FlexPlan

Advanced methodology and tools taking advantage of storage and FLEXibility in transmission and distribution grid PLANning

Grid development results of the regional studies

D5.2

Distribution Level	PU
Responsible Partner	R&D NESTER
Checked by WP leader	Aleksandr Egorov (R&D NESTER) – WP5 Leader Date: 12.02.2023
Verified by the appointed Reviewers	Klemen Dragaš (ELES) – Date: 27.02.2023 Rui Pestana (REN) – Date: 28.02.2023
Approved by Project Coordinator	Gianluigi Migliavacca (RSE) Date: 02.03.2023

This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement No 863819

Issue Record

Planned delivery date	31.12.2022
Actual date of delivery	02.03.2023
Status and version	FINAL

Version	Date	Author(s)	Notes
V0.1	18.10.2022	Aleksandr Egorov (R&D NESTER)	Creation of Table of Contents (ToC) and distribution of partners contributions
V0.2.1	27.01.2023	Aleksandr Egorov (R&D NESTER) Nicolò Italiano (R&D NESTER)	Contributions on Methodology section
V0.2.2	06.02.2023	Santiago Garcia Lazaro (TECNALIA) Raul Rodríguez Sanchez (TECNALIA) Oscar Aristo Damanik (KUL) Giacomo Bastianel (KUL) Dennis Schmid (TU-DORTMUND) Marco Rossi (RSE) Izabella Faifer (RSE) Boris Brdjanin (EKC) Dragana Orlic (EKC) Iver Bakken Sperstad (SINTEF) Michele Garau (SINTEF)	Contributions on Regional Cases section
V0.3	10.02.2023	Aleksandr Egorov (R&D NESTER) Nicolò Italiano (R&D NESTER) Ricardo Pastor (R&D NESTER)	Merged updates from Regional Case Leaders, contributions on Summary, Conclusions, Executive Summary, Introduction
V0.3.1	27.02.2023	Klemen Dragaš (ELES) Marko Kolenc (ELES)	Review contributions from ELES team
V0.3.2	28.02.2023	Rui Pestana (REN)	Review contributions from REN team
V0.4	02.03.2023	Aleksandr Egorov (R&D NESTER)	Updated the deliverable in accordance with the comments from reviewers

About FlexPlan

The FlexPlan project aims at establishing a new grid planning methodology considering the opportunity to introduce new storage and flexibility resources in electricity transmission and distribution grids as an alternative to building new grid elements. This is in line with the goals and principles of the new EC package *Clean Energy for all Europeans,* which emphasizes the potential usage of flexibility sources in the phases of grid planning and operation as alternative to grid expansion. In sight of this, FlexPlan creates a new innovative grid planning tool whose ambition is to go beyond the state of the art of planning methodologies, by including the following innovative features: integrated T&D planning, full inclusion of environmental analysis, probabilistic contingency methodologies replacing the N-1 criterion as well as optimal planning decision over several decades. However, FlexPlan is not limited to building a new tool but it also uses it to analyse six regional cases covering nearly the whole European continent, aimed at demonstrating the application of the tool on real scenarios as well as at casting a view on grid planning in Europe till 2050. In this way, the FlexPlan project tries to answer the question of which role flexibility could play and how its usage can contribute to reduce planning investments yet maintaining (at least) the current system security levels. The project ends up formulating guidelines for regulators and for the planning offices of TSOs and DSOs. The consortium includes three European TSOs, one of the most important European DSO group, several R&D companies and universities from 8 European Countries (among which the Italian RSE acting as project coordinator) and N-SIDE, the developer of the European market coupling platform EUPHEMIA.

Partners

Table of Contents

List of Abbreviations and Acronyms

Abbreviation/Acronym	Meaning
AC	Alternating Current
AQ	Air Quality
CF	Carbon Footprint
CGMES	Common Grid Model Exchange Standard
COP21	2015 United Nations Climate Change Conference
DC	Direct Current
DE	Distributed Energy
DER	Distributed Energy Resources
DiNeMo	Distribution Network Models
DSO	Distribution System Operator
DSR	Demand Side Response
EC	European Commission
ENTSO-E	European Network of Transmission System Operators for Electricity
EU	European Union
GA	Global Ambition
GEP	Grid Expansion Planning
H2	Hydrogen
HVDC	High Voltage Direct Current
LAES	Liquid Air Energy Storage
Li-ion	Lithion Ion
LM	Lagrange Multipliers
LMP	Local Marginal Price
MAF	Mid-term Adequacy Forecast
MILES	Model of International Energy Systems
MIP	Mixed Integer Programming
NaS	Sodium-Sulphur
NECP	National Energy and Climate Plans
NT	National Trends
OPF	Optimal Power Flow
OSM	OpenStreetMap
P2G	Power-to-gas
PV	Photovoltaic
RC	Regional Case
RES	Renewable Energy Sources
RoR	Run-of-River
T&D	Transmission and Distribution

TSO	Transmission System Operator
TYNDP	Ten-year Network Development Plan
VOLL	Value of loss load

Executive Summary

This deliverable includes the results of the tests of the new FlexPlan toolbox (pre-processor and grid expansion planning tool) for six regional cases. It presents both transmission and distribution infrastructure, impact of flexibility elements located both at transmission and distribution levels and comparison of the results. Based on this we are able to formulate recommendations for improving the existing network planning practices. The ultimate goal is to make it possible to accommodate an increased penetration of renewable energy sources in Europe.

To make a clear view on the activities that were carried out in the scope of WP5, the methodology to obtain the results is described in this deliverable with the simplifications that were implemented in order to preserve the numerical computability of the simulations, but also to preserve the accuracy of the results.

In this deliverable, a description is provided for every regional case, which includes the number of elements in the network by type and location, as well as the specific adaptations needed for each regional case to decrease the simulation time. The results for the three target years (2030, 2040 and 2050) are presented in the deliverable with the list and location of proposed flexibility element candidates and candidates for grid reinforcement, and the main result obtained by solving the optimal power flow and grid expansion planning problem. Based on these results, an analysis is carried out about the investment decisions for every decade. These results show that for most of the regional cases load curtailment costs play the major role in the total costs, mainly due to the limitation on the number of candidates considered by the simulations, which is a part of the aforementioned simplifications. For two regional cases number of proposed candidates in transmission network drastically decrease from 2030 to 2050 down to zero because the most severe congestions occur in distribution network, for other regional cases even if the number of transmission network candidates is not high, the approval rate is more than 50%.

All the results from the regional cases are analysed together to find similarities and trends, which can be useful for a future development of guidelines to improve the current grid expansion planning procedures.

1 Introduction

The increasing share of Renewable Energy Sources (RES) and the appearance of a new loads such as heat pumps or Electric Vehicles (EVs) have caused new grid development challenges in both transmission and distribution networks. The conventional approach for network development involves the construction of new or the upgrading of existing grid components, such as transmission lines and transformers. To address these challenges, FlexPlan endeavours to introduce a new optimization tool for transmission and distribution grid planning that incorporates the placement of flexibility elements in synergy with to the traditional grid planning methodology. The aim is to minimize the total cost of the power system, which encompasses costs related to infrastructure deployment, system dispatch-related operational costs, consumer costs resulting from load demand shifting and curtailment, and costs associated with environmental impact. The main information regarding the applied optimization criteria is presented in Deliverable D1.2 of the FlexPlan project [1]. The "cost oriented" approach was chosen versus multi-criteria approach to find out the optimal combination of new grid investments, both in installation of flexibility devices and conventional grid reinforcement, at the minimum costs. This approach is described in Deliverable D5.1 of the FlexPlan project [2]. The initial input data for the simulations consists of realistic geo-referenced grid models of the corresponding transmission and sub-transmission systems, complemented with created realistic synthetic distribution networks, and multiple data sets, which allow to simulate different energy scenarios. The main information about the flexibility resources, which are selected and modelled for the grid expansion planning, are described in Deliverable D2.2 of the FlexPlan project [3]. The analysis of the selection of these resources is a key for the development of the pre-processor, which proposes the possible candidates for the grid expansion planning study that is used in the new planning tool developed in the scope of FlexPlan project along with the grid models and generation and load scenarios.

The main objective of this deliverable is to provide the results of the regional case studies over three FlexPlan target years (2030, 2040 and 2050) by the FlexPlan planning tool.

The following chapters are organized as follows:

- Chapter 2 presents the main methodology used to obtain the results for the six different Regional Cases and the simplifications that were implemented in order to make the model computable.
- Chapter 3 provides a description of the six Regional Cases, the adaptations implemented within the Regional Case and, the results of the simulations and comparison of the results for six regional cases.
- Chapter 4 presents the main conclusion from the results of the simulations.

2 Methodology and simplifications

The methodology consists of three main steps:

- Obtaining the initial input data based on the gathering information for the grid model and the scenario time series;
- Solving the optimal power flow and identifying the possible candidates to be processed with the grid expansion planning tool;
- Solving the grid expansion planning problem by using the output data from the OPF and candidates that were obtained on the previous step.

The necessary input data consists of the scenarios to be simulated (time series), that were obtained from the verified sources such as Ten-year Network Development Plan (TYNDP) 2020 [4] from ENTSO-E and complemented with the TYDNP 2018 [5] and Mid-term Adequacy Forecast (MAF) 2018 [6] and the corresponding grid model, which was taken from verified sources such as ENTSO-E grid dataset [7], PyPSA-EUR model [8], complemented with local TSO's grid models and other sources. More information on the methodology adopted for collecting the data for the networks and Pan-EU scenarios can be found in deliverable D4.1 of the FlexPlan project [9]. Using this input data, a cost minimisation Optimal Power Flow (OPF) is run, in order to identify existing congestions and other relevant results (e.g. costs related to system operation including load and generation curtailment costs, generation costs). This OPF consists of a multi-period simulation considering time coupling constraints for demand flexibility and storage. Congestions are identified through the existence of non-zero Lagrange Multipliers (LM) associated with branch flow constraints. These OPF results are then used as an input for the pre-processing tool to propose a list of grid expansion candidates. More information on the identification and characterization of the proposed candidates can be found in deliverable D2.2 of the FlexPlan project [3]. Using the data obtained after solving the OPF and taking into consideration the proposed grid expansion candidates, the next step is to solve the grid expansion problem and to identify the candidates approved for the investment. The detailed methodology is presented in the Figure 2-1.

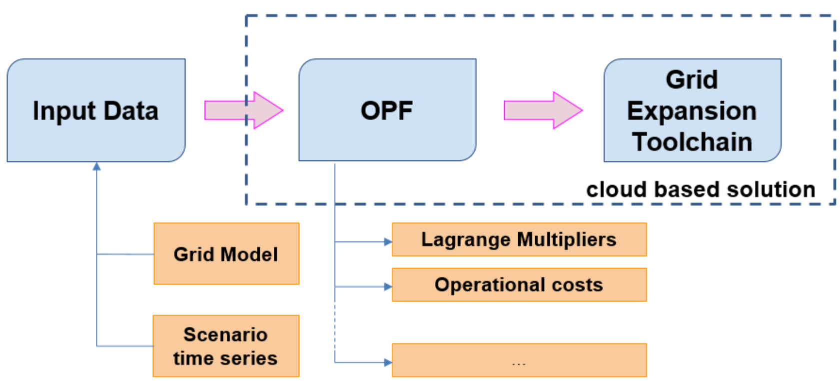


Figure 2-1 Workflow of the execution of FlexPlan RC simulations

The accuracy of the results obtained by the FlexPlan grid expansion planning tool is ensured by the fact that the result which solve the grid expansion problem is within the optimal gap (or Mixed Integer Programming (MIP) gap). The optimal gap is the minimum relative distance between the objective value of the optimal integer solution and the objective value of the best integer solution found. However, as the optimal objective value is not known, the best known lower bound is being used:

$$gap = \frac{|bound - objective_{value}|}{|bound|}$$

The quality of the optimal gap is therefore dependent not only on the quality of the best solution found but also on the quality of the best known lower bound. Thus, the MIP gap is chosen as one of the stopping criteria for the simulation. In this case, if the simulation is needed to be stopped within a certain amount of time, another stopping criteria was added to return the best integer solution found so far after a defined time. In order to define the MIP Gap solution with accuracy, tests have been carried out in Italian RC. Figure 2-2 shows the steps of finding the optimal solution for Italian RC.

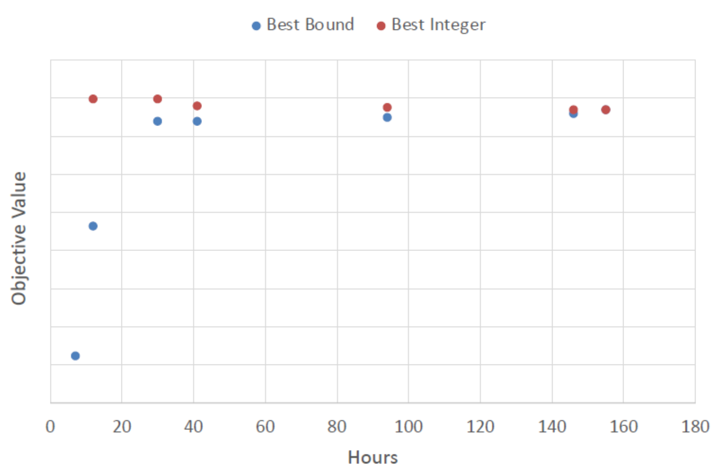


Figure 2-2 Steps to find the optimal solution for Italian RC

From the figure it can be seen, that the first integer solution was found after less than 12 hours with optimality gap = 0.09%, an optimality gap of 0.01% was reached after around 41 hours, the optimal solution was found after 155 hours. Thus, the MIP gap that can represent the accurate results is defined as 0.01% and the maximum runtime for the simulation was chosen to be 96 hours (4 days).

The experiences from the performance of the planning tool on the large-scale test cases within the regional case studies has shown a large simulation time for the OPF and large MIP gap within the chosen runtime for the grid expansion planning tool. For some of the regional cases, which were characterized by a short simulation time for OPF, the MIP gap resulting from solving the grid expansion planning problem was even bigger than the pre-established value and could reach 99%, which means that the found solution cannot be considered as optimal.

In order to decrease computational effort for the grid expansion tool, a set of simplifications were put into place. These simplifications answer to a two-fold objective: on one side to reduce the required simulation time (measure of computational effort), on the other side to preserve a high level of accuracy and fidelity of the results and obtain the final solutions within an accepted MIP gap. The latter objective is of upmost importance as the RCs are not only aimed at testing the FlexPlan tool, but also at providing realistic results that can impact the role of storage and other flexibility solutions in grid planning, feeding the subsequent development of regulatory guidelines.

The simplification measures, designed and validated by the RCs, are focused on the following aspects:

- Reduction of the data to be simulated, which include:
  - Considering only one scenario
  - Considering only the climatic variant with the highest probability
  - Considering four representative weeks per each target year (2030, 2040, 2050)
  - Considering hours aggregation in two-hour time blocks
- Simplification in the methodology by simulating the three target year years in a row instead of in a coordinated way
- Simplification in the methodology to simulate only a limited number of candidates for grid expansion planning
- Simplification of the mathematical description of some models (especially wherever they imply integral constraints)
- Other *ad hoc* simplifications at the Regional Case level.

The three FlexPlan studied scenarios are derived from major political drivers in coherence with ENTSO-E TYNDP 2020 [4], providing a common dataset to be used by all regional cases. These three scenarios provide different future possibilities for the European power system, aiming at achieving the climate targets set up by the European Commission. The scenarios considered in TYNDP 2020 are: National Trends (NT), Global Ambition (GA) and Distributed Energy (DE). NT scenario reflects the most recent EU member state National Energy and Climate Plans (NECP), submitted to the European Commission in line with the requirement to meet current European 2030 energy strategy targets. On the other hand, DE and GA scenarios are more ambitious and are fully in line with the COP 21 targets, providing different pathways reducing EU-28 emissions to net-zero by 2050. These two scenarios differ only on the focused technologies to reach the same climate target goals. More detailed information about the creation and the validation of the scenarios can be found in [9].

As can be seen in Table 2-1, in order to reach the climate targets, lignite and coal installed capacity will reach zero or negligible values and fossil fuels will be based on natural gas and decarbonized fossil fuels. While NT and GA scenarios present a similar total installed capacity (around 2 TW), DE scenario includes 37 % more installed capacity. This is due to the fact that DE scenario mostly bases the decarbonization strategy in distributed energy resources such as solar technologies, resulting in the need to have additional installed capacity to ensure system security levels. Also it can be seen that the climate targets are reached in this scenario through ambitious increases in the total installed capacity for wind and solar technologies while most fossil fuels will decrease to residual values. It is also worth mentioning that according to this scenario, battery energy storage systems will also play an important role (directly linked to wind and solar installed capacities) with a total installed capacity raising from 23 GW in 2030 to 198 GW in 2050, representing a share of 7.2% of all installed capacity.

Table 2-1 Installed capacity by technology for three scenarios

Description	2050 installed generation capacity [GW]		
	NT scenario	DE scenario	GA scenario
Nuclear Power	**66**	**69**	**62**
Lignite	**0**	**0**	**0**
Hard Coal	**0**	**0**	**0**
Oil	**2**	**2**	**2**
Natural Gas	**182**	**91**	**91**
Other fossil fuels	**63**	**63**	**63**
Mixed fuels	**0**	**0**	**0**
Wind Onshore	**471**	**792**	**531**
Wind Offshore	**186**	**111**	**221**
Solar	**611**	**1076**	**596**
Biomass	**1**	**2**	**1**
Other RES	**38**	**38**	**37**
Run-of-River Hydro	**56**	**56**	**56**
Storage Hydro	**77**	**77**	**77**
Pumped Storage Hydro	**105**	**105**	**105**
Battery	**109**	**198**	**62**
Demand Side Response (DSR)	**34**	**49**	**49**
Power-to-gas (P2G)	**5**	**5**	**2**
Total	**2006**	**2734**	**1955**

With the increasing amount of DERs (Distributed Energy Resources) in the network and the number of various projects related to the topic of distributed energy generation, it is expected that the DE scenario will play more valuable role in the future and therefore DE scenario is chosen as the main scenario to be simulated in the scope of FlexPlan project.

Also within one scenario and given the size of the considered networks, as well as the minimal required time series length, this number of features become very large, and feature reduction techniques should be used to make sure sensible clusters are produced from the initial dataset. K-means clustering was chosen as the clustering algorithm because of its simple but effective characteristics. The size of each cluster gives an indication of the probability of occurrence of the combination of load and generation present in that cluster and this probability is used as an input for the planning problem as well. The implemented scenario reduction methodology is shown in Figure 2-3 and consists of three steps:

- Clustering of the number of yearly variants;
- Clustering of the number of weeks to be simulated within one year;
- Clustering of the number of the hours within one week.

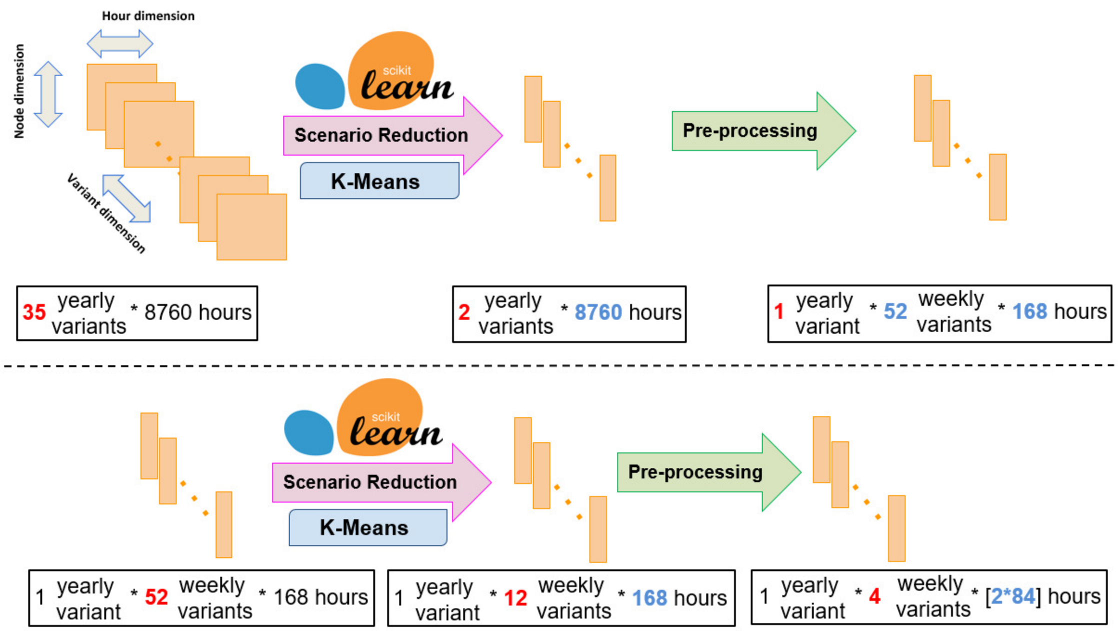


Figure 2-3 Implemented scenario reduction methodology

The first step consists in performing a reduction on the number of yearly variants. For this purpose, firstly 35 variants are clustering into two different clusters (K = 2), one random variant is selected for each cluster and the respective cluster probability is calculated for each cluster. Secondly, one variant with the highest probability is chosen to be simulated.

The second step consists in splitting independently every remaining yearly variant in 52 weekly variants (pre-processing) and then performing a second clustering, in order to reduce the number of weeks to be simulated for each variant, resulting in the simulation of representative weeks. Firstly the number of representative weeks is defined as 12 weeks, resulting in K = 12. The probability of each cluster is used to determine the representativeness of each of the selected weeks. To preserve the seasonal variability of different energy resources, the chosen set of 12 weeks must be indicative of the entire year. So, for this purpose, the K-means clustering algorithm returns the full 12 clusters. A selection is then performed to keep the seasonality while having a week for each cluster. This approach is implemented to allow the selection of one week per month. If this is not possible (because the K-means clustering results do not allow it), a relaxation entails choosing three variants for each season (winter, spring, summer and autumn). Secondly, to maintain the seasonality of the weeks while reducing the computational effort for the FlexPlan Tool, the number of representative weeks was manually reduced from 12 to 4 by selecting one week out of three within one season with the highest probability.

The third step consists in aggregating the data for several hours in one block so to create fewer time steps. For this purpose all the input parameters related to the time steps were changed in accordance with this methodology. Figure 2-4 and Figure 2-5 shows the results of the tests carried out for 2 weeks scenario OPF for Italian Regional Case with transmission and distribution networks for different time resolutions.

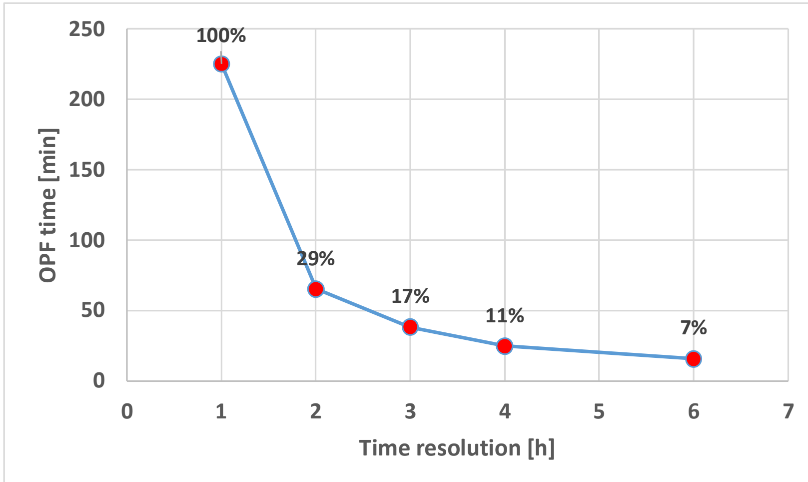


Figure 2-4 Dependency of computation time on the time resolution

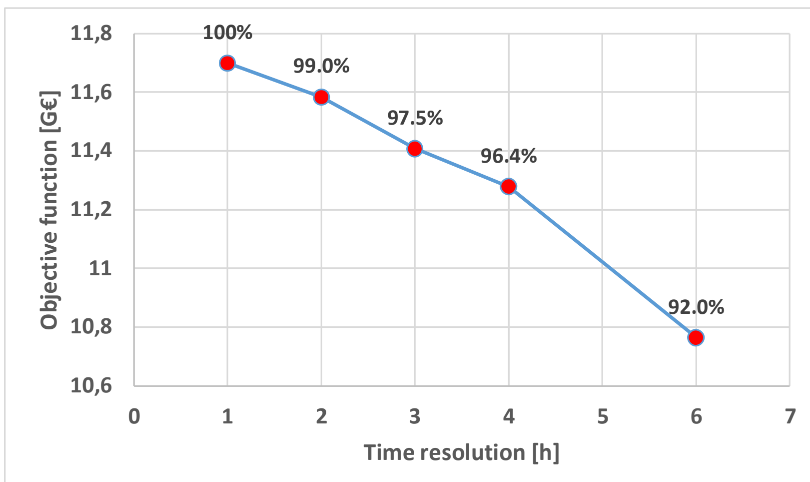


Figure 2-5 Dependency of solution of the grid expansion planning problem on the time resolution

From the figures it can be seen, that the aggregation of 2 hours into one block has the biggest impact on the simulation time (71% reduction in simulation time), but also preserves high accuracy of the results (1% decrease), which is defined as the result of the objective function after successful solution of the OPF. Aggregating 3 hours, 4 hours or 6 hours in one block reduces the accuracy of the results, but reduction of the simulation time is not so significant, so a **two-hour time resolution was chosen** as the best approach to reduce the simulation time for the third step of the scenario reduction methodology.

Another simplification concerns the methodology: instead of running three years (2030, 2040 and 2050) in coordinated manner, all the years are calculated in sequence so that the investment decisions in

2030 are approved to be added to the grid for 2040 together with the scenario for 2040 and the investment decisions in 2040 are approved to be added to the grid for 2050 together with the scenario for 2050. The reverse approach (first determine the required investments in 2050 and then go back to 2030 to evaluate the feasibility of these investments in 2030) was not chosen because in this case the first simulation would have the scenario data for 2050 and non-expanded grid data for 2025, which means that there will be a lot of congested lines and transformers and curtailed generators and loads, which will lead to significant increase in calculation time. In addition, due to the different lifetime of proposed candidates (10 years for storages and flexibility loads and 30 years for lines and transformers), after simulating the “reverse approach”, it is still necessary to run “direct approach” (from 2030 to 2050) in order to determine the required investments with regards to the expanded grid models. Also the number of possible candidates for the grid expansion planning, proposed by the pre-processor, was limited to 100 and they were sorted according to the values of the Lagrange Multipliers for the congestions, associated to those proposed candidates. In this case, not all congestions are solved by the FlexPlan Tool, but the most severe ones and there is a possibility that some congestions transfers from one decade to another, which leads to increasing number of congestions and high level of load and generation curtailment in some RCs with respect to a simulation with an unlimited number of proposed candidates. In general, those simplifications in the methodology allowed to reduce the number of integer variables in the calculation and significantly reduce the simulation time.

Another valuable simplification is related to the demand flexibility and storage modelling. These simplifications can be divided in four parts:

- Decomposition of large hydro storage modelling, which aims at solving the sub-problems with no direct connection to each other but to preserve the seasonal variability of the inflow of the hydroelectric dams based on utilization of the reservoirs;
- Conditions of the energy storage units, so that the value of stored energy in the end of the period need to be larger or equal than the value of stored energy in the beginning of the period, and the value of stored energy in the beginning of the first period (beginning of the year) needs to be equal 50% of the maximum capacity of the storage;
- Relaxation of the demand flexibility model and storage model, which aims at removing time dependent and integrality constraints, making the problem easier to solve by the optimisation solver.
- Concerning the modelling of hydrogen storage candidates, the capital expenses are calculated for the capacity of electrolyser (in kW), the operational expenses are considered as 2% of capital expenses per year for that electrolyser [10] [11].

More information on the simplification details of the demand flexibility and storage modelling can be found in deliverable D1.2 of the FlexPlan project [1], more information on the relevant parameter for the hydrogen storage candidates can be found in deliverable D2.2 of the FlexPlan project [3].

Also it is important to mention that some of the simplifications were implemented only within the particular Regional Case and will be presented in the Section 3.

3 Regional Cases

3.1 Iberian Peninsula

3.1.1 Overview of the adaptations for Regional Case

Compared to the network modelling described in D5.1, the Iberian Region case has the following simplifications and assumptions:

- The number of Distribution networks, which was reduced to 9.8% of total number of initially added distribution networks in order to decrease the computational time. The approach to select distribution lines was the following:
  - We considered geographical spread, thinking about choosing one transmission/sub-transmission bus each ten in an area (approximately, visually using a map were we have the buses identified).
  - For each selected bus, we checked that it had congestion probability. That can be checked by opening the files and checking the tags votageIssueRisk in buses and, mainly, overloadRisk in branches.
  - Once a bus was selected we selected all the distribution lines (PSx) connected to that bus.

Table 3-1 shows the number of the elements in the network.

Table 3-1 Description of the network, Iberian RC

Number of the nodes	6292
of which in transmission network	1832
of which in distribution network	4460
Number of AC branches	6720
of which in transmission network	2606
of which in distribution network	4114
Number of transformers	995
Number of storages	124
Number of flexibility loads	0 initially (total loads: 3705)

Figure 3-1 shows the transmission and sub-transmission networks (each distribution network is defined geographically with the same coordinates for all of its buses). In this figure red lines and dots represent the elements of the network with 220 kV and 400 kV voltage level, green represent 150 kV and 132 kV voltage level, yellow – 63 kV voltage level and blue – other.

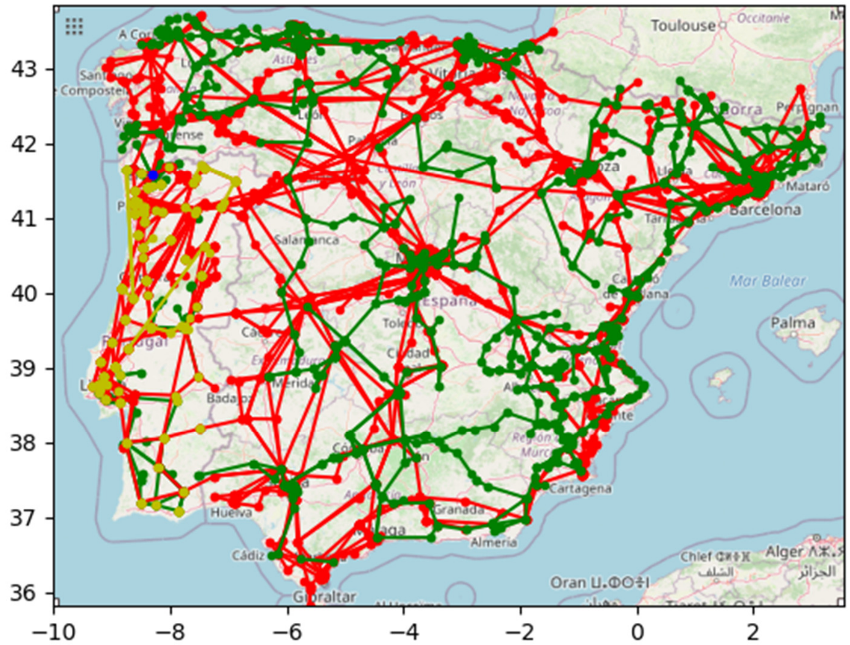


Figure 3-1 Iberian transmission and subtransmission network map

3.1.2 Results and analysis

Decade 2030

The Figure 3-2 shows the congested lines in the system, i.e. branches with Lagrange Multipliers different to zero for year 2030. Distribution networks and transformers are defined geographically with the same coordinates for all of its buses and, therefore, they appear as points in the figure (the numbers are an arbitrary indicator to distinguish them). The Figure 3-3 shows curtailed generators and curtailed load in 2030. All the curtailments have the same transparency, but can look darker when two or more elements overlap. Also this figure presents the yearly curtailed energy for generation and load.

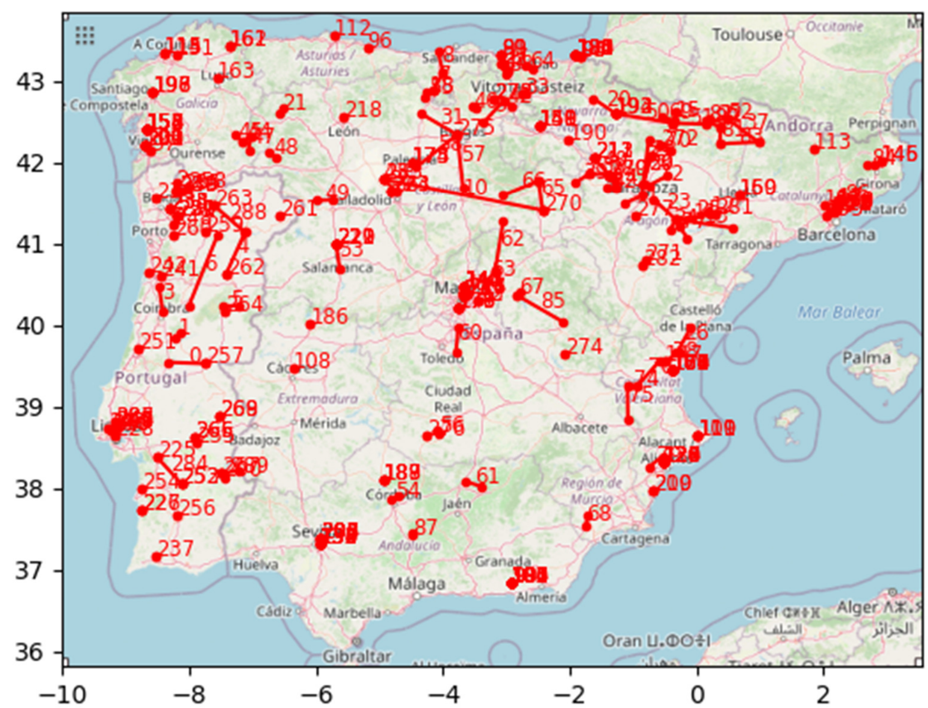


Figure 3-2 Congested lines and transformers for the Iberian Peninsula RC, 2030

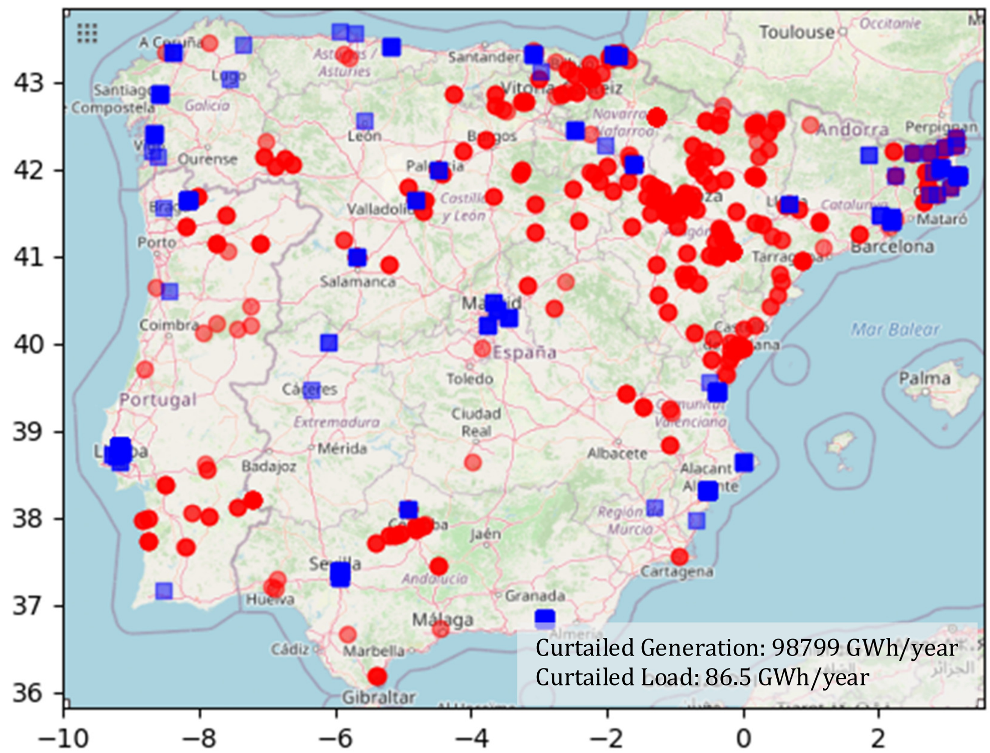


Figure 3-3 Curtailed generators (plotted as circles) and loads (plotted as squares) for the Iberian Peninsula RC and yearly curtailed energy (Year 2030)

The shown OPF results lead to the suggestion of 57 branches, 4 transformers, 6 storages and 33 flexible loads, these candidates in details are presented in Table 3-2. The investment costs in this table represent the sum of the investment costs for approved investment decisions by the grid expansion planning tool by type.

Table 3-2 Description of the candidates, 2030, Iberian RC

Type	AC Branch	Transformer	Storage	Flexibility load	Total
Number of candidates	57	4	6	33	100
Investment decisions	6 (Transmission) 30 (Distribution)	0 (Transmission) 2 (Distribution)	2 (H2) 0 (Flow)	9	49
Investment rejected	1 (Transmission) 20 (Distribution)	2 (Transmission) 0 (Distribution)	0 (H2) 4 (Flow)	24	51
Investment costs, €	7,641,950	244,781	893,333	9,000	8,789,064

Regarding the GEP simulation, an optimal solution was found in approximately 3 days, the results of the simulations (both OPF and GEP) are presented in Table 3-3.

Table 3-3 Results of simulation, 2030, Iberian RC

Total costs (Optimal Power Flow), €	107,737,927,098
Total costs (Grind Expansion Planning Tool), €	93,485,693,468
Execution time	258,656 seconds (3.0 days)
MIP Gap, %	0.0

The total costs for OPF simulation for 2030 and GEP simulation for 2030 are presented in details in Table 3-4 and Table 3-5 respectfully. In these tables and all the following tables, related to the OPF costs and GEP costs for all target years and all RCs, slack costs represent the costs of the slack bus generator in case it is activated.

Table 3-4 Costs results, OPF 2030, Iberian RC

Period	Week 1	Week 2	Week 3	Week 4	Total
Generation costs, €	716,426,713	6,857,200,477	7,877,532,190	4,148,320,144	19,599,479,524
Generation curtailment costs, €	17,423,391,190	21,476,875,370	15,149,497,454	8,316,439,909	62,366,203,923
Load curtailment costs, €	4,923,980,135	7,487,448,426	8,915,797,936	4,445,017,154	25,772,243,651
Load reduction costs, €	0	0	0	0	0
Load shifting costs, €	0	0	0	0	0
Slack costs, €	0	0	0	0	0
Total costs, €	23,063,798,038	35,821,524,272	31,942,827,581	16,909,777,207	107,737,927,098

Table 3-5 Costs results, GEP 2030, Iberian RC

Period	Week 1	Week 2	Week 3	Week 4	Total
Generation costs, €	303,874,905	6,619,162,447	7,175,776,483	4,025,644,942	18,124,458,777
Generation curtailment costs, €	17,569,251,133	21,350,423,960	15,311,538,520	8,186,765,555	62,417,979,169
Load curtailment costs, €	2,457,063,359	4,014,077,662	4,131,313,991	2,337,930,145	12,940,385,158
Load reduction costs, €	51,975	583,336	863,322	329,096	1,827,729
Load shifting costs, €	45,652	453,013	357,952	186,018	1,042,635
Slack costs, €	0	0	0	0	0
Total costs, €	20,330,287,024	31,984,700,419	26,619,850,269	14,550,855,756	93,485,693,468

The Figure 3-4 shows graphical comparison of OPF and GEP results in terms of costs.

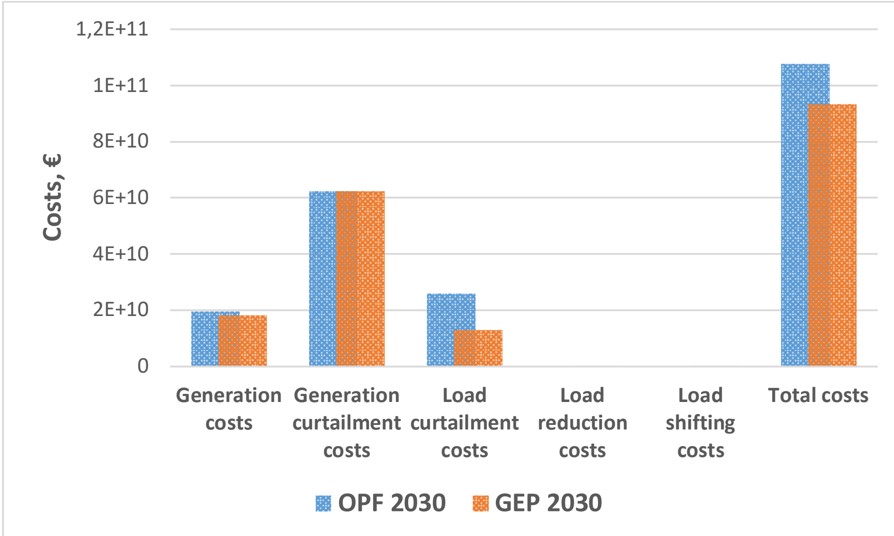


Figure 3-4 Comparison of the costs for OPF and GEP, 2030, Iberian RC

Analysing the results of 2030 it can be observed that:

- Generation is much higher than demand, which leads to generation curtailment. These generation and load profiles were generated by Model of International Energy Systems (MILES) software based on the scenarios, described in [9] and shown in Figure 3-6.

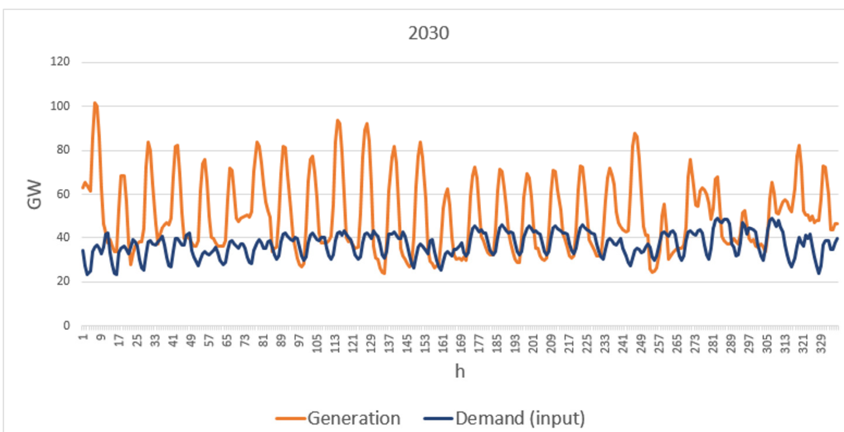


Figure 3-5 Generation and load profiles for 2030, Iberian RC

- Low number of candidates in transmission, because most severe congestions appear in distribution and limitation of the candidates.
- Quite balanced number of candidate investments and rejections.
- Flexible loads reduce load curtailment and the related system cost.
- The OPF cost is higher than the GEP costs: after the extension of the network, costs are reduced
- Highest costs are generation curtailment costs, due to the big unbalance between generation and demand.

- Load curtailment costs are also very high, similar to generation costs, because distribution networks seems to be very saturated in some hours due to high PV generation.

Decade 2040

The Figure 3-6 shows the congested lines in the system, i.e. branches with Lagrange Multipliers different to zero for year 2040. Distribution networks and transformers are defined geographically with the same coordinates for all of its buses and, therefore, they appear as points in the figure (the numbers are an arbitrary indicator to distinguish them). The Figure 3-7 shows curtailed generators and curtailed load in 2040. All the curtailments have the same transparency, but can look darker when two or more elements overlap. Also this figure presents the yearly curtailed energy for generation and load.

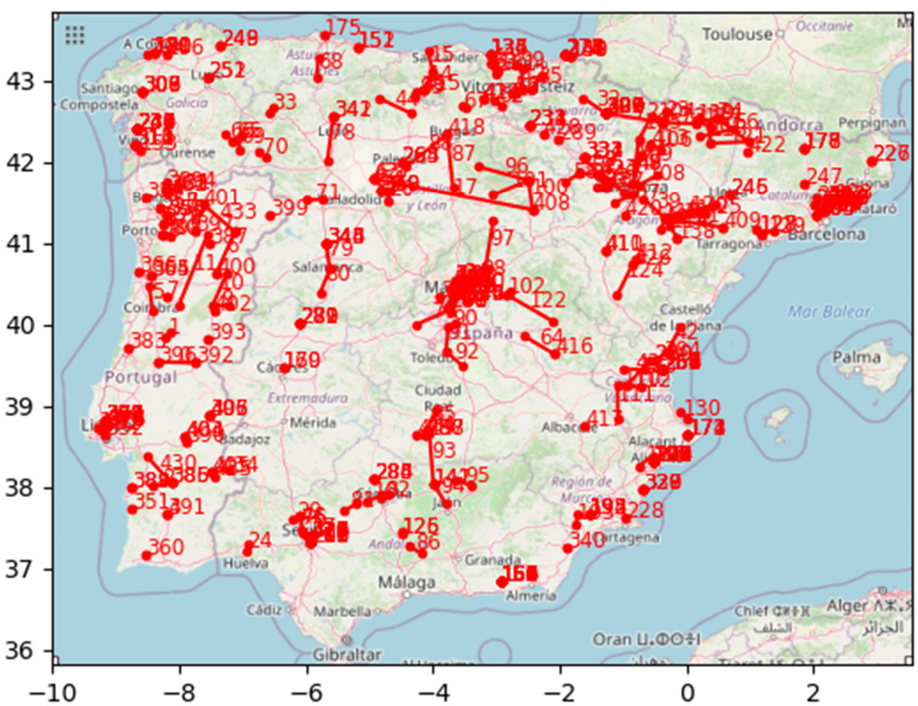


Figure 3-6 Congested lines and transformers for the Iberian Peninsula RC, 2040

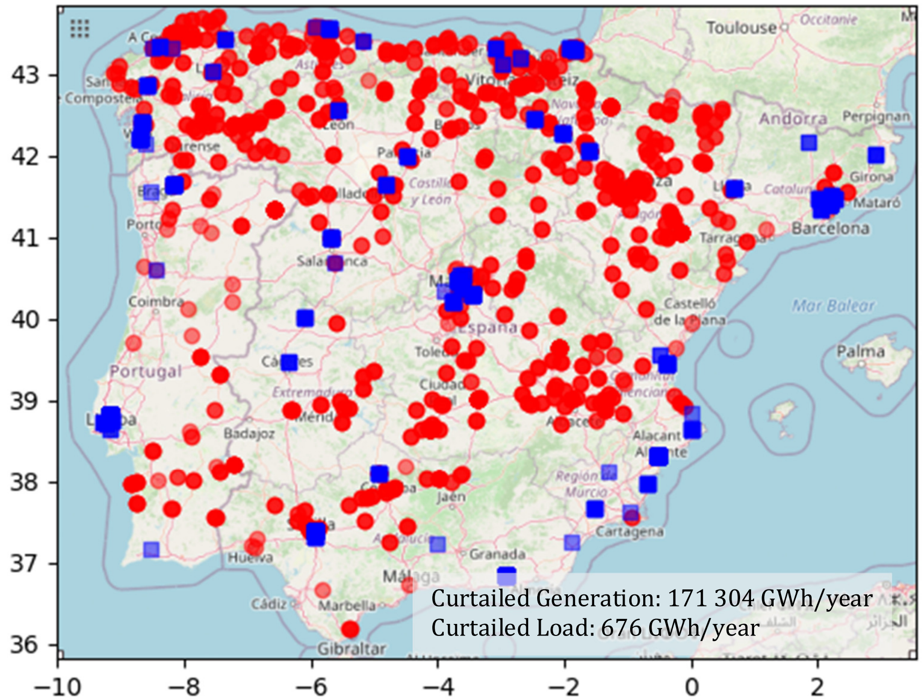


Figure 3-7 Curtailed generators (plotted as circles) and loads (plotted as squares) for the Iberian Peninsula RC and yearly curtailed energy (Year 2040)

The shown OPF results lead to the suggestion of 74 branches, 5 storages and 21 flexible loads, these candidates in details are presented in Table 3-6. The investment costs in this table represent the sum of the investment costs for approved investment decisions by the grid expansion planning tool by type.

Table 3-6 Description of the candidates, 2040, Iberian RC

Type	AC Branch	Transformer	Storage	Flexibility load	Total
Number of candidates	74	0	5	21	100
Investment decisions	0 (Transmission) 37 (Distribution)	0 (Transmission) 0 (Distribution)	0 (H2) 2 (Flow)	5	44
Investment rejected	0 (Transmission) 37 (Distribution)	0 (Transmission) 0 (Distribution)	0 (H2) 3 (Flow)	16	56
Investment costs, €	1,932,156	0	442,493	5,000	2,379,649

Regarding the GEP simulation, an optimal solution was found in approximately 2 hours, the results of the simulations (both OPF and GEP) are presented in Table 3-7. The GEP simulation time reduced significantly because the pre-processor hasn't suggested any candidate in the transmission network. This is due to the fact that the most severe congestions appear in distribution network.

Table 3-7 Results of simulation, 2040, Iberian RC

Total costs (Optimal Power Flow), €	134,462,665,834
Total costs (Grind Expansion Planning Tool), €	133,642,285,035
Execution time	6,424 seconds (0.1 days)
MIP Gap, %	0.000089

The total costs for OPF simulation for 2030 and GEP simulation for 2030 are presented in details in Table 3-8 and Table 3-9 respectfully.

Table 3-8 Costs results, OPF 2040, Iberian RC

Period	Week 1	Week 2	Week 3	Week 4	Total
Generation costs, €	4,553,528,433	1,395,755,290	2,466,266,260	6,922,836,769	15,338,386,752
Generation curtailment costs, €	21,235,237,941	40,905,992,939	30,011,967,444	11,914,449,777	104,067,648,101
Load curtailment costs, €	3,768,177,964	4,736,998,939	4,070,453,766	2,481,000,313	15,056,630,981
Load reduction costs, €	0	0	0	0	0
Load shifting costs, €	0	0	0	0	0
Slack costs, €	0	0	0	0	0
Total costs, €	29,556,944,337	47,038,747,168	36,548,687,470	21,318,286,859	134,462,665,834

Table 3-9 Costs results, GEP 2040, Iberian RC

Period	Week 1	Week 2	Week 3	Week 4	Total
Generation costs, €	4,570,999,633	1,401,406,427	2,476,375,202	6,933,317,266	15,382,098,527
Generation curtailment costs, €	21,225,543,742	40,900,353,983	30,005,405,745	11,910,389,598	104,041,693,068
Load curtailment costs, €	3,557,490,340	4,477,369,819	3,819,856,802	2,361,202,886	14,215,919,846
Load reduction costs, €	464,930	395,167	418,226	238,964	1,517,287
Load shifting costs, €	238,467	358,029	311,363	148,447	1,056,306
Slack costs, €	0	0	0	0	0
Total costs, €	29,354,737,112	46,779,883,425	36,302,367,337	21,205,297,161	133,642,285,035

The Figure 3-8 shows graphical comparison of OPF and GEP results in terms of costs.

