is a dispatch model based on cost minimization. It is formulated as a linear problem with an hourly resolution. Assuming a competitive situation with adequate anticipation by market participants, dispatch of generation units and flexibilities are determined simultaneously through optimization in the flexibility model. That leads to an operation of cost efficient generation units and flexibilities to cover the residual demand, i.e. total system minus infeed from variable RES. The model is implemented in Matlab and uses the CPLEX Solver.
The objective function minimizes the total costs over the considered time period T:

$$min \sum_{t \in T} [cost_t^{gen} \cdot prod_t^{gen} + cost_t^{flex} \cdot prod_t^{flex}]$$

Where $prod_t^{gen}$ and $prod_t^{flex}$ are decision variables.

The production of generation units and flexibilities has to equal the total electricity demand plus load mode of flexibilities and curtailment of intermittent RES:

$$prod_t^{gen} + prod_t^{RES} + prod_t^{flex} = dem_t + dem_t^{flex} + curt_t^{RES} \quad \forall t \in T$$

The marginal costs of the most expensive unit needed to satisfy the demand restriction determine the market price, which is reflected by the shadow price of this constraint.
The curtailment of RES in a given timestep may not exceed the RES infeed in the corresponding timestep:

$$curt_t^{RES} \leq prod_t^{RES} \quad \forall t \in T$$

Flexibilities are modelled through further restrictions. DSF is modelled as a virtual storage, which means that the potential power production $prod_t^{flex}$ (source mode) and power consumption dem_t^{flex} (load mode) are subject to time-dependent potentials:

$$prod_t^{flex} \leq prod_t^{flex,pot} \quad \forall t \in T$$

$$dem_t^{flex} \leq dem_t^{flex,pot} \quad \forall t \in T$$

Moreover, it is considered that there is a limited duration for the shift of load in case of DSF. D denotes the set of days d. Accordingly, the power is shifted within the respective day, so that the sum of the produced power equals the sum over the consumed power. In the model it is also possible to consider a limited duration for the shift of load smaller than 24 hours.

$$\sum_{z=1+(24 \cdot [d-1])}^{24+(24 \cdot [d-1])} prod_z^{flex} = \sum_{z=1+(24 \cdot [d-1])}^{24+(24 \cdot [d-1])} dem_z^{flex} \quad \forall d \in D$$

The time-dependent potentials are subject to the underlying load time series, which limits in both directions the power production and consumption of DSF.

$$prod_t^{flex,pot} = p \cdot \left[load_t - \min_d(load)\right] \quad \forall t \in T$$

$$dem_t^{flex,pot} = p \cdot \left[\max_d(load) - load_t\right] \quad \forall t \in T$$

Where p, expressed in %, denotes the share of the electrical load that is assumed to be flexible. As the duration of a load shift is limited to one day, the potential is subject to the minimum and maximum load of the respective day.

