WP4

Predictive Management Tools for Transmission and Distribution Systems Operation

D4.1

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Abbreviations and Acronyms

ADF	Augmented Dicky Fuller
ARIMA	Auto Regressive Integrated Moving Average Model
DA	Day-Ahead
DG	Distributed Generation
DER	Distributed Energy Resources
D-MPC AC OPF	Distribution level Model Predictive Control AC OPF
DSA	Dynamic Security Assessment
DSO	Distribution System Operator
EES	Electical Energy Storage
FL	Flexible Loads
LFSM	Limited Frequency Sensitivity Mode
LV	Low Voltage
MLA	Machine Learning Approaches
MPC	Model Predictive Control
MV	Medium Voltage
NLP	Non-Linear Programming
OP	Operating Point
OPF	Optimal Power Flow
PV	Photo-Voltaic
SCOPF	Security Constrained OPF
S-MP-MINLP	Stochastic Multi-Period Mixed Integer Non-Linear Programming
S-MP-MILP	Stochastic Multi-Period Mixed Integer Linear Programming
S-MP-SCOPF	Stochastic Multi-Period SCOPF
RES	Renewable Energy Sources
RoCoF	Rate of change of frequency
RT	Real-time
T-MPC AC OPF	Transmission level Model Predictive Control AC OPF
TSO	Transmission System Operator
VDIFD	Voltage Dip-Induced Frequency Deviations

Executive Summary

This deliverable titled “Specification of the operation tools” stems from WP4 of ATTEST project. The overarching objective of WP4 is to develop a set of six innovative tools for cost-optimal, secure, and coordinated predictive management in the operation of transmission and distribution networks. Specifically, the three tools for distribution system operators target ancillary services procurement in day-ahead operation planning, ancillary services activation in real-time operation, and state estimation, while the three tools for transmission system operators concern ancillary services procurement in day-ahead operation planning, ancillary services activation in real-time operation, and on-line dynamic security assessment. This deliverable aims to describe the functional and technical specifications of these six tools in detail, being mindful that their continuous development to the final version, which is due in ten months, may lead to further changes. The specification of each tool comprises five aspects, namely: functional description, technical description, input and output requirements, computational requirements, and interaction with other ATTEST tools.

1. Tool for ancillary services procurement in day-ahead operational planning of the distribution network (Task 4.1)

The accelerated penetration of renewable distributed generation (DG) units, distributed energy resources (DER) and flexibility deployments in distribution networks has put them in a transition phase from passive network operation to active grid management. Consequently, advanced tools, which must take-into-account the features of the power systems of the future, are needed to model, analyze and optimally operate such networks. The existing tools, which distribution system operators (DSOs) currently use to manage their networks, either lack advanced modelling and analyzing features or are ineffectively utilized due to large computational costs and poor observability of distribution networks. Accordingly, future power networks can no longer be analyzed and operated based on the existing tools and thus there is a strong need to develop advanced tools, which must cater the features of such energy systems, being able to perform an in-depth analysis of these networks thus leading to a reliable and optimal day-ahead and real-time operation by DSO. Furthermore, these tools must also foster a tight coordination between transmission system operator (TSO) and DSOs at their interfaces to share the flexibility present in the distribution networks.

The state-of-the-art tools for optimal operation planning of distribution networks consider the multi-temporal aspects but largely ignore the forecast uncertainty and interaction with TSO. Furthermore, existing tools are generally computationally costly, and these computational costs are expected to increase if the tools are extended to capture flexibility, uncertainties, interactions with the TSO and other factors. As a result, the scalability and tractability of these tools remain an open issue for real-world power systems. Consequently, to carry out the optimal operation of distribution systems of the future, it becomes incumbent to develop a tractable as well as a scalable optimal power flow (OPF) tool that on the one hand, models every aspect of these grids and on the other hand, remains computationally efficient.

To achieve this overarching objective, the task T4.1 proposes a day-ahead operational planning tool for distribution networks which employs a novel two-stage tractable algorithm in order to procure ancillary services by taking-into-account all aspects of future distribution networks such as flexible resources, uncertainty aspects of renewable DERs and interaction with TSO.

In the following, a high level functional and technical description of the developed tool is provided along with its computational requirements and interaction with the other tools of ATTEST project.

1.1. Functional description

The objective of this tool is to determine the optimal flexibility scheduling of available DG units and DER to support the procurement of ancillary services (congestion management and voltage control) by the DSO on a 24-hour basis. The tool optimizes the use of flexibility by mitigating renewable DG units' uncertainties and ensure that network capacity is never exceeded during the real-time operation stage of distribution networks.

The developed tool takes-into-account (i) the uncertainty modelling of renewable DG units, (ii) modern flexible DERs such as energy storages and flexible loads, (iii) aggregated flexibility of low-voltage systems at medium voltage (MV)/low voltage (LV) interface, and (iv) actions of network management controllers of MV grid and interaction with TSO. At its input, the tool utilizes distribution network data as well as generation scenarios representing the uncertain behavior of DG units (see 1.3.1). Furthermore, the output of the TSO/DSO coordination mechanism defines the constraints of this tool to ensure that TSO and DSO do not procure conflicting ancillary services in the market (see 1.3.2). The tool then minimizes the overall cost of network operation which consists of the expected cost associated with the DER deviation from the market schedule i.e., the cost required to re-dispatch the active and reactive power, and provides optimal set-point values of distribution control means along with the cost of procuring the ancillary services at its output.

The resulting OPF problem, involving all the above-mentioned features, becomes a stochastic multi-period mixed-integer non-linear programming (S-MP-MINLP) problem in its basic formulation which cannot be solved for large-size real world power systems due to current limitations of state-of-the-art MINLP solvers. Consequently, to break-down the high computational complexity of the resulting problem, a novel two-stage decomposition algorithm is developed which ensures the tractability as well as scalability of the resultant tool. The proposed algorithm iterates between the upper and lower levels, where in each level a specific dimension (either time or uncertainty) of the resulting problem is solved until a stopping criterion is met.

A high-level functional diagram of the developed tool is shown in Fig. 1.

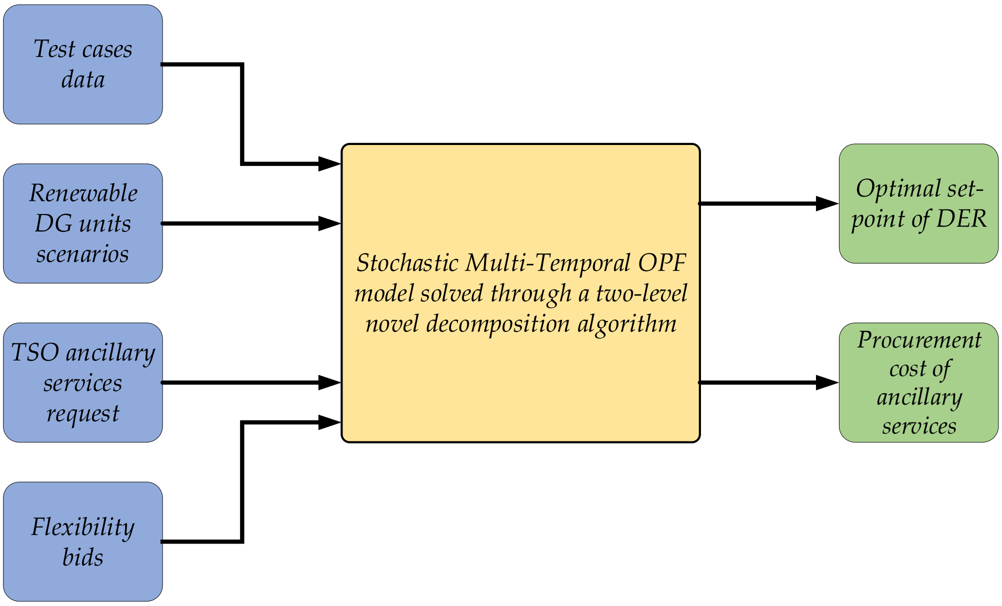

FIG. 1 HIGH LEVEL FUNCTIONAL DESCRIPTION OF TOOL 4.1

The developed tool will be tested on several real-world test cases which are developed in T2.3 as mentioned in Table 1. Further information about these test cases can be found in D2.3 (Test cases) of WP2 (Toolbox specification, support tools and test cases).

TABLE 1: TEST CASES FOR THE EVALUATION OF TOOL 4.1

Network Type	Country	Voltage Level (kV)	No. of networks
Distribution	*Portugal*	*15, 30, 60*	*3*
	Spain	*66, 110, 132*	*3*
	UK	*6.6, 11*	*3*
	Croatia	*10, 20, 35*	*3*

1.2. Technical description

The technical description of the developed tool can be divided into three parts namely (i) renewable DG units, wind and photo-voltaic (PV), scenario generation, (ii) development of a benchmark tool based on S-MP-MINLP AC OPF formulation, iii) development of a tractable tool based on stochastic multi-period mixed-integer programming (S-MP-MILP) AC OPF formulation. A brief and high-level description of each part is given below.

1.2.1. Renewable DG units' scenario generation through Auto-Regressive Integrated Moving Average (ARIMA) model

The variability in wind speed and solar irradiance is represented by a set of scenarios which are generated by a timeseries based ARIMA model [3]. The ARIMA model is a widely adopted methodology for generating future time-series due to their reliance on the past values of time-series. Resultantly, if enough historical wind speed and solar irradiance/power data is available, then ARIMA model becomes one of the best existing approaches to generate future scenarios of wind and solar power. Consequently, this modelling approach is adopted in this work and future wind and solar power scenarios are generated in the context of stochastic multi-period AC-OPF framework. In the following, a brief explanation corresponding to the generation of wind and solar power scenarios through ARIMA model is presented.

An ARIMA (p, d, q) model of a non-stationary random process ***Z(t)*** can be expressed as:

$$\left\{1-\sum_{i=1}^{p}\gamma_i B^i\right\}(1-B)^d Z(t)=\left\{1-\sum_{i=1}^{q}\theta_i B^i\right\}\omega(t) \tag{1}$$

where γ_i are auto-regressive terms, ϑ_i are moving-average terms, $\omega(t)$ is white noise having zero mean and variance λ^2, B is backshift operator such that $B^i Z(t) = Z(t-i)$. Based on this process, following approach is adopted for the generation of wind speed and solar power scenarios.

1) The order ***d*** for the chosen non-stationary wind and solar time-series is determined first by Augmented Dickey-Fuller (ADF) test. For wind series, the ADF test is applied on the complete wind speed data. However, the diurnal nature of solar power series leads to its transformation first into a set of new series, where each newly formed series now contains the data of the same/identical hour of the whole horizon, and subsequently, the order ***d*** is determined for each newly generated series.
2) For wind speed series, the autocorrelation and partial auto-correlations functions are used to determine the number of *q* and *p* terms, respectively.
3) For solar power series, initially the order of *p* and *q* is set to 4 and subsequently, those combination(s) of *p* and *q*, for which the polynomial of ARIMA model becomes non-invertible, are discarded.
4) After determining the value of (p,d,q), the coefficients γ_i and ϑ_i are determined for both series using maximum likelihood estimation for Weibull distribution.
5) The order (p,d,q) and coefficient terms are put in (1) to generate the scenarios for wind speed and solar power.
6) The generated scenarios are not the true representation of actual wind speed and solar power due to the presence of white noise in (1). Consequently, a distribution transformation process $Y(t) = \psi^{-1}F_z(Z)$ is used to obtain the true scenarios of wind speed and solar power. In the above formula, Z is the time series obtained from (1), F_z is the cumulative distribution function of Z and ψ^{-1} () is the quantile (inverse distribution) function of the historical wind speed and solar power distribution.
7) Finally, wind power scenarios are determined from the wind speed scenarios through a Weibull-based speed-power transformation model.

Once wind and solar power scenarios are determined, their probabilities are calculated by (2).

$$\min \sum_{t \in T} \left\{ \sum_{s \in S} \pi_s \alpha_s^t - \mu_t \right\}^2 \tag{2}$$

subject to:

$$\sum_{s \in S} \pi_s = 1$$

$$\pi_s \geq 0$$

This optimization problem determines the probability of each wind and solar power scenario independently. However, in the S-MP-MINLP/S-MP-MILP formulation, a scenario $s_{op}(t)$ is considered as a joint implementation of wind $s_{wp}(t)$ and solar $s_{pv}(t)$ scenarios and the probability of applied scenario i.e., $s_{op}(t)$ is determined as a product of probability of $s_{wp}(t) \times s_{pv}(t)$.

As stated before, historical input wind speed and solar irradiance/solar power data is needed to generate future scenarios of wind and solar power; consequently, DSOs can rely on either existing databases or weather prediction/measurement centres to have historical values of these quantities.

1.2.2. Benchmark Tool based on Stochastic Multi-Period Mixed Integer Non-Linear Programming AC OPF Formulation

In order to validate the accuracy of tractable tool T4.1 which is based on S-MP-MILP AC OPF formulation, a benchmark tool based on S-MP-MINLP AC OPF formulation is also developed [2] which optimally procures ancillary services from flexible DER in a day-ahead operational planning framework. The tool is developed for a medium-voltage distribution network assuming balanced operation i.e., a single-phase equivalent representation of distribution network is considered. Furthermore, renewable DG units (wind and solar) power scenarios, as developed in section Renewable DG units' scenario generation through Auto-Regressive Integrated Moving Average (ARIMA) model1.2.1, are taken as an input to this tool.

In order to mimic the distribution networks of the future, conventional and emerging technologies presented below, are modelled in the tool. It is important to emphasize that the considered flexibility options, except for the on-load tap changer transformers, are privately owned and are not DSOs assets. Furthermore, as the distribution network reconfiguration control option is out-of-scope of the project, therefore, it is not considered in the benchmark tool. Finally, the developed tool is applicable to distribution networks regardless of their topological layout or modelling details.

1. Energy storage systems
2. Flexible loads
3. Reactive power provision from renewable DG units
4. Active power curtailment of renewable DG units
5. On-Load Tap changing transformer control

Based on these flexibility sources, the following decision variables are considered in each uncertainty scenario and time-period.

