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Stéphane Allard

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THÈSE

Pour obtenir le grade de

DOCTEUR DE LA COMMUNAUTE UNIVERSITE GRENOBLE ALPES

Spécialité : **Génie Electrique**

Arrêté ministériel : 25 mai 2016

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codirigée par **Patrick CRIQUI**

préparée au sein du **Laboratoire de Génie Électrique de
Grenoble (G2Elab)**
dans l'**École Doctorale Electronique, Electrotechnique,
Automatique, Traitement du Signal (EEATS)**

Enjeux de flexibilité liés au développement des infrastructures réseaux pour l'intégration massive des énergies renouvelables variables dans le système électrique à l'horizon 2100

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Table of Contents

Acknowledgements / Remerciements	1
Table of Contents	3
Index of Figures	7
Index of Tables	12
Index of Acronyms	13
Introduction	15
Problem statement	17
Contributions.....	19
Scientific publications.....	20
Plan of the thesis.....	21
Chapter I. Representing the long-term evolution of the power system	23
I.1 The increase of complexity in prospective energy models	24
I.1.1 Demand forecasting	26
I.1.2 International energy prices	27
I.1.3 Endogenous technological progress.....	28
I.1.4 VRES representation.....	28
I.2 Power systems models	31
I.1.1 Technical modelling approach	31
I.1.2 Transmission grid planning models	31
I.3 Long-term energy models and power system models	33
I.3.1 Interactions between long-term energy and power system models.....	33
I.3.2 Comparisons of models: role of transmission grid	35
Conclusions	38
Chapter II. Transmission capacity expansion in a long-term energy model	41
II.1 Modelling state of the art.....	42
II.1.1 Long-term energy modelling: POLES model.....	42
II.1.2 Refining the temporal power sector representation with EUCAD	45
II.2 EUTGRID, a new model with an improved transmission grid representation.....	46
II.2.1 Model description	46
II.2.2 Construction of the databases	58
II.2.3 Validating EUTGRID	66
II.3 Sensitivity analysis on payback-period.....	74
Conclusions	76
Chapter III. Grid expansion and flexibility options with large scale integration of VRES	77

III.1	Assessing the role of the transmission grid.....	79
III.1.1	Socio-economic assumptions.....	79
III.1.2	Implementing a climate energy policy.....	80
III.1.3	Climate energy policy scenarios considered.....	82
III.2	European transmission grid development.....	84
III.2.1	Transmission grid requirements and VRES integration.....	84
III.2.2	Competition between HVAC and HVDC technologies.....	86
III.2.3	Reinforcements spatial location.....	89
III.3	Impact of grid development on energy mix and flexibility options.....	91
III.3.1	Emissions.....	92
III.3.2	Energy mix and power system costs.....	93
III.3.3	Flexibility options and security of supply.....	96
III.4	Including environmental indicators: LCA.....	99
III.4.1	New objective function.....	99
III.4.2	Comparisons on emissions and electricity costs.....	100
III.4.3	Impacts on energy mix and flexibility options.....	102
III.4.4	Transmission grid requirements.....	106
	Conclusions.....	109
Chapter IV.	Representing the distribution grids in long-term energy models.....	111
IV.1	Renewable integration in distribution grids.....	112
IV.1.1	New issues arise in the distribution grids.....	112
IV.1.2	Specific models to analyse distribution grids.....	116
IV.2	Representing the distribution grid in EUTGRID.....	117
IV.2.1	Linearizing the AC load flow equations.....	117
IV.2.2	Comparisons between EUTGRID&D and MATPOWER.....	121
IV.2.3	Generic distribution grids.....	123
IV.3	Analysis of the different distribution networks.....	127
IV.3.1	Analysis of the different issues with no implemented solution.....	127
IV.3.2	Solving the issues in the different networks.....	130
IV.4	Distribution grids representation in POLES.....	143
IV.4.1	Specific conditions for the coupling with POLES.....	143
IV.4.2	Impacts of representing the distribution grids.....	145
IV.4.3	Evolution of transmission grid infrastructure.....	153
	Conclusions.....	157
	Conclusions and perspectives.....	159
	Conclusions.....	160
	Perspectives.....	163
	References.....	165
	Annexes.....	183

Annex A - List of electricity producing technologies used in POLES	185
Annex B – Capacity validations.....	188
Annex C – Production validations	190
Solar production data	190
Wind on-shore and off-shore production data.....	192
European validations.....	193
Annex D – Urban, rural and mountainous regions.....	195
Annex E– Sensitivity analysis for the different solution on the energy mix in the distribution grids.....	198
Annex F– CO ₂ emissions factors for fossil production in POLES	200
Résumé de la thèse	201
Abstract / Résumé	208
Abstract	208
Résumé	208

Index of Figures

Figure I-1 – Overview of prospective energy models and power system models and how they can interact (based on [80])	34
Figure II-1 – Structure of the POLES model with the different energy modules [89].....	43
Figure II-2 – Distribution of distances for on-shore lines (HVAC and HVDC can compete) 51	
Figure II-3 – Average grid coefficients in Europe	54
Figure II-4 – Diagram describing the grid investment mechanism.....	55
Figure II-5 – Allowed pathways for on-shore HVAC/HVDC and sub-sea HVDC.....	56
Figure II-6 – Diagram of the coupling between POLES and EUTGRID	57
Figure II-7 – Final European nodes from "e-HIGHWAY 2050"	58
Figure II-8 – (a) Georeferencing ENTSO-E map 2012; (b) Aggregated transmission grid (HVAC & HVDC) in 2012	60
Figure II-9 – Typical days definition diagram (adapted from [12]).....	61
Figure II-10 – Typical days of VRES production (summer/winter) for Belgium	62
Figure II-11 – Electricity consumption versus GDP (left) and versus population (right) for French and English regions in 2014.....	63
Figure II-12 – Power plants in Europe according to their fuel and capacities (in MW) in 2018 [129], [130]	65
Figure II-13 – Diagram describing the potential checking module implemented in EUTGRID	66
Figure II-14 – Power flows from Switzerland to Italy (30/12/2012) – (a) using typical values; (b) using optimized susceptance matrix.....	67
Figure II-15 – Representing the hourly calculated power flows versus the historic ones (year 2012)	68
Figure II-16 – Energy mixes for two different days (26/09/2012 and 15/02/2012): real production data (left) and EUTGRID simulations (right) – France	69
Figure II-17 – Evolution of the transmission grid requirements [in TWkm] and of the maximal congestion cost [in k\$/year] at each step of the algorithm.....	71
Figure II-18 – Congestion costs at step 0 and at last step of the grid investment mechanism [in log(k\$/year)].....	71
Figure II-19 – Evolution of usage of flexibility options [in TWh] at each step of the algorithm	72
Figure III-1 – Population (left) and gross domestic product (right) for EUTGRID countries (2000 – 2100) [138], [139].	79

Figure III-2 – World cumulative CO ₂ emissions during 2011-2100 for two main scenarios (BAU and Clim)	81
Figure III-3 – Energy mixes for scenario “BAU-Copper” (left) and scenario “Clim – Copper” [in TWh].....	82
Figure III-4 – European transmission development for the different scenarios [TWkm].....	85
Figure III-5 – Share of VRES in Europe for “Clim-Copper”, “Clim-Dev” and “Clim-Dev+VRES+BAT+DR” [%].....	86
Figure III-6 – Mean European transmission grid requirement for frozen scenarios for the period 2030-2100 [GW]	90
Figure III-7 – Total transmission grid needs in scenario “Clim – Dev” (left) and in “Clim -Dev+VRES+BAT+DR” (right) for 2030-2100 [GW].....	91
Figure III-8 – Difference in cumulative emissions for “Clim-Frozen” and “Clim – Dev+VRES+BAT+DR” compared with “Clim-Dev” [%].....	93
Figure III-9 – European energy mixes for “Clim-Dev”, “Clim-Frozen” and “Clim – Dev+VRES+BAT+DR” [TWh]	94
Figure III-10 – European production costs and variable system costs for “Clim-Dev” and “Clim-Dev+VRES+BAT+DR” [\$/MWh]	96
Figure III-11 – Flexibility options and non-distributed energy for the different scenarios [TWh]	97
Figure III-12 – Percentage of Non-Distributed Energy from Load for scenario 3 in 2100 [%]	99
Figure III-13 – Yearly emissions for Europe for scenario 2 and 5 (outputs from POLES and EUTGRID).....	101
Figure III-14 – Yearly European average costs for the scenarios “Clim-Dev” and “Clim-LCA”	102
Figure III-15 – Energy mixes in 2030, 2050 and 2100 for the scenarios “Clim-Dev” and “Clim-LCA” [TWh]	103
Figure III-16 – Flexibility options and VRES curtailment in 2030, 2050 and 2100 for the scenarios “Clim-Dev” and “Clim-LCA” [TWh]	104
Figure III-17 – Flexibility options in 2030, 2050 and 2100 for the scenarios “Clim-Dev” and “Clim-LCA” [%]	105
Figure III-18 – Transmission grid development and share of VRES for the scenarios “Clim-Dev” and “Clim-LCA”	106
Figure III-19 – Total transmission grid needs in scenario “Clim-LCA” (right) and in scenario “Clim-Dev” (left) scenario for 2030-2100.....	108
Figure IV-1 – Solar capacity installed for each voltage level of the French power system [GW][150]	114

Figure IV-2 – Wind capacity installed for each voltage level of the French power system [GW][150]	115
Figure IV-3 – Grid flow limitation in EUTGRID. Representation based on [173].	120
Figure IV-4 – IEEE 30 Bus Test Case [175].	121
Figure IV-5 – Comparison of voltage between EUTGRID and MATPOWER.....	122
Figure IV-6 – Comparison of active power between EUTGRID and MATPOWER.	122
Figure IV-7 – Comparison of reactive power between EUTGRID and MATPOWER.	122
Figure IV-8 – European representative distribution grids implemented in EUTGRID and based on [187]	124
Figure IV-9 – Proposed distribution keys for urban network – Wind capacities (left) and load demand (right)	126
Figure IV-10 – Proposed distribution keys for semi-urban network – Wind capacities (left) and load demand (right).....	126
Figure IV-11 – Proposed distribution keys for rural network – Wind capacities (left) and load demand (right)	126
Figure IV-12 – VRES production and demand at node B_77 belonging to the medium voltage grid located at the end of a long line in summer (day n°5) [MWh/h]	128
Figure IV-13 – Voltage at node B_77 belonging to the medium voltage grid located at the end of a long line for summer (day n°5) [p.u.]	128
Figure IV-14 – Non-distributed energy in the rural distribution grid (share of solar production: 47 %).....	129
Figure IV-15 – Maximum voltage for each type of grid and each voltage level (100% solar)	130
Figure IV-16 – Simplified voltage profiles in case of under-voltage and resulting OLTC operation.	131
Figure IV-17 – Simplified voltage profiles in case of over-voltage and resulting OLTC operation.	131
Figure IV-18 – OLTC: Voltage at one node belonging to the medium voltage grid in summer (day n°5).....	132
Figure IV-19 – Maximum voltage before operating the OLTC (orange) and after operating the OLTC (blue) for rural grid and each voltage level (100% solar).....	133
Figure IV-20 – Number of yearly modifications of tap ratio for the OLTC for rural grid (100% solar)	133
Figure IV-21 – Reinforcement: Voltage at node B_77 belonging to the medium voltage grid in summer (day n°5)	134

Figure IV-22 – Reinforcement needs for the representative distribution grids with only solar production [km].....	135
Figure IV-23 – Curtailment: Energy mix at node B_77 belonging to the medium voltage grid in summer (day n°5) [MWh/h]	136
Figure IV-24 – Curtailment: Voltage at node B_77 belonging to the medium voltage grid in summer (day n°5) [p.u.].....	136
Figure IV-25 – Yearly energy curtailment in percentage of total solar energy for the representative distribution grids.....	137
Figure IV-26 – Storage: Energy mix at node B_77 belonging to the medium voltage grid in summer (day n°5) [MWh/h].....	138
Figure IV-27 – Storage: Voltage at node B_77 belonging to the medium voltage grid in summer (day n°5) [p.u.].....	138
Figure IV-28 – Percentage of energy stored compared to the yearly VRES production for the representative distribution grids [%].....	138
Figure IV-29 – Mean net present value for the different solutions and for each representative distribution grids [k\$].....	141
Figure IV-30 – Histogram of the least-costly solutions for each representative distribution grids [%]	142
Figure IV-31 – Computation time for running EUTGRID&D for one year and the same scenario with different number of distribution grids [minutes].....	144
Figure IV-32 – Yearly emissions in "Region IDF" for the two scenarios "Clim-Dev" and "Clim-Distrib" [MtCO ₂ eq]	146
Figure IV-33 – Yearly emissions in "Region HDF" for the two scenarios "Clim-Dev" and "Clim-Distrib" [MtCO ₂ eq]	146
Figure IV-34 – Yearly emissions in "Region PACA" for the two scenarios "Clim-Dev" and "Clim-Distrib" [MtCO ₂ eq].....	147
Figure IV-35 – Energy mix in 2010, 2030 and 2050 in "Region IDF" for the two scenarios "Clim-Dev" and "Clim-Distrib" [TWh].....	148
Figure IV-36 – Energy mix in 2010, 2030 and 2050 in "Region HDF" for the two scenarios "Clim-Dev" and "Clim-Distrib" [TWh].....	148
Figure IV-37 – Energy mix in 2010, 2030 and 2050 in "Region PACA" for the two scenarios "Clim-Dev" and "Clim-Distrib" [TWh].....	149
Figure IV-38 – Production from storage technologies in 2010, 2030 and 2050 in "Region IDF" for the two scenarios "Clim-Dev" and "Clim-Distrib" [GWh].....	150
Figure IV-39 – Production from storage technologies in "Region HDF" for the two scenarios "Clim-Dev" and "Clim-Distrib" [GWh]	150

Figure IV-40 – Production from storage technologies in 2010, 2030 and 2050 in "Region PACA" for the two scenarios "Clim-Dev" and "Clim-Distrib" [GWh]	151
Figure IV-41 – Shifting from demand response in 2010, 2030 and 2050 in "Region IDF" for the two scenarios "Clim-Dev" and "Clim-Distrib" [GWh]	151
Figure IV-42 – Shifting from demand response 2010, 2030 and 2050 in "Region HDF" for the two scenarios "Clim-Dev" and "Clim-Distrib" [GWh]	152
Figure IV-43 – Shifting from demand response in 2010, 2030 and 2050 in "Region PACA" for the two scenarios "Clim-Dev" and "Clim-Distrib" [GWh]	152
Figure IV-44 – Transmission grid interconnections for "Region PACA" from 2000 up to 2050 for the two scenarios "Clim-Dev" and "Clim-Distrib" [TWkm]	153
Figure IV-45 – European transmission grid infrastructure from 2000 up to 2050 for the two scenarios "Clim-Dev" and "Clim-Distrib" [TWkm]	154
Figure IV-46 – Total transmission grid needs in scenario "Clim – Dev" (left) and in "Clim - Distrib" (right) for 2030-2050 [GW]	156
Figure B-1 – Wind installed capacities versus results using e-HIGHWAY 2050's distribution keys (case France 2014 – nodes)	188
Figure B-2 – Wind installed capacities - Model versus historic data	189
Figure C-3 – Solar calculated capacity factor versus real data for Belgium (2012)	191
Figure C-4 – Wind power curves for ENERCON's turbine, real data (Belgium 2012) and implemented in EUTGRID	192
Figure C-5 – Wind on-shore calculated capacity factor versus real data for Belgium (2012)	193
Figure C-6 – Mean absolute error (%) for different countries according to their number of nodes	194
Figure D-7 – Typology of the different nodes in Europe	196
Figure E-8 – Distribution of least-cost options for different share of solar and wind in the representative distribution grids	199

Index of Tables

Table I-1 – Overview of the different long-term energy models presented	26
Table I-2 – Overview of the power sector and transmission grid characteristics within different bottom-up models (based on [41])	30
Table I-3 – Models comparison: modelling choices concerning grid representation and reinforcement	37
Table II-1 – Costs for reinforcing or expanding the grid for HVAC and HVDC	52
Table II-2 – Grid coefficients implemented in EUTGRID	53
Table II-3 – HVAC transmission grid typical characteristics [116]	59
Table II-4 – Comparison between ENTSO-E's transmission grid requirements and EUTGRID's for 2010-2030	73
Table II-5 – Payback period for different values of discount rate k	74
Table II-6 – Investments in the transmission grid for different values of payback periods ..	75
Table III-1 – Transmission grid investments for the frozen scenarios	87
Table III-2 – Transmission grid investments for the grid development scenarios	88
Table III-3 – Transmission grid requirements for scenario "Clim – LCA"	107
Table IV-1 – Costs parameters for the different solutions	140
Table IV-2 – Transmission grid investments for the two scenarios "Clim-Dev" and "Clim-Distrib"	155
Table A-1 – Technologies in POLES for the electricity module (adapted from [12])	185
Table D-2 – Equivalence between the classification from Eurostat and the one used for EUTGRID	195
Table D-3 – Grid coefficient values for each node	196
Table F-4 – CO ₂ emissions factors in [tCO ₂ /MWh] for fossil production (from POLES's database)	200

Index of Acronyms

[Model - Long-term] DICE	Dynamic Integrated model of Climate and the Economy
[Model - Long-term] E3ME	Energy Environment Economy model
[Model - Long-term] EMPIRE	European Model for Power system Investment with Renewable Energy
[Model - Long-term] GCAM	Global Change Assessment Model
[Model - Long-term] GREEN	General Equilibrium Environmental
[Model - Long-term] MARKAL	MARKet ALlocation
[Model - Long-term] MEDEE	Modèle d'Evolution de la Demande d'Énergie
[Model - Long-term] MESSAGE	Model for Energy Supply Strategy Alternatives and their General Environmental Impact
[Model - Long-term] POLES	Prospective Outlook on Long-term Energy Systems
[Model - Long-term] POTENCIA	Policy Oriented Tool for Energy and Climate Change Impact Assessment
[Model - Long-term] PRIMES	Price-Induced Market Equilibrium System
[Model - Long-term] TIMES	The Integrated MARKAL-EFOM
[Model - Long-term] WEM	World Energy Model

[Model - Power system] ANTARES	A New Tool for Adequacy Reports and Economic Simulations
[Model - Power system] COMPETES	COmprehensive Market Power in Electricity Transmission and Energy Simulator
[Model - Power system] ELMOD	ELectricity MODeL
[Model - Power system] EMMA	European Electricity Market Model
[Model - Power system] EUCAD	European Unit Commitment and Dispatch
[Model - Power system] EUTGRID	European Transmission Grid Investment and Dispatch
[Model - Power system] EUTGRID&D	European Transmission Grid and Dispatch with Distribution grid representation
[Model - Power system] LIMES	Long-term Investment Model for the Electricity Sector
[Model - Power system] PERSEUS	Programme-package for Emissions Reduction Strategies in Energy Use and Supply-Certificate Trading
[Model - Power system] REMIX	Renewable Energy Mix for sustainable electricity supply
[Model - Power system] SWITCH	Solar, Wind, Hydro, and Conventional generators and Transmission
[Model - Power system] URBS-EU	Urban Research Toolbox Energy System

BAT	Batteries
BAU	Business-As-Usual
BEIS	Department for Business, Energy and Industrial Strategy
CCS	Carbon Capture and Storage
CGE	Computable General Equilibrium
Clim	Climate
Dev	Development
DIMENSION	Dimension and Investment Model for European Electricity Markets
Distrib	Distribution
DR	Demand Response
DSO	Distribution System Operator

EDF	Electricité de France - Electricity of France
EnRV	Energies Renouvelables Variables
ENS	Energy Not Served
ENTSO-E	European Network of Transmission System Operators
GAMS	General Algebraic Modeling System
GDP	Gross Domestic Product
HDF	Hauts-de-France
HVAC	High Voltage Alternating Current
HVDC	High voltage direct current
IAM	Integrated Assessment Model
IDF	Ile-de-France
IEEE	Institute of Electrical and Electronics Engineers
IRENA	International Renewable Energy Agency
KNITRO	Nonlinear Interior point Trust Region Optimization
LCA	Life Cycle Assessment
MAE	Mean Absolute Error
NDE	Non-Distributed Energy
NTC	Net Transfer Capacity
NUTS	Nomenclature of Territorial Units for Statistics
OECD	Organisation for Economic Co-operation and Development
OLTC	On-Load Tap Changers
OPF	Optimal Power Flow
p.u.	per unit
PACA	Provence-Alpes-Côtes d'Azur
POP	Population
RES	Renewable Energy Sources
RTE	Réseau de Transport d'Electricité - Electricity Transmission Network
TSO	Transmission System Operator
TYNDP	Ten-Year Network Development Plan
UN	United-Nations
VRES	Variable Renewable Energy Sources

Introduction

In the recent years, the European power system has seen a major shift in its paradigm, which is mainly driven by two important challenges. The first challenge relates to the liberalization of the European electricity industry with the introduction of the first European directive in 1996 (*DIRECTIVE 96/92/EC [...] concerning common rules for the internal market in electricity*) [1]. The European power system can be divided between the generation and the demand sides with the transmission grid, which transports electricity to the final consumer. It was developed vertically with an important and centralized electricity production together with an extensive transmission grid, which ensures the system to be robust and reliable. The aim of the directive and the following ones was to introduce competition into these natural monopolies and to create a European market of electricity. The effect is the appearance of new actors mainly in the supply and demand sides. This context has allowed the rise of distributed generation in the power system. These small-scale energy sources are local and change the role of the consumers. In the past, they were considered as passive actors who only needed to be supplied at any time. Now they can control their energy consumption with these decentralized capacities and become “prosumers”: they are at the same time energy producers and energy consumers. The consequence of this liberalization has increased the complexity of the European power system and the need to better control its operations to achieve its security and reliability.

The second challenge deals with the rise of climate concerns and the introduction of climate energy policies to reduce the green-house gases emissions. It began with the international agreements such as Kyoto protocol [2] or the different United Nations Climate Change Conferences, which are held yearly since 1995. In this context, the electricity and heat sector accounts for 40% of the world CO₂ emissions in 2015 [3]. The consequence is that important efforts are taken to reduce its share. In Europe, specific policies have been implemented, which set targets for greenhouse gas emissions reduction, increase of the share of renewable and the improvement in energy efficiency. It corresponds to the “2020 climate & energy package” whose targets are set to 20% each [4].

More recently, the European Commission has developed a new package for 2030 with more ambitious targets [5]. The key ones refer to the reduction of 40% in greenhouse gas emissions, a share of renewable energy reaching 27% of energy consumption and a more integrated electricity market with the development of 10% to 15% transmission interconnections between countries. The renewable energy sources have some key characteristics, which make them play an important role in the climate energy policies. First, they do not produce any direct CO₂ emissions. Therefore, promoting its integration will help to replace the large and centralized fossil fuel capacities. These renewable energies gather solar, wind, hydro and biomass and their potential is huge with wind blowing, sun shining all

over Europe and biomass being available through forest and agriculture uses. With cleaner production in the energy mix, it further decreases the dependency on the access to oil and gas resources. In a context of relative scarcity and geopolitical issues, solving this issue becomes an important task and it favours the trend towards the electrification of new uses such as electric vehicles.

Because of the high complexity of the energy system and its important interactions with the global economy, these climate energy policies need to be assessed before being implemented. For these reasons, long-term energy models have been developed to represent the long-term evolution of the energy sector and its different impacts such as on the emissions or the energy prices. Their aim is to understand the key drivers for the changes in technologies development, the emergence of new uses. Using prospective scenarios, they help to discuss the issues related to the options of decarbonisation (for example, integration of variable renewable energies, development of storage technologies, and emergence of carbon capture and storage technologies and usage of flexibility options). Finally, these prospective scenarios are an important tool for the policy makers when developing new climate energy policies.

Problem statement

The European climate energy policies have begun to modify the operations of the power system with the integration of renewable energies. Traditionally, the generation side mostly consists of thermal power plants whose production is controllable and dispatchable. A distinction must be made between base load power plants (i.e. nuclear or coal power plants), which need time to be started and run almost all year (more than 7000 hours per year) and peak load power plants (i.e. gas and coal turbines), which can increase their production in less than an hour and run 3000 hours a year (in the power system, high peak load power plants run with less 550 hours per year)[6]. In this context, the operators have only to adequately predict the demand and the availability of the power plants before dispatching. However, the renewable energies have introduced new types of characteristics. Renewable energies such as biomass or hydro (except run-of-river hydro) are still dispatchable, but issues arise with wind and solar productions. These technologies cannot be controlled (they are referred as “non-dispatchable” technologies) and there are often called VRES (Variable Renewable Energy Sources): within an hour their production varies a lot as well as within a week or a season. To overcome these difficulties, fuel based peak power plants could be used to back-up these variations, but the resulting effect would be a costlier electricity and an increase in emissions, which would thwart the reduction of emissions from the renewable energies. Other solutions consist of adding more flexibility to the demand side: among them

are storage or demand response technologies. The development of storage technologies with stationary batteries or electric vehicles is of major interest: the surplus of energy produced would be charged at noon for example and dispatched during the peak hours. Similarly, the customers could, through demand flexibility, delay their energy consumption (for example, delaying a washing machine).

These important evolutions of the European power system bring issues, which are studied with long-term energy models. They have introduced a better representation of the power system, but some assumptions are made that can limit their analysis. Many studies have calculated the potential for each renewable energy source in every European country and it is unevenly located both in Europe and also within the countries. The type of area such as mountainous, urban or rural also modifies widely their production profile. Moreover, the existence of restricted areas (i.e. natural parks, airports, inhabitations) or even low social acceptance are two of the many drivers that limit the installation of wind and solar capacities. With a large-scale integration of VRES, the immediate consequence is an increase of production in specific regions and these bulks of energy need to be transported to the consumers, which are usually located far from the production sites. However, the distribution grids where most of wind and solar capacities are connected already experience issues related to the integration of VRES. They were designed to operate unidirectional flows, but with these production sources, reverse flows appear together with overvoltage situations, which congest the lines. In the transmission grid, which connects all Europe, the congestions are the main issues and it could potentially limit the integration of VRES.

These different issues lead to question the role of the grid in long-term energy scenarios and how it impacts the evolution of the energy mix.

The main scientific challenge refers to the representation of the different grid levels in Europe. If the grid is explicitly represented in long-term energy models, it is only limited to the transmission grid and it usually only has one node per country. The resulting power flows can only be seen as commercial ones and do not take into account the grid characteristics. Concerning the transmission grid, it should include more nodes to adequately observe the congestions together with more realistic power flow calculations. The modelling of the power system should also incorporate a representation of the distribution grids to analyse the issues linked to the integration of the VRES. An associated scientific challenge deals with the representation of the VRES variability within each region and their capacity distribution. The long-term energy models usually provide data on the national level and even though there is a strong development of the open data movement, hourly local production and geographic location of power plants capacities are mostly lacking. Therefore, methods to calculate VRES

production on a regional basis and their distribution should be developed. Finally, the long-term evolution of the grid should be integrated in the scenario analysis to observe the effects on the evolution of the energy mix.

Contributions

To address the above question, some important contributions were brought and are briefly described below.

The work carried out used the long-term energy model POLES (Prospective Outlook on Long-term Energy Systems) and developed a new European power sector EUTGRID (EUropean Transmission Grid Investment and Dispatch), which is based on a previous version EUCAD (EUropean Unit Commitment and Dispatch). The new power sector module has been improved through a finer representation of the transmission grid. It now includes more nodes per country and a realistic calculation of power flows with a DC load flow approach. It can distinguish between different cable technologies HVAC or HVDC to account for congestions and loop flows effects provoked by VRES production. A new algorithm has been developed to describe the expansion of the transmission grid. This transmission grid investment mechanism uses nodal prices to detect congestions and solves them by allowing a competition between HVAC and HVDC technologies. Each reinforcement project is being economically assessed through a payback period. Furthermore, representative distribution grids have been included together with a linearized AC load flow. Active and reactive power flows are now being calculated and voltage levels can be controlled.

As the new power sector module EUTGRID needs specific data such as installed capacities and hourly VRES production data, two methods have been developed and validated to build the adequate databases. The results from the new module have been compared and validated at three levels: the power flows, the energy mix and the transmission grid development.

These two contributions enable to form the final contribution: the coupling of this power sector module EUTGRID with the long-term energy model POLES and the use of long-term energy scenarios. The representation of the grid in the resulting power sector module now goes from the transmission grid up to the distribution grid with the implementation of the main technical constraints. This increase of complexity improves the representation of the evolution of the energy system and the decision of investments. This contribution is a major improvement in the field of the long-term energy modelling.

Scientific publications

The list below shows the different publications that have been presented in conferences and in journals during the PhD thesis. Some of them are still under review.

(i) Conference publications

- Stéphane Allard, Silvana Mima, Vincent Debusschere, Tuan Quoc Tran, Patrick Criqui, Nouredine Hadj-Saïd, "Large scale integration of variable renewable energies in the European power system: a model POLES-EUTGRID based approach", International Energy Workshop, 2018.
- Stéphane Allard, Silvana Mima, Vincent Debusschere, Tuan Quoc Tran, Patrick Criqui, Nouredine Hadj-Saïd, "Long-term transmission capacity planning in a scenario with high share of variable renewable energies", 2nd AIEE Energy Symposium on Current and Future Challenges to Energy Security, 2017.
- Jean-Nicolas Louis, Stéphane Allard, Freideriki Kotrotsou, Vincent Debusschere, "A Multi-Objective Optimisation Approach to the Prospective Development of the European Power System by 2050", 13th Conference on Sustainable Development of Energy, Water and Environment Systems, 2018.

(ii) Journal publications

- Jean-Nicolas Louis, Stéphane Allard, Vincent Debusschere, Silvana Mima, Tuan Tran-Quoc, and Nouredine Hadjsaid, 'Environmental impact indicators for the electricity mix and network development planning towards 2050 – A POLES and EUTGRID model', Energy, Aug. 2018.
- Stéphane Allard, Silvana Mima, Vincent Debusschere, Quoc Tuan Tran, Patrick Criqui and Nouredine Hadj-Saïd, "European transmission grid expansion as a flexibility option in a scenario of large scale variable renewable energies integration", Energy Economics (under review).
- Stéphane Allard, Silvana Mima, Vincent Debusschere, Quoc Tuan Tran, Patrick Criqui and Nouredine Hadj-Saïd, "Improving the load balancing through long-term grid development: a model POLES-EUTGRID based approach", Energy Economics (under review).

Plan of the thesis

The thesis is organized in four chapters. First, a literature review is carried out on the existing models dealing either with the long-term evolution of the energy system or with the ones dealing with the power sector representation. A special focus is made on the grid representation in these models and how these families of models benefit from each other to improve their analysis. Then, in the second chapter, the improvements added to the new power sector module EUTGRID are presented together with methods to construct the regional databases. A grid investment mechanism is developed to represent the expansion of the transmission grid. The coupling with the long-term energy model POLES is also presented. In the third chapter, this coupling is used in different long-term energy scenarios to assess the role of the transmission grid and the use of flexibility options. An exploratory work is also shown, which modifies the least-cost approach with the use of life cycle assessment emission factors. Finally, EUTGRID is further improved with the inclusion of distribution grids. An analysis is carried out on the issues of VRES integration in representative distribution grids together with a cost comparison of available solutions. A final long-term scenario is studied using EUTGRID and the representative distribution grids.

Chapter I. Representing the long-term evolution of the power system

Fighting climate change urges governments to implement efficient climate energy policies and large-scale integration of VRES (Variable Renewable Energies Sources) to strongly reduce CO₂ emissions [7], [8]. However, the power system was developed as a vertical system with an important and centralized electricity production (nuclear, coal etc.) together with an extensive transmission grid that brings electricity to the final consumer. This particular architecture was designed for the power system to be robust and reliable. On the opposite, VRES production is intermittent and less predictable. In a context of high share of VRES, it becomes more difficult for other electricity power plants to compensate the residual load. As a result, the system needs to be more flexible than before.

To maintain the stability of the system, the production must be permanently equal to the consumption (including losses). This main objective leads to two sorts of management of the power system, which are linked: short-term power management and long-term energy management. Short-term management corresponds to the operation of the power system within hours using local infrastructure (it considers among others congestions and voltage management) [9]. On the opposite, long-term management aims at identifying future bottlenecks at European level in years (up to 30 usually).

In this context, different tools exist that help studying the impacts of VRES in the power sector on different time horizons. The first family is called "Long-term energy models" and deals with prospective scenarios and aims at assessing the different climate policies. The level of details is kept simple, but simulations are run up to 2050 or 2100. The second family gathers "power system models", which perform technical analysis of given networks. The level of details is greater, and simulations are usually done from a day up to a year.

In sections I.1 and I.2, we describe the key features of these two different families of modelling tools and how they are used to represent the power sector. Then, in section I.3, we will analyse how they can be linked to improve assessment results when the focus is put on the representation of the transmission grid expansion.

I.1 The increase of complexity in prospective energy models

The oil and energy crisis in 1973 and the increase of computer performance have stimulated the development of prospective energy models. With the oil shocks, energy independency has become a major issue and the governments have realized that their energy policies needed to be assessed using prospective models. It is important to point out that the outputs of these models are not a prediction (with an estimable accuracy) but rather a support to

identify plausible scenarios and their possible consequences. Different sorts of models exist and are usually divided into two main categories: top-down and bottom-up [10]–[12].

In the top-down approach, the economy is considered as a whole with endogenous macro-economic variables. Their main focus is to analyse the performance of a given energy policy on the economy of a region. Technologies are not explicitly represented, and data are aggregated to the studied zone. Moreover, this family of models can be further split into various groups [11]: input-output models, econometric models, CGE models (Computable General Equilibrium) and system dynamics models. Finally, the main strengths of the top-down models are their ability to integrate a maximum number of macro-economic variables and give a comprehensive evaluation of the impacts of energy policies.

Many top-down models have been developed. An example is GREEN (General Equilibrium Environmental model), which is a recursive-dynamic global CGE model developed by OECD (Organisation for Economic Co-operation and Development) [13], [14]. It covers four OECD regions and can simulate policy from 1985 up to 2050 with 5-years or 20-years time-steps. Another well-known model would be DICE (Dynamic Integrated model of Climate and the Economy) [15], [16], which is a global model¹ and focus on the optimization of policies to face climate change. A third top-down model would be E3ME (Energy Environment Economy Model) [17], which is being maintained by Cambridge Econometrics for the European Commission. By using econometric analysis, it determines empirical behaviour and thus there is no optimization like in other CGE models. It covers all European countries and world's main countries and simulates up to 2050.

On the other hand, bottom-up models use a technico-economic approach to describe with greater detail the technologies within the energy sector. As they usually consider only one sector, they tend not to consider the macroeconomic impacts of the climate-energy policy, which they assess (unlike top-down models). However, they have the ability to represent changes in technologies. Therefore, the objective of these models is to find the best technology mix when assessing policies.

Sub-categories exist within the two classifications [12]: simulation and optimization. In the simulation sub-family, the aim is to produce plausible long-term scenarios. Conversely, optimization aims at finding the optimal trajectories. Table I-1 summarizes some long-term energy models (top-down and bottom-up) together with their main characteristics.

¹ Another version exists called RICE, which covers 12 regions.

Table I-1 – Overview of the different long-term energy models presented

	Top-down models (Macro-economic models)	Bottom-up models (Detailed technologies models)
Simulation (plausible trajectories)	<ul style="list-style-type: none"> ▪ E3ME [17], GREEN [13], [14] ▪ GCAM (Hybrid model) [21], [22] 	<ul style="list-style-type: none"> ▪ POLES [18], [19], PRIMES [20]
Optimization (optimal trajectories)	<ul style="list-style-type: none"> ▪ DICE [15], [16] ▪ MESSAGE (Hybrid model) [24] 	<ul style="list-style-type: none"> ▪ TIMES [23]

Because of their construction and their lack of technological details, top-down models have difficulties to deliver appropriate information when a major technological transition occurs within the energy system [10]. Thus, VRES integration is mostly studied using bottom-up models. Within this classification, the evolution of these models shows an increase in their modelling complexity to consider a growing number of specificities. Historically, four important key drivers stimulated their development: in the beginning of the 1970s, it was related with the modelling of energy demand; in the late 1980s, the representation of international energy prices was included in the long-term energy models; in the 2000s, the endogenization of technical progress was introduced; and recently, in the 2010s, the representation of VRES was improved.

1.1.1 Demand forecasting

Before the 1970s, the stability of the energy context and the clear separation between different energy carriers such as electricity and oil allowed the use of simple models to forecast energy demand. These models worked with simple econometric relations and were sufficient until the oil crisis in 1973 [25]. With the huge increase of oil price, important changes appeared: the reduction of oil dependency became an important target for the governments, new technologies with higher efficiency emerged and electricity started to be substituted to oil. In this context, the econometric tools have difficulties to adequately forecast long-term evolution of energy demand: the important transitions cannot be extrapolated based on past evolutions using statistical relations and their rigidity cannot include alternative energy policies [26], [27].

To overcome these difficulties, new models such as MEDEE (Modèle d'Evolution de la Demande d'Energie) were developed using a detailed representation of energy demand and simulation means [28], [29]. The approach consists of disaggregating in multiple end-use categories and calculating the useful energy demand based on the socio-economic activity and the technology evolution. The useful energy demand is then converted into final energy

demand by using efficiency and fuel mixes. The analysis of different expected future trends of the key drivers (i.e. the socio-economic activity and the technology evolution) forms the scenarios. As pointed out in [25], in MEDEE, energy demand is not directly linked with energy prices through elasticity coefficients. Moreover, the fuel substitution is not explicitly described as it occurs based on relative energy prices.

1.1.2 International energy prices

The limitations highlighted above were answered with the development of new long-term energy models. The level of disaggregation is increased, and the different energy carriers are explicitly represented. Therefore, they are now able to calculate energy prices and describe the substitution of fuels both in time and in space.

For example, POLES (Prospective Outlook on Long-term Energy Systems) [18], [19] is a simulation model, which determines the international prices for coal, gas and coal. More specifically, it is a recursive partial equilibrium model: the energy demand and supply for each region evolves according to the previous time-step. It covers the world and can simulate up to 2050 or 2100. Another bottom-up model, PRIMES (Price-Induced Market Equilibrium System) [20] uses the international energy prices from POLES and aims at finding the market equilibrium for each time-step. This model covers all European countries and simulates scenarios up to 2050. It is maintained by the E3MLab at National Technical University of Athens (Greece) and depending on the purpose of the study, it can include up to 11 sub-modules.

In parallel with the development of simulation models, optimization models have been created to propose optimal long-term trajectories. In the optimization family, TIMES (The Integrated MARKAL-EFOM) model generator [23] is being developed by the IEA-ETSAP community and many versions exist, which are used by more than 117 institutions in 70 countries [30], [31]. Hence, all TIMES versions share the same mathematical approach, which is to minimize the net total cost (or maximize the net total surplus) at the end of a given time horizon. For example, dedicated versions cover France [32], United-Kingdom [33] or Europe [34].

This high-level of detail in the energy sector representation is the main advantage of the bottom-up models but some criticisms exist concerning their lack of macro-effect. Hence, "hybrid models" exist combining the two different approaches. For example, GCAM (Global Change Assessment Model) [21], [22] is an integrated model (part of the Integrated Assessment model or IAM). It is a global dynamic recursive model, which combines a

representation of the macro-economy, the energy sector, the agriculture and land, and a physical earth system. Another model, which is also a IAM model, is MESSAGE (Model for Energy Supply Strategy Alternatives and their General Environmental Impact) [24]. However, its aim is to optimize energy supply and usage and it only covers the world with 11 regions [35].

I.1.3 Endogenous technological progress

With the emergence of the climate and energy challenges in the late 1980s, the long-term energy models extend their time horizon from 30-50 years up to 100 years. As pointed out in [36], this longer time frame brings new issues to the models such as the representation of technological progress. The previous bottom-up models included exogenous performance rates. With the use of century scenarios, this representation based on empirical studies implies that the technology would be improved even though it is not used anymore. Therefore, it misses the need to invest in a particular technology before being able to reduce the costs. This important effect is called the “learning-by-doing” effect: it describes the accumulation of experience as the technology is being deployed. In a long-term energy model, which runs up to 100 years, it is particularly important and must be included to avoid inconsistent evolutions.

Based on empirical studies, the endogenization of technological progress was made possible using learning curves. This learning curves relate the cost reduction of technologies to the cumulative installed capacities: each time a certain amount of a technology is installed, it implies a reduction of investment cost. It was first included in MESSAGE model [36] and then in MARKAL (MARKet ALlocation) model [37]. It was also implemented in POLES but it was even improved with the introduction of a new effect: the “learning-by-searching” effect, which describes the increase of knowledge as more investments are made in research and development [38]. The introduction of these two learning curve effects for each technology considered have improved the long-term energy models with more realism [39] but also it increased the complexity of the models.

I.1.4 VRES representation

In the beginning of 2000s, the climate challenge further increased with the need to find stronger reductions in CO₂ emissions. In this context, the large-scale integration of renewable energies together with the use of flexibility options has become an important part of climate-energy policies [4], [5]. The energy production from the renewable energies sources has the advantages to be CO₂ free and abundant all over the globe[40]. Within the renewable

technologies, two different types exist: the dispatchable ones use sources from hydro or biomass and the non-dispatchable use solar or wind. The solar and wind powers are usually referred as VRES (Variable Renewable Energy Sources) because of their intermittency and variability within a day, a week or even a season.

To analyse the modelling choices VRES in long-term energy models, a new typology has been introduced in [41]. It also includes a comparison of grid and storage representations in the power sector as their role will increase with higher share of VRES [42]. The relevant characteristics deal with, for example, the power system representation with the description of operation and/or capacity investment. The level of details both in time and in space is also important for the scenario analysis: for example, POLES considers two seasons (summer/winter) and a day of 12 two-hours blocks for each while PRIMES has only 11 blocks per year. In [41], the authors conclude that long-term energy models lack the inter-temporal representation of the power sector: for instance, the operation of storage and the VRES specific productions are usually not well described.

As pointed out in [41], [43], very few long-term energy models actually implement electricity dispatch and decision investments in the transmission grid. The grid representation is kept simpler than the VRES even though their integration can be limited with too low investments [44]. In many models such as POTENCIA (Policy Oriented Tool for Energy and Climate Change Impact Assessment) [45] and WEM-IEA (World Energy Model) [46], the grid is considered as a “copper plate” (i.e. no constraints are taken into account for power flows). Hence, there is a linear relation between investments in VRES capacities and investments in upgrading or extending the transmission grid: for each MW of VRES installed, they assume an increase of transmission grid investments. These investments are not based on economic values but on requirements, which are set by the model. It is worth mentioning two major long-term models TIMES and PRIMES, which both include a power sector and a transmission grid. However, the transmission grid evolution is set exogenously by the user. Table I-2 presents the relevant features of power sector representation in some bottom-up energy models.

Table I-2 – Overview of the power sector and transmission grid characteristics within different bottom-up models (based on [41])

Models (stand-alone version)	POLES	TIMES	PRIMES	GCAM	WEM-IEA	POTEnCIA
Power sector representation	Operation, Capacity investment	Operation, Capacity investment	Operation, Capacity investment	Capacity investment	Operation (<i>new from 2016</i>), Capacity investment	Operation, Capacity investment
Spatial representation	World	Europe ²	Europe	World	World	Europe
Grid						
Nodes and lines	57 nodes	36 nodes (one node per country)	24 nodes (one node per country)	32 regions (no interconnection)	25 regions (no interconnection)	28 nodes (one node per country)
Grid costs	No	Yes	Yes	Yes (Linear increase in grid investment)	Yes (Linear increase in grid investment)	Yes (Non-Linear increase in grid investment)
Grid expansion	No	Yes (Exogenous data)	Yes (Exogenous data)	Not Considered	Not Considered	Yes (simplified)

Based on these observations, the POLES model [47], [48] has been chosen and improved through a coupling with a specific dispatch module EUCAD [49]. In this coupling, EUCAD aims at optimising the power system operations while investments in the transmission grid are decided by POLES, depending of the usage of the interconnections. This dispatch module pertains to the family of power system models, which focus on representing the operations of the power sector. We present in the next section the different characteristics of this family with a focus on the representation of the transmission grid.

² Depend of the version. Here, we consider JRC-EU-Times model, which covers Europe

I.2 Power systems models

I.1.1 Technical modelling approach

Technical modelling aims at describing with precision the operation of the power system, at given time horizons [50]. The electric grid is depicted with details and parameters such as voltage, active and reactive power and frequency, which are described in the model. These models can be used in steady-state to calculate power flows or dynamically to analyse the behaviour of power plants. They can be applied in short-circuit analyses or planning studies. The answered questions deal with, for example, the stability of a grid in case of massive renewable integration in operational studies, or the management of storage and new flexibilities levers in a smart grid context.

Dedicated software programs are being used to represent and analyse these grids such as PowerFactory [51] or EUROSTAG [52]. Finally, models are being validated by comparison with actual measures. As the studied phenomena last from the micro-second up to the hour, the need for precise data is of crucial importance and usually, these studies only cover a portion of a national grid. Depending on the issue addressed, the power system models include some simplifications on the grid level (i.e. aggregation of production or demand at a node) or the temporal resolution (i.e. from micro-seconds to an hour).