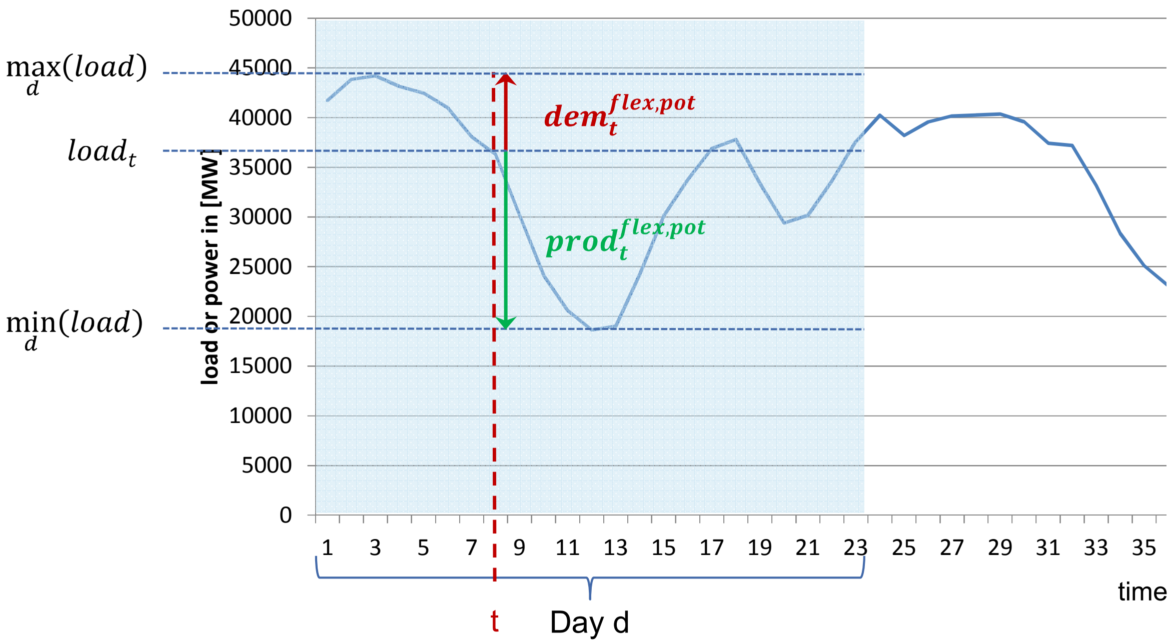


Figure 51 Share of the electrical load that is assumed to be flexible according to AmpFlex

In case of physical storages like pumped or battery storages the power production (source mode) and power consumption (load mode) is subject to the installed capacities and maximum storage levels.

Main outputs of the DSF model are the operation of generation units and flexibilities, storage filling levels and hourly market clearing prices (MCP). In order to assess the economic profitability of flexibilities (and generation units) the revenues and contribution margins are computed:

$$Contribution\ margin = \sum_{t=1}^{T} Revenue_t - cost_t^{flex} \cdot prod_t^{flex}$$

$$= \sum_{t=1}^{T} (MCP_t - cost_t^{flex}) \cdot prod_t^{flex}$$

The contribution margin, expressed in €/MW, will cover the fixed costs. Accordingly, in the case that the computed contribution margin exceeds the annual fixed costs the respective flexibility is considered as profitable and vice versa.

The following Table 12 summarizes the assumptions regarding the main parameters for the modelling of DSF in this study:

	DSF Ind & Business	DSF Household	Flexible Biomass**
Activation costs [€/MWh]	300	40	5
Max. shift duration [h]	8	4	12
Annual fixed costs [€/MW]*	1690	510	3900

* Depreciation period: 10 years for biomass and 20 years for DSF, interest rate: 6 %

** Only considered for Germany, fixed costs after flexibility premium

Table 12 Assumptions regarding the main parameters for the modelling of DSF

Moreover, in the DSF model costs of 9999 €/MWh for load curtailment are considered per country. Corresponding scarcity prices consequently reflect capacity payments in countries with capacity remuneration in place, e.g. France.

8.3 FB modelling details

The flow-based method implemented in day-ahead market coupling uses Power Transfer Distribution Factors (PTDF) factors that make it possible to model the real flows on the lines based on commercial exchanges between countries. PTDF[39] division factors allow to estimate the real flow that are to be expected in the different grid lines as a function of the commercial exchanges to be settle in the market between countries. Typically energy flows are unevenly distributed over the different paths between the different areas considered when there is a commercial exchange, e.g. of 100 MW considered between two given areas A and C, as shown below:

