ATTEST

WP7

Tools test and validation results

D7.2

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AUTHOR(S)	Mirna Gržanić, Karlo Šepetanc, Micael Filipe Simões, Filipe Soares, Andrey Churkin, Eduardo Martines Cesena, Baraa Mohandes, Florin Capitanescu, Mohammad Iman Alizadeh, Miguel Angel Sanz Bobi, Carlos Mateo Domingo, Thomas Gibon, Sabina Bednarova
OFFICIAL REVIEWER(S)	Filipe Soares, Mirna Gržanić

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1.1	Micael Filipe Simões, Filipe Soares (INESCTEC)	10/5/2023	Bidding optimization tools to support MES aggregators
1.2	Micael Filipe Simões, Filipe Soares (INESCTEC)	1/6/2023	Market simulator
1.3	Andrey Churkin, Eduardo Martines Cesena (UNIMAN)	12/6/2023	Optimization tool for distribution network planning
1.4	Andrey Churkin, Eduardo Martines Cesena (UNIMAN)	27/6/2023	Optimization tool for transmission network planning
1.5	Micael Filipe Simões (INESCTEC)	7/7/2023	Optimization tool for planning TSO/DSO shared technologies
1.6	Baraa Mohandes, Mohammad Iman Alizadeh, Florin Capitanescu (LIST)	15/7/2023	Tool for ancillary services procurement in day-ahead operation planning of the distribution network
1.7	Mohammad Iman Alizadeh, Florin Capitanescu (LIST)	15/8/2023	Tool for ancillary services procurement in day-ahead operation planning of the transmission network
1.8	Miguel Angel Sanz Bobi, Carlos Mateo Domingo (COMILLAS)	28/8/2023	KPIs simulations and demonstrations for WP5
1.9	Thomas Gibon, Sabina Bednarova (LIST)	01/08/2023	Environmental KPIs: avoided emissions and other impacts

1.10	Mirna Gržanić, Karlo Šepetanc (ICENT)	25/8/2023	Tool for ancillary services activation in real-time operation of the distribution network
1.11	Mirna Gržanić, Karlo Šepetanc (ICENT)	29/8/2023	Tool for ancillary services activation in real-time operation of the transmission network
1.12	Pedro Pereira Barbeiro	27/10/2023	Dynamic security assessment

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Abbreviations and Acronyms

ADN	Active Distribution Network
AGC	Automatic gain control
BaU	Business as Usual
CHP	Combined Heat and Power
DA	Day-Ahead
DG	Distributed Generation
DER	Distributed Energy Resources
DN	Distribution Network
DSA	Dynamic Security Assessment
DSO	Distribution System Operator
ESS	Energy Storage System
EV	Electric Vehicles
FL	Flexible Loads
IC	Investment cost
LV	Low Voltage
MPC	Model Predictive Control
MV	Medium Voltage

NLP	Non-Linear Programming
NOP	Normally open point
OP	Operating Point
OPF	Optimal Power Flow
PV	Photo-Voltaic
$\overline{P^{PV}}$	Peak power of PV
$\overline{P^{Sto,E,+}}$	Maximum charging power
$\overline{P^{Sto,E,-}}$	Maximum discharging power
SCOPF	Security Constrained OPF
RES	Renewable Energy Sources
RT	Real-time
TN	Transmission Network
TSO	Transmission System Operator
$\eta^{Sto,E}$	Initial battery state of energy

Executive Summary

This report refers to Task 7.2 – Tools test and validation, which was focused on testing and validating the tools developed in ATTEST from an economic, technical, and environmental perspective.

To this end, several networks and DER integration scenarios were selected from the test cases defined in WP2.

Several Key Performance Indicators (KPIs) were used to compare Business as Usual (BaU) scenario with the ATTEST solution to demonstrate the performance of the tools developed in the project. The KPIs are classified in 5 categories with a different specification for each tool. KPIs are calculated for provided Croatian, Portuguese, the UK, and Spanish distribution networks and Croatian, Portuguese, and the UK transmission network for 2030, 2040, and 2050.

The tools were integrated into the ATTEST platform, where they can be run with real-time data from the networks of Koprivnica and surrounding areas. However, due to technical impediments related to the secure operation of the networks involved in the demonstration, it was not possible to directly control some of the flexible assets through the platform. Therefore, as no flexibility is actually available in the networks in the 2020 scenario, no differences exist between the BaU and the ATTEST scenario for this year.

The results of this report were compiled and used to calculate the project final KPIs that are presented in D7.3.

1. Introduction

To enable massive integration of Renewable Energy Sources (RES) in order to foster the transition towards carbon-neutral power systems and reduce the harmful effects of climate change, power systems face some critical challenges. To ensure secure and reliable power system operation, ATTEST project delivered innovative tools for planning and operation of transmission and distribution systems from 2030 and beyond. The aim of this deliverable is to demonstrate the efficiency of developed tools by defining and calculating Key Performance Indicators (KPIs). Different KPIs are defined for each tool based on the tool's goal and functionality. The KPIs are calculated for the base case scenario for each year (without considering tools developed in the ATTEST project) and compared with the KPIs calculated considering innovations from the project. The methodology for KPIs specification and calculation will be defined and described for each tool in the next Sections.

1.1. Definition of KPIs

KPIs defined in the project are divided into 5 categories as demonstrated in Figure 1. The technical KPIs are related to voltage deviations, loading and losses minimization. To demonstrate the effectiveness of tools developed in the ATTEST project, the planning and operation of defined transmission and distribution networks are executed without considering the smart use of flexibility devices – electric vehicles (EV) as flexible loads and battery storage. The results are classified to demonstrate the number of undervoltage and overvoltage buses, losses and congested lines or transformers. In the second step, the planning and operation are simulated by using tools developed in the project and KPIs are calculated considering innovative ideas from the projects. These results are compared with the KPIs calculated in the first showing the decrease in overvoltage/undervoltage buses, losses and congestion.

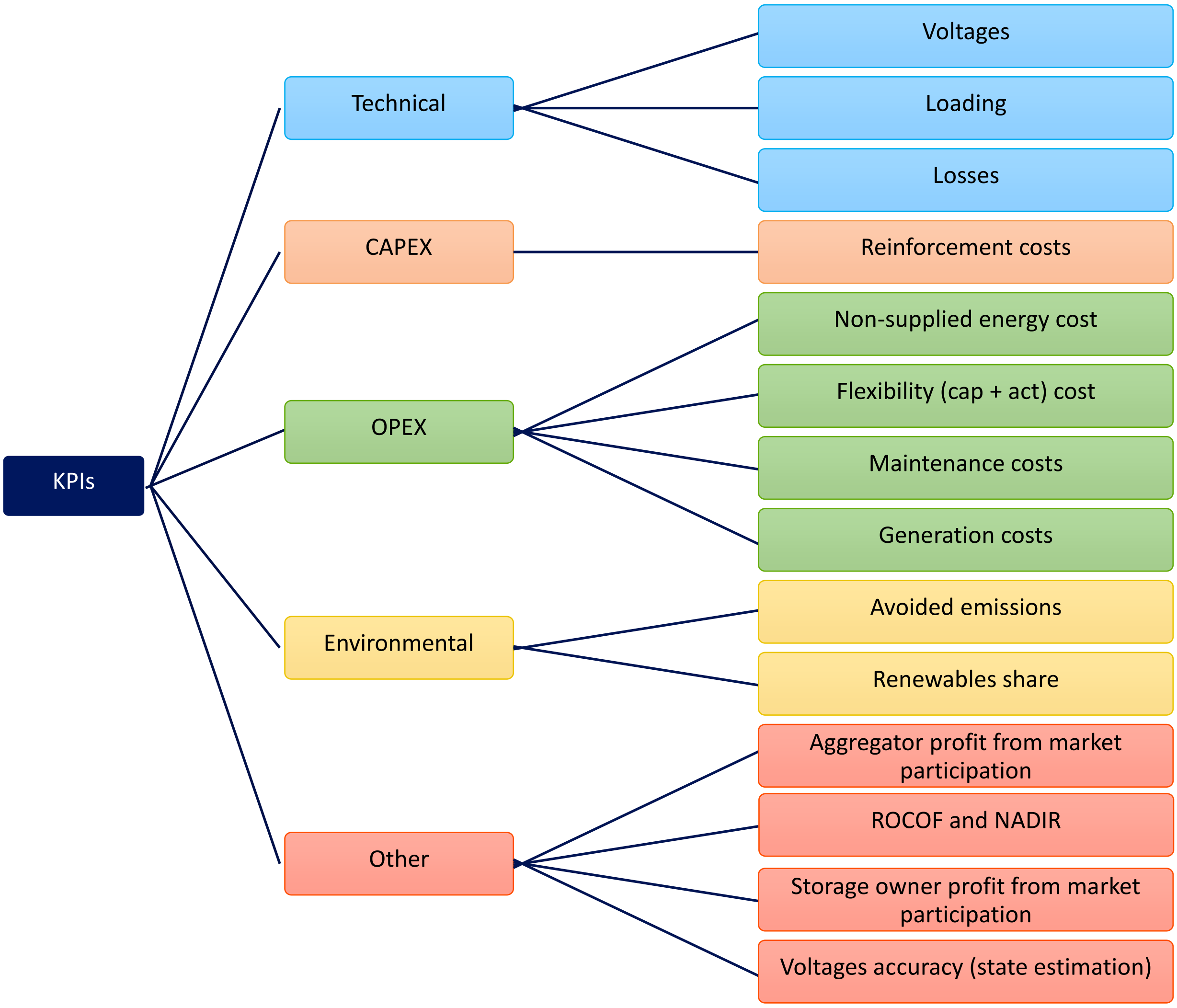


Figure 1 KPIs definition

1.2. Algorithm for KPIs calculation

The algorithm for KPIs calculation is provided in Figure 2.The selected tool is tested for a specific country and year. Depending on the tool, either transmission or distribution test network is selected and KPIs are calculated for BaU scenario and ATTEST scenario. These KPIs are calculated and compared for the selected year showing the quality of ATTEST tools in the power system operation. The same procedure is repeated for all years resulting in KPIs comparison over years. The algorithm is repeated for each country observed in the project.

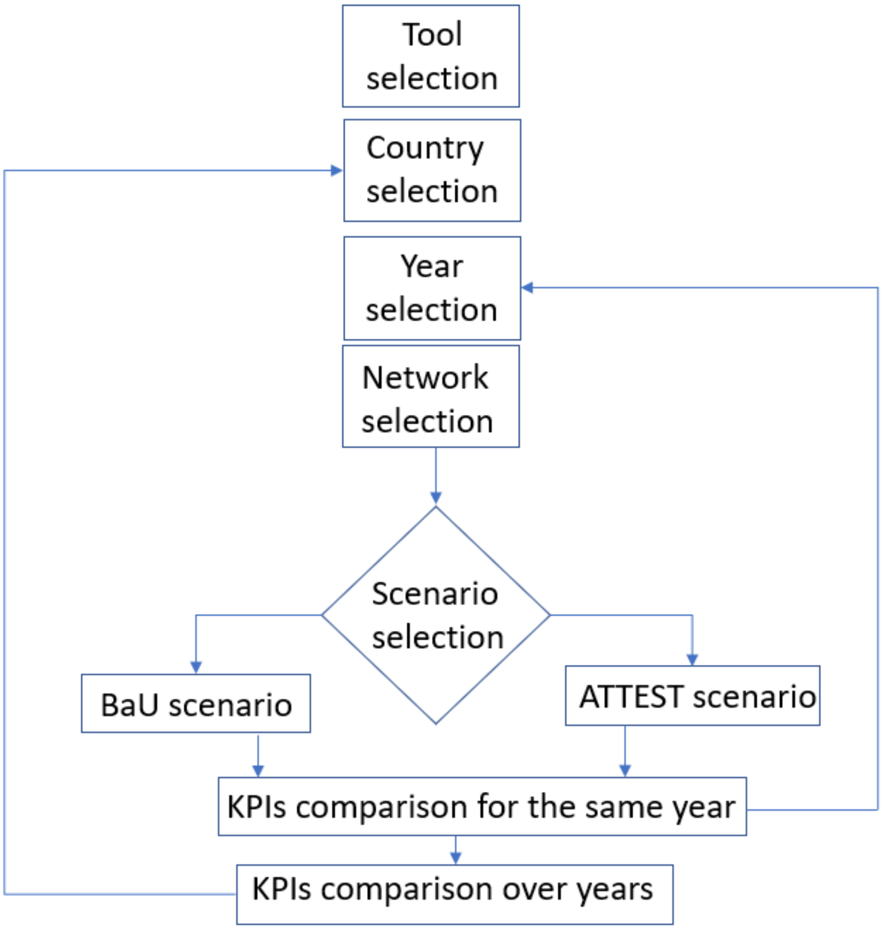


Figure 2 Algorithm for KPIs calculation

1.3. Networks for simulations

List of networks used for simulations and KPIs calculation are real network from the UK, Spain, Croatia, and Portugal which are defined and described in the ATTEST project in deliverable D2.3. These networks are listed in *Table I*.

Table I List of networks for simulations

List of networks for simulations		
Country	**Type**	**ATTEST reference**
PT	Distribution	*PT_Dx_01_2020*
	Transmission	*PT_Tx_2020*
ES	Distribution	*ES_Dx_03_2020*
	Transmission	*N/A*
UK	Distribution	*UK_Dx_01_2020*
	Transmission	*UK_Tx_2020*
HR	Distribution	*HR_Dx_01_2020*
	Transmission	*HR_Tx_01_2020 (extended version)*

2. KPIs simulations

Table II Summary of calculated KPIs for each tool

Task	Tool	Technical	CAPEX	OPEX	Environmental	Other	Simulation time	Networks
T2.5	Bidding optimization tool to support MES aggregators	Voltage problems		Non supplied energy/ Non supplied reserve		Aggregator's profit from market participation	2 typical days	Manchester microgrid + Mibel
T2.6	Market simulator					Electricity market prices	4 typical days	Iberian market
T3.1	Optimisation tool for distribution network planning		cost savings due to reduced network investments		avoided emissions due to reduced embodied carbon of network investments			All distribution
T3.2	Optimisation tool for transmission network planning		cost savings due to reduced network investments		avoided emissions due to reduced embodied carbon of network investments			All transmission
T3.3	Optimisation tool for planning TSO7DSO shared technologies	Voltage problems, line overloading, network losses, RES and load curtailment	Investments in shared energy storage	Non supplied energy + generation cost	Increase share of RES, greenhouse gas emissions reduction	Storage owner profit	2 typical days	IEEE and Croatia
T4.1	Tool for ancillary service procurement in day-ahead operation planning of the distribution network							
T4.2	Tool for ancillary service activation in real-time operation of distribution network	Number of buses with unallowed voltage deviations, number of overloaded lines and cumulative overload					2 typical days	All distribution
T4.4	Tool for ancillary service procurement in day-ahead operation planning of the transmission network	Line constraints violation		Flexibility cost, load and RES curtailment cost, fuel cost of generators			2 typical days	All transmission
T4.5	Tool for ancillary service activation in real-time operation of transmission network	Number of buses with unallowed voltage deviations, number of overloaded lines and cumulative overload					2 typical days	All transmission
T5.2 + T5.3	Tool for the definition of common life indicators for heterogeneous assets					Life Assessment		All transmission and all distribution

3. Scenarios definition

To demonstrate the evolution of KPIs for tools described in the previous section, the data provided in Table III show the increase of integration of different low carbon technologies in each country. To be more precise, Table III focused on the integration of electric vehicles, PV and storage on the country level which is downscaled on the observed part of the transmission and distribution network. The increasing trend can be seen for each technology.

Table III Scenarios for low-carbon technology integration over the years

Scenarios for new assets - DER										
Country	Year	Country level			Scale down for transmission network			Scale down for distribution network		
		EV (nr.)	PV (MW)	Storage (MWh)	EV (nr.)	PV (MW)	Storage (MWh)	EV (nr.)	PV (MW)	Storage (MWh)
PT (INESC TEC)	2020	0	0	0	0	0	0	0	0	0
	2030	694778	9872	329	694778	9872	329	1635	4.59	0.46
	2040	1305056	21486	3581	1305056	21486	3581	2671	6.07	3.04
	2050	5205000	32444	14324	5205000	32444	14324	10653	9.17	12.14
ES (COMILLAS)	2020	37000	11714	0	n.a.	n.a.	n.a.	95	26	0
	2030	5000000	39181	10000	n.a.	n.a.	n.a.	12897	88	26
	2040	1217265	67676	30000	n.a.	n.a.	n.a.	31398	152	77
	2050	1934531	80143	46000	n.a.	n.a.	n.a.	49900	179	119
UK (UNIMAN)	2020	0	0	0	0	0	0	0	0	0
	2030	1300000	39700	32600	1300000	39700	32600	871	2.6599	2.1842
	2040	3150000	67800	56800	3150000	67800	56800	2110.5	4.5426	3.8056
	2050	3310000	88600	86000	3310000	88600	86000	2217.7	5.9362	5.762
HR (HEP/HOPS)	2020	1343	85	0	310	20	0	30	1,5	0
	2030	68604	1039	150	15835	245	26,25	1715	40	3,75
	2040	257267	2514	1100	59382	590	192,5	6432	55	27,5
	2050	600289	3815	9600	138558	895	1680	15007	90	240

4. KPIs simulations and demonstrations for WP2

4.1. T2.5 – Bidding optimization tools to support MES aggregators

This chapter provides an overview of the key performance indicators (KPIs) obtained from simulations conducted on the tools developed in task 2.5. Specifically, the report focuses on two optimization tools: the day-ahead optimization tool and the real-time optimization tool. The day-ahead optimization tool is responsible for optimizing the aggregator's bids submitted to the day-ahead energy and reserves market, while the real-time optimization tool optimizes the delivery of services that were negotiated beforehand in the day-ahead markets.

The KPIs analyzed in this report primarily pertain to technical aspects, including an analysis of network problems, as well as non-supplied energy and reserves and the aggregator's profit. The evaluation of these KPIs is performed under two scenarios: one without the algorithms developed in the ATTEST project, and another with the inclusion of these algorithms. The analysis covers a span of four years (2020, 2030, 2040, and 2050) and examines two distinct periods of the year: Winter and Summer.

The structure of this report is organized as follows: The subsection 4.1.1 provides an overview of the inputs required to run the simulations, encompassing network data, resource characteristics, electricity and gas market data, as well as weather and inflexible load information. The subsection 4.1.2 presents a detailed analysis of the KPIs, highlighting the findings and observations derived from the simulations. Finally, the third and last subsection 4.1.3 offers the conclusions drawn from the analyses, summarizing the key outcomes and implications of the study.

By delving into the KPIs obtained from simulations conducted on the day-ahead and real-time optimization tools, this report aims to provide valuable insights into the performance and effectiveness of the developed algorithms in the ATTEST project.

4.1.1. Inputs

The simulations use the microgrid from the University of Manchester [1]. The microgrid is characterized by electricity, gas, and heat networks, as illustrated in Figure 3.

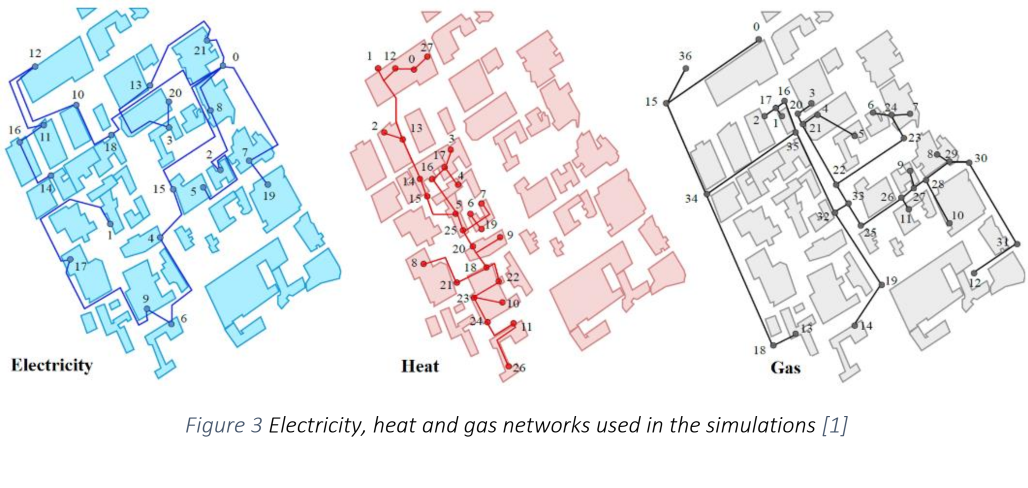


Figure 3 Electricity, heat and gas networks used in the simulations [1]

As stated in previous deliverables, it is important to note that, with the exception of the United Kingdom, the tools were not tested with the typical networks from the other countries participating in ATTEST (namely Portugal, Spain, and Croatia). This limitation arose due to the availability of only electricity network data for these particular cases. Unfortunately, the lack of gas and heat/cooling network data rendered it impossible to execute the tools for these countries.

4.1.1.1. Network data

The data of the electricity, gas, and heat networks is available in [1] and includes the parameters of the networks. The bounds of the voltages in the electricity network were fixed at 0.95 and 1.05 p.u., and the voltage in the slack bus 0 was fixed at 1 p.u. The mass flow limit of the heat network was set at 40 kg/s, the outlet temperature of each load was set at 70 °C, the supply temperature of generators was defined as 85 °C, and the ambient temperature of the ground was defined as 7 °C. The limit of the gas network's pressure was set to 2 bars.

4.1.1.2. Resources

It was assumed that there are several resources connected to electricity, gas, and heat networks. These resources are PV systems, energy storage systems (ESSs) and heat pumps (HPs). The aggregated power/capacity of each type of equipment gradually increases over the years, following predetermined adoption rates. The final figures for each year and type of equipment are presented in Table IV.

Table IV Aggregated power of heat pumps and PVs, and capacity of energy storage systems.

	2020	2030	2040	2050
HPs (MW)	21.0	23.1	39.4	51.6
PVs (MW)	7.5	8.3	14.1	18.4
ESSs (MWh)	2.5	2.8	4.8	7.3

These inputs are also presented in Figure 4.

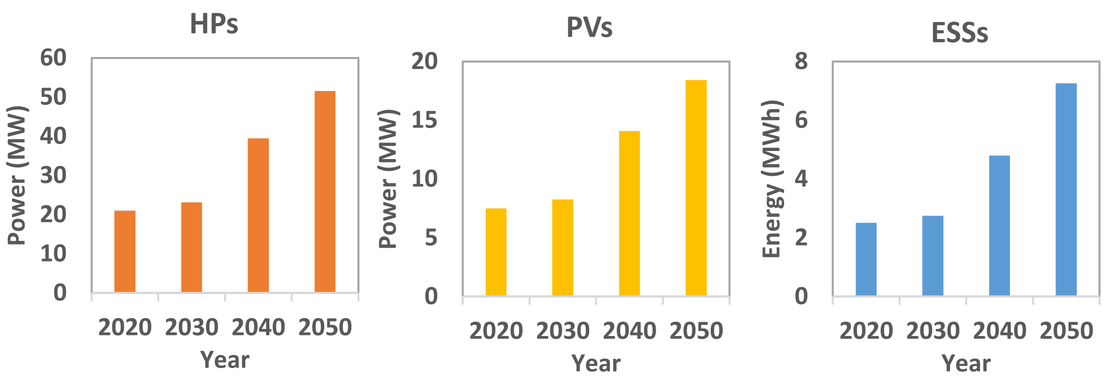


Figure 4 Total capacity installed of heat pumps, PVs, and energy storage systems

The parameters considered for the HPs are 3.45 of COP η^{HP}, and 750 kW of maximum electric power $\overline{P^{HP}}$. The parameters of the PVs are the peak power $\overline{P^{PV}}$ and it ranges from 750 to 1500 kW. The parameters of the ESSs are 0.9 of efficiency $\eta^{Sto,E}$, and 100 kW of maximum power for charging $\overline{P^{Sto,E,+}}$ and discharging $\overline{P^{Sto,E,-}}$. Their initial SOC $SOC_0^{Sto,E}$ was set to 100 kWh.

The CHPs are connected to the electricity nodes 6 and 12, gas nodes 0 and 14 and heat nodes 26 and 27. The parameters of the CHPs are 10 MW of maximum gas power, 0.35 of electricity efficiency, 0.45 of heat efficiency.

The heating flexible loads are characterized by β of 0.97 and R of 0.081 ºC/kWh. The comfort range defined for all users was set to [19, 23] ºC between 7h to 18h, and [16, 26] ºC for the remaining part of the day.

4.1.1.3. Electricity and gas market

The day-ahead and real-time tools are used by aggregators to participate in the day-ahead and real-time stages of the electricity and gas markets, respectively. This subsection presents the prices used in each of these phases.

The electricity and gas market prices were considered the same for 2020, 2030, 2040, and 2050, and they are differentiated by Winter and Summer seasons (with the exception of the AGC signal, which is the same for both seasons).

The electricity market data is divided by type of markets including the energy, secondary and tertiary markets. All electricity prices and reserve activation ratios were calculated using the gradient boosting algorithm [2] through the python package "scikit-learn"[3]. The point forecasts are used in the DA stage, while the actual values are used in the RT phase.

The electricity energy market data includes forecasts and actual values of energy price λ_t^E, and negative $\lambda_t^{E,-}$ and positive imbalances $\lambda_t^{E,+}$, as illustrated in Figure 5 and Figure 6. This information was sourced from references [4] and [5].

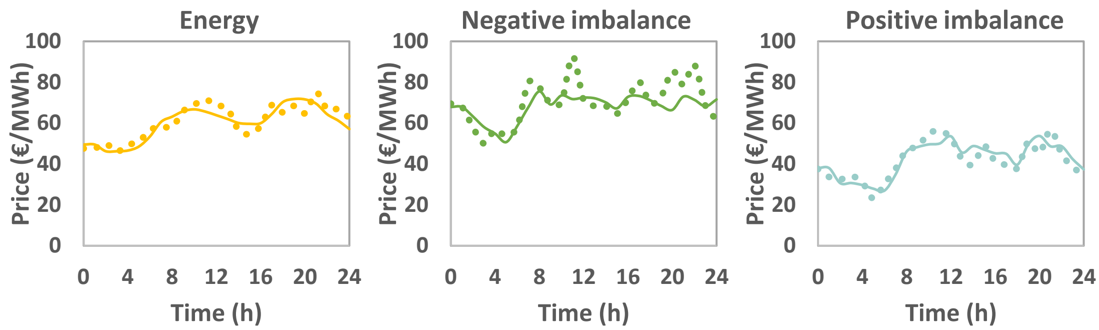


Figure 5 Energy market data forecasts (continuous line) and actual values (dashed line) for Winter

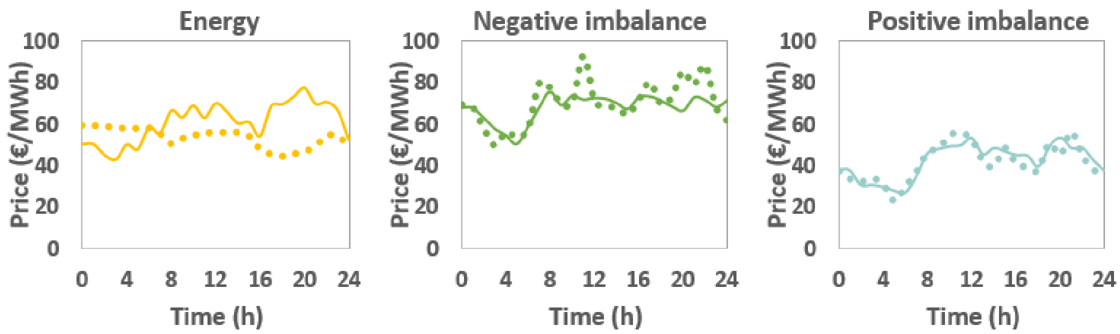


Figure 6 Energy market data forecasts (continuous line) and actual values (dashed line) for Summer

The electricity secondary market data includes forecasts and actual values of secondary reserve prices λ_t^B (for offering band), ratios of upward ϕ_t^U and downward ϕ_t^D mobilizations, and financial penalties for band not supplied $\lambda_t^{B,-}$ [4] and [5], as illustrated in Figure 7 and Figure 8. It also considers band utilization prices which are represented by the tertiary reserve prices. The penalty for band not supplied is equal to $1.5\lambda_t^B$.

During the RT stage, the secondary band sold in the DA market is dispatched according to the AGC signal sent by the TSO. Figure 9 presents the AGC signal used in this work with time-steps of 20s and normalized between -1 (upward) and 1 (downward). Positive values represent the activation of the downward reserve band while negative values represent the activation of the upward reserves band.

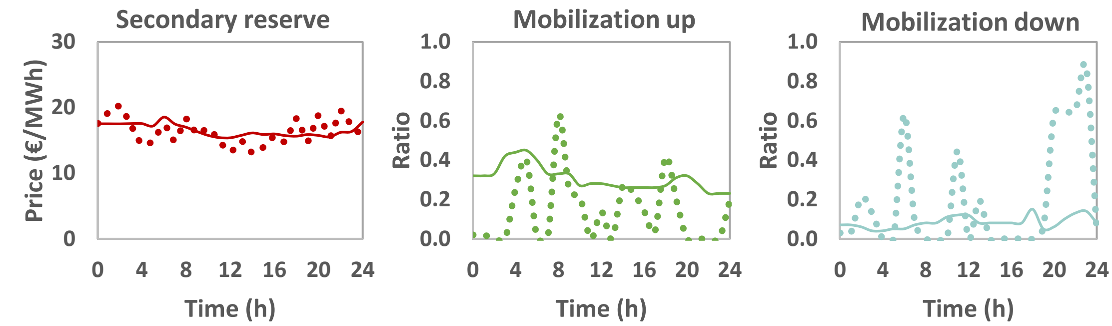


Figure 7 Secondary market data forecasts (continuous line) and actual values (dashed line) for Winter

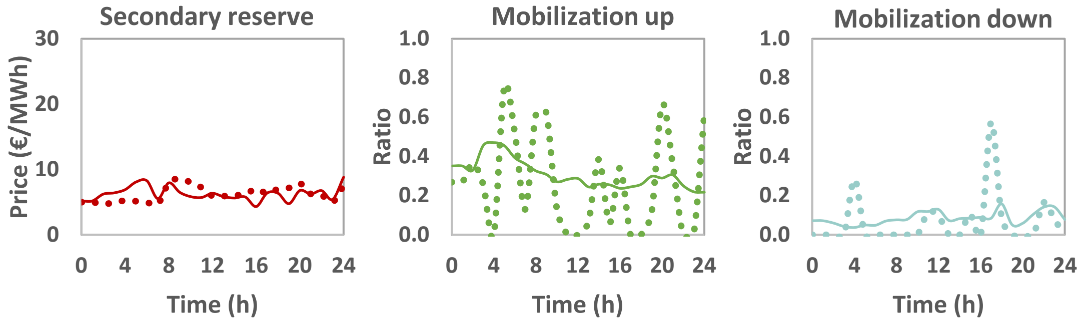


Figure 8 Secondary market data forecasts (continuous line) and actual values (dashed line) for Summer

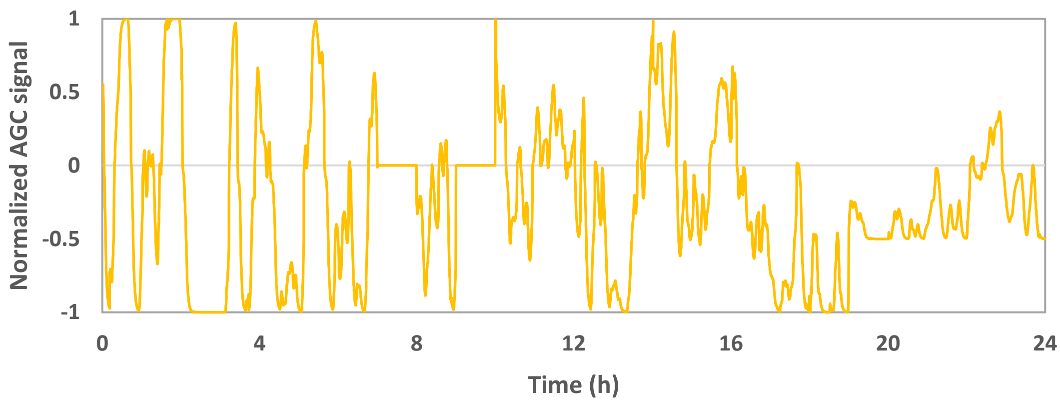


Figure 9 Normalized AGC signal

The electricity tertiary market data includes forecasts of upward $\lambda_t^{U,E}$ and downward $\lambda_t^{D,E}$ tertiary reserve prices as illustrated in Figure 10 and Figure 11 [4] and [5].

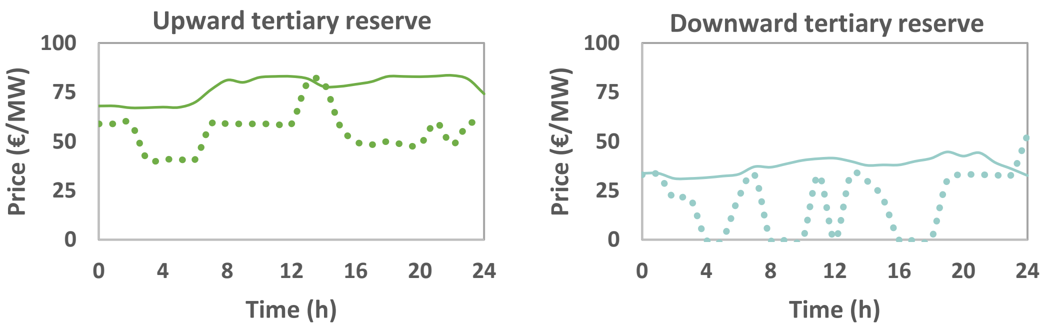


Figure 10 Tertiary market data forecasts (continuous line) and actual values (dashed line) for Winter

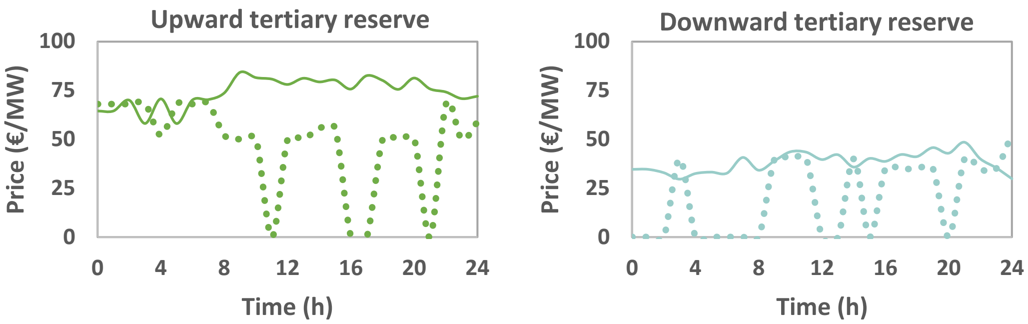


Figure 11 Tertiary market data forecasts (continuous line) and actual values (dashed line) for Summer

The forecasted gas market price is 22.99 €/MW and the actual gas market prices is 22.7 €/MW.

4.1.1.4. Weather data

All the data presented in this subsection is variable data in the form of point forecast and actual values. The point forecasts are used in the DA stage, while the actual values are used in the RT phase.

The PV generation $\overline{P^{PV}}$, outside temperature θ^{O}, and inflexible load (electricity $P^{IL,E}$, gas $P^{IL,G}$, heat $P^{IL,H}$, and hydrogen P^{IL,H_2}) point forecasts and actual values are presented in Figure 12 and Figure 13. The point forecasts were computed by the gradient boosting algorithm [2] from the python package "scikit-learn" [3]. This data and the actual values were collected from the MeteoGalicia website [6].

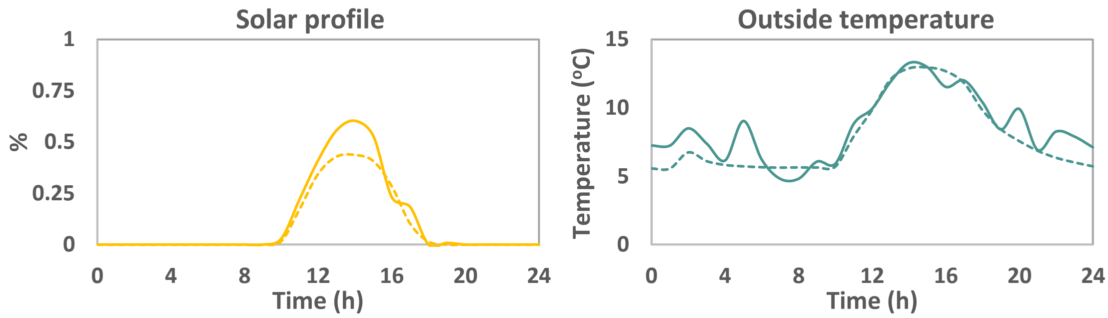


Figure 12 Solar profile and outside temperature forecasts (continuous line) and actual values (dashed lines) during Winter

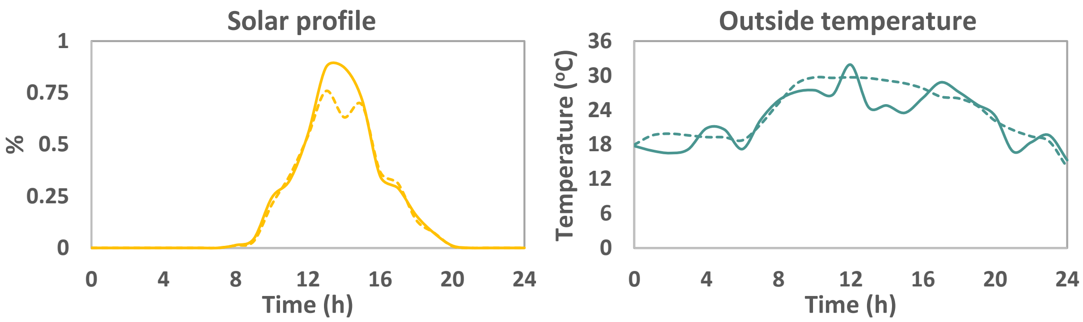


Figure 13 Solar profile and outside temperature forecasts (continuous line) and actual values (dashed lines) during Summer

4.1.1.5. *Inflexible load data*

All the data presented in this subsection is variable data in the form of actual values. They are used in both the DA and RT phases.

The inflexible load (electricity $P^{IL,E}$, gas $P^{IL,G}$, heat $P^{IL,H}$, and hydrogen P^{IL,H_2}) actual values are presented in Figure 14 and Figure 15 for the years 2020, 2030, 2040, and 2050. The values for 2020 (base year) were collected from [1]. Table V shows the load growth until 2050.

Table V Inflexible load per year and network

	2020	2030	2040	2050
Electricity (MWh)	17 098	17 909	22 399	24 700
Gas (MWh)	911	955	1 194	1 317
Heat (MWh)	13 829	14 485	18 117	19 977

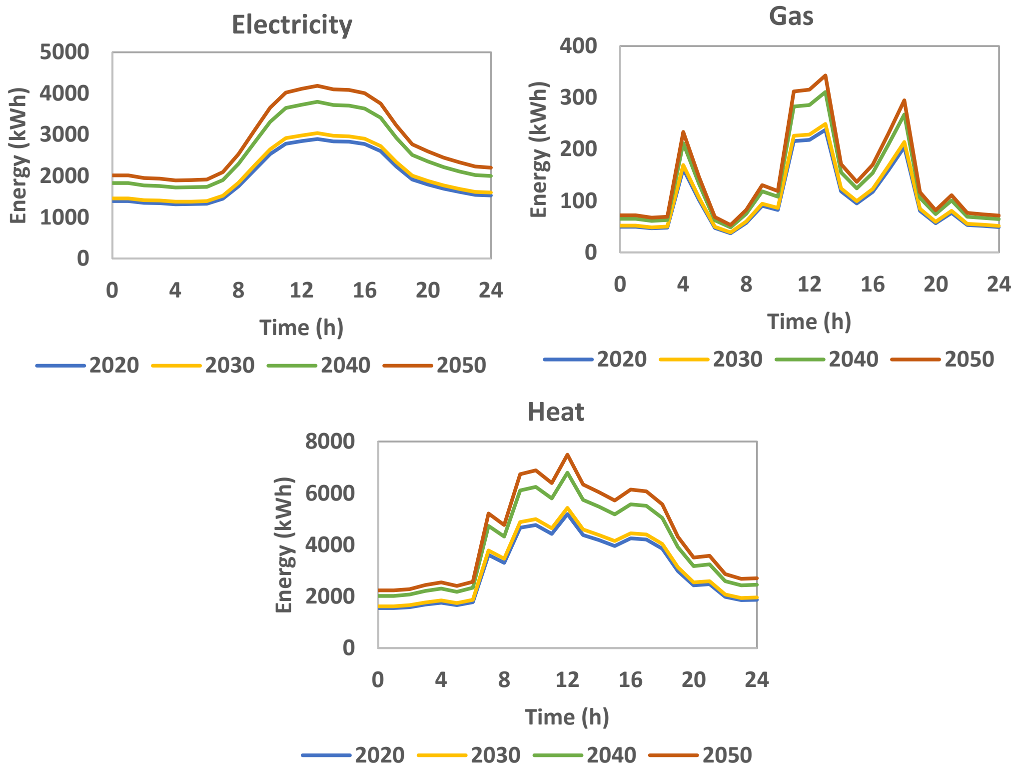


Figure 14 Electricity, natural gas, heat and inflexible loads forecasts for Winter

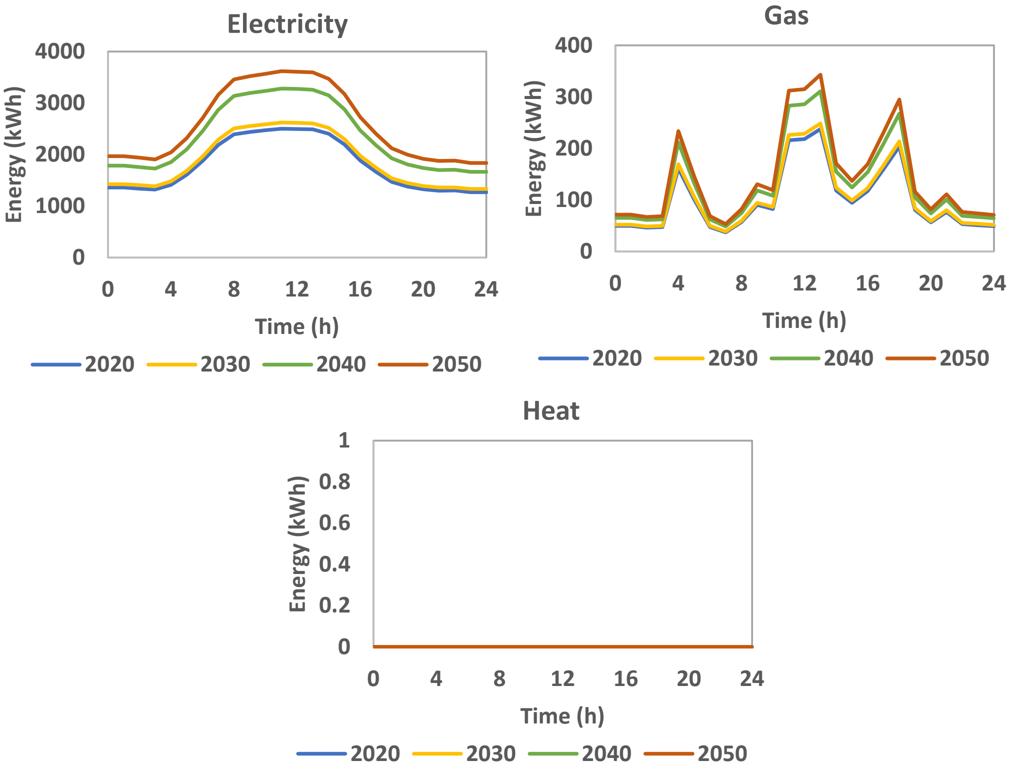


Figure 15 Electricity, natural gas, heat and inflexible loads forecasts for Summer

4.1.2. Key performance indicators (KPIs)

This section presents the KPIs computed after performing all the simulations. The analysis includes the evaluation of technical KPIs (constraints violations in section 4.1.2.1), as well as economic KPIs such as the non-supplied energy and reserves (in section 4.1.2.2) and the aggregator's economic performance (in section 4.1.2.3). The evaluation of each KPI is always performed by comparing two scenarios:

1. Base case - without the algorithms developed in the ATTEST project,
2. ATTEST algorithm - with the tool described in the sections above and in previous ATTEST deliverables.

4.1.2.1. Technical – network problems

This subsection discusses the technical KPIs. The number of problems occurring in the networks is presented here.

Figure 16, Figure 17, Table VI, and Table VII show the number of problems and maximum voltage limits for Winter and Summer, respectively. It is possible to observe that by using the tool developed (ATTEST algorithm), no voltage problems occurred in either case. On the contrary, several problems occurred in the base case, particularly in the electricity network. It is possible to observe that the number of problems increase from year 2020 to 2050 and that more voltage problems are detected during Summer. The maximum values of voltage are also higher during Summer, and they increase from 2020 to 2050. This happens because PV generation is higher in Summer, and it increases over the years.

Analyzing the maximum voltage, it is possible to observe that the maximum voltage values (1.15 p.u) and number of problems (107) occurred during the Summer of 2050. During Winter, the maximum voltage values increase from 1.039 p.u to 1.104 p.u. (a 6% increase), and the number of problems increases from 0 to 78, from 2020 to 2050. During Summer, the maximum voltage values increase from 1.066 p.u to 1.15 p.u. (a 8% increase) and the number of problems increase from 30 to 107 (a 250% increase), from 2020 to 2050.

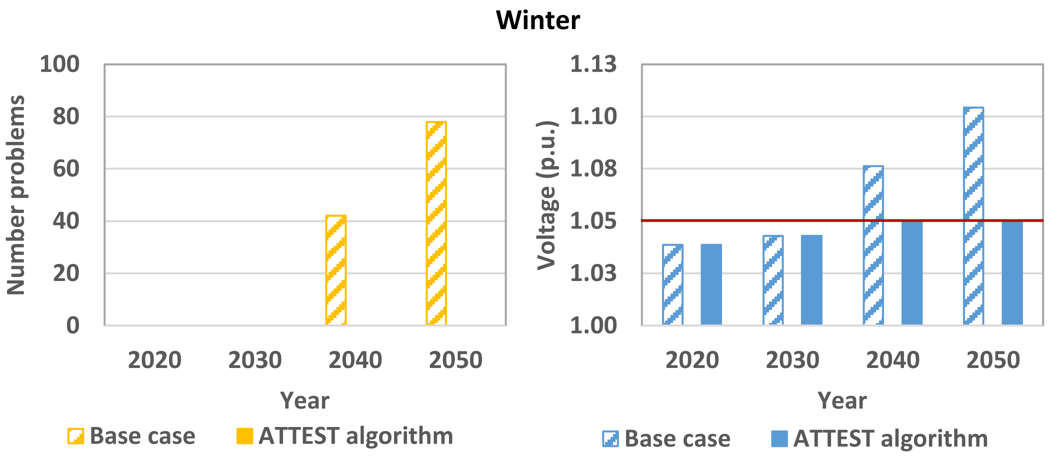


Figure 16 Number of problems and voltage values for the Winter scenarios

Table VI Number of problems and voltage values for the Winter scenarios

Winter					
		2020	2030	2040	2050
Base case	Number problems	0	0	42	78
	Maximum voltage (p.u)	1.04	1.04	1.08	1.10
	Minimum voltage (p.u)	0.96	0.96	0.96	0.97
ATTEST algorithm	Number problems	0	0	0	0
	Maximum voltage (p.u)	1.04	1.04	1.05	1.05
	Minimum voltage (p.u)	0.96	0.96	0.96	0.95

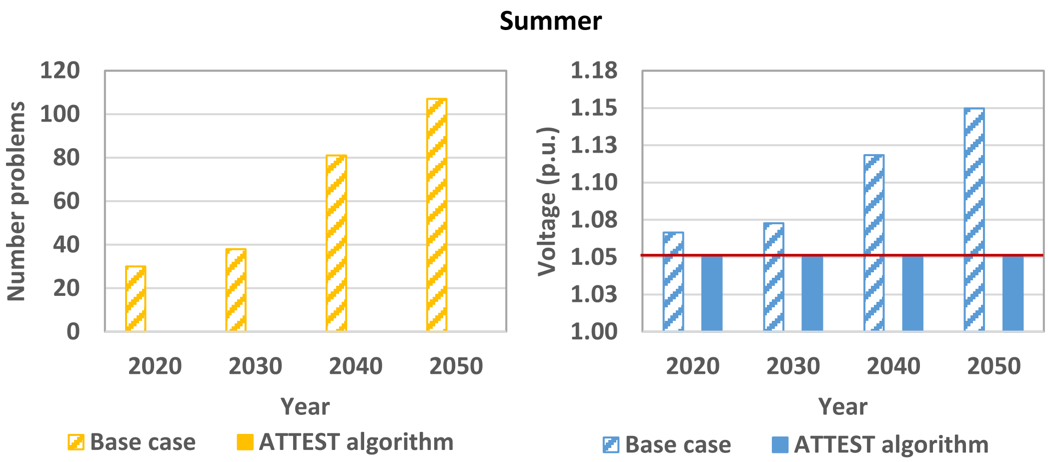


Figure 17 Number of problems and voltage values for the Summer scenarios

Table VII Number of problems and voltage values for the Summer scenarios

Summer					
		2020	2030	2040	2050
Base case	Number problems	30	38	81	107
	Maxmum voltage (p.u)	1.07	1.07	1.12	1.15
	Minimum voltage (p.u)	0.99	0.99	0.99	0.99
ATTEST algorithm	Number problems	0	0	0	0
	Maxmum voltage (p.u)	1.05	1.05	1.05	1.05
	Minimum voltage (p.u)	0.99	0.99	0.96	0.95

4.1.2.2. OPEX – non-supplied energy and reserves

This section analyses the non-supplied energy and reserves for the base case and for the scenario where the developed tool is used.

Figure 18 and Figure 19 show not supplied energy and reserve for typical Winter and Summer day.

Table VIII and Table IX present the values obtained for the non-supplied energy and reserves for Winter and Summer. It can be observed that energy and reserves could not be totally delivered in the base case. This occurs because during the day-ahead phase the aggregator submitted energy and reserves bids without considering network constraints. Therefore, during the delivery phase, the activation of the bids would violate network constraints and the DSO had to limit the bids to avoid technical problems.

The scenarios with non-supplied energy are those referred to 2040 and 2050, both Winter and Summer. When the developed tool was used (ATTEST algorithm), no problems were detected.

In relation to the reserves not supplied, these occurred in both Winter and Summer scenarios as shown in the following figures and tables.

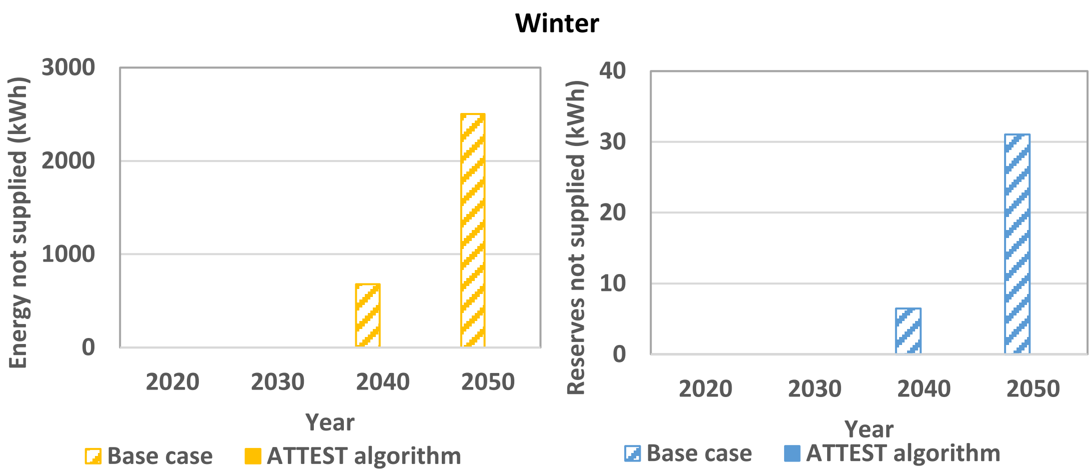


Figure 18 Energy and reserves not supplied for Winter

Table VIII Energy and reserves not supplied for Winter

		Winter			
		2020	**2030**	**2040**	**2050**
Energy not supplied (kWh)	**Base case**	0	0	679	2 504
	ATTEST algorithm	0	0	0	0
Reserves not supplied (kWh)	**Base case**	0	0	6	31
	ATTEST algorithm	0	0	0	0

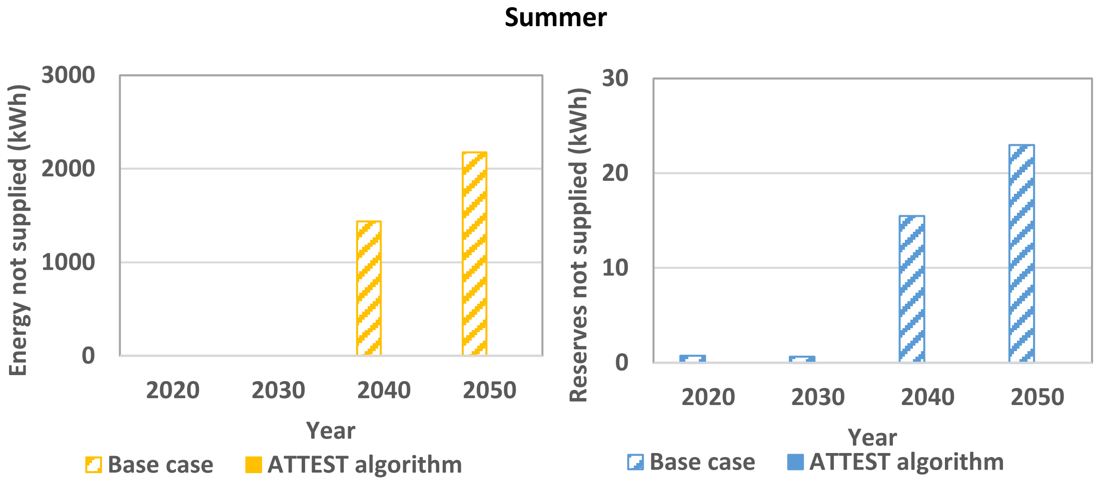


Figure 19 Energy and reserves not supplied for Summer

Table IX Energy and reserves not supplied for Summer

		Summer			
		2020	**2030**	**2040**	**2050**
Energy not supplied (kWh)	**Base case**	0	0	1 437	2 176
	ATTEST algorithm	0	0	0	0
Reserves not supplied (kWh)	**Base case**	0.7	0.6	15.5	23.0
	ATTEST algorithm	0	0	0	0

4.1.2.3. Aggregator profit

This section presents a discussion about the net-costs of the aggregator obtained for the different cases studied.

Figure 20, Figure 21, Table X, and Table XI present the net-costs of the aggregator for the different years and for Winter and Summer scenarios. We can conclude that costs decrease over the years. The reason for these results is mostly due to the higher installed PV capacity. This will increase not only the profit of injecting energy but also decrease the costs of buying electricity in the market. The higher capacity of energy storage systems also influences the decrease of costs as the aggregator has more room to perform energy arbitrage. Moreover, the increasing capacity of PVs, heat pumps, and energy storage, with the inherent increase in the overall flexibility, allows the aggregator to offer more reserve bids when it is more profitable.

A decrease in costs from Winter to Summer can also be observed, which is probably due to the lower energy consumption in Summer complemented by the higher generation from PVs.

One of the main conclusions from this analysis is that the aggregator's net-cost is lower with the ATTEST algorithm when compared to the base case, mainly because there are no cases with non-supplied energy and reserves when the optimization tools are used (i.e. the aggregator does not pay penalties for the non-supplied energy and non-delivered reserves).

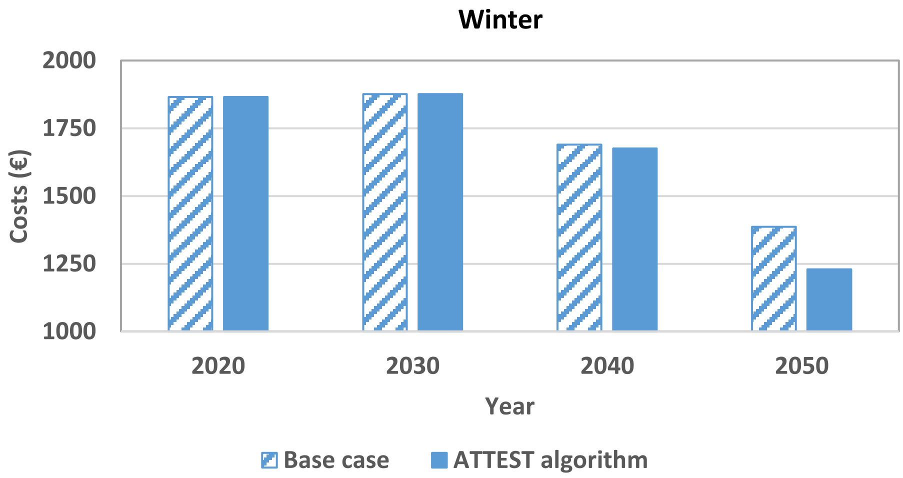


Figure 20 Aggregator net-costs for Winter

Table X Aggregator net-costs for Winter

		Winter			
		2020	**2030**	**2040**	**2050**
Aggregator's cost (€)	**Base case**	1 866	1 877	1 690	1 387
	ATTEST algorithm	1 866	1 877	1 676	1 230

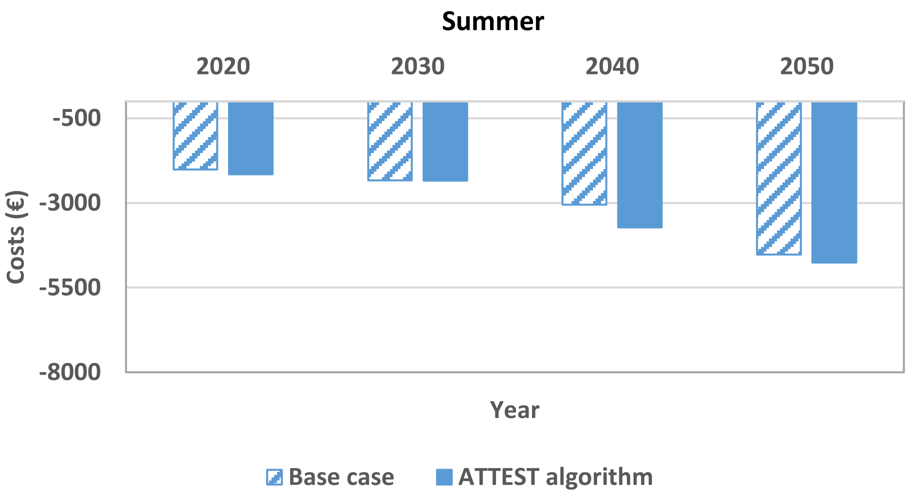


Figure 21 Aggregator net-costs for Summer

Table XI Aggregator net-costs for Summer

		Summer			
		2020	**2030**	**2040**	**2050**
Aggregator's cost (€)	**Base case**	-2 007	-2 336	-3 052	-4 524
	ATTEST algorithm	-2 155	-2 345	-3 725	-4 756

4.1.3.Conclusions

This report presents the KPIs obtained from the simulations of the tools developed in task 2.5. The tools are the day-ahead and real-time optimization tools to be used by aggregators. The KPIs analyzed here are technical (network technical violations), economic (non-supplied energy and reserves and the aggregator's profit). The analyses were performed for 2020, 2030, 2040 and 2050 and for two typical days (Winter and Summer).

From analyzing the energy and reserves that were not fully delivered, it can be seen that the traditional algorithms (base case) had several periods with non-supplied energy and reserves, which can be attributed to the non-consideration of the network constraints during the day-ahead bidding phase. Consequently, bids had to be limited by the DSO during the delivery phase, generating imbalances between accepted bids and effectively delivered quantities. The highest value of non-supplied energy was registered in 2050, suggesting that a high correlation exists with the PV integration levels. Non-supplied reserves occurred in both Winter (2040 and 2050) and Summer (2020, 2030, 2040, and 2050) scenarios, with the highest value being observed in 2050. The utilization of the optimization tools developed in task 2.5 (ATTEST algorithm case) prevented all the problems observed in the base case.

In relation to the technical KPIs, no voltage problems occurred in Winter or Summer in the "ATTEST algorithm" scenario. Conversely, several network problems were detected in all years in the base case, with predominance in the Summer scenarios. The maximum voltage values were higher in Summer and rose from 2020 to 2050 due to the PV generation increase. The highest maximum voltage (1.15 p.u) and number of problems (107) were observed in the Summer of 2050.

In relation to the aggregator's net costs, they decrease over time due to the increased overall flexibility available, which is boosted by the higher number of flexible resources installed. The increased capability for energy arbitrage enables the submission of more profitable bids, while simultaneously contributing to avoiding penalties for real-time imbalances.

4.2. T2.6 – Market simulator

4.2.1. Introduction

This technical report details the simulations for demonstrating the market simulator tool developed in T2.6 and reported in D2.6[1] by utilizing the Iberian day-ahead electricity market as a case study. The demonstration is based on computing the average annual electricity price as a key performance indicator (KPI), comparing results for four different years: 2020, 2030, 2040 and 2050. Each year provides a monthly analysis of typical week/weekend operational days with both daily results and monthly averages.

The structure of this report is organized as follows: section 2 presents the input data for the day-ahead electricity market simulations. This includes demand and generation installed power and typical day consumption profiles, primary energy prices and interconnection data. Section 3 provides the presentation of the KPI, with insights into the results obtained from the simulations. Finally, section 4 delivers conclusions drawn from the analysis.

4.2.2. Input data

The Iberian electrical system contemplated in the day-ahead electricity market clearing simulator considers the Spanish and Portuguese markets as two bidding zones. Each zone is comprised of: one load that represents the total aggregated energy for the bidding zone; generators grouped by generation technology to represent all existing generators of the bidding zone.

All loads and generators, within each zone, are connected to a single bus and both country single bus are connected by a single line with a maximum power flow that represents the interconnection capacity limits between both countries, for market purposes[2]. Additionally, both zones are considered isolated from other existent interconnections.

The simulation of the day-ahead electricity market clearing was performed considering an hourly optimization process, which considers representative week and weekend days. These days are classified in pairs of week and weekend days for each month enabling the extrapolation of prices representing a full year of market operation. The identification of the representative days is based on the load and generation installed powers and average historic energy profile data.

In subsections 4.2.2.1 and 4.2.2.2, the generation and load bids are presented. These bids are composed by a dual offering, made by participants seeking to either buy (load) or sell (generation) energy. They are defined by two essential components: the quantity of energy they are willing to provide or purchase and the specific price at which they offer this energy. Subsection 4.2.2.1 presents the generation bid data and subsection 4.2.2.2 presents the load bid data.

4.2.2.1. Generation bid definition

In this subsection it is presented the generation bid definition for the dual offering bid required to participate in the market. This information is divided into two parts. The first specifies data utilized for the quantity of energy which the generators are prepared to provide within the given timeframe. In the

[1] T. Abreu, L. Carvalho, and A. Madureira, "D2.6 - Market Simulator," 2020. Accessed: Jul. 26, 2023. [Online]. Available: https://attest-project.eu/wp-content/uploads/Attachment_0-4.pdf

[2] REN, "Capacity & Commercial Schedules - Market Session." https://mercado.ren.pt/EN/Electr/SystemManagement/Interconnections/CapProg/Pages/MktSession.aspx (accessed Jun. 05, 2023).

second it is detailed the considerations and calculations performed to create the bidding price at which each generator is willing to sell its energy.

Generators available bidding quantities

Each generator available bid quantity applied an available energy profile for each scenario, which differed on a technology basis. For coal, natural gas and nuclear energy fueled generators, the available bidding quantity for each typical day was set as equal to the respective installed power as seen in Table XII and Table XIII. For the remaining generators, which encompass the renewable generation for the Spanish and Portuguese markets, a normalized energy profile was applied to their respective installed power, also seen in Table XII and Table XIII..

The normalized data for the typical week and weekend days profiles was sourced from the historic data of 2020[3]. The historic data was grouped by month and then grouped by week and weekend. An average for each month, week and weekend were calculated, resulting in a single monthly energy profile for each week and weekend of 2020. These values were normalized using the installed power at the beginning of 2020[3].

The available energy profiles for 2020, 2030, 2040 and 2050 were then calculated by applying the calculated normalized profiles to the installed power of Table XII for the Spanish renewable energy generators and to the installed power of Table XIII for the Portuguese renewable energy generators.

Figure 22 and Figure 23 show the Spanish and Portuguese monthly energy bids for the year 2020, for a typical weekday. The remainder of the energy bid plots for the rest of the typical weekdays and weekend days are shown in Annex A.

Table XII – Generation technologies installed power in the Spanish zone.

Zone	ID	Year	2020	2030	2040	2050
		Technology	Installed Power (MW)			
ES	G0	Coal	7897	0	0	0
	G1	Natural Gas	30320	28466	28466	28466
	G2	Nuclear	7399	3181	0	0
	G3	Reservoir	18157	22157	22157	22157
	G4	Run of River	1976	1976	1976	1976
	G5	Wind	28033	50333	81172	93638
	G6	Solar	11374	46484	74964	86478
	G7	Other	6673	5740	5789	5809

[3] ENTSO-E, “Transparency Platform.” https://transparency.entsoe.eu/dashboard/show (accessed Feb. 22, 2023).

Table XIII – Generation technologies installed power in the Portuguese zone.

Zone	ID	Year	2020	2030	2040	2050
		Technology	Installed Power (MW)			
PT	G8	Coal	1756	0	0	0
	G9	Natural Gas	3829	2839	2839	2839
	G10	Reservoir	6388	8097	8097	8097
	G11	Run of River	619	635	635	635
	G12	Wind	5395	5937	6245	6709
	G13	Solar	1631	7810	9707	11817
	G14	Other	1698	1797	1852	1903

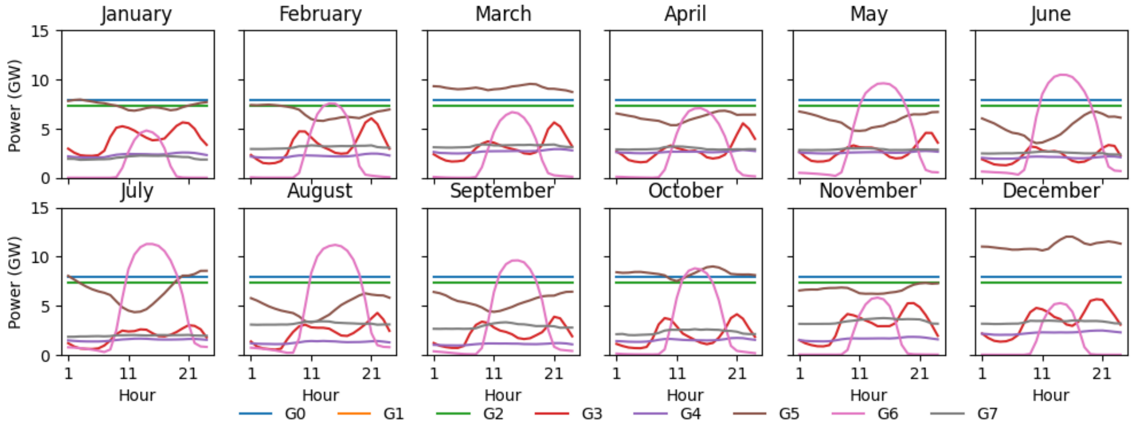


Figure 22: Spanish available energy profiles for a typical weekday for the 2020 scenario.

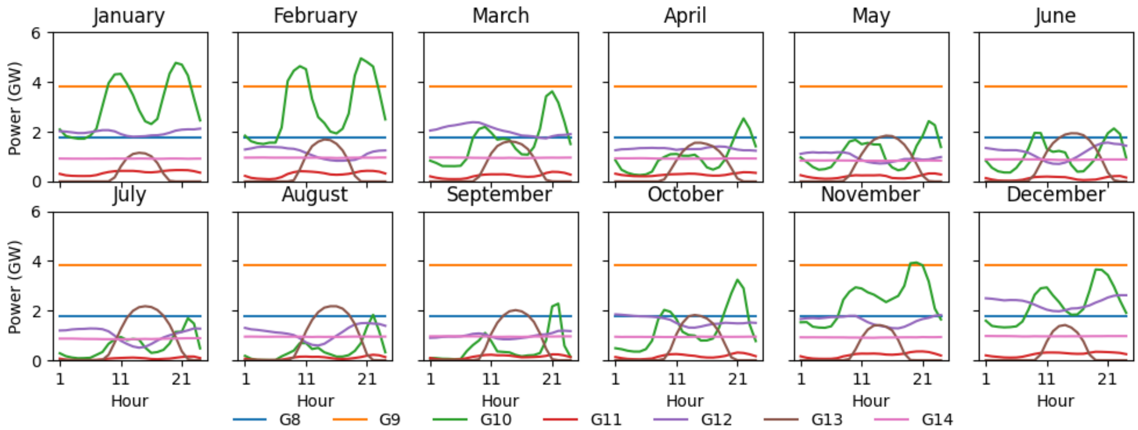


Figure 23: Portuguese available energy profiles for a typical weekday for the 2020 scenario

Generation bid pricing

Price bids were considered the same for both country zones. 2020 was considered as the base for the calculation of each technology base price. The following years assumed an increment of 10% to all price bids in comparison with the previous year.

Base prices (in €/MWh) for coal and natural gas generators were calculated by using the commodity price of the first trimester of 2023[4] and the assumptions shown in Table XIV. Accordingly, a monthly curve for natural gas, coal and $C0_2$ emissions prices was added to the monthly average price of the last five years[5,6]. Figure 24 shows the evolution of the commodities price over the months and years of simulation before the calculation of the final prices for coal and natural gas fired generators. Figure 25 shows the final price for coal and natural gas fired generators, with the considerations provided in Table XIV

For the hydro reservoir technology, the price considered at each hour follows the assumptions presented in (1).

$$\begin{cases} \mu_{m,h}^{hydro\ reservoir} = \max\left(\mu_{m,h}^{coal}, \mu_{m,h}^{natural\ gas}\right) + 1 & m \in \{Jan, Fev, Mar, Dec\} \\ \mu_{m,h}^{hydro\ reservoir} = \min\left(\mu_{m,h}^{coal}, \mu_{m,h}^{natural\ gas}\right) - 1 & m \in \{Apr, May, Jun, Jul, Aug, Sep, Oct, Nov\} \end{cases} \tag{1}$$

where $\mu_{m,h}^{hydro\ reservoir}$ is the price bid (in €/MWh) for hour h at month m for the hydro reservoir technology generators, $\mu_{m,h}^{coal}$ is the price bid (in €/MWh) for hour h at month m for the coal technology generator and where $\mu_{m,h}^{natural\ gas}$ is the price bid (in €/MWh) for hour h at month m for the hydro reservoir technology generators.

The levelized cost of energy for the nuclear energy generator was calculated based on the French levelized cost of electricity for nuclear plants operating at an 85% capacity factor over a 10-year period[7]. The price bids for the remaining technologies were set as zero.

Table XIV – Base technology price considerations.

Commodity	Commodity Price		Fuel and CO_2 Emissions ratio	Generator Efficiency	Technology Price
Gas	-	59.44	0.185	45%	150.70
Coal	159.45	22.84	0.85	30%	161.60
CO2	100.54	-	-	-	-
Units	€/ton	€/MWh	MWh/ton	%	€/MWh

4 ERSE, “Commodities Prices.” https://www.erse.pt/media/amamqup5/boletim_commodities_1t2023_vs_externa.pdf (accessed Jun. 05, 2023).
5 MIBGAS, “MIBGAS File Access.” https://www.mibgas.es/en/file-access (accessed Jun. 05, 2023).
6 Investing.com, “Coal (API2) CIF ARA (ARGUS-McCloskey).” https://pt.investing.com/commodities/coal-(api2)-cif-ara-futures-historical-data (accessed Jun. 05, 2023).
7 IEA, “Projected Costs of Generating Electricity,” 2020. Accessed: Feb. 16, 2023. [Online]. Available: https://www.iea.org/reports/projected-costs-of-generating-electricity-2020

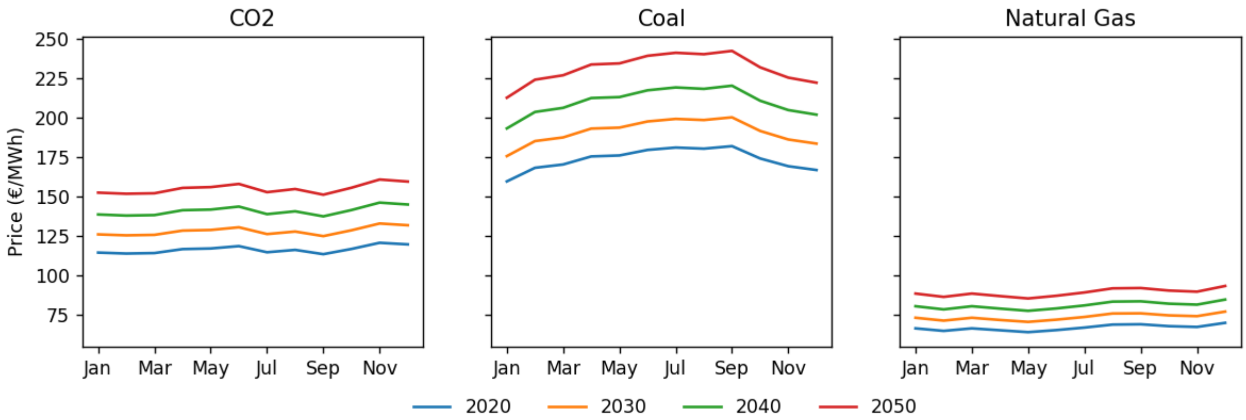


Figure 24: Commodity final electricity price considered in the price bid for the market simulator.

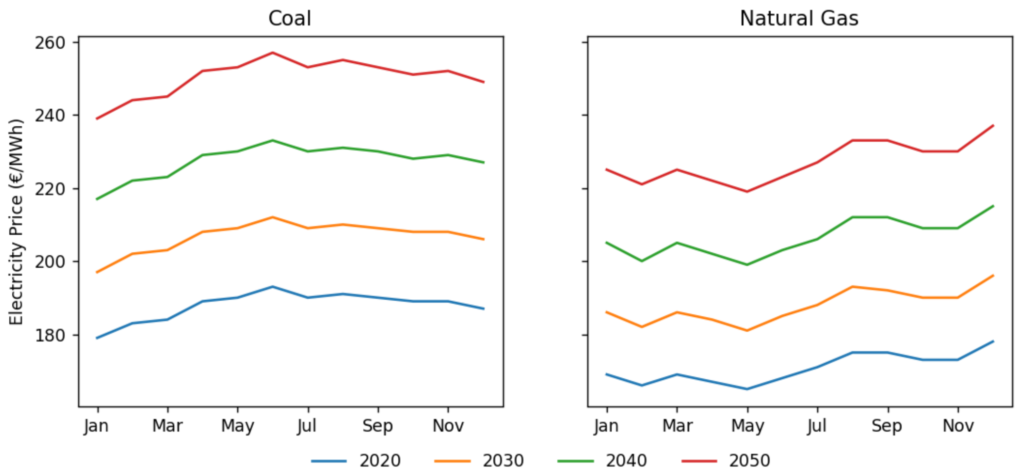


Figure 25: Final electricity price for coal and natural gas fueled generators.

4.2.2.2. Load bid definition

This subsection details the load bid definition for the dual offering bid required to participate in the market. The subsection follows a similar structure as in the previous subsection. The data utilized for the quantity of energy which each load wants to buy within the given timeframe and the states the considerations and calculations performed to create the bidding price at which each load is willing to buy energy are presented in the following subsections.

Load available bidding quantities

The calculation of the typical days for the load energy profile followed a similar process as the typical day calculation for the renewable generators. The load profile data was sourced from the historic data of 2020 available (see footnote 3 above) and separated by month and by week and weekend, with the average value for each hour of the day. Subsequently, the data was normalized by the total aggregated energy for 2020 and each typical day multiplied the normalized profile for each zone by the total aggregated load provided in Table XV for each simulation year. Figure 26 shows the Spanish and

Portuguese monthly energy bids for the year 2020, for a typical weekday. Annex B provides the Spanish and Portuguese monthly energy bids for 2030, 2040 and 2050.

