Umbrella Project

Final Report

Innovative tools for the future coordinated and stable operation of the pan-European electricity transmission system

Project supported by the European Commission under the 7th Framework Programme

Preface

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This final report contains the key results of the research carried out within the scope of the UMBRELLA Project. This project has received funding from the European Union's **Seventh Framework Programme** for research, technological development and demonstration under grant agreement no 282775.

Full project title:
Toolbox for Common Forecasting, Risk Assessment and Operational Optimisation in Grid Security Cooperations[1] of Transmission System Operators (TSOs)

THEME ENERGY.2011.7.2-1: Innovative tools for the future coordinated and stable operation of the pan-European electricity transmission system

All public project deliverables and publications can be found on the project website: **www.e-umbrella.eu** (until March 2021) and on **www.openaire.eu** (indefinitely). This final report serves as a summary of the research carried out in the period from 1 January 2012 until 31 December 2015, and therefore does not contain all scientific details. A list of references provides for further reading and in-depth insight into this subject matter.

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*In December 2013 UMBRELLA was awarded the **"EEGI Core" label***

EEGI
EUROPEAN ELECTRICITY GRID INITIATIVE
- CORE -

[1] *Coordinating organisations, also termed "cooperations"*

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List of Abbreviations

AC	Alternating Current
CGMES	Common Grid Model Exchange Standard
CIM	Common Information Model
DACF	Day-Ahead Congestion Forecast
DC	Direct Current
DSO	Distribution System Operator
ENTSO-E	European Network of Transmission System Operators for Electricity
EOPF	Enhanced Optimal Power Flow
FACTS	Flexible AC transmission system
FP7	Seventh Framework Programme
HVDC	High-voltage Direct Current
IDCF	Intraday Congestion Forecast
IEEE	Institute of Electrical and Electronics Engineers
KPI	Key Performance Indicator
NRA	National Regulatory Authority
OPF	Optimal Power Flow
PATL	Permanent Admissible Transmission Loading
PST	Phase-Shifting Transformer
PV	Photovoltaic
R&D	Research and Development
RES	Renewable Energy Sources
RG CE	ENTSO-E Regional Group Continental Europe
RSCI	Regional Security Coordination Initiative
TATL	Temporary Admissible Transmission Loading
TC	Test Case
TSC	TSO Security Cooperation
TSO	Transmission System Operator
UCTE DEF	Union for the Co-ordination of Transmission of Electricity Data Exchange Format

Executive Summary

Transmission system operators (TSOs) are facing new challenges in day-to-day grid operation and operational planning. The security issues affecting the pan-European electricity transmission system will become more and more challenging in the coming years due to:

- The growing contribution of less predictable and more variable renewable energy sources (RES) such as wind and photovoltaic (PV) generation;
- The need for the coordination of controllable devices such as phase-shifting transformers (PSTs), high-voltage direct-current (HVDC) lines and flexible alternating-current transmission systems (FACTSs);
- Partially controllable electricity demand;
- The increasing difficulty of building new transmission lines;
- The gradual integration of national markets into one common European electrical energy market;
- Market mechanisms not covering certain aspects of system security, leading to high deviations between scheduled and physical flows in terms of time, direction and volume.

Forecasting and uncertainty

As a consequence of these trends, meteorological forecasting errors may lead to unforeseen violations of operating limits and trigger cascading outages in stressed-system situations. These new constraints, but also new opportunities, result in more complex operational planning and transmission system operation, take the system closer to its operational limits, cause remedial actions to be taken more frequently in order to relieve congestion and, as a result, make it necessary to revise operational rules and procedures.

Against this backdrop, the tools for security assessment that are currently available and established will no longer be suitable for TSOs to make the right decisions. To be fully efficient, emerging Regional Security Cooperation Initiatives (RSCIs) need a new generation of tools to allow the different TSOs to increase coordination and react more quickly to the growing complexity of operational planning and system operation.

In order to mount a common response to this situation, nine TSOs[2] from Central and Central-Eastern Europe, organised within their RSCI, which is named TSO Security Cooperation (TSC), have joined forces with five universities[3] and one research institute[4] to investigate advanced deterministic and probabilistic methods beyond the state of the art to provide a coordinated solution to these increasing challenges in their target area. This research and development project, entitled “Innovative tools for the future coordinated and stable operation of the pan-European electricity transmission system” (UMBRELLA), is supported by the European Union as part of its Seventh Framework Programme (FP7). To cope with the above mentioned challenges TSOs at first have to find an answer to the

[2] Amprion GmbH (Germany), Austrian Power Grid AG (Austria), ČEPS (Czech Republic), Elektro-Slovenija (Slovenia), PSE S.A. (Poland), swissgrid (Switzerland), TenneT TSO B.V. (Netherlands), TenneT TSO GmbH (Germany; Coordinator) and TransnetBW GmbH (Germany).
[3] Delft University of Technology (Netherlands), Graz University of Technology (Austria), ETH Zurich (Switzerland), RWTH Aachen (Germany) and University of Duisburg-Essen (Germany).
[4] FGH - Forschungsgemeinschaft für elektrische Anlagen und Stromwirtschaft e.V. (Germany).

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question: What will be the upcoming system state? This requires the modelling of uncertainties related to RES and load forecasting deviations. Such deviations could be traded in the intraday markets.

This will lead to changes of load flows that need to be anticipated by the TSOs. In addition, deviations that cause load flows into neighbouring control areas have to be regarded as well. In this regard, the UMBRELLA Toolbox goes beyond state of the art by not just looking at one forecast. Instead, a wide range of deviations from the forecast and their probabilities are assessed by applying newly developed methods.

Risk assessment

To allow the system operator to make use of the numerous possible scenarios for the upcoming future, new methods to perform risk-based security assessment must be developed. Such risk assessment will allow the TSOs to answer the question whether the system will be secure. This includes a comparison of the well-known N-1 criterion with risk-based security criteria, taking into

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account both the probability of occurrence and the severity of outages, cascades and violations of operational limits. Additionally, the UMBRELLA Toolbox is capable of assessing additional operational costs that are the consequences of forecast deviations.

Optimisation

Once upcoming system states are known and their severity is assessed, system operators can undertake actions in order to ensure system security. Here, the need for coordination and modern, automated software tools is evident: the complexity of congestion management in transmission systems is growing due to an increase in the amount of congestion and the number of available remedial measures. The enhanced optimal power flow (EOPF) algorithm developed here may relieve TSOs' workload significantly by using deterministic or probabilistic optimisation algorithms that take both uncertainty and risk measures into account.

The UMBRELLA Optimisation Framework aims to provide optimal topological and redispatch measures as well as the curtailment of RES infeed and load-shedding measures by taking into account numerous objectives, such as regulatory restrictions, the cost of redispatch and other factors, ranging from day-ahead operational planning to close-to-real-time operation. This allows remedial measures with long activation times, such as thermal power plants, to be activated well in advance.
Since the methodology used for the probabilistic forecast of the future use of the new system is based on a statistical model, it is important to compile, validate and maintain historical data with which to build the statistical backbone of the system. Based on this methodology, a number of potentially critical scenarios for the future use of system developments can be identified.

UMBRELLA Toolbox

The developed modules are synthesised in the UMBRELLA Toolbox, which offers users the flexibility to apply either individual parts or the complete set of functionalities. By testing the UMBRELLA Prototype on historical test cases (TCs), the general functionalities of the UMBRELLA Toolbox have been validated and key performance indicators (KPIs) attest to the improvement achieved. The applied test system of nine TSOs' control areas includes some 7000 nodes, approx. 3000 branches and around 1400 transformers of which 46 are phase-shifters. Some modules are tested using test systems of the Institute of Electrical and Electronics Engineers (IEEE). For the implementation and further exploitation of the UMBRELLA Toolbox within RSCIs, a stepwise approach is proposed.

As an additional result of the UMBRELLA and iTesla projects, a set of recommendations is provided for stakeholders such as regulators, policymakers, TSOs and the European Network of Transmission System Operators for Electricity (ENTSO-E) to foster the necessary harmonisation of the legal, regulatory and operative framework as well as to allow data exchange so that the innovative software tools developed can be applied by TSOs and within RSCIs.

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Motivation

As part of the fight against climate change, the European Union is aiming to decarbonise its economy. An important aspect is to replace fossil-fuel-based electricity generation with RES such as wind and solar power. Therefore, European energy markets as well as energy grids have to be fit for renewables.

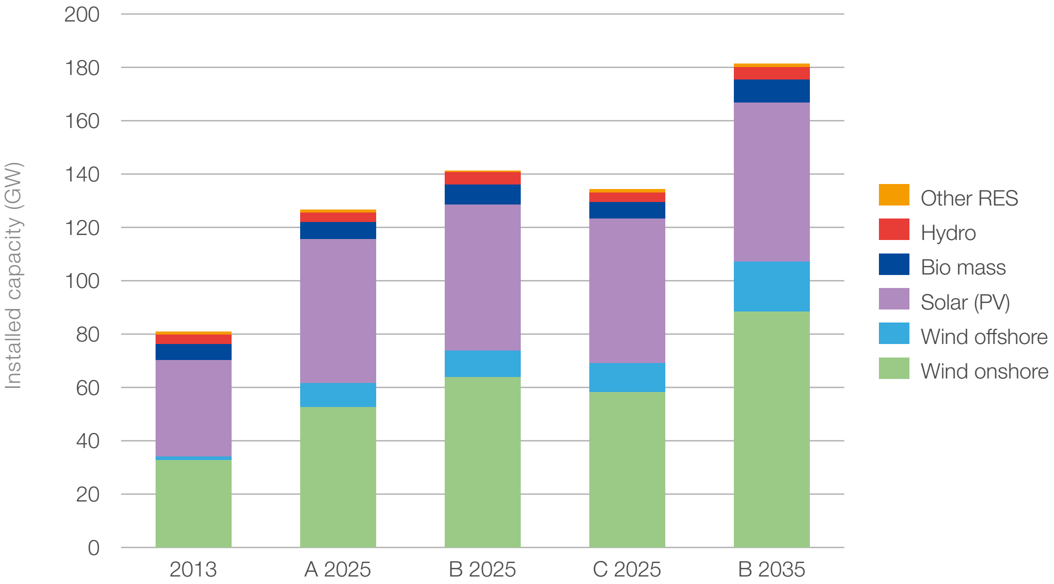

Figure 1: RES increase, based on Germany's grid development plan 2025, 2015 version

As can be seen from the data compiled in the latest available version of the German grid development plan[6] (Figure 1), German RES capacity is expected to grow, even in the most conservative scenario, by more than 50% between 2013 and 2025. Other EU countries are expected to undergo similar developments—partly time-delayed—over the coming years given the EU's ambitions for the so-called Energy Union.
In order to ensure the secure and stable operation of the transmission grid, TSOs predict the load and corresponding generation at a regional level, including forecasts for RES infeed and according to market outcomes the conventional power generation. They also aim at considering load-flow deviations caused by intraday market trades, power plant and grid equipment outages and volatile consumption. Based on these predictions, in the second step of their daily process the TSOs analyse where congestion may occur by taking into account the given capacity and availability of power lines, transformers and other grid elements. The interconnected transmission grid in Continental Europe is severely stressed as a result of the

[6] *Network Development Plan 2025 - Electricity, 1st Draft 2015, p. 29*
http://www.netzentwicklungsplan.de/_NEP_file_transfer/NEP_2025_1_Entwurf_Teil1.pdf

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insufficient harmonisation of regulatory frameworks and market rules in the various countries. More and more frequently in the congestion management process, TSOs identify severe overloading of grid elements by loop flows or transit flows, and this has a major influence on further decision making. Having collected the necessary operational data, TSOs take the available operational measures, such as changes to the network topology and flow-control device settings, to manage power flows within the capability of existing networks. If congestion cannot be relieved by such measures, counter-trade and redispatch have to be considered and implemented. As these measures are expensive and affect the market outcome they need to be kept to a minimum. For all the necessary remedial measures to be available in good time, TSOs aim to establish the most reliable forecast process possible. Operational planning can then take place one day in advance on the basis of those forecasts. This entire process is named the Day-Ahead Congestion Forecast (DACF). Short-term analysis is also constantly undertaken in the form of a so-called rolling Intraday Congestion Forecast (IDCF). This takes place from hours in advance until the end of the day, and monitors and tracks the actual development of the system state. It allows favouring less costly measures and delays the adoption of costly measures until they are guaranteed to be needed.