I.1.2 Transmission grid planning models

If these models are used for planning studies on a larger scale (Europe, USA), the level of details is reduced for simplicity. The covered area and the number of nodes are one of the first simplifications that are used: for example, the models covering Europe range from more than 2000 nodes like ELMOD [53] to one node per country for LIMES [54] or EUCAD [55]. This reduction of number of nodes relies on the assumption that within the considered area, there will be no congestion. Hence, it is possible to aggregate consumption and production to one node. However, with the large-scale integration of VRES, this assumption of one node per country becomes more and more difficult to assume.

Another distinction between the different models studying the energy systems on this scale is the implementation of transmission grid and its evolution. The majority of them simplify grid

representation with NTC³ (Net Transfer Capacity is the capacity available for commercial transactions) implemented in a transport model. In the transport model, flows are only limited by grid capacities and do not consider Kirchhoff's laws: this model can be seen as commercial exchanges. This hypothesis is used in many models such as EUCAD [55], LIMES [54], [57], REMIX [58], URBS-EU [59], EMPIRE [60], [61], SWITCH 2.0 [62]. The actual electricity flows often differ from the ones found using this method [63] and "unwanted" paths (called loop flows) appear more frequently in unplanned production such as VRES [64]. As a result, full power equations (AC load-flow) can be implemented such as in DIMENSION [65] but usually a linearization (called DC load-flow) is used: ANTARES [66]–[69], ELMOD [53], [70]–[72] or COMPETES [73].

Finally, different methods exist to implement transmission grid evolution in the models: the easiest one consists of considering exogenous investments such as in PERSEUS model [74], [75] or in COMPETES [73]. Other models such as EMPIRE or EMMA [76], [77] optimize total system costs and annualized transmission grid investments. However, this method works only with linear equations (i.e. with transport model). Finally, the models, which use DC load-flow and study the transmission capacity expansion, implement an iterative process such as in DIMENSION, in ELMOD or in ANTARES. However, they only consider one year and do not include a dynamic evolution in a long-term scenario.

If we analyse the ANTARES model [66], it is a sequential Monte-Carlo system simulator developed by the French transmission system operator, RTE. It uses Monte-Carlo method to simulate many different meteorological years on an hourly basis in order to assess the economic benefits of different projects (development of wind farms, grid expansion, etc.). ANTARES covers Europe with about 500 nodes and it is used to run many tests to localize future bottlenecks. Then, it can decide future grid investments based on three indicators: the energy not served (ENS), extra spillage (production curtailment) and thermal dispatch. The hypothesis is that reinforcements between two zones with significant differences between the values of indicators will have a greater impact on reducing the congestions. These set of reinforcements are then assessed by comparing the costs savings and the investments costs [78].

³ Apart from NTC, different definitions exist, which calculate the transmission capacity of the grid [56]:

1. Total Transfer Capacity (TTC) is the maximum capacity available for exchanges of electricity while respecting security constraints
2. Transmission Reliability Margin (TRM) is the minimum reserve that must be available to help other countries if needed
3. Available Transfer Capacity (ATC) is the capacity, which is being sold or put in auction

NB: $NTC = TTC - TRM$

On the other hand, ELMOD [53], was developed in order to analyse congestion management and investments decisions. It covers Europe with over 2000 nodes and optimizes the operation of the system for one year on an hourly basis. In a first version [70], the grid investment mechanism is based on nodal prices to detect congestions. The decision to invest is made if the annualized investments costs are lower than the welfare increase caused by the reinforcement option. In a more recent version [79], the objective is to minimize the sum of all investments and variable system costs.

To conclude, these electricity sector planning models rely heavily on exogenous hypotheses and they usually consist of a photography of one specific year. Consequently, they do not represent well the dynamic evolution of both the power system and the transmission grid infrastructure.

I.3 Long-term energy models and power system models

I.3.1 Interactions between long-term energy and power system models

The description of the long-term energy models and the power system models shows that each type of model lacks some key features that are implemented in the other one. On the one hand, long-term energy models have the ability to provide:

- (1) interactions between energy sectors;
- (2) consistent technological and economical hypotheses;
- (3) assessments of climate energy policies on a large scale and on long-term scenarios.

While on the other hand, power system models have:

- (1) a more detailed representation of power grid operations;
- (2) a more detailed grid representation;
- (3) a more in-depth analysis of VRES integration and its impacts.

Based on the review of the different families of energy system planning available in [80], Figure I-1 depicts how the different models can interact with each other by exchanging some key outputs. For instance, the long-term energy models provide detailed information about the generation capacities at national or regional level. The latter data is used as an input to the transmission planning models to calculate the investments needed in the grid infrastructure. The level of precision is then increased with the use of power system models,

which can determine the generation dispatch and perform load flow analyses on a short-term horizon.

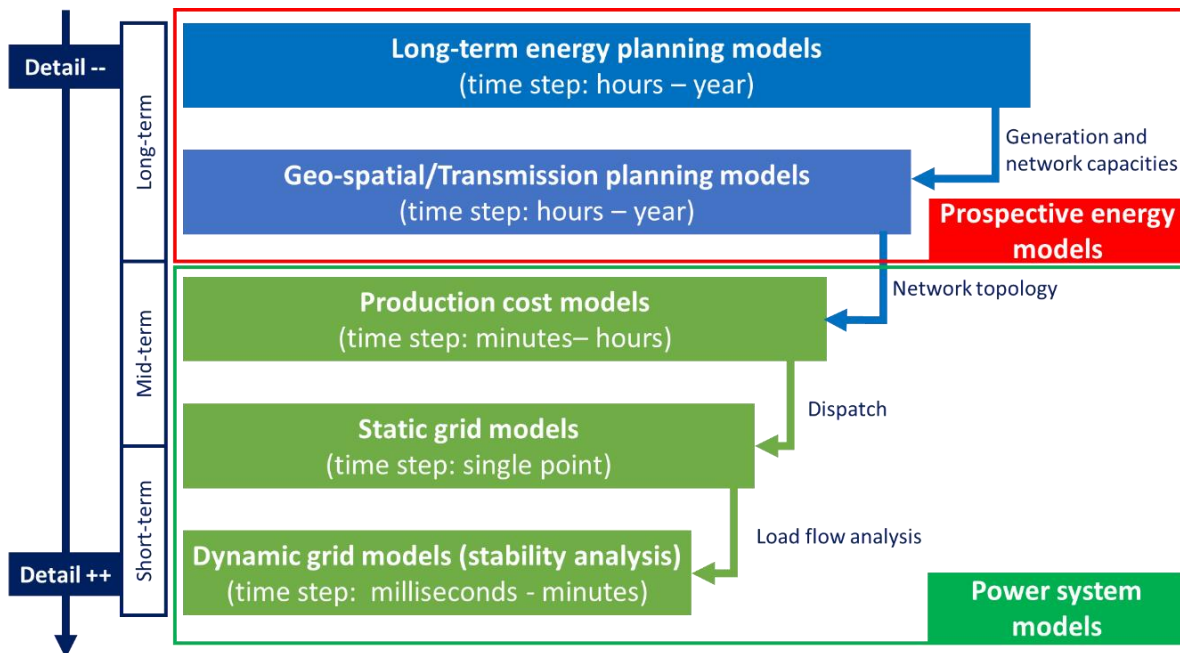


Figure I-1 – Overview of prospective energy models and power system models and how they can interact (based on [80])

Power system models usually analyse various extreme cases for one specific year. For example, the European project “E-highway 2050” used the model ANTARES and proposes five different scenarios: “Fossil & nuclear”, “Big & market”, “Large-scale RES”, “Small & local” and “100% RES” [81]. The objective is to cover all plausible scenarios and the hypotheses must be carefully explained. Moreover, as the study is carried only for one year, the conclusions drawn cannot be generalized for another targeted year. In that case, it must be rerun with adapted hypotheses.

Based on these observations, efforts and recommendations have been made to couple long-term energy models and power system models. A comparison with a unit-commitment model shows that long-term energy models can miss hidden costs from VRES integration [82], [83]. The most common coupling consists in soft-linking⁴ two different models with exogenous feed-backs. In terms of modelling, the outputs from the main model (here the long-term

⁴ Soft-linking two models consists of using the inputs of a model for the other one. However, the two models can be run separately.

energy models) are adapted to fit the inputs of the second model (in our case, power system models).

For example, in the following study [79], ELMOD uses the results from PRIMES to analyse different scenarios until 2050. Similarly, EMPIRE takes the scenarios from GCAM to perform its own analyses [61]. This soft-linking can also consist of iterations between the two different models until there is a convergence such as TIMES and ProPSIM [84]. Another version of TIMES includes also a soft link with NEPLAN in order to find transmission grid investments [85]. However, that work was limited to only 16 nodes and 22 lines.

To conclude, from our observation, POLES seems to be the only long-term energy model to implement a yearly feedback soft link with EUCAD [12]. That is what has been chosen as central tool for the present study.

1.3.2 Comparisons of models: role of transmission grid

The large-scale integration of VRES will boost electricity generation within certain regions and thus, electricity power flows will increase with their neighbouring regions. Therefore, the existing transmission grid may face congestion problems. As a result, reinforcement and extension of interconnections within Europe may play a crucial role to match this VRES production and consumption.

Hence, the transmission grid implementation and evolution within the different models is a key parameter to be analysed, based on the typology presented in [41]. The first main distinction is related to the grid representation: in power system models, the number of nodes is much more important than the one in long-term energy models. With a too small number of nodes, long-term energy model might miss congestions resulting from a specific climate energy policy and the associated grid costs.

As mentioned earlier, to compute power flows, technical models usually implement a transport model instead of using full power equations (AC load flow) or linearized ones (DC load flow). Similarly, some long-term energy models like TIMES or PRIMES also include them and if not, a coupling with a dedicated unit-commitment and dispatch module (like POLES with EUCAD) has been developed to improve the outputs. However, this simplified grid representation together with a reduced number of nodes might result in divergences between calculated and observed power flows. Therefore, it can modify the distribution of the power plant capacities within Europe in the long-term.

The main difference between long-term energy models and power system models lies in the evolution of the transmission grid. Some long-term energy models such as PRIMES or

TIMES also use exogenous data up to a certain time-horizon and then the user can include reinforcing costs together with specific bounds [86]. On the opposite, power system models are able to locate congestions and decide for reinforcements based on specific criteria [79]. For example, a soft link between TIMES and NEPLAN has been developed to determine reinforcement needs but the module has only 16 nodes and 22 lines. Moreover, the study is only carried for one target year as the method involves many iterations between the two models until they find a convergent point.

It is worth mentioning the coupling between POLES and EUCAD and its representation of the evolution of the grid. There are no associated costs to the grid investment, but the grid capacities evolve according to their usage. Although it is not based on economic assessment and the number of nodes is quite low (one node per country), this simplified method helps taking into account the transformation of the power system and the need to reinforce the grid. The comparison for different typical models is summarized in Table I-3.

Table I-3 – Models comparison: modelling choices concerning grid representation and reinforcement

	Long-term energy models				Power system models	
Models	POLES + EUCAD	JRC-EU-TIMES	GCAM	POTEnCIA	ELMOD	ANTARES
Time horizon	2100 (every year)	2050 (every year)	2100 (every 5 years)	2050 (every year)	1 year	1 year
Time step	Hourly (12 days per year)	Hourly (12 time slices per year)	Yearly	Hourly (1 day per year)	Hourly	Hourly
Type of results	Deterministic	Deterministic	Deterministic	Deterministic	Deterministic	Stochastic
Representation of Grid						
Spatial representation	World (Power sector: Europe)	Europe	World	Europe	Europe	Europe
Nodes	24	36	32	28	+400	500
Type of computation	Transport model	Transport model ⁵	Transport model	Transport model	DC load-flow	DC load-flow
Lines' characteristics	NTC	NTC			Typical capacities	NTC
Grid investment mechanism						
Grid reinforcement	Yes ⁶	Yes ⁶		Yes	Yes	Yes
Grid expansion	No	No		No	Yes	Yes
Grid investment triggering	Interconnectors' usage	Optimization using a linear reinforcement cost		Optimization using a transmission cost curve	Congestion	Specific indicators ⁷
Grid investment stopping criteria	Exogenous trend value				Welfare increases less than annualized investments	Indicators reach zero

⁵ Or DC load-flow depending of the needs⁶ Limited to existing transmission interconnections⁷ Not Distributed Energy, Thermal re-dispatch, Extra spillage

Conclusions

The EU power sector is experiencing a major transition towards a more decentralized system with large scale integration of VRES (Variable Renewable Energy Sources). Their characteristics (intermittency and low predictability) ask for more flexibility to ensure the security and the reliability of the power system. Demand response, storage technologies, VRES curtailment or/and higher degree of network reinforcement and meshing must be used for that.

Within Europe, renewable energy potentials are unevenly distributed and often far from consumption sites [87]. Hence, the existing transmission grid would face congestion and other flexibility options may not be sufficient to alleviate these bottlenecks. As a result, reinforcement and extension of interconnections within Europe may play a crucial role to match VRES production and consumption in line with the priorities set in the Energy Infrastructure package [88].

The impacts of this large-scale integration of VRES are analysed by using different families of tools. The comparison of their main features shows that they do not answer the same questions. Hence, long-term energy models have to assess scenarios with high share of renewable on economic aspects (which technologies emerge and at what cost?). These models also consider the emissions from the energy sector. However, their lack of details may miss some costs, which are linked to the intermittency of VRES. The power system models thus include some details to represent the challenge of VRES integration. However, they do not have the consistent technological and economical hypotheses. Finally, some long-term energy models are being soft-linked (and even coupled) with power system models to fill the gap and provide a better evaluation of climate energy policies.

This combination of two different types of model helps to better represent the power sector. However, the observation of their different characteristics shows that, in the long-term energy models, the representation of the transmission grid is still kept simple. The exchanges are usually optimized using a transport model (which can be seen as commercial exchanges) and the low number of nodes may underestimate the effect of congestions within a country. Also, in a simplified approach, the reinforcement/expansion of the transmission grid is considered exogenous to the models. The planning models have the ability to identify and propose new reinforcements in the transmission grid. Hence, in order to assess the role of the transmission grid in case of large scale integration of VRES, long-term energy models need to be coupled with a dedicated power system and transmission capacity module.

In the next chapter, the long-term energy model POLES will be presented. We will then describe the new power sector module coupled with POLES and which includes a dedicated transmission capacity planning based on congestions costs.

Chapter II. Transmission capacity expansion in a long-term energy model

The literature review presented in the previous chapter has underlined the main differences between long-term energy models and electricity system planning models, so as the need to better represent the transmission grid.

If an ambitious climate energy policy is set and the development of the adequate grid infrastructure is not anticipated, the transmission grid may face congestions and other flexibility options may not be sufficient to alleviate these bottlenecks. Hence, the climate energy policy might miss its objectives with a lower share of VRES within the energy mix and higher CO₂ emissions.

In order to study the interrelated impacts of climate energy policies and the transmission grid architecture dynamics as well as the interactions with others flexibility options, we use a model-based approach, which consists of coupling POLES, the long-term energy model and a new power system and transmission capacity expansion module called EUTGRID (European Transmission Grid Investment and Dispatch). This methodology allows to assess the climate energy policies using POLES and to quantify the transmission grid requirements, both in time and regionally as well as to analyse the interactions with other flexibility options.

The model POLES and the reasons for which we choose it will first be presented together with the former modelling of the European power system. Then, we show the methodology to construct the adequate input databases in order to improve the transmission grid representation and finally, we describe the new transmission grid capacity planning algorithm implemented in EUTGRID.

II.1 Modelling state of the art

II.1.1 Long-term energy modelling: POLES model

(i) Scope and objectives

The long-term energy model POLES is a simulation model, which aims at analysing the structure of the energy demand and the development of the technologies through the integration of climate energy policies. These scenarios represent prospective outlooks of the energy system, depending on the set of hypotheses considered. The model is global with 57 regional entities. It must be noted that some of these regions are aggregating several countries⁸. Moreover, it is run yearly with a time horizon up to 2100. Through the analysis

⁸ For example, all countries of EU-28 are included

and comparison of multiple scenarios, it provides detailed insights of technology development; it quantifies greenhouse gases emissions and international energy prices.

(ii) Model structure

POLES is bottom-up model with a detailed representation of the energy technologies. More specifically, it is a partial equilibrium model with dynamic recursive simulations: the results from the previous year are used as inputs for the next year. This particular modelling helps to consider the inertia of the system. It must be noted that POLES is not an optimisation model but market-oriented (i.e. market equilibrium influences future demand and supply).

POLES is structured by different modules, which describe the whole process of the energy system from production to consumption. Many energy sources are considered such as oil (one global market), gas, coal (three markets) and electricity. The energy demand takes into account exogenous parameters such as gross domestic product (GDP) and population (POP). In addition, yearly carbon values are included for each scenario to represent different climate energy policies. Figure II-1 shows the model structure of POLES and the interconnections between the modules with the main outputs, which are the consumption, the production and the emissions.

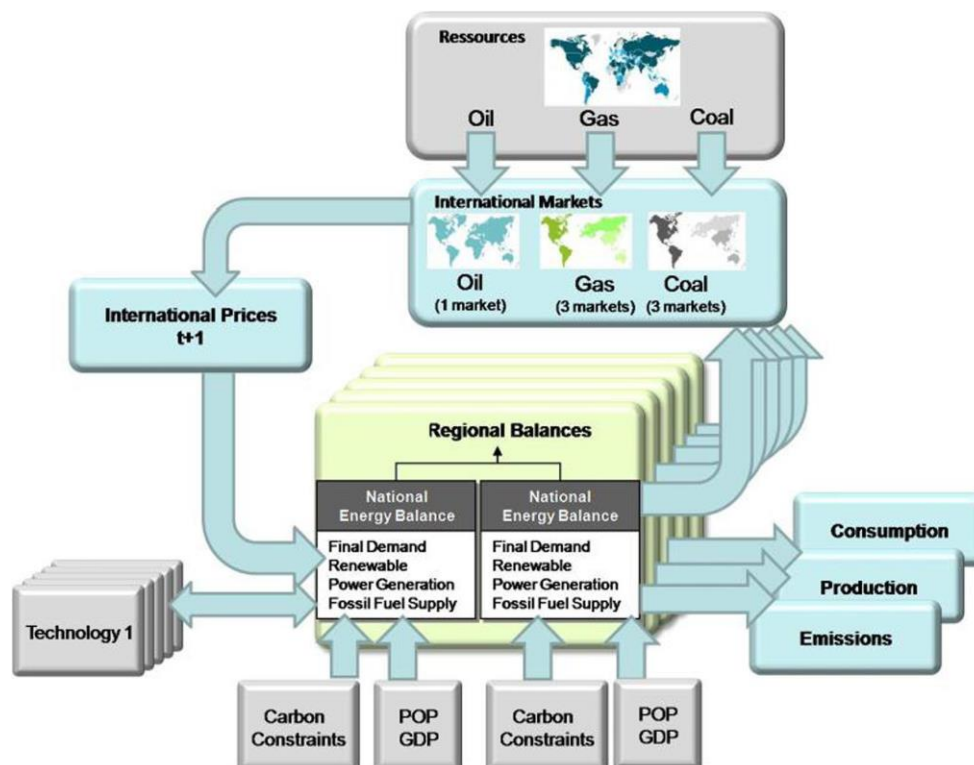


Figure II-1 – Structure of the POLES model with the different energy modules [89]

(iii) Power system representation - Demand

For each region considered, the total electricity demand results from the aggregation of all electricity demand from the five sectors represented in POLES: residential, services, transport, industry and agriculture. Other consumptions are added, which include self-consumption of power plants, grid losses, electricity for hydrogen production and the net electricity exports. The electricity exports are based on historic data and the last available data is kept for the whole simulation. In the current version, data have been updated for the year 2013. For each sector, typical load curves for summer and winter at 2-hour time steps are included. These curves evolve depending of the activity of the sectors and the international fuel prices. Finally, within the scenarios, the total energy demand is modified both in time and in place.

(iv) Power system representation – Capacity Supply

The investments in the different electricity production technologies are based on projected demand with rolling myopic expectations: every year, the demand is estimated in 10 years by using the past 10-year evolution. With this total expected demand, the load duration curve is determined, and it is divided in 7 load blocks: from 8760 hours, for the base load power plants to 730 hours, for the peak power plants. The expected supply capacities can now be determined: the power plants capacities are allocated to their different blocks so that the total expected demand is covered. The competition takes into account their production cost and their specific maturity. Concerning renewable capacities, maximum potentials limit their development within each region.

POLES model includes the decommissioning of the capacities by removing yearly a small share of the actual installed capacities. The gap between the expected capacities and the actual ones must be filled to ensure the security of supply. Therefore, it drives the yearly investments in the production technologies.

(v) Power system representation – Generation

Once the total demand is computed, POLES can perform a simplified dispatch of the generation production for the 41 generations technologies considered. A list of these technologies is available in Annex A - List of electricity producing technologies used in POLES. They are classified between three different types of production: the decentralised production (CHP, decentralised PV), the “must-run” production and the other technologies are dispatchable. The dispatching process works as follows: first, decentralised production is deduced from the total load curve. Then, large scale VRES production, which are considered as “must-run” power plants, further reduces the demand according to specific 2-

hours profile. Nuclear and hydraulic power plants are also considered as “must-run” power plants but they include specific production profiles to represent unavailability due to nuclear maintenance. Curtailment of production occurs if the total production combining VRES, hydro and nuclear production exceeds the total electricity demand.

The remaining technologies supply the residual load by competing based on their variable costs and taking into account maximum available capacities.

II.1.2 Refining the temporal power sector representation with EUCAD

The VRES integration in the power system modifies its operation and improving its representation is a key point to better assess its impacts [12]. With this objective in mind, a unit commitment and dispatch model called EUCAD was developed. It stands for European Unit Commitment And Dispatch and it represents 24 European countries with one node per country [55]. The variability of the VRES is represented by determining the hourly balancing for 12 representative VRES production days [90], [91]. EUCAD aims at minimizing the total system costs while taking into account system constraints [92], [93].

The key improvements relate to the representation of storage technologies: hydro pumped storage, adiabatic CAES, Lithium-ion stationary batteries and Vehicle-to-Grid batteries were added to the technology portfolio. Curtailment of VRES production and potential unserved load are also calculated within the dispatching process. Demand Response was also included in EUCAD together with the use of ramping constraints for the generation capacities. Finally, it takes into account the grid interconnections between countries and their expansion is based on their usage. It must also be noted that it is limited to twice the installed capacities on 2025. This limit has been chosen arbitrarily.

EUCAD can be used in a stand-alone mode, if the adequate data are provided, but it can also be coupled with POLES model, which helps to get an improved representation of the power system in long-term scenarios. This coupling works as a soft-link between the two models: it uses inputs from POLES such as variable costs, electricity demand, installed capacities, it determines the dispatching of the generation capacities and sends back to POLES the output data such as hourly production or curtailment. In this way, it allows dynamic investments, which are based on realistic power system operations. The complete set of equations including ramping capabilities, minimum and maximum generation capacities by technology or operations of storage technologies can be found in [12].

II.2 EUTGRID, a new model with an improved transmission grid representation

The representation of the power system in EUCAD needs some improvements to better assess the VRES integration. In EUCAD, it has been assumed that within each country, there is no congestion. This hypothesis can be considered as relevant with low share of VRES but with large-scale integration of VRES, congestions could appear both inside and between countries [94], [95]. With the current representation, which has only one node per country, the total system costs could be under-estimated, and the integration of renewable energies could be over-estimated.

Another assumption is related to the calculations of power flows, which are kept simple by using a “transport” model. It corresponds to commercial exchanges limited by the grid capacities and does not take into account the complete grid characteristics. Based on the usage of the interconnections in EUCAD, their upgrade is decided in POLES. This simple mechanism is not sufficiently realistic as it does not adequately represent the congestions within the transmission grid. Finally, it does not take into account possible expansion with other countries and within them. To overcome this situation, a new module has been developed, which improves EUCAD by including a grid investment mechanism to solve congestions and calculate the grid requirements in scenarios with large scale integration of VRES. This model is called EUTGRID and it stands for European Transmission Grid Investment and Dispatch.

In order to capture the impact of the large-scale integration of VRES into the transmission grid, it has been developed with four main objectives:

1. Implementing a more detailed transmission grid
2. Detecting congestions within the grid: improving power flows calculations
3. Implementing a Grid Mechanism Investment in the transmission grid
4. Coupling with POLES, the long-term energy model.

II.2.1 Model description

(i) Objective function

EUTGRID incorporates a unit commitment and dispatch tool that minimises the total operating costs of the system on a 24-hour basis for 12 typical days d (6 for each season summer/winter). The objective function T_d in equation (1) consists of summing over the nodes n and the hours t three different sorts of costs. The first part of the costs corresponds

to the NDE (Non-Distributed Energy) E_{END}^n with an associated cost C_{END}^n . It represents the energy that is not supplied to the consumers. It happens mainly because of power outages (for example, fallen trees, which break an electric line) but also when the lines are highly congested. This situation is highly unwanted and if it occurs, it shows that investments in capacities or in the infrastructure are highly needed. In France, the associated cost is set at 20k\$/MWh [96]–[98]. The second part of the costs corresponds to the production costs for each capacity: the endogenous variable P_{disp}^n is multiplied by the variable⁹ costs $C_{var,disp}^n$. The last part corresponds to the ramping costs. Each technology has ramping constraints, which show their ability to follow the variations of the load or of the VRES. The associated cost of the ramping capabilities includes the ramping cost per technology C_{ramp}^n in \$/MW² and the ramping value $R_{disp}^n(t)$.

$$\min T_d = \sum_{t,n} C_{END}^n * E_{END}^n(t) + C_{var,disp}^n * P_{disp}^n(t) + C_{ramp}^n * R_{disp}^n(t)^2 \quad (1)$$

where

Exogenous variables (extracted from POLES model or from literature):

- C_{END}^n , the economic cost of not serving the load (in \$/MWh)
- $C_{var,disp}^n$, the variable cost production of a technology (in \$/MWh)
- C_{ramp}^n , the ramping cost of dispatchable technologies (in \$/MW²)

Endogenous variables in EUTGRID:

- E_{END}^n , the unserved load (in MWh)
- P_{disp}^n , production from dispatchable technologies (in MWh)
- R_{disp}^n , hourly ramping from dispatchables technologies (in MWh)

(ii) Realistic power flow calculations – implementing DC loadflow equations

At each node and for each hour, the demand L^n in equation (2) must be equal to the sum of the supply and the net import and/or export flows F_{net}^n coming from the neighbouring nodes. The supply consists of the sum of the production of the dispatchable technologies $P_{disp}^n(t)$,

⁹ This variable costs correspond to the operation and maintenance costs. They are referred as "variable" because they depend of the amount of energy produced (MWh). It must be compared to the "fixed" costs, which are determined proportionally to the installed power capacity (MW), and correspond to the investments costs.

the productions from VRES sources P_{VRES}^n , which are reduced by the curtailed energy P_{Curt}^n . The demand side of the equation (2) also includes the energy stored E_{sto}^n and it is reduced by the NDE E_{END}^n . The net exchanges are described in equation (3) as the sum of the flows $F_{n \rightarrow p}$ and $F_{p \rightarrow n}$ respectively coming from and to the node n . These flows take into account grid losses η . These flows are also limited by the transmission grid capacities $F_{p \rightarrow n}^{max}$ and a security margin of 10% is included to consider contingency situations [99] (see equation (4)).

$$\forall(n, t) \quad \sum_{disp} P_{disp}^n(t) + \sum_{VRES} P_{VRES}^n(t) - P_{Curt}^n(t) = L^n(t) - E_{END}^n(t) + F_{net}^n(t) + \sum_{sto} E_{sto}^n(t) \quad (2)$$

$$\forall(n, t) \quad F_{net}^n(t) = \sum_p F_{n \rightarrow p}(t) - \eta * F_{p \rightarrow n}(t) \quad (3)$$

$$\forall(n, p, t) \quad |F_{p \rightarrow n}(t)| \leq 0.9 * F_{p \rightarrow n}^{max} \quad (4)$$

where

Exogenous variables (extracted from POLES model or from literature):

- L^n , the load demand [in MW]
- P_{VRES}^n , the production from VRES [in MW]
- η , the grid losses [in %]

Endogenous variables in EUTGRID:

- P_{Curt}^n , production curtailed from VRES [in MW]
- F_{net}^n , net exchange at node n [in MW]
- $F_{p \rightarrow n}$, power flow from node p to node n [in MW]

Equations (3) and (4) must be improved to better represent the flows within the European transmission grid. The transmission grid must follow physical laws known as Kirchhoff's and Ohm's laws. Because of these laws, the actual path followed by the electricity is often different from the path chosen with an optimal method such as in the "transport" model¹⁰ [63]. The resulting "unwanted" path is called loop flows and this phenomenon appears more frequently in case of unplanned production such as VRES and it can heavily stress the grid [64]. This can cause congestion within the grid. Therefore, a linearized model called "DC load flow"¹¹ is implemented in EUTGRID to calculate the power flows taking into account grid characteristics.

¹⁰ Power flows are only restricted by line capacities. Therefore, it can be seen as commercial contracts but it does not represent the grid reality.

¹¹ The linearization of AC load flow is called « DC load flow » because the resulting equations look like direct current flows.

The simplification consists in considering that the voltage at each node is equal to its nominal values and that the angles between each node have small variations. Consequently, reactive power is not included.

The flows are now differentiated between HVAC and HVDC technologies: $F_{n \rightarrow p}^{HVAC}$ and $F_{p \rightarrow n}^{HVDC}(t)$. $F_{n \rightarrow p}^{HVAC}$ now respect the DC load flow equation (6), which links the flow in a line np with its susceptance matrix $B_{n,p}$ and the angles θ_n and θ_p . For $F_{p \rightarrow n}^{HVDC}$, the flow can be controlled and for HVAC and HVDC, equation (4) is still valid but equation (5), which represents the net flows at node n replaces equation (3). This equation (5) represents the net flows in a line np . Finally, in equation (7), the value of the angle at a reference node must be set to zero to be able to solve these equations (it is often referred as "slack node").

$$\forall(n, t) \quad F_{net}^n(t) = \sum_p F_{n \rightarrow p}^{HVAC}(t) + F_{n \rightarrow p}^{HVDC}(t) - \eta_{HVAC} * F_{p \rightarrow n}^{HVAC}(t) - \eta_{HVDC} * F_{p \rightarrow n}^{HVDC}(t) \quad (5)$$

$$\forall(n, p, t) \quad F_{n \rightarrow p}^{HVAC} = V_{nom}^2 * B_{n,p} * (\theta_n(t) - \theta_p(t)) \quad (6)$$

$$\forall k \quad \theta_k^{ref}(t) = 0 \quad (7)$$

where

- $F_{n \rightarrow p}^{HVAC}$ and $F_{n \rightarrow p}^{HVDC}$ are the flows in HVAC or HVDC transmission lines between nodes n to p [in MW]
- η_{HVAC} and η_{HVDC} are the transmission grid losses¹² for HVAC and HVDC technologies [in %].
They are set to 2,5 % based on a survey on transmission losses in European countries [100].
- $B_{n,p}$ is the susceptance of the line between n and p [in S]
The matrix can be calculated using typical values such as presented in [101].
- V_{nom} is the nominal voltage in the transmission grid. It is set to 380 kV [in kV]
- θ_n is the angle of the nodes n .
- θ_k^{ref} is the reference angle k , which is set to zero to solve the load flow equations. The number of reference angles is equal to the number of groups of HVAC lines not connected to each other. For example, in EUTGRID, 6 nodes were set as references: one node

¹² As grid losses increase with the length of the line, the relative loss to the distance can be defined for HVAC and HVDC technologies (in %/1000km) [59]. However, in EUTGRID, there are too few nodes to take into account this losses related to the length of the line.

in Spain, one in the United-Kingdom, one for Corsica, one in Sweden, one for Ireland and one for Sicilia.

(iii) Description of the Grid Mechanism Investment

With the implementation of a DC model, it is not possible to directly optimize the operation of the power system and the grid investments. The resulting set of equations would become non-linear and it is very time-consuming to solve [59].

A method to address this problem is to iterate through the most congested lines and then increase the capacity of the transmission lines as done in ELMOD model [53], [70]. In EUTGRID it is implemented in a similar way but with some key improvements:

- Grid capacity increase can be chosen between HVAC (High Voltage Alternating Current) and HVDC (High Voltage Direct Current) technologies
- Grid costs are multiplied by a coefficient, which depends of the typology of the node (urban, rural and mountain) [102, p. 1].
- Grid investments are only allowed if the annualized reduction of the total costs covers the annualized investments in less than the payback period (P), which in our case is assumed to be ten years as used by the RTE (*Réseau de Transport d'Electricité* – Electricity Transmission Network, the French TSO (Transmission System Operator). It is implemented in equation (8) [103].

As mentioned earlier, the HVAC and HVDC technologies do not work similarly as power flows can be controlled in HVDC [104]. However, when there is a competition between the two, the latter technology is more expensive to install but the costs decrease as the total length installed. The break-even distance between the two technologies lie around 500 km: when the distance is above 500km, it is more interesting to install HVDC [105], [106]. In EUTGRID, the distances between the nodes follow a distribution as shown in Figure II-2 with a minimum distance of 152km and a maximum distance of 1581km while the median distance is equal to 376km. Therefore, in case of large integration of VRES, HVDC might be more competitive than HVAC in areas where distances are above 500km.

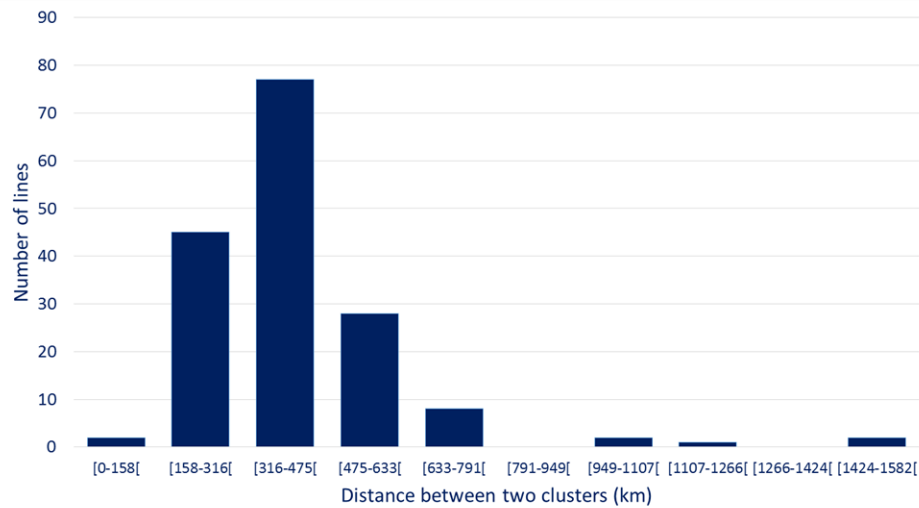


Figure II-2 – Distribution of distances for on-shore lines (HVAC and HVDC can compete)

1) Payback period and investments calculations

The indicator used in EUTGRID to choose between HVAC and HVDC is the payback period (P). This indicator is calculated as follows: the total investment I of the considered project is divided by the difference between the yearly total cost after the grid reinforcement O_B and the yearly total cost before the grid reinforcement O_A (see in equation (8)). The assumption is that the reduction of yearly total cost is a gain for the system and can pay back the investments chosen.

For a specific reinforcement project, its value must be below $P_{Project}$ to be accepted. In our case, it is set to ten years [103].

$$P = \frac{I}{(O_B - O_A)} \leq P_{Project} \quad (8)$$

Where:

- I is the total cost for investing in HVAC or HVDC lines [k\$];
- O_A is the yearly total cost of the system after grid reinforcement [k\$/year];
- O_B is the yearly total cost of the system before grid reinforcement [k\$/year];
- $P_{Project}$ is the payback period chosen by the TSOs to accept or reject a project.

If the payback period is negative, then it means that the considered project has increased the congestions in other nodes. Also, if for one project tested, the payback period with HVAC is lower than the one with HVDC then HVAC is considered more competitive and the reinforcement (or expansion) is accepted for HVAC.

The total investment I in equation (9) is broken into two parts: the investment in the transformer or the converter $C_C * P_{unit}$ and the cost of the line C_L , which is increased by a coefficient δ depending of the typology of the area.

$$I = C_C * P_{unit} + \delta * C_L \quad (9)$$

Where:

- C_C is the investments costs for HVAC transformer or for a converter station [k\$/MW]
- δ is a coefficient whose value depends of the typology of the node: it is more expensive to install a transmission line in a mountainous region than in a rural one [102]
- P_{unit} is the capacity of installed line in [MW]
- C_L is the total cost of a line, which adds investments costs and capacity costs [k\$]

The cost of the line C_L in equation (10) is also broken between the investments costs and the capacity costs.

$$C_L = d * C_{inv} + d * P_{unit} * C_{capa} \quad (10)$$

Where:

- d is the distance between 2 nodes¹³ [km]
- C_{inv} is the investments cost in [k\$/km]
- C_{capa} is the capacity cost in [k\$/km/MW]

The costs are taken from [107] and summarized in Table II-1.

Table II-1 – Costs for reinforcing or expanding the grid for HVAC and HVDC

	HVAC	HVDC
Line capacity P_{unit} [MW]	1700	1700
Transformer/Converter C_C [k\$/MW]	18,75	137,5
Investments costs C_{inv} [k\$/km]	1625	1625
Capacity costs C_{capa} [k\$/km*MW]	0,625	0,9375

As mentioned above, for each project, the typology of the node can modify the total investment needed. For example, it costs twice more to install a transmission line in a mountainous area than in an urban area. Therefore, for each node, a coefficient δ takes into

¹³ For simplification, the distance d between 2 clusters is taken as the distance between their centroids.

account its typology [108] and a multiplication factor based on a reviewing of reinforcing projects [102]. The method consists of calculating the coefficient δ . This coefficient calculated in equation (11) is the weighted average of rural, urban and mountain areas (A_{urban} , A_{rural} and $A_{mountain}$) with the cost coefficient (C_{urban} , C_{rural} and $C_{mountain}$) for each node.

$$\delta = \frac{A_{urban} * C_{urban} + A_{rural} * C_{rural} + A_{mountain} * C_{mountain}}{A_{urban} + A_{rural} + A_{mountain}} \quad (11)$$

where:

- C_{urban} , C_{rural} and $C_{mountain}$ are the multiplication costs, which are gathered in Table II-2.
- A_{urban} , A_{rural} and $A_{mountain}$ are the areas of the considered node by using Eurostat database [108]

Table II-2 – Grid coefficients implemented in EUTGRID

Typology of the area	Grid coefficient
Urban	1
Rural	1.38
Mountain	2.05
Unclear (Area not available in Eurostat)	1.1

This method helps to capture the diversity of typologies within the nodes and the resulting increase in transmission grid investments.

Annex D describes the method and the different values of the grid coefficient for each node are mapped in Figure II-3. A darker area means a higher grid coefficient and therefore a higher investment. For example, the investments in the regions around the Alps, the Pyrenees and the Norwegian mountains will cost more than those in Benelux regions, which are flatter and more urban.

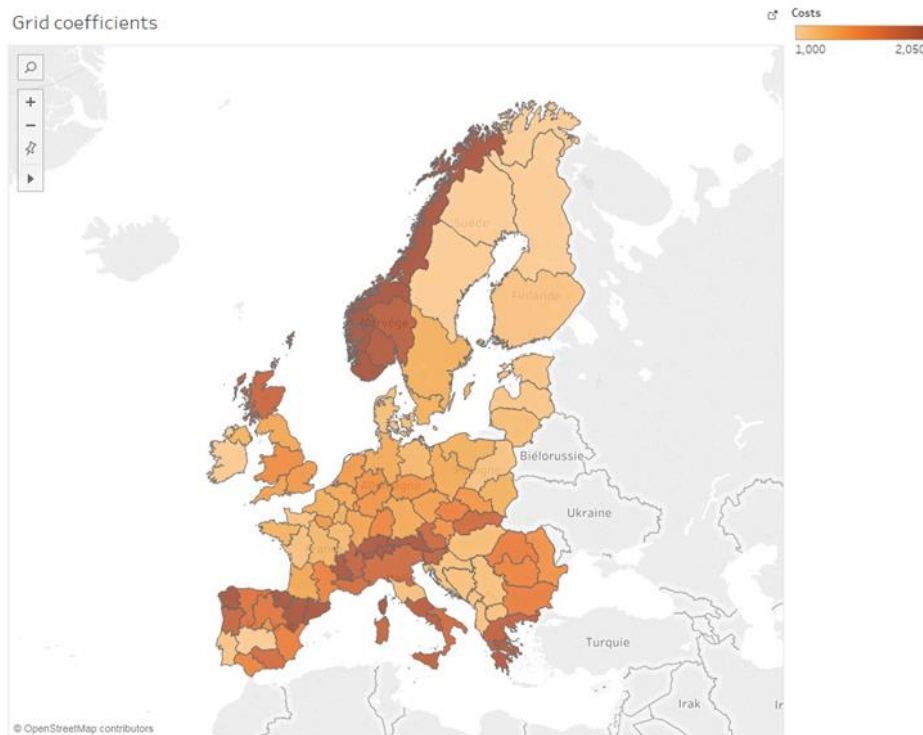


Figure II-3 – Average grid coefficients in Europe

2) Algorithm implemented

In order to detect the congestions in the European transmission grid, nodal prices are used as a signal. Indeed, a high price means that in order to satisfy the next MW of demand it is not possible to import from the congested line but power plants must be re-dispatched [9]. As a result, it has been assumed that the line with the highest difference between its two nodal prices is the most congested line [109], [110]. Consequently, this line should be considered to be reinforced in priority.

The mechanism of investment goes through different steps, which are described below. A flowchart available in Figure II-4 summarizes the algorithm.

- **Step 0:** Initialization.

Unit Commitment and dispatch is performed with initial capacities and transmission grid. Power flows and nodal prices are determined and total costs for the system is saved.

- **Step 1:** List of lines where their capacity might need to be increased.

This list is built as follows: the lines are sorted by descending order using their congestion cost. The hypothesis is that a line with a high congestion cost is more likely to have a congestion issue than one with a lower congestion cost.

These lines are chosen amongst allowed pathways, which are displayed on the map in Figure II-5.

- **Step 2:** Capacity increase and test.

A capacity increase at the first line of the list is being assessed using the cheapest technology (HVAC or HVDC).

- **Step 3:** Payback period.

The payback period is computed by dividing the value of reinforcement or expansion project and the reduction of total costs for the system.

- **Step 4 (a):** If the ratio is below 10 years, the reinforcement is accepted.

Go to Step 1.

- **Step 4 (b):** If the ratio is above 10 years, the reinforcement is refused, and the line is removed from the list of allowed lines to be reinforced. Go to **Step 2**.

- **Step 5:** Stopping criteria.

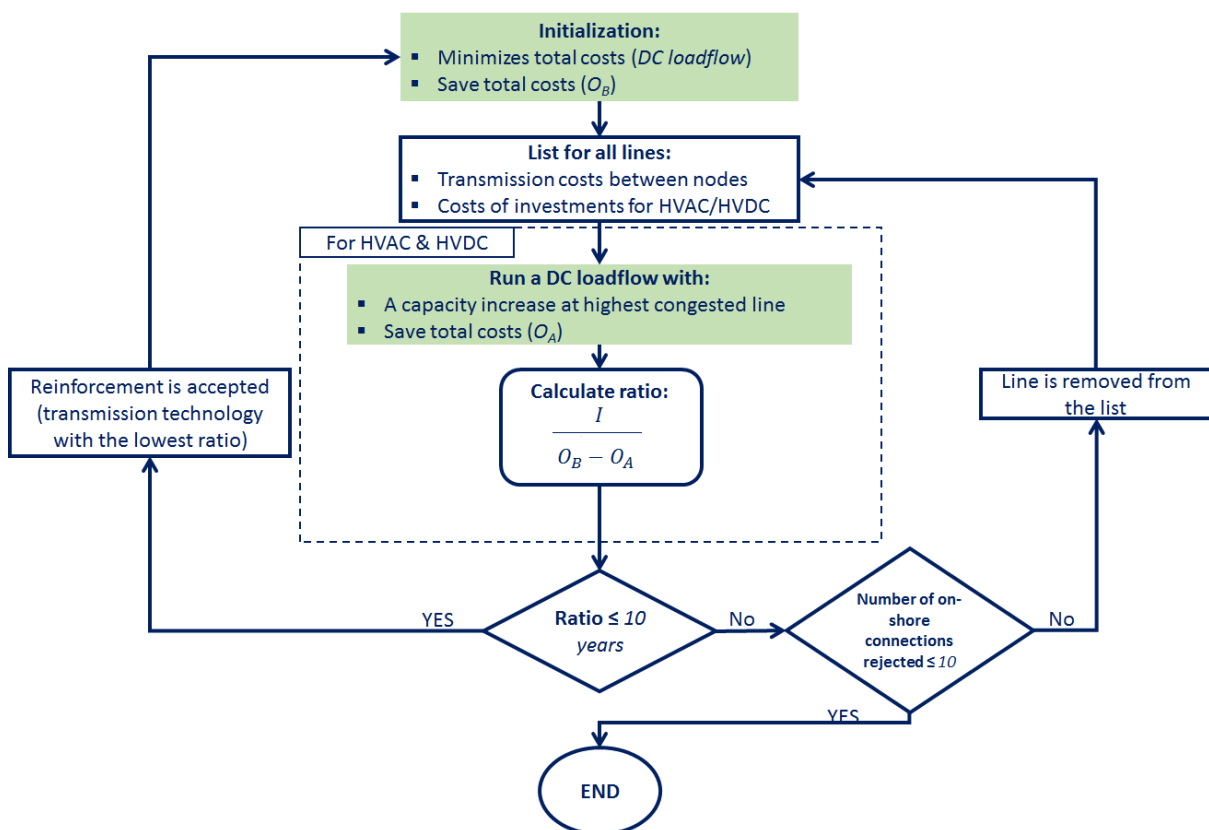


Figure II-4 – Diagram describing the grid investment mechanism

The algorithm stops when ten consecutive on-shore projects are rejected. The list gathers all reinforcement project (on-shore and off-shore). This criterion is set to reduce computations and at the same time to ensure that enough on-shore and off-shore connections are considered.