Table XV – Total aggregated load energy for each country

Zone	ID	Total Aggregated Energy (TWh)			
		2020	2030	2040	2050
ES	L0	240	250	300	320
PT	L1	50.1	53.4	60.4	67.4

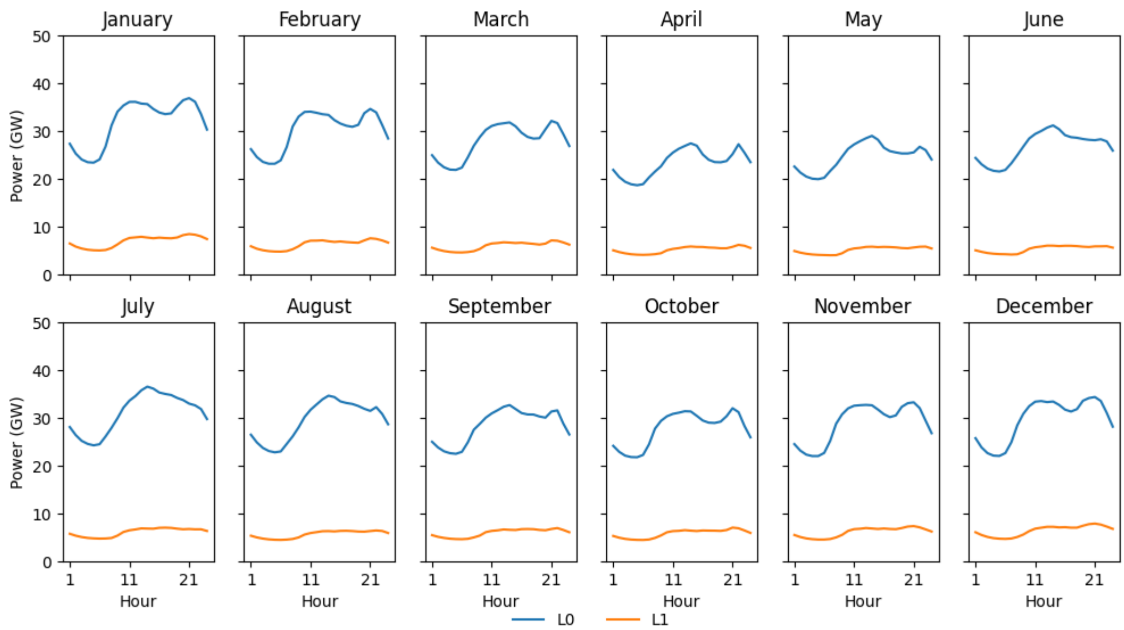


Figure 26: Spanish and Portuguese load energy bids for a typical weekday for the 2020 scenario.

Load bid pricing

Although the market simulator tool devised for the ATTEST project considers a symmetric energy market, for this report, the load price bids assume a behavior more in line with an asymmetric energy market. This means that all loads must be supplied, if there are sufficient available generation bids. This was achieved by having a load price bid of 2999 €/MWh, to ensure that all load energy bids will be cleared. This meant that two additional and fictional generators, G15 and G16, that represent the Spanish and Portuguese markets respectively were created to symbolize the costs of having load shed in the market clearing optimization. Both generators have a price bid of 3000 €/MWh and energy bid of 50000 MW.

4.2.3. Key performance indicators (KPIs)

This section presents the KPI results after performing all the simulations. Subsection 4.2.3.1 shows the results of running the market simulator tool, providing the market price for both zones for all scenarios. Subsection 4.2.3.2 provides a scenario where pumped storage is simulated and compared to the results from subsection 4.2.3.1.

4.2.3.1. *Iberian Market Simulation electricity prices*

Figure 27, Figure 28, Figure 29 and Figure 30 show the typical week and weekend day-ahead electricity prices for January, March, May and September while the average week and weekend market prices for each month is presented in Figure 31 and Table XVI, The absolute market splitting difference between the Spanish market price and the Portuguese market price being shown in Figure 32. The months shown in Figure 27 to Figure 30 were selected for expressing different behaviors of the market simulation.

Figure 27 shows the market price results for January. It is possible to see that there was no market splitting, having no interconnection congestion and utilizing generators from both countries to supply every load. In Figure 28 and Figure 29 show the market price results for March and May. In these, the interconnection shown moments of congestion which led to hours where market splitting occurred. This led to the Portuguese market having a higher electricity price than the Spanish market. An extreme case of the congestion problem is shown in Figure 30. In it, there was a congestion on the interconnection and there were no more available Portuguese generators to fulfill the Portuguese load bid. This resulted in a load cut, shown by the market price of 3000 €/MWh at the end of the 2050 scenario.

In Figure 32 it is possible to see that all market splitting happened in the 2040 and 2050 scenarios, where the amount of non-renewable energy bidding is drastically reduced. These results can be further inferred by the average market price comparison available in Table XVI.

It is also possible to see in these results that the 2030, 2040 and 2050 market results did not lead to a drastic decrease of the market price. This happened as there were moments where the use of thermal generators bidding is still required to achieve a load and generation equilibrium.

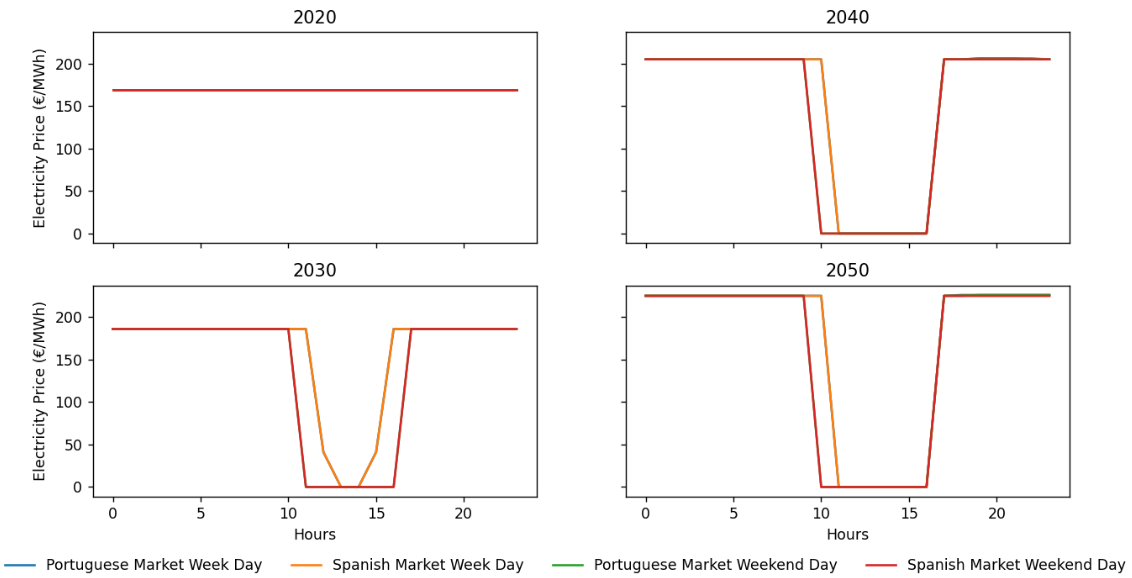


Figure 27: January Spanish and Portuguese markets typical days market price.

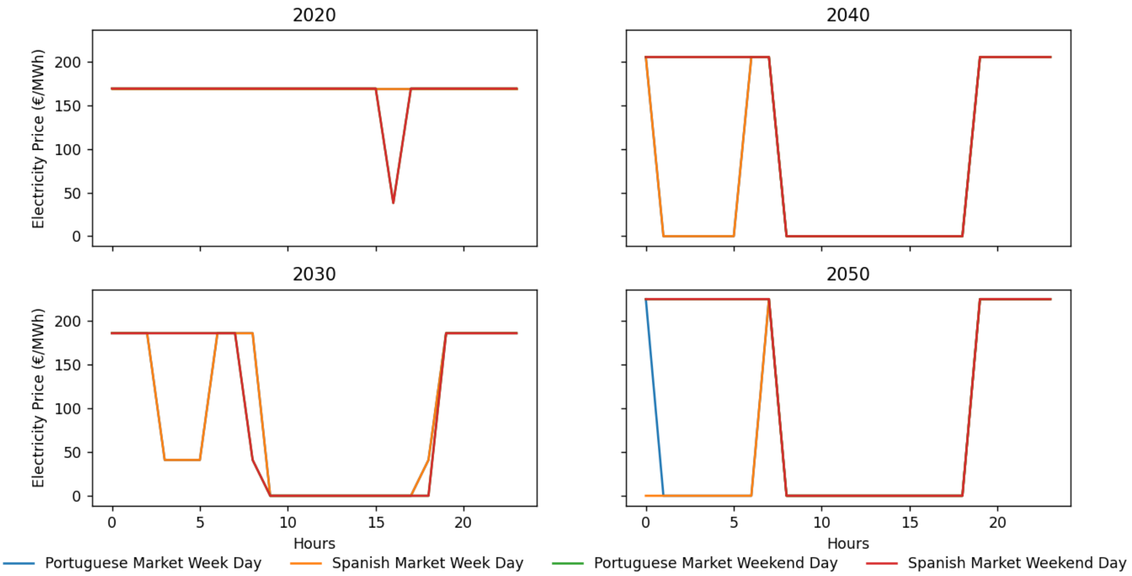


Figure 28: March Spanish and Portuguese markets typical days market price.

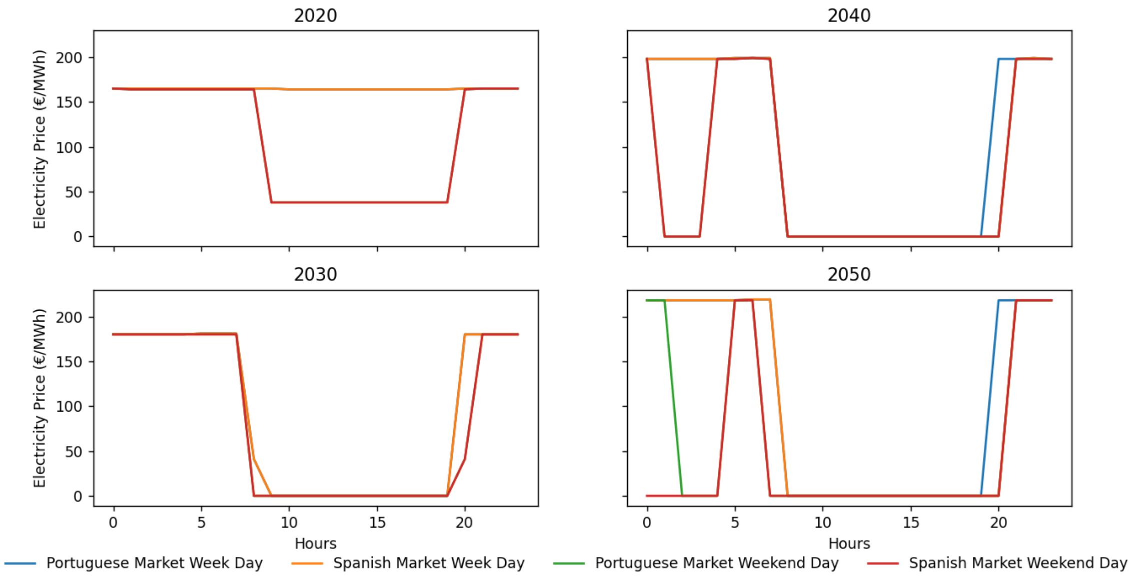


Figure 29: May Spanish and Portuguese markets typical days market price.

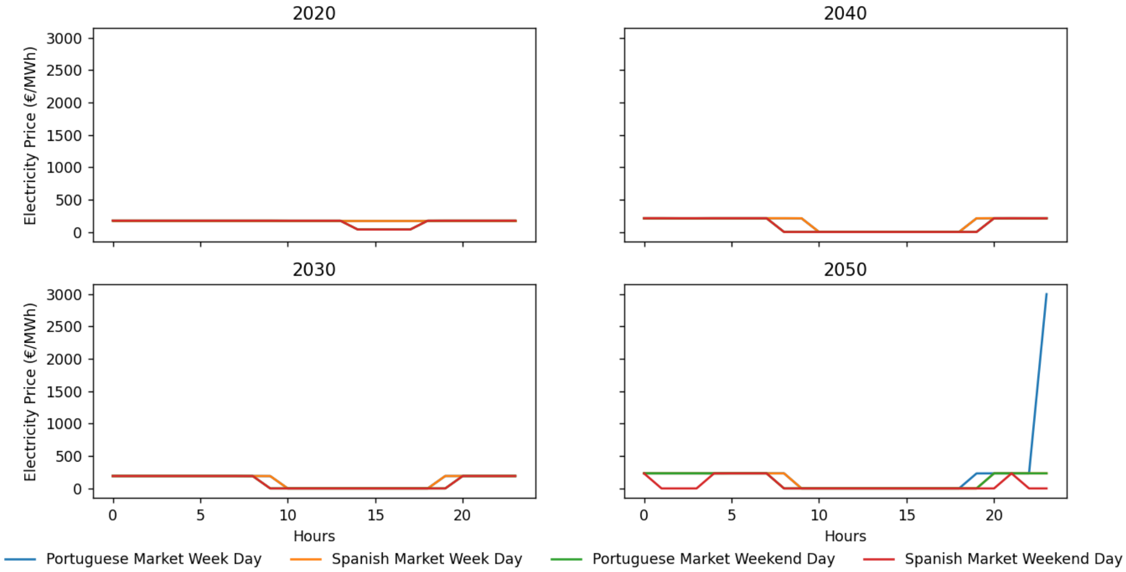


Figure 30: September Spanish and Portuguese markets typical days market price.

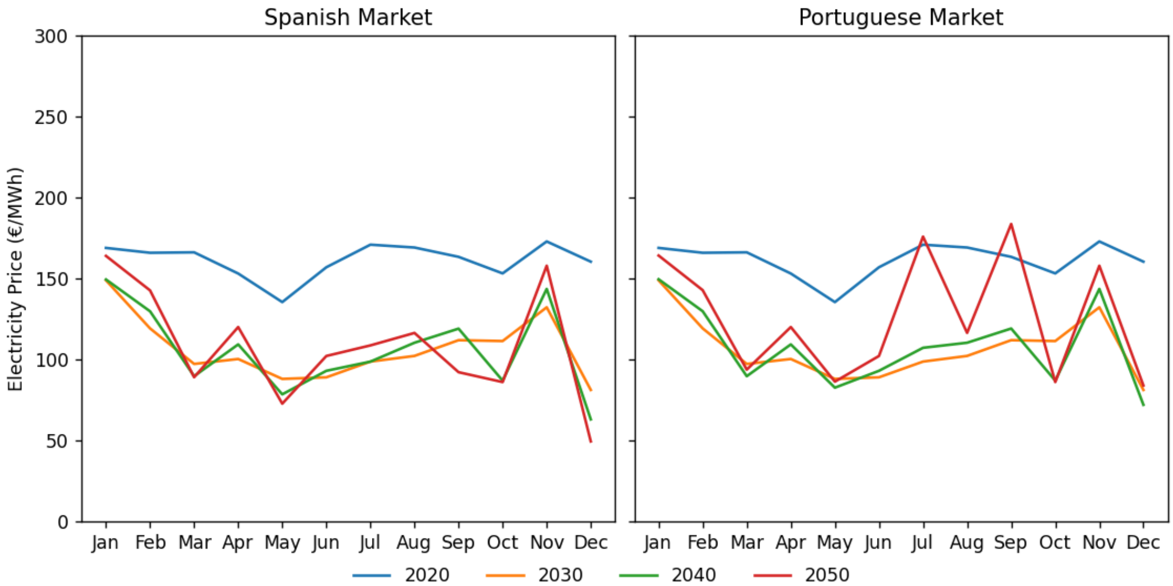


Figure 31: Spanish and Portuguese markets monthly typical day average electricity price.

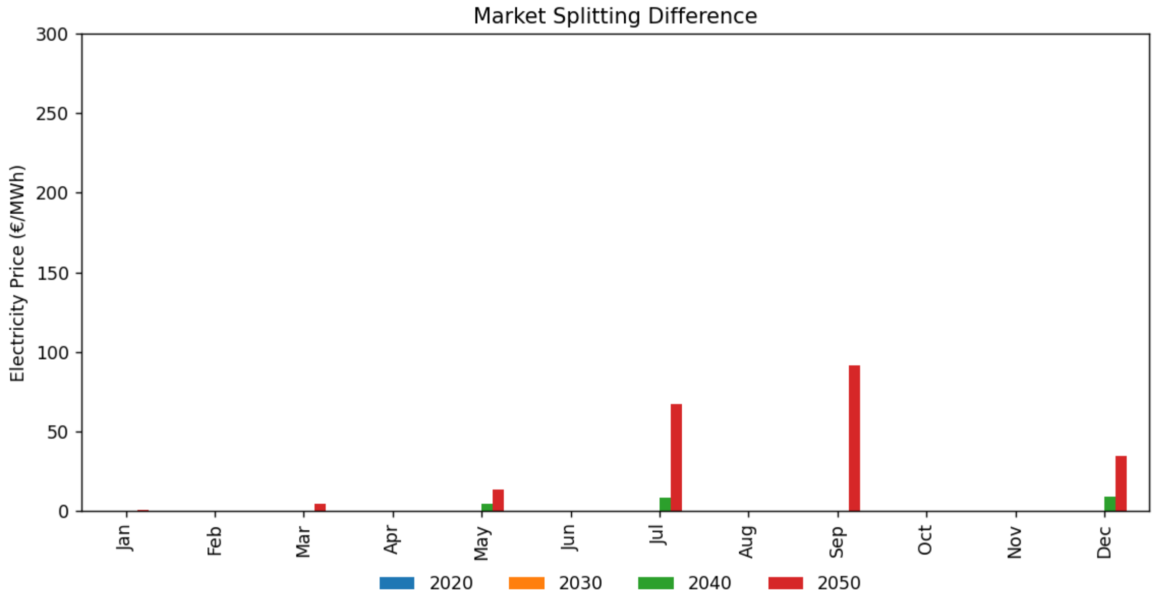


Figure 32: Average market splitting absolute difference between the Spanish and Portuguese markets for the typical day average electricity price for each month.

Table XVI – Average typical day electricity price

	Spanish Market				Portuguese Market			
	2020	2030	2040	2050	2020	2030	2040	2050
Jan	169	148.96	149.48	164.06	169	148.96	149.62	164.29
Feb	166	119.25	129.81	142.73	166	119.25	129.85	142.88
Mar	166.27	97.27	89.69	89.06	166.27	97.27	89.69	93.75
Apr	153.17	100.33	109.35	120.08	153.17	100.33	109.35	120.08
May	135.5	88.02	78.48	72.71	135.5	88.02	82.6	86.33
Jun	157.04	89	93.02	102.19	157.04	89	93.02	102.19
Jul	171	98.73	98.71	108.73	171	98.73	107.25	176
Aug	169.25	102.23	110.38	116.44	169.25	102.23	110.38	116.48
Sep	163.48	111.96	119.1	92.17	163.48	111.96	119.17	183.81
Out	153.25	111.42	86.96	86.06	153.25	111.42	86.96	86.06
Nov	173	132.29	143.65	157.98	173	132.29	143.65	157.98
Dec	160.5	81.19	63	49.38	160.5	81.19	72	83.94

4.2.3.2. Pumped storage simulation

To simulate pumped storage in each zone, three instances of the market simulator are run to obtain three different objectives: determine the average marginal price without pumped storage; determine the pumped storage pumping bid data and determine the pumped storage energy generation bid data.

The first market simulation runs the base case market clearing, calculated in subsection 4.2.3.1. From it, it is calculated its average marginal price that will serve as the reference price for the pumped storage pumping load bid calculation.

To calculate the pumped storage pumping load bid, a fictional load is created for the Spanish (L2) and Portuguese (L3) zones, that represent the pumping stage of the pumped storage simulation. For this, two assumptions are made:

I. The available energy profile is set to 60% of their respective hydro reservoir generator installed power. This is done to reflect the existent capacity of the hydro reservoirs for pumped storage.
II. The price bid for these loads is set at 60% of the reference price, which aims to ensure that the possibility of selling pumped storage energy when energy prices are lower than the reference price, is achieved by the fictional pumping of water when energy prices exceed the reference price.

The market simulation is once again run, considering loads L2 and L3 and it is determined the pumped storage pumping (quantity and price) data, as well as the market price for each hour. To achieve the complete simulation of pumped storage simulation of the hydro reservoir pumping bidding, the energy generation bid must be calculated. To achieve this, two fictional generators are added to represent the Spanish (G17) and Portuguese (G18) are introduced to represent the generation bid of each zone pumped storage with a price bid is set at 0 €/MWh.

To determine the available energy profile to be applied to the G17/G18 bids, it is calculated the average energy supplied to L2/L3 and the total energy supplied by their respective hydro reservoir generator, using the pumped storage pumping data calculated from the second market simulation. From these two values, the available energy profile is determined by an iterative process:

I. The market price is sorted from most expensive to least expensive.
II. The average of the energy supplied to L2/L3 in the three most expensive hours is calculated.
III. The average energy calculated is multiplied by 60% (to consider the pumped storage capability of the hydro reservoir).

Reaching this moment step, the value from III is compared to the total energy supplied by the hydro reservoir generator (G3 for the Spanish market and G10 for the Portuguese market) at the same three hours.

- ✗ If the total energy bid of the hydro reservoir generator is lower than the average energy of the fictional load, the process returns to II and the average is calculated adding the next most expensive hour.
- ✓ If the total energy bid exceeds the value calculated in III, the energy profile value for the selected hours of the fictional generators will be equal to the calculated average load energy, and zero for the remaining hours. Additionally, the value calculated in III is subtracted from the energy bid of the hydro reservoir generator for the respective hours.

With both the pumped storage fictional load and generation calculations finalized, the market is optimized for the third time, from which the market prices are determined, considering the simulation pumped storage.

Table XVII provides the average typical day monthly market price for each scenario and Figure 33, Figure 34, Figure 35 and Figure 36 show a comparison between the base case of subsection 4.2.3.1 and the market clearing considering pumped storage simulation for the typical weekday for January, March, May and September. Assessing the base case and the pumped storage simulation market prices it is possible to see that there was no shift in the behavior of the 2020 scenarios. This is attributed to the market price being highly influenced by the natural gas price as there is a high quantity of available natural gas fueled generation energy bidding and low quantity of available renewable fueled generation bidding available for that year. On the other hand, there were changes in the behavior between both cases for the remaining scenarios as there is an increase on the amount of renewable energy quantities and reduction to the coal and natural gas energy quantities in the bidding pool.

The influence of both the pumped storage simulation generation and load bids can be seen in the results. Load bidding led to an increase in the market price. Its impact is shown in Figure 33, Figure 34 and Figure 35 for the scenarios of 2030 and 2040 and 2050 and in a more drastic effect in the 2030 scenario between hour 10 and hour 15. As for the generating bid of the pumped storage, its weight on the market price can be better seen in Figure 34 and Figure 35 between hour 0 and hour 10 where the market price decreases as a result of accepting the pumped storage generation bid at those hours.

Comparing both cases, it is seen that there was a reduction of market splitting between the Portuguese and the Spanish market. This happened as the pumped storage simulation alleviated the number of congestions happening in the interconnection between both bidding zones. In Figure 36, the biggest congestion problem presented in this report for the base case, can be seen to be resolved in the pumped storage simulation case. For the 2050 scenario, the Portuguese base case experienced load cutting due to the inexistence of more Portuguese generation bids and due to the interconnection between both countries being at its maximum capacity. This problem was resolved in the pumped storage simulation case as the Portuguese pumped storage generator bid was able to match the Portuguese load bids and helped reduce the congestion of the interconnection and avoid the market splitting.

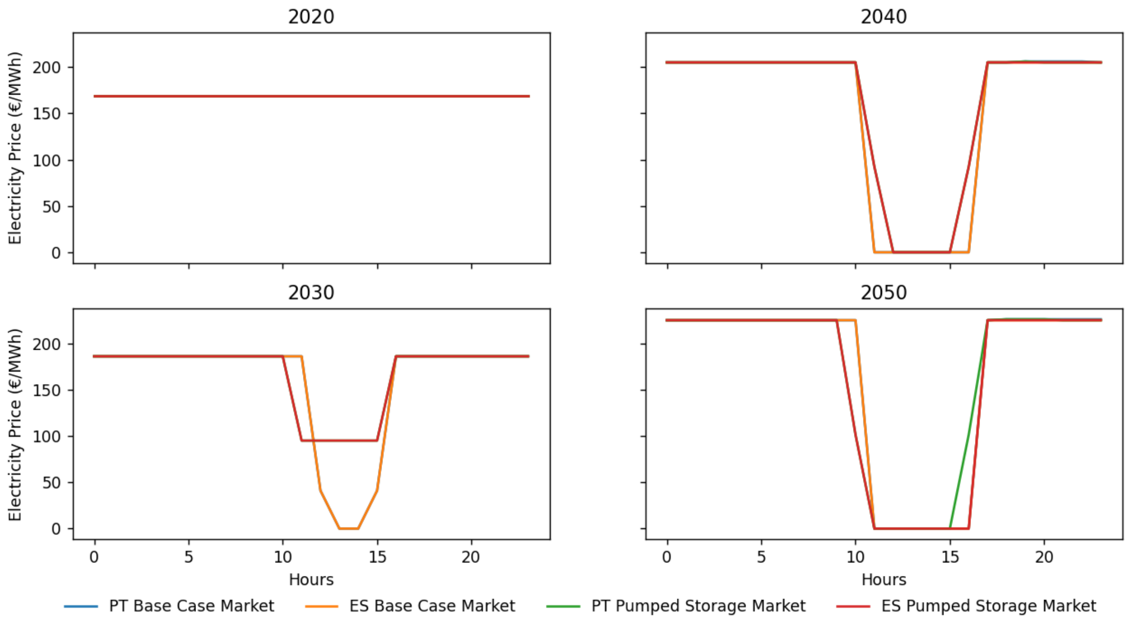


Figure 33: January typical weekday market price for the base case and the pumped storage market for all scenarios.

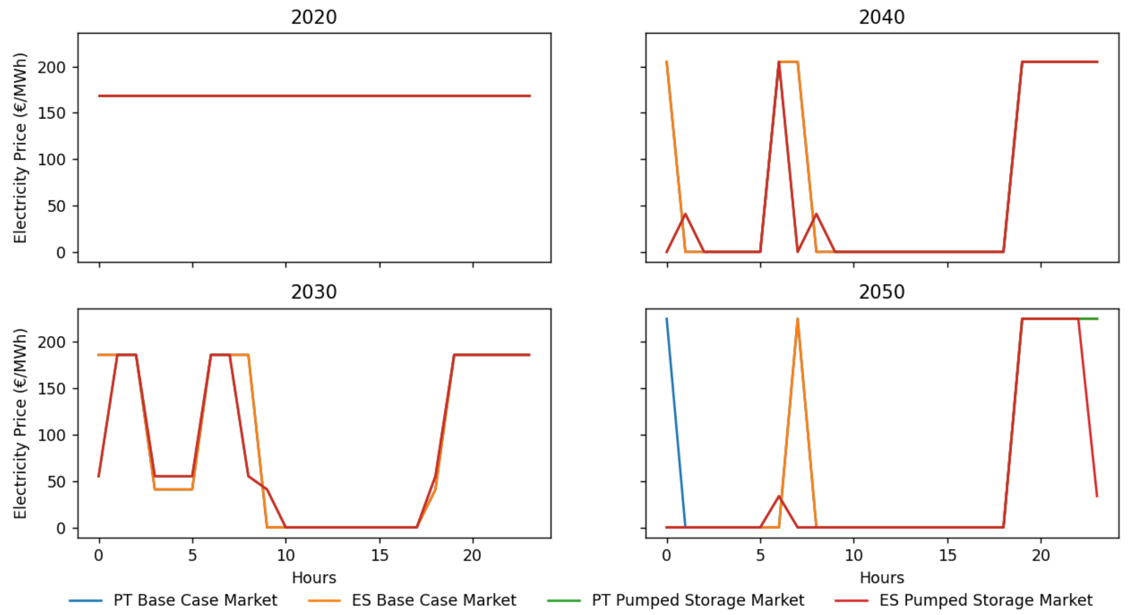


Figure 34: March typical weekday market price for the base case and the pumped storage market for all scenarios.

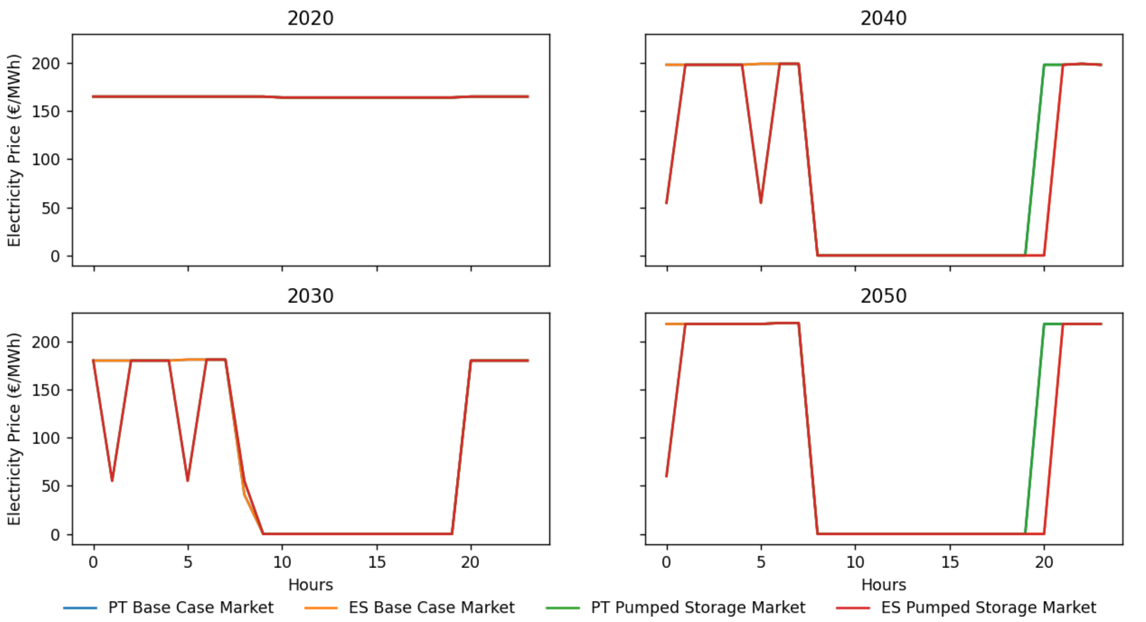


Figure 35: May typical weekday market price for the base case and the pumped storage market for all scenarios.

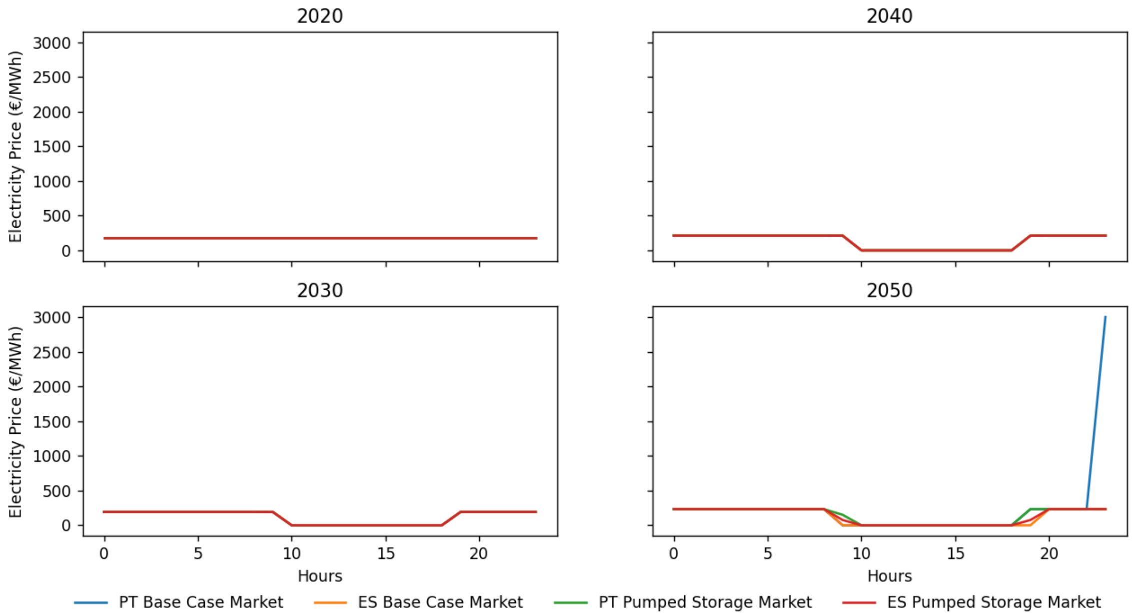


Figure 36: September typical weekday market price for the base case and the pumped storage market for all scenarios.

Table XVII – Average typical day electricity price for the pumped storage simulation case.

	Spanish Market				Portuguese Market			
	2020	2030	2040	2050	2020	2030	2040	2050
Jan	169	153.74	155.14	161.49	169	153.74	155.16	163.7
Feb	166	122.06	127.2	139.97	166	122.06	127.2	139.99
Mar	167.52	92.55	79.97	77.93	167.52	92.55	79.97	81.91
Apr	157.46	100.74	109.35	120.08	157.46	100.74	109.35	120.08
May	137.12	77.7	67.51	59.77	137.12	77.7	71.64	80.43
Jun	157.04	89.32	94.18	103.47	157.04	89.32	95.35	104.74
Jul	171	99.92	98.71	108.73	171	99.92	107.25	118.23
Aug	170.5	103.08	110.38	117.77	170.5	103.08	110.38	117.81
Sep	163.48	111.96	117.33	78.15	163.48	111.96	120.47	125.93
Out	154.13	109.63	77.86	65.29	154.13	109.63	78.51	72.69
Nov	173	133.37	141.03	157.98	173	133.37	141.03	157.98
Dec	169.05	75.85	41.62	12.1	169.05	75.85	54.34	64.93

4.2.4.Conclusions

This report presents the KPIs obtained from the simulations of the tool developed in T2.6. The tool consists of a market simulator for computing the day ahead electricity price of a system comprised by multiple interconnected zones by allocating which load and generation bids will be accepted. The analysis was performed for 2020, 2030, 2040 and 2050 and for twenty-four typical days (week and weekend days for each month of the year).

The market simulator was tested using the Iberian market as a case study. Both the Spanish and the Portuguese load and generation units were divided by technology and connected to their respective bidding zone (single bus). These buses were connected by a single line that was intended to represent the interconnection capacity.

The market simulator was tested on two market cases. The base case, where the market price was calculated for the existent data generation and load bids, without considering pumped storage and the pumped storage simulation case, where pumped storage capabilities of the hydro storage reservoir generators were simulated.

The market clearing results showed that the supply of the demand was met on a technology base by both bidding zones generations without zoning preference as coal and natural gas generation bidding price was considered equal for both bidding zones. Results also showed that the increase of renewable energy generators bidding and decrease of nuclear, coal and natural gas energy generations bidding did not lead to a drastic reduction of the average market price. This comes from the fact that there is still the need for the use of non-renewable energy to match the system load bidding.

Additionally, market splitting was also shown to occur only for the 2040 and 2050 scenarios. This occurred as the reduction of thermal generation led to a higher use of the interconnection between both bidding zones, which led to the congestion of the interconnection for the base case. The interconnection congestion and consequent market splitting were mitigated in the pumped storage simulation case. The inclusion of pumped storage simulation resulted in fewer congestions, market splitting and amount of load cutting.

5. KPIs simulations and demonstrations for WP3

Within the WP3 "Optimal design and planning tools for transmission and distribution systems" of ATTEST, three novel tools have been developed to enable both DSOs and TSOs to plan their networks effectively (including TSO/DSO shared technologies) in the presence of uncertainty and new emerging technologies, while considering the value of flexibility[8]. These tools offer optimized investment strategies that go beyond traditional congestion-driven asset-based network reinforcements. In the ATTEST planning approach, the use of flexibility (non-asset-based solutions) is explicitly modelled to provide additional network capacity and complement traditional network reinforcements. Therefore, as will be further demonstrated by the simulations, the developed tools enable reducing network investments (thus lowering the investment costs and the environmental impact of new lines), optimizing TSO-DSO flexibility markets and the use of energy storage, and avoiding potential voltage violations. Specifically, the following tools have been developed in WP3:

- Optimization tool for distribution network planning,
- Optimization tool for transmission network planning,
- Optimization tool for planning TSO/DSO shared technologies.

In the following sections, for each of these tools, a high-level description, modelling features and application goals will be provided. Then, the KPIs will be determined to estimate the tools' performance by comparing the BaU case and the ATTEST approach. Finally, the simulations will be presented for the selected transmission and distribution networks, and the tools' KPIs will be demonstrated and discussed. In total, seven networks will be analysed for WP3 KPIs simulations and demonstrations, as defined in Section 1.3**Error! Reference source not found.**. These networks comprise realistic systems (4 distribution systems and 3 transmission systems) from the UK, Croatia, Spain, and Portugal. Therefore, the following analysis provides practical insights into the systems' evolution, the needs for network reinforcements, and the benefits of flexibility utilization.

5.1. Optimization tool for distribution network planning

This section provides KPIs simulations and demonstrations for the WP3 tool "Optimization tool for distribution network planning". First, a high-level description and modelling features of the tool will be given to explain its applications in distribution network planning. Then, the KPIs will be defined to measure CAPEX and the environmental impact of the solutions identified by the tool. Finally, the simulations will be presented for four selected ATTEST cases: the UK, Croatian, Spanish, and Portuguese test distribution systems.

5.1.1. Description of the tool and KPIs calculation

The distribution network planning tool comprises multi-stage stochastic optimization models that enable exploiting the potential of flexible resources. The stochastic formulation (defined via a path-dependent non-recombining scenario tree) is complemented by a simulation-based optimization framework to produce adaptive path-dependent network reinforcement strategies. Multi-stage stochastic planning of distribution networks is challenging due to the high computational cost of evaluating large numbers of possible future investments in different stages (years in the context of this tool) and scenarios. To tackle this challenge, the proposed distribution network planning tool adopts a recursive algorithm for optimization. The recursive function considers a reduced search space by

[8] This flexibility is emerging at the demand side due to the integration of multi-energy technologies (e.g., controllable renewables generation, storage, electrified heating, and transports, etc.) which enable customers to trade energy services and support transmission and distribution networks.

terminating all infeasible investment strategies [7]. Thus, the computation time is minimized compared to a full exhaustive search.

The principles of path-dependent network planning can be visualised as shown in Figure 37. The planning tool receives two scenarios (corresponding to active and slow economies in this project) that form an envelope of possible future system development across multiple years, e.g., 2020, 2030, 2040, and 2050. These scenarios are not sufficient to capture the value of flexibility as, from the second time period (2030), the future is modelled as a deterministic path. This is unrealistic and neglects the value of flexibility to respond to uncertain futures. To address this issue, these two extreme scenarios are transformed into a scenario tree, where at each year, possible future trajectories branch into a more active one and a slower one. In total, 15 nodes are considered in the scenario tree for four years. In this manner, the planning problem represents a portfolio of investment decisions and can capture the effects of non-asset-based solutions, e.g., activating flexibility resources. The recursive function iteratively verifies the feasibility of different investment decisions, starting with the initial year (2020) and moving forward in time, while minimizing capital expenditures of the assets built.

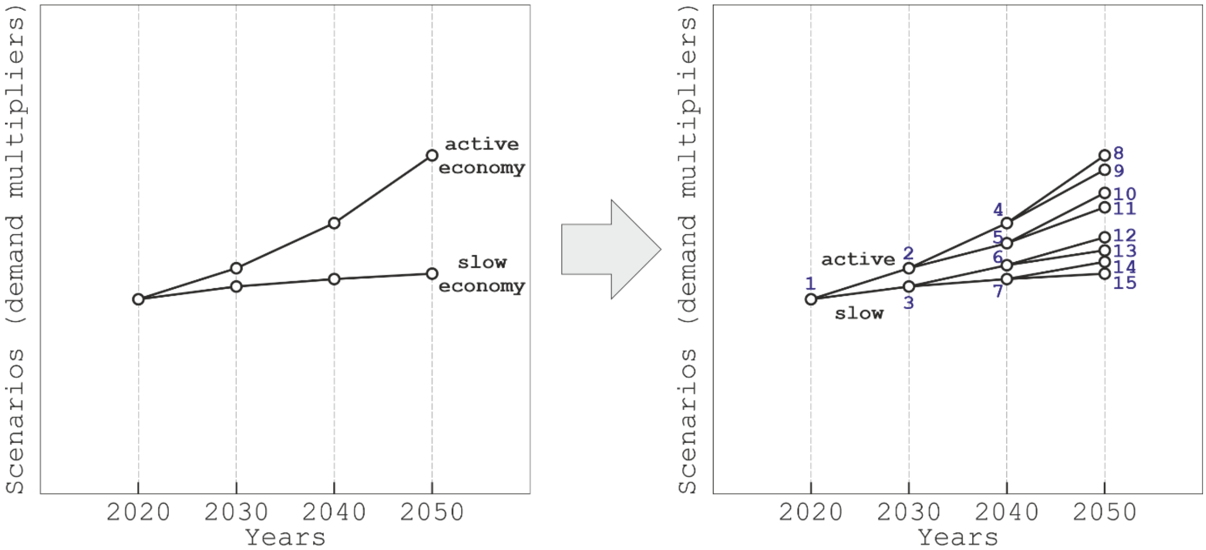


Figure 37 Visualisation of the path-dependent scenario trees generated in the network planning tools

Moreover, to further decrease the computational burden of the multi-stage stochastic investment planning problem, the tool includes a screening model (formulated as DC OPF) which identifies a finite set of investment clusters corresponding to potential network updates. The number of clusters produced depends on the number of distinguishable solutions (line capacity updates) in different scenarios and years and the parameter “--Max_clusters” set by users during the tool execution. Then, the identified investment cluster are passed to the recursive planning algorithm, which uses an AC OPF model to check the feasibility of the reinforcement decisions and produce a consistent portfolio of investment for the scenario tree, capturing the value of flexibility. The final output of the algorithm is a multi-year portfolio of optimal investments for the two given scenarios, active and slow economies.

To demonstrate the effectiveness of the ATTEST distribution network planning tool, the following two KPIs were considered:

1) CAPEX: cost savings due to reduced network investments, in €
2) Environmental impact: avoided emissions due to reduced embodied carbon of network investments, in tonnes of CO_2 equivalent

To estimate the selected KPIs, the planning model was solved two times for each ATTEST test distribution system:

1) First, a traditional investment planning problem was solved with the assumption that no flexibility can be used to support the network operation. This is referred to as the base case (BaU).
2) Second, the proposed multi-stage scenario-based stochastic investment planning problem was solved, where the forecasted levels of flexibility can be utilized in the future. This is referred to as the ATTEST approach.

Then, the tool's KPIs can be estimated using the following formulas (1)-(2):

$$KPI_{year,sc}^{cost} = \frac{IC_{year,sc}^{Base} - IC_{year,sc}^{ATTEST}}{IC_{year,sc}^{Base}} \cdot 100\% \tag{1}$$

$$KPI_{year,sc}^{env} = \frac{Carbon_{year,sc}^{Base} - Carbon_{year,sc}^{ATTEST}}{Carbon_{year,sc}^{Base}} \cdot 100\% \tag{2}$$

These formulas calculate the changes (in %) in the investment costs (IC) and in the embodied carbon ($Carbon$) between the BaU case and the ATTEST planning approach. Thus, a KPI of 100% implies that the ATTEST planning tool enables completely avoiding additional investments with associated costs and embodied carbon. A KPI of 0% means that there is no difference between the ATTEST approach and the base case.

In the simulations, it is assumed that the available flexibility comes from EVs (as flexible loads) and battery storage, according to the flexibility forecasts estimated by the project partners for each test system, as defined in Section 3. Finally, to analyse the tool's performance, solutions to these problems are compared and the CAPEX and environmental KPIs are presented in %.

Note that the KPIs for the planning tool are presented as separate values for each year and scenario ($year, sc$). That is, no aggregated estimation of KPIs is given for the entire planning horizon. This approach enables analysing the expected evolution of the networks in the future, tracking changes in the need for investments and the corresponding KPIs over time. For example, as will be demonstrated by the simulations, many of the considered networks have enough capacity to meet moderate demand growth. In such networks, no additional investment is required in 2020 and 2030. Only with the significant demand increase, usually in 2040 and 2050, line reinforcements become necessary. It is also important to note that the KPIs estimation based on the BaU/ATTEST comparison is case specific, and the results should be interpreted carefully for each network. For example, for some years and scenarios, the estimated KPIs can reach 100%. This does not however mean that the ATTEST planning approach fully solves all congestion and voltage issues of a distribution network. This can rather indicate that a test network initially had enough capacity to meet the demand for certain scenarios and years, and only a few additional reinforcements are required. If applying the ATTEST planning approach and utilizing flexibility resources, the need for such minor reinforcements disappears, and the tool KPIs scores its effectiveness as 100%. Additional comments and explanations will be given for such cases throughout the section.

5.1.2.Case study: UK distribution network

The first case study analysed with the distribution network planning tool is the UK distribution network (named "UK_Dx_01" among project partners, or "Distribution_Network_Urban_UK.m" in the ATTEST files). This network is well-tested by the WP3 tools developers, as it provides illustrative results with many distinguishable investments for the defined future scenarios.

UK_Dx_01 is a weakly meshed network with 30 buses, 30 lines, and the total peak active power consumption of 6.51 MW. The topology of the network is presented in Figure 38 as a graph, where the size of the circles is proportional to the nodal power demand. The color of the nodes corresponds to the voltage levels during the normal network operation in 2020. The network does not include any generators, although for modelling purposes the supply point located at primary substation 7 (shown by the green arrow) is introduced as a generator. The network includes two radial feeders that can be interconnected through the normally open point (NOP). That is, there are two sectionalizing switches and one tie switch, which enables dynamic network reconfiguration. Excluding cases where some customers are isolated from the system, there are four possible network configurations to consider:

(i) normal operation with NOP open (radial network),
(ii) normal operation with NOP closed (meshed network),
(iii) contingency power supply via line 7-1,
(iv) contingency power supply via 7-2.

Figure 38 displays radial network operation with the NOP open. For this configuration, the loading of the most loaded lines is shown by the red labels, in %. It can be seen that five lines use more than 50% of their maximum capacity to transfer power in the normal network operation, one of which, line 6-11, is loaded up to 71.16%.

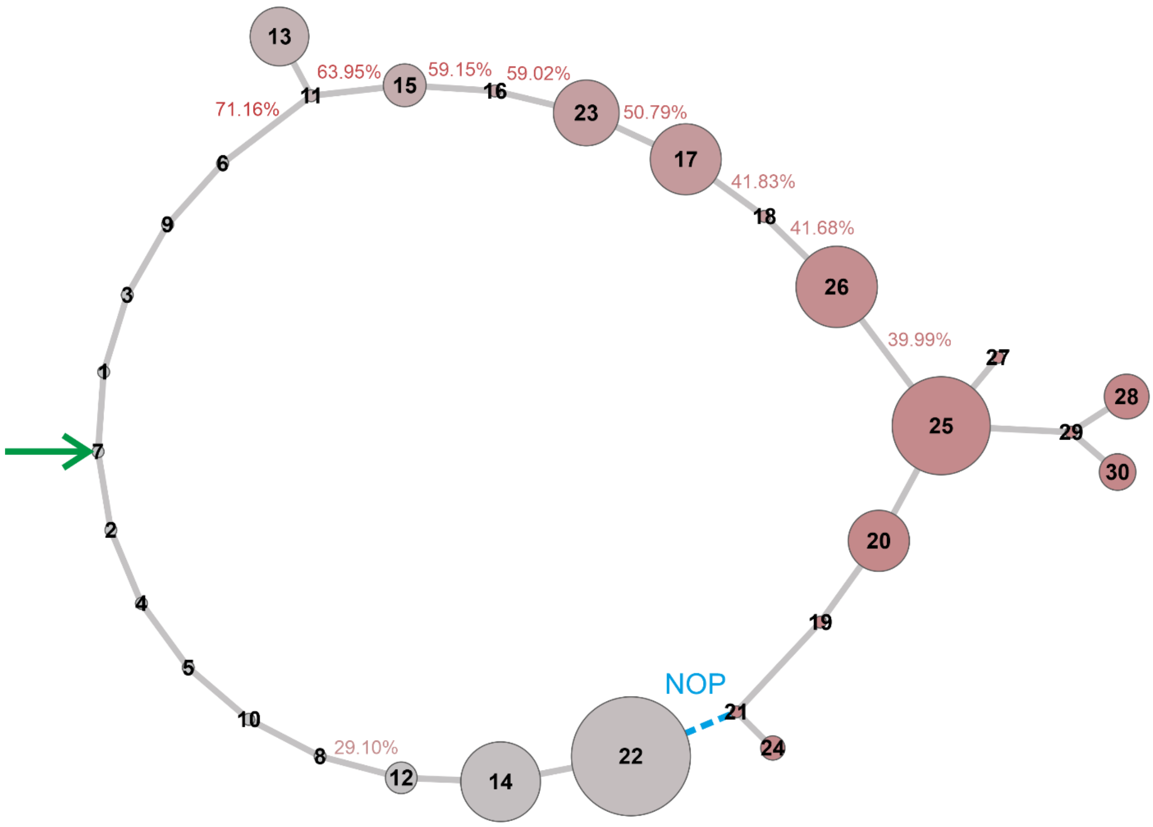


Figure 38 Topology of the UK distribution network (UK_Dx_01)

The line loadings shown in Figure 38 increase significantly during contingency power supply via one of the feeders. It has been verified by simulations that the contingency of line 7-2 is the most severe one. That is, more lines are heavily loaded when the entire network is supplied through line 7-1. Therefore, network operation with the contingency of line 7-2 is considered in the planning problem to identify reinforcements that ensure the N-1 security of the network.

As discussed in the previous section, two future scenarios have been developed in ATTEST for the UK networks, corresponding to active and slow economies. The load growth per each year and scenario is given by factors ranging from 1% to 3% of yearly growth. Considering these scenarios, the input for the planning tool was prepared as a path-dependent scenario tree with 15 tree nodes, as shown in Figure 39. The maximum peak load multiplier reaches the value of 1.93 in 2050, which means that the total demand of the network is expected to nearly double in 30 years.

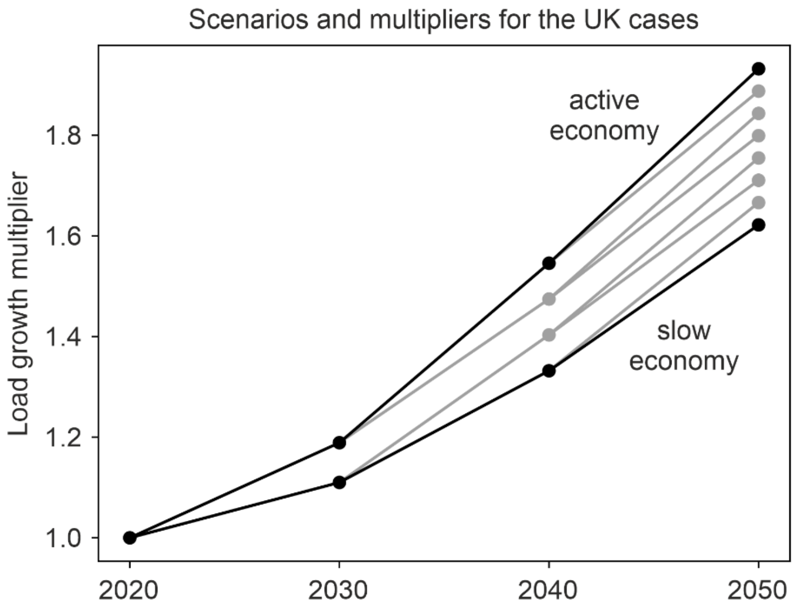


Figure 39 Example of the scenario tree input for the network planning tools: UK load growth scenarios

In view of the upcoming significant load growth and the considered contingency impacts, it becomes necessary to reinforce the UK distribution network to keep its operation feasible and economically efficient. The developed network planning tool was applied to this case to identify the optimized investment strategies. The results are displayed in Table XVIII in terms of the investment costs and carbon emissions for each year and scenario (the values corresponding to the slow economy scenario are shown in brackets).

Table XVIII KPIs simulations for the UK distribution network (UK_Dx_01)

Case:	Metrics:	Years: active economy (slow economy):			
		2020	2030	2040	2050
Base case (BaU) – no flexibility	Investment cost, €	0.00	27,312.41 (27,312.41)	87,008.34 (74,866.56)	234,067.31 (87,008.34)
	Environmental impact: embodied carbon emissions, tCO_2e	0.0	14.6 (14.6)	46.5 (40.0)	125.2 (46.5)
ATTEST approach – with flexibility	Investment cost, €	0.00	27,312.41 (27,312.41)	87,008.34 (27,312.41)	107,495.97 (48,293.47)
	Environmental impact: embodied carbon emissions, tCO_2e	0.0	14.6 (14.6)	46.5 (14.6)	57.5 (25.8)
Benefits of ATTEST solution	Avoided investment cost	-	€0.00; 0.0% (€0.00; 0.0%)	€0.00; 0.0% (€47,554.14; 63.5%)	€126,571.34; 54.1% (€38,714.87; 44.5%)

	Avoided carbon emissions	-	0.0 tCO_2e; 0.0% (0.0 tCO_2e; 0.0%)	0.0 tCO_2e; 0.0% (25.43 tCO_2e; 63.5%)	67.7 tCO_2e; 54.1% (20.7 tCO_2e; 44.5%)

The expected levels of flexibility used to estimate the ATTEST planning approach reach 14-20% of the total network power demand in 2050. However, utilization of this flexibility leads to much higher investment cost reductions (44.5-54.1% in 2050 depending on the scenario). This demonstrates the importance of the non-asset-based flexible resources for reliable and cost-effective network planning. However, as mentioned earlier, KPIs of the tool can vary substantially depending on the case, year, and scenario under consideration. For example, in 2030, the required reinforcements do not change between the BaU and ATTEST cases, and the tool benefits are 0%. This indicates that some network investments are vital in 2030 and cannot be complemented by the available level of flexibility. In the UK_Dx_01, the most significant investments are required in line 6-11, line 11-15, and line 15-16, starting from 2030. As the load growths and the flexible capacity increases more in 2040 and 2050, the benefits of the ATTEST planning become more evident. As will be further demonstrated by the simulations, many case studies require reinforcements only closer to the planning horizon, and the benefits of the tool can be estimated only in 2040 or 2050.

5.1.3.Case study: Croatian distribution network

The Croatian distribution network (also named "HR_Dx_01" and "A_KPC_35.m" in the ATTEST project) is a meshed network with 40 buses and 59 branches, 32 of which are transformers. The total peak active power demand of the network is 47.2 MW in 2020. The topology of the network is presented in Figure 40as a graph, where the size of the circles is proportional to the nodal power demand. The network has four generators (supply points) shown by green arrows.

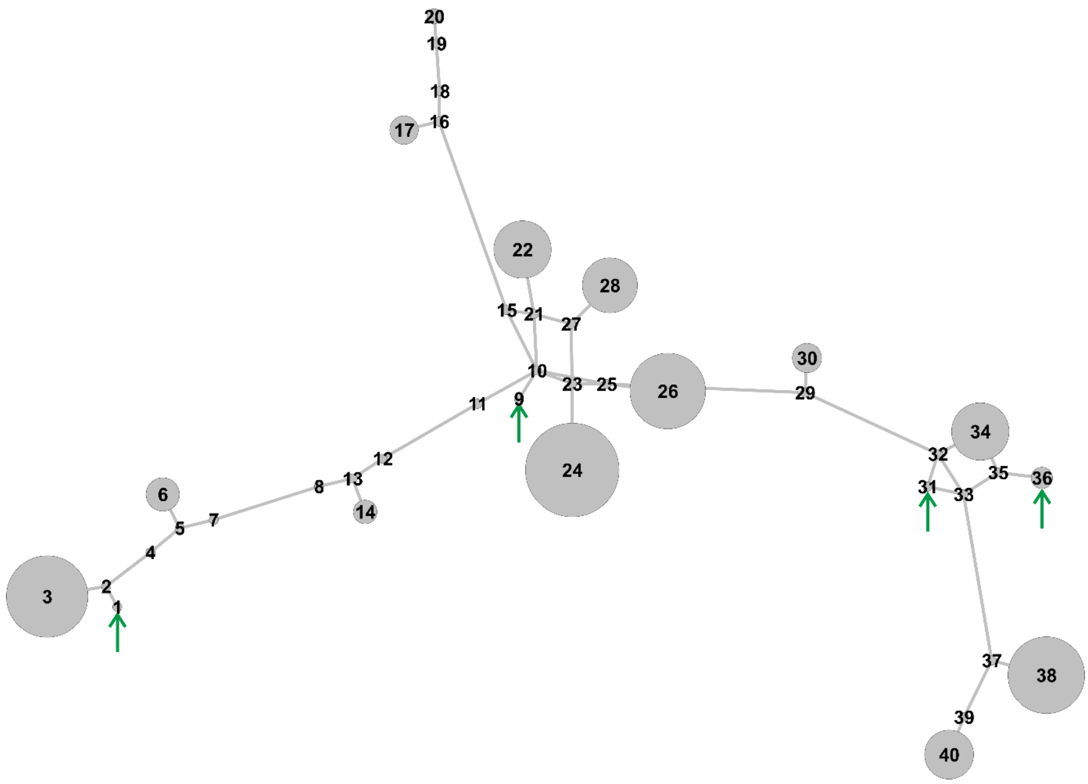


Figure 40 Topology of the Croatian distribution network (HR_Dx_01)

It is important to note that this network, due to its topology and the number of generators (supply points), has enough capacity to meet significant load growth. Moreover, the network can be divided into three networks, which can be operated as independent isolated subsystems. Considering these factors, the developed network planning tool did not identify many reinforcements. As shown in Table XIX, the Croatian distribution network requires investments only in 2050 for the active economy scenario.

Table XIX KPIs simulations for the Croatian distribution network (HR_Dx_01)

Case:	Metrics:	Years: active economy (slow economy):			
		2020	2030	2040	2050
Base case (BaU) – no flexibility	Investment cost, €	0.00	0.00 (0.00)	0.00 (0.00)	1,536,000.00 (0.00)
	Environmental impact: embodied carbon emissions, tCO_2e	0.0	0.0 (0.0)	0.0 (0.0)	263.4 (0.0)
ATTEST approach – with flexibility	Investment cost, €	0.00	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)
	Environmental impact: embodied carbon emissions, tCO_2e	0.0	0.0 (0.0)	0.0 (0.0)	0.0 (0.0)
Benefits of ATTEST solution	Avoided investment cost	-	-	-	€1,536,000.00; 100.0% (-)
	Avoided carbon emissions	-	-	-	263.4 tCO_2e; 100.0% (-)

The simulations for the Croatian distribution network were performed considering the contingency of line 10-23, which is the most severe contingency leading to higher volumes of reinforcement required. The planning tool identifies the need for investments in line 25-10, transformer 9-10, and transformer 23-24. These investments will be required only in 2050 when the power demand of the system doubles compared to the power consumption in 2020.

Note that, based on the scenarios considered, the ATTEST planning approach avoids all network reinforcement in 2050, gaining 100% benefits compared to the BaU case. That is, effective utilization of flexibility, which is expected to reach 12% of the total network power demand in 2050, enables the DSO to avoid future network investments. This result is not surprising considering the fact that the Croatian distribution network initially has significant line and transformer headroom, and the topology of the network allows decentralized power supply from four available generators.

5.1.4. Case study: Spanish distribution network

The Spanish distribution network (also named “ES_Dx_03” or “ES_Dx_03_matpower_rnm_network.m” in the ATTEST project) is one of the largest test systems selected for ATTEST tools demonstration. It has 437 buses, 454 branches, and a total active power demand of 230 MW in 2020. The topology of the network is presented in Figure 41. There is only one generator (supply point) at substation 1, as highlighted in green in the figure.

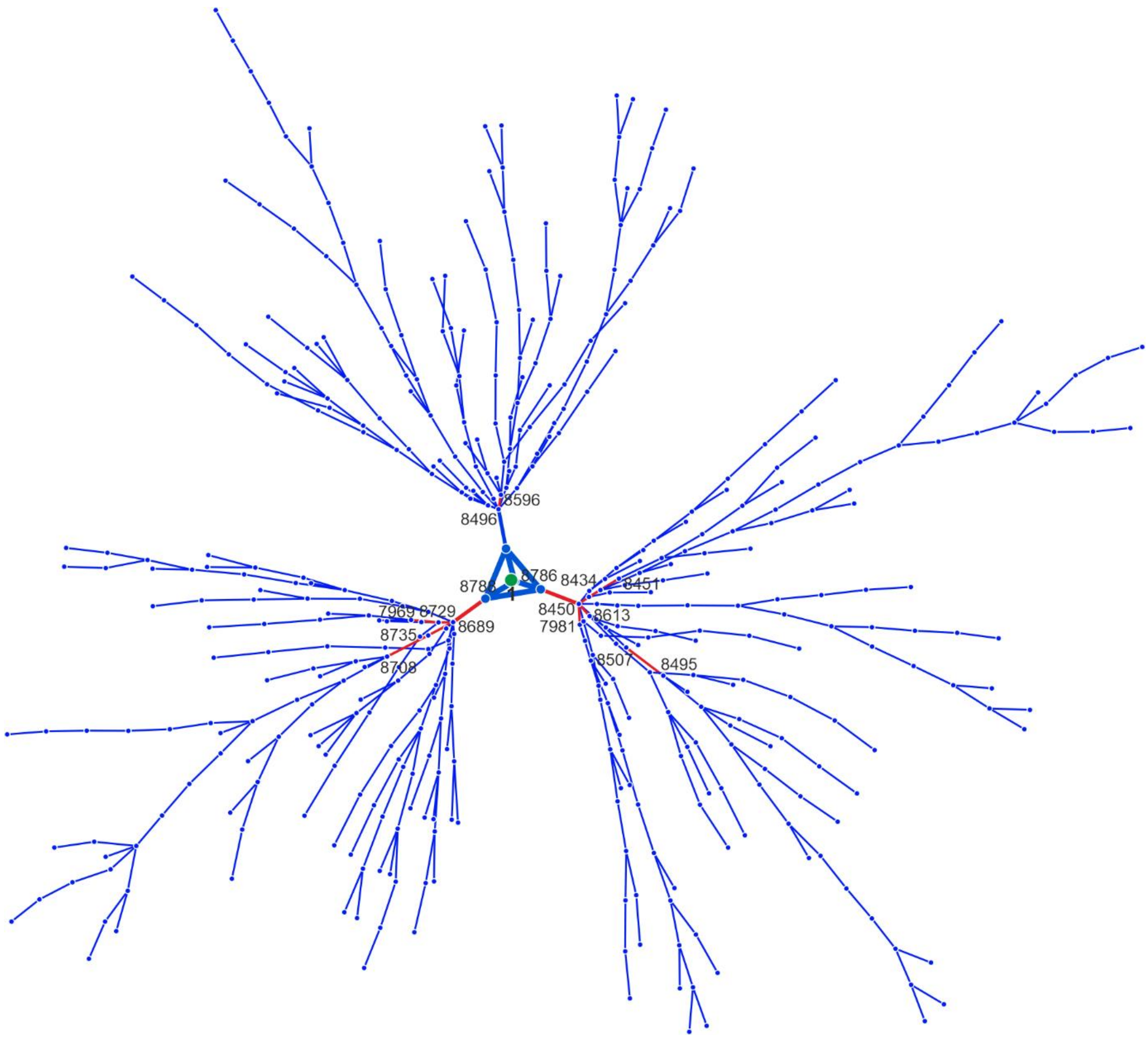


Figure 41 Topology of the Spanish distribution network (ES_Dx_03)

To identify the optimized investment strategies for the Spanish distribution network considering future power consumption growth, the developed network planning tool was applied to this case. The results are displayed in Table XX in terms of the investment costs and carbon emissions for each year and scenario.

Table XX KPIs simulations for the Spanish distribution network (ES_Dx_03)

Case:	Metrics:	Years: active economy (slow economy):			
		2020	2030	2040	2050
Base case (BaU) – no flexibility	Investment cost, €	0.00	0.00 (0.00)	0.00 (0.00)	933,954.60 (383,031.30)
	Environmental impact: embodied carbon emissions, tCO_2e	0.0	0.0 (0.0)	0.0 (0.0)	499.4 (204.8)
ATTEST approach – with flexibility	Investment cost, €	0.00	0.00 (0.00)	0.00 (0.00)	213,770.50 (0.00)
	Environmental impact: embodied carbon emissions, tCO_2e	0.0	0.0 (0.0)	0.0 (0.0)	114.3 (0.0)
Benefits of ATTEST solution	Avoided investment cost	-	-	-	€720,184.10; 77.1% (€383,031.30; 100.0%)
	Avoided carbon emissions	-	-	-	385.1 tCO_2e; 77.1% (204.8 tCO_2e; 100.0%)

The developed planning tool identified the need for multiple reinforcements in 2050, both in active economy and slow economy scenarios. The branches with the most significant reinforcements are highlighted in red in Figure 41, and the labels of the corresponding buses are displayed. These reinforcements are justified by the load growth forecast, which predicts that the total power consumption in 2050 will increase by 90% compared to 2020 load levels. In 2030 and 2040, no additional reinforcements are needed as the lines and transformers of the network have enough headroom.

The volume of available flexibility is expected to reach 11% of the total network power demand in 2050. The utilization of flexibility via the ATTEST planning approach reduces network investments significantly. For the active economy scenario, the investment cost decreases by 77.1% compared to the BaU case. For the slow economy scenario, effective utilization of flexibility allows to avoid any additional network reinforcements.

5.1.5. Case study: Portuguese distribution network

The Portuguese distribution network (also named “PT_Dx_01” and “Distribution_Network_PT1.m” in the ATTEST project) is a radial network with 191 buses, 190 lines, and one transformer. The topology of the network is presented as a graph in Figure 42. There is only one generator (supply point) at substation 2, as highlighted in green in the figure. The total active power demand of the network is 18.8 MW in 2020.

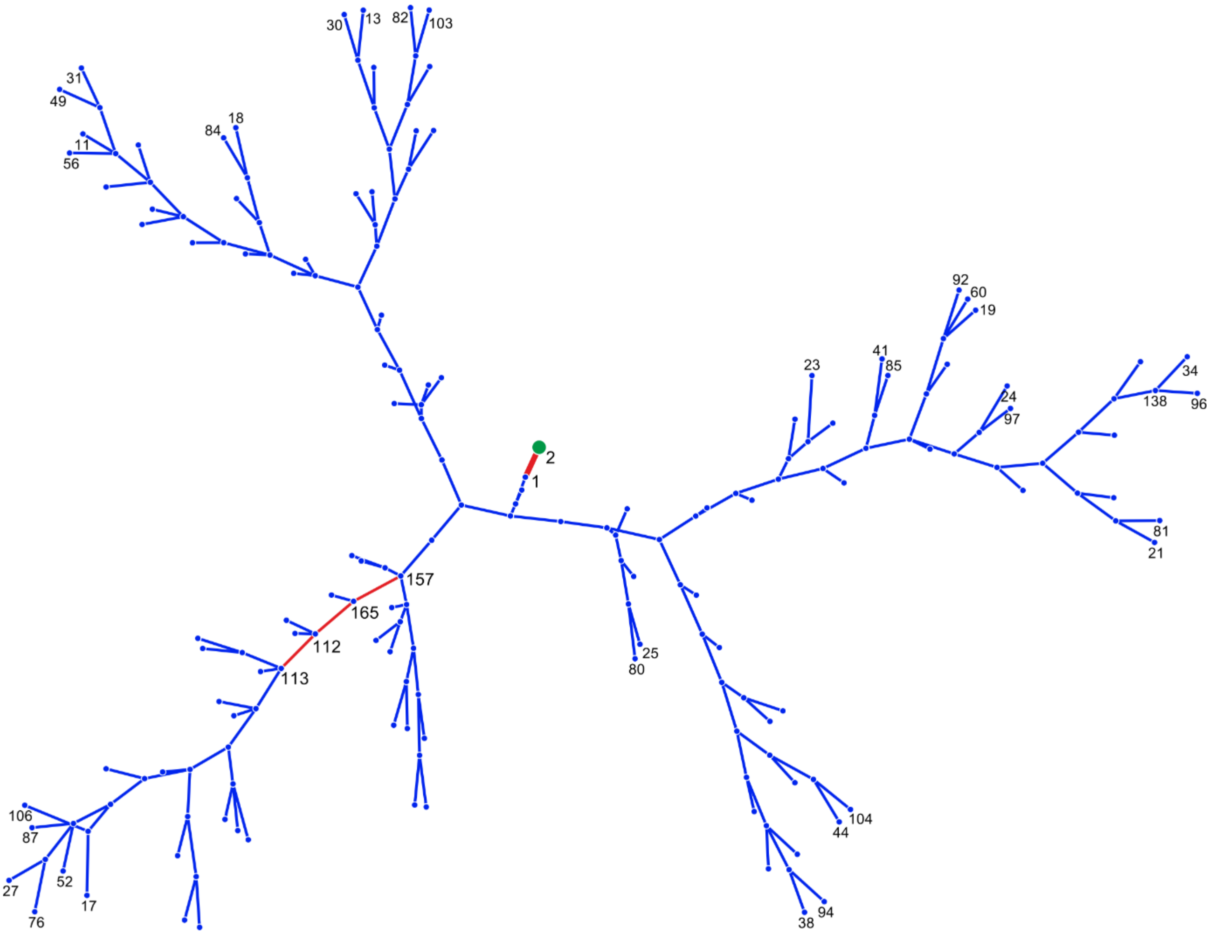


Figure 42 Topology of the Portuguese distribution network (PT_Dx_01)

It is expected that the peak power consumption of the network will increase by 80% in 2050 compared to the load levels in 2020. Thus, it becomes necessary to reinforce the Portuguese distribution network to keep its operation feasible and economically efficient. The developed network planning tool was applied to this case to identify the optimized investment strategies. The results are displayed in Table XXI in terms of the investment costs and carbon emissions for each year and scenario.

Table XXI KPIs simulations for the Portuguese distribution network (PT_Dx_01)

Case:	Metrics:	Years: active economy (slow economy):			
		2020	2030	2040	2050
Base case (BaU) – no flexibility	Investment cost, €	0.00	0.00 (0.00)	853.10 (0.00)	912,996.40 (63,412.40)
	Environmental impact: embodied carbon emissions, tCO_2e	0.0	0.0 (0.0)	0.5 (0.0)	82.0 (6.8)
ATTEST approach – with flexibility	Investment cost, €	0.00	0.00 (0.00)	0.00 (0.00)	181,706.20 (0.00)
	Environmental impact: embodied carbon emissions, tCO_2e	0.0	0.0 (0.0)	0.0 (0.0)	15.9 (0.0)
Benefits of ATTEST solution	Avoided investment cost	-	-	€853.10; 100.0% (-)	€731,290.20; 80.1% (€63,412.40; 100.0%)
	Avoided carbon emissions	-	-	0.5 tCO_2e; 100.0% (-)	66.04 tCO_2e; 80.6% (6.8 tCO_2e; 100.0%)

The developed planning tool identified the need for several reinforcements in 2050, both in active economy and slow economy scenarios. The branches that will need reinforcements are highlighted in red in Figure 42, and the labels of the corresponding buses are displayed. In 2030 and 2040, the network does not require significant reinforcements.

According to the data provided by the project partners, the length of many lines in the PT_Dx_01 is short, often ranging between 20 and 100 meters. Therefore, the cost of reinforcements for such short lines is negligible compared to other cases considered in ATTEST. The largest share of the investment costs presented in Table XXI is the cost of the transformer 1-2.

The volume of available flexibility is expected to reach 21% of the total network power demand in 2050. The utilization of flexibility via the ATTEST planning approach reduces network investments significantly. For the active economy scenario, the investment cost decreases by 80.1% compared to the BaU case. For the slow economy scenario, effective utilization of flexibility allows to avoid any additional network reinforcements.

5.1.6.Summary and conclusion

The above simulations performed for the four selected ATTEST test distribution systems demonstrate the impact of flexible resources on distribution network planning. Specifically, the effective utilization of flexibility allows to defer or significantly reduce network reinforcement, thus minimizing the associated costs and embodied carbon emissions. In some cases, incorporating flexibility into the planning problem allowed avoiding any additional network reinforcements, demonstrating the 100% effectiveness of the ATTEST planning approach (according to the selected KPIs). However, there are cases where, for certain years and economic scenarios, the effectiveness of the developed planning tool is 0%. That is, there is no difference between the ATTEST flexibility-utilizing approach and the base case (BaU). Therefore, considering the range of the results in the KPIs simulations, it is difficult to make a general conclusion about the average effectiveness of the distribution network planning tool. Instead, the value of flexibility should be interpreted carefully for each distribution system to provide insights and guidance for DSOs on potential critical network reinforcements and ways to mitigate them. Nevertheless, the performed simulations allow to draw the following findings:

- **The value of flexibility increases over the years**. In all simulations, the benefits of the ATTEST planning approach increase towards the planning horizon, reaching maximum values in 2050. This is justified by the two factors: 1) more network reinforcements take place in 2040 and 2050 due to a significant load growth, and 2) more flexible resources become available in the systems. Thus, utilizing flexibility in later years enables considerable reductions in network reinforcements with associated costs and embodied carbon. However, following this principle, the value of flexibility decreases in earlier years, as stated in the next point.
- **In some years and scenarios, utilizing flexibility can bring no benefits**. Many simulations demonstrated that the effectiveness of the ATTEST flexibility-utilizing approach can be 0% in 2020 and 2030. This usually indicates that a network has sufficient line and transformer capacities and does not require additional reinforcements in these years. Also, the amount of available flexibility may be insignificant to impact the reinforcement decisions. Thus, in such cases, flexibility utilization makes no difference in terms of network investment costs and embodied carbon.
- **Moderate volumes of flexibility can have great impact on network planning**. In all simulations, the expected volumes of flexibility reach 11-21% of the total network power demand in 2050. Yet, effective utilization of these flexible resources can lead to much greater network investment reductions: up to 54% for the UK case, 77% for the Spanish distribution network, 80% Portuguese network, and 100% for the Croatian distribution system. These results demonstrate the importance of flexibility in distribution network planning and emphasize the need for implementing flexible planning approaches such as the proposed ATTEST tool.

5.2. Optimization tool for transmission network planning

This section provides KPIs simulations and demonstrations for the WP3 tool "Optimization tool for transmission network planning". First, a high-level description and modelling features of the tool will be given to explain its applications in transmission network planning. Then, the KPIs will be defined to measure CAPEX and the environmental impact of the solutions identified by the tool. Finally, the simulations will be presented for three selected ATTEST cases: the UK, Croatian, and Portuguese transmission systems.

5.2.1. Description of the tool and KPIs calculation

The developed transmission network planning tool considers the uncertain future of the system development and identifies the optimal investment in assets (e.g., reinforcements of lines and transformers) and non-asset-based solutions (utilization of flexible sources). Similar to the distribution planning tool, the uncertain future is described by two extreme forecasts, the active and slow economy scenarios, as shown in Figure 37. Note that these scenarios are not sufficient to capture the value of flexibility as, from the second time period (2030), the future is modelled as a deterministic path. Therefore, to estimate the response of flexibility to uncertain futures, these two extreme scenarios are transformed into a scenario tree, where at each year, possible future trajectories branch into a more active one and a slower one. In total, 15 nodes are considered in the scenario tree for four years: 2020, 2030, 2040, and 2050.

The tool incorporates several modelling techniques and approaches.[9] A three-stage scenario-based stochastic optimization formulation is proposed to minimize the network reinforcement cost and the

[9] Note that due to the complexity of transmission networks, the transmission planning tool does not rely on the recursive function approach exploited in the distribution planning tool. Instead, a more traditional mathematical programming approach is used, which miniises the costs of network investments and operation subject to the N-1 security constraints analysed via the SC AC OPF tool developed in WP4.

cost of operation. To minimize the computational burden, the tool decomposes the planning problem into the investment and operation models. It also utilizes a screening model to identify and pre-select potentially attractive candidate investments. To account for the flexibility services provided by DSO, the transmission network planning tool includes available flexible power support at the TSO-DSO interfaces. In view of uncertainties influencing the operation of transmission networks, a stochastic operational model is formulated to identify possible worst-case short-term conditions and related long-term scenarios. Finally, to meet the N-1 security of transmission network operation, the investment model is complemented with the SC AC OPF analysis that enables identifying network binding constraints with respect to possible contingencies.

