evolvDSO

Development of methodologies and tools for new and evolving DSO roles for efficient DRES integration in distribution networks

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Validation of the Methodologies and Tools Developed for DSO

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Executive Summary

The evolvDSO project defined a set of new and evolving roles for the DSO, which also resulted in a set of new services that support Distributed Energy Resources (DER) and Distributed Renewable Energy Sources (DRES) integration. These new services resulted in ten Business Use Cases (BUC) that describe the priority business processes designed to implement the key services associated with the future DSO roles. Out of these, one BUC for each domain of activity has been selected. Then, the functions required to execute/enable the associated BUC were described in sixteen System Use Cases (SUC) that represent the most innovative functionalities covering five domains.

This work allowed the evolvDSO project to develop innovative tools within WP3 based on the future DSO's roles and business processes previously identified and that accomplish several steps in the SUCs. These tools cover four domains: planning, operational, TSO-DSO cooperation and maintenance.

This report describes the validation of methodologies of the tools developed in WP3 through computer simulation using real grid data provided by the project's DSO, specified in WP2. An adequate set of short, mid and long-term test scenarios were defined taking into account different hypotheses regarding future scenarios and related objectives defined in WP1 and WP2. Particular attention was paid to specific issues related to different countries regarding grid characteristics, but also rules and markets. Several tools were tested for more than one country/DSO.

Furthermore, the simulations test cases also evaluate the sensitivity of the results in connection with a set of defined elements: grid configuration, market rules, available flexibility (from demand response, storage, RES). In order to enable an economic valuation of the flexibility levers, a common methodology to calculate the flexibility cost of different resources was developed in the project and used in all simulations.

The following table summarizes the main results from the simulations performed for each country, comprising several test scenarios ranging from short-term (1-5 years) to long-term (20 years) time horizon.

Domain	Tool	Test Country	Short Description	Main Conclusions
Planning	FLEXPLAN	Germany	Time horizon between 5 and 10 years and scenarios for covering the uncertainties. Method for finding relevant network planning cases. Planning algorithm with combination of network reinforcements and the use of flexibilities. Impact assessment of ICT on the network reliability for future networks.	• Including flexibilities in network planning means an impact on network expansion costs. The value of a flexibility within the grid planning process varies case specific. The cost and technology of ICT will be a determining factor for the final cost savings. • The influence of ICT system on reliability in new grid structures is not negligible and depends on specific power system topology and redundancy. • Planning the network for a broader set of future scenarios leads to higher network expansion costs depending on the spread of the considered uncertainties. • To model the maximum network usage adequately 12(3) representative network planning cases are necessary in meshed(radial) networks. Yearly network losses as well as the yearly curtailed energy from renewables can be determined by 50 to 100 network planning cases depending on the required accuracy.
	TOPPLAN	Germany	Time horizon more than 30 years. The uncertainties are modelled by using fuzzy-logic. It identifies a cost-effective solution given a choice between classical solutions, such as reinforcement, dedicated feeders and new substations, or solutions that enforce the flexibility of the network just as reconfiguration, VVC and load control	• The tool solves all the network constraint violations in the different scenarios whereas the simple reinforcement method does not enable to reach any defined targets [i.e., precise optimization criteria: minimization of operating cost (OPEX) and minimization of investment (CAPEX)] • Flexibilities coupled with stochastic modelling enables to decrease the discount cost by 9.4% compared to the deterministic model without flexibilities for a medium DRES penetration scenario

Domain	Tool	Test Country	Short Description	Main Conclusions
Operational Planning	Robust Short-Term Economic Optimization	Italy	Application, based on several algorithms, which fulfils completely the short-term optimization of distribution network. It is capable to detect constraints violations and solve them through the least expensive set of actions (including flexible DER)	• The tool was able to solve all the network constraint violations in three different scenarios. It calculated, through two complementary optimization routines, the most cost-effective solution for each of the scenarios • The tool also showed its capability to handle inter-temporal constraints in the network, either through the optimal use of storage, or through the modulation of loads • It allowed an increase in the average DRES hosting capacity of the network by up to 7.37 times the average hosting capacity of the network without any optimization
	Replay	Italy	Field-oriented application which focuses on the investigation of grid management. Its main purpose is to perform a pro-active analysis of grid control actions by the means of an off-line fully operational SCADA platform. Its main goal is to analyze past events and actual real data and re-simulate them for improving grid management policies, as well as new software/hardware technical solutions testing and operators training	• The tool was able to reproduce a list of events occurred in the past and the real related network scheme with a precision and a high quality. • The possibility to modify the events in the past ensured the tool availability o realize *ex-post* analysis. The tool allowed to measure SAIDI as well as Criticalities Reduction Index. Other KPIs will be measured with use by the control center expert in the WP4 tests. • By the MAGO data flow (customer/producers profiles) the tool was able to realize a predictive analysis on the network behavior, considering the available profile of the customer/producer.
	Contingency simulation (co-simulation)	France	Select and simulate realistic contingencies in order to identify suitable levers and, as a consequence, corrective actions and policies to solve them in the more efficient and effective way. In addition to contingencies simulation also ICT performance analysis is performed through an innovative co-simulation module	• Obtains a complete set of asset unavailability events in a single simulation • Tests show that for many events no violations are detected, so they can be simply solved by grid re-configuration; anyway, in many cases only undervoltages are observed and no overvoltages

Domain	Tool	Test Country	Short Description	Main Conclusions
	LV State Estimation	Portugal France	Predicts the state of the system by making use of historical data and a low number of real-time measurements from smart-meters. The overall goal of this tool is to detect in the most accurate way the state of networks where topology is partially unknown (LV networks in most cases), using all the information available	*Portugal* • Only with 30% of the total SM having real-time communication the proposed tool was able to estimate voltage magnitude values with a Mean Absolute Error (MAE) of 0.49 V (0.21% * Un) and active power quantities with a MAE of 0.35 kW *France* • Only with 24% of the total SM having real-time communication the proposed tool was able to estimate voltage magnitude values with a MAE of 1.73 V (0.75% * Un) and active power quantities with a MAE of 0.58 kW

	LV Control	Portugal
		France
			Capable to manage all the controllable grid assets in order to provide a close-to-real-time solution to cope with voltage deviations in LV grids. Its output is a set of control actions, in the form of set points, which enables a coordinated operation of all the available DERs	*Portugal and France*
				• The value of energy curtailment of DRES and DER in the grids is considerably lower (40% minimum reduction in Portugal; 30% minimum reduction in France) and, in some scenarios, curtailment can even be avoided (100% reduction in several test scenarios in Portugal and France).
				• For long term scenarios, the share of DRES hosting capacity in the grid is increased using the tool:
				  ○ In the French network, in some test cases, the value of DRES hosting capacity can increase 3% without causing voltage problems.
				  ○ In the Portuguese network, the DRES hosting capacity increases up to 8%.
				• For the mid-term and long-term scenarios the value and impact of the tool proves to be greater.
				• The transformer with OLTC capability proves to be a valuable and cheaper solution, however, for future scenarios, that resource is not enough to maintain the voltages within limits.

Domain	Tool	Test Country	Short Description	Main Conclusions
Maintenance	Advanced Asset Management Tool	Ireland	Composed by two sub-tools, one focused on asset renewal planning and the other on identifying the most critical components in a network area. The overall goal of this tool is to give distribution network engineers usable insights on each component's role in a distribution network	• The insights offered by this tool allow substantial savings in combined network operation and renewal costs (on the order of €100,000 for the Irish test network over a 20 year horizon) The enhanced asset renewal plan schedules conductor upgrades at different intervals within the planning window to realize these savings, taking account of the time value of money • Expected customer minutes lost are reduced by up to 10% by leveraging new insights on component criticalities in the scheduling of maintenance and monitoring programs on the test network • The expected energy not supplied is reduced by up to 11.5% by leveraging new insights on component criticalities in the scheduling of maintenance and monitoring programs on the test network • Anticipated energy curtailment from distributed energy resources may be reduced by 10% to 33%, depending on future penetration level scenario
TSO-DSO Cooperation	Interval Constrained Power Flow	Portugal France Germany	Estimates the flexibility range in each primary substation node for the next hours and includes the flexibility cost	• It is possible to separate the contributions of different types of flexibilities, as well as flexibilities with different costs *Portugal* • The range of variation of reactive power is almost the same in all the scenarios. The main differences are related with the range of active power variations. This is due to a higher impact of the transformer TAPs and reactive power compensators when compared to the reactive power control of the wind parks. • The increase of flexibility of load and DRES throughout the scenarios leads to larger flexibility areas. However, the flexibility area of scenarios with higher flexibility range could not include the ones with lower flexibility due to the variation of the operating point. *France* • The evolution of the flexibility range in the primary substation depends on

Domain	Tool	Test Country	Short Description	Main Conclusions
				the combination of load growth trend and DRES increase. Some cases with higher penetration of RES have shown less flexibility range due to the reduction of the flexibility provided by the demand • Due to the radial structure of the network with a low number of transformers with tap change capability, the flexibility presented by the distribution network is almost equal to the sum of flexibilities available in the network *Germany* • In 2020 the distribution network will be able to provide more flexibility due the high penetration of DRES with high controllability of reactive power and possible wind power curtailment • In terms of active and reactive power, there is more flexibility in the primary substations than the sum of load and generator flexibilities available in the meshed network due to the high number of transformers with tap change capability offering flexibilities in the gridThe use of storage devices increases the flexibility range. However, there is no significant difference between centralized storage and distributed storage as far as the grid has sufficient capabilities.

Domain	Tool	Test Country	Short Description	Main Conclusions
	Sequential OPF	Portugal France	Derive a set of control actions that keep the active and reactive power flow within pre-agreed limits at the primary substations level (or TSO-DSO interface)	• In the French networks all scenarios of load growth and DRES increase are feasible due the activation of several flexibilities, especially to decrease their consumption. • The results obtained for French networks reveal that the flexible costs tend to be higher in scenarios with higher consumption or/and with higher generation due the activation of flexibilities. • In the Portuguese network all scenarios of load growth and DRES increase are feasible, by the activation of flexibilities from wind power curtailment, due the high amount of generation. • The French networks have a low number of open switching devices which make it difficult to obtain new topological configurations. The Portuguese Northeast network operates in closed loops which make it difficult to obtain new topological configurations. • The losses reduction using French networks was in average 24.8% considering all scenarios. • The losses reduction using Portuguese networks was in average 4.12% considering all scenarios. • It allows to increase DRES hosting capacity, in a French network was possible to increase this integration until 427%. • It reduces the necessity of wind power curtailment. Due the difficulties on finding new topological configurations these reduction was a marginal value.

Table of contents

List of Figures

List of Tables

Acknowledgements

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1 Introduction

The increasing levels of distributed energy resources (DER) flexibility in the distribution network, combined with high integration levels of Distributed Renewable Energy Sources (DRES), requires changes in the way DSO plan and operate the distribution networks and an active coordination with TSO and existing/future market mechanisms. In order to tackle this new energy paradigm, the evolvDSO project defined a set of new and evolving roles for the DSO, which also resulted in a set of new services that support DER and DRES integration [1].

These new services resulted in ten Business Use Cases (BUC) and their associated requirements that describe the priority business processes designed to implement the key services associated with the future DSO roles, as well as the methodological approach used [2].

Out of these, one BUC for each domain of activity has been selected. Then, the evolvDSO project has first identified the functions required to execute/enable the associated BUC, which were described in sixteen System Use Cases (SUC) with functional and non-functional requirements. These SUC represent the most innovative functionalities covering five domains. This work allowed the evolvDSO project to develop innovative tools within WP3 based on the future DSO's roles and business processes previously identified, as showed in Figure 1 and Figure 2.

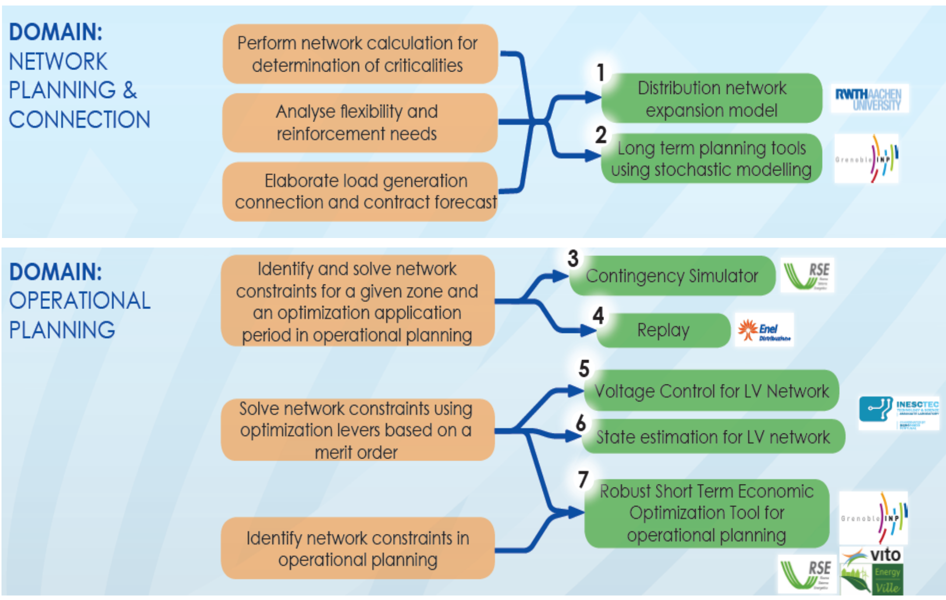


Figure 1 - Relation between System Use Cases (SUC) and evolvDSO tools in the network planning and operational domain.

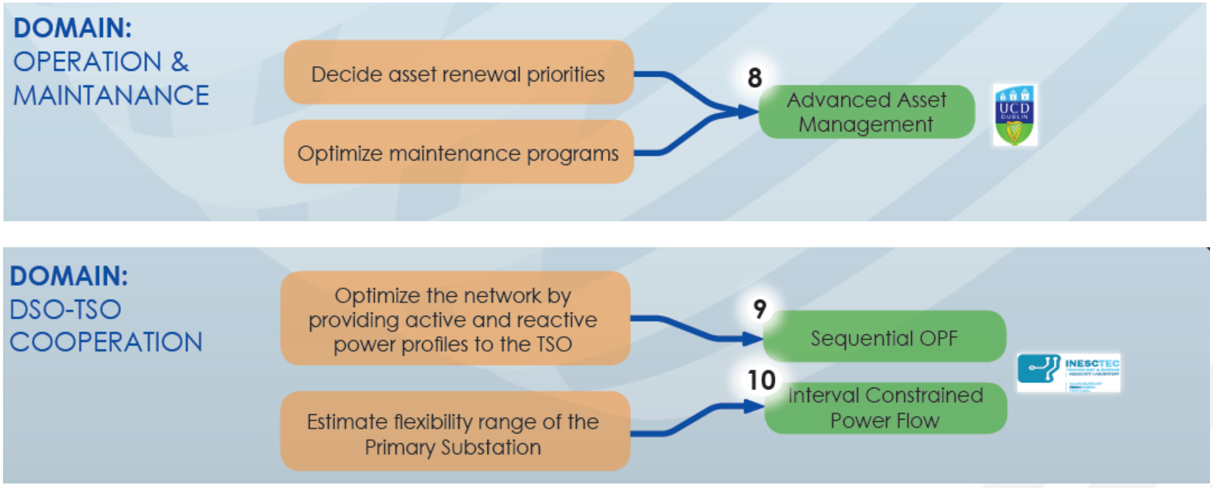


Figure 2 - Relation between System Use Cases (SUC) and evolvDSO tools in the maintenance and TSO-DSO domain.

For the network planning domain the following tools, described in D3.1 [4], were developed:

- *FLEXPLAN*: covers the shorter time horizon (i.e. 5 to 10 years in the future) and considers scenarios for the modelling of uncertainties. The applied methodology demonstrates a new method for finding relevant network planning cases. Based on the planning cases an optimal combination of network reinforcements and the usage of flexibilities are determined to solve congestions in the network. Further, the effect of an increasing influence of information and communication technology (ICT) systems, when planning future networks, is addressed;
- *TOPPLAN*: overs the longer time horizon (i.e. more than 30 years in the future) and the uncertainties are modelled by using the approach of fuzzy-logic. It identifies a cost-effective solution given a choice between classical solutions, such as reinforcement, dedicated feeders and new substations, or solutions that enforce the flexibility of the network just as reconfiguration, VVC, load control.

The operational planning domain is divided by MV and LV networks. For the MV networks the following tools were developed and described in D3.2 [5] and D3.3 [6]:

- *Robust Short-Term Economic Optimization Tool*: is an application, based on several algorithms, which fulfils completely the short-term optimization of distribution network; it is capable to detect constraints violations and solve them through the least expensive set of actions;
- *Network Reliability Tool (Replay)*: field-oriented application which focuses on the investigation of grid management; its main purpose is to perform a pro-active analysis of grid control actions by the means of an off-line fully operational SCADA platform. Its main goal is to analyze past events and actual real data and re-simulate them for improving grid management policies, as well as new software/hardware technical solutions testing and operators training;
- *Contingency simulation (co-simulation) Tool*: select and simulate realistic contingencies in order to identify suitable levers and, as a consequence, corrective actions and policies to solve them in the more efficient and effective way. In addition to contingencies simulation also ICT performance analysis is performed through an

innovative co-simulation module. The time horizon spans from short term to day-ahead, i.e. from 72 to 24 hours before the considered period.

For the LV network, the following tools were developed:

- *State Estimation for LV Networks*: algorithm capable to predict the state of the system by making use of historical data and a low number of real-time measurements from smart-meters. The overall goal of this tool is to detect in the most accurate way the state of networks where topology is partially unknown (LV networks in most cases), using all the information available;
- *Voltage Control for LV Networks*: it is capable to manage all the controllable grid assets in order to provide a close-to-real-time solution to cope with voltage deviations in LV grids. Its output is a set of control actions, in the form of set points, which enables a coordinated operation of all the available DERs.

Two tools contribute to the TSO-DSO cooperation domain (described in D3.3 [6]):

- *Interval Constrained Power Flow Tool*: estimates the flexibility range in each primary substation node for the next hours and includes the flexibility cost. This tool enables an evaluation of the DER aggregators' impact on the transmission network and provides means for a cost/benefit evaluation of the available levers;
- *Sequential Optimal Power Flow (OPF)*: derive a set of control actions that keep the active and reactive power flow within pre-agreed limits at the primary substations level (or TSO-DSO interface).

For the maintenance domain, an *Advanced Asset Management Tool* composed by two sub-tools, one focused on asset renewal planning and the other on identifying the most critical components in a network area, is was developed and it is described in D3.3 [6] . The overall goal of this tool is to give distribution network engineers usable insights on each component's role in a distribution network.

This report describes the validation of methodologies of the tools developed in Tasks 3.1-3.3 through computer simulation using real grid data provided by the project's DSO, specified in WP2. An adequate set of short, mid and long-term test scenarios were defined taking into account different hypothesis regarding future scenarios and related objectives defined in WP1 and WP2. Particular attention was paid to specific issues related to different countries (see Table 1) regarding grid characteristics, but also rules and markets. Several tools were tested for more than one country/DSO. Furthermore, the simulations test cases also evaluate the sensitivity of the results in connection with a set of defined elements: grid configuration, market rules, available flexibility (from demand response, storage, RES). In order to enable an economic valuation of the flexibility levers, a common methodology to calculate the flexibility cost of different resources was developed in the project and used in all simulations.

Domain	Tool	Country	DSO/Tool Developer
Planning	FLEXPLAN	Germany	RWE RWTH Aachen/FGH
	TOPPLAN	Germany	RWE Grenoble INP
Operational Planning	Robust Short-Term Economic Optimization	Italy	ENEL Grenoble INP/RSE/VITO
	Replay	Italy	ENEL
	Contingency simulation (co-simulation)	France	ERDF RSE
	LV State Estimation	Portugal France	EDP/ERDF INESC TEC
	LV Control	Portugal France	EDP/ERDF INESC TEC
Maintenance	Advanced Asset Management Tool	Ireland	ESB Networks UCD
TSO-DSO Cooperation	Interval Constrained Power Flow	Portugal France Germany	EDP/ERDF/RWE INESC TEC
	Sequential OPF	Portugal France	EDP/ERDF INESC TEC

Table 1 - Relation between tools and country level simulations.

1.1 Structure of this Report

This deliverable report is organized as follows: chapter 2 presents the results from the two planning tools and HV/MV networks in Germany; chapter 3 presents the results for the operational domain covering MV and LV networks in Portugal, France and Italy; the TSO-DSO cooperation domain is covered in chapter 4 for HV/MV networks in Portugal, France and Germany; the results for the maintenance domain are presented in chapter 5 for networks in Ireland. Additional simulation results and a common methodology to calculate the flexibility cost are described in appendix sections.

2 Planning Domain

Two tools belonging to the network planning domain were described in deliverable D3.1.

The tool "Short-term network reinforcements considering flexibilities and ICT reliability (FLEXPLAN)" covers the shorter timeframe (i.e. 5 to 10 years in the future) and considers scenarios for the modelling of uncertainties. The applied methodology demonstrates a new method for finding relevant network planning cases. Based on the planning cases an optimal combination of network reinforcements (e.g. building new lines or transformers) and the usage of flexibilities are determined to solve congestions in the network. Further, the effect of an increasing influence of information and communication technology (ICT) systems, when planning future networks, is addressed.
The tool "Long-term network topologies using stochastic modelling (TOPPLAN)" is used for planning the network for the longer time horizon (i.e. more than 30 years in the future) and the uncertainties are modelled by using the approach of fuzzy-logic. A cost-effective solution is identified given a choice between classical solutions, such as reinforcement, dedicated feeders and new substations, or solutions that enforce the flexibility of the network just as reconfiguration, VVC[1], load control. Due to the longer planning horizon it especially focuses on new possible network architectures.

The test cases for network planning are shown in Table 2.

#	Name	Description	Tool
1	Identification of relevant network planning cases	Evaluation of network planning cases for the dimensioning of network assets, for the determination of network losses and the flexibility amount.	FLEXPLAN sub-tool: "Selection of planning cases"
2	Influence on ICT on the network reliability	Measuring the effect of reliability for networks dependent on ICT.	FLEXPLAN sub-tool: "Determination of criticalities"
3	Analysis of flexibility prices on network expansion planning	Calculation of the reduced network expansion costs, when flexibility is allowed in planning.	FLEXPLAN sub-tool: "Optimization algorithm"
4	Robust network planning to cover the future uncertainty	Planning the future network for multiple scenarios in order to cover the uncertainty.	FLEXPLAN sub-tool: "Forecast the network usage"
5	Long term network planning : new topology vs reinforcement	Comparison of a new topology solution with reinforcement solution with or without flexibility.	TOPPLAN: "New topology vs reinforcement"
6	Long term network planning : stochastic vs deterministic modelling	Comparison of the interest of stochastic modelling.	TOPPLAN: "Stochastic vs deterministic modelling"

Table 2 - Test cases of the planning domain.

[1]Coordinated Voltage and Reactive Power Control

2.1 Network and Scenario Description

The planning tools are tested by one medium-voltage (MV) and one high-voltage (HV) network both situated in a northern rural part of Germany.

HV-Network

The meshed HV-network includes the 110-kV and the relevant 30-kV network[2]. Any underlying network is modelled by its equivalent elements.

For the short term forecast (~10 years in the future) three scenarios "S_u, S_{ml}, S_o"[3] can be derived using the annual growth rates of the scenarios of deliverable D1.1. As the scenarios of WP1 are based on expectations for whole Germany, a further scenario ("buest-guess") has been given by the DSO allowing a better regional specification (scenario S_{bg}). Table 3 shows the present network characteristics as well as the scenarios.

Characteristics	110-kV network	30-kV network
number of nodes	147	133
line kilometres	844 km	277 km
- thereof cables	-0,5%	-75%

in [MW]	now	S_u	S_{ml}	S_o	S_{bg}
load*	1396	1396	1396	1396	1377
pv	444	646	710	653	696
wind	362	504	538	739	871
biomass	109	145	157	131	130

Table 3 - Present network characteristics and scenarios for the HV-network.

MV-network

The radial MV-network includes the 10-kV voltages level and the primary substation (22 nodes, 92 km of lines thereof 73 % are cables). All underlying costumers are modelled by its equivalent elements.

For the future development the same approach as for the HV-network can be used in order to determine the scenarios for the network. As this network is investigated for the short as well as for the long-term Table 4 includes scenarios for both time horizons. A detailed expectation from a DSO for the network area was not available.

in [MW]		Short term (~10 years)			Long term (~40 years)		
	now	S_u	S_{ml}	S_o	S_u	S_{ml}	S_o
load*	19	19	19	19	19	19	19
pv	15	21	24	22	27	30	33
wind	9	13	13	18	18	21	25
biomass	3	4	5	4	5	6	7

Table 4 - Scenarios for load and generation in the MV-network (* maximal load, not simultaneous values).

Relation of Test Cases and scenarios

Table 5 provides the information about the networks used for the specific test case as well as the scenarios applied.

[2] In the considered network the 30-kV has a similar function as the 110-kV voltage level.

[3] u = under-expected scenario; ml = most-likely scenario; o = over-expected scenario;

#	Name	Network	Scenario
1	Identification of relevant network planning cases	High voltage network (HV), Medium voltage network (MV)	S_{bg} (HV), S_{ml} (MV)
2	Influence on ICT on the network reliability	High voltage network (HV), Medium voltage network (MV)	S_{bg} (HV), S_{ml} (MV)
3	Analysis of flexibility prices on network expansion planning	High voltage network (HV)	S_{bg}
4	Robust network planning to cover the future uncertainty	High voltage network (HV)	10 scenarios generated by S_u, S_{ml}, S_o and S_{bg}
5	Long term network planning : new topology vs reinforcement	Medium voltage network (MV)	S_u, S_{ml}, S_o(MV)
6	Long term network planning : stochastic vs deterministic modelling	Medium voltage network (MV)	S_{ml} (MV).

Table 5 - Relation of Test Cases and scenarios.

2.2 Test Cases Description and Hypothesis

2.2.1 #1: Identification of relevant network planning cases

Traditionally, a few network planning cases are used in network planning to determine the maximal network loading and design the network. Based on the experience of the network planner the assumptions for the so called “worst-cases” are often related to the maximal simultaneously feed-in of wind and pv units or the maximal load of customers. This approach has the benefit of modelling different loading situations with a few network planning cases, but there is a risk to overestimate the network loading and therefore overdimension the network. To tackle this issue, a new tool for the selection of relevant network planning cases, based on time-series (input data) has been developed. The tool included to types of network planning cases (NPC). The network planning cases for the dimensioning of operating equipment (NPC-D) are selected with a genetic algorithm, whereas the network planning cases for the estimation of time dependent figures (NPC-L), i.e. losses or curtailed energy, are selected by a cluster algorithm. These two tools are validated with the following test case.
First, the impact of the tool for the selection of NPC-D is assessed by identifying different numbers of NPCs. In the test case, four, eight and twelve NPC-D are determined to represent the time series (8760 NPC). With the increase of the amount of NPC-D the representation fitness of the time series rises as the voltages and currents, which occur in the network, can be better approximated. Therefore the comparison of the network loading, i.e. voltages, currents, caused by the whole time series and the network loading caused by the selected NPC-D are shown. Further, die impact of the number of NPC-D on the network expansion costs and the calculation time are displayed. It is expected, that with an increase of the NPC-D the resulting network costs sink and the calculation time rises due to more complex optimization problem.
To assess the impact of the tool for the selection of NPC-L, the losses of a network are calculated and compared by calculating each of the 8760 network planning cases

(time-series) with the determined NPC-L and projecting these on the whole year. It is expected, that with increasing number of NPC-L the projected losses match the losses of the time series more precise way.

2.2.2 #2: Influence of ICT on the network reliability

For the assessment of reliability in networks influenced by smart grid elements a new tool has been developed. The test case is applied on the HV- and MV-network and the related time series of customers are used. The given network models are enhanced by smart grid elements such as generation side management (GSM) for the curtailment of DRES. Furthermore, a parameterization of the smart grid elements is performed. Especially the settings for the use of flexibilities presented by DRES are of importance. According to the current regulatory framework in Germany new DRES, which shall be connected to the network and have a peak power of at least 100 kW, need to be equipped with a communication device by the DRES operator for remote control by the network operator [1]. For the test cases, in which flexibilities are used, it is therefore assumed, that all DRES feature such an intelligent electronic device (IED) for communication and can be controlled by the network operator. The control of DRES is modelled as continuous and the fall back states of the generation side management are a limited feed-in in case of network failure and a disconnection from the grid in case of functional failure. With this parameterization of the fall back states in the IED a secure operation of the power system can be guaranteed even in states of IED failure. Furthermore, a fibre optic network is modelled in parallel to the power system to simulate the information and communication technology system (ICT-system). For both HV- and MV-network it is assumed, that ICT equipment necessary for the communication with DRES in underlying and overlying networks is 100% reliable. As for the power system the reliability of the ICT-system is only evaluated for the network level under consideration.
Failure rates and repair times for electrical components are derived from the forum network technology/network operation (FNN) disturbance and availability statistic [8]. For the ICT-system equipment failure rates and mean times to repair are taken from the sources described in deliverable 3.1. The time dependency of the failure rates is modelled for each type of equipment in the power system and ICT-system according to the previous analyses.
First test runs have shown that the calculation of a whole year is time-consuming and similar network states are calculated multiple times. Therefore simulations have been carried out for a representative week out of the modelled time series. This leads to much shorter simulation times and a higher efficiency of the tool since similar network states are calculated less often. To select a representative week from the time series first the load duration curve of the network for a year has been calculated. The result is shown in appendix in Figure 225 on the left side. Afterwards the load duration curve for every week of the year is calculated and compared to the load duration curve of the year. The week, which shows the best matching load duration curve, is selected as representative week. A figure of the time series of the representative week is shown on the right side of Figure 225 in ANNEX II – Additional Results for Planning Domain.
In some test cases the use of flexibility during contingencies is an additional option for the network operator. Since the use of flexibility is a feature also used in normal operation mode, it will not be assessed as some kind of deficit state in the reliability analysis, but rather as an

extended normal operation mode. Therefore, only a disconnection from the grid will be assessed as deficit state in the reliability analysis.
Overall two test cases will be simulated and compared to determine the effect of flexibilities, smart grid elements and the ICT-system on overall reliability. In a first step, a grid operation with utilization of flexibilities and smart grid elements is considered. Therefore both power system and ICT-system failures are determined in the reliability assessment. Besides the consideration of possible additional failures the utilization of GSM and remote switching capabilities during the resupply process is taken into account as well.
In a second step, simulations with a reinforced power system are carried out for comparison reasons. The reinforcement measures and the necessary additional equipment have been determined with the optimization algorithm defined in D3.1. The reinforced power system no longer requires the use of GSM during common operating conditions. If line overloading should still occur during contingencies DG units are disconnected from the grid instantly.

2.2.3 #3: Analysis of flexibility prices on network expansion planning

The traditional way to resolve the criticalities in the network is using conventional network expansion measures as building new network assets like lines or transformers. As most of the criticalities are driven by renewable energy sources (DRES), these criticalities only arise a limited number of times in the year, because often these units do not feed-in with their installed capacity. This means that some network assets might only be necessary for a short time within each year, which raises the idea to include the flexibility of DRES (here: a possible curtailment) in the planning process. In most of the European countries a consideration of curtailment is currently not allowed, but discussed [9].
This test case therefore focuses on the impact of the usage of flexibility in the planning process, especially on the possibility to save network expansion costs. This implies that the regulation is adapted in this way that a certain curtailment of DRES is allowed in the planning stage. Nevertheless, the assumed price of curtailment has an impact on the planning results so that different prices have to be investigated to see the overall benefit in cost reduction. Here a flexibility price of 35 €/MWh, which was the average spot price of the last year at the electricity market[4] [10][11], and a price of 100 €/MWh is chosen. The price of 100 €/MWh have been used in various studies like in [1] as the price is ajar to the current feed-in tariff of DRES in Germany. The assumed costs for network expansion are taken from [12].
Currently the discussion leaves open, how a possible curtailment of DRES, maybe 3 % of the yearly energy feed-in, can be distributed among the DRES units. In [11] an equal reduction of curtailment is considered, which means that for example all DRES units are only allowed to feed-in with 70 % of the installed capacity. In this test case the curtailment of DRES is optimised for each hour in the considered year (8760 h). Therefore, the yearly energy curtailment will differ for each DRES unit, leading in total to a lower curtailment of energy for the whole network, but to a non-equally treatment of each customers. Further, it is assumed that all units including the ones in the underlying network are available.
In order to use the flexibility of the network units, ICT has to be installed. Depending on the reference the future ICT installation costs vary a lot [11][13][14]. The considered high voltage network only includes parts of the underlying medium voltage grid (30-kV). The complete underlying voltage network is not considered in the network model. Therefore, the capacity of

[4] Period from September 2014 till August 2015.

DRES in the underlying voltage network is aggregated to one network node. Hence, it is not obvious, how much units are behind one aggregated node as the capacity for a wind and PV unit is not a constant factor. On the other hand the question arises how the curtailed energy in the underlying network should be divided between the units. Maybe it could be cheaper to use an equal curtailment here, instead of an individual one. Therefore, in this case the ICT costs are not calculated explicitly, because neither the exact amount of network units is known, nor the price for ICT and the actual ICT technology being used. But the reduced costs for network planning, when flexibility is included, can be used to get an idea of how much expenditure is left to cover the ICT costs.
As the underlying network is not explicitly modelled, there is no information about any possible criticalities in the underlying network. If DRES units are curtailed a necessary reinforcement of the underlying network could be reduced as well. Therefore the cost reduction for the whole distribution network could be higher, when flexibility is used compared to the test case applied here. On the other hand the time of critical situations in the underlying network could differ from the HV-network leading to a different optimal use of flexibilities.
The network losses are calculated in test case #1. As the optimization algorithm, which determines the curtailment of DRES is not build for an optimization of network losses, the network losses are not considered at this stage in the solution evaluation. It is assumed that the losses not vary widely between the solutions and won't play the major driver for the decision.

2.2.4 #4: Robust network planning to cover the future uncertainty

A best-guess scenario describes the most probable development in the future from an expert perception. The network is therefore usually designed for the best-guess scenario. Alternative scenarios are possible and the network could be insufficiently dimensioned. Hence, the test case treats the question of how much more expensive is a network reinforcement to be technical feasible for all scenarios (a so called robust network).
In the first step, the model of the scenario generator is applied and it is shown how a set of scenarios – representing the uncertainty of the future use of the network – is developed based on the given input data of the DSO and WP1. The resulting set of scenarios is input to the optimization algorithm of the FLEXPLAN planning tool. The test case will concentrate on the comparison of the network cost. Therefore, the results of the network expansion costs when planning for a best-guess scenario is compared for when planning for multiple scenarios. Flexibilities are not considered in this test case.

2.2.5 #5: New Topology vs Reinforcement

In traditional planning, distribution networks are sized regarding extreme cases: maximum consumption and minimum production, and minimum consumption and maximum production. A commonly used technic as reinforcement was extended in TOPPLAN tool by taking into account the flexibilities brought by the ADA functions (Advanced distribution Automation functions) which can erase a constraints or reduce the peak power. But in an extreme case where almost all the line would have to be reinforced, a change of the target network could be considered. This test case presents a comparison between two possible strategies: designing the new architectures (new topologies) with new operation modes for integrating the high amount of production and reinforcement of the constrained areas solution with or without flexibility. The performance of each solution obtained on the scenarios for the MV network described in Table 3 is measured by two Key Performance Indicators (KPIs): Discount cost and Maximal amount of DER that can be connected (MDGR).

The inputs of the tool are the following:

- Scenarios of DRES penetration,
- Scenarios of load evolution,
- Network data (location of loads, load profiles, line characteristics),
- Economic parameters (discount rate, cost of operational solution deployment)

The outputs of the tool are:

- Constraints locations and occurrence in the network
- Four Technical solutions proposition
    - Solution N°1 :
        1. Reinforcement with or without flexibilities and degrees of freedom of the DSO,
        2. Global cost, MDGR.
    - Solution N°2 :
        - New topologies,

Global cost, MDGR.

2.2.6 #6: Stochastic vs Deterministic Modelling

The targets defined in the long term planning for loads and production using deterministic methods based on the most likely scenario might be never achieved exactly in practice as they are based on some assumptions. Otherwise, the stochastic modelling works with uncertainties defined as a range of values on variables. This test case aims to give a comparison of TOPPLAN solutions obtained with the stochastic and deterministic modelling on loads, productions and the flexibilities provided also by using a set of the ADA functions. Here, the fuzzy numbers are used to model the 1-year profile of loads/generation taking into account the flexibilities brought by the load shedding and the production curtailment and also the degrees of freedom of the DSO brought by the on-load tap changer and the reactive power injection. As in the previous test case, obtained solutions are evaluated by Stochastic Actualized Cost (SAC) and maximal amount of DER that can be connected (MDGR).

2.3 Simulation Results of the Test Cases

2.3.1 #1: Identification of relevant network planning case

HV-network

For the sub-tool network planning cases the time-series of the hourly feed-in and the hourly consumption of each costumer is necessary. The consumption for the 110-kV and the underlying network represent industry and business customers. The corresponding time-series are simulated based on real historic time series for such types of costumers. The consumption for the underlying network represent either a group of households or a group of industry, services, business customers. A distribution factor is randomly chosen out to split the total load at a node in those two groups. For wind and pv generation a fundamental approach based on historic weather data[5] is used in order to generate the time-series. For the biomass generation the feed-in is set to a constant feed-in of 87 % of the installed capacity.

Figure 3 shows the relation between the feed-in of DRES and load[6], which will be called NPC-"cloud" in the following. All presented values are p.u. based on the installed capacities / maximum load for the scenario S_{bg}. In the business-as-usual (BAU) situation not all hours of the year are analysed and worst-cases are considered for network planning. There are no general rules how to define the worst-cases, so they have to be chosen carefully with reference to the network under consideration. For this network a high simultaneously of wind is observed and the worst cases (BAU_x) shown in the figure are considered for the network.

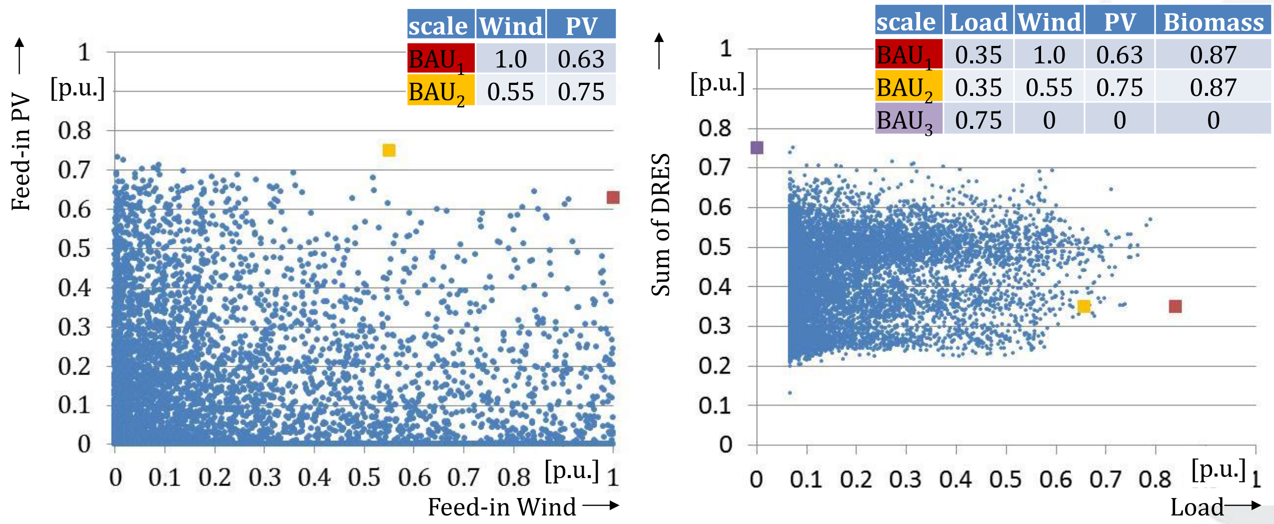


Figure 3 - Hourly feed-in of wind and pv-generation together with the defined worst cases.

The simulation of the generation leads to results that are less extreme than the worst-case assumptions, especially for maximal feed-in of pv. Further, it can be obtained, that maximum wind and pv feed-in rarely are simultaneous and have their maximal value in different hours.

Network Planning Cases for Dimensioning (NPC-D)

First, the NPC-D with the highest network loading have to be determined using a time-series simulation. 63 NPC of the 8760 NPC (time-series) cause the highest current on at least one line, and 57 NPC cause the highest or lowest voltage on at least one node (see Figure 227 in the appendix). As assumed, some of these for network planning tasks important NPC can be found at the edge of the NPC-"cloud". This was bound to happen, because for these NPC the generation or load is at its maxima, causing high network loading. Some of the NPC causing the highest currents and extreme voltages can be found slightly far from the clouds edges. This can be explained with the meshed grid structure and local load and generation phaenomena, for example a group of customers behaving different compared to the others.
In the next step, based on this preselection of NPC the developed algorithm for the determination of NPC-D is used. The method, described in deliverable D3.1, generates a

[5] Here the historic weather 2014 is chosen for generating the time-series.
[6] The simulation results have been verified with real-time measurement data of ten wind farms in the network. The modelling approach gives a good estimation of full load hours. On the other hand the model tends to over-estimate the feed-in close to nominal power and to under-estimate the feed-on of low power (see Figure 17 in the appendix).

predefined number of NPC-D with the goal of representing the preselected NPC and therefore the whole time-series. The results of this method for a number of 4 NPC-D and 8 NPC-D can be seen in Figure 4 (left).

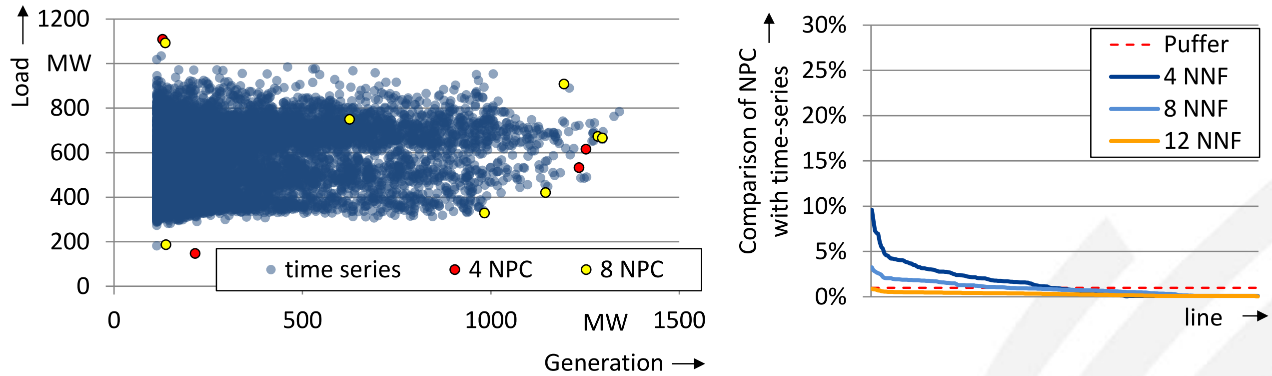


Figure 4 - Selection of NPC-D in HV-network.

As the figure shows, the resulting 4 NPC are located at the edge of the NPC-"cloud", one high load/low generation-case, one low load/low generation case and two high generation / medium load cases. By increasing the number of NPC to 8, these clearly sample the edge of the NPC-"cloud". The increase of NPC in theory leads to a better representation of the time-series. To prove this thesis, the resulting network loading – expressed by the line loading and the voltages – of the NPC are compared to the network loading caused by a time-series calculation. The results are shown in Figure 4 on the right.

The figure shows the overestimation of line loading by the determined NPC-D compared to the time series simulation. With 4 NPC-D the maximal deviation is nearly 10% of the line current. For nearly 50% of the lines the overestimation is below a buffer of 1% (the amount of buffer is user defined, 1% of the line load is the accepted accuracy in this example).

The similarity rises with an increasing number of NPC-D. With 8 NPC-D, the maximal overestimation shrinks to 2,5%, the deviation is below 1% for 70% of the lines. With 12 NPC-D, the deviation of all lines is below the defined buffer – which can be interpreted as an optimal representation of the time-series with 12 NPC-D. The same effect appears regarding the network voltages, illustrated in Figure 228 in the appendix.

The results for line loading and voltages show, that a number of 12 NPC-D is necessary for a good representation of the time-series. With a lower number the overestimation of network loading rises.

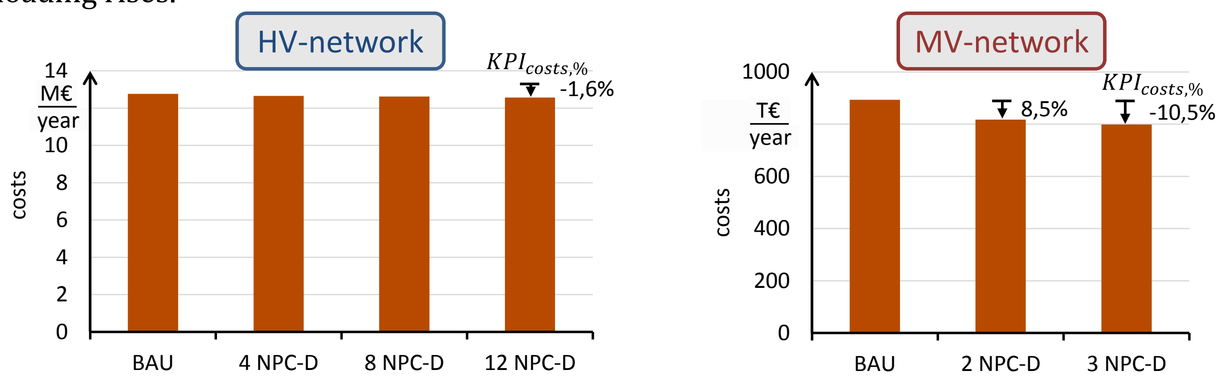


Figure 5 - Impact of NPC-D on network costs.

The left side of Figure 5 shows the results for network expansion costs for the HV-network. By selecting 4, 8 or 12 NPC-D with the proposed tool, the network costs can be reduced, for the reason that the network loading is modelled in a more realistic way. The total cost reduction amounts to 1,6% of the total costs. For the HV-network the BAU assumptions where already quite close to the NPC-“cloud”, therefore the determined further cost reduction is not very high.

Network Planning Cases for determination of losses (NPC-L)

The results of the implemented tool for reducing the number of network planning cases to a predefined number in order to calculate the losses are illustrated in the following. Input parameter is the time-series, including NPC for the whole year. These NPC are reduced using a k-Means algorithm and grouped into different clusters. The results for a number of k = 5 clusters can be seen in Figure 6 (left).

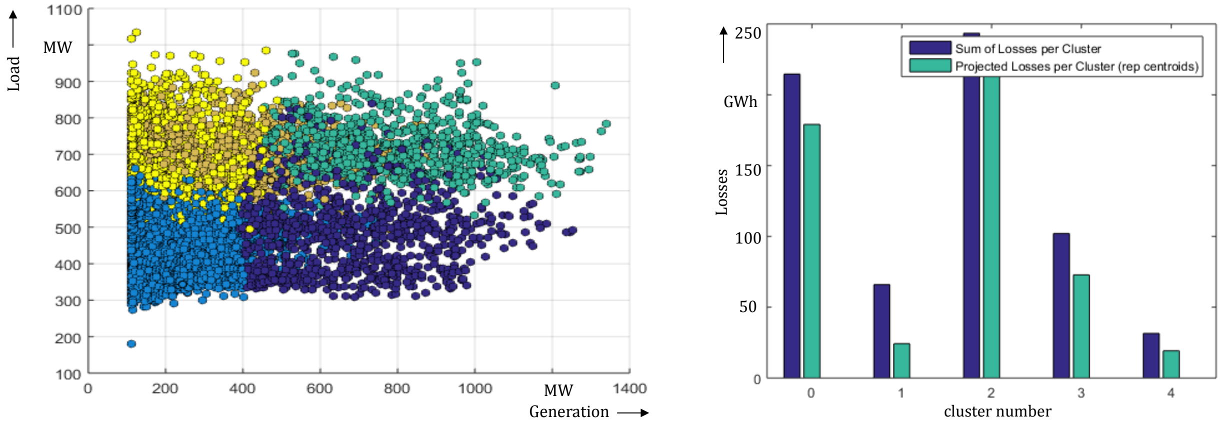


Figure 6 - Assignment of NPC to a cluster (k = 5).

As can be seen, similar NPC are grouped together. The overlapping of groups in the figure can be explained with the chosen visualization – the cluster algorithm groups NPC based on similarity in *n* dimensions, with *n* being the number of generators and consumers, while the figure pictures only two dimensions, total generation and total load. Nevertheless the tendency to group NPC with (for example) high generation and low load or with high load and low generation can be recognized.

In the next step, the comparison between the projected losses of a cluster, determined by calculating only one NPC of the cluster and extrapolate the results for the cluster, and the real losses of a cluster, determined by simulating each NPC by itself was made. The results can be seen in Figure 6 on the right. In each cluster, the projected losses are lower than the exact losses. This can be explained by the quadratic relation between losses and current – therefore the projection of the losses of the representative NPC, placed in the centre of the cluster, always underestimates the losses of the whole cluster. By increasing the number of clusters to be determined, the quality of extrapolation rises. An example for k = 20 can be seen in Figure 229 in the appendix. The cluster cutting enables a better representation of the NPC, because the similarity of each group is more homogeneous. Therefore the difference between the projected losses of each cluster and the precise losses decrease. The method was applied for different k (varying from 2 to 50). Figure 7 shows two different evaluations. First, the comparison of losses between time series and NPC-L, as shown in the pictures above, is

assessed. As can be seen, a number of 20 NPC-L leads to a high accuracy in losses determination with an error under 5%.
Another analysis was made by comparing the energy curtailment in the network necessary to comply with voltage and current constraints. The energy curtailment was calculated by the optimization algorithm of FLEXPLAN. A calculation based on a whole time-series was compared with an estimation using only a few NPC-L. The result shows, that with a number of 50 NPC-L, the energy curtailment could be estimated with an error of just 1 %. This reduction leads to much lower calculation times, which can be decreased by nearly $KPI_{t,\%}$ = 99% for each estimation of annual losses/energy curtailment (50 NPC-L instead of 8760 NPC-L).

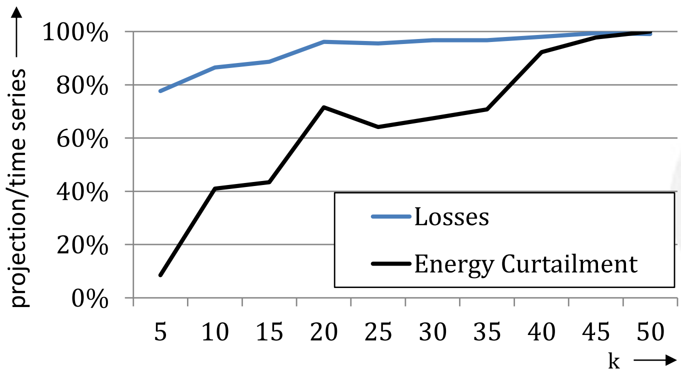


Figure 7 - Comparison between projected values and time-series.

MV-network
Figure 8 shows on the left the total generation (wind + pv + biomass) and the consumption. The worst-case assumptions shown in the figures compared to the HV-network have a higher value. The BAU-planning is based on 2 NPC, a high-load and a high-generation case. Here the BAU-assumptions include 1.0 p.u. of wind and 0.85 p.u. of pv in the high feed-in case.

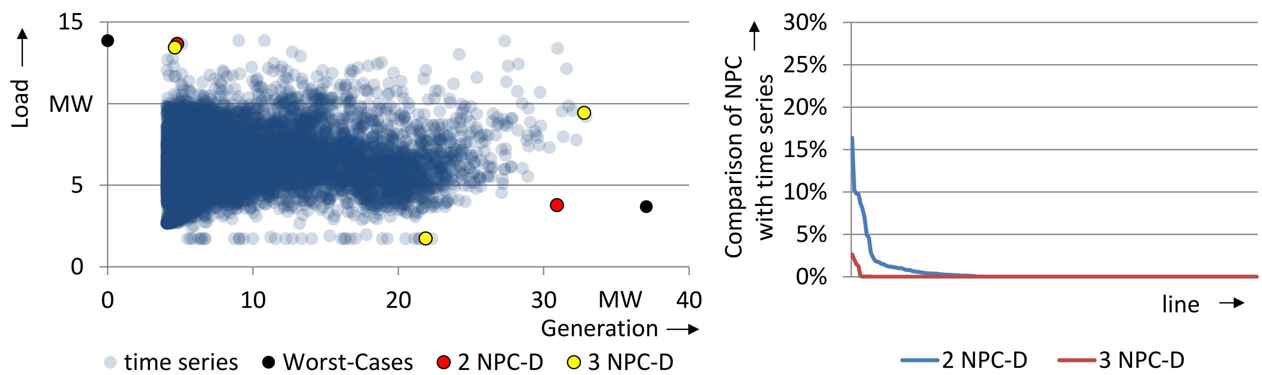


Figure 8 - Selection of NPC-D in MV-network.

On the right side of Figure 8 it can be seen that with 3 NPC-D the network loading can be modelled in the most precise way. Also the reduction in network planning costs can be calculated. By using 3-NPC the network costs can be reduced by 10,5% as shown in Figure 5 on the right hand side. Here the BAU assumptions have a significant impact on the possible cost reductions.

2.3.2 2#: Analysis of reliability

In the following results are presented for the system level in form of availability of supply indices. Availability of supply indices for specific customers may differ from these system level indices significantly because of the customer's time dependency of network usage, network connection point and reliability requirements.
Therefore only for the availability of supply indices on system level a comparison between the use of flexibilities for the integration of DRES (FLEX) and reinforcements for the integration of DRES (REIN) is made. Since only DRES units are equipped with GSM and connected to the ICT-system, it is distinguished between grid consumers and DRES in the evaluation as well as deficits caused by overloading, power system equipment (PSE) and ICT-system equipment (ICTE).

MV-network
From a reliability perspective MV-networks have a few characteristics, which are of importance during contingencies and therefore need to be taken into account in the evaluation of the results.
The MV-network shows two significant differences compared to the HV-networks during the fault clearance process. First redundancy can in most cases only be realized by switching operations and second the protection concept based on protection relays and switch gear facilitates no direct selective disconnection of faulty equipment. Therefore a fault may lead to a disconnection of a customer, whose electrical supply is not dependent on the faulty equipment but whose connection point lies in the same protection area as the faulty equipment. The exemplary MV-network selected for the test case features both of those described characteristics of MV-networks.

Figure 9 shows the average system interruption frequency index (ASIFI) and the average system interruption duration index (ASIDI) for the exemplary MV network in steps FLEX and REIN.

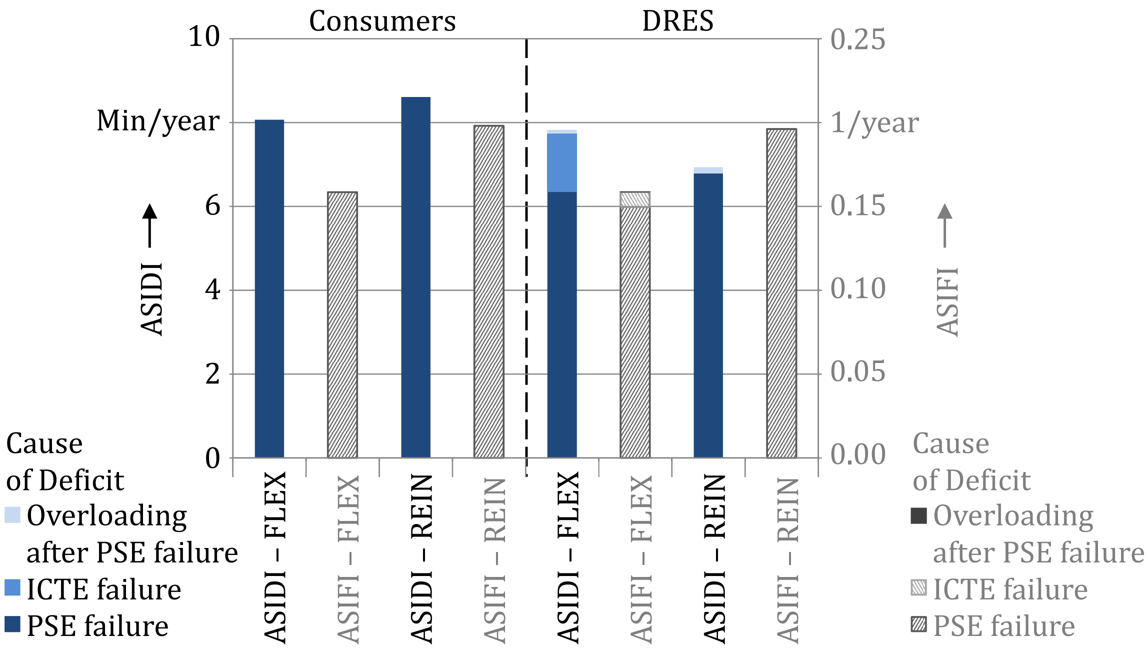


Figure 9 - ASIDI and ASIFI in steps FLEX and REIN for the MV-network.

The availability of supply of consumers is only influenced by the power system since the consumers do not provide flexibilities and therefore do not need a connection to the ICT-system. In step REIN the deficit frequency and the deficit probability for the customer rise. Due to the reinforcement in step REIN the number of power system equipment in the protection area of the consumer increases, which in turn leads to a higher frequency and probability of contingencies. At this point it has to be mentioned that parallel cables have been treated in the reliability analysis as if they would represent two single cables. Some failure causes such as damage during construction work may occur less often for parallel cables and therefore the illustrated results can be seen as a worst case scenario. Overall deficit frequency increases more than deficit probability in step REIN because additional equipment in general only causes failures of short duration in a power system equipped with remotely controlled switch gear. However for industrial consumers an increase of the ASIFI value by ~25% can be critical.

The availability of supply indices of DRES are influenced by the ICT-system and the power system. In step FLEX ICT-system failures contribute significantly to the total level of the indices. The main cause for this effect lies in the functional failure of the IED on which the generation side management is implemented. If the DRES can no longer be controlled, it will be disconnected from the network until the IED is replaced or repaired and occur compared to failures on power system equipment with a much higher frequency (e.g.~0.02 1/a) [15]. Deficits due to disconnection from power system because of overloading amount to ~1% of the deficit probability in the exemplary MV grid in step FLEX. In step REIN deficits caused by disconnection due to power system overloading can almost entirely be prevented. The reinforcement of the network will cause a significant rise of deficit frequency and probability in step REIN. Here the same causes apply as described for consumers above. Furthermore the deficit frequency and the deficit probability between consumer and DRES vary significantly even though they are connected at the same connection point because a DRES can for example be a photovoltaic unit, which only operates during day time hours. Therefore a unit's susceptibility for failures may be reduced significantly by its operation mode.

Overall deficit probability is lower for DRES than for consumers because DRES are less frequently installed in single branches without alternative supply paths. Overall the results of the exemplary MV-network lead to the following differences in ASIDI and ASIFI for steps FLEX and REIN.

$$\Delta ASIDI_{Con.} = ASIDI_{Con.,FLEX} - ASIDI_{Con.,REIN} = -0.541 \ {}^{Min}/_{a}$$
$$\Delta ASIFI_{Con.} = ASIFI_{Con.,FLEX} - ASIFI_{Con.,REIN} = -0.040 \ {}^{1}/_{a}$$
$$\Delta ASIDI_{DRES} = ASIDI_{DRES,FLEX} - ASIDI_{DRES,REIN} = 0.886 \ {}^{Min}/_{a}$$
$$\Delta ASIFI_{DRES} = ASIFI_{DRES,FLEX} - ASIFI_{DRES,REIN} = -0.038 \ {}^{1}/_{a}$$

HV-network

The characteristics of a HV-network are significantly different to those of a MV network and therefore need to be considered for the evaluation of the results as well.

HV-networks are usually highly redundant and feature a selective disconnection of faulty equipment. These characteristics lead to a high reliability of the network because only very few single faults such as bus bar failures may lead to a disconnection of customers. The exemplary HV-network selected for the test cases features both of those described characteristics of HV-networks.

Since in the HV-network availability of supply indices vary between connection points, average deficit frequency and the average deficit probability for connection points at 10-kV bus bars supplied by the HV-network are determined. Figure 10 shows the average deficit frequency and the average deficit probability for consumer connections and DRES connections at 10-kV bus bars supplied by the HV-network in steps FLEX and REIN.

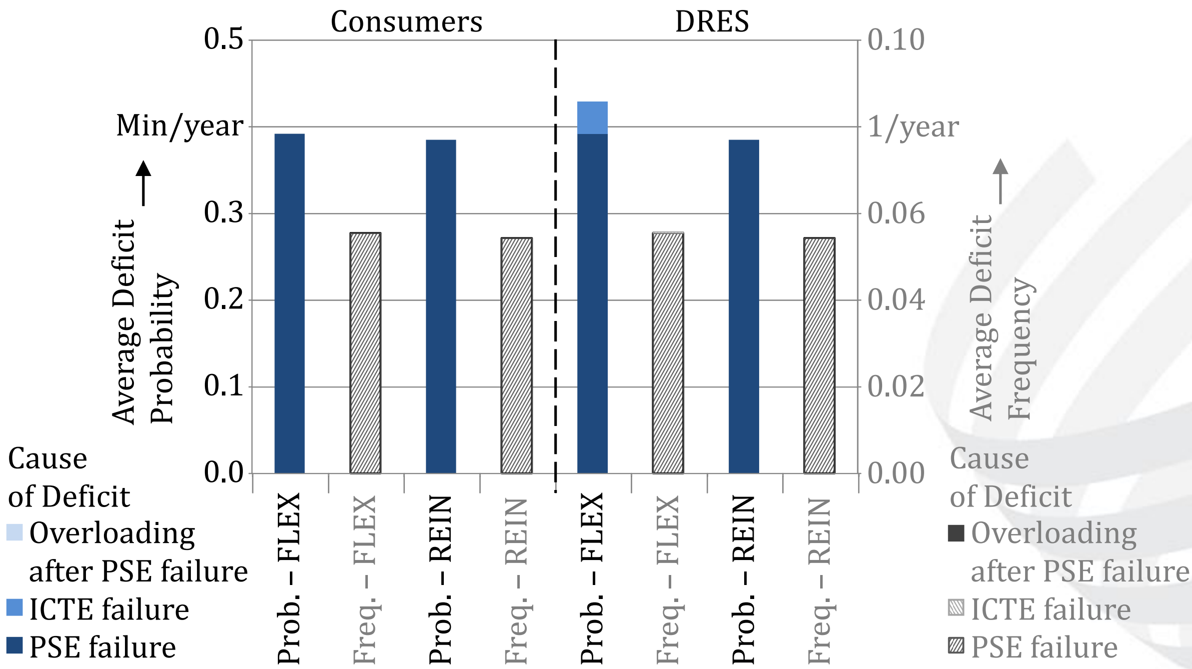


Figure 10 - Deficit probability and deficit frequency in steps FLEX and REIN for the exemplary HV-network.

In the exemplary HV-network all switch gear can be remotely controlled and circuit breakers are installed at the beginning and end of every line. This configuration and equipping of substations lead to a high degree of selectivity in case of contingencies.
For consumers only a very small difference between steps FLEX and REIN can be determined. The higher number of equipment due to network reinforcement has hardly an effect on reliability in step REIN. This effect can be ascribed to the high selectivity of the protection scheme. Since no additional power system equipment is added to the protection area of a significant amount of consumers, the reliability stays the same for both cases.
The availability of supply indices of the DRES are influenced by the power system and ICT-system as described previously for the MV-network. In the HV-network the increase of the reliability indices due to failures in the ICT-system is equally significant, even though it is assumed that more reliable ICT-system equipment is chosen for the operation of the HV-network than for the MV-network, because of a higher reliability of the HV-network. Deficit frequency and deficit probability caused by PSE do not change significantly for DRES in steps FLEX and REIN due to the effects previously described for consumers.
The level of deficit frequency and deficit probability is much lower than for the customers of the MV-network. Overall the results of the HV-network lead to the following differences in average deficit probability (ADP) and average deficit frequency (ADF) for steps FLEX and REIN.

$$\Delta \mathrm{ADP}_{Con.} = \mathrm{ADP}_{Con.,FLEX} - \mathrm{ADP}_{Con.,REIN} = 0.007\ {}^{Min}/_{a}$$
$$\Delta \mathrm{ADF}_{Con.} = \mathrm{ADF}_{Con.,FLEX} - \mathrm{ADF}_{Con.,REIN} = 0.001\ {}^{1}/_{a}$$

$$\Delta \mathrm{ADP}_{DRES} = \mathrm{ADP}_{DRES,FLEX} - \mathrm{ADP}_{DRES,REIN} = 0.044\ {}^{Min}/_{a}$$
$$\Delta \mathrm{ADF}_{DRES} = \mathrm{ADF}_{DRES,FLEX} - \mathrm{ADF}_{DRES,REIN} = 0.002\ {}^{1}/_{a}$$

2.3.3 3#: Analysis of flexibility prices on network expansion planning

The optimization algorithm of D3.1 is used for the planning of the high voltage network. Further the NPC-Ds of the test case #1 are used (12 NPC-Ds) to find the necessary expansion of the network. In order to determine the curtailed energy of DRES a yearly calculation of the network operation is necessary. Here all 8760 hours of the year are calculated to determine the curtailed energy at each substation of the network.

The results of the conventional solution, where no flexibility is used is the business as usual case and here described by a 100 % expansion plan. A sensitivity analysis on the network expansion is performed and the amount of expansion is varied between 0 % (no expansion) and the BAU case (100 % expansion). As the load doesn't increase significantly from today's value, and only DRES rises in the network, it is possible to achieve a secure network by curtailing DRES units instead of a reinforcement. The results of this sensitivity analysis are shown in Figure 11 for a flexibility price of 35 €/MWh (left) and a price of 100 €/MWh (right).

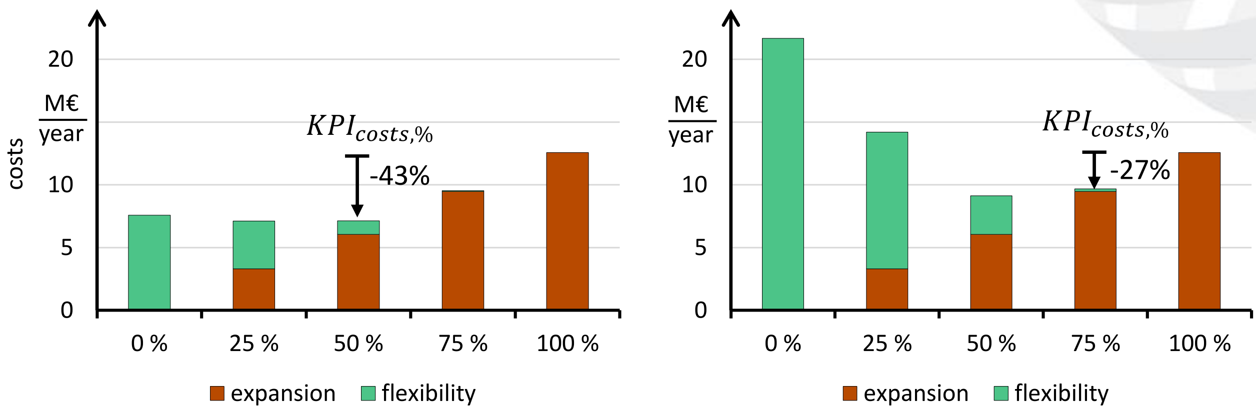


Figure 11 - Comparison of different flexibility prices on the planning result (left: flexibility price 35 €/MWh, right: flexibility price 100 €/MWh).

To 100 % reinforce the network costs 12,6 million € per year. In the case of a flexibility price of 100 €/MWh the total costs are the lowest for the 50 % expansion plan. Here the conventional expansion is roughly half compared to the business as usual case and 3,1 million € per year come on top for the curtailment of energy, leading in total to a cost reduction of 27 %. This offset can be used to cover the ICT installation cost in order to control the DRES units. Further, it can be seen that the 75 % expansion plan still has a total cost reduction of 23 %, but only uses a small amount of curtailment (0,2 million € per year). The total costs increase a lot, when the network is expanded less than 50 %. In case of no expansion the costs almost double compared to the business as usual case.

When the price for curtailment is reduced to 35 €/MWh, the solutions for a reduced grid reinforcement become more attractive. The 75 % expansion plan doesn't differ a lot compared to the case before because the amount of curtailment is very low. Therefore this solution is not very costs sensitive with regards to the flexibility price. For the 50 % expansion plan the total costs reduce to 7,1 million € per year meaning a cost reduction of 43 % to the business as usual case. The solutions of no grid expansion and 25 % grid expansion have almost the same costs as the 50 % expansion plan, but the share of flexibility costs and network expansion plan alter.

For each expansion plan the yearly curtailed energy can be calculated and is shown in Figure 12. In case of no expansion the curtailment of wind energy is around 12 % of the yearly feed-in, whereas for photovoltaic energy roughly 8 % is curtailed. The curtailed energy decreases exponentially until it reaches zero for the full expanded network. Also, the percentage of curtailed energy for wind and PV is for most solutions around the same (not considered the non-reinforced network). In case of the 50 % expansion plan the curtailed energy is lower than 2 % and therefore agrees with an often discussed level of 3 % energy curtailed per year [9].

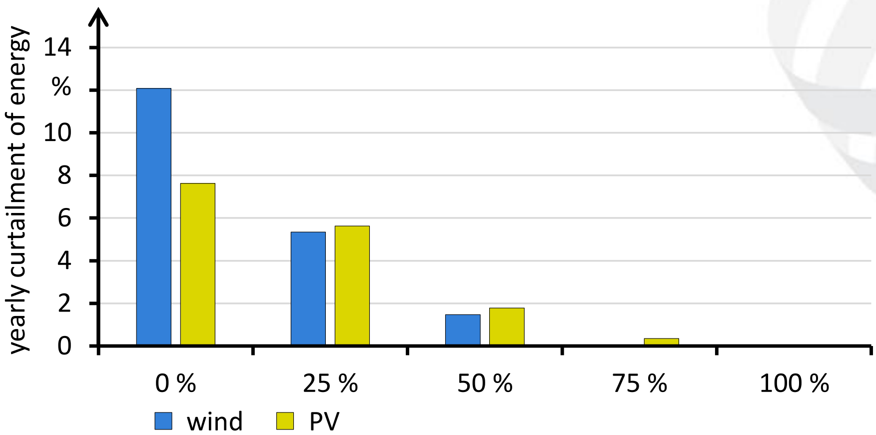


Figure 12 - Yearly energy curtailment of DRES for different expansion solutions.

In the following the 50 % expansion plan is further analysed. In Figure 13 the yearly curtailed energy per substation of the network is shown (here a substation can be one wind park or an aggregated value of the underlying voltage network feed-in). Only at 27 substations a curtailment occurs. For roughly ten substations the yearly curtailment is negligible, for others it is around the average value of curtailment of the whole network. Nevertheless, for some substations the curtailment is above 5 % and one substation even reaches a yearly curtailed energy of 21 %.

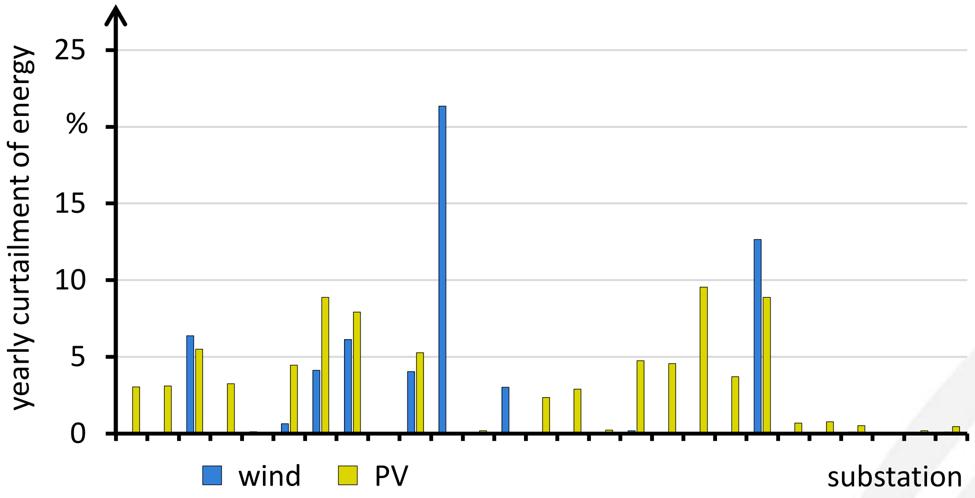


Figure 13 - Yearly energy curtailment of DRES per substation for the 50 % expansion plan.

In Figure 14 the hourly curtailment of DRES for the 50 % expansion plan for the whole network is shown. It can be seen that only for around 1000 hours a curtailment of DRES is necessary. Furthers for some hours the curtailment is rather high and reaches values of up to 140 MWh/h for PV and 120 MWh/h for wind respectively. In some hours the maximum curtailment reaches 215 MWh/h in total (e.g. hour 2485). Also it can be seen that in the summer manly PV units are curtailed, whereas in the winter month mainly wind power plants are curtailed.

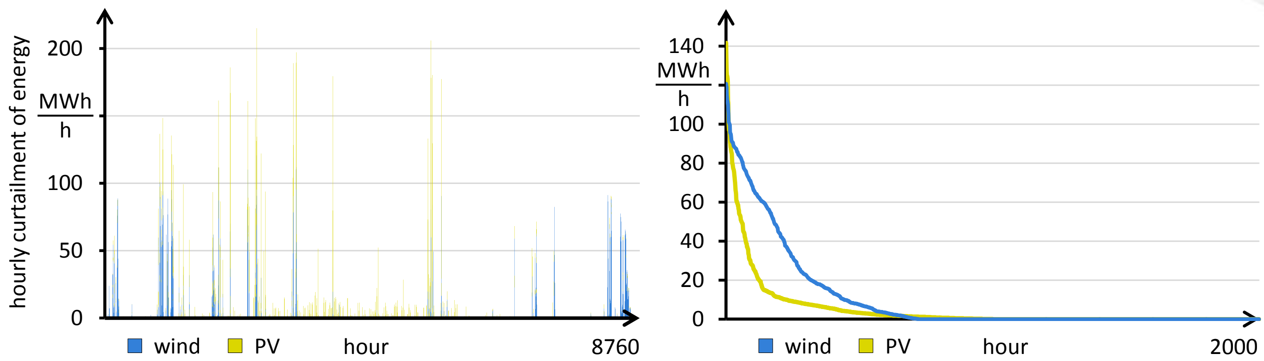


Figure 14 - Hourly curtailment of DRES for the whole year (left) and curtailment duration curve (right) for the 50 % expansion plan.

The most critical hour 2485 in the network can be further analysed. Figure 230 in the appendix shows the curtailed energy of the different wind and PV units in the network. The area with the highest curtailment is in the northeast of the network, where several wind and PV units have to be curtailed in order to avoid overloadings of network assets (here only overloaded lines are shown). In total a curtailment of 215 MWh is necessary.

2.3.4 4#: Robust network planning to cover the future uncertainty

The scenarios “S_u, S_{ml}, S_o” from chapter 0 are given for a national expectation. In order to get relevant input scenarios for the network. The scenarios are adapted by

$$\tilde{S}_u = S_{bg} - \frac{Range}{2} \;\; and \; \tilde{S}_o = S_{bg} + \frac{Range}{2}$$

Where *Range* is the range of uncertainty between the scenarios “S_u, S_{ml}, S_o” from chapter 0 (maximum minus minimum value). As this test case should investigate the robust scenario planning also regarding potential derivation of the load from the best-guess expectation (S_{bg}) the *Range* for the Load is set to the double difference between the National Allocation Plan and the scenario S_{bg}.

[MW]	Wind	PV	Biomass	Load
$\tilde{S}_u$	754	664	117	1359
S_{bg}	871	696	130	1377
$\tilde{S}_o$	988	728	143	1396
Range	234	64	26	37

Table 6: Input scenarios for sub-tool “Scenario Generation”.

As explained in Deliverable D3.1 the Scenario Generation consists in three steps:

1. Derivation of a distribution function for each source of uncertainty (wind, pv, biomass, load) by assessment of the input scenarios.
2. Simulating of N (N=1000) scenarios with equal probability by using uncorrelated random numbers for each source of uncertainty.
3. Clustering approach with k-means-algorithm to identify k (k=10) final scenarios and adjustment of the probabilities of the final scenarios based on the cluster results.

The Figure 15 demonstrates the simulation results before and after the clustering.

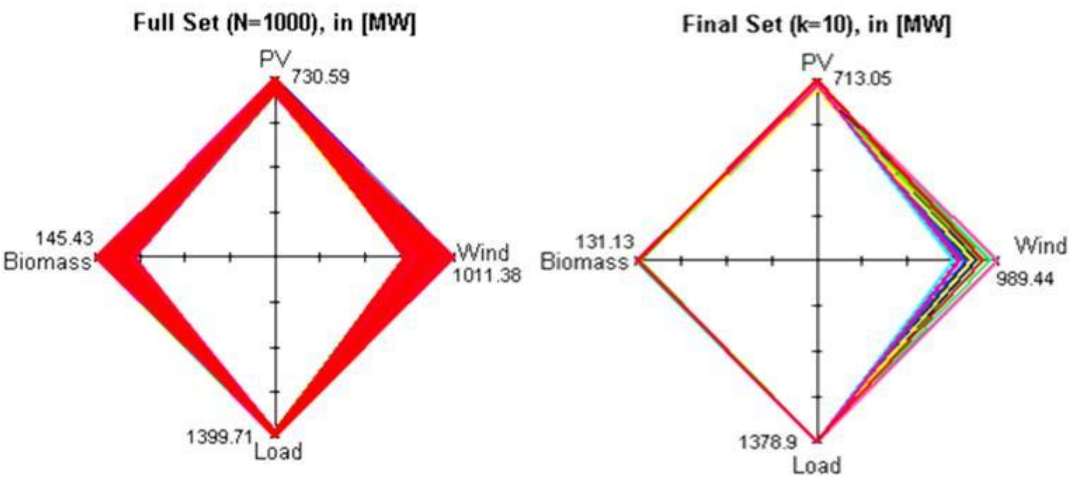


Figure 15 - Scenario generation: Full set and final set after clustering with k-means algorithm.

Figure 16 shows the installed capacity of each scenario (ordered with increasing probability of the scenario) in normalized based on the values of the detailed scenario S_{bg} and based on the present grid’s values.

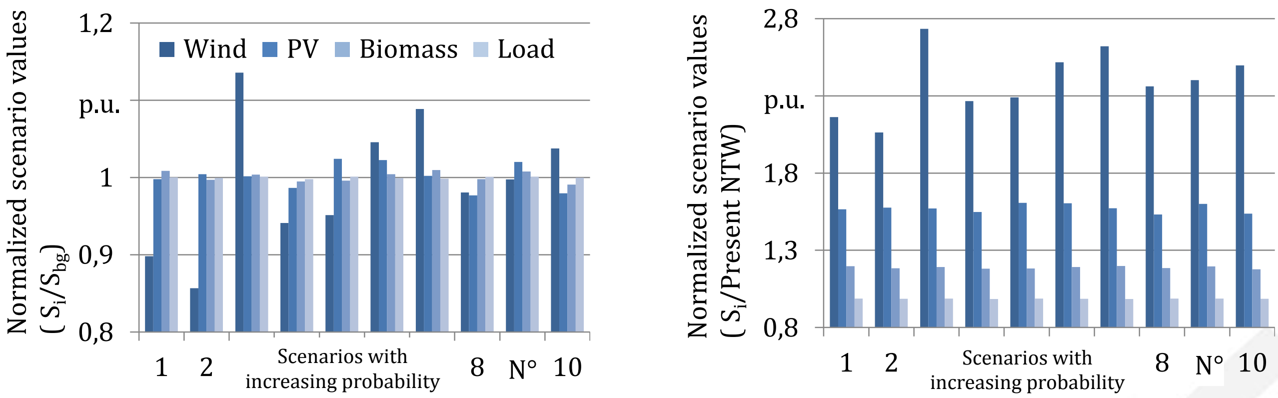


Figure 16 - Visualization of scenarios: normalized values.

These presented results of the tool “Scenario Generation” leads to the conclusions:

- The derivation to the best-guess scenario differs between the scenarios (and sources of uncertainty) because of the randomized simulation approach. The more extreme simulated scenarios (higher difference) come along with lower probability.
- The expected derivation over all scenarios to the best-guess-scenario is small, because of the synchronic positioning of the three input scenarios.
- The simulated set of 1000 scenarios includes the full range of possible values whereas the final scenario set of 10 scenarios does not include the most extreme ones and is more moderate. This is due to the clustering approach with the k-means-algorithm and the aim to group scenarios and representing them with a centroid.
- The range of the uncertainty in the installed capacity of wind is the highest due to higher absolute values compared to pv and biomass. The final scenarios therefore differ (in an absolute way) mainly in the installed capacity of wind. This is purposed (k-means-algorithm without normalizing the input data) because wind is the main source of uncertainty and the main driver for the network planning decision. The normalized values shows that pv and biomass still vary among the scenarios.

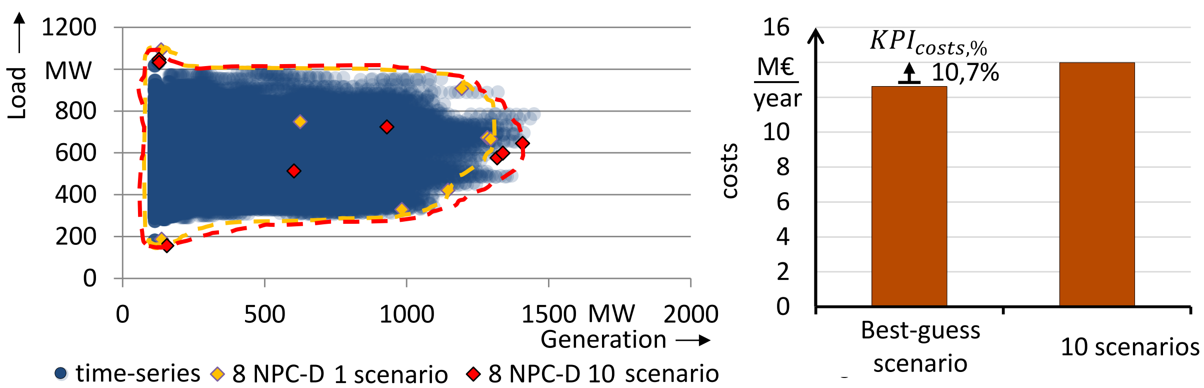


Figure 17 - Exemplary influence of robust planning on network costs.

In case of the 10 scenarios the NPC-“cloud” is much wider (higher DRES generation) compared when only one best-guess scenario is considered. All 8760 NPC multiplied by 10 scenarios are input for the determination of relevant network planning cases (NPC-D). The boundary of NPC-D is also wider as shown in Figure 17 on the left by the dashed lines. The network expansion costs are evaluated by the optimization tool for the 10 scenarios with 8 NPC-D. The solution for the best-guess scenario was already described in test case #1. It can be seen that the robust solution for the 10 scenarios is 10,7 % more expensive compared to best-guess case. The extra costs highly depend on the spread of uncertainties. Therefore the gap between the over- and under-expected scenario is crucial and needs to be well selected.

2.3.5 #5: New Topology vs Reinforcement

2.3.5.1 Network and variables modelling

The TOPPLAN tool was tested on the MV network. The scenarios given in Table 4 define the total load peak values on the S_U, S_{ml} and S_O (under expected, most likely and over expected) as constant. The time series 8760 daily profiles for load and productions were given by RWE. The flexibilities brought by the load shedding and the production curtailment and also the degrees of freedom of the DSO brought by the on-load tap changer and the reactive power injection were used. The Table 7 describes the available ranges of flexibilities defined for the scenarios on the S_U, S_{ml} and S_O.

Flexibilities	Available ranges		
	S_U	S_{ml}	S_O
Load shedding	5%	10% – 20%	30%
Production curtailment	5%	10% – 20%	30%
On-load tap changer	0.95p.u.	0.98 – 1.02 p.u.	1.05p.u.
Reactive power injection	$0.1P_{gen}$	$0.2–0.3P_{gen}$	$0.4P_{gen}$

Table 7 - Available ranges of flexibilities defined for the scenarios on the S_U, S_{ml} and S_O.

In the deterministic case we assumed the following hypothesis for the value of flexibilities calculated as an average of the available ranges:

- Load shedding – 17.5%,
- Production curtailment – 17.5%
- On-load tap changer– 1 p.u.
- Reactive power injection $0.25P_{gen}$

In the sub tool “Network reinforcement” the random location of new productions was considered. In the sub tool “New topology” we suppose the new production location is the same as the already installed in the network. In the further research this parameter can be defined as stochastic variable of the problem.

2.3.5.2 Network reinforcement

The sub tool “Network reinforcement” contains three main steps (algorithms):

- Constraint analysis aims at defining the set of constrained lines and nodes (see D3.1-3.1.2),
- Reinforcement procedure
- DRES insertion rate algorithm is used to check if the needed insertion rate is achieved on the reinforced network.

The defined in Table 4 scenario for long term planning can be expressed in percentage of growth rate. The Table 8 results it.

	[MW]	Long term (~40 years) growth rates (%)		
	present	S_U	S_{ml}	S_O
Load*	19	0	0	0
PV	15	80	100	120
Wind	9	100	133	177
Biomass	3	66	100	133

Table 8 - Given long term growth rates scenario for load and generation in the MV-network (* maximal load, not simultaneous values).

The tested "Reinforcement" sub tool on the MV network shows that even for the cable type 640mm^2 Cu (762A I_{max}) the MDGR is limited to 175% and there is no solution for the defined scenarios in Table 4. Therefore, the " Network reinforcement" tool does not allow to achieve the objectives.

2.3.5.3 New topologies

For developing the new topologies an optimization tool called automated optimal design of distribution network architecture described in D3.1-3.1.3 was used. The initial topology of a given MV network is shown on the Figure 18. First step of the algorithm is the construction of potential network graph having the same location of loads and substations (see Figure 19). For that, the set of nodes (buses) of the tested network which represent the loads, in-feed and substations has to be linked by the lines of potential networks. In other words we construct a maximal planar graph that is depicted on the Figure 20.

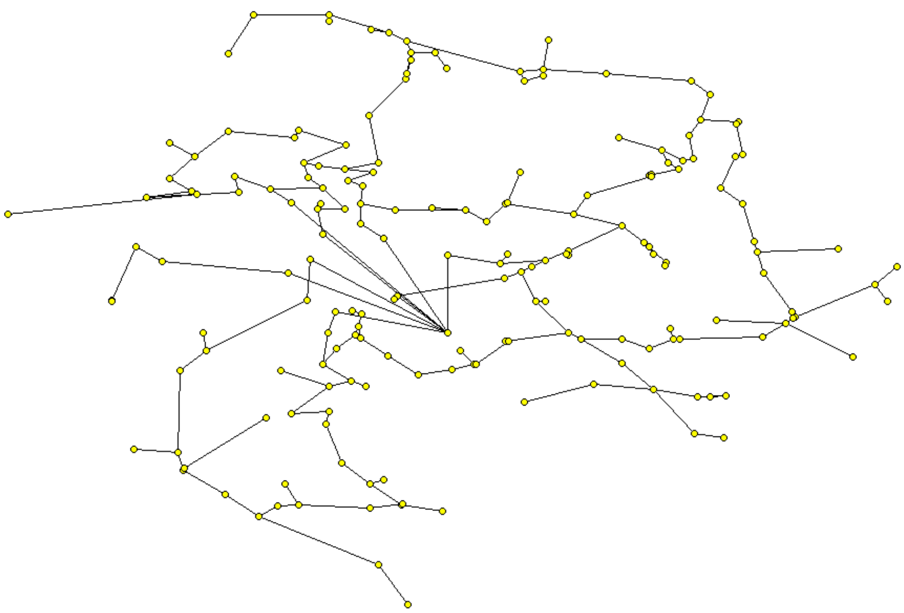


Figure 18 - Initial MV network topology.

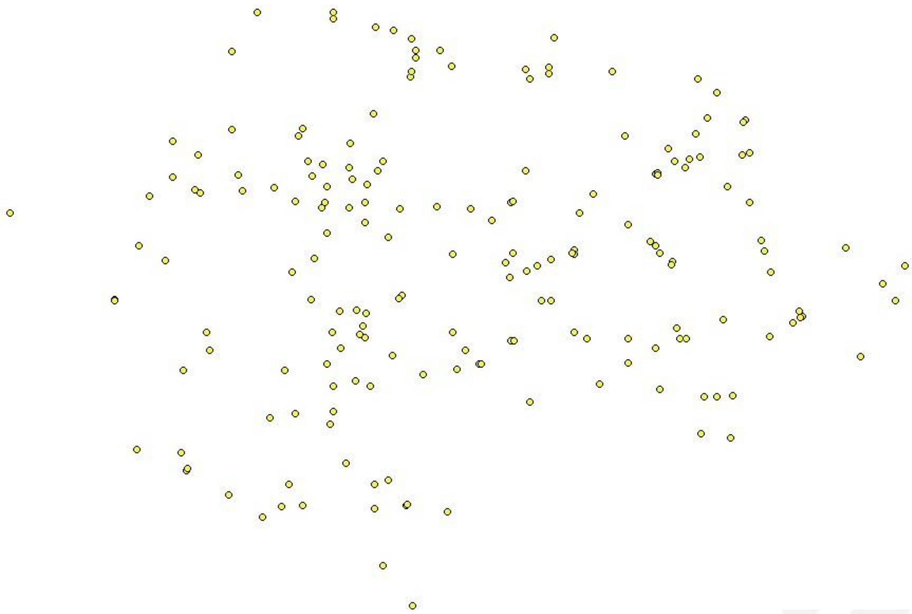


Figure 19 - Loads and substations location kept.

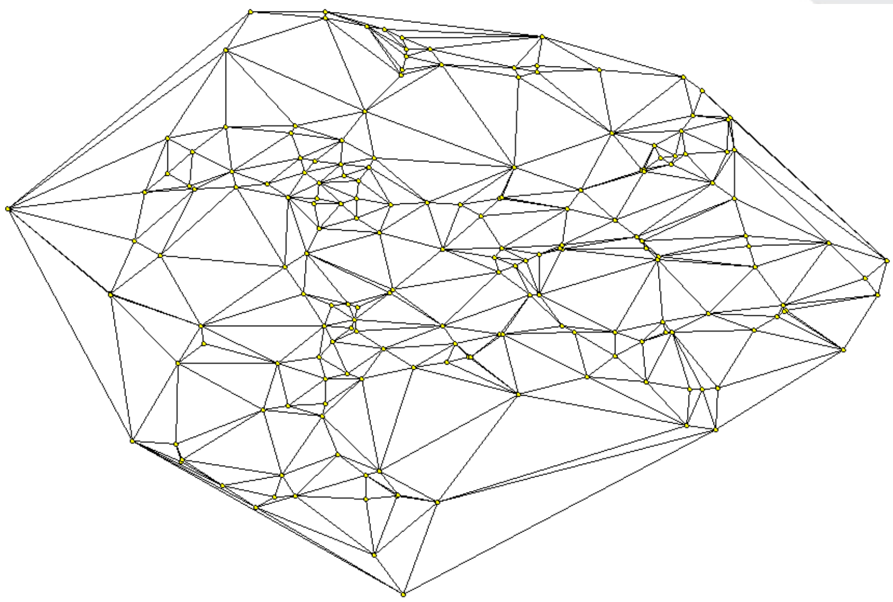


Figure 20 - Maximal planar graph of potential MV Network

The objective function of the algorithm is the minimization of the operating costs (OPEX) which depends of the technical losses and the minimization of investment (CAPEX) depending of the length of the network. A set of electrical constraints (I_{max}, V_{min}) were took into account in the problem as well as topological constraints (2-connectivity for all load/productions buses).
We assumed the following hypothesis:

- cable type 240mm^2 (419 A, R=0.125 Ω/km, X=0.1 Ω/km),
- 4 cables max per trench,
- loads and substations location kept,
- project lifetime N=40 years,

- minimal consumption is fixed to 20% of maximal consumption,
- topologies are defined for each scenario (S_U, S_{ml}, S_O) with and without flexibilities.

The topologies of the constructed networks are looped but for ensuring the radiality of the distribution network, the second step of the algorithm deals with the optimal placement of normally open switches optimal where the power losses have to be minimized.

2.3.5.4 Results

As it was mentioned in 2.3.5.2 that the tool "Network Reinforcement" cannot provide any solution for the tested network on the defined scenario, the presented results are only for the "New topology" tool. Obtained network topology for the solution without flexibilities is the same for three scenarios S_U, S_{ml}, S_O. Also, for the solution with flexibilities the same topology was found by the automated optimal design of distribution network architecture procedure for each scenario. But the normally open switches optimal placement algorithm provided the different radial configuration for each solution on each scenario.
The Figure 21, Figure 23, Figure 36Figure 22 and Figure 24 depict the obtained network topologies with optimal placed normally open switches (blue lines) and their corresponding radial configurations obtained for S_{ml} scenario with and without flexibilities.

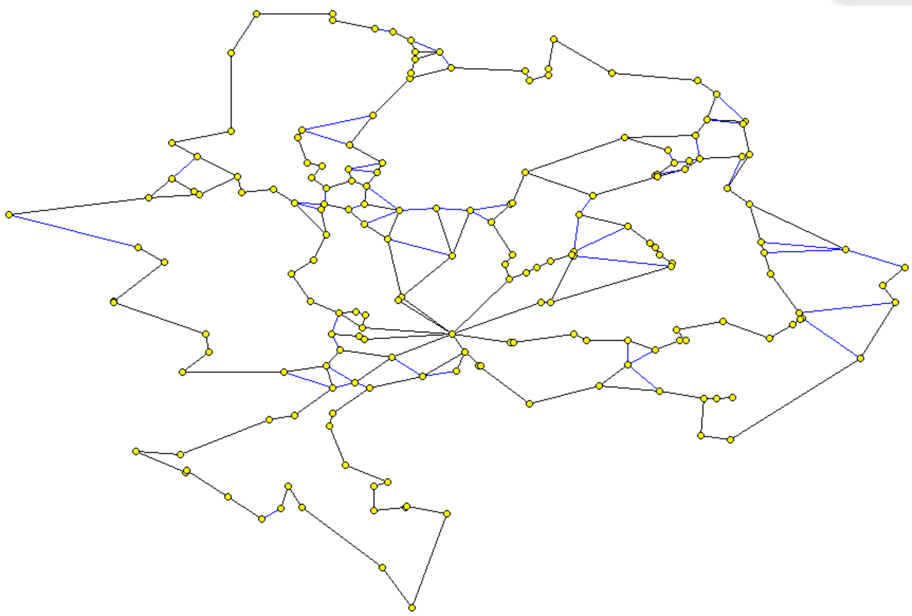


Figure 21 - Network topology of solution with flexibilities on MV Network with placed normally open switches (Sml scenario).

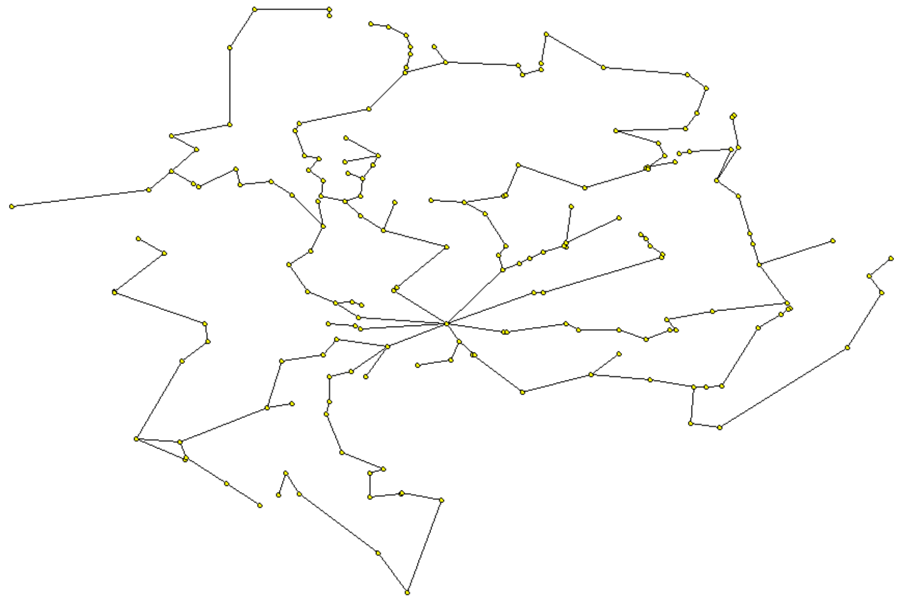


Figure 22 - Radial configuration of solution with flexibilities on MV Network (Sml scenario).

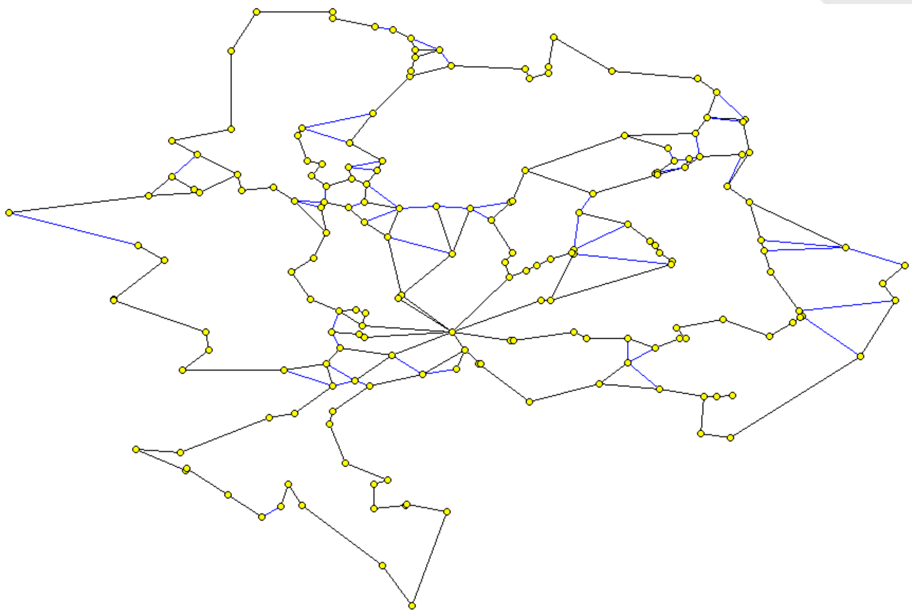


Figure 23 - Network topology of solution without flexibilities on MV Network with placed normally open switches (Sml scenario).

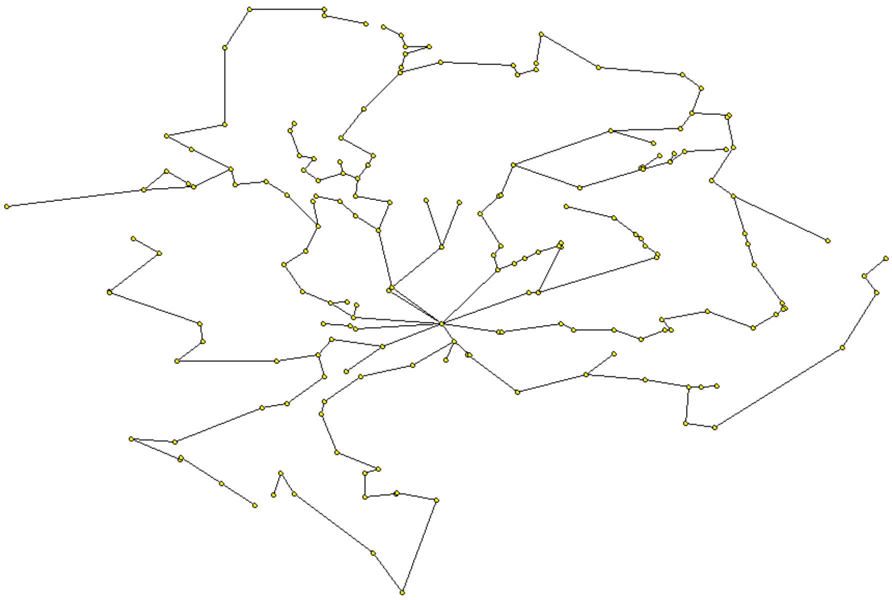


Figure 24 - Radial configuration of solution without flexibilities on MV Network (Sml scenario).

2.3.5.4.1 Maximal DRES insertion Rate (MDGR)

To measure the performance of obtained solutions a KPI MDGR was used. This KPI enables to estimate the amount of generation that can be connected to it without violating the technical constraints without any asumptions on their numbers, postitions and installed power.
The MDGR is defined by the following formula:

$$\boldsymbol{MDGR} = \left(\frac{\boldsymbol{P_{max\ DG}}}{\boldsymbol{P_{com\ max}}}\right) \times \mathbf{100}$$

Where:

$P_{max\ DRES}$ = maximal distributed generation production (MW)
$P_{com\ max}$ = maximal consumption (MW)

The Table 9 provides the MDGR values on the obtained solutions.

Solution	MDGR (%)		
	S_U	S_{ml}	S_O
Without flexibilities	173.3	208.9	244.3
With flexibilities	169.1	203.7	244.4

Table 9 - Maximum DRES penetration for the new topology solutions.

2.3.5.4.2 Discount Cost

Another KPI was used for the solution performance measurement – discount cost (see D3.1-3.1.4a). The Table 10 describes economical parameters used in the calculation of KPI.

Parameters	
Cable cost 240mm² Alu(k€/km)	20.1
Trench cost (k€/km)	100
Losses cost (k€/kW)	0.181

Discount rate (%)	8

Table 10 - Economical parameters.

Table 11 provides the discount costs of obtained topology solutions with and without flexibilities for three scenarios S_U, S_{ml}, S_O.

Solution	Discount cost (k€)		
	S_U	S_{ml}	S_O
Without flexibilities	9440.35	9592.06	9656.74
With flexibilities	8635.80	8686	8724.55

Table 11 - Discount costs of obtained solutions.

It should be noted that we did not take into account the flexibility deployment cost. These results show that the gain on CAPEX as well on OPEX is achieved in the case where the flexibilities were taken into account and total discount cost is lower than in the case without flexibilities.

2.3.6 #6: Stochastic vs Deterministic Modelling

2.3.6.1 Network and variables modelling

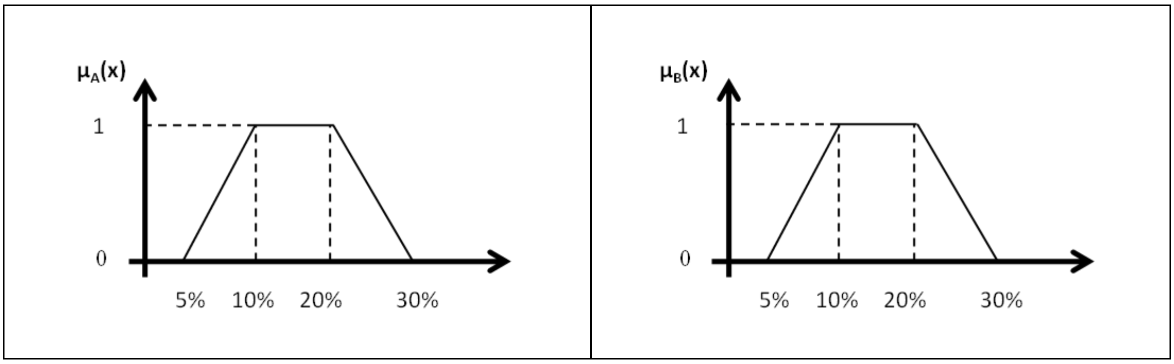
As in the previous test case (2.3.5) the TOPPLAN tool was tested on the MV. The most likely scenario given in Table 4 was considered.. The same assumptions were considered in deterministic case to model the network, the variables as well as the flexibilities as it was described it the section 2.3.5. For the stochastic case the variables representing the flexibilities are modelled as fuzzy numbers. We assume the hypothesis for the available range of flexibilities as it was defined in Table 7.

These quantities are defined as trapezoidal fuzzy numbers. The Figure 25 illustrates it. The resulting PQ peak values at each bus defined as load minus productions taking into account the flexibilities are calculated as center of gravity of a trapezoidal fuzzy number which it represents. The centroid can be found as a point of intersection of the line connecting the centers of bases with line given by the following formula:

$$Y = (b + 2a)/3(b + a),$$

where a and b are the bases of the trapezium which represents a fuzzy number.

In the sub tool "New topology" the location of new productions was considered as the same as the existing production in the network.



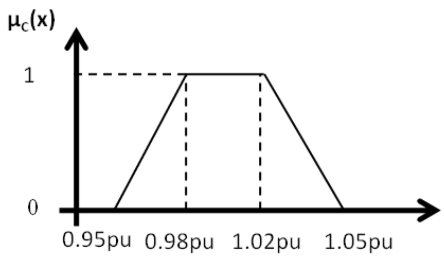
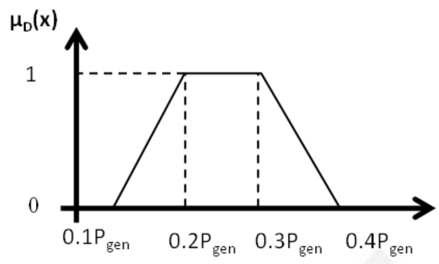
Load shedding fuzzy number	Production curtailment
 On-load tap changer	 Reactive power injection

Figure 25 - Flexibilities and degrees of freedom of the DSO fuzzification and their corresponding membership functions μA(x), μB(x), μC(x), μD(x).

2.3.6.2 Topology defining for scenario Sml

In the case of the stochastic modeling, the algorithm of new topology construction described in 2.3.5.3 is used. The topologies are defined for the scenario Sml with and without flexibilities using stochastic modelling. The others assumptions are the same as in the previous test case 2.3.5.3.

2.3.6.3 Results

Since the applying of "Network Reinforcement" tool doesn't solve the constraints in network for the defined scenario and the objectives cannot be achieved, the presented results are only for the "New topology" tool. The Figure 26 shows the network topology with optimal placed normally open switches (blue lines). The radial configuration of obtained network for Sml scenario with flexibilities is depicted on Figure 27.

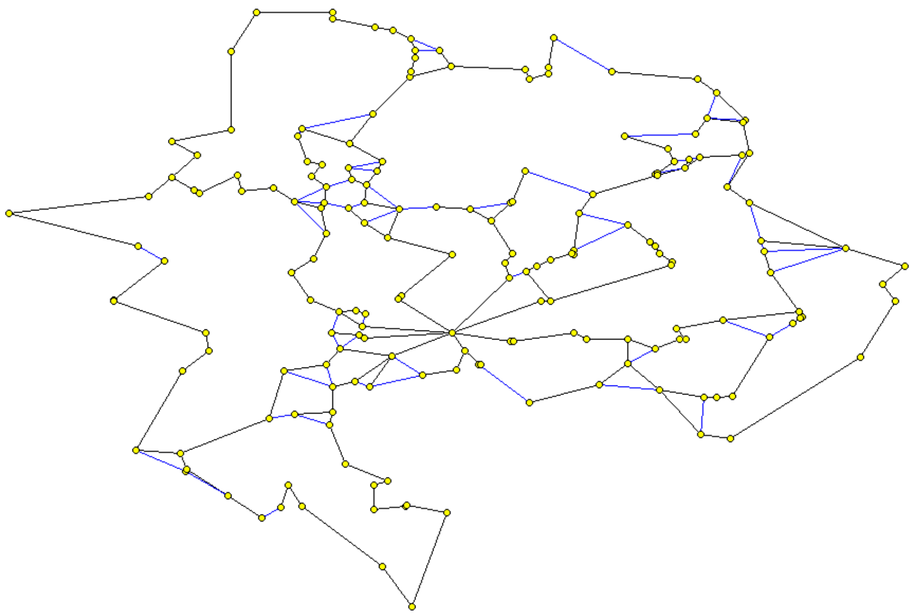


Figure 26 - Network topology of solution with flexibilities on MV Network with placed normally open switches (Sml scenario, stochastic case).

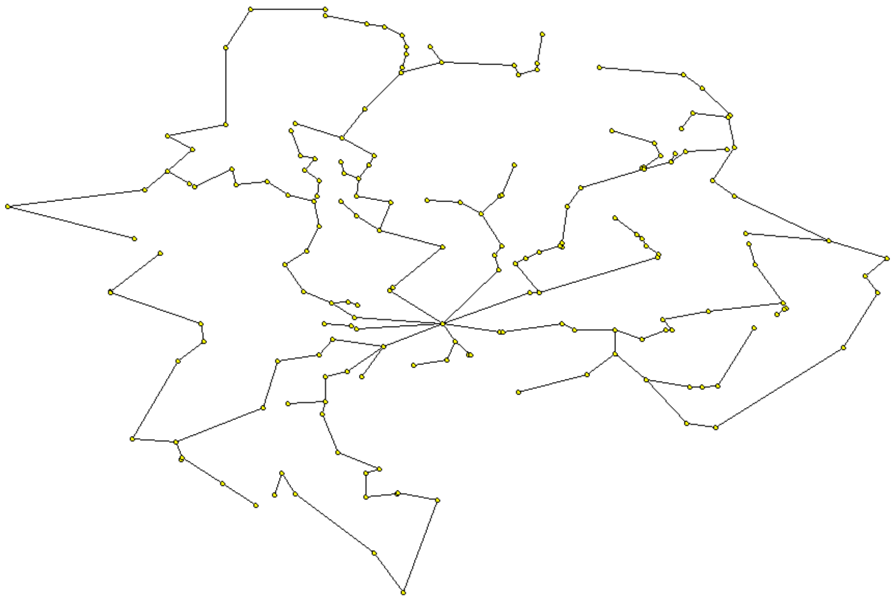


Figure 27 - Radial configuration of solution with flexibilities on MV Network Sml scenario stochastic case.

2.3.6.3.1 Maximal DRES insertion Rate (MDGR)

The obtained solution without flexibilities is the same as in the deterministic case that was presented in 2.3.5.4.1in Table 9. However, taking into account the flexibilities gives the different results on optimal placement the normally open switches for stochastic and deterministic cases.

The Table 12 results the MDGR values on the obtained solutions using stochastic and deterministic modeling.

Solution		MDGR (%)
		S_{ml}
Without flexibilities		308.9
With flexibilities	Deterministic case	303.7
	Stochastic case	302.2

Table 12 - Maximum DRES penetration for the new topology solutions.

It should be noted that the topologies for three cases presented in the Table 12 are different. We can observe that the stochastic modelling provides a solution with lower maximum DRES insertion rate. It is due to the lower discount cost of the network as it will be shown in the next section.

2.3.6.3.2 Stochastic Actualized Cost

Stochastic Actualized Cost is used for the solution performance measurement. The uncertainties of loads and generation in one hour interval are modeled by fuzzy membership functions as it was described in D3.1-3.1.1.b. The fuzzy function yields a degree of membership for each possible value of the uncertain value of loads and generation. In the one hour interval we suppose that the loads and the generations that are normally distributed with the expected values defined as peack values and the standard deviation defined as 0.01% of peack values. But in the presented model we define an approximation of normally distributed values of load and generation as trapezoidal fuzzy numbers with α-cuts taking α_1= 0.01 and α_2= 0.91.

The Table 13 describes economical parameters used in the calculation of SAC.

Parameters	
Cable cost 240mm² Alu(k€/km)	20.1
Trench cost (k€/km)	100
Losses cost (k€/kW)	0.181
Discount rate (%)	8

Table 13 - Economical parameters.

Table 14 results the ranges (trapezoidal numbers) of stochastic acualized cost for the solutions with and without flexibilities.

Solution		Discount cost/SAC (k€)			
		A1	**A2**	**A3**	**A4**
Stochastic case	**Without flexibilities**	9556.6	9585.7	9596.15	9629.81
	With flexibilities	8614.38	8642.21	8652.19	8684.39
Deterministic case	**Without flexibilities**	9590.9			
	With flexibilities	8686			

Table 14 - Discount costs of obtained solutions.

Using the flexibilities in stochastic modelling allows obtaining a network with minimum stochastic actualized cost. Even the upper bound given by value A4 in stochastic solution with flexibilities is lower than the result of the deterministic model with flexibilities. This follows from the fact that the found topologies for the solution with flexibilities are different in stochastic and deterministic cases. However, without using flexibilities the topologies are the same in stochastic and deterministic cases. Therefore, discount cost for deterministic case without flexibilities is a half value of an interval [A2, A3] of the SAC calculated for stochastic case without flexibilities.

2.4 Conclusions, Main Benefits and Limitations

2.4.1 Tool FLEXPLAN

The NPC used in planning can have a significant impact on network expansion costs depending on BAU-planning cases, especially for considered MV-network. 12(3) NPC are necessary in meshed(radial) networks to represent the maximal network loading caused by a time-series simulation. Annual figures like network losses or curtailed energy can be determined without calculating each hour of the year - roughly 50 to 100 NPC are necessary.

The Influence of smart grid applications (SGA) ICT system on reliability in new grid structures is not negligible and depends on specific power system topology and redundancy. The overall effect of ICT system on SAIDI and SAIFI values varies with used ICT equipment and SGA.

Including flexibilities in network planning shows a great impact on reduction of network expansion costs. Even for high flexibility prices network expansion costs can be reduced.

Some expansion measures are always wise in order to avoid high uncertainty of flexibility prices. The cost and technology of ICT will be the determining factor, how high the reduction will be in the end.

Planning the network for a broader development of the future means possible higher network loadings. This leads to higher network expansion costs. The extra costs highly depend on the spread of uncertainties. Therefore the gap between the over and under expected scenario is crucial and needs to be well selected.

The limitations and further research is therefore

- The robustness of determined network planning cases needs to be evaluated, when for example the network topology is changed by reinforcements
- Development of "rule of thumb" for the selection of network planning cases
- Investigation of different ICT technologies and their individual failure rates on the influence of reliability in distribution networks
- Integrated approach for all voltage levels of distribution network (LV/MV/HV)
- Enhancement of constructive heuristic by further knowledge of "real planner" (e.g. topology changes)
- Probabilistic planning for all scenarios (e.g. minimizing the expected value or least regret approach)
- Determination of probabilistic indices for a reinforcement measure

2.4.2 Tool TOPPLAN

The tool for the long term network planning TOPPLAN were assessed on two test cases. Real medium voltage network were studied according to defined scenario with high penetration of DRES for a long term perspective of 40 years. In the study the possible flexibility was considered as a stochastic input to choose between the reinforcement or the building of architecture. Then the technical choice in the network counted on this flexibility.

The first test case presented a comparison between two possible strategies: designing the new architectures (new topologies) with new operation modes for integrating the high amount of production and reinforcement of the constrained areas solution with or without flexibility. The tested "Reinforcement" sub tool on the MV network showed that there is no solution for the defined scenarios and this tool cannot be applied for solving the constraints in the network. Therefore, the using of sub tool for designing the new topologies is advantageous in the case of presence a high penetration of DRES in the network. The performance of each solution obtained on the scenarios was measured by two Key Performance Indicators (KPIs): Discount cost and Maximal amount of DER that can be connected (MDGR). Obtained solutions showed that without taking into account the flexibilities the discout cost of the network is higher than in the solution with flexibilities. However, the MDGR is lower in the network constructed with flexibilities.

Second test case aimed at giving a comparison of TOPPLAN solutions obtained with stochastic and deterministic modelling on loads, productions and the flexibilities provided also by using a set of the ADA functions. The fuzzy numbers approach were used to model the 1-year profile of loads/generation taking into account the flexibilities brought by the load shedding and the production curtailment and also the degrees of freedom of the DSO brought by the on-load tap changer and the reactive power injection. The numerical results of this test case showed the advantages of stochastic modelling. All obtained solutions were evaluated using two KPIs: Maximal amount of DER that can be connected (MDGR) and Stochastic Acualized Cost (SAC). In the case of the stochastic modeling, both KPIs have the lower values than KPIs of deterministic solutions.

3 Operational Domain

3.1 Networks Description

3.1.1 MV Networks in Italy

3.1.1.1 Network from the Atlantide project

Figure 28 represents the distribution network adopted for the testing of the Robust Economic Optimization Tool for Operational Planning (OP tool). The network is provided by ENEL Distribuzione, through the Atlantide project [18]. It is a typical radial distribution network where commercial, residential and industrial customers are connected. Generators are installed in the green buses and the loads in the red ones. In some cases (e.g. buses 8, 18, 31, 83) load and generation are connected to the same (green) bus. Finally, bus 1 is the slack bus - where the only OLTC installed in the network allows the MV/HV connection - while the transit buses are in blue.

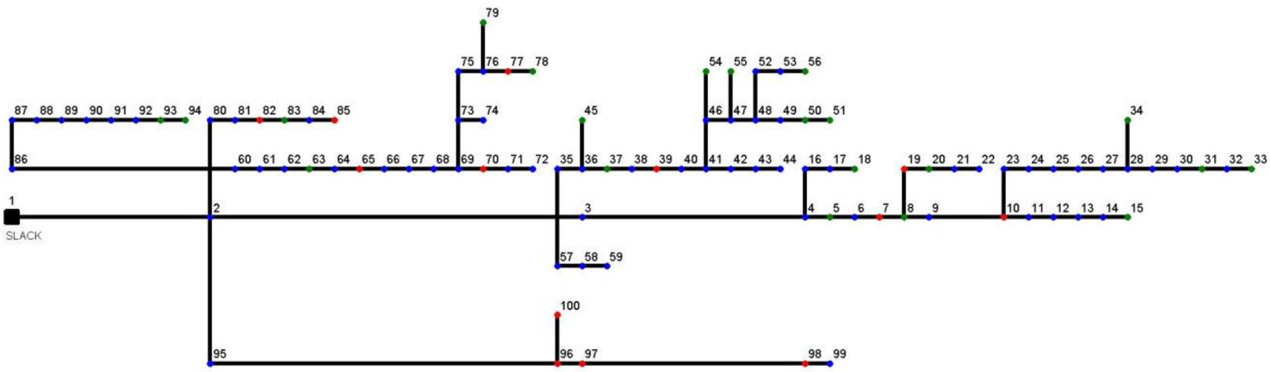


Figure 28 - Network – Robust Economic Optimization Tool for Operational Planning (OP Tool).

The radial network has 101 AC lines connecting the 100 AC buses with 15 kV as rated voltage. The total length of the lines is 120.42 km, divided in overhead lines (53.32 km) and cables (67.10 km).

OP Tool Network	
N° nodes	100
N° lines	101
N° feeders	7
Total length [km]	102.42

Table 15 - OP Tool - Number of Nodes and Lines in the Network.

A total of 128 loads are connected to the network, divided in residential (65), commercial (28) and industrial (35) loads. Moreover, the 28 generators connected to the network are either rotating (3 wind and 3 CHP) or static (22 PV). The load and generation profiles for each scenario are described in Section 3.2.1, as a part of the test cases description.

Table 16 - OP Tool - Number of Installed Loads and Generators

Loads and generators	
N° residential loads	65
N° commercial loads	28
N° industrial loads	35
N° rotating generators	6
N° static generators	22

Table 17 - OP Tool - Number of Installed Loads and Generators.

3.1.1.2 Cagliari Network (Sardegna region)

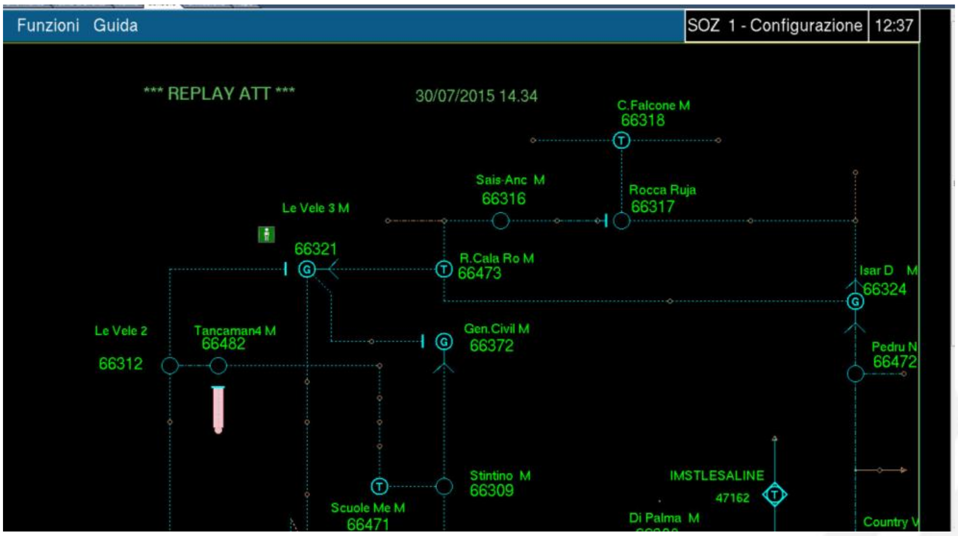
Regarding the data needed by the tool to support the operator in the network analysis, it is important to highlight three main data sets:

- Real time network
- Network Events
- Measurements (Load and generation forecast profiles)

Regarding the **real time network**, basically the Replay takes into account a copy of the real data base with the possibility to modify it by changing the configurations. In the testing phase, a portion of the network for the operation area of Cagliari (Sardegna region) has been considered, in particular, a partial section of the MV network including eight primary substations and the related MV distribution lines.
Here below the list of the primary substations involved with the related feeders.

- DS001380138
- DS001380107
- DS001380122
- DS001380118
- DS001380128
- DS001380143
- DS001380255
- DS001380108

The network is presented with the same schemes used by the SCADA in order to facilitate the operator in the use of the interface. In the following picture a representation is given.



The other group of data needed for the elaboration is the list of **network events.** This data are created with a specific simulator able to create the same kind of events that generally occur on the field.

An example of event created by the simulator is a short interruption (t<3min) that could be automatically solved on the grid because of an self-extinguishing event.
Here below an example of a list of events.

Allarmi e Variazioni di Stato Persistenti

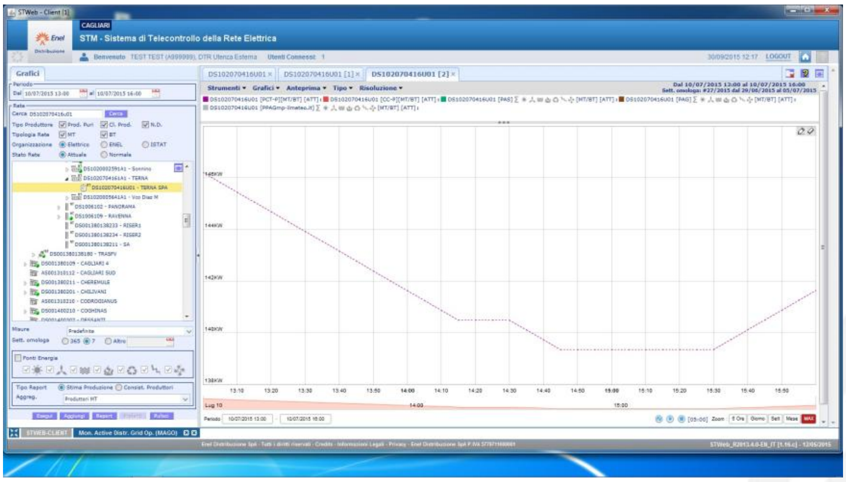
ORA	ESER	CABINA	MONTANTE	ENTE	ELEMENTO RETE	F	DESCRIZIONE	PARAMETRI
11:04:22	CGLR	OLBIA	PUTZOLU@	UPTA	S.Lu.Tras M		NON DISPONIBILE TELEC	
11:05:19	CGLR	VILLAPERUCCI	S.CROCE@	UPTA	8V.Garibal M		NON DISPONIBILE TELEC	
12:42:21	CGLR	NURRA	STINTINO	UPTA	IMSTLESALINE		FUORI SCANSIONE	
12:42:21	CGLR	NURRA	STINTINO	UPTA	IMSTLESALINE		NON DISPONIBILE TELEC	
12:42:36	CGLR	NURRA	STINTINO	IMS01	IMSTLESALINE:Le Salin		APERTO FSN AGGIORN MANUALE	
12:43:08	CGLR	NURRA	C.FALCONE	IMS	Cuile Nou:Country V M		APERTO FSN AGGIORN MANUALE	
12:43:08	CGLR	NURRA	C.FALCONE	UPTA	8P.Negra 2 M		NON DISPONIBILE TELEC	
12:43:08	CGLR	NURRA	C.FALCONE	UPTA	Le Vele 3 M		NON DISPONIBILE TELEC	
12:43:08	CGLR	NURRA	C.FALCONE	UPTA	Isar D M		NON DISPONIBILE TELEC	
12:43:08	CGLR	NURRA	C.FALCONE	UPTA	Country 2 M		NON DISPONIBILE TELEC	
12:43:08	CGLR	NURRA	C.FALCONE	UPTA	C.Falcone M		NON DISPONIBILE TELEC	
12:43:08	CGLR	NURRA	C.FALCONE	UPTA	Cala Reale		NON DISPONIBILE TELEC	
12:43:09	CGLR	NURRA	C.FALCONE	UPTA	Fornelli Mur		NON DISPONIBILE TELEC	
12:43:09	CGLR	NURRA	C.FALCONE	UPTA	S.Maria		NON DISPONIBILE TELEC	
12:43:09	CGLR	NURRA	C.FALCONE	UPTA	R.Cala Ro M		NON DISPONIBILE TELEC	
12:43:09	CGLR	NURRA	C.FALCONE	UPTA	Country V M		NON DISPONIBILE TELEC	
12:44:07	CGLR	VILLASOR 2	SERRAMANN@	LINMT			MANOVRE MT ECCESS. NUMEROSE	
12:44:58	CGLR	NURRA	CANAGLIA@	UPTA	@CLEANPOWER		FUORI SCANSIONE	
12:44:58	CGLR	NURRA	CANAGLIA@	UPTA	@CLEANPOWER		NON DISPONIBILE TELEC	
12:45:03	CGLR	NURRA	APPIU@	IMS06	@CLEANPOWER:Rsu Scala		APERTO FSN AGGIORN MANUALE	

Esci Tutti Eventi CP Eventi MT Eventi BT Cabina Esercizio Competenza SO

For each event the following data are highlighted:

- Time of the event
- Operation Area
- Primary Substation
- MV feeder
- Equipment involved
- Name of the element involved (label)
- Description of the event

Furthermore in order to realize predictive analysis the **measurement of load and generation data flow** is needed for the load flow calculation. The Replay has the possibility to use the data available from a specific forecasting tool already available in Enel Distribuzione (MAGO- Monitoring and control of Active distribution Grid Operation), which is shown in the following picture. This tool provides the forecasted profile of the producer when it is available for the requested period otherwise a “standard” profile based on the historical values is given.



3.1.2 LV Portuguese Network

The Portuguese LV system under study is a rural network and it is part of a Smart Grid Pilot Site developed under the Évora InovCity project. It has two main feeders which are connected to a MV/LV secondary substation (30 kV / 400 V / 230 V) equipped with a transformer of 100 kVA rated power. The network is composed by overhead lines with a high R/X ratio (around 10 in average) and has a total of 74 nodes containing 42 single-phase customers with contracted powers that vary between 1.15 and 6.9 kVA and 2 three-phase customers with contracted powers of 10.35 and 17.25 kVA (Table 18). There is no microgeneration unit installed in this network.

The selection of this network as case study was because of the number of available measurements with an acceptable quality in comparison to other similar Portuguese LV networks. In this network, each customer owns a Smart Meter (SM) capable of monitoring synchronously its active and reactive power consumption and voltage magnitude values.

Table 18 - Customers distribution.

Node ID	Customer ID	Feeder ID	Phase	Contracted Power (kVA)	Node ID	Customer ID	Feeder ID	Phase	Contracted Power (kVA)
8	C1	1	BN	3.45	53	C23	1	BN	6.90
9	C2	1	AN	3.45	54	C24	1	AN	3.45
15	C3	2	UNK	1.15	55	C25	2	BN	4.60
15	C4	2	UNK	6.90	61	C26	2	CN	3.45
15	C5	2	UNK	6.90	65	C27	1	CN	6.90
19	C6	1	AN	6.90	70	C28	1	AN	3.45
24	C7	1	BN	3.45	74	C29	2	AN	3.45
26	C8	1	BN	1.15	76	C30	1	AN	6.90
27	C9	1	ABCN	10.35	81	C31	1	AN	3.45
30	C10	2	CN	3.45	82	C32	1	CN	6.90
31	C11	2	CN	3.45	84	C33	1	BN	3.45
32	C12	1	BN	5.75	86	C34	2	AN	3.45
34	C13	1	CN	3.45	89	C35	1	BN	3.45
36	C14	2	UNK	1.15	92	C36	1	AN	3.45

Node ID	Customer ID	Feeder ID	Phase	Contracted Power (kVA)	Node ID	Customer ID	Feeder ID	Phase	Contracted Power (kVA)
38	C15	1	CN	3.45	93	C37	2	BN	6.90
39	C16	1	AN	3.45	95	C38	2	CN	3.45
40	C17	1	ABCN	17.25	96	C39	1	CN	3.45
42	C18	2	BN	1.15	100	C40	1	AN	3.45
44	C19	2	AN	3.45	101	C41	1	BN	6.90
48	C20	1	AN	3.45	102	C42	2	UNK	6.90
52	C21	2	AN	6.90	108	C43	2	AN	3.45
53	C22	1	CN	3.45	109	C44	2	CN	3.45

UNK: unknown

Table 19 - Customers distribution.

Customer ID	Meter ID	Historical Data Notes	Customer ID	Meter ID	Historical Data Notes
C1	SAG1450111978	V available	C23	SAG1450128464	V, P and Q available
C2	SAG1450112052	V, P and Q available	C24	SAG1450128357	V available
C3	SAG1450111988	V available	C25	SAG1450112009	V, P and Q available
C4	SAG1450128458	V available	C26	SAG1450128372	V, P and Q available
C5	SAG1450128459	V, P and Q available	C27	SAG1450111973	V, P and Q available
C6	SAG1450112016	V, P and Q available	C28	SAG1450111972	V available
C7	SAG1450111920	V available	C29	LGZ0011604697	Inexistent historical data
C8	SAG1450111918	V available	C30	SAG1450111927	V, P and Q available
C9	SAG1462000041	V, P and Q available	C31	SAG1450128423	Inexistent historical data
C10	SAG1450112007	V, P and Q available	C32	SAG1450112049	V, P and Q available
C11	SAG1450128460	V, P and Q available	C33	SAG1450111963	V, P and Q available
C12	LGZ0011604701	Inexistent historical data	C34	LGZ0011604785	Inexistent historical data
C13	SAG1450111959	V, P and Q available	C35	SAG1450112056	V, P and Q available
C14	SAG1350108952	V available	C36	SAG1450111917	V, P and Q available
C15	SAG1450111916	V, P and Q available	C37	SAG1450112055	V, P and Q available
C16	SAG1450112010	V, P and Q available	C38	SAG1450111945	V, P and Q available
C17	SAG1350100625	V, P and Q available	C39	SAG1450111930	V, P and Q available
C18	SAG1450111943	V available	C40	SAG1450111919	V, P and Q available
C19	SAG1450128456	V, P and Q available	C41	SAG1450111960	V, P and Q available
C20	SAG1450112057	V, P and Q available	C42	SAG1450128556	V, P and Q available
C21	SAG1450111941	V, P and Q available	C43	SAG1450112054	V, P and Q available
C22	SAG1450111936	V, P and Q available	C44	SAG1350108954	V available

V: Voltage magnitude measurements; P: Active power measurements; Q: Reactive power measurements.

Table 20 – Customers' meter ID and historical data information.

3.1.2.1 Historical Database

The historical database includes real average records related to the load (in time steps of 15 minutes) of the active and reactive power values, as well as voltage magnitude values for a period approximately of two months and a half (a universe of 7456 samples). About 6784 samples of the historical database were selected for training purposes and the other 672 samples for the evaluation set.

The results shown in section 3.3.2.1 are referred to the evaluation set.

3.1.2.2 Definition of the Number of Smart Meters with Real-time Capabilities

In general terms, the criterion behind the choice of SM with the capability of transmitting data in real-time (SM_r) was to ensure the existence of electrical information, at least, in all the network feeders and in all phases. In this sense, after a correlation analysis between the voltage magnitude values available in the historical database, 2 SM_r per phase were selected for monitoring at a given customer's premise electrical quantities in each one of the main network feeders, making a total of 12 SM_r. It is important to note that a SM where either its phase connection was unknown/not available (see Table 18) or its historical data had some lack of information (see Table 20) was not selected as a candidate in this selection process.
The chosen devices were intended to be installed in the field, but for a few of them some technical constraints turned its terrain installation not feasible. On one hand, the *General Packet Radio Service* (GPRS) signal for all the consumption nodes belonging to the feeder 2 (Table 18) did not have enough quality, which would cause problems on data transmission. On the other hand, the installation of three of the six SM_r foreseen for the other feeder was also not possible due to infra-structure constraints. Therefore, three other new SM_r were selected using the same process as described before.
In Table 21 are presented the final version of the two different sets of SM_r considered in the scope of this study.

Number of SM	Meter ID
6	SAG1450112056 - SAG1450111960 - SAG1450112052 - SAG1450112057 - SAG1450111973 - SAG1450112049
12	SAG1450128464 - SAG1450111927 - SAG1450111945 – SAG1450112054 - SAG1450112055 - SAG1450112056 - SAG1450112007 - SAG1450111941 - SAG1450111973 - SAG1450112009 - SAG1450112052 - SAG1450111936

Table 21 - Sets of SM with the capability of transmitting data in real-time.

3.1.3 LV French Network

The French LV network under study is composed by underground and overhead lines with a moderated R/X ratio (1.7 in average). It is connected to a MV/LV secondary substation equipped with a 20 kV/ 400 V (230 V) transformer with a rated power of 400 kVA. The transformer has a delta connected winding on its primary and a wye/star connected winding on its secondary.
The network has a total of 77 nodes containing 132 single-phase customers with contracted powers varying between 3 and 12 kVA and 3 three-phase customers with contracted powers of 12 and 18 kVA. This network also contains 14 microgeneration units (photovoltaic panels), of which 12 are single-phase connected with installed capacities between 2.9 and 18 kW and 2 units are three-phase correspondently with 8 and 18 kW of installed capacity. Table 22 and Table 23 show respectively the existing customers and the microgeneration units connected per phase.

Node ID	Customer ID	Phase	Contracted Power (kVA)	Meter ID	Node ID	Customer ID	Phase	Contracted Power (kVA)	Meter ID
192	L56	BN	9	F03MeterLO0056	324	L5	CN	6	F01MeterLO0005
192	L57	BN	12	F03MeterLO0057	324	L6	CN	9	F01MeterLO0006
192	L58	BN	9	F03MeterLO0058	325	L1	CN	9	F01MeterLO0001
192	L59	BN	12	F03MeterLO0059	326	L14	BN	9	F02MeterLO0014
193	L67	BN	9	F04MeterLO0067	327	L12	AN	12	F02MeterLO0012

Node ID	Customer ID	Phase	Contracted Power (kVA)	Meter ID	Node ID	Customer ID	Phase	Contracted Power (kVA)	Meter ID
194	L64	BN	9	F04MeterL00064	327	L13	AN	9	F02MeterL00013
212	L33	CN	9	F02MeterL00033	328	L36	AN	9	F02MeterL00036
212	L34	CN	9	F02MeterL00034	329	L23	CN	6	F02MeterL00023
212	L35	CN	9	F02MeterL00035	329	L24	CN	9	F02MeterL00024
213	L29	AN	6	F02MeterL00029	330	L15	AN	9	F02MeterL00015
213	L30	AN	9	F02MeterL00030	330	L16	AN	9	F02MeterL00016
213	L31	AN	9	F02MeterL00031	331	L40	AN	12	F03MeterL00040
213	L32	AN	9	F02MeterL00032	331	L41	AN	9	F03MeterL00041
214	L26	CN	9	F02MeterL00026	331	L42	AN	9	F03MeterL00042
214	L27	CN	9	F02MeterL00027	331	L43	AN	9	F03MeterL00043
214	L28	CN	9	F02MeterL00028	331	L44	AN	9	F03MeterL00044
215	L25	AN	9	F02MeterL00025	331	L45	AN	9	F03MeterL00045
217	L17	AN	9	F02MeterL00017	332	L37	AN	6	F03MeterL00037
217	L18	AN	9	F02MeterL00018	332	L38	AN	9	F03MeterL00038
217	L19	AN	12	F02MeterL00019	332	L39	AN	9	F03MeterL00039
217	L20	AN	6	F02MeterL00020	333	L60	BN	9	F03MeterL00060
218	L119	BN	12	F07MeterL00119	333	L61	BN	9	F03MeterL00061
218	L120	BN	9	F07MeterL00120	333	L62	BN	9	F03MeterL00062
219	L106	BN	9	F07MeterL00106	335	L50	CN	6	F03MeterL00050
219	L107	BN	12	F07MeterL00107	335	L51	CN	9	F03MeterL00051
221	L114	CN	9	F07MeterL00114	335	L53	CN	9	F03MeterL00053
221	L115	CN	9	F07MeterL00115	335	L54	CN	6	F03MeterL00054
222	L116	AN	12	F07MeterL00116	335	L55	CN	9	F03MeterL00055
222	L117	AN	12	F07MeterL00117	336	L49	CN	9	F03MeterL00049
222	L118	AN	9	F07MeterL00118	337	L66	AN	9	F04MeterL00066
223	L108	CN	9	F07MeterL00108	338	L63	CN	6	F04MeterL00063
223	L109	CN	12	F07MeterL00109	339	L70	BN	11	F04MeterL00070
223	L110	CN	12	F07MeterL00110	340	L68	BN	9	F04MeterL00068
223	L111	CN	12	F07MeterL00111	340	L69	BN	6	F04MeterL00069
312	L87	CN	6	F06MeterL00087	341	L79	AN	9	F05MeterL00079
312	L88	CN	6	F06MeterL00088	341	L80	AN	9	F05MeterL00080
312	L89	CN	9	F06MeterL00089	342	L74	AN	6	F05MeterL00074
312	L90	CN	9	F06MeterL00090	342	L75	AN	9	F05MeterL00075
312	L91	CN	9	F06MeterL00091	342	L76	AN	9	F05MeterL00076
313	L81	BN	6	F06MeterL00081	342	L77	AN	9	F05MeterL00077
313	L82	BN	12	F06MeterL00082	342	L78	AN	9	F05MeterL00078
313	L84	BN	9	F06MeterL00084	343	L71	CN	9	F05MeterL00071
313	L85	BN	9	F06MeterL00085	343	L72	CN	9	F05MeterL00072
313	L86	BN	6	F06MeterL00086	343	L73	CN	6	F05MeterL00073
314	L99	AN	9	F07MeterL00099	609	L121	CN	6	F08MeterL00121
315	L98	AN	6	F07MeterL00098	610	L133	BN	9	F08MeterL00133
316	L92	CN	9	F07MeterL00092	611	L132	ABCN	18	F08MeterL00132
316	L93	CN	9	F07MeterL00093	613	L129	CN	6	F08MeterL00129
316	L94	CN	9	F07MeterL00094	614	L128	CN	6	F08MeterL00128
316	L95	CN	9	F07MeterL00095	615	L127	BN	6	F08MeterL00127
316	L96	CN	6	F07MeterL00096	616	L122	BN	3	F08MeterL00122
316	L97	CN	6	F07MeterL00097	616	L123	BN	6	F08MeterL00123
317	L112	BN	12	F07MeterL00112	616	L124	BN	6	F08MeterL00124
317	L113	BN	6	F07MeterL00113	616	L125	BN	6	F08MeterL00125
318	L103	AN	6	F07MeterL00103	616	L126	BN	9	F08MeterL00126
318	L104	AN	9	F07MeterL00104	618	L141	CN	3	F08MeterL00141
319	L100	CN	12	F07MeterL00100	619	L137	AN	6	F08MeterL00137
319	L101	CN	6	F07MeterL00101	619	L138	AN	6	F08MeterL00138
319	L102	CN	6	F07MeterL00102	619	L139	ABCN	18	F08MeterL00139
322	L135	BN	9	F08MeterL00135	619	L140	AN	6	F08MeterL00140
323	L7	CN	9	F01MeterL00007	621	L136	BN	6	F08MeterL00136
323	L8	CN	9	F01MeterL00008	622	L134	AN	9	F08MeterL00134
323	L9	CN	9	F01MeterL00009	623	L131	ABCN	12	F08MeterL00131

Node ID	Customer ID	Phase	Contracted Power (kVA)	Meter ID	Node ID	Customer ID	Phase	Contracted Power (kVA)	Meter ID
323	L10	CN	9	F01MeterLO0010	624	L130	BN	9	F08MeterLO0130
323	L11	CN	6	F01MeterLO0011	625	L144	AN	12	F08MeterLO0144
324	L2	CN	9	F01MeterLO0002	626	L142	AN	6	F08MeterLO0142
324	L3	CN	6	F01MeterLO0003	626	L143	AN	6	F08MeterLO0143
324	L4	CN	12	F01MeterLO0004					

Table 22- Consumers distribution.

Node ID	Customer ID	Phase	Installed Capacity (kVA)	Meter ID	Node ID	Customer ID	Phase	Installed Capacity (kVA)	Meter ID
213	G6	ABCN	8	F02MeterGE0006	328	G7	AN	3	F02MeterGE0007
215	G5	AN	2.9	F02MeterGE0005	329	G4	CN	6	F02MeterGE0004
313	G11	ABCN	18	F06MeterGE0011	330	G3	AN	18	F02MeterGE0003
316	G12	CN	6	F07MeterGE0012	331	G8	AN	2.9	F03MeterGE0008
316	G13	CN	3	F07MeterGE0013	338	G9	CN	6	F04MeterGE0009
324	G2	CN	6	F01MeterGE0002	342	G10	AN	3	F05MeterGE0010
325	G1	AN	2.9	F01MeterGE0001	626	G14	AN	6	F08MeterGE0014

Table 23 – Microgeneration units distribution.

For this case study, it was assumed that each customer had a SM capable of monitoring synchronously (in time steps of 10 minutes) the active power and the voltage magnitude values.

3.1.3.1 Historical Database

Differently from the Portuguese network, in the French network selected to be studied here, no telemetry data regarding the bus voltage magnitudes and power measurements in loads and microgeneration units was available. Therefore, these data were generated through a three-phase power flow algorithm based on backward/forward sweep method [19]. In the next paragraphs the procedure followed to generate the load and microgeneration data used in the power flow simulations will be briefly described.

Regarding load data, an historical database of four months (between 24th of April and 28th of August of 2014) from another French network (in time steps of 10 minutes) was used as the starting point for generating the load inputs required for the power flow simulations with the French network under study. Since there was a significant lack of information in this historical database about the consumers' behaviour, it was required to compute mean load diagrams for each load in the network, one diagram for weekdays and another for weekends. Afterwards, the mean load diagrams were randomly assigned to the customers of the network under study, accordingly to their contracted power and type (i.e. residential or commercial). It is important to mention that in some cases, the number of loads of a given contracted power exceeds the number of diagrams available for that contracted power. In such cases the approach followed consisted on randomly assigning to the "extra" loads one of the mean load diagrams associated with the contracted power of the corresponding loads.

In order to represent the real-world behaviour of the customers for different days and along the day, each one of the mean load diagrams assigned to the customers was disturbed in terms of shape and magnitude according to the following process:

i) A random value drawn from a Gaussian distribution (with an average equal to its mean load diagram and a standard deviation of 20%) was applied to obtain distinct diagrams per day (a new random value was generated per day).
ii) The daily diagrams computed in i) were rearranged by replacing each time instant with a value drawn from the same diagram as follows: the same time instant was selected with a probability of 50%, the immediately previous or forward time instants were selected with a probability of 22.5% each and the two times before or ahead time instants were selected with a probability of 2.5% each.
iii) Gaussian noise with a standard deviation of 1% (typical value) was added to each time instant in order to represent the accuracy of the measurement equipment.

In what concerns the microgeneration data, several different profiles were used in the simulations. Based on real data gathered from a meteorological station, the profiles were firstly arranged in five different groups, representative of the most common daily sky conditions (e.g. clear sky, few clouds, overcast clouds, etc.). Each one of the groups created is composed in average by four different profiles. For each group of profiles, the average probability of occurrence during the season under study (time range between 1st of March and 30th of September) was computed. The calculations were performed according to real French meteorological data available from 2014. Afterwards, for each day in the time range under study, a microgeneration profile was randomly assigned to the microgeneration units according to the probabilities calculated before. It is important to note that the profiles belonging to a given group (clear sky, few clouds, overcast clouds, etc.) have exactly the same probability to be chosen. Moreover, considering the area usually covered by a LV network as the one under study, it was assumed that the microgeneration units were geographically close, thus all units connected to the network follow the same profile in a given day (profiles are expressed in percentage of units peak power). Nevertheless, in order to introduce additional variability in the microgeneration profiles, a Gaussian distribution with an average equal to the microgeneration profile assigned and a standard deviation of 4% was applied.

In the power flow simulations, the voltage at the reference node, i.e. the low voltage side of a MV/LV substation, was assumed to vary in a small range as it is usually verified in the LV side of a real MV/LV substation. In this sense, voltage variations were introduced per phase and taking into account the inversely proportional behaviour between voltage and power consumption. The maximum values at the reference node in each phase were assumed to occur when the power injected by the MV upstream network was at the lowest values (low load demand and high microgeneration production if available). Conversely, the minimum voltages values at the reference level were considered for time instants where the power injected by the MV upstream network was at the highest values. Moreover, the maximum and minimum values for each phase at the reference node were settled down in such a way that the voltage values in all the downstream network nodes did not exceed +/-10% of the nominal voltage, i.e., were within a range of 207 V – 253 V. For the other operational points, voltage at the reference level was calculated per phase through the use of a linear interpolation. Later, in order to have more realistic voltage profiles, Gaussian noise with a standard deviation of 1% was also added.

Six months of simulated data were then generated according to the information described before. The historical database was divided in two sets: the last week (1008 samples) was

used for the evaluation set and the remaining (25344 samples) was used for training purposes.
The results shown in section 3.3.3.1 are referred to the evaluation set.

3.1.3.2 Definition of the Number of Smart Meters with Real-time Capabilities

Unlike the Portuguese network where a real historical database was available, a different approach was followed with the French LV network in order to determine the number of SM_r. The approach consisted on iteratively replacing the existing SM by SM_r in the nodes with the largest Mean Absolute Error (MAE) until an acceptable value for the MAE was obtained. Whenever such network nodes had several SM (customers) connected to, the SM that led to a lower MAE was the only one replaced by a SM_r. It should be stated that as there was no information that allows relating the consumers with the producers as a unique customer, they were treated separately.

Although this methodology could be better than distribute SM_r in a randomly way, it was not totally optimised, since the optimal combination of SM_r (for a given number of SM_r) was not considered.

3.1.4 MV French network

The French MV network considered for the study of the CCS Tool consisted in two parts: each is made by a primary substation and two feeders. They are configured for radial service but some interconnecting branches are present in order to perform reconfiguration.
For ease of computing each network/feeder was simulated on its own but in the analysis reported in the following the availability of interconnecting branches was exploited for create hypothetical new grid configurations to cope with selected contingencies.
Figure 29 and Figure 30 show the schematic topology of these networks. The red dots represents the wind generators while the green dots highlight the interconnection nodes for back-up feeding.

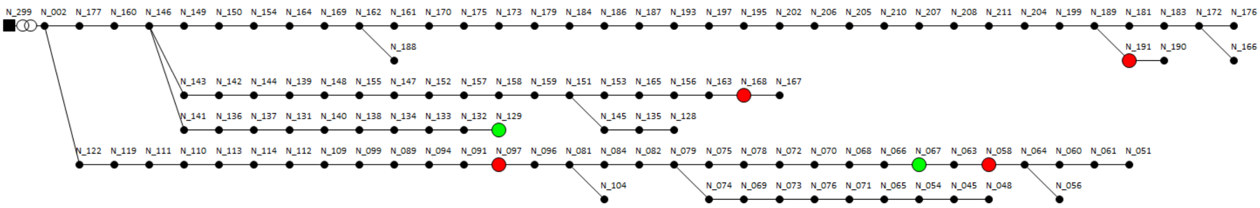


Figure 29: Network #1 – Contingency Co-Simulation Tool (CCS Tool)

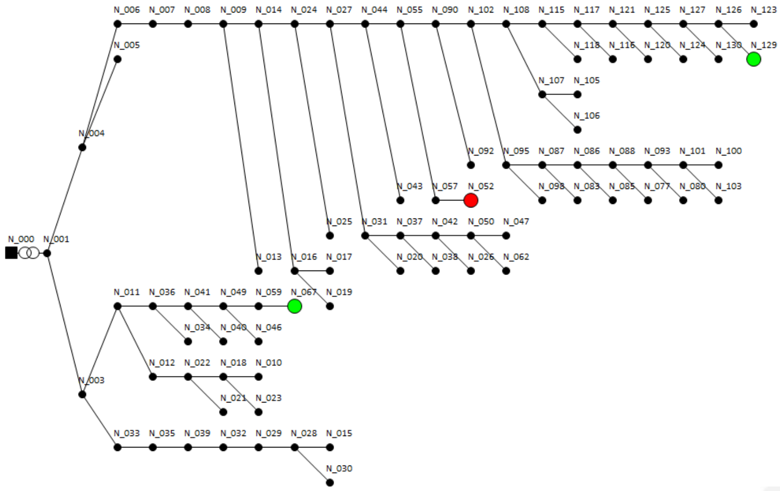


Figure 30: Network #2 – Contingency Co-Simulation Tool (CCS Tool)

The first network is fed by two 36MVA 63/20kV OLTC transformers, one for each feeder, with a 53,3% load-in. The OLTC is installed on the secondary MV winding and the windings have a wye-wye connection. This network has 113 MV nodes and 115 branches; 4 wind plants and a total of 107 loads (12 industrial and 95 aggregated) are connected to it.
The second network is smallest: it has 86 nodes and 85 branches, and feeds 51 loads (9 industrial and 42 aggregated). The primary substation has the same configuration of the previous one except for the transformers power (20MVA) and load-in (68,3 %). Only one wind plant is connected to this network.

3.1.4.1 Database

In addition to network topology data, profiles data, reliability data and weather/site data have been employed in the following tests.
Generation profiles were obtained as average curves from historical databases of power generation and wind speed yearly series related to 2011 to 2014 time period; from these series have been computed daily, weekly and monthly profiles.
The aggregated loads mentioned before are made by residential (80%) and commercial loads (20%). Some small power MV loads are also present, presumably of agricultural type. Since the average load profiles given are divided per number of customers connected at node, regardless the type of the load, 4 mixed residential/commercial average profiles have been compiled merging together profiles which are very close in shape. For industrial loads another specific average profile has been considered. Since no EV charging load profiles can be obtained, some generic profiles were compiled. All the time series given are in step of one hour or half an hour; when necessary they were interpolated for build quarter an hour daily profiles.
The Contingency selection module based on a Monte-Carlo Simulation algorithm needs reliability information regarding the various network objects/devices; some of these data were derived from average values related to French MV grids, while for the missing parameters reasonable average values applicable for this type of grids were considered. These quantities are summarized in Table 24.

Table 24 - CCS Tool – Reliability parameters

	OH line	UG line	PS trafo	PS	Wind plant
Life (years)	40	40	25	25	-
MTTR(h)	4	10	48	48	80
MTTF(h)	-	-	-	-	3000
N° of faults (faults/year)	7	1,2	0,1	-	-
N° of COD (faults/year)	-	-	-	0,01	-

The Co-simulation analysis requires weather and site information (like psychrometric curves and soil impedance) for model the terrain and environment behaviour in respect to ICT transmission. All these data were derived from anonymized data of locations similar to that of the test network.

3.2 Test Cases Description and Hypothesis

3.2.1 Robust Short-Term Economic Optimization Tool for Operational Planning

Test Cases Description

For the Robust Economic Optimization tool for Operational Planning (OP tool), given the Atlantide network elaborated before, three test cases were created. They correspond to the status quo (2012), short-term scenario (2018) and mid-term scenario (2023) for Italy.

Table 25 presents the different test cases. The values presented correspond to the "connected" values of the parameters. There is one test case for each scenario, and the terms test case, and scenario are used interchangeably in the context of this tool.

Data \ Scenario	Given Network	Status Quo (2012)	Short-Term (2018)	Mid-Term (2023)
Connected Load	29.74 MW	27.32 MW	26.8 MW	27.2 MW
PV Generation	8.82 MW	7.75 MW	12.45 MW	17.2 MW
Wind Generation	11.38 MW	2.31 MW	3.21 MW	3.96 MW
Storage	-	1 MW / 1 MWh	2 MW / 1 MWh	2 MW / 2 MWh
Combined Heat and Power Generation	13.67 MW	13.67 MW	13.67 MW	13.67 MW

Table 25 - OP Tool - Values for Parameters in Test Cases.

The values for these parameters were calculated with the information available in deliverable D1.1, which defines a limited and representative set of future scenarios, and in the task T1.1 survey. The link for each parameter's value with respect to these documents is established below.

Connected Load

The connected load in the network comprises three different types of loads namely residential (RES), industrial (IND), and commercial (COM). The D1.1 section dedicated to Italy only provides information regarding the evolution of the connected load in the entire electrical network. There is no specific information available for distribution networks alone. However, in the T1.1 survey for Italy, the evolution of residential loads in distribution networks is indicated. This evolution is extrapolated to industrial and commercial loads, which provides the final connected load values for the three test cases. Each load in the network is multiplied with a conversion factor in order to adhere to the scenario values. For load profiles, the profiles provided in the Atlantide libraries is taken into account.

PV Generation

For PV generation, D1.1 provides the total amount of PV generation connected to all distribution networks in Italy. For the 2012 scenario, it stands at 15.5 GW. For the 2018 and 2023 scenarios, it is 24.9 GW and 34.4 GW respectively. Considering that the number of HV/MV substations in Italy is 2000, and that the PV generation is equally spread over the 2000 distribution networks, we arrive at connected PV generation values for the test network.

Wind Generation

For Wind generation, D1.1 provides the total amount connected to distribution networks in Italy for the status quo and mid-term scenarios. They are 0.7 GW and 1.2 GW, respectively. However, by following the same approach as that of PV generation, the connected wind generation turns out to be extremely low (0.35 MW and 0.6 MW, respectively).

Therefore, a second methodology was developed to calculate the connected wind generation. This methodology relies on the connection rules for wind power in Italy, which allow wind farms of up to 10MW to connect to the distribution network. In the report [17], it is mentioned that in 2012, a total of 810 wind generators were connected to the distribution network, with a total installed capacity of 623.7 MW. This translates to an average generator size of 0.77 MW.

Based on this information, the three wind generators in the network were resized to obtain installed capacity values of 0.141 MW, 0.405 MW, and 1.762 MW, respectively. The total installed capacity for the wind generators in the status quo scenario is therefore 2.308 MW. For the short and mid-term scenarios, the installed capacity is considered to follow the evolution in D1.1, providing values of 3.21 MW and 3.96 MW.

Storage

The given network possesses no storage systems. In D1.1, three different capacities for storage systems are presented. These capacities are considered to be installed at the primary substation for the three different scenarios.

Combined Heat and Power Generation
There is no information regarding the evolution of combined heat and power generation in either the deliverable D1.1 or the T1.1 survey. Therefore, the installed capacity of the CHP is not considered to vary in the three test cases.

Hypotheses

In order to simulate the given network with the OP tool, many hypotheses were made. These mainly concern the amount and type of flexibilities, the regulatory framework in place, and the market rules, and are elaborated below.

Flexibilities
The hypotheses made for the amount, type, and location of flexibilities is elucidated Table 26. It is to be noted that the costs of the use of the flexibilities have been calculated with the help of the methodology included in ANNEX I – Methodology for Flexibility Cost Calculation of this deliverable.

Flexibility \ Scenario	Status Quo (2012)	Short-Term (2018)	Mid-Term (2023)
OLTC	Available in Primary Substation	Available in Primary Substation	Available in Primary Substation
Storage	Available in Primary Substation. Maximum Charging / Discharging rate of 1 MW/h.	Available in Primary Substation. Maximum Charging / Discharging rate of 1 MW/h.	Available in Primary Substation. Maximum Charging / Discharging rate of 2 MW/h.
DRES Curtailment	All DRES generators participate, up to 100% of produced power at each time step.	All DRES generators participate, up to 100% of produced power at each time step.	All DRES generators participate, up to 100% of produced power at each time step.
DRES Reactive Power Compensation	All DRES generators participate, with a power factor limit of 0.8.	All DRES generators participate, with a power factor limit of 0.8.	All DRES generators participate, with a power factor limit of 0.8.
Load Modulation	17 curtailable loads. Load increase up to 10% or 20%, and decrease up to 10% or 70%, depending on time period.	17 curtailable loads. Load increase up to 10% or 20%, and decrease up to 10% or 70%, depending on time period.	22 curtailable loads. Load increase up to 10% or 20%, and decrease up to 10% or 70%, depending on time period.
Combined Heat and Power Generation	All CHPs participate, curtailable up to 100% of the produced power at each time step.	All CHPs participate, curtailable up to 100% of the produced power at each time step.	All CHPs participate, curtailable up to 100% of the produced power at each time step.

Table 26 - OP Tool - Estimation of Flexibilities for Scenarios.

Regulatory Framework and Market Rules

For the tool to function, the regulatory framework has to allow the establishment of a market-like portal where the flexibilities in the network can be traded. This portal has to be specific to a particular distribution network, and the only client has to be the Distribution System Operator. Also, the DSO should be able to exploit these flexibilities as long as an offer for such flexibility is made.

Cost of Flexibilities

For the OP tool, the cost ranges for flexibilities used are presented in Table 27. The costs were calculated based on the common methodology presented in ANNEX I – Methodology for Flexibility Cost Calculation of this deliverable.

Flexibility \ Scenario	Status Quo (2012)	Short-Term (2018)	Mid-Term (2023)
OLTC	31.55 €/tap change(1)	38.25 €/tap change(1)	45.53 €/tap change(1)
Storage	Buy: -486 to -406 €/MWh (DSO pays to store energy) Sell: 600 to 680 €/MWh	Buy: -247 to -195 €/MWh (DSO pays to store energy) Sell: 304 to 366 €/MWh	Buy: -57 to -0.2 €/MWh (DSO pays to store energy) Sell: 113 to 170 €/MWh
DRES Curtailment	324 to 404 €/MWh	217 to 270 €/MWh	163 to 220 €/MWh
DRES Reactive Power Compensation	2.8 to 6.9 €/MVArh	1.7 to 4.3 €/MVArh	1.4 to 4.2 €/MVArh
Load Modulation	Load Decrease: 45 €/MWh Load Increase: 30 €/MWh	Load Decrease: 45 €/MWh Load Increase: 30 €/MWh	Load Decrease: 45 €/MWh Load Increase: 30 €/MWh
CHP Curtailment	28 to 108 €/MWh	8.5 to 61 €/MWh	8 to 65 €/MWh

(1) For the On-Load Tap Changer, the cost per operation was calculated through the equations presented in the second methodology for HV/MV OLTCs in Annex I. The unit cost per MVA for the transformer was considered to be 9500 €, with the depreciation of the transformer being non-linear (depreciation factor of 1.05), maintenance cost equal to half the cost of the transformer, one operation per day allowed, and 10000 operations before maintenance.

Table 27 - OP Tool - Cost Ranges for Flexibilities.

List of Operational and EEGI KPIs

As defined in D3.2 and in D5.1, the operational and EEGI KPIs for the OP Tool, along with the concerned sub-tool / module are listed in Table 28. The results of the impact assessment done with these KPIs is presented along with the results.

Sl. No.	Name of KPI	KPI Type	Calculated for
1.	Increased RES and DER hosting capacity	EEGI KPI	OP Tool

2.	Increased Use of Sources of Flexibility by DSOs	Operational KPI	Economic Analysis Module
3.	Voltage Profiles Quality	Operational KPI	RSE Optimization Routine
4.	Efficiency Improvement Optimization	Operational KPI	VITO Optimization Routine

Table 28 - OP Tool - List of EEGI and Operational KPIs.

3.2.2 Network Reliability Tool - Replay

The Replay is an off line SCADA system that can support the control room operators and back office operators in short term operation analysis. In particular, as described in the D3.2, the Replay performs network analysis reproducing the grid and its dynamics with a high fidelity representation and using a real time approach. The tool could be used by the control center operators as well as the back office specialists.

Two types of analysis are envisaged: 1) ex-post analysis and 2) predictive analysis. The first one is mainly related to the aspects of quality of service in particular the purpose of this functionality is the observation of the occurred events, alarms, faults and other criticalities , i.e. the analysis of the signals collected from the fie and recorded in the SCADA database.

The Replay tool within the evolvDSO project will be used as a support to network management activities, therefore a subset of the signals available to the operator have been chosen from the complete list available within the SCADA operator interface with the aim to focus on electric faults and electric aspects of the network.

In the present section a general overview of the test cases is given. All the test are realized in the Enel Distribuzione Smart grid Lab in Milano, in view of the implementation in real operation environment with didactical and analysis purpose.

The scope of the testing phase is testing the network of Cagliari (Sardegna - Partial Scheme: 8 primary substations). In particular an MV line with MV customers and producers has been selected.

In the following section a schematic representation of the test is proposed.

1. **Real Operation System**

A simulation of real condition in a network has been carried out to test the functionalities of the Replay:

- Selection of an MV Line with active and passive customers (NTW dB of Cagliari);
- Selection of a defined time interval in the past considering a long interruption (t>3min);
- Visualization of the list of events created by the simulator;
- Visualization of the NTW scheme on the basis of the list of events;
- Visualization on the RETIM tool of the data related to the selected interruption (SAIDI).

2. **Replay System Simulation**

In the current section a specific test in the Replay system is created to verify that the tool is able to reproduce the same conditions and to copy the events of the Real Operation System:

- NTW dB considered: the same NTW section in the real operation system
- Selected time interval in the past considering a long interruption (t>3min);
- Visualization of the list of events in the Replay System
- Visualization of the NTW scheme in the Replay System

The test consists in verifying the correspondence between the events occurred in the real system and the representation of network scheme and protocol event given by the replay tool.

3. **Replay System-*ex post* analysis**

In the third group an ex-post analysis has been carried out by the observation of the list of event in the past and the analysis of the RETIM data related to the quality of service.

In the second phase a new network configuration is applied in order to reduce the SAIDI compared with the initial value shown by the real operation system.

The test consist in the giving evidence of the realized operations on the NTW scheme and visualizing the potential advantages of acting the new operations strategy.

4. **Replay System *predictive* analysis**

The fourth test consists in the solution of criticalities on the network (over current and voltage violations) by acting on the following levers:

- Network configuration: possibility to open and close MV breakers on the network changing;

- Network power modulation: possibility to change the injection power customer and producer.

In the predictive analysis (short time), the innovative assumption is the possibility to introduce non-firm contracts to let DSOs the opportunity to change the active power injection under specific conditions. The hypothesis implies that all the specific conditions must be agreed with the customer through bilateral contracts.
It is important to highlight that in the current Italian regulatory framework, there is no possibility to activate flexible contracts modulating active power, consequently testing scenarios for the D3.4 are built on the basis of theoretical cases where producers and customers give availability to power modulations.
All the contractual aspects are out of the scope of the document as well as the remuneration aspects.

Regarding the penetration of RES and data load related to the customer connected to the considered MV line, they are presented directly in the test with table and sheet elaborated by the Replay.

3.2.3 Low Voltage Distribution State Estimator

Regarding the Portuguese LV network, the two scenarios described in section 3.1.2.2 were considered. Although the scenario with 6 SM with the capability of transmitting data in real-time was the one that is going to be installed in the field, the scenario with 12 SM_r was still considered for comparison purposes. A third scenario with the same SM_r as in scenario 2, but where active power quantities were estimated too was also considered.
In Table 29 for each scenario is summarised:

- the number of real-time measurements existing in the network (computed from the SM_r available in the network in each scenario);
- the total number of variables to be estimated;
- the m/n factor that gives the relation between the two previous quantities (expressed in percentage).

Scenario	Number of SM_r	Number of real-time measurements (m)	Number of variables to be estimated (n)	m/n (%)
1	6	23	36	63.9
2	12	41	30	136.7
3	12	41	49	83.7

Table 29 - Real-time measurements scenarios for Portugal.

Regarding the French LV network, as described in section 3.1.3, the definition of SM_r consisted in iteratively considering the node locations with the largest MAE until an acceptable MAE value was obtained. Twenty SM_r was the number required to meet the established MAE target. Table 30 is similar to the presented for the Portuguese case, but it also shows the customers ID that own SM_r.

<table>
<tr><th>Scenario</th><th>Number of SM_r</th><th>Number of real-time measurements (m)</th><th>Number of variables to be estimated (n)</th><th>m/n (%)</th><th>Customer ID</th></tr>
<tr><td>1</td><td>5</td><td>24</td><td>150</td><td>16.0</td><td>L135 - L131 - L139 - L144 - L103</td></tr>
<tr><td>2</td><td>10</td><td>38</td><td>143</td><td>26.6</td><td>L135 - L131 - L139 - L144 - L103 - L125 - G6 - L37 - L114 - L1</td></tr>
<tr><td>3</td><td>15</td><td>48</td><td>138</td><td>34.8</td><td>L135 - L131 - L139 - L144 - L103 - L125 - G6 - L37 - L114 - L1 - G10 - L64 - L13 - L66 - L121</td></tr>
<tr><td>4</td><td>20</td><td>58</td><td>133</td><td>43.6</td><td rowspan="2">L135 - L131 - L139 - L144 - L103 - L125 - G6 - L37 - L114 - L1 - G10 - L64 - L13 - L66 - L121 - G3 - L107 - L102 - G9 - L110</td></tr>
<tr><td>5</td><td>20</td><td>58</td><td>266</td><td>21.8</td></tr>
</table>

Table 30 - Real-time measurements scenarios for France.

As it can be seen in Table 30, a total of five scenarios were considered for study purposes. In the first three, the number of SM_r stays below the number of SM_r required to meet the MAE target defined as acceptable for voltage values. This goal is only achieved in scenario 4. The first three scenarios were thus considered only for comparison purposes. A variant of the scenario 4, scenario 5, was also considered with the aim of demonstrating the capability of the LV distribution state estimator (DSE) to estimate active power values as well.

In order to assess the influence of the quantity of historical data used for training the estimator on the state estimation accuracy, the training process was run several times with variations on the amount of historical data used; namely, the tests were carried out for scenario 4 with historical databases corresponding to 3 months, 1 month and 1 week of data.

It is important to state that for both study cases, the Portuguese case and the French one, it was considered that the MV/LV secondary substation held a Distribution Transformer Controller (DTC) which has, among other functions, the SM information concentrator function – like an head-end server. Furthermore, the associated measurement equipment with the capability of monitoring in real-time the active and reactive power flows in the transformer (when available) and the voltage magnitude at the LV side of the transformer was also assumed.

Several Key Performance Indicators (KPIs) were computed in order to assess this tool accuracy and performance, as described in *deliverable D3.2*. Table 31 the list of KPIs used for this tool is summarised.

KPI ID	KPI Name	Unit of measurement
1	Accuracy of active and reactive branch power flow	Kilowatt (kW) and KiloVAr (kVAr)
2	Accuracy of active and reactive bus power injections	Kilowatt (kW) and KiloVAr (kVAr)
3	Accuracy of voltage	Volt (V)
4	Error Estimation Index (EEI)	-
5	Ability to accurately discern measurements	Percentage (%)

Table 31 – List of KPIs.

It should be noted that the estimation of voltage phase angles was not performed since the metering devices do not have the capability to measure such variables. Therefore, in the KPI ID 3 calculation, only the voltage magnitude values were considered. For the same reason, the active branch power flow could not be computed and, consequently, the KPI ID 1 could not be calculated. Moreover, in the scope of this study, the estimation of the reactive power was not performed, thus the KPIs with ID 2, ID 4 and ID 5 were calculated only taking into account active power values.

Regarding specifically the Portuguese LV network, as its historical database was composed by real data records, these data were used in the KPIs calculation as the “true values” otherwise their computation would not be possible. For this reason, the calculation of the KPI with ID 5 was not performed for the Portuguese case.

Recalling that the mathematical expressions related with the KPI ID 2 for the 1-norm and 2-norm involve a sum of errors (see *deliverable D3.2*), which depends on the number of customers present in the network, it is evident that this KPI enables only comparisons in relative terms. In this sense, the main goal of this KPI is the evaluation of accuracy either between scenarios with a different amount of SM_r for a given DSE or to compare different DSE tools under the same network conditions and scenarios. These considerations are also valid for the KPI with ID 3. Therefore, since the results achieved for these KPIs should not be seen in absolute terms, no conclusions should be made regarding the degree of accuracy on the estimation of the related electrical quantities.

Differently from 1-norm and 2-norm, the infinity norm associated with the KPI ID 2 allows taking some conclusions about the DSE accuracy, since the mathematical expression of this norm does not involve a sum of errors, but is related with maximum absolute errors.

3.2.4 Low Voltage Control

For the LVC tool, described in deliverable D3.2, a set of test cases were defined in order to test the efficiency of the proposed methodology considering the proposed networks. For each of the networks, the three scenarios defined in WP1 were tested considering different penetration of RES, load growth and flexibility regarding the data presented also in WP1 for each country, for the different time frames.
Within each of the WP1 scenarios, a situation of overvoltage and undervoltage was considered. Both the state estimation and the smart power flow as a simulation platform in the LVC were tested in order to assess the performance of the tool. The different approaches to the proposed test cases are explained in detail in the following subsections. In Table 32 and Table 33, a summary of the test cases for the French and Portuguese networks is shown, illustrating which situation and which method was used in each test case. Regarding the Portuguese network, for the *Status Quo* scenario the LVC tool with Smart Power Flow was not tested due to the lack of important information related with the network, namely the connection phases of some single phase costumers and the insistence of historical data records for active and reactive power measurements.

WP1 Scenarios	Status Quo		Mid-term Forecast		Long-term Forecast	
1-Overvoltage 2-Undervoltage	A1	A2	B1	B2	C1	C2
State Estimation	X	X	-	-	-	-
Smart Power Flow	X	X	X	X	X	X

Table 32 – Test case summary for the Portuguese network.

WP1 Scenarios	Status Quo		Mid-term Forecast		Long-term Forecast	
1-Overvoltage 2-Undervoltage	A1	A2	B1	B2	C1	C2
State Estimation	X	X				
Smart Power Flow	-	-	X	X	X	X

Table 33 – Test case summary for the French network.

As defined in *deliverable D3.2*, the LVC tool uses flexibility costs associated to each equipment type, which are used as input data to calculate the given rank in the merit order. These flexibility costs are described in full detail in ANNEX I – Methodology for Flexibility Cost Calculation.

Moreover, several KPIs were used in order to evaluate the benefits from using the proposed methodology. A detailed description list of the KPIs was included in *deliverable D3.2* and a summary of the relevant KPIs is presented in Table 34.

KPI index	KPI name	Unit of measurement
1	Increase RES and DER hosting capacity	Percentage of increased hosting capacity in kW (%)
2	Reduced energy Curtailment of RES and DER	Percentage of reduction of energy curtailed in kWh (%)
3	Increased hosting capacity for electric vehicles and other loads	Percentage of increased hosting capacity in kW (%)
4	Reduction of Technical Losses	Percentage of energy (%)
5	Share of Electrical Energy produced by RES	Percentage of energy (%)
6	Voltage Deviation index	Percentage of the voltage deviation index (%)
7	Quantify the number of regularized voltage deviations	Percentage of voltage violations in the network (%)

Table 34 - KPIs description.

3.2.4.1 Test Case A1

This test case refers to the WP1 Scenario representing the *Status Quo* of the network exploration. A historical database of the network measurements is available containing different snapshots of the network state for an extended period of time. For simulation purposes, a situation period where an overvoltage (and an undervoltage for **Test Case A2**) occurs is identified and imported to the LVC tool as if it were the actual network measurements.
It is considered that all the resources presented in the network are flexible resources, meaning that each resource is suitable to be controlled within the LVC. The complete list of all the resources available in the Status Quo scenario is in accordance with the characterization made in section 3.1.2 and section 3.1.3, respectively for the Portuguese and French networks.

For this scenario two different approaches were tested differing in the simulation tool used to test the selected set-points. This means that the same test case is simulated with the state estimation and with the smart power flow in order to enable a comparison between the two solutions. Once more, in the Portuguese network, for the *Status Quo* scenario, the LVC tool was tested based only on the results of the state estimation due the reasons already mentioned.

Since a historical database is available, the state estimation may be used to test the impact of the proposed set-points until the voltage deviation situation is managed. In this case it is considered that some meters do not have real time capability meaning that the respective measurements are estimated using the state estimation tool. The list of meters with real time capability can be observed in Table 29 and Table 30, respectively for the Portuguese and French networks

In the other approach, using the smart power flow, the knowledge of the full characteristics of the network is a pre-requisite.

3.2.4.2 Test Case A2

For this test case, the same methodology is used as in TEST CASE A1, for an undervoltage situation.

Similarly to the test case A1, for the French network, also two simulations are presented, one using the smart power flow and other using state estimation in order to manage the voltage deviation within the LVC, whereas for the Portuguese network only state estimation is used due to the reasons already stated presented in the test case A2.