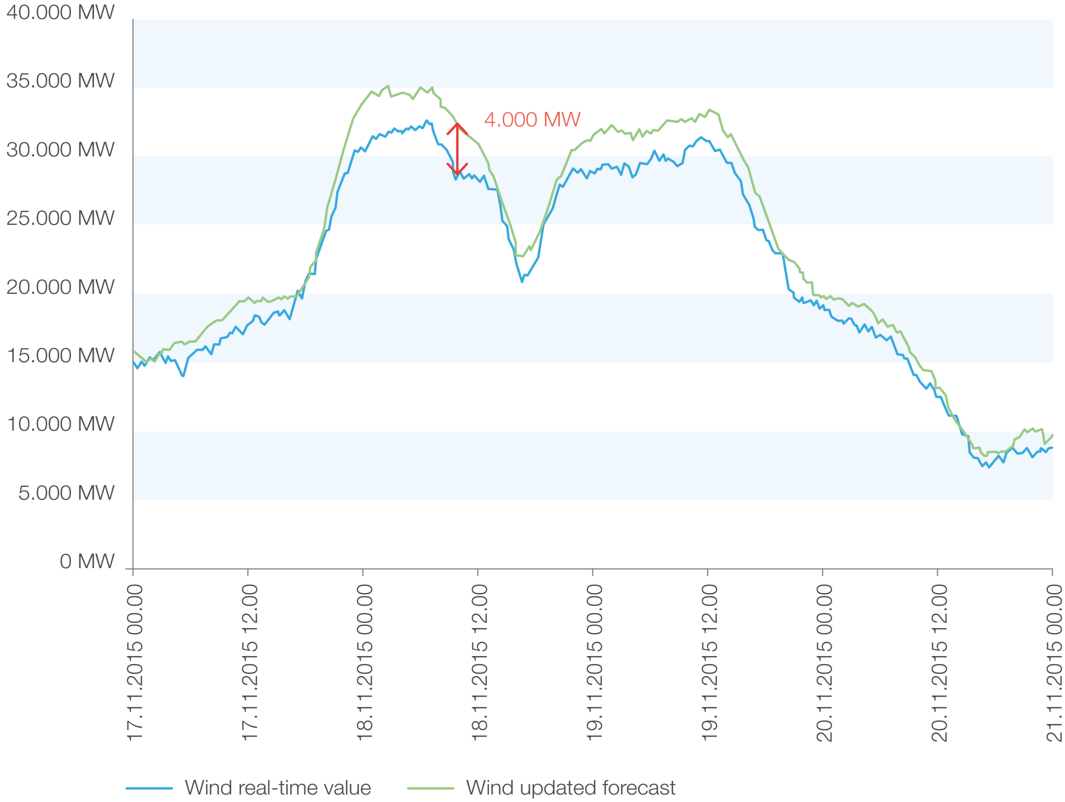

Figure 2: Example TenneT Germany: Wind deviation from forecast

However, the growing proportion of electricity generated by intermittent RES, as well as increasing market-based cross-border flows and related physical flows, are nowadays leading to a significant increase in the uncertainty surrounding the generation of forecasts and the related power flow in the grid.

This is a difficult challenge to face, as the transmission grid is not designed for this purpose and the construction of new power lines will take a number of years. Furthermore, new storage technologies have not yet reached industrial maturity or economic viability.

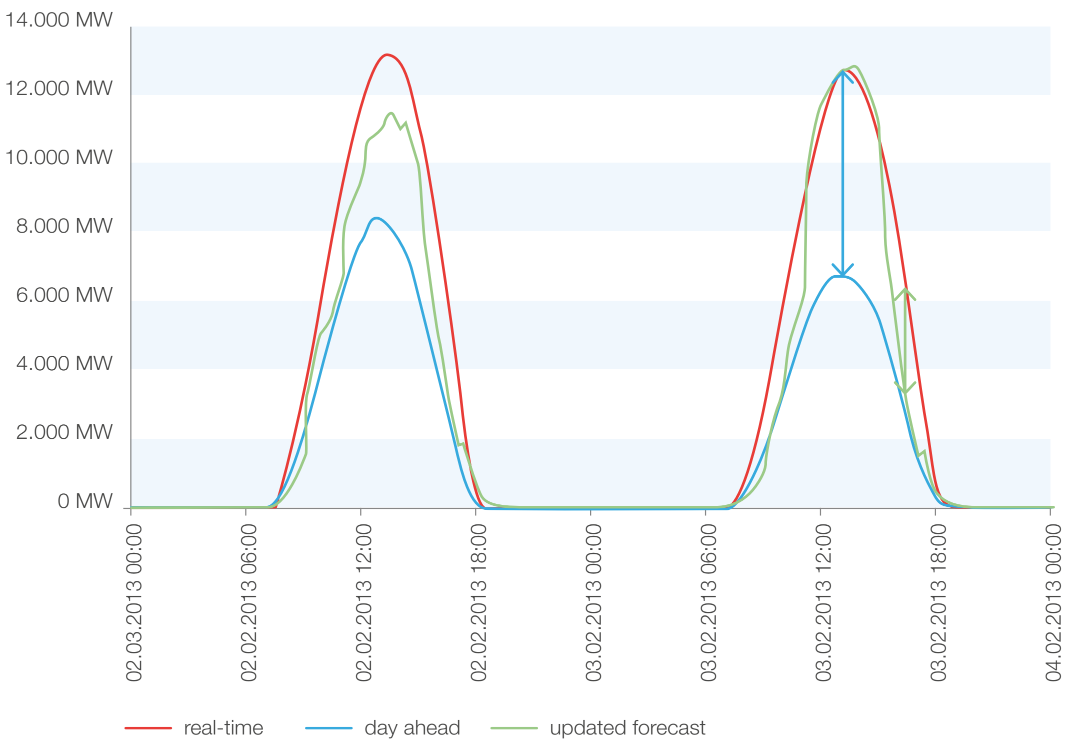

Figure 3: TenneT Germany, PV forecast deviation: fog forecasted, but not occurred (deviation 6000 MW to DACF; 3000 MW to updated forecast)

Especially if wind infeed arrives earlier or later than expected or even falls short of or overshoots the forecasted level of infeed (Figure 2), the load flows in the grid can differ considerably from the predictions. Forecast deviations for PV installations have similar critical effects if fog or clouds unexpectedly shield them from solar radiation or, on the contrary, allow for more infeed than initially expected (Figure 3).

Currently, the DACF, short-term and real-time forecasts are merely deterministic. Uncertainty is considered only implicitly, by means of security margins. As such uncertainty grows due to the increase in volatile RES infeed and intraday electricity market trades, however, the classic deterministic approach for each single control area is no longer sufficient. As can be seen from the example of TenneT, the rise of RES generation capacity (Figure 1) goes hand in hand with the soaring number of TSO interventions needed (Figure 4) to safeguard transmission system operation. Concurrently with this, the incidents to be dealt with by the TSOs will continue to increase in number as well as in duration. Furthermore, European electricity market integration is leading to an increase in the scale of unscheduled cross-border flows, which also require even better multilateral coordination between different TSOs. As most of the uncertain processes involved are taking place on lower voltages in the distribution grid, TSOs can observe only the aggregated behaviour of these processes on the high-voltage grid, which makes it difficult to collect data and to derive relevant information from them.

These challenges reveal the need for automated and multilaterally optimised methods to safeguard the operation of the transmission system and to make optimal use of the existing grid capacity.

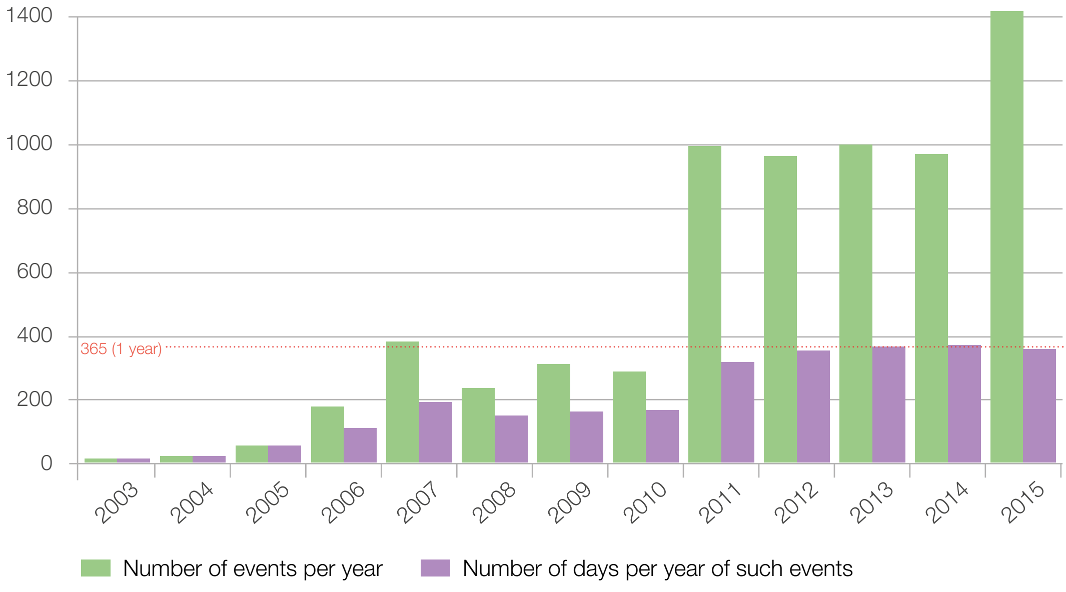

Figure 4: Incidents with counter-measures in the control area of TenneT Germany (excluding voltage/reactive power problems)

Especially in mainland Central Europe as a synchronous area with pre-existing large RES generation facilities, the difference between actual physical flows and market exchanges in the Central Europe synchronous area can be very substantial in time, direction and volume. In search of a holistic approach to the aforementioned TSOs' challenges, nine TSOs[7] from Central and Central-Eastern Europe, organised within their RSCI, named TSC, have joined forces with five universities[8] and one research institute[9] to investigate advanced deterministic and probabilistic methods beyond the state of the art to bring a coordinated solution to these increasing challenges for their control areas (Figure 5).

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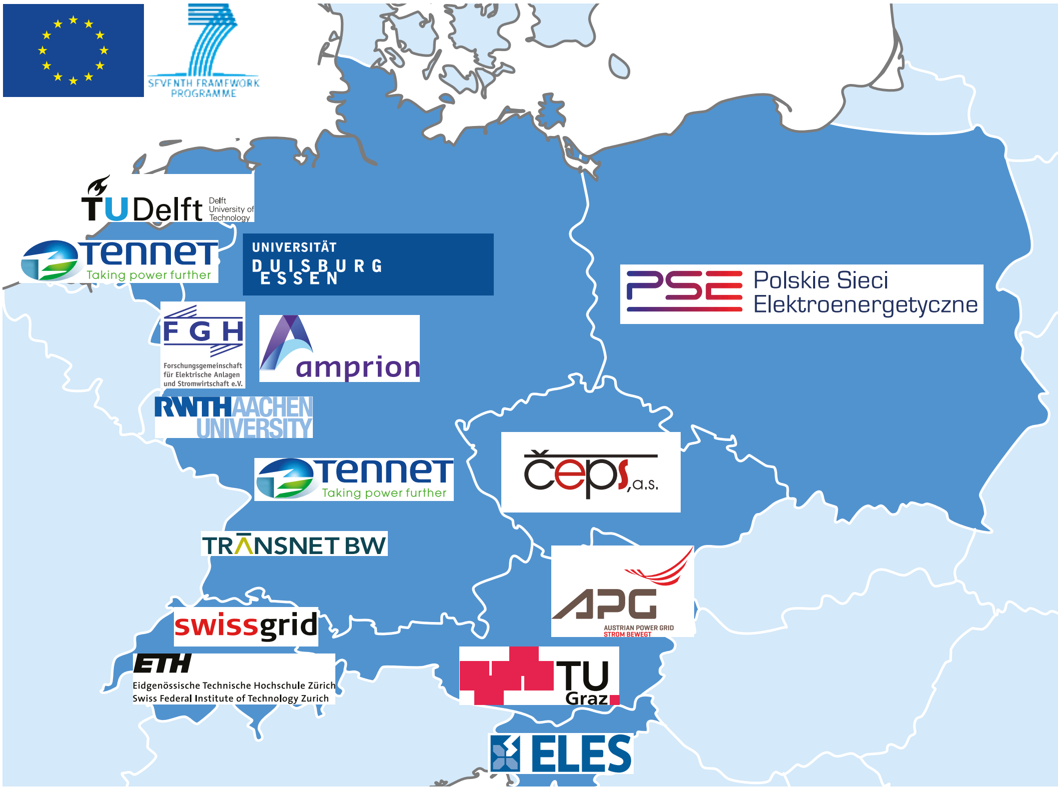

Figure 5: Target area and participants of the UMBRELLA FP7 R&D project

[7] Amprion GmbH (Germany), Austrian Power Grid AG (Austria), ČEPS (Czech Republic), Elektro-Slovenija (Slovenia), PSE S.A. (Poland), swissgrid (Switzerland), TenneT TSO B.V. (Netherlands), TenneT TSO GmbH (Germany; Coordinator) and TransnetBW GmbH (Germany).

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[9] FGH - Forschungsgemeinschaft für elektrische Anlagen und Stromwirtschaft e.V. (Germany).