At a high level, the tool divides the planning problem into a series of targeted subproblems, which are iteratively solved to find the cost-minimizing solution with N-1 network operation security guarantees. Specifically, there are three main components of the transmission network planning tool:

1. *Screening model*
   Optimizing a planning strategy for transmission networks can be computationally expensive considering the potentially massive number of investments available, some of which can become attractive under uncertain future conditions. Finding the optimal multi-year portfolio of investments is a hard combinatorial problem. To mitigate this issue, the planning tool utilises a screening model to identify and pre-select potentially attractive candidate investments. The screening model is a simplified transmission planning model, a DC OPF model with a linear cost function for network investments. The model is applied to different conditions across scenarios to identify which network components would normally be reinforced. The relevant options are then selected to create an investment catalogue, i.e., potentially optimal reinforcements of transmission lines and transformers.
2. *Investment model - part 1*
   This investment model takes the outputs of the screening model (a list of attractive investment options) to identify the least-cost investments across a stochastic future given by the scenario tree using a MILP formulation. Part 1 of the investment model focuses on minimizing investment costs while ignoring the operation costs. An AC SCOPF model, developed in WP4 [8], is applied for the peak time period to identify the requirements in new investments.
3. *Investment model - part 2*
   Part 2 of the investment model focuses on minimizing both investment costs and operation costs. For this purpose, the objective function of the model is extended to include operational costs, and the ACOPF model is applied for 24h of a typical day to estimate the operational costs.

The final output of the transmission planning tool is a multi-year portfolio of optimal N-1 secure investments for the two given scenarios, active and slow economies. To demonstrate the effectiveness of the tool, the following two KPIs were considered:

1) CAPEX: cost savings due to reduced network investments, in € mln
2) Environmental impact: avoided emissions due to reduced embodied carbon of network investments, in tonnes of CO_2 equivalent

To estimate the selected KPIs, the planning model was solved two times for each ATTEST test transmission system:

3) First, a traditional investment planning problem was solved with the assumption that no flexibility can be used to support the network operation. This is referred to as the base case (BaU).

4) Second, the proposed multi-stage scenario-based stochastic investment planning problem was solved, where the forecasted levels of flexibility can be utilized in the future. This is referred to as the ATTEST approach.

Then, the tool's KPIs can be estimated using the following formulas:

$$KPI_{year,sc}^{cost} = \frac{IC_{year,sc}^{Base} - IC_{year,sc}^{ATTEST}}{IC_{year,sc}^{Base}} 100\% \tag{3}$$

$$KPI_{year,sc}^{env} = \frac{Carbon_{year,sc}^{Base} - Carbon_{year,sc}^{ATTEST}}{Carbon_{year,sc}^{Base}} 100\% \tag{4}$$

These formulas calculate the changes (in %) in the investment costs (IC) and in the embodied carbon ($Carbon$) between the BaU case and the ATTEST planning approach. Thus, a KPI of 100% implies that the ATTEST planning tool enables completely avoiding additional investments with associated costs and embodied carbon. A KPI of 0% means that there is no difference between the ATTEST approach and the base case.

In the simulations, it is assumed that the available flexibility comes from EVs (as flexible loads) and battery storage, according to the flexibility forecasts estimated by the project partners for each test system, as defined in Section 3. Finally, to analyse the tool's performance, solutions to these problems are compared and the CAPEX and environmental KPIs are presented in %.

Note that the KPIs for the planning tool are presented as separate values for each year and scenario ($year, sc$). That is, no aggregated estimation of KPIs is given for the entire planning horizon. This approach enables analysing the expected evolution of the networks in the future, tracking changes in the need for investments and the corresponding KPIs over time. For example, as will be demonstrated by the simulations, many of the considered networks have enough capacity to meet moderate demand growth. In such networks, no additional investment is required in 2020 and 2030. Only with the significant demand increase, usually in 2040 and 2050, line reinforcements become necessary. It is also important to note that the KPIs estimation based on the BaU/ATTEST comparison is case specific, and the results should be interpreted carefully for each network. For example, for some years and scenarios, the estimated KPIs can reach 100%. This does not however mean that the ATTEST approach fully solves all planning and operational issue of transmission networks. This can rather indicate that a test network initially had enough capacity to meet the demand for certain scenarios and years, and only a few additional reinforcements are required. If applying the ATTEST planning approach and utilizing flexibility resources, the need for such minor reinforcements disappears, and the tool KPIs scores its effectiveness as 100%. Additional comments and explanations will be given for such cases throughout the section.

5.2.2. Case study: UK transmission network

The UK transmission network (also named "UK_Tx" and "Transmission_Network_UK.m" in the ATTEST project) is a simplified representation of the country-level UK power system. The network has 30 buses, 51 lines, and the total peak active power demand of 57.2 GW in 2020. The topology of the network is presented as a graph in Figure 43. There are 66 generators in the UK transmission network model, located at 25 different buses. In combination with the meshed network topology, this makes the UK transmission system reliable enough and prepared to meet future demand growth.

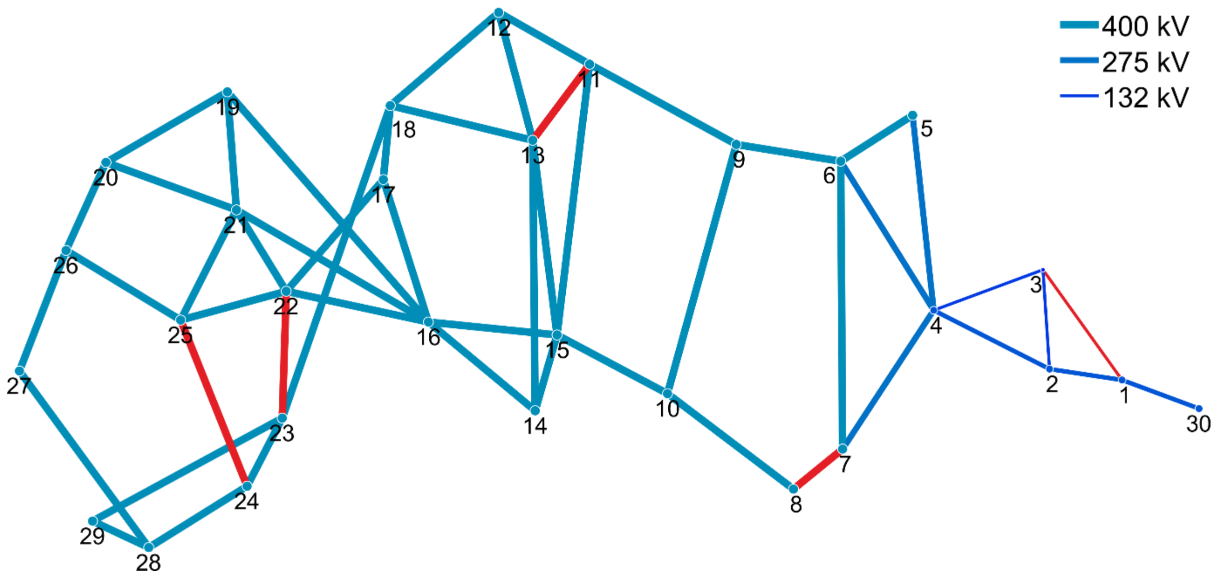


Figure 43 Topology of the UK transmission network (UK_Tx)

Based on the active economy scenario, it is expected that the peak power consumption of the network will increase by 93% in 2050 compared to the load levels in 2020, as visualized in Figure 39. Thus, it becomes necessary to reinforce the UK transmission network to keep its operation feasible and economically efficient. The developed network planning tool was applied to this case to identify the optimized investment strategies. The results are displayed in Table XXII in terms of the investment costs (€ mln) and carbon emissions for each year and scenario.

Table XXII KPIs simulations for the UK transmission network (UK_Tx)

Case:	Metrics:	Years: active economy (slow economy):			
		2020	2030	2040	2050
Base case (BaU) – no flexibility	Investment cost, € mln	0.00	857.06 (171.41)	6,523.17 (2,975.90)	15,314.92 (3,261.59)
	Environmental impact: embodied carbon emissions, $ktCO_2e$	0.0	27.0 (5.4)	205.5 (93.7)	482.4 (102.7)
ATTEST approach – with flexibility	Investment cost, € mln	0.00	0.00 (0.00)	0.00 (0.00)	6,523.17 (0.00)
	Environmental impact: embodied carbon emissions, $ktCO_2e$	0.0	0.0 (0.0)	0.0 (0.0)	205.5 (0.0)
Benefits of ATTEST solution	Avoided investment cost	-	€mln857.06; 100.0% (€mln171.41; 100.0%)	€mln6,523.17; 100.0% (€mln2,975.90; 100.0%)	€mln8,791.74; 57.4% (€mln3,261.59; 100.0%)
	Avoided carbon emissions	-	27.0 $ktCO_2e$; 100.0% (5.4 $ktCO_2e$; 100.0%)	205.5 $ktCO_2e$; 100.0% (93.7 $ktCO_2e$; 100.0%)	276.9 $ktCO_2e$; 57.4% (102.7 $ktCO_2e$; 100.0%)

The developed planning tool identified the need for several reinforcements in both active economy and slow economy scenarios, starting from 2030. In total, there are five lines that will require investments, as highlighted in red in Figure 43. Lines 1-3, 7-8, and 11-13 will require additional capacity to transfer more power from the North, while reinforcements of lines 22-23 and 24-25 will strengthen the power supply of the nodes in the South of England, where the main demand is located. Some of these investments will be required as early as 2030. However, the most significant investments (of up to €15.3 bln) are expected to take pace in 2050.

The volume of available flexibility is expected to reach 23% of the total network power demand in 2050. The utilization of flexibility via the ATTEST planning approach reduces network investments significantly. For the active economy scenario, the investment cost decreases by 57.4% in 2050 compared to the BaU case. For other years and scenarios, effective utilization of flexibility allows to avoid any additional network reinforcements.

5.2.3.Case study: Croatian transmission network

The Croatian transmission network (also named "HR_Tx_01_new_Koprivnica" and "Location1.m" in the ATTEST project) is the real anonymized Croatian Transmission grid located around the Koprivnica substation. The network has 31 buses, 48 branches, and the total peak active power demand of 575 MW in 2020. The topology of the network is presented as a graph in Figure 44. There are 11 generators in the Croatian transmission network model, located at 8 different buses. The sufficient generation capacity and the meshed network topology make the HR_Tx_01_new_Koprivnica system reliable enough and prepared to meet future demand growth.

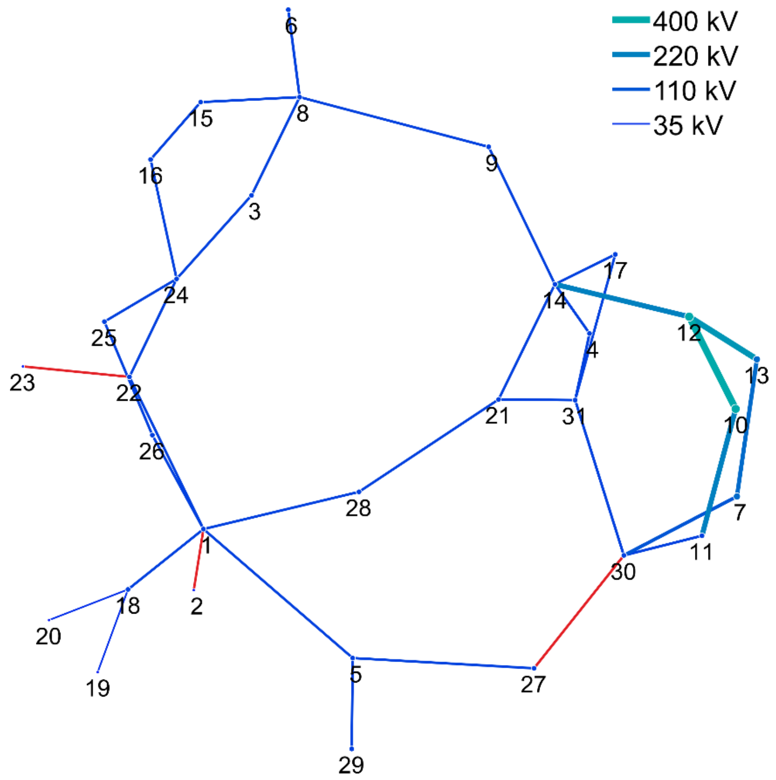


Figure 44 Topology of the Croatian transmission network (HR_Tx_01)

Based on the active economy scenario, it is expected that the peak power consumption of the network will almost double in 2050 compared to the load levels in 2020. Thus, it becomes necessary to reinforce the Croatian transmission network to keep its operation feasible and economically efficient. The developed network planning tool was applied to this case to identify the optimized investment strategies. The results are displayed in Table XXIII in terms of the investment costs (€ mln) and carbon emissions for each year and scenario.

Table XXIII KPIs simulations for the Croatian transmission network (HR_Tx_01)

Case:	Metrics:	Years: active economy (slow economy):			
		2020	2030	2040	2050
Base case (BaU) – no flexibility	Investment cost, € mln	0.00	0.00 (0.00)	0.00 (0.00)	13.79 (0.00)

	Environmental impact: embodied carbon emissions, tCO_2e	0.0	0.0 (0.0)	0.0 (0.0)	434.4 (0.0)
ATTEST approach – with flexibility	Investment cost, € mln	0.00	0.00 (0.00)	0.00 (0.00)	5.93 (0.00)
	Environmental impact: embodied carbon emissions, tCO_2e	0.0	0.0 (0.0)	0.0 (0.0)	186.8 (0.0)
Benefits of ATTEST solution	Avoided investment cost	-	-	-	€mln7.86; 57.0% (-)
	Avoided carbon emissions	-	-	-	247.6 tCO_2e; 57.0% (-)

The developed planning tool identified very few reinforcements for the HR_Tx_01_new_Koprivnica system. Only three branches will require investments in 2050 for the active economy scenario, as highlighted in red in Figure 44. In other years and scenarios, the system needs no additional reinforcements as the lines and transformers have enough headroom.

The volume of available flexibility is expected to reach 9.5% of the total network power demand in 2050. The utilization of flexibility via the ATTEST planning approach reduces network investments significantly. For the active economy scenario, the investment cost decreases by 57.0% in 2050 compared to the BaU case. For other years and scenarios, effective utilization of flexibility does not impact the network planning decisions since there is no need for network reinforcement in both BaU and ATTEST cases.

5.2.4. Case study: Portuguese transmission network

The Portuguese transmission network (also named “PT_Tx” and “Transmission_Network_PT.m” in the ATTEST project) is the real transmission grid model of Portugal as of 2020. The network has 304 buses, 557 branches, 7 interconnections with Spain, 270 generators, and the total peak active power demand of 8.48 GW. The topology of the network is presented as a graph in Figure 45. The high number of generators and the meshed network topology make the PT_Tx system reliable enough and prepared to meet future demand growth.

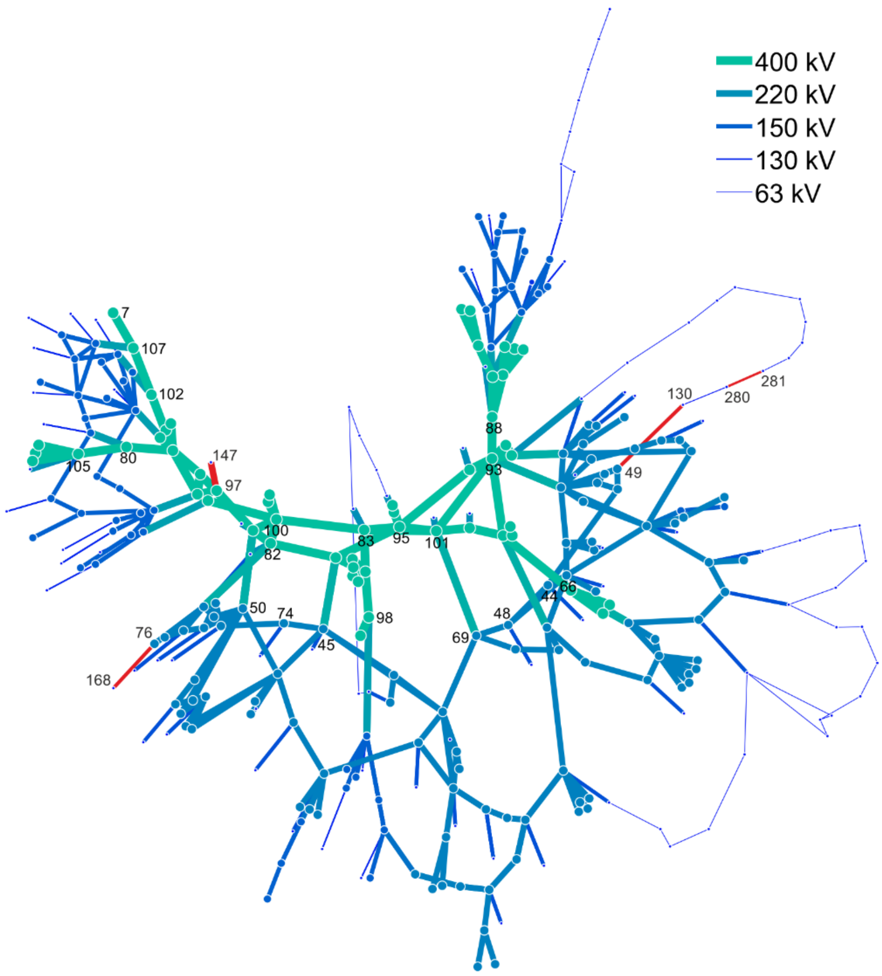


Figure 45 Topology of the Portuguese transmission network (PT_Tx)

Based on the active economy scenario, it is expected that the peak power consumption of the network will increase by 80% in 2050 compared to the load levels in 2020. Thus, it becomes necessary to reinforce the Portuguese transmission network to keep its operation feasible and economically efficient. The developed network planning tool was applied to this case to identify the optimized investment strategies. The results are displayed in Table XXIV in terms of the investment costs (€ mln) and carbon emissions for each year and scenario.

Table XXIV KPIs simulations for the Portuguese transmission network (PT_Tx)

Case:	Metrics:	Years: active economy (slow economy):			
		2020	2030	2040	2050
Base case (BaU) – no flexibility	Investment cost, € mln	0.00	0.00 (0.00)	1.80 (0.00)	14.46 (2.70)
	Environmental impact: embodied carbon emissions, tCO_2e	0.0	0.0 (0.0)	450.0 (0.0)	3,274.1 (675.0)
ATTEST approach – with flexibility	Investment cost, € mln	0.00	0.00 (0.00)	0.90 (0.00)	1.20 (0.00)
	Environmental impact: embodied carbon emissions, tCO_2e	0.0	0.0 (0.0)	225.0 (0.0)	300.0 (0.0)
Benefits of ATTEST solution	Avoided investment cost	-	-	€mln0.90; 50.0% (-)	€mln13.26; 91.7% (€mln2.70; 100.0%)
	Avoided carbon emissions	-	-	225.0 tCO_2e; 50.0% (-)	2,974.1 tCO_2e; 90.8% (675.0 tCO_2e; 100.0%)

The developed planning tool identified very few reinforcements for the PT_Tx system. Only four branches will require investments in 2040 and 2050 for the active economy scenario, as highlighted in red in Figure 45. In other years and scenarios, the system needs no additional reinforcements as the lines and transformers have enough headroom.

The volume of available flexibility is expected to reach 28% of the total network power demand in 2050. The utilization of flexibility via the ATTEST planning approach reduces network investments significantly. For the active economy scenario, the investment cost decreases by 50.0% in 2040 and by 91.7% in 2050 compared to the BaU case. For other years and scenarios, effective utilization of flexibility does not impact the network planning decisions since there is no need for network reinforcement in both BaU and ATTEST cases.

5.2.5. Summary and conclusion

The above simulations performed for the three selected ATTEST test transmission systems demonstrate the impact of flexible resources on transmission network planning. Specifically, the effective utilization of flexibility allows to defer or significantly reduce network reinforcement, thus minimizing the associated costs and embodied carbon emissions. In some cases, e.g., slow economy scenarios for the UK and Portuguese systems, incorporating flexibility into the planning problem allowed avoiding any additional network reinforcements, demonstrating the 100% effectiveness of the ATTEST planning approach (according to the selected KPIs). However, there are cases where, for certain years and economic scenarios, the effectiveness of the developed planning tool is 0%. That is, there is no difference between the ATTEST flexibility-utilizing approach and the base case (BaU). Therefore, considering the range of the results in the KPIs simulations, it is difficult to make a general conclusion about the average effectiveness of the transmission network planning tool. Instead, the value of flexibility should be interpreted carefully for each transmission system to provide insights and guidance for TSOs on potential critical network reinforcements and ways to mitigate them. Nevertheless, the performed simulations allow to draw the following findings:

- **The value of flexibility increases over the years**. In all simulations, the benefits of the ATTEST transmission planning approach increase in 2040 and 2050 when more network reinforcements take place to meet the load growth. Effective utilization of flexibility in later years enables considerable reductions in network reinforcements with associated costs and embodied carbon. However, following this principle, the value of flexibility decreases in earlier years, as stated in the next point.
- **In some years and scenarios, utilizing flexibility can bring no benefits**. Many simulations demonstrated that the effectiveness of the ATTEST flexibility-utilizing approach can be 0% in 2020 and 2030. This usually indicates that a network has sufficient line and transformer capacities and does not require additional reinforcements in these years. Also, the amount of available flexibility may be insignificant to impact the reinforcement decisions. Thus, in such cases, flexibility utilization makes no difference in terms of network investment costs and embodied carbon.
- **Moderate volumes of flexibility can have great impact on network planning**. In all simulations, the expected volumes of flexibility reach 9-28% of the total network power demand in 2050. Yet, effective utilization of these flexible resources can lead to much greater network investment reductions: 57-100% for the UK case, 57% for the Croatian transmission network, and 50-92% for the Portuguese transmission system. These results demonstrate the importance of flexibility in transmission network planning and emphasize the need for implementing flexible planning approaches such as the proposed ATTEST tool.

Comparing the simulations for the ATTEST distribution networks (Section 5.1) and transmission networks (Section 5.2), it can be noted that the considered transmission systems are better prepared for future load growth. For example, in the Croatian transmission network, the developed planning tool identified that only 3 out of 48 branches will require reinforcements. Such differences are justified by the complex meshed topologies of transmission systems and large numbers of generators placed at different parts of the networks. Conversely, distribution networks have few generators (usually, only a single supply point) and radial topologies, which makes it necessary to reinforce multiple lines and transformers to meet future load growth.

5.3. Optimization tool for planning TSO/DSO shared technologies

This section presents the KPIs obtained from the simulations conducted for the tool developed in Task 3.3 -- optimization tool for planning TSO/DSO shared technologies. The tool is focused on the planning of shared Energy Storage Systems (ESSs) that can be simultaneously used by TSO and DSOs for the operation of their networks. It is considered that the investment in the shared ESSs is performed by a third-party investor, the Energy Storage System Owner (ESSO), that can participate in energy and secondary reserve markets to maximize its profits. The outcome of the tool is an investment plan in shared ESSs to be installed per year and interface node (primary substation) between the transmission and Active Distribution Networks (ADNs) participating in the TSO-DSO coordination scheme. Since the tool simulates the coordinated operation of TN and ADNs participating in the coordination scheme, in addition to ESSO's KPIs it can be also determined KPIs related to the operation of the power system under the proposed TSO-DSO coordination mechanism.

5.3.1. Case Studies Description

The tool was tested for two case studies: part of the Croatian Transmission Network (TN) corresponding to the Koprivnica region (*HR_Tx_01*), and a case study comprising of standard IEEE networks. In the following subsections it is described the obtained results in detail, including the assumptions made in the planning procedure. Detailed data regarding the case studies can be found in ATTEST's project repository [9].

5.3.1.1. Koprivnica

The TN adopted in this case study consists of *HR_Tx_01*. Associated with this region of the Croatian network there are two DNs, *HR_Dx_01* and *HR_Dx_02*. Each of the two DNs consists of three radially operated subnetworks, totaling 6 ADNs participating in the coordination mechanism. Figure 46 shows a diagram of the TN, with identification of the nodes of the ADNs participating in the TSO-DSO coordination scheme. It is also shown the location of the renewable and conventional generators. For the years 2030, 2040, and 2050, the reinforcement plans produced by Task 3.1 – Optimization tool for transmission network planning, and Task 3.2 – Optimization tool for distribution network planning for TN and DNs were considered.

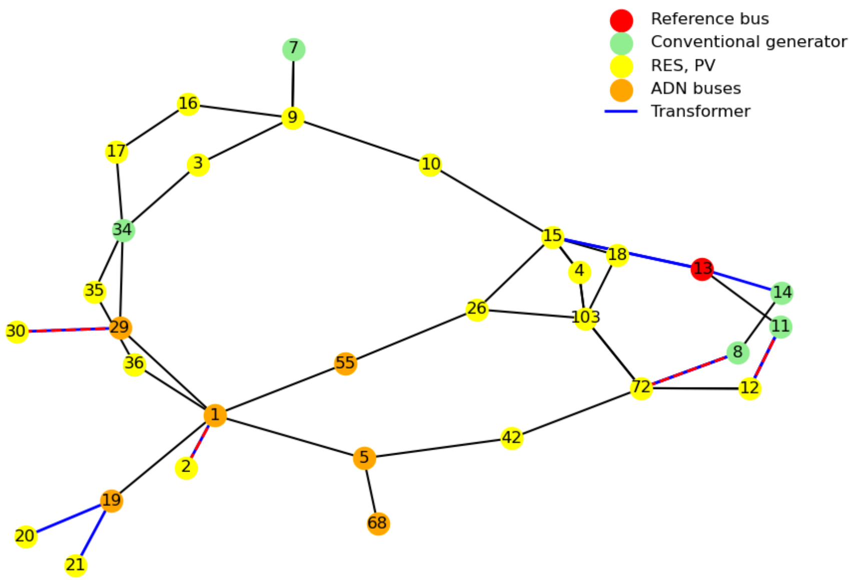


Figure 46 Task 3.3. Case study Koprivnica. Network diagram

5.3.1.2. IEEE

The TN adopted in this case study consists of IEEE 30-bus test system. A total of five ADNs were considered to be participating in the TSO-DSO coordination scheme. The ADNs adopted in this case study consist of the IEEE 18-bus, and IEEE 33-bus distribution test systems. The IEEE 18-bus networks were connected to nodes 16, 18 and 24 of the TN; and IEEE 33-bus networks were connected to nodes 3 and 26 of the TN. Figure 47 shows a network diagram of the TN, with identification of the nodes of the ADNs participating in the TSO-DSO coordination scheme.

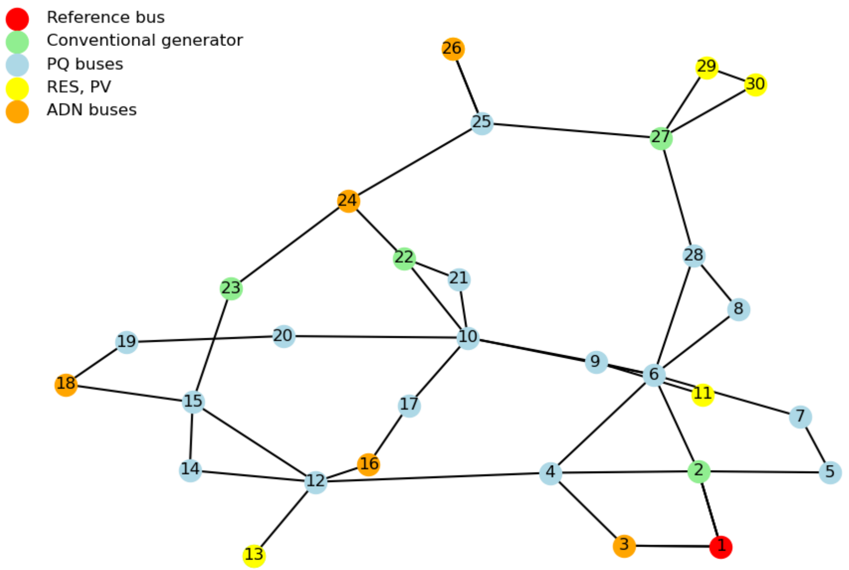


Figure 47 Task 3.3. Case study IEEE. Network diagram

The consumption profiles adopted in this case study are based on normalized consumption profiles obtained from *HR_Tx_01* and *HR_Dx_01* networks (for TN and DNs, respectively), that were adjusted to the consumption standard values as defined in the test systems original files.

For the TN, one operational scenario was adopted. Figure 48 and Figure 49 show the active and reactive power consumption profiles adopted for the TN (IEEE 30-bus test system) for a Summer and Winter representative day, respectively, for the year 2020.

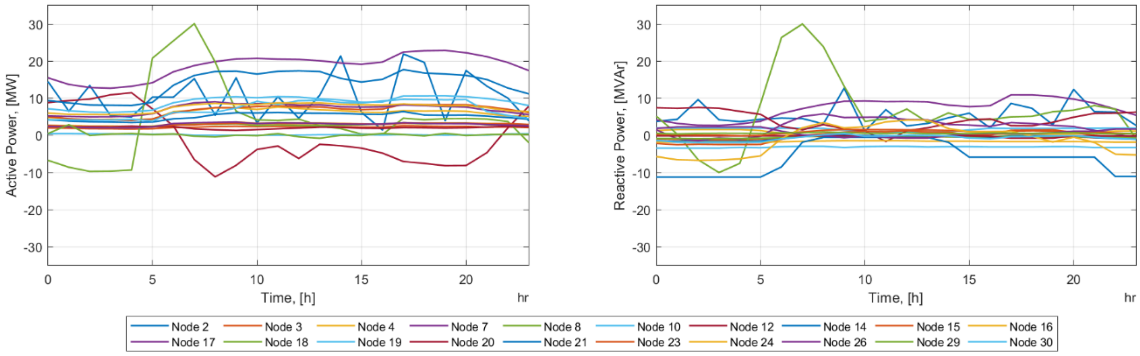


Figure 48 Task 3.3. Case study IEEE. 30-bus TN. Winter consumption profiles, year 2020

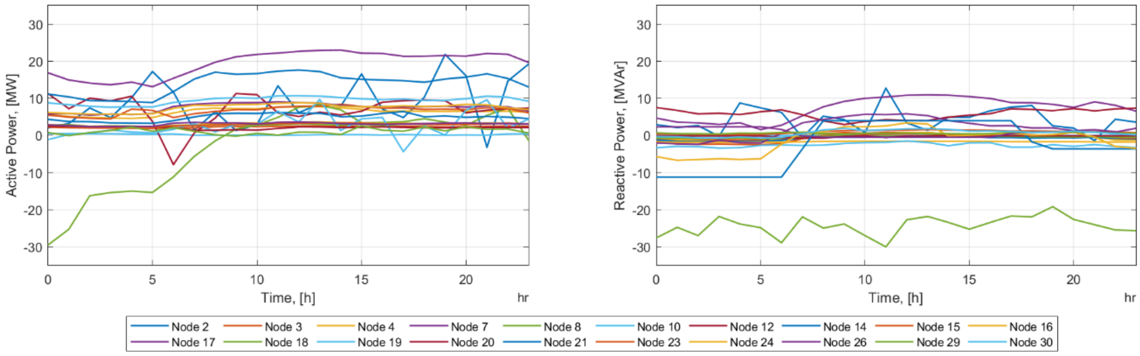


Figure 49 Task 3.3. Case study IEEE. 30-bus TN. Summer consumption profiles, year 2020

For the ADNs (IEEE 18-bus and IEEE 33-bus test systems), three operational scenarios were adopted. Figure 50 and Figure 51 show the active and reactive power consumption profiles adopted for the IEEE 18-bus test system, for a Winter and Summer representative day, for the year 2020. Figure 52 and Figure 53 show the active and reactive power consumption profiles adopted for the IEEE 33-bus test system, for a Winter and Summer representative day, for the year 2020.

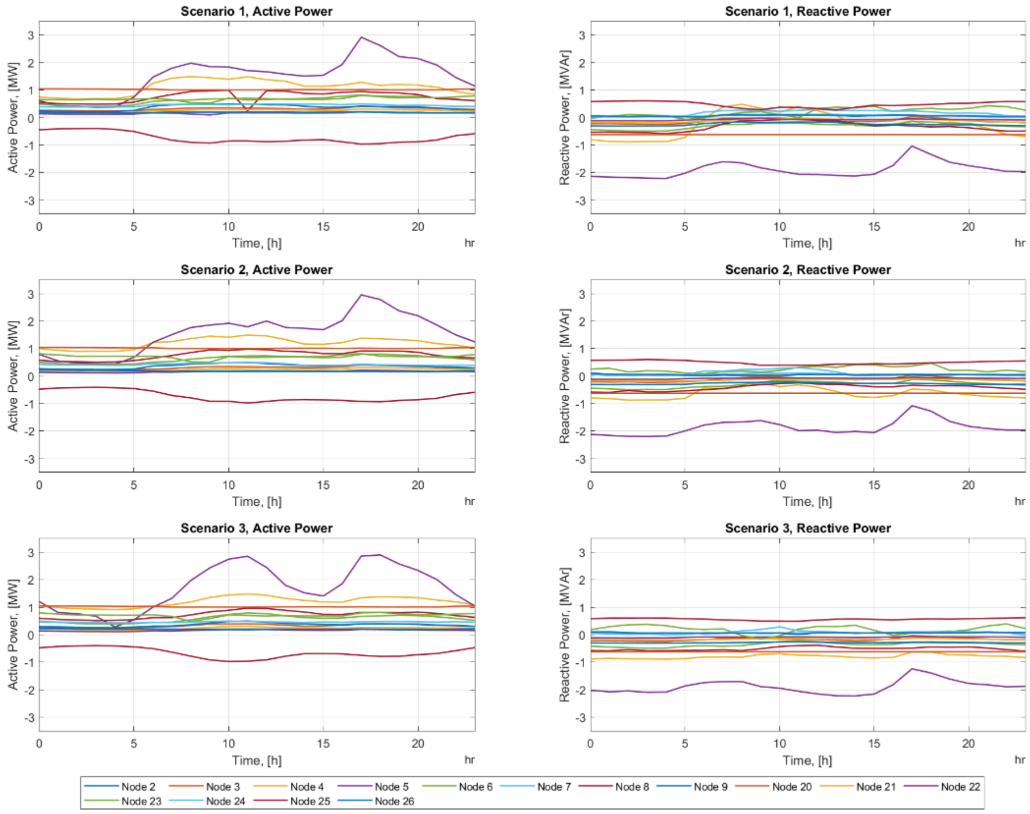


Figure 50 Task 3.3. Case study IEEE. 18-bus DN. Winter consumption profiles, year 2020.

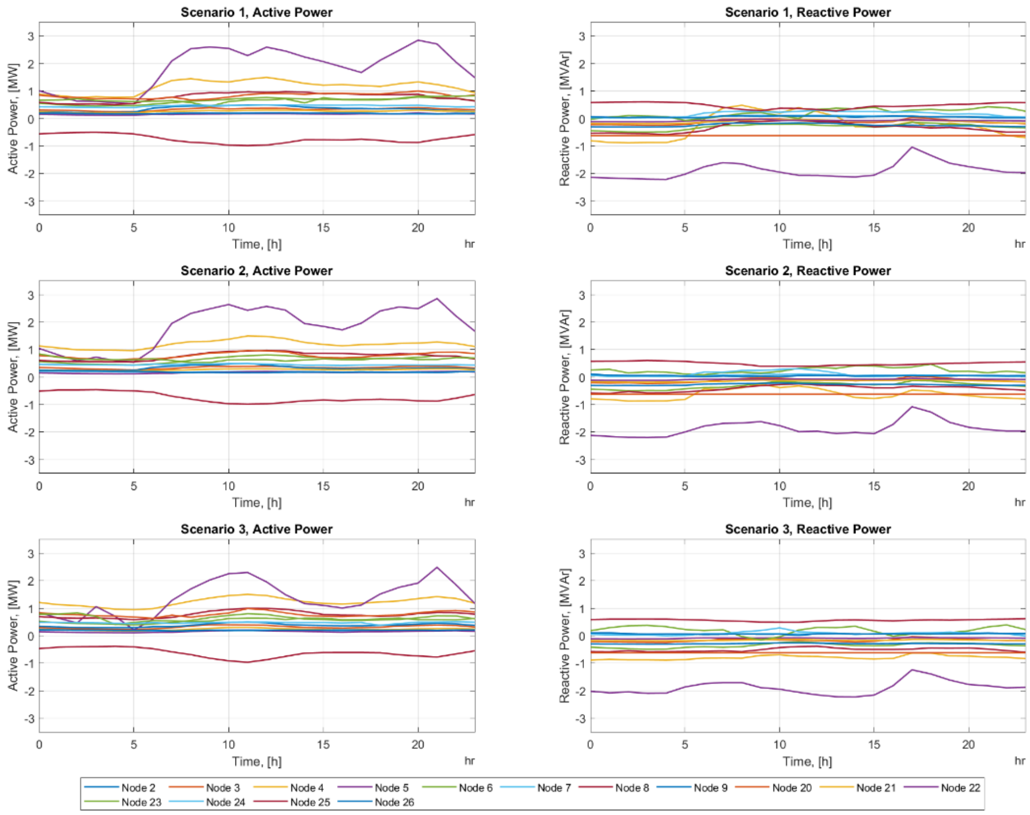


Figure 51 Task 3.3. Case study IEEE. 18-bus DN. Summer consumption profiles, year 2020.

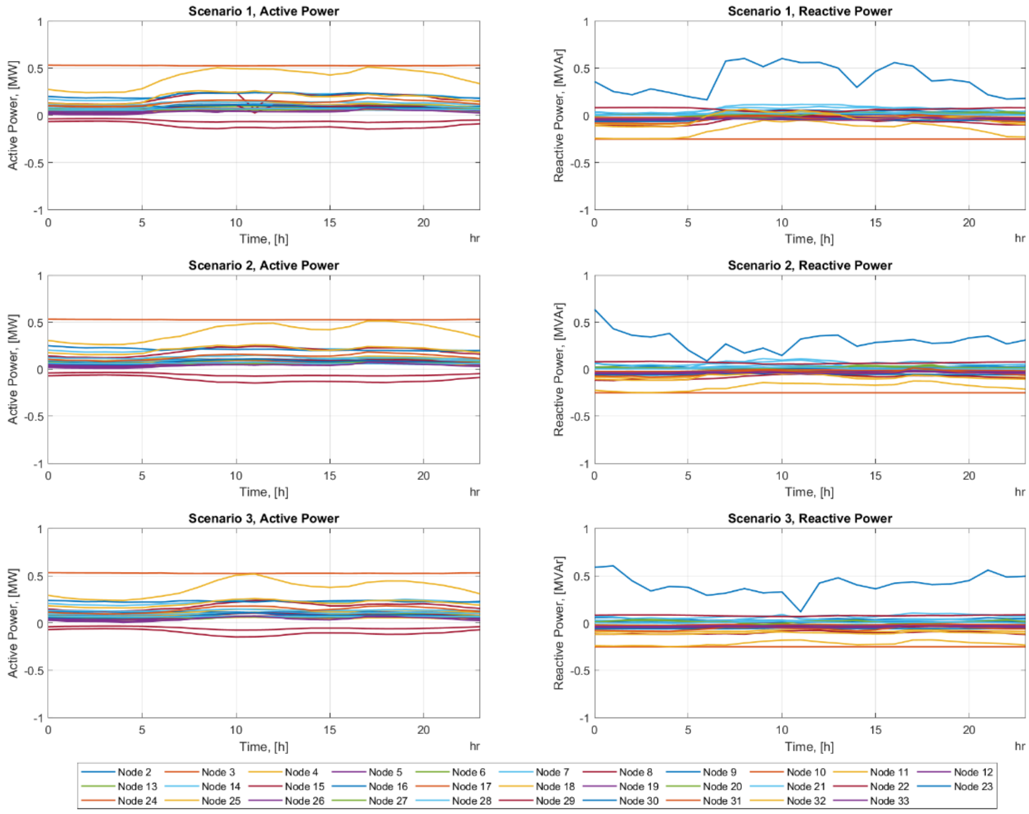


Figure 52 Task 3.3. Case study IEEE. 33-bus DN. Winter consumption profiles, year 2020.

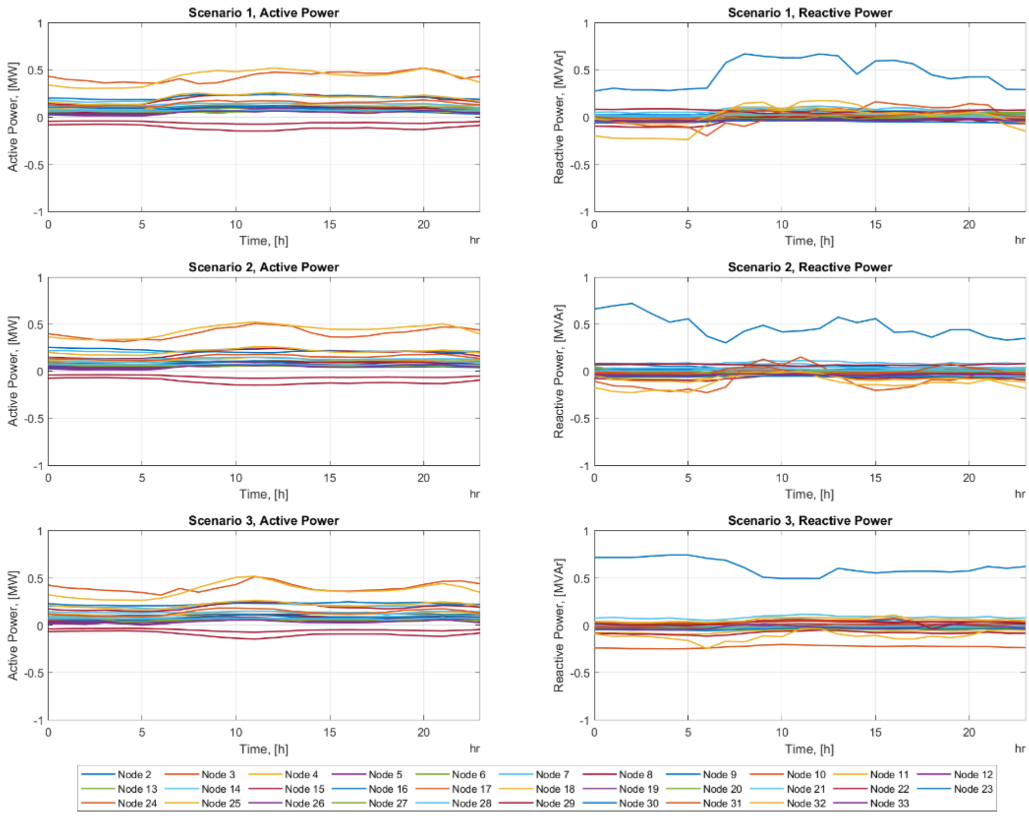


Figure 53 Task 3.3. Case study IEEE. 33-bus DN. Summer consumption profiles, year 2020.

Figure 54 shows the aggregated EV load profiles for the IEEE 30-bus, IEEE 33-bus, and IEEE 18-bus test systems in year 2020. Similarly, to the consumption profiles, EV load profiles are also based on the normalized profiles from “Koprivnica” case study, that were adjusted to the IEEE test systems. The maximum and minimum EV load profiles correspond to the upper and lower flexibility bands that EVs can provide to the operation of the networks.

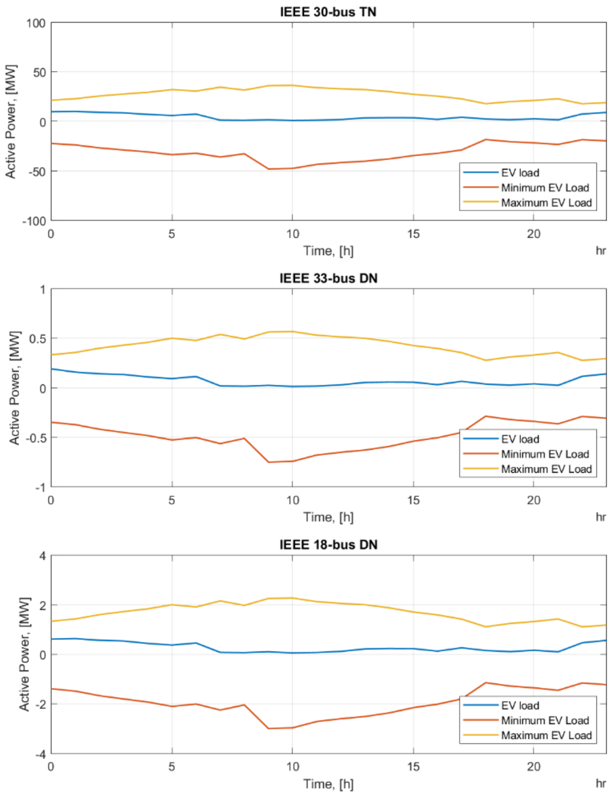


Figure 54 Task 3.3. Case study IEEE. EV load profiles, year 2020.

Table XXV lists the growth factors considered for traditional and EV load in this case study.

Table XXV Task 3.3. Case study IEEE. Load growth factors

Network	Growth factor	Value, [%]
TN	Load	1.00%
	EV Load	10.00%
ADN Node 24	Load	1.00%
	EV Load	5.00%
ADN Node 16	Load	1.00%
	EV Load	5.00%
ADN Node 18	Load	1.00%
	EV Load	5.00%
ADN Node 26	Load	1.00%
	EV Load	5.00%
ADN Node 3	Load	1.00%
	EV Load	5.00%

In Figure 55 shows the total PV installed capacity per network and year. In Table of the annex section is listed the installed PV capacity per network, year, and network node. In Figure 56 shows the total ESS installed capacity per network and year. In Table of the annex section is listed the ESS capacity installed per network, year, and network node.

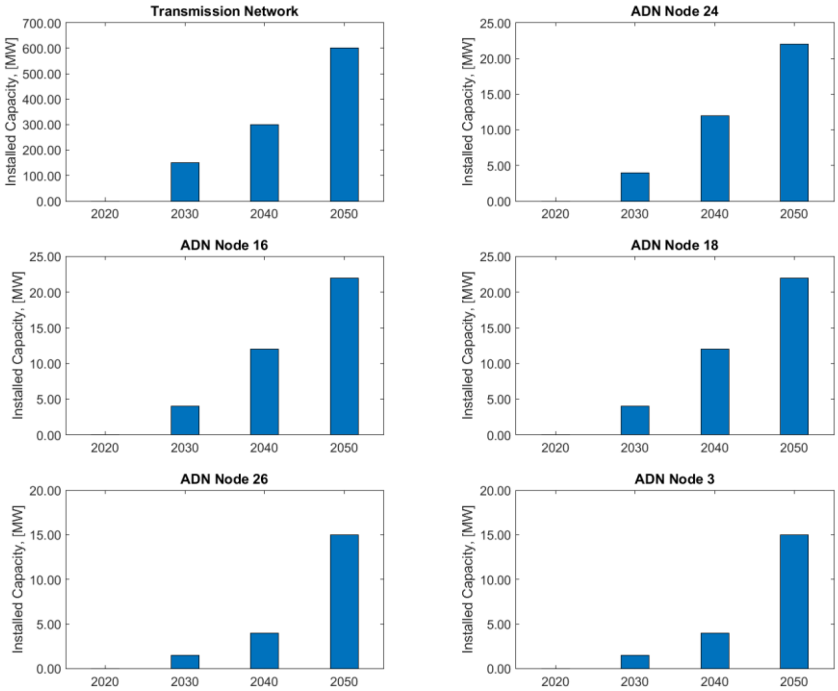


Figure 55 – Task 3.3. Case study IEEE. Total PV installed capacity per network and year.

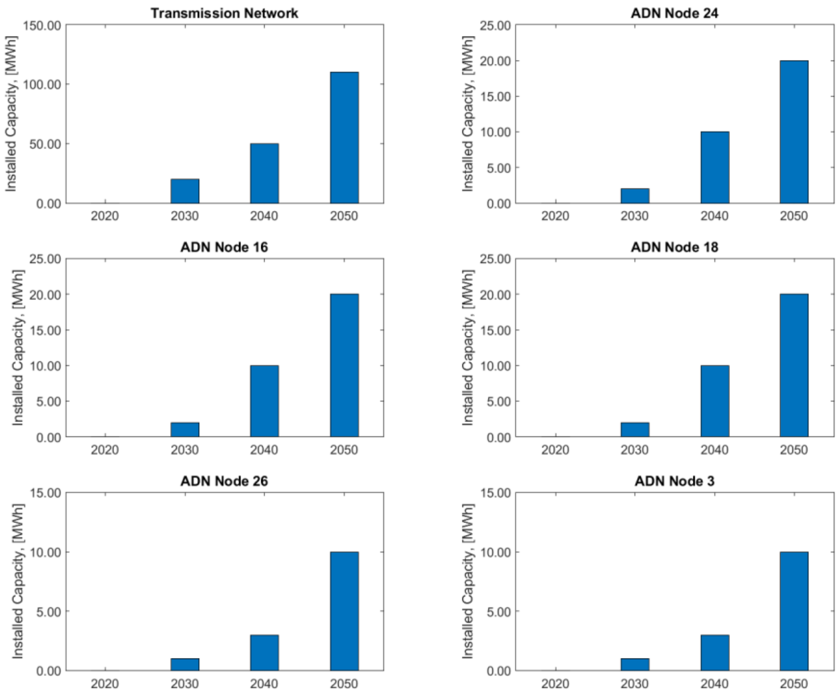


Figure 56 Task 3.3. Total ESS installed capacity per network and year.

5.3.2. Market Data

Three market price scenarios were considered in the simulations, for both “Koprivnica” and “IEEE” case studies. Figure 57 shows the energy prices for year 2020, Figure 58 shows the secondary reserve prices for year 2020, and Figure 59 shows the tertiary reserve (upward and downward) prices for year 2020. The prices were obtained from the Portuguese TSO’s market platform [10]. Table XXVI lists the market prices’ growth factors that were assumed in the simulations.

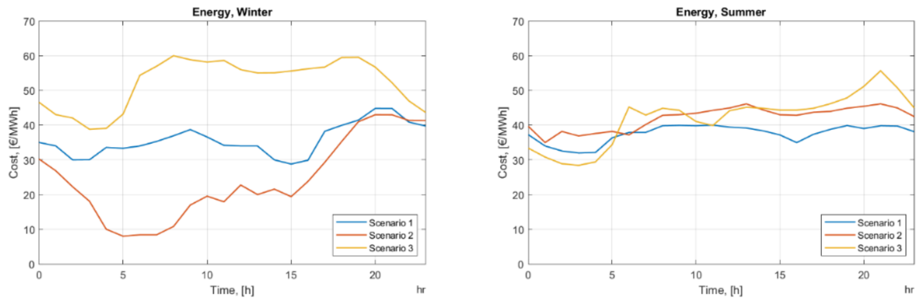


Figure 57 Task 3.3. Market prices. Energy, year 2020.

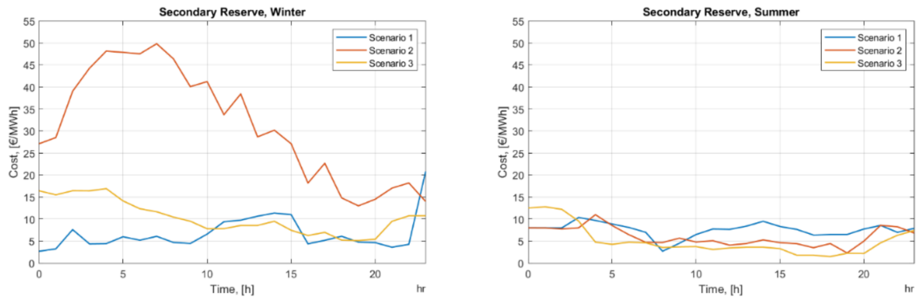


Figure 58 Task 3.3. Market prices. Secondary reserve, year 2020.

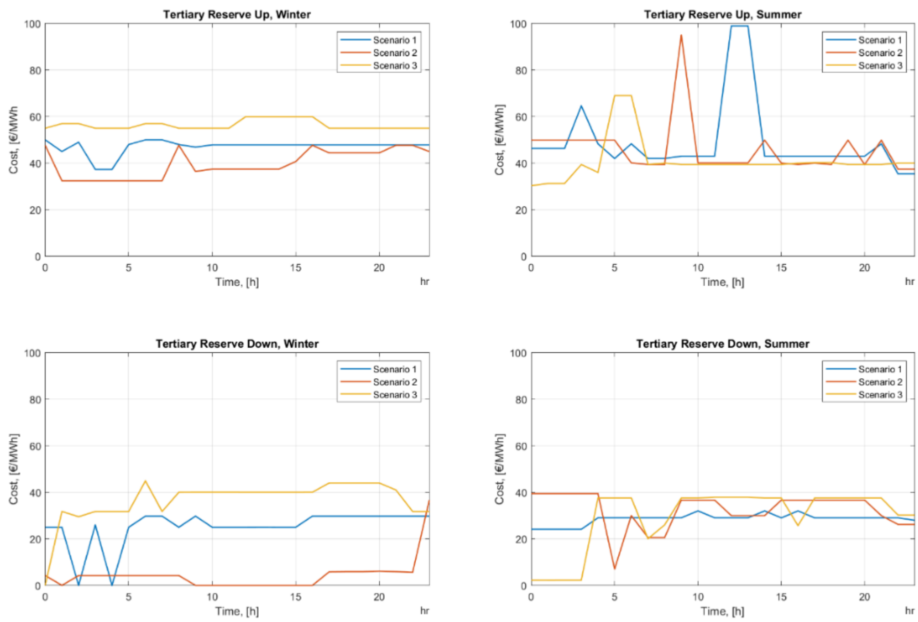


Figure 59 Task 3.3. Market prices. Tertiary reserve, year 2020.

Table XXVI Task 3.3. Market prices. Growth factors

Growth factor	Value, [%]
Energy	1.00%
Secondary Reserve	2.50%
Tertiary Reserve, Upward	2.50%
Tertiary Reserve, Downward	2.50%

5.3.3. Shared ESS Data

It is assumed that the battery ESSs to be installed are based on Li-Ion technology. Table XXVII shows the investment costs assumed for the shared ESSs for the planning horizon, decomposed by power rating and energy capacity components, estimated from NREL's *Utility-Scale Battery Storage* report [11]. It was assumed a calendar life of 20 years for the battery ESSs.

Table XXVII Task 3.3. Investment costs considered for shared ESSs

	2020	2030	2040	2050
S, [€/MVA]	69000.00	39600.00	34800.00	29800.00
E, [€/MVA]	276000.00	158400.00	139200.00	119200.00

Three reserve activation scenarios were considered in the simulations. Figure 60 shows the upward and downward secondary reserve activation for the year 2020. The reserve activation values were obtained from the Portuguese TSO's market platform [10].

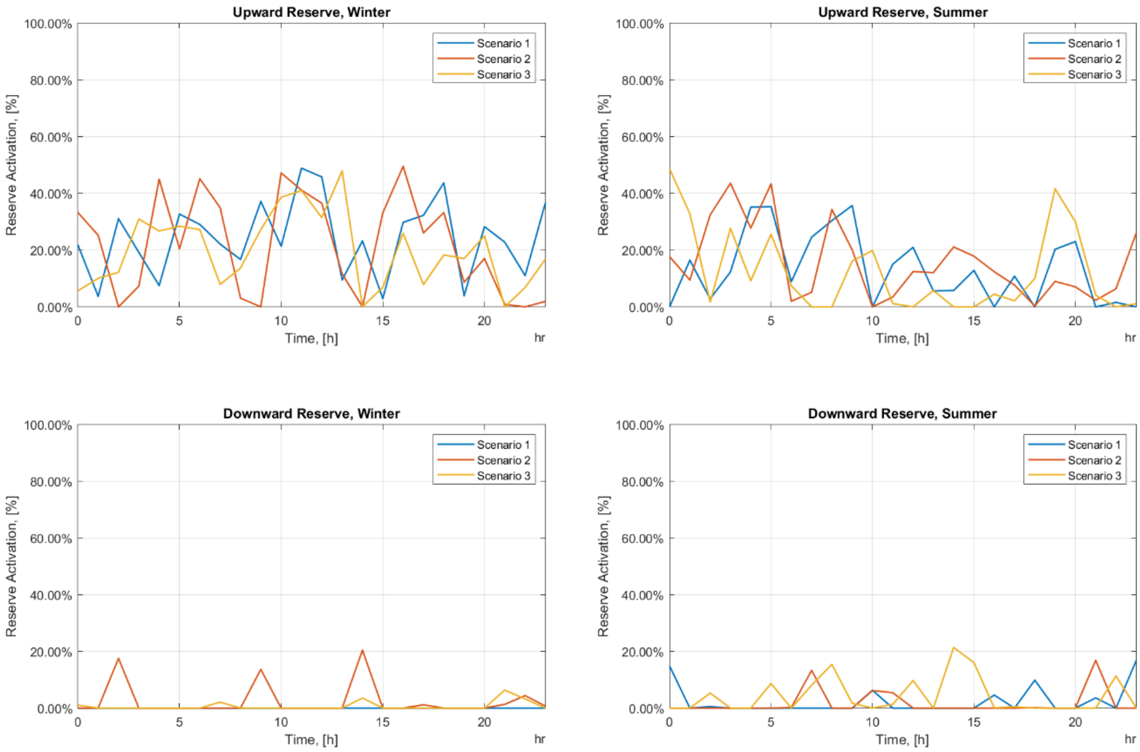


Figure 60 Task 3.3. Secondary reserve activation ratio, year 2020.

5.3.4. Key Performance Indicators

In this subsection are presented the KPIs obtained in Task 3.3 for the “Koprivnica” and “IEEE” case studies. In addition to the KPIs related to the ESSO, detailed information regarding technical and environmental KPIs is also provided.

5.3.4.1. Koprivnica Case Study

In the Koprivnica case study it was considered that the ESSO had an investment budget of 6.00 M€. The interest rate was considered to be 2.00%, and it was assumed that the technology of the battery ESSs to be installed is Li-ion. It was assumed that the maximum installable ESS capacity per node is 2.50 MVAh, related to the space available at the primary substations for the installation of the shared ESS units.

Investment Plan, Estimated Profit, and Cash Flows

Table XXVIII shows the investment plan in shared ESSs to be installed at the interface nodes between TN and ADNs participating in the coordination scheme.

Table XXVIII Task 3.3. Case study Koprivnica. Investment plan in shared ESSs

ADN Node	Type	2020	2030	2040	2050
29	S, [MVA]	0.00	10.00	0.00	10.00
	E, [MVAh]	0.00	2.50	0.00	2.50
1	S, [MVA]	0.00	10.00	0.00	10.00
	E, [MVAh]	0.00	2.50	0.00	2.50
19	S, [MVA]	0.00	10.00	0.00	10.00
	E, [MVAh]	0.00	2.50	0.00	2.50
55	S, [MVA]	0.00	10.00	0.00	10.00
	E, [MVAh]	0.00	2.50	0.00	2.50
5	S, [MVA]	1.47	8.53	1.47	8.53
	E, [MVAh]	0.37	2.13	0.37	2.13
68	S, [MVA]	0.00	10.00	0.00	10.00
	E, [MVAh]	0.00	2.50	0.00	2.50

As it is possible to see from Table XXVIII, the preferred years for investment are 2030 and 2050. Relatively small ESS units are also installed in the years 2020 and 2040 in node 5. The ESSO maximizes the investment in years 2030 and 2050, maximizing the installed capacity per node. It is important to note that it was considered that the ESSs have a calendar lifetime of 20 years.

The estimated profit of the ESSO is 38.55 M€, with an investment of 5.02 M€, NPV. Figure 61 shows the estimated cash flows from the investment in shared ESSs and the cumulative profit, in Net Present Value (NPV). It is important to note that the yearly cash flows were extrapolated from the simulation years (2020, 2030, 2040, and 2050).

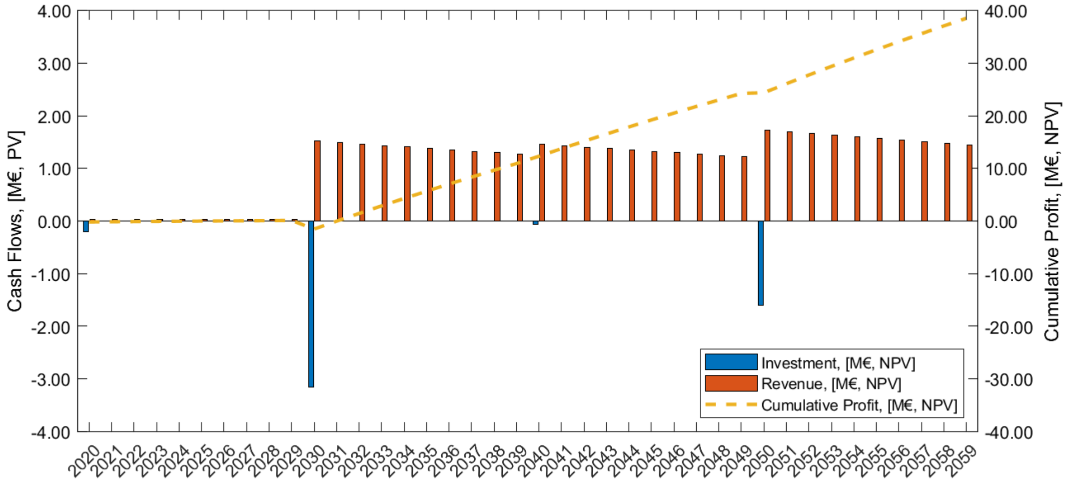


Figure 61 Task 3.3. Case study Koprivnica. ESSO's estimated cash flows.

As it is possible to see from Figure 61, ESSO's profits decrease after the years where the investments in are performed (2020, 2030, 2040, and 2050). This fact can be explained by the actualization of the cash flows, and by the degradation of the ESSs' energy capacity -- which leads to lower profits.

Voltage Magnitude

Table XXIX shows the expected maximum and minimum voltage magnitude per network, year, and day, for the BaU and ATTEST scenarios. Voltage magnitude values are shown as expected values, i.e., as the weighted sum of the voltage magnitude values considering the probability of occurrence of each scenario.

Table XXIX Task 3.3. Case study Koprivnica. Expected maximum and minimum voltage magnitude

			2020		2030		2040		2050	
Network	Control	Voltage KPI	Winter	Summ.	Winter	Summ.	Winter	Summ.	Winter	Summ.
TN	BaU	Max. mag., [p.u.]	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10
		Min. Mag., [p.u.]	1.07	1.07	1.06	1.07	1.06	1.06	1.04	1.04
	ATTEST	Max. mag., [p.u.]	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10
		Min. Mag., [p.u.]	0.98	0.99	0.98	0.98	0.97	0.98	1.02	0.98
ADN Node 29	Bau	Max. mag., [p.u.]	1.06	1.05	1.06	1.05	1.06	1.05	1.06	1.05
		Min. Mag., [p.u.]	1.00	0.99	1.00	0.99	0.99	0.98	0.97	0.96
	ATTEST	Max. mag., [p.u.]	1.09	1.10	1.09	1.09	1.09	1.10	1.10	1.09
		Min. Mag., [p.u.]	0.94	0.94	0.94	0.94	0.95	0.94	1.01	0.96
ADN Node 1	Bau	Max. mag., [p.u.]	1.06	1.06	1.06	1.06	1.06	1.06	1.06	1.06
		Min. Mag., [p.u.]	1.02	1.02	1.01	1.02	1.01	1.01	0.99	1.00
	ATTEST	Max. mag., [p.u.]	1.09	1.10	1.09	1.09	1.09	1.10	1.09	1.09
		Min. Mag., [p.u.]	0.95	0.95	0.95	0.95	0.95	0.95	0.96	0.96
ADN Node 19	Bau	Max. mag., [p.u.]	1.05	1.05	1.07	1.07	1.07	1.07	1.08	1.08
		Min. Mag., [p.u.]	1.05	1.05	1.05	1.05	1.04	1.04	1.04	1.04
	ATTEST	Max. mag., [p.u.]	1.10	1.10	1.09	1.09	1.09	1.09	1.09	1.09
		Min. Mag., [p.u.]	0.95	0.95	0.95	0.95	0.94	0.94	0.94	0.94
ADN Node 55	Bau	Max. mag., [p.u.]	1.01	1.01	1.00	1.01	1.01	1.01	1.02	1.01
		Min. Mag., [p.u.]	0.98	0.98	0.97	0.97	0.97	0.97	0.96	0.96
	ATTEST	Max. mag., [p.u.]	1.10	1.10	1.09	1.09	1.09	1.09	1.09	1.09
		Min. Mag., [p.u.]	0.97	0.98	0.97	0.97	0.97	0.98	0.96	0.97
ADN Node 5	Bau	Max. mag., [p.u.]	1.01	1.01	1.01	1.00	1.01	1.00	1.00	1.00
		Min. Mag., [p.u.]	0.99	0.99	0.98	0.98	0.98	0.98	0.97	0.97
	ATTEST	Max. mag., [p.u.]	1.10	1.10	1.09	1.09	1.09	1.10	1.09	1.10
		Min. Mag., [p.u.]	0.95	0.98	0.94	0.99	0.96	0.95	0.95	0.96
ADN Node 68	Bau	Max. mag., [p.u.]	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
		Min. Mag., [p.u.]	0.96	0.97	0.95	0.96	0.95	0.96	0.96	0.96
	ATTEST	Max. mag., [p.u.]	1.10	1.10	1.09	1.09	1.09	1.10	1.09	1.10
		Min. Mag., [p.u.]	0.97	0.98	0.97	0.97	0.97	0.97	0.95	0.96

From Table XXIX it is possible to see that no voltage magnitude violations were obtained, for all of the networks, representative years and days, for both the BaU and ATTEST scenarios.

Branch Loading

Table XXX shows the expected maximum branch loading per network, year, and day, for the BaU and ATTEST scenarios. Branch loading values are shown as a percentage of the admissible current in the branch. Furthermore, the values shown are expected values, i.e., as the weighted sum of the loading values considering the probability of occurrence of each scenario.

Table XXX Task 3.3. Case study Koprivnica. Expected maximum branch loading

		2020		2030		2040		2050	
Network	Control	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer
TN	BaU	67.85%	70.84%	76.15%	79.06%	85.60%	88.98%	94.52%	86.92%
	ATTEST	99.36%	94.97%	99.52%	99.51%	99.49%	99.58%	100.00%	100.00%
ADN Node 29	BaU	97.75%	95.00%	97.15%	89.15%	98.80%	93.73%	99.98%	98.08%
	ATTEST	100.00%	99.95%	97.57%	96.54%	98.37%	99.02%	99.05%	97.27%
ADN Node 1	BaU	90.47%	90.97%	98.21%	96.59%	98.78%	97.38%	97.35%	97.85%
	ATTEST	99.99%	100.00%	99.27%	100.00%	99.89%	99.87%	99.14%	99.68%
ADN Node 19	BaU	34.49%	34.49%	45.13%	45.13%	49.44%	49.44%	65.08%	65.08%
	ATTEST	83.50%	83.61%	84.42%	84.91%	88.63%	99.81%	92.97%	95.73%
ADN Node 55	BaU	65.42%	62.67%	80.69%	74.52%	86.47%	80.11%	97.94%	93.42%
	ATTEST	90.09%	94.70%	90.54%	96.92%	90.44%	89.98%	97.09%	91.10%
ADN Node 5	BaU	38.38%	31.77%	40.94%	37.80%	45.76%	42.70%	60.29%	56.76%
	ATTEST	89.64%	90.11%	94.63%	89.56%	93.89%	95.23%	93.55%	93.57%
ADN Node 68	BaU	87.63%	89.51%	87.06%	90.42%	87.39%	90.66%	83.93%	90.90%
	ATTEST	88.53%	89.67%	89.40%	90.31%	90.75%	90.02%	96.56%	99.23%

From Table XXX it is possible to see that no branch overloads were obtained, for all of the networks, representative years, and days, for both the BaU and ATTEST scenarios. However, although no branch overloads were registered, for some of the networks and representative days, the maximum line loading reaches 100.00%. Furthermore, it is also possible to see that the maximum branch loading tends to increase with the ATTEST solution, especially in those networks where the maximum branch loading is relatively low. Maximum branch loading tends to be maintained for those networks that are already operating close to the limits, e.g. ADNs connected to nodes 29, 1, and 68 of the TN. It is also possible to see that the maximum branch loading tends to increase over the planning period. This can be explained by the growing amount of flexibility, and growing interactions between TSO and DSOs to take advantage of this flexibility.

RES and Load Curtailment

Table XXXI shows the RES and load curtailment obtained, for all of the networks, representative years, and days, for both the BaU and ATTEST scenarios. RES and load curtailment values are shown as expected values, i.e., as the weighted sum of the curtailment values considering the probability of occurrence of each scenario.

Table XXXI Task 3.3. Case study Koprivnica. RES and load curtailment

			2020		2030		2040		2050	
Network	Control	Curtailment	Winter	Summ.	Winter	Summ.	Winter	Summ.	Winter	Summ.
TN	BaU	RES, [MWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Load, [MWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	ATTEST	RES, [MWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Load, [MWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ADN Node 29	BaU	RES, [MWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Load, [MWh]	0.38	7.72	0.00	5.93	2.65	17.72	17.65	51.96
	ATTEST	RES, [MWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Load, [MWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ADN Node 1	BaU	RES, [MWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Load, [MWh]	0.00	0.00	3.57	2.82	10.69	9.01	4.50	11.51
	ATTEST	RES, [MWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Load, [MWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ADN Node 19	BaU	RES, [MWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Load, [MWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	ATTEST	RES, [MWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Load, [MWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ADN Node 55	BaU	RES, [MWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.02
		Load, [MWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	ATTEST	RES, [MWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Load, [MWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ADN Node 5	BaU	RES, [MWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Load, [MWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	ATTEST	RES, [MWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Load, [MWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ADN Node 68	BaU	RES, [MWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Load, [MWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	ATTEST	RES, [MWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Load, [MWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

As it is possible to see from Table XXXI, a significant amount of load curtailment is required in the ADNs connected to nodes 29 and 1 of the TN with the BaU solution. For the ADN connected to node 29, 7 out of the 8 representative days simulated require load curtailment. For the ADN connected to node 1, curtailment is required from 2030 onwards. It is also possible to see that the amount of load curtailment tends to increase over the years. Furthermore, it is also possible to see that RES curtailment is required in the ADN connected to node 55, in 2050. No load or RES curtailments are required with the ATTEST solution.

Network Losses

Figure 62 shows the expected power losses per network, year, and representative day for the BaU and ATTEST scenarios. Network losses are shown as expected values, i.e., as the weighted sum of the loss values considering the probability of occurrence of each scenario.

As it is possible to see from Figure 62, network losses tend to slightly increase with the ATTEST solution towards the end of the planning period. In earlier years, there is not a clear pattern, increasing in some representative days, and decreasing in others. This can be explained by the fact that with the ATTEST load and RES curtailment are totally avoided, while keeping the voltage magnitude and branch power flows within the admissible limits. Table of the annex section shows the expected network losses KPIs for the Koprivnica case study in detail.

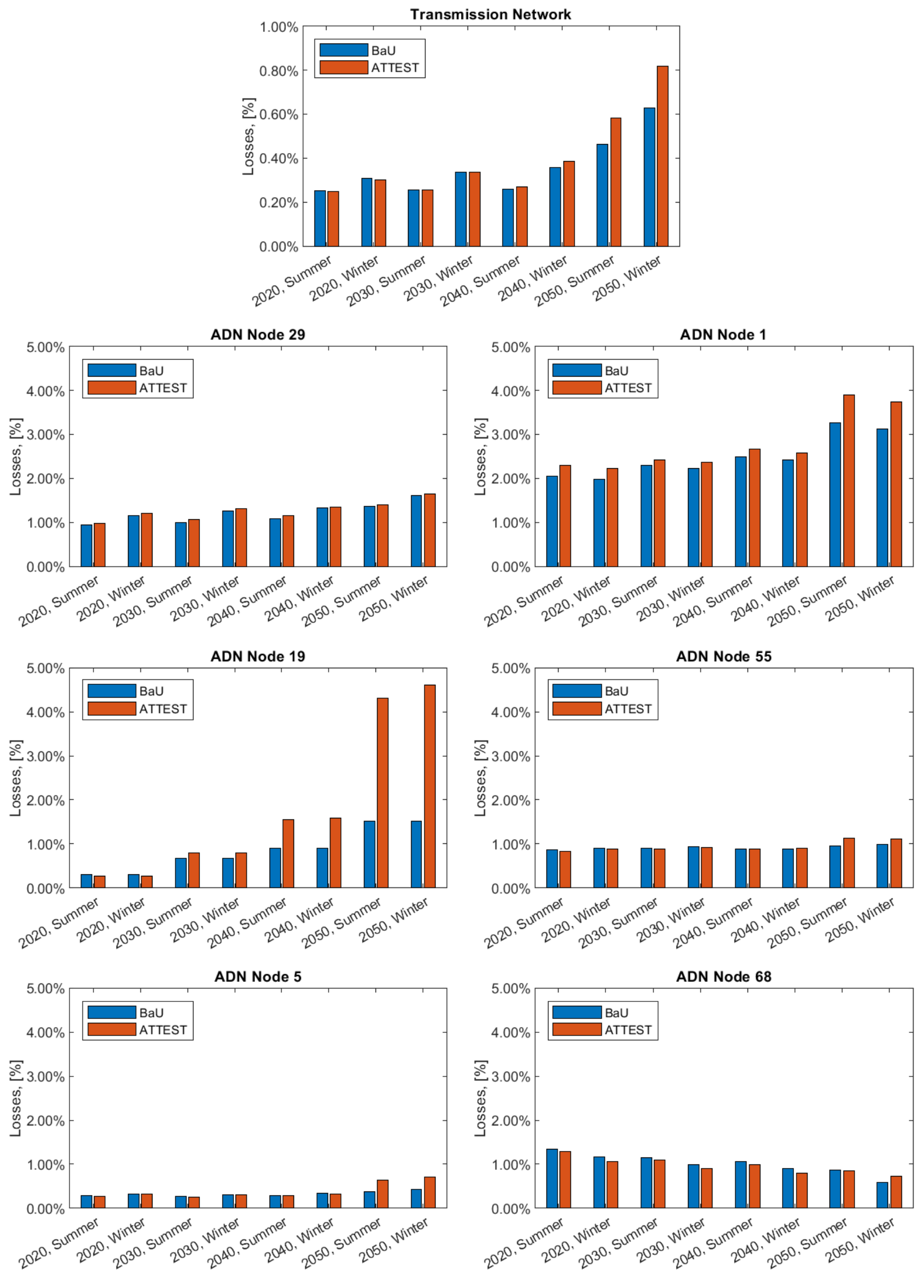


Figure 62 Task 3.3. Case study Koprivnica. Expected active power losses per network, year, and representative day.

RES Share

Figure 63 shows the expected RES share per network, year, and representative day, for the BaU and ATTEST scenarios. The RES share for the ADNs was calculated considering the generation mix of the energy imported from the TN.

As it is possible to see from Figure 63, RES penetration at the TN level reaches around 20.00% in 2050. The ADN with the highest RES penetration level is the ADN connected to node 19 of the TN, where the RES penetration level reaches around 85.00% in 2050. Furthermore, it can be also observed that for some representative days, RES share decreases slightly with the ATTEST solution. This can be explained by the fact that with the ATTEST solution, no load curtailment is required (higher conventional generation), leading to a lower RES penetration level when expressed in relative terms. Table LX of the annex section shows the expected RES share KPIs for the Koprivnica case study in detail.

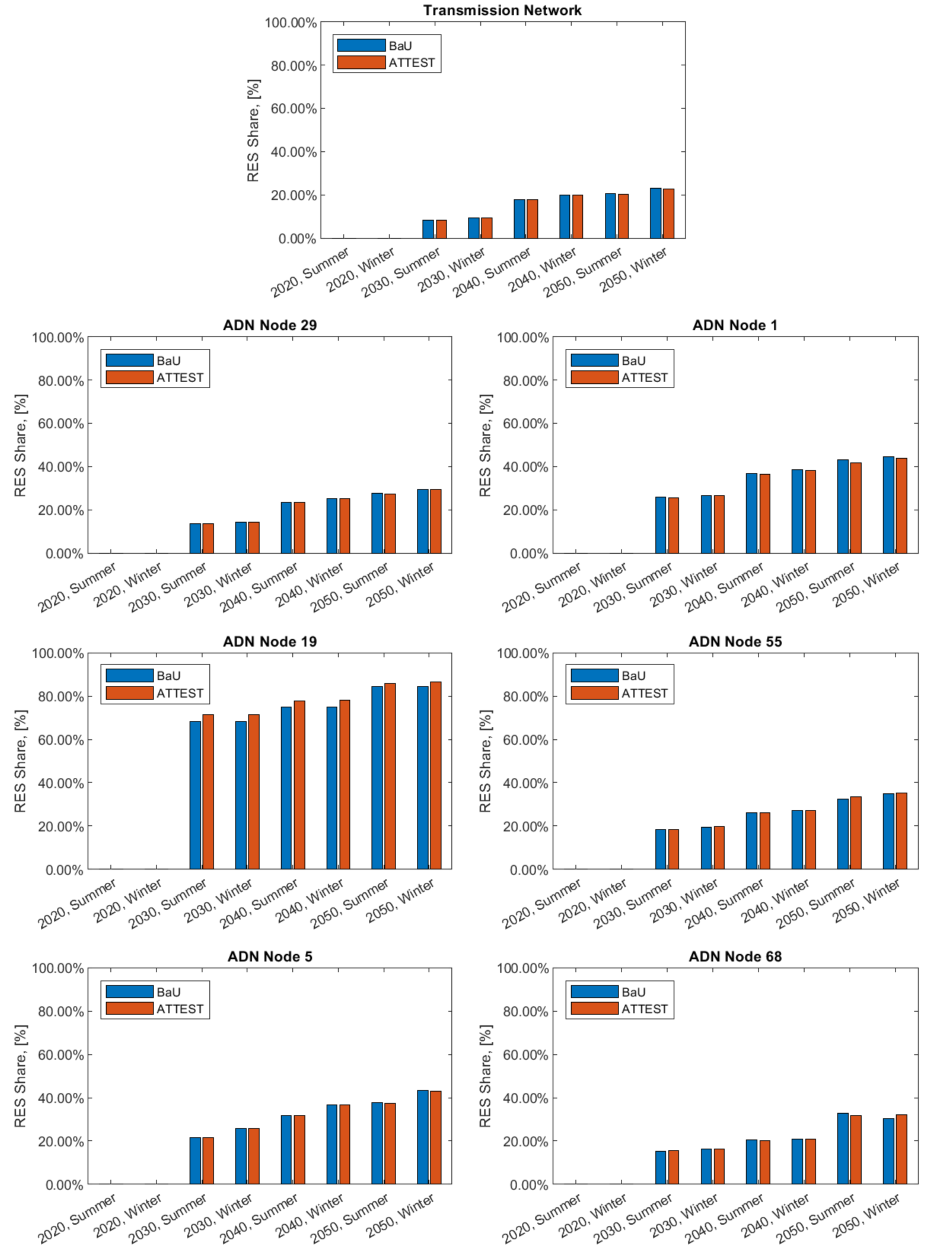


Figure 63 Task 3.3. Case study Koprivnica. Expected RES share per network, year, and representative day.