3.2.4.3 Test Case B1

Test Case B1 refers to a WP1 scenario representing a mid-term forecast of the available networks for which different penetration of RES and load are presented. It is also considered the existence of flexible resources that in the test cases A1 and A2 were non-existent, such as storage devices and the MV/LV transformer with on-load-tap-change (OLTC) capability. This test case corresponds to the overvoltage scenario referred in test case A1 with the load and generation scaled to the proportion proposed in the mid-term forecast.

Since in this case it is not possible to have a real historical database for the future operational conditions of the network, only the smart power flow is used as the simulation platform for the remaining test cases.

3.2.4.4 Test Case B2

The same network exploration characteristics as stated for the "Test Case B1" and which are provided by WP1 mid-term scenario forecast are tested. In this particular test case, an under voltage occurrence is simulated.

3.2.4.5 Test Case C1

This test case refers to overvoltage scenario for a scenario where the RES and load penetration are scaled regarding the WP1 long-term scenario forecast. In this case more resources are assumed to be available for control within the LVC are connected to the grid, such as storage devices, meaning there is a higher flexibility for voltage control.

3.2.4.6 Test Case C2

Similar to the test case C1 in terms of the same network exploration characteristics, same network characteristics are used for an instance but instead of an overvoltage situation, an undervoltage situation is considered.

3.2.5 Contingency Co-simulation Tool

Test Cases Description

Given the network described before, considering the assumptions reported in deliverable D1.1 for France, five test cases were created for testing CCS Tool. They are all referred to the mid-term scenario (2025) and consider different flexibilities and load evolution. Table 35summarizes these Test Cases.

Table 35 - CCS Tool – Test Cases

Data	Given Network	Test 1	Test2	Test 3	Test 4	Test 5
Connected Load	16.46 MW	16.95 MW	15.96 MW	15.96 MW	15.96 MW	15.96 MW
Wind Generation	7.96 MW	14.34 MW	14.34 MW	14.34 MW	14.34 MW	14.34 MW
Industrial load flexibilities	-	0.5 MW	0.5 MW	0.5 MW	0.5 MW	0.5 MW
EV charging	-	-	-	2MW(at substation level)	-	-
Residential/ Commercial load flexibilities	-	-	-	-	-	0.5 MW

The parameters considered in these Test Cases have been defined starting from information available in deliverable D1.1 and obtained from the test network owner, ERDF. In the following assumptions made are explained in details.

Connected Load

Five different types of loads have been considered in the Test Cases, one for industrial loads (IND) and four for the aggregated loads (RCmix 1 to 4). These ones are obtained from the load profiles given at substation levels based on the number of connected customers. These aggregated loads are made up mainly by residential customers (80%) and commercial customers (20%). Most of the given load profiles are quite similar, so the profiles considered for the simulations are obtained as average profiles and four final profiles were selected.
In the France section of the D1.1 the forecasted trends for loads growth/decrease are reported; for the mid-term an increase (most likely scenario) or a decrease (under-expected/over-expected scenario) of 3% is foreseen. These trends have been modelled, respectively, in Test 1 and Test 2. Since no specific growth curve has been specified, the resulting values for tests were obtained by a linear increase/decrease of the nominal values given.

Wind Generation

For the French mid-term scenario, an increase of 82% of the installed capacity of wind plants is expected, as reported in D1.1.
Since no additional indications were given about the power generation increase, this extra capacity has been spread randomly through the already existing generators and one extra wind plant was created. Final capacities ranges from 1,02 MW to 7,492 MW.

EV charging
The only information about EV charging in the French mid-term scenario reported in D1.1 states that an high diffusion of charging stations is expected in the medium to long-term. Since no specific details are given, it was decided to consider 2MW for EV charging stations at substation level. This assumption has been translated in additional loads with dedicated profile, connected in parallel to all Res/Com loads with an average power of at least 30kW. The power size of EV charging loads has been fixed in 10% of the power value for the correspondent "master" aggregated loads. EV charging loads has their own load profile which has been defined taking in to account the information reported in Deliverable 9.3 of the EC project "Green eMotion".

Industrial Loads Modulation
For industrial load modulation, a power reduction of 0.5MW overall is allowed. Since the total power drained by industrial loads is 4.63 MW (average), the maximum modulation for the single load has been fixed to 10% of the average load power.

Aggregated Loads Modulation
Similarly to industrial loads also for aggregated load modulation, a power reduction of 0.5MW overall is allowed. In this case the total power of aggregated loads is 12.28 MW (average), the maximum modulation for the single load has been fixed to 4% of the average load power. The initial hypothesis states that this flexibilities should be implemented at substation level for LV aggregated loads; since no detailed data about LV aggregated loads are available for this network, it was decided to consider only aggregated loads correspondent to more than 3-4 customers, which can be reasonably considered as urban LV networks. Anyway, if the overall power reduction would be spread to all aggregated loads, this would result in a maximum modulation per load of 3%, not far away from the value chosen.

Hypotheses on regulatory framework, market rules and management policies

The hypotheses about regulatory framework and market rules behind the tests carried out for CCS Tool are similar to those made for the other i.e., briefly, the trade of flexibilities is allowed and their exploitation is technically feasible for the DSOs. Specific market rules are not considered for this tool since it doesn't deal with the economic aspects of flexibilities. On the other side knowledge about DSO standard policies for network management and flexibilities usage would be very helpful in particular for comparison with the results obtained from the tool. By the way, no specific information about these topics was available due to confidential rules. When necessary, reasonable hypotheses were made; they are explained in the test results section.

List of KPIs

As defined in D3.3 and in D5.1, the KPIs for the CCS Tool are listed in Table 28. Two KPIs, AUR time index and CS performance indexes, were not calculated for the described test cases. The AUR time index requires data on asset recovery and maintenance policies which is not available in the given dataset and could be assessed during the field tests covered by WP4. CS performance indexes cannot be calculated since they require specific historic data (MTTF, MTTR Gaussian distribution of the tested network) which is not available nor in the given dataset neither as a common reference from similar networks.

The results of the impact assessment done with KPIs is presented along with the results.

Table 36 - CCS Tool - List of KPIs

No.	Name of KPI	Calculated
1.	SAIDI variation index	Yes
2.	AUR time index	No
3.	Energy curtailment index	Yes
4.	CS performance indexes	No

3.3 Simulation Results of the Test Cases

3.3.1 Results for Italy

3.3.1.1 Robust Short Term Economic Optimization Tool for Operational Planning

In the network used in the simulations, severe under-voltage issues arise during a major part of the day, in all three tested scenarios (2012, 2018 and 2023), as shown in Figure 31 - Figure 33. Over-voltages or current congestions do not occur at any time step. In these baseline scenarios, it is assumed that the slack bus voltage of the distribution grid is set at 1 pu. In the tested network, bus 33 experiences the lowest voltages during the day. In order to conform to the general convention, all our simulation and optimisation processes divide the 24h-day into 96 periods of 15 minutes.

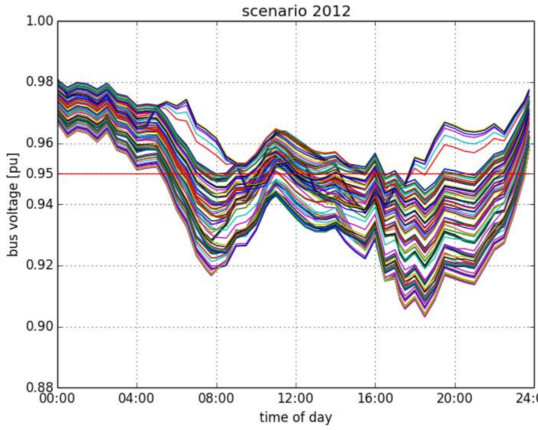


Figure 31 - OP Tool - Baseline scenario 2012: bus voltage magnitudes of all buses. The minimal allowed bus voltage is indicated as a red line.

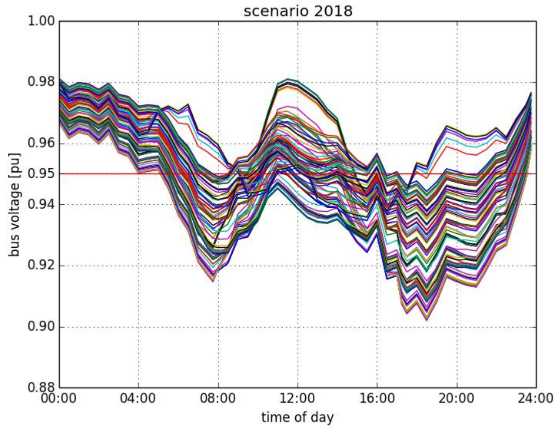


Figure 32 - OP Tool - Baseline scenario 2018: bus voltage magnitudes of all buses. The minimal allowed bus voltage is indicated as a red line.

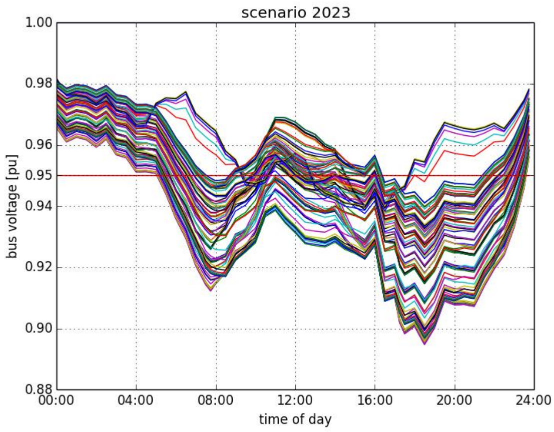


Figure 33 - OP Tool - Baseline scenario 2023: bus voltage magnitudes of all buses. The minimal allowed bus voltage is indicated as a red line.

Results from the VITO Optimization Routine

OLTC Presence

One of the levers to solve the voltage violations in the network is an On Load Tap Changer (OLTC). The optimal (i.e. cheapest) solution to solve the voltage issues in each scenario is to fix the OLTC tap to a certain higher value. In Figure 34-Figure 36, the bus voltages are shown with the OLTC tap set at 1.05 pu in each scenario. As can be seen, all under-voltage issues can in principle be solved using this lever alone. Based on the economic data given in Table 27, the cost of this solution would be 31.55 € for the 2012 scenario, 38.25 € for the 2018 scenario and 45.53 € for the 2023 scenario.

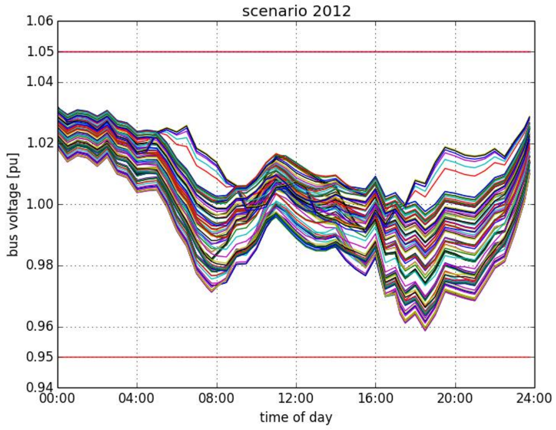


Figure 34 - OP Tool - Scenario 2012 with OLTC tap at 1.05 pu.: bus voltage magnitudes of all buses are shown. The minimal and maximal allowed bus voltage is indicated as a red line.

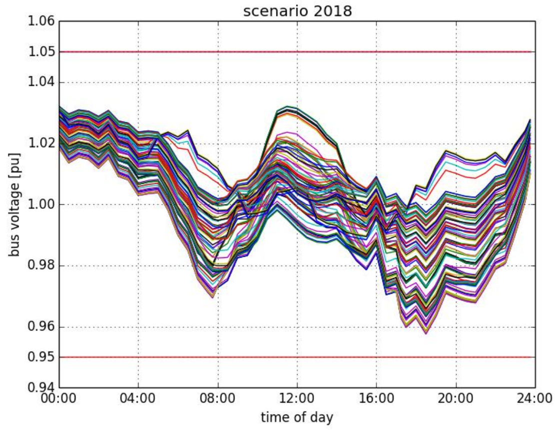


Figure 35 - OP Tool - Scenario 2018 with OLTC tap at 1.05 pu: bus voltage magnitudes of all buses are shown. The minimal and maximal allowed bus voltage is indicated as a red line.

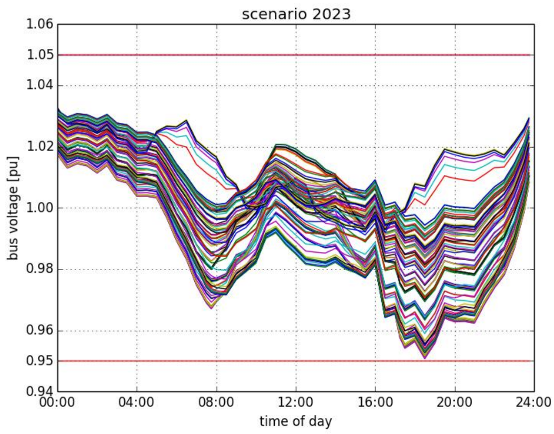


Figure 36 - OP Tool - Scenario 2023 with OLTC tap at 1.05 pu: bus voltage magnitudes of all buses are shown. The minimal and maximal allowed bus voltage is indicated as a red line.

No OLTC Presence

In order to extend the application domain of our algorithms and tools to also include more challenging and practical problems, we will assume in all the following simulations that the OLTC tap is fixed at a certain value in each scenario, and is not further used to solve the under-voltage issues. Flexibility from the other available levers (curtailable load, CHP, Wind and PV generators) is now used to solve the voltage issues as cost-effective as possible. In order to solve the violations using the VITO optimization routine, in the 2012 and 2018 scenarios, the OLTC tap is assumed to be fixed at 1.02 pu. In the 2023 scenario, the OLTC tap is fixed at 1.03 pu. It is assumed that the power factor of the wind and solar generators is restricted to a minimum of 0.8. The CHP is assumed to have no reactive flexibility. The power factor of the curtailable loads is assumed to be constant during curtailment. The output of the routine provides an optimal operational planning for an entire day, so that no network constraints are violated.

Status Quo Scenario (2012)

For the Status Quo scenario, the simulation results are shown in Figure 37-Figure 42. Figure 37 shows the baseline scenario, with OLTC tap setting fixed at 1.02 p.u. As shown in the figure, under voltage incidents are observed during morning-hours (around 8h00) and during evening hours as well. In total there are 1353 voltage issues during the day, the minimal voltage encountered is 0.925 p.u.

Figure 38 shows the voltage magnitudes after solving the optimal power flow problem: all under voltage incidents are solved. To solve the under voltages, curtailment of the generators was not used, as indicated in Figure 39, the power production curves before and after optimal power flow are exactly the same. Reactive power compensation from both wind power generators as well as PV generators was used as a lever, as shown in Figure 40. Since the power factor of the generators is constrained to 0.8, reactive power compensation is only possible when generators are producing.

This is why there is no reactive power compensation during the late evening hours of the PV installations. Figure 41 shows the curtailable load contribution to the optimal power flow solution. Finally, Figure 42 shows the variation of the cost to solve all under voltage issues during the day. The total cost of the solution is 584.6 €.

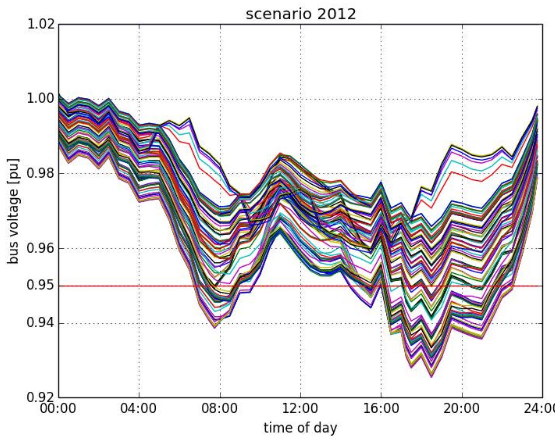


Figure 37 - OP Tool - Baseline scenario 2012 with OLTC tap at 1.02 pu: Bus voltage magnitudes of all buses are shown. The minimal allowed bus voltage is indicated as a red line.

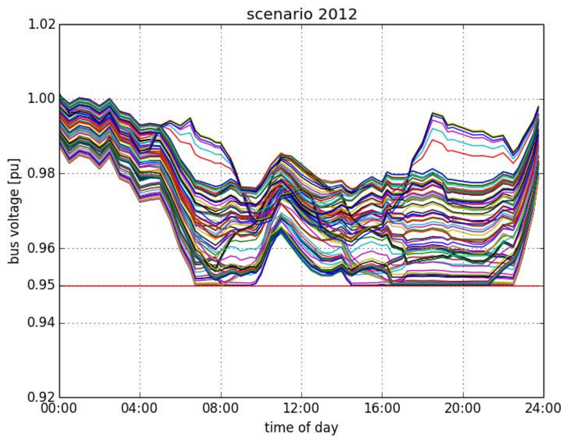


Figure 38 - OP Tool - Scenario 2012 after optimization: Bus voltage magnitudes of all buses are shown. The minimal allowed bus voltage is indicated as a red line.

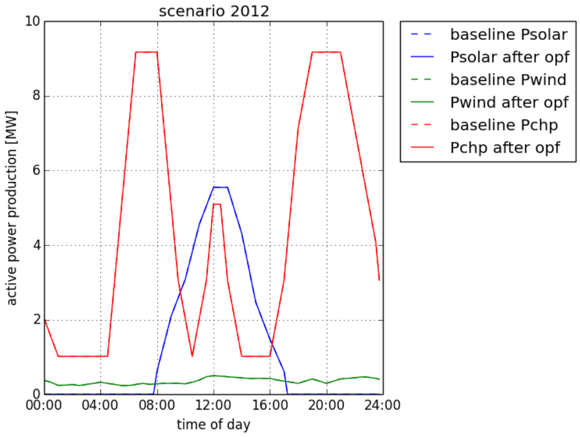


Figure 39 - OP Tool - Scenario 2012: Combined generated power by solar generators, wind generators and CHPs, before and after optimization.

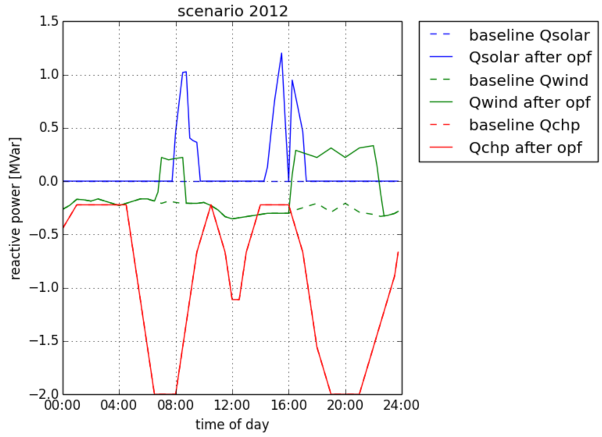


Figure 40 - OP Tool - Scenario 2012: Combined reactive power generated by solar generators, wind generators and CHPs, before and after optimization.

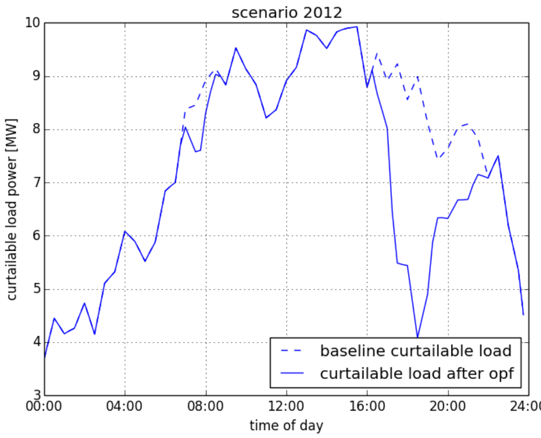


Figure 41 - OP Tool - Scenario 2012: Combined curtailable load power consumption, before and after optimization.

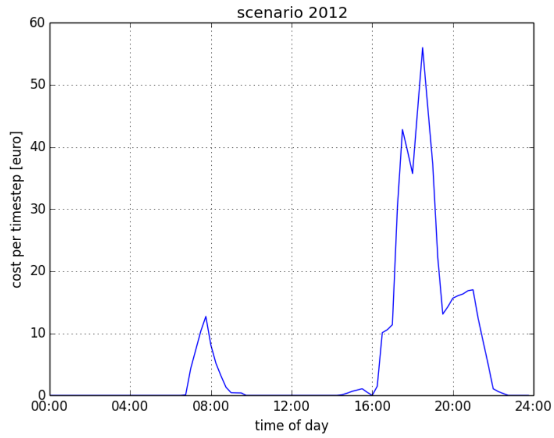


Figure 42 - OP Tool - Scenario 2012: Cost of OPF solution per time step.

Short-Term Scenario (2018)

The results for the short term scenario are shown in ANNEX III – Additional Results for Operational Domain.

The levers used to solve the under-voltage constraints in the 2018 scenario are the same as for the Status Quo scenario: reactive power compensation from wind and PV generators, and load curtailment. The total cost of the solution is 760.5 €. In comparison with the Status Quo scenario, more load curtailment and more reactive power compensation from the solar panels is needed, because in this Short-Term scenario, the load has increased, while wind power production is less.

Mid-Term Scenario (2023)

The results for the mid-term scenario are shown in ANNEX III – Additional Results for Operational Domain.

The levers used to solve the under-voltage constraints in the 2023 scenario are the same as for the Status Quo and Short-Term scenario: reactive power compensation from wind and PV generators, and load curtailment. The total cost of the solution is 592.7 €. The cost of the solution in comparison with the Short-Term scenario is less, because the load has decreased, while production from CHP's has increased. Consequently, less load curtailment and less reactive power compensation is required to solve the under voltage issues.

Mid-Term Scenario (2023) with Inter-temporal Constraints

The levers that can be used to solve grid congestions and voltage constraints in the previous scenarios do not contain any inter-temporal constraints. Inter-temporal constraints of flexible resources are constraints in which the actions taken at one time step have an influence on the availability of the resource on other time steps. Chances are that the number of flexible resources with inter-temporal constraints will be increasingly present. A common example of such flexible resources are shiftable loads, where the consumption profile of a load can only be shifted in time (as opposed to time-independent curtailment).

As explained in the deliverable D3.2, the operational planning tool developed is able to find an optimal solution which also includes inter-temporal constraints in the optimisation levers. In order to show the full capabilities of the tool developed, one load, a curtailable load in the original scenario, was changed to a load with inter temporal constraints, further called a modulable load, in the 2023 scenario. It is assumed that this modulable load is able to shift its consumption over time, i.e. consumption that is curtailed at one point in time, should be consumed later or earlier in time. This behaviour is simulated by adding a 'sinusoidal' load (with a predefined period and amplitude) to the original load. The operational planning tool should then find the optimal activation time of this modulation behaviour. The inspiration of the modelling of modulable loads as described here is based on the benchmark given in [16]. For the sake of simplicity it is assumed further on that activating the modulation of the load is free (zero cost).

As explained in D3.2, the VITO optimization routine uses a two-step approach. First, the load-flow equations (i.e. the network constraints) are linearized around a solution found by an optimal power flow of the baseline scenario, without including the inter-temporal constraints. Then, a constraint-programming (CP) search using the linearized load-flow equations, tries to find a better and cheaper solution by including the levers that have inter-temporal constraints. Finally, the constraint-programming solution is checked for feasibility by a full load-flow. As long as calculation time remains, this two-step search can be continued in an iterative way, allowing the CP-component to search different region in the solution space.

Figure 43 shows the linearized load flow results of the optimal solution found without inter-temporal constraints.

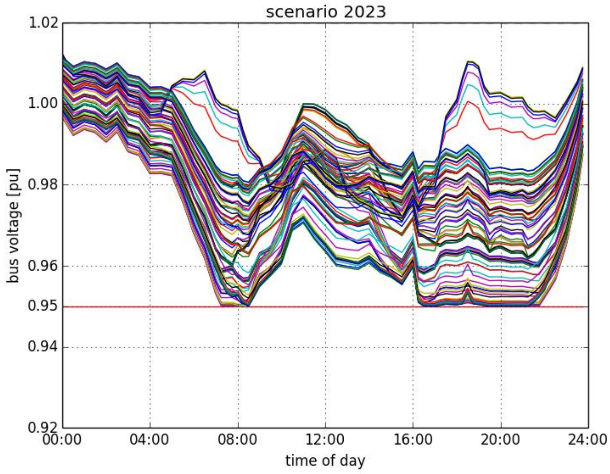


Figure 43 - OP Tool - Scenario 2023: Linearized load flow results of the OPF solution without inter-temporal constraints.

Figure 44 shows the optimal activation of a single modulable load: the load consumption is shifted towards mid-day, i.e. before the evening-load peak. The optimal modulation activation time is found to be at time step 45, i.e. at 11h15.

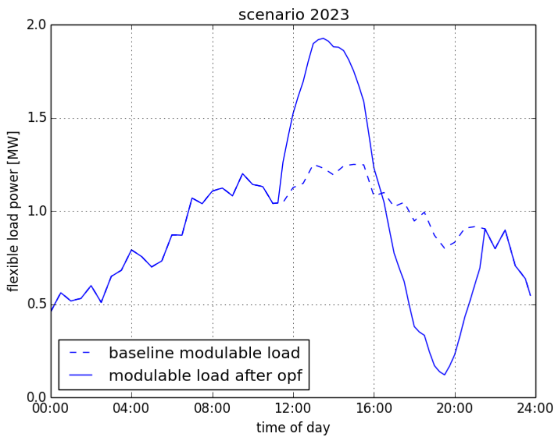


Figure 44 - OP Tool - Optimal activation of modulable load found by Constraint Programming.

The overall change in load of all flexible (i.e. curtailable and modulable) loads is shown in Figure 45. The flexible load consumption in the optimal solution without inter-temporal constraints is also shown.

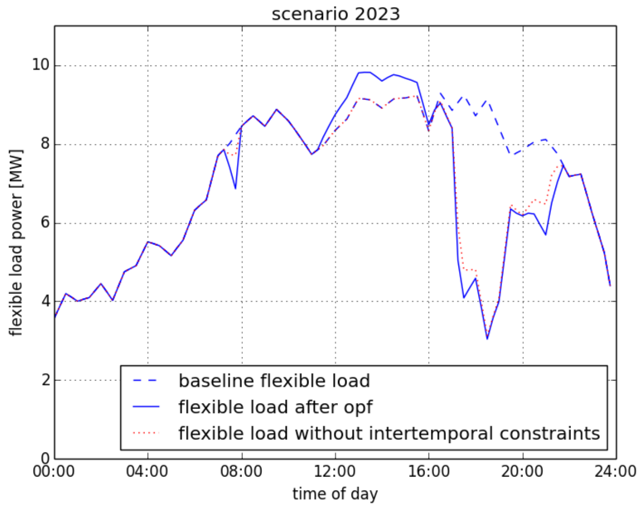


Figure 45 - OP Tool - Overall change in flexible load consumption (curtailable loads + modulable load) in constraint programming solution.

Figure 46 and Figure 47 show the combined active power, respectively reactive power generated by the power production resources in the network (solar generators, wind generators and CHPs).

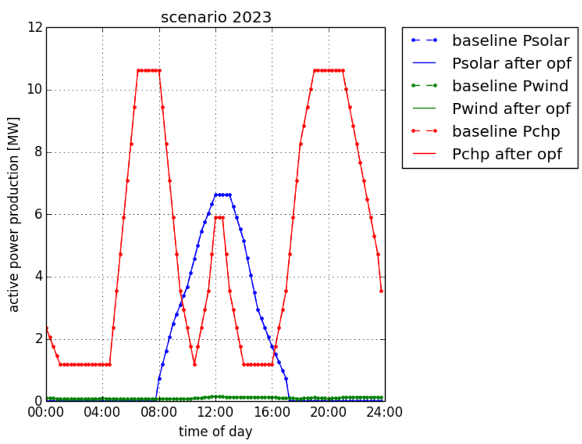


Figure 46 - OP Tool - Combined generated power by solar generators, wind generators and CHPs, before and after optimization with inter-temporal constraints.

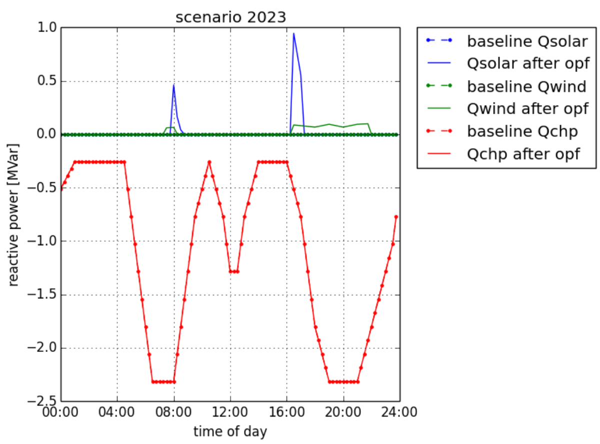


Figure 47 - OP Tool - Combined reactive power by solar generators, wind generators and CHPs, before and after optimization with inter-temporal constraints.

Since fewer loads need to be curtailed, because of the activation of the modulable load, the overall cost of the solution is lowered, as can be seen in Figure 48. The overall cost of the OPF solution including inter-temporal constraints is 561.7 euro (compared with 592.8 euro of the solution without inter-temporal constraints).

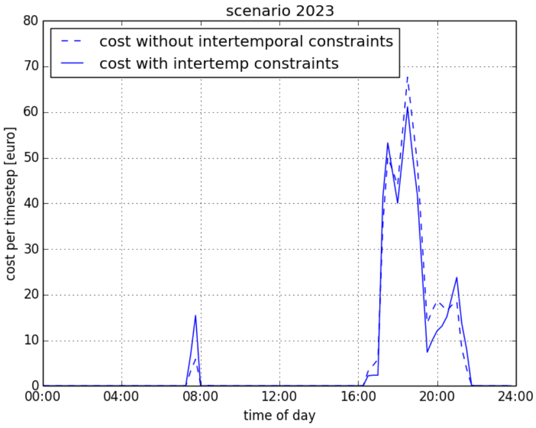


Figure 48: OP Tool - Cost per time step of the load flow solution including inter-temporal constraints. The cost of the solution without inter-temporal constraints is also included in the plot for reference.

Finally, the full load flow results confirm the feasibility of the found solution by the constraint programming search, as shown in Figure 49.

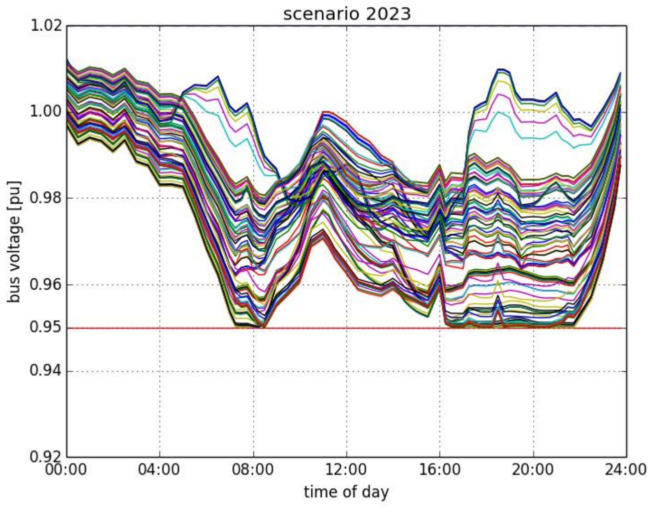


Figure 49 - OP Tool - Full load flow of OPF solution with inter-temporal constraints.

Results from the RSE Optimization Routine

As for the VITO optimization routine, the RSE optimizer considers the 24h day conventionally divided in 96 periods of 15' each. CHP generators do not provide reactive power support. For the RSE optimizer, the active power modulation is provided by loads - which can vary their active power profile - and by DGs - which can reduce the active power injection and provide reactive power support. The RSE optimizer in the following simulation uses mainly the modulation of the active power from loads, because the main congestions are under-voltages. Then, the only solution is to reduce the loads and increase the reactive power injection from generators. The results presented in the following are related to the optimization of the whole day. In each period the optimizer guarantees the respect of all the network constraints and that the network operates in an optimal operating point.

OLTC Presence

As shown by the VITO optimizer, the use of the OLTC can solve the voltage congestions by itself. When the voltage set point is fixed to 1.05 pu and the simulations are performed, it can be seen that no other resources are necessary for the network management: all the voltages respect the defined limits [1.05; 0.95]. Hence, the final cost is related to the change of the OLTC position in each scenario: 31.55 € in 2012, 38.25 € in 2018 and 45.53 € in 2023, see Table 27.

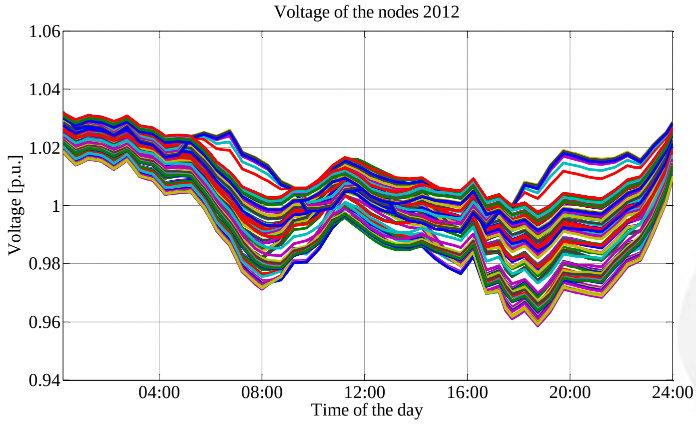


Figure 50 - OP Tool - Scenario 2012: Bus voltage magnitudes of all buses with OLTC tap at 1.05 pu

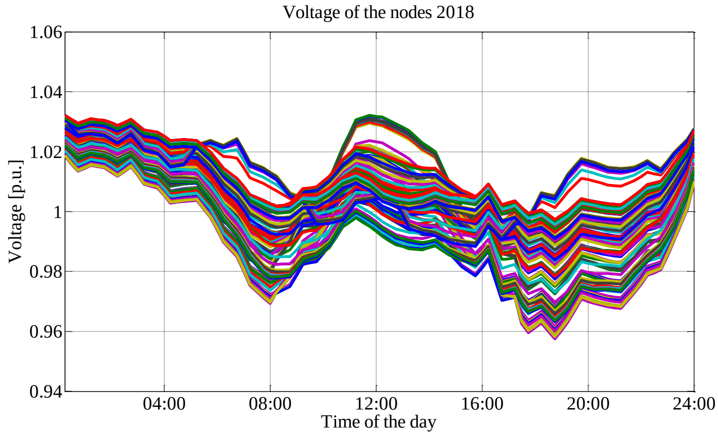


Figure 51 - OP Tool - Scenario 2018: Bus voltage magnitudes of all buses with OLTC tap at 1.05 pu

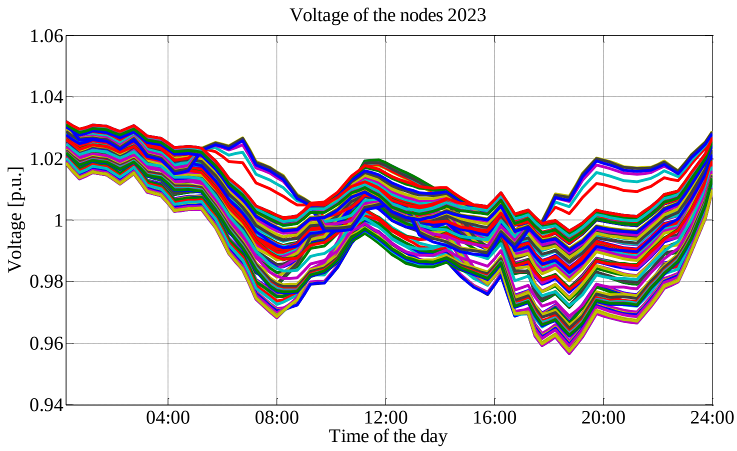


Figure 52 - OP Tool - Scenario 2023: Bus voltage magnitudes of all buses with OLTC tap at 1.05 pu

No OLTC Presence

Similar to the VITO optimizer, the results outlined from the analyses with a fixed value for the OLTC voltage are presented here. Due to the very high impact it has on the network operating conditions, the OLTC voltage is fixed for the RSE optimizer as well. For the three test scenarios, the OLTC voltage is set to 1.034 pu. It is expected that the other flexibilities available in the network (e.g. controllable loads and re-dispatchable generators) will intervene to support the network and respect constraints.

Status Quo Scenario (2012)

The results for the simulation of the 2012 scenario are presented from Figure 53 to Figure 56. 143 under-voltages are detected during the whole observation period and solved when the optimizer is activated, see Figure 53. Voltage violations are concentrated around 8.00 AM and the late afternoon/early evening. Load shedding intervenes only in the late afternoon and during peak loads when DG production is not available, Figure 54. In terms of reactive power, -Figure 55 - only wind generators provide support when under-voltages are experienced, leading to higher voltages. DGs provide a small contribution during the morning while, in the afternoon they provide more reactive support. DGs do not provide reactive power support when their production is zero. Finally, the cost for the RSE optimization in 2012 is 63.29 €.

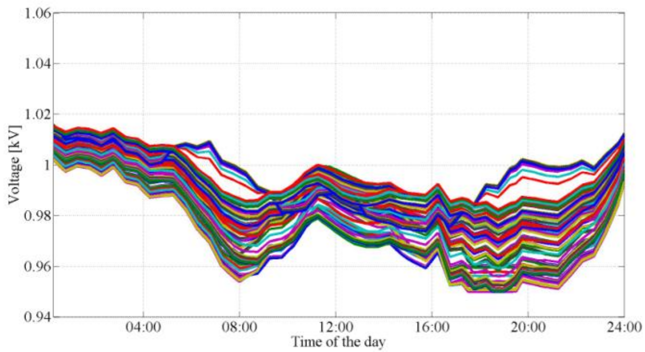


Figure 53 - OP Tool - Scenario 2012: Bus voltage magnitudes of all buses with OLTC tap at 1.034 pu

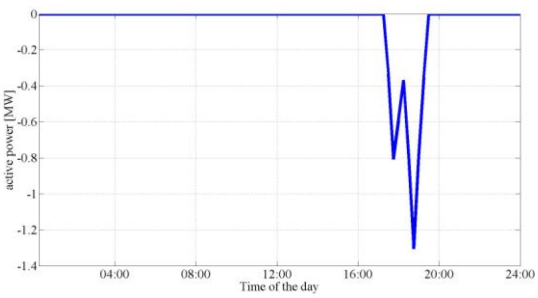


Figure 54 - OP Tool - Scenario 2012 - Active power modulation from loads. In the peak of load some load shedding is required.

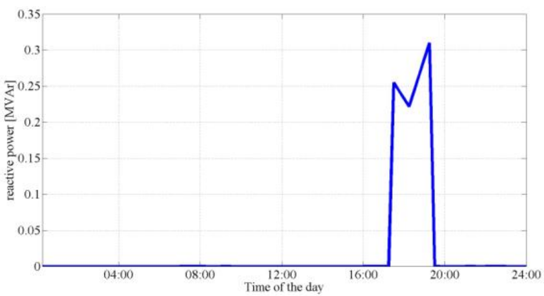


Figure 55 - OP Tool - Scenario 2012 - Reactive power modulation from generators. The reactive power is used to increase the voltage.

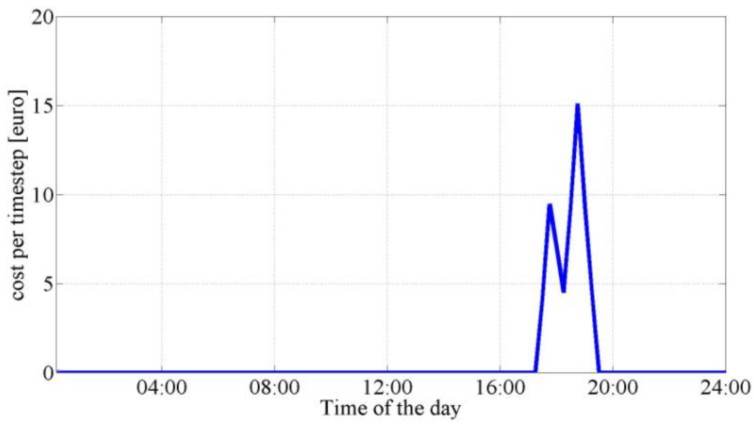


Figure 56 - OP Tool - Scenario 2012 - Cost of OPF solution per period

Short-Term Scenario (2018)

With respect to the 2012 scenario, in the 2018 scenario, higher load and DG penetration are envisaged. In these new conditions the RSE optimizer produces the outcomes presented from Figure 57Figure 58 to Figure 60. With respect to the Status Quo scenario, in 2018 the higher load and injection from DG lead to a higher number of voltage violations – 158 which are fully solved by the optimizer.

With respect to the 2012 scenario, a higher contribution in terms of active power modulation is necessary. Hence, more load shedding occurs in the afternoon, when the peak occurs, Figure 58. Moreover, even if the reactive power support by wind generators is lower - Figure 59 – it helps in increasing network voltages. The final optimization cost for each period is depicted in Figure 60 - The total cost is 112.83 € - which is higher than the 2012 one.

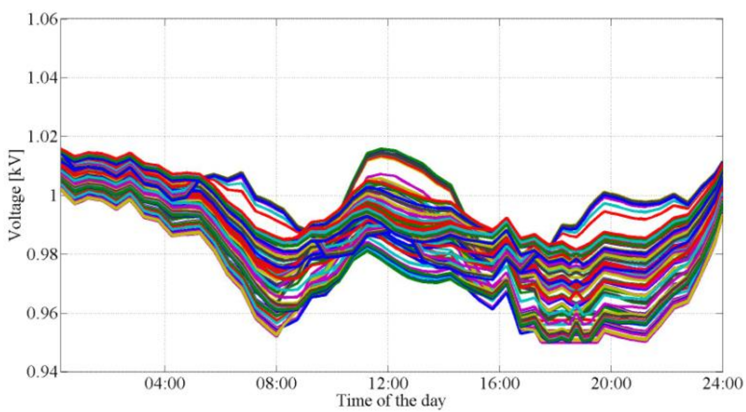


Figure 57 - OP Tool - Scenario 2018: Bus voltage magnitudes of all buses with OLTC tap at 1.034 pu

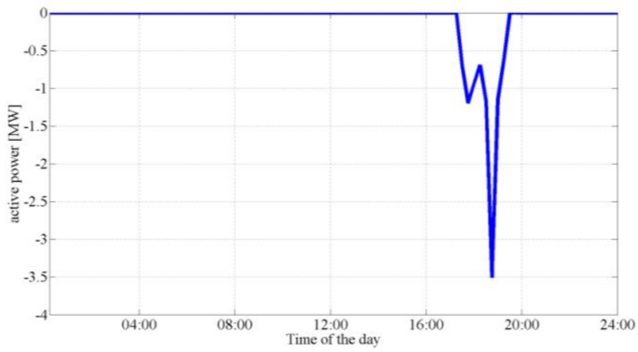


Figure 58 - OP Tool - Scenario 2018 - Active power modulation from load. In the peak of load some load shedding is required.

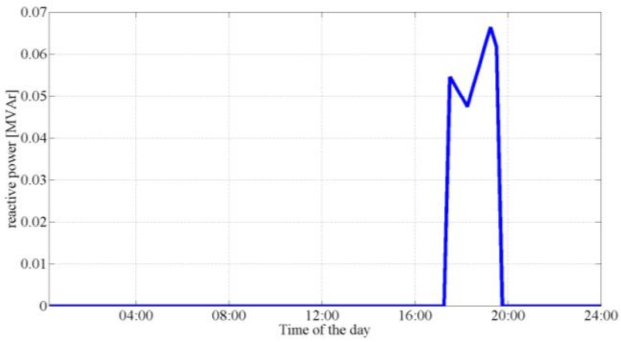


Figure 59 - OP Tool - Scenario 2018 - Reactive power modulation from generators. The reactive power is used to increase the voltage.

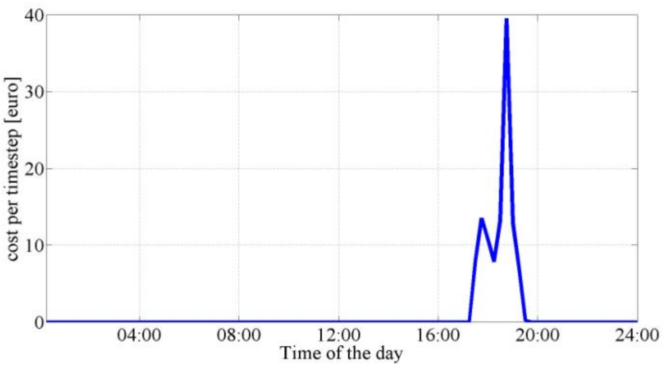


Figure 60 - OP Tool - Scenario 2018 - Cost of OPF solution per period

Mid-Term Scenario (2023)

In 2023, a further increase in the load and DG penetration is envisaged. The 207 under-voltages identified are solved through the usage of load shedding and reactive power compensation from DGs. The 2023 active power support from loads - Figure 62 – has a similar profile to the previous solutions, intervening in the late afternoon/evening. On the other side, the reactive power provided by wind and PV generators contributes to solve voltage violations. The smaller contribution provided by the loads and the higher reactive support from DGs lead to a cheaper solution compared to the previous ones. The final cost is in fact 54.82 €.

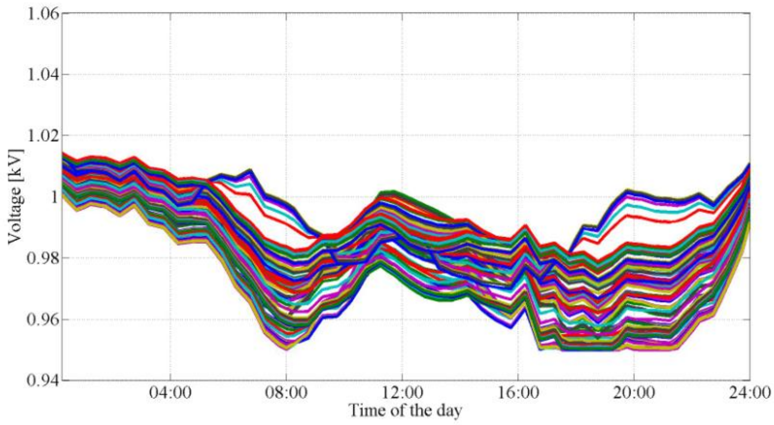


Figure 61 - OP Tool - Scenario 2023: Bus voltage magnitudes of all buses with OLTC tap at 1.034 pu

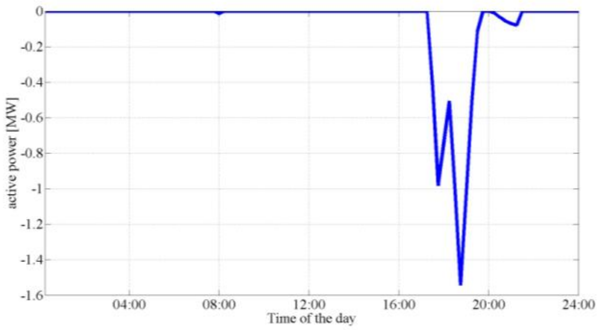


Figure 62 - OP Tool - Scenario 2023 - Active power modulation from load. In the peak of load some load shedding is required.

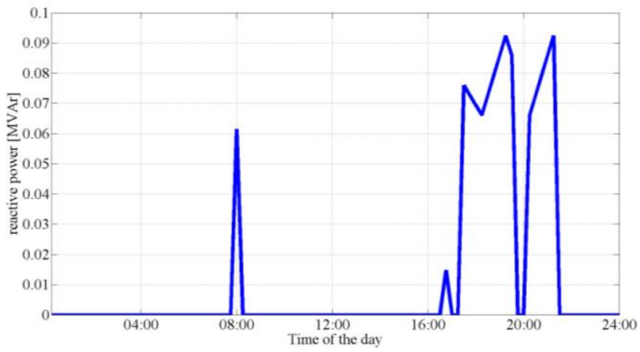


Figure 63 - OP Tool - Scenario 2023 - Reactive power modulation from generators. The reactive power is used to increase the voltage.

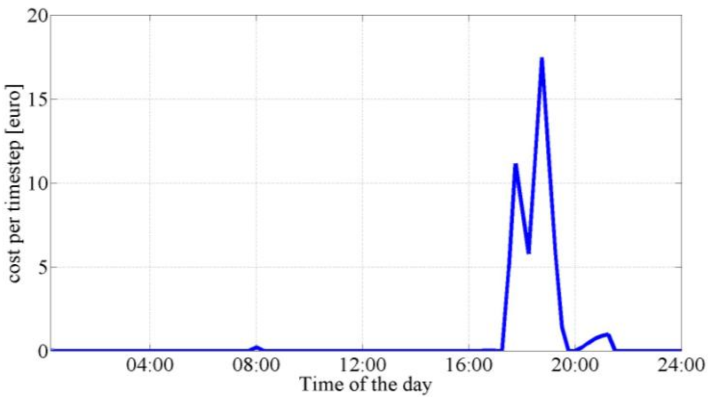


Figure 64 - OP Tool - Scenario 2023: cost of OPF solution per period

Calculation of KPIs for the OP Tool

The calculation of the EEGI and Operational KPIs for the OP Tool, first presented in Table 28, is presented here.

EEGI KPI - Increased RES and DER Hosting Capacity

This KPI is calculated for the entire tool, as follows:

$$\Delta HC_{\%} = \frac{HC_{tool} - HC_{BL}}{HC_{BL}} * 100$$

Where:
$\Delta HC_{\%}$ is the variation of hosting capacity with respect to the Baseline approach;
HC_{tool} is the hosting capacity with the tool;
HC_{BL} is the hosting capacity in the Baseline scenario.

The hosting capacity, in the context of the tool, is defined as the ratio of the total active power of DRES present in the network to the total active power of the load in the network at every time step. Since the hosting capacity is calculated over 96 time steps for each scenario, for simplicity, the average, maximum, and minimum of these hosting capacities is taken for evaluation of the KPI. Consequently, Table 37, Table 38, and Table 39 present these values, along with the corresponding calculated values of the KPI.

Scenario	HC_{BL} (%)	HC_{tool} (%)	$\Delta HC_{\%}$ (%)
2012	0	11.92	Inf
2018	0	9.45	Inf
2023	0	10.93	Inf

Table 37 - OP Tool - Increased RES and DER Minimum Hosting Capacity.

Scenario	HC_{BL} (%)	HC_{tool} (%)	$\Delta HC_{\%}$ (%)
2012	5.47	37.75	590.13
2018	4.72	39.51	737.08
2023	5.42	40.41	645.57

Table 38 - OP Tool - Increased RES and DER Average Hosting Capacity.

Scenario	HC_{BL} (%)	HC_{tool} (%)	$\Delta HC_{\%}$ (%)
2012	46.72	69.54	48.84
2018	44.02	81.83	85.89
2023	50.32	75.85	50.74

Table 39 - OP Tool - Increased RES and DER Maximum Hosting Capacity.

The tables show that the minimum increase of hosting capacity with the tool is close to 50%, while the maximum increase is close to 600%. This effectively proves the usefulness of the developed tool.

Increased Use of Sources of Flexibility by DSOs - Economic Analysis Module KPI

For the economic analysis module, elaborated in D3.2, the corresponding operational KPI is "Increased Use of Sources of Flexibility by DSOs". This KPI is calculated as follows:

$$\text{Increase in Flexibility Use (in \%)} = \frac{\text{No. of (one of each type of) flexibilities provided in the merit order}}{\text{No. of (one of each type of) flexibilities currently used by the DSO}} * 100$$

The number of types of flexibilities provided in the merit order amounts to six (Battery Storage, CHP Active Power, DRES Curtailment, DRES Reactive Power Compensation, Load Modulation, and On-Load Tap Changer), while we assume that the DSO uses only the On-Load Tap Changer to manage networks in the short-term. This translates to an increase of 600% in the types of flexibilities used with the OP tool.

Calculation of KPIs for VITO Optimization Routine

For the VITO optimization routine, the relevant operational KPI is the 'Efficiency Improvement Optimization' (*KPI ID OP_04*).

This KPI aims to reveal the relationship between calculation time and error of results compared to optimum, and is calculated as the *relative overcost* (relative to a conservative under-estimation of the minimal cost) at a certain percentage of the maximally available computation time.

For the scenarios without inter-temporal constraints, no iteration was required by the routine. The absence of inter-temporal constraints in the used levers allowed us to find optimal solutions for each of the 96 time steps separately, without having to employ combinatorial optimisation tools like Constraint Programming. Therefore, the calculation of each scenario is relatively fast, and the overall optimal solution is immediately found. The calculation times of the three scenarios are given in Table 40. In the solutions found by the operational planning tool, all network constraints have been solved completely.

The relative overcost is **0%** for all three scenarios if calculation time is above the indicated calculation time, since the solution found is immediately the optimal solution.

Scenario 2012	75.4 sec.
Scenario 2018	67.05 sec
Scenario 2023	48.9 sec

Table 40 - OP Tool - VITO KPI - Calculation Times for the Scenarios.

The overcost percentage (Operational KPI, KPI ID OP_04) is also calculated for the scenario with inter-temporal constraints. In this scenario, one iteration is present, to include the inter-temporal constraint optimisation as explained above.

The conservative under-estimation of the minimal cost to keep the network constraints within its limits is assumed to be 550€, for the calculation of the overcost percentage KPI. With a maximal available calculation time assumed to be 15 minutes, the overcost reached after 5% of the calculation time is **7.8%**. After 10% of the calculation time, the overcost reaches **2%**.

The calculation time of the constraint-programming engine in its present implementation equals more or less the calculation time of the optimal power flow engine. It is assumed that by applying adequate search strategies in the constraint programming engine, this calculation time can be reduced significantly. However, the more inter-temporal constraints are involved, the longer the calculation times will become.

Calculation of KPIs for RSE Optimization Routine

The RSE optimization routine's performances are measured through the voltage profiles quality operational KPI. Basically, the KPI evaluates the duration of voltage constraint violations in a period (in this case 15' period). A detected violation is supposed to occur until the end of the period and it is evaluated as follows:

$$\Delta DV = DV_{BL} - DV_{SS}$$

where:

- ΔDV represents the variation of voltage violation duration with respect to the Baseline scenario;
- DV_SS represents the voltage violation duration when the Smart Solution is introduced;
- DV_BL represents the voltage violation duration in the Baseline scenario.

The baseline conditions assume that a load flow is adopted for the calculation and no optimization aspects are considered. On the other hand, the "Smart Solution" conditions adopt the RSE optimization routine for the network analysis. Table 41 collects the KPI values for the three scenarios. Whatever the scenario in baseline conditions - i.e. RSE optimizer is not active – network constraints violations occur. In particular, the higher the load and DRES penetration the higher the violations in the network. The highest number of violations occurs in 2023 when 207 violations are detected. On the other hand, the introduction of the RSE optimizer avoids network constraint violations in all the scenarios, proving the improvement of the voltage profiles quality.

	Baseline conditions		Smart Solution conditions		
Scenario	Number of violations	DV_{BL} [minutes]	Number of violations	DV_{SS} [minutes]	ΔDV [minutes]
2012	143	2145	0	0	2145
2018	158	2370	0	0	2370
2023	207	3105	0	0	3105

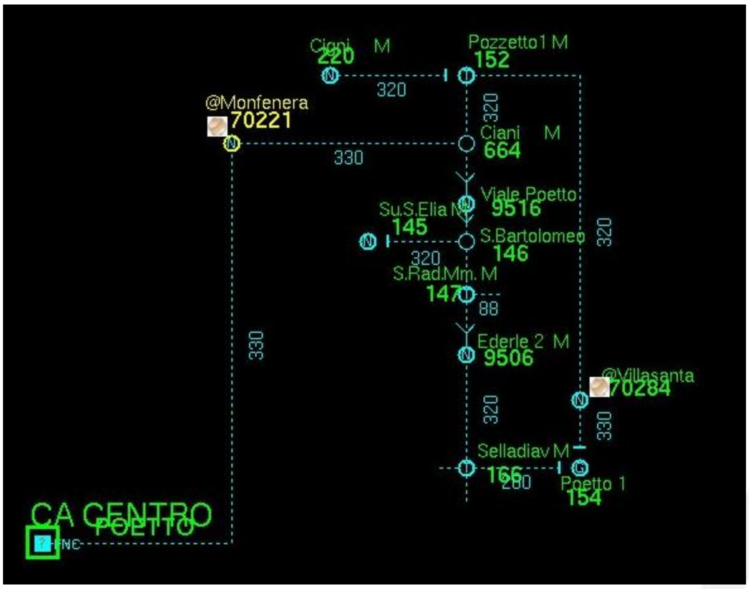
Table 41 - OP Tool - Number of violations with and without the RSE optimizer

3.3.1.2 Network Reliability Tool - Replay

The following section presents for the Replay tool the set of realized tests to verify the main functionalities of the Replay methodology.

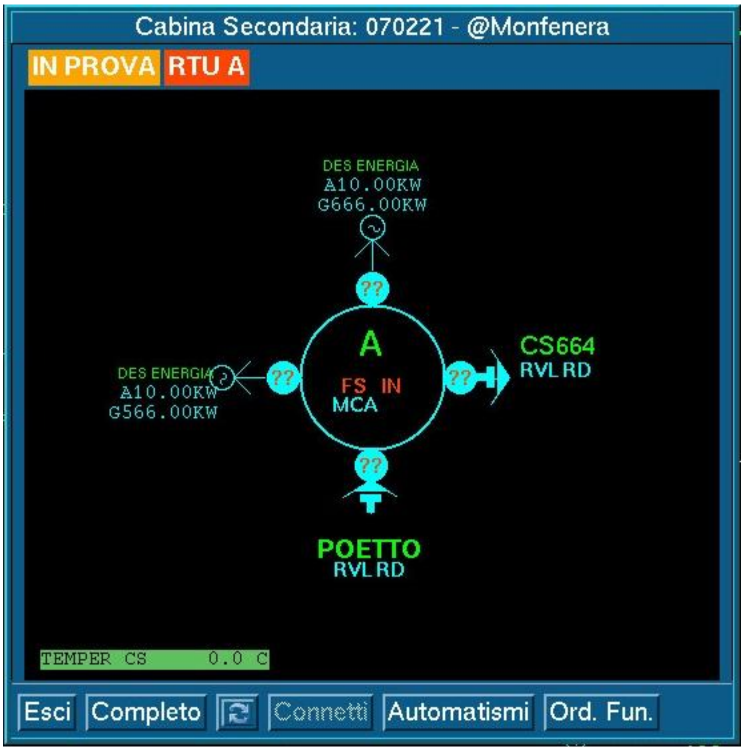
1. **Real Operation System**

The selected MV feeder to be analyzed in the system in operation is called "POETTO". The selected feeder is connected to the primary substation called "CA CENTRO". In the following picture a partial orthogonal representation of the feeder is given.

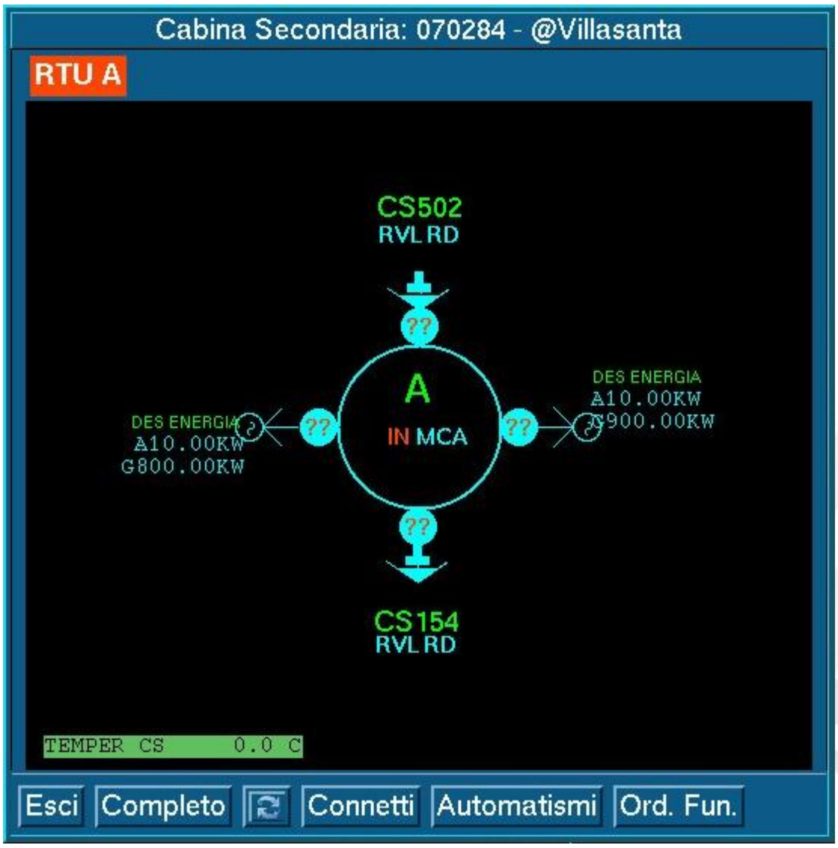


The considered MV feeder has different medium voltage and low voltage customers and producers.

The secondary substation selected for the operations is called "Monfenera". In the following picture a detailed scheme of the cabin is represented in the same way as in the Enel Scada System.



Here below an example of an MV line that will be out of service with the related customers. The secondary substation considered is called "Villasanta".



As a first step, a time interval in the real operation system is selected:

Day: 25/09/2015
Time Interval: 15:05 - 15:25

In the following picture a representation of the list of events related to the time interval for the real operation system is given.

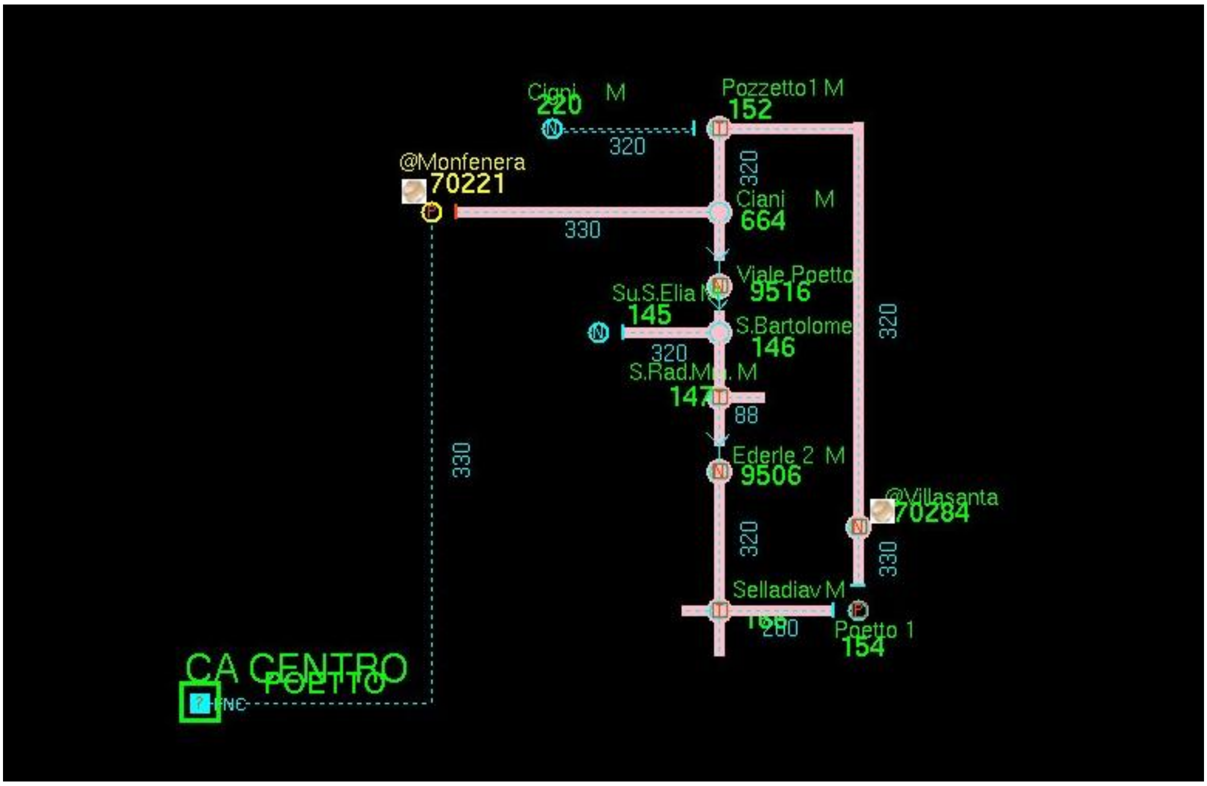
N.Pr...	Data Ora da Sist.	Nodo	CO	Cab. Primaria	Montante	Ente	Codifica Elemento	F	Descrizione Evento	Parametri	Data Ora da Op./App.
1	25/09/2015 10:01:47	UE1	DS10...			ESER			CONCESSIONE AUT DELEGA AT-MT		
2	25/09/2015 15:06:00	Z1	DS10...	CA CENTRO	POETTO	CABS	@Monfenera;CS070221/;/	P	IN PROVA		
3	25/09/2015 15:06:07	Z1	DS10...	CA CENTRO	POETTO	UPTA	@Monfenera;CS070221/;/	P	FUORI SCANSIONE		
4	25/09/2015 15:06:38	Z1	DS10...	CA CENTRO	POETTO	IMS02	@Monfenera;CS070221/CS000664;/	P	APERTO FSN AGGIORN MANUALE		
5	25/09/2015 15:07:52	Z1	DS10...	CA CENTRO	FIERA	CABS	Etfas;CS000144/;/	P	IN PROVA		
6	25/09/2015 15:07:56	Z1	DS10...	CA CENTRO	FIERA	UPTA	Etfas;CS000144/;/	P	FUORI SCANSIONE		
7	25/09/2015 15:07:59	Z1	DS10...	CA CENTRO	FIERA	IMS04	Etfas;CS000144/CS000143;/	P	CHIUSO FSN AGGIORN MANUALE		
8	25/09/2015 15:07:59		DS10...	MOLENTARGI...	FLEMING	DIRE			INIZIO PARALLELO FSN		
9	25/09/2015 15:07:59		DS10...	CA CENTRO	FIERA	DIRE			INIZIO PARALLELO FSN		
10	25/09/2015 15:10:08	Z1	DS10...	CA CENTRO	LIVORNO	CABS	Cagna M;CS000111/;/	P	IN PROVA		
11	25/09/2015 15:10:12	Z1	DS10...	CA CENTRO	LIVORNO	UPTA	Cagna M;CS000111/;/	P	FUORI SCANSIONE		
12	25/09/2015 15:10:21	Z1	DS10...	CA CENTRO	LIVORNO	IMS01	Cagna M;CS000111/CS000115;/	P	APERTO FSN AGGIORN MANUALE		
13	25/09/2015 15:11:06		DS10...	MURAVERA	VILLAPUTZU	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
14	25/09/2015 15:11:06		DS10...	MURAVERA	C.S.LORENZ	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
15	25/09/2015 15:11:06		DS10...	MURAVERA	MURAVERA	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
16	25/09/2015 15:11:06		DS10...	MURAVERA	CANNISONI	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
17	25/09/2015 15:11:06		DS10...	MURAVERA	COSTA REI	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
18	25/09/2015 15:11:07		DS10...	MURAVERA	VILLAPUTZU	LINMT			NEUTRALIZZAZIONE IN CORSO		
19	25/09/2015 15:11:07		DS10...	MURAVERA	C.S.LORENZ	LINMT			NEUTRALIZZAZIONE IN CORSO		
20	25/09/2015 15:11:07		DS10...	MURAVERA	MURAVERA	LINMT			NEUTRALIZZAZIONE IN CORSO		
21	25/09/2015 15:11:07		DS10...	MURAVERA	CANNISONI	LINMT			NEUTRALIZZAZIONE IN CORSO		
22	25/09/2015 15:11:07		DS10...	MURAVERA	COSTA REI	LINMT			NEUTRALIZZAZIONE IN CORSO		
23	25/09/2015 15:12:18		DS10...	MURAVERA	S.PRIAMO@	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
24	25/09/2015 15:12:18		DS10...	MURAVERA	SPADULA	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
25	25/09/2015 15:12:18		DS10...	MURAVERA	EAF@	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
26	25/09/2015 15:12:18		DS10...	OVODDA	TETI	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
27	25/09/2015 15:12:18		DS10...	OVODDA	AVV.STATIC	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
28	25/09/2015 15:12:19		DS10...	MURAVERA	S.PRIAMO@	LINMT			NEUTRALIZZAZIONE IN CORSO		
29	25/09/2015 15:12:19		DS10...	MURAVERA	SPADULA	LINMT			NEUTRALIZZAZIONE IN CORSO		
30	25/09/2015 15:12:19		DS10...	MURAVERA	EAF@	LINMT			NEUTRALIZZAZIONE IN CORSO		
31	25/09/2015 15:12:19		DS10...	OVODDA	TETI	LINMT			NEUTRALIZZAZIONE IN CORSO		
32	25/09/2015 15:12:19		DS10...	OVODDA	AVV.STATIC	LINMT			NEUTRALIZZAZIONE IN CORSO		
33	25/09/2015 15:13:30		DS10...	MURAVERA	VILLAPUTZU	LINMT			RICHIUSURE ECCESS. NUMEROSE		
34	25/09/2015 15:13:30		DS10...	MURAVERA	VILLAPUTZU	LINMT			RICH RAPIDA POSITIVA		
35	25/09/2015 15:13:30		DS10...	MURAVERA	C.S.LORENZ	LINMT			RICHIUSURE ECCESS. NUMEROSE		
36	25/09/2015 15:13:30		DS10...	MURAVERA	C.S.LORENZ	LINMT			RICH RAPIDA POSITIVA		
37	25/09/2015 15:13:30		DS10...	MURAVERA	MURAVERA	LINMT			RICHIUSURE ECCESS. NUMEROSE		
38	25/09/2015 15:13:30		DS10...	MURAVERA	MURAVERA	LINMT			RICH RAPIDA POSITIVA		
39	25/09/2015 15:13:30		DS10...	MURAVERA	CANNISONI	LINMT			RICHIUSURE ECCESS. NUMEROSE		
40	25/09/2015 15:13:30		DS10...	MURAVERA	CANNISONI	LINMT			RICH RAPIDA POSITIVA		
41	25/09/2015 15:13:30		DS10...	MURAVERA	COSTA REI	LINMT			RICHIUSURE ECCESS. NUMEROSE		
42	25/09/2015 15:13:30		DS10...	MURAVERA	COSTA REI	LINMT			RICH RAPIDA POSITIVA		

N.Pr...	Data Ora da Sist.	Nodo	CO	Cab. Primaria	Montante	Ente	Codifica Elemento	F	Descrizione Evento	Parametri	Data Ora da Op./App.
43	25/09/2015 15:14:42		DS10...	MURAVERA	S.PRIAMO@	LINMT			RICHIUSURE ECCESS. NUMEROSE		
44	25/09/2015 15:14:42		DS10...	MURAVERA	S.PRIAMO@	LINMT			RICH RAPIDA POSITIVA		
45	25/09/2015 15:14:42		DS10...	MURAVERA	SPADULA	LINMT			RICHIUSURE ECCESS. NUMEROSE		
46	25/09/2015 15:14:42		DS10...	MURAVERA	SPADULA	LINMT			RICH RAPIDA POSITIVA		
47	25/09/2015 15:14:42		DS10...	MURAVERA	EAF@	LINMT			RICHIUSURE ECCESS. NUMEROSE		
48	25/09/2015 15:14:42		DS10...	MURAVERA	EAF@	LINMT			RICH RAPIDA POSITIVA		
49	25/09/2015 15:14:42		DS10...	OVODDA	TETI	LINMT			RICHIUSURE ECCESS. NUMEROSE		
50	25/09/2015 15:14:42		DS10...	OVODDA	TETI	LINMT			RICH RAPIDA POSITIVA		
51	25/09/2015 15:14:42		DS10...	OVODDA	AVV.STATIC	LINMT			RICHIUSURE ECCESS. NUMEROSE		
52	25/09/2015 15:14:42		DS10...	OVODDA	AVV.STATIC	LINMT			RICH RAPIDA POSITIVA		
53	25/09/2015 15:15:46		DS10...	MURAVERA	VILLAPUTZU	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
54	25/09/2015 15:15:46		DS10...	MURAVERA	C.S.LORENZ	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
55	25/09/2015 15:15:46		DS10...	MURAVERA	MURAVERA	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
56	25/09/2015 15:15:46		DS10...	MURAVERA	CANNISONI	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
57	25/09/2015 15:15:46		DS10...	MURAVERA	COSTA REI	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
58	25/09/2015 15:15:47		DS10...	MURAVERA	VILLAPUTZU	LINMT			NEUTRALIZZAZIONE IN CORSO		
59	25/09/2015 15:15:47		DS10...	MURAVERA	C.S.LORENZ	LINMT			NEUTRALIZZAZIONE IN CORSO		
60	25/09/2015 15:15:47		DS10...	MURAVERA	MURAVERA	LINMT			NEUTRALIZZAZIONE IN CORSO		
61	25/09/2015 15:15:47		DS10...	MURAVERA	CANNISONI	LINMT			NEUTRALIZZAZIONE IN CORSO		
62	25/09/2015 15:15:47		DS10...	MURAVERA	COSTA REI	LINMT			NEUTRALIZZAZIONE IN CORSO		
63	25/09/2015 15:16:58		DS10...	MURAVERA	S.PRIAMO@	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
64	25/09/2015 15:16:58		DS10...	MURAVERA	SPADULA	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
65	25/09/2015 15:16:58		DS10...	MURAVERA	EAF@	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
66	25/09/2015 15:16:58		DS10...	OVODDA	TETI	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
67	25/09/2015 15:16:58		DS10...	OVODDA	AVV.STATIC	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
68	25/09/2015 15:16:59		DS10...	MURAVERA	S.PRIAMO@	LINMT			NEUTRALIZZAZIONE IN CORSO		
69	25/09/2015 15:16:59		DS10...	MURAVERA	SPADULA	LINMT			NEUTRALIZZAZIONE IN CORSO		
70	25/09/2015 15:16:59		DS10...	MURAVERA	EAF@	LINMT			NEUTRALIZZAZIONE IN CORSO		
71	25/09/2015 15:16:59		DS10...	OVODDA	TETI	LINMT			NEUTRALIZZAZIONE IN CORSO		
72	25/09/2015 15:16:59		DS10...	OVODDA	AVV.STATIC	LINMT			NEUTRALIZZAZIONE IN CORSO		
73	25/09/2015 15:18:10		DS10...	MURAVERA	VILLAPUTZU	LINMT			RICHIUSURE ECCESS. NUMEROSE		
74	25/09/2015 15:18:10		DS10...	MURAVERA	VILLAPUTZU	LINMT			RICH RAPIDA POSITIVA		
75	25/09/2015 15:18:10		DS10...	MURAVERA	C.S.LORENZ	LINMT			RICHIUSURE ECCESS. NUMEROSE		
76	25/09/2015 15:18:10		DS10...	MURAVERA	C.S.LORENZ	LINMT			RICH RAPIDA POSITIVA		
77	25/09/2015 15:18:10		DS10...	MURAVERA	MURAVERA	LINMT			RICHIUSURE ECCESS. NUMEROSE		
78	25/09/2015 15:18:10		DS10...	MURAVERA	MURAVERA	LINMT			RICH RAPIDA POSITIVA		
79	25/09/2015 15:18:10		DS10...	MURAVERA	CANNISONI	LINMT			RICHIUSURE ECCESS. NUMEROSE		
80	25/09/2015 15:18:10		DS10...	MURAVERA	CANNISONI	LINMT			RICH RAPIDA POSITIVA		
81	25/09/2015 15:18:10		DS10...	MURAVERA	COSTA REI	LINMT			RICHIUSURE ECCESS. NUMEROSE		
82	25/09/2015 15:18:10		DS10...	MURAVERA	COSTA REI	LINMT			RICH RAPIDA POSITIVA		
83	25/09/2015 15:19:22		DS10...	MURAVERA	S.PRIAMO@	LINMT			RICHIUSURE ECCESS. NUMEROSE		
84	25/09/2015 15:19:22		DS10...	MURAVERA	S.PRIAMO@	LINMT			RICH RAPIDA POSITIVA		

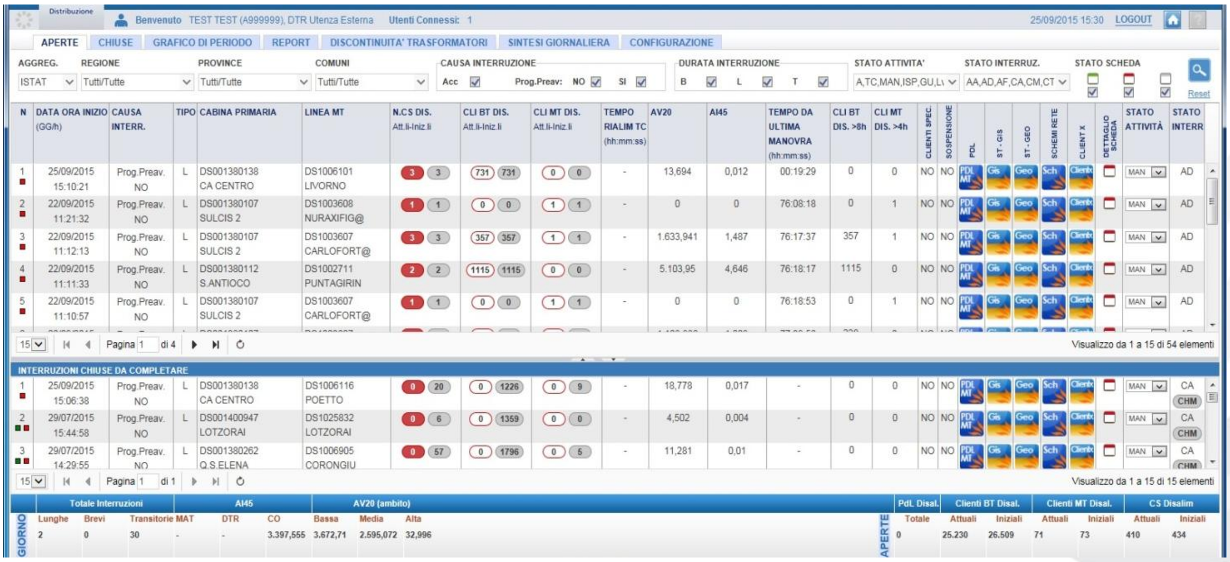
N.Pr...	Data Ora da Sist.	Nodo	CO	Cab. Primaria	Montante	Ente	Codifica Elemento	F	Descrizione Evento	Parametri	Data Ora da Op./App.
84	25/09/2015 15:19:22		DS10...	MURAVERA	S.PRIAMO@	LINMT			RICH RAPIDA POSITIVA		
85	25/09/2015 15:19:22		DS10...	MURAVERA	SPADULA	LINMT			RICHIUSURE ECCESS. NUMEROSE		
86	25/09/2015 15:19:22		DS10...	MURAVERA	SPADULA	LINMT			RICH RAPIDA POSITIVA		
87	25/09/2015 15:19:22		DS10...	MURAVERA	EAF@	LINMT			RICHIUSURE ECCESS. NUMEROSE		
88	25/09/2015 15:19:22		DS10...	MURAVERA	EAF@	LINMT			RICH RAPIDA POSITIVA		
89	25/09/2015 15:19:22		DS10...	OVODDA	TETI	LINMT			RICHIUSURE ECCESS. NUMEROSE		
90	25/09/2015 15:19:22		DS10...	OVODDA	TETI	LINMT			RICH RAPIDA POSITIVA		
91	25/09/2015 15:19:22		DS10...	OVODDA	AVV.STATIC	LINMT			RICHIUSURE ECCESS. NUMEROSE		
92	25/09/2015 15:19:22		DS10...	OVODDA	AVV.STATIC	LINMT			RICH RAPIDA POSITIVA		
93	25/09/2015 15:21:57	Z1	DS10...	CA CENTRO	POETTO	IMS02	@Monfenera;CS070221/CS000664;/	P	CHIUSO SN AGGIORN MANUALE		
94	25/09/2015 15:22:06		DS10...	MURAVERA	VILLAPUTZU	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
95	25/09/2015 15:22:06		DS10...	MURAVERA	C.S.LORENZ	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
96	25/09/2015 15:22:06		DS10...	MURAVERA	MURAVERA	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
97	25/09/2015 15:22:06		DS10...	MURAVERA	CANNISONI	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
98	25/09/2015 15:22:06		DS10...	MURAVERA	COSTA REI	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
99	25/09/2015 15:22:07		DS10...	MURAVERA	VILLAPUTZU	LINMT			NEUTRALIZZAZIONE IN CORSO		
100	25/09/2015 15:22:07		DS10...	MURAVERA	C.S.LORENZ	LINMT			NEUTRALIZZAZIONE IN CORSO		
101	25/09/2015 15:22:07		DS10...	MURAVERA	MURAVERA	LINMT			NEUTRALIZZAZIONE IN CORSO		
102	25/09/2015 15:22:07		DS10...	MURAVERA	CANNISONI	LINMT			NEUTRALIZZAZIONE IN CORSO		
103	25/09/2015 15:22:07		DS10...	MURAVERA	COSTA REI	LINMT			NEUTRALIZZAZIONE IN CORSO		
104	25/09/2015 15:23:18		DS10...	MURAVERA	S.PRIAMO@	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
105	25/09/2015 15:23:18		DS10...	MURAVERA	SPADULA	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
106	25/09/2015 15:23:18		DS10...	MURAVERA	EAF@	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
107	25/09/2015 15:23:18		DS10...	OVODDA	TETI	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
108	25/09/2015 15:23:18		DS10...	OVODDA	AVV.STATIC	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
109	25/09/2015 15:23:19		DS10...	MURAVERA	S.PRIAMO@	LINMT			NEUTRALIZZAZIONE IN CORSO		
110	25/09/2015 15:23:19		DS10...	MURAVERA	SPADULA	LINMT			NEUTRALIZZAZIONE IN CORSO		
111	25/09/2015 15:23:19		DS10...	MURAVERA	EAF@	LINMT			NEUTRALIZZAZIONE IN CORSO		
112	25/09/2015 15:23:19		DS10...	OVODDA	TETI	LINMT			NEUTRALIZZAZIONE IN CORSO		
113	25/09/2015 15:23:19		DS10...	OVODDA	AVV.STATIC	LINMT			NEUTRALIZZAZIONE IN CORSO		
114	25/09/2015 15:24:30		DS10...	MURAVERA	VILLAPUTZU	LINMT			RICHIUSURE ECCESS. NUMEROSE		
115	25/09/2015 15:24:30		DS10...	MURAVERA	VILLAPUTZU	LINMT			RICH RAPIDA POSITIVA		
116	25/09/2015 15:24:30		DS10...	MURAVERA	C.S.LORENZ	LINMT			RICHIUSURE ECCESS. NUMEROSE		
117	25/09/2015 15:24:30		DS10...	MURAVERA	C.S.LORENZ	LINMT			RICH RAPIDA POSITIVA		
118	25/09/2015 15:24:30		DS10...	MURAVERA	MURAVERA	LINMT			RICHIUSURE ECCESS. NUMEROSE		
119	25/09/2015 15:24:30		DS10...	MURAVERA	MURAVERA	LINMT			RICH RAPIDA POSITIVA		
120	25/09/2015 15:24:30		DS10...	MURAVERA	CANNISONI	LINMT			RICHIUSURE ECCESS. NUMEROSE		
121	25/09/2015 15:24:30		DS10...	MURAVERA	CANNISONI	LINMT			RICH RAPIDA POSITIVA		
122	25/09/2015 15:24:30		DS10...	MURAVERA	COSTA REI	LINMT			RICHIUSURE ECCESS. NUMEROSE		
123	25/09/2015 15:24:30		DS10...	MURAVERA	COSTA REI	LINMT			RICH RAPIDA POSITIVA		
124	25/09/2015 15:25:42		DS10...	MURAVERA	S.PRIAMO@	LINMT			RICHIUSURE ECCESS. NUMEROSE		
125	25/09/2015 15:25:42		DS10...	MURAVERA	S.PRIAMO@	LINMT			RICH RAPIDA POSITIVA		

In the real system in operation (green line) (15:06) a long interruption occurred on the network (interruption time > 3min). The interruption is represented as the list of events below the green line. This interruption involves the secondary substation 70284.

In the following representation a scheme of the portion of the network out of service is represented.



Using the RETIM tool, it is possible to monitoring the interruptions and analyse the data related to the quality of service, in particular the customers out of service and the “AV20” parameter calculation for the interruption considered (AV20 corresponds to the cumulated minutes of interruption * total number of customers affected by the interruption). In the considered case 18.78 min*customers is the current value of AV20.



2. Replay System Simulation

In the current section the purpose of the test is to reproduce the events occurred in the system in operation with the possibility to select a group of events and apply them on the network scheme. The operator will have the possibility to select the final event and visualize the corresponding scheme.

In the Replay Session, it is possible to insert the time interval corresponding to the real time interval to be analyzed.

Day: 25/09/2015

Time Interval: 15:05 – 15:25

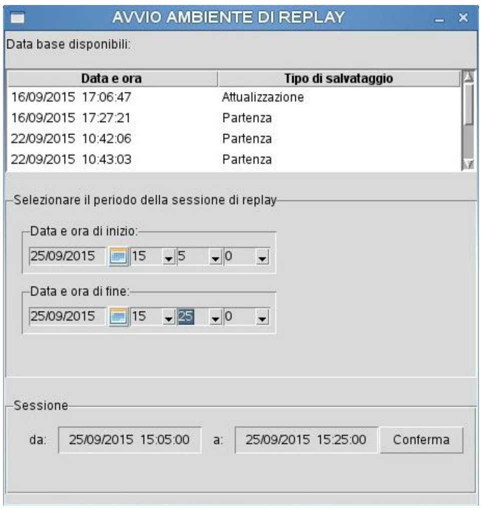
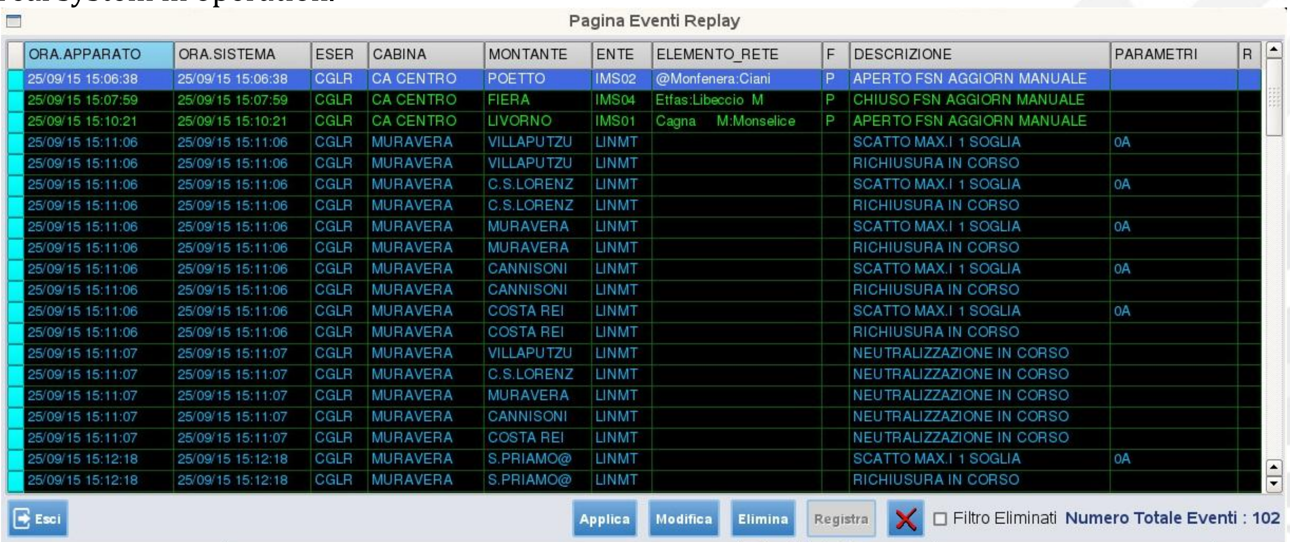


Figure 65: Selection of the database and the interval time to be analyzed

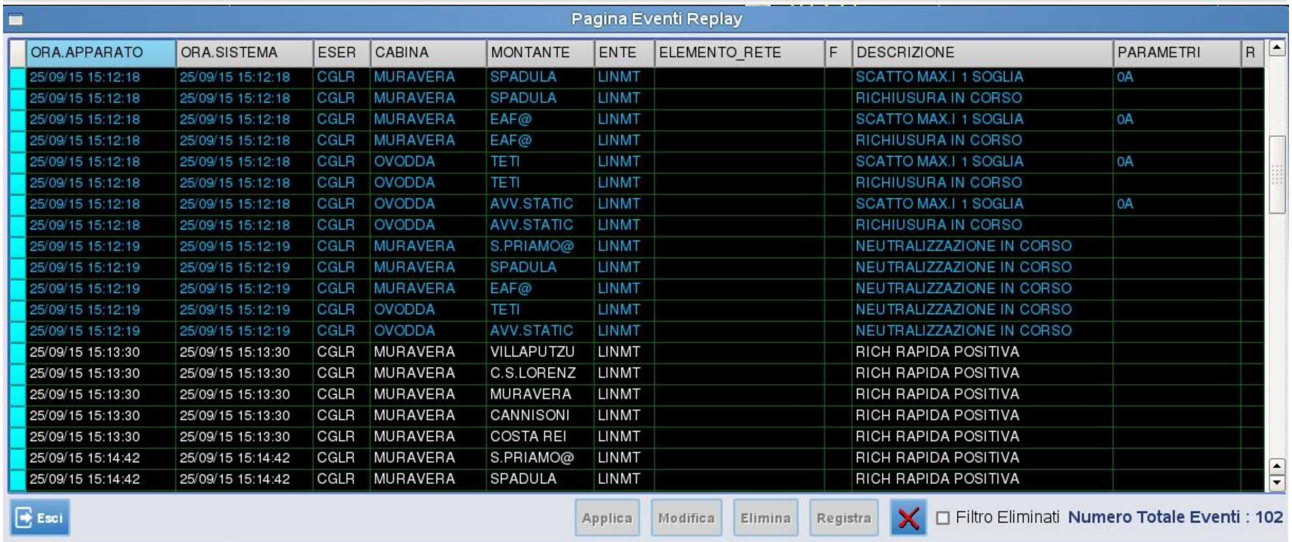
In the next screenshot it is possible to see the complete list of events obtained by the Replay. The list includes a selection of the events occurred in operation to be managed in the simulations.

It is important to highlight that the Replay is able to select the most relevant events for the operation, i.e. only the events affecting the quality of service, while alarms related to the other aspects are excluded (e.g. doors opening).

In the following pictures it is possible to note the correspondence with the list events in the real system in operation.



ORA.APPARATO	ORA.SISTEMA	ESER	CABINA	MONTANTE	ENTE	ELEMENTO_RETE	F	DESCRIZIONE	PARAMETRI	R
25/09/15 15:06:38	25/09/15 15:06:38	CGLR	CA CENTRO	POETTO	IMS02	@Monfenera:Ciani	P	APERTO FSN AGGIORN MANUALE		
25/09/15 15:07:59	25/09/15 15:07:59	CGLR	CA CENTRO	FIERA	IMS04	Etfas:Libeccio M	P	CHIUSO FSN AGGIORN MANUALE		
25/09/15 15:10:21	25/09/15 15:10:21	CGLR	CA CENTRO	LIVORNO	IMS01	Cagna M:Monselice	P	APERTO FSN AGGIORN MANUALE		
25/09/15 15:11:06	25/09/15 15:11:06	CGLR	MURAVERA	VILLAPUTZU	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
25/09/15 15:11:06	25/09/15 15:11:06	CGLR	MURAVERA	VILLAPUTZU	LINMT			RICHIUSURA IN CORSO		
25/09/15 15:11:06	25/09/15 15:11:06	CGLR	MURAVERA	C.S.LORENZ	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
25/09/15 15:11:06	25/09/15 15:11:06	CGLR	MURAVERA	C.S.LORENZ	LINMT			RICHIUSURA IN CORSO		
25/09/15 15:11:06	25/09/15 15:11:06	CGLR	MURAVERA	MURAVERA	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
25/09/15 15:11:06	25/09/15 15:11:06	CGLR	MURAVERA	MURAVERA	LINMT			RICHIUSURA IN CORSO		
25/09/15 15:11:06	25/09/15 15:11:06	CGLR	MURAVERA	CANNISONI	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
25/09/15 15:11:06	25/09/15 15:11:06	CGLR	MURAVERA	CANNISONI	LINMT			RICHIUSURA IN CORSO		
25/09/15 15:11:06	25/09/15 15:11:06	CGLR	MURAVERA	COSTA REI	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
25/09/15 15:11:06	25/09/15 15:11:06	CGLR	MURAVERA	COSTA REI	LINMT			RICHIUSURA IN CORSO		
25/09/15 15:11:07	25/09/15 15:11:07	CGLR	MURAVERA	VILLAPUTZU	LINMT			NEUTRALIZZAZIONE IN CORSO		
25/09/15 15:11:07	25/09/15 15:11:07	CGLR	MURAVERA	C.S.LORENZ	LINMT			NEUTRALIZZAZIONE IN CORSO		
25/09/15 15:11:07	25/09/15 15:11:07	CGLR	MURAVERA	MURAVERA	LINMT			NEUTRALIZZAZIONE IN CORSO		
25/09/15 15:11:07	25/09/15 15:11:07	CGLR	MURAVERA	CANNISONI	LINMT			NEUTRALIZZAZIONE IN CORSO		
25/09/15 15:11:07	25/09/15 15:11:07	CGLR	MURAVERA	COSTA REI	LINMT			NEUTRALIZZAZIONE IN CORSO		
25/09/15 15:12:18	25/09/15 15:12:18	CGLR	MURAVERA	S.PRIAMO@	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
25/09/15 15:12:18	25/09/15 15:12:18	CGLR	MURAVERA	S.PRIAMO@	LINMT			RICHIUSURA IN CORSO		



ORA.APPARATO	ORA.SISTEMA	ESER	CABINA	MONTANTE	ENTE	ELEMENTO_RETE	F	DESCRIZIONE	PARAMETRI	R
25/09/15 15:12:18	25/09/15 15:12:18	CGLR	MURAVERA	SPADULA	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
25/09/15 15:12:18	25/09/15 15:12:18	CGLR	MURAVERA	SPADULA	LINMT			RICHIUSURA IN CORSO		
25/09/15 15:12:18	25/09/15 15:12:18	CGLR	MURAVERA	EAF@	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
25/09/15 15:12:18	25/09/15 15:12:18	CGLR	MURAVERA	EAF@	LINMT			RICHIUSURA IN CORSO		
25/09/15 15:12:18	25/09/15 15:12:18	CGLR	OVODDA	TETI	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
25/09/15 15:12:18	25/09/15 15:12:18	CGLR	OVODDA	TETI	LINMT			RICHIUSURA IN CORSO		
25/09/15 15:12:18	25/09/15 15:12:18	CGLR	OVODDA	AVV.STATIC	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
25/09/15 15:12:18	25/09/15 15:12:18	CGLR	OVODDA	AVV.STATIC	LINMT			RICHIUSURA IN CORSO		
25/09/15 15:12:19	25/09/15 15:12:19	CGLR	MURAVERA	S.PRIAMO@	LINMT			NEUTRALIZZAZIONE IN CORSO		
25/09/15 15:12:19	25/09/15 15:12:19	CGLR	MURAVERA	SPADULA	LINMT			NEUTRALIZZAZIONE IN CORSO		
25/09/15 15:12:19	25/09/15 15:12:19	CGLR	MURAVERA	EAF@	LINMT			NEUTRALIZZAZIONE IN CORSO		
25/09/15 15:12:19	25/09/15 15:12:19	CGLR	OVODDA	TETI	LINMT			NEUTRALIZZAZIONE IN CORSO		
25/09/15 15:12:19	25/09/15 15:12:19	CGLR	OVODDA	AVV.STATIC	LINMT			NEUTRALIZZAZIONE IN CORSO		
25/09/15 15:13:30	25/09/15 15:13:30	CGLR	MURAVERA	VILLAPUTZU	LINMT			RICH RAPIDA POSITIVA		
25/09/15 15:13:30	25/09/15 15:13:30	CGLR	MURAVERA	C.S.LORENZ	LINMT			RICH RAPIDA POSITIVA		
25/09/15 15:13:30	25/09/15 15:13:30	CGLR	MURAVERA	MURAVERA	LINMT			RICH RAPIDA POSITIVA		
25/09/15 15:13:30	25/09/15 15:13:30	CGLR	MURAVERA	CANNISONI	LINMT			RICH RAPIDA POSITIVA		
25/09/15 15:13:30	25/09/15 15:13:30	CGLR	MURAVERA	COSTA REI	LINMT			RICH RAPIDA POSITIVA		
25/09/15 15:14:42	25/09/15 15:14:42	CGLR	MURAVERA	S.PRIAMO@	LINMT			RICH RAPIDA POSITIVA		
25/09/15 15:14:42	25/09/15 15:14:42	CGLR	MURAVERA	SPADULA	LINMT			RICH RAPIDA POSITIVA		

Pagina Eventi Replay

ORA.APPARATO	ORA.SISTEMA	ESER	CABINA	MONTANTE	ENTE	ELEMENTO_RETE	F	DESCRIZIONE	PARAMETRI	R
25/09/15 15:14:42	25/09/15 15:14:42	CGLR	MURAVERA	EAF@	LINMT			RICH RAPIDA POSITIVA		
25/09/15 15:14:42	25/09/15 15:14:42	CGLR	OVODDA	TETI	LINMT			RICH RAPIDA POSITIVA		
25/09/15 15:14:42	25/09/15 15:14:42	CGLR	OVODDA	AVV.STATIC	LINMT			RICH RAPIDA POSITIVA		
25/09/15 15:15:46	25/09/15 15:15:46	CGLR	MURAVERA	VILLAPUTZU	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
25/09/15 15:15:46	25/09/15 15:15:46	CGLR	MURAVERA	VILLAPUTZU	LINMT			RICHIUSURA IN CORSO		
25/09/15 15:15:46	25/09/15 15:15:46	CGLR	MURAVERA	C.S.LORENZ	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
25/09/15 15:15:46	25/09/15 15:15:46	CGLR	MURAVERA	C.S.LORENZ	LINMT			RICHIUSURA IN CORSO		
25/09/15 15:15:46	25/09/15 15:15:46	CGLR	MURAVERA	MURAVERA	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
25/09/15 15:15:46	25/09/15 15:15:46	CGLR	MURAVERA	MURAVERA	LINMT			RICHIUSURA IN CORSO		
25/09/15 15:15:46	25/09/15 15:15:46	CGLR	MURAVERA	CANNISONI	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
25/09/15 15:15:46	25/09/15 15:15:46	CGLR	MURAVERA	CANNISONI	LINMT			RICHIUSURA IN CORSO		
25/09/15 15:15:46	25/09/15 15:15:46	CGLR	MURAVERA	COSTA REI	LINMT			RICHIUSURA IN CORSO		
25/09/15 15:15:47	25/09/15 15:15:47	CGLR	MURAVERA	VILLAPUTZU	LINMT			NEUTRALIZZAZIONE IN CORSO		
25/09/15 15:15:47	25/09/15 15:15:47	CGLR	MURAVERA	C.S.LORENZ	LINMT			NEUTRALIZZAZIONE IN CORSO		
25/09/15 15:15:47	25/09/15 15:15:47	CGLR	MURAVERA	MURAVERA	LINMT			NEUTRALIZZAZIONE IN CORSO		
25/09/15 15:15:47	25/09/15 15:15:47	CGLR	MURAVERA	CANNISONI	LINMT			NEUTRALIZZAZIONE IN CORSO		
25/09/15 15:15:47	25/09/15 15:15:47	CGLR	MURAVERA	COSTA REI	LINMT			NEUTRALIZZAZIONE IN CORSO		
25/09/15 15:16:58	25/09/15 15:16:58	CGLR	MURAVERA	S.PRIAMO@	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
25/09/15 15:16:58	25/09/15 15:16:58	CGLR	MURAVERA	S.PRIAMO@	LINMT			RICHIUSURA IN CORSO		
25/09/15 15:16:58	25/09/15 15:16:58	CGLR	MURAVERA	SPADULA	LINMT			SCATTO MAX.I 1 SOGLIA	0A	

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Pagina Eventi Replay

ORA.APPARATO	ORA.SISTEMA	ESER	CABINA	MONTANTE	ENTE	ELEMENTO_RETE	F	DESCRIZIONE	PARAMETRI	R
25/09/15 15:16:58	25/09/15 15:16:58	CGLR	MURAVERA	SPADULA	LINMT			RICHIUSURA IN CORSO		
25/09/15 15:16:58	25/09/15 15:16:58	CGLR	MURAVERA	EAF@	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
25/09/15 15:16:58	25/09/15 15:16:58	CGLR	MURAVERA	EAF@	LINMT			RICHIUSURA IN CORSO		
25/09/15 15:16:58	25/09/15 15:16:58	CGLR	OVODDA	TETI	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
25/09/15 15:16:58	25/09/15 15:16:58	CGLR	OVODDA	TETI	LINMT			RICHIUSURA IN CORSO		
25/09/15 15:16:58	25/09/15 15:16:58	CGLR	OVODDA	AVV.STATIC	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
25/09/15 15:16:58	25/09/15 15:16:58	CGLR	OVODDA	AVV.STATIC	LINMT			RICHIUSURA IN CORSO		
25/09/15 15:16:59	25/09/15 15:16:59	CGLR	MURAVERA	S.PRIAMO@	LINMT			NEUTRALIZZAZIONE IN CORSO		
25/09/15 15:16:59	25/09/15 15:16:59	CGLR	MURAVERA	SPADULA	LINMT			NEUTRALIZZAZIONE IN CORSO		
25/09/15 15:16:59	25/09/15 15:16:59	CGLR	MURAVERA	EAF@	LINMT			NEUTRALIZZAZIONE IN CORSO		
25/09/15 15:16:59	25/09/15 15:16:59	CGLR	OVODDA	TETI	LINMT			NEUTRALIZZAZIONE IN CORSO		
25/09/15 15:16:59	25/09/15 15:16:59	CGLR	OVODDA	AVV.STATIC	LINMT			NEUTRALIZZAZIONE IN CORSO		
25/09/15 15:18:10	25/09/15 15:18:10	CGLR	MURAVERA	VILLAPUTZU	LINMT			RICH RAPIDA POSITIVA		
25/09/15 15:18:10	25/09/15 15:18:10	CGLR	MURAVERA	C.S.LORENZ	LINMT			RICH RAPIDA POSITIVA		
25/09/15 15:18:10	25/09/15 15:18:10	CGLR	MURAVERA	MURAVERA	LINMT			RICH RAPIDA POSITIVA		
25/09/15 15:18:10	25/09/15 15:18:10	CGLR	MURAVERA	CANNISONI	LINMT			RICH RAPIDA POSITIVA		
25/09/15 15:18:10	25/09/15 15:18:10	CGLR	MURAVERA	COSTA REI	LINMT			RICH RAPIDA POSITIVA		
25/09/15 15:19:22	25/09/15 15:19:22	CGLR	MURAVERA	S.PRIAMO@	LINMT			RICH RAPIDA POSITIVA		
25/09/15 15:19:22	25/09/15 15:19:22	CGLR	MURAVERA	SPADULA	LINMT			RICH RAPIDA POSITIVA		
25/09/15 15:19:22	25/09/15 15:19:22	CGLR	MURAVERA	EAF@	LINMT			RICH RAPIDA POSITIVA		

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Pagina Eventi Replay

ORA.APPARATO	ORA.SISTEMA	ESER	CABINA	MONTANTE	ENTE	ELEMENTO_RETE	F	DESCRIZIONE	PARAMETRI	R
25/09/15 15:19:22	25/09/15 15:19:22	CGLR	MURAVERA	S.PRIAMO@	LINMT			RICH RAPIDA POSITIVA		
25/09/15 15:19:22	25/09/15 15:19:22	CGLR	MURAVERA	SPADULA	LINMT			RICH RAPIDA POSITIVA		
25/09/15 15:19:22	25/09/15 15:19:22	CGLR	MURAVERA	EAF@	LINMT			RICH RAPIDA POSITIVA		
25/09/15 15:19:22	25/09/15 15:19:22	CGLR	OVODDA	TETI	LINMT			RICH RAPIDA POSITIVA		
25/09/15 15:19:22	25/09/15 15:19:22	CGLR	OVODDA	AVV.STATIC	LINMT			RICH RAPIDA POSITIVA		
25/09/15 15:21:57	25/09/15 15:21:57	CGLR	CA CENTRO	POETTO	IMS02	@Monfenera:Ciani	P	CHIUSO SN AGGIORN MANUALE		
25/09/15 15:22:06	25/09/15 15:22:06	CGLR	MURAVERA	VILLAPUTZU	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
25/09/15 15:22:06	25/09/15 15:22:06	CGLR	MURAVERA	VILLAPUTZU	LINMT			RICHIUSURA IN CORSO		
25/09/15 15:22:06	25/09/15 15:22:06	CGLR	MURAVERA	C.S.LORENZ	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
25/09/15 15:22:06	25/09/15 15:22:06	CGLR	MURAVERA	C.S.LORENZ	LINMT			RICHIUSURA IN CORSO		
25/09/15 15:22:06	25/09/15 15:22:06	CGLR	MURAVERA	MURAVERA	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
25/09/15 15:22:06	25/09/15 15:22:06	CGLR	MURAVERA	MURAVERA	LINMT			RICHIUSURA IN CORSO		
25/09/15 15:22:06	25/09/15 15:22:06	CGLR	MURAVERA	CANNISONI	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
25/09/15 15:22:06	25/09/15 15:22:06	CGLR	MURAVERA	CANNISONI	LINMT			RICHIUSURA IN CORSO		
25/09/15 15:22:06	25/09/15 15:22:06	CGLR	MURAVERA	COSTA REI	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
25/09/15 15:22:06	25/09/15 15:22:06	CGLR	MURAVERA	COSTA REI	LINMT			RICHIUSURA IN CORSO		
25/09/15 15:22:07	25/09/15 15:22:07	CGLR	MURAVERA	VILLAPUTZU	LINMT			NEUTRALIZZAZIONE IN CORSO		
25/09/15 15:22:07	25/09/15 15:22:07	CGLR	MURAVERA	C.S.LORENZ	LINMT			NEUTRALIZZAZIONE IN CORSO		
25/09/15 15:22:07	25/09/15 15:22:07	CGLR	MURAVERA	MURAVERA	LINMT			NEUTRALIZZAZIONE IN CORSO		
25/09/15 15:22:07	25/09/15 15:22:07	CGLR	MURAVERA	CANNISONI	LINMT			NEUTRALIZZAZIONE IN CORSO		

Esci | Applica | Modifica | Elimina | Registra | Filtro Eliminati **Numero Totale Eventi : 102**

Pagina Eventi Replay

ORA.APPARATO	ORA.SISTEMA	ESER	CABINA	MONTANTE	ENTE	ELEMENTO_RETE	F	DESCRIZIONE	PARAMETRI	R
25/09/15 15:21:57	25/09/15 15:21:57	CGLR	CA CENTRO	POETTO	IMS02	@Monfenera:Ciani	P	CHIUSO SN AGGIORN MANUALE		
25/09/15 15:22:06	25/09/15 15:22:06	CGLR	MURAVERA	VILLAPUTZU	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
25/09/15 15:22:06	25/09/15 15:22:06	CGLR	MURAVERA	VILLAPUTZU	LINMT			RICHIUSURA IN CORSO		
25/09/15 15:22:06	25/09/15 15:22:06	CGLR	MURAVERA	C.S.LORENZ	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
25/09/15 15:22:06	25/09/15 15:22:06	CGLR	MURAVERA	C.S.LORENZ	LINMT			RICHIUSURA IN CORSO		
25/09/15 15:22:06	25/09/15 15:22:06	CGLR	MURAVERA	MURAVERA	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
25/09/15 15:22:06	25/09/15 15:22:06	CGLR	MURAVERA	MURAVERA	LINMT			RICHIUSURA IN CORSO		
25/09/15 15:22:06	25/09/15 15:22:06	CGLR	MURAVERA	CANNISONI	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
25/09/15 15:22:06	25/09/15 15:22:06	CGLR	MURAVERA	CANNISONI	LINMT			RICHIUSURA IN CORSO		
25/09/15 15:22:06	25/09/15 15:22:06	CGLR	MURAVERA	COSTA REI	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
25/09/15 15:22:06	25/09/15 15:22:06	CGLR	MURAVERA	COSTA REI	LINMT			RICHIUSURA IN CORSO		
25/09/15 15:22:07	25/09/15 15:22:07	CGLR	MURAVERA	VILLAPUTZU	LINMT			NEUTRALIZZAZIONE IN CORSO		
25/09/15 15:22:07	25/09/15 15:22:07	CGLR	MURAVERA	C.S.LORENZ	LINMT			NEUTRALIZZAZIONE IN CORSO		
25/09/15 15:22:07	25/09/15 15:22:07	CGLR	MURAVERA	MURAVERA	LINMT			NEUTRALIZZAZIONE IN CORSO		
25/09/15 15:22:07	25/09/15 15:22:07	CGLR	MURAVERA	CANNISONI	LINMT			NEUTRALIZZAZIONE IN CORSO		
25/09/15 15:22:07	25/09/15 15:22:07	CGLR	MURAVERA	COSTA REI	LINMT			NEUTRALIZZAZIONE IN CORSO		
25/09/15 15:23:18	25/09/15 15:23:18	CGLR	MURAVERA	S.PRIAMO@	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
25/09/15 15:23:18	25/09/15 15:23:18	CGLR	MURAVERA	S.PRIAMO@	LINMT			RICHIUSURA IN CORSO		
25/09/15 15:23:18	25/09/15 15:23:18	CGLR	MURAVERA	SPADULA	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
25/09/15 15:23:18	25/09/15 15:23:18	CGLR	MURAVERA	SPADULA	LINMT			RICHIUSURA IN CORSO		

Esci   Applica   Modifica   Elimina   Registra   Filtro Eliminati   Numero Totale Eventi : 102

The electric scheme represented below refers to the starting time of the interval (network status at 15:05) when the MV feeder POETTO is still working normally.

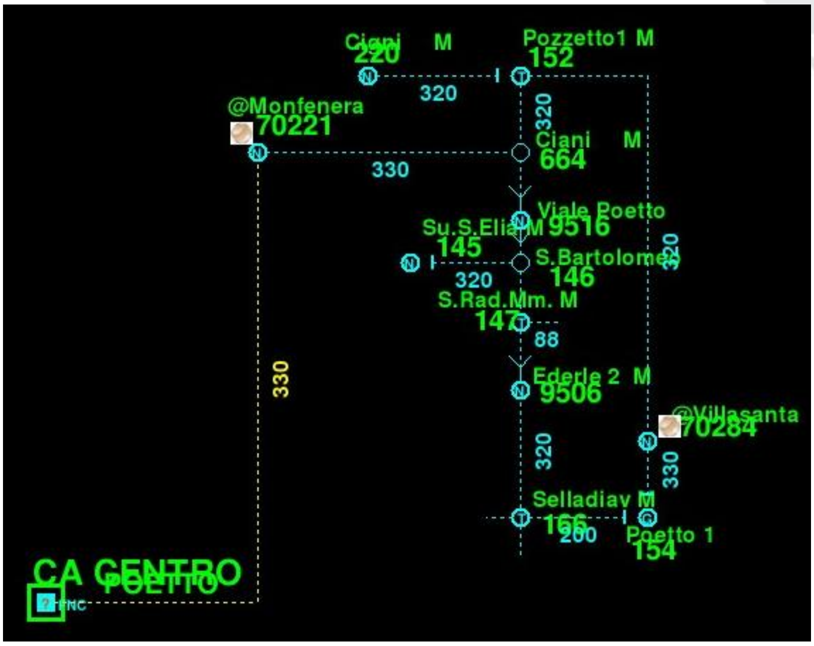
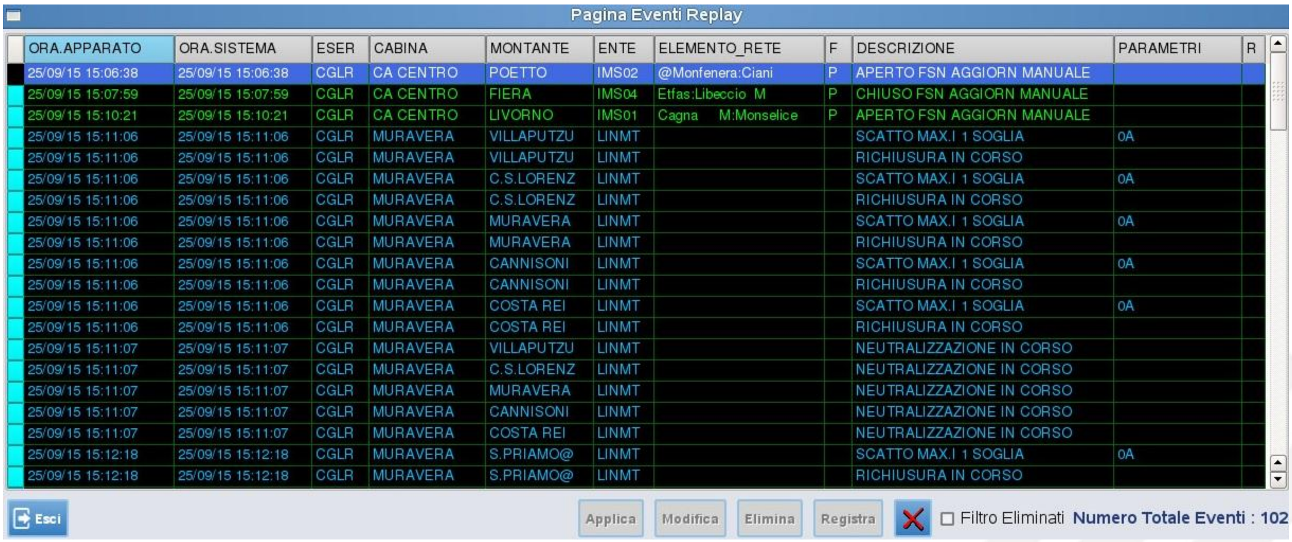


Figure 66: Network Scheme "POETTO" at the starting time interval.

In the following picture the evolution of the network, once the event "*Aperto Fuori Stato Normale*" occurred, is shown. This event causes the outage of the entire feeder as well as it occurred in the Real Operation System.



ORA.APPARATO	ORA.SISTEMA	ESER	CABINA	MONTANTE	ENTE	ELEMENTO_RETE	F	DESCRIZIONE	PARAMETRI	R
25/09/15 15:06:38	25/09/15 15:06:38	CGLR	CA CENTRO	POETTO	IMS02	@Monfenera:Ciani	P	APERTO FSN AGGIORN MANUALE		
25/09/15 15:07:59	25/09/15 15:07:59	CGLR	CA CENTRO	FIERA	IMS04	Etfas:Libeccio M	P	CHIUSO FSN AGGIORN MANUALE		
25/09/15 15:10:21	25/09/15 15:10:21	CGLR	CA CENTRO	LIVORNO	IMS01	Cagna M:Monselice	P	APERTO FSN AGGIORN MANUALE		
25/09/15 15:11:06	25/09/15 15:11:06	CGLR	MURAVERA	VILLAPUTZU	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
25/09/15 15:11:06	25/09/15 15:11:06	CGLR	MURAVERA	VILLAPUTZU	LINMT			RICHIUSURA IN CORSO		
25/09/15 15:11:06	25/09/15 15:11:06	CGLR	MURAVERA	C.S.LORENZ	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
25/09/15 15:11:06	25/09/15 15:11:06	CGLR	MURAVERA	C.S.LORENZ	LINMT			RICHIUSURA IN CORSO		
25/09/15 15:11:06	25/09/15 15:11:06	CGLR	MURAVERA	MURAVERA	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
25/09/15 15:11:06	25/09/15 15:11:06	CGLR	MURAVERA	MURAVERA	LINMT			RICHIUSURA IN CORSO		
25/09/15 15:11:06	25/09/15 15:11:06	CGLR	MURAVERA	CANNISONI	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
25/09/15 15:11:06	25/09/15 15:11:06	CGLR	MURAVERA	CANNISONI	LINMT			RICHIUSURA IN CORSO		
25/09/15 15:11:06	25/09/15 15:11:06	CGLR	MURAVERA	COSTA REI	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
25/09/15 15:11:06	25/09/15 15:11:06	CGLR	MURAVERA	COSTA REI	LINMT			RICHIUSURA IN CORSO		
25/09/15 15:11:07	25/09/15 15:11:07	CGLR	MURAVERA	VILLAPUTZU	LINMT			NEUTRALIZZAZIONE IN CORSO		
25/09/15 15:11:07	25/09/15 15:11:07	CGLR	MURAVERA	C.S.LORENZ	LINMT			NEUTRALIZZAZIONE IN CORSO		
25/09/15 15:11:07	25/09/15 15:11:07	CGLR	MURAVERA	MURAVERA	LINMT			NEUTRALIZZAZIONE IN CORSO		
25/09/15 15:11:07	25/09/15 15:11:07	CGLR	MURAVERA	CANNISONI	LINMT			NEUTRALIZZAZIONE IN CORSO		
25/09/15 15:11:07	25/09/15 15:11:07	CGLR	MURAVERA	COSTA REI	LINMT			NEUTRALIZZAZIONE IN CORSO		
25/09/15 15:12:18	25/09/15 15:12:18	CGLR	MURAVERA	S.PRIAMO@	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
25/09/15 15:12:18	25/09/15 15:12:18	CGLR	MURAVERA	S.PRIAMO@	LINMT			RICHIUSURA IN CORSO		

Figure 67: List of events occurred after the event "Aperto Fuori Stato Normale"

In the picture below a representation of the secondary substation "Monfenera 070221" is given. This node has been affected by the outage and in particular it is interesting to see that only the breaker CS664 is opened.

Figure 68: Representation of the secondary substation "Monfenera 070221"

The following picture represents the network at the end time of the selected interval time. It is important to highlight that the representation is the same of the one produced by the Real Operation System and it guarantees the Replay correct mode of operation.

Figure 69: Representation of the network at the ending time of the interval

In order to complete the validation of the operation mode of Replay it is necessary to check the RETIM data and in particular the AV20 to compare those values with the ones in RETIM corresponding to the real operation conditions.

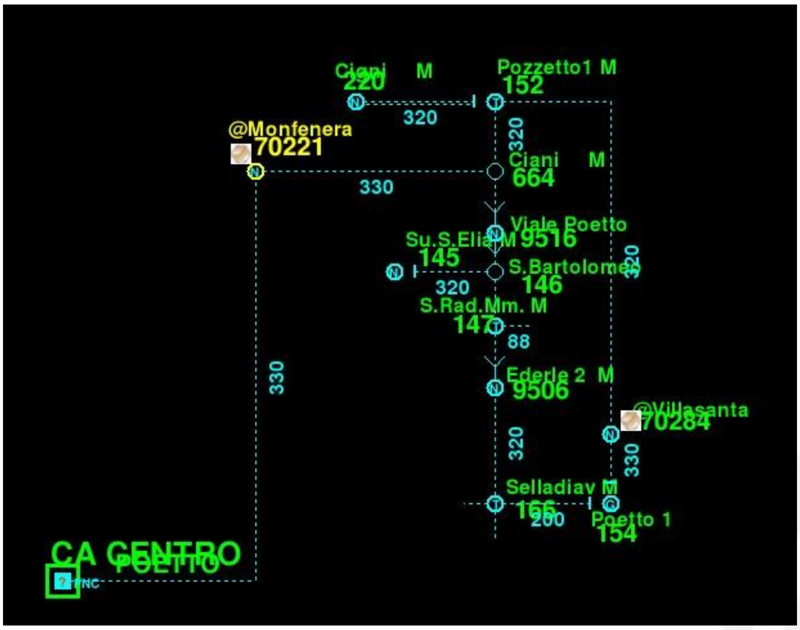
At 15:21 the breaker in the secondary substation "Monfenera 70221" has been closed, the network feeder "POETTO" is powered again and the corresponding interruption has been solved.

In the following pictures a complete list of events, the electric scheme with the repowered conditions and the corresponding RETIM interface are represented.

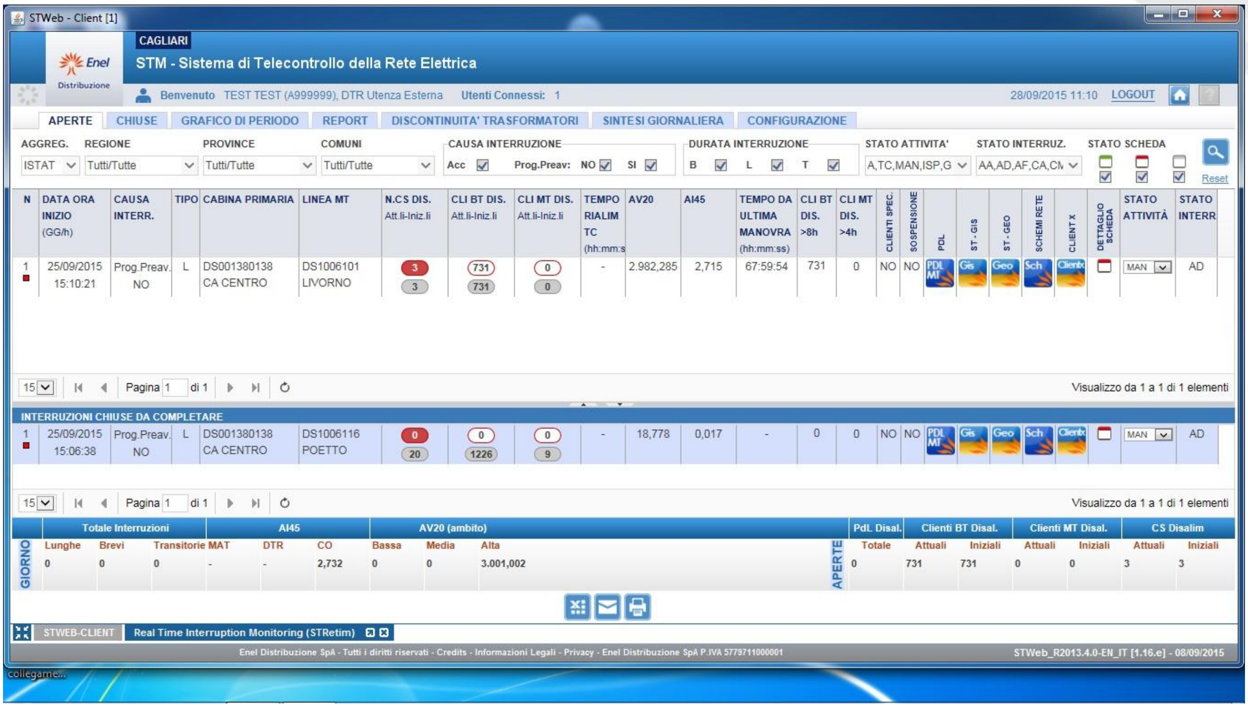
Pagina Eventi Replay

ORA.APPARATO	ORA.SISTEMA	ESER	CABINA	MONTANTE	ENTE	ELEMENTO_RETE	F	DESCRIZIONE	PARAMETRI	R
25/09/15 15:16:59	25/09/15 15:16:59	CGLR	MURAVERA	SPADULA	LINMT			NEUTRALIZZAZIONE IN CORSO		
25/09/15 15:16:59	25/09/15 15:16:59	CGLR	MURAVERA	EAF@	LINMT			NEUTRALIZZAZIONE IN CORSO		
25/09/15 15:16:59	25/09/15 15:16:59	CGLR	OVODDA	TETI	LINMT			NEUTRALIZZAZIONE IN CORSO		
25/09/15 15:16:59	25/09/15 15:16:59	CGLR	OVODDA	AVV.STATIC	LINMT			NEUTRALIZZAZIONE IN CORSO		
25/09/15 15:18:10	25/09/15 15:18:10	CGLR	MURAVERA	VILLAPUTZU	LINMT			RICH RAPIDA POSITIVA		
25/09/15 15:18:10	25/09/15 15:18:10	CGLR	MURAVERA	C.S.LORENZ	LINMT			RICH RAPIDA POSITIVA		
25/09/15 15:18:10	25/09/15 15:18:10	CGLR	MURAVERA	MURAVERA	LINMT			RICH RAPIDA POSITIVA		
25/09/15 15:18:10	25/09/15 15:18:10	CGLR	MURAVERA	CANNISONI	LINMT			RICH RAPIDA POSITIVA		
25/09/15 15:18:10	25/09/15 15:18:10	CGLR	MURAVERA	COSTA REI	LINMT			RICH RAPIDA POSITIVA		
25/09/15 15:19:22	25/09/15 15:19:22	CGLR	MURAVERA	S.PRIAMO@	LINMT			RICH RAPIDA POSITIVA		
25/09/15 15:19:22	25/09/15 15:19:22	CGLR	MURAVERA	SPADULA	LINMT			RICH RAPIDA POSITIVA		
25/09/15 15:19:22	25/09/15 15:19:22	CGLR	MURAVERA	EAF@	LINMT			RICH RAPIDA POSITIVA		
25/09/15 15:19:22	25/09/15 15:19:22	CGLR	OVODDA	TETI	LINMT			RICH RAPIDA POSITIVA		
25/09/15 15:19:22	25/09/15 15:19:22	CGLR	OVODDA	AVV.STATIC	LINMT			RICH RAPIDA POSITIVA		
25/09/15 15:21:57	25/09/15 15:21:57	CGLR	CA CENTRO	POETTO	IMS02	@Monfenera:Ciani	P	CHIUSO SN AGGIORN MANUALE		
25/09/15 15:22:06	25/09/15 15:22:06	CGLR	MURAVERA	VILLAPUTZU	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
25/09/15 15:22:06	25/09/15 15:22:06	CGLR	MURAVERA	VILLAPUTZU	LINMT			RICHIUSURA IN CORSO		
25/09/15 15:22:06	25/09/15 15:22:06	CGLR	MURAVERA	C.S.LORENZ	LINMT			SCATTO MAX.I 1 SOGLIA	0A	
25/09/15 15:22:06	25/09/15 15:22:06	CGLR	MURAVERA	C.S.LORENZ	LINMT			RICHIUSURA IN CORSO		
25/09/15 15:22:06	25/09/15 15:22:06	CGLR	MURAVERA	MURAVERA	LINMT			SCATTO MAX.I 1 SOGLIA	0A	

Esci | Applica | Modifica | Elimina | Registra | Filtro Eliminati | Numero Totale Eventi : 102



The following picture represents the RETIM interface in the Replay System. The value of the AV20 in the simulation is the same of the Real Operation System (**18.78 min*customers).** This examples proves that Replay is correctly working.



3. Replay System-ex post analysis

By the use of the Replay tool it is possible to modify the configuration of specific network and at a defined time interval, e.g. under fault condition, to choose the configuration that can potentially minimize the outage for the customers, to monitor the results in terms of quality of service and in particular with the aim to minimize the A20 parameter (min*customers).

In the test described below, the time interval selected is the same considered in the Real System Operation:

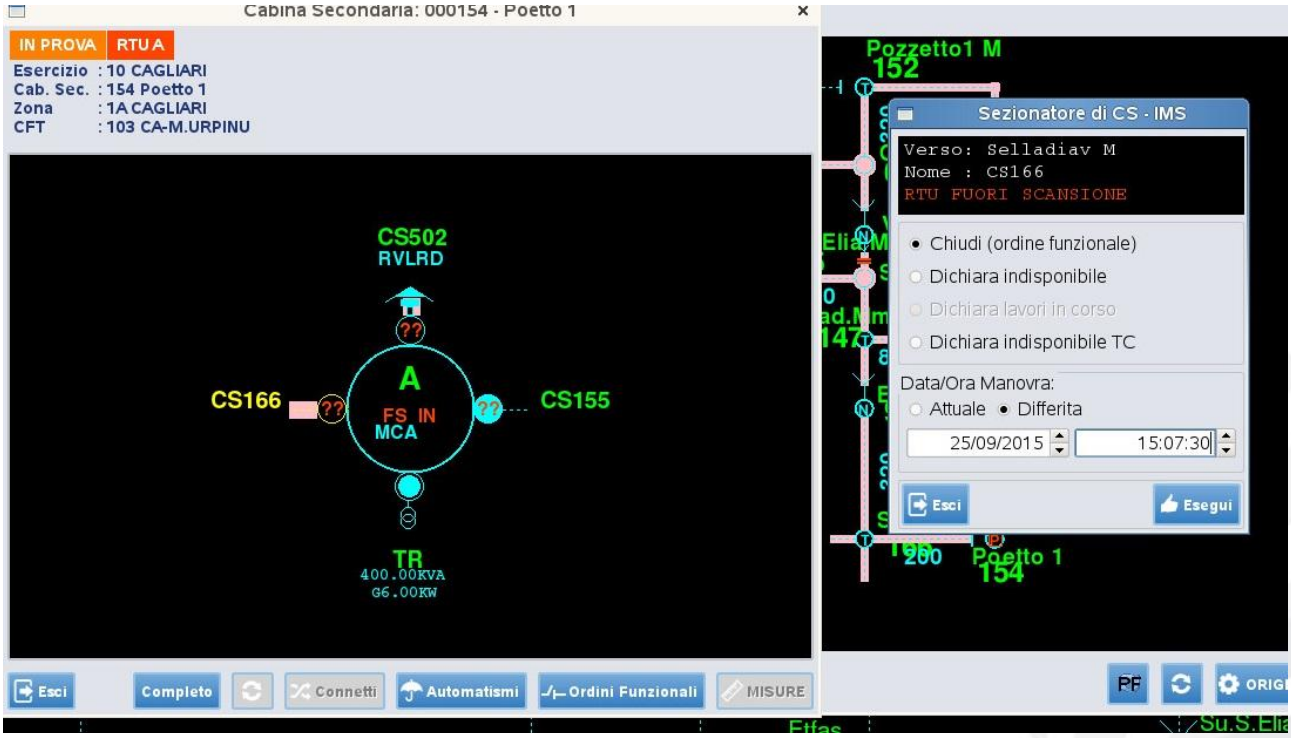
Day: 25/09/2015
Time Interval: 15:05 – 15:25

The test consists in opening the breakers in the secondary substation 70221 and repowering the line by the use of another feeder and compare the solutions in order to improve the network management.

In order to repower the MV feeder by the another feeder the following operations are proposed:

- Opening of the secondary substation “Villasanc 000502” breaker CS529
- Reclosing of the secondary substation “Poetto 1” breakers CS166 and CS502.

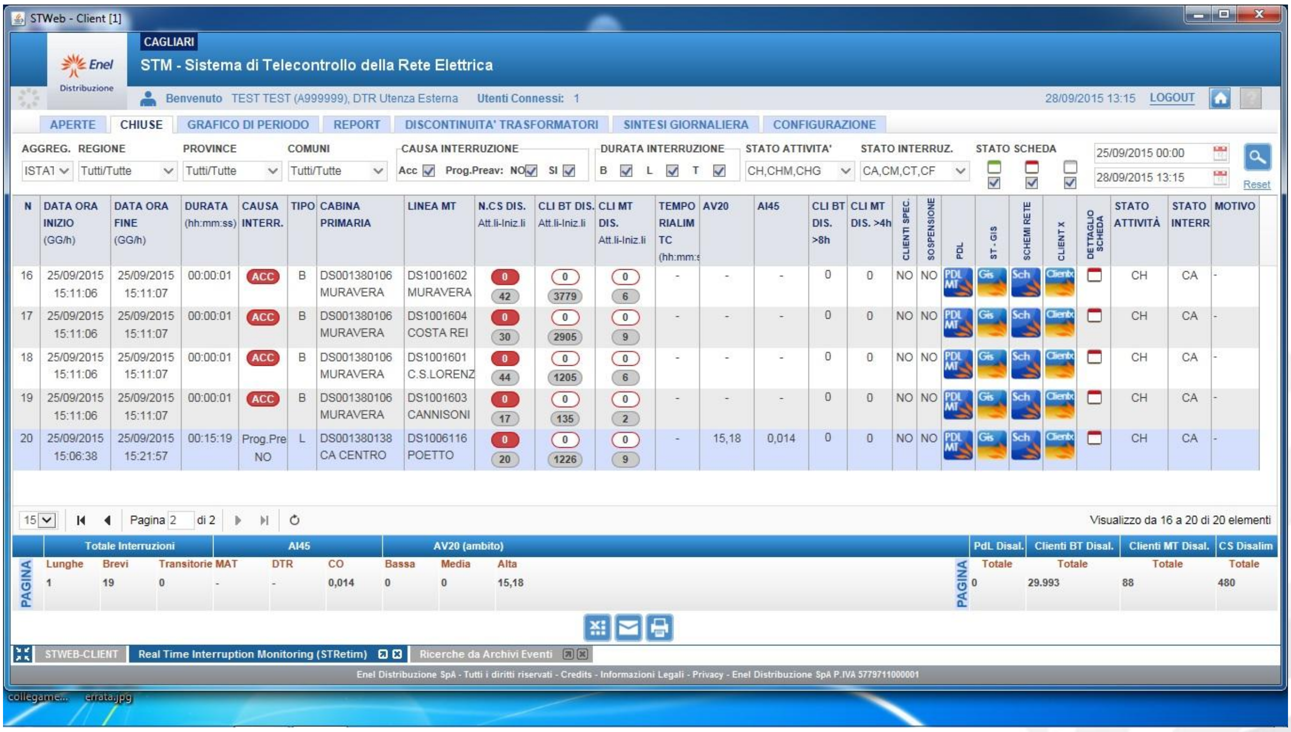
All the operations on the network are carried out by the use of the SCADA interface which performs functional orders (commands) able to act the proper operations in the SCADA.
In the next picture an example of this operations is given.



The representation of network configuration given in Figure below, shows the section of the network that has been repowered and the partial section still interrupted.

RETIM Replay allows to calculate the new value of AV20 managing the network once the feeder is repowered. In this case the value of AV20 (min*customers) is 15.18. This evaluation means that introducing a rational network management, a potential SAIDI reduction is possible. Furthermore it is interesting to highlight that by the use of this test method it is possible to measure the KPI identified as SRI (SAIDI Reduction Index).[7]

[7] The calculation of AV20 is almost identical to that of the SAIDI. For more details, please refer to D3.2 "Tools and methodologies for forecasting, operational scheduling and grid optimization".



4. Replay System *predictive* analysis

In the current section an example of predictive analysis is given by using the Load flow calculation. In particular the Replay tool allows to define a scenario to be tested by the selection of a network and by the upload of a data base of events.

Applying the scenario to be simulated, it is possible to select a network – e.g. the MV network in the Area of Cagliari – and at the same time create or modify the existing DB event.

The network considered is the one referred to the 25/0972015 (15:05) (see paragraph 3.1)
In the following picture a representation of the interface mask used in Replay is given.

The proposed scenario for the load flow calculation is the number **Id. 53** and the time interval considered to elaborate the calculation is:

Day: 10/07/2015
Time Interval: 13:00 – 16:00

When a load flow calculation is requested, the Replay multifunctional calculator requests data to MAGO (forecast data) available for the considered time interval. If the data are not available a standard profile based on the historical values is given.

Mainly two kind of criticalities could be detected: overloads and voltage out of range. In particular regarding the voltage range in Italy the regulatory rules admit a range **±10%,** but for the purpose of this document a range of **±3%** has been set. The respect of the parameters related to the quality of the voltage (violations) are defined in the normative CEI EN 50160.

The proposed scenario presents one criticality of overload in the branch, as highlighted in red, whereas in terms of voltage criticalities the conditions are not respected in different nodes (choosing a range **±3%**).

In the following table a simple representation of the load flow calculation results is given.
In the first table an example of the results related to the current calculation for each branch is given. In the example below the current medium value is represented compared with the branch limit.

CODICE NODO1	CODICE NODO2	CORRENTE (A)	LIMITE IMAX (A)	ALARM
DS102000043102	DS102000044101	32	320	0
DS001380138225	DS102009371102	82	330	0
DS102000427102	DS102000713102	35	320	0
DS102000044103	DS102000342103	34	320	0
DS102009377102	DS102000454104	37	330	0
DS102000501102	DS102000614101	25	320	0
DS102000029102	DS102000028101	54	320	0
DS102000589102	DS102000699102	22	540	0
DS102000022101	DS102000023103	29	320	0
DS102000454102	DS102000501101	28	320	0
DS102000138101	DS102000137101	19	340	0
DS102000664102	DS102000659102	109	320	0
DS102000041103	DS102000138102	23	320	0
DS102000152101	DS102000659101	110	320	0
DS102000589101	DS102000117101	18	320	0
DS102000424101	DS102000421102	66	320	0
DS001380138224	DS102000217103	20	330	0
DS102000749102	DS001380138219	40	330	0
DS102000025105	DS102009375103	63	320	0
DS102000699104	DS001380138213	26	320	0
DS102000539102	**DS102000502101**	**114**	**100**	**1**

In the next picture two examples of voltage violations are represented in the table showing the voltage value for each node compared with the required limit.

CODICE NODO	TENSIONE (kV)	QUALITY	MAXV (kV)	ALARM_MAXV	MINV (kV)	ALARM_MINV
DS1020001561A1	15,57285907	192	15,45	1	14,55	0
DS1020004321A1	15,57624362	192	15,45	1	14,55	0

CODICE NODO	TENSIONE (kV)	QUALITY	MAXV (kV)	ALARM_MAXV	MINV (kV)	ALARM_MINV
DS1020001561A1	15,44218595	192	16,5	0	13,5	0

Once the Replay simulator has supported the operator identify the criticalities on the network, considerations on the available flexibility (in terms of active power modulation) can be exploited to solve the network problems.

In order to identify the solution, two levers are available:

- **new network configuration**
- **active power modulation**

Regarding the network configuration the approach is similar to the one used for optimizing the interruptions time interval, whereas in the case of the power modulation the approach is more complex because of the use of a separated interface to access the network DB.
In the following picture the interface to modify the active power (the contractual power injection) is shown.

Record da 1 a 2 di 2 · 1 di 1 · Visibili 50

		Data AMS	Codice unità	Serie nodo	Numero nodo	Stato	Tipo Elem.	Id Elem	Pot. disp.	Pot. in franchigia	Pot. gruppi	Pot prodotta	Tens. nom.
		2015-04-30 00:00	DS10	2	070416	E	U	01	1200	600			15
		2015-04-30 00:00	DS10	2	070416	E	U	01	600	600			15

In the represented example, the reduction of the active power of the 50% (from 1200kVA to 600 kVA) for the customer connected in the node 070416, allows to eliminate the voltage criticality in the highlighted node.

CODICE NODO	TENSIONE (kV)	QUALITY	MAXV (kV)	ALARM_MAXV	MINV (kV)	ALARM_MINV
DS1020001561A1	15,44218595	192	16,5	0	13,5	0

This approach it is only an example representing how to test the correct operation mode of the simulator working on the real network and with the real network data. In a future market context where flexibility rules will be defined and power modulations will be applied within defined bounders, it could be possible to have agreement with producers and customers in order to support the DSOs solving network criticalities and increasing DRES penetration level.

<u>Analysis of the KPIs on the basis of the executed tests</u>

In the current section a brief analysis of the measurability of KPIs and some observations for each of them are given.

Regarding the possibility to potentially reduce the SAIDI by the introduction of the Replay in the training activity, in the previous sections a specific testis given (pag.30). In particular with the possibility to execute an ex post analysis, the SAIDI could be reduced of 20% (AV20 value from 18,78 to 15,18)

Quality of Service (Customer/Producer point of view)
AV20: min * customers
AV20 reduction for each faults to be managed by the control room operator $AV20[\%] = \frac{AV20_{BAU} - AV20_{REPLAY}}{AV20_{BAU}}$ •communication times "standardized"   •field crew time to operate "standardized" (only control room activity is considered)

Regarding the possibility to execute load flow calculation directly on the SCADA system, by using power modulation it is possible to reduce a high number of criticalities compared with the traditional approach. For this report, fictitious criticalities (1 overcurrent and 2 overvoltages) have been created to test the performance of the tool while in WP4, this KPIs will be concretely calculated by using the Replay on a portion of the network with several criticalities.

Reduce energy curtailment of RES and DER:
Criticalities Reduction Index
Number of criticalities reduced by agreed power modulation (from *Pn* → to *Pc*) $CRI = \left[\frac{(n_v)_{Pn} - (n_v)_{Pc}}{(n_v)_{Pn}}\right]_{lineX}$

The assessment of the KPIs indicated below can be only addressed theoretically. This kind of KPIs are based on calculations and considerations on the DSOs internal processes, they are dependent from the procedures of the DSO and the already existing systems and tools. Anyway an estimation of their values will be built and described in the scope of the deliverable of the WP4. In particular in the following tables a formula for each of them is represented.

Training Time Saving (DSO point of view)
Time needed to become expert SCADA operator (*e.g. fault management*)
Fixed a "standard" number/kind of faults as a learning program → evaluate the time saving by Replay $TTS[\%] = \frac{(n_g \times t_F)_{BAU} - (n_g \times t_F)_{REPLAY}}{(n_g \times t_F)_{BAU}}$

Training Cost Saving (DSO point of view)
Costs needed to become expert SCADA operator *e.g. fault management*
Fixed a "standard" number/kind of faults as a learning program → evaluate the time saving using a SCADA real events simulator. $TCS[\%] = \frac{(n_g \times C_{F1})_{BAU} - (n_g \times C_{F2})_{REPLAY}}{(n_g \times t_F)_{BAU}}$

Time Activity Saved (DSO point of view)

Time Activity Saved

Evaluate the time saved on the operator daily activities by the use of replay

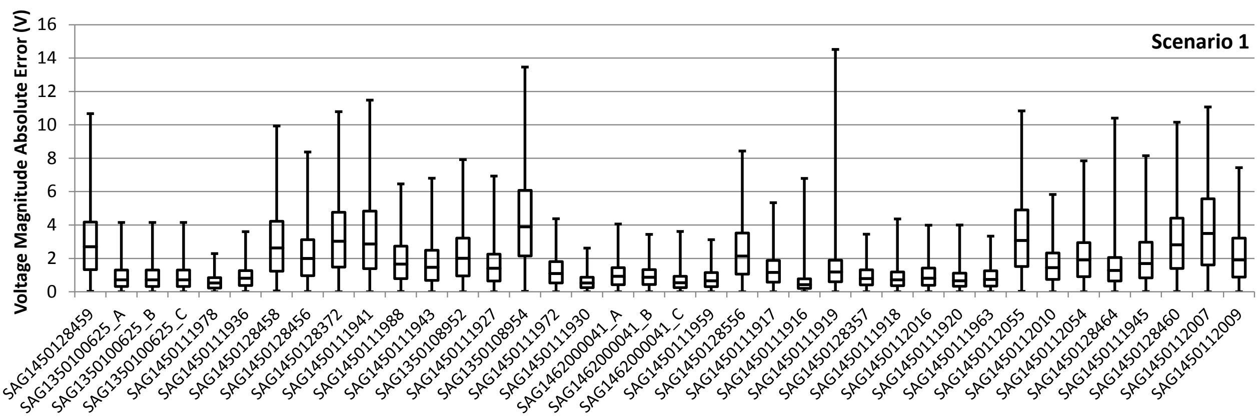
$$Time\,Activity\,Saved = \frac{(t)_{BAU} - (t)_{Replay}}{(t)_{BAU}}$$

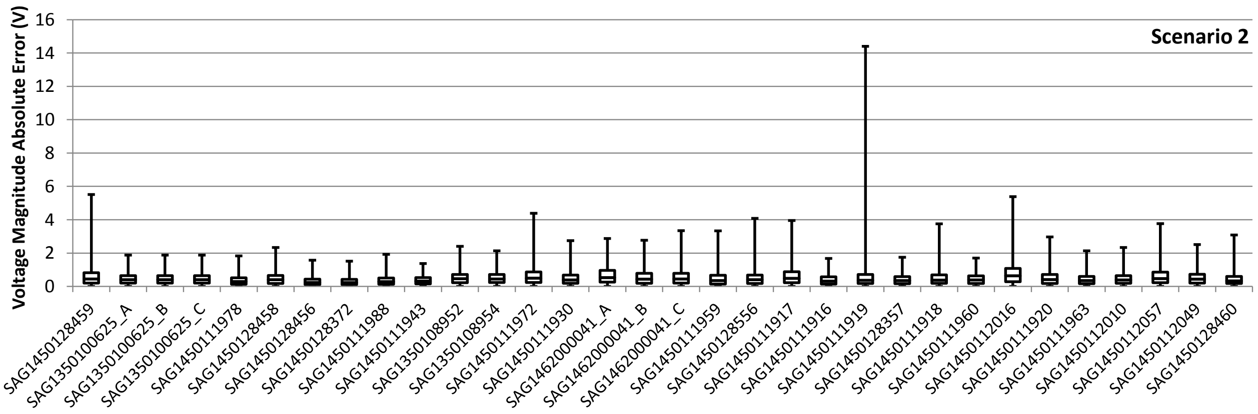
t BAU= time needed to manage a specific activity by a SCADA operator
t REPLAY = time needed to manage a specific activity (the same) by a SCADA operator

3.3.2 Results for Portugal

3.3.2.1 Low Voltage Distribution State Estimator

In Figure 70 boxplots with the absolute error obtained in scenarios 1, 2 and 3 for the voltage magnitude in all the customers not being monitored in real-time are depicted for the entire evaluation set (see section 0). The absolute error was calculated between the real values (gathered from the SM installed at the customers' premise) and the estimated values obtained with the DSE developed. As it was expected, the estimation accuracy is improved when more real-time measurements are available. However, the improvement verified in scenario 2 comparing with scenario 1 was not only due to the number of real-time measurements available (twice the number of the existing in scenario 1), but also due to their location that contributed to overcome the lack of electrical information in the other feeder. It should be recalled that in scenario 1 there are no SM_r connected to feeder 2, whereas in scenario 2 both feeders have the same number of customers with SM_r.





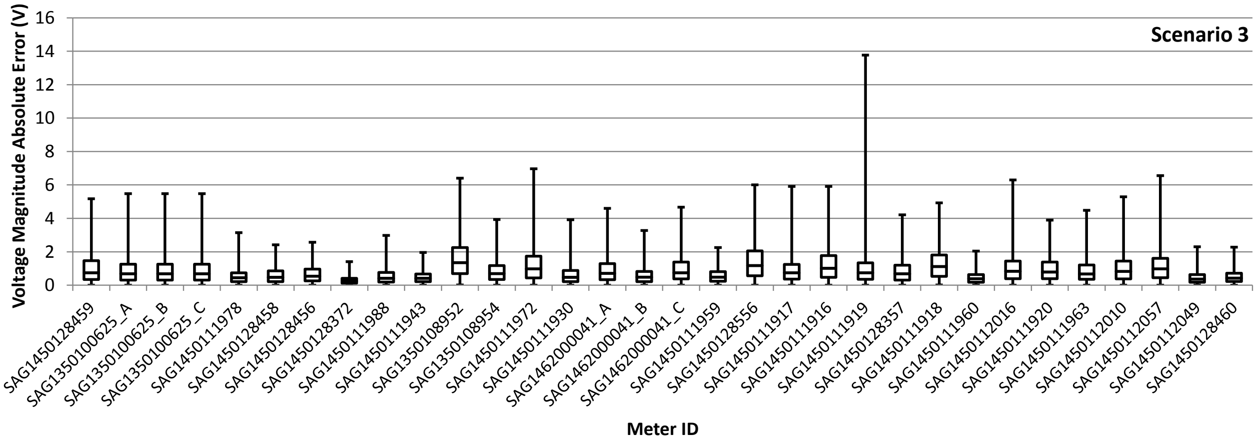


Figure 70 – Voltage magnitude absolute error for all customers (not being real-time monitored) in scenarios 1, 2 and 3.

Comparing the voltage magnitude absolute error obtained for the three scenarios, it can be observed that the error in scenario 3 is smaller than the obtained in scenario 1 and bigger than the obtained in scenario 2. Although the number of real-time measurements available in scenario 3 is the same as in scenario 2, the number of variables to be estimated in scenario 3 is higher due to the estimation of the active power values in this scenario.

The state estimation error obtained in scenario 1 accounts for the worst results in all the scenarios under study. Nevertheless, the value attained is lower than 4 V in 75% of the cases (75% of the samples analysed) in the large majority of the SM, which gives good indications regarding the estimation accuracy of the DSE.

Looking to Figure 70, it is also possible to see that the maximum absolute error obtained for the customer with SM "SAG1450111919" hardly varies from one scenario to another (remains at around 14 V in the three scenarios). Despite this value may seem high, it occurs only once, being the next higher value lower than 5 V in all scenarios. This result can be observed in Table 42, where it is presented the four worst values for the absolute error obtained for the SM "SAG1450111919" in each scenario. After the inspection in the historical database of all quantities measured in this time instant, a careful electrical analysis was performed. The analysis made included the comparison between the voltage profiles verified for this time instant and the voltage profiles of other similar time instants in terms of the power consumed in each node. At the end, the conclusion is that the value of 14 V attained for the absolute error in the SM "SAG1450111919" was in fact due to a measurement gross error.

Scenario 1 (V)	Scenario 2 (V)	Scenario 3 (V)
14.5	14.4	13.8
4.7	2.1	4.7
4.0	1.9	4.2
3.9	1.9	4.0

Table 42 – The four worst values for the absolute error obtained for the SM SAG1450111919 in each scenario.

In Figure 71 the cumulative distribution function of the absolute error for the SM "SAG1450111919" in all the scenarios is depicted, from which one may have a better perspective about the probability of the absolute error stays below a given value. From its analysis it can be seen that in 90% of the cases the absolute error stays below than 2.4 V, 1.1 V and 2.0 V in scenarios 1, 2 and 3 respectively.

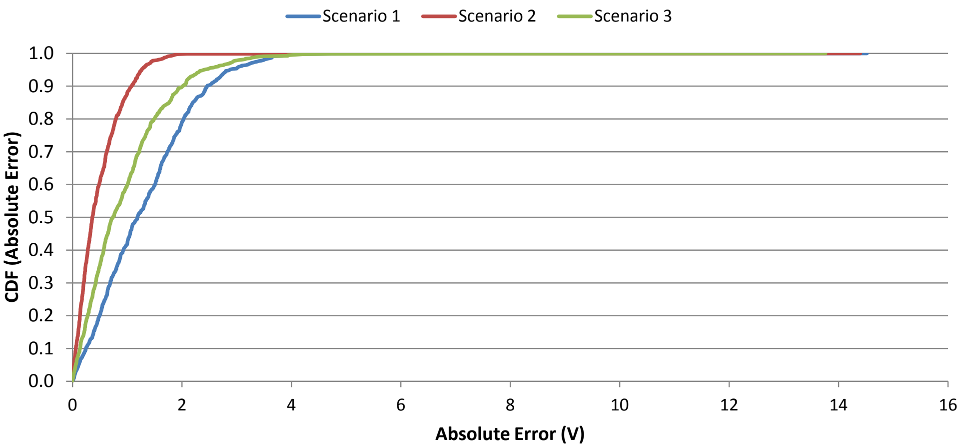


Figure 71 - Cumulative distribution function of the voltage magnitude absolute error obtained for the customer with SM SAG1450111919 in each scenario.

In Figure 72 the active power absolute error for all customers that are not being monitored in real-time manner and for which historical data of all electrical quantities was available is displayed (see Table 20). Comparing with Figure 70, the estimated values for the active power are in less number than the voltage values, which is explained due to the lack of historical data related with this electrical quantity.

Observing Figure 72, it can be seen that despite there are maximum absolute errors around of 2.5 kW, the majority of errors stays lower than 0.5 kW in 75% of the cases. The MAE obtained for the active power estimation was 0.35 kW.

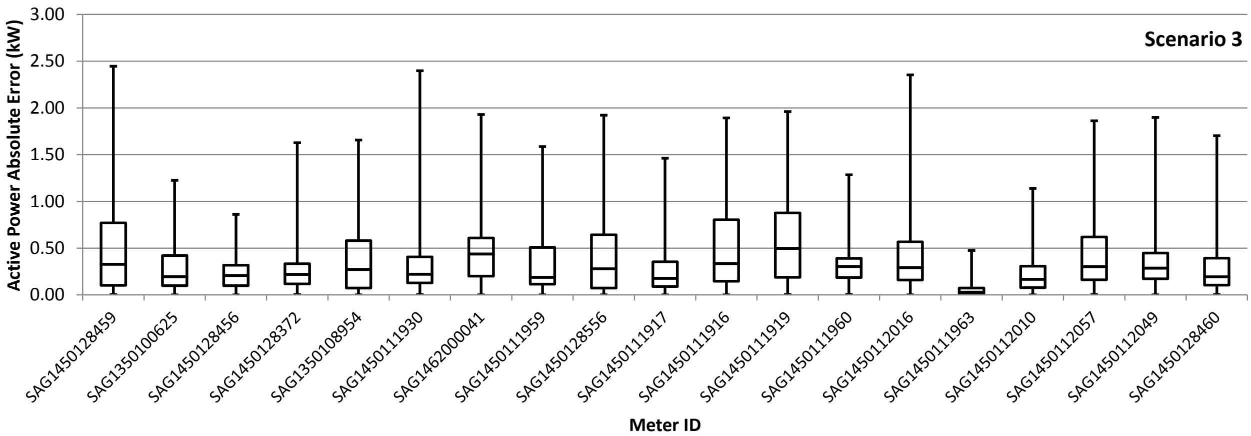


Figure 72 - Active power absolute error for all customers (not being real-time monitored) and for which was available a valid historical database.

In the next few pages graphical representations for the list of KPIs exposed in Table 31 are shown. Tables with minimum, average and maximum values for each KPI calculated are also presented.

In Figure 73 and Table 43 the results for the KPI that evaluates the accuracy of active power injections are shown. It is important to state that this KPI was only calculated for scenario 3, since it was only in this scenario that values of active power injections were estimated. The results for the 1-norm and 2-norm seem to be high. Nevertheless, as it was referred in section 3.2.3, the purpose of the results for this KPI is only to make relative comparisons. In this sense, no conclusions about the DSE accuracy in absolute terms should be taken when looking to the results attained for these 2 norms. Additionally, it is important to have in mind that these results may have been influenced by measurement errors, since in its calculation measured values were used (real data gathered from the customers' SM) instead of the true values which are unknown.

Differently from 1-norm and 2-norm, the infinity norm allows taking some conclusions about the DSE accuracy, since its mathematical expression does not involve a sum of errors, but is only related with maximum absolute errors. From the results obtained for this norm, it can be seen that in 75% of all the time instants analysed the maximum error is below than 1.4 kW.

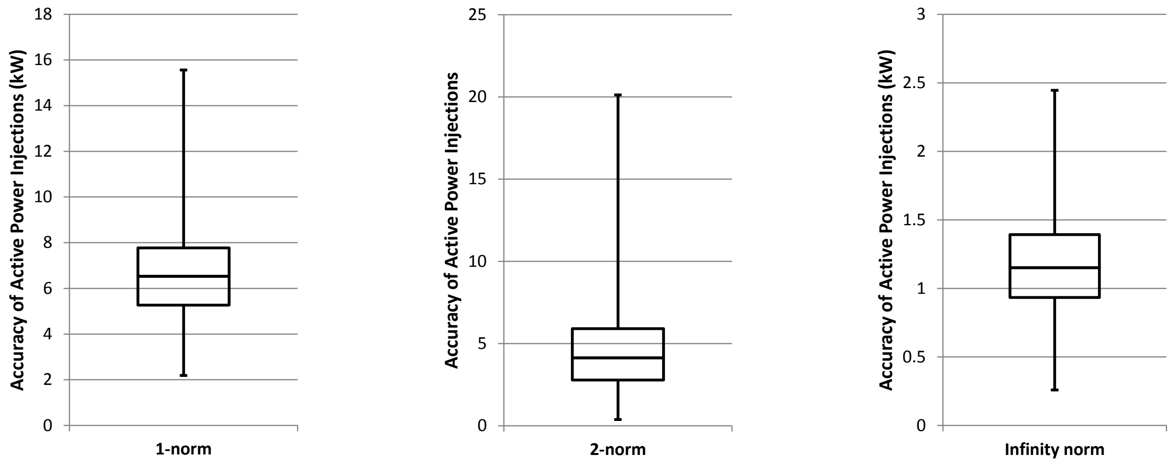


Figure 73 – Accuracy of active power injections KPI.

	1-norm (kW)	2-norm	Infinity norm (kW)
Maximum	15.558	20.115	2.445
Average	6.652	4.592	1.166
Minimum	2.190	0.379	0.259

Table 43 – Accuracy of active power injections KPI.

The accuracy of voltage index is presented in Figure 74 and Table 44 for each scenario. From the results it can be noticed a significant improvement of voltage accuracy from scenario 1 to scenario 2 due to the increase on the number of SM_r. It should be recalled that in scenario 1 no real-time information exists in one of the two network feeders. This fact had a strong impact on the estimation and, consequently, on the accuracy of voltage index. In scenario 3, in spite of the number of SM_r is the same as in scenario 2, the accuracy of voltage estimation slightly decreases due to the larger number of quantities intended to be estimated (besides voltage magnitudes, some active power values were estimated as well).

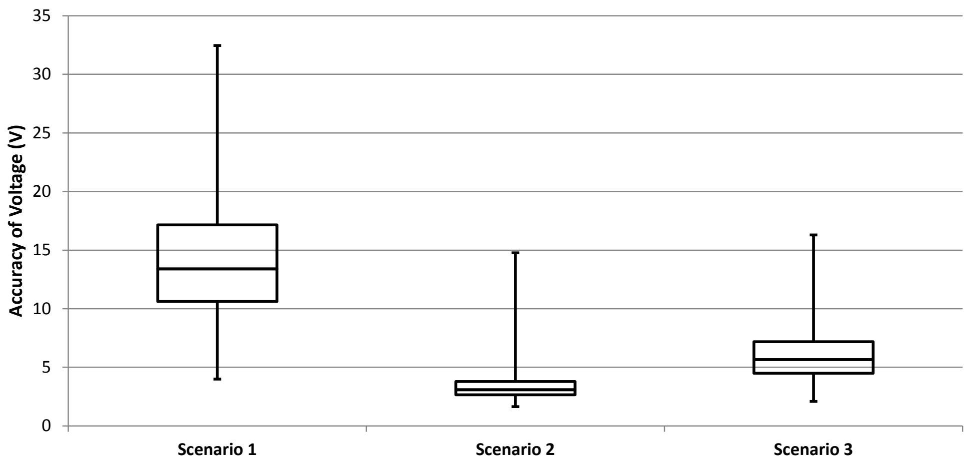


Figure 74 - Accuracy of voltage KPI.

	Scenario 1 (V)	Scenario 2 (V)	Scenario 3 (V)
Maximum	32.5	14.8	16.3
Average	14.1	3.4	6.0
Minimum	4.0	1.6	2.1

Table 44 – Accuracy of voltage KPI.

Figure 75 and Table 45 show the variation of the EEI values in each scenario. This index depends on the number of measurements for which the estimation was performed and on the range of values of the standard deviations. Assuming for each measurement a random Gaussian noise of about ± 3 standard deviations around the mean, the maximum (threshold) value for the EEI index would be 9 times the number of estimated measurements (see Table 45). Thus, the threshold for the scenarios 1, 2 and 3 are respectively 324, 270 and 441. From Figure 75 and Table 45, it is evident that the values of EEI index for scenarios 1 and 2 are very low when compared to the threshold value. This result supports once more the good accuracy of the DSE. Although in scenario 3 the maximum obtained is higher than the correspondent threshold, this result occurs only in 2 time instants of the entire evaluation set.

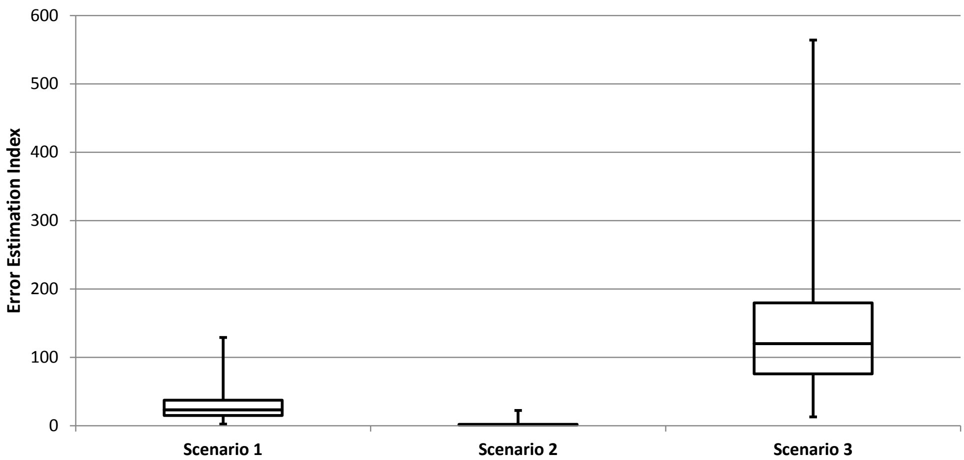


Figure 75 - Error estimation index KPI.

	Scenario 1	Scenario 2	Scenario 3
Maximum	129.06	22.26	563.98
Average	27.83	1.71	137.94
Minimum	2.38	0.34	12.98

Table 45 – Error estimation index KPI.

3.3.2.2 Low Voltage Control

3.3.2.2.1 Test Case A1

Similarly to what was considered for the French Network, the voltage limits assumed for the Portuguese network are +/-8% of the nominal voltage level, which defines the acceptable voltage range within the interval [211.6; 248.4] V. It is assumed that when the state estimation tool is used, an associated estimation error affects the voltage values so, for those cases, the acceptable range considers the 2% of estimation error. Therefore, the voltage limits, when the state estimation is used, is between [216.2; 243.8] V.

Regarding the Portuguese network, despite overvoltage violations have been verified in the *Status Quo* scenario, there are no controllable resources in the network that could allow the management of the overvoltage problem in this scenario. Therefore, the LVC tool was not able to found neither test any suitable solution to solve this problem. In Table 46, the maximum voltage value registered in the available historical database provided for this network is presented. It is important to mention that this overvoltage problem occurs at the bottom of the network in a node where a three-phase customer is directly connected and which has single phase clients nearly located as well. Therefore, even thought for “Test Case A1” there are no microgeneration units connected in the network, an unbalanced situation motivated by the different distribution of the loads (even inside a three-phase customer’s facility) together with a “bad” grounded neutral could easily result on a floating neutral situation that can lead to an overvoltage problem in a given phase.

Problem Location (Node ID)	Problem Location (Customer ID)	Problem Location (Meter ID)	Phase	Voltage Value (V)
27	C9	SAG1462000041	B	249.00

Table 46 - A1: Initial voltage value.

As expected, since there are no microgeneration units, storage devices nor transformers with OLTC in this network, the list of equipment that can be actuated in order to solve the overvoltage problem is empty.

3.3.2.2.2 Test Case A2

The initial voltage value for the undervoltage scenario selected is presented in Table 47.

Problem Location (Node ID)	Problem Location (Customer ID)	Problem Location (Meter ID)	Phase	Voltage Value (V)
76	C30	SAG1450111927	A	206.00

Table 47 – A2: Initial voltage value.

The sorted list of equipment ordered by their given rank is as follow in Table 48.
The rank of each equipment is calculated regarding the cost of actuation (which differs for each type of equipment), the connection topology (mono-phase or three-phase) the contract type (flexible or non-flexible) and the distance to voltage deviation location.

Order	Type	Customer ID	Meter ID	RANK

1	Load	C30	SAG1450111927	1551000000000
2	Load	C36	SAG1450111917	1551000034000
3	Load	C6	SAG1450112016	1551000069000
4	Load	C40	SAG1450111919	1551000103000
5	Load	C16	SAG1450112010	1551000121000
6	Load	C2	SAG1450112052	1551000127000
7	Load	C20	SAG1450112057	1551000136000
8	Load	C21	SAG1450111941	1551000636000
9	Load	C19	SAG1450128456	1551000646000
10	Load	C43	SAG1450112054	1551000664000
11	Load	C9	SAG1462000041	1561000011000
12	Load	C17	SAG1350100625	1561000034000

Table 48 – A2: Equipment rank.

The resulting set-point is shown in Table 49 where the load to be actuated in order to solve the undervoltage problem is identified. In this case, the state estimation algorithm was used within the LVC to predict the voltage values in the network if the corrective action had been implemented.

Steps	Customer ID	Meter ID	Initial Power (kW)	Set point (kW)
1	C30	SAG1450111927	6.47	2.35

Table 49 – A2: Set-points.

In the Table 50 it is presented the final voltage value obtained is presented.

Problem Location (Node ID)	Problem Location (Customer ID)	Problem Location (Meter ID)	Phase	Voltage Value (V)
76	C30	SAG1450111927	A	221.65

Table 50 – A2: Final voltage value with state estimation.

The voltage variation in the problematic node, where the customer *350466* is connected, can be observed.

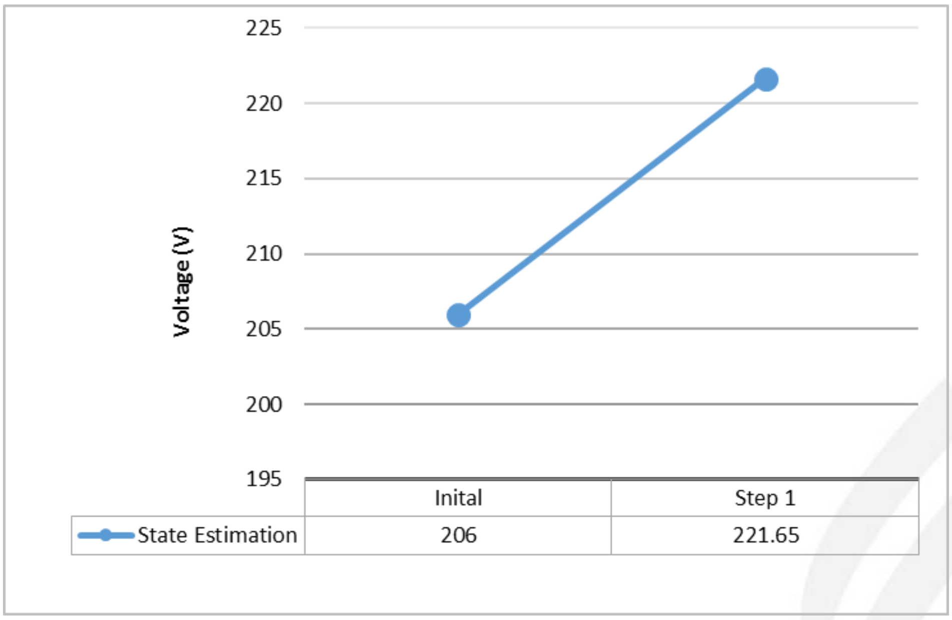


Figure 76 - A2: Voltage evolution within LVC.

The relevant KPIs for this test case were computed and are presented in Table 51.

KPI index	KPI name	Value (%)
1	Increase RES and DER hosting capacity	3.49
2	Reduced energy Curtailment of RES and DER	40
3	Increased hosting capacity for electric vehicles and other loads	3.49
4	Reduction of Technical Losses	-
5	Share of Electrical Energy produced by RES	0
6	Voltage Deviation index	100
7	Quantify the number of regularized voltage deviations	100

Table 51 - A2: KPIs.

Due to the impossibility of running a power flow analysis, as mentioned previously in 3.1.2, the KPI regarding the reduction of technical losses could not be calculated for this test case.

3.3.2.2.3 Test Case B1

For the mid-term forecast, taking into account the guidelines presented in WP1 scenarios, the generation growth is predicted to be five times higher than the current network exploration scenario. Relatively to the load, the average power will increase by a factor of 1.4.

An updated network was modelled considering these factors. All loads nominal power were scaled by a factor of 1.4. A set of new generators and energy storage units were also connected in some consumer nodes (in the same phase). As this network there were no generators in the *Status Quo* scenario, it was assumed the connection of three new generators with a nominal power capacity equal to half of the contracted power of the correspondent customer (according with the Portuguese legislation in this field). The new producers were randomly selected among existing customers in the network. Additionally, three energy storage units with a nominal power of 3kW were connected to the grid in nodes where both consumers and microgeneration units already exist. The OLTC capability for the MV/LV transformer was also assumed.

It is important to mention that the load profiles adopted were the same as in case A1 and the generation profiles were created following the same process as described in section 3.1.3.1. Regarding the few number of customers that in the *Status Quo* scenario (test cases A1 and A2) does not have neither historical data nor information about its connection phase (see Table 18 and Table 20), the following approach was followed for the “Mid-term” scenario:

- Regarding the load profiles, it was assigned to each customer under these circumstances a profile acquired from a customer with the same contracted power (customer already connected in the network in the *Status Quo* scenario);
- Regarding the customers where its connection phase was unavailable, they were connected randomly to a certain phase.

A characterization of the customers that were assumed to exist in the Portuguese network in the “Mid-term scenario is given in ANNEX II - Table 201. In this table, it is possible to observe the contracted power of each new customer, as well as phase and node of connection.

ANNEX II - Table 202 gives complementary information about the metering devices owned by each one of the customers presented in ANNEX II - Table 201.

In ANNEX II - Table 203, it is presented the installed capacity for the microgeneration units and energy storage units that were assumed to exist in the “Mid-term” scenario. It is also shown the identifiers of the correspondent customers and metering equipment.

With the updated network characteristics and for the same time frame selected in test case A1, a higher voltage value has occurred in a different location due the higher total generation installed. The voltage value attained and the correspondent node and customer are shown in Table 52.

Problem Location (Node ID)	Problem Location (Customer ID)	Problem Location (Meter ID)	Phase	Voltage Value (V)
32	C12	GEN0011604701	B	254.47

Table 52 - B1: Initial voltage level.

The merit order of actuation for this test is presented in Table 53. Notice that the transformer has the lower cost of actuation, hence the first position in the merit order list, and the energy storage units are the equipment that have the higher cost of actuation so naturally are the last type of equipment to be actuated. The generators all have the same actuation cost and type of contract, so they are differentiated, in this particular case, by their respective connection topology and distance to costumer 350466.

Order	Type	Customer ID	Meter ID	RANK

1	Transformer	-	TransEBMASTER	120000000000
3	Generator	C12	GEN0011604701	2031000000000
4	Generator	C54	GEN0012604701	2031000000000
4	Generator	C51	GEN1463000041	2031000006000
5	Generator	C58	GEN1351100625	2031000022000
6	Generator	C9	GEN1462000041	2041000006000
7	Generator	C17	GEN1350100625	2041000022000
8	Energy Storage	-	ES00000000002	45900000110501
9	Energy Storage	-	ES00000000001	45910000060501

Table 53 - B1: Equipment rank.

After running the LVC tool, it was seen that only the transformer is necessary to overcome the voltage deviation problem. The tested set-points are shown in Table 54.

Steps	Unit ID	Meter ID	Tap Position	Initial Voltage (V)	Voltage (V)
1	Transformer01	TransEBMASTER	2	244.00	234.00

Table 54 - B1: Set-points.

The final voltage value, after the set-points corresponding to change two taps positions in the transformer is presented in Table 55

Problem Location (Node ID)	Problem Location (Customer ID)	Problem Location (Meter ID)	Phase	Voltage Value (V)
32	C12	GEN0011604701	B	244.89

Table 55 - B1: Final voltage level.

The voltage variation in the problematic node, where the customer *350469* is connected, can be observed.

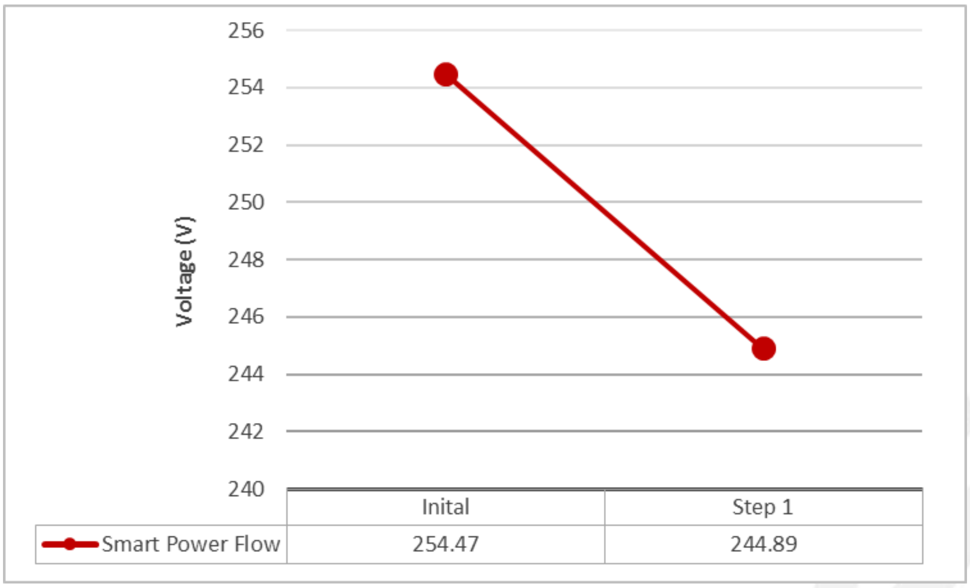


Figure 77 - B1: Voltage evolution within LVC.