1. Amount of curtailed generation of each renewable DG unit
2. Active power charging of each storage unit
3. Active power discharging of each storage unit

4. Active power over-demand of each flexible load
5. Active power under-demand of each flexible load
6. Active power flow from HV upstream grid
7. Reactive power flow from HV upstream grid
8. Power factor of each DG unit
9. Binary variables that models the charging of each storage unit
10. Binary variables that models the overdemand of each flexible load

In the developed tool, all the above-mentioned decision variables are treated as wait-and-see decision variables i.e., even though the optimization problem would be solved in a day-ahead operational planning framework, DSO would set the optimal set-point of all DER after running the real-time activation tool developed in Task 4.2.

Finally, the tool at its output provides the expected cost of procurement of ancillary services, which is related to the DER deviation from the market schedule, and optimal set-points of each flexible DER during each time period and uncertainty scenario.

1.2.3. Tractable Tool based on Stochastic Multi-Period Mixed Integer Linear Programming AC OPF formulation

The tractable tool based on S-MP-MILP AC OPF formulation employs a novel two-level decomposition algorithm by resorting to novel linearized AC active and reactive power injection, and longitudinal branch current expressions. In the upper level of the proposed algorithm, a multi-period mixed integer linear programming (MP-MILP) AC OPF model is solved for a representative scenario. The binary variables obtained in this level are fixed in the lower level which solves a time-coupled multi-period NLP AC OPF problem by considering all uncertainty scenarios.

In this regard, a novel second-order linear approximation of the AC OPF model is developed which is based on the novel square value of voltage magnitude and voltage angle difference variables. Furthermore, it does not use small angle and flat/near voltage assumptions and implicitly models network losses and their dependency on both voltage magnitude and voltage angle terms. Full information about the power system physical quantities is available from the obtained converged solution and therefore there is no loss of information as observed in relaxation techniques.

The tool considers the same flexibility options as outlined in section 1.2.2 with the same afore-mentioned decision variables and solves the problem of minimizing the cost of procuring ancillary services. Finally, the tool at its output provides the same information as reported in section 1.2.2 i.e., the cost of procuring ancillary services and optimal re-dispatch of available flexible DERs.

1.3. Input and output requirements

As reported in section 1.1, the input and output data of developed S-MP-MILP based AC OPF tool is as follows.

1.3.1. Input data

The input data of this tool is

i) Test cases which are developed in T2.3 (Test cases) of WP2 and datasets from Croatian DSO (HEP ODS) which are provided in WP7. The test cases provide the necessary network data such as information related to network buses, lines, loads, transformers and generation units. Please refer to Appendix A.1 which depicts the network data information.

ii) Ancillary services bids offered by flexibility providers as defined in T2.6 (Market simulator).

iii) Renewable DG units' uncertainty scenarios which come from the scenario generation approach. The generated scenarios using the scenario-generation tool mentioned in section 1.2.1 are described in Appendix A.2.

iv) Specific TSO requests (from T4.4) for ancillary services in terms of active and reactive power set-points at substations interfacing TSO and DSO in order to ensure that TSO and DSO do not procure conflicting ancillary services in the ancillary services market

1.3.2. Output data

The output data of this tool is

i) Expected cost of the procurement of ancillary services for congestion management and voltage control

ii) Optimal set-points of each DER/optimal re-adjustment of flexible assets corresponding to various ancillary services during each uncertainty scenario and time-period.

1.4. Computational requirements

The developed tool is programmed in Julia under Windows platform with Jump being used as a modelling layer and several solvers such as BARON, IPOPT and CBC are used to solve MINLP, NLP and MILP version of the stochastic multi-period AC OPF problems.

For solving small size S-MP-MINLP and S-MP-MILP AC OPF problem, 16 GB memory is enough. However, for large-scale power systems, the exact memory requirement is still to be decided.

1.5. Interaction with other tools

Fig. 2 shows the interaction of tool T4.1 with the other tools of ATTEST project. The interaction of tool T4.1 can be split into two main categories which are described in the following subsections.

1.5.1. Input data from ATTEST Tools

The tool T4.1 utilizes the test cases developed in T2.3, datasets from Croatian DSO (HEP ODS) provided in WP7 and flexibility bid offers (flexibility resources activation cost) from the market simulator (T2.6) as input data. Furthermore, the tool interacts with the T4.4 (TSO/DSO coordination mechanism) and responds to TSO specific requests (issued from T4.4) for ancillary services in terms of active and/or reactive power setpoints at the interconnection substation of TSO and DSO.

1.5.2. Output data to ATTEST Tools

The tool provides information about the optimal-set points of DER/optimal readjustment of flexibility resources corresponding to various ancillary services, and the cost of activation of ancillary services which will be utilized by real-time ancillary services activation tool (T4.2) during real-time operation of distribution network.

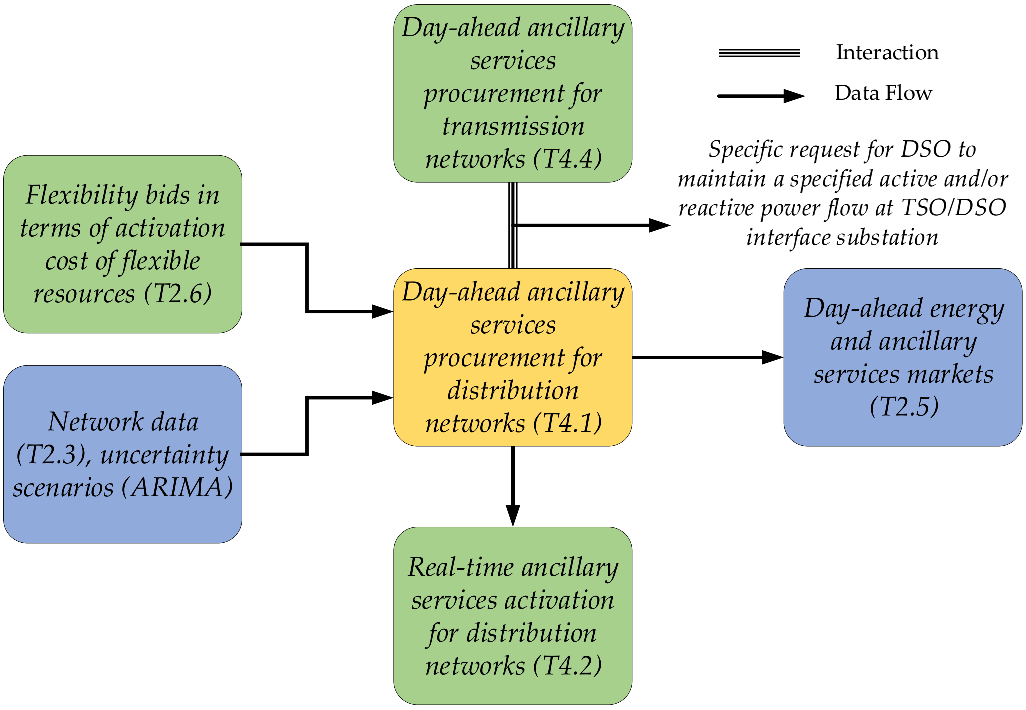

FIG. 2: INTERACTION OF TOOL 4.1 WITH OTHER ATTEST TOOLS

2. Tool for ancillary services activation in real-time operation of the distribution network (Task 4.2)

2.1. Functional description

System operators make decisions in the day-ahead (DA) stage to ensure secure and stable network operation for the next day considering different scenarios. Due to imperfect predictions of load, production of renewable energy sources (RES), or possible contingencies in the network, these decisions can deviate from the realized events in real-time (RT). Unlike predictions made in DA stage, precise measurements and correct information are available in RT which require corrective actions from the system operators in order to satisfy network constraints and, for the TSO, to maintain frequency control among others.

In order to ensure this, the purpose of this tool is to activate flexibility service providers connected to the distribution grid according to the signals sent by the TSO and, at the same time, to satisfy distribution network constraints. This tool receives information in each time step from the tool developed in T4.5 (Tool for ancillary services activation in real-time operation of the transmission network) in which the TSO requires from the DSO either to follow the agreed DA schedule in terms of active (P^{DA}) and reactive (Q^{DA}) power exchange at each TSO/ DSO interface (HV/MV connection point) or to activate distributed flexibility providers reserved in DA stage (these active and reactive power request can be in range from $[P^{DA} - P^{down}, P^{DA} + P^{up}]$ and $[Q^{DA} - Q^{down}, Q^{DA} + Q^{up}]$, where $P^{down}, P^{up}, Q^{down}, Q^{up}$ are reserved active and reactive power in DA for providing flexibility services to the TSO). The DSO can receive this request either as:

i) one value for active and one value of reactive power in terms of P^{req} and Q^{res},
ii) two values for active power, either $P^{DA} - P^{act\_down}$ or $P^{DA} + P^{act\_up}$, where P^{act_down} can be in range from $[0, P^{down}]$ and P^{act_up} can be in range from $[0, P^{up}]$, and two values of reactive power, either $Q^{DA} - Q^{act\_down}$ or $Q^{DA} + Q^{act\_up}$, where Q^{act_down} can be in range from $[0, Q^{down}]$ and Q^{act_up} can be in range from $[0, Q^{up}]$.

The problem is formulated as multi-temporal distribution level model predictive control AC OPF (D-MPC-AC OPF). The DSO runs RT OPF to determine the minimal cost of flexibility activation to satisfy the request from the TSO and in the same to solve local congestion and voltage problems if state estimator detects the violation of distribution network constraints. In the case without distribution constraints violation and no request from the TSO for flexibility activation, the model can have different objectives, such as loss minimization. The problem needs to include multi-temporal features, such as ramping rates, energy storage state of energy, shiftable load constraints, etc.

Model predictive control checks if the required flexibility service provider in time-step *t* was activated in the previous time step *t-1* and if the service was provided. Moreover, model predictive control checks if the service from the same provider will be needed in the time step *t+n.* The MPC rolls every 5/15-minutes and predicts the optimal operating points in order to solve local congestion and voltage problems.

In practice, real-time monitoring is limited at the distribution level. To tackle this issue, the tool for ancillary services activation in real-time operation of the distribution network developed in T4.2. receives the data from the state estimator, including the topology estimation and real-time-measurements (active and reactive power on current injections and grid status). The tool receives the reserved amount of flexibility for each ancillary service provider connected to the distribution grid from the DA stage from the tool developed in T4.1. and activation price of each flexibility provider from the tool developed in T2.6.

A functional diagram of the tool is given in Fig. 3:

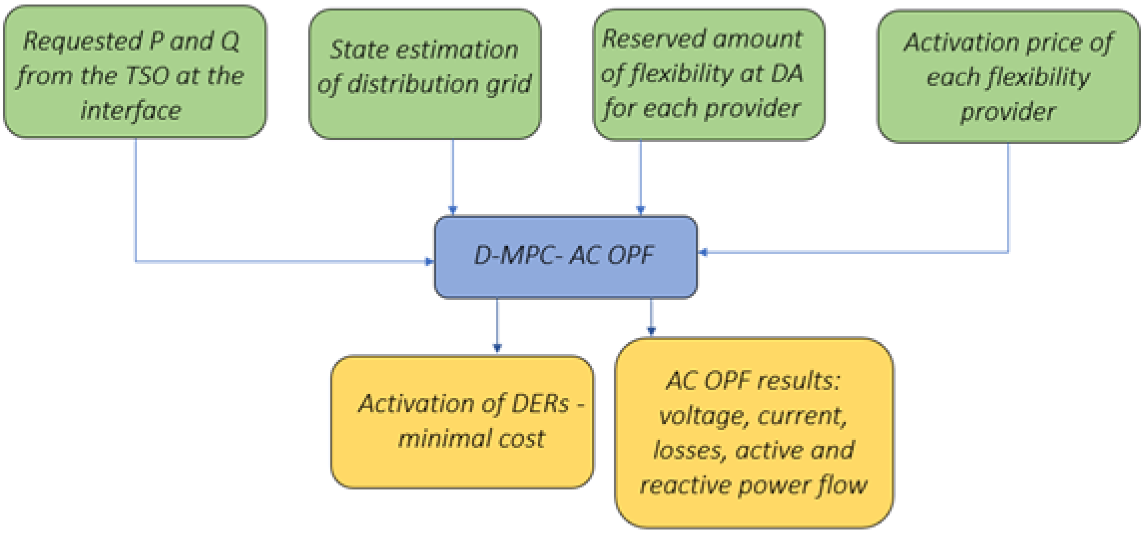

FIG. 3: HIGH LEVEL FUNCTIONAL DESCRIPTION OF TOOL 4.2

2.2. Technical description

The tool developed in T2.4. receives active and reactive power request in RT from the TSO for each time step at the TSO/DSO interface. The tool runs the AC OPF algorithm minimizing flexibility activation cost to satisfy the request sent by the TSO.

The objective function minimizes the cost of flexibility activation when needed:

$$\sum_{i \in I} \lambda^i F_t^i \quad \forall t \in T \tag{3}$$

λ^i is activation price of flexibility provider *i* and F_t^i is activated amount of flexibility from provider *i* in the time step t (both active and reactive power flexibility activation is considered).

The tool uses the AC model of the OPF problem in rectangular coordinates as described with (4) and (5):

$$P_{ij} = e_i^2 G_{ij} + f_i^2 G_{ij} - e_i e_j G_{ij} + e_i f_j B_{ij} - f_i e_j B_{ij} - f_i f_j G_{ij} \tag{4}$$

$$Q_{ij} = -e_i^2 B_{ij} - f_j^2 B_{ij} + e_i e_j B_{ij} + e_i f_j G_{ij} - f_i e_j G_{ij} + f_i f_j B_{ij} \tag{5}$$

where P_{ij} and Q_{ij} represent active and reactive power flows on the line ij, e_i and f_i are real and imaginary part of voltage at the bus i, while B_{ij} and G_{ij} are susceptance and conductance of the line ij. The same network data (B_{ij} and G_{ij}) are used in T4.1 for DA operational planning of the distribution network. The tool considers DG units connected to the distribution network, storage units, OLTC transformers and other flexibility providers.