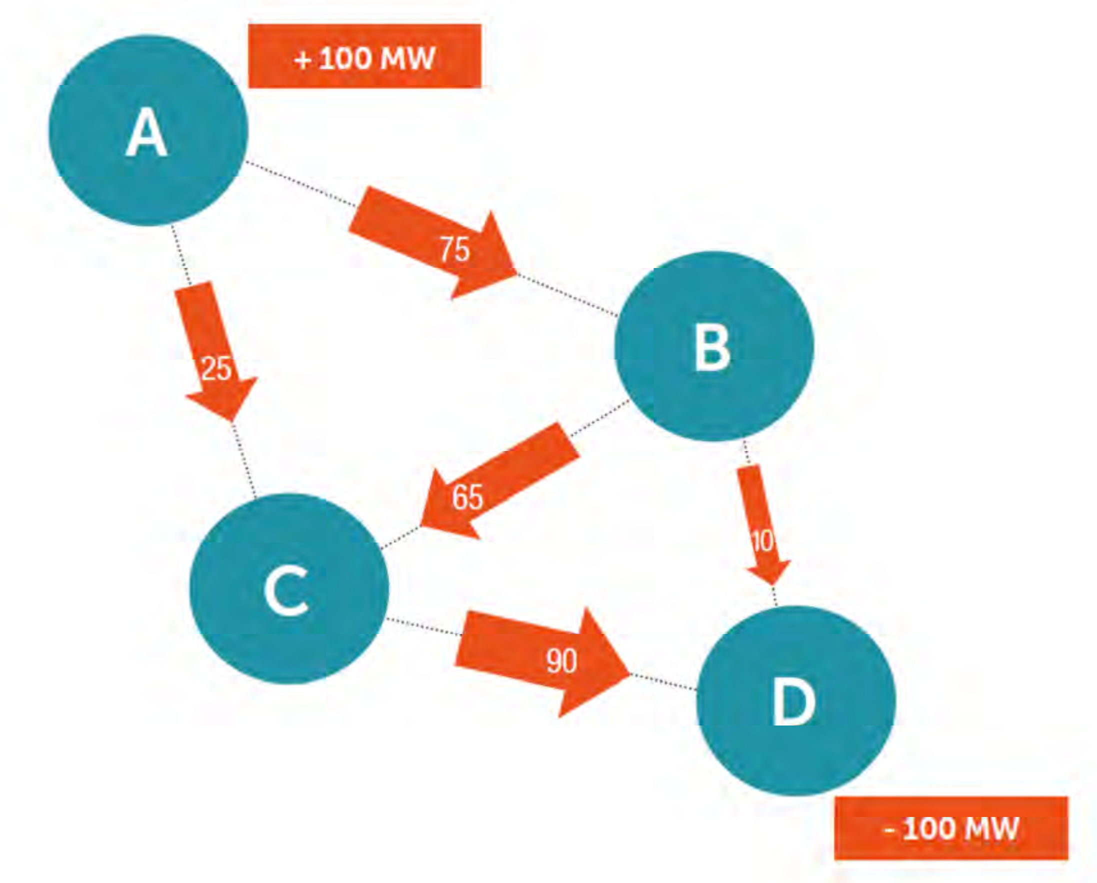


Figure 52: Systematic example for the difference between market flow and the real physical flows taken into consideration when using fb modelling

EXAMPLE: Commercial exchanges between two countries can generate physical flows through other borders. Electricity flows via the path with the least impedance (resulting physical flows from an energy exchange of 100 MW between 2 zones.

The PTDF factors of this example determine that:

- **75% of the injection from A goes to B and 25% of the injection from A goes to C**
- **65% of the injection from B goes to C and 10% of the injection from B goes to D**
- **Finally the total injection coming into C is 25% + 65% = 90% which goes to D**

[39] PTDF: Power Transfer Distribution Factor

Since the commercial exchange of 100 MW is a between A and D in the case above, i.e. exchange (A → D), the PTDFs for each grid element is referred as PTDF(A → D). In the example above

Commercial Exchange (A → D)	Grid Element 1	Grid Element 2	Grid Element 3	Grid Element 4	Grid Element 5
$PTDF_{(A \rightarrow D)}$	25%	75%	65%	90%	10%

A matrix of exchanges vs grid elements can therefore be defined (only A → D numbers shown for simplicity here)