Generation Costs

Figure 64 shows the expected total daily costs with conventional generation for the Koprivnica case study. Table XXXII Task 3.3. Case study IEEE. Summary of daily generation costs lists in addition the expected reduction obtained with the ATTEST solution. Figure 190 of the annex section provides expected hourly cost data per year and representative day.

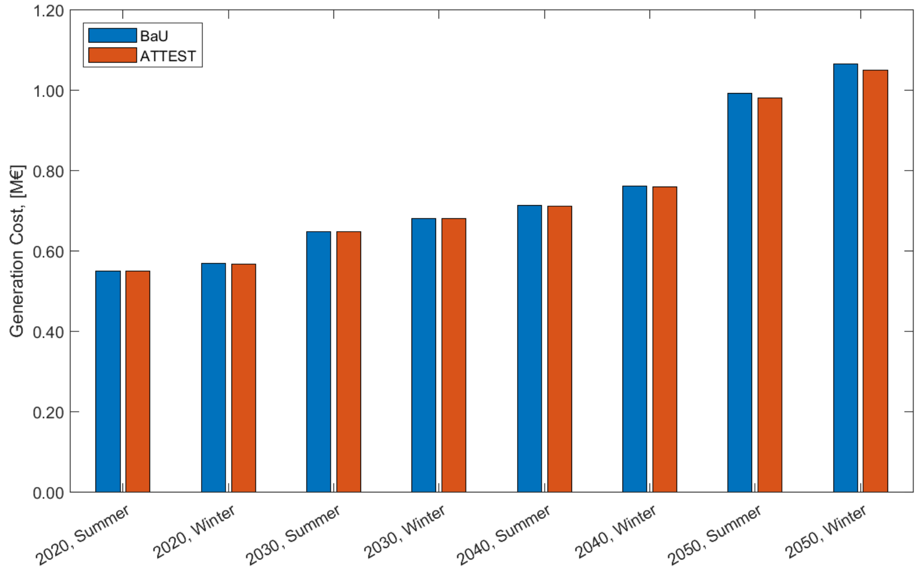


Figure 64 Task 3.3. Case study Koprivnica. Total generation cost per year and representative day.

Table XXXII Task 3.3. Case study IEEE. Summary of daily generation costs

		2020		2030		2040		2050	
Control	Cost	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer
BaU	Cost, [k€]	568.30	549.76	680.77	648.68	762.40	713.05	1066.18	993.18
ATTEST	Cost, [k€]	567.68	549.17	679.77	647.88	759.71	711.28	1050.27	981.13
	Reduction, [%]	0.11%	0.11%	0.15%	0.12%	0.35%	0.25%	1.49%	1.21%

As it is possible to see from Figure 64 and Table XXXII Task 3.3. Case study IEEE. Summary of daily generation costs, generation costs are always lower with the ATTEST solution for all representative days of the planning horizon. It can be highlighted that with the ATTEST solution, all of the load is supplied, leading to higher generation levels. This is an interesting result, as it shows that with the ATTEST solution, all of the load is supplied in a safe manner, while simultaneously achieving lower costs with conventional generation.

Avoided Emissions

Greenhouse gas (GHG) emissions were estimated considering a total life cycle emission factor of 540.00 kg CO_2e/MWh for conventional generators (corresponding to gas production, Croatia), and an emission factor of 29.00 kg CO_2e/MWh for PV generators (solar production, Croatia) [12]. Figure 65 shows the expected GHG emissions per year and representative day. Table XXXIII Task 3.3. Case study Koprivnica. Summary of daily GHG emissions lists in addition the expected reduction obtained with the ATTEST solution. Figure 191 of the annex section provides expected hourly GHG emissions per year and representative day.

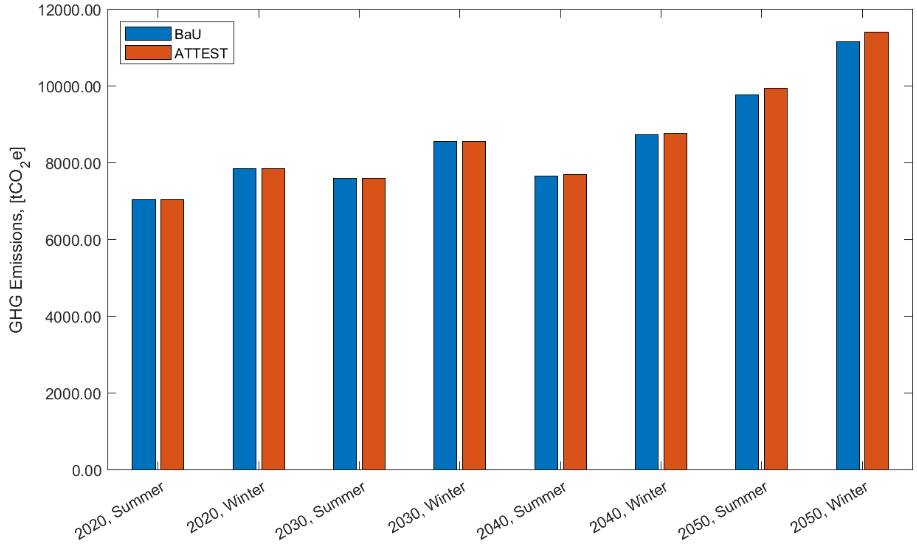


Figure 65 Task 3.3. Case study Koprivnica. GHG emissions per year and representative day.

Table XXXIII Task 3.3. Case study Koprivnica. Summary of daily GHG emissions

		2020		2030		2040		2050	
Control	Emissions	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer
BaU	Emissions, [tCO_2e]	8054.10	7035.79	8770.38	7803.20	8937.44	7867.16	11349.32	9978.42
ATTEST	Emissions, [tCO_2e]	8045.22	7226.21	8767.78	7799.71	8970.52	7886.12	11589.05	10132.02
	Reduction, [%]	0.11%	-2.71%	0.03%	0.04%	-0.37%	-0.24%	-2.11%	-1.54%

As it is possible to see from Figure 65 and Table XXXIII Task 3.3. Case study Koprivnica. Summary of daily GHG emissions, GHG emissions tend to increase slightly with the ATTEST solution towards the end of the planning period. This can, once again, be explained by the fact that with the ATTEST solution all of the load is supplied, leading to higher conventional generation values, and therefore higher GHG emissions.

Summary and Conclusions

In this subsection are presented the KPIs obtained for Task 3.3 – optimization tool for planning TSO/DSO shared technologies, for case study "Koprivnica". It can be seen that with an investment budget of 6.00 M€, the ESSO's would profit 38.55 M€ NPV, showing that this might be an interesting investment to a private investor.

In this case study it is analysed part of the Croatian network, comprising of the Koprivnica region. One of the main conclusions from this case study is that a high level of load cannot be supplied with the BaU solution. Furthermore, a relatively small amount of RES curtailment is also required. This means that with the BaU solution, significant investments in network reinforcements would be required, to fulfil the voltage magnitude and branch power flow limits. With the ATTEST solution, all of the load is supplied, and no RES curtailment is required, meaning that investments in network reinforcements could be deferred. Furthermore, conventional generation costs are also lower for the operators, even with a higher load being supplied. It has been also observed that GHG emissions tend to increase slightly, specially towards the end of the planning period, which can be explained by the higher conventional generation values.

5.3.4.2. IEEE Case Study

In the IEEE case study, it was considered that the ESSO had an investment budget of 5.00 M€. Similarly, to the Koprivnica case study, it was assumed an interest rate of 2.00%, and that the technology of the battery ESSs to be installed is Li-ion. It was also assumed a maximum installable capacity of 2.50 MVAh per interface node.

Investment Plan, Estimated Profit, and Cash Flows

Table XXXIV Task 3.3. Case study IEEE. Investment plan in shared ESSs shows the investment plan in shared ESSs to be installed at the interface nodes between TN and ADNs participating in the coordination scheme.

Table XXXIV Task 3.3. Case study IEEE. Investment plan in shared ESSs

ADN Node	Type	2020	2030	2040	2050
24	S, [MVA]	1.41	0.00	10.00	0.00
	E, [MVAh]	0.35	0.00	2.50	0.00
16	S, [MVA]	8.69	0.00	10.00	0.00
	E, [MVAh]	2.17	0.00	2.50	0.00
18	S, [MVA]	4.59	0.00	10.00	0.00
	E, [MVAh]	1.15	0.00	2.50	0.00
26	S, [MVA]	3.06	0.00	10.00	0.00
	E, [MVAh]	0.76	0.00	2.50	0.00
3	S, [MVA]	1.51	0.00	10.00	0.00
	E, [MVAh]	0.38	0.00	2.50	0.00

As it is possible to see from Table XXXIV, the preferred years for investment are 2020 and 2040. Furthermore, it can be also observed that in 2040 the ESSO maximizes the installed capacity of the shared ESSs. This can be explained by the fact that the revenues obtained from participating in the energy and secondary reserve markets are maximized by a balance between investing towards the end of the planning period, when the revenues from participating in the energy and secondary reserve markets are higher, and maximizing the ESS units utilization – with a 20 year calendar lifetime.

The estimated profit of the ESSO is 21.48 M€, with an investment of 5.00 M€, NPV. Unlike the previous case study, here the ESSO uses all of the budget available for the installation of the shared ESSs. Figure 66 shows the estimated cash flows for the investment in shared ESSs, and the cumulative profit, in Net Present Value (NPV), for the planning horizon.

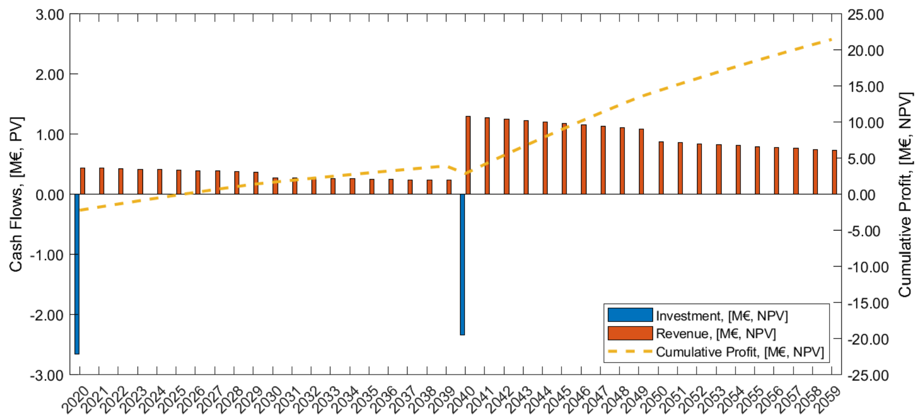


Figure 66 Task 3.3. Case study IEEE. ESSO's estimated cash flows.

Voltage Magnitude

Figure 67 shows the expected number of voltage violations per network, year, and representative day for the BaU and ATTEST scenarios. Figure 68 and Figure 69 show the maximum and minimum expected voltage magnitudes per network, year, and representative day for the BaU and ATTEST scenarios.

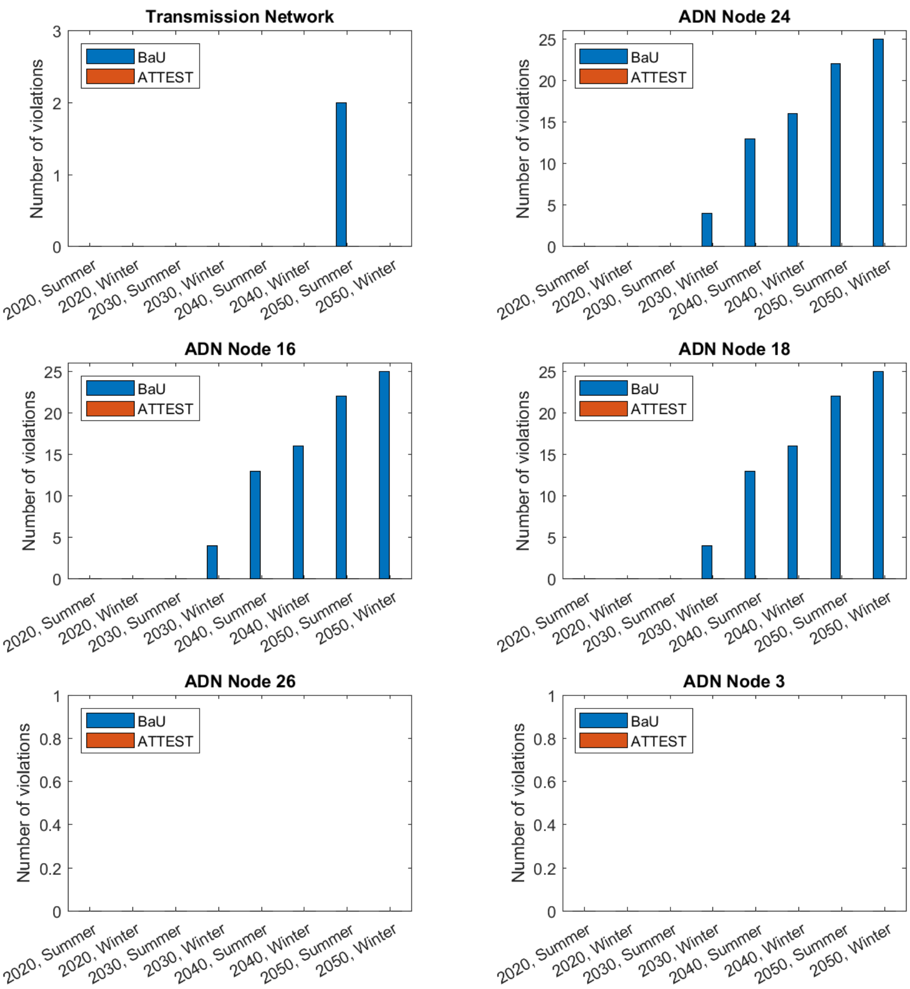


Figure 67 Task 3.3. Case study IEEE. Expected number of voltage violations per network, year, and representative day.

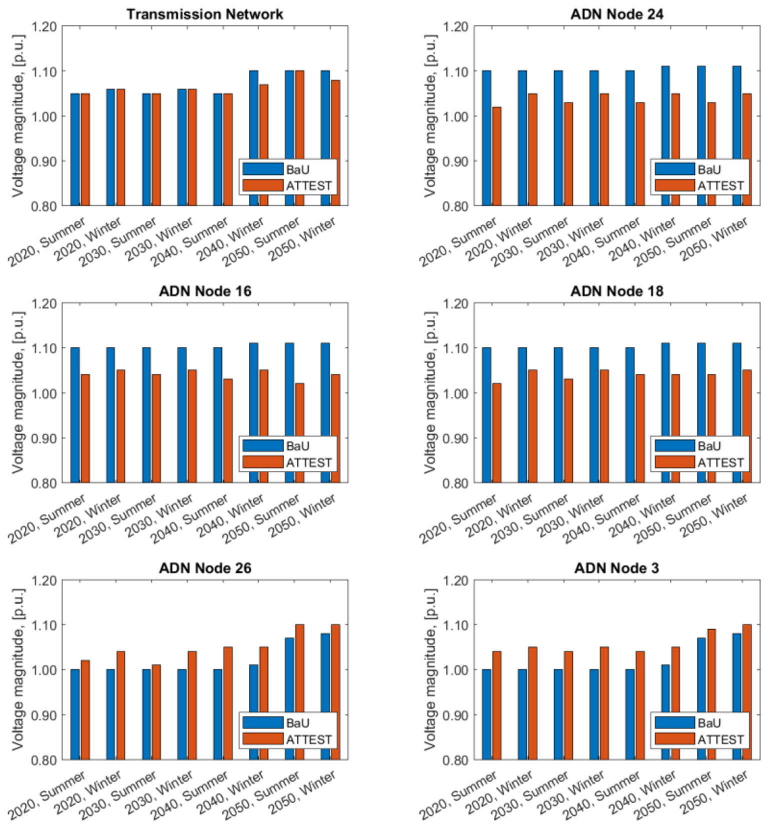


Figure 68 Task 3.3. Case study IEEE. Expected maximum voltage magnitude per network, year, and representative day.

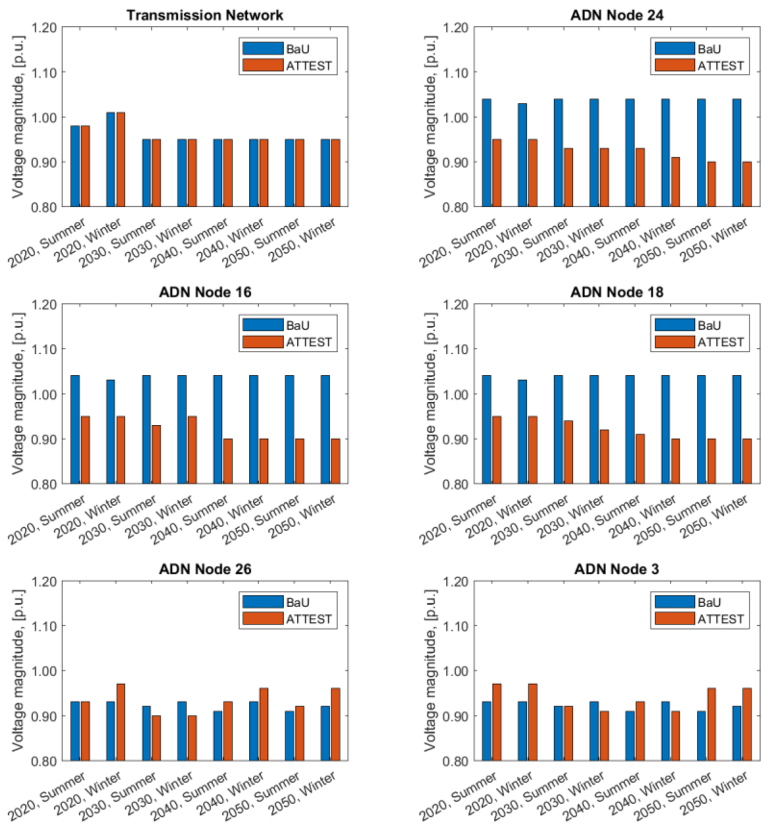


Figure 69 Task 3.3. Case study IEEE. Expected minimum voltage magnitude per network, year and representative day.

As it is possible to see from Figure 67, some of the networks comprising of this case study are highly stressed, with ADNs connected to nodes 24, 16, and 18 of the TN being especially prone to voltage violations. All of the voltage violations expected to occur in the BaU scenario are solved with the ATTEST solution. Table LXIII of the annex section shows the voltage technical KPIs for the IEEE case study in detail.

Branch Loading

Figure 70 shows the expected maximum branch loading per network, year, and representative day for the BaU and ATTEST scenarios.

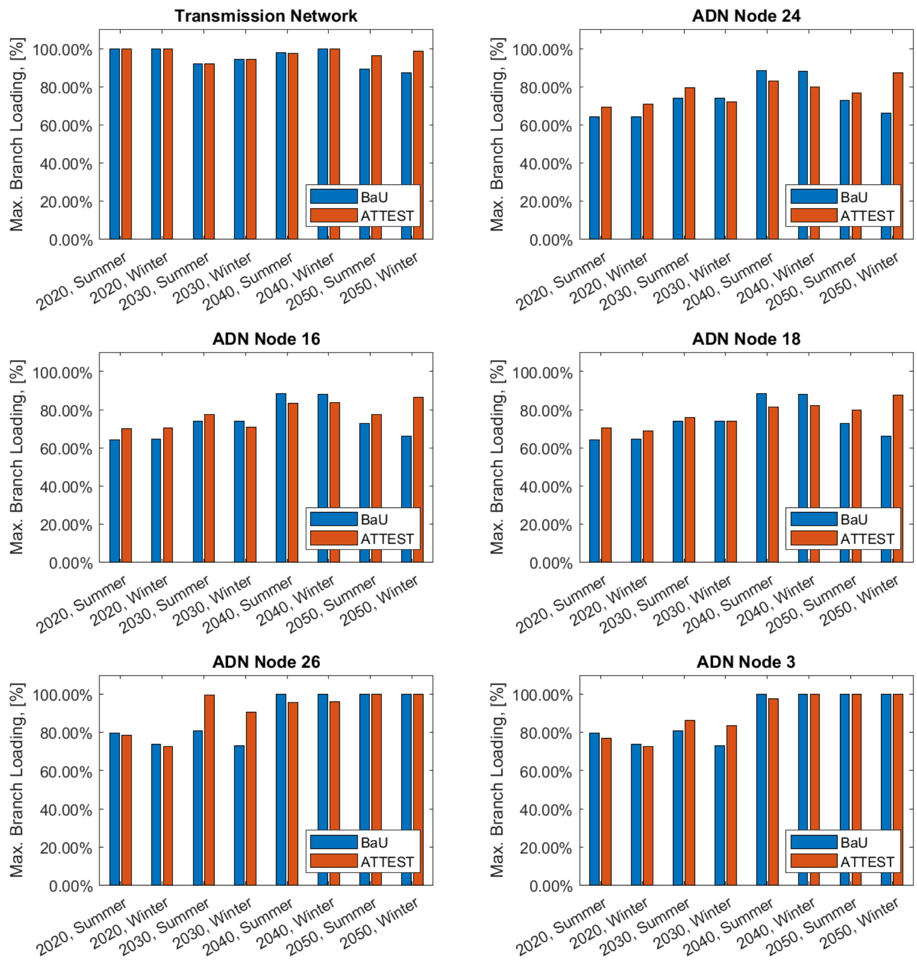


Figure 70 Task 3.3. Case study IEEE. Expected maximum branch loading per network, year and representative day.

No branch overloads were registered in the BaU and ATTEST scenarios. It can be also observed that the ADNs connected to nodes 26 and 3 of the TN reach a maximum branch loading of 100.00% in the years 2040 and 2050. In general, the ADNs participating in the coordination scheme are operating very close to their limits, either from a voltage magnitude (ADNs connected to nodes 24, 26, and 18), or branch loading (ADNs connected to nodes 26 and 3) perspective. Table LXIV of the annex section shows the branch loading KPIs for the IEEE case study in detail.

RES and Load Curtailment

Figure 71 shows the expected RES curtailment per network, year, and representative day for the BaU and ATTEST scenarios. No load curtailment was required in this case study.

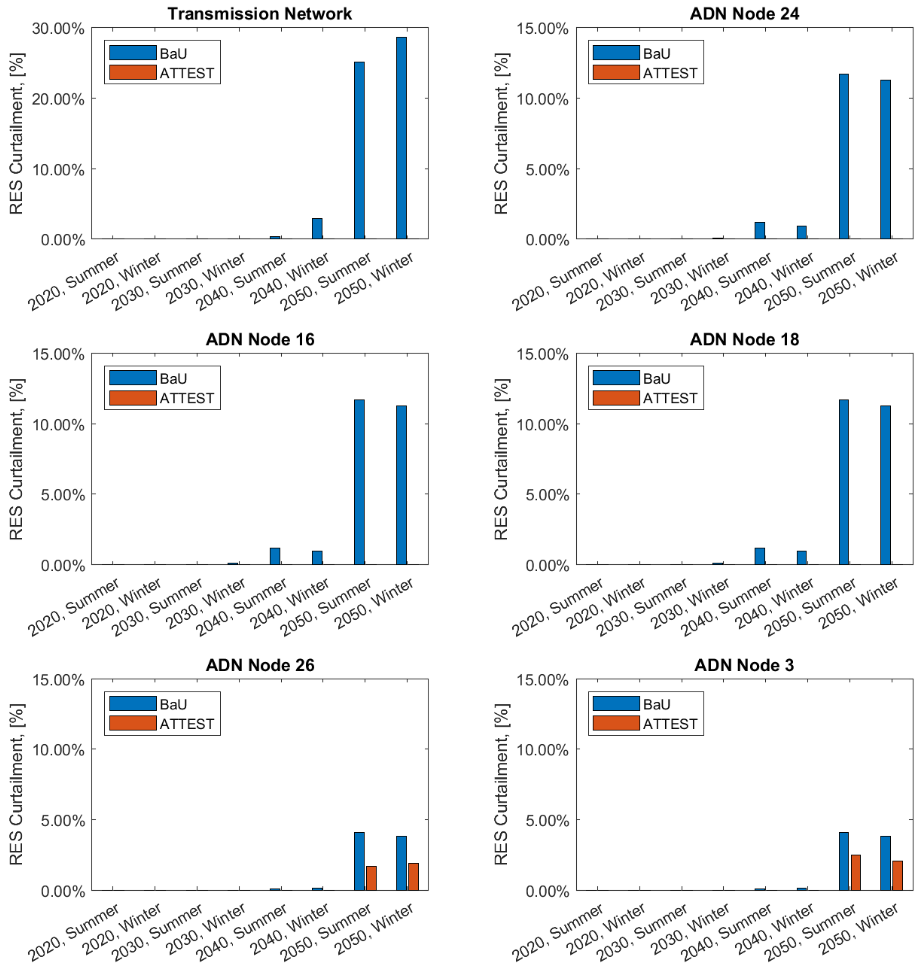


Figure 71 Task 3.3. Case study IEEE. Expected RES curtailment per network, year, and representative day.

As it possible to see from Figure 71, RES curtailment is drastically reduced with the ATTEST solution. At the TN level, RES curtailment reaches a maximum of 25.11% for the Summer day of 2050, and 28.67% for the Winter day of 2050 with the BaU solution. For the ADNs connected to nodes 24, 16, and 18 of the TN, RES curtailment reaches 11.70% for the Summer day of 2050 and 11.28% for the Winter day of 2050. With the ATTEST solution, all of the RES curtailment at the TN level, and ADNs connected to nodes 24, 16, and 18 of the TN is avoided. For the ADNs connected to node 26 and node 3 of the TN, some curtailment is still required to keep the voltage magnitude and branch loading within the admissible limits in the year 2050. For the ADN connected to node 26, RES curtailment is reduced from 4.11% to 1.70% in the Summer day of 2050, and from 3.84% to 1.92% in the Winter day of 2050. For the ADN connected to node 3, RES curtailment is reduced from 4.11% to 2.48% in the Summer day of 2050, and from 3.84% to 2.07% in the Winter day of 2050.

Table XXXV provides a summary of the total RES curtailment in the ADNs connected to nodes 26 and 3, and the RES curtailment reduction obtained with the ATTEST solution. Table of the annex section shows the RES curtailment technical KPIs for the IEEE case study in detail.

Table XXXV Task 3.3. Case study IEEE. RES curtailment summary

			2020		2030		2040		2050	
Network	Control	Curtailment	Winter	Summ.	Winter	Summ.	Winter	Summ.	Winter	Summ.
ADN Node 26	BaU	Curt., [MWh]	0.00	0.00	0.00	0.00	0.04	0.03	3.40	3.64
	ATTEST	Curt., [MWh]	0.00	0.00	0.00	0.00	0.00	0.00	1.70	1.50
		Reduc., [%]	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%	49.99%	58.75%
ADN Node 3	BaU	Curt., [MWh]	0.00	0.00	0.00	0.00	0.04	0.03	3.40	3.64
	ATTEST	Curt., [MWh]	0.00	0.00	0.00	0.00	0.00	0.00	1.83	2.19
		Reduc., [%]	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%	46.05%	39.70%

Network Losses

Figure 72 shows the expected power losses per network, year, and representative day for the BaU and ATTEST scenarios.

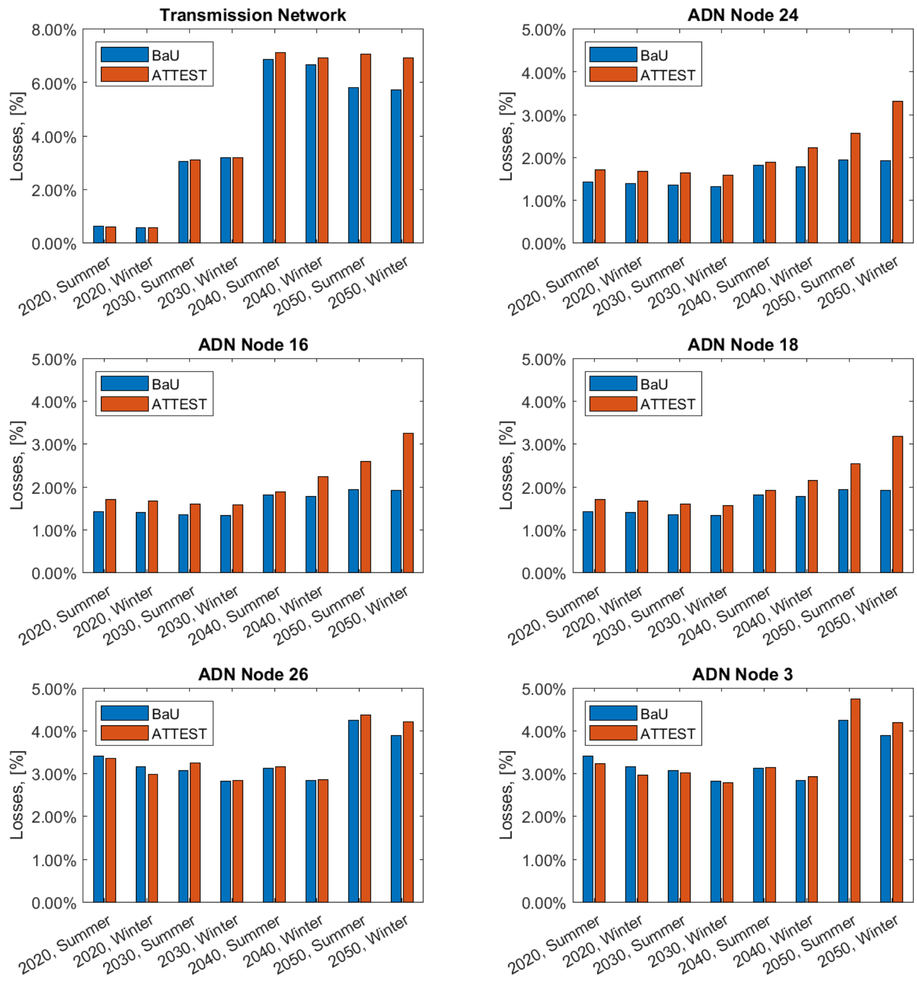


Figure 72 Task 3.3. Case study IEEE. Expected active power losses per network, year, and representative day.

As it is possible to see from Figure 72, network losses tend to slightly increase with the ATTEST solution towards the end of the planning period. In earlier years, there is not a clear pattern, increasing in some representative days, and decreasing in others. This can be explained by the fact that the ATTEST solution maximizes the penetration of RES generation (minimizing RES curtailment) while avoiding voltage violations and branch congestions, therefore operating the network closer to its limits. Table LXVI of the annex section shows the expected network losses KPIs for the IEEE case study in detail.

RES Share

Figure 73 shows the expected RES share per network, year, and representative day for the BaU and ATTEST scenarios. For the DNs, the RES share was calculated considering the generation mix of the energy imported from the TN.

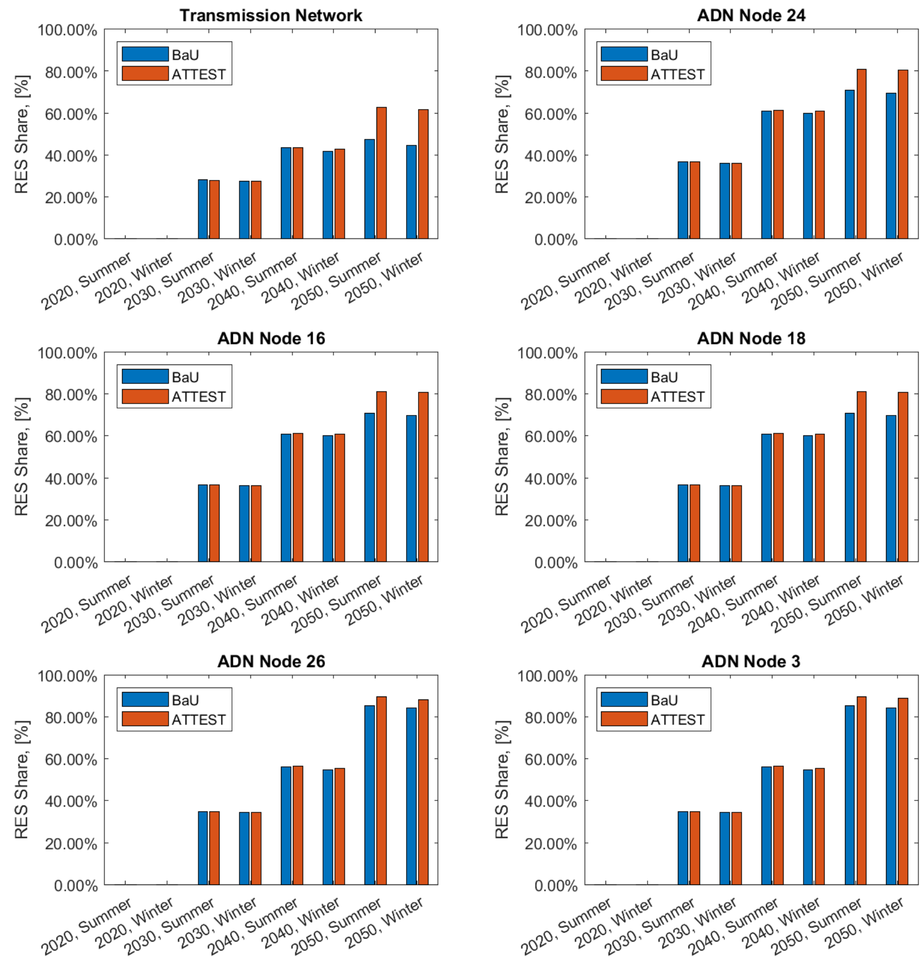


Figure 73 Task 3.3. Case study IEEE. Expected RES share per network, year, and representative day.

As it is possible to see from Figure 73, RES penetration increases significantly with the ATTEST solution, and for all networks participating in the coordination scheme. From the figure, it is possible to see that in year 2050 RES penetration exceeds 80.00% in all of the ADNs participating in the coordination scheme, and 60.00% in the TN. Table XXXVI provides a summary of the total RES generation, and the RES share increase obtained with the ATTEST solution. Table LXVII of the annex section shows the RES generation per network and representative day for the IEEE case study in detail.

Table XXXVI Task 3.3. Case study IEEE. RES penetration summary

			2020		2030		2040		2050	
Network	Control	RES Gen.	Winter	Summ.	Winter	Summ.	Winter	Summ.	Winter	Summ.
TN	BaU	Gen., [MWh]	0.00	0.00	884.88	884.88	1718.54	1763.97	2524.78	2650.77
	ATTEST	Gen., [MWh]	0.00	0.00	884.88	884.88	1769.76	1769.76	3539.52	3539.52
		Increase, [%]	N/A	N/A	0.00%	0.00%	2.98%	0.33%	40.19%	33.53%
ADN Node 24	BaU	Gen., [MWh]	0.00	0.00	70.53	72.39	133.25	137.28	177.58	182.95
	ATTEST	Gen., [MWh]	0.00	0.00	70.67	72.56	136.17	138.65	212.09	214.45
		Increase, [%]	N/A	N/A	0.21%	0.23%	2.19%	1.00%	19.43%	17.22%
ADN Node 16	BaU	Gen., [MWh]	0.00	0.00	70.53	72.39	133.25	137.28	177.58	182.95
	ATTEST	Gen., [MWh]	0.00	0.00	70.72	72.57	136.16	138.64	212.11	214.44
		Increase, [%]	N/A	N/A	0.27%	0.25%	2.18%	0.99%	19.44%	17.22%
ADN Node 18	BaU	Gen., [MWh]	0.00	0.00	70.53	72.39	133.25	137.28	177.58	182.95
	ATTEST	Gen., [MWh]	0.00	0.00	70.69	72.57	136.17	138.69	212.10	214.28
		Increase, [%]	N/A	N/A	0.23%	0.24%	2.19%	1.03%	19.44%	17.13%
ADN Node 26	BaU	Gen., [MWh]	0.00	0.00	32.04	32.28	57.30	58.29	100.36	100.59
	ATTEST	Gen., [MWh]	0.00	0.00	32.09	32.36	58.54	58.65	111.45	108.62
		Increase, [%]	N/A	N/A	0.16%	0.25%	2.17%	0.61%	11.05%	7.98%
ADN Node 3	BaU	Gen., [MWh]	0.00	0.00	32.04	32.28	57.30	58.29	100.36	100.59
	ATTEST	Gen., [MWh]	0.00	0.00	32.09	32.33	58.54	58.65	108.95	107.67
		Increase, [%]	N/A	N/A	0.15%	0.17%	2.17%	0.61%	8.56%	7.03%

From Figure 73 and Table XXXVI it is possible to see that RES penetration increases for all networks, and representative days. In 2050, RES penetration in the TN increases 40.19% in the ATTEST scenario, when compared to the BaU scenario, for the Winter representative day and 33.53% for Summer. For the ADNs connected to nodes 24, 16, and 18, it increases an average of 19.44% and 17.19% for the Winter and Summer representative days, respectively, and for the ADNs connected to nodes 26 and 3 increases an average of 9.80% and 7.50% for the Winter and Summer representative days, respectively.

Generation Costs

Figure 74 shows the expected total daily costs with conventional generation costs. Table XXXVII lists in addition the expected reduction obtained with the ATTEST solution. Figure 192 of the annex section provides expected hourly cost data per year and representative day.

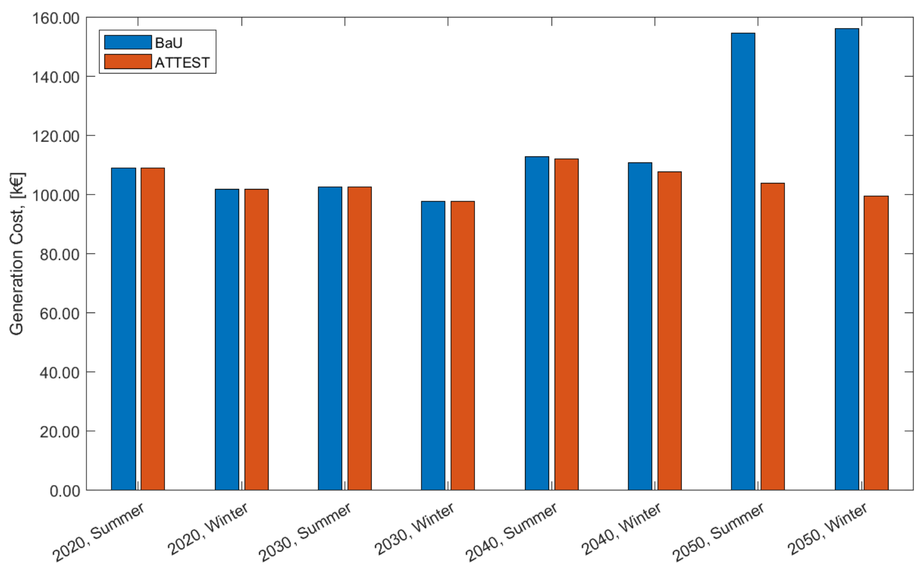


Figure 74 Task 3.3. Case study IEEE. Total generation cost per year and representative day.

Table XXXVII Task 3.3. Case study IEEE. Summary of daily generation costs

		2020		2030		2040		2050	
Control	Cost	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer
BaU	Cost, [k€]	101.81	109.04	97.82	102.55	110.81	112.81	156.18	154.76
ATTEST	Cost, [k€]	101.80	109.05	97.66	102.47	107.62	112.16	99.38	103.91
	Reduction, [%]	0.01%	-0.01%	0.16%	0.08%	2.88%	0.58%	36.37%	32.86%

As it possible to see from Table XXXVII, generation costs with the ATTEST solution are lower than with BaU solution. The cost savings are significantly high for year 2050. For the Winter representative day, the generation cost decreases 36.37%, and in Winter and 32.86% in Summer. This is a very interesting result, showing that with the proposed tool, a very large share of the RES curtailment can be avoided, which ultimately leads to a reduction of the costs with conventional generation.

From the analysis of Figure 192 it is also possible to see that towards the end of the planning period, in years 2040 and 2050, there are several periods in the middle of the day where the generation costs are null – no production from conventional generation. Therefore, it can be also concluded that by diversifying the renewable generation mix (e.g., by considering wind generation), the generation costs with conventional generation could potentially be further decreased.

Avoided Emissions

Similarly, to the Koprivnica case study, GHG emissions were estimated considering a total life cycle emission factor of 540.00 kg CO_2e/MWh for conventional generation, and an emission factor of 29.00 kg CO_2e/MWh for PV generators [12]. Figure 75 shows the expected GHG emissions per year and representative day. Table XXXVIII lists in addition the expected reduction obtained with the ATTEST solution. Figure 193 of the annex section provides expected hourly GHG emissions per year and representative day.

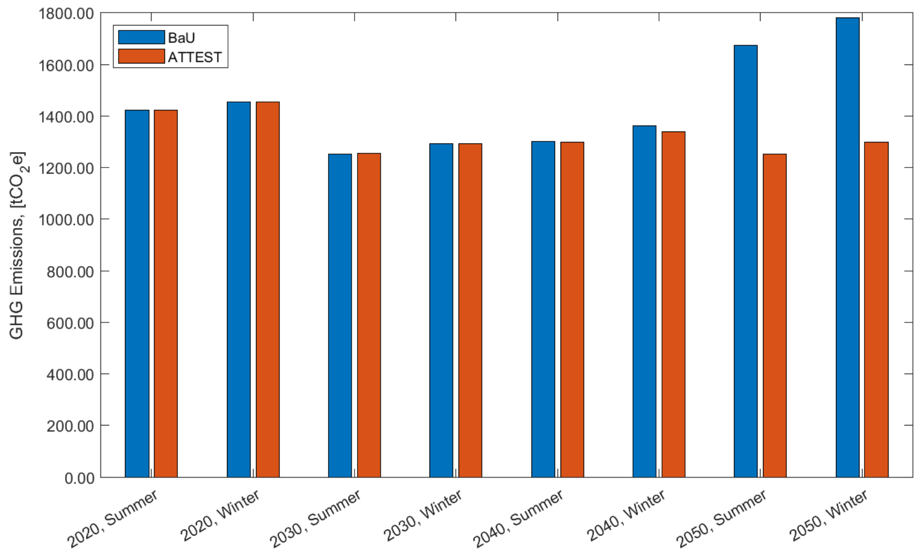


Figure 75 Task 3.3. Case study IEEE. GHG emissions per year and representative day.

Table XXXVIII Task 3.3. Case study IEEE. Summary of daily GHG emissions

		2020		2030		2040		2050	
Control	Emissions	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer
BaU	Emissions, [tCO_2e]	1454.94	1422.89	1291.86	1252.79	1360.62	1300.34	1781.29	1674.50
ATTEST	Emissions, [tCO_2e]	1455.39	1423.28	1293.86	1254.11	1338.09	1298.42	1299.42	1252.11
	Reduction, [%]	-0.03%	-0.03%	-0.15%	-0.11%	1.66%	0.15%	27.05%	25.22%

As it is possible to see from Table XXXVIII, the highest reduction in GHG emissions is obtained for year 2050. For the Winter representative day, the GHG emissions decrease 27.05%, and for Summer decrease 25.22%.

From the analysis of Figure 193, and similarly to the generation costs, it is possible to see that the GHG emissions tend to be very low in the middle of the day, due to solar PV production. Therefore, it can be concluded that a diversification of the renewable generation mix, e.g. integration of wind generation, could potentially lead to further reductions in the GHG emissions.

Summary and Conclusions

In this subsection the KPIs obtained for Task 3.3 are presented – optimization tool for planning TSO/DSO shared technologies, for case study "IEEE". It can be seen that with an investment budget of 5.00 M€, the ESSO would profit 21.48 M€ NPV, showing that this might be an interesting investment to a private investor.

Regarding technical KPIs, it can be seen that the ATTEST solution provides very interesting results. It is shown that without the ATTEST solution, voltage violations are expected to occur at the TN-level and several of the ADNs participating in the TSO-DSO coordination scheme and that the number and magnitude of these violations are expected to increase towards the end of the planning period. No voltage violation problems are expected to occur with the ATTEST solution. A similar situation occurs for RES curtailment. Without the ATTEST solution, in 2050, it can be seen that at the TN-level RES curtailment reaches 25.11% for the Summer representative day, and 28.67% for Winter. No curtailment is required with the ATTEST solution. This ultimately leads to a significant reduction in conventional generation, and therefore a reduction in costs and GHG emissions. In 2050, conventional generation costs decrease of 36.37% in Winter, and 32.82% in Summer. It can be also observed that the higher penetration of RES generation in the network leads to a slight increase of the power losses towards the end of the planning period – especially 2050. This can be explained by the fact that the higher RES penetration leads to the operation of the network closer to its limits – while simultaneously avoiding voltage and branch overloading problems.

Regarding the environmental KPIs, it can be seen that the RES share in the generation mix increases for all networks participating in the TSO-DSO coordination scheme. At the TN level, in 2050, RES penetration reaches 62.78% in Summer, and 61.82% in Winter. For ADNs, RES penetration exceeds 80.00% in the year 2050. Regarding GHG emissions, it was shown that with the ATTEST solution it can be reached a reduction of GHG emissions between 25.22% in Summer and 27.05% in Winter.

From the analysis of the results, it can be seen that with the ATTEST solution it is possible to integrate considerably larger amounts of RES generation, while maintaining the safe operation of the network. Furthermore, it was also shown that the diversification of the RES generation mix could potentially lead to even better results.

5.3.5. Summary and Conclusions

In this section the results obtained from the simulations conducted for the tool developed in Task 3.3 are presented – optimization tool for planning TSO/DSO shared technologies. Two case studies were presented. The first case study comprises of part of the Croatian network corresponding to the Koprivnica region. This case study was developed within the ATTEST project, with data supplied by HOPS and HEP ODS. The outputs from the tools developed within Task 3.1 (optimization tool for distribution network planning) and Task 3.2 (optimization tool for transmission network planning) were taken into consideration. The second case study comprises of standard IEEE test systems. The data used in this case study is based on the Koprivnica case study (real profiles), that were adapted to these test systems.

The tool was able to determine an optimal investment plan in shared ESSs in both case studies. In the first case study (Koprivnica) it was considered an investment budget of 6.00 M€. It was shown that the ESSO invested a total of 5.02 M€ NPV, earning a profit of 38.55 M€ NPV from this investment. In case study "IEEE", it was considered an investment budget of 5.00 M€. In this case, the ESSO used all of the budget available, earning a profit of 21.48 M€ NPV.

It was also shown that the proposed tool can bring several benefits to the operation of future power systems. Regarding case study "Koprivnica", it was shown that with the BaU approach, a significant amount of load curtailment would be required to maintain voltage magnitude and branch power flows within the admissible limits. This leads to the conclusion that with the BaU approach, significant amounts of investment in network reinforcements would be required to avoid voltage and overloading problems. With the ATTEST solution it was shown that all load is supplied, and even a small reduction in costs with conventional generation would be achieved.

In case study "IEEE", with the BaU approach, voltage violations are expected to occur, and that these violations tend to occur more frequently and with higher severity towards the end of the planning period. With the ATTEST solution, all voltage violations are avoided. It was also shown that with the ATTEST solution it can be integrated considerably larger amounts of RES generation, while maintaining the safe operation of the network. At the TN level, RES curtailment is completely avoided. This leads to a significant decrease in conventional generation, and therefore with associated costs and GHG emissions. Furthermore, it was also shown that the diversification of the RES generation mix could potentially lead to further reductions in conventional generation, as there are several periods of the day that the power system runs only on solar generation.

6. KPIs simulations and demonstrations for WP4

6.1. Tool for ancillary services procurement in day-ahead operation planning of the distribution network

This section first briefly introduces via a high-level description the main modelling features of the tool developed in the task T4.1 "Tool for ancillary services procurement in day-ahead operation planning of distribution networks" of ATTEST project. This introduction lays the ground for the main goal, which is to present and discuss the KPIs simulation results obtained with the tool.

6.1.1. High-level description of the proposed ATTEST approach

The main objective of the proposed ATTEST tool is to enable DSOs to optimally procure ancillary services, specifically for voltage control and congestion management, resorting to the flexibility of emerging sources such as RES, flexible loads (e.g. EVs) and energy storage systems (ESS). To carry out the optimal operation of distribution networks of the future, LIST team developed a tractable stochastic multi-period optimal power flow (S-MP-OPF) tool that models every aspect of these grids (e.g. energy time coupling of flexible resources, uncertainty aspects of renewable DERs) and is computationally efficient.

The objective of this tool is to determine the optimal flexibility scheduling of available 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 RES 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 RES units, (ii) modern flexible DER such as EES and flexible loads (FL), (iii) aggregated flexibility of low-voltage systems at medium-voltage/low-voltage interface, and (iv) actions of network management controllers (e.g. on-load tap changer transformer) of medium-voltage grid.

At its input, the tool utilizes distribution network data as well as generation scenarios representing the uncertain behavior of RES.

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, is a stochastic multi-period mixed-integer non-linear programming (MINLP) problem in its basic formulation which cannot be solved for large-size real world power systems due to the current limitations of state-of-the-art MINLP solvers. Consequently, to break-down the high computational complexity of the resulting problem, a novel tractable methodology [13], [14], based on mixed-integer linear model (MILP) and a sophisticated heuristic sequential linearization algorithm (SLA), is developed which ensures the tractability as well as scalability of the proposed tool.

The output data of this tool are: (i) the expected cost of the procurement of ancillary services, (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, and (iii) the total number of nodes voltage and branch current violation as well as the magnitude of maximum violation.

In the following section the KPIs are calculated to evaluate the proposed ATTEST tool's performance by comparing the BaU case and a series of test cases for which the proposed tool is used.

6.1.2. KPIs calculations

6.1.2.1. The methodology used and test cases

The proposed ATTEST tool is run for different combinations of the test cases for four networks, as follows. A total number of 108 simulations have been run. Each simulation is characterized by a unique combination among the features below:

- Country network envisioned operating scenarios: {ES, PT, HR-Green, HR-Brown, HR-Red, UK}
- Year: {2020 (Base), 2030, 2040, 2050}
- Day type: {Business day, Weekend}
- Season: {Winter, Spring}. In some cases: {Summer, Autumn}

Furthermore, in the UK system, additional variations are introduced by 3 network modes:

- Network status: {No contingency, outage of line 1-7, outage of line 2-7}

In any simulation, if the network does not present any constraint violation at an envisioned operating scenario, the simulation is terminated as the operation is safe and does not require any control action. Otherwise, the simulation proceeds and attempts to utilize flexibility assets to rectify the congestions (thermal overload, undervoltage or overvoltage). If the attempt is successful and a solution is obtained, the results are exported and the simulation is, indeed, terminated. Moreover, another simulation is run with the same network characteristics, however, attempting to rectify the congestions without flexibility assets, merely by adjusting On Load Tap Changer (OLTC) transformer ratio, which also corresponds to the Business as Usual (BaU) case. Therefore, a new criterion exists for some, but not all, operation scenarios:

- Flexibility assets: {With Flex Assets, Without Flex Assets}

The process is illustrated in Figure 76.

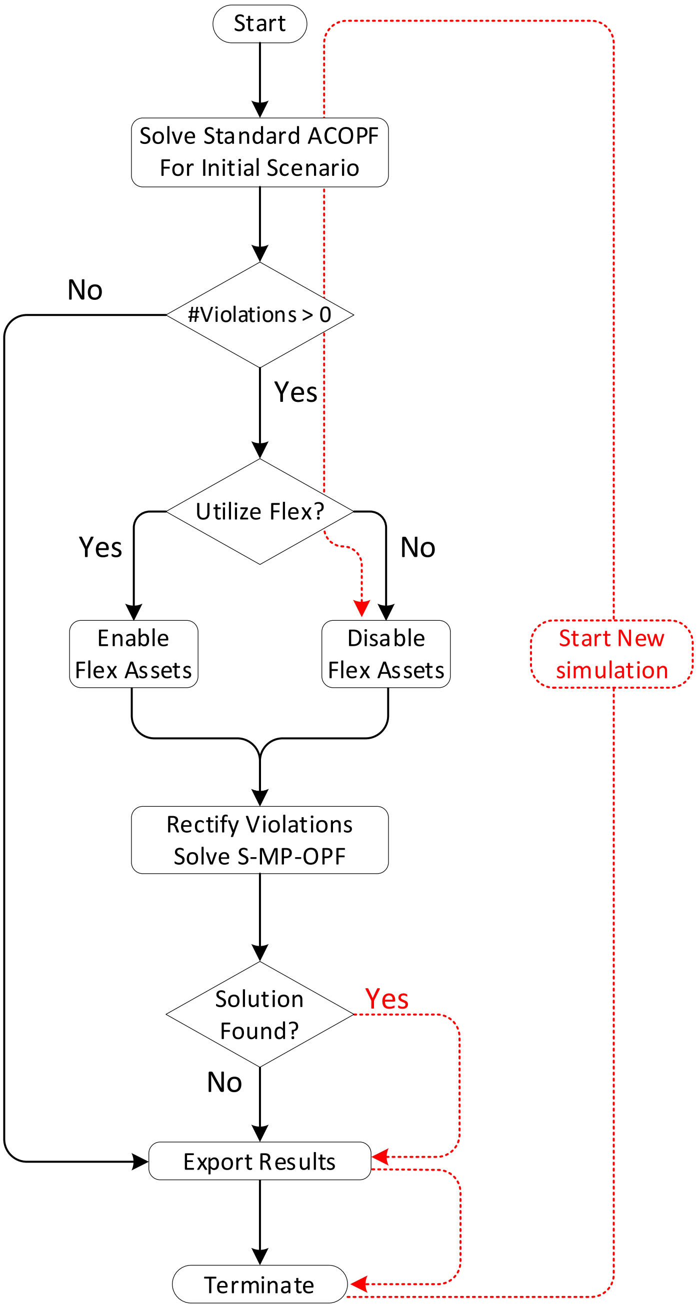


Figure 76 Operation Scenario Handling Approach

6.1.2.2. Overall KPIs results at one glance

The 108 combinations can be grouped either by year or geographic location.

Figure 77 presents a histogram for the 108 scenarios, grouped by year. In each group, the first bar (*N*: Blue) represents the total number of scenarios in this year. For example, 6 simulations were run for the base year (2020), and 26 simulations were run for year 2030. The second bar in each group (*ViolationsExist*: Orange) represents as a first KPI the number of cases where violations exist (e.g. voltage excursions outside the statutory limits, thermal overload). For example, out of the 26 cases in year 2030, only 17 cases observed violations and needed rectification measures. On the other hand, (26 – 17=) 9 cases did not observe any violations and did not need any intervention. The third bar

(*SolutionFound*: Green) indicates, as another KPI, the number of cases where the network congestions were successfully solved by the proposed tool, and a solution is found. Note that the BaU scenario, that uses only OLTC control for one deterministic weather scenario at the time is not able to solve any case. As the proposed tool models OLTCs and other DERs jointly in a 24 hours ahead operation profile including also weather uncertainty, this KPI highlights clearly the added value of the proposed tool over BaU scenario.

Using the same example for year 2030, out of 17 scenarios needing intervention, a successful solution was obtained in only seven scenarios, and (17 – 7=) 10 scenarios could not be solved with the available set of mitigation actions. Finally, the fourth bar (*Flex_utilized*: Red) indicates the number of cases where the solution featured utilization of flexibility assets. For example, in the 2030 year group, out of the 7 scenarios successfully solved, only 3 scenarios involved utilization of any flexibility asset (e.g. RES curtailment, EES, flexible load). On the other hand, 4 scenarios (7 – 3) were solved without activating any flexibility assets.

Very importantly, the Figure 77 also shows that, as expected, the network constraint violations grow steadily with the increase of the penetration of distributed energy resources (DERs, particularly RES) in time. However, these violations cannot always be controlled by the available flexibility, the number of uncontrollable scenarios exacerbating in time. Such observations raise awareness and should support the DSOs in planning carefully the flexibility to be able to control any network constraint for the assumed penetration of DERs. This tool and the one in distribution network planning should be valuable assets in ensuring a smooth and cost-effective energy transition in distribution networks.

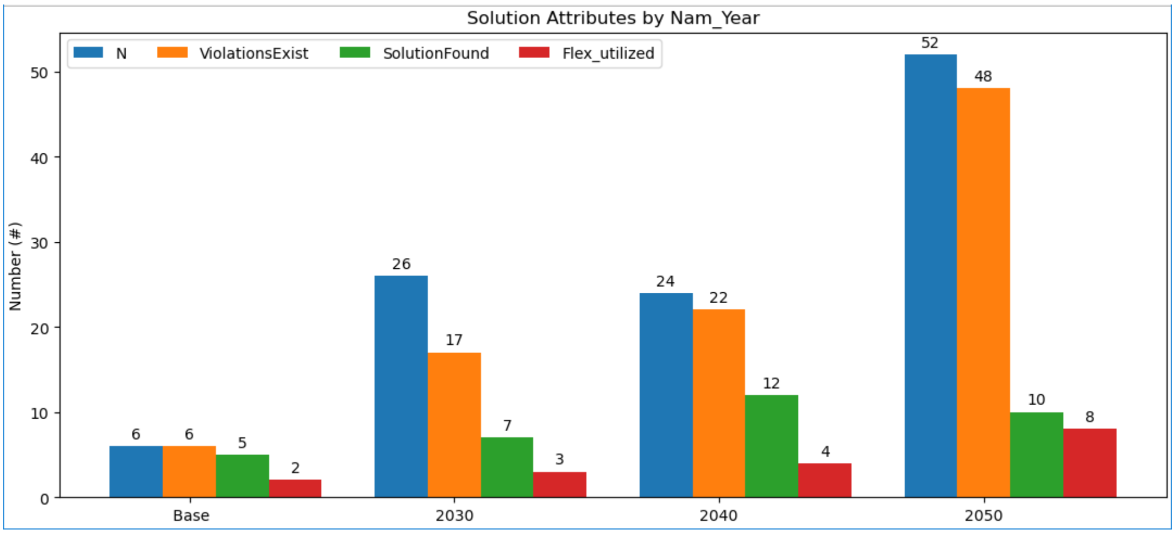


Figure 77. Results grouped overall per conutries by Year of the energy transition

Figure 78 also presents the same result data from a different perspective. The data in Figure 78 are grouped by geographic location. The same terminology is used in the histogram. It is noticeable that many scenarios in the PT and UK systems do not suffer any violations. Additionally, all problematic cases in the PT and HR-RED networks were solved without any flexibility assets, and hence the total cost of mitigation action (i.e. OLTCs ration changes) is zero.

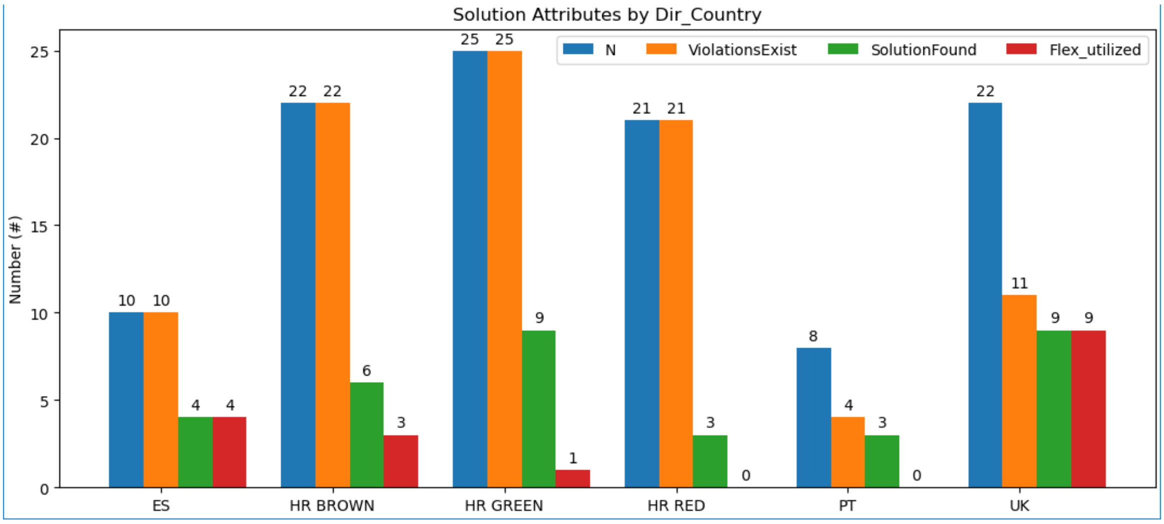
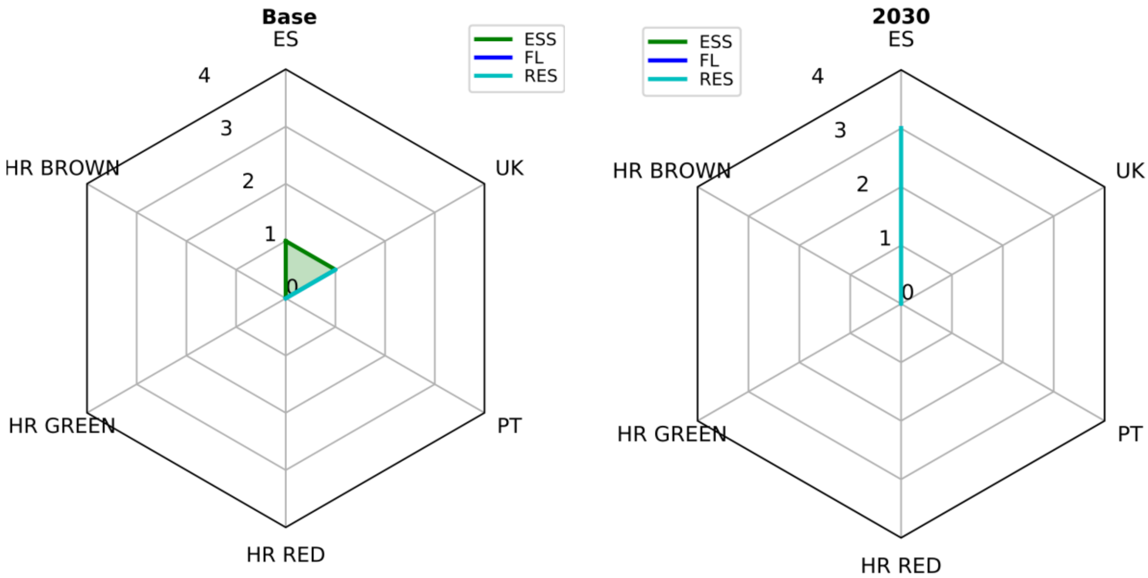


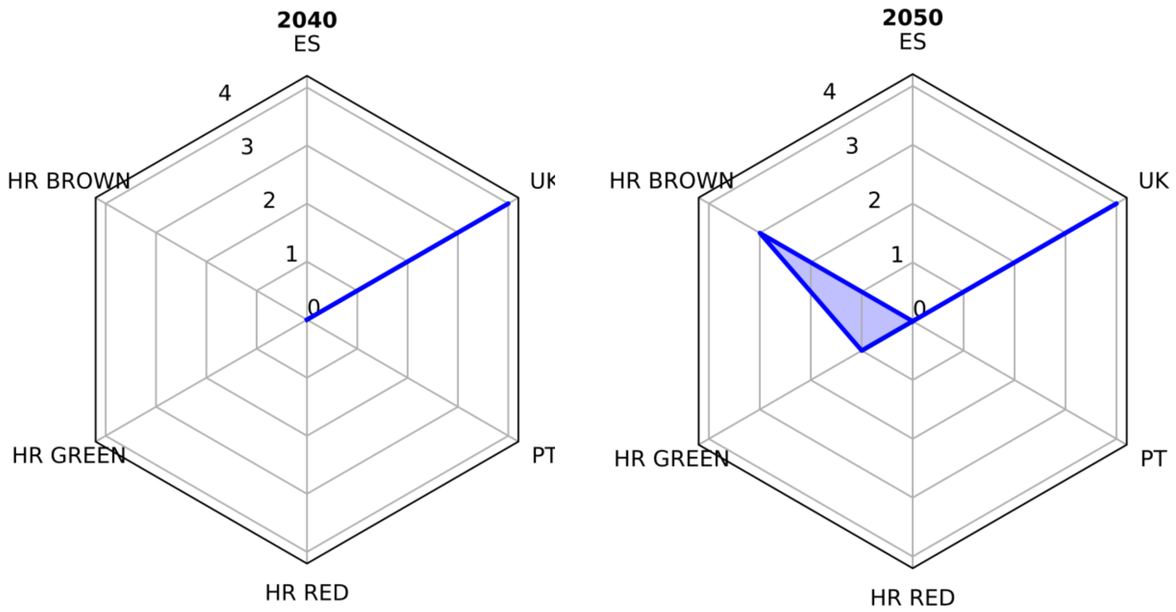
Figure 78. Results grouped by Country

Figure 77 and Figure 78 reported whether, or not, flexibility assets were utilized at all. However, for brevity, the two figures did not report which type of flexibility asset was activated.

Figure 79 provides more detail on the utilization of flexibility assets, which are RES, energy storage systems (ESS) and flexible loads (FLs). Results are grouped by year {base (2020), 2030, 2040, and 2050}. Each radar plot details flexibility utilization for the six geographic locations (grids): {ES, UK, PT, HR-Red, HR-Green, and HR-Brown}. The line curve for each asset type is drawn in a different color. In the base year (2020), the ESS was deployed once only in the UK network and ES network, respectively. In contrast, the RES was curtailed in one scenario in the UK system. Similarly, subplot c reveals that out of all scenarios for year 2050, the flexible load (FL: Green) was utilized in three scenarios in the HR-Brown network, in one scenario in the HR-Green network, and in four scenarios in the UK network. Similarly, out of all the cases of year 2030, flexible load (FL: Green) was used in three scenarios of the ES network only.



a) Utilization of Flexible Assets in Base Year (2020) *b) Utilization of Flexible Assets in Year 2030*



c) Utilization of Flexible Assets in Year 2040 *d) Utilization of Flexible Assets in Year 2050*

Figure 79. Radarplots of Flexibility Assets Utilization

Furthermore, we take a further look at the main KPIs, which are the number of violations and cost of flexibility usage at the solution in all scenarios. Figure 80Figure 77 is a histogram of this data for scenarios grouped by year. In each group, the first bar represents the total number of violations in the group. The lower (red) part of the bar represents the number of voltage violations, while the upper segment reports the number of line-limit violations. It is worth noting that the violations are counted for all buses in the system, for each of 10 weather scenarios, for all 24 hours of the operation profile. For example, in the case of ES system, 16,832 violations of the lines' thermal limits were observed, and 12,011 violations of the bus voltage limits were also observed. Hence, the total number of violations would be, 28,843. Furthermore, the second bar in the group (blue) represents the cost of the solution, for solved cases. For example, the ES case costs 1,198 monetary units in average among the different seasons and day-types.

The same data is represented from another perspective, where cases are grouped by year. This is shown in Figure 81. For example, in the year 2030, a total of 15,497 violations were counted, composed of 11,716 voltage band violations, and 3,781 thermal limit violations. The cost of the solutions in the 2030 group is 1,198 monetary units.

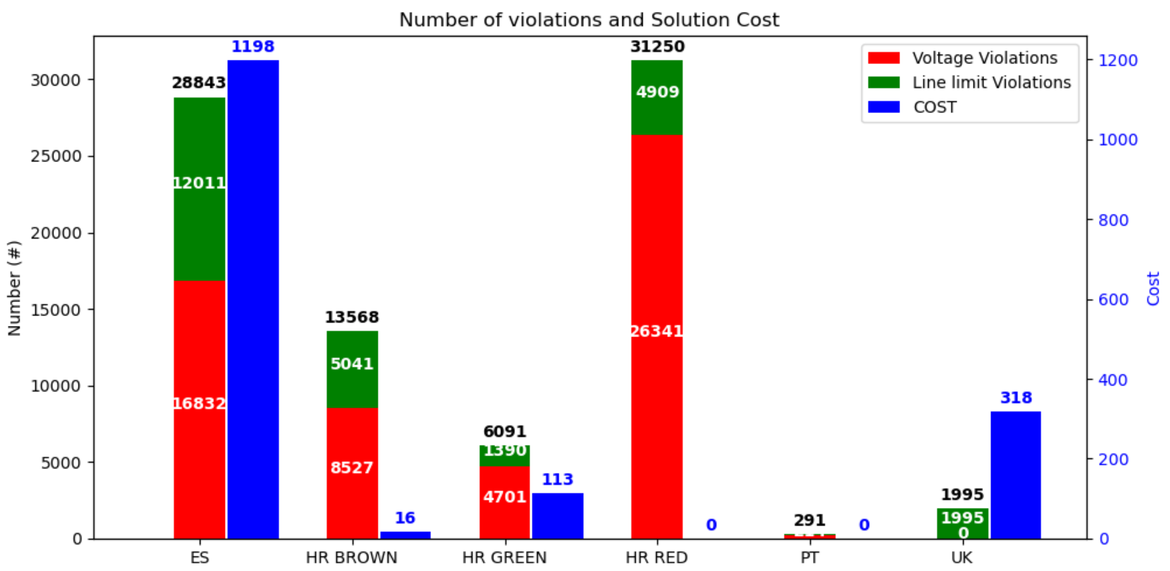


Figure 80. Number of Violations (left axis) and Cost of Flexibility usage (right axis) grouped by System (Country)

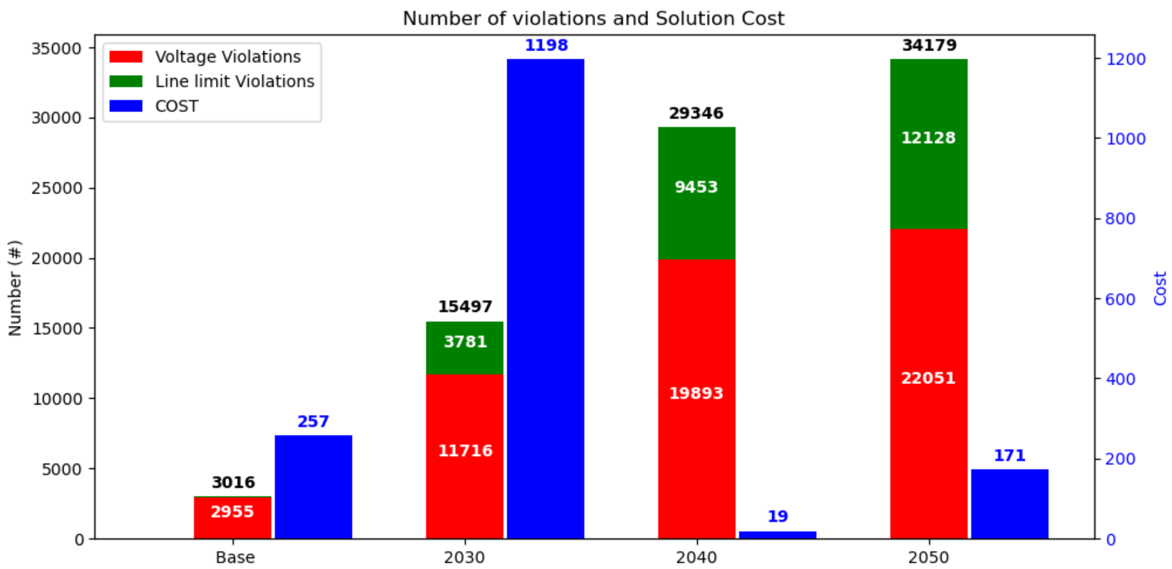


Figure 81. Number of Violations (left axis) and Cost of flexibility usage (right axis) grouped by Year

6.1.2.3. Some numerical issues encountered

We disclose transparently some numerical issues faced with the proposed tool on some energy transition scenarios developed in WP7 of ATTEST. Let first mention that the core development of this tool was achieved before a final version of the test cases of WP7 become available. However, after its complete development, the tool was preliminarily but thoroughly tested on three distribution networks: the IEEE 33-bus "Baran & Wu" network, which is widely used for benchmarking algorithms in power systems community, and two versions of the UK and PT networks. To mimic energy transition scenarios toward renewable energy supply, all these networks were modified, basically by assuming the deployment of a large amount of RES (wind and solar) but also energy storage systems and flexible loads. For each network two different "stressed" operating conditions (light stress and heavy stress) were constructed, in which several operating constraints (voltage and/or thermal limits) are violated slightly (light stress) or severely (high stress). For each network and stress case, nine problem instances, differing in terms of flexible options used to remove constraints violated were solved successfully. All problems were solved in general with very good accuracy (both objective value and constraints satisfaction) and fast. These results obtained with the tool were reported in two papers ([13]and [14]), published after thorough peer-review, testifying the soundness of the methodology implemented in the tool and the results, in two top journals. Further results are also reported in a conference paper [15].

Then the tool was run on the final version of the test cases developed in WP7. Unfortunately, and apparently surprisingly, the tool failed to converge in some of these test cases where constraints are violated. There is no scientific evidence of the reason of this failure to converge because we cannot verify in the frame of the project if the problem that we attempt to solve is feasible as today there is no such a complex tool. Clearly, if the problem is infeasible our tool cannot converge and find a feasible solution. Obtaining such scientific evidence would require developing another tool from scratch to model accurately the problem at hand, which is not only not affordable in the frame of ATTEST but also not scalable (i.e., it may solve only small problems).

In the majority of cases in which the tool does not converge, we observed that a very large number of constraints are violated (e.g., hundreds to thousands, see the figures presented so far), which means that the optimization problems are highly stressed and hence may be infeasible. Such a huge number of violations is not practical (indeed in real networks the number of constraints violated is generally small and of small magnitude but above all the violations are controllable) and may pose problems to the linear approximations used in the tool. Note that, even if there is only one violated constraint but there is no source of flexibility properly placed to correct it, the problem will be infeasible. However, even if any such problem is feasible, as the proposed tool implements a sophisticated algorithm (which linearizes the problem and resorts to a sequence of MILP approximations), a MILP approximation of such a stressed problem may be infeasible. In the latter case the tool cannot proceed with the search for a feasible solution, such an option being not foreseen at development stage since we didn't encounter such cases in the numerous preliminary runs using the 3 different networks.

The infeasible cases encountered suggest that the energy transition scenarios we built up could be too crude, leading to highly stressed conditions where there is not enough flexibility in the grid, in general, or at suitable locations, in particular. These are important observations fostering the improvement of the methodology to build up realistic scenarios for the energy transition.

6.1.2.4. KPIs results per country

Croatian Networks: First, the main KPIs (the operation cost and total and type of constraints violation) are presented for the three Croatian (HR) networks (green, red and brown).

For the green network one can observe from the upper plot of Figure 82 that, as expected, initially the growing amount of DERs stress the network, which leads to an increasing trend of the number of overall violated constraints as well as individual constraints (voltage and thermal). The total number of violations (across 24 hours and 10 uncertain scenarios per hour) is alarmingly high. Despite this, the lower plot of Figure 7 indicates that activated the costly flexibility is needed only in 2050, while in the previous decades the OLTC ratio optimization, action which has practically zero cost, is capable to remove those violations.