The map displayed in Figure II-5 shows the allowed paths of expansion or reinforcement in Europe. These paths are classified into two sorts: the routes for onshore HVAC/HVDC (in black) and the ones for subsea HVDC (in pink). These paths are exogenous to EUTGRID and can be modified if needed.

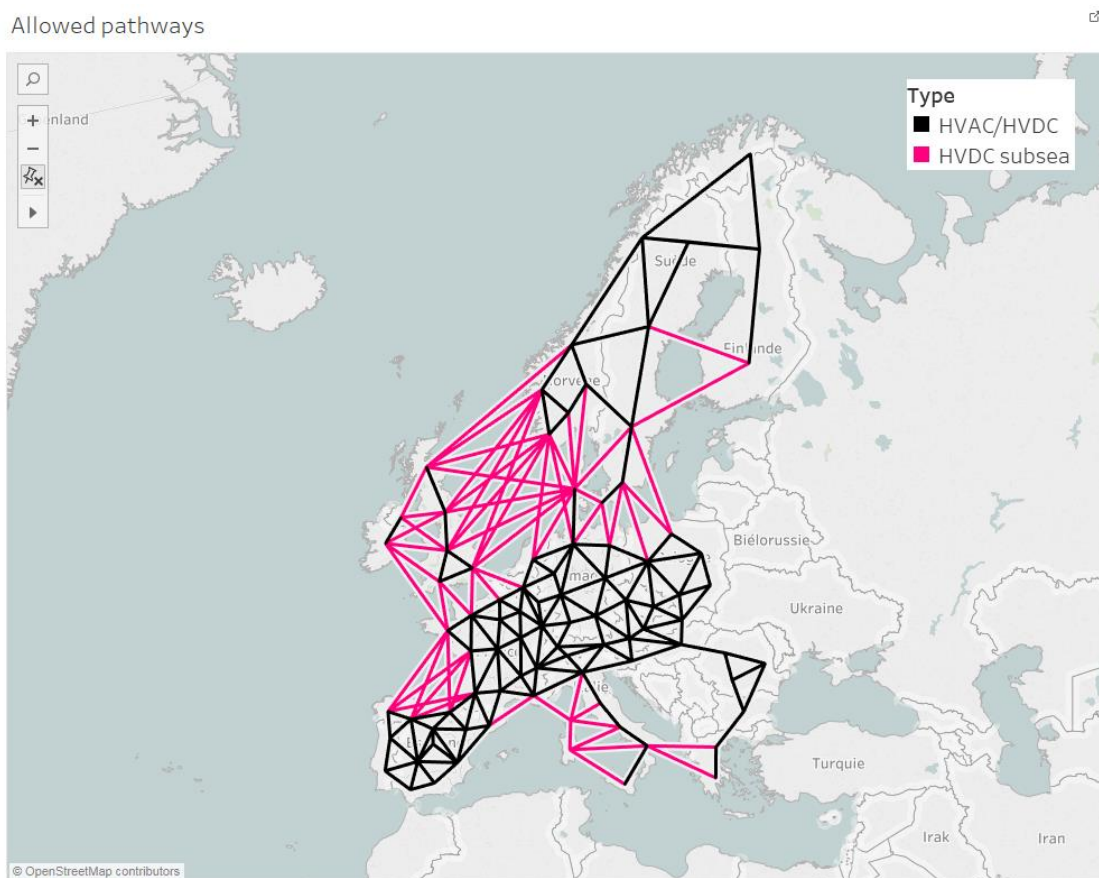


Figure II-5 – Allowed pathways for on-shore HVAC/HVDC and sub-sea HVDC

(iv) Description of the coupling between POLES and EUTGRID

EUTGRID provides in-depth details on the operations of the power sector and it is coupled with POLES, the long-term energy model. The IRENA (International Renewable Energy Agency) report [80] underlines that *such a "coupling" approach can translate a system's needs for flexibility in operation (a focus of production cost models) into decisions around investment (a focus of generation expansion models).*" This connection works as an exchange of information between POLES and EUTGRID for every simulated year.

The coupling can be described as follows: at year N, POLES provides the state of the power system with installed capacities, electricity demand at state level. These pieces of information are used as input data for EUTGRID, which computes the operation of the power sector. Then, the output data are sent back to POLES, which can make the investments decisions and move to the next year. This is shown in Figure II-6.

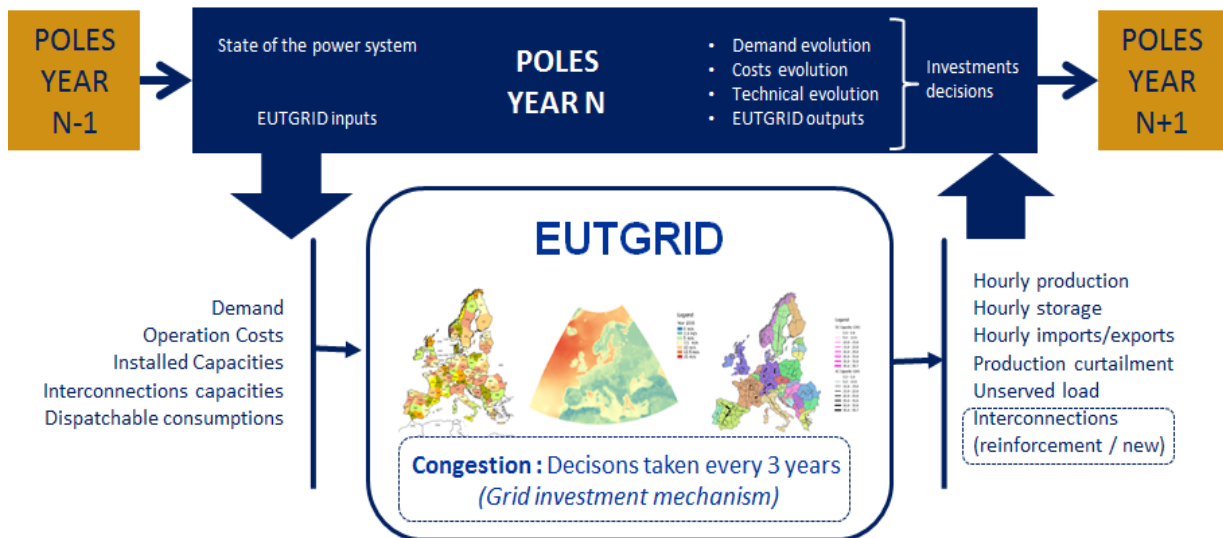


Figure II-6 – Diagram of the coupling between POLES and EUTGRID

By computing the power dispatch over Europe, EUTGRID is able to detect the congestions and decide new investments in the transmission grid. However, with the fast and large-scale integration of VRES capacities, a double phenomenon must be taken into account: reinforcements to prevent future bottlenecks need to be anticipated while at the same time, actual congestions must be resolved as installed capacities differ from expectations. This is done by using the expected capacities and demand determined by POLES with myopic simulations and the mechanism implemented within EUTGRID.

To capture these two types of planning, the mechanism consists of a 3-year rolling window. At the beginning of this 3-year period, transmission grid investments are calculated based on expected installed capacities 10 years ahead: it is the anticipative planning. Then at the end of the 3-year period, the investments needs are determined using actual installed power plant capacities in order to solve congestions.

II.2.2 Construction of the databases

(i) Evolution of the transmission grid from 2012 to 2030

The European project "e-Highway 2050" has developed a clustering method to reduce the grid representation model from the current 10'000 nodes to 95 nodes [111]. EUTGRID implements "e-HIGHWAY 2050" clustering (see Figure II-7) constructing the corresponding databases for these 87 nodes. It is important to note that the nodes, which were proposed do not cover two countries and also that transmission system operators were consulted on this clustering. Thanks to this particular splitting, it is possible to consider the requirements for reinforcing or expanding both between countries and within. In EUTGRID, the European transmission grid covers 24 countries and it does not include Baltic and western Balkans countries.

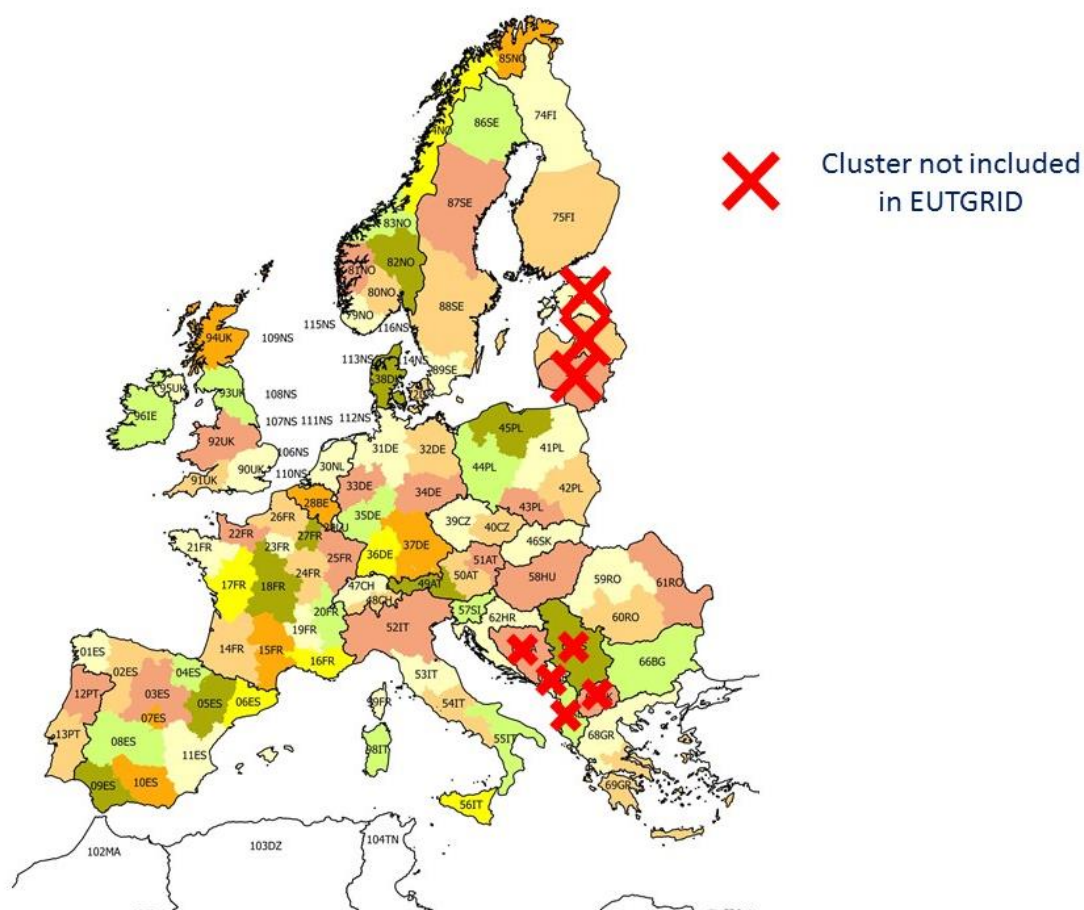


Figure II-7 – Final European nodes from "e-HIGHWAY 2050"

1) Initial conditions

An aggregated transmission grid, which connects the different nodes is needed to start the simulations. It should have the following characteristics: maximum capacities and impedance values of the transmission lines for the power flow calculations. In [111], this work has been done by using 2012 grid data and TYNDP (Ten-Year Network Development Plan) 2014 document [112]. However, the results for 2012 are not available for confidential reasons [113].

In this context, different datasets exist that describe the pan-European transmission grid such as TYNDP 2014¹⁴ [114]. This version is very useful for calculating power flows and perform in-depth power system analyses, but the coordinates of its nodes are lacking. To fill this gap, J.Bialek made publicly available a dataset based on ENTSO-E (European Network of Transmission System Operators) map [115]. However, the available map only had normalized coordinates that were difficult to fit on a map.

As a result, the extraction of transmission grid characteristics from available maps was done at the borders between nodes using ENTSO-E's map from 2012 and applying the method described in [101]. It was assumed that within a node there is no congestion. For each line, the following characteristics were retrieved: voltage (110kV, 220kV, and 380kV), the number of circuits per line and type of line (AC or DC). Based on these data, it is possible to get the thermal transmission limit of HVAC by using typical values, which are gathered in Table II-3[116]. For HVDC, as the number of transmission lines using these technology is low, the capacity for each line was added manually by using TYNDP 2014, which lists all HVDC projects [112].

Table II-3 – HVAC transmission grid typical characteristics [116]

Voltage (kV)	Number of wires	Thermal limit (per one circuit) (MVA)
380	4	1700
220	2	490
110	1	140

Figure II-8 illustrates the process of extracting the aggregated transmission grid for 2012. The map on the left combines the map of the European transmission grid provided by ENTSO-E and the mask of the e-Highway 2050 clustering. The map on the right shows the aggregated European transmission grid for 2012, which is being implanted in EUTGRID.

¹⁴ Many other datasets are available and a list, which is regularly maintained can be found at : http://wiki.openmod-initiative.org/wiki/Transmission_network_datasets

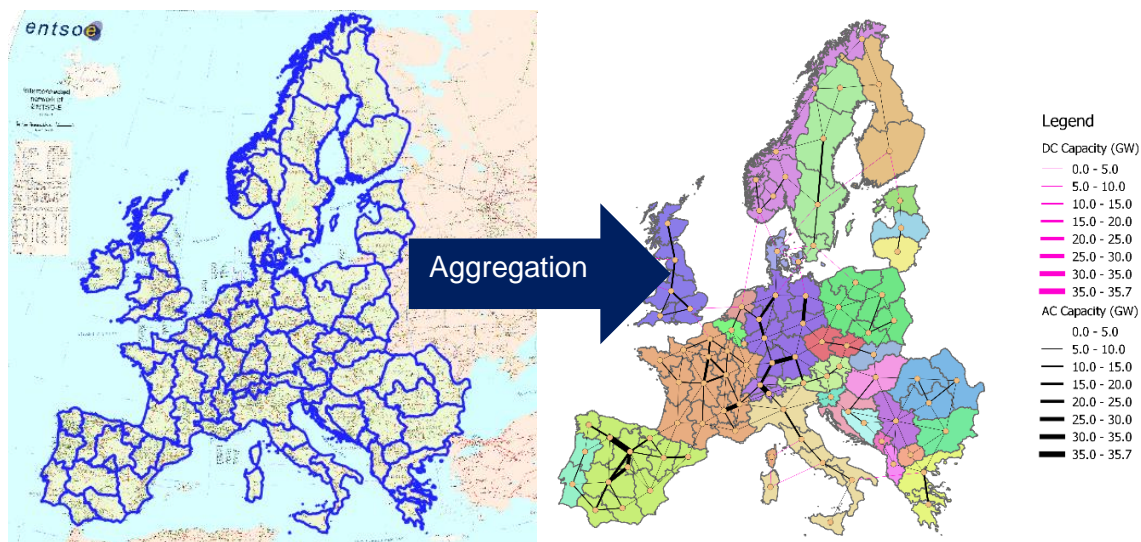


Figure II-8 – (a) Georeferencing ENTSO-E map 2012; (b) Aggregated transmission grid (HVAC & HVDC) in 2012

2) Evolution of the transmission grid towards 2030

The evolution of both the demand and the installed capacities within Europe modifies the power flows and can put some pressure in some regions. For this reason, since 2010, ENTSOE produces every two years a report which identifies future bottlenecks and the investments needed to relieve them. Hence the European project "e-Highway 2050" used the report TYNDP published in 2014 [112] in order to identify the new investments for each nodes in 2030 and made them publicly available [111]. However, the evolution of the transmission grid from 2012 up to 2030 is not available [113]. For this reason, the table of HVDC projects from TYNDP 2014 was used in this work with their expected commissioned time. For AC cable investments, a linear approximation of grid capacity and circuits has been used from 2012 up to 2030 for simplification.

(ii) Typical VRES production days

Because of their variability, VRES need to be well represented into the model so that hourly, daily and seasonal variations are taken into account [12]. Although it would be most precise to run EUTGRID with hourly historic production data for each node, it would require extensive data and computation time.

Hourly production data for each node do not exist as most of them do not represent actual administrative regions. Therefore, capacity factors were calculated using wind speed and solar radiation data from reanalysis database (it is a database which standardizes and correct past meteorological observations at a very detailed precision) [117]. We used available data

running from 2011-2016 which allow us to include exceptional days where production can be very low or very high. Hourly solar and wind production at node level were determined using the methods described in [118] and in Annex C. Moreover, these production data were compared with historic production data (sources include ENTSO-E [119] and Elia [120], [121]) (see Annex C for a description of the validation method).

Finally, in order to limit the number of days to be computed and at the same time keep a good representation of renewable production variabilities, the clustering method introduced in [90] was applied to get six typical VRES production days for summer and for winter (see Figure II-9 for a description of the method). It must be pointed out that these typical days correspond to the same dates for all nodes. This allows us to get consistency on the European level when performing the unit and commitment dispatch.

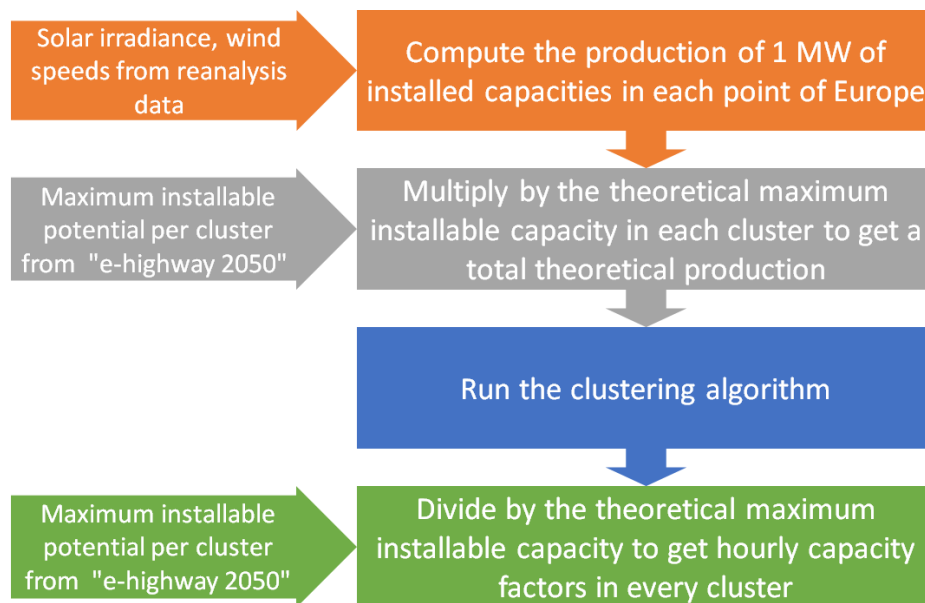


Figure II-9 – Typical days definition diagram (adapted from [12])

To illustrate the clustering process, the case of Belgium is taken. It corresponds to one node in EUTGRID. Figure II-10 shows the VRES capacity factors in Belgium. The figure is divided into two parts: summer production is located on the first row and winter on the second one. Then capacity factors are separated by columns: the solar capacity factor is on the left column, the wind onshore in the middle and the wind offshore on the right column. The different colours correspond to the 6 days and in the legend, the percentage of each season is included.

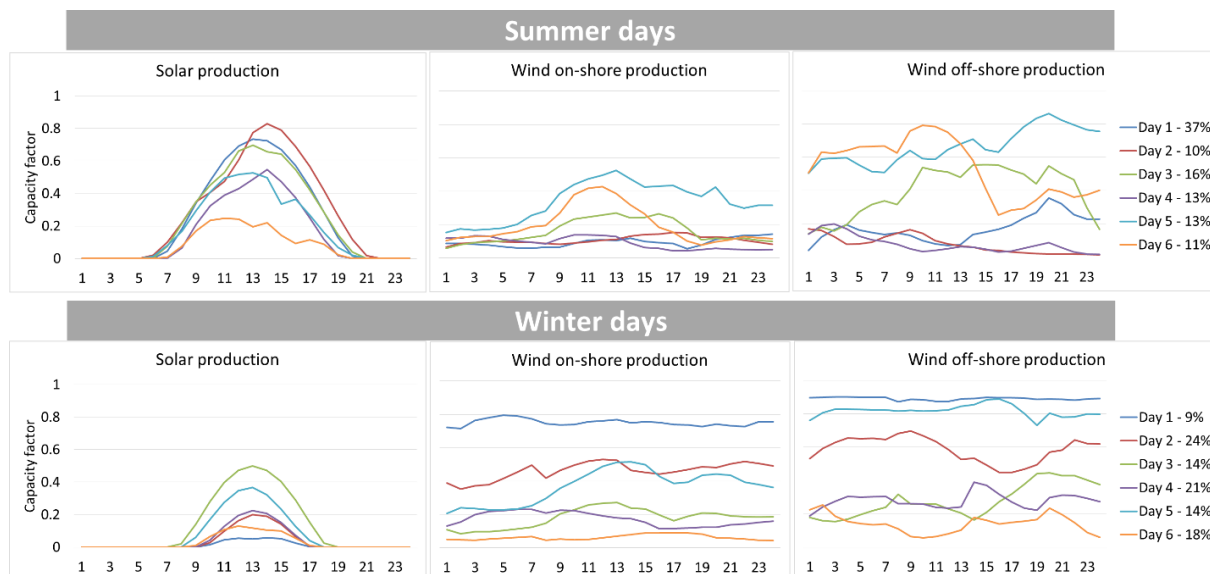


Figure II-10 – Typical days of VRES production (summer/winter) for Belgium

For solar, the hourly capacity factors follow the classic bell shape and their maximum value changes between the season and also between days. For example, the clustering process has chosen some days in summer where the production presents some important variations such as Day 5 or 6. For on-shore wind, the capacity factors differ between each day: in winter, during Day 1, the production is more important than in Day 6. Between seasons, it can be observed that the production is lower in summer than in winter [122]. Finally, for off-shore wind, the representative productions for each day have more variations within each day but the mean production is higher than for onshore wind and solar.

These differences show that the use of typical days can adequately capture the intrinsic variation of VRES. Thus, it will help to analyse with precision the impacts of these sources on the European power system.

(iii) Regional allocation of demand and generation capacities on European scale

As previously mentioned, EUTGRID has implemented a more detailed transmission grid with 87 nodes based on the project "e-highway 2050" [111]. At the same time, the coupling with POLES provides input data which are available only on a country basis: for example, national installed capacities, national demand, etc. Because of this situation, it is necessary to build the corresponding database for these 87 nodes for the demand and then the supply. POLES country data for electricity demand and supply has been split into nodes based on different distribution keys for VRES and conventional capacities and electricity consumption: population, wind speed, solar irradiation, thermal and hydro installed capacities and available land by node.

- Electricity consumption

Electricity consumption in a region depends on different factors such as GDP and population as implemented in POLES. However, in EUTGRID, for simplification, population distribution was used as a proxy for electricity consumption [123]. It has been validated using the electricity consumption of all French and English regions in 2014 and their corresponding population and GDP (sources: RTE, BEIS (Department for Business, Energy and Industrial Strategy) and Eurostat). In Figure II-11, two graphs are shown: on the left side, electricity consumption for English and French regions is plotted versus GDP (Gross Domestic Product). On the right side, electricity consumption for English and French regions is plotted versus population. A linear regression was applied and the comparisons of R^2 show that population is a better linear distribution key than GDP.

For 2000 up to 2014, historic data available from Eurostat (demo_r_gind3 [124]) at NUTS 3 (Nomenclature of Territorial Units for Statistics) level were used to calculate the distribution keys within each country. Then, from 2014 up to 2050, projections from Eurostat (proj_13rpms3 [125]) were exploited. After 2050, the distributions are the same as the ones calculated for the year 2050.

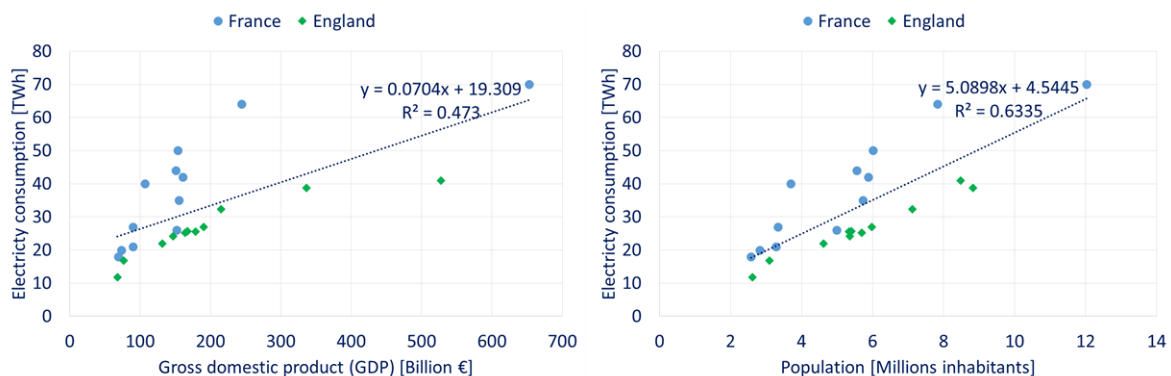


Figure II-11 – Electricity consumption versus GDP (left) and versus population (right) for French and English regions in 2014

- Conventional and hydro capacities

As pointed out by transmission system operators in [126], future power plants are mainly built next to already installed ones as social acceptance is higher. For these reasons, in EUTGRID, actual capacities are considered as a proxy for the distribution of conventional and hydro capacities. Data were retrieved from public sources such as Enipedia and Global energy observatory databases [127], [128]¹⁵.

- VRES capacities

Installation of VRES strongly depends on potentials and social acceptance or geopolitical issues that are difficult to take into account in a model [131], [132]. For this reason, simplified proxies which consist in linear distribution keys using weighted capacity factors were used for solar and wind technologies [126]. These distributions are linear combinations of population, maximum potential, and available land for building. These coefficients were determined through fitting with historic data (source: government databases. If, for a country, historic data at a local level did not exist, the same coefficients as its neighbour were used.).

To keep as close as reality, up to 2015, the distribution keys are calculated from historic data (if available). Then from 2015 up to 2025, a linear extrapolation with the fitting coefficients is applied while ensuring that the sum is equal to one for each country and each VRES technology. This is to make certain that there is no break between the historic distribution keys and the fitting ones. Annex B explains the methodology with more details.

¹⁵ A project led by the World Resources Institute (WRI) published an open-based power plant database using public sources and amongst them Enipedia and Global energy observatory [129], [130].

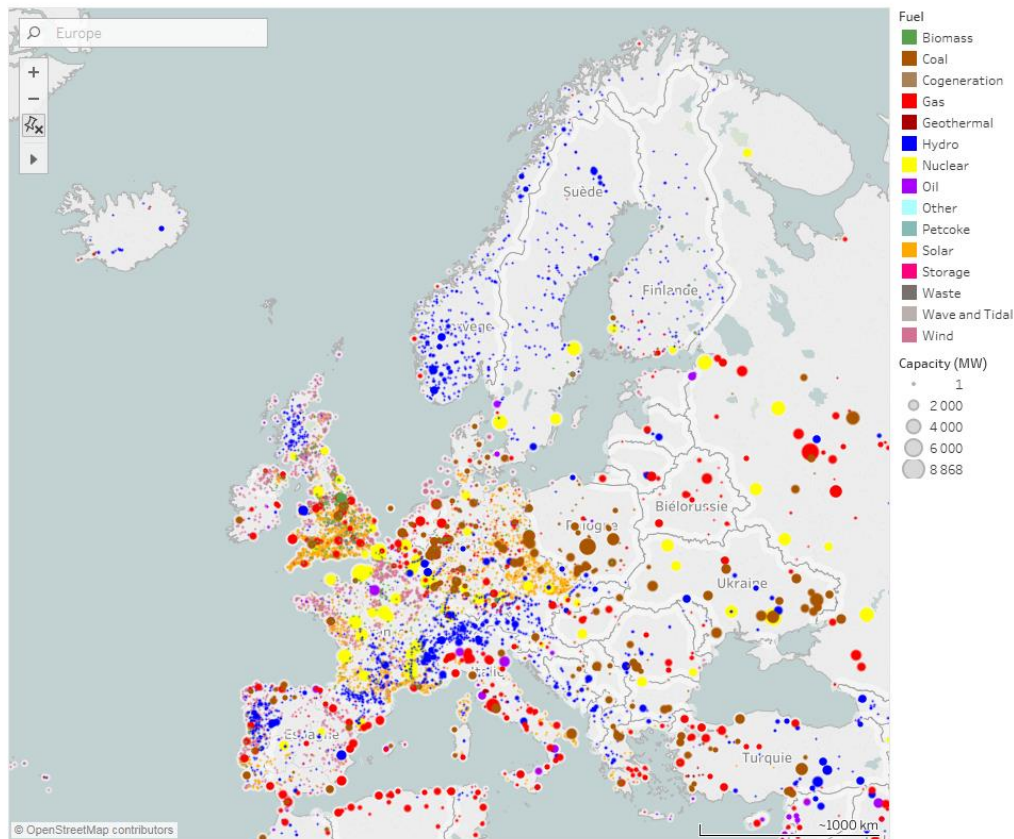


Figure II-12 – Power plants in Europe according to their fuel and capacities (in MW) in 2018 [129], [130]

- Technical potential limitations

Within each region, the installation of VRES is limited by a number of factors. The major limitation is the available land for building wind turbines or solar panels. In POLES, the maximum technical potential (in GWe) is computed every year for all VRES technologies. In EUTGRID, a small module has been implemented which ensures that a region does not have more installed capacities than its potential. The flowchart displayed in Figure II-13 shows the process in a simplified way and the module works as follows: first, for each VRES technology, it allocates the national potential over the nodes according to the distribution keys calculated in "e-highway 2050". In a second step, it allocates the capacities to be installed according to the distribution keys presented before and add them to the already installed capacities from the previous year. Then, it checks that the total capacities for each node does not exceeds its limits. If not, then the model continues to the unit commitment module. Otherwise, it takes the capacities installed in excess and allocates the residual to the other nodes. This step is done until the limitations are respected.

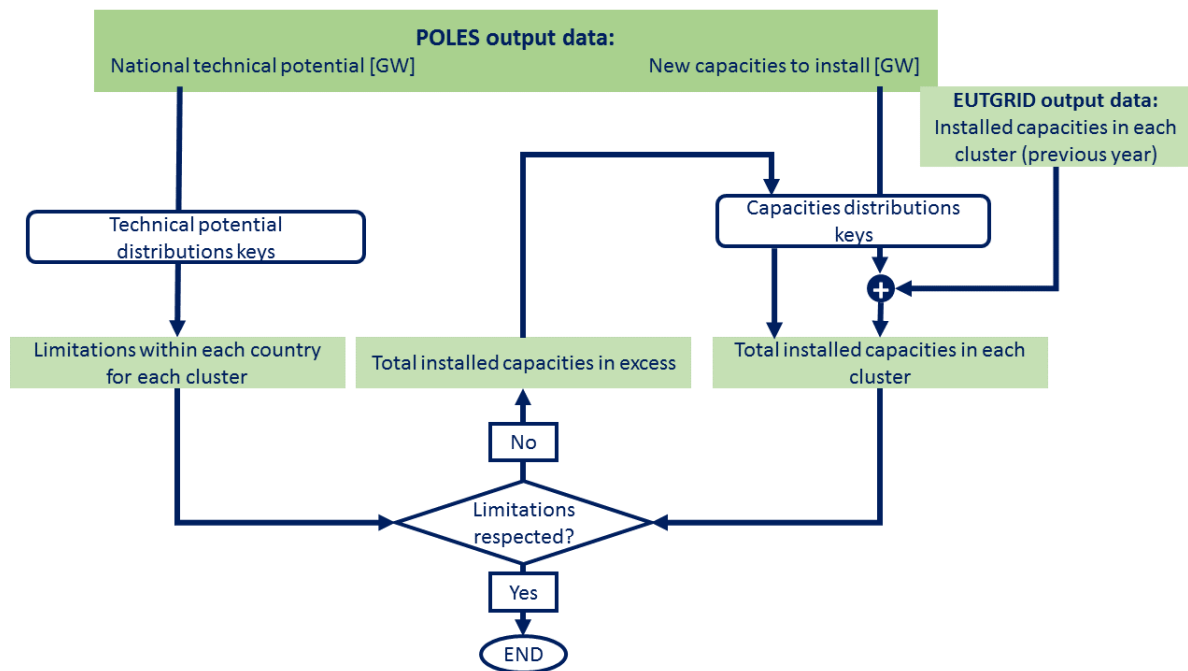


Figure II-13 – Diagram describing the potential checking module implemented in EUTGRID

This module has the advantage to capture an interesting effect which could exist in case of large-scale integration of VRES: the regions which have the best energy potential are chosen in priority up to the point where it is not possible to install more capacities. Then, regions with a lower potential will be selected and the national load factor for wind may decrease.

II.2.3 Validating EUTGRID

After describing the EUTGRID model and the different databases used, validations have been carried out on four levels. The power flows at interconnections are first analysed, then the resulting energy mixes on national level. A third step of validations deals with the process within the Grid Investment mechanism. Finally, the transmission grid requirements decided by EUTGRID should be compared with ENTSO-E's own investments.

(i) Power flow validations

A first test run was made, and results were compared with historic values at interconnections between countries. These power flows data are available at “ENTSO-E Transparency Platform” [119] and the year 2012 was used for comparison. The task was performed using 24 days from 2012 as the computation for a complete year would be excessive. In Figure II-14 - (a), the historic hourly flow Italy and Switzerland for one day in orange is compared

with the flow by EUTGRID. The comparison shows an important divergence. These results can be explained because the maximum available capacity of a line is reduced as the distance increases [133]. Moreover, the aggregation of the lines does not take into account the fact that some lines might be not available. These pieces of information are difficult to get and EUTGRID overestimates the power flows which go through the interconnections. Therefore, the characteristics of the susceptance matrix must be artificially modified to take into account these phenomena and better represent the power flows in the European transmission grid.

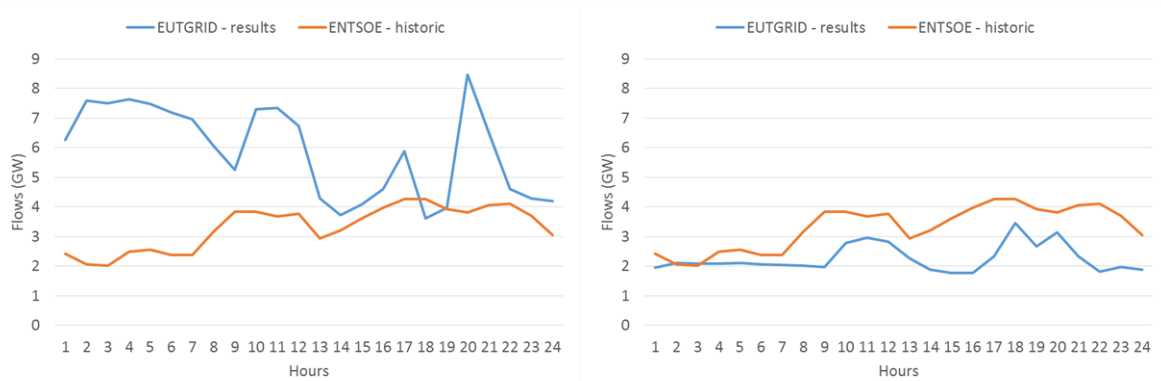


Figure II-14 – Power flows from Switzerland to Italy (30/12/2012) – (a) using typical values; (b) using optimized susceptance matrix

The goal is to find the susceptance matrix $B_{i,j}$ that matches the interconnection flows calculated $F_{i,j}$ and the historic flows $F_{hist_{i,j}}$ using a least squares approach similarly to the method described in [111].

$$\min\{B_{i,j}\} \sum_{t,i,j} (F_{i,j}(t) - F_{hist_{i,j}}(t))^2 \quad (12)$$

while respecting the DC-OPF equations

where

- $F_{i,j}(t)$ is the aggregated flow from country i to country j at hour t
- $F_{hist_{i,j}}(t)$ is the historic flow from country i to country j at hour t (data available at “ENTSO-E Transparency Platform”)

The values found for the susceptance should not be taken as real values but relatively for one to another. Taking the same day as previously shown, the flows calculated by EUTGRID and the historic flows are plotted in Figure II-14 – (b) and it can be seen that the calculated flows fit better the historic values. For the 24 days computed, the MAE (Mean Absolute Error)

between historic flows and the flows obtained with EUTGRID and typical values for the transmission grid is equal to 1.46 GW. With the optimized susceptance matrix, the MAE is equal to 0.77 GW. In Figure II-15, the calculated hourly power flows are plotted versus the historic power flows at the same hour for the two susceptance matrices: in orange for the typical values and in blue for the best candidate. The results show that the coefficient of determination is greater with the optimized susceptance matrix (0.45 against 0.27). Therefore, the transmission grid has been greatly improved but by lack of time, we did not try to find a better candidate matrix.

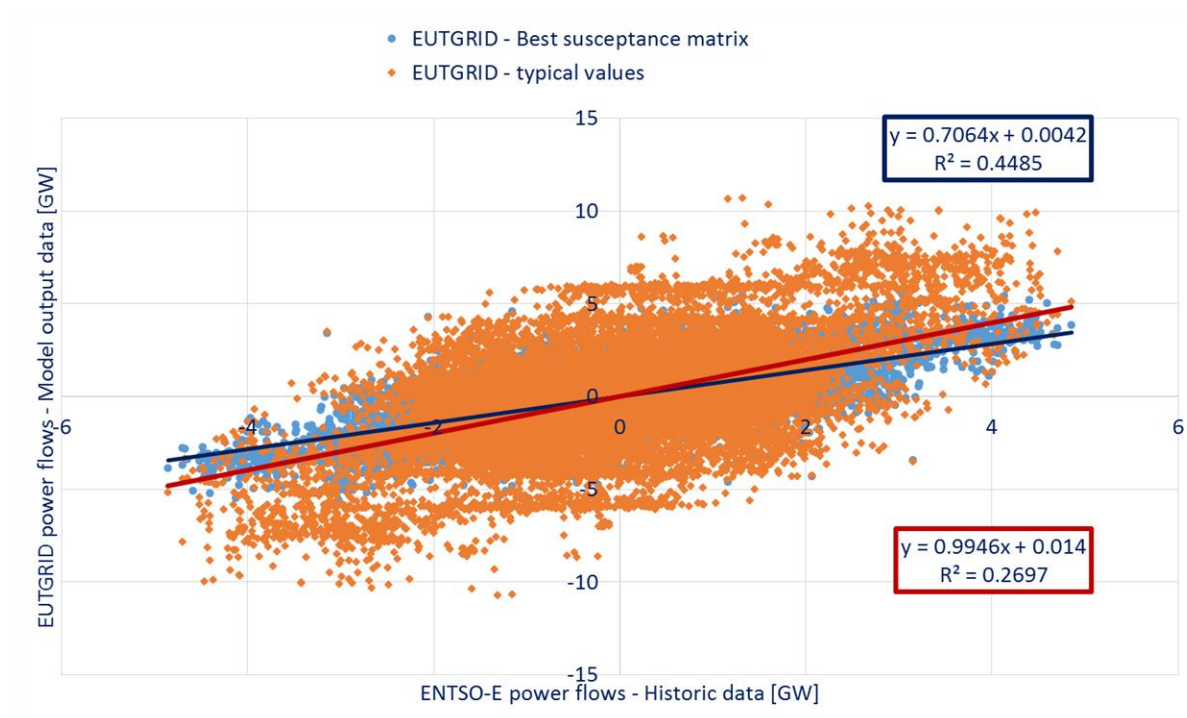


Figure II-15 – Representing the hourly calculated power flows versus the historic ones (year 2012)

(ii) Production validations

While finding an optimal susceptance matrix, we must ensure that the energy mixes found do not deviate too much. For this validation, the French energy mix for the year 2012 was used with data from ENTSO-E and from RTE [134]. RTE provides extensive production data for the year 2012 and ENTSO-E provides hourly power flows between countries. Furthermore, for hourly VRES production and distribution keys, we use the materials described previously together with the transmission grid description. We also need to recall that as EUTGRID uses the same core as EUCAD, it shares the same biases which were pointed out in [12] : the most important ones are the use of optimization which creates

situations with "winner-take-all" effects and operation of storage in EUTGRID/EUCAD that are performed daily, while hydro could be used weekly.

Taking these remarks into account, we compare RTE data and EUTGRID results in Figure II-16 for two different days (26/09/2012 for the summer and 15/02/2012 for the winter). The figure illustrates the energy mix for RTE on the left side and for EUTGRID on the right side (summer is on the first line and winter on the second line). The results show the same biases as described in EUCAD model. For example, the use of coal power plants is still largely over-evaluated while the gas power plants produce less than in reality. Some of the explanations given in [12] include the European air pollution regulation or the international coal prices from POLES' database which is not the actual price paid by EDF (*Electricité de France* – Electricity of France). However, with the implementation of a more detailed representation of the transmission grid and a DC load flow, during winter days, there is an over-evaluation of production from oil and biomass power plants which were not observed in EUCAD. These differences happen especially in the "Ile de France" region, which is a node with high demand and many oil capacities. As a result, during these special days, congestions are very high and thus, there is a need to call these expensive back-up capacities.

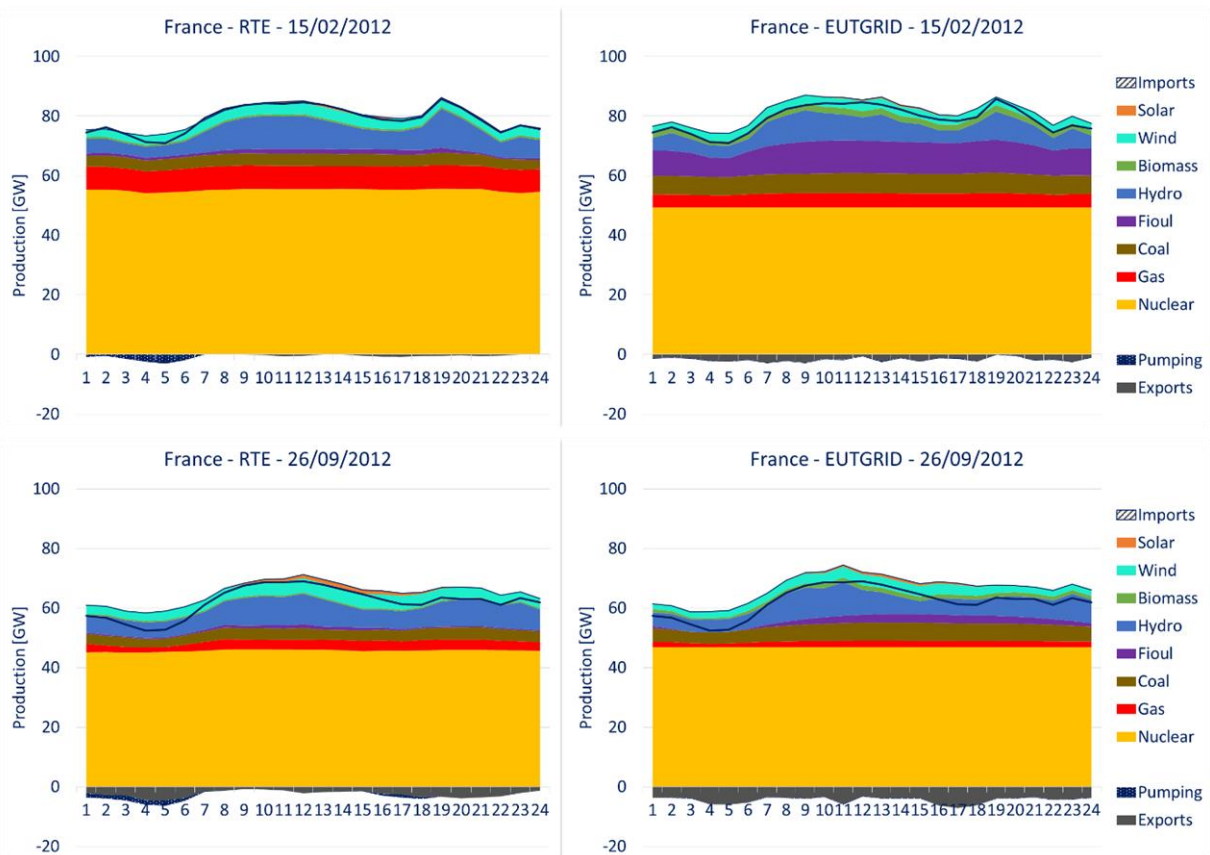


Figure II-16 – Energy mixes for two different days (26/09/2012 and 15/02/2012): real production data (left) and EUTGRID simulations (right) – France

(iii) Understanding the effects on the power system: a first test case

To show the process of the algorithm and its main role on the power system, which is to detect and relieve the congestions, the evolution of some indicators is analysed at each step, once a reinforcement is accepted. These indicators are the yearly maximum transmission congestions costs in k\$/year, the total investments needs in TWkm and the use of flexibility options (curtailment, storage and demand response) in TWh.