Following decision variables are considered in each time interval:

i) active and reactive power flow on each line,
ii) voltage magnitude and angle at each bus,
iii) current on each line,
iv) activated flexibility for each distributed service provider and total cost for activation.

2.3. Input and output requirements

2.3.1. Input data

The input data for this tool are following:

i) Test cases which are developed in T2.3 (Test cases) of WP2 and datasets from Croatian DSO (HEP ODS) which are provided in WP7. The test cases provide the necessary network data such as information related to network buses (network topology), lines (susceptance and conductance of the line, thermal capacity of lines), transformer characteristics, active and reactive values of load and generation units,
ii) The upper and lower bound of ancillary services reserved in T4.1 (Ancillary services procurement in day-ahead operational planning of the distribution network) for each flexibility service provider together with the number of activations,
iii) State estimation of distribution network from T4.3.,
iv) Active and reactive power at the interface requested by the TSO in RT, specified in T4.5 (active and reactive power flow from the upstream grid)
v) Technical constraints of the flexibility service providers (maximum charging and discharging power of battery, battery capacity, etc.),
vi) The price of flexibility activation determined in T2.6.

2.3.2. Output data

The outputs of the tool include:

i) Information about activated flexibility service from each provider (how much is provided, when is the service called and for how long),
ii) Minimal cost for providing flexibility services from resources connected to the distribution network and activated to satisfy both the request from the TSO and distribution network constraints,
iii) Active and reactive power flow,
iv) Voltage magnitude and angle at each bus,
v) Current on each line,
vi) Losses in the distribution network.

2.4. Computational requirements

The developed tool is programmed in AMPL and uses the KNITRO solver.

For solving small size AC OPF problem, 8 GB memory is enough. However, for large-scale power systems, memory requirements increase to 16 GB. Since the model does not contain binary variables, the computational time does not exceed 10 seconds.

2.5. Interaction with other tools

Fig. 4 shows the interaction between tool T4.2 and the other tools of ATTEST project. Tool 4.2. receives data from:

i) test cases developed in T2.3,

ii) active and reactive power requests from the TSO at the interface (these values can be in the range from $[P^{DA} - P^{down}, P^{DA} + P^{up}]$ and $[Q^{DA} - Q^{down}, Q^{DA} + Q^{up}]$) from T4.5,

iii) estimated load profile and network topology from T4.3. which serve as required input for AC OPF analysis due to insufficient data for the distribution level,

iv) upper and lower bound of reserved flexibility in DA for both active and reactive power for each flexibility service provider from T4.1,

v) activation price of each flexibility service provider from T2.6.

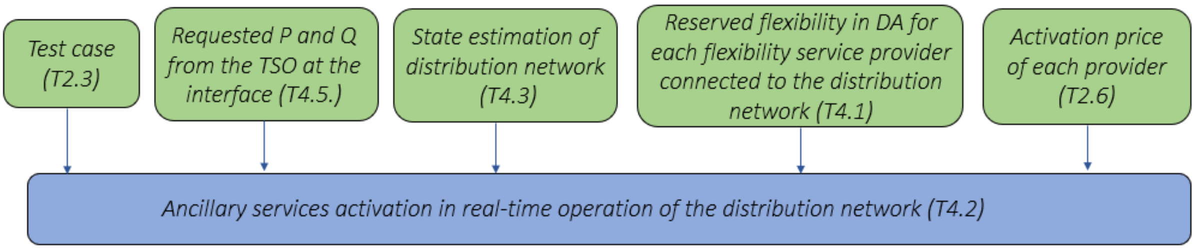

FIG. 4: INTERACTION OF TOOL 4.2 WITH OTHER ATTEST TOOLS

3. Tool for state estimation of distribution networks (Task 4.3)

3.1. Functional description

State estimation is one of the key functions in power system monitoring and control. It is typically employed in transmission systems and normally represents an input for the optimal power flow, voltage control and other advanced energy management systems functions. The state estimation, in general, is the calculation of the most likely complete and consistent network representation, based on the measurements collected from the actual system. More information can be found in [3] and [4].

In electric power systems the parameters that are required to determine all other quantities of a power system are: voltage magnitudes V_k (where k=1..n is the number of modeled nodes in the system), phase angles θ_k for all the nodes, transformer tap – tap ratio magnitude t_{kn} and phase shift angle ϕ_{kn}. These electric quantities serve at estimating any other quantity like for instance the active and reactive power flows through a line or transformer P_{kn}, Q_{kn}. Given a set of measurements z, any value in the power system can be decomposed into:

$$z_j = h_j(\boldsymbol{x}) + e_j \tag{1}$$

where

- $\boldsymbol{x}$ is the *true* system state vector of voltages magnitudes and voltage angles $[V_1, V_2 \dots, V_k, \theta_1, \theta_2, \dots \theta_k]$ – this vector is a theoretical value never really known in practice;
- z_j is the j-th measurement;
- h_j relates the j-th measurement to the true states and
- e_j is the (inevitable) measurement error.

In most general terms, the task of state estimation is to determine the most likely state of the system, based on the measured quantities. More precisely, the task of state estimation starts with taking the collected measurements from the network, compounds them with the so-called pseudo measurements, processes the information on breaker positions to calculate the estimated system topology, filters out the bad and erroneous data, and then calculates (i.e., *estimates*) the most probable system state vector consisting of estimated voltages magnitudes and voltage angles.

State estimation is required due to various imperfections and uncertainties in measurement data value chain: current and voltage transformers are not ideal, transducers such as analog to digital convertors may introduce additional errors, imperfections in SCADA systems and challenging time synchronization with remote intelligent electronic devices (IED) data may result in skewed values attributed to a given time instant, calculation rounding errors etc. There are several classic methods such as minimum variance method, maximum likelihood method and weighted least squares method. Without going into details at this point, several assumptions are normally made about the statistical properties of metering errors and the weighted least squares power system estimator is the most used method in practice. After the preliminary data preparation steps, the state estimation is then converted into an optimization problem where measurement errors are assumed to be independent.

In the case of distribution networks, the above uncertainty in the data is exacerbated by several orders of magnitude by the lack of live measurements from the actual distribution system. This means there is a clear distinction between the task of state estimation in transmission networks, where most of the network is covered by the measurements, and in distribution networks where this is not the case. Therefore, the main challenge of state estimation in MV distribution networks is the scarcity of real-time network monitoring. This means that estimating the key real-time quantities (i.e. pseudo-measurements) is a crucial part for the MV network state estimation.

In practice, for MV networks the data at feeder points is generally available, but live data availability is not possible for the load nodes so the typical approach to MV state estimation is to focus on so-called load calibration, i.e., determining the active and reactive power and current injection at the load nodes, based on the most recently available measurements and the other available information on the network. Furthermore, in medium voltage distribution networks the network topology status may be unknown or uncertain, even when the corresponding historical data exists. This calls for an approach robust enough to handle uncertain topological situations.

The proposed method for state estimation should be able to collect the relevant data from diverse sources as the MV state estimation complexity increases with the presence of distributed energy sources in the network. The proposed estimation method for MV networks is designed so that it can gather and utilize the available information for the calibration part coming from other sources of data as well. One can expect availability of typical daily load profiles or a historical database of energy and power, or even data from smart meters with a certain delay, and there may be forecasted data on energy production for distributed energy sources that can be included as input to pseudo load measurement estimation.

3.2. Technical description

As explained in the previous chapter, the principal challenge of the state estimation in the context of medium voltage distribution networks is the lack of available data, compared to high voltage transmission networks.

The data required for MV state estimation is as follows, where available:

- SCADA acquired live measurements in HV to MV substations
- SCADA acquired live measurements in MV to LV substations
- Network parameters (R, X)
- Network topology
- Switchgear statuses
- Network load information

The above values can be divided in two distinct types of values, whose acquisition requires quite opposing approaches:

- Values available live from the SCADA system
- Values that must be calculated indirectly and estimated from the data available in systems other than SCADA.

The former must be acquired as soon as possible with little impact on the existing systems, while on the latter, the principal integration challenge is keeping up with the data semantics. Given the functional description above, the state estimator tool can be divided into four main principal blocks, of which two are data adapter modules and two algorithm modules, and two infrastructural components:

1) SCADA live data adapter and corresponding simulation tool
2) Other data adapter interface
3) Pseudo measurement generator algorithm module
4) State estimation algorithm module
5) Main event-driven platform

6) Graphical user interface

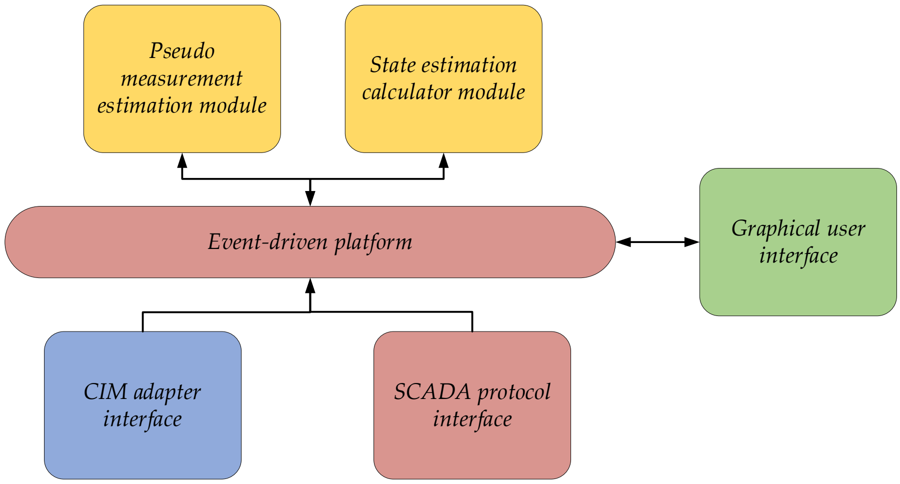

FIG. 5: THE MAIN BUILDING BLOCKS OF T4.3 STATE ESTIMATION TOOL

The former two components are data acquisition components, while the latter are related to analytics. The latter two modules are interfaced using an approach that allows parallel testing of different algorithms, as explained below.

3.2.1. Live SCADA data adapter and main event-driven platform

As the state estimator must work with live data, the ATTEST state estimator is designed to be pluggable into a distribution network control centre and utilizes KONČAR's open source automation platform called PROZA HAT to support commonly used communication protocols in order to get "live" values from the SCADA systems in place at the DSO.

In this event-driven platform, any change in the observed system is seen as a generic event in this event-driven module. This platform considers events as general, central data structures carrying the information indicating the change. In this case, the change in SCADA measurement value then triggers the change in this interface module, which may in turn trigger recalculation of estimated values. The module consists of a central event bus, with several protocol converters and functionalities to trigger the data processing modules.

The graphical user interface modules from the platform are also used in the current state estimation implementation so it can be implemented seamlessly in the DSO control centre. Furthermore, during the development phase, this is also utilized as a simulation tool to simulate the arrival of live data from the SCADA system. While other tools also include data ingestion, the event-driven nature of this module merits being pointed out.

3.2.2. CIM compliant data adapter module

For the data not available in the SCADA system that may serve as an input to the state estimation algorithm, such as load curves from the load points, the state estimation tool will utilize the IEC CIM-compliant [5] data access backbone infrastructure to connect to other systems in the DSO. The IEC Common Information Model is a data dictionary defining the relations and semantics of all data related to electrical networks and in the recent years has become the de-facto standard for information exchange among the systems in the DSO. Being compatible with this standard makes the ATTEST tools future-proof and minimizes the maintenance burden in the future. While the module described in previous chapter focuses on being event-driven, this data acquisition module primarily focuses on data integration.

3.2.3. Pseudo measurement generation module

Both this module and the following module are plugged into the central event-driven system backbone through a glue component called Artificial Intelligence Model Manager or AIMM. The AIMM approach allows implementation of diverse analytical algorithms, implemented as plugins, while the remaining system stays unchanged – and allows the implementation of several algorithms at the same time so that the results can be directly compared. As the SCADA interface module allows simulation of arrival of new data, this rounds up the environment for testing several pseudo measurement estimation and state estimation algorithms.

At the time of writing of the document, the current development version of the pseudo measurement estimator uses a simple linear extrapolation method to extrapolate all the loads in the system. These are then fed back to the central event driven platform, so the state estimator sees the pseudo measurements in the same fashion as the "ordinary" measurements acquired from SCADA.

3.2.4. State estimator algorithm module

this module initially collects the data from the event-driven bus and subsequently, performs the topology estimation by means of an optimization algorithm, and calculates the most probable system state vector consisting of estimated voltages and voltage angles. At the time of writing of this deliverable, the topology estimator submodule has not yet been implemented and only the simple direct Gauss-Newton calculation has been implemented to determine the voltage angles and magnitudes out of the available values. Other methods are tested in parallel as described in the chapter above.

3.3. Input and output requirements

3.3.1. Input data

The input data for this tool are following:

i) Static network data test cases, coming from T2.3 (Test cases) of WP2 and datasets from Croatian DSO (HEP ODS) which are provided in WP7. The test cases provide the static network data on lines (susceptance and conductance of the line, thermal capacity of lines), transformer characteristics, active and reactive limits of load and generation units etc.

ii) The current operating points from the live monitored values in HV/MV substations and MV/LV substations, where available

iii) Other data suitable for estimation of missing pseudo measurements such as historical load curves, current temperature, day of the week etc.

3.3.2. Output data

The outputs of the tool include the state vector of the network:

i) Voltage magnitude and angle at each bus,
ii) Active and reactive power flows.