Methods for improved forecasting, optimisation and risk-based assessment have been successfully developed for the new UMBRELLA Toolbox. The effectiveness of the Toolbox has been demonstrated in tests using the UMBRELLA Prototype, which comprises most of the developed methods.
This report presents an easy digest of the objectives of and rationales behind the UMBRELLA Project, the methods developed for the UMBRELLA Toolbox and the results of the tests carried out using the Prototype. These are then combined with the FP7 sister project iTesla[10] to produce a set of recommendations for the ENTSO-E and other stakeholders such as National Regulatory Authorities (NRAs), policymakers and the power industry. The report concludes with a description of the prerequisites for the safe operation of the pan-European transmission system, including the provision of data of the necessary quality and quantity.

[10] *Innovative Tools for Electrical System Security within Large Area (iTesla)*

Proposed Solutions for TSOs

What will be the upcoming system states?

Will the RES infeed prediction be accurate? If not, how significant will the deviation be?

Modern power systems with a high share of installed wind and solar power capacity rely heavily on accurate forecasts. Unforeseen deviations from the forecasts can lead to insecure system states. However, no forecast is perfect, and this is especially true for these variable energy sources. In addition, if possible deviations from the forecast continue to be ignored, the TSOs cannot prepare for them. The fact that wind and PV power plants are normally connected to subordinate grid levels, which cannot be directly monitored by TSOs, further complicates the process of forecasting and measuring RES infeed.

In order to account for possible deviations from RES infeed predictions and thereby provide TSOs with appropriate foresight, the uncertainty of those predictions needs to be described statistically. Enabling TSOs to leverage this additional uncertainty information requires a level of detail that will allow it to be used in downstream tools.
The UMBRELLA Project therefore models forecast uncertainty for each grid node individually, distinguishing between solar and wind power generation. The objective is to provide TSOs with a probability function at each grid node for wind and solar power forecasting errors (Figure 6).
The estimation of the probability functions is carried out using historical forecast and measurement data. A range of methods has been developed to generate the required information for cases in which these data are not yet available.

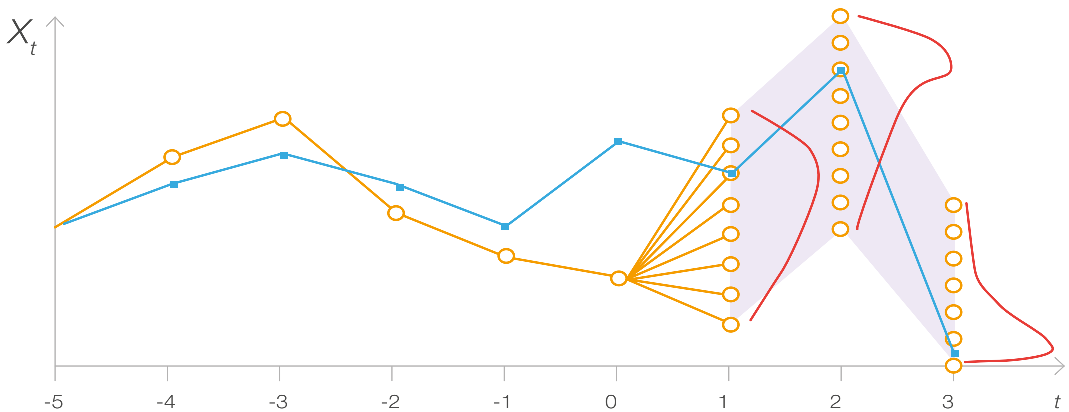


Figure 6: Observed infeed time series (for t≤0) and corresponding forecasts (for t>0) together with the associated conditional probability distribution of forecasting errors

Once the data are available or have been generated, so-called conditional probability density functions are estimated. The probability distributions are conditional on the deterministic prediction in order to account for different forecasting error patterns dependent on the expected level of infeed. Non-parametric methods have been selected because they are capable of replicating the historical distribution of forecasting errors instead of assuming one specific parametric distribution. The fact that uncertainty increases with look-ahead time is incorporated by estimating a different probability distribution for each look-ahead timestamp.

Another particularity of weather-related predictions is the spatial interdependency between different sites. For instance, deviations from the predictions often occur with a similar magnitude in different locations. In order to make use of these spatial interdependencies, a copula is estimated and applied.

Finally, the information regarding uncertainty at each grid node and the spatial interdependencies between the different grid nodes is combined in order to generate Monte Carlo simulations, which yield a full sample of possible deviations from the predicted RES infeed at each grid node.

In addition to the uncertainty regarding RES infeed, a similar non-parametric approach is applied to load predictions, which are also subject to uncertainty. Hence, uncertainty relating to the vertical grid load, i.e. the load flow from TSO grids down into DSO grids (Figure 7), which consists of load and RES infeed prediction errors, is captured by this approach and can be simulated using Monte Carlo methods.

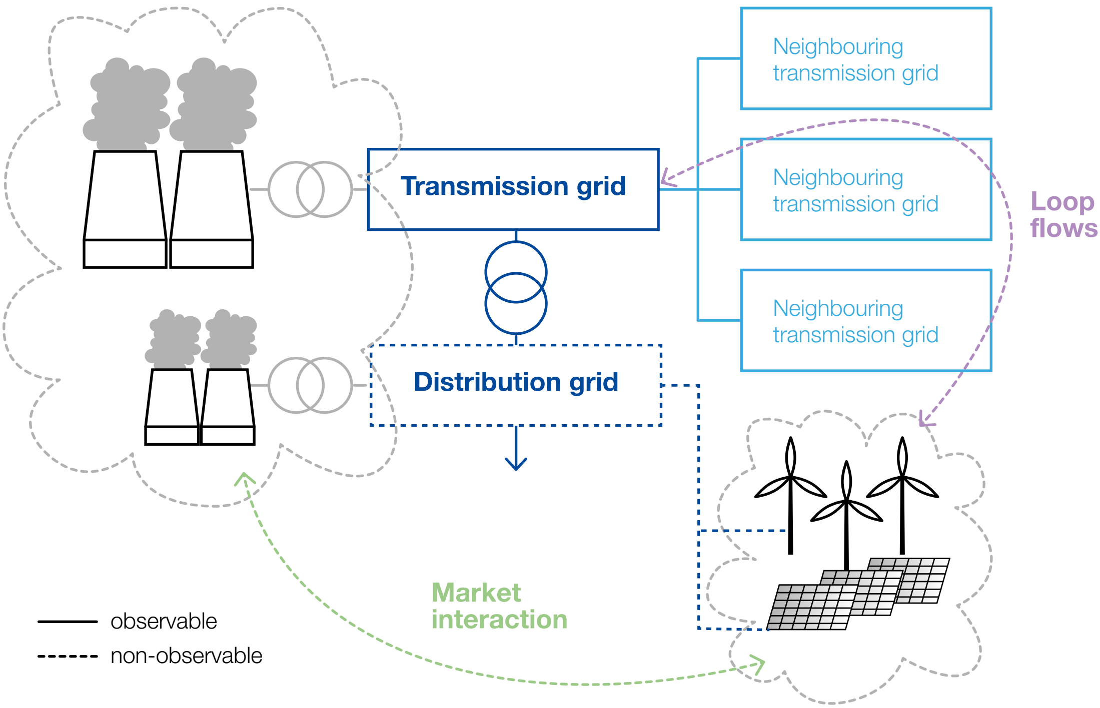


Figure 7: Observable and non-observable factors (solid and dashed lines) from a TSOs perspective and relevant interdependencies between those factors (dotted lines)

How will the markets react?

Erroneous RES infeed and load predictions will frequently be compensated for by other market players which have a more flexible generation portfolio. This will normally happen close to real time, when there is less uncertainty in the system. However, this leaves only a short period of time for TSOs to react accordingly. In modern energy markets, such forecast deviations can be traded on national intraday markets. This and other interdependencies are illustrated in Figure 7. The resulting shifts in generation follow the laws of markets rather than physics and are mostly unforeseen because these intraday trades are often submitted to the TSOs rather late. The ability to anticipate trades would be highly welcomed as a means of assessing possible impacts on system security in advance.

Once the uncertainty surrounding the vertical load (Figure 7) has been modelled as described above, the impact on intraday markets and, thus, conventional generation directly connected to the transmission grid can be assessed. Since market rules define shifts in generation, a market model that reflects the intraday merit order (Figure 8) has been developed.

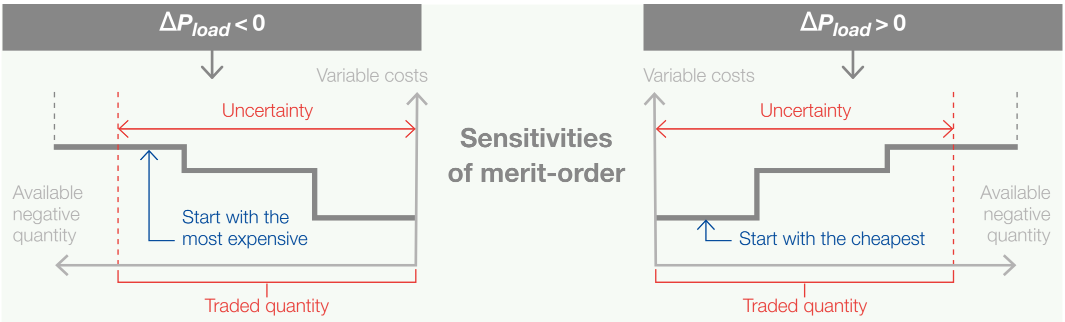


Figure 8: Merit order sensitivities to assess the potential range of short-term trading due to forecast uncertainty

The submitted day-ahead power plant schedules reveal which power plant could become active on the intraday market. Possible power plant outages are modelled with state of the art methods, namely exponential distributions. Up- and downward technical flexibility is derived from day-ahead schedules and the permissible minimum and maximum power output levels. Subsequently, the dataset is enriched with economic information, namely the variable costs that are deduced from fuel costs and efficiency. This yields so-called merit order sensitivities as shown in Figure 8. Using the input from the load side, the shift in generation can be computed for each power plant. Combined with the knowledge of the point of connection to the grid, the change in generation at each grid node can then be determined. In order to account for uncertainty in economic power plant parameters, efficiencies—and thus variable costs—are modelled as stochastic. This entire process is also carried out separately for each look-ahead hour and corresponding Monte Carlo simulations of trading activities are derived.

How many of the deviations will be transferred to neighbouring control zones?

If deviations from schedules occur in an interconnected system, cross-border flows will also deviate from expectations according to the laws of physics. Especially in the case of high deviations from RES infeed predictions, unexpected power flows between control zones can lead to system states that jeopardise the system's security. The interaction with other security factors is illustrated in Figure 7.

The change of cross-border flows due to uncertainty in the system can be modelled using historical data. Thorough data analysis has shown that the change in cross-border flows is driven significantly by a limited number of key forecast parameters. Besides information on the timestamp that accounts for diurnal and seasonal patterns, the uncertainty of forecasts concerning wind and solar power as well as load has a high impact. In order to take all these interdependencies into consideration and still achieve manageable computational effort, an artificial neural network model has been selected. The artificial neural network is trained with the aforementioned data and historical physical flows. Seventeen countries are incorporated in order to account for loop flows properly. The look-ahead hour is taken into account by training 24 artificial neural networks, i.e. one for each look-ahead hour.

For the simulation process, the deviations from the RES infeed and load predictions obtained via Monte Carlo simulation are used as an input. Thus, this tool helps to anticipate deviations from the scheduled cross-border flows by taking the current situation of the respective day and hour of the day into account.

What are the implications for power flows?

Deviations from RES infeed and load predictions and unexpected shifts in generation resulting from the intraday market lead to changing power flows and, hence, unexpected line loadings as well as node voltages. Uncertainty relating to where and when these situations may arise makes it difficult for TSOs to prepare for them adequately. Therefore the possible occurrence of a critical system state should be identified well in advance in order to allow the system operator to prepare adequate remedial measures.

The aforementioned information about relevant uncertainty concerning e.g. RES infeed can be utilised to anticipate future changes in power flows. At this point, detailed Monte Carlo simulations at a grid-node level directly provide the input needed for load-flow calculations (Figure 9). However, changes in active infeed and load also affect the reactive load at each grid node. This is modelled using an artificial neural network that determines the vertical reactive load for each simulation run. Inputs are all simulated RES infeed and load values, information about the hour of the day, the type of day and the day-ahead reactive load value. Finally, as many load-flow calculations are run as there are Monte Carlo simulations. Consequently, for each load-flow calculation, fundamental system parameters, that is to say line loadings and node voltages, are computed, which yield a distribution of system state parameters. Thus, instead of having only one deterministic line loading value, the system operator is now fully aware of all likely line loadings and can prepare for these properly. Depending on the reliability criterion applied, which in most cases is the N-1 criterion, the system state can be determined for each simulation run. This provides the system operator with a one-dimensional measure, namely a critical or uncritical system state, for each simulation run. In addition, information about the distribution of system parameters is a crucial input for downstream tools.