As in the previous situation, the relevant KPIs were calculated and are shown in Table 56.

KPI index	KPI name	Value (%)
1	Increase RES and DER hosting capacity	3.82
2	Reduced energy Curtailment of RES and DER	100
3	Increased hosting capacity for electric vehicles and other loads	0
4	Reduction of Technical Losses	-1090.6
5	Share of Electrical Energy produced by RES	2.75
6	Voltage Deviation index	100
7	Quantify the number of regularized voltage deviations	100

Table 56 - B1: KPIs.

The resulting value of KPI index 4, referring to the technical losses reduction, should not be critically evaluated regarding its magnitude. For these test cases the active power losses magnitude is very low: the total active power losses in phase A for the baseline scenario is 54W and in the scenario where the LVC tool is used the resulting value is 640W. The higher power losses value is a normal consequence of the higher power flow in the grid. With the LVC tool, a producer is not disconnected from the grid, only the OLTC is actuated comparing to the baseline scenario where a producer needs to be disconnected in order to maintain the voltage values within the regulated limits.
The LVC tool is not designed to minimize power losses, it might by an effect of a higher RES integration but there is no direct correlation.

3.3.2.2.4 Test Case B2

This case has the same conditions as test case B1 but corresponds to an undervoltage situation. The voltage value obtained for this scenario is shown in Table 57.

Problem Location	Problem Location	Problem Location	Phase	Voltage Value (V)

(Node ID)	(Customer ID)	(Meter ID)		
76	C30	SAG1450111927	A	194.80

Table 57 - B2: Initial voltage level.

The list of equipment selected and sorted for this scenario is shown in ANNEX II - Table 204.

Similarly to test case B1, only the OLTC transformer is required to be actuated for mitigating the undervoltage problem. The set-points are detailed in Table 58.

Steps	Unit ID	Meter ID	Tap Position	Initial Voltage (V)	Voltage (V)
1	Transformer001	TransEBMASTER	4	234.00	244.00
2	Transformer001		5	244.00	254.00

Table 58 - B2: Set-points.

The final voltage value for the problematic node is presented below.

Problem Location (Node ID)	Problem Location (Customer ID)	Problem Location (SM ID)	Phase	Voltage Value (V)
76	C30	SAG1450111927	A	219.02

Table 59 - B2: Final voltage level.

The voltage evolution can be seen in Figure 97.

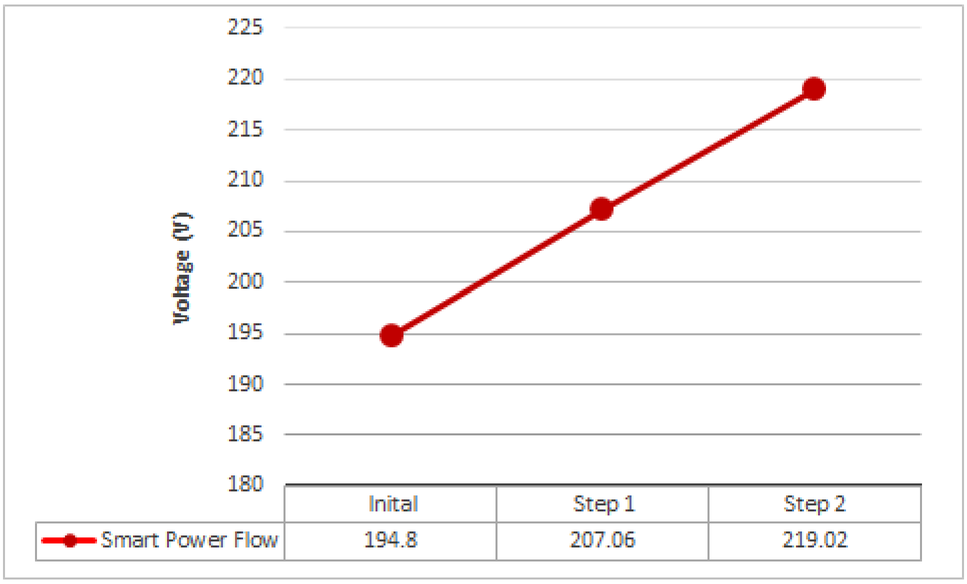


Figure 78 - B2: Voltage evolution within LVC.

For the test case B2, the resulting KPIs values are shown in Table 60.

KPI index	KPI name	Value (%)
1	Increase RES and DER hosting capacity	7.51

2	Reduced energy Curtailment of RES and DER	100
3	Increased hosting capacity for electric vehicles and other loads	7.9
4	Reduction of Technical Losses	-116.3
5	Share of Electrical Energy produced by RES	0
6	Voltage Deviation index	75.86
7	Quantify the number of regularized voltage deviations	75.86

Table 60 - B2: KPIs.

3.3.2.2.5 Test Case C1

The set of test cases C1 and C2 are related to the long-term forecast scenarios of WP1. The RES penetration is 1.57 times higher than the total installed power in B1and B2 and the load suffers significant increase by a factor of 5.53 in relation to the test cases A1 and A2. Additional energy storage units were also connected throughout the network.

Similarly to what was done in test case B1 and B2, the total installed capacity in microgeneration units integrated in C1 and C2 scenarios was upgraded, meaning that several new generation units were added into de grid.

Regarding the distribution of the new customers (either consumers or producers) and energy storage units, the approach followed was analog to the one used for the test cases B1 and B2. The same stands for the consumption/generation profiles of these units.

A characterization of new customers that were assumed to exist in the Portuguese network in the Long-term scenario comparatively to Status-Quo scenario is presented in ANNEX II - Table 205, while the a characterization of the correspondent metering equipment is given in ANNEX II - Table 206.

In ANNEX II - Table 207, the installed capacity for the microgeneration units and energy storage units that were assumed to exist in the "Long-term" scenario is presented. The identifiers of the correspondent customers and metering equipment are also shown.

For this test case, an overvoltage situation was verified. The voltage magnitude registered is slightly lower than in the test case B1 (254.47 V) and occurs in the same node and customer, as it can be observed in Table 61. This is due to the fact that there is higher load growth when comparing the RES growth, i.e., while new consumers appeared in this node, the new microgeneration units were connected in other phases or other points of the grid that are electrically distant.

Problem Location (Node ID)	Problem Location (Customer ID)	Problem Location (Meter ID)	Phase	Voltage Value (V)
32	C12	GEN0011604701	B	253.64

Table 61 - C1: Initial voltage level.

The merit order of actuation for this test is presented in Table 62.

Order	Type	Customer ID	Meter ID	RANK
1	Transformer	-	TransEBMASTER	120000000000
3	Generator	C12	GEN0011604701	2031000000000
4	Generator	C54	GEN0012604701	2031000000000
4	Generator	C51	GEN1463000041	2031000006000
5	Generator	C58	GEN1351100625	2031000022000
6	Generator	C9	GEN1462000041	2041000006000
7	Generator	C17	GEN1350100625	2041000022000
8	Energy Storage	-	ES00000000002	45900000110501
9	Energy Storage	-	ES00000000001	45910000060501
10	Energy Storage	-	ES00000000005	45910000220501

Table 62 - C1: Equipment rank.

The set-point tested within the LVC for this test case is presented in Table 63. In this case, only the transformer with OLTC is actuated.

Steps	Unit ID	Meter ID	Tap Position	Initial Voltage (V)	Voltage (V)
1	Transformer001	TransEBMASTER	2	244.00	234.00

Table 63 - C1: Set-points.

The final voltage value obtained after the LVC is shown in Table 64.

Problem Location (Node ID)	Problem Location (Customer ID)	Problem Location (Meter ID)	Phase	Voltage Value (V)
32	C12	GEN0011604701	B	244.03

Table 64 - C1: Final voltage level

For each set-point tested, the voltage evolution resulting from the smart power flow in the LVC tool can be observed in Figure 79.

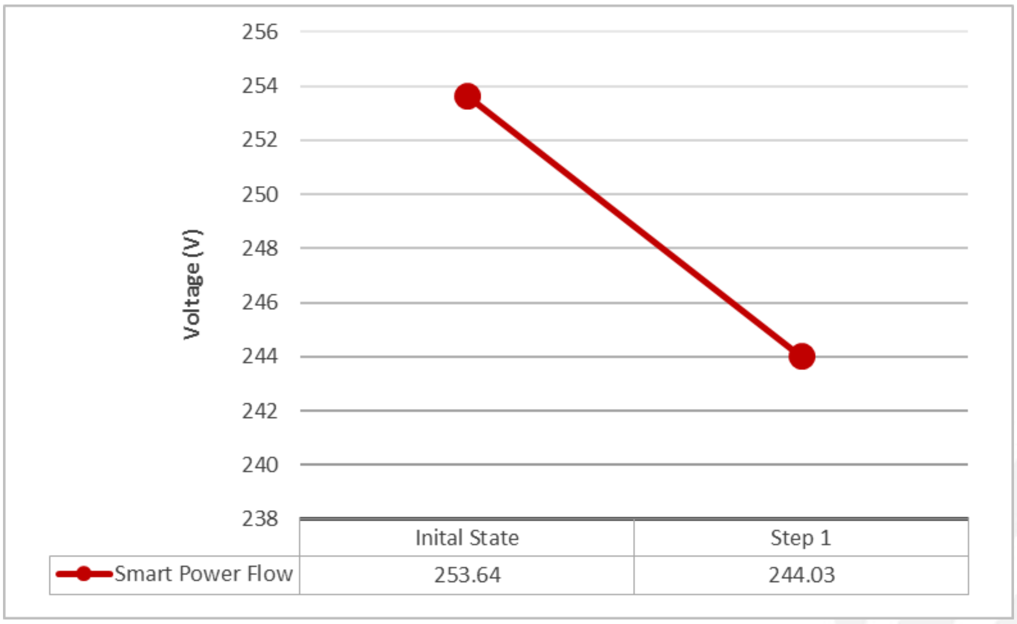


Figure 79 – C1: Voltage evolution within LVC.

Once again, the resulting KPIs values for the current test case were computed and are presented in Table 65.

KPI index	KPI name	Value (%)
1	Increase RES and DER hosting capacity	2.71
2	Reduced energy Curtailment of RES and DER	100
3	Increased hosting capacity for electric vehicles and other loads	0
4	Reduction of Technical Losses	-869.7
5	Share of Electrical Energy produced by RES	2.04
6	Voltage Deviation index	100
7	Quantify the number of regularized voltage deviations	100

Table 65 - C1: KPIs.

3.3.2.2.6 Teste Case C2

For this last test case, similar conditions as the in previous test case C1 were considered (in terms of the grid assets exiting in the grid). The same instant where the undervoltage situation occurred in test case A2 was simulated. In this case, as the load has increased by a factor of 1.86, the minimum voltages levels in the network are significantly higher than in test case A2. As can be seen in Table 66, the minimum voltage level occurred in the same node and customer as in the test case A2, but now with a magnitude of 182.14 V comparatively with the 206.00 V registered in the test case A2.

Problem Location (Node ID)	Problem Location (Customer ID)	Problem Location (Meter ID)	Phase	Voltage Value (V)
76	C30	SAG1450111927	A	182.14

Table 66 – C2: Initial voltage level.

The merit order of actuation for this test is presented in ANNEX II - Table 208.

The set-points tested within the LVC for this test case are detailed in Table 57. For this case, besides de OLTC actuation, customer 350466 (which represents a load) is also partially curtailed in order to manage the undervoltage situation.

Steps	Unit ID	Meter ID	Tap Position	Initial Voltage (V)	Voltage (V)
1	Transformer001	TransEBMASTER	4	234.00	244.00
2	Transformer001		5	244.00	254.00
Steps	**Customer ID**	**Meter ID**	**-**	**Initial Power (kW)**	**Set point (kW)**
3	C30	SAG1450111927	-	6.47	5.78
4	C30	SAG1450111927	-	5.78	5.09
5	C30	SAG1450111927	-	5.09	4.40
6	C30	SAG1450111927	-	4.40	3.71

Table 67 – C2: Set-points.

Due to the severity of the undervoltage in this test case, more control actions are needed to manage the voltage deviation. Comparing with test case B2, the consumption levels are now higher, leading to lower voltage values throughout the network and, consequently, further control actions are needed.

For each set-point tested, the voltage evolution resulting from the smart power flow in the LVC tool can be observed in Figure 80.

Problem Location (Node ID)	Problem Location (Customer ID)	Problem Location (Meter ID)	Phase	Voltage Value (V)
76	C30	SAG1450111927	A	212.37

Table 68 – C2: Final voltage level.

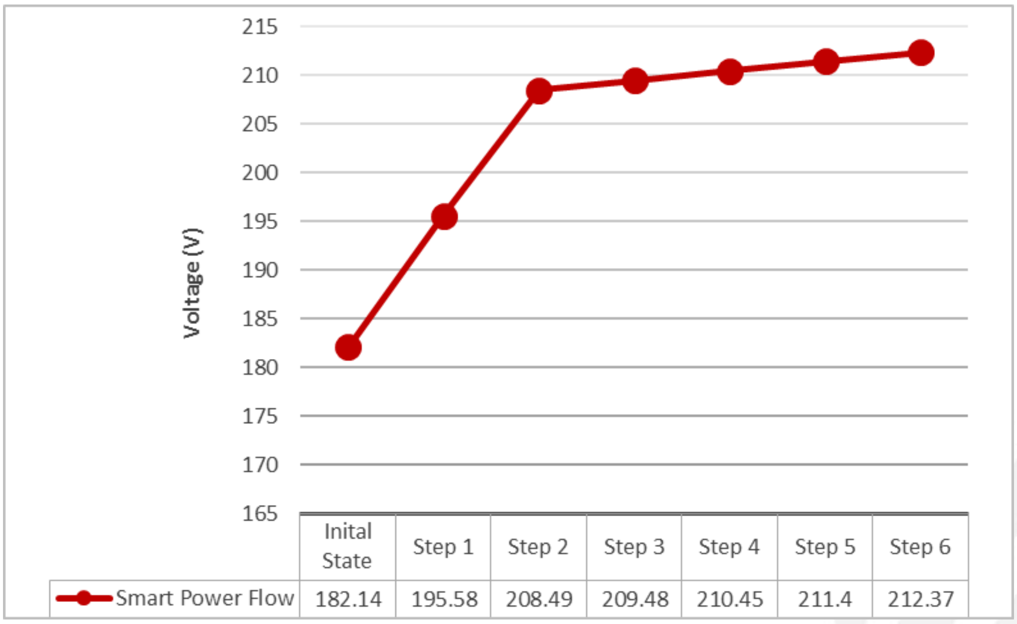


Figure 80 - C2: Voltage evolution within LVC

Once again, the resulting KPIs values for the current test case were computed and are presented in Table 69.

KPI index	KPI name	Value (%)
1	Increase RES and DER hosting capacity	5.88
2	Reduced energy Curtailment of RES and DER	88.57
3	Increased hosting capacity for electric vehicles and other loads	6.29
4	Reduction of Technical Losses	-107.7
5	Share of Electrical Energy produced by RES	0.33
6	Voltage Deviation index	80
7	Quantify the number of regularized voltage deviations	80

Table 69 - C2: KPIs.

3.3.3 Results for France

3.3.3.1 Low Voltage Distribution State Estimator

As it was stated before, the historical database for the French LV network consisted in simulated data. In this sense and in contrast to the Portuguese case, the real values for the absolute error calculation were generated through power flows instead of records gathered from SM.

In Figure 81 the MAE variation is shown in regards to the increment of SM_r (see section 0). As it can be seen, the MAE decreases with the increment of SM_r, meaning that the estimation accuracy is improved when more real-time measurements are available.

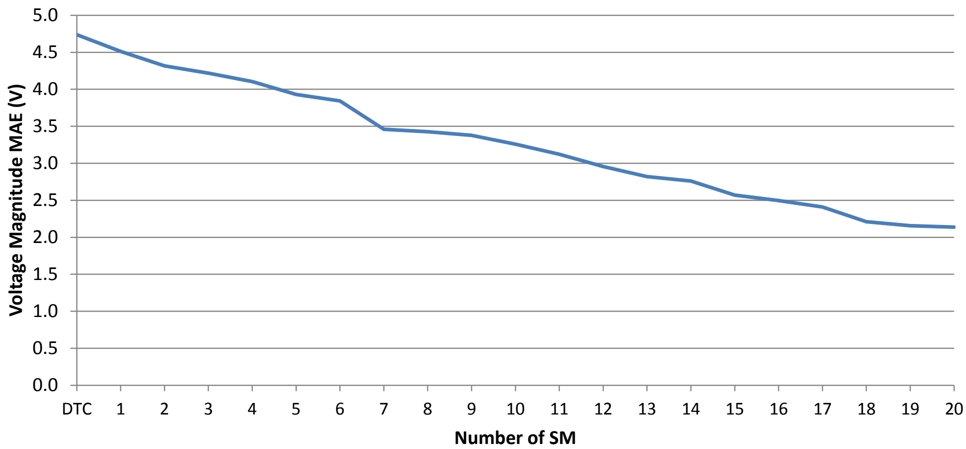
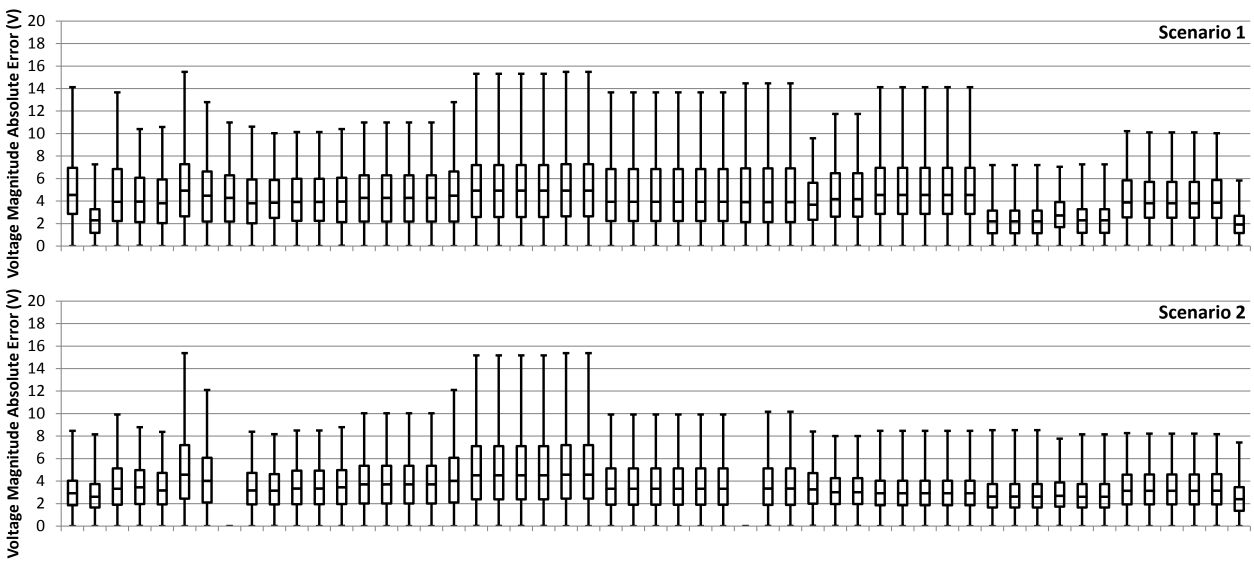


Figure 81 – Voltage magnitude MAE obtained with the increment of SM_r.

It should be noted that the results were grouped per phase due to the number of customers present in this network.

In Figure 82 the voltage magnitude absolute error for all the customers (not being monitored in real-time) connected to phase A is presented for the evaluation set defined in section 3.1.3.1. The figures related to the voltage magnitude absolute error for all the customers connected to phases B and C are in ANNEX III – Additional Results (Figure 251 and Figure 252, respectively).

Similarly to the verified in the results presented for the Portuguese case, there is a clear general improvement in the state estimation results when more measurements are available in real-time. In fact, in the scenario 4, the voltage magnitude absolute error obtained is lower than 4 V in 75% of the cases for all the customers connected to each phase. The maximum MAE obtained for scenario 4 was 2.3 V, a value verified in phase C (Table 70). This result can be seen as a good indicator regarding the accuracy of the proposed DSE for the estimation of voltage magnitude values.



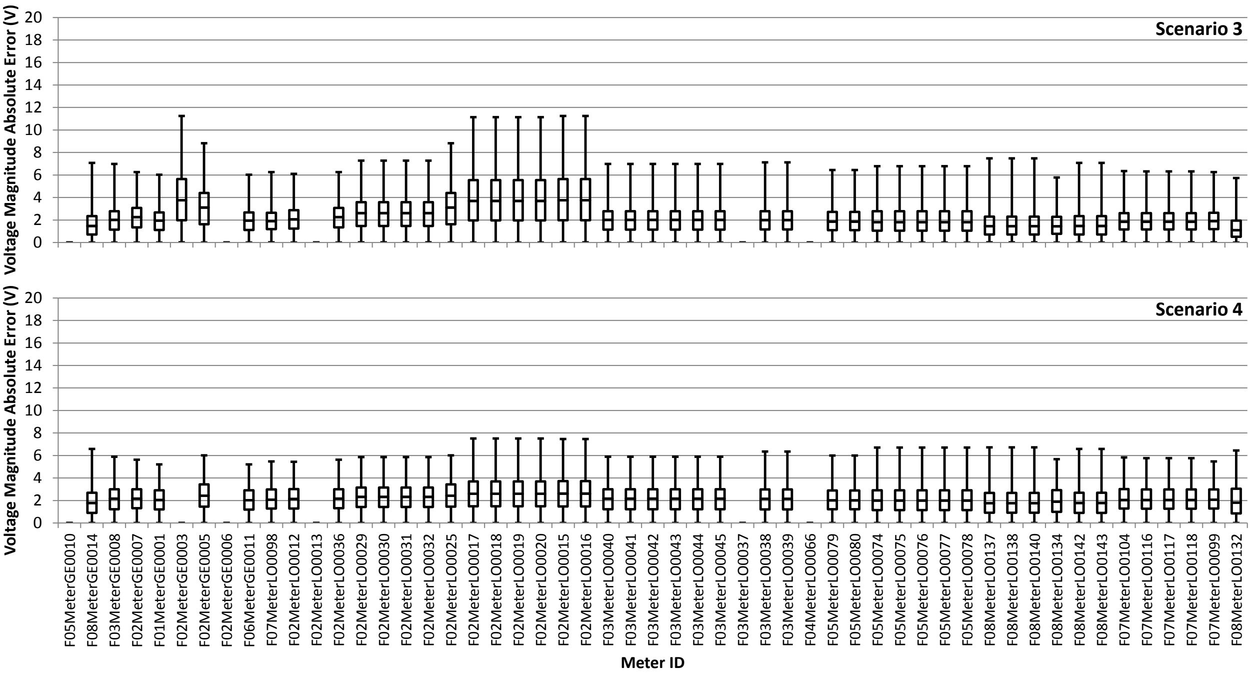


Figure 82 – Voltage magnitude absolute error for all customers connected to phase A (not being real-time monitored) in scenarios 1, 2, 3 and 4.

Scenario	Phase A (V)	Phase B (V)	Phase C (V)
1	4.2	3.4	4.0
2	3.5	2.7	3.4
3	2.3	2.1	3.1
4	2.2	1.9	2.3

Table 70 – Voltage magnitude MAE obtained for each phase in each scenario.

In Figure 83 the absolute error for the voltage magnitude is shown for all customers not being monitored in real-time and connected to phase A. The figures related to phases B and C are in ANNEX III – Additional Results (Figure 253 and Figure 254, respectively). But now different amounts of the historical data used for training purposes are being considered. As it was presented in section 3.2.3, the base scenario for testing the different sets of historical data (3 months, 1 month and 1 week) was the scenario 4, where the DSE had been trained with 6 months of historical data.

Comparing respectively Figure 83, Figure 253 and Figure 254 with the ones related to scenario 4 (Figure 82, Figure 251 and Figure 252), it can be observed that when considering 1 month of historical data, the DSE was able to perform a state estimation with a similar accuracy as when 6 months of data were considered. This fact means that 1 month of historical data was enough so that the DSE could learn the patterns/correlations between the electrical variables for the system under study. In contrast, when only 1 week was used, the DSE was not able to properly learn the network behaviour, something that could be expected since the consumption/generation variability introduced cannot be represented by only one week of data. Moreover, it can be seen that the estimation accuracy obtained was slightly better when 3 months of historical data was considered than when 6 months were used. These facts highlight the importance of having a representative historical database (with enough data), but also of making a previous evaluation of the historical database in order to find the most appropriate amount of historical data to be used in the training process of the DSE, particularly when a large amount of historical data is available.

In Table 71 the voltage magnitude MAE obtained for each phase is presented, considering a different amount of historical data in the DSE training process (scenario 4). As it can be seen, the results attained support once more the conclusions made in the paragraph above.

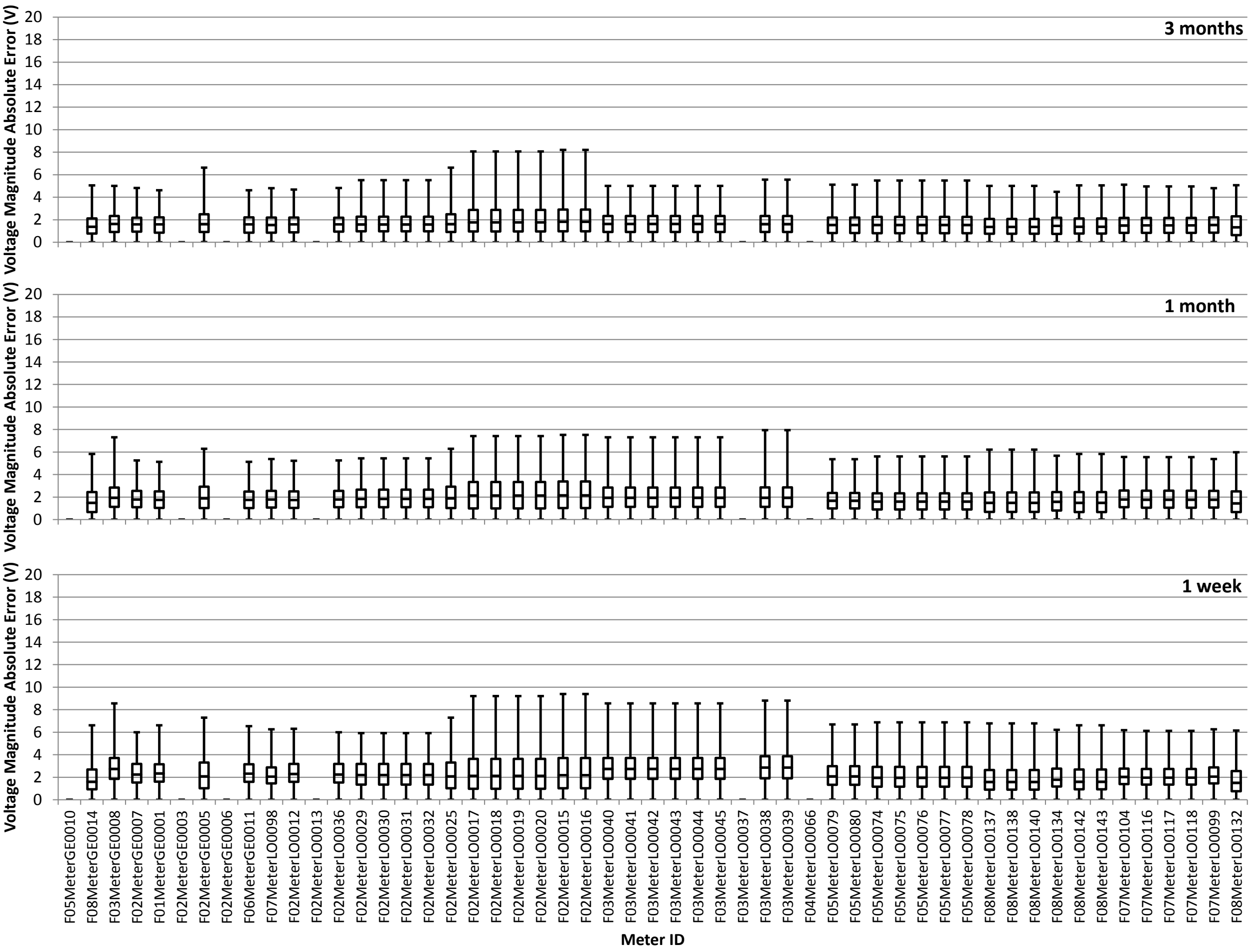


Figure 83 – Voltage magnitude absolute error for all customers connected to phase A (not being real-time monitored), considering a different amount of data for training the proposed DSE: 3 months, 1 month and 1 week.

Amount of data for training purposes	Phase A (V)	Phase B (V)	Phase C (V)
6 months	2.2	1.9	2.3
3 months	1.7	1.8	2.0
1 month	1.9	1.9	2.3
1 week	2.3	2.2	2.9

Table 71 – Voltage Magnitude MAE obtained for each phase considering a different amount of data for training the proposed DSE (regarding the scenario 4).

In Figure 84 the active power absolute error is shown for all customers not being monitored in real-time and connected to phase A. The active power absolute error for all customers

connected to phases B and C are in ANNEX III – Additional Results (Figure 255 and Figure 256, respectively).
As it can be seen, the absolute error values obtained for several customers in scenario 5 are relatively high. This result may be explained by the low ratio between the number of real-time measurements and the large number of variables to be estimated (see Table 72).
In order to obtain a more accurate estimation, the number of SM_r was increased for the customers whose absolute error was greater than 6 kW. In this sense, state estimation simulations were performed taking into account each new set of SM_r until the greatest absolute error was lower than 6 kW for all customers (considering all phases). In Figure 84, Figure 255 and Figure 256 the active power absolute error is depicted for two of the new sets of SM_r, one considering 31 and the other one 36 SM_r. For this last scenario, the active power absolute error obtained is lower than 1 kW in 75% of the cases in a large majority of the customers.

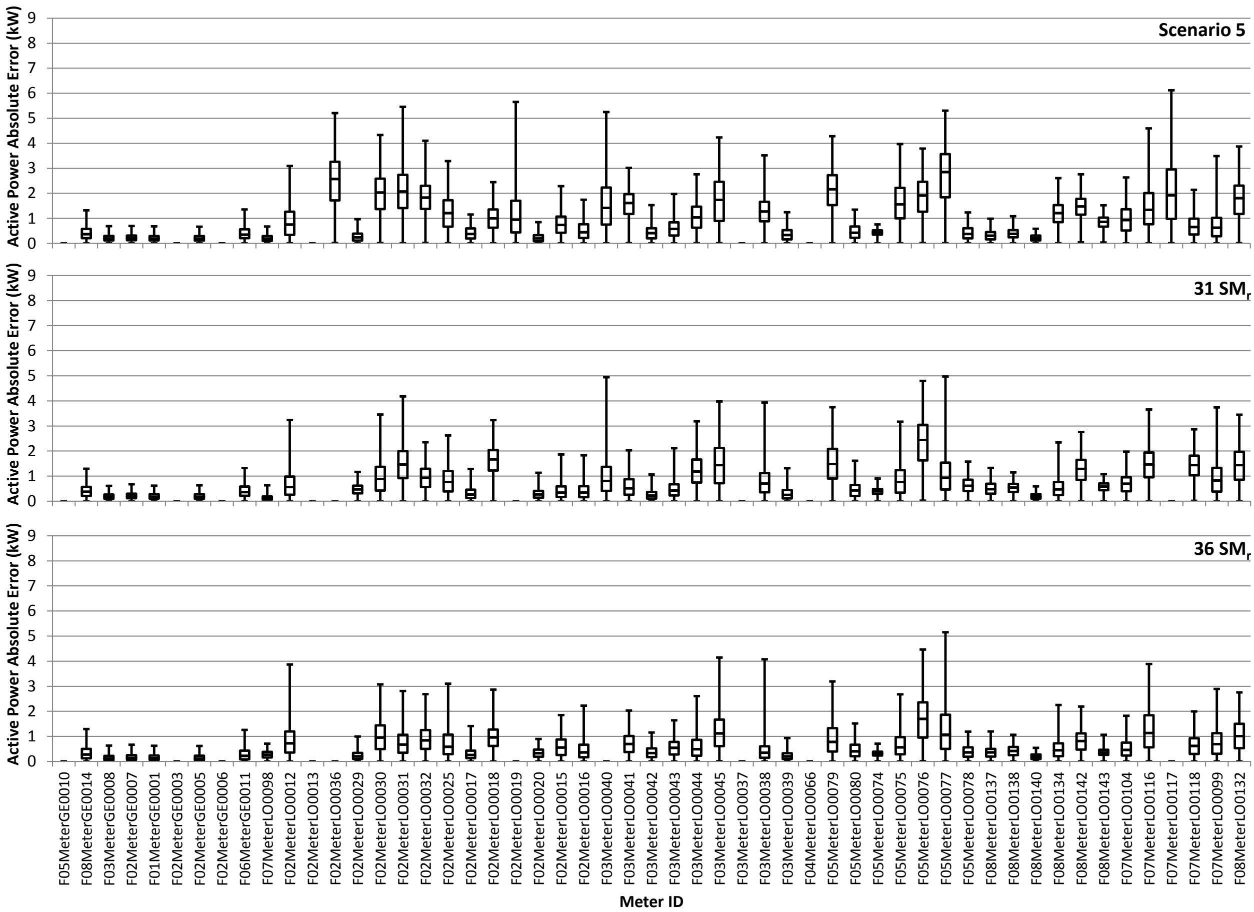


Figure 84 – Active power absolute error for all customers connected to phase A (not being real-time monitored) in scenario 5 and in another two new scenarios considering a larger number of SM_r.

In Figure 85 are depicted the cumulative distribution functions of the active power absolute error per each phase for the customer with the highest error in the scenario with 36 SM_r and for the same customer in the scenario 5. A clear improvement in the state estimation accuracy considering a larger number of SM_r appears when observing this figure.
Table 72 emphasises this fact. Reductions in the MAE of about 40% compared with the two scenarios under analysis can be seen. It should be highlighted that the state estimation accuracy of the active power quantity could be enhanced if more SM_r had been considered. In

a real-world application, a careful cost-benefit analysis between the number of SM_r to be installed and the correspondent accuracy improvement must be inevitably carried out, since a solution with more SM_r will be certainly more expensive.

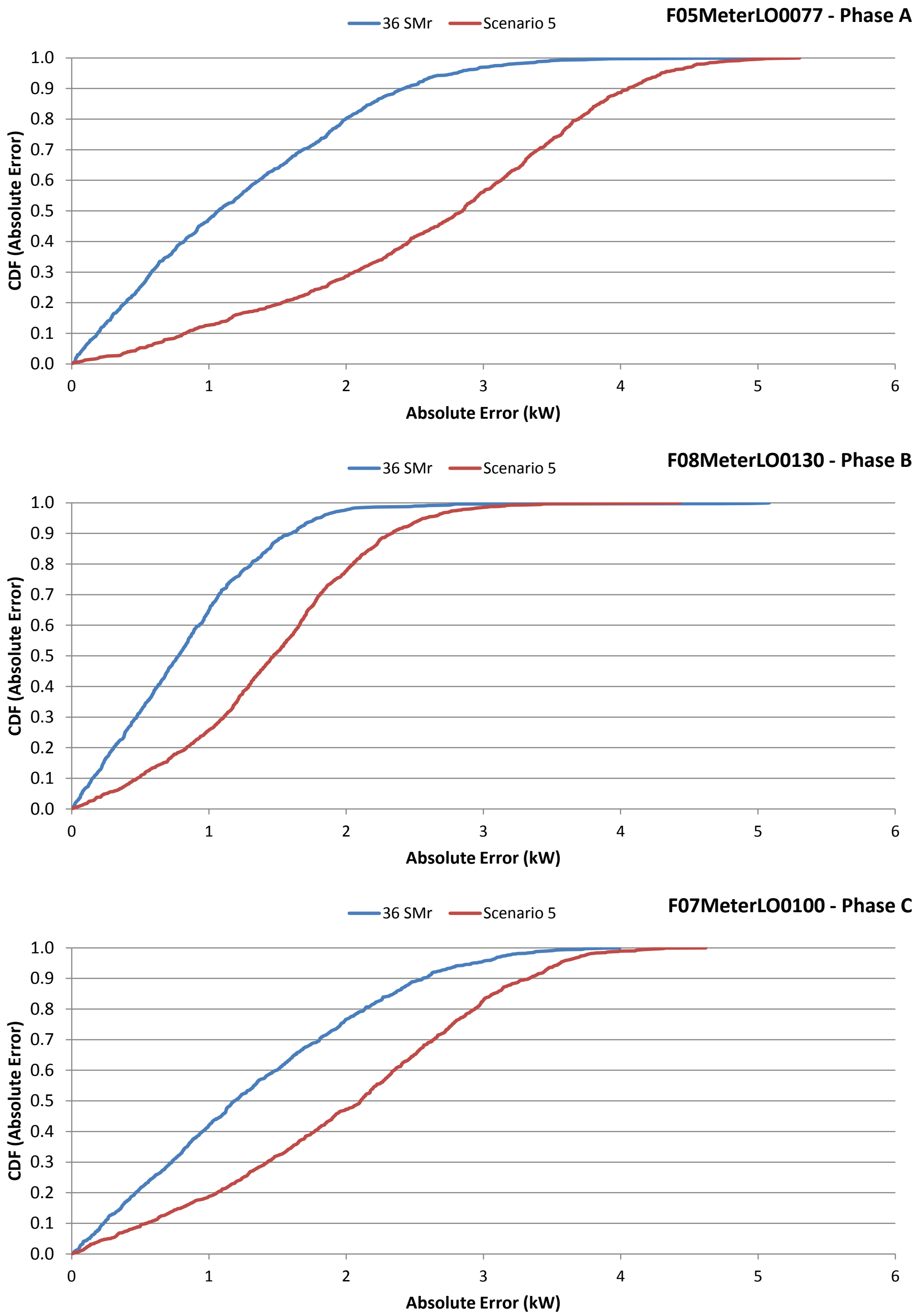
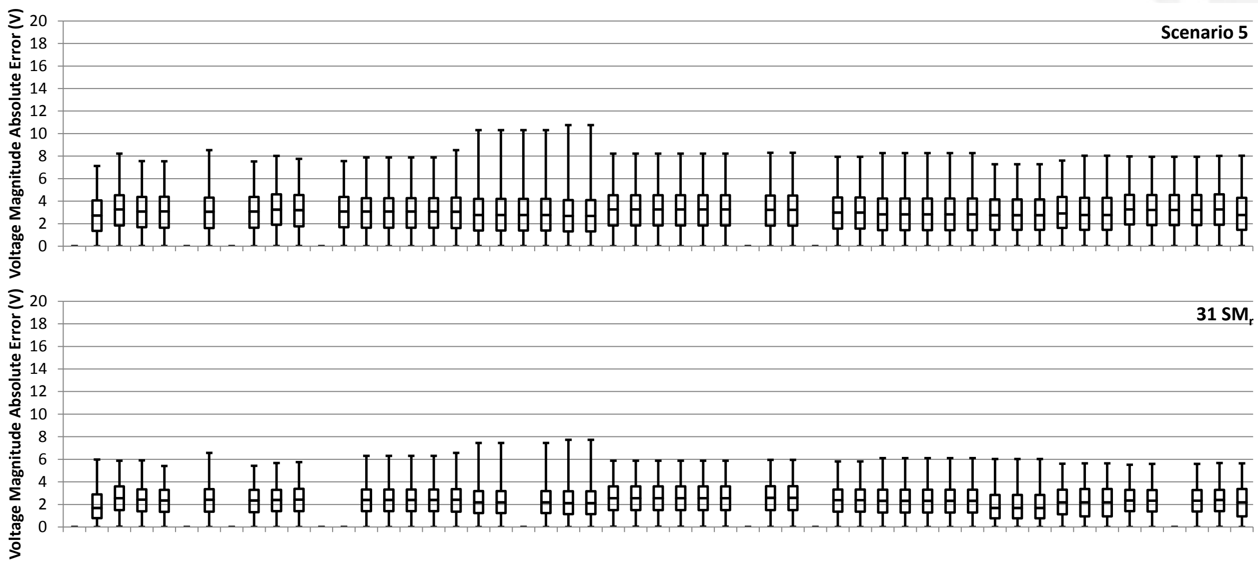


Figure 85 – Cumulative distribution function of the active power absolute error for the customer with the highest error in each phase for the scenario with 36 SM_r.

Table 72 – Active power MAE obtained for each phase in each scenario.

Scenario	Phase A (kW)	Phase B (kW)	Phase C (kW)
5 (20 SMr)	0.992	1.109	0.999
31 SMr	0.747	0.755	0.713
36 SMr	0.585	0.567	0.591

Regarding the voltage magnitude values, by comparing Figure 86 with the Figure 82 (and also by comparing Figure 257 and Figure 258 with the Figure 251 and Figure 252 present in ANNEX III – Additional Results), it can be observed that the DSE performed a state estimation less accurate in scenario 5 than in scenario 4. Although the number of real-time measurements was equal in both scenarios, this result was expected due to the higher number of variables to be estimated in scenario 5, which includes the estimation of active power quantities (see section 3.2.3). In fact, the number of variables in scenario 5 is twice the number of variables estimated in scenario 4 (see Table 73). As expected, in the other two scenarios, due to the higher number of SM_r assumed (respectively 31 and 36 SM_r were considered), the state estimation accuracy obtained was better than the one attained for scenario 5. In addition, comparing the results obtained for these scenarios and the ones obtained for scenario 4, it can be concluded that for scenario 4, and for the one with 31 SM_r, the results are quite similar in terms of estimation accuracy on voltage magnitude values. On the contrary, the state estimation error verified in the scenario with 36 SM_r is lower than the error obtained in scenario 4.



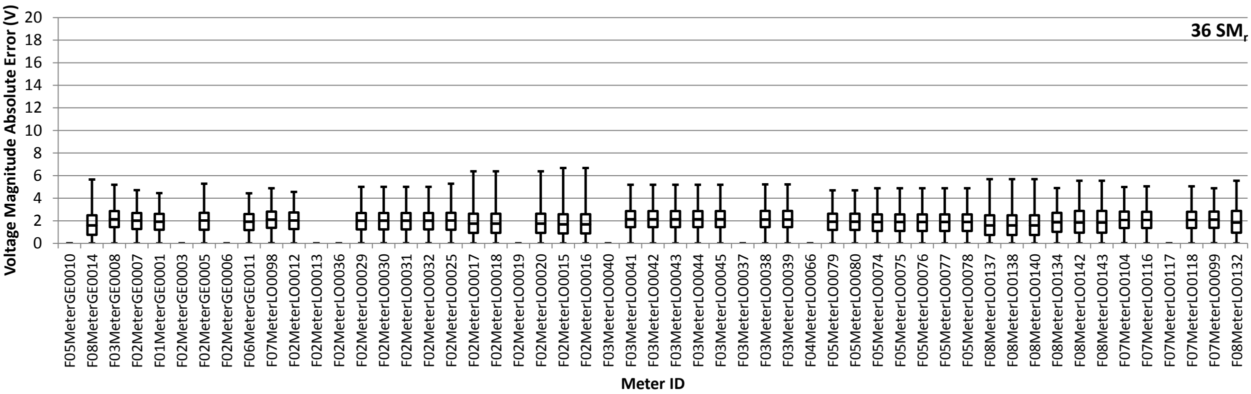


Figure 86 – Voltage magnitude absolute error for all customers connected to phase A (not being real-time monitored) in scenario 5 and in another two new scenarios considering a larger number of SM_r.

Table 73 summarises the MAE for each phase in each scenario analysed. It is possible to observe that the presented results are in accordance with all the considerations made so far.

Scenario	Phase A (V)	Phase B (V)	Phase C (V)
4 (20 SMr)	2.2	1.9	2.3
5 (20 SMr)	3.1	2.5	2.8
31 SM_r	2.3	1.9	2.2
36 SM_r	2.0	1.4	1.7

Table 73 – Voltage magnitude MAE obtained for each phase in each scenario.

The results for all the referred KPIs (see Table 31) are depicted over the next few pages. The results are shown graphically as well as in table format, where the minimum, average and maximum values for each KPI are presented.

From Figure 87 to Figure 89 and Table 74 to Table 76 is presented the accuracy of active power injections KPI for the scenarios where active power injections were estimated: scenario 5, scenario with 31 SM_r and scenario with 36 SM_r. Although the results may seem high for the different norms calculated, they make sense taking into account the number of customers present in the network (see *deliverable D3.2* for more details about the mathematical expressions of these norms). The results attained for the different norms in the scenarios evidence that a better estimation is achieved when the number of SM_r is increased. Therefore, regarding the estimation of power injections, scenario 5 accounts for the worst results whereas the best results are obtained in the scenario with 36 SM_r.

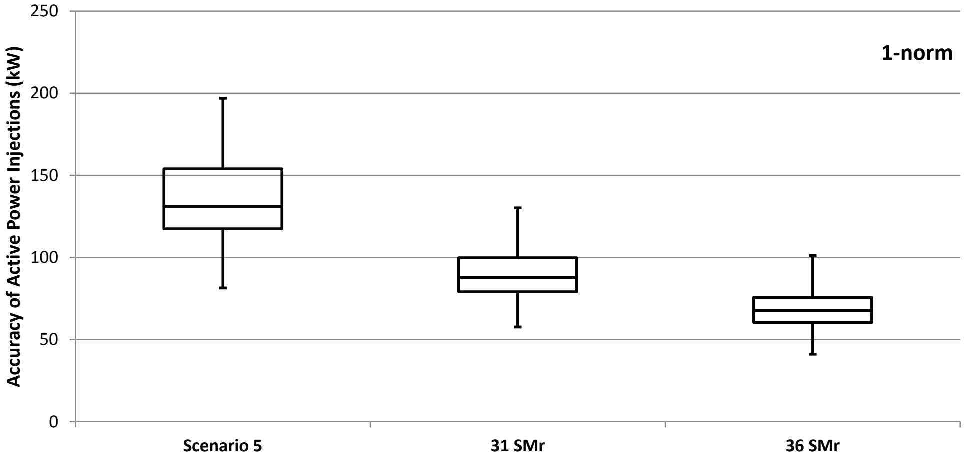


Figure 87 – Accuracy of active power injections KPI (1-norm).

Table 74 – Accuracy of active power injections KPI (1-norm).

	Scenario 5 (kW)	31 SM_r (kW)	36 SM_r (kW)
Maximum	196.853	130.078	101.079
Average	136.081	89.692	68.281
Minimum	81.326	57.585	41.085

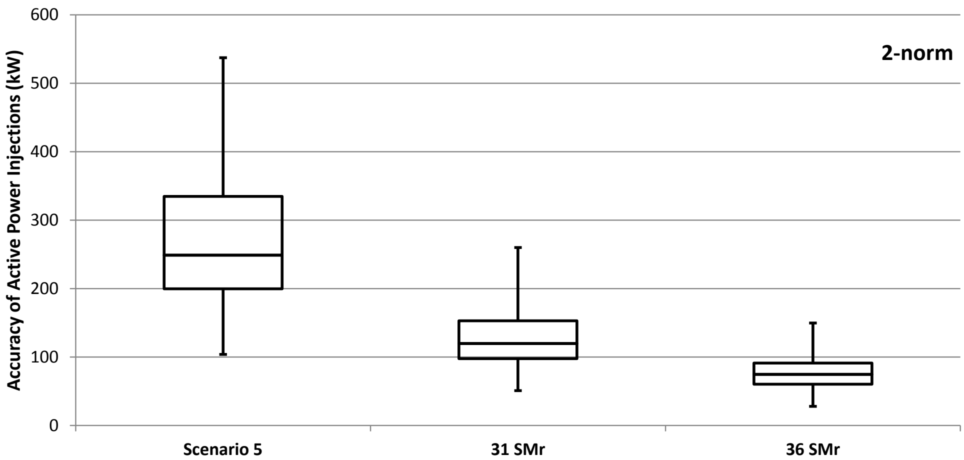


Figure 88 – Accuracy of active power injections KPI (2-norm).

	Scenario 5 (kW)	31 SM_r (kW)	36 SM_r (kW)
Maximum	537.124	259.961	149.626
Average	274.005	128.029	77.247
Minimum	103.699	50.943	27.942

Table 75 – Accuracy of active power injections KPI (2-norm).

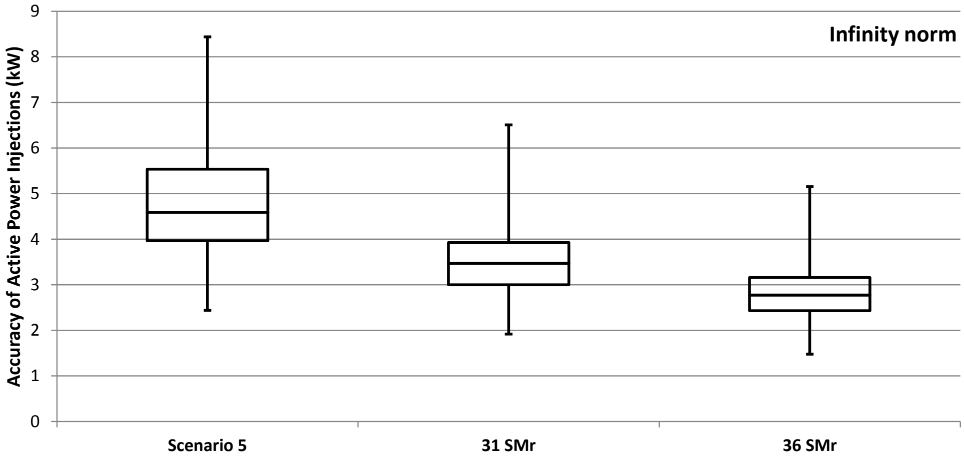


Figure 89 – Accuracy of active power injections KPI (Infinity norm).

	Scenario 5 (kW)	31 SM_r (kW)	36 SM_r (kW)
Maximum	8.438	6.505	5.153
Average	4.795	3.488	2.832
Minimum	2.439	1.919	1.476

Table 76 – Accuracy of active power injections KPI (Infinity norm).

In Figure 90 and Table 77 the accuracy of voltage index is presented for each scenario. The index results may seem high, yet they make sense taking into account the big number of customers present in the network. Comparing the results obtained in all the scenarios, it is evident the improvement in the voltage accuracy with the increment of the number of SM_r.

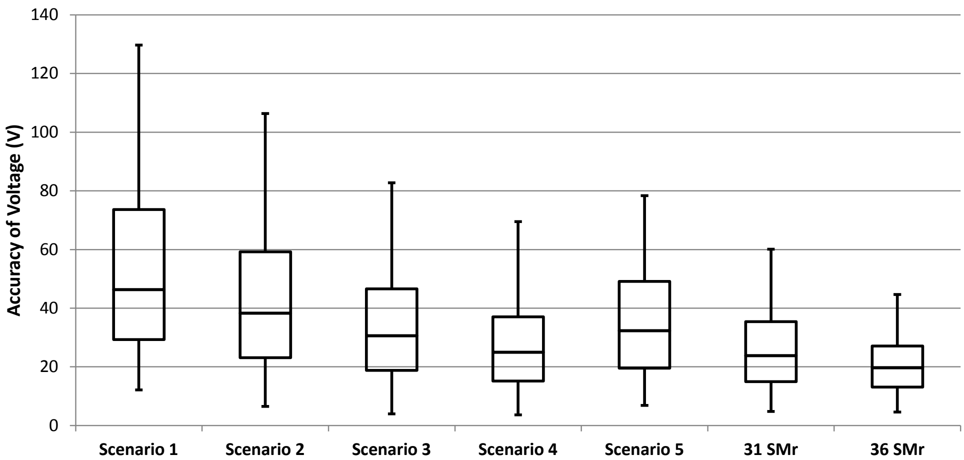


Figure 90 – Accuracy of voltage KPI.

	Scenario 1 (V)	Scenario 2 (V)	Scenario 3 (V)	Scenario 4 (V)	Scenario 5 (V)	31 SM_r (V)	36 SM_r (V)
Maximum	129.7	106.4	82.7	69.5	78.4	60.1	44.6
Average	52.2	41.8	32.7	26.6	34.4	25.4	20.3
Minimum	12.2	6.5	3.9	3.6	6.8	4.8	4.6

Table 77 – Accuracy of voltage KPI.

Figure 91 and Table 78 show the variation of the EEI values in each scenario. In Table 78 are also computed the threshold values for each scenario which were calculated in a similar way as it was done for the Portuguese case (see section 3.3.2.1). It is clear that the EEI values obtained in each scenario are far below than its threshold value, which accounts for a good accuracy achieved by the proposed DSE.

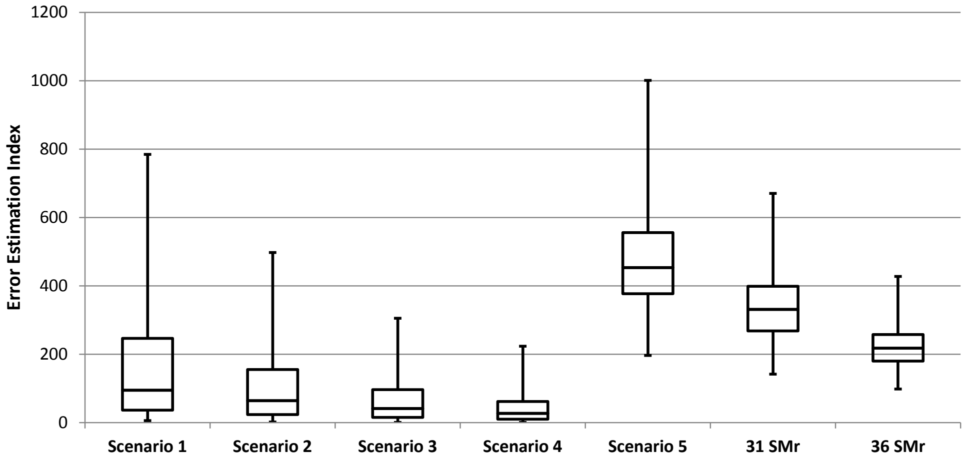


Figure 91 – Error estimation index KPI.

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	31 SM_r	36 SM_r
Maximum	784.78	497.78	305.06	223.66	1000.75	670.52	427.83
Average	153.86	98.02	60.96	39.76	478.52	339.55	221.59
Minimum	5.92	1.61	0.55	0.46	196.60	141.66	97.89
Threshold	1350	1287	1242	1197	2394	2196	2106

Table 78 – Error estimation index KPI.

The last KPI (PIPi) determines the ability of the DSE to accurately discern active power injection measurements. The results for this KPI are shown in Figure 92 and Table 79. This KPI is an estimation error ratio considering the 2-norm metric of the difference between true and estimated values and the 2-norm metric of the difference between true and measured values. Accordingly with the mathematical expression presented in *deliverable D3.2*, for a good estimation, each active power injection estimated should lie closer to the true value than the measured value. In this case the entire metric will be less than one. As it can be seen in Figure 92 and Table 79, this requirement is only partially met, since there are a few cases (samples of the evaluation set) for which the PIPi is higher than one. Moreover, for the three scenarios under analysis, it is noticed that 75% of the cases are below than 0.6 (verified for scenario 1), which indicates the good estimation performed. In Table 80 the percentage of cases in each scenario where the PIPi is less than one is shown.

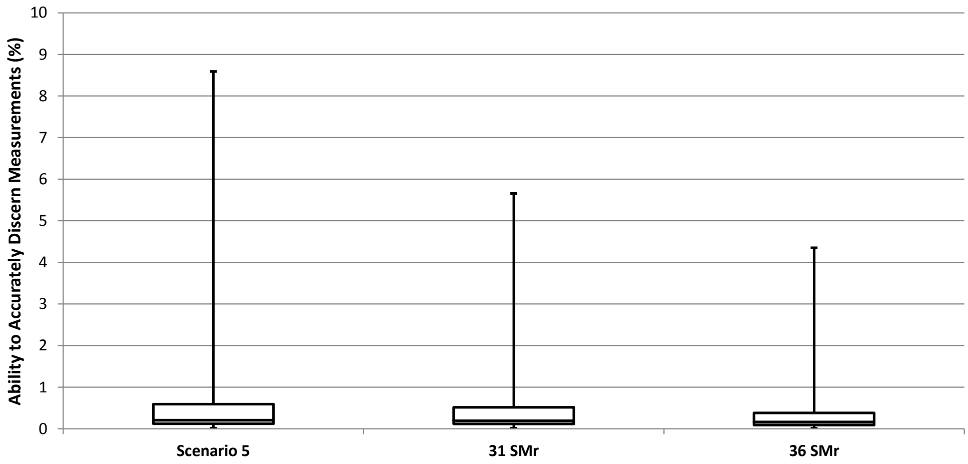


Figure 92 – Ability of accurately discern active power injection measurements KPI.

Table 79 – Ability of accurately discern active power injection measurements KPI.

	Scenario 5 (%)	31 SM_r (%)	36 SM_r (%)
Maximum	8.59	5.66	4.35
Average	0.75	0.56	0.43
Minimum	0.01	0.01	0.01

Scenario 5 (%)	31 SM_r (%)	36 SM_r (%)
79.5	81.3	85.2

Table 80 – Percentage of cases in each scenario for which the PIPi is less than one.

3.3.3.2 Low Voltage Control

3.3.3.2.1 Test Case A1

The contractual voltage limits for the French network are +/- 10% but, regarding the maximum and minimum values presented in the historical database and, in order to test the present tool with the required depth, the voltage limits here considered are +/-8% of the nominal voltage level. The acceptable voltage range is within the interval [211.6; 248.4] V, voltages values outside this range will trigger the LVC tool. It is assumed that when the state estimation tool is used, an associated estimation error affects the voltage values so, for those cases, the acceptable range also considers the 2% of estimation error. Therefore, the voltage limits, when the state estimation is used, is between [216.2; 243.8] V.

For the selected situation, with the overvoltage occurrence, the corresponding magnitude and location is shown in the following table.

Location	Phase	Voltage Value (V)
F02_Gene_00003	A	248.67

Table 81 - A1: Initial voltage value.

The sorted list of equipment ordered by their given rank is shown in Table 82.
The rank of each equipment is calculated regarding the cost of actuation (which differs for each type of equipment), the connection topology (mono-phase or three-phase) the contract type (flexible or non-flexible) and the distance to the voltage deviation location.

Order	Type	Equipment ID	RANK
1	Generator	F02_Gene_00003	2690031000000001
2	Generator	F02_Gene_00005	2690031000119001
3	Generator	F03_Gene_00008	2690031000155001
4	Generator	F02_Gene_00007	2690031000164001
5	Generator	F01_Gene_00001	2690031000276001
6	Generator	F05_Gene_00010	2690031000336001
7	Generator	F08_Gene_00014	2690031000758001
8	Generator	F02_Gene_00006	2690041000149001
9	Generator	F06_Gene_00011	2690041000222001

Table 82 - A1: Equipment rank.

In Table 83 the resulting set-points for this test case using the state estimation as a simulation platform are presented. The set-points for the smart power flow simulation are represented in Table 84.

Steps	Unit ID	Initial Power (kW)	Set point (kW)
1	F02_Gene_00003	-17.01	-6.21
2	F02_Gene_00003	-6.21	0

Table 83 - A1: Set-points with state estimation

Steps	Unit ID	Initial Power (kW)	Set point (kW)
1	F02_Gene_00003	-17.01	-6.21

Table 84 - A1: Set-points with smart power flow

With the state estimation, it is required to test two set-points within the LVC tool to manage the voltage deviation, the final output results in a set-point that represents more power curtailment for *F02_Gene_00003*.

In Figure 93 there is a graphic representation of the amount of power curtailed for the case where the LVC tool uses the state estimation or the smart power flow.

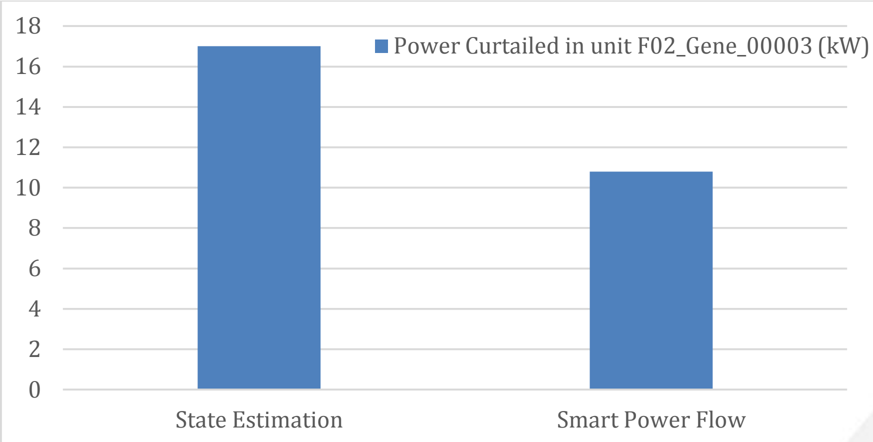


Figure 93 - A1: Power curtailed

The final voltage values for each case are represented in Table 85 and Table 86 respectively.

Location	Phase	Voltage Value (V)
F02_Gene_00003	A	240.65

Table 85 - A1: Final voltage using state estimation.

Location	Phase	Voltage Value (V)
F02_Gene_00003	A	243.22

Table 86 - A1: Final voltage using the smart power flow.

When the state estimation is used to test the proposed set-points, the overvoltage situation is not managed with the first set-point (that implies a curtailment of 60% of the unit nominal power) so another set-point is applied. The graphic evolution of the voltage obtained with each set-point can be analysed in Figure 94. It must be stressed that these intermediate set-points are computed inside the algorithm, which works iteratively in order to find the best solution, and only the final solution is sent to the corresponding resources.

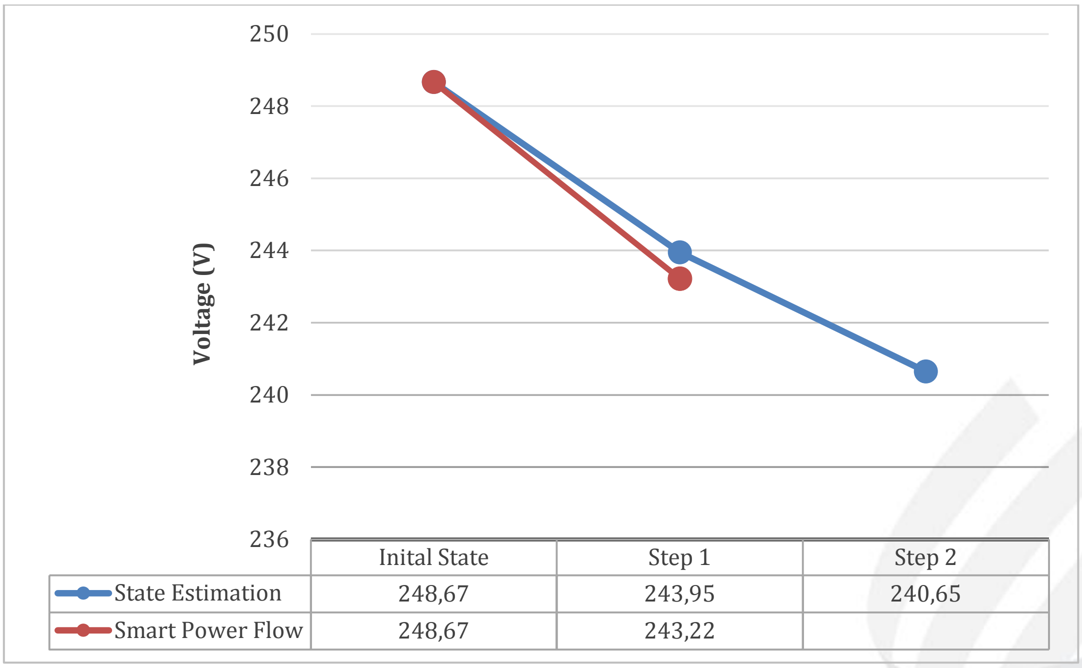


Figure 94 - A1: Voltage differences within the LVC tool

In the Table 87 the KPIs calculated values for the current test case are provided. Full description of each KPI was presented in Table 87.

KPI index	KPI name	Value (%)
1	Increase RES and DER hosting capacity	1.45
2	Reduced energy Curtailment of RES and DER	35
3	Increased hosting capacity for electric vehicles and other loads	0
4	Reduction of Technical Losses	-4.47
5	Share of Electrical Energy produced by RES	3.24
6	Voltage Deviation index	100
7	Quantify the number of regularized voltage deviations	100

Table 87 - A1: KPIs

The KPI corresponding to the reduction of technical losses, the KPI index 4, has a negative percentage as a normal consequence of the higher power flow in the grid. With the LVC tool, less power is curtailed from the grid comparing to the baseline scenario.

3.3.3.2.2 Test Case A2

The initial voltage value for the undervoltage scenario selected is presented in Table 88.

Location	Phase	Voltage Value (V)
F08_Load_00135	2	207.25

Table 88 – A2: Initial voltage value

The sorted list of equipment ordered by their given rank is as follow in ANNEX II -

Table 209.

The resulting set-points, using the state estimation and the smart power flow, are exactly the same as the undervoltage situation is managed in both cases with only one set-point, as shown in Table 89.

Steps	Unit ID	Initial Power (kW)	Set point (kW)
1	F08_Load_00135	8.39	2.99

Table 89 – A2: Set-points.

The final voltage value is presented in the following tables for the cases using state estimation and the smart power flow.

Location	Phase	Voltage Value (V)
F08_Load_00135	2	224.66

Table 90 – A2: Final voltage value with state estimation.

Location	Phase	Voltage Value (V)
F08_Load_00135	2	220.79

Table 91 - A2: Final voltage with smart power flow.

The difference in both approaches in terms of the final results is shown in the next figure.

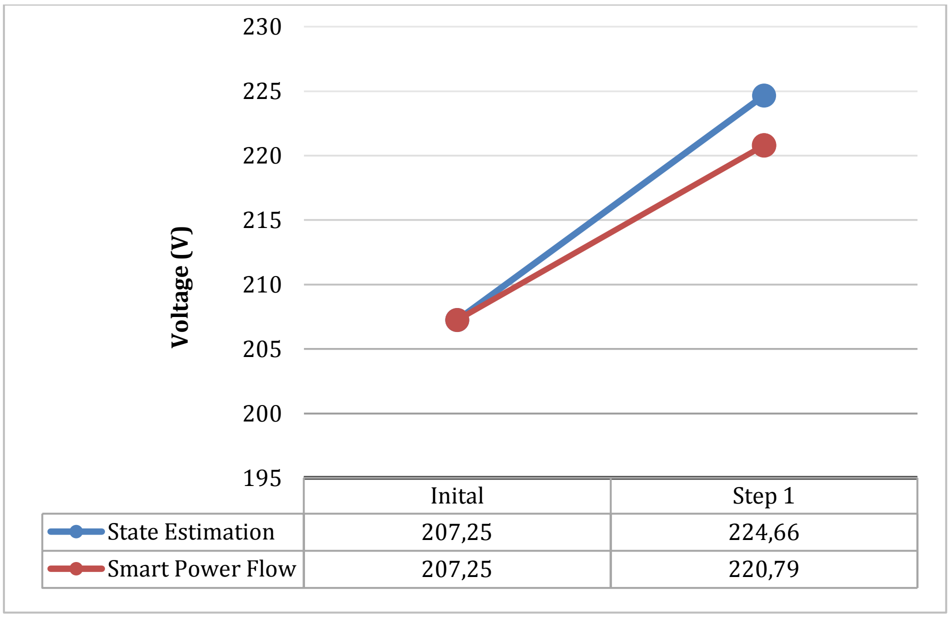


Figure 95 - A2: Voltage evolution within the LVC tool.

The relevant KPIs for this test case were computed and are presented in Table 92.

KPI index	KPI name	Value (%)

1	Increase RES and DER hosting capacity	0.72
2	Reduced energy Curtailment of RES and DER	33
3	Increased hosting capacity for electric vehicles and other loads	0.77
4	Reduction of Technical Losses	-19.05
5	Share of Electrical Energy produced by RES	-0.0013
6	Voltage Deviation index	100
7	Quantify the number of regularized voltage deviations	100

Table 92 - A2: KPIs

3.3.3.2.3 Test Case B1

For the mid-term forecast, taking into account the guidelines presented in WP1 scenarios, the generation growth is predicted to be five times higher than the current network exploration scenario. Relatively to the load, the average power will slightly decrease by a factor of 0.92.

An updated network was modelled considering these factors. All load nominal power was scaled by a factor of 0.92 and new generators were connected in all consumer nodes (without prior generation) in the same phase as the consumption.All new generators have the same nominal power (assumed to be 3kW) and a generation profile was created in accordance with the original generators.

The generation distribution pattern was established in compliance with the significant generation growth considering the *Status Quo*. Connecting fewer generators, but with a higher nominal power, might cause situations where the generation greatly surpasses the installed consumer load, which may not be a realistic scenario. Furthermore, the even distribution prevents a situation with higher unbalanced phases.

In addition, three energy storage units were randomly connected to the grid with a nominal power of 3kW and it is now assumed that the MV/LV transformer has OLTC capability.

With the updated network characteristics and for the same time frame selected in test case A1 (meaning that the load and generation profiles are the same) a higher voltage value is obtained, due the significant higher total generation installed.

The voltage value obtained can be confirmed in Table 93.

Location	Phase	Voltage Value (V)
F08_Load_00122	2	257.80

Table 93 - B1: Initial voltage level.

The merit order of actuation for this test is as follows in ANNEX II - Table 210.

After running the LVC tool, only the transformer is necessary to overcome the voltage deviation problem. The tested set-points are shown in Table 94.

Steps	Unit ID	Tap Position	Initial Voltage (V)	Voltage (V)
1	Transformer001	4	243.31	233.31
2	Transformer001	5	233.31	223.31

Table 94 - B1: Set-points.

The final voltage value, after the set-points corresponding to the change of two tap positions in the transformer, is presented in Table 95.

Location	Phase	Voltage Value (V)
F08_Load_00122	2	238.95

Table 95 - B1: Final voltage level.

In the Figure 96, the voltage variation in the problematic node, where the equipment *F08_Load_00122* is connected, can be observed.

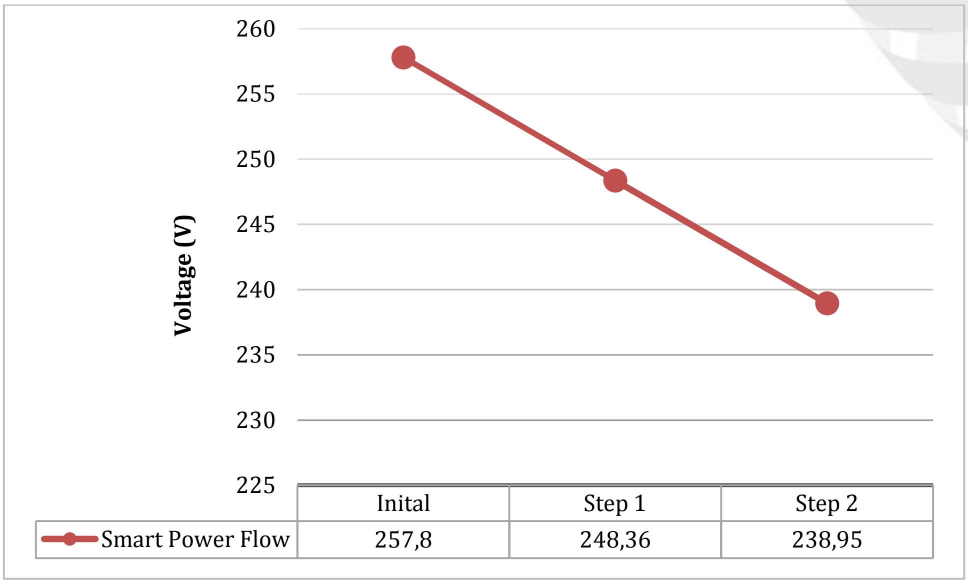


Figure 96 - B1: Voltage evolution within the LVC tool.

As in the previous situation, the relevant KPIs were calculated and are shown in Table 96.

KPI index	KPI name	Value (%)
1	Increase RES and DER hosting capacity	0.98
2	Reduced energy Curtailment of RES and DER	100
3	Increased hosting capacity for electric vehicles and other loads	0
4	Reduction of Technical Losses	-243.4
5	Share of Electrical Energy produced by RES	0.08
6	Voltage Deviation index	100
7	Quantify the number of regularized voltage deviations	100

Table 96 - B1: KPIs.

3.3.3.2.4 Test Case B2

This case has the same conditions as test case B1 but corresponds to an undervoltage situation. The voltage value for this scenario is shown in Table 97.

Location	Phase	Voltage Value (V)
F08_Load_00135	2	210.09

Table 97 - B2: Initial voltage level.

The list of equipment selected and sorted for this scenario is shown in ANNEX II -Table 211.

Similarly to test case B1, only the OLTC transformer is actuated for controlling the undervoltage. The set-points are detailed in Table 98.

Steps	Unit ID	Tap Position	Initial Voltage (V)	Voltage (V)
1	Transformer001	2	232.74	242.74

Table 98 - B2: Set-points.

The final voltage level for the problematic node is presented below.

Location	Phase	Voltage Value (V)
F08_Load_00135	2	221.25

Table 99 - B2: Final voltage level.

The voltage evolution can be seen in Figure 97.

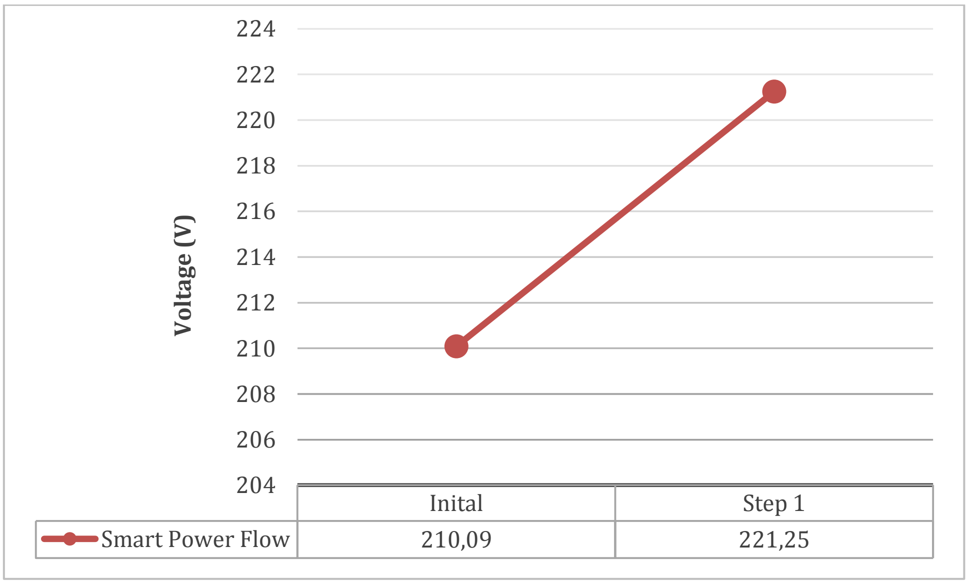


Figure 97 - B2: Voltage evolution within the LVC tool.

For test case B2, the resulting KPIs values are shown in Table 100.

KPI index	KPI name	Value (%)
1	Increase RES and DER hosting capacity	0.58
2	Reduced energy Curtailment of RES and DER	100
3	Increased hosting capacity for electric vehicles and other loads	0.084
4	Reduction of Technical Losses	-54.4
5	Share of Electrical Energy produced by RES	-2.26
6	Voltage Deviation index	100
7	Quantify the number of regularized voltage deviations	100

Table 100 - B2: KPIs.

3.3.3.2.5 Test Case C1

The set of test cases C1 and C2 are related to the long-term forecast scenarios of WP1. The RES penetration is nine times higher than the total installed power in A1 and A2 and the load suffers a reduction by a factor of 0.85. Additional energy storage units are connected throughout the network.

Similarly to what was done in test case B1 and B2, the nominal power of the generations units integrated in those scenarios is now upgraded, meaning that each of the new generation units will now have a rated nominal power of 6kW. The same generation profiles are applied to the remaining generators so that the operation conditions are the same as the test cases A.

Regarding the loads, all the consumers have their rated power scaled to a factor of 0.85 of their nominal power and the same consumer patterns are applied.

For this test case, the overvoltage situation has, as expected, a magnitude significantly higher than in the test case A1. The value can be observed in Table 101.

Location	Phase	Voltage Value (V)
F08_Load_00122	2	272.95

Table 101 - C1: Initial voltage level.

The merit order of actuation, sorted by the equipment given rank, is as follows in ANNEX II - Table 212.

The set-points tested within the LVC tool for this test case are detailed in Table 102.

Steps	Unit ID	Tap Position	Initial Voltage (V)	Voltage (V)
1	Transformer001	4	243.31	233.31
2	Transformer001	5	233.31	223.31
Steps	**Unit ID**	**-**	**Initial Power (kW)**	**Set point (kW)**

3	F08_Gene_x0122	-	5.18	1.57
4	F08_Gene_x0122	-	1.57	0
5	F08_Gene_x0123	-	5.59	1.99
6	F08_Gene_x0123	-	1.99	0

Table 102 - C1: Set-points.

The final voltage value obtained after the LVC tool is shown in Table 103.

Location	Phase	Voltage Value (V)
F08_Load_00122	2	247.27

Table 103 - C1: Final voltage level

For each set-point tested, the voltage evolution resulting from the smart power flow in the LVC tool can be observed in Figure 98.

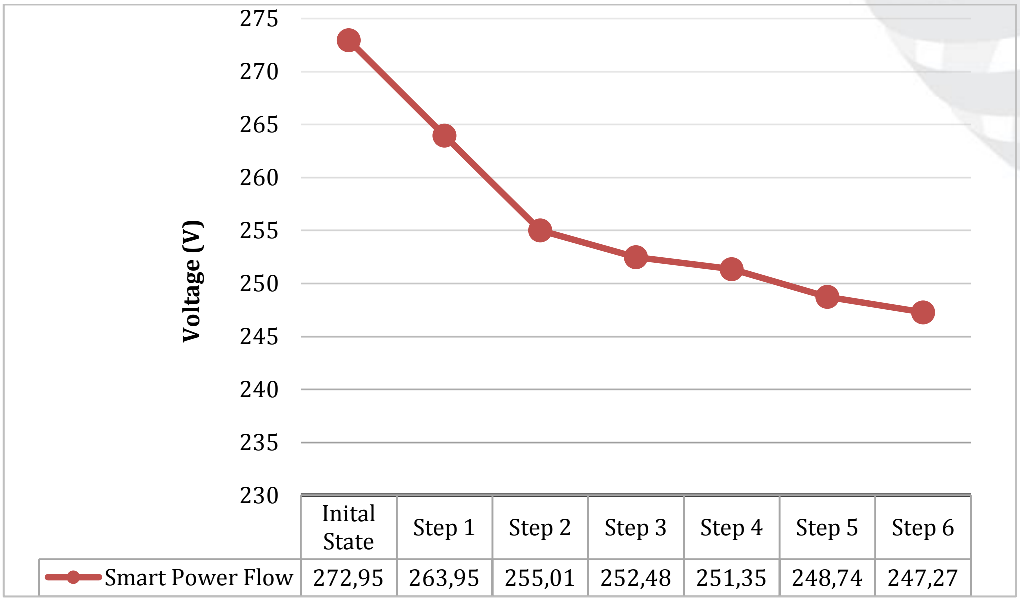


Figure 98 – C1: Voltage evolution within the LVC tool.

Once again, the resulting KPIs values for the current test case were computed and are presented in Table 104.

KPI index	KPI name	Value (%)
1	Increase RES and DER hosting capacity	3.01
2	Reduced energy Curtailment of RES and DER	100
3	Increased hosting capacity for electric vehicles and other loads	0
4	Reduction of Technical Losses	-191.429
5	Share of Electrical Energy produced by RES	32.69
6	Voltage Deviation index	100
7	Quantify the number of regularized voltage deviations	100

Table 104 - C1: KPIs.

3.3.3.2.6 Test Case C2

For the last test case, similar conditions as the previous simulation (test case C1) are considered for the same instant where the undervoltage situation occurred in test case A2. In this case, as the load has decreased by a factor of 0.85, the minimum voltages levels in the network are now higher compared to test case A2. The minimum voltage level for this instant is now within the proposed limits so that the LVC tool does not propose any set-points.

The minimum voltage level in network for this test case can be observed inTable 105.

Location	Phase	Voltage Value (V)
F08_Load_00135	2	212.02

Table 105 - C2: Initial voltage level.

3.3.3.3 Contingency Co-Simulation Tool

The first part of the analysis performed for the CCS Tool on the MV French network concerns the reliability simulation. This analysis has been run with the Contingency Selection module, based on a pseudo-sequential Monte-Carlo algorithm. The scope of this analysis is to define a set of realistic contingencies to be simulated with the Co-Simulation module.
For this task no specific test cases have been considered since the reliability analysis is slightly affected by the presence of flexibilities and also by minor changes in load/generation profiles, as for example load variations considered in Test Cases 1 and 2. On the other side, different results can arise if topology, grid configuration and reliability parameters are modified, as it has been observed in some exploring trials. Since no alternative grid configurations and different sets of reliability parameters have been considered, only one reliability simulation for each of the two networks has been performed. The Monte-Carlo simulation has been run for a time interval of 2000 years and 5000 extractions were done. Each run requires no more than 8-10 minutes, so if major changes in input data aren't necessary, a single run can give enough information on the asset faults which can be realistically faced. In Table 106 and Table 107 the identified events are reported.

Table 106 – Reliability analysis results for network 1

Event N.	Start hour	Duration [h]	Node 1	Node 2	Gen	PS trafo
1	17:00	25	119	122		
2	18:00	11	162	169		
3	18:00	11			34	
4	21:00	6	184	186		
5	12:00	14	81	104		
6	12:00	14			168	
7	12:00	14			191	
8	8:00	27	181	189		
9	2:00	6	195	202		
10	13:00	26	184	186		
11	23:00	22				2

Table 107 – Reliability analysis results for network 2

Event N.	Start hour	Duration [h]	Node 1	Node 2	Gen	PS trafo
1	14:00	8	55	90		
2	14:00	17	3	33		
3	18:00	10	115	117		
4	22:00	9	10	18		
5	13:00	16				1
6	4:00	9	26	42		
7	5:00	11	117	121		
8	7:00	13	41	49		
9	18:00	11	42	50		
10	9:00	10	37	42		
11	15:00	8	14	16		
12	20:00	12	27	31		
13	20:00	11	77	88		
14	9:00	12				1
15	7:00	10				2
16	5:00	12				2

Not all the detected events have been simulated; some of them drive to minor modifications in network configuration so simulation aren't worth the efforts, producing results which are not relevant. Some other cannot be simulated because they require more knowledge about reconfiguration and management policies adopted. For example, PS trafo faults could be interesting to be analysed only if it would be possible to know how feeders are shifted from one transformer to another; an event such this could require some modifications also on other feeders which, in this case, are not detailed and can be considered only as transformers load-in factors.

Based on these considerations, taking into account the feasibility to perform a back-up feeding between two feeders belonging to different PS, one example has been selected in order to explore the issues which arise if a consistent part of a feeder, isolated from the PS by a branch fault, is fed through a back-up from another PS. The grid configuration consequently to Event n°1 for network 1 has been considered. The resulting topology is reported in Figure 99. Another example (Example 2) has been specifically built for showing over-voltage resolution capability and co-simulation analysis; this one considers the network 2 and events 1 and 11 from Table 107.

<u>Example 1: under-voltage</u>

The relevant Test Cases reported in Table 35 have been applied to this network. In the following obtained results are showed.
For this network configuration, under-voltage violations were observed due to the load increase forced by the addition of a consistent part of another feeder and then load shapes and load modulation flexibilities have a strong impact. The considered time period spans from 17:00 to 18:00 of the day after, for an overall duration of 25 hours. These data comes from the reliability analysis.

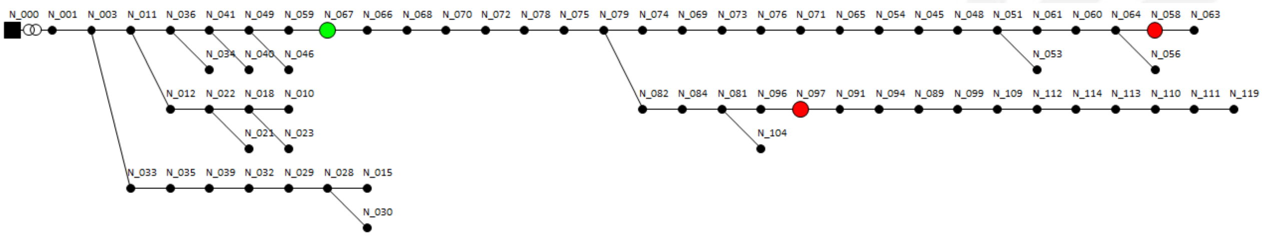


Figure 99 – Reconfiguration after branch fault between nodes 119 and 122.

Test case 1:

For Test Case 1 the load capacity is increased of 3% compared to the baseline network, and load modulation flexibilities are available only for industrial loads; they are pictured as rectangular orange nodes in Figure 100. Two wind plants are connected to the network, in nodes N_058 and N_097; their nominal power is, respectively, 1,824 MVA and 1,827 MVA.

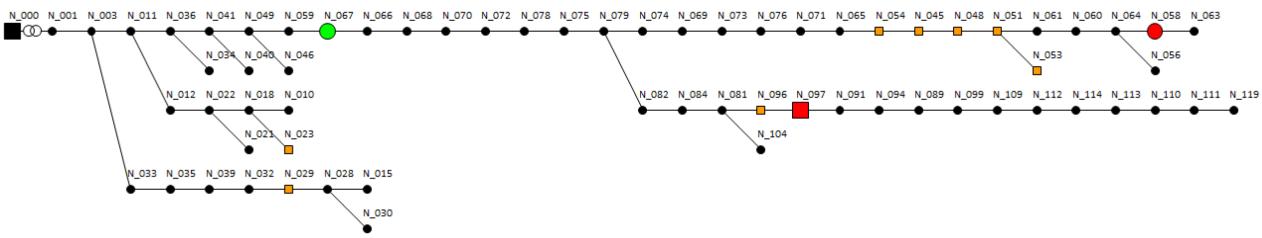


Figure 100 – Example 1: network under test, Test Cases 1 and 2

In Figure 101 – Example 1: voltage profiles, Test Case 1 the voltage profiles at nodes for the whole time period are reported. Under-voltages are observed repeatedly in nodes N_074 and N_053.

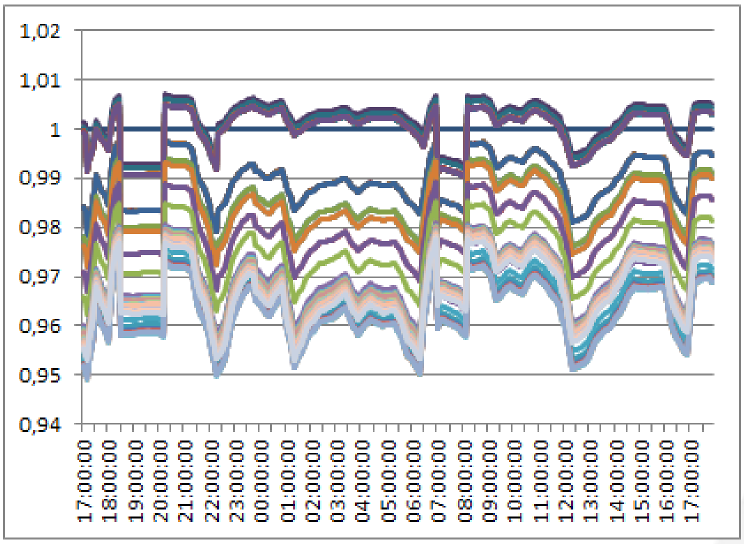


Figure 101 – Example 1: voltage profiles, Test Case 1

Since the major under-voltages were experienced in branches connected to wind generators and industrial loads, they were all solved by the Tool; a total of 131 DMS calls took place. All load flexibilities have been exploited at the maximum level; both active and reactive power resources of generators have been employed as well. Reactive power injection took highest values at the beginning, from 17:00 to 22:00, and from 7:00 to the 18:00. In this last case this is due mainly to the overall load profile of the network, while in the evening hours the residential loads draw the most power. Since in this Test Case they cannot be modulated, then the only way to solve violations is the reactive power production.

In Figure 102, Figure 103, and Figure 104 active and reactive power profiles of wind generators and the overall load profile are reported.

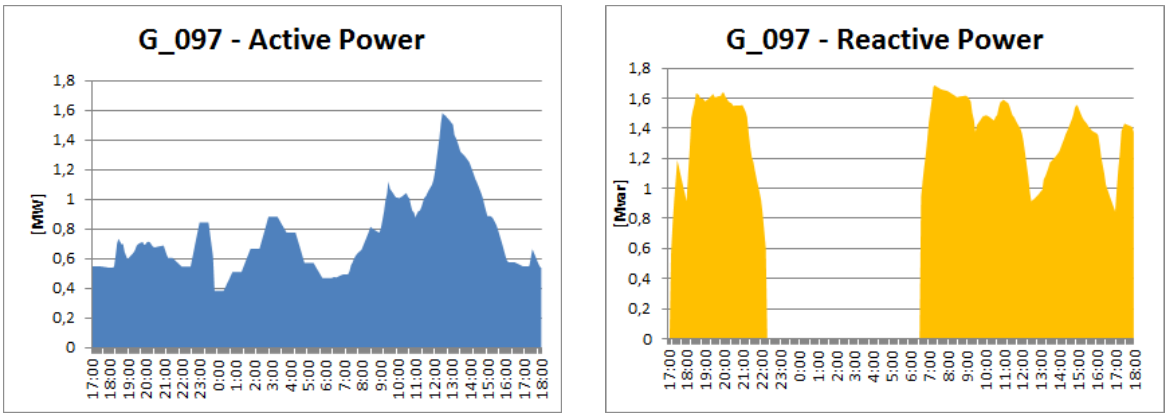


Figure 102 – Example 1: G_097 power profiles, Test Case 1

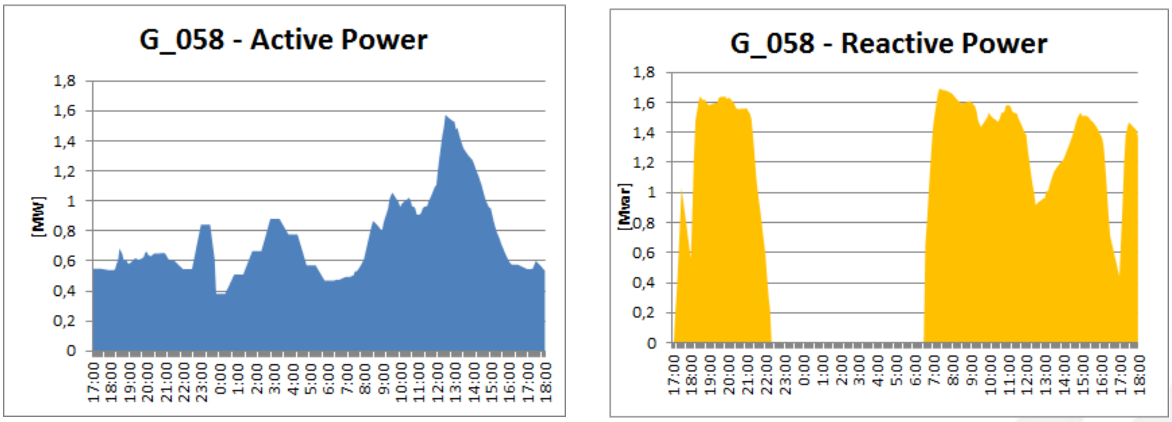


Figure 103 – Example 1: G_058 power profiles, Test Case 1

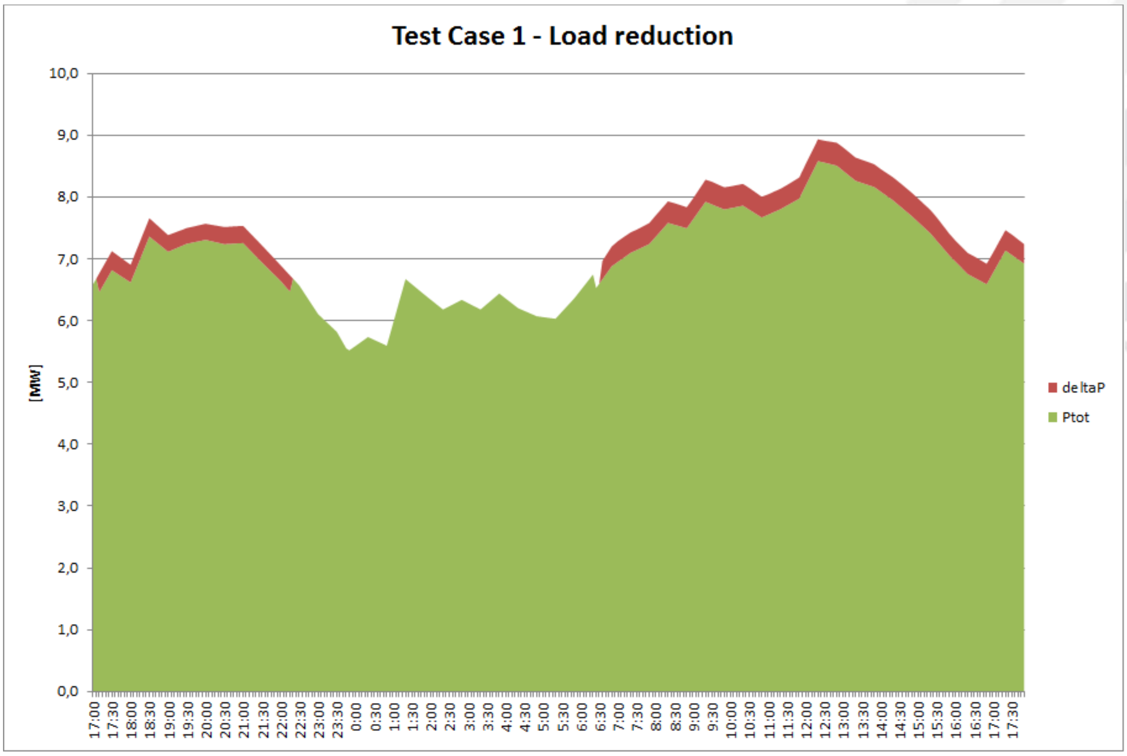


Figure 104 – Example 1: overall load profile and load modulation reduction, Test Case 1

Test case 2:

The only main difference between Test Case 1 and Test Case 2 is the load capacity, which is now reduced of 3% compared to the baseline network; as expected, very similar results appear apart from the slightly shorter duration of time intervals in which voltage violations are observed. In Figure 105, Figure 106, Figure 107, and Figure 108, the voltage profiles at nodes, active and reactive power profiles of wind generators, and overall load profile are respectively reported.

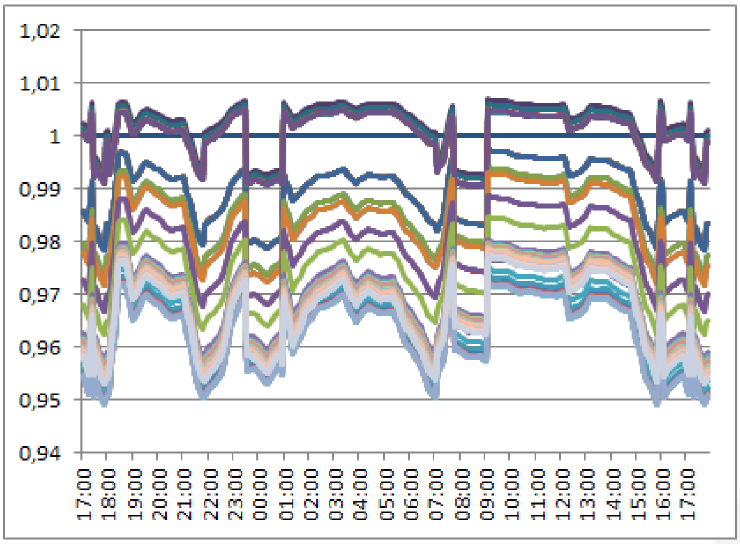


Figure 105 – Example 1: voltage profiles, Test Case 2

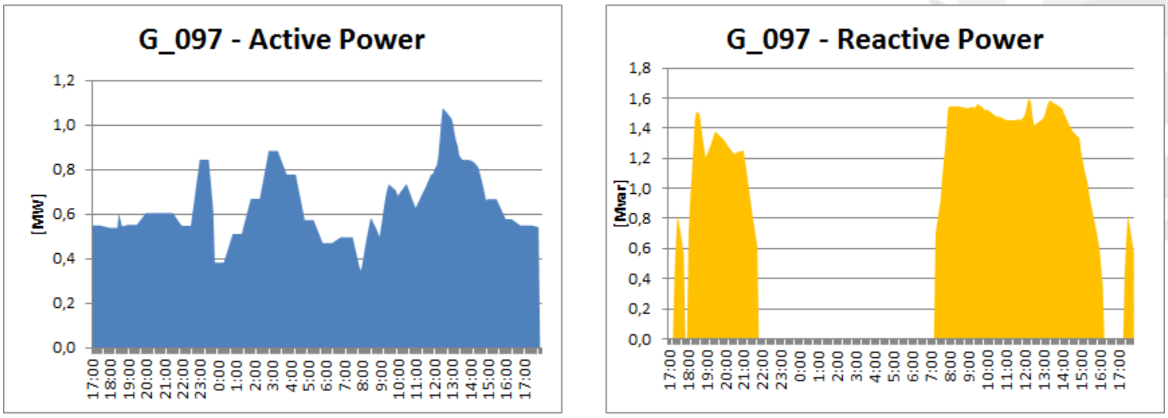


Figure 106 – Example 1: G_097 power profiles, Test Case 2

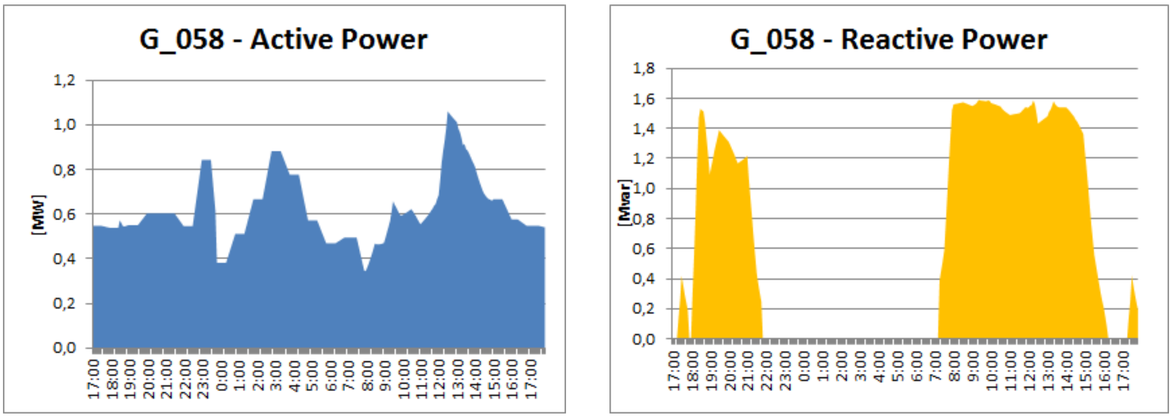


Figure 107 – Example 1: G_058 power profiles, Test Case 2

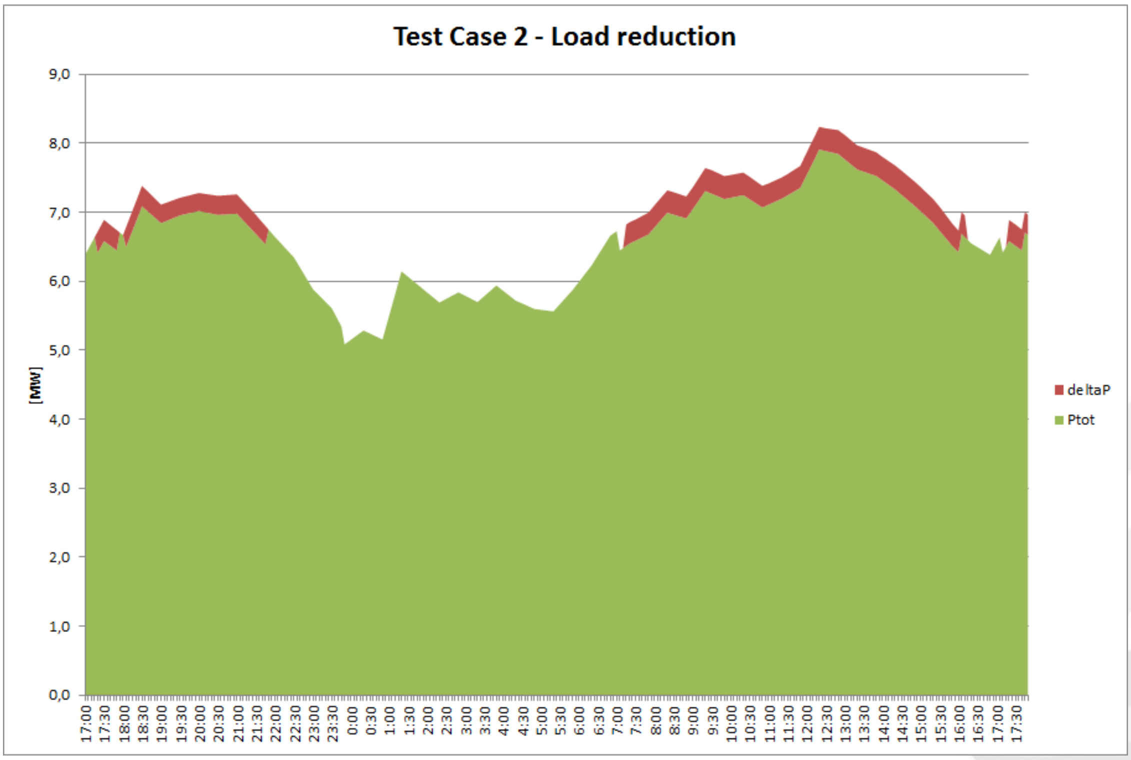


Figure 108 – Example 1: overall load profile and load modulation reduction, Test Case 2

Test case 3:

For Test Case 3 the same conditions of Test Case 2 have been considered plus an EV charging "sub-load" for each load with an average power equal or more than 30kW (nodes pictured in yellow in Figure 109 – Example 1: network under test, Test Case 3). Since this consist in a 10% increase of most loads, the overall load profile is further increased in respect to baseline network scenario, more than in Test Case 1. In these conditions the available flexibilities were not sufficient to avoid violations. Indeed, corresponding to the load peak (12:30-12:45) the exploitation of active resources reached it maximum. In these conditions no optimization has been performed, resulting in an under-voltage violation, as can be easily observed in Figure 110. In Figure 111 and Figure 112 the power profiles of generators show that the active power fall to the fixed value (no dispatching control from the DMS) and the reactive power is null during that specific time interval.

Figure 109 – Example 1: network under test, Test Case 3

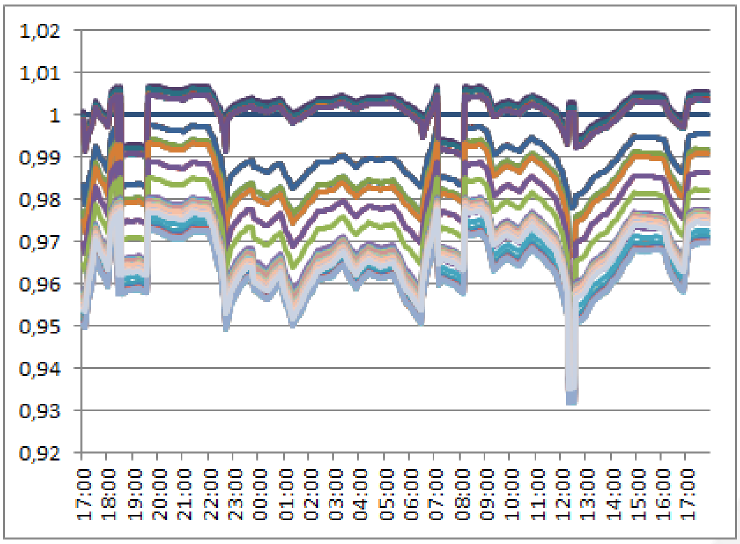


Figure 110 – Example 1: voltage profiles, Test Case 3

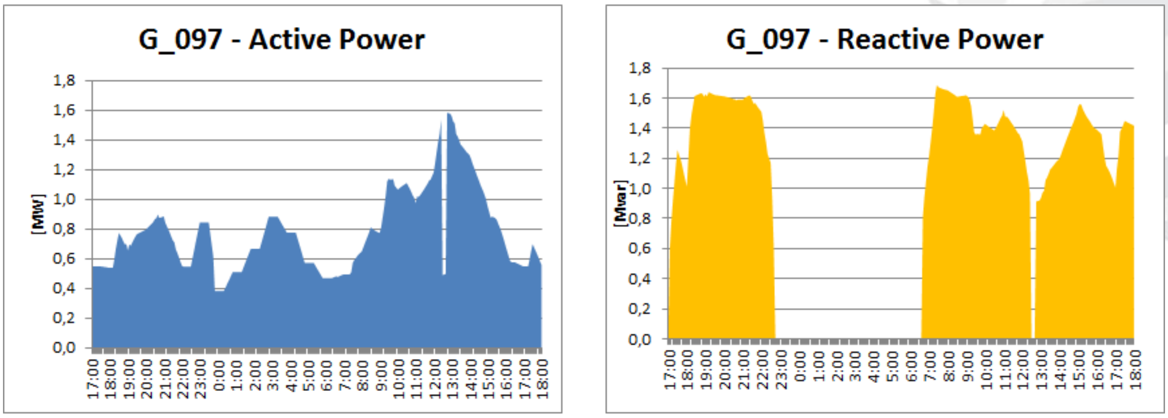


Figure 111 – Example 1: G_097 power profiles, Test Case 3

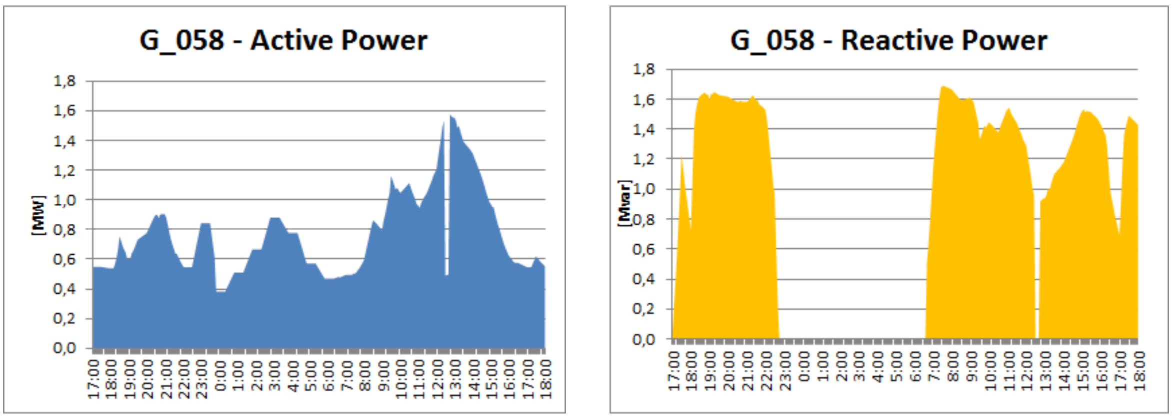


Figure 112 – Example 1: G_058 power profiles, Test Case 3

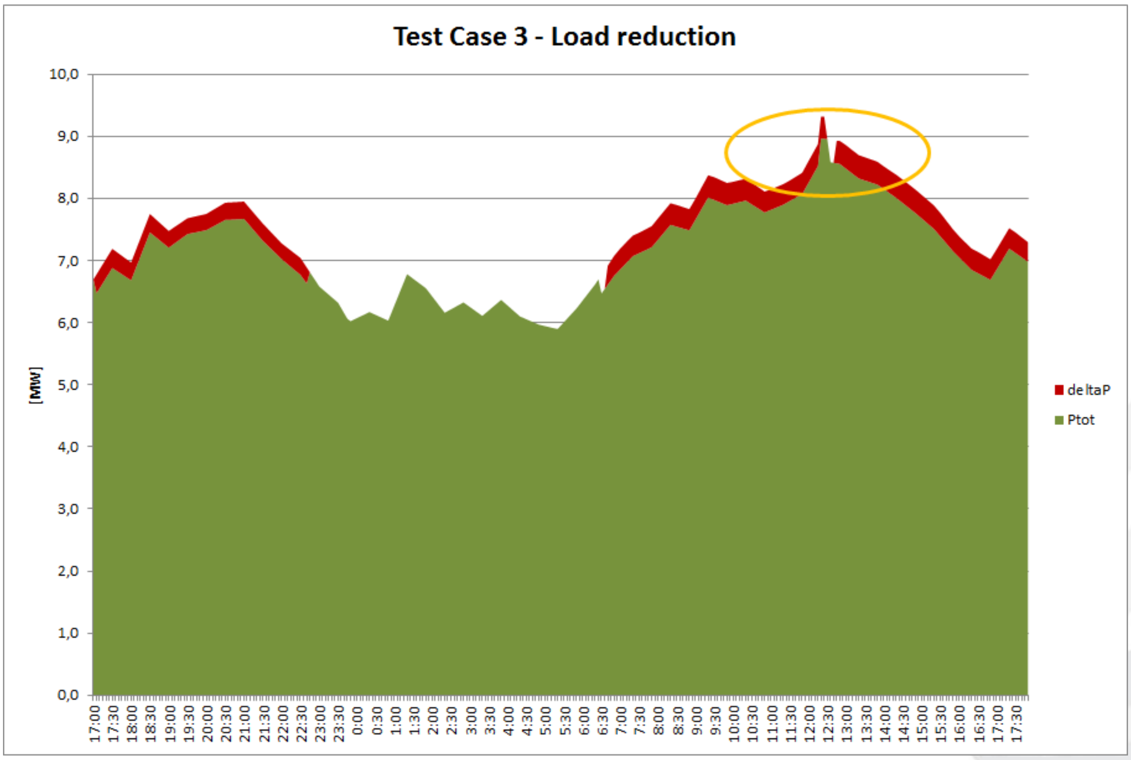


Figure 113 – Example 1: overall load profile and load modulation reduction, Test Case 3

Test case 4:

In Test Case 4, residential/commercial load modulation flexibilities have been considered; they are pictured in light blue in Figure 114. The results are quite similar to those achieved in Test Case 2, apart from the voltage profiles (Figure 115) which are more indented due to the “punctual” load modulation.

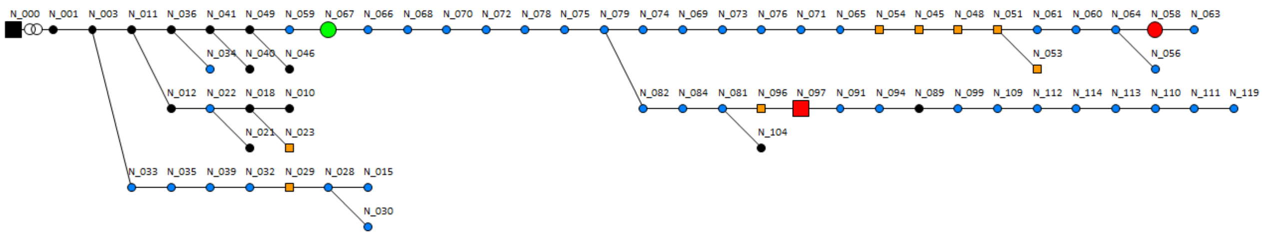


Figure 114 – Example 1: network under test, Test Cases 4

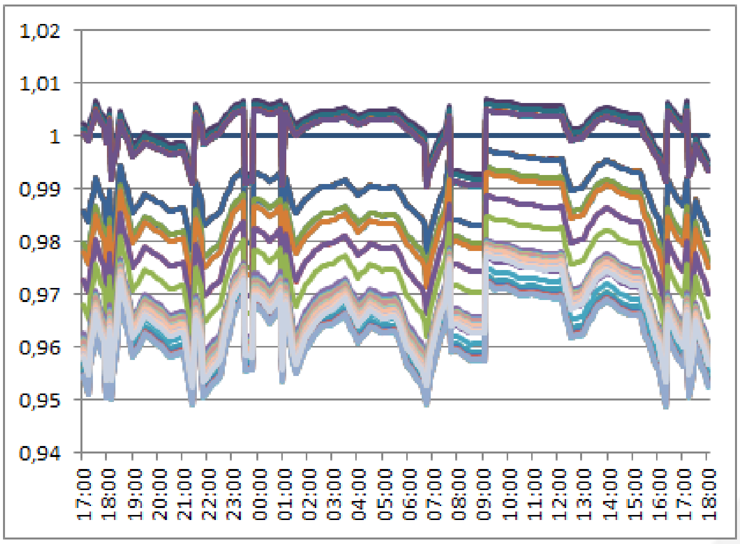
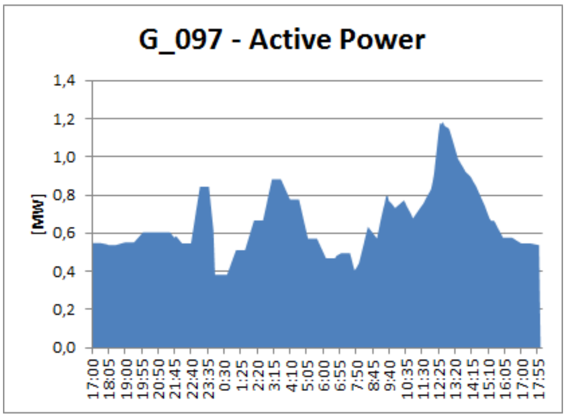


Figure 115 – Example 1: voltage profiles, Test Case 4

As can be observed in Figure 116 and Figure 117, the enhanced load modulation capabilities had a positive impact on the exploitation of reactive power from wind generators, which was reduced both in absolute values than in duration.



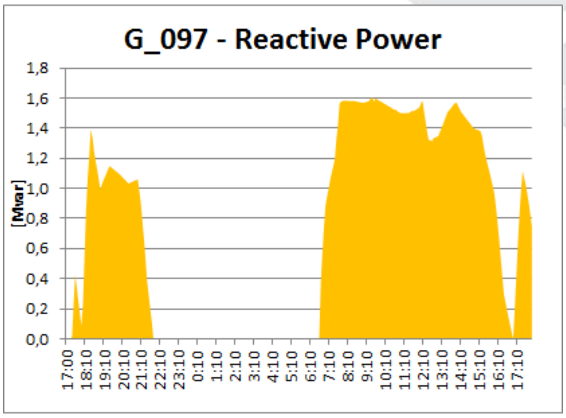
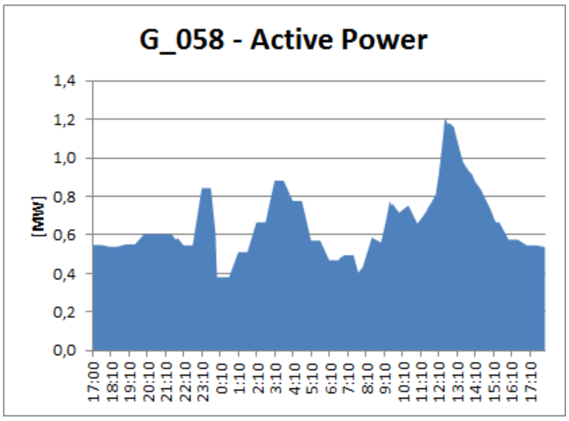


Figure 116 – Example 1: G_097 power profiles, Test Case 4



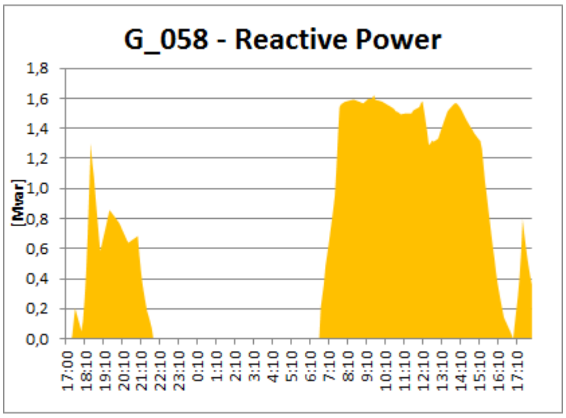


Figure 117 – Example 1: G_058 power profiles, Test Case 4

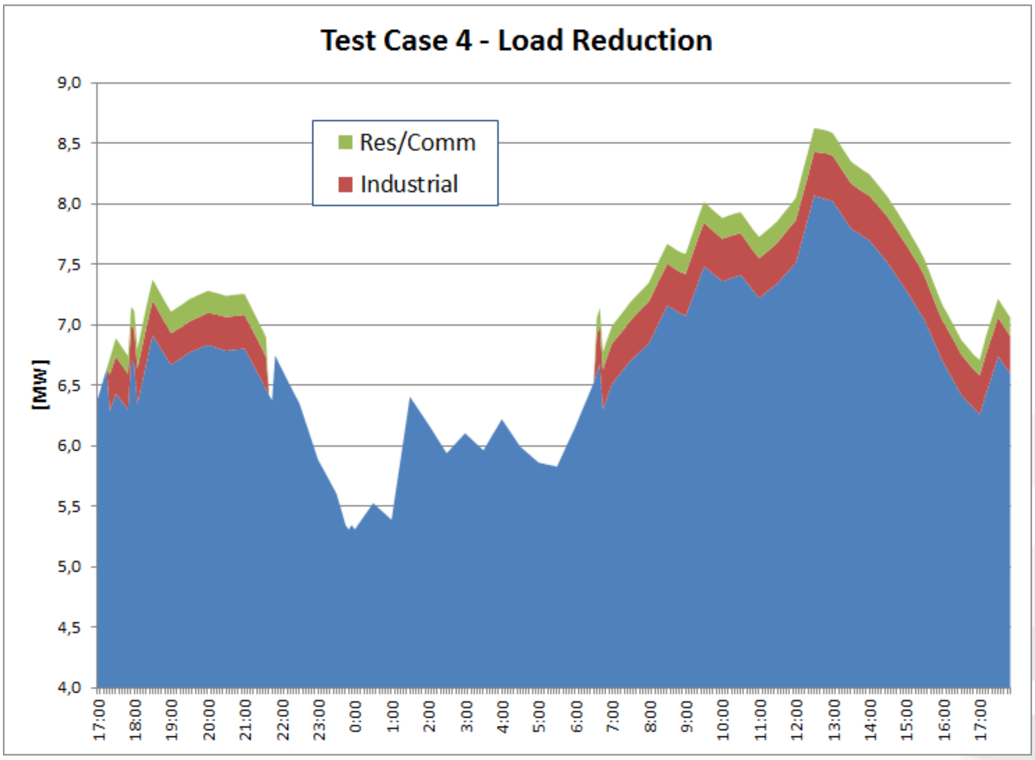


Figure 118 – Example 1: overall load profile and load modulation reduction, Test Case 4

Example 2: over-voltage

Many simulations of the given network, considering different events gathered from the reliability analysis, showed only under-voltage violations and, in several cases, no violations at all. In order to show also Tool capability to deal with over-voltage violations, an "artificial" example was created. The base topology for this example was derived from the network in Figure 30 in which two events were considered to happen concurrently, event N°1 and N°11 from the Table 107; the resulting topology is reported in Figure 119 and Figure 120:

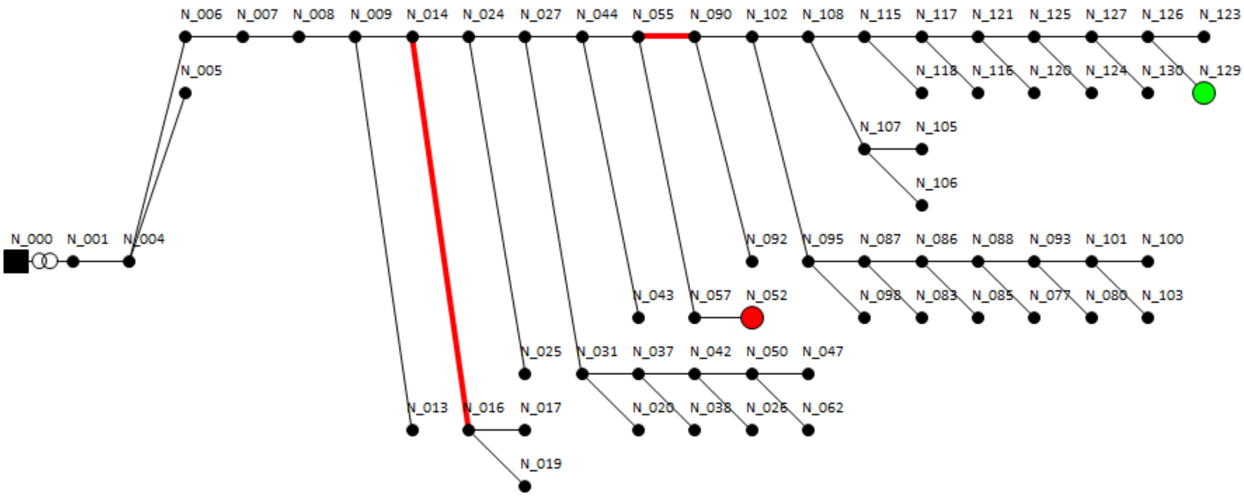


Figure 119 – Example 2: modifications of network 2

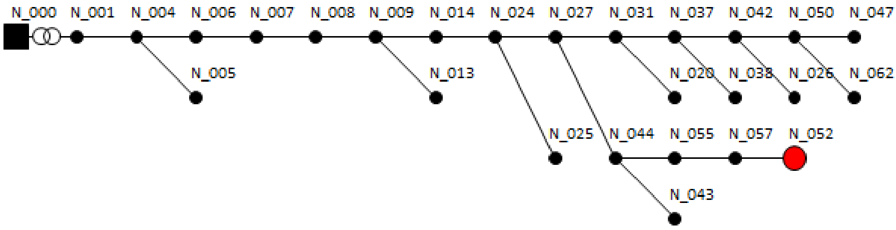


Figure 120 – Example 2: network under test

Further on, the highest wind speed profile was selected from given data and the slack node HV set-point was set to 1.025 pu.
Both the hypotheses of Test Case 1 and Test Case 2 were applied to this network configuration. The resulting voltage and power profiles are presented in Figure 121, Figure 122, and Figure 123.

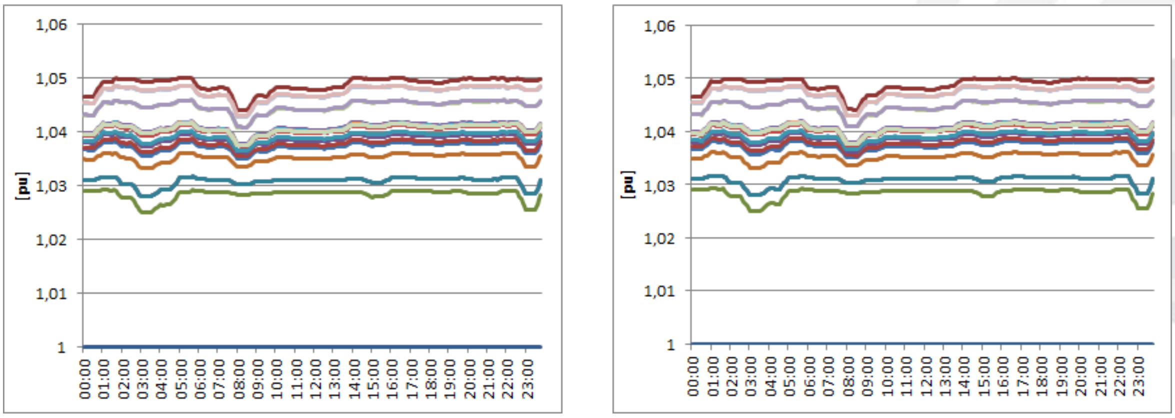


Figure 121 – Example 2: voltage profiles, Test Cases 1 and 2

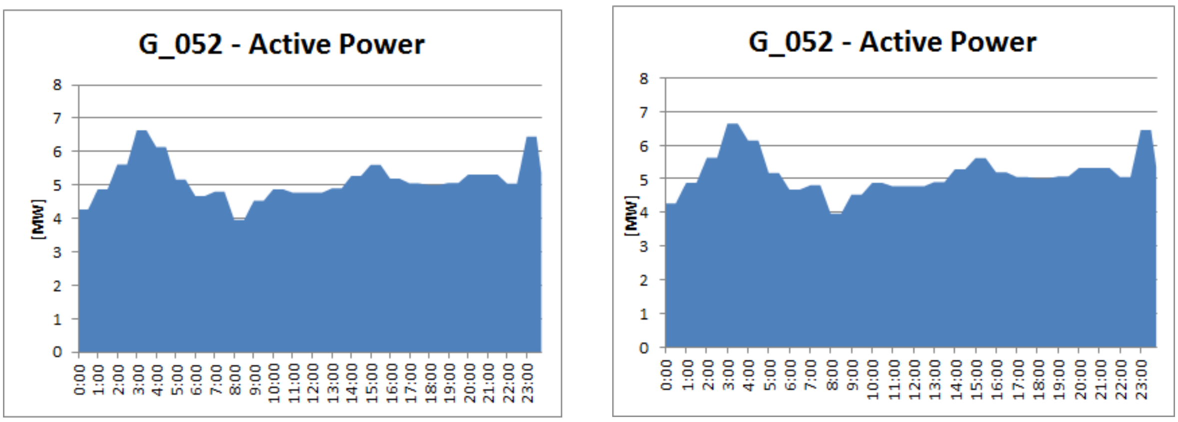


Figure 122 – Example 2: G_052 active power profiles, Test Cases 1 and 2

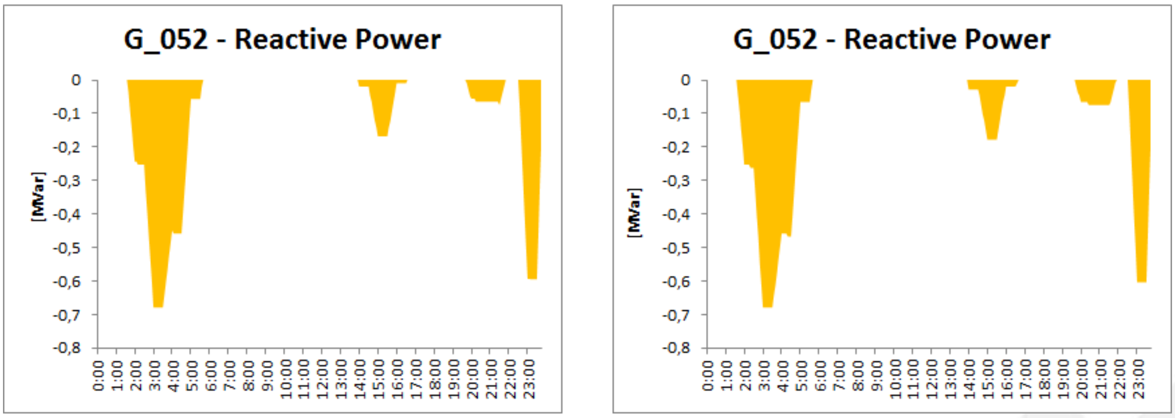


Figure 123 – Example 2: G_052 reactive power profiles, Test Cases 1 and 2

No major differences has been observed between Test Cases results; over-voltage violations (occurring between 1:45 to 5:35, 14:00 to 16:10, 19:30 to 21:45, 22:15 to 23:45) were all solved through reactive power generation from wind plant G_052. The effort was a little stronger for Test Case 2 where intrinsic compensation from loads is lower due to 3% reduction. Anyway in both cases the generation curtailment can be avoided without exiting from the voltage limits.

The network defined in example 2 has been considered also for showing the capability of the *Co-simulation module* to analyze the *ICT system behavior*. The computational efforts of the co-simulation analysis increase proportionally to the number of active nodes (nodes equipped with ICT remote devices such Smart-Meters, for example) and to their distance from the Base Station (usually located in primary substation); thus, considering a standard PC, some real network and ICT configuration may not be simulated mainly for memory issues. The optimization of computational resources for co-simulation analysis is an open point which will be faced in future developments of the Tool.

The results of the communication systems analysis applied to this network with Test Case 2 assumptions are presented in the following figures.

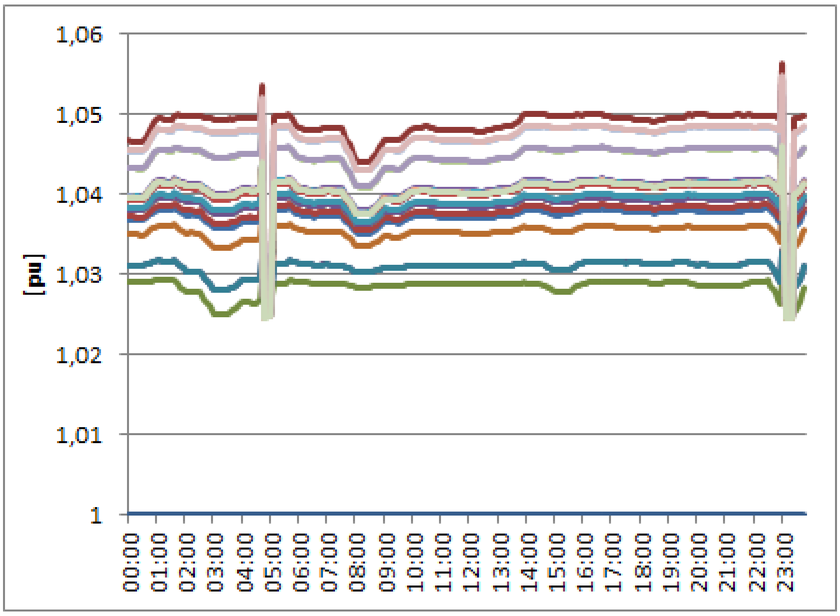


Figure 124 – Example 2: co-simulation analysis, voltage profiles

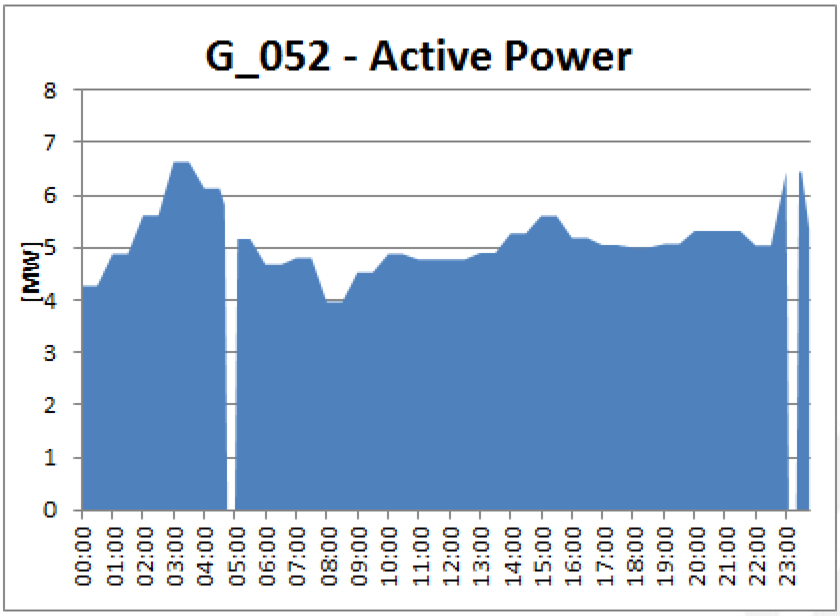


Figure 125 – Example 2: co-simulation analysis, G_052 active power profile

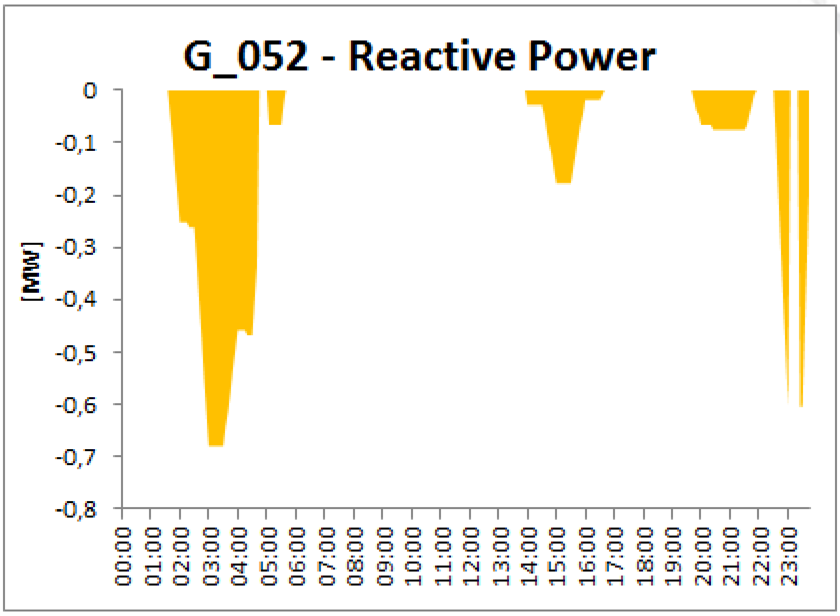


Figure 126 – Example 2: co-simulation analysis, G_052 reactive power profile

As can be observed in Figure 127, Figure 128, Figure 129, in two cases, from 4:40 to 5:05 and from 23:00 to 23:30, the resolution of over-voltage violation is not performed due to disconnection of the generator from the network; this action was taken from the DMS because the persisting over-voltage violation together with unfavorable transmission conditions.
In the following figures, some excerpt of the output log file are presented.

```
************************************************************************************
        POWER NETWORK DATA

Power Network: SR2-Fd1_T2_5590-1416
Components DB: Lib_Componenti_Ufficiale
Profiles DB: Lib_Profili_Ufficiale2
AMProfiles DB: Lib_Profili_AM_Ufficiale

        DMS SETTINGS

Optimal P Control: 0
Optimal P & Q Control: 1
Losses optimization: 0

         SITE AND WEATHER DATA

Location:France

Site and weather condition for selected city and month:

T ['C]: 11.0
UR [%]: 80
P [mbar]: 1016.3000
Ground conductivity: Good ground
Site type: Rolling plains
Antennas siting criteria: Care
Average rainy days: 7
Average monthly precipitation:48.90

        LOAD FLOW PERIOD

Start Date: 10-Dec-2025
End Date: 10-Dec-2025 23:45:00
Simulation Step Size [s]: 300

        ICT SETTINGS

Ict Medium: WiMAX
Packet Size [Byte]: 100
************************************************************************************
```

Figure 127 – Example 2: co-simulation analysis, input data

```
        Delay messages delivered to active nodes:
        N_052: 0.003518 s
04:20:00
        Overvoltage on N_052 @ 04:20:00 detected by smart meter

        Communication between N_052 and DMS successfully delivered in 0.003518 s

        Active Nodes: N_052
        DMS optimization done

        Delay messages delivered to active nodes:
        N_052: 0.003518 s
04:30:00
        Overvoltage on N_052 @ 04:30:00 detected by smart meter

        Communication between N_052 and DMS successfully delivered in 0.003518 s

        Active Nodes: N_052
        DMS optimization done

        Delay messages delivered to active nodes:
        N_052: 0.003518 s
04:35:00
        Overvoltage on N_052 @ 04:35:00 detected by smart meter

        Communication between N_052 and DMS successfully delivered in 0.003518 s

        Active Nodes: N_052
        DMS optimization done

        Delay messages delivered to active nodes:
        N_052: 0.003518 s
04:45:00
        Overvoltage on N_052 @ 04:40:00 detected by smart meter
        Generator at node N_052 disconnected from the network due to persisting overvoltage condition
        A new connection will be tried in the next quarter of hour
04:50:00
                Generator at node N_052 disconnected from the network due to persisting overvoltage co
        A new connection will be tried in the next quarter of hour
05:00:00
                Generator at node N_052 disconnected from the network due to persisting overvoltage co
        A new connection will be tried in the next quarter of hour
05:05:00
        Overvoltage on N_052 @ 05:05:00 detected by smart meter

        Communication between N_052 and DMS successfully delivered in 0.003518 s

        Active Nodes: N_052
        DMS optimization done

        Delay messages delivered to active nodes:
        N_052: 0.003518 s
```

Figure 128 – Example 2: co-simulation analysis, excerpt of analysis steps

```
********************************************************************************

       SIMULATION SUMMARY

Number of DMS calls: 77
Number of DMS actions: 77
Number of messages sent: 76
Number of messages successfully received: 76
Error rate in communication: 0.0130
Average of latency in communication: 0.003518


********************************************************************************
```

Figure 129 – Example 2: co-simulation analysis, summary of the results

Calculation of KPIs for the CCS Tool

The calculation of the KPIs for the CCS Tool is presented here.

SAIDI variation index

The calculation formula for this KPI is the following:

$$\Delta SAIDI[\%] = \frac{SAIDI_{tool} - SAIDI_{baseline}}{SAIDI_{baseline}} \times 100\ \%$$

Where:

$\Delta SAIDI$ = SAIDI variation between baseline and tool scenario

$SAIDI_{baseline}$ = SAIDI calculated for a suitable time period during which the Co-sim tool is not employed

$SAIDI_{tool}$ = SAIDI calculated for a suitable time period during which the Co-sim tool is employed

Example 1 results were used for the calculation of this KPI. The baseline scenario, in the context of the tool, should be considered as the management of networks, modified in order to face the events detected by reliability analysis, following the actual DSO policies for this type of situations. Since it is not possible to define a unique policy for all the possible situations and any kind of information about policies adopted by the DSOs has been available, the baseline scenario has been defined on the following assumptions: 1) no flexibilities available, 2) voltage profiles must stay within the limits for the whole observation period, 3) load can be disconnected, and 4) active power production can be reduced until generators minimum output. Two scenario have been considered, 1 and 2, with the same load values of Test Case 1 (+3%) and Test Case 2 (-3%), respectively (see Table 108).
Applying these hypotheses on example 1 results in the figures reported in Table 109:

Table 108 - CCS Tool – SAIDI values for baseline scenario

Scenario	N° of customers	SAIDI [min]
1	8592	48,9
2	8592	45

Table 109 - CCS Tool – SAIDI variation index

Test Case	$SAIDI_{baseline}$ [min]	$SAIDI_{tool}$ [min]	$\Delta SAIDI[\%]$
1	48,9	0	-100%
2	45	0	-100%
3	45	1,93	-97%
4	45	0	-100%

As shown in the Test Case 3 results, in the 12:30-12:45 time interval the network cannot be optimized due to a lack of active resources (all available resources employed). For the KPI calculation it was assumed that some loads were shed, resulting in a non-zero SAIDI value; this is in line with baseline scenario assumptions.
Anyway, this KPI values should be treated with caution because the considered assumptions may be significantly different from real. More accurate values for this KPI could be obtained if actually used policies are considered for the baseline scenario definition.
Even with this limitation, the calculated values show that the joint usage of CCS Tool and flexibilities could avoid/reduce load shedding and improve network management in presence of contingencies.

Energy curtailment index

The calculation formula for this KPI is the following:

$$\Delta E_{not-injected}[\%] = \frac{E_{not-injected}^{baseline} - E_{not-injected}^{tool}}{E_{not-injected}^{baseline}} \times 100\%$$

Where:
$\Delta E_{not-injected} =$ reduction in energy not-injected
$E_{not-injected}^{baseline} =$ energy not-injected in the grid due to asset unavailability when CCS Tool is not employed
$E_{not-injected}^{tool} =$ energy not-injected in the grid due to asset unavailability when CCS Tool is employed

This KPI is applied to example 2. The baseline scenario is based on the same assumptions considered for the SAIDI variation index KPI. Calculation results are reported in Table 110.

Table 110 - CCS Tool – Energy curtailment index

Test Case	$E_{not-injected}^{baseline}$ [MWh]	$E_{not-injected}^{tool}$ [MWh]	$\Delta E_{not-injected}[\%]$
1	5,18	0	100%
2	5,34	0	100%
2 + co-sim	5,34	3,95	26%

These results show that the DMS active control on reactive power generated by wind plant can effectively avoid generation curtailment, saving generated energy. This could be not completely achievable if the ICT transmission doesn't perform correctly, resulting in a consistent loss of energy if generators output is curtailed or reduced.

This results highlight that the co-simulation analysis can be strategic for active resources planning in the short-term period; if some harmful conditions for communications (bad weather, ICT bus congestions, etc..) can be foreseen for a specific time in the future, their impact on the actual availability of active resources can be assessed and a more reliable planning in case of contingencies occurrence can be done.

3.4 Conclusions, Main Benefits and Limitations

3.4.1 Robust Short-Term Economic Optimization Tool for Operational Planning

Table 111 presents the main results obtained in the three scenarios for both the RSE optimizer and the VITO optimizer. The OLTC voltage is fixed at 1.034 pu in the RSE optimizer, while in the VITO optimizer the OLTC voltage is fixed at 1.02 pu in the 2012 and 2018 scenario, and at 1.03 pu in the 2023 scenario. In these conditions, load curtailment allows to manage the network within the technical limits. The highest load is foreseen in 2023 however, in 2018 the larger contribution of the loads provides a higher cost in terms of active power regulation due to local congestions.

	RSE optimizer OLTC at 1.034 pu	**VITO optimizer** OLTC at 1.02 pu (2012,2018)/1.03 pu (2023)
Scenario	Solution cost [€]	Solution cost [€]
2012	63.29	584.6
2018	112.83	760.5
2023	54.82	592.8

Table 111 - OP Tool - Recap of the RSE and VITO Optimization Results.

Given that the network is able to accept the energy produced by the DGs in all the scenarios, their curtailment never occurs. Given that the resources available are limited when network violations occur, the reactive power support provided by generators is marginal. In case the OLTC is free to vary its voltage, the flexibilities do not provide any kind of support. In fact, the results show that the OLTC allows the respect of all the network constraints with lower economic efforts.

The network operates near the current limits, so a higher production requires the increase of absorption from the loads, due to the high cost of generation curtailment. Moreover, it is shown that with a rectangular capability curve (as the current Italian regulatory framework foresees) DGs provide reactive power support also when they do not produce active power (e.g. PV systems during the night). Hence, a smaller support from loads is necessary, leading to a cheaper optimized solution.

In case the OLTC voltage is reduced, a higher use of the flexibilities is necessary leading to a higher cost: this is indicated by the different results from both the RSE as VITO tool component in Table 111. This allows to highlight the importance of the OLTC voltage: small variations in its value can change the network operating conditions, leading to high differences in the use of the resources. The inclusion of inter-temporal constraints in the optimisation levers can lead to a cheaper optimizer solution as shown by the VITO tool component.

In conclusion, the tests allowed to prove the efficiency of the whole tool for Operational Planning purposes and to identify what are the resources that supports network management and their cost. Finally, the network made available by ENEL, together with the merit order input and the scenarios foreseen in WP1 have been successfully tested and their results discussed.

3.4.2 Network Reliability Tool - Replay

The replay tool described in deliverable D3.2 can be considered the starting point to realize a didactical platform for the SCADA operators. At the same time, because of its nature of off-line SCADA system, it represents the potential test platform for future innovative tools able to avoid impact on real systems in operation.

Within the WP3, the tests has been executed on a real network scheme (Sardegna control center area) and they have been realized by the use of a real system installed in the Smart Grid Laboratory of Milano. The visualization and the elaboration of the network occurred events in the past with the possibility to calculate load flow identifying and solving network criticalities represent the main test results because of the complexity and the quantity of data to be managed. The measurements of SAIDI on the real and replay systems, the calculation of electrical parameters (load flow) combined with the possibility to modify the network configuration, represents the opportunity to realize the ex-post and predictive analysis to support the SCADA operator in network management.

Furthermore the replay tool is able to support the elaboration of possible new scenarios to individuate solutions for the already existing network criticalities in a context of flexibility contracts. With regards of future scenarios of DRES integration, new studies are foreseen in the WP4 tests taking into account perspective of DRES increasing in the same network portion considered (Sardegna area). From a technical point of view the innovative functionalities allow to measure the identified KPIs and highlights how a potential use of the Replay methodology in a DSO can increase the sensitivity of quality of service for new SCADA operators and can increase the possibility of testing the network in a perspective of an active grid.

3.4.3 Low Voltage Distribution State Estimator

The LV DSE tool presented in *deliverable D3.2* was evaluated in this work for two distinct real LV networks, one from Portugal and the other from France. The DSE used on this study may be a good alternative to the classic methods. One of the major benefits of the DSE presented is its capability to achieve a state estimation solution without any knowledge of the networks' parameters and topology, what would be impossible with the traditional state estimation techniques usually employed.

In general terms, the results obtained for both networks demonstrated that when a representative historical dataset exists the proposed DSE can perform estimation of voltage magnitude values in a very effective and accurate way, even when a low number of real-time measurements are available. On the other hand, the estimation of electrical power quantities seems to be more difficult to perform, mainly due to the different behaviour of customers and due to the variability introduced by microgeneration units based on renewable energy sources. Nevertheless, if a more optimistic scenario is assumed for the networks (e.g. 25% of the customers owning a SM_r), the errors of active power estimations tend to drop considerably. As expected, the same result is verified for voltage magnitudes, but even more satisfactory values are achieved for both the mean and maximum estimation errors. This conclusion highlights the importance of using methodologies to find the most suitable locations for the installation on the one hand, and the necessity to perform a carefully analysis of the trade-off between a better accuracy and an increased cost when it comes to real-world applications on the other hand.

One of the limitations of the DSE used in this study is related to the historical database required for the training purposes. It is crucial, for a successful and effective training process, that a representative database exists, i.e., several samples sufficiently diversified in terms of the generation and consumers patterns, as well as in terms of the electrical changes, even more if they occur often in the network (e.g. topology changes), should be present. Additionally, all data samples should be synchronised data for all the existing time instants (operational points). A representative historical database will ensure that the DSE can learn the necessary patterns/correlations between the electrical variables of a given network. It is also important to avoid the existence of errors related to the measurements acquisition in the historical database. In this sense, the existence of methods to manage and filter the historical database gains importance in the context of a DSE based on the use of artificial intelligence techniques, such as the one evaluated here.

In the networks under study, the results achieved regarding the amount of historical data supports that there is no rule of thumb regarding the quantity of data to be used in the training procedure. In the networks analysed, it was verified that a non-representative historical database (with small number of data samples) yields the worst results. The estimation accuracy is improved when more historical data is added until a certain point where the results begin to worsen because the size of the database reach enormous proportions while the new additional data does not bring any added value (all the existing patterns/correlations have been already learned with the previous data). Therefore, tests are required to achieve the “optimal” value, which will be always case dependent on the different load/generation patterns that exist in the time horizon intended to run the DSE. For example, if there are few distinct consumption/generation patterns in the network for the period where DSE is intended to run, less historical data is required, comparing with a case where several distinct patterns exist, or even no patterns exist at all. Additionally, for historical databases with a large number of samples (e.g. one year), since load demand usually obeys to well-defined seasonal patterns, it is normally possible to split the data in seasonal patterns leading to more accurate results.

Finally, it is important to state that the existence of an advanced metering infrastructure capable of transmitting data in real-time to network operators, foreseen in a smart grids paradigm, can serve as an enabler to the state estimation in distribution grids based on artificial intelligence techniques, especially in poorly characterised distribution grids.

3.4.4 Low voltage control

The LVC tool main limitations are directly connected to the set of input data available. For simulations using the state estimation within the LVC tool, a representative historical database supporting the state estimation tool is required in order to have a better correlation between the power curtailed and the real voltage variation in the network. Using the smart power flow, a full knowledge of the network technical characteristics is the mandatory requisite otherwise the method will not output reliable results.

If the minimum standard of input data quality is reached, the LVC tool proves to be reliable and cost effective to manage voltage deviations. The results attained in this *deliverable* give a strong feedback regarding the value of this tool facing the *status quo* of the actual networks and, moreover, as the mid/long term scenarios are considered, the importance and impact of such kind of tool proves to be greater.

Considering the lack of historical data for the state estimation hypothesis, a safer approach may be executed to minimize the issue. This approach may be executed modifying some input parameters, corresponding to the percentage magnitude of nominal power to be curtailed (which is calculated in function of the selected equipment distance to the problem node and the magnitude of the voltage variation, as explained in *deliverable D3.2*). With these new set-points and a higher estimation error value (that is also an input parameter), the resulting LVC outputs would be set-points which imply higher power curtailments but assures, with a higher security degree, that the voltage deviation is solved. Still, a compromise between estimation error and reliability of the solution must always be maintained, as the quality of the historical data available might not be easily quantified.

3.4.5 Contingency Co-simulation Tool

The results of simulations performed with CCS Tool presented in this document shows its capability to define a set of realistic contingencies and to deal with voltage violations which they can originate in the network.

Co-simulation sub-tool allows to test the capability of the available active resources to face voltage violations and to evaluate the most effective solutions to solve contingencies; it is valuable also to verify if flexibilities could be actually exploited fully, analysing ICT transmission behaviour in different operating conditions. This Tool can also be successfully employed in Operational Planning to define effective counter-measures for asset unavailability events, to plan suitable network configuration for maintenance task and to evaluate, from the technical point of view, new types of flexibilities where they can solve or reduce violations originated from events likely to occur.

One of the main limitations observed during these tests is the high amount of computational resources which are necessary to simulate ICT systems with more than 3-4 active nodes; even if this issue can be take on with high performance calculators, it limits the usage of this tool for real, complex networks. At this stage of development only WiMax and Wi-Fi data transmission systems have been implemented; while their operating can be easily affected by weather conditions and an accurate analysis is valuable, the capability of analyse also wired and radio communications systems could improve the versatility of the overall Tool.

From these tests arise the need to equip the CCS Tool with a reconfiguration module which can be employed to define more realistic network reconfigurations in order to define reliable baseline scenarios and to adequately prepare the modified networks for co-simulation analysis.

Another point which can be improved in future developments is the optimizer module used by the Co-simulation sub-tool; it is up to the task for selecting the most effective active resources from the technical point of view but it doesn't allow an accurate techno-economical optimization like other tools. Anyway, the CCS tool is based on a modular framework so different optimizers could be easily integrated.

4 TSO-DSO Cooperation Domain

The following two tools will be tested, in a simulation environment, for real distribution networks in Portugal and France.

Sequential Optimal Power Flow (SOPF)

The Sequential Optimal Power Flow (SOPF) tool aims to minimize the costs associated with the activation of flexibilities on distribution networks. The process searches for the optimal values through the network reconfiguration and the control of voltage and reactive power (VVC). It considers consecutive periods of analysis using a sliding window approach taking into account inter-temporal constraints. The objective is to reduce the flexibility operational costs, while assuring the proper functioning of the network within a given timeframe. Generically, this tool proposes to define the state of the contracted flexible resources and the resources owned by the DSO for each time interval during the desired operational planning period, aiming to guarantee to the TSO agreed active and reactive power domains at primary substations.

Interval Constrained Power Flow (ICPF)

The ICPF tool works in the TSO-DSO coordination domain. Its main goal is to estimate the flexibility range at the TSO-DSO boundary (primary substations) by aggregating the distribution network flexibility in order to enable a technical and economic evaluation of the flexibility from the bulk power system point of view. Therefore, this tool estimates a region of feasible values of active and reactive power exchanged at the boundary nodes between transmission and distribution networks.

4.1 Networks Description

In the next sections it will be described the networks used for simulations.

4.1.1 Portuguese Networks Description

Two geographical unconnected network areas were chosen, with different characteristics as presented in the next section. The main motivation to select these two networks is mainly related with the high amount of DG connected to the distribution network (wind farms and hydro generation) and also the fact that one of the selected 60 kV network is normally operated in closed loop.

4.1.1.1 Northeast HV/MV Network Description

The first chosen network is located in the northeast area of Portugal and it is mainly characterized by:

1. 60 kV network normally operated in closed loop, connecting 4 EHV/HV primary substations;
2. Low consumption;

3. High amount of DG connected to the distribution network (wind farms and hydro generation);
4. 11 HV/MV substations;
5. 14 MV feeders (of two selected HV/MV substations).

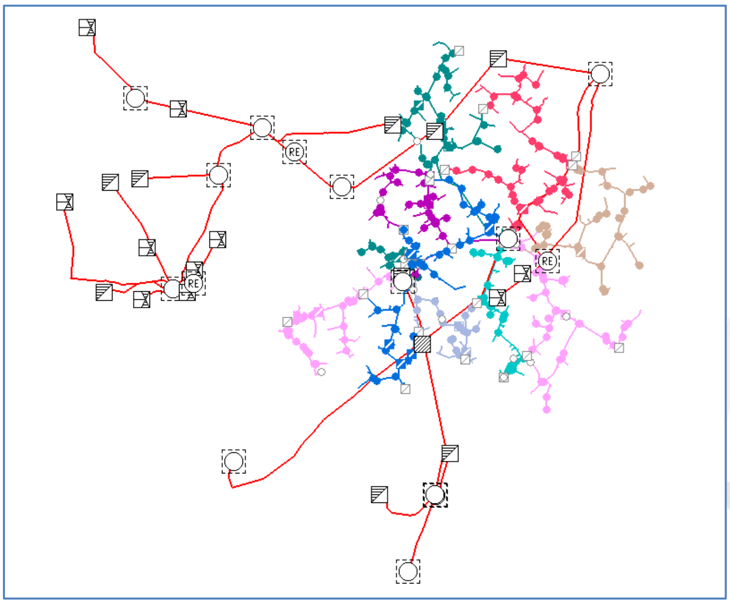


Figure 130 - Geographical representation of the Northeast network

The Northeast EHV/HV transport substations are equipped with 8 power transformers with a total power transformation capacity of 897 MVA. There is availability of historical data regarding active and reactive power measurements in all 60 kV feeders.

Considering the observability of the selected network, one year of historical measures, available from telemetry and SCADA systems, were provided:

Historical data available	Telemetry	SCADA
HV Feeders	-	MW, Mvar
HV/MV Transformers	MW, Mvar	A, MW, Mvar
MV Capacitor Banks	-	Mvar
DG	MW, Mvar	-
MV Feeders	-	A

Table 112 – Historical data.

The voltage range defined for each 60 kV busbar from the EHV/HV primary substations is described in the following table:

EHV/HV primary substations	Umin (kV)	Umax (kV)	Uavg (kV)	ΔU (%)
EHV/HV1	61.7	64.2	63.0	2.0%
EHV/HV2	61.7	64.2	63.0	2.0%
EHV/HV3	62.7	65.3	64.0	2.0%
EHV/HV4	63.7	66.3	65.0	2.0%

Table 113 – Voltage range at EHV/HV.

The reactive power limits are aggregated by the four EHV/HV primary substations and should meet the legal regulation of tan φ < 0.3 on peak hours. Regarding the off peak hours no reactive power is allowed to be injected at any TSO-DSO connection points.

The total HV/MV installed capacity is 298 MVA and each HV/MV distribution substation is equipped with one or two power transformers, all with OLTC capability as stated in the next table.

Table 114 – HV/MV power transformers characteristics.

HV/MV substation	id	Voltage (kV)	Un1 (kV)	Un2 (kV)	Nominal Power (MVA)	Taps (#)	UMax (kV)	Umin (kV)	Ucc1-2 (%)
HV/MV1	TP1	60/15	62.0	15.8	30.0	19	70.1	53.9	8.9
HV/MV1	TP2	60/15	62.0	15.8	30.0	19	70.1	53.9	8.6
HV/MV2	TP2	60/15	60.0	15.8	20.0	23	69.9	50.1	10.5
HV/MV3	TP1	60/30	60.0	33.0	20.0	25	70.8	49.2	9.6
HV/MV4	TP1	60/15	63.7	16.6	15.0	16	69,6	57.0	8.0
HV/MV5	TP1	60/15	60.0	16.0	15.0	27	70.0	50.0	5.3
HV/MV5	TP2	60/15	60.0	16.0	15.0	27	70.0	50.0	5.2
HV/MV6	TP1	60/15	60.0	15.8	10.0	23	69.9	50.1	8.0
HV/MV7	TP1	60/30	60.0	31.5	31.5	25	69.9	50.1	12.0
HV/MV7	TP2	60/30	60.0	31.5	31.5	25	69.9	50.1	12.0
HV/MV8	TP1	60/30	60.0	33.0	15.0	25	70.8	49.2	9.6
HV/MV8	TP2	60/30	60.0	33.0	15.0	25	70.8	49.2	9.6
HV/MV9	TP2	60/30	60.0	33.0	20.0	25	70.8	49.2	9.7
HV/MV10	TP1	60/30	60.0	31.5	20.0	23	69.9	51.1	9.6
HV/MV11	TP1	60/30	60.0	31.5	10.0	23	69.9	51.1	8.4

Capacitor banks are connected to the MV busbar in some HV/MV substations, in order to maintain the reactive power within the regulatory limits, and also to control the HV network losses. The installed capacity is 34 Mvar, distributed as indicated in the next table.

Table 115 – MV Capacitor Banks.

HV/MV substation	Bus (#)	Step	id	Voltage (kV)	Cap (Mvar)
HV/MV1	1	1	CB1	15	4.0
HV/MV2	2	1	CB2	15	3.4
HV/MV3	1	1	S1CB1	30	3.4
HV/MV3	1	2	S2CB1	30	3.4
HV/MV5	2	1	CB2	15	3.0
HV/MV7	2	1	CB2	30	4.0
HV/MV8	1	1	CB1	30	3.0
HV/MV8	2	1	CB2	30	3.0
HV/MV9	2	1	S1CB2	30	3.4
HV/MV9	2	2	S2CB2	30	3.4

One of the main characteristics of the selected network is linked to the high value of Distributed Generation, implying regularly reverse load flows at the EHV/HV primary substations.

Table 116 – Distributed Generation connected.

DG	Voltage Level	Nominal Power (MVA)
BIO	MV	0.77
WIND	HV	191.49
WIND	MV	1.96
HYDRO	HV	76.45
HYDRO	MV	1.06
Total		**271.77**

Within this scope, it was also provided the 30 kV network associated with two HV/MV substations which supply 764 MV/LV substations distributed by 14 MV feeders.

4.1.1.2 Western HV/MV Network Description

The second chosen network is located in the west area of Portugal and it is mainly characterized by:

1. 60 kV network normally operated in open loop, connected to 2 EHV/HV primary substations;
2. Medium to high consumption;
3. High amount of DG connected to the distribution network;
4. 16 HV/MV substations;
5. 39 MV feeders (of two selected HV/MV substations).

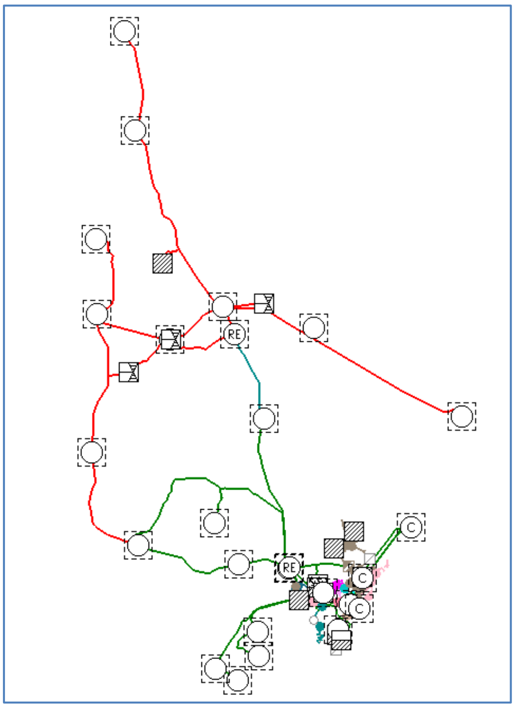


Figure 131 - Geographical representation of the Western network

The Western EHV/HV transport substations are equipped with 5 power transformers with a total power transformation capacity of 850 MVA. There is availability of historical data regarding currents, active and reactive power measurements in all 60 kV feeders.

Considering the observability of the selected network, one year of historical measures, available from telemetry and SCADA systems, were provided:

Table 117 – Historical data

Historical data available	Telemetry	SCADA
HV Feeders	-	A, MW, Mvar
HV/MV Transformers	MW, Mvar	A, MW, Mvar
MV Capacitor Banks	-	Mvar
DG	MW, Mvar	-
MV Feeders	-	A

The voltage range defined for each 60 kV busbar from the EHV/HV primary substations is described in the following table:

Table 118 – Voltage range at EHV/HV.

EHV/HV primary substations	Umin (kV)	Umax (kV)	Uavg (kV)	ΔU (%)
EHV/HV1	62.0	65.0	63.5	2.4%
EHV/HV2	61.2	64.2	62.7	2.4%

The reactive power limits should meet the legal regulation of tan φ < 0.3 on peak hours, for each EHV/HV primary substation. Regarding the off peak hours no reactive power is allowed to be injected at any TSO-DSO connection points.

The total HV/MV installed capacity is 763.5 MVA and each HV/MV distribution substation is equipped with one up to four power transformers, all with OLTC capability as stated in the next table.

Table 119 – HV/MV power transformers characteristics.

HV/MV substation	id	Voltage (kV)	Un1 (kV)	Un2 (kV)	Nominal Power (MVA)	Taps (#)	UMax (kV)	Umin (kV)	Ucc1-2 (%)
HV/MV1	TP2	60/30	60.0	32.8	20.0	19	69.6	50.4	10.7
HV/MV2	TP1	60/10	60.0	10.5	20.0	23	69.9	50.1	10.0
HV/MV2	TP2	60/10	60.0	10.5	20.0	23	69.9	50.1	10.0
HV/MV3	TP2	60/30	63.0	31.5	30.0	19	67.7	50.7	8.2
HV/MV3	TP3	60/30	60.0	31.5	31.5	23	70,0	50.0	12.3
HV/MV4	TP1	60/30	60.0	31.5	20.0	23	69.9	50.1	9.9
HV/MV4	TP2	60/30	60.0	31.5	20.0	13	64.6	50.9	10.0
HV/MV5	TP1	60/30	60.0	31.5	20.0	13	64.6	50.9	9.9
HV/MV5	TP2	60/30	60.0	31.5	20.0	13	64.6	50.9	10.0
HV/MV6	TP1	60/30	63.0	31.5	30.0	19	67.7	50.7	10.5
HV/MV6	TP2	60/10	60.0	10.5	20.0	23	69.9	50.1	10.0
HV/MV6	TP3	60/30	63.0	31.5	30.0	19	67.7	50.7	10.5
HV/MV7	TP1	60/10	63.0	10.5	20.0	19	67.7	50.7	7.6
HV/MV7	TP2	60/30	60.0	31.5	31.5	23	69.9	50.1	11.7
HV/MV8	TP1	60/10	60.0	10.5	31.5	23	69.9	50.1	12.2
HV/MV8	TP2	60/10	60.0	10.5	31.5	23	69.9	50.1	12.5
HV/MV9	TP2	60/10	63.0	10.5	20.0	19	67.7	50.7	7.6
HV/MV10	TP1	60/10	60.0	10.5	20.0	23	69.9	50.1	9.4
HV/MV10	TP2	60/10	60.0	10.5	20.0	23	69.9	50.1	9.4
HV/MV11	TP1	60/10	60.0	10.5	31.5	23	69.9	50.1	12.1
HV/MV11	TP2	60/10	60.0	10.5	31.5	23	69.9	50.1	12.1
HV/MV12	TP1	60/10	60.0	10.5	10.0	19	67.7	50.7	7.6
HV/MV13	TP1	60/10	60.0	10.0	10.0	19	67.7	50.7	7.6
HV/MV13	TP1A	60/10	60.0	10.0	10.0	19	67.7	50.7	7.6
HV/MV13	TP2	60/10	60.0	10.0	10.0	19	67.7	50.7	7.6
HV/MV13	TP2A	60/10	60.0	10.0	10.0	19	67.7	50.7	7.6
HV/MV14	TP1	60/10	60.0	10.5	20.0	23	69.9	50.1	10.0
HV/MV14	TP2	60/10	60.0	10.5	20.0	23	69.9	50.1	10.1
HV/MV15	TP1	60/10	60.0	10.5	20.0	23	69.9	50.1	9.8
HV/MV15	TP2	60/10	60.0	31.5	31.5	23	69.9	50.1	12.1
HV/MV15	TP3	60/10	60.0	31.5	31.5	23	69.9	50.1	12.1
HV/MV15	TP4	60/10	60.0	31.5	31.5	23	69.9	50.1	11.9
HV/MV16	TP1	60/10	63.0	10.5	20.0	19	67.7	50.7	7.6
HV/MV16	TP2	60/10	63.0	10.5	20.0	19	67.7	50.7	7.6

Capacitor banks are connected to the MV busbar in some HV/MV substations, in order to maintain the reactive power within the regulatory limits, and also to control the HV network losses. The installed capacity is 96.6 Mvar, distributed as indicated in the next table.

Table 120 – MV Capacitor Banks.

HV/MV substation	Bus (#)	Step	id	Voltage (kV)	Cap (Mvar)
HV/MV1	2	1	CB2	30	3.4
HV/MV2	2	1	S1CB2	10	3.3
HV/MV2	2	2	S2CB2	10	3.3
HV/MV3	1	1	S1CB1	30	3.7
HV/MV3	1	2	S2CB1	30	3.7
HV/MV3	1	1	CB2	30	3.7
HV/MV4	1	1	CB1	30	3.4
HV/MV4	2	2	CB2	30	3.4
HV/MV5	2	1	CB2	30	3.0
HV/MV6	1	1	CB1	30	5.5
HV/MV6	2	2	CB2	30	5.6
HV/MV6	1	1	CB1	10	2.7
HV/MV6	2	2	CB2	10	2.6
HV/MV7	2	1	CB2	10	3.4
HV/MV7	2	1	CB2	30	3.4
HV/MV8	1	1	CB1	10	2.5
HV/MV8	2	1	CB2	10	2.5
HV/MV9	2	1	CB2	10	3.4
HV/MV11	1	1	CB1	10	2.8
HV/MV11	2	1	S1CB2	10	2.8
HV/MV11	2	2	S2CB2	10	3.4
HV/MV13	1	1	CB1	10	2.9
HV/MV13	2	1	CB2	10	2.8
HV/MV14	1	1	CB1	10	3.3
HV/MV14	2	1	CB2	10	3.3
HV/MV15	1	1	CB1	10	3.1
HV/MV15	2	1	CB2	10	3.1
HV/MV16	1	1	CB1	10	3.3
HV/MV16	2	1	CB2	10	3.3

One of the main characteristics of the selected network is linked to the high value of Distributed Generation, implying regularly reverse load flows at the EHV/HV primary substations.

Table 121 – Distributed Generation connected.

DG	Voltage Level	Nominal Power (MVA)
BIO	MV	1.80
CHP	HV	9.28
CHP	MV	8.81

WIND	HV	68.45
PV	MV	12.00
WASTE	HV	63.00
Total		**163.34**

Within this scope, it was also provided the 10 and 30 kV network associated with two HV/MV substations which supply 335 MV/LV substations distributed by 39 MV feeders.

4.1.2 French Networks Description

4.1.2.1 Sequential Optimal Power Flow (SOPF)

In this section two French distribution networks (MV network 5 and MV network 6) will be described regarding their most important characteristics as well as some data used in the base scenario which corresponds to the WP1 "status quo" scenario.

MV network 5 – Description

The first network is a 20 kV distribution which has two primary substations (HV/MV), four power transformers with connection to a 63 kV network, 951 nodes, 558 power lines, 240 nodes with loads, 6 wind generators and 394 switching devices. It hasn't any capacitor bank. The data for the primary substations is presented in Table 122 considering the WP1 "status quo" scenario.

Table 122 – Primary substations of MV network 5.

Id	Node	Pmax (MW)	Pmin (MW)	Qmax (Mvar)	Qmin (Mvar)
RHTB1	525	70.11	0.00	21.03	-21.03
RHTB2	861	37.08	0.00	11.12	-11.12

The values for the maximum active injected power were obtained considering that this value is 90% of the maximum power consumption of the HV/MV substation. For the values of the maximum and minimum injected reactive power it was considered that tg $\varphi \in [-0.3 ; 0.3]$. Each HV/MV substation has two power transformers connected. Information about them can be seen at Table 123.

Table 123 –Transformers of MV network 5.

Id	Substation	Voltage (kV)			Nominal Power (MVA)	Tap position			Parameters		
		control node	Primary	Secondary		Nominal	Max	Min	Ucc (%Uref)	P_leakage (%Sn)	P_copper (%Sn)
Tr1	RHTB1	521	63	20	36	0	8	-8	17	0.061101778	0.55829
Tr2	RHTB1	522	63	20	36	0	8	-8	17	0.061101778	0.55829
Tr3	RHTB2	854	63	20	20	0	8	-8	12	0.1099832	0.6299985
Tr4	RHTB2	855	63	20	20	0	8	-8	12	0.1099832	0.6299985

The control limits of the voltage at the secondary node were considered 1.05 and 0.95 p.u. for maximum and minimum respectively.
For the simulation tests two load scenarios are studied, one for the winter and another for the summer. 24 periods of one hour are considered for each scenario. Figure 132 presents the normalized base profile of the active and reactive load powers used for the tests.

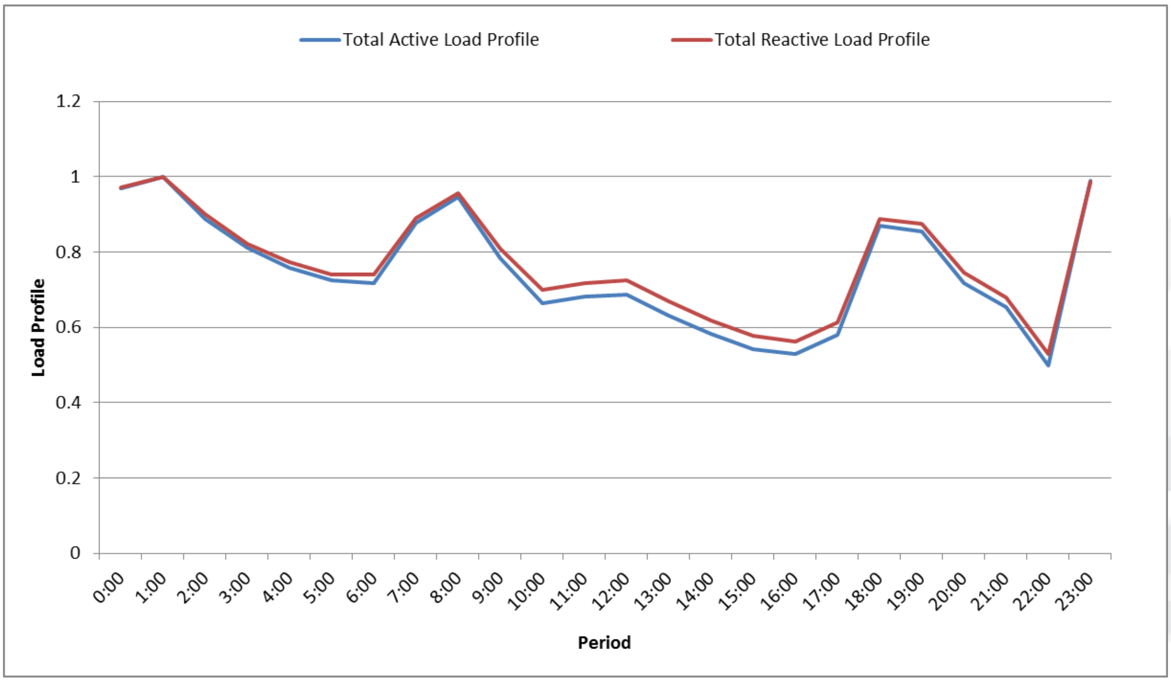


Figure 132 - Profiles of active and reactive power used for simulations of MV networks

Table 124 shows the total active and reactive load powers for each period used for WP1 "Status Quo" scenario.

Table 124 – Load power for MV network 5 for Status Quo Scenario.

Period	Winter		Summer	
	Active Power (MW)	Reactive Power (Mvar)	Active Power (MW)	Reactive Power (Mvar)
1	115.281	34.584	103.071	30.400
2	119.098	35.547	108.611	31.895
3	105.813	31.986	93.533	27.742
4	96.506	29.251	83.745	24.851
5	90.410	27.495	77.110	22.934
6	86.265	26.335	75.736	22.543
7	85.363	26.282	77.628	23.124
8	104.656	31.626	91.759	27.068
9	112.775	33.986	99.965	29.498
10	93.370	28.782	81.418	24.500
11	79.021	24.856	69.877	21.372
12	81.073	25.476	69.207	21.270
13	81.714	25.777	68.786	21.310
14	75.030	23.786	62.980	19.557
15	69.481	22.006	58.303	18.088
16	64.699	20.529	53.755	16.660
17	63.107	19.965	52.724	16.280

Period	Winter		Summer	
	Active Power (MW)	Reactive Power (Mvar)	Active Power (MW)	Reactive Power (Mvar)
18	69.222	21.818	59.397	18.268
19	103.516	31.597	94.968	28.365
20	101.724	31.141	92.184	27.645
21	85.471	26.479	74.534	22.612
22	77.953	24.152	67.513	20.495
23	59.523	18.815	50.841	15.734
24	117.793	35.041	106.906	31.317

All the generators of this distribution network are wind power generators. Their description can be found in Table 5. For simulation purposes, the reference value Pref is combined with information regarding increasing wind generation along the time and daily wind generation profiles.