3.4. Computational requirements

The computational requirements are defined by the

i) computational of the algorithm used for pseudo measurement estimation, especially if a neural network-based algorithm is used in the supervised learning mode,
ii) computational requirements of the optimization algorithm utilized to calculate the estimated state vector
iii) the dataset sizes

The overhead induced by the event driven platform and CIM adapter is comparatively negligible. One can expect that for reasonably sized network of several hundred nodes, several GBs of memory should be comfortably enough for the above. The final state estimation calculation is an optimization step that is CPU bound. The current implementation which is tested on a smaller sized case from Northern Croatia, admittedly with rather simple algorithms, uses 4 GB memory and solves in a few seconds time.

Neural network and other non-linear predictor-based pseudo measurement generators that require the training step might be more demanding in terms of computational resources, but it can be performed asynchronously or even in a distributed fashion, so the training is performed on another machine, and the state estimation machine utilizes the configuration retrieved from the training machine through the AIMM interface.

3.5. Interaction with other tools

The outputs of this state estimator serve as inputs for several other tools within the scope of the ATTEST project, given the lack of live data in typical distribution network. The task of this tool is to provide inputs to most other tools in ATTEST project that require live values from the network. Even when the distribution network becomes fully observable with measurements available across the grid, the state estimation will remain as a preprocessing step to filter out the erroneous values and gross errors.

4. Tool for ancillary services procurement in day-ahead operational planning of the transmission network (Task 4.4)

To achieve a significant reduction of greenhouse gas emissions, the European Union (EU) aims to produce most of its electricity from RES. Under such massive RES penetration, RES variability poses significant technical and economic challenges to the operation and planning of future energy systems. From the operational point of view, one of the most important challenges is that future energy systems will face different production patterns compared to those observed in the past or those anticipated in the initial system design. Power systems operate close to their security limits and hence fulfilling N-1 security (i.e. the system is always capable to withstand the loss of any single equipment) becomes a challenging task, particularly under stressed operation conditions, unexpected RES output, and/or unavailability of effective control actions. In this context, time-dependent emerging flexibility resources, such as flexible loads (FL) and electrical energy storage (EES) systems, which are directly connected to the transmission network, and DER units present in distribution systems can play a major role in reserve procurement to support secure TSO operation planning. Thus, unlike traditional scheme in which TSO and DSO operate independently, tight coordination between TSO and DSO at their interfaces is irrevocable to share the flexibility provided by distribution networks.

The conventional tool to ensure cost-optimal procurement of ancillary services (e.g. for managing congestion and voltage control) is the deterministic AC security-constrained optimal power flow (SCOPF). This state-of-the-art tool is mainly used in the day-ahead operation to enforce N-1 security at a given period.

Considering the stochastic nature of RES, ensuring N-1 security, multi period decision making and a fully integrated TSO-DSO coordination largely increase the computational burden of SCOPF, which is inherently a non-convex, non-linear problem.

Consequently, to achieve the optimal operation of transmission systems of the future while considering the above-mentioned aspects, it becomes crucial to develop a tractable as well as scalable computationally efficient SCOPF tool. Task 4.4 proposes such a tractable while scalable day-ahead SCOPF tool in order to procure ancillary services by taking-into-account all mentioned aspects of future transmission networks, as illustrated in Fig. 6.

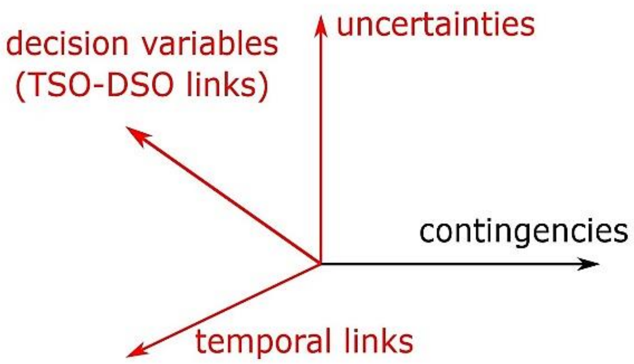

FIG. 6: DIFFERENT INDEPENDENT EXTENSIONS OF SCOPF FRAMEWORK CONSIDERED IN TASK 4.4

In the following subsections, a high-level functional description accompanied with a technical description of the developed tool is provided along with its computational requirements and interaction with the other tools of ATTEST project.

4.1. Functional description

The main objective of this tool is to enable TSOs to optimally procure ancillary services in day-ahead operation planning, specifically for voltage control and congestion management, to mitigate renewables uncertainty and ensure that the network N-1 security criterion is satisfied in real-time. For this purpose, the developed SCOPF tool considers a set of postulated contingencies, the uncertainty of the renewables, 24-hours ahead temporal interlinks, and effective cooperation of TSO and DSO at the TSO-DSO interface to enable TSO to benefit from additional flexibility provided by demand side resources as well as flexibility from conventional generators, and FL and ESS directly connected to the transmission network.

The tool minimizes the overall cost of transmission network operation which consists of the expected cost associated with the active power deviation (i.e. known as redispatch cost) from the market cleared values along with the cost of procuring ancillary services from other resources (i.e. flexibility imported through TSO-DSO interface, and FL and ESS directly connected to the transmission network).

The resulting SCOPF problem which involves all the above-mentioned features is a stochastic multi-period AC security constrained optimal power flow (S-MP-SCOPF) [6]. In addition, the problem size increases sharply by adding more scenarios and contingencies. To reduce the computational complexity, a two-stage tractable S-MP-SCOPF model is going to be developed. In the first stage, active power scheduling is considered as the main contributor in congestion management in an approximated AC power flow model, while in the second stage, reactive power optimization is performed for voltage control given the optimal active power profile and the subset of congested/almost congested transmission lines for each contingency, scenario and time period imported from the first stage.

The proposed tool is going to be tested against several real-world test cases which are developed in T2.3 as mentioned in Table 2. Further information about these test cases can be found in D2.3 (Test cases) of WP2 (Toolbox specification, support tools and test cases).

TABLE 2: TRANSMISSION NETWORK TEST CASES DEVELOPED IN T2.3

Network Type	Country	No. of networks
Transmission	*Portugal*	*7*
	UK	*1*
	Croatia	*2*

4.2. Technical description

This section is divided into two parts namely i) development of a benchmark tool on S-MP-SCOPF formulation for both normal operation and post-contingency states, and ii) development of tractable tool based on two-stage S-MP-SCOPF formulation.

4.2.1. Benchmark Tool based on S-MP-SCOPF Formulation

For the sake of reproducibility and comparison, a benchmark tool based on S-MP-SOCPF formulation is developed [6]. In the proposed tool, the objective function consists of the following terms:

i. Expected cost of normal operation state of:
   - Conventional generators

ii. Expected cost of both normal operation and post-contingency operation states of:
   - Energy Storage Systems

- Flexible Loads
- Generation Curtailment
- Load Curtailment

To prevent infeasibilities both load and renewable generation curtailment are considered for all operation states (i.e. normal operation and post-contingency states).

The developed tool considers the following sets of constraints:

i. Constraints for both normal operation and post-contingency operation states for each scenario at each time:
    - Generators active and reactive power limit
    - Voltage magnitude limit
    - Approximated longitudinal branch current limit
    - Active and reactive power balance equations
    - Full AC power flow equations in rectangular mode
    - Constraints associated with ESS:
        - Charge/discharge/State-of-charge (SoC) limit
        - Approximated constraint regarding simultaneous activation of charge and discharge states prevention
        - Energy preservation of ESS
    - Constraints associated with FL:
        - Energy balance of a FL over whole time horizon
        - Limits on the increase and decrease of active power of FL
    - Load / generation curtailment limit

ii. Coupling constraints:
    - Restriction on the ramping of each generator for two successive time intervals of normal operating state
    - Coupling constraint between active power of each generator in normal operation and post-contingency states

Accordingly, following decision variables are considered in each uncertainty scenario, time-period, and operation state:

- Active and reactive power output of conventional generators
- Real and imaginary parts of the voltage of each node
- Under/Over demand of FL
- Charge/Discharge of ESS
- SoC of ESS
- Curtailed load
- Curtailed renewable generation

The developed tool is tested in different test cases, fulfilling task 4.4.1. In these test cases a direct approach toward the full AC power flow model is applied using rectangular coordinates of voltages.

Table 3 summarizes the characteristics of the test cases used for benchmarking. The first test case (i.e. 5_bus) is a small case with 5 nodes without transformers and shunt devices. The second test case (i.e. Nordic32) is a simplified version of Swedish power system with 60 nodes.

It is noted that to test the scalability of the proposed benchmark tool, the number of renewable energy scenarios is gradually increased up to the computational limit of the non-linear solver tool for the Nordic32 test system. For additional number of scenarios, the non-linear solver (i.e. IPOPT in Julia/JuMP open source programming language) fails to compile the optimization problem.

TABLE 3: CHARACTERISTICS OF TEST CASES FOR BENCHMARKING

Case name	5_bus	Nordic32
No. of nodes	5	60
No. of Generators	3	23
No. of branches	6	57
No. of Contingencies	6	33
No. of Transformers	0	31
No. of FL	2	3
No. of ESS	1	2
No. Shunts	0	12
No. of scenarios	10	30
No. of decision Variables	42,000	4,968,420
No. of constraints	58,710	8,627,880
Elapsed time (s)	30	22,110

As can be observed from Table 3, the largest problem that a non-linear solver could handle has roughly 5 million decision variables and 9 million constraints which is a similar size of an OPF problem on a system with 1.5 million of nodes.

For all benchmark tests inter-temporal constraints associated with FL and ESS are also considered that along with the ramping limit of conventional generators make the tool time-dependent and not applicable for parallel computing.

It is noted that for the sake of simplicity, the tap ratio of transformers is considered as a fixed parameter and not a decision variable.

4.2.1. Tractable Tool based on two stage S-MP-SCOPF formulation

In this subsection, the procedure of the two-stage tractable tool is briefly explained.

Due to two major reasons the proposed full S-MP-SCOPF will be decomposed into two active and reactive power optimization stages:

i. For the sake of tractability: since the AC SCOPF is a non-convex and non-linear problem which is NP-hard in general. Dealing with uncertainties and multiple time scheduling will exacerbate the tractability of this problem. To decrease the computational complexity, it is necessary to break down the whole problem into simpler sub-problems.
ii. Unlike distribution networks, congestions and voltage issues in transmission networks are not tightly coupled and can be dealt with separately with some tailored approximations. Thus, active power, as the main contributor in congestion management, can be considered in an approximated and more tractable linear SCOPF problem while reactive power, as the main contributor in voltage control, can be considered in an explicit sub-problem.

For these reasons, a two stage tractable model is going to be developed in which the first stage optimizes the active power for congestion management purpose using an approximated power flow model while the second stage optimizes the reactive power of transmission system for voltage control given the optimal set-points of active power along with a sub-set of congested or almost congested lines from the first stage.

4.3. Input and output requirements

This section briefly introduces the input and output of the developed S-MP-SCOPF model.

4.3.1. Input data

The input data of this tool is:

i) Cleared active power set points of conventional generators out of energy market T2.6.
ii) Test cases which are developed in T2.3 (Test cases) of WP2. The test cases provide the necessary network data such as information related to network buses, lines, loads, transformers and generation units.
iii) Ancillary services bids offered by flexibility providers developed in T2.5.
iv) Set of postulated contingencies.
v) Set of renewables uncertainty scenarios.
vi) Active and reactive power ranges as additional demand side sources of ancillary service provided by DSO at the TSO-DSO interface.

4.3.2. Output data

The output data of this tool is:

i) Expected redispatch cost of conventional generators
ii) Expected ancillary service procurement cost of FL and ESS
iii) Optimal set-points of active and reactive power generation of each generator, for each scenario, operation state, and time period
iv) Optimal set-point of active and reactive power flow at the TSO-DSO interface.

4.4. Computational requirements

The developed tool is programmed in Julia under Windows platform with JuMP being used as a modelling layer and IPOPT as internal non-linear solver. For IPOPT different parameter 'mu' strategies setups are tested such as Mehrotra's probing heuristic, LOQO's centrality rule, and quality-function. In addition, since there are no other reliable internal linear solvers for IPOPT for Windows platform than MUMPS, all the simulations are done based on this linear solver.

For small test cases, adaptive mu strategies had better performance in comparison to standard setting of IPOPT in terms of convergence speed. However, for large test cases, proper memory allocation for adaptive mu strategies was unreliable. As showed in Table 3, the largest test case that IPOPT could solve took 22,110 seconds.

4.5. Interaction with other tools

The overall interaction of the current task 4.4 with other tools is illustrated in Fig. 7.

The input data of this task (T4.4) are the test cases developed in T2.3 and the ancillary services bids offered by flexibility providers defined in T2.5. This tool interacts with the tool developed for DSO in T4.1 according to the TSO/DSO coordination mechanism defined in T2.4.

The tool provides the information about buying bids for transmission network ancillary services for day-ahead energy and & ancillary services markets (T2.6).

The SCOPF formulation of T4.4 will receive as input constrains from task 4.6 (tool for on-line dynamic security assessment) to guarantee that real-time dispatch solutions meet the necessary volume of inertia (synthetic or synchronous) capable of limiting the rate of change of frequency (RoCoF) as well as the minimum primary frequency control power reserve that must be available to cope with postulated contingencies. This interaction requires further thought as T4.6 will apply to specific data sets not initially foreseen in T2.3 or T4.4.