The test case consists of taking the European power system with levels of demand and installed power capacities from 2040 and determining the necessary transmission grid requirements with the infrastructure of 2012 as the initial point. This unrealistic case aims at highlighting the role of investing in the transmission grid under important constraints and its effects on other indicators. The first visible effect of the reinforcement of the transmission grid is the reduction of the congestions: as the transmission grid is being upgraded, the maximal congestion cost decreases. It is visible in Figure II-17, where the additional reinforcement requirement (in blue) and the maximal congestion cost (in orange) are shown for every step in the algorithm. However, after almost 30 steps, there is no more decrease as the most congested line has been rejected during the process and cannot be reinforced further.

The reduction of congestion can be analysed spatially. In Figure II-18, two maps are displayed: on the left side, the congestions costs at the initial stage and on the right side, the congestion costs at the final stage. It can be observed that at the end of the simulation, there are still some congestions within Europe. The use of the payback period explains these results as some lines were rejected even if they were highly congested. Initially, Germany had the most congested areas with really important differences between its nodes. Then came Scandinavia, France and United-Kingdom as the most congested areas. It corresponds to areas where the transmission grid capacities are limited and around 11TWh of demand could not be supplied. Renewable energy is also curtailed but it only represents 3TWh. Therefore, the reinforcements first aim at reducing the non-distributed energy.

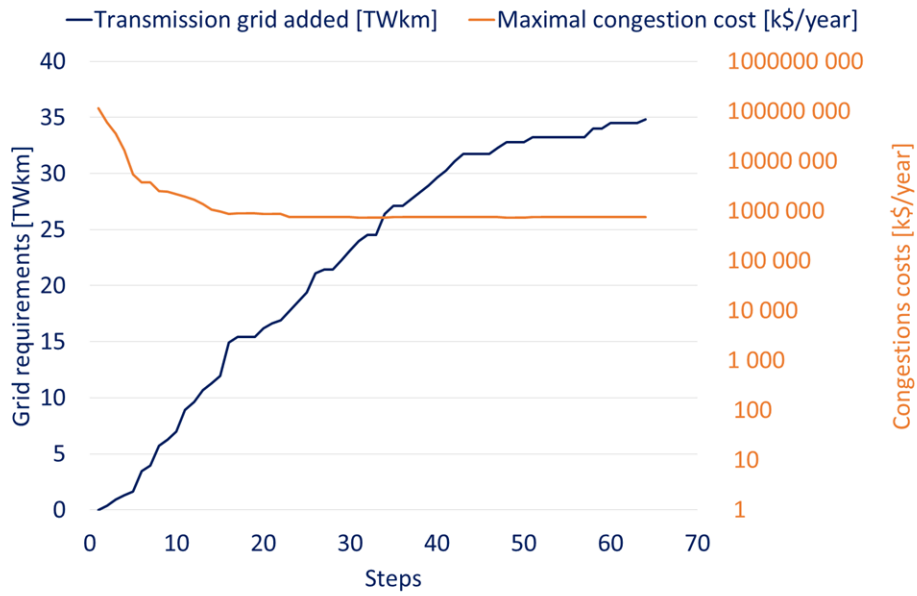


Figure II-17 – Evolution of the transmission grid requirements [in TWkm] and of the maximal congestion cost [in k\$/year] at each step of the algorithm

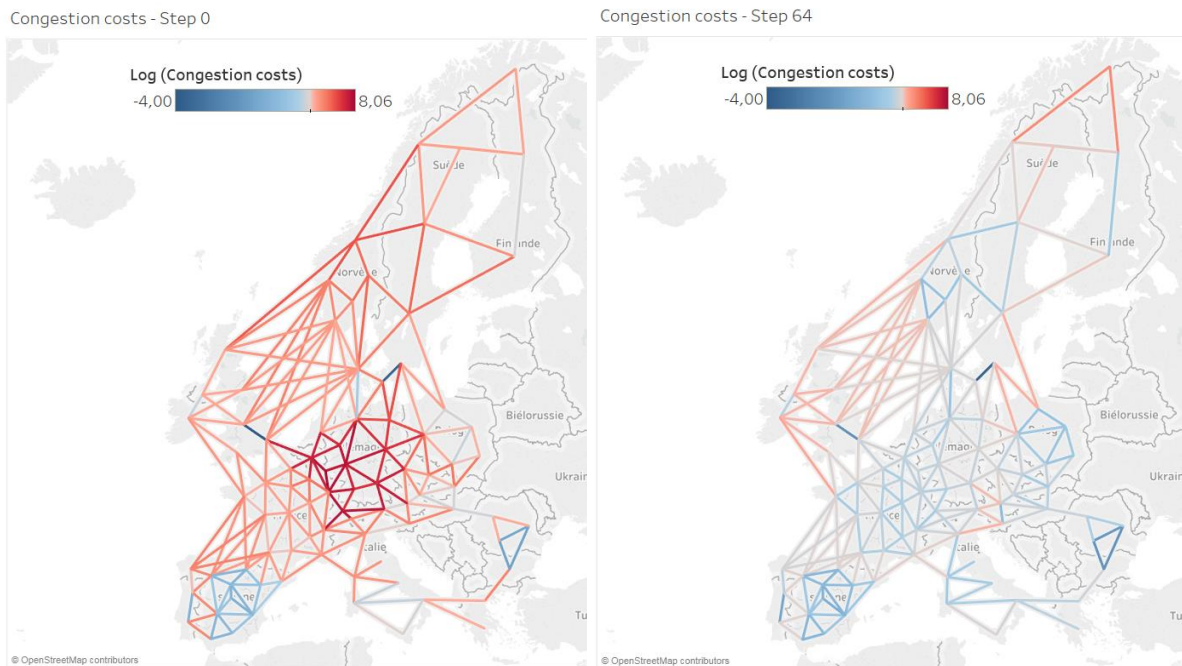


Figure II-18 – Congestion costs at step 0 and at last step of the grid investment mechanism [in log(k\$/year)]

To understand the effect of the reinforcement on the flexibility options, the amount of energy curtailed, of energy from storage technologies and from demand response are shown Figure II-19. Non-distributed energy is also included in the graph. The first indicator to be reduced

is the non-distributed energy and it highlights the positive impact of upgrading the transmission grid: in less than five steps, there is no more non-distributed energy.

The next steps aim at reducing the curtailment of renewable energies: their operating costs is set to zero. Finally, after 25 steps, the curtailed production reaches less than 0,5 TWh. An interesting effect of the transmission grid expansion is the continuous decrease of production from storage technologies. With more connections between nodes, a more robust transmission grid allows to benefit from cheaper technologies. It can also be noticed that demand response is used at its maximum potential underlying the fact that flexible demand can have a positive impact in reducing the total system costs.

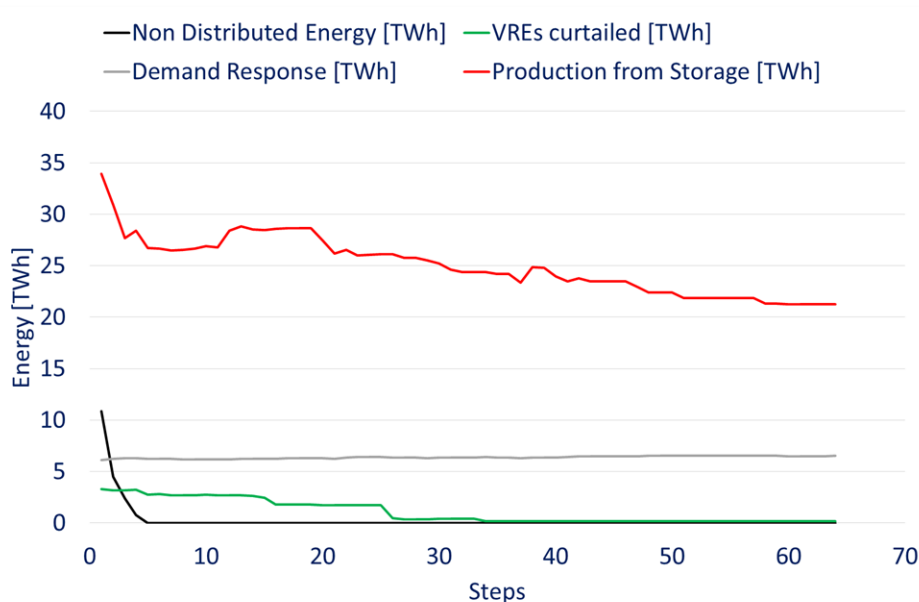


Figure II-19 – Evolution of usage of flexibility options [in TWh] at each step of the algorithm

(iv) Transmission grid requirements

The validation of the coupling of POLES and EUTGRID has been performed by running two different scenarios from 2000 until 2030: (1) a business-as-usual scenario “BAU- Grid” with no climate policy implemented; (2) a 2°C scenario “Clim – Grid” with a climate policy which aims at keeping the cumulative CO₂ emissions under 1’300 GtCO₂ from 2011 until 2100 [135]. These scenarios will be further described in the next chapter. The resulting transmission grid investments from the period 2010 – 2030 are gathered in Table II-4 and can be compared with ENTSO-E’s investments which are available from [112]. It can be noted that for all the indicators chosen, the investments decided by ENTSO-E are above the

ones found by EUTGRID for each scenario analysed. For example, European TSOs have decided to install more HVAC and HVDC capacities (202GW and 42GW). These investments connect more regions with around 61'000 km of lines added than for EUTGRID. Indeed, EUTGRID installs at most 70 GW of HVAC and 58 GWs of HVDC which result in between 18000 km and 25000 of lines added.

Table II-4 – Comparison between ENTSO-E's transmission grid requirements and EUTGRID's for 2010-2030

Scenario		2010 - 2030		
		ENTSO-E	BAU - Grid	Clim - Grid
Production VRES [%]			[5%; 18%]	[5%; 28%]
Transmission grid	HVAC added [GW]	202	70	68
	HVDC added [GW]	42	37	58
	Line length added [000km]	61	18	25
	Grid added [TWkm]	97	46	60
	Total grid investment [b\$]	150 (ENTSO-E's estimation)	76	103

As a result, the total investment for ENTSO-E's transmission planning reaches 150b\$ according to the TYNDP 2014 report [112]¹⁶. This value can be compared to EUTGRID's total grid investment of 103b\$ (-31%) in "Clim – Grid" scenario. This large difference can be explained by different factors: first, the TYNDP report is based on detailed insights of the transmission grid. TSOs know the actual state of the transmission grid and can better estimate the future location of VRES capacities. As a result, they already have preliminary technical and economic studies to evaluate the reinforcements and the extension of their transmission grid. Hence, these studies take into account the grid reality and also social acceptance. EUTGRID does not have this knowledge and it can decide to extend the grid in a region where it is actually very difficult due to important reluctance from the population.

ENTSO-E also maintained an update of the projects TYNDP 2014 and this report showed that 3% of the projects are cancelled, 15% are delayed and 15% are rescheduled [136]. More specifically, during the period 2025-2030 or after 2030, 22% of the projects are either cancelled, rescheduled according to the table of planning. These projects are the most subject to modifications as more precise technical and economic studies will be made. Finally, these projects represent at most 33b\$ which let 117b\$ of transmission grid investments during the period 2010-2030.

¹⁶ If EUTGRID recalculates the total budget ENTSO-E's investments with the transmission grid costs presented in the previous section, the total grid investment reaches 180b\$.

As EUTGRID cannot consider cancellations, delays or rescheduling, these final investments of 117b\$ for ENTSO-E can be compared with EUTGRID's own investments of 103b\$ (-12%).

II.3 Sensitivity analysis on payback-period

As previously explained, the payback period consists of calculating the number of years needed for the expected revenues to cover the investments made in the first year. In EUTGRID, the revenues are considered to be the reduction of the total system costs and the default value of the payback period is set to 10 years.

However, this calculation does not consider that today's value of any future revenue or cost decreases with time. Therefore, a more appropriate calculation would be to integrate the discounted reductions of costs.

In the following simplified example, we show the effect of a discount rate on the payback period.

At year 0, a reinforcement project is being assessed. It needs an investment I equal to 1b\$ and the expected reduction of total system costs is equal to $\Delta C = 100k\$$.

As a result, the payback period P_0 is equal to $P_0 = \frac{I}{\Delta C} = 10 \text{ years}$ and the reinforcement project would be accepted in EUTGRID. If the discount rate k is taken into account, the payback period P_k should be calculated using the formula shown in equation (13):

$$I = \sum_{t=1}^{P_k} \Delta C * (1 + k)^{-t} \quad (13)$$

Using this formula and the same example, the payback period P_k is calculated for each discount rate k and the results are gathered in Table II-5.

The results show that by using a discount rate of 0%, we underestimate the real payback period by 2 years compared to a calculation if a discount rate equal to 2% is chosen. The payback value is underestimated by 11 years if the discount rate is set to 8%. The latter corresponds to a very conservative situation where almost no risks are taken. In [137], ENTSO-E recommends to use a 4%/yr discount rate.

Table II-5 – Payback period for different values of discount rate k

k	0%	2%	4%	8%
$P_k[\text{years}]$	10	12	15	21

In EUTGRID, by changing the value of the threshold parameter, the different situations can be considered. Consequently, a sensitivity analysis was performed on the period 2010-2030 using a climate energy scenario. In these cases, the reinforcement module is run with four different values: 5 years (very conservative), 10 years (conservative - default), 15 years (risky), 20 years (very risky). For each simulation, the following outputs are retrieved and gathered in Table II-5: the total line length in thousands of kilometres, the resulting total grid added in TWkm with the distribution between HVAC and HVDC and finally the total investment budget in b\$.

Table II-6 – Investments in the transmission grid for different values of payback periods

Payback period [Years]		2010 – 2030			
		5 years	10 years	15 years	20 years
Transmission grid	HVAC added [GW]	46	68	87	102
	HVDC added [GW]	26	58	92	100
	Line length added [000km]	13	25	38	50
	Grid added [TWkm]	30	60	89	108
	Total grid investment [b\$]	54	103	156	197

The sensitivity analysis shows that with a riskier approach (low discount rate or long payback period) more investments are accepted. For example, with a payback period of 20 years, it reaches 50 000 km and it is almost four times the value found with a payback period of five years. The other indicators follow the same trend with up to 108TWkm added and 197 b\$ invested if the payback period is set to 20 years. However, the breaking down of the investments between HVAC and HVDC shows that HVAC technologies are mainly chosen if the payback values are low. With a lower initial investment, HVAC technologies have a lower payback period and are chosen first.

Conclusions

The long-term energy model POLES is a simulation model with a bottom-up representation of the energy system. Its dynamic recursive simulations help to take into account the inertia of the system. However, in its stand-alone version, the electricity sector is represented in a simplified manner for transmission grid or storage technologies. To overcome these imperfections, a module EUCAD was coupled to POLES. It represents with a higher level of details the European power system and it introduces new storage technologies and demand response which would be needed in large scale integration of VRES. These improvements allow to have better analysis of the impacts of VRES within the energy sector. Although it has better described the transmission grid, it is still simplified with only a node per country and power exchanges which do not take into account the grid characteristics. As a result, EUCAD misses the transmission grid requirements within a country as congestions appear but also between interconnections with the "loop flows" effect.

Therefore, the new module EUTGRID has been developed in this study: it incorporates the previous modelling approach but with a finer spatial resolution and a transmission capacity expansion module. Because there are now more nodes for each country, a method to construct the adequate databases was described and validated. The model was also improved with realistic power flows thanks to the implementation of DC load flow. The transmission capacity expansion module uses the results from the optimization process to detect and relieve congestions through the competition of HVAC and HVDC technologies.

EUTGRID is then coupled with POLES in year by year process. The European power system is optimized based on the inputs from POLES and EUTGRID sends back information to POLES on the operation of the system. EUTGRID determines the transmission grid requirements on a 3-year rolling window: at the beginning of the period, it uses the state of the power system as seen by POLES in 10 years. Then, in the end, it uses the actual state of the power system to solve the last congestions which might have not been seen before. Hence, this new coupling allows to analyse the evolution of the transmission grid both in time and space.

Chapter III. Grid expansion and flexibility options with large scale integration of VRES

The improved power EUTGRID model presented in the previous chapter allows to determine the grid reinforcement needs on a European level. This Grid Mechanism Investment is based on nodal prices together with a DC-load flow and a more detailed description of the European transmission grid. This development goes beyond "conventional" energy systems modelling, where the electricity grid is usually represented as a copper plate. Coupled with the long-term energy model POLES, it allows for a more distinct analysis of energy technology and energy policy.

In this framework, results from prospective scenarios are presented to analyse the role of the transmission grid infrastructure in the energy system. The development of the infrastructure is not as flexible as the installation of VRES capacities and it needs time to be expanded but more importantly, it must be economically justified. Moreover, some technologies are expected to emerge after 2050. For these reasons, the long-term energy scenarios presented in this chapter go up to 2100. It will help to draw some observable trends.

The main characteristics of the scenarios analysed are first presented. They all correspond to the same climate energy policy to limit the rise of the temperature to 2°C in 2100. The reference case corresponds to the situation with an optimal grid development: there is no budget constraints and the reinforcement projects are economically assessed using EUTGRID. The development of the European transmission grid is then characterised by comparing the results of the reference case to scenarios with modified hypotheses (limited grid investments, favouring the use of flexibility options). In the following section, an analysis is carried to evaluate the impacts of the transmission grids on different indicators such as the emissions, the use of flexibility options and the security of supply. Finally, an exploratory work is being presented, which replaces the current least-cost approach by an LCA-approach (Life Cycle Assessment): the dispatch of the electricity production is performed using emissions factors (in kgCO₂eq/MWh) based on LCA studies¹⁷ instead of operation and maintenance costs as usually done in power system models.

¹⁷ Life Cycle Assessment studies assess the environmental impacts of each technology from extraction to recycling. Different indicators exist such as climate change, land-use or ozone depletion. They are calculated for a MWh produced.

III.1 Assessing the role of the transmission grid

III.1.1 Socio-economic assumptions

The long-term energy model POLES is a partial equilibrium model for the energy system. Exogenous hypotheses are needed to describe the evolution of the economy during the simulation. Thus, they will influence energy demand in the different countries and the resulting international energy prices. Exogenous assumptions on the population, the gross domestic production trajectories must be provided to the model: the historical and projection data comes from UN and Eurostat for the population and World Bank and OECD for GDP. It is the same database as used in GECO 2017 [138], [139] and the same data are applied for all scenarios presented in the next sections. Figure III-1 represents these exogenous data for the 24 European countries included in EUTGRID. In the considered scenario, the overall population slightly decreases after 2060 to reach around 509 million inhabitants. However, the dynamics vary within Europe. For example, the German population decreases during the century and in 2100 loses around 20 million inhabitants. On the opposite, United-Kingdom and France gain respectively 26.4 and 20 million inhabitants.

The implemented GDP projections consider that all European countries increase their economic activity. From 2000 up to 2100, it should increase 4.20% per year on average. However, in the last years of the simulation, French and English GDPs should catch up with German GDP. The French GDP should even slightly over exceed the German GDP with 7982b\$ (2005 ppa) versus 7534 b\$ (2005 ppa) for Germany.

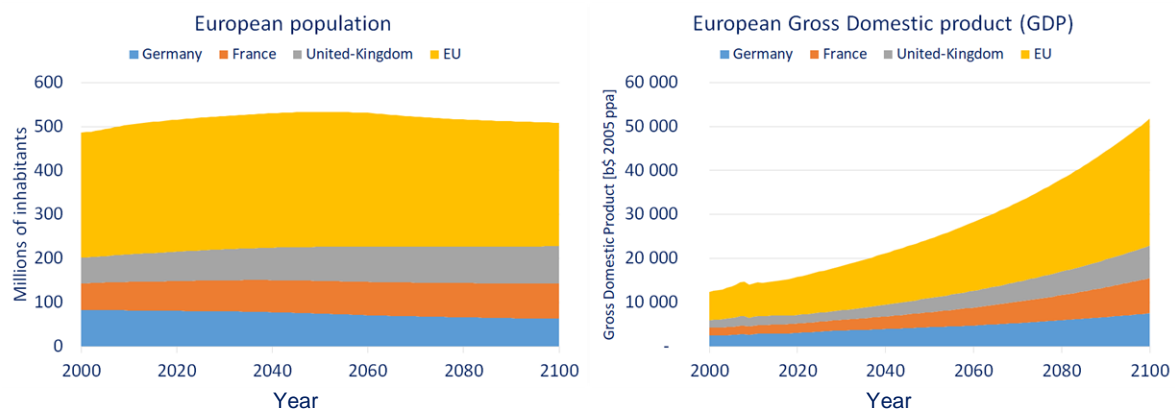


Figure III-1 – Population (left) and gross domestic product (right) for EUTGRID countries (2000 – 2100) [138], [139].

To calibrate the outputs of the simulation, the POLES model also uses different databases to cover the historical years up to the year 2010. These databases come from a variety of sources such as Enerdata, which provides data for the hydro resource, the energy demand by sector, the international energy prices, or the energy reserves. Another important input to POLES is the use of learning curves for the different technologies. Two different learning curves are considered: “learning-by-doing” and “learning-by-searching” which help to better represent the investment cost reduction for the different technologies.

III.1.2 Implementing a climate energy policy

Once all the adequate databases are available and updated, POLES can be run to provide different outputs on the evolution of the energy system. If nothing has been modified in POLES or in the different databases, the resulting scenario is considered as a business-as-usual case where no new climate energy policy is implemented. Usually, it acts as a reference case to be compared with other scenarios. In POLES, the implementation of a climate policy scenario is done using exogenous carbon values. As a result, in POLES, the cost of the most polluting technologies will increase. These more expensive technologies will then be replaced by cheaper and cleaner ones.

To illustrate the difference, a scenario business-as-usual (scenario “BAU - Copper”) and a climate energy scenario of type 2°C (scenario “Clim - Copper”) are set up in POLES. The climate energy policy analysed in this manuscript aims at keeping the cumulative CO₂ emissions under 1 300 GtCO₂eq from 2011 up to 2100 as stated in [135]. It means that the rise of the global temperature should be kept under +2°C. In these scenarios, the grid is not a constraint and all European countries can export to any other European countries. With this modelling approach, the grid is described as a “copper plate”.

The resulting cumulative emissions for the two scenarios are shown in Figure III-2 where the cumulative emission for scenario “BAU - Copper” is displayed in dotted line and the cumulative emission for scenario “Clim - Copper” is drawn in plain line. In scenario “BAU - Copper”, the emissions do not decrease, and the CO₂ total budget almost reaches 5000 GtCO₂eq at the end of the century. It would mean an increase of the global temperature above the 2°C. On the opposite in scenario “Clim-Copper”, the cumulative emission is stabilized around 1000 GtCO₂eq at the end of the century which is well under the 1300 GtCO₂eq limit.

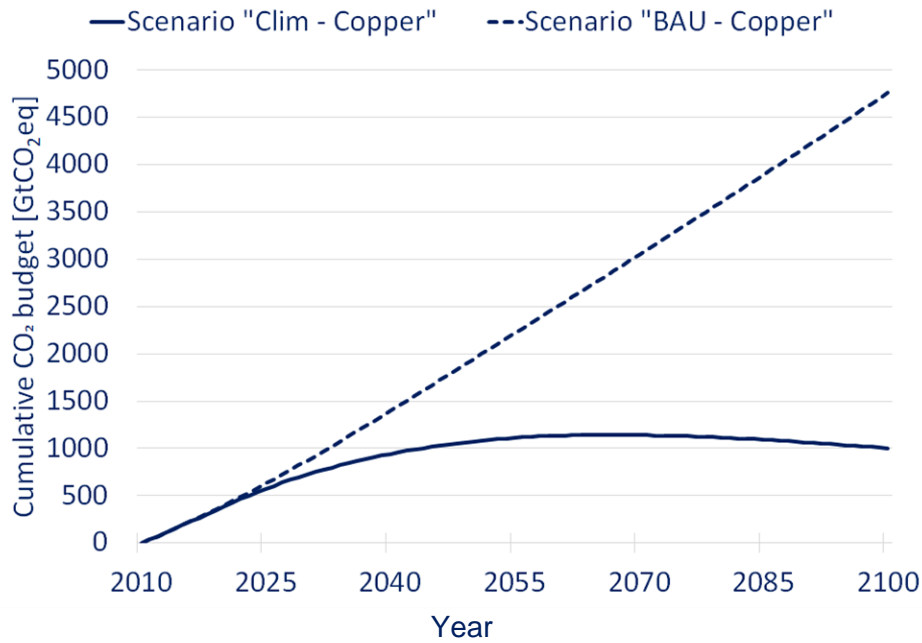


Figure III-2 – World cumulative CO₂ emissions during 2011-2100 for two main scenarios (BAU and Clim)

This limitation in emissions shows that the energy system has seen an important shift and especially the power sector. The analysis of the energy mix for the two scenarios highlights these fast changes. Figure III-3 shows the two energy mixes for Europe for the scenario "BAU-Copper" on the left side and scenario "Clim – Copper" on the right side. The energy mixes are decomposed in nuclear production, fossil production with no CCS (Carbon Capture and Storage), fossil production with CCS, hydro production, renewable production (geothermal and biomass), wind production, solar production, production from storage technologies (discharging). The load is shown in dotted line. Only European countries are included in EUTGRID. For this reason, imports and exports are equal to zero.

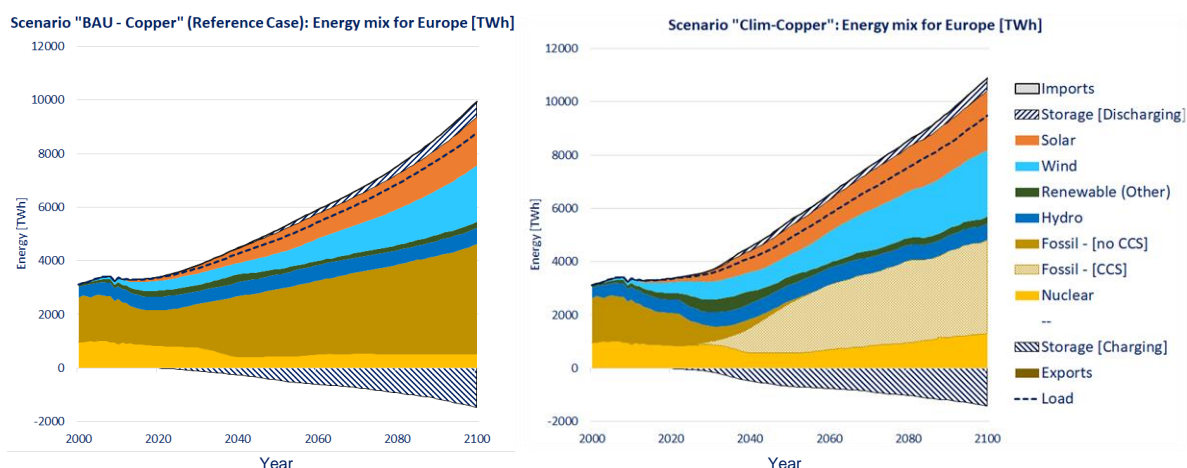


Figure III-3 – Energy mixes for scenario “BAU-Copper” (left) and scenario “Clim – Copper” [in TWh]

The main impact of the climate energy policy is the replacement of coal and gas conventional capacities by CCS technologies. It concentrates most of the efforts to reduce the emissions in the power sector. A second impact of this policy is a slight increase of electricity demand while total European energy demand has been reduced by 20% during the period 2040-2100 (compared to the scenario "BAU-Copper"). It highlights the important role of electricity in decarbonizing the economy. A third effect of the climate energy policy is a faster integration of VRES in the power sector. It increases from 5% in 2010, reaches up to 30% in 2030 and finally, it attains 46% in 2100. For a business-as-usual policy, the rate is lower with only 19% in 2030 and in 2100, VRES production reaches 42% of total European production.

III.1.3 Climate energy policy scenarios considered

To assess the role of the transmission grid, different scenarios with the same climate energy policy are set up. They share the same socio-economic hypotheses, but they differ on the grid representation and the type of investments in the transmission grid.

- **Scenario "Clim – Copper":** a scenario where grid operations are technically optimal and without any budget constraint. This scenario has been presented previously and it will be considered as the reference case.

In this scenario, it has been assumed that there are no constraints on electricity exchanges between the 24 countries: the grid is considered as a copper plate. In many models, it is the way of presenting the electricity system.

- **Scenario "Clim – Dev":** a scenario where the infrastructure investments are made on an economic criterion and without any budget constraint.

In this scenario, the grid is included, and a grid investment mechanism is being used: EUTGRID is being run and grid requirements are determined based on congestions and the payback period for HVAC and HVDC cables.

- Scenario "Clim – Frozen": a scenario where the infrastructure investments are made on an economic criterion and with a budget constraint that is applied in 2040. In this scenario, the grid is also represented and EUTGRID is being implemented. However, the social acceptance for new transmission grid reinforcements becomes so low that there are no more investments in the transmission grid after 2040. This social acceptance can deal with impacts on landscapes, increased noise, safety concerns and loss of property value [140].

To understand how the limitation of the transmission grid has an impact on the VRES integration and the use of flexibility options, three scenarios are also presented and analysed. For this reason, the investments in VRES capacities, in storage technologies and the demand response potential are modified. However, each new scenario includes a new hypothesis while keeping the previous ones. They are based on the scenario "Clim – Frozen" with some differences in the hypotheses.

- Scenario "Clim – Frozen + VRES": the investments in solar and wind capacities are divided by 50% after 2025 compared to scenario "Clim – Dev".
- Scenario "Clim – Frozen + VRES + BAT": the investments in the stationary storage technologies (i.e. BAT in POLES model) are divided by 50% compared to scenario "Clim – Dev" together with the hypotheses used in the previous scenario.
- Scenario "Clim – Frozen + VRES + BAT + DR": the maximum potential of demand response is increased from 5% of peak demand to 25% for each country. This value corresponds to an optimist potential based on different studies which assessed the DR potential in each European country [141], [142]. The hypotheses used in the previous scenario are also included.

A final scenario is analysed which combines the grid development and the best measures described previously:

- Scenario "Clim – Dev + VRES + BAT + DR": This scenario will help to investigate how a large-scale integration of VRES together with the development of stationary storage technologies and demand response potential will affect the planning of the European transmission grid.

III.2 European transmission grid development

The scenarios described above implement a Transmission Grid Mechanism, which expands and/or reinforces the European transmission grid. Between these scenarios, the investments and the representation of transmission grid have been modified to underline the role of the transmission grid. For example, the reduction of investments costs of solar and wind capacities aims at favouring the rise of share of VRES and consequently, it should put more constraints on the grid. In this context, the evolution of the transmission grid during the century must be analysed in terms of investments needs but also regarding the choice of cable technologies and finally, their spatial location.

III.2.1 Transmission grid requirements and VRES integration

The Transmission Grid Mechanism implemented in EUTGRID aims at locating the bottlenecks and relieving the most severe ones through the reinforcement and the expansion of the transmission grid. Figure III-4 illustrates the development of the European transmission grid for the above described scenarios. This development of the grid infrastructure is shown in TWkm: it multiplies the capacity reinforcement by the length of the lines. This indicator helps to compare different situations: for example, between a small line that is highly upgraded and a long line that is reinforced only once, the indicators “length added” and “capacity added in GW” could be used separately but will not describe well the situation. In the figure, from 2000 up to 2012, the grid of 2012 is used and then from 2012 up to 2030, the investments from ENTSO-E are included.

After 2030, the transmission grid investment mechanism is applied and the outputs for the scenarios differ. For the frozen scenarios, the grid development is being stopped around year 2040 as the budget is constrained. The grid is being reinforced around 536 TWkm. For the two scenarios "Clim-Dev" and "Clim – Dev+VRES+BAT+DR", the Transmission Grid Mechanism is used without budget constraint and the investments keep increasing during the century. As it can be observed in the figure, the expansion of the grid is done by steps. These steps come from the planning decisions implemented in EUTGRID: the reinforcements are decided every 3 years on a rolling window and at the end of this period, the expected power system at ten years is used to relieve future congestions. The consequence is an anticipation of major congestions in the European power system and the need to reinforce massively the grid.

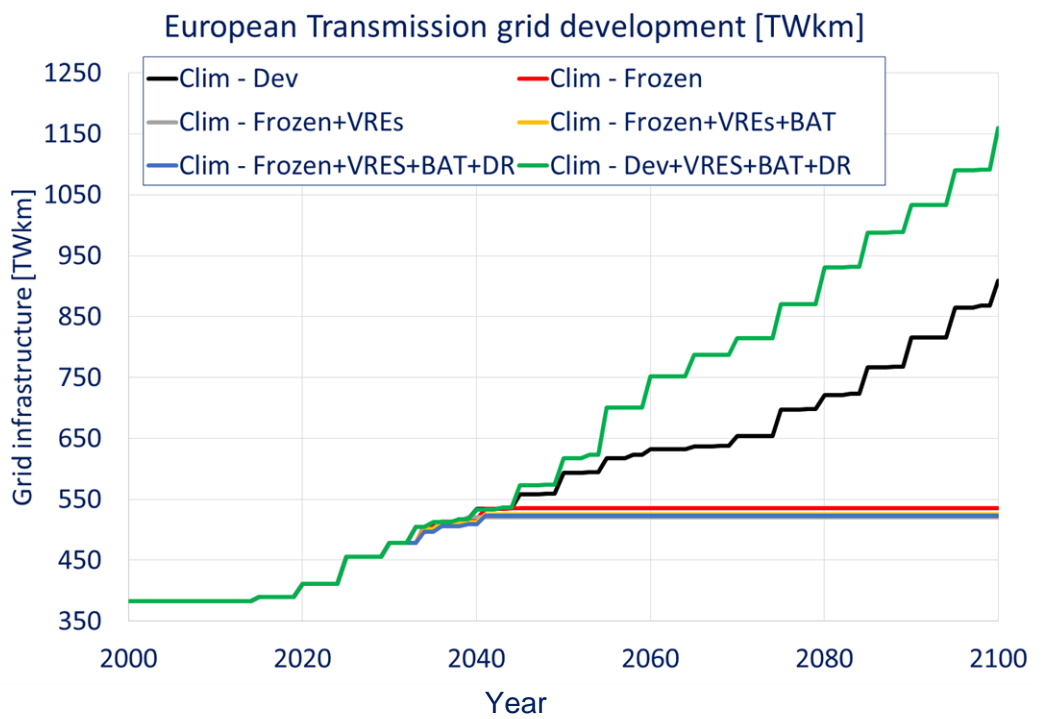


Figure III-4 – European transmission development for the different scenarios [TWkm]

It is particularly relevant for scenario "Clim – Dev+VRES+BAT+DR" where the steps of reinforcement are higher, and the grid infrastructure increases up to 1160 TWkm. In scenario "Clim-Dev", the transmission grid only reaches 909 TWkm. These results must be put in parallel with the VRES integration in the power system. Figure III-5 shows the share of VRES in the European power system during the century for the three scenarios "Clim-Copper", "Clim-Dev" and Clim–Dev+VRES+BAT+DR".

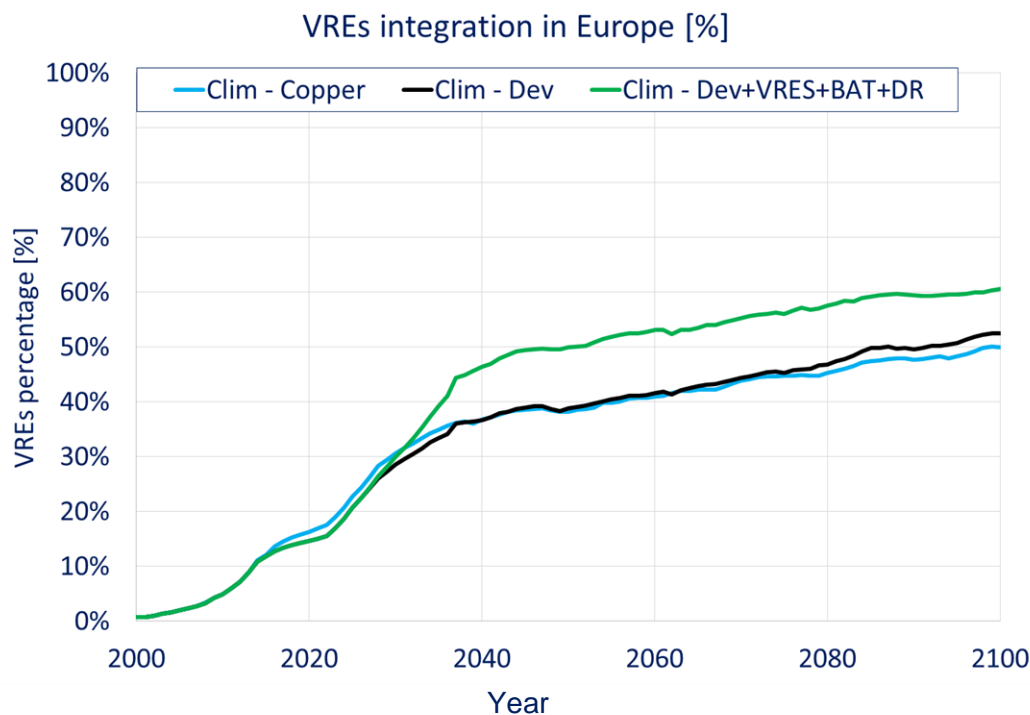


Figure III-5 – Share of VRES in Europe for "Clim-Copper", "Clim-Dev" and "Clim-Dev+VRES+BAT+DR" [%]

In "Clim-Copper" and "Clim-Dev", the share of VRES follows the same trend to reach around 50% of the total European demand. The difference between the two scenarios comes from the representation of the transmission grid which is included in "Clim-Dev". Thanks to the calculation of realistic power flows, congestion and VRES curtailment are taken into account. Consequently, some countries have increased their share of VRES although it is sometimes needed to curtail this production. With the reduction of VRES costs, the share of VRES has greatly increased in scenario "Clim – Dev+VRES+BAT+DR" and it reaches up to 60%. These results show that the speed of increase of VRES production is a key driver for the grid development.

III.2.2 Competition between HVAC and HVDC technologies

One of the key features of EUTGRID is the competition between HVAC and HVDC technologies to reinforce the grid. For HVAC technologies, its main advantage is its low cost compared to HVDC when the distance is lower than 500km. On the opposite, HVDC has the ability to control the power flows. To understand this competition, the transmission grid requirements can be analysed in the two situations: when the investments are frozen after exceeding the budget constraint and when the Transmission Grid Mechanism is being used without constraints.

(i) Frozen investments

The results for each frozen scenario are gathered in Table III-1. In the first column, the outputs are shown for the period 2010-2030. Then, in the other columns, the results are displayed for the different scenarios and for the period 2030-2100. The share of VRES and the grid reinforcement are displayed in the first two rows of the table. In the other rows, the breaking down of these reinforcements between HVAC and HVDC and the total investment budget are shown.

In 2030, the VRES production reaches 30% of the European demand and attains 54% in 2100 in "Clim-Frozen" scenario. It corresponds to 57 TWkm of grid expansion (3rd line of the table). With a reduction of VRES investments costs, the effect is a share VRES reaching 64% in the next scenarios. The transmission grid requirements decrease in these scenarios and are equal to around 45 TWkm. Some differences exist between the frozen scenarios with investment reductions and can be explained by the hypotheses which modify the dispatching (and thus the congestion costs). The large increase of VRES has the effect of modifying the choice of reinforcement technologies. In 2010-2030, lines are upgraded using mainly HVAC (74% of the investments). Then a shift occurs in "Clim-Frozen" with 77% of lines being reinforced with HVDC technologies. For the next scenarios, only HVDC technologies are being used. These results show that HVDC is particularly suitable in a power system with high share of VRES. Finally, the total grid investments are similar as it was the constraint in these scenarios

Table III-1 – Transmission grid investments for the frozen scenarios

Scenario			"Clim - Frozen"	"Clim - Frozen +VRES"	"Clim - Frozen +VRES+BAT"	"Clim - Frozen +VRES+BAT +DR"
Time period		2010 - 2030	2030 - 2100	2030 - 2100	2030 - 2100	2030 - 2100
Production VRES [%]		[5%; 29%]	[29%; 54%]	[30%; 64%]	[30%; 64%]	[30%; 64%]
Transmission grid	Grid added [TWkm]	97	57	42	46	44
	-- HVAC [%]	74%	23%	0%	0%	0%
	-- HVDC [%]	26%	77%	100%	100%	100%
	Total grid investment [b\$]	180	103	89	96	95

(ii) Transmission Grid Mechanism implemented

Similarly to the previous section, the transmission grid requirements can be analysed for the scenarios with grid development "Clim-Dev" and "Clim - Dev+VRES+BAT+DR". Table III-2 gathers the similar results as in Table III-1. However, the periods 2030-2050 and 2050-2100 are distinguished for a better comparison. In the first two rows, the share of VRES and the grid added for the two scenarios are only taken from the Figure III-4. For example, it can be observed that during 2030-2050 the grid is reinforced in the same magnitude but during 2050-2100, "Clim - Dev+VRES+BAT+DR" needs almost as twice as more upgrades than in scenario "Clim-Dev" with 542 TWkm versus 316 TWkm. The breaking down of these new reinforcements shows also the predominance of HVDC technologies. The share is similar for the two scenarios during 2030-2050: 70% for HVDC and 30% for HVAC. For "Clim-Dev", this share is almost the same during 2050-2100. However, in scenario "Clim - Dev+VRES+BAT+DR", it is reduced to reach 59%. This difference can be explained by the need to connect more nearby regions. In this case, HVAC technologies are mostly chosen because it is always cheaper than HVDC cables.

Table III-2 – Transmission grid investments for the grid development scenarios

Time period		2010 - 2030	2030 - 2050		2050-2100	
Scenario			"Clim - Dev"	"Clim - Dev+VRES+BAT+DR"	"Clim - Dev"	"Clim - Dev+VRES+BAT+DR"
Production VRES [%]		[5%; 29%]	[29%; 39%]	[30%; 50%]	[39%; 53%]	[50%; 61%]
Transmission grid	Grid added [TWkm]	97	114	139	316	542
	-- HVAC [%]	74%	30%	28%	32%	41%
	-- HVDC [%]	26%	70%	72%	68%	59%
	Total grid investment [b\$]	180 (≈9b\$/year)	194 (≈9.7b\$/year)	238 (≈11.9b\$/year)	475 (≈9.5b\$/year)	856 (≈17.1b\$/year)

With these transmission grid requirements, the resulting total budget can be calculated for the different periods and for each scenario. It can be observed that the yearly need is almost constant for "Clim-Dev" with 9b\$/year during 2010-2030, 9.7b\$/year during 2030-2050 and 9.5b\$/year during 2050-2100. However, this rate increases largely for scenario "Clim - Dev+VRES+BAT+DR": 9b\$/year during 2010-2030, 11.9b\$/year during 2030-2050 and

17.1b\$/year during 2050-2100. These results underline the fact that with a fast VRES integration, the needs to upgrade the transmission grid are increased.

III.2.3 Reinforcements spatial location

The more detailed representation of the transmission grid in EUTGRID allows to represent the evolution of the transmission grid dynamically in time and in space. The location of the grid reinforcements shows the most congested areas but also the ones that add flexibility to the European power system such as Switzerland with their hydro power plants.

(i) Frozen investments

Within the frozen scenarios, the transmission grid investments are almost similar in terms of amount of reinforcement (TWkm) and of chosen technologies. However, the analysis of the location of these upgrades show that with different hypotheses, the reinforcements are not always the same. To illustrate this, for the period 2030-2100, the mean reinforcement has been calculated for all frozen scenarios and it was retrieved the number of scenarios in which each line has been reinforced. The results are shown on a map in Figure III-6 where the size of the line corresponds to the reinforcement capacity and in colour is the number of scenarios. If a reinforcement is made in all scenarios, the interconnection is displayed in dark colour which highlights its importance.