Table 125 – Wind generators for MV network 5.

id	Node	Pref (MW)	Qref (Mvar)
N1sync02	83	0.39	0.00
N1sync03	89	1.14	0.00
N1sync05	211	0.52	0.52
N1sync01	320	1.26	0.00
N1sync04	479	1.02	0.00
N2sync06	771	4.03	0.00

The variation of wind power depends on the wind profile that is considered. The Figure 133 shows the profile used for simulations.

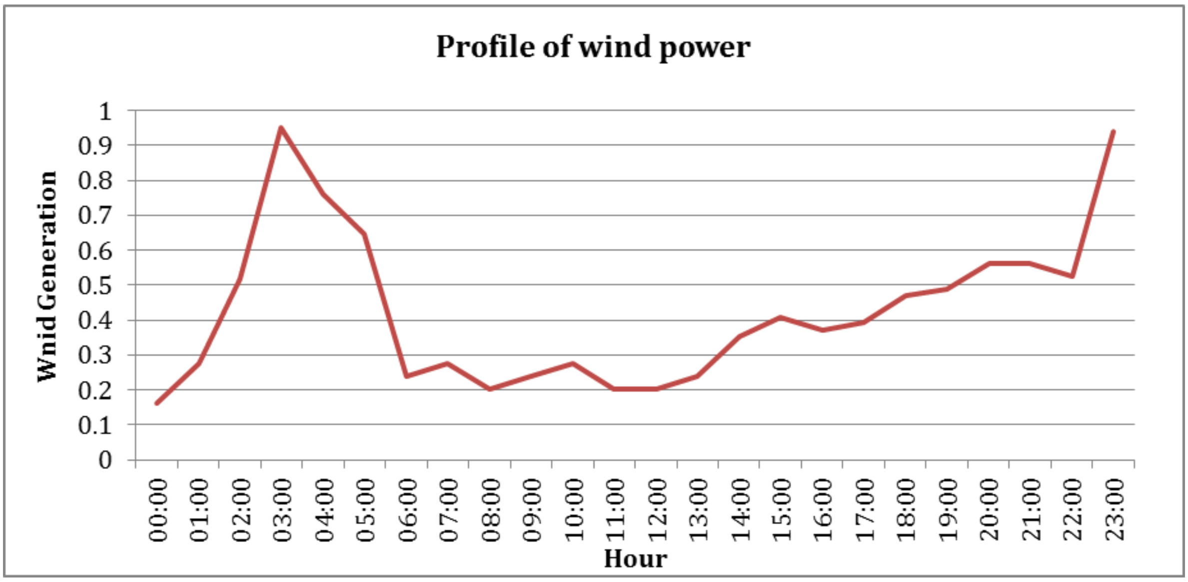


Figure 133 - Profile of wind power used for simulations of MV networks.

<u>MV network 6 – Description</u>

The second network is a 20 kV and 15 kV distribution which has two primary substations, 2 power transformers (HV/MV) connected to the primary substations with connection to a 63 kV network, three auto transformers, 570 power lines, 248 nodes with loads and 155 switching devices. It has neither capacitor bank nor any generator. The data for the primary substations is presented on Table 126 considering the status quo WP1 scenario.

Table 126 – Primary substations of MV network 6.

Id	Node	Pmax (MW)	Pmin (MW)	Qmax (Mvar)	Qmin (Mvar)
RHTB1	311	7.215	0.00	2.164	-2.164
RHTB2	651	18.101	0.00	5.43	-5.43

As the previous network, the values for the maximum active injected power were obtained considering that this value is 90% of the maximum power consumption of the HV/MV substation. For the values of maximum and minimum reactive injected power it was considered that tg $\varphi \in [-0.3 ; 0.3]$.
Each primary substation has one transformer connected but the network has three more auto transformers. The description of these transformers can be seen at Table 127.

Table 127 –Transformers for MV network 6.

Id	Substation	Voltage (kV)			Nominal Power (MVA)	Tap position			Parameters		
		control node	Primary	Secondary		Nominal	Max	Min	Ucc (%Uref)	P_leakage (%Sn)	P_copper (%Sn)
Tr1	RHTB1	262	20	15	2	0	3	-3	2.4998	0.099995	0.3750
Tr2	RHTB1	264	20	15	2	0	3	-3	2	0.0750	0.3750
Tr3	RHTB1	308	63	20	20	0	9	-9	12	0.1099	0.6299
Tr4	RHTB2	614	20	15	5	0	3	-3	2	0.0600	0.3000
Tr5	RHTB2	645	63	20	20	0	9	-9	12	0.1099	0.6299

Table 128 shows the total active and reactive load power for each period used for WP1 Status Quo scenario.

Table 128 – Load power for MV network 6 for Status Quo Scenario.

Period	Winter		Summer	
	Active Power (MW)	Reactive Power (Mvar)	Active Power (MW)	Reactive Power (Mvar)
1	27.6885	7.3287	25.325	6.623
2	28.6548	7.5363	26.742	6.961
3	25.1334	6.6838	22.786	5.975
4	22.9168	6.1112	20.427	5.357
5	21.3787	5.7141	18.753	4.922
6	20.2820	5.4315	18.374	4.819
7	20.5859	5.6421	18.880	4.958
8	25.8223	6.9731	22.740	5.949
9	27.6977	7.4275	24.852	6.510
10	22.3675	6.0830	19.828	5.246
11	18.4649	5.0916	16.681	4.454
12	18.8578	5.1867	16.350	4.377

13	18.7219	5.1711	15.885	4.278
14	16.9859	4.7075	14.435	3.891
15	15.9301	4.4149	13.562	3.661
16	14.8329	4.1113	12.563	3.383
17	14.5682	4.0267	12.390	3.322
18	16.0925	4.4430	14.047	3.763
19	24.9025	6.7156	23.228	6.123
20	24.2664	6.5636	22.331	5.907
21	20.0535	5.4793	17.723	4.724
22	18.3840	5.0340	16.095	4.299
23	13.2544	3.6318	11.732	3.163
24	28.5799	7.5144	26.511	6.903

The same profile of wind generation used for the previous network were also applied to network 6 (Figure 133). The network 6 has no generators in the status quo scenario but in the others scenarios it has a generator that simulates the penetration of wind power.

4.1.2.2 Interval Constrained Power Flow (ICPF)

In order to simulate the different test cases that will be defined in 4.2.2, two real French networks were provided by ERDF. These networks presented a typical configuration of a distribution network including the existence of switches (controllable or manual) in order to allow network reconfiguration. The ICPF tool does not deal with network reconfiguration and for this reason the input file does not consider these devices. This led to the necessity of modelling these two networks in a way where they could be used for the simulations in the ICPF tool.

First of all an algorithm was developed in order to find the existing islands in each network. After running this algorithm it was understood that each network could be divide in two independent parts. Due to the existence of opened switches, there were two parts of each network that only were connected by opened switches. Therefore, the isolated nodes were eliminated and the initial two French networks were transformed in four sub-networks.

A new algorithm was developed to eliminate the closed switches. Since each closed switch connects two buses, the followed methodology consists in eliminating one of the buses and connect to the other one every load, branch, generator or transformer that was connected to the first one. Finally, since a considerable number of buses disappeared it was necessary to make a bus renumbering in order to have a correct input file. The data regarding each network will be presented in 4.3.2.2.

4.2 Test Cases Description and Hypothesis

4.2.1 Sequential Optimal Power Flow (SOPF)

4.2.1.1 Portuguese test cases

Table 129 resumes a definition of WP1 scenarios that were taken into account to run the simulations of the SOPF tool using Portuguese networks.

Table 129 – WP1 scenarios for Portuguese networks.

Scenario	Generation/demand	Criteria
1 (Status quo)	Status quo	-Demand flexibility: Only from interruptible consumers -No wind curtailment, only reactive power control
2 (Short-term)	demand growth: +7.5% DRES increase: Wind: +11.9% Solar PV:+113.6%	-Demand flexibility: Only from interruptible consumers -Wind curtailment only for additional capacities
3 (Short-term)	Demand growth: 7.5% DRES increase: Wind: +14.3% Solar PV:+136.4%	-Homothetic increase of the demand and installed wind capacity -Demand flexibility: Only from interruptible consumers -Wind curtailment for additional capacities
4 (Mid-term)	Demand growth: +18.9% DRES increase: Wind:+26.32.% Solar PV: +240.9%	-Homothetic increase of the demand and installed wind capacity -Demand flexibility: Only from interruptible consumers -Wind curtailment for additional capacities of all the wind parks and for new wind parks
5 (Mid-term)	Demand growth: +18.9% DRES increase: Wind:+31.0.% Solar PV: +281.8%	-Homothetic increase of the demand and installed wind capacity -Demand flexibility: Only from interruptible consumers -Wind curtailment for additional capacities of all the wind parks and for new wind parks
6 (Long-term)	Demand growth: +37.7% DRES increase: Wind:+50.1.% Solar PV: +404.5%	-Homothetic increase of the demand and installed wind capacity -Demand flexibility: Only from interruptible consumers -Wind curtailment for additional capacities of all the wind parks and for new wind parks

The Northeast Portuguese network is characterized by having a low consumption and a large amount of distributed generation connected into the network. The Western network has medium/high consumption and also a large amount of distributed generation. Figure 134 and Figure 135 show the curves of load power for both networks along 24 periods at Status-quo scenario.

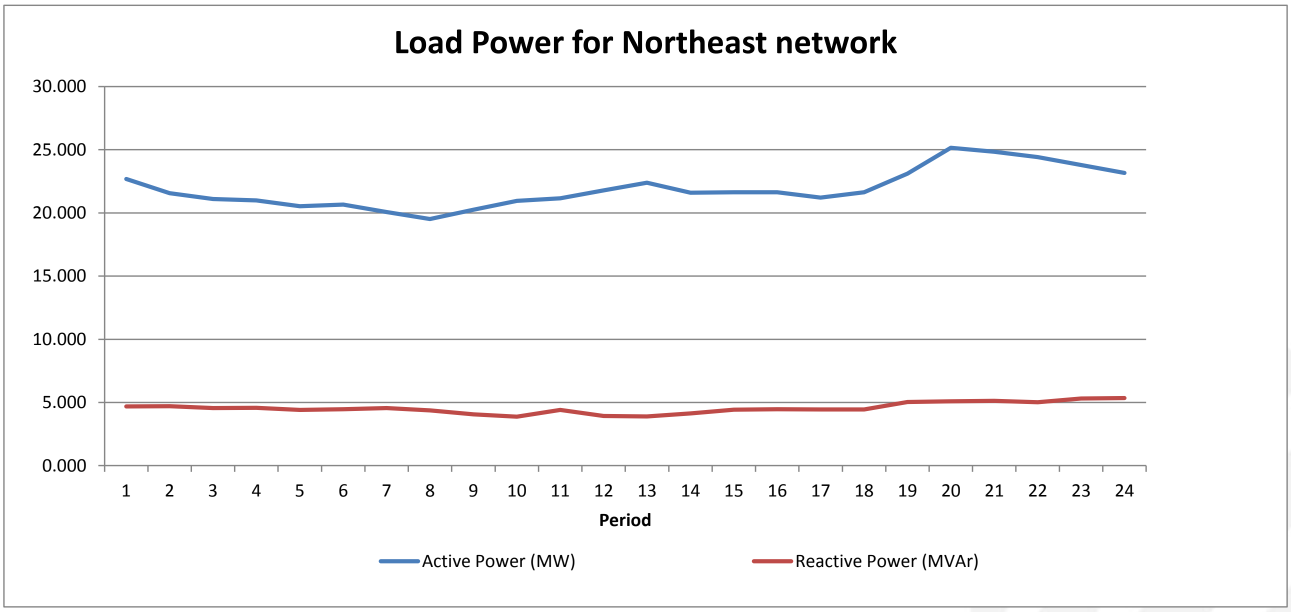


Figure 134 – Load Power for Status-quo scenario using the Northeast network.

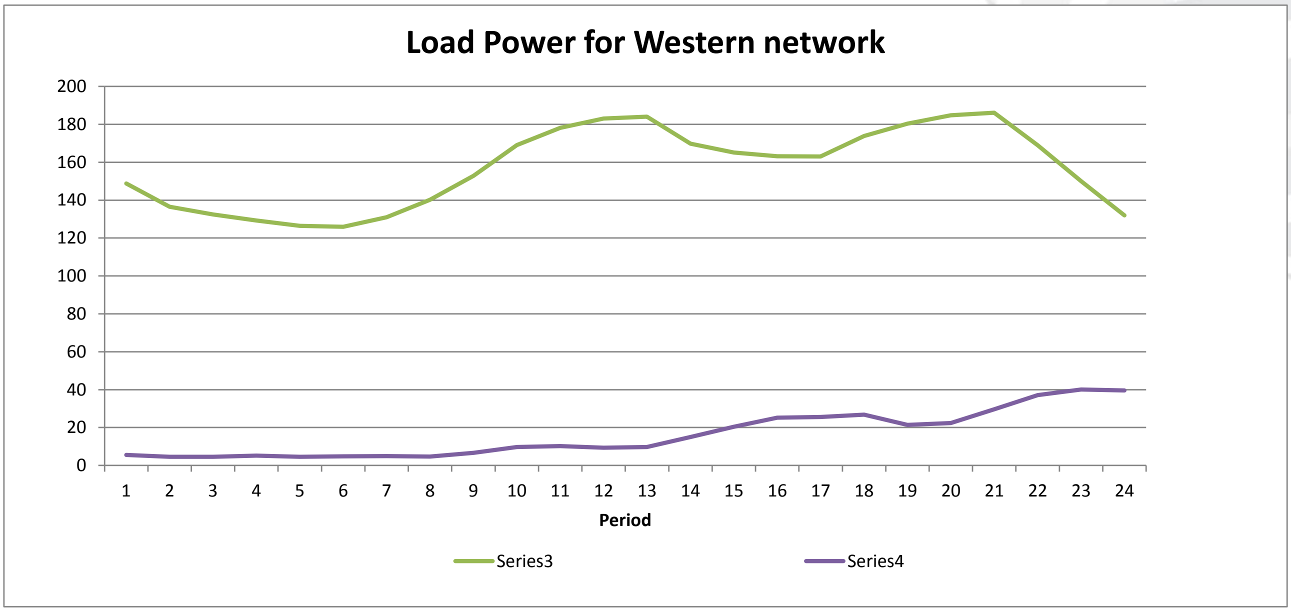


Figure 135 – Load Power for Status-quo scenario using the Western network.

Figure 136 and Figure 137 show the generated power in the distribution networks along 24 periods at Status-quo scenario. In the Northeast network there were wind generators but there was not photovoltaic generation. In the Western network there were both of these production technologies. The generation by DRES wind units and Photovoltaic units were increased for short, mid and long-term taking into account the information explained in Table 129.

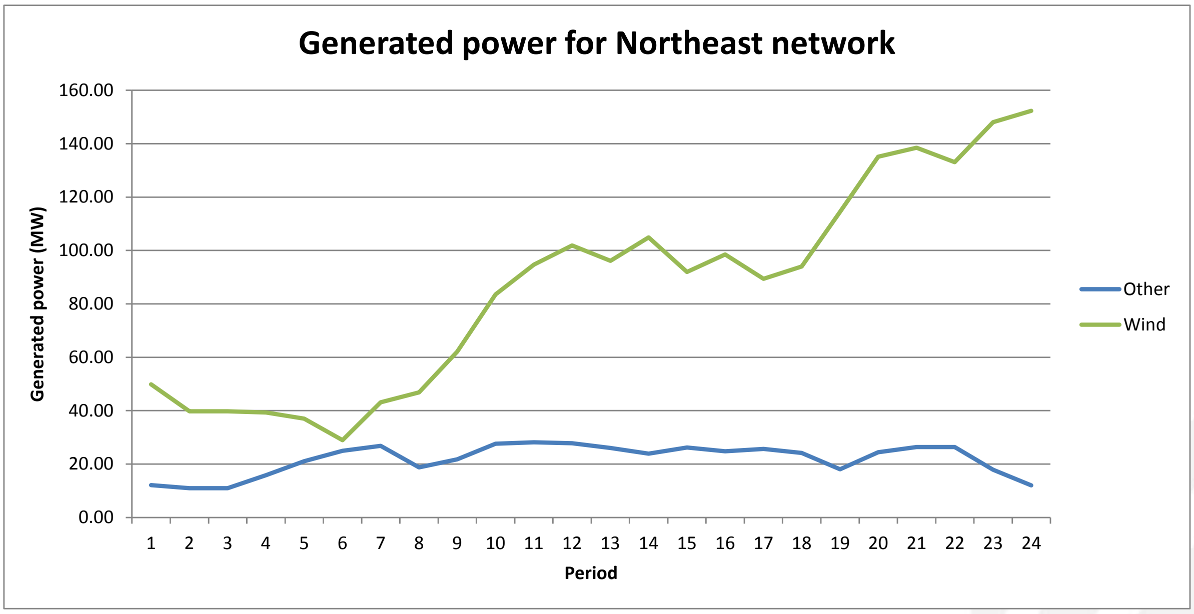


Figure 136 – Generated Active Power for Status-quo scenario using Northeast network.

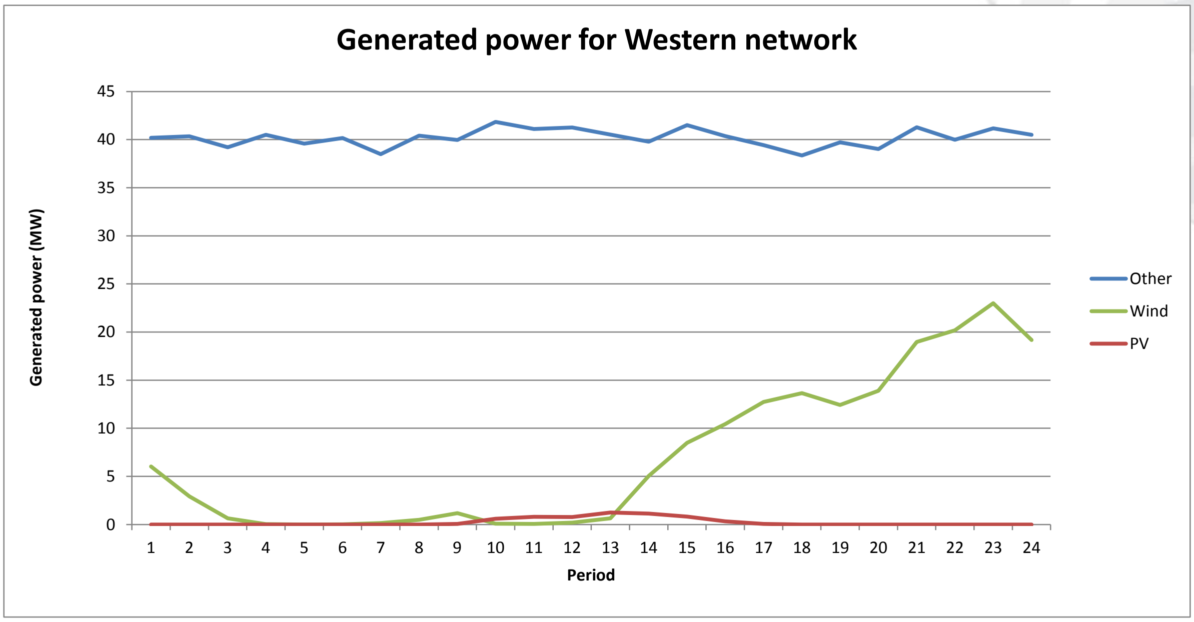


Figure 137 – Generated Active Power for Status-quo scenario using the Western network.

Regarding the flexibilities, the tool simulates a flexible load using a fictitious generator. So, when a positive value is assigned to a flexible load in the results, it means the load power becomes lower. Similarly, when a negative value is assigned to a flexible load, it means the load power becomes higher. In the WP1 definition there is a mention to demand flexibilities which corresponds to interruptible consumers. In the Northeast network there was not any interruptible consumer, while in the Western network there were 3 interruptible consumers. These three consumers were used to provide flexibility by reducing their consumption when it was needed.

In relation to flexibility provided by generators, each machine of wind power had the availability to make wind curtailment if it was necessary. In the short-term scenarios only the new capacities could be curtailed. In the mid and long-term were simulated the creation of new wind parks in the same area of the original ones. In mid and long-term scenarios all the

generation of new wind parks could be curtailed as well as the new capacities installed in the original wind parks.
Regarding the active and reactive power limits of the primary substations for all scenarios, it was considered that active power limits correspond to the maximum apparent power of the transformers connected to transmission network. However, this value was obtained by considering a contingency (N-1). So, for instance, in the substations that had two similar transformers the value obtained corresponds to a maximum apparent power of one of the transformers. The reactive power limits are aggregated by the primary substations and should met the legal regulation of tan φ <0.3 on peak hours. Concerning the off peak hours no reactive power is allowed to be injected at any TSO-DSO connection points:

- Reactive energy supplied on peak hours (0.3≤ tg φ ≤ 0.4) : 0.007821€/kVAr.h
- Reactive energy supplied on peak hours (0.4≤ tg φ ≤ 0.5) : 0.0237€/kVAr.h
- Reactive energy supplied on peak hours (tg φ ≥ 0.5) : 0.0711€/kVAr.h
- Reactive energy received on the off peak hours : 0.0177 €/kVAr.h

Table 130 presents the active and reactive power limits taking into account the considerations explained above for the Portuguese networks. These values were maintained along the scenarios. The exceeded active power flow in the primary substations is penalized in the objective function but has no costs associated. The exceeded reactive power flow in the primary substations has into account the costs described above related to tan φ.

Table 130 – Active and reactive power limits at the primary substations of Portuguese networks.

Network	Primary substation	Node	Pmax	Pmin	Qmax	Qmin
Northeast	Netcon1	2359	126	-126	37.8	0.0
Northeast	Netcon2	4336	63	-63	18.9	0.0
Northeast	Netcon3	5359	120	-120	36	0.0
Northeast	Netcon4	10202	126	-126	37.8	0.0
Western	Netcon1	1375	170	-170	51	0.0
Western	Netcon2	10636	340	-340	102	0.0

In order to compute the costs related to the activation of flexible consumption, a model that takes into account the market clearing prices of the day was used. The idea behind this model is that DSO pays the actual consumption plus a premium for flexible adjustment. Considering, for instance, that 40 MWh were purchased in the electrical energy market at 50 €/MWh, and the flexibility operator offered 30 MW (for one hour -> 30 MWh) of load reduction at 80 €/MWh. The DSO selects this load reduction and pays 30×(80-50) = 900 €. For the simulations exposed in this report, the same values were always used for the market prices that are presented on Figure 141.

The cost of changing the transformer taps between periods should also be considered. For the simulations presented in this report it was considered that one change on a specific tap of a transformer costs 0.92 €. This value was obtained using the next equation (first methodology exposed in ANNEX I – Methodology for Flexibility Cost Calculation) that calculates the cost of changing a tap in HV/MV transformer.

$$c_{HV/MV} = \frac{1}{T_T}\left(\frac{a_T - a'_T}{a_T} \cdot F_{T+OLTC} + \frac{F_{OT} \cdot a'_T}{t_{OT}}\right)$$

Where:
$\boldsymbol{T_T}$: Total allowable adjustment times (times) – considered equal to **76650** (7*365*30) adjustment times
$\boldsymbol{a'_T}$: Lifetime after tap changed T_T times (year) – considered equal to **30 years**
$\boldsymbol{t_{OT}}$: Maintenance period (year) – considered equal to **5 years**
$\boldsymbol{F_{OT}}$: Maintenance cost (€/times)-considered equal to **3300** (300+3000) **€**
$\boldsymbol{a_T}$: Lifetime when the tap is never adjusted (year) – considered equal to **40 years**
$\boldsymbol{F_{T+OLTC}}$: Capital cost of the transformer (including the OLTC cost) – considered equal to **204250 €**

The Portuguese networks have capacitor banks and so it is important to establish also a cost of changing capacitor bank taps. The following expression is detailed in ANNEX I – Methodology for Flexibility Cost Calculation and can be used to calculate these costs.

$$c_{CB} = \frac{1}{T_T}\left(F_{CB} + \frac{F_{OT} \cdot a'_T}{t_{OT}}\right)$$

Where:
T_T: Total allowable adjustment times (times)-considered equal to **21900** (2*365*30) adjustment times
a'_T: Lifetime after step changed T_T times (year)-considered equal to **30 years**
t_{OT}: Maintenance period (year) - considered equal to **0.25**
F_{OT}: Maintenance cost (€/times) – considered equal to **150€**
F_{CB}: Capital cost of the capacitor bank – considered equal to **6500 €/Mvar (15 kV), 8800 €/Mvar (30 kV)**

The cost used to penalize the changing of capacitor banks taps between periods was 0.6 €.

After filtering the available flexibilities for each network taking into account the conditions described in the WP1 scenarios definition, it is possible to group them by their presence in each scenario. Table 131 and Table 132 show the information with the flexibility prices of increase (upward) or decrease (downward) the generation or consumption for each Portuguese network. For these simulations the flexibilities associated to generation represent the wind curtailment and the ones associated to demand represent the availability of interruptible consumers to decrease their consumption.

Table 131 – Flexibility information for Portuguese Northeast network.

Flexibility information			Flexible price (€/MWh)		WP1 scenarios					
Type	id	Node	Upward	Downward	Scen 1	Scen 2	Scen 3	Scen 4	Scen 5	Scen 6
Wind curtailment	Flexsc04	nod02457	NV	31		✓	✓	✓	✓	✓
	Flexsc05	nod02809	NV	34		✓	✓	✓	✓	✓
	Flexsc06	nod02936	NV	27		✓	✓	✓	✓	✓
	Flexsc08	nod04312	NV	30		✓	✓	✓	✓	✓
	Flexsc09	nod05741	NV	22		✓	✓	✓	✓	✓
	Flexsc10	nod07079	NV	33		✓	✓	✓	✓	✓
	Flexsc11	nod07765	NV	32		✓	✓	✓	✓	✓
	Flexsc12	nod08271	NV	31		✓	✓	✓	✓	✓
	Flexsc13	nod09216	NV	34		✓	✓	✓	✓	✓
	Flexsc14	nod09239	NV	27		✓	✓	✓	✓	✓
	Flexsc15	nod10099	NV	29		✓	✓	✓	✓	✓
	Flexsc17	nod11025	NV	22		✓	✓	✓	✓	✓
	Flexsc19	nod11756	NV	32		✓	✓	✓	✓	✓
	Flexsc19'	nod11756	NV	32				✓	✓	✓
	Flexsc17'	nod11025	NV	22					✓	✓
	Flexsc11'	nod07765	NV	32						✓
	Flexsc010'	nod07079	NV	33						✓

Table 132 – Flexibility information for Western Portuguese networks.

Flexibility information			Flexible price (€/MWh)		WP1 scenarios					
Type	id	Node	Upward	Downward	Scen 1	Scen 2	Scen 3	Scen 4	Scen 5	Scen 6
Consumers	FlexL075	2831	90	NV	✓	✓	✓	✓	✓	✓
	FlexL151	5475	81	NV	✓	✓	✓	✓	✓	✓
	FlexL356	12161	83	NV	✓	✓	✓	✓	✓	✓
Wind curtailment	Flexsc09	6333	NV	32		✓	✓	✓	✓	✓
	Flexsc11	6540	NV	24		✓	✓	✓	✓	✓
	Flexsc14	11238	NV	30		✓	✓	✓	✓	✓
	Flexsc09'	6333	NV	31				✓	✓	✓

All the flexible resources presented in the tables above are modelled as generators in the SOPF tool. The flexible loads (consumers) do not have the capacity to increase their consumption, so the downward price has no value (NV). Similarly, for generators there was not the possibility to increase the generation, so the upward price has no value (NV).

4.2.1.2 French test cases

Table 133 resumes a definition of WP1 scenarios that were taken into account to run the simulations of the SOPF tool using French networks.

Table 133 –WP1 scenarios for French networks.

Scenario	Generation/demand	Criteria
1 (Status quo)	Status quo	-No demand flexibility was considered -No wind curtailment, only reactive power control
2 (Short-term)	demand growth: +0.5% Wind increase: +34.6%	-Demand flexibility: 20% of the MV customers with contracted power over 200kW could provide ±20% flexibility for 2 to 4 hours. -Wind curtailment only for additional capacities

Scenario	Generation/demand	Criteria
3 (Short-term)	Demand growth: -2.4% Wind increase: +40.1%	-Homothetic increase of the demand and installed wind capacity -Demand flexibility: 20% of the MV customers with contracted power over 200kW could provide ±20% flexibility for 2 to 4 hours. -Wind curtailment only for additional capacities
4 (Mid-term)	Demand growth: +3.2% Wind increase: +82.5%	-Homothetic increase of the demand and installed wind capacity -Demand flexibility: 50% of the MV customers with contracted power over 200kW could provide ±20% flexibility for 2 to 4 hours. 5% of MV/LV substations with more than 20 customers could provide ±20% flexibility for 1 to 2 hours -Wind curtailment for all the wind parks
5 (Mid-term)	Demand growth: -3.1% Wind increase: +103.6%	-Homothetic increase of the demand and installed wind capacity -Demand flexibility: 50% of the MV customers with contracted power over 200kW could provide ±20% flexibility for 2 to 4 hours. 5% of MV/LV substations with more than 20 customers could provide ±20% flexibility for 1 to 2 hours -Wind curtailment for all the wind parks
6 (Long-term)	Demand growth: +18.4% Wind increase: +207.5%	-Homothetic increase of the demand and installed wind capacity -Demand flexibility: 80% of the MV customers with contracted power over 200kW could provide ±20% flexibility for 2 to 4 hours. 10% of MV/LV substations with more than 20 customers could provide ±20% flexibility for 1 to 2 hours -Wind curtailment for all the wind parks
7 (Long-term)	Demand growth: -2.8% Wind increase: +253.8%	-Homothetic increase of the demand and installed wind capacity -Demand flexibility: 80% of the MV customers with contracted power over 200kW could provide ±20% flexibility for 2 to 4 hours. 10% of MV/LV substations with more than 20 customers could provide ±20% flexibility for 1 to 2 hours -Wind curtailment for all the wind parks

Considering the WP1 scenarios definition and the data received from DSO, some adjustments are needed. In order to obtain the load profiles for each network and for each scenario, the profile construction process started from the values Pref (MW) and Qref (Mvar) as well as the number of consumers linked to each load. The values Pref and Qref were multiplied with the profile associated to the typical number of consumers. The list of typical number of consumers is presented in Table 134. For each typical number of consumers in this list there is a load power profile associated for each period (24 × 21 load profiles) for summer season and another load profile for each period for winter season (24 x 21 load profiles). There are 21 different profiles per season, because when the number of consumers is 1, 2 or 10, the profiles depend on the contracted power of the consumer. In case the number of consumers is one, the load profile is different if the contracted power is greater than 1 kW or not. In the case of number of consumers be two, the same thing happens. In the case of the number of consumers is ten, the load profile is different if the contracted power is greater than 20 kW or not.

Table 134 –Typical list of number of consumers (21 different values).

1 (<1kW)	1 (>1kW)	2 (<1kW)	2 (>1kW)	4	5	9	10 (<20kW)	10 (>20kW)	11	17
24	34	47	64	85	121	158	440	301	241	

The Figure 138 shows an example of different profiles for 1 consumer. In this case there are four different profiles depending on the contracted power and the time of the year.

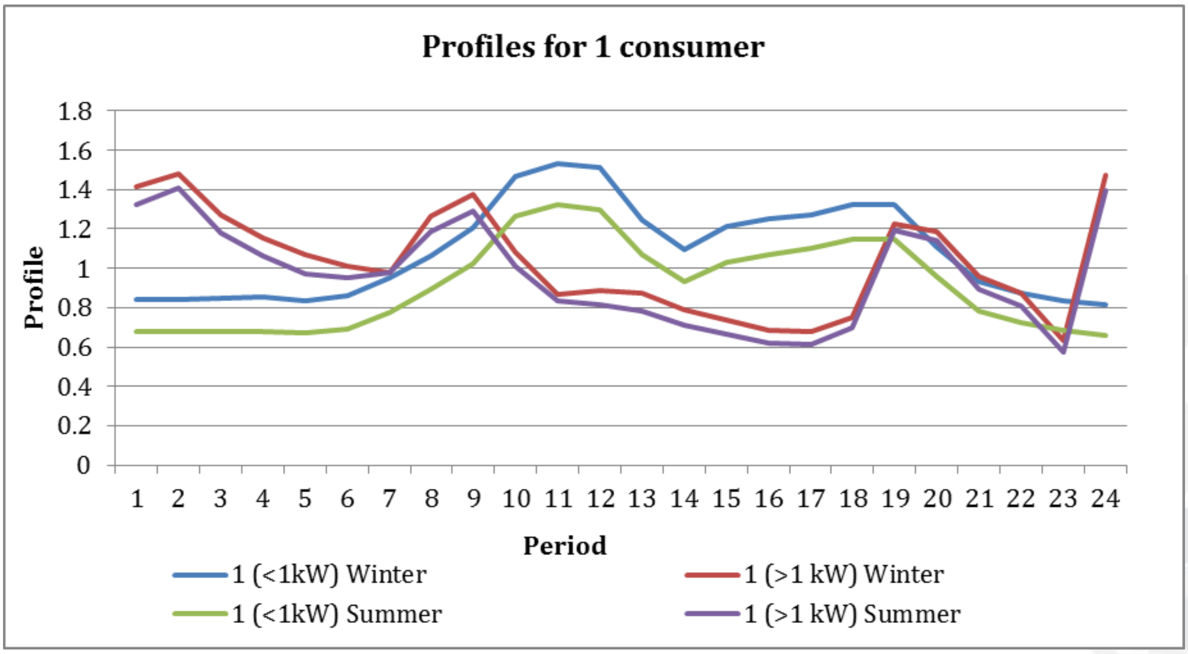


Figure 138 – Different Profiles of load power for 1 consumer.

The Figure 139 shows another example of load profiles considering this time 10 consumers depending on the contracted power and the time of the year.

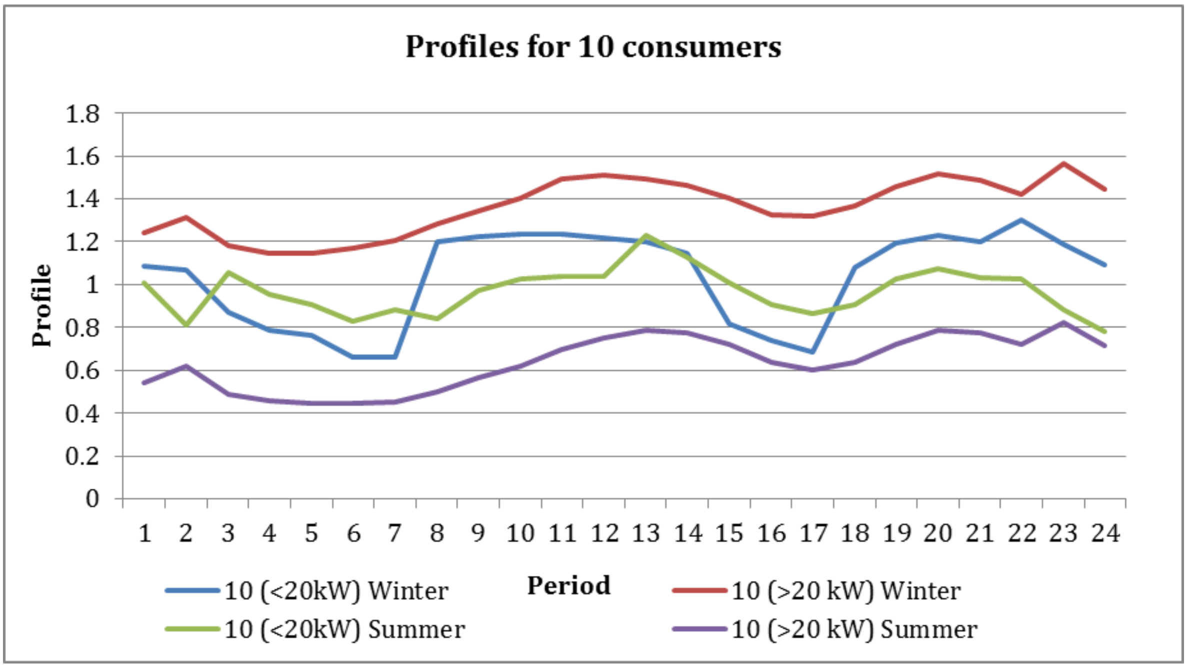


Figure 139 – Different Profiles of load power for 10 consumers.

Another example of load profiles can be seen in Figure 140. This time concerns different profiles of 440 consumers depending the time of the year.

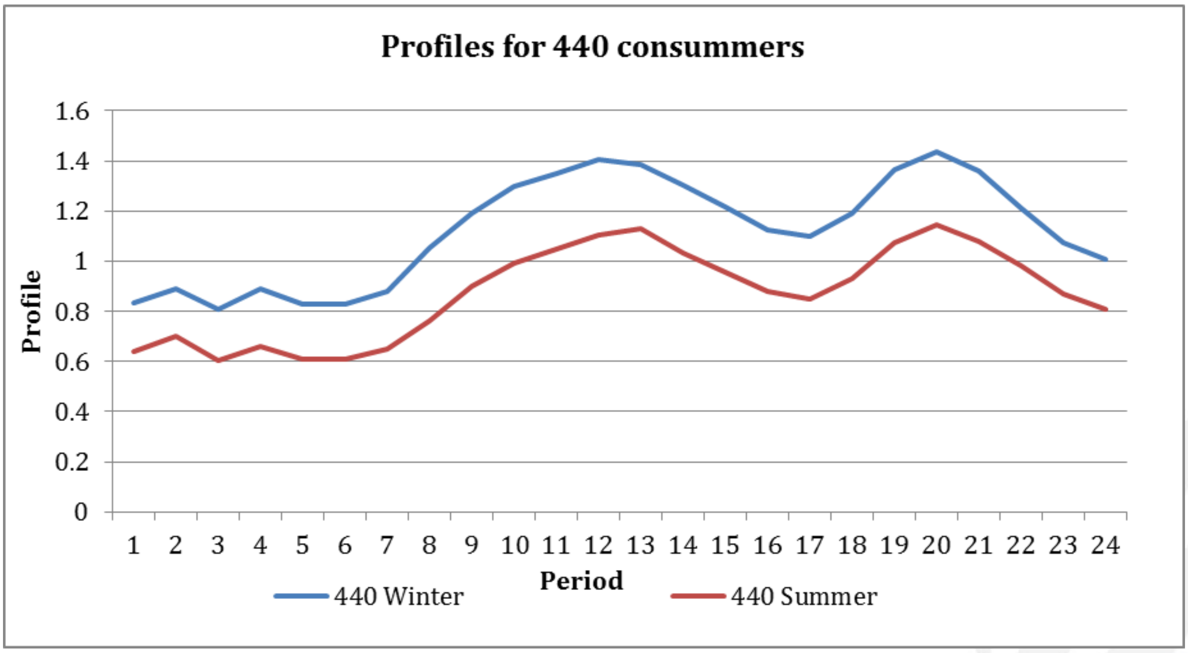


Figure 140 – Different Profiles of load power for 440 consumers.

Thus, for the cases when the number of consumers associated to a load doesn't belong to this list, an interpolation taking into account the two nearest values of number of consumers and values of load profile was made. For instance, considering a number of clients of loadX equal to 7, the closest values of typical number of consumers in Table 135 are 5 and 9. Considering these two profiles have values of 0.96 and 1.3 for a determined period p, the variation of the profile between these two typical numbers (nc) is:

$$\Delta Profile(5-9) = \frac{1.3 - 0.96}{9-5} = 0.085$$

The normalized profile value of the loadX at period p will be:

$$Profile(LoadX, nc = 7, p) = (7-5) \times 0.085 + 0.96 = 1.13$$

The value of active load power of the loadX at period p with Pref = 0.5 MW will be:

$$P(LoadX) = 1.13 \times 0.5 = 0.565\ MW$$

Regarding the flexibilities, the tool simulates a flexible load using a fictitious generator. So, when a positive value is assigned to a flexible load in the results, it means the load power becomes lower. Similarly, when a negative value is assigned to a flexible load, it means the load power becomes higher.

In the WP1 definition there is a mention to flexibilities for 2 to 4 hours or for 1 to 2 hours. We consider that the number of hours represent the availability to increase or decrease the load if it is necessary at consecutive periods (hours). It is not mandatory to change the load, only to keep its availability to change.

For the generation value of the wind generators for all periods and all scenarios the Pref value of the machine was used and increased by the dispatched value. For each machine the

availability to make wind curtailment was made available if it was necessary. In the short-term only the new capacities could be curtailed, and for the mid-term and long-term it is possible to curtail all the wind parks as suggested in the simulation scenarios of WP1.
The active and reactive power limits of the primary substations for all scenarios were obtained considering the following rules:

- **Active Power**: 90% of the maximum power consumption of the HV/MV substation. This value changes with the variation of consumption along the scenarios. The maximum power consumption occurs in the winter scenarios, so for each WP1 scenario, the maximum value of load was always obtained from winter cases.
- **Reactive Power:** considered that tan φ ϵ [-0.3; 0.3]

In order to penalize solutions with active power values that do not comply with the established limits, a variable cost term (penalty) has been adopted. In these types of irregularities the fixed cost term is ignored because it does not rely on how the tool changes the control variables. Moreover, the simulations intend to simulate a sequential series of 24 periods of one hour, while the fixed costs refer to an annual or monthly average values. Thus, if possible the tool always tries to find a solution where the power limits are satisfied in each period. The adopted penalization (α) for active power was the cost coefficient for high voltage usage, 0.6554 €/kW, used for HV/MV substations. This value is also used to penalize out-of-boundaries reactive power injection (0.6554€/kvar).

The values used for the MV network 5 for the limits of active power (MW) and for the limits of reactive power (Mvar) for each WP1 scenario for each primary substation are presented in Table 136.

Table 136 –Active and reactive power limits at primary substations for MV network 5.

WP1 scenario	RHTB0001				RHTB0002			
	Pmax	Pmin	Qmax	Qmin	Pmax	Pmin	Qmax	Qmin
1	70.11	0	21.03	-21.03	37.08	0	11.12	-11.12
2	70.46	0	21.14	-21.14	37.26	0	11.18	-11.18
3	68.43	0	20.53	-20.53	36.19	0	10.86	-10.86
4	72.35	0	21.71	-21.71	38.26	0	11.48	-11.48
5	67.94	0	20.38	-20.38	35.93	0	10.78	-10.78
6	83.01	0	24.90	-24.90	43.90	0	13.17	-13.17
7	68.15	0	20.44	-20.44	36.04	0	10.81	-10.81

The values used for the MV network 6 for the limits of active power (MW) and for the limits of reactive power (Mvar) for each WP1 scenario for each primary substation are identified in Table 137.

Table 137 –Active and reactive power limits at primary substations for MV network 6.

WP1 scenario	RHTB0001				RHTB0002			
	Pmax	Pmin	Qmax	Qmin	Pmax	Pmin	Qmax	Qmin
1	7.39	0	2.22	-2.22	18.55	0	5.56	-5.56
2	7.43	0	2.23	-2.23	18.64	0	5.59	-5.59
3	7.21	0	2.16	-2.16	18.10	0	5.43	-5.43
4	7.63	0	2.29	-2.29	19.14	0	5.74	-5.74
5	7.16	0	2.15	-2.15	17.97	0	5.39	-5.39
6	8.75	0	2.63	-2.63	21.96	0	6.59	-6.59
7	7.19	0	2.16	-2.16	18.03	0	5.41	-5.41

In order to compute the costs related to the activation of flexible consumption, a model that takes into account the market clearing prices of the day was used. The idea behind this model is that DSO pays the actual consumption plus a premium for flexible adjustment. Considering, for instance, that 40 MWh were purchased in the electrical energy market at 50 €/MWh, and the flexibility operator offered 30 MW (for one hour -> 30 MWh) of load reduction at 80 €/MWh. The DSO selects this load reduction and pays 30×(80-50) = 900 €. For the simulations exposed in this report, the same values were always used for the market prices that are presented on Figure 141.

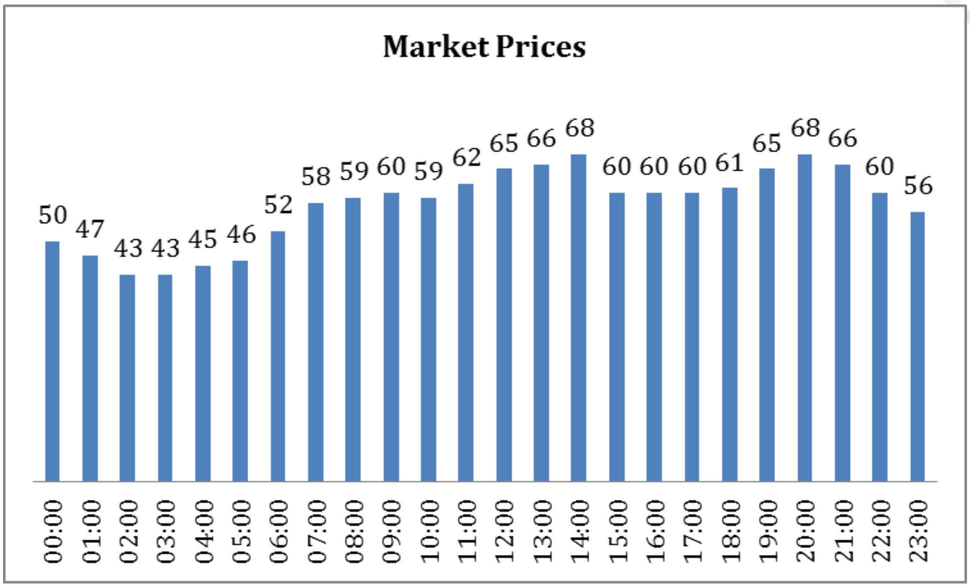


Figure 141 - Market Prices (€/MWh)

The cost of changing the transformer taps between periods should also be considered. For the simulations presented in this report it was considered that one change on a specific tap of a transformer costs 3 €. This value was obtained using the next equation (first methodology exposed in ANNEX I – Methodology for Flexibility Cost Calculation) that calculates the cost of changing a tap in HV/MV transformer.

$$c_{HV/MV} = \frac{1}{T_T}\left(\frac{a_T - a'_T}{a_T} \cdot F_{T+OLTC} + \frac{F_{OT} \cdot a'_T}{t_{OT}}\right)$$

Where:
$\boldsymbol{T_T}$: Total allowable adjustment times (times) – considered equal to **76650** (7*365*30) adjustment times
$\boldsymbol{a'_T}$: Lifetime after tap changed T_T times (year) – considered equal to **30 years**
$\boldsymbol{t_{OT}}$: Maintenance period (year) – considered equal to **5 years**
$\boldsymbol{F_{OT}}$: Maintenance cost (€/times)-considered equal to **3300** (300+3000) **€**
$\boldsymbol{a_T}$: Lifetime when the tap is never adjusted (year) – considered equal to **40 years**
$\boldsymbol{F_{T+OLTC}}$: Capital cost of the transformer (including the OLTC cost) – considered equal to **842000 €**

After filtering the available flexibilities for each network taking into account the conditions described in the WP1 scenarios definition, it is possible to group them by their presence in each scenario. Table 138 shows this information with the flexibility prices of increase (upward) or decrease (downward) the generation or consumption, divided per type of flexibility for the MV network 5.

All the flexible resources presented in Table 138 are modelled as generators in the SOPF tool. The flexible loads (MV costumers or MV/LV substations) have a flexibility range, according the percentage of flexibility indicated on Table 133, that each load could provide. It was decided to consider also 5% of all MV substations (mid-term) and 10% (long-term) with more than 20 customers as flexible loads, although WP1 definition scenarios doesn't suggest exactly this. The reason of that decision is to evaluate also a case where a flexible load could belong to more than one costumer. For each existing generator in the network, the modelling of wind curtailment is made by inserting an additional generator in the same node. This new generator will have the ability of curtail a percentage of the actual production depending on the WP1 scenario.

Table 138 – Flexibility information used on simulations for MV network 5.

Flexibility information			Price (€/MWh)		WP1 scenarios						
type	id	Node	Upward	Downward	Scen 1	Scen 2	Scen 3	Scen 4	Scen 5	Scen 6	Scen 7
MV costumers	FlexL063	138	22	90		✓	✓	✓	✓	✓	✓
	FlexL169	473	33	81		✓	✓	✓	✓	✓	✓
	FlexL200	762	28	72				✓	✓	✓	✓
	FlexL117	312	23	86				✓	✓	✓	✓
	FlexL201	766	28	81						✓	✓
	FlexL090	228	21	82						✓	✓
Wind curtailment	Flexsc02	83	83	32		✓	✓	✓	✓	✓	✓
	Flexsc03	89	82	31		✓	✓	✓	✓	✓	✓
	Flexsc05	211	79	34		✓	✓	✓	✓	✓	✓
	Flexsc01	320	77	27		✓	✓	✓	✓	✓	✓
	Flexsc04	479	85	29		✓	✓	✓	✓	✓	✓
	Flexsc06	771	89	30		✓	✓	✓	✓	✓	✓
MV/LV substations	FlexL001	1	36	89				✓	✓	✓	✓
	FlexL002	4	35	77				✓	✓	✓	✓
	FlexL003	21	31	81				✓	✓	✓	✓
	FlexL005	25	33	74				✓	✓	✓	✓
	FlexL007	29	33	81				✓	✓	✓	✓
	FlexL009	31	29	73						✓	✓
	FlexL011	33	25	71						✓	✓
	FlexL012	34	24	76						✓	✓
	FlexL016	42	20	75						✓	✓
	FlexL019	45	26	91						✓	✓

As it was done for the MV network 5, the flexibilities hypotheses within this network were filtered taking into account the conditions of the WP1 scenarios definition (Table 133). This network has less flexible resources within the WP1 conditions, but it is a network with less consumption as well. Furthermore, the original MV network 6 doesn't have any generator. In this case, WP1 suggests consider that wind power penetration should be equal to 10%, 20% and 40% for short-term, mid-term and long term scenarios respectively. The node chosen to insert a new generator in this network, in order to model the wind power penetration, was the node 643 because it is the node with the highest consumption. So, to simulate the wind curtailment, like MV network 5, a fictitious generator was created at the same node.

Table 139 – Flexibility information used on simulations for MV network 6.

Flexibility information			Price (€/MWh)		WP1 scenarios						
type	id	Node	Upward	Downward	Scen 1	Scen 2	Scen 3	Scen 4	Scen 5	Scen 6	Scen 7
MV costumers	FlexL007	7	22	90		✓	✓	✓	✓	✓	✓
Wind curtailment	Flexsc01	643	81	33		✓	✓	✓	✓	✓	✓
MV/LV substations	FlexL020	60	31	76				✓	✓	✓	✓
	FlexL021	61	27	78						✓	✓

4.2.2 Interval Constrained Power Flow (ICPF)

4.2.2.1 Portuguese Test Cases

This section describes the test cases and presents the hypothesis description. For each scenario, the penetration of RES, the load growth and the degrees of flexibility available are presented. Table 140 summarizes the WP1 scenarios that were considered in the ICPF simulations.

Table 140 - WP1 Scenarios for Portugal

Scenario	Generation/demand	Criteria
1 (status quo)	Status quo	Demand flexibility: Only from interruptible consumers No wind curtailment, only reactive power control
2 (Short-term) Up to 4 years	Demand growth: +7.5% Wind Power increase: +11.9% Solar PV increase: +113.6%	Demand flexibility: Only from interruptible consumers Wind curtailment only for additional capacity
3 (Short-term) Up to 4 years	Demand growth: +7.5% Wind Power increase: +14.3% Solar PV increase: +136.4%	Demand flexibility: Only from interruptible consumers Wind curtailment only for additional capacity when The wind generation is higher than the original capacity
4 (Mid-term) Up to 10 years	Demand growth: +18.9% Wind Power increase: +26.32% Solar PV increase: +240.9%	Demand flexibility: Only from interruptible consumers Wind curtailment only for additional capacity of existing wind parks and for new wind parks
5 (Mid-term) Up to 10 years	Demand growth: +18.9% Wind Power increase: +31.0% Solar PV increase: +281.8%	Demand flexibility: Only from interruptible consumers Wind curtailment only for additional capacity when The wind generation is higher than the original capacity
6 (Long-term) Up to 20 years	Demand growth: +37.7% Wind Power increase: +50.1% Solar PV increase: +404.5%	Demand flexibility: Only from interruptible consumers Wind curtailment only for additional capacity when The wind generation is higher than the original capacity

The reactive power control that was used throughout the simulations follows the following rule:

$$Qmax = 0.4 * Pref$$
$$Qmin = -0.35 * Pref$$

The demand flexibility will not change in the scenarios since the interruptible consumers will be responsible for it in all of them. On the other hand, the wind curtailment will be higher in the scenarios in which the curtailment will be available for all the wind parks. This analysis will be more detailed when analysing the results for each scenario. Since the transformer TAPs, the reactive power compensators, the interruptible consumers and the wind parks will be responsible for provide flexibility to the distribution network, some important data regarding them will be presented. Table 141 shows the exact location of transformer TAPs and their number of TAP positions in the northeast network.

Table 141 – Location and number of TAP positions in the Northeast network

fbus	tbus	Smax	Step_Down_Positions	Step_Up_Positions
1155	2168	15	11	11
1155	2991	15	11	11
1168	2720	20	12	12
1170	1173	31.5	11	11
1170	1174	31.5	11	11
1176	1182	20	11	11
1188	1191	10	11	11
1189	1193	15	7	8
1197	1200	30	9	9
1197	1198	30	9	9
1201	1203	15	13	13
1201	1204	15	13	13
1215	1219	20	12	12
1211	1216	20	5	16

Table 142 shows the number of TAP positions of the power transformers that compose the western network.

Table 142 - Location and number of TAP positions in the Western network

fbus	tbus	Smax	Step_Down_Positions	Step_Up_Positions
263	275	20	11	11
287	308	20	11	11
304	328	10	9	9
305	332	10	9	9
287	309	20	11	11
327	351	10	9	9
327	352	10	9	9
305	329	10	9	9
305	330	10	9	9
305	331	10	9	9
335	356	31.5	11	11
336	1069	20	11	11
336	1089	20	11	11
335	355	31.5	11	11
370	385	20	9	9
440	451	31.5	11	11
440	452	31.5	11	11
252	1087	20	11	11
1103	1107	10	11	11
1103	1105	10	11	11
1113	1120	20	11	11
1114	1122	10	9	9
1113	1121	20	11	11
1114	1123	10	9	9

1149	1154	40	11	11
1150	1155	20	9	9
1150	1156	20	11	11
1149	1153	40	0	0
1166	1168	31.5	11	11
1166	1169	20	11	11

The information regarding the position of the reactive power compensators is described in Table 143.

Table 143 – Location of the reactive power compensators in the Northeast network

bus	Nominal Q	step%
1198	4	100
1216	3.4	100
2720	3.4	100
2720	3.4	50
1203	3	100
1174	4	100
1700	3	100
410	3	100
1219	3.4	100
1219	3.4	50

Table 143 shows that most of the reactive power compensators are located at the secondary node of the power transformers. Moreover, these capacitor banks have 2 or 3 step positions.

Table 144 - Location of the reactive power compensators in the Western network

bus	Nominal Q	step%
1123	3.3	100
1122	3.3	100
1105	2.8	100
1107	1.4	100
1168	3.4	100
1169	3.4	100
1146	6.8	50
1143	6.8	50
271	3.4	100
1120	3.4	100
1121	6.8	50
452	2.5	100
451	2.5	100

385	3.4	100
355	2.8	100
356	6.2	50
331	2.8	100
330	2.8	100
1155	6.6	50
1156	6.6	50
351	3.3	100
352	3.3	100

Table 144 shows the step positions available in each reactive power compensator presented in the western network. Regarding the DRES, there are different types in this distribution network. In Table 145 the exact location of the wind parks and their active power injection are described.

Table 145 – Location and active power injection of the Wind Parks in the Northeast network

Bus	Active Power (MW)
2993	8.95
2996	1.90
2999	0.38
3000	18.28
3001	3.46
3002	1.25
3003	2.26
3004	0.40
3005	3.54
3007	0.39
3008	1.92
3009	14.93
3013	4.41

It is also important to highlight that the other types of DRES are considered redispatchable generators.

Table 146 - Location and active power injection of the Wind Parks in the Western network

Bus	Active Power (MW)
1178	0.55
1179	2.33
1180	0.0775

Table 146 shows the wind parks that are connected to the western network. Regarding other types of DRES, this network is also composed by photovoltaic generators that will increase their power injection throughout the scenarios. The demand flexibility will be provided by interruptible consumers. In the northeast network these type of consumers does not exist while in the western network there 3 interruptible consumers. Their location is provided in table Table 147.

Table 147 – Interruptible consumers in the Western network

Interruptible Consumers	Bus
Solvay	273
Central cerveja	1091
Cimpor	1096

4.2.2.2 French Test Cases

This section describes the test cases and presents the hypothesis description. For each scenario, the penetration of RES, the load growth and the degrees of flexibility available are presented. Table 148 summarizes the WP1 scenarios that were considered in the ICPF simulation.

Table 148 – WP1 Scenarios for France

Scenario	Generation/demand	Criteria
1 (Status quo)	Status quo	-No demand flexibility was considered -No wind curtailment, only reactive power control
2 (Short-term)	Demand growth: +0.5% Wind increase: +34.6%	-Demand flexibility: 20% of the MV customers with contracted power over 200kW could provide ±20% flexibility for 2 to 4 hours. -Wind curtailment only for additional capacities
3 (Short-term)	Demand growth: -2.4% Wind increase: +40.1%	-Homothetic increase of the demand and installed wind capacity -Demand flexibility: 20% of the MV customers with contracted power over 200kW could provide ±20% flexibility. -Wind curtailment only for additional capacities
4 (Mid-term)	Demand growth: +3.2% Wind increase: +82.5%	-Homothetic increase of the demand and installed wind capacity -Demand flexibility: 50% of the MV customers with contracted power over 200kW could provide ±20% flexibility for 2 to 4 hours. 5% of MV/LV substations with more than 20 customers could provide ±20% flexibility for 1 to 2 hours -Wind curtailment for all the wind parks
5 (Mid-term)	Demand growth: -3.1% Wind increase: +103.6%	-Homothetic increase of the demand and installed wind capacity -Demand flexibility: 50% of the MV customers with contracted power over 200kW could provide ±20% flexibility for 2 to 4 hours. 5% of MV/LV substations with more than 20 customers could provide ±20% flexibility for 1 to 2 hours -Wind curtailment for all the wind parks
6 (Long-term)	Demand growth: +18.4% Wind increase: +207.5%	-Homothetic increase of the demand and installed wind capacity -Demand flexibility: 80% of the MV customers with contracted power over 200kW could provide ±20% flexibility for 2 to 4 hours. 10% of MV/LV substations with more than 20 customers could provide ±20% flexibility for 1 to 2 hours -Wind curtailment for all the wind parks

7 (Long-term)	Demand growth: -2.8% Wind increase: +253.8%	-Homothetic increase of the demand and installed wind capacity -Demand flexibility: 80% of the MV customers with contracted power over 200kW could provide ±20% flexibility for 2 to 4 hours. 10% of MV/LV substations with more than 20 customers could provide ±20% flexibility for 1 to 2 hours -Wind curtailment for all the wind parks

The reactive power control that was used throughout the simulations follows the following rule:

$$Qmax = 0.4 * Pref$$
$$Qmin = -0.35 * Pref$$

Moreover, all the following simulations are run considering a pre-determined tolerance (see D3.3) of 10 degrees.

Having in consideration the flexibility criteria provided in Table 148 for each scenario, it is possible to cluster it per type of flexibility available. Therefore, for each French network, a table that summarizes the type of flexibility and its location for each scenario will be provided. As it was explained in 4.1.2.2 each French network was divided in two sub-networks.

Table 149 - Flexibility data used on simulations for MV network 5 – Part 1

Flexibility information		WP1 scenarios						
type	Node	Scen 1	Scen 2	Scen 3	Scen 4	Scen 5	Scen 6	Scen 7
MV costumers	57		✓	✓	✓	✓	✓	✓
	65						✓	
	68						✓	
	78						✓	
	92		✓	✓	✓	✓	✓	✓
	93						✓	
	94						✓	
	95						✓	✓
	99						✓	✓
	100						✓	✓
	108						✓	
	111		✓	✓	✓	✓	✓	✓
	118				✓	✓	✓	✓
	122				✓	✓	✓	✓
	137						✓	✓
	143						✓	
	145						✓	
	147						✓	✓
	156						✓	
	161						✓	
	165						✓	✓
	173						✓	✓
	175						✓	
	176				✓	✓	✓	✓
	189				✓	✓	✓	✓
	193				✓	✓	✓	✓
	196				✓		✓	
	207				✓	✓	✓	✓
	208		✓	✓	✓	✓	✓	✓
Wind curtailment	50		✓	✓	✓	✓	✓	✓
	52		✓	✓	✓	✓	✓	✓
	103		✓	✓	✓	✓	✓	✓
	140		✓	✓	✓	✓	✓	✓
	195		✓	✓	✓	✓	✓	✓

Table 149 shows exactly how flexibilities were used for each test case. The next tables will show the same characteristics for the other networks. A particularity regarding the number of MV customers able to provide flexibility will be analysed.

Table 150 - Flexibility data used on simulations for MV network 5 – Part 2

Flexibility information		WP1 scenarios						
type	Node	Scen 1	Scen 2	Scen 3	Scen 4	Scen 5	Scen 6	Scen 7
MV costumers	70		✓	✓	✓	✓	✓	✓
	71		✓	✓	✓	✓	✓	✓
Wind curtailment	50		✓	✓	✓	✓	✓	✓

As it is possible to observe in Table 150 there are only two MV customers that fulfil the requirement that allows them to provide flexibility to the distribution network. This requirement is established in Table 148. This situation is very different when compared with the number of customers that can provide flexibility in the part 1 of this network. However it is important to understand why both MV customers provide demand flexibility for every scenario with the exception of the *status quo*. With only two customers there was no sense in applying the rule established for the short, mid and long-terms regarding the demand flexibility. Therefore instead of using 20, 50 and 80% of the MV customers with contracted power over 200 kW for each term, it was decided that every customers fulfilling this requirement would provide flexibility for all the scenarios. It is also possible to notice this situation in the following networks.

Table 151 - Flexibility data used on simulations for MV network 6 – Part 1

Flexibility information		WP1 scenarios						
type	Node	Scen 1	Scen 2	Scen 3	Scen 4	Scen 5	Scen 6	Scen 7
MV costumers	135		✓	✓	✓	✓	✓	✓
	211		✓	✓	✓	✓	✓	✓
	213		✓	✓	✓	✓	✓	✓
Wind curtailment	13		✓	✓	✓	✓	✓	✓

In this new network only three MV customers are able to provide flexibility to the distribution network. It is also important to state that in the *status quo* there is the possibility of reactive power control. Moreover, in scenarios 2 and 3 the wind power curtailment is only applied to additional capacities while in scenarios 4, 5, 6 and 7, all the wind parks are able to provide this type of flexibility.

Flexibility information		WP1 scenarios						
type	Node	Scen 1	Scen 2	Scen 3	Scen 4	Scen 5	Scen 6	Scen 7
MV costumers	107		✓	✓	✓	✓	✓	✓
	109		✓	✓	✓	✓	✓	✓
Wind curtailment	170		✓	✓	✓	✓	✓	✓

Table 152 - Flexibility data used on simulations for MV network 6 – Part 2

Table 152 shows the flexibility data provided by this distribution network. In order to perform the simulations for each scenario a 24h load and generation profiles were provided. The following tables define these profiles.

Table 153 – Generation Profiles

Generation Profile		
Hour	Profile1	Profile2
00:00	0.31481481	0.16296296
01:00	0.37037037	0.27777778
02:00	0.35185185	0.51851852
03:00	0.24074074	0.95185185
04:00	0.27777778	0.75925926
05:00	0.12962963	0.64814815
06:00	0.35185185	0.24074074
07:00	0.35185185	0.27777778
08:00	0.2037037	0.2037037
09:00	0.31481481	0.24074074
10:00	0.37037037	0.27777778
11:00	0.40740741	0.2037037
12:00	0.40740741	0.2037037
13:00	0.40740741	0.24074074
14:00	0.40740741	0.35185185
15:00	0.44444444	0.40740741
16:00	0.37037037	0.37037037
17:00	0.31481481	0.39481481
18:00	0.24074074	0.46888889
19:00	0.24074074	0.48740741
20:00	0.24074074	0.56148148
21:00	0.24074074	0.56148148
22:00	0.2037037	0.52444444
23:00	0.2037037	0.93925926

Table 153 presents two generation profiles. Further it will be explained how these profiles are used in the ICPF tool. Figure 142 allows to understand better how the Wind Farm profiles evolve throughout the 24 h period.

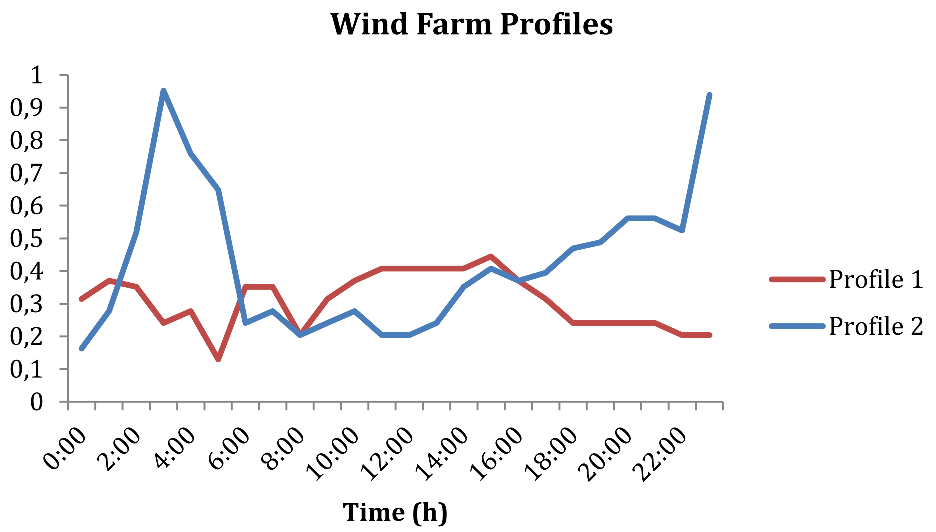


Figure 142 – Wind Farm Profiles

Regarding the demand profiles, two were provided: one for the summer and one for the winter. However, for the ICPF tool there is no need to simulate all the 24 periods that compose the profiles. The use of the complete profiles would not have a considerable impact regarding the conclusions that are expected to be drawn. Therefore, it was decided to simulate the ICPF tool only for the 0.00h-3.00h period. In terms of generation profiles, the second was chosen. The composition of the demand profile had some particularities. The demand profile depends on the customers per substation. Moreover, the demand profile values were only available for a set of number of customers. Table 154 shows the list of the customer numbers that was provided for the load profiles.

Table 154 - List of number of consumers

1	2	4	5	9	10	11	17	24	34	47	64	85	121	158	440	301	241

Therefore, if the number of customers in a given load bus is equal to one of these values, there is no problem. However, there are several load buses that have a number of customers different from the ones listed in Table 154. For these cases, an interpolation taking into account the two nearest values of consumers and the values of their load profile was developed. For instance, consider a number of clients equal to 37. The nearest values in the list of consumer numbers in Table 154 are 34 and 47. Consider also that for these numbers of customers the normalized load profiles values are 0.99 and 1.21 for a determined period p. The variation of the profile between the numbers of consumers 34 and 47 is given through:

$$\Delta Profile = \frac{0.99 - 1.21}{34 - 47} = 0.0169$$

Thus, the normalized profile value at period p will be:

$$Profile(number\ of\ customers = 37) = (37 - 34) \times 0.0169 + 0.99 = 1.0407$$

Then, this normalized profile value is multiplied by P_{ref} and Q_{ref}.

4.2.2.3 Germany Test Cases

This section describes the test cases and presents the hypothesis description for the German network. For each scenario, the penetration of RES and the degrees of flexibility available are presented. Table 155 and Table 156 summarize the WP1 scenarios that will be considered in the following simulations.

Table 155 - WP1 Scenarios for Germany (original RWE specifications)

Test Num.	Test Case	Parameter(s) of WP1 scenario(s)	Characterisitcs of the Current network for the Simulation	Criteria to link with the simulation details	Grid	Demand	RES	Transformer tap change	Power plant redispatch	RES Q(U) - Control	RES Curtailment	Storage
1	Status quo	Present situation	Present situation	Present situation	2015	2015	2015	Allowed	Allowed	No	No	No
2	No grid expansion & new RES controlled	"Mid-term" & "most likely" WP1 Scenario for Germany	Present grid, demand unchanged, RES moderately growing on a high penetration level	RES increased at today's locations, only new RES built after 2015 are controlled	2015	2015	2020	Allowed	Allowed	Only new (> 2015)	Only new (> 2015)	No
3	No grid expansion & all RES controlled	"Mid-term" & "most likely" WP1 Scenario for Germany	Present grid, demand unchanged, RES moderately decreasing on a high penetration level	RES increased at today's locations, any RES are controlled	2015	2015	2020	Allowed	Allowed	Allowed	Allowed	No
4	No grid expansion & Central storage/flex.	"Mid-term" & "most likely" WP1 Scenario for Germany	Present grid, demand unchanged, RES moderately growing on a high penetration level	RES increased at today's locations, only new RES built after 2015 are controllled, two central storage devices installed	2015	2015	2020	Allowed	Allowed	Only new (> 2015)	Only new (> 2015)	Central
5	No grid expansion & Distributed storage/flex.	"Mid-term" & "most likely" WP1 Scenario for Germany	Present grid, demand unchanged, RES moderately growing on a high penetration level	RES increased at today's locations, only new RES built after 2015 are controllled, Distributed Storage installed, same amount as Central Storage, but spread over all HV/MV Substations	2015	2015	2020	Allowed	Allowed	Only new (> 2015)	Only new (> 2015)	Distributed
6	No grid expansion & Superposition of all	"Mid-term" & "most likely" WP1 Scenario for Germany	Present grid, demand unchanged, RES moderately growing on a high penetration level	Superposition of the cases above	2015	2015	2020	Allowed	Allowed	Allowed	Allowed	Central + Distributed

Table 156 - WP1 Scenarios for Germany (with RWE's suggested modifications)

Test Num.	Test Case	Parameter(s) of WP1 scenario(s)	Characterisitcs of the Current network for the Simulation	Criteria to link with the simulation details	Grid	Demand	RES	Transformer tap change	Power plant redispatch	RES Q(U) - Control	RES Curtailment	Storage
1	Status quo	Present situation	Present situation	Present situation	2015	2015	2015	Allowed	No	Only existing RES	No	No
2	No grid expansion & existing RES controlled	"Mid-term" & "most likely" WP1 Scenario for Germany	Present grid, demand unchanged, RES moderately growing on a high penetration level	Power plant redispatch, existing RES are controlled	2015	2015	2015	Allowed	Allowed	Only existing RES	No	No
3	No grid expansion & new RES controlled	"Mid-term" & "most likely" WP1 Scenario for Germany	Present grid, demand unchanged, RES moderately decreasing on a high penetration level	RES increased at today's locations, only new RES built after 2015 are controllled	2015	2015	2020	Allowed	Allowed	Only existing RES	Only new (> 2015)	No
4	No grid expansion & all RES controlled	"Mid-term" & "most likely" WP1 Scenario for Germany	Present grid, demand unchanged, RES moderately growing on a high penetration level	RES increased at today's locations, all RES are controllled	2015	2015	2020	Allowed	Allowed	Only existing RES	Allowed	No
5	No grid expansion & Central Storage/flex.	"Mid-term" & "most likely" WP1 Scenario for Germany	Present grid, demand unchanged, RES moderately growing on a high penetration level	RES increased at today's locations, all RES are controllled, two central storage devices installed	2015	2015	2020	Allowed	Allowed	Only existing RES	Allowed	Central
6	No grid expansion & Distributed Storage/flex.	"Mid-term" & "most likely" WP1 Scenario for Germany	Present grid, demand unchanged, RES moderately growing on a high penetration level	RES increased at today's locations, all RES are controllled, Distributed Storage installed, same amount as Central Storage, but spread over	2015	2015	2020	Allowed	Allowed	Only existing RES	Allowed	Distributed

				all HV/MV Substations								

Each test case is based upon a snapshot of an operating point of the German distribution network, which was send by the DSO. For the first snapshot, the reactive power control used for the simulations goes with the following rule:

$$Qmax = 0.4 * Pref$$
$$Qmin = -0.35 * Pref$$

For the succeeding snapshots and according to RWE's indications (Table 156), the reactive power control will follow the rule:

$$Qmax = \tan[\cos^{-1}(0.95)] * Pref$$
$$Qmin = \tan[\cos^{-1}(-0.95)] * Pref$$

As for the most important highlights regarding the snapshots used for the simulation scenarios, the following set of tables provides a brief description of the main characteristics and assumptions that relate to the German distribution network.

Table 157 – German distribution network characteristics highlights

<table>
<tr><th colspan="2">Snapshot</th><th>Case A</th><th>Case B</th><th>Case C</th></tr>
<tr><td colspan="2">WP1 Scenarios</td><td>Table 155</td><td>Table 156</td><td>Table 156</td></tr>
<tr><td colspan="2">RES Production Level</td><td>66%</td><td>93%</td><td>9%</td></tr>
<tr><td colspan="2">Number of connected Wind Parks</td><td>7</td><td>8</td><td>4</td></tr>
<tr><td rowspan="2">Wind Park generation</td><td>MW</td><td>83.77</td><td>181.59</td><td>1.22</td></tr>
<tr><td>Mvar</td><td>6.54</td><td>10.39</td><td>0.82</td></tr>
<tr><td colspan="2">Biomass power plant generation</td><td>109.45</td><td>109.45</td><td>109.45</td></tr>
<tr><td colspan="2">Number of Transmission interconnections</td><td>6</td><td>6</td><td>6</td></tr>
<tr><td colspan="2">Boundary Node / Primary Substation (slack bus)</td><td colspan="3">Wehrendorf (at 380 kV)</td></tr>
<tr><td rowspan="2">Total Net Load</td><td>MW</td><td>501.45</td><td>491.44</td><td>699.95</td></tr>
<tr><td>Mvar</td><td>350.58</td><td>249.77</td><td>260.79</td></tr>
</table>

Table 158 - Renewable Energy Sources (RES) type and description

RES Type	Number of Units	$P_{min,2015}$ (MW)	$P_{max,2015}$ (MW)	$P_{min,2020}$ (MW)	$P_{max,2020}$ (MW)
Biomass	73	43.77	109.45	52.60	130.52
Wind Park	15	0	211.07	0	507.87
Wind (distributed)	72	0	80.67	0	194.13
PV	73	0	443.85	0	695.80

Table 159 – Distribution network bus voltage levels

Bus Voltage (kV)	Existing Number
380	7
220	6
110	147
30	133
10	132
6	2
Total	427

Table 160 - Power transformers description

Power Transformers	Existing Number	Steps Down	Steps Up
2 winding	3	---	---
	113	9	9
	72	13	13
3 winding	12	---	---
	15	9	9
	4	13	13
Total	219		

4.3 Simulation Results of the Test Cases

4.3.1 Results for Portugal

4.3.1.1 Sequential Optimal Power Flow (SOPF)

In the next sections the global results will be presented for 6 simulations made for each Portuguese network, considering the WP1 scenarios for Portuguese test cases. In the Table 161 it is possible to see the initial and final states of several variables along the temporal series of 24 periods for the Portuguese status quo scenario using the Northeast network. The analogous results for other scenarios using the Northeast network and the Western network can be seen in ANNEX IV – Additional Results for TSO-DSO Cooperation Domain. The list of variables that can be analysed in the Portuguese networks is extensive, with several generators, transformers and capacitor banks. Thus, it was decided to show the following data results:

- InitTotLoss (P) – Total active power losses in the initial state of the network before running the optimization (kW);
- FinalTotLoss (P) – Total active power losses in the final state of the network after running the optimization (kW);
- PowerGen (P) – Total active power generated in all network (MW);
- PowerGen (Q) – Total reactive power generated in all network (MVAr);
- Cost (€) – Total flexibility costs considering penalties for power values out of boundaries, for activation of flexible loads or generators and for changing taps of transformer and capacitor banks;
- From Netcon_{01} (Pfinal) to Netcon_i (Pfinal) - Injected active power by the primary substation in the final state of the network after the optimization (MW). The number of primary substations is *i*;
- From Netcon_{01} (Qfinal) to Netcon_i (Qfinal) - Injected reactive power by the primary substation in the final state of the network after the optimization (MVAr). The number of primary substations is *i*;
- Trans_{001} (tap) to Trans_j (tap) – Final tap position of the transformer. The number of transformers is *j*;
- Capa_{0001} (MVAr) to Capa_k (MVAr) – Final value of injected reactive power by the capacitor bank. The number of capacitor banks is *k*;

In both networks were not possible to find an alternative configuration to the initial one. The Northeast network is a meshed network with several loops and the primary substations connected to each other. This type of networks makes it difficult to obtain a better topology because it is usually the solution close to the optimum one in terms of network operation. In the Western network the fact of the tool cannot find an alternative configuration may be related with the fact of active power limits in the substations were to large compared to the effective injected power in those substations. Thus, due the limits were not surpassed, probably the tool did not change the configuration because it would not lead to better results.

4.3.1.1.1 Results for Northeast network

There were made six simulations using Northeast network regarding the six scenarios previously defined. In the Table 161 it is possible to see the status-quo global results for 24 periods. The next global results are in ANNEX IV – Additional Results for TSO-DSO Cooperation Domain. Then, there will be exposed the results for the KPI of the simulations using the Northeast network.
The tool was capable to reduce the active power losses in all simulations using different profiles of consumption and generation. In order to avoid high penalizations by surpassed reactive power limits related with tg φ, the tool managed transformer and capacitor banks taps. The active power limits in the primary substations were higher than the real injection at all periods and all scenarios. This situation leaded to results where no flexible resources were activated.

Table 161 – Northeast network scenario 1.

Period	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
InitTotLoss (P)	96.61231	56.92949	56.73658	59.33813	64.91381	61.43398	82.3518	48.38489	72.54949	167.066	189.9932	207.7185	232.9341	201.6981	193.9687	197.3252	165.0921	148.4717	164.5852	238.5263	283.6079	265.3821	222.1892	215.9327
FinalTotLoss (P)	87.46602	56.94935	50.8807	54.27143	60.69288	57.13898	76.09798	42.79749	66.28072	161.9045	181.5372	201.454	228.1724	196.5156	188.7175	188.5439	161.7005	141.0265	157.8726	233.0476	272.7398	262.8688	221.5025	208.4358
PowerGen (P)	22.59916	21.43707	20.96942	20.86497	20.41862	20.53733	19.9605	19.38168	20.13475	20.94627	21.17041	21.79821	22.43317	21.6197	21.63695	21.6461	21.20557	21.593	23.08818	25.20147	24.94295	24.49335	23.83427	23.19998
PowerGen (Q)	4.522019	4.444195	4.307204	4.317801	4.164756	4.208518	4.359977	4.07742	3.826205	3.940827	4.537412	4.112374	4.153016	4.277887	4.572333	4.602568	4.484397	4.442021	5.077283	5.350291	5.530637	5.373984	5.510271	5.536804
Cost	200.6901	162.5923	155.7449	158.0904	163.4747	161.2181	187.4297	149.7829	158.4465	70.91138	73.87582	269.3049	62.82789	260.3465	234.4043	68.78247	257.3458	65.39473	273.1694	359.1704	375.3385	385.3099	406.2695	397.2224
netcon01 (Pfinal)	-9.85867	-7.316	-7.44569	-8.5748	-9.41	-8.3465	-12.5003	-11.5545	-15.9208	-22.5464	-25.4181	-26.9761	-24.9319	-26.8002	-24.1162	-25.4112	-23.4636	-24.1444	-27.3591	-33.5775	-34.9854	-33.745	-35.5134	-35.2873
netcon01 (Qfinal)	-5.35219	-2.60898	-2.26099	-2.79829	-2.23331	-3.39483	-5.84674	-1.58967	-2.39056	-12.868	-13.48	-13.2424	-14.9508	-14.0171	-14.7631	-12.6893	-12.6255	-5.5092	-4.75636	-8.84279	-9.01891	-10.051	-10.324	-8.64246
netcon02 (Pfinal)	-9.85867	-7.316	-7.44569	-8.5748	-9.41	-8.3465	-12.5003	-11.5545	-15.9208	-22.5464	-25.4181	-26.9761	-24.9319	-26.8002	-24.1162	-25.4112	-23.4636	-24.1444	-27.3591	-33.5775	-34.9854	-33.745	-35.5134	-35.2873
netcon02 (Qfinal)	4.033036	2.260894	3.042463	5.322631	3.548338	4.005456	6.904816	4.550644	6.508291	8.683209	9.062245	11.23649	7.726364	10.8585	9.763895	8.411005	10.68126	7.901129	11.37424	15.00297	15.68517	16.1059	14.67134	16.56514
netcon03 (Pfinal)	-9.85867	-7.316	-7.44569	-8.5748	-9.41	-8.3465	-12.5003	-11.5545	-15.9208	-22.5464	-25.4181	-26.9761	-24.9319	-26.8002	-24.1162	-25.4112	-23.4636	-24.1444	-27.3591	-33.5775	-34.9854	-33.745	-35.5134	-35.2873
netcon03 (Qfinal)	-5.78284	-6.37363	-6.33477	-5.89609	-6.79915	-5.47625	-4.50522	-5.35232	-6.33558	-8.91931	-9.06064	-10.6713	-10.2537	-8.03703	-7.54232	-6.62674	-5.39719	-7.27409	-10.9324	-14.7897	-16.3986	-15.1402	-12.4596	-13.5961
netcon04 (Pfinal)	-9.85482	-7.32492	-7.44352	-8.58065	-9.41138	-8.34317	-12.5087	-11.5549	-15.9228	-22.5446	-25.4153	-26.9734	-24.9311	-26.7998	-24.1145	-25.4104	-23.4637	-24.1537	-27.3645	-33.5861	-34.9908	-33.7516	-35.5055	-35.2781
netcon04 (Qfinal)	3.838597	2.144822	2.075218	2.84522	1.487994	2.266271	3.149814	-1.31694	-0.17544	3.868004	3.13593	3.671764	4.466909	3.710841	5.161289	3.53992	4.849361	1.355342	1.563594	2.090741	3.467495	4.217613	0.176303	0.968057
trans004 (tap)	9	15	13	14	15	15	15	15	14	12	12	15	13	14	13	13	14	11	15	13	15	11	10	11
trans012 (tap)	15	15	11	14	15	15	15	15	13	13	15	15	15	15	15	14	15	12	13	10	13	15	14	11
trans008 (tap)	16	10	16	14	14	12	16	16	16	7	10	16	10	13	12	15	16	15	15	14	16	15	15	10
trans002 (tap)	16	21	14	16	19	14	11	16	16	19	20	23	16	16	15	18	21	22	17	22	22	15	15	15
trans006 (tap)	10	9	12	12	11	6	12	6	12	9	12	6	6	12	12	6	10	8	9	6	6	6	6	6
trans010 (tap)	12	12	10	7	10	8	11	5	6	9	8	8	11	12	9	12	11	11	8	9	12	6	7	11
trans015 (tap)	16	18	9	9	16	16	8	10	13	18	8	10	13	7	13	13	13	13	14	9	17	15	8	12
trans001 (tap)	10	17	16	8	12	18	14	16	17	15	8	9	18	10	10	17	18	11	14	15	7	7	13	14
trans014 (tap)	16	16	12	14	14	17	12	14	18	16	10	12	15	19	18	10	11	18	19	10	10	10	10	10
trans011 (tap)	12	13	14	9	13	8	13	8	6	13	9	10	9	11	12	15	6	14	12	15	13	8	15	7
trans016 (tap)	10	15	14	8	15	14	12	15	8	10	10	14	11	15	7	9	12	14	9	10	12	9	12	9
trans013 (tap)	15	16	14	15	14	7	13	16	12	8	8	11	11	8	12	9	16	14	12	12	8	9	14	15
trans003 (tap)	5	9	7	5	7	8	10	7	7	5	9	9	6	6	10	9	9	10	8	9	9	7	6	6
trans007 (tap)	18	14	11	15	14	17	19	12	16	22	21	21	19	21	20	20	19	18	19	21	16	16	16	15
Capa0001 (Mvar)	0	0	0	0	0	0	0	0	0	4	4	4	4	4	4	0	0	0	0	4	4	4	4	4
Capa0002 (Mvar)	0	0	0	0	0	0	0	0	0	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	0	3.4	3.4	3.4	3.4	3.4	3.4
Capa0003 (Mvar)	3.4	3.4	3.4	0	3.4	3.4	0	3.4	3.4	3.4	3.4	0	3.4	0	3.4	3.4	0	3.4	3.4	0	0	0	0	0
Capa0004 (Mvar)	3.4	3.4	3.4	3.4	3.4	1.7	3.4	3.4	1.7	0	1.7	3.4	3.4	3.4	0	3.4	1.7	3.4	0	1.7	1.7	0	3.4	0
Capa0005 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Capa0006 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Capa0009 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Capa0010 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

4.3.1.1.1.1 Operational KPI for Northeast network

Figure 143 resumes the variation along the periods of total active power losses between the initial solution and the optimized one for each WP1 scenario in the Portuguese Northeast network. It shows that the values of improvement are not very different between the scenarios neither between the periods. Probably the initial solutions are already with reduced power losses, which can explain the small value of losses improvement for this simulation.

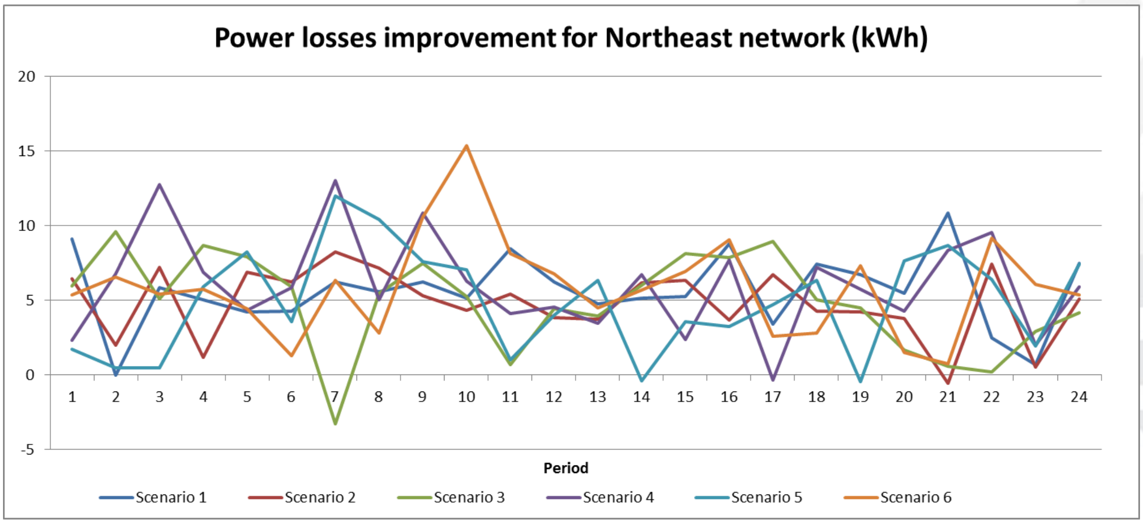


Figure 143 - Total losses improvement (kWh) for Northeast network.

Table 162 presents the total values for power losses for Northeast network.

Table 162 – Total values of active power losses (MW) of Northeast network.

Scenario	Total initial power Losses (kWh)	Total final power Losses (kWh)	Total improvement (kWh)	Improvement (%)
1	3693.74	3558.61	135.13	3.7%
2	4408.19	4292.22	115.96	2.6%
3	4543.37	4425.98	117.39	2.6%
4	5850.13	5704.06	146.06	2.5%
5	5349.64	5231.36	118.28	2.2%
6	5707.66	5566.88	140.78	2.5%

Figure 144 shows the injected active power by the primary substations of the Northeast network for each scenario. The sum of maximum limits and sum of minimum limits of injected power for primary substation are also represented. The curves of injected power are the sum of injected active power at all substations. There are small differences of injected active power between the scenarios and the distance to the power limits was never crossed along the periods.

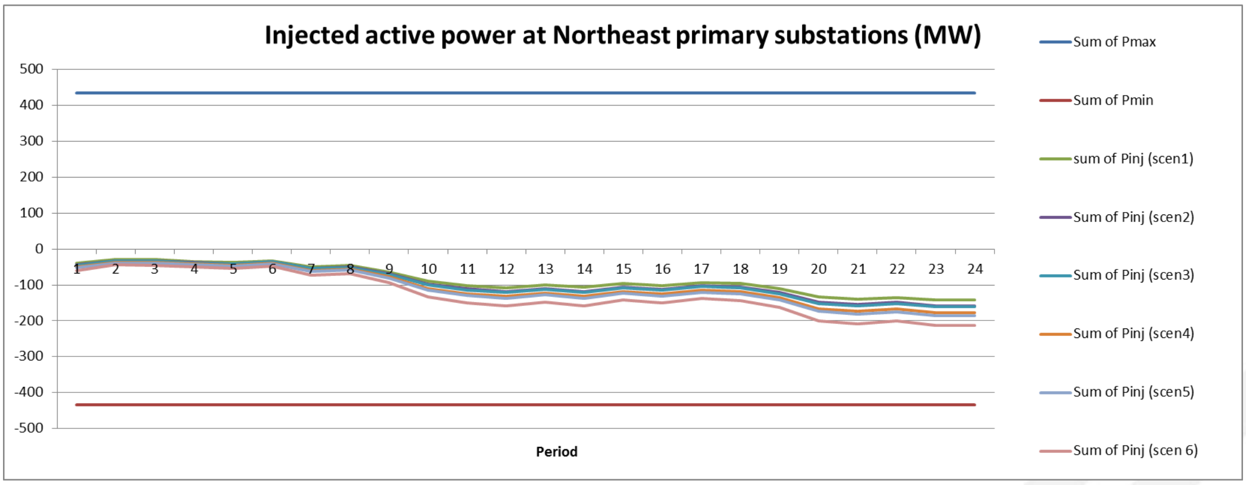


Figure 144 – Injected active power by primary substations of the Northeast network.

Figure 145 shows the sum of the injected reactive power by the four primary substations. In order to the make the Figure clearer, the reactive power limits were not presented. The total maximum reactive power at primary substations was 130.5 MVAr and the minimum was 0 MVAr. As it is possible to see at the figure, at some periods the minimum limits were surpassed which could made the solution penalized by reactive costs depending on the period.

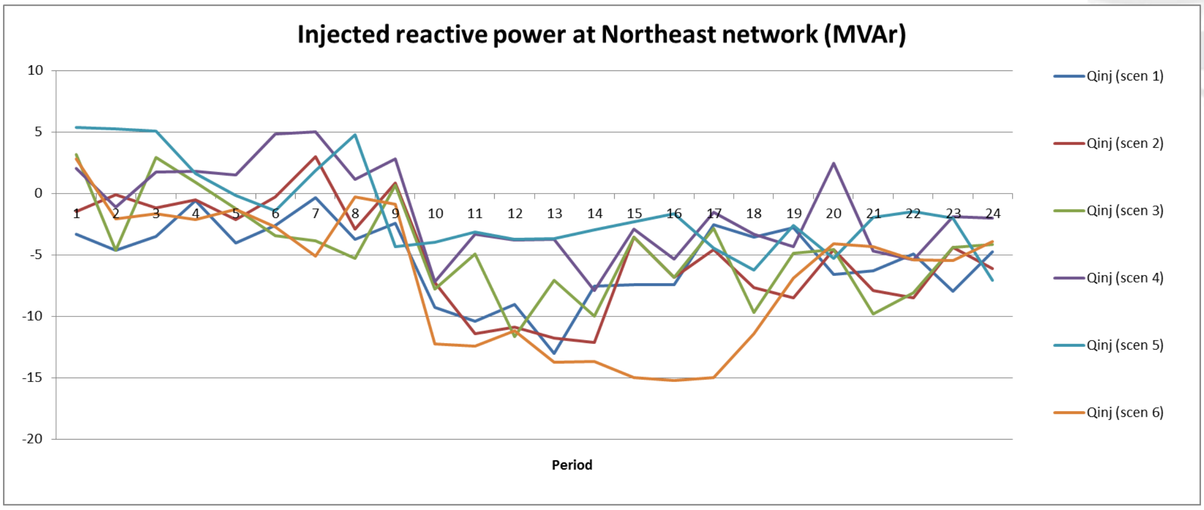


Figure 145 – Injected reactive power by primary substations of the Northeast network.

4.3.1.1.2 Results for Western network

There were made six simulations using Western network regarding the six scenarios previously defined. The global results for all simulations can be seen in ANNEX IV – Additional Results for TSO-DSO Cooperation Domain. Then, there will be exposed the results for the KPI of the simulations using the Northeast network.

The tool was capable to reduce the active power losses in all simulations using different profiles of consumption and generation. In order to avoid high penalizations by surpassed reactive power limits related with tg φ, the tool managed transformer and capacitor banks taps. The active power limits in the primary substations were higher than the real injection at all periods and all scenarios. This situation led to results where no flexible resources were activated.

4.3.1.1.2.1 Operational KPI for Western network

Figure 146 resumes the variation along the periods of total active power losses between the initial solution and the optimized one for each WP1 scenario in the Portuguese Western network. It shows that the values of improvement go with the DRES generation along the periods and that the improvement increases along the scenarios. In the mid and long term scenarios the penetration of DRES is higher, which can explain this situation.

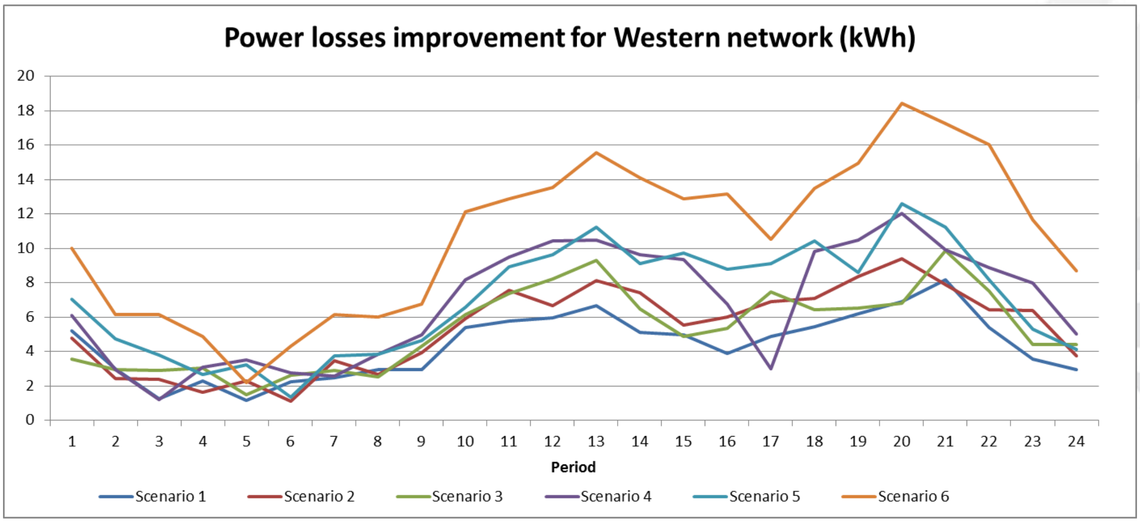


Figure 146 - Total losses improvement (kWh) for Western network.

Table 163 presents the total values for power losses for Western network.

Table 163 – Total values of active power losses (MW) of Western network.

Scenario	Total initial power Losses (kWh)	Total final power Losses (kWh)	Total improvement (kWh)	Improvement (%)
1	1402.75	1298.06	104.69	7.5%
2	1609.96	1481.96	128.00	8.0%
3	1608.44	1481.08	127.36	7.9%
4	1956.15	1793.77	162.39	8.3%
5	1955.27	1786.65	168.62	8.6%
6	2605.63	2348.02	257.61	9.9%

The results of injected active power by the primary substations of the Western network will be showed for each substation, contrary to what was done in the previous network. In this network each primary substation are feeding different MV substations, so it was necessary to separate the results.
Figure 147 and Figure 148 show the injected active power by the primary substations of the Western network for each scenario as well as the maximum and minimum active power limits. In both cases it is possible to see that the active power limits are distant from the real

injected power by the primary substation. The values of injected power are increasing along with scenarios, as the consumption is being increased.

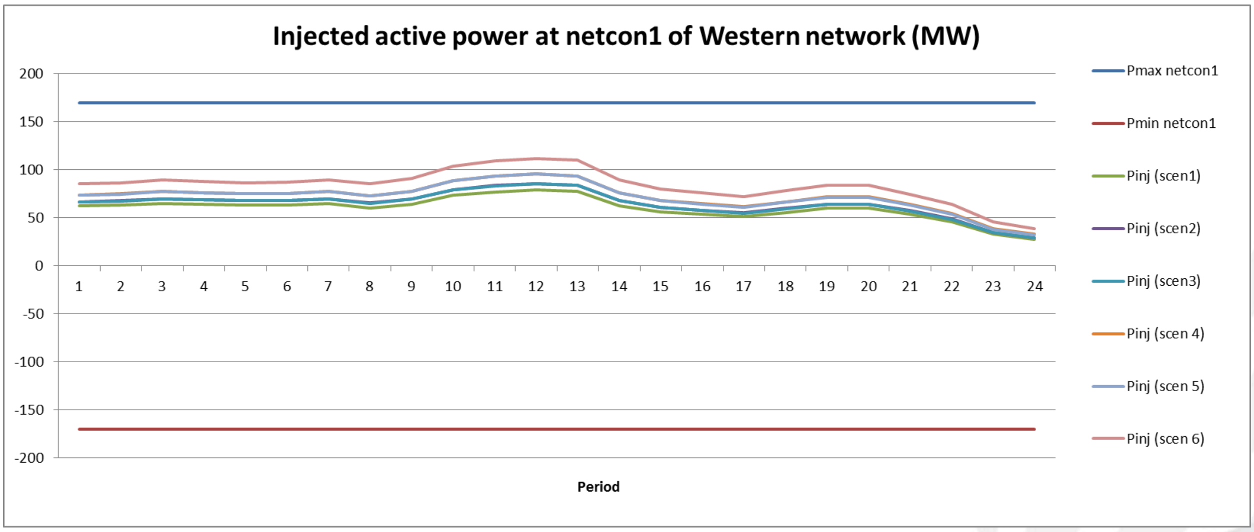


Figure 147 – Injected active power by primary substation-netcon1 of the Western network.

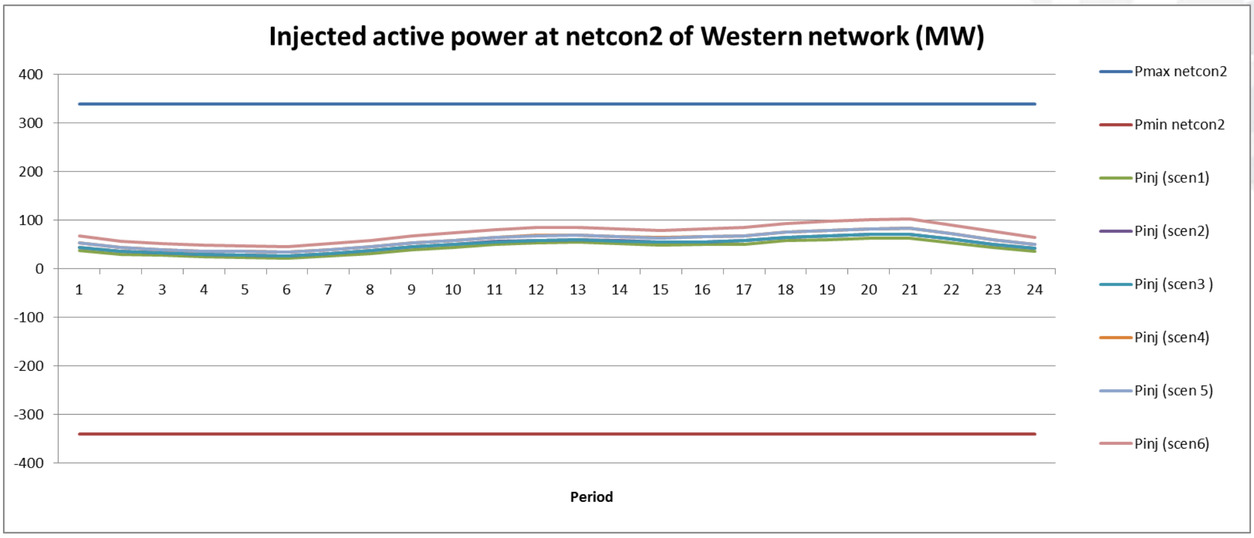


Figure 148 – Injected active power by primary substation-netcon2 of the Western network.

Figure 149 shows the sum of the injected reactive power by the two primary substations of Western network. In order to the make the Figure clearer, the reactive power limits were not presented. The total maximum reactive power at primary substations was 153 MVAr and the minimum was 0 MVAr. As it is possible to see at the figure, at some periods the minimum limits were surpassed which could made the solution penalized by reactive costs depending on the period.

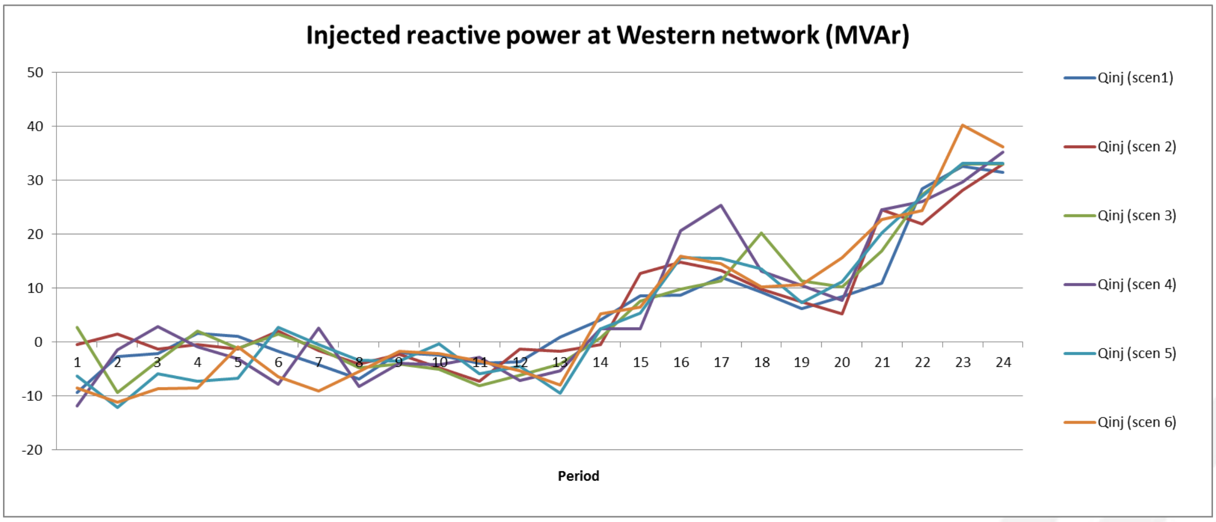


Figure 149 – Injected reactive power by primary substations of the Western network.

4.3.1.1.3 Other KPI for Portuguese networks

In the next sections there will be presented other KPIs results, which were obtained using Portuguese networks in the simulations. First there will be presented the total costs associated to each scenario used in simulations. Then there will be showed a resume of the total execution time of the simulations for all periods. In the end there will be presented the KIPs related with increased RES and reduced energy curtailment.

4.3.1.1.3.1 Total costs for Portuguese networks

Figure 150 shows the total costs obtained in the simulations using Portuguese Northeast and Western networks. It is possible to see in the both cases that in the Northeast network the higher costs occur when the scenario 4 and 5 were considered (mid-term). In the western network the higher costs occur in the scenario 6 (long-term). The Northeast network has higher penetration of DRES and low consumption, while the Western network has a higher profile of consumption and less penetration of DRES. In the situations of high consumption, the long-term scenario seems to lead to more costs due the demand growth in this scenario be 37,7%. In the situations of high penetration of DRES, the mid-term scenarios seem to lead to more costs because increased DRES generation is elevated compared with demand growth.
The total costs are mostly due the injection of reactive power at primary substations and due the limits of tg φ, since during the simulations the flexible resources were not activated, but also reflects the changing of the taps of transformers and capacitor banks between periods. This situation occurred because the active power limits imposed in the primary substations are high when compared with the real injection power, which limited the necessity of activate flexible resources.

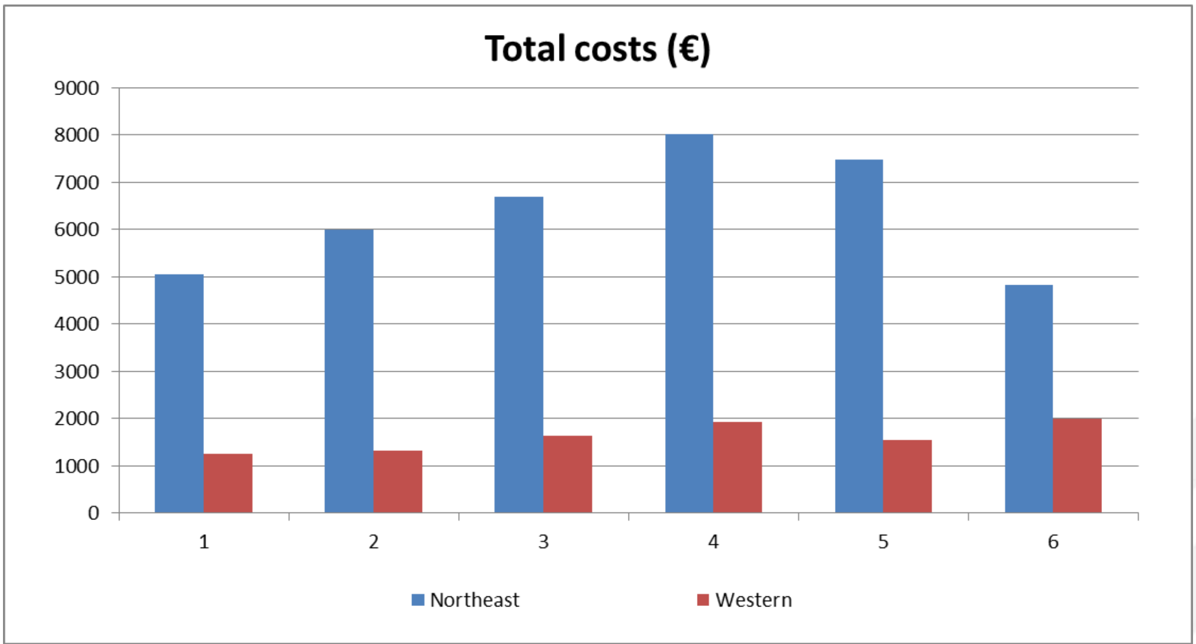


Figure 150 – Total costs obtained using Portuguese Northeast and Western networks.

4.3.1.1.3.2 *Execution time for Portuguese networks*

Table 164 resume the execution time of the tool for each simulation performed using Portuguese networks. The differences between the running times depend on the proper characteristics of each network. The Northeast network has a large amount of DRES penetration and low consumption while the Western network has a large amount of consumption and less DRES penetration. The Northeast network is a meshed network, while the Western network is almost radial. It is possible to see that, using Northeast network, the simulations take less time in the mid and long term scenarios.

Table 164 - Execution time of the simulations using Portuguese Northeast and Western networks.

scenarios	1	2	3	4	5	6
Northeast network (seconds)	2540.27	2556.90	2558.16	1353.38	1169.57	1160.91
Western network (seconds)	299.60	299.25	314.88	313.68	325.45	328.22

4.3.1.1.3.3 *Increased RES and DER Hosting Capacity using a Portuguese network (5)*

In order to compute the DRES capacity of the network it was used a simplified model. The idea is to obtain the maximum values of generation for each existing generator without compromising the proper functioning of the network. In the results using Portuguese Northeast network, at some periods, the values of demand and generation led to overload in some power lines. For instance, in the period 10 of the simulation for the status quo scenario there was a total DRES generation of 112.12 MW and the total consumption was 20.9 MW.

This scenario led to overload in three lines (line1843, line 1844 and line52). On the other side, in the previous period (period 9) the total DRES generation was 83.1 MW and the total consumption was 20.25 MW. In this period, the simulation did not led to any overload of power lines neither other limits violation.

So, considering this information, it was decided to create a middle scenario of generation that leads to a situation more close to the limits as much as possible. Starting from the values of generation present in the period 9, the generation was successively increased until break some power limits. This approach was made with two different simulations. The first one did not use the SOPF tool functionalities, namely changing the taps of transformers and capacitor banks and reconfiguration. The second one used the SOPF tool with all functionalities. The presence of flexible resources was not taken into account in these simulations in order to distinguish more easily the different possibilities of DRES penetration.

The values for dispatch of every generator at period 9 and period 10 are resumed in the Table 165. In the other columns of the table it is possible to see the middle point of generation profile obtained for each simulation (without SOPF and with SOPF).

Table 165 – Results of the simulations for KPI5 using a Portuguese network.

Generator id	Period 9 (MW)	Period 10 (MW)	Without SOPF (MW)	With SOPF (MW)
Sinc1	0.73	0.51	0.73	0.73
Sinc2	4.61	8.40	**6.60**	**6.80**
Sinc3	0.34	0.32	0.34	0.34
Sinc4	4.41	11.65	**9.90**	**10.00**
Sinc5	8.95	16.04	13.00	13.00
Sinc6	18.28	12.99	18.28	18.28
Sinc7	0.00	0.00	0.00	0.00
Sinc8	2.26	2.28	2.26	2.26
Sinc9	1.92	2.39	1.92	1.92
Sinc10	1.90	3.94	3.20	3.20
Sinc11	0.40	0.87	0.70	0.70
Sinc12	0.39	1.05	0.80	0.80
Sinc13	14.93	21.54	**17.30**	**17.40**
Sinc14	3.46	4.26	3.46	3.46
Sinc15	3.54	6.12	4.90	4.90
Sinc16	4.06	5.10	4.06	4.06
Sinc17	0.38	0.24	0.38	0.38
Sinc18	8.52	7.36	8.52	8.52
Sinc19	1.25	0.13	1.25	1.25
Sinc20	3.49	5.94	4.80	4.80

As it is possible to see, the second simulation allowed to allocate more 0.4 MW of distribution generation in this scenario than the first simulation. If a profile of generation obtained in the second simulation was used on the first simulation, the constraints of apparent power at two power lines (line1843, line 1844) would be violated. In the second simulation the tool allowed to change the taps of transformers and capacitor banks. These modifications have caused the possibility of produce more power without compromise the network.

The differences between the maximum values with the SOPF tool and the first tool are not significant. The main reason is related with the fact, in this network, the SOPF tool does not change the topological configuration. If the tool was capable to find another configuration, the DRES capacity will probably increase significantly, because the SOPF tool searches for optimal configuration solutions with fewer costs due flexible activation and due the network power losses. In a situation where constraints are violated, the solutions are penalized in its objective function, and so, the tool would be forced to find another feasible topology for network if it would be possible. Note that the values obtained for maximum dispatched values represent the simultaneous maximum values and not the individual ones. There are other combinations which generator values are close to simultaneous limits of the network constraints.

4.3.1.1.3.4 Reduced energy curtailment of RES and DER using a Portuguese network (6)

In order to compute the energy curtailment of RES and DER it was used a scenario with low consumption and with initial generated power by the DRES units higher than total consumption. The Northeast network has already these characteristics, so for the simulations of this KPI it was used this network. However, some changes were made in the minimum power limits of the primary substations to force the SOPF tool to activate curtail the wind generation. The new limits created for this simulation were defined in the Table 166.

Table 166 – Power limits of the primary substations for the simulation of Portuguese KPI 6.

Primary substation	Pmax (MW)	Pmin (MW)	Qmax (MVAr)	Qmin (MVAr)
Netcon1	126	-25	37.8	0.0
Netcon2	63	-25	18.9	0.0
Netcon3	120	-25	36	0.0
Netcon4	126	-25	37.8	0.0

The load scenario corresponds to the period 10 of the scenario 2 as well as the profile of wind generation. The total consumption in that period is 22.53 MW and the total dispatched generation by all the DRES units is 121.06 MW. This period was chosen because the balance of active power limits, generation and consumption is close to null. The Table 167 shows the dispatched values of active power in this period for each wind park. Besides those generators, there are others but they are not wind generators.

Table 167 – Initial generated power of wind power generators of Portuguese KPI 6.

Generator id	Initial Generated Power (MW)
Sinc4	13.03
Sinc5	17.95
Sinc6	14.54
Sinc8	2.55
Sinc9	2.67
Sinc10	4.41
Sinc11	0.97
Sinc12	1.18
Sinc13	24.11
Sinc14	4.76
Sinc15	6.84
Sinc17	0.40
Sinc19	0.15

The Table 168 resumes the maximum, minimum and initial dispatched values for all the fictitious generators used in this simulation which simulates the wind curtailment. The last columns present the downward costs for activating each of these flexibilities used for this simulation.

Table 168 – Data of flexible generators that simulates the wind curtailment for KPI 6.

Generator id	Initial Generated Power (MW)	Pmax (MW)	Pmin (MW)	Downward Cost (€/MWh)
FlexSc4	0.00	0.00	-0.52579	31
FlexSc5	0.00	0.00	-0.001	34
FlexSc6	0.00	0.00	-0.43892	27
FlexSc8	0.00	0.00	-0.26726	30
FlexSc9	0.00	0.00	-0.06377	22
FlexSc10	0.00	0.00	-0.001	33
FlexSc11	0.00	0.00	-0.01034	32
FlexSc12	0.00	0.00	-0.01439	31
FlexSc13	0.00	0.00	-0.94616	34
FlexSc14	0.00	0.00	-0.36157	27
FlexSc15	0.00	0.00	-0.03254	29
FlexSc17	0.00	0.00	-0.0021	22
FlexSc19	0.00	0.00	-0.00219	32

They were made two different simulations. The first one runs a power flow without considering the possibility to change the taps of the transformers or capacitor banks and without the possibility to change the topological configuration of the network. The second one considers these functionalities of SOPF. The main results for these two simulations are resumed in the Table 169. There are showed the difference between values of injected active power by curtailment resources for the two simulations.

Table 169 – Results for simulations of Portuguese KPI 6.

Generator id	Without SOPF- Injected active power (MW)	With SOPF- Injected active power (MW)
FlexSc4	-0.52579	-0.52579
FlexSc5	-0.001	-0.001
FlexSc6	-0.43892	-0.43892
FlexSc8	-0.26726	-0.26726
FlexSc9	-0.06377	-0.06377
FlexSc10	-0.001	-0.001
FlexSc11	-0.01034	-0.01034
FlexSc12	-0.01439	-0.01439
FlexSc13	-0.94616	-0.94616
FlexSc14	**-0.36157**	**-0.023**
FlexSc15	-0.03254	-0.03254
FlexSc17	**-0.0021**	**0.000**
FlexSc19	-0.00219	-0.00219

As it is possible to see in the table above, the values obtained for active power of wind curtailment are similar between simulations. The main reason is related with the fact of, using this network, the SOPF tool does not change the topological configuration. If the tool were able to find another configuration, the variety of solutions will be higher and thus the curtailment would be different. In this case the values obtained are close. The adjustment made in the transformer taps and capacitor banks is not sufficient to made substantial changes in the curtailment of DRES values.

4.3.1.2 Interval Constrained Power Flow Results (ICPF)

The results obtained for the different test cases will be analysed in this section. They will be compared with each other in such a way that will allow to highlight the impact of different flexibility criteria in the construction of the flexibility cost maps. Moreover, all the simulations for the different scenarios will have as final goal the maximum flexibility area. As explained in section 4.1.1, two Portuguese networks will be tested with the ICPF tool. Therefore, the 6 test cases will be simulated for each one of the following networks:

- Northeast network
- Western network

In the following simulations, we consider that the transformers can vary their taps up to 2 positions from the current position. Moreover, only the wind parks will be responsible for the reactive power control and for generation power curtailment.

4.3.1.2.1 Northeast network

The characteristics of the northeast network were presented in sections 4.1.1.1 and 4.2.2.1. The results for each test case are presented in the following sections.

4.3.1.2.1.1 Status quo, short-term scenario 2 and short-term scenario 3

In this section the results obtained for the status quo and for the short-term scenarios will be analysed. The status quo is the baseline scenario and for this reason is characterized by the current characteristics of the network regarding the available generation and the demand that needs to be feed. The short term scenarios are characterized by 7.5% of demand growth and by a wind power increase of 11.9% and 14.3% for scenarios 2 and 3 respectively. Since there is no solar PV generators in this network, the description of their generation increase that is stated in 4.2.2.1 will not be considered. More details about these scenarios are presented in 4.2.2.1.

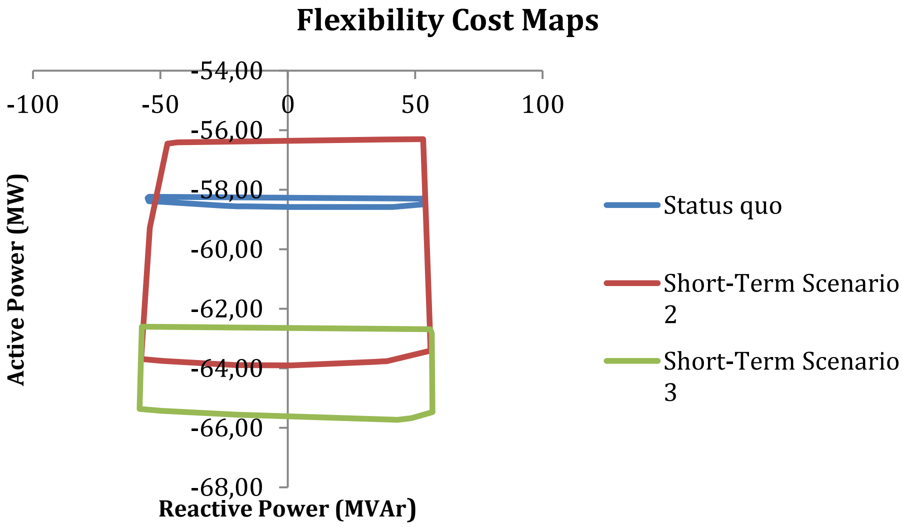


Figure 151 – Flexibility Cost Maps for the status quo and short-term scenarios.

Figure 151 shows the flexibility cost maps that were obtained for the three different scenarios. First of all, in all the scenarios the primary substation is consuming active power from the distribution network since the DRES presented in this network is clearly higher than the demand. The status quo scenario presents a considerable range of reactive power flexibility that is in accordance with the reactive power control provided by the wind parks, the transformer TAPs and the capacitor banks. However, not all the available reactive power flexibility is being used due to network constraints. Moreover, it seems that only the wind parks and the transformer TAPs are contributing for the reactive power control since the range of reactive power injection is similar to the range of reactive power consumption and, as we know, the capacitor banks are only capable of inject reactive power in the grid. The slight range of active power that can be observable in the status quo is only provided by the impact of transformer TAPs on the voltage since there are not interruptible consumers in the northeast network. Regarding the operating points of the short-term scenarios, they suffer an active power translation when compared with the one obtained for status quo since the wind power increase is clearly higher than the demand growth. This means that the primary substation will need to consume more active power from the distribution network. Another conclusion to be drawn from Figure 151 is related with the active power range presented by the short-term scenarios. Scenario 2 shows a flexibility area with an active power range clearly higher than the ones presented by status quo and scenario 3. According 4.2.2.1, scenario 2 is characterized by wind curtailment only for additional capacities in all the wind parks while in scenario 3 this type of flexibility is only available when the wind generation is higher than the original capacity. Since in scenario 3 only one Wind Park fulfills this requirement, it was expected that scenario 2 would present a higher margin of active power flexibility.

The flexibility area regarding these last simulations can be compared with the flexibility that the distribution network could provide in order to validate the obtained results.

Table 170 – Flexibilities available in the distribution grid of the northeast network

	Status Quo		Short-Term 2		Short-Term 3	
	P (MW)	Q(MVAr)	P (MW)	Q(MVAr)	P (MW)	Q(MVAr)
Demand Flexibiliy	-	-	-	-	-	-
WP Flexibility	-	185.25	7.39	206.74	2.61	211.74
Capacitor Banks	-	34	-	34	-	34
Total	0	219.25	7.39	240.74	2.61	245.74

Table 171 – Flexibility areas for the status quo and short-term scenarios

	Status Quo		Short-Term 2		Short-Term 3	
	P (MW)	Q(MVAr)	P (MW)	Q(MVAr)	P (MW)	Q(MVAr)
Flexibility Area	0.34	107.82	7.6	113.54	2.83	114.93

Table 170 and Table 171 show that the analysis that was made through Figure 151 is coherent with the available flexibility in the distribution network.

4.3.1.2.1.2 Mid-term scenario 4, mid-term scenario 5 and long-term scenario 6

In this section the results obtained for the mid and long term scenarios will be analysed. These scenarios are characterized by a higher increase of the wind power penetration and of the demand comparing with the previous ones. On the other hand, for these scenarios the wind power increase is still clearly higher than the demand growth. Thus, is once again expected a translation of the operating point. The mid-term scenarios are characterized by 18.9% of demand growth and by a wind power increase of 26.32% and 31% for scenarios 4 and 5 respectively. The long-term scenario allows a load growth of 37.7% while the wind power increases of 50.1%. More details about these scenarios are presented in 4.2.2.1.

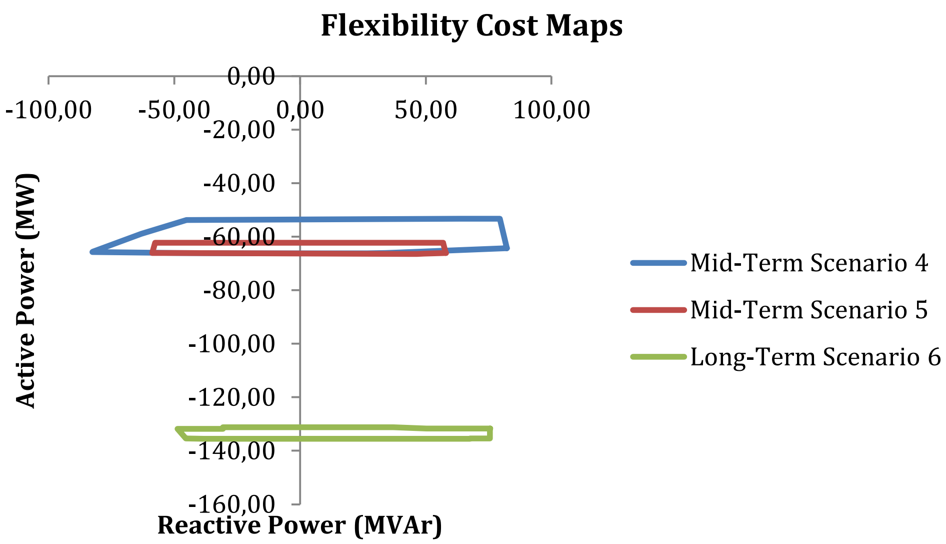


Figure 152 – Flexibility Cost Maps for the mid-term and long-term scenarios

Figure 152 shows, as expected, that the new flexibility areas suffered a translation when compared with the ones obtained for status quo and short-term scenarios. Therefore, these scenarios are characterized by a higher power flow from the distribution to the transmission network. Comparing these new flexibility areas between each other, some more conclusions can be drawn. The range of reactive power flexibility in these new scenarios increases slightly. The reason behind this growth can be related with the higher reactive power control provided by the wind parks, with the TAP variation or with the reactive power compensators. Figure 152 shows that this increase is correlated only with a higher injection of reactive power through the available types of flexibility. As we know, the capacitors bank are only capable of inject reactive power on the grid. Therefore, it seems that these devices are responsible for this behaviour. Table 172 and Table 173 show that not all the available reactive power flexibility is being used due to network constraints. Regarding active power flexibility, mid-term scenario 4 is clear the one that allows more wind power curtailment since it is characterized by a considerable increase of wind penetration and the curtailment is available for all the existing wind parks and new wind parks. Scenarios 5 and 6 are characterized by higher wind power penetrations than scenario 4, but the wind curtailment is only available when the wind generation is higher than the original capacity. Moreover, the flexibility areas of scenarios 5 and 6 present exactly the same active power flexibility. This is due to a requirement that is stated on WP1 test cases (see 4.2.2.1): "Up to +20% of the increase of wind generation will be represented by the increase of the installed capacity of existing wind parks. Additional need for wind capacity will be represented by new wind parks installed in the same area of the existing parks". Since the increase of wind power for these two scenarios is set on 20%, the addition capacity that is curtailed is exactly the same. Moreover, a situation of overload in some branches due to a significant increase of wind power penetration in the long-term scenario was surpassed by reinforce the maximum capacity of the power lines by 50%.

The flexibility areas presented in Figure 152 can be compared with the flexibilities that the distribution network could provide in order to validate the obtained results.

Table 172 - Flexibilities available in the distribution grid of the northeast network

	Mid-Term 4		Mid-Term 5		Long-Term 6	
	P (MW)	Q(MVAr)	P (MW)	Q(MVAr)	P (MW)	Q(MVAr)
Demand Flexibiliy	-	-	-	-	-	-
WP Flexibility	28	234	3.66	242.68	3.66	278
Capacitor Banks	-	34	-	34	-	34
Total	28	268	3.66	276.68	3.66	312

Table 173 - Flexibility areas for the mid-term and long term scenarios

	Mid-Term 4		Mid-Term 5		Long-Term 6	
	P (MW)	Q(MVAr)	P (MW)	Q(MVAr)	P (MW)	Q(MVAr)
Flexibility Area	12.94	164.9	3.87	116.76	3.81	124.5

Table 172 and Table 173 show that the analysis that was made is in accordance with the available flexibility in the distribution network.

4.3.1.2.1.3 Operational KPIs

In order to evaluate the performance of the ICPF tool, two Operational KPIs are calculated for the Portuguese networks: the flexibility area increase and the computational time reduction. Both KPIs were described in D3.3:

- The computational time reduction is the result of the comparison between the average time of the power flows that were ran in the Monte Carlo Simulation (MCS) and the average time of the OPF's that were obtained with the same program used to run the power flows in the MCS.
- The flexibility area increase was obtained using the ICPF. Therefore, the MCS has been run for 1000, 10000 and 100000 randomly extracted samples.

Table 174 – Operational KPIs for the northeast network

Scenario	Flexibility area increase (%)			Computational time reduction (%)		
	1 000 samples	10 000 samples	100 000 samples	1 000 samples	10 000 samples	100 000 samples
1	91.8293	75.6094	64.0509	27.4024	92.9494	99.2935
2	79.7726	64.9415	52.152	5.4369	90.6553	99.062
3	66.2776	46.0476	34.5623	30.4187	93.137	99.3094
4	80.9	66.5	55.1	35.3	93.6	99.4
5	59.6705	41.0083	34.408	35.1103	93.848	99.385
6	70.1	59.8	57.5*	-89.9	81.5	90.9*

*Results obtained using 20000 samples.

Table 174 shows that the ICPF tool allowed a clear increase of the size of the estimated flexibility area with respect to the MCS. This behaviour is related to the fact that the ICPF tool is able to identify the high and the low cost zones while the MCS not. Table 174 also shows that a considerable reduction in terms of computational was achieved. With these KPIs results it is proved that a solution that is able to provide the increase of the flexibility area in less computational time is possible. In other words, an effective output in a reasonable amount of time is provided by the ICPF.

4.3.1.2.2 Western network

The characteristics of the western network were presented in sections 4.2.1.1 and 4.2.2.1. The results for each test case are presented in the following sections.

4.3.1.2.2.1 Status quo, short-term, mid-term and long-term scenarios

Since the analysis of the obtained results will have similarities with the explanation that was provided for the northeast network, all the scenarios will be presented in Figure 153. First of all, this network is characterized by a demand that is higher than the power provided by the DRES. This observation will have important implications in the following analysis since the transmission network will need to inject power in order to feed the demand, which is the opposite behaviour that was presented for the northeast network. More details related with the wind power, solar PV and demand increase throughout the scenarios are described in 4.2.2.1, 4.3.1.2.1.1 and 4.3.1.2.1.2.

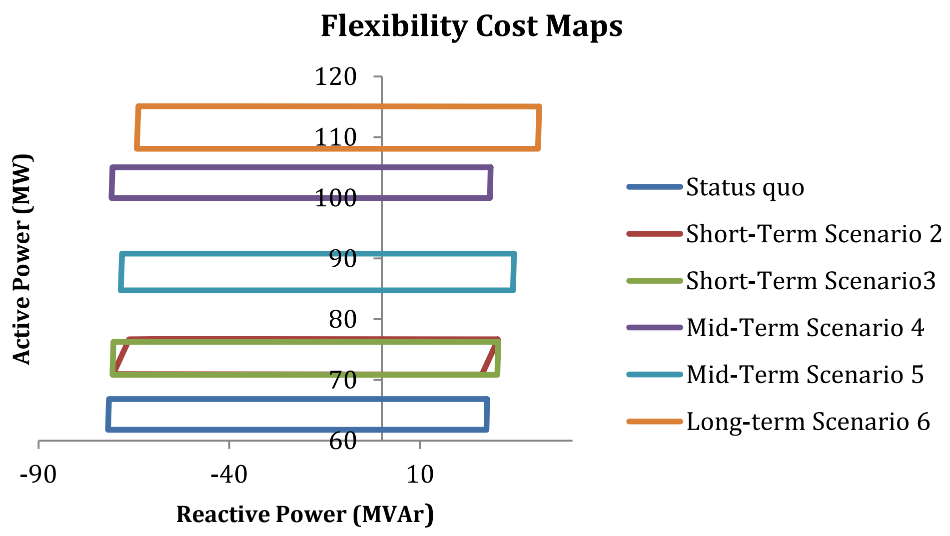


Figure 153 – Flexibility Cost Maps for the test cases of the Western network

Figure 153 shows that the status quo has a flexibility area with considerable ranges of active and reactive power. As well as for the northeast network, the reactive range of flexibility is provided by the reactive power control of the wind parks, by the transformer TAPs and by the reactive power compensators. On the other and contrary to what happens in the northeast network, the western one is composed by three interruptible consumers which explain the range of active power in this flexibility area. Moreover, this flexibility area shows that the network constraints are far from their limits since the flexibility provided in the distribution network is being totally used. This is also a contrast when comparing with the northeast network. This analysis can be validated in Table 175 and Table 176. The short-term scenarios follow the same demand growth, but scenario 3 has a higher increase of wind power penetration and solar PV. Figure 153 shows that the flexibility areas obtained for the short-term scenarios suffered an active power translation when compared with the status quo. This is explained by a higher increase of the demand comparing with the DRES growth which led to a translation of the operating point. Therefore, in these scenarios the transmission network needs to inject more active power in the distribution grid in order to fulfil the demand requirements. Moreover, the operating point of scenario 2 has a slightly higher value of active power comparing with scenario 3 due to the slight increase of the distributed generation in this last one. Both short-term scenarios present a higher range of reactive power flexibility since they are characterized by an increase of the installed wind capacity. The differences in terms of active power flexibility between the short-term scenarios are explained by the number of wind parks in which the wind curtailment is available. Considering the flexibility criteria presented in 4.2.2.1, scenario 2 is the only that allows to curtail wind power in all the wind parks. The mid-term scenarios present also an active power translation of the operating points. The reason behind this behaviour is once again related with a higher increase of the demand when compared with the distributed generation increase. Figure 153 also shows that in scenario 5 the transmission network needs to inject less active power in the distribution network than in scenario 4 in order to feed the demand. This is related with the fact that both scenarios are characterized for the same demand increase however scenario 5 follows a higher growth of the wind power penetration and solar PV. Regarding the active power flexibility range in both flexibility areas, they are similar since the interruptible consumers are the main source of this flexibility (the wind curtailment provided by the wind parks is almost insignificant since the wind penetration is low). In terms of reactive power flexibility, scenario 5 presents a higher margin since the increase of installed wind capacity is higher in this test case. The analysis for the long-term scenario is similar to the previous ones. The higher increase of the demand leads to the translation of the operating point. Moreover, the increase of the interruptible consumer allows a higher active power flexibility when compared with the previous scenarios. On the other hand, the increase of the installed wind power capacity had as consequence a higher margin of reactive power flexibility.

The flexibility areas presented in Figure 153 can be compared with the flexibilities that the distribution network could provide in order to validate the obtained results.

Table 175 – Flexibilities available in the distribution network

	Status Quo		Short-Term 2		Short-Term 3		Mid-Term 4		Mid-Term 5		Long-Term 6	
	P (MW)	Q(MVAr)	P (MW)	Q(MVAr)	P (MW)	Q(MVAr)	P (MW)	Q(MVAr)	P (MW)	Q(MVAr)	P (MW)	Q(MVAr)
Demand Flexibiliy	5.05	0.5	5.43	0.53	5.43	0.53	6	0.59	6	0.59	6.95	0.68
WP Flexibility	-	11.25	0.35	12.59	-	12.86	0.77	14.2	-	14.74	-	16.89
Capacitor Banks	-	87.6	-	87.6	-	87.6	-	87.6	-	87.6	-	87.6
Total	5.05	99.35	5.78	100.72	5.43	100.99	6.77	102.39	6	102.93	6.95	105.17

Table 176 – Flexibility areas for all the test cases

	Status Quo		Short-Term 2		Short-Term 3		Mid-Term 4		Mid-Term 5		Long-Term 6	
	P (MW)	Q(MVAr)	P (MW)	Q(MVAr)	P (MW)	Q(MVAr)	P (MW)	Q(MVAr)	P (MW)	Q(MVAr)	P (MW)	Q(MVAr)
Flexibility Area	5.08	99.38	5.81	100.8	5.46	101.1	5.08	99.38	6.04	103.09	6.96	105.48

Table 175 and Table 176 show that the simulations that were ran by the ICPF tool lead to coherent results.

4.3.1.2.2.2 *Operational KPIs*

The two Operational KPIs that are presented in table allow to validate the effectiveness of the ICPF tool. Tabe x shows the increase of the size of the estimated flexibility area with respect to the Monte Carlo Simulation. The ICPF tool is thus able to identify the high and the low cost zones. Moreover, a considerable reduction in terms of computational was also achieved. Thus, the increase of the flexibility area in less computational time is possible.

Table 177 – Operational KPIs for the Western network

Scenario	Flexibility area increase (%)				Computational time reduction (%)			
	1 000 samples	10 000 samples	100 000 samples	1000000 samples	1 000 samples	10 000 samples	100 000 samples	1000000 samples
1	70.8221	62.8475	55.4958	50.2768	68.8617	97.0156	99.7829	99.9794
2	70.8461	63.5458	55.4723	50.0935	59.0988	96.0756	99.6985	99.9692
3	71.186	63.171	55.867	50.464	67.6834	96.9774	99.7399	99.9736
4	71.2446	60.841	56.187	49.112	75.091	97.736	99.7608	99.9758
5	67.356	62.144	54.921	50.2394	69.42	97.234	99.7011	99.9694
6	67.458	62.51	55.22	50.9482	81.697	98.075	99.788	99.9784

4.3.2 Results for France

4.3.2.1 Sequential Optimal Power Flow (SOPF)

In the next sections the global results will be presented for 14 simulations made for each network, considering the seven WP1 scenarios and the two sub scenarios (winter and summer). In the Table 178 it is possible to see the initial and final state of several variables along the temporal series of 24 periods for the status quo winter scenario using the Network 5. The analogous results for other scenarios using the Network 5 and Network 6 can be seen in ANNEX IV – Additional Results for TSO-DSO Cooperation Domain. Thus, for each period it is possible to analyse the following data results:

- InitTotLoss (P) – Total active power losses in the initial state of the network before running the optimization (kW);
- InitTotLoss (Q) - Total reactive power losses in the initial state of the network before running the optimization (kVAr);
- FinalTotLoss (P) – Total active power losses in the final state of the network after running the optimization (kW);
- FinalTotLoss (Q) - Total reactive power losses in the final state of the network after running the optimization (kVAr);
- PowerGen (P) – Total active power generated in all network (MW);
- PowerGen (Q) – Total reactive power generated in all network (MVAr);
- Cost (€) – Total flexibility costs considering penalties for power values out of boundaries, for activation of flexible loads or generators and for changing transformer taps;

- N1sync02 (P) to N2sync06 (P) – Generated Active power of wind generator (for MV network 5) (MW);
- SyncPe01 (P) – Generated active power of the generator used to simulate the penetration of wind power (for MV network 6)(MW);
- FlexL… (P) – active power generated by a fictitious generator that simulates a flexible load. If this value is positive it means that a load decrease occurs. (MW);
- Flexsc.. (P) – active power generated by a fictitious generator that modelled the wind curtailment. (MW);
- RHTB0001 (Pinit) and RHTB0002 (Pinit) – Injected active power by the primary substation in the initial state of the network before the optimization (MW);
- RHTB0001 (Pfinal) and RHTB0002 (Pfinal) - Injected active power by the primary substation in the final state of the network after the optimization (MW);
- RHTB0001 (Qinit) and RHTB0002 (Qinit) – Injected reactive power by the primary substation in the initial state of the network before the optimization (MVAr);
- RHTB0001 (Qfinal) and RHTB0002 (Qfinal) - Injected reactive power by the primary substation in the final state of the network after the optimization (MVAr);
- Nt1Tr001 (tap) to Nt2Tr004 (tap) – Final tap position of the transformer (for MV network 5);
- Nt1Tr001 (tap) to Nt2Tr005 (tap) – Final tap position of the transformer (for MV network 6).

The first comment of the global results is about the reconfiguration of the network. In both MV networks were not possible to find an alternative configuration. The MV network 5 has initially only 17 switches opened (total are 394 switches) and 4 of them are not controllable. The MV network 6 has initially only 8 switches opened (total are 155 switches) and 2 of them are not controllable.
The fact the tool cannot find an alternative configuration is explained by different reasons. The SOPF tool searches for initially open switches in the network and then, if it is feasible, tries to change the configuration by closing this switch and opening another in the same loop. In the tests we made, the tool cannot find this kind of opened loops in the networks at the beginning of the process. Besides, the freedom of changing the states of the switches depends on its operability as well. In any case, we could interpret this situation as an initial configuration already optimized.

4.3.2.1.1 Results for MV network 5 - Winter

Taking into account the several periods of the day, the season of the year, the initial state of the network, the available flexibilities, the penetration of wind generation and the evolution of consumption, all these factors could contribute for different results along the tested scenarios.

For instance, the comparison of the results for “MV network 5 Winter Scenario 1” with the “MV network 5 Scenario 2” reveals the significance of the flexibilities existence. We can

observe that the two flexible loads (FlexL063 and FlexL169) are activated in the periods where the cost is higher in the “MV network 5 Winter Scenario 1” reducing the consumption and the total costs. This happens because the price DSO has to pay to activate the flexible loads is less than the penalties for exceeding the power limits in primary substations. It is important to note that in the “MV network 5 Scenario 2” the Wind generation is 34.6% higher than in the “MV network 5 Scenario 1” which contributes to the injected power by the primary substations to be reduced.. On the other hand, the demand is also higher in the second scenario but the maximum injected power at primary substations is also increased.
With this example it is possible to see what happens in the periods with higher load. In the “MV network 5 Scenario 2”, the primary substation RHTB0001 injects the maximum power (70.46 MW). Then the flexible loads (FlexL063 and FlexL169) that are fed by this primary substation reduce their power. In this case the maximum reduction of the load combined with the maximum power of primary substation is not sufficient to feed all the loads. Thus, the amount of power that is missing is injected by the primary substation. That’s why in the “MV network 5 Scenario 2” RHTB0001 injects active power (71.14 MW) above it maximum.
For some simulations using the MV network 5-winter scenario, we obtained results with apparent power superior to limits at some branches, namely in the scenario 4, 5, 6 and 7 and mostly in the power transformers.

Table 178 – Network 5 winter scenario 1.

Period	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
InitTotLoss (P)	1529.65	1590.763	1393.26	1086.929	985.6607	929.7854	1027.24	1356.072	1588.969	1224.811	994.5811	1067.347	1170.8	1014.773	809.293	689.0172	638.3159	747.9197	1384.762	1397.203	1053.596	858.8829	599.3516	1485.661
InitTotLoss (Q)	17650.66	19499.44	14776.7	10033.11	8495.15	7493.988	8344.816	14916.64	18659.92	11074.81	6589.694	7394.335	7874.451	5774.908	3891.852	2590.229	2230.862	3616.179	14119.43	13534.02	7809.193	5512.149	1308.71	18158.62
FinalTotLoss (P)	1172.043	1217.785	1076.827	862.3416	786.1359	743.5238	827.9607	1054.415	1210.57	1002.717	821.5219	877.486	937.7465	845.0267	679.5999	584.1922	540.7446	631.1406	1069.171	1077.092	856.6481	719.6423	515.754	1145.014
FinalTotLoss (Q)	11673.77	13075.93	9819.057	5976.918	4772.252	4072.348	5415.536	9996.7	12734.91	8491.216	4603.644	5378.509	5406.822	4231.096	2316.954	1106.337	654.193	1989.986	9397.626	8957.657	5262.944	3582.676	20.57042	12087.5
PowerGen (P)	114.5491	118.0821	104.932	95.55349	89.44083	85.29497	84.52414	103.7964	111.9477	92.53185	78.13972	80.1653	80.94741	74.12113	68.54878	63.77726	62.23251	68.2892	102.6111	100.8644	84.62809	77.14568	58.71135	116.9794
PowerGen (Q)	45.49153	47.72444	41.01881	34.49524	31.55796	29.71507	31.02265	40.85377	45.90247	36.53381	28.77096	30.13754	30.49942	27.30914	23.67246	21.02818	20.04899	23.17665	40.20219	39.32101	31.05428	27.11786	18.30048	46.34163
Cost (€)	10124.45	13394.7	5811.307	1854.943	527.0095	3	331.9913	5706.139	11015.74	3037.258	3	430.3755	822.7812	6	6	3	6	6	5279.093	4695.568	762.7512	3	0	10919.58
N1sync02 (P)	0.3298	0.279748	0.201178	0.369337	0.294608	0.251463	0.093392	0.107786	0.079036	0.093392	0.107786	0.079036	0.079036	0.093392	0.136537	0.158071	0.143715	0.153182	0.181933	0.189111	0.217862	0.217862	0.203467	0.364448
N1sync03 (P)	0.9639	0.817614	0.587979	1.079455	0.861046	0.734945	0.272954	0.315025	0.230996	0.272954	0.315025	0.230996	0.230996	0.272954	0.399055	0.461992	0.420034	0.447703	0.531733	0.552712	0.636741	0.636741	0.59467	1.065166
N1sync05 (P)	0.44285	0.375641	0.270139	0.49594	0.395595	0.33766	0.125405	0.144734	0.106128	0.125405	0.144734	0.106128	0.106128	0.125405	0.18334	0.212255	0.192978	0.205691	0.244297	0.253935	0.292542	0.292542	0.273212	0.489375
N1sync01 (P)	1.071	0.90846	0.65331	1.199394	0.956718	0.816606	0.303282	0.350028	0.256662	0.303282	0.350028	0.256662	0.256662	0.303282	0.443394	0.513324	0.466704	0.497448	0.590814	0.614124	0.70749	0.70749	0.660744	1.183518
N1sync04 (P)	0.867	0.73542	0.52887	0.970938	0.774486	0.661062	0.245514	0.283356	0.207774	0.245514	0.283356	0.207774	0.207774	0.245514	0.358938	0.415548	0.377808	0.402696	0.478278	0.497148	0.57273	0.57273	0.534888	0.958086
N2sync06 (P)	3.4272	2.907072	2.090592	3.838061	3.061498	2.613139	0.970502	1.12009	0.821318	0.970502	1.12009	0.821318	0.821318	0.970502	1.418861	1.642637	1.493453	1.591834	1.890605	1.965197	2.263968	2.263968	2.114381	3.787258
RHTB0001 (Pinit)	72.52046	74.84223	68.15734	60.00755	56.95038	54.86895	56.32878	67.75502	73.38727	61.74843	52.9892	54.74387	55.92097	51.27572	46.57289	42.9353	41.77187	45.72532	67.07968	66.30603	55.80097	50.56092	39.12351	72.84402
RHTB0001 (Pfinal)	72.22392	74.53732	67.88775	59.82277	56.78217	54.70925	56.15913	67.5053	73.07305	61.5626	52.83825	54.57804	55.71128	51.12433	46.4583	42.84305	41.68682	45.62393	66.80877	66.02713	55.62842	50.44137	39.04922	72.57329
RHTB0001 (Qinit)	35.87614	37.27562	32.26704	27.08051	24.81195	23.37349	23.93608	31.43219	35.55785	27.58763	22.24448	23.28642	24.34654	21.46212	18.54341	16.44643	15.63018	17.91776	31.5585	31.21456	24.31248	20.89167	14.49261	35.90034
RHTB0001 (Qfinal)	31.21142	32.36719	28.24268	23.84985	21.83744	20.55664	21.52615	27.47133	30.82591	25.65839	20.63163	21.68542	22.27957	20.21753	17.2067	15.15287	14.24236	16.53657	27.65543	27.38922	22.18798	19.29453	13.33434	31.24221
RHTB0002 (Pinit)	35.28383	37.58808	32.75863	27.8172	26.34587	25.19729	26.38347	34.02169	37.23629	28.99428	23.00248	23.90929	23.55743	21.00406	19.16544	17.54297	17.46353	19.38209	31.92901	30.8059	24.3326	22.03262	15.28913	36.62761
RHTB0002 (Pfinal)	35.22343	37.52086	32.71216	27.7776	26.31471	25.17084	26.35396	33.97006	37.17273	28.9582	22.98045	23.88535	23.53422	20.98576	19.15036	17.53038	17.451	19.36672	31.88467	30.76503	24.30833	22.01298	15.28077	36.5583
RHTB0002 (Qinit)	15.59146	16.87111	13.70806	11.47464	10.47306	9.767404	10.02104	14.34037	16.26727	11.52918	8.517105	8.866682	8.620125	7.395014	6.707242	6.068506	5.997869	6.888255	13.36432	12.68168	9.293314	8.159649	5.094907	16.51065
RHTB0002 (Qfinal)	14.28011	15.35725	12.77613	10.64539	9.720518	9.158435	9.496498	13.38244	15.07656	10.87542	8.139326	8.45212	8.219852	7.091614	6.465762	5.875313	5.806637	6.640085	12.54675	11.93179	8.866305	7.823335	4.966138	15.09942
Nt1Tr002 (tap)	6	6	6	7	7	7	5	7	6	3	3	3	4	2	3	4	5	4	6	6	4	4	4	6
Nt1Tr001 (tap)	6	6	6	7	7	7	5	6	6	2	3	2	3	2	3	3	4	3	6	6	4	3	3	6
Nt2Tr003 (tap)	6	6	14	8	8	11	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	7
Nt2Tr004 (tap)	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17

4.3.2.1.1.1 Operational KPI for MV network 5 - winter

Figure 154 resumes the variation along the periods of total active power losses between the initial solution and the optimized one for each WP1 scenario. It shows that the hours with more consumption are the hours when the tool manages to reduce more the active losses, because the initial solution is, at these hours, worse than others. It can be seen that in the first scenarios, the network had less capacity to reduce the active losses because it has less flexible resources and wind generation which can control active power more close to the load nodes. Moreover, the initial power losses in other scenarios were already higher due the higher consumption and generation, so it is possible to reduce more losses in these scenarios.

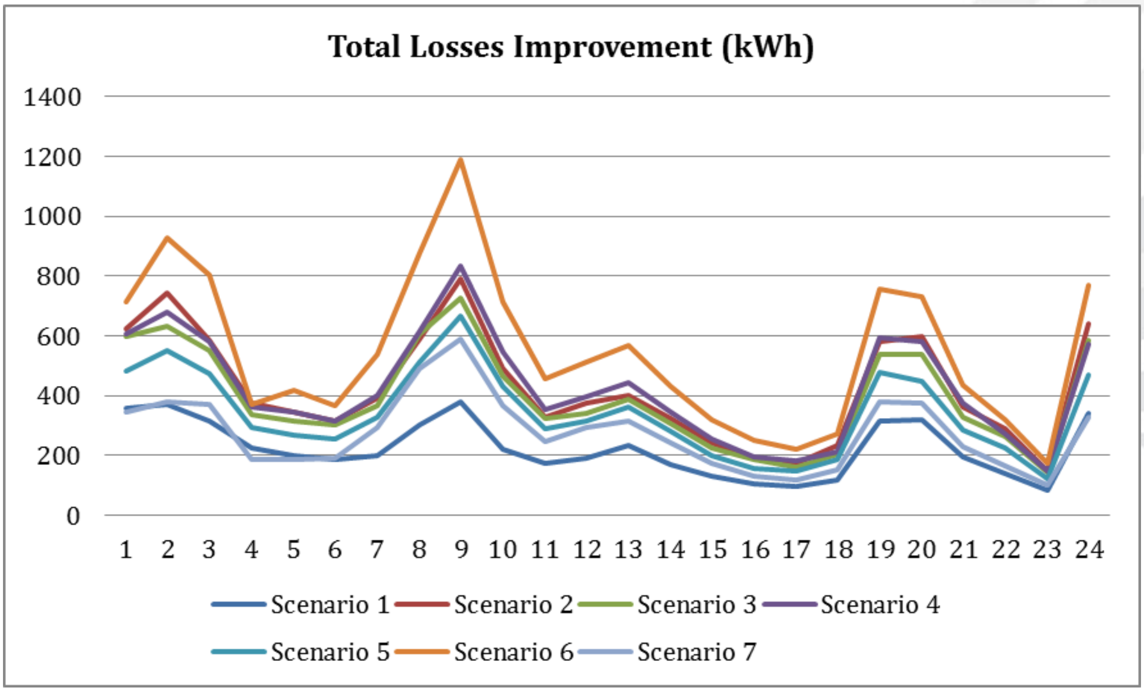


Figure 154 - Total losses improvement (kWh) for network 5 in winter

Table 179 presents the total values for power losses for network 5 in the winter.

Table 179 – Total values of active power losses (MW) of network 5-winter.

Scenario	Total initial power Losses (kWh)	Total final power Losses (kWh)	Total improvement (kWh)	Improvement (%)
1	26624.64	21255.09	5369.54	20.2%
2	35521.48	25370.38	10151.09	28.6%
3	33155.86	23714.40	9441.46	28.5%
4	36324.43	26102.72	10221.71	28.1%
5	31495.73	23264.98	8230.75	26.1%
6	47549.40	34406.18	13143.22	27.6%
7	31829.31	25166.68	6662.64	20.9%

Figure 155 shows the sum of the distances of the injected active power by the two primary substations to the active power limits of the primary substations. It is possible to see that these distances come along with load power profile. The scenario 6 presents the larger distance to the limits because it is a scenario that combines high wind power generated with flexible resources and reduced consumption in relation to the basis scenario.

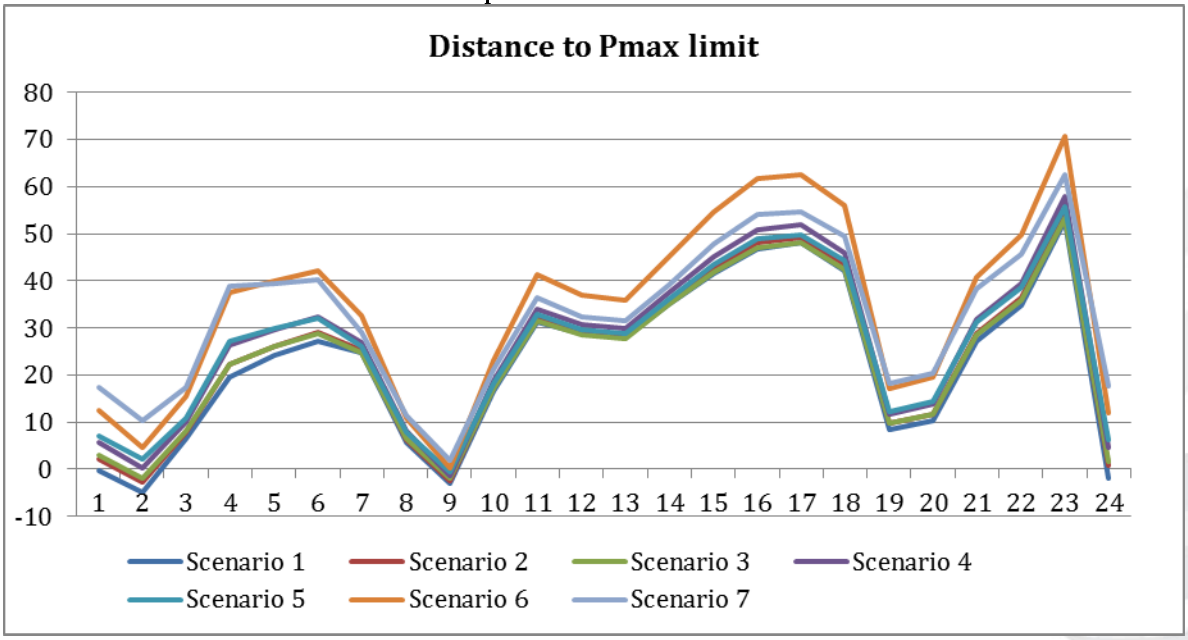


Figure 155 - Distance to the active power limits (MW) for network 5 in winter

Since all the scenarios have results with an injected active power above the minimum, it is not worth to analyse the distance to the minimum active power limit. This distance corresponds to the actual injected active power by the two substations. Figure 156 shows the sum of distances of the injected reactive power by the two substations to the reactive power upper limit. In some periods the reactive power is above its maximum which made the solution penalized by reactive costs.

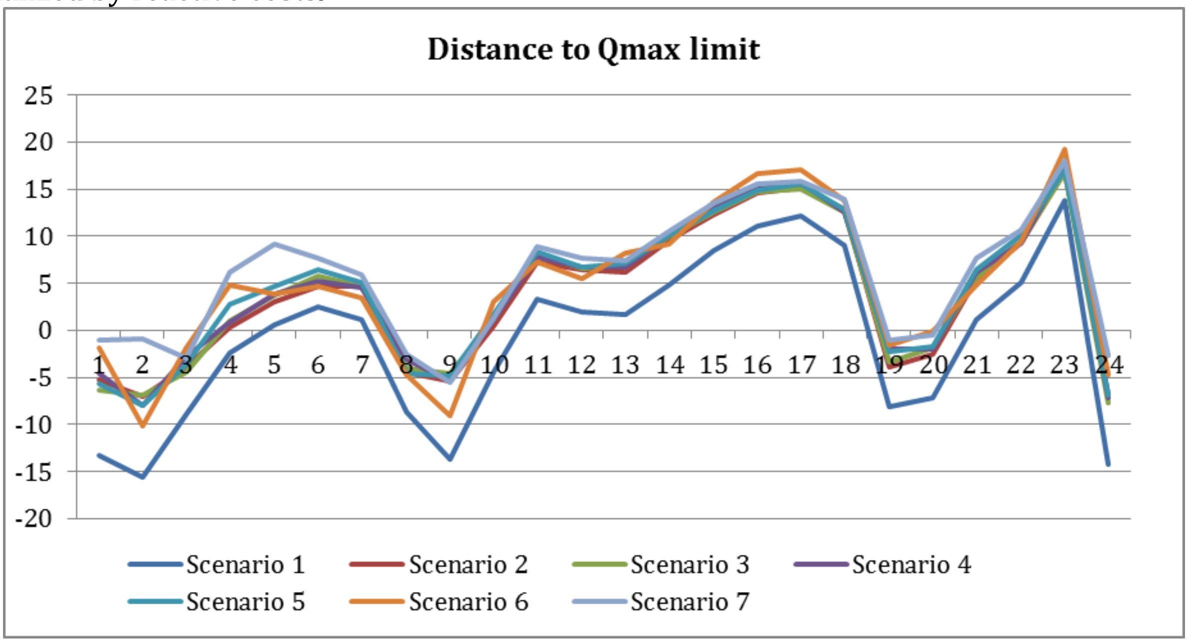


Figure 156 - Distance to the reactive power upper limits (MVAr) for network 5 in winter

Figure 157 shows the distances of the reactive injected power to the lower limit along the periods for all the seven scenarios. It can be observed that the values are all positive which means that the transmission network is injecting reactive power instead of consuming.

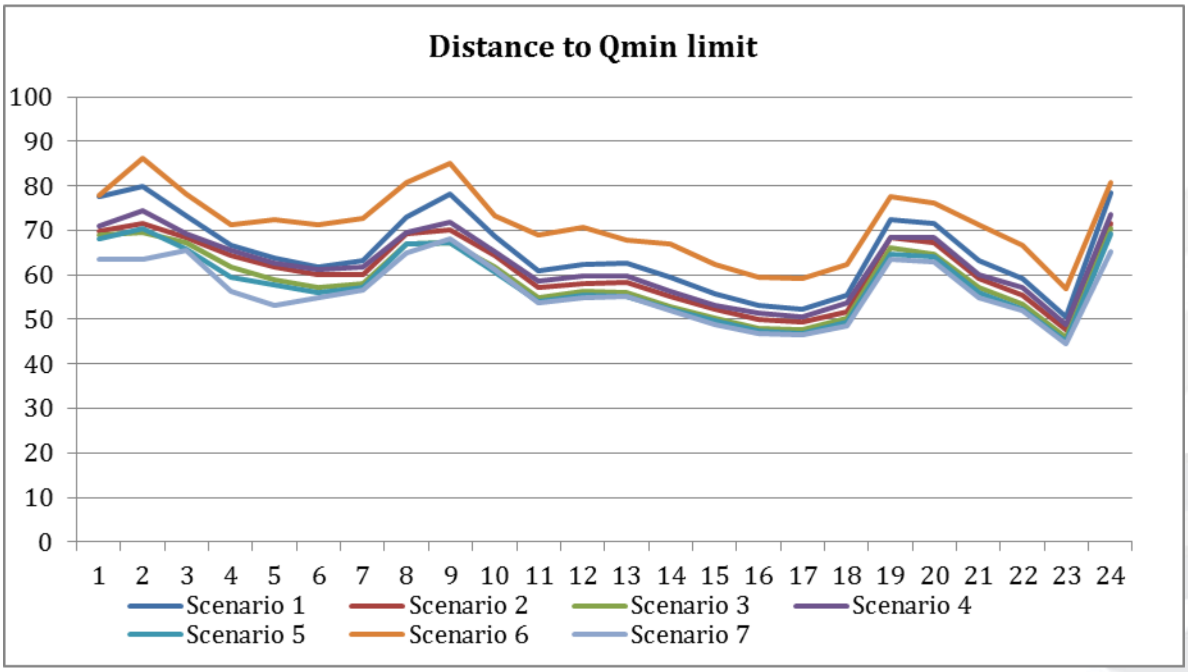


Figure 157 - Distance to the reactive power under limits (MVAr) for network 5 in winter

Figure 158 resumes the total costs obtained for simulations using MV network 5 in the winter scenario. We can see that in the peak hours the cost has the tendency to be higher due to the power congestion of the substations. The total costs in the figure do not contain the cost contribution of the transformer taps changing, but this contribution is very small when compared with the rest of the costs.

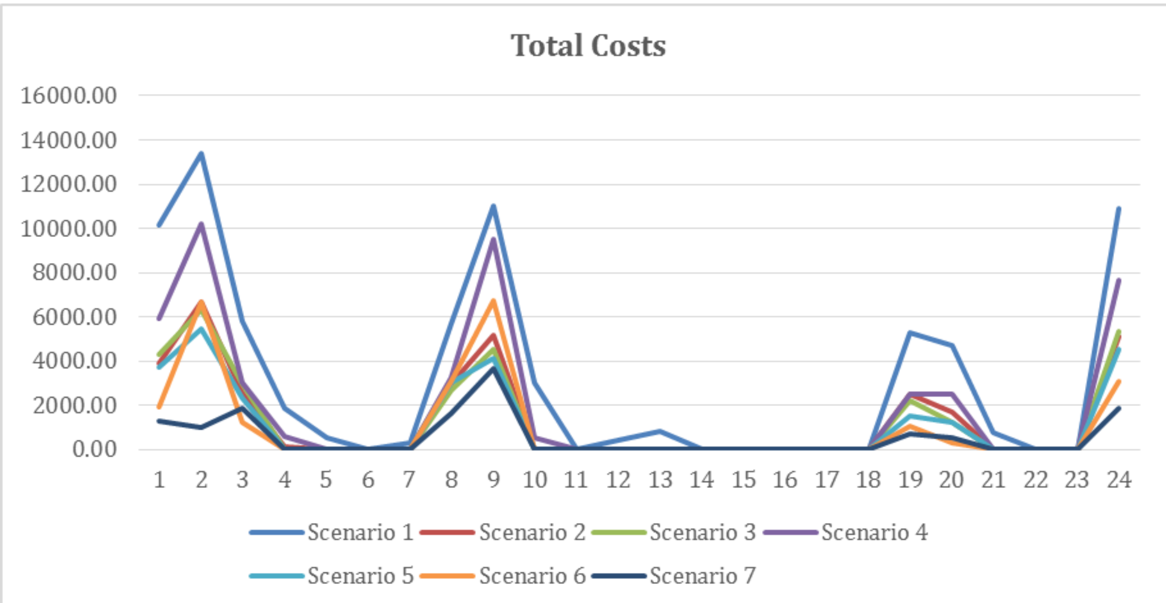


Figure 158 – Total costs (€) for network 5 in winter

Table 180 shows the total costs of the network 5 during the winter period.

Table 180 – Total costs (€) of network 5-winter.

Scenario	Total costs
1	74647.70
2	30733.83
3	29561.90
4	45676.15
5	25873.27
6	24018.78
7	12584.75

The sum of energy curtailment of RES for these simulations was always equal to zero, because the minimum of injected active power by the substations has never been violated. This situation occurs for all the simulations using all the networks. A definition of a tighter minimum value of injected power by the substations could cause different results.
Figure 159 resumes the wind power generated along the periods for every scenario taking into account the MV network 5-winter. The evolution of wind power follows the profile of wind power previously specified on Figure 133.

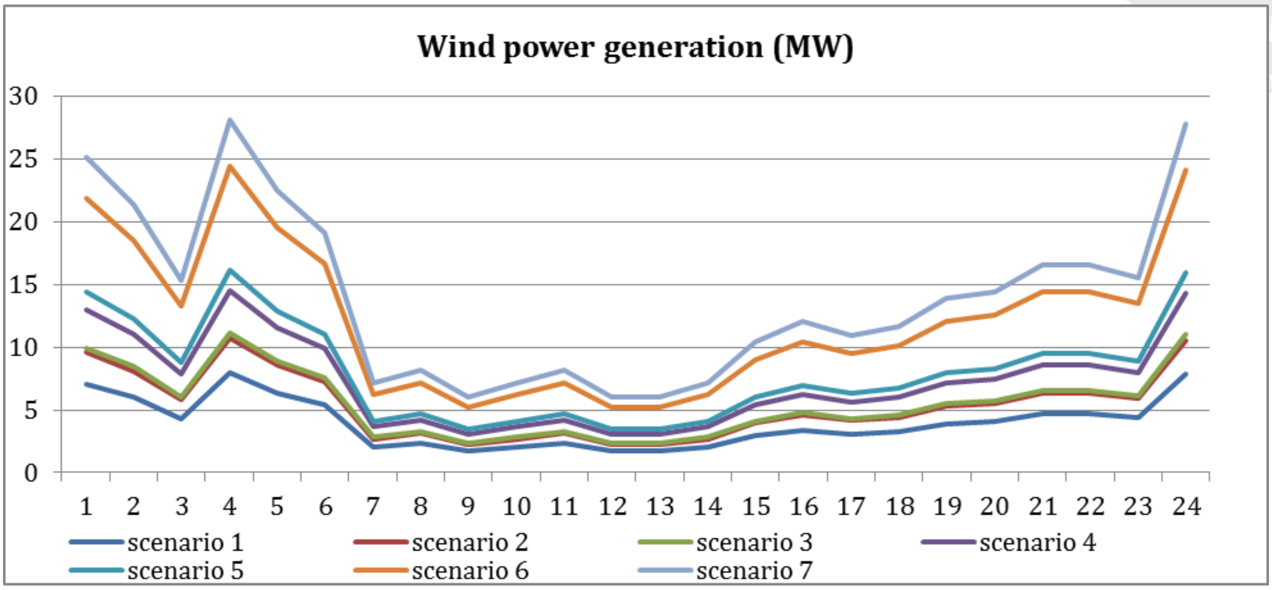


Figure 159 – Total wind power generated (MW) for network 5 in winter

4.3.2.1.2 Results for MV network 5 – Summer

The tables of the results for MV network 5 using the input data associated to summer season (see in ANNEX IV – Additional Results for TSO-DSO Cooperation Domain) showed that, using the data of the summer causes a relief in the network because it has significant less consumption. Thus, the cases where the flexible resources had to be activated are smaller

than in the previous case. The main reasons for these costs are due to the crossover of the injection of the reactive power limits. An improvement of the active power losses comes mainly from changing the transformer taps. Note that the optimization searches for a solution with less flexible costs, but in the end runs a fuzzy algorithm only to make the voltage and reactive power control. So, in some cases the solution founded has no flexibility costs, but by running the voltage var control in the end to minimize the losses, the cost of changing some taps are summed to the final cost.
For some of simulations using the MV network 5- summer we obtained results with apparent power superior to limits at some branches, namely in the scenario 6 and 7 and mostly in the power transformers. Besides, the transformer Nt2Tr003 exceeds the apparent power along all scenarios.

4.3.2.1.2.1 Operational KPI for MV network 5 - Summer

Figure 160 shows the total active power losses improvement for the simulations made with MV network 5 in the summer season. Like the previous results we can see that the higher variation happens in the scenario with more consumption. Again, the figure shows that the curve of total losses variation goes along with the load profile.

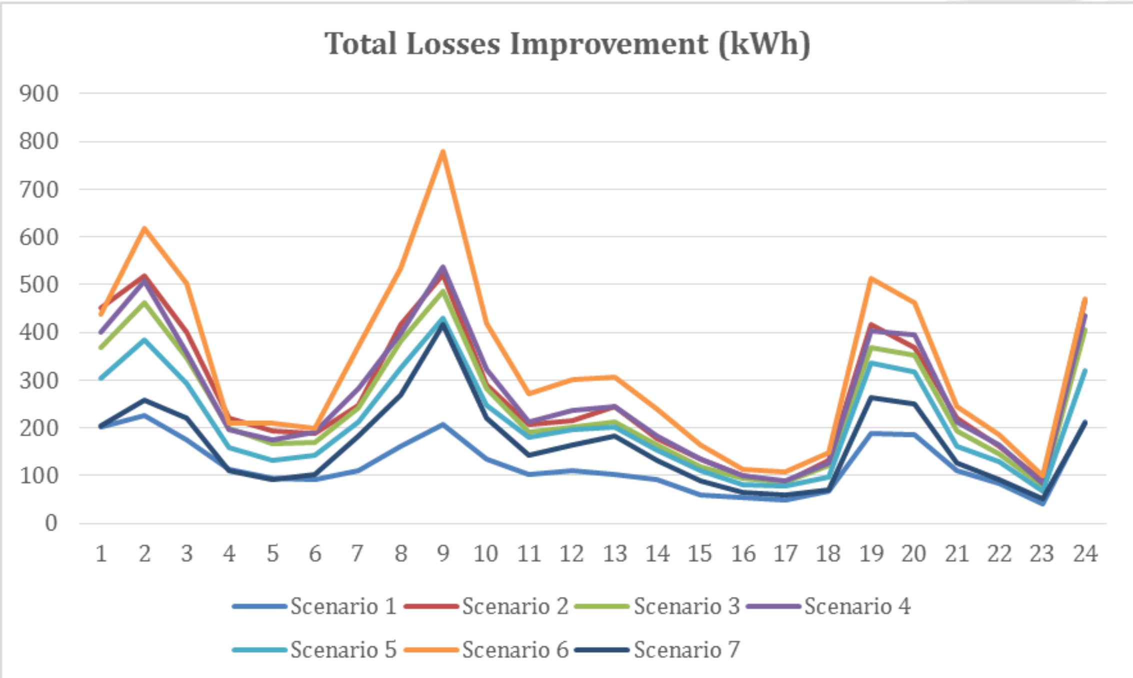


Figure 160 - Total Losses improvement (kWh) for network 5 in the summer

Table 181 resumes the total values of active power losses for network 5 in summer.

Table 181 – Total values of power losses for network 5 - summer

Scenario	Total initial power Losses (kWh)	Total final power Losses (kWh)	Total improvement (kWh)	Improvement (%)
1	17057.15	14080.81	2976.34	17.4%
2	23048.19	16570.87	6477.32	28.1%

3	21584.04	15742.35	5841.69	27.1%
4	23736.78	17346.47	6390.31	26.9%
5	20739.43	15675.62	5063.81	24.4%
6	31226.61	23319.46	7907.15	25.3%
7	22431.18	18456.34	3974.83	17.7%

Figure 161 shows the sum of the distances of the active power injected by the substations to their upper limits. Like before, there are some distances with negative values which means these solutions are being penalized with active costs.

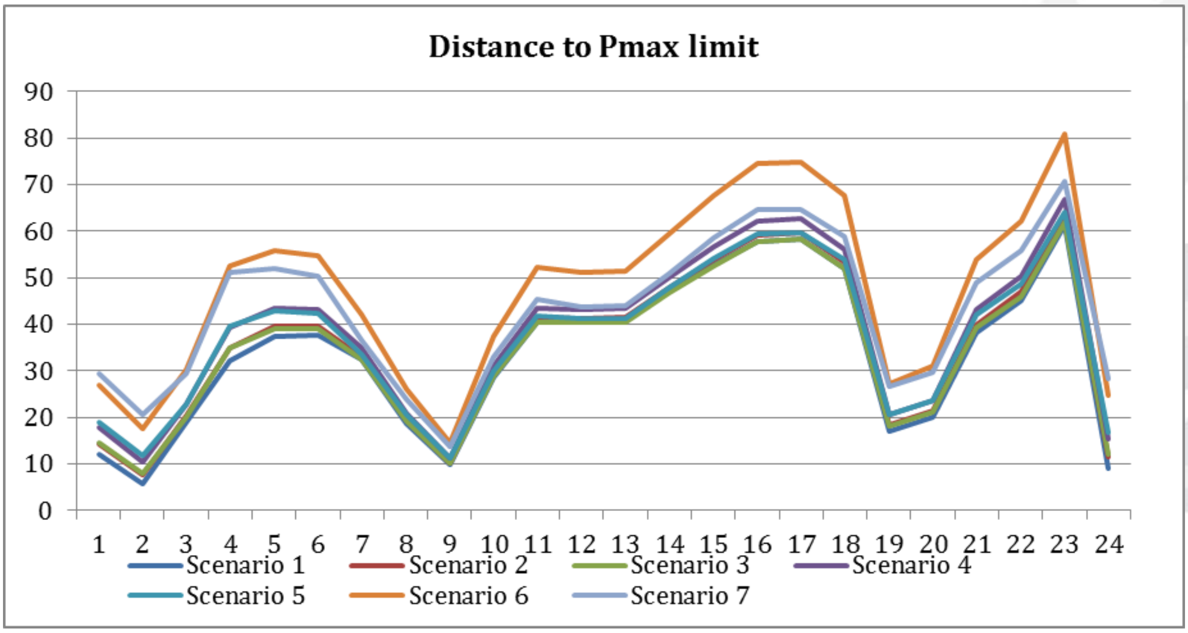


Figure 161 – Distance to the active power upper limits (MW) for network 5 in the summer

Figure 162 shows the sum of the distances of the reactive power injected by the primary substations to their upper limits. We can see that the reactive distances come along with the distances to the active power upper limits.

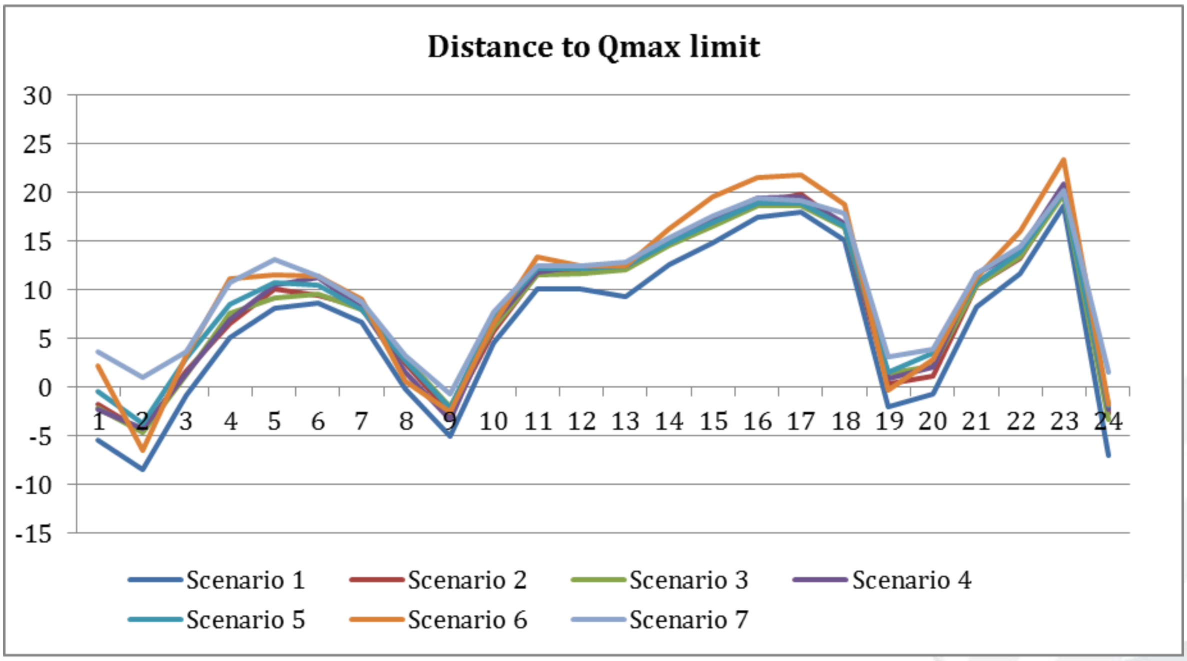


Figure 162 – Distance to the reactive power upper limits (MVAr) for network 5 in the summer

Figure 163 resumes the sum of the distances of the reactive power injected by the primary substations to the under reactive power limits. Once again the values are all positives which can mean that the primary substations are probably injecting reactive power.