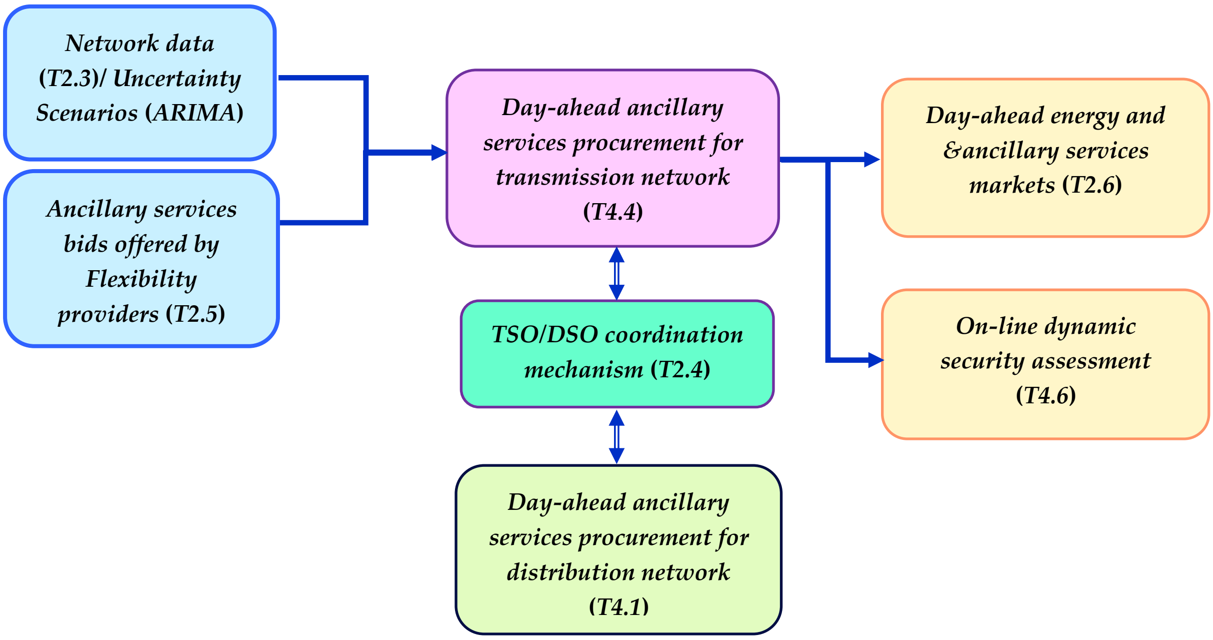

FIG. 7: INTERACTION OF TOOL 4.4 WITH OTHER ATTEST TOOLS

5. Tool for ancillary services activation in real-time operation of the transmission network (Task 4.5)

5.1. Functional description

The decisions made in the DA stage must ensure secure and stable network operation under the realization of different possible scenarios. The TSO is responsible for several tasks among which only congestion management and voltage control at the transmission network as well as frequency regulation fall under the scope of this project. The TSO reserves flexibility service providers connected to both transmission and distribution network in the DA stage to ensure that adequate amount of ancillary service is available in RT. The TSO has accurate network information in RT, which can differ from the decision made in the DA and activates reserved flexibility from resources connected to the transmission and distribution network to elevate transmission network problems and maintain the power balance in the entire system. The tool is activated when dynamic security assessment detects an emergency (constraint violation) or an unexpected event (such as disconnection of more than one line due to different inconvenience, such as storm).

The purpose of this tool is to activate flexibility service providers connected to the transmission and distribution grid for frequency control, congestion management and to solve voltage problems at the transmission level. The tool receives information about reserved AS in the DA stage:

i) for each service provider i_t connected to the transmission network (the maximum upper $P_{i_t}^{up}/Q_{i_t}^{up}$and lower value $P_{i_t}^{down}/Q_{i_t}^{down}$ that can be activated in RT),
ii) flexibility points at each TSO/DSO interface ($[P^{DA}-P^{down}, P^{DA}+P^{up}]$ and $[Q^{DA}-Q^{down}, Q^{DA}+Q^{up}]$ where P^{DA} and Q^{DA} are agreed active and reactive power exchange in DA and $P^{down}, P^{up}, Q^{down}, Q^{up}$ reserved lower and upper amount of active and reactive power for providing AS).

The TSO sends active and reactive power request at each interconnection point with the DSO which results in flexibility activation together with activation of generators and flexibility service providers connected to the transmission network according to the principle of minimal cost. The information exchange between TSO and DSO at each HV/MV connection point can be defined as:

i) one value of active and reactive power exchange P^{req} and Q^{res},
ii) separate values of active and reactive power exchange agreed on DA stage P^{DA} and Q^{DA} and activated flexibility in RT P^{act_down}, P^{act_up}, Q^{act_down}, Q^{act_up}. P^{act_down} can be in range from $[0, P^{down}]$ and P^{act_up} can be in range from $[0, P^{up}]$, while Q^{act_down} can be in range from $[0, Q^{down}]$ and Q^{act_up} can be in range from $[0, Q^{up}]$. The information DSO receives is in the form of $P^{DA}-P^{act\_down}$ or $P^{DA}+P^{act\_up}$ and $Q^{DA}-Q^{act\_down}$ or $Q^{DA}+Q^{act\_up}$.

The TSO calculates the volume and cost of activated AS for each transmission level connected flexibility provider as well as activated ancillary service volume (active and reactive power values) at the interface with the DS0 as the result of transmission level model predictive control AC OPF (T-MPC-AC OPF). At the TSO/DSO interface the information exchange is required to ensure that DSO receives requested values of active and reactive power in each time step from the TSO. The problem is solved in stochastic linear model predictive control fashion considering if the flexibility service provider connected to the transmission network was activated in the previous time step *t-1* and checks if the service is required from the same ancillary service provider in the next time step *t+k.* MPC rolls every

5/15-minutes and predicts the optimal operating points. Additional constraints for primary frequency control will be integrated in the model, such as extra feature or constraint on the generators in RT which needs to ensure proper reserve to maintain the frequency stability.

The tool developed in task 4.5 should normally receive input from tool 4.6 for on-line dynamic security assessment which serves for identification of contingencies which occur in R, which is achieved with exploiting PMU's measurements if state estimator fails. Moreover, tool 4.6 prevails threat of frequency stability and integrates frequency security constraints in the formulation of the tool 4.4. However, this link between tasks 4.5 and 4.6 requires further thought as the latter may use different data sets than those derived in T2.3 and assumed at proposal stage.

A functional diagram of tool 4.5 is given in Fig. 8.

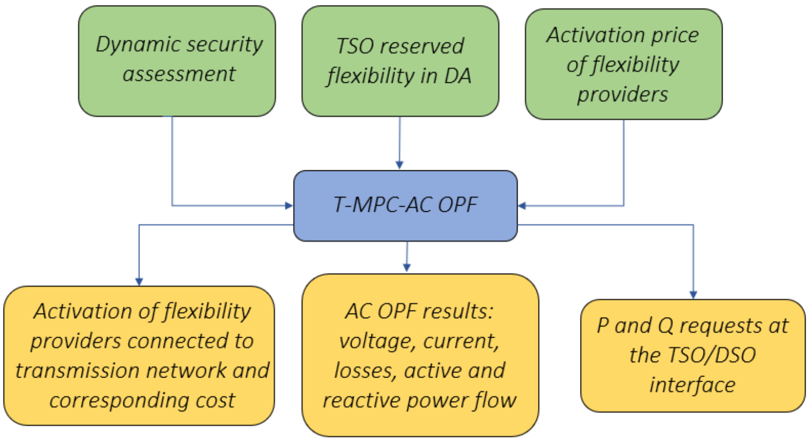

FIG. 8: HIGH LEVEL FUNCTION DESCRIPTION OF TOOL 4.5

5.2. Technical description

The objective function minimizes operation cost taking into account the activation of flexibility service providers. The tool considers power exchange at different HV/MV connection points and balances power in the network respecting all network constraints (voltage and thermal limits).

The tool uses the AC model of the OPF problem in rectangular coordinates as described by (6) and (7):

$$P_{ij} = e_i^2 G_{ij} + f_i^2 G_{ij} - e_i e_j G_{ij} + e_i f_j B_{ij} - f_i e_j B_{ij} - f_i f_j G_{ij} \tag{6}$$

$$Q_{ij} = -e_i^2 B_{ij} - f_j^2 B_{ij} + e_i e_j B_{ij} + e_i f_j G_{ij} - f_i e_j G_{ij} + f_i f_j B_{ij} \tag{7}$$

where P_{ij} and Q_{ij} represent active and reactive power flows on the line ij, e_i and f_i are real and imaginary part of voltage at the bus i, while B_{ij} and G_{ij} are susceptance and conductance of the line ij. The same network data (B_{ij} and G_{ij}) are used in T4.4. for DA operational planning of the transmission network. The tool considers conventional power plants units, RES and consumers connected to the transmission network and flexibility P-Q charts at the interface with the distribution network (HV/MV substations).

Following decision variables are considered in each time interval:

i) active and reactive power flow on each line,

ii) voltage magnitude and angle at each bus,
iii) current on each line,
iv) activated flexibility for each flexibility service provider connected to the transmission network,
v) active and reactive power flow to/from the downstream grids.

The output of the tool is an optimal and stable transmission network operation as the result of AC OPF. The results provide the amount of activated flexibility from the TSO at the transmission network and active and reactive power requests at the interface with the DSO, active and reactive power flow, voltage magnitude and the angle at each bus, current on each line and losses in the transmission network.

5.3. Input and output requirements

5.3.1. Input data

The input data of this tool is

i) test cases which are developed in T2.3 (Test cases) of WP2 and datasets from Croatian TSO (HOPS) which are provided in WP7. The test cases provide the necessary network data such as information related to network buses (network topology), lines (susceptance and conductance of the line, thermal capacity of lines), transformers, loads and generation units,
ii) ancillary services bids reserved in T4.4. (Ancillary services procurement in day-ahead operational planning of the transmission network) together with the number of activations,
iii) forecasted time series of load and generation data,
iv) online dynamic security assessment,
v) flexibility service providers technical constraints,
vi) activation price.

5.3.2. Output data

The output data of this tool is:

i) information about activated flexibility service from each provider (how much is provided, when is the service called and for how long) connected to the transmission grid,
ii) active and reactive power flow,
iii) voltage magnitude and angle at each bus,
iv) current on each line,
v) losses in the transmission network,
vi) active and reactive power request at the interface with the DSO:
- one value for active and one value of reactive power in terms of P^{req} and Q^{res}, or
- two values for active power, either $P^{DA} - P^{act\_down}$ or $P^{DA} + P^{act\_up}$, where P^{act_down} can be in range from $[0, P^{down}]$ and P^{act_up} can be in range from $[0, P^{up}]$, and two values of reactive power, either $Q^{DA} - Q^{act\_down}$ or $Q^{DA} + Q^{act\_up}$, where Q^{act_down} can be in range from $[0, Q^{down}]$ and Q^{act_up} can be in range from $[0, Q^{up}]$.

5.4. Computational requirements

The developed tool is programmed in AMPL and uses KNITRO solver.

For solving small size AC OPF problem, 8 GB memory is enough. However, for large-scale power systems, memory requirements increase to 16 GB. Simulation time does not exceed 10 seconds since the model does not include binary variables.

5.5. Interaction with other tools

Fig. 9 shows the interaction of tool T4.5 with the other tools of ATTEST project. Tool 4.5 receives data from:

i) test cases developed in T2.3,
ii) online security assessment from T4.6,
iii) the upper and lower bound of reserved flexibility in DA from resources connected to the transmission grid that can be activated in RT and upper and lower bound of reserved flexibility at each HV/MV connection points from T4.4,
iv) activation price of each service provider from T2.6.

Tool 4.5 sends active and reactive power requests to the tool developed in T4.2. at each TSO/DSO connection point for ancillary service activation in real-time operation of distribution:

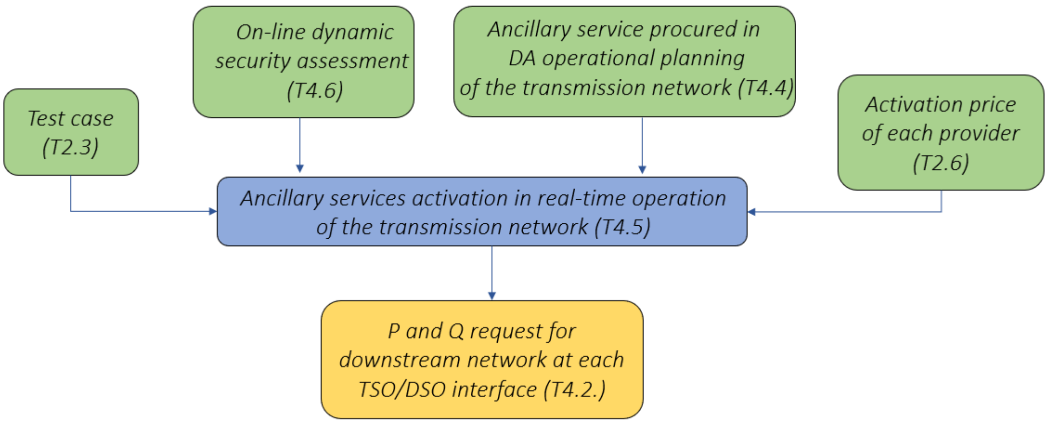

FIG. 9: INTERACTION OF TOOL 4.5 WITH OTHER ATTEST TOOLS

6. Tool for on-line dynamic security assessment (Task 4.6)

If maintaining grid security has been a challenging task until now, the fast-growing stochasticity and dynamics behavior verified in today's power systems will certainly turn this task even more challenging than before. Among the main challenges, the following deserves special attention: large penetration of RES, bi-directional power flows caused by demand responses and storage devices, hybrid AC/DC systems with heavy power transfers, a growing number of power electronic devices, increased applications of advanced protection and control systems, and new market strategies / rules. In particular, the large-scale integration of RES, connected to the grid through power electric converters, could be one of the major concerns in the scope of system security.

Over the last two decades, ambitious plans to face climate change and reduce greenhouse gas emissions have led to massive investments worldwide in the wind and solar power plants, namely in the European Union. For the next decades, with the technological maturity ,cost declining expected for these technologies and the need to cope with the legally binding international targets on climate change established under the 2015 Paris Agreement, much more investments and adoption of carbon-free energy sources are expected to be considered by the EU members [7]-[8]. In fact, to tackle this energy transition towards a complete decarbonization of the energy sector, EU leaders have agreed on a very ambitious goal for cutting greenhouse gases - reducing them by 55% by 2030 (compared with 1990 levels) [9], rather than the 40% initially established under the Paris Agreement. More recently, aiming to be carbon neutral by 2050 (an economy with net-zero greenhouse gas emissions) as envisioned in [9], a reform of the country's Climate Action Law is undergoing and includes: stepping up the 2030 target for emission by cutting it to 65% (instead of the 55%), tougher emission budgets in all sectors, and new reduction targets for the 2040s. Therefore, in the years to come there will be a significant replacement of a large part of synchronous generation by non-synchronous RES generators that will be mainly connected to the grid through power electronic interfaces. By observing the most optimistic scenarios RES integration stated in [7]-[8] by 2030, the synchronous grid of Continental Europe is likely to experience a 30% reduction of the overall synchronous inertia, and it is quite evident that this the value will raise substantially up to 2050.