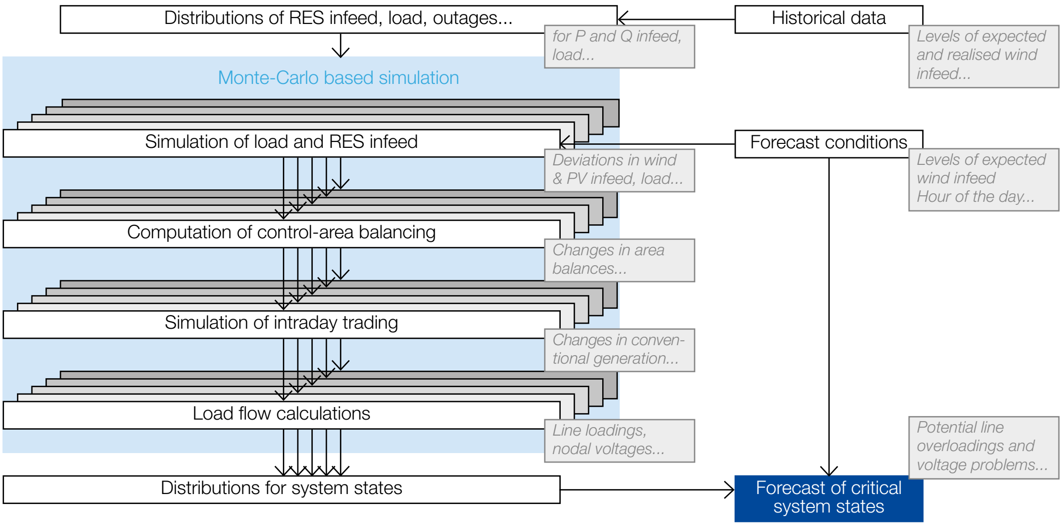


Figure 9: Identification of critical system states

The fact that some forecast conditions lead to critical system states and some do not can be used to forecast critical system states. In order to reduce computational effort, a selective approach has been developed. This approach assesses the similarity of system states by comparing the similarity of the Monte Carlo simulations (Figure 9). Hence, only a fraction of all simulation runs have to be examined accurately by means of a full contingency analysis. The remainder is classified according to the similarity of the simulated inputs. This helps TSOs to identify critical system states far in advance and gives them more time to prepare counter-measures.

Will the system be secure?

Uncertainty from renewables, load and intraday trading changes power system operation. However, the TSO's main task remains the same: to provide customers with a reliable supply of electricity in a cost-efficient manner. Traditionally, power system security has been assessed using a deterministic security criterion, namely the N-1 criterion. Within the UMBRELLA Project, the development of risk-based criteria complementing the traditional, deterministic N-1 criterion is motivated by the changing operating conditions in the grid.

The risk-based security criteria developed within UMBRELLA provide additional information on the security of the system. Now, it is possible to state whether or not the system is secure by including risk from low-probability, high-impact events (e.g. N-k outages that lead to cascades), as well as by appropriately incorporating forecast uncertainty and probabilistic and risk-based security criteria. These security criteria can also provide information about how secure the system is and how much more secure or insecure it will become following a given change in the operating conditions. The presented approaches are thus an extension of and an improvement to the existing N-1 criterion.

The risk-based criteria help the system operator to manage system security in the presence of uncertainty and find effective actions to reduce risk when necessary. However, several challenges exist relating to both risk modelling (how to quantify risk and security) and the definition of security criteria (how secure is secure enough?). Below, we show how these questions have been addressed within the UMBRELLA Project.

How secure is the system?

Modelling risk in an uncertain environment.

Review of the N-1 security criterion

The N-1 security criterion requires the system to be in a state where no single contingency can be expected to have a major impact on system operation. This implies that no contingency should lead to the outage of further components, and the N-1 security criterion can thus be seen as one meant to secure the system against cascading. The benefits of the N-1 security criterion are its conceptual simplicity and its ability to provide a clear answer on whether or not the system is considered secure.

While the N-1 criterion implicitly incorporates the probability of outages through the use of a list of credible contingencies, it lacks consideration of the impact of forecast deviations, explicit modelling of the probability of an outage and assessment of the actual risk related to an N-1 violation. The risk-based approaches presented below try to mitigate these drawbacks.

Modelling risk

Modelling risk is the first step towards mitigating it. Risk-based security assessment weighs the severity of a disturbance against the probability that it will take place. For modelling probabilities, we consider two different kinds of disturbance: component outages and forecast deviations.

1) A component outage is a binary event with a probability of occurrence. The probability of outages can be estimated in different ways, such as by using historical data, and can vary depending on several external factors, such as the weather forecast.
2) A forecast deviation is better modelled as a continuous random variable with a corresponding probability distribution. The probability of forecast deviations is obtained from probabilistic forecasts such as the ones described previously.

Where severity modelling is concerned, two main approaches exist:

1) On the one hand, severity can be modelled using overall reliability parameters such as Expected Energy Not Served. These parameters incorporate the effect of cascading events and best reflect the impact on the customers in the system. However, computing the risk requires extensive calculations (i.e. Monte Carlo simulations), and these types of risk measures are typically used to analyse the risk for a given operating condition rather than for the purpose of inclusion in an optimisation problem.
2) On the other hand, severity can be modelled in terms of the violation of technical limits, such as by assessing dependency on the power flow of a line or on voltage magnitude. Such models typically consider the situation after an N-1 outage, and do not simulate how a potential cascade would develop further. Thus, these risk measures do not reflect the full risk of cascading events, but they are relatively easy to compute. Furthermore, technical violations can be easily understood and influenced by the system operator.

Which severity measure to choose depends on the purpose for which it is intended. Within UMBRELLA, both types have been used. For implementation within risk-based optimal power flow (OPF) algorithms, severity measures of the second type are used as they are relatively easier to evaluate from a computational perspective. Risk-assessment tools used to assess the risk of a given dispatch rely on the first type of severity measures, or a combination of both.

Below, we present the risk-modelling approaches developed in UMBRELLA.

Probability of overload[11]

When the power injections in the system are affected by forecast uncertainty, important parameters such as transmission line loading become uncertain. One way to handle this uncertainty is to ensure that the probability of overload remains below a predefined limit. Reducing the probability of overload requires a reduction in the available capacity. This reduction can be interpreted as a security margin against uncertainty, that is to say an uncertainty margin (Figure 10).

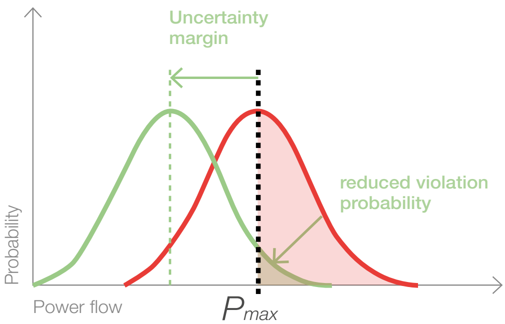


Figure 10: Illustration of an uncertainty margin

Risk of overload[12]

While reducing the probability of overload reduces risk, this does not take into account the severity of the overload. To account for this, we used severity functions. In particular, we developed a risk model which not only accounts for the probability of an outage and the size of the overload, but also the operator's ability to relieve the overload through remedial actions. An overload for which cheap remedial actions are available is thus considered less severe. The corresponding severity function is shown in Figure 11.

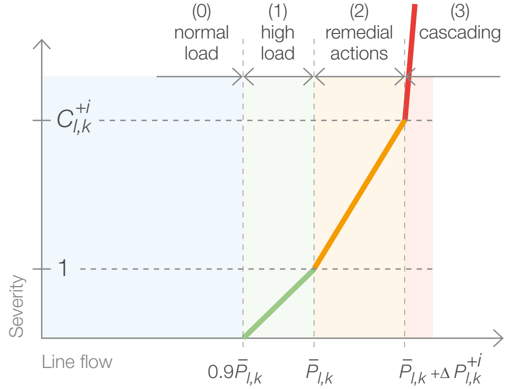


Figure 11: Severity function, constraint violations and availability of remedial actions

Assessment of cascading risk[13]

To handle risk due to cascading events, a three-step framework was developed as depicted in Figure 12. In the first step, a risk-based OPF is solved. The OPF minimises cost subject to constraints on the probability of cascade initiation, that is to say the

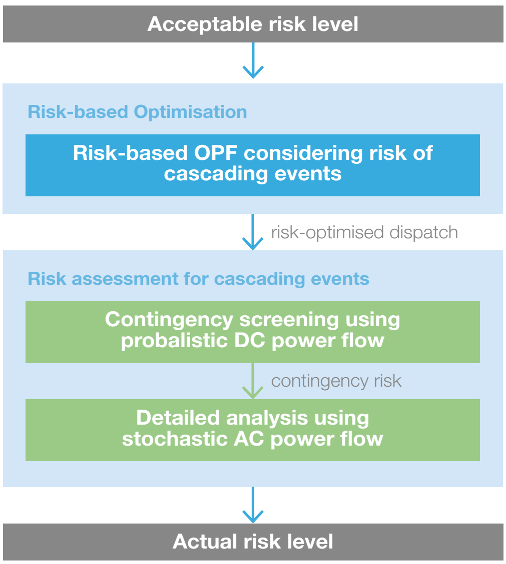


Figure 12: Three-step framework to mitigate and assess risk from cascading events

[11] *References see [1], [2] and [3].*
[12] *References see [4], [5], [6] and [7].*
[13] *References see [4], [5], [22], [23], [24] and [25]*

probability that an initial outage will lead to further outages. The outcome of this first step is a risk-mitigated dispatch.

In the second step, the dispatch is analysed in more detail using a cascade simulation. This is based on a probabilistic DC power flow, and accounts for the forecast uncertainty (represented through a multivariate normal distribution) and the possibility of multiple simultaneous outages. This method assesses overall system risk by screening a large number of possible outage combinations: at the beginning of the simulation, an upper and lower bound are defined for the risk. As shown in Figure 13, the gap between these is narrowed as more outage situations are accounted for, and the simulation stops when the gap reaches a pre-defined stopping criterion. The outcome of this second step is a measure of the overall system risk in terms of expected lost load, as well as information about the most dangerous contingencies.

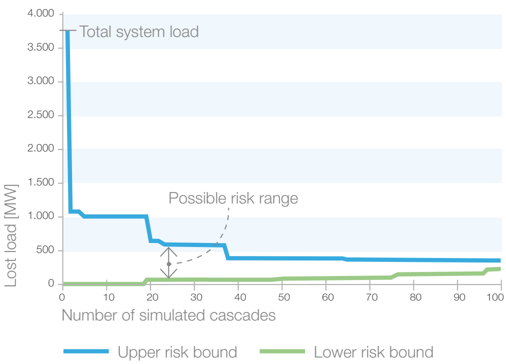
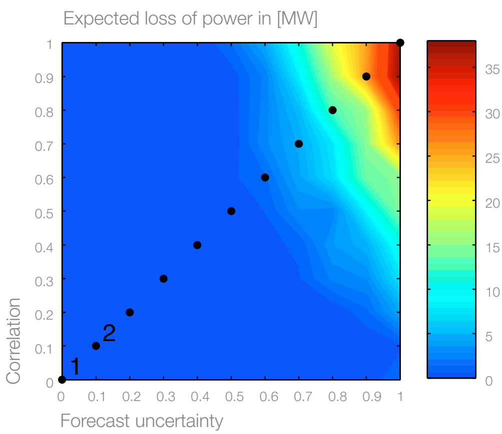


Figure 13: Simulation of total cascading risk in the system

In the third step, a more detailed cascade simulation is run for the most dangerous situations. Unlike in the previous methods, the power system is represented through the full AC power flow equations. Thus, not only transmission line overloads but also voltage issues are included in the security assessment. Uncertainty is accounted for using a Monte Carlo simulation based on samples, which allows for incorporation of generic uncertainty distributions. By incorporating the pre-screening of the samples and algorithm improvements, it is possible to run the simulation on large-scale grids without compromising computational tractability.



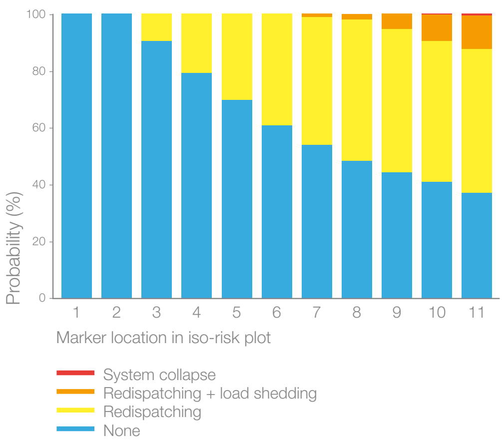


Figure 14: Example output of the third step in the cascading risk assessment: Iso-risk plot for different levels and correlation of forecast uncertainties (top) and probability of redispatch, load shed and system collapse at particular operating points (bottom).

How secure is secure enough?