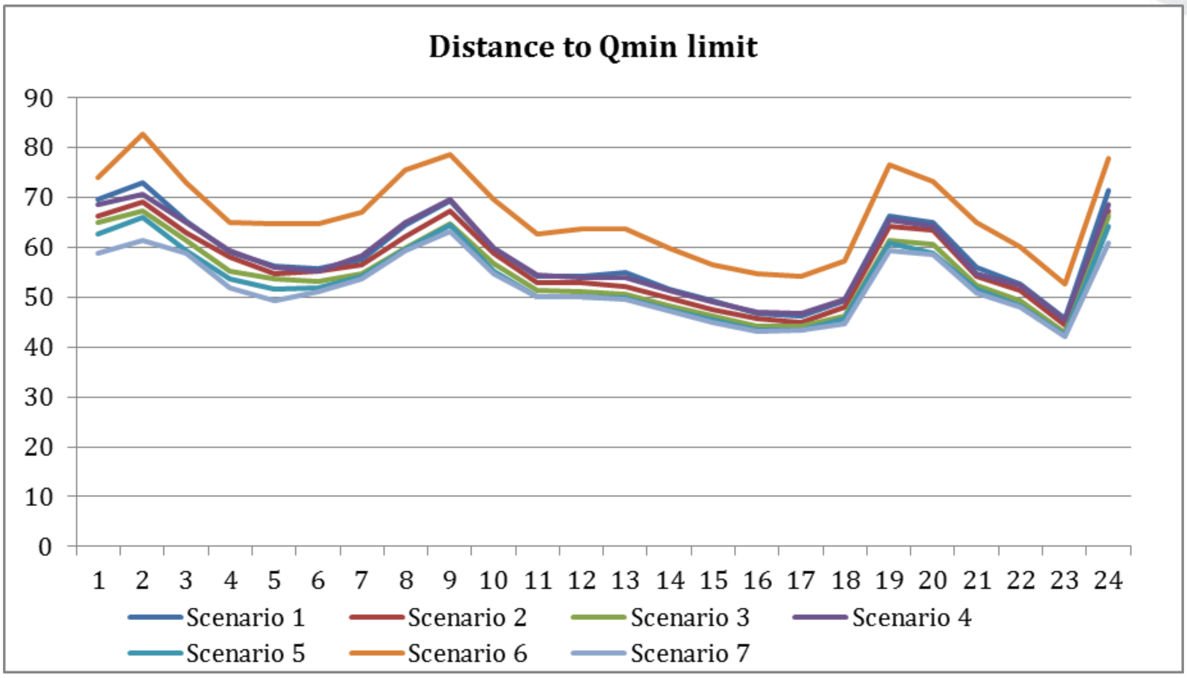


Figure 163 – Distance to the reactive power under limits (Mvar) for network 5 in the summer

Figure 164 resumes the total costs for MV network 5 with the summer sub scenario. We can see that in the peak hours the costs raise, but in general in the summer the substations have less power congestions which leads to lower costs. Once again, the costs indexed to changing of transformer taps are not included in this image.

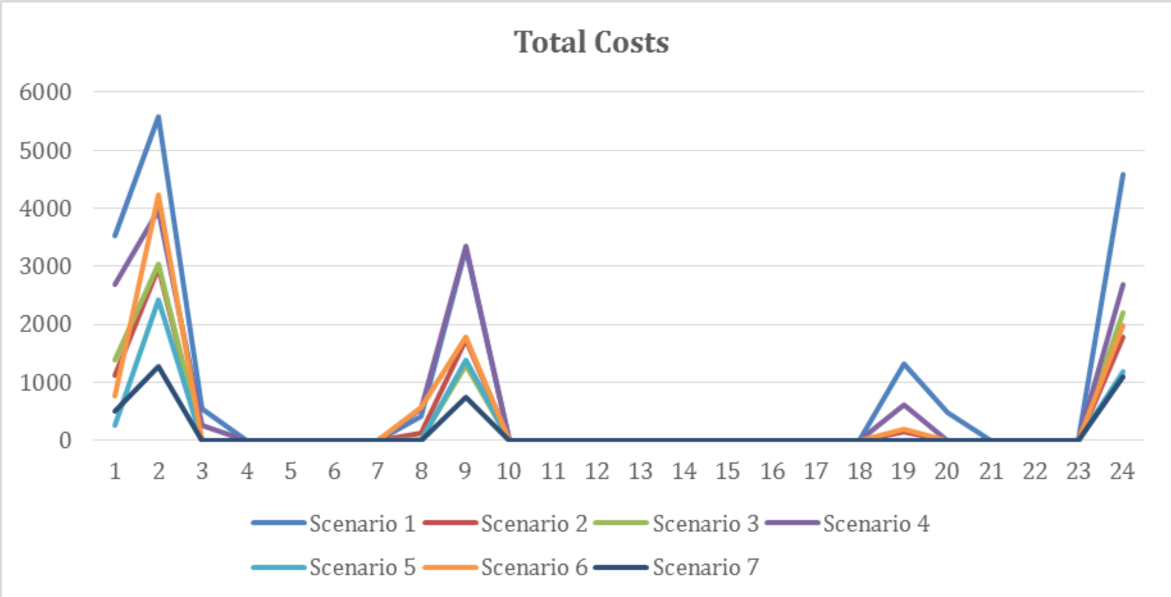


Figure 164 – Total costs (€) for network 5 in the summer

Table 182 resumes the total values of active power losses for network 5 in summer.

Table 182 – Total costs for network 5- summer.

Scenario	Total costs
1	19792.09
2	7888.19
3	7954.60
4	14120.19
5	5267.82
6	9546.83
7	3639.67

Figure 165 shows the evolution of generated wind power along the periods for each WP1 scenario. The curves go along with the wind power profile presented in Figure 133.

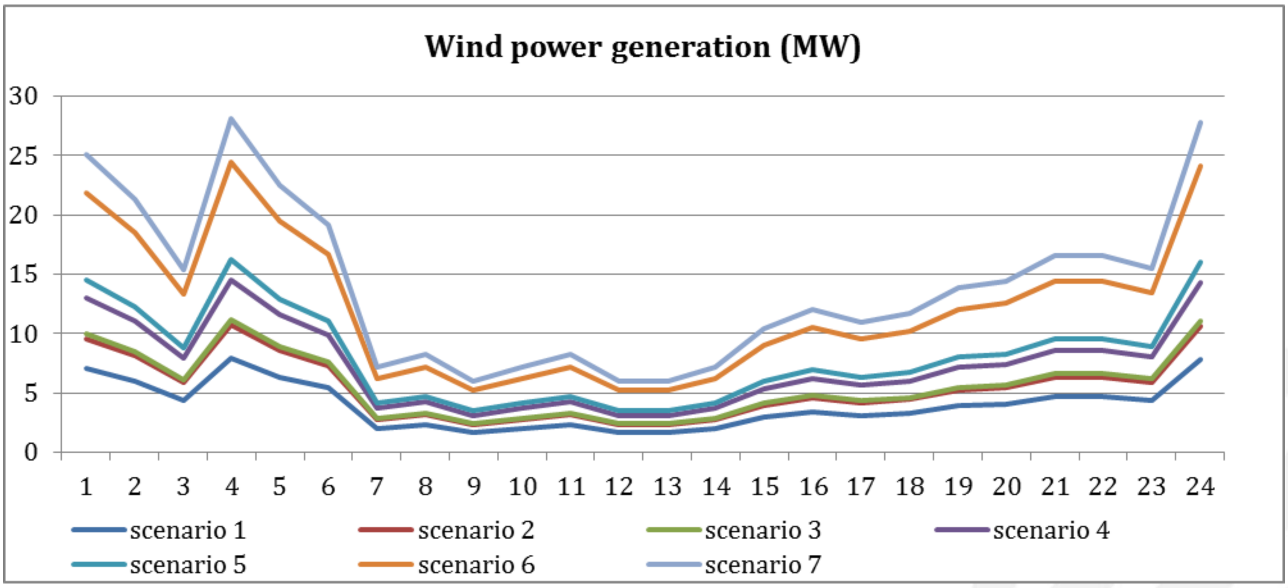


Figure 165 – Total wind power generated (MW) for network 5 in the summer

4.3.2.1.3 Results for Network 6 – winter

The results obtained using the MV network 6 with winter scenario can be seen also in ANNEX IV – Additional Results for TSO-DSO Cooperation Domain. Once more, we can observe the difference between the status quo scenario (1) and the other scenarios. This network has no wind generation in the original network. Even taking into account that along the WP1 scenarios the consumption varies and wind power generation grows, the main reason of the capacity of controlling costs comes from the presence of flexible resources. In this network this point is critical since the active and reactive power limits at the primary substations are expensive to break.
For all of simulations using the MV network 6- winter we did not obtain results with apparent power superior to limits in the branches, even in the worst scenarios with higher demand.

4.3.2.1.3.1 Operational KPI for MV network 6 - winter

Figure 166 resumes the improvement of the active power losses between the initial state of the network and it after optimization state for each period and for each WP1 scenario. We can see that this improvement goes along with the load power profile. The values of losses reduction are, in this case, closer to each other, because it is a network with less consumption and with less flexible resources inserted than MV network 5.

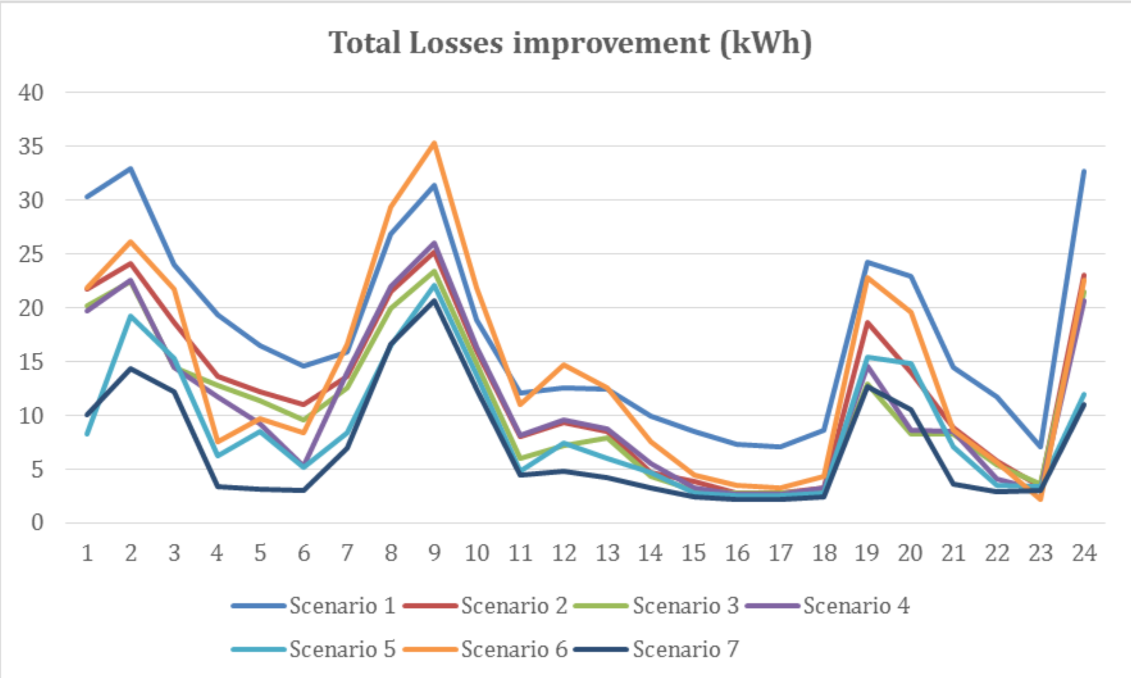


Figure 166 - Total losses improvement (kWh) for network 6 in the winter

Table 183 resumes the total values of active power losses for network 6 in winter.

Table 183 – Total values of power losses for network 6- winter.

Scenario	Total initial power Losses (kWh)	Total final power Losses (kWh)	Total improvement (kWh)	Improvement (%)
1	4122.95	3700.71	422.24	10.2%
2	3737.17	3442.63	294.54	7.9%
3	3582.75	3324.53	258.22	7.2%
4	3666.71	3402.40	264.31	7.2%
5	3350.85	3137.88	212.97	6.4%
6	4117.93	3776.54	341.38	8.3%
7	3027.56	2855.31	172.24	5.7%

Figure 167 shows the sum of the distances of the active power injected by the two primary substations to their upper limits for each period and for each WP1 scenario. We can see that the curves come along with the active load power profile as well as the previous cases.

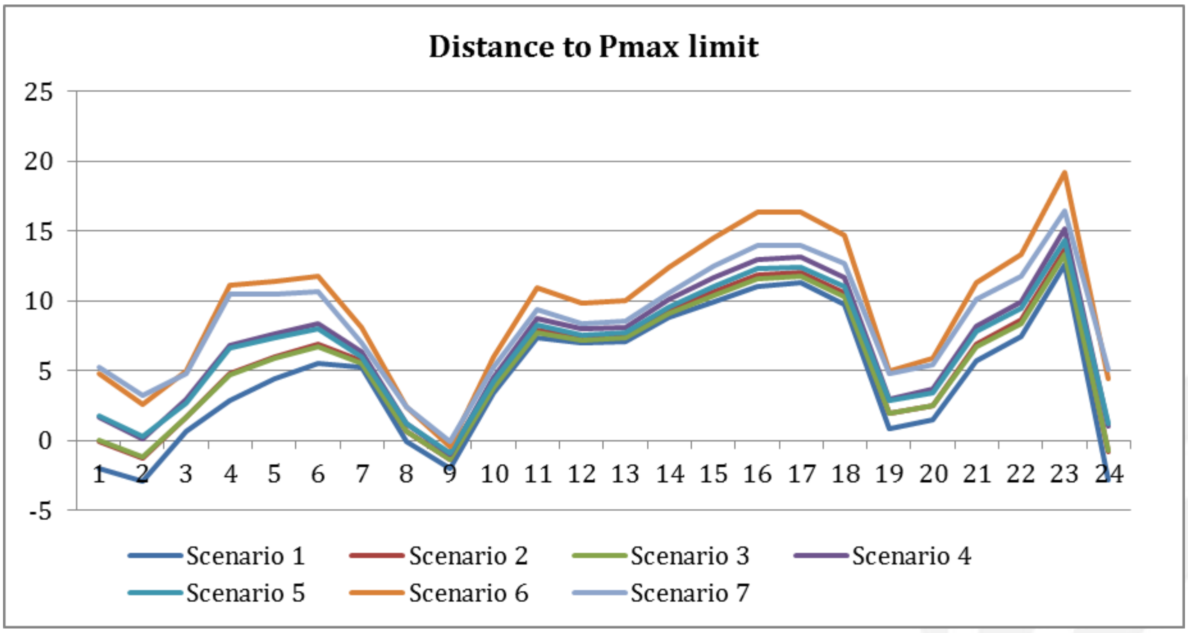


Figure 167 – Distance of injected active power to upper limits (MW) for network 6 in the winter

Figure 168 shows the sum of the distances of the injected reactive power to their upper limits for the simulation for MV network 6 in the winter sub scenario. Almost all the values are positive which means that the reactive power injected by the two substations is in average below the limits.

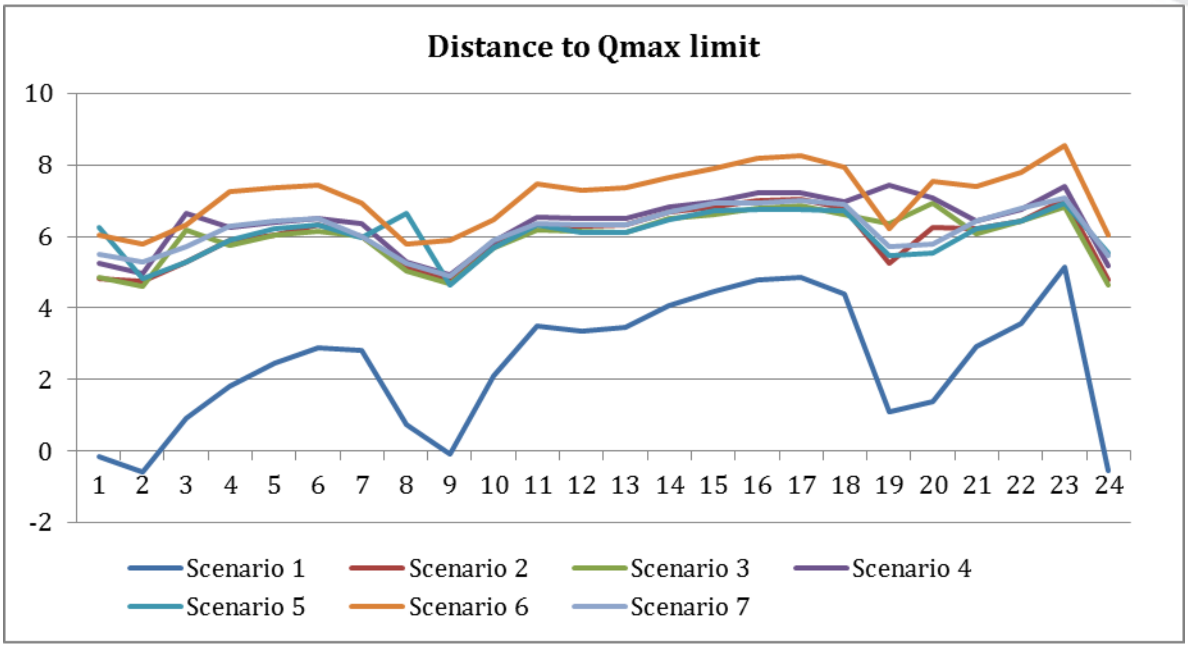


Figure 168 – Distance of injected reactive power to upper limits (MVAr) for network 6 in the winter

Figure 169 presents the evolution of the distances of the injected reactive power to their under limits along the periods of every scenarios. As in the previous results, the values are all positive and distant to the zero value which indicates that the injected reactive power is within the limits.

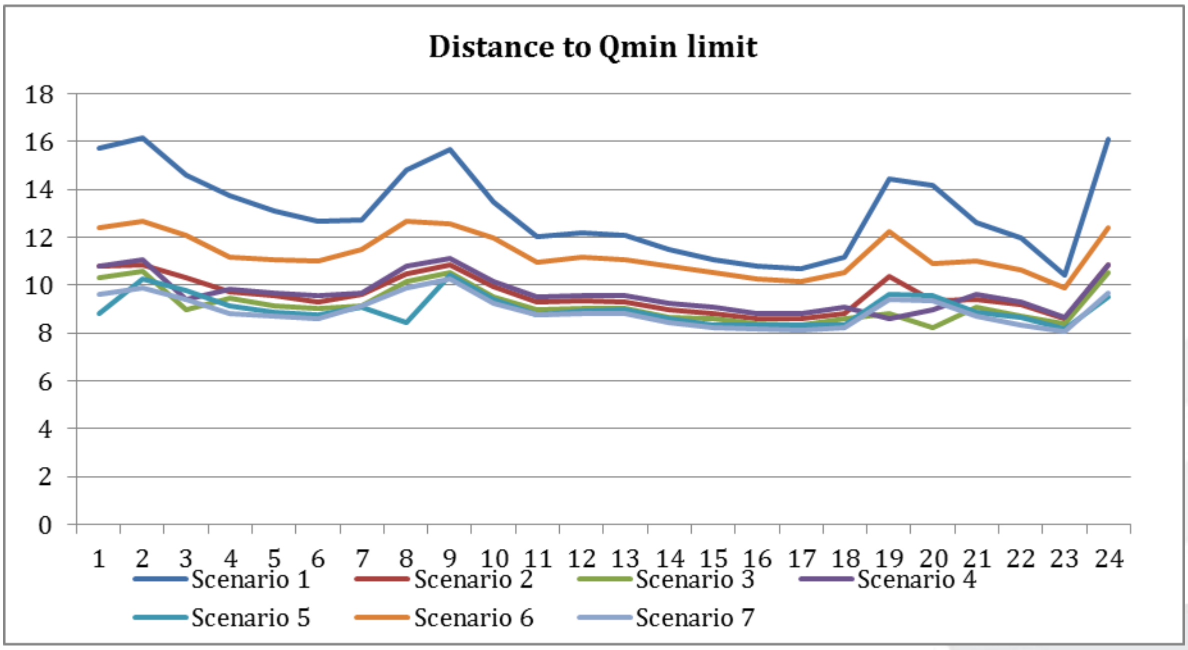


Figure 169 – Distance of injected reactive power to under limits (MVAr) for network 6 in the winter

Figure 174 resumes the total costs for simulations with MV network 6 at winter for each period and for each scenario. We can observe that in this network the costs are lower than in the previous one, which demonstrates that the type of network has an influence on the simulations too.

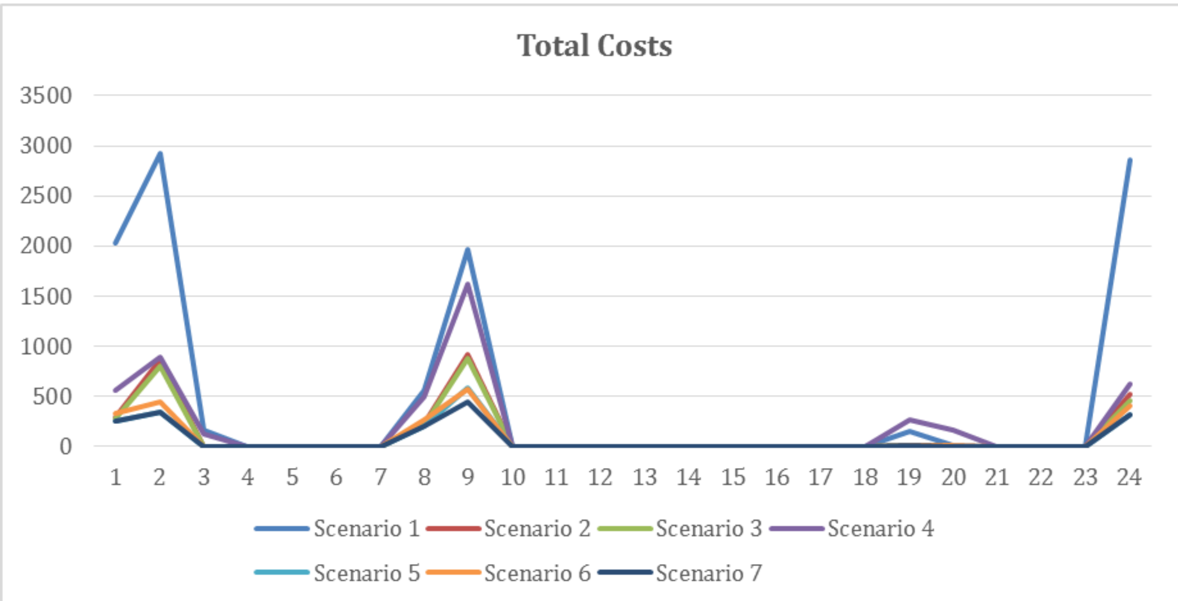


Figure 170 – Total costs (€) for network 6 in the winter

Table 184 resumes the total costs for network 6 in winter.

Table 184 – Total costs of network 6 - winter.

Scenario	Total costs
1	10661.52
2	2806.87
3	2632.61
4	4725.75
5	1711.52
6	2030.28
7	1533.24

Figure 171 shows the curves for wind power generation in the MV network 6 – winter. The evolution goes along with the wind generation profile previously defined. We can see the curve from scenario 1 is not present because in the MV network 6 there is no wind power in the original network. For the rest of the scenarios, it was considered that for scenarios short-term, mid-term and long-term, the wind power penetration would correspond to 10%, 20% and 40% of the consumption. Thus, the scenario 2 and 3 are overlapping because they refer to the short-term scenario. The same happens with scenario 4 and 5 (mid-term) and with scenarios 6 and 7 (long-term).

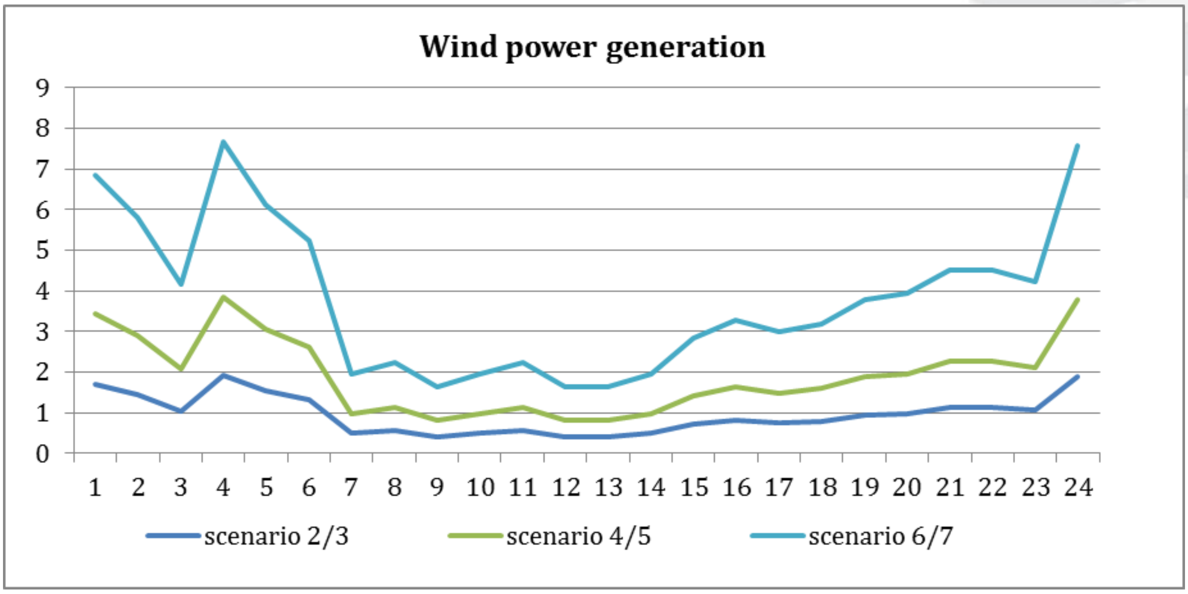


Figure 171 – Total wind power generated (MW) for network 6 in the winter

4.3.2.1.4 Results for MV network 6 – Summer

The results concern the simulations made with MV network 6 using the data from the summer season can be seen also in ANNEX IV – Additional Results for TSO-DSO Cooperation Domain. The results show us that having a network with less load power, typical of the summer season, relieve the primary substations and cause less activation of flexible resources. The minimum values of active power injected by the primary substations were too small to make the flexible loads increase their power. In a situation where the minimum was tighter, the optimization would find a solution less expensive by searching for the activation of flexible loads in order to increase their values.

For all of the simulations using the MV network 6 - summer we did not obtain results with apparent power superior to limits in the branches, even in the worst scenarios with higher demand.

4.3.2.1.4.1 Operational KPI for MV network 6 - summer

Figure 172 shows the total active losses improvement along the periods for all WP1 scenarios considering the MV network 6 during summer. Like before, the values are closer to each other when compared to MV network 5. This situation occurs because of the lower presence of flexible resources in this network and because of the lesser necessity to have them.

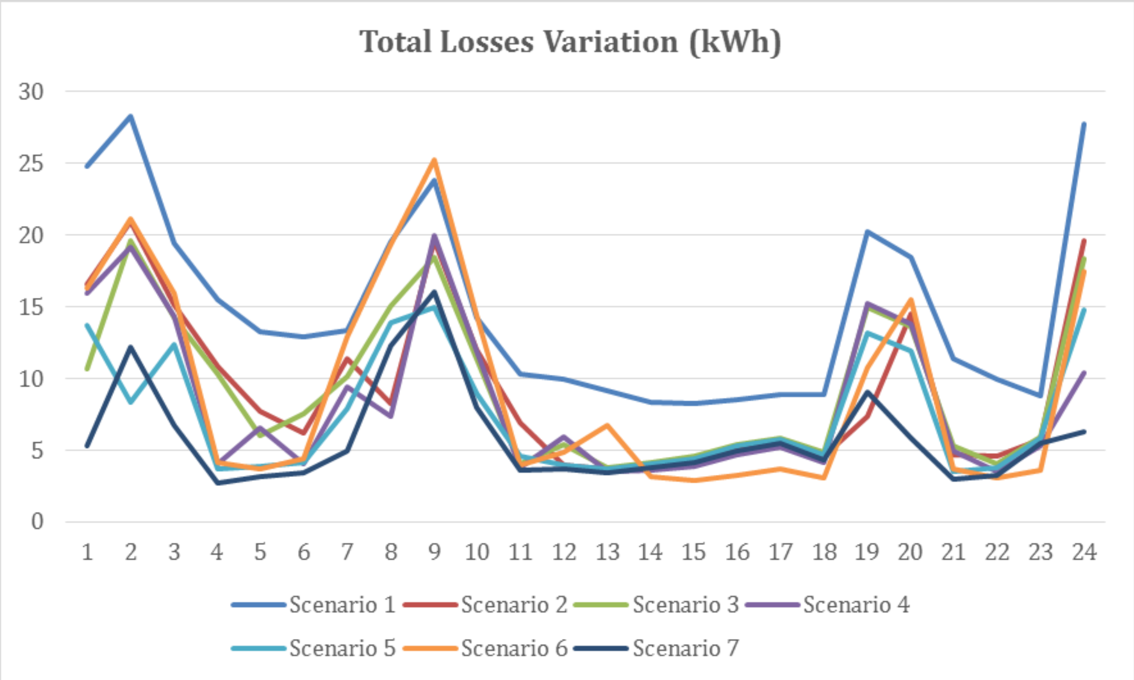


Figure 172 - Total losses variation (kWh) for the network 6 in the summer

Table 185 resumes the total active power losses for network 6 in summer.

Table 185 – Total values of power losses for network 6- summer.

Scenario	Total initial power Losses (kWh)	Total final power Losses (kWh)	Total improvement (kWh)	Improvement (%)
1	3399.18	3045.30	353.88	10.4%
2	3092.52	2869.26	223.25	7.2%
3	2979.27	2755.60	223.67	7.5%
4	3005.82	2805.20	200.62	6.7%
5	2776.14	2594.81	181.33	6.5%
6	3261.89	3038.75	223.14	6.8%
7	2485.59	2344.90	140.68	5.7%

Figure 173 shows the sum of the distances of injected active power to the upper limits of the two substations. The result is similar to the previous ones and shows that in almost every period the active power is within the limits.

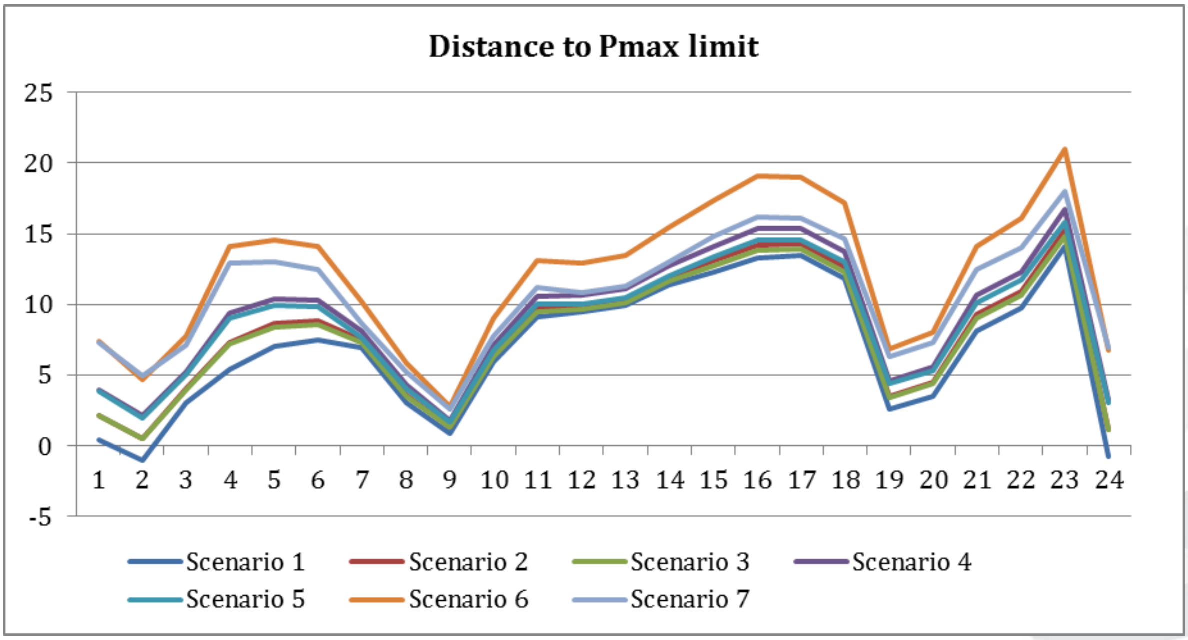


Figure 173 – Distances of active power to the upper limits (MW) for the network 6 in the summer

Figure 174 presents the evolution of distances of the reactive power injected by the two primary substations to their upper limits. The simulations with the MV network 6 for summer have results with all the values of reactive power below the upper limits.

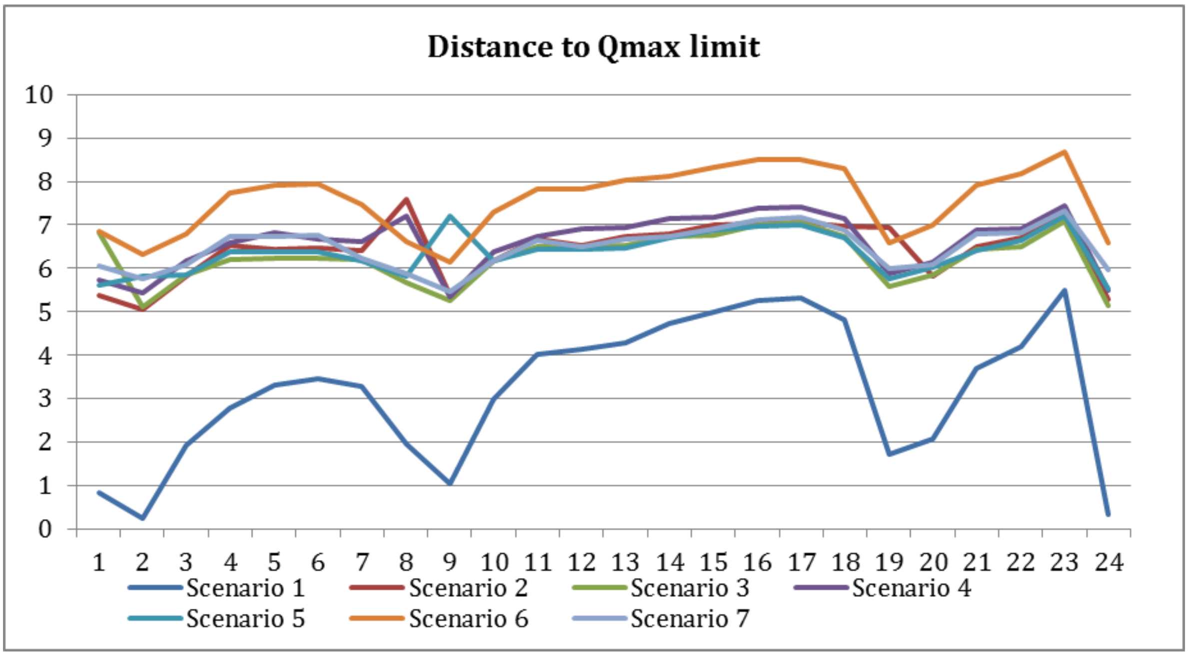


Figure 174 – Distances of reactive power to the upper limits (MVAr) for the network 6 in the summer

Figure 175 shows the sum of the distances of injected reactive power to the under limits along the periods and scenarios for MV network 6 summer case. Since the under limits are all negative, and the distance to these values are all positive, we can conclude that in this network the values of injected reactive power are above the under limits.

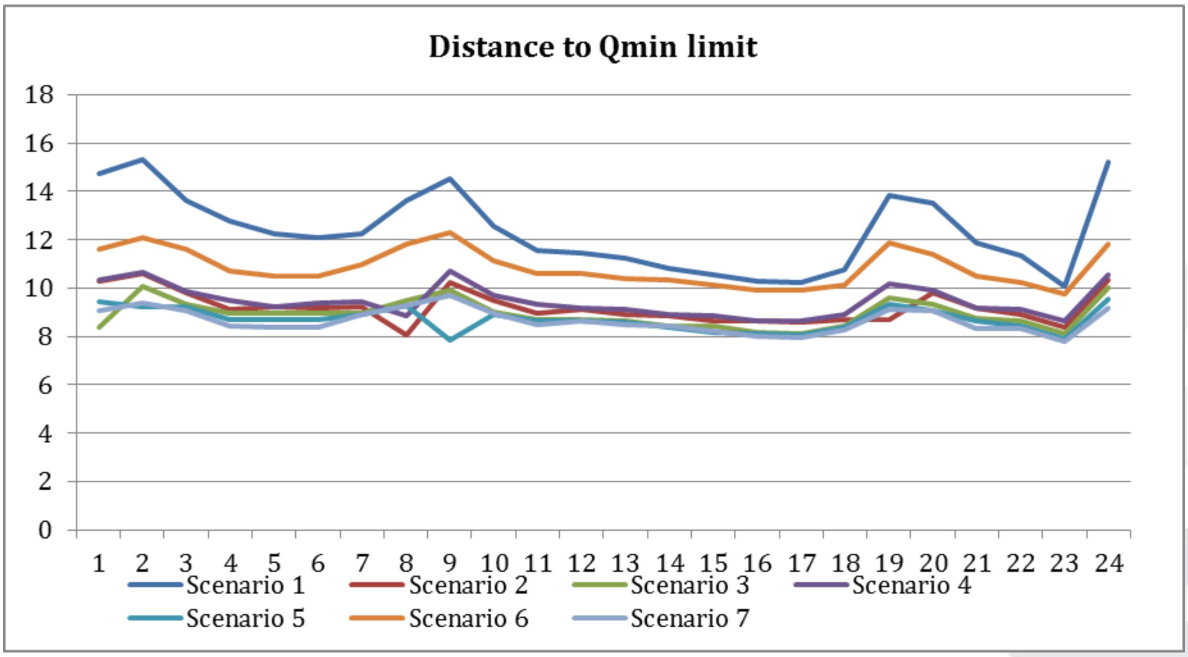


Figure 175 – Distances of reactive power to the under limits (MVAr) for the network 6 in the summer

Figure 176 resumes the total costs obtained for the simulations using the MV network 6 during summer for each scenario. This network has the lower costs of all the simulations. Besides being a network with less congestions in the initial state, it also has a lower consumption since the considered sub scenario is a summer one. Once again, the costs associated to the changing of the taps are not included in this image.

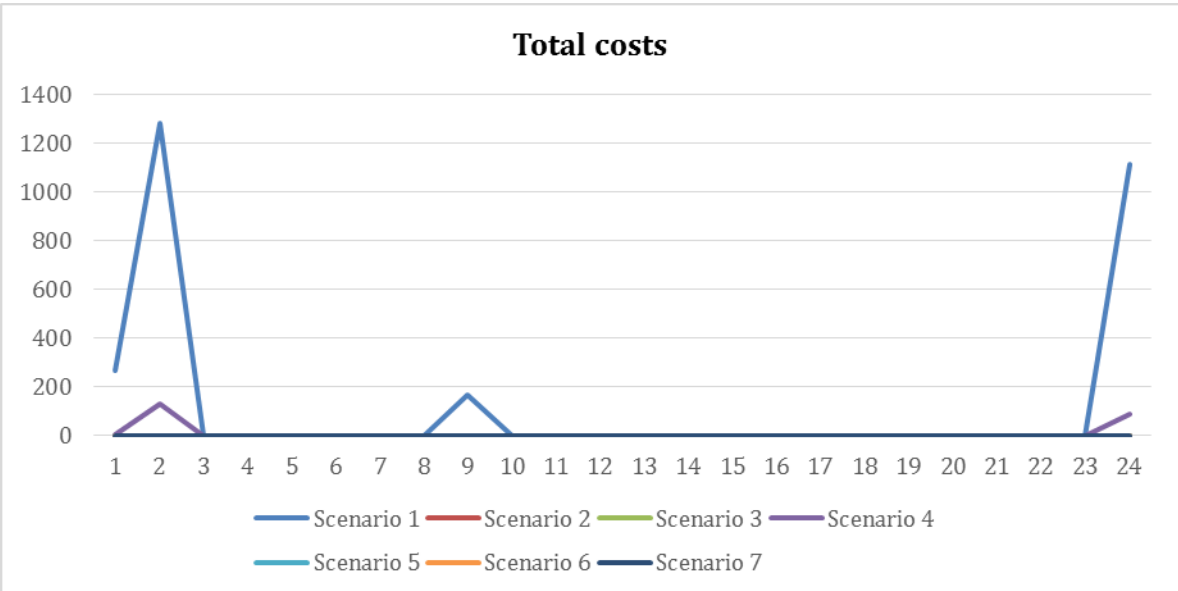


Figure 176 – Total costs (€) for the network 6 in the summer

Table 186 resumes the total costs for network 6 in summer.

Table 186 – Total costs for network 6 - summer.

Scenario	Total costs
1	2839.38
2	60.00
3	66.00
4	226.32
5	51.00
6	75.00
7	60.00

Figure 177 shows the curves of the generated wind power along the periods using the MV network 6-summer scenario. Like before, the scenario 1 was not included because there is no wind power in the original network. The subsequent scenarios have a generator which simulates the wind power penetration for each scenario. The short-term, mid-term and long-term scenarios share the same production.

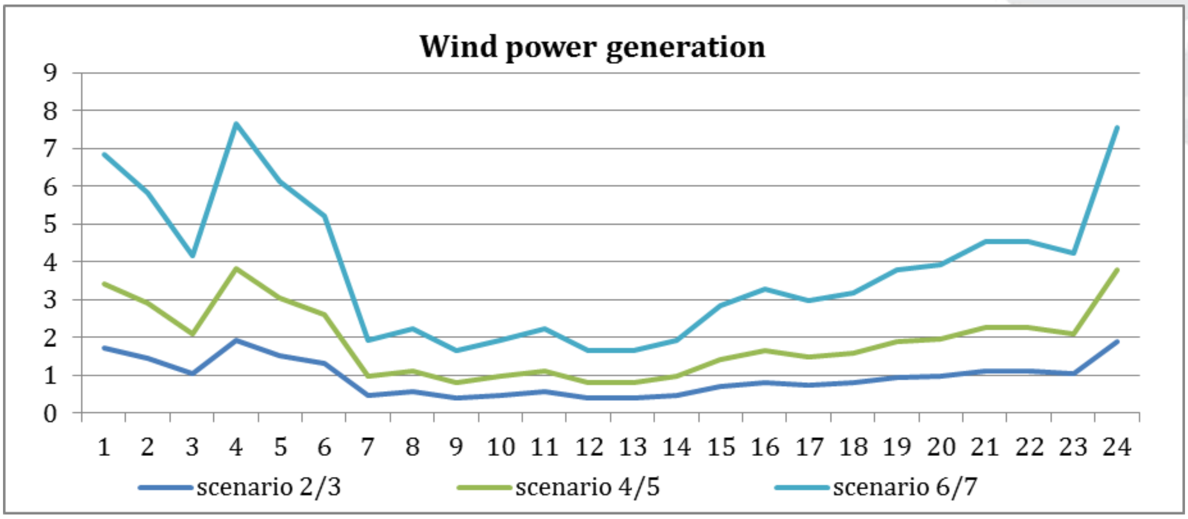


Figure 177 – Total wind power generated (MW) for the network 6 in the summer

4.3.2.1.5 Other KPI

4.3.2.1.5.1 Execution time for French networks

Table 187 and Table 188 resume the execution time of the tool for each simulation performed. We can see that the simulations with the MV network 6 were globally faster than with the MV network 5. While the MV network 6 has more nodes with loads, it has a lesser amount of load power and does not have any wind power generator. This causes a more fluid execution of the program. For the same reasons, we can see that there are also differences between the time execution for the summer and winter scenarios. The scenarios 4 and 6 almost always have the largest values of execution time because a growing of amount of load power and an increasing amount of flexible resources are combined in these scenarios. Thus, with more variety to search different feasible solutions the optimization needs more time to consider all the hypotheses.

Table 187 - Execution time of the simulation in the network 5

	Summer							winter						
scenarios	1	2	3	4	5	6	7	1	2	3	4	5	6	7
seconds	61.12	59.20	58.73	112.65	62.40	66.74	65.36	70.19	88.43	88.60	201.99	112.17	117.10	100.93

Table 188 - Execution time of the simulation in the network 6

	Summer							winter						
scenarios	1	2	3	4	5	6	7	1	2	3	4	5	6	7
seconds	49.67	51.73	51.13	66.19	51.50	49.35	49.5	64.36	78.60	72.77	100.91	94.67	108.26	105.04

4.3.2.1.5.2 Increased RES and DER Hosting Capacity (5)

In order to compute the DRES capacity of the network it was used a simplified model. The idea is to obtain the maximum values of generation for each existing generator without compromising the proper functioning of the network. Thus, initially the generators were divided by it network island which in this case corresponds to the number of primary substations. Then, for each island, the dispatched values of generators were successively and homothetic increased until some constraints reach its admissible limits values. When a limit is reached, doesn't mean all the DRES units are producing the individual maximum values. In order to obtain a solution close to the one with simultaneous generation levels equal to constraints limits, the homothetic increase is made until the first constraint is violated. Then, each generator production is individually increased until the next violation occurs.
The load scenario used in these simulations was based on the original winter scenario at it first period. The amount of power consumed in this period is high enough for the purposes of these simulations and does not cause congestions and violated constraints in the beginning of the process. The total active power consumed was 115.28 MW and the total reactive power consumed was 34.58 Mvar. The limits of the injected active power (MW) and injected reactive power (Mvar) of each primary substation can be seen on the Table 189.

Table 189 – Active and reactive power limits at the primary substations used in simulations of KPI 5.

RHTB0001				RHTB0002			
Pmax	**Pmin**	**Qmax**	**Qmin**	**Pmax**	**Pmin**	**Qmax**	**Qmin**
70.11	0.00	21.03	-21.03	37.08	0.00	11.12	-11.12

There were made two different simulations. The first one does not use the functionalities of the SOPF tool (namely the changing of the transformer taps and the switches states) and

provides the sum of the total DRES generated for a given scenario. The value obtained after this process is then compared with the value obtained in a second simulation using the SOPF tool with all functionalities. It was used the French network 5 with data corresponding to the winter scenario, considering the status quo scenario of WP1.
The presence of flexible resources was not taken into account in these simulations in order to distinguish more easily the different possibilities of DRES penetration.
The obtained values for dispatch of generated power by each generator using this methodology are presented in the Table 190. The first column refers to the simulation before using complete SOPF tool, and the second column refers to results using SOPF tool.

Table 190 – Results of the simulations for KPI 5.

Generator id	Original values (MW)	Without SOPF (MW)	With SOPF (MW)
N1sync02	0.388	5.00	5.00
N1sync03	1.134	3.00	3.00
N1sync05	0.521	**8.90**	**9.00**
N1sync01	1.26	3.50	3.50
N1sync04	1.02	**3.90**	**4.00**
N2sync06	4.032	11.20	11.20

As it is possible to see, the second simulation allowed to allocate more 0.2 MW of distribution generation in this scenario. If a profile of generation obtained on the second simulation was used in the first simulation, the constraints of apparent power at two power lines (line 248 and line 46) would be violated. In the second simulation the tool allowed to change the transformer taps. These modifications have caused the reduction of power losses in the network and the possibility of produce more power without compromise the network. The results of the changes in the transformer taps can be seen at Table 191.

Table 191 – Transformer taps for the second simulation of the KPI 5.

Transformer id	Initial Tap Position	Final Tap Position
Trans1	9	6
Trans2	9	6
Trans3	9	10
Trans4	9	17

The difference between the maximum values obtained with the SOPF tool and the first tool is not significant. The main reason is related with the fact that, using this network, the SOPF tool does not change the topological configuration. If the tool was capable to find another configuration, the DRES capacity will probably increase significantly, because the SOPF tool searches for optimal configuration solutions with fewer costs due flexible activation and due the network power losses. In a situation where constraints are violated, the solutions are penalized in its objective function, and so, the tool would be forced to find another feasible topology for network if it would be possible. Note that the values obtained for maximum dispatched values represent the simultaneous maximum values and not the individual ones. There are other combinations which generator values are close to simultaneous limits of the network constraints.

4.3.2.1.5.3 Reduced energy curtailment of RES and DER (6)

In order to compute the energy curtailment of RES and DER it was created a scenario with a low consumption compared to the scenarios used in the previous tests. Besides that, the initial generated power by the DRES units is close to the global consumption in this network.
The load scenario is based on the original summer scenario in the period 23 (less consumption), but the power consumption was reduced proportionally in order to create a scenario where the distributed generation has a more active role. The total active power consumed in this new scenario was 29.55 MW and the total reactive power consumed was 8.72 MVAr, while the total generated power by DRES units is 35.7 MW. In the original scenario the active power was 50.84 MW and the reactive power was 15.73 MVAr.

The Table 192 shows the dispatched values for wind power generators used in the scenario for the simulation of this KPI.

Table 192 – Dispatched values of generated power for the simulations of KPI 6.

Generator id	Original values (MW)
N1sync02	5.00
N1sync3	3.00
N1sync05	9.00
N1sync01	3.50
N1sync04	4.00
N2sync06	11.20

The Table 193 resumes the maximum, minimum and initial dispatched values for all the fictitious generators used in this simulation which simulate the flexible loads and the wind curtailment. A negative value of the power of a flexible load means an increase of the load power and a wind curtailment generator negative value of power means that the existing generator in that node is reducing it production. The last columns present the upward and downward costs for activating each of these flexibilities used for this simulation.

Table 193 – Flexible resources data used in simulations of KPI 6.

Generator id	Initial generated power (MW)	Pmax (MW)	Pmin (MW)	Upward cost (€/MWh)	Downward cost (€/MWh)
FlexL063	0.00	0.0088	-0.0088	90	32
FlexL169	0.00	0.0032	-0.0032	81	31
FlexL200	0.00	0.0029	-0.0029	72	34
FlexL117	0.00	0.0024	-0.0024	86	27
FlexL201	0.00	0.0021	-0.0021	81	29
FlexL090	0.00	0.0019	-0.0019	82	30
Flexsc02	0.00	0.00	-5.00	-	22
Flexsc03	0.00	0.00	-3.00	-	33
Flexsc05	0.00	0.00	-9.00	-	28
Flexsc01	0.00	0.00	-3.50	-	23

Flexsc04	0.00	0.00	-4.00	-	28
Flexsc06	0.00	0.00	-11.20	-	21

The limits of the injected active power (MW) and injected reactive power (MVAr) of each primary substation are the same used in the previous KPI simulations and can be seen on Table 189. There were made two different simulations. The first one runs a power flow without considering the possibility to change the taps of the transformers and without the possibility to change the topological configuration of the network. The second one considers these functionalities of SOPF. The simulations were made for the period 23 (period with less consumption) of the summer scenario of the MV network 5 taking into account the changes mentioned in the previous tables and the proportional consumption reduction. The main results for these two simulations are resumed in the Table 194.

Table 194 – Results of the simulations of KPI 6.

Generator /Flexible Load /Wind curtailment /Primary Substation	without SOPF- Injected Active Power (MW)	with SOPF - Injected Active Power (MW)
N1sync02	5.00	5.00
N1sync03	3.000	3.00
N1sync05	9.000	9.00
N1sync01	3.500	3.50
N1sync04	4.000	4.00
N2sync06	11.20	11.20
FlexL063	-0.0088	-0.0088
FlexL169	-0.0032	-0.0032
FlexL200	0.00	0.00
FlexL117	0.00	0.00
FlexL201	0.00	0.000
FlexL090	-0.0019	-0.0019
Flexsc02	0.00	0.00
Flexsc03	-3.00	-3.00
Flexsc05	**-2.093**	**-2.090**
Flexsc01	0.00	0.00
Flexsc04	0.00	0.00
Flexsc06	**-0.394**	**-0.388**
RHTB0001	**0.244**	**0.233**
RHTB0002	0.00	0.00

As it is possible to see in the table above, the values obtained for activated power of flexible loads, wind curtailment and injected power by the substations are similar.
The main reason is related with the fact of, using this network, the SOPF tool does not change the topological configuration. If the tool were able to find another configuration, the variety of solutions will be higher and thus the curtailment of DES and DER would be different. In this case, the values obtained are almost the same. The adjustment made in the transformer taps reduce the power losses in the network but is not sufficient to made substantial changes in the curtailment of DES and DER values. Moreover, the network does not have any capacitor bank which can change the results from one simulation to another.

4.3.2.2 Interval Constrained Power Flow Results

The results obtained for the different test cases will be analysed separately. But, each new test case result will be compared with the results obtained for the previous ones since it is important to observe the evolution throughout the different scenarios. Furthermore, all the simulations for the different scenarios will have as final goal the maximum flexibility area.

As explained in section 4.1.2.2, each one of the two French networks was divided into two parts. Therefore, the 7 test cases were simulated for the four resulting networks:

- MV_ntwk_5_cplt – Part 1;
- MV_ntwk_5_cplt – Part 2;
- MV_ntwk_6_cplt – Part 1;
- MV_ntwk_6_cplt – Part 2

4.3.2.2.1 MV_ntwk_5_cplt – Part 1

The characteristics of the first part of the 1st French network are summarized as following:

- Number of buses: 402;
- Number of branches: 399;
- Number of transformer TAPs: 2;
- Number of generators: 5;
- Active Power Load: 50.29 MW;
- Reactive Power Load: 16.03 MVAr;
- Number of customers with $P_{ref} > 200\ kW$: 26.

All seven scenarios presented in 4.2.2 were tested for this network and the results are presented in the following sections.

4.3.2.2.1.1 *Scenario 1 - Status quo*

The *Status quo* scenario illustrates the baseline scenario. It is characterized by the standard parameters of flexibility and demand. The network characteristics used for this scenario are the ones sent by the DSO. Regarding the flexibility criteria, this scenario only allows reactive power control, no demand flexibility.

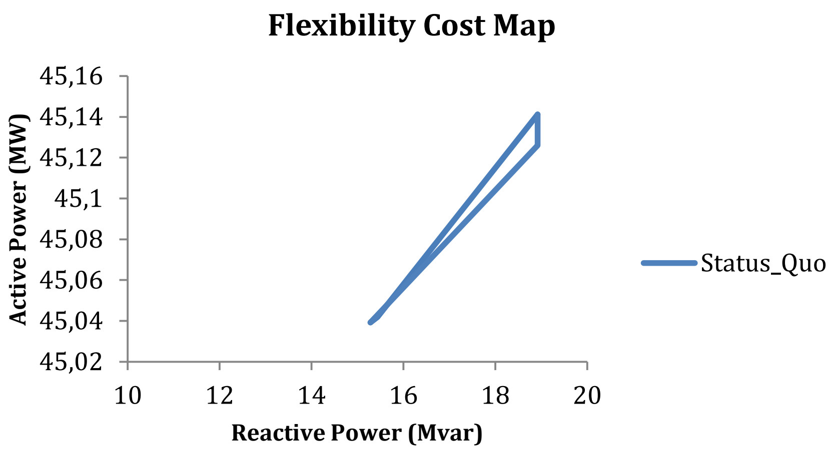


Figure 178 - Flexibility Cost Map for scenario 1 – status quo – Network5_Part1

Figure 178 shows the region of feasible values of active and reactive power exchanged at the boundary node. The obtained flexibility area presents a range regarding the reactive power since only the reactive power control rule is followed in this scenario and no active power flexibility is provided by the distribution network. The small range of active power observed is due to the transformer TAPs variations and its impact on the voltage. Moreover, the reactive power flexibility provided by the wind parks is used at its maximum level since the network constraints are far from their limits and since it is our goal to obtain the maximum flexibility.
In order to confirm these observations, we compare the flexibility area with the degree of flexibility provided by the wind parks. Figure 178 presents a range of reactive power flexibility of 3.64 MVAr. The flexibility allowed by the distributed generation was set at 2.8 MVAr. The difference between both values reflects the flexibility provided by the transformer TAPs.

4.3.2.2.1.2 Scenario 2 – Short-Term

Scenario 2 is the first of the short-term test cases.

The short-term scenarios are characterized by different flexibility criteria when compared with the *status quo* scenario. Demand flexibility will be provided by 20% of the MV customers with contracted power over 200 kW. The magnitude of this flexibility will be equal to +/- 20% of the demand. Regarding the wind power flexibility it will only be allowed for additional capacities.

This particular scenario will be characterized by a wind power increase of 34.6% and a demand growth of 0.5%.

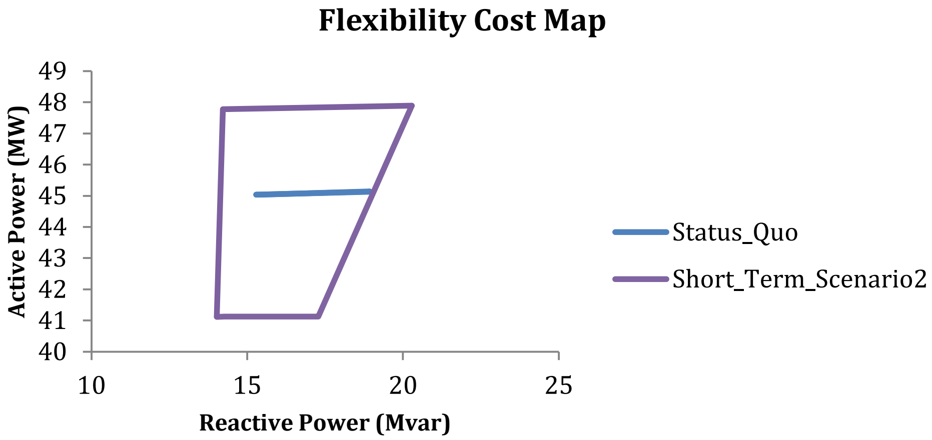


Figure 179 - Flexibility Cost Map for scenario 2 – short-term - Network5_Part1

Figure 179 presents the flexibility area obtained for scenario 2. The addition of demand flexibility and wind power curtailment in the flexibility criteria had obvious consequences in the flexibility area. The flexibility area of scenario 2 covers the one obtained for *status quo*. Moreover, this scenario presents a considerable range of active power values that can be provided by the boundary node because of possible wind curtailment and demand flexibility. The increase regarding the demand and the wind power installed capacity also contributed to this behaviour.

The flexibility that was allowed in the distribution network for this simulation was:
- Demand Flexibility: 5.39 MW and 1.46 MVAr;
- Generation Flexibility: 1.22 MW and 4.15 MVAr;
- Transformer TAPs.

As seen in Figure 179, the flexibility area obtained for this simulation has a range of 6.26 MVAr of reactive power and a range of 6.77 MW of active power. The computed flexibility area is therefore in accordance with the flexibility provided by the distribution network.

4.3.2.2.1.3 Scenario 3 – Short-Term

Scenario 3 is characterized by the same flexibility criteria that the previous one.
But, this test case requires an increase of the installed wind power a little higher than the one used for scenario 2 (34.6% vs 40.1 %) and follows a different direction regarding the demand growth with a 2.4% decrease of the demand (vs a 0.5%. increase for scenario 2).
It is also important to notice that the demand variation can cause a different number of customers with contracted power over 200 kW which means that, depending on the scenario, more or less customers can provide demand flexibility. This means that if the demand increases more customers can have a contracted power over 200 kW.

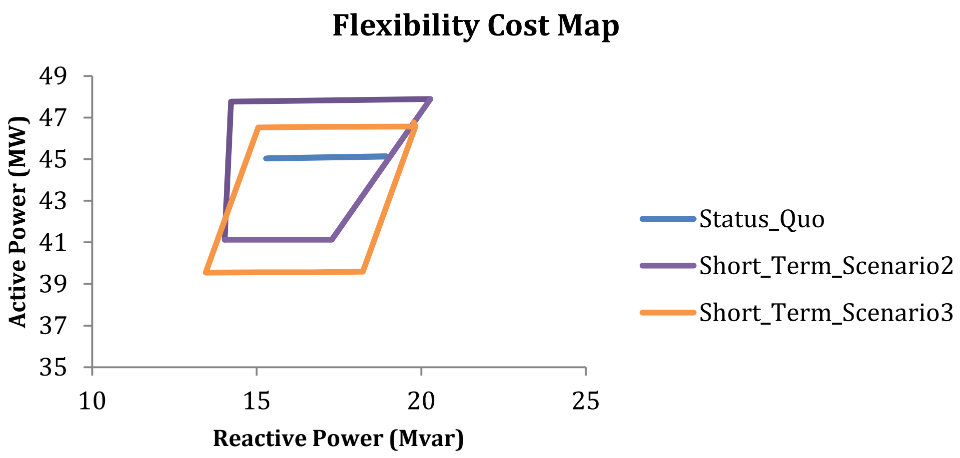


Figure 180 - Flexibility Cost Map for scenario 3 – short-term - Network5_Part1

Figure 180 shows that the flexibility area obtained by scenario 3 is slightly different from the one obtained for scenario 2. The flexibility criteria are the same, but the variations regarding the wind power and the opposite demand growth explain the fact that neither of the flexibility areas covers completely the other one.
For the same reasons as scenario 2, the flexibility area obtained for scenario 3 covers the area obtained for the *status quo*.

The flexibility that was allowed in the distribution network for this simulation was:
- Demand Flexibility: 5.2 MW and 1.4 MVAr;
- Generation Flexibility: 1.65 MW and 4.3 MVAr;
- Transformer TAPs.

As seen in Figure 180, the flexibility area of scenario 3 is characterized by a range of 6.37 MVAr of reactive power and of 7.21 MW of active power. The computed flexibility area is thus in accordance with the flexibility provided by the distribution network.

4.3.2.2.1.4 Scenario 4 – Mid-Term

Scenario 4 illustrates the first mid-term test case.

The mid-term scenarios are characterized by different flexibility criteria when compared with the short-term ones. The number of MV customers with contracted power over 200kW that could provide ±20% of demand flexibility increases to 50% and the wind curtailment is now allowed to all the wind parks. Considering these requirements it is expected significant variations in the flexibility areas computed for these scenarios.
The possibility of branch reinforcement due to the increase of the flexibility, demand and wind power installed capacity is also considered. It was however not used since the branches have enough capacity to provide the expected results.

The homothetic increase of 3.2% of the demand and of 82.5% of the installed wind capacity was presented in 4.2.2 for Scenario 4.

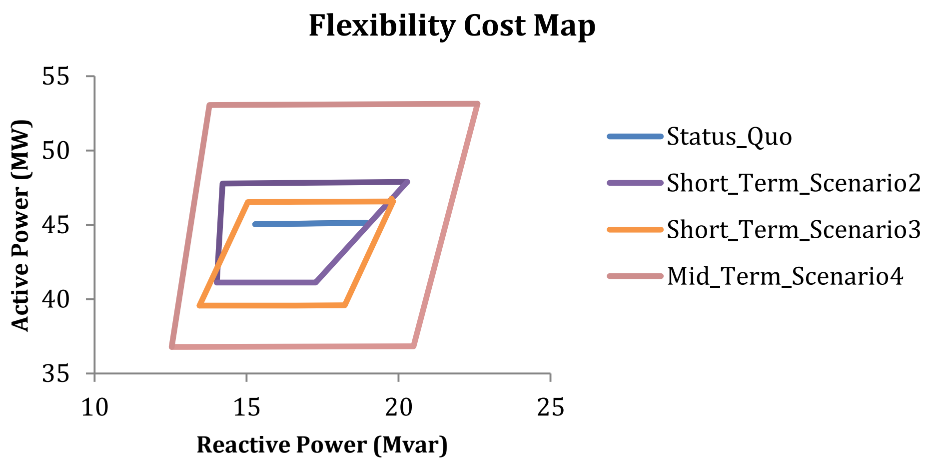


Figure 181 - Flexibility Cost Map for scenario 4 – mid-term - Network5_Part1

Figure 181 shows the flexibility area obtained.

The obtained flexibility area is clearly higher and covers the ones obtained for the short-term scenarios since the demand and the wind power see a considerable increase and since there is a clear increase of the flexibility of the distribution network because more MV customers can provide flexibility and wind curtailment is available for all the wind parks.
If this behaviour was expected when comparing scenarios 4 and 2, it was not mandatory when comparing scenario 4 and 3; these two scenarios follow opposite directions in terms of demand growth which could lead to a situation where the flexibility area obtained for scenario 4 would not cover the one obtained for scenario 3. This happens because of the considerable increase of both flexibility and wind power in scenario 4.

The flexibility that was allowed in the distribution network for this simulation was:
- Demand Flexibility: 12.71 MW and 3.44 MVAr;
- Generation Flexibility: 3.4 MW and 5.63 MVAr;
- Transformer TAPs.

As seen in Figure 181, the flexibility area of scenario 4 presents a range of active power of 16.36 MW and of reactive power of 10.06 MVAr which is validated by the flexibility allowed by the distribution network.

4.3.2.2.1.5 Scenario 5 – Mid-Term

As a mid-term scenario, scenario 5 follows the same flexibility criteria as scenario 4, but the situation is not the same regarding the wind power and demand growth. While the installed wind power capacity increases for both scenarios (+82.5% vs +103.6%), the demand growth follows a different direction with a decrease of 3.1% (vs +3.2% for scenario 4).
The branch reinforcement still does not need to be activated.

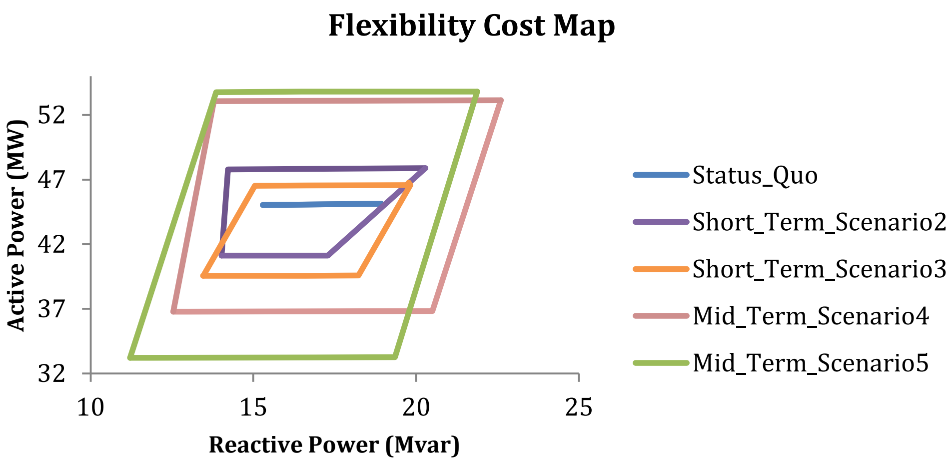


Figure 182 - Flexibility Cost Map for scenario 5 – mid-term - Network5_Part1

Figure 182 shows the flexibility area obtained for scenario 5. Both mid-term scenarios have similar flexibility areas since they follow the same flexibility criteria. Their differences are related to the variations in terms of wind power and demand growth, the latter explaining why neither of their flexibility areas covers the other one.

Figure 182 also shows that the flexibility area of this mid-term scenario is higher than the short-term ones and covers them. The increase of the flexibility criteria in the mid-term scenarios explains this. However it was not mandatory that this flexibility area would cover both short-term scenarios since scenario 2 follows an opposite demand growth trend.

The flexibility that was allowed in the distribution network for this simulation was:

- Demand Flexibility: 11.85 MW and 3.2 MVAr;
- Generation Flexibility: 8.38 MW and 6.28 MVAr;
- Transformer TAPs.

As observed in Figure 182, the feasible values of active and reactive power exchanged at the boundary node present a variation of 20.61 MW and 10.65 MVAr respectively. These values are validated by the flexibility allowed by the distribution network.

4.3.2.2.1.6 Scenario 6 – Long-Term

The long-term scenarios are defined by a different set of flexibility requirements regarding the demand flexibility: up to 80% of the MV customers with a contracted power over 200 kW are able to provide a +-/20% load flexibility. The number of customers contributing to the provision of flexibility thus considerably increases. The flexibility provided by the wind parks remains however unchanged which means that all the wind parks provide flexibility to the distribution network.
Different values are also considered for both wind power and demand capacity: in particular for Scenario 6, the wind power capacity increases of 207.5% and the demand of 18.4%.

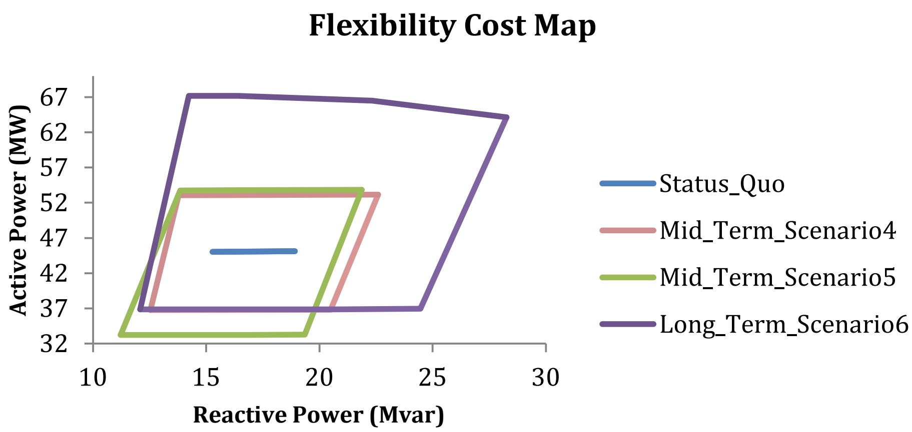


Figure 183 - Flexibility Cost Map for scenario 6 – long-term - Network5_Part1

Figure 183 shows a flexibility area for the long-term scenario clearly higher than the ones obtained for the mid-term test cases because of the large increase of the flexibility degree and the wind power increase.
Figure 183 also shows that the flexibility area only covers one of the obtained for the mid-term scenarios because of different demand growth of these scenarios: if on the one hand scenarios 6 and 4 follow the same trend for the load evolution, on the other hand scenarios 6 and 5 follow an opposite direction leading to a partial coverage of the flexibility area of scenario 5.

As observed in Figure 183, the flexibility area achieved for scenario 6 has a range of 16.18 MVAr of reactive power and 30.31 MW of active power, while the flexibility allowed in the distribution network for this simulation was:

- Demand Flexibility: 17.05 MW and 4.94 MVAr;
- Generation Flexibility: 12.65 MW and 9.49 MVAr;
- Transformer TAPs.

The comparison between these two flexibility information allows to validate the result achieved by the ICPF tool.

4.3.2.2.1.7 Scenario 7 – Long-Term

Scenario 7 is characterized by the same flexibility criteria that the previous one. However, the demand decrease (-2.8%) followed by this scenario affects the number of customers able to provide demand flexibility. On the other hand, the increase of the wind power allows more wind power to be curtailed. This will lead to a flexibility area different from the previous one.

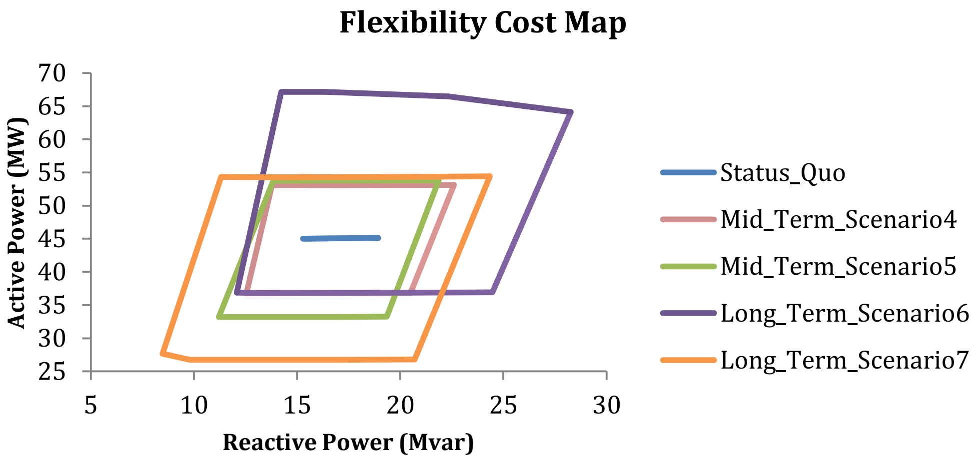


Figure 184 - Flexibility Cost Map for scenario 7 – long-term - Network5_Part1

The flexibility area of scenario 7 is smaller than the one of scenario 6, and neither completely covers the other one. It is explained by the decrease of the demand which has an important impact upon the number of MV customers that could provide flexibility. This decreasing flexibility cannot be compensated by the larger wind power increase.
In contrast with scenario 6, the flexibility area of scenario 7 covers the one obtained for scenario 5 since both scenarios follow the same growth trend and scenario 7 is characterized by a higher degree of flexibility and a higher wind power increase.
While the flexibility area of scenario 7 also covers the one of scenario 4, it was not required to since they follow opposite growth trends.

Regarding the flexibility area of scenario 7, a range of 15.87 MVAr of reactive power and of 26.78 MW of active power can be provided at the boundary node, while the flexibility allowed in the distribution network for this simulation was:
- Demand Flexibility: 12.64 MW and 3.51 MVAr;
- Generation Flexibility: 14.55 MW and 10.92 MVAr;
- Transformer TAPs.

The comparison between these two flexibility information allows to validate the result achieved by the ICPF tool.

4.3.2.2.1.8 Operational KPIs

In order to evaluate the performance of the ICPF tool, two Operational KPIs are calculated for the French networks: the flexibility area increase and the computational time reduction. Both KPIs were described in D3.3:

- The computational time reduction is the result of the comparison between the average time of the power flows that were ran in the Monte Carlo Simulation (MCS) and the average time of the OPF’s that were obtained with the same program used to run the power flows in the MCS.
- The flexibility area increase was obtained using the ICPF. Therefore, the MCS has been run for 1000, 10000 and 100000 randomly extracted samples.

Table 195 – Operational KPIs for MV_ntwk_5_cplt – Part 1

Scenario	Flexibility area increase (%)			Computational time reduction (%)		
	1 000 samples	10 000 samples	100 000 samples	1 000 samples	10 000 samples	100 000 samples
1	-	-	-	85.20	98.49	99.86
2	388.42	210.90	116.80	72.05	97.17	99.68
3	406.46	216.65	120.65	62.73	96.24	99.62
4	999.33	426.46	205.21	66.17	96.59	99.67
5	748.46	444.51	212.58	53.66	95.34	99.57
6	1994.7	509.8	326.5	54.26	95.34	99.49
7	1045.3	418.3	213.3	52.65	95.19	99.49

Table 195 shows that the ICPF tool allowed a clear increase of the size of the estimated flexibility area with respect to the MCS. This behaviour is related to the fact that the ICPF tool is able to identify the high and the low cost zones while the MCS not. Table 195 also shows that a considerable reduction in terms of computational was achieved. With these KPIs results it is proved that a solution that is able to provide the increase of the flexibility area in less computational time is possible. In other words, an effective output in a reasonable amount of time is provided by the ICPF.

In order to avoid an extended document, the results and critical analysis of the other French networks are presented in ANNEX IV – Additional Results for TSO-DSO Cooperation Domain.

4.3.2.2.1.9 Flexibility Cost Maps

This section will present the result for a specific scenario of one of the presented networks, but for different maximum flexibility costs. The goal is allow to understand how the flexibility areas will vary consider different maximum costs that the user is willing to pay.

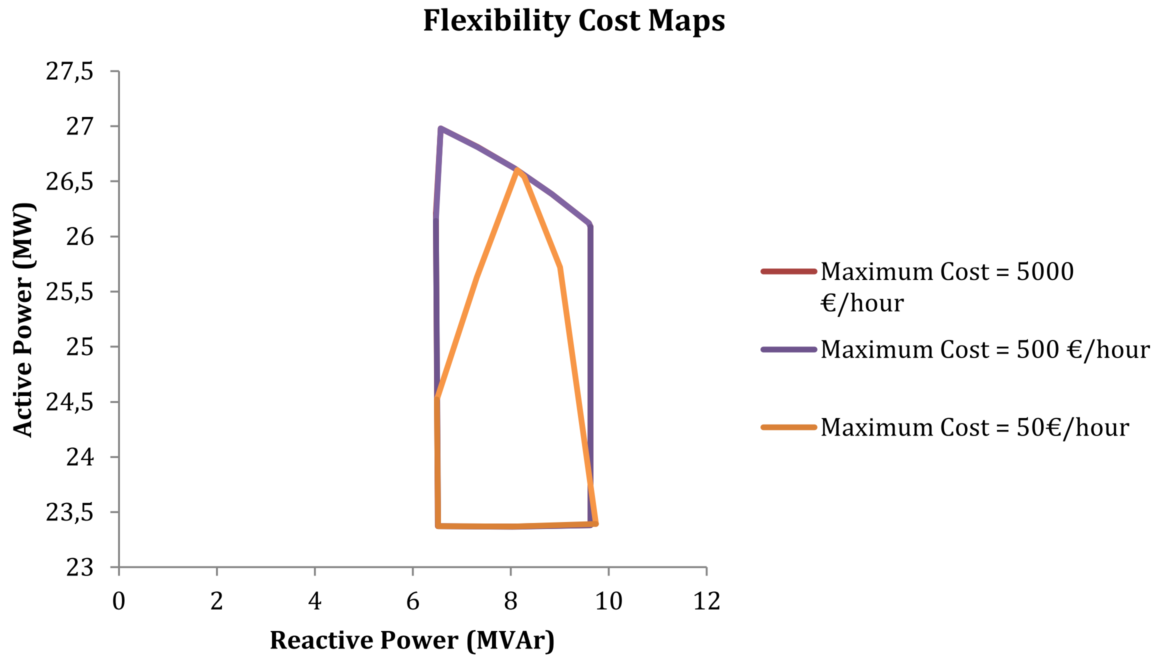


Figure 185 – Flexibility Cost Maps for different maximum flexibility costs

Figure 185 shows in a clear way the influence of different maximum flexibility costs upon the flexibility areas. The flexibility areas considering a maximum costs of 5000 €/hour and 500 €/hour are exactly the same. This means that the cost of the flexibility that is being used by the distribution network is less than 500 €/hour. When the maximum flexibility cost passes to 50€/hour is notorious that not all the flexibility available on the distribution network is being used and for the reason the flexibility area is smaller.

4.3.3 Results for Germany

In this section, the results of the developed simulations for each test case will be presented and subject to analysis. For each new test case, the results will be compared with the ones obtained for previous scenarios. With this approach, it will be possible to show the evolution of the results throughout the scenarios. Moreover, the final goal of each simulation is to obtain the maximum flexibility area of each test case. Before proceeding with the analysis of the obtained results, a consideration about the German network needs to be made. Although this network is composed by several connections between the transmission and the distribution networks, only one of them will be analysed. The others ones will have fixed power exchanges.

- ***CASE A – Moderate RES Production***

Test case “Case A” for the German distribution network is based upon a snapshot of the system which is characterized by a moderate level of RES production (wind generation is at 66% of its maximum capacity). In section 4.2.2.2, the parameter(s) of WP1 scenario(s), the characteristics of the current network and the criteria to link the scenario with the simulation details were presented (see Table 155). For Case A, an extra initial simulation scenario (Scenario 0) was added at the request of the RWE representatives. Simulations following Scenario 0 will proceed according to Table 155 specifications, starting with Scenario 1 (*status quo*), which relates to the present situation of the German distribution network. The flexibility criteria used for Case A differs from the criteria that are used for Cases B and C (see Table 155 and Table 156).

For flexibility purposes, the following sources are considered:

- Transformer tap changes
- Power plant redispatch
- RES active power curtailment
- RES reactive power control
- Storage devices

No load flexibility is considered, so it remains unchanged between scenarios. A total of seven different scenarios were constructed, based on an incremental allowed flexibility logic. Table 196 presents the simulation scenarios description and the main results obtained for the conduced simulations using the ICPF tool.

- **Scenario 0 – *Only transformer tap changes***

For Scenario 0, only transformer tap variations are allowed. The German network comprises a large number of power transformers with tap changing capability (see Table 160). Most of these transformers have 9 possible tap up or down positions, some have 13. Therefore, it can be expected that the transformers alone can provide a considerable amount of reactive power flexibility. This assumption can be confirmed through the analysis of the results obtained for scenario 0 as it can be seen by looking at Figure 186, which shows a variation of 160.39 Mvar for the reactive power flexibility range. As for the active power flexibility range only a small variation was observed, amounting to 11.97 MW. Such a variation is related with power losses.

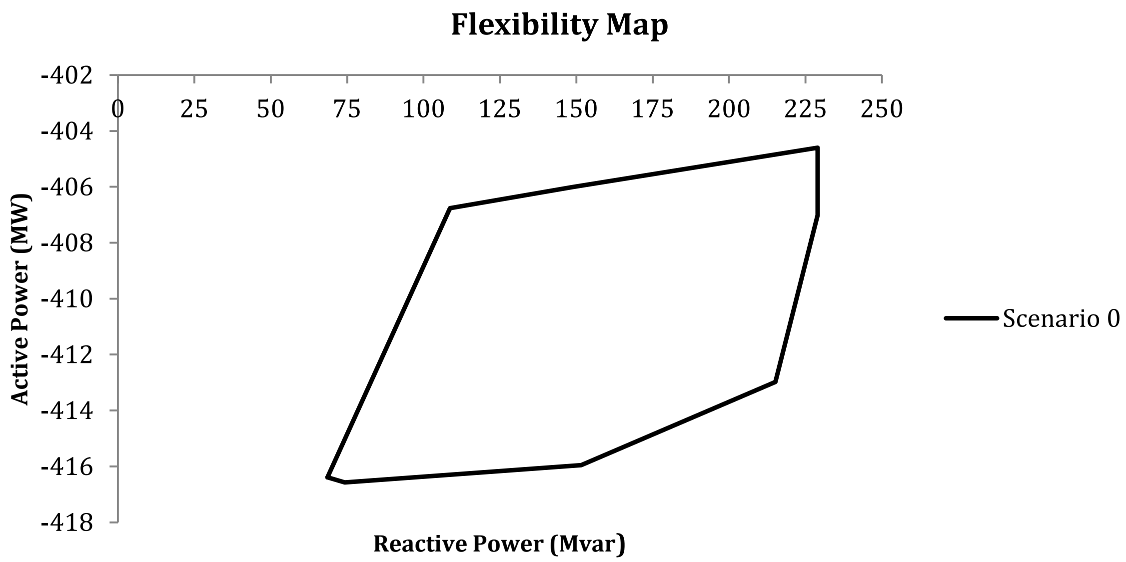


Figure 186 - Flexibility Map for scenario_0 – mid-term– Case A

- **Scenarios 1, 2 and 3**

Scenario 1 is the *status quo* test case scenario for Case A and it includes the possibility of transformer tap changes and power plant redispatch. Power plant redispatch is provided by the possibility of reducing the biomass power plant production to its technical minimum. For the German case such a production level corresponds to 40% of its maximum production capacity as it exists in 2015. As for reactive power flexibility, no additional amount is considered, so the observed variation should be small.

For Scenario 1, the following flexibility criteria are defined:

- Transformer tap changes
- Power plant redispatch: 63.54 MW

Scenarios 2 and 3 are constructed from Scenario 1, but allow for RES reactive power control (Q(U) control) and RES active power curtailment. These flexibility criteria relate only to the wind generation units, which are considered as being operating at 66% of their maximum capacity. For Scenario 2, only wind generation capacity built after 2015 is considered. For Scenario 3, the total wind generation capacity considered matches the total capacity as it is projected to be by 2020. For these scenarios it can be expected that both active and reactive power flexibility ranges are going to be significantly widened.

Scenario 2 is characterized by the following allowed flexibility:

- Transformer tap changes
- Power plant redispatch: 63.54 MW
- RES reactive power control: 52.99 Mvar
- RES curtailment: 121.17 MW

Scenario 3 counts with following allowed flexibility:

- Transformer tap changes
- Power plant redispatch: 63.54 MW
- RES reactive power control: 135.54 Mvar
- RES curtailment: 171.41 MW
-

For the conduced simulations, Figure 187 presents the obtained results.

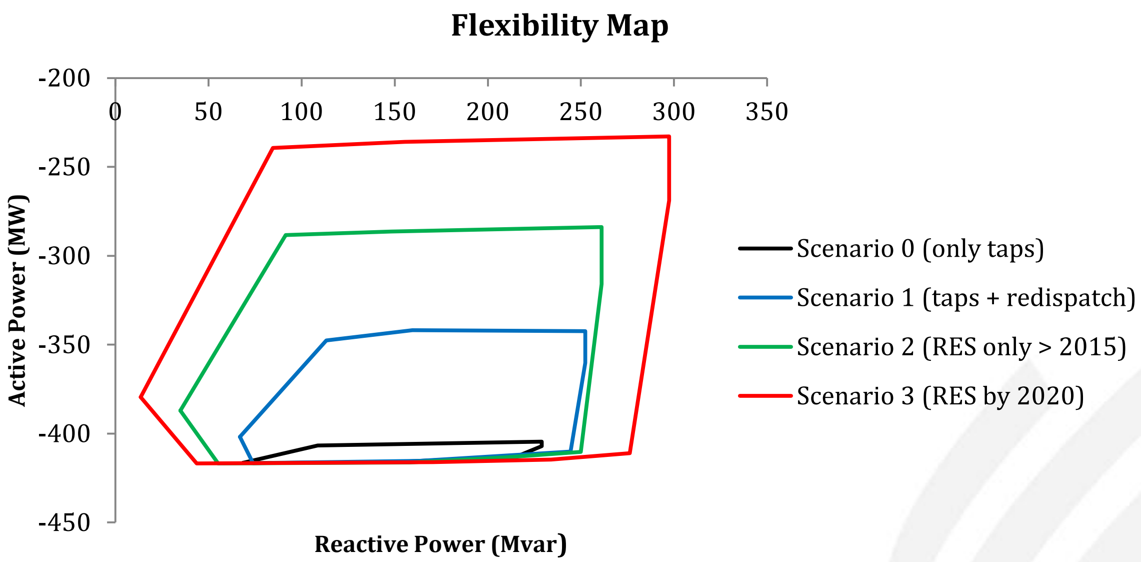


Figure 187 - Flexibility Map for scenarios 1, 2 and 3 – mid-term– Case A

Through the inspection of Figure 187, it is possible to verify that the flexibility area grows sequentially from Scenario 1 to Scenario 3. Such an observation was expected, since the allowed flexibility grows between scenarios. The flexibility area for Scenario 1 is shown to be covering the Scenario 0 area, since active power curtailment was allowed. As for the reactive power flexibility range, only a small increase is verified, because no additional flexibility was allowed.

The obtained area for Scenario 2 covers the one from Scenario 1, since in addition to the possibility of transformer tap change variations and power plant redispatch, RES reactive power control and active power curtailment were considered. For Scenario 2, both active and reactive power flexibility ranges have grown. Scenario 3 flexibility area covers the obtained area for Scenario 2 and so the remaining scenarios areas. By 2020, the total RES production capacity is projected to surpass the current existing capacity and so, as it was expected, the active and reactive power flexibility ranges cover all the previous simulation scenarios.

- **Scenarios 4, 5 and 6**

Scenarios 4 and 5 depart from Scenario 2 flexibility criteria with the addition of storage devices. For Scenario 4, two storage devices were added to the substations of *Wehrendorf* and *Ibbenbüren*. For each storage device a total capacity of ±25 MW was defined, amounting to ±100 MW. As for Scenario 4, the same storage capacity was added, but distributed over all the HV/MV substations. Taking into account the added flexibility sources it is expected that both de minimum and the maximum active power flexibility limits are going to be widened in relation to the previous simulation scenarios.

Scenario 6 is the last simulation scenario and it comprises the superposition of all the previous scenarios flexibility criteria. As such, it can be expected that both active and reactive power flexibility ranges are going to be the biggest from all the simulation scenarios.

For Scenario 4 and 5, the following flexibility criteria are considered:

- Transformer tap changes
- Power plant redispatch: 63.54 MW
- RES reactive power control: 52.99 Mvar
- RES curtailment: 121.17 MW
- Storage devices (central/distributed): ±50 MW

The obtained results for scenarios 4, 5 and 6 can be observed in Figure 188.

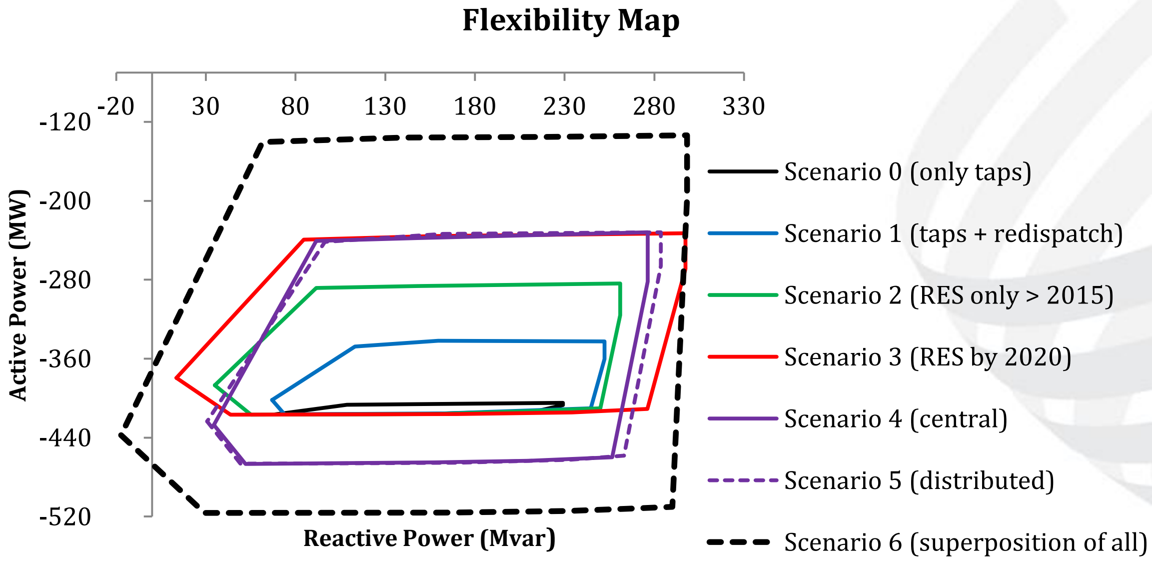


Figure 188 - Flexibility Map for all the simulation scenarios – mid-term– Case A

Figure 188 clearly shows that the obtained area for scenarios 4 and 5 covers all the previous simulation scenarios with the exception of Scenario 3 which has a wider reactive power flexibility range, since it considers the RES generation capacity as it is expected to be by 2020. Moreover, since the storage devices can exchange active power with the distribution network in a bidirectional way, both active power minimum and maximum limits have grown. The reactive power flexibility ranges for Scenarios 4 and 5 have been slightly widened. Looking in a more general way to the obtained results it is possible to verify that no significant difference between the flexibility ranges for the centralized and distributed storage scenarios was observed. This might be due to the fact the network is operating far from the technical limits (voltage limits and branch capacities).
Scenario 6 covers all the previous scenarios flexibility area as it was expected. Its flexibility ranges represent the maximum ranges possible to obtain with the defined criteria, as Scenario 6 criteria is comprised by the previous scenarios allowed flexibility.

Having proceeded with the analysis of the simulation results, Table 196 provides a summary for the conduced simulations scenarios description. The obtained results are also shown in a more compact format. As a final remark, it should be noted that the observed difference between the specified and the verified flexibility values from the obtained results can be explained by taking into account the flexibility ranges that are provided by the transformers with tap change capability (see scenario 0 results).

Table 196 - Scenarios description and flexibility ranges for the German Network for Case A simulations

Simulation scenarios for Case A (wind generation at 66%)		Flexibility Ranges			
		Active Power (MW)		Reactive Power (Mvar)	
Scenario	**Description**	**Scenario criteria**	**Verified from results**	**Scenario criteria**	**Verified from results**
0	only transformer taps changes	---	11.97	---	160.39
status quo	taps changes and power plant redispatch	63.54	74.79	---	185.45
2	*status quo* and RES curtail and Q(U) control (only RES built after 2015)	121.17	132.84	52.99	226.18
3	*status quo* and RES curtail and Q(U) control (RES by 2020)	171.41	183.87	135.54	283.94
4 & 5	scenario 2 and storage devices at substations (central and distributed)	221.17	228.69	52.99	262.92
6	superposition of all the above	371.41	382.72	135.54	315.57

- ***CASE B – High RES Production***

Test case "Case B" for the German distribution network is based on a snapshot for which the system is operating with a high level of RES production (wind generation is at 93% of its maximum capacity). In section 4.2.2.2, the parameter(s) of WP1 scenario(s), the characteristics of the current network and the criteria to link the scenario with the simulation details were presented (see Table 156). The available flexibility sources for Case B are the same as previously used, but the flexibility criteria are different.

No load flexibility is allowed. A total of six different scenarios were constructed, based on an incremental allowed flexibility logic. Table 199 presents the simulation scenarios description and the main results obtained with the ICPF tool.

- ***Status Quo***

The *status quo* scenario represents the present situation for the German network and it allows only for transformer tap changes and existing RES reactive power control as sources of flexibility. Specifically, *status quo* is characterized by the following allowed flexibility:

- Transformer tap changes
- RES reactive power control: 259.52 Mvar

Figure 189 presents the obtained flexibility area.

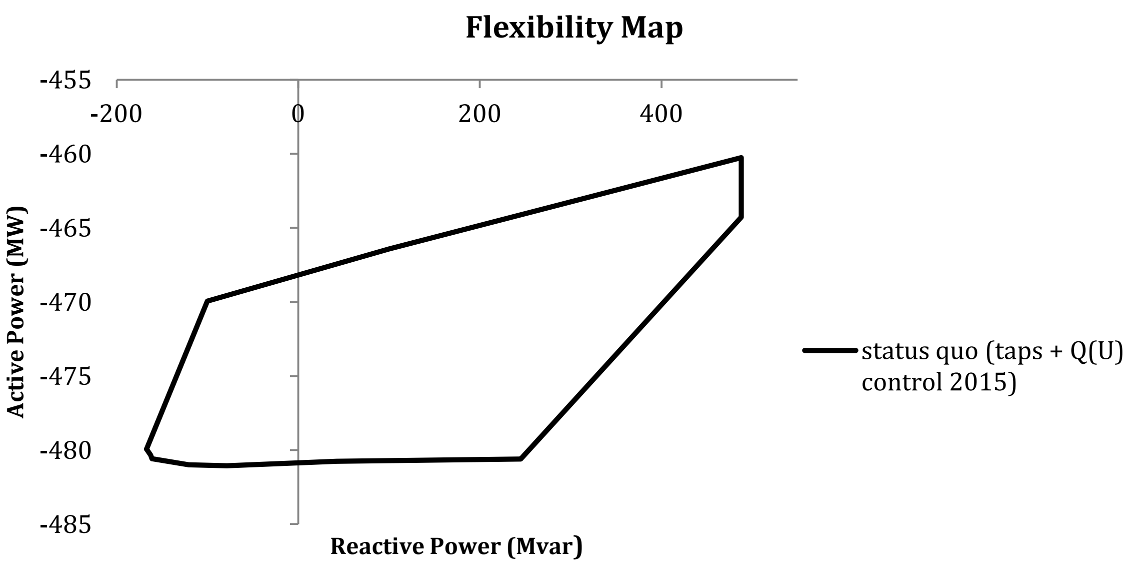


Figure 189 - Flexibility Map for status quo test case scenario– mid-term– Case B

As it can be seen, the obtained flexibility range for the reactive power is quite significant. Such an observation was expected, since the variation of transformer taps is related with voltage regulation. As we know, for highly inductive networks the reactive power flow is closely linked to voltage regulation. The *status quo* reactive power flexibility range has a value of 657.48 Mvar. The scenario directly defined criteria amounted to 259.52 Mvar. Considering this two values, it can be said that by only changing the transformer taps positions, a total of 397.96 Mvar of flexibility are provided. As it was previously stated, the German network has a large number of power transformers, so this value is in accordance with the expected results. Regarding the active power, a small flexibility range was obtained (20.80 MW), since no active power flexibility criteria was considered. Such a result is due to power losses.

- **Scenarios 1, 2 and 3**

Scenarios 1, 2 and 3 account for the same flexibility criteria as *status quo* scenario, but allow also for power plant redispatch and RES reactive power control and curtailment. Scenario 1, considers the possibility of biomass power plants redispatch, allowing the reduction of active power production to 40% of their current maximum capacity. The biomass power plants are considered to be operating at 100% of their total capacity, so up to 60% of their production can be curtailed. As for the reactive power flexibility criteria, it stays the same as for *status quo* scenario.

For Scenario 1, the following flexibility criteria are defined:

- Transformer tap changes
- RES reactive power control: 259.52 Mvar
- Power plant redispatch: 65.67 MW

Scenarios 2 and 3 consider the same flexibility criteria as Scenario 1, but allow also for additional active power curtailment, which is provided by RES generation units. For these scenarios, only wind generation was considered. For Scenario 2, only wind generation units built after 2015 were considered. For Scenario 3, the considered wind generation capacity corresponds to the one that its projected to be available by 2020. Case B is characterized by a high RES penetration, so the wind units are considered to be producing at 93% of their maximum capacity.

Scenario 2 is characterized by the following allowed flexibility:

- Transformer tap changes
- RES reactive power control: 259.52 Mvar
- Power plant redispatch: 65.67 MW
- RES curtailment: 401.25 MW

Scenario 3 counts with following allowed flexibility:

- Transformer tap changes
- RES reactive power control: 259.52 Mvar
- Power plant redispatch: 65.67 MW

- RES curtailment: 686.59 MW

For the current simulation scenarios, it can be expected that the active power flexibility range will grow significantly, whilst the reactive power range will vary slightly.

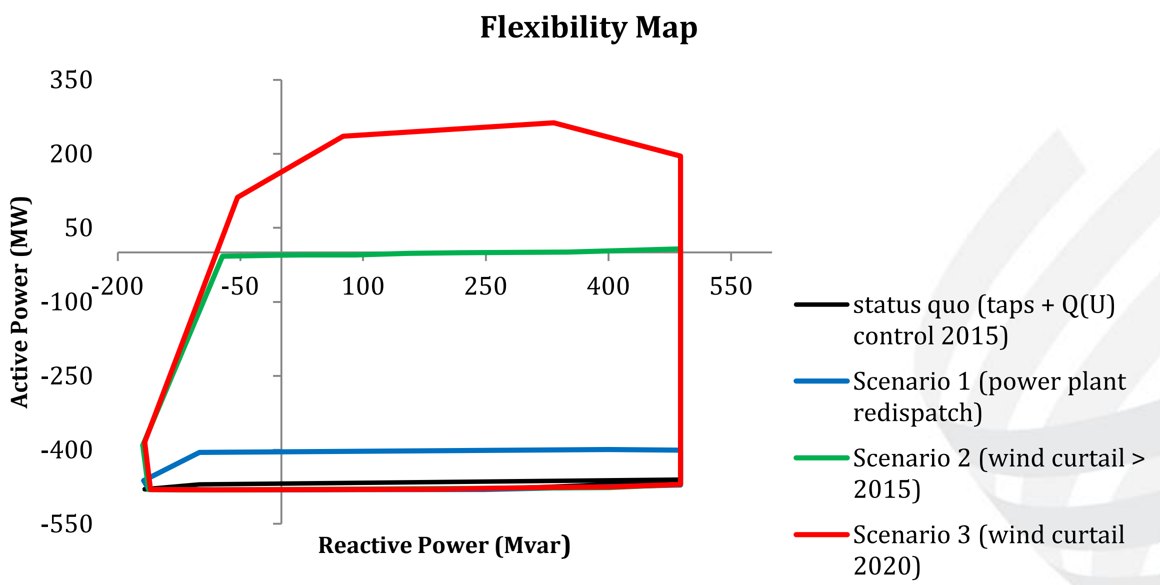


Figure 190 - Flexibility Map for scenarios 1, 2 and 3 – mid-term– Case B

Through the inspection of Figure 190, it can be seen that the obtained results are in accordance with the expected variations between scenarios. Since no additional reactive power flexibility criteria were added, no significant variation was observed. As for the active power, a considerable increase was obtained from scenario 1 to 3. By comparison with scenarios 2 and 3, Scenario 1 experiences only a small increase for the active power range, since 65.67 MW of biomass production are allowed to be curtailed. For scenarios 2 and 3, 401.25 MW and 686.59 MW of wind power can be curtailed, respectively. So, it should not be surprising the observation of such an increase for the active power flexibility range.

○ Scenarios 4 and 5

For the previous simulation scenarios, only biomass power plant redispatch, RES curtailment and reactive power control were allowed. Scenarios 4 and 5 consider the addition of storage devices, providing the possibility of injecting/absorbing active power. Through such and addition, not only the maximum active power value is going to be increased, but the minimum value, as well. For Scenario 4, two storage devices with a capacity of ±25 MW each were considered to be installed at the *Wehrendorf* and *Ibbenbüren* primary substations. As for Scenario 5, the same storage capacity was considered, but spread over all the HV/MV substations. Given the above stated, it is expected that the active power flexibility is going to grow for both scenarios.

For Scenario 4 and 5, the following flexibility criteria are considered:

- Transformer tap changes
- RES reactive power control: 259.52 Mvar
- Power plant redispatch: 65.67 MW
- RES curtailment: 686.59 MW
- Storage devices (central/distributed): ±50 MW

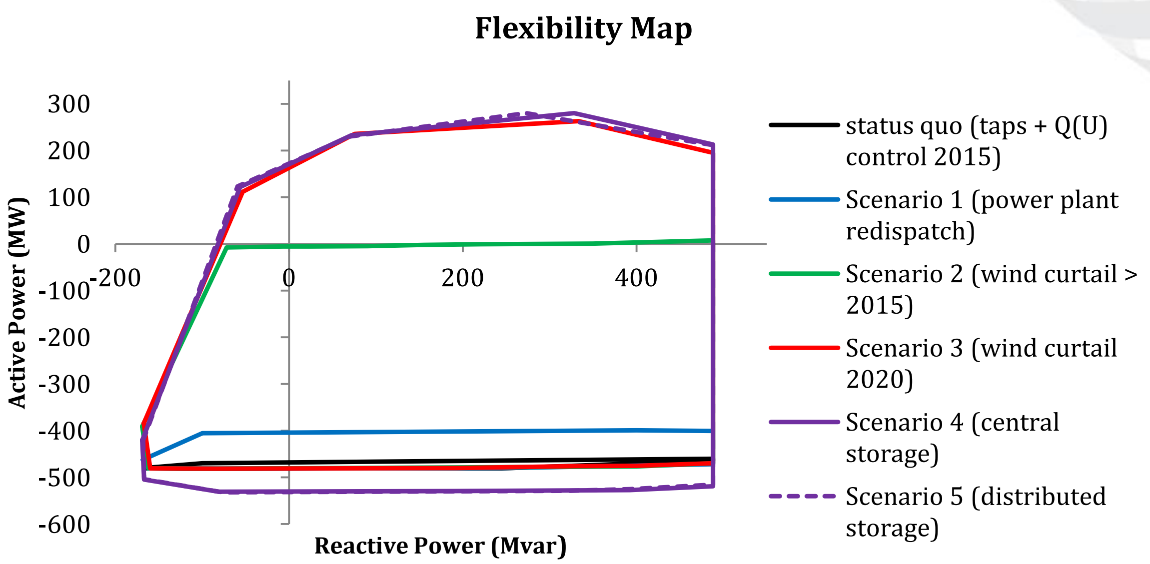


Figure 191 - Flexibility Map for all the simulation scenarios – mid-term– Case B

Figure 191 shows all the simulation scenarios obtained flexibility area. As expected, scenarios 4 and 5 flexibility areas cover all the previous scenarios areas. Both scenarios have the defined flexibility criteria from the previous scenarios, with the additional possibility of absorbing/injecting active power. Such a possibility, allows for the increase of both minimum and maximum active power limits. Comparing scenarios 3, 4 and 5, it is possible to notice that the maximum active power value is very similar for all of them (around 280 MW). Such an observation indicates that the network maximum operating point has been reached, given the allowed flexibility values. This means that even if more flexibility was added, it would never be used, since it would certainly lead to the violation of the network branch flow limits.

Table 197 below, presents a short summary for the test case scenarios description and the corresponding obtained results.

Table 197 - Scenarios description and flexibility ranges for the German Network for Case B simulations

Simulation scenarios for Case B (wind generation at 93%)		Flexibility Ranges			
		Active Power (MW)		Reactive Power (Mvar)	
Scenario	**Description**	**Scenario criteria**	**Verified from results**	**Scenario criteria**	**Verified from results**
status quo	transformer taps changes and Q(U) control for existing RES (2015)	---	20.80	259.52	655.33
1	*status quo* and power plant redispatch	65.67	81.61	259.52	656.40
2	scenario 1 and wind curtail (only wind built after 2015)	466.92	488.23	259.52	657.38
3	scenario 2 and wind curtail (wind by 2020)	752.26	744.12	259.52	655.30
4	scenario 3 and storage devices at primary substations (central)	852.26	810.75	259.52	657.12
5	scenario 3 and storage devices at HV/MV substations (distributed)	852.26	811.90	259.52	656.22

- **Operational KPI's**

The performance and effectiveness of the ICPF tool can be evaluated through two operational KPI's that were presented in D3.3. In the one hand, the flexibility area that was obtained with the ICPF tool will be compared with the flexibility area achieved through the Monte Carlo Simulation (MCS). Therefore, the flexibility area increase will be measured. In the other hand, the computational time reduction will result from the comparison between the average time of the power flows that were ran in the MCS and the average times of the OPF's that were obtained with the same program used to run the power flows in the MCS. Moreover, the MCS has been run for 1000, 10000 and 100000 randomly extracted samples.

Table 198 – Operational KPI's for the German distribution network – Case B

Scenario	Flexibility area increase (% of area)			Computational time reduction (% of time)		
	1 000 samples	10 000 samples	100 000 samples	1 000 samples	10 000 samples	100 000 samples
status quo	93.9	91.4	87.3	74.4	97.7	99.8
1	95.8	93.7	91.2	75.9	97.7	99.8
2	94.1	92.2	90.0	54.0	95.3	99.6
3	92.9	89.9	86.7	58.5	95.6	99.6
4	92.1	90.1	86.4	69.3	96.9	99.7
5	94.8	89.9	87.0	58.0	95.8	99.6

Table 198 shows the KPI's that were obtained for the Case B simulation scenarios. Since the MCS is based on a sampling process, it was not able to identify the high and the low system's operating limits. Therefore, it was already expected that the ICPF tool would lead to an increase of the size of the estimated flexibility area. Moreover, the flexibility area increase that can be observed in Table 198 has a considerable value. Furthermore, a considerable reduction in terms of computational was obtained. Having these conclusions in mind is easy to understand that the ICPF tool led to an increase of the flexibility area in less computational time.

○ *CASE C – Low RES Production*

Test case "Case C" for the German distribution network is based on a snapshot for which the system is operating with a low level of RES production (wind generation is at 9% of its maximum capacity). In section 4.2.2.2, the parameter(s) of WP1 scenario(s), the characteristics of the current network and the criteria to link the scenario with the simulation details were presented (see Table 156). The available flexibility sources for Case C are the same as previously used for Case B.

Like previously stated, no load flexibility is allowed. A total of six different scenarios were constructed, based on an incremental allowed flexibility logic. Table 199 presents the simulation scenarios description and the main results obtained for the conduced simulations using the ICPF tool.

○ *Status Quo*

For the *status quo* test case scenario, only transformer tap variations and existing RES reactive power control are allowed as flexibility sources. Thus, a wide flexibility range can be expected for the reactive power. As for the active power range, it is expected to be small when compared to the reactive power range, since no flexibility criteria are linked to it.
This way, *status quo* test case scenario is characterized by the following flexibility criteria:

- Transformer tap changes
- RES reactive power control: 84.57 Mvar

Figure 192 shows the region of feasible values of active and reactive power exchange in the boundary node.

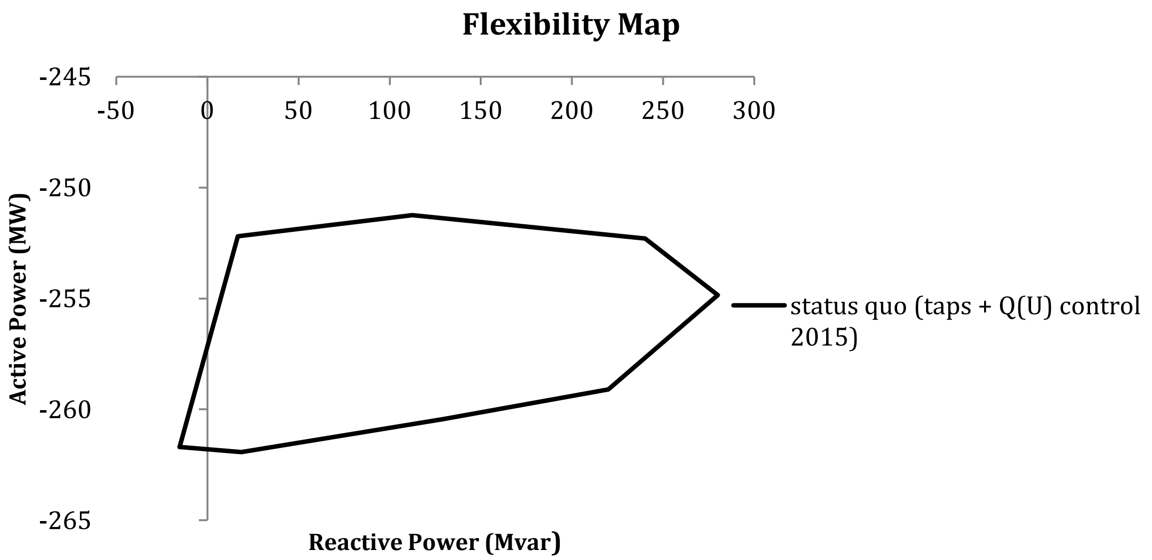


Figure 192 - Flexibility Map for *status quo* test case scenario– mid-term– Case C

Given that only flexibility criteria regarding the reactive power control were included, the obtained results are in accordance with the expectation. A total range of 84.57 Mvar was defined for RES reactive power control. Since the obtained flexibility range is equal to 295.22 Mvar, this means that the transformer tap changes alone provide for a range of 210.65 Mvar. Like previously observed, when there is only reactive power control available, the obtained active power flexibility range is small. This small range of 10.68 MW is due to power losses.

- **Scenarios 1, 2 and 3**

Scenarios 1, 2 and 3 are characterized by different flexibility criteria when compared to *status quo*. Departing from the previous simulation scenario, active power flexibility is also considered. For all scenarios the reactive power flexibility criteria remains the same.
For Scenario 1, power plant redispatch is allowed. Such a redispatch is provided by the possibility of reducing the biomass power plant production to 40% of its maximum production, as it currently exists (in 2015).

For Scenario 1, the following flexibility criteria are defined:

- Transformer tap changes
- RES reactive power control: 84.57 Mvar
- Power plant redispatch: 65.67 MW

Test case scenarios 2 and 3 are constructed from Scenario 1, but allow the curtailment of wind production. As above stated, for Case C the wind production is considered to be at 9% of the total wind capacity. For Scenario 2 only wind generation capacity built after 2015 is considered. Scenario 3 considers the projected wind generation capacity by 2020. Since the active power flexibility criteria as been increased for the current simulation scenarios, a growth regarding the obtained active power flexibility ranges can be expected.

Scenario 2 allows for:

- Transformer tap changes
- RES reactive power control: 84.57 Mvar
- Power plant redispatch: 65.67 MW
- RES curtailment: 27.01MW

Scenario 3 counts with:

- Transformer tap changes
- RES reactive power control: 84.57 Mvar
- Power plant redispatch: 65.67 MW
- RES curtailment: 46.21 MW

For the descripted scenarios, Figure 193 presents the obtained results.

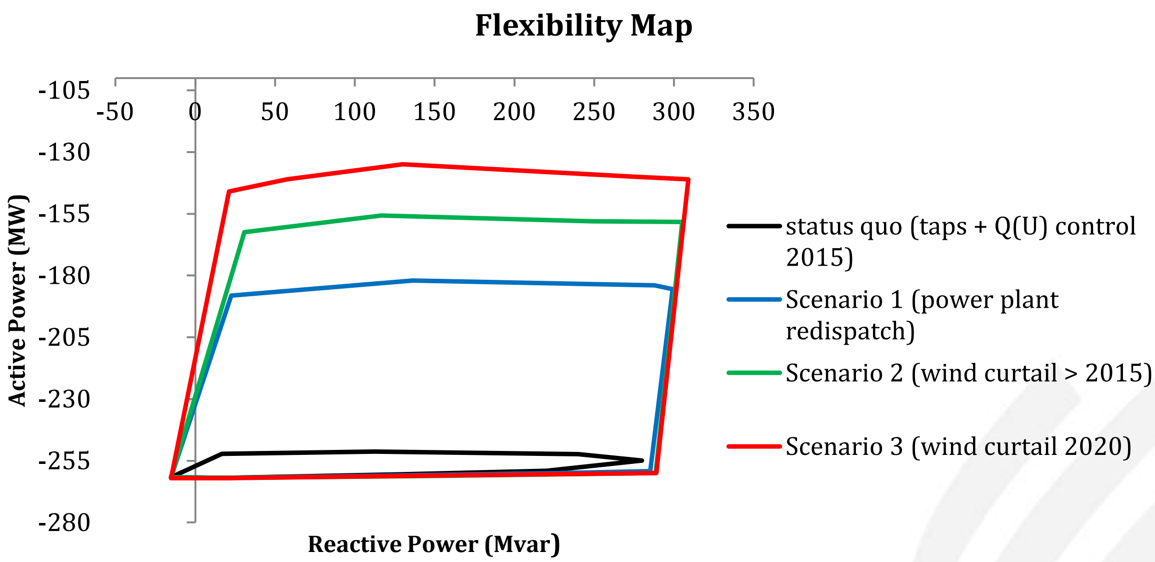


Figure 193 - Flexibility Map for scenarios 1, 2 and 3 – mid-term– Case C

Through the inspection of the presented figure, it can be seen that the obtained active power flexibility ranges follow the specified increase for active power production. Scenario 1 area is shown to be covering the obtained flexibility area for the *status quo* scenario, since active power flexibility was added. As for the reactive power flexibility range, no significant variation was observed, because no additional flexibility was considered.
Scenarios 2 and 3, both cover the flexibility area obtained for Scenario 1, because more active power flexibility was added. Scenario 3 covers Scenario 2 area, because the projected total wind generation capacity for 2020 is greater than the current wind capacity. Just like for Scenario 1, no additional reactive power flexibility criteria was considered, which results on an almost unnoticeable variation regarding the associated flexibility range.

- **Scenarios 4 and 5**

Scenarios 4 and 5 flexibility criteria are defined on top of Scenario 3 criteria, including the addition of storage devices. For Scenario 4, two storage devices were considered to be installed at the *Wehrendorf* and *Ibbenbüren* substations. Just like before, each storage device will have a total capacity of ±25 MW. For Scenario 5, the same amount of storage capacity is considered, but spread over all the HV/MV substations. Taking into account the defined flexibility criteria, it can be expected that the minimum and maximum active power flexibility limits will increase, since the storage devices can either inject or absorb active power.

For Scenario 4 and 5, the following flexibility criteria are considered:

- Transformer tap changes
- RES reactive power control: 84.57 Mvar
- Power plant redispatch: 65.67 MW
- RES curtailment: 46.21 MW
- Storage devices (central/distributed): ±50 MW

The obtained results for Scenarios 4 and 5 can be observed in Figure 194, which presents the flexibility areas for all the simulation scenarios.

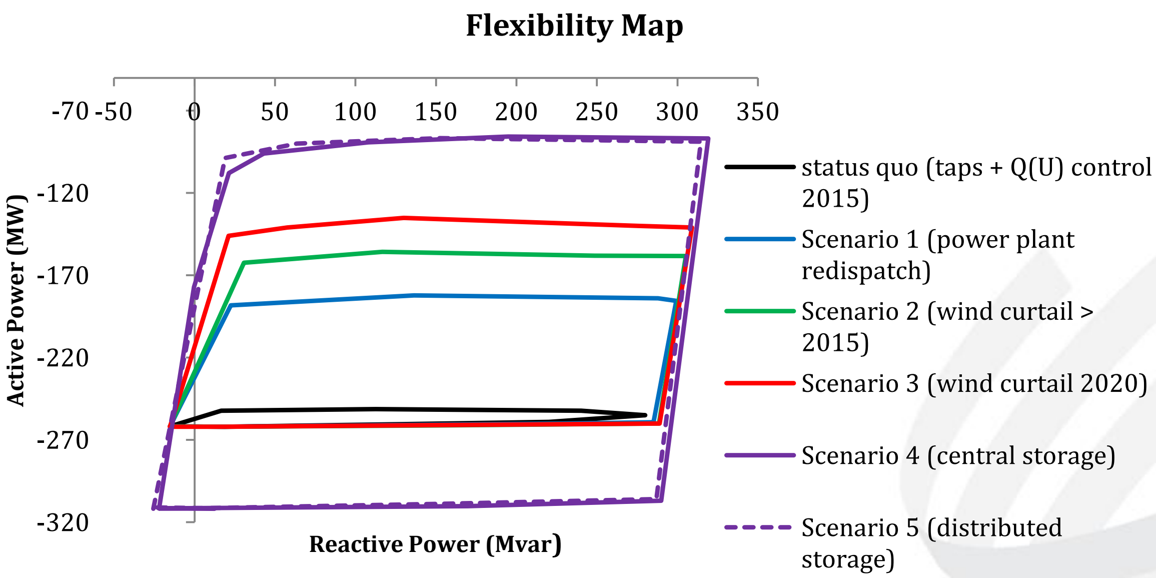


Figure 194 - Flexibility Map for all the simulation scenarios – mid-term– Case C

Figure 194 supports the assumption that the installation of storage devices significantly widens the active power flexibility range for Scenarios 4 and 5. Regarding the reactive power flexibility range, no considerable variation was obtained. These results are in accordance with the expected. Scenarios 4 and 5 flexibility areas are shown to be covering the obtained areas for all the previous scenarios, since they have the greatest allowed flexibility criteria for Case C.

Table 199, presented below, provides a short summary for the test case scenarios description and the corresponding obtained results.

Table 199 - Scenarios description and flexibility ranges for the German Network for Case C simulations

Simulation scenarios for Case C (wind generation at 9%)		Flexibility Ranges			
		Active Power (MW)		Reactive Power (Mvar)	
Scenario	**Description**	**Scenario criteria**	**Verified from results**	**Scenario criteria**	**Verified from results**
status quo	transformer taps changes and Q(U) control for existing RES (2015)	---	10.68	84.57	295.22
1	*status quo* and power plant redispatch	65.67	79.84	84.57	314.49
2	scenario 1 and wind curtail (only wind built after 2015)	92.68	106.28	84.57	320.40
3	scenario 2 and wind curtail (wind by 2020)	111.88	127.00	84.57	324.20
4	scenario 3 and storage devices at primary substations (central)	211.49	225.99	84.57	341.03

5	scenario 3 and storage devices at HV/MV substations (distributed)	211.49	225.09	84.57	340.06

- **Operational KPI's**

For the German network Case C scenarios, Table 200 presents the two KPIs which allows us to access the effectiveness of the ICPF tool. The computational time reduction results from the comparison between the average time of the power flows that were ran in the MCS and the average times of the OPF's that were obtained with the same program used to run the power flows in the MCS. Like previously, the flexibility area increase was obtained using the ICPF tool. The MCS has been run for 1000, 10000 and 100000 randomly extracted samples.

Table 200 – Operational KPI's for the German distribution network – Case C

Scenario	**Flexibility area increase (% of area)**			**Computational time reduction (% of time)**		
	1 000 samples	10 000 samples	100 000 samples	1 000 samples	10 000 samples	100 000 samples
status quo	81.8	75.8	65.2	91.0	99.1	99.9
1	98.2	97.6	96.6	88.9	98.8	99.8
2	97.5	96.0	94.7	88.5	98.8	99.9
3	96.8	94.8	93.2	86.4	98.6	99.9
4	98.3	97.2	96.4	85.6	98.6	99.9
5	98.2	97.2	96.3	87.6	98.7	99.9

Like previously obtained for Case B, it is possible to verify that for Case C, an increase in the size of the estimated flexibility area was observed (see Table 200). Such an observation shows that in comparison with Monte Carlo Simulation, the ICPF tool is able to more accurately identify the high and low values for the network operating limits. Moreover, a significant computational time reduction was also achieved.

4.4 Conclusions, Main Benefits and Limitations

4.4.1 Sequential Optimal Power Flow (SOPF)

The main objective of the Sequential OPF tool is to provide a set of control set-points for the different flexibilities in the distribution system in order to maintain the power exchanged between transmission and distribution systems within the authorized minimum and maximum limits. This document intended to demonstrate several results when applying the SOPF tool to real networks.

4.4.1.1 Portuguese networks

For the Portuguese case, there were made several tests using two Portuguese networks considering different scenarios of consumption, generation and available flexible resources. The results obtained with the simulations showed that the total power losses increase along with the scenarios as the profiles of demand and generation are increasing. The percentage of

improvement of active power losses was higher in the Western network reaching the maximum value of 9.9% in scenario 6, but the tool was able to reduce the active power losses in all simulations. The reconfiguration of the topology did not occur in any of the networks. The Northeast network is normally operated in closed loop which difficult to obtain a better solution. The Western network, as well as Northeast, had active power limits at primary substations that were higher compared to effective power injection. Probably due the fact of these limits were not surpassed, the tool was not capable to change the configuration. This situation also led to results where no flexible resources were activated. In these simulations the tool was able to avoid high penalizations by surpassed reactive power limits related with tg φ by managing the taps of transformers and capacitor banks.
As it happened with the simulations for French networks, the SOPF tool was able to proceed to an optimization of the voltage control, improving the total power losses and reducing the total costs covering several sequential timeframes while taking into account the different scenarios. Moreover, the simulations were made in a reasonable execution time using real and large networks.

4.4.1.2 French networks

Several tests were performed with two French distribution networks ("network 5" and "network 6") considering different scenarios of consumption, wind power penetration, available flexible resources, time of the year and limits at the TSO-DSO boundaries. The results obtained with the simulations for winter scenarios reveal that the flexible costs tend to be higher in these scenarios due the increased power consumption, which causes more values out of the boundaries and more activations of flexibilities. Both networks do not have a lot of opened and operable switching devices in the initial configuration which reduces the freedom to change the configuration starting point. During the simulations, several flexible loads were activated, especially to decrease their consumption. No wind curtailment occurred in these simulations. The minimum limits of injected active power by the primary substations are responsible for this situation. Using tighter limits would cause different results regarding the wind curtailment.
The costs used for penalize the power out of boundaries at substations considered only the variable cost term depending on the amount that exceeded the limits. The changing of the taps of transformers between periods had a small cost weight in regards to the total flexible costs, in order to penalize the solutions that use several consecutive operations in transformers.

Starting from the initial network configurations, the SOPF tool was able to proceed to an optimization of the voltage control and the flexibility activations for a period covering several sequential timeframes while taking into account the different scenarios. Moreover, the simulations were made in a reasonable execution time using real and large networks.

4.4.2 Interval Constrained Power Flow (ICPF)

4.4.2.1 Portuguese Networks

The ICPF tool was tested for two Portuguese networks with very different characteristics. One of the analyzed networks presents more generation than the load available due to a high penetration of RES. There are situations in which part of the transmission network power flows through the distribution network. Considering this, the ICPF tool proved its effectiveness in two networks with very different characteristics. Usually scenarios with more flexibility available in the distribution network lead to higher flexibility areas (unless due to network constraints) and therefore they cover scenarios with less flexibility. For the Portuguese networks, scenarios with higher flexibility actually lead to higher flexibility areas. However, this does not mean that higher flexibility areas cover lower ones. This behaviour is related with the translation of the operating point. The higher increase of RES in the northeast network and the higher increase of the demand in the western network explain this. There was also possible to observe that in the northeast network the range of active power flexibility was increasing throughout the scenarios while in the western network this behaviour was not so visible. This is due to a higher impact of wind curtailment (higher wind power penetration) in the northeast network.

The obtained KPIs allowed to prove the effectiveness of the ICPF tool. The ICPF tool leads to a clear increase of the size of the estimated flexibility area when compared with the MCS. The problem presented by the MCS of identifies the high and the low cost zoned is consistently surpassed by the ICPF tool.

4.4.2.2 French Networks

The main conclusions can be drawn using the two operational KPIs that were computed for the ICPF for the different scenarios.
The comparison between the KPIs that were obtained through the ICPF tool and the ones obtained with the MCS prove the effectiveness and efficiency of the developed method. The ICPF tool leads to a clear increase of the size of the estimated flexibility area when compared with the MCS. This proves that the problem of identifying the high and the low cost zones was consistently solved by the ICPF tool.
Moreover, the computational time also displayed a clear reduction: a solution able to provide the increase of the flexibility area is obtained in less computational time than with MCS.

A limitation regarding the ICPF tool is related to the fact that the method is not totally optimized at this moment. It will be possible throughout a deeper optimization of the method to decrease the convergence time of the OPF's. Moreover, it was possible to observe that flexibility area increase of the status quo's scenario was not calculated. This is due to some convergence problems in these cases. This problem will be matter of further studies in order to find a solution.

4.4.2.3 German Networks

The German distribution network simulations were based on three different snapshots, representing various operating points. The main difference between cases relates to the considered RES production level. The conduced simulations aimed at obtaining the flexibility areas for multiple scenarios for each major case considering a moderate, a high and a low RES production level. For every case, the obtained flexibility areas were verified as being coherent with the pre-simulation defined flexibility criteria, except for the Case B scenarios 3, 4 and 5, where it was observed that the network's maximum operating point was reached. Such an observation meant that any additional flexibility would not contribute for the flexibility area increase, thus being wasted. It was also shown that one of the most significant sources of flexibility for the German network is the large number of power transformers that it comprises. By allowing only transformer taps changes, it was shown that a considerable reactive power flexibility range was obtained.

The analysis of the two operational KPIs for the German network allowed to verify that the ICPF tool provides a better description of the network operating limits when compared to the Monte Carlo Simulation results. From the obtained values, it was possible to comprehend that the ICPF tool allows for an increase in the size of the estimated flexibility area while providing, at the same time, a considerable reduction on the computational time.

5 Maintenance Domain

The two subtools that make up UCD's *advanced asset management* offline analysis tool sit within the "*Operation and Maintenance*" domain. Each subtool offers actionable insights to the distribution system planner, to improve the quality of asset renewal and maintenance planning decisions. How critical would the failure of a particular transformer be? What would be the financial implications of uprating a length of overhead line?

These questions are answered via two complementary sub-tools: an assets-renewal module, and a maintenance priorities module. In the following validating simulations, these tools are used to perform a desktop analysis on a sample distribution network. Various KPIs are used to gauge the improvement in network reliability and investment & operation cost that could be realized by making line maintenance and renewal decisions informed by the tool's insights.

5.1 Network Description

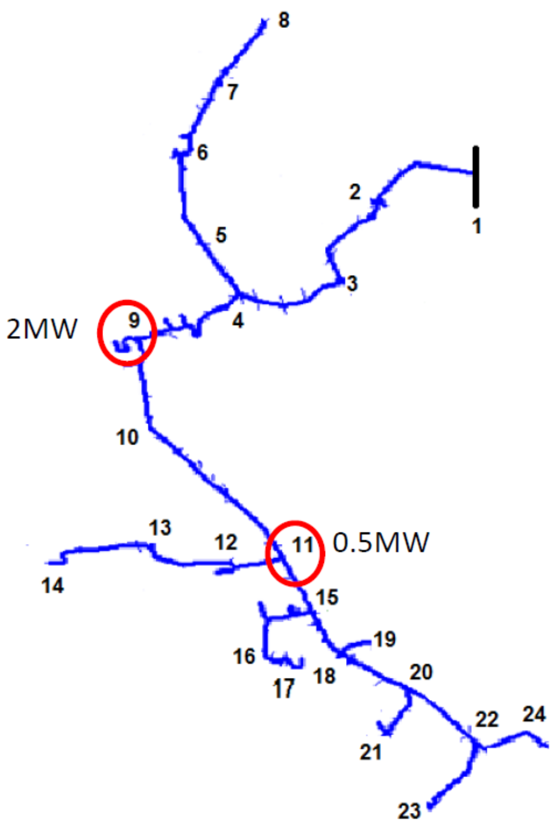


Figure 195 – The exemplary Irish rural network

The test network used for evaluating the performance of the algorithm is an Irish 20 kV distribution network fed by a 38 kV substation. A one-line diagram of this network is depicted in Figure 195, where the location and distribution of the consumers and distributed generation units are marked. In keeping with Irish norms, the generating sites were taken to represent wind farms. For this network, the technical characteristics of the network including the geographical coordinates of all the equipment are available. This network is about 10 km in length, serving a dispersed population. It is modelled with 24 buses and 22 branches. It serves a baseline load of around 16 MW.

5.2 Test Cases Description and Hypothesis

Horizon	Expectation	Scenario	Renewable penetration (%)	Total Wind (MW)	Duration (years)
	Current situation	0	14.2	2.5	-
Short term	Under expected	1	25.7	4.3	4
	Most likely	2	31	5.3	4
	Over expected	3	38	6.4	4
Medium Term	Under expected	4	32.2	5.5	10
	Most likely	5	40	6.8	10
	Over expected	6	50	8.5	10
Long term	Under expected	7	41	7	20
	Most likely	8	52	8.8	20
	Over expected	9	60	10	20

The test scenarios are used to demonstrate that the tool can optimize maintenance decision on a distribution network over the full range of renewable penetration levels that may manifest. The scenarios are based on the expectation envelopes described more fully in the deliverables of WP1. The range of DRES penetration levels considered is shown in Figure 196 and Figure 197.
The principal hypothesis to be tested is that optimal asset renewal and maintenance decisions will realise substantial improvements in the network's reliability and financial efficiency.

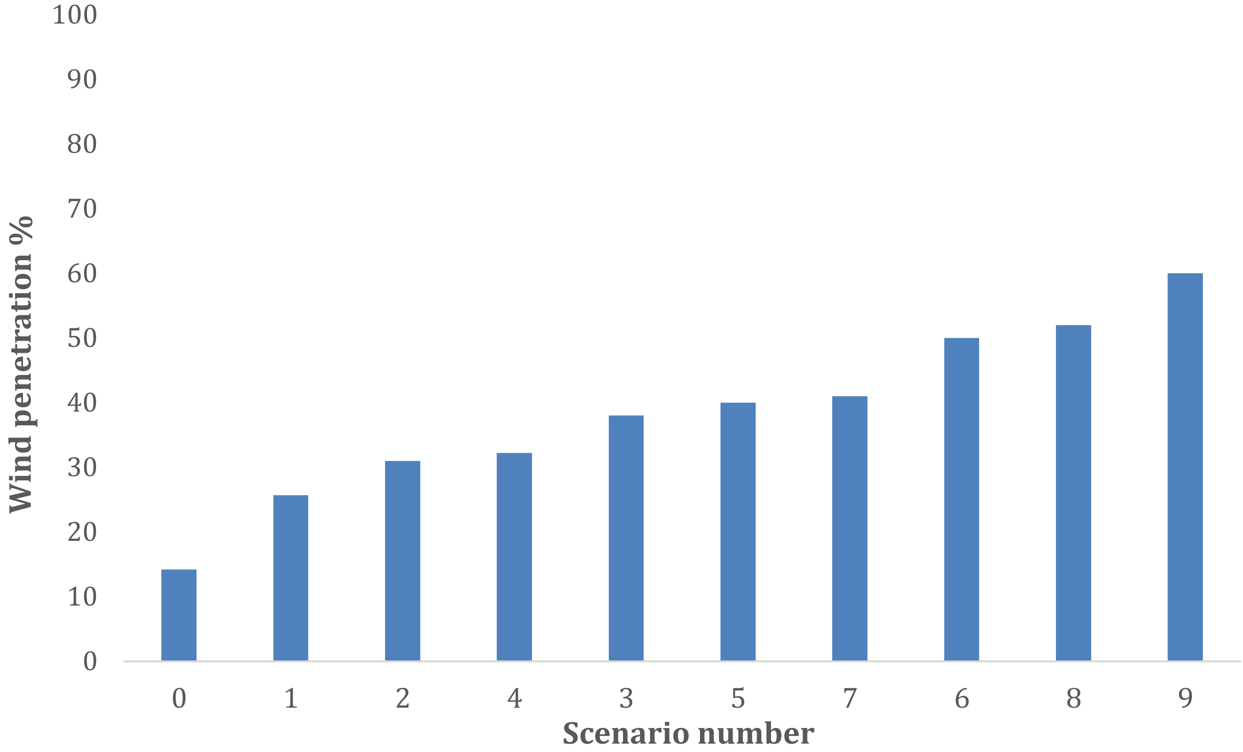


Figure 196 –Wind penetration levels for each scenario

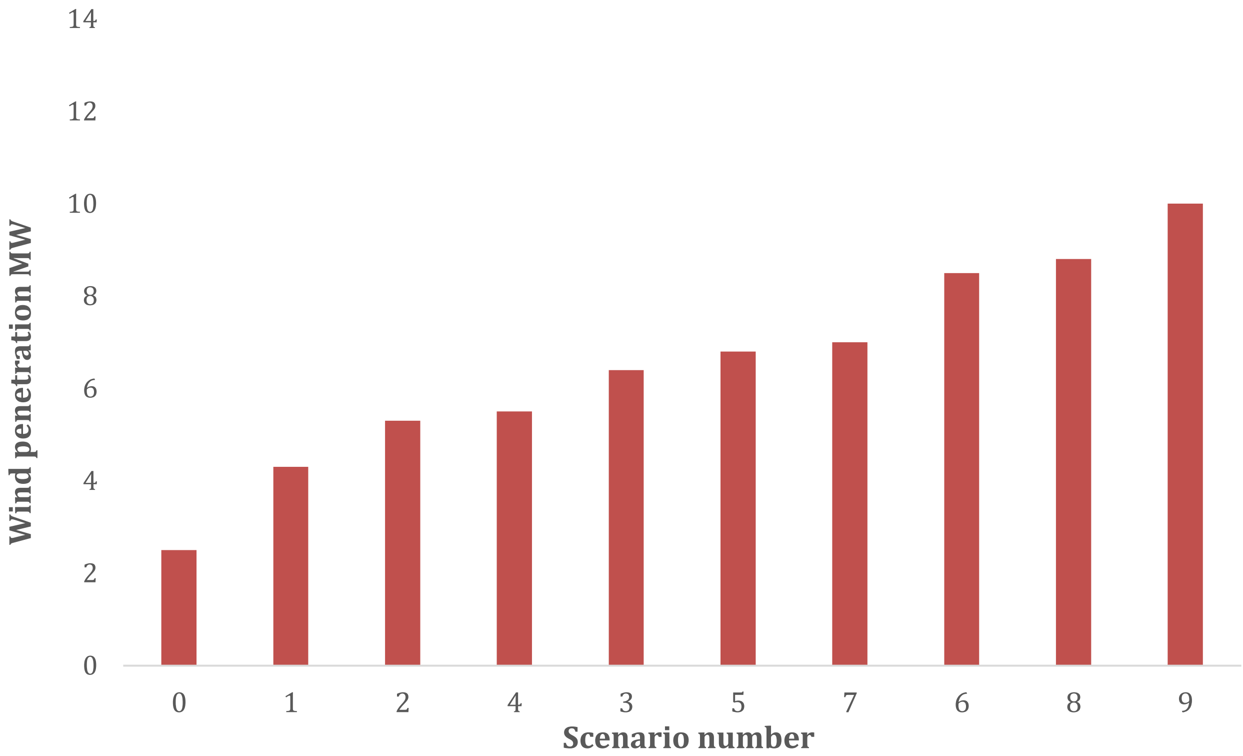


Figure 197 –Scenarios sorted by the installed MW capacity of wind on the network

5.3 Simulation Results of the Test Cases

The advanced asset management tool is applied on the test network, for a variety of scenarios, to inform exemplary asset renewal and maintenance plans. In each case, a 20 year planning and operation window is used. The enhanced asset renewal and maintenance regimes are compared against status quo network operating decisions to calculate the relevant KPIs and thusly to gauge the value of the tool's network insights.

5.3.1 Reliability analysis

For each scenario, the reliability improvement that can be realised by enhancing maintenance priorities in line with calculated asset risk levels is determined. This calculation is performed by first considering the potential impact of every individual line outage in terms of energy not supplied and customer minutes lost, as well as the attendant DRES curtailment. With this assessment in hand, the most critical components, taken to be the worst 5, are assumed to enjoy an enhanced monitoring and maintenance regime, thus increasing their availability by an assumed 5%. This improvement in network availability can then be compared against the business-as-usual case.

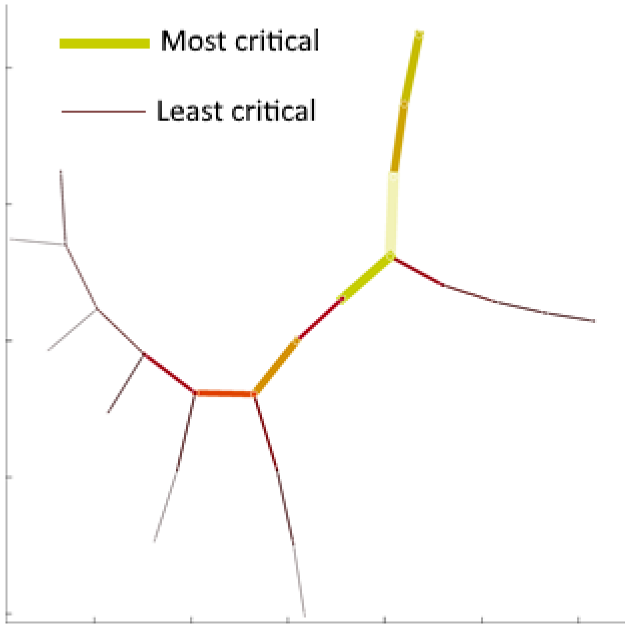


Figure 198 –The tool's visualization of the baseline energy-not-supplied risk associated with each electrical branch component in scenario 0

Figure 198 shows the baseline *risk* associated with each branch in the network for *scenario 0*. If an enhanced maintenance regime is then stipulated based on these risk levels, the network criticality profile shifts to that shown below:

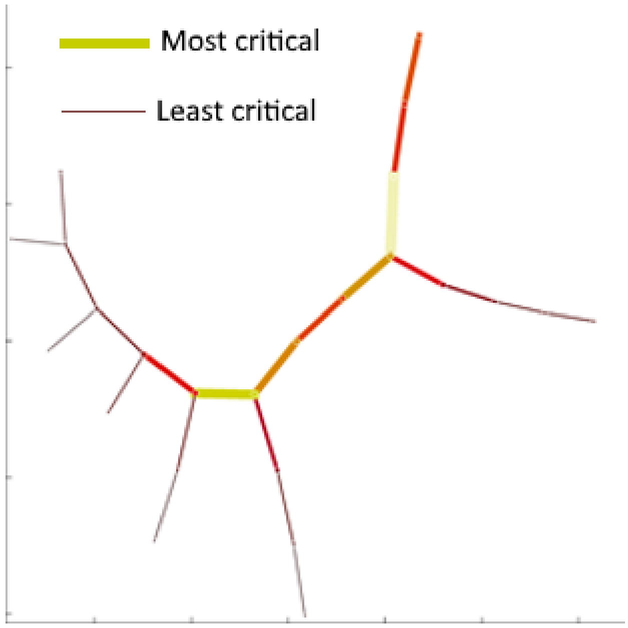


Figure 199 –The tool's visualization of the energy-not-supplied risk associated with each electrical branch component in scenario 0, assuming enhanced asset maintenance and inspection priorities

Conceptually, and by extension, the comparison of Figure 199 and Figure 198 is embodied in the KPIs which consider R_{enh}, CML_{enh} and $Curt_{enh}$

5.3.2 Asset renewal analysis

In each scenario, the tool considers a 20 year window over which to optimize the upgrading of conductors on the network. Conceptually, upgrading a line earlier results in a greater saving in losses over the planning period, however, the time value of money favours a delayed upgrade expenditure. The asset renewal subtool uses advanced computation techniques to balance these factors. The upgrade cost is taken to be 58, 000 Euros/km of line and the active losses penalty costs are taken to be 40 Euros/MWh. Annual demand growth is taken to be 2%. It is assumed that the existing lines are 185 XLPE (with 0.158 Ω/km) the upgrade option is 400 XLPE (with 0.106 Ω/km).
An investment pathway is calculated for each scenario, from which the KPIs can be derived. The financial efficiencies realised by this enhanced investment pathway is quantified with the frist KPI, which considers the discounted network renewal and operation cost.
The comparative business-as-usual case for the asset renewal analysis is taken to be a naïve loss-minimization strategy without considering the upgrade costs. In these conditions, the planner just tries to minimize the cost of energy losses. The optimal strategy simultaneously considers the losses and the discounted upgrade costs. The various trade-offs between these objectives can be shown as a Pareto front for each asset renewal appraisal.

5.3.3 Key Performance Indicators

5.3.3.1 Gauging network cost efficiency

The first KPI determines the extent that the optimal asset renewal tool improves the financial efficiency of the distribution system investment.

$$KPI_1 = C_{bau} - C_{opt}$$

This KPI makes a direct comparison, denominated in euros, between the cost of implementing the naïve and the enhanced asset renewal schedules.

The optimal asset renewal tool finds the Pareto optimal front in the first step, as shown in Figure 200.

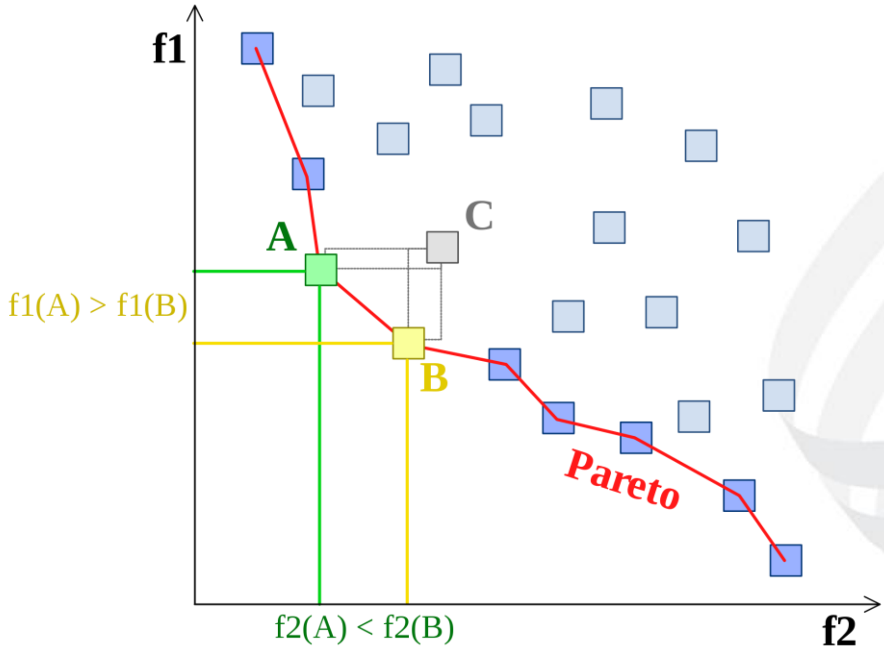


Figure 200 Typical Pareto optimal front for bi-objective optimisation (*f1* is the upgrade cost and *f2* is the active losses cost)

The second step performs a trade-off analysis to find a good solution. The fuzzy satisfying method is used for trade-off analysis. The fuzzy satisfying method, more fully described in [20], is implemented for this tool as follows:
In this problem, both objective functions should be minimized. Although they can be both expressed as Euros (and summed together), this may be inappropriate depending on the differing regulatory frameworks for different DSOs. The active loss compensation is treated differently in different countries. So, in order to enhance the capability of this tool it is modelled as a multi-objective problem. Additionally, the DSO can do the trade-off analysis to decide whether it should upgrade an asset or not. For this reason, the performance of each solution (i) on Pareto optimal front is normalized using the following equation:

$$\mu^i_{f1} = \frac{f_1 - f^1_{max}}{f^1_{min} - f^1_{max}}$$

f^1_{max}, f^1_{min} are the maximum and minimum values of *asset renewal cost* (f_1) on the Pareto optimal front.
The same procedure is done for active losses cost:

$$\mu^i_{f2} = \frac{f_2 - f^2_{max}}{f^2_{min} - f^2_{max}}$$

f_{max}^2, f_{min}^2 are the maximum and minimum values of $active\ losses\ costs$ (f_2) on the Pareto optimal front. In this way, the performance of each solution has two normalized values (one for each distinct objective function).
In the next step, the minimum value of these performance measures is calculated $(\mu^i{}_{f1}, \mu^i{}_{f2})$. This number will show the weakness of this solution (i) in optimizing both objective functions.
Finally, the solution with the strongest weakness is chosen as the final solution.

$$\max_{i}(\min\,(\mu^i{}_{f1}, \mu^i{}_{f2}))$$

5.3.3.2 Gauging network reliability

The second KPI assess the improvement that can be attained in aggregate network *risk* that can be effected by enhanced maintenance and inspection regimes informed by the tool. The risk is defined here as the expected energy not supplied, R, where R_{enh}, R_{bau} are the risk after and before network enhancement, respectively. A percentage comparison is made:

$$KPI_2 = \frac{R_{enh}}{R_{bau}} * 100\%$$

The next KPI assesses the extent that the tool can improve the quality of supply by reducing the customer minute lost, CML, where CML_{enh} and CML_{bau} are the customer minute lost before and after network enhancement, respectively:

$$KPI_3 = \frac{CML_{enh}}{CML_{bau}} * 100\%$$

The next KPI gauges the extent that this tool can reduce energy curtailment of RES and DER. The curtailment is defined as the total DER/RES Energy that cannot be injected to the grid $(Curt)$. $Curt_{enh}, Curt_{bau}$ are the anticipated energy curtailments before and after network enhancement, respectively.

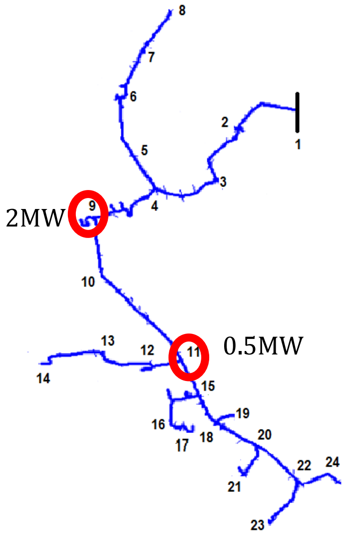
$$KPI_4 = \frac{Curt_{enh}}{Curt_{bau}} * 100\%$$

Finally, the reduced energy curtailment of RES and DER can also assessed using the KPI of Deliverable-D2-2. KPI B.2:

$$KPI_{EEGI} = \frac{E_{not\ injected}^{baseline} - E_{not\ injected}^{measured}}{E_{not\ injected}^{baseline}} * 100\%$$

5.3.4 Scenario Results

5.3.4.1 Scenario 0: Current situation



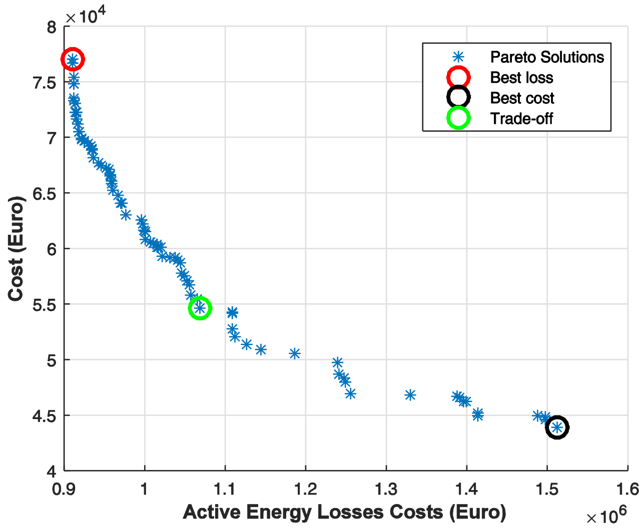


Figure 201 –Results of applying the tool under scenario 0

In Figure 201 is shown the pareto front calculated by the tool for the asset renewal plan on the network, under the scenario 0 conditions visualized on the left. The optimal trade-off here is marked with a green circle. Solution 11 is chosen using the described fuzzy satisfying method as the most appropriate solution.
The pursuit of this plan realises a cost saving quantified by this KPI:

$$KPI_1 = C_{bau} - C_{opt} = 0.1367 * 10^6 Euros$$

By using the tool to discover which network components are most critical, an enhanced maintenance and inspection regime can be followed. This improves network reliability as assessed with the following KPIs:
The second KPI assess the improvement that can be attained in aggregate network *risk* that can be effected by enhanced maintenance and inspection regimes informed by the tool. The risk is defined here as the expected energy not supplied, R, where R_{enh}, R_{bau} are the risk after and before network enhancement, respectively. A percentage comparison is made:

$$KPI_2 = \frac{R_{enh}}{R_{bau}} * 100\% = 92.4937\%$$

This means that the total expected energy not supplied is reduced by 7.5% by using the asset renewal management tool.
The KPI_3 shows how the quality of the service is improved using the reliability analysis tool. The customer minute lost is the average number of minutes per that a customer does not receive any service.

$$KPI_3 = \frac{CML_{enh}}{CML_{bau}} * 100\% = 92.5082\%$$

The quality of service is improved by 7.5%.

The KPI_4 shows how the technical performance of the distribution network is improved in order to absorb more energy from DRES.

$$KPI_4 = \frac{Curt_{enh}}{Curt_{bau}} * 100\% = 67.5341\%$$

$$KPI_{EEGI} = \frac{E_{not\ injected}^{baseline} - E_{not\ injected}^{measured}}{E_{not\ injected}^{baseline}} * 100\% = 32.47\%$$

KPI_{EEGI} and KPI_4 are decreased by 32.5%. This shows how the DSO has used the clean and local energy resources in a more efficient way. This index arises when RES is available, but the grid operator does not allow it to inject power into the grid because of certain technical issues. In other words, the RES cannot be dispatched. These technical issues might be because of thermal limits of the networks, voltage constraints or islanding caused by line outage.

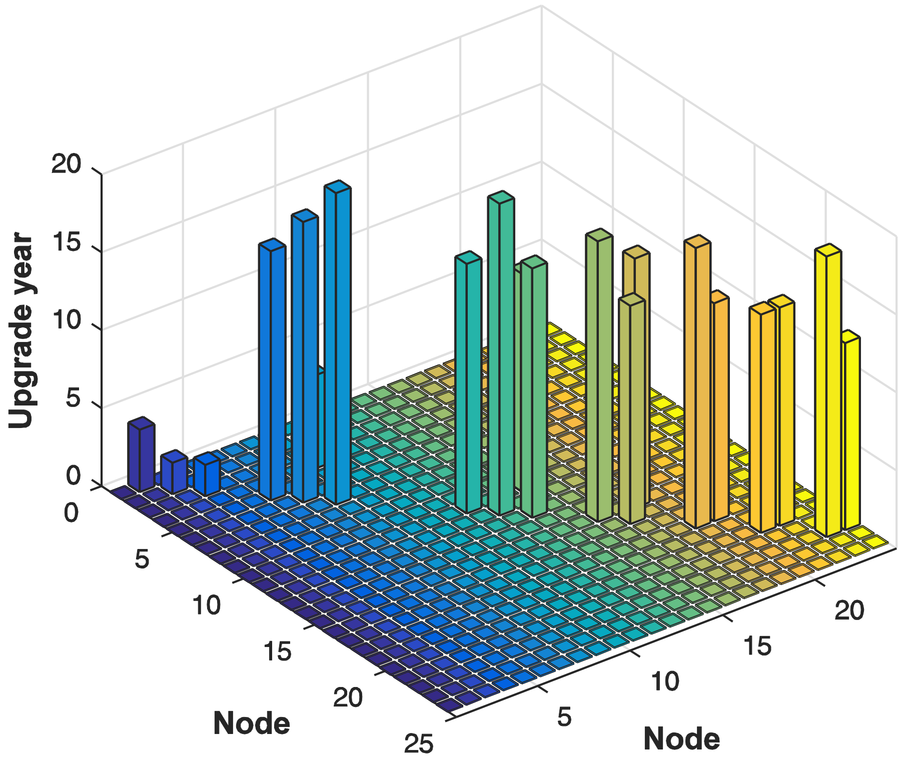


Figure 202 Timing of line upgrade for scenario 0

The optimal asset renewal plan for this scenario is depicted in Figure 202, which shows the year in which each branch ought to be upgraded. The location of each bar identifies its starting and ending node, and its height shows the year in which it should be upgraded. This data is also given in the below table. Here, the expected energy not supplied, EENS, associated with each line outage before and after the network upgrade is also given.

Line number	from	to	EENS(old)	EENS(new)	upgrade time
1	1	2	24.2308	14.2770	4
2	2	3	22.8632	13.3231	2
3	3	4	31.9542	25.8897	2
4	4	5	8.6516	11.0418	-
5	5	6	4.6235	5.9009	16
6	6	7	2.6870	3.4294	18
7	7	8	2.6092	3.3301	20
8	4	9	24.3244	16.4272	6
9	9	10	10.7403	13.7076	-
10	10	11	21.2433	16.8396	-
11	11	12	6.2434	7.9683	16
12	12	13	2.5897	3.3052	20
13	13	14	1.0705	1.3662	16
14	11	15	16.2066	20.6842	14
15	15	16	2.8092	3.5853	18
16	16	17	1.1307	1.4431	14
17	15	18	9.3670	11.9549	16
18	18	19	2.2379	2.8562	18
19	18	20	3.2583	4.1585	14
20	20	21	0.9927	1.2669	14
21	20	22	2.9218	3.7290	14
22	22	23	0.9757	1.2453	18
23	22	24	2.0171	2.5743	12

As indicated above, lines 4,9,10 are not upgraded. The timing of other upgrades are indicated in the last column.

5.3.4.2 Scenario 1: Short term, most likely

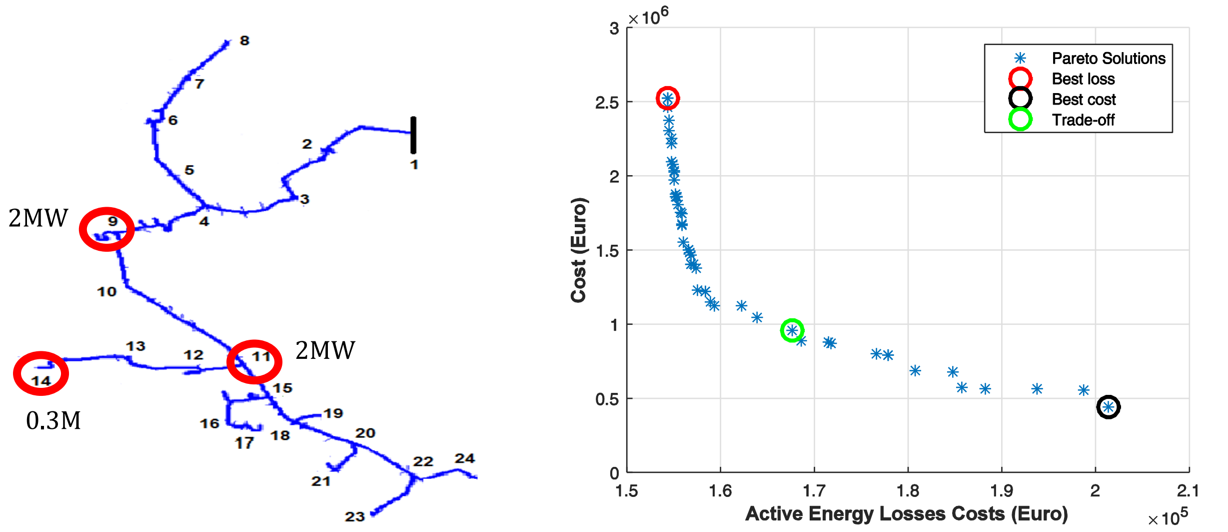


Figure 203 –Results of applying the tool under scenario 1

In Figure 203 is shown the Pareto front calculated by the tool for the asset renewal plan on the network, under the scenario 1 conditions visualized on the left. The optimal trade-off here is marked with a green circle. Solution 9 is chosen using the described fuzzy satisfying method as the most suitable solution.
The pursuit of this plan realises a cost saving quantified by this KPI:

$$KPI_1 = C_{bau} - C_{opt} = 1.5539 * 10^6 Euros$$

By using the tool to discover which network components are most critical, an enhanced maintenance and inspection regime can be followed. This improves network reliability as assessed with the following KPIs:

The second KPI assess the improvement that can be attained in aggregate network *risk* that can be effected by enhanced maintenance and inspection regimes informed by the tool. The risk is defined here as the expected energy not supplied, R, where R_{enh}, R_{bau} are the risk after and before network enhancement, respectively. A percentage comparison is made:

$$KPI_2 = \frac{R_{enh}}{R_{bau}} * 100\% = 89.6683\%$$

This means that the total expected energy not supplied is reduced by 10.4% by employing the reliability managagement tool.

The KPI_3 shows how the quality of the service is improved using the reliability analysis tool. The customer minute lost is the average number of minutes per that a customer does not receive any service.

$$KPI_3 = \frac{CML_{enh}}{CML_{bau}} * 100\% = 90.5044\%$$

The quality of service has improved by 9.5% using this subtool under this scenario.

$$KPI_4 = \frac{Curt_{enh}}{Curt_{bau}} * 100\% = 75.8654\%$$

$$KPI_{EEGI} = \frac{E^{baseline}_{not\ injected} - E^{measured}_{not\ injected}}{E^{baseline}_{not\ injected}} * 100\% = 24.13\%$$

KPI_{EEGI} and KPI_4 are decreased by 24.1%. This shows how the DSO has used the clean and local energy resources in a more efficient way. By reducing this KPI the DSO is assured that DRES can inject their power into the grid. This will not only beneficial for DRES developers/owners but also for DSO since they receive connections fees from DRES.

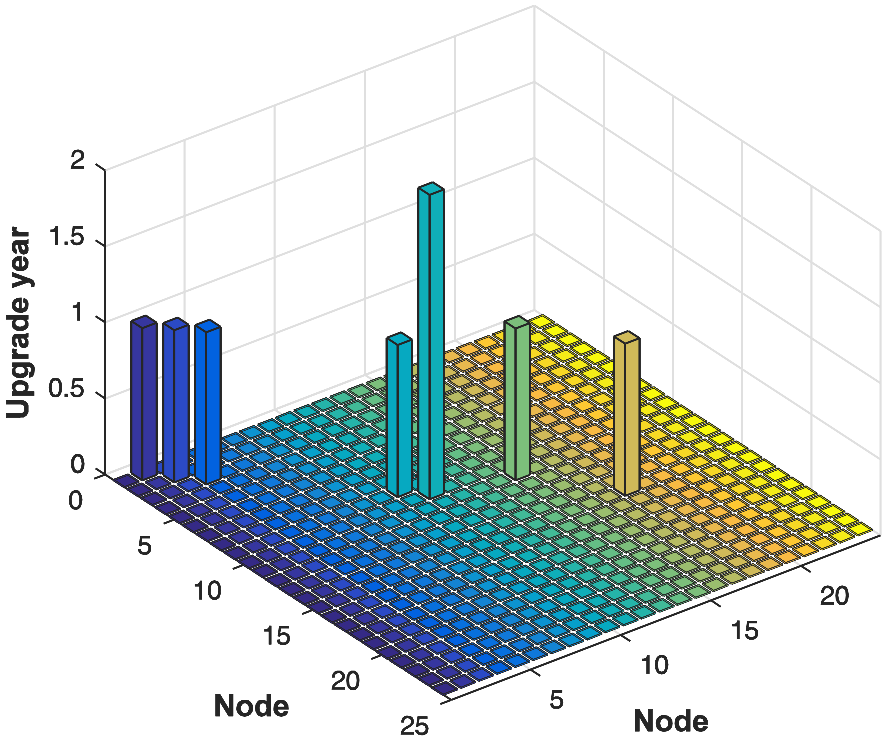


Figure 204 Timing of line upgrade for scenario 1

Line number	from	to	EENS(old)	EENS(new)	upgrade time
1	1	2	11.2312	6.6175	1
2	2	3	10.7326	6.2542	1
3	3	4	15.4745	12.5377	1
4	4	5	2.9645	3.7835	-
5	5	6	1.5843	2.0220	-
6	6	7	0.9207	1.1751	-
7	7	8	0.8941	1.1411	-
8	4	9	8.3349	5.6289	-
9	9	10	4.8928	6.2446	1
10	10	11	9.6890	7.6805	2
11	11	12	2.1393	2.7304	-
12	12	13	0.8874	1.1326	-
13	13	14	0.3668	0.4681	-
14	11	15	5.5533	7.0876	1
15	15	16	0.9626	1.2285	-
16	16	17	0.3874	0.4945	-
17	15	18	3.2097	4.0964	1
18	18	19	0.7668	0.9787	-
19	18	20	1.1165	1.4249	-
20	20	21	0.3401	0.4341	-
21	20	22	1.0012	1.2778	-
22	22	23	0.3343	0.4267	-
23	22	24	0.6912	0.8821	-

The timing of each upgrades are indicated in the last column. As indicated above, line 10 is upgraded in the second year and the rest of them (lines 1,2,3,9,14,17) are upgraded in year 1. The rest of the lines are not needed to be upgraded.

5.3.4.3 Scenario 2 Short term, over expected

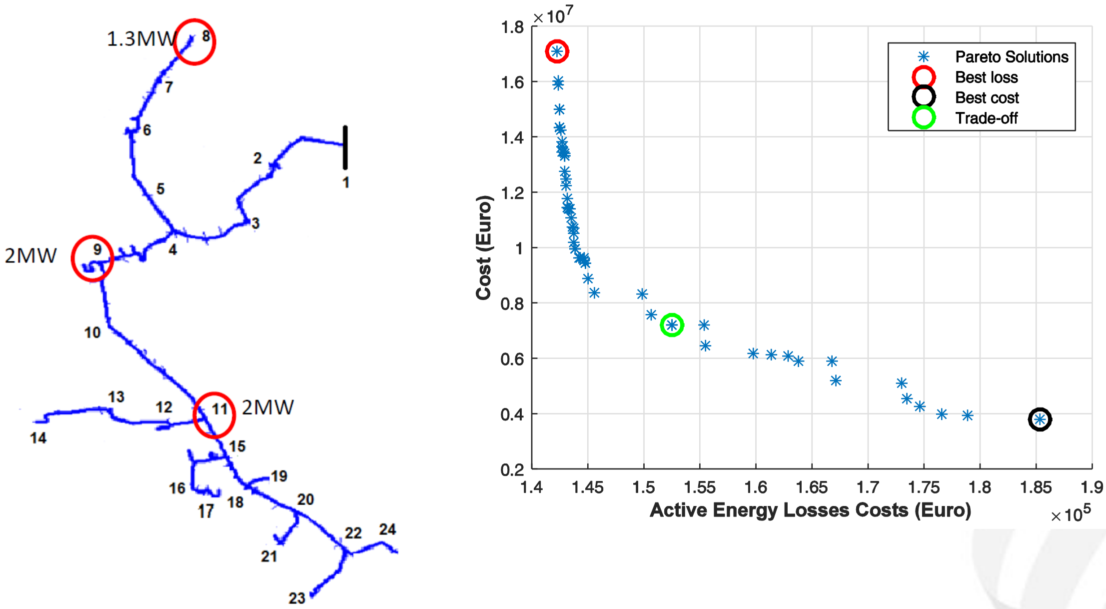


Figure 205 –Results of applying the tool under scenario 2

In Figure 205 is shown the Pareto front calculated by the tool for the asset renewal plan on the network, under the scenario 2 conditions visualized on the left. The optimal trade-off here is marked with a green circle. Solution 21 is chosen using the described fuzzy satisfying method as a suitable solution.

$$KPI_1 = C_{bau} - C_{opt} = 9.8806 * 10^6 Euros$$

The second KPI assess the improvement that can be attained in aggregate network *risk* that can be effected by enhanced maintenance and inspection regimes informed by the tool. The risk is defined here as the expected energy not supplied, R, where R_{enh}, R_{bau} are the risk after and before network enhancement, respectively. A percentage comparison is made:

$$KPI_2 = \frac{R_{enh}}{R_{bau}} * 100\% = 89.4268\%$$

The KPI_3 shows how the quality of the service is improved using the maintenance management tool. The customer minute lost is the average number of minutes per that a customer does not receive any service.

$$KPI_3 = \frac{CML_{enh}}{CML_{bau}} * 100\% = 90.3395\%$$

The quality of service has improved by 9.7% using this subtool in these conditions.

$$KPI_4 = \frac{Curt_{enh}}{Curt_{bau}} * 100\% = 80.1474\%$$

$$KPI_{EEGI} = \frac{E^{baseline}_{not\ injected} - E^{measured}_{not\ injected}}{E^{baseline}_{not\ injected}} * 100\% = 19.85\%$$

KPI_{EEGI} and KPI_4 are decreased by 19.9%. This shows how the DSO has used the reliability analysis in a way that reduces the total DRES energy curtailments.

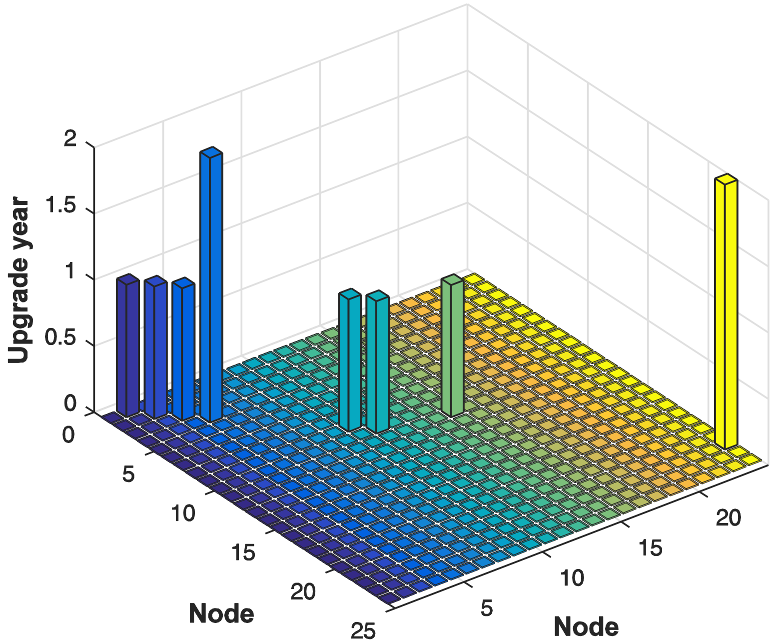


Figure 206 Timing of line upgrade for scenario

Line number	from	to	EENS(old)	EENS(new)	upgrade time
1	1	2	11.2312	6.6175	1
2	2	3	10.7326	6.2542	1
3	3	4	15.4745	12.5377	1
4	4	5	2.9645	3.7835	2
5	5	6	1.5843	2.0220	-
6	6	7	0.9207	1.1751	-
7	7	8	0.8941	1.1411	-
8	4	9	8.3349	5.6289	-
9	9	10	3.7604	4.7993	1
10	10	11	7.4385	5.8965	1
11	11	12	2.1393	2.7304	-
12	12	13	0.8874	1.1326	-
13	13	14	0.3668	0.4681	-
14	11	15	5.5533	7.0876	1
15	15	16	0.9626	1.2285	-
16	16	17	0.3874	0.4945	-
17	15	18	3.2097	4.0964	-
18	18	19	0.7668	0.9787	-
19	18	20	1.1165	1.4249	-

20	20	21	0.3401	0.4341	-
21	20	22	1.0012	1.2778	-
22	22	23	0.3343	0.4267	-
23	22	24	0.6912	0.8821	2

The timing of each upgrades are indicated in the last column. As indicated above, line 4 , 23 are upgraded in the second year and the rest of them (lines 1,2,3,9,10,14) are upgraded in year 1. The rest of the lines are not needed to be upgraded.

5.3.4.4 Scenario 3: Short term, under expected

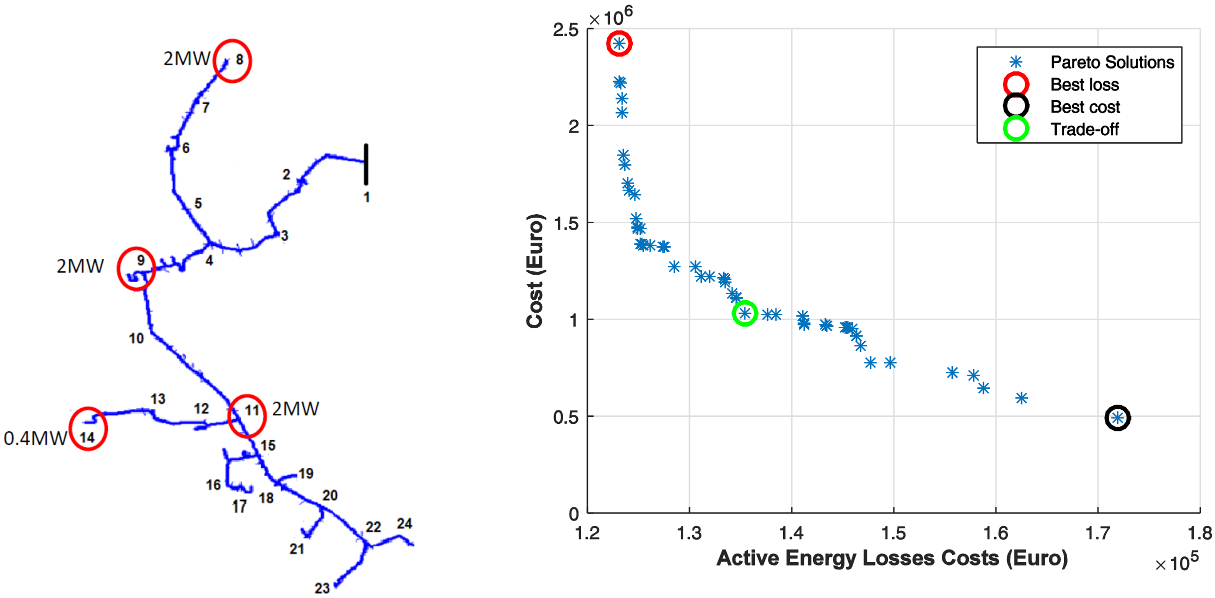


Figure 207 –Results of applying the tool under scenario 3

In Figure 207 is shown the Pareto front calculated by the tool for the asset renewal plan on the network, under the scenario 3 conditions visualized on the left. The optimal trade-off here is marked with a green circle. Solution 17 is chosen using the described fuzzy satisfying method as the best solution.

$$KPI_1 = C_{bau} - C_{opt} = 1.3828 * 10^6 Euros$$

The second KPI assess the improvement that can be attained in aggregate network *risk* that can be effected by enhanced maintenance and inspection regimes informed by the tool. The risk is defined here as the expected energy not supplied, R, where R_{enh}, R_{bau} are the risk after and before network enhancement, respectively. A percentage comparison is made:

$$KPI_2 = \frac{R_{enh}}{R_{bau}} * 100\% = 89.6683\%$$

The KPI_3 shows how the quality of the service is improved using the reliability analysis tool. The customer minute lost is the average number of minutes per that a customer does not receive any service.

$$KPI_3 = \frac{CML_{enh}}{CML_{bau}} * 100\% = 90.5046\%$$

The quality of service has improved by 9.5% using this subtool in this scenario.

$$KPI_4 = \frac{Curt_{enh}}{Curt_{bau}} * 100\% = 85.8286\%$$

$$KPI_{EEGI} = \frac{E_{not\ injected}^{baseline} - E_{not\ injected}^{measured}}{E_{not\ injected}^{baseline}} * 100\% = 14.17\%$$

KPI_{EEGI} and KPI_4 are decreased by 14.17%.