As generally acknowledged, the main problem is that the large deployment of such type of non-synchronous generation will determine a reduction of the power system rotational energy or system inertia. This can lead to very fast dynamics in case of contingencies and thus to strong negative impacts on short-term frequency stability, as indicated in several recent studies [10]-[12] and Transmission System Operators (TSOs) reports [13]-[16]. In fact, when decommissioning of synchronous machines replaced by inverter connected generation, two systemic impacts have major relevance: the aforementioned decrease of system inertia that could lead to critical RoCoF, as well as the short-circuit power reduction [16]. In case of relevant short-circuit power reduction the voltage sags following grid short circuits lead to lower residual voltages and the perimeter of their influence is wider. Within this scope, it is particularly relevant the consequences of Voltage Dip-Induced Frequency deviations (VDIFD) [17]. The large-scale integration of wind power generation (type 3 and type 4 wind turbines), given the delayed post-fault active power recovery may lead to severe underfrequency events following the fault clearance. The impact of VDIFD is largely dependent on the amount of synchronous inertia available as well as on the penetration levels of wind generation. Another consequence of reduced inertia and increased RoCoF is that frequency containment reserves have less time to limit the frequency nadir/zenith to the acceptable range, which can potentially result in a lack of, and therefore a scarcity of effective reserve.

It has been shown [12], [16]-[17] that for the continental European system the increase in RoCoF at higher penetration levels will certainly occur, being more significant for particular parts /control areas of the system. These references state that RoCoF values will remain safe, i.e., generally below 1 Hz/s in most continental European countries considering the reference incident (-3GW in France, i.e. tripping of the 2 largest nuclear plants, and -2GW in the other zones). As such, for the moment, there is no global scarcity of reserve or inertia at the European level for a given event, but a localized scarcity of inertia or reserve may emerge due to the reduction of the dynamic coupling. Therefore, in some regions, such as in the Iberian Peninsula, RoCoF values can easily reach 1.3 Hz/s [17]. This happens since it is less interconnected with the rest of the continental power system and presents lower regional inertia due to the high penetration of non-synchronous generation. These values can be problematic as not all systems can currently run with such high levels of RoCoF. For instance, the grid codes of Great-Britain and Ireland and Northern Ireland stipulate that generating assets shall withstand RoCoF values up to 1 Hz/s (calculated over 500 ms time period). This value was the result of many years of discussion and consultation between the different stakeholders. As already mentioned, despite in the Continental Europe ENTSO-E proposed [14] to set 2 Hz/s (calculated over a 500 ms time frame), there are still some doubts as to whether manufacturers can fulfill this requirement and if they can do so with acceptable costs [18]. Additionally, new requirements on RoCoF withstand capabilities introduced through the RfG Code [19] only apply to the new generators. For all these reasons, it is considered that RoCoF higher than 1 Hz/s raise concerns.

These vulnerabilities are further exposed under system separation events, where frequency stability is significatively endangered [20]. European system split events, besides being more likely to increase RoCoF values (greater than 2 Hz/s in several cases[1]), they usually also lead to under/over frequency situations, namely causing extremely low NADIRs [14]-[17]. These low NADIRs and/or high Zeniths under system split events are not related to any reserve scarcity given that such imbalances can only be managed by defense plan actions such as load shedding or Limited Frequency Sensitivity Mode for Underfrequencies/Overfrequencies (LFSM-U/O) mechanisms. In some cases, especially for both Iberian and Italian splits, the activation of these mechanisms may be still insufficient to avoid blackout situations [17]. Even though that the probability of splitting events is very low, analysis suggests that controlling both the RoCoF and NADIR/Zenith values is crucial, particularly in the systems such as the Iberian Peninsula. Solutions will have to be found to deal with this problem. Restricting the SNSP in the Iberian Peninsula or incentivizing alternatives for providing inertia (Synchronous condensers, batteries settled to perform Grid Forming control of the Renewables) are possible mitigation measures [15]-[17].

Considering the above, it becomes clear that if until now ensuring the grid's security has been always dependent on the results of heavy operational planning studies conducted off-line, in order to guide TSOs through day-to-day operations, this is no longer enough. The main reason is related to the large time required for the conventional dynamic security evaluation, which makes the approach unfeasible
for on-line purposes. In this context, and considering the increasing complexity of power systems, new Dynamic Security Assessment (DSA) approaches are required to guarantee system security.

There are two mainstreams envisioned for the DSA approaches: offline DSA and online DSA. Regarding the online scope, a snapshot of the actual system condition is taken, and comprehensive security analysis performed in near-real-time with sufficient speed to either invoke automatic controls, routines for suggesting actions to be taken by the operator to ensure that security is maintained. The online DSA tools allows in this way to update the current operating conditions and can be used complement to the result of offline DSA for higher reliability. Many sophisticated systems are already

[1] For instance, in the case the Iberian Peninsula disconnecting from the remainder of the Continental system [17].

in use today, being capable of assessing transient/frequency security, voltage security, and small-signal security in a very short timeframe. To deal with the complexity of such assessments, these new tools must use a wide range of system measurements, analytical techniques, computer system architectures, and visualization methods.

Although the need for new online DSA tools is clearly growing in most power systems, detailed and exhaustive off-line studies are still important and can often still be used when they can be transformed to general guidelines, trends, and directions to follow. Such may be the case in power systems in which the uncertainties and variations of operation either not exist or can be shown to have minimal impact on system dynamic performance. Additionally, offline running may be required to perform rapidly dynamic evaluation when running algorithms such as constrained economic dispatch or security constrained optimal power flow [21] to perform day-ahead or intraday evaluation of the market proposals. However, to meet these purposes the use of conventional time-domain dynamic simulations is totally unfeasible, thus alternative DSA tools, for instance based on Machine Learning Approaches (MLA), must be considered as possible, reliable, and an efficient solution.

With security being of paramount importance to the electric power industry as a whole, it is therefore important that all those involved in system operations can take advantage of the DSA tools already available or to be developed in the future, either for real-time or offline purposes.

Similar to the DSA approaches based on artificial intelligence methodologies described in the available literature, the tool to be developed in the scope of task 4.6 of ATTEST can be seen as conceptually identical but integrating several additional novel features that will allow overcoming some of the main challenges expected in future power systems. More specifically, the tool will be designed to provide useful outputs for other important tools, such as the SCOPF, and to be run in real-time to facilitate system control and management performed by TSOs, enabling them to take preventive measures to avoid frequency stability related problems. The tool will also incorporate modules to generate the functional knowledge required to guarantee a high-performance level. These modules will create a large set of system operating points and run full time-domain dynamic simulations for each of them. Results achieved will be stored in a database and analyzed with a feature selection algorithm, which will be used to fine-tune the more meaningful attributes/input variables of the MLA.

In the following section, a high level functional and technical description of the developed tool is provided, including its computational requirements and possible interactions with other tools of the ATTEST project.

6.1. Functional description

The main goal of this tool is to perform dynamic security assessment with respect to frequency stability in future power systems characterized by large shares of converter interfaced generation, connected both at the transmission and distribution grid. This tool will have the inherent capability of inferring specific system indices related to likely dynamic security incidents and to suggest preventive control actions.

As previously explained, the capability of assessing system security with respect to network faults that may lead to severe post-fault frequency deviations due to the power recovery ramps of converter interfaced RES (such as wind power) after fault clearance. As an illustrative example, through the identification of the minimum synchronous inertia required to ensure system's dynamic security for a specific operation scenario, this tool can support the decision-maker regarding the re-dispatching of generators, limiting the total amount of RES (based on electronic power converters), keeping synchronous generation in operation, or bringing on-line synchronous condensers. For this specific purpose, frequency security constraints / indicators (such as RoCoF and NADIR) will be the key indicators to be evaluated in order to guarantee that the system is secure regarding the operational scenarios (snapshots) and disturbances. These security indicators will be derived using a machine learning approach that will exploit functional knowledge obtained using an off-line dynamic simulation tool of the electric power system for a set of critical contingencies to be identified and covering the foreseen operating scenarios.

The data set generated in this manner will be characterized by a large number of operating points, each one characterized by a large dimension vector of primary attributes. In this way, a filtering stage will be used (using, for example, an F measure of separability), such that only the most relevant primary variables for the problem under analysis will be kept, while discarding at the same time the most correlated variables with the ones selected in the first place. This will allow reducing largely the dimension of the problem. Afterwards, machine learning approaches will be analyzed to evaluate their suitability for this specific application, such Decision Trees, Regression Trees or Artificial Neural Networks, in order to design the best security function that better supports the dynamic security assessment.

Ultimately, this tool will enable defining the required volume of inertia and primary frequency control reserves for assuring dynamic security of all operating scenarios. These outputs will be considered within the SCOPF formulation of T4.4, aiming to guarantee *ex ante* that each dispatch solution is dynamically secure.

Based on the general functional description of the approach described above, a high-level functional diagram of the developed tool is shown in Fig. 10.

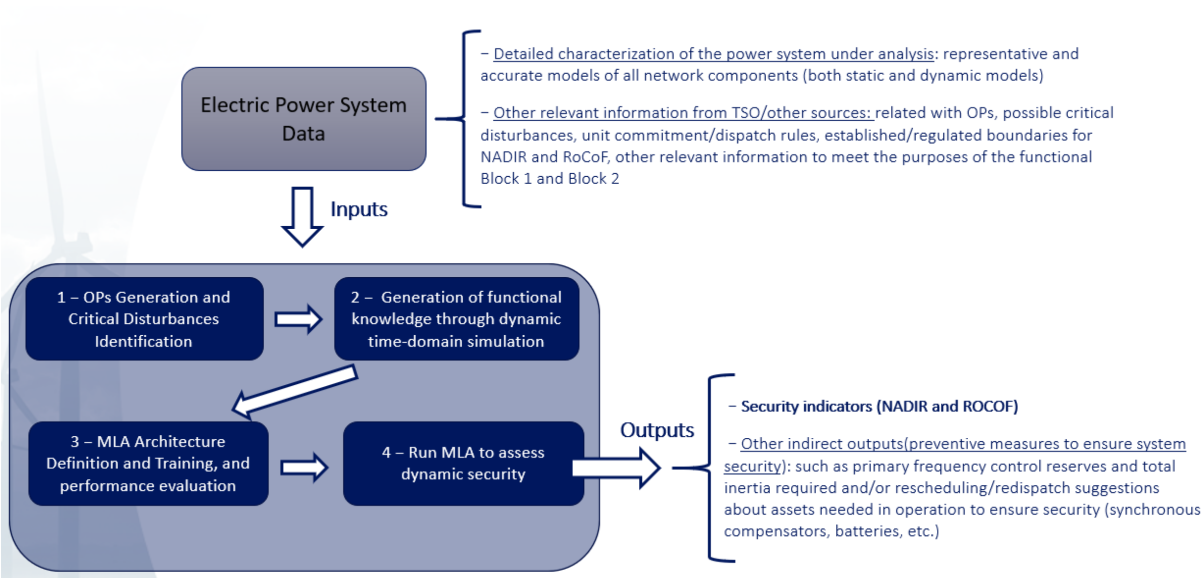

FIG. 10: HIGH LEVEL FUNCTIONAL DESCRIPTION OF TOOL 4.6

This tool will be tested considering the IEEE 39-bus system commonly known as "the 10-machine New-England Power System". This test case, has been widely used by the academic/scientific community as a benchmark study case to address problems (testing methodologies and tools) in the scope of the transient/frequency stability domain [22]-[23]. The original system's parameters are descried in [24] and in [25]. Meanwhile, several modifications have been introduced in studies with different purposes depending on the specificities of the problem that authors are dealing with.

Similarly, modifications regarding the generation portfolio will be performed in the context of this work, namely the consideration of an increased RES integration. These modifications will closely follow those that have been considered in [26], in particular regarding the location and size of RES to be integrated in the network.

6.2. Technical description

As referenced in the previous section and depicted in Fig. 10, the developed tool can be divided into four main blocks:

1. Operating Points Generation and Critical Disturbances Identification.
2. Generation of functional knowledge through dynamic time-domain simulation.
3. MLA Architecture Definition and Training, and performance evaluation.
4. Run MLA to assess dynamic security.

A detailed description of each block is provided in the following sections.

6.2.1. Operating points generation and critical disturbances identification

The main goal of this functional block is the generation of a global dataset with information regarding the behavior of the system in several operating conditions, as well as the identification of the most critical disturbances in the scope of frequency stability.

In order to ensure representativeness of the tool regarding all the possible sets of operating conditions the system will face, the generated dataset will be composed of a large number of operating points (scenarios). For each scenario, the expected operational conditions will be considered, namely those that influence grid dynamic security, such as: operational rules (e.g., spinning reserve criteria), load levels, dispatch solutions and availability of several other controllable and noncontrollable devices.

From a given generation portfolio and grid topology, it is possible to identify beforehand the reference incidents that lead the system to critical security regions, as well as the options to be considered to bring the system to a secure operating region. This is done by evaluating frequency response attained in the dynamic simulations and then by computing the frequency indicators (RoCoF and NADIR) and comparing them with the correspondent boundaries established/regulated[2]. As critical reference incidents, faults and power generation outages will be considered. System re-dispatch involving possible RES curtailment, with consequent conventional generation redispatch, and activation of synchronous inertia will be considered as TSO-level solutions to bring the system to a secure operating region.