PTDF	Grid Element 1	Grid Element 2	Grid Element 3	Grid Element 4	Grid Element 5
$PTDF_{(A \rightarrow B)}$	-	-	-	-	-
$PTDF_{(A \rightarrow C)}$	-	-	-	-	-
$PTDF_{(A \rightarrow D)}$	25%	75%	65%	90%	10%
$PTDF_{(B \rightarrow C)}$	-	-	-	-	-
$PTDF_{(B \rightarrow D)}$	-	-	-	-	-
$PTDF_{(C \rightarrow D)}$	-	-	-	-	-

For each hour of the year, the impact of energy exchanges on each line/element (also called 'branch') is calculated taking into account the N-1 criteria. A critical 'branch' is a physical element of the grid, which has reached its maximum transmission capacity and therefore constrains the total flow of the system around it.

In typical situations, energy exchanges lead to many constraints. Those constraints form a domain of possible maximum energy exchanges between the CWE countries (this is called the flow-based domain).

Looking at the system above, and e.g. at the possible commercial exchanges between A → B and A → C, the basic equations defining the condition of each of the interconnections in the system above as critical branch is given by the following type of equation

For each of the 5 interconnections shown above:

$$PTDF(A \rightarrow B) * Exchange(A \rightarrow B) + PTDF(A \rightarrow C) * Exchange\ (A \rightarrow C) \leq RAM$$

, where RAM is the Remaining Available Margin (RAM) of each line.

Each CB can be drawn on the plane defined by the relevant exchanges between any two areas of the system considered (in this case the plane of Exchange (A → B) vs Exchange (A → C) **as a line** (each of the dotted lines in the Figure below).
The set of all intersecting, 'constraining' elements, i.e. all relevant CBs define a polygon (connected grey lines) or so-called FB domain, as depicted schematically below.
The coloured squares correspond to the so-called Available Transfer Capacity (ATC) domains, which provide the Available Transfer Capacity considering long-term nominated power flows and NTCs in a traditional NTC non flow-based scheme.