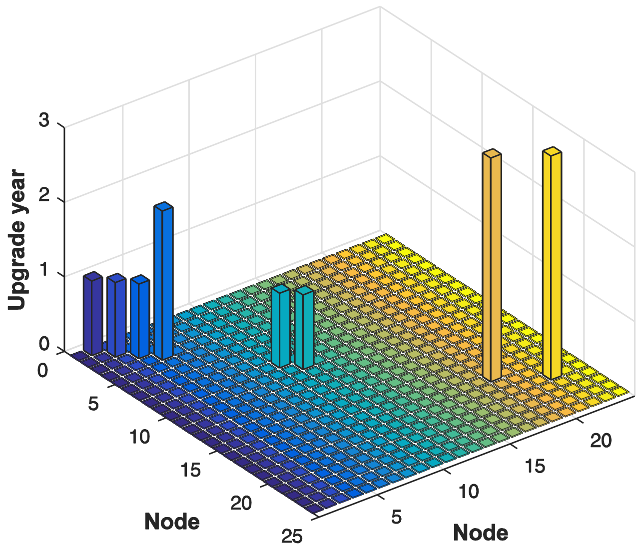


Figure 208 Timing of line upgrade for scenario 3

Line number	from	to	EENS(old)	EENS(new)	upgrade time
1	1	2	11.2312	6.6175	1
2	2	3	10.7326	6.2542	1
3	3	4	15.4745	12.5377	1
4	4	5	2.9645	3.7835	2
5	5	6	1.5843	2.0220	-
6	6	7	0.9207	1.1751	-
7	7	8	0.8941	1.1411	-
8	4	9	8.3349	5.6289	-
9	9	10	4.8928	6.2446	1
10	10	11	9.6890	7.6805	1
11	11	12	2.1393	2.7304	-
12	12	13	0.8874	1.1326	-

13	13	14	0.3668	0.4681	-
14	11	15	5.5533	7.0876	-
15	15	16	0.9626	1.2285	-
16	16	17	0.3874	0.4945	-
17	15	18	3.2097	4.0964	-
18	18	19	0.7668	0.9787	3
19	18	20	1.1165	1.4249	-
20	20	21	0.3401	0.4341	-
21	20	22	1.0012	1.2778	3
22	22	23	0.3343	0.4267	-
23	22	24	0.6912	0.8821	-

The timing of each upgrade is indicated in the last column. As indicated above, line 4 is upgraded in the second year and the rest of them (lines 1, 2, 3, 9, 10, 14) are upgraded in year 1. The lines number 18 and 21 are upgraded in year 3. The rest of the lines are not needed to be upgraded.

5.3.4.5 Scenario 4: Medium term, under expected

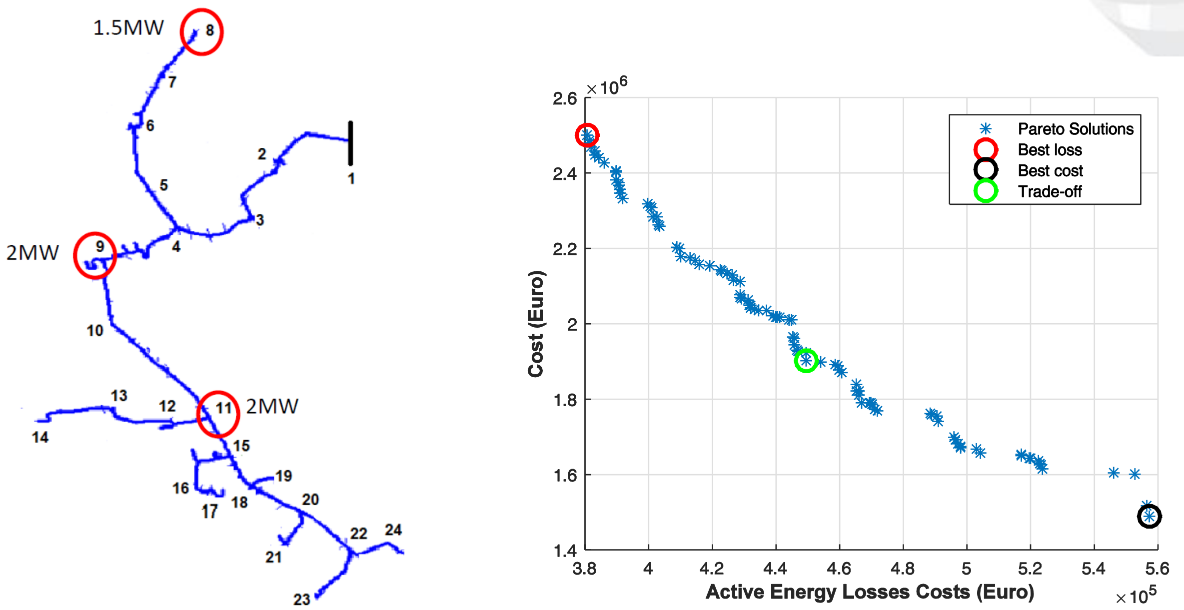


Figure 209 –Results of applying the tool under scenario 4

In Figure 209 is shown the Pareto front calculated by the tool for the asset renewal plan on the network, under the scenario 4 conditions visualized on the left. The optimal trade-off here is marked with a green circle. Solution 26 is chosen using the described fuzzy satisfying method as the most appropriate solution.

$$KPI_1 = C_{bau} - C_{opt} = 0.5289 * 10^6 Euros$$

The second KPI assess the improvement that can be attained in aggregate network *risk* that can be effected by enhanced maintenance and inspection regimes informed by the tool. The risk is defined here as the expected energy not supplied, R, where R_{enh}, R_{bau} are the risk after and before network enhancement, respectively. A percentage comparison is made:

$$KPI_2 = \frac{R_{enh}}{R_{bau}} * 100\% = 89.4416\%$$

The KPI_3 shows how the quality of the service is improved using the reliability analysis tool. The customer minute lost is the average number of minutes per that a customer does not receive any service.

$$KPI_3 = \frac{CML_{enh}}{CML_{bau}} * 100\% = 90.4097\%$$

The quality of service has improved by 9.6% using this subtool in this scenario.

$$KPI_4 = \frac{Curt_{enh}}{Curt_{bau}} * 100\% = 81.2674\%$$

$$KPI_{EEGI} = \frac{E_{not\ injected}^{baseline} - E_{not\ injected}^{measured}}{E_{not\ injected}^{baseline}} * 100\% = 18.73\%$$

KPI_{EEGI} and KPI_4 are decreased by 18.7%.

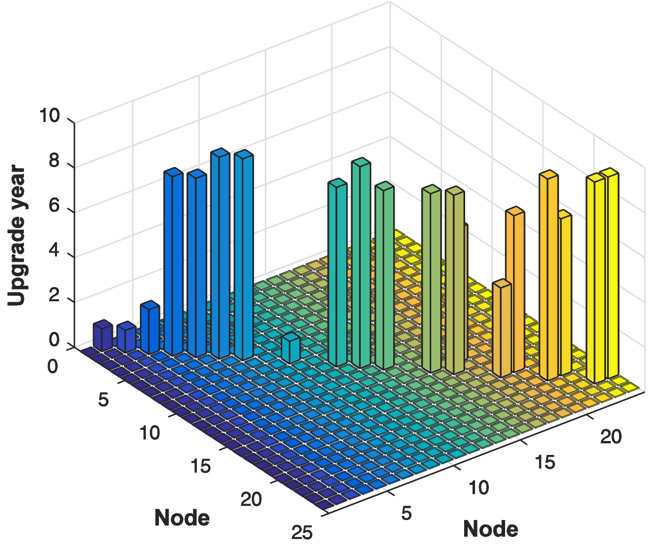


Figure 210 Timing of line upgrade for scenario 4

Line number	from	to	EENS(old)	EENS(new)	upgrade time
1	1	2	29.8375	17.5805	1
2	2	3	28.5129	16.6154	1
3	3	4	41.1105	33.3084	2
4	4	5	7.8757	10.0516	8
5	5	6	4.2088	5.3717	8
6	6	7	2.4461	3.1219	9
7	7	8	2.3752	3.0314	9
8	4	9	22.1430	14.9541	-
9	9	10	10.1675	12.9766	1
10	10	11	20.1141	15.9445	-
11	11	12	5.6835	7.2537	8
12	12	13	2.3575	3.0088	9
13	13	14	0.9745	1.2437	8
14	11	15	14.7532	18.8293	-
15	15	16	2.5573	3.2638	8
16	16	17	1.0293	1.3137	8
17	15	18	8.5270	10.8829	6
18	18	19	2.0372	2.6000	4
19	18	20	2.9661	3.7856	7
20	20	21	0.9037	1.1533	9
21	20	22	2.6598	3.3946	7
22	22	23	0.8882	1.1336	9
23	22	24	1.8362	2.3435	9

The timing of each upgrade is indicated in the last column. As indicated above, lines 8,10 and 14 are not upgraded. The rest of the lines are upgraded in the specified year.

5.3.4.6 Scenario 5: Medium term, most likely

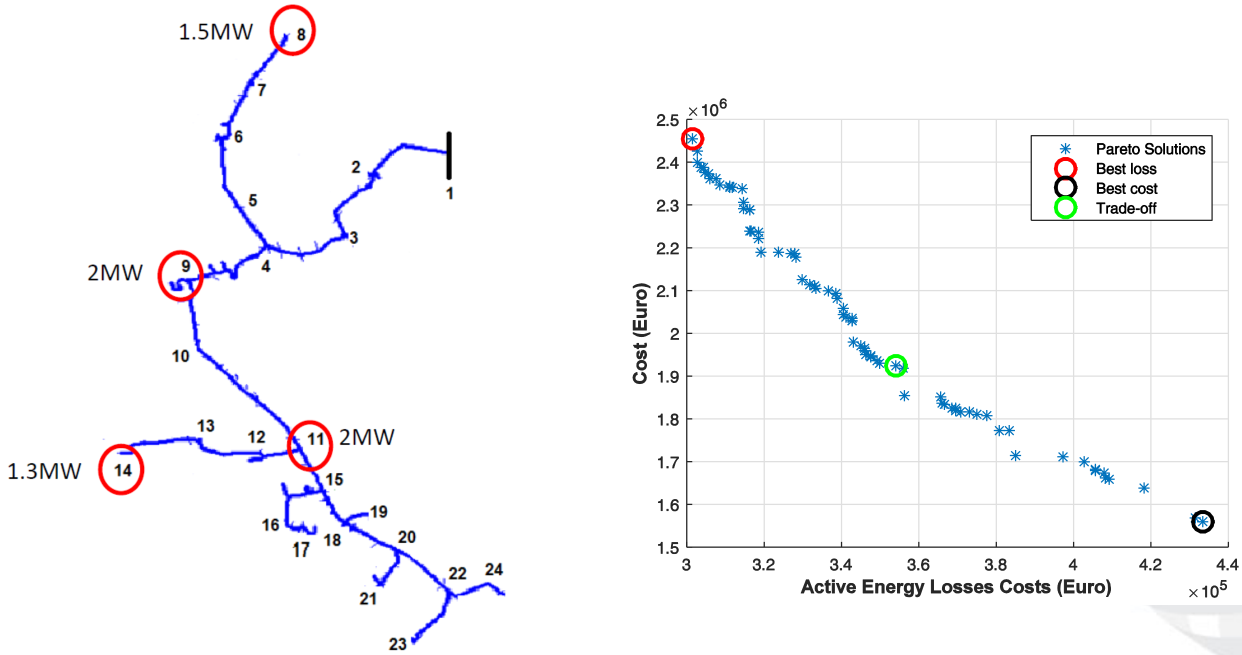


Figure 211 –Results of applying the tool under scenario 5

In Figure 211 is shown the Pareto front calculated by the tool for the asset renewal plan on the network, under the scenario 5 conditions visualized on the left. The optimal trade-off here is marked with a green circle. Solution 26 is chosen using the described fuzzy satisfying method as the most appropriate solution.

$$KPI_1 = C_{bau} - C_{opt} = 0.4794 * 10^6 Euros$$

The second KPI assess the improvement that can be attained in aggregate network *risk* that can be effected by enhanced maintenance and inspection regimes informed by the tool. The risk is defined here as the expected energy not supplied, R, where R_{enh}, R_{bau} are the risk after and before network enhancement, respectively. A percentage comparison is made:

$$KPI_2 = \frac{R_{enh}}{R_{bau}} * 100\% = 89.6683\%$$

The KPI_3 shows how the quality of the service is improved using the reliability analysis tool. The customer minute lost is the average number of minutes per that a customer does not receive any service.

$$KPI_3 = \frac{CML_{enh}}{CML_{bau}} * 100\% = 90.5555\%$$

The quality of service has improved by 9.4% using this subtool.

$$KPI_4 = \frac{Curt_{enh}}{Curt_{bau}} * 100\% = 86.1085\%$$

$$KPI_{EEGI} = \frac{E_{not\ injected}^{baseline} - E_{not\ injected}^{measured}}{E_{not\ injected}^{baseline}} * 100\% = 13.89\%$$

KPI_{EEGI} and KPI_4 are decreased by 13.9%. This shows how the DSO has done the reliability analysis tool in a way that reduces the total DRES energy curtailments.

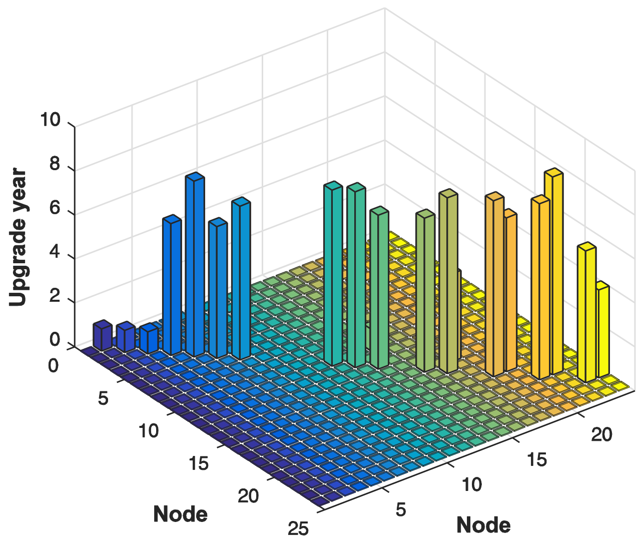


Figure 212 Timing of line upgrade for scenario 5

Line number	from	to	EENS(old)	EENS(new)	upgrade time
1	1	2	29.8375	17.5805	1
2	2	3	28.5129	16.6154	1
3	3	4	41.1105	33.3084	1
4	4	5	7.8757	10.0516	6
5	5	6	4.2088	5.3717	8
6	6	7	2.4461	3.1219	6
7	7	8	2.3752	3.0314	7
8	4	9	22.1430	14.9541	-
9	9	10	12.9986	16.5899	-
10	10	11	25.7404	20.4044	-
11	11	12	5.6835	7.2537	8
12	12	13	2.3575	3.0088	8
13	13	14	0.9745	1.2437	7
14	11	15	14.7532	18.8293	1
15	15	16	2.5573	3.2638	7
16	16	17	1.0293	1.3137	8

17	15	18	8.5270	10.8829	4
18	18	19	2.0372	2.6000	8
19	18	20	2.9661	3.7856	7
20	20	21	0.9037	1.1533	8
21	20	22	2.6598	3.3946	9
22	22	23	0.8882	1.1336	6
23	22	24	1.8362	2.3435	4

The timing of each upgrade is indicated in the last column. As indicated above, lines 8,9 and 10 are not upgraded. The rest of the lines are upgraded in the specified year.

5.3.4.7 Scenario 6: Medium term, over expected

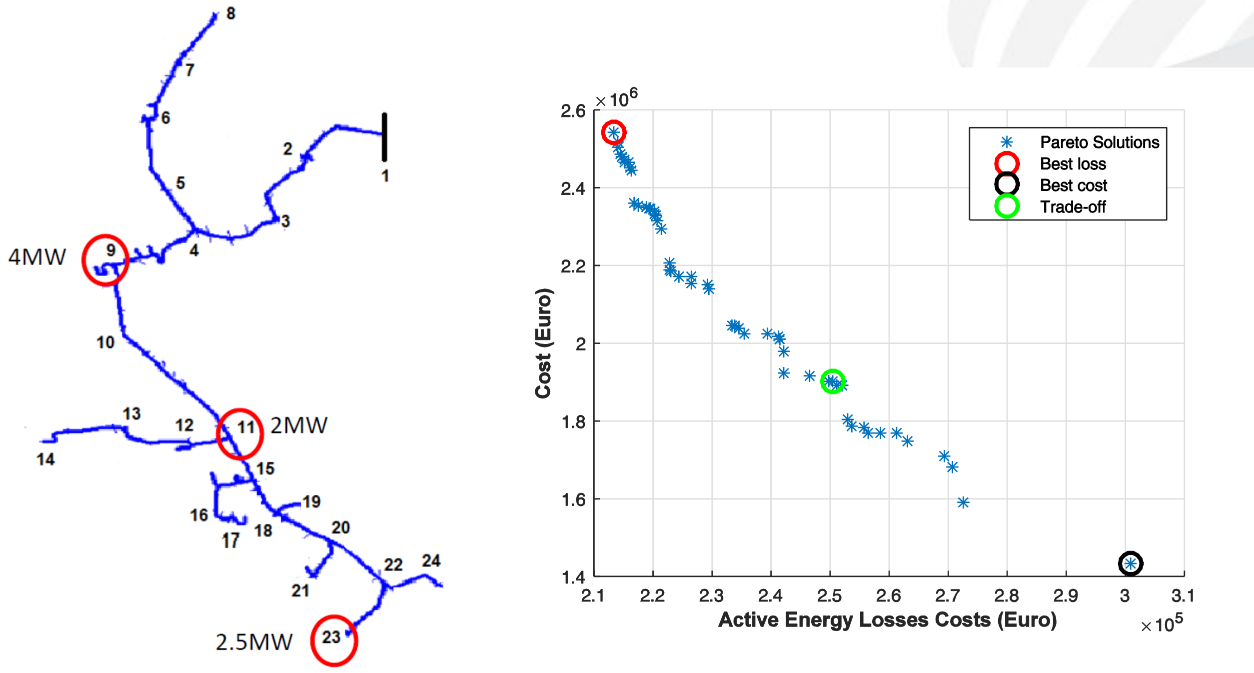


Figure 213 –Results of applying the tool under scenario 6

In Figure 213 is shown the Pareto front calculated by the tool for the asset renewal plan on the network, under the scenario 6 conditions visualized on the left. The optimal trade-off here is marked with a green circle. Solution 43 is chosen using the described fuzzy satisfying method as the best solution.

$$KPI_1 = C_{bau} - C_{opt} = 0.6032 * 10^6 Euros$$

The second KPI assess the improvement that can be attained in aggregate network *risk* that can be effected by enhanced maintenance and inspection regimes informed by the tool. The risk is defined here as the expected energy not supplied, R, where R_{enh}, R_{bau} are the risk after and before network enhancement, respectively. A percentage comparison is made:

$$KPI_2 = \frac{R_{enh}}{R_{bau}} * 100\% = \ 89.6683\%$$

The KPI_3 shows how the quality of the service is improved using the reliability analysis tool. The customer minute lost is the average number of minutes per that a customer does not receive any service.

$$KPI_3 = \frac{CML_{enh}}{CML_{bau}} * 100\% = 90.5572\%$$

The quality of service has improved by 9.5% using this subtool.

$$KPI_4 = \frac{Curt_{enh}}{Curt_{bau}} * 100\% = 84.0862\%$$

$$KPI_{EEGI} = \frac{E^{baseline}_{not\ injected} - E^{measured}_{not\ injected}}{E^{baseline}_{not\ injected}} * 100\% = 15.91\%$$

KPI_{EEGI} and KPI_4 are decreased by 15.9%. This shows how the DSO has done the reliability analysis tool in a way that reduces the total DRES energy curtailments.

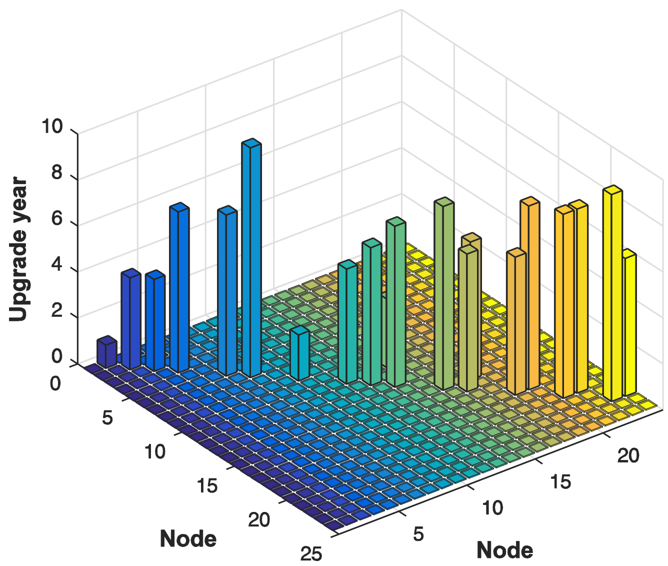


Figure 214 Timing of line upgrade for scenario 6

Line number	from	to	EENS(old)	EENS(new)	upgrade time
1	1	2	29.8375	17.5805	1
2	2	3	28.5129	16.6154	4
3	3	4	41.1105	33.3084	4
4	4	5	7.8757	10.0516	7
5	5	6	4.2088	5.3717	-
6	6	7	2.4461	3.1219	7
7	7	8	2.3752	3.0314	10

8	4	9	22.1430	14.9541	-
9	9	10	12.9986	16.5899	2
10	10	11	25.7404	20.4044	-
11	11	12	5.6835	7.2537	5
12	12	13	2.3575	3.0088	6
13	13	14	0.9745	1.2437	7
14	11	15	14.7532	18.8293	3
15	15	16	2.5573	3.2638	8
16	16	17	1.0293	1.3137	6
17	15	18	8.5270	10.8829	6
18	18	19	2.0372	2.6000	6
19	18	20	2.9661	3.7856	8
20	20	21	0.9037	1.1533	8
21	20	22	2.6598	3.3946	8
22	22	23	0.8882	1.1336	9
23	22	24	1.8362	2.3435	6

The timing of each upgrade is indicated in the last column. As indicated above, lines 5,8,10 are not upgraded. The rest of the lines are upgraded in the specified year.

5.3.4.8 Scenario 7: Long term, under expected

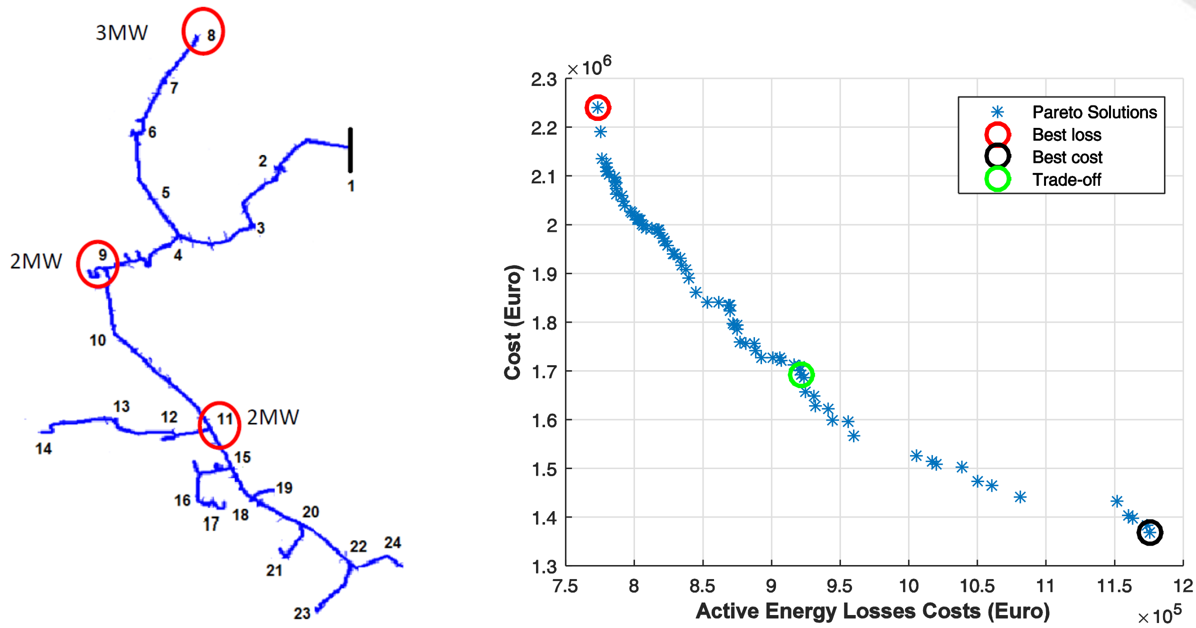


Figure 215 –Results of applying the tool under scenario 7

In Figure 215 is shown the Pareto front calculated by the tool for the asset renewal plan on the network, under the scenario 7 conditions visualized on the left. The optimal trade-off here is marked with a green circle. Solution 63 is chosen using the described fuzzy satisfying method as the best solution.

$$KPI_1 = C_{bau} - C_{opt} = 0.3978 * 10^6 Euros$$

The second KPI assess the improvement that can be attained in aggregate network *risk* that can be effected by enhanced maintenance and inspection regimes informed by the tool. The risk is defined here as the expected energy not supplied, R, where R_{enh}, R_{bau} are the risk after and before network enhancement, respectively. A percentage comparison is made:

$$KPI_2 = \frac{R_{enh}}{R_{bau}} * 100\% = 89.4627\%$$

The KPI_3 shows how the quality of the service is improved using the reliability analysis tool. The customer minute lost is the average number of minutes per that a customer does not receive any service.

$$KPI_3 = \frac{CML_{enh}}{CML_{bau}} * 100\% = 90.4585\%$$

The quality of service has improved by 9.6% using this subtool.

$$KPI_4 = \frac{Curt_{enh}}{Curt_{bau}} * 100\% = 86.9912\%$$

$$KPI_{EEGI} = \frac{E_{not\ injected}^{baseline} - E_{not\ injected}^{measured}}{E_{not\ injected}^{baseline}} * 100\% = 13.01\%$$

KPI_{EEGI} and KPI_4 are decreased by 13%. This shows how the DSO has done the reliability analysis tool in a way that reduces the total DRES energy curtailments.

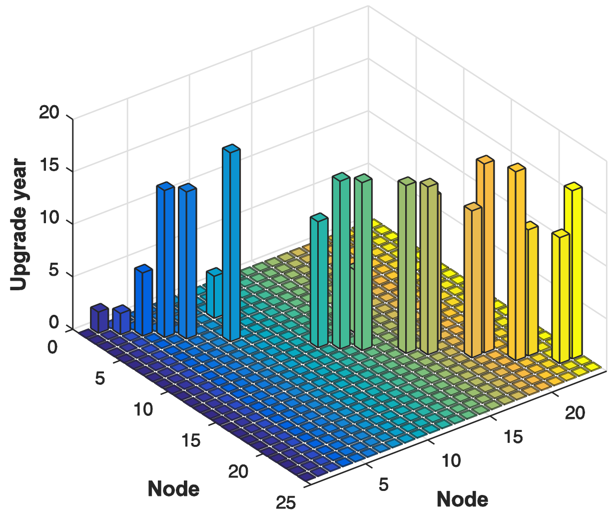


Figure 216 Timing of line upgrade for scenario 7

Line number	from	to	EENS(old)	EENS(new)	upgrade time
1	1	2	32.7769	19.3124	2
2	2	3	31.3218	18.2522	2
3	3	4	45.1604	36.5897	6
4	4	5	8.6516	11.0418	14
5	5	6	4.6235	5.9009	14
6	6	7	2.6870	3.4294	-
7	7	8	2.6092	3.3301	18
8	4	9	24.3244	16.4272	4
9	9	10	11.4480	14.6109	-
10	10	11	22.6499	17.9546	-
11	11	12	6.2434	7.9683	12
12	12	13	2.5897	3.3052	16
13	13	14	1.0705	1.3662	16
14	11	15	16.2066	20.6842	6
15	15	16	2.8092	3.5853	16
16	16	17	1.1307	1.4431	16
17	15	18	9.3670	11.9549	14
18	18	19	2.2379	2.8562	14
19	18	20	3.2583	4.1585	18
20	20	21	0.9927	1.2669	18
21	20	22	2.9218	3.7290	12
22	22	23	0.9757	1.2453	12
23	22	24	2.0171	2.5743	16

The timing of each upgrade is indicated in the last column. As indicated above, lines 6,9 and 10 are not upgraded. The rest of the lines are upgraded in the specified year.

5.3.4.9 Scenario 8: Long term, most likely

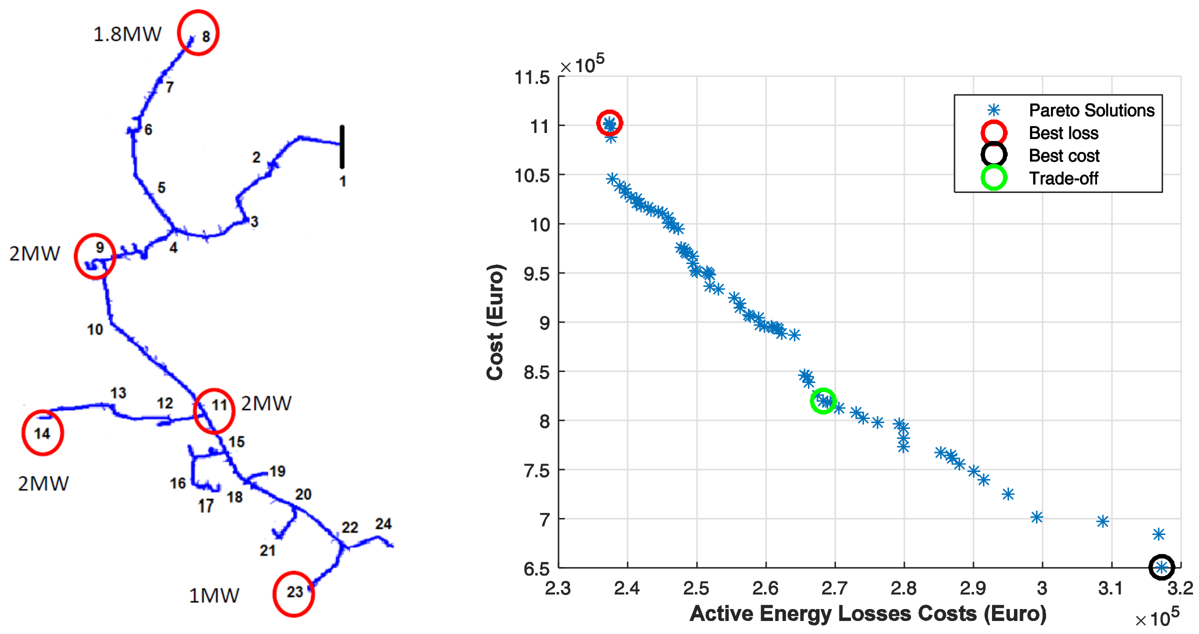


Figure 217 –Results of applying the tool under scenario 8

In Figure 217Figure 211 is shown the Pareto front calculated by the tool for the asset renewal plan on the network, under the scenario 8 conditions visualized on the left. The optimal trade-off here is marked with a green circle. Solution 39 is chosen using the described fuzzy satisfying method as the best solution.

$$KPI_1 = C_{bau} - C_{opt} = 0.2524 * 10^6 Euros$$

The second KPI assess the improvement that can be attained in aggregate network *risk* that can be effected by enhanced maintenance and inspection regimes informed by the tool. The risk is defined here as the expected energy not supplied, R, where R_{enh}, R_{bau} are the risk after and before network enhancement, respectively. A percentage comparison is made:

$$KPI_2 = \frac{R_{enh}}{R_{bau}} * 100\% = 89.6684\%$$

The KPI_3 shows how the quality of the service is improved using the reliability analysis tool. The customer minute lost is the average number of minutes per that a customer does not receive any service.

$$KPI_3 = \frac{CML_{enh}}{CML_{bau}} * 100\% = 90.6134\%$$

The quality of service has improved by 9.4% using this subtool.

$$KPI_4 = \frac{Curt_{enh}}{Curt_{bau}} * 100\% = 89.3930\%$$

$$KPI_{EEGI} = \frac{E^{baseline}_{not\ injected} - E^{measured}_{not\ injected}}{E^{baseline}_{not\ injected}} * 100\% = 10.61\%$$

KPI_{EEGI} and KPI_4 are decreased by 10.6%. This shows how the DSO has done the reliability analysis tool in a way that reduces the total DRES energy curtailments.

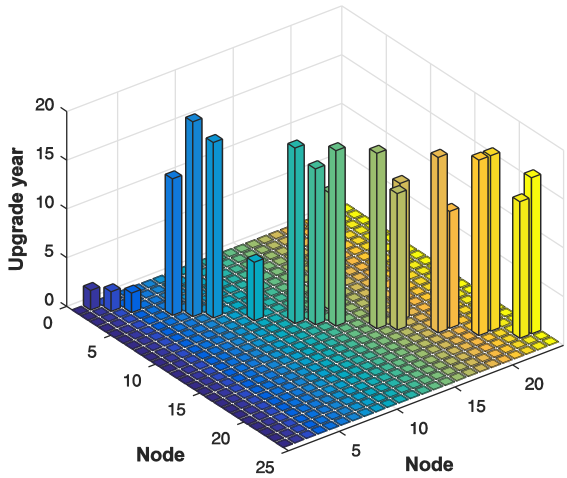


Figure 218 Timing of line upgrade for scenario 8

Line number	from	to	EENS(old)	EENS(new)	upgrade time
1	1	2	32.7769	19.3124	2
2	2	3	31.3218	18.2522	2
3	3	4	45.1604	36.5897	2
4	4	5	8.6516	11.0418	-
5	5	6	4.6235	5.9009	14
6	6	7	2.6870	3.4294	20
7	7	8	2.6092	3.3301	18
8	4	9	24.3244	16.4272	-
9	9	10	14.2791	18.2242	6
10	10	11	28.2762	22.4145	-
11	11	12	6.2434	7.9683	18
12	12	13	2.5897	3.3052	16
13	13	14	1.0705	1.3662	18
14	11	15	16.2066	20.6842	12
15	15	16	2.8092	3.5853	18
16	16	17	1.1307	1.4431	14
17	15	18	9.3670	11.9549	14

18	18	19	2.2379	2.8562	18
19	18	20	3.2583	4.1585	12
20	20	21	0.9927	1.2669	18
21	20	22	2.9218	3.7290	18
22	22	23	0.9757	1.2453	14
23	22	24	2.0171	2.5743	16

The timing of each upgrade is indicated in the last column. As indicated above, lines 4,8,10 are not upgraded. The rest of the lines are upgraded in the specified year.

5.3.4.10 Scenario 9: Long term, over expected

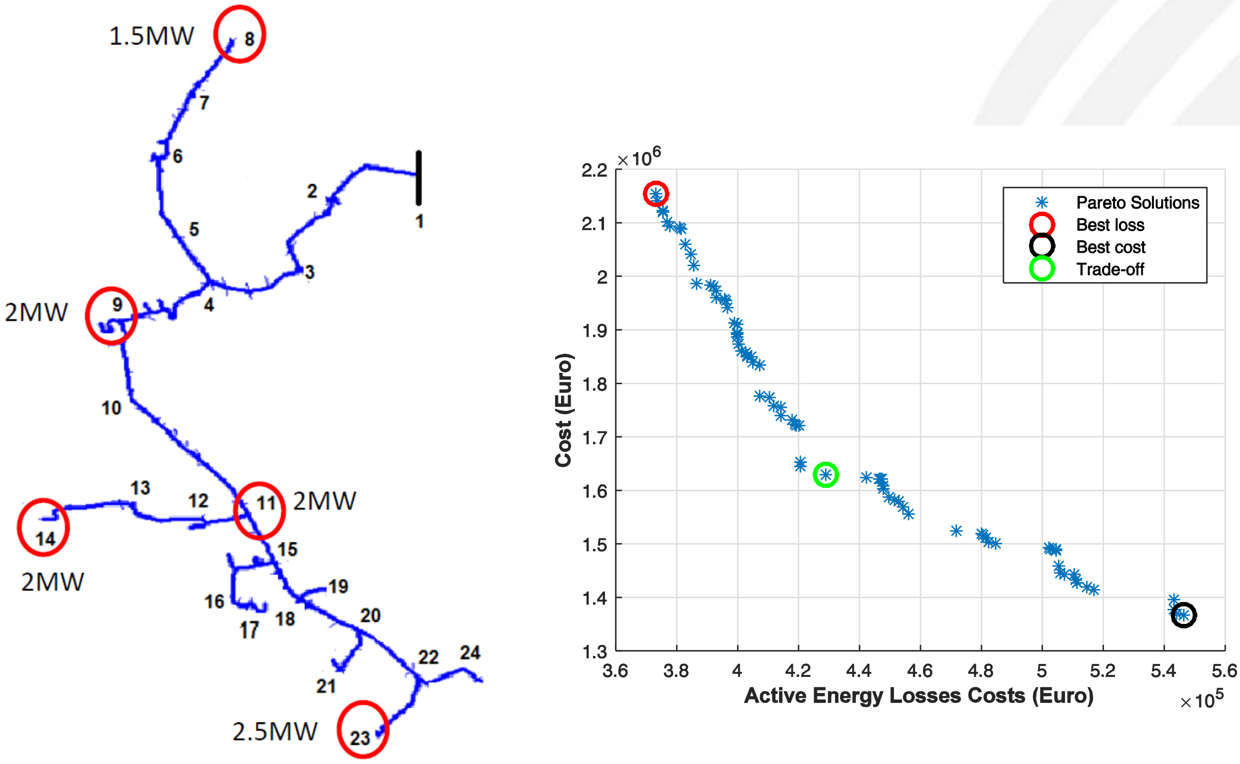


Figure 219 –Results of applying the tool under scenario 9

In Figure 219Figure 211 is shown the pareto front calculated by the tool for the asset renewal plan on the network, under the scenario 9 conditions visualized on the left. The optimal trade-off here is marked with a green circle. Solution 6 is chosen using the described fuzzy satisfying method as the best solution.

$$KPI_1 = C_{bau} - C_{opt} = 0.4692 * 10^6 Euros$$

The second KPI assess the improvement that can be attained in aggregate network *risk* that can be effected by enhanced maintenance and inspection regimes informed by the tool. The risk is defined here as the expected energy not supplied, R, where R_{enh}, R_{bau} are the risk after and before network enhancement, respectively. A percentage comparison is made:

$$KPI_2 = \frac{R_{enh}}{R_{bau}} * 100\% = 89.6684\%$$

The KPI_3 shows how the quality of the service is improved using the reliability analysis tool. The customer minute lost is the average number of minutes per that a customer does not receive any service.

$$KPI_3 = \frac{CML_{enh}}{CML_{bau}} * 100\% = 90.5864\%$$

The quality of service has improved by 9.5% using this subtool.

$$KPI_4 = \frac{Curt_{enh}}{Curt_{bau}} * 100\% = 90.7435\%$$

$$KPI_{EEGI} = \frac{E^{baseline}_{not\ injected} - E^{measured}_{not\ injected}}{E^{baseline}_{not\ injected}} * 100\% = 9.26\%$$

KPI_{EEGI} and KPI_4 are decreased by 9.3%. This shows how the DSO has done the reliability analysis tool in a way that reduces the total DRES energy curtailments.

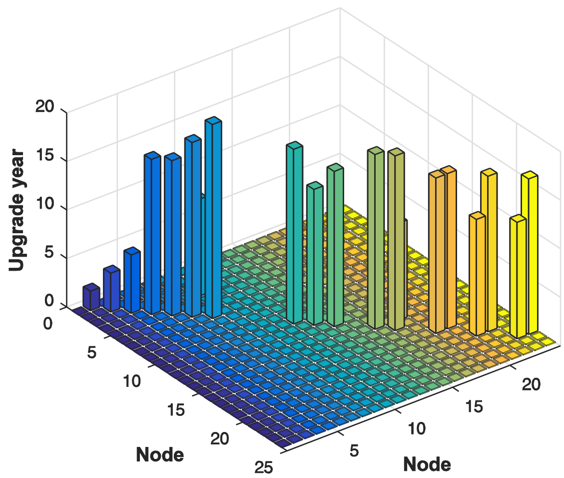


Figure 220 Timing of line upgrade for scenario 9

Line number	from	to	EENS(old)	EENS(new)	upgrade time
1	1	2	32.7769	19.3124	2
2	2	3	31.3218	18.2522	4
3	3	4	45.1604	36.5897	6
4	4	5	8.6516	11.0418	16
5	5	6	4.6235	5.9009	16
6	6	7	2.6870	3.4294	18

7	7	8	2.6092	3.3301	20
8	4	9	24.3244	16.4272	10
9	9	10	14.2791	18.2242	-
10	10	11	28.2762	22.4145	-
11	11	12	6.2434	7.9683	18
12	12	13	2.5897	3.3052	14
13	13	14	1.0705	1.3662	16
14	11	15	16.2066	20.6842	-
15	15	16	2.8092	3.5853	18
16	16	17	1.1307	1.4431	18
17	15	18	9.3670	11.9549	10
18	18	19	2.2379	2.8562	16
19	18	20	3.2583	4.1585	16
20	20	21	0.9927	1.2669	12
21	20	22	2.9218	3.7290	16
22	22	23	0.9757	1.2453	12
23	22	24	2.0171	2.5743	16

The timing of each upgrade is indicated in the last column. As indicated above, lines 9, 10, 14 are not upgraded. The rest of the lines are upgraded in the specified year.

5.4 Conclusions, Main Benefits and Limitations

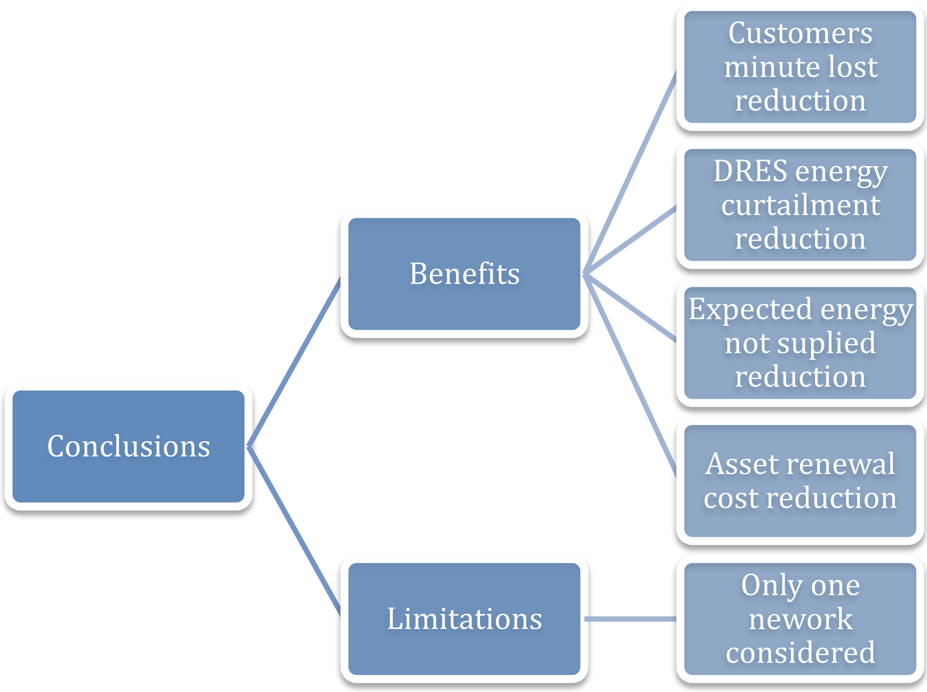


Figure 221 - A graphical summary the tool's benefits and limitations

A high level summary of the tool's performance in these validating simulations is given in Figure 221. While the benefits are clear across several metrics, one proviso on these results is that just one test network has been considered.

5.4.1 Summary of the simulations

The trial simulations on the test network meaningfully demonstrate the additional value that can be unlocked via the actionable insights that the tool gives to the network's asset manager. The tool was applied to the test network across a wide variety of scenarios and in all cases could give useful and actionable insights to help streamline and enhance asset renewal and maintenance decision. Furthermore, pareto fronts were insightfully throughout used to show the range of investment decision trade-offs that could be made.

It was observed that the extent of conductor upgrades varied with the level of DRES penetration considered. This underlines how asset management decisions must be duly cognizant of the new and emerging roles for distribution system operators as facilitators of variable renewable generating technologies. The interaction between renewable generation and distribution system asset utilization is subtle and complex, and so new tools, such as the present one, are necessary to efficiently manage modern smart networks.

5.4.2 Main benefits

The actionable insights that the tool reveals offer substantial improvements in network asset renewal costs, as well as contributing to valuable improvements in network reliability. These improvements are quantified using five distinct KPIs across ten scenarios. In all cases, these KPIs recorded improvements in network asset management decisions. This is a very satisfactory set of results for these validating trials of the tool.
For the concrete benefits in the asset renewals ambit, the tool's recommended investment pathway offers substantial cost-savings over a naïve cost-minimizing strategy. While this varied from scenario to scenario, savings in combined network operation and renewal costs on the order of €100,000 for the Irish test network over a 20 year horizon were found. In addition, savings in active power losses have an environmental and social benefit that may not be fully impounded in their penalty pricing. Another benefit of the asset renewal subtool is its use of pareto optimal front to present the various trade-offs that can be achieved by conflicting network planning objectives. This offers flexibility to network asset managers to tailor asset renewal schemes under various organizational objectives, and to better understand the interplay between different incentives.
The other principal benefit this tool offers is in the network reliability dimension. Here, too, substantial improvements are possible when network maintenance and inspection priorities are informed by component outage criticalities. Network reliability is also shown to be meaningfully enhanced across all scenarios considered in these trial simulations. Expected customer minutes lost are reduced by up to 10%. This is complemented by reductions in expected energy not supplied of up to 11.5%, and reductions in anticipated energy curtailment of DRES in the range of 10% to 33%. The improvement in anticipated curtailment of DRES is obviously closely connected to the penetration level of renewables considered when performing the simulations.

In summary, across the complimentary ambits of asset renewal and network maintenance, the tool offers substantial benefits in enhancing network asset management decisions. These results are encouraging and validate the efficacy of the tool.

5.4.3 Limitations

While these simulations are generally satisfactory, one limitation attending them is that only one test network has been considered. Furthermore, only one potential conductor upgrade option was considered for this network. Further trialing of the tool in an asset management context will further draw out its capabilities where more upgrade options exist. This trialing will also draw out the benefits it may realize on a broader range of distribution networks.

5.4.4 Conclusions

- Substantial cost savings can be achieved with the tool, by stipulating enhanced network renewal plans informed by a multi-criteria, multi-year analysis
- Using the developed tool for establishing network inspection and maintenance priorities can meaningfully improve the network's reliability, whether quantified through customer minutes lost, expected DRES curtailment or network risk measures. In all cases, the quality of the service for the DSO's customers is increased.
- The simulations show that not only is the penetration level of DRES is important in distribution networks but also that the concentration of them are also of great importance. In other words, the impact of a certain MW capacity of DRES can be different depending on how the network accommodates this aggregate capacity.
- The developed sub-tool for asset renewal has an important impact on network planning. This is because it can provide technical and economic view for network planner regarding the asset renewal cost as well as the loss payment reductions. The general framework formulated in this subtool is applicable in different countries with different regulatory frameworks.
- The reduction in DRES curtailment is definitely a benefit for not only DRES developer but also for the distribution system operator. This is because when the DRES owners can make profit by injecting power into the grid then the connection fees are justified. Furthermore, the clean energy is then utilised instead more of fossil fuel base resources.

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ANNEX I – Methodology for Flexibility Cost Calculation

This annex describes the common methodology to calculate the flexibility cost for different levers. It is important to stress that this methodology is only an approximation that enables the creation of a merit order for the different levers and it is used by all tools tested in this deliverable.

DSO Own Flexibilities

HV/MV Substation with On-Load Tap-Changing (OLTC)

For the flexibility cost calculation of the HV / MV Substation with OLTC, two alternative methodologies that share the same philosophy have been developed. The first methodology elaborates a model of the OLTC cost that includes a fraction of the capital/investment cost, while the second methodology focuses more on the cost per operation of the OLTC with respect to its depreciation cost.

In the first methodology, the cost of changing the tap position of one OLTC in the HV/MV substation results from the combination of maintenance and capital cost of the transformer plus OLTC (adjusted by considering the decrease in its lifetime due to voltage regulation actions)[8]. The cost in €/tap change is given by the following formula:

$$c_{HV/MV} = \frac{1}{T_T}\left(\frac{a_T - a'_T}{a_T} \cdot F_{T+OLTC} + \frac{F_{OT} \cdot a'_T}{t_{OT}}\right)$$

where
T_T: Total allowable adjustment times (times)
a'_T: Lifetime after tap changed T_T times (year)
t_{OT}: Maintenance period (year)
F_{OT}: Maintenance cost (€/times)
a_T: Lifetime when the tap is never adjusted (year)
F_{T+OLTC}: Capital cost of the transformer (including the OLTC cost)

Note that only a fraction of the capital cost is considered since the primary function of the transformer is not voltage regulation.

The following typical values were considered for the parameters:

- Capital cost of the transformer + OLTC (€/MVA): 9,500 – 29,500 €/MVA
- Maintenance cost and period
  - Minor maintenance (functional tests) performed every year in high critical level substations, every 2 years in moderate critical level substations and every 3 years in low critical level substations – 300€
  - Major maintenance (functional tests, oil change and diverter switch visual inspection), performed every 5 years or 40,000 (up to 100,000) switching operations – 3.000€
- Expected lifetime after tap changed T times
  - No studies or statistical available that could relate the number of switching operations with the remaining lifetime. Expected lifetime of 30 up to 40 years, if maintenance plan is fulfilled
- Expected number of changes per day: 7

[8] Based on: Y. Zhang and Z. Ren, "Optimal reactive power dispatch considering costs of adjusting the control devices," *IEEE Transactions on Power Systems*, vol. 20(3), Aug. 2005.

- Lifetime when the tap is never adjusted (year): additional 10 years

In the second methodology, it is assumed that the capital costs are independent on the number of operations in the lifetime of the OLTC and hence, they are not directly taken into account. The operating expenditures are mainly associated to OLTC losses that can be considered constant across the tapping range. In this context, operating costs are not considered.

The depreciation is an economic aspect that depends on the initial investment cost, the period considered for the amortization (e.g. twenty years) and on a factor (K_i) that considers the statistical deterioration of OLTCs. The depreciation is included in the model with the following approach:

- C_{invest} is the investment cost for the considered OLTC;
- n is the amortization period (e.g. twenty years);
- K_i is a factor that considers the statistic degradation of the OLTC for each year.

The annual depreciation C_{deprec} is calculated as follows:

$$C_{deprec-i} = \frac{C_{invest}}{K_i * n}; \qquad i = 1 \div n$$

Of course, the following conditions have to be respected:

$$C_{invest} = \sum_{i=1}^{n} C_{deprec-i} = \sum_{i=1}^{n} \frac{C_{invest}}{K_i * n}; \qquad \sum_{i=1}^{n} K_i = n$$

If, as in this context, K_i is assumed to be unitary for the whole amortization period, the formula becomes:

$$C_{invest} = \sum_{i=1}^{n} C_{deprec-i} = \sum_{i=1}^{n} \frac{C_{invest}}{n}$$

Maintenance costs are related to the use of the electrical machine. Currently, there is a preventive approach that performs maintenance after a fixed number of OLTC operations.

As explained above, in terms of maintenance, the cost for each operation depends on the total maintenance cost (C_{maint_tot}) and the number of operations before the OLTC is maintained ($\#\_opeartions$):

$$C_{maint} = \frac{C_{maint\_tot}}{\#\_operations}$$

In order to make the depreciation and the maintenance costs comparable, they have to be homogeneous. Based on the DSO experiences, it is possible to define the depreciation as a function of the average number of operations an OLTC does every year ($\#\_operations\_avg$):

$$C_{deprec_{op}-i} = \frac{C_{deprec-i}}{\#\_operations\_avg} = \left(\frac{C_{invest}}{K_i * n}\right) * \frac{1}{\#\_operations\_avg}; \qquad i = 1 \div n$$

In conclusion, OLTCs are modelled as follows:

$$C_{OLTC} = C_{maint} + C_{deprec_{op}}$$

MV/LV Substation with On-Load Tap-Changing (OLTC)

The cost of changing the tap position of one OLTC in the MV/LV substation results from the combination of maintenance, capital cost of the transformer (adjusted by considering the decrease in its lifetime due to voltage regulation actions) and capital cost of the OLTC. The cost in €/tap change is given by the following formula:

$$c_{MV/LV} = \frac{1}{T_T}\left(F_{OLTC} + \frac{a_T - a'_T}{a_T} \cdot F_T + \frac{F_{OT} \cdot a'_T}{t_{OT}}\right)$$

where
T_T: Total allowable adjustment times (times)
a'_T: Lifetime after tap changed T_T times (year)
t_{OT}: Maintenance period (year)
F_{OT}: Maintenance cost (€/times)
a_T: Lifetime when the tap is never adjusted (year)
F_T: Capital cost of the transformer
F_{OLTC}: Capital cost of the OLTC

The following typical values were considered for the parameters:

- Capital cost of cabin MV/LV transformer: 8.5 – 20 €/kVA
- Capital cost of the transformer MV/LV transformer + OLTC (€/kVA): 31 €/kVA - 43 €/kVA
  - OLTC capital cost: 12.5 €/kVA - 23 €/kVA
- Maintenance cost and period
  - Approximated yearly OPEX of 1% of the invest
- The OLTC (MV/LV) should be usable for about 650,000 switching cycles. Some manufacturers talk about 2,000,000 switching cycles
  - So it is probable that the OLTC will not be the critical component for the transformers lifetime and maintenance
- Expected number of changes per day: N/A. This number should be defined by the tool (e.g., LV control)

Capacitor Banks

The cost of changing the tap position of one capacitor banks in the MV/LV substation results from the combination of maintenance and capital cost. The cost in €/tap change is given by the following formula:

$$c_{CB} = \frac{1}{T_T}\left(F_{CB} + \frac{F_{OT} \cdot a'_T}{t_{OT}}\right)$$

where
T_T: Total allowable adjustment times (times)
a'_T: Lifetime after step changed T_T times (year)
t_{OT}: Maintenance period (year)
F_{OT}: Maintenance cost (€/times)
F_{CB}: Capital cost of the capacitor bank

Note that, in contrast to the OLTC, the capacitor banks are exclusively used for Volt/VAR control, thus the total capital cost is depreciated.

The following typical values were considered for the parameters:

- Capital cost: 6500 €/Mvar (15 kV), 8800 €/Mvar (30 kV)
- Maintenance cost and period
    - Visual inspection every 3 months, integrated in the general substation inspection (150€/substation inspection)
- Expected lifetime: 30 years
- Expected number of changes per day
    - Average of 2 changes per day, considering a maximum number of 4 changes per day

If we were to consider the capacitor banks as devices that have static and switching elements, a comparison with the second methodology proposed in sub-section “HV/MV Substation with On-Load Tap-Changing (OLTC)” can be drawn. This means that the capacitor banks can also be characterized by the same equations in that methodology.

Switchers and Breakers

The cost of operating a switcher or breaker for network reconfiguration results from the combination of maintenance and capital cost. The cost in €/change is given by the following formula:

$$c_{S/B} = \frac{1}{T_T}\left(F_{S/B} + \frac{F_{OT} \cdot a'_T}{t_{OT}}\right)$$

where
T_T: Total allowable adjustment times (times)
a'_T: Lifetime after step changed T_T times (year)
t_{OT}: Maintenance period (year)
$F_{S/B}$: Maintenance cost (€/times)
F_{CB}: Capital cost of the capacitor bank

The following typical values were considered for the parameters:

- Capital cost
    - 60kV – 15.5k€
    - 60kV (GIS) – 61 k€
    - 30kV – 15.3 k€
    - 15kV – 4.9 k€
- Maintenance cost and period: N/A
- Expected lifetime: 30 years
- Expected number of changes per day
    - Average of 1 change per day (this excludes changes resulting from maintenance operations or unplanned grid events)

DRES Reactive Power Compensation

In many countries, there are grid codes that govern reactive power compensation from grid-connected DRES inverters. They impose limits of reactive power until which the compensation has to be provided free of cost. Therefore, the cost of reactive power compensation from DRES within these limits has to be considered zero. However, beyond these limits, the additional inverter losses due to reactive power injection or consumption can be taken into account for the calculation of the cost.

$$C_{DRES-Q} = \begin{cases} 0 & < GCL \\ C(\Delta E_p^{inv}) & > GCL \end{cases}$$

In the equation above, $C(\Delta E_p^{inv})$ is the cost associated with the additional inverter losses, and GCL is the grid code limit for reactive power compensation.

Storage Systems (Batteries)

If we assume that the batteries are owned by a commercial party, the DSO does not have to do the investment of the battery energy storage system but has as consequence that the commercial party reclaims investment and depreciation in the utilization price.

The battery exploitation cost C^{tot}, consists of 3 parts:

- Investment costs (C^{depr}): Typically costs which are not (or limited) subject to use of the flexibility but depreciate over time, e.g. invertor, installation, …
- Battery degradation (C^{deg}): The battery is a significant part of the investment which is subject wear which will be treated separately
- Variable costs (C^{var}): Other unaccounted costs

$$C^{tot} = C^{depr} + C^{deg} + C^{var}$$

The depreciation cost equation translates an investment cost into a variable cost. The calculation is based on the real hardware investment cost C^{HW}, the expected or desired payback time T^{PB}, and the expected energy throughput of the battery energy storage system per year EET.

$$C^{depr} = \frac{C^{HW}}{T^{PB}.EET}$$

The life time of a battery depends on the way the battery will be used. The battery lifetime is either limited by the shelf-lifetime or the cycle-lifetime, whichever is reached first. Also when the battery is not used, the battery lifetime is limited and called the shelf-lifetime. In order to ease the economic parametrization, it is assumed that the maximum number cycles battery will be used before the shelf-lifetime is reached. A well accepted measure of battery life is the Lifetime Energy Throughput (LET). This is the total amount of energy which can be put into and taken out of a battery over all the cycles in its lifetime before its capacity reduces to 80% of its initial capacity when new. Typically the LET is specified as function of the Depth Of Discharge (DOD). In order to keep the equations simple, it is assumed that a fixed DOD is respected which results in a fixed value for the LET.

$$C^{deg} = \frac{c^{bat}.E_{max}}{LET}.\eta_c.\eta_{in}$$

Here, c^{bat} is the specific battery cost, E_{max} is the nominal battery capacity, and η_c, η_{in} are the efficiencies of the charging and discharging of the battery. Depending on the day-ahead electricity spot market price (P^{DA}), the minimum amount of money to be paid for buy and sell offers for battery storage energy is:

$$P^{buy} = P^{DA} - \frac{K^{tot}}{2} - margin$$

$$P^{sell} = P^{DA} + \frac{K^{tot}}{2} + margin$$

Combined Heat and Power (CHP)

A combined heat and power (CHP) generator is capable of, as its name suggests, generating both electrical power and useful heat. It can be considered thermodynamically more efficient than conventional generators as it uses the heat generated during the production of electricity, instead of being wasted.

In the project, the CHP is considered to operate at 0%, and 70-100% of its rating. Depending on the three principal commodities for the CHP, five operation cases are elaborated:

- The price of gas purchased
- The selling price of electricity in the day-ahead market
- The purchase price of electricity from the day-ahead market

Sl. No.	Ascending Order of Prices → → →		
1	Electricity Selling Price (Es)	Gas Purchase Price (G) = Electricity Purchase Price (Ep)	
2	Electricity Selling Price (Es)	Electricity Purchase Price (Ep)	Gas Purchase Price (G)
3	Electricity Selling Price (Es)	Gas Purchase Price (G)	Electricity Purchase Price (Ep)
4	Gas Purchase Price (G)	Electricity Selling Price (Es)	Electricity Purchase Price (Ep)
5	Gas Purchase Price (G) = Electricity Selling Price (Es)		Electricity Purchase Price (Ep)

For each of the scenarios, an analysis of the CHP owner's strategy, and what the DSO should do if he wants something else out of the CHP is discussed below. It is to be noted that the CHP delivers power at a fixed ratio of 0.6 Thermal to 0.4 Electrical.

In case neither the heat or electricity demand is in the operating range (even when the flexibility offered by the buffer is taken into account), the CHP switches off, electricity is purchased from the grid, and the boiler is used to satisfy the heat requirement. Both the CHP and the Boiler are considered to operate at an efficiency of 90%, and this is factored into the gas price ($G = G_{org}/0.9$).

Case 1 (Es < G = Ep)

1. Normal Strategy:
   For this case, the normal working strategy of the CHP owner in order to maximize profits is described in the table below. There is generally no point in selling the electricity generated by the CHP because the selling price is less than the gas price.

w.r.t. CHP rating	**Heat > Rating**	**Heat < Rating (<70%)**	**Heat < Rating (>70%)**	**Heat = Rating**

<table>
<tr><td>Company Demand > Rating</td><td>Supply the heat demand of the company either with the CHP or boiler. Supply electricity demand with CHP or the network.</td><td>Supply heat with the boiler. Purchase electricity from the network.</td><td colspan="2">Supply the heat demand of the company either with the CHP or boiler. Supply electricity demand with CHP or the network.</td></tr>
<tr><td>Company Demand < Rating (<70%)</td><td colspan="4">Supply heat with the boiler, purchase electricity from the network.</td></tr>
<tr><td>Company Demand < Rating (>70%)</td><td rowspan="2">Supply the heat demand of the company either with the CHP or boiler. Supply electricity demand with CHP or the network.</td><td rowspan="2">Supply heat with the boiler, purchase electricity from the network.</td><td rowspan="2" colspan="2">Supply the heat demand of the company either with the CHP or boiler. Supply electricity demand with CHP or the network.</td></tr>
<tr><td>Company Demand = Rating</td></tr>
</table>

2. What the DSO should do: In order to make the CHP owner go against his normal strategy, the DSO has to offer some sort of compensation. The following tables discuss the same (one when additional power is needed, one when lesser power is needed). In all the cases, the technical constraints on the CHP operation limit the flexibility that the DSO wants from the CHP.

   a. When DSO needs more power injection (or lesser power drawn):
   If the DSO needs more power to be injected (lesser power to be drawn), here is what he has to do.

<table>
<tr><th>w.r.t. CHP rating</th><th>Heat > Rating</th><th>Heat < Rating (<70%)</th><th>Heat < Rating (>70%)</th><th>Heat = Rating</th></tr>
<tr><td>Company Demand > Rating</td><td>If CHP is not used, pay at least (G-Es) + Start-up Cost (CHP). Else, not possible.</td><td rowspan="4">Not Possible.</td><td colspan="2">If CHP is not used, pay at least (G-Es) + Start-up Cost (CHP). Else, not possible.</td></tr>
<tr><td>Company Demand < Rating (<70%)</td><td>Pay at least (G-Es) + Start-up Cost (CHP)</td><td colspan="2">Pay at least (G-Es) + Start-up Cost (CHP)</td></tr>
<tr><td>Company Demand < Rating (>70%)</td><td rowspan="2">If CHP is not used, pay at least (G-Es) + Start-up Cost (CHP). Else, not possible.</td><td rowspan="2" colspan="2">If CHP is not used, pay at least (G-Es) + Start-up Cost (CHP). Else, not possible.</td></tr>
<tr><td>Company Demand = Rating</td></tr>
</table>

b. When DSO needs lesser power injection (or more power drawn):
When the DSO needs lesser power to be injected, or more power to be drawn, this is what has to be done. Heat demand shifting happens from CHP to the boiler (only as much as it can handle). Energy related costs are for each unit, start-up and shutdown.

<table>
<tr><th>w.r.t. CHP rating</th><th>Heat > Rating</th><th>Heat < Rating (<70%)</th><th>Heat < Rating (>70%)</th><th>Heat = Rating</th></tr>
<tr><td>Company Demand > Rating</td><td>If CHP is used, pay at least 0 + Shut-down Cost (if CHP is shutdown). Else, not possible.</td><td>Not Possible.</td><td colspan="2">If CHP is used, pay at least 0 + Shut-down Cost (if CHP is shutdown). Else, not possible.</td></tr>
<tr><td>Company Demand < Rating (<70%)</td><td colspan="4">Not Possible.</td></tr>
<tr><td>Company Demand < Rating (>70%)</td><td rowspan="2">If CHP is used, pay at least 0 + Shut-down Cost (if CHP is shutdown). Else, not possible.</td><td rowspan="2">Not Possible.</td><td rowspan="2" colspan="2">If CHP is used, pay at least 0 + Shut-down Cost (if CHP is shutdown). Else, not possible.</td></tr>
<tr><td>Company Demand = Rating</td></tr>
</table>

Case 2 (Es < Ep < G)

1. Normal Strategy:
For this case, the normal working strategy of the CHP owner in order to maximize profits is described in the table below. There is generally no point operating the CHP because the gas price is the highest. In all cases, the boiler is used to supply the heat, and electricity is purchased from the network. There is no interest to sell the generated electricity.

<table>
<tr><th>w.r.t. CHP rating</th><th>Heat > Rating</th><th>Heat < Rating (<70%)</th><th>Heat < Rating (>70%)</th><th>Heat = Rating</th></tr>
<tr><td>Company Demand > Rating</td><td rowspan="4" colspan="4">Supply heat with the boiler, purchase electricity from the network.</td></tr>
<tr><td>Company Demand < Rating (<70%)</td></tr>
<tr><td>Company Demand < Rating (>70%)</td></tr>
<tr><td>Company Demand = Rating</td></tr>
</table>

2. What the DSO should do:

a. When DSO needs more power injection (or lesser power drawn):

Since the CHP owner has not started the CHP up, every time the DSO demands this, the DSO will have to pay a start-up cost. The minimum power demand that the DSO must make is 70% of the electric power output of the CHP. The maximum power that can be asked for depends on the heat requirement or CHP rating, whichever is lower.

<table>
<tr><th>w.r.t. CHP rating</th><th>Heat > Rating</th><th>Heat < Rating (<70%)</th><th>Heat < Rating (>70%)</th><th>Heat = Rating</th></tr>
<tr><td>Company Demand > Rating</td><td rowspan="4">Pay at least (G-Es) + Start-up costs of CHP.</td><td rowspan="4">Not Possible.</td><td rowspan="4" colspan="2">Pay at least (G-Es) + Start-up costs of CHP.</td></tr>
<tr><td>Company Demand < Rating (<70%)</td></tr>
<tr><td>Company Demand < Rating (>70%)</td></tr>
<tr><td>Company Demand = Rating</td></tr>
</table>

b. When the DSO needs lesser power injection (or more power drawn):
Since the CHP is not producing any power, this is not possible.

Case 3 (Es < G < Ep)

1. Normal Strategy:
For this case, the normal working strategy of the CHP owner in order to maximize profits is described in the table below. There is generally an interest to supply the company with CHP electricity, as purchasing it from the network is costlier. There is still no interest to sell it.

<table>
<tr><th>w.r.t. CHP rating</th><th>Heat > Rating</th><th>Heat < Rating (<70%)</th><th>Heat < Rating (>70%)</th><th>Heat = Rating</th></tr>
<tr><td>Company Demand > Rating</td><td>Set CHP at 100%. Use boiler for additional heat, and purchase additional electricity.</td><td rowspan="2">Supply heat with the boiler, purchase electricity from the network.</td><td colspan="2">Supply electricity demand with CHP first (till heat demand is satisfied), buy remaining electricity.</td></tr>
<tr><td>Company Demand < Rating (<70%)</td><td>If $Pd > \frac{Pg(G-Es)}{(Ep-Es)}$, use CHP at 70%, use boiler for additional heat, inject additional electricity. Else, supply heat with the boiler,</td><td colspan="2">If $Pd > \frac{Pg(G-Es)}{(Ep-Es)}$, use CHP at 70%, use boiler for additional heat, inject additional electricity. Else, supply heat with the boiler, purchase electricity from the network.</td></tr>
</table>

	purchase electricity from the network.			
Company Demand < Rating (>70%)	Supply company's electricity demand with CHP. Use boiler for additional heat.		If heat requirement < electricity (w.r.t CHP ratio), use CHP to supply heat, purchase additional electricity from network. Else, supply company's electricity demand with CHP. Use boiler for additional heat.	Supply company's electricity demand with CHP. Use boiler for additional heat.
Company Demand = Rating	Set CHP at 100%. Use boiler for additional heat.		Use CHP to supply heat, purchase additional electricity from network.	Supply the heat and electricity demand with the CHP.

2. What the DSO should do:

    a. When DSO needs more power injected (or lesser power drawn):
    In case the DSO needs more power injected or lesser power drawn in this scenario, the following table explains what needs to be done.

w.r.t. CHP rating	**Heat > Rating**	**Heat < Rating (<70%)**	**Heat < Rating (>70%)**	**Heat = Rating**
Company Demand > Rating	Not Possible.	Not Possible.	Not Possible.	
Company Demand < Rating (<70%)	Pay at least $\frac{Pg(G-Es)+Pd(Es-Ep)}{Px}+G$ for every Px demanded.		Pay at least $\frac{Pg(G-Es)+Pd(Es-Ep)}{Px}+G$ for every Px demanded.	
Company Demand < Rating (>70%)	Pay at least (G-Es) till 100% CHP Rating + Shutdown cost (if boiler is shutdown).		If heat requirement < electricity (w.r.t CHP ratio), not possible. Else, pay at least (G-Es) till CHP satisfies heat	Pay at least (G-Es) till 100% CHP Rating + Shutdown cost (if boiler is shutdown).

			requirement + Shutdown cost (if 2boiler is shutdown).	
Company Demand = Rating	Not Possible.		Not Possible.	

b. When the DSO needs lesser power injection (or more power drawn):
If the DSO needs lesser power injection from the CHP, here is what he needs to do.

w.r.t. CHP rating	**Heat > Rating**	**Heat < Rating (<70%)**	**Heat < Rating (>70%)**	**Heat = Rating**
Company Demand > Rating	Pay at least (Ep-G) + Shutdown Cost (if CHP is shutdown).		Pay at least (Ep-G) + Start-up Cost (for boiler) + Shutdown Cost (if CHP is shutdown).	
Company Demand < Rating (<70%)	If CHP is operating at 70%, pay at least Shutdown Cost (for CHP) + Pg(Es-G)+ Pd(Ep-Es). Else, not possible.	Not Possible.	If CHP is operating at 70%, pay at least Shutdown Cost (for CHP) + Pg(Es-G)+ Pd(Ep-Es). Else, not possible.	
Company Demand < Rating (>70%)	Pay at least (Ep-G) + Shutdown Cost (if CHP is shutdown).		Pay at least (Ep-G) + Start-up Cost (if boiler is started) + Shutdown Cost (if CHP is shutdown).	Pay at least (Ep-G) + Shutdown Cost (if CHP is shutdown).
Company Demand = Rating			Pay at least (Ep-G) + Start-up Cost (for boiler) + Shutdown Cost (if CHP is shutdown).	

Case 4 (G < Es < Ep)

1. Normal Strategy:
For this case, the normal working strategy of the CHP owner in order to maximize profits is described in the table below. The interest here is to satisfy the company's demand with the CHP and sell additional electricity. The heat demand will restrict the CHP output.

w.r.t. CHP rating	**Heat > Rating**	**Heat < Rating (<70%)**	**Heat < Rating (>70%)**	**Heat = Rating**
Company Demand > Rating	Set CHP at 100%. Use boiler for additional heat, and purchase additional electricity.	Supply heat with the boiler, purchase electricity from the network.	Supply the heat demand of the company with the CHP, and purchase additional electricity.	
Company Demand <	Set CHP at 100%, use boiler for		Use CHP to satisfy heat demand. Inject additional electricity.	

Rating (<70%)	additional heat, and inject additional electricity.			
Company Demand < Rating (>70%)			Use CHP to satisfy heat demand. Purchase / inject electricity.	Use CHP to satisfy heat demand. Inject additional electricity.
Company Demand = Rating	Set CHP at 100%, use boiler for additional heat.		Use CHP to satisfy heat demand. Purchase additional electricity.	Supply the heat and electricity demand with the CHP.

2. What the DSO should do:

   a. When DSO needs more power injection (or lesser power drawn):
   Since the CHP owner is already producing (and injecting) as much electricity as he can, the DSO cannot ask for more power, as the heat demand limits the CHP's production. Therefore, this is not possible.

   b. When the DSO needs lesser power injection (or more power drawn):
   If the DSO needs lesser power injection from the CHP, here is what he needs to do.

w.r.t. CHP rating	**Heat > Rating**	**Heat < Rating (<70%)**	**Heat < Rating (>70%)**	**Heat = Rating**
Company Demand > Rating	Pay at least (Ep-G) for each unit of electric energy drawn + Shutdown Cost (if CHP is stopped).	Not Possible.	Pay at least (Ep-G) for each unit of electric energy drawn + Start-up Cost (for boiler) + Shutdown Cost (if CHP is stopped).	
Company Demand < Rating (<70%)	Pay at least (Es-G) until CHP ceases to meet electricity demand. Then pay at least (Ep-G) + Shutdown Cost (if CHP is stopped).		Pay at least (Es-G) + Start-up cost (for boiler) until CHP is at 70%. Then pay at least (Ep-G) + Shutdown Cost.	
Company Demand < Rating (>70%)			Pay at least (Es-G) + Start-up (for boiler) cost until CHP ceases to meet electricity demand. Then pay at least (Ep-G) + Shutdown Cost (if CHP is stopped).	
Company Demand = Rating	Pay at least (Ep-G) for each unit of electric energy drawn + Shutdown Cost (if CHP is stopped).		Pay at least (Ep-G) + Start-up Cost (for boiler) + Shutdown Cost (if CHP is stopped).	

Case 5 (Es = G < Ep)

1. Normal Strategy:
For this case, the normal working strategy of the CHP owner in order to maximize profits is described in the table below. There is generally no point in selling the electricity generated by the CHP because the selling price is equal to the gas price. However, there is an interest to satisfy company electricity demand with the CHP as the purchase price from the network is higher.

<table>
<tr><th>w.r.t. CHP rating</th><th>Heat > Rating</th><th>Heat < Rating (<70%)</th><th>Heat < Rating (>70%)</th><th>Heat = Rating</th></tr>
<tr><td>Company Demand > Rating</td><td>Set CHP at 100%. Use boiler for additional heat, and purchase additional electricity.</td><td rowspan="4">Supply heat with the boiler, purchase electricity from the network.</td><td colspan="2">Supply the heat demand of the company with the CHP, purchase additional electricity from the network.</td></tr>
<tr><td>Company Demand < Rating (<70%)</td><td>Set CHP at 70%, inject additional electricity, use boiler for extra heat.</td><td colspan="2">Use CHP to satisfy heat demand. Inject additional electricity.</td></tr>
<tr><td>Company Demand < Rating (>70%)</td><td rowspan="2">Set CHP at company’s electricity demand, use boiler for additional heat.</td><td>Use CHP to satisfy heat demand. Buy/inject electricity.</td><td>Set CHP at company’s demand, use boiler for additional heat.</td></tr>
<tr><td>Company Demand = Rating</td><td>Use CHP to satisfy heat demand. Buy additional electricity.</td><td>Supply the heat and electricity demand with the CHP.</td></tr>
</table>

2. What the DSO should do:

   a. When DSO needs more power injected (or lesser power drawn):
   If the DSO needs to achieve this, the following table explains what he has to do.

<table>
<tr><th>w.r.t. CHP rating</th><th>Heat > Rating</th><th>Heat < Rating (<70%)</th><th>Heat < Rating (>70%)</th><th>Heat = Rating</th></tr>
<tr><td>Company Demand > Rating</td><td>Not Possible.</td><td rowspan="3" colspan="3">Not Possible.</td></tr>
<tr><td>Company Demand < Rating (<70%)</td><td rowspan="2">Pay Shutdown Cost (If boiler is shut down).</td></tr>
<tr><td>Company Demand < Rating (>70%)</td></tr>
</table>

<table>
<tr><td>Company Demand = Rating</td><td>Not Possible.</td><td></td></tr>
</table>

b. When the DSO needs lesser power injection (or more power drawn):
If the DSO needs lesser power injection from the CHP, here is what he needs to do.

<table>
<tr><td>w.r.t. CHP rating</td><td>Heat > Rating</td><td>Heat < Rating (<70%)</td><td>Heat < Rating (>70%)</td><td>Heat = Rating</td></tr>
<tr><td>Company Demand > Rating</td><td>Pay at least (Ep-G) for each unit of electric energy drawn + Shutdown Cost (if CHP is stopped).</td><td rowspan="4">Not Possible.</td><td colspan="2">Pay at least (Ep-G) for each unit of electric energy drawn + Start-up Cost (for boiler) + Shutdown Cost (if CHP is stopped).</td></tr>
<tr><td>Company Demand < Rating (<70%)</td><td>Pay at least (Ep-G) for each unit of electric energy drawn + Shutdown Cost (CHP)</td><td colspan="2">Pay at least (Es-G) + Start-up cost (for boiler) until CHP is at 70%. Then pay at least (Ep-G) + Shutdown Cost.</td></tr>
<tr><td>Company Demand < Rating (>70%)</td><td rowspan="2">Pay at least (Ep-G) for each unit of electric energy drawn + Shutdown Cost (if CHP is stopped).</td><td colspan="2">Pay at least (Es-G) + Start-up (for boiler) cost until CHP ceases to meet electricity demand. Then pay at least (Ep-G) + Shutdown Cost (if CHP is stopped).</td></tr>
<tr><td>Company Demand = Rating</td><td colspan="2">Pay at least (Ep-G) + Start-up Cost (for boiler) + Shutdown Cost (if CHP is stopped).</td></tr>
</table>

DRES Curtailment

For DRES curtailment, there are two components in the unit cost function. The first component is the component that corresponds to the loss of revenue. This is nothing but the price of electricity at which the DRES unit(s) will sell the generated electricity, and is the day-ahead power exchange market price for the time period when it is curtailed $(C(E_p^{da})^t)$. The second component corresponds to the loss of incentives, which is the additional feed-in tariff component (FIT^{pr}). If the DRES unit has a contract to sell electricity generated at a pre-determined incentivized tariff, this should be the compensated instead.

$$C^{tot} = (C(E_p^{da})^t + FIT^{pr})$$

Demand Response (DR)

In this section, when we speak about Demand Response (DR) flexibilities, we refer to any electricity consumer who is able to adjust its electricity consumption following a request from either the DSO or an aggregator who would request it on behalf of the DSO. This consumption adjustment can be two-folds:

Load decrease

The electricity consumer would be here able to reduce its electricity consumption for a short period of time (from a few minutes to a few hours maximum), thus relieving the grid from a power offtake. This could be for example useful in case there is congestion in the distribution grid or in case voltage cannot be sustained at an acceptable level.

Load increase

The electricity consumer would be here able to increase its electricity consumption for a short period of time (from a few minutes to a few hours maximum), thus absorbing extra power from the grid. This could be for example useful in case there is congestion in the distribution grid (too much generation in a certain area of the grid) or in case of local over-voltage.
As part of the EvolvDSO project, we defined two ways for the DSO to procure those type DR (Demand Response) flexibilities:

Long term flexibilities

For this type of DR flexibilities, the DSO is paying a fee (fixed fee) to the electricity consumer (either directly or via an aggregator) so that the consumer is making its flexibility available to the DSO on a pre-defined period of time. For example the DSO could pay 50 000€ for having a 1 MW load decrease flexibility available any time during a one year period. In case the DSO needs this electricity consumer to decrease its load, the electricity consuming would reduce its offtake from the grid by 1MW. It has to be noted that the number of times the DSO can request this load decrease and the length of each load decrease are pre-defined in the contract between the DSO and the electricity consumer.
The exact way those flexibilities would be procured can differ from one country/market to another. It could be for example via bilateral contracting or via calls for tender. However, the fact the flexibility is procured well ahead of real time (typically from a few months to 2 to 3 years) and is paid for being available on a pre-defined period of time makes it a long term flexibility.

Short term flexibilities

This type of flexibilities would only be made available to the DSO on a short term basis. Typically, the electricity consumers (or their aggregator) would submit on a daily basis, their flexibility capability and the price associated with it. For example, we could see an electricity consumer proposing 2 MW of load increase which can be activated by the DSO anytime on the next day, with a 2 hours' notice period and for a maximum period of 2 hours. As a compensation for this potential over consumption, the electricity consumer would ask the DSO to pay 400€/hour, should the DSO have to use this flexibility. The fact the flexibility does not require a fixed fee for being available and has no requirement from the DSO to be available makes it a short term flexibility.

Fixed cost and variable cost

The price the DSO would have to pay to 1/ have DR flexibilities available and 2/ be able to activate them I split into two components:

- For long term flexibilities, the DSO would pay a fixed cost for having the DR flexibility available. We typically express this cost in €/MW/year or €/MW (with the underlying assumption that the DR flexibility will be paid for a one year period). Short term flexibilities do not have this fixed cost as they have no commitment to be available
- For long term and short flexibilities, the DSO would have to pay a variable cost for the activation of the flexibility. This cost is typically expressed in €/MWh

Assumptions around the settlement model

The definition of a settlement model to allow electricity consumer to offer their flexibility to a DSO has to be explicitly defined. Particularly, the fact that the load increase or load decrease of an electricity consumer is changing the energy that will be billed by its electricity supplier means we need to define if this impact on the suppliers business is settled or not. Choosing one settlement option or one other would greatly change the cost of DR flexibilities.
The definition of this settlement model will clearly be an assumption of our project as there may be several possible settlement models in the future.

The two charts below represent a load increase from an electricity consumer. Each of them describe a different way of treating the impact of the load decrease on the supplier business.

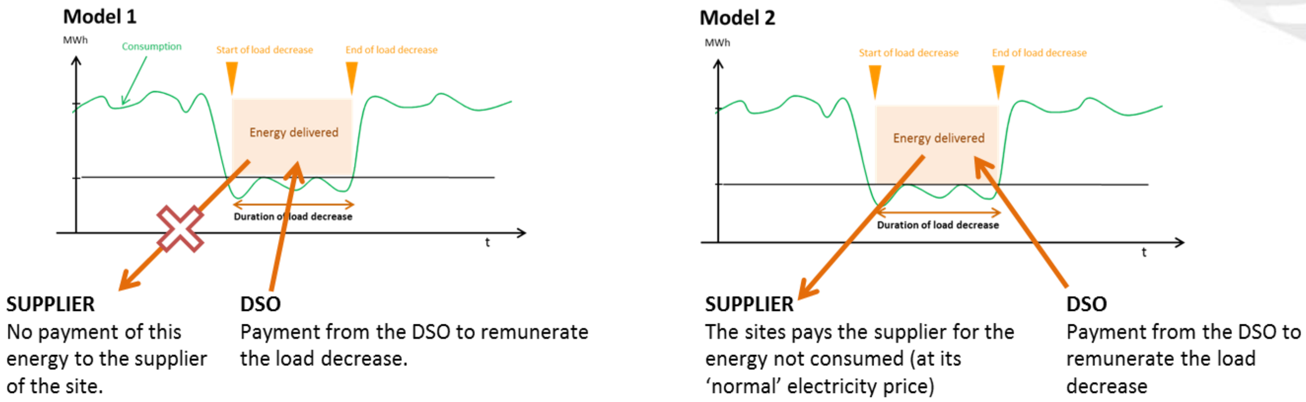


Figure 222 – Example of settlement models for load decrease

For both models displayed above, the cost of the flexibility will not be the same as in model 2 the site has to reimburse the energy to its supplier whilst in model 1 it does not.
For the evolvDSO project, we propose to choose model 1 as this model is simpler to understand, already exists in certain countries, as USA, UK, Belgium or Korea, for flexibilities which are activated by TSO and, although model 2 has been tested for load decrease in some countries as France, a similar model has never been tested for load increase.

How to assess their costs?

In this part we show how we assess the DR flexibility cost for short and long term flexibilities and for load increase and load decrease.

Long term load decrease

For most of the long term load decrease products we assume, the price the DSO will have to pay to secure DR flexibilities only a fixed price (i.e. €/MW) - we assume it is a reasonable assumption as:

- These are committed product, hence the electricity consumer expects to be paid a fixed price to commit being available
- Consumers tend to favor fixed price

Values were assessed against international benchmark based on TSO flexibility products which are similar to those proposed for the DSO. More than 100 DR programs were assessed in several dozen countries around the world (USA, EU and Asia).
The table below gives the long term product we defined as part of the EvolvDSO project and their associated price ranges:

Term	Decrease / Increa	Notice period	# of hours/year	# hours per day	DR flex fixed fee (€/MW/year)	DR flex variable cost for the DSO (€/MW
Long term	Demand decrease	Not relevant	Max 1000	Max 3 hours	12000 - 24000	0
Long term	Demand decrease	Not relevant	Max 200	Max 3 hours	8000 - 15000	0
Long term	Demand decrease	Not relevant	Max 3000	Max 12 hours	40000 - 100000	0
Long term	Demand decrease	Not relevant	Max 20	Max 5 hours	5000 - 10000	200

Long term load increase

Similarly, for the long term load increase products we assume the price the DSO will have to pay to secure DR flexibility is only a fixed price (i.e. €/MW) - we assume it is a reasonable assumption as:

- These are committed product, hence the DR expect to be paid a fixed price to commit being available
- Consumers tend to favor fixed price

Values were assessed against international benchmark based on TSO flexibility products which are similar to those proposed for the DSO.

The table below gives the long term product we defined as part of the EvolvDSO project and their associated price ranges:

Term	Decrease / Increa	Notice period	# of hours/year	# hours per day	DR flex fixed fee (€/MW/year)	DR flex variable cost for the DSO (€/MW
Long term	Demand increase	Not relevant	Max 1000	Max 3 hours	12000 - 24000	0
Long term	Demand increase	Not relevant	Max 200	Max 3 hours	8000 - 15000	0
Long term	Demand increase	Not relevant	Max 3000	Max 12 hours	40000 - 100000	0

Short term load decrease

If a consumer wants to decrease its consumption, it will do so if it is more economic than carrying on consuming. Therefore the price it gets for load decrease has to be attractive.
We assume that the maximum electricity market prices observed in the electricity markets are a good proxy for the earning the site would expect to do under such occasion.

Therefore the cost of the flexibility will be assessed by averaging the 20 highest prices observed on the electricity market. This can be:

- The electricity day ahead prices for flexibilities with a few hours' notice period | example in France in 2014 = 81,80€/MWh
- The upward regulation prices for flexibilities with a few minutes notice period | example in France in 2014 = 269,14€/MWh

The chart below gives an example of bidding strategy from an electricity consumer and the impact on the DR flexibility cost for the DSO:

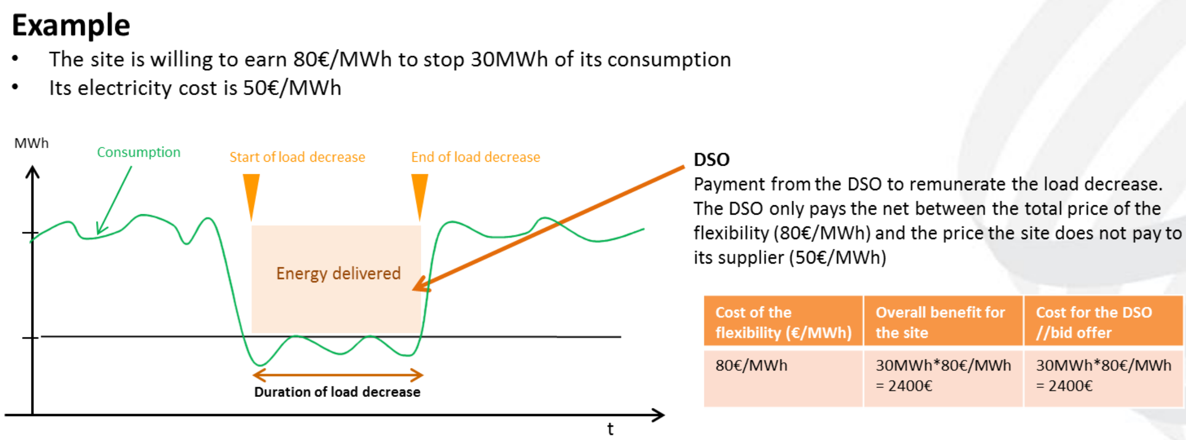


Figure 223 –Example of bidding strategy for load decrease and cost for the DSO

Short term load increase

If an electricity consumer wants to increase its consumption, it will do so if it is more economic than not consuming. Therefore the price it pays for over consuming has to be attractive.
We assume that the minimum electricity market prices observed in the markets are a good proxy for the price the site would be willing to pay to over-consume.
One thing which has to be considered when it comes to load increase flexibility is that, when increasing its load, the site will pay its supplier for the energy overconsumed
Therefore, if the site wants the over consumed energy to be worth the minimum electricity market prices, the cost of the flexibility paid by the DSO will have to be:

Electricity cost - minimum electricity market price

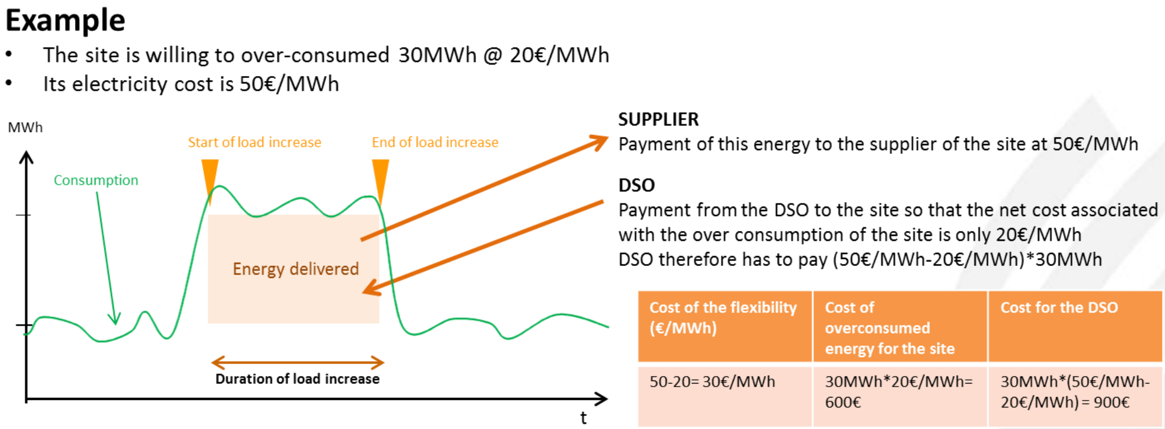
Where:

- Minimum electricity market price = Average of 20 lowest prices observed on:
    - The electricity day ahead prices for flexibilities with a few hours' notice period | example in France in 2014 = 0,03€/MWh
    - The downward regulation prices for flexibilities with a few minutes notice period | example in France in 2014 = -10,71€/MWh
- 'Electricity cost' = average of electricity day ahead prices | example: France in 2014 = 34€/MWh

Therefore, for France, the cost of a short term load increase flexibility would be assessed to be:

- 33,7€/MWh for flexibilities with a few hours' notice period
- 44,71€/MWh for flexibilities with a few minutes notice period

The chart below gives an example of bidding strategy from a site and the impact on the DR flexibility cost for the DSO:



Cost of the flexibility (€/MWh)	Cost of overconsumed energy for the site	Cost for the DSO
50-20= 30€/MWh	30MWh*20€/MWh= 600€	30MWh*(50€/MWh-20€/MWh) = 900€

Figure 224 – Example of bidding strategy for load increase and cost for the DSO

ANNEX II – Additional Results for Planning Domain

Short-term network reinforcements considering flexibilities and ICT reliability (FLEXPLAN)

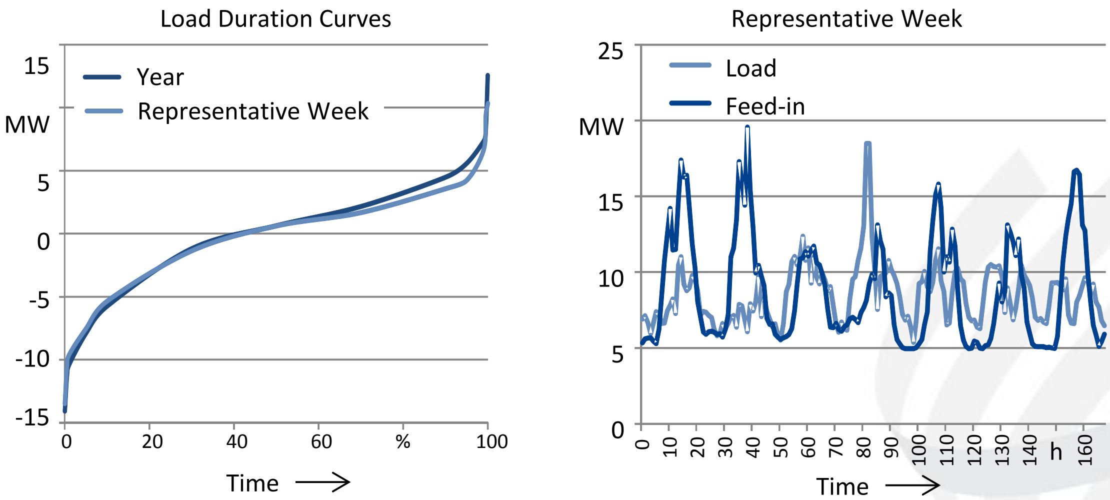


Figure 225: Selection of representative week for reliability analysis

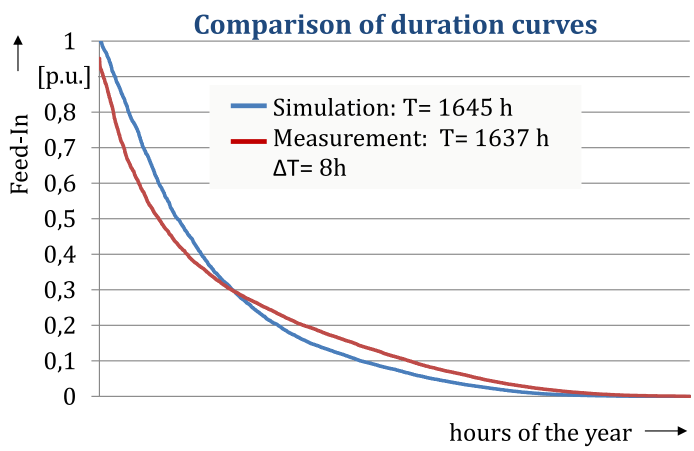


Figure 226: Comparison of duration curve for ten wind farms

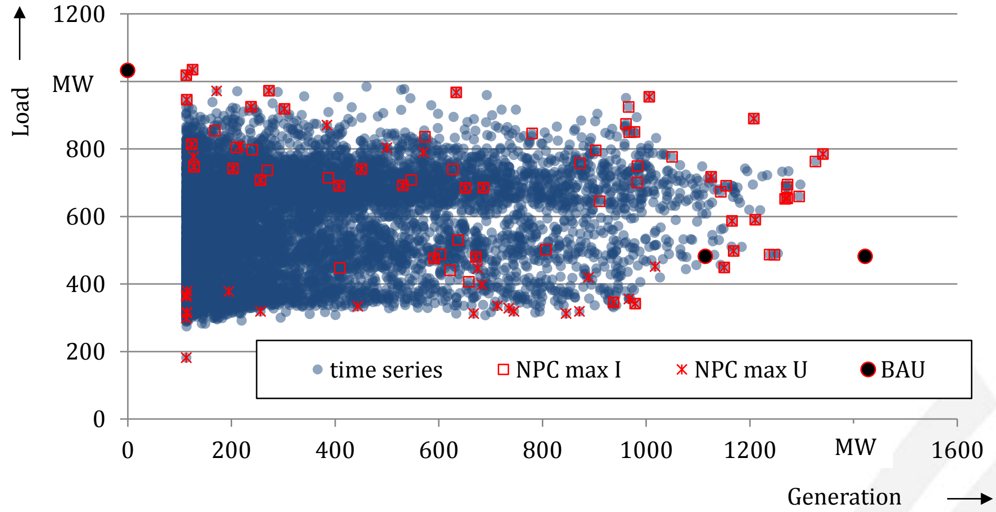


Figure 227: NPC with highest network load

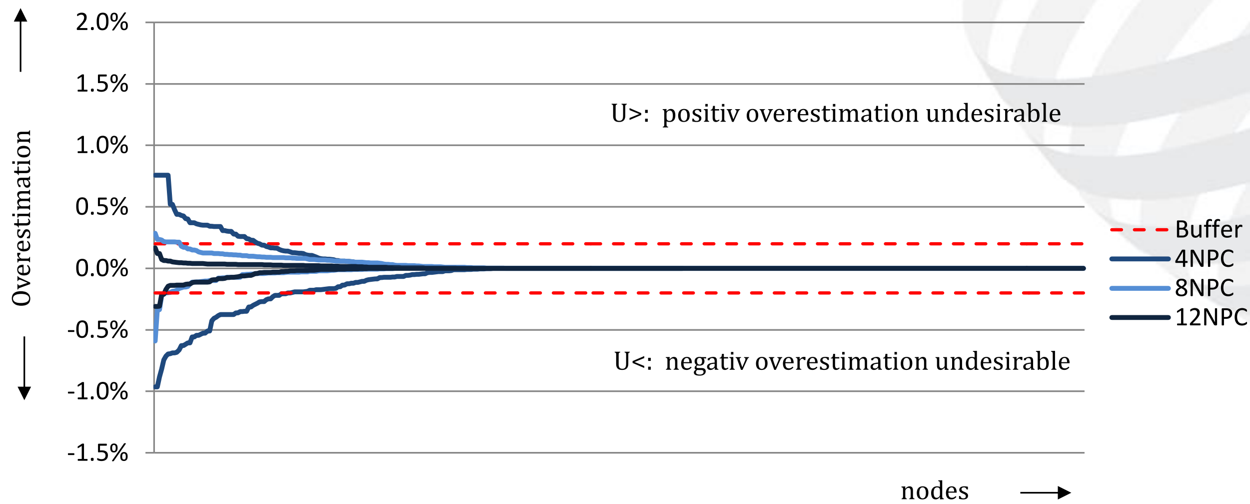


Figure 228: Comparison voltages: NPC-D vs. time series

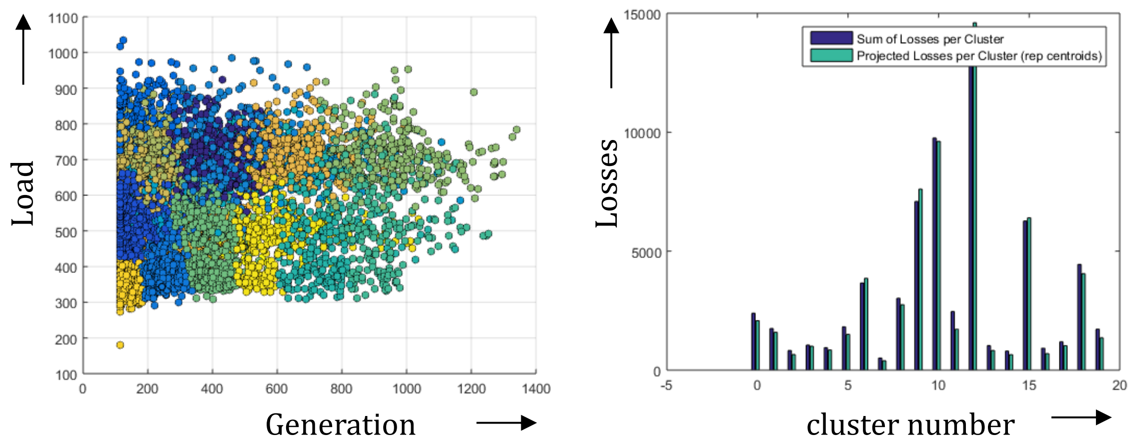


Figure 229: results for higher cluster numbers (k=20)

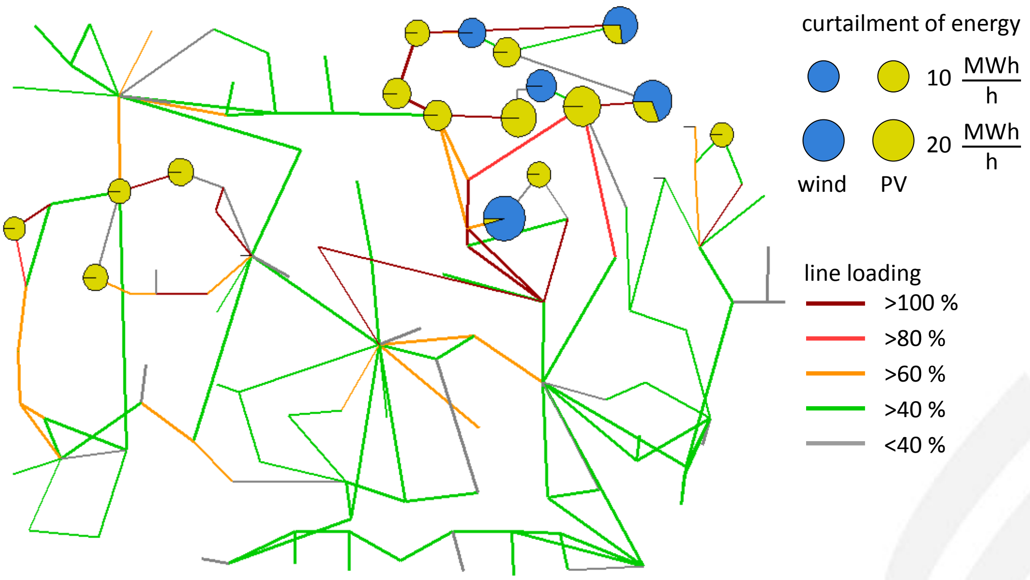


Figure 230: Line loadings and curtailment of DRES for a specific hour in the 50 % expansion plan

ANNEX III – Additional Results for Operational Domain

Robust Short-Term Economic Optimization Tool for Operational Planning

Additional results of VITO optimisation routine

Short-Term Scenario (2018)

For the short term scenario, the simulation results are shown in Figure 231-Figure 236. Figure 231 shows the baseline scenario, with OLTC tap setting fixed at 1.02 pu. As shown in the figure, under voltage incidents are observed during morning-hours (around 8h00) and during evening hours as well. In total there are 1299 voltage issues during the day, the minimal voltage encountered is 0.924 pu.

Figure 232 shows the voltage magnitudes after solving the optimal power flow problem: all under voltage incidents are solved. As can be seen in Figure 233, Figure 234 and Figure 235, the levers used to solve the under-voltage constraints in the 2018 scenario are the same as for the Status Quo scenario: reactive power compensation from wind and PV generators, and load curtailment. Figure 236 shows the variation of the cost to solve all under voltage issues during the day. The total cost of the solution is 760.5 €. In comparison with the Status Quo scenario, more load curtailment and more reactive power compensation from the solar panels is needed, because in this Short-Term scenario, the load has increased, while wind power production is less.

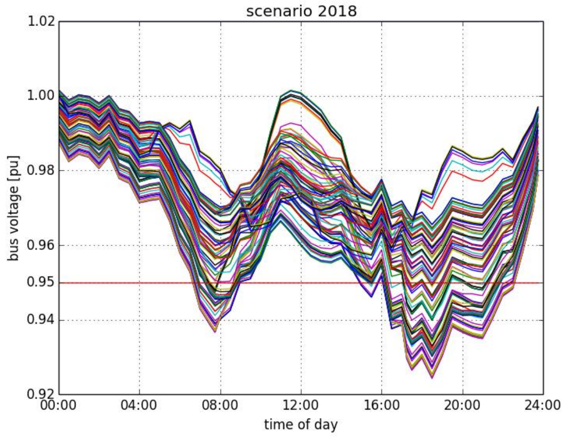


Figure 231: OP Tool - Baseline scenario 2018 with OLTC tap at 1.02 pu: Bus voltage magnitudes of all buses are shown. The minimal allowed bus voltage is as a red line.

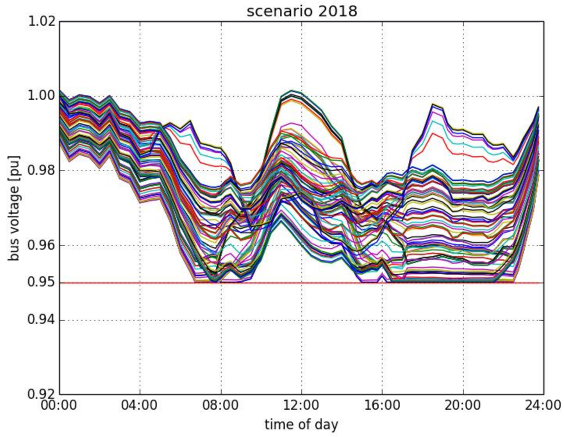


Figure 232: OP Tool - Scenario 2018 after optimization: Bus voltage magnitudes of all buses are shown. The minimal allowed bus voltage is indicated as a red line.

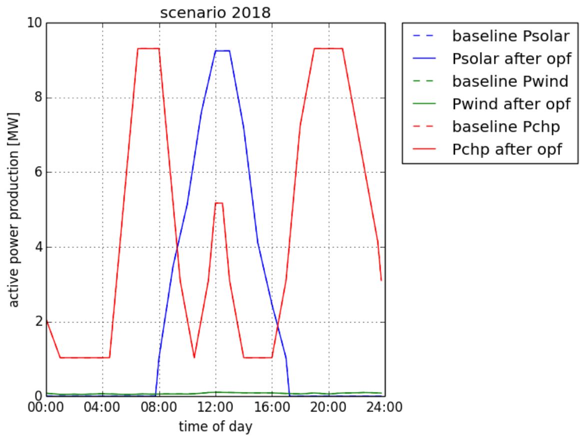


Figure 233: OP Tool - Scenario 2018: Combined generated power by solar generators, wind generators and CHPs, before and after optimization.

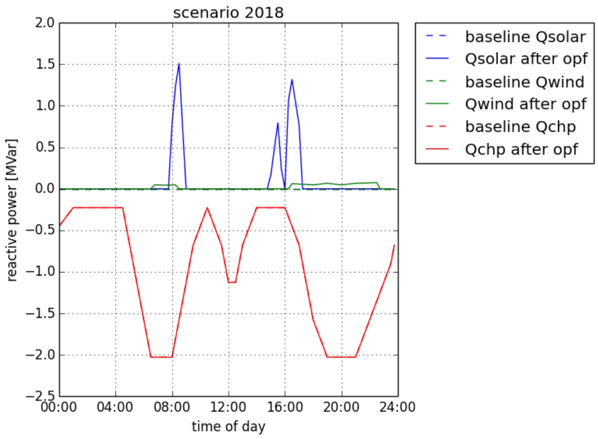


Figure 234: OP Tool - Scenario 2018: Combined reactive power generated by solar generators, wind generators and CHPs, before and after optimization.

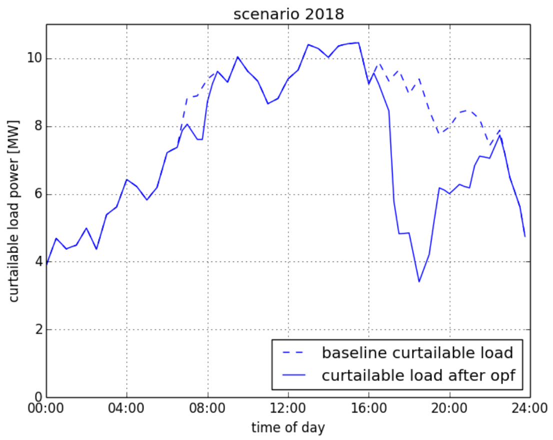


Figure 235: OP Tool - Scenario 2018: Combined curtailable load power consumption, before and after optimization.

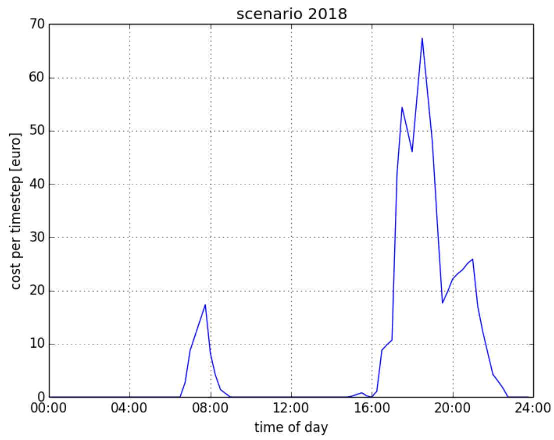


Figure 236: OP Tool - Scenario 2018: Cost of OPF solution per time step.

Mid-Term Scenario (2023)

For the Mid-Term scenario, the simulation results are shown in Figure 237-Figure 242. Figure 237 shows the baseline scenario, with OLTC tap setting fixed at 1.03 pu. As shown in the figure, under voltage incidents are observed during morning-hours (around 8h00) and during evening hours as well. In total there are 707 voltage issues during the day, the minimal voltage encountered is 0.928 pu. Figure 238 shows the voltage magnitudes after solving the optimal power flow problem: all under voltage incidents are solved. As can be seen in Figure 239, Figure 240 and Figure 241 the levers used to solve the under-voltage constraints in the 2023 scenario are the same as for the Status Quo and Short-Term scenario: reactive power compensation from wind and PV generators, and load curtailment. Figure 242 shows the variation of the cost to solve all under voltage issues during the day. The total cost of the solution is 592.7 €. The cost of the solution in comparison with the Short-Term scenario is less, because the load has decreased, while production from CHP's has increased. Consequently, less load curtailment and less reactive power compensation is required to solve the under voltage issues.

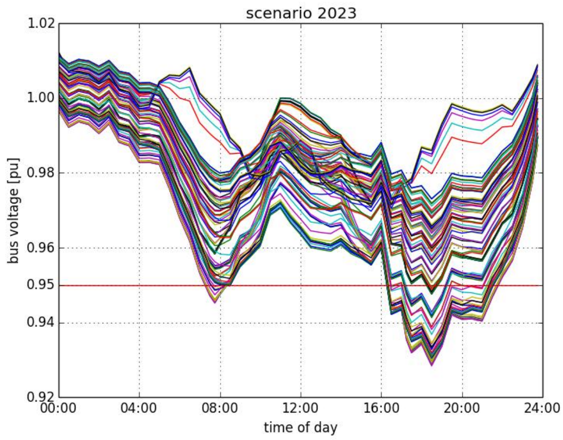


Figure 237 - OP Tool - Baseline scenario 2023 with OLTC tap at 1.03 pu: Bus voltage magnitudes of all buses are shown. The minimal allowed bus voltage is indicated as a red line.

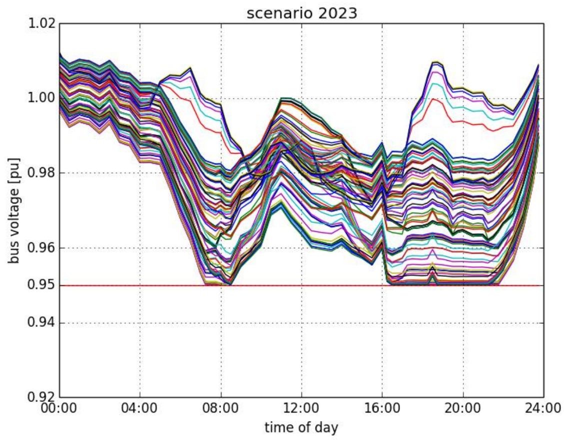


Figure 238 - OP Tool - Scenario 2023 after optimization: Bus voltage magnitudes of all buses are shown. The minimal allowed bus voltage is indicated as a red line.

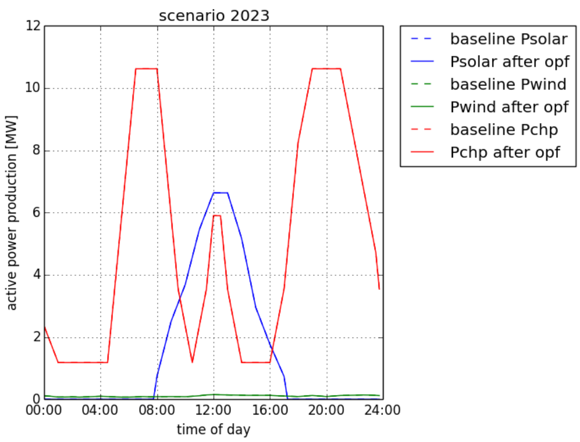


Figure 239 - OP Tool - Scenario 2023: Combined generated power by solar generators, wind generators and CHPs, before and after optimization.

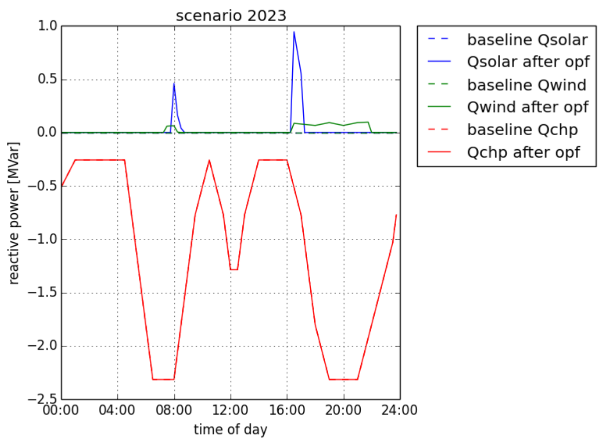


Figure 240 - OP Tool - Scenario 2023: Combined reactive power generated by solar generators, wind generators and CHPs, before and after optimization.

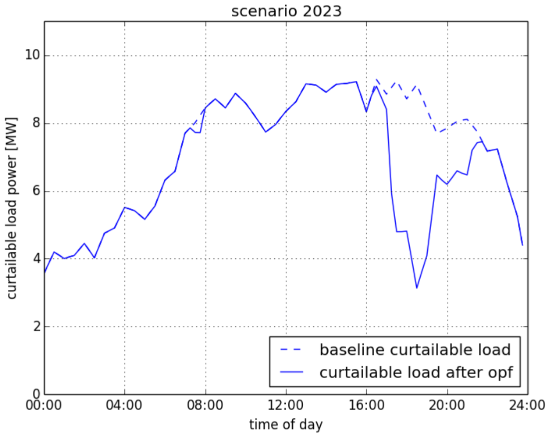


Figure 241 - OP Tool - Scenario 2023: Combined curtailable load power consumption, before and after optimization.

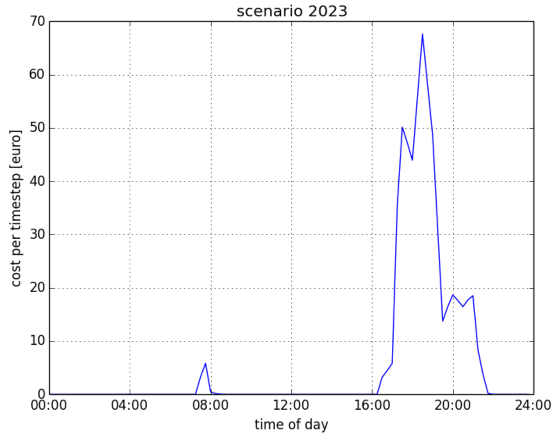


Figure 242 - OP Tool - Scenario 2023: Cost of OPF solution per time step.

Additional results from RSE optimization routine

Sensitivity analyses for the RSE optimization

To better study the behaviour of the control solution, the simulations are repeated with different parameters of the scenario and of the resources' characteristics.

<u>**Scenario 2023: Generation 15% higher**</u>

It is considered the scenario where the generation is 15% higher than the original value. This could be an example of a day with higher wind or solar radiance. This case is particularly interesting since some current violations, due to the high generation, occurs. In this case then it is necessary to modulate the generation and the load to reduce the currents. The total cost is 55.00 €, very close to the normal case since it is necessary to modulate the load to solve current violations, but at the same time the number of voltage violations decreases.

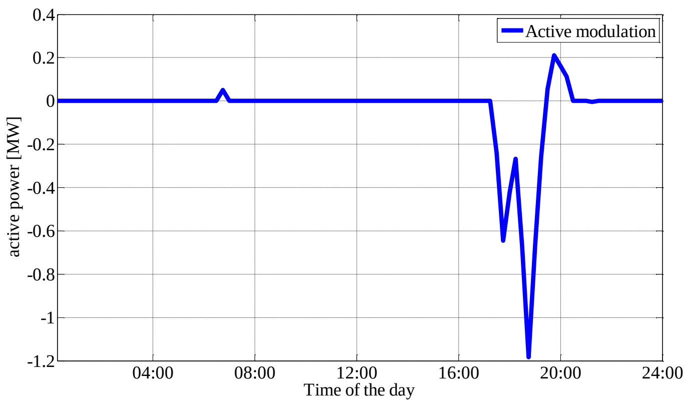


Figure 243 - OP Tool - Scenario 2023: cost of OPF solution per period

<u>**Scenario 2023: rectangular PV capability**</u>

Another interesting configuration is to change the characteristic of the PV inverters. In this frame, a rectangular capability is considered, according to the Italian regulatory framework. This allows the photovoltaic generators to exchange reactive power also when the production is zero. In this cases, the reactive modulation is enough to solve the voltage violations, reducing also the total cost to 32.3 €.

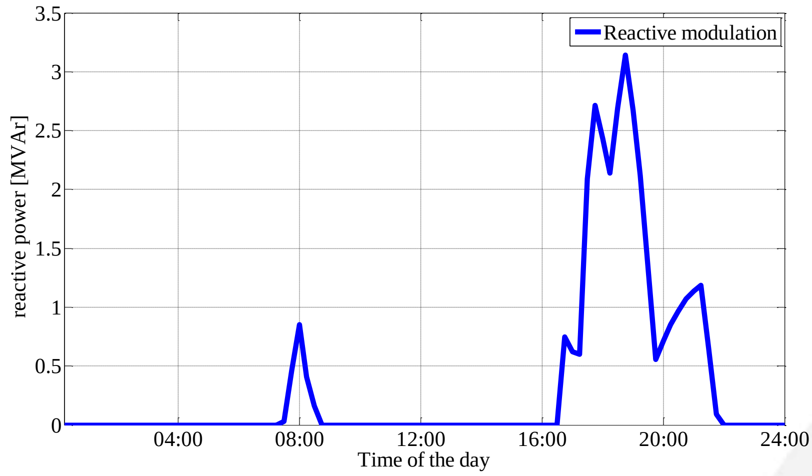


Figure 244 - OP Tool - Reactive power modulation with rectangular capability curve for the PV generators in 2023

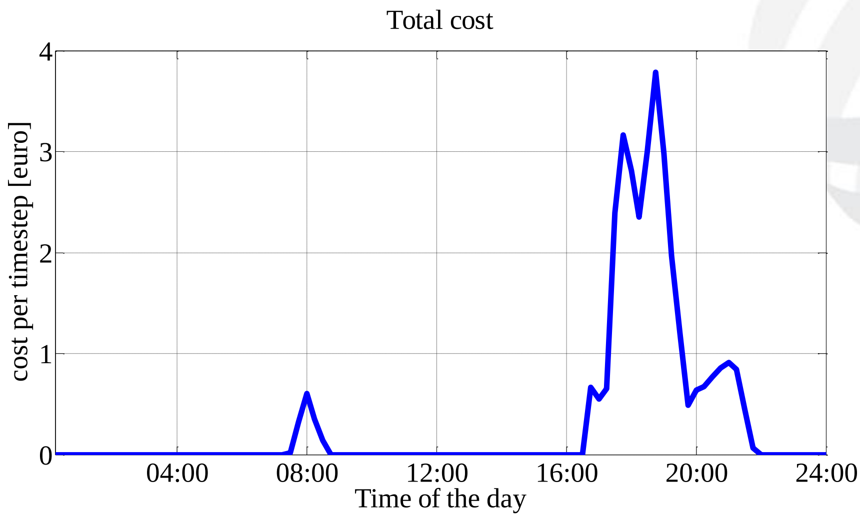


Figure 245 - OP Tool - Total cost with rectangular capability curve for the PV generators in 2023

Scenario 2023 Reduced Cost

Another test is performed reducing the modulation cost of one load. The total exchange of active power increases, even if the total cost decreases. This is given by the fact that the optimizer uses the cheapest resource at the maximum rate.

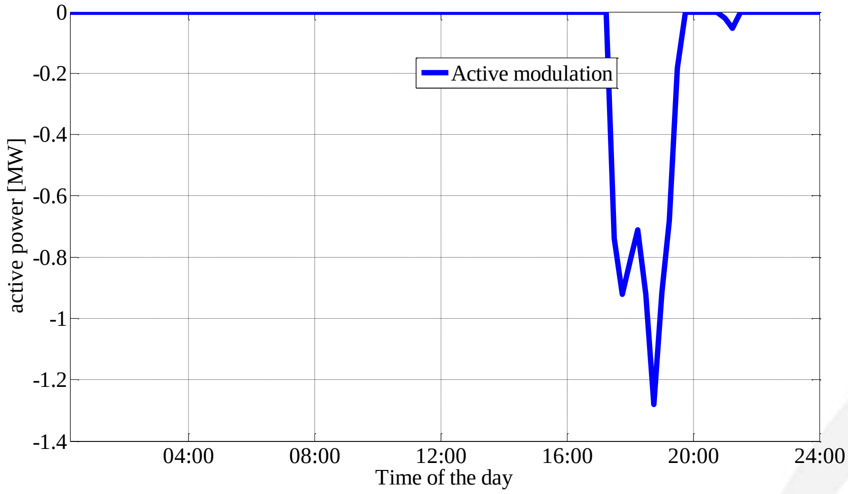


Figure 246 - OP Tool - Active power modulation with reduced cost in 2023

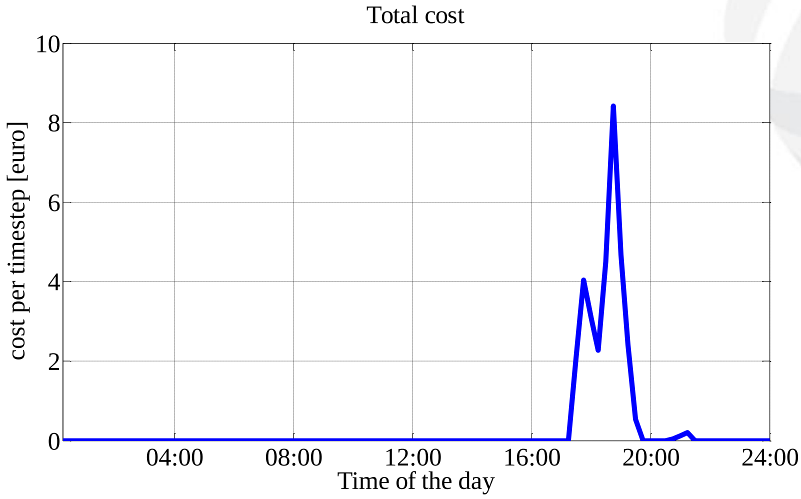


Figure 247 - OP Tool - Total cost with reduced cost for a load in 2023

Scenario 2023: OLTC position of 1.0327 pu

In this case, the OLTC position is slightly reduced to 1.0327 p.u. This little variation greatly change the use of the resources. In fact, the active and reactive modulations are higher, especially when the minimum of the voltage occurs. The higher use of the resources increase the total cost to 81.4 €. Hence, this simulation highlights the importance of the OLTC position for network management purposes: small changes in its voltage determine high differences in the use of the resources.

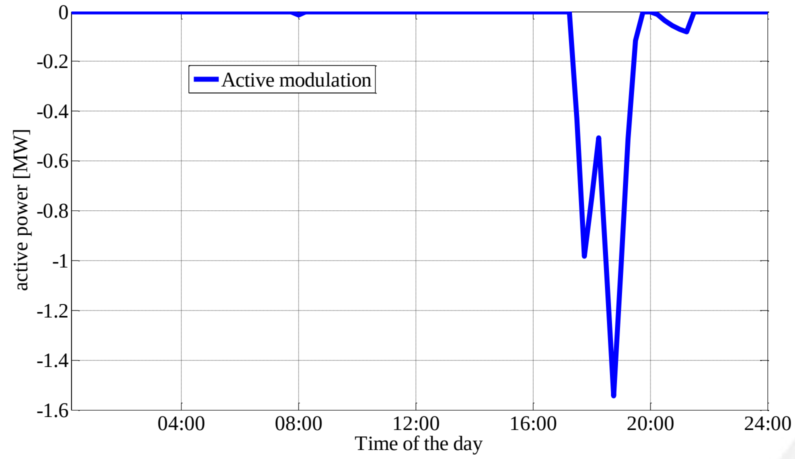


Figure 248 - OP Tool - Active power modulation with $V_{OLTC-HV}$=1.0327 pu in 2023

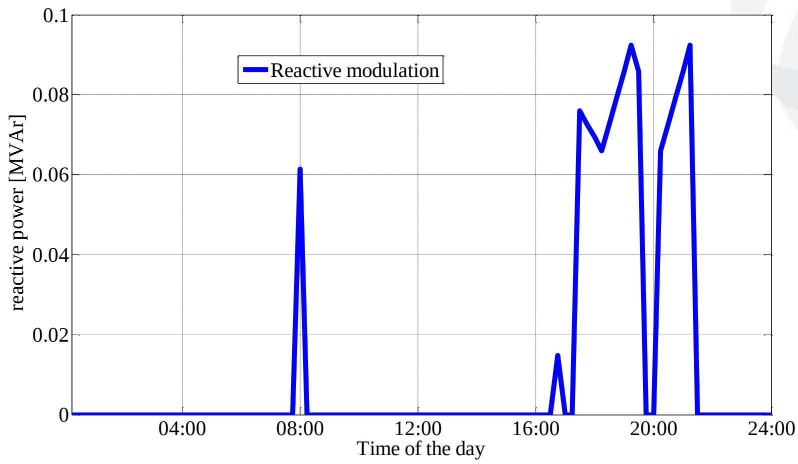


Figure 249 - OP Tool - Reactive power modulation with $V_{OLTC-HV}$=1.0327 pu in 2023

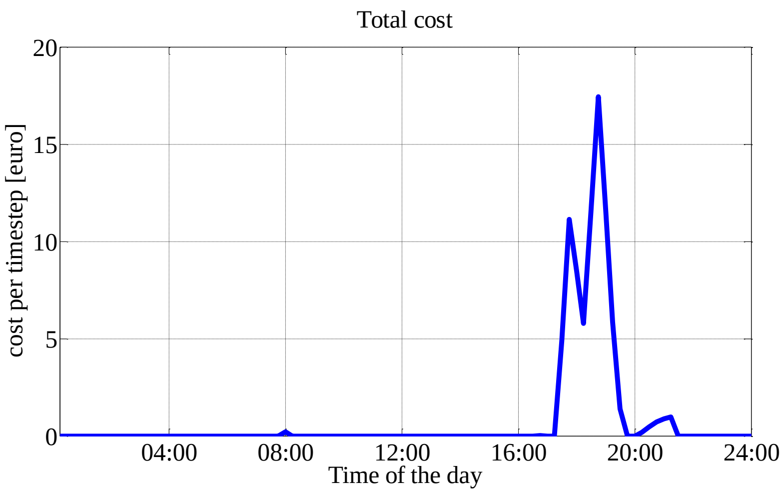


Figure 250 - OP Tool - Total cost with $V_{OLTC-HV}$=1.0327 pu in 2023

Low Voltage Distribution State Estimator

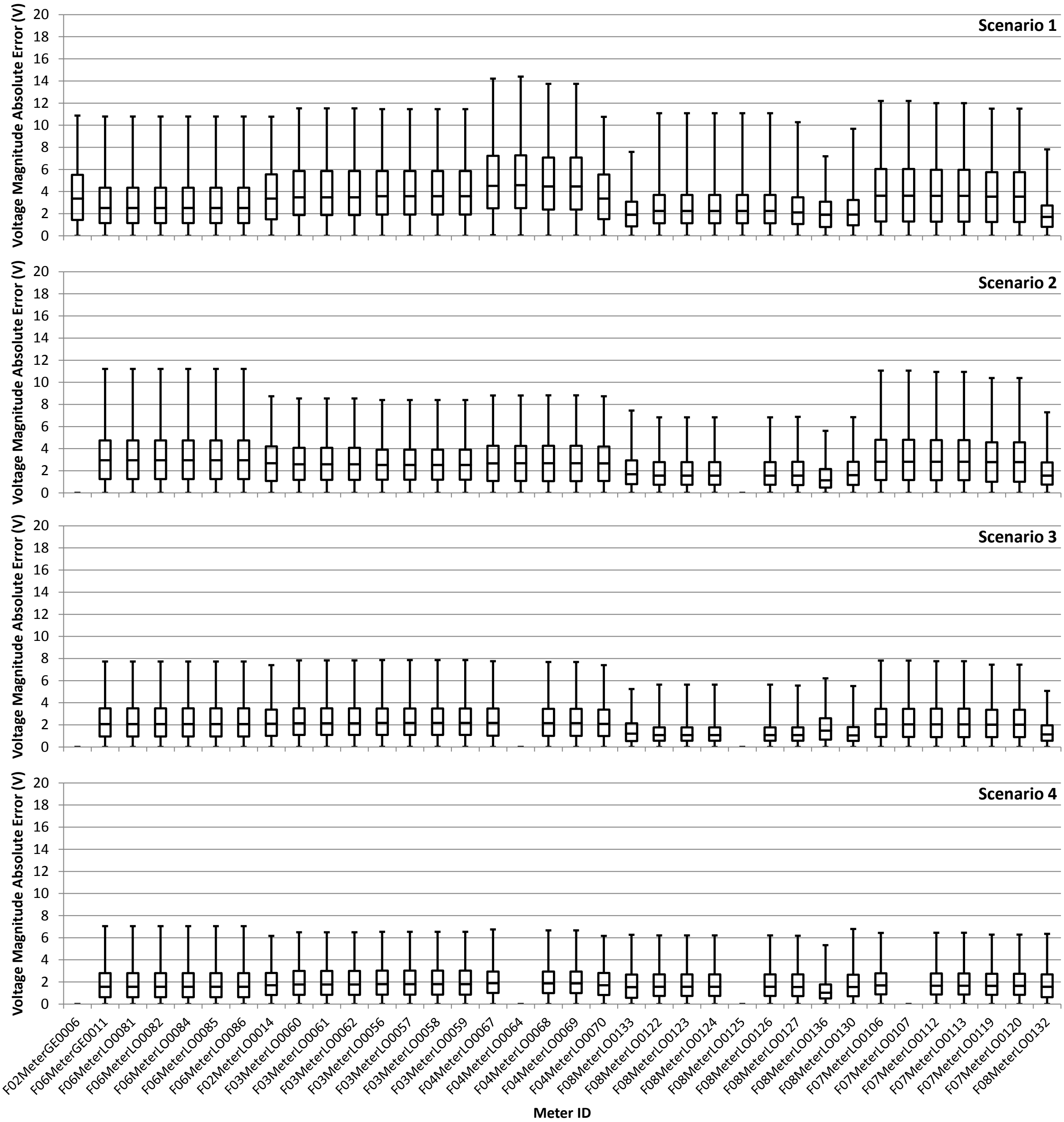


Figure 251 – Voltage magnitude absolute error for all customers connected to phase B (not being real-time monitored) in scenarios 1, 2, 3 and 4.

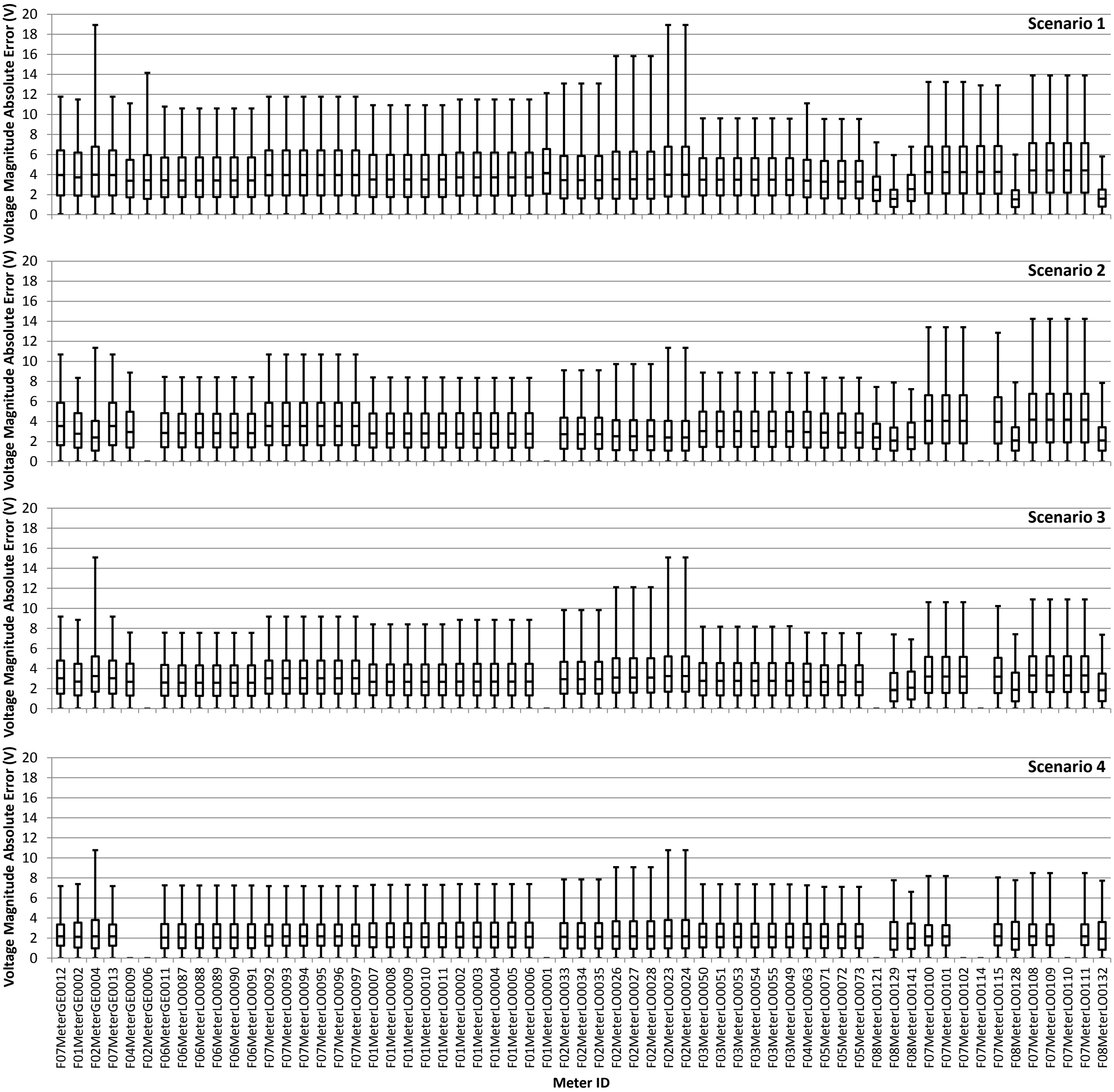
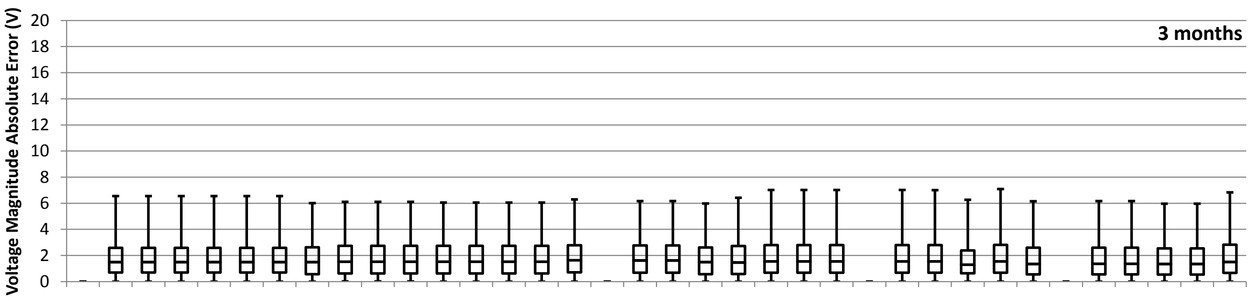


Figure 252 – Voltage magnitude absolute error for all customers connected to phase C (not being real-time monitored) in scenarios 1, 2, 3 and 4.



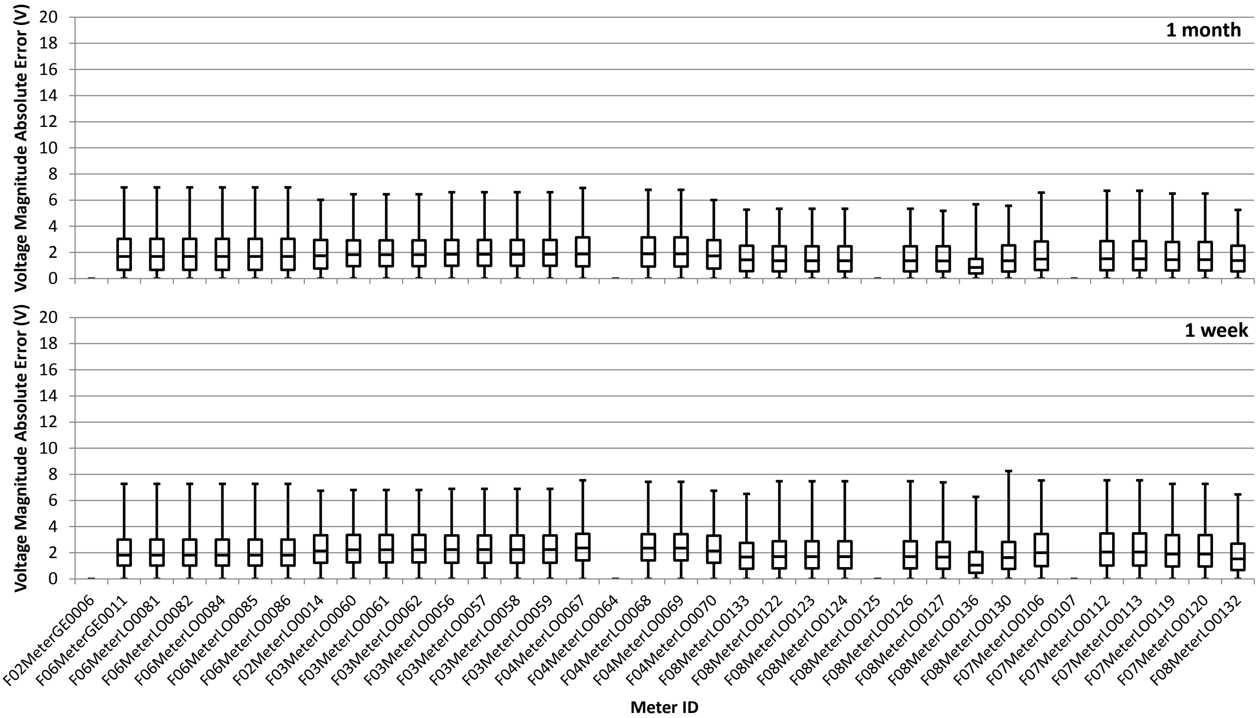
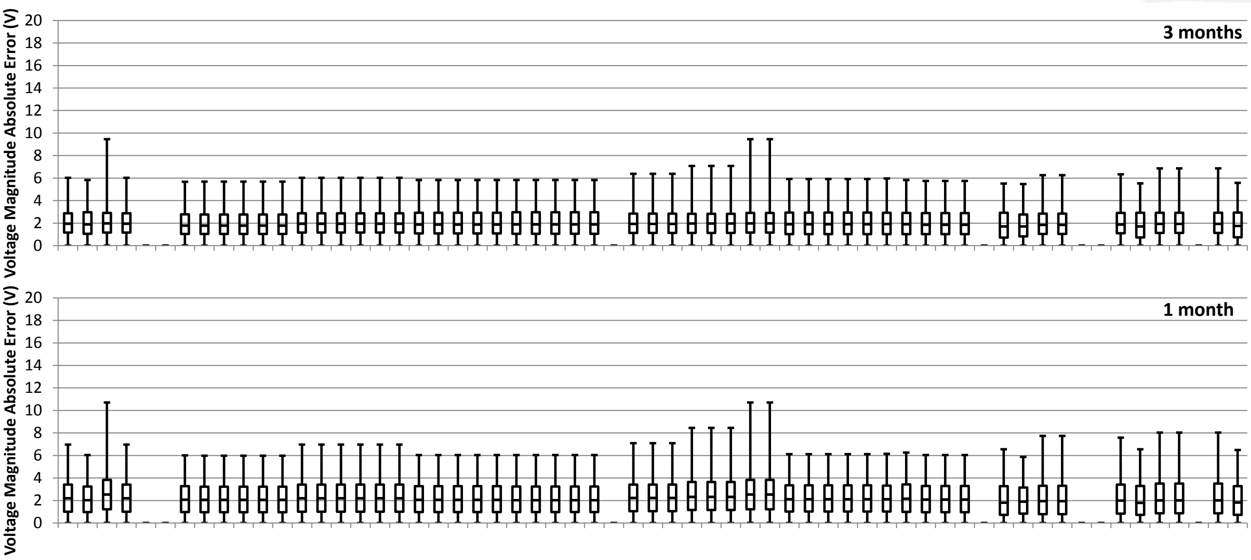


Figure 253 – Voltage magnitude absolute error for all customers connected to phase B (not being real-time monitored), considering a different amount of data for training the proposed DSE: 3 months, 1 month and 1 week.



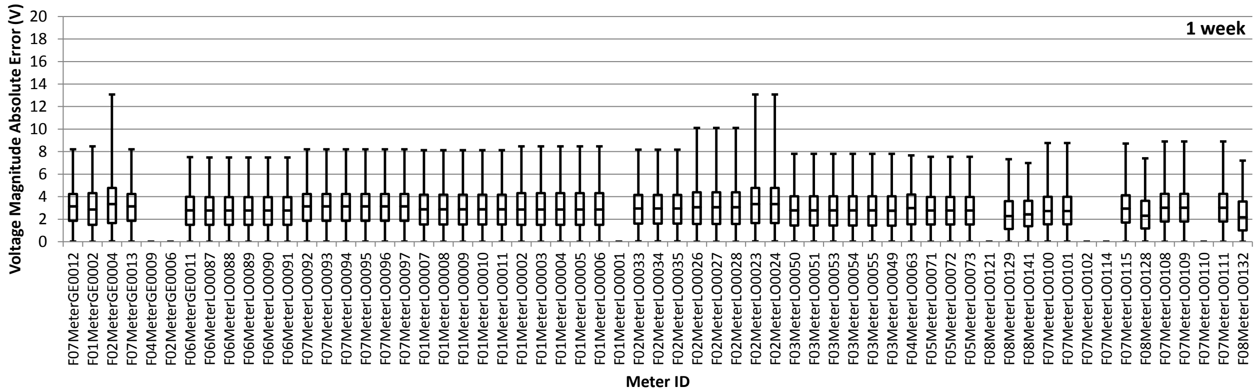


Figure 254 – Voltage magnitude absolute error for all customers connected to phase C (not being real-time monitored), considering a different amount of data for training the proposed DSE: 3 months, 1 month and 1 week.

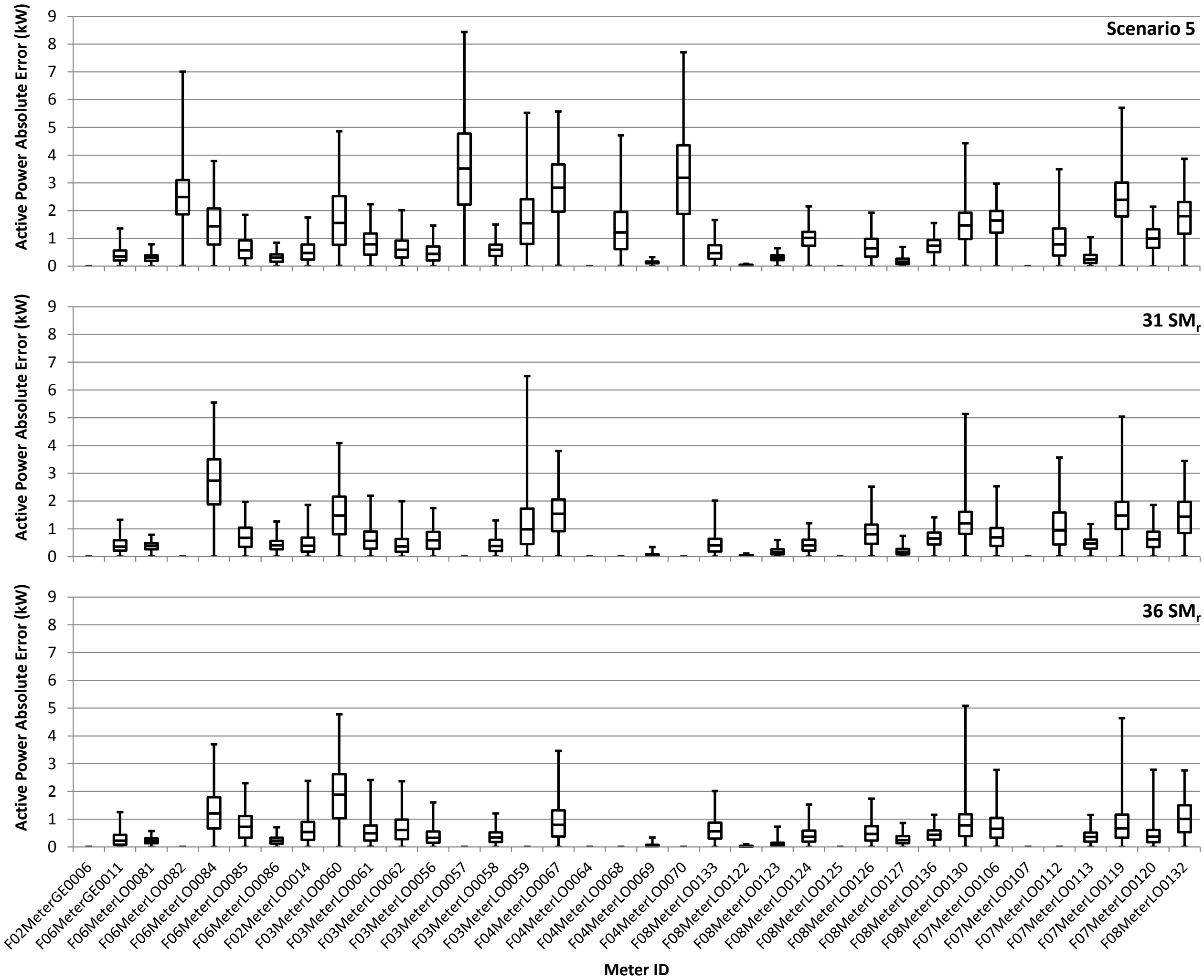


Figure 255 – Active power absolute error for all customers connected to phase B (not being real-time monitored) in scenario 5 and in another two new scenarios considering a larger number of SM_r.

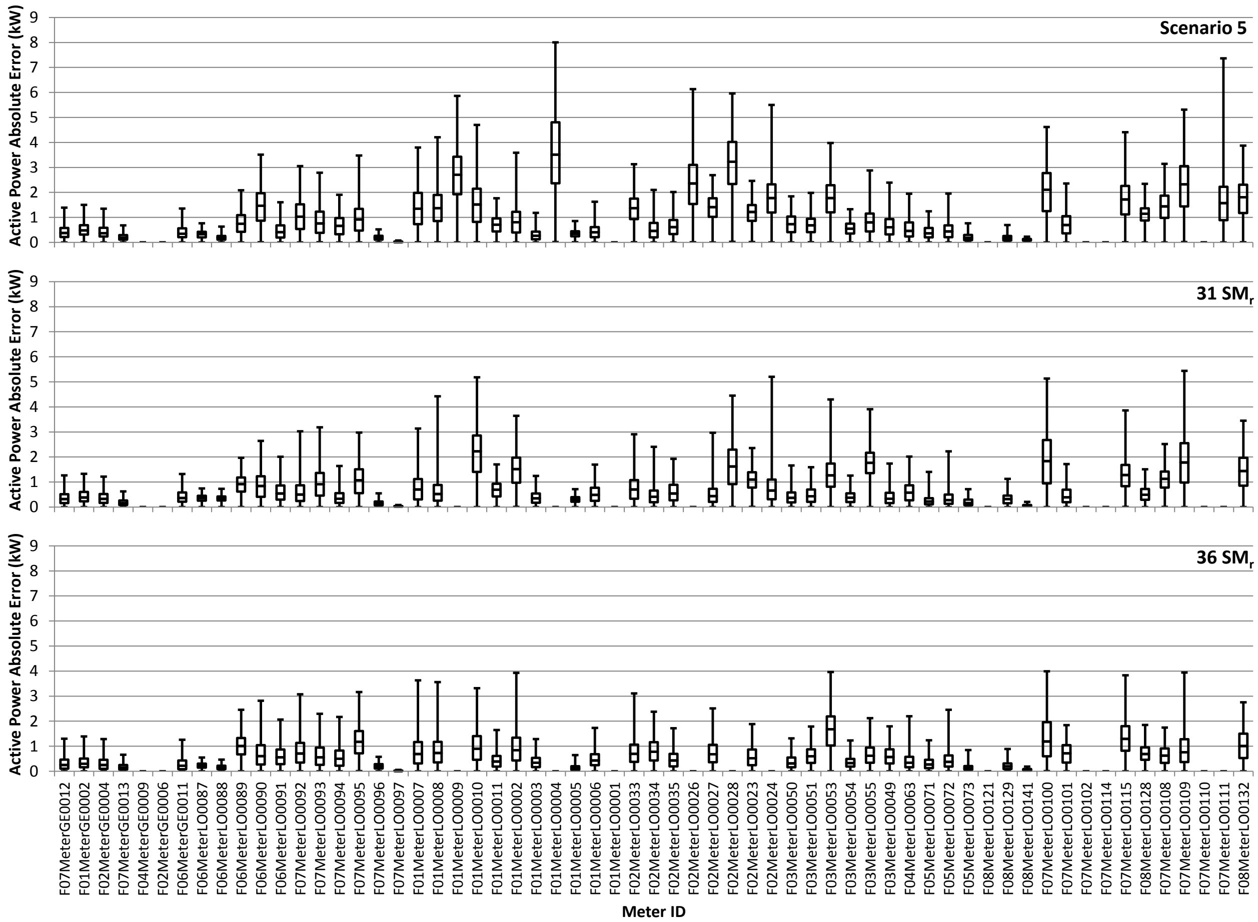
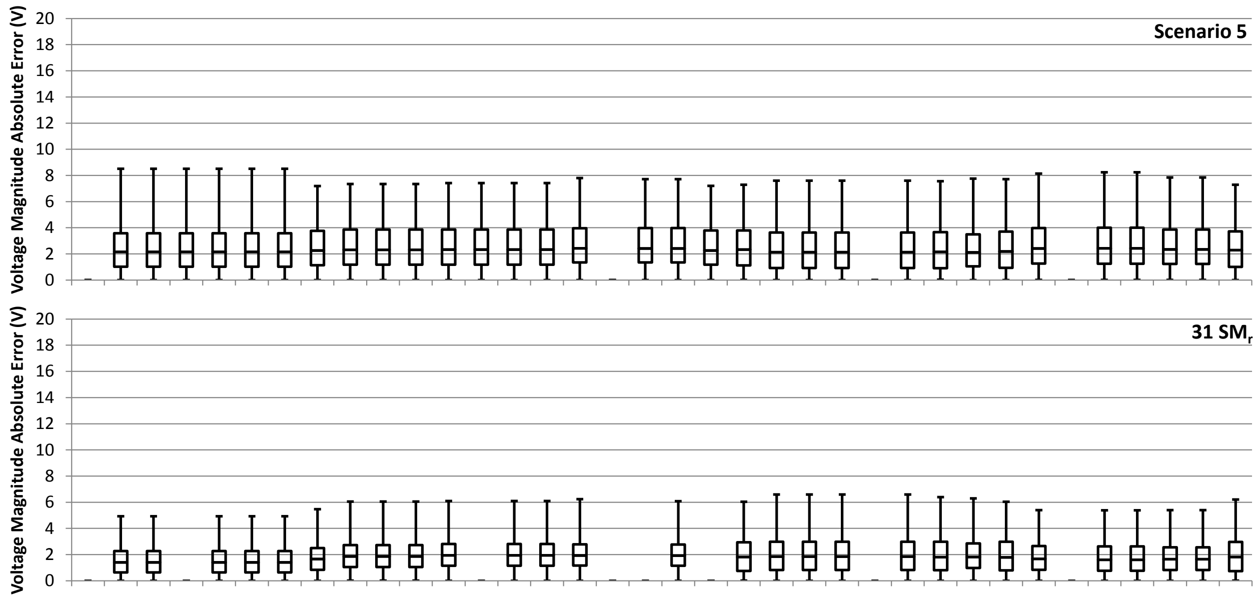


Figure 256 – Active power absolute error for all customers connected to phase C (not being real-time monitored) in scenario 5 and in another two new scenarios considering a larger number of SM_r.



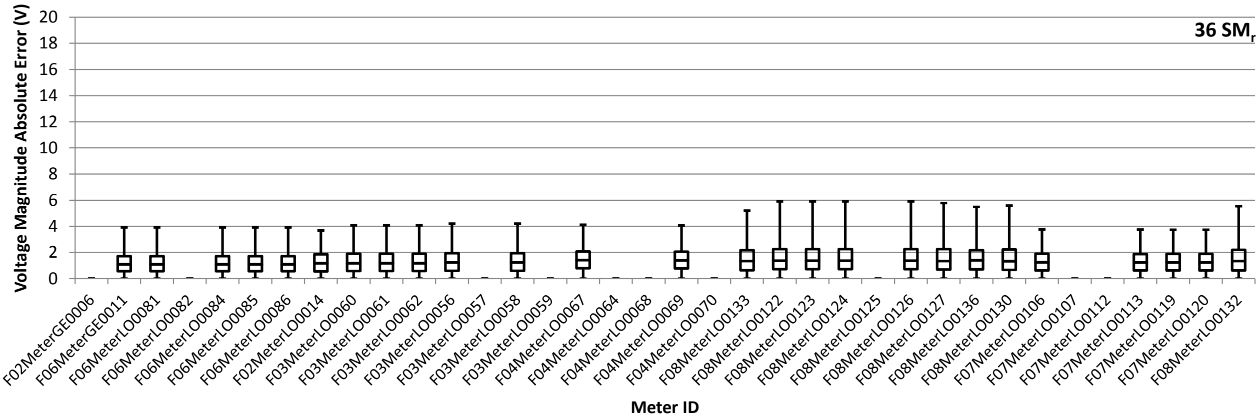


Figure 257 – Voltage magnitude absolute error for all customers connected to phase B (not being real-time monitored) in scenario 5 and in another two new scenarios considering a larger number of SM_r.

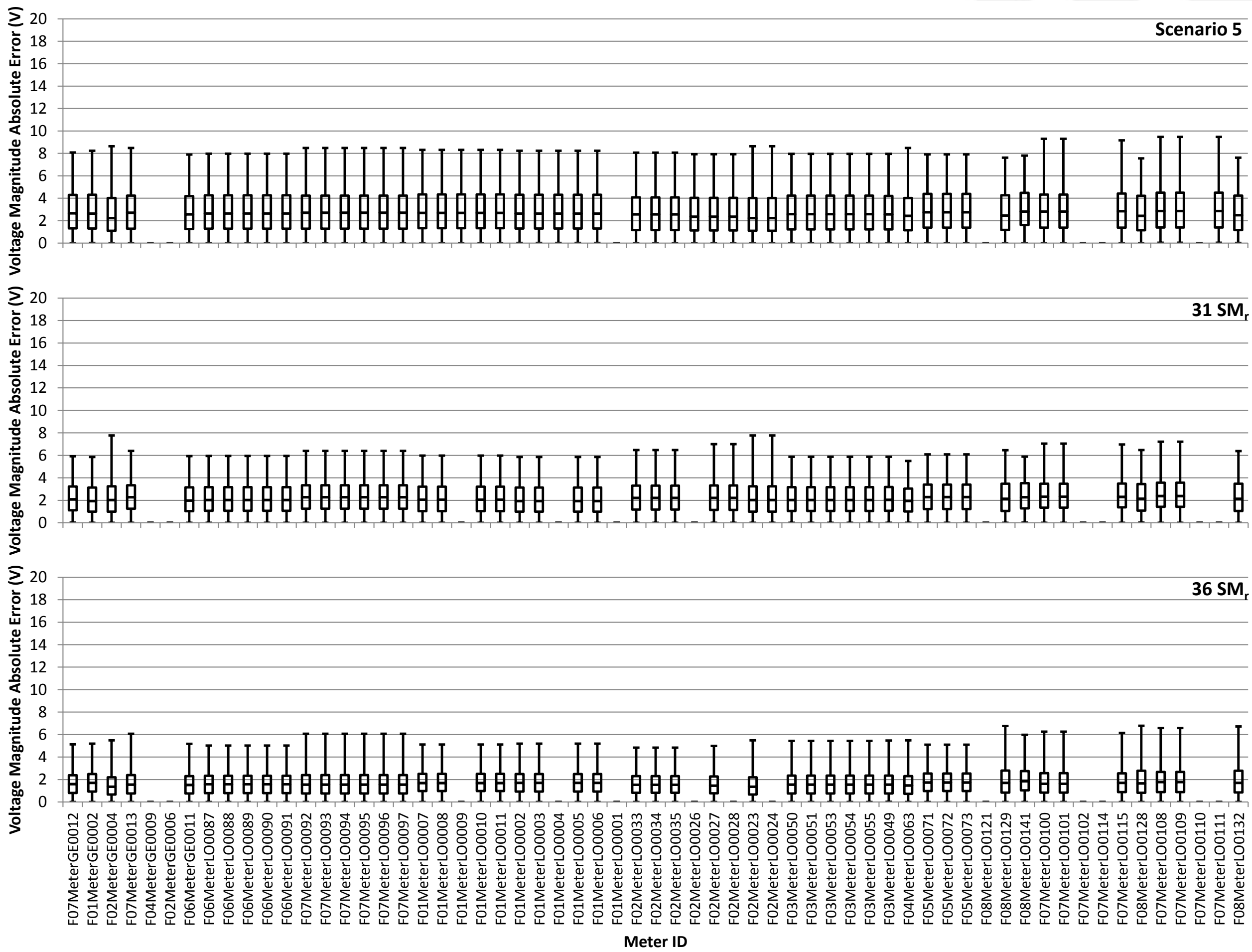


Figure 258 – Voltage magnitude absolute error for all customers connected to phase C (not being real-time monitored) in scenario 5 and in another two new scenarios considering a larger number of SM_r.

Low Voltage Control

Table 201 - Customers distribution: Mid-term scenario

Node ID	Customer ID	Feeder ID	Phase	Contracted Power (kVA)	Node ID	Customer ID	Feeder ID	Phase	Contracted Power (kVA)
8	C45	1	BN	1.15	54	C63	1	AN	1.15
9	C46	1	AN	1.15	55	C64	2	BN	2.30
15	C3	2	BN	1.15	61	C65	2	CN	1.15
15	C4	2	AN	6.90	65	C66	1	CN	3.45
15	C47	2	BN	3.45	70	C67	1	AN	1.15
15	C5	2	CN	6.90	74	C68	2	AN	1.15
15	C48	2	CN	3.45	76	C69	1	AN	3.45
19	C49	1	AN	3.45	81	C70	1	AN	1.15
24	C50	1	BN	1.15	82	C71	1	CN	3.45
27	C51	1	BN	4.60	84	C72	1	BN	1.15
30	C52	2	CN	1.15	86	C73	2	AN	1.15
31	C53	2	CN	1.15	89	C74	1	BN	1.15
32	C54	1	BN	2.30	92	C75	1	AN	1.15
34	C55	1	CN	1.15	93	C76	2	BN	3.45
36	C14	2	BN	1.15	95	C77	2	CN	1.15
38	C56	1	CN	1.15	96	C78	1	CN	1.15
39	C57	1	AN	1.15	100	C79	1	AN	1.15
40	C58	1	BN	6.90	101	C80	1	BN	3.45
44	C59	2	AN	1.15	102	C42	2	BN	6.90
48	C60	1	AN	1.15	102	C81	2	BN	3.45
52	C61	2	AN	3.45	108	C82	2	AN	1.15
53	C62	1	BN	3.45	109	C83	2	CN	1.15

Table 202 - Customers' meter ID: Mid-term scenario

Customer ID	Meter ID	Customer ID	Meter ID
C45	SAG1451111978	C63	SAG1451128357
C46	SAG1451112052	C64	SAG1451112009
C3	SAG1450111988	C65	SAG1451128372
C4	SAG1450128458	C66	SAG1451111973
C47	SAG1451128458	C67	SAG1451111972
C5	SAG1450128459	C68	LGZ0012604697
C48	SAG1451128459	C69	SAG1451111927
C49	SAG1451112016	C70	SAG1451128423
C50	SAG1451111920	C71	SAG1451112049
C51	SAG1463000041	C72	SAG1451111963
C52	SAG1451112007	C73	LGZ0012604785
C53	SAG1451128460	C74	SAG1451112056
C54	LGZ0012604701	C75	SAG1451111917
C55	SAG1451111959	C76	SAG1451112055
C14	SAG1350108952	C77	SAG1451111945
C56	SAG1451111916	C78	SAG1451111930
C57	SAG1451112010	C79	SAG1451111919
C58	SAG1351100625	C80	SAG1451111960
C59	SAG1451128456	C42	SAG1450128556

Customer ID	Meter ID	Customer ID	Meter ID
C60	SAG1451112057	C81	SAG1451128556
C61	SAG1451111941	C82	SAG1451112054
C62	SAG1451128464	C83	SAG1351108954

Table 203 - Microgeneration and energy storages distribution: Mid-term scenario.

Node ID	Customer ID	Installed Capacity (kW)	Meter ID
27	C9	5.18	GEN1462000041
27	C51	2.30	GEN1463000041
32	C12	2.88	GEN0011604701
32	C54	1.15	GEN0012604701
40	C17	8.63	GEN1350100625
40	C58	3.45	GEN1351100625
27	-	3.00	ES00000000001
32	-	3.00	ES00000000002
76	-	3.00	ES00000000003

Table 204 - B2: Equipment rank

Order	Type	Customer ID	Meter ID	RANK
1	Transformer	-	TransEBMASTER	120000000000
2	Load	C30	SAG1450111927	1551000000000
3	Load	C69	SAG1451111927	1551000000000
4	Load	C31	SAG1450128423	1551000024000
5	Load	C70	SAG1451128423	1551000024000
6	Load	C36	SAG1450111917	1551000034000
7	Load	C75	SAG1451111917	1551000034000
8	Load	C24	SAG1450128357	1551000059000
9	Load	C63	SAG1451128357	1551000059000
10	Load	C6	SAG1450112016	1551000069000
11	Load	C49	SAG1451112016	1551000069000
12	Load	C40	SAG1450111919	1551000103000
13	Load	C79	SAG1451111919	1551000103000
14	Load	C16	SAG1450112010	1551000121000
15	Load	C57	SAG1451112010	1551000121000
16	Load	C28	SAG1450111972	1551000122000
17	Load	C67	SAG1451111972	1551000122000
18	Load	C2	SAG1450112052	1551000127000
19	Load	C46	SAG1451112052	1551000127000
20	Load	C20	SAG1450112057	1551000136000
21	Load	C60	SAG1451112057	1551000136000
22	Load	C29	LGZ0011604697	1551000280000

23	Load	C68	LGZ0012604697	1551000280000
24	Load	C34	LGZ0011604785	1551000286000
25	Load	C73	LGZ0012604785	1551000286000
26	Load	C21	SAG1450111941	1551000636000
27	Load	C61	SAG1451111941	1551000636000
28	Load	C19	SAG1450128456	1551000646000
29	Load	C59	SAG1451128456	1551000646000
30	Load	C4	SAG1450128458	1551000650000
31	Load	C43	SAG1450112054	1551000664000
32	Load	C82	SAG1451112054	1551000664000
33	Load	C9	SAG1462000041	1561000011000
34	Load	C17	SAG1350100625	1561000034000
35	Energy Storage	-	ES00000000003	45900000110501
36	Energy Storage	-	ES00000000001	45910000110501

Table 205 - Customers distribution: Long-term scenario

Node ID	Customer ID	Feeder ID	Phase	Contracted Power (kVA)	Node ID	Customer ID	Feeder ID	Phase	Contracted Power (kVA)
8	C45	1	BN	1.15	61	C65	2	CN	1.15
8	C84	1	BN	2.30	61	C103	2	CN	2.30
9	C46	1	AN	1.15	65	C66	1	CN	3.45
9	C85	1	AN	2.30	65	C104	1	CN	2.30
15	C47	2	BN	3.45	70	C67	1	AN	1.15
15	C86	2	BN	2.30	70	C105	1	AN	2.30
15	C48	2	CN	3.45	74	C68	2	AN	1.15
19	C49	1	AN	3.45	74	C106	2	AN	2.30
19	C87	1	AN	2.30	76	C69	1	AN	3.45
24	C50	1	BN	1.15	76	C107	1	AN	2.30
24	C88	1	BN	2.30	81	C70	1	AN	1.15
27	C51	1	BN	4.60	81	C108	1	AN	2.30
27	C89	1	AN	4.60	82	C71	1	CN	3.45
30	C52	2	CN	1.15	82	C109	1	CN	2.30
30	C90	2	CN	2.30	84	C72	1	BN	1.15
31	C53	2	CN	1.15	84	C110	1	BN	2.30
31	C91	2	CN	2.30	86	C73	2	AN	1.15
32	C54	1	BN	2.30	86	C111	2	AN	2.30
32	C92	1	BN	2.30	89	C74	1	BN	1.15
34	C55	1	CN	1.15	89	C112	1	BN	2.30
34	C93	1	CN	2.30	92	C75	1	AN	1.15
38	C56	1	CN	1.15	92	C113	1	AN	2.30
38	C94	1	CN	2.30	93	C76	2	BN	3.45
39	C57	1	AN	1.15	93	C114	2	BN	2.30
39	C95	1	AN	2.30	95	C77	2	CN	1.15
40	C58	1	BN	6.90	95	C115	2	CN	2.30
40	C96	1	AN	6.90	96	C78	1	CN	1.15
44	C59	2	AN	1.15	96	C116	1	CN	2.30
44	C97	2	AN	2.30	100	C79	1	AN	1.15
48	C60	1	AN	1.15	100	C117	1	AN	2.30

Node ID	Customer ID	Feeder ID	Phase	Contracted Power (kVA)	Node ID	Customer ID	Feeder ID	Phase	Contracted Power (kVA)
48	C98	1	AN	2.30	101	C80	1	BN	3.45
52	C61	2	AN	3.45	101	C118	1	BN	2.30
52	C99	2	AN	2.30	102	C81	2	BN	3.45
53	C100	1	CN	3.45	102	C119	2	BN	2.30
53	C62	1	BN	3.45	108	C82	2	AN	1.15
54	C63	1	AN	1.15	108	C120	2	AN	2.30
54	C101	1	AN	2.30	109	C83	2	CN	1.15
55	C64	2	BN	2.30	109	C121	2	CN	2.30
55	C102	2	BN	1.15					

Table 206 - Customers' meter ID: Long-term scenario.

Customer ID	Meter ID	Customer ID	Meter ID
C45	SAG1451111978	C65	SAG1451128372
C84	SAG1452111978	C103	SAG1452128372
C46	SAG1451112052	C66	SAG1451111973
C85	SAG1452112052	C104	SAG1452111973
C47	SAG1451128458	C67	SAG1451111972
C86	SAG1452128458	C105	SAG1452111972
C48	SAG1451128459	C68	LGZ0012604697
C49	SAG1451112016	C106	LGZ0013604697
C87	SAG1452112016	C69	SAG1451111927
C50	SAG1451111920	C107	SAG1452111927
C88	SAG1452111920	C70	SAG1451128423
C51	SAG1463000041	C108	SAG1452128423
C89	SAG1464000041	C71	SAG1451112049
C52	SAG1451112007	C109	SAG1452112049
C90	SAG1452112007	C72	SAG1451111963
C53	SAG1451128460	C110	SAG1452111963
C91	SAG1452128460	C73	LGZ0012604785
C54	LGZ0012604701	C111	LGZ0013604785
C92	LGZ0013604701	C74	SAG1451112056
C55	SAG1451111959	C112	SAG1452112056
C93	SAG1452111959	C75	SAG1451111917
C56	SAG1451111916	C113	SAG1452111917
C94	SAG1452111916	C76	SAG1451112055
C57	SAG1451112010	C114	SAG1452112055
C95	SAG1452112010	C77	SAG1451111945
C58	SAG1351100625	C115	SAG1452111945
C96	SAG1352100625	C78	SAG1451111930
C59	SAG1451128456	C116	SAG1452111930
C97	SAG1452128456	C79	SAG1451111919
C60	SAG1451112057	C117	SAG1452111919
C98	SAG1452112057	C80	SAG1451111960
C61	SAG1451111941	C118	SAG1452111960
C99	SAG1452111941	C81	SAG1451128556
C100	SAG1451111936	C119	SAG1452128556
C62	SAG1451128464	C82	SAG1451112054
C63	SAG1451128357	C120	SAG1452112054
C101	SAG1452128357	C83	SAG1351108954

Customer ID	Meter ID	Customer ID	Meter ID
C64	SAG1451112009	C121	SAG1352108954
C102	SAG1452112009		

Table 207 - Microgeneration and energy storages distribution: Long-term scenario.

Node ID	Customer ID	Installed Capacity (kW)	Meter ID
19	C6	3.45	GEN1450112016
27	C9	5.18	GEN1462000041
27	C51	2.30	GEN1463000041
32	C12	2.88	GEN0011604701
32	C54	1.15	GEN0012604701
38	C15	1.13	GEN1450111916
40	C17	8.63	GEN1350100625
40	C58	3.45	GEN1351100625
76	C30	3.45	GEN1450111927
96	C39	1.73	GEN1450111930
27	-	3.00	ES00000000001
32	-	3.00	ES00000000002
76	-	3.00	ES00000000003
19	-	3.00	ES00000000004
40	-	3.00	ES00000000005
96	-	3.00	ES00000000006

Table 208 – C2: Equipment rank.

Order	Type	Customer ID	Meter ID	RANK
1	Transformer	-	TransEBMASTER	120000000000
2	Load	C30	SAG1450111927	1551000000000
3	Load	C69	SAG1451111927	1551000000000
4	Load	C107	SAG1452111927	1551000000000
5	Load	C89	SAG1464000041	1551000011000
6	Load	C31	SAG1450128423	1551000024000
7	Load	C70	SAG1451128423	1551000024000
8	Load	C108	SAG1452128423	1551000024000
9	Load	C36	SAG1450111917	1551000034000
10	Load	C75	SAG1451111917	1551000034000
11	Load	C96	SAG1352100625	1551000034000
12	Load	C113	SAG1452111917	1551000034000
13	Load	C24	SAG1450128357	1551000059000
14	Load	C63	SAG1451128357	1551000059000
15	Load	C101	SAG1452128357	1551000059000
16	Load	C6	SAG1450112016	1551000069000
17	Load	C49	SAG1451112016	1551000069000

18	Load	C87	SAG1452112016	1551000069000
19	Load	C40	SAG1450111919	1551000103000
20	Load	C79	SAG1451111919	1551000103000
21	Load	C117	SAG1452111919	1551000103000
22	Load	C16	SAG1450112010	1551000121000
23	Load	C57	SAG1451112010	1551000121000
24	Load	C95	SAG1452112010	1551000121000
25	Load	C28	SAG1450111972	1551000122000
26	Load	C67	SAG1451111972	1551000122000
27	Load	C105	SAG1452111972	1551000122000
28	Load	C2	SAG1450112052	1551000127000
29	Load	C46	SAG1451112052	1551000127000
30	Load	C85	SAG1452112052	1551000127000
31	Load	C20	SAG1450112057	1551000136000
32	Load	C60	SAG1451112057	1551000136000
33	Load	C98	SAG1452112057	1551000136000
34	Load	C29	LGZ0011604697	1551000280000
35	Load	C68	LGZ0012604697	1551000280000
36	Load	C106	LGZ0013604697	1551000280000
37	Load	C34	LGZ0011604785	1551000286000
38	Load	C73	LGZ0012604785	1551000286000
39	Load	C111	LGZ0013604785	1551000286000
40	Load	C21	SAG1450111941	1551000636000
41	Load	C61	SAG1451111941	1551000636000
42	Load	C99	SAG1452111941	1551000636000
43	Load	C19	SAG1450128456	1551000646000
44	Load	C59	SAG1451128456	1551000646000
45	Load	C97	SAG1452128456	1551000646000
46	Load	C4	SAG1450128458	1551000650000
47	Load	C43	SAG1450112054	1551000664000
48	Load	C82	SAG1451112054	1551000664000
49	Load	C120	SAG1452112054	1551000664000
50	Load	C9	SAG1462000041	1561000011000
51	Load	C17	SAG1350100625	1561000034000
52	Energy Storage	-	ES00000000003	45900000110501
53	Energy Storage	-	ES00000000004	45900000690501
54	Energy Storage	-	ES00000000001	45910000110501
55	Energy Storage	-	ES00000000005	45910000340501

Table 209 – A2: Equipment rank.