The methodology behind the creation of functional knowledge encompasses several steps, which can be briefly described as follows:

i) Defining a range for load variation with respect to minimum and maximum values for the active and reactive power allowed in each load bus *i* (named respectively as $P_{i_{min}}$, $P_{i_{max}}$, $Q_{i_{min}}$ and $Q_{i_{max}}$);

ii) Define a linear growth between the minimum and peak load for the active and reactive power ($P_{i_{max}}$, $Q_{i_{max}}$ and $P_{i_{min}}$, $P_{i_{min}}$) in all buses such that all loads will increase the same percentage regarding the difference between the peak and minimum load values. In this way several

[2] In the specific case of the Synchronous Zone of Continental Europe, they are regulated in [27].

distinct load levels Z can be considered and the correspondent load step increment ΔX can be computed ($\Delta X = \sum(P_{i_{max}} - P_{i_{min}})/Z$);

iii) Compute the active load *Pi* and reactive load *Qi* for all the load buses *i* considering the *Z* load levels and the load step increment ΔX defined in step ii);

iv) For each load level defined in iii) consider combinations of different wind generation and solar PV levels according to the following rational:
   a. For all wind buses, consider wind power output changing between 0 MW and the installed capacity, with steps of *ΔRES_Wind* (e.g., 20%), such that all generation wind power buses will increase simultaneously the same percentage regarding the maximum power. In large scale power systems, a complementary approach can be followed to identify geographical areas in which higher correlation of wind production can be clustered. This way, different wind production levels can be defined for each cluster.

   b. For all solar PV generation buses assume that power output will change between 0 MW and the installed capacity, with steps of *ΔRES_Solar* (e.g., 20%), in each PV generation bus according to a correlation table with the load between a defined value (e.g., *Pmin + 30%* and *Pmax - 20%*). The rationale is to assure that there is no PV production during valley hours. As for wind generation, in large scale power systems, a complementary approach can be also followed for identifying geographical areas in which higher correlation of solar production can be clustered.

   c. Compute $P_{RES_{TOTAL}}$ given by the sum of solar PV generation and wind power generation

   d. Regarding reactive power distribution, the power converters assigned to these generation technologies can usually be operated under different reactive power control modes (fixed power factor, voltage control, etc.), therefore reactive power levels can be either the ones resulting from operators' restrictions and grid code requirements or the results of the load flow problems.

v) Compute the total number of operating points $Z_{OP_{TOTAL}}$ *given* by the combination of the all the *Z* load levels defined in step ii) with all the combinations for wind generation and solar PV levels defined in step vi);

vi) For each OP perform unit scheduling / commitment followed by a dispatch procedure for the conventional synchronous generation units available, in order to supply the remaining load by *PC* ($PC = \left(\%P_{Losses_{estimation}} * PL_{Z_{TOTAL}} + PL_{Z_{TOTAL}}\right) - P_{RES_{TOTAL}}\ [MW]$).

Regarding the step vi) present above, it is important to note that the unit commitment process can be based on a merit order (where the unavailability of generation units is considered), to be provided by the TSO or be defined by the user. When it comes to the dispatch process, it can be based on some economic criteria directly related with technology type and other technical characteristics of each unit (for example its size / nominal power whenever the technology is the same). Afterwards, a dispatch solution for the conventional synchronous generation will be generated. It could be either optimal or based on some rules that approximate the actual operating practices followed in the system under study. When the optimal dispatch is intended to be avoided, a simple way to execute this task is to admit a homothetic load distribution among all the available units according to their nominal power.

Finally, it is important to state that in both the unit commitment and dispatch processes, spinning reserve criteria (regulated in grid codes or defined by TSO practices) should be considered. If unavailability (due to maintenance or repair) of the conventional units is to be considered, one can assume that, for each load level and RES generation scenario, each conventional unit (one at each time) scheduled to be in operation is out of service. This leads to a considerable increase in the number of scenarios to be analyzed, but it generates diversity to the set of operating points.

After developing the dynamic behavior analysis for all OPs (to be performed under the scope of block 2 – see Fig. 10 and section 6.2.2), the corresponding results regarding all the dynamic security indices are computed. This approach will enable generating a sufficiently diverse dataset that represents the functional knowledge, since it integrates different load levels, different renewable penetration levels, as well as several possibilities of dispatch of synchronous generators.

6.2.2. Generation of functional knowledge through dynamic time-domain simulation

In this block, all the Operating Points (OP) defined in block 1 are evaluated from a dynamic security point of view. Each operating point resulting from the sampling and dispatching process is then accessed in a steady-state regime to define a credible operating scenario considering grid constrains. An OPF-like tool will support the definition of the pre-fault operating condition for each OP.

Then, for each OP, the predefined list of reference incidents is simulated in order to compute the dynamic security indicators (ROCOF and NADIR) leading to the development of a complete functional database.

From the previous description one realizes that it is crucial having the complete static and dynamic model of the power study system under study. For interconnect systems, a detailed model of neighboring countries may be required for transient stability studies. For frequency stability studies, a representative equivalent model of neighboring countries is sufficient.

After running all the simulations, the most relevant results from dynamic simulations, as well as data related with the operating conditions simulated are gathered and compiled for each pair of OP and simulated contingency and saved in a database. This includes primary variables and stability indicators that involve the following type of information:

- <u>Characteristics related to the OP conditions (primary variables):</u> active produced powers (generation units, batteries); active consumed powers in load buses; aggregated values regarding total active powers categorized by the technology: synchronous, non-synchronous (renewable or non-renewable based power electronics converters); spinning reserve available (synchronous and non-synchronous); total synchronous and synthetic/virtual inertia, inertia per machine and/or the aggregated inertia values per technology. Apart from these steady variables, it may be relevant to include dynamic related variables to characterize each OP, namely for the short circuit related contingencies. These variables are the accelerating powers at t0+ (just after the fault), defined for each generation bus as the difference between the generated mechanical power and electrical power at the generation bus just after fault inception, divided by the inertia constant.
- <u>Stability indicators:</u> frequency stability indicators (NADIR and RoCoF).

The dataset composed of the variables listed above (primary characteristic variables plus stability indicators) can be seen as functional knowledge that describes the dynamic behavior of the system under study. As it will be explained in the following section, in the scope functional block 3, this dataset, after being processed by applying feature selection / extraction techniques will allow defining the MLA structure, being also used for training and testing purposes (see section 6.2.4).

6.2.3. MLA Architecture definition

In this functional block 3, the most appropriate MLA structures are defined. In this context, as presented in section 6.3, there are several MLA such as Support Vector Machine, Artificial Neural Networks, Decision Tree (DT) and Kernel Regression Tree (KRT), among others that can be used, each one with several advantages and disadvantages. In the selection of the MLA to be adopted, some preliminary analysis over the literature will be carried out.

In order to properly define MLA structure (in terms of its internal parameters and learning algorithm), it is required to select the attributes to be used. This means identifying the input variables, also known as explanatory variables in the context of MLA, and the output variables. For this purpose, a pre-processing stage based on data mining techniques, in particular the so-called feature selection / extraction techniques, deserves particular attention. In this way it is possible to characterize all the operating points of the dataset by a reduced dimension vector of characteristics and proceed with the MLA, where the input set should be as small as possible while still having enough discriminatory ability.

A feature selection technique, either based on an F measure of separability [28] or statistical correlation functions will be used. In this process, the most correlated variables are discarded, whereas the less correlated and independent ones are prone to be selected as the system explanatory variables. Moreover, there are some additional characteristics that the attributes should satisfy and that should be considered in this feature selection process, namely:

- They should be directly related to the dynamic phenomena under study;
- They should be independent (or easy related) for further control use;
- Controllable variables should be independent or, at least, its relation should be “clear-cut” in order to simplify the control algorithm;
- System control variables, namely dispatchable variables, should be selected as potential candidates;
- Their number should be as low as possible without losing relevant information. This means that some attributes could be aggregated. Some examples are: to use the “equivalent machine” concept to group similar generators operating in parallel in the same power plant, to group generators by technology (wind, solar, hydro, thermal, etc.) or even consider larger groups (e.g., synchronous and non-synchronous generators), among other related possibilities.

Some preliminary analyses have found that generated powers, inertias, accelerating powers and spinning reserves are likely to be very interesting variables due to their relation regarding the phenomena under analysis, being also workable for the preventive control algorithms. This view is supported by some authors in several publications, such as in [29]-[30].

Following the identification of the explanatory attributes/variables to be used as inputs of the MLA based tool, the next step is related to the selection of the output variables. Considering the aim of this tool and project, as well as the specificities of DSA security problem identified (frequency stability oriented), frequency security indicators (NADIR and RoCoF) are the most suitable attributes to assess system security level in terms of frequency stability.

The adoption of back tracking search approaches over regression trees can provide control solutions in terms of redispatches in the system when a required level of security is to be kept. This type of outputs leads to the definition of preventive measures with respect to the day-ahead forecasted operating conditions or due to system unsecure states that are prone to occur under non-expected operating conditions verified in real-time. The “indirect” outputs can be achieved for instance using a systematic approach based on a gradient iterative procedure that exploits the sensitivities of the MLA inputs relatively to its “direct” outputs (frequency security indicators) in order to move the system towards a secure region [31], which is defined considering the boundaries established/regulated for these indicators.

Fig. 11 describes an illustrative example of a possible MLA structure regarding its input and output variables. It is a result of preliminary analysis carried out for the IEEE New England test system (see section 6.1), being the inputs variables selected with the help of statistical correlation functions, as previously mentioned.

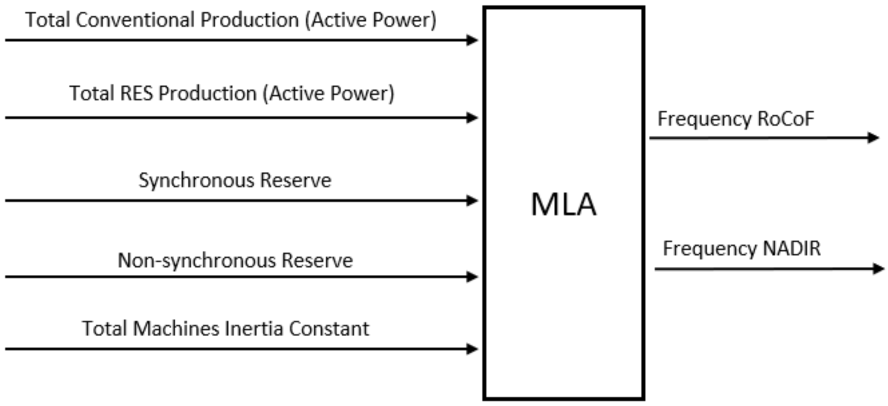

FIG. 11: ILLUSTRATIVE EXAMPLE OF THE POSSIBLE INPUT AND OUTPUT VARIABLES OF THE MLA STRUCTURE TO BE CONSIDERED

Having the input and output variables already defined, the final step to be performed involves the definition and characterization of the complete MLA structure in terms of its internal architecture, learning algorithm, control parameters, and other internal relevant functions/parameters.

6.2.4. MLA Architecture definition and training, and performance evaluation

This section presents the main functions to be performed under this functional block, namely: training process of the MLA, testing and performance evaluation regarding relevant criteria.

The training process aims to produce a properly trained MLA structure (to be used as a “black box”) capable of being used online, in real time, to accurately assess dynamic security with respect to frequency stability. Hence, the training process will allow MLA to learn the dynamic behavior of the system from the functional knowledge generated in the functional block 2 as described in section 6.2.2. For this purpose, the global database of functional knowledge needs to be firstly converted into a smaller dataset, suitable to be used directly in the training and testing processes. This task is done by separating the data associated with the input and output variables, defined in the functional block 3 (see section 6.2.3) for all OPs and for each disturbance. In this sense, it is envisioned that an MLA structure will only deal with a single pre-defined disturbance. Otherwise, the learning procedure would lead to an MLA with different output sets of security indices but suffering from a low performance. The reason behind is intrinsically related with the dynamic behavior of the system, which can be completely different depending on the type of the simulated disturbance. Thus, the true correlations between the inputs and the outputs variables (or even between distinct inputs variables) would be completely disrupted if data from different contingencies was used together.

The total amount of data used for training and testing the MLA is given by the following expression:

Total number. of MLA dataset points: $Z_{OP_{TOTAL}} * Nr_{Input\_vars} * Nr_{Output\_vars}$

where:

- *Total number. of MLA dataset points* is the amount of data used to train and test the MLA structure (for each disturbance defined in in block 1 – see section 6.2.1;
- $Z_{OP_{TOTAL}}$ is the total number of OPs attained in block 1 (see section 6.2.10);
- Nr_{Input_vars} is the number of attributes/input variables under the scope of block 3 through the feature method chosen (see section 6.2.4);
- Nr_{Output_vars} is the total number of output variables defined (in the scope of this tool only 2 variables are considered: RoCoF and NADIR).

Afterwards, by randomly splitting this dataset using a rule where 2/3 of the OPs are for training and 1/3 for testing purposes, the final training and testing datasets are created. Finally, a standardization/normalization procedure is carried out for these two datasets to enhance the MLA performance. This procedure is not mandatory, but it usually allows a more efficient training (speeding up learning and accelerating convergence) and leads to better predictions. The type of standardization/normalization technique to be adopted may be different for input and output variables and will be analyzed case by case depending on the type of physical information that each variable represents.

The training process is finally preformed according to a pre-defined stopping criterion (see section 6.2.3 for more details), which corresponds to running the MLA for the training dataset. At the end of this process, the performance of the MLA can then be evaluated. In the context of this tool, the evaluation criteria chosen are based on the following aspects: accuracy /quality, comprehensibility, classification errors, and computational efficiency.

The quality of the MLA structures is assessed by computing the following numerical indices:

Mean Absolute Error (MAE) given by:

$$MAE = \frac{1}{N(TS)} \sum_{OP_i \in TS} |y_i - \hat{y}_i(OP_i)|$$

Root Mean Squared Error (RMSE) given by:

$$RMSE = \sqrt{\frac{1}{N(TS)} \sum_{OP_i \in TS} \left(y_i - \hat{y}_i(OP_i)\right)^2}$$

where:

- $N(TS)$: Number of operating points (OP) in the Testing Set (TS);
- y_i: Real value of the security index, for OP_i;
- $\hat{y}_i$: Value estimated by the structure, for the security index of OP_i.