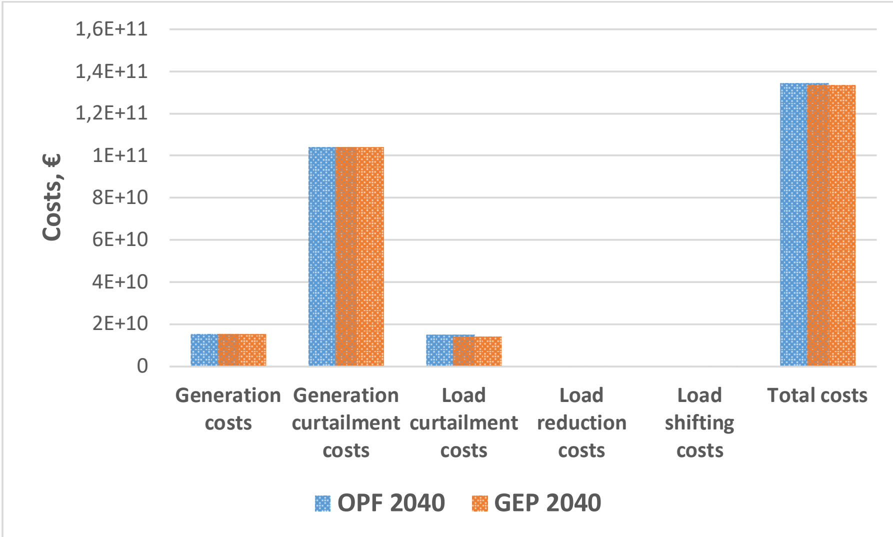


Figure 3-8 Comparison of the costs for OPF and GEP, 2040, Iberian RC

Analysing the results of 2040 it can be observed:

- Generation is much higher than demand, which leads to generation curtailment, similar to 2030. Figure 3-9 shows the profiles, generated by MILES software.

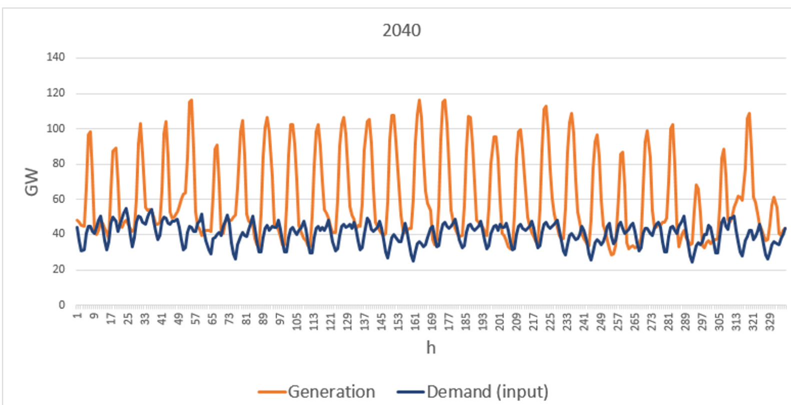


Figure 3-9 Generation and load profiles for 2040, Iberian RC

- Most severe congestions appear in distribution grid. Branch candidates do not appear in transmission.
- Balanced number of candidate investments and rejections (44 candidates are approved out of 100 in total).
- Flexible loads reduce load curtailment and the related system cost.
- The OPF cost is higher than the GEP costs: after the extension of the network, costs are reduced
- Highest costs are generation curtailment costs, due to the big unbalance between generation and demand.

- Load curtailment costs are also high, similar to generation costs, because distribution networks seem to be very saturated.
- Overall the difference in the costs for OPF and GEP in 2040 is not high (less than 1%) because approved candidates in distribution solve the issues within their area of influence.

Decade 2050

The Figure 3-10 shows the congested lines in the system, i.e. branches with Lagrange Multipliers different to zero for year 2050. Distribution networks and transformers are defined geographically with the same coordinates for all of its buses and, therefore, they appear as points in the figure (the numbers are an arbitrary indicator to distinguish them). The Figure 3-11 shows curtailed generators and curtailed load in 2050. All the curtailments have the same transparency, but can look darker when two or more elements overlap. Also this figure presents the yearly curtailed energy for generation and load.

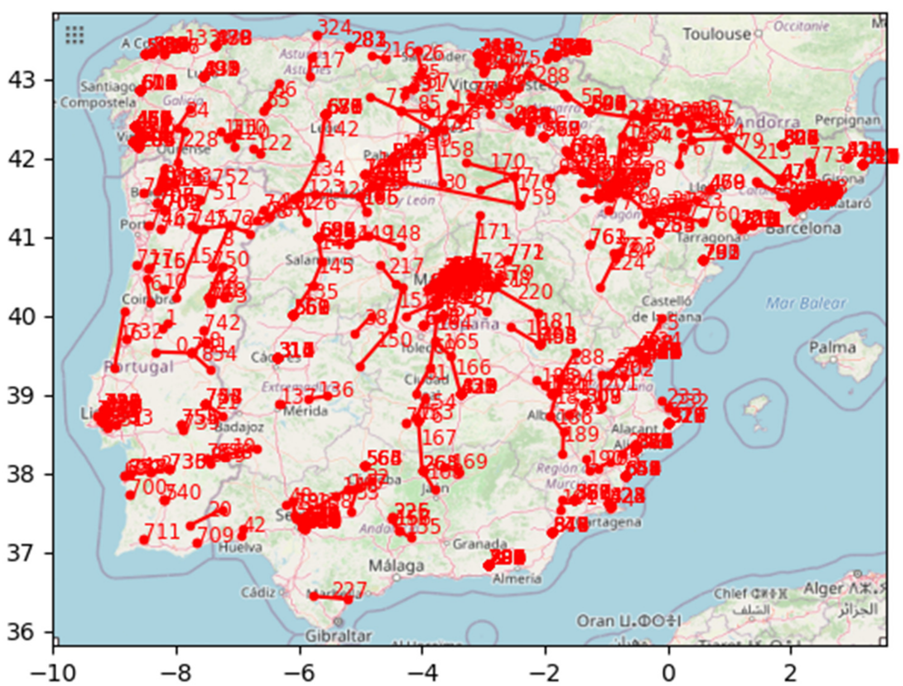


Figure 3-10 Congested lines and transformers for the Iberian Peninsula RC, 2050

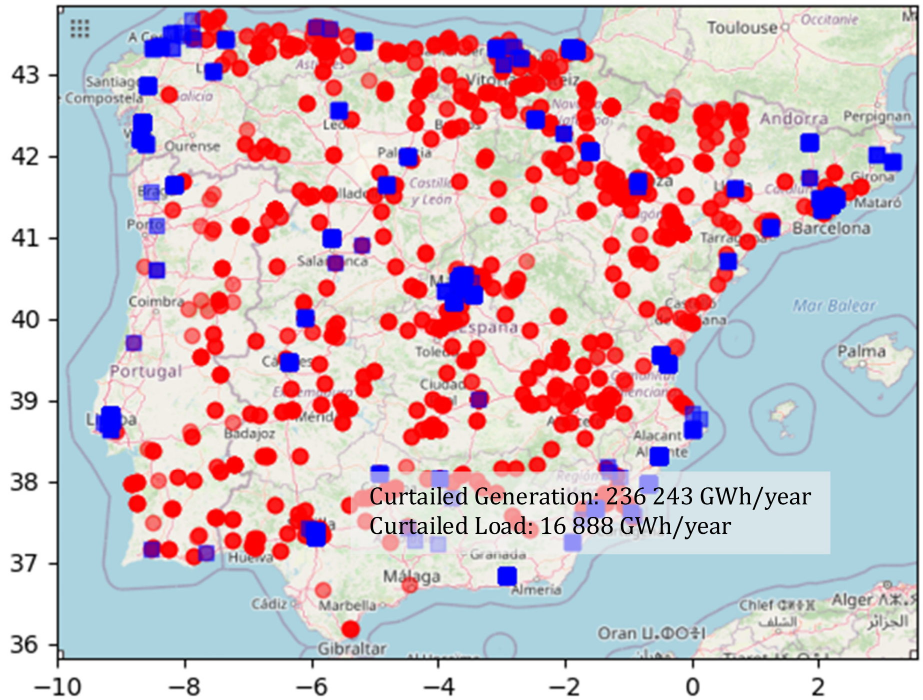


Figure 3-11 Curtailed generators (plotted as circles) and loads (plotted as squares) for the Iberian Peninsula RC and yearly curtailed energy (Year 2050)

The shown OPF results lead to the suggestion of 98 branches and 2 storages, these candidates in details are presented in Table 3-10. The investment costs in this table represent the sum of the investment costs for approved investment decisions by the grid expansion planning tool by type.

Table 3-10 Description of the candidates, 2050, Iberian RC

Type	AC Branch	Transformer	Storage	Flexibility load	Total
Number of candidates	98	0	2	0	100
Investment decisions	0 (Transmission) 36 (Distribution)	0 (Transmission) 0 (Distribution)	1 (H2) 1 (Flow)	0	38
Investment rejected	0 (Transmission) 62 (Distribution)	0 (Transmission) 0 (Distribution)	0 (H2) 0 (Flow)	0	62
Investment costs, €	2,148,374	0	8,379,467	0	10,527,841

Regarding the GEP simulation, an optimal solution was found in approximately 22 hours, the results of the simulations (both OPF and GEP) are presented in Table 3-11. The GEP simulation time, similar to year 2040, is much lower than the simulation time for 2030 because the pre-processor hasn't suggested any candidate in the transmission network. This is due to the fact that the most severe congestions appear in the distribution network, as it was in year 2040.

Table 3-11 Results of simulation, 2050, Iberian RC

Total costs (Optimal Power Flow), €	238,234,332,403
Total costs (Grind Expansion Planning Tool), €	236,684,653,257
Execution time	77889 seconds (0.9 days)
MIP Gap, %	0.0

The total costs for OPF simulation for 2030 and GEP simulation for 2030 are presented in details in Table 3-12 and Table 3-13 respectfully.

Table 3-12 Costs results, OPF 2050, Iberian RC

Period	Week 1	Week 2	Week 3	Week 4	Total
Generation costs, €	9,783,263,335	7,312,235,037	12,890,471,680	16,560,116,069	46,546,086,122
Generation curtailment costs, €	23,439,554,975	35,698,553,112	63,030,659,607	21,222,789,465	143,391,557,159
Load curtailment costs, €	10,645,150,224	8,347,735,093	19,539,229,468	9,764,574,337	48,296,689,122
Load reduction costs, €	0	0	0	0	0
Load shifting costs, €	0	0	0	0	0
Slack costs, €	0	0	0	0	0
Total costs, €	43,867,968,534	51,358,523,242	95,460,360,755	47,547,479,871	238,234,332,403

Table 3-13 Costs results, GEP 2050, Iberian RC

Period	Week 1	Week 2	Week 3	Week 4	Total
Generation costs, €	9,804,623,397	7,327,644,179	12,917,770,182	16,591,209,882	46,641,247,640
Generation curtailment costs, €	23,429,743,834	35,684,850,444	63,017,744,764	21,209,748,470	143,342,087,512
Load curtailment costs, €	10,376,463,956	8,022,635,374	18,848,414,896	9,453,803,879	46,701,318,105
Load reduction costs, €	0	0	0	0	0
Load shifting costs, €	0	0	0	0	0
Slack costs, €	0	0	0	0	0
Total costs, €	43,610,831,186	51,035,129,998	94,783,929,842	47,254,762,231	236,684,653,257

The Figure 3-12 shows graphical comparison of OPF and GEP results in terms of costs.

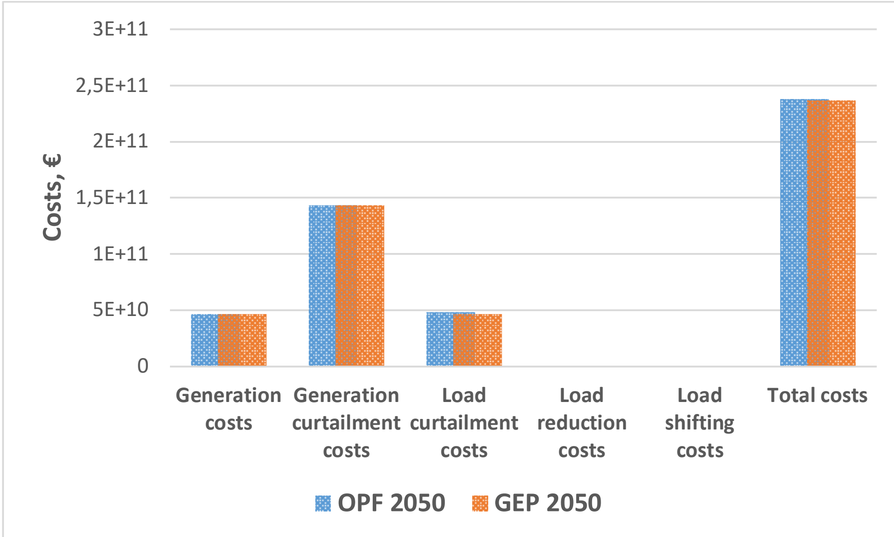


Figure 3-12 Comparison of the costs for OPF and GEP, 2050, Iberian RC

Analysing the results of 2050 it can be observed:

- Generation is much higher than demand, which leads to generation curtailment, similar to 2030 and 2040. Figure 3-13 shows the generation and load profiles, generated by MILES software.

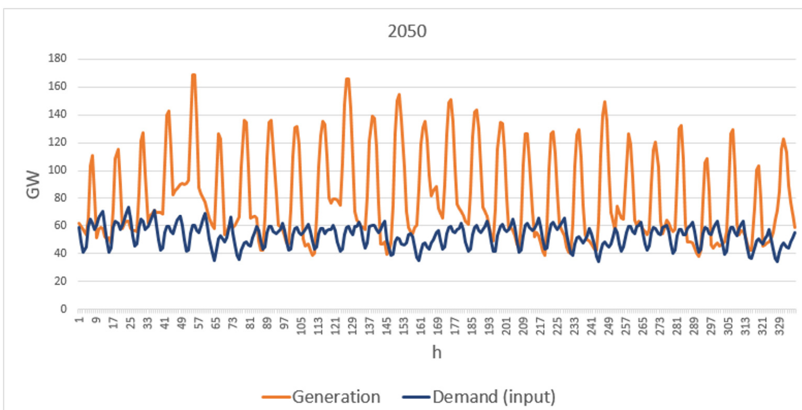


Figure 3-13 Generation and load profiles for 2050, Iberian RC

- Most severe congestions appear in distribution. Branch candidates do not appear in transmission.
- Quite balanced number of candidate investments and rejections.
- There are no load reduction or load shifting costs due to the absence of the flexible load candidates.
- The OPF cost is higher than the GEP costs: after the extension of the network, costs are reduced
- Highest costs are generation curtailment costs, due to the big unbalance between generation and demand.

- Load curtailment costs are also high, similar to generation costs, because distribution networks seem to be very saturated.

In addition, two more tests were run for all target years (2030, 2040 and 2050) with another two sets of candidates including less transmission network candidates (same candidates, but without congestion influences in other branches) and more transmission candidates. This was performed to analyse if the number of transmission candidates had an impact on the results or not. We observed that a high number of transmission candidates (we did the test with 17), provided memory errors in the tool. We considered the following terminology to identify the three variants for which the 3 Grid Expansion Planning steps were run:

- v1: 3 transmission branches among the 100 grid expansion candidates that were considered in 2030. The difference with v2 is that, in this case, the four lines influenced by a congested line, i.e. lines with congestion possibility but not congested at the moment, are not included as candidates.
- v2: 7 transmission branches among the 100 grid expansion candidates that were considered in 2030. This is the example provided above, showing the results by the pre-processor.
- v3: 11 transmission branches among the 100 grid expansion candidates that were considered in 2030. Four more transmission candidates are added, and 4 distribution candidates removed with respect to v2. The four new candidates are congested but ranked lower according to the congestion severity.

The Table 3-14 compares the candidates in the three versions for the three years.

Table 3-14 List of candidates in for different test runs, Iberian RC

Candidate	2030			2040			2050		
	v1	v2	v3	v1	v2	v3	v1	v2	v3
AC branch in transmission	3	7	11	4	0	0	0	0	0
AC branch in distribution	52	50	46	70	74	75	100	98	100
Transformer in transmission	1	2	2	1	0	0	0	0	0
Transformer in distribution	2	2	2	0	0	0	0	0	0
Storage (H2)	2	2	2	1	0	0	0	1	0
Storage (Flow battery)	6	4	4	4	5	5	0	1	0
Flexible Load	34	33	33	20	21	20	0	0	0
Total	100	100	100	100	100	100	100	100	100

After carrying out the analysis, the comparison between the results obtained are shown in the Table 3-15 and Table 3-16 that indicates which costs are higher or lower in both versions for each category. Load reduction costs and Load shifting costs are equal 0 for 2050 because the pre-processor hasn't suggested any flexible load candidate for this year.

Table 3-15 Maximum value of GEP costs for variants with different number of candidates, Iberian RC

GEP output costs(maximum values)	v1 vs. v2 vs. v3 (Maximum value of the costs)			
	2030	2040	2050	Total
Generation costs	v2	v2	v2	v2

GEP output costs(maximum values)	v1 vs. v2 vs. v3 (Maximum value of the costs)			
	2030	2040	2050	Total
Generation curtailment costs	v1	v1	v1	v1
Load curtailment costs	v3	v1	v3	v3
Load reduction costs	v3	v3	v1/v2/v3	v1
Load shifting costs	v3	v3	v1/v2/v3	v1
Total costs	v1	v1	v2	v3

Table 3-16 Minimum value of GEP costs for variants with different number of candidates, Iberian RC

GEP output costs(minimum values)	v1 vs. v2 vs. v3 (Minimum value of the costs)			
	2030	2040	2050	Total
Generation costs	v1	v3	v1	v1
Generation curtailment costs	v3	v3	v3	v3
Load curtailment costs	v1	v3	v1	v1
Load reduction costs	v1	v1	v1/v2/v3	v2
Load shifting costs	v2	v2	v1/v2/v3	v2
Total costs	v3	v3	v1	v1

Focusing on the total cost, the results show that v1 provides a lower total cost, while v3. provides the maximum cost. An answer for this could be that option v1 is the one that has more candidates from the congestion severity ranking performed by the candidate pre-processor tool, and v3 the one with lowest number of ranked candidates.

Increasing the number of candidates in transmission does not provide better results for the system (congestions are not solved in distribution, for example).

Considering the congestion ranking provided by the pre-processor, gives better results (influenced lines, if not in the ranking, do not improve the result).

Analysing the results it can be observed:

- The considered scenario is quite unbalanced in terms of Generation (very high renewable production) and Demand (not so big increase). Shows the power for generation and load in 2030, 2040 and 2050 respectively.
- The main congestions are found at the distribution level.
- As a result, the system suffers from high generation and load curtailment, which represents high costs.
- The OPF cost is higher than the GEP costs: after the extension of the network, costs are reduced.

Environmental impact assessment

The environmental impact assessment is done through the calculation of costs for CO_2-Emissions (Carbon Footprint impact) and Air Quality Impact for 2030, 2040, and 2050 after solving the grid expansion planning problem. Whereas the air quality calculations are limited to thermal generation, carbon footprint calculations take into account all the emission of greenhouse gasses occurring during the entire life cycle of the analyzed product/service, so it means both for the generation and proposed candidates. More information on the methodology, calculations and the costs related to carbon footprint and air quality can be found in deliverable D1.2 of the FlexPlan project [1].

The Table 3-17 shows the percentages of the carbon footprint costs related to generation with respect to the total generation costs in three decades and air quality costs related to generation with respect to the total generation costs in three decades.

Table 3-17 Environmental impact assessment for generation

Year	2030	2040	2050
Carbon Footprint impact assessment for generation, %	43.79	57.48	56.83
Air Quality impact assessment for generation, %	10.85	9.43	9.20

The Table 3-18 shows the percentages of the total carbon footprint costs (related to the power plants and proposed candidates) with respect to the total costs in three decades and total air quality costs with respect to the total costs in three decades.

Table 3-18 Environmental impact assessment for generation

Year	2030	2040	2050
Carbon Footprint impact assessment, %	8.49	6.62	11.2
Air Quality impact assessment, %	2.1	1.08	1.81

In general, the cost ratio of the carbon footprint in the Iberian regional case is high relative to the cost of generation due to the operation of conventional power plants and the significant growth of the CO2 price in 2040 and 2050.

3.2 France and BeNeLux

3.2.1 Overview of the adaptations for Regional Case

Compared to deliverable 5.1 [2], the France and BeNeLux regional case's grid has been divided in two parts and reduced consistently. The main reason behind the applied network reductions is the size of the original files (the size of the pre-processor input file for France was 2 GB, which made it not possible to be uploaded to the server). In fact, the high computational complexity due to the thousands of network elements lead to extremely long computational times for both the Optimal Power Flow (OPF) and Grid Expansion Planning problems (GEP), in the order of several days for a single one-week-long OPF simulation.

Therefore, the two parts include respectively the Benelux (Belgium, the Netherlands and Luxembourg) and French grids. While the power through the interconnections between the Benelux Countries is constrained only by the lines' capacity, the power exchange between the two parts of the regional case is instead fixed, as performed between each regional case in the project. The fixed power flows data follow what shown in [12].

The following subsection describes the network reductions applied to the regional case. Due to the dimension of the French power system, stronger approximations are performed on it in order to maintain an appropriate computational time while losing little information.

France

Following the methodology shown in the Figure 3-14 below, the Renewable Energy Sources (RES) generators are aggregated in a single RES generator ("Hydro" represent only Hydro RoR power plants). This reduction is performed in the pre-processing stage by multiplying each generator by its capacity factor and summing the power outputs. As a result, the final number of RES generators in the optimisation is reduced by a factor of 4, compared to the original grid, without losing information about the power output except for the generator type.

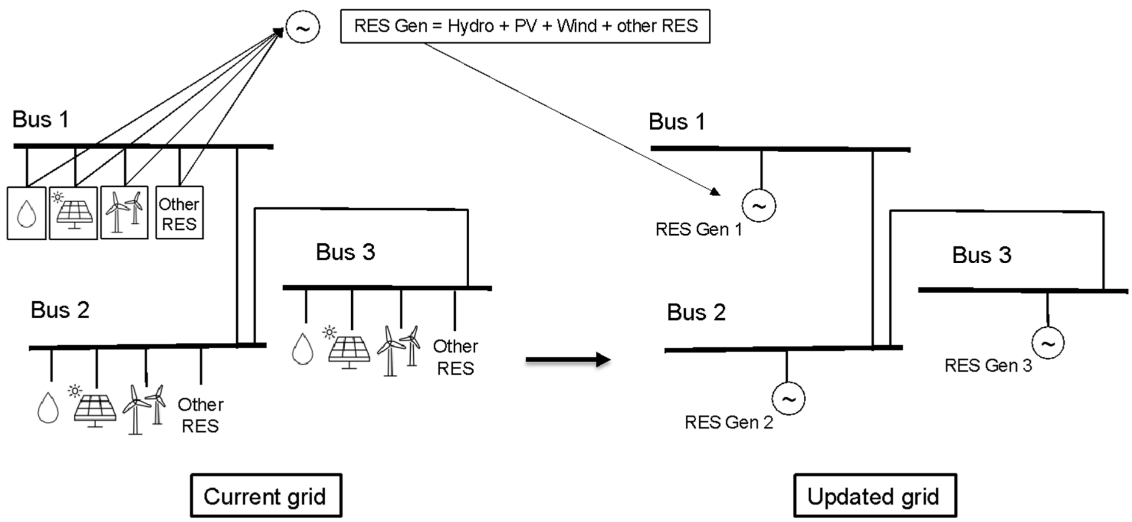


Figure 3-14 Aggregation of RES generators for French network

Another grid reduction being applied concerns the number of ac branches in the system, with parallel lines reduced to one single line. The overall maximum line capacity is preserved by multiplying the susceptance of the final single line by the original number of lines. Therefore, the surrogated line has a x-fold increase in power capacity, where x is the number of parallel lines before the reduction.

France and BeNeLux

Due to the extremely high amount of network elements in the models and impossibility to increase the computational power, several assumptions have been made to reduce the grid complexity.

First of all, generator units from the same power plant or connected to the same bus have been aggregated. On the network level, there is no difference in the maximum power capacity of the aggregated generators. As no unit commitment constraints are involved in the optimisation process, this assumption leads to a decrease in the number of generators while preserving all the initial information regarding the generators.

Secondly, as shown in Figure 3-15 below, another reduction technique is based on the position of transmission buses in the power system. Based on their coordinates, transmission buses in proximity to each other are grouped in a single transmission bus and their loads and generator capacities summed. Such a technique leads to a consistent reduction in the number of branches, generators and loads at the transmission level. At the same time, the branches connecting these different transmission sub-areas are preserved. Should a transmission bus have one or more distribution grids, they are transferred to the reduced transmission bus. Nevertheless, distribution grids belonging to these newly generated transmission buses are kept separate. Since distribution grids often have power congestions, aggregating them would lead to an underestimation of the investment needed at that level and would go against the projects' goals.

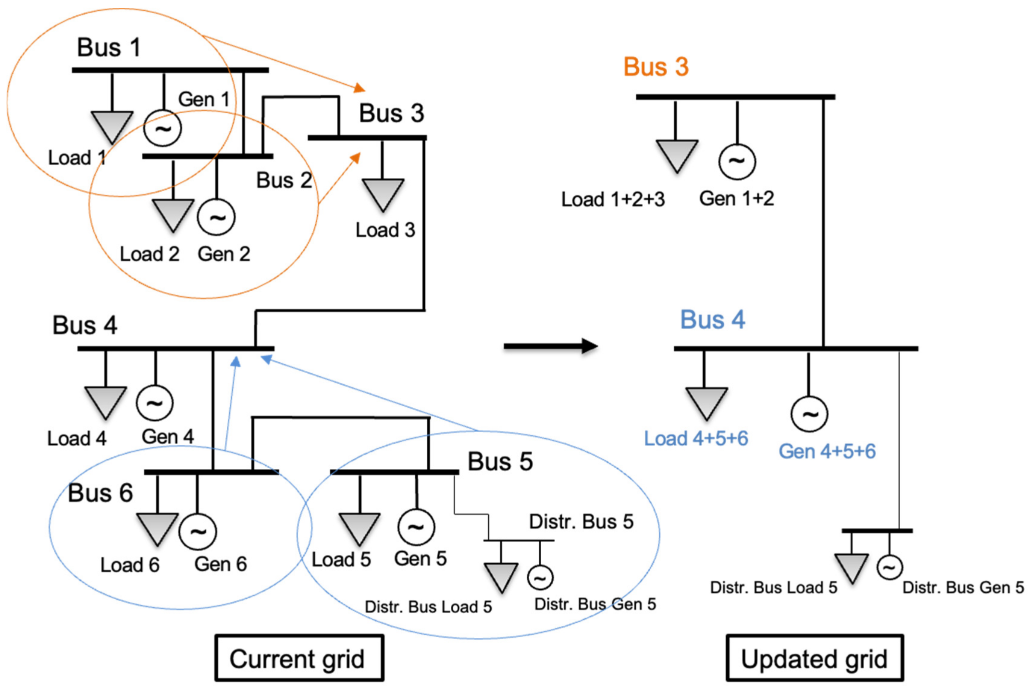


Figure 3-15 Grid reduction method applied to selected areas of the power grid where buses are in proximity to each other

Thirdly, hydro Run-of-River (RoR) and hydro reservoir generators are omitted from the two grids due to the reduced number of such generators in the system. In fact, since considering water availability and seasonality is behind the scope of the project, hydro reservoir generators are modelled as storage units. Therefore, there are 6 storage units in France and 2 in Benelux, as highlighted respectively in Table 3-19 and Table 3-20 thereafter.

Table 3-19 Number of network elements in France

Number of the nodes	6649
of which in transmission network	2665
of which in distribution network	3984
Number of AC branches	6662
of which in transmission network	2922
of which in distribution network	3740
Number of transformers	868
Number of storages	6
Number of flexibility loads	0

Table 3-20 Number of network elements in BeNeLux

Number of the nodes	3607
of which in transmission network	2390
of which in distribution network	1217
Number of AC branches	3181

of which in transmission network	2069
of which in distribution network	1112
Number of transformers	1128
Number of storages	2
Number of flexibility loads	0

Fourthly, the number of distribution networks used for each part of the regional case is 5% of the available synthetic distribution networks computed at an earlier stage of the project [CITE]. Table 3-19 and Table 3-20 prove how selecting only 5% of the distribution networks lead to thousands of grid components, i.e. variables and constraints, added to the model. Therefore, a trade-off is made between the accuracy of the model and the computational time. If a distribution network is attached to a transmission bus, the RES generation capacity of the transmission bus is distributed among the RES generators present at the distribution level. The capacity is not distributed equally, but relies on a 'TechnologyPowerPortion' parameters which indicates the weight of a single RES generator out of the total RES capacity installed in that distribution network.

3.2.2 Results and analysis

France

In this section, the simulation results for region France are presented. Similar to other regional cases, the analysis will be provided for each planning year, namely 2030, 2040 and 2050. The simulations consist of the GEP and OPF simulations. As explained in the methodology, the pre-processor tool gives the GEP candidates for each planning year based on the results from the OPF simulation. However, an adjustment needs to be made in planning years 2040 and 2050 because like in 2030, the pre-processor tool does not give any candidates on the transmission level. The routine of adding manually the transmission candidates will be explained in a later part of this section. For all planning years, the number of candidates is kept to 100.

Decade 2030

Table 3-21 summarizes the OPF and GEP simulations of France in 2030. As we can see from the table, the total costs of the OPF are higher than the total GEP costs, almost twice as much. With the setup explained in the previous sections, the GEP for France 2030 finished in 11.6 hours with no MIP gap. The main reason for the relatively low computational effort is the absence of transmission candidates. As highlighted previously in the text, the GEP computational cost comes mostly from solving the planning on the transmission networks. We will see later in the GEP 2040 and 2050 how the computational cost becomes significantly higher once the transmission candidates are incorporated in the planning problem.

Table 3-21 Summary of the simulation of France 2030

Total costs (Optimal Power Flow), €	1,246,900,000,000
Total costs (Grid Expansion Planning Tool), €	782,125,000,000
Execution time	41739 seconds (11.6 hours)
MIP Gap, %	0.00

Table 3-22 shows the list of candidates obtained from the pre-processor tool and the investment decisions from the GEP simulation for 2030. In this planning year, the candidates are taken directly from the pre-processor output without any modifications, which we will see later for 2040 and 2050. Another thing to mention is that the pre-processor tool does not also give any storage candidates. The majority of the candidates comes in the form of ac branches with a total of 60 candidates, which are all on the distribution networks. The GEP simulation decides to invest in 38 out of 60 ac branch candidates, hence more than half of the total candidates. Furthermore, all transformer candidates are accepted to be built. There are 15 flexible load candidates as well, 6 of which are rejected. To summarize, 72 out of 100 candidates are decided to be built with a total investment cost of € 2,497,838, which mostly depends on the transformer candidates.

Table 3-22 List of candidates and investment decisions of GEP France 2030

Type	AC Branch	Transformer	Storage	Flexibility load	Total
Number of candidates	60	25	0	15	100
Investment decisions	0 (Transmission) 38 (Distribution)	0 (Transmission) 25 (Distribution)	0	0 (Transmission) 9 (Distribution)	0 (Transmission) 72 (Distribution)
Investment rejected	0 (Transmission) 22 (Distribution)	0 (Transmission) 0 (Distribution)	0	0 (Transmission) 6 (Distribution)	0 (Transmission) 28 (Distribution)
Investment costs, €	625,445	1,863,393	0	9,000	2,497,838

The OPF costs of France 2030 are described in Table 3-23. The costs are split into 4 representative weeks. The costs consist of the generation costs, the generation curtailment costs, the load curtailment costs, the load reduction costs, the load shifting costs, and the slack costs. However, in 2030, the last three cost categories have zero costs. The load shifting and reduction costs are non-existent since there are no flexible loads in the system. The load curtailment costs account for the majority of the costs with a total of 1,062.300 bn€. One of the main reasons, apart from the necessity to curtail the load, is because the load curtailment of each load is significantly higher than the average generation costs, which are typically around 100 €/MWh. For all cases in France and Benelux, the load curtailment cost is 50,000 €/MWh (since accurate information is not available, a very high value was chosen to force the load curtailment as the very last resource). The results show that the total load curtailment costs are the highest in Week 4 and the lowest in Week 3. One of the main contributions to this occurrence is because of the lowest RES generation surplus compared to the total load as seen from Figure 3-16. “RW” in this figure stands for “Representative Week”. The RES generation plays an important role to the local supply of the load since they are in general located close to the load, if not connected to the same buses. They therefore help to avoid congestions in the network.

Table 3-23 Cost results of OPF France 2030

Period	Week 1	Week 2	Week 3	Week 4	Total
Generation costs, €	44,000,000,000	45,800,000,000	29,700,000,000	64,800,000,000	184,300,000,000
Generation curtailment costs, €	0	0	0	0	0
Load curtailment costs, €	331,000,000,000	200,000,000,000	62,300,000,000	469,000,000,000	1,062,300,000,000
Load reduction costs, €	0	0	0	0	0
Load shifting costs, €	0	0	0	0	0
Slack costs, €	0	0	0	0	0
Total costs, €	375,000,000,000	246,000,000,000	91,900,000,000	534,000,000,000	1,246,900,000,000

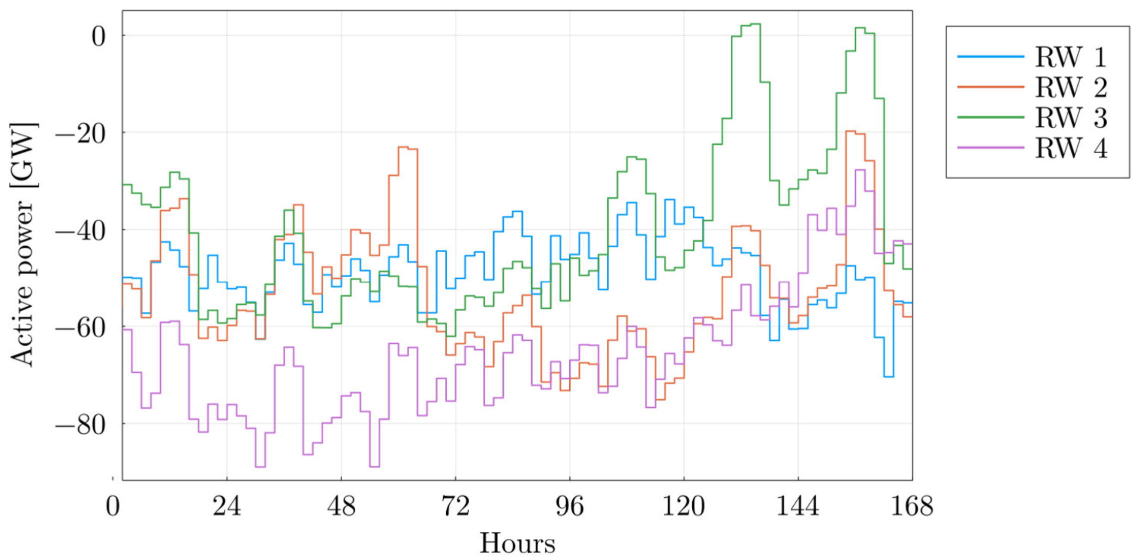


Figure 3-16 RES generation surplus compared to the total load in 2030

Table 3-24 shows the results of the GEP simulation for France 2030. Similar to the OPF costs, the GEP costs are split into each representative week. In general, the share of the costs for each category is comparable to the OPF costs, with rather significant cost reduction due to the investment decisions made in the GEP process. For example, in the most severe week (Week 4) the load curtailment costs decrease from 469.000 bn€ to 276.000 bn€. The improvement applies to the other representative weeks. In total, the costs are reduced to 782.125 bn€.

Table 3-24 Cost results of GEP France 2030

Period	Week 1	Week 2	Week 3	Week 4	Total
Generation costs, €	44,200,000,000	45,900,000,000	29,750,000,000	65,070,000,000	184,920,000,000
Generation curtailment costs, €	0	0	8,000,000	0	8,000,000
Load curtailment costs, €	185,000,000,000	103,300,000,000	32,750,000,000	276,000,000,000	597,050,000,000
Load reduction costs, €	0	0	0	0	0
Load shifting costs, €	38,000,000	5,000,000	4,000,000	101,000,000	147,000,000
Slack costs, €	0	0	0	0	0
Total costs, €	229,238,000,000	149,205,000,000	62,512,000,000	341,171,000,000	782,125,000,000

Figure 3-17 shows an overview of the list of candidates and the investment decisions made in 2030. The figure displays the noticeably congested buses, i.e., buses with a relatively high local marginal price over the analysed period. As expected, the investment candidates are generally located nearby the congested buses. The branch candidates are seen as points at a transmission bus instead of lines since they are on the distribution networks attached to the respective transmission buses.

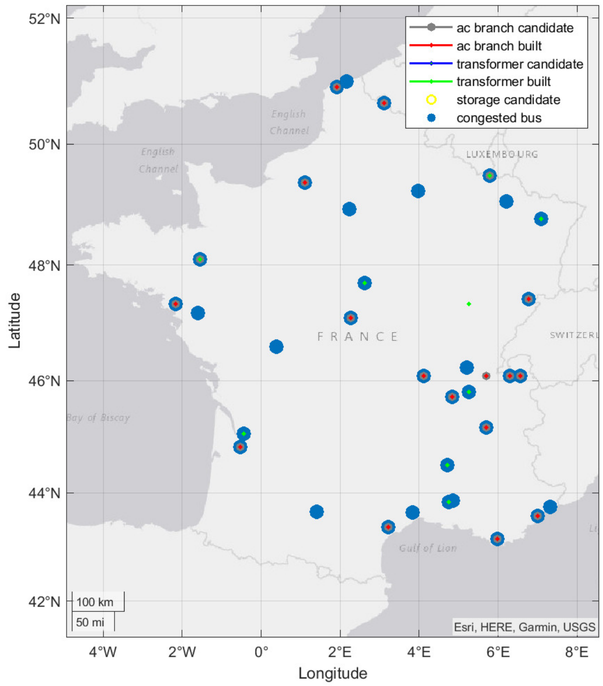


Figure 3-17 Map of the GEP results of France 2030

Decade 2040

In the planning year 2040, 6 transmission ac branch candidates are added manually based on the overloading of the lines throughout the four representative weeks. Another noticeable difference from the planning year 2030 is the existence of a storage candidate in the distribution level. However, similar to the results from 2030, there are no investments made for transmission candidates, which means that the manually added transmission ac branch candidates are rejected. This implies that the investment is strictly made to relieve congestions at the buses with a high local marginal price since the manually transmission ac branch candidates are not necessarily connected to congested buses.

Table 3-25 List of candidates and investment decisions of GEP France 2040

Type	AC Branch	Transformer	Storage	Flexibility load	Total
Number of candidates	79	7	1	13	100
Investment decisions	0 (Transmission) 42 (Distribution)	0 (Transmission) 7 (Distribution)	1 (Flow Battery)	0 (Transmission) 8 (Distribution)	0 (Transmission) 58 (Distribution)
Investment rejected	6 (Transmission) 31 (Distribution)	0 (Transmission) 0 (Distribution)	0	0 (Transmission) 5 (Distribution)	6 (Transmission) 36 (Distribution)
Investment costs, €	1,006,757	1,378,346	215,120	8,000	2,608,223

Although there are only 6 transmission candidates out of 100 total candidates, the additional candidates on the transmission network dramatically increase the computational time for the GEP simulation, as shown in Table 3-26. The simulation time lasts for more than four times the simulation time for the planning year 2030. The MIP gap for this simulation is 0.0004%, which is much lower than the MIP gap limit (0.01%), hence it is acceptable.

Table 3-26 Summary of the simulation of France 2040

Total costs (Optimal Power Flow), €	1,423,300,000,000
Total costs (Grid Expansion Planning Tool), €	1,236,584,000,000
Execution time	173658 seconds (48.24 hours)
MIP Gap, %	0.0004

Compared to 2030, the total OPF costs in 2040 are higher as seen in Table 3-27. Another difference is that the highest load curtailment cost occurs in week 1 instead of in week 4, although the difference between both weeks is relatively small. This can also be explained by the surplus or deficit of the RES generation in Figure 3-18. In general, the operational cost improvement is again exhibited by the lower total GEP costs with respect to the total OPF costs. Since there are flexible loads built in the GEP 2030, we now start seeing the load shifting costs added to the operational costs. That said, the load shifting costs are much smaller compared to the rest of the costs.

Table 3-27 Cost results of OPF France 2040

Period	Week 1	Week 2	Week 3	Week 4	Total
Generation costs, €	64,900,000,000	37,500,000,000	20,900,000,000	65,500,000,000	188,800,000,000
Generation curtailment costs, €	0	7,960,000,000	9,560,000,000	0	17,520,000,000
Load curtailment costs, €	507,000,000,000	196,000,000,000	33,700,000,000	481,000,000,000	1,217,700,000,000
Load reduction costs, €	0	0	0	0	0
Load shifting costs, €	2,000,000	27,000,000	7,000,000	10,000,000	46,000,000
Slack costs, €	0	0	0	0	0
Total costs, €	572,000,000,000	241,000,000,000	64,300,000,000	546,000,000,000	1,423,300,000,000

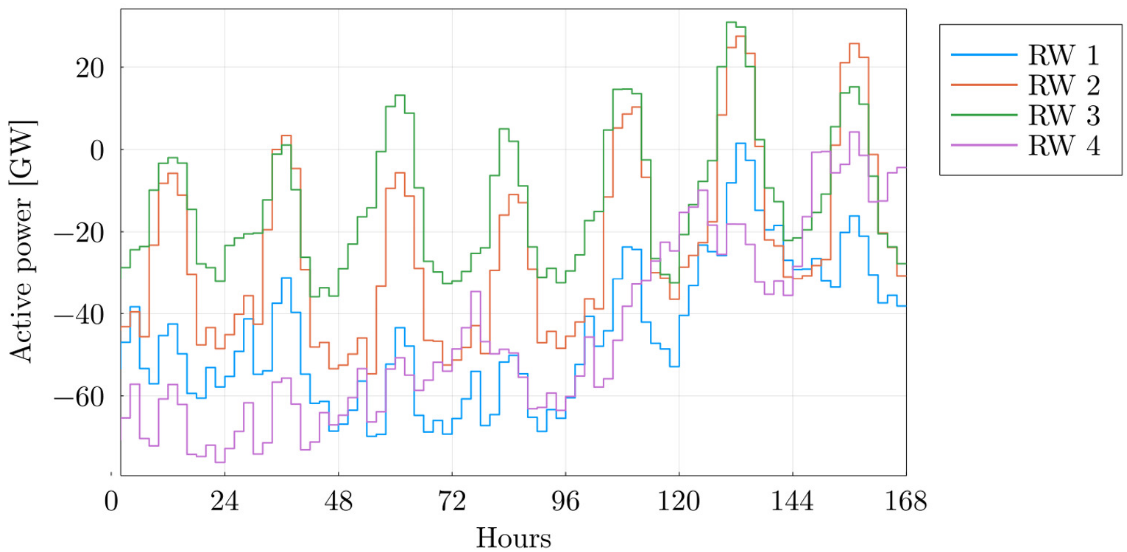


Figure 3-18 RES generation surplus compared to the total load in 2040

The investment decisions obtained from the GEP simulation result in the total operational costs shown in Table 3-28. As usual, the operational cost reduction originates from the total load curtailment cost reduction, which accounts for almost 200 bn€ less. We also see the increase of the load shifting costs from 46 M€ to 350 M€ after adding 8 flexible loads on the distribution level. Figure 3-19 shows the overview of the investment and congested bus locations. Similar to 2030, the build candidates are located at or nearby the congested buses. In the figure, we can also finally see the appearance of one accepted storage candidate.

Table 3-28 Cost results of GEP France 2040

Period	Week 1	Week 2	Week 3	Week 4	Total
Generation costs, €	65,000,000,000	37,600,000,000	21,000,000,000	65,500,000,000	189,100,000,000
Generation curtailment costs, €	0	8,500,000,000	10,200,000,000	34,000,000	18,734,000,000
Load curtailment costs, €	428,000,000,000	163,000,000,000	29,400,000,000	408,000,000,000	1,028,400,000,000
Load reduction costs, €	0	0	0	0	0
Load shifting costs, €	134,000,000	91,000,000	10,000,000	116,000,000	350,000,000
Slack costs, €	0	0	0	0	0
Total costs, €	493,134,000,000	209,191,000,000	60,610,000,000	473,650,000,000	1,236,584,000,000

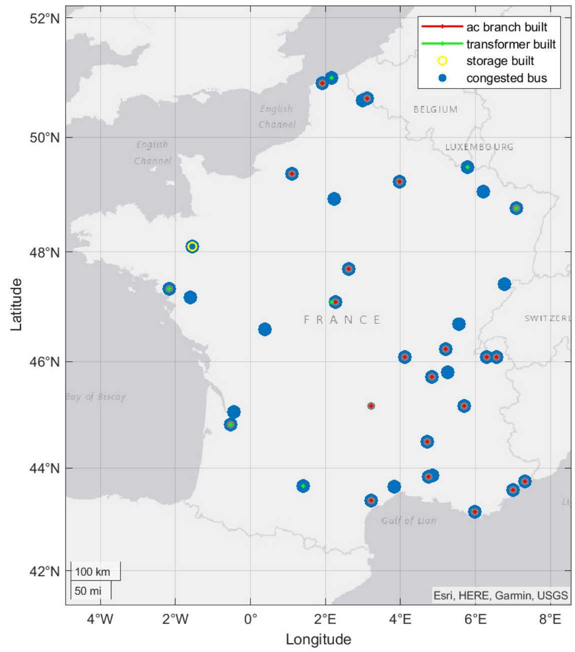


Figure 3-19 Map of the GEP results of France 2040

Decade 2050

Table 3-29 presents the list of candidates and investment decisions of the GEP simulation for France 2050. This time, there are two storage candidates, all of them are hydrogen units. The GEP simulation results in one of them being built. Resembling the previous planning years, the AC branch candidates have the highest share of candidates with a total of 67 candidates. 39 AC branch candidates on the distribution level are accepted. Meanwhile, all manually added transmission AC branch candidates are rejected, analogous to the planning year 2040. The total investment costs in 2050 add up to 3,205,064 €.

Table 3-29 List of candidates and investment decisions of GEP France 2050

Type	AC Branch	Transformer	Storage	Flexibility load	Total
Number of candidates	67	19	2	12	100
Investment decisions	0 (Transmission) 39 (Distribution)	0 (Transmission) 19 (Distribution)	1 (Hydrogen)	0 (Transmission) 8 (Distribution)	0 (Transmission) 67 (Distribution)
Investment rejected	6 (Transmission) 22 (Distribution)	0 (Transmission) 0 (Distribution)	1 (Hydrogen)	0 (Transmission) 4 (Distribution)	6 (Transmission) 27 (Distribution)
Investment costs, €	748,803	2,246,660	201,600	8,000	3,205,064

The summary of the 2050 OPF and GEP simulations is provided in Table 3-30. The computational time of the GEP simulation is virtually identical to the simulation for 2040 with a slightly higher MIP gap of 0.0051 % compared to 0.0004 % in 2040. This is of course due to the alike number of candidates, especially between the number of candidates on the transmission level and on the distribution level. Similar to the results in the previous planning years, the investment made from the GEP simulation reduces the total costs, in this case, from 2,146 bn€ to 1,554 bn€.

Table 3-30 Summary of the simulation of France 2050

Total costs (Optimal Power Flow), €	2,146,000,000,000
Total costs (Grid Expansion Planning Tool), €	1,553,993,000,000
Execution time	173,655 seconds (48.24 hours)
MIP Gap, %	0.0051

The OPF cost results are given in Table 3-31. As we can see from the table, the representative week 4 has the highest total generation costs and the load curtailment costs. Using the same argument as the previous planning years, the total load curtailment costs and the generation costs heavily depend on the surplus or deficit between the RES generation and demand in each representative week. As shown in Figure 3-20, the representative week 4 has the lowest surplus, hence the high costs. That said, due to the limited availability of the RES generation, the generation curtailment cost is the lowest in the representative week 4 with a total of 53 M€.

Table 3-31 Cost results of OPF France 2050

Period	Week 1	Week 2	Week 3	Week 4	Total
Generation costs, €	37,000,000,000	16,100,000,000	19,400,000,000	56,900,000,000	129,400,000,000
Generation curtailment costs, €	15,700,000,000	33,900,000,000	35,300,000,000	53,000,000	84,953,000,000
Load curtailment costs, €	632,000,000,000	306,000,000,000	154,000,000,000	839,000,000,000	1,931,000,000,000
Load reduction costs, €	0	0	0	0	0
Load shifting costs, €	72,000,000	69,000,000	61,000,000	54,000,000	255,000,000
Slack costs, €	0	0	0	0	0
Total costs, €	685,000,000,000	356,000,000,000	209,000,000,000	896,000,000,000	2,146,000,000,000

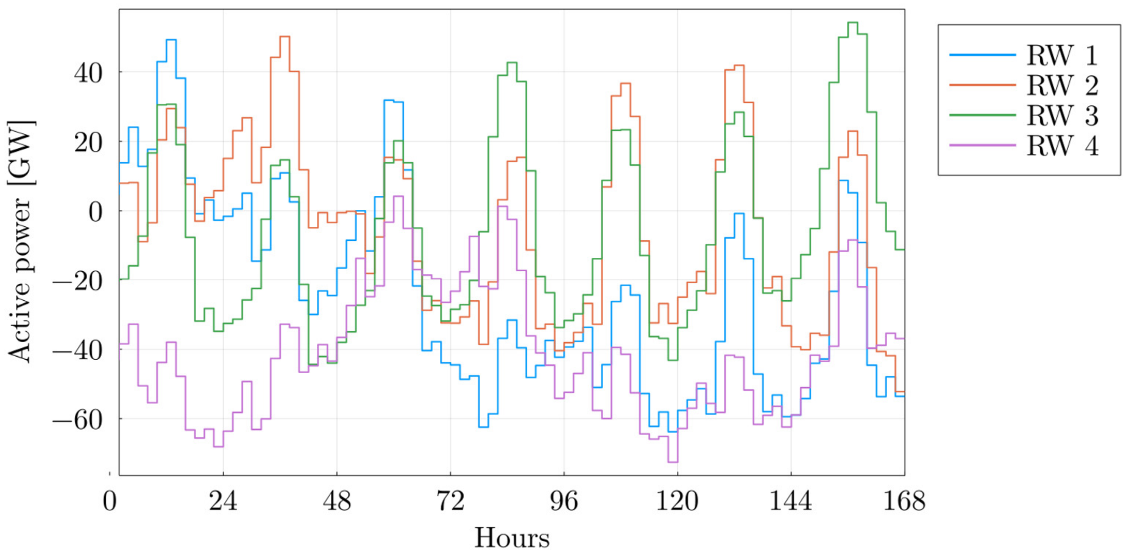


Figure 3-20 RES generation surplus compared to the total load in 2050

The GEP 2050 cost results for France are listed in Table 3-32. Parallel to the planning year 2040, the load curtailment cost reduction contributes the highest to the improvement of the total operational costs with a total load curtailment reduction of almost 600 bn€. The other costs are relatively the same as in the OPF simulation. It is worth noting that the total load shifting costs are almost double due to the investment of 8 flexible loads on the distribution level. However, as in the previous planning years, the load shifting costs are very small compared to the total costs.

Table 3-32 Cost results of GEP France 2050

Period	Week 1	Week 2	Week 3	Week 4	Total
Generation costs, €	37,200,000,000	16,200,000,000	19,500,000,000	57,200,000,000	130,100,000,000
Generation curtailment costs, €	16,600,000,000	25,800,000,000	36,900,000,000	85,000,000	79,385,000,000
Load curtailment costs, €	436,000,000,000	203,000,000,000	102,000,000,000	603,000,000,000	1,344,000,000,000
Load reduction costs, €	0	0	0	0	0
Load shifting costs, €	86,000,000	224,000,000	127,000,000	71,000,000	508,000,000
Slack costs, €	0	0	0	0	0
Total costs, €	489,886,000,000	245,224,000,000	158,527,000,000	660,356,000,000	1,553,993,000,000

The locations of the investment are laid out in Figure 3-21. Due to how the MILES time series are spread out in the system as explained in the methodology, we can see similar locations of congested buses as in the previous planning years. We can also notice that some congested buses are consistently close to the borders, namely with Belgium, Luxembourg, Germany, and Switzerland throughout all planning years. The same as in 2040, we can also see from the figure that a storage candidate is accepted. Interestingly, the location of this storage is relatively close to the built storage in 2040, which can be seen in Figure 3-19.