Order	Type	Equipment ID	RANK
1	Load	F08_Load_00135	2690051000000000
2	Load	F08_Load_00136	2690051000228000
3	Load	F04_Load_00064	2690051000480000
4	Load	F04_Load_00068	2690051000505000
5	Load	F04_Load_00069	2690051000505000
6	Load	F04_Load_00067	2690051000511000
7	Load	F03_Load_00056	2690051000519000
8	Load	F03_Load_00057	2690051000519000
9	Load	F03_Load_00058	2690051000519000
10	Load	F03_Load_00059	2690051000519000
11	Load	F03_Load_00060	2690051000587000
12	Load	F03_Load_00061	2690051000587000
13	Load	F03_Load_00062	2690051000587000
14	Load	F08_Load_00122	2690051000596000
15	Load	F08_Load_00123	2690051000596000
16	Load	F08_Load_00124	2690051000596000
17	Load	F08_Load_00125	2690051000596000
18	Load	F08_Load_00126	2690051000596000
19	Load	F07_Load_00106	2690051000615000
20	Load	F07_Load_00107	2690051000615000
21	Load	F08_Load_00127	2690051000617000
22	Load	F07_Load_00112	2690051000630000
23	Load	F07_Load_00113	2690051000630000
24	Load	F02_Load_00014	2690051000637000
25	Load	F08_Load_00130	2690051000640000
26	Load	F04_Load_00070	2690051000650000
27	Load	F07_Load_00119	2690051000689000
28	Load	F07_Load_00120	2690051000689000
29	Load	F08_Load_00133	2690051000707000
30	Load	F06_Load_00081	2690051000713000
31	Load	F06_Load_00082	2690051000713000
32	Load	F06_Load_00084	2690051000713000
33	Load	F06_Load_00085	2690051000713000
34	Load	F06_Load_00086	2690051000713000
35	Load	F08_Load_00139	2690061000385000
36	Load	F08_Load_00131	2690061000644000
37	Load	F08_Load_00132	2690061000701000

Table 210 - B1: Equipment rank.

Order	Type	Equipment ID	RANK
1	Transformer	Transformer001	120000000000
2	Generator	F08_Gene_x0122	2690031000000000
3	Generator	F08_Gene_x0123	2690031000000000
4	Generator	F08_Gene_x0124	2690031000000000
5	Generator	F08_Gene_x0125	2690031000000000
6	Generator	F08_Gene_x0126	2690031000000000
7	Generator	F08_Gene_x0127	2690031000026000
8	Generator	F07_Gene_x0106	2690031000069000
9	Generator	F07_Gene_x0107	2690031000069000
10	Generator	F08_Gene_x0130	2690031000096000
11	Generator	F08_Gene_x0133	2690031000121000
12	Generator	F07_Gene_x0112	2690031000142000
13	Generator	F07_Gene_x0113	2690031000142000
14	Generator	F04_Gene_x0067	2690031000173000
15	Generator	F04_Gene_x0068	2690031000184000
16	Generator	F04_Gene_x0069	2690031000184000
17	Generator	F07_Gene_x0119	2690031000194000
18	Generator	F07_Gene_x0120	2690031000194000
19	Generator	F04_Gene_x0064	2690031000201000
20	Generator	F04_Gene_x0070	2690031000269000
21	Generator	F02_Gene_x0014	2690031000327000
22	Generator	F03_Gene_x0056	2690031000359000
23	Generator	F03_Gene_x0057	2690031000359000
24	Generator	F03_Gene_x0058	2690031000359000
25	Generator	F03_Gene_x0059	2690031000359000
26	Generator	F03_Gene_x0060	2690031000379000
27	Generator	F03_Gene_x0061	2690031000379000
28	Generator	F03_Gene_x0062	2690031000379000
29	Generator	F06_Gene_x0082	2690031000407000
30	Generator	F06_Gene_x0084	2690031000407000
31	Generator	F06_Gene_x0085	2690031000407000
32	Generator	F06_Gene_x0086	2690031000407000
33	Generator	F08_Gene_x0136	2690031000407000
34	Generator	F08_Gene_x0135	2690031000596000
35	Generator	F08_Gene_x0131	2690041000089000
36	Generator	F08_Gene_x0132	2690041000112000
37	Generator	F08_Gene_x0139	2690041000337000
38	Generator	F06_Gene_00011	2690041000407000

39	Generator	F02_Gene_00006	2690041000503000
40	Energy Storage	EnergyStorage2	3792600000960500

Table 211 - B2: Equipment rank.

Order	Type	Equipment ID	RANK
1	Transformer	Transformer001	120000000000
2	Load	F08_Load_00135	2690051000000000
3	Load	F08_Load_00136	2690051000228000
4	Load	F04_Load_00064	2690051000480000
5	Load	F04_Load_00068	2690051000505000
6	Load	F04_Load_00069	2690051000505000
7	Load	F04_Load_00067	2690051000511000
8	Load	F03_Load_00056	2690051000519000
9	Load	F03_Load_00057	2690051000519000
10	Load	F03_Load_00058	2690051000519000
11	Load	F03_Load_00059	2690051000519000
12	Load	F03_Load_00060	2690051000587000
13	Load	F03_Load_00061	2690051000587000
14	Load	F03_Load_00062	2690051000587000
15	Load	F08_Load_00122	2690051000596000
16	Load	F08_Load_00123	2690051000596000
17	Load	F08_Load_00124	2690051000596000
18	Load	F08_Load_00125	2690051000596000
19	Load	F08_Load_00126	2690051000596000
20	Load	F07_Load_00106	2690051000615000
21	Load	F07_Load_00107	2690051000615000
22	Load	F08_Load_00127	2690051000617000
23	Load	F07_Load_00112	2690051000630000
24	Load	F07_Load_00113	2690051000630000
25	Load	F02_Load_00014	2690051000637000
26	Load	F08_Load_00130	2690051000640000
27	Load	F04_Load_00070	2690051000650000
28	Load	F07_Load_00119	2690051000689000
29	Load	F07_Load_00120	2690051000689000
30	Load	F08_Load_00133	2690051000707000
31	Load	F06_Load_00081	2690051000713000
32	Load	F06_Load_00082	2690051000713000
33	Load	F06_Load_00084	2690051000713000
34	Load	F06_Load_00085	2690051000713000
35	Load	F06_Load_00086	2690051000713000

36	Load	F08_Load_00139	2690061000385000
37	Load	F08_Load_00131	2690061000644000
38	Load	F08_Load_00132	2690061000701000
39	Energy Storage	EnergyStorage2	4592600005680500

Table 212 - C1: Equipment rank.

Order	Type	Equipment ID	RANK
1	Transformer	Transformer001	120000000000
2	Generator	F08_Gene_x0122	2690031000000000
3	Generator	F08_Gene_x0123	2690031000000000
4	Generator	F08_Gene_x0124	2690031000000000
5	Generator	F08_Gene_x0125	2690031000000000
6	Generator	F08_Gene_x0126	2690031000000000
7	Generator	F08_Gene_x0127	2690031000026000
8	Generator	F07_Gene_x0106	2690031000069000
9	Generator	F07_Gene_x0107	2690031000069000
10	Generator	F08_Gene_x0130	2690031000096000
11	Generator	F08_Gene_x0133	2690031000121000
12	Generator	F07_Gene_x0112	2690031000142000
13	Generator	F07_Gene_x0113	2690031000142000
14	Generator	F04_Gene_x0067	2690031000173000
15	Generator	F04_Gene_x0068	2690031000184000
16	Generator	F04_Gene_x0069	2690031000184000
17	Generator	F07_Gene_x0119	2690031000194000
18	Generator	F07_Gene_x0120	2690031000194000
19	Generator	F04_Gene_x0064	2690031000201000
20	Generator	F04_Gene_x0070	2690031000269000
21	Generator	F02_Gene_x0014	2690031000327000
22	Generator	F03_Gene_x0056	2690031000359000
23	Generator	F03_Gene_x0057	2690031000359000
24	Generator	F03_Gene_x0058	2690031000359000
25	Generator	F03_Gene_x0059	2690031000359000
26	Generator	F03_Gene_x0060	2690031000379000
27	Generator	F03_Gene_x0061	2690031000379000
28	Generator	F03_Gene_x0062	2690031000379000
29	Generator	F06_Gene_x0082	2690031000407000
30	Generator	F06_Gene_x0084	2690031000407000
31	Generator	F06_Gene_x0085	2690031000407000
32	Generator	F06_Gene_x0086	2690031000407000
33	Generator	F08_Gene_x0136	2690031000407000

34	Generator	F08_Gene_x0135	2690031000596000
35	Generator	F08_Gene_x0131	2690041000089000
36	Generator	F08_Gene_x0132	2690041000112000
37	Generator	F08_Gene_x0139	2690041000337000
38	Generator	F06_Gene_00011	2690041000407000
39	Generator	F02_Gene_00006	2690041000503000
40	Energy Storage	EnergyStorage4	3792600000000500
41	Energy Storage	EnergyStorage2	3792600000960500
42	Energy Storage	EnergyStorage5	3792600003590500
43	Energy Storage	EnergyStorage6	3792600005030500

ANNEX IV – Additional Results for TSO-DSO Cooperation Domain

Sequential Optimal Power Flow (SOPF)

Portuguese Networks

Table 213 – Northeast network scenario 2.

Period	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
InitTotLoss (P)	115.9132	72.63533	70.09737	67.75322	75.18054	68.6597	98.91144	57.94681	83.16946	198.9378	219.8323	246.4001	278.0485	240.4296	230.0095	233.7805	199.2484	177.3127	197.934	283.2723	338.2517	322.1767	268.7087	263.5779
FinalTotLoss (P)	109.4574	70.6293	62.85308	66.53716	68.29799	62.42923	90.67963	50.77406	77.84979	194.5724	214.4247	242.5486	274.3072	234.2208	223.6368	230.0988	192.5272	173.025	193.72	279.4725	338.7887	314.7213	268.1935	258.4593
PowerGen (P)	24.29777	23.05965	22.55238	22.43627	21.96141	22.07511	21.46725	20.84042	21.66553	22.53101	22.77504	23.4581	24.14066	23.26431	23.28608	23.28566	22.79591	23.23909	24.84388	27.13538	26.85492	26.36611	25.64531	24.9594
PowerGen (Q)	4.93688	4.83606	4.899077	4.918365	4.754905	4.802582	4.736539	4.645189	4.160785	4.320245	4.970497	4.526348	4.588177	4.706325	4.999629	5.041814	4.907094	4.86251	5.564755	5.882281	6.090581	5.894688	6.05029	6.071702
Cost	220.843	178.6028	171.0281	171.3938	176.3621	172.587	202.2733	155.769	665.8945	268.2967	76.97726	91.09678	77.70303	75.60402	312.4542	275.8951	83.30896	261.1534	298.111	421.2707	436.4444	360.0863	430.7107	421.07
netcon01 (Pfinal)	-10.9158	-8.09446	-8.22945	-9.34617	-10.1254	-8.82143	-13.4031	-12.5784	-17.3875	-24.6317	-27.8304	-29.5915	-27.368	-29.5066	-26.4333	-27.9309	-25.7247	-26.5351	-30.3255	-37.1104	-38.6311	-37.2365	-39.4676	-39.3785
netcon01 (Qfinal)	-5.73545	-2.69679	-2.30991	-2.87889	-2.2039	-3.43459	-6.12897	-1.47254	-2.41349	-13.8252	-14.1922	-13.7584	-15.6925	-15.0487	-15.3234	-15.9238	-13.2173	-12.4696	-9.76761	-8.55617	-10.7788	-9.78149	-10.2907	-8.48988
netcon02 (Pfinal)	-10.9158	-8.09446	-8.22945	-9.34617	-10.1254	-8.82143	-13.4031	-12.5784	-17.3875	-24.6317	-27.8304	-29.5915	-27.368	-29.5066	-26.4333	-27.9309	-25.7247	-26.5351	-30.3255	-37.1104	-38.6311	-37.2365	-39.4676	-39.3785
netcon02 (Qfinal)	5.779427	5.604281	5.028179	5.836002	5.215353	5.892107	9.555867	5.684599	9.298094	11.16864	9.535515	11.26413	9.628312	9.359931	13.03182	11.51456	10.19166	10.89255	12.45194	17.62324	18.28879	15.06693	18.42394	17.24761
netcon03 (Pfinal)	-10.9158	-8.09446	-8.22945	-9.34617	-10.1254	-8.82143	-13.4031	-12.5784	-17.3875	-24.6317	-27.8304	-29.5915	-27.368	-29.5066	-26.4333	-27.9309	-25.7247	-26.5351	-30.3255	-37.1104	-38.6311	-37.2365	-39.4676	-39.3785
netcon03 (Qfinal)	-6.50427	-7.15648	-7.11541	-6.56709	-7.52278	-6.0788	-5.02772	-6.02065	-6.98648	-9.79896	-9.93073	-11.7287	-11.3082	-8.94171	-8.26173	-7.58189	-5.92813	-8.77292	-12.7136	-16.401	-19.6688	-16.7637	-13.8398	-15.096
netcon04 (Pfinal)	-10.9148	-8.08698	-8.21928	-9.35521	-10.1123	-8.82059	-13.4036	-12.5844	-17.3821	-24.634	-27.8238	-29.5874	-27.3654	-29.5058	-26.434	-27.9216	-25.7401	-26.5255	-30.3198	-37.1133	-38.6219	-37.2445	-39.462	-39.3852
netcon04 (Qfinal)	5.025557	4.183867	3.265284	3.100296	2.386885	3.387596	4.639861	-1.07004	1.010909	5.214176	3.185169	3.399388	5.631561	2.551636	7.036761	5.217252	4.426569	2.745601	1.586296	2.821354	4.298841	2.993011	1.36109	0.26477
trans004 (tap)	13	14	14	15	14	15	15	12	13	13	14	11	15	12	15	14	14	15	15	14	12	15	13	15
trans012 (tap)	15	14	15	13	15	12	11	15	13	13	14	13	9	15	12	10	9	15	12	14	15	11	15	15
trans008 (tap)	16	15	7	12	14	16	12	10	16	13	14	14	16	9	10	14	8	13	11	16	12	7	13	12
trans002 (tap)	22	22	20	15	18	20	14	19	15	16	17	13	16	16	19	16	15	23	14	22	15	14	15	22
trans006 (tap)	9	9	7	7	12	6	8	11	10	7	7	6	7	10	12	12	11	10	6	6	6	6	6	6
trans010 (tap)	6	12	7	5	8	6	6	7	11	9	6	6	7	11	10	9	7	9	6	6	9	11	10	10
trans015 (tap)	12	11	14	12	12	10	15	8	8	10	15	17	13	12	14	18	12	14	14	11	8	16	18	7
trans001 (tap)	14	9	15	9	8	10	13	15	9	8	11	14	17	8	17	10	7	7	7	14	14	16	7	12
trans014 (tap)	12	11	11	19	15	18	10	15	15	13	14	10	11	16	19	19	12	16	10	10	10	11	10	10
trans011 (tap)	14	15	14	9	9	12	10	11	9	10	12	7	11	13	12	14	9	15	8	6	12	9	6	12
trans016 (tap)	15	10	8	12	14	11	9	6	11	6	7	6	9	9	13	10	9	14	8	8	6	10	12	7
trans013 (tap)	7	16	10	13	13	10	15	7	15	13	14	13	10	9	13	8	14	15	15	12	14	16	10	13
trans003 (tap)	8	8	9	9	9	8	10	9	8	5	8	10	6	6	5	9	10	8	7	7	6	6	9	8
trans007 (tap)	23	8	18	15	13	22	17	22	17	14	16	15	14	22	19	19	21	23	21	21	13	16	16	22
Capa0001 (Mvar)	0	0	0	0	0	0	0	0	0	4	4	4	4	4	4	4	0	4	4	4	4	4	4	4
Capa0002 (Mvar)	0	0	0	0	0	0	0	0	0	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
Capa0003 (Mvar)	3.4	0	0	0	3.4	3.4	0	3.4	0	0	3.4	3.4	3.4	3.4	0	3.4	3.4	0	3.4	0	0	3.4	0	0
Capa0004 (Mvar)	1.7	3.4	3.4	3.4	1.7	0	0	1.7	1.7	1.7	3.4	1.7	3.4	3.4	0	0	0	3.4	0	0	0	0	0	1.7
Capa0005 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3	0	0	0
Capa0006 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Capa0009 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Capa0010 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 214 – Northeast network scenario 3.

Period	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
InitTotLoss (P)	118.6153	77.51197	71.49078	73.21376	76.93722	69.24395	98.21441	59.19719	87.37677	204.1077	226.7903	252.9116	284.6712	248.7713	238.0405	242.1018	204.6396	181.8938	203.2181	292.4374	349.0928	329.2352	280.8839	272.7714
FinalTotLoss (P)	112.6206	67.89993	66.36354	64.52682	69.02791	63.35338	101.4916	53.70311	79.8767	198.8512	226.0625	248.4725	280.728	242.7364	229.8839	234.2514	195.6841	176.8513	198.7011	290.7818	348.5027	329.0266	277.9706	268.614
PowerGen (P)	24.30457	23.05115	22.54234	22.45537	21.95978	22.08523	21.48264	20.84263	21.65688	22.53209	22.77889	23.46303	24.1498	23.27157	23.29094	23.29653	22.81121	23.24775	24.84948	27.13569	26.86637	26.38272	25.66379	24.97629
PowerGen (Q)	4.942968	4.835916	4.912085	4.92144	4.750223	4.814409	4.744115	4.66046	4.169817	4.340665	4.980568	4.545384	4.597969	4.723222	5.024059	5.069668	4.916377	4.882311	5.579621	5.892104	6.120117	5.955841	6.072179	6.097106
Cost	224.4263	180.2262	173.7721	173.7671	177.9815	173.4019	203.1409	173.1478	666.1818	273.5313	332.5927	97.44195	305.9507	87.33281	316.7412	280.5394	279.4086	81.23114	358.0938	427.7743	414.4641	428.1574	434.5244	421.6071
netcon01 (Pfinal)	-11.2103	-8.33969	-8.46517	-9.58985	-10.3444	-8.99223	-13.6637	-12.8662	-17.7604	-25.1293	-28.4017	-30.1931	-27.9357	-30.1402	-26.9871	-28.5198	-26.255	-27.0975	-31.0109	-37.9224	-39.4564	-38.0344	-40.3477	-40.289
netcon01 (Qfinal)	-5.78945	-2.691	-2.30075	-2.86913	-2.17522	-3.41741	-6.16487	-1.42502	-2.39773	-14.4237	-14.3292	-13.7986	-15.7258	-14.9655	-15.4275	-16.0404	-13.5538	-12.7982	-9.73222	-8.47438	-10.6988	-11.882	-10.2654	-8.26709
netcon02 (Pfinal)	-11.2103	-8.33969	-8.46517	-9.58985	-10.3444	-8.99223	-13.6637	-12.8662	-17.7604	-25.1293	-28.4017	-30.1931	-27.9357	-30.1402	-26.9871	-28.5198	-26.255	-27.0975	-31.0109	-37.9224	-39.4564	-38.0344	-40.3477	-40.289
netcon02 (Qfinal)	8.836566	2.854935	7.707424	6.841938	5.91205	3.990224	5.367352	4.30925	9.302136	11.3895	13.88155	12.07543	12.75741	10.78287	13.21271	11.71052	11.61218	10.0027	14.95754	17.89765	17.36136	17.93913	18.7342	18.67068
netcon03 (Pfinal)	-11.2103	-8.33969	-8.46517	-9.58985	-10.3444	-8.99223	-13.6637	-12.8662	-17.7604	-25.1293	-28.4017	-30.1931	-27.9357	-30.1402	-26.9871	-28.5198	-26.255	-27.0975	-31.0109	-37.9224	-39.4564	-38.0344	-40.3477	-40.289
netcon03 (Qfinal)	-6.61881	-7.28788	-7.2457	-6.67704	-7.64294	-6.17592	-5.10863	-6.13725	-7.08959	-9.98945	-10.082	-13.6523	-11.4822	-9.07169	-8.38001	-7.69685	-6.02819	-8.93959	-12.9341	-16.6924	-19.9951	-18.5603	-14.0806	-15.3491
netcon04 (Pfinal)	-11.2146	-8.33979	-8.48216	-9.57508	-10.347	-8.98808	-13.6562	-12.8688	-17.7619	-25.1399	-28.4061	-30.1978	-27.9432	-30.1377	-26.9778	-28.524	-26.2638	-27.0996	-31.0079	-37.927	-39.4543	-38.034	-40.3431	-40.2867
netcon04 (Qfinal)	6.786269	2.514792	4.791252	3.615092	2.722037	2.217949	2.105544	-2.0167	0.876789	5.269195	5.637393	3.766342	7.425848	3.280081	7.071728	5.24973	5.174113	2.09476	2.86273	2.735418	3.55018	4.477344	1.257205	0.800414
trans004 (tap)	14	15	15	14	13	15	15	14	13	12	14	15	11	14	10	14	15	15	15	11	12	15	14	15
trans012 (tap)	10	10	9	15	9	14	14	15	13	14	15	15	12	15	15	13	15	14	10	13	11	15	15	14
trans008 (tap)	14	9	14	7	8	16	13	8	12	15	11	8	16	9	11	14	8	13	12	9	9	14	13	14
trans002 (tap)	20	16	17	20	20	19	21	15	21	22	20	19	16	22	20	16	20	21	15	16	15	16	12	15
trans006 (tap)	8	8	7	10	7	10	10	7	6	12	6	6	8	10	12	12	10	8	6	6	6	6	6	7
trans010 (tap)	11	6	11	8	7	8	6	9	9	6	12	11	8	7	12	6	12	11	8	11	10	11	12	12
trans015 (tap)	17	13	9	18	9	15	13	15	8	7	15	18	12	9	8	8	18	8	15	12	8	8	17	13
trans001 (tap)	11	7	13	8	7	16	18	15	9	17	8	17	17	8	9	10	11	9	15	14	12	13	7	13
trans014 (tap)	15	18	11	15	19	19	11	18	10	3	15	10	10	18	19	19	10	16	10	10	10	10	10	10
trans011 (tap)	15	9	12	9	9	12	6	6	8	13	6	6	12	13	8	14	15	10	8	7	15	12	14	11
trans016 (tap)	10	15	9	15	9	8	9	8	7	12	11	11	12	13	6	12	11	6	14	12	8	10	11	12
trans013 (tap)	14	13	11	9	8	16	8	16	15	10	7	12	13	9	16	16	13	15	13	11	11	7	9	8
trans003 (tap)	10	6	5	9	8	5	6	8	10	9	7	5	7	8	5	9	8	5	5	5	5	5	5	9
trans007 (tap)	16	14	22	15	14	14	15	17	22	21	15	21	19	18	13	16	22	17	17	15	15	15	15	15
Capa0001 (Mvar)	0	0	0	0	0	0	0	0	0	4	4	4	4	4	4	4	0	4	4	4	4	4	4	4
Capa0002 (Mvar)	0	0	0	0	0	0	0	0	0	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
Capa0003 (Mvar)	0	3.4	0	0	3.4	3.4	3.4	3.4	0	0	0	0	0	3.4	0	3.4	0	3.4	0	0	0	0	0	0
Capa0004 (Mvar)	0	3.4	0	1.7	0	3.4	3.4	3.4	1.7	1.7	0	3.4	1.7	1.7	0	0	1.7	1.7	0	0	1.7	0	0	0
Capa0005 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3	3	0	0
Capa0006 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Capa0009 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Capa0010 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	1.7	0	0	0	0	0	0	0	0	0	0	0	0

Table 215 – Northeast network scenario 4.

Period	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
InitTotLoss (P)	144.4007	97.83875	97.53404	91.55315	97.20204	88.00916	127.6446	76.43516	117.5889	257.0583	289.9777	324.9217	358.8634	316.4349	296.5637	308.4518	252.3552	235.6606	269.2954	384.3746	457.6315	432.2132	367.0209	361.0959
FinalTotLoss (P)	142.0852	91.04742	84.78349	84.6411	92.84359	82.17234	114.6198	71.37812	106.7087	250.7419	285.8282	320.3824	355.4055	309.6857	294.167	300.7207	252.6903	228.4295	263.5366	380.0672	449.2957	422.6484	365.0245	355.1617
PowerGen (P)	26.89275	25.50489	24.9544	24.838	24.29972	24.43889	23.76675	23.06456	23.97156	24.95429	25.22932	25.99763	26.757	25.78079	25.79968	25.8053	25.2698	25.75067	27.5277	30.07335	29.78347	29.23512	28.43439	27.68319
PowerGen (Q)	5.563078	5.438984	5.262758	5.277513	5.087018	5.142148	5.334715	4.972021	4.704289	4.939624	5.674505	5.199976	5.264264	5.397972	5.721856	5.774492	5.604029	5.540675	6.342205	6.7429	6.991051	6.7961	6.943097	6.960923
Cost	241.0535	193.292	185.7474	185.9394	190.5761	186.1	219.9968	150.5567	745.5019	280.0194	366.0772	384.5026	444.3809	103.0608	423.1318	317.153	339.9814	349.2335	370.1208	472.5933	440.9265	424.1806	500.4887	492.6832
netcon01 (Pfinal)	-12.2568	-9.08685	-9.23393	-10.4215	-11.2015	-9.66955	-14.8116	-14.009	-19.3921	-27.4672	-31.0729	-33.0699	-30.5894	-33.0418	-29.5308	-31.2488	-28.7378	-29.6829	-34.0721	-41.6355	-43.3115	-41.7316	-44.3915	-44.3784
netcon01 (Qfinal)	-5.95603	-2.78734	-2.37506	-2.92946	-2.16091	-3.4669	-6.21842	-1.31499	-2.23515	-14.1678	-14.5791	-13.4405	-15.8399	-15.4795	-16.6881	-16.6921	-16.0381	-13.3282	-9.19452	-3.39503	-7.29001	-9.05158	-9.34204	-7.62721
netcon02 (Pfinal)	-12.2568	-9.08685	-9.23393	-10.4215	-11.2015	-9.66955	-14.8116	-14.009	-19.3921	-27.4672	-31.0729	-33.0699	-30.5894	-33.0418	-29.5308	-31.2488	-28.7378	-29.6829	-34.0721	-41.6355	-43.3115	-41.7316	-44.3915	-44.3784
netcon02 (Qfinal)	7.670391	4.523255	6.430008	6.882373	7.108998	8.62084	10.53607	7.991331	10.41775	11.68858	15.2944	16.07184	15.14257	12.79387	14.56518	13.2554	14.19331	14.58369	15.46501	19.76343	18.47791	17.77133	20.71103	20.65897
netcon03 (Pfinal)	-12.2568	-9.08685	-9.23393	-10.4215	-11.2015	-9.66955	-14.8116	-14.009	-19.3921	-27.4672	-31.0729	-33.0699	-30.5894	-33.0418	-29.5308	-31.2488	-28.7378	-29.6829	-34.0721	-41.6355	-43.3115	-41.7316	-44.3915	-44.3784
netcon03 (Qfinal)	-7.42552	-7.92972	-7.88186	-7.33831	-8.36882	-6.77604	-5.93959	-6.95375	-8.20897	-11.6474	-12.0012	-13.9821	-13.4745	-11.1302	-10.266	-9.589	-7.89458	-10.8049	-15.1759	-19.1209	-21.4919	-19.94	-16.9197	-18.2456
netcon04 (Pfinal)	-12.2568	-9.09456	-9.23382	-10.4175	-11.1957	-9.66245	-14.8184	-14.0084	-19.3923	-27.4742	-31.0821	-33.0726	-30.5847	-33.0437	-29.5281	-31.2382	-28.737	-29.6706	-34.0659	-41.6401	-43.3021	-41.7402	-44.391	-44.3717
netcon04 (Qfinal)	7.805923	5.129339	5.621429	5.194622	4.943847	6.499045	6.691457	1.480767	2.865826	6.991218	7.996857	7.587217	10.47205	5.972344	9.504816	7.741482	8.259237	6.247891	4.588055	5.23223	5.652618	5.851324	3.714524	3.211137
trans004 (tap)	14	11	14	10	14	15	15	15	15	14	14	14	15	15	15	15	15	15	15	15	12	14	15	15
trans012 (tap)	15	15	11	15	14	14	10	12	14	15	15	15	11	14	14	15	14	15	14	11	15	15	14	12
trans008 (tap)	15	16	15	15	14	14	14	12	15	16	15	15	14	14	15	16	14	14	13	14	15	15	14	8
trans002 (tap)	13	15	11	13	14	13	16	14	11	14	15	14	14	14	14	15	14	14	14	14	13	13	14	14
trans006 (tap)	6	12	6	10	12	8	10	7	12	6	6	6	6	10	8	7	12	6	6	11	9	6	7	6
trans010 (tap)	11	11	9	9	9	7	9	10	6	6	6	11	8	9	12	8	7	8	10	7	8	8	11	10
trans015 (tap)	16	18	15	15	8	14	15	17	18	12	14	13	16	14	14	15	7	16	11	18	15	8	14	11
trans001 (tap)	15	7	8	12	10	13	11	16	12	10	15	8	15	15	8	13	18	13	17	17	15	11	17	9
trans014 (tap)	13	15	18	11	19	18	10	17	14	10	10	10	10	10	10	18	19	11	10	10	10	10	10	10
trans011 (tap)	8	11	8	10	8	15	12	11	10	11	8	7	6	9	14	12	15	15	15	15	13	7	11	8
trans016 (tap)	15	14	15	8	8	15	15	9	13	7	14	10	11	13	8	15	14	14	8	15	15	7	15	7
trans013 (tap)	14	10	15	11	9	15	15	13	15	15	9	15	9	12	9	16	12	15	10	10	7	14	14	11
trans003 (tap)	6	7	5	8	9	5	9	6	7	9	9	6	10	8	9	5	10	8	9	9	8	6	9	5
trans007 (tap)	12	12	12	12	13	11	11	11	11	12	10	13	15	11	10	15	11	11	13	12	12	11	7	12
Capa0001 (Mvar)	0	0	0	0	0	0	0	0	0	4	4	4	4	4	4	4	4	4	4	0	4	4	4	4
Capa0002 (Mvar)	0	0	0	0	0	0	0	0	0	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
Capa0003 (Mvar)	3.4	3.4	3.4	3.4	3.4	0	0	0	0	3.4	0	0	0	3.4	0	3.4	0	0	0	0	3.4	3.4	0	0
Capa0004 (Mvar)	0	3.4	0	0	0	0	0	3.4	1.7	0	0	0	0	1.7	0	0	0	0	1.7	0	0	0	0	0
Capa0005 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Capa0006 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Capa0009 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Capa0010 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 216 – Northeast network scenario 5.

Period	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
InitTotLoss (P)	132.6927	83.71087	80.89627	84.82153	91.9452	79.2389	120.7599	71.07188	107.7878	240.8198	260.9341	297.7644	333.5581	283.6274	273.859	279.8568	237.924	214.4785	240.6168	352.9031	419.8549	391.6754	334.5646	334.2785
FinalTotLoss (P)	130.946	83.21237	80.38761	78.89293	83.7047	75.65686	108.7428	60.62412	100.184	233.7574	259.9295	293.7758	327.2114	284.0044	270.2926	276.5756	233.1909	208.1502	241.066	345.2309	411.146	385.2461	332.5876	326.8398
PowerGen (P)	26.8897	25.5111	24.95937	24.83473	24.28434	24.42935	23.75393	23.05326	23.95932	24.93892	25.21605	25.98059	26.73073	25.75252	25.77389	25.7865	25.23823	25.71603	27.50897	30.03614	29.73883	29.19623	28.41627	27.64683
PowerGen (Q)	5.537484	5.412564	5.238147	5.25168	5.070886	5.125949	5.300659	4.951315	4.685207	4.870027	5.598194	5.106701	5.172697	5.310209	5.639425	5.695005	5.527349	5.48278	6.269109	6.640675	6.876465	6.676257	6.833283	6.859535
Cost	230.699	185.4595	177.3066	176.109	180.2276	175.2878	206.9352	139.463	207.1633	338.3115	378.2634	397.1882	374.5793	393.3797	360.5085	376.3824	93.20566	308.0392	408.4232	437.1858	505.0581	487.8454	486.4845	448.1939
netcon01 (Pfinal)	-12.985	-9.68395	-9.82626	-11.0699	-11.8817	-10.303	-15.6344	-14.7775	-20.3738	-28.7736	-32.5147	-34.5949	-32.0255	-34.5544	-30.9185	-32.698	-30.0903	-31.0694	-35.6311	-43.5079	-45.2494	-43.6135	-46.3388	-46.3088
netcon01 (Qfinal)	-5.76925	-2.63151	-2.22041	-2.76052	-1.98442	-3.30162	-6.00495	-1.11121	-5.35802	-13.8439	-14.1124	-13.0643	-15.4933	-15.2172	-15.8431	-15.8837	-13.78	-12.5118	-8.80362	-6.97141	-7.29723	-7.98363	-9.02912	-7.14999
netcon02 (Pfinal)	-12.985	-9.68395	-9.82626	-11.0699	-11.8817	-10.303	-15.6344	-14.7775	-20.3738	-28.7736	-32.5147	-34.5949	-32.0255	-34.5544	-30.9185	-32.698	-30.0903	-31.0694	-35.6311	-43.5079	-45.2494	-43.6135	-46.3388	-46.3088
netcon02 (Qfinal)	9.997142	8.71927	8.71102	6.972712	6.264419	4.856368	8.784147	10.51392	8.589171	14.12285	15.80858	16.6071	15.65314	16.4464	15.05943	15.72922	11.45706	12.87085	17.08115	18.32008	21.15857	20.43229	21.37391	18.0955
netcon03 (Pfinal)	-12.985	-9.68395	-9.82626	-11.0699	-11.8817	-10.303	-15.6344	-14.7775	-20.3738	-28.7736	-32.5147	-34.5949	-32.0255	-34.5544	-30.9185	-32.698	-30.0903	-31.0694	-35.6311	-43.5079	-45.2494	-43.6135	-46.3388	-46.3088
netcon03 (Qfinal)	-6.99341	-7.57525	-7.52573	-6.95185	-7.96064	-6.39826	-5.44901	-6.49687	-7.96903	-10.8687	-11.1284	-13.0747	-12.6193	-10.2377	-9.38486	-8.6774	-6.88931	-9.92838	-14.2508	-18.4225	-20.3912	-18.7635	-15.7786	-17.1005
netcon04 (Pfinal)	-12.9854	-9.67707	-9.82186	-11.0655	-11.8904	-10.3017	-15.6429	-14.7943	-20.3792	-28.7703	-32.5099	-34.5846	-32.0227	-34.5541	-30.9205	-32.6796	-30.1008	-31.0758	-35.6178	-43.5202	-45.253	-43.6133	-46.3274	-46.3168
netcon04 (Qfinal)	8.188374	6.785423	6.158638	4.373827	3.533043	3.433589	4.557269	1.930846	0.467126	6.647247	6.338313	5.825641	8.818654	6.058917	7.907928	7.22883	4.821751	3.37387	3.430277	1.841356	4.593968	4.855559	1.453862	-0.90172
trans004 (tap)	13	13	13	13	14	13	14	9	14	13	13	13	12	13	15	12	14	11	13	13	14	9	13	14
trans012 (tap)	13	14	14	14	13	13	14	15	13	12	10	11	13	14	15	14	13	14	14	14	14	9	14	11
trans008 (tap)	12	12	12	12	13	15	14	8	13	13	12	12	11	12	14	12	13	12	12	14	14	11	12	13
trans002 (tap)	15	15	15	18	14	16	12	15	14	15	15	15	15	15	15	15	14	14	15	13	13	15	13	14
trans006 (tap)	10	11	10	7	11	8	7	9	12	6	6	6	6	6	10	12	6	7	6	6	6	10	6	6
trans010 (tap)	10	9	8	9	7	6	8	8	12	8	12	11	6	7	10	6	9	12	9	11	12	7	12	8
trans015 (tap)	13	11	14	17	14	16	17	18	12	16	14	16	15	10	16	14	12	17	8	11	12	8	11	17
trans001 (tap)	9	17	15	18	11	15	17	11	12	9	17	11	8	14	10	16	15	16	11	17	10	17	12	17
trans014 (tap)	16	18	13	17	19	11	19	18	15	10	11	10	10	15	12	15	12	14	10	12	10	10	10	10
trans011 (tap)	13	13	9	7	9	12	15	9	6	15	12	14	12	11	7	11	8	11	8	11	15	14	14	14
trans016 (tap)	15	13	10	14	7	15	8	13	15	12	7	13	12	14	11	11	15	14	11	8	11	12	15	14
trans013 (tap)	12	14	11	12	16	11	10	10	14	12	9	7	10	8	14	7	16	7	9	13	9	12	8	12
trans003 (tap)	8	8	9	8	8	6	6	10	10	10	6	7	10	10	8	5	7	7	9	9	8	8	5	7
trans007 (tap)	15	15	15	15	14	15	12	15	14	15	14	15	15	15	12	15	15	15	15	13	14	15	15	14
Capa0001 (Mvar)	0	0	0	0	0	0	0	0	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Capa0002 (Mvar)	0	0	0	0	0	0	0	0	0	3.4	3.4	3.4	3.4	3.4	3.4	3.4	0	3.4	3.4	3.4	3.4	3.4	3.4	3.4
Capa0003 (Mvar)	0	0	0	0	3.4	3.4	0	0	3.4	0	0	0	0	0	0	0	3.4	0	0	0	0	0	0	3.4
Capa0004 (Mvar)	0	0	0	3.4	1.7	3.4	3.4	0	1.7	0	0	0	0	0	0	0	1.7	3.4	0	3.4	0	0	0	1.7
Capa0005 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Capa0006 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Capa0009 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Capa0010 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 217 – Northeast network scenario 6.

Period	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
InitTotLoss (P)	147.8001	101.2412	94.14221	93.22683	98.8891	86.79212	121.6366	74.53972	115.6409	260.0113	283.081	312.7557	349.5616	303.3703	290.0689	298.1399	248.4689	225.7489	264.3287	373.4277	438.5167	419.7762	357.1055	349.3931
FinalTotLoss (P)	142.4336	94.65172	88.69468	87.48997	94.4164	85.50003	115.2718	71.69766	105.0763	244.6666	274.9213	305.9899	345.081	297.6853	283.1362	289.0543	245.8562	222.9474	256.9766	371.9018	437.764	410.6192	351.0178	344.0301
PowerGen (P)	31.13599	29.54188	28.87994	28.76284	28.12649	28.29028	27.50952	26.69917	27.74022	28.86263	29.17537	30.04639	30.92643	29.79892	29.82116	29.82149	29.2083	29.76804	31.83622	34.76581	34.40444	33.7803	32.86048	31.99204
PowerGen (Q)	6.456116	6.32128	6.122606	6.148159	5.937606	5.991879	6.188535	5.797237	5.472955	5.648844	6.467997	5.903485	5.960518	6.135983	6.525568	6.579072	6.408979	6.346788	7.275717	7.673901	7.925177	7.699597	7.895686	7.927957
Cost	241.8312	196.042	187.6338	187.0539	191.4751	187.2352	217.9231	149.001	273.1653	99.31099	111.7141	106.1017	439.8454	106.5099	106.1988	119.3046	331.6294	105.7311	129.1233	152.6619	158.2155	152.9808	451.7839	429.161
netcon01 (Pfinal)	-14.8849	-11.0986	-11.2646	-12.7173	-13.6961	-11.9135	-18.0381	-17.0003	-23.4315	-33.0975	-37.3918	-39.768	-36.8125	-39.6964	-35.5474	-37.5715	-34.5907	-35.6979	-40.875	-49.9474	-51.9542	-50.0837	-53.1417	-53.0716
netcon01 (Qfinal)	-5.01797	-2.05929	-1.64209	-2.10844	-1.27293	-2.66373	-5.08671	-0.26406	-0.82876	-12.2304	-12.4101	-11.1421	-13.7024	-13.6442	-14.945	-15.1673	-14.9411	-11.3683	-6.85442	-4.06976	-4.30105	-5.36244	-5.43088	-3.89562
netcon02 (Pfinal)	-14.8849	-11.0986	-11.2646	-12.7173	-13.6961	-11.9135	-18.0381	-17.0003	-23.4315	-33.0975	-37.3918	-39.768	-36.8125	-39.6964	-35.5474	-37.5715	-34.5907	-35.6979	-40.875	-49.9474	-51.9542	-50.0837	-53.1417	-53.0716
netcon02 (Qfinal)	7.528297	6.400407	6.39012	5.902881	9.296265	8.756658	10.54564	8.038617	11.32343	12.23769	13.82356	13.18268	14.73308	13.23487	13.11838	14.79409	13.8409	13.05858	16.04952	19.05919	19.76927	19.09996	19.96149	18.85366
netcon03 (Pfinal)	-14.8849	-11.0986	-11.2646	-12.7173	-13.6961	-11.9135	-18.0381	-17.0003	-23.4315	-33.0975	-37.3918	-39.768	-36.8125	-39.6964	-35.5474	-37.5715	-34.5907	-35.6979	-40.875	-49.9474	-51.9542	-50.0837	-53.1417	-53.0716
netcon03 (Qfinal)	-8.40752	-8.77924	-8.7214	-8.22228	-9.27369	-7.64335	-6.95414	-7.91679	-9.36148	-13.0755	-13.5449	-15.6052	-15.0333	-12.7894	-11.8107	-11.214	-9.46044	-12.324	-16.8444	-21.4458	-23.4974	-21.8059	-18.8288	-20.1474
netcon04 (Pfinal)	-14.8794	-11.0925	-11.2763	-12.7154	-13.6951	-11.9092	-18.0362	-17	-23.4353	-33.0949	-37.3893	-39.7695	-36.8062	-39.6919	-35.5467	-37.5641	-34.5896	-35.6982	-40.8687	-49.942	-51.9531	-50.0887	-53.1545	-53.0731
netcon04 (Qfinal)	8.720718	7.126954	6.463468	5.493426	7.056621	7.41096	7.552407	2.306668	4.208427	8.191385	8.073893	6.793763	11.13303	7.187562	9.636503	9.64103	9.008525	6.348284	6.096255	6.099382	7.67906	7.852248	4.562416	3.42678
trans004 (tap)	13	11	13	14	12	13	13	13	14	14	14	13	13	14	8	13	11	13	9	14	13	13	10	12
trans012 (tap)	15	13	14	14	14	14	14	12	15	14	13	14	14	11	15	14	13	14	15	15	14	10	14	8
trans008 (tap)	12	12	12	14	12	12	12	12	13	13	13	9	8	12	13	12	12	11	12	13	12	9	16	13
trans002 (tap)	14	12	15	13	16	12	15	11	14	10	15	14	15	15	14	14	13	13	14	14	15	12	15	15
trans006 (tap)	10	11	10	12	11	12	7	11	10	6	6	6	6	7	6	7	9	6	6	10	6	10	12	7
trans010 (tap)	11	8	8	8	11	10	7	10	8	11	9	12	11	6	12	11	9	8	6	12	12	6	11	6
trans015 (tap)	14	12	17	14	11	11	13	15	16	14	16	14	17	10	7	13	16	14	15	18	13	14	18	17
trans001 (tap)	13	10	14	16	15	11	10	7	15	14	10	8	12	13	9	18	18	11	13	14	10	16	18	9
trans014 (tap)	14	17	19	10	19	18	11	19	11	10	10	10	10	10	10	11	13	10	10	11	15	12	12	16
trans011 (tap)	8	13	10	11	13	13	6	12	10	8	14	13	9	12	13	10	7	14	10	8	7	15	12	14
trans016 (tap)	14	12	15	10	11	11	13	7	9	8	12	13	14	12	11	11	9	14	7	11	12	13	9	12
trans013 (tap)	8	14	13	15	15	12	11	14	16	9	16	13	15	8	11	16	14	8	13	16	12	15	9	12
trans003 (tap)	10	7	10	9	8	6	8	9	7	8	5	9	7	5	6	9	5	7	9	5	6	7	9	6
trans007 (tap)	15	12	15	14	15	15	15	15	14	14	14	15	15	15	14	13	15	14	15	13	14	15	15	15
Capa0001 (Mvar)	0	0	0	0	0	0	0	0	0	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Capa0002 (Mvar)	0	0	0	0	0	0	0	0	0	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
Capa0003 (Mvar)	3.4	3.4	0	3.4	0	0	0	3.4	0	0	0	3.4	0	3.4	0	0	0	0	0	0	0	0	0	0
Capa0004 (Mvar)	0	0	3.4	1.7	0	0	0	0	0	1.7	1.7	0	0	0	1.7	0	0	1.7	0	0	0	0	0	1.7
Capa0005 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Capa0006 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Capa0009 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Capa0010 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 218 – Western network scenario 1-part 1.

Period	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
InitTotLoss (P)	50.81866	41.45717	38.04296	36.29962	34.73453	34.11467	36.18946	41.06173	48.88172	60.90476	69.90551	75.81314	78.06595	70.44968	64.52538	64.26059	62.83086	70.63993	74.9948	81.2309	83.88076	73.5524	60.63574	49.45664
FinalTotLoss (P)	45.60298	38.47452	36.77985	34.02814	33.56427	31.85872	33.69669	38.13551	45.95487	55.52973	64.14706	69.84578	71.39068	65.36269	59.55473	60.38515	57.95447	65.19826	68.80791	74.31162	75.7067	68.1453	57.10017	46.52066
PowerGen (P)	148.8791	136.5411	132.5299	129.2921	126.5002	125.946	130.9869	140.2855	152.8944	169.0544	178.2037	183.0753	184.1158	169.8343	165.1955	163.2722	163.1076	173.9532	180.4803	184.8343	186.2101	168.9941	150.0738	132.0173
PowerGen (Q)	6.258975	5.158619	5.188043	5.726665	5.143223	5.245768	5.464829	5.318552	7.446899	10.62155	11.25457	10.4604	10.84734	16.11138	21.47766	26.29434	26.57374	27.96674	22.62195	23.65998	30.93892	38.44958	41.1736	40.39803
Cost	165.5684	100.5651	83.93929	81.70274	79.66139	78.85714	76.46964	121.4604	24.52	21.44	19.92	21.12	20.8	18.08	20.52	19.92	22.96	26.96	25.44	20.84	23.6	133.047	21.8	19.7
netcon02 (Pfinal)	38.1221	30.14198	27.50251	24.65282	23.93223	22.6247	27.17956	31.66061	39.11584	44.47357	50.36231	53.12645	55.19737	52.2037	49.06945	49.69255	51.02866	57.64858	59.77991	63.34278	63.6793	54.35873	44.40521	36.0332
netcon02 (Qfinal)	-4.30318	2.994666	2.653176	6.231728	5.532572	2.786124	0.140417	-0.80367	2.765268	2.431488	0.192147	4.3713	5.037528	2.849269	2.01079	-2.24372	5.423766	2.119416	4.021564	1.246443	0.628799	11.52071	5.960709	6.868547
netcon01 (Pfinal)	62.27445	63.13666	65.16741	64.10931	62.98297	63.15631	65.15735	60.2624	63.95729	73.31959	77.14164	78.95031	77.61519	62.81962	56.54833	53.77014	51.23147	55.68441	59.92292	59.92655	53.65335	45.85791	32.88862	27.67155
netcon01 (Qfinal)	-5.01707	-5.64775	-4.70844	-4.58208	-4.46675	-4.42131	-4.28642	-6.0246	-4.72302	-4.78945	-4.14618	-7.98136	-4.03785	1.306804	6.607422	10.95442	6.682172	7.178299	2.142364	7.13543	10.36881	16.93479	26.70168	24.69048
trans042 (tap)	11	11	12	12	12	11	9	14	12	12	8	12	12	13	14	12	7	13	12	12	13	12	12	7
trans001 (tap)	7	8	11	12	12	12	11	12	10	8	10	7	11	12	7	12	7	11	6	6	7	12	11	6
trans029 (tap)	8	12	12	12	12	12	12	12	12	6	12	12	12	12	12	9	10	11	12	10	9	12	10	12
trans033 (tap)	10	11	12	12	12	12	12	11	12	13	10	12	9	13	13	13	11	14	11	13	12	7	9	11
trans005 (tap)	9	5	7	10	10	10	10	7	10	11	12	10	10	10	5	10	8	7	7	9	8	10	12	6
trans007 (tap)	4	9	10	6	10	10	9	6	10	7	5	10	9	6	6	8	6	4	10	4	4	6	10	10
trans045 (tap)	10	11	10	10	9	12	10	11	10	10	9	10	10	10	6	9	12	10	9	12	10	9	11	12
trans006 (tap)	11	8	10	10	11	10	11	13	10	8	10	10	6	11	9	13	12	11	10	9	10	8	11	5
trans046 (tap)	4	4	10	6	10	4	5	4	8	4	4	4	4	4	4	4	4	5	4	4	4	7	6	6
trans013 (tap)	10	10	10	10	10	11	10	10	7	12	9	10	10	10	9	9	6	12	10	13	6	10	12	13
trans039 (tap)	11	12	12	13	8	12	12	11	10	6	11	12	11	12	15	12	6	12	12	10	9	12	10	10
trans044 (tap)	12	9	12	10	10	12	9	9	7	9	10	12	8	10	11	10	9	12	6	6	10	12	10	8
trans028 (tap)	6	8	10	10	10	9	11	11	10	4	9	11	10	10	10	8	12	10	11	6	6	10	4	10
trans026 (tap)	8	10	10	10	10	9	6	10	13	10	7	12	8	9	9	10	10	9	7	7	8	6	8	13
trans036 (tap)	9	12	12	9	9	8	11	9	9	9	9	12	6	8	8	12	11	10	12	6	6	8	11	10
trans019 (tap)	8	14	9	12	12	6	11	12	11	12	12	8	6	12	8	10	10	12	9	11	6	12	8	11
trans040 (tap)	7	6	8	7	7	8	13	6	6	10	13	7	7	12	7	11	10	6	8	10	9	6	12	11
trans018 (tap)	8	9	6	10	7	11	14	14	8	6	11	6	8	11	12	13	11	7	14	12	12	7	8	12
trans027 (tap)	13	14	12	12	13	11	12	14	14	12	12	12	14	14	11	11	13	9	12	14	9	14	12	14
trans041 (tap)	11	10	9	9	13	12	11	12	11	9	13	12	14	11	9	13	8	9	15	7	14	13	12	9
trans002 (tap)	12	11	13	16	14	12	17	10	13	13	17	11	13	13	14	13	9	11	12	11	13	10	9	11

Table 219 – Western network scenario 1-part 2.

Period	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
trans032 (tap)	10	9	8	7	9	8	9	9	8	7	10	12	10	8	10	10	8	7	10	13	10	10	14	9
trans009 (tap)	11	10	8	8	13	9	9	7	10	8	9	11	10	10	10	11	9	8	7	7	10	7	10	12
trans034 (tap)	11	4	7	7	11	5	5	7	4	12	5	4	5	10	8	6	9	10	4	6	9	4	10	6
trans023 (tap)	9	8	10	7	7	7	8	6	11	9	9	6	8	8	13	13	7	6	8	12	6	6	11	12
trans043 (tap)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
trans037 (tap)	7	12	7	7	12	8	11	6	7	7	7	7	7	15	7	7	7	7	11	7	7	6	7	8
trans011 (tap)	12	12	7	13	10	11	11	11	12	10	11	15	13	7	6	11	11	12	13	13	15	12	15	10
trans030 (tap)	12	8	7	6	11	10	8	7	6	6	6	6	7	12	10	11	12	12	8	12	8	7	12	8
trans012 (tap)	13	15	15	15	15	16	15	15	15	15	15	15	15	15	15	15	16	15	15	15	16	15	15	15
trans008 (tap)	10	16	16	15	16	15	15	16	15	15	15	15	15	16	15	16	15	16	12	15	16	15	12	16
capac012 (Mvar)	2.5	0	0	0	0	0	2.5	2.5	0	2.5	2.5	0	2.5	2.5	0	2.5	0	2.5	0	2.5	2.5	2.5	2.5	2.5
capac013 (Mvar)	2.5	0	0	0	0	0	0	0	0	0	2.5	2.5	0	0	2.5	2.5	2.5	2.5	2.5	2.5	2.5	0	2.5	2.5
capac014 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac015 (Mvar)	2.8	0	0	0	0	0	2.8	2.8	2.8	2.8	2.8	0	0	2.8	2.8	2.8	0	2.8	2.8	2.8	2.8	0	0	0
capac016 (Mvar)	2.8	3.4	3.4	0	0	2.8	0	2.8	2.8	3.4	2.8	3.4	2.8	2.8	3.4	6.2	3.4	2.8	3.4	2.8	2.8	0	2.8	2.8
capac017 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac018 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac021 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac022 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac001 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac002 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac003 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac004 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac005 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	3.4	0	0	0	0	0	0	0	0	3.4	0	0	0
capac006 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3.4	3.4	3.4	0	0	3.4	0	0
capac007 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac008 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac009 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac010 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac011 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac019 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac020 (Mvar)	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	0	0

Table 220 – Western network scenario 2-part 1.

Period	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
InitTotLoss (P)	57.91849	47.72631	43.80298	42.01855	39.75733	39.52368	41.42981	47.0974	56.1485	69.80284	79.99763	86.93192	89.16659	80.55875	74.4242	73.6025	72.93409	81.05866	86.37183	92.74978	96.0711	84.728	69.38984	56.75003
FinalTotLoss (P)	53.16116	45.31071	41.41608	40.37256	37.4849	38.43425	37.97481	44.43806	52.21318	63.90322	72.45637	80.24728	81.03092	73.12922	68.87595	67.58696	66.04182	73.9679	78.03321	83.37894	88.20434	78.27755	63.01454	53.00391
PowerGen (P)	160.0492	146.786	142.4715	138.9921	135.9895	135.3956	140.8119	150.8103	164.3647	181.7382	191.5731	196.8111	197.9277	182.5749	177.5899	175.5197	175.3441	187.0036	194.0206	198.7014	200.1828	181.6739	161.3305	141.9212
PowerGen (Q)	6.834425	5.629599	5.626312	6.235178	5.565784	5.73103	5.893651	5.786214	8.07288	11.50396	12.15429	11.35651	11.72689	17.35678	23.20133	28.30116	28.65501	30.1303	24.38402	25.51092	33.45768	41.42191	44.2765	43.50248
Cost	151.1143	104.6614	91.23801	84.3547	78.08184	72.90745	138.2131	109.556	21.8	19.7	18.6	21.6	25.8	23.2	21.5	22	23.97	21.5	29.3	27.4	22.1	150.9145	21.4	22.3
netcon02 (Pfinal)	43.99834	35.43097	32.50727	29.54019	28.69702	27.33489	32.10557	37.06735	44.9418	50.14627	56.21233	59.19643	60.7415	57.64167	54.82521	56.01366	57.71584	64.85068	67.24338	71.02355	71.55581	61.43388	50.82352	41.77551
netcon02 (Qfinal)	8.094445	7.434219	3.870127	4.264012	3.097728	6.084692	6.259587	2.091196	6.22339	0.234568	1.045206	3.258654	6.053579	-0.50224	6.136495	3.602526	1.093194	1.036248	1.328596	1.565465	8.65432	2.653855	3.150538	10.05237
netcon01 (Pfinal)	66.84931	67.74476	70.02687	68.91775	67.70748	67.8945	70.03727	65.32097	69.34932	79.46114	83.56929	85.50887	84.05335	67.9547	61.0619	57.98873	55.15966	59.90831	64.52146	64.45759	57.49143	49.06168	34.99027	29.55015
netcon01 (Qfinal)	-8.50364	-5.87918	-5.12079	-4.7319	-4.37751	-4.08517	-7.77475	-6.15571	-8.45159	-4.94756	-8.26837	-4.58971	-7.78609	0.084095	6.595726	11.2462	12.20084	8.751094	6.203565	3.743975	15.84989	19.21935	24.99308	22.94195
trans042 (tap)	12	12	11	12	12	13	7	12	12	7	12	13	7	8	11	9	11	8	6	11	11	12	7	8
trans001 (tap)	8	13	12	12	11	12	9	9	13	8	9	12	7	12	12	6	13	8	6	10	14	7	8	11
trans029 (tap)	11	12	11	12	12	11	8	12	12	6	7	11	9	10	11	12	6	11	10	10	7	12	10	12
trans033 (tap)	12	12	12	12	12	12	12	15	11	13	8	10	11	12	11	12	10	8	6	9	13	12	12	12
trans005 (tap)	10	10	10	9	10	10	5	12	12	12	4	8	13	11	9	7	12	10	13	13	8	8	10	6
trans007 (tap)	10	10	10	10	9	10	5	10	9	5	4	10	8	8	7	6	4	7	8	4	4	6	4	11
trans045 (tap)	11	10	10	10	12	10	10	10	9	13	9	5	10	13	10	10	12	8	5	7	8	7	10	11
trans006 (tap)	12	10	10	10	12	13	6	9	9	7	10	7	6	9	9	10	12	11	13	9	10	13	9	12
trans046 (tap)	4	6	6	10	5	10	5	4	4	4	4	4	4	4	4	5	4	4	4	4	4	5	5	4
trans013 (tap)	11	10	10	10	7	8	10	11	11	8	10	12	10	8	10	10	11	9	9	11	10	12	10	13
trans039 (tap)	14	12	11	10	12	11	10	12	11	15	9	13	7	12	11	11	12	12	15	15	9	11	11	11
trans044 (tap)	12	12	12	10	11	9	8	12	12	11	11	11	10	13	7	9	6	11	8	11	12	10	9	13
trans028 (tap)	5	10	9	10	10	12	10	8	7	11	9	10	9	9	12	11	4	9	6	4	6	4	4	7
trans026 (tap)	11	10	13	6	10	10	8	11	10	8	10	10	7	11	8	7	7	10	4	9	10	9	4	10
trans036 (tap)	12	8	13	12	12	12	6	12	6	12	6	6	6	7	12	13	10	10	9	6	8	7	8	7
trans019 (tap)	12	10	12	10	11	12	9	11	11	10	11	15	9	9	12	9	6	12	7	6	12	9	7	11
trans040 (tap)	11	13	6	11	8	12	10	9	7	12	8	6	10	6	12	10	7	6	6	7	6	12	9	10
trans018 (tap)	12	7	8	9	15	12	9	7	9	11	6	9	13	13	11	8	11	6	10	6	10	10	12	12
trans027 (tap)	9	7	11	11	14	14	13	13	14	12	9	11	8	9	11	13	7	11	12	14	6	12	11	15
trans041 (tap)	12	13	8	12	11	10	14	9	14	15	7	9	11	11	8	10	14	13	6	10	8	12	12	15
trans002 (tap)	13	12	12	16	14	14	15	19	10	17	14	11	9	13	12	13	12	13	13	13	14	12	18	10

Table 221 – Western network scenario 2-part 2.

Period	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
trans032 (tap)	13	9	8	8	16	10	8	7	10	10	11	11	14	9	13	10	13	9	8	11	10	9	7	8
trans009 (tap)	8	11	8	10	8	11	7	8	8	10	7	7	7	10	13	8	10	10	9	9	12	12	10	10
trans034 (tap)	4	6	10	9	7	8	4	6	6	12	7	7	4	11	6	8	7	8	8	5	4	8	10	10
trans023 (tap)	9	7	7	6	8	10	6	6	7	8	6	6	6	6	6	6	12	6	10	7	9	10	8	9
trans043 (tap)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
trans037 (tap)	8	7	9	14	12	7	7	7	10	8	7	6	8	7	7	7	7	7	6	7	6	7	7	7
trans011 (tap)	12	11	9	13	6	13	9	12	8	10	9	6	12	9	9	7	11	11	9	9	6	14	8	12
trans030 (tap)	8	11	10	13	6	12	7	11	9	8	6	8	6	6	8	8	6	6	10	6	7	12	11	8
trans012 (tap)	9	15	16	15	15	15	15	15	16	12	15	15	15	15	15	15	15	15	15	15	15	15	15	15
trans008 (tap)	8	15	15	15	16	16	15	16	16	16	15	15	15	15	15	16	15	15	15	15	15	15	15	16
capac012 (Mvar)	0	0	0	0	0	0	0	2.5	0	2.5	2.5	2.5	2.5	2.5	0	2.5	2.5	0	2.5	2.5	2.5	2.5	2.5	0
capac013 (Mvar)	0	0	0	2.5	0	0	0	0	2.5	2.5	2.5	0	2.5	2.5	0	2.5	2.5	2.5	2.5	2.5	0	2.5	2.5	0
capac014 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac015 (Mvar)	0	0	0	0	0	0	0	0	0	2.8	2.8	0	0	2.8	2.8	0	2.8	2.8	2.8	2.8	0	2.8	2.8	2.8
capac016 (Mvar)	0	0	2.8	0	2.8	0	0	2.8	0	3.4	2.8	6.2	0	3.4	3.4	3.4	3.4	6.2	3.4	3.4	2.8	3.4	2.8	3.4
capac017 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac018 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac021 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac022 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac001 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac002 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac003 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac004 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	1.4	0	0	0	0	0	0	0	0	0	0
capac005 (Mvar)	0	0	0	0	0	0	0	0	0	0	3.4	0	0	0	0	0	0	0	0	0	0	3.4	0	0
capac006 (Mvar)	3.4	0	0	0	0	0	3.4	0	3.4	0	0	0	3.4	0	0	0	0	3.4	0	3.4	0	0	0	0
capac007 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac008 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac009 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac010 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac011 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac019 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac020 (Mvar)	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3

Table 222 – Western network scenario 3-part 1.

Period	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
InitTotLoss (P)	57.63309	47.441	43.71984	42.12754	39.75733	39.4251	41.42876	46.9964	55.99587	69.4778	79.75651	86.82258	89.15978	80.35464	73.76743	73.84306	72.79297	81.43704	86.47152	93.02685	95.95928	84.72275	69.47908	56.84135
FinalTotLoss (P)	54.08024	44.47993	40.80521	39.11068	38.26732	36.82458	38.51977	44.46254	51.70045	63.33465	72.38613	78.59425	79.87241	73.89871	68.89697	68.51284	65.34728	75.01415	79.93294	86.23201	86.07283	77.22605	65.0667	52.44004
PowerGen (P)	160.0504	146.7847	142.47	138.9909	135.9903	135.3943	140.8126	150.8111	164.364	181.7386	191.5731	196.8089	197.9276	182.5757	177.5895	175.52	175.3431	187.0043	194.0222	198.7042	200.18	181.6727	161.3323	141.9211
PowerGen (Q)	6.855574	5.604529	5.607351	6.209422	5.579412	5.699112	5.909993	5.789537	8.065673	11.49353	12.15074	11.29727	11.71694	17.36561	23.17569	28.3312	28.64329	30.17342	24.43882	25.60531	33.35888	41.37027	44.33621	43.50824
Cost	94.94344	166.5947	85.00511	84.5087	82.38132	81.49894	76.8951	107.3863	21.8	23.2	24.9	19.8	25.5	23.1	17.8	18.6	19.1	21.6	22.5	24.6	27.3	528.0914	22.2	22.3
netcon02 (Pfinal)	43.9992	35.42989	32.50551	29.5395	28.69745	27.33448	32.10542	37.06806	44.91979	49.97537	55.99428	58.97759	60.38928	57.32703	54.60017	55.92027	57.69476	64.85027	67.2452	71.02489	71.55347	61.43336	50.8256	41.77649
netcon02 (Qfinal)	8.111188	-0.32375	1.255488	6.748557	3.496349	6.068134	3.191105	1.350686	1.305223	0.136992	0.157654	2.43398	0.254896	2.760422	3.680986	1.12409	2.931672	7.635859	5.670685	6.018093	1.21128	5.048758	9.631169	10.4431
netcon01 (Pfinal)	66.70461	67.67438	70.01156	68.91637	67.70783	67.89339	70.03428	65.30908	69.31983	79.45794	83.56821	85.50323	84.03823	67.83453	60.85905	57.73841	54.8529	59.58183	64.22309	64.12517	57.03559	48.5768	34.43804	29.08865
netcon01 (Qfinal)	-5.33014	-9.05448	-4.76865	-4.74061	-4.62041	-4.57056	-4.31046	-6.03313	-5.3755	-5.22105	-8.27752	-8.56983	-4.28526	-1.89825	3.973599	8.722241	8.362058	12.55866	5.721457	4.224244	15.73131	22.25702	23.33866	22.56671
trans042 (tap)	12	12	11	9	12	12	9	11	12	9	7	7	10	7	6	12	11	10	10	12	6	8	12	12
trans001 (tap)	12	13	8	8	12	12	6	11	14	9	8	8	6	7	8	12	6	10	12	12	9	7	7	11
trans029 (tap)	12	8	9	12	12	12	9	12	9	13	12	11	9	11	11	6	7	11	10	9	9	15	13	14
trans033 (tap)	12	12	9	12	12	12	10	12	8	14	11	12	13	12	11	12	14	8	10	15	8	6	12	12
trans005 (tap)	10	10	12	10	10	8	10	10	10	13	11	13	10	10	9	10	11	11	12	4	13	5	9	6
trans007 (tap)	10	11	10	7	10	10	7	10	10	6	6	8	4	10	9	10	4	10	10	6	5	8	6	10
trans045 (tap)	10	11	10	10	9	10	7	10	10	7	10	10	7	12	5	8	12	10	10	10	9	10	10	10
trans006 (tap)	10	10	8	10	10	7	6	10	12	13	4	8	13	11	10	10	11	10	10	10	7	9	10	7
trans046 (tap)	5	4	5	4	7	6	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	6	4
trans013 (tap)	10	11	12	10	10	11	13	10	7	10	11	10	11	7	10	5	8	13	9	9	12	12	10	8
trans039 (tap)	12	11	12	12	12	12	8	12	12	9	10	10	12	12	7	12	10	12	8	12	9	8	13	10
trans044 (tap)	12	6	9	12	12	7	8	12	11	12	10	6	9	14	11	14	12	7	10	13	13	12	11	12
trans028 (tap)	10	10	4	10	10	10	13	10	6	10	8	7	10	7	5	7	7	8	7	6	9	10	9	7
trans026 (tap)	10	11	4	9	11	10	10	9	10	10	11	5	9	10	10	10	10	11	10	6	8	8	9	9
trans036 (tap)	12	14	10	13	12	12	12	14	12	12	9	12	15	10	6	9	12	10	6	7	6	6	12	12
trans019 (tap)	12	10	12	13	12	12	11	12	10	8	11	7	7	6	12	8	6	7	12	13	6	6	9	12
trans040 (tap)	9	7	9	7	10	7	7	7	9	6	6	10	6	14	12	6	11	8	7	7	6	7	8	8
trans018 (tap)	13	9	12	9	13	15	14	8	10	7	11	9	6	11	12	14	7	7	7	12	9	15	12	11
trans027 (tap)	12	12	10	10	13	14	12	7	10	11	11	13	6	10	8	8	12	13	10	12	10	15	14	13
trans041 (tap)	14	13	6	10	14	10	8	13	6	15	9	7	15	13	10	15	12	15	8	14	14	13	13	12
trans002 (tap)	12	10	14	15	10	11	11	10	15	13	9	16	13	9	10	14	12	9	13	15	13	11	11	14
trans032 (tap)	10	8	10	13	11	13	9	12	7	11	7	10	9	7	10	8	10	11	12	7	11	12	10	9

Table 223 – Western network scenario 3-part 2.

Period	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
trans009 (tap)	10	8	8	9	11	9	13	8	7	7	7	10	7	10	10	10	9	12	9	10	11	8	11	8
trans034 (tap)	10	9	4	8	8	7	9	8	5	4	4	4	5	11	12	9	6	10	8	8	9	10	9	10
trans023 (tap)	7	9	10	6	6	6	8	7	6	6	6	6	6	8	12	11	8	10	6	9	8	7	6	6
trans043 (tap)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
trans037 (tap)	6	7	6	7	7	8	6	7	6	6	7	9	6	7	7	6	10	14	6	10	7	7	6	6
trans011 (tap)	12	8	12	11	9	7	10	7	9	9	6	8	10	11	12	12	9	12	11	11	6	12	15	10
trans030 (tap)	12	12	12	10	10	10	7	8	6	6	7	6	6	10	12	7	7	8	11	9	6	12	14	10
trans012 (tap)	6	16	15	15	16	15	16	15	16	15	15	15	15	16	15	15	15	14	15	15	15	16	15	16
trans008 (tap)	12	16	15	16	15	15	15	15	15	15	15	15	15	15	15	15	12	13	15	15	15	15	15	15
capac012 (Mvar)	0	2.5	2.5	0	2.5	0	0	0	0	0	2.5	2.5	2.5	2.5	2.5	2.5	2.5	0	2.5	2.5	2.5	2.5	0	0
capac013 (Mvar)	0	2.5	0	0	0	0	0	0	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	0	2.5	0	2.5	2.5	2.5	2.5	0
capac014 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac015 (Mvar)	0	0	2.8	0	0	0	2.8	2.8	2.8	2.8	0	0	2.8	0	0	2.8	2.8	0	2.8	0	2.8	0	0	2.8
capac016 (Mvar)	0	2.8	0	0	0	0	0	3.4	2.8	6.2	6.2	3.4	2.8	2.8	2.8	3.4	3.4	3.4	3.4	2.8	2.8	3.4	2.8	3.4
capac017 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac018 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac021 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac022 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac001 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac002 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac003 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac004 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1.4	0
capac005 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	3.4	0	0	0	0	0	3.4	0	0	0	0
capac006 (Mvar)	0	0	0	0	0	0	0	0	0	0	3.4	3.4	0	0	0	3.4	3.4	0	0	0	0	0	0	0
capac007 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac008 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac009 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac010 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac011 (Mvar)	0	3.4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac019 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac020 (Mvar)	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	6.6	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3

Table 224 – Western network scenario 4-part 1

Period	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
InitTotLoss (P)	70.26801	58.16984	53.26588	50.73921	47.99641	47.54971	50.33287	57.4325	67.92892	84.31197	97.19336	105.1116	108.3749	97.72164	90.11807	89.76	88.12007	98.78082	105.5602	113.5415	117.0999	103.1755	84.68538	68.91326
FinalTotLoss (P)	64.16603	55.20476	52.04621	47.66203	44.48584	44.77142	47.78023	53.57242	62.97716	76.15093	87.71691	94.69461	97.8789	88.10723	80.77482	83.0171	85.13122	88.95543	95.0982	101.5188	107.1681	94.31168	76.69329	63.8823
PowerGen (P)	177.027	162.3571	157.5863	153.7344	150.4132	149.7561	155.7512	166.8085	181.7995	201.0166	211.8963	217.6868	218.9252	201.9425	196.4265	194.1407	193.9516	206.8425	214.6051	219.7812	221.4204	200.9474	178.4456	156.9767
PowerGen (Q)	7.667141	6.342329	6.353535	6.956665	6.214826	6.392643	6.654037	6.501048	9.032431	12.80725	13.58714	12.6432	13.14462	19.32287	25.72051	31.48043	31.95602	33.45643	27.13846	28.39388	37.18941	45.96555	49.13583	48.23258
Cost	217.1454	174.1239	82.96867	85.47569	80.92916	142.2211	79.67033	146.6141	22.4	21	21.2	22.6	24.8	19.6	18.4	17.5	16.9	25.6	24.7	23.5	25.9	591.87	22.4	26.3
netcon02 (Pfinal)	52.92802	43.46909	40.1157	36.96845	35.939	34.49311	39.59596	45.28566	53.84402	59.11336	65.53788	68.85348	69.87053	66.53424	64.0159	65.80874	67.92939	75.79622	78.59118	82.69714	83.52578	72.19356	60.58307	50.50407
netcon02 (Qfinal)	0.403979	8.330661	7.482728	3.933924	1.519191	0.248298	7.047957	-2.03156	1.450536	1.15408	1.69878	-2.46658	1.75468	0.351685	-2.31511	7.363111	11.75055	2.424487	3.62497	-0.80062	6.870186	1.165971	1.794675	9.832737
netcon01 (Pfinal)	74.02609	74.8563	77.43956	76.22672	74.88921	75.09539	77.46313	73.02879	77.5864	88.79715	93.34286	95.48456	93.86464	75.94599	68.23423	64.78754	61.59871	66.83343	71.9668	71.85799	64.02292	54.6663	39.02959	33.11068
netcon01 (Qfinal)	-12.2342	-9.80361	-4.6536	-4.79524	-4.53837	-8.00119	-4.46725	-6.21782	-5.34354	-5.30935	-4.54625	-4.59962	-7.12559	2.071522	4.730749	13.30772	13.58697	10.68754	6.957041	8.50682	17.61752	24.9481	27.96144	25.4385
trans042 (tap)	8	15	12	12	10	12	12	12	12	7	11	6	10	6	11	11	8	10	6	8	12	12	9	12
trans001 (tap)	11	12	11	10	11	9	12	12	12	6	7	11	8	6	7	6	12	6	6	6	13	8	11	12
trans029 (tap)	11	14	12	9	12	9	12	8	15	9	10	10	12	10	8	12	12	11	9	7	9	11	12	12
trans033 (tap)	13	11	11	12	11	9	12	15	13	12	9	10	12	13	14	8	12	14	10	14	11	12	12	12
trans005 (tap)	7	8	10	10	10	13	10	10	10	9	7	11	11	10	11	12	10	10	10	11	11	8	11	10
trans007 (tap)	9	10	10	10	6	9	10	10	8	11	8	8	6	9	6	5	6	5	8	6	4	9	9	10
trans045 (tap)	7	10	7	12	10	10	10	10	7	10	11	11	10	7	10	12	6	10	11	12	11	11	10	10
trans006 (tap)	13	10	10	10	11	10	12	9	13	12	10	11	9	11	6	12	8	7	5	9	10	10	8	10
trans046 (tap)	4	6	10	6	5	5	10	4	4	4	4	4	4	4	4	4	10	4	4	4	4	6	4	5
trans013 (tap)	11	10	10	9	9	10	13	9	12	7	9	11	6	11	9	11	10	11	11	12	12	9	11	10
trans039 (tap)	11	12	12	12	9	9	12	10	12	9	12	12	12	6	8	7	12	6	7	11	11	12	11	11
trans044 (tap)	9	12	13	12	7	11	6	12	8	9	8	8	9	15	9	8	12	6	7	10	12	13	11	10
trans028 (tap)	9	13	10	10	10	7	11	7	9	6	7	5	5	13	10	8	10	10	6	6	10	10	9	12
trans026 (tap)	10	9	10	6	7	10	9	8	4	10	7	4	10	10	4	12	10	4	7	9	8	6	8	4
trans036 (tap)	11	12	8	12	10	12	12	11	8	8	8	7	8	9	7	6	12	6	9	8	12	8	8	11
trans019 (tap)	11	12	12	8	12	12	12	12	10	11	11	8	12	12	6	12	12	7	6	6	6	6	6	6
trans040 (tap)	11	7	9	8	10	12	6	7	8	6	9	6	6	6	6	12	8	6	10	8	7	9	6	12
trans018 (tap)	8	8	12	11	8	12	12	8	6	11	6	9	6	13	15	11	12	11	8	11	9	11	7	7
trans027 (tap)	13	10	11	13	11	13	10	12	11	12	9	9	15	11	10	7	9	12	14	13	12	9	15	15
trans041 (tap)	9	14	12	13	15	12	9	13	10	8	9	13	11	11	12	12	12	10	13	11	13	14	12	11
trans002 (tap)	10	10	14	9	10	15	12	12	12	16	18	14	15	12	11	14	14	15	12	13	12	15	12	10
trans032 (tap)	9	7	11	13	7	11	9	10	9	7	8	7	7	8	7	11	10	10	8	14	12	8	11	7

Table 225 – Western network scenario 4-part 2

Period	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
trans009 (tap)	10	10	9	12	12	7	12	11	14	7	8	7	8	7	8	11	8	11	8	7	7	7	7	7
trans034 (tap)	7	4	5	4	5	7	6	8	7	6	4	5	4	5	10	5	11	12	4	4	4	6	10	12
trans023 (tap)	11	9	12	6	7	6	7	7	7	6	6	6	8	6	9	9	9	8	7	6	6	6	7	6
trans043 (tap)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
trans037 (tap)	6	6	8	15	7	7	10	7	7	9	7	7	9	7	7	7	7	6	7	6	6	6	6	6
trans011 (tap)	12	14	12	6	6	13	9	12	12	6	6	13	12	12	12	11	10	12	12	12	10	7	9	6
trans030 (tap)	11	7	12	6	7	12	7	9	11	6	6	6	6	7	7	14	9	7	12	6	7	6	7	6
trans012 (tap)	12	15	16	15	15	16	16	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	16	15
trans008 (tap)	6	15	15	16	15	15	15	16	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	16
capac012 (Mvar)	2.5	0	0	0	2.5	0	0	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	0	0	2.5	2.5	2.5	2.5	2.5	2.5	0
capac013 (Mvar)	0	0	0	0	2.5	0	0	2.5	0	2.5	2.5	2.5	2.5	2.5	2.5	0	0	2.5	2.5	2.5	0	2.5	2.5	2.5
capac014 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac015 (Mvar)	2.8	0	0	0	0	2.8	0	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	0	2.8	2.8	2.8	2.8	2.8	2.8	2.8
capac016 (Mvar)	2.8	0	0	3.4	0	3.4	0	2.8	3.4	3.4	3.4	6.2	2.8	3.4	6.2	3.4	2.8	3.4	2.8	6.2	2.8	6.2	6.2	3.4
capac017 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac018 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac021 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac022 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac001 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac002 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac003 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac004 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac005 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	3.4	0	0	0	0	3.4	0	0	0	0	0	0
capac006 (Mvar)	3.4	0	0	0	0	0	0	0	0	0	0	0	0	0	3.4	0	0	0	0	0	0	0	0	0
capac007 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac008 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac009 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac010 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac011 (Mvar)	3.4	3.4	0	0	0	3.4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac019 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac020 (Mvar)	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3

Table 226 – Western network scenario 5-part 1

Period	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
InitTotLoss (P)	70.25562	58.17646	53.16245	50.73676	47.99641	47.74034	50.32419	57.33792	67.60052	84.20067	96.97968	105.2249	108.497	97.24449	89.68774	90.00622	88.07054	99.34699	105.5282	113.4861	116.7631	103.0231	84.91445	68.96128
FinalTotLoss (P)	63.22561	53.44615	49.38459	48.07504	44.75125	46.40897	46.56075	53.47901	62.96508	77.624	88.07889	95.57203	97.26757	88.15028	79.97703	81.21497	78.96174	88.90986	96.92069	100.8795	105.5317	94.83015	79.60205	64.82913
PowerGen (P)	177.0263	162.3542	157.5832	153.7349	150.4138	149.7577	155.7495	166.8075	181.8006	201.0175	211.8971	217.6879	218.9255	201.9433	196.426	194.139	193.9448	206.8422	214.6065	219.7813	221.4189	200.9472	178.4489	156.978
PowerGen (Q)	7.640067	6.295371	6.299064	6.965421	6.224236	6.424824	6.627325	6.49546	9.033985	12.86653	13.58415	12.64385	13.125	19.32976	25.69621	31.44132	31.80109	33.45832	27.20915	28.373	37.11787	45.99326	49.19658	48.266
Cost	157.4884	251.1305	103.9867	128.8004	143.3627	71.76502	82.00389	110.695	22.3	21.4	26.3	22.8	19.8	17.6	18.6	18.6	24.7	25.9	26.9	27.2	24.8	151.0099	22.2	25.3
netcon02 (Pfinal)	52.92801	43.46666	40.11332	36.96823	35.9394	34.49386	39.59442	45.28504	53.80387	58.80473	65.14761	68.46425	69.23937	65.9709	63.61477	65.63994	67.88552	75.79644	78.59266	82.697	83.52312	72.19194	60.58511	50.50444
netcon02 (Qfinal)	2.605608	1.982412	-0.49407	-3.1453	1.427171	6.807297	4.195312	2.92649	1.862106	5.007651	-1.32076	0.092405	-2.00976	3.660357	0.770649	2.753004	2.353019	2.484247	7.156971	2.682051	2.579531	7.867286	4.879352	7.174551
netcon01 (Pfinal)	73.74266	74.71911	77.40833	76.22579	74.88935	75.09579	77.45549	73.005	77.5322	88.79327	93.34065	95.47538	93.83479	75.70975	67.83613	64.29843	61.00169	66.1941	71.38537	71.20716	63.13606	53.72352	37.9546	32.21371
netcon01 (Qfinal)	-8.86375	-14.1543	-5.34699	-4.09766	-8.06569	-4.02062	-4.59909	-6.22006	-5.34201	-5.29955	-4.53747	-4.59557	-7.46724	-1.23031	4.551888	12.93266	13.20558	11.07992	0.149851	8.500518	17.63318	19.23154	28.22163	26.03257
trans042 (tap)	11	10	12	14	10	12	12	12	12	10	7	7	8	8	7	10	6	7	8	11	11	9	10	10
trans001 (tap)	12	9	14	12	12	12	10	11	9	11	11	6	9	6	7	6	6	6	12	6	6	6	7	12
trans029 (tap)	10	11	10	12	12	12	10	11	8	13	9	11	7	12	11	12	10	6	12	11	6	15	13	11
trans033 (tap)	8	9	12	11	13	11	12	14	15	13	10	11	15	12	14	15	11	12	12	12	9	13	8	13
trans005 (tap)	13	12	9	10	10	8	10	12	13	9	8	10	11	10	13	11	9	9	10	6	9	6	4	11
trans007 (tap)	6	10	5	7	9	8	10	8	5	8	4	9	8	9	4	4	5	6	6	5	4	5	10	11
trans045 (tap)	10	9	9	10	10	10	10	10	13	7	10	8	9	9	12	13	11	11	8	6	13	10	7	13
trans006 (tap)	8	4	10	10	8	10	10	10	10	13	8	10	13	10	12	11	7	7	10	13	10	8	10	9
trans046 (tap)	4	4	4	7	6	9	7	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	9	8
trans013 (tap)	12	10	9	10	10	10	10	9	10	12	5	11	5	10	4	11	10	10	12	8	8	13	13	12
trans039 (tap)	12	12	12	13	12	12	12	12	10	12	10	12	11	12	9	13	10	9	12	7	11	9	11	12
trans044 (tap)	10	10	12	7	6	12	8	10	14	11	12	9	12	11	6	6	8	7	10	7	10	12	11	6
trans028 (tap)	7	11	7	8	10	7	4	9	7	4	9	10	7	10	4	4	4	8	4	5	10	8	7	7
trans026 (tap)	10	8	9	10	7	10	10	7	10	10	10	11	4	9	7	4	10	10	4	6	5	4	11	9
trans036 (tap)	8	12	12	12	8	12	8	12	8	12	11	11	9	9	8	10	10	6	6	6	7	7	12	12
trans019 (tap)	6	11	12	9	13	10	9	8	11	12	6	6	12	11	7	11	10	11	12	6	8	10	8	11
trans040 (tap)	8	7	7	8	6	12	7	6	6	7	12	6	6	7	8	12	6	6	7	6	11	10	8	6
trans018 (tap)	6	9	12	10	12	12	7	13	13	11	12	11	7	11	11	15	14	8	14	10	8	11	12	11
trans027 (tap)	8	9	10	8	12	12	6	10	11	14	10	13	7	14	12	12	11	15	14	13	9	15	6	13
trans041 (tap)	12	7	15	10	12	8	9	12	13	11	7	10	14	13	14	8	13	12	13	12	10	9	8	11
trans002 (tap)	9	17	16	9	12	12	14	11	9	16	9	12	12	11	11	11	12	12	13	10	13	11	11	11
trans032 (tap)	7	10	10	12	8	8	8	9	11	13	11	13	9	9	11	7	9	10	13	11	11	7	14	9

Table 227 – Western network scenario 5-part 2

Period	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
trans009 (tap)	10	7	17	9	13	14	10	7	10	11	10	7	7	7	11	7	8	9	12	10	8	9	9	11
trans034 (tap)	9	7	8	8	6	8	4	6	10	4	4	6	4	9	7	8	5	10	4	4	6	10	8	11
trans023 (tap)	7	6	6	12	6	6	6	7	7	6	6	6	6	6	6	6	6	9	6	6	6	12	9	11
trans043 (tap)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
trans037 (tap)	6	7	7	14	10	8	13	9	8	7	7	8	7	9	7	7	6	7	7	14	6	6	6	7
trans011 (tap)	8	14	12	14	10	13	8	12	13	9	6	12	14	8	6	10	6	6	6	9	10	12	10	14
trans030 (tap)	12	7	6	11	10	12	6	10	10	6	6	6	7	6	8	11	10	7	11	8	8	7	12	14
trans012 (tap)	6	15	15	15	16	15	15	15	15	15	15	15	15	15	15	15	15	14	15	15	15	15	15	16
trans008 (tap)	12	15	16	16	12	16	16	15	15	15	15	15	15	15	16	15	15	15	15	15	15	15	15	15
capac012 (Mvar)	2.5	2.5	0	2.5	2.5	0	0	2.5	2.5	0	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
capac013 (Mvar)	0	0	2.5	2.5	2.5	0	2.5	0	0	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	0	2.5	2.5	2.5	2.5	2.5
capac014 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac015 (Mvar)	0	0	2.8	2.8	0	0	0	0	2.8	2.8	2.8	2.8	2.8	0	2.8	2.8	2.8	2.8	2.8	2.8	2.8	0	2.8	2.8
capac016 (Mvar)	3.4	3.4	2.8	2.8	0	0	0	2.8	2.8	3.4	6.2	3.4	6.2	3.4	3.4	2.8	2.8	3.4	3.4	3.4	3.4	2.8	3.4	3.4
capac017 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac018 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac021 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac022 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac001 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac002 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3.3	0	0	0	0	0
capac003 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac004 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac005 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3.4	0	0	0	3.4	0	0
capac006 (Mvar)	0	3.4	0	0	3.4	0	0	0	0	0	0	0	3.4	3.4	3.4	0	0	0	3.4	0	0	0	0	0
capac007 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac008 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac009 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac010 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac011 (Mvar)	3.4	3.4	0	0	0	3.4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac019 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac020 (Mvar)	3.3	3.3	3.3	3.3	3.3	0	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	6.6	3.3	3.3

Table 228 – Western network scenario 6-part 1

Period	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
InitTotLoss (P)	93.62616	77.10974	70.62874	67.27297	63.78406	62.66582	66.90087	76.14114	90.11227	112.2208	129.1547	140.3004	143.7679	129.7848	119.9907	119.8156	117.6198	132.3938	140.7174	151.8201	156.3418	137.9958	113.2461	92.22111
FinalTotLoss (P)	83.62868	70.98611	64.49638	62.41084	61.61054	58.36105	60.76479	70.11419	83.34248	100.1191	116.2886	126.7866	128.2176	115.6822	107.1313	106.6711	107.1129	118.9112	125.7731	133.403	139.089	121.9779	101.5949	83.54902
PowerGen (P)	205.0269	188.0348	182.5075	178.0494	174.2055	173.4407	180.3835	193.1906	210.5561	232.8118	245.4151	252.1246	253.5564	233.8867	227.4987	224.8485	224.626	239.5631	248.5522	254.5478	256.4452	232.7329	206.6741	181.8053
PowerGen (Q)	9.082681	7.468621	7.446337	8.212585	7.412038	7.528263	7.813453	7.692775	10.6866	15.05308	16.00762	14.95808	15.478	22.64988	30.06267	36.64176	37.1511	39.05289	31.72987	33.18097	43.31182	53.49607	57.17306	56.06295
Cost	239.3057	197.2489	163.9671	213.2635	156.8679	210.0052	160.9666	118.3967	19.6	18.8	25.6	24.9	23.5	22.4	23.3	22.8	22.9	24.6	21.7	22.9	27.1	166.4385	28.2	29.4
netcon02 (Pfinal)	67.65743	56.72324	52.65977	49.22012	47.8871	46.29963	51.94387	58.83802	68.57311	74.25006	81.36094	85.22864	85.64179	81.83896	79.6335	82.15212	84.80401	93.85173	97.30557	101.951	103.2648	89.93457	76.67707	64.89681
netcon02 (Qfinal)	5.001408	-1.60369	0.528991	3.495848	7.936978	5.479693	-0.93092	1.227692	3.79467	3.002805	4.705623	2.523145	-0.47443	1.680714	0.446618	0.305536	1.874503	1.30251	2.012113	5.017686	1.574829	3.194523	7.304394	8.842677
netcon01 (Pfinal)	85.85966	86.58486	89.66206	88.28178	86.73344	86.97107	89.7095	85.73959	91.17234	104.1976	109.4624	111.9391	110.047	89.12816	80.06382	75.99873	72.21761	78.2527	84.24543	84.06285	74.79641	63.9132	45.69525	38.98435
netcon01 (Qfinal)	-13.4862	-9.50642	-9.22978	-12.0149	-8.8287	-11.8308	-8.12935	-6.65518	-5.50902	-5.16362	-8.26951	-7.89123	-7.40554	3.501551	6.100315	15.69253	12.61743	8.923756	8.652237	10.59184	21.1613	21.20425	32.98396	27.36115
trans042 (tap)	8	11	14	11	12	11	8	11	13	6	10	8	9	6	7	6	6	6	6	6	11	6	8	8
trans001 (tap)	8	12	12	15	12	11	10	10	11	7	6	8	6	7	9	7	12	6	6	6	6	7	7	9
trans029 (tap)	12	12	12	10	12	12	12	11	11	7	9	11	8	6	8	7	11	9	7	10	10	12	14	12
trans033 (tap)	12	12	11	12	10	12	9	12	15	11	8	12	15	12	13	12	8	15	15	10	10	10	7	10
trans005 (tap)	11	9	8	10	10	10	10	10	6	11	7	8	9	12	9	11	13	8	9	10	10	8	11	11
trans007 (tap)	6	9	6	9	10	8	4	5	7	4	4	6	5	6	10	4	7	6	4	4	9	6	8	4
trans045 (tap)	13	10	9	9	10	11	11	11	6	12	9	10	11	13	12	8	9	11	12	7	4	11	8	10
trans006 (tap)	10	10	13	9	10	10	4	8	9	13	10	10	8	10	11	13	8	8	13	10	7	10	8	9
trans046 (tap)	4	5	4	4	10	5	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	6
trans013 (tap)	10	10	10	8	10	10	9	8	9	9	9	8	10	8	7	12	6	11	13	13	11	9	8	13
trans039 (tap)	11	10	9	12	12	9	13	8	13	11	9	11	7	12	11	10	12	12	6	6	6	7	6	13
trans044 (tap)	12	8	8	8	12	7	9	9	9	8	12	12	6	12	7	9	9	6	9	6	6	7	9	7
trans028 (tap)	11	6	5	8	10	10	4	10	6	9	10	8	4	4	5	5	11	6	8	5	6	7	7	5
trans026 (tap)	11	10	4	11	10	9	8	6	12	4	5	10	4	6	4	6	8	10	8	4	4	4	5	4
trans036 (tap)	13	7	7	12	12	12	6	11	9	7	12	8	12	6	9	6	6	7	6	6	6	8	7	6
trans019 (tap)	12	9	12	12	9	8	6	13	12	6	8	6	7	8	7	8	12	6	6	7	6	6	10	7
trans040 (tap)	10	8	7	7	6	6	11	9	6	6	6	7	8	7	6	6	6	11	11	8	6	7	6	7
trans018 (tap)	7	11	12	15	13	12	11	8	12	6	11	11	6	11	12	7	10	9	6	6	6	10	10	6
trans027 (tap)	12	11	11	8	10	12	12	10	11	13	11	13	11	11	14	11	11	12	9	14	11	15	12	12
trans041 (tap)	7	11	9	13	10	14	7	6	8	13	9	8	14	12	10	12	12	8	10	13	13	13	14	14
trans002 (tap)	9	15	15	9	11	11	10	12	14	9	12	11	18	13	12	13	13	15	18	10	11	13	10	14
trans032 (tap)	8	10	7	7	8	10	10	10	11	10	13	9	10	11	8	9	14	8	7	7	10	10	10	12

Table 229 – Western network scenario 6-part 2

Period	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
trans009 (tap)	10	7	12	10	9	7	7	8	8	12	7	10	9	9	12	9	9	10	8	9	9	7	11	11
trans034 (tap)	4	4	9	4	5	5	6	8	4	7	4	8	6	5	9	11	8	6	7	4	4	4	7	10
trans023 (tap)	6	10	6	7	6	6	6	6	7	8	6	6	6	9	6	6	6	6	6	6	6	6	6	11
trans043 (tap)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
trans037 (tap)	11	7	8	9	7	9	11	9	6	8	7	7	8	7	8	8	7	7	7	7	6	6	6	7
trans011 (tap)	6	6	11	6	8	8	11	9	12	9	6	8	7	12	12	8	8	9	8	8	13	8	13	8
trans030 (tap)	9	10	9	7	6	7	11	7	6	6	6	6	6	6	7	12	6	9	9	6	6	6	11	12
trans012 (tap)	6	15	15	16	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	16
trans008 (tap)	7	15	15	15	15	16	15	15	16	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
capac012 (Mvar)	2.5	2.5	2.5	2.5	0	0	0	2.5	0	2.5	2.5	2.5	2.5	0	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
capac013 (Mvar)	0	2.5	2.5	0	0	2.5	2.5	0	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
capac014 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac015 (Mvar)	0	2.8	0	2.8	0	0	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
capac016 (Mvar)	2.8	2.8	2.8	0	0	0	2.8	3.4	2.8	3.4	2.8	3.4	6.2	6.2	6.2	6.2	6.2	6.2	6.2	3.4	6.2	6.2	3.4	3.4
capac017 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac018 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac021 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac022 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac001 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac002 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3.3	0	0
capac003 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac004 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1.4	0	0
capac005 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	3.4	0	0	0	0	0	0	0	0	0	0	0	0
capac006 (Mvar)	3.4	3.4	0	3.4	0	3.4	0	0	0	0	3.4	0	3.4	0	3.4	0	3.4	3.4	0	0	0	3.4	0	0
capac007 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac008 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac009 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac010 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac011 (Mvar)	3.4	0	3.4	3.4	3.4	3.4	3.4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac019 (Mvar)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
capac020 (Mvar)	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	6.6	3.3	3.3	3.3	3.3	3.3	6.6

French Networks

Table 230 – Network 5 winter scenario 2.

Period	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
InitTotLoss (P)	2017.361	2135.597	1886.544	1436.684	1303.755	1230.915	1383.681	1874.155	2181.177	1662.677	1320.225	1428.397	1555.368	1338.49	1053.525	891.7593	829.5078	977.815	1866.969	1873.104	1388.229	1126.784	783.3125	1975.445
InitTotLoss (Q)	13442.53	15090.16	11621.12	7439.659	6322.687	5573.019	6577.378	12033.5	14990.05	8843.351	5029.81	5766.904	6122.726	4338.593	2691.096	1565.714	1293.937	2452.981	11107.2	10582.42	5831.416	3948.406	441.262	13848.26
FinalTotLoss (P)	1392.312	1390.745	1300.424	1059.417	958.2344	914.9544	992.3149	1284.153	1391.799	1170.582	990.8172	1051.944	1154.433	1015.448	811.2741	699.9646	656.5215	743.0554	1287.331	1276.908	1024.449	835.6954	634.9976	1332.611
FinalTotLoss (Q)	13593.32	14038.57	11881.61	7949.759	6640.543	6021.062	6807.198	13008.82	14008	9138.282	5501.124	5946.095	6414.052	4509.827	2815.435	1706.448	1595.575	2285.738	11476.6	10086.19	5967.841	3692.649	596.3633	13400.68
PowerGen (P)	115.3362	118.8393	105.6748	96.22394	90.05609	85.88896	85.10689	104.5398	112.6826	93.15727	78.69555	80.73615	81.56413	74.65791	69.0198	64.209	62.65675	68.73938	103.337	101.5631	85.2147	77.64383	59.11879	117.7462
PowerGen (Q)	47.58153	48.86209	43.23712	36.61494	33.56423	31.79483	32.5473	44.0199	47.34157	37.3201	29.79345	30.82838	31.63203	27.70702	24.28094	21.73062	21.08958	23.58117	42.43514	40.60136	31.89357	27.34946	18.96582	47.82656
Cost (€)	3921.075	6695.103	2561.247	161.1024	9	3	3	2943.778	5170.317	42.28317	9	6	9	9	3	0	6	9	2525.167	1690.737	9	6	6	5092.023
N1sync02 (P)	0.443911	0.376541	0.270786	0.497128	0.396543	0.338469	0.125705	0.14508	0.106382	0.125705	0.14508	0.106382	0.106382	0.125705	0.183779	0.212764	0.193441	0.206184	0.244882	0.254544	0.293242	0.293242	0.273867	0.490548
N1sync03 (P)	1.297409	1.100508	0.79142	1.452946	1.158968	0.989237	0.367396	0.424024	0.31092	0.367396	0.424024	0.31092	0.31092	0.367396	0.537127	0.621841	0.565365	0.602609	0.715712	0.74395	0.857053	0.857053	0.800425	1.433714
N1sync05 (P)	0.596076	0.505613	0.363606	0.667535	0.532471	0.45449	0.168795	0.194812	0.142848	0.168795	0.194812	0.142848	0.142848	0.168795	0.246776	0.285696	0.259749	0.27686	0.328824	0.341797	0.393761	0.393761	0.367744	0.658699
N1sync01 (P)	1.441566	1.222787	0.879355	1.614384	1.287742	1.099152	0.408218	0.471138	0.345467	0.408218	0.471138	0.345467	0.345467	0.408218	0.596808	0.690934	0.628184	0.669565	0.795236	0.826611	0.952282	0.952282	0.889361	1.593015
N1sync04 (P)	1.166982	0.989875	0.711859	1.306883	1.042458	0.889789	0.330462	0.381397	0.279664	0.330462	0.381397	0.279664	0.279664	0.330462	0.483131	0.559328	0.50853	0.542029	0.643762	0.669161	0.770895	0.770895	0.719959	1.289584
FlexL063 (P)	0.2602	0.2602	0	0	0	0	0	0	0.2602	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.2602
FlexL169 (P)	0.0946	0.0946	0	0	0	0	0	0	0.0946	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0946
Flexsc02 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc03 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc05 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc01 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc04 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
N2sync06 (P)	4.613011	3.912919	2.813937	5.16603	4.120776	3.517285	1.306296	1.507641	1.105495	1.306296	1.507641	1.105495	1.105495	1.306296	1.909787	2.210989	2.010187	2.142608	2.544754	2.645155	3.047301	3.047301	2.845957	5.097649
Flexsc06 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RHTB0001 (Pinit)	71.69029	74.25656	68.15957	59.20422	56.39445	54.45462	56.56211	68.10921	73.56519	62.07674	53.13689	55.03778	56.24511	51.47297	46.50495	42.73182	41.60659	45.57643	67.13992	66.33534	55.55466	50.2281	38.71188	71.88019
RHTB0001 (Pfinal)	71.14286	73.62757	67.65076	58.8594	56.07607	54.15931	56.22411	67.62576	72.95364	61.64835	52.84165	54.70348	55.89066	51.17791	46.29067	42.55982	41.45359	45.3665	66.64274	65.81621	55.22244	49.95983	38.57214	71.31912
RHTB0001 (Qinit)	5.491718	6.116106	3.846654	3.222644	2.439511	1.903935	1.187686	3.651047	4.742921	1.935156	0.284603	0.349817	0.147435	-0.39049	-0.43964	-0.54066	-0.50762	-0.17311	3.333577	2.957773	1.194042	0.745783	-0.62517	6.224553
RHTB0001 (Qfinal)	23.74253	24.46248	23.74361	21.37516	19.43868	18.25971	18.51387	23.70344	23.34515	21.19386	16.86592	17.35845	18.03823	15.6588	13.68315	11.98072	11.56037	12.91698	24.11474	23.59655	18.19905	15.43474	10.61651	24.53849
RHTB0002 (Pinit)	34.35719	36.86456	32.27043	26.69209	25.46825	24.46202	26.22932	33.89654	37.26124	28.86585	22.76402	23.78409	23.42919	20.79945	18.79158	17.08168	17.05257	18.95039	31.50352	30.34277	23.70931	21.3923	14.65668	35.5908
RHTB0002 (Pfinal)	34.27956	36.7487	32.1931	26.65963	25.44106	24.44123	26.1759	33.78995	37.08341	28.80205	22.7298	23.7419	23.3827	20.77313	18.77173	17.06764	17.03771	18.93303	31.42105	30.26571	23.67773	21.36947	14.64934	35.50904
RHTB0002 (Qinit)	10.54786	11.02944	8.778523	8.409498	7.428733	6.789961	5.951587	8.543177	9.556075	6.92363	5.277588	5.324602	5.137791	4.510672	4.392617	4.167572	4.053867	4.601499	8.452093	8.071182	6.274074	5.631724	3.899677	11.26483
RHTB0002 (Qfinal)	13.85601	14.86857	12.46793	10.65113	9.902667	9.417968	9.181437	13.09634	14.33983	10.7337	8.12839	8.463462	8.0866	7.078905	6.315321	5.715415	5.600365	6.511601	12.04175	11.28678	8.669297	7.651955	4.79227	14.66451
Nt1Tr002 (tap)	6	8	6	6	7	7	7	5	7	7	6	7	6	7	7	7	6	9	6	8	7	9	7	8
Nt1Tr001 (tap)	7	9	7	6	7	7	7	5	8	7	6	7	6	7	7	7	6	9	6	8	7	9	7	8
Nt2Tr003 (tap)	9	10	8	10	8	6	7	7	11	6	7	7	9	7	9	9	9	8	9	10	9	9	9	9
Nt2Tr004 (tap)	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17

Table 231 – Network 5 winter scenario 3.

Period	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
InitTotLoss (P)	1873.949	1982.153	1755.986	1343.084	1217.4	1149.298	1294.638	1748.76	2034.868	1554.333	1235.441	1337.936	1456.579	1253.732	986.4347	835.5593	777.7295	915.4484	1738.557	1744.422	1295.278	1052.886	735.5547	1835.828
InitTotLoss (Q)	12179.59	13742.37	10551.95	6577.941	5563.3	4879.495	5887.295	10992.99	13777.68	8011.692	4428.96	5133.632	5466.716	3786.79	2226.556	1166.187	916.3442	1997.969	10081.49	9586.437	5132.384	3373.289	103.7235	12541.25
FinalTotLoss (P)	1276.145	1347.423	1204.491	1008.203	902.7737	846.5279	928.2305	1141.866	1309.491	1089.989	912.8814	995.2392	1070.428	945.8446	758.9518	650.745	614.8012	710.5565	1198.245	1205.759	964.9127	788.439	592.748	1249.708
FinalTotLoss (Q)	11835.39	13875.85	10613.31	7165.071	5809.297	4855.828	5971.017	10203.22	12782.33	8029.622	4291.376	5451.253	5234.333	3640.781	2177.038	1017.872	1062.479	2146.759	10116.15	9265.587	5292.049	3156.429	18.83473	12252.99
PowerGen (P)	111.9321	115.4069	102.5671	93.42667	87.42967	83.36867	82.61566	101.418	109.3889	90.42242	76.37543	78.38014	79.15985	72.46334	66.99927	62.32425	60.82297	66.74482	100.3032	98.59815	82.7258	75.38022	57.38955	114.3041
PowerGen (Q)	44.84283	47.69442	41.06416	35.00294	31.95627	29.88722	30.96881	40.31975	45.154	35.39913	27.88322	29.61597	29.72461	26.16911	23.02312	20.45977	19.98956	22.82791	40.18134	38.90014	30.46966	26.13059	17.85898	45.68545
Cost (€)	4302.229	6348.089	2949.18	6	6	6	6	2670.968	4520.766	6	6	6	6	0	0	6	6	0	2201.521	1254.641	6	6	0	5344.497
N1sync02 (P)	0.46205	0.391927	0.28185	0.517441	0.412746	0.352299	0.130842	0.151009	0.110729	0.130842	0.151009	0.110729	0.110729	0.130842	0.191289	0.221458	0.201345	0.214609	0.254888	0.264945	0.305225	0.305225	0.285058	0.510592
N1sync03 (P)	1.350424	1.145477	0.823759	1.512316	1.206326	1.029659	0.382408	0.44135	0.323625	0.382408	0.44135	0.323625	0.323625	0.382408	0.559075	0.64725	0.588467	0.627232	0.744957	0.774349	0.892074	0.892074	0.833132	1.492298
N1sync05 (P)	0.620433	0.526273	0.378464	0.694812	0.554229	0.473062	0.175692	0.202772	0.148685	0.175692	0.202772	0.148685	0.148685	0.175692	0.256859	0.29737	0.270363	0.288173	0.34226	0.355763	0.409851	0.409851	0.382771	0.685615
N1sync01 (P)	1.500471	1.272752	0.915287	1.680351	1.340362	1.144065	0.424898	0.490389	0.359583	0.424898	0.490389	0.359583	0.359583	0.424898	0.621195	0.719167	0.653852	0.696925	0.82773	0.860388	0.991193	0.991193	0.925702	1.658109
N1sync04 (P)	1.214667	1.030323	0.740947	1.360284	1.085055	0.926148	0.343965	0.396982	0.291091	0.343965	0.396982	0.291091	0.291091	0.343965	0.502872	0.582183	0.529309	0.564177	0.670067	0.696504	0.802395	0.802395	0.749378	1.342278
FlexL063 (P)	0.2602	0.2602	0	0	0	0	0	0	0.2602	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.2602
FlexL169 (P)	0.0946	0.0946	0	0	0	0	0	0	0.0946	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0946
Flexsc02 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc03 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc05 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc01 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc04 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
N2sync06 (P)	4.801507	4.072808	2.928919	5.377123	4.289158	3.661008	1.359674	1.569246	1.150667	1.359674	1.569246	1.150667	1.150667	1.359674	1.987824	2.301334	2.092327	2.230159	2.648737	2.753241	3.171819	3.171819	2.962248	5.305948
Flexsc06 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RHTB0001 (Pinit)	69.19131	71.73457	65.91797	57.05654	54.41231	52.57717	54.79064	65.97425	71.28397	60.13687	51.44916	53.32335	54.49098	49.84772	44.98656	41.30454	40.22961	44.06971	64.94924	64.15898	53.67456	48.51159	37.35571	69.34197
RHTB0001 (Pfinal)	68.65909	71.19334	65.43919	56.74491	54.12309	52.30017	54.47969	65.47547	70.70647	59.74291	51.16208	53.02427	54.14693	49.56894	44.7837	41.13407	40.08125	43.88801	64.48142	63.68388	53.37128	48.26654	37.22068	68.82396
RHTB0001 (Qinit)	5.135425	5.715145	3.546096	3.025376	2.269993	1.753704	1.019473	3.344141	4.365137	1.714279	0.162748	0.211412	0.008405	-0.48745	-0.50348	-0.58085	-0.54715	-0.23709	3.052441	2.693995	1.052234	0.645589	-0.63662	5.849241
RHTB0001 (Qfinal)	24.45947	23.96361	24.09968	20.19914	18.29955	16.95802	17.70172	23.10705	22.05978	20.32912	15.6743	16.79584	16.79055	14.70178	12.78075	11.24541	11.01335	12.60092	23.28079	22.36897	17.41339	14.70247	9.935795	25.18731
RHTB0002 (Pinit)	33.03423	35.51272	31.13141	25.5627	24.44413	23.50805	25.37396	32.79893	36.09117	27.93242	21.99709	23.01511	22.67065	20.10455	18.114	16.43369	16.41916	18.2522	30.4056	29.27265	22.80906	20.55856	14.03698	34.19859
RHTB0002 (Pfinal)	32.96863	35.41921	31.05868	25.53943	24.4187	23.48225	25.31849	32.69081	35.94329	27.86203	21.9616	22.97148	22.62853	20.07692	18.09645	16.42141	16.40606	18.23553	30.33311	29.20907	22.78196	20.54113	14.03059	34.13045
RHTB0002 (Qinit)	10.20442	10.63757	8.468628	8.198554	7.230571	6.602667	5.730848	8.204569	9.157063	6.660309	5.097539	5.129808	4.950067	4.35714	4.264674	4.060083	3.944789	4.47244	8.151544	7.791558	6.095059	5.480919	3.825294	10.89909
RHTB0002 (Qfinal)	13.23864	14.31102	11.78038	10.22637	9.348575	8.718082	8.961959	12.34394	13.92468	9.970595	7.674253	7.985106	7.710895	6.653011	5.999115	5.419938	5.397993	6.208553	11.46308	10.92101	8.303279	7.315943	4.624558	13.9303
Nt1Tr002 (tap)	8	6	7	6	7	8	7	9	8	7	8	6	8	8	8	9	7	7	7	8	7	9	9	8
Nt1Tr001 (tap)	8	7	7	6	7	8	7	9	9	7	8	6	8	8	8	9	7	7	7	8	7	9	9	8
Nt2Tr003 (tap)	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Nt2Tr004 (tap)	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17

Table 232 – Network 5 winter scenario 4.

Period	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
InitTotLoss (P)	2041.869	2156.384	1919.409	1493.097	1339.151	1258.757	1426.479	1868.803	2242.393	1718.511	1357.533	1478.249	1611.435	1380.745	1077.004	909.5553	845.8975	997.5542	1908.831	1914.507	1416.132	1149.781	804.0851	2008.267
InitTotLoss (Q)	13344.8	15153.42	11901.19	7295.691	6274.598	5579.918	6941.185	12318.53	15660.68	9311.161	5295.795	6131.789	6505.032	4608.54	2813.306	1618.794	1359.149	2538.862	11428.56	10866.6	5902.637	3971.432	416.8862	13686.43
FinalTotLoss (P)	1433.239	1474.736	1337.039	1130.7	995.0569	942.5435	1025.027	1252.45	1410.416	1171.672	1005.429	1081.186	1165.496	1034.967	820.1097	713.3782	662.7195	786.8869	1315.917	1333.289	1039.098	878.6922	654.9016	1437.771
FinalTotLoss (Q)	13142.79	15319.71	12294.98	7629.817	6276.983	5841.104	7313.277	12365.8	14059.24	8618.101	5388.774	6169.977	5959.675	4434.859	2569.434	1619.921	1364.154	3109.043	11374.93	10860.82	5542.315	4182.236	455.0511	14286.71
PowerGen (P)	118.4383	122.0786	108.5155	98.85185	92.4866	88.19956	87.39943	107.2822	115.6911	95.62973	80.79779	82.9062	83.73546	76.65592	70.8611	65.92863	64.32533	70.61	106.1072	104.3138	87.49118	79.75033	60.71015	120.9788
PowerGen (Q)	48.04402	51.07866	44.493	37.06487	33.92414	32.30869	33.74536	44.21032	48.2883	37.55799	30.33424	31.7212	31.85514	28.25579	24.61159	22.18202	21.37699	24.9768	43.16516	42.1957	32.16451	28.47455	19.31833	49.63733
Cost (€)	5921.875	10225.04	3051.404	581.7899	6	6	6	3228.421	9513.022	529.0631	6	0	6	6	6	6	0	6	2480.686	2507.415	6	6	6	7637.436
N1sync02 (P)	0.601885	0.51054	0.36715	0.67404	0.53766	0.45892	0.17044	0.19671	0.14424	0.17044	0.19671	0.14424	0.14424	0.17044	0.24918	0.28848	0.26228	0.279558	0.332028	0.345128	0.397598	0.397598	0.371328	0.665118
N1sync03 (P)	1.759118	1.492146	1.073062	1.970005	1.571409	1.341275	0.498141	0.574921	0.421567	0.498141	0.574921	0.421567	0.421567	0.498141	0.728275	0.843135	0.766561	0.817058	0.970412	1.008699	1.162052	1.162052	1.085272	1.943928
N1sync05 (P)	0.808201	0.685545	0.493003	0.90509	0.721961	0.61623	0.228864	0.264139	0.193683	0.228864	0.264139	0.193683	0.193683	0.228864	0.334595	0.387366	0.352186	0.375386	0.445842	0.463432	0.533888	0.533888	0.498613	0.89311
N1sync01 (P)	1.954575	1.65794	1.192291	2.188894	1.74601	1.490306	0.55349	0.638801	0.468408	0.55349	0.638801	0.468408	0.468408	0.55349	0.809194	0.936816	0.851735	0.907843	1.078236	1.120776	1.291169	1.291169	1.205858	2.15992
N1sync04 (P)	1.582275	1.342141	0.965188	1.771962	1.413437	1.206438	0.448063	0.517125	0.379188	0.448063	0.517125	0.379188	0.379188	0.448063	0.655062	0.758375	0.6895	0.73492	0.872857	0.907295	1.045232	1.045232	0.976171	1.748507
FlexL063 (P)	0.2602	0.2602	0	0	0	0	0	0.2602	0.2602	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.2602
FlexL169 (P)	0.0946	0.0946	0	0	0	0	0	0.0946	0.0946	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0946
FlexL117 (P)	0.0732	0.0732	0	0	0	0	0	0.0732	0.0732	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0732
FlexL001 (P)	0.064	0.064	0	0	0	0	0	0.064	0.064	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.064
FlexL002 (P)	0.0542	0.0542	0.0542	0	0	0	0	0.0542	0.0542	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0542
FlexL003 (P)	0.053	0.053	0	0	0	0	0	0.053	0.053	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.053
FlexL005 (P)	0.0386	0.0386	0.0386	0	0	0	0	0.0386	0.0386	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0386
FlexL007 (P)	0.0446	0.0446	0	0	0	0	0	0.0446	0.0446	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0446
Flexsc02 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc03 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc05 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc01 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc04 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
N2sync06 (P)	6.25464	5.305406	3.81533	7.004461	5.587233	4.768979	1.771167	2.044164	1.498906	1.771167	2.044164	1.498906	1.498906	1.771167	2.589421	2.997812	2.725551	2.905096	3.450354	3.586484	4.131742	4.131742	3.858745	6.911745
Flexsc06 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL200 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RHTB0001 (Pinit)	71.60857	74.50204	68.96694	58.92902	56.42322	54.65083	57.62943	68.67248	74.83625	63.29765	54.03651	56.14032	57.38292	52.40334	47.07382	43.08791	42.0056	46.03457	68.03771	67.17389	55.95085	50.48104	38.72988	71.63075
RHTB0001 (Pfinal)	71.05609	73.90802	68.37074	58.58285	56.09892	54.35587	57.28594	68.17194	74.16823	62.82572	53.72026	55.78929	56.98136	52.08711	46.84145	42.90812	41.83594	45.84641	67.51627	66.65442	55.59722	50.22609	38.58709	71.11675
RHTB0001 (Qinit)	6.087768	6.705227	4.293188	3.742271	2.87877	2.291966	1.435705	4.139011	5.18824	2.224132	0.507304	0.557976	0.353962	-0.20329	-0.22808	-0.31703	-0.2981	0.060012	3.735615	3.350466	1.534363	1.068391	-0.3607	6.864967
RHTB0001 (Qfinal)	23.75993	25.91392	23.43598	21.38338	19.37281	18.64591	19.29937	23.05449	23.52382	21.33577	17.19414	17.88743	18.18316	15.94392	13.49122	12.33568	11.71532	13.91268	22.9597	23.56295	18.12934	16.14024	10.7047	25.64143
RHTB0002 (Pinit)	33.79525	36.58212	32.21471	25.77081	24.82979	23.98282	26.50131	34.30778	37.89848	29.20876	22.87754	24.05697	23.69249	20.92639	18.66986	16.8189	16.85301	18.75835	31.51266	30.28928	23.3557	20.97871	14.13193	34.91387
RHTB0002 (Pfinal)	33.73908	36.49448	32.14394	25.75455	24.80997	23.96154	26.44333	34.19196	37.73452	29.13385	22.84167	24.01092	23.64811	20.89865	18.65392	16.80852	16.84158	18.74373	31.44118	30.22753	23.33227	20.96256	14.12708	34.85735
RHTB0002 (Qinit)	11.33391	11.75764	9.352536	9.232944	8.114066	7.39478	6.304158	9.000651	10.02334	7.307943	5.628149	5.636883	5.444339	4.817885	4.763441	4.569647	4.429217	5.00436	8.992284	8.6104	6.814572	6.160833	4.379296	12.11227
RHTB0002 (Qfinal)	13.99633	15.24611	12.57186	10.88912	9.954309	9.326833	9.341154	13.22809	15.06207	10.71104	8.206643	8.587693	8.300786	7.115687	6.406477	5.838497	5.791138	6.649615	12.21012	11.64765	8.838234	7.808882	4.89916	14.67798
Nt1Tr002 (tap)	7	6	6	7	8	7	6	6	9	9	7	7	9	8	9	8	8	5	7	7	9	7	8	6
Nt1Tr001 (tap)	8	7	6	7	8	7	6	7	10	9	7	7	9	8	9	8	8	5	7	7	9	7	8	6
Nt2Tr003 (tap)	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Nt2Tr004 (tap)	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17

Table 233 – Network 5 winter scenario 5.

Period	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
InitTotLoss (P)	1811.121	1837.058	1645.207	1323.219	1169.83	1092.821	1229.235	1656.773	1920.141	1478.322	1170.27	1277.641	1392.332	1193.196	930.9484	789.6172	734.7286	863.3207	1629.012	1634.771	1219.8	996.4696	708.1834	1791.713
InitTotLoss (Q)	10810.97	12153.47	9519.926	5393.808	4585.276	4031.904	5401.651	10284.7	12977.9	7457.515	3952.321	4720.802	5043.628	3376.403	1772.68	724.06	513.1741	1519.446	9132.863	8637.01	4338.598	2686.632	-333.748	11060.65
FinalTotLoss (P)	1327.753	1287.953	1170.035	1031.128	901.5538	839.4723	899.8188	1143.99	1253.554	1047.77	882.1888	963.3055	1030.952	910.0425	732.7769	631.331	586.7263	677.3249	1149.333	1184.549	934.2024	770.9372	585.3812	1322.899
FinalTotLoss (Q)	11444.24	12339.89	9902.985	5308.602	4663.394	4143.333	5788.126	10946.22	12481.62	7523.002	4080.349	5194.599	4858.573	3322.366	1929.436	752.7163	542.2451	1542.137	9262.37	9224.241	4554.172	2583.566	-382.396	11656.44
PowerGen (P)	111.19	114.5294	101.8056	92.78669	86.80785	82.76971	82.00137	100.7009	108.5578	89.73949	75.8035	77.79314	78.5603	71.91458	66.49801	61.86269	60.36362	66.23797	99.54345	97.87839	82.10868	74.8277	56.97516	113.5664
PowerGen (Q)	44.21471	45.9158	40.13463	32.94612	30.6227	28.99472	30.60662	40.84633	44.62115	34.69618	27.50295	29.18543	29.17319	25.68886	22.62596	20.05554	19.33435	22.07489	39.11187	38.64592	29.55111	25.39247	17.33022	44.8491
Cost (€)	3706.572	5440.151	2338.075	9	9	3	9	3025.015	4109.613	3	0	9	9	3	9	6	0	0	1523.709	1256.399	9	9	3	4518.739
N1sync02 (P)	0.671473	0.569567	0.409598	0.751971	0.599823	0.511978	0.190145	0.219453	0.160916	0.190145	0.219453	0.160916	0.160916	0.190145	0.27799	0.321833	0.292604	0.311879	0.370416	0.38503	0.443567	0.443567	0.414259	0.742017
N1sync03 (P)	1.9625	1.664662	1.197125	2.19777	1.75309	1.496349	0.555734	0.641391	0.470307	0.555734	0.641391	0.470307	0.470307	0.555734	0.812475	0.940615	0.855188	0.911524	1.082608	1.125321	1.296405	1.296405	1.210747	2.168678
N1sync05 (P)	0.901643	0.764805	0.550002	1.009734	0.805432	0.687476	0.255324	0.294678	0.216076	0.255324	0.294678	0.216076	0.216076	0.255324	0.37328	0.432152	0.392904	0.418786	0.497388	0.517012	0.595614	0.595614	0.55626	0.996368
N1sync01 (P)	2.180556	1.849625	1.330139	2.441966	1.947878	1.66261	0.617482	0.712657	0.522564	0.617482	0.712657	0.522564	0.522564	0.617482	0.90275	1.045128	0.950209	1.012804	1.202897	1.250356	1.44045	1.44045	1.345275	2.409643
N1sync04 (P)	1.765212	1.497315	1.076779	1.97683	1.576853	1.345922	0.499867	0.576913	0.423028	0.499867	0.576913	0.423028	0.423028	0.499867	0.730798	0.846056	0.769217	0.819889	0.973774	1.012193	1.166078	1.166078	1.089032	1.950663
FlexL063 (P)	0	0.2602	0	0	0	0	0	0	0.2602	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL169 (P)	0	0.0946	0	0	0	0	0	0	0.0946	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL117 (P)	0	0.0732	0	0	0	0	0	0	0.0732	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL001 (P)	0	0.064	0	0	0	0	0	0	0.064	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL002 (P)	0	0.0542	0	0	0	0	0	0	0.0542	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL003 (P)	0	0.053	0	0	0	0	0	0	0.053	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL005 (P)	0	0.0386	0	0	0	0	0	0	0.0386	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL007 (P)	0	0.0446	0	0	0	0	0	0	0.0446	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc02 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc03 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc05 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc01 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc04 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
N2sync06 (P)	6.977779	5.918799	4.256445	7.814292	6.233209	5.320351	1.975943	2.280502	1.672204	1.975943	2.280502	1.672204	1.672204	1.975943	2.888801	3.344409	3.04067	3.240973	3.849271	4.001141	4.609439	4.609439	4.304879	7.710856
Flexsc06 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL200 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RHTB0001 (Pinit)	66.58183	68.73544	63.90424	53.88705	51.81465	50.31276	53.68144	64.66695	69.79645	58.98304	50.25561	52.33088	53.4868	48.7729	43.63214	39.82287	38.86474	42.60165	63.08659	62.24641	51.63961	46.5264	35.5741	66.48324
RHTB0001 (Pfinal)	66.12976	68.24242	63.4676	53.60002	51.55719	50.06958	53.397	64.23213	69.27296	58.61034	49.99425	52.04728	53.16	48.51043	43.45145	39.67331	38.7262	42.43135	62.65725	61.83436	51.36863	46.30907	35.45651	66.04959
RHTB0001 (Qinit)	5.262354	5.889831	3.659706	3.399111	2.577527	2.022283	1.085438	3.369509	4.377427	1.757051	0.262615	0.269549	0.06363	-0.39687	-0.33651	-0.36653	-0.34958	-0.04379	3.155597	2.810319	1.273157	0.900928	-0.33298	6.008284
RHTB0001 (Qfinal)	24.37564	25.44533	23.2413	18.46461	17.47664	16.27435	17.3249	23.49119	22.61516	19.72464	15.34079	16.52519	16.53142	14.4784	12.5023	11.01439	10.3956	12.29235	22.41171	22.28457	16.66551	14.01738	9.62038	25.10531
RHTB0002 (Pinit)	30.63243	33.3959	29.55652	22.99926	22.34522	21.68567	24.55486	31.8212	35.28049	27.09252	21.10841	22.31156	21.9698	19.32903	17.07163	15.26625	15.34458	17.10069	28.96021	27.7912	21.20313	18.97347	12.60216	31.57377
RHTB0002 (Pfinal)	30.60109	33.33979	29.5179	22.99411	22.33438	21.67545	24.50987	31.74319	35.13739	27.03465	21.08366	22.28076	21.93521	19.30965	17.06047	15.25919	15.33663	17.09077	28.90985	27.75298	21.1885	18.96708	12.5982	31.53859
RHTB0002 (Qinit)	10.70616	10.99965	8.745281	8.921854	7.796866	7.082783	5.853841	8.29465	9.174252	6.763641	5.271167	5.23896	5.061942	4.516468	4.535893	4.396664	4.246737	4.781168	8.398332	8.065781	6.506496	5.919155	4.300095	11.45027
RHTB0002 (Qfinal)	12.43952	13.66144	11.48125	9.959321	9.07412	8.509465	8.80893	12.27948	13.43886	9.703944	7.478063	7.897671	7.544237	6.521291	5.89861	5.290619	5.233672	6.05117	11.06371	10.53249	8.062013	7.066184	4.44594	12.93531
Nt1Tr002 (tap)	6	7	7	9	8	8	6	6	7	7	7	6	8	8	7	8	8	8	7	6	7	9	9	6
Nt1Tr001 (tap)	6	7	7	9	8	8	6	6	7	7	7	6	8	8	7	8	8	8	7	6	7	9	9	6
Nt2Tr003 (tap)	9	9	7	8	9	8	9	7	11	9	9	7	9	8	9	9	9	9	9	8	9	8	9	10
Nt2Tr004 (tap)	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17

Table 234 – Network 5 winter scenario 6.

Period	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
InitTotLoss (P)	2791.588	2901.118	2474.354	2094.026	1793.155	1647.345	1826.323	2502.262	2943.649	2217.647	1729.131	1903.144	2080.754	1765.896	1360.747	1150.668	1064.695	1260.944	2443.314	2450.604	1818.024	1482.033	1049.648	2798.328
InitTotLoss (Q)	17477.79	20153.6	15881.11	9476.724	8370.974	7621.461	10040.78	17369.95	21582.58	13149.29	7830.388	9077.414	9572.776	7019.3	4514.797	2926.764	2635.644	4104.02	15358.64	14596.58	8135	5704.758	1337.348	17789.56
FinalTotLoss (P)	2076.262	1974.874	1670.479	1723.668	1375.821	1281.428	1287.711	1624.536	1755.268	1505.161	1273.679	1389.563	1510.912	1336.216	1039.229	897.8057	842.0815	986.4198	1686.177	1720.05	1384.135	1160.878	873.6838	2030.137
FinalTotLoss (Q)	16543.14	19330.56	14334.61	10080.76	8085.177	8374.631	10443.34	16863.89	18669.93	12335.29	8149.718	9703.234	9501.946	7725.59	4440.612	2695.468	2837.905	4548.81	14889.95	14157.72	8719.869	6262.569	1522.627	15681.8
PowerGen (P)	136.3144	140.3421	124.635	113.8379	106.3428	101.3902	100.3839	123.271	132.868	109.8757	92.81828	95.2662	96.24232	88.09514	81.39633	75.71841	73.88513	81.09355	121.9118	119.8682	100.5695	91.64925	69.77728	139.178
PowerGen (Q)	56.58372	60.3565	51.27502	43.8512	39.80415	38.73991	40.76851	53.39875	57.94052	45.53771	36.76789	39.01646	39.21128	35.05503	29.72925	26.28622	25.80388	29.63733	51.36239	50.10773	39.26306	34.13267	23.16847	56.23921
Cost (€)	1909.078	6660.649	1260.136	6	9	9	3	3071.925	6735.308	9	9	6	9	9	6	9	9	6	1041.474	284.5719	6	0	9	3100.637
N1sync02 (P)	1.014135	0.860225	0.618622	1.135712	0.905921	0.773248	0.287179	0.331443	0.243034	0.287179	0.331443	0.243034	0.243034	0.287179	0.419852	0.486069	0.441924	0.471036	0.559445	0.581517	0.669926	0.669926	0.625662	1.120679
N1sync03 (P)	2.963992	2.514163	1.808035	3.319323	2.647717	2.259957	0.839333	0.968702	0.710312	0.839333	0.968702	0.710312	0.710312	0.839333	1.227093	1.420624	1.291603	1.376687	1.635078	1.699588	1.957979	1.957979	1.828609	3.275386
N1sync05 (P)	1.361764	1.155096	0.830676	1.525015	1.216456	1.038305	0.385619	0.445056	0.326343	0.385619	0.445056	0.326343	0.326343	0.385619	0.56377	0.652685	0.593409	0.632499	0.751213	0.780851	0.899565	0.899565	0.840128	1.504829
N1sync01 (P)	3.293325	2.793514	2.008928	3.688137	2.941908	2.511063	0.932592	1.076336	0.789236	0.932592	1.076336	0.789236	0.789236	0.932592	1.363437	1.578471	1.435115	1.529653	1.816753	1.888431	2.175532	2.175532	2.031788	3.639318
N1sync04 (P)	2.666025	2.261416	1.626275	2.985634	2.381544	2.032766	0.754956	0.87132	0.638905	0.754956	0.87132	0.638905	0.638905	0.754956	1.103734	1.27781	1.16176	1.23829	1.470705	1.52873	1.761145	1.761145	1.644781	2.946114
FlexL063 (P)	0	0	0	0	0	0	0	0	0.2602	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL169 (P)	0	0	0	0	0	0	0	0	0.0946	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL117 (P)	0	0	0	0	0	0	0	0	0.0732	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL090 (P)	0	0	0	0	0	0	0	0	0.0568	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL001 (P)	0	0	0	0	0	0	0	0	0.064	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL002 (P)	0	0	0	0	0	0	0	0	0.0542	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL003 (P)	0	0	0	0	0	0	0	0	0.053	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL005 (P)	0	0	0	0	0	0	0	0	0.0386	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL007 (P)	0	0	0	0	0	0	0	0	0.0446	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL009 (P)	0	0	0	0	0	0	0	0	0.031	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL011 (P)	0	0.0282	0	0	0	0	0	0	0.0282	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL012 (P)	0	0	0	0	0	0	0	0	0.0514	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL016 (P)	0	0	0	0	0	0	0	0	0.029	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL019 (P)	0	0	0	0	0	0	0	0	0.0472	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc02 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc03 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc05 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc01 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc04 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
N2sync06 (P)	10.53864	8.939246	6.42857	11.80204	9.414105	8.035403	2.984295	3.444276	2.525554	2.984295	3.444276	2.525554	2.525554	2.984295	4.362997	5.051108	4.592367	4.894888	5.81361	6.04298	6.961702	6.961702	6.501721	11.64582
Flexsc06 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL200 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL201 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RHTB0001 (Pinit)	79.54692	83.79938	77.1262	63.6367	61.57958	60.02158	65.26378	78.7038	85.15811	71.81636	60.96882	63.73589	65.18712	59.26848	52.61798	47.77468	46.67877	51.22389	76.25722	75.18513	61.9106	55.60281	42.2461	79.18104
RHTB0001 (Pfinal)	78.85343	82.6116	76.39203	63.27519	61.1708	59.6634	64.79015	77.97942	84.20948	71.19686	60.53885	63.26174	64.66351	58.86895	52.30962	47.53024	46.47172	50.9606	75.56701	74.50942	61.49105	55.29034	42.08068	78.45597
RHTB0001 (Qinit)	8.656188	9.43347	6.448569	5.817192	4.652512	3.869146	2.708158	6.076602	7.593359	3.782095	1.565212	1.6359	1.435529	0.685139	0.615729	0.482528	0.456292	0.959209	5.77203	5.307194	2.962719	2.318749	0.462934	9.608618
RHTB0001 (Qfinal)	23.79044	32.17633	25.44354	20.54742	22.59754	22.33643	23.49807	27.21925	29.64819	22.36687	20.83122	22.44241	20.02346	20.43326	16.77799	14.54493	14.24947	16.54555	25.33317	24.55029	22.76043	19.50342	12.96993	24.91757
RHTB0002 (Pinit)	35.64511	39.28388	34.99153	26.1157	25.673	25.08387	29.4748	38.30781	42.7389	32.5878	25.16792	26.81064	26.39168	23.07238	20.05686	17.72822	17.90415	20.00116	34.36494	32.89152	24.66693	21.94179	14.22788	36.63303
RHTB0002 (Pfinal)	35.62314	39.17867	34.92182	26.1068	25.66439	25.07605	29.4098	38.15447	42.49918	32.49481	25.1423	26.77107	26.34543	23.04222	20.04582	17.72141	17.89724	19.98989	34.29799	32.83666	24.65256	21.93307	14.22391	36.58991
RHTB0002 (Qinit)	14.57983	14.95965	11.86874	12.2422	10.66173	9.668565	7.931372	11.27023	12.50852	9.148127	7.131552	7.073721	6.845111	6.126419	6.181931	6.025507	5.810417	6.52262	11.38278	10.93956	8.872765	8.103693	5.981123	15.60925
RHTB0002 (Qfinal)	16.08276	16.03494	14.53881	12.75373	11.66076	10.99195	11.06109	15.53209	17.4556	12.72922	9.95605	10.10277	9.789736	8.522603	7.644951	6.867324	6.802235	7.795839	14.32013	13.60411	10.43511	9.098523	5.80295	17.87757
Nt1Tr002 (tap)	8	6	9	5	9	6	6	6	9	8	7	6	7	5	8	9	7	6	7	7	6	6	7	10
Nt1Tr001 (tap)	10	7	10	7	9	6	6	7	10	8	7	6	7	5	8	9	7	6	8	8	6	6	7	12
Nt2Tr003 (tap)	8	15	10	10	9	8	9	11	12	10	6	6	8	9	9	10	9	9	9	9	9	9	10	10
Nt2Tr004 (tap)	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17

Table 235 – Network 5 winter scenario 7.

Period	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
InitTotLoss (P)	1963.372	1918.655	1580.401	1704.461	1348.895	1184.129	1155.34	1552.004	1816.443	1391.883	1102.117	1209.86	1320.474	1127.083	892.9719	784.2274	721.7954	843.4083	1544.864	1557.626	1230.51	1038.851	784.7279	2055.216
InitTotLoss (Q)	8682.179	10314.47	8007.079	3951.272	3271.209	2843.485	4745.379	9346.128	12237.7	6731.003	3277.031	4186.195	4498.895	2805.893	1102.352	76.76465	-81.3233	812.9902	7743.961	7242.451	3186.952	1705.489	-914.086	8843.983
FinalTotLoss (P)	1618.59	1538.076	1208.846	1517.586	1161.39	992.9144	861.0679	1060.048	1224.641	1026.265	855.198	914.8699	1003.366	882.4932	718.9439	652.4688	601.7474	692.8244	1166.439	1180.627	1001.802	874.0899	685.2597	1727.122
FinalTotLoss (Q)	8710.821	10757.39	8783.308	4330.908	3231.973	2972.004	5005.72	8831.012	12309.91	7376.667	3520.337	4333.344	4677.185	2967.574	1005.703	28.32047	-6.32116	878.1306	8173.482	7539.597	3267.48	1970.991	-942.826	8946.772
PowerGen (P)	111.8209	115.13	102.156	93.55717	87.3336	83.17679	82.21368	100.9252	108.8611	89.99252	76.00843	77.98261	78.77272	72.10687	66.6848	62.07414	60.56421	66.45368	99.86517	98.17384	82.42756	75.16013	57.25008	114.3181
PowerGen (Q)	41.5823	44.43638	39.10876	32.0534	29.27103	27.90018	29.90075	38.82401	44.54873	34.63334	27.01504	28.39895	29.06677	25.40346	21.76184	19.39189	18.84462	21.47038	38.11526	37.05248	28.34144	24.85048	16.82501	42.24145
Cos (€)	1300.436	1013.738	1893.069	6	6	3	9	1657.162	3632.766	9	9	3	3	3	6	0	6	0	720.0306	535.136	6	6	6	1844.411
N1sync02 (P)	1.166832	0.989748	0.711768	1.306715	1.042325	0.889675	0.330419	0.381348	0.279628	0.330419	0.381348	0.279628	0.279628	0.330419	0.483069	0.559256	0.508464	0.541959	0.64368	0.669075	0.770796	0.770796	0.719867	1.289418
N1sync03 (P)	3.410278	2.892718	2.08027	3.81911	3.046381	2.600237	0.965711	1.114559	0.817263	0.965711	1.114559	0.817263	0.817263	0.965711	1.411855	1.634526	1.486079	1.583974	1.88127	1.955494	2.25279	2.25279	2.103941	3.768558
N1sync05 (P)	1.566803	1.329018	0.95575	1.754635	1.399616	1.194641	0.443682	0.512068	0.37548	0.443682	0.512068	0.37548	0.37548	0.443682	0.648657	0.75096	0.682758	0.727734	0.864322	0.898423	1.035012	1.035012	0.966625	1.73141
N1sync01 (P)	3.789198	3.214131	2.311411	4.243456	3.384868	2.889152	1.073012	1.238399	0.90807	1.073012	1.238399	0.90807	0.90807	1.073012	1.568728	1.81614	1.651199	1.759971	2.0903	2.172771	2.5031	2.5031	2.337712	4.187287
N1sync04 (P)	3.067446	2.601916	1.871142	3.435179	2.740131	2.338837	0.868629	1.002514	0.735104	0.868629	1.002514	0.735104	0.735104	0.868629	1.269923	1.470209	1.336685	1.424738	1.692148	1.75891	2.026319	2.026319	1.892434	3.389708
FlexL063 (P)	0	0	0	0	0	0	0	0	0.2602	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL169 (P)	0	0	0	0	0	0	0	0	0.0946	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL117 (P)	0	0	0	0	0	0	0	0	0.0732	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL090 (P)	0	0	0	0	0	0	0	0	0.0568	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL001 (P)	0	0	0	0	0	0	0	0	0.064	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL002 (P)	0	0	0	0	0	0	0	0	0.0542	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL003 (P)	0	0	0	0	0	0	0	0	0.053	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL005 (P)	0	0	0	0	0	0	0	0	0.0386	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL007 (P)	0	0	0	0	0	0	0	0	0.0446	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL009 (P)	0	0	0	0	0	0	0	0	0.031	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL011 (P)	0	0	0	0	0	0	0	0	0.0282	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL012 (P)	0	0	0	0	0	0	0	0	0.0514	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL016 (P)	0	0	0	0	0	0	0	0	0.029	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL019 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc02 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc03 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc05 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc01 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc04 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
N2sync06 (P)	12.12543	10.28522	7.396514	13.57906	10.83158	9.245286	3.433637	3.962877	2.905824	3.433637	3.962877	2.905824	2.905824	3.433637	5.01993	5.811649	5.283836	5.631907	6.68896	6.952866	8.009919	8.009919	7.480679	13.39932
Flexsc06 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL200 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL201 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RHTB0001 (Pinit)	61.10455	64.84443	60.59592	47.78656	46.94799	46.16358	52.21736	62.97476	68.67432	57.52645	48.53158	51.10849	52.26325	47.28295	41.40703	37.23143	36.51855	40.0967	60.10355	59.13461	48.03631	42.92541	32.21894	60.45076
RHTB0001 (Pfinal)	60.76451	64.46803	60.2374	47.61253	46.76697	45.97717	51.94799	62.54066	67.92102	57.19153	48.29622	50.83649	51.96598	47.05812	41.23933	37.1052	36.40357	39.95163	59.74488	58.77253	47.81188	42.77074	32.13106	60.12687
RHTB0001 (Qinit)	6.071081	6.422664	4.164613	4.531656	3.495886	2.816589	1.362651	3.643857	4.592935	2.013434	0.592597	0.505819	0.293089	-0.11043	0.121811	0.194946	0.167999	0.481787	3.61657	3.293392	1.935307	1.616442	0.436631	6.92307
RHTB0001 (Qfinal)	19.44555	19.83858	22.62711	15.3479	13.09058	15.4853	16.75319	22.16792	23.16398	19.86237	15.02502	15.90402	16.33784	14.33144	11.97179	10.47247	10.28446	11.54807	21.24582	21.26091	15.87884	13.78706	8.832743	20.31673
RHTB0002 (Pinit)	25.93527	29.35352	26.60484	17.81947	18.1283	18.04668	23.17554	30.23068	34.1336	25.71667	19.51021	21.14776	20.80324	17.94441	15.04719	12.92997	13.21524	14.83508	26.2794	25.00873	18.02208	15.79398	9.627961	26.42979
RHTB0002 (Pfinal)	25.93044	29.34923	26.59172	17.80648	18.12172	18.04179	23.1506	30.1728	34.03993	25.6859	19.50044	21.12475	20.78537	17.93366	15.04332	12.9262	13.21161	14.83177	26.25961	24.99377	18.01774	15.79146	9.617758	26.42549
RHTB0002 (Qinit)	12.36365	12.29855	9.705762	11.06267	9.462215	8.489857	6.318868	8.76643	9.499581	7.210171	5.842513	5.647976	5.470271	5.023429	5.314544	5.33083	5.090368	5.660165	9.265736	8.990014	7.713182	7.168011	5.57447	13.28808
RHTB0002 (Qfinal)	12.79598	12.34938	11.50835	9.776886	8.943263	8.162966	8.604049	11.61674	13.56175	10.05002	7.370874	7.667141	7.474383	6.388452	5.742528	5.196113	5.14303	5.806977	11.10899	10.55164	7.764722	6.845259	4.409937	13.62597
Nt1Tr002 (tap)	7	6	6	6	8	8	7	9	7	6	7	7	7	7	9	9	8	8	6	7	8	7	9	7
Nt1Tr001 (tap)	9	7	6	7	9	8	7	9	7	6	7	7	7	7	9	9	8	8	7	7	8	7	9	9
Nt2Tr003 (tap)	9	9	8	9	9	9	8	9	8	7	8	9	8	9	9	9	9	9	9	9	9	9	9	9
Nt2Tr004 (tap)	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17

Table 236 – Network 5 summer scenario 1.

Period	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
InitTotLoss (P)	1038.189	1138.564	906.6435	688.6589	598.2754	585.5228	658.7024	854.0853	1038.387	751.8147	610.0856	635.1867	697.51	592.0932	480.546	398.0787	374.1604	453.2219	958.284	944.5025	662.1656	546.8244	375.6019	1070.048
InitTotLoss (Q)	12153.67	14483.78	9680.99	5669.771	4284.9	4146.431	5488.69	9581.941	12736.55	6624.212	3585.487	3609.281	3716.034	2244.277	1023.592	47.1588	-118.774	1078.602	10338.05	9465.236	4232.968	2540.077	-553.34	13223.33
FinalTotLoss (P)	837.0896	911.2898	732.754	574.2491	503.963	494.4191	546.8655	692.851	831.4425	618.0201	506.6713	525.6799	595.2236	501.6212	420.8017	342.9862	324.6024	386.17	769.8852	757.7974	550.3214	462.0728	335.8262	858.2097
FinalTotLoss (Q)	7778.176	9527.577	5907.754	2721.05	1586.899	1555.134	2818.837	5908.12	8384.378	3719.064	1285.437	1306.47	2111.874	530.6891	-325.058	-1556.79	-1677.55	-723.397	6490.155	5796.178	1785.215	472.6727	-1768.03	8520.855
PowerGen (P)	102.3195	107.63	92.6704	82.88216	76.2619	74.89331	76.84356	90.91487	99.14718	80.56983	69.01906	68.28324	68.03262	62.07176	57.46623	52.94876	51.95321	58.54485	94.06785	91.32099	73.68177	66.73875	50.12509	106.1061
PowerGen (Q)	37.53291	40.66078	33.00494	26.99362	23.97413	23.55802	25.4069	32.354	37.21535	27.62937	22.10626	21.99327	22.87736	19.51881	17.25576	14.6397	14.16055	17.04574	34.18034	32.78597	23.83248	20.46923	13.53691	39.17113
Cost (€)	3523.651	5576.654	565.0136	9	6	3	9	426.7444	3315.522	6	6	6	6	6	6	6	0	0	1332.374	478.7952	9	9	6	4606.338
N1sync02 (P)	0.3298	0.279748	0.201178	0.369337	0.294608	0.251463	0.093392	0.107786	0.079036	0.093392	0.107786	0.079036	0.079036	0.093392	0.136537	0.158071	0.143715	0.153182	0.181933	0.189111	0.217862	0.217862	0.203467	0.364448
N1sync03 (P)	0.9639	0.817614	0.587979	1.079455	0.861046	0.734945	0.272954	0.315025	0.230996	0.272954	0.315025	0.230996	0.230996	0.272954	0.399055	0.461992	0.420034	0.447703	0.531733	0.552712	0.636741	0.636741	0.59467	1.065166
N1sync05 (P)	0.44285	0.375641	0.270139	0.49594	0.395595	0.33766	0.125405	0.144734	0.106128	0.125405	0.144734	0.106128	0.106128	0.125405	0.18334	0.212255	0.192978	0.205691	0.244297	0.253935	0.292542	0.292542	0.273212	0.489375
N1sync01 (P)	1.071	0.90846	0.65331	1.199394	0.956718	0.816606	0.303282	0.350028	0.256662	0.303282	0.350028	0.256662	0.256662	0.303282	0.443394	0.513324	0.466704	0.497448	0.590814	0.614124	0.70749	0.70749	0.660744	1.183518
N1sync04 (P)	0.867	0.73542	0.52887	0.970938	0.774486	0.661062	0.245514	0.283356	0.207774	0.245514	0.283356	0.207774	0.207774	0.245514	0.358938	0.415548	0.377808	0.402696	0.478278	0.497148	0.57273	0.57273	0.534888	0.958086
N2sync06 (P)	3.4272	2.907072	2.090592	3.838061	3.061498	2.613139	0.970502	1.12009	0.821318	0.970502	1.12009	0.821318	0.821318	0.970502	1.418861	1.642637	1.493453	1.591834	1.890605	1.965197	2.263968	2.263968	2.114381	3.787258
RHTB0001 (Pinit)	62.78471	66.3617	58.32673	49.93964	46.55689	46.16882	49.22576	57.53082	63.18119	52.00447	45.0213	45.1668	45.75165	41.62361	37.75736	34.25201	33.50351	37.73913	59.61338	58.23621	46.97557	42.33262	32.06901	64.23001
RHTB0001 (Pfinal)	62.63625	66.1929	58.19149	49.85858	46.48761	46.10051	49.14148	57.41174	63.02715	51.90057	44.9374	45.0764	45.667	41.54724	37.70916	34.2065	33.46367	37.68459	59.4655	58.08562	46.88336	42.26342	32.04184	64.07889
RHTB0001 (Qinit)	27.98562	30.15367	24.62531	19.95328	17.73204	17.36052	18.56948	23.49887	27.17561	20.37403	16.60715	16.7043	17.34456	15.06596	13.02153	11.20489	10.69281	12.86518	25.47941	24.78343	18.16244	15.51339	10.34567	28.90237
RHTB0001 (Qfinal)	24.73191	26.52434	21.62261	17.7032	15.65652	15.32636	16.38305	20.58879	23.79598	17.99841	14.63104	14.71855	16.02672	13.57031	11.84175	9.732921	9.267651	11.25297	22.36613	21.76388	16.07147	13.69926	9.241824	25.43676
RHTB0002 (Pinit)	32.63376	35.47131	30.18528	25.10375	23.45528	23.40062	25.71854	31.22405	34.47073	26.68805	21.7801	21.52401	20.68132	18.52758	16.82714	15.3471	15.40364	17.5742	30.72499	29.19907	22.12667	19.79951	13.71031	34.23991
RHTB0002 (Pfinal)	32.58155	35.41313	30.14685	25.07046	23.43034	23.37792	25.69103	31.18211	34.41812	26.65821	21.76065	21.50493	20.66371	18.51347	16.81694	15.33844	15.39485	17.5617	30.6847	29.16315	22.10708	19.784	13.70188	34.17937
RHTB0002 (Qinit)	13.92963	15.46396	12.15702	9.990457	8.943475	8.791794	9.508644	12.53349	14.39598	10.16178	7.802172	7.593234	7.13994	6.16864	5.580343	5.037309	5.024962	5.984211	12.55292	11.67576	8.119081	7.025846	4.395042	14.9711
RHTB0002 (Qfinal)	12.80101	14.13644	11.38233	9.290421	8.317615	8.231657	9.023849	11.76521	13.41938	9.630968	7.475222	7.274722	6.850643	5.948495	5.414018	4.906783	4.892897	5.79277	11.81421	11.02209	7.761003	6.769966	4.295081	13.73437
Nt1Tr002 (tap)	6	6	7	8	7	7	8	7	7	8	7	8	4	6	4	8	8	8	7	7	8	7	5	6
Nt1Tr001 (tap)	6	6	7	8	7	7	8	7	7	8	7	8	3	5	4	8	8	8	7	7	8	7	5	7
Nt2Tr003 (tap)	7	6	14	8	8	10	17	17	17	17	17	17	17	17	17	17	17	17	17	17	16	17	17	7
Nt2Tr004 (tap)	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17

Table 237 – Network 5 summer scenario 2.

Period	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
InitTotLoss (P)	1411.627	1573.454	1240.341	916.5564	791.1061	775.5841	904.8089	1198.153	1483.064	1033.722	816.028	854.8845	935.6552	784.8414	623.0401	509.1743	478.7482	587.3606	1312.782	1284.604	875.4141	714.4274	483.0827	1459.732
InitTotLoss (Q)	9396.235	11432.92	7617.065	4010.828	2949.836	2891.376	4305.567	7795.75	10515.72	5257.983	2588.021	2649.234	2708.758	1418.784	309.4992	-551.867	-672.817	353.1338	8189.108	7418.435	2956.732	1524.902	-1108.87	10239.44
FinalTotLoss (P)	960.4248	1054.646	839.3913	694.712	597.496	585.9561	656.0185	781.4147	960.5163	743.3659	609.303	640.5019	691.9138	606.8961	487.5024	408.9021	392.38	454.0424	894.9679	917.4826	654.5148	554.0045	393.5138	991.0056
FinalTotLoss (Q)	8994.274	11474.47	7229.034	4132.185	2942.976	3168.292	4735.477	7182.441	10440.53	5779.458	2815.082	2915.454	2478.345	1605.961	342.6927	-505.484	-574.499	290.009	8143.456	8236.124	2986.361	1745.695	-1202.5	9903.958
PowerGen (P)	102.95	108.3068	93.23657	83.4141	76.73411	75.35673	77.33411	91.45437	99.76766	81.0947	69.46419	68.73678	68.46648	62.48486	57.81618	53.27641	52.27785	58.90177	94.65927	91.93337	74.15158	67.16201	50.43233	106.7651
PowerGen (Q)	38.9052	42.76472	34.46605	28.52734	25.44537	25.28405	27.43742	33.7653	39.42023	29.80838	23.74275	23.70654	23.35058	20.6909	18.01047	15.77181	15.34242	18.14673	35.97629	35.36521	25.14502	21.84465	14.18439	40.70813
Cost (€)	1127.817	2977.797	9	6	3	6	6	128.353	1745.079	6	3	3	9	9	9	3	6	9	161.2386	9	6	6	6	1792.901
N1sync02 (P)	0.443911	0.376541	0.270786	0.497128	0.396543	0.338469	0.125705	0.14508	0.106382	0.125705	0.14508	0.106382	0.106382	0.125705	0.183779	0.212764	0.193441	0.206184	0.244882	0.254544	0.293242	0.293242	0.273867	0.490548
N1sync03 (P)	1.297409	1.100508	0.79142	1.452946	1.158968	0.989237	0.367396	0.424024	0.31092	0.367396	0.424024	0.31092	0.31092	0.367396	0.537127	0.621841	0.565365	0.602609	0.715712	0.74395	0.857053	0.857053	0.800425	1.433714
N1sync05 (P)	0.596076	0.505613	0.363606	0.667535	0.532471	0.45449	0.168795	0.194812	0.142848	0.168795	0.194812	0.142848	0.142848	0.168795	0.246776	0.285696	0.259749	0.27686	0.328824	0.341797	0.393761	0.393761	0.367744	0.658699
N1sync01 (P)	1.441566	1.222787	0.879355	1.614384	1.287742	1.099152	0.408218	0.471138	0.345467	0.408218	0.471138	0.345467	0.345467	0.408218	0.596808	0.690934	0.628184	0.669565	0.795236	0.826611	0.952282	0.952282	0.889361	1.593015
N1sync04 (P)	1.166982	0.989875	0.711859	1.306883	1.042458	0.889789	0.330462	0.381397	0.279664	0.330462	0.381397	0.279664	0.279664	0.330462	0.483131	0.559328	0.50853	0.542029	0.643762	0.669161	0.770895	0.770895	0.719959	1.289584
FlexL063 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL169 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc02 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc03 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc05 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc01 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc04 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
N2sync06 (P)	4.613011	3.912919	2.813937	5.16603	4.120776	3.517285	1.306296	1.507641	1.105495	1.306296	1.507641	1.105495	1.105495	1.306296	1.909787	2.210989	2.010187	2.142608	2.544754	2.645155	3.047301	3.047301	2.845957	5.097649
Flexsc06 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RHTB0001 (Pinit)	62.15902	65.99219	58.13543	48.9693	45.83074	45.60542	49.3206	57.68377	63.54328	52.14402	45.01119	45.27831	45.88628	41.64725	37.55417	33.92093	33.21739	37.46317	59.51791	58.09982	46.57086	41.85963	31.55439	63.48895
RHTB0001 (Pfinal)	61.77001	65.5539	57.7967	48.7658	45.65632	45.43847	49.11779	57.35504	63.13976	51.89606	44.8394	45.09912	45.67961	41.49371	37.43313	33.82981	33.14133	37.34499	59.16489	57.79105	46.37175	41.71839	31.47126	63.09919
RHTB0001 (Qinit)	4.807633	5.498774	3.400367	3.040462	2.304948	2.075867	1.772367	3.338722	4.098479	1.857028	0.68261	0.39863	0.021915	-0.27728	-0.22044	-0.1809	-0.12156	0.181135	3.37489	2.892088	1.236791	0.846797	-0.26258	5.568012
RHTB0001 (Qfinal)	21.7164	22.89446	19.70001	16.33943	13.80787	14.56103	14.89092	18.43494	21.8282	16.91921	13.18893	13.22867	13.1146	11.60087	9.890796	8.667714	7.747005	10.1329	20.49443	20.58638	14.20716	12.38798	7.96121	22.00798
RHTB0002 (Pinit)	31.68323	34.72523	29.67114	23.96176	22.55804	22.65254	25.55548	31.06326	34.45616	26.53436	21.52832	21.37474	20.52555	18.3036	16.43876	14.87326	14.98058	17.13038	30.28603	28.71947	21.48711	19.14271	13.06937	33.1817
RHTB0002 (Pfinal)	31.62104	34.64468	29.60891	23.94339	22.53884	22.62984	25.50945	30.97524	34.33712	26.49177	21.5007	21.34689	20.4961	18.28428	16.42564	14.86506	14.97107	17.11693	30.22121	28.6611	21.4653	19.12909	13.06375	33.10273
RHTB0002 (Qinit)	9.649627	10.26995	7.942792	7.631712	6.626149	6.303308	5.842986	7.684901	8.613499	6.262148	4.983873	4.698791	4.397012	3.918914	3.853121	3.686414	3.606001	4.19476	8.097609	7.60559	5.714003	5.093117	3.549771	10.43286
RHTB0002 (Qfinal)	12.32176	13.95265	10.97674	9.376421	8.462407	8.32543	9.170466	11.36096	13.13805	9.59241	7.462188	7.36275	6.785732	5.924396	5.305777	4.7531	4.771773	5.648136	11.41114	10.54688	7.639479	6.644912	4.161437	13.03123
Nt1Tr002 (tap)	8	7	9	8	8	7	6	9	7	7	7	7	9	7	8	8	7	9	8	5	8	7	10	7
Nt1Tr001 (tap)	9	8	9	8	9	7	7	10	8	7	7	7	9	7	8	8	8	9	8	5	8	7	10	8
Nt2Tr003 (tap)	10	8	9	9	9	9	7	9	8	5	8	7	9	8	9	9	9	9	8	9	9	9	9	12
Nt2Tr004 (tap)	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	15	16	17	17	17	17	17	17	17

Table 238 – Network 5 summer scenario 3.

Period	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
InitTotLoss (P)	1316.943	1464.33	1156.838	865.0047	744.4766	728.1515	848.0272	1119.843	1386.254	968.1252	765.3665	802.6983	878.3172	737.2014	585.6554	479.9297	451.4979	552.3312	1224.125	1198.249	819.8195	670.9709	457.1051	1362.777
InitTotLoss (Q)	8416.68	10337.82	6811.133	3391.309	2421.999	2378.962	3758.568	7024.115	9590.033	4651.68	2141.957	2210.277	2265.733	1050.243	-2.22518	-813.195	-923.075	34.33291	7354.808	6630.465	2448.7	1112.526	-1341.72	9188.601
FinalTotLoss (P)	949.1968	1001.48	810.6152	665.2702	577.1202	557.5625	607.2507	738.3685	900.9471	686.6739	574.0787	601.5673	665.3566	572.5558	465.8268	384.8672	364.5661	430.9187	855.5319	845.3578	625.7077	525.8922	378.2541	957.384
FinalTotLoss (Q)	9196.04	10694.24	7039.889	3407.109	2715.625	2653.78	3940.844	6478.548	9430.01	4818.584	2319.059	2366.515	2402.033	1198.406	159.995	-841.566	-857.425	-18.8197	7655.883	6821.618	2673.379	1328.143	-1349.37	9306.553
PowerGen (P)	99.99577	105.1588	90.54161	80.99773	74.51676	73.17077	75.07278	88.79489	96.85694	78.7196	67.44212	66.73292	66.48424	60.66214	56.14029	51.72704	50.75304	57.19226	91.91421	89.23492	72.00196	65.20917	48.97319	103.6793
PowerGen (Q)	38.24372	41.08174	33.49094	27.0983	24.56867	24.13135	25.9881	32.29433	37.57356	28.15631	22.64302	22.55816	22.67197	19.72847	17.31805	14.96613	14.60045	17.32291	34.68573	33.16786	24.19261	20.84301	13.59359	39.22163
Cost (€)	1397.381	3039.631	3	6	6	0	0	24.09943	1313.826	3	0	0	0	0	0	6	6	6	6	3	0	0	6	2203.661
N1sync02 (P)	0.46205	0.391927	0.28185	0.517441	0.412746	0.352299	0.130842	0.151009	0.110729	0.130842	0.151009	0.110729	0.110729	0.130842	0.191289	0.221458	0.201345	0.214609	0.254888	0.264945	0.305225	0.305225	0.285058	0.510592
N1sync03 (P)	1.350424	1.145477	0.823759	1.512316	1.206326	1.029659	0.382408	0.44135	0.323625	0.382408	0.44135	0.323625	0.323625	0.382408	0.559075	0.64725	0.588467	0.627232	0.744957	0.774349	0.892074	0.892074	0.833132	1.492298
N1sync05 (P)	0.620433	0.526273	0.378464	0.694812	0.554229	0.473062	0.175692	0.202772	0.148685	0.175692	0.202772	0.148685	0.148685	0.175692	0.256859	0.29737	0.270363	0.288173	0.34226	0.355763	0.409851	0.409851	0.382771	0.685615
N1sync01 (P)	1.500471	1.272752	0.915287	1.680351	1.340362	1.144065	0.424898	0.490389	0.359583	0.424898	0.490389	0.359583	0.359583	0.424898	0.621195	0.719167	0.653852	0.696925	0.82773	0.860388	0.991193	0.991193	0.925702	1.658109
N1sync04 (P)	1.214667	1.030323	0.740947	1.360284	1.085055	0.926148	0.343965	0.396982	0.291091	0.343965	0.396982	0.291091	0.291091	0.343965	0.502872	0.582183	0.529309	0.564177	0.670067	0.696504	0.802395	0.802395	0.749378	1.342278
FlexL063 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL169 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc02 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc03 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc05 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc01 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc04 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
N2sync06 (P)	4.801507	4.072808	2.928919	5.377123	4.289158	3.661008	1.359674	1.569246	1.150667	1.359674	1.569246	1.150667	1.150667	1.359674	1.987824	2.301334	2.092327	2.230159	2.648737	2.753241	3.171819	3.171819	2.962248	5.305948
Flexsc06 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RHTB0001 (Pinit)	59.97291	63.74386	56.20858	47.14107	44.17563	44.00267	47.77558	55.8738	61.5872	50.51318	43.57696	43.86606	44.45328	40.32556	36.30953	32.76222	32.09545	36.20505	57.56927	56.18448	44.97064	40.40169	30.4168	61.22733
RHTB0001 (Pfinal)	59.65253	63.35609	55.91675	46.95589	44.02403	43.85113	47.58256	55.57153	61.21599	50.28511	43.41888	43.70082	44.27371	40.18128	36.20236	32.67615	32.01814	36.09691	57.26218	55.88271	44.79504	40.27028	30.34366	60.8731
RHTB0001 (Qinit)	4.537511	5.174263	3.17623	2.909611	2.196689	1.966423	1.622615	3.102911	3.801922	1.691446	0.587037	0.304331	-0.06398	-0.33436	-0.25423	-0.19805	-0.14156	0.139873	3.140192	2.681224	1.140434	0.78321	-0.25832	5.271425
RHTB0001 (Qfinal)	21.68432	22.78444	19.52041	14.73783	14.03796	13.81095	14.75716	17.56956	20.89233	16.11093	12.77307	12.81411	12.77198	11.22228	9.706965	8.177476	8.076656	9.459346	19.1495	19.02756	13.63831	11.68454	7.492338	22.05482
RHTB0002 (Pinit)	30.44108	33.43827	28.61004	22.91409	21.62063	21.75247	24.72051	30.05083	33.37068	25.6704	20.79829	20.67715	19.85286	17.68214	15.83041	14.29024	14.4081	16.48588	29.2249	27.69815	20.65087	18.37787	12.4963	31.86255
RHTB0002 (Pfinal)	30.39369	33.36318	28.55563	22.89951	21.60485	21.7334	24.67274	29.97162	33.25657	25.61701	20.77149	20.64772	19.82615	17.66339	15.81881	14.28213	14.39924	16.47408	29.16339	27.64702	20.63437	18.36634	12.49124	31.81135
RHTB0002 (Qinit)	9.354379	9.918689	7.675278	7.46176	6.468761	6.140477	5.629379	7.390678	8.262755	6.031208	4.818387	4.533118	4.243493	3.792304	3.749797	3.600944	3.517328	4.084855	7.816028	7.350433	5.560629	4.971467	3.491069	10.11254
RHTB0002 (Qfinal)	11.83261	13.22905	10.5259	9.019622	8.117714	7.975266	8.674349	10.8839	12.48795	9.166382	7.115872	6.921985	6.539052	5.618362	5.109061	4.585811	4.595341	5.444935	10.84994	10.10767	7.301063	6.335286	4.009465	12.68316
Nt1Tr002 (tap)	5	6	7	8	7	7	7	9	7	7	7	7	7	7	7	9	8	9	6	7	7	7	9	7
Nt1Tr001 (tap)	6	7	7	9	7	7	7	10	8	7	7	7	7	7	7	9	8	9	7	7	7	7	9	8
Nt2Tr003 (tap)	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Nt2Tr004 (tap)	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17

Table 239 – Network 5 summer scenario 4.

Period	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
InitTotLoss (P)	1457.043	1610.314	1265.607	984.2302	830.3556	802.5536	928.9115	1231.515	1536.873	1062.831	835.1026	879.7759	963.6789	804.6318	635.0678	520.4432	488.4597	599.0314	1339.659	1310.538	896.2942	734.4207	502.2827	1517.159
InitTotLoss (Q)	9352.976	11537.27	7778.01	3854.082	2860.793	2851.216	4572.562	8180.939	11106.2	5566.065	2758.645	2875.525	2936.308	1567.272	356.6704	-550.904	-660.099	380.53	8410.382	7597.543	2960.726	1500.785	-1153.31	10153.85
FinalTotLoss (P)	1056.344	1101.246	907.0864	788.4085	655.5762	611.1057	646.1163	834.2794	998.8732	740.3606	623.2272	642.344	718.6997	621.9069	500.7949	421.9507	398.5312	472.3369	935.4045	915.4616	684.5788	570.5825	419.0439	1082.215
FinalTotLoss (Q)	9846.273	11512.45	8487.63	4234.245	3070.407	2684.277	4334.822	8463.708	11270.1	5479.81	2947.717	2667.788	2889.993	1727.296	410.4762	-478.939	-485.795	454.5174	8741.731	7509.911	2904.31	1441.103	-1156.62	9918.204
PowerGen (P)	105.7859	111.2348	95.78657	85.73009	78.83764	77.39064	79.38425	93.94323	102.4605	83.25058	71.32796	70.56812	70.31408	64.16228	59.36963	54.70977	53.67793	60.49015	97.21876	94.37655	76.15619	68.9654	51.80214	109.698
PowerGen (Q)	40.56055	43.64344	36.45634	29.28465	26.17724	25.39412	27.64708	35.76072	41.02845	30.15657	24.4378	24.01797	24.32296	21.32516	18.55287	16.23545	15.8587	18.7908	37.32245	35.36779	25.65822	22.07584	14.64359	41.54962
Cost (€)	2691.058	3976.653	276.6813	6	3	6	3	557.996	3346.177	6	6	6	6	6	6	0	6	6	611.5524	6	3	3	0	2687.077
N1sync02 (P)	0.601885	0.51054	0.36715	0.67404	0.53766	0.45892	0.17044	0.19671	0.14424	0.17044	0.19671	0.14424	0.14424	0.17044	0.24918	0.28848	0.26228	0.279558	0.332028	0.345128	0.397598	0.397598	0.371328	0.665118
N1sync03 (P)	1.759118	1.492146	1.073062	1.970005	1.571409	1.341275	0.498141	0.574921	0.421567	0.498141	0.574921	0.421567	0.421567	0.498141	0.728275	0.843135	0.766561	0.817058	0.970412	1.008699	1.162052	1.162052	1.085272	1.943928
N1sync05 (P)	0.808201	0.685545	0.493003	0.90509	0.721961	0.61623	0.228864	0.264139	0.193683	0.228864	0.264139	0.193683	0.193683	0.228864	0.334595	0.387366	0.352186	0.375386	0.445842	0.463432	0.533888	0.533888	0.498613	0.89311
N1sync01 (P)	1.954575	1.65794	1.192291	2.188894	1.74601	1.490306	0.55349	0.638801	0.468408	0.55349	0.638801	0.468408	0.468408	0.55349	0.809194	0.936816	0.851735	0.907843	1.078236	1.120776	1.291169	1.291169	1.205858	2.15992
N1sync04 (P)	1.582275	1.342141	0.965188	1.771962	1.413437	1.206438	0.448063	0.517125	0.379188	0.448063	0.517125	0.379188	0.379188	0.448063	0.655062	0.758375	0.6895	0.73492	0.872857	0.907295	1.045232	1.045232	0.976171	1.748507
FlexL063 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL169 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL117 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL001 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL002 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL003 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL005 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL007 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc02 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc03 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc05 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc01 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc04 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
N2sync06 (P)	6.25464	5.305406	3.81533	7.004461	5.587233	4.768979	1.771167	2.044164	1.498906	1.771167	2.044164	1.498906	1.498906	1.771167	2.589421	2.997812	2.725551	2.905096	3.450354	3.586484	4.131742	4.131742	3.858745	6.911745
Flexsc06 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL200 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RHTB0001 (Pinit)	62.17067	66.36096	58.69052	48.4374	45.58762	45.57164	50.18626	58.70483	64.87475	53.08728	45.69187	46.11397	46.73323	42.30457	37.88059	34.04142	33.39151	37.70345	60.20843	58.71467	46.72846	41.89183	31.38431	63.36465
RHTB0001 (Pfinal)	61.80861	65.92028	58.38332	48.25094	45.42424	45.39526	49.95344	58.39148	64.46208	52.82049	45.50852	45.90876	46.52379	42.14568	37.75794	33.95058	33.30991	37.58842	59.86415	58.36803	46.53208	41.73964	31.30605	62.97023
RHTB0001 (Qinit)	5.351014	6.031247	3.800556	3.573889	2.748635	2.470953	2.016708	3.665401	4.448346	2.111674	0.900248	0.581741	0.19351	-0.11018	-0.01356	0.048233	0.092991	0.417416	3.762485	3.267382	1.573794	1.171291	0.015954	6.161732
RHTB0001 (Qfinal)	22.96075	23.42984	20.63757	16.68511	14.08766	13.50269	15.77229	19.99199	23.04083	16.98936	13.72206	13.36477	13.7987	12.08494	10.4163	8.896861	8.777283	10.5305	20.73808	20.39556	13.69965	12.40181	8.086081	22.10453
RHTB0002 (Pinit)	31.05528	34.38924	29.54857	22.9741	21.84712	22.12833	25.81063	31.39978	35.0178	26.81562	21.61211	21.58359	20.7116	18.3648	16.2561	14.55386	14.7277	16.89187	30.26487	28.62516	21.07778	18.67257	12.50427	32.44599
RHTB0002 (Pfinal)	31.01661	34.32084	29.49723	22.9647	21.83569	22.11323	25.76065	31.31588	34.89247	26.75993	21.58358	21.55337	20.68429	18.34644	16.24596	14.54721	14.7202	16.88187	30.20488	28.57671	21.06243	18.66408	12.50011	32.40544
RHTB0002 (Qinit)	10.42298	10.98276	8.496465	8.452697	7.303911	6.902062	6.192328	8.113006	9.04409	6.624505	5.328992	4.990924	4.679936	4.209452	4.212656	4.080703	3.973262	4.590251	8.62946	8.13427	6.246388	5.615468	4.026133	11.27012
RHTB0002 (Qfinal)	12.53005	14.01335	11.16025	9.542268	8.57906	8.457651	9.236759	11.69851	13.44954	9.565801	7.626511	7.380807	6.976742	6.037648	5.480402	4.879974	4.865515	5.8592	11.57069	10.70433	7.799716	6.794812	4.265187	13.37561
Nt1Tr002 (tap)	6	7	5	7	7	9	9	6	6	8	7	9	8	7	8	8	7	8	6	8	8	9	9	8
Nt1Tr001 (tap)	7	8	6	7	8	10	9	7	7	8	7	9	8	7	8	8	7	8	7	8	9	9	9	9
Nt2Tr003 (tap)	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Nt2Tr004 (tap)	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17

Table 240 – Network 5 summer scenario 5.

Period	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
InitTotLoss (P)	1276.622	1387.785	1088.945	910.7048	751.6971	714.4243	803.76	1058.914	1322.157	917.9807	723.7608	763.9912	836.8434	699.9133	555.841	461.4839	432.7274	526.5142	1149.233	1125.985	784.3014	650.1311	455.9603	1339.75
InitTotLoss (Q)	7175.402	9091.38	5973.943	2502.861	1695.973	1712.31	3351.229	6458.656	9047.486	4212.946	1758.367	1894.211	1947.647	742.9359	-341.543	-1134.51	-1219.79	-332.928	6542.638	5833.315	1826.108	582.5988	-1666.48	7824.624
FinalTotLoss (P)	972.1173	1003.191	796.9903	753.1688	618.5016	571.2332	590.7137	732.2532	892.8111	670.7261	543.5175	566.6486	634.623	545.7092	444.269	380.2175	355.6314	428.9774	813.4733	808.5539	623.2441	521.0867	389.4936	1018.465
FinalTotLoss (Q)	7693.927	9579	6284.83	2523.542	1913.431	1852.511	3711.573	6603.398	9542.186	4573.196	1691.102	1700.109	1936.592	771.5739	-377.939	-1140.36	-1217.37	-143.03	6460.416	5682.704	2135.714	559.1714	-1673.82	8071.658
PowerGen (P)	99.30829	104.4135	89.88433	80.50947	74.02782	72.66364	74.52212	88.1572	96.16056	78.14397	66.9292	66.22371	65.98144	60.20477	55.71988	51.3543	50.38291	56.78317	91.21899	88.56417	71.48754	64.74119	48.63606	103.0036
PowerGen (Q)	36.53301	39.7484	32.54526	26.04484	23.60956	23.1759	25.60017	32.23383	37.48352	27.74336	21.86464	21.74701	22.06113	19.16936	16.65765	14.55415	14.12988	17.07432	33.29557	31.83996	23.50014	19.93508	13.16234	37.77187
Cost (€)	271.9125	2420.73	9	9	9	3	9	6	1387.634	3	6	3	9	0	6	0	0	6	9	6	9	9	3	1205.543
N1sync02 (P)	0.671473	0.569567	0.409598	0.751971	0.599823	0.511978	0.190145	0.219453	0.160916	0.190145	0.219453	0.160916	0.160916	0.190145	0.27799	0.321833	0.292604	0.311879	0.370416	0.38503	0.443567	0.443567	0.414259	0.742017
N1sync03 (P)	1.9625	1.664662	1.197125	2.19777	1.75309	1.496349	0.555734	0.641391	0.470307	0.555734	0.641391	0.470307	0.470307	0.555734	0.812475	0.940615	0.855188	0.911524	1.082608	1.125321	1.296405	1.296405	1.210747	2.168678
N1sync05 (P)	0.901643	0.764805	0.550002	1.009734	0.805432	0.687476	0.255324	0.294678	0.216076	0.255324	0.294678	0.216076	0.216076	0.255324	0.37328	0.432152	0.392904	0.418786	0.497388	0.517012	0.595614	0.595614	0.55626	0.996368
N1sync01 (P)	2.180556	1.849625	1.330139	2.441966	1.947878	1.66261	0.617482	0.712657	0.522564	0.617482	0.712657	0.522564	0.522564	0.617482	0.90275	1.045128	0.950209	1.012804	1.202897	1.250356	1.44045	1.44045	1.345275	2.409643
N1sync04 (P)	1.765212	1.497315	1.076779	1.97683	1.576853	1.345922	0.499867	0.576913	0.423028	0.499867	0.576913	0.423028	0.423028	0.499867	0.730798	0.846056	0.769217	0.819889	0.973774	1.012193	1.166078	1.166078	1.089032	1.950663
FlexL063 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL169 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL117 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL001 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL002 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL003 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL005 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL007 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc02 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc03 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc05 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc01 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc04 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
N2sync06 (P)	6.977779	5.918799	4.256445	7.814292	6.233209	5.320351	1.975943	2.280502	1.672204	1.975943	2.280502	1.672204	1.672204	1.975943	2.888801	3.344409	3.04067	3.240973	3.849271	4.001141	4.609439	4.609439	4.304879	7.710856
Flexsc06 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL200 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RHTB0001 (Pinit)	57.08511	61.18893	54.29616	44.09379	41.69326	41.83347	46.732	54.65953	60.54088	49.44614	42.45754	42.95645	43.53671	39.33554	35.03554	31.36187	30.80649	34.81257	55.78578	54.35704	43.0231	38.50143	28.70539	58.08158
RHTB0001 (Pfinal)	56.80011	60.84658	54.03058	43.94309	41.56635	41.69902	46.55128	54.39244	60.19863	49.23888	42.29804	42.79033	43.36182	39.19686	34.93237	31.2863	30.73564	34.723	55.48309	54.07354	42.87448	38.37983	28.64387	57.7801
RHTB0001 (Qinit)	4.836666	5.382472	3.355053	3.384516	2.58874	2.296157	1.709629	3.171503	3.813095	1.769091	0.71412	0.390735	0.022577	-0.21331	-0.05268	0.052976	0.087674	0.366885	3.288304	2.847579	1.41542	1.088561	0.081783	5.598326
RHTB0001 (Qfinal)	20.49764	22.33974	17.89019	13.95591	12.6533	13.04485	14.5216	17.70248	20.78738	14.88846	11.92443	12.23299	12.35457	10.84983	9.270109	7.805891	7.843753	9.363758	18.96868	17.52049	13.26878	11.05808	7.212995	21.10113
RHTB0002 (Pinit)	28.06858	31.34442	27.06014	20.38069	19.55151	19.94871	23.90872	29.09877	32.58398	24.85061	19.92326	19.99354	19.17572	16.92728	14.80863	13.14271	13.35197	15.3512	27.7927	26.23353	19.06733	16.81493	11.07606	29.26514
RHTB0002 (Pfinal)	28.04902	31.30215	27.03367	20.37382	19.54518	19.93993	23.87634	29.03917	32.49684	24.81059	19.90556	19.96828	19.15453	16.91341	14.80142	13.13781	13.34648	15.34431	27.75955	26.19958	19.0615	16.8098	11.07174	29.24528
RHTB0002 (Qinit)	9.903507	10.31563	7.983798	8.234535	7.078772	6.645176	5.758006	7.50548	8.301703	6.151972	5.004256	4.657473	4.373264	3.96781	4.040136	3.957155	3.836511	4.410014	8.077924	7.644386	5.999255	5.436285	3.98234	10.71029
RHTB0002 (Qfinal)	11.07697	12.5135	10.24208	8.627509	7.789543	7.63679	8.604895	10.72744	12.47585	9.100603	7.008798	6.68208	6.389348	5.515066	4.932969	4.476196	4.448559	5.303961	10.62531	10.13635	7.145949	6.145892	3.881636	11.88426
Nt1Tr002 (tap)	6	6	7	8	7	8	7	7	6	6	9	9	8	8	9	9	9	7	9	8	7	9	9	7
Nt1Tr001 (tap)	7	7	8	9	8	8	7	8	7	7	9	9	8	8	9	9	9	7	9	9	7	9	9	8
Nt2Tr003 (tap)	9	9	7	10	9	9	7	8	7	8	8	10	9	9	9	9	9	9	7	9	8	9	10	9
Nt2Tr004 (tap)	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17

Table 241 – Network 5 summer scenario 6.