Assessing the impact of uncertainty on operation costs.[14]

Power system security has a cost. As explained above, reducing the probability of overloads leads to a decrease in the available transmission capacity. To assess the impact of uncertainty on cost the nominal difference in cost between a deterministic OPF solution (based on the operating point forecast with nominal transmission capacity) and a probabilistic OPF solution (where the probability of overload is limited, thus reducing the transmission capacity by the uncertainty margin) is chosen. The cost-of-uncertainty thus reflects the cost caused by the reduction of the number of transmission line overloads.

Different ways to reduce the impact on cost through the intelligent use of power-flow control devices, such as HVDC links and PSTs, were also investigated. The proposed method incorporates corrective power-flow control actions to handle uncertainty by changing the set points of HVDC and PSTs in reaction to forecast deviations (Figure 15). The corrective control was modelled through affine policies, which imply that the set-points change proportionally to the size of the forecast deviation. Policy-based control has several advantages: first, it allows us to treat the fluctuations as continuous variables (as opposed to a representation through a finite number of scenarios). Second, it provides a control policy which can easily be implemented by the TSO. Third, it allows us to account for uncertainty in operational planning without compromising computational tractability. The use of corrective control reduces the uncertainty margins on congested lines, which reduces the cost of incorporating uncertainty. Figure 16 illustrates how corrective control actions can be used to reduce the variability of the power flows, thus decreasing the probability of violation while keeping the uncertainty margin constant.

[14] *References see [1], [4] and [8]*

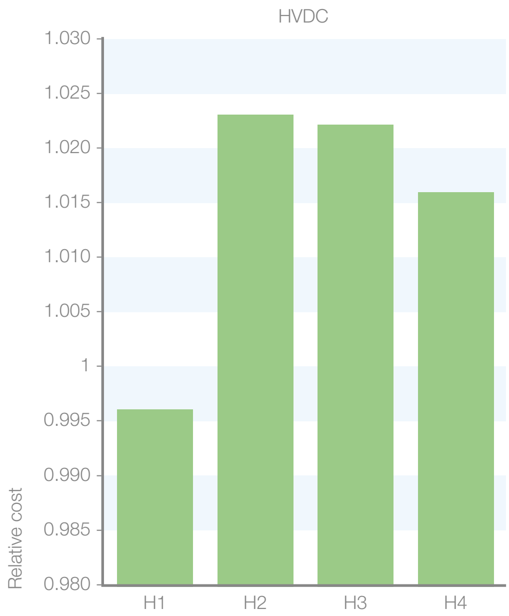


Figure 15: The cost of the generation dispatch 1) without uncertainty (H1), 2) with uncertainty but without corrective control (H2), 3) with uncertainty and with corrective control based on overall power deviation (H3), and 4) with uncertainty and with corrective

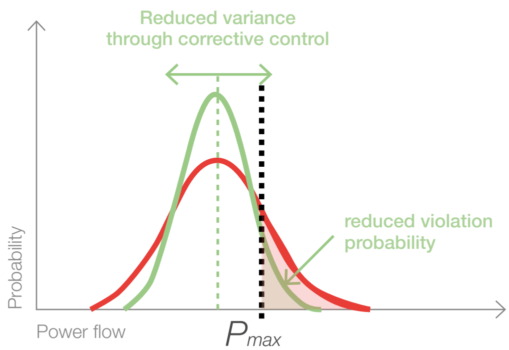


Figure 16: Power flow variance reduction through control actions

What should be done to ensure system security?

How can TSOs choose from a huge selection of possible actions?

The complexity of congestion management in transmission system operation is growing due to two major factors. First, the amount of congestion has increased significantly in recent years. Although it is comparably straightforward to relieve a single instance of congestion, managing a large number of congested elements while most of the other elements are highly loaded is a huge challenge. Second, the number of available and cost-efficient remedial measures is increasing due to newly built PSTs and plans to build HVDC lines in parallel to the AC grid. These measures often have effects that cross borders, hence leading to a growing need for coordination in transmission system operation. The combination of both these phenomena is increasingly pushing operational processes to their limits.

To enable the efficient handling of congestion management problems, the UMBRELLA Project has developed optimisation algorithms which will help TSOs to cope with a growing amount of congestion on the one hand and increased complexity on the other. These optimisation algorithms are EOPF algorithms which provide TSOs with information about the optimised selection of remedial measures to ensure secure grid operation while minimising market impact and thereby maximising the power transits achieved.

From a technical perspective, the EOPF algorithms take into account the possibility of adjusting the network topology, changing the tap position of transformers and shunt elements and defining the set points of HVDC transmission lines. Furthermore, redispatch measures and measures such as the curtailment of RES and load shedding are taken into account. For all measures, the technical restrictions are considered, including their potential for preventive and post-contingency implementation. To take into account the numerous different objectives in transmission system operation, such as regulatory restrictions and cost considerations, a detailed cost model enables the definition of real operational priorities.

In short, the developed EOPF algorithms support transmission system operation at all stages, from operational planning to real-time operation.

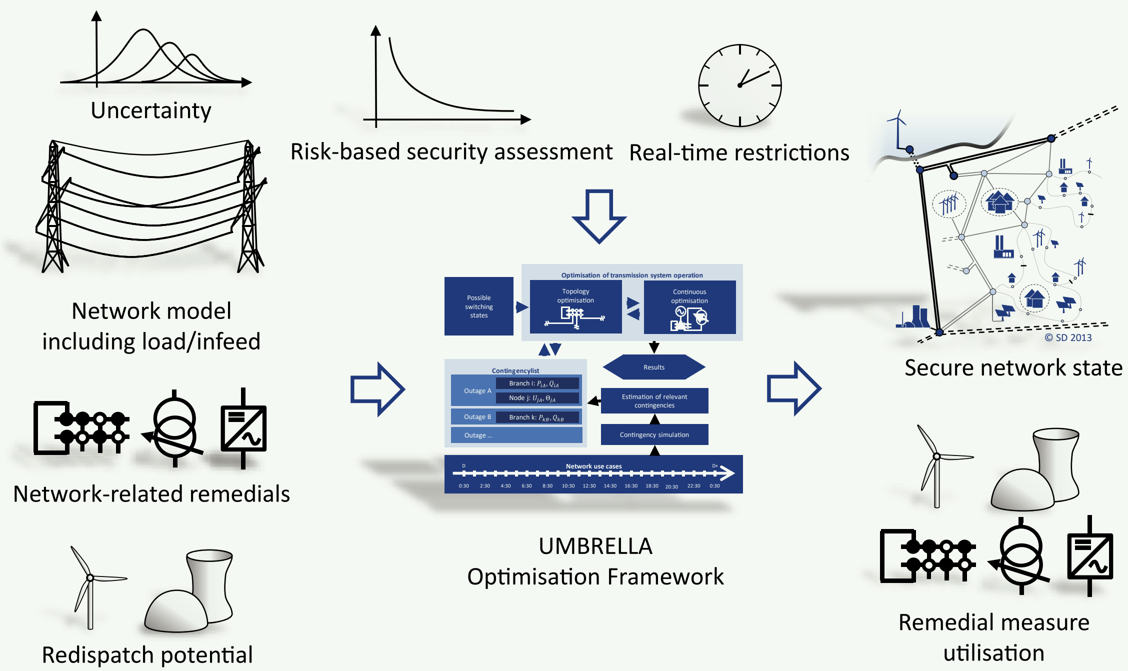


Figure 17: The UMBRELLA Optimisation Framework

How can recommendations be provided in real time?

The use of optimisation algorithms to support transmission system operation is widely discussed in the scientific literature. Nevertheless, no out-of-the-box solution is available for optimised guidance on congestion management for transmission system operation. This is mainly due to the huge complexity of the optimisation problem resulting from huge transmission grid models, multi-period optimisation and binary decisions.

If they are to be useful for the operational planning process and real-time operation, optimisation algorithms need to be extremely efficient in achieving adequate results in the limited time frame available for operational processes.
To cope with the challenge of computational restrictions in real-world applications, all parts of the UMBRELLA Optimisation Framework have been designed especially considering computational efficiency. Thus, the Optimisation Framework uses multiple methods and algorithms to ensure the best possible computational performance and practical applicability.

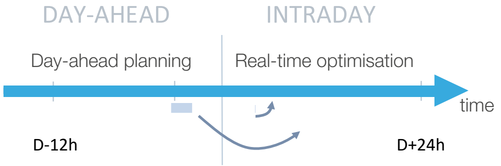
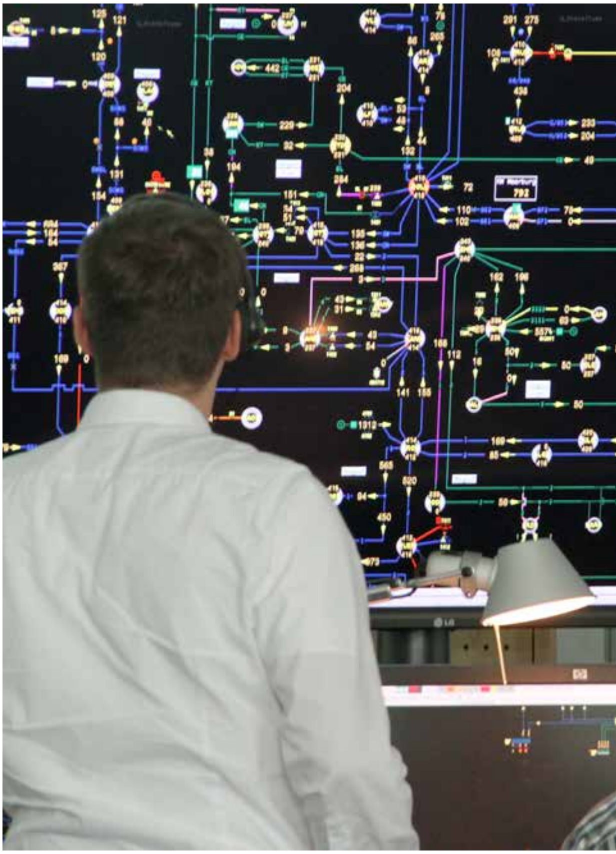


Figure 18: Accounting for different time periods in transmission grid operation

The success of implementation is based on the interdisciplinary work of engineers in identifying relevant components and introducing model reductions, mathematicians in choosing efficient algorithms to solve the mathematical problem and programmers in contributing the required knowhow in the fields of efficient implementation, parallel processing, vectorisation and template meta programming.

Thanks to these combined efforts, the UMBRELLA Optimisation Framework is a convincing solution for optimisation problems in transmission system operation, enabling a wide range of applications and providing extraordinary computational performance.



How can the variety of upcoming system states be taken into account?

Pan-European market activities and resulting cross-border flows, as well as growing decentralised energy resources, are leading to increasing power transits and bringing the transmission grid closer to its technical limits. Consequently, security margins are becoming smaller and TSOs are frequently applying remedial measures in order to relieve congestion. Furthermore, meteorological forecasts are error-prone and the respective infeeds from RES lead to deviations of load flows from expected system states. Especially when systems are stressed, forecasting errors can lead to unforeseen violations of operating limits and might trigger cascading outages, resulting in a blackout as a worst-case scenario.

Uncertainty included

The challenge of uncertainty in operational processes will be a major driver for future developments in the field of transmission system operation. To handle this growing challenge, uncertainty should be appropriately accounted for in the Optimisation Framework. Within UMBRELLA, two main approaches have been investigated.

The first approach represents the uncertainty forecast through its mean and covariance, and uses the uncertainty margins described above to ensure that the system will remain secure with a given probability. Uncertainty is thus included through a dynamic adjustment of available transmission capacity, which efficiently accounts for the impact of uncertain renewable infeeds without increasing computational load.

Coping with uncertainty

The second approach represents uncertainty through a number of critical scenarios for upcoming infeed developments. The system state and available remedial measures are optimised while considering interdependencies between the scenarios due to the limited flexibility of conventional power plants. This approach aims to avoid unmanageable system situations in real-time transmission grid operation. Therefore, adequate security margins as well as sufficient system flexibility are computed for all possible upcoming system states. Thereby, the straightforward way of coping with uncertainty—to wait as long as possible to activate a certain measure—is enabled in a secure manner.

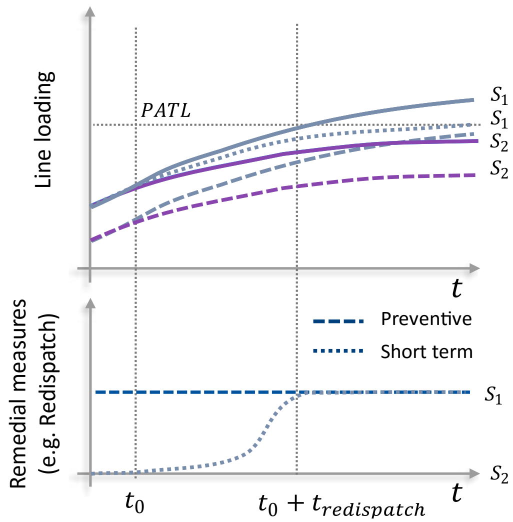


Figure 19: Remedial actions have to be planned in due time taking into account potential system development and the availability of remedial measures available in the short term.