European transmission grid reinforcement for frozen scenarios

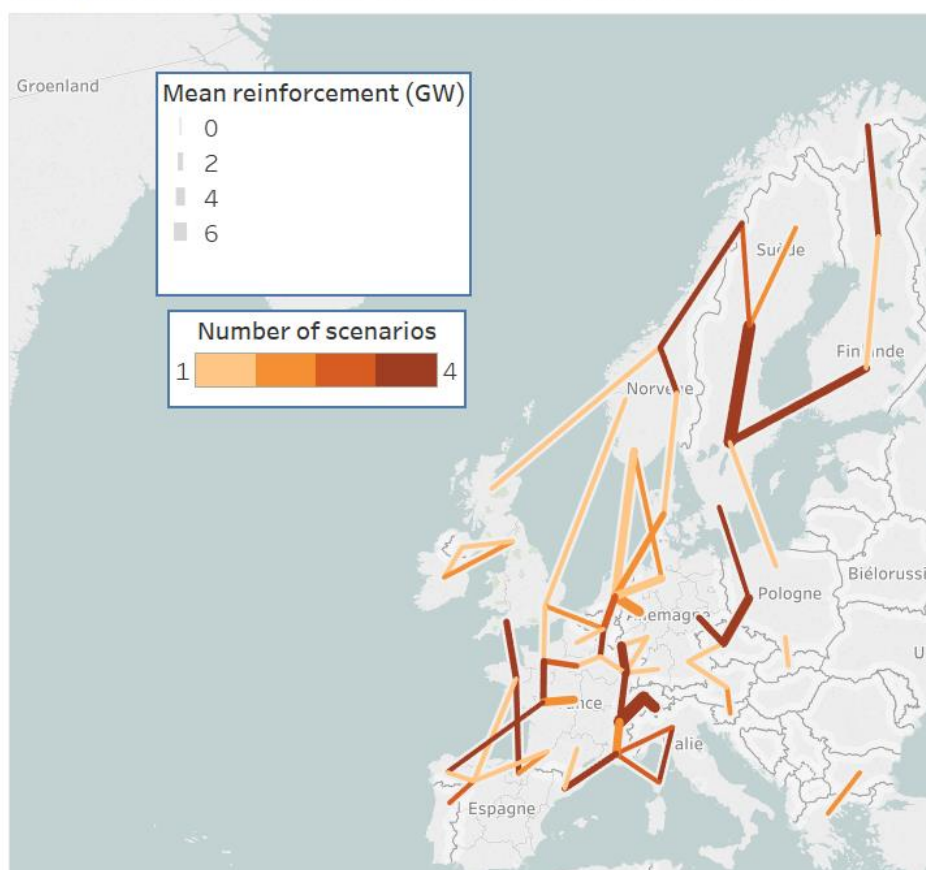


Figure III-6 – Mean European transmission grid requirement for frozen scenarios for the period 2030-2100 [GW]

The results show some areas where the need for reinforcements is very important. One can observe that three main corridors are always reinforced. The first one connects Germany, Switzerland, France, Italy and Spain. It aims at benefiting from the Swiss hydropower plants but also from the German wind production and the solar production from Italy and Spain. The second corridor is located on the west European coast and connects England, France and Spain. The objective is to transport the energy from the English wind off-shore power plants and also to use the Spanish solar power plants. Finally, Sweden needs important upgrades to benefit from the Finnish nuclear production and also to use its own hydro power production.

(ii) Transmission Grid Mechanism implemented

The analysis of the location of the transmission grid requirements for the two scenarios "Clim - Dev" and "Clim - Dev+VRES+BAT+DR" confirms the findings presented in the previous paragraph. Figure III-7 displays two maps of Europe with the reinforcements in HVAC (in

black) and HVDC (in pink) for the period 2030-2100. The left map corresponds to "Clim - Dev" and the right map corresponds to "Clim - Dev+VRES+BAT+DR". The comparison between the two maps shows two things: first, there are more new interconnections in "Clim - Dev+VRES+BAT+DR": the North Sea region is more densely interconnected, central Europe has also more new transmission lines. Then, the transmission lines are more upgraded in "Clim - Dev+VRES+BAT+DR": for example, the interconnection between France and England has been increased as well as the corridor connecting France and Italy. In both scenarios, the Transmission Grid Mechanism tends to improve the transmission grid so that it becomes a copper plate. However, the large-scale integration of VRES affects all regions and the grid must both be more expanded and more reinforced.

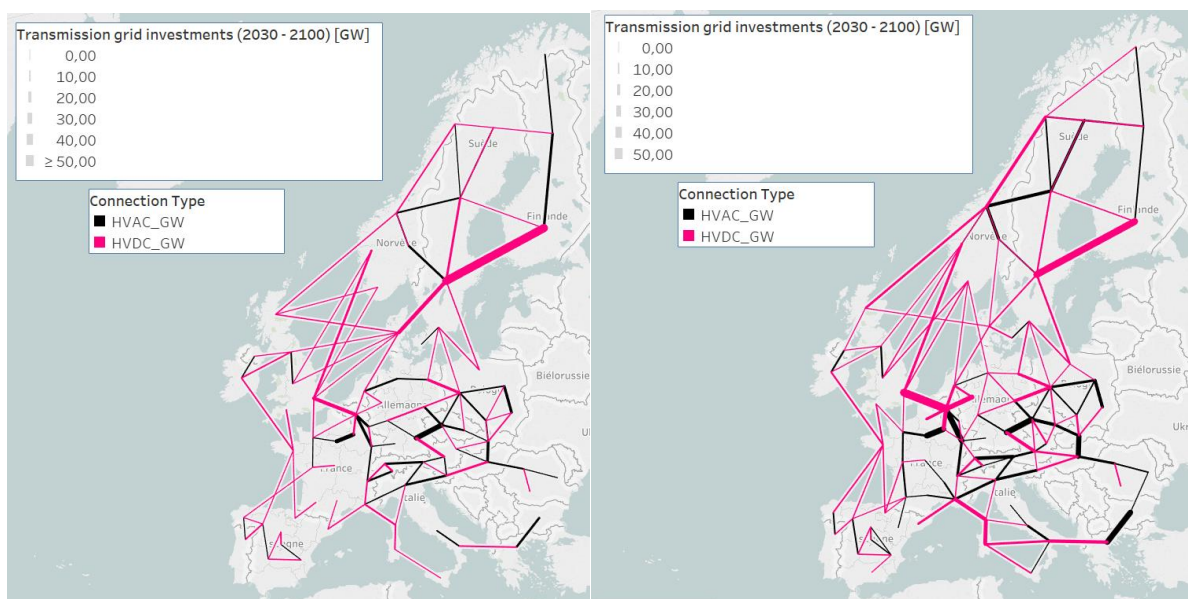


Figure III-7 – Total transmission grid needs in scenario "Clim – Dev" (left) and in "Clim - Dev+VRES+BAT+DR" (right) for 2030-2100 [GW]

III.3 Impact of grid development on energy mix and flexibility options

Grid developments in Europe have the immediate effect of modifying the dispatching of the different producing technologies: the congestions are taken into account; the power flows are more realistic, and loop flows from VRES integration are better described. To illustrate these different impacts resulting from the representation of the grid, the scenarios "Clim-Dev", "Clim-Frozen" and "Clim-Dev+VRES+BAT+DR" will be analysed on their CO₂ emissions, their costs and their energy mix. Finally, a comparison will be made on the

different scenarios including the frozen scenarios to understand how the flexibility options have been used.

III.3.1 Emissions

POLES model simulates global world emissions that are consistent with the success of a climate energy policy. Because here only the European power sector is described in detail, we will focus on the European energy system for the three scenarios "Clim-Dev", "Clim-Frozen" and "Clim-Dev+VRES+BAT+DR". Scenario "Clim-Dev" acts as the reference case. "Clim-Frozen" will help to understand the impacts of limiting the transmission grid development while "Clim-Dev+VRES+BAT+DR" will show the effects of a large-scale integration of VRES together with more flexibility through low cost batteries and high demand response potential.

The cumulative European emissions starting from 2011 are calculated for the three scenarios. At the end of 2100, in the scenario "Clim-Dev", the cumulative emissions reach a value of 127 GtCO₂eq. Figure III-8 shows the difference in cumulative emissions for "Clim-Frozen" and "Clim – Dev+VRES+BAT+DR" compared with "Clim-Dev". The results show that in 2100 the emissions have increased by 1.4% for "Clim-Frozen" and they have decreased by 2% for "Clim-Dev+VRES+BAT+DR". In 2050, the cumulative emissions in the scenario "Clim-Dev+VRES+BAT+DR" are slightly greater than the ones the "Clim-Dev" and it could be explained by the integration of VRES which might increase the congestions and the need for back-up technologies (fossil production for example).

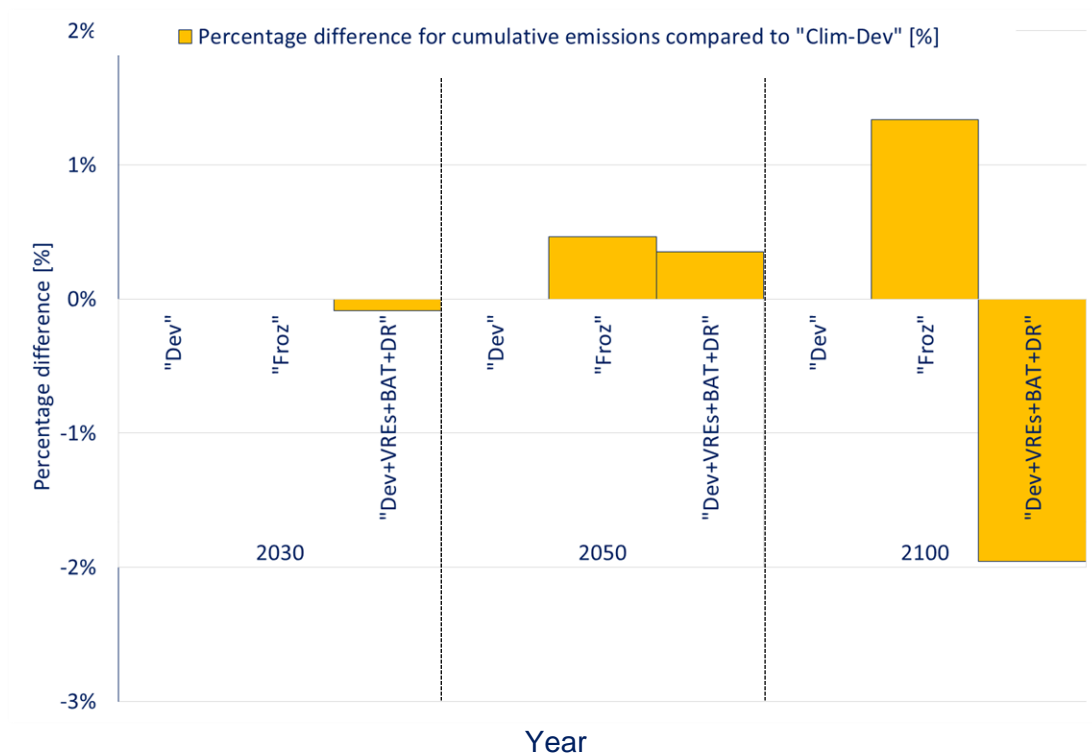


Figure III-8 – Difference in cumulative emissions for "Clim-Frozen" and "Clim – Dev+VRES+BAT+DR" compared with "Clim-Dev" [%]

III.3.2 Energy mix and power system costs

(i) Energy mix in the different scenarios

In the previous section, it has been observed that the three scenarios "Clim-Dev", "Clim-Frozen" and "Clim – Dev+VRES+BAT+DR" result in different European emissions. It shows that the energy mixes have been modified because of the grid limitation for "Clim-Frozen" and because of the large-scale integration of VRES for "Clim – Dev+VRES+BAT+DR". Figure III-9 shows the breaking down of the European energy mix for the three scenarios and for 2030, 2050 and 2100. Nuclear production, fossil production with no CCS, fossil production with CCS, hydro production, VRES production and production from other renewable (geothermal and biomass) are included in this figure.

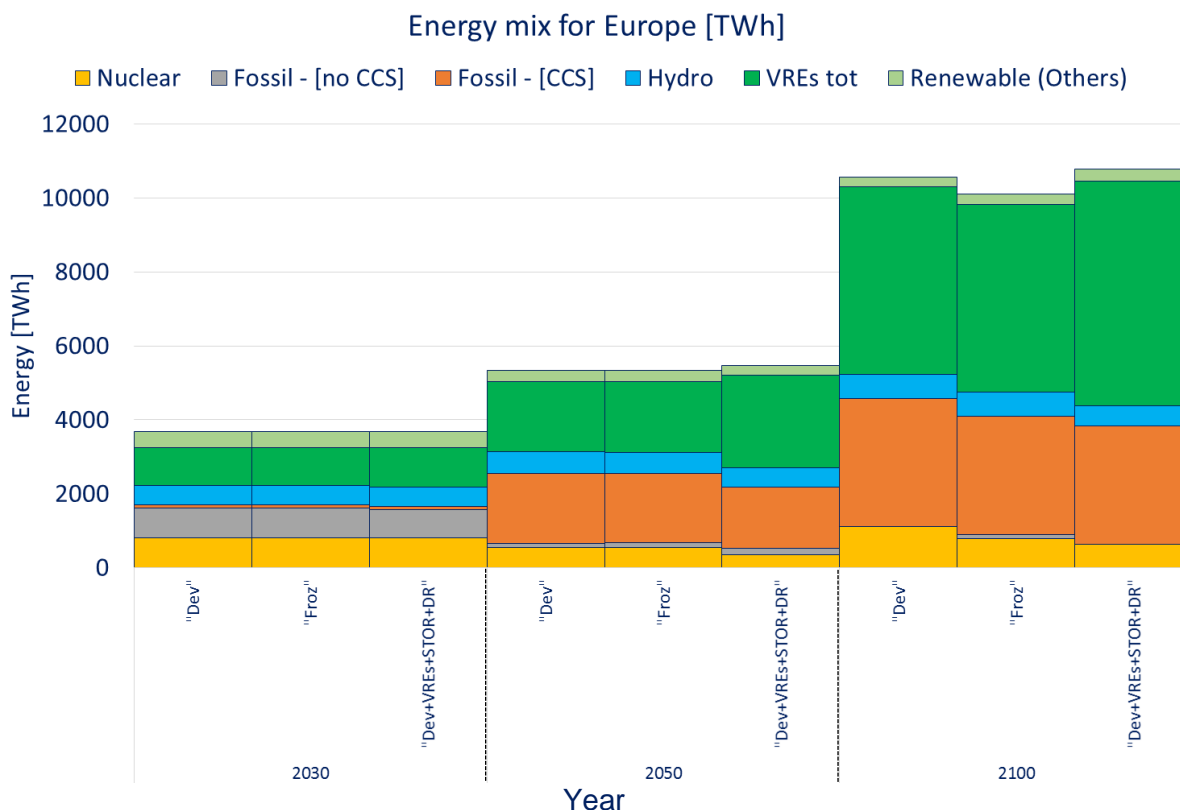


Figure III-9 – European energy mixes for "Clim-Dev", "Clim-Frozen" and "Clim – Dev+VRES+BAT+DR" [TWh]

In all scenarios, the total production increases to reach around 10 000 TWh in 2100. It can be observed that the total production in "Clim - Frozen" is lower because non-distributed energy appears and consequently, it reduces the need for supply. The total production "Clim – Dev+VRES+BAT+DR" is slightly greater: with the reduction of VRES investments costs and stationary storage investments costs, the production costs in "Clim – Dev+VRES+BAT+DR" decrease (see next section). Electricity becomes cheaper compared to other energies. The consequence is a shift of demand from other energies to electricity and therefore, there is an increase of total load by 4% in 2100.

Regarding the energy mixes, they are similar for all scenarios in 2030. After 2040, some distinctions appear but they also share some common trend: CCS technologies are widely used to decarbonize the power system and become the main supplier of electricity in all scenarios (apart from VRES). One can observe that nuclear production decreases in the two scenarios "Clim – Frozen" and "Clim – Dev+VRES+BAT+DR". For each scenario, a different explanation can be given: in scenario "Clim – Frozen", the grid limitations restrict the maximum energy produced by nuclear power plants while in scenario "Clim – Dev+VRES+BAT+DR", the large-scale integration of VRES reduces the residual load to be supplied by other production capacities. The important grid limitations in scenario "Clim-

Frozen” also justify the energy produced from fossil capacities with no CCS, which aims at reducing the resulting congestions.

(ii) Electricity costs for grid development scenarios

In the scenario "Clim-Frozen", non-distributed energy occurs starting from 2060 and it is very expensive. For this reason, the effect on the electricity costs can only be analysed for the grid development scenarios. Figure III-10 shows two types of electricity costs for the European power system and for each scenario "Clim-Dev" (in green) and "Clim-Dev+VRES+BAT+DR" (in blue): the production costs which include the investments costs (plain line) and the variable system costs (dotted line). The variable system costs are outputs from EUTGRID and they include operation and maintenance costs but also ramping costs.

In scenario "Clim-Dev", the production costs stay around 85 \$/MWh along the simulation. For the scenario "Clim-Dev+VRES+BAT+DR", there is a clear reduction after 2030 as the investments in VRES and storage technologies are reduced. At the end of the century, the production costs reach 68\$/MWh which a decrease of 22%. If the variable system costs are now analysed, it can be observed three different periods for the two scenarios: from 2000 up to 2040, these costs increase to attain 60\$/MWh for "Clim-Dev" and 54\$/MWh for "Clim-Dev+VRES+BAT+DR"; from 2040 up to 2060, the costs follow the same decreasing trend (around 25 \$/MWh for both scenarios); from 2060 up to 2100, the variable system costs increase again to reach 43 \$/MWh for "Clim-Dev" and 37\$/MWh for "Clim-Dev+VRES+BAT+DR". The difference between the two scenarios represents a reduction of around 13% for "Clim-Dev+VRES+BAT+DR".

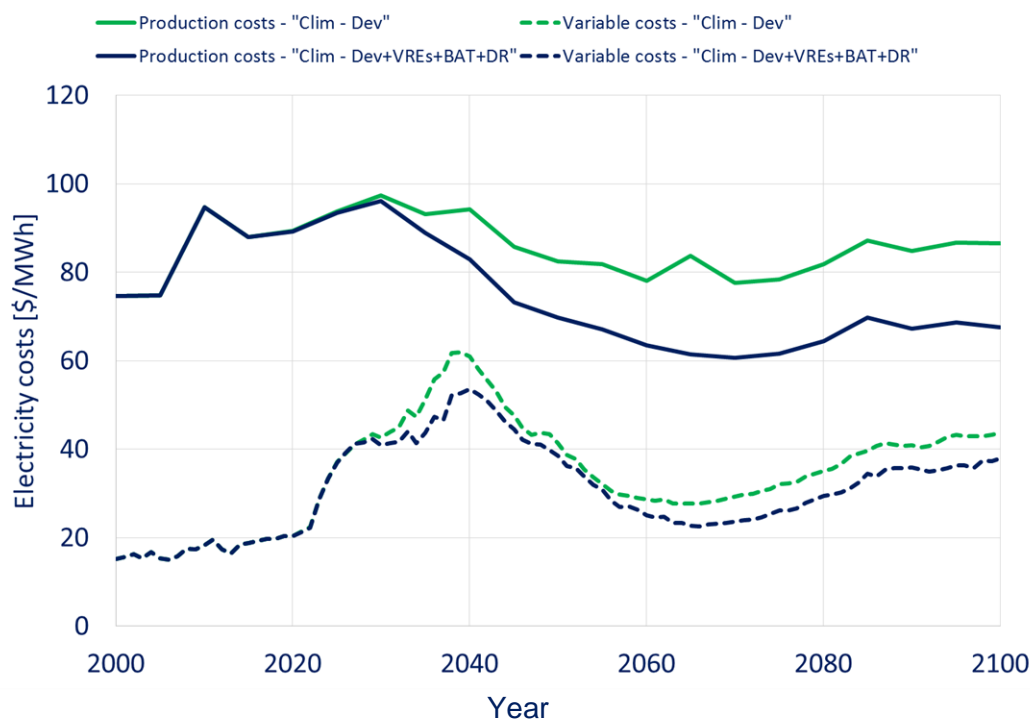


Figure III-10 – European production costs and variable system costs for "Clim-Dev" and "Clim-Dev+VRES+BAT+DR" [\$/MWh]

For the period 2010-2040, the implementation of the climate energy policy increases the cost of the most polluting technologies. However, new cleaner and cheaper technologies are not yet available at this time and therefore, more expensive technologies are still used. Then, the availability of cheaper production power plants also explains the decrease until 2060. For the last period, it results from the integration of VRES which needs back up technologies to follow the high variability of VRES with high ramping capabilities. As mentioned earlier, between the two scenarios, the production costs are reduced by 22% while the variable system costs have only been reduced by 13%. The flexibility costs increase their importance compared to the investments costs. This difference further highlights the importance of flexible production technologies.

III.3.3 Flexibility options and security of supply

To assess the role of the transmission grid, the impact on the use of the flexibility options must also be analysed. These flexibility options gather the use of storage technologies, the demand response and curtailment of VRES production. Figure III-11 shows the production of these flexibility options together with the non-distributed energy for 2030, 2050 and 2100 and also for all the scenarios presented earlier. For the storage technologies, a distinction is made between production from stationary batteries (BAT), vehicle-to-grid (V2G) and the rest

of storage technologies (Rest of STOR). VRES curtailment and non-distributed energy are shown in the negative part of the figure as they should be avoided in the energy dispatch. It must be recalled that non-distributed energy is an indicator for the TSOs that reinforcement investments are needed but it may not happen in reality.

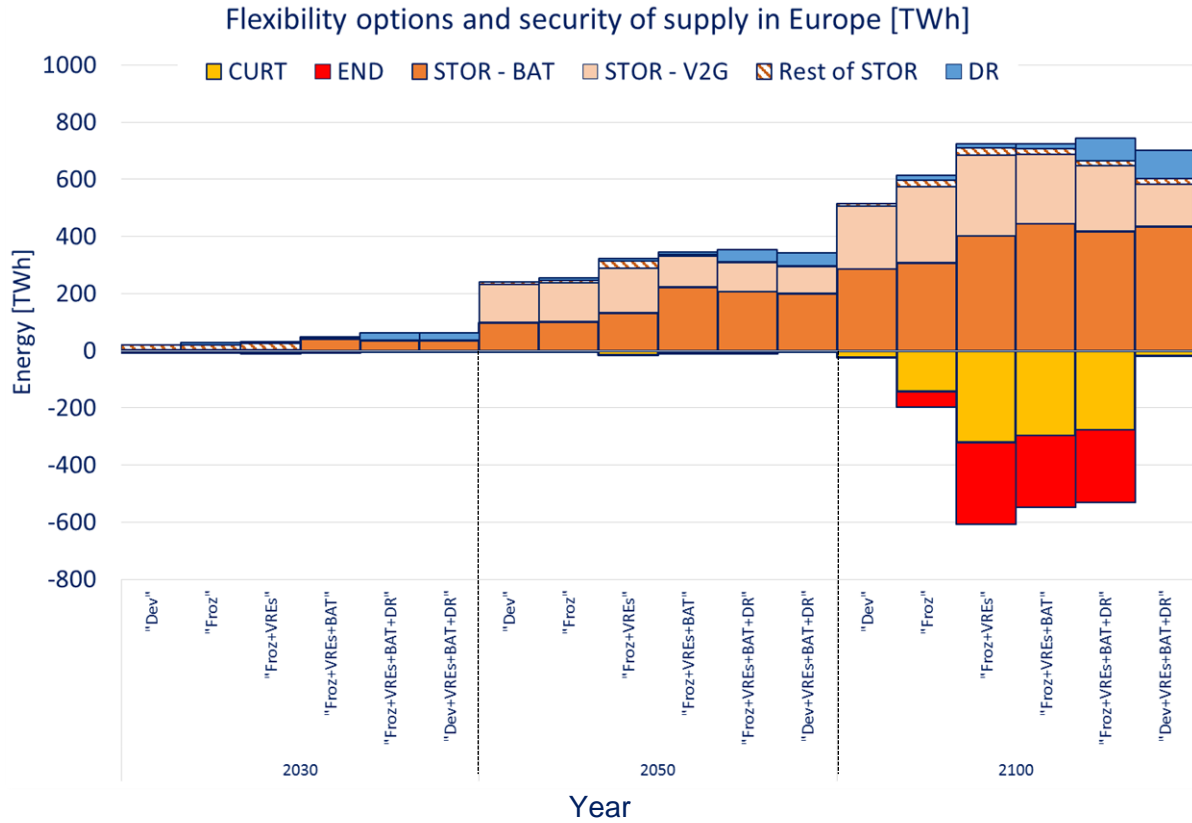


Figure III-11 – Flexibility options and non-distributed energy for the different scenarios [TWh]

The main results show that stationary storage technologies are the main source of flexibility and their use increases during the century to reach almost 400TWh for all the different scenarios. Then production from V2G technologies also rises but it attains around 200 TWh. The analysis of the different scenarios shows that the use of storage technologies increases with the limitation of grid development in "Clim-Frozen" compare to the reference case "Clim-Dev". If VRES and also the storage technologies investments are reduced ("Clim-Frozen+VRES" and "Clim-Frozen+VRES+BAT"), it can be observed a larger production from storage. These results highlight the importance of storage technologies to better integrate the VRES and alleviate congestions. With the increase of the demand response potential ("Clim-Frozen+VRES+BAT+DR"), the production from demand response is multiplied by four but it further reduces the use of storage technologies. It can be explained because demand response is almost free compared to other storage technologies.

It must also be observed that VRES curtailment also appears in all scenarios in 2100. However, the amounts of energy spilled are significantly different. In "Clim-Dev" and "Clim-Dev+VRES+BAT+DR", there is almost no energy curtailed. With the limited grid development ("Clim-Frozen"), VRES curtailment attains 144 TWh and if more VRES capacities are installed ("Clim-Frozen+VRES"), the amount of spilled energy reaches 320 TWh. It underlines the fact that VRES capacities are located in areas which are far from the consumption areas and therefore, there is a strong need to connect these regions. It also shows that VRES production increases the congestion in the transmission grid. Finally, with more storage and demand response potential ("Clim-Frozen+VRES+BAT" and "Clim-Frozen+VRES+BAT+DR"), VRES curtailment is being reduced but to small proportion (less than 45 TWh).

In all the frozen scenarios, non-distributed energy appears in some regions in 2060 and increases exponentially to reach 56TWh in 2100. It represents less than 0.6% of the total European load but the associated cost is really important. With the integration of VRES in scenario "Clim-Frozen+VRES", the amount of non-distributed energy is further increased 286 TWh. Therefore, this is a consequence of the large scale integration of VRES which has congested many HVAC interconnections. Figure III-12 shows a map of the NDE distribution in percentage of the region load in 2100 for the scenario "Clim-Frozen". It can be observed that not all regions have energy security issues but it affects some important ones such as Ile-de-France, South of England and Benelux.

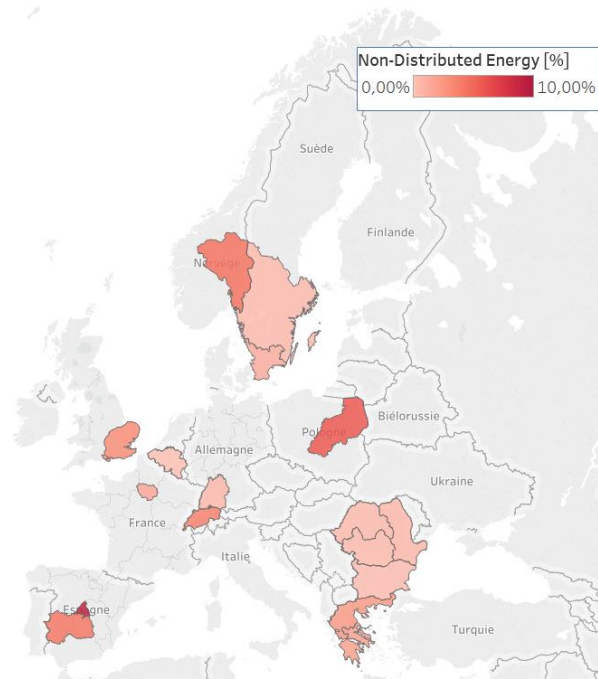


Figure III-12 – Percentage of Non-Distributed Energy from Load for scenario 3 in 2100 [%]

Therefore, the flexibility options and the investments in new capacities are deemed insufficient to insure the European security of supply. The investments in the power plant capacities could have been determined cluster by cluster and not spread through a linear distribution key as done with EUTGRID. However, as pointed out previously, the social acceptance of having new power plants in new areas is low and therefore, the results obtained can be considered relevant for the analysis.

III.4 Including environmental indicators: LCA

III.4.1 New objective function

The unit commitment and dispatch model EUTGRID relies on a minimization of variable system costs to determine the production of each technologies. The decarbonisation of the power system is carried through the increase of the different variable costs for the most polluting technologies thanks to the implementation of a carbon value in POLES. To achieve this reduction of CO₂ emissions, using environmental indicators could be used to dispatch the electricity power plants instead of the current least cost approach.

To this end, a joint work was carried with Jean-Nicolas Louis from Oulu University in Finland to assess the use of environmental indicators in a dispatch module. A method was developed

to construct the adequate databases of current and prospective environmental impact for each technology available in EUTGRID and for each indicator considered [143]. More precisely, for each indicator I , an emission factor $Em_{I,disp}^n$ [kgCO_{2eq}/GWh] is calculated for each node n , for every day d and each dispatchable technology $disp$ based on current and prospective data.

Finally, daily emissions for all Europe $Em_{I,d}$ [kgCO_{2eq}] are calculated by multiplying $Em_{I,disp}^n$ with the yearly production of each technology at each node $P_{disp}^n(t)$ [GWh]. The main objective function in EUTGRID (see equation 3) has been replaced by equation (14):

$$\min Em_{I,d} = \sum_{t,n} Em_{I,disp}^n * P_{disp}^n(t) \quad (14)$$

The scenario “Clim –LCA” analysed in this section shares the same framework as the one described in scenario “Clim –Dev” but in 2013, the least-emissions approach is being used until 2100 with the indicator climate change.

III.4.2 Comparisons on emissions and electricity costs

In POLES, the emissions of production technologies from coal, oil and gas are considered to be the main sources of pollution. For some technologies such as hydro or nuclear, their carbon content in their emissions is approximated to zero and production from biomass is considered to have negative emissions. The calculation of the indicator "Climate Change" does not include these assumptions. As a result, POLES and EUTGRID with environmental objective differ in their approach to calculate the total emissions for the European power sector.

Figure III-13 illustrates the emissions for the two scenarios “Clim-Dev” (in green) and “Clim-LCA” (in blue). Two sets of emissions are also shown: in plain lines, the emissions calculated by POLES and in dotted lines, the emissions calculated by the LCA method. Overall, the European yearly emissions for the two scenarios follow the same trend but with some distinctions. It can be observed that the immediate effect of switching in 2013 to an environmental approach in EUTGRID is a clear reduction of CO₂ emissions for Europe compared to scenario “Clim – Dev”. This decrease is also visible in calculated emissions by POLES. However, at the end of the century, for scenario “Clim – Dev”, the emissions using POLES’ method are lower. If the LCA’s method is used, then it is the opposite. This difference comes from the hypothesis used in POLES that biomass production produces negative emissions. In the LCA approach, it is not the case and for this reason, in scenario “Clim-

LCA”, biomass production is lower and the yearly emissions with POLES’ method are always positive.

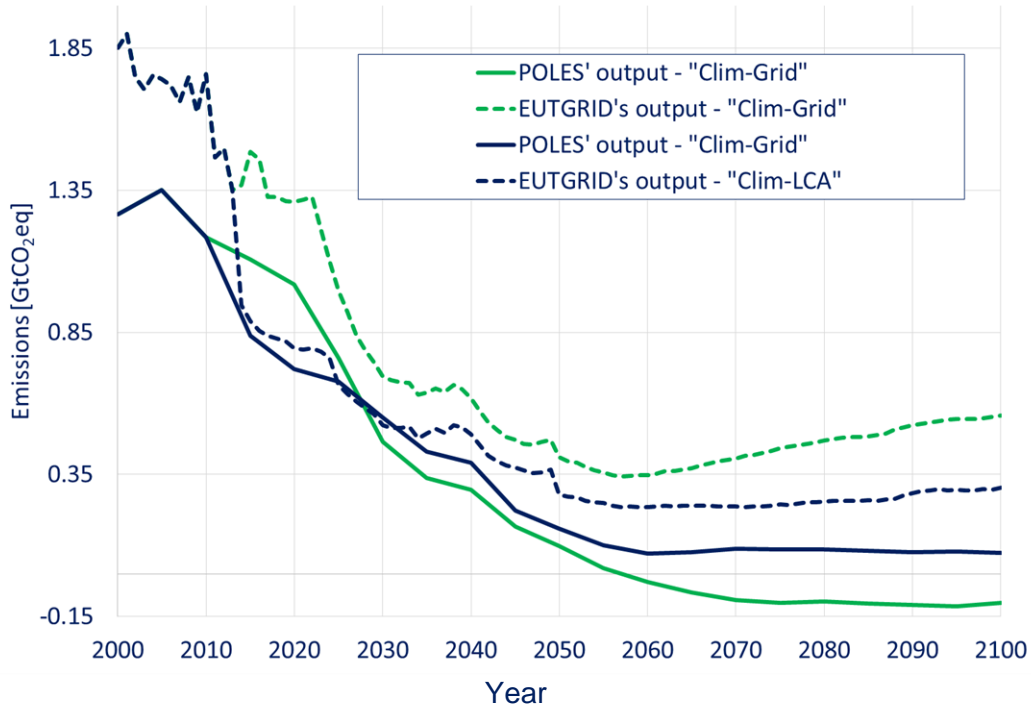


Figure III-13 – Yearly emissions for Europe for scenario 2 and 5 (outputs from POLES and EUTGRID)

These comparisons highlight that the use of a least-cost approach can reach the same target as a LCA approach but with some important delays. This difference in calculations suggests that the inclusion of LCA indicators directly within POLES could be an interesting perspective to understand how the energy sector would change based on realistic emissions factors.

The second main effect of including environmental indicator is the increase of production and variable system costs. Figure III-14 shows the average variable system costs (in dotted line) and the production cost (plain line) for the two scenarios “Clim-Dev” (in green) and “Clim-LCA” (in blue). For scenario “Clim-LCA”, the electricity costs see the same trend as explained for Figure III-10. On average the production costs for “Clim-LCA” are 6% higher than the one for scenario “Clim-Dev” while the variable system costs for “Clim-LCA” have risen by 35% compared to scenario “Clim-Dev”. This increase shows that the minimization of emissions relies on the flexibility of power plants to compensate the variability of wind and solar.

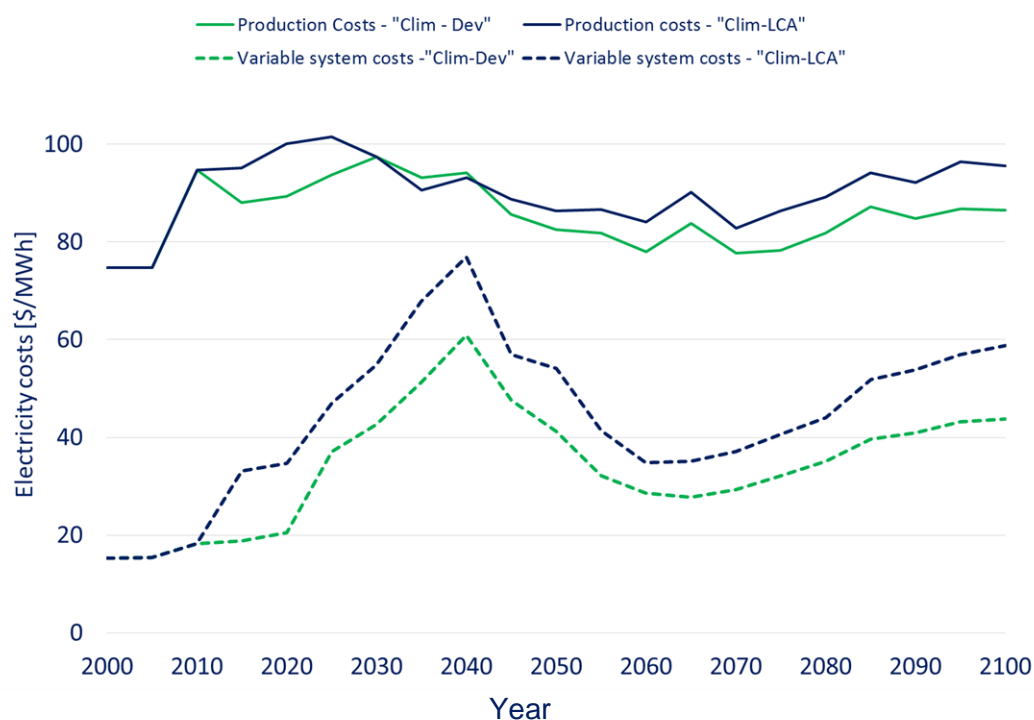


Figure III-14 – Yearly European average costs for the scenarios “Clim-Dev” and “Clim-LCA”

III.4.3 Impacts on energy mix and flexibility options

(i) Energy mix

The use of LCA factors in the objective function modifies the resulting dispatch of production capacities. It favours the use of cleaner technologies without considering the total costs. Figure III-15 shows the European energy mixes in 2030, 2050 and 2100 for the scenarios “Clim-Dev” and “Clim-LCA”. These energy mixes distinguish the production between nuclear, fossil without CCS and with CCS, hydro, VRES and other renewable (geothermal and biomass). The scenario “Clim-LCA” follows the same trends as already described for “Clim-Dev”. VRES capacities become the main source of electricity in 2100. Production from fossil fuel with no CCS has completely disappeared in 2100 while fossil production from CCS increases during the century.

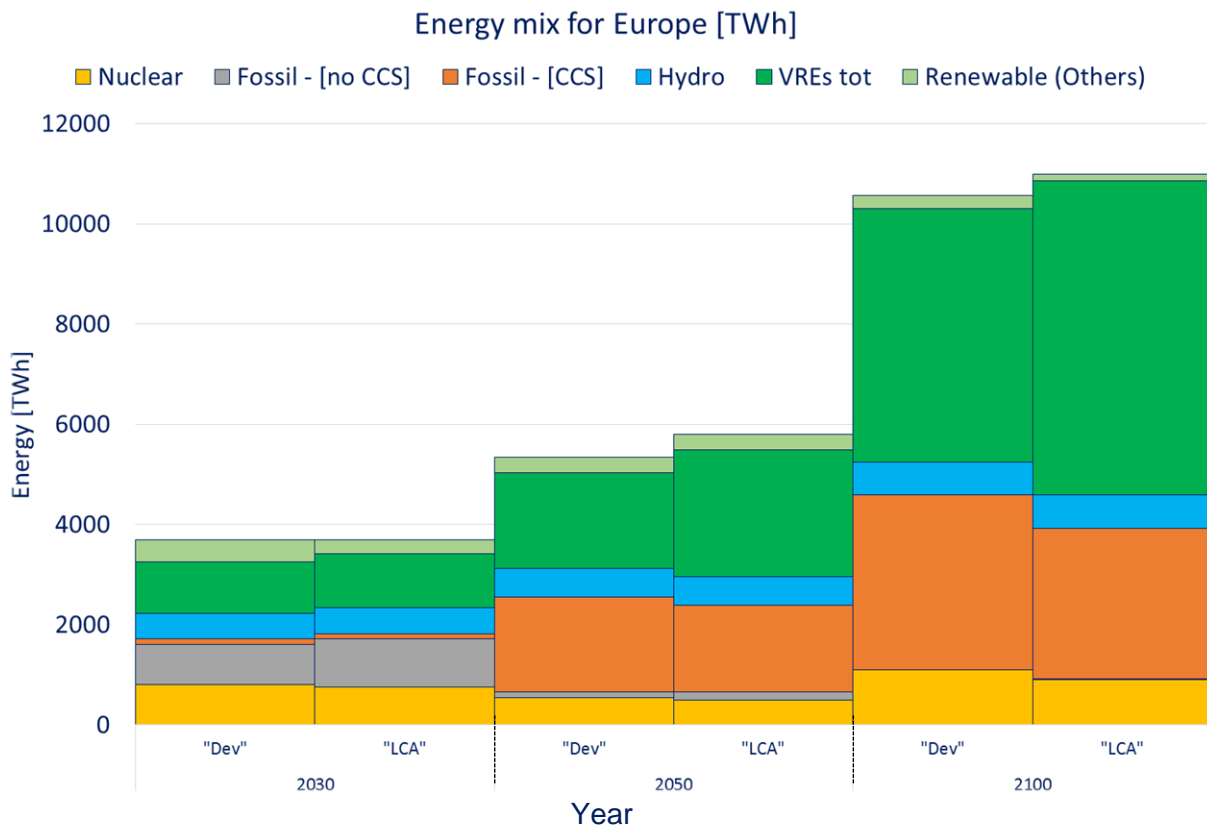


Figure III-15 – Energy mixes in 2030, 2050 and 2100 for the scenarios "Clim-Dev" and "Clim-LCA" [TWh]

These major trends in the two scenarios confirms that a least-cost approach together with an implementation of climate energy policy is almost as effective as an LCA approach. However, a deeper analysis of the energy mixes reveals some differences. In 2030, production from fossil fuel with no CCS is slightly greater in scenario "Clim-LCA": this production gathers production from gas, coal and oil. The consequence of LCA approach is the use of gas power plants to decarbonize the European power system together with VRES, hydro and nuclear productions. In POLES, the efficiency of the CCS system is considered to be 97%. Therefore, the emissions of these technologies are equal to the losses of the captured emissions (i.e. 3%). However, in "Clim-LCA", based on a reviewing of the literature, the CCS technologies have a lower LCA factor compared to technologies without CCS, but the reduction is not so important compared to the hypotheses used in POLES. The emissions from CCS technologies represent on average 30% of the emissions from no CCS technologies. The immediate consequences are a lower use of CCS technologies throughout the simulation.

(ii) Flexibility options

Flexibility from demand and production is one of the keys to better integrate VRES. These options are the storage technologies, demand response and curtailment of VRES production. To this end, Figure III-16 shows the energy produced from these options for the scenarios "Clim-Dev" and "Clim-LCA" in 2030, 2050 and 2100. Storage technologies are broken into stationary storage (STOR-BAT), vehicle-to-grid (V2G) and rest of storage technologies (Rest of STOR). VRES curtailment is considered as negative production as it is spilled energy. It can be observed that the use of flexibility options follows also the same major trends within the two scenarios. Overall, the use of flexibility options increases to reach more than 500 TWh in 2100 with stationary batteries and V2G technologies being the main sources of flexibility.

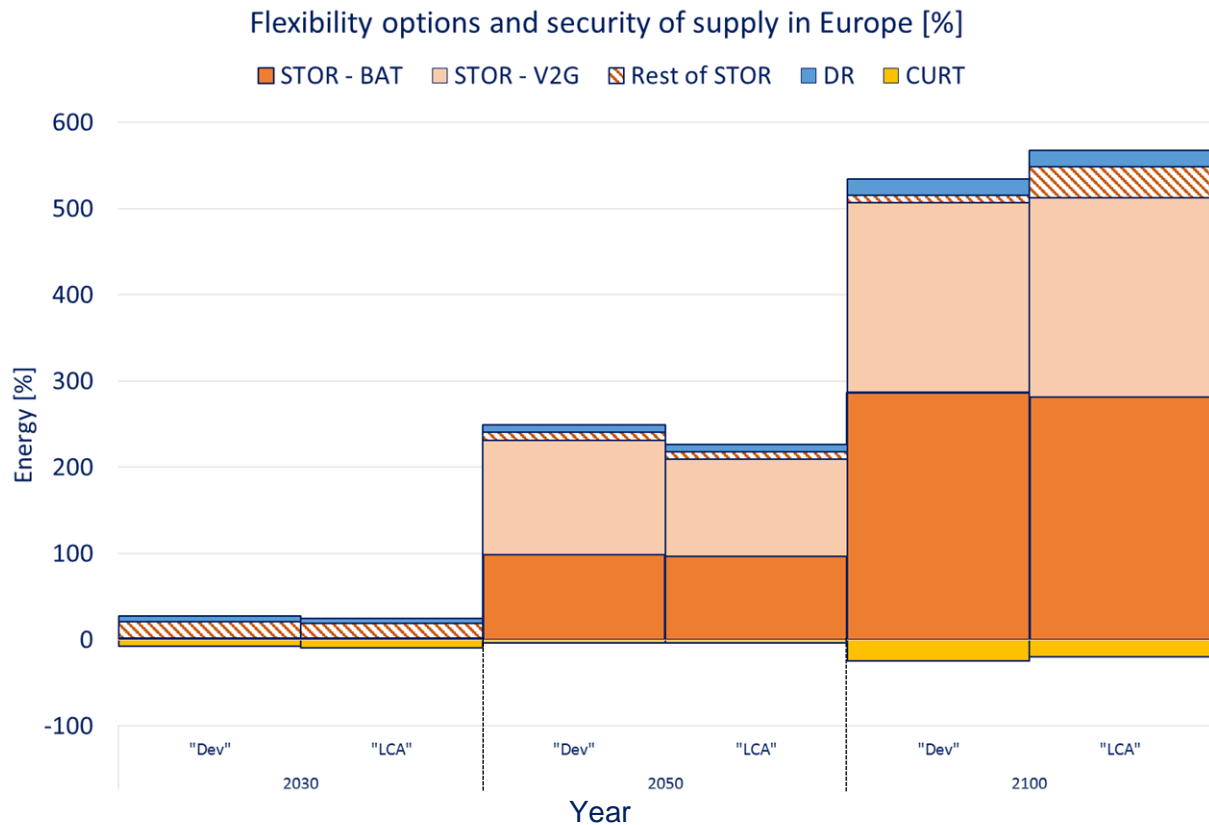


Figure III-16 – Flexibility options and VRES curtailment in 2030, 2050 and 2100 for the scenarios "Clim-Dev" and "Clim-LCA" [TWh]

If the two scenarios are compared yearly, it can be pointed out that in 2030 and 2050, the amounts of energy from flexibility options are lower for "Clim-LCA" while it is the opposite in 2100. The production from stationary batteries is almost similar for the two scenarios unlike the production from V2G. The reasons of these differences can be explained with two main reasons for 2050 and 2100: in 2050, the production from other technologies is greater in

"Clim-LCA" therefore there is less needs to store energy. Also, V2G has more constraints than STOR-BAT: it must ensure that the electric vehicles are being charged before helping the grid. In 2100, the share of VRES has increased and even though the demand is lower, all storage technologies are used to integrate this clean energy. The resulting effect is a lower curtailment of VRES in 2100 compared to "Clim-Dev".