Period	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
InitTotLoss (P)	1996.198	2127.284	1626.84	1507.729	1188.549	1094.837	1175.93	1574.264	1997.18	1351.387	1049.348	1112.386	1222.874	1011.17	797.7304	665.579	618.0758	759.6767	1712.448	1676.179	1171.628	973.9686	683.6416	2131.705
InitTotLoss (Q)	12127.64	15045.73	10585.97	5337.237	4194.973	4246.807	6956.131	11580.77	15611.92	8249.02	4545.799	4821.095	4905.211	3072.564	1390.623	209.0456	98.7908	1379.186	11479.86	10405.29	4449.561	2641.351	-580.091	13047.2
FinalTotLoss (P)	1557.283	1508.671	1124.162	1298.613	979.1488	894.8378	804.3086	1039.417	1219.266	932.8803	778.5494	812.3399	916.3667	770.7341	632.2305	551.9445	510.2241	611.8461	1200.312	1214.804	926.9622	786.9962	585.0054	1662.556
FinalTotLoss (Q)	12318	14877.63	9666.468	5362.821	4134.56	4732.036	6462.41	11428.47	14292.33	8221.936	4628.781	4911.026	5387.073	3170.324	1451.511	428.4068	316.1515	1627.77	11859.23	11061.25	4846.487	2606.611	-628.243	13178.04
PowerGen (P)	121.7121	127.8635	109.9782	98.75111	90.67642	88.98297	91.13953	107.8621	117.6249	95.59577	81.89715	81.03721	80.76221	73.6697	68.17092	62.83505	61.63652	69.47167	111.6649	108.4415	87.51449	79.25852	59.53594	126.276
PowerGen (Q)	47.55603	51.74127	41.75475	34.10308	30.64497	30.78654	33.20823	42.74582	48.43376	36.53325	29.28405	29.40519	29.97664	25.65392	22.26502	19.60378	19.06734	22.66802	44.64965	43.0223	30.95115	26.28541	17.49921	49.46861
Cost (€)	775.4176	4247.099	9	6	3	9	6	577.0953	1780.245	9	0	6	9	9	3	6	0	0	214.0935	6	9	9	6	1991.882
N1sync02 (P)	1.014135	0.860225	0.618622	1.135712	0.905921	0.773248	0.287179	0.331443	0.243034	0.287179	0.331443	0.243034	0.243034	0.287179	0.419852	0.486069	0.441924	0.471036	0.559445	0.581517	0.669926	0.669926	0.625662	1.120679
N1sync03 (P)	2.963992	2.514163	1.808035	3.319323	2.647717	2.259957	0.839333	0.968702	0.710312	0.839333	0.968702	0.710312	0.710312	0.839333	1.227093	1.420624	1.291603	1.376687	1.635078	1.699588	1.957979	1.957979	1.828609	3.275386
N1sync05 (P)	1.361764	1.155096	0.830676	1.525015	1.216456	1.038305	0.385619	0.445056	0.326343	0.385619	0.445056	0.326343	0.326343	0.385619	0.56377	0.652685	0.593409	0.632499	0.751213	0.780851	0.899565	0.899565	0.840128	1.504829
N1sync01 (P)	3.293325	2.793514	2.008928	3.688137	2.941908	2.511063	0.932592	1.076336	0.789236	0.932592	1.076336	0.789236	0.789236	0.932592	1.363437	1.578471	1.435115	1.529653	1.816753	1.888431	2.175532	2.175532	2.031788	3.639318
N1sync04 (P)	2.666025	2.261416	1.626275	2.985634	2.381544	2.032766	0.754956	0.87132	0.638905	0.754956	0.87132	0.638905	0.638905	0.754956	1.103734	1.27781	1.16176	1.23829	1.470705	1.52873	1.761145	1.761145	1.644781	2.946114
FlexL063 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL169 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL117 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL090 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL001 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL002 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL003 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL005 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL007 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL009 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL011 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL012 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL016 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL019 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc02 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc03 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc05 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc01 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc04 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
N2sync06 (P)	10.53864	8.939246	6.42857	11.80204	9.414105	8.035403	2.984295	3.444276	2.525554	2.984295	3.444276	2.525554	2.525554	2.984295	4.362997	5.051108	4.592367	4.894888	5.81361	6.04298	6.961702	6.961702	6.501721	11.64582
Flexsc06 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL200 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL201 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RHTB0001 (Pinit)	67.80476	73.18786	65.22661	51.58477	49.11757	49.56975	56.64358	66.29484	73.74854	59.99196	51.31353	52.13126	52.86486	47.59415	42.00203	37.34568	36.75671	41.609	67.19427	65.39555	51.27316	45.71443	33.79496	68.80397
RHTB0001 (Pfinal)	67.38893	72.6401	64.77649	51.38522	48.91757	49.37679	56.32664	65.84911	73.14582	59.6358	51.07031	51.86023	52.58673	47.36807	41.84537	37.23735	36.65474	41.47236	66.74775	64.97954	51.03422	45.53429	33.70345	68.36934
RHTB0001 (Qinit)	7.707499	8.527299	5.634381	5.494155	4.349956	3.939093	3.197609	5.34348	6.395692	3.375764	1.837784	1.424356	0.991563	0.580127	0.709054	0.781037	0.791408	1.241773	5.598926	4.997032	2.846135	2.312457	0.82786	8.733943
RHTB0001 (Qfinal)	21.57024	28.70725	21.98747	15.70878	16.51754	16.69204	18.31261	23.39649	24.7594	20.15056	15.73334	16.62587	17.22959	14.50667	12.08934	10.72356	10.41582	12.45768	25.03171	22.82628	17.57935	14.14173	9.542422	23.55414
RHTB0002 (Pinit)	32.50844	36.77058	31.93312	22.91962	22.26062	22.96253	28.68361	34.96496	39.42088	29.83836	23.7173	23.97267	22.9705	20.13031	17.29091	15.13462	15.46997	17.86168	32.93601	30.98522	22.06023	19.30523	12.36531	33.80907
RHTB0002 (Pfinal)	32.48532	36.69974	31.88056	22.91004	22.25121	22.95544	28.62892	34.87582	39.2457	29.77599	23.6897	23.9436	22.94209	20.11766	17.28467	15.13094	15.46561	17.85625	32.8704	30.93984	22.05443	19.29839	12.3598	33.77454
RHTB0002 (Qinit)	13.50006	14.02661	10.83503	11.34745	9.721833	9.09318	7.789432	10.16778	11.2785	8.307763	6.769822	6.290512	5.918526	5.391213	5.532279	5.456057	5.276932	6.033142	10.94257	10.36466	8.20584	7.471261	5.578657	14.61324
RHTB0002 (Qfinal)	14.35304	15.83257	12.79942	11.18934	10.00403	9.90082	10.63969	14.03671	15.87704	11.34128	8.977898	8.943195	8.393967	7.279602	6.429433	5.79019	5.798256	6.837545	13.35461	12.39822	9.246419	7.95192	5.076566	16.19995
Nt1Tr002 (tap)	6	7	9	7	8	6	9	8	8	7	7	8	6	8	8	7	7	7	6	5	7	8	9	6
Nt1Tr001 (tap)	8	7	10	9	9	7	10	8	9	8	8	8	6	8	8	7	7	7	6	6	7	9	9	8
Nt2Tr003 (tap)	10	12	11	11	11	9	9	8	11	9	9	7	8	7	9	9	9	9	11	10	8	10	11	11
Nt2Tr004 (tap)	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17

Table 242 – Network 5 summer scenario 7.

Period	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
InitTotLoss (P)	1541.839	1496.412	1094.616	1416.538	1032.732	884.0375	759.2713	997.3066	1249.977	865.2625	689.3238	722.6633	792.2296	665.6365	559.5107	503.8131	461.4192	551.313	1121.337	1109.751	865.6278	756.9412	580.4457	1713.173
InitTotLoss (Q)	5520.751	7321.304	4750.332	1595	823.7608	832.9453	2787.973	5683.824	8396.774	3613.784	1202.237	1462.88	1514.069	300.5801	-838.785	-1584.27	-1643.72	-863.382	5352.389	4663.872	958.0855	-131.555	-2046.94	6072.197
FinalTotLoss (P)	1336.5	1237.614	874.0248	1305.189	939.6561	781.0757	575.9956	729.1278	834.3673	644.111	546.9966	557.8966	609.0867	534.9345	470.1265	439.7336	403.1749	479.9508	858.0027	860.112	739.5989	666.1306	528.5652	1504.373
FinalTotLoss (Q)	5687.752	7743.804	5243.51	1605.071	951.8208	957.9596	3119.599	6177.157	8098.682	3745.535	1438.594	1563.453	1400.97	399.4984	-838.94	-1567.93	-1546.8	-721.763	5404.729	4640.356	1097.335	77.12048	-1932.96	6274.397
PowerGen (P)	99.97707	104.968	90.23724	81.30828	74.57375	73.0944	74.7363	88.42473	96.3971	78.35723	67.13817	66.41535	66.15531	60.379	55.91714	51.57182	50.58545	57.00893	91.54343	88.88735	71.82079	65.08527	48.9246	103.8052
PowerGen (Q)	34.61564	38.00632	31.58588	25.19771	22.7117	22.34421	25.07616	31.88675	36.12683	26.98764	21.67492	21.66758	21.58325	18.85439	16.24972	14.17524	13.84801	16.54914	32.32318	30.87791	22.52437	19.51359	12.94913	36.066
Cost (€)	513.0352	1285.876	3	6	9	3	9	3	759.1868	9	6	9	9	9	9	0	6	3	9	3	9	9	0	1102.571
N1sync02 (P)	1.166832	0.989748	0.711768	1.306715	1.042325	0.889675	0.330419	0.381348	0.279628	0.330419	0.381348	0.279628	0.279628	0.330419	0.483069	0.559256	0.508464	0.541959	0.64368	0.669075	0.770796	0.770796	0.719867	1.289418
N1sync03 (P)	3.410278	2.892718	2.08027	3.81911	3.046381	2.600237	0.965711	1.114559	0.817263	0.965711	1.114559	0.817263	0.817263	0.965711	1.411855	1.634526	1.486079	1.583974	1.88127	1.955494	2.25279	2.25279	2.103941	3.768558
N1sync05 (P)	1.566803	1.329018	0.95575	1.754635	1.399616	1.194641	0.443682	0.512068	0.37548	0.443682	0.512068	0.37548	0.37548	0.443682	0.648657	0.75096	0.682758	0.727734	0.864322	0.898423	1.035012	1.035012	0.966625	1.73141
N1sync01 (P)	3.789198	3.214131	2.311411	4.243456	3.384868	2.889152	1.073012	1.238399	0.90807	1.073012	1.238399	0.90807	0.90807	1.073012	1.568728	1.81614	1.651199	1.759971	2.0903	2.172771	2.5031	2.5031	2.337712	4.187287
N1sync04 (P)	3.067446	2.601916	1.871142	3.435179	2.740131	2.338837	0.868629	1.002514	0.735104	0.868629	1.002514	0.735104	0.735104	0.868629	1.269923	1.470209	1.336685	1.424738	1.692148	1.75891	2.026319	2.026319	1.892434	3.389708
FlexL063 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL169 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL117 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL090 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL001 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL002 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL003 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL005 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL007 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL009 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL011 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL012 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL016 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL019 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc02 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc03 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc05 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc01 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flexsc04 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
N2sync06 (P)	12.12543	10.28522	7.396514	13.57906	10.83158	9.245286	3.433637	3.962877	2.905824	3.433637	3.962877	2.905824	2.905824	3.433637	5.01993	5.811649	5.283836	5.631907	6.68896	6.952866	8.009919	8.009919	7.480679	13.39932
Flexsc06 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL200 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL201 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RHTB0001 (Pinit)	51.67265	56.60292	51.01671	38.06738	36.87626	37.72187	45.27154	52.96974	59.35447	47.98779	40.7391	41.72746	42.30501	37.85108	32.81717	28.7828	28.46893	32.31988	52.82816	51.27199	39.45212	34.93338	25.36983	52.11432
RHTB0001 (Pfinal)	51.47161	56.35295	50.80649	37.9754	36.79567	37.6274	45.10856	52.73644	59.01262	47.79252	40.60774	41.57732	42.13667	37.72767	32.7327	28.72508	28.41602	32.2534	52.57671	51.03003	39.3323	34.8507	25.33193	51.91006
RHTB0001 (Qinit)	5.818275	6.159578	3.96602	4.713726	3.667166	3.208722	2.026066	3.503276	4.04292	2.073358	1.09286	0.666412	0.292774	0.122761	0.469491	0.688047	0.669078	0.959072	3.826824	3.416018	2.181917	1.901697	0.928955	6.681715
RHTB0001 (Qfinal)	16.03493	17.47495	17.36593	11.81424	10.2352	12.37174	14.19166	17.56137	19.98626	14.69146	11.98942	12.0466	12.13789	10.5539	8.86129	7.514161	7.625756	8.184381	17.56761	17.53581	12.61787	10.86276	7.057458	17.22409
RHTB0002 (Pinit)	23.38387	27.31123	24.11431	15.21426	15.34486	16.3166	22.533	27.51145	31.43688	23.47551	18.32725	18.82874	18.00941	15.54203	12.78605	10.80953	11.22504	13.089	25.118	23.45754	15.89314	13.6424	8.104578	24.1341
RHTB0002 (Pfinal)	23.37948	27.30234	24.1039	15.19473	15.33318	16.30916	22.51265	27.47652	31.36311	23.44962	18.31866	18.81666	17.99727	15.53624	12.78228	10.80401	11.22041	13.08525	25.10604	23.44979	15.89056	13.63664	8.091409	24.12945
RHTB0002 (Qinit)	11.63885	11.66872	8.99123	10.46306	8.81942	8.093799	6.231759	8.006624	8.646883	6.618551	5.589072	5.083371	4.803984	4.495521	4.847995	4.923423	4.707655	5.315386	8.968375	8.598918	7.25061	6.730508	5.285419	12.62529
RHTB0002 (Qfinal)	11.59457	12.76461	10.176	8.703047	7.817725	7.461752	8.326913	10.37886	11.95641	8.822262	6.767676	6.708062	6.261165	5.362828	4.807033	4.321817	4.386238	5.18075	10.58119	9.829905	6.927821	6.000409	3.899085	12.48492
Nt1Tr002 (tap)	7	6	6	8	7	8	7	6	8	7	7	8	9	8	9	9	8	7	8	9	8	7	7	7
Nt1Tr001 (tap)	9	8	7	9	8	8	7	7	9	8	7	8	9	8	9	9	8	8	9	9	8	7	7	9
Nt2Tr003 (tap)	9	9	9	9	10	10	8	8	9	9	9	8	9	8	9	9	9	9	8	8	9	10	10	9
Nt2Tr004 (tap)	17	17	17	17	17	17	17	17	17	16	17	17	17	17	17	17	17	17	17	17	17	17	17	17

Table 243 – Network 6 winter scenario 1.

Period	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
InitTotLoss (P)	242.75	255.57	208.61	181.33	164.08	152.66	165.94	226.49	249.98	183.11	143.97	147.01	146.93	130.41	120.26	110.63	107.71	120.72	212.06	204.94	157.44	140.25	95.61	254.47
InitTotLoss (Q)	1353.15	1611.50	754.02	291.38	-0.71	-195.28	-156.36	885.78	1333.33	172.74	-496.55	-435.96	-459.88	-714.31	-855.40	-993.04	-1024.75	-833.78	689.13	552.42	-241.48	-508.06	-1171.45	1594.50
FinalTotLoss (P)	212.48	222.64	184.64	162.01	147.64	138.12	150.07	199.64	218.59	164.21	131.91	134.40	134.47	120.48	111.79	103.37	100.62	112.07	187.78	182.03	142.97	128.48	88.54	221.75
FinalTotLoss (Q)	612.17	818.57	164.03	-155.25	-379.27	-537.44	-688.45	82.83	445.42	-390.87	-818.70	-769.51	-844.76	-996.92	-1095.54	-1094.13	-1098.81	-1069.17	-39.04	-149.13	-612.01	-829.40	-987.92	804.87
PowerGen (P)	27.90	28.87	25.32	23.08	21.52	20.42	20.73	26.02	27.91	22.53	18.59	18.99	18.85	17.10	16.04	14.93	14.67	16.20	25.09	24.44	20.19	18.51	13.34	28.80
PowerGen (Q)	7.94	8.35	6.85	5.95	5.33	4.89	4.95	7.05	7.87	5.69	4.27	4.41	4.33	3.71	3.32	3.01	2.92	3.37	6.67	6.41	4.86	4.20	2.64	8.32
Cost (€)	2029.71	2925.97	161.47	3.00	3.00	0.00	6.00	565.72	1973.76	9.00	3.00	0.00	3.00	3.00	0.00	0.00	0.00	0.00	152.43	13.51	6.00	0.00	0.00	2868.95
RHTB0001 (Pinit)	7.99	8.12	7.35	6.75	6.34	6.05	6.60	7.91	8.30	6.94	5.93	6.01	6.05	5.54	5.17	4.83	4.71	5.18	7.55	7.42	6.29	5.79	4.14	8.09
RHTB0001 (Pfinal)	7.98	8.12	7.34	6.75	6.34	6.05	6.60	7.90	8.29	6.94	5.92	6.01	6.05	5.54	5.17	4.82	4.71	5.18	7.55	7.41	6.29	5.79	4.14	8.08
RHTB0001 (Qinit)	1.45	1.48	1.21	0.99	0.83	0.73	1.04	1.53	1.65	1.14	0.77	0.80	0.83	0.63	0.48	0.34	0.29	0.48	1.36	1.32	0.89	0.69	0.05	1.46
RHTB0001 (Qfinal)	1.24	1.26	1.05	0.88	0.75	0.65	0.76	1.15	1.28	0.89	0.65	0.68	0.65	0.52	0.39	0.37	0.34	0.39	1.04	1.00	0.76	0.57	0.34	1.25
RHTB0002 (Pinit)	19.94	20.78	17.99	16.34	15.20	14.38	14.15	18.14	19.65	15.61	12.68	12.99	12.82	11.57	10.88	10.12	9.96	11.03	17.56	17.05	13.92	12.73	9.21	20.74
RHTB0002 (Pfinal)	19.91	20.76	17.97	16.33	15.19	14.37	14.14	18.11	19.62	15.59	12.67	12.98	12.81	11.57	10.87	10.11	9.96	11.02	17.54	17.03	13.91	12.72	9.21	20.71
RHTB0002 (Qinit)	7.23	7.67	6.22	5.41	4.88	4.51	4.44	6.33	7.10	5.11	3.82	3.95	3.88	3.36	3.08	2.77	2.71	3.13	6.04	5.80	4.35	3.83	2.41	7.64
RHTB0002 (Qfinal)	6.70	7.09	5.80	5.07	4.58	4.25	4.19	5.90	6.60	4.80	3.62	3.74	3.67	3.19	2.93	2.64	2.58	2.98	5.63	5.41	4.10	3.63	2.30	7.07
Nt1Tr001 (tap)	3.00	3.00	-1.00	-1.00	0.00	0.00	-3.00	0.00	0.00	-3.00	-3.00	-3.00	-3.00	-3.00	-3.00	-3.00	-3.00	-3.00	-3.00	-3.00	-3.00	-3.00	-3.00	3.00
Nt1Tr002 (tap)	-3.00	-3.00	-3.00	-3.00	-3.00	-3.00	-3.00	0.00	-1.00	-3.00	-3.00	-3.00	-3.00	-3.00	-3.00	-3.00	-3.00	-3.00	-3.00	-3.00	-3.00	-3.00	-3.00	-3.00
Nt1Tr003 (tap)	4.00	4.00	7.00	9.00	9.00	9.00	4.00	0.00	0.00	5.00	9.00	9.00	7.00	9.00	9.00	9.00	9.00	9.00	3.00	3.00	9.00	9.00	9.00	4.00
Nt2Tr004 (tap)	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	1.00	1.00	3.00	3.00	3.00	3.00
Nt2Tr005 (tap)	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00

Table 244 – Network 6 winter scenario 2.

Period	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
InitTotLoss (P)	205.2006	218.6611	187.5545	155.7067	144.7045	136.8752	157.5334	205.2933	227.4146	172.4634	136.7565	140.608	140.7284	124.9595	113.9743	104.4487	102.1285	113.7306	188.7319	185.8418	143.8297	128.6367	89.04357	212.3421
InitTotLoss (Q)	599.0707	860.64	283.0738	-258.515	-426.491	-549.014	-369.857	479.7393	888.0263	-89.1221	-680.238	-605.45	-624.995	-859.804	-1013.5	-1145.83	-1165.45	-1005.96	233.3898	133.4523	-551.757	-775.223	-1326.99	744.3657
FinalTotLoss (P)	183.5089	194.5545	168.9357	142.0232	132.5551	125.8289	143.8931	183.7828	202.2082	156.5105	128.7174	131.2682	132.2298	120.2419	110.1325	101.659	99.33796	110.4737	170.1147	171.8425	134.9534	122.8806	85.66873	189.3108
FinalTotLoss (Q)	108.7341	324.4955	-189.501	-583.299	-709.496	-798.434	-833.524	-174.655	149.305	-600.818	-902.855	-852.548	-910.262	-1019.89	-1148.65	-1156.52	-1132.63	-1121.29	-303.35	-370.274	-790.975	-957.788	-1056.89	228.3406
PowerGen (P)	28.00677	28.98879	25.42461	23.17006	21.61499	20.50626	20.83073	26.13262	28.03565	22.6337	18.6836	19.08114	18.94595	17.18909	16.11806	15.00574	14.73639	16.28077	25.19467	24.55722	20.2864	18.59661	13.40413	28.90835
PowerGen (Q)	7.471783	7.89616	6.525454	5.554736	5.02989	4.657131	4.835972	6.832197	7.612686	5.511681	4.210843	4.357034	4.286014	3.708102	3.285711	2.96997	2.903103	3.340407	6.444813	6.225082	4.712545	4.098199	2.590646	7.77797
Cost (€)	282.8587	858.7794	6	3	3	3	6	237.8027	923.7434	9	9	6	6	6	0	3	0	0	10.63463	6.615149	3	3	3	525.4334
FlexL007 (P)	0.1702	0.1702	0	0	0	0	0	0.1702	0.1702	0	0	0	0	0	0	0	0	0	0.159815	0.024606	0	0	0	0.1702
SyncPe01 (P)	1.711565	1.45181	1.044055	1.916752	1.528931	1.305018	0.484675	0.55938	0.410172	0.484675	0.55938	0.410172	0.410172	0.484675	0.708588	0.820343	0.74584	0.794972	0.94418	0.981432	1.13064	1.13064	1.055935	1.89138
Flexsc01 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RHTB0001 (Pinit)	7.853802	7.989559	7.382618	6.787434	6.371332	6.079018	6.633858	7.774469	8.163456	6.975668	5.957338	6.040185	6.07997	5.56873	5.195077	4.849354	4.734148	5.209494	7.428723	7.428715	6.320147	5.818042	4.159387	7.955453
RHTB0001 (Pfinal)	7.850157	7.985795	7.379535	6.784688	6.369013	6.076955	6.630269	7.769757	8.158462	6.972047	5.95451	6.037341	6.077375	5.566256	5.193102	4.84714	4.730929	5.207563	7.425043	7.42457	6.317159	5.815559	4.156965	7.95174
RHTB0001 (Qinit)	1.445753	1.47113	1.2293	1.002076	0.845577	0.737845	1.056098	1.516673	1.643596	1.157965	0.785448	0.810238	0.841082	0.643438	0.489419	0.354078	0.30289	0.487361	1.354877	1.329548	0.902629	0.70565	0.055654	1.455221
RHTB0001 (Qfinal)	1.291619	1.31466	1.046138	0.883028	0.746989	0.656787	0.778073	1.174341	1.281032	0.875023	0.663501	0.687159	0.663298	0.526963	0.390378	0.361514	0.347634	0.397345	1.095743	1.006676	0.775474	0.586021	0.340895	1.299455
RHTB0002 (Pinit)	18.29347	19.40189	17.0172	14.4805	13.72779	13.13419	13.72568	17.6498	19.31669	15.18913	12.17541	12.64042	12.4642	11.14074	10.21854	9.340403	9.261742	10.28067	16.68035	16.13625	12.84477	11.654	8.193071	18.91491
RHTB0002 (Pfinal)	18.27485	19.38098	17.00102	14.46862	13.71705	13.12429	13.71578	17.63328	19.29682	15.17698	12.16972	12.63363	12.4584	11.13816	10.21637	9.338255	9.259618	10.27824	16.66564	16.12661	12.83861	11.65041	8.191228	18.89503
RHTB0002 (Qinit)	0.044866	0.11233	-0.02369	-0.13061	-0.15492	-0.17169	-0.15508	0.008989	0.106784	-0.10474	-0.19433	-0.18409	-0.18813	-0.21249	-0.22324	-0.22871	-0.22898	-0.22266	-0.04015	-0.06526	-0.17911	-0.20424	-0.22888	0.081802
RHTB0002 (Qfinal)	1.700253	1.746035	1.471814	1.039959	1.026423	0.83505	1.026294	1.493213	1.74222	1.237952	0.816016	0.824211	0.81966	0.623529	0.616713	0.440489	0.440426	0.614564	1.461221	0.551237	0.825218	0.804602	0.443153	1.725196
Nt1Tr001 (tap)	3	3	-2	-2	-1	0	-3	-2	-1	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	3
Nt1Tr002 (tap)	-3	-3	-3	-3	-3	-3	-3	-2	-1	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3
Nt1Tr003 (tap)	6	6	7	9	9	9	4	2	1	4	9	9	7	9	9	9	9	9	5	3	9	9	9	6
Nt2Tr004 (tap)	3	3	3	3	3	3	3	3	3	3	2	3	3	3	3	3	3	3	3	3	3	3	3	3
Nt2Tr005 (tap)	9	9	9	9	9	9	9	9	9	9	6	7	6	3	3	2	2	2	9	6	6	4	2	9

Table 245 – Network 6 winter scenario 3.

Period	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
InitTotLoss (P)	195.5459	208.3054	179.2507	149.0783	138.8456	131.5452	151.0789	195.8763	216.7748	165.1496	131.5372	135.1999	135.3024	120.4606	110.1031	101.1378	98.9766	109.86	180.348	177.6198	138.0697	123.8013	86.66907	202.2168
InitTotLoss (Q)	446.2038	693.7779	153.7247	-360.148	-516.193	-630.39	-457.905	340.9902	726.4225	-193.52	-750.546	-679.491	-697.893	-919.36	-1064.9	-1189.83	-1208.08	-1058.11	107.669	13.48879	-632.052	-842.264	-1361.04	581.613
FinalTotLoss (P)	175.3377	185.8097	164.8421	136.3255	127.5029	122.0141	138.4824	175.9124	193.339	150.3624	125.5395	128.0628	127.4005	116.0912	107.0915	98.4152	96.23575	106.8194	167.4032	169.4253	129.8104	118.4691	83.09374	180.7491
FinalTotLoss (Q)	9.806042	214.0349	-171.001	-654.46	-758.64	-826.38	-875.639	-277.088	41.34101	-626.252	-934.788	-886.14	-917.524	-1074.23	-1140.85	-1155.75	-1173.12	-1128.79	-294.909	-353.414	-860.982	-1018.02	-1054.58	148.0042
PowerGen (P)	27.19571	28.14914	24.69154	22.49991	20.99004	19.91431	20.22839	25.37597	27.22363	21.97896	18.14518	18.53111	18.39784	16.69239	15.65317	14.57141	14.31092	15.81051	24.46986	23.85115	19.69976	18.05911	13.01716	28.07086
PowerGen (Q)	7.16037	7.567194	6.348854	5.306761	4.815176	4.471584	4.63028	6.527573	7.2894	5.309896	4.03158	4.173023	4.126431	3.517231	3.166252	2.845801	2.746112	3.204528	6.258538	6.051674	4.48364	3.891973	2.486924	7.477198
Cost (€)	271.3161	801.4678	9	3	3	6	9	221.6987	875.5321	3	6	3	3	3	3	0	0	0	10.47992	6.577491	6	3	3	469.5358
FlexL007 (P)	0.1702	0.1702	0	0	0	0	0	0.1702	0.1702	0	0	0	0	0	0	0	0	0	0.15448	0.0231	0	0	0	0.1702
SyncPe01 (P)	1.711565	1.45181	1.044055	1.916752	1.528931	1.305018	0.484675	0.55938	0.410172	0.484675	0.55938	0.410172	0.410172	0.484675	0.708588	0.820343	0.74584	0.794972	0.94418	0.981432	1.13064	1.13064	1.055935	1.89138
Flexsc01 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RHTB0001 (Pinit)	7.621512	7.753345	7.16902	6.591213	6.187251	5.903458	6.441778	7.544175	7.921874	6.773704	5.785064	5.865516	5.904105	5.407795	5.045082	4.709455	4.597627	5.059093	7.214388	7.214381	6.137351	5.649919	4.039697	7.720237
RHTB0001 (Pfinal)	7.618178	7.749893	7.165997	6.588717	6.18511	5.90152	6.438624	7.539972	7.917412	6.770503	5.782438	5.862876	5.901349	5.405502	5.043304	4.706255	4.594448	5.057298	7.211108	7.210737	6.134576	5.647618	4.03695	7.716629
RHTB0001 (Qinit)	1.350868	1.375165	1.142722	0.923847	0.773029	0.669173	0.975971	1.419238	1.541344	1.074119	0.715137	0.739046	0.768812	0.578209	0.429625	0.298992	0.249568	0.427616	1.2643	1.239563	0.828112	0.638189	0.010792	1.359841
RHTB0001 (Qfinal)	1.228894	1.250966	1.031009	0.82183	0.703	0.615417	0.732597	1.094171	1.209695	0.856273	0.595734	0.618576	0.647648	0.463949	0.377125	0.34392	0.2952	0.38079	1.039439	0.952981	0.703807	0.520956	0.330436	1.260465
RHTB0002 (Pinit)	17.71326	18.79688	16.49372	14.00559	13.28611	12.71631	13.31439	17.12194	18.74453	14.73521	11.80705	12.26287	12.09177	10.80464	9.902737	9.046882	8.972678	9.960566	16.16956	15.64024	12.44032	11.28422	7.926049	18.31131
RHTB0002 (Pfinal)	17.69577	18.77724	16.48148	13.99444	13.276	12.70777	13.30509	17.10642	18.72584	14.72378	11.80336	12.25806	12.08632	10.80221	9.901275	9.044815	8.970633	9.958237	16.16009	15.63589	12.43455	11.28085	7.924271	18.29265
RHTB0002 (Qinit)	0.012506	0.07458	-0.04894	-0.14633	-0.16758	-0.1822	-0.1669	-0.01848	0.071322	-0.12174	-0.20153	-0.19251	-0.19605	-0.21701	-0.22574	-0.22952	-0.22964	-0.22532	-0.06377	-0.08659	-0.1886	-0.21031	-0.22779	0.045913
RHTB0002 (Qfinal)	1.495563	1.720277	0.37866	1.03111	0.837131	0.827538	0.837432	1.475194	1.718055	1.045046	0.806383	0.814716	0.81503	0.620485	0.612589	0.440445	0.440509	0.612843	0.200115	-0.29901	0.819407	0.626543	0.444854	1.700966
Nt1Tr001 (tap)	3	3	-1	-1	1	2	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	3
Nt1Tr002 (tap)	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3
Nt1Tr003 (tap)	7	7	9	9	9	9	5	3	3	6	9	9	9	9	9	9	9	9	6	4	9	9	9	8
Nt2Tr004 (tap)	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Nt2Tr005 (tap)	9	9	7	9	9	8	9	9	9	9	4	5	6	3	2	2	2	2	6	3	6	4	2	9

Table 246 – Network 6 winter scenario 4.

Period	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
InitTotLoss (P)	194.5196	210.4657	180.3659	145.0399	137.321	131.3096	159.4534	207.5626	232.0938	174.7375	137.4155	142.4645	142.6502	125.8273	113.1214	102.837	100.8209	112.3083	186.2382	179.4019	140.261	125.0663	86.0246	199.4009
InitTotLoss (Q)	370.2067	679.2124	165.9881	-484.728	-587.713	-674.028	-366.804	489.2002	942.6172	-79.3088	-695.615	-597.93	-617.665	-868.385	-1051.14	-1194.77	-1207.01	-1053.69	159.9596	32.44865	-647.74	-867.084	-1395.09	472.9309
FinalTotLoss (P)	174.7791	187.8915	165.8754	133.3299	128.1483	126.0513	145.4803	185.6414	206.037	158.4135	129.31	132.9448	133.9265	120.3248	109.8572	100.1483	98.17578	109.0616	171.6808	170.7728	131.8259	120.9521	83.0486	178.7243
FinalTotLoss (Q)	-138.357	116.8514	-136.24	-771.134	-826.859	-825.753	-863.087	-166.912	194.3093	-624.7	-972.521	-902.631	-933.873	-1042.05	-1186.05	-1252.65	-1206.4	-1188.63	-358.835	-341.91	-932.343	-1017.16	-1154.83	-24.5465
PowerGen (P)	28.74555	29.75572	26.09987	23.78006	22.18769	21.05403	21.38807	26.83161	28.78725	23.23946	19.18328	19.59232	19.45309	17.64775	16.5478	15.40515	15.12935	16.71456	25.86853	25.21129	20.82506	19.091	13.75938	29.66934
PowerGen (Q)	7.422518	7.891946	6.756598	5.531869	5.066405	4.776318	4.958676	7.028188	7.858206	5.651967	4.281339	4.449355	4.402	3.813055	3.367025	2.987058	2.942966	3.393485	6.570555	6.430687	4.721488	4.174753	2.591135	7.727934
Cost (€)	553.2998	891.5035	126.9861	9	3	6	9	506.7015	1628.884	9	6	3	6	6	3	0	0	0	263.9418	169.8813	6	6	0	629.5565
FlexL007 (P)	0.1702	0.1702	0.1702	0	0	0	0	0.1702	0.1702	0	0	0	0	0	0	0	0	0	0.1702	0.1702	0	0	0	0.1702
FlexL020 (P)	0.0182	0.0182	0.0182	0	0	0	0	0.0182	0.0182	0	0	0	0	0	0	0	0	0	0.0182	0.0182	0	0	0	0.0182
SyncPe01 (P)	3.42313	2.90362	2.088109	3.833503	3.057862	2.610036	0.96935	1.11876	0.820343	0.96935	1.11876	0.820343	0.820343	0.96935	1.417176	1.640686	1.491679	1.589943	1.88836	1.962863	2.26128	2.26128	2.11187	3.78276
Flexsc01 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RHTB0001 (Pinit)	8.051655	8.19109	7.389341	6.970193	6.54278	6.242527	6.812776	7.970397	8.369908	7.16379	6.117802	6.202878	6.24378	5.71863	5.334782	4.979652	4.861297	5.349576	7.604256	7.461742	6.490409	5.974633	4.270853	8.156059
RHTB0001 (Pfinal)	8.047702	8.187017	7.386072	6.967255	6.540238	6.2403	6.808717	7.965171	8.364357	7.159709	6.115132	6.200196	6.240912	5.715982	5.332594	4.977865	4.858921	5.3474	7.600211	7.457845	6.487547	5.971975	4.268681	8.152046
RHTB0001 (Qinit)	1.53265	1.559047	1.284533	1.075457	0.913604	0.80222	1.13127	1.605903	1.737294	1.236644	0.851366	0.876986	0.908844	0.704569	0.545435	0.405664	0.352817	0.543331	1.4369	1.389645	0.97251	0.768883	0.09763	1.542601
RHTB0001 (Qfinal)	1.31675	1.340744	1.190884	0.9533	0.798493	0.705566	0.817707	1.259268	1.370008	0.917962	0.672983	0.697449	0.698967	0.585966	0.4322	0.365351	0.36787	0.429945	1.111196	1.098464	0.7887	0.646951	0.349939	1.354303
RHTB0002 (Pinit)	17.10266	18.49571	16.44936	12.989	12.59718	12.20764	13.61975	17.57565	19.43427	15.12245	11.95472	12.57851	12.39757	10.9656	9.799456	8.788596	8.780744	9.778641	16.20183	15.60668	12.08167	10.85951	7.380484	17.56333
RHTB0002 (Pfinal)	17.08632	18.47668	16.43729	12.9793	12.58959	12.20369	13.61001	17.55928	19.41415	15.1104	11.94939	12.57178	12.39183	10.96242	9.798026	8.786594	8.778747	9.777216	16.19156	15.60218	12.07623	10.85775	7.378823	17.54613
RHTB0002 (Qinit)	-0.01923	0.056716	-0.05093	-0.17528	-0.18488	-0.1935	-0.15818	0.005068	0.114345	-0.10729	-0.19871	-0.1855	-0.18958	-0.2149	-0.22638	-0.22974	-0.22975	-0.2265	-0.06226	-0.08791	-0.19612	-0.21619	-0.22415	0.004628
RHTB0002 (Qfinal)	1.474797	1.708261	0.199657	0.833404	0.82388	0.809973	0.842008	1.490644	1.747423	1.236452	0.813566	0.823442	0.818809	0.623745	0.612242	0.440873	0.440882	0.612186	-0.51566	-0.13021	0.815067	0.61929	0.279126	1.49044
Nt1Tr001 (tap)	3	3	3	-2	-2	-1	-3	-2	-1	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	3
Nt1Tr002 (tap)	-3	-3	-3	-3	-3	-3	-3	-2	-1	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3
Nt1Tr003 (tap)	4	4	8	9	9	9	3	2	1	3	7	7	6	9	9	9	9	9	3	4	7	9	9	5
Nt2Tr004 (tap)	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Nt2Tr005 (tap)	9	9	7	9	7	3	9	9	9	9	6	7	6	4	2	2	2	2	7	3	6	2	2	9

Table 247 – Network 6 winter scenario 5.

Period	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
InitTotLoss (P)	174.718	188.9679	166.7358	131.7399	125.3854	120.3555	145.5496	187.3128	209.0759	158.9774	126.2333	130.7978	130.9408	116.1675	104.9238	95.89327	94.1917	104.1543	169.069	166.433	128.2389	115.0195	81.19415	178.7736
InitTotLoss (Q)	61.06673	336.3816	-77.3742	-683.9	-766.877	-838.333	-554.816	192.5955	594.2653	-302.651	-844.523	-756.368	-773.651	-994.827	-1158.1	-1285.03	-1294.94	-1161.49	-99.7157	-192.888	-811.986	-1003.28	-1462.48	146.0521
FinalTotLoss (P)	166.4955	169.7366	151.4441	125.5581	116.9184	115.1734	137.1679	170.794	186.9702	145.2077	121.3928	123.3711	124.994	111.5037	102.1579	93.39154	91.6708	101.3831	153.6818	151.5732	121.1368	111.5892	77.78759	166.7799
FinalTotLoss (Q)	-122.087	-54.972	-433.49	-840.173	-954.619	-951.506	-862.994	-362.46	-67.9328	-716.922	-1007.09	-968.892	-956.425	-1155.65	-1217.79	-1246.45	-1216.57	-1215.44	-549.454	-656.322	-1019.22	-1143.12	-1144.09	-81.4606
PowerGen (P)	26.99353	27.93231	24.50221	22.32876	20.82982	19.76551	20.08299	25.19012	27.02339	21.81725	18.01179	18.39442	18.26439	16.56891	15.5367	14.46259	14.20606	15.69239	24.28184	23.66346	19.55073	17.92355	12.91906	27.85682
PowerGen (Q)	6.975544	7.242895	6.038739	5.078394	4.57921	4.308449	4.603445	6.393396	7.128141	5.17665	3.923631	4.053962	4.051331	3.402865	3.058327	2.726393	2.683556	3.086631	5.956991	5.702849	4.287042	3.731638	2.37178	7.196039
Cost (€)	256.7804	349.0661	3	6	6	6	9	210.4824	585.8518	3	6	3	3	0	3	0	0	0	10.19056	3.317997	6	3	0	325.8318
FlexL007 (P)	0.1702	0.1702	0	0	0	0	0	0.1702	0.1702	0	0	0	0	0	0	0	0	0	0.135088	0.004712	0	0	0	0.1702
FlexL020 (P)	0.0182	0.0182	0	0	0	0	0	0.0182	0.0182	0	0	0	0	0	0	0	0	0	0.0182	0.0182	0	0	0	0.0182
SyncPe01 (P)	3.42313	2.90362	2.088109	3.833503	3.057862	2.610036	0.96935	1.11876	0.820343	0.96935	1.11876	0.820343	0.820343	0.96935	1.417176	1.640686	1.491679	1.589943	1.88836	1.962863	2.26128	2.26128	2.11187	3.78276
Flexsc01 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RHTB0001 (Pinit)	7.546969	7.677877	7.117476	6.543861	6.142828	5.861091	6.395429	7.470038	7.845025	6.724969	5.743492	5.823366	5.861667	5.368959	5.008885	4.675694	4.564681	5.022798	7.16265	7.162643	6.09324	5.609348	4.010812	7.645014
RHTB0001 (Pfinal)	7.543533	7.674324	7.11452	6.541426	6.140722	5.859184	6.392366	7.466037	7.840764	6.721857	5.740914	5.820774	5.858961	5.366709	5.007095	4.672503	4.563185	5.020975	7.15945	7.159084	6.090515	5.60709	4.007978	7.641461
RHTB0001 (Qinit)	1.326023	1.350059	1.121931	0.905056	0.755598	0.65267	0.956725	1.393715	1.514592	1.053982	0.698241	0.721939	0.751447	0.562531	0.415249	0.285745	0.236744	0.413252	1.243094	1.218628	0.810208	0.621976	-2E-06	1.334888
RHTB0001 (Qfinal)	1.229666	1.251459	0.996386	0.816922	0.686239	0.599522	0.744441	1.070151	1.184558	0.837006	0.579439	0.602086	0.630911	0.448794	0.374655	0.330894	0.330896	0.378242	1.019166	0.964068	0.686577	0.50531	0.326822	1.263924
RHTB0002 (Pinit)	15.84342	17.18245	15.31279	11.95846	11.63851	11.30051	12.72646	16.42921	18.19145	14.13655	11.1547	11.75846	11.58864	10.23562	9.113667	8.151236	8.153033	9.083548	15.09274	14.5297	11.20361	10.05669	6.800753	16.25348
RHTB0002 (Pfinal)	15.83847	17.16597	15.29958	11.95383	11.63124	11.29629	12.72127	16.41692	18.17388	14.12604	11.15211	11.75331	11.58509	10.23285	9.112429	8.149397	8.151196	9.08147	15.08074	14.5186	11.19893	10.05518	6.799214	16.2442
RHTB0002 (Qinit)	-0.07784	-0.01523	-0.09977	-0.19842	-0.20436	-0.20994	-0.182	-0.05195	0.038952	-0.14221	-0.21225	-0.2024	-0.2054	-0.22306	-0.22934	-0.2287	-0.22872	-0.22939	-0.10835	-0.12891	-0.21144	-0.22448	-0.21841	-0.05977
RHTB0002 (Qfinal)	0.048813	1.477389	1.241007	0.808587	0.636569	0.626825	0.821656	-0.16841	1.696287	1.03335	0.623718	0.811545	0.803831	0.619499	0.440452	0.443429	0.44341	0.44048	1.053038	1.040943	0.629571	0.613412	0.285999	0.737138
Nt1Tr001 (tap)	3	3	0	0	1	2	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	3
Nt1Tr002 (tap)	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3
Nt1Tr003 (tap)	8	8	8	9	9	9	6	3	3	6	9	9	9	9	9	9	9	9	6	5	9	9	9	9
Nt2Tr004 (tap)	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Nt2Tr005 (tap)	3	9	9	4	8	4	5	8	9	9	3	6	4	4	2	2	2	2	9	9	6	2	2	5

Table 248 – Network 6 winter scenario 6.

Period	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
InitTotLoss (P)	208.0317	231.2116	207.4978	148.4924	143.956	139.5022	187.7258	247.9237	282.4278	206.9126	158.2987	166.705	167.1261	144.5189	125.7774	111.8977	109.867	123.7735	213.1252	204.1544	154.2621	135.7459	88.94813	210.0434
InitTotLoss (Q)	444.7222	894.7591	461.4937	-567.498	-593.731	-640.039	-40.1706	1017.194	1657.63	321.8015	-474.633	-312.244	-336.466	-671.346	-945.962	-1138.41	-1140.99	-966.627	462.8366	295.4585	-559.219	-815.673	-1407.9	497.9625
FinalTotLoss (P)	186.1383	204.999	185.7141	140.9671	134.2495	131.0797	171.167	218.5239	247.097	185.0596	147.3147	152.0421	154.5953	136.9647	121.3647	108.4458	106.5968	119.4483	190.2594	184.5323	145.5974	130.1665	86.72836	187.4916
FinalTotLoss (Q)	-169.506	177.6838	-204.079	-951.178	-964.181	-929.788	-574.415	221.0512	737.3816	-345.127	-918.42	-843.362	-804.898	-1054.62	-1150.26	-1272.92	-1274.02	-1170.1	-207.287	-328.32	-1009.35	-1157.89	-1367.47	-150.595
PowerGen (P)	32.96577	34.12789	29.94064	27.27093	25.44326	24.14179	24.54251	30.78909	33.03793	26.66564	22.00767	22.47752	22.3192	20.2464	18.98086	17.66857	17.35328	19.17119	29.67192	28.91318	23.88665	21.89469	15.77584	34.0218
PowerGen (Q)	8.506031	9.097788	7.708163	6.282102	5.799065	5.498958	6.104783	8.47571	9.529631	6.855846	5.109133	5.296768	5.316751	4.518202	4.076243	3.591763	3.490476	4.089732	7.742662	7.441561	5.476734	4.801404	2.921812	8.743554
Cost (€)	332.7525	447.1054	6	12	6	6	9	278.6323	578.6988	9	12	12	9	6	6	3	0	3	17.4842	16.6658	9	12	3	421.9375
FlexL007 (P)	0.1702	0.1702	0	0	0	0	0	0.1702	0.1702	0	0	0	0	0	0	0	0	0	0.1702	0.1702	0	0	0	0.1702
FlexL020 (P)	0.0182	0.0182	0	0	0	0	0	0.0182	0.0182	0	0	0	0	0	0	0	0	0	0.0182	0.0182	0	0	0	0.0182
FlexL021 (P)	0.0162	0.0162	0	0	0	0	0	0.0162	0.0162	0	0	0	0	0	0	0	0	0	0.0162	0.0162	0	0	0	0.0162
SyncPe01 (P)	6.846261	5.80724	4.176219	7.667006	6.115724	5.220072	1.9387	2.237519	1.640686	1.9387	2.237519	1.640686	1.640686	1.9387	2.834352	3.281372	2.983359	3.179887	3.776719	3.925726	4.522559	4.522559	4.22374	7.565521
Flexsc01 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RHTB0001 (Pinit)	9.254765	9.414812	8.703031	8.00031	7.509088	7.164056	7.821589	9.163342	9.622113	8.224432	7.022424	7.120057	7.167291	6.563649	6.122246	5.714037	5.577902	6.139154	8.741839	8.578144	7.450243	6.857314	4.89891	9.374536
RHTB0001 (Pfinal)	9.248039	9.407848	8.69712	7.995883	7.505546	7.160979	7.816911	9.154228	9.612378	8.217408	7.019383	7.115518	7.164588	6.561388	6.119446	5.711386	5.575451	6.136389	8.734703	8.571226	7.445586	6.853552	4.895679	9.36768
RHTB0001 (Qinit)	2.045556	2.078072	1.779825	1.498521	1.305321	1.172588	1.564848	2.132875	2.29097	1.690751	1.230756	1.261212	1.298983	1.055993	0.867028	0.701497	0.639012	0.864677	1.929827	1.873052	1.375044	1.13257	0.337701	2.058409
RHTB0001 (Qfinal)	1.71352	1.714557	1.406378	1.165922	1.045457	0.978474	1.247847	1.709396	1.84255	1.29636	0.931648	0.915984	1.010757	0.767811	0.688354	0.582963	0.522472	0.685843	1.548044	1.480422	0.993607	0.819001	0.378862	1.695935
RHTB0002 (Pinit)	16.68168	18.72771	17.08275	11.6117	11.82878	11.76675	14.79843	19.21239	21.60512	16.52396	12.7585	13.73122	13.52352	11.75145	10.02856	8.676935	8.795623	9.856356	16.97114	16.22388	11.92227	10.52023	6.657935	16.89996
RHTB0002 (Pfinal)	16.66687	18.7082	17.0673	11.60804	11.82199	11.76074	14.7869	19.19274	21.58027	16.50953	12.75077	13.72132	13.51392	11.74631	10.02707	8.675813	8.794469	9.85491	16.9559	16.21163	11.91851	10.51858	6.656415	16.884
RHTB0002 (Qinit)	-0.03965	0.070713	-0.02019	-0.2045	-0.20072	-0.20192	-0.11935	0.100292	0.268513	-0.04749	-0.18115	-0.15484	-0.16095	-0.20246	-0.22467	-0.22962	-0.22964	-0.22589	-0.0258	-0.06113	-0.19909	-0.22001	-0.21654	-0.02901
RHTB0002 (Qfinal)	1.461779	1.717817	1.474231	0.80188	0.815767	0.811989	1.046507	1.737837	1.490429	1.456566	0.828111	1.026464	0.840566	0.811557	0.613303	0.441264	0.440953	0.612581	1.470566	0.182975	0.808147	0.616514	0.288138	1.468628
Nt1Tr001 (tap)	3	3	-1	-3	-3	-3	-3	-1	0	-1	-3	-1	-3	-3	-3	-3	-3	-3	-1	0	0	-3	-3	3
Nt1Tr002 (tap)	-2	-1	-1	-3	-3	-3	-2	-1	0	-1	-3	-1	-3	-3	-3	-3	-3	-3	-2	-1	0	-3	-3	-1
Nt1Tr003 (tap)	1	0	1	3	5	7	-5	0	-1	0	-4	1	-6	-4	7	9	9	7	1	0	-1	3	9	0
Nt2Tr004 (tap)	-2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Nt2Tr005 (tap)	9	9	9	3	7	6	9	9	9	9	8	9	9	6	2	2	2	2	9	8	4	2	2	9

Table 249 – Network 6 winter scenario 7.

Period	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
InitTotLoss (P)	144.4341	160.4801	148.4928	107.7991	106.2172	104.2206	138.6121	176.5244	200.4407	151.2454	119.1856	125.3931	125.6275	110.5843	97.70912	88.54961	87.45704	96.13052	152.864	150.2752	114.2639	102.614	73.68903	144.7475
InitTotLoss (Q)	-514.19	-205.099	-426.904	-1141.42	-1133.37	-1146.99	-690.118	-11.5787	430.6759	-453.045	-981.346	-861.95	-877.646	-1103.52	-1297.43	-1426.49	-1424.65	-1316.12	-411.632	-504.075	-1080.51	-1241.55	-1606.25	-500.791
FinalTotLoss (P)	134.3905	146.112	136.28	104.3942	103.0591	101.2659	131.6968	159.8719	179.8245	138.7897	114.8071	120.5966	121.4658	107.3774	95.27927	86.39425	85.23517	93.73322	140.2267	139.7215	110.6127	99.75747	70.65318	133.7693
FinalTotLoss (Q)	-731.1	-504.027	-709.905	-1244.78	-1219.98	-1217.74	-969.955	-569.319	-203.318	-841.904	-1134.96	-1024.23	-1026.26	-1236.45	-1356.51	-1381.44	-1379.66	-1365.85	-808.539	-884.947	-1221.88	-1370.33	-1283.8	-709.157
PowerGen (P)	27.04383	27.99465	24.56245	22.37634	20.88009	19.81245	20.13927	25.25665	27.09933	21.87793	18.06059	18.44822	18.31702	16.61574	15.57763	14.50008	14.24166	15.73303	24.34309	23.7244	19.60036	17.96687	12.95169	27.90954
PowerGen (Q)	6.387642	6.816456	5.783235	4.692126	4.330985	4.058507	4.513408	6.207454	7.015035	5.069915	3.811036	4.014187	3.997009	3.336182	2.932906	2.603703	2.523509	2.949598	5.71805	5.493912	4.100829	3.519523	2.243039	6.590893
Cost (€)	247.6514	337.2658	6	6	3	3	9	201.0324	441.1947	3	6	0	3	0	0	0	0	0	10.01363	6.263848	6	0	0	316.8205
FlexL007 (P)	0.1702	0.1702	0	0	0	0	0	0.1702	0.1702	0	0	0	0	0	0	0	0	0	0.119491	0	0	0	0	0.1702
FlexL020 (P)	0.0182	0.0182	0	0	0	0	0	0.0182	0.0182	0	0	0	0	0	0	0	0	0	0.0182	0.0182	0	0	0	0.0182
FlexL021 (P)	0.0162	0.0162	0	0	0	0	0	0.0162	0.0162	0	0	0	0	0	0	0	0	0	0.0162	0.004896	0	0	0	0.0162
SyncPe01 (P)	6.846261	5.80724	4.176219	7.667006	6.115724	5.220072	1.9387	2.237519	1.640686	1.9387	2.237519	1.640686	1.640686	1.9387	2.834352	3.281372	2.983359	3.179887	3.776719	3.925726	4.522559	4.522559	4.22374	7.565521
Flexsc01 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RHTB0001 (Pinit)	7.554518	7.685856	7.139566	6.564154	6.161866	5.879248	6.415292	7.477298	7.853464	6.745855	5.761308	5.841429	5.879855	5.385603	5.024398	4.690163	4.578801	5.038352	7.184823	7.184816	6.112144	5.626735	4.023191	7.652895
RHTB0001 (Pfinal)	7.551088	7.682307	7.136573	6.561701	6.159745	5.877328	6.412192	7.4733	7.849203	6.742704	5.758709	5.838817	5.877127	5.383334	5.022619	4.686968	4.575627	5.036536	7.181577	7.181207	6.109398	5.624459	4.020393	7.649344
RHTB0001 (Qinit)	1.333918	1.358063	1.130836	0.913105	0.763064	0.65974	0.964969	1.401803	1.523105	1.062607	0.705479	0.729267	0.758885	0.569247	0.421407	0.29142	0.242238	0.419405	1.252903	1.228065	0.817877	0.628921	0.004622	1.342844
RHTB0001 (Qfinal)	1.237401	1.259292	1.019645	0.824644	0.693419	0.606332	0.752342	1.078075	1.192877	0.845259	0.586419	0.60915	0.63808	0.455286	0.374912	0.336474	0.28799	0.381398	1.028528	0.973066	0.693958	0.512012	0.329087	1.271708
RHTB0002 (Pinit)	12.44932	14.31212	13.25974	8.149462	8.606567	8.717019	11.79205	15.35366	17.42092	13.20567	10.06646	10.97121	10.80095	9.294991	7.72155	6.533232	6.684199	7.518299	13.2401	12.60112	8.969601	7.820766	4.708758	12.49834
RHTB0002 (Pfinal)	12.44188	14.3005	13.24966	8.147628	8.604621	8.715045	11.78837	15.34123	17.40484	13.19652	10.06436	10.96871	10.79921	9.293704	7.720656	6.531736	6.682678	7.516602	13.2309	12.59437	8.968402	7.819851	4.707559	12.49008
RHTB0002 (Qinit)	-0.18797	-0.13605	-0.16811	-0.22825	-0.22935	-0.22947	-0.20171	-0.09815	-0.00305	-0.16975	-0.22441	-0.21477	-0.21697	-0.2288	-0.22655	-0.215	-0.21695	-0.22515	-0.16869	-0.18475	-0.22938	-0.227	-0.18072	-0.18682
RHTB0002 (Qfinal)	0.822348	1.037036	0.836991	0.443905	0.441716	0.441329	0.806312	1.242003	1.485326	0.836051	0.616162	0.622003	0.618685	0.44053	0.276026	0.289901	0.287674	0.277851	0.836681	0.823996	0.440788	0.275368	0.156601	0.825518
Nt1Tr001 (tap)	3	3	-1	0	1	2	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	3
Nt1Tr002 (tap)	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3
Nt1Tr003 (tap)	8	8	9	9	9	9	6	3	3	6	9	9	9	9	9	9	9	9	6	5	9	9	9	9
Nt2Tr004 (tap)	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Nt2Tr005 (tap)	7	9	9	2	2	2	4	9	9	9	3	3	2	2	2	2	2	2	9	7	2	2	2	8

Table 250 – Network 6 summer scenario 1.

Period	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
InitTotLoss (P)	206.8479	225.5744	175.9866	150.3337	134.1349	130.5947	135.3518	175.3309	201.2332	145.5077	117.8813	115.4935	112.3984	101.4589	95.61139	88.82024	87.40091	98.09356	182.2823	172.4705	126.7146	113.1605	83.98268	222.5169
InitTotLoss (Q)	824.6461	1163.078	288.5661	-149.329	-428.816	-488.594	-409.437	285.7563	721.5394	-258.629	-746.294	-792.753	-858.473	-1038.79	-1137.23	-1243.11	-1259.97	-1080.95	371.8263	191.6454	-596.411	-825.305	-1324.99	1108.147
FinalTotLoss (P)	182.0108	197.2923	156.5113	134.8722	120.8752	117.7264	122.0164	155.8426	177.4492	131.2269	107.5619	105.5747	103.2299	93.10608	87.39275	80.338	78.53692	89.17461	162.015	153.9926	115.3512	103.1748	75.23438	194.7969
FinalTotLoss (Q)	321.8379	593.8495	-111.246	-348.46	-459.029	-484.723	-464.098	-114.023	238.8752	-436.445	-693.444	-726.713	-793.232	-845.331	-856.675	-855.502	-865.563	-788.26	-43.026	-188.632	-634.558	-708.792	-875.465	549.709
PowerGen (P)	25.50381	26.93657	22.94016	20.55882	18.87205	18.48995	19.00033	22.8937	25.02659	19.95557	16.78663	16.45356	15.98661	14.52635	13.64756	12.64169	12.46726	14.13413	23.38701	22.4825	17.83632	16.19617	11.80616	26.70305
PowerGen (Q)	6.942109	7.55175	5.861183	5.002389	4.462287	4.333465	4.492969	5.832045	6.746404	4.803669	3.759992	3.649363	3.484214	3.044794	2.801471	2.526701	2.455461	2.971339	6.077864	5.715925	4.088804	3.589111	2.287267	7.450405
Cost (€)	269.1199	1284.906	0	0	0	0	0	0	167.629	0	0	0	0	3	0	0	3	3	0	0	0	0	3	1120.722
RHTB0001 (Pinit)	7.065272	7.362986	6.399152	5.736489	5.277159	5.163298	5.324638	6.325679	6.94258	5.681392	4.890032	4.823707	4.776835	4.356683	4.084116	3.760585	3.670973	4.150947	6.59389	6.393591	5.170339	4.710419	3.514521	7.303741
RHTB0001 (Pfinal)	7.06226	7.3597	6.396721	5.733269	5.274993	5.161003	5.322546	6.32329	6.939686	5.678284	4.887965	4.821638	4.774908	4.354086	4.080739	3.756381	3.66629	4.147327	6.591301	6.391166	5.168473	4.708048	3.509517	7.300512
RHTB0001 (Qinit)	1.027702	1.123535	0.781371	0.531299	0.363877	0.32031	0.383557	0.741704	0.984786	0.537564	0.267619	0.249502	0.249287	0.096033	-0.00395	-0.12648	-0.1667	0.004049	0.873908	0.808582	0.366775	0.20018	-0.21364	1.101893
RHTB0001 (Qfinal)	0.967708	1.058414	0.73224	0.606464	0.567295	0.547746	0.565414	0.693777	0.926857	0.613197	0.498418	0.485599	0.472609	0.419171	0.389487	0.361358	0.315662	0.419171	0.821592	0.759367	0.530653	0.482376	0.268978	1.037823
RHTB0002 (Pinit)	18.46344	19.60191	16.56058	14.83897	13.60813	13.3379	13.689	16.58761	18.10786	14.28966	11.9059	11.63885	11.21815	10.17756	9.571491	8.889296	8.804873	9.991901	16.81348	16.10749	12.67601	11.49488	8.300174	19.42708
RHTB0002 (Pfinal)	18.44155	19.57687	16.54343	14.82555	13.59706	13.32894	13.67779	16.57041	18.0869	14.27729	11.89867	11.63193	11.2117	10.17226	9.566825	8.885309	8.800969	9.986807	16.79571	16.09133	12.66785	11.48813	8.296646	19.40254
RHTB0002 (Qinit)	6.418308	6.998491	5.480827	4.6753	4.128518	4.00312	4.163947	5.491323	6.245399	4.449086	3.435655	3.33031	3.166647	2.753967	2.526082	2.264423	2.226645	2.675988	5.619975	5.288814	3.755073	3.26925	2.050516	6.90801
RHTB0002 (Qfinal)	5.974401	6.493337	5.128943	4.395925	3.894992	3.785719	3.927555	5.138269	5.819547	4.190472	3.261574	3.163764	3.011605	2.625624	2.411984	2.165343	2.139799	2.552168	5.256272	4.956558	3.558151	3.106735	2.018289	6.412582
Nt1Tr001 (tap)	3	3	3	3	3	3	3	3	3	3	3	3	3	1	1	1	2	3	3	3	3	3	2	3
Nt1Tr002 (tap)	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3
Nt1Tr003 (tap)	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Nt2Tr004 (tap)	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Nt2Tr005 (tap)	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9

Table 251 – Network 6 summer scenario 2.

Period	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
InitTotLoss (P)	177.4972	195.7827	158.3208	128.5799	118.1089	116.8201	127.6429	162.5136	187.105	136.9568	111.5917	110.5389	107.8202	97.2708	90.59355	83.80605	82.84772	92.19766	165.0172	156.257	115.2496	103.3992	78.35964	188.2384
InitTotLoss (Q)	193.276	517.2619	-111.224	-618.414	-783.222	-798.917	-606.25	-22.0174	381.2736	-474.227	-908.014	-927.941	-984.769	-1153.11	-1264.62	-1367.44	-1375.11	-1226.73	-21.4353	-178.111	-859.875	-1051.08	-1458.35	378.0109
FinalTotLoss (P)	160.9225	174.8594	143.1508	117.7501	110.4389	110.6502	116.2931	154.2745	167.4815	124.9288	104.6881	106.5704	104.1347	93.3488	86.2988	78.66463	77.25304	87.61712	157.6359	141.7439	110.5617	98.81099	72.5985	168.5857
FinalTotLoss (Q)	-121.643	120.0249	-400.331	-686.08	-689.326	-642.04	-602.683	-178.837	7.956896	-582.911	-771.477	-730.18	-797.097	-860.492	-894.893	-900.855	-920.939	-836.45	-162.257	-454.984	-751.708	-813.44	-987.471	4.852062
PowerGen (P)	25.60851	27.04701	23.03989	20.64236	18.95455	18.57391	19.08818	23.00499	25.14004	20.04756	16.86633	16.53547	16.0661	14.59794	13.71347	12.702	12.5271	14.20201	23.49793	22.58106	17.91931	16.27145	11.86136	26.80856
PowerGen (Q)	6.530659	7.111663	5.600903	4.687427	4.255584	4.19923	4.378156	5.795909	6.546939	4.68231	3.70315	3.666692	3.500638	3.048112	2.780803	2.497212	2.415667	2.941277	5.988124	5.477975	3.994169	3.50489	2.190031	6.939001
Cost (€)	0	3	0	3	6	3	3	3	3	0	3	3	0	3	0	3	3	0	3	3	3	0	6	6
FlexL007 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SyncPe01 (P)	1.711565	1.45181	1.044055	1.916752	1.528931	1.305018	0.484675	0.55938	0.410172	0.484675	0.55938	0.410172	0.410172	0.484675	0.708588	0.820343	0.74584	0.794972	0.94418	0.981432	1.13064	1.13064	1.055935	1.89138
Flexsc01 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RHTB0001 (Pinit)	7.100657	7.399875	6.431171	5.765159	5.303511	5.189075	5.35123	6.357324	6.977347	5.709791	4.914442	4.847785	4.80068	4.378409	4.104468	3.779305	3.68924	4.171632	6.6269	6.42559	5.196163	4.733923	3.532002	7.340331
RHTB0001 (Pfinal)	7.097613	7.396555	6.428714	5.761342	5.301369	5.186808	5.349159	6.354911	6.974423	5.706675	4.912406	4.845747	4.798784	4.375866	4.10117	3.77516	3.684638	4.168094	6.624283	6.423141	5.194316	4.731591	3.527051	7.337069
RHTB0001 (Qinit)	1.041522	1.137987	0.793626	0.541999	0.373551	0.329721	0.39335	0.753719	0.998332	0.548289	0.276691	0.258462	0.258239	0.104073	0.003501	-0.11975	-0.16019	0.011551	0.886735	0.820991	0.376447	0.208847	-0.20741	1.116206
RHTB0001 (Qfinal)	0.980915	1.0722	0.743996	0.630976	0.568878	0.557167	0.569738	0.705305	0.939811	0.623658	0.502254	0.489354	0.476331	0.41984	0.390115	0.362353	0.309444	0.420002	0.833887	0.771275	0.534847	0.485995	0.275473	1.05148
RHTB0002 (Pinit)	16.81374	18.21711	15.58076	12.97392	12.13057	12.08679	13.26441	16.09746	17.77303	13.86716	11.40022	11.2823	10.85975	9.739645	8.905731	8.10831	8.098429	9.241046	15.93515	15.18948	11.59799	10.41231	7.280003	17.59736
RHTB0002 (Pfinal)	16.79933	18.19865	15.56712	12.96427	12.12425	12.08208	13.25434	16.0907	17.75544	13.85621	11.39454	11.27955	10.85715	9.737397	8.903712	8.106496	8.096619	9.238941	15.92946	15.17649	11.59436	10.40922	7.278373	17.58011
RHTB0002 (Qinit)	-0.03363	0.040492	-0.08901	-0.17578	-0.19515	-0.19605	-0.16823	-0.06698	0.015664	-0.15075	-0.20852	-0.21037	-0.2163	-0.2268	-0.22971	-0.22858	-0.22855	-0.22902	-0.07406	-0.10467	-0.20519	-0.22135	-0.22336	0.006317
RHTB0002 (Qfinal)	1.463585	1.697326	1.247515	0.650683	0.815603	0.810149	0.83676	-0.46896	1.497613	1.028629	0.630897	0.794564	0.619164	0.611993	0.440607	0.443643	0.443701	0.440438	0.052029	1.238012	0.801219	0.617804	0.280114	1.491488
Nt1Tr001 (tap)	3	3	3	2	3	3	3	3	3	3	3	3	3	1	1	2	3	3	3	3	3	3	2	3
Nt1Tr002 (tap)	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3
Nt1Tr003 (tap)	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Nt2Tr004 (tap)	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Nt2Tr005 (tap)	8	9	9	9	6	4	9	4	9	9	6	2	2	2	2	2	2	2	3	9	3	3	2	9

Table 252 – Network 6 summer scenario 3.

Period	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
InitTotLoss (P)	169.6563	186.9305	151.8249	123.666	113.9257	112.7667	123.1262	155.9194	179.0951	131.8683	107.9799	107.0171	104.4478	94.51515	88.20384	81.81805	80.93579	89.70765	158.1356	149.8815	111.2995	100.1699	76.67645	179.6986
InitTotLoss (Q)	65.28995	371.4289	-217.464	-698.51	-851.757	-865.624	-680.803	-130.92	249.8069	-556.404	-965.256	-983.448	-1036.96	-1195.79	-1301.49	-1398.58	-1405.63	-1266.13	-132.397	-280.03	-922.146	-1101.98	-1484.69	237.8644
FinalTotLoss (P)	158.9655	167.3336	137.6035	113.359	107.9542	105.1946	113.0071	140.8738	160.6576	120.4518	103.9113	101.601	100.6852	90.40713	83.66057	76.41316	75.09138	84.87911	143.2022	136.2714	105.9592	96.08955	70.71187	161.315
FinalTotLoss (Q)	-137.785	-0.74738	-485.641	-758.124	-679.938	-692.736	-613.443	-382.316	-101.048	-632.627	-753.144	-770.847	-810.231	-867.159	-893.854	-943.215	-949.472	-839.69	-409.376	-539.752	-783.543	-815.085	-1024.75	-111.312
PowerGen (P)	24.87222	26.26405	22.37361	20.04635	18.40828	18.03565	18.53742	22.33214	24.41259	19.46752	16.38186	16.0564	15.60203	14.17638	13.31746	12.33547	12.16566	13.79179	22.81012	21.92806	17.4008	15.80201	11.51928	26.03255
PowerGen (Q)	6.322515	6.789107	5.342433	4.46359	4.122204	4.008712	4.223618	5.420271	6.249207	4.477237	3.592306	3.499022	3.363382	2.928008	2.674071	2.356774	2.29083	2.826668	5.56451	5.221959	3.825347	3.378369	2.061037	6.622711
Cost(€)	0	3	0	3	6	3	3	3	0	3	6	3	6	3	3	3	0	0	6	3	3	3	0	3
FlexL007 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SyncPe01 (P)	1.711565	1.45181	1.044055	1.916752	1.528931	1.305018	0.484675	0.55938	0.410172	0.484675	0.55938	0.410172	0.410172	0.484675	0.708588	0.820343	0.74584	0.794972	0.94418	0.981432	1.13064	1.13064	1.055935	1.89138
Flexsc01 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RHTB0001 (Pinit)	6.895453	7.185951	6.245487	5.598892	5.150687	5.039584	5.197012	6.173808	6.775728	5.545096	4.772877	4.70815	4.662393	4.25241	3.986438	3.670738	3.583301	4.051673	6.435472	6.240018	5.046402	4.597617	3.430622	7.128142
RHTB0001 (Pfinal)	6.89259	7.182828	6.243174	5.59573	5.148388	5.037127	5.194802	6.171468	6.772977	5.541354	4.770656	4.705908	4.660303	4.249543	3.982692	3.666268	3.578388	4.047636	6.43318	6.237713	5.044428	4.595033	3.425418	7.125073
RHTB0001 (Qinit)	0.961629	1.05445	0.722762	0.48011	0.317586	0.275277	0.336698	0.684245	0.920021	0.486255	0.224203	0.206618	0.20644	0.057546	-0.03962	-0.15875	-0.19786	-0.03187	0.812568	0.749236	0.320495	0.158697	-0.24349	1.033475
RHTB0001 (Qfinal)	0.904533	0.992479	0.678968	0.569726	0.55564	0.542018	0.550914	0.673688	0.864888	0.579316	0.467911	0.47618	0.461483	0.40709	0.381912	0.310981	0.27262	0.409	0.771821	0.702388	0.519436	0.470879	0.227496	0.972503
RHTB0002 (Pinit)	16.27679	17.64676	15.09923	12.54295	11.73543	11.69943	12.86665	15.61499	17.24603	13.45183	11.05448	10.94432	10.53405	9.444325	8.628121	7.850611	7.843184	8.951205	15.44618	14.72116	11.2299	10.07869	7.039503	17.03229
RHTB0002 (Pfinal)	16.26806	17.62941	15.08638	12.53387	11.73096	11.69351	12.85794	15.60129	17.22944	13.44149	11.05182	10.94032	10.53155	9.442162	8.626176	7.848858	7.841434	8.949178	15.43276	14.70891	11.22573	10.07634	7.037923	17.0161
RHTB0002 (Qinit)	-0.05886	0.008928	-0.10813	-0.1862	-0.20273	-0.20339	-0.17858	-0.08763	-0.01216	-0.16304	-0.21369	-0.2152	-0.22013	-0.22831	-0.22975	-0.22741	-0.22737	-0.22965	-0.09451	-0.12218	-0.21111	-0.22437	-0.22108	-0.02285
RHTB0002 (Qfinal)	-0.1334	1.493196	1.05313	0.828204	0.805617	0.811057	0.829392	1.248341	1.479298	0.839431	0.621164	0.623557	0.616334	0.440619	0.441245	0.274895	0.274948	0.440556	1.244149	1.044803	0.626043	0.613456	0.282869	1.472401
Nt1Tr001 (tap)	3	3	3	3	3	3	3	3	3	2	3	3	2	1	2	3	3	3	3	3	3	3	3	3
Nt1Tr002 (tap)	-3	-3	-3	-1	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-1	-3	-3	-3	-3	-3
Nt1Tr003 (tap)	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Nt2Tr004 (tap)	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Nt2Tr005 (tap)	5	9	9	9	4	6	8	9	9	9	2	4	2	2	2	2	2	2	9	9	4	2	2	9

Table 253 – Network 6 summer scenario 4.

Period	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
InitTotLoss (P)	165.9599	185.2146	154.2362	118.1689	110.7231	110.927	127.8445	163.0359	190.0575	137.5148	110.9894	110.9485	108.2009	96.90832	88.92607	81.58426	80.91579	89.98944	162.0392	152.9116	110.8682	99.20643	75.30653	173.3418
InitTotLoss (Q)	-34.5322	316.451	-205.462	-829.121	-934.19	-920.901	-613.337	-27.9477	417.3402	-477.67	-930.499	-931.222	-989.066	-1169.39	-1304.6	-1416.11	-1417.48	-1276.39	-97.1622	-260.268	-955.518	-1140.89	-1521.88	95.49016
FinalTotLoss (P)	150.0235	166.0304	139.9125	114.1517	104.1722	106.9005	118.4589	155.6964	170.1081	125.6207	107.1978	105.0379	104.6858	93.27012	85.02008	76.87822	75.7278	85.82539	146.7797	139.1344	105.9358	95.67726	70.00588	162.9461
FinalTotLoss (Q)	-336.971	-46.8223	-478.401	-798.66	-855.655	-763.228	-609.895	-167.52	37.95209	-638.416	-771.783	-807.507	-840.51	-908.227	-956.309	-975.391	-959.689	-916.55	-387.907	-523.075	-908.029	-922.564	-1048.73	-100.506
PowerGen (P)	26.2813	27.76015	23.65181	21.19113	19.45457	19.06622	19.60006	23.62034	25.81359	20.58437	17.31918	16.97534	16.49551	14.98759	14.07839	13.0389	12.86007	14.57954	24.11415	23.18132	18.39136	16.70284	12.1755	27.51865
PowerGen (Q)	6.49412	7.132764	5.684109	4.723797	4.222147	4.208169	4.504789	5.967789	6.752645	4.772079	3.823114	3.707553	3.572741	3.105736	2.81909	2.508106	2.466579	2.96406	5.927758	5.569322	3.956997	3.511927	2.214164	7.020043
Cost (€)	2.79514	132.6345	0	3	6	6	3	3	3	0	3	3	3	3	0	3	0	0	3	0	6	6	3	96.88639
FlexL007 (P)	0.058048	0.1702	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.1702
FlexL020 (P)	0.0182	0.0182	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0182
SyncPe01 (P)	3.42313	2.90362	2.088109	3.833503	3.057862	2.610036	0.96935	1.11876	0.820343	0.96935	1.11876	0.820343	0.820343	0.96935	1.417176	1.640686	1.491679	1.589943	1.88836	1.962863	2.26128	2.26128	2.11187	3.78276
Flexsc01 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RHTB0001 (Pinit)	7.214428	7.408371	6.604104	5.920003	5.445833	5.328292	5.494851	6.528238	7.165126	5.863173	5.046279	4.977824	4.929465	4.495749	4.214385	3.880407	3.787893	4.283343	6.805186	6.598422	5.335635	4.860861	3.626408	7.347201
RHTB0001 (Pfinal)	7.211268	7.404995	6.601508	5.917038	5.443798	5.32616	5.492869	6.525688	7.162035	5.860876	5.044385	4.975936	4.92771	4.493457	4.211427	3.876094	3.783582	4.280187	6.80242	6.595833	5.332035	4.858721	3.621753	7.343883
RHTB0001 (Qinit)	1.107258	1.193252	0.860074	0.599994	0.42597	0.38071	0.446416	0.818859	1.0718	0.606416	0.325835	0.307001	0.306733	0.147612	0.043844	-0.08327	-0.12497	0.052174	0.956294	0.888274	0.428849	0.255794	-0.17367	1.170819
RHTB0001 (Qfinal)	1.044553	1.127042	0.807699	0.660824	0.586569	0.570588	0.586877	0.76777	1.010027	0.630528	0.516916	0.503598	0.48507	0.431072	0.407673	0.364559	0.346073	0.428805	0.900515	0.835806	0.523573	0.496972	0.308333	1.105704
RHTB0002 (Pinit)	15.5843	17.27979	14.97484	11.44339	10.95821	11.1327	13.14603	15.9816	17.84895	13.76494	11.15873	11.18389	10.75002	9.526966	8.451688	7.523799	7.586499	8.711375	15.43677	14.63474	10.80196	9.585043	6.443343	16.21154
RHTB0002 (Pfinal)	15.57065	17.26314	14.96219	11.44059	10.95291	11.13002	13.13784	15.97589	17.83121	13.75415	11.15603	11.17906	10.74745	9.524778	8.449786	7.522117	7.584805	8.709409	15.42337	14.62262	10.79804	9.582838	6.441878	16.20361
RHTB0002 (Qinit)	-0.0887	-0.01024	-0.11277	-0.20757	-0.21481	-0.21242	-0.17138	-0.07202	0.019839	-0.15384	-0.21216	-0.21182	-0.21763	-0.22791	-0.22949	-0.22528	-0.22574	-0.22972	-0.09483	-0.1252	-0.21689	-0.22753	-0.21385	-0.06165
RHTB0002 (Qfinal)	1.247809	1.480652	1.050405	0.796832	0.628151	0.793022	0.831582	0.053803	1.683551	1.026983	0.793186	0.627373	0.618172	0.440805	0.441932	0.277705	0.277121	0.441076	1.243998	1.043086	0.622658	0.611702	0.29121	1.43741
Nt1Tr001 (tap)	3	3	3	3	3	3	3	3	3	3	3	3	3	1	1	3	3	3	3	3	2	3	2	3
Nt1Tr002 (tap)	-3	-3	-3	-3	-2	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3
Nt1Tr003 (tap)	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Nt2Tr004 (tap)	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Nt2Tr005 (tap)	9	9	9	2	6	2	7	3	9	9	2	5	2	2	2	2	2	2	9	9	4	2	2	4

Table 254 – Network 6 summer scenario 5.

Period	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
InitTotLoss (P)	151.1218	169.2885	140.6689	108.5165	102.3689	102.7222	118.1927	148.9311	172.7703	126.6188	103.3233	103.4046	100.9775	91.05215	83.9467	77.50694	76.97691	84.8365	147.5679	139.5476	102.7659	92.63232	71.95641	158.4445
InitTotLoss (Q)	-281.959	41.47134	-425.396	-983.279	-1068.8	-1054.07	-771.894	-259.844	134.5137	-652.733	-1051.06	-1049.41	-1100.1	-1259.32	-1380.38	-1478.95	-1479.49	-1356.83	-328.533	-471.859	-1081.3	-1242.76	-1573.06	-160.803
FinalTotLoss (P)	137.4276	160.9112	128.2952	104.8089	98.47886	98.62065	110.2817	135.027	157.7742	117.6448	98.77979	99.46943	97.31804	87.02496	79.51066	72.21229	71.23326	80.14409	134.3664	127.6438	99.23003	88.83669	66.13198	143.6418
FinalTotLoss (Q)	-542.218	-117.086	-646.726	-913.368	-848.651	-803.808	-648.43	-474.968	-150.933	-698.604	-818.472	-797.407	-865.351	-913.081	-963.533	-1020.37	-1020.39	-919.449	-580.256	-699.101	-896.988	-941.863	-1109.48	-441.84
PowerGen (P)	24.67343	26.07045	22.20481	19.89486	18.26754	17.90047	18.40254	22.16706	24.23576	19.32657	16.25996	15.93983	15.48747	14.07193	13.21832	12.24334	12.07508	13.68869	22.63856	21.76313	17.27002	15.6821	11.43258	25.82932
PowerGen (Q)	5.871748	6.624061	5.13971	4.271052	3.919028	3.86387	4.153915	5.285848	6.153765	4.377719	3.495717	3.441786	3.278305	2.854461	2.577824	2.25595	2.196662	2.719983	5.349765	5.021275	3.678833	3.221433	1.954174	6.243883
Cost (€)	0	3	3	6	3	0	3	3	3	3	3	3	3	3	0	3	0	0	3	0	3	0	0	3
FlexL007 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL020 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SyncPe01 (P)	3.42313	2.90362	2.088109	3.833503	3.057862	2.610036	0.96935	1.11876	0.820343	0.96935	1.11876	0.820343	0.820343	0.96935	1.417176	1.640686	1.491679	1.589943	1.88836	1.962863	2.26128	2.26128	2.11187	3.78276
Flexsc01 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RHTB0001 (Pinit)	6.845932	7.134326	6.200676	5.558765	5.113804	5.003505	5.159793	6.129519	6.727072	5.505349	4.738712	4.674451	4.62902	4.222001	3.957952	3.644535	3.557732	4.022721	6.389275	6.195234	5.01026	4.56472	3.406154	7.076936
RHTB0001 (Pfinal)	6.843111	7.131249	6.198388	5.55564	5.111461	5.000996	5.157541	6.127136	6.724361	5.502224	4.736425	4.672152	4.626876	4.219033	3.954058	3.639987	3.552748	4.018557	6.38685	6.192964	5.008247	4.562069	3.400881	7.073912
RHTB0001 (Qinit)	0.94244	1.034389	0.705735	0.465233	0.304129	0.262185	0.323077	0.667551	0.901211	0.471343	0.21158	0.194148	0.193982	0.046353	-0.05	-0.16813	-0.20692	-0.04232	0.794749	0.731995	0.30704	0.146635	-0.25218	1.013607
RHTB0001 (Qfinal)	0.886174	0.973322	0.674415	0.558866	0.550061	0.539243	0.550591	0.671838	0.846879	0.551006	0.483663	0.473868	0.454104	0.410236	0.376179	0.301224	0.263203	0.404729	0.745675	0.685826	0.516629	0.466174	0.218483	0.953523
RHTB0002 (Pinit)	14.41896	16.04176	13.92935	10.5082	10.10057	10.29185	12.28211	14.93374	16.70425	12.86287	10.40786	10.4498	10.0426	8.885563	7.84884	6.96423	7.032233	8.081997	14.37506	13.61788	10.00282	8.860755	5.921199	14.98531
RHTB0002 (Pfinal)	14.40719	16.03558	13.91831	10.50572	10.09822	10.28943	12.27565	14.92117	16.69106	12.855	10.40478	10.44733	10.04025	8.883552	7.847084	6.962666	7.030656	8.08019	14.36335	13.6073	10.0005	8.858749	5.919828	14.97265
RHTB0002 (Qinit)	-0.13259	-0.06926	-0.1487	-0.22015	-0.22404	-0.22239	-0.19203	-0.11438	-0.03898	-0.17865	-0.22139	-0.22099	-0.22468	-0.22971	-0.22736	-0.22025	-0.22097	-0.22843	-0.13421	-0.15814	-0.22488	-0.22963	-0.20582	-0.11225
RHTB0002 (Qfinal)	1.038898	0.740462	1.029827	0.616409	0.613727	0.614807	0.817384	1.049412	-0.5156	0.827325	0.617778	0.615734	0.613247	0.44066	0.274949	0.283843	0.282993	0.443864	1.037905	0.842078	0.613167	0.440799	0.129782	1.050791
Nt1Tr001 (tap)	3	3	3	3	3	3	3	3	3	3	3	3	2	1	1	3	3	3	3	3	3	3	3	3
Nt1Tr002 (tap)	-3	-3	-3	0	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3
Nt1Tr003 (tap)	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Nt2Tr004 (tap)	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Nt2Tr005 (tap)	9	3	9	2	2	2	6	9	8	7	3	2	2	2	2	2	2	2	9	9	2	2	2	9

Table 255 – Network 6 summer scenario 6.

Period	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
InitTotLoss (P)	174.2124	202.4651	169.1933	116.048	111.3033	113.7014	144.8427	188.3425	226.1198	157.4366	122.9497	124.8286	121.4878	106.287	94.23244	84.36322	83.94441	94.5286	180.7731	169.0623	116.327	102.5474	75.64511	181.2525
InitTotLoss (Q)	-17.453	486.4804	-26.2556	-950.943	-990.591	-931.722	-359.624	352.8118	976.2891	-188.021	-773.361	-737.762	-809.844	-1051.1	-1256.77	-1404.74	-1396.4	-1239.33	138.0642	-70.6935	-930.355	-1141.93	-1550.97	89.16947
FinalTotLoss (P)	157.8781	181.3235	153.2634	111.9287	107.6199	109.2864	131.9079	168.9583	200.8821	143.0385	119.0202	119.9934	114.763	103.1086	91.35921	81.14279	80.2931	91.46121	170.0097	153.566	112.6241	99.53398	72.05598	163.741
FinalTotLoss (Q)	-460.44	-73.3516	-329.175	-1029.51	-1061.08	-995.632	-606.416	-15.4431	391.8179	-462.886	-817.982	-791.183	-920.058	-969.817	-1089.5	-1110.81	-1049.93	-1050.08	-145.344	-417.954	-998.121	-1083.02	-1162.45	-402.521
PowerGen (P)	30.1383	31.84005	27.12827	24.29431	22.30801	21.86098	22.48282	27.08975	29.62166	23.6155	19.86598	19.47492	18.91964	17.18945	16.14604	14.95292	14.74761	16.72019	27.6678	26.58991	21.09334	19.15166	13.96046	31.54893
PowerGen (Q)	7.378694	8.165584	6.741186	5.309518	4.763241	4.706926	5.260208	7.023731	8.097431	5.745056	4.452632	4.387791	4.142116	3.626957	3.24391	2.892216	2.879983	3.404027	7.10243	6.573653	4.592454	3.999765	2.578973	7.768682
Cost (€)	0	3	3	3	0	3	3	0	3	3	3	3	3	6	3	3	3	0	6	6	9	3	0	6
FlexL007 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL020 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL021 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SyncPe01 (P)	6.846261	5.80724	4.176219	7.667006	6.115724	5.220072	1.9387	2.237519	1.640686	1.9387	2.237519	1.640686	1.640686	1.9387	2.834352	3.281372	2.983359	3.179887	3.776719	3.925726	4.522559	4.522559	4.22374	7.565521
Flexsc01 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RHTB0001 (Pinit)	8.368892	8.722049	7.578643	6.792509	6.247719	6.112667	6.304065	7.49137	8.223421	6.727474	5.789106	5.710522	5.655115	5.156861	4.833645	4.44996	4.343631	4.912697	7.809958	7.572443	6.121508	5.576058	4.158218	8.651776
RHTB0001 (Pfinal)	8.36464	8.717213	7.575185	6.789759	6.245407	6.110431	6.301715	7.487976	8.219367	6.724792	5.787117	5.708555	5.653277	5.153388	4.831875	4.447509	4.340725	4.910771	7.806431	7.569192	6.119442	5.573147	4.154944	8.647059
RHTB0001 (Qinit)	1.548941	1.669107	1.242683	0.93326	0.726764	0.673191	0.750966	1.193855	1.495512	0.940395	0.60751	0.585152	0.584594	0.396747	0.274474	0.124997	0.076095	0.284445	1.357054	1.275699	0.72946	0.524709	0.018799	1.642101
RHTB0001 (Qfinal)	1.327619	1.410355	1.173364	0.877802	0.679939	0.648955	0.703267	1.126258	1.30635	0.885809	0.598861	0.585945	0.566139	0.495078	0.459056	0.430347	0.434059	0.491729	1.204249	1.154936	0.6891	0.598818	0.411236	1.384858
RHTB0002 (Pinit)	14.93999	17.33235	15.39019	9.839825	9.949184	10.53361	14.25392	17.38111	19.78333	14.96464	11.8443	12.12959	11.63156	10.09973	8.481727	7.225656	7.425189	8.63148	16.09248	15.10786	10.45382	9.058022	5.583097	15.34961
RHTB0002 (Pfinal)	14.9274	17.31559	15.37686	9.837547	9.946874	10.53048	14.2424	17.36426	19.76161	14.952	11.84135	12.12568	11.62568	10.09737	8.479813	7.224034	7.423527	8.629531	16.08465	15.09499	10.45134	9.055958	5.581776	15.33635
RHTB0002 (Qinit)	-0.11374	-0.00732	-0.09653	-0.22564	-0.22499	-0.21978	-0.13826	-0.00506	0.137285	-0.11318	-0.2007	-0.19518	-0.20459	-0.22414	-0.22945	-0.22272	-0.22444	-0.22958	-0.06698	-0.10761	-0.22068	-0.22922	-0.1996	-0.0979
RHTB0002 (Qfinal)	1.050038	1.482672	1.243064	0.612891	0.613222	0.618886	1.035615	1.484016	1.763236	1.050152	0.802315	0.808674	0.632939	0.613618	0.441913	0.280868	0.278755	0.441419	1.433111	1.053557	0.616036	0.440728	0.13652	1.242381
Nt1Tr001 (tap)	3	3	3	3	3	3	3	3	3	3	3	3	3	2	1	2	3	3	3	3	3	3	3	3
Nt1Tr002 (tap)	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-2	-3	-3	-3
Nt1Tr003 (tap)	4	3	9	9	9	9	9	9	5	9	9	9	9	9	9	9	9	9	6	7	9	9	9	3
Nt2Tr004 (tap)	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Nt2Tr005 (tap)	9	9	9	2	2	3	9	9	9	9	2	3	6	2	2	2	2	2	4	9	2	2	2	9

Table 256 – Network 6 summer scenario 7.

Period	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
InitTotLoss (P)	124.0759	143.0441	124.108	87.96544	86.04583	88.14665	111.3372	139.2989	165.0086	119.4586	96.64994	98.49935	96.27146	86.13195	77.72971	71.27471	71.18602	77.69255	132.0289	124.3221	90.34944	81.79631	65.56707	127.6009
InitTotLoss (Q)	-798.11	-459.54	-741.841	-1375.3	-1380.17	-1332.14	-903.291	-444.519	-15.0497	-790.246	-1179.01	-1143.76	-1190.71	-1353.78	-1499.38	-1598.06	-1590.13	-1493.39	-625.81	-763.126	-1318.56	-1449.76	-1695.08	-749.261
FinalTotLoss (P)	118.7847	130.8875	117.4133	85.22457	82.94284	84.75852	106.3957	127.0445	148.9553	111.498	93.08306	94.82842	92.86302	82.3723	73.61591	66.29728	65.73778	73.36613	123.0182	118.5285	87.4205	78.53279	60.05747	121.2786
FinalTotLoss (Q)	-894.362	-690.075	-860.844	-1294.21	-1150.66	-1073.88	-726.241	-636.929	-320.523	-800.41	-925.62	-892.26	-952.276	-1011.33	-1079.33	-1133.92	-1125.85	-1051.94	-797.718	-873.992	-1136.32	-1149.33	-1225.93	-864.77
PowerGen (P)	24.73087	26.12065	22.26229	19.93646	18.30826	17.94172	18.45529	22.22734	24.30149	19.37928	16.3043	15.98423	15.53067	14.11061	13.25312	12.27511	12.10675	13.72406	22.69688	21.821	17.31138	15.72008	11.4617	25.8866
PowerGen (Q)	5.540223	6.071961	4.943441	3.905728	3.631799	3.608282	4.090979	5.141838	6.003704	4.288517	3.401918	3.360086	3.204229	2.768302	2.473191	2.152548	2.101174	2.598981	5.15067	4.864103	3.453685	3.026961	1.847216	5.842416
Cost (€)	0	6	3	6	3	0	3	3	0	6	6	0	0	3	3	3	0	0	3	3	3	0	0	6
FlexL007 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL020 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FlexL021 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SyncPe01 (P)	6.846261	5.80724	4.176219	7.667006	6.115724	5.220072	1.9387	2.237519	1.640686	1.9387	2.237519	1.640686	1.640686	1.9387	2.834352	3.281372	2.983359	3.179887	3.776719	3.925726	4.522559	4.522559	4.22374	7.565521
Flexsc01 (P)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RHTB0001 (Pinit)	6.867155	7.156451	6.21988	5.575962	5.129611	5.018967	5.175744	6.148499	6.747924	5.522383	4.753354	4.688894	4.643322	4.235033	3.97016	3.655765	3.56869	4.035129	6.409073	6.214427	5.025749	4.578819	3.41664	7.098881
RHTB0001 (Pfinal)	6.864437	7.153354	6.217584	5.572742	5.127287	5.016481	5.173509	6.146151	6.745196	5.518648	4.751089	4.686619	4.641202	4.232128	3.966314	3.65125	3.563737	4.031015	6.406633	6.212142	5.023755	4.576204	3.411397	7.095955
RHTB0001 (Qinit)	0.950659	1.042982	0.713028	0.471606	0.309894	0.267794	0.328912	0.674702	0.909268	0.477731	0.216988	0.19949	0.199319	0.051148	-0.04555	-0.16411	-0.20304	-0.03784	0.802382	0.73938	0.312804	0.151802	-0.24846	1.022117
RHTB0001 (Qfinal)	0.898877	0.981528	0.675541	0.557409	0.550569	0.539694	0.553776	0.670214	0.854594	0.570975	0.491695	0.474131	0.458781	0.407179	0.378553	0.305404	0.267237	0.407192	0.752999	0.692921	0.509107	0.461362	0.222344	0.966492
RHTB0002 (Pinit)	11.02353	13.16999	11.87382	6.698226	7.066833	7.706888	11.34659	13.85459	15.92984	11.9288	9.317821	9.659153	9.250893	7.941561	6.45392	5.343766	5.560971	6.514638	12.52103	11.68759	7.766801	6.622821	3.827647	11.22928
RHTB0002 (Pfinal)	11.02017	13.16005	11.86848	6.696715	7.065249	7.70517	11.34308	13.84367	15.91561	11.92193	9.315693	9.656928	9.248782	7.939785	6.452451	5.342486	5.559659	6.513161	12.51353	11.68313	7.765063	6.62132	3.826561	11.22512
RHTB0002 (Qinit)	-0.21365	-0.17039	-0.19999	-0.21676	-0.22098	-0.22625	-0.20925	-0.151	-0.07424	-0.19912	-0.22867	-0.22718	-0.22894	-0.22779	-0.21394	-0.19495	-0.19926	-0.21474	-0.18657	-0.20343	-0.22667	-0.21605	-0.15702	-0.21064
RHTB0002 (Qfinal)	0.622913	0.835936	0.810162	0.287854	0.282928	0.27637	0.798339	1.028579	1.256674	0.816353	0.440595	0.611842	0.440501	0.44482	0.291097	0.141515	0.13689	0.290195	0.822985	0.805225	0.275816	0.288687	0.01114	0.626556
Nt1Tr001 (tap)	3	3	3	3	3	3	3	3	3	2	3	3	3	2	1	3	3	3	3	3	3	3	3	3
Nt1Tr002 (tap)	-2	-3	-3	-2	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-3	-2
Nt1Tr003 (tap)	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Nt2Tr004 (tap)	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Nt2Tr005 (tap)	3	9	5	2	2	2	3	9	9	7	2	2	2	2	2	2	2	2	7	4	2	2	2	4

Interval Constrained Power Flow (ICPF)

1 MV_ntwk_5_cplt – Part 2

The characteristics of the second part of the 1st French network are summarized as following:

- Number of buses: 161;
- Number of branches: 159;
- Number of transformer TAPs: 2;
- Number of generators: 1;
- Active Power Load: 27.28 MW;
- Reactive Power Load: 8.11 MVAr;
- Number of customers with $P_{ref} > 200\ kW$: 2.
-

Given the limited number of MV customers with $P_{ref} > 200\ kW$ in this network, we consider that all of them will have access to demand flexibility for the short, mid and long term scenarios. Only for the status quo scenario this lever is not considered.

All seven scenarios presented in 4.2.2 were tested for this network and the results are presented in the following sections in the same way as the previous sub-network. Please refer to it for more details regarding the scenarios integration.

1.1 Scenario 1 - Status quo

The results for the simulation of this baseline scenario are presented in Figure 259.

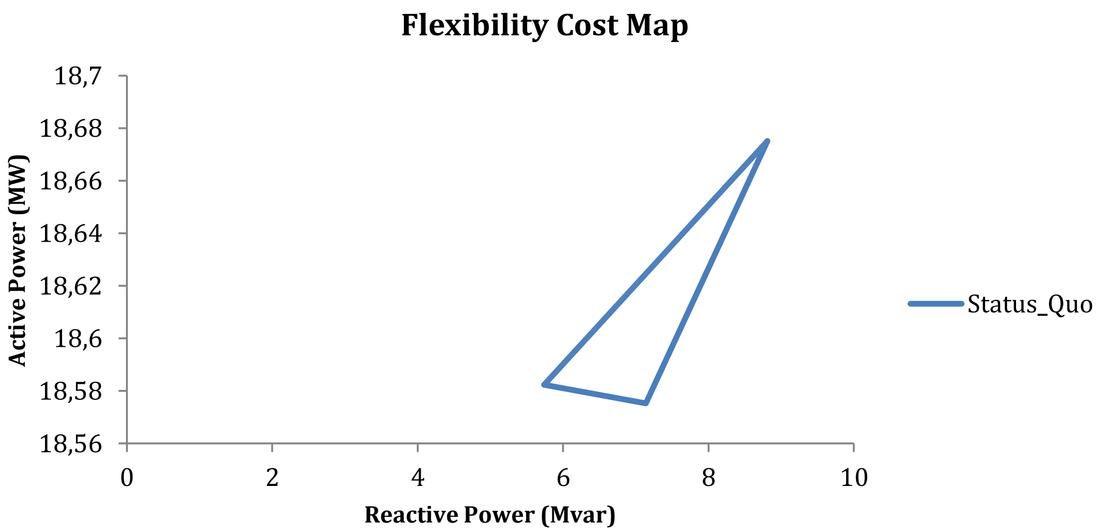


Figure 259 – Flexibility Cost Map for scenario 1 – *status quo* - Network5_Part2

Figure 259 allows to understand that the obtained results are in accordance with the expectations. To reach this conclusion is only necessary to observe the scale of the active and reactive power axes. On the one hand, the active power variation is almost equal to zero since in the *status quo* scenario there is no flexibility provided in terms of active power. The transformer TAPs variations and its impact on the voltage are responsible for this small variation. On the other hand, the variation in terms of reactive power is in accordance with the reactive power control rule. Therefore, the user has the possibility of choose any point (power exchange in the boundary node) inside this region.

By observing Figure 259, the feasible values of reactive power exchange at the boundary node presents a range of 3.07 MVAr. The flexibility criteria for this scenario allowed:
- Demand Flexibility: 0 MVAr & 0 MW,
- Generation Flexibility: 2.87 MVAr & 0 MW,
- Transformer TAPs,

which validates the result achieved by the ICPF tool.

1.2 Scenario 2 – Short-Term

The results obtained for this first short-term scenario and the comparison with the *status quo* can be observed in Figure 260. The characteristics of this scenario are described in more details in sections 4.2.2.2 and 4.3.2.2.1.2.

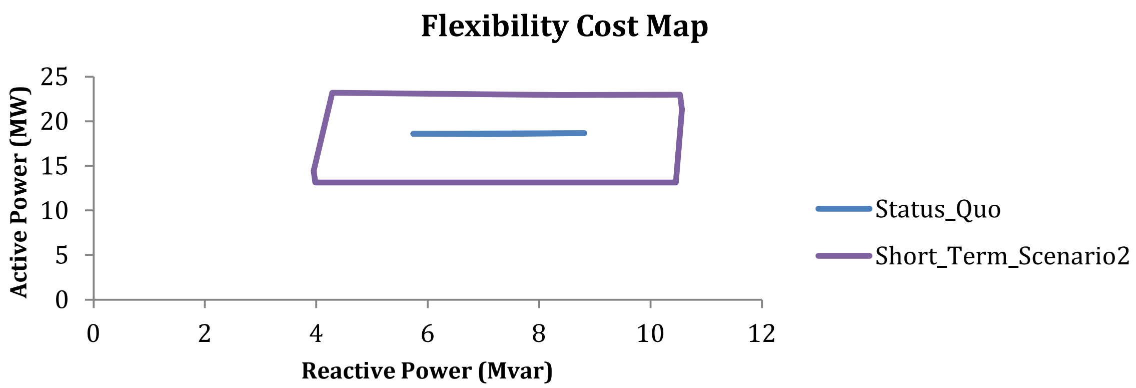


Figure 260 - Flexibility Cost Map for scenario 2 – short-term - Network5_Part2

As expected, the increase of the flexibility options in terms of demand and wind power curtailment led to the growth of the flexibility area which covers the entire baseline scenario. This behaviour was already expected since the reactive power control keeps available and, moreover, new flexibility features are added. By observing Figure 260, the feasible values of active and reactive power exchanged at the boundary node present a range of 10.78 MW and 6.61 MVAr respectively. The flexibility criteria for this scenario allowed:
- Demand Flexibility: 8.5 MW and 2.5 MVAr;
- Generation Flexibility: 1.33 MW and 3.87MVAr;
- Transformer TAPs.

1.3 Scenario 3 – Short-Term

This short-term scenario presents an increase of 40.1% of wind power comparatively to the baseline scenario and a demand decrease of -2.4%. With flexibility features remaining unchanged compared to the previous scenario, the results obtained are shown in Figure 261.

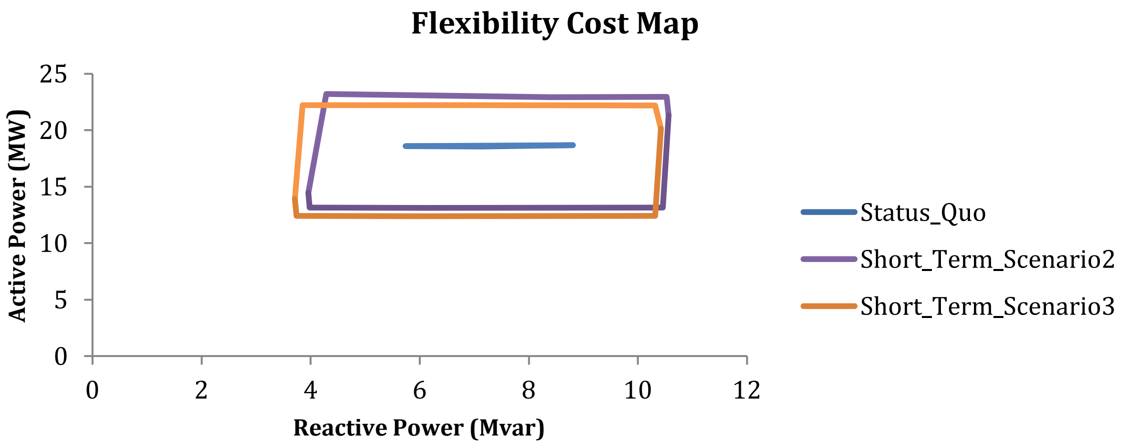


Figure 261 - Flexibility Cost Map for scenario 3 – short-term - Network5_Part2

The flexibility cost map shown in Figure 261 allows to draw several conclusions.
First of all, the flexibility area covers the *status quo* scenario since additional flexibility was introduced in the distribution network when compared to the baseline scenario.
When comparing the results for both short-term scenarios, it is possible to observe that neither of them covers the other one while their flexibility cost maps are very similar. This is explained by the larger increase of wind power penetration and decrease in terms of demand in scenario 3, and by the fact that the flexibility criteria used in the simulations are the same for both scenarios.
By observing Figure 261, the feasible values of active and reactive power exchanged at the boundary node presents a range of 9.82 MW and 6.71 MVAr respectively. The flexibility criteria for this scenario allowed:

- Demand Flexibility: 8.25 MW and 2.43 MVAr;
- Generation Flexibility: 1.54 MW and 4.03MVAr;
- Transformer TAPs.

1.4 Scenario 4 – Mid-Term

Mid-term scenarios are characterized by a higher homothetic increase of the demand and installed wind capacity than the short-term ones and changing flexibility conditions. More information is provided in sections 4.2.2.2 and 4.3.2.2.1.4.

It is to be noted that the branch reinforcement possibility due to increasing flexibility, demand and wind power installed capacity is available, however it was not used since the branches have enough capacity to provide the expected results.

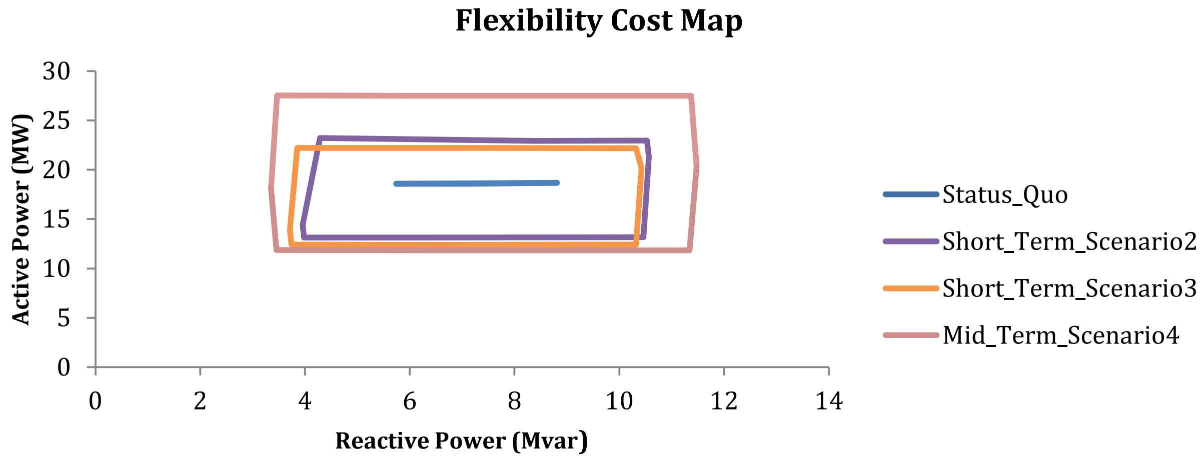


Figure 262 - Flexibility Cost Map for scenario 4 – mid-term - Network5_Part2

Figure 262 shows that the flexibility cost map for this new scenario covers the flexibility cost maps that were obtained in the previous ones. Although not necessarily, this new result covers the second short-term scenario since the differences between the flexibilities provided when comparing the short-term with the mid-term scenarios are considerable. Even for scenario 3 where the demand decreases, this area is covered by a scenario with larger flexibility resources.

By observing Figure 262, the feasible values of active and reactive power exchanged at the boundary node presents a range of 15.69 MW and 8.12 MVAr respectively. The flexibility criteria for this scenario allowed:

- Demand Flexibility: 8.73 MW and 2.57 MVAr;
- Generation Flexibility: 7 MW and 5.25 MVAr;
- Transformer TAPs.

1.5 Scenario 5 – Mid-Term

This second mid-term scenario follows the same trend than scenario 3, but amplified: the wind power continues to increase and the demand to decrease. Despite this increase, the branch reinforcement still does not need to be activated.

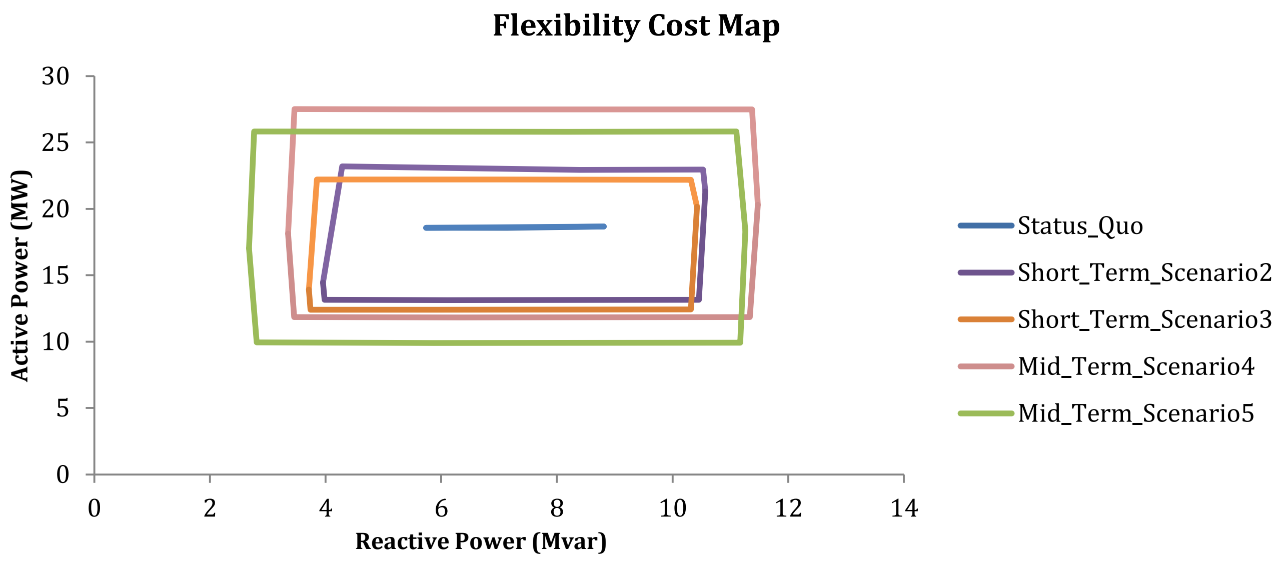


Figure 263 - Flexibility Cost Map for scenario 5 – mid-term - Network5_Part2

Figure 263 shows that the differences in terms of flexibility area are not so visible when comparing both mid-term scenarios since their flexibility criteria is the same. The increase of wind power between these two scenarios is followed by a decrease in terms of demand which explains why neither of these flexibility areas cover the other one.However, the increase of the flexibility conditions stated in 4.2.2 leads to higher flexibility area than the ones obtained for *status quo* and for short-term scenarios.

By observing Figure 263, the feasible values of active and reactive power exchanged at the boundary node presents a range of 15.92 MW and 8.58 MVAr respectively. The flexibility criteria for this scenario allowed:

- Demand Flexibility: 8.19 MW and 2.41 MVAr;
- Generation Flexibility: 7.81 MW and 5.86MVAr;
- Transformer TAPs.

1.6 Scenario 6 – Long-Term

The following two scenarios consider a long-term period where the increase in terms of wind power is considerable and can cause problems of overload in the branches. The possibility of proceeding to branch reinforcements is considered, but was not used again.
As explained in section 1, the number of MV customers providing flexibility will be kept the same although the demand flexibility conditions change.

In this first long-term scenario, an increase of 207.5% in the installed capacity and an increase of 18.4% in terms of demand are considered.

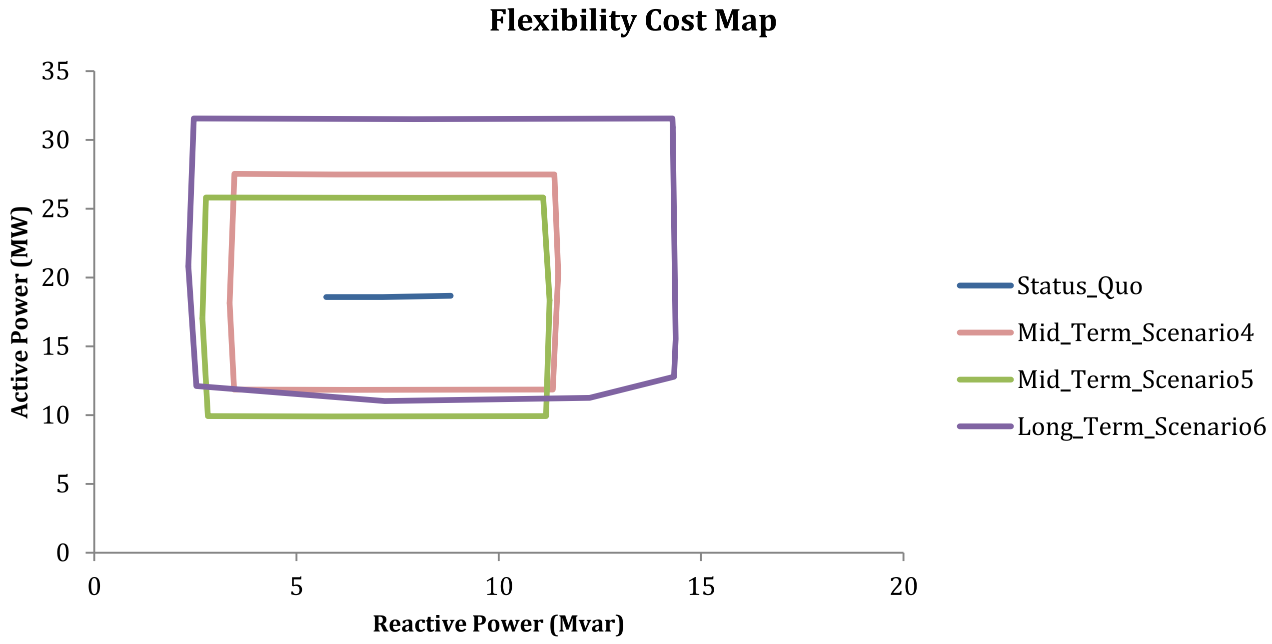


Figure 264 - Flexibility Cost Map for scenario 6 – long-term - Network5_Part2

The flexibility area for this first long-term scenario is in accordance with the expectations. The biggest flexibility area until now is obtained since the wind generation and demand considerably increase. The area covers all the other scenarios with the exception of scenario 5. This is related to the different trend of load increase between these two scenarios.

By observing Figure 264, the feasible values of active and reactive power exchanged at the boundary node present a range of 20.54 MW and 11.97 MVAr respectively. The flexibility criteria for this scenario allowed:

- Demand Flexibility: 10.01 MW and 2.95 MVAr;
- Generation Flexibility: 11.8 MW and 8.85 MVAr;
- Transformer TAPs.

1.7 Scenario 7 – Long-Term

For this second long-term scenario we should expect a flexibility area similar to the previous one. Moreover, since this scenario has the same trend that scenario 5 in terms of wind power and demand increase it should cover its flexibility area. A wind power increase of 253.8% and a demand decrease of 2.8% are faced. The flexibility conditions are the same as those used in the first long-term scenario.

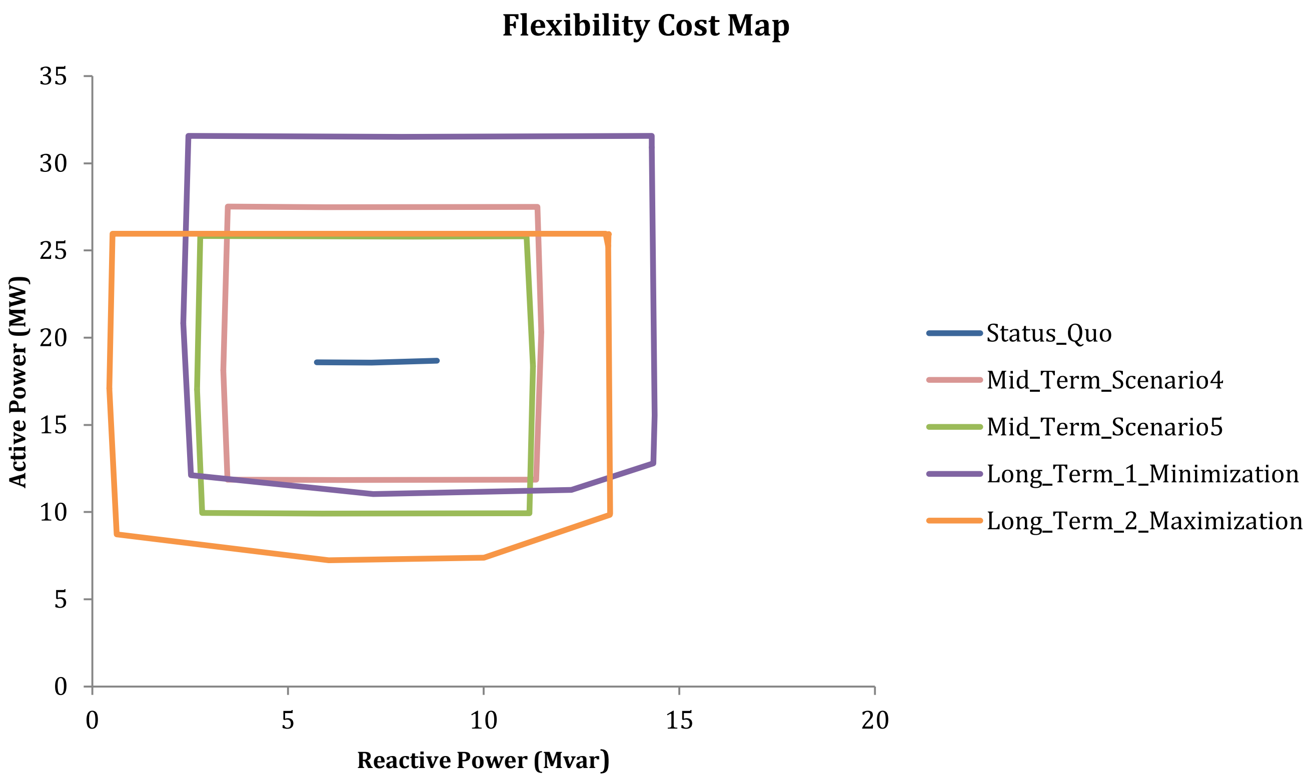


Figure 265 - Flexibility Cost Map for scenario 7 – long-term - Network5_Part2

As it is possible to observe in Figure 265, the results respect the assumptions that were made in the last paragraph. In the one hand, a flexibility area similar to the one obtained for the first long-term scenario was obtained and, in the other hand, this flexibility are covers the one obtained for the second mid-term scenario.

By observing Figure 265, the feasible values of active and reactive power exchanged at the boundary node present a range of 18.72 MW and 12.76 MVAr respectively. The flexibility criteria for this scenario allowed:

- Demand Flexibility: 8.22 MW and 2.42 MVAr;
- Generation Flexibility: 13.58 MW and 10.18MVAr;
- Transformer TAPs.

1.8 Operational KPIs

The two previously presented (4.3.2.2.1.8) Operational KPIs are calculated. As it is possible to observe in Table 257, the MCS has been run for different numbers of randomly extracted samples.

Table 257 – Operation KPIs for MV_ntwk_5_cplt – Part 2

Scenario	Flexibility area increase (%)			Computational time reduction (%)		
	1 000 samples	10 000 samples	100 000 samples	1 000 samples	10 000 samples	100 000 samples
1	-	-	-	86.89	98.66	99.86
2	273.62	128.65	79.27	70.12	97.0	99.71
3	273.49	126.82	79.17	71.36	97.09	99.71
4	274.98	114.73	69.19	70.89	97.01	99.70
5	217.96	102.76	63.85	71.69	97.13	99.73
6	213.79	108.72	69.80	70.73	97.19	99.61
7	180.51	104.03	57.20	60.43	95.98	99.64

Table 257 shows that the ICPF tool is able to provide an effective output. The increase of the size of the estimated flexibility area when compared with the MCS is clear. This shows that the ICPF tool is able to identify the high and the low cost zones. A considerable reduction in terms of computational was also achieved. Therefore, the increase of the flexibility area in less computational time is possible.

2 MV_ntwk_6_cplt – Part 1

The characteristics of the first part of the 2nd French network are summarized as following:

- Number of buses: 391;
- Number of branches: 387;
- Number of transformer TAPs: 3;
- Number of generators: 0;
- Active Power Load: 6.21 MW;
- Reactive Power Load: 1.887 MVAr;
- Number of customers with $P_{ref} > 200\ kW$: 3.

In section 4.2.2 a particularity for networks with no wind generation was stated: "If there is no wind generation in the "*status quo*" scenario, the wind power penetration will be considered to be equal to 10%, 20% and 40% for short-term, mid-term and long-term scenario, respectively". The French network used here reflects this particular case. For this reason, we have decided to connect a wind park on bus 13.

Also as before, given the limited number of MV customers with $P_{ref} > 200\ kW$ in this network, we consider that all of them will have access to demand flexibility for the short, mid and long term scenarios. Only for the status quo scenario this lever is not considered.

2.1 Scenario 1 – Status quo

In the *status quo*, only reactive power control of the generation is allowed. Since there is no wind generation in the network sent by the DSO, the reactive power control rule explained in the beginning of this section will consider a $P_{max} = 10\% * P_{ref}$. Therefore, a range of reactive power flexibility of [-0.207; 0.237] MVAr is available. The results considering these criteria are presented in Figure 266.

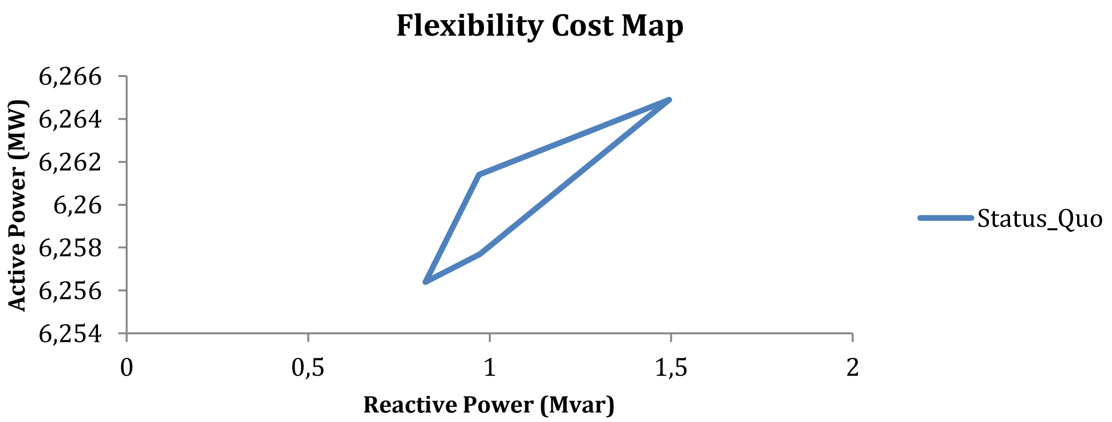


Figure 266 - Flexibility Cost Map for scenario 1 – *status quo* – Network6_Part1

Figure 266 shows that all the available reactive flexibility is used since the network is far away from their constraint limits.
The reactive power variation is equal to 0.67 MVAr. A part of this variation is explained by the reactive power control (0.44 MVAr), while the other part comes from the flexibility provided by the the variation, in number of steps, between the initial and the final TAP of the OLTC.
The variation in terms of active power is negligible since the flexibility in terms of active power is not available for this scenario. The small range of active power observed is due to the transformer TAPs variations and its impact on the voltage.

2.2 Scenario 2 – Short-Term

Scenario 2 is a short-term test case characterized by a demand growth of 0.5% and a wind power increase of 34.6% (see sections 4.2.2.2 and 4.3.2.2.1.2 for more details). Also, since there is no wind generation in the "*status quo*" scenario, a wind power penetration equal to 10% of P_{ref} is considered here.

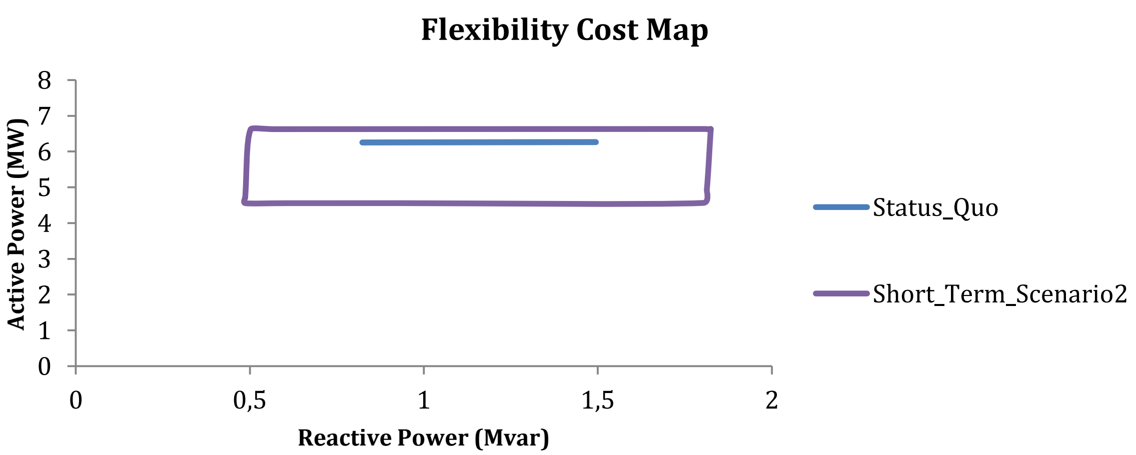


Figure 267 - Flexibility Cost Map for scenario 2 – short-term – Network6_Part1

Figure 267 shows that a reactive power flexibility of 1.32 MVAr and an active power flexibility of 1.92 MW are provided by the distribution network. In regards, the considered flexibility criteria are the following:

- Demand Flexibility: 1.85 MW and 0.5 MVAr;
- Generation Flexibility: 0.20 MW and 0.6 MVAr;
- Transformer TAPs.

Considering the flexibilities features available in the distribution network for this scenario, the sum of them plus the flexibility available in the transformer TAPs fulfils the flexibility presented in Figure 267. As expected, the flexibility area of this scenario covers the flexibility area obtained for the *status quo* scenario.

2.3 Scenario 3 – Short-Term

This short-term scenario presents an increase of 40.1% of wind power comparatively to the baseline scenario and a demand decrease of -2.4%. With flexibility and wind power penetration features remaining unchanged compared to the previous scenario, the results obtained are shown in Figure 268.

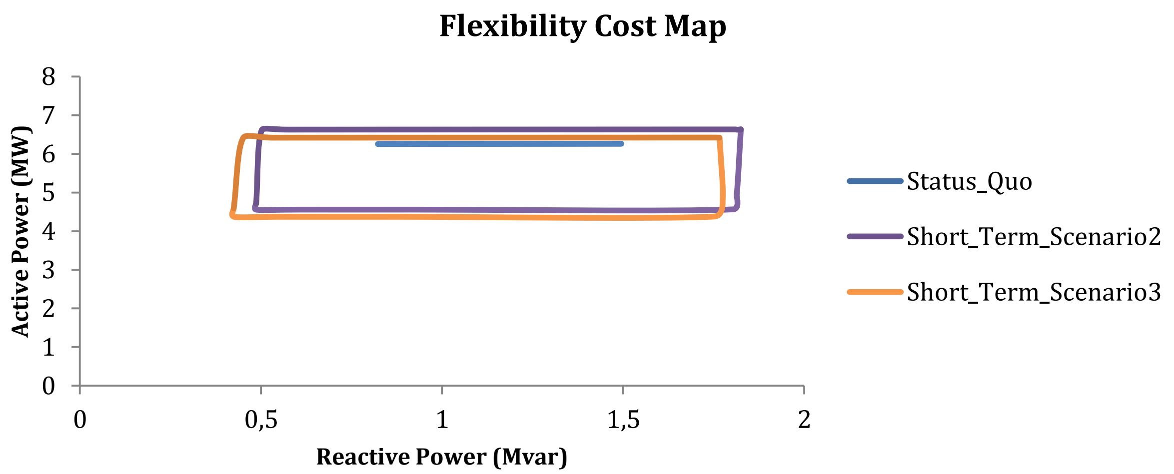


Figure 268 - Flexibility Cost Map for scenario 3 – short-term – Network6_Part1

Figure 268 shows that the flexibility area is very similar to the one obtained for scenario 2. This was expected since the flexibility criteria remained the same. The slight differences observed between these two areas are related with the higher increase in terms of installed capacity and with the decrease of the demand in scenario 3. This is why neither of these flexibility areas covers the other one. As expected the obtained flexibility area covers the one obtained for the *status quo*.

The characteristics of this new area show an allowable reactive flexibility of 1.34 MVAr and active flexibility of 2.05 MW. These values are in accordance with the flexibilities provided by the distribution network:

- Demand Flexibility: 1.8 MW and 0.49 MVAr;
- Generation Flexibility: 0.24 MW and 0.62 MVAr;
- Transformer TAPs.

2.4 Scenario 4 – Mid-Term

Scenario 4 is the first of the mid-term scenarios, characterized by a new set of flexibility criteria regarding generation and demand, and a demand growth of 3.2% and wind power increase of 82.5%. But, since we consider that all three MV customers provide flexibility, the demand flexibility will remain the same between short-term and mid-term scenarios. On the other hand, the generation flexibility will be characterized by wind curtailment for all wind parks. A wind power penetration equal to 20% of P_{ref} will be added to the generation system since there is no wind generation in the "*status quo*". This requirement is stated in 4.2.2.

Since these increases start to be significant, branch reinforcements are allowed if necessary, but were again not used since the line capacities were not reached.

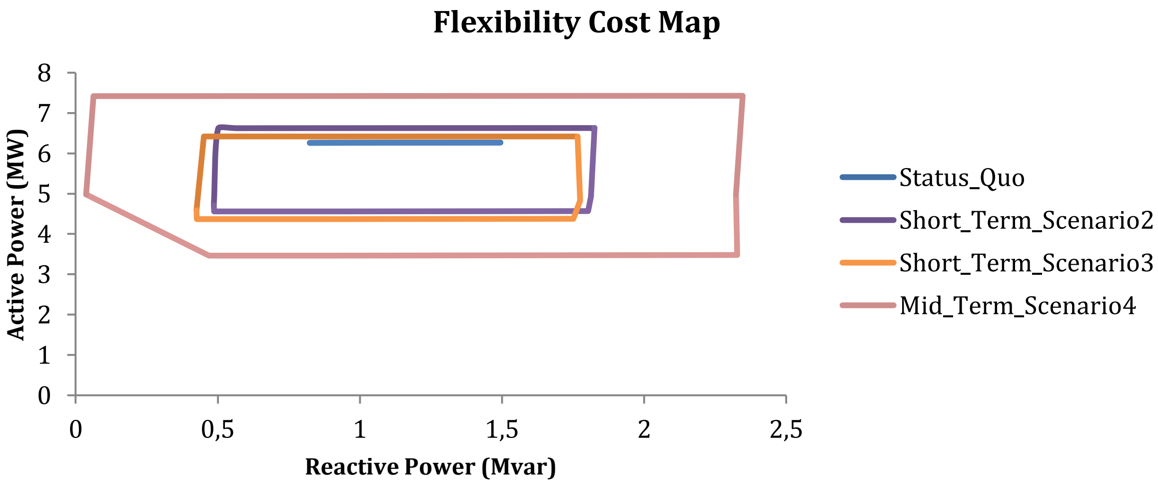


Figure 269 - Flexibility Cost Map for scenario 4 – mid-term – Network6_Part1

Figure 269 presents the comparison between the flexibility cost map for scenario 4 and the previous flexibility cost maps. It shows that the flexibility cost map for this new scenario covers the flexibility cost maps that were obtained in the previous ones.
This was expected for the status quo scenario and for scenario 2. Scenarios 2 and 4 are characterized by a demand growth and a wind power increase. However, these tendencies are amplified for scenario 4. The computed area also covers the one for scenario 3 which was not mandatory since a demand growth is established for scenario 4 and a demand decrease is defined for scenario 3.
The new flexibility area shows that the distribution network provides a reactive power flexibility of 2.29 MVAr and an active power flexibility of 3.95 MW. According to the flexibilities available in the distribution network for this scenario, the results are correct:

- Demand Flexibility: 1.90 MW and 0.51 MVAr;
- Generation Flexibility: 2.04 MW and 1.53 MVAr;
- Transformer TAPs.

2.5 Scenario 5 – Mid-Term

This second mid-term scenario follows the same trend than scenario 3, but amplified: the wind power continues to increase (+103.6%) and the demand to decrease (-3.1%). So more wind power capacity will be available while the load power will be lower. Despite this increase, the branch reinforcement still does not need to be activated.

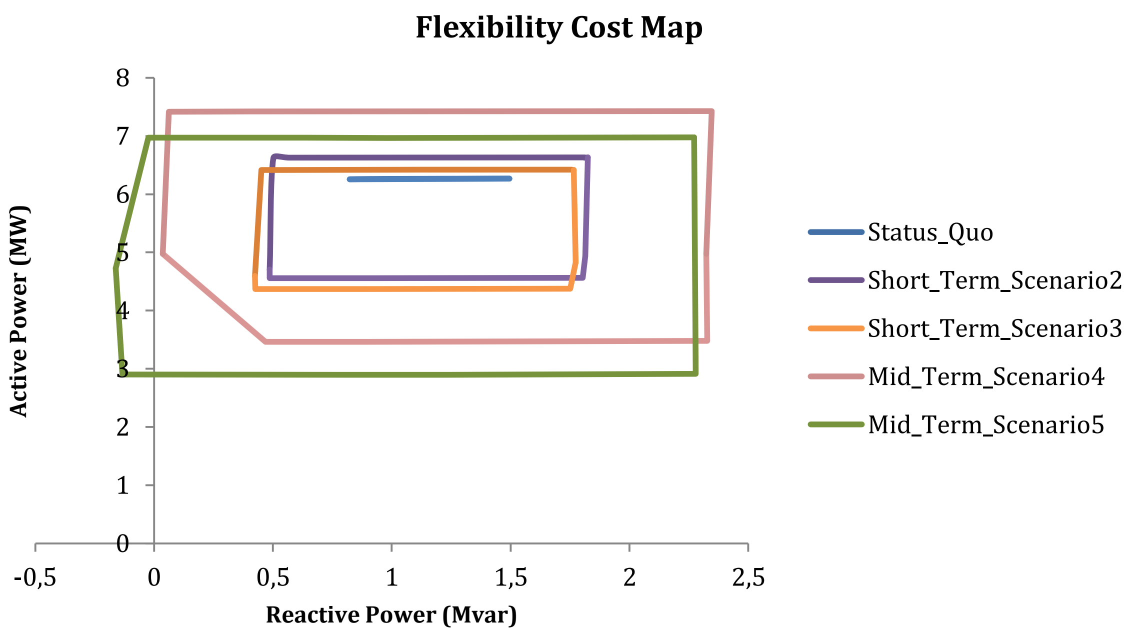


Figure 270 - Flexibility Cost Map for scenario 5 – mid-term – Network6_Part1

Figure 270 shows the flexibility cost map obtained regarding scenario 5. The flexibility areas of scenario 5 and 4 are similar because the same flexibility criteria are used.
This new flexibility area covers the one obtained for scenario 3 since the trends of the mid-term scenario amplify those of the short-term one. It also covers the one achieved for scenario 2 since we consider scenarios with different flexibility criteria. In scenario 5, the distribution network is in conditions of provide a higher margin of flexibility compensating the opposite trends in terms of demand growth followed by the scenario 2.

The flexibility area obtained for scenario 5 shows that the distribution network provides a reactive power flexibility of 2.43 MVAr and an active power flexibility of 4.08 MW. According to the flexibilities available in the distribution network for this scenario, the results are correct:

- Demand Flexibility: 1.79MW and 0.48 MVAr;
- Generation Flexibility: 2.28MW and 1.71MVAr;
- Transformer TAPs.

2.6 Scenario 6 – Long-Term

The long-term scenarios are characterized for a considerable variation of demand and wind power generation when compared with the *status quo* scenario. This requirement can obviously lead to a situation of overload in the branches. For this reason the possibility of branch reinforcement is available in these simulations. As it was already stated in section 2, a generator is connected to bus 13. Considering the wind power increase, this generator will inject in the distribution network 6.89 MW for scenario 6 and 7.93 MW for scenario 7. Moreover, the connection of this bus to the distribution network is made only by one branch that has a maximum flow capacity of 5.02 MVA. This means that an increase in the maximum flow capacity of this branch is necessary if we want to provide to the distribution network a degree of flexibility near to its maximum. For this reason, the maximum capacity of this branch was increased by 70%, to a maximum capacity of 8.54 MVA.
The flexibility criteria for these scenarios will be basically the same as the ones used for the mid-term scenarios., but since we are treating the test cases that belong to the long-term, the wind power penetration will be considered equal to 40% P_{ref}.

For scenario 6, the wind power increases of 207.5% and the demand grows to 18.4% relatively to the *status quo* scenario.

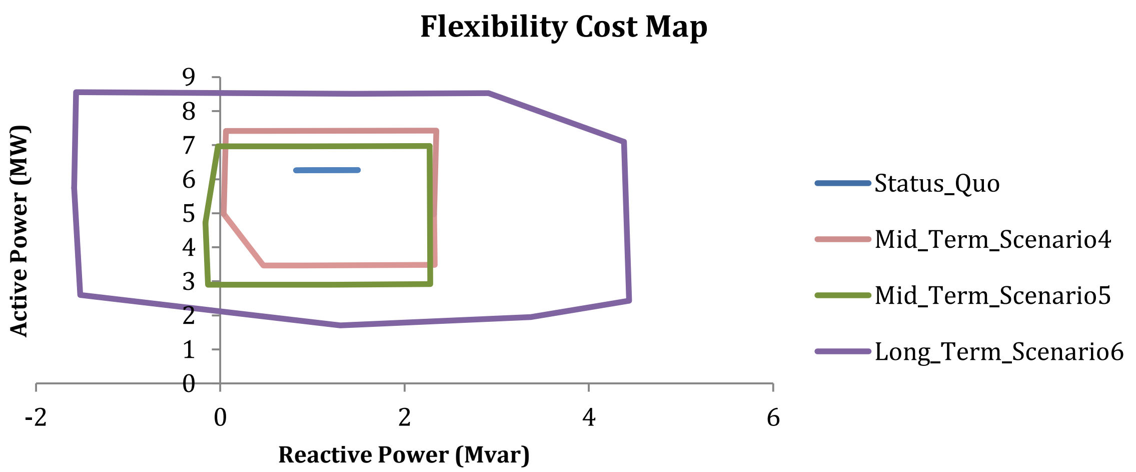


Figure 271 - Flexibility Cost Map for scenario 6 – long-term – Network6_Part1

Figure 271 shows that the flexibility area obtained for scenario 6 covers the one achieved for scenario 4 since the demand growth and the increase of the installed wind capacity are higher in scenario 6 and both scenarios follow the same trend of demand growth.
Figure 271 also shows that the flexibility area obtained for this scenario covers the one obtained for scenario 5. This behaviour was not mandatory since the load growth for these two scenarios follow opposite directions. However since the difference in terms of wind power increase is considerable between mid and long-term scenarios, the flexibility area of scenario 6 is higher than the one obtained for scenario 4.

The flexibility area obtained for scenario 6 shows that the distribution network provides a reactive power flexibility of 5.97 MVAr and an active power flexibility of 6.85 MW. According to the flexibilities available in the network for this scenario, the results are correct; the only reason why the flexibilities are not being used at its maximum is related with the maximum flow capacity of the branch connected to bus 13.

- Demand Flexibility: 2.18 MW and 0.59 MVAr;
- Generation Flexibility: 6.89 MW and 5.17 MVAr;
- Transformer TAPs.

2.7 Scenario 7 – Long-Term

Scenario 7 is characterized by the same flexibility criteria that the previous one. However, the demand decrease (-2.8%) in this scenario follows a different trend. On the other hand, the increase of the wind power (253.8%) allows more wind power to be curtailed. This increase will create the same constraints on maximum flow capacity of the branch connected to bus 13, requiring reinforcement.
This will lead to compute similar flexibility areas for the 2 long-term scenarios, but neither of them will cover the other one.

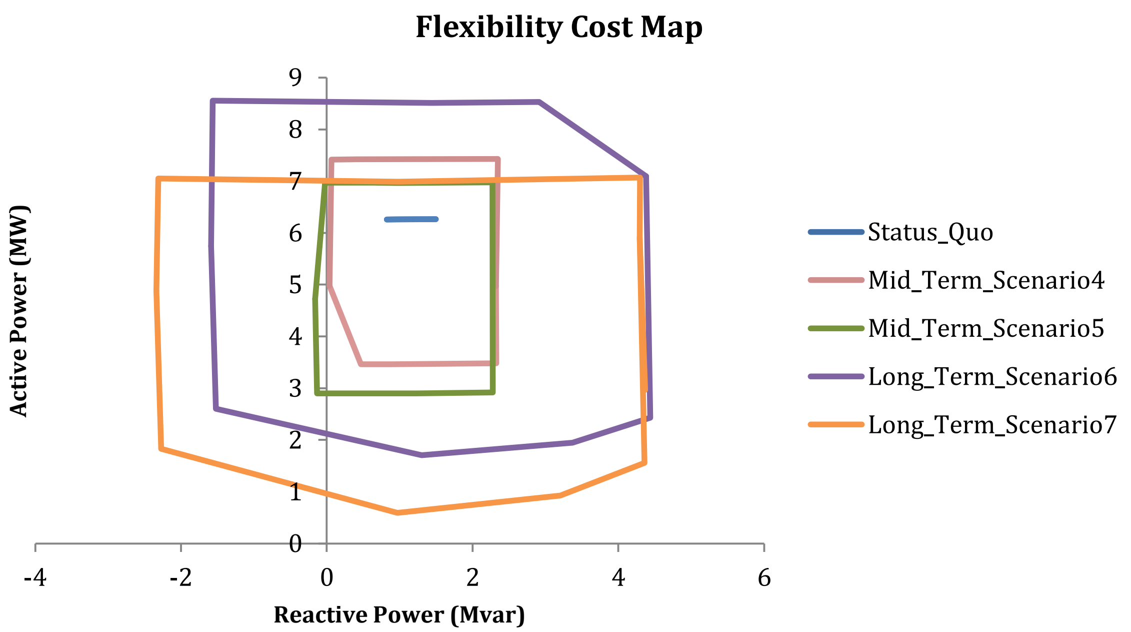


Figure 272 - Flexibility Cost Map for scenario 7 – long-term – Network6_Part1

Figure 272 shows the similarity between the flexibility areas of scenarios 6 and 7. The flexibility area obtained for scenario 7 covers the one obtained for scenario 5 since their trends are similar, and even amplified with the long-term scenario.
However, the flexibility area obtained for this scenario does not cover the one obtained for scenario 4: even if they follow the same flexibility criteria, they follow different trends of demand growth.

The flexibility area obtained for scenario 7 shows that the distribution network provides a reactive power flexibility of 6.7 MVAr and an active power flexibility of 6.48MW. According to the flexibilities available in the distribution network for this scenario, the results are correct.

The only reason why the flexibilities are not being used at its maximum is related with the maximum flow capacity of the branch connected to bus 13.

- Demand Flexibility: 1.79 MW and 0.48 MVAr;
- Generation Flexibility: 7.93 MW and 5.94 MVAr;
- Transformer TAPs.

2.8 Operational KPIs

Table 258 shows the two Operational KPIs obtained for this network. The increase of the size of the estimated flexibility area when compared with the MCS is clear. This shows that the ICPF tool is able to identify the high and the low cost zones. Moreover, a considerable reduction in terms of computational is also achieved. Therefore, the KPIs obtained for this network are consistent with the ones that were presented in D3.3 for the test networks.

Table 258 – Operational KPIs for MV_ntwk_6_cplt – Part 1

Scenario	Flexibility area increase (%)			Computational time reduction (%)		
	1 000 samples	10 000 samples	100 000 samples	1 000 samples	10 000 samples	100 000 samples
1	-	-	-	82.24	98.28	99.82
2	269.72	179.15	111.40	32.59	92.93	99.29
3	265.57	176.92	110.28	35.83	93.87	99.34
4	128.69	78.48	52.00	59.52	96.56	99.52
5	126.11	79.04	54.17	33.07	93.82	99.34
6	75.39	39.50	27.54	43.33	93.60	99.41
7	112.14	72.97	61.24	44.63	93.89	99.46

3 MV_ntwk_6_cplt – Part 2

The characteristics of the second part of the 2nd French network are summarized as following:

- Number of buses: 185;
- Number of branches: 182;
- Number of transformer TAPs: 2;
- Number of generators: 0;
- Active Power Load: 10.92 MW;
- Reactive Power Load: 2.8 MVAr;
- Number of customers with $P_{ref} > 200\ kW$: 2.

As before, the number of wind parks present in the distribution system is equal to zero, but it is to be noted that the ICPF tool did not reach the convergence criteria by simulating the *status quo* with no wind generation. In fact, the transformer that connects the transmission and distribution networks is linked only by a branch whose maximum flow capacity is 6.76

MVA. The problem is that the demand is higher than this value in the network description. This means that without distributed generators, the transmission network is not able to feed all the demand. Therefore, two options were studied to solve this problem. One of them was the increase of the maximum flow capacity of the branch that was referred previously. The other one considered the inclusion of a distributed generator that would be able to feed a significant part of the demand. In the simulations presented in this section, the second option was considered.

A generator able to feed 108% of the active power load was thus added to bus 170. The main reason why a generator able to inject more than the active power load was added to the distribution system is linked with the fact that we want to show scenarios in which the transmission network will need to consume active power instead of inject. Since now the distribution network has already one Wind Park, the *status quo* is characterized for wind power penetration. Therefore, the rule described in WP3 for the case with no wind penetration in the *status quo* will not be followed.

3.1 Scenario 1 – Status quo

The *Status quo* scenario illustrates the baseline scenario. It is characterized by the standard parameters of flexibility and demand. The network characteristics used for this scenario are the ones sent by the DSO. Regarding the flexibility criteria, this scenario only allows reactive power control, no demand flexibility.

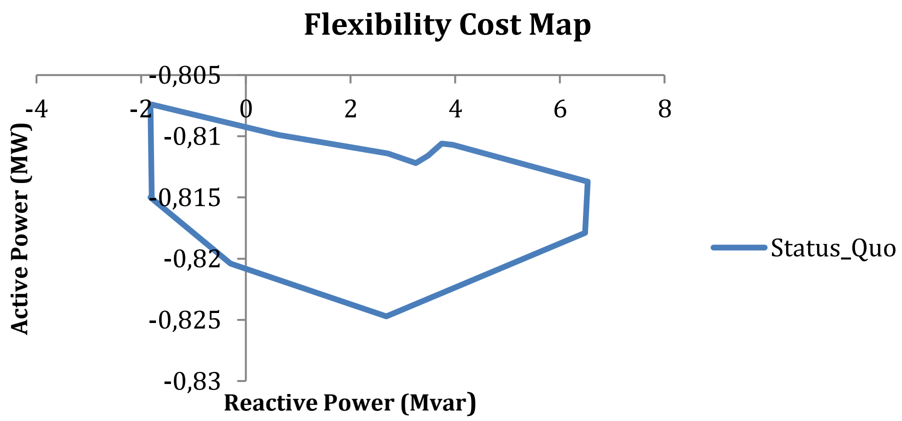


Figure 273 - Flexibility Cost Map for scenario 1 – *status quo* – Network6_Part2

The flexibility cost map obtained for this scenario is in accordance with the expectations.

The region of feasible values of active and reactive power exchanged at the boundary node between transmission and distribution networks displays a variation between the maximum and the minimum of reactive power since only reactive power control was provided by the distribution network.

The limited range of active power values observed in Figure 273 is explained by to the transformer TAPs variations and its impact on the voltage, since there is no flexibility provided in terms of active power, neither by the generation system, neither by the demand.

In order to confirm the presented results is possible to make a comparison between them and the flexibilities available in the distribution network: Figure 273 shows a variation of reactive power of 8.35 MVAr while the flexibilities provided by the distribution system can be summarized as follows:

- Generation Flexibility: 8.87 MVAr;
- Transformer TAPs.

The reason why not all the flexibility was used is related with the maximum flow capacity of the branch that connects the HV/MV transformer to the distribution system.

3.2 Scenario 2 – Short-Term

Scenario 2 is characterized by a wind power increase of 34.6% and a demand growth of 0.5%. The characteristics of this scenario are described in more details in sections 4.2.2.2 and 4.3.2.2.1.2.

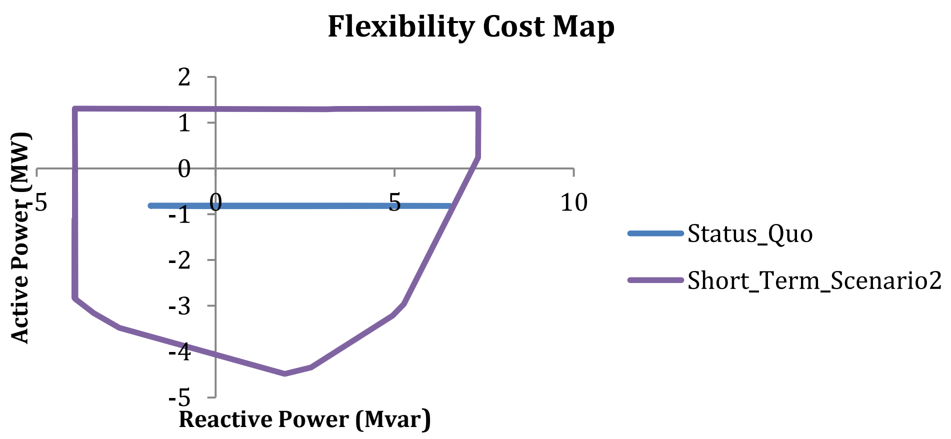


Figure 274 - Flexibility Cost Map for scenario 2 – mid-term – Network6_Part2

Figure 274 shows that the flexibility area obtained for this short-term scenario covers the one achieved for *status quo* because of larger flexibility criteria.

By analysing Figure 274 it is possible to observe a range of 11.27 MVAr of reactive power and a range of 5.79 MW of active power. This higher variation in terms of reactive power was already expected since the reactive power control is more expressive than the wind power curtailment. The following flexibility data provided by the distribution network is coherent with this assumption.

- Demand Flexibility: 4.11 MW and 1.01 MVAr;
- Generation Flexibility: 4.09 MW and 11.93 MVAr;
- Transformer TAPs.

Once again the only reason why the distribution network does not provide more flexibility is related to the maximum flow capacity of the branch that connects the HV/MV transformer to the distribution system.

3.3 Scenario 3 – Short-Term

Short-term scenario 3 follows the same flexibility criteria as scenario 2, but follows a different trend for demand growth: wind power increases of 40.1% and demand decreases of -2.4%.

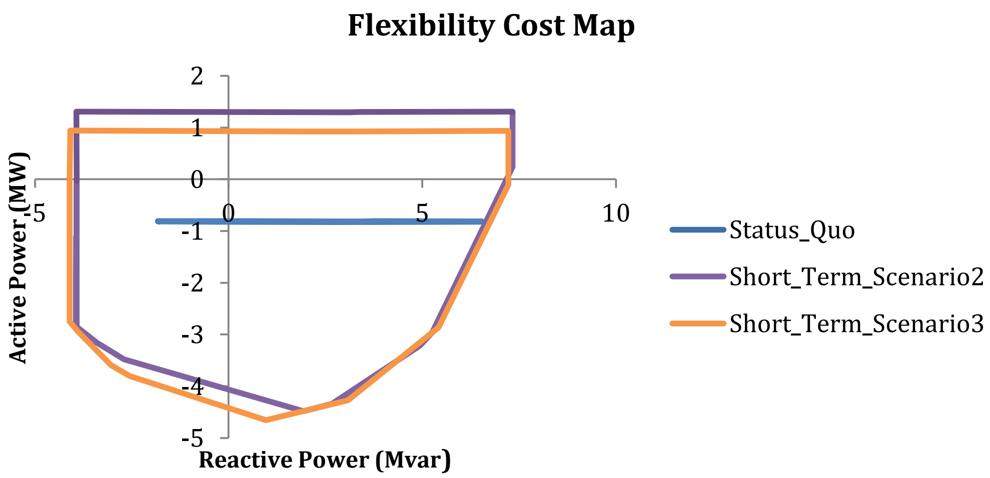


Figure 275 - Flexibility Cost Map for scenario 3 – short-term – Network6_Part2

Figure 275 shows that the flexibility areas of scenarios 3 and 2 are very similar since their flexibility characteristics are the same. The differences between these two areas are explained by a higher increase of the wind power and a decrease in the demand in scenario 3. The opposite demand growth trends between these two scenarios explains why neither of the flexibility areas covers the other one.
Moreover this flexibility area covers the one obtained for the *status quo*.

The flexibility area is described by a range of 11.33 MVAr of reactive power and of 5.59 MW of active power. The flexibilities provided by the distribution network allow this region of feasible values of active and reactive power exchanged at the boundary node. These flexibilities can be summarized as follows:

- Demand Flexibility: 3.99 MW and 0.98 MVAr;
- Generation Flexibility: 4.74 MW and 12.42 MVAr;
- Transformer TAPs.

3.4 Scenario 4 – Mid-Term

For mid-term scenario 4, a considerable growth is expected in the installed wind power and in the demand according to WP3 as well as a change in flexibility conditions. The characteristics of this scenario are described in more details in sections 4.2.2.2 and 4.3.2.2.1.4.
Regarding the possibility of branch reinforcement in the mid-term scenarios, the inclusion of a generator in the bus 170 described in 3 brought a situation of overload in some branches due to the significant increase of the wind power. In order to solve this situation, a branch reinforcement of 30% was established. The consequences of these changes in terms of flexibility cost map can be observed in Figure 276.

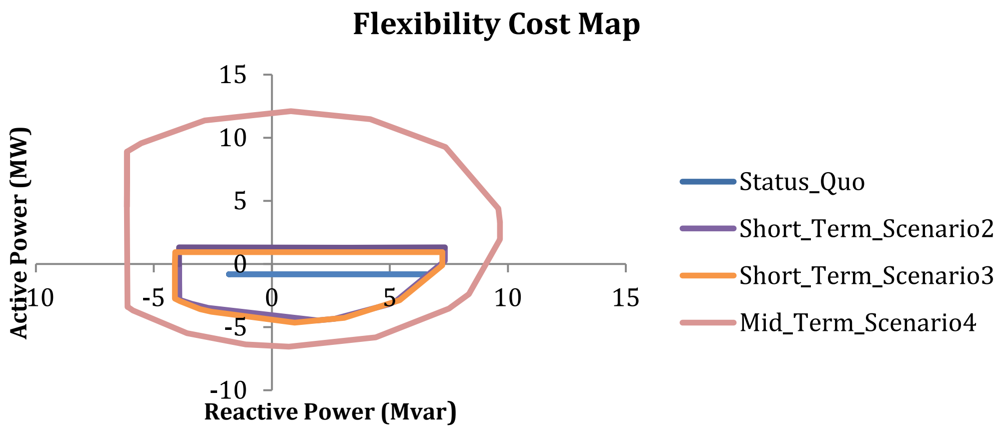


Figure 276 - Flexibility Cost Map for scenario 4 – mid-term – Network6_Part2

Figure 276 shows that the flexibility area obtained for the mid-term scenario is clearly bigger that the ones obtained for the short-term scenarios and covers them all. This is explained since the wind power increase and demand growth are higher and the flexibility criteria are clearly favourable with the possibility of curtailment for all the wind parks. Moreover, the branch reinforcement also led to a situation in which the wind parks are able to provide more flexibility to the distribution network. That area for scenario 3 would be covered by this new one was not obvious since the demand growth follows opposite trends.

Observing Figure 276 is possible to see that a range of 15.8 MVAr of reactive power and 18.66 MW of active power can be offered by the transmission system through the boundary node. The flexibility data provided by the distribution network can be summarized as follows:

- Demand Flexibility: 4.22 MW and 1.04 MVAr;
- Generation Flexibility: 21.58 MW and 16.18 MVAr;
- Transformer TAPs.

3.5 Scenario 5 – Mid-Term

This second mid-term scenario follows the same trend than scenario 3, but amplified: the wind power continues to increase and the demand to decrease. The branch reinforcement established in the previous scenario remains here.

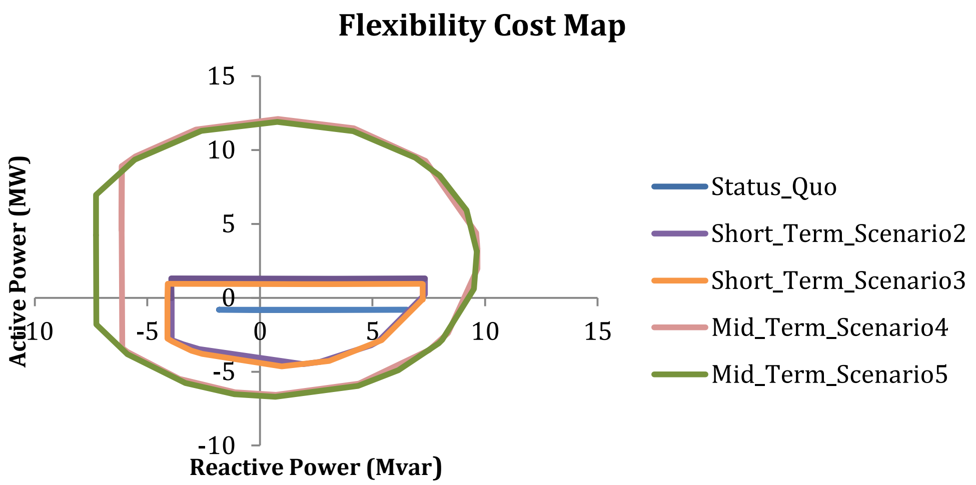


Figure 277 - Flexibility Cost Map for scenario 5 – mid-term – Network6_Part2

Figure 277 shows that the flexibility areas of scenarios 4 and 5 are quite similar, however neither of them is covered by the other one since they follow different demand growth trends. The flexibility area of scenario 5 covers the one from scenario 3 since they follow the same trend of wind power increase and demand growth, but the mid-term scenarios are characterized by wider flexibility criteria.
It is also possible to observe that the flexibility area of scenario 5 covers the one of scenario 2 due to the wider flexibility criteria in the mid-term scenarios that can be used due to the branch reinforcement that was established. However, this was not mandatory since they do not follow the same demand growth trend: scenario 2 is characterized for a demand increase while scenario 5 is characterized for the opposite.

The flexibility range that can be offered by the boundary node between the transmission and distribution networks is defined for 16.90 MVAr of reactive power and 18.6 MW of active power. The flexibilities provides by the distribution network can be summarized as follows:

- Demand Flexibility: 3.96 MW and 0.98 MVAr;
- Generation Flexibility: 24.07 MW and 18.05 MVAr;
- Transformer TAPs.

It can be observed that the flexibility for this test-case is not used at its maximum levels. The reason that explains this behaviour is linked with the maximum flow capacity of the branches.

3.6 Scenario 6 – Long-Term

For scenario 6, a considerable growth is expected in the installed wind power (207.5%) and in the demand (18.4%) according to WP3.
Moreover for the same reason as before, branch reinforcement will be necessary. Since in the long-term scenarios the wind power increase is more significant, the branch reinforcement will be of 50%.

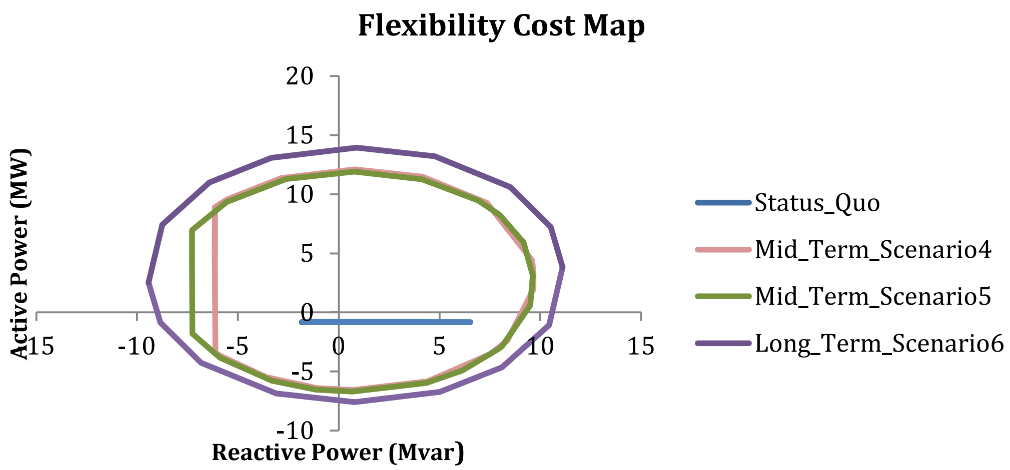


Figure 278 - Flexibility Cost Map for scenario 6 – long-term – Network6_Part2

Figure 278 shows the comparison between the flexibility areas obtained for the long-term scenario and for the mid-term scenarios. Although the flexibility criteria do not change for this new scenario, the demand and wind power increase allow a bigger flexibility area than the mid-term scenarios.
It is also possible to observe that scenario 6 flexibility area covers both mid-term scenarios. This is explained by the higher demand growth and wind power increase in this scenario. This behaviour was to be expected when comparing the scenario 6 with scenario 4 since they follow the same flexibility conditions and the same trends for wind power increase and demand growth. However the situation was not mandatory when comparing scenario 6 with 5 since the demand growth does not follow the same trend for these two scenarios.

Regarding the flexibility area, the one obtained for scenario 6 has the following characteristics: 20.54 MVAr of reactive power range and 21.53 MW of active power range. The flexibilities provided by the distribution network validate this result.

- Demand Flexibility: 4.84 MW and 1.19 MVAr;
- Generation Flexibility: 36.36 MW and 27.27 MVAr;
- Transformer TAPs.

It can be observed that the flexibility for this test-case is not being used at its maximum levels. The reason explaining this behaviour is linked with the maximum flow capacity of the branches.

3.7 Scenario 7 – Long-Term

This second long-term scenario follows the same trend than scenario 5, but amplified: a wind power increase of 253.8% and a demand decrease of 2.8% are faced. The flexibility conditions are the same as those used in the first long-term scenario.

The branch reinforcement is kept at 50%.

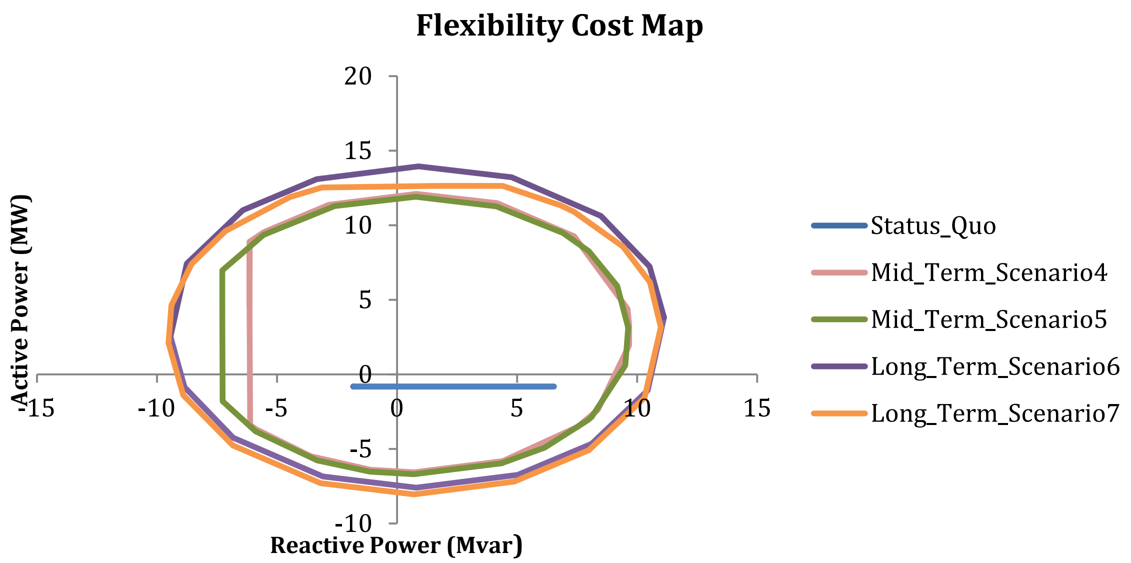


Figure 279 - Flexibility Cost Map for scenario 7 – long-term – Network6_Part2

Figure 279 shows that the flexibility areas of scenarios 7 and 6 are similar. The different trends of demand growth between them explain the fact why neither covers the other one.
Comparing the new flexibility area with the one obtained for scenario 5 also shows that it covers the one obtained for the mid-term. This was expected since both scenarios have the same flexibility criteria (remember the fact that there are only two customers with contracted power over 200 kW) but the wind power increase between them is equal to 150.2% while the demand increases by 0.3%.
Comparing scenarios 7 and 4 the flexibility area of the first one is bigger than the one achieved for the second one for the same reasons. Between these two scenarios there is a wind power increase of 171.3 % and a demand decrease only of 6%. However it was not mandatory since they follow different trends of demand growth.

The flexibility area regarding this last simulation had the follow characteristics: a range of active power of 20.67 MW and a range of reactive power of 20.5 MVAr. The flexibility that the distribution network could provide for this simulation is described as follows:

- Demand Flexibility: 3.97 MW and 0.98 MVAr;
- Generation Flexibility: 41.83 MW and 31.37MVAr;
- Transformer TAPs.

Once again the reason explaining why not all the available flexibility is being used is linked with the maximum flow capacity of the branches.

3.8 Operational KPIs

The two Operational KPIs that are presented in Table 259 allow to validate the effectiveness of the ICPF tool. Table 259 shows the increase of the size of the estimated flexibility area with respect to the Monte Carlo Simulation. The ICPF tool is thus able to identify the high and the low cost zones. Moreover, a considerable reduction in terms of computational was also achieved. Thus, the increase of the flexibility area in less computational time is possible.

Table 259 – Operational KPIs for MV_ntwk_6_cplt – Part 2

Scenario	Flexibility area increase (%)			Computational time reduction (%)		
	1 000 samples	10 000 samples	100 000 samples	1 000 samples	10 000 samples	100 000 samples
1	-	-	-	75.17	97.46	99.69
2	122.69	53.60	18.31	54.95	95.38	99.63
3	176.62	86.24	39.40	59.41	95.77	99.56
4	37.82	13.45	7.45	54.57	95.19	99.59
5	49.32	13.73	7.73	50.93	95.20	99.65
6	36.79	11.76	5.20	65.74	96.52	99.68
7	60.21	11.48	5.28	68.78	96.78	99.53

ANNEX V – Additional Results for Maintenance Domain

Effect of wind penetration level on enhanced network operating cost

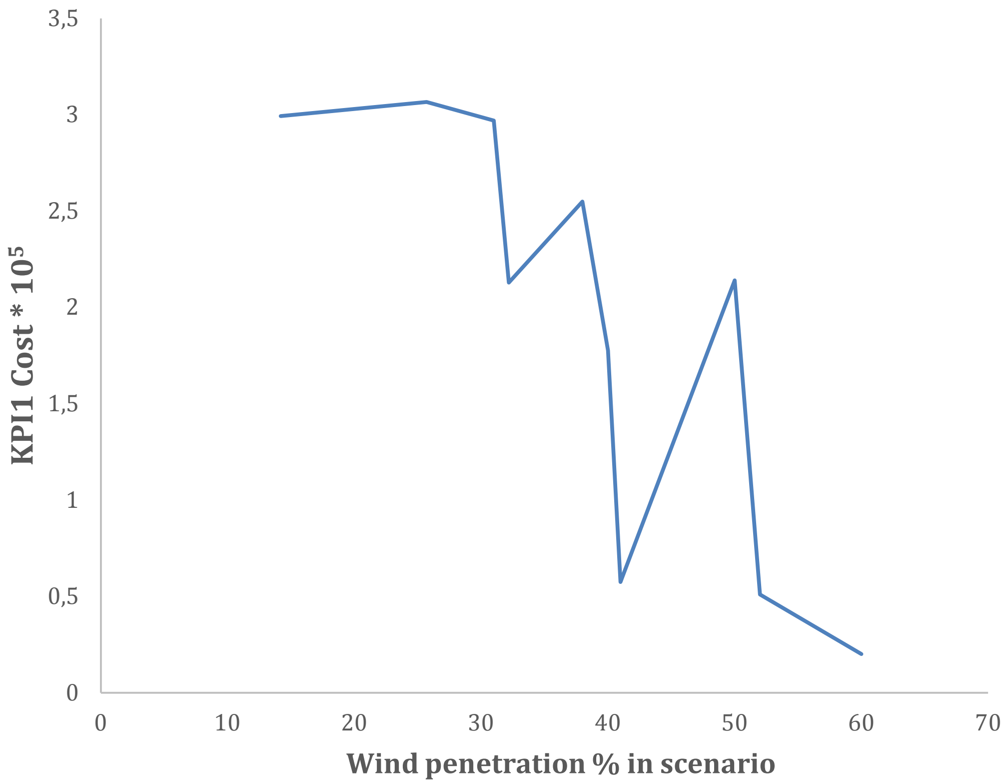


Figure 280 –The relationship between the prevailing wind penetration level and the costing KPI achieved by the tool

As shown in Figure 280, higher wind penetration levels appear to be associated with a diminution in the financial efficiencies facilitated by the tool. This can be interpreted as showing that the main financial efficiency that the tool achieves is diminishing active power losses, however raising the amount of wind penetration on the test network naturally reduces the baseline active power losses.

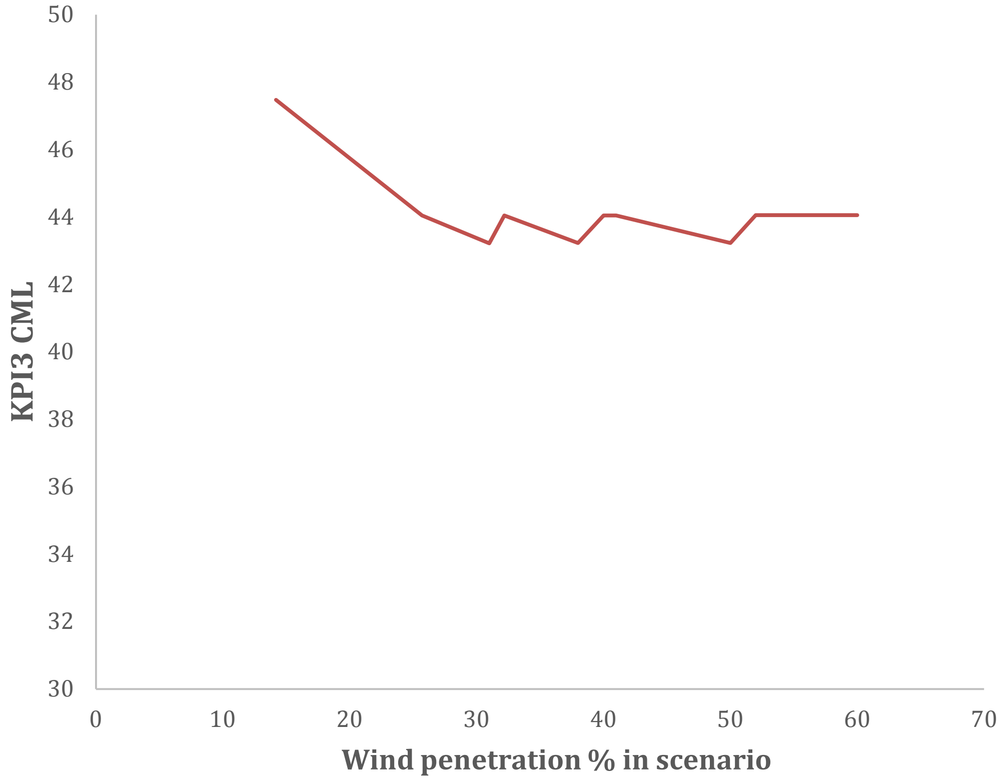


Figure 281 –The relationship between the prevailing wind penetration level and the enhanced CML achieved by the tool

As shown in Figure 281 between each scenario's wind penetration level and the KPI estimating the effect on customer minutes lost is not as clear. For this particular network, it appears that this KPI substantially plateaus at a penetration level around 20%.