From a technical perspective, this is achieved by distinguishing between remedial measures with long activation times and those which can be activated quickly. Measures with long activation times, such as power-plant startup decisions, must be chosen up to two days beforehand, and this affects all upcoming system states. Meanwhile, remedial measures with very short activation times only have an impact on certain scenarios.

Wide range of methodologies

With this set of solutions, the UMBRELLA Project provides a wide range of methodologies which can be used to account for uncertainty in congestion management applications across all transmission grid operation processes.

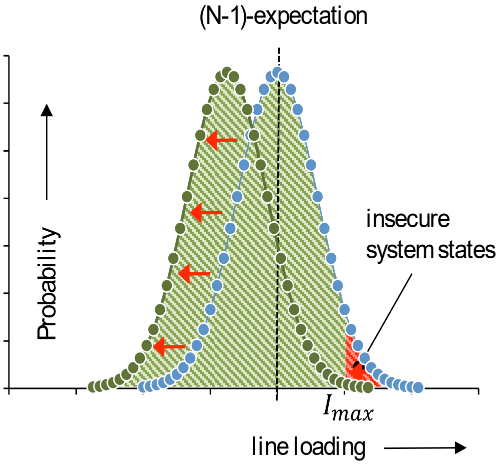


Figure 20:
The principle of probabilistic optimisation

Could the electrical energy markets contribute to security enhancement?

In much of Europe, electricity markets are operated as self-dispatch markets, where there is a strict division between the energy market and the operation of the electrical grid. In the self-dispatch market, market participants are responsible for being balanced (i.e., for covering their own demand or selling their surplus energy on the market) and the market is cleared without considering transmission capacity (with the exception of cross-border electricity exchange).

Other electricity market designs include the central-dispatch market, which is applied in some parts of Europe (e.g., Poland). In the central-dispatch market, market operation is coupled with the operation of the electrical grid. Market participants submit bids for generation and demand, and the market is cleared by the TSO, taking into account technical limits such as transmission capacity.

Within UMBRELLA, these two market designs were compared conceptually. Central-dispatch market clearing leads to costlier generation dispatch than the initial generation dispatch obtained in the self-dispatch market, since the central-dispatch market accounts for transmission constraints (thus limiting the transmission of electricity from low-cost to high-cost parts of the grid). However, the generation dispatch obtained from the self-dispatch market requires a large amount of redispatch to obtain a N-1 safe dispatch. Therefore, the overall operation cost (market clearing plus redispatch) will always be lower for the central-dispatch market design.

UMBRELLA Toolbox

Toolbox Overview

How to support current TSOs' processes with an innovative toolbox combining the modules developed

The complexity of the operational planning and real-time operation processes carried out by European TSOs has increased significantly in recent years. In order to support TSOs in handling the related challenges, the results of the UMBRELLA Project have been garnered with a view to improving and enhancing current processes. Figure 21 provides an overview of the potential areas of application of the UMBRELLA Toolbox.

Support real-time operation

Despite the fact that the vast majority of functionalities developed within the project focus on the operational planning process, a module is offered to support real-time operation.

The UMBRELLA Toolbox is capable of dealing with deterministic forecasts of system use obtained from current processes and, furthermore, offers the option of taking uncertainty into account by applying the functionalities generating probabilistic system use forecasts.

Both approaches to forecasting the future use of the system can be used as an input for the Optimisation Framework. In addition, the system state can be assessed based on the N-1 principle, which represents the state of the art, and on risk-based security methodologies.

Finally, the UMBRELLA Toolbox offers the flexibility to apply either individual modules or the complete set of functionalities.

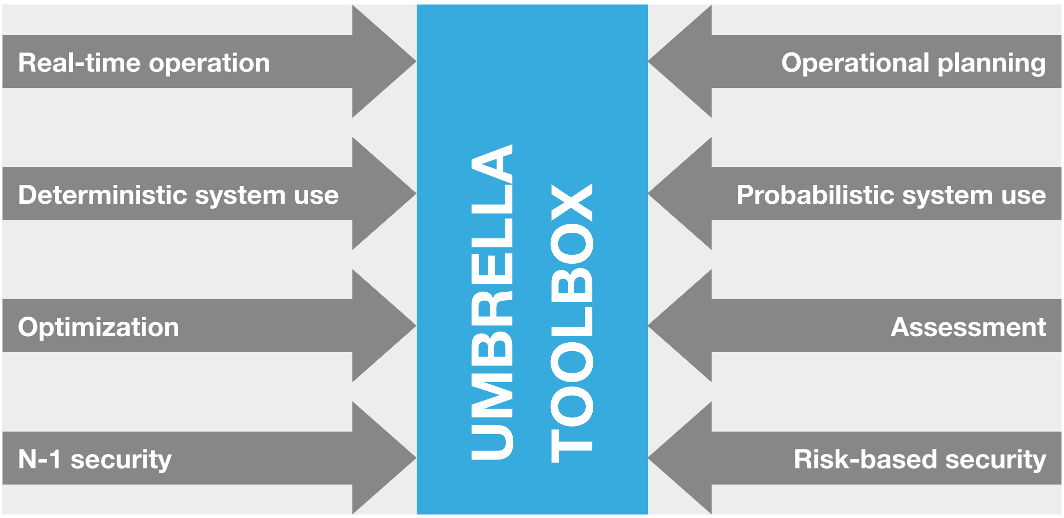


Figure 21: Overview of areas of application of UMBRELLA Toolbox

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How can the toolbox be integrated into current processes?

Figure 22 provides a schematic overview of the current, improved and enhanced operational planning processes.
The overall purpose of the operational planning process is to provide information for real-time operation.
The current process consists of a deterministic forecast of the future use of the system by generators and consumers of electrical energy. Based on the forecast, the resulting state of the transmission system is assessed and the system state is then optimised, for instance by adjusting the system topology or by system usage (redispatch). In the current process, optimisation is carried out by participating TSOs individually. The result of the optimisation is merged and, again, assessed. The relevant information from the final result is then transferred to real-time operation.

The current process can be improved by applying the UMBRELLA Optimisation Framework developed (see yellow box in Figure 22). Here, optimisation is carried out by means of a single algorithm.

A potential enhancement of the current process through developments arising from the UMBRELLA Project is depicted at the bottom of Figure 22. The main objective of this approach is to consider uncertainty arising from the forecast of loads and intermittent generation, for example. The deterministic forecast of future use of the system is replaced by a probabilistic approach. The state of the transmission system can be assessed using a risk-based methodology instead of the N-1 criterion currently applied. The Optimisation Framework helps to improve the security of the system if necessary.

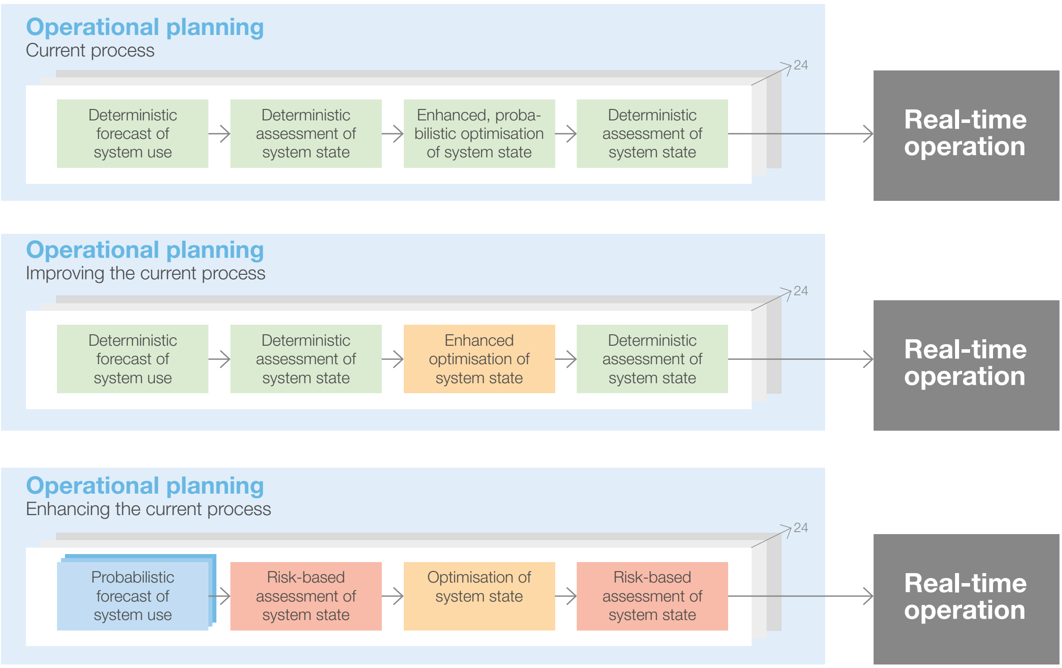


Figure 22: Potential steps for the evolution of the current operational planning process

Toolbox Assessment

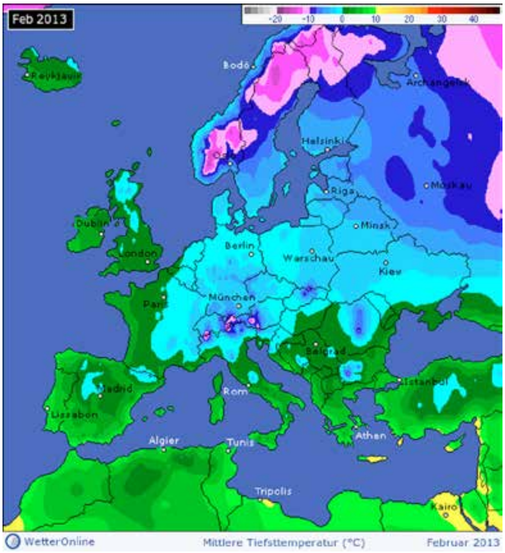
In order to test the Toolbox Prototype, several TCs have been selected, covering seasonal aspects and different infeed scenarios for RES which resulted in stressed-grid situations. This required a significant number of remedial actions, such as topological measures and redispatch, on the part of the TSOs in order to ensure the safe and reliable operation of the transmission system.

Two TCs, one of which was run in winter and the other in summer, are described in detail below as examples. After defining the TCs, the Toolbox Prototype was tested and evaluated. For this purpose, the TC datasets had to be checked and adjusted by the TSOs.

Model corrections and improvements and remedial actions were implemented manually and compared with the semi-automated work of the Toolbox Prototype's optimisation functionality. The probabilistic results were counter-checked against the TSOs' operational experience.

Test Case TC1: 8 February 2012

On 8 February 2012, a cold snap appeared over Europe. An extraordinarily high load occurred, especially in France due to its large share of direct electric heating. Furthermore, a delivery shortage of natural gas from Eastern Europe meant that about 1.7 GW of German natural gas-fired power plants were unavailable.
This scenario must also be seen in context of the aftermath of the nuclear phase-out which occurred in Germany in 2011, diminishing the installed capacity of the Germany's power plants by approximately 8.3 GW.



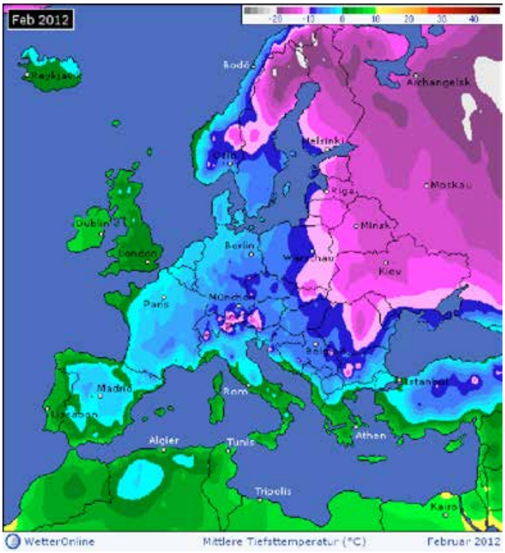


Figure 23: Graphical presentation of the average minimum temperature in February 2012 (right-hand side) and February 2013 (left-hand side) (source: http://www.wetteronline.de)

Test Case TC2: 22 August 2012

On 22 August 2012, the grid was stressed due to a number of factors combined:

- The general weakening of the transmission grid in summer due to necessary maintenance works.
- Inspections of power plants, which often cannot be cancelled.
- Changes in load and the resulting power flows caused by the summer holidays in several countries.

In Germany, the combination of wind and PV infeed and load concluded in a market result and a related power-plant dispatch, which led to a stressed situation in Germany and several adjacent countries.

Deterministic results

The result of the deterministic optimisation functionality of the Toolbox Prototype is explained in Tables 1-3. For brevity's sake, we refer to the optimisation functionality as simply "the Optimiser".
In the **Base Case**, each TSO implemented model corrections and improvements in the datasets for their control area in order to achieve a common starting point for further evaluation.
The **Classic Approach** represents the datasets after each TSO has implemented their remedial actions manually as usually preformed during the DACF process.
The **Modern Approach** represents the datasets after the Optimiser has implemented remedial actions in an automated manner. The degrees of freedom for the Optimiser were the set of topological measures previously provided by the TSOs from the Classic Approach as well as redispatch and available PST tap changes.