To better understand the impact of changing the objective function on the usage of flexibility options, the results presented in Figure III-16 are now displayed in percentage in Figure III-17. Curtailment of VRES production is being removed as it is not a flexibility for the supply side. The figure shows the options preferred for each scenario and in 2030, 2050 and 2100.

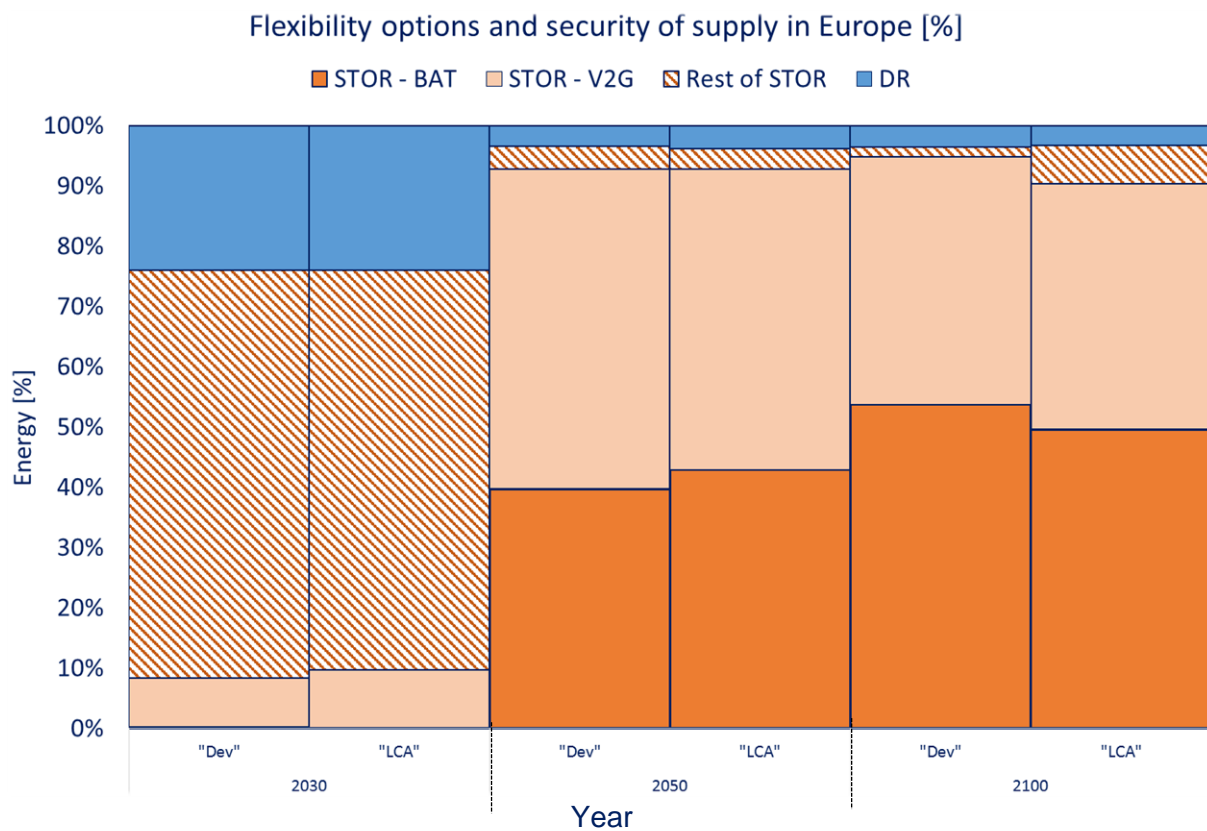


Figure III-17 – Flexibility options in 2030, 2050 and 2100 for the scenarios “Clim-Dev” and “Clim-LCA” [%]

As expected, production from stationary batteries and from V2G increase their share in all scenarios. However, there are some important differences across scenarios. In 2030, both scenarios use mainly other storage technologies (i.e. hydro pumped storage) but for "Clim-LCA", V2G are slightly more used. For the years 2050 and 2100, stationary batteries and V2G become the main sources of flexibility for "Clim-Dev". For "Clim-LCA", it also uses other storage technologies. In the LCA database, there is no associated emissions factors for these technologies. Therefore, they only compete based on their efficiency and the implemented

constraints: these reasons explain why more other storage technologies are used. In "Clim-Dev", V2G and stationary batteries are cheaper to use than other storage technologies. Therefore, their use is favoured.

III.4.4 Transmission grid requirements

(i) Grid development

Similarly to the previous scenarios, the transmission grid needs increases as VRES integration and demand rise. Figure III-18 shows the transmission grid development (in plain line) and the share of VRES (in dotted line) for the two scenarios "Clim-Dev" (in green) and "Clim-LCA" (in blue). In 2100, for "Clim-LCA", the grid infrastructure has been reinforced to attain 784 TWkm while the share of VRES reached 52% of total generation. In this particular scenario, the transmission grid requirements are lower than in scenario "Clim-Dev" but the share of VRES is higher. In Figure III-18, the analysis of the increments in grid infrastructure shows that the biggest investments are decided when EUTGRID anticipate the congestions with the expected power system in 10 years. And it seems that in scenario "Clim-Dev", the expected capacities are more ambitious than in scenario "Clim-LCA".

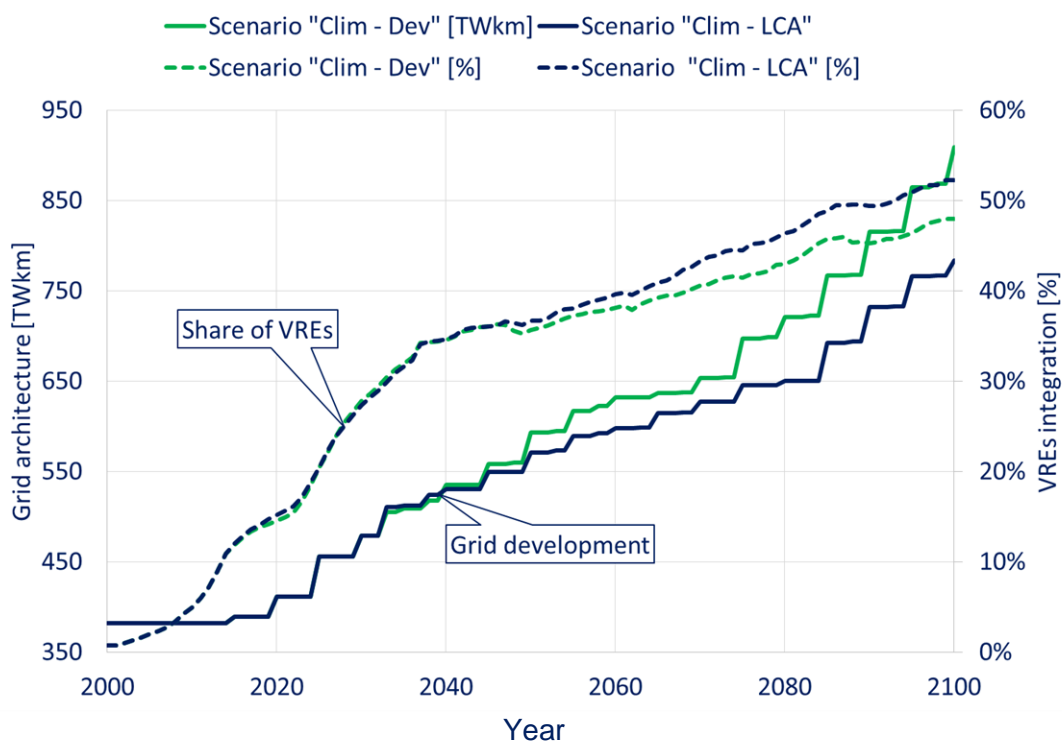


Figure III-18 – Transmission grid development and share of VRES for the scenarios "Clim-Dev" and "Clim-LCA"

The results for the periods 2010-2030, 2030-2050 and 2050-2100 are gathered in Table III-3. These results include the transmission grid reinforcements in TWkm, their breaking down between HVAC and HVDC technologies and the total budget needed to achieve these upgrades. The comparison with "Clim-Dev" shows a similar trend in HVAC and HVDC choices: HVDC technologies are also mainly used for the reinforcement. In 2050-2100, it consists of 76% of the reinforced lines compared with 68% in "Clim-Dev". In this scenario, there is a higher share of VRES and controlling the power flows is a key advantage. It further confirms the conclusion that HVDC technologies are more suitable in large-scale integration of VRES. Because of less transmission grid requirements, the yearly total budget is lower than in previous scenarios with around 8b\$/year. It indicates that the planning method implemented in EUTGRID might over-estimate the transmission grid requirements.

Table III-3 – Transmission grid requirements for scenario "Clim – LCA"

Time period		2010 - 2030	2030 - 2050	2050 - 2100
Production VRES [%]		[5%; 28%]	[28%; 40%]	[40%; 56%]
Transmission grid	Grid added [TWkm]	97	92	213
	-- HVAC [%]	74%	35%	24%
	-- HVDC [%]	26%	65%	76%
	Total grid investment [b\$]	180 (≈9b\$/year)	155 (≈7.8b\$/year)	373 (≈7.5b\$/year)

(ii) *Spatial location of grid requirements*

The LCA indicators do not only affect the dispatching and the transmission grid requirements but also the spatial location of these new reinforcements. The maps displayed in Figure III-19 shows the transmissions grid requirements for the period 2030-2100 for "Clim-LCA" on the right side. The map on the left side corresponds to the scenario "Clim-Dev" which was also displayed in Figure III-7. It can be observed that in "Clim-LCA" two corridors exists. The first goes from Scandinavia, it goes through the United-Kingdom then France up to Spain. The second one starts from Finland and connects the central Europe. These two routes points out the fact that Scandinavian countries and countries from the South have a cleaner energy with hydro and wind and solar. Unlike in the least-cost scenarios, Switzerland and Austria need less interconnections to the other countries. The hydropower plants have also associated emissions factors unlike in POLES and their use is less favoured.

The main differences between the two scenarios are the increase of the interconnections between France, England and Spain and also around the Benelux area. The upgrades of the

transmission grid indicate that these areas have lower LCA factors whose values depends of the countries.

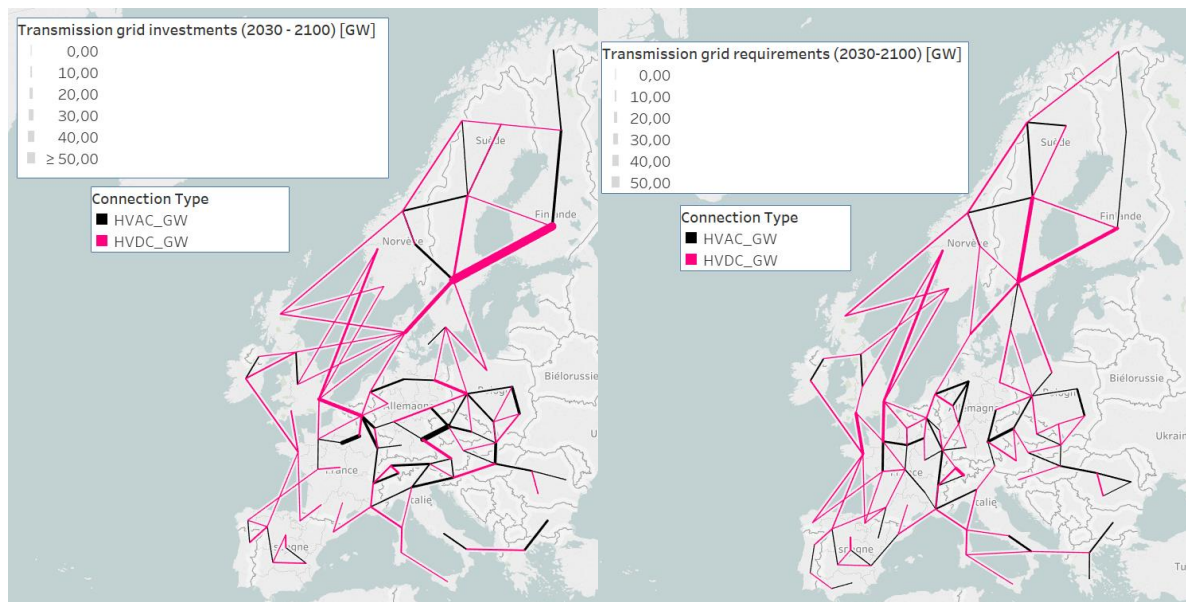


Figure III-19 – Total transmission grid needs in scenario “Clim-LCA” (right) and in scenario “Clim-Dev” (left) scenario for 2030-2100

Conclusions

The coupling of EUTGRID and POLES allows to analyse the development of the European transmission grid in long-term energy scenarios with strong climate policies. The characteristics of these scenarios are first presented to better understand the different results. In all scenarios, a climate energy policy is implemented to limit the rise of the global temperature to 2°C. The scenarios are then distinguished some allowing the development of the grid and some where the grid investment budget is constrained. In the first case, the reference case corresponds to the situation where the transmission grid evolves as the default situation and a scenario where flexibility options and VRES integration are promoted. In the second case, a first scenario sees its grid development frozen in 2040. The grid investment is also limited in three other scenarios but measures favouring the VRES integration, batteries and then the demand response are being added.

The results are first analysed according to the European grid development. The transmission grid requirements largely increase with the VRES integration. With adequate measures, the share of VRES rises up to 64% compared to 54% and the resulting effect is a speed of VRES development twice as fast the reference scenario. The key driver of this expansion seems to be the anticipation reinforcements: POLES simulates a much higher share of VRES and therefore, important congestions must be located and alleviated. EUTGRID distinguishes the reinforcements between HVAC and HVDC technologies and the results show that the new projects are mostly done with HVDC technologies. The specificity of HVDC helps to better control the important power flows which are the consequences of the large-scale integration of the VRES. Using HVDC to expand the grid is particularly relevant when the grid development is limited. Depending of the scenarios considered, the grid development is modified and the analysis of the grid architecture for the frozen scenarios has shown that some interconnections are always reinforced. This comparison underlines their importance.

The transmission grid expansion is not only affected by the integration of VRES and thus the implementation of the climate energy policy, but it also impacts CO₂ emissions, the energy mix and the flexibility options. If the transmission grid development is constrained, the resulting consequence is an increase of the European emissions: with the increase of load, many lines are congested, and polluting technologies must be called to supply the demand. However, the combination of the development of the transmission grid and the reduction of the investments cost for VRES capacities and stationary batteries and the increase of demand response potential help to reduce the total emissions and also the electricity costs. The investments costs reduction is the main driver of this reduction as the variable system costs slightly decrease. It indicates that in the future, the costs will be mostly consisting of

the associated ramping costs. The usage of flexibility options increases in all scenarios, but the rise is more important with frozen investments in the transmission grid. The main source of the flexibility comes from the storage technologies. However, in all frozen scenarios, non-distributed energy appears. In planning studies, this value reveals the impossibility to supply the demand and the need to reinforce. It illustrates the importance of the transmission grid in a large-scale integration of VRES. It must be pointed out that the increase of VRES in a situation with limited investments provokes more constraints.

Finally, an exploratory work is presented, which substitutes the minimization of total emissions to the current least-cost approach. These emissions are calculated based on LCA factors and the results show some differences with POLES' own calculations of CO₂ emissions. The impact of this new objective function also affects the energy mix: the share of VRES has increased. However, some technologies such as CCS are less used because the emissions factors with the LCA approach are higher relative to the other technologies. The resulting grid development is lower even though the locations of the reinforcements are similar.

Chapter IV. Representing the distribution grids in long-term energy models

The new model EUTGRID developed and presented in the two previous chapters focuses on the representation of the European transmission grid and its development. The main hypothesis used considers that within a region there is no congestion, but this is only true if the sub-transmission and the distribution grids are well sized.

Nowadays, most of the capacities are installed in the distribution grids, which were not designed to connect these productions and face new issues such as overvoltage and congestion. These problems must be tackled with solutions like storage technologies, demand response or reinforcement. However, in long-term energy models, these questions are not taken into account. With the large-scale integration of VRES which are presented in the different prospective scenarios, the associated costs to this integration could be underestimated.

For this reason, EUTGRID is further improved and the new developments are presented in this chapter. It consists of representing voltage and power flows (active and reactive) in the distribution grids. This new model is then used to analyse the different issues related to the integration of VRES in three representative distribution grids. Technical solutions such as OLTC (On-Load Tap Changers), reinforcement, VRES curtailment and storage technologies are presented. A cost comparison between these solutions is also carried out. Finally, the new version of EUTGRID is coupled with POLES and the impacts on the emissions, the flexibility options and the evolution of the transmission grid are shown.

IV.1 Renewable integration in distribution grids

IV.1.1 New issues arise in the distribution grids

(i) DSOs obligations

The European power system consists of four main networks: the transmission grid, the sub-transmission grid, the medium-voltage distribution grid and the low-voltage distribution grid. The transmission grid connects the different countries and transport electricity over long distances. It is modelled in EUTGRID and with the assumption that no congestion existed, the other grids were not considered. The sub-transmission grid is connected to the transmission grid and usually covers a region. Its voltage level ranges from 63 to 90 kV for France [144]. This grid is highly meshed and therefore very similar to the transmission grid. From the sub-transmission grid, the electricity flows to the medium-voltage distribution grid which operates at 11 and 33 kV. It is finally

connected the low-voltage grid where most loads are connected. It operates at 230 V (voltage neutral to phase) [145].

The distribution grids cover larger areas than the transmission grids. For example, ENEDIS, the French DSO (Distribution System Operator), operates 1.35 million kilometres [146] while RTE, the French TSO only manages 105 660 kilometres [147]. As a consequence, the regulation in all European countries imposes that the DSOs respect a high quality of supply. The European standard EN 50160 provides the voltage characteristics and the possible deviations at the customers' level. It also includes technical limitations such as interruptions time, harmonic voltage etc.

In the French distribution system, the constraints for the voltage levels are the following: in the medium-voltage grids, the voltage can vary in a range $\pm 5\%$ around the nominal voltage [148]. This nominal value is equal to 11 or 33 kV. Concerning the low-voltage grids, the voltage can vary in a range $\pm 10\%$ around the nominal voltage (230V) [149]. Additional constraints exist but, in this manuscript, only these limits will be considered and implemented.

(ii) Rise of VRES in the distribution grids

In France, the solar capacities increased over the years to reach almost 7GW. However, their distribution is unequal over the different networks as illustrated in Figure IV-1. It shows the cumulative installed capacities for the low-voltage, the medium-voltage and the transmission grids from 2011 to 2016 [150]. In 2011, almost 66% of the capacities were connected to the low-voltage grid and 33% to the medium-voltage grid. Then, the share slightly decreased but remained important with more than 91% of the capacities connected to the low and medium voltage grids.

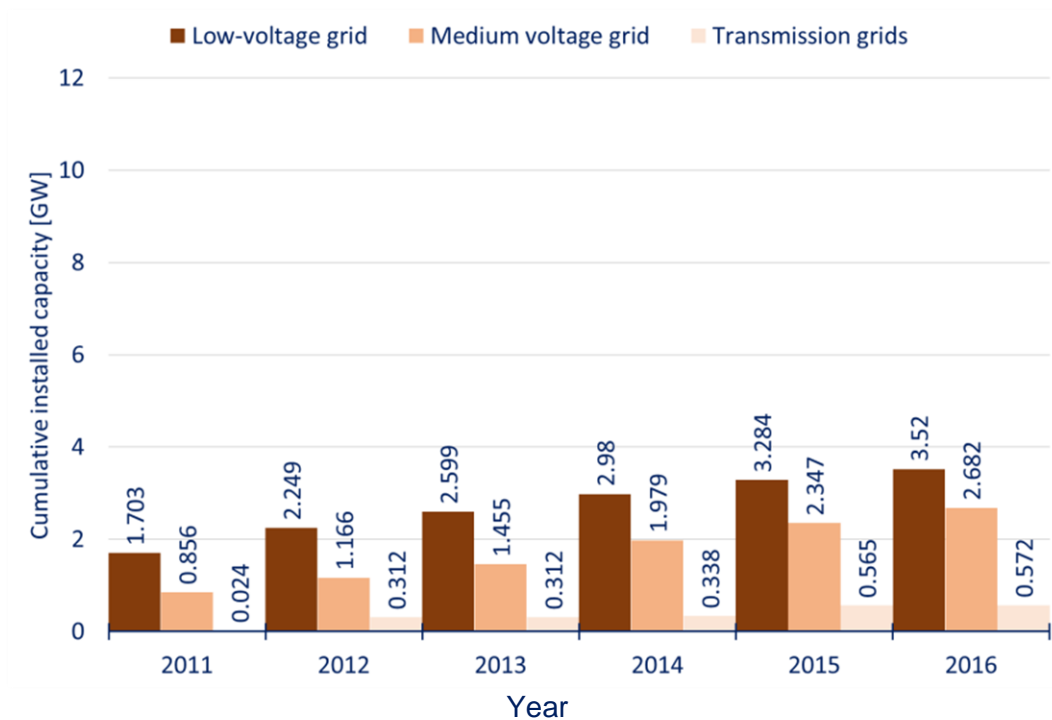


Figure IV-1 – Solar capacity installed for each voltage level of the French power system [GW][150]

Wind power plants have also increased during 2011-2016 with around 12GW installed in 2016 in the medium and the transmission grid. It can be observed that the amount of installed wind capacities is almost 80% higher than the amount of installed solar capacities in 2016. The distribution among the different voltage grids is also unequal as illustrated in Figure IV-2. It shows the cumulative installed capacities for the low-voltage, the medium-voltage and the transmission grids from 2011 to 2016 (source: RTE). Unlike solar capacities, wind capacities are almost only connected to the medium-grid voltage and it represents 94% of all capacities in France.

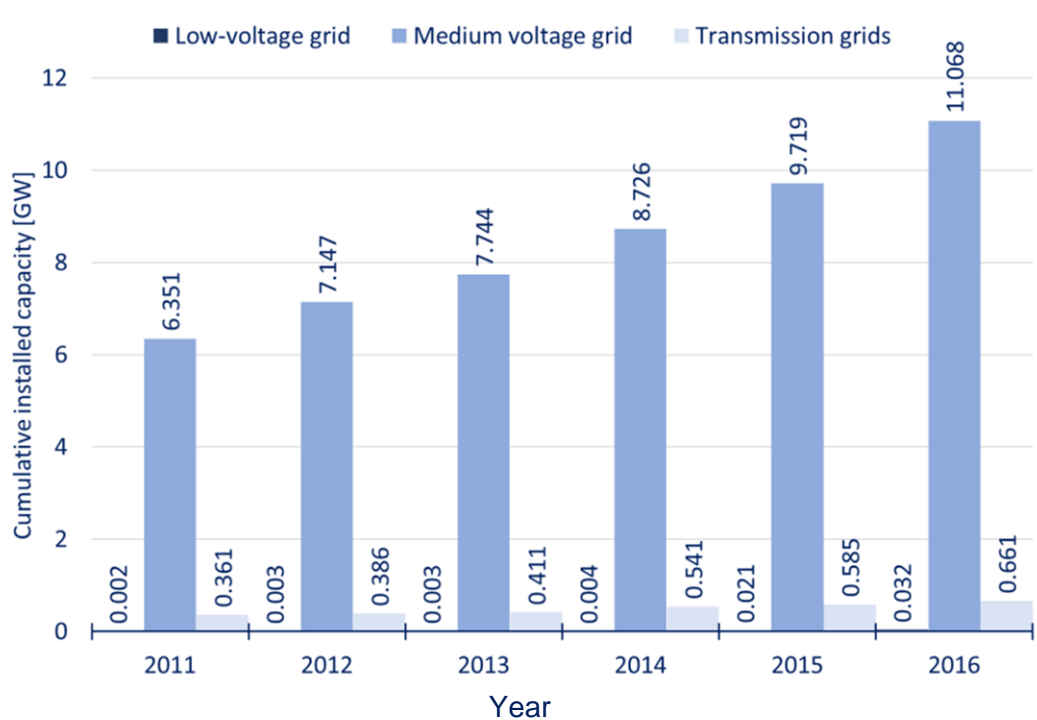


Figure IV-2 – Wind capacity installed for each voltage level of the French power system [GW][150]

Figure IV-1 and Figure IV-2 show that the distribution grids have absorbed most of the integration of the VRES. The consequences are that the different issues related to the VRES integration will be firstly observed in the distribution grids. For this reason, it is interesting to model the low-voltage grids in the long-term energy models.

(iii) Issues related to VRES integration

Before analysing the difficulties implied by the installation of VRES power plants, the large-scale integration of VRES offer some significant benefits. Notably, it helps answering environmental concerns as these distributed power plants replace more polluting ones [151]. Depending on the conditions of installation, it can also defer grid investments [152], [153].

These benefits have promoted the large-scale integration of VRES within the distribution grids. However, the distribution grids were not designed for the connection of generation devices [154]. As a consequence, the VRES sources provoke a number of problems that DSOs must tackle [155], [156]. The first one deals with the voltage rise effect: the production from VRES sources increases the voltage locally. Depending of the residual

load¹⁸, the rise can be significant especially when demand is low. If there is no active voltage control, it can result in violations of voltage limits [157]. The second main impact is related to the occurrence of reverse power flows: production from VRES sources can now exceed the demand and power flows can go up to the medium-voltage grid [158]. However, the distribution grids were usually radially built, and it was assumed that flows were unidirectional. Because of these new issues combined with power quality problems, new protection schemes must be designed to avoid disturbances in the electricity supply [152], [159]. The amount of energy can also surpass the grid capacities and DSOs also face situations of congestion especially in rural distribution grids. To solve these problems, some of national standards require that these distributed grids should be automatically disconnected in case of abnormal operations [160]. It has also led some DSOs to restrict the VRES integration [161]. These effects call for more flexibility in the distribution grids.

IV.1.2 Specific models to analyse distribution grids

According to [161], there is a strong need to develop adequate tools to assess the impacts of VRES integration in the distribution grids and propose solutions. Usually, simulation models are first set up to understand the influence of the VRES integration on the quality of supply (i.e. voltage harmonics)[162].

However, the studies are generally case-specific: a given distribution grid is usually described, and the solutions are analysed to solve the identified issues. For example, in [163], the high penetration of solar PVs is analysed on three voltage levels and different solutions ranging from volt-VAR-control to power peak control are presented. Based on the different observations, new control systems are also proposed to avoid the different problems [164], [165]. In these studies, the technical aspects are the main objectives. However, many other articles focus on the use of flexibility options to help the integration of VRES and usually a minimization cost objective is added to the analysis. Battery energy systems strategies are modelled and applied in real distribution grids [166], [167]; similarly, demand response and electric vehicles charging are used to avoid congestions [168]. Reconfiguration of the distribution grids seems also to be a strategy for higher penetration of VRES [169]. One of the main limitations of these studies is the robustness

¹⁸ Demand minus production at each node

of the results. The use of stochastic models can be a solution as deterministic models can underestimate the investments needs [170], [171].

As previously shown in chapter I, long-term energy models usually do not include a representation of the transmission grid. Therefore, the distribution grids are not considered either and the cost of overvoltage or congestion management are hidden. The only models, which include a power sector representation (TIMES and PRIMES) do not have a physical representation of the distribution grids. They rather have a cost approach: the demand and production are allocated to each voltage level. The flows are calculated based on transmission and distribution grids costs [172].

IV.2 Representing the distribution grid in EUTGRID

IV.2.1 Linearizing the AC load flow equations

(i) Power flows

In the previous chapter, the power flows in the transmission grid were calculated considering that voltage was constant and that the angles between each node presented small variations. As a result, the reactive power was considered negligible, in a DC approximation.

However, in the distribution grid, the resistance and the reactance of the lines have a direct effect on voltage level and reactive powers cannot be neglected anymore. If we recall the complete power flow equations for active power $P_k(t)$ and reactive power $Q_k(t)$ for each node k , these values depend of the bus admittance Y , the angles θ and voltage V as shown in (15) and in (16). The real part G of the Y admittance matrix is built as described in (18) and the active flow in the line kj results in the following power flow equation (19).

$$\forall(k, t) \quad P_k(t) = \sum_j |V_k| |V_j| * (G_{kj} * \cos(\theta_k - \theta_j) + B_{kj} * \sin(\theta_k - \theta_j)) \quad (15)$$

$$Q_k(t) = \sum_j |V_k| |V_j| * (G_{kj} * \sin(\theta_k - \theta_j) - B_{kj} * \cos(\theta_k - \theta_j)) \quad (16)$$

In equation (15), the active power at each node k is related to the sum of power flows coming from the neighbouring nodes as depicted in equation (17).

$$\begin{aligned}
P_k(t) &= \sum_{j \neq k} P_{k,j}(t) \quad (17) \\
\forall(k, t) &= \left[\sum_{j \neq k} |V_k| |V_j| * (G_{kj} \cos(\theta_k - \theta_j) + B_{kj} \sin(\theta_k - \theta_j)) \right] + |V_k|^2 * G_{kk} \\
&= \left[\sum_{j \neq k} |V_k| |V_j| * (G_{kj} \cos(\theta_k - \theta_j) + B_{kj} \sin(\theta_k - \theta_j)) - |V_k|^2 * G_{kj} \right]
\end{aligned}$$

With

$$\begin{aligned}
G_{kk} &= \sum_{j \neq k} G_{kj} \quad (18) \\
G_{kj} &= -G_{jk}
\end{aligned}$$

$$P_{k,j}(t) = |V_k| |V_j| * (G_{kj} \cos(\theta_k - \theta_j) + B_{kj} \sin(\theta_k - \theta_j)) - |V_k|^2 * G_{kj} \quad (19)$$

In the distribution grid, the differences between angles can be considered small. As a result, the approximations of sine functions can be replaced by the difference: $\sin(\theta_k - \theta_j) \approx \theta_k - \theta_j$. The cosine function can be replaced by: $\cos(\theta_k - \theta_j) \approx 1$. The equation (19) can be approximated by equation (20).

$$\begin{aligned}
P_{k,j}(t) &\approx |V_k| |V_j| \left(G_{kj} + B_{kj} * (\theta_k - \theta_j) \right) - |V_k|^2 * G_{kj} \quad (20) \\
&= |V_k| * \left(-G_{kj} (|V_k| - |V_j|) + |V_j| * B_{kj} * (\theta_k - \theta_j) \right)
\end{aligned}$$

The final assumption used in [173] considers that voltage magnitude at each node does not deviates too much from their nominal value V_{nom} but that the differences of two voltages have the most effect on power flows. Therefore, equation (20) can be replaced by (21). With the use of the per-unit system¹⁹, V_{nom} is equal to 1 p.u.

$$P_{k,j}(t) \approx V_{nom} * \left(-G_{kj} (|V_k| - |V_j|) + |V_j| * B_{kj} * (\theta_k - \theta_j) \right) \quad (21)$$

Similarly, reactive flow in line kj can be approximated using the same hypotheses as described in equation (22).

¹⁹ In a per-unit system, the different values of power and voltages are expressed as the ratio of their real value and a defined base unit value.

$$\begin{aligned}
Q_{k,j}(t) &= |V_k||V_j| * (G_{kj} \sin(\theta_k - \theta_j) - B_{kj} \cos(\theta_k - \theta_j)) + |V_k|^2 * B_{kj} \quad (22) \\
&\approx |V_k||V_j| * (G_{kj}(\theta_k - \theta_j) - B_{kj}) + |V_k|^2 * B_{kj} \\
&= |V_k| * (B_{kj}(|V_k| - |V_j|) + |V_j| * G_{kj} * (\theta_k - \theta_j)) \\
&\approx V_{nom} * (B_{kj}(|V_k| - |V_j|) + V_{nom} * G_{kj} * (\theta_k - \theta_j))
\end{aligned}$$

(ii) Grid limitations – Apparent power

The active and reactive power flows are linked with the non-linear equation (24) where $S_{k,j}$ is the apparent power of the considered line kj . This apparent power is limited by the transmission line capacity (see equation (24)).

$$S_{k,j}(t) = P_{k,j}(t)^2 + Q_{k,j}(t)^2 \quad (23)$$

$$S_{k,j}(t) \leq S_{k,j}^{max} \quad (24)$$

The linearization of the equation (24) follows the method described in [173]. The flows can be represented in a P/Q diagram (see Figure IV-3). The apparent power flow is limited by the dotted circle. Two sets of constraints are introduced to linearize the apparent flow limitations.

First, based on equations (23) and (24), the active and reactive power flows are limited by the apparent power. It is depicted in the following equations (25) and (26). It corresponds in Figure IV-3 to the lines $P = \pm 1$ and $Q = \pm 1$.

$$-S_{k,j}^{max} \leq P_{k,j}(t) \leq S_{k,j}^{max} \quad (25)$$

$$-S_{k,j}^{max} \leq Q_{k,j}(t) \leq S_{k,j}^{max} \quad (26)$$

The final approximations correspond to the restrictions of the areas in the corners of the squares and can be summarized in equation (27).

$$c_{\alpha}^P * P_{k,j}(t) + c_{\alpha}^Q * Q_{k,j} \leq \sqrt{2} * S_{k,j}^{max} \quad (27)$$

These 4 constraints are determined by the parameters c_{α}^P and c_{α}^Q which describe the four quadrants. However, these approximations have some limitations: some areas which are not feasible with the non-linear equations can still be chosen.

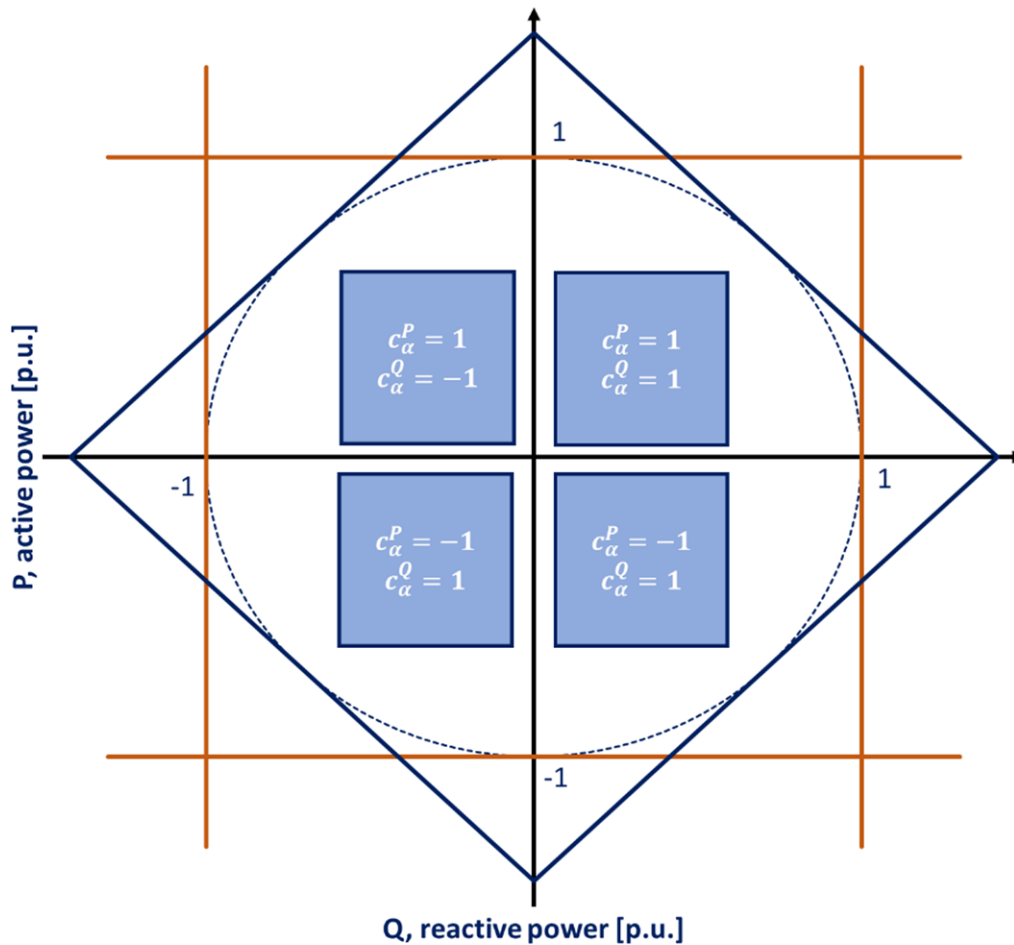


Figure IV-3 – Grid flow limitation in EUTGRID. Representation based on [173].

With the complete equations, a non-linear solver is needed in EUTGRID, but in the context of this work, it takes too much time to find a solution. As an illustration, a test was carried out in GAMS (General Algebraic Modeling System) with KNITRO (Nonlinear Interior point Trust Region Optimization) but it took more than an hour to solve only one day. Because the dispatching must be run a high number of times, there is a trade-off to find between the accuracy of the solution and the time taken to solve the problem. Therefore the method presented in [173] has the main advantage to introduce linear equations and to allow using a solver such as CPLEX, which is much more fast and efficient to solve linear problems.

IV.2.2 Comparisons between EUTGRID&D and MATPOWER

The linear equations representing the AC load flow are implemented in GAMS using the solver CPLEX. Consequently, EUTGRID with these new set of equations now forms a new model called EUTGRID&D (European Transmission Grid and Dispatch with Distribution grid representation). The results are compared with the ones from the ones from the package MATPOWER [174] available on MATLAB software program which provides steady-state power system simulation. The test grid is the IEEE (Institute of Electrical and Electronics Engineers) 30 Bus Test Case which represents a portion of the American Electric Power System which is both available in MATPOWER and in [175]. The grid is presented in Figure IV-4.

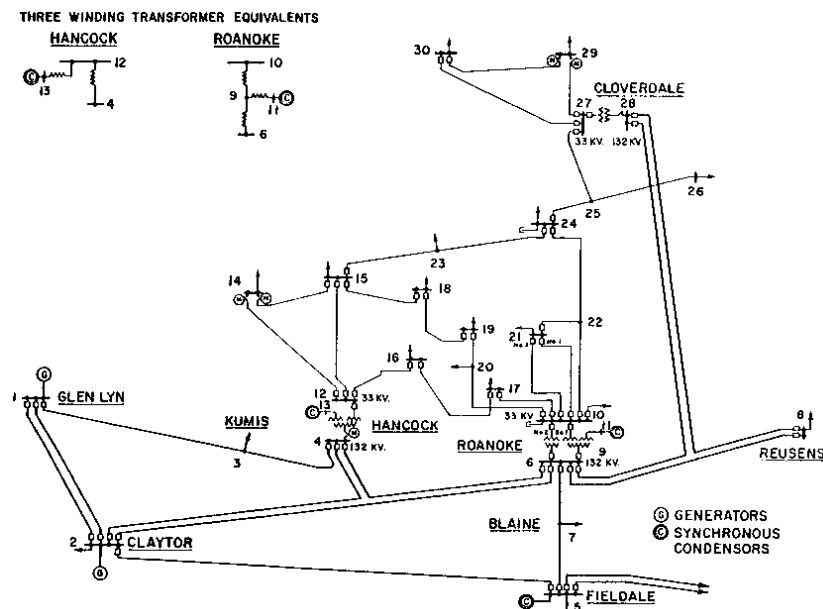


Figure IV-4 – IEEE 30 Bus Test Case [175].

In the following figures, the calculated values of voltage, active and reactive power flows are then plotted versus the ones found with MATPOWER: Figure IV-5 for voltage measures, Figure IV-6 for active power flows and Figure IV-7 for reactive power flows. All the values are presented in per unit (p.u.) which consists of dividing the calculated voltage by the nominal value.

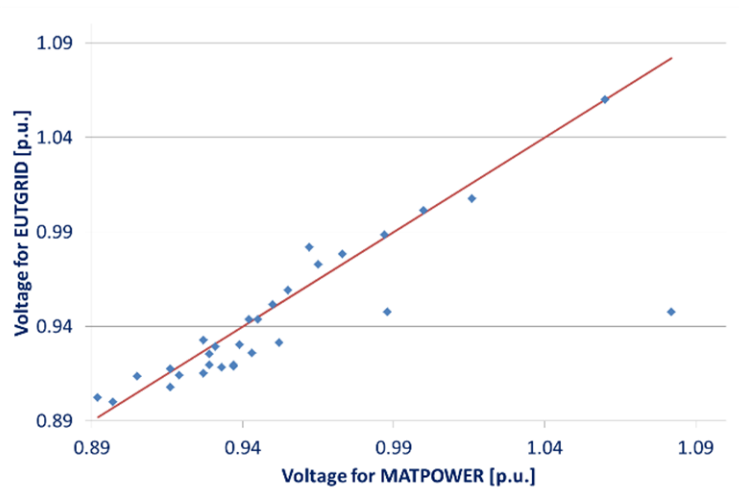


Figure IV-5 – Comparison of voltage between EUTGRID and MATPOWER.

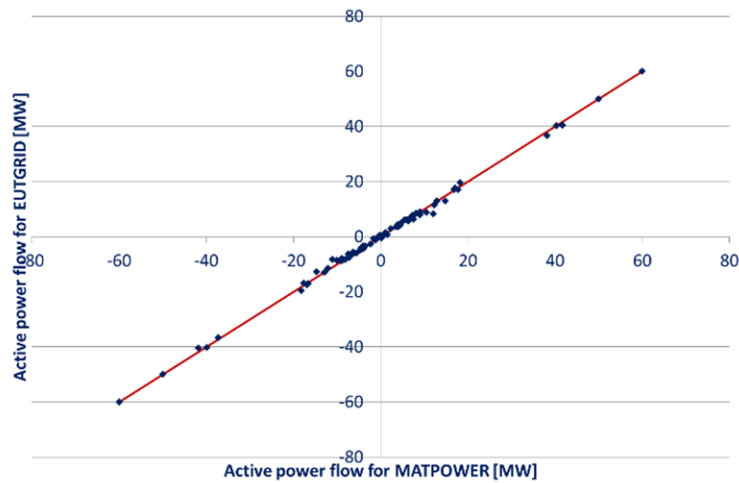


Figure IV-6 – Comparison of active power between EUTGRID and MATPOWER.

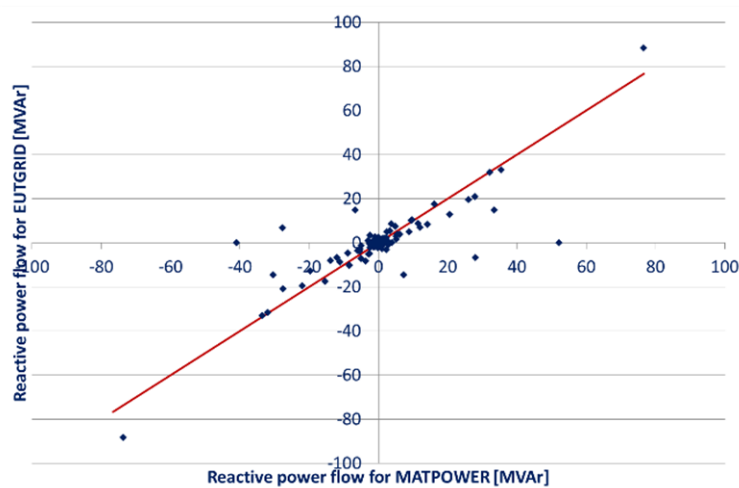


Figure IV-7 – Comparison of reactive power between EUTGRID and MATPOWER.

From these comparisons, it can be observed that the linearization implemented fits to some extent to the MATPOWER model. Some deviations exist specially on voltage levels and reactive power flows. The calculation of the mean absolute error (MAE) for the voltage is equal to 0.013 p.u. while the MAE for active power flows reaches 0.6 MW and for reactive power flows it reaches 5.5MVar. For the sake of our simulations, voltage and active power flows magnitudes are considered well determined with the linearized equations. To conclude, the set of equations representing the linearized AC load flow has been validated and can be used in EUTGRID to analyse issues in the distribution grids.