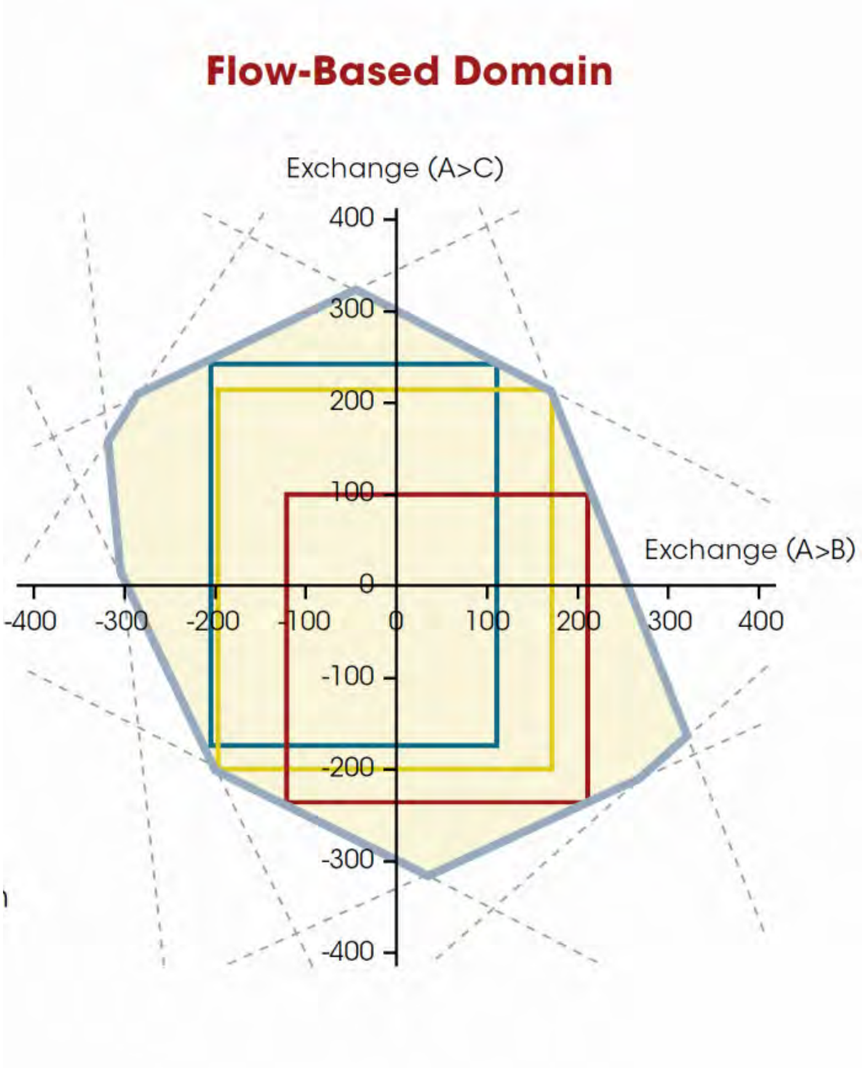


Figure 53: Example of flow-based domain (see CWE Flow-Based[40])

Thus flow-based domains are typically constructed based on ‘critical branches’ (lines or grid elements – hereafter referred as CBs), taking account: 1) the impact of an outage on these CBs, 2) a flow reliability margin (FRM) on each CB and 3) possibly ‘remedial actions’ that can be taken after an outage to unload part of the concerned CB.

Furthermore in the PLEF assessment, the planned grid reinforcement up to 2018/19, have also been considered. An overview table of these reinforcements is given below:

[40] http://www.elia.be/nl/producten-en-diensten/cross-border-mechanismen/transmissiecapaciteit-op-de-grenzen/flow-based-marktkoppeling-centr-w-europa

TSO	Information
Elia	Upgrade thermal rating of lines - update to high temperature conductor BRABO I: Lines Doel-Zandvliet + 2nd PST at Zandvliet New grid topology at Doel – Mercator – Horta
TenneT NL	New line between Amprion and TenneT NL Upgrade thermal rating of lines on the 380 kV ring Upgrade thermal rating of lines Borssele – Geertuidenberg New grid topology Krimpen aan de IJssel – Diemen – Oostzaan
Amprion	Change due to new station of Blatzheim New line between Amprion and TenneT DE New line between Amprion and TenneT NL Upgrades from 220kV to 380kV Updated line rating Switch of machine line Switch from Roki to St. Peter New transformers Replacement of transformer
APG	Upgrade of the existing 220 kV line Kaprun -Tauern to 380 kV 3rd 380/220 kV transformer in St. Peter 3rd 380/220 kV transformer in Obersielach Upgrade of the existing 220 kV line Ernsthofen – Weißenbach using high temperature conductors
TransnetBW	New substation with new lines and transformers; changed Imax New topology
TenneT DE	Closing bus bar coupler New Lines New nodes due to new grid topology, new lines Lines out of operation New Trafo Trafo in operation Update of rated voltage
50Hertz	New transformers New lines

8.4 Net Transfer Capacities

Border/Boundary	NTC 18-19	NTC 23-24	Border/Boundary	NTC 18-19	NTC 23-24
AT-CH	1200	1700	DE-FR	3000	3000
AT-DE	5000	6500	DEkf-DE	400	400
BE-DE	0	1000	DE-LUG	1000	1000
BE-FR	1800	2800	DE-LUv	1300	1300
BE-LUB	380	380	DE-NL	3950	4450
BE-LUG	300	300	FR-BE	3300	4300
BE-NL	1400	2400	FR-CH	3150	3700
CH-AT	1200	1700	FR-DE	3000	3000
CH-DE	4600	4600	FR-LUF	380	380
CH-FR	1300	1300	LU-BE	180	180
DE-AT	5000	6500	LU-DE	1000	1000
DE-BE	0	1000	LUv-DE	1300	1300
DE-CH	2700	2700	NL-BE	1400	3400
DE-DEkf	400	400	NL-DE	3950	4450

Table 13 Net Transfer Capacities[41]

[41] Please note: During the course of the study, German and Austrian NRAs agreed on minimum long-term capacities of min. 4.9 GW for the DE/AT border at 1st October 2018.