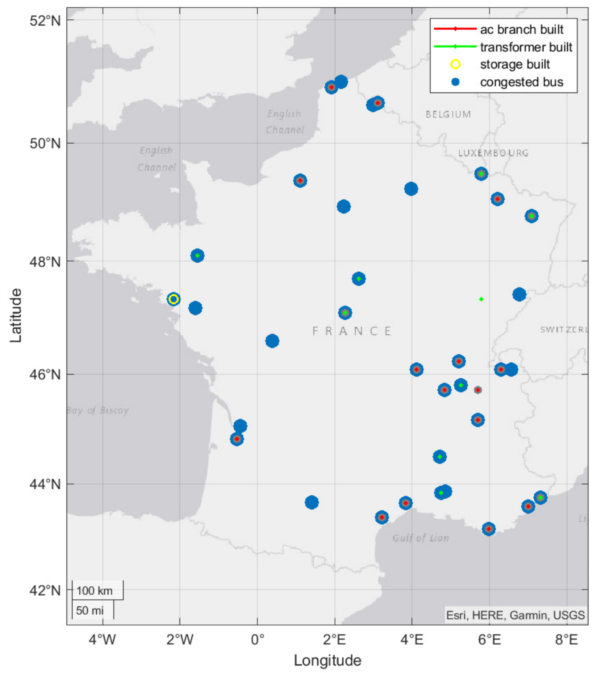


Figure 3-21 Map of the GEP results of France 2050

BeNeLux

The section elaborates on the results of the OPF and GEP simulations for the planning years 2030, 2040 and 2050, similarly to what was done in the previous section with France.

Decade 2030

The GEP tool leads to a consistent decrease in the total costs compared to the OPF, as shown in Table 3-33 thereafter. The execution time of the simulations is more than double the GEP for France 2030. The main reason behind the difference is the presence of transmission candidates in year 2030, listed in Table 3-34. As anticipated earlier, the number of transmission candidates increases the length of the simulation. The pattern is recurrent throughout the three planning years for Benelux. As the pre-processor output led to a higher amount of transmission candidates for each planning year, some assumptions needed to be taken. In fact, the total number of candidates for Benelux in 2030 (85) is lower than the one in France (100). The transmission candidates for the two simulations are respectively 18 and 0. In order to keep the GEP simulations within an acceptable computational time, a reduction of the candidates on the transmission level needed to be performed. For this reason, the years 2040 has a total of 65 candidates (21 transmission candidates, Table 3-37), while 2050 has 85 (31 transmission candidates, Table 3-41). Since the computational time does not only depend on the number of transmission candidates, but also on the load and RES generation levels and bottlenecks in the electric grid, the results help to grasp the functionalities of the planning tool, even if they are sub-optimal, due to many assumptions. A trade-off needed to be made between computational time and optimality of the simulation, as having a bigger number of transmission candidates might have led to weeks-long simulations.

Table 3-33 Summary of the simulation of Benelux 2030

Total costs (Optimal Power Flow), €	1,117,099,000,000
Total costs (Grid Expansion Planning Tool), €	434,443,000,000
Execution time	87,156 seconds (24.21 hours)
MIP Gap, %	0.0088

Table 3-34 lists the decisions/rejections for each investment category. Differently from France where 60 of the 100 candidates were AC branches, the majority of candidates in Benelux are transformers, followed by storage and flexible loads. Only 3 out of 18 of transmission candidates are not built, highlighting the need for grid reinforcements on the transmission level in terms of AC branches (6 built), transformers (4 built) and storage (5 built). On the distribution level, 31 transformers, 3 AC branches, 7 storage units and 1 flexible load are built. Similarly to the transmission level, the investment decisions are oriented towards enhancing the power transfer capability of the grid. This fact is confirmed by the reduction of the load curtailment costs between the OPF results in Table 3-35 and GEP results in Table 3-36. While the generation cost reductions are comparable between the representative weeks, the values of the load curtailment costs for GEP range from 35 to 38% of the OPF costs. The grid investments have therefore led to saving roughly two thirds of the original OPF load curtailment costs.

Table 3-34 List of candidates and investment decisions of GEP Benelux 2030

Type	**AC Branch**	**Transformer**	**Storage**	**Flexibility load**	**Total**
Number of candidates	13	35	19	18	85
Investment decisions	6 (Transmission) 3 (Distribution)	4 (Transmission) 31 (Distribution)	5 (Transmission) 7 (Distribution)	0 (Transmission) 1 (Distribution)	15 (Transmission) 42 (Distribution)
Investment rejected	0 (Transmission) 4 (Distribution)	0 (Transmission) 0 (Distribution)	0 (Transmission) 7 (Distribution)	3 (Transmission) 14 (Distribution)	3 (Transmission) 25 (Distribution)
Investment costs, €	2,742,407	4,965,800	14,006,528	1,000	21,715,729

Table 3-35 Cost results of OPF Benelux 2030

Period	Week 1	Week 2	Week 3	Week 4	Total
Generation costs, €	22,900,000,000	14,100,000,000	17,600,000,000	13,300,000,000	67,900,000,000
Generation curtailment costs, €	0	99,000,000	0	0	99,000,000
Load curtailment costs, €	331,000,000,000	225,800,000,000	234,500,000,000	257,800,000,000	1049,100,000,000
Load reduction costs, €	0	0	0	0	0
Load shifting costs, €	0	0	0	0	0

Period	Week 1	Week 2	Week 3	Week 4	Total
Slack costs, €	0	0	0	0	0
Total costs, €	353,900,000,000	239,999,000,000	252,100,000,000	271,100,000,000	1117,099,000,000

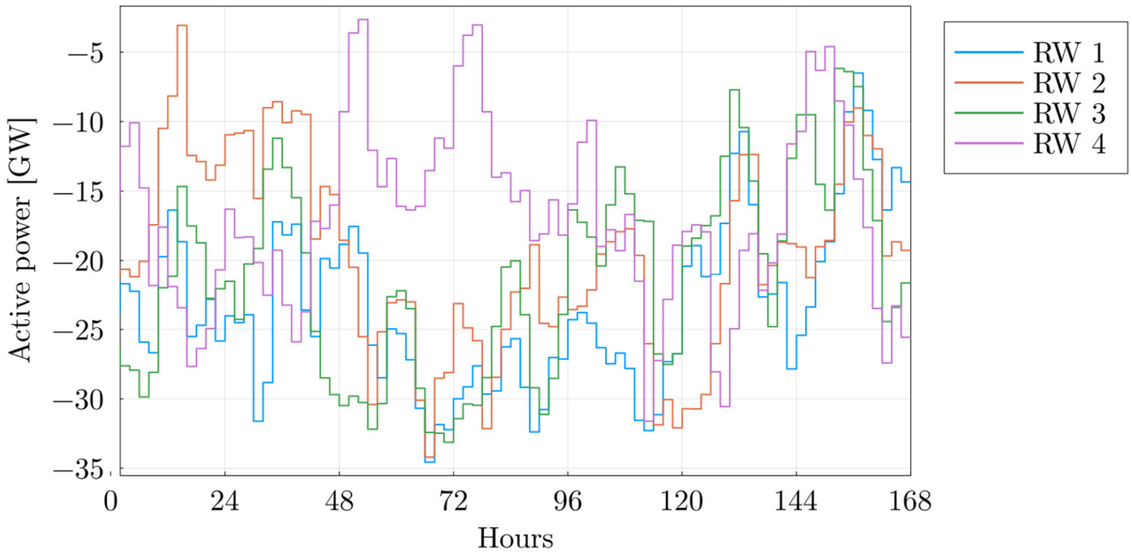


Figure 3-22 RES generation surplus compared to the total load in 2030

Table 3-36 Cost results of GEP Benelux 2030

Period	Week 1	Week 2	Week 3	Week 4	Total
Generation costs, €	22,800,000,000	13,400,000,000	17,060,000,000	12,800,000,000	66,060,000,000
Generation curtailment costs, €	0	55,000,000	0	0	55,000,000
Load curtailment costs, €	115,000,000,000	83,600,000,000	89,500,000,000	99,300,000,000	387,400,000,000
Load reduction costs, €	0	0	0	0	0
Load shifting costs, €	1,000,000	0	1,000,000	2,000,000	5,000,000
Slack costs, €	0	0	0	0	0
Total costs, €	137,801,000,000	97,055,000,000	106,561,000,000	112,102,000,000	453,520,000,000

Figure 3-23 below shows how the transformer investments mainly took place near congested buses. This is not the case for ac branch investments, which are expected to influence the power flow in the grid even if not close to the main congested buses.

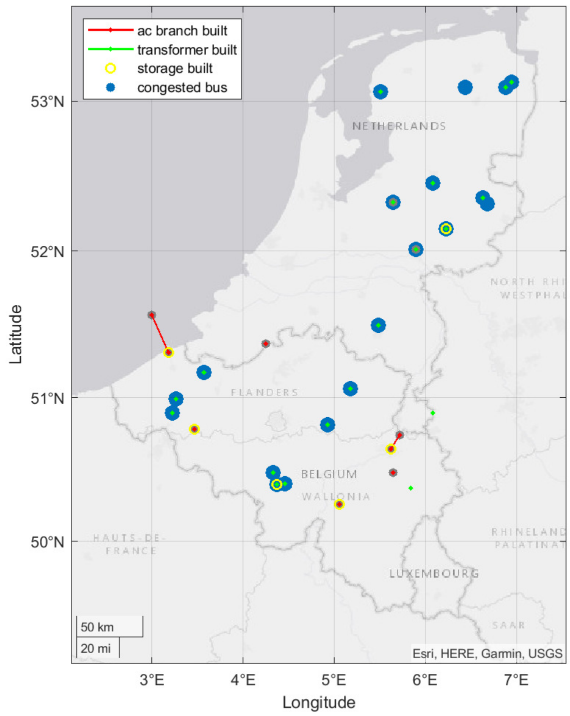


Figure 3-23 Map of the GEP results of Benelux 2030

Decade 2040

The results of the simulations for year 2040 are summarised in Table 3-37. Compared to 2030, the total costs for both the OPF and GEP are significantly lower. This fact goes against the trend seen in France, i.e. both OPF and GEP costs increasing over the planning years, with the GEP being lower than the OPF ones. Nevertheless, the difference is explained by comparing Figure 3-22 and Figure 3-24, showing the difference between RES generation and demand data from [12] for 2030 and 2040 respectively.

While in 2030 the RES generation never exceeds the load throughout the representative weeks, in 2040 the RES generation happens to be higher than the demand for several hours in all the representative weeks. This is confirmed by the difference in generation curtailment between 2030 (Table 3-35) and 2040 (Table 3-39). While in 2030 there are no generation curtailment costs as the load is always higher than the RES generation, the high surplus of RES generation leads to consistent generation curtailment costs in representative weeks 1, 2 and 4.

As shown in Figure 3-25 and Figure 3-26, the wind and solar PV generation in 2040 are significantly increased compared to 2030, while the demand in the two planning years does not follow the trend. In fact, the two demands in Figure 3-27 are comparable. For this reason, it is confirmed that the difference in the total costs bulk figures between 2030 and 2040 depends on the input data.

Table 3-37 Summary of the simulation of Benelux 2040

Total costs (Optimal Power Flow), €	434,443,000,000
Total costs (Grid Expansion Planning Tool), €	179,654,000,000
Execution time	77,370 seconds (21.50 hours)
MIP Gap, %	0.0279

Table 3-38 List of candidates and investment decisions of GEP Benelux 2040

Type	**AC Branch**	**Transformer**	**Storage**	**Flexibility load**	**Total**
Number of candidates	28	7	19	11	65
Investment decisions	7 (Transmission) 11 (Distribution)	4 (Transmission) 3 (Distribution)	1 (Transmission) 6 (Distribution)	0 (Transmission) 4 (Distribution)	12 (Transmission) 24 (Distribution)
Investment rejected	2 (Transmission) 8 (Distribution)	0 (Transmission) 0 (Distribution)	5 (Transmission) 7 (Distribution)	2 (Transmission) 5 (Distribution)	9 (Transmission) 20 (Distribution)
Investment costs, €	3,389,394	3,384,234	12,638,730	4,000	19,416,358

Table 3-39 Cost results of OPF Benelux 2040

Period	Week 1	Week 2	Week 3	Week 4	Total
Generation costs, €	13,050,000,000	13,740,000,000	8,570,000,000	9,670,000,000	45,030,000,000
Generation curtailment costs, €	1,680,000,000	1,650,000,000	0	9,570,000,000	12,900,000,000
Load curtailment costs, €	112,000,000,000	96,500,000,000	82,100,000,000	85,900,000,000	376,500,000,000
Load reduction costs, €	0	0	0	0	0
Load shifting costs, €	2,000,000	1,000,000	1,000,000	9,000,000	13,000,000
Slack costs, €	0	0	0	0	0
Total costs, €	126,732,000,000	111,891,000,000	90,671,000,000	105,149,000,000	434,443,000,000

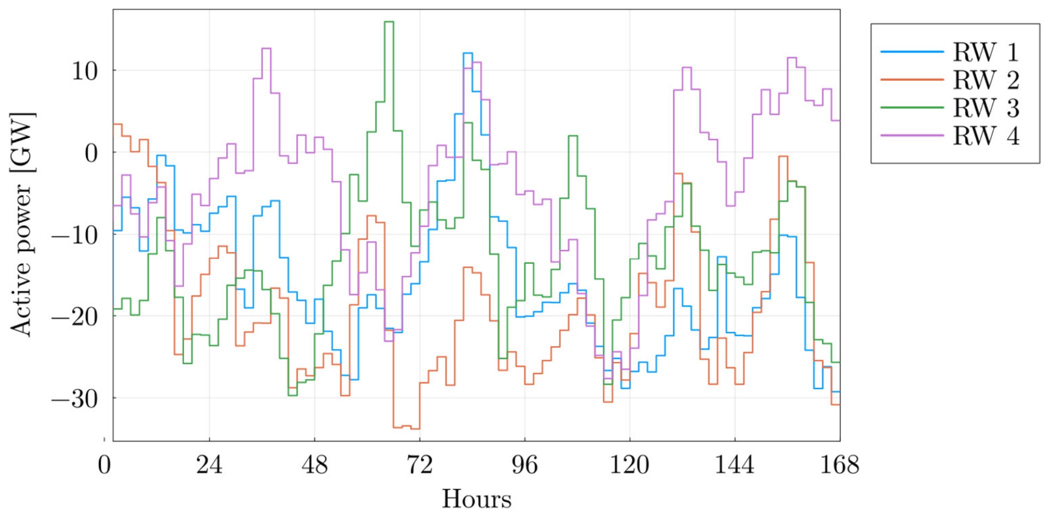


Figure 3-24 RES generation surplus compared to the total load in 2040

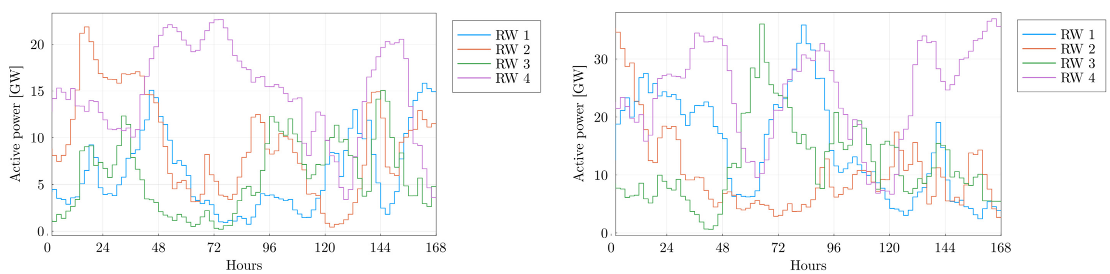


Figure 3-25 Comparison between wind generation in 2030 (left) and 2040 (right)

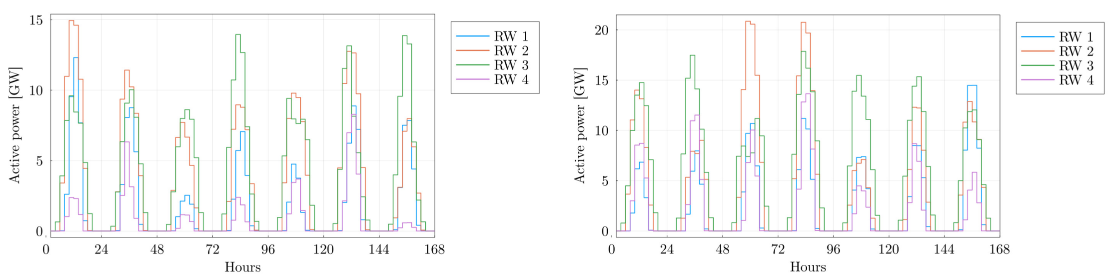


Figure 3-26 Comparison between solar PV generation in 2030 (left) and 2040 (right)

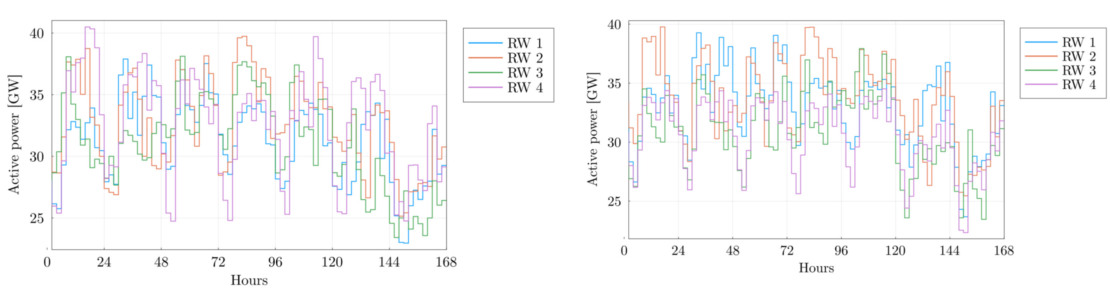


Figure 3-27 Comparison between demand in 2030 (left) and 2040 (right)

Nevertheless, the GEP tool results can be analysed, as the selection of candidates is not biased by the difference in input data. Compared to 2030, the candidates for 2040, as it can be seen in Table 3-38, see an increased amount of ac branches and the same amount of storage candidates, even though the total number of candidates decreases. Moreover, the ratio between investment decisions and investments rejected for both transmission and distribution level is lower for 2040 than 2030. This may be due to the fact that the investments in 2030 already compensated the most urgent need for investments in the grid, while the candidates in 2040 are not as economically beneficial. Comparing Figure 3-23 and Figure 3-28 supports the hypothesis, as there are less congested buses in the territory.

Table 3-40 Cost results of GEP Benelux 2040

Period	Week 1	Week 2	Week 3	Week 4	Total
Generation costs, €	12,600,000,000	13,300,000,000	8,240,000,000	9,450,000,000	43,590,000,000
Generation curtailment costs, €	1,440,000,000	1,120,000,000	1,950,000,000	8,250,000,000	12,760,000,000
Load curtailment costs, €	39,000,000,000	30,900,000,000	22,900,000,000	30,200,000,000	123,000,000,000
Load reduction costs, €	0	0	0	0	0
Load shifting costs, €	117,000,000	110,000,000	1,000,000	76,000,000	304,000,000
Slack costs, €	0	0	0	0	0
Total costs, €	53,157,000,000	45,430,000,000	33,091,000,000	47,976,000,000	179,654,000,000

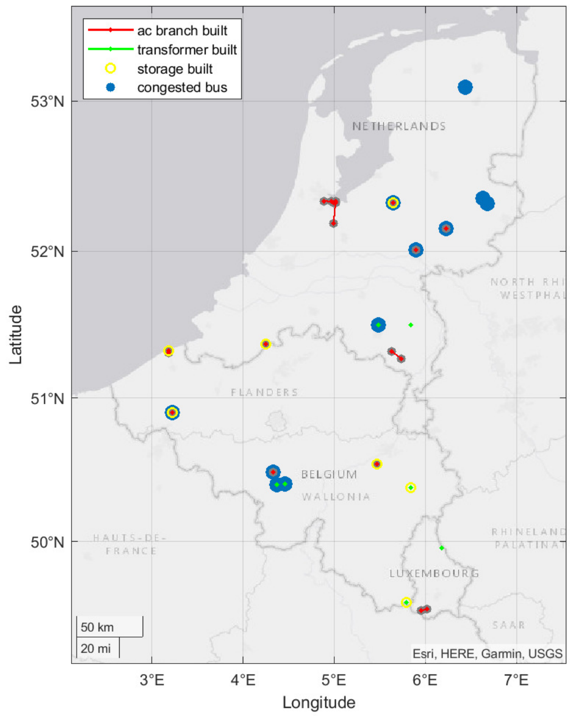


Figure 3-28 Map of the GEP results of Benelux 2040

Decade 2050

Finally, the OPF and GEP results for the last planning year, 2050, are summarized in Table 3-41 thereafter.

Table 3-41 Summary of the simulation of Benelux 2050

Total costs (Optimal Power Flow), €	532,213,000,000
Total costs (Grid Expansion Planning Tool), €	247,138,000,000
Execution time	107,486 seconds (29.86 hours)
MIP Gap, %	0.938

Compared to 2040, the total costs are higher for both the OPF and GEP simulations. The difference between RES generation and demand has an increased volatility and high positive and negative peak values in compared to the 2040 values in Figure 3-24, leading to a massive amount of generation curtailment and related generation curtailment costs. This fact explains the increase in the OPF costs between 2040 (Table 3-39) and 2050 (Table 3-43).

Even though there is a distinct amount of candidates being built of both transmission and distribution level, as reported in Table 3-41, the GEP costs for 2050, shown in Table 3-44, are highly influenced by the generation curtailment costs. These costs see almost a ten-fold increase compared to the same category in 2040, displayed in Table 3-40. The reasons behind such a difference can be summarized in two main points.

On one hand, the reduction in the number of transmission candidates may influence the generation curtailments costs, as possible investments in transmission lines capable of transferring high amount of RES power along the grid are not considered. Nevertheless, because 7 out of the 10 ac branches investment candidates are not built, the reduction in the transmission candidates does not seem to bias the results.

On the other hand, the huge surplus of RES compared to demand in the last hours of representative weeks 1 and 2, shown in Figure 3-29, leads to a massive increase in generation curtailment costs. Due to the distributed nature of RES, the generator centers may be decoupled from the loads and lead to overloaded lines whose capacity is extremely lower than the RES generation, therefore leading to substantial curtailments in RES generation.

Table 3-42 List of candidates and investment decisions of GEP Benelux 2050

Type	**AC Branch**	**Transformer**	**Storage**	**Flexibility load**	**Total**
Number of candidates	33	18	20	14	85
Investment decisions	3 (Transmission) 12 (Distribution)	4 (Transmission) 14 (Distribution)	11 (Transmission) 1 (Distribution)	0 (Transmission) 5 (Distribution)	18 (Transmission) 32 (Distribution)
Investment rejected	7 (Transmission) 11 (Distribution)	0 (Transmission) 0 (Distribution)	2 (Transmission) 6 (Distribution)	4 (Transmission) 5 (Distribution)	13 (Transmission) 22 (Distribution)
Investment costs, €	889,368	6,852,213	30,354,082	5,000	38,100,663

Table 3-43 Cost results of OPF Benelux 2050

Period	Week 1	Week 2	Week 3	Week 4	Total
Generation costs, €	7,578,000,000	16,520,000,000	8,870,000,000	3,960,000,000	36,928,000,000
Generation curtailment costs, €	32,800,000,000	25,100,000,000	1,710,000,000	53,300,000,000	112,910,000,000
Load curtailment costs, €	113,000,000,000	117,000,000,000	78,700,000,000	73,000,000,000	381,700,000,000
Load reduction costs, €	0	0	0	0	0
Load shifting costs, €	93,000,000	90,000,000	335,000,000	157,000,000	675,000,000
Slack costs, €	0	0	0	0	0
Total costs, €	153,471,000,000	158,710,000,000	89,615,000,000	130,417,000,000	532,213,000,000

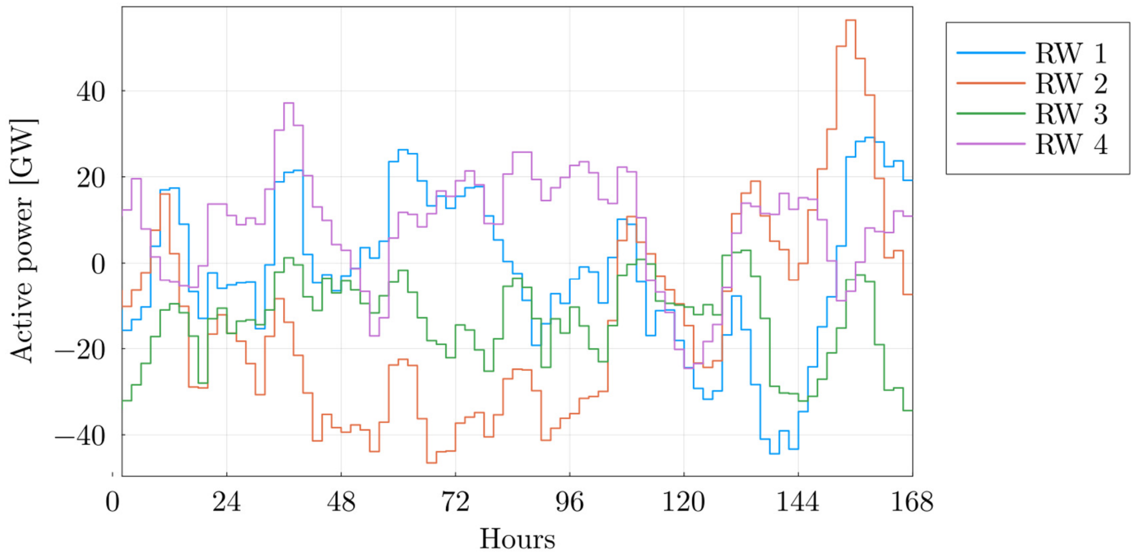


Figure 3-29 RES generation surplus compared to the total load in Benelux 2050

Table 3-44 Cost results of GEP Benelux 2050

Period	Week 1	Week 2	Week 3	Week 4	Total
Generation costs, €	7,191,000,000	16,440,000,000	8,524,000,000	3,603,000,000	35,758,000,000
Generation curtailment costs, €	31,150,000,000	24,000,000,000	1,276,000,000	50,860,000,000	107,286,000,000
Load curtailment costs, €	29,360,000,000	29,780,000,000	22,544,000,000	21,790,000,000	103,474,000,000
Load reduction costs, €	0	0	0	0	0
Load shifting costs, €	133,000,000	165,000,000	217,000,000	105,000,000	620,000,000
Slack costs, €	0	0	0	0	0
Total costs, €	67,834,000,000	70,385,000,000	32,561,000,000	76,358,000,000	247,138,000,000

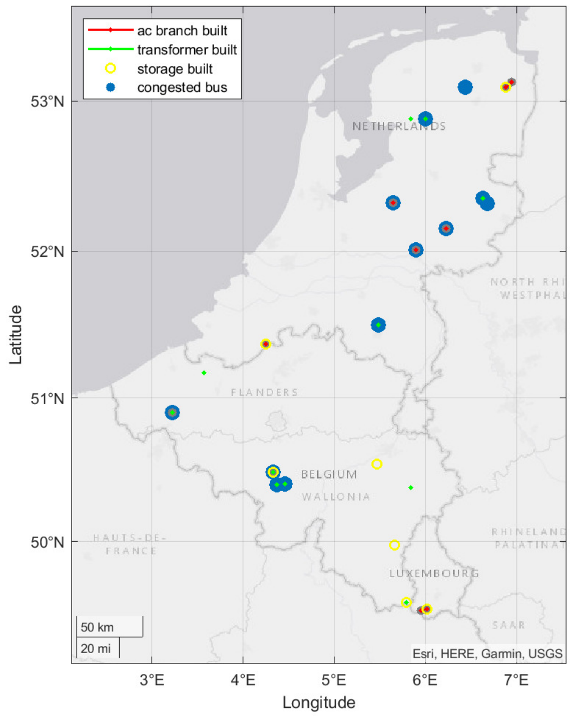


Figure 3-30 Map of the GEP results of Benelux 2050

Environmental impact assessment

The environmental impact assessment aims to compute the electricity generation costs related to the generation emissions in terms of carbon footprint and air quality costs. In Table 3-45 and Table 3-46, four metrics related to these costs are listed for France and Benelux for each of the three planning years.

- Carbon Footprint (CF) impact assessment for generation: percentage ratio of CF costs related to the total generation costs
- Air Quality (AQ) impact assessment for generation: percentage ratio of AQ costs related to the total generation costs.
- Carbon Footprint (CF) impact assessment: percentage ratio of CF costs related to the total costs
- Air Quality (AQ) impact assessment: percentage ratio of AQ costs related to the total costs.

Starting from Table 3-45, the share of carbon footprint costs out of the total generation costs increases over time, while the share of the air quality costs is constant. The reason behind this trend is the constant high use of conventional generators in 2040 and 2050, following the increasing load throughout the planning years. Even though the RES generation is increasing over time, the limited power capacity of the lines in the French power grid leads to a steep increase in the RES generation curtailment costs in 2040 (Table 3-28) and 2050 (Table 3-31) compared to 2030 (Table 3-24). These grid limitations cause a consistent amount of load being curtailed in 2040 and 2050, i.e. higher load curtailment costs and higher total costs. As a consequence, since the total costs of the GEP problem are shown to increase over the time horizon being considered, the shares of carbon footprint and air quality costs out of the total costs decrease over time.

Table 3-45 Metrics of the environmental costs assessment for the three planning years 2030, 2040 and 2050 in France

Metric	2030	2040	2050
Carbon Footprint impact assessment for generation, %	20.01	24.33	23.23
Air Quality impact assessment for generation, %	8.49	8.31	8.32
Carbon Footprint impact assessment, %	4.73	3.72	1.95
Air Quality impact assessment, %	2.01	1.27	0.7

Table 3-46 shows the relative carbon footprint and air quality costs with respect to the total generations costs and the total costs. As seen from the table, the relative environmental impacts with respect to the generation is generally the same throughout the years although we see earlier in this section that the absolute values of the total generation costs vary. One of the reasons is because the majority of generation comes from the cheapest conventional generators with identical fraction between their fuel costs and their environmental costs, i.e., 20% and 1.37% for the carbon footprint and air quality costs, respectively. However, since we have a significantly lower total cost in 2040, the carbon footprint and air quality impacts are seen to be increased to 4.85% and 0.34%, respectively. In 2050, the values return again to similar ones as in 2030.

Table 3-46 Metrics of the environmental costs assessment for the three planning years 2030, 2040 and 2050 in BeNeLux

Metric	2030	2040	2050
Carbon Footprint impact assessment for generation, %	19.99	19.98	20.01
Air Quality impact assessment for generation, %	1.37	1.37	1.37
Carbon Footprint impact assessment, %	2.91	4.85	2.89
Air Quality impact assessment, %	0.20	0.34	0.20

3.3 Germany, Switzerland and Austria

3.3.1 Overview of the adaptations for Regional Case

This Regional Case was divided into two regions, due to the high computational effort when running the OPF. One region consists of Germany, the other region consists of Switzerland and Austria. Consequently, the cross-border-flows between those two regions are modelled according to the method of border-flows between different Regional Cases and therefore are based on the market-simulation results of MILES for the initial weather-variant.

Table 3-47 and Table 3-48 show the basic characteristics of the networks, then the applied simplifications are presented.

Table 3-47 Description of the network, Germany

Number of the nodes	4336
of which in transmission network	1171
of which in distribution network	3165
Number of AC branches	4470
of which in transmission network	1485
of which in distribution network	2985
Number of transformers	332
Number of storages	4
Number of flexibility loads	0
Number of DC branches	13

Table 3-48 Description of the network, Austria and Switzerland

Number of the nodes	297
of which in transmission network	297
of which in distribution network	0
Number of AC branches	318
of which in transmission network	318
of which in distribution network	0
Number of transformers	89
Number of storages	17
Number of flexibility loads	0

The German network consists of significantly more nodes and edges than the combined Austrian and Swiss one. The grid model in Germany consists of the transmission grid, which ENTSO-E has made available, and selected subordinate high-voltage grids, as well as medium-voltage grids. Due to the high computation time, only three high-voltage (sub-transmission) grid groups are integrated into the model. For this purpose, regions in Germany were selected that are as heterogeneous as possible and for which there is a high quality OpenStreetMap-data basis. Thus, the first high-voltage grid is located in the north, where there is relatively little load, but a lot of feed-in from wind energy units. Another high-voltage grid is located in the west, an urban area with an additional high load from industry. The last high-voltage grid describes the border region to France and is also characterized by high potentials for photovoltaic plants. The medium-voltage (distribution) networks generated within the project are connected to the high-voltage networks. In Austria and Switzerland, only the transmission network is simulated due to lack of data.

To reduce complexity and computational effort, various simplifications are made to the network models of both regions. Since the ENTSO-E data contained information on fields of busbars in substations, each substation initially consisted of a large number of network nodes. By analysing which fields of the busbars are coupled via closed switches, the number of nodes could be significantly reduced. This also led to a more efficient modelling of lines that are directly routed to one substation via different substations. The simplification was possible if the line was always routed via isolated fields of the respective substations. As a result, the switching state that had been delivered was consequently mapped in a fixed way and not further variably adapted as probably required in future scenarios.

Another simplification that was carried out does not have any influence on the results, but the possible analysis afterwards: Since both wind and photovoltaic plants have a weather-dependent maximum feed-in at any given time and are thus modelled in the same way, these two technologies were combined into one generator at each grid node. Accordingly, it is no longer possible to distinguish in the evaluation whether wind or PV plants are curtailed at a node.

Because imports and exports between regional cases were to be treated as fixed, imports were initially not modelled as a dispatchable generator either, but as a generator with a time-dependent feed-in that could only be curtailed at very high cost. Exports were modelled as loads with very high curtailment costs, too. However, analyses of the scenario data of the selected weather variants have shown that the given imports and exports do not fit the respective supply task. This is due to the fact that the market simulation, which determines imports and exports, was not carried out for all weather variants, but only for the initial weather year considered. Figure 3-31 shows the available generation (RE supply and available power plant capacities) and the imports in green for the representative weeks for 2030 in Germany. The load to be covered including exports are shown in blue.

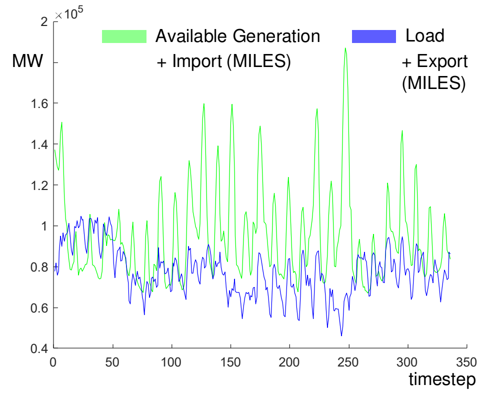


Figure 3-31 Load and available generation in Germany for the representative weeks in 2030

In 24 % of the points in time, the available generation is lower than the load to be covered. Thus, irrespective of the expansion status of the grid, no supply would be possible without curtailing a large number of loads. In order to be able to produce plausible results, imports were implemented as dispatchable generators (costs higher than the most expensive generator in the inland) and the costs for export curtailment were set to the level lower than load curtailment in the inland. The additional dispatchable import is limited to the power-limit of each line. However, because this dispatchable generator is available on top of the already existing import on each border, the maximum power delivered by this generator is subject to the effective free capacity (max power of line – import taking place + export taking place = possible additional dispatchable generation) on each cross-border-line. Thus, border flows can be adjusted within the capacities so that the supply task can still be fulfilled. This modelling leads to unavoidable curtailment costs, so that the actual costs of the power system differ from those in the expansion simulation. In addition, the costs for increasing imports and reducing exports are the same at all borders, so that in times when exports have to be reduced anyway, they are carried out at points that are useful for the grid.

Regarding the allocation of the regionalization results (loads and feed-ins), the geo-coordinates were used to find the nearest network node. If several network nodes have the same distance, for example because a substation has several non-coupled busbars, then the loads and feed-ins are distributed to these nodes with equal shares. This can result in lines being loaded differently than in reality, but is unavoidable given the underlying information. Loads of electric Vehicles and Heat Pumps are not modelled as flexible, because there is no spatial distribution of these loads and also no share in the total load is available in the regionalisation. In addition, the transfer of the constraints for the modelling of heat pumps and the charging of electric vehicles as flexible loads would lead to the need for a large number of loads per node, so that the computational effort would increase accordingly and this would be in contradiction to the performed simplifications for generators.

The investment costs for the addition of a flexible Load is not changed from the Pre-Processor costs of 1,000 €. This can be explained by the fact that, on the one hand, it is not possible to estimate how expensive the flexibilization of a load is and, on the other hand, there is a double pricing of the use of flexibility in the

OPF anyway, when using the Pre-Processor output. The cost to make an existing load flexible is very individual. For industrial processes, the cost depends on the process and the automation already in place. If electric vehicles or heat pumps are to be integrated into the energy system as flexible loads, the costs depend on the corresponding number of consumers. A double pricing of the use of flexible loads for the relief of network congestions takes place, because besides the increase of the fundamental dispatching costs there is a cost share which is credited to the provider of the flexibility. These costs make sense if, for example, losses in production occur due to the use of flexibility, but in most cases the increase in electricity purchase costs is decisive and taken into account by the increased dispatch costs already.

The simplifications discussed so far apply to both regions. In the following sections, simplifications are presented that were necessary for the investigation in the German network. In order to increase the north-south transit capacity, four HVDCs that have already been approved by regulation were integrated into the starting network. The exact network nodes for the necessary converters are not yet known in some cases and were connected to a node in the region. Furthermore, no expansion measures were carried out in the AC network, so that the effect of the HVDC connections may be reduced. Unfortunately, an endogenous calculation to evaluate HVDCs with the expansion tool was not possible because investments in DC lines and converters are made independently, so HVDC candidates result in a large increase in calculation time.

OPF tests have shown that the modelling of storages has a large impact on the computation time. In order to map the trade-off between computation time and modelling accuracy, various investigations of the runtime for an OPF for one week were carried out. Exemplary, but not complete results are shown in Table 3-49:

Table 3-49 Dependency of the computation time on number of storages

Number of Storages	Calculation Time
23	600 min
0	26 min
1 Storage: #1	40 min
1 Storage: #2	40 min
2 Storages: #1 + #2	45 min
1 Storage: #3	41 min
3 Storages: #1 + #2 + #3	35 min

As shown in the table, the calculation time for 23 storages is supposed to be not acceptable for the GEP-Analysis. An increase in calculation time by at least a factor of 1.5 could be noticed, when adding one storage. The combination of storages sometimes lead to an increase in calculation time (see storage #1+#2) and sometimes even lowered it (3 Storages). Plenty additional configurations were tested, and based on the results, it was decided that the capacity and power of all pump storages was divided into four pump storage locations in Germany. In this way, the capacity of the storage facilities has been represented, but it cannot be assumed that it can be fully utilised because the grid infrastructure in these areas is naturally not designed for this increased capacity.

The figures showing the Lagrange multipliers of lines and transformers have been made so that the equipment with the larger Lagrange multiplier is visible and on top. However, since lines can run in parallel as they connect substations with the same coordinates, it cannot be ruled out that individual assets with a Lagrange multiplier not equal to zero are hidden in the illustrations. For the representation of the load and generator curtailment, all loads or generators that have the same coordinates have been combined. If, for example, loads are connected to both the 220 kV and 380 kV levels, they are displayed together accordingly.

3.3.2 Results and analysis

Results for Austria and Switzerland

In the following sections, the Results for the region of Austria and Switzerland are presented. In contrast to the German grid, the GEP could be calculated for all 4 weeks together, so that the results are shown accordingly. The accepted candidates were consequently carried over into the following decade as determined by the GEP, because the MIP-Gap was considered accurate enough for each decade.

The Cross-Border-Lines to Germany are not shown explicitly in the plots of the grid. The reason is, that due to the uncoupling of this Regional-Case after being coupled in the analysis leading to the final results, the generators and loads representing imports from Germany or exports to Germany are directly coupled to the substations in Austria and Switzerland. Additionally, some Interconnectors in the east of Switzerland, connecting it to France are shown too short, because the target coordinates were set in a short distance to the Swiss Node. However, the electrical parameters and length in the modelling are identical to those delivered by ENTSO-E, so this is just a visual constraint.

Austria and Switzerland 2030

The grid utilisation of the year 2030 is shown in Figure 3-32. If a line has a non-zero Lagrange multiplier, it is coloured accordingly (the legend on the right shows Lagrange Multipliers, the higher the numbers, the more time the elements are congested). Assets with a Lagrange multiplier of zero are shown in grey. Due to the fact that lines run parallel and connect substations with coordinates close to each other, individual lines may be overdrawn in the figure. Overall, there are comparatively few congestions.

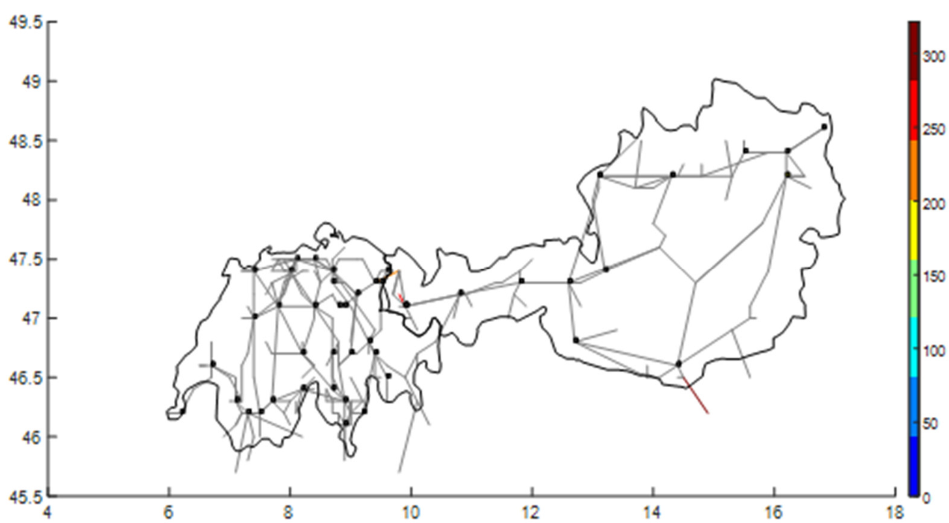


Figure 3-32 Lagrange Multipliers of Lines and Transformers in Austria and Switzerland 2030

The necessary curtailment of loads and generators is correspondingly low, as shown in Figure 3-33. The higher the numbers in the legend, the bigger share of the load is curtailed.

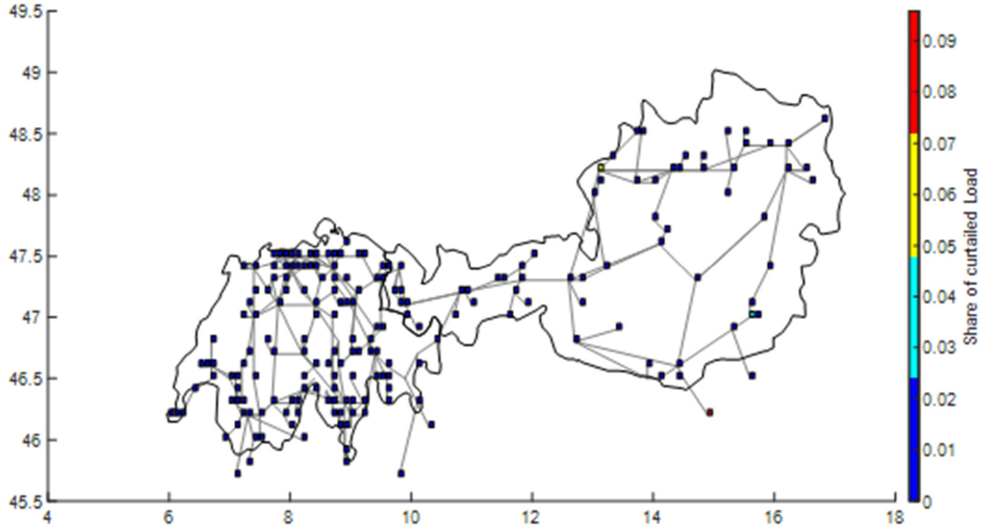


Figure 3-33 Load Curtailment in Austria and Switzerland 2030

There is almost no curtailment of loads. In the south of Austria, about 3% of the annual load is curtailed at a node during the course of the year. One border line to Italy shows congestions. The border flows were actually scaled to the capacities of the lines based on the capacity, so this result is unexpected. An error in the dimensioning of the export load or line can therefore not be excluded. However, the influence of this curtailment on the situation in the Austrian grid is considered negligible and border interconnections are not suggested by the pre-processor. Thus, only a small offset of load curtailment costs is to be expected in the considerations at this point.

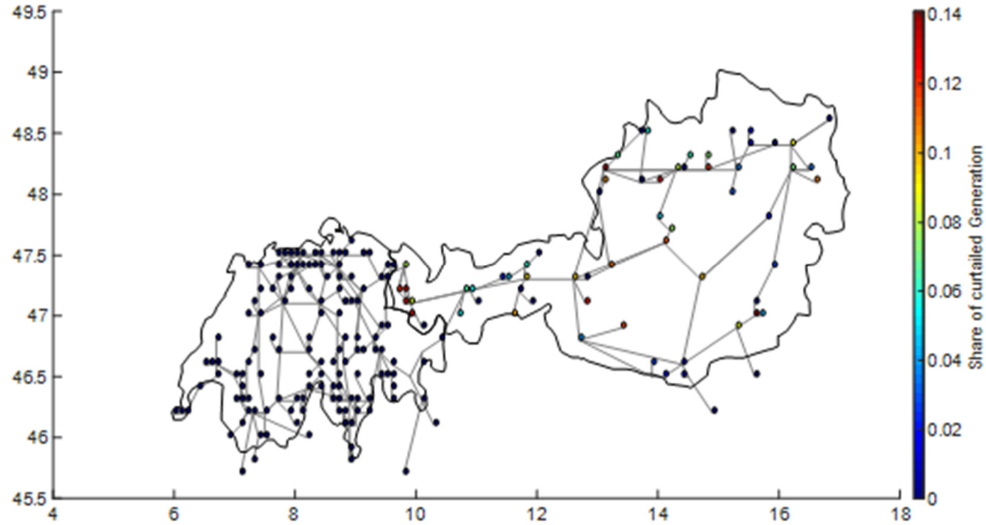


Figure 3-34 Share of curtailed generation in Austria and Switzerland 2030

While the interventions in the behavior of the loads have turned out to be small, a relatively large amount of curtailment of generation occurs, which is presented in Figure 3-34. The higher the numbers in the legend, the bigger share of the generation is curtailed. This shows that at some points in the year there is excess capacity due to renewable energy. Since the load is not flexible, it must be regulated accordingly. It can be assumed that the dispatch would otherwise be more economical, since the grid is not the limiting factor, as only a few non-zero Lagrange multipliers have occurred.

The shown OPF-Results lead to the suggestion of 9 AC-Branches, 11 Storages and 5 flexible Loads, when 25 candidates were set as the limit in the Pre-Processor. These candidates in details are presented in Table 3-50.

Table 3-50 Description of the candidates, 2030, Austria and Switzerland

Type	AC Branch	Transformer	Storage	Flexibility load	Total
Number of candidates	9	0	11	5	25
Investment decisions	4	0	1	5	10
Investment rejected	5	0	10	0	15
Investment costs, €	46,800,000	0	2,400,000	5,000	49,205,000

According to the findings and analysis of generation curtailment, it should be emphasized that investments are made in all 5 candidates for load flexibility. On the other hand, it can be highlighted, that all but one storage investments are rejected. Since these come with higher costs, it can be assumed that the temporal distribution of Renewable Energy surpluses is economically unfavourable and thus there is not enough incentive to invest in storage facilities. The storage-candidates cover different types (5xH2; 3x

FlowBattery; 1x Li; 1x NaS; 1xLAES) of which one H2-Storage was accepted. Only 4 AC-Branches are chosen as an investment, which makes sense due to the few lines with a Lagrange multiplier bigger than zero.

Regarding the GEP-simulation, an optimal solution was found in 12 minutes, the results of the simulation are presented in Table 3-51.

Table 3-51 Results of simulation, 2030, Austria and Switzerland

Total costs (Optimal Power Flow), €	1,480,000,000,000
Total costs (Grind Expansion Planning Tool), €	8,170,000,000
Execution time	12.1 min
MIP Gap, %	0.0

The total costs are presented in Table 3-52 and could be lowered significantly, which will be analyzed further, by comparing the OPF-Result to the GEP-Result:

Table 3-52 Costs results, OPF 2030, Austria and Switzerland

Period	Week 1	Week 2	Week 3	Week 4	Total
Generation costs, €	141,100,000	174,400,000	177,100,000	146,600,000	639,310,000
Generation curtailment costs, €	3,054,700,000	1,909,200,000	925,600,000	3,510,100,000	9,399,500,000
Load curtailment costs, €	479,400,000	1,888,000,000	1,580,300,000	842,300,000	4,790,000,000
Load reduction costs, €	0	0	0	0	0
Load shifting costs, €	0	0	0	0	0
Slack costs, €	0	0	0	0	0
Total costs, €	3,675,200,000	3,971,600,000	2,683,000,000	4,498,900,000	14,829,000,000

As previously assumed, the investments are mainly used to increase Renewable Energy integration and thus also reduce the generation costs of the remaining units by approximately 25 %. The still existing load curtailment-costs are mostly driven by the export-curtailment on the cross-border-line to Italy, which can't be expanded in the planning process and is occurring most likely due to a mismatch in capacities of this specific line.

The resulting costs for the GEP simulation for 2030 are presented in Table 3-53.

Table 3-53 Costs results, GEP 2030, Austria and Switzerland

Period	Week 1	Week 2	Week 3	Week 4	Total
Generation costs, €	106,400,000	132,600,000	134,100,000	110,500,000	483,600,000

Period	Week 1	Week 2	Week 3	Week 4	Total
Generation curtailment costs, €	1,848,400,000	1,101,000,000	455,200,000	2,241,300,000	5,645,900,000
Load curtailment costs, €	360,300,000	607,900,000	1,068,900,000	0	2,037,000,000
Load reduction costs, €	0	0	0	0	0
Load shifting costs, €	0	100,000	0	0	100,000
Slack costs, €	0	0	0	0	0
Total costs, €	2,315,100,000	1,841,500,000	1,658,200,000	2,351,800,000	8,166,600,000

Overall, only few investments in assets are necessary in order to fulfil the supply task. A large incentive to make the load flexible in order to increase the integration of RE becomes visible. However, the investment in Storages is not expected to be economically optimal.

Austria and Switzerland 2040

In 2040, significantly more AC-Branches show a Lagrange multiplier higher than zero.