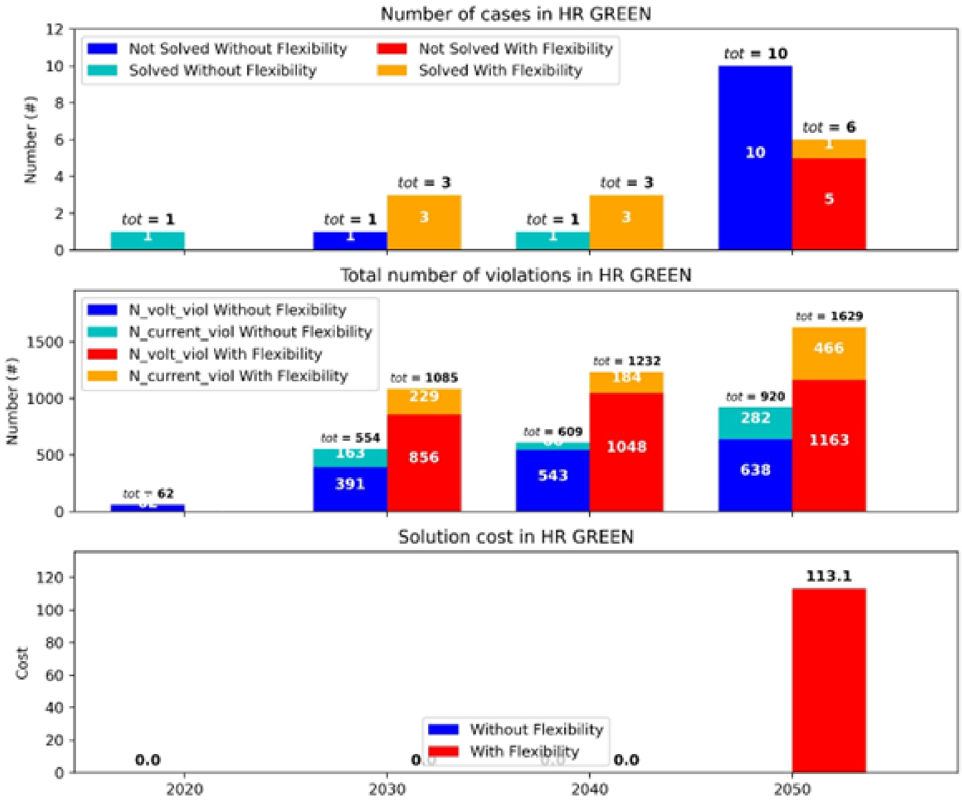


Figure 82 Number of cases, total number of violated constraints and solution cost for HR GREEN network

For the red HR network one can notice from the upper plot of Figure 83, as regards constraint violation, the same trend as for the previous network. However, the network seems more stressed with a larger number of total constraint violations. observe from that, as expected, initially the growing amount of DERs stress the network, which leads to an increasing trend of the number of overall violated constraints as well as individual constraints (voltage and thermal). The lower plot of the figure clearly indicates that OLTC ratio optimization, an action which has practically zero cost, is capable to remove all violations.

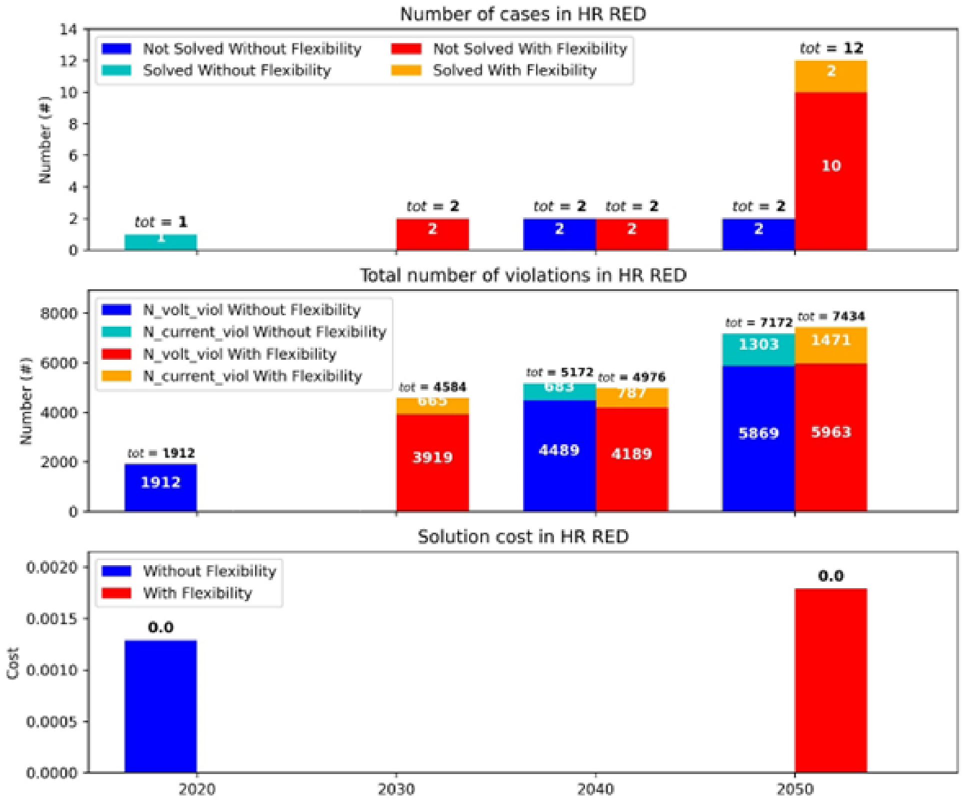


Figure 83 Number of cases, total number of violated constraints and solution cost for HR RED network.

Figure 84 shows that the HR brown network presents the same trends in terms of both constraint violation and cost as the green HR network.

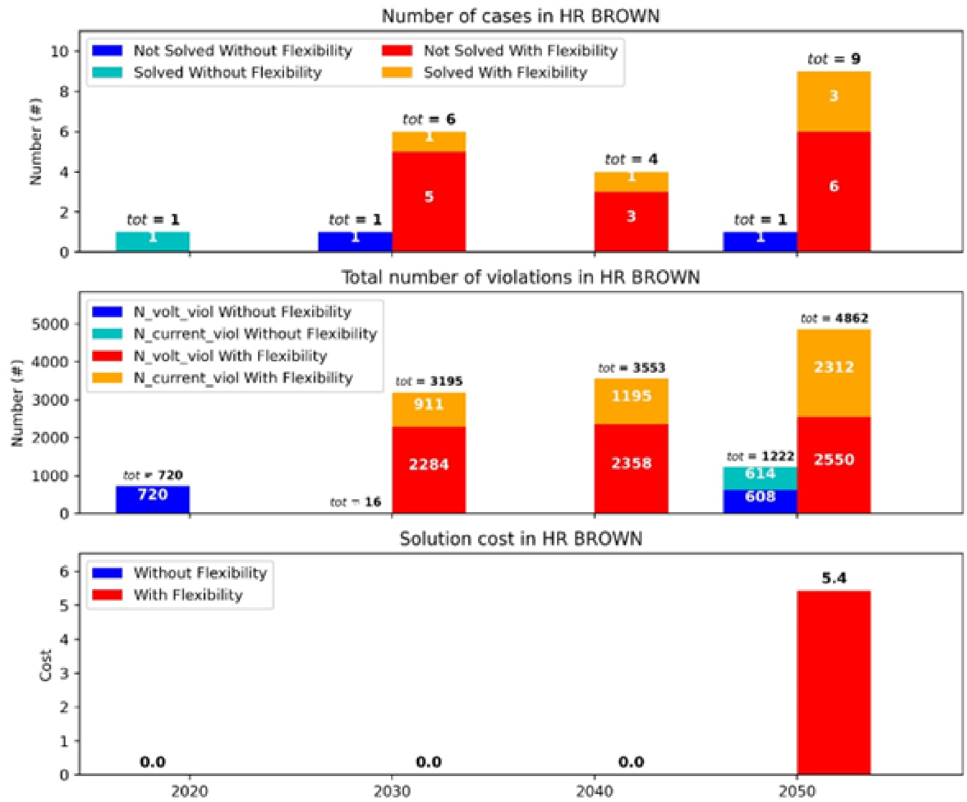


Figure 84 Number of cases, total number of violated constraints and solution cost for HR BROWN network

One can safely conclude that overall, across the three Croation networks, one expects that violations of constraints may occur in the future, but they are all controllable by local flexible resources at negligible cost, except for 2050. The usage of local flexible resources (storage, EV shifting, flexible demand) is indispensable as compared to the business as usual to succeed the energy transition.

UK Network: Figure 85 displays the KPIs calculated for the UK network. One can observe that a small amount of violations is already observed recently (2020 scenario) and the cost of removing them is high as it pertains of curtailing the output of renewable generation, which is expensive. The figure shows no issues are foreseen in the energy transition scenario to 2030. Growing constraints violations are envisioned for 2040 and 2050 but the cost of removing them, although increasing, is not significant due to the presence of flexible assets (storage and flexible demand), which activation cost is cheaper than renewable production curtailment. The usage of local flexible resources is indispensable as compared to business as usual to succeed the energy transition.

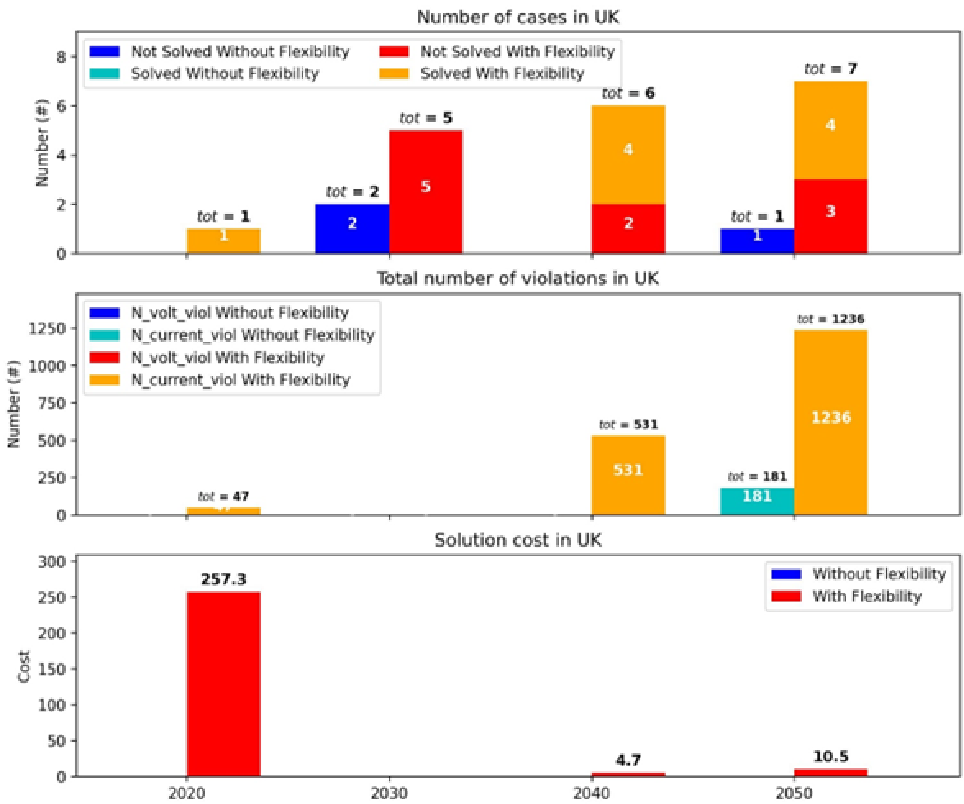


Figure 85 Number of cases, total number of violated constraints and solution cost for the UK network

Portugal Network: The main KPIs (the operation cost and total and type of constraints violation) of the Portuguese network are presented in Figure 86. As for the UK network, one can observe that a small amount of violations is already observed recently (2020 scenario); however, the cost of removing them is almost zero, all these voltage violations cane be straightforwardly controlled by the cheap OLTC actions. Energy transition scenarios show no constraint violations in 2030 and 2050 and only a small number in 2040. Fortunately, the cheap OLTC is again able to fully control these constraint violations. Accordingly, despite the presence of flexibility, the latter is not eventually used and the business-as-usual case (i.e., without flexibility) should suffice for this network to succeed locally the energy transition.

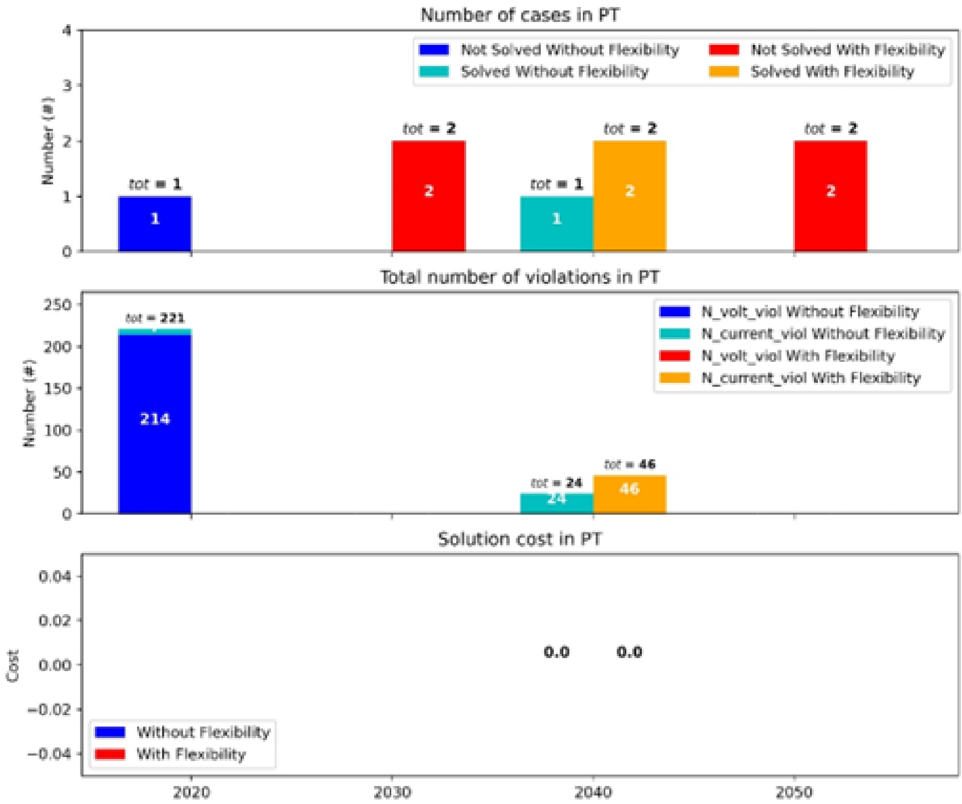


Figure 86 Number of cases, total number of violated constraints and solution cost for PT network

Spain Network: The main KPIs (the operation cost and total and type of constraints violation) calculated for the Spanish network are presented in Figure 87. Note that in 2020 there are almost no operation issues (i.e., violated constraints). The number of initially violated constraints is growing, as expected, in time. The cases with flexibility present less operation issues than the business as usual. Finally, a large cost of using energy storage to rectify operation issues is present only in 2030.

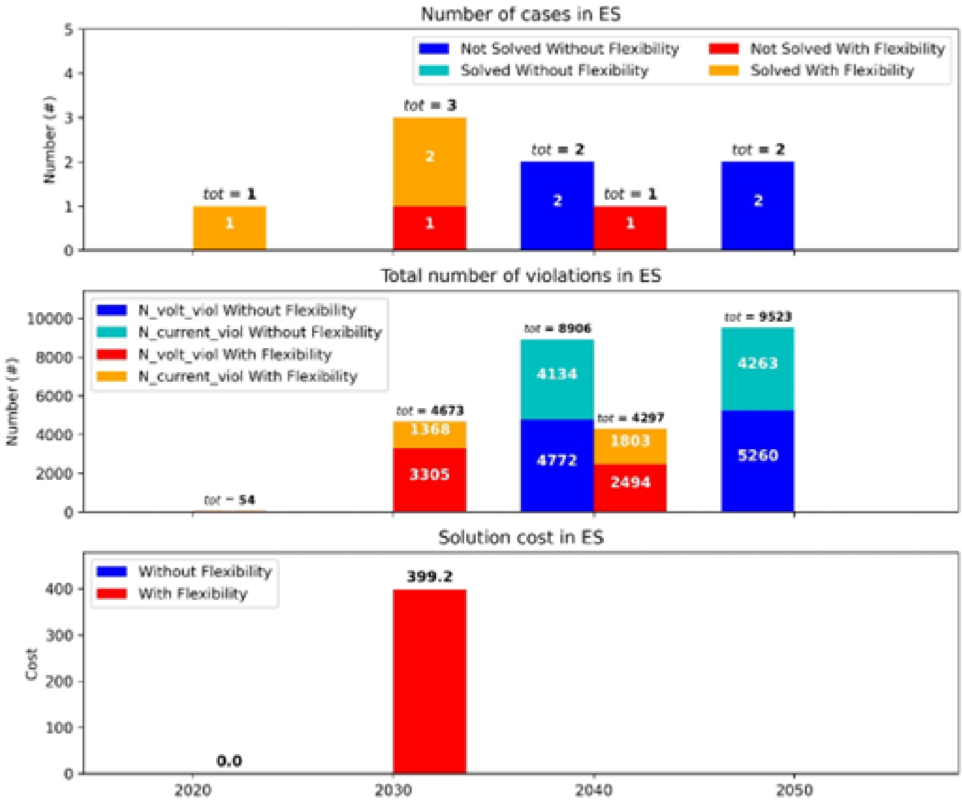


Figure 87 Number of cases, total number of violated constraints and solution cost for ES network

6.2. Tool for ancillary services activation in real-time operation of the distribution network

This chapter focuses on KPIs calculation in real-time operation of distribution network. To evaluate the efficiency of the developed tool, several KPIs will be compared for each country and the year considering the BaU scenario without using RT tool developed in the ATTEST project in distribution network operation and RT operation in distribution network with the tool developed in the project. The simulations are focused on 2 groups of KPIs. The first one is related to line overloading in the distribution network, while the second one is related to unallowed voltage deviations distinguishing undervoltage and overvoltage network problems. As defined in the project, the tool T4.2 for ancillary service activation in real-time operation in distribution network is responsible not only for mitigating distribution network problems, but also for providing required service to the transmission network operator at the interconnection points between TSO and DSO. This subchapter will show the performance of T4.2 tool in term of solving problems in the distribution networks, but also the volume of activated ancillary services for supporting secure and reliable operation of transmission network considering the TSO/DSO coordination approach developed in the ATTEST project. KPIs are calculated for two days: typical Summer and Winter day for 2030, 2040, and 2050.

6.2.1. Input data

Scenarios of new low-carbon technology integration data for distribution level in Croatia, UK, Spain, and Portugal for 2030, 2040, and 2050 are provided in Figure 88, Figure 89, and Figure 90:

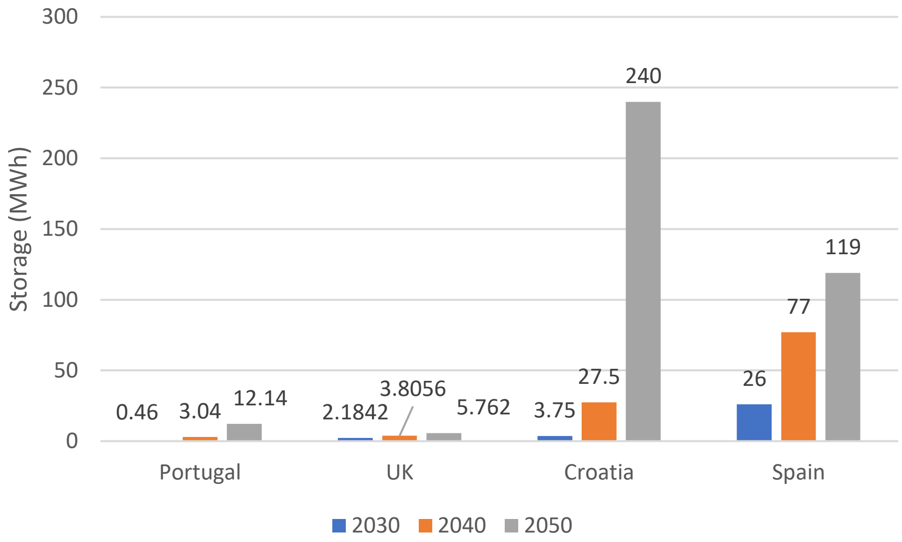


Figure 88 Scenarios of storage capacity increase over the years on the distribution level

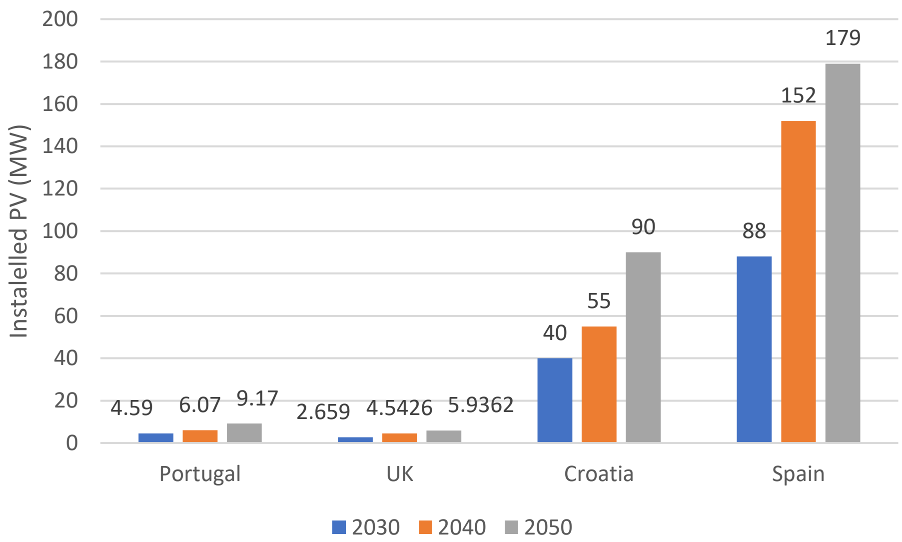


Figure 89 Scenarios of PV integration over the years on the distribution level

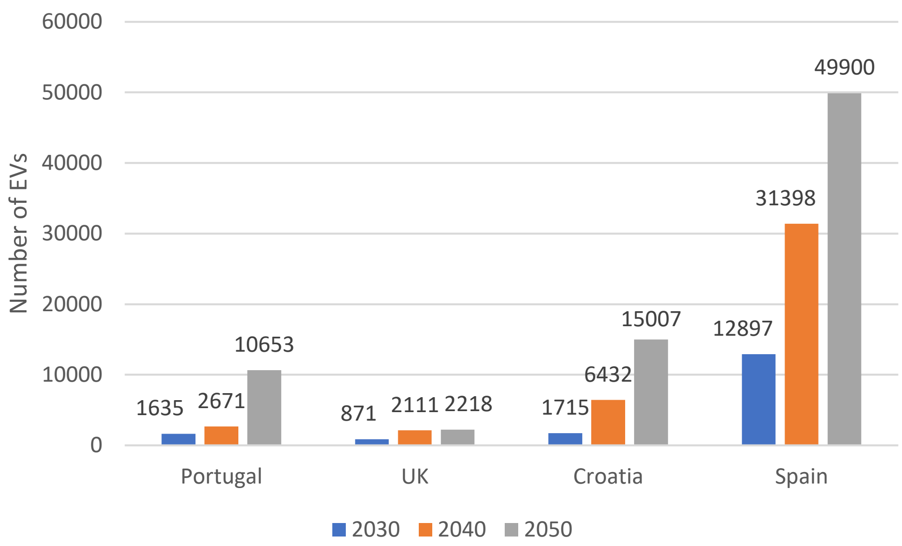


Figure 90 Scenarios of EV integration over the years on the distribution level

6.2.1.Croatia

The number of overloaded lines for 2040 and 2050, as well as total amount of overload is shown in Figure 131 and Figure 132, respectively.

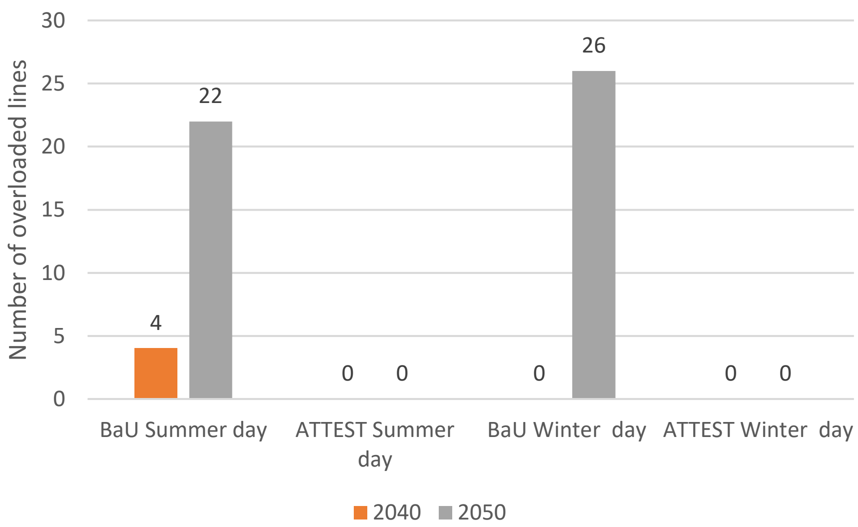


Figure 91 Number of overloaded lines over the years

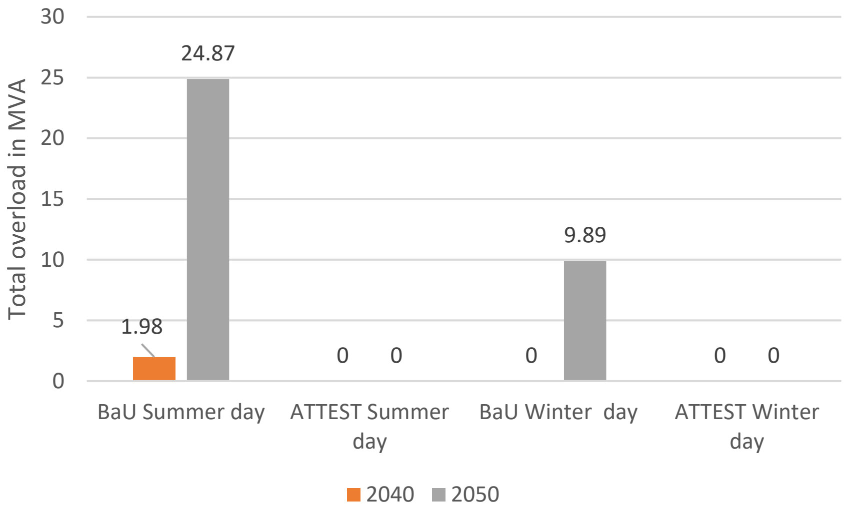


Figure 92 Total network overloading over the years

As it can be seen from Figure 131 and Figure 132, the tool T4.2 solved all problems related to the lines overloading in the observed part of distribution network. With the data given for simulations for all years there were not any network problems regarding overvoltage. Table XXXIX shows number of undervoltage buses and cumulative undervoltage for 2050 for typical Summer and Winnter day. It can be seen that with the ATTEST approach all undervoltage problems are solved.

Table XXXIX Overvoltage problems in 2050 solved with ATTEST approach

2050	BaU		ATTEST	
	Summer	Winter	Summer	Winter
Number of undervoltage buses	30	0.20	0	0
Cummulative undervoltage	-0.1722	-0.0906	0	0

To satisfy the agreed level of active and reactive power at the TSO/DSO interconnection point and mitigate distribution network violations, the amount of upward and downward flexibility activated from flexible EV load for each specific day and over the years are shown in Figure 93 and Figure 94.

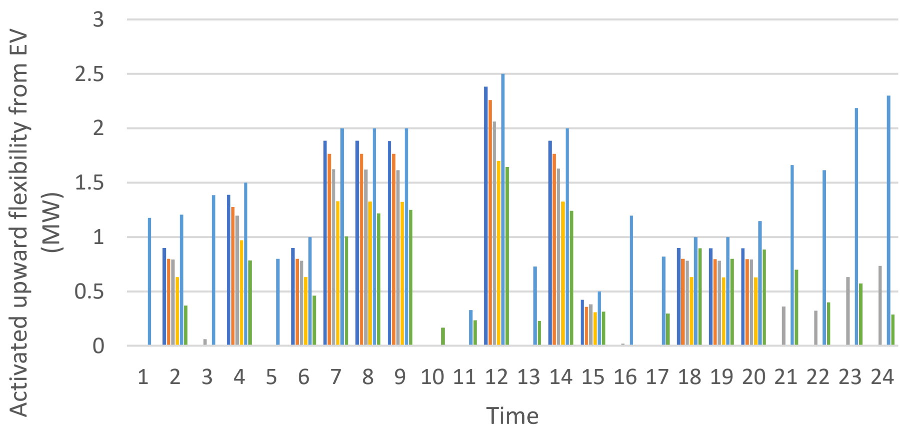


Figure 93 Activated upward flexibility from EV

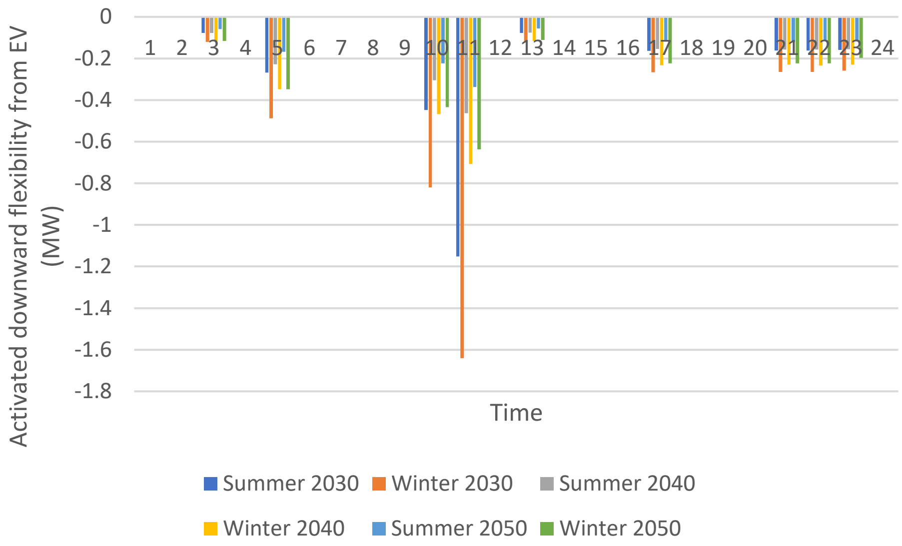


Figure 94 Activated downward flexibility from EV

Figure 95 and Figure 96 show active and reactive upward and downward flexibility provided from storage units in Summer and Winnter days over the years.

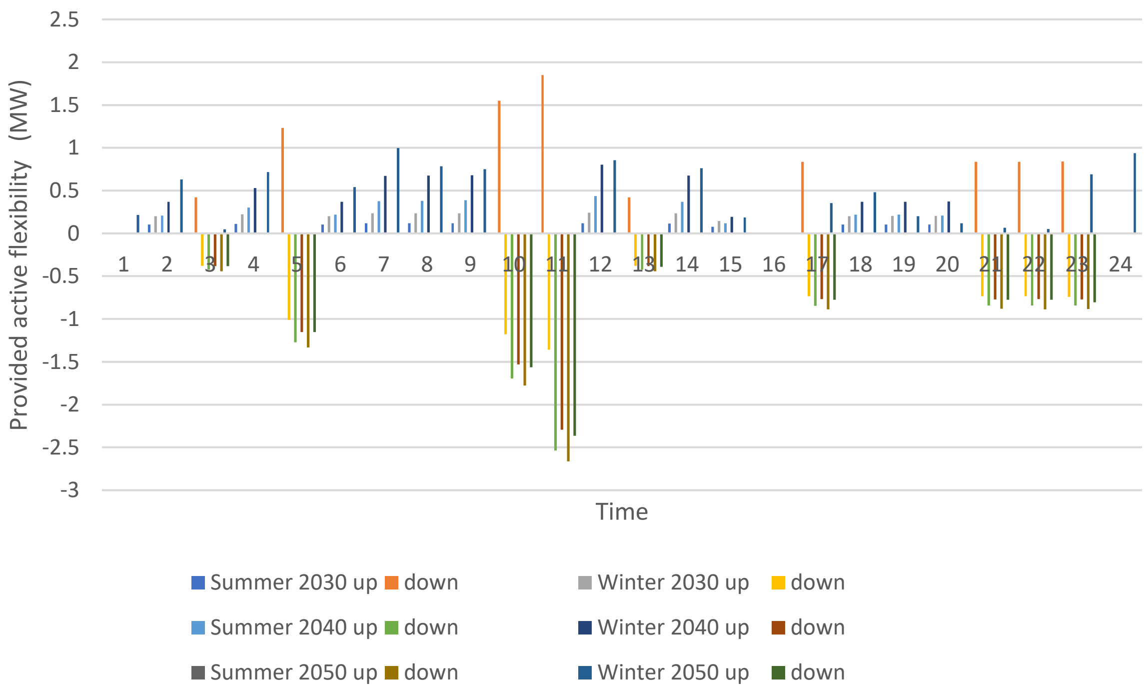


Figure 95 Provided upward and downward active power flexibility from storage units

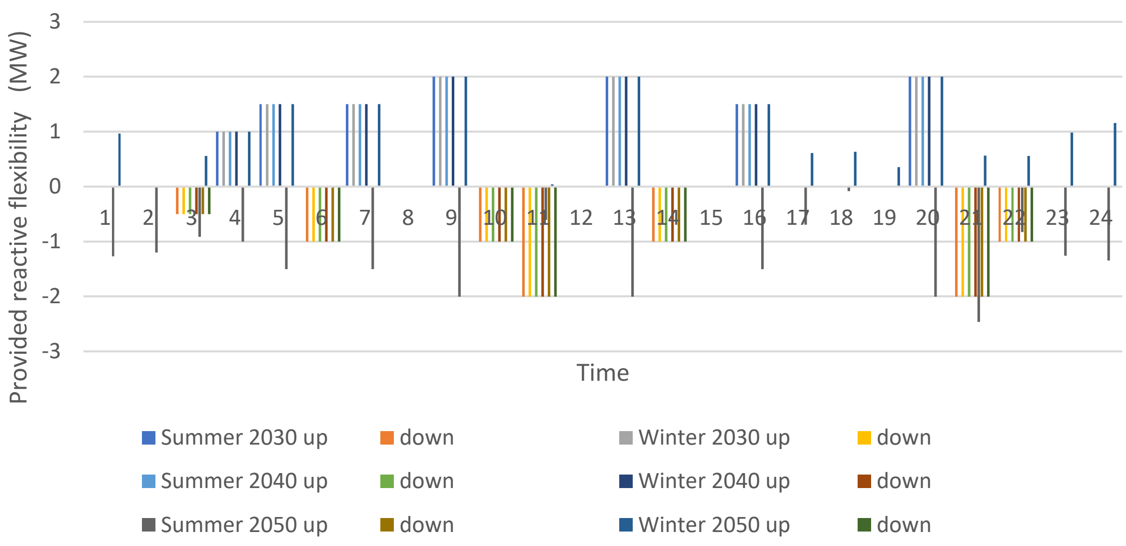


Figure 96 Provided upward and downward reactive power flexibility from storage units

Figure 97 compares losses in BaU scenario with ATTEST solution. Although the tool was not focused on losses minimization, it can be seen that losses are reduced in ATTEST approach from 1 % to almost 6 %.

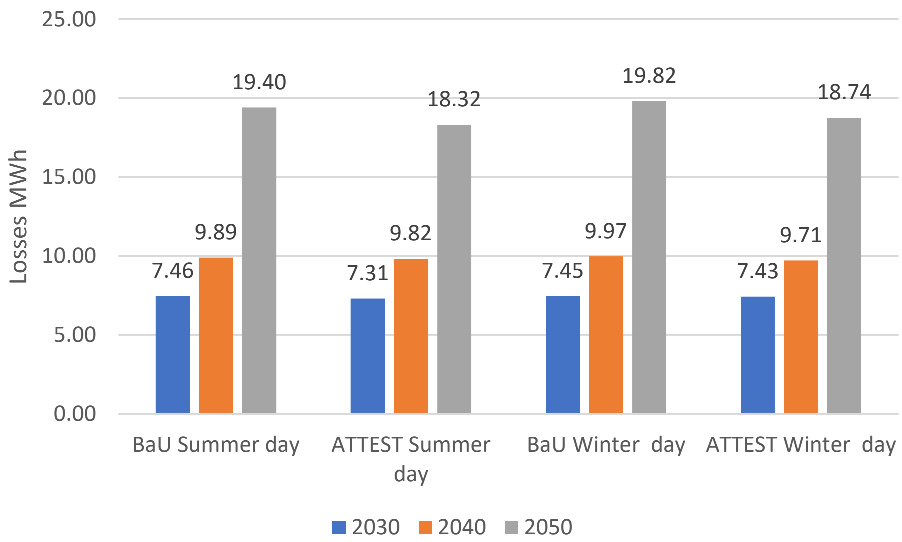


Figure 97 Losses over the years in Croatia

6.2.2. Portugal

The number of overloaded lines 2050 and total amount of overload is shown in Table XL. It can be seen that in 2030 and 2040 there was not a single line overloaded. Moreover, there were not any problems related to unallowed voltage deviations, either undervoltage or overvoltage.

Table XL Congestion problems in 2050 solved with ATTEST approach

2050	BaU		ATTEST	
	Summer	Winter	Summer	Winter
Number of overloaded lines	24	24	0	0
Cummulative overload	64.56	80.57	0	0

The amount of upward and downward flexibility activated from flexible EV load for each specific day and over the years are shown in Figure 98 and Figure 99.

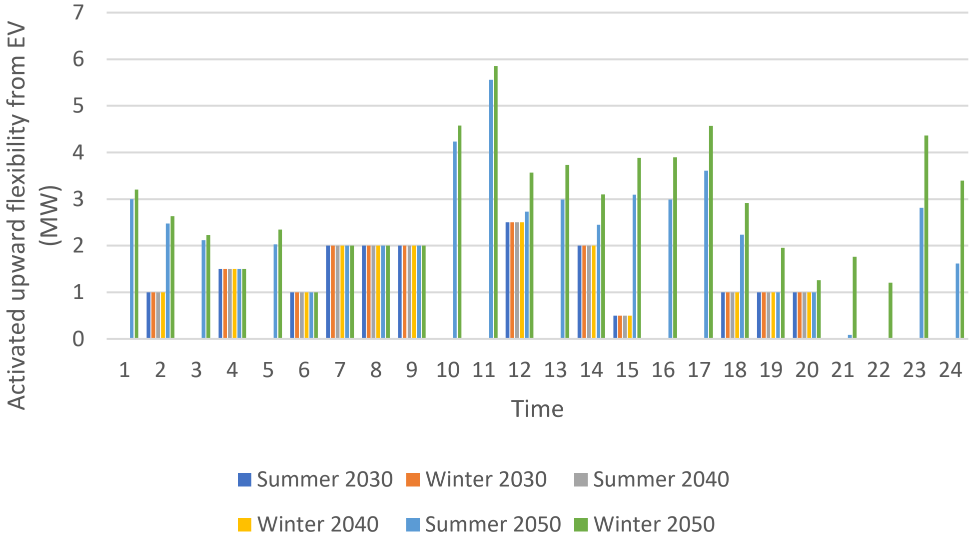


Figure 98 Activated upward flexibility from EV

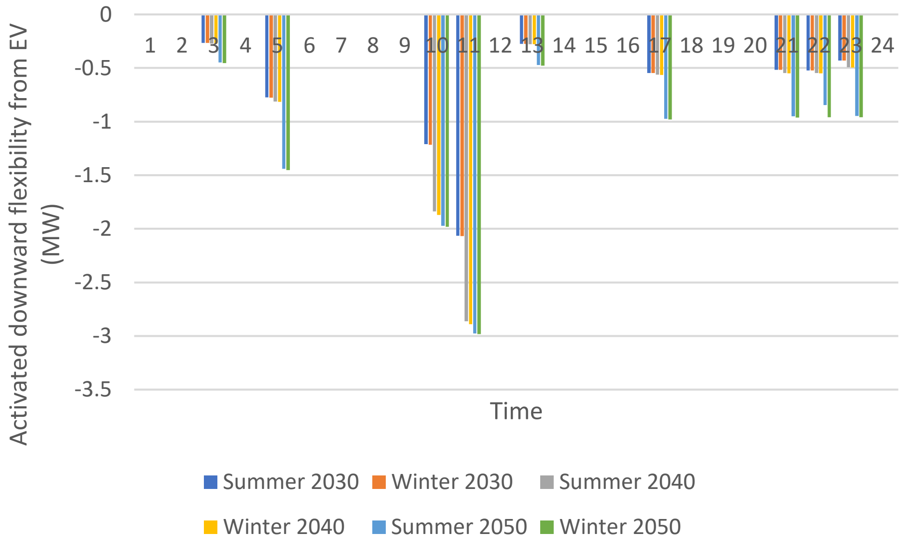


Figure 99 Activated downward flexibility from EV

Figure 100 and Figure 101 show active and reactive upward and downward flexibility provided from storage units in Summer and Winnter days over the years.

Figure 100 Provided upward and downward active power flexibility from storage units

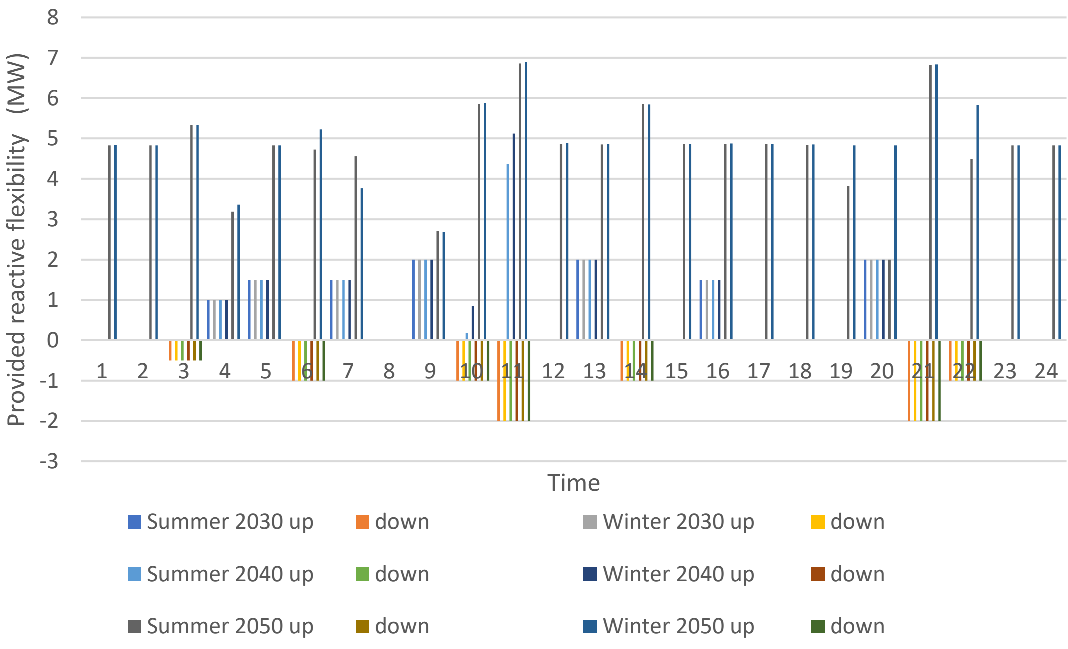


Figure 101 Provided upward and downward reactive power flexibility from storage units

Figure 102 shows daily value of losses over the year for typical Summer and Winter day in Portugal. It can be noticed that losses are reduced with ATTEST approach from 4 % to almost 15 %.

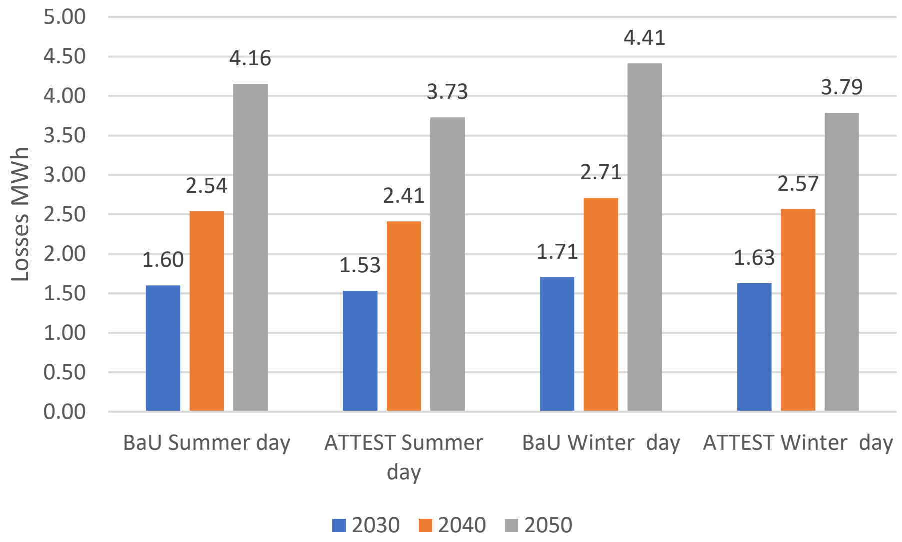


Figure 102 Losses over the years in Portugal

6.2.3.The United Kingdom

The number of overloaded lines for 2040 and 2050, as well as the total amount of overload is shown in Figure 103 and Figure 104, respectively. There was not any congestion problem in 2030. Moreover, in the observed period from 2030 to 2050, there were not any problems associated with unallowed voltage deviations, neither undervoltage nor overvoltage.

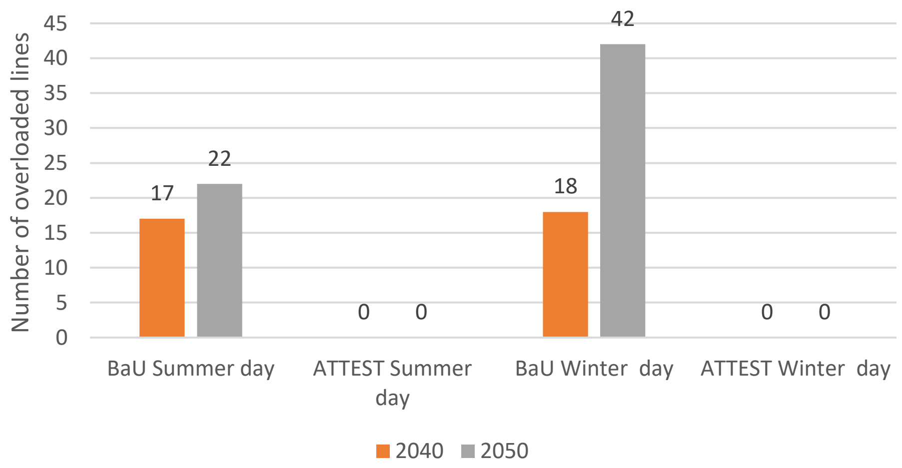


Figure 103 Number of overloaded lines over the years

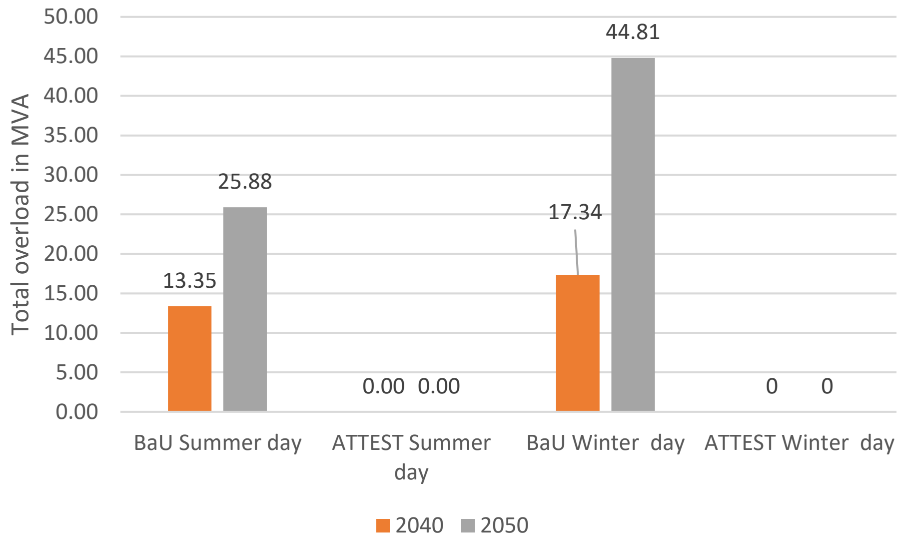


Figure 104 Total network overloading over the years

The amount of upward and downward flexibility activated from flexible EV load for each specific day and over the years are shown in Figure 105 and Figure 106, while active and reactive upward and downward flexibility provided from storage units in Summer and Winnter days over the years are shown in Figure 107 and Figure 108.

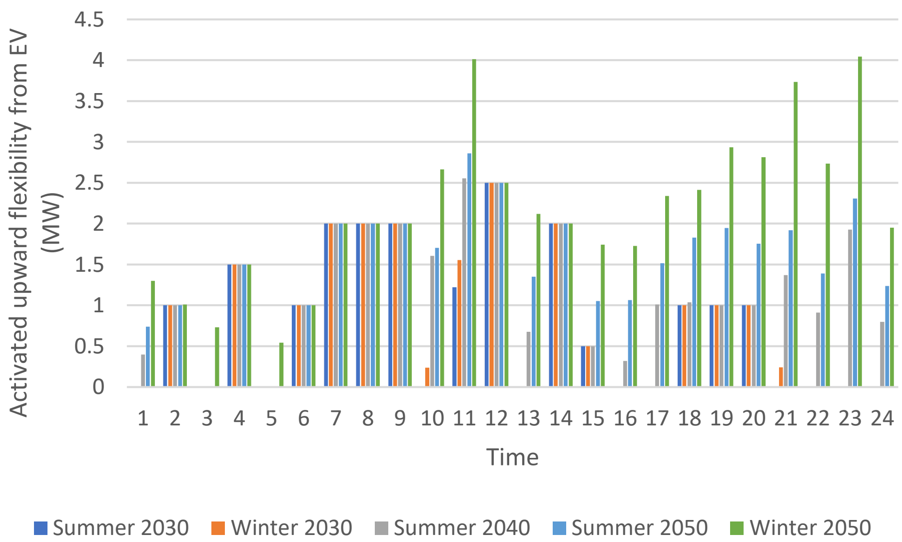


Figure 105 Activated upward flexibility from EV

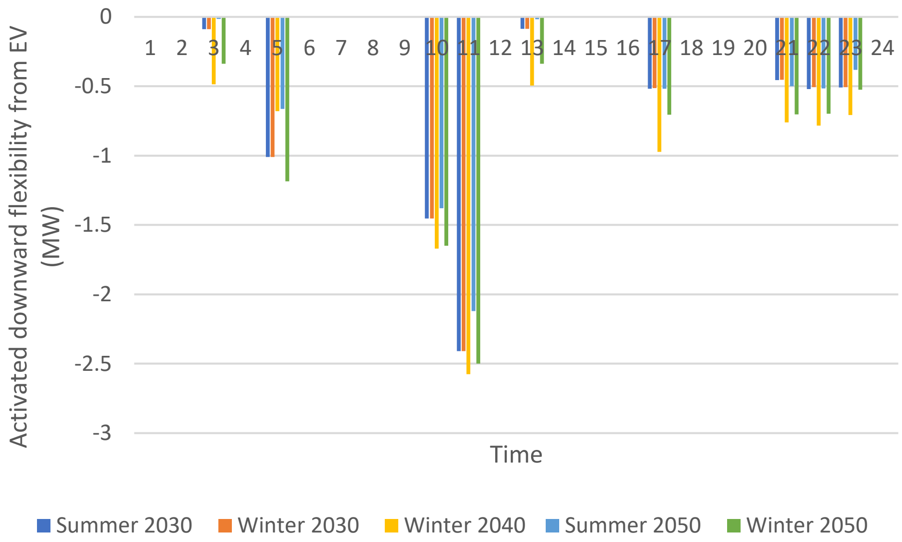


Figure 106 Activated downward flexibility from EV

Figure 107 Provided upward and downward active power flexibility from storage units

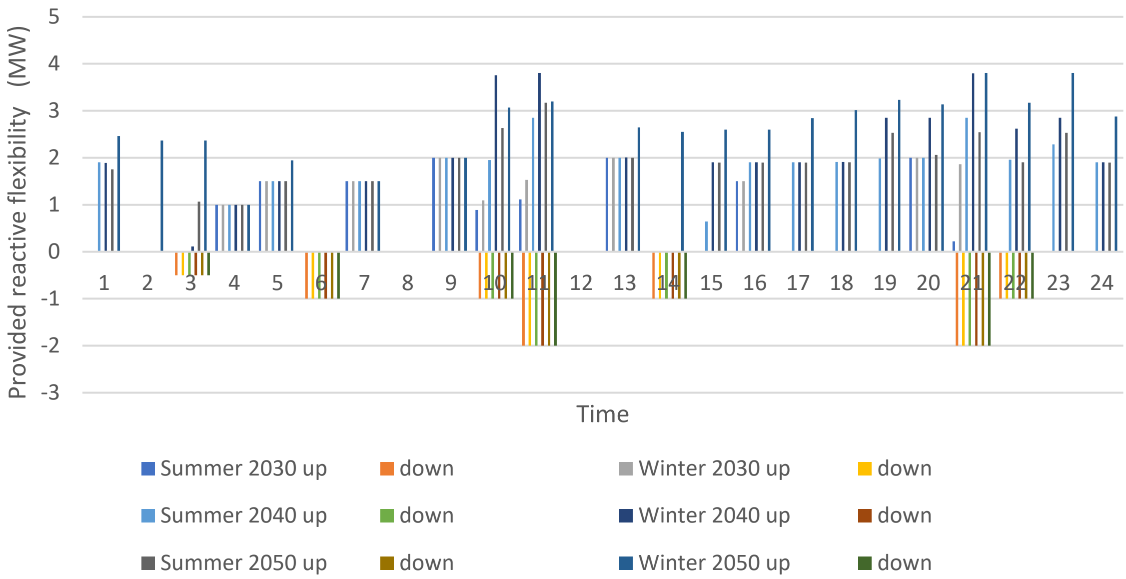


Figure 108 Provided upward and downward reactive power flexibility from storage units

Figure 109 compares the reduction of losses with ATTEST approach compared with BaU scenario. It can be seen that losses are reduced from 20% to almost 40 % in 2050.

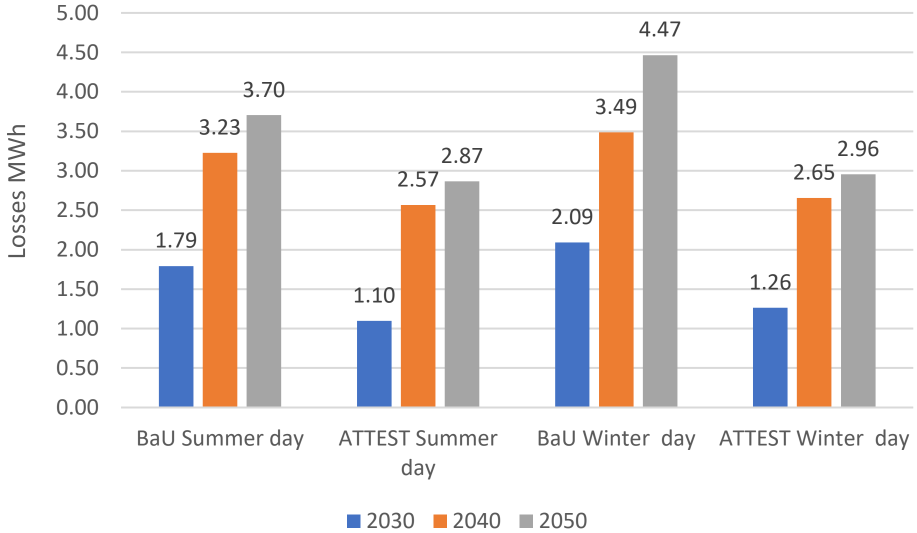


Figure 109 Losses over the years in the UK

6.2.4.Spain

The number of overloaded lines 2050 and total amount of overload is shown in Table XLVII. It can be seen that the ATTEST approach could not be able to solve the problems due to the size of the network and DERs placement in the distribution network. These problems occur in the radial part of the distribution network without flexibility sources, i.e. there were not any flexibility resources to solve network problems in that part of the grid. In 2030 and 2040 there was not a single line overloaded. Moreover, there were not any problems related to unallowed voltage deviations, either undervoltage or overvoltage.

Table XLI Congestion problems in 2050 solved with ATTEST approach

2050	BaU		ATTEST	
	Summer	Winter	Summer	Winter
Number of overloaded lines	28	9	28	9
Cummulative overload	27.95	22.21	27.86	22.21

The amount of upward and downward flexibility activated from flexible EV load for each specific day and over the years to satisfy the flexibility request from the TSO are shown in Figure 110 and Figure 111, while active and reactive upward and downward flexibility provided from storage units in Summer and Winnter days over the years are shown in Figure 112 and Figure 113.

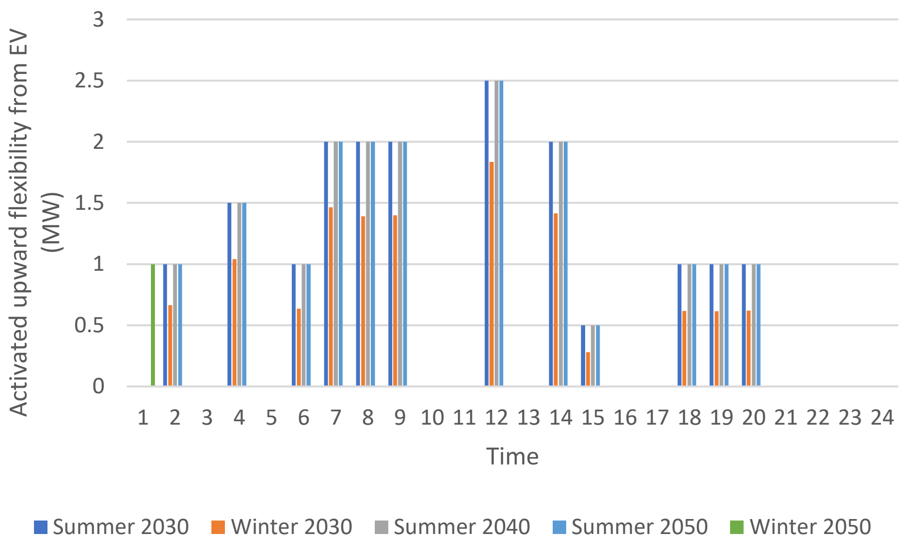


Figure 110 Activated upward flexibility from EV

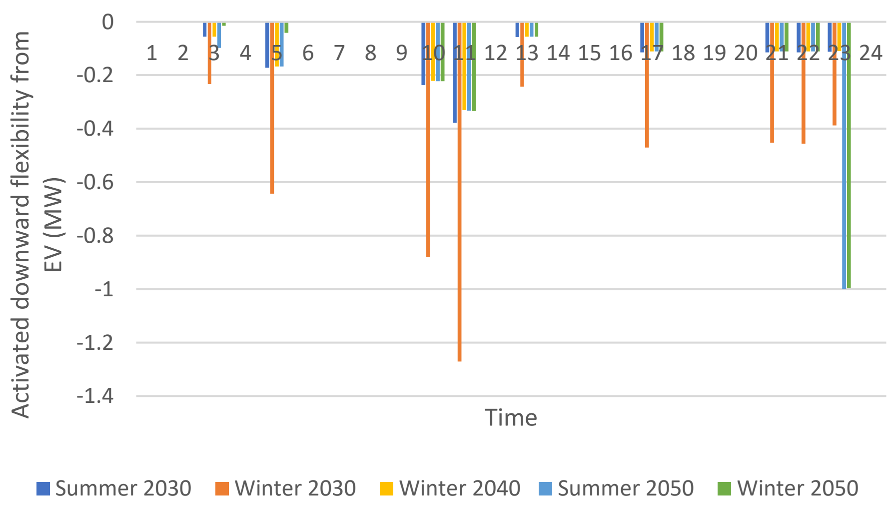


Figure 111 Activated downward flexibility from EV

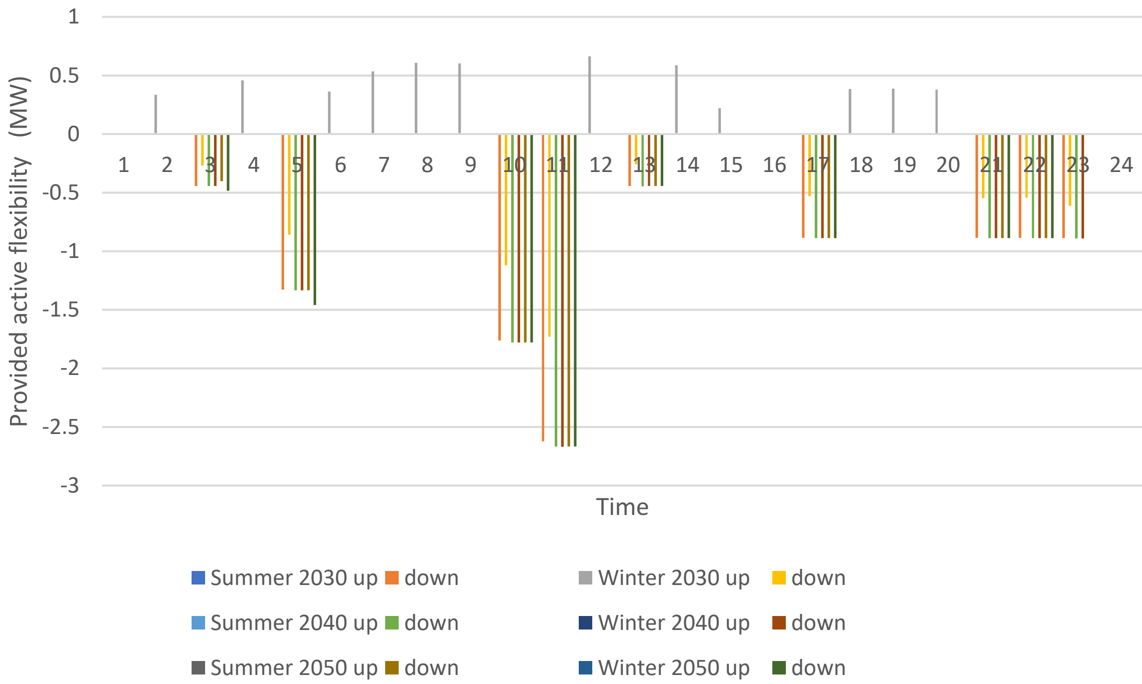


Figure 112 Provided upward and downward active power flexibility from storage units

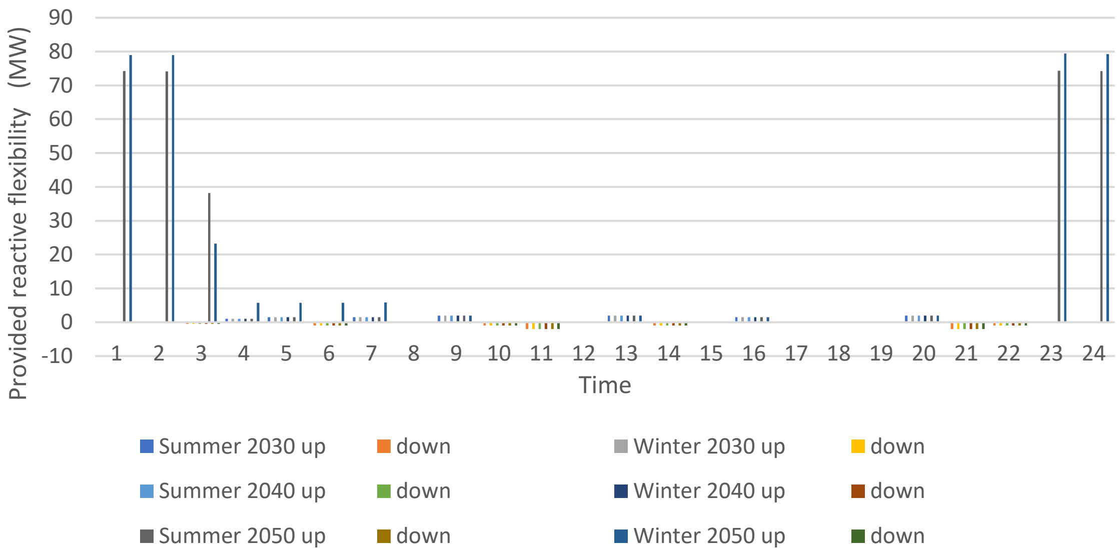


Figure 113 Provided upward and downward reactive power flexibility from storage units

Figure 114 shows losses over the years in Spain for typical Summer and Winter day. In 2030 losses are reduced by 1 % with ATTEST approach, while in 2040 from 1% to almost 2%. However, in 2050 losses are increased with ATTEST approach from 2% to 6 %. This increase happens because the algorithm developed for ancillary service activation in real-time operation of distribution network is focused on mitigating overloading and unallowed voltage deviations, while losses are not considered as direct part of the optimization.

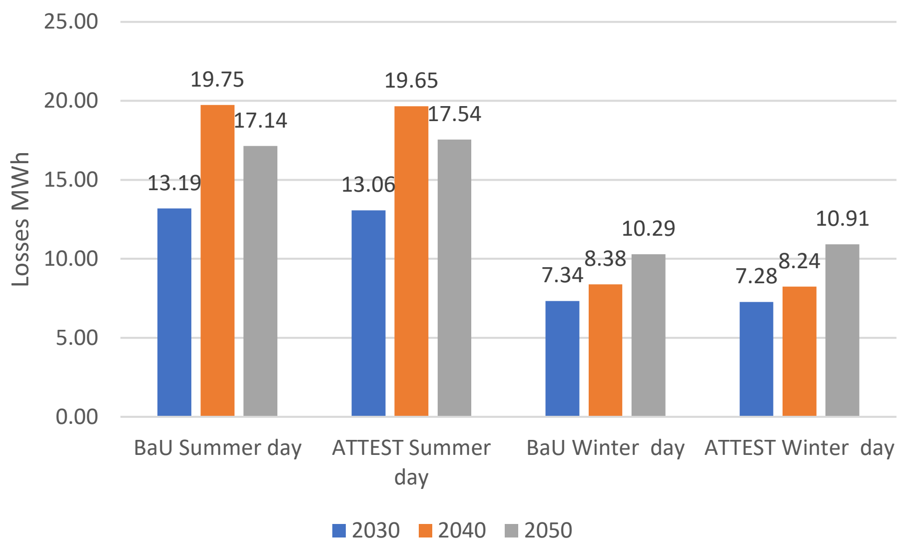


Figure 114 Losses over the years in Spain

6.3. Tool for ancillary services procurement in day-ahead operation planning of the transmission network

This section presents a high-level description and modelling features as well as the KPIs simulation results of the tool developed under the task T4.4 "Tool for ancillary services procurement in day-ahead operation planning of transmission networks" in WP4 of ATTEST project. The main objective of the proposed computationally tractable ATTEST tool is to enable TSOs to optimally procure ancillary services resorting to the flexibility of emerging sources such as EV and energy storage systems (ESS), specifically for voltage control and congestion management, to mitigate renewables uncertainty and ensure that the network N-1 security criterion is satisfied in a multi-period day-ahead scheduling, disseminated in [16].

In the following sections, first a high-level description of the proposed ATTEST approach is explained briefly and then, the KPIs are calculated to evaluate the proposed ATTEST tool's performance by comparing the BaU case and a series of test cases for which the proposed tool is used.

6.3.1. High-level description of the proposed ATTEST approach

The conventional tool to ensure cost-optimal procurement of ancillary services (e.g. for managing congestion and voltages) 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 for a given time period.

Considering the stochasticity of RES, ensuring N-1 security, and multi period decision making 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 a tractable and scalable day-ahead SCOPF tool in order to procure ancillary services by taking into account all mentioned aspects of future transmission networks.

The resulting SCOPF problem, which involves all the above-mentioned features, is a stochastic multi-period AC security constrained optimal power flow (S-MP-AC-SCOPF), the most complete and challenging uncertainty-aware and flexibility-driven SCOPF problem to date, published in [8]. Consequently, to break-down the high computational complexity of the resulting problem, a novel tractable methodology, based on a sequential linear algorithm (SLA) is developed which ensures the tractability as well as scalability of the tool. The methodology combines in the best possible way (i.e., by adapting and leveraging) of the most advanced knowledge and techniques in the area of SCOPF, combining them in a unique way. The methodology achieves tractability by solving sequentially a limited number of different linear approximations of the S-MP-AC-SCOPF problem. These linear approximations differ in terms of losses approximation, carefully reduced sets of constraints or tightening of critical constraints. Further information about the proposed methodology can be found in D4.5.

The proposed tool is tested against several test cases which are developed in T2.3 as discussed in the next section.

6.3.2. KPIs calculations

The proposed ATTEST tool is run for different combinations of the test cases for three networks (i.e., Portuguese, UK, and Croatian) as shown in the following Table XLII:

Table XLII Combination list of test cases for simulations

Country	Flexibility activation	2020		2030		2040		2050	
		Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
Portuguese	With		X	X	X	X	X	X	X
	Without	X	X	X	X	X	X	X	X
UK	With		X	X	X	X	X	X	X
	Without	X	X	X	X	X	X	X	X
Croatian	With		X	X	X	X	X	X	X
	Without	X	X	X	X	X	X	X	X

As indicated in Table XLII, a total number of 45 different cases are generated with respect to different country networks, activation of FL, year, and the typical day of the year (i.e., summer or winter). As in the year 2020 no flexibility was assumed, the corresponding cases are removed from the list, i.e., gray cells. Moving from 2020 to 2050, the system load is increased with a load growth factor, and the EV, ESS, and PV shares are increased with the specific scaling factors as well. It should be noted that the locations of these assets are changed for the winter and summer days in order to test the tool's ability to work with different locations of flexible assets. In the following, results of the ATTEST tool over these cases are discussed.

6.3.2.1. Security assessment

Before the utilization per se of the proposed tool, all cases are checked against a so-called security assessment tool (SA), in which the given operating point is tested against each element of the set of tuples (renewables power production scenarios, contingencies) by running a power flow calculation. The goal of the SA tool is to detect the violated constraints (i.e., bus voltages and line flow thermal limits) at the power flow solution and filter out the harmless contingencies. Note that the results of SA tool followed by ATTEST tool run in mode “without flexibility”, are considered as the BaU, which will be then compared with the proposed ATTEST tool.

The results of the SA tool over all cases are briefly provided in the three following tables, i.e., Table XLIII, Table XLIV, and Table XLV. Each of these three tables briefly indicates the outcome of the BaU tool with three different terms, namely: secure, insecure, and infeasible. The term secure represents the converged power flows over the full set of above-mentioned tuples with no constraint violations. Accordingly, since there are no harmful tuples, the ATTEST tool is not needed, and the methodology terminates. The term insecure indicates a case that notwithstanding the power flow is converges successfully for all tuples, some constraints w.r.t specific tuples are violated. Then, the harmless corresponding contingencies are removed from the set of contingencies and the tractable ATTEST tool is triggered over the set of harmful contingencies. The term infeasible refers to the case where the power flow does not converge for at least one tuple. Similarly, the harmless corresponding contingencies are removed from the initial set of contingencies and the ATTEST tool is triggered for the harmful remaining contingencies.

As indicated in Table XLIII and Table XLIV no secure case is observed for the Portuguese and the UK networks meaning that SA detected some constraint violations in all cases. In addition, 3 cases in Portuguese and 4 cases in the UK networks are even infeasible for some tuples. On the other hand, Croatian network is robust enough to be secure in 12 different cases. This means, as mentioned before, the ATTEST tool is no longer needed for these cases.

As will be shown in the following section, the ATTEST solution is so robust to handle and remove constraint violations for all the cases with the acceptable accuracy while retaining tractability.

Table XLIII SA results for each simulation of Portuguese network

		2020		**2030**		**2040**		**2050**	
		Summer	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**
With Flexibility	Normal state			Insecure	Insecure	Insecure	Insecure	Insecure	Insecure
	Post contingency state			Infeasible	Insecure	Insecure	Insecure	Insecure	Insecure
Without Flexibility	Normal state	Insecure	Insecure	Insecure	Insecure	Insecure	Insecure	Insecure	Insecure
	Post contingency state	Insecure	Insecure	Infeasible	Insecure	Insecure	Infeasible	Insecure	Insecure

Table XLIV SA results for each simulation of the UK network

		2020		2030		2040		2050	
		Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
With Flexibility	Normal state			Insecure	Insecure	Insecure	Insecure	Insecure	Insecure
	Post contingency state			Infeasible	Infeasible	Insecure	Infeasible	Insecure	Insecure
Without Flexibility	Normal state	Insecure	Insecure	Insecure	Insecure	Insecure	Insecure	Insecure	Insecure
	Post contingency state	Insecure	Insecure	Infeasible	Insecure	Insecure	Insecure	Insecure	Insecure

Table XLV SA results for each simulation of Croatian network

		2020		2030		2040		2050	
		Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
With Flexibility	Normal state			Secure	Secure	Insecure	Insecure	Insecure	Insecure
	Post contingency state			Secure	Secure	Insecure	Insecure	Insecure	Insecure
Without Flexibility	Normal state	Secure	Secure	Secure	Secure	Insecure	Insecure	Insecure	Insecure
	Post contingency state	Secure	Secure	Secure	Secure	Insecure	Insecure	Insecure	Insecure

6.3.2.2. ATTEST tool

Given the harmful set of contingencies at the result of BaU tool, the proposed ATTEST tool is run for the insecure and infeasible cases. It is noted that the objective of the proposed tool represents the short-term day-ahead operation costs which are classified into OPEX cost terms. Thus, no CAPEX cost is seen in the proposed day-ahead operation planning tool. Accordingly, the performance of the ATTEST tool is demonstrated initially against cost reductions. Then, BaU and the proposed ATTEST solution are compared against the constraint violations explicitly for both voltages and line flow thermal limits for normal and post contingency operation states. The discussions of the obtained results are presented hereafter per country. Note that we consider BaU the ATTEST tool in mode "without flexibility", which is an already a significant enhancement of the real BaU, which consists in solving deterministic AC SCOPF for each time period separately and without considering flexibility.

Portuguese Network: First, the objective cost is compared for different years per country w.r.t flexibility activation for a typical summer day, as illustrated in Figure 115.

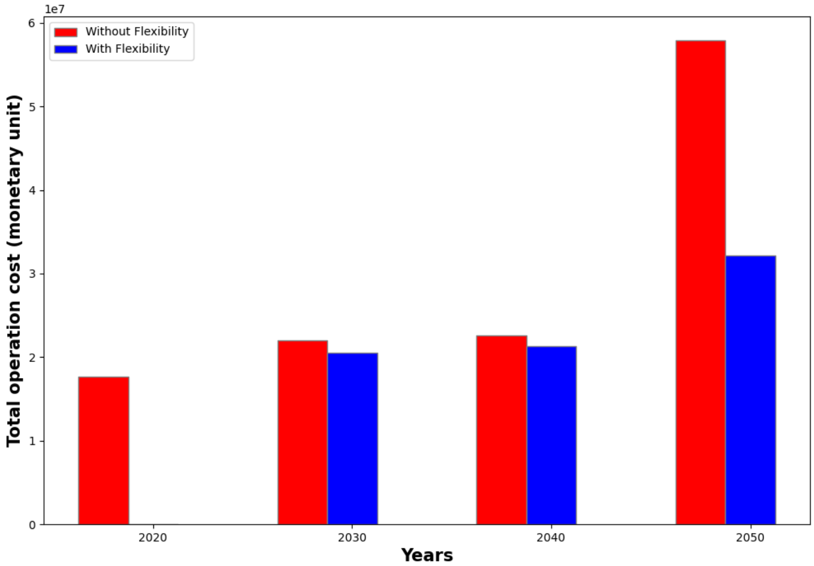


Figure 115 Total operation cost comparison with against without flexibility activation for Portuguese network (summer day)

As indicated in Figure 115, the total operation cost increases gradually, as expected as the years grow for both with and without flexibility activation options mainly due to both load and renewables growth. Increased load would directly increase the operation cost on the one hand and the extra penetration of renewables must be curtailed on the other hand that cause even larger operation cost.

As there is no flexibility penetration for the year 2020, the operation cost of the three remaining years can be compared. Keeping this in mind, the first notable observation is that the activation of flexibility reduces the total operation cost for all years 2030, 2040, and 2050, demonstrating the superiority of ATTEST solution over the BaU. Particularly, the largest difference is observed for the year 2050 with the largest shares of renewables and load growth.

Approximately 45% of cost reduction, i.e., $[1 - (2.247\text{e}7 - 5.788\text{e}7)/5.788\text{e}7] \times 100 \approx 45\%$, is mainly because of both load and renewable curtailment cost reduction, as shown in Figure 116. This figure compares the detailed cost terms for the Portuguese network, year 2050 on a summer day, in a logarithmic scale. The cost terms (CT) CT1 to CT9 are defined as follows:

CT1: Fuel cost of generators in normal operation state
CT2: Flexibility procurement cost of EV in normal operation state
CT3: Flexibility procurement cost of ESS in normal operation state
CT4: Load curtailment cost in normal operation state
CT5: Renewable curtailment cost in normal operation state
CT6: Expected flexibility procurement cost in post-contingency states
CT7: Expected flexibility procurement cost in post-contingency states
CT8: Expected load curtailment cost in post-contingency states
CT9: Expected renewable curtailment in post-contingency states

Figure 116 shows that thanks to the effective deployment of the flexibility from flexible resources, the large load curtailments in both CT4 and CT8 are avoided. In addition, the renewables' curtailment is also reduced in post-contingency states.