IV.2.3 Generic distribution grids

Different datasets describing the distribution grids are openly available to analyse issues within the power system. For example, in 1991, the Test Feeder Working Group from the IEEE organization released five models [176]. New models mainly based on American real distribution grids were added to help researchers testing their new methods [177], [178]. Other archiving websites exist which also share similar models [179]–[181]. These datasets include very detailed descriptions of real grids to perform extensive power system analyses. However, these models mainly focus on the North American grids and usually describe low voltage grids.

Regarding the representation of the European distribution grids, a project called ‘LV network Solutions’ with the University of Manchester made available 25 detailed models of low-voltage grids from Manchester [182], [183]. These datasets could be used in EUTGRID, but the representation of the medium voltage is lacking, and it is only limited to urban areas. A previous project led by the Centre for Sustainable Electricity and Distribution Generation provided 6 typical networks which were representative of the distribution system of the United-Kingdom [184]. However, the website is not accessible anymore even if an unofficial archive is available [185].

The Distribution System Operators Observatory from the European Joint Research Centre collected data on European distribution systems and released 13 different representative distribution networks with different voltage levels [186], [187]. In this dataset, three networks are geo-referenced and have the following characteristics: urban, semi-urban and rural. Figure IV-8 shows the resulting representative networks: the first main difference is related to the distance between each node: the rural network has long lines (up to 10km) while the urban one has shorter lines (not exceeding 1km). The semi-urban network represents an intermediate situation where a major portion of

the grid has short lines with some long lines. It must be noted that these networks have a connection with the high-voltage network (through a transformer).

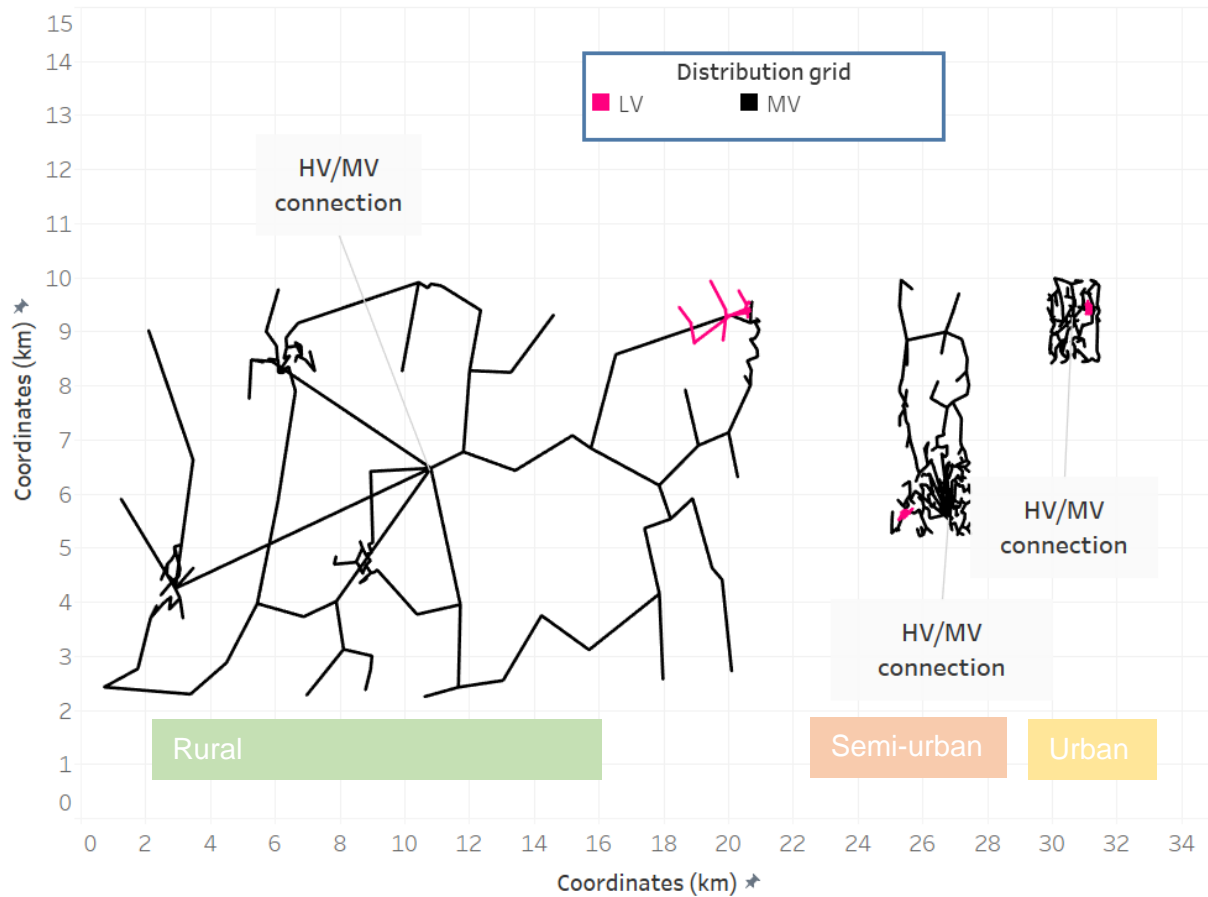


Figure IV-8 – European representative distribution grids implemented in EUTGRID and based on [187]

The only producing technologies available in the distribution grids are the onshore wind (i.e. WN1-WN3 in POLES), the decentralized PV (i.e. DPV in POLES). Storage technologies are also included but they are limited to the stationary batteries (i.e. BAT in POLES), vehicle-to-grid (i.e. V2G in POLES) and grid-to-vehicle (i.e. G2V in POLES). The main hypothesis assumes that all the different technologies are distributed according to the distribution of the population except for wind capacities. According to the data provided by RTE, almost all wind production is injected in the medium voltage level. Therefore, no wind capacities will be installed in the low voltage level, but rather the medium voltage. This last hypothesis describes the situation where wind turbines are installed in less populated areas where social acceptance is likely to be higher.

Finally, these distribution keys help to draw more characteristics regarding the different representative networks. The allocation in percentage is represented for the urban network in Figure IV-9, for the semi-rural one in Figure IV-10 and for the rural one in Figure IV-11. For each of these figures, two maps are shown: the left one corresponds to the allocation of wind capacities and the right one to the allocation of demand. In urban areas (see Figure IV-9), the demand is equally distributed amongst the different nodes. In the rural network (see Figure IV-11), the loads are more dispersed with 6 groups of nodes where most demand is concentrated. These bulks of demand correspond to small settlements. The semi-urban network (see Figure IV-10) shares the characteristics of urban and rural networks with uniform demand distribution in the urban portion and small demand in the rural part.

Because of the complexity of these networks, they have been simplified so that the dispatch can be solved in EUTGRID in a reasonable time. Low-voltage customers and VRES producers are aggregated to their nearest medium node voltage. However, for each representative network, one low-voltage network has been included in the model to draw some conclusion on that voltage level.

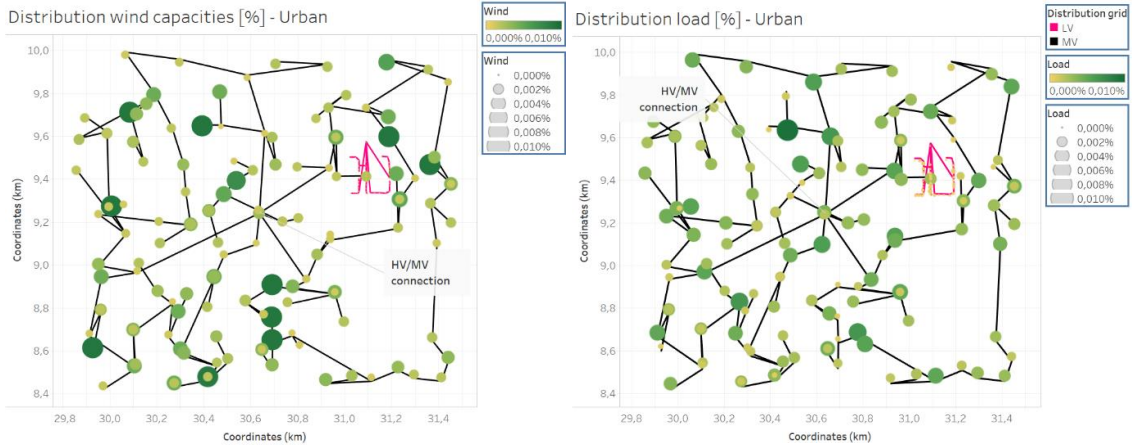


Figure IV-9 – Proposed distribution keys for urban network – Wind capacities (left) and load demand (right)

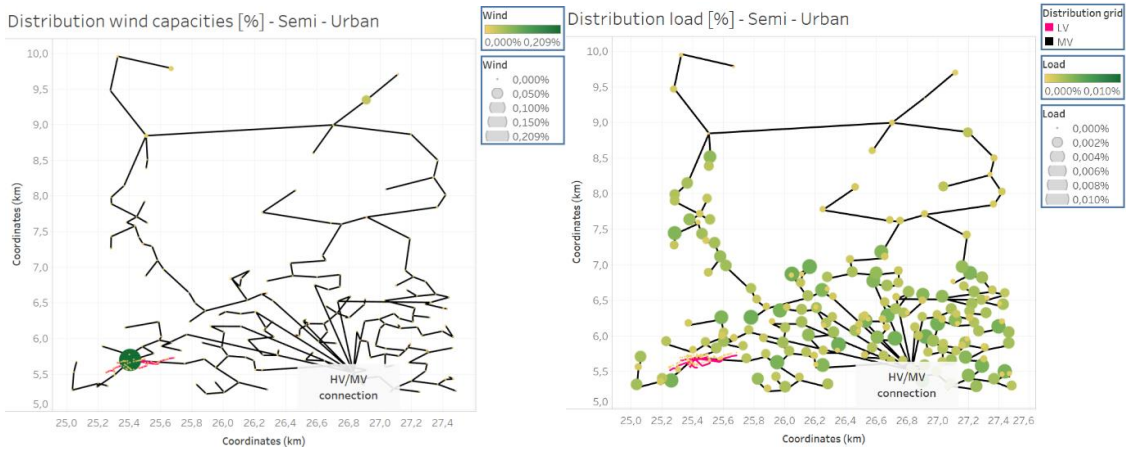


Figure IV-10 – Proposed distribution keys for semi-urban network – Wind capacities (left) and load demand (right)

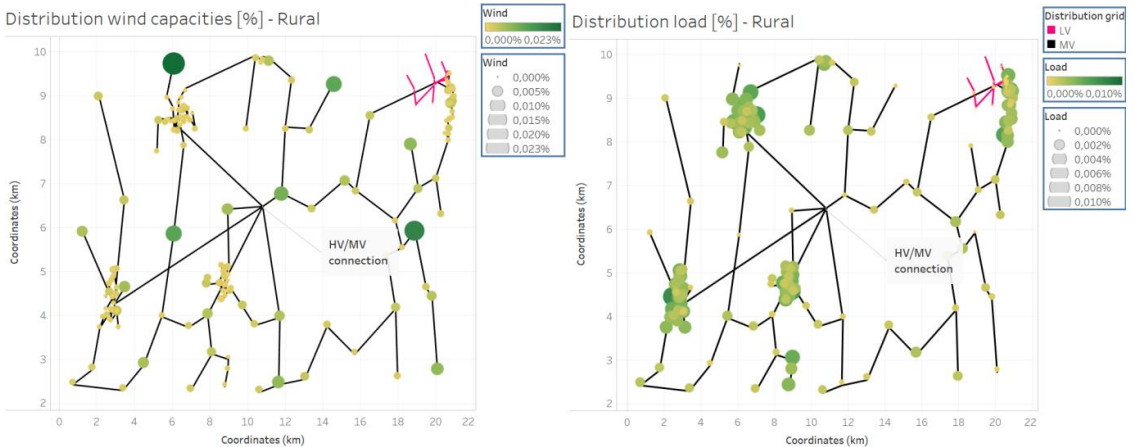


Figure IV-11 – Proposed distribution keys for rural network – Wind capacities (left) and load demand (right)

IV.3 Analysis of the different distribution networks

In EUTGRID, the set of equations describing the linearized AC load flow is included with the representation of the three distribution networks previously presented: rural, semi-urban and urban. The rural distribution network is connected to the French node located in the South of France (it corresponds to the node “16-FR” in EUTGRID). This region has been chosen because it installs more solar PV in the scenarios “Clim-Dev”. The semi-urban distribution network is connected to the French node located in the North of France (it corresponds to the node “26-FR” in EUTGRID). This region has been chosen because it concentrates more wind than PV capacities. Finally, the urban distribution network is connected to the densest French node located in Ile de France (it corresponds to the node “23-FR” in EUTGRID).

Before analysing the effect of including a representation of distribution grids in our model, an analysis is performed on the different networks to characterize the issues, which happen in context of large-scale integration of VRES. Then different solutions such as OLTC, reinforcement, storage or VRES curtailment are presented to solve them and help reaching a high share of VRES production. Finally, the costs of these solutions are calculated and compared in different scenarios of VRES integration.

IV.3.1 Analysis of the different issues with no implemented solution

(i) Occurrence of overvoltage and non-distributed energy

The rising share of VRES modifies the operation of the three considered networks. The flows change their direction from the production nodes up to the transformer. Depending on the characteristics of the networks and the level of VRES production, it can threaten the security of the power system. In a steady-state situation, over-voltage and congestions can occur.

In a situation with only solar PVs, the rural distribution grid sees a greater increase of voltage level than in the other representative distribution grids. Figure IV-12 represents the solar production for a summer day at node B_77 of the medium voltage level which is located at the end of a long line (its demand is included in the graph). The day corresponds to the representative day n°5 shown in the previous chapter and the different figures presented will only focus on the same node and the same day.

The analysed situation corresponds to a share of VRES of 40%²⁰. The solar production increases at noon and largely exceeds the demand. The consequence is that power flows in the grid rise with the voltage level at that node. This result can be observed in Figure IV-13 where the corresponding hourly voltage has been plotted in green. Its shape follows the bell curve of solar production and it exceeds the voltage limits for six hours. With the comparison of the hourly voltage with no solar production which is drawn with a dotted green line, solar PVs have boosted the voltage level by 0,1 p.u. which represents 2kV in that case.

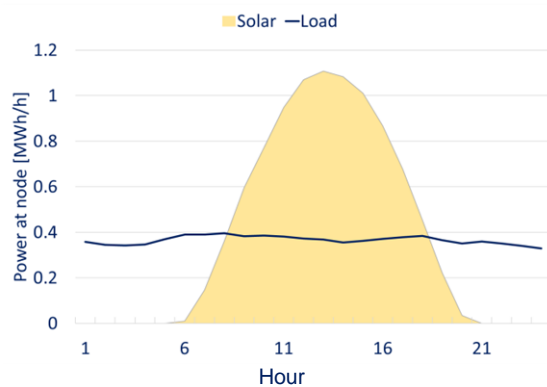


Figure IV-12 – VRES production and demand at node B_77 belonging to the medium voltage grid located at the end of a long line in summer (day n°5) [MWh/h]

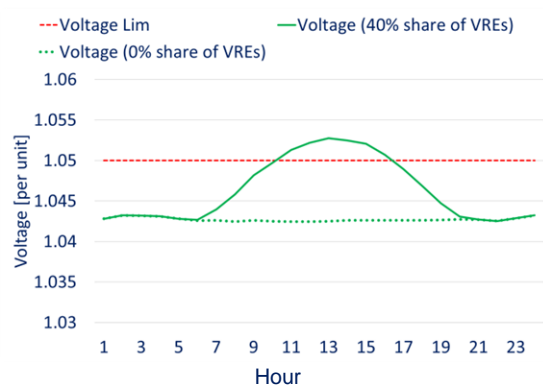


Figure IV-13 – Voltage at node B_77 belonging to the medium voltage grid located at the end of a long line for summer (day n°5) [p.u.]

If the share of VRES keeps increasing above 45% in the rural distribution grid, congestions appear. For example, if more PVs are installed in the rural distribution grid to reach 47% of the demand, then non-distributed energy appears at every node representing around 4MWh. It is equivalent to 1,8 % of the demand of this grid. In Figure IV-14, the amount of NDE at each node of the network is represented in kWh together with the percentage of its yearly demand. It can be observed that almost all nodes have a similar level of NDE but in low-voltage grid, it represents only 0,40% of the demand.

²⁰ The share is equal to ratio between yearly solar production and yearly demand

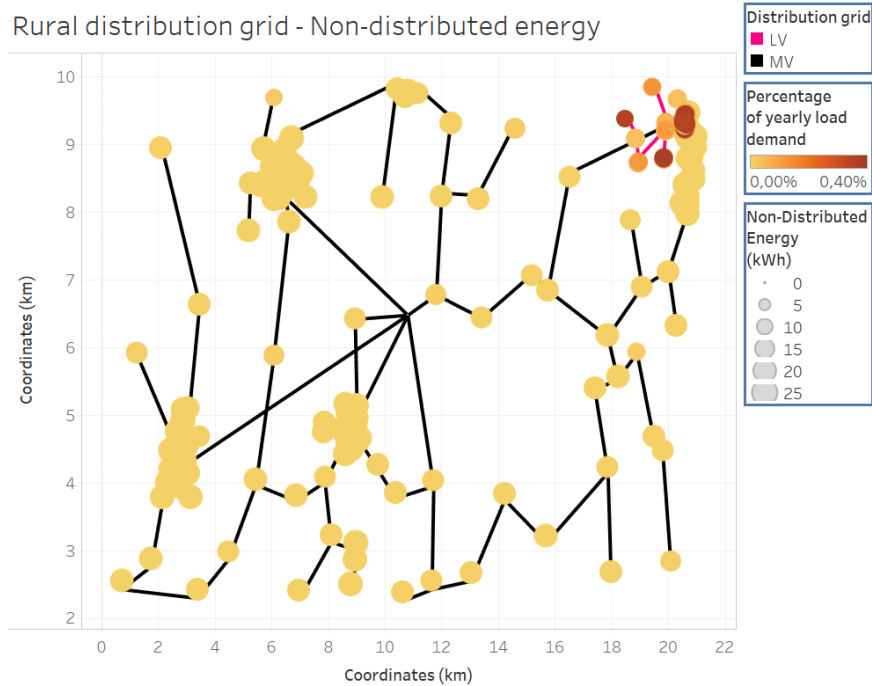


Figure IV-14 – Non-distributed energy in the rural distribution grid (share of solar production: 47 %)

(ii) Results for different share of VRES

The analysis of the different issues has been carried for the three representative distribution grids. The share of solar production is gradually increased in each distribution grid and for every percentage, EUTGRID has computed the dispatch and the resulting voltage values in the distribution grids. Finally, the maximum voltages for the medium-voltage and low-voltage grids can be retrieved. In the low-voltage grid, the maximum voltage values in per unit are always greater than the ones in the medium-voltage grid: there is a second transformer, which connects the medium-voltage to the low-voltage and increases the voltage in per unit. The results are gathered in Figure IV-15. In the graph, the maximum voltage increases faster in the low-voltage grid for all networks. It can be observed that the rural low-voltage is the most sensitive to the integration of solar PVs with an important rise after 25% of solar production. It almost reaches the upper limit of 1,1 p.u. In the medium-voltage grids, only the rural distribution grid sees a visible increase in voltage from 1,047 p.u. up to 1,058. This violation of the limit of 1,05 p.u. occurs when around 30% of demand is covered by solar PVs. For the urban and semi-urban distribution grids, congestions occur before overvoltage issues

when the share of PV production reaches almost 40%. For this reason, after a share of 45% VRES, the voltage values have not been shown in Figure IV-15.

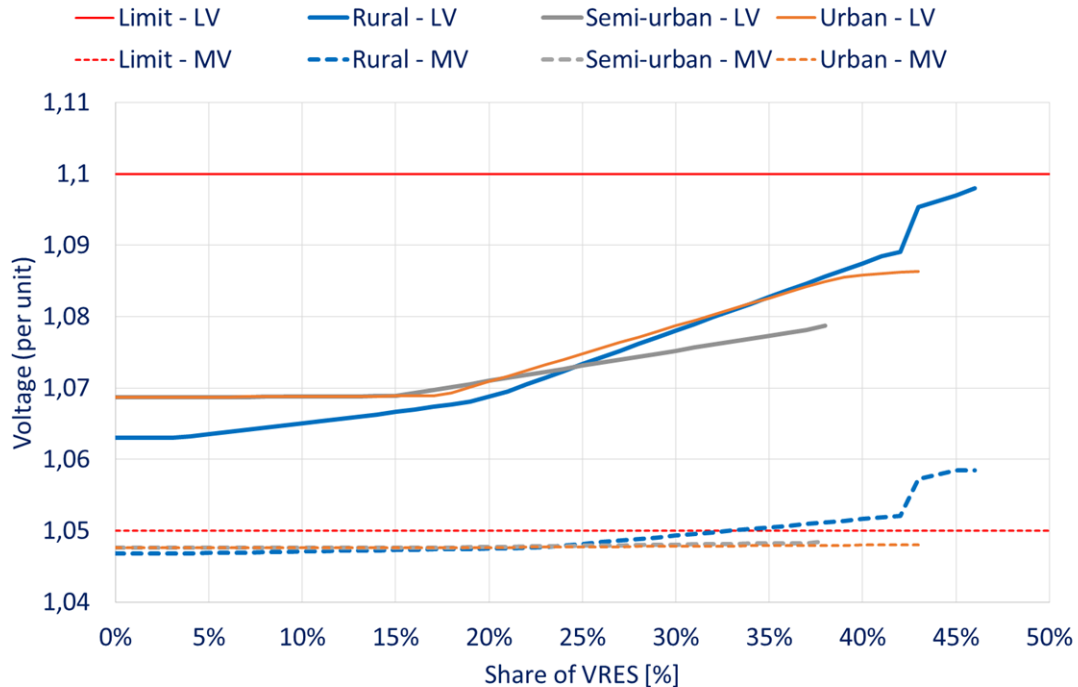


Figure IV-15 – Maximum voltage for each type of grid and each voltage level (100% solar)

IV.3.2 Solving the issues in the different networks

To help the integration of VRES in the distribution grids, the voltage and the congestions issues must be tackled. Different solutions exist which act directly at the voltage level such as the On-Load Tap Changers (OLTC) or the reinforcement. Another group of solutions acts on the energy production to reduce voltage and it can also reduce congestions. It includes VRES curtailment and storage technologies. The operation of the different technologies will be first presented and then a cost comparison will be carried out.

(i) Acting on voltage issues only

Voltage control can be achieved with the use of an OLTC. The OLTC modifies its tap ratio to maintain the voltage at the secondary winding of the transformer within the accepted limits. Figure IV-16 presents the operation of the OLTC in a very simplified situation with under-voltage. The transformer is located at point T and the voltage profile

of the line is shown in orange. It steadily drops from the transformer up to the end of a line (if there is no local production). At one point, it even goes under the voltage limits. To solve this situation, the OLTC increases the voltage at the beginning of the line until the limits are respected: the resulting voltage profile corresponds to the green line. However, with the integration of VRES, over-voltage situation can occur and similarly to the over-voltage case, the OLTC will change its settings to respect the limits. This is shown in Figure IV-17 with the consequence that the OLTC must reduce the voltage at the secondary of the transformer.

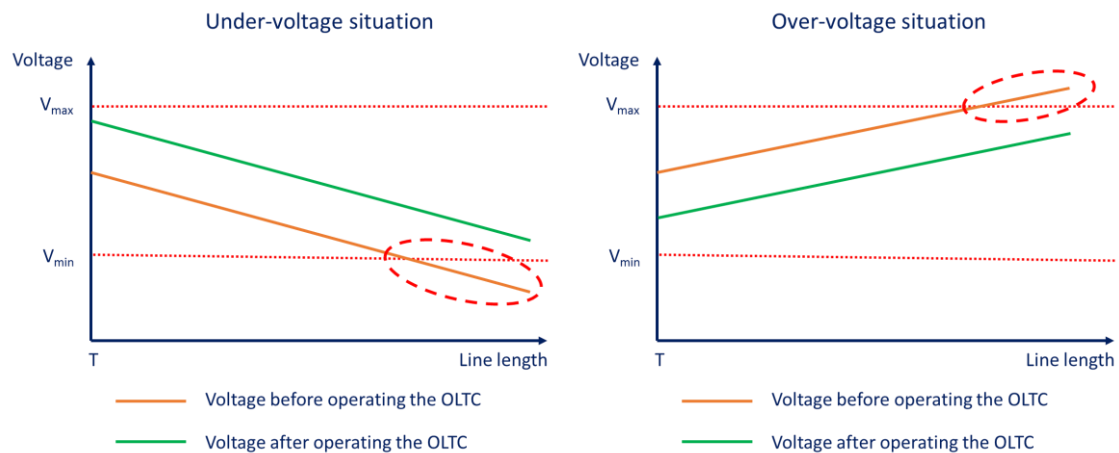


Figure IV-16 – Simplified voltage profiles in case of under-voltage and resulting OLTC operation.

Figure IV-17 – Simplified voltage profiles in case of over-voltage and resulting OLTC operation.

In EUTGRID, an OLTC with 9-tap is implemented [188] and no losses are considered. The different setting of the tap ratio can change the voltage from [-7,5%; -5%; -3,5%; -1,75%; 0%; 1,75%; 3,5%; 5%; 7,5%].

Now, the OLTC replaces the transformer between high-voltage and medium-voltage grids and we can recall the case with 40% of solar production: overvoltage occurs during the mid-day as illustrated previously in Figure IV-13 for node B_77 of the medium-voltage grid. In Figure IV-18, the voltage at this node with no solution is visible in a green dotted line while the resulting voltage after OLTC operated is drawn in green regular line. The OLTC has modified its settings twice in the days to respect the limits: first, at hour 11, the tap ratio was reduced similarly as in the example presented in Figure IV-17. Then, at hour 18, the set ratio is put back to its initial state to avoid a possible undervoltage situation (the situation illustrated in Figure IV-16). The OLTC is suitable to solve under- and over-voltage situations.

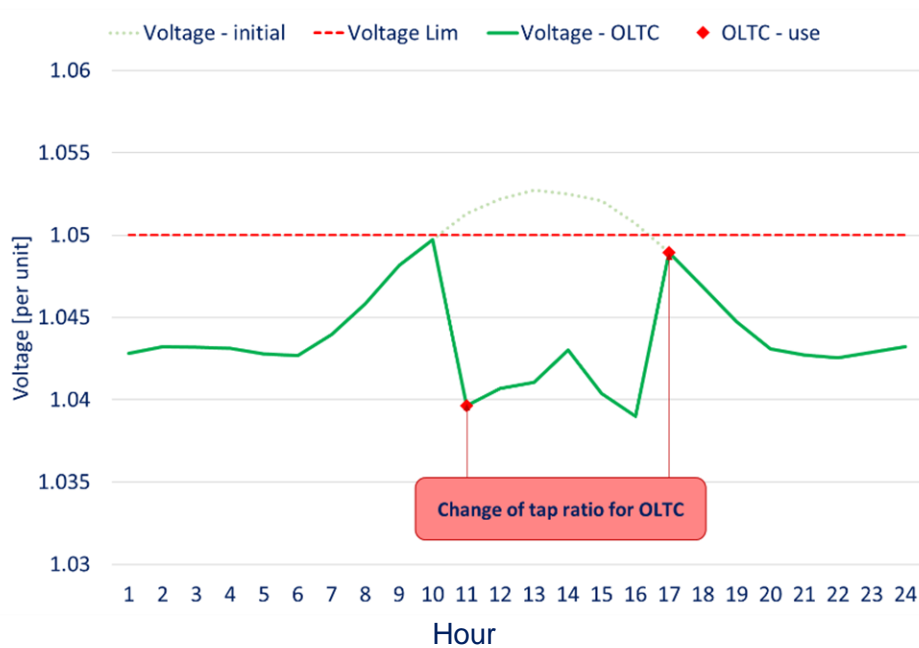


Figure IV-18 – OLTC: Voltage at one node belonging to the medium voltage grid in summer (day n°5)

Finally, the maximum voltages for low-voltage and medium-voltage grids are retrieved for each percentage integration of solar PVs in the rural distribution grid in Figure IV-19. The voltage values before operating the OLTC are in orange and after operating the OLTC in blue. Once the share of solar production exceeds 30%, the OLTC modifies its tap ratio and maintains the voltage at the medium-voltage grid under 1,05 p.u. until the share reaches 45%. It can be observed that the voltage at the low-voltage grid stays around 1,08 p.u. and when the share of solar production reaches 44%, the maximum voltage increases up to 1,086 p.u. The consequence is that the OLTC must modify more often its tap ratio as the share increases: Figure IV-20 shows a bar graph with the number of yearly modifications versus the share of VRES. When the share of VRES is around 30%, only 35 changes of tap ratio are required while with a share of 45%, the number of changes is 10 times higher. However, congestions still appear when the share of solar production increases too much. Those cannot be solved with the only use of OLTC.

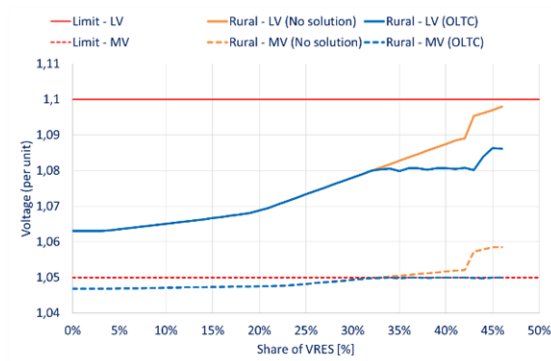


Figure IV-19 – Maximum voltage before operating the OLTC (orange) and after operating the OLTC (blue) for rural grid and each voltage level (100% solar)

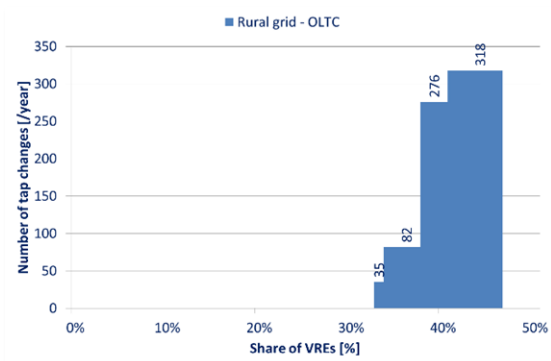


Figure IV-20 – Number of yearly modifications of tap ratio for the OLTC for rural grid (100% solar)

Another way to reduce the overvoltage situation is to reinforce the grid. It has also the advantage of alleviating the congestions. In EUTGRID, the same grid investment mechanism as presented in chapter II is applied but with some differences: it is only restricted to the distribution grids and the most congested lines are reinforced until there are no more NDE and without considering any payback period.

The hourly voltage at node B_77 is drawn in green in Figure IV-21 together with the voltage without any solution in dotted line. The resulting effect of the reinforcement is an important reduction of the maximum voltage under the limits. However, the mean value of the voltage is slightly greater than the mean value of the initial state. It is a consequence of a better grid which allows more power flows and lower voltage drops from the transformer up to the end of the lines.

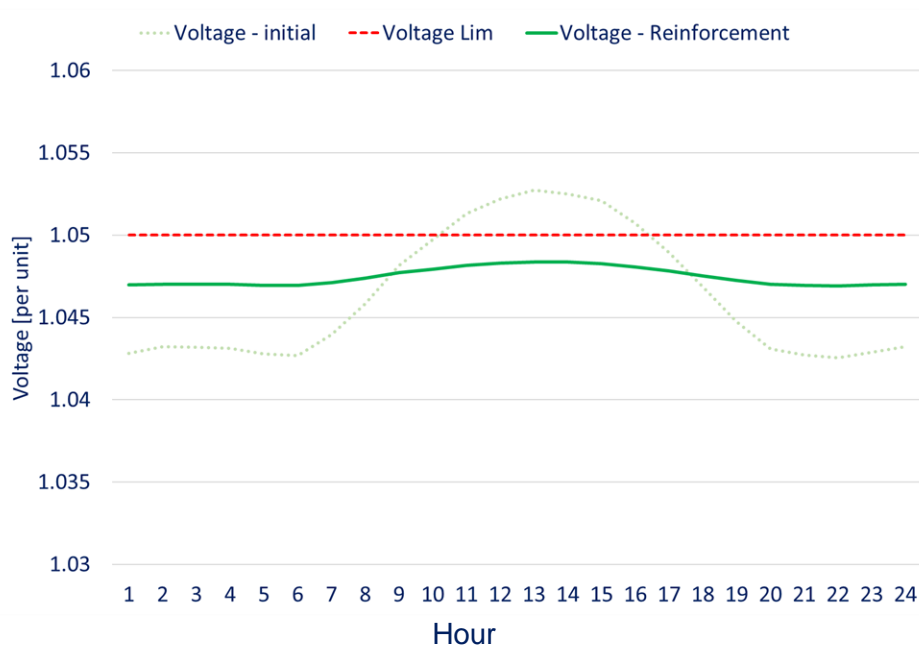


Figure IV-21 – Reinforcement: Voltage at node B_77 belonging to the medium voltage grid in summer (day n°5)

The method of reinforcement described here is a simplified version of reinforcement studies which require a detailed description of the grid and an adequate planning of these reinforcements [145]. Within the described framework, all the representative distribution grids manage to integrate the rising solar production up to 100% while keeping the voltage in the limits. However, the reinforcements need differ between each one. For each percentage of solar integration, EUTGRID reinforces the grid and the results of these needs are illustrated in Figure IV-22. In this graph, rural additional reinforcements are shown in blue, semi-urban ones in grey and urban in orange. For all of these grids, the length of the reinforcement rises as the integration of solar increases. Because of its long lines, the rural grid must reinforce more than 30km and these needs increase steadily from 30% share of VRES up to 60%. After this point, no more additional reinforcements are needed. Concerning the urban grid, there are fewer reinforcements thanks to its robustness and its shorter lines. Almost up to 70% of renewable integration, almost no reinforcements are made: it represents less than 2km. However, after this point, the grid needs to be increased two more times at 70% and at 90% to reach around 10km of additional reinforcements. Finally, the semi-urban distribution grid combines the characteristics of the two previous representative grids with additional requirements starting at 40% to reach up to 20 km of reinforcements. These requirements are the consequences of its long lines.

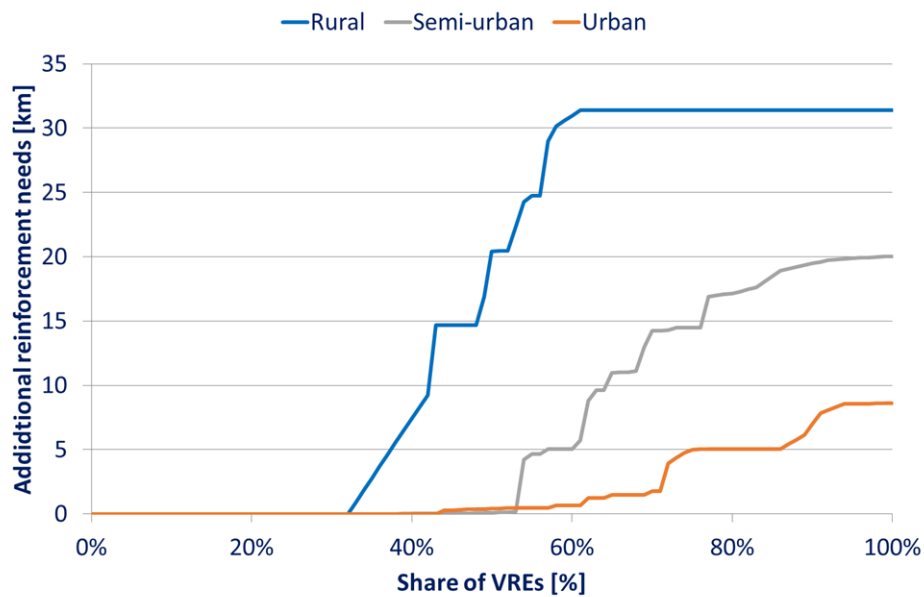


Figure IV-22 – Reinforcement needs for the representative distribution grids with only solar production [km]

(ii) Acting on energy production

As the solar production provokes over-voltages in the distribution grid, curtailing the production is another way to limit those violations. To illustrate that operation, the same node as before (for the summer day n°5) is again considered. In Figure IV-23, the hourly load is drawn in blue and the solar energy injected to the grid is shown in yellow. The grey area corresponds to the spilled energy. As expected the solar energy is curtailed during the midday when over-voltages occur if there is no solution. For this particular day, 35% of the solar energy has been spilled so that voltage stays within the limits. Figure IV-24 shows the resulting voltage kept below 1,05 p.u. in green while the initial one is drawn in a dotted line.

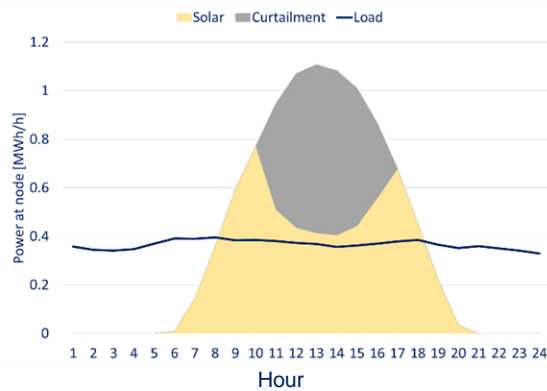


Figure IV-23 – Curtailment: Energy mix at node B_77 belonging to the medium voltage grid in summer (day n°5) [MWh/h]

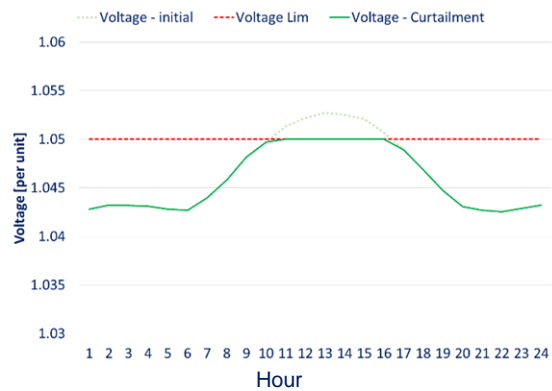


Figure IV-24 – Curtailment: Voltage at node B_77 belonging to the medium voltage grid in summer (day n°5) [p.u.]

The main drawback of curtailing the VRES production is that this energy is lost. In Figure IV-25, the percentage of energy curtailed has been shown for the representative distribution grids (rural in blue, semi-urban in grey and urban in orange). For all the different grids, the spilled energy follows an exponential curve as the share of VRES increases. In the rural grid, 80% of the solar energy must be lost to cover 100% of the yearly demand. For the urban and semi-urban grids, around 20% must be shed. Therefore, in this rural grid, if VRES curtailment is the only solution considered, new VRES capacities will probably never be installed: either curtailment is not reimbursed, and losses will be too important for producers, or if curtailment is reimbursed then other cheaper solutions should be considered.

As a result from the important decreases of PV modules prices, a new trend begins to emerge, which consists of over-sizing the solar panels [189], [190]. It costs less to increase the size of the panels and the overall costs (including fixed and variable ones) are lower. Finally, it enables the PV panels to produce during more hours while reaching its maximum power earlier in the day (for example, it could be a limit from the grid). Therefore, it will produce more energy than a PV panel whose maximum peak does not exceed the limit. In this context, the increase of energy produced induced by the oversizing exceeds the resulting curtailed energy.

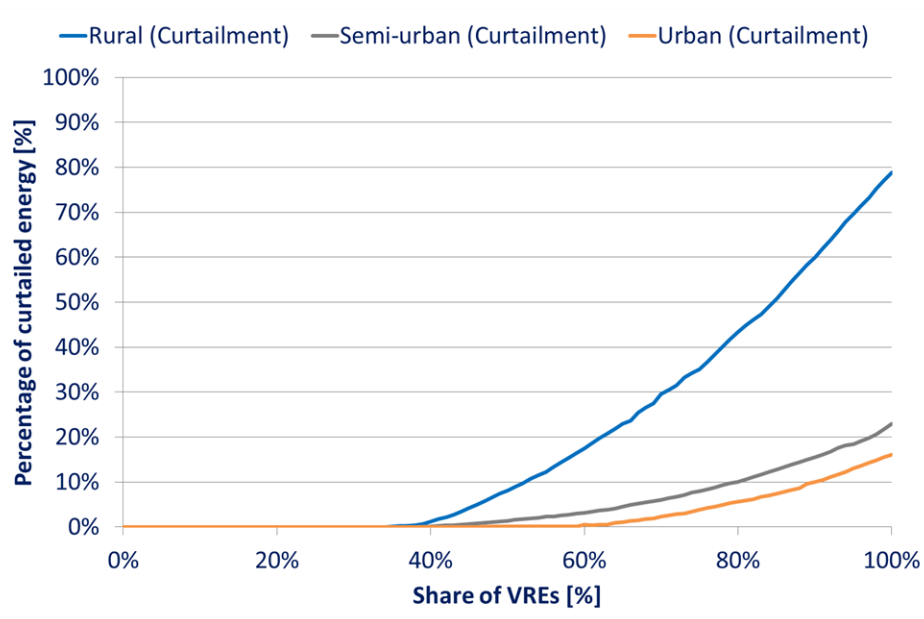


Figure IV-25 – Yearly energy curtailment in percentage of total solar energy for the representative distribution grids.

One solution would be to use storage batteries that charge the surplus of energy from VRES sources and discharge it when it is the most needed. In EUTGRID, for simplification, batteries capacities correspond to lithium-ion technologies and are distributed following the population. Moreover, the installed capacities are equally increased until there is no more NDE in the distribution grid. The operation of the storage capacities is illustrated in Figure IV-26 for the summer day n°5 at the same node as previously analysed. In this graph, the demand is included in blue line and the solar energy is shown in yellow. The charging period of the batteries corresponds to the hatched area in dark blue while the discharging period corresponds to the hatched area in light blue. During the period with high solar production, the batteries are being charged to alleviate the congestions and the overvoltage during these hours. Otherwise, because of the implemented strategies, storage capacities are being discharged during the low solar production and during off-peak hours: batteries must have the same state of charge at the beginning and at the end of the day. The resulting voltage is drawn in green in Figure IV-27 and it can be observed that the limits are respected.

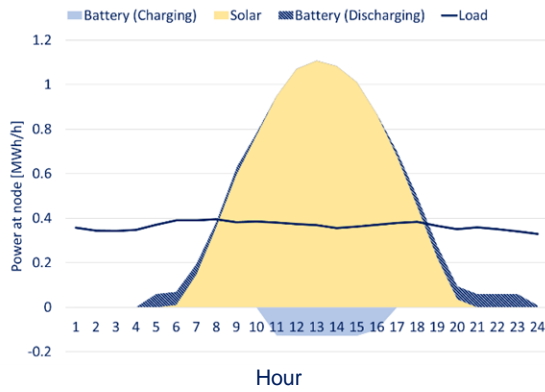


Figure IV-26 – Storage: Energy mix at node B_77 belonging to the medium voltage grid in summer (day n°5) [MWh/h]

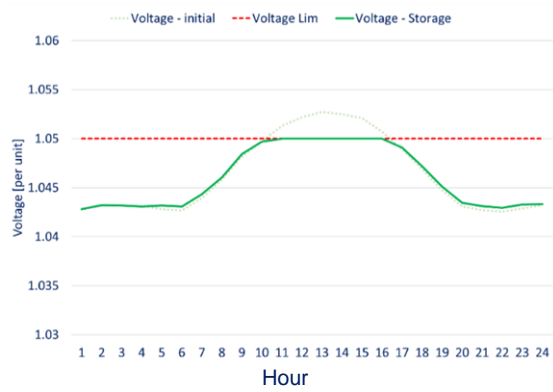


Figure IV-27 – Storage: Voltage at node B_77 belonging to the medium voltage grid in summer (day n°5) [p.u.]

Figure IV-28 shows the ratios of energy charged by storage technologies and VRES energy produced for the distribution grids and for each percentage of VRES integration (rural in blue, semi-urban in grey and urban in orange). The results show that the amount of energy charged by batteries increases in all grids. Compared to curtailment of VRES generation, charging of batteries capacities represents less energy with less than 20% of VRES energy produced.