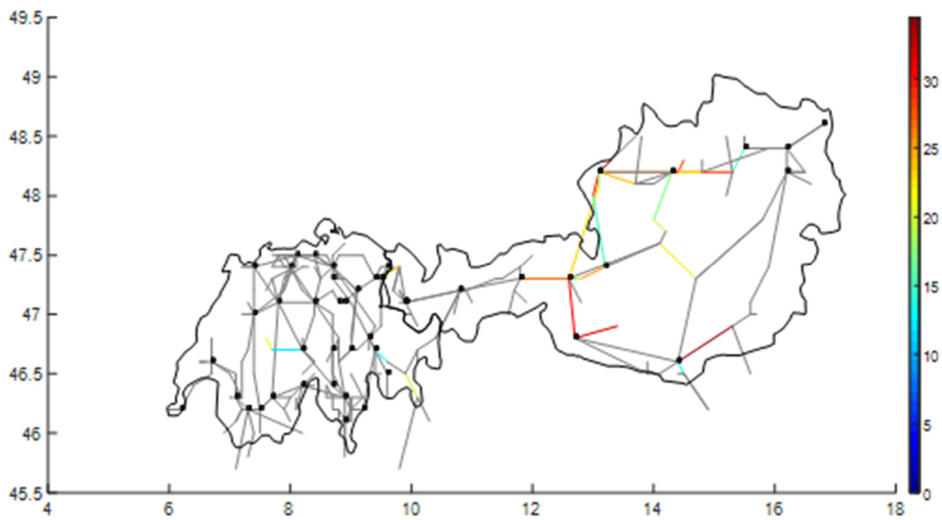


Figure 3-35 Lagrange Multiplier of Lines and Transformers in Austria and Switzerland 2040

As shown in Figure 3-35 and Figure 3-36, there are far more congestions in the Austrian network than in the Swiss network. This could be based on a higher RE-penetration. Compared to the situation in 2030, there is a large increase in the number of assets with a Lagrange multiplier bigger than zero. This is due to severe curtailment of loads and generation:

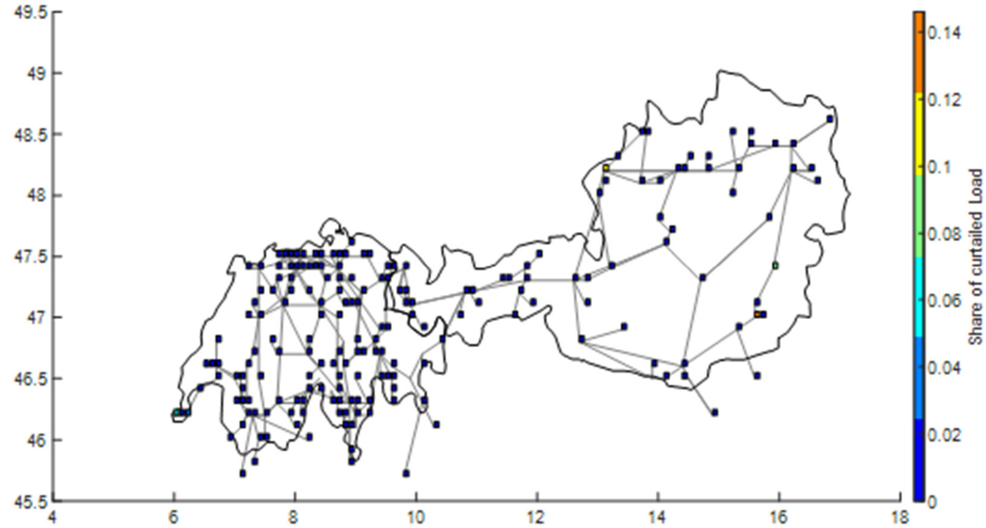


Figure 3-36 Share of curtailed Load in Austria and Switzerland 2040

Compared to the result of 2030, more load curtailment takes place, with one load curtailed by 14 %.

A greater difference becomes visible in the curtailment of renewable energies. In some cases, up to 25 % of the yearly energy are curtailed. No region in Austria stands out in particular, which indicates a relatively even expansion of RE. The curtailment of generation in Switzerland is less distinct, these results are presented in Figure 3-37.

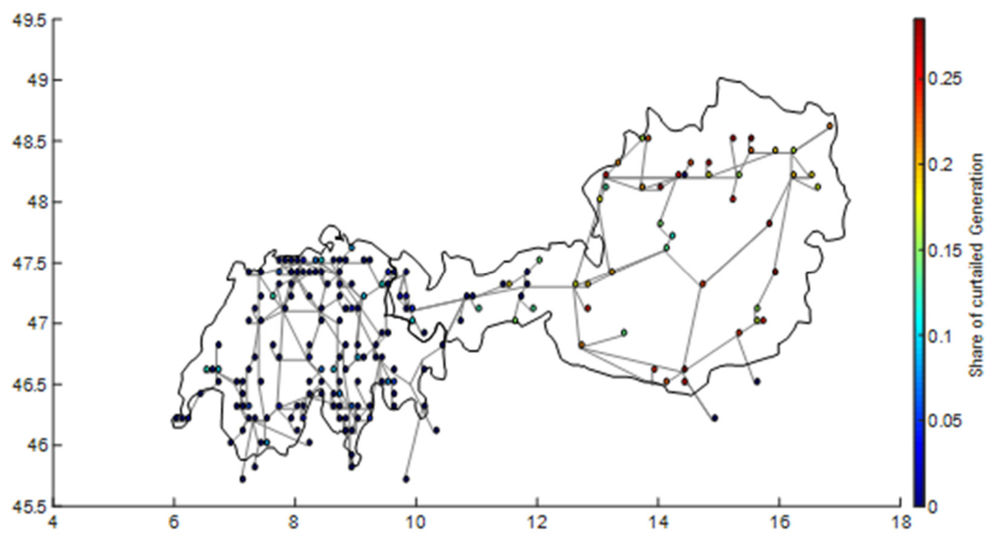


Figure 3-37 Share of curtailed generation in Austria and Switzerland 2040

Due to the low computation time for the year 2030, it was decided to use 100 candidates for the year 2040, which is presented in Table 3-54. 18 AC-Branches as well as one transformer are suggested by the pre-processor. 45 Storages are proposed in addition to 19 flexible loads. Comparing to other RCs, there's probably a bigger volatility in the residual load and / or the merit-order of generators is very steep and therefore the storages are good for keeping the generation-costs low.

Table 3-54 Description of the candidates, 2040, Austria and Switzerland

Type	AC Branch	Transformer	Storage	Flexibility load	Total
Number of candidates	35	1	45	19	100
Investment decisions	18	0	38	19	75
Investment rejected	17	1	7	0	25
Investment costs €	124,800,000	0	211,200,000	19,000	336,019,000

As shown in the results, all of the flexible loads are accepted. This is in line with the findings of the year 2030. Additionally, the investment in 38 storages takes place (22xH2; 8xFlow; 2xLi; 2xNaS; 4xLAES). This a significant change in comparison to the year 2030 and shows, that there are more times with a high RE generation and that it's economically attractive to store it. Nevertheless, additional connections in the grids are accepted (18 AC-Branches). This shows, that in addition to the temporal shift of consumption (flexible loads and storages) and generation (storages), spatial distribution (branches) still is important.

The maximum calculation time of 24 hours was reached, however the MIP Gap is considerably low with 0.23 %, which is shown in Table 3-55. Therefore, this result is considered accurate enough.

Table 3-55 Results of simulation, 2040, Austria and Switzerland

Total costs (Optimal Power Flow), €	35,700,000,000
Total costs (Grind Expansion Planning Tool), €	32,400,000,000
Execution time	24.05 hours
MIP Gap, %	0.23

In the non-expanded OPF a lot of generation curtailment takes place, especially in weeks 2 and 3. Table 3-56 shows the costs for OPF 2040 for Austria and Switzerland, in week 1 the most important part of the costs are the consequence of load curtailment.

Table 3-56 Costs results, OPF 2040, Austria and Switzerland

Period	Week 1	Week 2	Week 3	Week 4	Total
Generation costs, €	224,400,000	27,100,000	100,000	48,100,000	299,650,000
Generation curtailment costs, €	372,000,000	4,749,900,000	5,644,700,000	106,400,000	10,873,000,000
Load curtailment costs, €	13,102,800,000	4,707,400,000	2,466,200,000	4,207,000,000	24,483,000,000
Load reduction costs, €	200,000	0	0	100,000	300,000

Period	Week 1	Week 2	Week 3	Week 4	Total
Load shifting costs, €	200,000	0	0	100,000	300,000
Slack costs, €	0	0	0	0	0
Total costs, €	13,700,000,000	9,484,400,000	8,111,100,000	4,361,500,000	35,656,000,000

Because there is less generation curtailment, it is assumed, that week 1 represents the weather variants of high load and not as much RES-availability. However, week 4 shows, that for some of the weather variants, most likely moderate load and RE-availability, there is not much need for much curtailment. It's interesting to see, that there is considerably low load shifting in week 2 and week 3, even though there is a lot of generation curtailment. One explanation may be that the periods of postponement are not sufficient to increase RE integration. At times of high load, (weeks 1 and 4) there is a correspondingly greater deployment, so that there the load can be sensibly shifted to periods with comparatively more generation. Table 3-57 shows the costs for the solving the GEP problem in 2040 for Austria and Switzerland.

Table 3-57 Costs results, GEP 2040, Austria and Switzerland

Period	Week 1	Week 2	Week 3	Week 4	Total
Generation costs, €	11,800,000	400,000	200,000	600,000	13,000,000
Generation curtailment costs, €	10,000,000	3,731,800,000	4,182,700,000	103,000,000	8,027,400,000
Load curtailment costs, €	12,645,100,000	4,705,200,000	2,466,200,000	4,191,500,000	24,008,000,000
Load reduction costs, €	0	0	0	0	0
Load shifting costs, €	200,000	1,000,000	1,200,000	0	2,407,200
Slack costs, €	0	0	0	0	0
Total costs, €	12,667,000,000	8,438,400,000	6,650,400,000	4,295,100,000	32,051,000,000

It is immediately noticeable that the costs for reducing the feed-in fall by about 27 %. However, the load curtailment costs stay approximately the same. The reason for this is, that again, there is some load-curtailment on cross-border-flows which cannot be solved by expansion measures, therefore this is partly an offset in the data. It's especially interesting, that with the integration of additional flexible loads, the usage of flexible loads rises sharply in week 2 and 3. This is a sign, that the positioning of those flexible loads has a big influence and the load shifting is used often. These developments lead to a high integration of renewable energies, as the remaining generation costs are very low and reduced by over 95 %. Based on the non-expanded OPF result, it was assumed that there is high load and not as much RE in the region, because of the high generation costs. However, even in this period, the generation costs can be lowered significantly by investing into assets.

Overall, this result shows, that a high RE-integration can be achieved in the region by investing in AC-Branches and additionally into flexible loads as well as storages.

Austria and Switzerland 2050

The network utilization in the year 2050 and the Lagrange-Multipliers are shown in Figure 3-38.

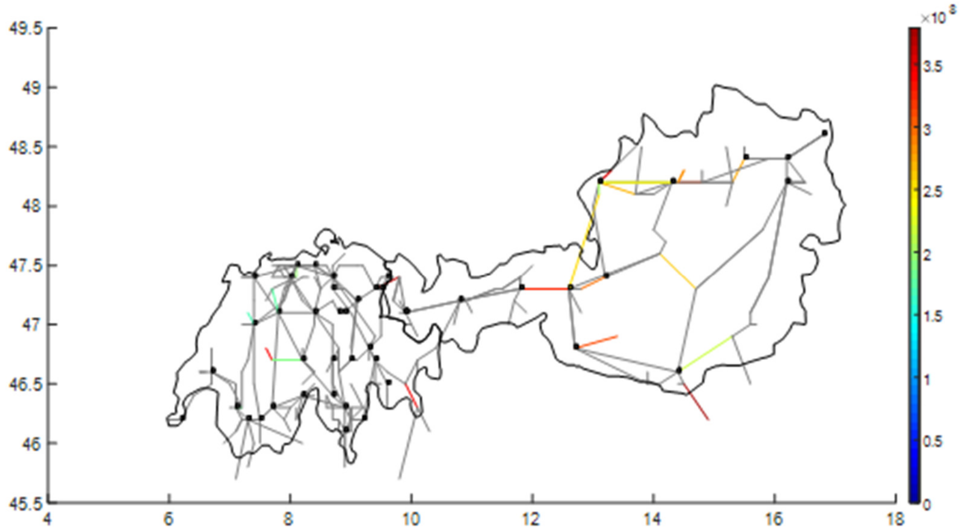


Figure 3-38 Lagrange Multipliers of Lines and Transformers in Austria and Switzerland 2050

In comparison to the amount of lines, that had a Lagrange-Multiplier higher than zero in 2040, the amount of lines with a Lagrange-Multiplier higher than zero in 2050 is not significantly different. However, the amount of load- and generation curtailment, which is presented in Figure 3-39 and Figure 3-40, shows, that the existing network-constraints are more severe.

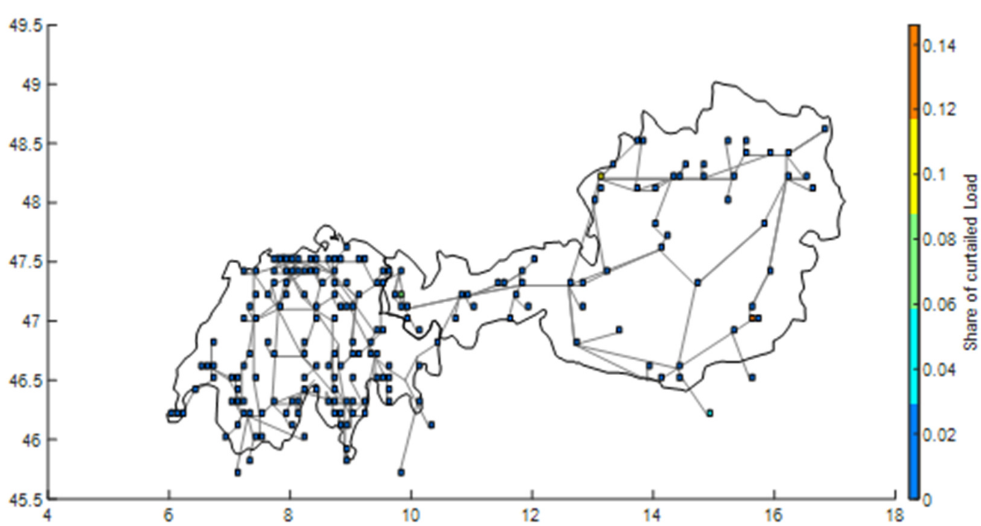


Figure 3-39 Share of curtailed Load in Austria and Switzerland 2050

Again, most of the load-curtailment is due to export-curtailment. The costs, that can be influenced, arise primarily in the curtailment of renewable energies:

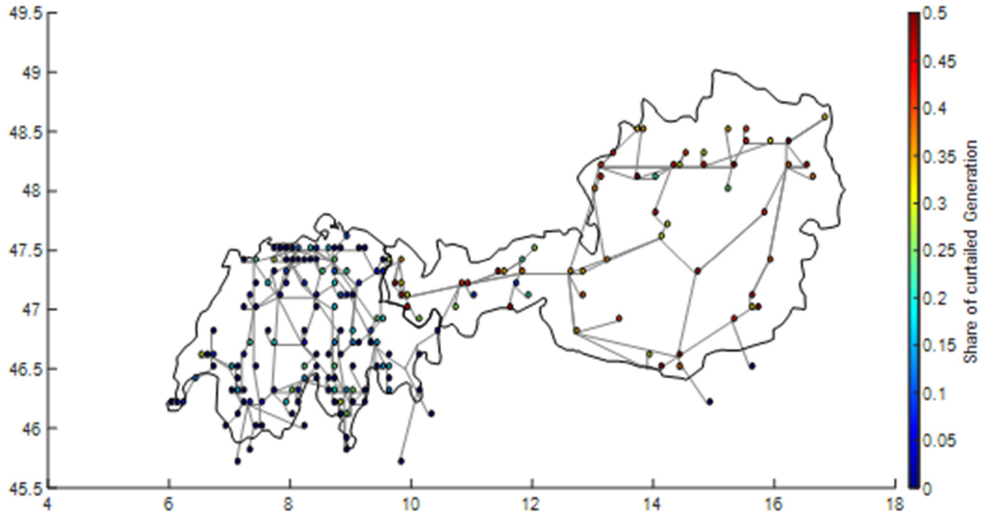


Figure 3-40 Share of curtailed Generation in Austria and Switzerland 2050

Up to 50% of the generated energy is curtailed in some cases. Again, there are no regional particularities in Austria. The amount of curtailed energy in Switzerland is comparably lower again. The Pre-Processor proposes 59 candidates, of which 20 are AC Branches, 20 are Storages (13xH2; 4xFlow; 1xLi; 1xNaS; 1xLAES) and 19 are flexible Loads, which is shown in Table 3-58. Most of the proposed flexible loads and storages (13xH2; 3xFlow; 1xLAES) are accepted. However, again 13 AC Branches are accepted, too. This shows, that there is still some need for transport, even though the flexibility is higher.

Table 3-58 Description of the candidates, 2050, Austria and Switzerland

Type	**AC Branch**	**Transformer**	**Storage**	**Flexibility load**	**Total**
Number of candidates	20	0	20	19	59
Investment decisions	13	0	17	17	47
Investment rejected	7	0	3	2	12
Investment costs €	130,800,000	0	190,400,000	17,000	321,217,000

As seen in Table 3-59, in the 3 hours of execution time, an optimal solution could be found.

Table 3-59 Results of simulation, 2050, Austria and Switzerland

Total costs (Optimal Power Flow), €	194,000,000,000
Total costs (Grind Expansion Planning Tool), €	127,000,000,000
Execution time	3 hours
MIP Gap, %	0

The costs results for the OPP are shown in Table 3-60.

Table 3-60 Costs results, OPF 2050, Austria and Switzerland

Period	Week 1	Week 2	Week 3	Week 4	Total
Generation costs, €	274,400,000	35,300,000	800,000	749,000,000	1,059,400,000
Generation curtailment costs, €	11,397,200,000	55,564,100,000	49,971,200,000	503,400,000	117,440,000,000
Load curtailment costs, €	42,613,600,000	13,522,100,000	6,455,500,000	12,995,000,000	75,586,000,000
Load reduction costs, €	0	0	0	0	0
Load shifting costs, €	5,000,000	7,200,000	8,100,000	4,100,000	24,409,000
Slack costs, €	0	0	0	0	0
Total costs, €	54,290,000,000	69,129,000,000	56,435,000,000	14,251,000,000	194,110,000,000

Compared to the expanded network in the year 2040, which is the same as the network for the 2050 non-expanded OPF, a 10-fold increase in Load shifting costs is noticeable. This could be due to different weather variants and accordingly other situations, but because the weeks are representative for each decade and there is a heterogeneity in each decade, it can be assumed, that the benefit of load-shifting in 2050 is higher, than in 2040. Interestingly, in the expanded network for 2050, the Load shifting costs stagnate, as shown in Table 3-61.

Table 3-61 Costs results, GEP 2050, Austria and Switzerland

Period	Week 1	Week 2	Week 3	Week 4	Total
Generation costs, €	30,100,000	19,500,000	200,000	476,000,000	525,910,000
Generation curtailment costs, €	6,238,600,000	38,368,700,000	34,345,200,000	268,500,000	79,221,000,000
Load curtailment costs, €	24,879,200,000	9,255,800,000	4,851,400,000	8,261,400,000	47,248,000,000
Load reduction costs, €	800,000	0	0	2,000,000	2,800,000
Load shifting costs, €	3,600,000	8,100,000	8,300,000	3,500,000	23,500,000
Slack costs, €	0	0	0	0	0
Total costs, €	31,152,000,000	47,652,000,000	39,205,000,000	9,011,400,000	127,020,000,000

As stated before, the load shifting costs are slightly lower, however Load reduction is chosen in the expanded grid. In comparison to the non-expanded 2050 OPF, generation costs are lower, because higher integration of renewable energy is achieved (see generation curtailment costs). In summary, the trend that has also emerged between the decades 2030 and 2040 is repeated.

In summary, in the Austria and Switzerland region, flexible loads have already been shown to be cost-reducing in a future scenario with relatively low RE penetration. Storage will also be used from 2040 to increase the efficiency of the energy system. Nevertheless, it has been shown in all scenarios that conventional grid expansion in the form of AC lines is also necessary to ensure spatial distribution.

Environmental Costs Austria and Switzerland

The share of costs for CO2-Emissions and Air-Quality-Impact are shown in Table 3-62.

Table 3-62 CO_2-Emissions and Air Quality-Impact, Austria and Switzerland

Metric \ Year	2030	2040	2050
Carbon Footprint impact assessment for generation	0.086%	2.064 %	0.800 %
Air Quality impact assessment for generation	< 0.0001 %	0.001 %	0.001 %
Carbon Footprint impact assessment	0.0051 %	0.0173 %	0.0044 %
Air Quality impact assessment	< 0.00001 %	< 0.00001 %	< 0.00001 %

Overall, the share of Carbon Footprint and Air Quality Costs in the Region Austria and Switzerland is low, because of the high share of renewable and hydro-power production in the energy system. A step in the year 2040 is noticeable, because the CO_2-Price rises.

Summary of Austria and Switzerland

The FlexPlan method was successfully applied in the region of Austria and Switzerland. The added value of flexibility as a supplement to conventional expansion measures became clear. It should be emphasised that investments in flexible loads were already made in 2030, whereas a higher penetration of RE generation was necessary for storages (2040).

Results for Germany

In the following section, the results and analysis for the German region are presented. The results of the OPF were determined in a calculation for all 4 weeks. The (GEP) expansion simulation, on the other hand, was performed individually for each week in order to save computing time. The results of some weeks show a MIP Gap that is larger than the target of 0.01%. Thus, no expansion results with high accuracy are known for these weeks. A calculation of all weeks together with a reduced amount of candidates was tested in the project, but the MIP gaps in the available calculation time were also not satisfactory. Therefore, the results of the weeks with an optimal MIP gap are analysed separately. For the following decades, the results of the weeks are analysed and all measures that resulted in a cost reduction in at least one week are accepted.

Because the number of candidates needed to be reduced drastically in order to get satisfactory results in acceptable calculation time, only the AC-Branch-candidates that were proposed by the pre-processor first are chosen, because they have the overall highest influence on the objective function. In order to investigate the different ways to solve a congestion, storage candidates and flexible load candidates were selected so that they have an impact on the same congestion. As a result, it can be assumed that the selected candidates may be effective candidates for only a subset of the weeks. On the other hand, it is also an option that there are no candidates that act on the most severe congestions of other weeks.

All study cases in Germany have in common that the import and export time series do not match the weather situations of the weather variants. In some weeks, this results in the load not being able to be supplied as otherwise the power balance is not achieved, even if all available power plants are used and the network constraints would be neglected. This required the already described adapted modelling of the border flows. As a consequence, in a few weeks the comparatively expensive imports will have to be increased anyway and exports will be reduced, resulting in a fundamentally high level of objective function. Since the adjustment of the border flows has the same price at all borders, there is a degree of freedom for the solver: the adjustment of the import and export time series can be done in such a way that as few congestions as possible occur. However, the influence of this degree of freedom on the computation time and the corresponding MIP gaps could not be conclusively investigated during the project duration. Yet, the influence on the resulting costs and expansion measures must be taken into account when evaluating the results.

Germany 2030

The Lagrange-Multipliers based on the OPF are shown in Figure 3-41.

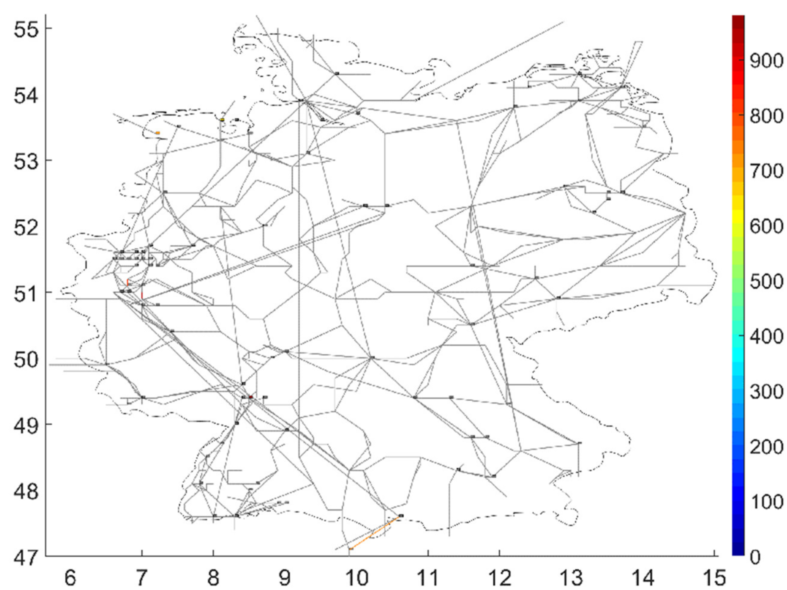


Figure 3-41 Lagrange Multipliers of Lines and Transformers in Germany 2030

Only a few of Branches and transformers show a Lagrange multiplier bigger than zero. This result is unexpected, because for example the HVDC-connectors are oftentimes utilized to 100 % as shown in Figure 3-42.

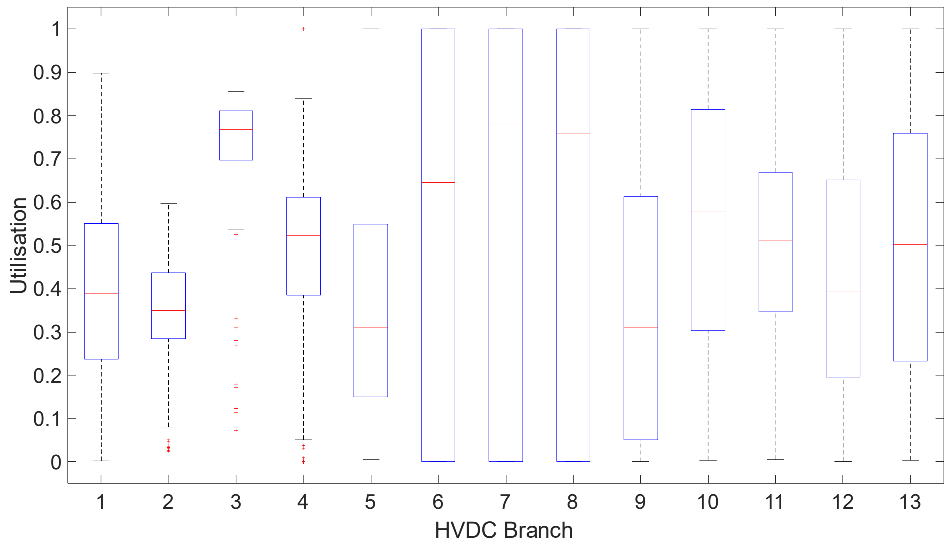


Figure 3-42 Utilisation of HVDC-Connectors in the German Network (2030)

It is to notice, that the HVDC-Branches 6, 7, 8 and 9 are Interconnectors and therefore the utilization of 100 % without any Lagrange-multiplier makes sense, because this means that the Import- or Export-Capacities were fully used in the underlying market-simulation for the initial weather-variant. The other HVDC-Branches, however, represent domestic power flows. It could be assumed, that more capacities could lead to lower curtailment of Loads in southern Germany. This becomes clear when looking at Figure 3-43 and Figure 3-44.

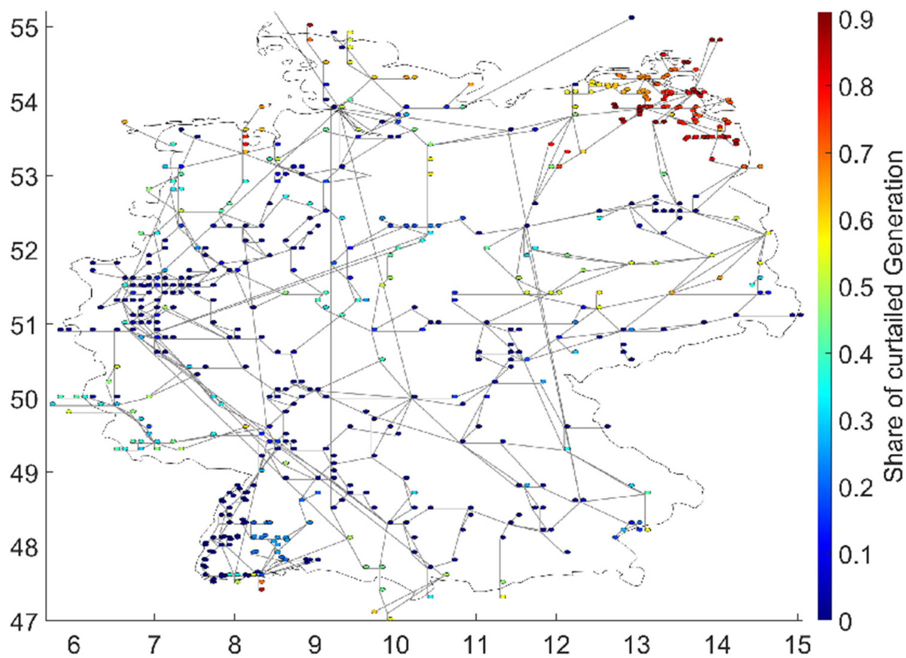


Figure 3-43 Share of curtailed Load in Germany 2030

Most of the load-curtailment takes place in southern Germany. The High-Voltage-Grid Utilisation seems to be high, based on the load-curtailment in south-west-Germany. Because only little information was available when allocating loads to high-voltage nodes due to the data origin (OpenStreetMap), this overload is probably due to the modelling. Most of the curtailment consequently happens in the underlying Medium-Voltage-Grids. But because neither transformers nor AC-Branches in the medium voltage grid have a Lagrange multiplier not equal to zero, this curtailment seems to be necessary because of overlying network (transmission grid) constraints. It's interesting to notice, that the Export of Energy in the south is oftentimes curtailed, which makes sense due to the modelling of cross-border-flows, which was necessary because of power-balance-issues (see adaptions). The Export in northern Germany is not curtailed, because the costs for load-curtailment are the same regardless of the border. As a result of the power-balance-issues, load curtailment of exports is necessary anyway, and the OPF uses this degree of freedom to lower the grid utilisation by curtailing exports in southern Germany and not curtailing them in northern Germany, lowering the need for power transport from northern to southern Germany. The opposite is true, when analysing the Generation-Curtailment:

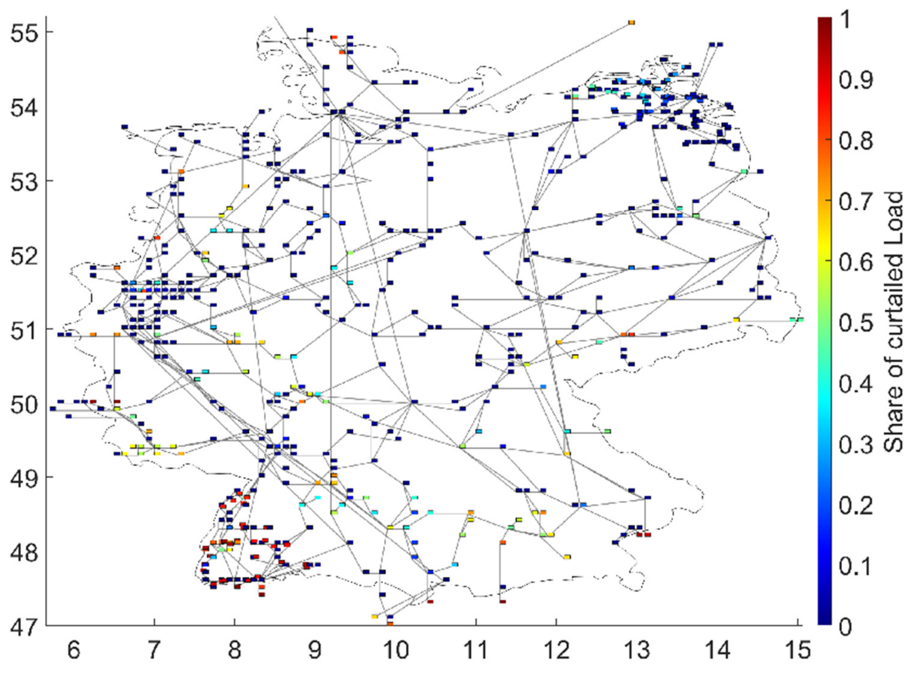


Figure 3-44 Share of curtailed Generation in Germany 2030

Most of the Import-curtailment takes place in northern Germany, especially in the modelled high voltage grid. As with the loads in the high voltage grid in southern Germany, this could be due to the matching of generators to the nodes in the high voltage grid. Nevertheless, German studies show the need for expansion of high voltage grids, so this is not an unexpected result. But even in southern Germany, some import curtailment occurs, this could be due to grid constraints in times of high-PV-generation in southern Germany.

Overall, it can be noticed, that load curtailment is needed in southern Germany, while generation curtailment is necessary in northern Germany. However, the Lagrange multipliers do not reflect this fully. This could be the case because interconnected grid expansion measures are necessary. As a first step, the generators in the north must be better integrated into the grid on a regional basis (for example see high-voltage network constraints) so that an investment in lines to the south can show any added value at all. Considered individually, the added value of further north-south connections may not be apparent.

Because the number of candidates, than can be used in the GEP are low, due to calculation time constraints, three AC-Branches are used as candidates as shown in Table 3-63. The three storages and flexible load, that are used, offer an alternative to the AC-Branch grid-expansion measures, because they offer a solution for the same congestion. All of these measures have in common, that they offer a solution to integrate generation and load locally. They are used to connect network-nodes that are only a few kilometres apart and are therefore used to connect different circuits, which are not connected due to the static switching state (see adaptions). Because of this, it makes sense, that only in one of the four weeks the AC-Branches were chosen as an investment and the storage or flexible loads are no alternative in this regard. It is to notice, that due to a high MIP gap, no robust results could be obtained in week 2.

Table 3-63 Description of the candidates, 2030, Germany

Type	AC Branch	Transformer	Storage	Flexibility load	Total
Number of candidates	3	0	3	1	7
Investment decisions*	Week 1: 3 Week 3: 0 Week 4: 0	0	Week 1: 0 Week 3: 0 Week 4: 0	Week 1: 0 Week 3: 0 Week 4: 0	Week 1: 3 Week 3: 0 Week 4: 0
Investment rejected	Week 1: 0 Week 3: 3 Week 4: 3	0	Week 1: 3 Week 3: 3 Week 4: 3	Week 1: 1 Week 3: 1 Week 4: 1	Week 1: 4 Week 3: 7 Week 4: 7
Investment costs, €	Week 1: 4,849,000 Week 3: 0 Week 4: 0	0	Week 1: 0 Week 3: 0 Week 4: 0	Week 1: 0 Week 3: 0 Week 4: 0	Week 1: 4,849,000 Week 3: 0 Week 4: 0

** Due to the high MIP Gap, no information on investment decisions could be gathered in week 2.*

As could be seen from Table 3-64, the simulation time was exceeded in week 2, which results in a non-satisfying MIP gap. The numbers for Execution time and MIP Gap are separated for all simulated weeks.

Table 3-64 Results of simulation, 2030, Germany

Total costs (Optimal Power Flow), €*	1,498,568,400,000
Total costs (Grind Expansion Planning Tool), €	1,365,675,000,000
Execution time	20.6 hours/ 1 day/ 4.1 hours/ 1.1 hours
MIP Gap, % (fitting to week)	0,0 / 95.49/ 0,0/ 0,0

** Due to the high MIP Gap in week 2, the total costs of week 2 equal the OPF costs of week 2.*

The non-expanded OPF-Results for Germany are shown in Table 3-65.

Table 3-65 Costs results, OPF 2030, Germany

Period	Week 1	Week 2	Week 3	Week 4	Total
Generation costs, €	138,573,000,000	56,578,300,000	31,763,800,000	89,784,300,000	316,700,000,000
Generation curtailment costs, €	3,577,600,000	6,658,000,000	13,308,200,000	2,277,800,000	25,822,000,000
Load curtailment costs, €	516,121,300,000	202,949,600,000	104,763,000,000	332,213,500,000	1,156,000,000,000
Load reduction costs, €	0	0	0	0	0
Load shifting costs, €	0	0	0	0	0

Period	Week 1	Week 2	Week 3	Week 4	Total
Slack costs, €	0	0	0	0	0
Total costs, €	658,272,000,000	266,186,000,000	149,835,000,000	424,276,000,000	1,498,568,400,000

As expected, the costs for load-reduction and generation-curtailment are high. Additionally, due to the necessary additional generation from Imports in order to obtain a power-balance, the Generation-Costs are high, too. Due to the expansion measure in week 1, the obtained costs for this week in the GEP are lower.

Table 3-66 Costs results, GEP 2030, Germany

Period	Week 1	Week 2*	Week 3	Week 4	Total
Generation costs, €	108,579,900,000	56,578,300,000 (the same as OPF)	31,763,800,000 (the same as OPF)	89,784,300,000 (the same as OPF)	286,706,300,000
Generation curtailment costs, €	2,971,200,000	6,658,000,000 (the same as OPF)	13,308,200,000 (the same as OPF)	2,277,800,000 (the same as OPF)	25,215,200,000
Load curtailment costs, €	413,826,600,000	202,949,600,000 (the same as OPF)	104,763,000,000 (the same as OPF)	332,213,500,000 (the same as OPF)	1,053,752,700,000
Load reduction costs, €	0	0 (the same as OPF)	0 (the same as OPF)	0 (the same as OPF)	0
Load shifting costs, €	0	0 (the same as OPF)	0 (the same as OPF)	0 (the same as OPF)	0
Slack costs, €	0	0 (the same as OPF)	0 (the same as OPF)	0 (the same as OPF)	0
Total costs, €	525,378,000,000	266,186,000,000 (the same as OPF)	149,835,000,000 (the same as OPF)	424,276,000,000 (the same as OPF)	1,365,675,000,000

** Due to the high MIP Gap, no information on investment decisions could be gathered.*

In order to not have the costs in Table 3-66, it is assumed, that no investment takes place, and the costs of the OPF are copied, in order to not have an offset in the data and as less inaccurate information as possible.

Nevertheless, the results are not satisfactory. As was highlighted in the analysis of the OPF, two grid expansion objectives must be achieved, which would massively increase the number of necessary expansion candidates:

1. Local expansion measures in order to integrate the additional generation and load
2. After local integration is successful, supra-regional expansion-measures must be identified

This requirement, in combination with the high computing time of the German network, leads to a problem that could not be solved within the scope of the project.

Germany 2040

Building on the results of the GEP for 2030, the network is reinforced by the three accepted lines and the scenario for the year 2040 is calculated.

The obtained lagrange Multipliers are shown in Figure 3-45.

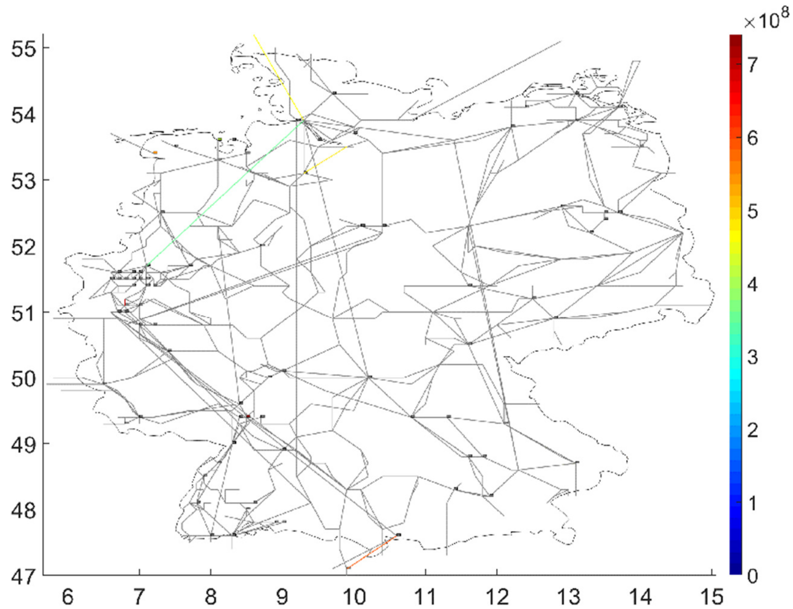


Figure 3-45 Lagrange Multipliers of Lines and Transformers in Germany 2040

This time, supra-regional Branches show a Lagrange-Multiplier higher than zero. This is most likely the case, because generators, are directly connected to the network nodes in northern Germany, and therefore, the influence of curtailment of these generators is visible in the Lagrange multipliers of these supra-regional branches. The two interconnectors are assigned a Lagrange multiplier because the flexible feed-ins were modelled in addition to the import that occurs anyway and thus more generation capacity is available abroad than can be transported via the lines. Since the lines cannot be overloaded, this has no influence on the results in dispatch, but leads to a Lagrange multiplier not equal to zero, since generators are basically available abroad that could feed in in the south. Since no interconnectors are suggested by the pre-processor as candidates, they can be disregarded in the figure.

The share of curtailed load in comparison to the Results 2030 rise, as well as the curtailed generation, as shown in Figure 3-46 and Figure 3-47.

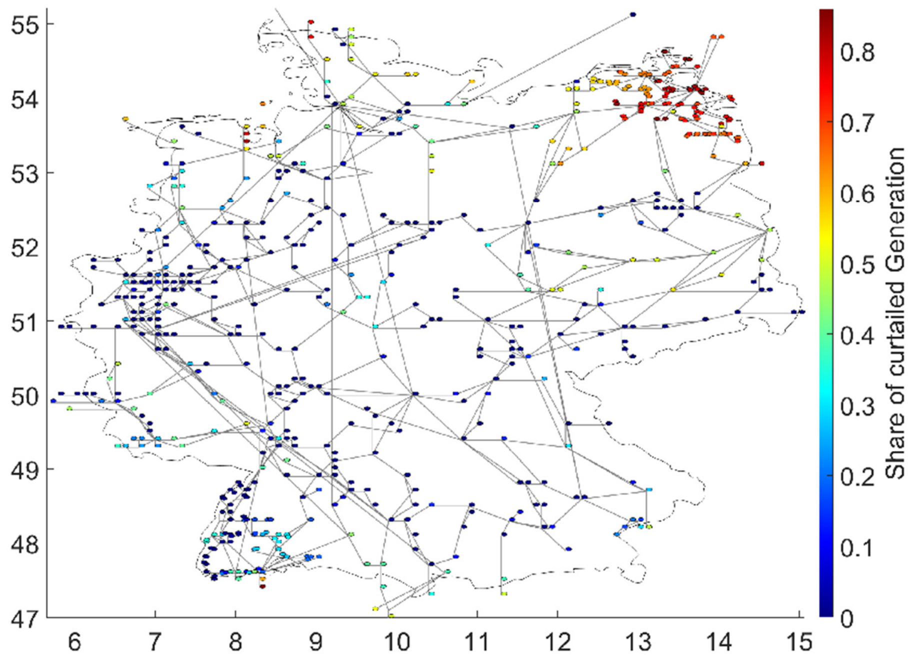


Figure 3-46 Share of curtailed Load in Germany 2040

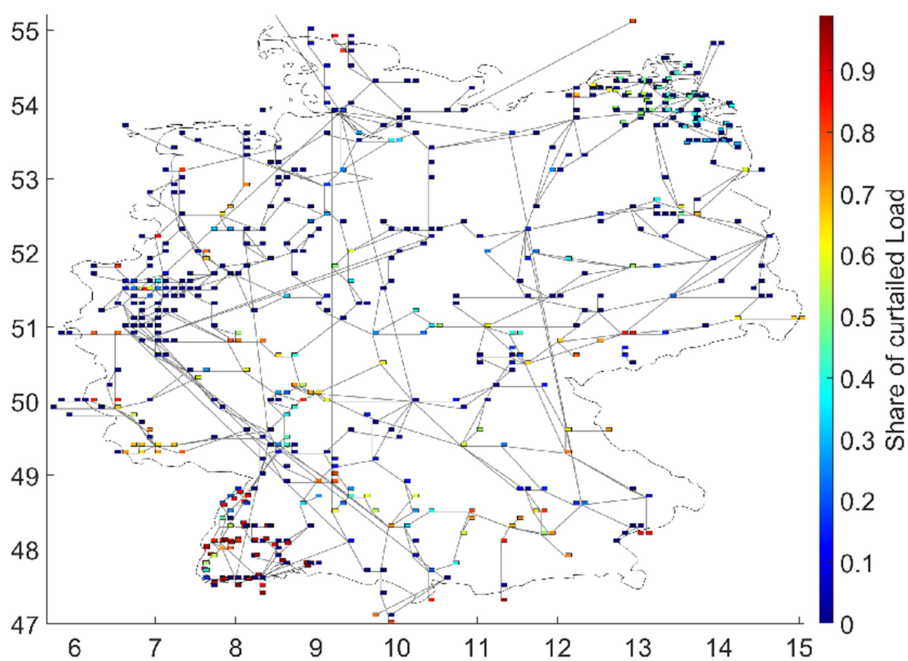


Figure 3-47 Share of curtailed Generation in Germany (2040)

In summary, the trend from 2030 continues and no noteworthy peculiarities stand out.

As presented in Table 3-67, the 3 chosen AC-candidates, with the highest Lagrange-Multiplier, that have additional storage and flexible load as an alternative, are regionally effective measures. Both storages are hydrogen-based.

Table 3-67 Description of the candidates, 2040, Germany

Type	AC Branch	Transformer	Storage	Flexibility load	Total
Number of candidates	3	0	2	1	6
Investment decisions	Week 1: 0 Week 2: 2 Week 3: 2 Week 4: 3	0	Week 1: 0 Week 2: 1 Week 3: 0 Week 4: 2	Week 1: 0 Week 2: 1 Week 3: 1 Week 4: 0	Week 1: 0 Week 2: 3 Week 3: 3 Week 4: 5
Investment rejected	Week 1: 3 Week 2: 1 Week 3: 1 Week 4: 0	0	Week 1: 2 Week 2: 1 Week 3: 2 Week 4: 0	Week 1: 1 Week 2: 0 Week 3: 0 Week 4: 1	Week 1: 6 Week 2: 3 Week 3: 3 Week 4: 1
Investment costs, €	Week 1: 0 Week 2: 4,600,000 Week 3: 4,900,000 Week 4: 6,000,000	0	Week 1: 0 Week 2: 1,600,000 Week 3: 0 Week 4: 4,500,000	Week 1: 0 Week 2: 1,000 Week 3: 1,000 Week 4: 0	Week 1: 0 Week 2: 6,201,000 Week 3: 4,901,000 Week 4: 10,500,000

An investment in two of the AC-Branches is preferred in two weeks, while in one week all 3 candidates are approved. Additionally, a benefit of storages and flexible loads becomes visible, as they are accepted in some of the weeks.

As could be seen from Table 3-68, the four necessary GEP-calculations all reach optimality within the time limit of 24 hours. The numbers for Execution time and MIP Gap are separated for all simulated weeks.

Table 3-68 Results of simulation, 2040, Germany

Total costs (Optimal Power Flow), €	1,772,187,000,000
Total costs (Grind Expansion Planning Tool), €	1,481,892,100,000
Execution time	20.8h/19.6h/17h/20.9h
MIP Gap, % (fitting to week)	0.00/0.00/0.00/0.00

The returned costs for each week are shown in Table 3-69and Table 3-70.

Table 3-69 Costs results, OPF 2040, Germany

Period	Week 1	Week 2	Week 3	Week 4	Total
Generation costs, €	74,049,900,000	98,407,100,000	194,672,000,000	79,492,300,000	446,621,300,000
Generation curtailment costs, €	3,508,800,000	6,171,400,000	8,361,500,000	7,582,800,000	25,624,500,000

Period	Week 1	Week 2	Week 3	Week 4	Total
Load curtailment costs, €	236,871,500,000	217,275,100,000	544,270,100,000	284,591,800,000	1,283,008,500,000
Load reduction costs, €	0	0	0	0	0
Load shifting costs, €	0	0	0	0	0
Slack costs, €	0	0	0	0	0
Total costs, €	314,430,000,000	338,790,000,000	747,300,000,000	371,667,000,000	1,772,187,000,000

Table 3-70 Costs results, GEP 2040, Germany

Period	Week 1	Week 2	Week 3	Week 4	Total
Generation costs, €	74,049,900,000 (the same as OPF)	79,298,000,000	155,448,500,000	63,980,400,000	372,776,800,000
Generation curtailment costs, €	3,508,800,000 (the same as OPF)	5,035,400,000	6,819,900,000	6,171,400,000	21,535,500,000
Load curtailment costs, €	236,871,500,000 (the same as OPF)	177,415,100,000	441,691,200,000	230,688,900,000	1,086,666,700,000
Load reduction costs, €	0 (the same as OPF)	2,900,000	5,900,000	0	8,800,000
Load shifting costs, €	0 (the same as OPF)	100,000	100,000	0	200,000
Slack costs, €	0 (the same as OPF)	0	0	0	0
Total costs, €	314,430,000,000 (the same as OPF)	261,959,000,000	604,086,000,000	301,417,100,000	1,481,892,100,000

There is still a need for a lot of load-curtailment, as well as generation curtailment. The conclusion of the year 2030 continues to apply in this decade as well

Germany 2050

The following results of the OPF for 2050 show that the share of curtailed load and generation rises drastically. This makes sense, because only six AC-Branches, two storages and one flexible load were added in comparison to the starting grid. The Lagrange Multipliers of lines and transformers, share of curtailed load and share of curtailed generation is shown in Figure 3-48, Figure 3-49 and Figure 3-50 respectively.

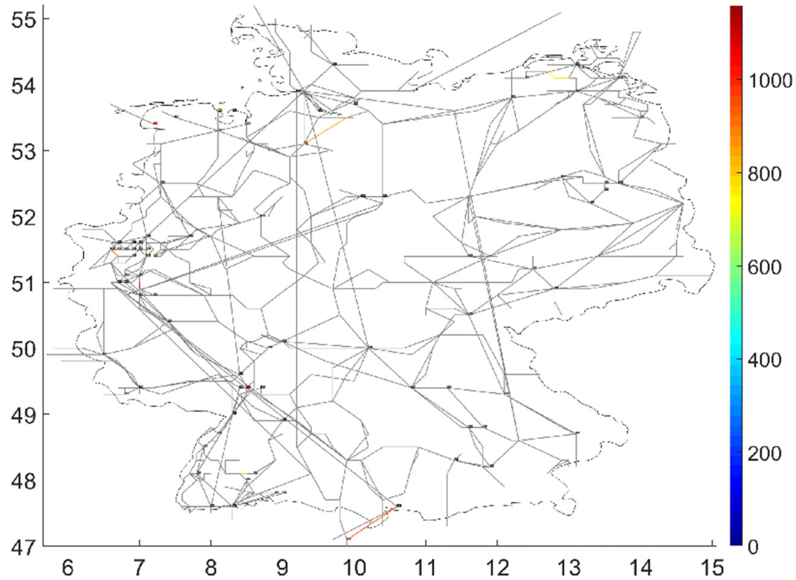


Figure 3-48 Lagrange Multipliers of Lines and Transformers in Germany 2050

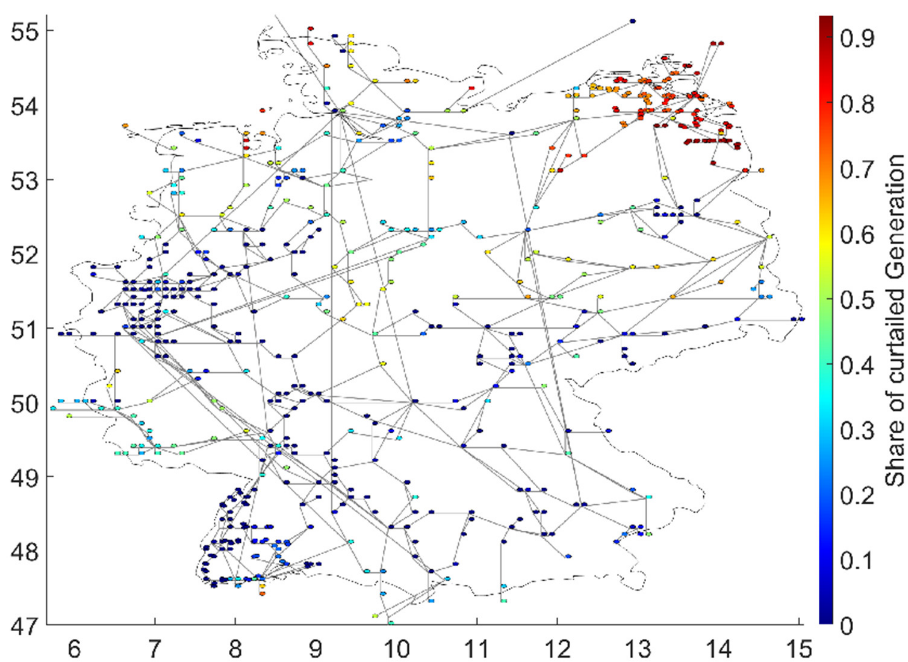


Figure 3-49 Share of curtailed Load in Germany 2050

In comparision to the previous years, more load curtailment was observed in other parts of Germany than only in southern Germany.