Sample results for TC2

The tables below show the overload factors of the N-1 analysis of the Base Case (Table 1), the Classic Approach (Table 2) and the Modern Approach (Table 3) for TC2. In order to ensure that the tables are comprehensible, only a certain subset of contingencies and timestamps for one TSO are considered. It must also be borne in mind that the second column, labelled "worst case", represents the highest percentage load of a transmission network element during the course of the day; further information will be derived from these numbers.

Table 1 explains the percentage line loading for N-1 contingencies in the Base Case which would occur if the operator did not implement any counter-measures.

Base Case TSO 1	worst case	Hour								
		9:30	10:30	11:30	12:30	13:30	14:30	15:30	16:30	17:30
Contingency 1	123.4	123.4	88.9	101.1	96.7	100.3	117.5	101.8	101.4	101.3
Contingency 2	122.4				102.0	112.6	122.4	120.5	116.9	
Contingency 3	122.0				110.6	118.5	121.0	122.0	113.0	110.6
Contingency 4	122.0				110.6	118.5	121.0	122.0	113.0	110.6
Contingency 5	108.2					106.6	106.0	108.2	99.8	
Contingency 6	105.8	105.5		89.2	87.4	91.6	105.8	94.0	92.5	90.5
Contingency 7	100.9	100.9	71.7	81.5	74.7	77.0	94.1	77.8	79.7	76.9

Table 1: Results of the N-1 analysis of the Base Case for TC2

Base Case TSO 1	worst case	Hour								
		9:30	10:30	11:30	12:30	13:30	14:30	15:30	16:30	17:30
Contingency 1	112.4	112.4	75.1	87.3	78.7	74.5	98.5	73.2	76.7	72.9
Contingency 2	90.1				77.9	83.7	90.1	89.2	84.1	71.8
Contingency 3	102.6				102.6			96.8		
Contingency 4	101.1		71.0	89.1		90.9	92.8		83.7	85.7
Contingency 5	91.8					87.7		86.4		
Contingency 6	123.0	123.0	85.5	102.4	94.5	90.5	112.3	88.5	90.4	
Contingency 7	117.0	117.0	79.5	94.8	82.8	79.0	108.1	75.3	80.7	74.5

Table 2: Results of the Classic Approach to N-1 contingency management for TC2

Base Case TSO 1	worst case	Hour								
		9:30	10:30	11:30	12:30	13:30	14:30	15:30	16:30	17:30
Contingency 1	90.5	85.0	77.0	87.7	86.0	88.7	89.5	77.6	90.5	88.8
Contingency 2	82.4	82.4	71.2	79.6	73.8	75.2	82.2		78.6	76.2
Contingency 3	99.7	99.2	88.5	99.4	95.4	97.6	99.4	82.0	99.4	99.7
Contingency 4	99.5	71.8	84.6	97.3	95.3	93.7	91.7	99.5	92.0	99.5
Contingency 5	99.5		84.6	97.3	99.5	99.5	99.5	99.5	99.5	99.5
Contingency 6	99.6	85.0	91.0	87.9	89.8	96.9	98.1	97.7	99.6	91.6
Contingency 7	92.4		82.5	89.7	82.4	92.1	92.4	91.7	86.1	75.5

Table 3: Results of the Modern Approach to N-1 contingency management for test case TC2

Table 2 represents the results of the N-1 analysis for the Classic Approach, which means the manual implementation of remedial actions based on the experience of the operators. Note, however, that the TSOs had a limited number of iterations for relieving congestion in their control areas. Some contingencies are therefore still unresolved.
As a result of the remedial actions implemented by the operators in the Classic Approach, the number of overloads decreases significantly. Despite this, certain contingencies show an increased overload after the implementation of remedial actions. This means that for these timestamps additional preventive or curative remedial actions would have to be evaluated and implemented.

Table 3 shows that the remedial actions implemented by the Optimiser resolved all overloads. Furthermore, the values are often close to 100% in the N-1 case. This means that the transmission grid would operate to its maximum capacity, taking into account sufficient security of supply. The Optimiser uses costly remedial actions only if absolutely necessary, which could ultimately bring the biggest benefit for the reduction of costs for the TSOs' daily operation.

Overall results for all TSOs

The main objective of optimisation is to keep security of supply at the current level or higher. At the same time, it coordinates remedial actions across the system with the aim of reducing the costs of system operation. The optimisation algorithm gives priority to less costly remedial actions and tries to relieve congestion in the system in the most efficient way. The use of best possible options results in a potential reduction of the required number of remedial actions and the need for redispatch, which ultimately results in increased social welfare.

1. Improved system security

The added value of the Optimiser has been assessed and can be seen in Figure 24. Again, it must be recalled that the TSOs had a limited number of iterations for relieving congestion in their control areas. Therefore, some contingencies are still unresolved.
This chart shows the results of the N-1 contingency analysis for all TSOs. The values represent the number of elements which were overloaded at least once during the day. After analysing the results of both TC1 and TC2, the following can be concluded:

- After the manual implementation of the remedial actions (Classic Approach), the mean number of critical contingencies decreases by 55%.
- After the implementation of remedial actions by the Optimiser (Modern Approach), the mean number of critical contingencies decreases by 97%.

Results of N-1 contingency analysis

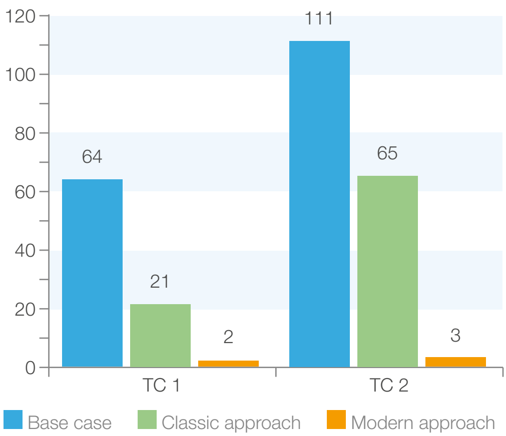


Figure 24: Evaluation of the results of the N-1 analysis as a total of 9 TSOs

2. Reduced amount of required redispatch

The same comparison has been carried out for the second TC. In general, the optimisation algorithm managed to reduce the amount of redispatch compared with a manual estimation of required redispatch measures. This is because it considers the combined relieving of multiple instances of congestion. While there is barely any advantage in situations with very little congestion, the Optimisation Framework becomes extremely beneficial in the case of a large number of redispatch measures.

This is confirmed by the situation with the largest number of redispatch measures in the Classic Approach, namely the 12:30 timestamp in TC2. The amount of redispatch estimated in the Classic Approach for this timestamp is 2770 MW. Meanwhile, the Optimisation Framework achieves a less critical system state, with a redispatch of just 1204 MW. This results in the subsequent Project KPI: a 57% reduction in redispatch.

To give an idea of the financial impact of this reduction, we assume a 10% reduction in redispatch costs (which is far below the TC results) as a result of the UMBRELLA Optimisation Framework. This 10% saving of redispatch costs in Germany alone would allow overall UMBRELLA Project costs to be recovered in one month.

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How does the Optimiser support the TSO or operational planner in their daily work?

First of all, the Optimiser is able to find effective remedial actions by proposing topological measures from a predefined list of operational measures, by changing the tap positions of PSTs or by means of efficient redispatch. This speeds up the current experience-based process significantly by avoiding unnecessary iteration steps, since the conflicting activation of remedial actions by different TSOs is avoided. This gives the operators and operational planners the necessary time to prepare the actual implementation of the proposed remedies.

Probabilistic results for nodes

To test probabilistic functionalities, 1000 + 1 system use cases (SUCs) were created for each time stamp (the "+1" is the DACF point forecast). This means that for the 24 timestamps of the two TCs described, a total of 48000 + 48 SUCs were created. After this, each TSO checked the nodal distribution of the load and the resulting power-flow distribution on the lines.

A spot check on a particular node of TC1 was chosen in order to verify the probabilistic forecast on a node with a high load and only a minor infeed from renewables and conventional generation in the underlying grid. As expected, the distribution shows a narrow band around the deterministic DACF point forecast, which matches the operational experience closely.

In contrast, the node of the TC2 was chosen in order to verify the probabilistic forecast on a node with high load and infeed variation. In particular, the node has a high installed PV capacity as well as several conventional generation units in the underlying distribution network.

Example of node for Test Case 1 (20120208 19:30)

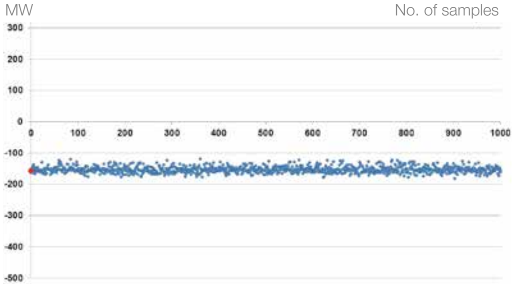

Figure 25: Aggregated load/infeed at the selected node from Test Case 1.

Example of node for Test Case 2 (20120822 12:30)

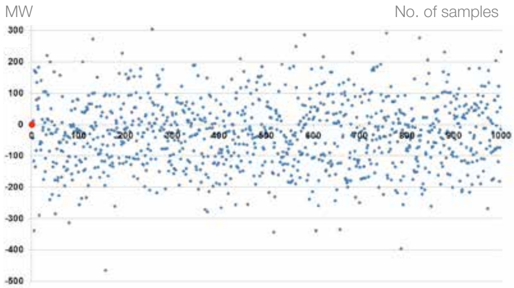

Figure 26: Aggregated load/infeed at the selected node from Test Case 2

Depending on the operational scenario (e.g., weather, time of day) the node can resemble a load or an infeed. The high dispersion of the values is caused by the uncertainty of the underlying generation. The average value of the 1000 SUCs, which were generated by the probabilistic functionalities, is close to 0. This tallies closely with the DACF point forecast, which is also 0.

Probabilistic results for lines

Once the nodal distributions had been checked, the resulting power-flow distribution on the lines was analysed by the TSOs.

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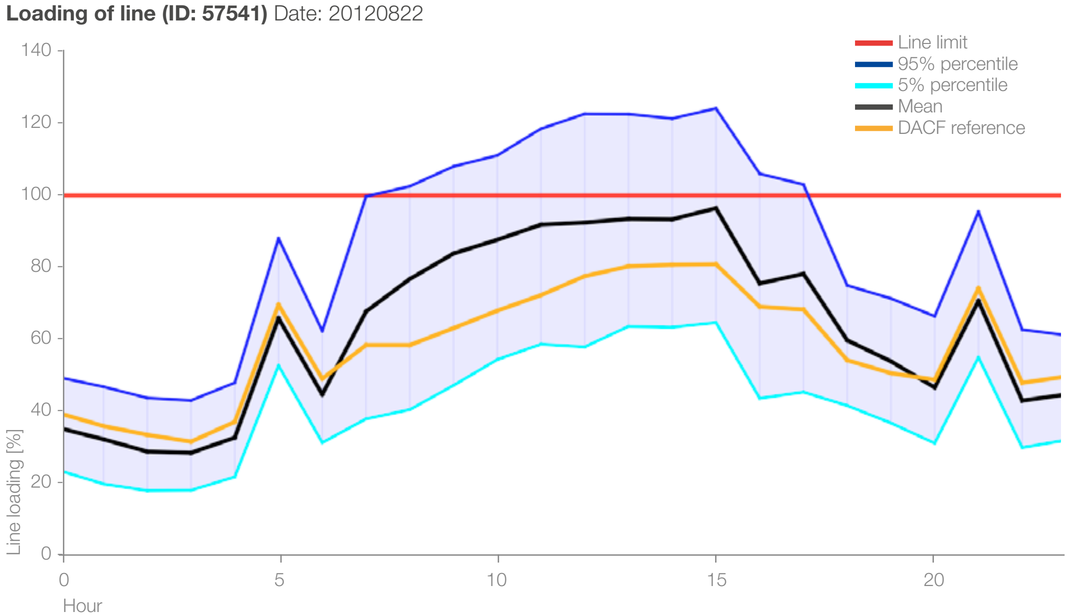

Figure 27: Loading of a selected line from TC2: 24-hour overview

The line in Figure 27 verifies the load-flow results based on the probabilistic forecast. At one end of the line is the infeed of a coal power station; at the other is a pumped-storage power plant. The 24-hour overview diagram shows a good correlation with the operational experience. As long as the power plant feeds in close to nominal power, the operation of the pump storage affects line loading directly. For the timestamps 5:30 and 21:30, the pumped-storage power plant is pumping, resulting in the two sudden line-loading peaks.

Between 6:00 and 20:00, the line loading for the DACF reference is lower than the mean value. For these timestamps, there is also a high spread (approximately 60%), which can be explained by the high level of uncertainty from wind and PV forecasts. For the other timestamps, the mean value and DACF are very close and the spread is lower.