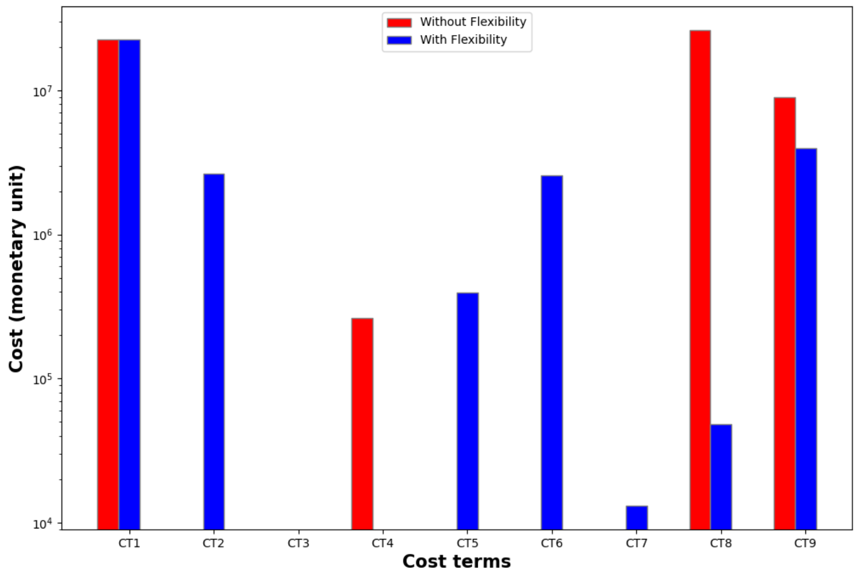


Figure 116 Detailed cost terms for the simulation on Portuguese network, year 2050 on the summer day.

Similar justification is valid for the winter day as shown in both total operation cost in Figure 117 and detailed cost terms in Figure 118. However, in this case, the load curtailment in normal operation is increased compared to the case without flexibility. Meanwhile, the ATTEST tool finally could manage to find lower total operation cost of 36%, i.e., $[1-(3.289\mathrm{e}7-5.150\mathrm{e}7)/5.150\mathrm{e}7]\times 100 \approx 36\%$. This could be expectable since as previously mentioned, the flexibility assets are located differently for the summer and the winter day alternatives and accordingly different load curtailment pattern is plausible.

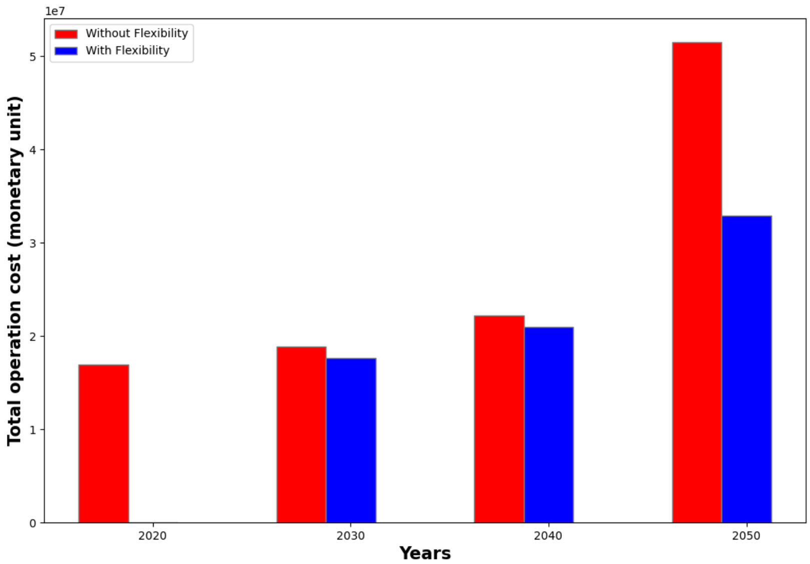


Figure 117 Total operation cost comparison with against flexibility activation for Portuguese network (winter day)

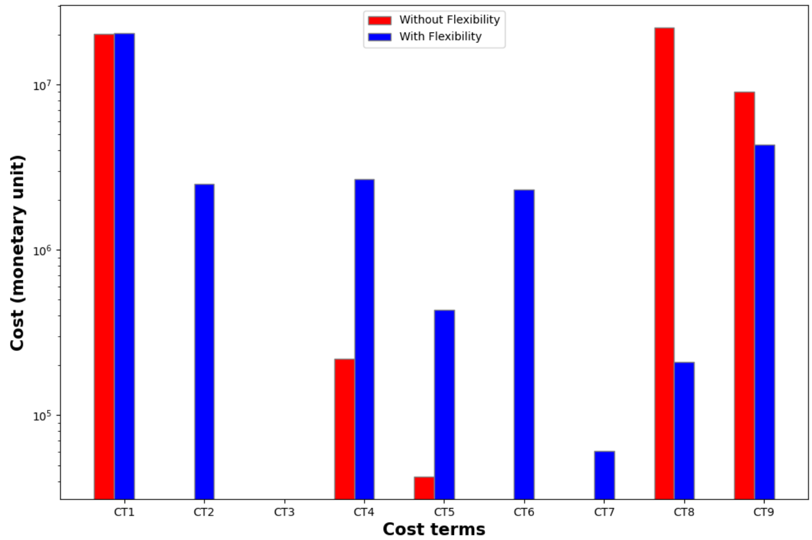


Figure 118 Detailed cost terms for the simulation on Portuguese network, year 2050 for the winter day.

As mentioned earlier in this section, the BaU was unable to identify the secure operation in any simulation cases of this country. However, as will be shown hereafter the proposed ATTEST tool is robust enough to handle not only the insecure but also the infeasible cases. Among 15 simulations for this country, the two most relevant cases are shown in Figure 119, where CV1 to CV4 are different constraint violation terms defined as:

CV1: Number of voltage constraint violations in normal operation state
CV2: Number of line flow constraint violations in normal operation state
CV3: Number of voltage constraint violations in post-contingency operation states
CV4: Number of line flow constraint violations in post-contingency operation states

This figure indicates that the BaU detected 1804 constraint violations for the case of year 2050, without flexibility on a summer day, while the remaining constraint violations followed by the proposed ATTEST tool is reduced to only 13, with the largest violation magnitude being 0.003 p.u., which shows the high performance of the proposed tool. A similar trend is also observed in the case with flexibility, and this time the initial number of total constraint violations were 1490 while the final remaining violated constraints are only 2 and the largest violation magnitude was 0.003 p.u. One can observe the practicality of the proposed tool in removing the violated constraints for the two other cases which are with and without flexibility on a winter day for year 2050, as well in Figure 120. It is noted that among 45 different cases for all three countries, the worst performance of the proposed tool w.r.t number of remaining constraint violations is observed in Figure 120 under the case without flexibility, with 100 violated constraints and 0.1 p.u. being the largest violation magnitude. Even in this worst case, almost 95% of the violations are removed.

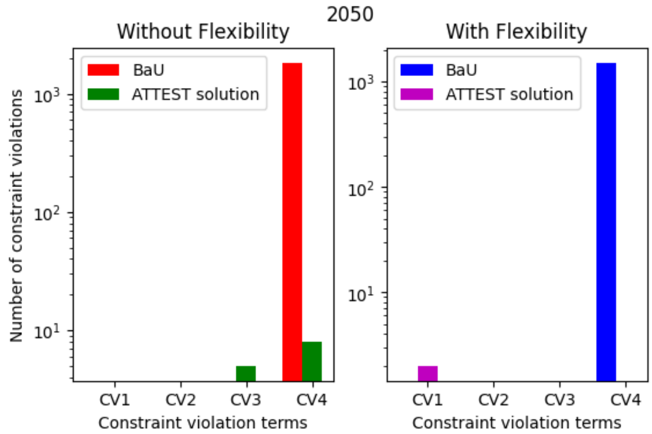


Figure 119 Constraint violations for Portuguese network, year 2050 and summer day.

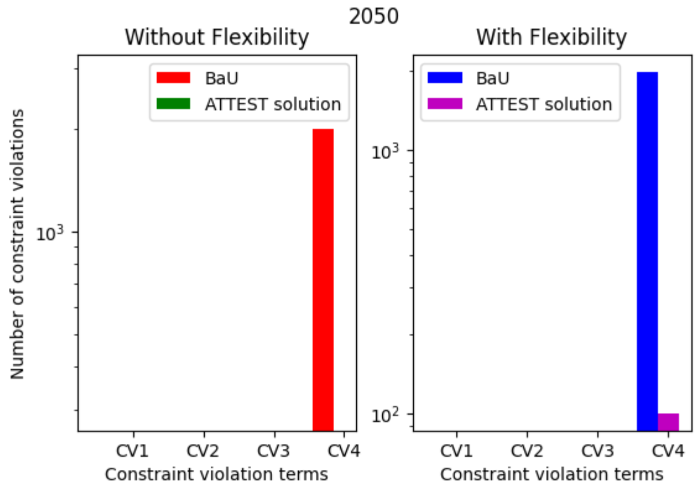


Figure 120 Constraint violation for Portuguese network, year 2050, and winter day

To have a general view of the different cases solved for this country, Figure 121 shows total number of constraint violations for representative cases. It is observed in these cases that, as the operation is more stressed, the BaU detects more constraint violations, while almost all violations are removed by the ATTEST tool. This clearly supports the performance and necessity of the proposed methodology.

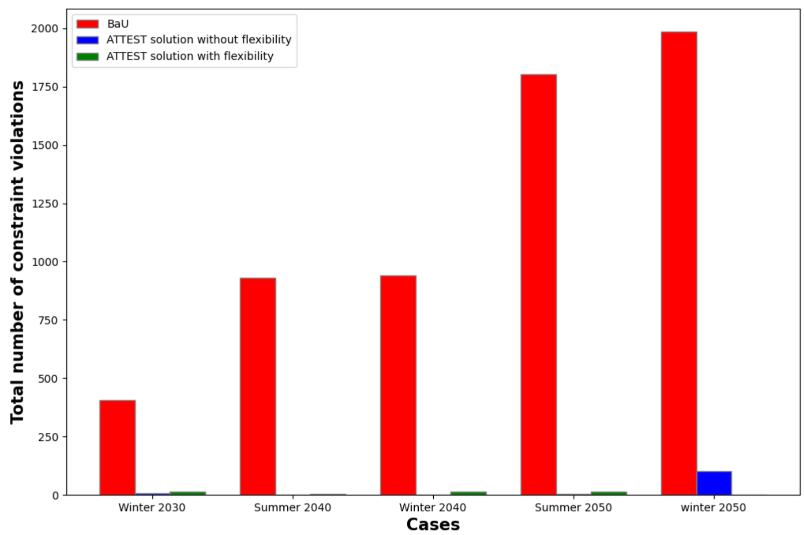


Figure 121 Total constraint violations for representative simulations of the Portuguese network.

From the computational tractability point of view, among the 45 simulations, the largest computation time of the tractable tool amounts roughly to 45 minutes for the Portuguese network in 2040, with flexibility on a winter day. Even in this worst time-consuming case, the running time is in the range of one hour, the time limit an operator would be willing to wait in the day-ahead of operation.

The UK Network: Starting with the total operation cost, Figure 122 compares the cases with and without flexibility activation for a typical winter day. As expected, the total operation cost increases gradually, as the years grow for both with and without flexibility activated options. However, the rate of increase for the case without flexibility is much higher than that of the case with flexibility. This can be explained by the fact that excess load and renewables in the case without flexibility must be curtailed, while optimally deploying the flexibility sources in the case with flexibility trades-off the flexibility activation cost and load or renewable curtailment, thus smoothing the cost increment. Numerically speaking, the total operation cost increases by approximately 22% for the case without flexibility, i.e. $[1 - (4.273\text{e}7 - 5.437\text{e}7)/5.437\text{e}7] \times 100 \approx 22\%$, from year 2030 to 2050, while for the other case, the cost increases by almost 14%, i.e. $[1 - (3.301\text{e}7 - 3.813\text{e}7)/3.813\text{e}7] \times 100 \approx 14\%$.

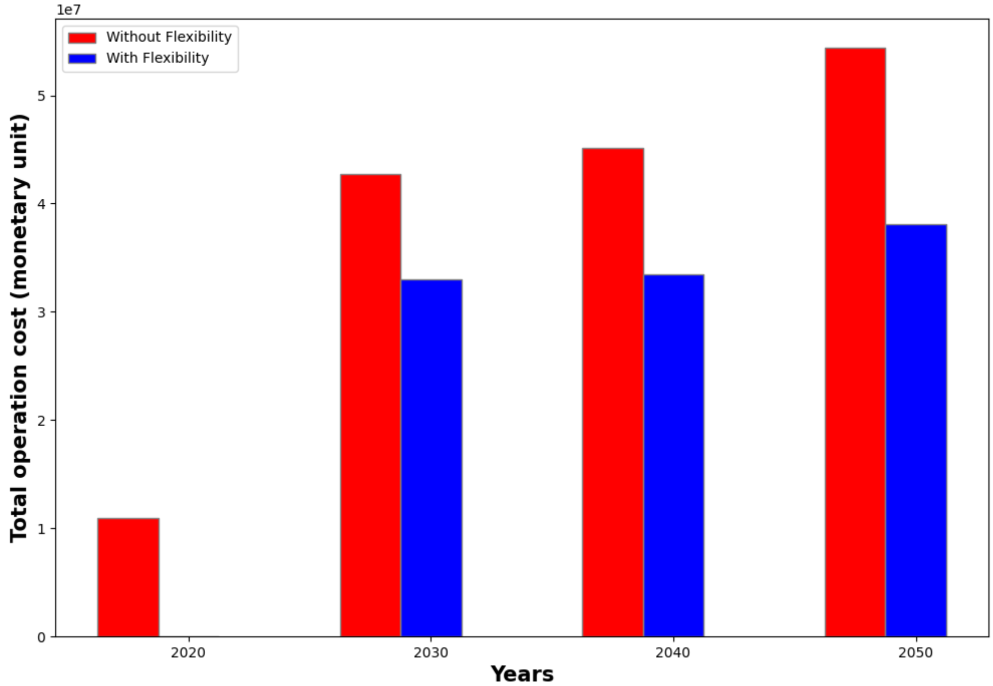


Figure 122 Total operation cost comparison with against without flexibility activation for the UK network (winter day)

The cost increment for the summer day, as in Figure 123, is even smaller for the with flexibility case, i.e. 5% $[1 - (3.137\text{e}7 - 3.291\text{e}7)/3.291\text{e}7] \times 100 \approx 5\%$ while the cost increment for the without flexibility case is 23%, i.e. $[1 - (4.197\text{e}7 - 5.444\text{e}7)/5.444\text{e}7] \times 100 \approx 23\%$.

Like in the previous network study, a detailed cost-term determination can better explain the large difference in the total operation cost for the cases with and without flexibility, specifically for the year 2050, which has the largest difference. Accordingly, Figure 124 shows the detailed cost terms for the case of year 2050 (winter day). This figure demonstrates that thanks to the effective deployment of the flexibility from flexible resources, both load and renewable curtailment CT4 and CT5 for normal operation state as well as CT7 and CT8 for post contingency operation states are largely reduced.

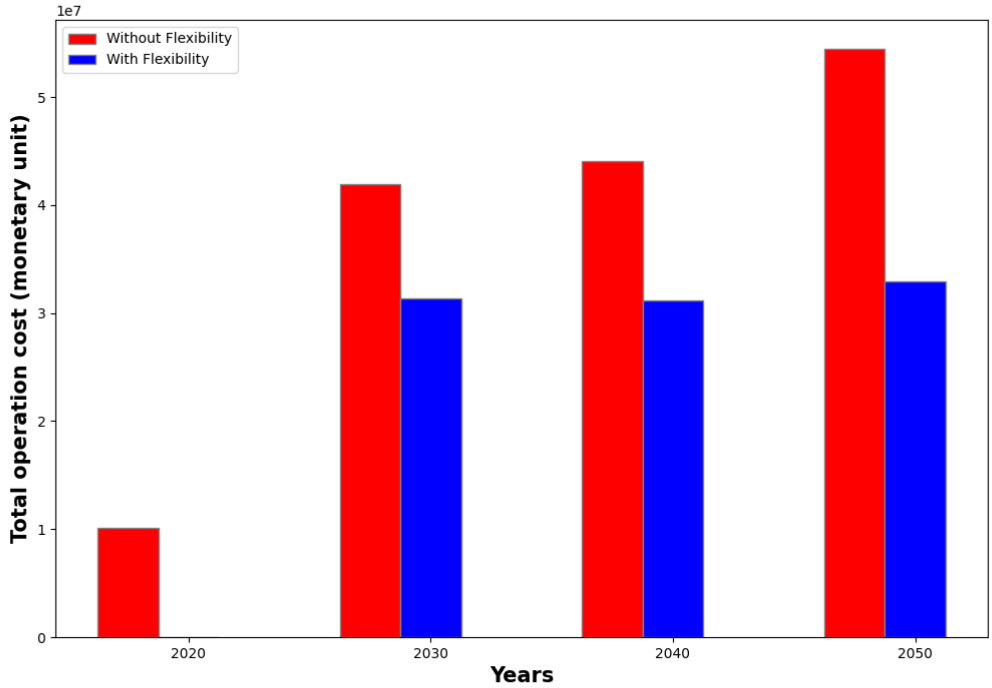


Figure 123 Total operation cost comparison with against without flexibility activation for the UK network (summer day)

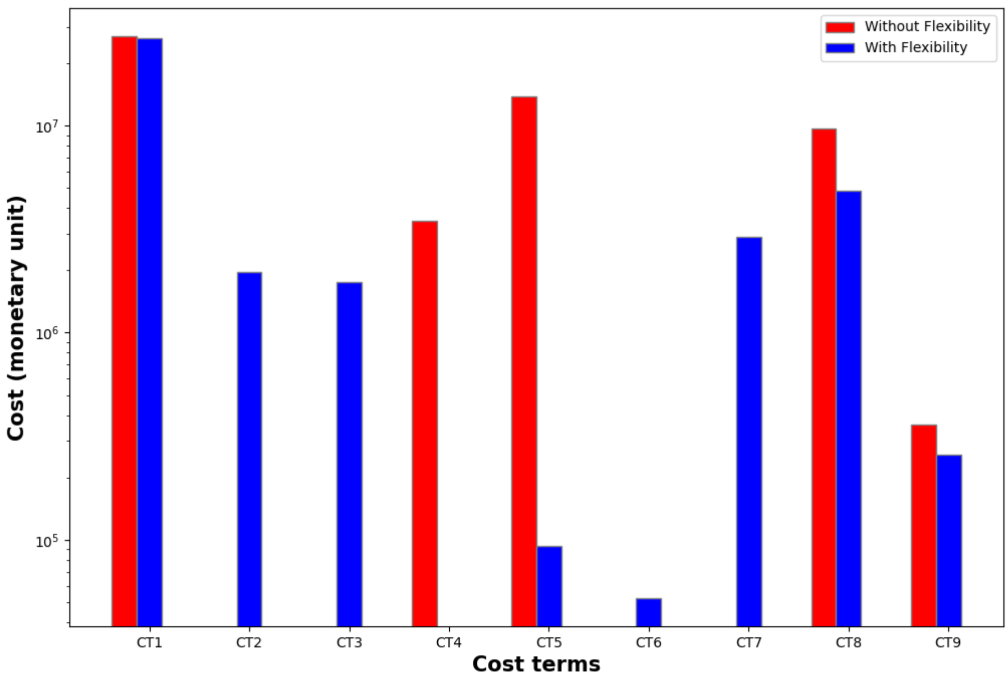


Figure 124 Detailed cost terms for the simulation on the UK network, year 2050 on the winter day

Regarding constraint violation reduction, the UK network confirms again the applicability of the proposed ATTEST tool.

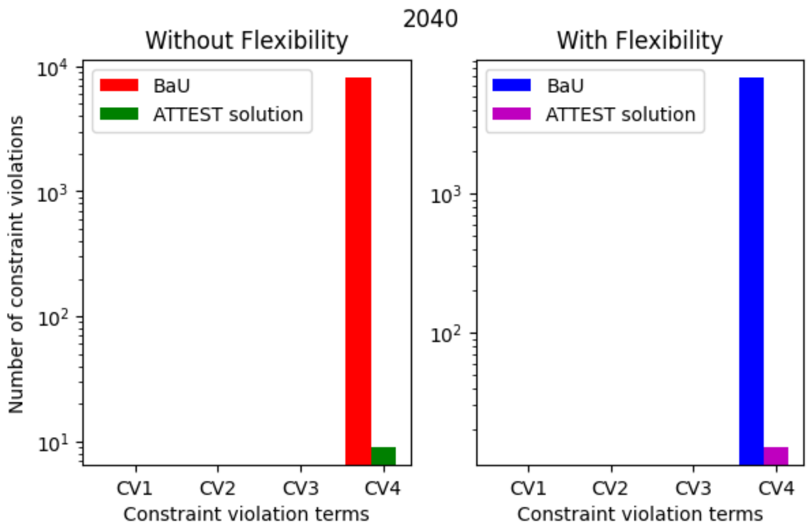


Figure 125 Constraint violations for UK network, year 2040 (summer day).

Figure 125 shows the reduction of the number of constraint violation, from 8029 detected in the BaU, to 9 remained violations (the largest violation magnitude is as low as 0.003 p.u.) when flexibility is not activated. The right-hand side "with flexibility" figure also indicates a huge constraint violation reduction. In the latter case, 6759 line flow constraint violations found in BaU are reduced to 15 remained violations with 0.006 p.u. being the largest violation magnitude. The amount of remained constraint violations is almost negligible compared with the total number of 1,200,000 line flow constraints, i.e. number of contingencies (50) x number of time periods (24) x number of scenarios (10) x number of lines (100) = 1,200,000.

The overall view of the ability of the proposed methodology to remove the violations is illustrated in Figure 126. This figure shows that the largest number of remained constraint violations after running the proposed tool appears in the case 2050 (winter, with flexibility); it contains 24 line flow violations and the largest violation magnitude is 0.007 p. u.

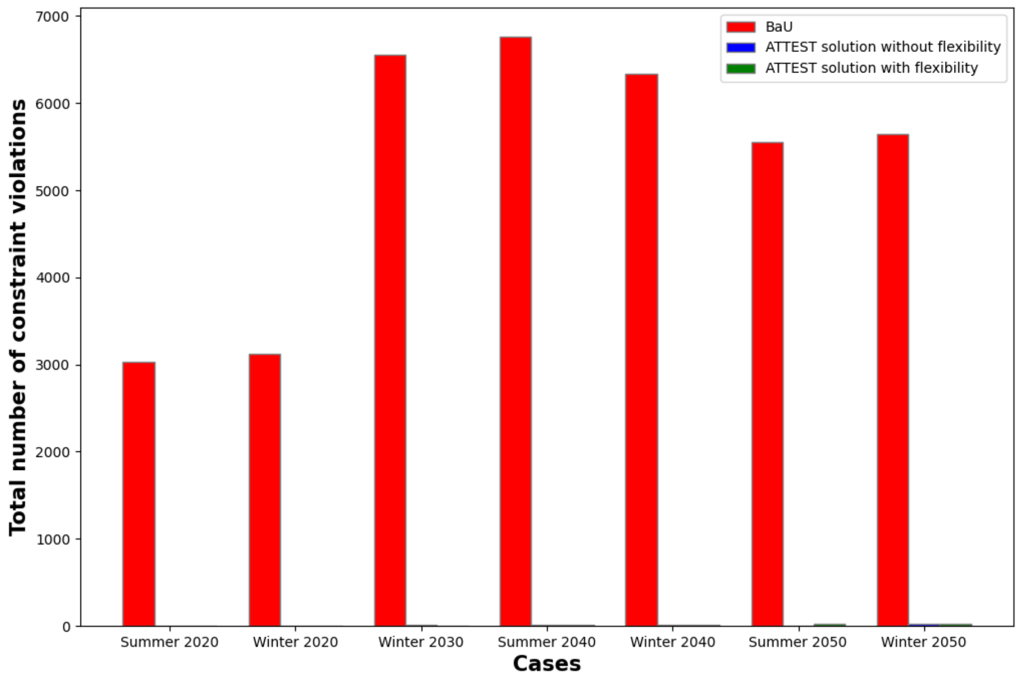


Figure 126 Total constraint violations for representative simulations of the UK network.

Croatian Network: Since all features discussed for the previous two networks also hold for the Croatian network, comprehensive details are not provided, focusing only on the main different aspects.

The important point to discuss in these cases is the reduction of fuel costs for generators in normal operation state, along with the common total operating cost reduction in the case of flexibility activations. This happens the most in the year 2050 on a summer day, as depicted in Figure 127.

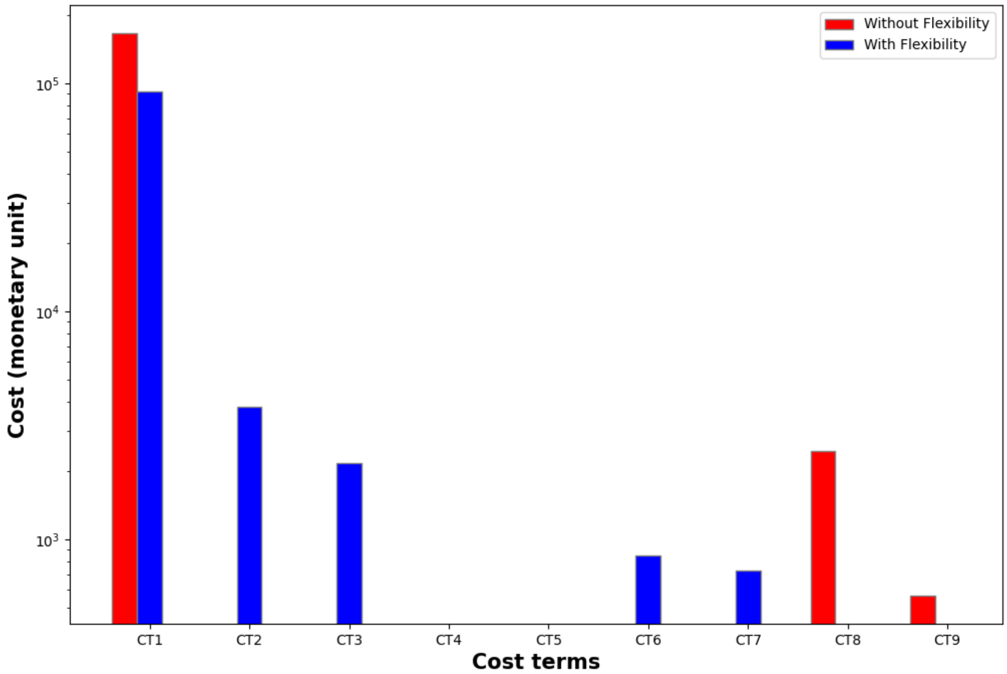


Figure 127 Detailed cost terms for the simulation on Croatian network, year 2050 on the summer day.

This figure indicates that activating flexibilities not only removes the load and renewable curtailments totally in the post-contingency state, i.e. CT8 and CT9, but also diminish the fuel cost of generators in normal operation from 165,938 monetary unit (m.u.) without activation of flexibilities to 91,873 m.u. for the case with flexibilities. This behaviour stems from the fact that when flexibilities are not used to tackle costly curtailment of either load or renewables, i.e. no values for CT4 and CT5, there would be enough room for flexibilities to also reduce the normal power production of generators.

6.4. Tool for ancillary services activation in real-time operation of the transmission network

This subsection defines and compares KPIs calculated by the tool for ancillary service activation in real-time operation of the transmission network developed in task T4.5. This tool activates required flexibility from resources connected to the transmission and distribution network in order to follow reserved flexibility from day-ahead stage (tool developed in task T4.4 for day-ahead procurement of ancillary services in the transmission network). The tool minimizes the deviation from day-ahead schedule in order to keep the voltage in the allowed limits and minimize overloaded lines by activating energy storage units and flexible EV load or curtail PV production.

The KPIs calculated by this tool are focused on the technical aspects in the transmission network operation. Technical KPIs calculated to demonstrate the benefits of the tool for ancillary service activation in real-time operation of the transmission network are divided into three categories:

i) number of overloaded lines and total overload in MVA,
ii) number of undervoltage buses and cumulative undervoltage,
iii) number of overvoltage buses and cumulative overvoltage.

To demonstrate the efficiency and performance of the tool, KPIs are calculated for two scenarios. The first scenario is Business as Usual (BaU) in which the real-time operation of the transmission network is considered without flexibility activation developed in the ATTECT project. The second scenario is ATTEST approach in which different levels of potential flexibility are available and tool activates this flexibility in order to ensure secure operation of transmission system by solving network problems. KPIs are calculated for 2030, 2040, and 2050 for two cases: Summer day and Winter day.

6.4.1. Input data

Scenarios of new low-carbon technology integration data for Croatia, UK, and Portugal for 2030, 2040, and 2050 are provided in Figure 128, Figure 129 and Figure 130:

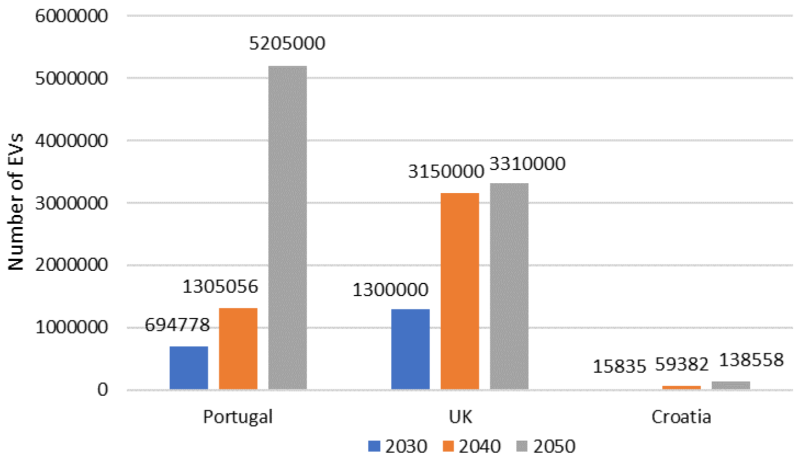


Figure 128 Scenarios of EVs integration over the years

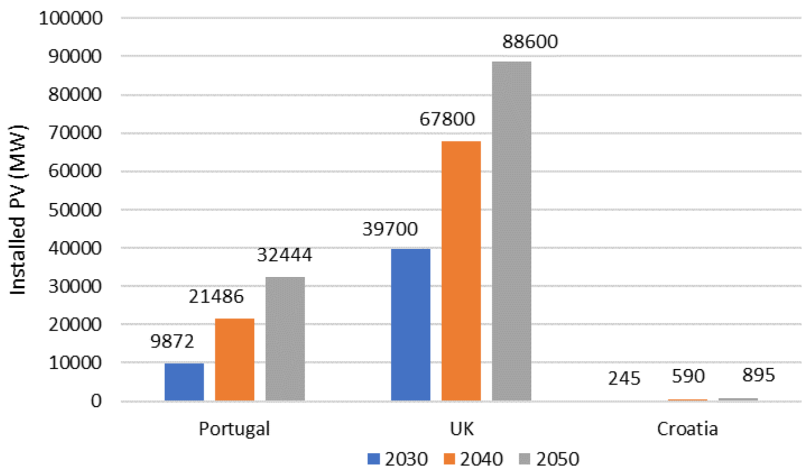


Figure 129 Scenarios of PV integration over the years

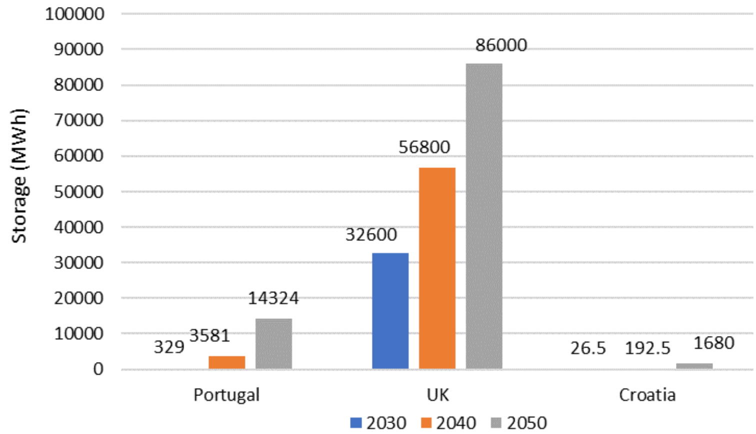


Figure 130 Scenarios of storage integration over the years

The input data provided above are used in the tools for day-ahead procurement and real-time activation of ancillary service in the transmission network. Moreover, the tool for real-time activation of ancillary services receives for each country and year for the location of each type of low-carbon technology in the network with associated PV profile, daily non-flexible load profile, EV load and amount of flexible EV profile. The tool for day-ahead procurement of ancillary services provides an input regarding the reserved amount of flexibility for each typical day for a 24-hour period: reserved EV upward flexibility and reserved EV downward flexibility, state of charge, charging, and discharging of battery storage units, load and RES curtailment, active and reactive power in generator nodes.

The following sections present a detailed analysis of the KPIs for Croatia, Portugal, and the UK focusing on the comparison of BaU and ATTEST solutions. These sections will demonstrate the effectiveness of the tool developed in the ATTEST project highlighting the decreased number of overloaded lines and total cumulative line overloading, together with KPIs related to voltage deviations.

6.4.2. Croatia

The number of overloaded lines for 2030, 2040, and 2050, as well as total amount of overload is shown in Figure 131 and Figure 132, respectively. It can be seen that for 2030 and 2040 there was not a significant problem in the network. However, in 2050 it can be seen that during characteristic summer and winter days 52 and 30 lines were overloaded with total 623.6 and 500.68 MVA overloading.

Applying ATTEST tool on real-time network operation results in reducing the number of overloaded lines and total amount of overload in MVA.

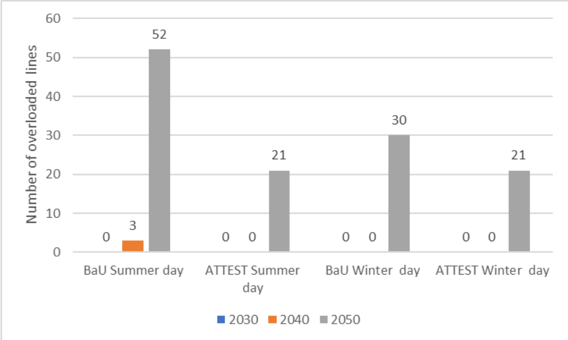


Figure 131 The number of overloaded lines for typical days over the years in Croatia

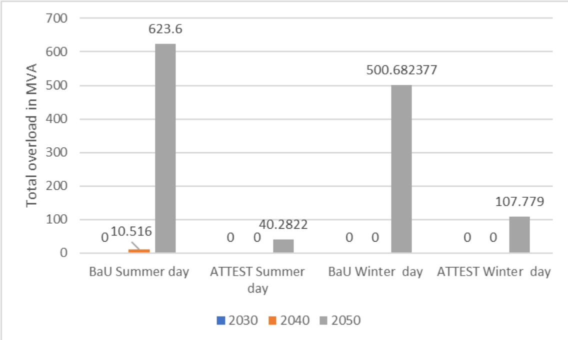


Figure 132 Total amount of overload for typical days over the years in Croatia

Figure 133 and Figure 134 present number of overvoltage buses and cumulative daily overvoltage in p.u. It can be seen that ATTEST solution results in decreased number of overvoltage buses for typical summer day compared to the BaU approach. To be more precise, ATTEST solution reduced the number of overvoltage buses by 11 %, 24%, and 70 % for 2030, 2040, and 2050, respectively. However, during the winter day in 2050 more overvoltage buses are detected with ATTEST solution compared to BaU approach. There is a logical and mathematical reason for this exception. The objective function in the tool allows voltage deviation with a double penalty scheme to mitigate line overloading. The first penalty step for lower deviation is set for maximum 0.05 p.u. overvoltage, and the second one is set for higher overvoltage with a much higher penalty factor. This results in a tradeoff of increased number of overvoltage buses and reduced overloading. As shown in Figure 133 and Figure 134, in 2050 there are 22 buses with a total daily 0.5125 p.u. overvoltage. This implies that on average each bus is approximately only 0.02 p.u. above the allowed voltage limit, indicating that only the lower penalty was used as is intended by the tool.

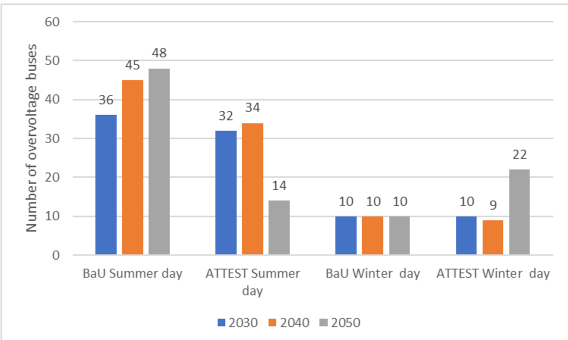


Figure 133 Number of overvoltage buses for typical days over the years in Croatia

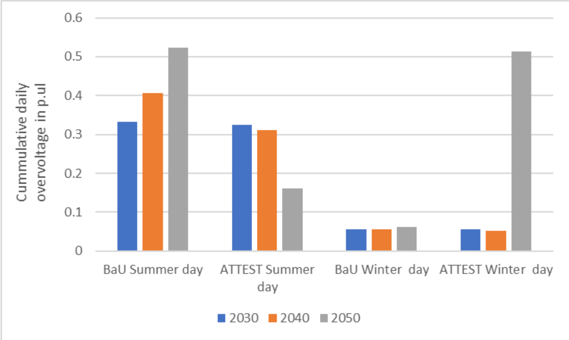


Figure 134 Cumulative daily overvoltage in p.u. for typical days over the years in Croatia

Figure 135 and Figure 136 present number of undervoltage buses and cumulative daily underloading in p.u. It can be seen that problems with undervoltage buses occurred only in 2050. During the entire summer day only one bus was detected as an undervoltage bus, while during the winter day three buses had unallowed voltage drop. It can be seen from Figure 135 and Figure 136 that the ATTEST solution was capable of solving all detected issues.

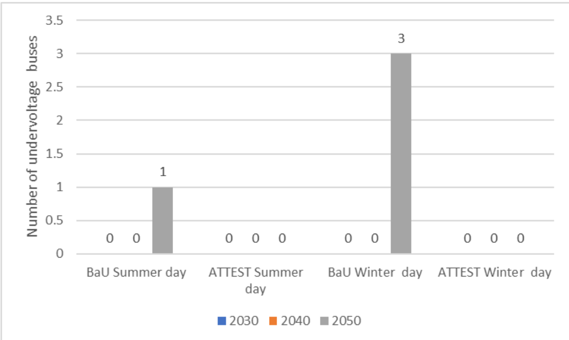


Figure 135 N*umber of undervoltage buses for typical days over the years in Croatia*

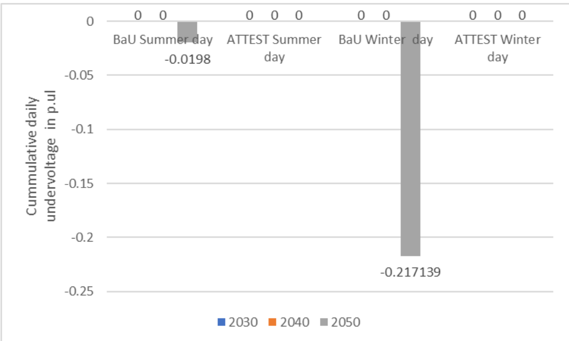


Figure 136 Cumulative daily underloading in p.u. for typical days over the years in Croatia

Figure 137 shows losses in Croatian transmission network during the observed period. It can be seen that losses are slightly increased in 2030 and in Winter day in 2040 and 2050 with ATTEST approach, while in 2040 Summer day and 2050 Summer day losses are decreased by 0. 2 % and by almost 17 %.

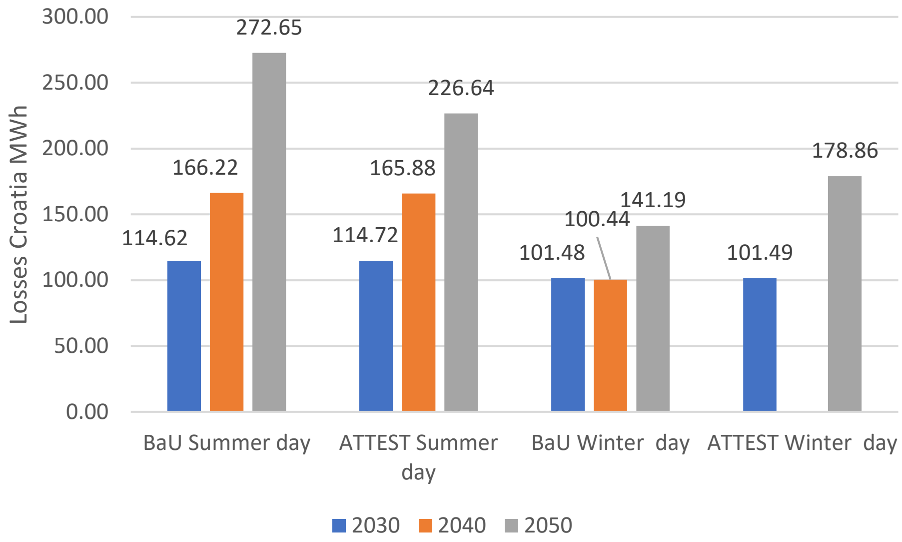


Figure 137 Losses over the years in Croatia

6.4.3. Portugal

Figure 138 and Figure 139show the number of overloaded lines with total daily overload in MVA for typical summer and winter days in 2030, 2040, and 2050. It can be seen that with ATTEST solution the number of overloaded lines is significantly decreased compared to BaU approach. During the summer day the number of overloaded lines is decreased by 25% in 2030 and 2040, and by 41 % in 2050 using the tool developed in T4.5 in the ATTEST project. Moreover, during the winter day, the number of overloaded lines is reduced by 36 %, 22%, and 40% in 2030, 2040, and 2050, respectively.

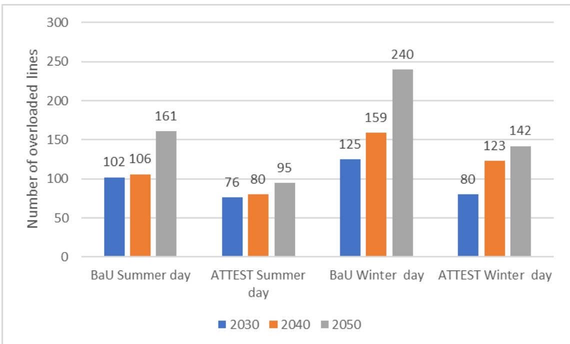


Figure 138 The number of overloaded lines for typical days over the years in Portugal

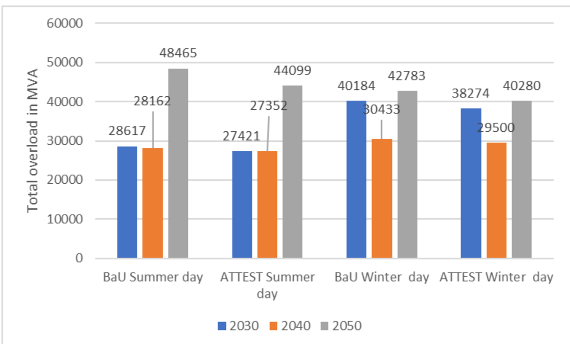


Figure 139 Total amount of overload for typical days over the years in Portugal

Figure 140 and Figure 141show the number of overvoltage buses and cumulative daily overvoltage in p.u. in 2030, 2040, and 2050. ATTEST solution results in more overvoltage buses compared to the BaU approach because of double penalty scheme for voltage deviation in the objective function as described before. More precisely, 6 buses are above the voltage limits in 2030 during the summer day, 19 in 2040, and 26 in 2050 due to increasing level of installed PV capacity. During the winter period, 1 bus is above the allowed voltage limit in 2030, while 8 buses in 2040, and 32 buses in 2050. If these numbers from Figure 140are compared with cumulative daily overvoltage in Figure 141, it can be concluded that each bus has approximately a very small unallowed deviation. The average unallowed deviation for a summer day is 0.0018 p.u. for 2030, 0.0147 p.u. for 2040, and 0.0224 p.u. for 2050., while for winter day 0.00051 p.u. for 2030, 0.01764 p.u. for 2040, and 0.02703 p.u. for 2050.

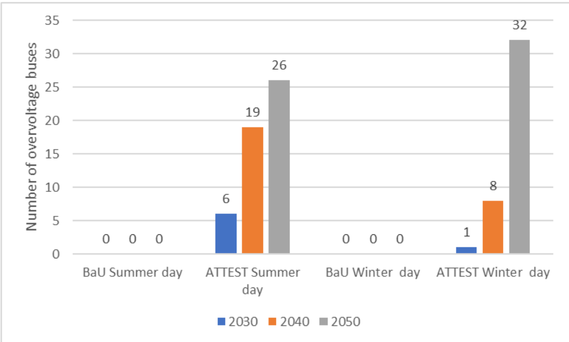


Figure 140 Number of overvoltage buses for typical days over the years in Portugal

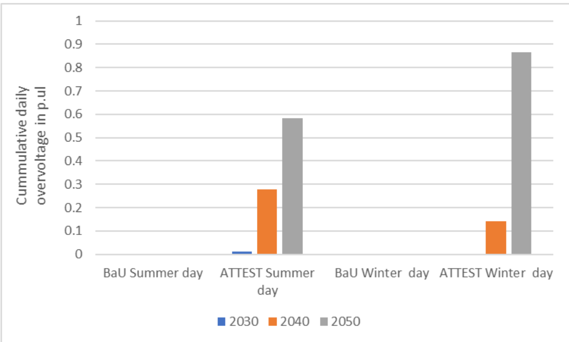


Figure 141 Cumulative daily overvoltage in p.u. for typical days over the years in Portugal

Only one undervoltage bus is detected during the summer day in 2050 when ATTEST solution is used with 0.000524 p.u. below allowed voltage level as shown in Figure 142 and Figure 143.

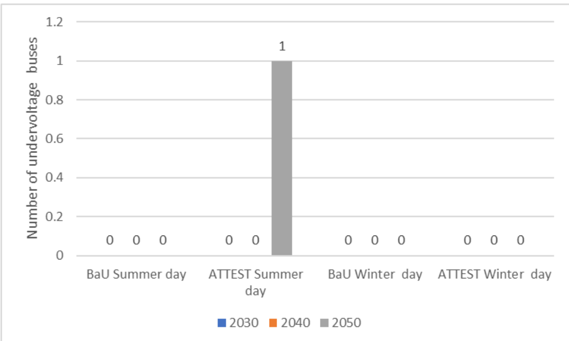


Figure 142 Number of undervoltage buses for typical days over the years in Portugal

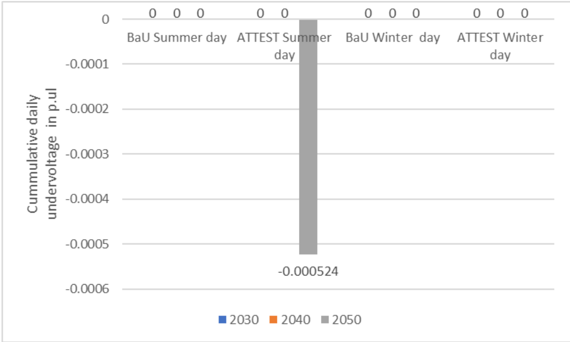


Figure 143 Cumulative daily undervoltage in p.u. for typical days over the years in Portugal

Losses in Portuguese transmission network are shown in Figure 144. The losses increased with ATTEST approach from 1% to almost 50 % because the tool did not focus on losses reduction, only on reduction of overloading and voltage problems.

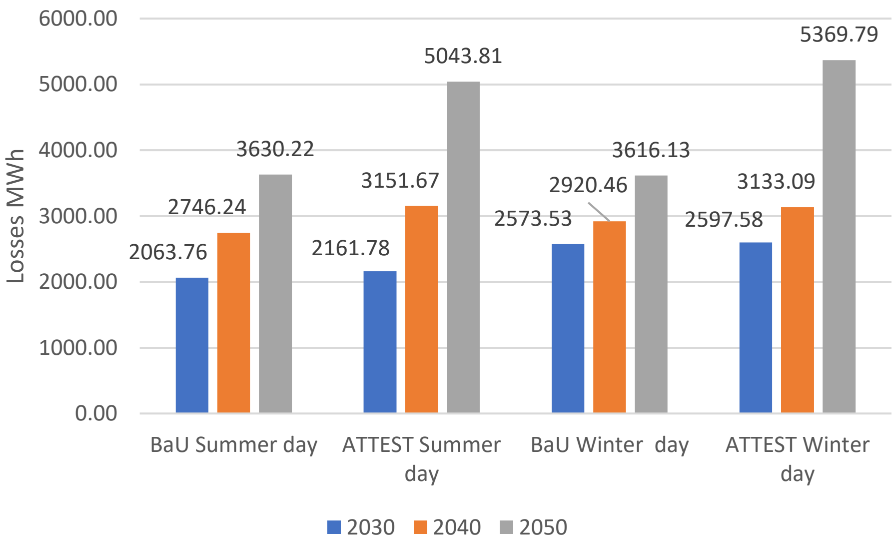


Figure 144 Losses over the years

6.4.4.The United Kingdom

ATTEST tool for real-time activation of ancillary services in the transmission network used for mitigating congestion and line overloading in transmission network was capable of solving all network issues as shown in Figure 145 and Figure 146. The tool activated required flexibility to completely reduce overloading during summer and winter days. In total 19701 MVA in 2030, 5211 MVA in 2040, and 19863 MVA in 2050 in the summer day was reduced, while 3656 MVA in 2030, 3885 MVA in 2040, and 17919 MVA in 2050 in the winter day.

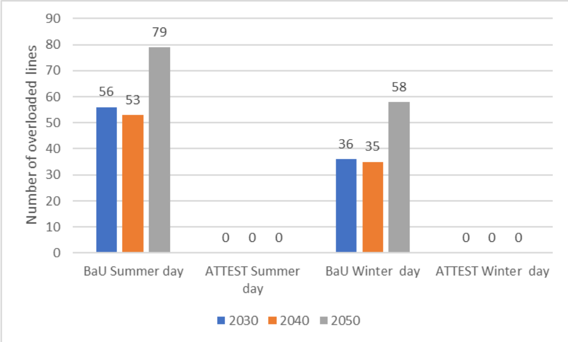


Figure 145 The number of overloaded lines for typical days over the years in the UK

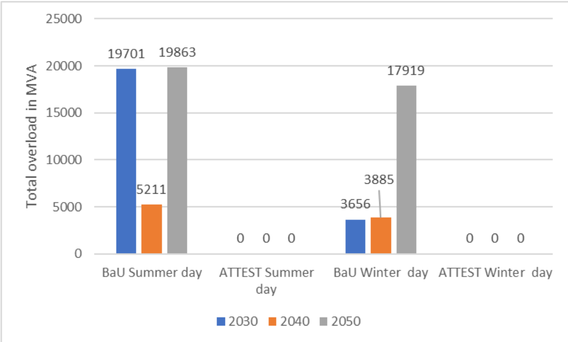


Figure 146 Total amount of overload for typical days over the years in in the UK

The number of overvoltage buses and cumulative daily overvoltage in p.u. are shown in Figure 147 and Figure 148. As can be noticed from the Figures, ATTEST solution resulted in a significant decrease of overvoltage buses. If ATTEST solution is compared with BaU approach in summer day, the number of overvoltage buses is decreased by 95 % in 2030, 92 % in 2040, and 89 % in 2050, while in winter day for more than 98 % in 2030 and 2040, and 88 % in 2050.

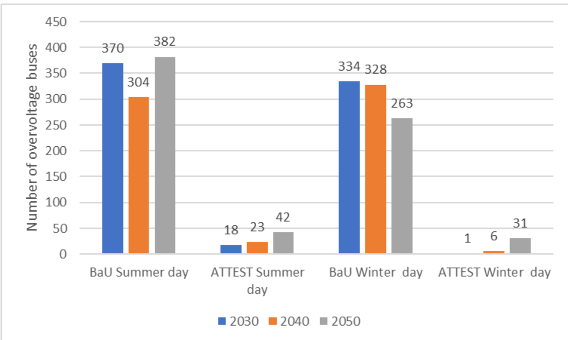


Figure 147 Number of overvoltage buses for typical days over the years in the UK

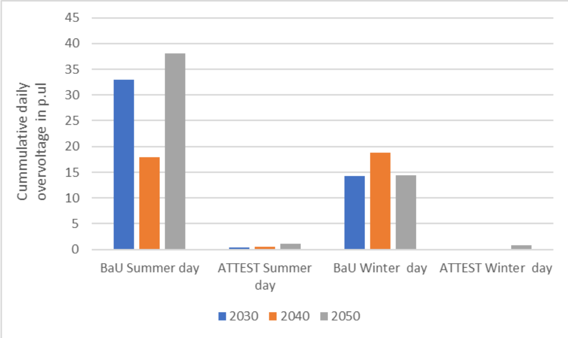


Figure 148 Cumulative daily overvoltage in p.u. for typical days over the years in the UK

Figure 149 and Figure 150 compare the number of undervoltage buses and cumulative daily undervoltage in p.u. for summer and winter day in BaU approach with ATTEST solution. ATTEST solution reduced the number of undervoltage buses by 42 % in 2030, 86 % in 2040, and 86 % in 2050 during the summer day, and by 60 % in 2030, 77 % in 2040 and more than 96 % in 2050 during the winter day.

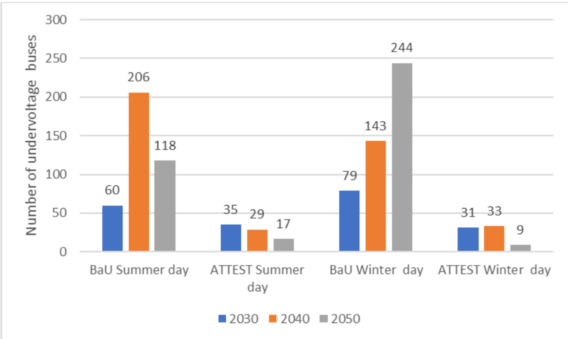


Figure 149 Number of undervoltage buses for typical days over the years in the UK

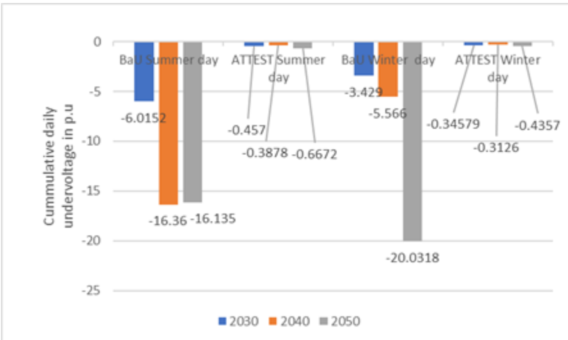


Figure 150 Cumulative daily undervoltage in p.u. for typical days over the years in the UK

Losses in the UK transmission network are shown in Figure 151. Losses are reduced with ATTEST approach from 1% to 5%, except on Winter day in 2050 when they increased by 0.06 %.

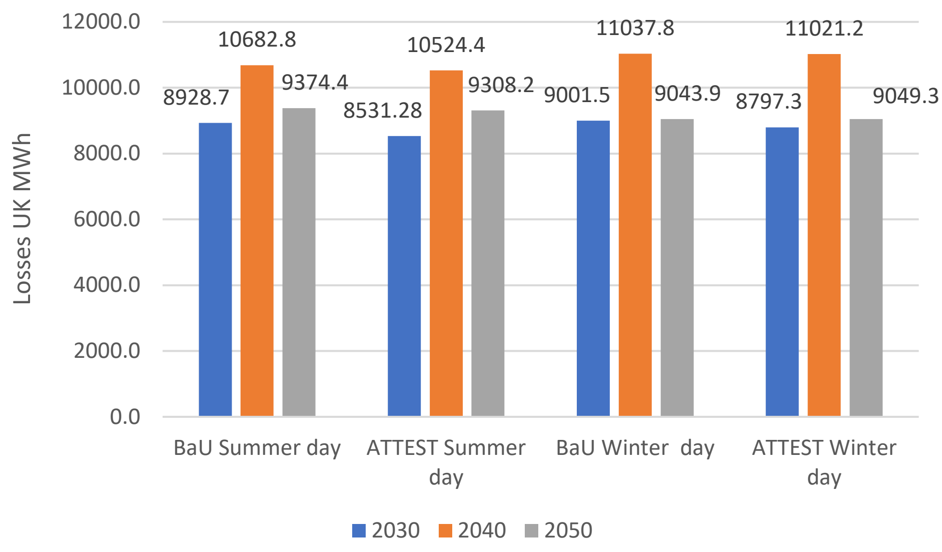


Figure 151 Losses comparison in the UK transmission network

6.5. Tool for on-line dynamic security assessment

This section provides KPIs simulations for the WP4 tool "Tool for on-line dynamic security assessment" developed in task T4.6. First, a high-level description and modelling features of the tool will be given to explain its applications in both transmission network day-ahead operational planning and real time preventive operation control. Then, the KPIs will be defined to measure technical impacts related with dynamic secure as well as evaluating the performance and impacts of the tool regarding other aspects, such as the maximum RES share that can be integrated. Finally, the simulations will be presented for the case study defined for this tool – the IEEE 39-bus system commonly known as "the 10-machine New-England Power System")[10]. 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 [17], [18], consequently enabling the proof of concept of this tool.

To demonstrate the efficiency and performance of the tool, the defined KPIs are calculated for two scenarios. The first scenario is Business as Usual (BaU) in which the real-time operation of the transmission network is considered without Synchronous Condensers (SCs) existing in the system. The second scenario is ATTEST approach in which several SCs are available, thus the tool can ensure the secure of operation of transmission system by bringing them online. KPIs are calculated for 2020, 2030, and 2050 scenarios which were defined according to total RES share (computed in % to the total consumption).

6.5.1. Description of the tool and KPIs calculation

The tool for on-line DSA implements a machine learning approach based on an Artificial Neural Networks (ANNs) to perform on-line dynamic security assessment with respect to frequency stability in future power systems characterized by large shares of converter interfaced generation, namely Renewable Energy Sources (RES) such as wind and solar. The ANNs are trained off-line using functional knowledge obtained through off-line dynamic simulations for a set of critical contingencies and for all the foreseen operating scenarios envisioned from 2020 up to 2050. For this specific purpose, frequency indicators, namely the Rate of Change of Frequency (RoCoF) and the minimum value of frequency

[10] It is worth to mention that, due to confidential aspects, the dynamic data required for this tool was not available for the ATTEST benchmark networks that were tested in the context of other tools.

reached during the transient period (nadir) were properly defined as the tool outputs. Through the comparison of results attained for these indicators with the regulated limits established, a classification regarding system security (secure/insecure states) can be performed. Therefore, this tool has the inherent capability of assessing system security with respect to network faults that may lead to severe post-fault frequency deviations due to the active power recovery ramps after fault clearance of converter interfaced RES in a faster and accurate way.

In case unsecure operating conditions are identified, either by RoCoF and/or frequency nadir violations, it is assumed that the system can be moved to a secure operational domain through the identification of additional synchronous inertia to the system, namely though the selective connection of additional synchronous condensers. Hence, in addition to the classification (secure/unsecure) of the operation scenario, this tool can support the decision-maker by keeping the already dispatched Synchronous Generators (SGs) in operation while bringing on-line Synchronous Condensers (SCs), and thus providing also information about the minimum inertia needed to ensure system dynamic security in terms of frequency stability.

It is worth mentioning that this tool was developed considering a standalone version that might be run either on-line or off-line (e.g., for day-ahead operational planning purposes), but also in integration with other two ATTEST tools: T4.4 – Tool for ancillary services procurement in day-ahead operation planning of the transmission network and T4.5 – Tool for ancillary services activation in real-time operation of the transmission network. The complete functional specification and description of overall methodology of the tool (in conceptual terms), together with details on the specific algorithms/methodologies that integrates all functional blocks envisioned for the tool are described in the Deliverable D4.1 [19] of the ATTEST project. Complementary, it can be found in del 4.7 [20] a user's guidance on the fundamental procedures for exploiting the tool, accompanied by illustrative examples and results.

To demonstrate the effectiveness of the tool and evaluate its performance, several KPIs were defined taking into account the following two categories: i) performance numerical indices related with aspect such as accuracy/quality, comprehensibility and classification errors; ii) technical aspects related to the transmission network operation such as the maximum RES share that can be integrated in the system. At the end, the following KPIs were considered:

1) Mean Absolute Error (MAE) given by:

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

2) Root Mean Squared Error (RMSE) given by:

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

3) Global Classification Error given by:

$$Global\ Class.Error = \frac{N^{\underline{o}}\{OPs\ of\ the\ TS\ incorrectly\ class.\}}{N^{\underline{o}}\{OPs\ of\ the\ TS\}} \times 100\%$$

4) False Alarm Error given by:

$$False\ Alarm\ Error = \frac{N^{\underline{o}}\{\text{"}secure\text{"}\ OPs\ of\ the\ TS\ class.\ as\ \text{"}unsecure\text{"}\}}{N^{\underline{o}}\{\text{"}secure\text{"}\ OPs\ of\ the\ TS\ \}} \times 100\%$$

5) Missed Alarm Error given by:

$$Missed\ Alarm\ Error = \frac{N^{\underline{o}}\{\text{"}unsecure\text{"}\ OPs\ of\ the\ TS\ class.\ as\ \text{"}secure\text{"}\}}{N^{\underline{o}}\{\text{"}unsecure\text{"}\ OPs\ of\ the\ TS\ \}} \times 100\%$$

6) % of unsecure OPs solved (the system is brought to a dynamic secure region due to the dispatch of SCs suggested by to the tool) given by:

$$\% \ of \ unsecure \ OPs \ solved = \frac{Nº\{"unsecure" \ OPs \ of \ the \ TS \ turned \ "secure"\}}{Nº\{"unsecure" \ OPs \ of \ the \ TS\ \}} \times 100\%$$

7) SCs required to ensure dynamic security, i.e., turn “secure” all the “unsecure” OPs identified by the tool. The SCs are characterized in terms of the total number required to ensure security for all OPs and the correspondent IDs (SC1, SC2 or SC3) – see Figure 152 in section 6.5.2.
8) Maximum % of RES that can be integrated (without putting system dynamic security at risk and considering all OPs for a given year).

where:

- $N(TS)$: Number of operating points (OPs) in the Testing Set (*TS*);
- y_i: Real value of the security index, for OP_i;
- $\hat{y}_i$: Value estimated by the ANN structure, for the security index of OP_i.
- $"unsecure\ OPs"$: OPs where nadir is greater than or equal to 0.8 Hz and/or RoCoF is greater than or equal to 1 Hz/s;
- $"secure\ OPs"$: OPs where nadir is less than 0.8 Hz and/or RoCoF is less than 1 Hz/s.

All the KPIs presented above were evaluated for a demonstrative Test Set (TS) by comparing the real/true nadir and RoCoF values that resulted from the PSS/E dynamic simulations with the corresponding ones that were estimated by the ANN model (tool’s outputs). The TS was defined in such way to be sufficiently representative of all the operating conditions expected from 2020 till 2050 in a daily/hourly basis and taking into account all the feasible load/generation combinations expected for this time frame.

As already mentioned, the KPIs were calculated for a Business as Usual (BaU) scenario, in which the real-time operation of the transmission network is considered without Synchronous Condensers (SCs) existing in the system, and for a second scenario is ATTEST approach in which several SCs are available. For both these variants, the KPIs were calculated considering 2020, 2030, and 2050 scenarios which were defined by clustering the data according to a maximum value of RES share that was admitted for each year. Therefore, although the KPIs are presented as separate values for each year and scenario ($year, sc$), they should be seen as an aggregated index for the time horizon up to year under analysis. In other words, this means that KPIs calculated for a given year takes into consideration OPs from the previous years. As example, all the possible unsecure cases that may occur from 2020 to 2050 are considered in the calculation of the KPIs related to the year 2050. Additional comments and explanations will be given for such cases in the 6.5.2.1

6.5.2. Case study: IEEE 39-bus system (“10-machine New-England Power System”)

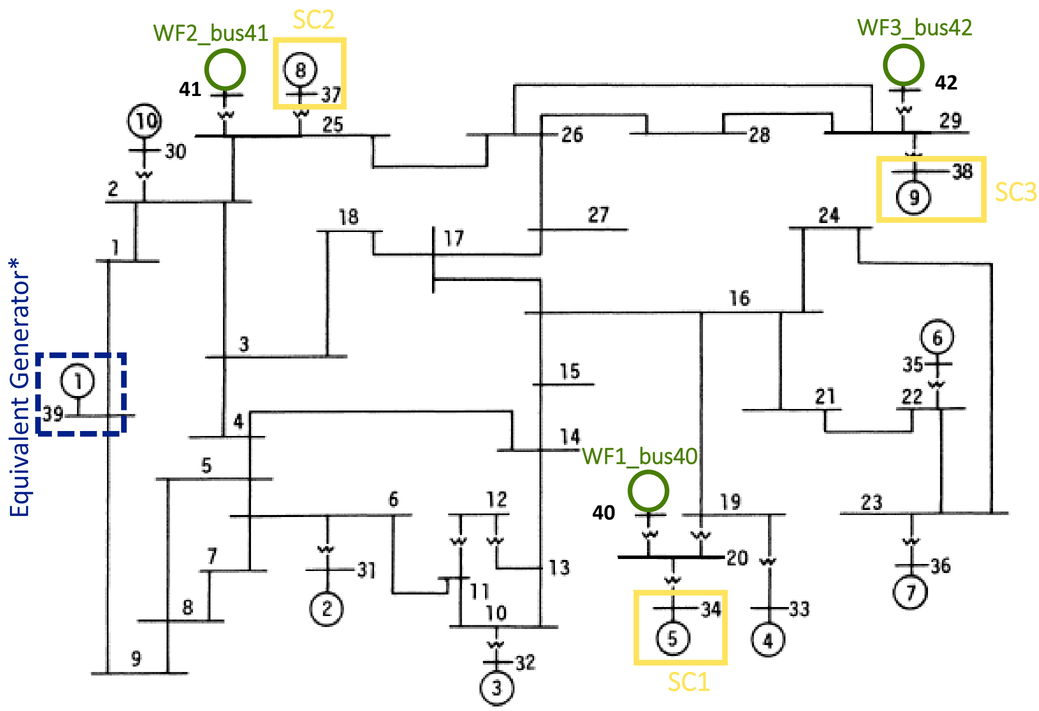
The case study chosen to test the tool was the IEEE 39-bus system, commonly known as “the 10-machine New-England Power System”. This system is a simplified model of the high voltage transmission system in the northeast of the U.S.A. (New England area). It was presented for the first time in 1970 and since then it has been widely used by the academic/scientific community as a benchmark system to address problems (testing methodologies and tools) in the transient/frequency stability domain [17], [18].

The original system consists of 39 buses (nodes), 10 generators, 19 loads, 34 lines and 12 transformers. The nominal frequency of the New England transmission system is 60 Hz and the main voltage level is 345 kV (nominal voltage). The correspondent static and dynamic data can be found in [21] and in[22].

Meanwhile, several modifications have been introduced in studies with different purposes depending on the specificities of the problem that authors are dealing with. In the same way, in order to enable the proof of concept of the DSA tool in the context of the ATTEST project, a few modifications and assumptions related with generation portfolio were also required to be performed, namely an increased RES integration. Regarding the location and size of RES to be integrated in the network, the modifications have closely followed those that were considered in [23]. The main modifications and assumptions introduced in the IEEE 39-bus system in relation to the original data are presented below:

- 3 out of the 10 existing SGs were considered to be decommissioned and refurbished to operate as Synchronous Condensers (SC), which means that they are able to perform reactive power / voltage control and provide inertia to the system (1/3 of the correspondent machine's original inertia was assumed for each SC). Additional information about this technology, namely with respect to the potential benefits that the exploitation of SC might bring to the system in terms of dynamic security can be found in [23] ;
- 3 new Wind Farms (WFs) were considered to be installed in locations nearby the decommissioned power plants and having approximately the same rated power: WF1 at bus 40 with 800 MW, WF2 at bus 41 with 700 MW and WF3 at bus 42 with 1000 MW. State-of-art wind generators, more specifically full-size frequency converters (type IV) were assumed to be equipping these WF. This technology implies that the WF are capable of performing reactive power / voltage control within a large range of their P/Q curve and have *Fault Ride Through* (FRT) ability as well;
- WFs are assumed to be grid code compliant, particularly regarding robustness requirements taking into account FRT and dynamic injection of reactive current during voltage sags. Moreover, the post fault active power ramp recovery was assumed to be 1 MWpu/s. Each WF was connect to the grid through a proper step-up transformer with a rated power sized to the correspondent WF (in MVA) and with a short circuit reactance of 6% (typical value).
- The equivalent generator that represents the remaining interconnected system is modeled by the machine Nr. 1 connected at bus 39. It has a strong impact in the dynamic stability phenomena / frequency excursions due to its size. Thus, aiming at ensuring future scenarios with a very high level of RES integration on generation mix of the remaining interconnect system, it was considered a reduction of about 70% in its total inertia. Note that such scenarios are likely to be the most critical regarding frequency stability problems – the ones that are envisioned to be addressed by this tool.

Based in the above considerations, it is presented in Figure 152 the final single-line diagram of the IEEE 39-bus system, which was adapted from the original presented in [21], [22] and modified according to the aforementioned assumptions. The main modifications performed over network's infrastructure are highlighted in color and correspond to the 3 new WF (green circles) and to the 3 new SC (yellow squares) that were considered to be integrated in this system.



*Models the remaining interconnected system in terms of all existing synchronous generation units (total inertia) as well as the power flows interchanges with the New England area

Figure 152 – Single-line diagram of the IEEE 39-bus system modified to meet the purposes of tool T4.6.

This system was modeled in Siemens PTI PSS/E (version 34). The static model used for steady-state power flow calculations is based on a balanced network representation (positive sequence) whose data were taken from [21], [22]. The new devices included (WFs and SCs) were modeled based on the information stated above. The final static and dynamic models and the corresponding parameters adopted for all the simulated devices are described in the ATTEST deliverables 4.1 [19] and 4.7[20].

6.5.2.1. Definition of the TS to perform the KPIs evaluation

In order to calculate the KPIs defined in section 6.5.1, a TS composed by data being enough representative of diversity of all the foreseen operating conditions from 2020 to 2050 was firstly needed to be created. It should be recalled that due to lack of information available for the IEEE-39 bus system under analysis, i.e., there was no historical information available such as historical measurements, market data, or similar data, all the OPs were generated based on unit commitment / dispatch procedure specifically developed to meet this purpose. This process was controlled by a set of assumptions and variables related to operational rules (e.g., spinning reserve/dispatch criteria), minimum technical requirements regarding the active power output of each unit, load and RES integration, and availability of other controllable and non-controllable devices (e.g., SC). Afterwards, all the OPs generated through this process were evaluated by running RMS dynamic simulations in order to achieve the true/real values regarding the dynamic frequency indicators (nadir and RoCoF) associated to each critical contingency identified. These data include primary variables and stability indicators, namely:

- Characteristics related to the OP conditions (primary variables): active/reactive powers produced (per generation units and SCs); aggregated active/reactive consumed powers in load buses; aggregated values regarding total active/reactive powers categorized by the technology: synchronous, non-synchronous (renewable or non-renewable based power electronics converters); spinning reserve available (synchronous and non-synchronous); total SGs inertia; SC inertia per machine.

- Stability indicators: frequency stability indicators (nadir and RoCoF).

Finally, a dataset composed of the variables listed before (primary characteristic variables and grid frequency indicators) was processed to build a functional knowledge database that describes the dynamic behavior of the system under study. This database was then used to define the training set and TS. More especially, this database is composed by a total of 534000 cases (OPs), being the TS composed by 15% of the cases (80100 OPs) – cases that were randomly selected from the functional knowledge database. Note that the TS composed by data related with OPs that have not been used during the training process of the tool. More information on about the algorithms/methodologies followed in this process (envisioned under the scope of the functional block 2 of the tool) can be found in see ATTEST deliverables 4.1 [19] and 4.7 [20].

Figure 153 depicts the results attained for the frequency stability indicators (nadir and RoCoF) for the TS analyzed. It is a scatter chart where nadir was plotted as function of RoCoF for all the OPs that composed the TS for the worst contingency (the one that led to the largest nadir/RoCof values). In this system the worst contingency refers to a three-phase short-circuit simulated at bus 16 with 250ms of clearance time (see Figure 152). The frequency stability boundaries adopted are highlighted in this figure by red lines for both nadir and RoCoF, allowing to compute the correspondent secure and unsecure regions of operation as shown respectively in the green and red rectangles.

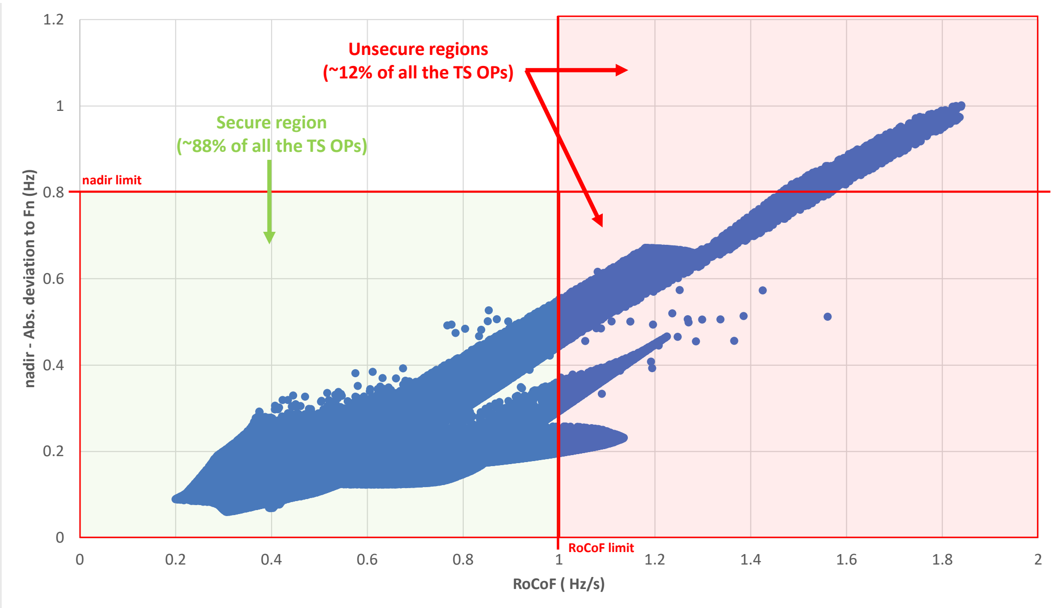


Figure 153 – nadir and RoCoF results (true/real values) attained for all the OPs simulated in the TS and for a three-phase symmetrical short circuit occurred at bus 16 with a clearance time of 250 ms.

As it can be seen in Figure 153, nearly 88% of the OPs that composed the TS fall in a secure region, whereas 12% are prone to bring the system to a dynamically unsecure region regarding frequency indicators. As expected, nadir and RoCoF have a strong correlation, being it almost linear. Moreover, it was verified that the large majority of the OPs in the unsecure area correspond to low load scenarios with high wind integration. This result was expected due to the lower synchronous inertia present in the system in these scenarios.

To compute the KPIs for the BaU and ATTEST scenarios and the years 2020, 2030 and 2050, the TS data was clustered considering respectively a maximum of 25%, 50%, and 75% of RES share penetration (computed in % of the total consumption) for the referred years. In Figure 154 is presented the true/real values obtained from PSS/E dynamic RMS simulations for the nadir along the years, whereas in Figure 155 is presented similar data regarding RoCoF values.