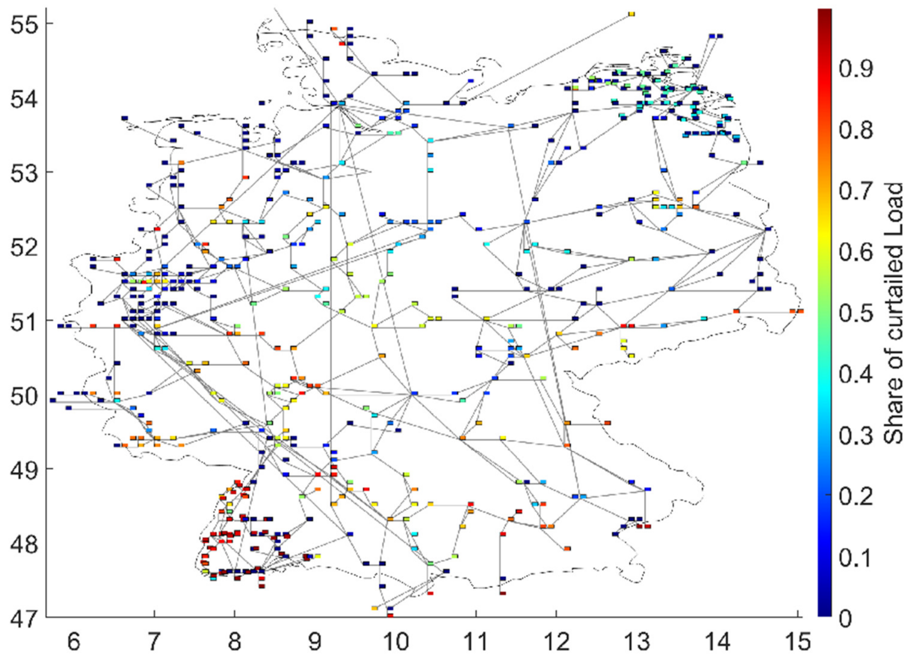


Figure 3-50 Share of curtailed Generation in Germany 2050

In addition to the generation curtailment, it becomes clear, that the non-expanded grid is not really suitable for this supply task. However, again only few candidates can be calculated due to calculation-time constraints, as can be seen in Table 3-71.

Table 3-71 Description of the candidates, 2050, Germany

Type	AC Branch	Transformer	Storage	Flexibility load	Total
Number of candidates	3	0	3	2	8
Investment decisions	Week 3: 0	0	Week 3: 0	Week 3: 0	Week 3: 0
Investment rejected	Week 3: 3	0	Week 3: 3	Week 3:2	Week 3: 8
Investment costs, €	Week 3: 0	0	Week 3: 0	Week 3: 0	Week 3: 0

However, even though the number of candidates was low, in three of the four weeks, no satisfying MIP gap could be reached. In week 3, the only week with an optimal result, each candidate was rejected, most likely because the reduced candidates were not needed in this specific supply task resulting from the clustering. The results of the simulation are presented in Table 3-72. The numbers for Execution time and MIP Gap are separated for all simulated weeks.

Table 3-72 Results of simulation, 2050, Germany

Total costs (Optimal Power Flow), €	2,963,740,000,000
Total costs (Grind Expansion Planning Tool), €	-
Execution time	24h/24h/1.2h/24h
MIP Gap, % (fitting to week)	96,4/97.5/0/97.1

Because no candidate was accepted, the GEP-Results equal the OPF-Results, as can be seen from Table 3-73 and Table 3-74.

Table 3-73 Costs results, OPF 2050, Germany

Period	Week 1	Week 2	Week 3	Week 4	Total
Generation costs, €	75,243,900,000	116,143,000,000	86,395,200,000	179,887,200,000	457,669,300,000
Generation curtailment costs, €	20,529,800,000	6,214,700,000	9,216,700,000	1,043,300,000	37,004,500,000
Load curtailment costs, €	476,515,400,000	522,622,100,000	391,730,600,000	1,068,801,200,000	2,459,669,300,000
Load reduction costs, €	5,700,000	5,800,000	4,400,000	10,300,000	26,200,000
Load shifting costs, €	100,000	100,000	200,000	100,000	500,000
Slack costs, €	0	0	0	0	0
Total costs, €	572,300,000,000	644,990,000,000	487,350,000,000	1,259,100,000,000	2,963,740,000,000

Table 3-74 Costs results, GEP 2050, Germany

Period	Week 1	Week 2	Week 3	Week 4	Total
Generation costs, €	The same as OPF	The same as OPF	The same as OPF	The same as OPF	The same as OPF
Generation curtailment costs, €	The same as OPF	The same as OPF	The same as OPF	The same as OPF	The same as OPF
Load curtailment costs, €	The same as OPF	The same as OPF	The same as OPF	The same as OPF	The same as OPF
Load reduction costs, €	The same as OPF	The same as OPF	The same as OPF	The same as OPF	The same as OPF
Load shifting costs, €	The same as OPF	The same as OPF	The same as OPF	The same as OPF	The same as OPF
Slack costs, €	The same as OPF	The same as OPF	The same as OPF	The same as OPF	The same as OPF
Total costs, €	The same as OPF	The same as OPF	The same as OPF	The same as OPF	The same as OPF

In summary, no reliable results could be achieved for the year 2050 in Germany. This is also due to the fact that the grid has not been appropriately upgraded up to this point and that many loads and generators were also curtailed in 2030 and 2040. As a result, the 2050 scenario was tested almost in the starting grid, so that the expansion method reached its limits.

Environmental Costs Germany

The share of costs for CO_2-Emissions and Air-Quality-Impact are shown in Table 3-75.

Table 3-75 CO_2-Emissions and Air-Quality-Impact, Germany

Metric \ Year	2030	2040	2050
Carbon Footprint impact assessment for generation	0.43 %	0.291 %	0.225 %
Air Quality impact assessment for generation	0.003 %	0.001 %	0.001 %
Carbon Footprint impact assessment	0.034 %	0.0733 %	0.0347 %
Air Quality impact assessment	0.0002 %	0.0002 %	0.0001 %

Summary of Germany

The German network poses challenges for grid expansion planning due to the large number of nodes and properties. Thus, it was determined that, on the one hand, the regional integration of RE plants and increasing load must be achieved and, on the other hand, a supra-regional transport of energy must take place. These two characteristics pose challenges for the FlexPlan method, as the added value for the target function of measures only becomes clear when both things are achieved. Increased integration of RE plants in the grid in northern Germany makes no sense if the energy cannot be transported to the south. Conversely, an increase in transport capacities to the south also makes no sense if the renewable energy cannot be fed into the grid locally. However, if more computing time is available and parameterisations are partially re-tuned (handling of imports / exports), the tool offers good possibilities to determine the network expansion. In its current form, however, this still requires a smart choice of candidates so that both regional and supra-regional measures can be suitably checked together. Unfortunately, due to the restrictions in the number of candidates, this could not be conclusively checked during the project.

3.4 Italy

3.4.1 Overview of the adaptations for Regional Case

Due to the complexity of the simulations to be executed a list of possible simplifications and alterations were proposed and implemented for testing the planning procedure. In particular, the following actions have been applied:

- Since the first simulation tests, the presence of storage units had a significant impact on the computational effort requested to the tool. For this reason, the amount of these units has been reduced to 33: 15 pumped hydro and 18 reservoir power plants.
- A set of experiments was carried out to define the simulation parameters with the best performance. The minimum computational time has been achieved by selecting:
  - Power/energy values normalized to 100 MVA.
  - Scaling factor of the objective function equal to 1 (default value).
  - CPLEX solver parameters set to default.
  - Operative and investment costs expressed in Euros.
- Short transmission lines (below 10-km length) have been removed from network model (buses connected by these lines have been merged to preserve their connection).
- A limited portion (10%) of distribution network has been considered with the full details. First, the grids experiencing congestions were selected, then the remaining portions of the grid have been included into the model in a simplified form.
- A limited number of candidates has been requested from the pre-processor to manage the complexity of the mixed-integer problem solved by the FlexPlan tool. In particular:
  - the limitation has been mainly represented by the number of candidates for transmission network, which model complexity required a maximum of 20 candidates to be solved in an acceptable time.
  - no limitations have been identified for the distribution network, which limit has been set to 80÷100 candidates.
- Processing the full 4-week dataset of the scenario resulted in non-acceptable processing time, due to memory limitation of the available hardware. Therefore, the following heuristic procedure have been applied:
  - The selected candidates (integer solution) are determined for each week separately, by assuming that it is representative of the full 2030.
  - Candidates that are "accepted" in all of the weeks are confirmed as "accepted". Candidates that are systematically "not-accepted", they are confirmed as "not-accepted".
  - Candidates that are sometimes "accepted", sometimes "not-accepted" are classified as "uncertain investments".

- Finally, “accepted candidates” are added to the network model and the 4-week scenario is launched in order to determine the selection of the “uncertain candidates”.

At the end of the simplification process, the network is composed by the elements reported in Table 3-76.

Table 3-76 Description of the network, Italy

Number of the nodes	5654
of which in transmission network	1451
of which in distribution network	4203
Number of AC branches	5906
of which in transmission network	2072
of which in distribution network	3834
Number of transformers	672
of which in transmission network	
of which in distribution network	
Number of storages	33
Number of flexibility loads	0

3.4.2 Results and analysis

Decade 2030

Once 2030 scenario data (4 representative weeks, 1 variant) have been included within the network mode, the non-expanded Optimal Power Flow has been carried out. The simulation converged to the optimal dispatching solution and, as expected from a non-expanded grid, congestions occurred (Figure 3-51) and they determined load and generation curtailment (Figure 3-52). The legend on the right shows Lagrange Multipliers, the higher the numbers, the more time the elements are congested. The dispatching costs, as well as the costs assigned to congestions (load and generation curtailment) are reported for each representative week in Table 3-77.

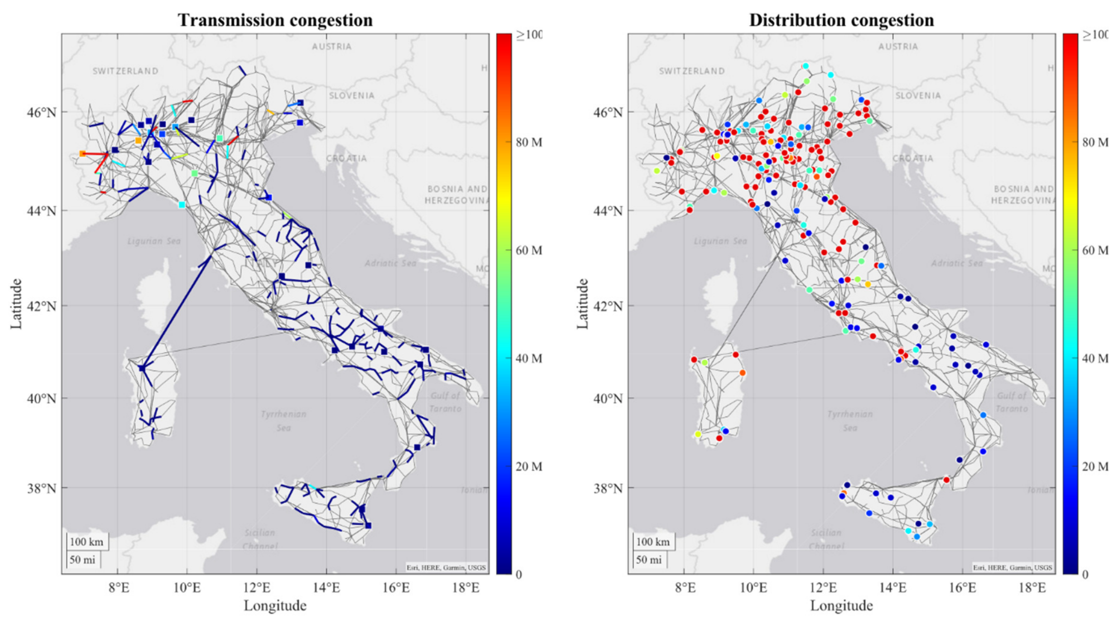


Figure 3-51 Overloaded lines (plotted as lines) and transformers (plotted as squares) for the Italian RC and related Lagrange Multipliers (Year 2030)

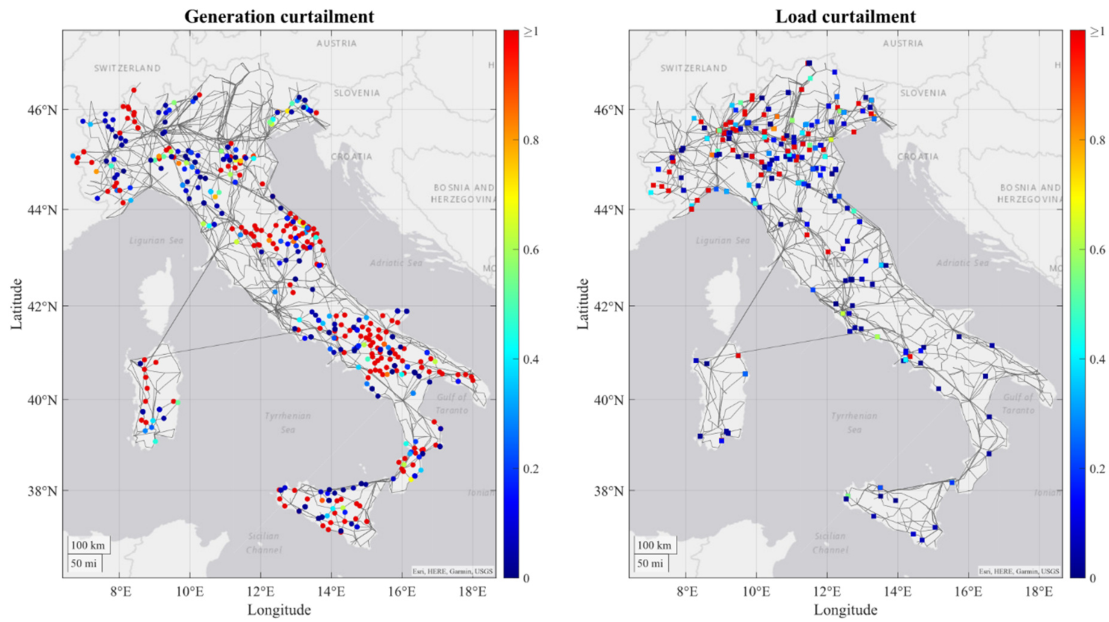


Figure 3-52 Curtailed generators (plotted as circles) and loads (plotted as squares) for the Italian RC and yearly curtailed energy (Year 2030)

Looking at the maps reported in Figure 3-51 and Figure 3-52, it can be noticed that the location of congestions matches the one of curtailed generation and load. From the analysis of their geographical displacement, the following points can be stated:

- The congestions with the highest impact on the objective function (which means greater values of Lagrange Multipliers) are in the north of Italy. Indeed, load curtailment is mostly concentrated in this area, and it is due to the non-sufficient capacity of both transmission and distribution lines/transformers.
- In the remaining part of Italy (centre, south and major islands), congestions are still widespread but less severe (lower Lagrange multipliers) with respect to the ones experienced in Northern Italy. This can be explained by looking at the occurrence of generation and load curtailment. The first is significantly higher with respect to the second and, since its costs is lower than load curtailment, the congestion severity is lower as well.

Table 3-77 Costs results, OPF 2030, Italy

Period	Week 1	Week 2	Week 3	Week 4	Total
Generation costs, €	31,221,000,000	15,188,000,000	41,982,000,000	28,767,000,000	117,158,000,000
Generation curtailment costs, €	902,000,000	465,000,000	206,000,000	141,000,000	1,720,000,000

Period	Week 1	Week 2	Week 3	Week 4	Total
Load curtailment costs, €	8,898,000,000	1,644,000,000	16,945,000,000	4,059,000,000	31,546,000,000
Load reduction costs, €	0	0	0	0	0
Load shifting costs, €	0	0	0	0	0
Slack costs, €	0	0	0	0	0
Total costs, €	41,021,000,000	17,297,000,000	59,133,000,000	32,967,000,000	150,424,000,000

According to the limitation in the number of candidates to be proposed, the FlexPlan tool is not in the conditions to address all the congestions occurring on transmission and distribution grids. In these circumstances, only the most severe congestions were considered, and for the case study, they correspond to areas where load curtailment occurs. In Table 3-78, the considered list of candidates (with the details on their acceptance) is reported.

Table 3-78 Description of candidates, 2030, Italy

Type	**AC Branch**	**Transformer**	**Storage**	**Flexibility load**	**Total**
Number of candidates	90	2	9	19	120
Investment decisions	7 (Transmission) 40 (Distribution)	1 (Transmission) 0 (Distribution)	5 (H2) 1 (FB)	5 (Distribution)	13 46
Investment rejected	6 (Transmission) 37 (Distribution)	1 (Transmission) 0 (Distribution)	0 3 (FB)	0 14	7 54
Investment costs (€)	8,462,000	1,082,000	1,584,000	5,000	11,133,000

Once candidates have been proposed, the selection of investments have been carried out by a dedicated process (Grid Expansion Planning), and the related results are reported in Table above. The selection has been carried out by considering the impacts of candidates on the system costs, which details are reported in Table 3-79.

Table 3-79 Costs results, GEP 2030, Italy

Period	Week 1	Week 2	Week 3	Week 4	Total
Generation costs, €	30,623,000,000	14,996,000,000	41,237,000,000	28,132,000,000	114,989,000,000
Generation curtailment costs, €	877,000,000	456,000,000	150,000,000	126,000,000	1,609,000,000
Load curtailment costs, €	6,112,000,000	1,038,000,000	11,909,000,000	2,539,000,000	21,599,000,000
Load reduction costs, €	332,000	50,000	1,043,000	159,000	1,584,000

Period	Week 1	Week 2	Week 3	Week 4	Total
Load shifting costs, €	17,000	13,000	20,000	13,000	62,000
Slack costs, €	0	0	0	0	0
Total costs, €	37,612,000,000	16,490,000,000	53,297,000,000	30,797,000,000	138,199,000,000

By comparing the costs before (Table 3-77) and after (Table 3-79) the introduction of investments, it can be noticed that system costs reduced from 150.424 G€ to 138.199 G€, which is about 8 % reduction obtained thanks to about 11 M€ of investments. As expected, the cost reduction can be mostly attributed to the mitigation of load curtailment, which is about 31 % reduction. At the same time, the benefits of new investments can be perceived also in terms of renewable generation, for which a curtailment reduction of more than 6% is achieved.

Finally, Table 3-80 reports a summary of the entire planning procedure. Total costs and processing times are listed, while the optimality tolerance (MIP gap) is not applicable because of the applied heuristic process, which does not provide indications on the optimality closeness.

Table 3-80 Results of simulation, 2030, Italy

Total costs (Optimal Power Flow), €	150,424,000,000
Total costs (Grid Expansion Planning Tool), €	138,199,000,000
Execution time OPF/GEP	4,207 sec (1.17 h) / 277,362 sec (77.05 h)
MIP Gap, %	not applicable

Another important result reported by the simulations consists of the CO2 emissions/footprint and air quality impact of generation and investments. As shown in Table 3-81, the most significant portion of these costs is represented by the environmental impact of fossil-fuel-based generation, while the carbon footprint of accepted investments is not perceptible in practice. However, from the analysis of numbers related to generators impact, it can be noticed that investments bring positive effects in terms of environmental indicators, since they determine a reduction of about 2.4 % in CO2 emissions and about 31.6 % in air quality indication (years of life lost).

Table 3-81 Environmental impact assessment, 2030, Italy

CO2 impact of investments in new lines, €	Transmission Distribution	390,000 50,000	(0.00028% of total costs) (0.00003% of total costs)
CO2 impact of investments in new transformers, €	Transmission Distribution	90,000 0	(0.00007% of total costs) (0% of total costs)
CO2 impact of investments in new storage units, €	Transmission Distribution	0 0	(0% of total costs) (0% of total costs)
CO2 impact of generation, €	Before investments 61,040,810,000 (40.6% of total costs)		After investments 59,556,310,000 (43.1% of total costs)
Air quality impact of generation, €	Before investments 142,850,000 (0.1% of total costs)		After investments 97,750,000 (0.1% of total costs)

Decade 2040

The same procedure was followed for the processing of 2040 scenario. In this case, the candidates accepted during 2030 and with a lifetime longer than 10 years have been included within the network model. The results of the non-expanded Optimal Power Flow are reported in Figure 3-53 and, from a comparison with 2030 output, it can be noticed that the severity of congestions (Lagrange Multipliers) is significantly higher. This situation is justified by two main factors:

- First, the number of candidates considered for 2030 was not enough to clear all the congestions experienced in the same decade. This condition implies that they persist in 2040.
- As a second factor, load and renewable generation continuously increase and, consequently, this affects the loading of lines and transformers.

The consequence of the experienced congestion consists of curtailed generation and demand (Figure 3-54) which, as it happens for the Lagrange Multipliers of grid elements, they result higher with respect to 2030.

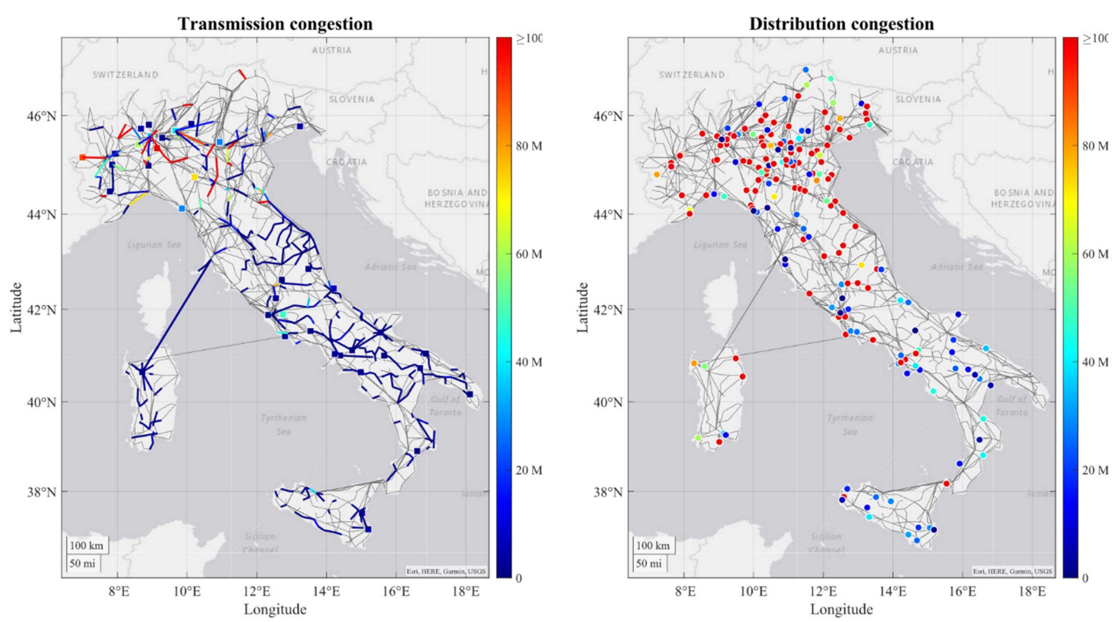


Figure 3-53 Overloaded lines (plotted as lines) and transformers (plotted as squares) for the Italian RC and related Lagrange Multipliers (Year 2040)

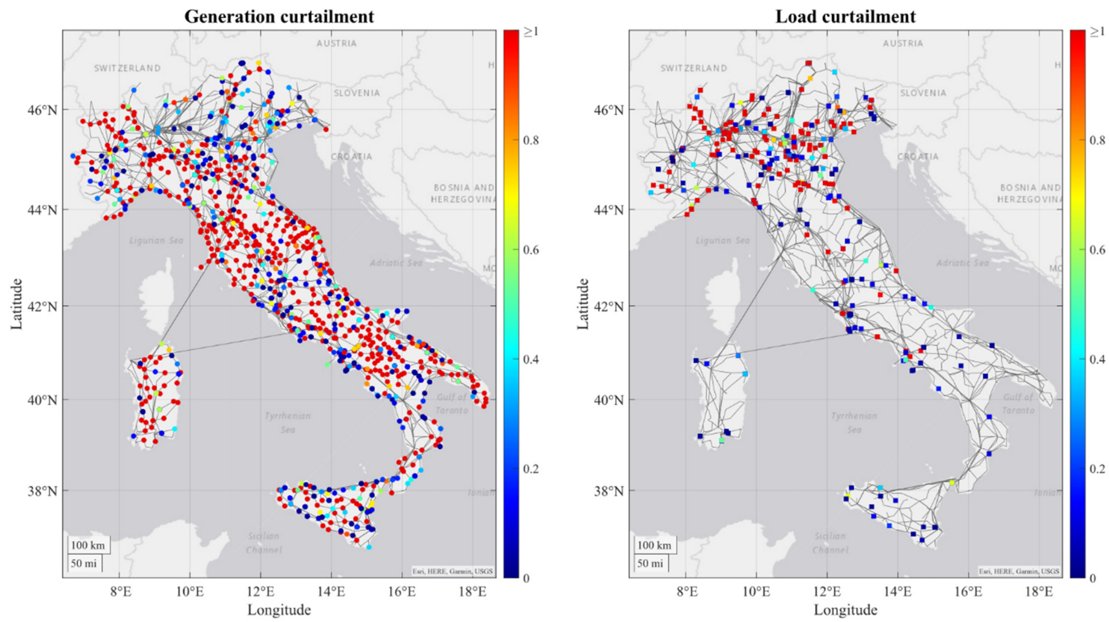


Figure 3-54 Curtailed generators (plotted as circles) and loads (plotted as squares) for the Italian RC and yearly curtailed energy (Year 2040)

Table 3-82 lists the numerical results of the simulation of 2040 scenario, which confirms the statements reported above. Load, generation increased and as a result, in absence of the required grid investments, increased generation and demand curtailments as well. The same can be stated for non-dispatchable generation (mostly renewable), as its curtailment is higher with respect to 2030. The pre-existing congested infrastructure conditioned insufficient reinforcements in 2030 have its impact as well. From the analysis of the results, Week 2 and Week 3 features the lowest costs in terms of generation and curtailment. Since they are representative of spring and summer seasons, the economic performance can be explained with the share between production from renewables and load, which prevents their curtailment and reduces the need of programmable generation.

Table 3-82 Costs results, OPF 2040, Italy

Period	Week 1	Week 2	Week 3	Week 4	Total
Generation costs, €	90,235,000,000	53,850,000,000	55,194,000,000	89,808,000,000	289,087,000,000
Generation curtailment costs, €	1,460,000,000	802,000,000	1,896,000,000	1,023,000,000	5,181,000,000
Load curtailment costs, €	64,317,000,000	4,490,000,000	8,287,000,000	77,302,000,000	154,396,000,000
Load reduction costs, €	0	0	0	0	0

Period	Week 1	Week 2	Week 3	Week 4	Total
Load shifting costs, €	0	0	0	0	0
Slack costs, €	0	0	0	0	0
Total costs, €	155,976,000,000	59,145,000,000	65,361,000,000	168,134,000,000	448,617,000,000

Since renewables and load are assumed to have the same concentration of the previous decade, the same considerations deduced for 2030 concerning the areas in which curtailment occurs can be concluded. Again, the severity of congestions is higher in the Northern regions of Italy and, for this reason, the candidates proposed by the FlexPlan tool are located there. Once candidates have been proposed, the selection of investments have been carried out by a Grid Expansion Planning process, and the related results are reported in Table 3-83. The selection has been carried out by considering the impacts of candidates on the system costs, which details are reported in Table 3-84.

Table 3-83 Description of candidates, 2040, Italy

Type	**AC Branch**	**Transformer**	**Storage**	**Flexibility load**	**Total**
Number of candidates	85	0	7	12	104
Investment decisions	12 (Transmission) 17 (Distribution)	0 (Transmission) 0 (Distribution)	4 (H2) 2 (FB)	9 (Distribution)	16 28
Investment rejected	4 (Transmission) 52 (Distribution)	0 (Transmission) 0 (Distribution)	0 1 (FB)	0 3	4 56
Investment costs (€)	15,103,000	0	1,841,000	9,000	16,953,000

Table 3-84 Costs results, GEP 2040, Italy

Period	Week 1	Week 2	Week 3	Week 4	Total
Generation costs, €	89,702,000,000	53,743,000,000	54,888,000,000	90,469,000,000	288,801,000,000
Generation curtailment costs, €	1,424,000,000	805,000,000	1,880,000,000	1,024,000,000	5,134,000,000
Load curtailment costs, €	49,045,000,000	4,065,000,000	5,719,000,000	59,098,000,000	117,928,000,000
Load reduction costs, €	2,620,000	804,000	1,957,000	3,616,000	8,997,000
Load shifting costs, €	235,000	151,000	181,000	212,000	789,000
Slack costs, €	0	0	0	0	0
Total costs, €	140,174,000,000	58,614,000,000	62,489,000,000	150,595,000,000	411,873,000,000

Similarly with respect to the 2030 case, by comparing the costs before (Table 3-82) and after (Table 3-84) the introduction of investments, it can be noticed that system costs reduced from 448.617 G€ to 411.873 G€, which is about 8 % reduction obtained thanks to about 17 M€ of investments. Again, the cost reduction can be mostly attributed to the mitigation of load curtailment, which is about 24 % reduction. Concerning the other costs, no significant improvements can be noticed, which proves the increasing severity of demand curtailment.

Finally, Table 3-85 reports a summary of the entire planning procedure. Total costs and processing times are listed, while the optimality tolerance (MIP gap) is not applicable because of the applied heuristic process, which does not provide indications on the optimality closeness.

Table 3-85 Results of simulation, 2040, Italy

Total costs (Optimal Power Flow), €	448,617,000,000
Total costs (Grid Expansion Planning Tool), €	411,873,000,000
Execution time OPF/GEP	4,847 sec (1.35 h) / 310,762 sec (86.3 h)
MIP Gap, %	not applicable

Also, for 2040, another important result reported by the simulations consists of the CO2 emissions/footprint and air quality impact of generation and investments. As shown in Table 3-86, the most significant portion of these costs is represented by the environmental impact of fossil-fuel-based generation, while the carbon footprint of accepted investments is not perceptible in practice. However, from the analysis of numbers related to generators impact the following points can be extrapolated:

- With respect to 2030, CO_2 penalties are increased and, consequently, they represent a larger portion of the total costs.
- Contrarily to 2030, in this case the investments do not bring visible benefits in terms of CO_2 emissions and impact on air quality, which remain practically unaltered after the planning process.

Table 3-86 Environmental impact assessment, 2040, Italy

CO2 impact of investments in new lines, €	Transmission Distribution	710,000 30,000	(0.000002% of total costs) (0.000000% of total costs)
CO2 impact of investments in new transformers, €	Transmission Distribution	0 0	(0% of total costs) (0% of total costs)
CO2 impact of investments in new storage units, €	Transmission Distribution	0 0	(0% of total costs) (0% of total costs)
CO2 impact of generation, €	Before investments 217,635,400,000 (48.5% of total costs)		After investments 217,103,300,000 (52.7% of total costs)
Air quality impact of generation, €	Before investments 247,350,000 (0.05% of total costs)		After investments 225,000,000 (0.05% of total costs)

Decade 2050

The last decade, considered by the FlexPlan project for what concern the Italian regional case and, as it happened for 2030 and 2040, it has been processed by running the planning sequence described above. The candidates accepted during the planning of 2030 and 2040 were added to the model when their lifetime was longer than the end of 2050. The results of the non-expanded Optimal Power Flow are reported in Figure 3-55 and, by comparing them with the results obtained for the previous decades, it can be noticed that severity of congestions (Lagrange Multipliers) is averagely higher than 2030 and 2040. Also, south of Italy begins to be affected by severe congestions at all voltage levels. This behaviour is justified by the following reasons (which are the same observed for 2040):

- The congestions experienced during the previous decades have not been completely solved. This is due to the limitations in terms of the number of candidates that FlexPlan was considering. However, the severity of some congestions decreased in areas in which candidates have been accepted.
- Load and renewable generation is increased with respect to 2040, causing new grid congestions (or increase the severity of the pre-existing ones).

The presence of congestions determines curtailment of both renewable generation and demand, as shown in Figure 3-56. From a comparison with respect to 2040, it can be noticed that generation curtailment is reduced in some areas of the north of Italy (more precisely the centre of the Po valley). In addition to investments carried out during the previous decade, this behaviour is also a consequence of the local energy sharing between load and generation (both located at distribution level). For what concern load curtailment, it increases with respect to 2040 and it started to be experienced significantly also in the south of Italy and islands.

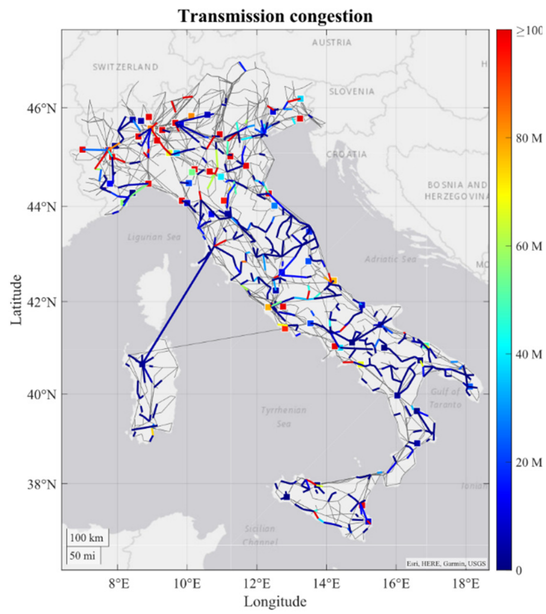


Figure 3-55 Overloaded lines (plotted as lines) and transformers (plotted as squares) for the Italian RC and related Lagrange Multipliers (Year 2050)

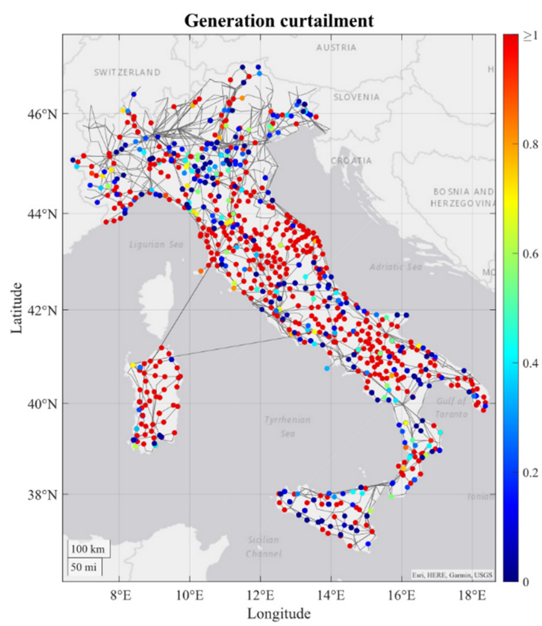


Figure 3-56 Curtailed generators (plotted as circles) and loads (plotted as squares) for the Italian RC and yearly curtailed energy (Year 2050)

Table 3-87 lists the numerical results of the simulation of 2050 scenario, which confirms the statements reported above. As well as for 2040, the load and generation growth led to an increase of generation and demand curtailments, 2050 curtailments values are higher than in 2030 and 2040. Looking at the weekly costs, and similarly to what happened in 2040, it can be noticed that:

- Generation costs is lower in week 2 (representative of spring season) and week 3 (representative of summer season). This is due to the high production of energy from photovoltaics.
- Also load curtailment costs have reduction during these two periods (especially during summer), thanks to the local share of load and photovoltaic production.
- Renewable generation is high in summer, so more severe curtailment occurs in that period than in other seasons.

Table 3-87 Costs results, OPF 2050, Italy

Period	Week 1	Week 2	Week 3	Week 4	Total
Generation costs, €	101,898,000,000	89,213,000,000	83,674,000,000	102,406,000,000	377,191,000,000
Generation curtailment costs, €	2,989,000,000	2,437,000,000	4,109,000,000	2,670,000,000	12,205,000,000
Load curtailment costs, €	172,425,000,000	128,075,000,000	108,696,000,000	152,349,000,000	561,545,000,000
Load reduction costs, €	0	0	0	0	0
Load shifting costs, €	0	0	0	0	0
Slack costs, €	0	0	0	0	0
Total costs, €	175,414,000,000	219,725,000,000	196,479,000,000	257,425,000,000	950,941,000,000

Since congestions are widespread over the Italian territory, and not concentrated in the northern part, candidates are expected to be distributed over the entire area. However, because of the pre-existing overloading conditions, the north area counts the majority of the possible investments. Their selection has been carried out by Grid Expansion Planning dedicated process, and the related results are reported in Table 3-88. The selection has been carried out by considering the impacts of candidates on the system costs, which details are reported in Table 3-89.

Table 3-88 Description of candidates, 2050, Italy

Type	**AC Branch**	**Transformer**	**Storage**	**Flexibility load**	**Total**
Number of candidates	92	9	5	1	107
Investment decisions	6(Transmission) 29 (Distribution)	4 (Transmission) 4(Distribution)	4 (H2) 1 (FB)	1 0	15 34
Investment rejected	4 (Transmission) 53 (Distribution)	1 (Transmission) 0 (Distribution)	0	0	5 53

Type	AC Branch	Transformer	Storage	Flexibility load	Total
Investment costs (€)	9,080,000	5,003,000	8,157,000	1,000	22,241,000

Table 3-89 Costs results, GEP 2050, Italy

Period	Week 1	Week 2	Week 3	Week 4	Total
Generation costs, €	102,251,000,000	89,365,000,000	83,473,000,000	102,870,000,000	377,959,000,000
Generation curtailment costs, €	2,928,000,000	2,384,000,000	4,042,000,000	2,592,000,000	11,946,000,000
Load curtailment costs, €	135,899,000,000	90,075,000,000	72,184,000,000	103,892,000,000	402,051,000,000
Load reduction costs, €	1,800,000	1,000,000	1,300,000	1,900,000	6,000,000
Load shifting costs, €	89,000	82,000	89,000	89,000	350,000
Slack costs, €	0	0	0	0	0
Total costs, €	241,080,000,000	181,825,000,000	159,700,000,000	209,356,000,000	791,962,000,000

Similarly with respect to the previous decades, by comparing the costs before (Table 3-87) and after (Table 3-89) the introduction of investments, it can be noticed that system costs reduced from 950,941,000,000 € to 791,962,000,000 €, which is about 17 % reduction obtained thanks to about 22,241,000 € of investments. Again, the cost reduction can be mostly attributed to the mitigation of load curtailment, which is about 28 % reduction. Concerning the other costs, no significant improvements can be noticed, which proves the increasing severity of demand curtailment.

Finally, Table 3-90 reports a summary of the entire planning procedure. Total costs and processing times are listed, while the optimality tolerance (MIP gap) is not applicable because of the applied heuristic process, which does not provide indications on the optimality closeness.

Table 3-90 Results of simulation, 2050, Italy

Total costs (Optimal Power Flow), €	950,941,000,000
Total costs (Grid Expansion Planning Tool), €	791,962,000,000
Execution time OPF/GEP	4,633 sec (1.3 h) / 211,999 sec (58.9 h)
MIP Gap, %	not applicable

Finally, also for 2050 the results in terms of CO_2 emissions/footprint and air quality impact of generation and investments are reported in Table 3-91, which drives to the same conclusions discussed for 2040.

Table 3-91 Environmental impact assessment, 2050, Italy

CO2 impact of investments in new lines, €	Transmission 360,000 Distribution 70,000	(0.000045% of total costs) (0.000009% of total costs)
CO2 impact of investments in new transformers, €	Transmission 320,000 Distribution 350,000	(0.000091% of total costs) (0.000044% of total costs)
CO2 impact of investments in new storage units, €	Transmission 0 Distribution 0	(0% of total costs) (0% of total costs)
CO2 impact of generation, €	Before investments 288,227,640,000 (30.310% of total costs)	After investments 288,029,130,000 (36.369% of total costs)
Air quality impact of generation, €	Before investments 362,180,000 (0.038% of total costs)	After investments 353,290,000 (0.045% of total costs)

Conclusions

As anticipated in previous sections, the project resources have not allowed the consideration of an appropriate number of candidates for the planning of the Italian power system. This condition resulted in two major drawbacks that can be listed as follows:

- The low number of candidates forces the process to consider a limited set of alternatives. In ideal conditions, for each congestion, different storage technologies and different portions of demand flexibilization should be put in competition together with the reinforcement of lines and transformers.
- The number of congestions exceeds the number of proposed candidates. This condition determines unsolved lines/transformer overloading and load/generation curtailment, which severity increases with the next decades.

This last statement is particularly visible in the results listed within the previous sections, and graphically reported in Figure 3-57.

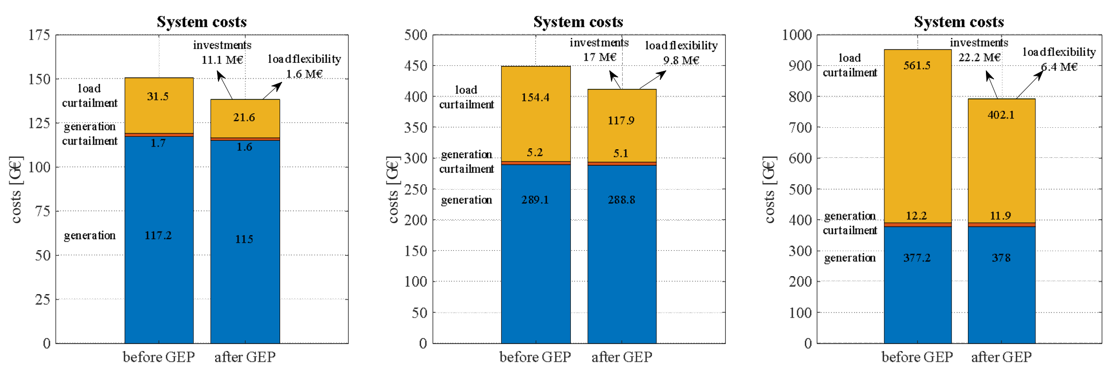


Figure 3-57 Results of the FlexPlan planning tool for the three considered decade (from left to right: 2030, 2040 and 2050)

Despite these issues, important points can be extracted from the results related to the Italian regional case:

- Flexibility (from storage and demand) is frequently selected as profitable investment, and often it is called to work in synergy with the network reinforcement corresponding to the same congestion.
- The relaxed optimality selected for the solver (0.01%) and the implemented heuristics do not guarantee that all the selected investments are supporting the reduction of system costs. This happens when the costs of investments are much lower than the total system costs (and below the optimality tolerance). As lesson-learned, a post-processing check is recommended to discriminate these conditions.

3.5 Balkan Region

3.5.1 Overview of the adaptations for Regional Case

The Balkan regional case consists of the networks of Serbia, Montenegro, Croatia, Bosnia and Herzegovina, Slovenia, North Macedonia, and Albania including transmission and distribution networks. The distribution networks were synthetically created based on the data obtained from the DiNeMo (Distribution Network Models) platform [13]. The models used are ENTSOE models of the transmission networks in x format which were converted to JSON format, and then the distribution networks were added to them.

The adaptations made on this model imply adaptations of both grid and scenario data:

- Reduction of the number of seasonal storages from 12 to 6 (one per each country except Slovenia) due to computational effort of OPF simulation. The other 6 were put among RoRs.
- 15% of distribution networks that were most risky in terms of congestion and voltage violations were added to the transmission grid model.

Table 3-92 gives the number of elements (nodes, AC branches, transformers, storages, and flexibility loads) in the model. Note that in the Balkan regional case, transformers are modelled as AC branches and none of the loads are flexible.

Table 3-92 Description of the Balkan network

Number of the nodes	2973
of which in transmission network	1961
of which in distribution network	1012
Number of AC branches	4089
of which in transmission network	3077
of which in distribution network	1012
Number of transformers	0
Number of storages	6
Number of flexibility loads	0

3.5.2 Results and analysis

Decade 2030

OPF results for 2030 show that 63 out of 4089 branches (1.5%) have LM values different from zero. Figure 3-58 shows the geographical distribution of observed congestions where the figure on the left shows the congestions that were observed in the transmission network while the right one shows congestions in distribution networks. Some distribution networks have more than one congestion, but the figure shows only the most critical one. Congestions are colored based on their annual average LM value.

As can be seen, the congestions in the distribution networks are spread throughout the region and are more severe. In contrast, the congestions in the transmission network are concentrated mainly in the western part of the region as well as the northwestern part.

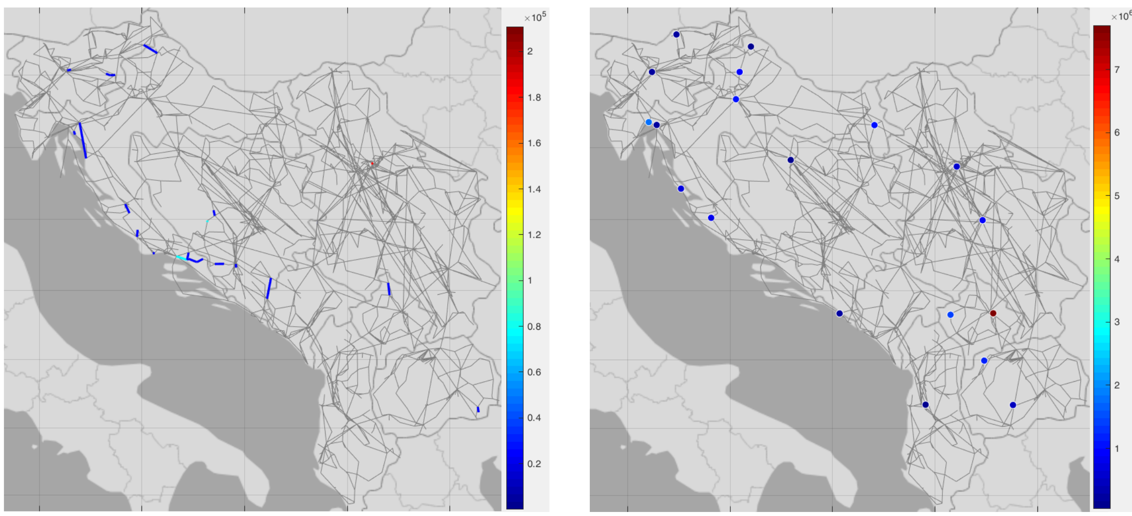


Figure 3-58: Overloaded AC branches (transmission – left, distribution – right) for the Balkan RC and related Lagrange Multipliers (Year 2030).

From the OPF results, it can be concluded that demand curtailment occurs only in distribution networks. Given that the costs of demand curtailment are 10,000 €/MWh, this leads to the fact that the congestions in these networks are much higher compared to those in the transmission network and therefore they are a higher priority for solving, which will be seen later.

On the other hand, all generation curtailment occurs in solar, wind, and RoR power plants connected directly to the transmission network (mostly 110 kV network).

Figure 3-59 presents a geographical representation of annual demand and generation curtailment in the region. It can be observed that the congestions in distribution networks geographically coincide with the locations of demand curtailment. Unlike demand curtailment, generation curtailment is more widespread and much larger. As can be seen from the color bar in the figure, the annual value of generation curtailment in one of the nodes goes up to 100 GWh per year, while demand curtailment goes up to a maximum of 1.4 GWh. Two areas with the largest generation curtailment, one in the western part and the other in the northwestern part of the region, are bordered by red rectangles in Figure 3-59. These areas coincide geographically with the highest congestions in the transmission network. Generation curtailment in the western area accounts for about 60%, while generation curtailment in the northwestern area accounts for about 20% of the total generation curtailment of the region.

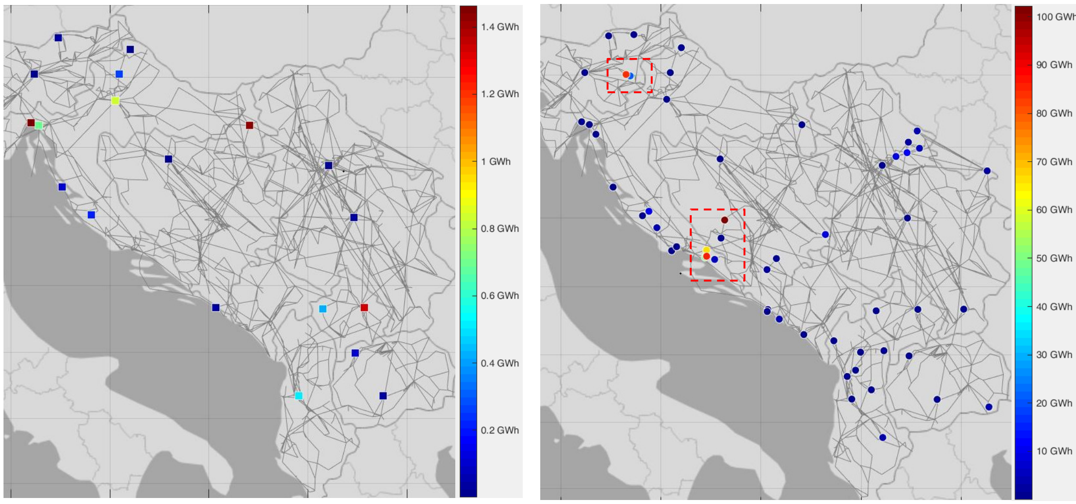


Figure 3-59: Curtailed loads (plotted as squares) and generators (plotted as circles) for the Balkan RC and yearly curtailed energy (Year 2030).

The graphs in Figure 3-60 show the evolution of demand and generation curtailment for all 4 representative weeks. It can be noted that demand curtailment is most prevalent in the 1st and 4th week in the evening during the working week. As previously stated, demand curtailment occurs only in distribution, which is a consequence of the insufficient capacity necessary to supply demand in these networks. The generation curtailment is present in all 4 weeks but the most dominant at the beginning of the 4th week.

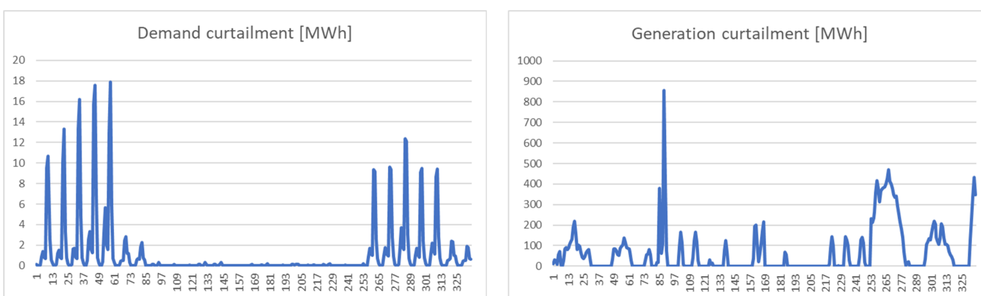


Figure 3-60: Change in demand curtailment (left) and generation curtailment (right) for 4 representative weeks (Year 2030).

Figure 3-61 represents the cumulative annual load (left) and generation curtailment (right) by representative weeks.

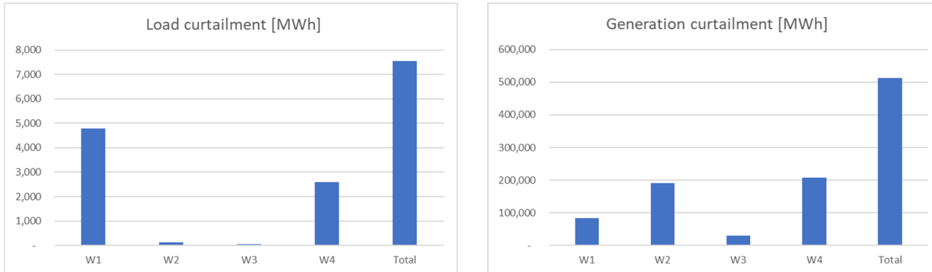


Figure 3-61: Load (left) and generation (right) curtailment for 4 representative weeks on an annual level (Year 2030).