8.5 Alignment of tools

The following graph illustrates that the simulation results (LOLE) from Antares and PowrSym are both similar in magnitude and trend for the base case as well as for all the sensitivities in the study.

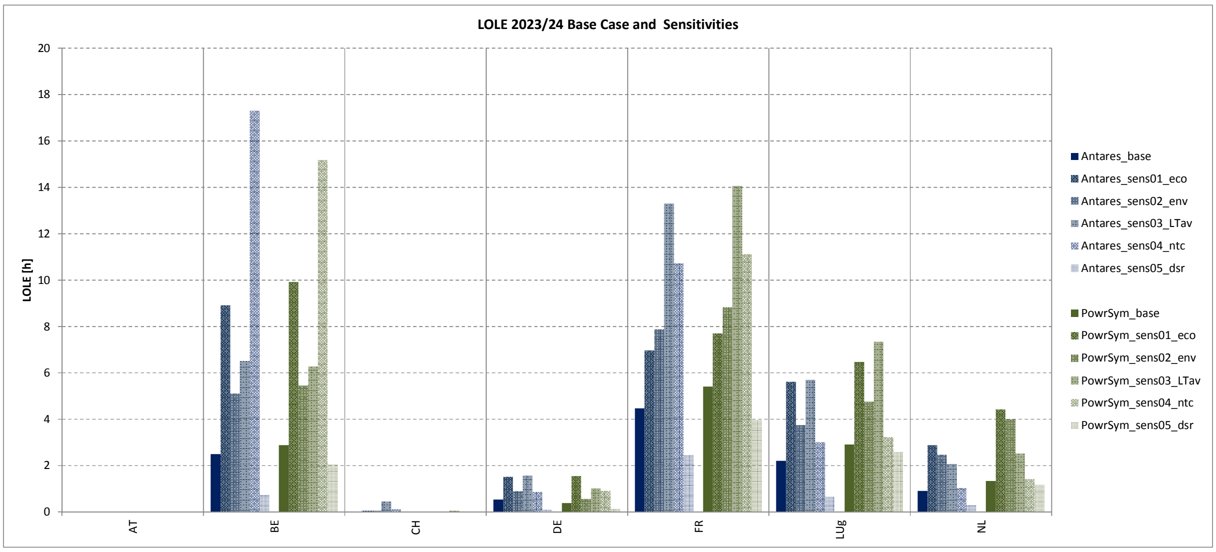


Figure 54 LOLE 23/24 Base Case and Sensitivities

8.6 Glossary

CCGT	Combined Cycle Gas Turbine
CHP	Combined Heat and Power
CWE	Central West Europe (including AT, BE, DE, FR, LU and NL)
DCM	Decentralized capacity market
DSR	Demand Side Response
EENS	Expected Energy not Served
ENS	Energy not Served
EOM	Energy-only-market
FBMC	Flow-Based Market Coupling
GAA	Generation Adequacy Assessment
GR	Grid Reserve
IEA	International Energy Agency
LOLE	Loss of Load Expectation
MAF	Mid-term Adequacy Forecast (ENTSO-E annual report)
MILP	Mixed-Integer Linear-Programming
NRA	National Regulatory Authority
NTC	Net Transfer Capacity
OCGT	Open Cycle Gas Turbine
PECD	Pan-European Climate Database
PEMMDB	Pan-European Market Modelling Database
PLEF	Pentalateral Energy Forum (including AT, BE, CH, DE, FR, LU, NL)
RAM	Remaining Availability Capacity
RoR	Run of River
ROW	Rest of the World
SR	Strategic Reserve
TSO	Transmission System Operator
TYNDP	Ten Year Network Development Plan
WEO	World Energy Outlook

8.7 Contact

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