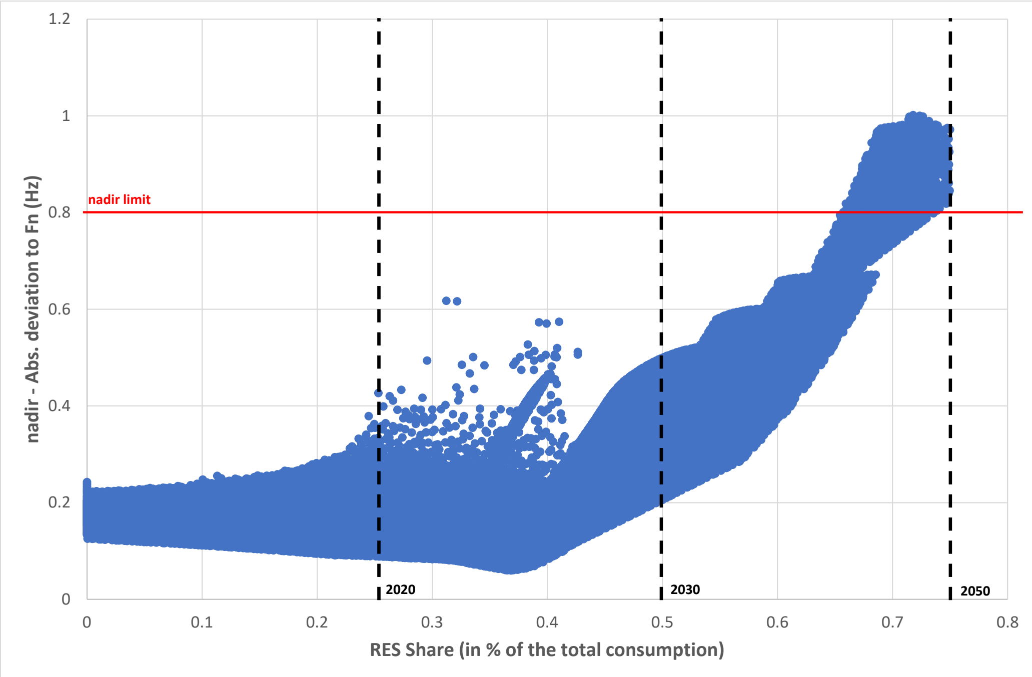


Figure 154 – nadir results (true/real values) from 2020 to 2050 as function of the RES share

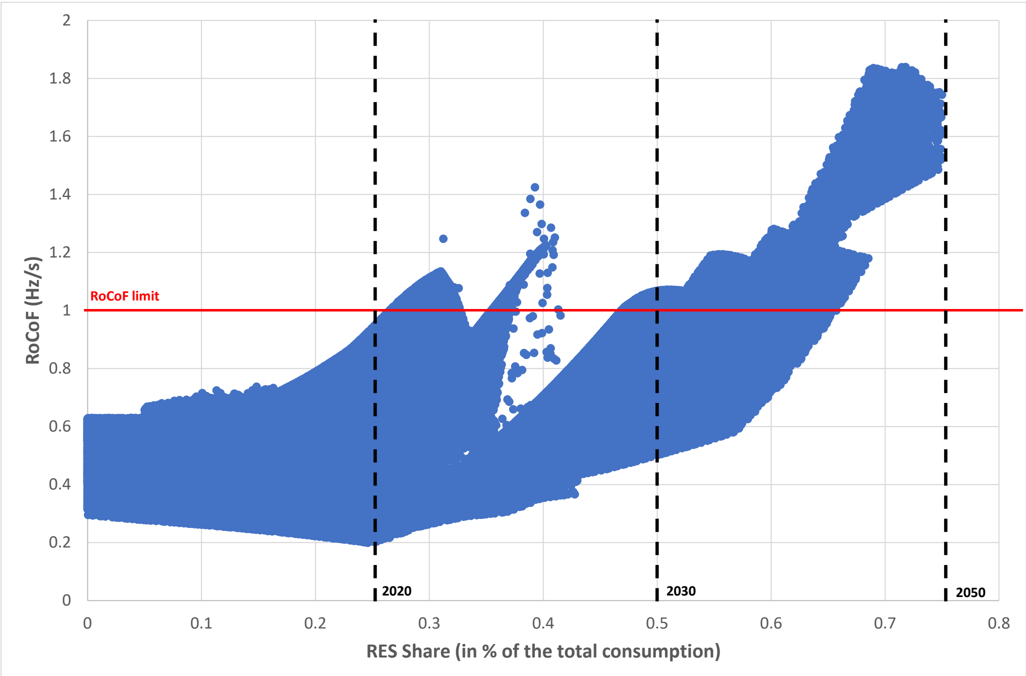


Figure 155 – RoCoF results (true/real values) from 2020 to 2050 as function of the RES share

As it can be seen in the two figures above, there is a tendency in both nadir and RoCoF values to increase with the amount of RES penetration. More specifically, a nonlinear tendence is observed, which increases significantly when the RES share is higher than 50% (after 2030). This result might be explained mainly because of the much less inertia present in the system for these more critical operating conditions. It should be noted that synchronous machines are being replaced by RES (in this case based on wind power converters), thus the post-fault frequency deviations due to the active power recovery ramps associated with this technology after faults lead to higher nadir/RoCoF (slower dynamic response when compared to synchronous machines). Moreover, one should bear mind that the complex dynamic phenomena under analysis, although is mainly influenced by inertia (swing equation), the results explanation is not straightforward, since they are influenced by several other factors (having a direct or indirect cross relationship) such as the location of the synchronous machines dispatched (for the same inertia), amount of load, RES share and location and fault location. All these factors may explain the range of values obtained for nadir and RoCof for the same value of RES share.

6.5.2.2. KPIs Results

In Figure 156 and Figure 157 are shown the results estimated by the tool for on-line DSA respectively for the frequency nadir (maximum absolute deviation to Fn) and for RoCof as function of corresponding true/real values obtained from the dynamic simulation performed in PSS/E for all the OPs in the TS analyzed. As it can be seen in these figures, although there are some outliers (in a very small percentage), there is a strong correlation (almost linear) between the estimated and the real values, both for nadir and RoCoF. These results evidence the good performance of the tool regarding its accuracy on estimating these indicators.

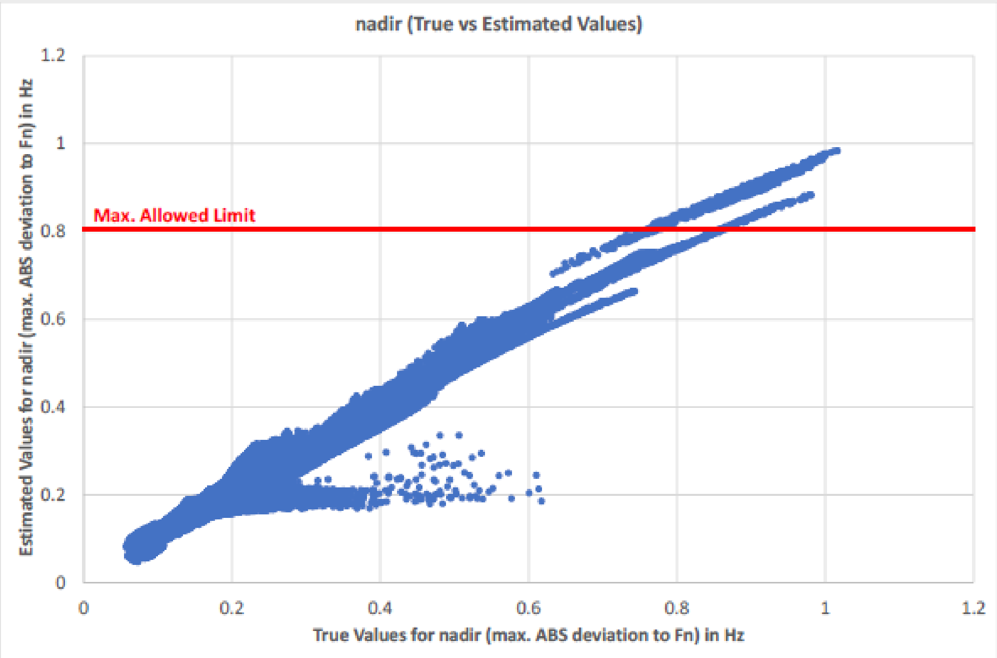


Figure 156 – True vs estimated values for nadir attained after running the tool for all the OPs that composes the TS.

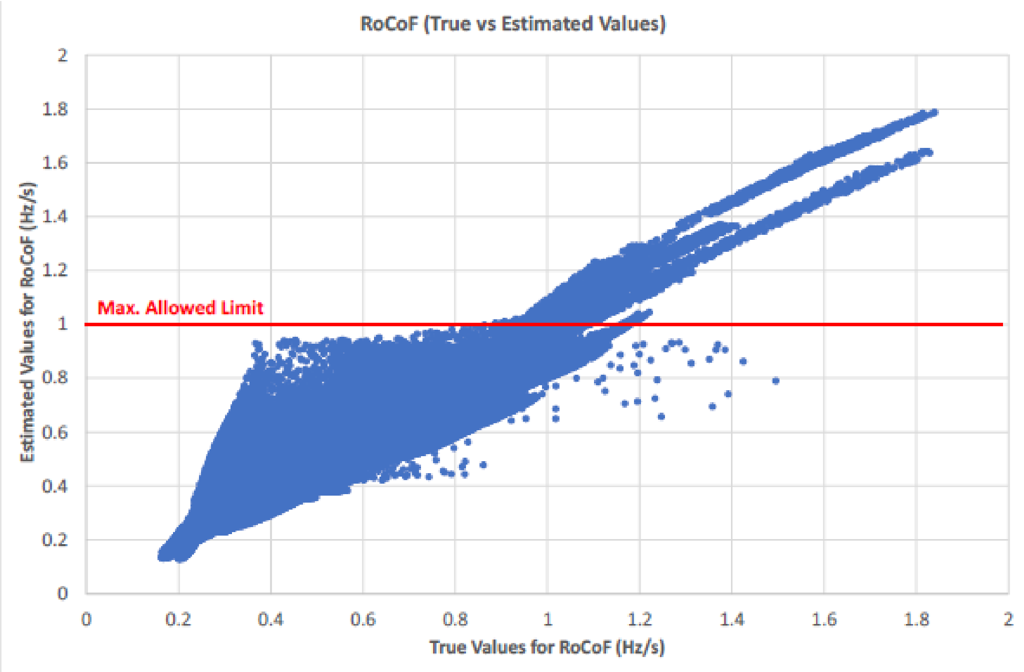


Figure 157 – True vs estimated values for RoCoF attained after running the tool for all the OPs that composes the TS.

In view of the upcoming, the final results for all the KPIs as defined in section 6.5.1 are displayed in Table XLVI taking into consideration the BaU and ATTEST scenarios for the years 2020, 2030 and 2050.

Table XLVI – KPIs simulations for the IEEE 39-bus system (tool for on-line DSA – T4.6)

Scenario	KPIs / Metrics	Years (RES share increasing along the years)		
		2020	2030	2050
Base case (BaU) – without SCs	MAE – nadir (deviation to Fn in Hz)	0.008	0.010	0.011
	RMSE – nadir (Hz) (deviation to Fn in Hz)	0.012	0.015	0.017
	MAE – Rocof (Hz/s)	0.038	0.043	0.045
	RMSE- Rocod (Hz/s)	0.051	0.055	0.066
	Global Class. Error	0.85% (99.15% accuracy)	0.87% (99.13% accuracy)	0.89% (99.11% accuracy)
	False Alarm Error	0.07% (99.93% accuracy)	0.22% (99.78% accuracy)	0.31% (99.69% accuracy)
	Missed Alarm Error	0.12% (99.88% accuracy)	0.58% (99.42% accuracy)	0.72% (99.28% accuracy)
	% of unsecure OPs solved	– (No SCs available)	– (No SCs available)	– (No SCs available)
	SCs required to ensure security	– (No SCs available)	– (No SCs available)	– (No SCs available)
	Max. RES Share (%) allowed (for all OPs of TS)	25%	25%	25%
ATTEST approach – with SCs	MAE – nadir (deviation to Fn in Hz)	0.008	0.010	0.011
	RMSE – nadir (Hz) (deviation to Fn in Hz)	0.012	0.015	0.017
	MAE – Rocof (Hz/s)	0.038	0.043	0.045
	RMSE- Rocod (Hz/s)	0.051	0.055	0.066
	Global Class. Error	0.85% (99.15% accuracy)	0.87% (99.13% accuracy)	0.89% (99.11% accuracy)
	False Alarm Error	0.07%	0.22%	0.31%

		(99.93% accuracy)	(99.78% accuracy)	(99.69% accuracy)
	Missed Alarm Error	0.12% (99.88% accuracy)	0.58% (99.42% accuracy)	0.72% (99.28% accuracy)
	% of unsecure OPs solved	– (No unsecure OPs)	99.42%	99.28%
	SCs required to ensure security	– (all OPs secure)	– 1 (SC3)	– 3 (SC1, SC2, SC3)
	Max. RES Share (%) allowed (for all OPs of TS)	25%	50%	75%

As it is possible to see from the results of Table XLVI, the tool for on-line DSA accounts for very promising results regarding estimation accuracy for all the analyzed KPIs concerning this aspect. For instance, in terms of the global classification error, more than 99% of the OPs were correctly classified in both BaU and ATTEST scenarios and for the entire period analyzed (2020-2050). Moreover, the higher value attained for "Missed Alarm Error" KPI (system is unsecure but it is estimated as secure) was below 0.72% for all the years up to 2050, which means that only 70 OPs in a total of the 9612 unsecure presents in the TS analyzed were badly estimated as secure. Therefore, being this KPI probably the most relevant indicator for the TSOs, this is a very promising result in the context of the DSA performed by this tool.

The preventive control algorithm envisioned and integrated into the tool (see ATTEST deliverable 4.7 **Error! Reference source not found.**), which computes the necessary SCs needed to be turned on to ensure dynamic system security secure (by bringing in this way more synchronous inertia to the system), allows to bring to a security region 99.42% and 99.28% of all the unsecure OPs registered correspondently in 2030 and 2050 (in 2020 there not expected unsecure cases). As expected, the % of unsecure OPs "not solved" by the tool matches the % of the "Missed Alarms" registered for a given year.

Finally, it is worth mentioning that the ATTEST approach, due to the assumption that SCs devices are available in the system, enable a much higher RES share along the years. In this system, considering such scenario, the tool allows the RES share to increase from 25% in 2020 up to 75% in 2050, whereas in the BaU scenario the maximum value is 25% for all years. These results mean a strong reduction in conventional fossil fuel-based energy generation and therefore in GHG emissions[11]. Once more, it is important to bear in mind that these results were obtained by assuming that the maximum RES share must be verified for all the OPs analyzed in given year, although the RES share can reach higher values for some OPs (even in 2020).

6.5.3. Summary and Conclusions

This section presents the results obtained from the KPIs simulations conducted for the tool developed in Task 4.6 – tool for on-line dynamic security assessment. The simulations were presented for one case study – the IEEE 39-bus system commonly known as "the 10-machine New-England Power System"). This case study, being a benchmark system in the scope of the transient/frequency stability domain, enables the proof of concept of this tool.

Several KPIs were defined to measure technical impacts related with dynamic secure as well as evaluating the performance and impacts of the tool regarding other aspects, such as the maximum RES share that can be integrated. The KPIs were then calculated for two scenarios: i) a first scenario was the Business as Usual (BaU) in which the real-time operation of the transmission network is considered

[11] This GHG emissions (namely CO_2 equivalent avoided emissions) were not calculated do to the unavailability of realistic data for the IEEE 39-bus system analyzed

without Synchronous Condensers (SCs) existing in the system; ii) a second scenario was the ATTEST approach in which several SCs are available, thus the tool can ensure the secure of operation of transmission system by bringing them online. KPIs were calculated for 2020, 2030, and 2050 scenarios which were defined according to a maximum % of RES share assumed for each year.

The results have shown that with the steadily growing integration of non-synchronous resources, maintaining system frequency within acceptable limits in low-inertia RES dominated power systems will be a challenging task in future scenarios. Of particular relevance, it was verified that critical faults (e.g., severe short-circuits) occurring in power grids might have a large impact on key frequency indicators (i.e., RoCoF and its nadir) and may lead to violations of the established limits, namely due to the lack of adequate post-fault active power ramps and low inertia. This conclusion is evident when analyzing the results for the BaU scenario, where the maximum RES share allowed attained was 25% in 2050. Differently, the ATTEST approach might bring several benefits. In fact, for this scenario, it was verified that RES share can be increased up to 75% due to the additional inertia provided by the SCs that were admitted as being present in the system. In this case, the tool, through a preventive control algorithm, successfully manages the SCs to turn the “unsecure” operating conditions into “secure” ones at a dynamic point of view. The higher RES share that can be integrated in the systems can be translated into a significative reduction in GHG emissions (namely in CO_2), admitting that it implies the replacement of conventional fossil fuel-based generation units by RES.

Regarding the estimation accuracy for both nadir and RoCof frequency indicators, the tool for on-line DSA accounts for very promising results, i.e., very high quality and reliable estimations. For instance, the global classification error attained for BaU and ATTEST scenarios along the years (between 2020-2050) stays below 1%, meaning that more than 99% of the OPs were correctly classified. In particular, the higher value attained for “Missed Alarm Error” KPI (system is unsecure but it is estimated as secure), which is probably the most relevant indicator for the TSOs, was below 0.72% for all the years up to 2050 both for BaU and ATTEST scenarios.

In the view of the above, it can be concluded that the tool for on-line DSA appear to be an effective, robust, and accurate tool that might bring several benefits to system in future scenarios. Because it is based on machine learning approach (ANNs) the tool is suitable to be run either on-line or off-line (e.g., for day-ahead operational planning purposes), and considering multiple contingencies at same time due to a parallel processing implementation. Consequently, it can provide support to the decision-makers, in particular TSOs. In addition to the direct outputs (frequency stability indicators – nadir and RoCoF), the tool was design to suggest preventive control measures that enables to ensure dynamic system security. The preventive suggestions implemented was the SCs required to bring the system to a secure region. Nevertheless, the tool can be easily adapted to propose/compute other measures/variables such as the minimum synchronous or synthetic inertia required, the energy storage devices (e.g., batteries) that need to be turn on, or even the generators that needed be rescheduling/redispatch, among others. In this sense, besides the standalone version of tool proposed, the tool was also designed to be used in integration with the following two ATTEST tools in order to exploit also the static features (e.g., flexibility). More specifically, it was considered the integration with *T4.4 tool – Tool for ancillary services procurement in day-ahead operation planning of the transmission network* and with the *T4.5 tool – Tool for ancillary services activation in real-time operation of the transmission network.*

7. KPIs simulations and demonstrations for WP5

The estimation of Key Performance Indicators (KPIs) is a crucial aspect of any research project aimed at assessing the effectiveness of a particular technology or system. They give a set of indicators about reaching strategic goals or/and objectives of an organization, project, or process. Businesses use KPIs to track progress toward goals and identify areas for improvement. Quantitative and qualitative KPIs can measure financial, operational, and customer performance. KPIs should be relevant, specific, measurable, achievable, and time-bound (SMART). Performance management relies on KPIs to track and assess project or organization success.

ATTEST Tool 5.2 developed in WP5 enables the calculation of a total indicator for each power grid asset. This tool is particularly useful in evaluating the condition of power grid assets, as it provides a quantifiable measure of the overall condition of the assets. The tool is designed to assign a value between 0 and 1 to each indicator, where 0 represents the best condition, and 1 represents the worst condition.

Tool 5.2 cannot only calculate the total indicator for each asset of the power grid but also estimates the Key Performance Indicators (KPIs) for the power grid as a whole.

The KPIs are calculated by taking the mean value of the condition indicators obtained from all the power grid assets over four different time periods: 2020, 2030, 2040, and 2050. This method enables a comprehensive evaluation of the power grid performance over time, as well as the identification of areas in need of improvement.

The evolution of the KPI over time provides valuable insights into the health of the assets in the power grid. Analysts can identify patterns and assess the overall condition of assets by analysing trends in KPI values over time.

The estimation of KPIs from WP5 in the cases studied in WP7 is limited to considering only one dimension, "Life Assessment." This approach was adopted because obtaining information from other dimensions for future scenarios beyond 2020 is challenging.

7.1. Method of estimation

The estimation of KPIs is conducted in three different scenarios to evaluate the power grid performance comprehensively. The first scenario involves estimating KPIs based on power grids without flexibility using Tool 5.2, which is based on life assessment indicators. This scenario provides a baseline measure of the power grid performance without considering any flexibility measures.

The second scenario involves estimating KPIs considering power grids with flexibility using Tool 5.2, which is also based on life assessment indicators. This scenario considers the potential benefits of flexibility measures, which can improve the power grid performance and resilience.

The third scenario involves estimating KPIs under power grids with flexibility using Tool 5.3, which is based on life assessment indicators and the application of all recommended asset management actions. This scenario provides an assessment of the power grid performance, assuming that the actions recommended in the report are all implemented. This approach enables analysts to evaluate the potential impact of specific interventions and to identify the most effective strategies for improving the power grid's performance.

Overall, these three scenarios provide a comprehensive assessment of the power grid performance under different conditions and with varying levels of flexibility. This approach enables policymakers, grid operators, and investors to make informed decisions about investments and policy changes that will improve the power grid performance and ensure its long-term sustainability.

It is convenient to remember that the condition indicators estimated by the tools developed in WP5 range from 0, representing the good condition of assets, to 1, indicating the poor condition of assets. For specific cases, KPIs have not been calculated with Tool 5.3 due to their extremely low values, signifying that all assets are in good condition and do not require any special recommendations.

As a general comment for all the cases, an increasing value of the KPIs from 2020 to 2050 is observed, which agrees with the increasing trend of the load values in the power grids.

Next, the different cases analyzed and the KPIs obtained will be presented.

7.2. Portugal

7.2.1. Portuguese transmission case

Table XLVII compares mean values of Life Assessment over the years in Portuguese transmission test case considering BaU solution (without flexibility) and ATTEST solution (with flexibility).

Table XLVII Mean values of Life Assessment over the years in Portuguese transmission test case

Years	KPIs With_flexibility		KPIs Without_flexibility	
	Mean (LA)	STD(LA)	Mean (LA)	STD(LA)
2020	0.2303	0.1325	0.2215	0.1293
2030	0.2380	0.1287	0.2379	0.1285
2040	0.2480	0.1281	0.2483	0.1283
2050	0.2527	0.1264	0.2566	0.1263

Table XLVIII shows mean values of Life Assessment over the years in Portuguese transmission test case accepting suggestions for asset management.

Table XLVIII Mean values of Life Assessment over the years in Portuguese transmission test case accepting suggestions for asset management (Tool 5.3)

	Mean (LA)	STD(LA)
2020	0.1485	0.1080
2030	0.1498	0.1083
2040	0.1512	0.1150
2050	0.1595	0.1208

The mean values presented in these tables are presented in a graphical form in Figure 158.

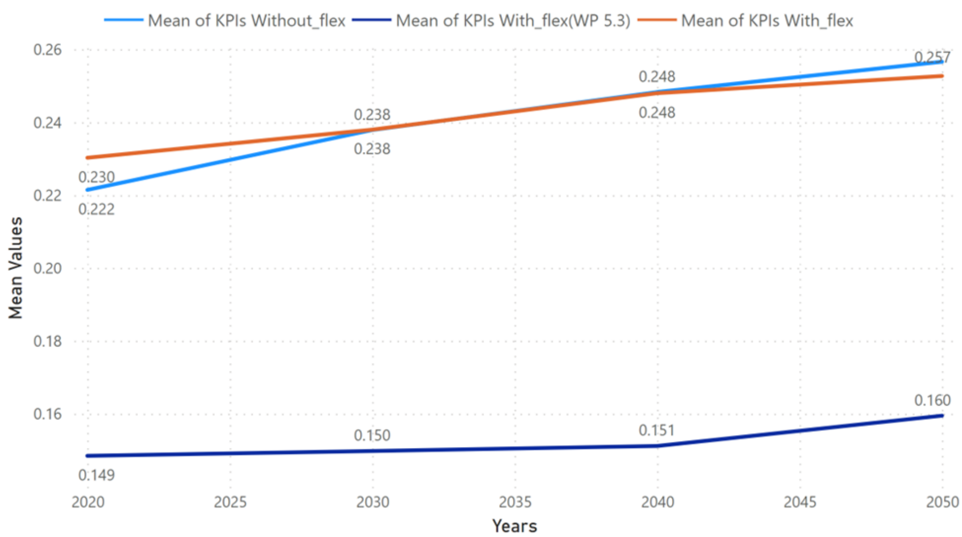


Figure 158 Mean values of Life Assessment over the years in Portuguese transmission test case

In the PT_TX scenario, a KPI value below 0.25 typically indicates that the assets are in good condition and functioning effectively. The values observed suggest continuing to apply the resources used in the current maintenance and asset management plans. However, some few assets in the study have KPI values higher than 0.75, meaning a worse condition than most part of the assets. They should be monitored carefully or replaced as soon as possible. According to the suggestions from Tool 5.3, implementing the actions suggested by this tool should improve the KPIs, demonstrating the enhanced condition of the assets after accepting the recommended management actions. Over time, the increasing trend observed in all the cases is due to the growing profile of loads in the assets that will stress their lives.

7.2.2.Portuguese distribution case

Table XLIX compares mean values of Life Assessment over the years in Portuguese distribution test case considering BaU solution (without flexibility) and ATTEST solution (with flexibility).

Table XLIX Mean values of Life Assessment over the years in Portuguese distribution test case

Years	KPIs With_flexibility		KPIs Without_flexibility	
	Mean (LA)	STD(LA)	Mean (LA)	STD(LA)
2020	0.0691	0.1379	0.06911	0.1379
2030	0.0607	0.1447	-	-
2040	0.0647	0.1489	0.0648	0.1495
2050	0.0663	0.1498	-	-

The mean values in these three tables are presented in a graphical form in Figure 159 (when data are available).

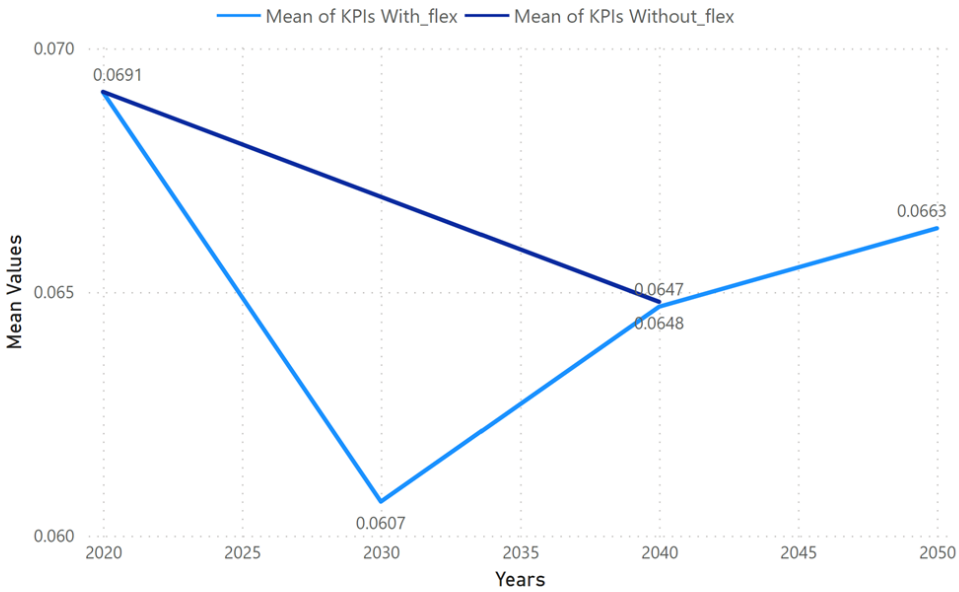


Figure 159 Mean values of Life Assessment over the years in Portuguese distribution test case

In the PT_DX scenario KPIs values below 0.25 typically indicate that the assets are in good condition, functioning effectively without special asset management efforts different than those applied in the current asset management and maintenance plans. KPIs have not been calculated with Tool 5.3 due to their extremely low values, signifying that all assets are in good condition and do not require any special recommendations. Scenarios 2030 and 2050 do not have values due to convergence problems. In general, the assets will not be significantly stressed over time.

7.3. Croatia

7.3.1. Croatian transmission case

Table L compares mean values of Life Assessment over the years in Croatian transmission test case considering BaU solution (without flexibility) and ATTEST solution (with flexibility).

Table L Mean values of Life Assessment over the years in Croatian transmission test case

Years	KPIs With_flexibility		KPIs Without_flexibility	
	Mean (LA)	STD(LA)	Mean (LA)	STD(LA)
2020	0.0410	0.0590	0.0431	0.061
2030	0.0425	0.0680	0.0402	0.0618
2040	0.0406	0.0605	0.0408	0.0611
2050	0.0685	0.1052	0.0436	0.0644

The mean values in these three tables are presented in a graphical form in Figure 160.

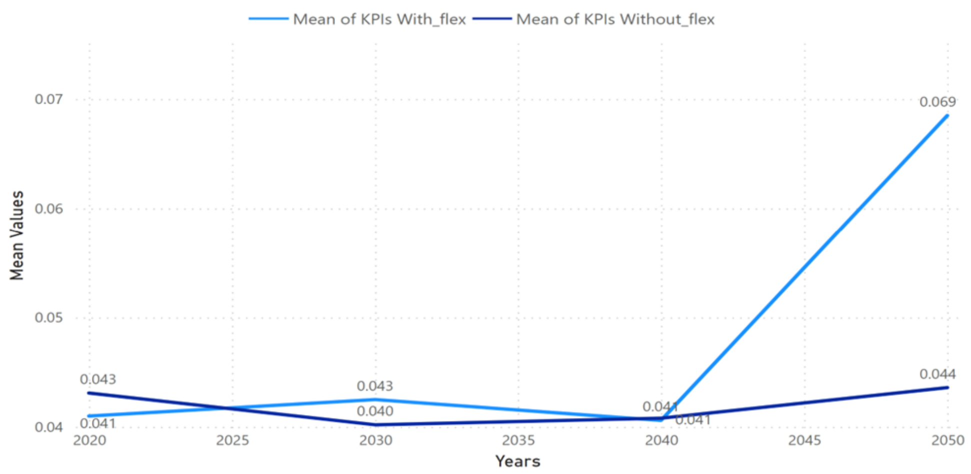


Figure 160 Mean values of Life Assessment over the years in Croatian transmission test case

In the HR_TX scenario KPIs have not been calculated with Tool 5.3 due to their extremely low values, signifying that the assets do not require any different asset management strategy that this currently applies. It is important to note that for the scenario 2050, an important change in the health condition of the assets is expected with respect to the previous periods. This is due to an important increase in load profiles in the assets.

7.3.2.Croatian distribution case

Table LI compares mean values of Life Assessment over the years in Croatian distribution test case considering BaU solution (without flexibility) and ATTEST solution (with flexibility).

Table LI Mean values of Life Assessment over the years in Croatian distribution test case

Years	KPIs With_flexibility		KPIs Without_flexibility	
	Mean (LA)	STD(LA)	Mean (LA)	STD(LA)
2020	NA	NA	0.2860	0.1604
2030	0.3661	0.1438	NA	NA
2040	0.3618	0.1468	0.3654	0.1466
2050	0.3730	0.1486	0.3808	0.1400

Table LII shows mean values of Life Assessment over the years in Croatian distribution test case accepting suggestions for asset management.

Table LII Mean values of Life Assessment over the years in Croatian distribution test case accepting suggestions for asset management (Tool 5.3)

	Mean (LA)	**STD(LA)**
2020	**NA**	**NA**
2030	0.2243	0.1612
2040	0.2234	0.1600
2050	0.2345	0.1732

The mean values in these three tables are presented in a graphical form in Figure 161.

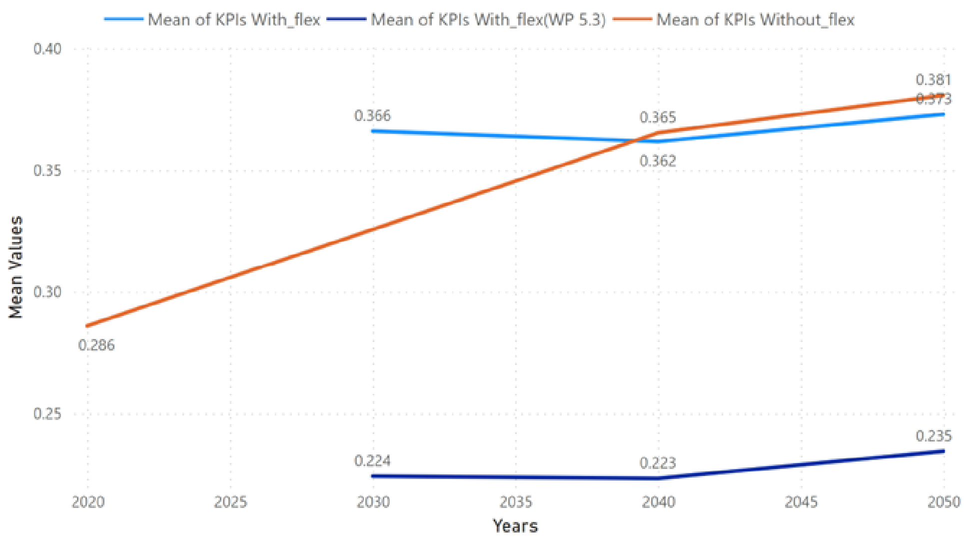


Figure 161 Mean values of Life Assessment over the years in Croatian distribution test case

As in previous cases analysed, in the HR_DX scenario, a KPI value below 0.25 typically indicates that the assets are in good condition and functioning effectively without needing special maintenance efforts different from those in the current maintenance plan. However, in this case, there are certain assets with KPI values higher than 0.75, meaning a very different condition with respect to most assets. This suggests to pay special attention to these assets and their lives.

Some KPIs were not possible to estimate due to convergence problems in some of the cases studied. In general, the condition of the assets will be stressed over time due to the growing load profiles in the assets.

According to the recommended asset management actions from Tool 5.3, the mean value of the KPIs should improve around 1/3 of the values observed without these recommendations.

7.4. The United Kingdom

7.4.1. UK transmission case

Table LIII compares mean values of Life Assessment over the years in the UK transmission test case considering BaU solution (without flexibility) and ATTEST solution (with flexibility).

Table LIII Mean values of Life Assessment over the years in the UK transmission test case

Years	KPIs With_flexibility		KPIs Without_flexibility	
	Mean (LA)	STD(LA)	Mean (LA)	STD(LA)
2020	0.1723	0.0901	0.1958	0.1381
2030	0.1832	0.1203	0.1811	0.1178
2040	0.2000	0.1072	0.1979	0.1052
2050	0.1861	0.0942	0.1814	0.0906

Table LIV shows mean values of Life Assessment over the years in the UK transmission test case accepting suggestions for asset management.

Table LIV Mean values of Life Assessment over the years in the UK transmission test case accepting suggestions for asset management (Tool 5.3)

	Mean (LA)	STD(LA)
2020	0.1224	0.1023
2030	0.1219	0.1083
2040	0.1317	0.1150
2050	0.1235	0.1000

The mean values in these three tables are presented in a graphical form in Figure 162.

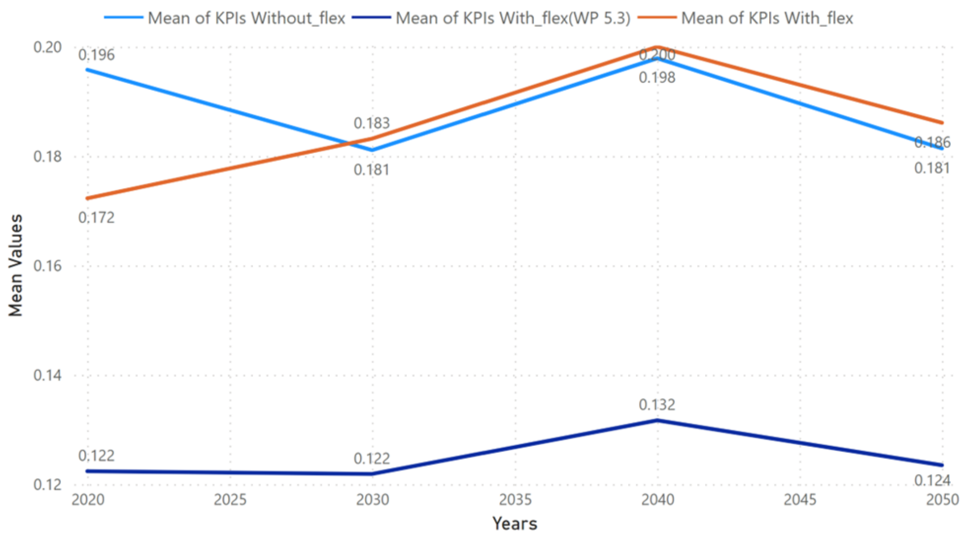


Figure 162 Mean values of Life Assessment over the years in the UK transmission test case

In the UK_TX scenario, the KPI mean values are below 0.25, meaning that most of the assets are not stressed and the current asset management strategy is effective to keep these values over time.

As observed, in 2040, the KPI mean value is higher compared to values in 2030 and 2050. This could be attributed to a higher distribution of loads in some zones of the power grid that could stress the assets more. If the actions suggested by tool 5.3 are applied, the KPIs obtained are lower, keeping the assets even in a better health condition.

7.4.2.UK distribution case

Table LV compares mean values of Life Assessment over the years in the UK distribution test case considering BaU solution (without flexibility) and ATTEST solution (with flexibility).

Table LV Mean values of Life Assessment over the years in the UK distribution test case

Years	KPIs With_flexibility		KPIs Without_flexibility	
	Mean (LA)	STD(LA)	Mean (LA)	STD(LA)
2020	0.2893	0.2287	0.2893	0.2287
2030	0.2505	0.2446	0.2576	0.2406
2040	0.2685	0.2392	NA	NA
2050	0.2698	0.2395	NA	NA

Table LVI shows mean values of Life Assessment over the years in the UK distribution test case accepting suggestions for asset management.

Table LVI Mean values of Life Assessment over the years in the UK distribution test case accepting suggestions for asset management (Tool 5.3)

	Mean (LA)	STD(LA)
2020	0.1638	0.1132
2030	0.1832	0.1209
2040	0.1458	0.0923
2050	0.1486	0.0947

The mean values in these three tables are presented in a graphical form in Figure 163.

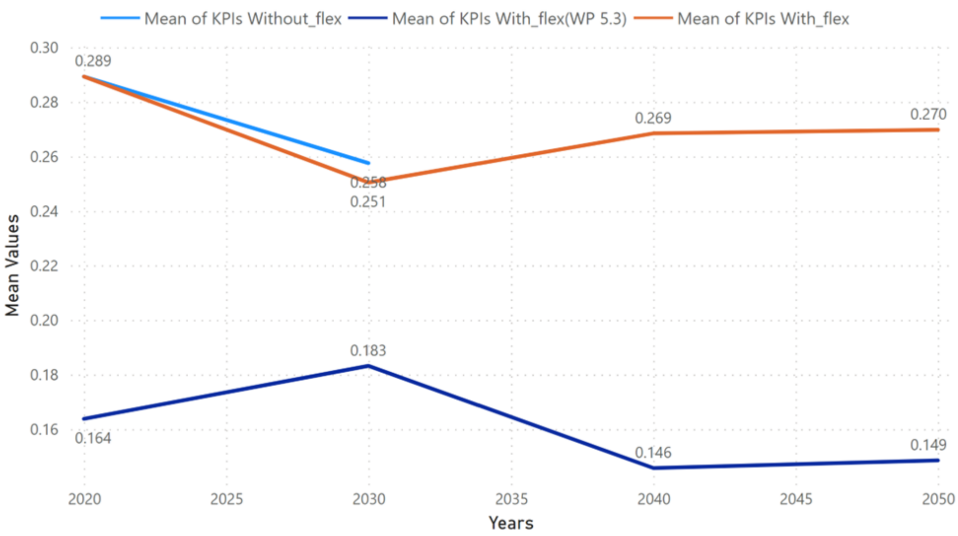


Figure 163 Mean values of Life Assessment over the years in the UK distribution test case

Also, in the UK_DX scenario, the mean values of the KPIs are below 0.25, meaning that the assets are generally in good condition. As in other cases presented before, there are some assets whose KPI values exceed 0.75, suggesting that they are more stressed than most of the other assets and should be under special attention from an asset management point of view.

As per the recommendations from Tool 5.3, their put in practice should lead to an improvement in the KPI, reflecting a better condition of the assets after implementing the suggested management strategies.

7.5. Spain

7.5.1.Spanish distribution case

Table LVII compares mean values of Life Assessment over the years in Spanish distribution test case considering BaU solution (without flexibility) and ATTEST solution (with flexibility).

Table LVII Mean values of Life Assessment over the years in Spanish distribution test case

Years	KPIs With_flexibility		KPIs Without_flexibility	
	Mean (LA)	STD(LA)	Mean (LA)	STD(LA)
2020	NA	NA	NA	NA
2030	0.0513	0.8760	NA	NA
2040	0.0600	0.0954	NA	NA
2050	0.0606	0.0953	NA	NA

The mean values in these three tables are presented in a graphical form in Figure 164.

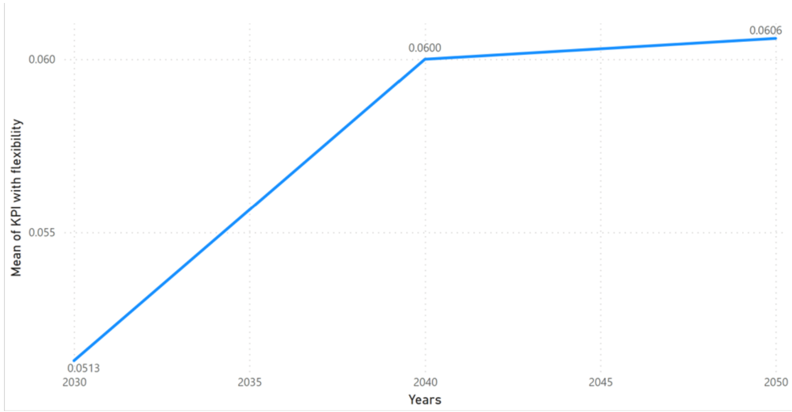


Figure 164 Mean values of Life Assessment over the years in Spanish distribution test case

Unfortunately, this case had convergence problems to find load solutions in most part of the cases studied. The recommendations of actions from Tool 5.3 were not estimated due to the extremely low values of the KPIs observed. According to the values obtained for the KPIs, the current asset management strategy is sufficiently effective to be continuously applied in the future.

8. Environmental KPIs: avoided emissions and other impacts

Avoided emissions refer to the amount of greenhouse gas emissions avoided by adopting ATTEST tools, allowing the high penetration of renewable, low-carbon electricity generation sources in the various grids addressed in the project. The main methodology for calculating avoided emissions is aligned with the rest of the KPIs, whereby the national electricity mix scenarios made possible by ATTEST are assessed and compared with a reference baseline scenario. At least two scenarios are therefore quantified in terms of lifecycle indicators for greenhouse gas emissions, and the net difference between the two emission pathways is defined as the avoided emissions, either yearly (in 2050) or cumulatively (until 2050) to be used as the KPIs for this section.

The main data source for emission factors is the ecoinvent 3.9.1 database, which provides a set of lifecycle indicators for all electricity generation and storage technologies, in a region-specific way. The data sources for energy scenarios are grid-specific, they are provided in the subsequent section.

For each case, the impact assessment was primarily carried out for greenhouse gas emissions, i.e. all substances listed as GHG by the Kyoto Protocol, but other indicators are also available, and provided here for information. Characterization factors from the “Environmental Footprint v3.1” methodology were used in this work.

8.1. The United Kingdom

The scenario data for the UK grid is extracted from the "Future Energy Scenarios 2021 Data Workbook” published by UK’s National Grid ESO[12]. These future energy scenarios (FES) for the national grid’s

[12] The file is available at https://www.nationalgrideso.com/future-energy/future-energy-scenarios

production mix and interconnections have been derived, namely: “Steady Progression”, with minimal behavioral changes and limited decarbonization efforts; “System Transformation”, with supply-side flexibility and hydrogen for heating; “Consumer Transformation”, with higher electrification and consumer behavioral change; and “Leading the Way” as the fastest credible decarbonization scenario. ATTEST tools are assumed to enable the “Leading the Way” by allowing a very high share of renewables in the grid. “Steady Progression” embodies the reference scenario for the sake of this analysis.

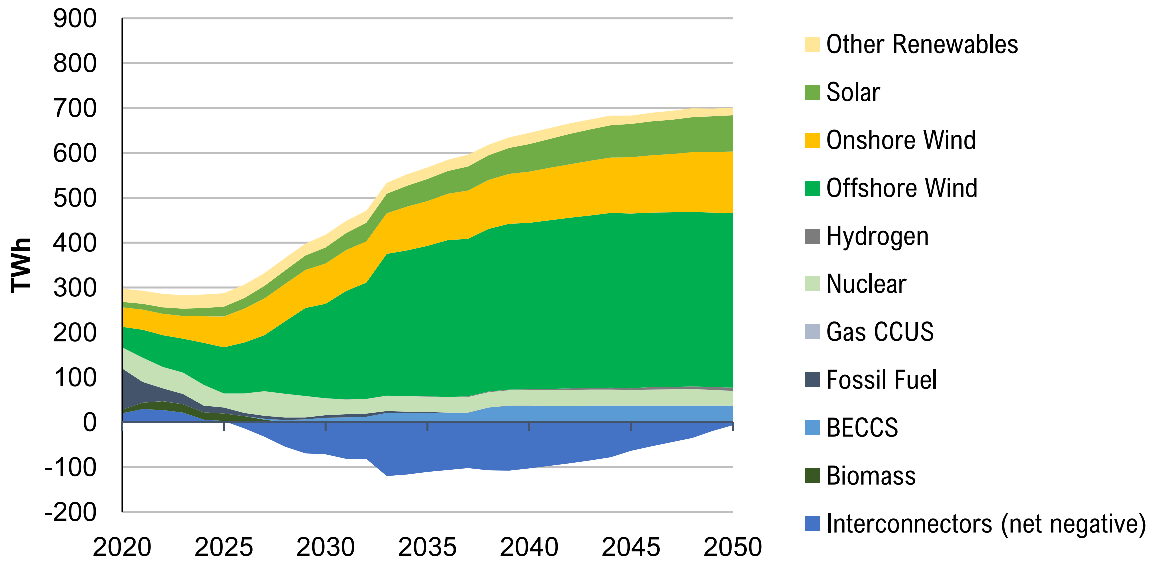


Figure 165. “Leading the Way” scenario for the UK production mix and interconnections.

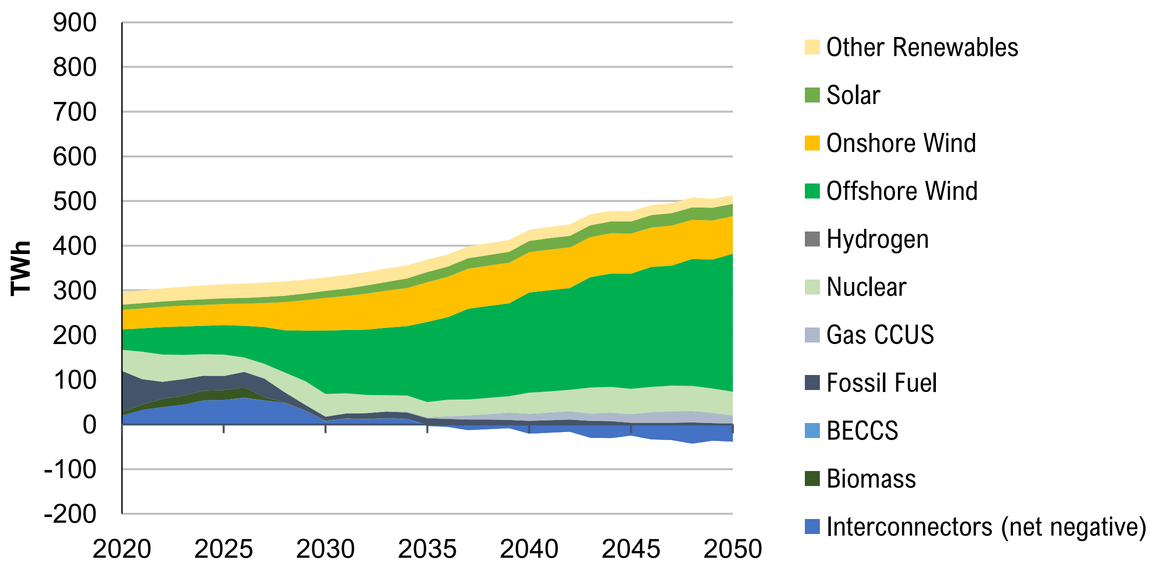


Figure 166. “Steady progression” scenario for the UK production mix and interconnections.

The lifecycle assessment of scenarios is carried out by attributing unit environmental impact factors to each source of electricity based on its annual production (per TWh), and to storage (batteries) based on annual capacity increase (per GW installed). The data source for these factors is ecoinvent 3.9.1, which uses a slightly different classification of electricity sources as the FES; matching is therefore required, as detailed in Table . In the FES data, battery storage is documented as installed capacity of batteries of unspecified chemistry, whereas ecoinvent provides environmental impact factors per kg of battery, for five various chemistries. An equal share of each chemistry was assumed, with 4 full load hours of storage, and the following density: LFP 116 Wh/kg, $LiMn_2O_4$ 114 Wh/kg, NCA 159 Wh/kg, NMC111 142 Wh/kg and NMC811 149 Wh/kg. The conversion between capacity installed and kg is therefore made possible. Regarding interconnectors, FES does not provide a detail of source countries, the same net import mix as listed in ecoinvent was assumed here, as shown in Table . The rest of the technologies, for electricity generation, match relatively well, with ecoinvent being slightly more detailed. In this case, the existing shares in ecoinvent inventories were used.

Table LVIII. Concordance between FES and ecoinvent classification of electricity generation and storage categories.

	FES 2021 classification											
Name of ecoinvent process (all UK-specific except storage)	Interconnectors	Biomass	BECCS	Fossil Fuel	Gas CCUS	Nuclear	Hydrogen	Offshore Wind	Onshore Wind	Solar	Other Renewables	Battery
electricity production, hard coal	-	-	-	6%	-	-	-	-	-	-	-	-
electricity production, natural gas, combined cycle power plant	-	-	-	-	-	-	-	-	-	-	-	-
electricity production, natural gas, conventional power plant	-	-	-	94%	-	-	-	-	-	-	-	-
electricity production, oil	-	-	-	0%	-	-	-	-	-	-	-	-
electricity production, deep geothermal	-	-	-	-	-	-	-	-	-	-	-	-
electricity production, hydro, pumped storage	-	-	-	-	-	-	-	-	-	-	30%	-
electricity production, hydro, run-of-river	-	-	-	-	-	-	-	-	-	-	70%	-
electricity production, nuclear, boiling water reactor	-	-	-	-	-	87%	-	-	-	-	-	-
electricity production, nuclear, pressure water reactor	-	-	-	-	-	13%	-	-	-	-	-	-
electricity production, photovoltaic, 3kWp slanted-roof installation, multi-Si, panel, mounted	-	-	-	-	-	-	-	-	-	19%	-	-
electricity production, photovoltaic, 3kWp slanted-roof installation, single-Si, panel, mounted	-	-	-	-	-	-	-	-	-	15%	-	-
electricity production, photovoltaic, 570kWp open ground installation, multi-Si	-	-	-	-	-	-	-	-	-	66%	-	-
electricity production, wind, 1-3MW turbine, offshore	-	-	-	-	-	-	-	100%	-	-	-	-
electricity production, wind, 1-3MW turbine, onshore	-	-	-	-	-	-	-	-	84%	-	-	-
electricity production, wind, <1MW turbine, onshore	-	-	-	-	-	-	-	-	10%	-	-	-
electricity production, wind, >3MW turbine, onshore	-	-	-	-	-	-	-	-	6%	-	-	-
electricity, high voltage, import from BE	21%	-	-	-	-	-	-	-	-	-	-	-
electricity, high voltage, import from FR	48%	-	-	-	-	-	-	-	-	-	-	-
electricity, high voltage, import from IE	6%	-	-	-	-	-	-	-	-	-	-	-
electricity, high voltage, import from NL	25%	-	-	-	-	-	-	-	-	-	-	-
heat and power co-generation, wood chips, 6667 kW, state-of-the-art 2014	-	100%	-	-	-	-	-	-	-	-	-	-
electricity production, natural gas, combined cycle power plant, CCUS dummy	-	-	-	-	100%	-	-	-	-	-	-	-
heat and power co-generation, wood chips, 6667 kW, state-of-the-art 2014, CCUS dummy	-	-	100%	-	-	-	-	-	-	-	-	-
market for battery, Li-ion, LFP, rechargeable, prismatic	-	-	-	-	-	-	-	-	-	-	-	20%
market for battery, Li-ion, LiMn2O4, rechargeable, prismatic	-	-	-	-	-	-	-	-	-	-	-	20%
market for battery, Li-ion, NCA, rechargeable, prismatic	-	-	-	-	-	-	-	-	-	-	-	20%
market for battery, Li-ion, NMC111, rechargeable, prismatic	-	-	-	-	-	-	-	-	-	-	-	20%
market for battery, Li-ion, NMC811, rechargeable, prismatic	-	-	-	-	-	-	-	-	-	-	-	20%

Time series for electricity production by source are available as $n_{t,FES} \times n_y$ tables for each scenario s, P_s; the technology classification concordance matrix H has format $n_{t,ei} \times n_{t,FES}$ (Table); and the impact factors are contained in a $n_{t,ei} \times n_{IF}$ table, B. The time series of environmental impacts for scenario s E_s can be directly calculated as:

$$E_s = B^T H P_s$$

Dividing the time series with the values of the first year (2020) provides an overview of how environmental impacts vary over time. These normalized results are shown in Figure 167 for the ATTEST-compatible "Leading the Way" scenario, while Figure 168 shows the results for the reference "Steady Progression" scenario.

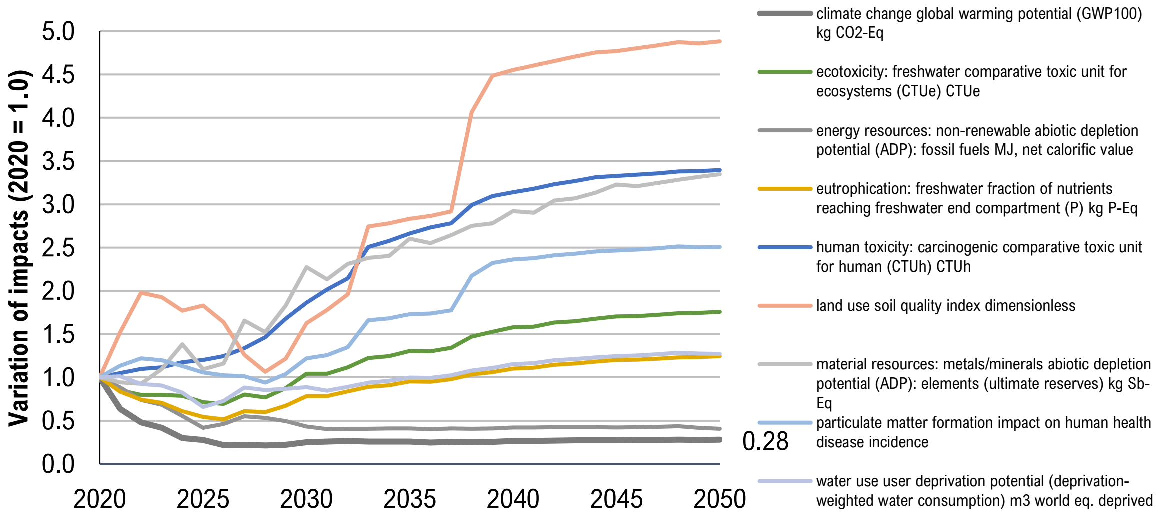


Figure 167. Evolution of lifecycle environmental impacts of the UK national grid under the "Leading the Way" scenario.

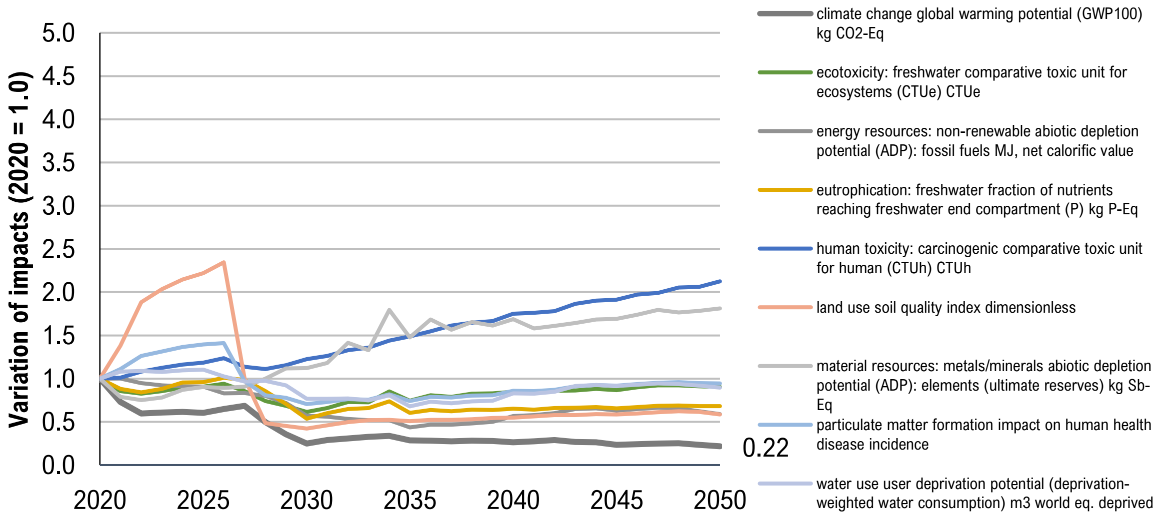


Figure 168. Evolution of lifecycle environmental impacts of the UK national grid under the "Steady Progression" scenario.

As expected, climate change impacts decrease in both scenarios, respectively by 72% and 78% in the "Leading the Way" and "Steady Progression" scenarios, as also shown in Figure 169. Among co-benefits of decarbonization are other impact reductions, including the use of fossil fuels (both scenarios) or land and water use (Steady Progression only). When comparing 2050 to 2020, the "Leading the Way" scenario leads to large increases in land use (× 5), human toxicity and material resources (× 3.5), particulate matter formation (× 2.5) or freshwater ecotoxicity (× 1.8). In addition to climate change impacts, these indicators are shown in Figure 170.

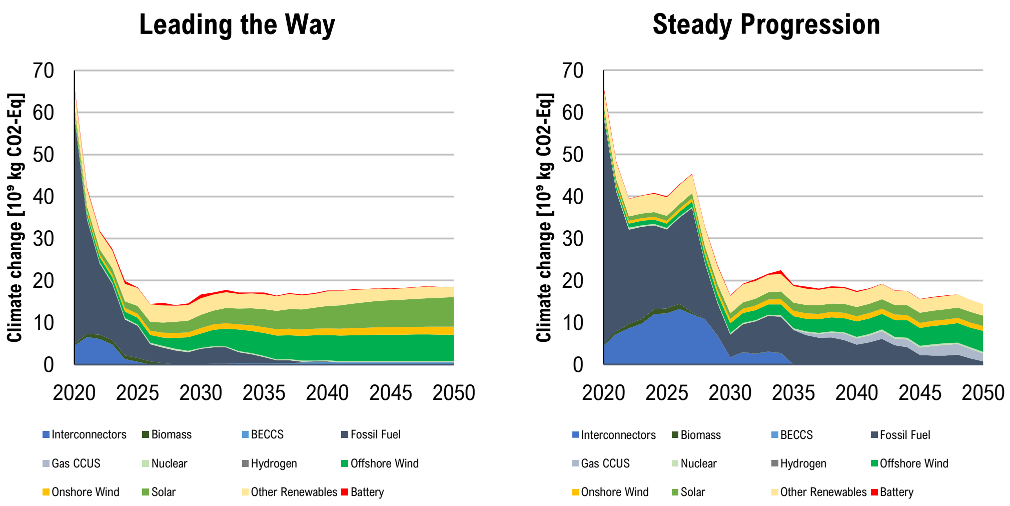


Figure 169. Climate change impacts (greenhouse gas emissions) for the two main UK scenarios.

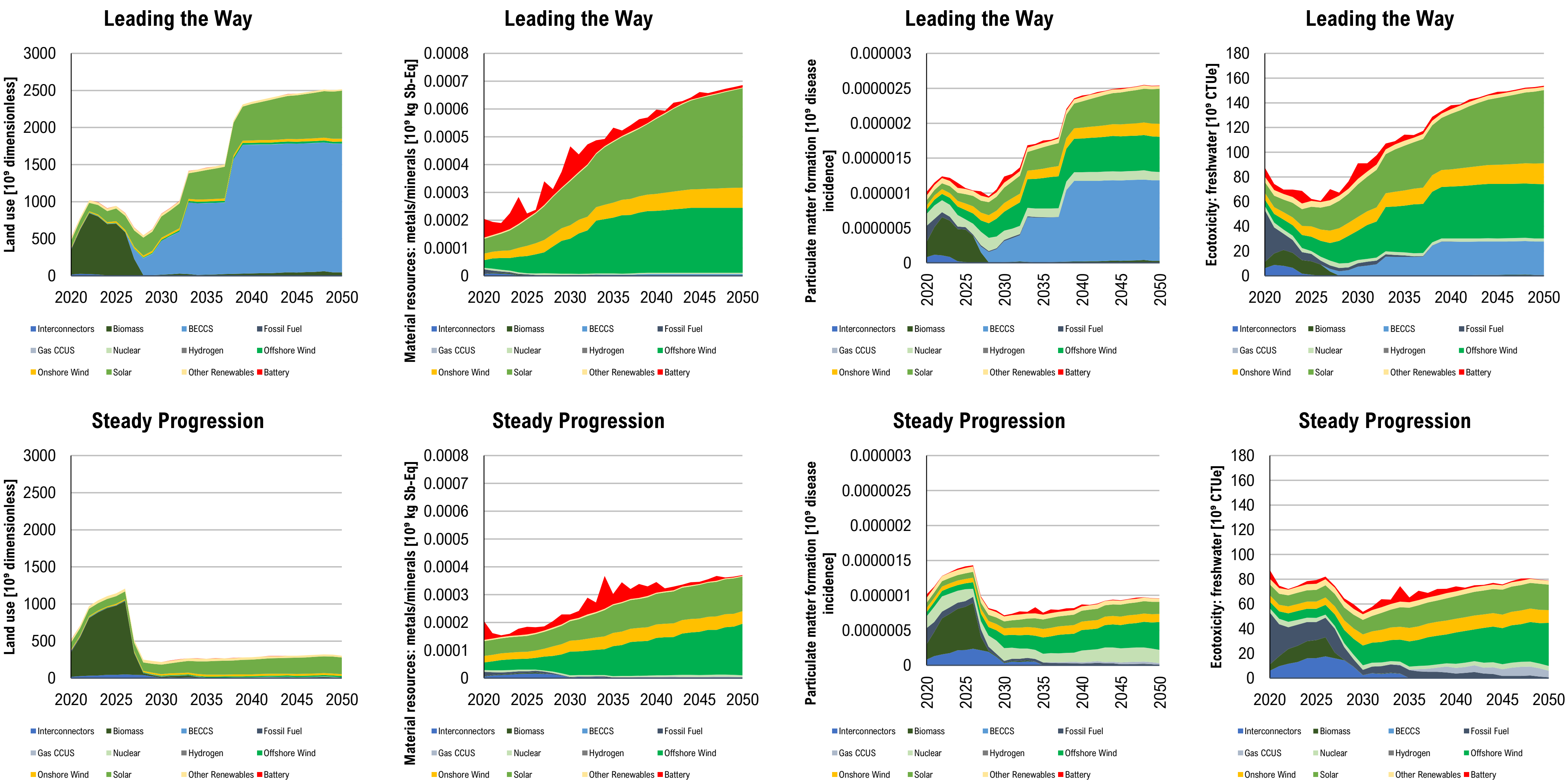


Figure 170. Comparison of potential impacts on land use, material resources, PM formation, and ecotoxicity between the "Leading the Way" and "Steady Progression" UK electricity mix scenarios.

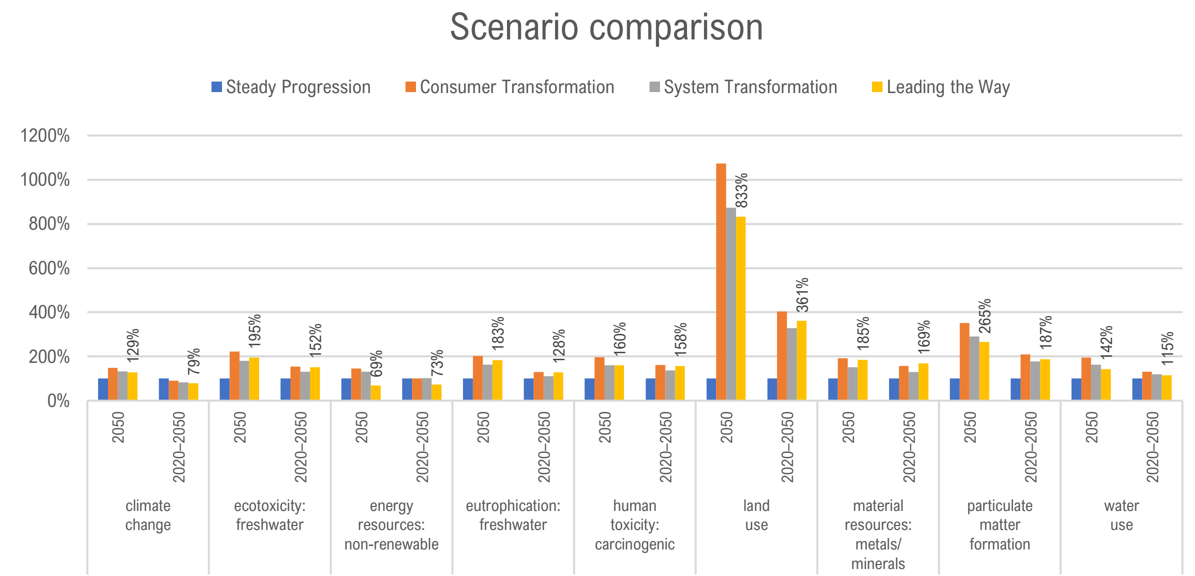


Figure 171. Comparison of the four scenarios presented in the FES, with "Steady Progression" as reference, and numbers shown for "Leading the Way", as the scenario aligned with ATTEST tools.

Following the "Leading the Way" scenario has the potential to reduce greenhouse gas emissions by 164 Mt CO_2 eq. over the 2020–2050 period a 21% decrease compared with "Steady Progression". The only other avoided impact in the list of indicators calculated is in non-renewable resources, with 10300 PJ of fossil resources avoided, or a 27% decrease.

Land use and PM formation are particularly high in the "Leading the Way" due to the deployment of BECCS. While BECCS offers significant cuts in GHG emissions, it also leads to a substantial rise in land use (due to feedstock cultivation) and in PM emissions due to biomass combustion. Solar also contributes to land use, as it is assumed to use land for utility-scale capacity installation. Material resources are also solicited because of the upsurge in solar and wind (both onshore and offshore) installed capacity up to 2050.

A similar approach was used for the three other geographical areas (Portugal, Croatia, and Spain), but with fewer data points. The next three subsections also compare an "active" (or "dynamic") scenario with a counterfactual "slow" one, with data for 2020, 2030, 2040, and 2050 only. Due to scarcer data, the list of indicators in the following subsections is also not as detailed as with the UK case.

8.2. Portugal

Future scenarios for Portugal were collected from ATTEST WP2, representing two potential trajectories for the national electricity production mix, namely a "slow" pathway and a "dynamic" pathway. The slow pathway is intended to represent a business-as-usual energy system, only accounting for current policies and rate of deployment. The active pathway focuses on adding a higher share of renewables to the grid. Electricity supply is also much higher in the "dynamic" pathway, with nearly 100 TWh/year in 2050, as opposed to nearly 70 TWh/year in the "slow" pathway, as seen on Figure 172 and Figure 173, reflecting the higher electrification level of the Portuguese economy in the former case.

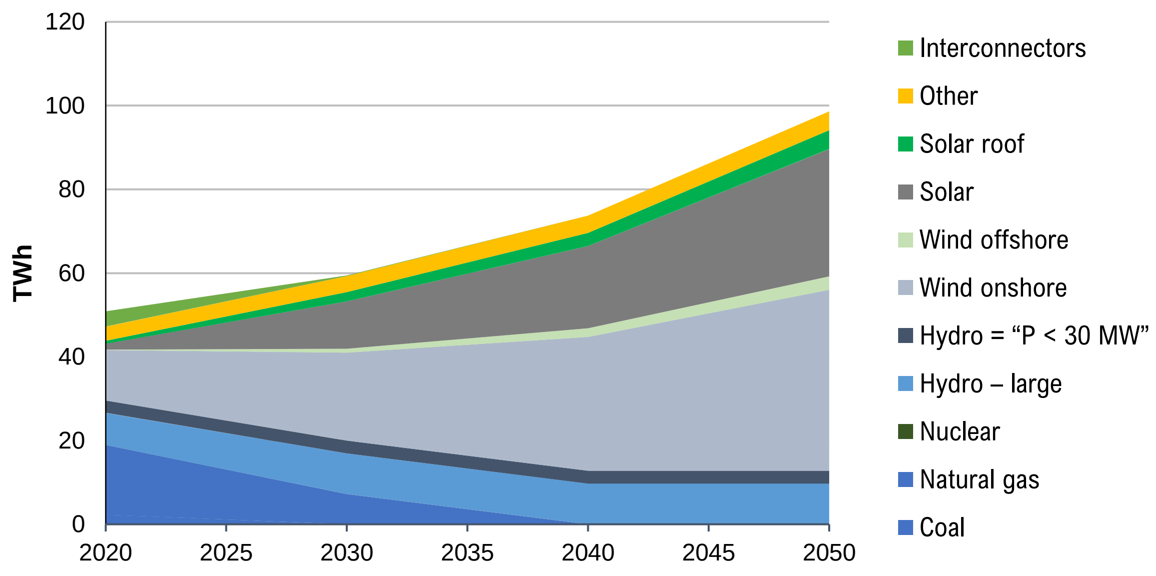


Figure 172. “Dynamic” scenario for Portugal production mix and interconnections.

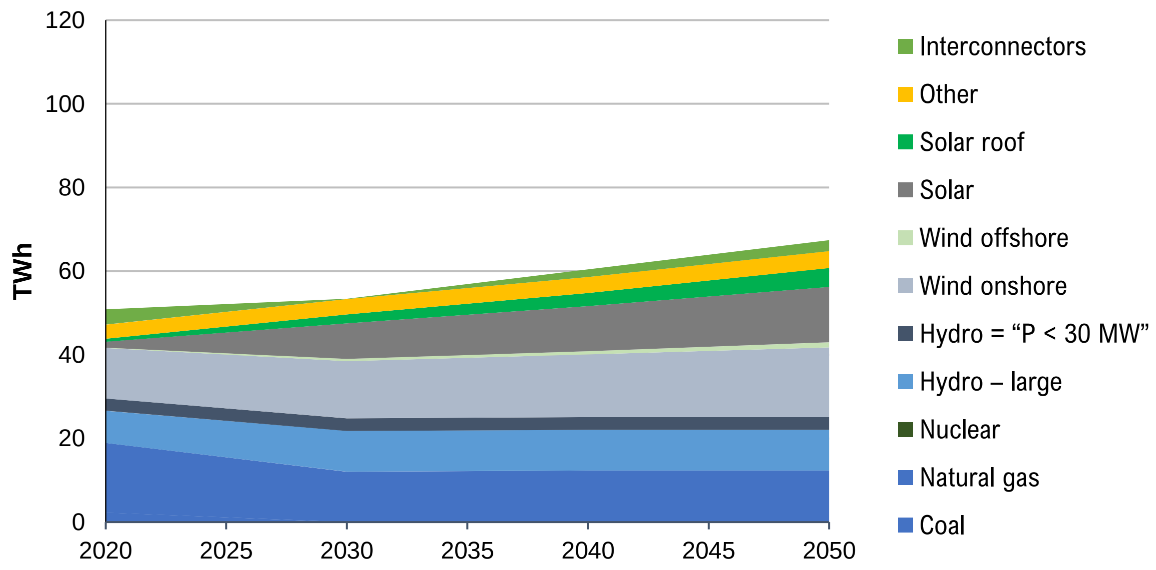


Figure 173. “Slow” scenario for Portugal production mix and interconnections.

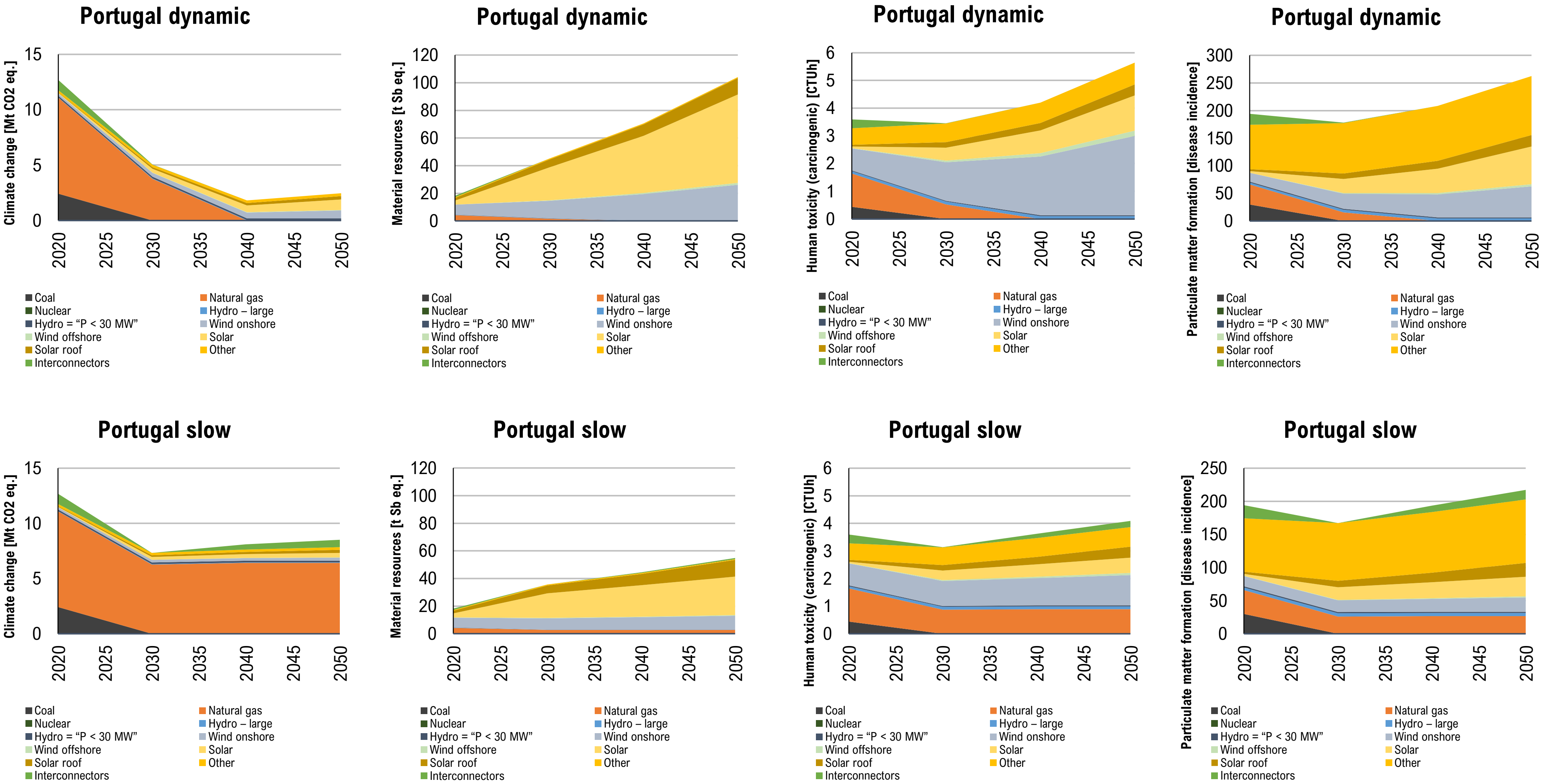


Figure 174. Comparison of potential impacts on climate change, material resources, human toxicity, and PM formation between the "Dynamic" and "Slow" Portugal electricity mix scenarios.

Translating the two Portuguese energy mix pathways into environmental impacts reveals similarities with the UK case, as shown in Figure 174. The dynamic pathway is faster to decarbonize, but comes along with trade-offs, such as a higher material footprint and potential toxicity impacts, from the value chains of energy infrastructure. Similar PM emissions are found in both pathways.

8.3. Croatia

Future scenarios for Croatia were collected from ATTEST WP2, representing two potential trajectories for the national electricity production mix, namely a "slow" pathway and an "active" pathway. The slow pathway is intended to represent a business-as-usual energy system, only accounting for current policies and rate of deployment. The active pathway focuses on adding a higher share of renewables to the grid. Note that "Nuclear" production is listed as "Nuclear – import" since the corresponding power plant is geographically located in Slovenia (Krško), is co-owned by both the Croatian and the Slovenian states, and is providing power to the Croatian grid.