As for the pre-processor results, it was agreed that the number of candidates proposed by it should be limited to 100. The number of congestions that were handled was lower than 100, because some congestions had a larger number of proposed candidates, as can be seen in Table 3-94. Table 3-93 shows the share of each type of candidate proposed by the Pre-processor as well as the investment decisions by the GEP and investment costs. Keep in mind that transformers are also proposed, but they are modelled in the Balkan case in the same way as lines, i.e. as AC branches.

Table 3-93 Description of the candidates (Year 2030).

Type	**AC Branch**	**Transformer**	**Storage**	**Flexibility load**	**Total**
Number of candidates	37	0	38	25	100
Investment decisions	7 (Transmission) 10 (Distribution)	0 (Transmission) 0 (Distribution)	1 (H2) 1 (Flow Battery) 0 (Li Battery) 4 (LAES)	15	38
Investment rejected	5 (Transmission) 15 (Distribution)	0 (Transmission) 0 (Distribution)	3 (H2) 20 (Flow Battery) 9 (Li Battery) 0 (LAES)	10	62
Investment costs, €	17,086,360	0	817,624	15,000	17,918,985

Out of a total of 37 AC branches proposed as candidates, 17 were approved as investments by the GEP, of which 7 are in the transmission network and 10 are in the distribution network.

As for the storages, a total of 38 storages of different types (hydrogen storage, flow battery, lithium battery, and LAES) were proposed. Almost all candidates were connected to distribution, only 5 to the transmission network. In the end, GEP approved a total of 6 storages, of which one hydrogen storage is connected to the transmission and 1 flow battery, and 4 LAES storages are connected to a distribution network.

Out of a total of 25 flexible loads proposed by the Pre-processor, 2 were connected to the transmission network and 23 to the distribution network. A total of 15 were accepted as investments by the GEP (including both flexible loads on the transmission network). Note that all loads in the Balkan case are initially non-flexible but the pre-processor makes load candidates flexible in a percentage.

As mentioned, congestions in distribution networks are more severe and therefore most of the candidates are proposed for these networks. Candidates in the transmission network are focused on the three most severe congestions in this network, which are located in the area near the border of Croatia and Bosnia and Herzegovina, in the interior of Bosnia and Herzegovina, as well as in Serbia in the area of Belgrade (zoomed part in Figure 3-62). Some of AC branch candidates represent direct reinforcement of congested branches, others represent the reinforcement of branches highly influenced by the increase of capacity in the mentioned three branches. Those lines are initially not congested at all or are congested, but significantly less compared to those three.

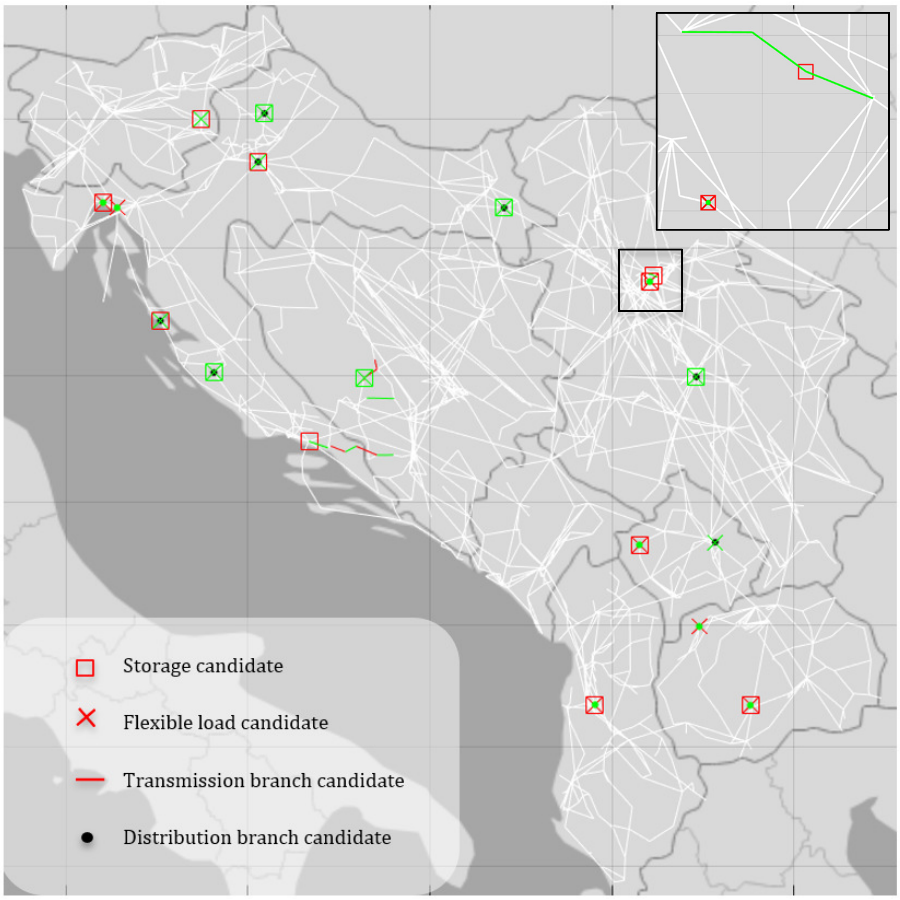


Figure 3-62: Geographical representation of different types of candidates (Year 2030).

The following table shows all congestions in the network in 2030, the maximum durations of congestions as well as the proposed candidates for each of them. Congestions are ranked by severity starting with the most severe, and those in bold represent those in the transmission network.

Table 3-94 Congested branches and proposed candidates (Year 2030).

No.	Branch	Type	Congestion duration	Storage candidate				Branch candidate	Flexible load candidate
				H2	Flow	Li-ion	LAES		
1	JPRJPRIS3D2_PS1_307_308	Line	9					×	✓
2	HKR_HKRASI5_PS2_2_54	Line	9					✓	×
3	JPEJPEJA210_PS1_2_19	Line	8					✓	×
4	HPE_HPEHLI5_PS1_392_394	Line	8		×			✓	×
5	HPE_HPEHLI5_PS1_521_522	Line	8		×			×	
6	HPE_HPEHLI5_PS2_2_415	Line	8					×	
7	ATI_ATIRA15_PS2_2_21	Line	7		×			✓	×
8	HPE_HPEHLI5_PS1_2_662	Line	7		×			✓	×
9	HPE_HPEHLI5_PS2_118_121	Line	7		×			✓	×
10	JPEJPEJA210_PS1_2_292	Line	4		×			✓	×
11	**ACJBG/JBGD1752-JBG/JBGD2351_1**	Line	29	×				✓	
12	TETTETOVO 2_PS2_2_27	Line	5					✓	×
13	HVI_HVINKO5_PS1_trafo	Transformer	3		×			×	✓
14	HVI_HVINKO5_PS3_trafo	Transformer	3		×			×	✓
15	HVI_HVINKO5_PS2_trafo	Transformer	3		×	×	✓	×	✓
16	HVI_HVINKO5_PS4_trafo	Transformer	3		×	×	✓	×	✓
17	HMR_HMRACL5_PS1_trafo	Transformer	3		×	×		×	✓
18	HMR_HMRACL5_PS2_trafo	Transformer	3		×	×		×	✓
19	HMR_HMRACL5_PS3_trafo	Transformer	3		×	×		×	✓
20	HMR_HMRACL5_PS4_trafo	Transformer	3		×	×		×	✓
21	JKRAJKRAG8D_PS1_207_208	Line	3		✓			×	✓
22	HTE_HTEJER5_PS1_trafo	Transformer	3		×	×	✓	×	✓
23	HBE_HBENKO5_PS1_trafo	Transformer	3		×	×	✓	×	✓
24	HPA_HPAG 5_PS1_trafo	Transformer	2		×	×		×	✓
25	**ACHHE_/HHEKRA5-HZA_/HZAKUC5_1**	Line	32	×				✓	
26	JBGJBGD16D1_PS2_2_57	Line	2		×			✓	×
27	**ACWKUP/WKUPRE5-WWDB/WWDBRD5_1**	Line	26	✓				×	
28	PRIPRILEP 2_PS1_2_143	Line	4		×			✓	×
29	**ACHE BLANCA999-TEB999999999_1**	Line	5	×	×				✓
30	ZEL_RAVNE111_PS1_trafo	Transformer	1						
31	ZEL_RAVNE111_PS4_trafo	Transformer	1						
32	**ACWBUG/WBUGOJ5-WDVA/WDVAKU5_1**	Line	5					×	
33	**ACJLEP/JLEPOS5-JVAL/JVALAC5_1**	Line	10						
34	ZEL_RAVNE111_PS2_trafo	Transformer	1						
35	ZEL_RAVNE111_PS3_trafo	Transformer	1						
36	VIC_PS1_trafo	Transformer	1						
37	VIC_PS2_trafo	Transformer	1						
38	HKO_HKOMOL5_PS1_trafo	Transformer	2						
39	HKO_HKOMOL5_PS2_trafo	Transformer	2						
40	HKO_HKOMOL5_PS3_trafo	Transformer	2						
41	HKO_HKOMOL5_PS4_trafo	Transformer	2						
42	HKR_HKRASI5_PS1_trafo	Transformer	2						
43	**ACHOB_/HOBROV5-HVE_/HVEBRU5_1**	Line	23						
44	ATI_ATIRA15_PS1_135_136	Line	1						
45	**ACHHE_/HHEKRA5-HVE_/HVEKAT5_1**	Line	3						
46	**ACJBB/JBBAST21-JRH/JRHBBA21_1**	Line	7						
47	**ACHIM_/HIMOTS5-HZA_/HZAGVO5_1**	Line	3					✓	
48	**ACHE BLANCA999-SEVNICA99999_1**	Line	5						
49	**ACHHE_/HHEKRA5-HVE/HVELUKOV_1**	Line	27						
50	**ACHBI_/HBILIC5-HVE_/HVEGLA5_1**	Line	13						
51	**ACHVE_/HVEKAT5-HZA_/HZAGVO5_1**	Line	4					×	
52	**ACWBIL/WBILEC5-WGAC/WGACKO5_1**	Line	5						
53	WBLUWBLUK45_PS1_2_158	Line	1						
54	HCA_HCAKOV5_PS1_trafo	Transformer	1						
55	HCA_HCAKOV5_PS2_trafo	Transformer	1						
56	**ACHJE_/HJELIN5-HTR_/HTROGI5_1**	Line	3						
57	**ACHCR_/HCRIKV5-HHE_/HHEVIN5_1**	Line	5						
58	**ACVALANDOVO999-VEC BOGDANCI_1**	Line	1						
59	**ACHMELIN2(1)99-HSE_/HSENJ 2_1**	Line	4						
60	**ACWGRU/WGRUDE5-WSBR/WSBRIJ5_1**	Line	1					✓	
61	**ACHNE_/HNEDEL5-HE FORMIN999_1**	Line	1						
62	**ACPOLJE9999999-TETOL9999999_1**	Line	1						
63	**ACWMOS/WMOST15-WMOS/WMOST25_1**	Line	1						

It can be seen from the table that the maximum durations of congestion in the transmission network are longer compared to those in the distribution network. For this reason, candidates such as hydrogen storage are suitable for these congestions because they have a large energy capacity. For the two most severe cases of transmission congestions, line reinforcement was accepted by the GEP tool. There are also two cases where hydrogen storage is selected in one and flexible demand in the other.

As far as distribution networks are concerned, various cases can be observed in Table 3-94. In some cases, it was sufficient to engage flexible demand only, in some a combination of flexible demand and battery/storage, and in the rest only line/transformer reinforcement was profitable.

Table 3-95 presents the total costs before the expansion (OPF results) and after the expansion of the network (GEP results). Table 3-96 presents the total costs incurred before any network expansion as calculated using the OPF tool divided into four representative weeks (or rather seasons) and scaled to a ten-year period. Generation curtailment costs for all generating units are equal to zero and therefore the total generation curtailment costs are also zero. Load reduction and shifting costs are not incurred because initially in the model for 2030 no load in the network was set to be flexible. Table 3-97 shows the costs in the same form as the previous table, but this time after applying the network expansion with the candidates selected by the GEP tool. In this case, there are also the costs of load reduction and shifting because some loads have become flexible as a result of the GEP simulation.

Table 3-95 Results of the simulation (Year 2030).

Total costs (Optimal Power Flow), €	16,020,571,231
Total costs (Grid Expansion Planning Tool), €	15,222,306,165
Execution time	370406 seconds 4.3 days
MIP Gap, %	0.01%

Table 3-96 Cost results - OPF (Year 2030).

Period	Week 1	Week 2	Week 3	Week 4	Total
Generation costs, €	5,658,181,944	3,403,068,388	2,254,446,136	4,066,348,917	15,382,045,385
Generation curtailment costs, €	-	-	-	-	-
Load curtailment costs, €	405,221,270	10,159,133	3,859,728	219,285,715	638,525,846
Load reduction costs, €	-	-	-	-	-
Load shifting costs, €	-	-	-	-	-
Slack costs, €	-	-	-	-	-
Total costs, €	6,063,403,214	3,413,227,521	2,258,305,864	4,285,634,632	16,020,571,231

Table 3-97 Cost results - GEP (Year 2030).

Period	Week 1	Week 2	Week 3	Week 4	Total
Generation costs, €	5,531,358,147	3,225,083,042	2,248,647,912	3,939,850,925	14,944,940,025
Generation curtailment costs, €	-	-	-	-	-
Load curtailment costs, €	151,808,794	9,240,824	2,988,381	93,216,523	257,254,521
Load reduction costs, €	1,695,319	11,803	4,454	134,007	1,845,583

Period	Week 1	Week 2	Week 3	Week 4	Total
Load shifting costs, €	224,390	8,995	3,666	109,999	347,050
Slack costs, €	-	-	-	-	-
Total costs, €	5,685,086,650	3,234,344,663	2,251,644,412	4,033,311,454	15,204,387,180

The following figures show graphical comparison of OPF and GEP results in terms of costs and energy (generation curtailment). It can be concluded that generation costs are 3% lower after network expansion, while load curtailment costs are reduced by almost 60% thanks to reinforcements in distribution networks. Reduced generation curtailment cannot be observed through costs because its price is zero, but it can therefore be observed through curtailed energy. It can be concluded from this that the generation curtailment was reduced by about 40% thanks to reinforcement in the transmission network, which led to a reduction in the price of electricity generation (generation costs). All of this led to a reduction of total costs by 5%.

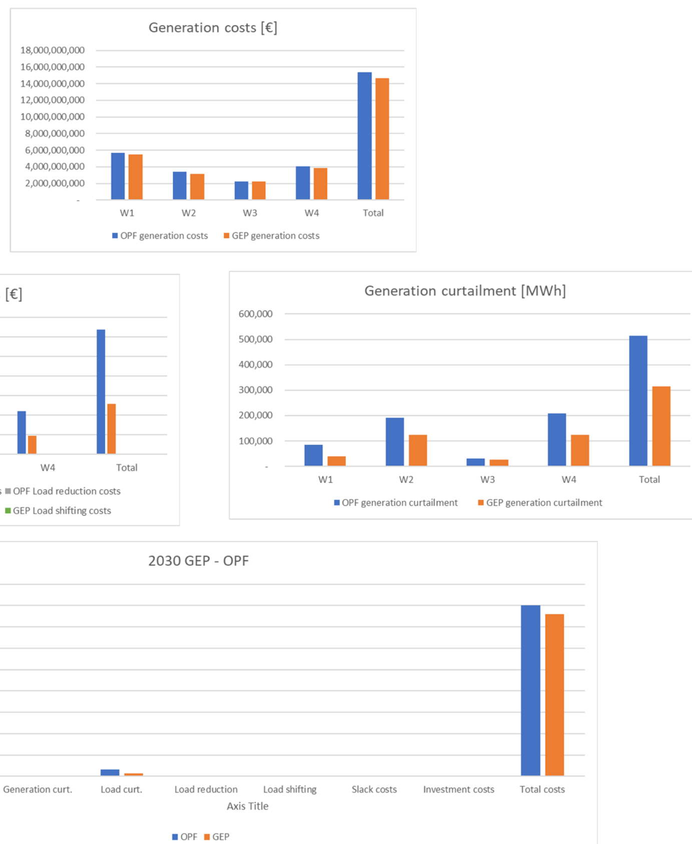
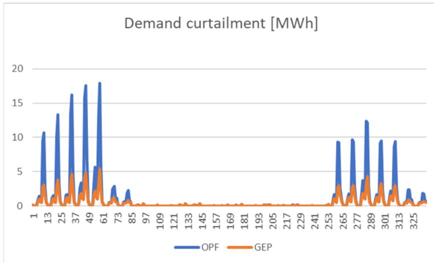


Figure 3-63: Comparison of OPF and GEP results (Year 2030)

The following figure shows hourly demand and generation curtailment for 4 weeks before (OPF) and after network expansion (GEP).



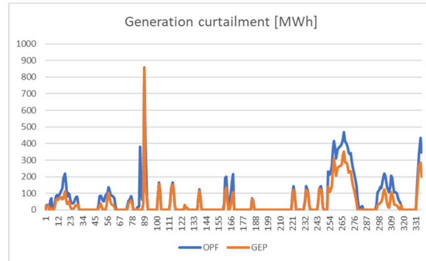


Figure 3-64: Change in demand curtailment (left) and generation curtailment (right) for 4 representative weeks after network expansion (Year 2030).

Considering the candidates of the transmission network were suppressed by the candidates from distribution networks, one additional simulation for 2030 was performed, for which 19 additional transmission candidates, proposed by the Pre-processor were included. Figure 3-65 shows the geographical representation of candidates that were analyzed and approved by the GEP. These candidates are the same as those in Figure 3-62 with the addition of 19 transmission candidates that were mentioned above.

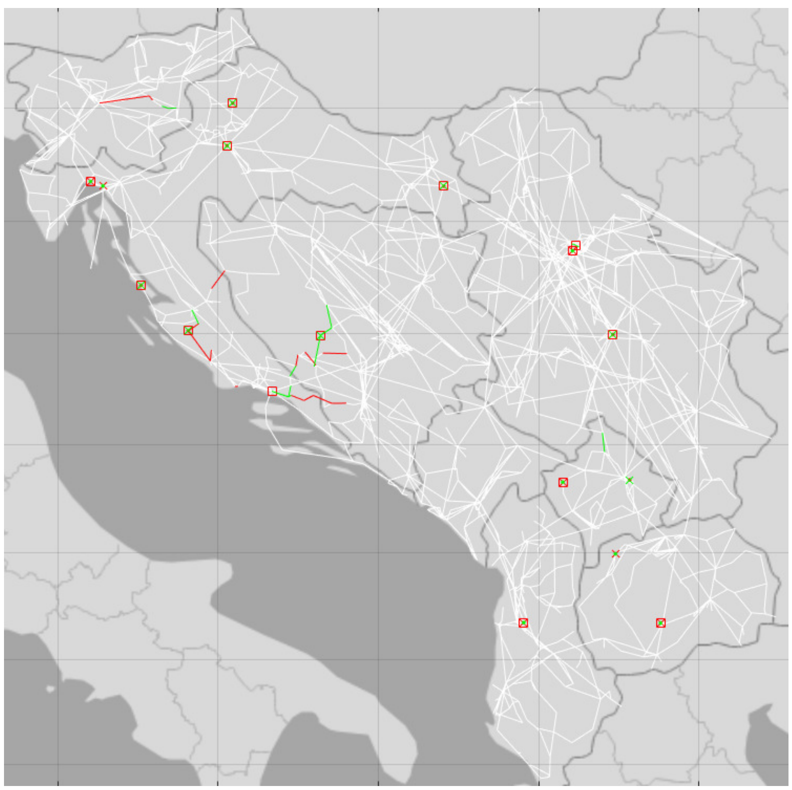
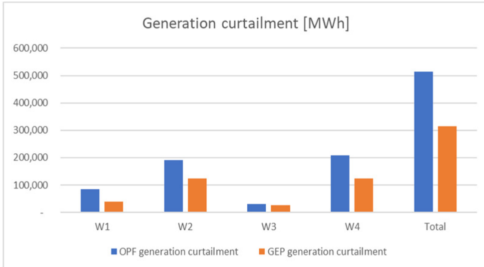


Figure 3-65: Geographical representation of different types of candidates (Year 2030 – additional candidates).

Without going into detailed analysis, it was determined that the selected candidates in the transmission network had the greatest impact on the reduction of generation curtailment, which can be seen in the following figure. In this case, the reduction of generation curtailment went to about 81%.



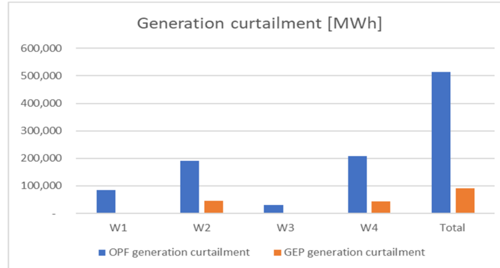


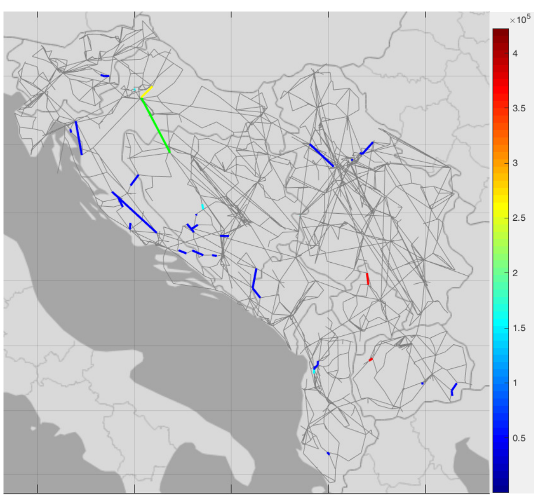
Figure 3-66: Generation curtailment in case of 100 candidates (left) and 100+19 transmission candidates (Year 2030).

The reason why the further analyses for 2040 and 2050 are based on the case of 100 candidates and not on this one, is that the precision of results in the case with 100 candidates is higher, that is, the agreed value for the MIP gap was respected.

Decade 2040

As expected, OPF results for 2040 show more congestions than in 2030. More precisely, 109 out of 4089 branches (2.66%) have LM values different from zero. Figure 3-67 shows the geographical distribution of observed congestions where the figure on the right shows the congestions that were observed in the transmission network while the left one shows congestions in distribution networks.

As in 2030, congestions in distribution networks are more severe (LMs are an order of magnitude higher) which, as mentioned, is a consequence of the high costs of load curtailment that occurs in these networks. Due to the limitation of the number of candidates to 100, congestions in the transmission network were treated less in 2030 compared to congestions in distribution, and for this reason, some of them will be repeated in 2040. Those that were treated in 2030 have either been completely removed or are now ranked very low in terms of severity.



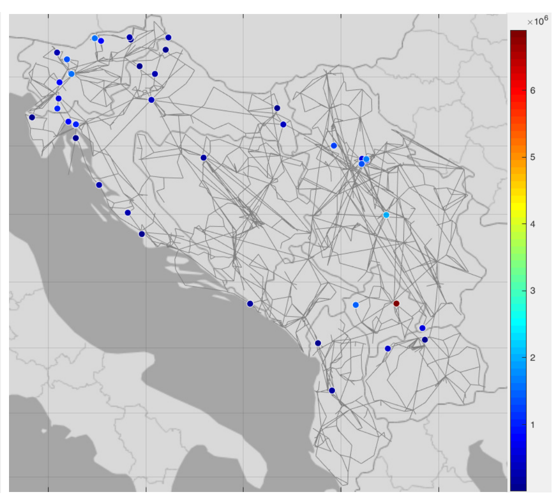


Figure 3-67: Overloaded AC branches (transmission – left, distribution – right) for the Balkan RC and related Lagrange Multipliers (Year 2040).

Year 2040 differs the most in that renewable energy sources are also distributed across distribution networks, while in 2030 they were all large-scale power plants connected to the transmission. Figure 3-68 shows the geographical distribution of annual load curtailment (left) and annual generation curtailment (right) in the region. As can be seen from the color bar in the figure, the annual value of generation curtailment in one of the nodes goes up to 500 GWh per year, while demand curtailment goes up to a maximum of 2.5 GWh. In 2040, as well, generation curtailment prevails over load curtailment.

In relation to 2030, demand curtailment in 2040, in addition to distribution, also occurs in the transmission network. Since the generation is also located on the distribution level, generation curtailment occurs in it as well, but it is still the most prevalent in the transmission level with a share of 93% of the total generation curtailment. The reason why there is so much generation curtailment in 2040 is not only due to insufficient network capacity but also due to excess production by renewable energy sources.

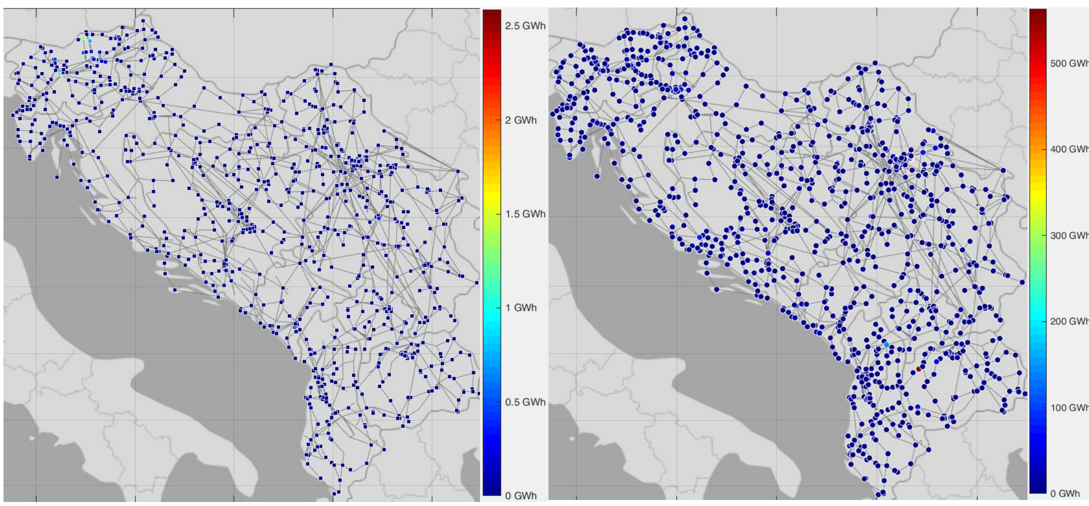


Figure 3-68: Curtailed loads (plotted as squares) and generators (plotted as circles) for the Balkan RC and yearly curtailed energy (Year 2040).

The graphs in Figure 3-69 show the change in demand and generation curtailment for all 4 representative weeks. It can be noted that demand curtailment is most prevalent in the 1st and 4th week in the evening during the working week with the exception of one peak that occurs in the middle of the third week. Generation curtailment is present mostly in the first three weeks, in the hours when consumption is lower and production from renewable sources is higher.

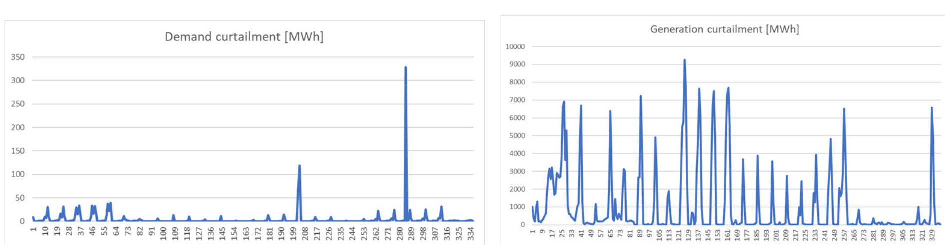


Figure 3-69: Change in demand curtailment (left) and generation curtailment (right) for 4 representative weeks (Year 2040).

Figure *3-73*

Figure 3-70 represents the annual load (left) and generation curtailment (right) by representative weeks.

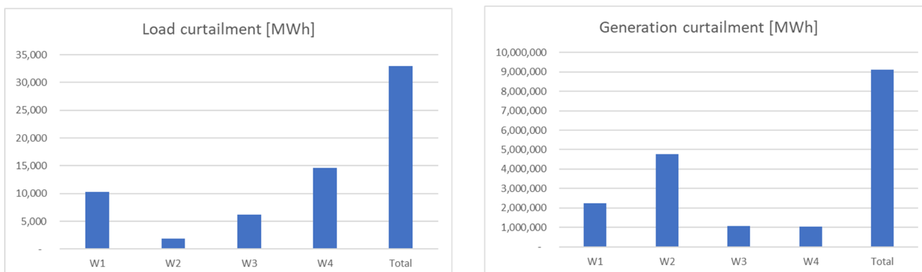


Figure 3-70: Load (left) and generation (right) curtailment for 4 representative weeks on an annual level (Year 2040).

As explained earlier, the number of candidates is limited to 100, so even in this case the number of congestions treated was less than 100 because almost all congestions had several different types of candidates proposed. Table 3-98 shows the share of each type of candidate proposed by the Pre-processor as well as the investment decisions by the GEP and investment costs. Keep in mind that transformers are also proposed, but they are modeled in the Balkan case in the same way as lines, i.e. as AC branches.

Table 3-98 Description of the candidates (Year 2040).

Type	AC Branch	Transformer	Storage	Flexibility load	Total
Number of candidates	40	0	38	22	100
Investment decisions	6 (Transmission) 11 (Distribution)	0 (Transmission) 0 (Distribution)	4 (H2) 9 (Flow Battery) 1 (Li Battery) 4 (LAES)	16	51
Investment rejected	7 (Transmission) 16 (Distribution)	0 (Transmission) 0 (Distribution)	0 (H2) 15 (Flow Battery) 4 (Li Battery) 1 (LAES)	6	49
Investment costs, €	13,907,101	0	5,892,247	10,809	19,810,157

Out of a total of 40 AC branches proposed as candidates, 17 were approved as investments by GEP, of which 6 are in the transmission network and 11 are in the distribution network.

As for the storages, a total of 38 storages of different types (hydrogen storage, flow battery, lithium battery, and LAES) were proposed. Almost all candidates were connected to distribution, but only 5 to the transmission network. In the end, GEP approved a total of 18 storages, of which 5 connected to the transmission network (4 hydrogen storages and one LAES).

Out of a total of 22 flexible loads proposed by the Pre-processor, one was connected to the transmission network and 21 to the distribution networks. A total of 16 were accepted as investments by the GEP, including the one connected to the transmission network. Note that all loads in the Balkan case were initially non-flexible (except those that were accepted by the GEP in 2030) but the Pre-processor made load candidates flexible in a percentage.

Figure 3-71 represents a geographical representation of all proposed candidates for 2040. As mentioned, congestions in distribution networks are more severe and therefore most of the candidates proposed by the Pre-processor are related to these networks. Candidates for distribution networks are mostly proposed in the area of Slovenia, southern Serbia, and around Belgrade (zoomed part in the figure), which coincides with the locations of distribution network congestions seen in Figure 3-67. As for candidates in the transmission network, they are focused on the most severe congestions in this network (one in Albania, one in Macedonia, two in Serbia, and one between Bosnia and Herzegovina and Croatia).

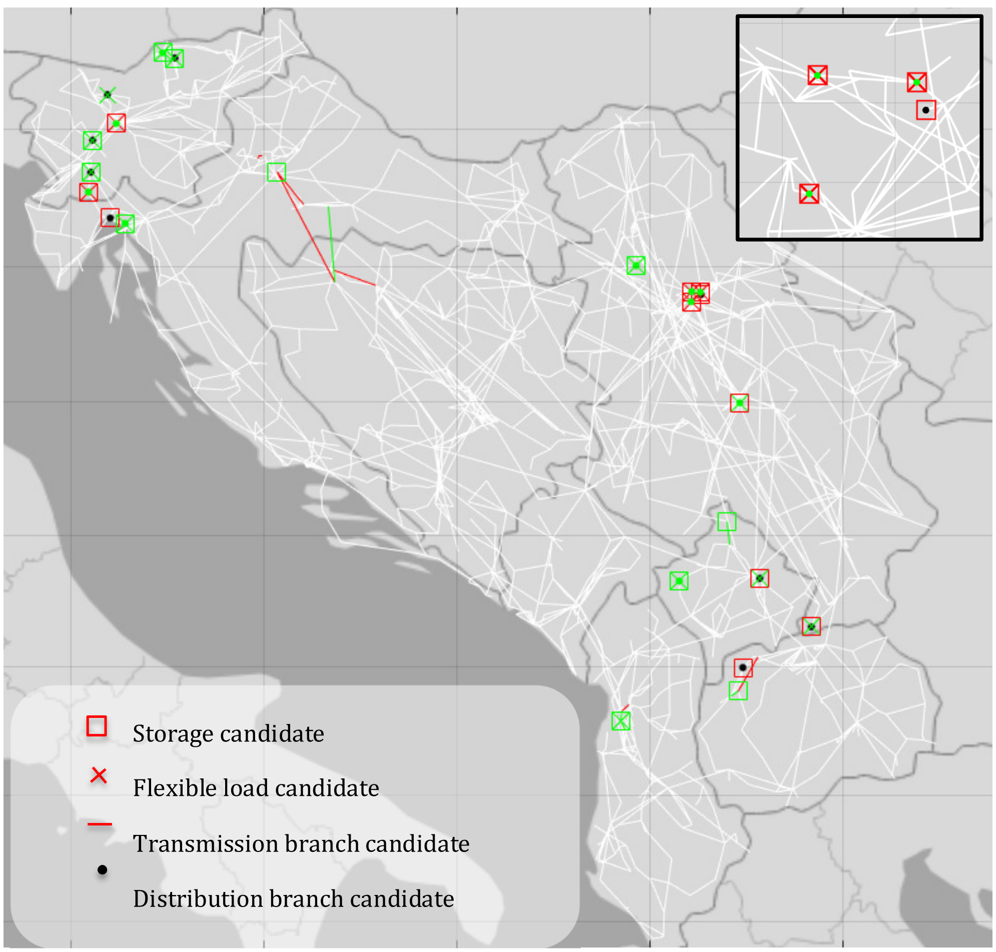


Figure 3-71: Geographical representation of different types of candidates (Year 2040).

The following table (Table 3-99) lists only congestions in 2040 that are treated by the candidates (other congestions are omitted due to table size), the maximum durations of congestions as well as the proposed candidates for each of them. Congestions are ranked by severity starting with the most severe, and those in bold represent those in the transmission network.

Table 3-99 Congested branches and proposed candidates (Year 2040).

No.	Branch	Type	Congestion duration	Storage candidate				Branch candidate	Flexible load
				H2	Flow	Li-ion	LAES		
1	JPRJPRIS3D2_PS1_307_308	Line	81					×	
2	JKRAJKRAG8D_PS1_207_208	Line	9		✓			✓	✓
3	**ACGOS/GOSTIVAR-VRUTO/VRUTOK_1**	Line	48	✓				✓	
4	JBGJBGD1 D2_PS1_2_181	Line	7		×			✓	×
5	VIC_PS1_trafo	Transformer	4		×			✓	×
6	VIC_PS2_trafo	Transformer	4		×			✓	×
7	ZEL_RAVNE111_PS1_trafo	Transformer	4		✓			×	✓
8	ZEL_RAVNE111_PS2_trafo	Transformer	4		✓			×	✓
9	ZEL_RAVNE111_PS3_trafo	Transformer	4		✓			✓	✓
10	ZEL_RAVNE111_PS4_trafo	Transformer	4		✓			×	✓
11	JPEJPEJA210_PS1_292_293	Line	8		✓			✓	✓
12	JBGJBGD16D1_PS2_2_85	Line	6		×			✓	×
13	PRIMSKOVO_PS1_trafo	Transformer	4					×	✓
14	PRIMSKOVO_PS2_trafo	Transformer	4					×	✓
15	JRUJRUMA1D2_PS1_2_161	Line	6		✓			✓	✓
16	**ACJLEP/JLEPOS5-JVAL/JVALAC5_1**	Line	18	✓				✓	
17	IL_BISTRICA_PS1_trafo	Transformer	3		×	×	×	✓	×
18	HKR_HKRASI5_PS2_54_56	Line	8		✓			✓	✓
19	**ACJBB/JBBAST21-JRH/JRHBBA21_1**	Line	19					✓	
20	JPRJPRIS3D2_PS1_2_410	Line	7		×			×	✓
21	LOGATEC_PS1_trafo	Transformer	3		×	×	✓	×	✓
22	SL-GRADEC_PS1_trafo	Transformer	3		✓	✓	✓	×	✓
23	HPE_HPEHLI5_PS1_521_522	Line	5		×			×	
24	HPE_HPEHLI5_PS2_2_415	Line	4		×			×	
25	JBGDJBGD47D_PS2_2_60	Line	4		×			✓	×
26	HPE_HPEHLI5_PS1_394_397	Line	4		×			×	
27	PIVKA_PS1_trafo	Transformer	2		×	×	✓	×	✓
28	JPREJPRESED_PS1_23_26	Line	4		×			×	✓
29	JBGDJBGD19D_PS2_59_60	Line	4		×			×	
30	TETTETOVO 2_PS2_27_28	Line	5		×	×		×	
31	**ACWPRI/WPRIJ22-HMRACL2(1)99_1**	Line	5	✓			✓	×	
32	HMR_HMRACL5_PS3_trafo	Transformer	3						
33	**ACALA_/ALAC2 5-AMA_/AMAMUR5_1**	Line	10	✓				✓	✓

The results of the OPF and GEP calculations can be seen in the following tables. Table 3-100 presents the total costs before the expansion (OPF results) and after the expansion of the network (GEP results) for 2040. Table 3-101 presents the total costs incurred in 2040 before any network expansion as calculated using the OPF tool, divided into four representative weeks (or rather seasons) and scaled to a ten-year period. Generation curtailment costs for all generating units are equal to zero and therefore the total generation curtailment costs are also zero. Compared to 2030, there is load reduction and shifting costs in the OPF results for 2040 due to the fact that certain loads were enabled to be flexible as a result of the GEP simulation for 2030.

The table shows the costs in the same form as the previous table, but this time after applying the network expansion with the candidates for 2040 chosen by the GEP tool.

Table 3-100 Results of the simulation (Year 2040).

Total costs (Optimal Power Flow), €	26,907,697,389

Total costs (Grid Expansion Planning Tool), €	25,038,879,429
Execution time	518 400 seconds 6 days
MIP Gap, %	0.09%

Table 3-101 Cost results - OPF (Year 2040).

Period	Week 1	Week 2	Week 3	Week 4	Total
Generation costs, €	1,241,694,640	1,294,482,127	9,249,578,734	13,245,094,083	25,030,849,584
Generation curtailment costs, €	-	-	-	-	-
Load curtailment costs, €	589,214,516	104,022,568	353,405,140	829,986,547	1,876,628,771
Load reduction costs, €	79,987	153	27,341	22,669	130,150
Load shifting costs, €	25,565	15,666	25,794	21,859	88,884
Slack costs, €	-	-	-	-	-
Total costs, €	1,831,014,709	1,398,520,513	9,603,037,009	14,075,125,158	26,907,697,389

Table 3-102 Cost results - GEP (Year 2040).

Period	Week 1	Week 2	Week 3	Week 4	Total
Generation costs, €	979,893,894	1,121,620,042	9,112,276,812	13,030,991,173	24,244,781,921
Generation curtailment costs, €	-	-	-	-	-
Load curtailment costs, €	284,743,790	19,544,560	81,406,185	384,791,223	770,485,757
Load reduction costs, €	1,195,007	12,544	308,093	1,797,349	3,312,993
Load shifting costs, €	190,316	50,431	70,310	177,543	488,601
Slack costs, €	-	-	-	-	-
Total costs, €	1,266,023,007	1,141,227,578	9,194,061,400	13,417,757,287	25,019,069,272

Figure 3-72

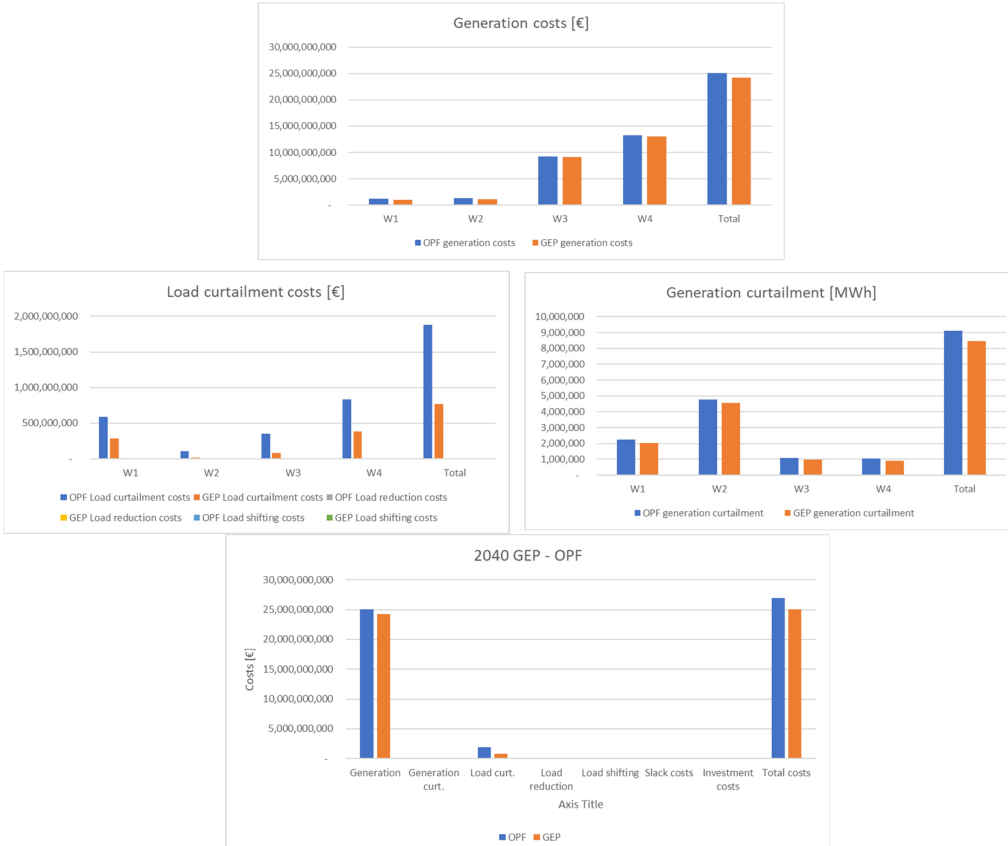


Figure 3-72 shows graphical comparisons of OPF and GEP results in terms of costs and energy. It can be concluded that generation costs are 3% lower after network expansion, while load curtailment costs are reduced by 59% thanks to reinforcements in distribution networks. Reduced generation curtailment cannot be observed through costs because its price is zero, but it can therefore be observed through curtailed energy. It can be concluded from this that the generation curtailment was reduced by about 7%.

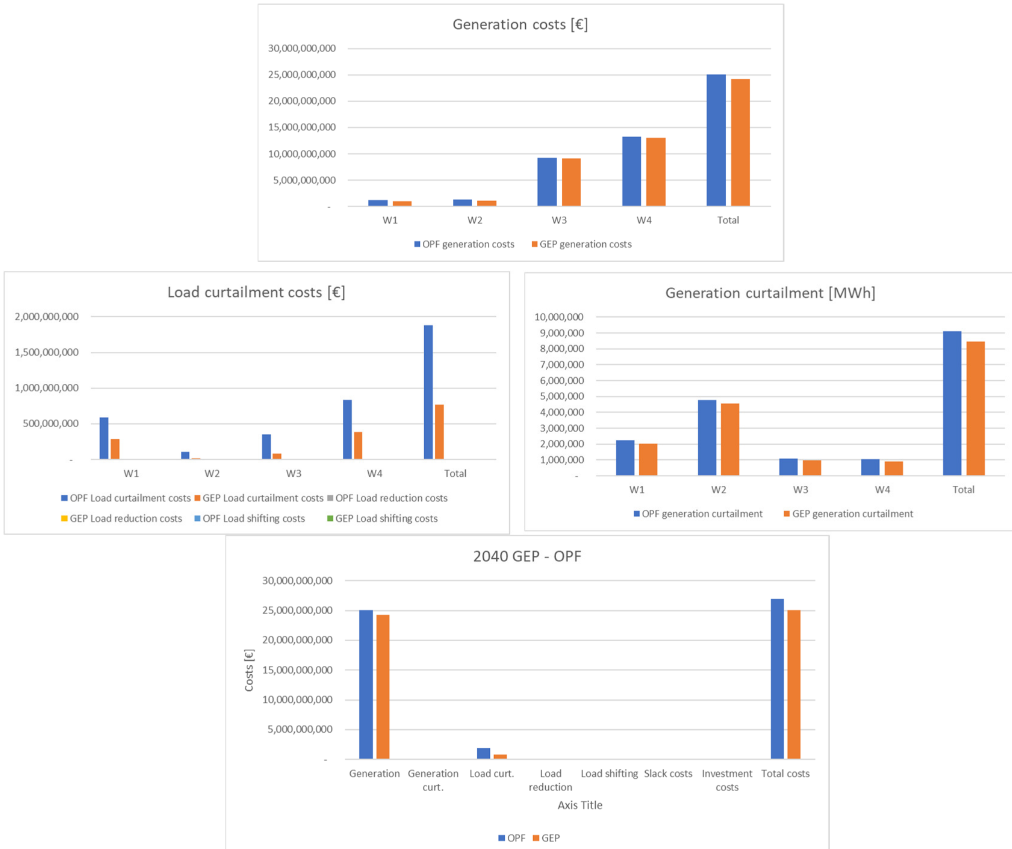


Figure 3-72: Comparation of OPF and GEP results (Year 2040)

Figure 3-73 shows hourly demand and generation curtailment for 4 weeks before (OPF) and after network expansion (GEP).

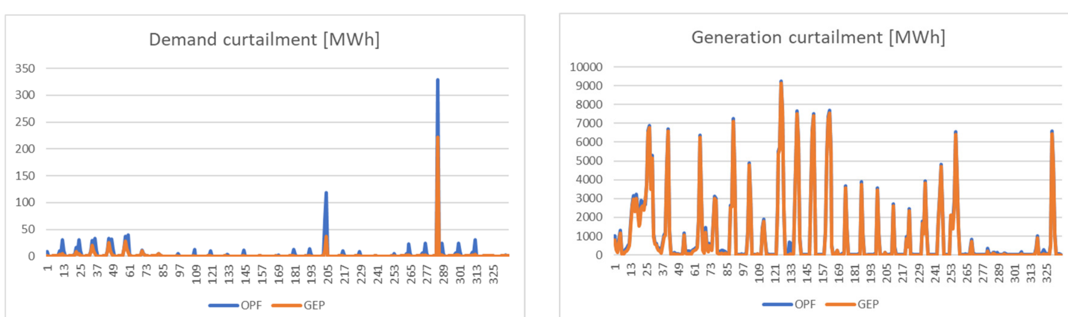


Figure 3-73: Change in demand curtailment (left) and generation curtailment (right) for 4 representative weeks after network expansion (Year 2040).

Decade 2050

As expected, OPF results for 2050 show more congestions than in 2040. More precisely, 212 out of 4089 branches (5.18%) have LM values different from zero. Figure 3-74 shows the geographical distribution of observed congestions where the figure on the right shows the congestions that were observed in the transmission network while the left one shows congestions in distribution networks.

As can be seen from Figure 3-58, Figure 3-67, and Figure 3-74, the values of LMs for distribution networks decrease as time progresses, while for the transmission network, they increase and in 2050 the highest congestions reach the same order of magnitude as the highest congestions in distribution networks. This is not surprising, given that in 2030 and 2040 congestions are mostly treated in distribution networks. Again, it appears that some of the congestions that occurred in the transmission network and were treated in 2040, due to the increase of demand and renewable energy supply, also occur in 2050.

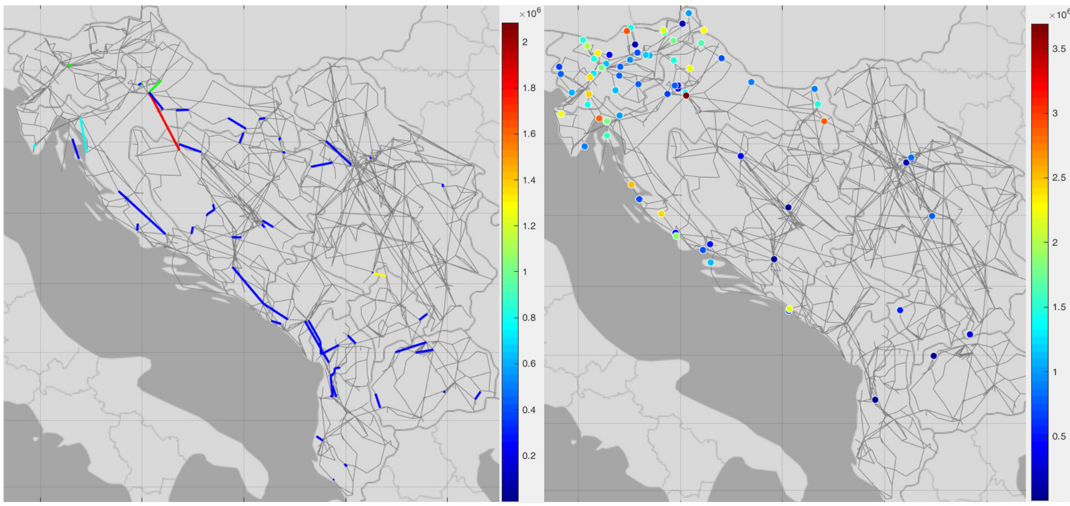


Figure 3-74: Overloaded AC branches (transmission – left, distribution – right) for the Balkan RC and related Lagrange Multipliers (Year 2050).

Figure 3-75 shows the geographical distribution of annual load curtailment (left) and annual generation curtailment (right) in the region. As expected, demand curtailment is more severe in 2050 compared to previous years due to increased demand and insufficient capacity of distribution networks to supply this demand. It goes up to 60 GWh per year as in one of the distribution networks in Slovenia. On the other hand, generation curtailment is widespread throughout the region. The largest occurs in the area of northern Macedonia, and it goes up to 700 GWh per year.

Demand curtailment still prevails in the distribution networks with a share of about 80%, while generation curtailment dominates in the transmission network with a share of 98% of total generation curtailment.

The reason why there is so much generation curtailment in 2050 is not only due to insufficient network capacity but also due to excess production by renewable energy sources.

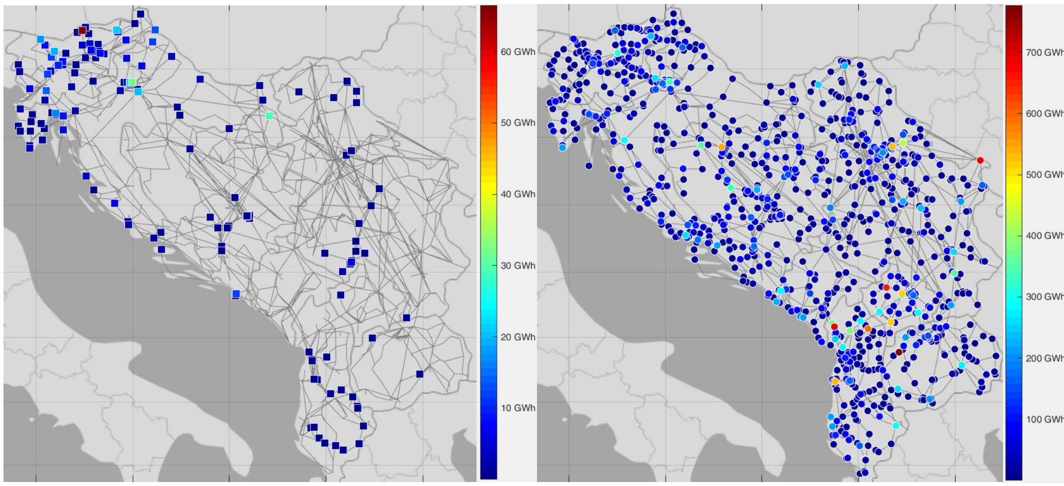


Figure 3-75: Curtailed loads (plotted as squares) and generators (plotted as circles) for the Balkan RC and yearly curtailed energy (Year 2050).