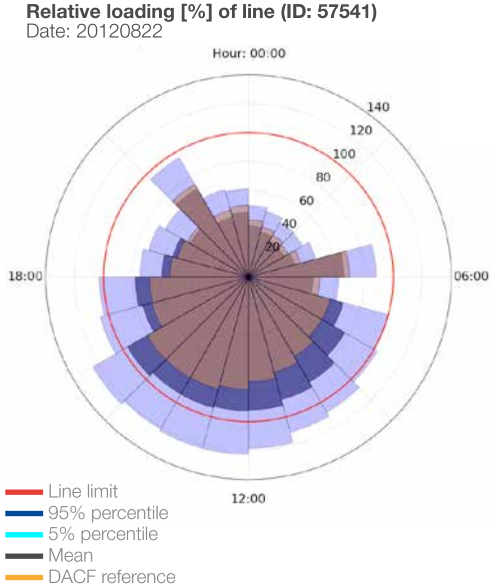

Figure 28: Loading of a selected line from TC 2: alternative 24-hour overview

Probability Distribution of loading line (ID: 57541) Date: 20120822 12:30

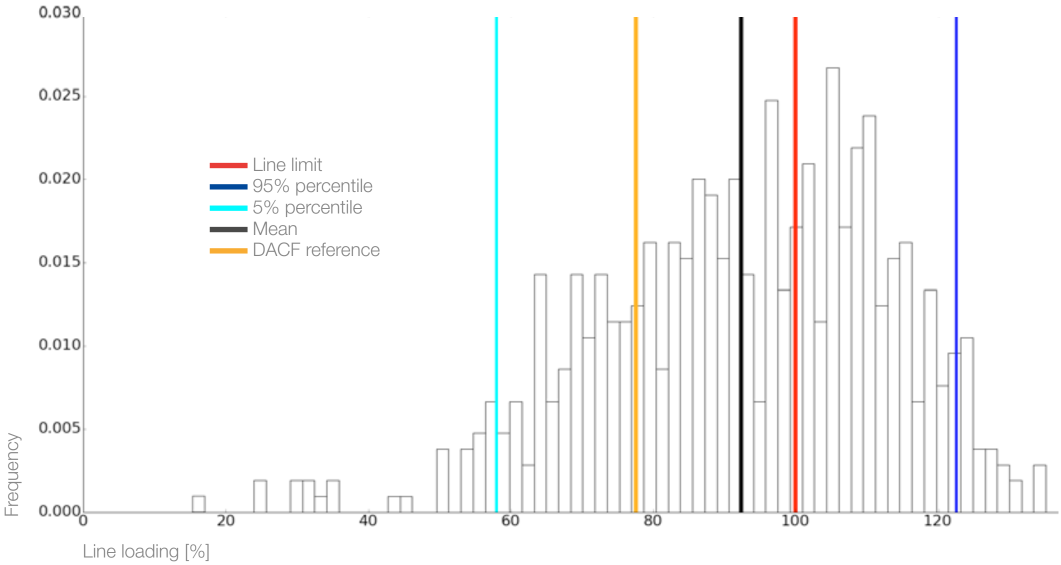

Figure 29: Loading of a selected line from Test Case 2: detailed probability distribution of the loading for a single timestamp (one single hour)

In this example, the mean value and the 95% percentile represent the possibility that the point forecast from the current DACF does not give the operator information about what the actual worst case could be.

The chosen visualisation in the diagram contains the same information as the previous diagram; this visualisation simply offers an alternative overview for operational staff.

The single-hour diagram also shows the upper and lower 5% of the SUCs, which were not considered in the 24-hour overview. In this case, the DACF differs from the mean value by about 10% points. The hourly diagram gives additional information in case the operator wants to verify the whole range of SUCs.

Recommendations

Over the past four years, the iTesla and UMBRELLA Projects have developed toolboxes in order to ensure secure grid operation. Based on these collaborative projects, common recommendations to ENTSO-E regarding TSO and RSCI rules for business processes and data exchange have been proposed. These address the need to meet requirements for TSOs and distribution system operators (DSOs) to improve interoperability and security in the pan-European grid system.

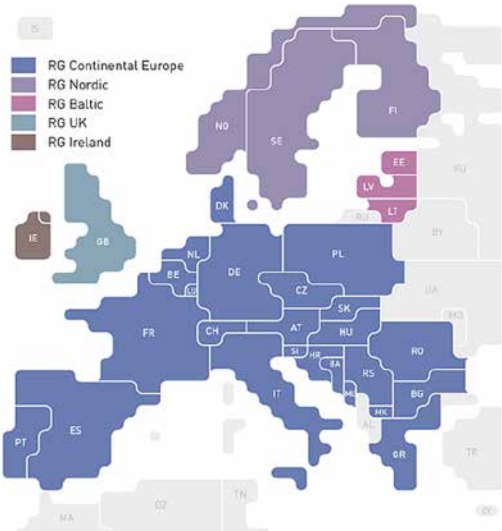

Figure 30: ENTSO-E regional groups [1]

Data format

In ENTSO-E Regional Group Continental Europe (RG CE), the Union for the Coordination of Transmission of Electricity Data Exchange Format (UCTE DEF) is currently in operation for several processes (DACF, IDCF and the two-day-ahead congestion forecast) which are performed by all TSOs. The UCTE DEF format is no longer suitable for tackling challenges with the grid as it is impossible to incorporate some of the data and limitations of the identifiers. After some investigation, the Common Information Model (CIM)/XML-based format for the Common Grid Model Exchange Standard (CGMES) was selected as the future format for the ENTSO-E RG CE. Consequently, European TSOs should switch the stationary data in their respective systems to CGMES format as soon as possible. Network element identifiers should be unique and consistent across the datasets so that an advance security assessment can be carried out.

Itemisation of formerly aggregated data

Most of the tools used by the TSOs to generate CGMES files have only a bus-branch description of the grid. This is unacceptable, since the thorough mapping of stationary and dynamic data is required to run accurate (dynamic) simulations. Therefore, TSOs should model the topology in a breaker-oriented way in order to assign equipment and loads properly.
When exchanging data using the CGMES format,

European TSOs should use consistent identifiers for equipment in order be able to match them with additional data automatically. The incorporation of this additional information, such as redispatch potential, should be considered in the further development of CGMES. The aggregation of injections (loads and generation units, as well as RES) should be avoided, whenever possible, and forbidden for large generation units.
Furthermore, a common understanding and, as far as possible, the harmonisation of the details of grid modelling should be sought by the TSOs. Only with this modelling is the use of the tools developed within both projects possible.

Exchange of contingency and merit-order data

In addition to the stationary data in their respective systems, European TSOs should exchange a list of contingencies to be simulated, or a methodology for determining these, as well as a catalogue of relevant remedial actions. In order to be exhaustive, the tools for assessing the security of power system situations should simulate not only the impact of the contingencies selected by the operator but also the efficiency of remedial actions adopted in cases of violation caused by these contingencies.
In addition, the merit order of remedial actions must be harmonised so that common proposals for remedial actions can be obtained from the new tools developed by iTesla and UMBRELLA. To ensure that the results of the innovative tools can be used most effectively, an open, transparent exchange of all required details is necessary.

Exchange of dynamic data

The need to take into account dynamic phenomena in operation in a more systematic way was fully confirmed by a survey conducted among iTesla TSOs at the beginning of the project. The next generation of tools to be developed by iTesla, which will be made available to operators in the next few years, will therefore include functionalities for accurate time domain simulations, potentially from a local geographical perimeter up to the pan-European one.
These models will simulate the dynamic behaviour of generators, control systems, protections and all other components with fast dynamic behaviours. They will detect every possible dangerous dynamic phenomenon that could occur in case of contingency N-1/N-k or if a remedial action were put in place by the operator to alleviate a constraint.
To this end, European TSOs should exchange dynamic data from their respective systems to be able to run time domain simulations on all or parts of the European system in order to ensure the systematic security assessment of system situations from D-2 to close to real time.

Short-tem solution for exchange of dynamic data

For the iTesla project, some TSOs have provided dynamic data in CIM format with very basic information and default parameter values compared to the data available in their own native format. It is unlikely that the CIM version of dynamic data, which is currently being prepared, will be ready any time soon. As a consequence, the best short-term option is for European TSOs to exchange dynamic data using the standard or individual TSO format used for internal dynamic studies.

Risk-based criteria for security assessment

Currently, no explicit calculation of risk takes place as part of operational planning or real-time operation. Moreover, even though the forecasted system state was N-1 secure, uncertainty due to intraday energy trades and forecasting errors regarding power injections from RES power plants

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might lead to frequent violations of the N-1 criterion in real-time operation.

In order to incorporate these risks, European TSOs should be encouraged to develop and include common risk-based criteria for security assessment in the operational planning process and real-time operation. In particular, these criteria should include data related to the reliability and/or failure rates of equipment, estimates of the (cost of) energy not served, as well as more comprehensive forecasts to describe uncertainty regarding RES, load and intraday trading.

Defence and restorations procedures

ENTSO-E analyses power system security based on:

- A conceptual classification of the system operating conditions into a number of system states: Normal, Alert, Emergency, Blackout and Restoration; and
- A defence plan, which is composed of a Special Protection Scheme and a System Protection Scheme [2].

To this end, European TSOs are encouraged to continue the harmonisation of defence plans and restoration procedures and consider the integration of solutions for coordinated power flow control as well as for the early detection of voltage and frequency instability.

Harmonisation of legal and regulatory framework

As stated in the previous recommendations, transmission system operation is increasingly complex due, among other things, to the increase in RES and cross-border trading. Therefore, the future security assessment tools developed by iTesla and UMBRELLA will support operational planners in a coordinated fashion by finding a common optimal solution for different types of congestion and combinations of uncertainty, taking time-dependent conditions into account. TSOs' experience shows that for daily operation to be successful, European TSOs should further develop and harmonise their processes for operational planning and real-time operation, incorporating the preferable functionalities from the research projects.

Support from the legal and regulatory side is needed in order to achieve the best possible solutions in terms of a European optimum. The most promising approach by which to achieve this is strong cooperation among the national regulation authorities.

Conclusions

In the framework of the UMBRELLA Project, we have developed a dedicated innovative toolbox to support TSOs' and RSCIs' future efforts to ensure grid security. The UMBRELLA Toolbox includes:

- The simulation of uncertainty caused by market activities and RES.
- A deterministic and probabilistic optimisation framework for corrective actions to cope with simulated risks on different timescales and increasing system complexity; the aim of this is to reduce the total cost of uncertainty while also increasing system security and transmission capacity.
- Risk-based assessment tools for anticipated system states with and without corrective actions.

The tools developed are synthesised in the UMBRELLA Toolbox, which offers users the flexibility of applying either individual modules or the complete set of functionalities. The individual software tools are extensively tested using IEEE test systems based on the historical datasets of the nine TSOs' target area through a decentralised approach. Thus, the concept of the individual methods, as well as the UMBRELLA Toolbox

Prototype that combines them, is proven by applying them to historical TCs, such as the cold snap on 8 February 2012 and the stressed-grid situation which arose on 22 August 2012.

The tests performed by the TSOs with the support of the universities and research institutes show that the UMBRELLA Toolbox is able to:

- calculate remedial actions to ensure the safe and reliable operation of the transmission network; and
- give the operator additional information about the range of uncertainty that can be expected.

It is shown that the application of the UMBRELLA Toolbox Optimisation Framework speeds up the current experience-based process significantly by avoiding unnecessary iteration steps, since the conflicting activation of remedial actions by different TSOs is avoided. This gives the operators and operational planners the necessary time to prepare the actual implementation of the proposed remedies.

According to the GRID+ concept, KPIs are evaluated to compare business as usual with the results of the new innovative tools. This reveals the significant progress brought about by the new tools. Besides a considerable improvement in the security of system operation, the recovery of overall UMBRELLA Project can be expected within one month when the UMBRELLA Toolbox functionalities are applied.

Further development of the Toolbox and a parallel dry run are currently being prepared by the TSC initiative. This will enable TSOs to identify optimal settings for the Toolbox in order to implement it in daily operational planning processes as well as in real-time operation.

As the envisaged exploitation of the UMBRELLA Toolbox shall be embedded in established information systems, the extension and harmonisation of data exchanges is crucial. A stepwise approach is proposed for the implementation of the UMBRELLA Toolbox by TSOs and RSCIs to overcome the challenges on the path from research to the industrialisation of the UMBRELLA Toolbox. Thus, the adaptation of processes and the introduction of the new CGMES data format can go hand in hand with the gradual introduction of the related tools.

As a result of the UMBRELLA and iTesla projects, a set of recommendations is provided for stakeholders such as regulators, policymakers, TSOs and ENTSO-E to foster the necessary harmonisation of the legal, regulatory and operative framework as well as to allow data exchange for the application of the new software tools.

In conclusion, the UMBRELLA Project has fully achieved its goals of developing scientific methods beyond the state of the art and demonstrating and testing the UMBRELLA Toolbox concept.

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