The classification accuracy can be inferred by the following misclassifications rates:

$$Global\ Class.Error = \frac{Nº\{OP\ of\ the\ TS\ incorrectly\ class.\}}{Nº\{OP\ of\ the\ TS\}} \times 100\%$$

$$False\ Alarm\ Error = \frac{Nº\{"secure"\ OP\ of\ the\ TS\ class.\ as\ "insecure"\}}{Nº\{"secure"\ OP\ of\ the\ TS\ \}} \times 100\%$$

$$Missed\ Alarm\ Error = \frac{Nº\{"insecure"\ OP\ of\ the\ TS\ class.\ as\ "secure"\}}{Nº\{"insecure"\ OP\ of\ the\ TS\ \}} \times 100\%$$

Each test case analyzed during the testing process can be seen as assessing the dynamic security in a given operating scenario (one snapshot). Therefore, while the computational efficiency for the training process is assessed by calculating the total time required, for the testing process it is considered the mean time of the total number of test cases evaluated.

6.2.5. Run MLA to assess dynamic security

The running process of the MLA, performed under functional block 5 (see Fig. 10 in section 6.1), corresponds to running the already trained MLA with a given set of inputs. As mentioned before, its execution can be either offline to assess system security with respect to the day-ahead forecasted operating conditions, or online, in real time, to assess current system operating condition (or anticipate future states that are prone to occur in the next time steps).

6.3. Input and output requirements

Considering the functional and technical description performed respectively in section 6.2 and 6.3, the input and output data have been compiled and are summarized in the following sections.

6.3.1. Input data

The input data of this tool is:

i) Power system data regarding all network components in order to build a representative and accurate static and dynamic model of the network. Some examples of the data required are related to models/parameters of power lines, transformers, shunt devices, HVDC links, load, generators and associated controls (primary frequency regulators/governors, excitation systems/AVRs, etc.), adequacy to Fault ride through (FRT) requirements, among others.

ii) Information to create the system snapshots/operational scenarios and define the most critical disturbances, security criteria/indicators and the corresponding boundary conditions. It can be directly provided by TSO or other stakeholders or derived from public access information such as historical load/generation diagrams, market information, etc. (see section 6.2.1 for further details).

6.3.2. Output data

The output data of this tool can be divided into direct or indirect outputs:

i) <u>Direct outputs</u>: Dynamic security indicators such as RoCoF and NADIR.

ii) **Indirect outputs**: Preventive suggestions to ensure dynamic system security during offline execution (for day-head forecasted operating conditions) or preventive/corrective measures to ensure dynamic security during online utilization (for real time operating conditions or for future conditions expected in a very short time-frame). Some examples of preventive suggestions are minimum inertia required, rescheduling/redispatch of generation, etc. that may be used as constraints within the SCOPF formulation proposed in Task 4.4 (tool for ancillary services procurement in day-ahead operation planning of the transmission network).

6.4. Computational requirements

The tool will be developed in Python (Windows OS) with Siemens PTI PSS/E (version 34) being used as simulation software, for running both static and time-domain dynamic simulations. It is important to bear in mind that these simulations are required to evaluate the OPs and generate the global dataset of functional knowledge (6.2.2).

The algorithm that generates functional knowledge and the training process is usually very time-consuming and require a significant amount of data storage (ca. 16 GB). As these tasks are intended to be executed offline, processing capacity and computational time are not a major concern.

In general, the MLA runs very fast both online and offline and the computational requirements are minimal. Some preliminary simulations with the IEEE 39-bus system and adopting an ANN based architecture (with 5 inputs variables) have run in less than a second. This fact holds when they are applied to the large majority of DSA related problems, as it has been demonstrated in several studies.

The computational requirements and time performance of the DSA tool should not impose any significant obstacles to its scalability and replicability[3], mainly because the inputs variables will remain very similar (in number and type) when considering larger systems, different system topologies and generation portfolios. On the other hand, when it comes to generation of functional knowledge, the algorithm and the training process are more demanding and time execution may grow significantly with the problem size. However, as mentioned before, as these processes are intended to be executed offline, such aspects should not be an issue.

6.5. Interaction with other tools

6.5.1. Output data to ATTEST Tools

The outputs of this tool may be used as inputs of the tool for ancillary services procurement in day-ahead operation planning of the transmission network (T4.4), which is based on a deterministic SCOPF, and of the tool for ancillary services activation in real-time for the transmission network (T4.5). Inputs from other ATTEST tools are not required.

More specifically, the DSA may provide to the tool developed in T4.5 the volume of total inertia (synthetic or synchronous) capable of limiting the rate of change of frequency (RoCoF) or deeper frequency (NADIR), in order to ensure system security in terms of frequency stability for the predefined disturbances. Information about assets (conventional synchronous machines, synchronous compensators, batteries, etc.) that are required to be in operation to reach such value of inertia may also be provided. In addition, the DSA tool can also provide the minimum primary frequency control

[3] The scalability of a tool may be defined as its ability to deal with an increase of the problem, in size, scope or range, whereas replicability refers to the ability to be duplicated in another location or time.

power reserve that must be available to cope with postulated contingencies. However, it must be stressed that the integration with the tools of T4.4 and T4.5 is only possible if the system model used is the same in both tools. A good performance of the DSA tool can only be attained if the complete transmission system model is available, together with representative models of the neighboring countries (in the case of interconnected systems).

Fig. 12 shows possible interactions of the DSA with other tools developed in ATTEST.

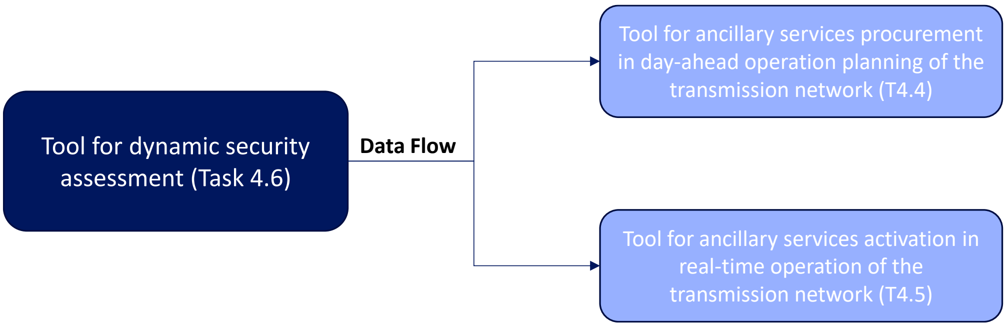

FIG. 12: INTERACTION OF TOOL 4.6 WITH OTHER ATTEST TOOLS

7. Conclusions

Given the technical nature of this deliverable, this is rather a summary than a conclusion per se. This deliverable has provided a detailed functional and technical specification of the six innovative tools, which are currently under development in WP4 of ATTEST project, for optimal and coordinated predictive management of the operation of transmission and distribution networks. These tools comprise three tools for distribution system operators which target: ancillary services procurement in day-ahead operation planning, ancillary services activation in real-time operation, and state estimation, as well as three tools for transmission system operators, which concern ancillary services procurement in day-ahead operation planning, ancillary services activation in real-time operation, and on-line dynamic security assessment. The functional and technical specifications of these six tools correspond to today stage. Accordingly, their ongoing development until their final version due in ten months from now may lead to further although normally minor changes. The specification of each tool has clearly and extensively described the five key typical aspects, namely: functional description, technical description, input and output requirements, computational requirements, and interaction with other ATTEST tools. These tools are being tested on real-word test cases provided in WP2 by different transmission and distribution system operators and we hope they will serve them to better operate their systems in the future.

8. Appendices

8.1. Appendix A.1

Appendix A. 1 presents an example of network data that acts as an input to the several tools (tasks 4.1, 4.4) developed in WP4. In the following, only buses and branch data of a distribution network are shown in Figs. 11 and 12, respectively. Nevertheless, data corresponding to loads, generation and flexibility sources is also set up in the presented format.

```
%% bus data
%   bus_i   type    Pd  Qd  Gs  Bs  area    Vm  Va  baseKV  zone    Vmax    Vmin
mpc.bus = [
    1   1   3.699   3.151   0   0   8   1.03619 -0.9058 110 1   1.1 0.9;
    2   1   25.397  1.21    0   0   8   1.00979 -5.0846 35  1   1.1 0.9;
    19  1   0   0   0   0   8   1.03278 -1.4684 110 1   1.1 0.9;
    20  1   4.325   -0.208  0   0   8   1.08453 -2.0922 35  1   1.1 0.9;
    21  1   9.66    0.687   0   0   8   1.08133 -2.8603 35  1   1.1 0.9;
    29  1   0   0   0   0   8   1.03962 -0.4453 110 1   1.1 0.9;
    30  1   14.775  0.777   0   0   8   1.00435 -2.9107 35  1   1.1 0.9;
    34  2   0   0   0   0   8   1.04397 0.1713  110 1   1.1 0.9;
    35  1   0   0   0   0   8   1.04267 -0.0647 110 1   1.1 0.9;
    36  3   -0.802  2.107   0   0   8   1.04377 0   110 1   1.1 0.9;
    37  1   15.904  1.772   0   0   8   1.01718 -2.6394 35  1   1.1 0.9;
    38  4   0   0   0   0   8   1   0   35  1   1.1 0.9;
];
```

FIG. 13: FORMAT OF BUS DATA

```
%% branch data
%   fbus    tbus    r   x   b   rateA   rateB   rateC   ratio   angle   status  angmin  angmax
mpc.branch = [
    1   19  0.0221157   0.075562    0.00731 123 0   0   0   0   1   -360    360;
    1   29  0.0193388   0.0676859   0.00649 123 0   0   0   0   1   -360    360;
    1   36  0.0169587   0.0593554   0.00563 123 0   0   0   0   1   -360    360;
    29  34  0.0121984   0.0426942   0.00403 123 0   0   0   0   1   -360    360;
    34  35  0.0112066   0.0379157   0.00371 123 0   0   0   0   1   -360    360;
    35  36  0.0100165   0.0350579   0.00332 123 0   0   0   0   1   -360    360;
    1   2   0.0090375   0.268098    0   40  48  48  1.01731602  0   1   -360    360;
    1   2   0.0090375   0.268098    0   40  48  48  1.01731602  0   0   -360    360;
    19  20  0.0090375   0.268098    0   20  24  24  0.952380952 0   1   -360    360;
    19  21  0.0090375   0.268098    0   20  24  24  0.952380952 0   1   -360    360;
    29  30  0.0090375   0.268098    0   20  24  24  1.03030303  0   0   -360    360;
    29  30  0.0090375   0.268098    0   22  26.4    26.4    1.03030303  0   1   -360    360;
    35  37  0.0090375   0.268098    0   40  48  48  1.01731602  0   1   -360    360;
    35  38  0.0090375   0.268098    0   22  26.4    26.4    0.952380952 0   0   -360    360;
];
```

FIG. 14: FORMAT OF BRANCH DATA

8.2. Appendix A.2

Appendix A.2 presents the scenarios of wind and solar power which are generated using scenario generation tool (section 2.2.1). Figs. 13 and 14 show the wind and solar power data, respectively. In both figures, for the sake of simplicity, only 10 scenarios are shown and for each scenario, the values corresponding to a horizon of 10 hours are reported.

Wind Power Scenarios

Scn/Time	t1	t2	t3	t4	t5	t6	t7	t8	t9	t10
s1	0.01	0.06	0.08	0.24	0.31	0.29	0.06	0.14	0.18	0.63
s2	0.30	0.52	0.35	0.12	0.33	0.36	0.30	0.12	0.11	0.06
s3	0.00	0.03	0.18	0.10	0.05	0.06	0.12	0.37	0.21	0.06
s4	0.17	0.18	0.11	0.09	0.19	0.25	0.12	0.03	0.04	0.17
s5	0.29	0.51	0.71	0.69	0.68	0.13	0.07	0.19	0.16	0.05
s6	0.11	0.15	0.13	0.16	0.14	0.11	0.11	0.26	0.11	0.27
s7	0.21	0.06	0.24	0.54	0.25	0.28	0.16	0.02	0.03	0.01
s8	0.06	0.12	0.25	0.08	0.07	0.11	0.29	0.21	0.18	0.20
s9	0.05	0.11	0.11	0.01	0.00	0.00	0.00	0.02	0.23	0.28
s10	0.03	0.01	0.07	0.21	0.33	0.44	0.24	0.16	0.16	0.25

FIG. 15: WIND POWER SCENARIOS

%% Solar Scenarios

%%Scn/Time	t1	t2	t3	t4	t5	t6	t7	t8	t9	t10
s1	0.00	0.00	0.00	0.00	0.00	0.07	0.37	0.57	0.69	0.74
s2	0.00	0.00	0.00	0.00	0.00	0.09	0.40	0.52	0.71	0.75
s3	0.00	0.00	0.00	0.00	0.00	0.10	0.37	0.59	0.63	0.75
s4	0.00	0.00	0.00	0.00	0.00	0.08	0.39	0.57	0.66	0.70
s5	0.00	0.00	0.00	0.00	0.00	0.07	0.37	0.52	0.64	0.78
s6	0.00	0.00	0.00	0.00	0.00	0.10	0.39	0.52	0.65	0.76
s7	0.00	0.00	0.00	0.00	0.00	0.10	0.40	0.60	0.70	0.67
s8	0.00	0.00	0.00	0.00	0.00	0.08	0.41	0.57	0.72	0.71
s9	0.00	0.00	0.00	0.00	0.00	0.10	0.36	0.53	0.65	0.76
s10	0.00	0.00	0.00	0.00	0.00	0.06	0.38	0.55	0.68	0.76

FIG. 16: SOLAR POWER SCENARIOS

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