The graphs in Figure 3-76 show the change in demand and generation curtailment for all four representative weeks. It can be noted that demand curtailment occurs in the evening mostly on working days. Generation curtailment is present mostly in the first three weeks, in the hours when consumption is lower and production from renewable sources is higher.

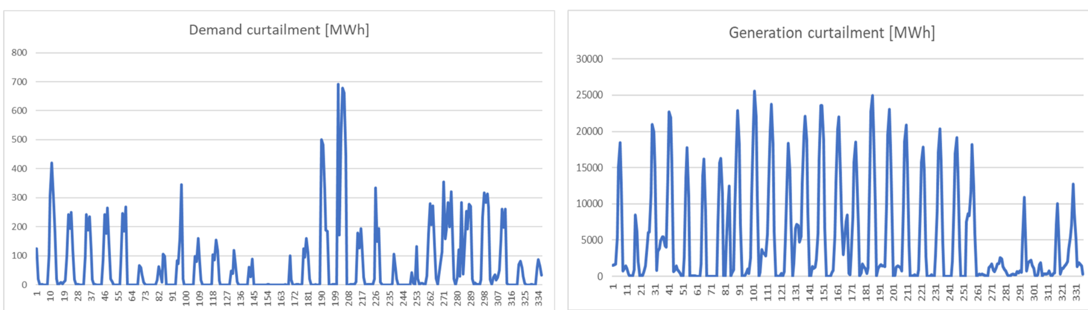


Figure 3-76: Change in demand curtailment (left) and generation curtailment (right) for 4 representative weeks (Year 2050).

The figure represents the annual load (left) and generation curtailment (right) by representative weeks.

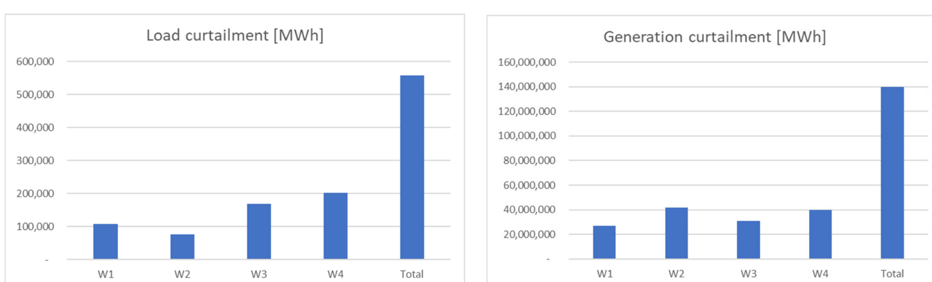


Figure 3-77: Load (left) and generation (right) curtailment for 4 representative weeks on an annual level (Year 2050).

As explained earlier, the number of candidates is limited to 100, so even in this case the number of congestions treated was less than 100 because almost all congestions had several different types of candidates proposed. The table shows the share of each type of candidate proposed by the Pre-processor as well as the investment decisions by the GEP and investment costs. Keep in mind that transformers are also proposed, but they are modelled in the Balkan case in the same way as lines, i.e. as AC branches.

Table 3-103 Description of the candidates (Year 2050).

Type	**AC Branch**	**Transformer**	**Storage**	**Flexibility load**	**Total**
Number of candidates	44	0	23	33	100
Investment decisions	3 (Transmission) 22 (Distribution)	0 (Transmission) 0 (Distribution)	2 (H2) 19 (Flow Battery) 0 (Li Battery) 0 (LAES)	33	79
Investment rejected	4 (Transmission) 15 (Distribution)	0 (Transmission) 0 (Distribution)	0 (H2) 2 (Flow Battery) 0 (Li Battery) 0 (LAES)	0	21
Investment costs, €	19,977,269	0	5,457,204	15,061	25,449,534

Out of a total of 44 AC branches proposed as candidates, 25 were approved as investments by GEP, of which 3 are in the transmission network and 22 are in the distribution network.

As for the storages, a total of 23 storages of different types (hydrogen storage and flow battery) were proposed. Most of the candidates were connected to distribution and only 6 were to the transmission network. In the end, GEP approved a total of 18 storages, of which 2 were connected to the transmission network (2 hydrogen storages).

Out of a total of 33 flexible loads proposed by the Pre-processor, all were connected to the distribution networks and accepted as investments by the GEP tool. Note that all loads in the Balkan case were initially non-flexible (except those that were accepted by the GEP tool in 2030 and 2040) but the Pre-processor made load candidates flexible in a percentage.

Figure 3-78 represents a geographical representation of all candidates proposed for 2050. As mentioned, congestions in distribution networks are more severe and therefore most of the candidates proposed by the Pre-processor are related to these networks. Candidates for distribution networks are mostly proposed in the area of Slovenia and Croatia which coincides with the locations of distribution network congestions seen in Figure 3-74. It was observed that almost all the congestions that were treated in these areas were actually congestions on the transformers that connect the distribution networks with the transmission network. As for candidates in the transmission network, they are focused on the two most severe congestions in this network (AC branches that are bolded in Table 3-104). One of these congestions is already known as it was the subject of optimization by the GEP tool in 2040 and it is located on the border between Croatia and Bosnia and Herzegovina (220 kV line Mraclin – Prijedor). The other one is located in the south of Serbia (110 kV line Novi Pazar - Leposavic). Other transmission lines that can be seen as candidates in Figure 3-78 are suggested by the Pre-processor because they are greatly affected by the expansion of the two previously mentioned transmission lines.

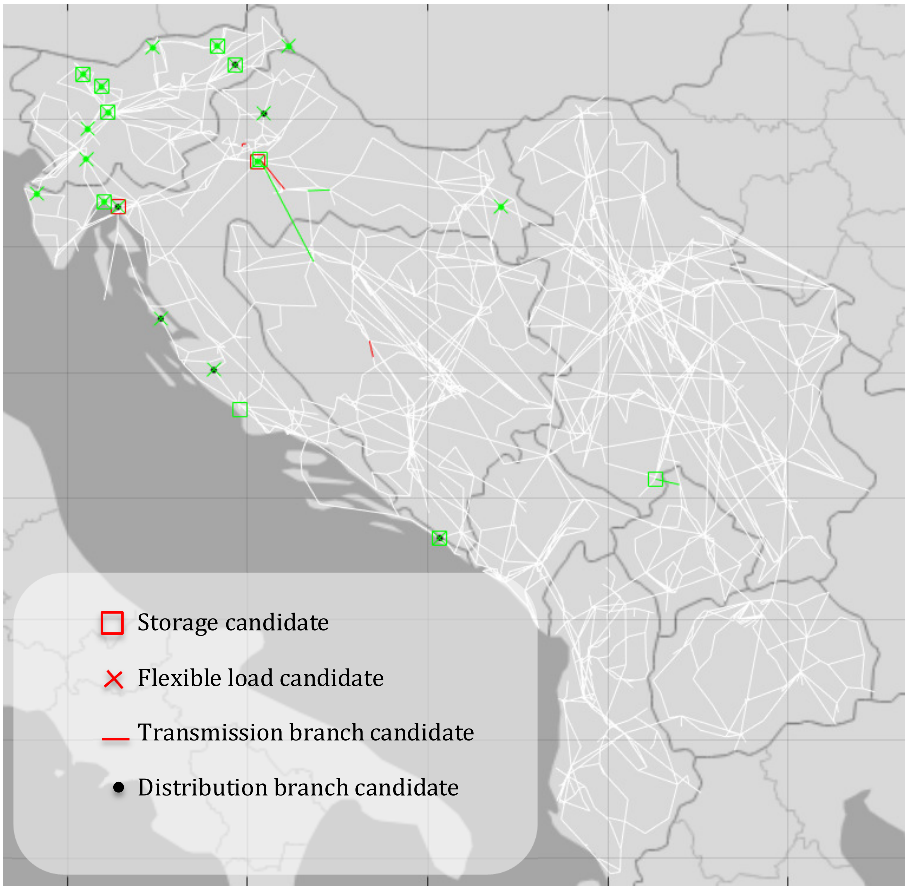


Figure 3-78: Geographical representation of different types of candidates (Year 2050).

The following table (Table 3-104) lists only congestions in 2050 that are treated by the candidates (other congestions are omitted due to table size), the maximum durations of congestions as well as the proposed candidates for each of them. Congestions are ranked by severity starting with the most severe, and those in bold represent those in the transmission network.

Table 3-104 Congested branches and proposed candidates (Year 2050).

No.	Branch	Congestion duration	Storage candidate				Branch candidate	Flexible load
			H2	Flow	Li-ion	LAES		
1	HMR_HMRACL5_PS3_trafo	11					✓	✓
2	ZEL_RAVNE111_PS2_trafo	18					✓	✓
3	HPE_HPEHLI5_PS1_521_522	7		✓			×	
4	ZEL_RAVNE111_PS4_trafo	12					✓	
5	HVI_HVINKO5_PS3_trafo	10					✓	✓
6	HVI_HVINKO5_PS1_trafo	10					✓	✓
7	ZEL_RAVNE111_PS1_trafo	11					✓	✓
8	HMR_HMRACL5_PS4_trafo	10					×	✓
9	HVI_HVINKO5_PS4_trafo	10					✓	✓
10	HMR_HMRACL5_PS1_trafo	10					×	✓
11	LOGATEC_PS1_trafo	11					✓	✓
12	PIVKA_PS1_trafo	11					✓	✓
13	HVI_HVINKO5_PS2_trafo	10					✓	✓
14	HMR_HMRACL5_PS2_trafo	10		×			×	✓
15	PRIMSKOVO_PS1_trafo	11		✓			✓	✓
16	HPA_HPAG 5_PS1_trafo	10					×	✓
17	PRIMSKOVO_PS2_trafo	11		✓			✓	✓
18	HBE_HBENKO5_PS1_trafo	10					×	✓
19	LENDAVA_PS1_trafo	10					✓	✓
20	HTE_HTEJER5_PS1_trafo	10					×	✓
21	HPE_HPEHLI5_PS1_662_663	6		✓			✓	✓
22	HBU_HBUJE 5_PS1_2_168	9					✓	✓
23	MELJE_PS2_trafo	10		✓			✓	✓
24	MELJE_PS1_trafo	10		✓			✓	✓
25	**ACWPRI/WPRIJ22-HMRACL2(1)99_1**	14	✓				✓	
26	RADOVLJICA_PS1_trafo	10		✓			✓	✓
27	HKO_HKOMOL5_PS3_trafo	9		✓			×	✓
28	HKO_HKOMOL5_PS4_trafo	9		✓			×	✓
29	HPE_HPEHLI5_PS2_2_415	6		✓			✓	
30	HPE_HPEHLI5_PS1_394_397	5		✓			✓	
31	BRDO_PS1_trafo	10		✓			✓	✓
32	BRDO_PS2_trafo	10		✓			✓	✓
33	HPE_HPEHLI5_PS2_121_129	5		✓			×	✓
34	HKO_HKOMOL5_PS1_trafo	9		✓			×	✓
35	HKO_HKOMOL5_PS2_trafo	9		✓			×	✓
36	**ACJLEP/JLEPOS5-JNPA/JNPAZ25_1**	29	✓				✓	
37	BREG_PS1_trafo	9		✓			×	✓
38	BREG_PS2_trafo	9		✓			×	✓
39	HKR_HKRASI5_PS1_trafo	9		×			×	✓
40	HRA_HRAZIN5_PS1_trafo	9		✓				

It can be seen from the table that the maximum durations of congestion in the transmission network are still longer compared to those in the distribution network. For this reason, candidates such as hydrogen storage are suitable for these congestions because they have a large energy capacity. For both cases in which transmission congestions were treated, both hydrogen storage and line reinforcement were accepted by the GEP tool. As far as distribution networks are concerned, various cases can be observed in Table 3-104. In some cases, it was sufficient only to engage flexible demand or the battery or a combination of these two sources of flexibility, and in others, both battery and flexible demand together with transformer/line enforcement.

The results of the OPF and GEP calculations can be seen in the following tables. Table 3-105 presents the total costs before the expansion (OPF results) and after the expansion of the network (GEP results) for 2050. Table 3-106 presents the total costs incurred in 2050 before any network expansion as calculated using the OPF tool, divided into four representative weeks (or rather seasons) and scaled to a ten-year period. Generation curtailment costs for all generating units are equal to zero and therefore the total generation curtailment costs are also zero. Table 3-107 shows the costs in the same form as the previous table, but this time after applying the network expansion with the candidates for 2050 selected by the GEP tool.

Table 3-105 Results of the simulation (Year 2050).

Total costs (Optimal Power Flow), €	31,102,508,591
Total costs (Grid Expansion Planning Tool), €	18,457,680,670
Execution time	129216 seconds 1.5 days
MIP Gap, %	0.01%

Table 3-106 Cost results - OPF (Year 2050).

Period	Week 1	Week 2	Week 3	Week 4	Total
Generation costs, €	2,128,888,508	1,584,192,655	2,162,113,423	3,745,709,722	9,620,904,308
Generation curtailment costs, €	-	-	-	-	-
Load curtailment costs, €	4,135,081,049	2,985,059,167	6,544,786,096	7,815,009,749	21,479,936,061
Load reduction costs, €	295,610	267,961	300,177	635,285	1,499,033
Load shifting costs, €	35,809	49,999	49,001	34,380	169,189
Slack costs, €	-	-	-	-	-
Total costs, €	6,264,300,975	4,569,569,781	8,707,248,697	11,561,389,136	31,102,508,591

Table 3-107 Cost results - GEP (Year 2050).

Period	Week 1	Week 2	Week 3	Week 4	Total
Generation costs, €	1,964,830,822	1,393,365,663	2,018,357,093	3,152,148,700	8,528,702,278
Generation curtailment costs, €	-	-	-	-	-
Load curtailment costs, €	1,887,458,573	977,814,713	3,174,554,922	3,257,829,306	9,297,657,513
Load reduction costs, €	132,239,782	159,001,518	133,460,988	201,507,202	626,209,490
Load shifting costs, €	867,144	1,920,153	1,431,566	892,527	5,111,389
Slack costs, €	-	-	-	-	-
Total costs, €	3,985,396,321	2,532,102,047	5,327,804,568	6,612,377,735	18,457,680,670

Figure 3-79 shows graphical comparisons of OPF and GEP results in terms of costs and energy. It can be concluded that generation costs are about 11.5% lower after network expansion, while load curtailment costs are reduced by 57% mostly thanks to reinforcements in distribution networks. Reduced generation curtailment cannot be observed through costs because its price is zero, but it can therefore be observed through curtailed energy. It can be concluded from this that the generation curtailment was reduced by about 2%.

Compared to 2030 and 2040, total costs are significantly reduced after network expansion. The reason is the demand curtailment costs, which were initially very high (higher than the generation costs) and which have been significantly reduced by investments in distribution networks.

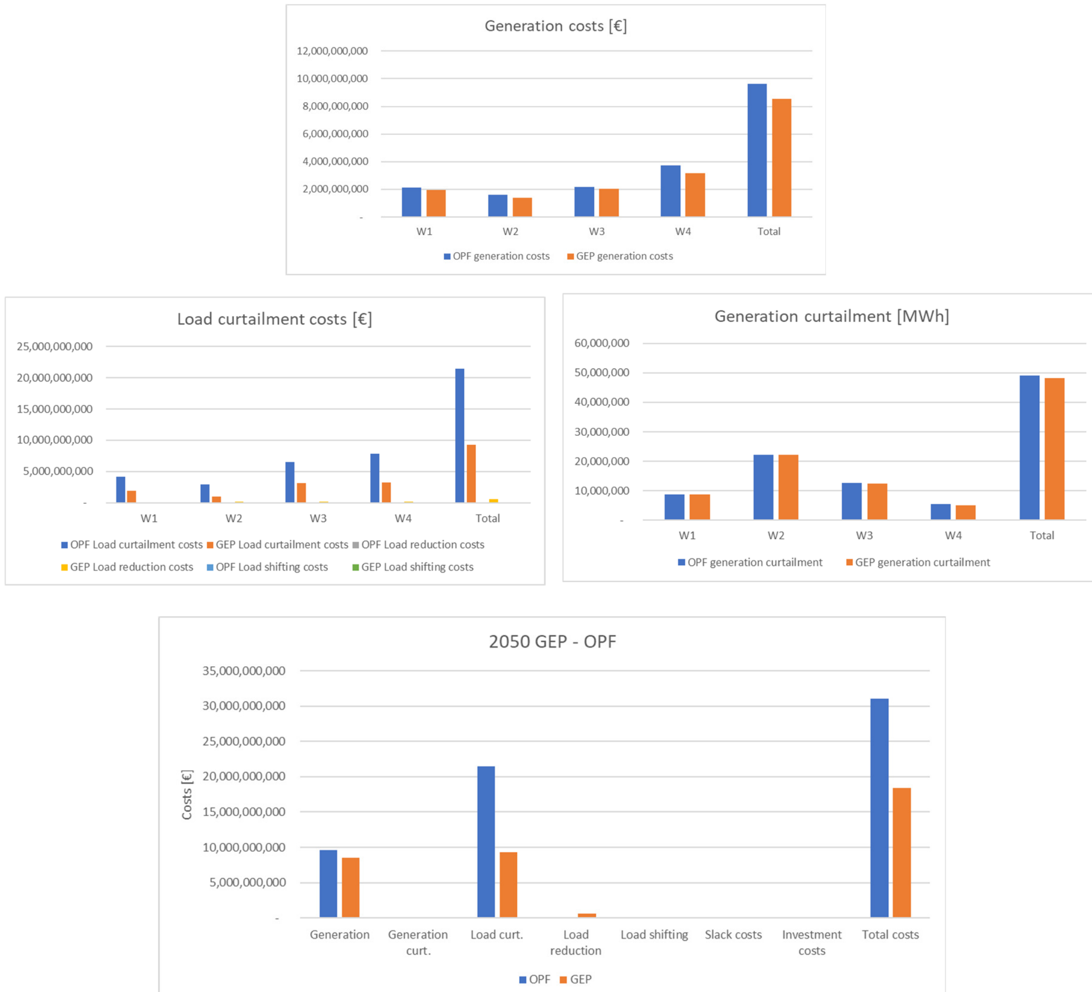


Figure 3-79: Comparation of OPF and GEP results (Year 2050)

The following figure shows hourly demand and generation curtailment for 4 weeks before (OPF) and after network expansion (GEP).

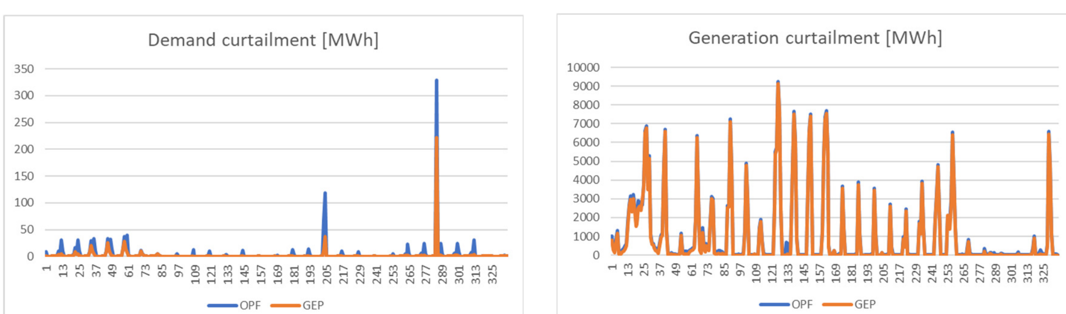


Figure 3-80: Change in demand curtailment (left) and generation curtailment (right) for 4 representative weeks after

Environmental impact assessment for Balkan RC

The environmental impact assessment is done through the calculation of carbon footprint and air quality costs for 2030, 2040, and 2050. Carbon footprint and air quality costs of conventional power plants are included in the generation costs resulting from the GEP tool so they had to be extracted. Table 3-108 presents the share of these costs in the generation costs and total costs.

Table 3-108 Environmental costs for Balkan RC

Metric\Year	2030	2040	2050
Carbon Footprint impact assessment for generation	48.1%	72.1%	70.9%
Air Quality impact assessment for generation	1.9%	0.8%	2.1%
Carbon Footprint impact assessment	47.3%	69.8%	32.8%
Air Quality impact assessment	1.9%	0.81%	0.9%

The reason why the share of carbon footprint costs in total generation costs is so large lies in the fact that for the Balkan case, it was assumed that RES generation costs are equal to zero. The percentage continues to rise in 2040 and 2050 despite the shutdown of more and more conventional power plants and the increase of renewable sources. The biggest reason for this is the large increase in the price of CO_2 in 2040 and 2050, as well as the fact that the share of renewable sources in total generation costs is not visible because their generation costs are equal to zero as mentioned above.

As for the share of carbon footprint costs in the system total costs, it drops significantly at the transition from 2040 to 2050, due to the fact that in 2050 demand curtailment costs account for a significant share of total costs.

3.6 Nordic Countries

3.6.1 Overview of the adaptations for Regional Case

Since the ENTSO-E data set used for the transmission grid for other regional cases did not include data for the Nordic synchronous system, grid data had to be sourced elsewhere. The four countries have different policies with respect to sharing of power system data. NVE, the Norwegian Water Resources and Energy Directorate [14], has shared with SINTEF Energy Research the data of the Norwegian transmission grid under a Non-Disclosure Agreement. Therefore, the Norwegian transmission and sub-transmission grid is fully covered with highly reliable data. In the case of Denmark, the Danish TSO Energinet [15] releases the transmission system data through an Excel file openly on their website. Finally, data from Finland and Sweden is not available through their institutional websites, nor there has been the opportunity to gain access to this data through direct contact with the respective TSOs. For this reason, in order to have a complete model of the transmission grid of the Nordic region, open source data has been used for Sweden and Finland. The main sources that have been used are PyPSA-EUR model [8], and OpenStreetMap (OSM) [16], as documented in more detail in Deliverable 5.1 [2].

Since the finalization of D5.1, the case for the Nordic region has been developed and specified further in collaboration with Norwegian stakeholders, starting with a workshop in November 2021. The conclusion from that workshop was that the main interest of Norwegian stakeholders lies in grid development for certain, concrete areas of Norway with real challenges expected over the 2020–2040 time horizon. One of the areas of interest was then selected as a focus area for the case, and a collaboration was established with the local DSO for this part of Norway. Throughout 2022, a series of meetings were arranged with the DSO to make the case more relevant and realistic and to better be able to validate the results.

When it became apparent that it was necessary to reduce the computational time in the OPF and GEP calculations, the case development described above also guided the adaptations necessary to reduce the complexity of the transmission system model:

1. The planning study would focus on the Norwegian sub-regional case
2. An area in the western part of the country would be represented in more details

Starting from decision 1, it has been decided that Norway would keep the highly detailed NVE power system model from the initial dataset described in Deliverable D5.1, whereas Finland, Sweden and Denmark would be modelled with the PyPSA-EUR dataset.

Compared with the model described in the Deliverable 5.1, the main simplification is therefore the abandonment of both the Energinet and OpenStreetMap datasets, respectively for Denmark and for Sweden-Finland areas. The outcome of this simplification is to have a simpler model in the area outside of Norway, with only three voltage levels (220kV, 300kV, 380kV), that has proven to bring faster computational time in the full Nordics OPF and GEP calculations. In this context, also NVE dataset has undergone a process of simplification that has filtered out all the lines with voltage levels below 107 kV. The network used in the Nordic Countries RC is presented in Figure 3-81.

Figure 3-81 Transmission system of Nordics RC

Starting from decision 2, several actions have been taken, with the common aim to reproduce an area of Norway with a high fidelity of modelling detail, and to be able to cross-check the results with the knowledge and expertise of the project partners regarding the planning issues related to the area. The focus area is the area around the city of Bergen in the Western parts of Norway. The area is currently a net importer of electric energy, and electrification initiatives and establishment of new power-intensive industry is expected to further exacerbate the situation. In large parts of the year, power is imported from the areas to the East across the interface labelled "BKK-snittet" in Figure 3-83. The local DSO and the TSO expect that this interface and the other interfaces shown as vertical dashed lines in Figure 3-83 will be bottlenecks in the area over the next decade. Considering this and the need to reduce the computation time, the following adaptations and simplifications were carried out. The adaptations are also summarized in Figure 3-83 below.

- Norway is a hydropower-dominated power system, and to ensure a realistic modelling of hydropower, reference hydropower generation schedules were generated by the EMPS model, which is a fundamental multi-area hydro-thermal power market model [17]. This reference production is modelled as non-dispatchable (VRES-based) generation. The reservoir-hydropower plants' flexibility to deviate from this reference production is modelled as energy storage elements with a time-dependent power capacity to capture seasonal variation in the flexibility of the hydropower plants.
- The storage units of the model representing reservoir-hydropower plants are reduced to those that are connected in the focus area; in order to further reduce the computational time, the 15 largest units out of 32 are kept. All the remaining storage units in the Nordic region are modelled as non-dispatchable generators, since flexibility provision from these units could not be used to alleviate bottlenecks in the focus area.
- Inspection of the load profiles in the focus area revealed that the disaggregation methodology based on MILES profiles would not reproduce the load distribution that is characteristic to the challenges in the grid area. More specifically, much of the load consumption is in reality concentrated around Mongstad and Kollsnes to the far West, and the TSO and DSO expect that much of the future load growth also comes here.
- Moreover, the load growth from the present situation to 2030, 2040 and 2050 was adjusted to reflect that the load growth in the area expected by the local DSO [18] and the TSO [19] is much higher than what is captured by the disaggregation of MILES profiles (on a national level in Figure 3-85). The TSO's load growth scenarios for the area [19] are reproduced in Figure 3-84. To use a scenario for the focus area considered more realistic by Norwegian stakeholders, new point loads for 2030, 2040 and 2050 were added according to [19]. After discussions with the local DSO, the high scenario of Figure 3-84 was selected to "stress-test" the FlexPlan tool in this regional case.
- It was found that the grid topology around bus "Frøyset" (in the north-western part of the focus area) had not been updated since the construction of the 300 kV line Haugsvær–Lindås and the decommissioning of the 132 kV line Frøyset-Matre. This was corrected by inserting new 300 kV buses and new 300–132 kV transformers with similar parameters as comparable transformers in the area.
- The distribution grids included in the model are those connected to the 41 buses to the west of the Bergenssnittet interface shown in Figure 3-83. Distribution grids in other parts of the Nordic region are expected to contribute negligibly to the power flow and flexibility potential relevant to the focus area.

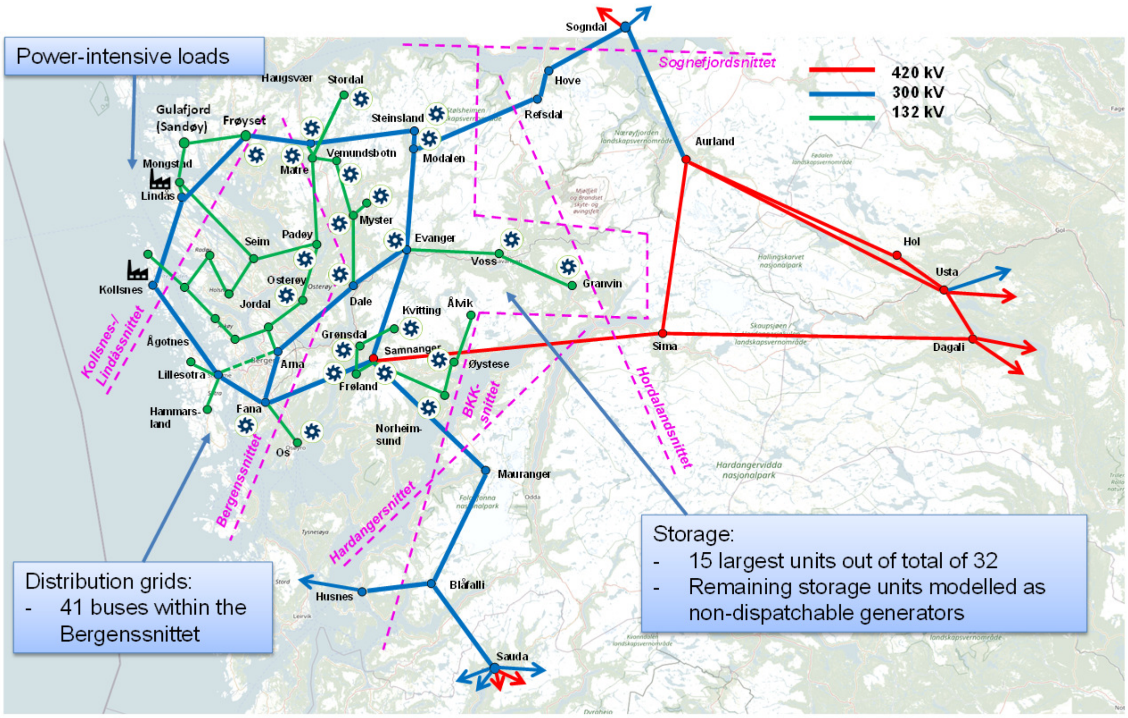


Figure 3-82 Simplifications for the area around Bergen

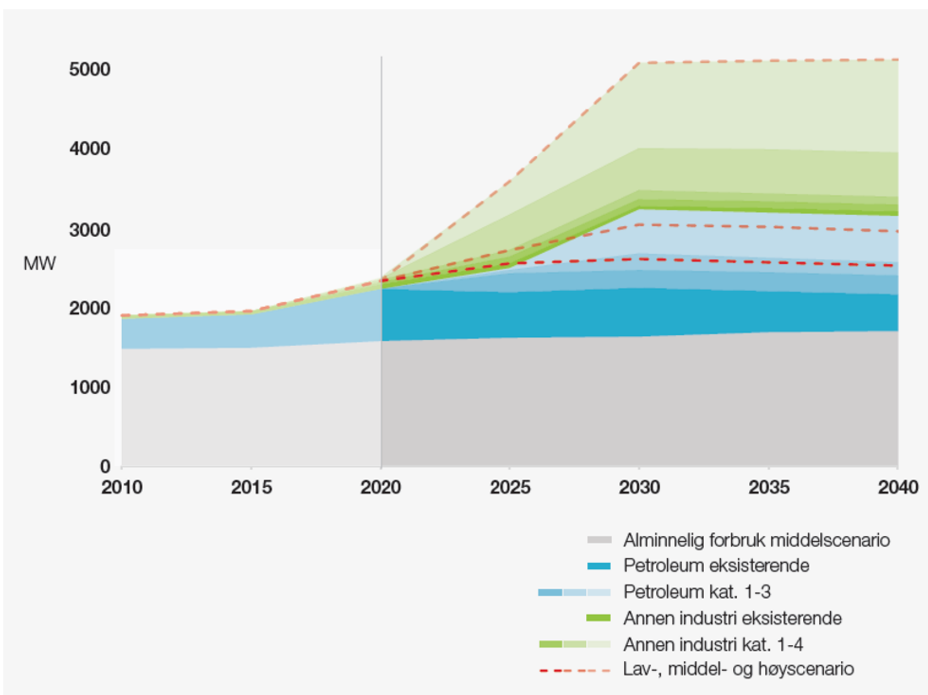


Figure 3-83 The Norwegian TSO's load growth scenarios for the focus area. Source: [Statnett, 2020].

A summary of the Nordics grid in terms of number of main components is reported in Table 3-109.

Table 3-109 Description of the network, Nordic Countries RC

Number of the nodes	4950
of which in transmission network	1196
of which in distribution network	3754
Number of AC branches	5081
of which in transmission network	1402
of which in distribution network	3679
Number of transformers	245
Number of storages	15
Number of flexibility loads	0

Figure 3-84 shows the evolution of scenarios in the decades 2030, 2040 and 2050 in terms of total load and generation.

Figure 3-84 Load and generation scenario in the Nordic RC

A set of further assumptions is summarized in the following list:

- DC lines are modelled as AC lines
- Generation curtailment cost is assumed to be equal to 0 €/MWh for all generation types
- Generation costs for generation plants fed by renewable energy sources are assumed as 0€/MWh
- The value of loss load (VOLL) is assumed as 5000 €/MWh

- Power exchange between borders is modelled by a pair of generator-load at both terminals of the trans-border lines. In this case, generators are modelled with a generation curtailment cost equal to the VOLL, i.e. 5000 €/MWh, for the sake of symmetry with the part of the model represented by the load.
- Load and generation profiles are represented by time series with a time discretization step of 2 hours.
- Within the focus area, the power line capacity values have been recalculated in order to take into account the operational margin for N-1 emergency operation, as estimated from the information available in [19].
- Parameters and profiles' values have been rounded in order to reduce the number of significant digits and improve the convergence rate of the optimization solver. 4 decimal digits have been used for rounding power profiles' values, whereas for component parameters (i.e. line resistance and reactance), the values have been rounded to the 6th digit.

A base power of 100 MVA has been adopted, and an objective function scaling factor of 10000.

The selection of the representative weeks calculated for the Nordic RC analysis is visualized for the three target years in Figure 3-86. In cyan it is highlighted the representative week actually chosen as representative for each season.

	Winter												
	50	51	0	1	2	3	4	5	6	7	8	9	10
DE2030_variant1				SELECT			TRUE				TRUE		
DE2040_variant1			TRUE			TRUE				SELECT			TRUE
DE2050_variant1		TRUE				SELECT				TRUE			
	Spring												
	11	12	13	14	15	16	17	18	19	20	21	22	23
DE2030_variant1		SELECT		TRUE						TRUE			
DE2040_variant1				TRUE					SELECT				
DE2050_variant1	TRUE		SELECT							TRUE			
	Summer												
	24	25	26	27	28	29	30	31	32	33	34	35	36
DE2030_variant1		SELECT					TRUE					TRUE	
DE2040_variant1		TRUE						SELECT					
DE2050_variant1	TRUE				SELECT					TRUE			
	Autumn												
	37	38	39	40	41	42	43	44	45	46	47	48	49
DE2030_variant1					SELECT				TRUE				TRUE
DE2040_variant1	TRUE				TRUE			SELECT				TRUE	
DE2050_variant1		SELECT				TRUE					TRUE		

Figure 3-85 Representative weeks for the Nordic RC

3.6.2 Results and analysis

Decade 2030

In Figure 3-86 and Figure 3-87 the results from the OPF, based on the grid scenario 2030, are shown.

Figure 3-86 shows the overloads over the transmission lines in terms of number of occurrences over the 336 hour-samples analysed. A high density of overloads can be observed around the area of Bergen, which validates the modelling choice of focusing in that area with a higher detail in terms of storage units, distribution lines and improved load profiles (high intensity loads).

In addition, Figure 3-87 shows that, before any grid or flexibility reinforcement, load and generation curtailment are relevant actions taken by the OPF to solve the line congestions. The areas where load curtailment is observed are Bergen, Oslo, Trondheim, and sparsely in the whole Denmark. Nevertheless, it should be observed the high density of load curtailment in Bergen (observe colormap scale in Figure 3-87). Generally, load and generation curtailment is localized around the terminal buses of overloaded branches, as could reasonably be expected.

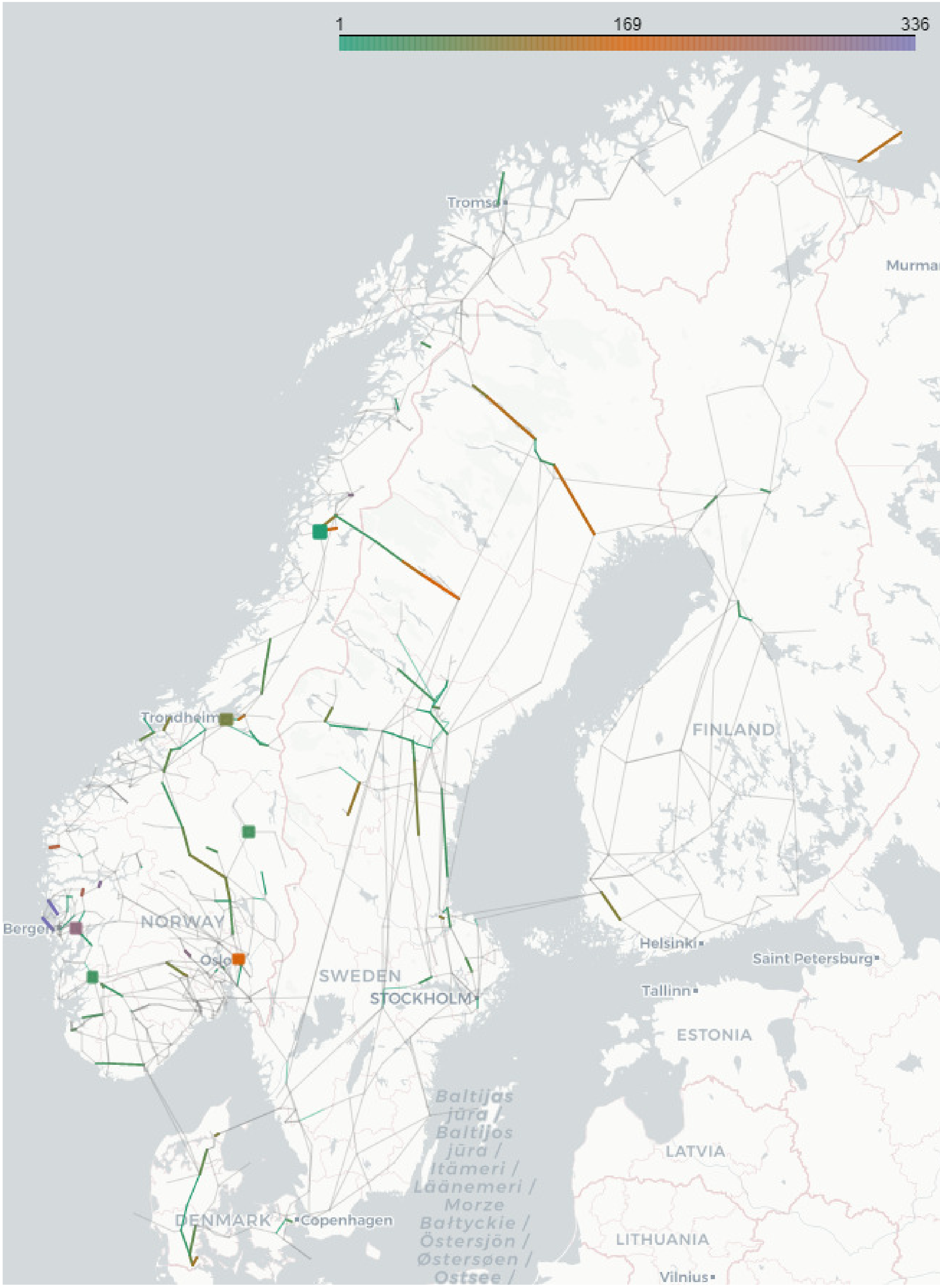
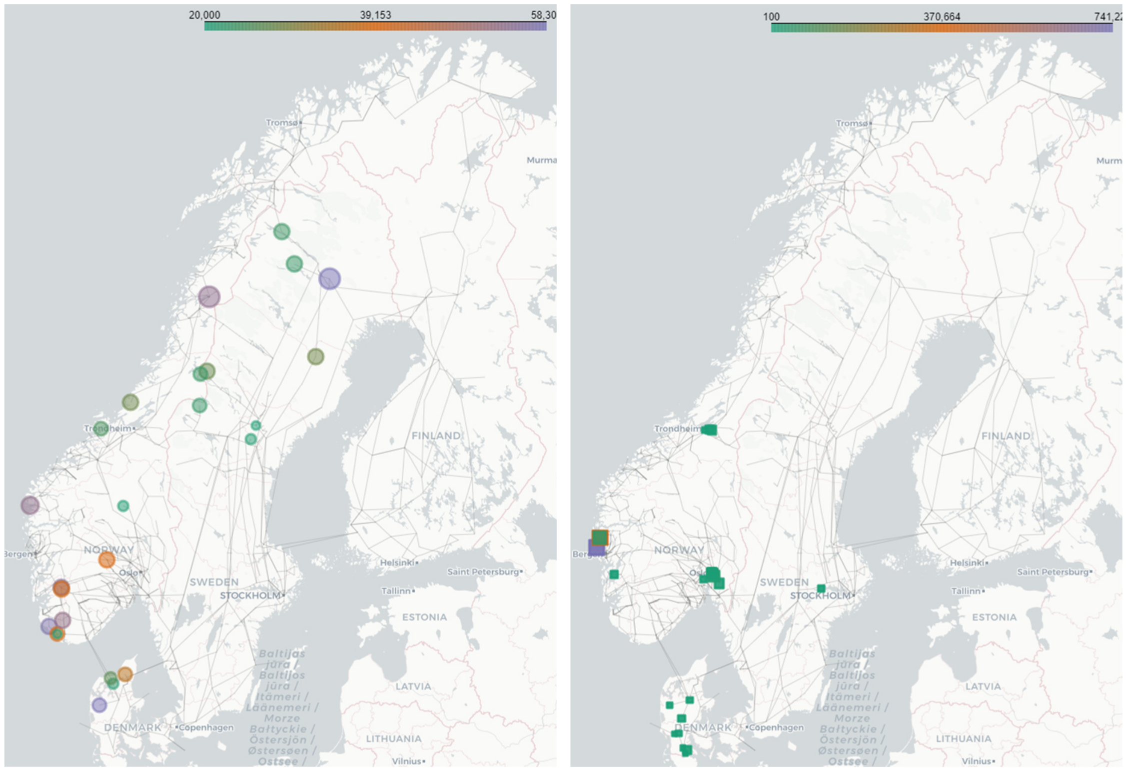


Figure 3-86 Overloaded lines (plotted as lines) and transformers (plotted as squares) for the Nordic RC and related Lagrange Multipliers (Year 2030)



(a) (b)

Figure 3-87 Curtailed generators (plotted as circles, (a)) and loads (plotted as squares, (b)) for the Nordic RC and yearly curtailed energy (Year 2030)

Table 3-110 Description of Candidates 2030

Type	AC Branch	Transformer	Storage	Flexibility load	Total
Number of candidates	108	0	3	3	114
Investment decisions	7 (Transmission) 63 (Distribution)	0 (Transmission) 0 (Distribution)	0 (H2) 0 (Li-Ion)	3 (Transmission) 0 (Distribution)	73
Investment rejected	6 (Transmission) 32 (Distribution)	0 (Transmission) 0 (Distribution)	2 (H2) 1 (Li-Ion)	0 (Transmission) 0 (Distribution)	41
Investment costs (M€)	111,600,000	0	0	11,000	111,611,000

Table 3-110 summarizes the selection of candidates for the GEP analysis for 2030.

A total number of 114 candidates were given as input of the GEP tool, of which 100 generated by the preprocessor, and 14 candidates selected from a manual list of potential expansion measures that was created based on the inputs from Norwegian stakeholders. These candidates are described by the following bullet points:

- The following candidates had been suggested or considered by the Norwegian TSO in their early-stage grid development plan (concept selection) [Statnett, 2020]:
    - Sogndal-Aurland (reinforcement)

    - Sogndal-Modalen (reinforcement)
    - Kollsnes-Lille Sotra (reinforcement)
    - Modalen-Kollsnes (reinforcement)
    - Samnanger-Kollsnes (new line)
    - Modalen-Kollsnes (new line)
- The following candidate was added to also consider a sub-transmission grid candidate:
    - Seim-Mongstad (new, parallel line)
- The following candidates were added to consider transmission grid candidates in entirely different parts of the Nordic region:
    - Fåberg-Sunndalsøra (new, parallel line)
    - Tjele-Landerupgård (new line)
- A 50 MW / 600 MWh hydrogen storage candidate at Mongstad was included to represent prospective hydrogen production project that had recently been considered in the area.
- A 50 MW / 600 MWh Li-ion battery candidate at Lindås was included as a complement to the hydrogen storage candidate.
- An 80 MW demand flexibility candidate was included at Mongstad to test representing the prospective hydrogen production project by a demand flexibility model instead of as storage model.
- A 220 MW demand flexibility candidate at Kollsnes was included to represent electrification of offshore oil&gas installations supplied from this bus.
- A 30 MW demand flexibility candidate at Ågotnes was included to consider distribution-level demand flexibility. (Almost no other load in the area is located at the distribution level.)

Table 3-111 summarizes the results of the studies for 2030, whereas Table 3-112 and Table 3-113 reports the costs for each representative week of the different cost items for OPF (non-expanded network) and GEP.

Table 3-111 Results of the simulation 2030

Total costs (Optimal Power Flow), €	480,071,200,000
Total costs (Grid Expansion Planning Tool), €	120,274,840,000
Execution time	109,858.7 seconds (30.5 h)
MIP Gap, %	0

Table 3-112 Results of OPF 2030

Period	Week 1	Week 2	Week 3	Week 4	Total
Generation costs, €	2,382,750,000	750,400,000	627,200,000	145,820,000	3,906,180,000
Generation curtailment costs, €	10,164,980,000	8,808,520,000	9,863,900,000	12,778,610,000	41,616,010,000

Period	Week 1	Week 2	Week 3	Week 4	Total
Load curtailment costs, €	117,185,900,000	107,534,290,000	109,471,040,000	100,357,770,000	434,549,010,000
Load reduction costs, €	0	0	0	0	0
Load shifting costs, €	0	0	0	0	0
Slack costs, €	0	0	0	0	0
Total costs, €	129,733,630,000	117,093,220,000	119,962,150,000	113,282,200,000	480,071,200,000

Table 3-113 Results of GEP 2030

Period	Week 1	Week 2	Week 3	Week 4	Total
Generation costs, €	3,372,380,000	1,264,770,000	1,523,320,000	180,480,000	6,340,960,000
Generation curtailment costs, €	10,164,980,000	8,808,520,000	9,868,720,000	12,778,610,000	41,620,830,000
Load curtailment costs, €	26,281,470,000	16,344,180,000	17,810,470,000	9,437,560,000	69,873,690,000
Load reduction costs, €	609,730,000	610,120,000	609,600,000	609,470,000	2,438,920,000
Load shifting costs, €	160,000	180,000	100,000	0	440,000
Slack costs, €	0	0	0	0	0
Total costs, €	40,428,720,000	27,027,780,000	29,812,220,000	23,006,130,000	120,274,840,000

Figure 3-88 Investment decisions (Year 2030): Transmission acBranches plotted as red lines, Flexible loads as blue circles

In Figure 3-89 the investment decisions accepted by the GEP tool at transmission grid level are shown. It can be observed that all the candidate flexible loads are accepted as expansion of the grid. Moreover, the investment decisions in terms of transmission line reinforcement are placed within the focus area. Comparing these results with Figure 3-86 and Figure 3-87, the investment decisions can be motivated by the convergence in this area of both a high load curtailment and generation curtailment (whereas in the rest of the Nordic region load curtailment and generation curtailment appear as alternative solutions for solving line congestions, due to either the absence of highly dense load or high power generation).

The numerical results in terms of costs are summarized graphically by the diagram in Figure 3-90. After GEP solutions, the total costs are reduced by 75%. The main contribution in cost reduction is represented by the reduction in load curtailment, due to the reduction in terms of line congestions. This further motivates the GEP decisions to invest in network reinforcement in areas where the load curtailment was more predominant, i.e. the area around Bergen. Slack costs are equal to 0 both in the non-expanded and expanded networks, and generation curtailment costs do not show a significant variation between non-expanded and expanded networks. Load reduction costs and load shifting costs represent a new cost item in the expanded network, due to the flexible loads that have been added after the grid expansion, but remain relatively small. Regarding generation costs, the expanded network shows a slight increase in this cost entry. One likely contributor to this trend is the reduction in terms of load curtailment due to the network expansion, which causes increased load to be served by generation.

An important observation has to be made regarding the generation curtailment costs: the general assumption is on having 0 €/MWh as generation curtailment costs for standard generation power plants; nevertheless, as mentioned in the assumptions listed in Section 3.6.1, it has been assumed a value of generation curtailment cost of 5000 €/MWh for the generators that model the power exchange through the borders of the countries of the Nordic regional area. From the graph in Figure 3-90, it can be observed how the generation curtailment associated to the inter-border power flows is significant both before and after the network expansion.

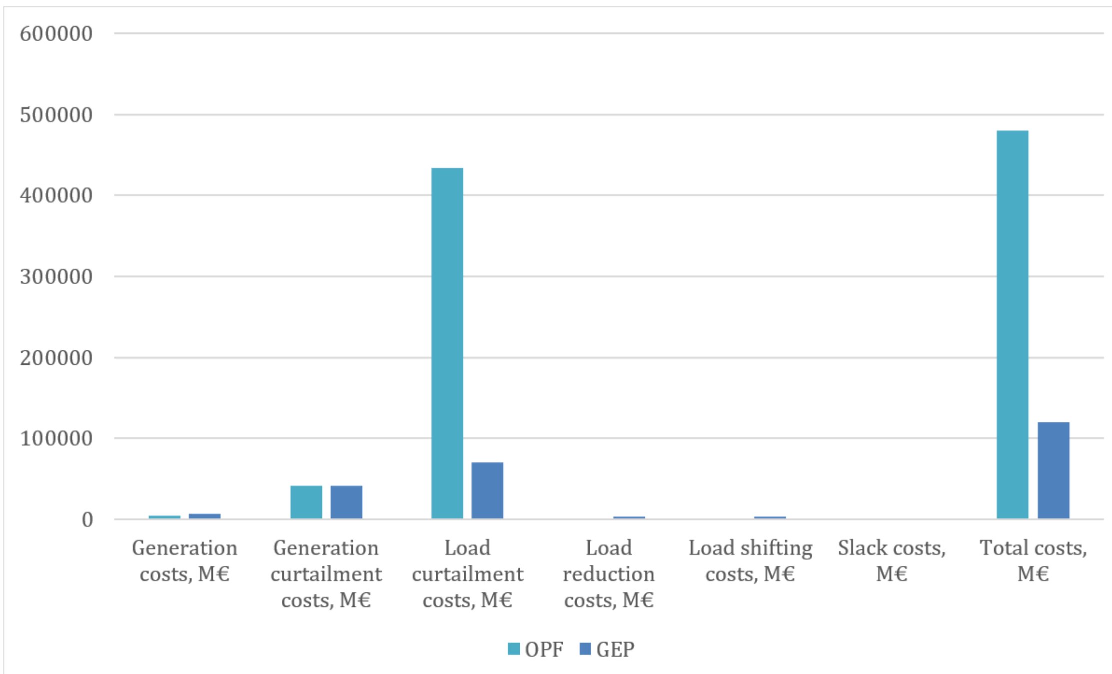


Figure 3-89 Comparison of cost results between non-expanded network (OPF) and GEP solutions (Year 2030).

Decade 2040

In Figure 3-90 and Figure 3-91 the results from the OPF, based on the grid scenario 2040, are shown.

Figure 3-90 shows the overloads over the transmission lines in terms of number of occurrences over the 336 hour-samples analysed. Compared with the previous initial scenario of 2030 represented in Figure 3-86, it can be observed how the area of Bergen is partially relieved from the high density of overloads measured in 2030. The focus area is still impacted by overloads on both lines and transformers, but the same entity of overloads is observed in the remaining part of the Nordic area.

Figure 3-91 shows that, exactly as in the case of 2030, the urban centres are significantly affected by load curtailment as main measure for solving network overload, whereas generation curtailment is observed sparsely throughout the whole Nordic Regional area. If the colormap scales are observed in terms of maximum scale value, it can be observed that the maximum value of load curtailment in 2040 is reduced by the 75% compared with the 2030 scenario, whereas the generation curtailment is increased, both in terms of maximum entity and in terms of sites where it is implemented as OPF measure.