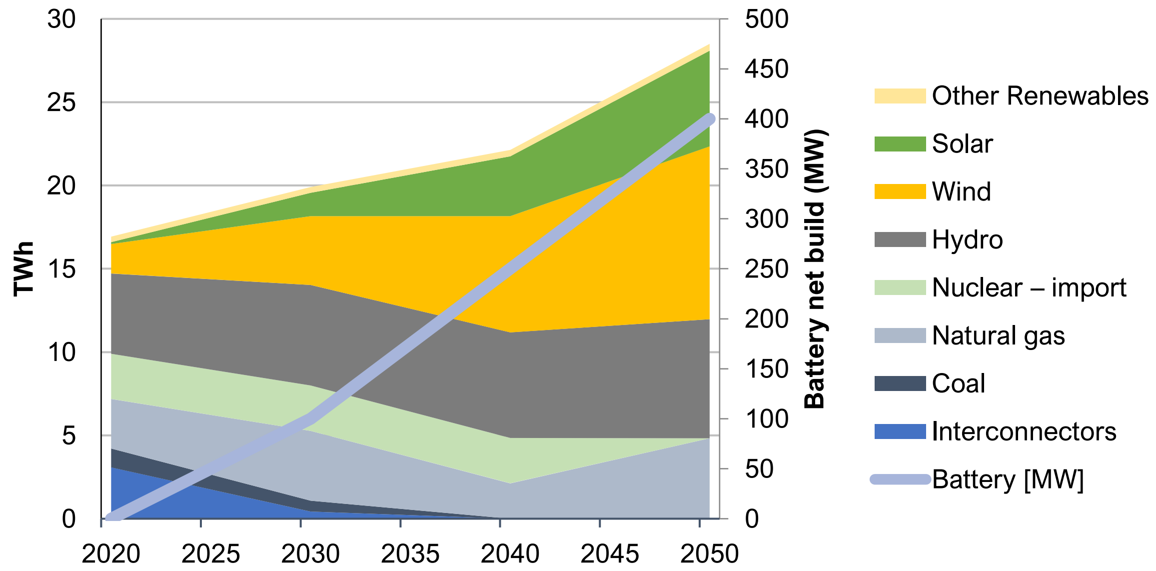


Figure 175. "Active" scenario for Croatia production mix and interconnections.

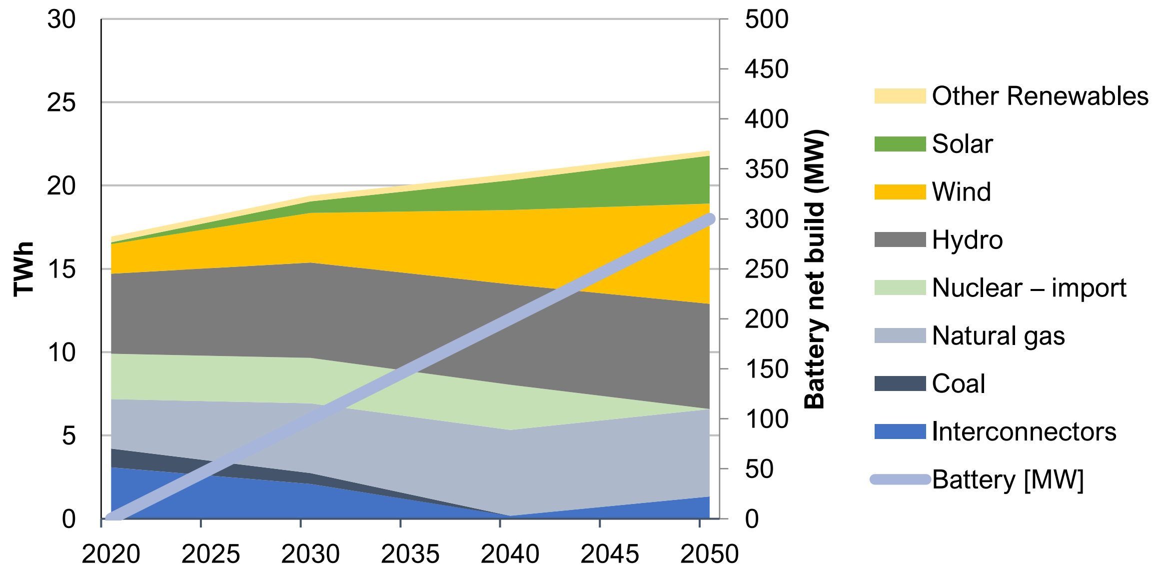


Figure 176. "Slow" scenario for Croatia production mix and interconnections.

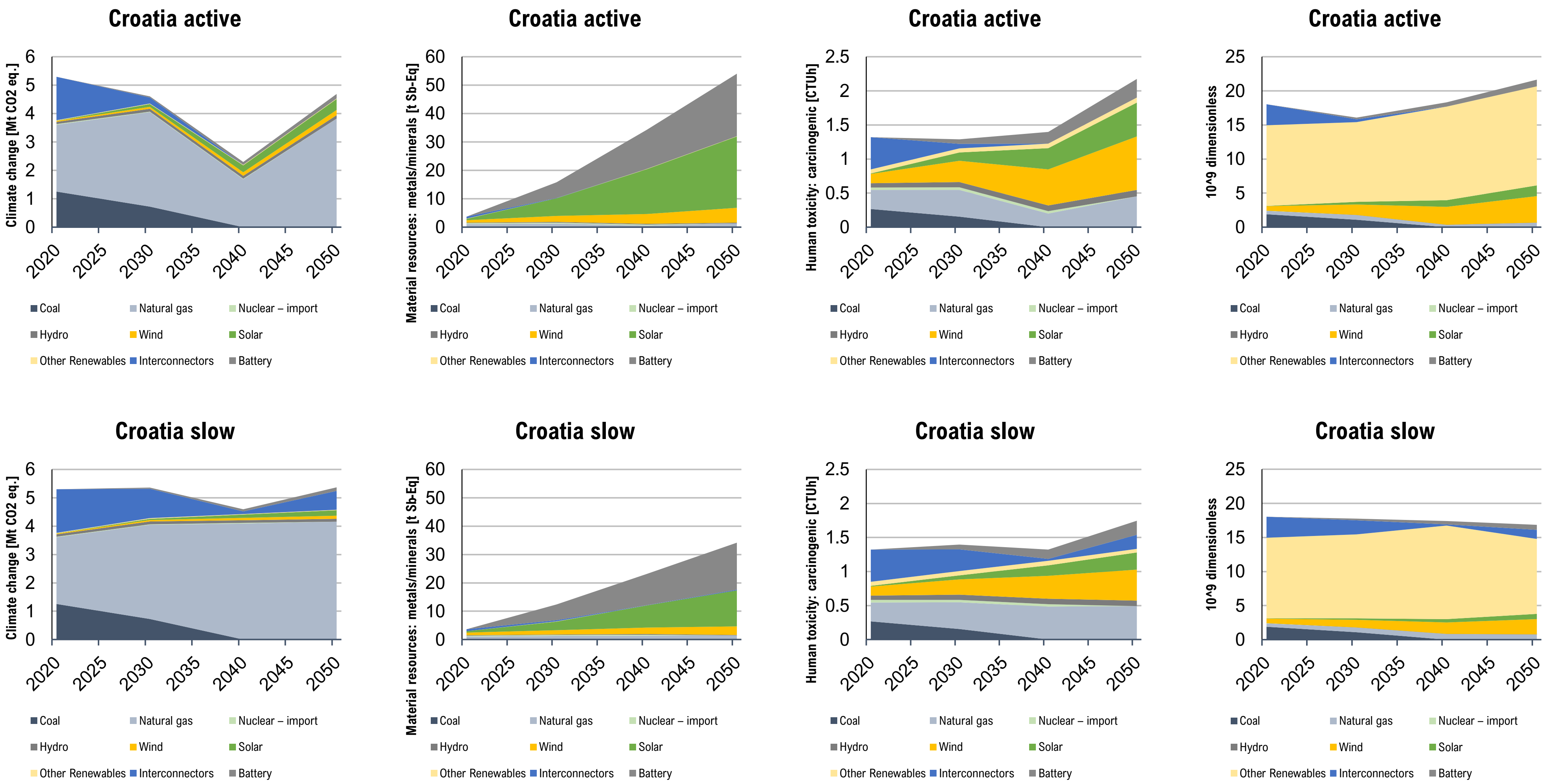


Figure 177. Comparison of potential impacts on climate change, material resources, human toxicity, and PM formation between the "active" and "slow" Croatian electricity mix scenarios.

Figure 177 shows a comparison of the “active” and “slow” Croatian production mix scenarios, from the perspective of four environmental impact indicators. A first remark is that the active scenario is only slightly more efficient at decarbonizing the grid. The reason for this is that natural gas power production is modelled as an adjustment variable. As the modelling is based on installed capacity values, all low-carbon resources are considered first to meet the final demand of Croatia, with natural gas supplementing the rest. The phase-out of nuclear power production in 2050 requires a significant uptick in gas output, which results in an increase of GHG emissions as renewables are not deployed fast enough. It is however likely that extending the analysis to 2060 and later would show GHG emissions decreasing again and that this phase is transitional. Regarding the rest of selected indicators, we see material, toxicity and PM emissions increasing in the active scenario, due to a combination of renewable deployment (with a higher material footprint than conventional power) and a significantly higher supply of electricity to the grid.

8.4. Spain

Future scenarios for Spain were collected from ATTEST WP2 and from the National Energy-Climate Plan of Spain. They represent two potential trajectories for the national electricity production mix, namely a “slow” pathway and an “active” pathway. The slow pathway is intended to represent a business-as-usual energy system, only accounting for current policies and rate of deployment. The active pathway focuses on adding a higher share of renewables to the grid.

Spain has a few particularities, namely a significant share of thermoelectric solar (or concentrated solar power), and high level of exports, as seen especially in the active scenario (Figure 178).

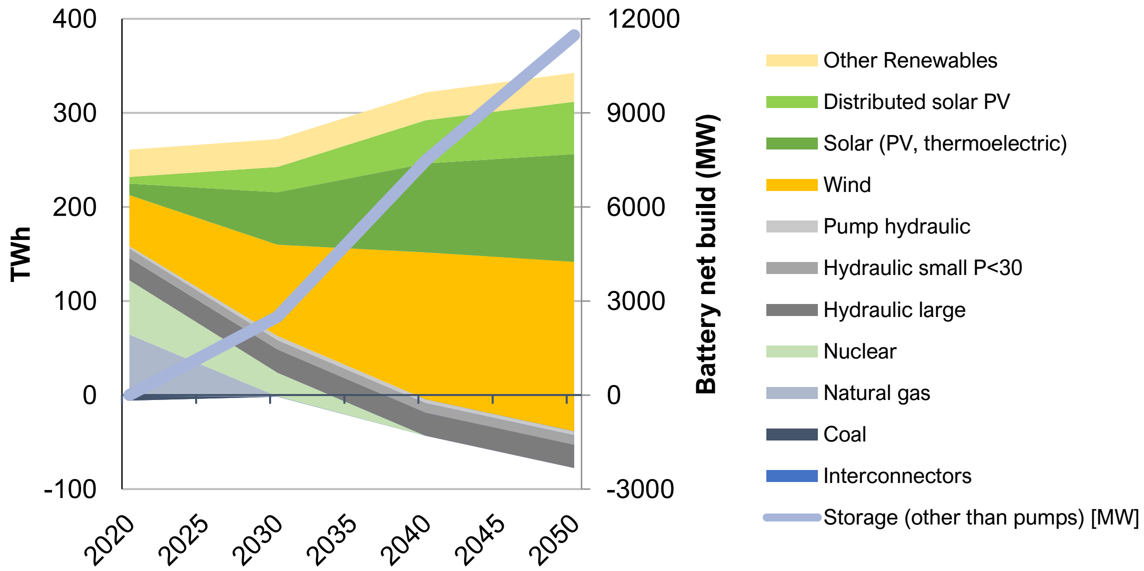


Figure 178. “Active” scenario for Spain production mix and interconnections.

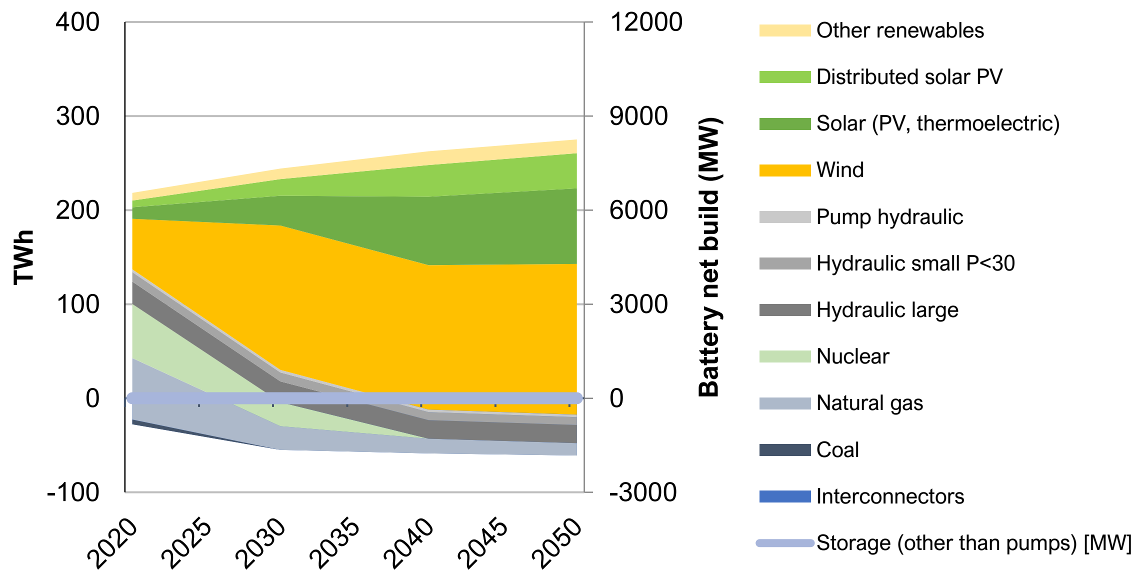


Figure 179. "Slow" scenario for Spain production mix and interconnections.

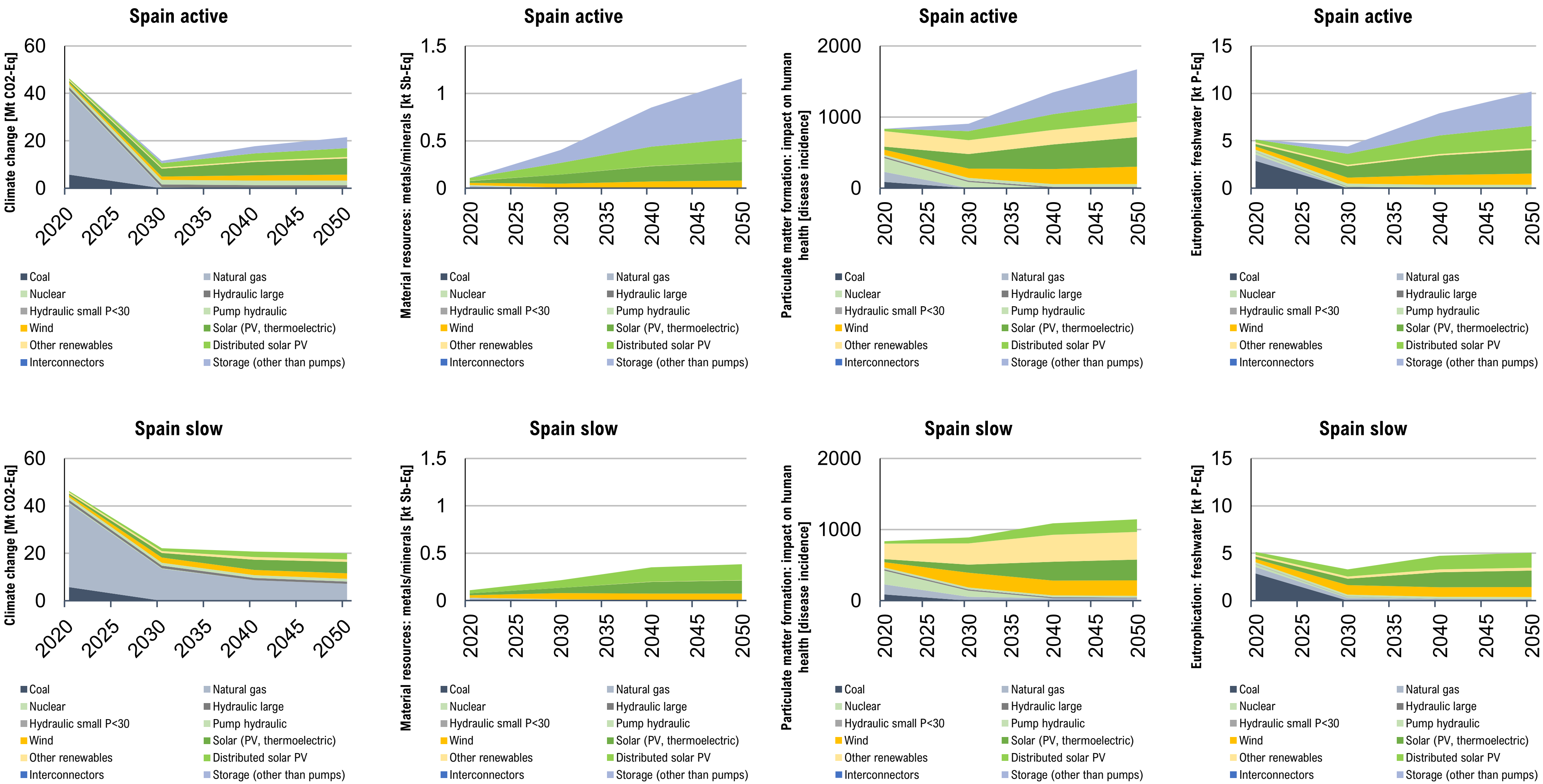


Figure 180. Comparison of potential impacts on climate change, material resources, human toxicity, and PM formation between the “active” and “slow” Spanish electricity mix scenarios.

The future Spanish electricity mix will be lower-carbon than today, whichever pathway is foreseen, as fossil fuels are phased out in both the “active” and “slow” scenarios. A slight rebound can be expected in the active scenario, as a significant amount of battery storage is being built. This shows clearly on the “Material resources” indicator, as chemical batteries contain elements that are associated with a particularly high characterization factor in this impact category. This is also visible, although slightly less so, on the PM and eutrophication indicators.

8.5. Conclusions

The results of the environmental impact assessment of the various mix pathways reveal similar trends across countries. A first observation is that active (or “dynamic”) scenarios tend to decarbonize faster the electricity grids, which confirms that they align with ambitious climate targets, relatively to “slow” scenarios. In some countries, long-term emissions of active and slow scenarios seem on par, for three main reasons: (1) active scenarios plan for a higher electricity supply, reflecting a higher degree of electrification of the economy, (2) emission factors are assumed constant in time, whereas they will most likely decrease, as the rollout of renewable will decarbonize electricity supply – including electricity used in producing renewable infrastructure, (3) battery production is higher in active scenario, in response to the deeper intermittency of production.

In general, the main drawbacks of ambitious renewable electricity scenarios are material requirements and land use, confirmed here in the four use cases. These results should however be mitigated as the recycling industry will grow as the amount of renewable energy infrastructure reaches its lifetime, which will decrease the reliance on virgin materials. Land use is assumed relatively high for solar technologies as a large share of them (photovoltaics and/or concentrated solar power) is ground-mounted – however, it is becoming increasingly clear that large arrays can be mounted on without any land sealing, even sharing space with other activities (agrivoltaics).

Impact assessment results presented in this section should therefore be interpreted as conservative estimates, since future infrastructure will likely be less impactful as the background economy itself becomes “cleaner”. This virtuous cycle is not captured in the results shown here. In addition, life cycle impact assessment is a rather generic exercise, especially when characterizing material requirements, as it cannot capture the criticality of a given value chain accurately, but only as a global average.

Finally, case-specific assumptions have been made when it was not clear how future installed capacity would meet national demand, especially how much NGCC/interconnectors should complement intermittent sources. This occurred for the estimation of the Croatian mix, which shows a higher GHG footprint in 2050 than in 2040 because not enough renewables are installed to pick up the gap left by the nuclear power plant phase-out. Longer term estimates would probably show that this gap would narrow and even disappear in the subsequent decades, but those were not provided.

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10. Annex

10.1. Annex 1 | Task T2.6 – Market simulator

10.1.1. Annex A

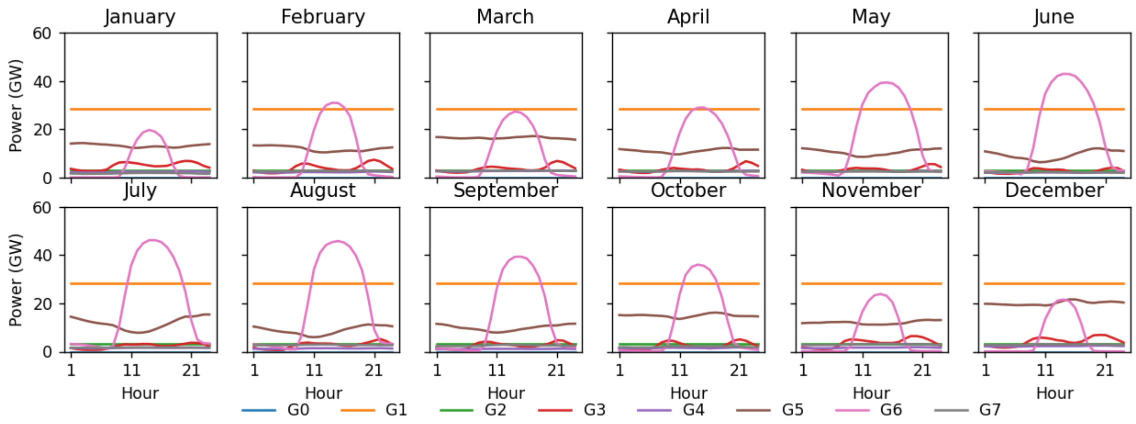

Figure 181: Spanish available energy profiles for a typical weekday for the 2030 scenario.

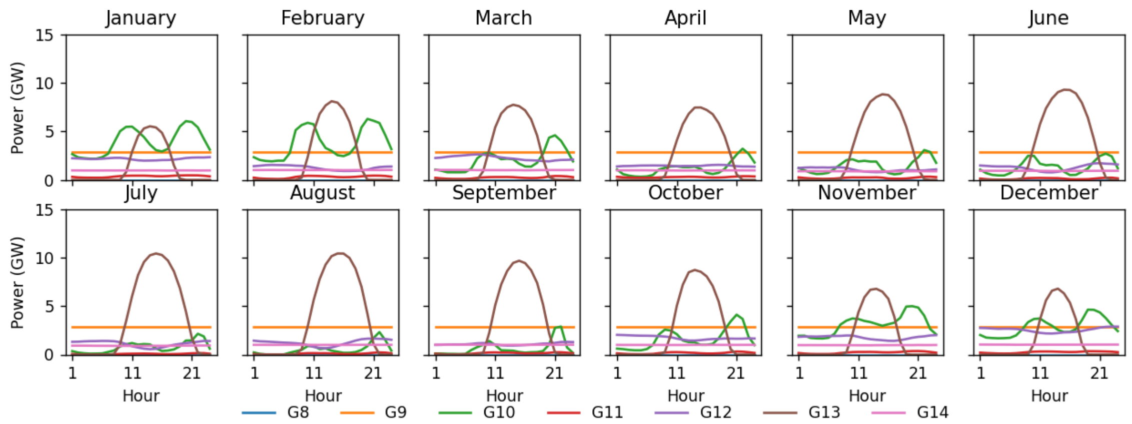

Figure 182: Portuguese available energy profiles for a typical weekday for the 2030 scenario.

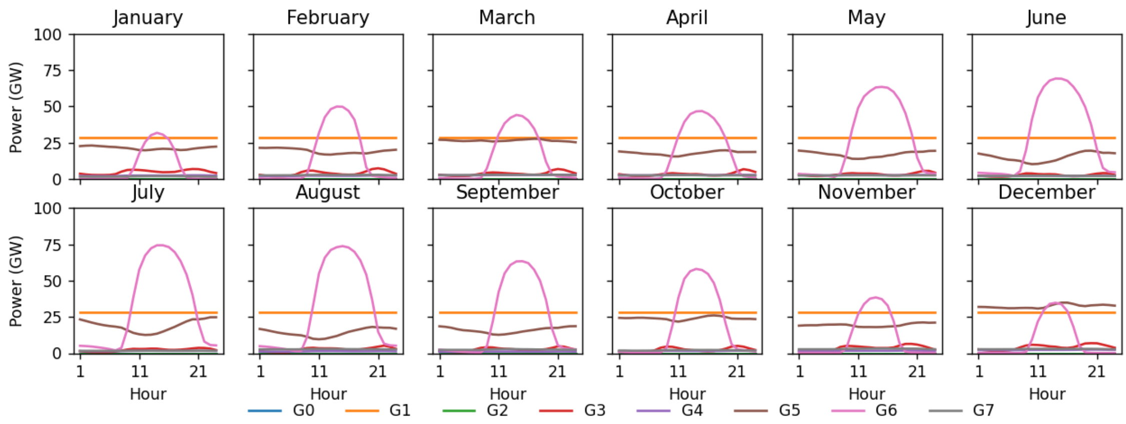

Figure 183: Spanish available energy profiles for a typical weekday for the 2040 scenario.

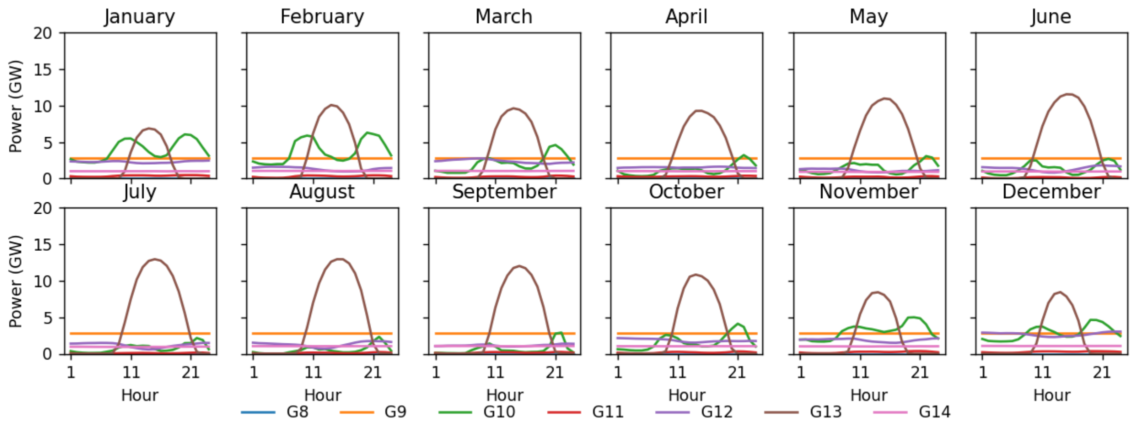

Figure 184: Portuguese available energy profiles for a typical weekday for the 2040 scenario.

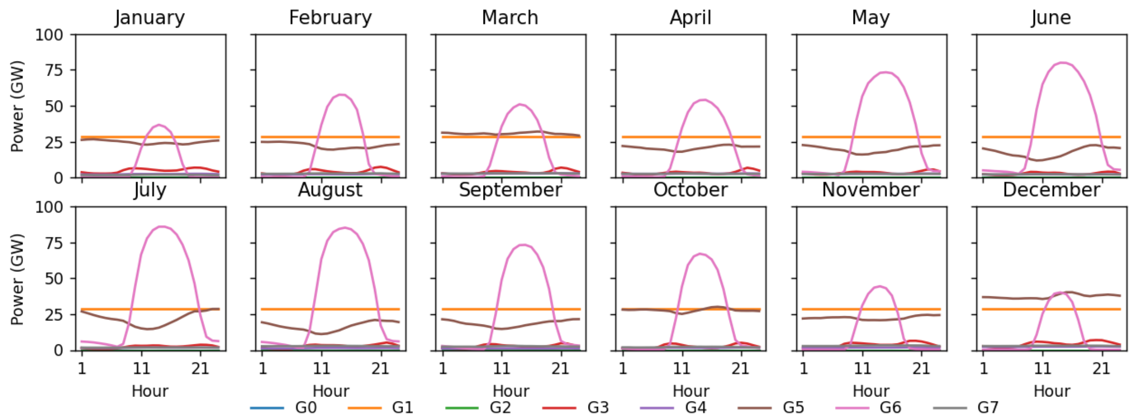

Figure 185: Spanish available energy profiles for a typical weekday for the 2050 scenario.

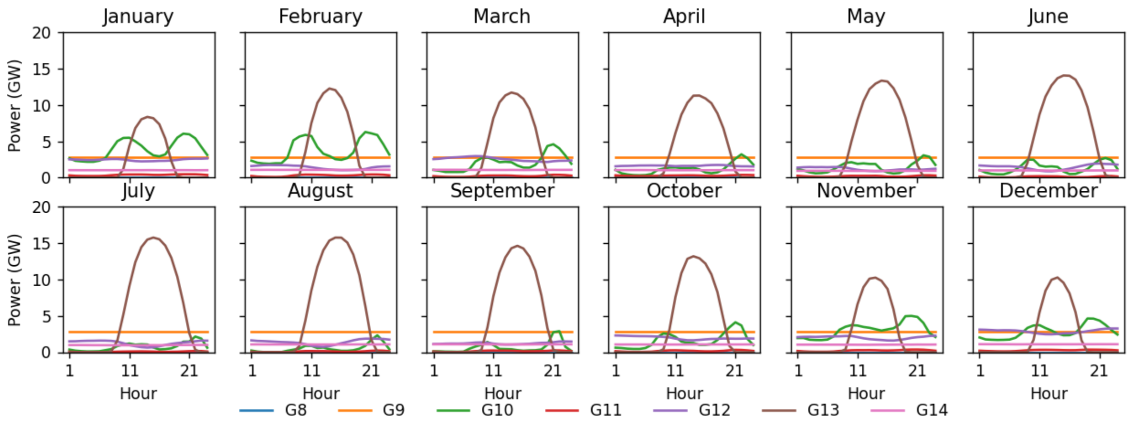

Figure 186: Portuguese available energy profiles for a typical weekday for the 2050 scenario.

10.1.2. Annex B

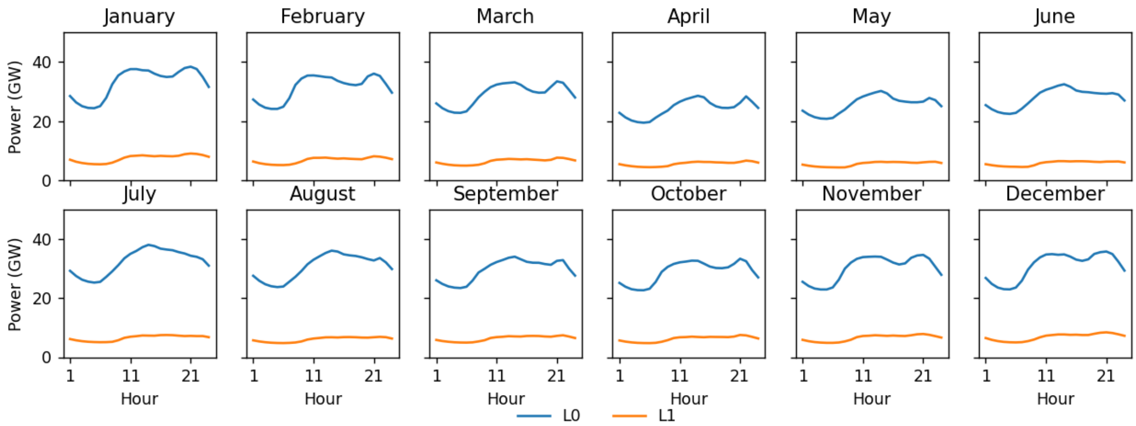

Figure 187: Spanish and Portuguese load energy bids for a typical weekday for the 2030 scenario.

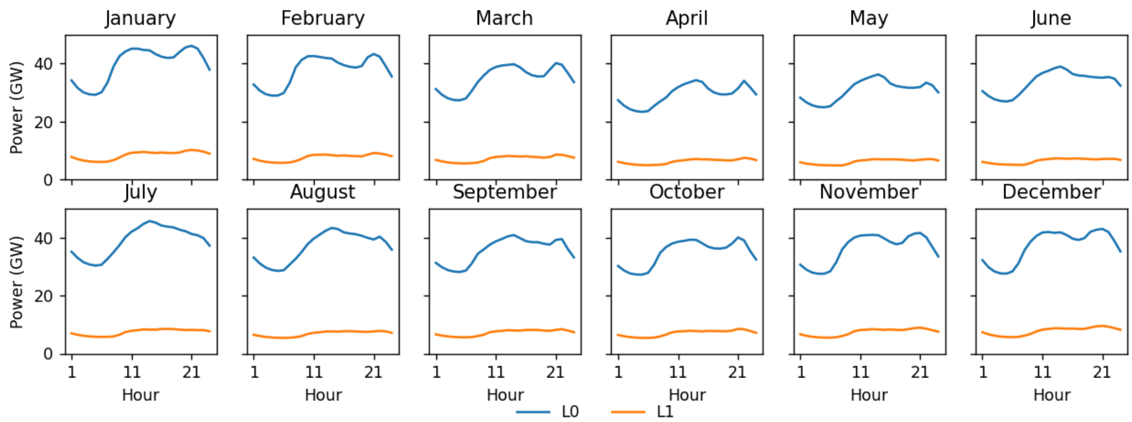

Figure 188: Spanish and Portuguese load energy bids for a typical weekday for the 2040 scenario.

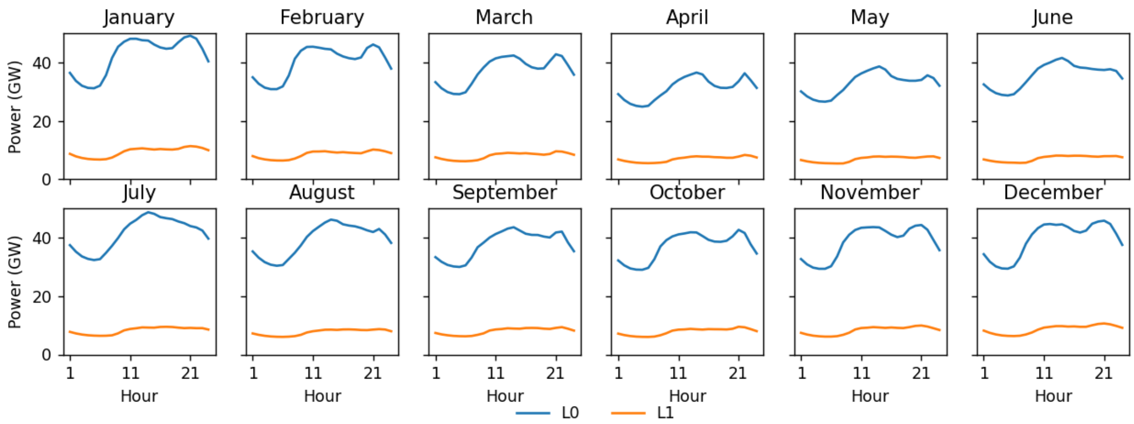

Figure 189: Spanish and Portuguese load energy bids for a typical weekday for the 2050 scenario.

10.2. Annex 2 | Task 3.3 – Optimization tool for planning TSO/DSO shared technologies

Information regarding Task 3.3 are provided in this section– optimization tool for planning TSO/DSO shared technologies case studies.

10.2.1. Case Study Koprivnica

Information regarding the KPIs obtained for case study "Koprivnica" are provided in this subsection.

10.2.1.1. Network Losses

Table shows the expected network losses per network, year, and representative day for case study "Koprivnica", fot the BaU and ATTEST scenarios.

Table LIX - Task 3.3. Technical KPIs. Case study Koprivnica. Expected losses per network, year, and representative day.

			2020	2030	2040	2050	2020	2030	2040	2050
Network	Control	Losses KPI	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer
TN	BaU	Losses, [MWh]	46.81	35.09	61.11	42.53	74.00	49.09	173.06	117.41
		Losses, [%]	0.31%	0.25%	0.34%	0.26%	0.36%	0.26%	0.63%	0.46%
	ATTEST	Losses, [MWh]	46.45	34.94	60.73	42.07	78.50	49.92	221.39	143.46
		Losses, [%]	0.30%	0.25%	0.33%	0.25%	0.38%	0.27%	0.82%	0.58%
ADN Node 29	BaU	Losses, [MWh]	6.90	5.87	8.92	7.41	10.29	8.96	15.22	14.10
		Losses, [%]	1.16%	0.94%	1.26%	1.00%	1.33%	1.09%	1.61%	1.36%
	ATTEST	Losses, [MWh]	7.34	6.16	9.45	7.87	10.94	9.47	17.36	15.02
		Losses, [%]	1.20%	0.98%	1.31%	1.06%	1.35%	1.15%	1.65%	1.40%
ADN Node 1	BaU	Losses, [MWh]	10.90	11.17	14.41	14.73	17.53	17.86	30.22	31.73
		Losses, [%]	1.98%	2.05%	2.22%	2.30%	2.41%	2.49%	3.13%	3.27%
	ATTEST	Losses, [MWh]	12.23	12.54	15.42	15.72	19.18	19.63	36.89	38.23
		Losses, [%]	2.22%	2.30%	2.36%	2.43%	2.58%	2.66%	3.73%	3.90%
ADN Node 19	BaU	Losses, [MWh]	0.10	0.10	0.68	0.68	1.15	1.15	2.79	2.79
		Losses, [%]	0.30%	0.30%	0.67%	0.67%	0.90%	0.90%	1.51%	1.51%
	ATTEST	Losses, [MWh]	0.08	0.08	0.77	0.77	1.95	1.90	8.42	7.79
		Losses, [%]	0.27%	0.27%	0.79%	0.80%	1.59%	1.55%	4.61%	4.32%
	BaU	Losses, [MWh]	1.20	1.03	1.49	1.29	1.58	1.42	2.35	2.03

ADN Node 55		Losses, [%]	0.90%	0.86%	0.94%	0.91%	0.88%	0.88%	0.99%	0.95%
	ATTEST	Losses, [MWh]	1.18	0.99	1.46	1.27	1.62	1.43	2.64	2.40
		Losses, [%]	0.88%	0.82%	0.92%	0.89%	0.90%	0.89%	1.12%	1.12%
ADN Node 5	BaU	Losses, [MWh]	0.95	0.64	1.07	0.72	1.31	0.88	2.20	1.51
		Losses, [%]	0.33%	0.28%	0.31%	0.26%	0.34%	0.28%	0.43%	0.37%
	ATTEST	Losses, [MWh]	0.95	0.61	1.02	0.69	1.28	0.91	3.60	2.59
		Losses, [%]	0.33%	0.27%	0.30%	0.25%	0.33%	0.29%	0.70%	0.63%
ADN Node 68	BaU	Losses, [MWh]	2.67	2.93	2.69	2.96	2.54	2.88	1.78	2.66
		Losses, [%]	1.16%	1.33%	1.00%	1.15%	0.90%	1.06%	0.58%	0.86%
	ATTEST	Losses, [MWh]	2.41	2.78	2.43	2.79	2.25	2.67	2.22	2.48
		Losses, [%]	1.06%	1.29%	0.91%	1.10%	0.79%	0.98%	0.72%	0.86%

10.2.1.2. RES Share

Table shows the expected network losses per network, year, and representative day for case study "Koprivnica" for the BaU and ATTEST scenarios.

Table LX - Task 3.3. Environmental KPIs. Case study Koprivnica. Expected RES generation per network, year, and representative day.

			2020	2030	2040	2050	2020	2030	2040	2050
Network	Control	Losses KPI	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer
TN	BaU	Gen., [MWh]	0.00	0.00	1445.30	1445.30	3480.53	3480.53	5279.78	5279.78
		Gen., [%]	0.00%	0.00%	9.36%	8.39%	19.91%	17.88%	22.86%	20.56%
	ATTEST	Gen., [MWh]	0.00	0.00	1445.30	1445.30	3480.52	3480.52	5279.78	5279.78
		Gen., [%]	0.00%	0.00%	9.36%	8.39%	19.86%	17.82%	22.56%	20.22%
ADN Node 29	BaU	Gen., [MWh]	0.00	0.00	106.12	97.49	209.85	188.26	314.37	280.02
		Gen., [%]	0.00%	0.00%	14.22%	13.45%	25.20%	23.53%	29.34%	27.62%
	ATTEST	Gen., [MWh]	0.00	0.00	106.34	98.19	210.95	192.00	319.39	292.60
		Gen., [%]	0.00%	0.00%	14.21%	13.39%	25.17%	23.39%	29.21%	27.22%
ADN Node 1	BaU	Gen., [MWh]	0.00	0.00	176.20	171.54	287.46	277.21	449.72	432.95
		Gen., [%]	0.00%	0.00%	26.74%	25.81%	38.59%	36.85%	44.62%	42.99%
	ATTEST	Gen., [MWh]	0.00	0.00	177.05	172.17	291.34	280.39	459.82	443.96
		Gen., [%]	0.00%	0.00%	26.51%	25.61%	38.11%	36.41%	43.71%	41.86%
ADN Node 19	BaU	Gen., [MWh]	0.00	0.00	69.54	69.54	95.62	95.62	156.46	156.46
		Gen., [%]	0.00%	0.00%	68.41%	68.41%	74.81%	74.81%	84.51%	84.51%
	ATTEST	Gen., [MWh]	0.00	0.00	69.54	69.54	95.62	95.62	156.46	156.46
		Gen., [%]	0.00%	0.00%	71.55%	71.56%	78.06%	77.66%	86.65%	85.71%
ADN Node 55	BaU	Gen., [MWh]	0.00	0.00	27.86	29.03	44.08	47.29	75.63	77.76
		Gen., [%]	0.00%	0.00%	19.40%	18.19%	27.04%	26.16%	35.01%	32.54%
	ATTEST	Gen., [MWh]	0.00	0.00	28.35	29.58	44.90	47.59	77.72	81.87
		Gen., [%]	0.00%	0.00%	19.63%	18.44%	27.07%	25.91%	35.16%	33.53%
ADN Node 5	BaU	Gen., [MWh]	0.00	0.00	70.08	74.32	113.56	123.70	179.44	194.33
		Gen., [%]	0.00%	0.00%	25.70%	21.55%	36.56%	31.65%	43.46%	37.63%
	ATTEST	Gen., [MWh]	0.00	0.00	70.32	74.63	114.74	124.80	181.44	196.27
		Gen., [%]	0.00%	0.00%	25.66%	21.56%	36.60%	31.71%	43.05%	37.37%
ADN Node 68	BaU	Gen., [MWh]	0.00	0.00	41.52	41.52	57.09	57.09	93.41	102.12
		Gen., [%]	0.00%	0.00%	16.19%	15.36%	20.88%	20.32%	30.38%	32.83%
	ATTEST	Gen., [MWh]	0.00	0.00	41.52	41.52	57.09	57.09	93.41	100.10
		Gen., [%]	0.00%	0.00%	16.40%	15.52%	20.98%	20.11%	32.19%	31.61%

10.2.1.3. Generation Costs

Figure 190 shows the expected generation costs per year and representative day for case study "Koprivnica", for the BaU and ATTEST scenarios.

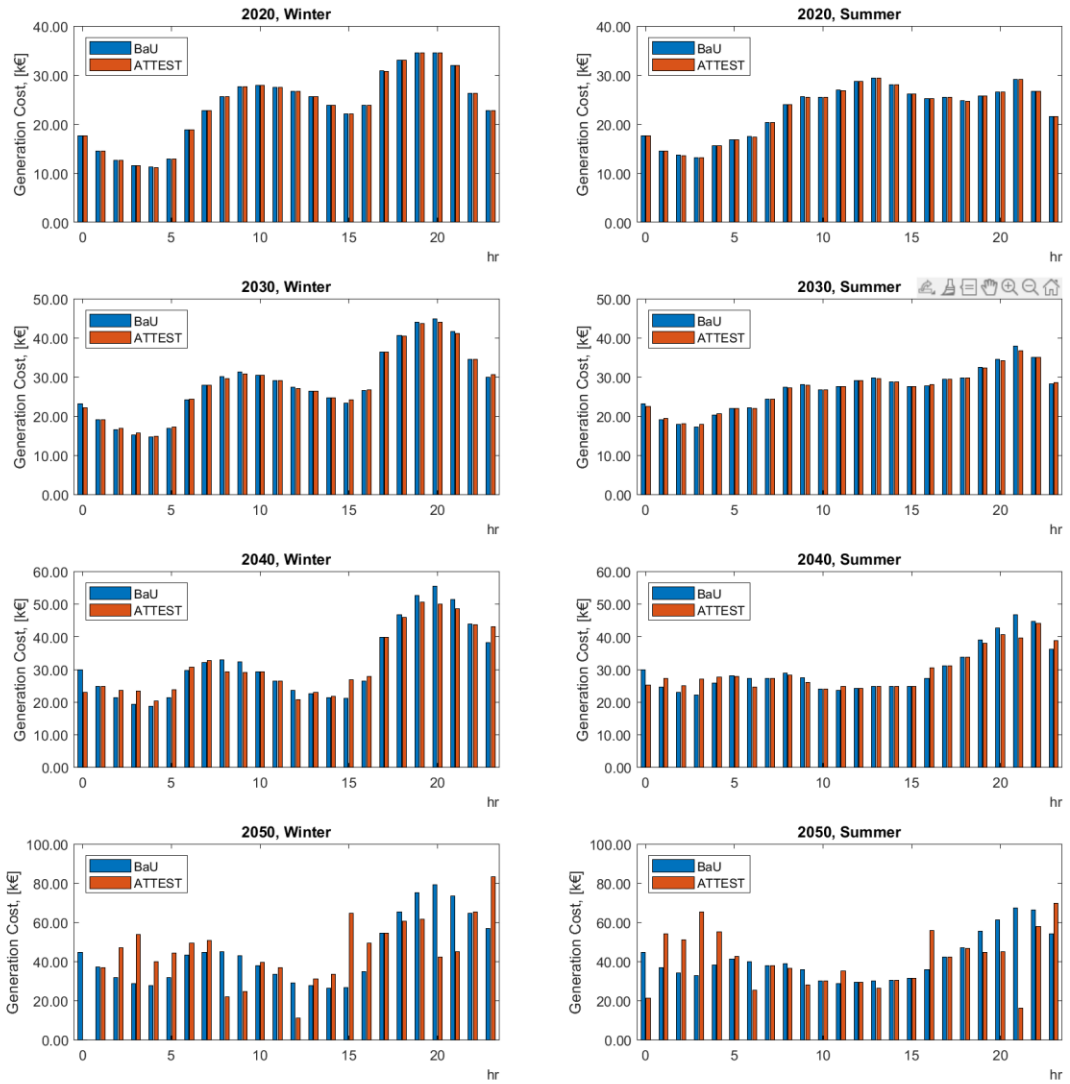

Figure 190 - Task 3.3. Case study IEEE. Expected hourly generation costs per year and representative day.

10.2.1.4. GHG Emissions

Figure 191 shows the expected GHG emissions per year and representative day for case study “Koprivnica”, for the BaU and ATTEST scenarios.

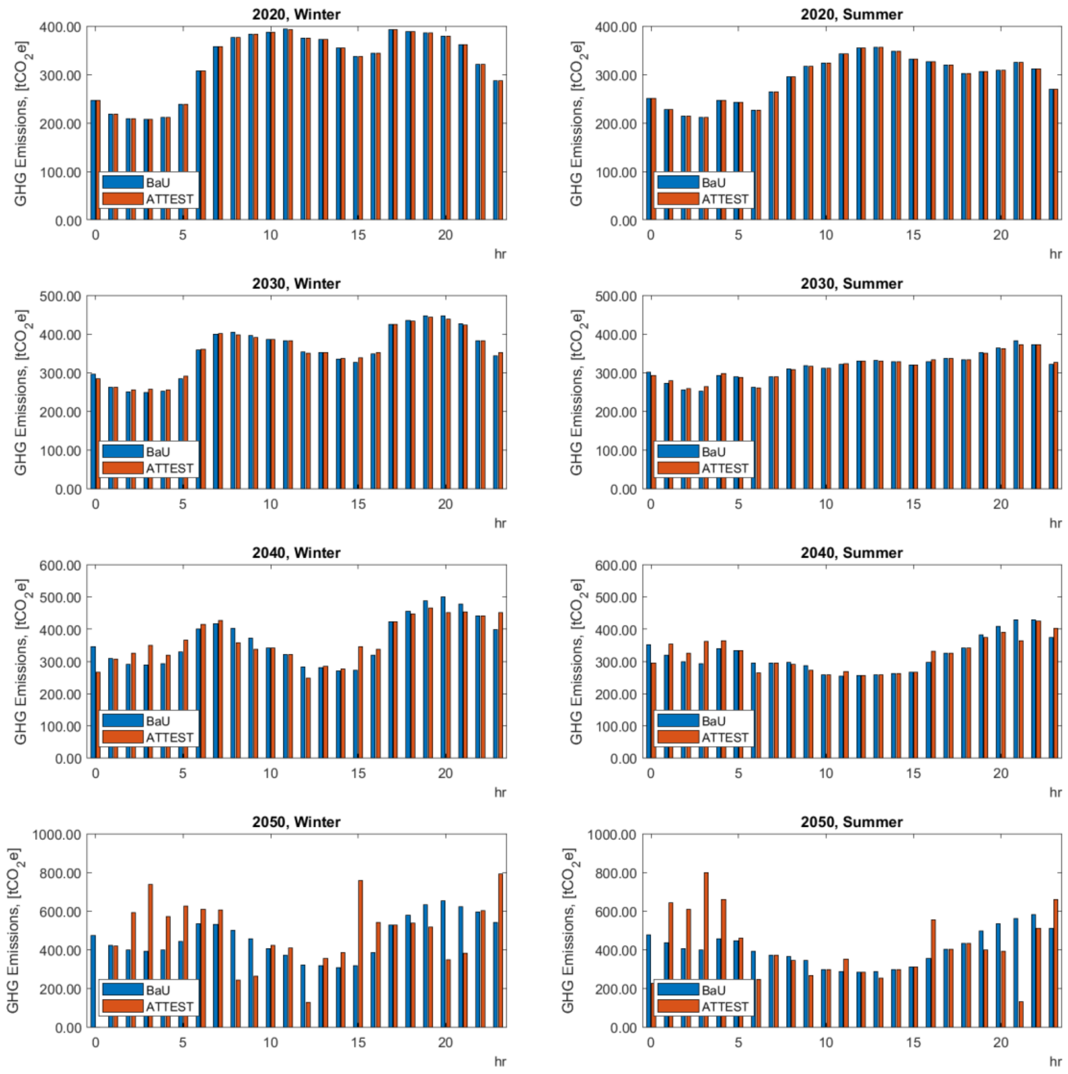

Figure 191 - Task 3.3. Case study Koprivnica. Expected hourly GHG emissions per year and representative day.

10.2.2. Case Study IEEE

10.2.2.1. PV and ESS Installed Capacity

Table and Table show the PV and ESS installed capacity per network, year, and network node for the "IEEE case study", for the BaU and ATTEST scenarios.

Table LXI – Task 3.3. Case study IEEE. Installed PV capacity per year and network node.

		Installed capacity per year, [MW]			
Network	Node	2020	2030	2040	2050
TN	11	-	-	-	150.00
	13	-	-	-	150.00
	26	-	-	100.00	100.00
	29	-	75.00	100.00	100.00
	30	-	75.00	100.00	100.00
ADN Node 24	8	-	2.00	2.00	4.00
	9	-	-	-	4.00
	22	-	-	4.00	4.00
	24	-	-	4.00	4.00

	26	-	2.00	2.00	6.00
ADN Node 16	8	-	2.00	2.00	4.00
	9	-	-	-	4.00
	22	-	-	4.00	4.00
	24	-	-	4.00	4.00
	26	-	2.00	2.00	6.00
ADN Node 18	8	-	2.00	2.00	4.00
	9	-	-	-	4.00
	22	-	-	4.00	4.00
	24	-	-	4.00	4.00
	26	-	2.00	2.00	6.00
ADN Node 26	18	-	-	-	2.50
	22	-	-	1.00	2.50
	25	-	0.50	1.50	5.00
	33	-	1.00	1.50	5.00
ADN Node 3	18	-	-	-	2.50
	22	-	-	1.00	2.50
	25	-	0.50	1.50	5.00
	33	-	1.00	1.50	5.00

Table LXII – Task 3.3. Case study IEEE. Installed ESS capacity per year and network node.

		Installed capacity per year, [MWh]			
Network	Node	2020	2030	2040	2050
TN	9	-	-	-	40.00
	12	-	-	10.00	10.00
	25	-	-	20.00	20.00
	27	-	20.00	20.00	40.00
ADN Node 24	2	-	-	-	4.00
	7	-	-	-	4.00
	20	-	-	4.00	4.00
	23	-	-	4.00	4.00
	25	-	2.00	2.00	4.00
ADN Node 16	2	-	-	-	4.00
	7	-	-	-	4.00
	20	-	-	4.00	4.00
	23	-	-	4.00	4.00
	25	-	2.00	2.00	4.00
ADN Node 18	2	-	-	-	4.00
	7	-	-	-	4.00
	20	-	-	4.00	4.00
	23	-	-	4.00	4.00
	25	-	2.00	2.00	4.00
ADN Node 26	6	-	-	-	2.00
	9	-	-	-	2.00
	15	-	-	1.00	1.00
	23	-	0.50	0.50	2.00
	27	-	-	1.00	1.00
	31	-	0.50	0.50	2.00
ADN Node 3	6	-	-	-	2.00
	9	-	-	-	2.00
	15	-	-	1.00	1.00
	23	-	0.50	0.50	2.00
	27	-	-	1.00	1.00
	31	-	0.50	0.50	2.00

10.2.2.2. Voltage Magnitude

Table shows the expected number of voltage violations, and maximum and minimum voltage magnitudes per network, year and representative day for case study "IEEE".

Table LXIII – Task 3.3. Technical KPIs. Case study IEEE. Expected voltage magnitude per network, year and representative day.

			2020		2030		2040		2050	
Network	Control	Voltage KPI	Winter	Summ.	Winter	Summ.	Winter	Summ.	Winter	Summ.
TN	BaU	# Violations	0	0	0	0	0	0	0	2
		Max., [p.u.]	1.06	1.05	1.06	1.05	1.10	1.05	1.10	1.10
		Min, [p.u.]	1.01	0.98	0.95	0.95	0.95	0.95	0.95	0.95
	ATTEST	# Violations	0	0	0	0	0	0	0	0
		Max., [p.u.]	1.06	1.05	1.06	1.05	1.07	1.05	1.08	1.10
		Min, [p.u.]	1.01	0.98	0.95	0.95	0.95	0.95	0.95	0.95
ADN Node 24	BaU	# Violations	0	0	4	0	16	13	25	22
		Max., [p.u.]	1.10	1.10	1.10	1.10	1.11	1.10	1.11	1.11
		Min, [p.u.]	1.03	1.04	1.04	1.04	1.04	1.04	1.04	1.04
	ATTEST	# Violations	0	0	0	0	0	0	0	0
		Max., [p.u.]	1.05	1.02	1.05	1.03	1.05	1.03	1.05	1.03
		Min, [p.u.]	0.95	0.95	0.93	0.93	0.91	0.93	0.90	0.90
ADN Node 16	BaU	# Violations	0	0	4	0	16	13	25	22
		Max., [p.u.]	1.10	1.10	1.10	1.10	1.11	1.10	1.11	1.11
		Min, [p.u.]	1.03	1.04	1.04	1.04	1.04	1.04	1.04	1.04
	ATTEST	# Violations	0	0	0	0	0	0	0	0
		Max., [p.u.]	1.05	1.04	1.05	1.04	1.05	1.03	1.04	1.02
		Min, [p.u.]	0.95	0.95	0.95	0.93	0.90	0.90	0.90	0.90
ADN Node 18	BaU	# Violations	0	0	4	0	16	13	25	22
		Max., [p.u.]	1.10	1.10	1.10	1.10	1.11	1.10	1.11	1.11
		Min, [p.u.]	1.03	1.04	1.04	1.04	1.04	1.04	1.04	1.04
	ATTEST	# Violations	0	0	0	0	0	0	0	0
		Max., [p.u.]	1.05	1.02	1.05	1.03	1.04	1.04	1.05	1.04
		Min, [p.u.]	0.95	0.95	0.92	0.94	0.90	0.91	0.90	0.90
ADN Node 26	BaU	# Violations	0	0	0	0	0	0	0	0
		Max., [p.u.]	1.00	1.00	1.00	1.00	1.01	1.00	1.08	1.07
		Min, [p.u.]	0.93	0.93	0.93	0.92	0.93	0.91	0.92	0.91
	ATTEST	# Violations	0	0	0	0	0	0	0	0
		Max., [p.u.]	1.04	1.02	1.04	1.01	1.05	1.05	1.10	1.10
		Min, [p.u.]	0.97	0.93	0.90	0.90	0.96	0.93	0.96	0.92
ADN Node 3	BaU	# Violations	0	0	0	0	0	0	0	0
		Max., [p.u.]	1.00	1.00	1.00	1.00	1.01	1.00	1.08	1.07
		Min, [p.u.]	0.93	0.93	0.93	0.92	0.93	0.91	0.92	0.91
	ATTEST	# Violations	0	0	0	0	0	0	0	0
		Max., [p.u.]	1.05	1.04	1.05	1.04	1.05	1.04	1.10	1.09
		Min, [p.u.]	0.97	0.97	0.91	0.92	0.91	0.93	0.96	0.96

10.2.2.3. Branch Loading

Table shows the expected branch loading violations and maximum branch loading per network, year, and representative day for case study "IEEE".

Table LXIV – Task 3.3. Technical KPIs. Expected branch loading per network, year, and representative day.

			2020		2030		2040		2050	
Network	Control	Loading KPI	Winter	Summ.	Winter	Summ.	Winter	Summ.	Winter	Summ.
TN	BaU	# Violations	0	0	0	0	0	0	0	0
		Max., [%]	100.00%	100.00%	94.46%	91.99%	100.00%	98.01%	87.31%	89.17%
	ATTEST	# Violations	0	0	0	0	0	0	0	0
		Max., [%]	100.00%	99.92%	94.40%	91.99%	100.00%	97.38%	98.68%	96.23%
ADN Node 24	BaU	# Violations	0	0	0	0	0	0	0	0
		Max., [%]	64.42%	64.13%	74.09%	74.04%	87.98%	88.44%	66.29%	72.83%
	ATTEST	# Violations	0	0	0	0	0	0	0	0
		Max., [%]	70.94%	69.46%	72.22%	79.61%	79.82%	83.27%	87.24%	76.81%
ADN Node 16	BaU	# Violations	0	0	0	0	0	0	0	0
		Max., [%]	64.42%	64.13%	74.09%	74.04%	87.98%	88.44%	66.29%	72.83%
	ATTEST	# Violations	0	0	0	0	0	0	0	0
		Max., [%]	70.46%	69.92%	70.92%	77.61%	83.71%	83.28%	86.58%	77.61%
	BaU	# Violations	0	0	0	0	0	0	0	0

ADN Node 18		Max., [%]	64.42%	64.13%	74.09%	74.04%	87.98%	88.44%	66.29%	72.83%
	ATTEST	# Violations	0	0	0	0	0	0	0	0
		Max., [%]	68.74%	70.58%	74.02%	75.99%	82.20%	81.29%	87.81%	79.75%
ADN Node 26	BaU	# Violations	0	0	0	0	0	0	0	0
		Max., [%]	73.69%	79.64%	73.09%	80.99%	100.00%	100.00%	100.00%	100.00%
	ATTEST	# Violations	0	0	0	0	0	0	0	0
		Max., [%]	72.61%	78.63%	90.71%	99.56%	96.09%	95.83%	100.00%	100.00%
ADN Node 3	BaU	# Violations	0	0	0	0	0	0	0	0
		Max., [%]	73.69%	79.64%	73.09%	80.99%	100.00%	100.00%	100.00%	100.00%
	ATTEST	# Violations	0	0	0	0	0	0	0	0
		Max., [%]	72.66%	77.05%	83.56%	86.22%	99.95%	97.76%	100.00%	100.00%

10.2.2.4. RES Curtailment

Table shows the expected RES curtailment per network, year, and representative day for case study "IEEE".

Table LXV – Task 3.3. Technical KPIs. Expected RES curtailment per network, year and representative day.

			2020		2030		2040		2050	
Network	Control	RES Curt. KPI	Winter	Summ.	Winter	Summ.	Winter	Summ.	Winter	Summ.
TN	BaU	Curt., [MWh]	0.00	0.00	0.00	0.00	51.22	5.79	1014.74	888.75
		Curt., [%]	0.00%	0.00%	0.00%	0.00%	2.89%	0.33%	28.67%	25.11%
	ATTEST	Curt., [MWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Curt., [%]	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
ADN Node 24	BaU	Curt., [MWh]	0.00	0.00	0.02	0.01	0.67	0.83	14.63	15.18
		Curt., [%]	0.00%	0.00%	0.09%	0.03%	0.95%	1.17%	11.28%	11.70%
	ATTEST	Curt., [MWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Curt., [%]	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
ADN Node 16	BaU	Curt., [MWh]	0.00	0.00	0.02	0.01	0.67	0.83	14.63	15.18
		Curt., [%]	0.00%	0.00%	0.09%	0.03%	0.95%	1.17%	11.28%	11.70%
	ATTEST	Curt., [MWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Curt., [%]	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
ADN Node 18	BaU	Curt., [MWh]	0.00	0.00	0.02	0.01	0.67	0.83	14.63	15.18
		Curt., [%]	0.00%	0.00%	0.09%	0.03%	0.95%	1.17%	11.28%	11.70%
	ATTEST	Curt., [MWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Curt., [%]	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
ADN Node 26	BaU	Curt., [MWh]	0.00	0.00	0.00	0.00	0.04	0.03	3.40	3.64
		Curt., [%]	0.00%	0.00%	0.00%	0.00%	0.17%	0.12%	3.84%	4.11%
	ATTEST	Curt., [MWh]	0.00	0.00	0.00	0.00	0.00	0.00	1.70	1.50
		Curt., [%]	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	1.92%	1.70%
ADN Node 3	BaU	Curt., [MWh]	0.00	0.00	0.00	0.00	0.04	0.03	3.40	3.64
		Curt., [%]	0.00%	0.00%	0.00%	0.00%	0.17%	0.12%	3.84%	4.11%
	ATTEST	Curt., [MWh]	0.00	0.00	0.00	0.00	0.00	0.00	1.83	2.19
		Curt., [%]	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	2.07%	2.48%

10.2.2.5. Network Losses

Table shows the expected network losses per network, year, and representative day for case study "IEEE".

Table LXVI – Task 3.3. Technical KPIs. Case study IEEE. Expected losses per network, year, and representative day.

			2020		2030		2040		2050	
Network	Control	Loading KPI	Winter	Summ.	Winter	Summ.	Winter	Summ.	Winter	Summ.
TN	BaU	Losses, [MWh]	16.69	17.69	105.49	99.81	267.02	272.11	303.18	306.07
		Losses, [%]	0.58%	0.63%	3.20%	3.06%	6.68%	6.88%	5.73%	5.83%
	ATTEST	Losses, [MWh]	16.69	18.10	104.78	99.37	263.25	265.65	331.24	330.98
		Losses, [%]	0.57%	0.63%	3.20%	3.10%	6.94%	7.14%	6.91%	7.03%
	BaU	Losses, [MWh]	2.39	2.48	2.55	2.64	3.87	4.03	4.81	4.94

ADN		Losses, [%]	1.40%	1.43%	1.33%	1.35%	1.78%	1.82%	1.92%	1.95%
Node 24	ATTEST	Losses, [MWh]	2.87	2.95	3.00	3.06	4.07	4.54	7.50	8.10
		Losses, [%]	1.68%	1.70%	1.56%	1.57%	1.87%	2.06%	3.00%	3.19%
ADN	BaU	Losses, [MWh]	2.39	2.48	2.55	2.64	3.87	4.03	4.81	4.94
Node 16		Losses, [%]	1.40%	1.43%	1.33%	1.35%	1.78%	1.82%	1.92%	1.95%
	ATTEST	Losses, [MWh]	2.85	2.95	3.02	3.08	4.00	4.32	7.75	8.21
		Losses, [%]	1.67%	1.70%	1.57%	1.58%	1.84%	1.95%	3.10%	3.24%
ADN	BaU	Losses, [MWh]	2.39	2.48	2.55	2.64	3.87	4.03	4.81	4.94
Node 18		Losses, [%]	1.40%	1.43%	1.33%	1.35%	1.78%	1.82%	1.92%	1.95%
	ATTEST	Losses, [MWh]	2.84	2.97	2.98	3.09	3.99	4.49	7.36	8.27
		Losses, [%]	1.66%	1.71%	1.55%	1.58%	1.83%	2.03%	2.94%	3.26%
ADN	BaU	Losses, [MWh]	2.57	2.74	2.56	2.75	2.90	3.15	4.47	4.79
Node 26		Losses, [%]	3.16%	3.41%	2.82%	3.07%	2.85%	3.14%	3.90%	4.24%
	ATTEST	Losses, [MWh]	2.41	2.72	2.58	2.90	2.92	3.18	4.84	4.96
		Losses, [%]	2.96%	3.39%	2.84%	3.24%	2.87%	3.17%	4.21%	4.37%
ADN	BaU	Losses, [MWh]	2.57	2.74	2.56	2.75	2.90	3.15	4.47	4.79
Node 3		Losses, [%]	3.16%	3.41%	2.82%	3.07%	2.85%	3.14%	3.90%	4.24%
	ATTEST	Losses, [MWh]	2.42	2.62	2.54	2.69	2.99	3.16	4.84	5.40
		Losses, [%]	2.97%	3.26%	2.79%	3.00%	2.94%	3.15%	4.21%	4.76%

10.2.2.6. RES Share

Table shows the expected RES penetration per network, year, and representative day for case study "IEEE".

Table LXVII – Task 3.3. Environmental KPIs. Case study IEEE. Expected RES generation per network, year, and representative day.

			2020		2030		2040		2050	
Network	Control	RES Gen. KPI	Winter	Summ.	Winter	Summ.	Winter	Summ.	Winter	Summ.
TN	BaU	Gen., [MWh]	0.00	0.00	884.88	884.88	1718.54	1763.97	2524.78	2650.77
		Gen., [%]	0.00%	0.00%	27.44%	28.07%	41.59%	43.41%	44.61%	47.49%
	ATTEST	Gen., [MWh]	0.00	0.00	884.88	884.88	1769.76	1769.76	3539.52	3539.52
		Gen., [%]	0.00%	0.00%	27.41%	28.05%	42.76%	43.53%	61.82%	62.78%
ADN	BaU	Gen., [MWh]	0.00	0.00	70.53	72.39	133.25	137.28	177.58	182.95
Node 24		Gen., [%]	0.00%	0.00%	36.22%	36.66%	60.05%	61.00%	69.61%	70.77%
	ATTEST	Gen., [MWh]	0.00	0.00	70.67	72.56	136.17	138.65	212.09	214.45
		Gen., [%]	0.00%	0.00%	36.17%	36.61%	60.88%	61.17%	80.66%	81.03%
ADN	BaU	Gen., [MWh]	0.00	0.00	70.53	72.39	133.25	137.28	177.58	182.95
Node 16		Gen., [%]	0.00%	0.00%	36.22%	36.66%	60.05%	61.00%	69.61%	70.77%
	ATTEST	Gen., [MWh]	0.00	0.00	70.72	72.57	136.16	138.64	212.11	214.44
		Gen., [%]	0.00%	0.00%	36.17%	36.61%	60.88%	61.17%	80.66%	81.03%
ADN	BaU	Gen., [MWh]	0.00	0.00	70.53	72.39	133.25	137.28	177.58	182.95
Node 18		Gen., [%]	0.00%	0.00%	36.22%	36.66%	60.05%	61.00%	69.61%	70.77%
	ATTEST	Gen., [MWh]	0.00	0.00	70.69	72.57	136.17	138.69	212.10	214.28
		Gen., [%]	0.00%	0.00%	36.17%	36.61%	60.88%	61.16%	80.66%	81.05%
ADN	BaU	Gen., [MWh]	0.00	0.00	32.04	32.28	57.30	58.29	100.36	100.59
Node 26		Gen., [%]	0.00%	0.00%	34.32%	34.96%	54.73%	56.29%	84.11%	85.25%
	ATTEST	Gen., [MWh]	0.00	0.00	32.09	32.36	58.54	58.65	111.45	108.62
		Gen., [%]	0.00%	0.00%	34.27%	34.92%	55.58%	56.33%	87.98%	89.44%
ADN	BaU	Gen., [MWh]	0.00	0.00	32.04	32.28	57.30	58.29	100.36	100.59
Node 3		Gen., [%]	0.00%	0.00%	34.32%	34.96%	54.73%	56.29%	84.11%	85.25%
	ATTEST	Gen., [MWh]	0.00	0.00	32.09	32.33	58.54	58.65	108.95	107.67
		Gen., [%]	0.00%	0.00%	34.27%	34.92%	55.59%	56.33%	88.78%	89.47%

10.2.2.7. Generation Costs

Figure 192 shows the expected costs with conventional generation per year and representative day at the TN-level.

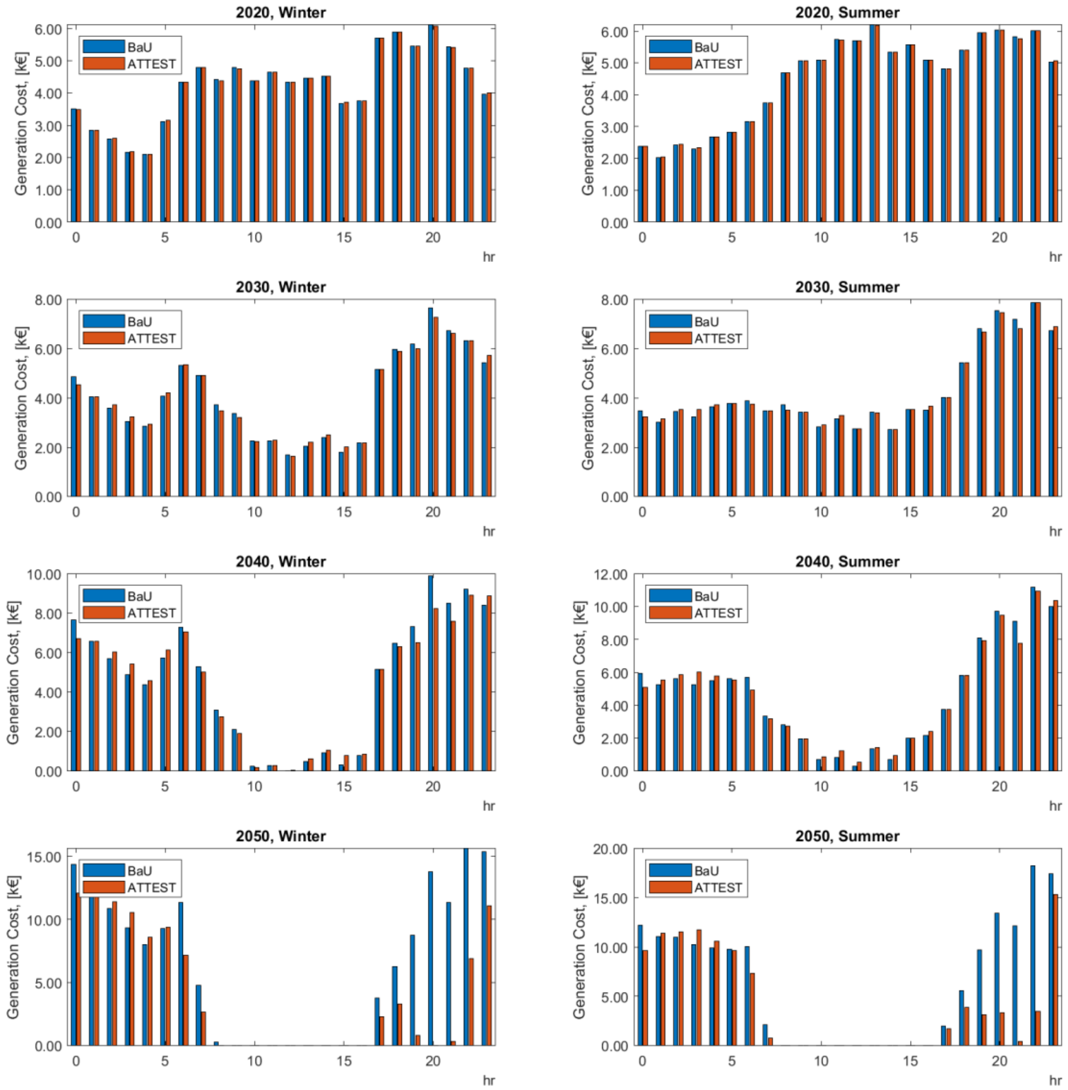

Figure 192 – Task 3.3. Case study IEEE. Expected hourly generation costs per year and representative day.

10.2.2.8. GHG Emissions

Figure 193 shows the expected GHG emissions per year and representative day at the TN-level.

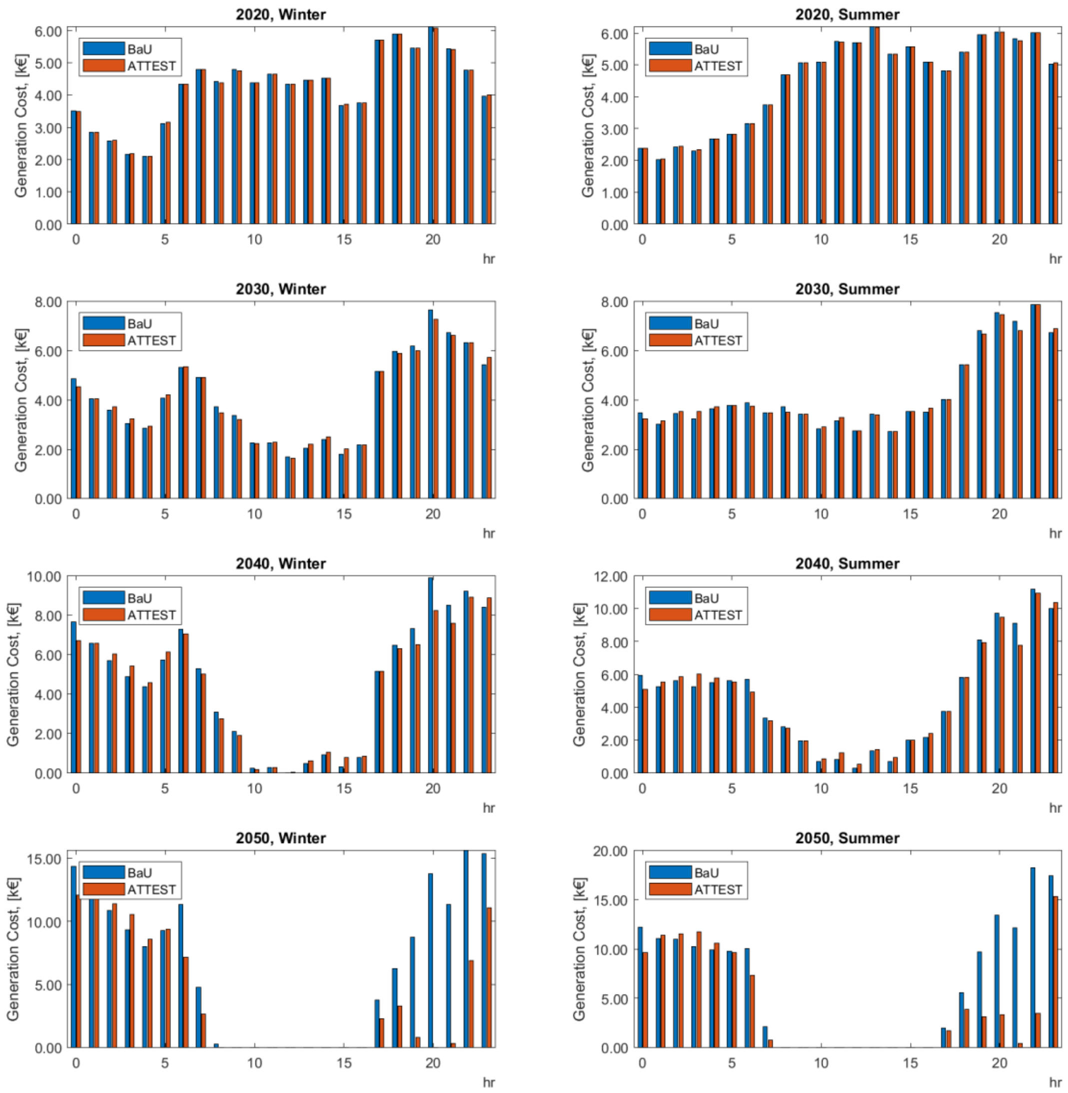

Figure 193 - Task 3.3. Case study IEEE. Expected hourly GHG emissions per year and representative day.