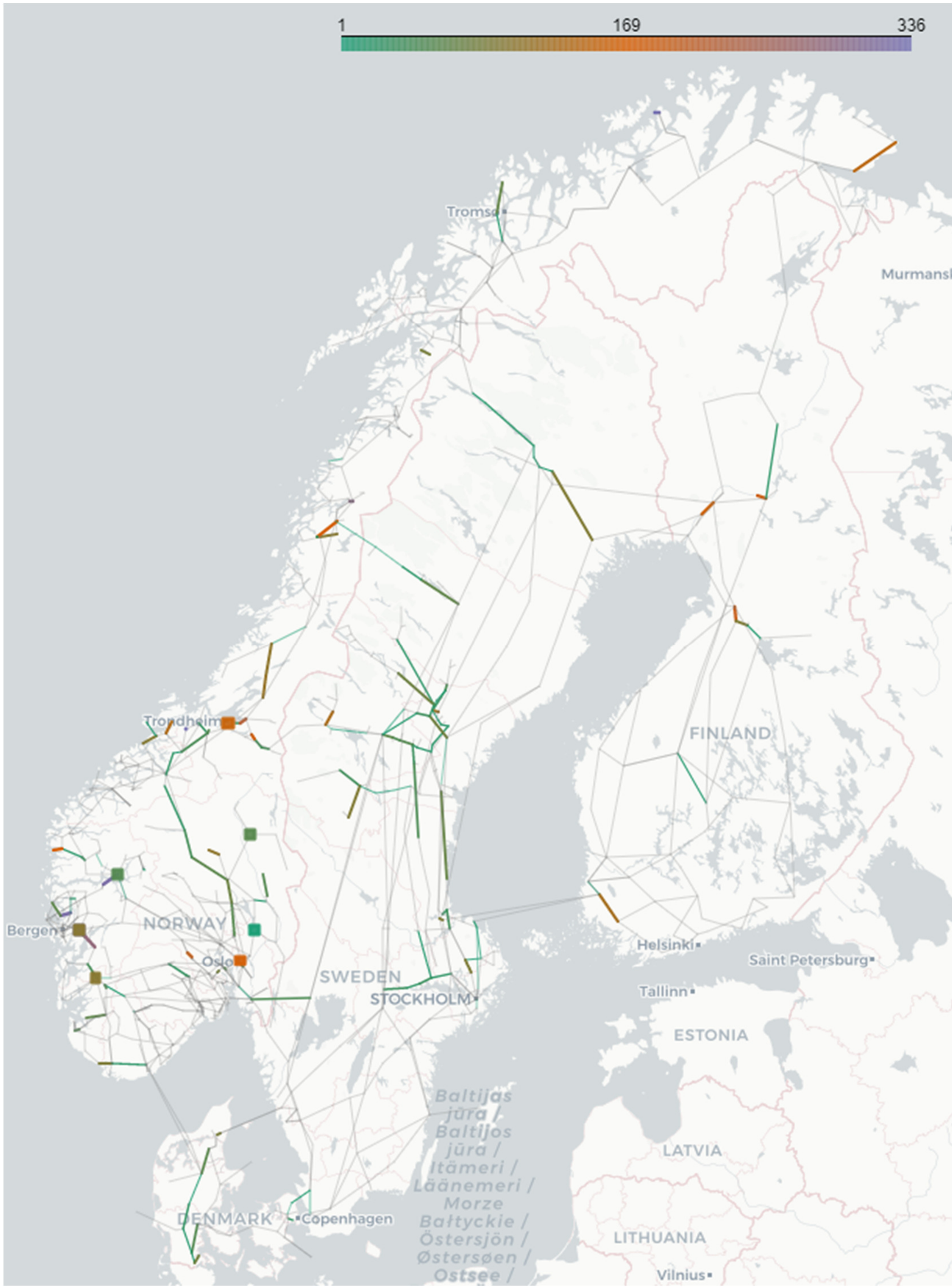
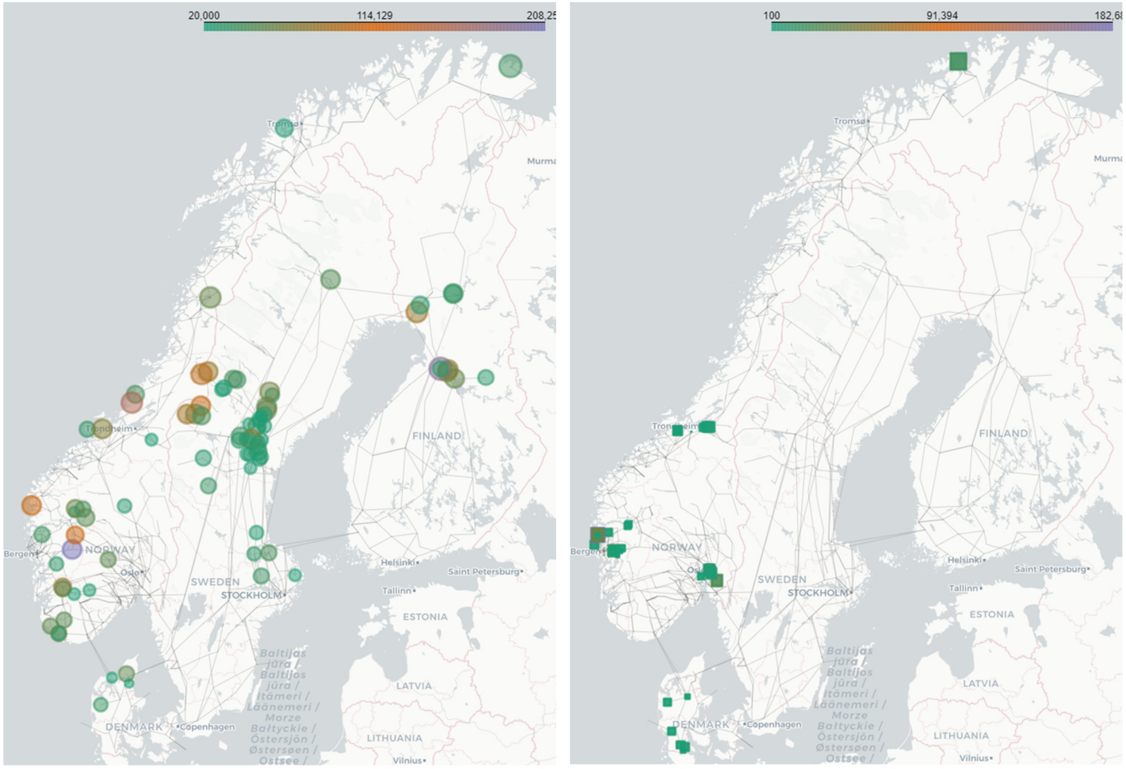


Figure 3-90 Overloaded lines (plotted as lines) and transformers (plotted as squares) for the Nordic RC and related Lagrange Multipliers (Year 2040)



(a) (b)

Figure 3-91 Curtailed generators (plotted as circles, (a)) and loads (plotted as squares, (b)) for the Nordic RC and yearly curtailed energy (Year 2040)

A total number of 100 candidates were generated from the preprocessor as input of the GEP tool. In Table 3-114 these candidates are described in terms of components, and the number of accepted candidates is also reported. In contrast to 2030, no manual adaptations based on stakeholder inputs were carried out for the 2040 analysis. The reason for this is that Norwegian stakeholders showed greater interest in grid development studies centered around 2030, and no specific inputs were received for years much further into the future and for much more uncertain load and generation forecasts. For this reason, the results for 2040 and 2050 are also expected to be substantially less accurate than the results for 2030 and are therefore given less emphasis in the analysis.

Table 3-114 Description of candidates 2040

Type	**AC Branch**	**Transformer**	**Storage**	**Flexibility load**	**Total**
Number of candidates	89	3	8	0	100
Investment decisions	23 (Transmission) 20 (Distribution)	2 (Transmission) 0 (Distribution)	8 (H2) 0 (Li-Ion)	0	53
Investment rejected	3 (Transmission) 43 (Distribution)	1 (Transmission) 0 (Distribution)	0	0	47
Investment costs (M€)	56,489,000	3,215,000	10,112,000	0	69,816,000

Table 3-115 summarizes the results of the studies for 2040, whereas Table 3-116 and Table 3-117 reports the costs for each representative week of the different cost items for OPF (non-expanded network) and GEP.

Table 3-115 Results of the simulation 2040

Total costs (Optimal Power Flow), €	168,505,980,000
Total costs (Grid Expansion Planning Tool), €	63,632,800,000
Execution time	693 618 seconds (192.67 h)
MIP Gap, %	0.07

Table 3-116 Results of OPF 2040

Period	Week 1	Week 2	Week 3	Week 4	Total
Generation costs, €	154,270,000	890,140,000	314,150,000	1,485,000,000	2,843,560,000
Generation curtailment costs, €	0	4,697,910,000	7,131,880,000	14,399,930,000	26,229,720,000
Load curtailment costs, €	34,133,890,000	29,718,220,000	29,348,540,000	43,964,150,000	137,164,800,000
Load reduction costs, €	557,330,000	575,510,000	557,330,000	575,510,000	2,265,690,000
Load shifting costs, €	0	1,210,000	40,000	950,000	2,210,000
Slack costs, €	0	0	0	0	0
Total costs, €	34,845,500,000	35,882,990,000	37,351,940,000	60,425,540,000	168,505,980,000

Table 3-117 Results of GEP 2040

Period	Week 1	Week 2	Week 3	Week 4	Total
Generation costs, €	135,160,000	782,650,000	364,170,000	1,315,800,000	2,597,770,000
Generation curtailment costs, €	0	4,697,910,000	6,971,480,000	13,945,990,000	25,615,380,000
Load curtailment costs, €	6,085,600,000	5,390,880,000	10,343,530,000	11,580,000,000	33,400,010,000
Load reduction costs, €	340,600,000	557,330,000	557,330,000	557,330,000	2,012,600,000
Load shifting costs, €	0	3,960,000	2,820,000	260,000	7,040,000
Slack costs, €	0	0	0	0	0
Total costs, €	6,561,360,000	11,432,740,000	18,239,330,000	27,399,370,000	63,632,800,000

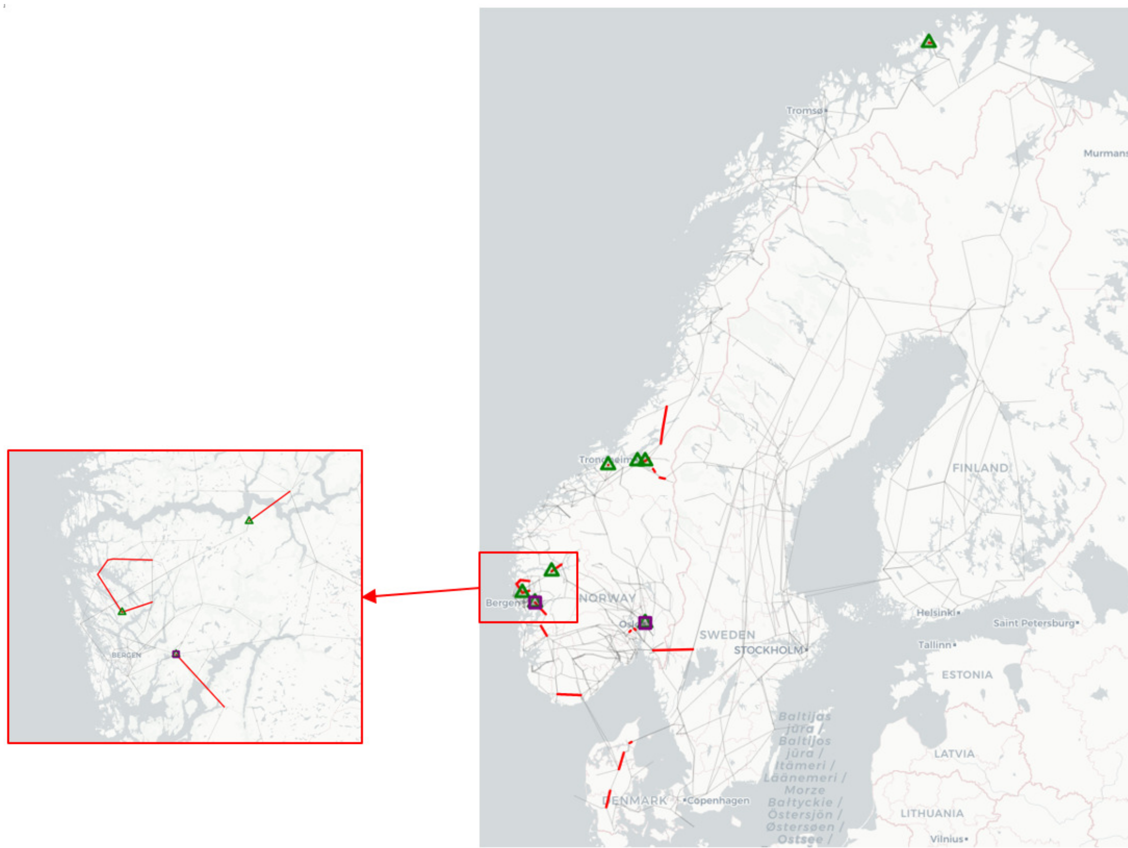


Figure 3-92 Investment decisions (Year 2040): Transmission acBranches plotted as red lines, Transformers as purple squares, Storage units as green triangles.

In Figure 3-92 the investment decisions accepted by the GEP tool at transmission grid level are shown. In general, it can be observed that in 2040 the investment decisions in terms of network reinforcement are placed not only within the focus area (such as in 2030), but address a larger area that also includes Sweden and Finland. This is reasonable because the focus area had a relatively large share of the load increase for 2030 compared with 2040. In addition to line reinforcements, in the scenario 2040 two new transformers (out of the 3 transformers candidates generated by the pre-processors) are installed as reinforcement of the previous substations, which in Figure 3-90 are marked as severely congested. Moreover, 8 H2 storage units are selected as flexible resource for the grid. In general, it can be observed that this measure is adopted mostly in urban areas (Trondheim, Bergen and Oslo), with the exception of a single storage unit in Nord Norway, which is placed at the terminal bus of a congested feeder.

The numerical results in terms of costs are summarized graphically by the diagram in Figure 3-93. After GEP solutions, the total costs are reduced by 62%. Similarly, as for the 2030, the main contribution in cost reduction is represented by the reduction in load curtailment, due to the reduction in terms of line congestions. Generation costs and generation curtailment costs do not show a significant change after the network expansion. Also load reduction costs are roughly the same after implementing the expansion plan, due to no additional flexible loads being installed in 2040.

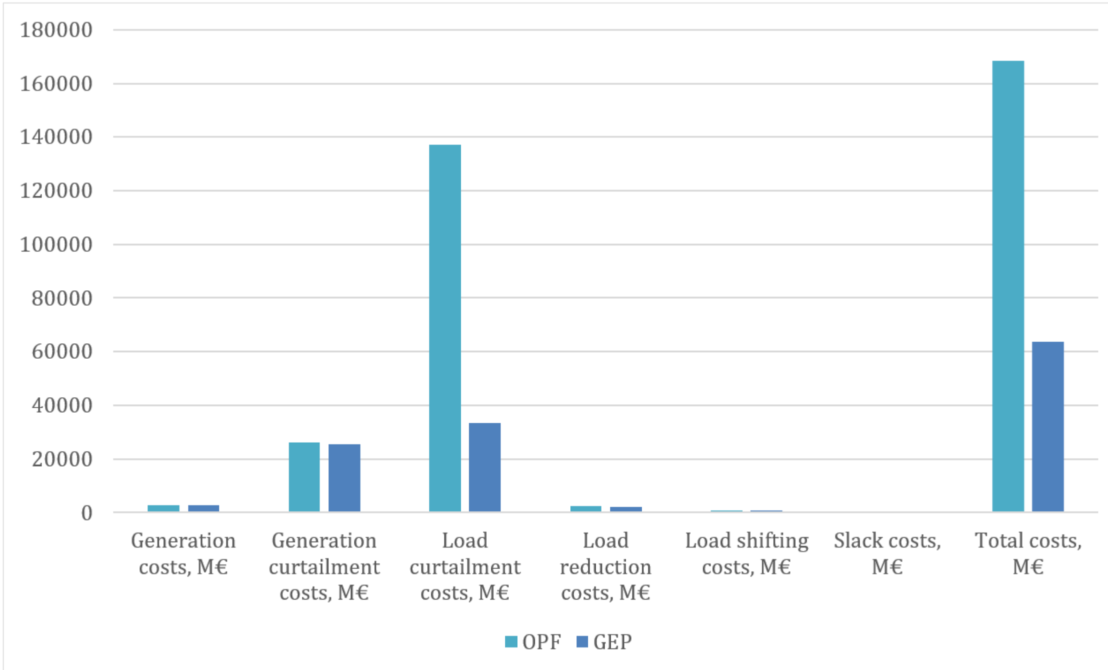


Figure 3-93 Comparison of cost results between non-expanded network (OPF) and GEP solutions (Year 2040)

Decade 2050

In Figure 3-94 and Figure 3-95 the results from the OPF, based on the grid scenario 2050, are shown.

Figure 3-94 shows the overloads over the transmission lines in terms of number of occurrences over the 336 hour-samples analysed. What can be observed is that the focus area around Bergen is again affected by significant occurrences of overload conditions, whereas the remaining part of the Nordic region does not show a significant worsening of line and transformer congestions if compared with 2040 (Figure 3-90).

As in the case of 2030 and 2040, the urban centres are significantly affected by load curtailment as the main measure for solving network overload, whereas generation curtailment is observed sparsely throughout the whole Nordic Regional area (Figure 3-91). Nevertheless, it should be observed that the magnitude of load curtailment is further notably reduced compared with the scenario 2040, despite the overall load increase for 2050 in the whole Nordic area (Figure 3-85), and the maximum value of load curtailment for 2050 is about 7 500 MWh (compared with about 182 000 MWh in 2040).

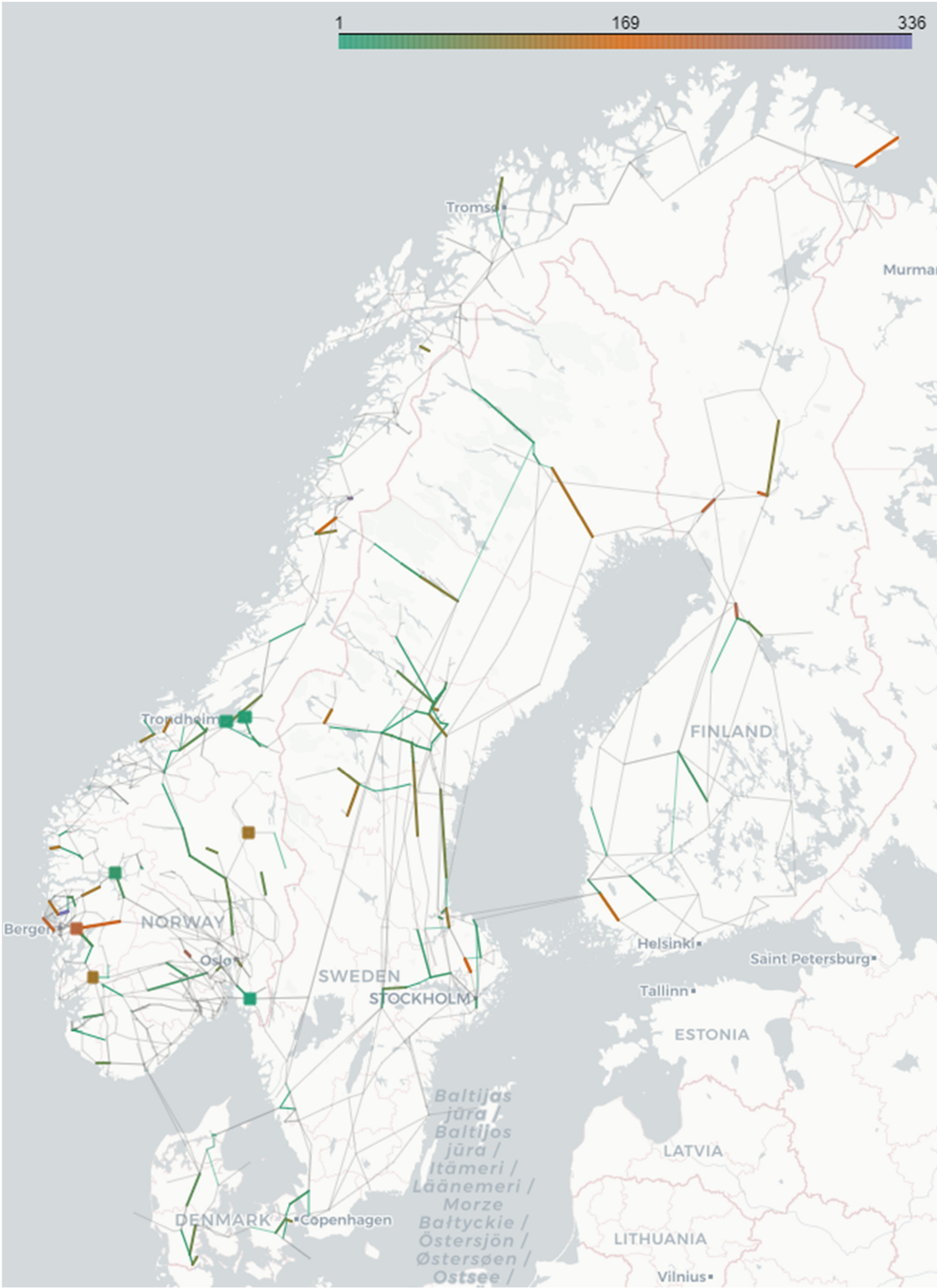
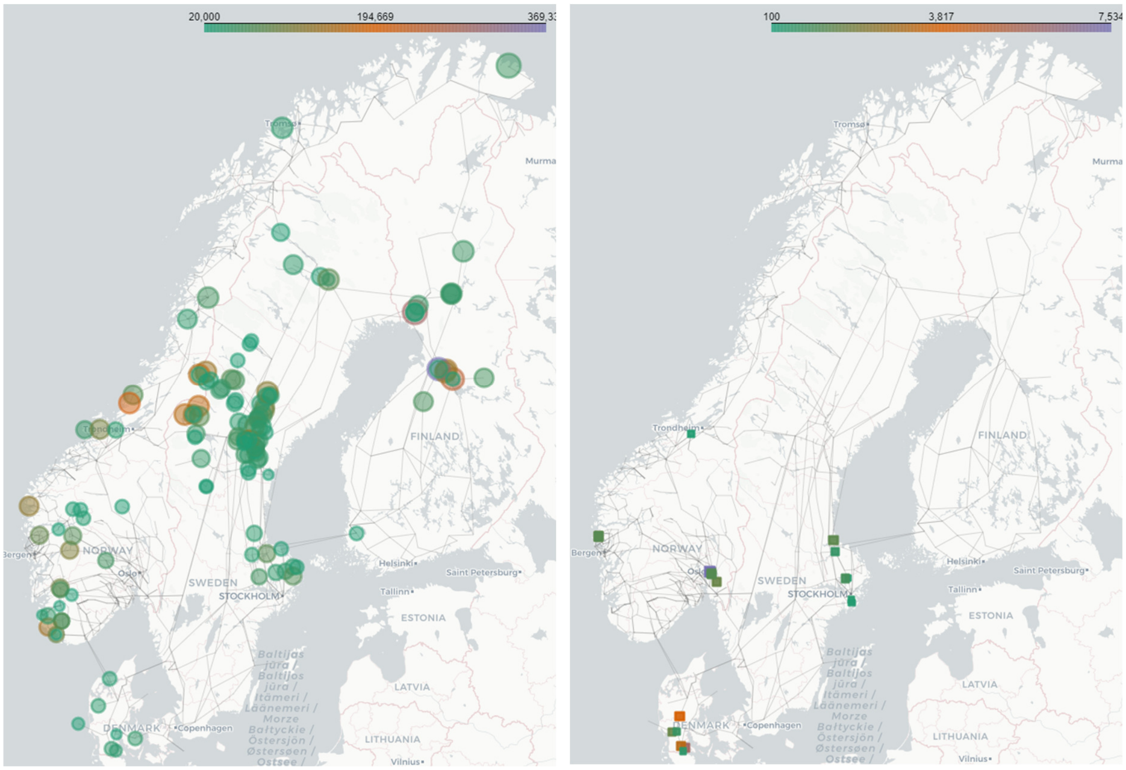


Figure 3-94 Overloaded lines (plotted as lines) and transformers (plotted as squares) for the Nordic RC and related Lagrange Multipliers (Year 2050)



(a) (b)

Figure 3-95 Curtailed generators (plotted as circles, (a)) and loads (plotted as squares, (b)) for the Nordic RC and yearly curtailed energy (Year 2050).

A total number of 100 candidates were generated from the preprocessor as input of the GEP tool. In Table 3-118 these candidates are described in terms of components, and the number of accepted candidates is also reported.

Table 3-118 Description of candidates 2050

Type	AC Branch	Transformer	Storage	Flexibility load	Total
Number of candidates	79	0	2	19	100
Investment decisions	5 (Transmission) 12 (Distribution)	0 (Transmission) 0 (Distribution)	2 (H2) 0 (Li-Ion)	0 (Transmission) 13 (Distribution)	32
Investment rejected	2 (Transmission) 60 (Distribution)	0 (Transmission) 0 (Distribution)	0 (H2) 0 (Li-Ion)	0 (Transmission) 6 (Distribution)	68
Investment costs (M€)	12,460,000	0	13,000	1,300	12.474,300

Table 3-119 summarizes the results of the studies for 2050, whereas Table 3-120 and Table 3-121 reports the costs for each representative week of the different cost items for OPF (non-expanded network) and GEP.

Table 3-119 Results of the simulation 2050

Total costs (Optimal Power Flow), M€	88,524,660,000
Total costs (Grid Expansion Planning Tool), M€	83,845,900,000
Execution time	115 109.3 seconds (31.97 h)
MIP Gap, %	0.0099

Table 3-120 Results of OPF 2050

Period	Week 1	Week 2	Week 3	Week 4	Total
Generation costs, €	2,380,510,000	4,594,360,000	6,800,870,000	529,330,000	14,305,070,000
Generation curtailment costs, €	12,804,970,000	7,470,280,000	4,909,130,000	3,975,860,000	29,160,240,000
Load curtailment costs, €	25,240,620,000	11,706,880,000	6,560,050,000	114,830,000	43,622,390,000
Load reduction costs, €	341,340,000	397,350,000	493,480,000	186,880,000	1,419,060,000
Load shifting costs, €	100,000	7,610,000	7,820,000	2,380,000	17,900,000
Slack costs, €	0	0	0	0	0
Total costs, €	40,767,540,000	24,176,480,000	18,771,350,000	4,809,280,000	88,524,660,000

Table 3-121 Results of GEP 2050

Period	Week 1	Week 2	Week 3	Week 4	Total
Generation costs, €	2,357,010,000	4,116,370,000	6,067,110,000	444,550,000	12,985,040,000
Generation curtailment costs, €	12,804,970,000	7,470,280,000	4,909,130,000	3,975,860,000	29,160,240,000
Load curtailment costs, €	24,085,950,000	11,280,410,000	5,962,120,000	93,110,000	41,421,590,000
Load reduction costs, €	4,340,000	103,130,000	145,720,000	6,050,000	259,240,000
Load shifting costs, €	0	7,560,000	9,430,000	2,810,000	19,800,000
Slack costs, €	0	0	0	0	0
Total costs, €	39,252,270,000	22,977,750,000	17,093,510,000	4,522,380,000	83,845,900,000

Figure 3-96 Investment decisions (Year 2050): Transmission acBranches plotted as red lines, Storage units as green triangles

In Figure 3-96 the investment decisions accepted by the GEP tool at transmission grid level are shown. It can be observed that the investments at transmission grid level are, as for the case of 2030, concentrated within the focus area, with 5 transmission lines and two storage units. The focus area is further reinforced by the installation of 13 flexible loads at distribution system level. The reader is reminded on the simplification assumption that has restricted the distribution grid characterization only within the focus area; the details of distribution grids components are not represented in Figure 3-96 for the sake of graphical simplicity. Another adaptation that is relevant to recall is that the load growth scenario is more detailed (granular) and higher for the focus area. Since there were only a limited number of transmission line candidates from the preprocessor that could be considered by the GEP, this may explain why no transmission line investments outside the focus area were prioritized in the 2030 results shown in Figure 3-96.

The numerical results in terms of costs are summarized graphically by the diagram in Figure 3-97. After GEP solutions, the total costs are only slightly reduced in 2050, by 5%, where the main contribution in cost reduction is represented by the reduction in generation costs, load curtailment costs and load reduction costs, whereas generation curtailment costs are kept roughly unchanged.

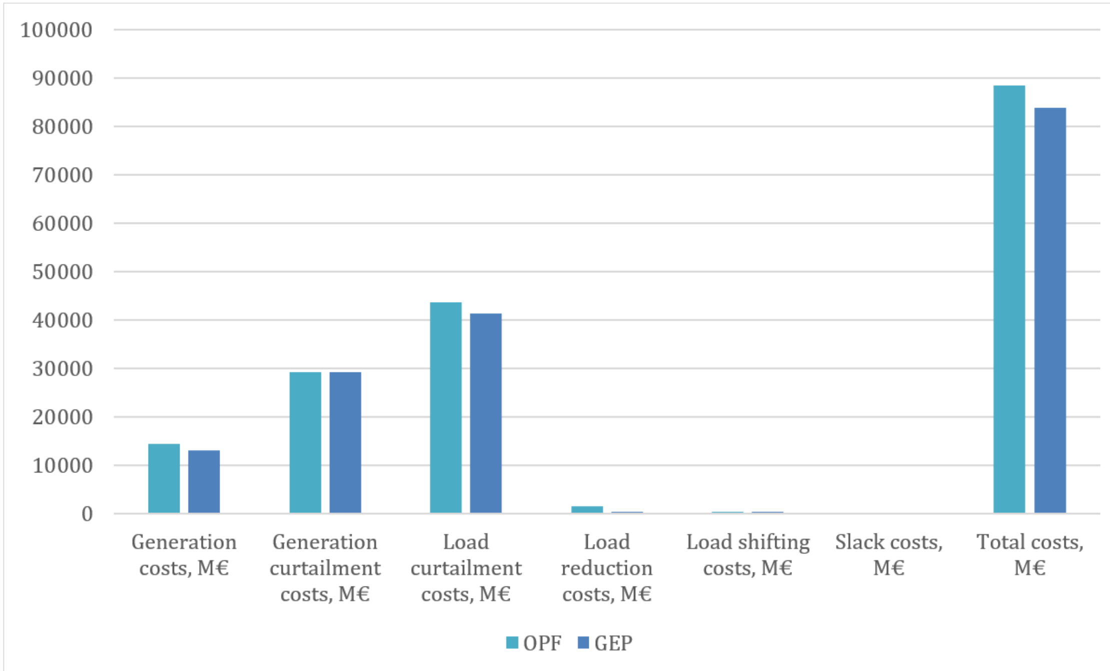


Figure 3-97 Comparison of cost results between non-expanded network (OPF) and GEP solutions (Year 2050)

Environmental impact assessment

In Table 3-122 the results related to the assessment of the environmental impact of the power system are reported. The analysis is divided into four points:

a) Carbon Footprint (CF) impact assessment for generation: it reports the percentage ratio of CF costs related to the total generation costs
b) Air Quality (AQ) impact assessment for generation: it reports the percentage ratio of AQ costs related to the total generation costs.
c) Carbon Footprint (CF) impact assessment: it reports the percentage ratio of CF costs related to the total costs
d) Air Quality (AQ) impact assessment: it reports the percentage ratio of AQ costs related to the total costs.

The values are reported for all the three decades analyzed (2030, 2040 and 2050). For total generation costs and total costs, refer to Table 3-113, Table 3-117 and Table 3-121, for 2030, 2040 and 2050, respectively.

It can be observed that in the Nordic region the impact of CF and AQ costs on both generation costs and total costs is relatively small. This is mostly due to the high share of power plants with null or small CO2 costs among the thermal units (most notably nuclear, bio and gas).

The results do not show a uniform trend in terms of CF and AQ costs evolution in the three decades analyzed, due to the several factors that co-participate to the definition of environmental costs:

- The evolution of load and generation scenario; in particular, the generation from thermal units, according to the scenario analyzed, is expected to increase, especially in 2050, with a proportional increase in the CF;
- The air quality impact is negligible for all the decades, due to the specific generation portfolio of the Nordic region

Table 3-122 Environmental costs assessment in the three decades 2030, 2040 and 2050

Metric		**2030**	**2040**	**2050**
(a)	Carbon Footprint impact assessment for generation [%]	8.092	5.219	11.377
(b)	Air Quality impact assessment for generation [%]	0.070	0.025	0.038
(c)	Carbon Footprint impact assessment [%]	0.273	0.229	1.761
(d)	Air Quality impact assessment [%]	0.002	0.001	0.006

Summary of the results

To further analyse, interpret and validate the results for the Nordic RC, a second physical workshop with Norwegian stakeholders was organized in November 2022. The conclusions from the framework are summarized below to give a qualitative evaluation of the results and their implications.

The results from this analysis and comparable analyses known to the participants purposes indicate that the role of flexibility in grid planning is strongly case dependent. In this particular case, the use of flexibility to reduce grid investments is very limited. This was attributed to the following characteristics of the situation in the focus area: i) A very high and sustained load growth was expected, and ii) the loads in the system were dominated by industrial end-users with mostly flat load profiles and relatively limited flexibility potential.

The situation in the focus area is representative of several other areas of the Norwegian power system but not all. In retrospect, if for instance the Oslo area had been selected as focus area, then the conclusions were expected to be different. In that grid area (as in several other Norwegian areas), electrical heating constitutes a large share of the present-day load, and the flexibility potential is therefore greater. Moreover, electrical vehicle charging constitutes a significant and increasing load contribution, and so the flexible share of the load demand is expected to be even greater in the future. None of these conditions hold in the grid area around Bergen.

The role of Norwegian hydropower and the flexibility it can provide was also discussed in the workshop. What role hydropower flexibility can have in the future for different purposes, services and markets is a question that goes beyond the scope of the FlexPlan methodology, but reservoir-hydropower plants were expected to be a dominant flexibility source also in the future Nordic power system, and it was believed that its potential for congestion management could be even better utilized. However, in the focus area selected for the Nordic RC, most of the flexible hydropower was located on the wrong side of the major bottlenecks in the grid area, and hydropower therefore played a relatively limited role.

Relatively few energy storage investments were suggested by the planning tool for any of the target years. For the focus area, it is likely that the reason is that the relatively flat load profiles in the western part of the area makes it impossible for storage devices to charge enough during low-load hours to supply the excess load demand during high-load hours. During the workshop it was identified that flexible generation resources in the western parts of the focus area would be the most relevant candidate to relieve congestions, but new power plants are not included as candidates in the FlexPlan methodology. Another missing factor that could be significant for the case is offshore wind power: The expected installation of wind power off the western coast of Norway by 2040 [20] far outweighs the expected installation of onshore wind power and solar PV power included in the MILES time series. If included in the analysis, offshore wind power and associated offshore grid (inter)connections, could change the conclusions for the case significantly. However, it was also highlighted that very large grid investments would nevertheless be needed in the focus areas because wind power varies over so long timescales it would take flexibility resources with extremely large energy capacity locally in the grid area to balance the offshore wind production.

3.7 Summary and comparison of the results

Summarizing the results from the section 3, it should be noted that despite the simplifications described in Section 2, there was the need to split two of the RCs' networks in order to be able to complete the simulations. For the German network, due to high number of the nodes and branches and also the fact that in the German network supra-regional measures only make sense if local investments in RES integration are performed, it led to very high computation time required and not accurate results within the limited computation time available. In this case, in order to reach reasonable results, a restricted number of proposed candidates was considered. Yet, this led to high levels of curtailment after, during the grid expansion planning and very high power-flows from north to south, which resulted in a large number of congested lines in the network, nevertheless, the results are still optimal taking into account all this boundaries that were implemented in the simulations.

The Nordic RC was developed with a different approach, compared to other RCs, due to the absence of the network data in the ENTSO-E Grid model, which was the main source of network data for other RCs. The Nordic RC used the network data from the Norwegian regulator and was more focused on Norway due to availability of more detailed and quality assured network data. Furthermore, a special emphasis on the region of Bergen, along the Western coast, was given due to stakeholder inputs and the collaboration that could be established with the local DSO. Part of the adaptation of the Nordic RC was to represent the focus area in more detail, with load growth scenarios more closely in line with DSO and TSO expectations of establishment of new major power-intensive industries connected to certain buses in the area.

Nevertheless, it was possible to find the patterns and similarities in the results of different RCs. These similarities can be aggregated in several different groups:

- Number of congestions;
- Number and type of investment decisions;
- Variations of the costs before and after solving grid expansion planning problem;
- Environmental impact assessment.

Number of congestions

For most of the RCs, the results show that the number of congestions increase with each time horizon (2030, 2040, 2050). The main reasons that explain this behaviour are:

- Increased load and/or generation profiles in the scenarios, provided by MILES. This lead to existence of more overloaded lines (congestions) which resulted in Lagrange Multipliers different from 0;
- Limiting the number of candidates to be processed in the GEP Tool. This leads to the fact that not all the congestions are eliminated while solving the grid expansion planning problem and these congestions can occur in the following decades. In this case, the pre-processor can suggest the same candidates in future decades if they were not approved in the previous ones. If the

computational power is increased, it will be possible not to limit the number of candidates and the number of congestions will decrease with each time horizon.

Number and type of investment decisions

The location and the number of the conventional grid expansion candidates (lines and transformers) are different from one RC to another, but from the results in Section 3 it can be seen that for most of the RCs the percent of the conventional grid expansion candidates in transmission network does not exceed 37.1% (13 conventional candidates in transmission to the total 35 conventional candidates in BeNeLux region in 2040). In this analysis the German part of Germany, Switzerland and Austria RC is not included since no candidates in distribution network were considered for the calculation due to the high computation time.

The approval rate for transmission network candidates (percent of investment decisions in transmission network to the total number of proposed candidates in transmission network) is also different from one RC to another, but does not go below 42.9% (3 investment decisions to 7 proposed candidates in Balkan RC in 2050). The only exception is the French network, where no investment decisions occur in all decades in transmission even after manual addition of 6 transmission candidates in 2040 and 2050. As for the change in the number of candidates from one decade to the following, it can be seen that there is a tendency to decrease the approval rate or keep the same from 2030 to 2040 and from 2040 to 2050 at least for four RCs out of six (Iberian RC, BeNeLux region of France and BeNeLux RC, Swiss and Austrian region of Germany, Switzerland and Austria RC, Balkan RC). As for remaining two RCs:

- For the Italian RC, many of the congestions in 2030 are not addressed (due to the limiting factor of 100 candidates maximum from the pre-processor) and significant increase of load and renewable generation, yet, the number of the investment decisions in transmission network as well as the approval rate increases in 2040;
- For the Nordic RC, the investment decisions in transmission in 2030 are mainly located in the focus area of Bergen, relieving this area from overloads. However, more congestions were observed across the whole region in 2040, which leads to significant increase in the number of suggested conventional candidates and investment decisions for 2040. Investment decisions in both 2030 and 2040 significantly reduce the number of suggested conventional candidates in transmission (from 13 and 29 in 2030 and 2040 respectfully to 7 in 2050). However, the approval rate in transmission is still high and more than 71% (5 suggested candidates in transmission approved out of 7).

Regarding the storage and flexible load candidates, the results are heterogeneous and vary due to different operation of the system as well as duration of the congestions, resulting in the selection of different types of storage candidates. As for the storage candidates, only in the Nordic RC in 2030 storage candidates are not approved after solving the grid expansion planning problem, but overall there is a tendency in increasing the approval rate of the storage candidates from 2030 to 2040 and then to 2050 in all RCs, which means that taking into account the number of investment decisions in conventional infrastructure candidates, the storage candidates works in synergy with the approved reinforcements of the network to reduce the total costs since the storage candidates can reduce the power fluctuation in distribution networks with high penetration of wind and solar generation. With regard to flexibility loads, the approval rate varies and can be from 6% (in BeNeLux network for 2030) to 100% (in many cases). The average approval rate for flexibility loads is 64%.

Variations of the costs before and after solving grid expansion planning problem

Also, it is important to mention that the selection of the candidates by the pre-processor is based on the OPF results and indirectly depends on the OPF costs. For four RCs out of six the total costs increase throughout the three decades, which is due to the fact that not all of the congestions are solved during the GEP simulation because of the limited number of candidates. However, for other two RCs (or regions inside one RC) the total costs in 2030 are higher than in 2040 and 2050:

- In BeNeLux region of France and BeNeLux RC the total costs in 2040 reduced by approximately 60% compared to 2030. This is explained by the fact that load curtailment costs, which are the main contribution to the total costs, lowered by approximately 68% after 2030 investments, and because of the unbalanced input data, where the scenario of 2040 forecasts a significant increase in RES generation, whereas the load profile does not increase so drastically.
- In the Nordic RC the total costs in 2040 were reduced by approximately 47% compared to 2030. This is explained by the fact that in 2030 there is a high density of the congestions around focus area of Bergen and in this case all suggested flexible load candidates and suggested grid reinforcement in transmission network in the focused area are approved. These investment decisions in 2030 reduced the load curtailment costs by 84%. In 2040, the focus area of Bergen partially relieved from overloads experienced throughout all the Nordic area, and the load curtailment costs, which is the largest contributor to the total costs in 2040, was reduced by 76%.

For other RCs (and regions in RCs):

- In the Iberian RC, generation curtailment costs are the main contributor to the total costs. In 2030 due to investments decisions both in reinforcement of transmission network (6 approved candidates) and flexible resources, it was possible to reduce load curtailment costs by 50%, which led to reduction of total costs by 13%. However, since there are no suggested candidates in the transmission network in 2040 and 2050, congestions are solved only locally, and hence the reduction of the total costs after investment decisions is less than 1%.
- In French region of France and BeNeLux RC load curtailment costs are the main contributor to the total costs over all the years and after investment decisions decrease by 37%, 13% and 28% in 2030, 2040 and 2050 respectively. This happens as result of the simplification related to the limitation of the number of suggested candidates and increased load in the scenarios.
- In the Swiss and Austrian region in Germany, Switzerland and Austria RC the main share of the total costs varies from year to year, in 2030 and 2050 the main share is in generation

curtailment costs, in 2040 is the load curtailment costs. In 2030 the total costs reduces by 45%, with only a few investments in assets necessary to fulfil the supply task, a large incentive to make load flexible in order to increase the integration of RES becomes visible. However, as per Nordic RC, the investment in storage capacity is not expected to be economically optimal in this first decade. In 2040 and 2050 the total cost reduces by 10% and 35% and the results show that a high RES integration can be achieved in the region by investing in the grid reinforcement, flexible loads as well as storage.

- In the Italian RC the main share of the total costs is changing throughout the years. In fact, while in 2030 the main contribution comes from generation costs and load curtailment costs are comparably smaller, the latter increase significantly from 2030 to 2040 and then to 2050 and start to be the main contribution to the total costs in 2050. Load curtailment costs increase from 2030 to 2050 as result of many congestions which are not eliminated in previous decades (due to the limiting factor of 100 candidates maximum from the pre-processor) and significant increase of load and renewable generation.
- In the Balkan RC the main share of the total costs in 2030 and 2040 is generation costs, while the load curtailment costs play the main role in 2050. Load curtailment costs increase from 2030 to 2050 because many of the congestions in the previous decades are not eliminated (due to the limiting factor of 100 candidates maximum from the pre-processor) and increase of load in the scenarios, similarly to Italian RC.

Worth mentioning is that for all RCs, costs related to flexible loads, i.e. load reduction and load shifting costs, are quite small with regard to total costs, even with several accepted flexible load candidates, as per Balkan RC.

Environmental impact assessment

Comparing results of the environmental costs, it can be seen that for all RCs the carbon footprint impact plays more significant role to generation costs and, as a result, to total costs. However, the impact of the carbon footprint on total costs varies from the maximum of 69.8% (for the Balkan RC in 2040) to less than 0.01% (for the German region in 2050). This percentage can be very high as result of the operation of conventional power plants, especially in urban area, and high share of the generation costs in the total costs.

4 Conclusions

This deliverable contains a brief description of the methodology developed within the FlexPlan project, including:

- Data gathering (generation and load profiles, cross-border flows between regional cases and between countries within the regional case, transmission and distribution networks, carbon footprint and air quality costs);
- Obtaining possible candidates for flexibility element candidates and candidates for grid reinforcement based on the OPF calculations;
- Results of tests of the new innovative grid expansion planning tool for six various regional cases.

To be able to demonstrate numerical tractability of the calculations, several simplifications are needed to be implemented and they are described in this deliverable in details.

The results for the three target years (2030, 2040, 2050) are presented for all six regional cases, including:

- Number, location and severity of congestions after running OPF calculations;
- OPF calculation costs by type;
- Number, location and type of candidates for installation of flexibility elements or grid reinforcements, proposed by the pre-processor;
- The results of the GEP calculation with number, location and type of approved candidates and resulting GEP calculation costs.

An analysis of the results is carried out too. Different optimal solutions are obtained by the regional cases with respect to the variety of the data and the simplifications that have been implemented within each regional case (e.g. different number of proposed candidates by either manually adding of the candidates in consultation with TSO or reducing the number of candidates to make the calculations feasible). The environmental impact is also assessed for the six regional cases and the effect of the carbon footprint and air quality on the simulations is evaluated.

As for the results for the regional cases:

- The Iberian RC is characterized with high generation curtailment costs for all target years because the generation is higher than demand due to the scenario profiles, generated by MILES software. The number of candidates in transmission network reduces and both in 2040 and 2050 no candidates in transmission network are evaluated. This happens due to the fact that the number of candidates is limited and the list of possible candidates is ranked by Lagrange Multipliers and the most severe congestions appear in distribution network. The number of proposed storage candidates and flexibility load candidates decrease to 2050 because of the duration and severity of the congestions.
- The France and BeNeLux RC was divided in two parts in order to reduce the computation time. The French region is characterized with high load curtailment costs and similar to Iberian RC, no candidates in transmission network from the pre-processor are calculated and even manually added six line candidates in transmission network in 2040 and 2050 were not

approved, which means that the investment in these lines do not decrease the result of solving the grid expansion planning problem. The BeNeLux region, in contrary to French region, is characterized with large number of candidates, located in transmission network and the approval rate of these candidates for traditional grid reinforcement candidates (lines and transformers) does not go below 50%. The total costs in 2040 are lower than in 2030 because the scenario of 2040 forecasts a significant increase in RES generation, whereas the load profile does not increase so drastically.

- The Germany, Switzerland and Austria RC was also divided in two parts in order to reduce the computation time. However, even with these simplification the German region is characterized with a large number of elements (nodes and branches) and the number of candidates was needed to be drastically reduced and limited with only transmission network candidates, nevertheless the distribution networks were added to the model in order to evaluate the impact of the transmission network candidates on distribution networks. The results for German region show that the main share of the total costs is load curtailment costs for all target years due to large power flows between northern and southern part of Germany. Swiss and Austrian region is characterized with a big share of load curtailment costs in the target years and large number of storage candidates and flexibility load candidates in 2040 and 2050 because of higher penetration of RES generation in these target years.
- The Italy RC is characterized with increasing share of load curtailment costs in 2050 comparing to 2030 and 2040 (due to the limited number of calculated candidates) and large number of transmission network candidates in all target years. Storage candidates and flexibility load candidates are frequently selected as profitable investment, and often it is called to work in synergy with the network reinforcement corresponding to the same congestion.
- The Balkan RC consists of transmission and distribution networks of seven countries. The main share of the costs for 2030 and 2040 is the generation costs, however in 2050 the main share is the load curtailment costs due to large increase of the load profiles in the scenarios. Due to increasing penetration of RES generation in 2040 and 2050, the approval rate of storage candidates and flexibility load candidates increase from 15% in 2030 to 91% in 2050 and from 60% in 2030 to 100% in 2050 respectively.
- In the Nordic RC the total costs in 2040 are lower than in 2030 because the approved candidates in 2030 decrease significantly the load curtailment in the network and the focus area near Bergen partially relieved from overloads. The approval rate of the conventional grid reinforcement candidates in transmission network is higher than 50% in all target years and in distribution networks it decreases from 66% in 2030 to 17% in 2050 because investments in distribution network do not decrease the result of solving the grid expansion planning problem.

The results showed that along with the traditional grid reinforcements, flexibility elements described in [3] are indeed selected by the planning tool to help compensating variable RES generation or load fluctuation, resulting in a decrease of generation and load curtailment costs. These results and the analysis carried out upon these results will be an input for further regulatory considerations to analyze the potential impact of the inclusion of flexibility resources into TSO and DSO grid planning studies at the pan-European level. Such considerations are included into deliverable D6.3 of the FlexPlan project.

5 References

[1] Project FlexPlan , "D1.2 Probabilistic optimization of T&D systems planning with high grid flexibility and its scalability," 2021. [Online]. Available: https://flexplan-project.eu/wp-content/uploads/2021/03/D1.2_20210325_V1.0.pdf.

[2] Project FlexPlan , "D5.1 Data sets and planning criteria for the regional studies," 2021. [Online]. Available: https://flexplan-project.eu/wp-content/uploads/2021/09/D5.1_20210915_V1.0.pdf.

[3] Project FlexPlan, "D2.2 Flexibility elements identification and characterization," [Online]. Available: https://flexplan-project.eu/wp-content/uploads/2020/06/D2.2_20200622_V1.0.pdf.

[4] ENTSO-E, "TYNDP 2020 Scenario Report," [Online]. Available: https://2020.entsos-tyndp-scenarios.eu/wp-content/uploads/2020/06/TYNDP_2020_Joint_ScenarioReport_final.pdf.

[5] ENTSO-E, "TYNDP 2018 Scenario Report," [Online]. Available: https://www.entsoe.eu/Documents/TYNDP%20documents/TYNDP2018/Scenario_Report_2018_Final.pdf.

[6] ENTSO-E, "Mid-term Adequacy Forecast, 2018 Edition," [Online]. Available: https://docstore.entsoe.eu/Documents/SDC%20documents/MAF/2018/MAF%202018%20Executive%20Report.pdf.

[7] ENTSO-E , "ENTSO-E Transmission System Map," 2022. [Online]. Available: https://www.entsoe.eu/data/map/. [Accessed 12 Apr. 2022].

[8] "PyPSA-Eur Model," [Online]. Available: https://pypsa-eur.readthedocs.io/en/latest/.

[9] Project FlexPlan, "D4.1 Pan-European scenario data," 2020. [Online]. Available: https://flexplan-project.eu/wp-content/uploads/2020/08/D4.1_20200803_V1.pdf.

[10] Project STORE&GO, "D8.3 Report on the costs involved with PtG technologies and their potentials across the EU," [Online]. Available: https://www.storeandgo.info/fileadmin/downloads/deliverables_2020/Update/20180424_STOREandGO_D8.3_RUG_accepted.pdf.

[11] IEA, "The future of Hydrogen - Seizing today's opportunities," 2019.

[12] Project FlexPlan, "D4.2 Pan-European Simulation Results," [Online]. Available: https://flexplan-project.eu/wp-content/uploads/2021/03/D4.2_20210326_V1.0.pdf.

[13] JRC Smart Electricity Systems and Interoperability, "The DiNeMo platform," [Online]. Available: https://ses.jrc.ec.europa.eu/dinemo.

[14] NVE, "Norwegian Water Resources and Energy Directorate," [Online]. Available: https://www.nve.no/.

[15] "ENERGINET EN," [Online]. Available: https://en.energinet.dk/.

[16] "OpenStreetMap (OSM)," [Online]. Available: https://www.openstreetmap.org/.

[17] O. Wolfgang, A. Haugstad, B. Mo, A. Gjelsvik, I. Wangensteen, and G. Doorman, "Hydro reservoir handling in Norway before and after deregulation," *Energy,* vol. 34, no. 10, pp. 1642-1651.

[18] BKK Net, "Regional Kraftsystemutredning for BKK-området og indre Hardanger, 2020 – 2040," 2020.

[19] Statnett, "Konseptvalgutredning Bergen og omland," 2020.

[20] Norwegian Government, "press release 2022-05-11," [Online]. Available: https://www.regjeringen.no/no/aktuelt/kraftfull-satsing-pa-havvind/id2912297/.