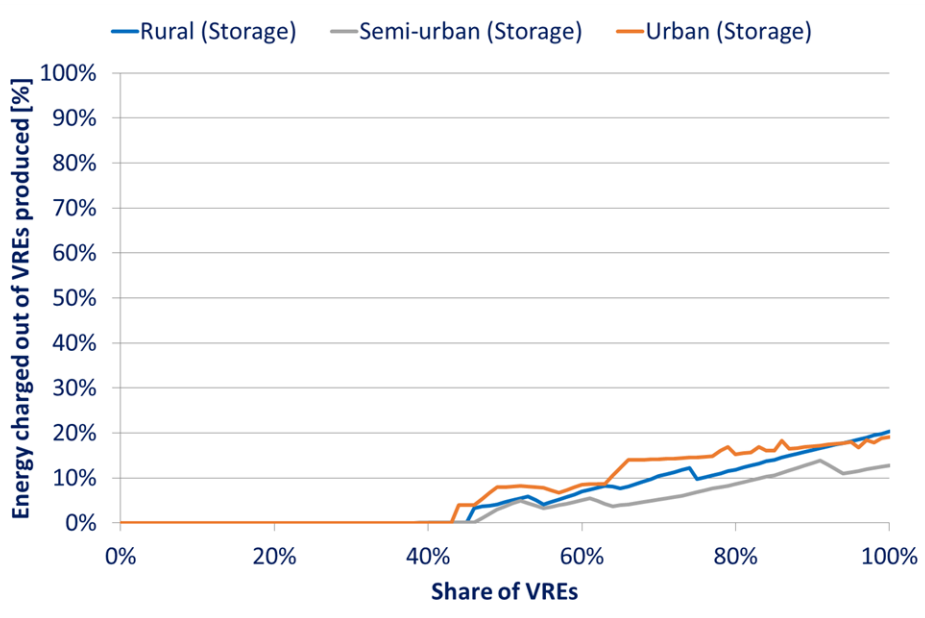


Figure IV-28 – Percentage of energy stored compared to the yearly VRES production for the representative distribution grids [%]

(iii) Cost comparisons

To understand in which conditions the different presented solutions can be preferred, a technical and economic analysis is performed. In this study, the cost of each solution is calculated for different scenarios of solar integration using a Monte-Carlo approach. 30-year periods are considered. First, the cost parameters are presented.

(iv) OLTC – cost parameters

The OLTC is only implemented in the rural grid as it is the only grid where over-voltages occur. It has also been assumed that it was already installed. Therefore, there are no initial investment costs. The cost parameters for the OLTC are listed in Table IV-1 and taken from [191]. The transformer rating is equal to 80 MVA and because of the changes in tap ratio, the maintenance must be done after 10 000 modifications. In that case, the maintenance cost corresponds to half of the total investment for the transformer.

(v) Reinforcement – cost parameters

In distribution grids, the cost of reinforcement mostly depends on the length line and not the capacity needs. The value of the investments also varies with the typology of the grids. In this case study, the cost of reinforcement is considered to be 150 \$/m in urban and semi-urban areas and 96 \$/m in rural areas [192]. It has also been assumed that the reinforcements do not need any maintenance during the 30-year scenario. Another hypothesis is also included: a line is reinforced only once during the scenario. Therefore, the planning anticipates the needs.

(vi) Curtailment – cost parameters

Previously, the results have shown that the amount of curtailed energy could be very important, and it could slow down the integration of solar energy in the energy system. Therefore, this shed energy is assumed to be reimbursed by the distribution system operators and in this case-study, the French feed-in tariff will be used. It is equal to 200 \$/MWh [193].

(vii) Storage – cost parameters

The storage technologies consist of stationary batteries with lithium-ion. The costs are decomposed in two parts: the investments costs for each installed kW and the usage costs for charging. The cost per unit of newly installed batteries is equal to 136 \$/kW and is taken from POLES database for the year 2015. The cost per unit of charged energy is also taken from POLES database for the year 2015 and is equal to 2.15

\$/MWh. Finally, the technical lifetime of the installed batteries is set to 15 years [194], [195].

(viii) Results

The different costs for the solutions presented are gathered in Table IV-1 and the associated the net present value can be calculated for each solution and the different paths of solar integration using a Monte-Carlo approach. The discount rate used is set to 8% as proposed by the French Regulatory Commission of Energy [196].

Table IV-1 – Costs parameters for the different solutions

Solution	Parameter	Value
OLTC	Transformer rating	80 MVA [191]
	Cost (new transformer)	11,9 k\$/MVA [191]
	Operations before maintenance	10 000 [191]
Reinforcement	Rural reinforcement	96 \$/m [192]
	Urban and semi-urban reinforcement	150 \$/m [192]
Curtailment	Cost (spilled energy)	200 \$/MWh [193]
Storage	Capacity costs	136 \$/kW (from POLES' database)
	Usage costs	2.15 \$/MWh (from POLES' database)

The Monte-Carlo approach consists of randomly choosing a high number of scenarios over a period of 30 years. It was also assumed that the share of VRES always increases to reach the target percentage. In this analysis, for each target percentage, around 500 000 unique scenarios were randomly selected: it corresponds to a margin of error of 0,23% with a confidence level of 99,9% [197]. Finally, Figure IV-29 gathers the mean present value for each solution and for each representative distribution grid. The y-axis corresponds to the share of VRES at the end of the 30-year period. From top to bottom, the costs are presented for rural, semi-urban and urban grids. Solar curtailment is shown in green; reinforcement is in red and storage in orange. Because the OLTC has never been replaced, there is no associated cost and it is not visible on this figure. In all grids, three parts can be analysed but it is more noticeable in the rural distribution grid. The first part begins from 0% to around 35%: no solutions are needed. Then from 35% to around 65%, the solutions have similar costs. It can be noted that the cost for the curtailment exponentially increases while the cost of the storage rises by steps. Finally, the cost of reinforcement steadily increases but for a high share of VRES, reinforcement becomes the least-costly option.

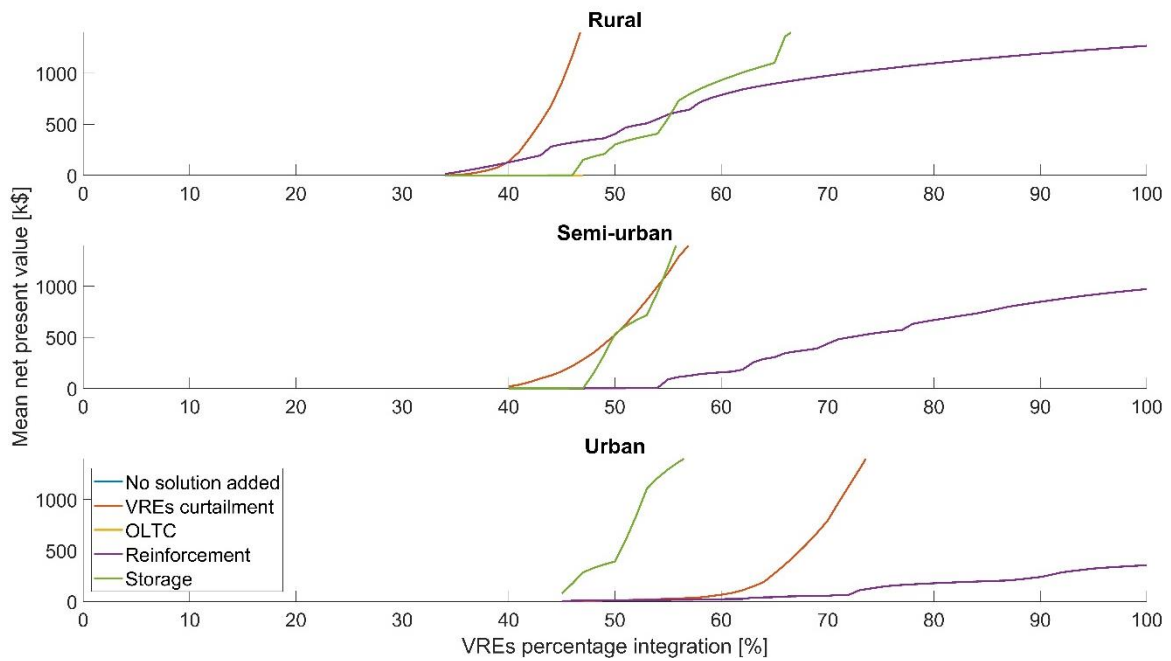


Figure IV-29 – Mean net present value for the different solutions and for each representative distribution grids [k\$]

Between the different distribution grids, the reinforcement is the most favoured option if a high share of renewable is targeted. However, if the integration reaches around 50%, storage capacities seem to be a good choice in rural areas while curtailing VRES production seems to be preferable in urban areas.

The histogram of the least cost solutions shown in Figure IV-30 confirms these conclusions. From top to bottom, the costs are presented for rural, semi-urban and urban grids. When there is no overvoltage or congestions issues, no solutions are implemented, and it corresponds to the areas in blue.

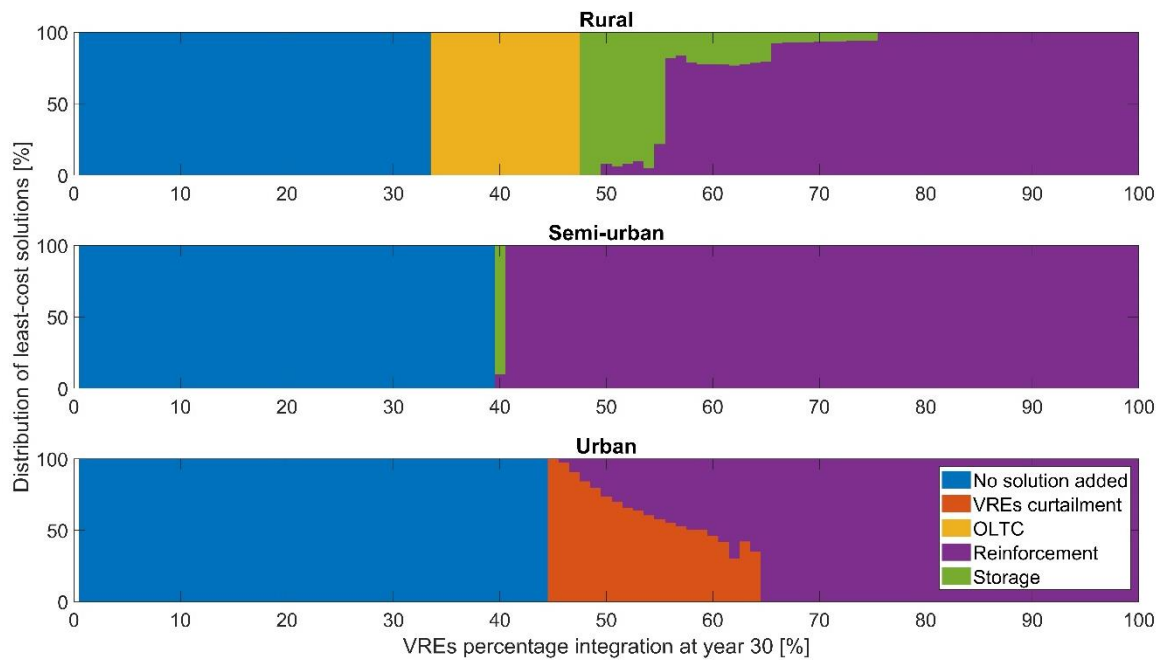


Figure IV-30 – Histogram of the least-costly solutions for each representative distribution grids [%]

As rural distribution grid has some overvoltage issues, the OLTC is used (area in light yellow) until some congestions appear. Then storage solutions are the cheapest from 47% up to 55% of solar integration (illustrated in red). However, from 55% to 65%, in half of the scenarios, reinforcing the rural grid is cheaper (areas in light orange). In these scenarios, there is a fast integration of VRES at the beginning of the 30-years period. Therefore, the cost of installing the storage capacities plus the cost of replacement 15 years later exceed the cost of reinforcement. With higher share of VRES, reinforcement is the only acceptable solution.

For the semi-urban grid, storage capacities are preferred only at 40% share of VRES. Otherwise, reinforcing the grid is the least costly option. Finally, for the urban distribution grid, curtailing the VRES sources is the cheapest solution if the targeted share ranges from 45% up to 65% (area in green). Meanwhile, reinforcement progressively becomes the cheapest solution.

In the analysed case study, the VRES sources only consisted of solar production but wind turbines are also included in the medium-voltage grid. A sensitivity analysis has been performed with different energy mix between solar and wind. It is available in Annex E. The results show that without any solution, the rural distribution grid can only integrate 30% of VRES while for urban and semi-urban grids, it can reach up to 100%. Concerning the different solutions, reinforcement is the preferred one for high share of

renewable and for all distribution grids. The storage capacities seem to be more interesting when solar production is higher than wind production. It can better store the surplus of energy and discharge during the off-peak periods. Finally, curtailing production is a common solution in the urban grid but also in the rural grid when wind production is high.

All the presented outcomes underline the fact that with the integration of VRES, the distribution grids face issues which were not taken into account by default in EUTGRID. These issues consist of over-voltage and congestions. Different solutions exist such as OLTC, storage capacities, curtailment and reinforcement. However, because of the aggregation made in EUTGRID, these solutions directly compete with more efficient technologies and the consequences are an under-estimation of the associated costs.

IV.4 Distribution grids representation in POLES

The chapters II and III have shown that EUTGRID can be coupled with POLES. This coupling helps to have better insights on the evolution of the transmission grid and its impacts on the power system. The new version EUTGRID&D (European Transmission Grid and Dispatch with Distribution grid representation) now includes representative distribution grids and can also be coupled with POLES. The same scenario as scenario "Clim – Dev" will be implemented and analysed, referred to as scenario "Clim – Distrib". First, specific conditions for the scenario are described so that the simulation can be run in an acceptable duration. Then the results will be compared for the energy mix and the flexibility options for three different regions. Finally, the transmission grid infrastructure evolution will be analysed.

IV.4.1 Specific conditions for the coupling with POLES

(i) Restriction of distribution grid representation

To cover all the European demand, EUTGRID&D needs almost 90 000 representative distribution grids. It would be possible to include them in EUTGRID&D with the representative distribution grids described earlier but the computing time would be unacceptable with today's computers. To illustrate this increase in time computation, EUTGRID&D was run for one year with different number of representative distribution grids. Figure IV-31 shows the computation time versus the number of representative distribution grids included: it takes less than 3 minutes to run with only the transmission

grid but with three distribution grids, the simulation needs 21 minutes to end²¹. Each time three more distribution grids are added to the model the simulation is being increased by at least 21 minutes.

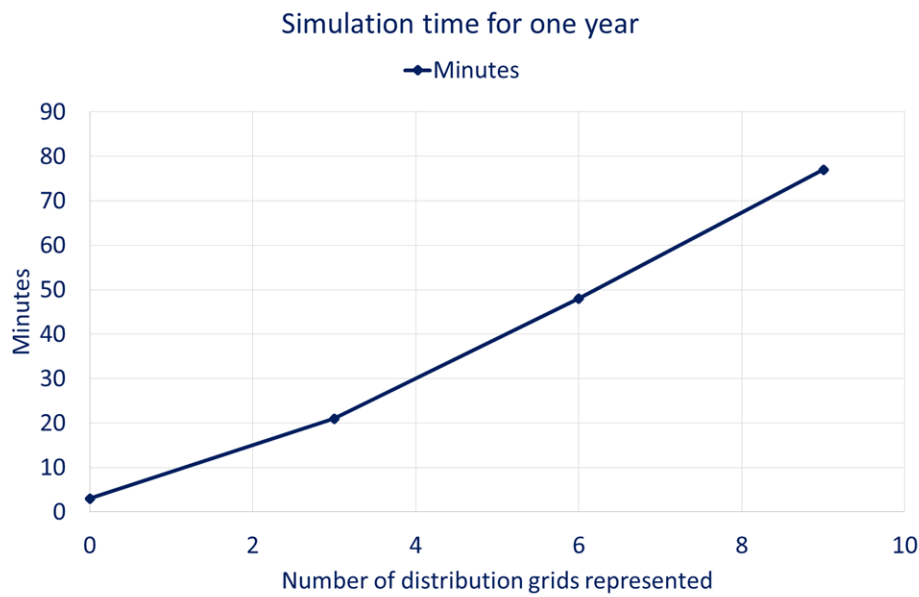


Figure IV-31 – Computation time for running EUTGRID&D for one year and the same scenario with different number of distribution grids [minutes]

For this reason and the fact that adding new distribution grids will also multiply the quantity of results, EUTGRID&D will only include the three representative distribution grids (rural, semi-urban and urban) presented in section IV.3.

The rural distribution grid will be connected to node “16_FR” located in South of France where most of the solar PV are installed. The semi-urban distribution grid will be connected to the node “26_FR” located in the North of France where most of the wind turbines are build. Finally, the urban distribution grid will be connected to Ile-de-France which is the most populated French region.

(ii) Transmission Grid Investment Mechanism

In this scenario, the distribution grids will not be reinforced. As it is very costly to reinforce these distribution grids, the planning of reinforcements is done as far in time as possible. Based on the analysis of the representative distribution grids in the previous section, it can be observed that the grids are well sized. The assumption of no reinforcement can

²¹ EUTGRID&D was run on DELL laptop with Intel Core i7, a processor 2.80 GHz and 8 Go of RAM.

be considered relevant for the first 30-40 years of the simulation. For the rest of the simulation, it was also assumed that no reinforcement is done because it would need a very long time to run the simulations. Moreover, the scenario is only run from 2000 to 2050. This hypothesis means that the Grid Investment Mechanism will only be limited to the European transmission grid.

IV.4.2 Impacts of representing the distribution grids

As mentioned earlier, the scenario "Clim – Distrib" is run with EUTGRID&D coupled with POLES with the same climate energy policy as in the scenario "Clim – Dev". The results are compared region by region for their local emissions and the use of flexibility options. In the next section, the three distribution grids will be associated to the region where they are connected. The Ile-de-France region with the representative urban distribution grid is referred to "Region IDF". The North region with the representative semi-urban distribution grid is referred to "Region HDF" (Hauts-de-France). The South region with the representative rural distribution is referred to "Region PACA" (Provence-Alpes-Côtes d'Azur).

(i) Emissions in the regions

1) Calculating method

The calculation of CO₂ emissions in each region will use the same hypotheses as in POLES: only the fossil production is considered to emit CO₂ emissions. Within the fossil production, production from coal pollutes more than production from oil. Finally, production from gas is the cleanest energy. The different carbon content for each fossil fuel is gathered in Table F-4 and are taken from POLES' database.

The emissions in a region are calculated for the energy supplied in this particular region without taking into account import and export [198]. The total local emissions E_i^{tot} is calculated using the CO₂ emissions factors defined in Table F-4 and the local production for each fuel (see equation (28)).

$$\text{For each region } i \quad E_i^{tot} = C_{coal} * P_i^{gas} + C_{oil} * P_i^{oil} + C_{gas} * P_i^{gas} \quad (28)$$

2) Results

For each region, the emissions are calculated in MtCO₂eq and two scenarios are compared: the scenario "Clim-Dev" with the distribution grids aggregated and the scenario "Clim-Distrib" with three representative distribution grids represented. The results are displayed in Figure IV-32 for the "Region IDF", in Figure IV-33 for the "Region

HDF" and in Figure IV-34 for the "Region PACA". In green, the scenario "Clim-Dev" and in orange, the scenario "Clim-Distrib". It can be observed that the yearly emissions follow the same behaviour in all regions, but they are greater in scenario "Clim-Distrib". This rise can be explained because of the increased detail of the distribution grid, new congestions and voltage level arise because of VRES production and there is a stronger need for back-up capacities which are more polluting.

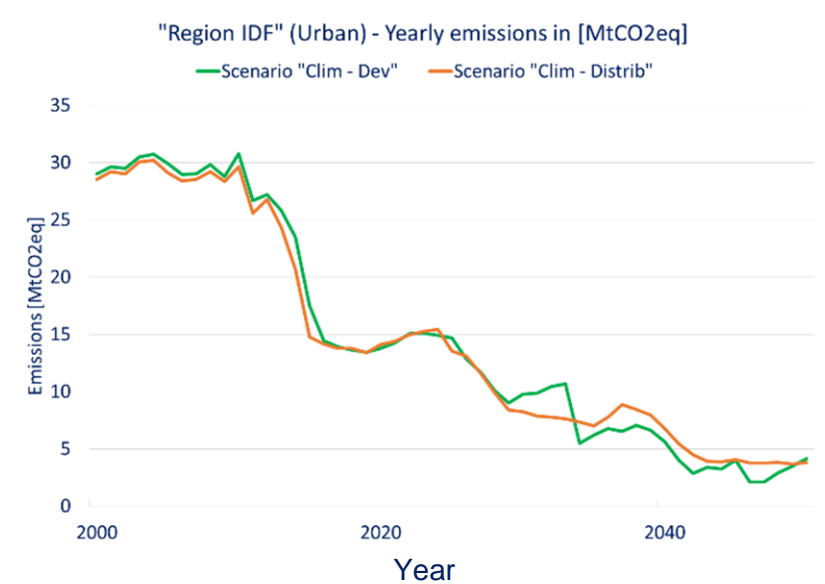


Figure IV-32 – Yearly emissions in "Region IDF" for the two scenarios "Clim-Dev" and "Clim-Distrib" [MtCO₂eq]

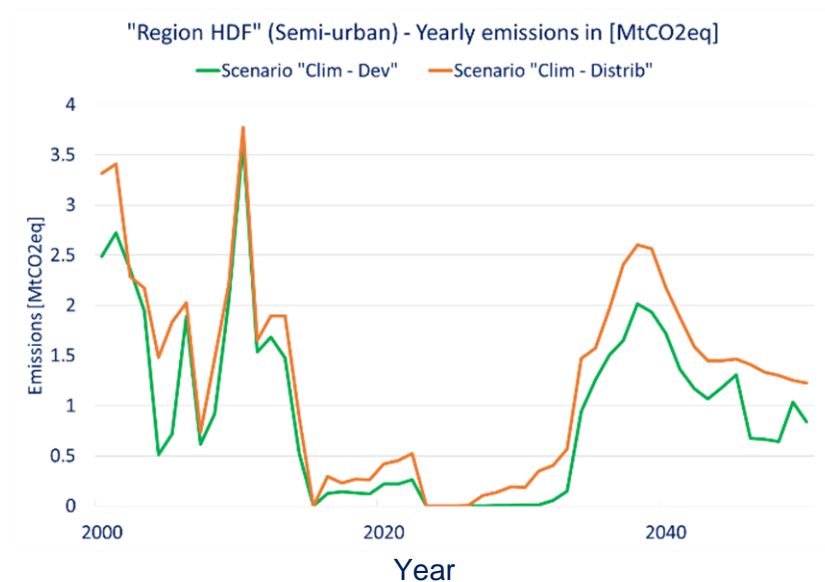


Figure IV-33 – Yearly emissions in "Region HDF" for the two scenarios "Clim-Dev" and "Clim-Distrib" [MtCO₂eq]

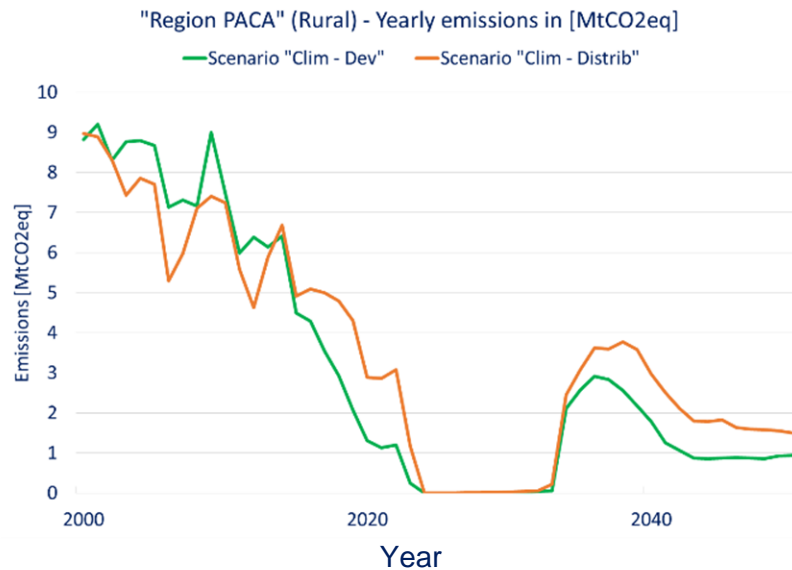


Figure IV-34– Yearly emissions in "Region PACA" for the two scenarios "Clim-Dev" and "Clim-Distrib" [MtCO₂eq]

(ii) Energy mix

In the two regions "HDF" and "PACA", it can be observed that the emissions decrease until 2020 to rise again and then stabilize in 2050. To understand these fluctuations, the energy mixes in the two scenarios "Clim-Dev" and "Clim-Distrib" are displayed for the year 2010, 2030 and 2050 respectively in Figure IV-35 for "Region IDF", in Figure IV-36 for "Region HDF" and in Figure IV-37 for "Region PACA". The production is distinguished between nuclear, fossil with no CCS and with CCS, hydro, renewable (from geothermal and biomass) and VRES. Imports and exports are also shown.

The figures highlight the different situations for the analysed regions. "Region IDF" with the urban distribution grid relies on importations to supply its increasing demand. The production from fossil fuel with no CCS is being replaced by more VRES production and fossil technologies with CCS. In the "Region HDF", the nuclear phase out after 2030 has pushed to introduce more VRES production and fossil technologies with CCS. In the "region PACA", the same trend occurs but it managed to become a net exporter in 2100.

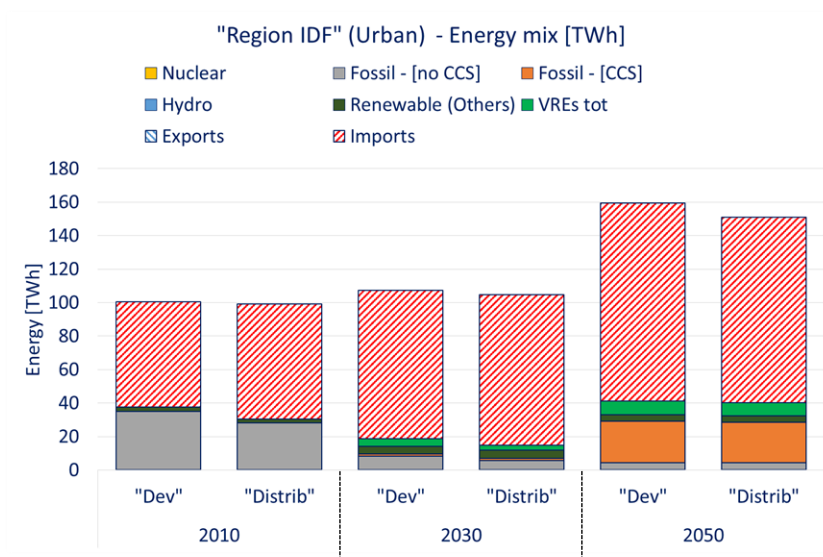


Figure IV-35 – Energy mix in 2010, 2030 and 2050 in "Region IDF" for the two scenarios "Clim-Dev" and "Clim-Distrib" [TWh]

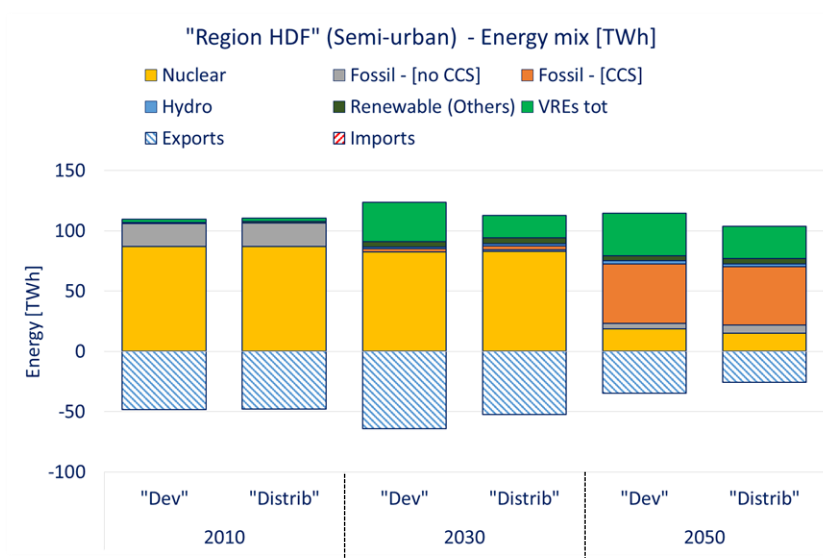


Figure IV-36 – Energy mix in 2010, 2030 and 2050 in "Region HDF" for the two scenarios "Clim-Dev" and "Clim-Distrib" [TWh]

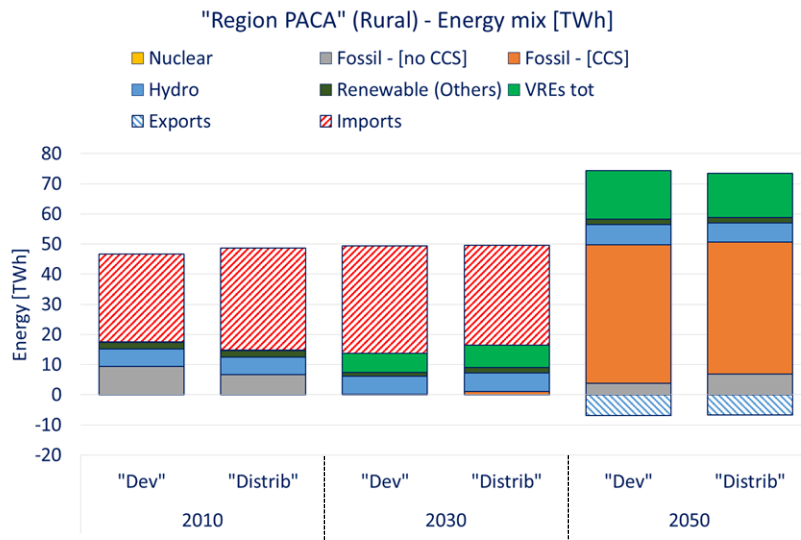


Figure IV-37 – Energy mix in 2010, 2030 and 2050 in "Region PACA" for the two scenarios "Clim-Dev" and "Clim-Distrib" [TWh]

Between the two scenarios, some distinctions can be observed: there are less importations and lower exportations in "Clim-Distrib" than in "Clim-Dev"; production from fossil fuel with no CCS also increased. These results indicate that the representation of the distribution grids modify the dispatching as more issues related to congestion and over-voltage need solving. It suggests also that a limited integration of VRES in the distribution grids reduces the exchanges between the neighbouring regions.

(iii) Flexibility options

In the distribution grids, the flexibility options are the only ways of solving the congestion and overvoltage issues. The analysis will focus on the storage technologies and the use of demand response. Curtailment of VRES production is also available but, in the scenario "Clim-Distrib", there is no spilled energy. If compared with "Clim-Dev", the "region PACA" had to curtail up to 6 TWh of VRES energy.

To illustrate the changes between the two scenarios, Figure IV-38 to Figure IV-40 show the production from storage technologies from 2000 to 2050 and Figure IV-41 to Figure IV-43 display the demand shifted by demand response technologies during the same period. For both storage and demand response, the produced energy is higher for "Region IDF" which is more populated and in similar levels for the two other regions.

Concerning the production from storage technologies, it can be observed that it increased similarly in all regions and for the two scenarios. However, there is a delay between "Clim-Dev" and "Clim-Distrib" and it is caused by the allocation of the stationary

batteries and V2G technologies in the distribution grid. A small part of the regional capacities is distributed among the nodes in the distribution grid. During the dispatch, the use of these storage capacities is limited by the congestions and the overvoltage issues in the distribution grid. Therefore, their usage is being reduced compared to the scenario "Clim-Dev".

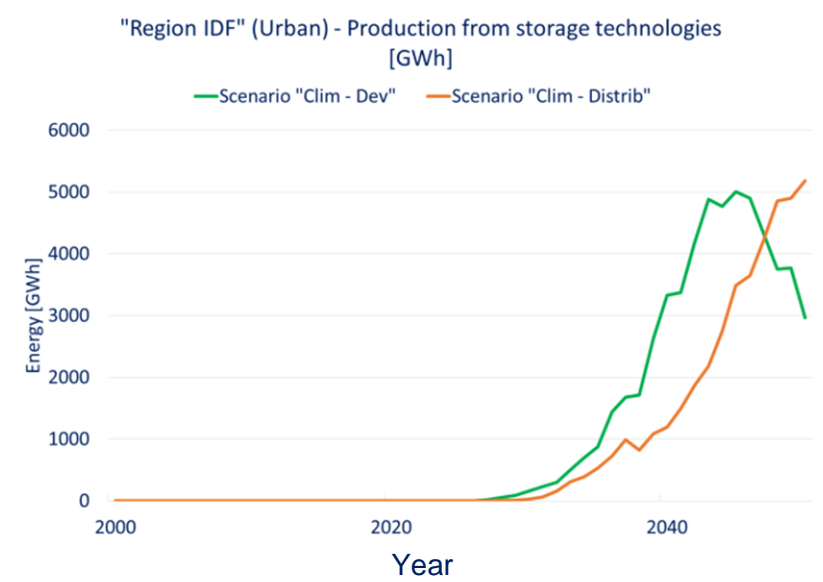


Figure IV-38 – Production from storage technologies in 2010, 2030 and 2050 in "Region IDF" for the two scenarios "Clim-Dev" and "Clim-Distrib" [GWh]

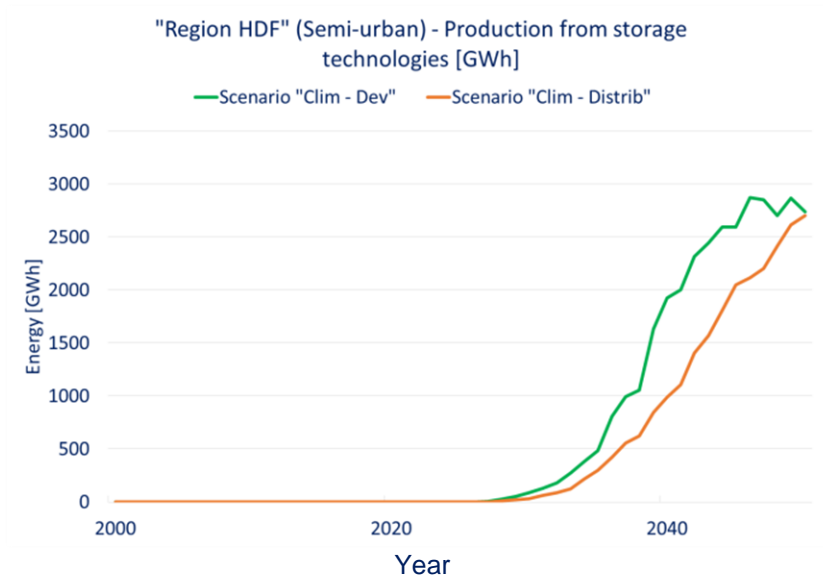


Figure IV-39 – Production from storage technologies in "Region HDF" for the two scenarios "Clim-Dev" and "Clim-Distrib" [GWh]

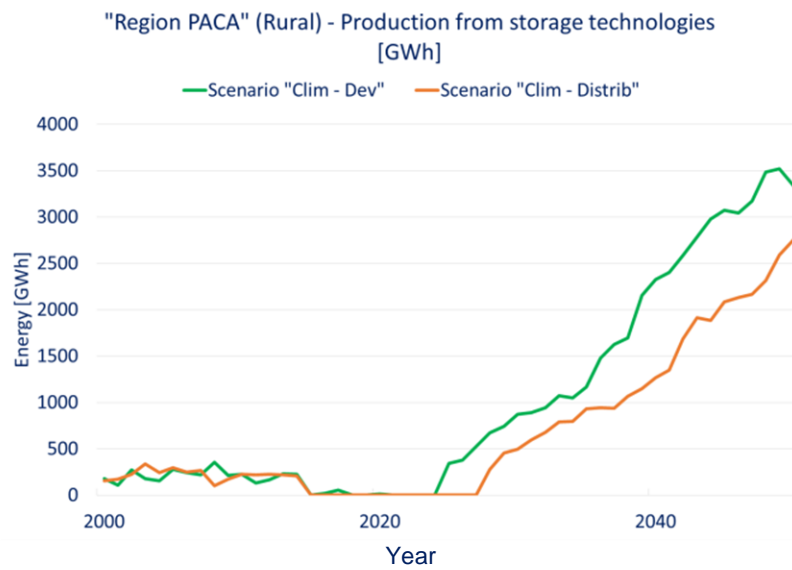


Figure IV-40 – Production from storage technologies in 2010, 2030 and 2050 in "Region PACA" for the two scenarios "Clim-Dev" and "Clim-Distrib" [GWh]

A similar result can be observed when the yearly load shifting is being analysed for the two scenarios and for the different regions. In the Figure IV-41 to Figure IV-43, the amount of energy shifted is also lower. As the demand response potential is only limited to 5% of the peak demand, its usage is still needed, and the difference becomes less visible than with storage technologies.

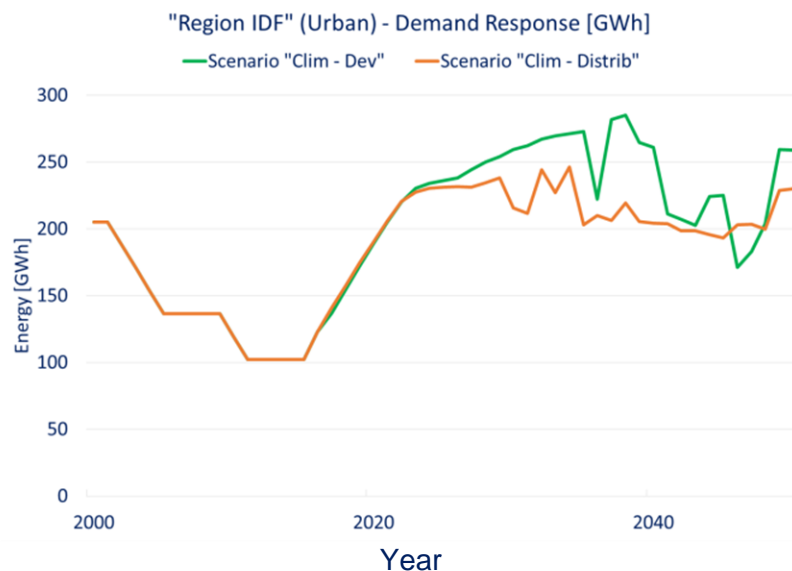


Figure IV-41 – Shifting from demand response in 2010, 2030 and 2050 in "Region IDF" for the two scenarios "Clim-Dev" and "Clim-Distrib" [GWh]

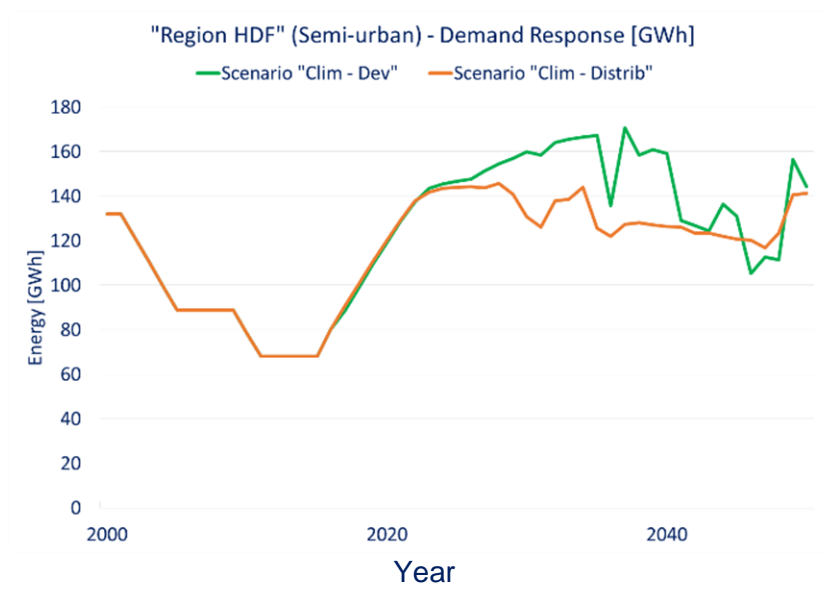


Figure IV-42 – Shifting from demand response 2010, 2030 and 2050 in "Region HDF" for the two scenarios "Clim-Dev" and "Clim-Distrib" [GWh]

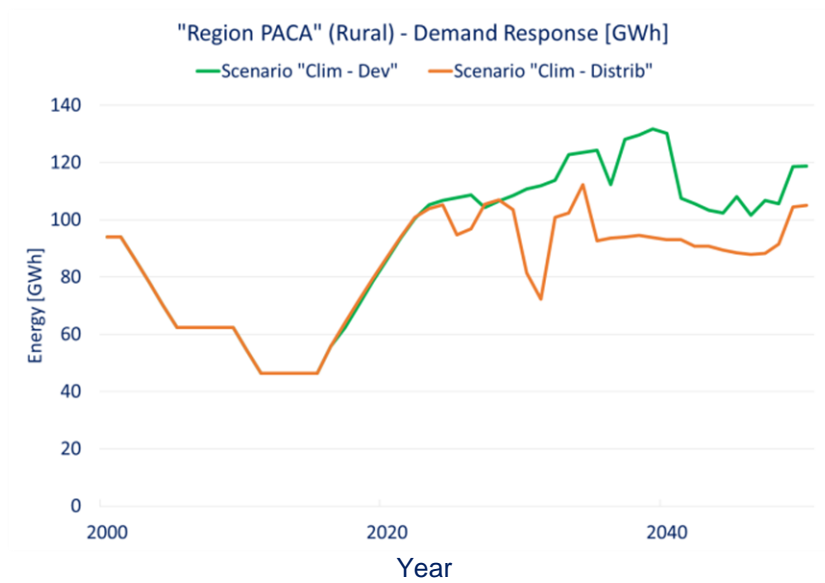


Figure IV-43 – Shifting from demand response in 2010, 2030 and 2050 in "Region PACA" for the two scenarios "Clim-Dev" and "Clim-Distrib" [GWh]

IV.4.3 Evolution of transmission grid infrastructure

All the modifications observed in the emissions, the energy mixes and the flexibility options reduce exchanges between regions. Consequently, the transmission grid requirements are modified.

(i) Development of the interconnections around the analysed regions

For the regions "IDF" and "HDF", the investments planned during 2010-2030 by ENTSO-E were sufficient for the period 2030-2050. But for the region "PACA", the reinforcements have been decided differently. Figure IV-44 shows the number of interconnections for the "Region PACA" from 2000 up to 2050 for the two scenarios "Clim-Dev" (in green) and "Clim-Distrib" (in orange).

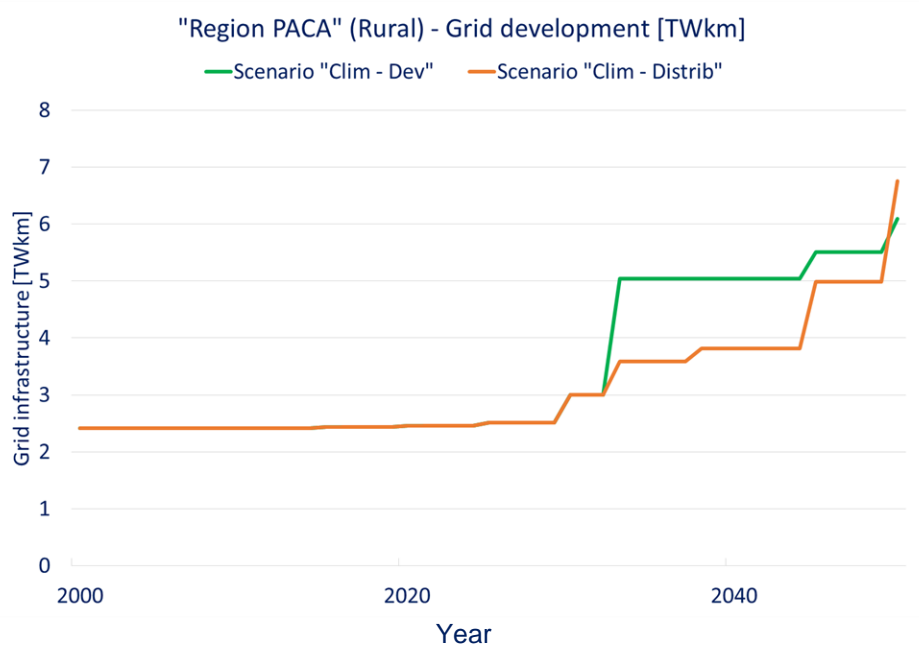


Figure IV-44 – Transmission grid interconnections for "Region PACA" from 2000 up to 2050 for the two scenarios "Clim-Dev" and "Clim-Distrib" [TWkm]

At the end of the scenarios, the grid interconnections reach the same level with almost 6 TWkm. However, the time of reinforcement is different: in 2033 for "Clim-Dev" and in 2043 and 2048 for "Clim-Distrib". The difference is due to the fact that 6 TWh of VRES production are still spilled in "Clim-Dev" and a reinforcement is useful to integrate this cheap energy. Moreover, HVDC technologies is chosen to integrate this large amount of energy. In scenario "Clim-Distrib", the reinforcement decisions follow the load increase and only with HVAC technologies. The representation of the three

representative distribution grids suggests that it can have an important impact on the evolution of the transmission grid.

(ii) Transmission grid development at European level

The development of the transmission grid is determined on the European level and compared to the scenario "Clim-Dev", the findings confirm the important changes both in terms of total grid requirements and technologies chosen between HVAC and HVDC. However, it should be recalled that the modelling framework is limited to only three representative distribution grids, which have been included in the European sector.

Figure IV-45 shows the evolution of the total transmission grid for the two scenarios "Clim-Dev" (in green) and "Clim-Distrib" (in orange). Up to 2030, the investments are the same. Then the development of the European transmission grid is lower in scenario "Clim-Distrib". It reaches 563 TWkm in 2050 while in "Clim-Dev" the grid has been upgraded up to 594 TWkm.

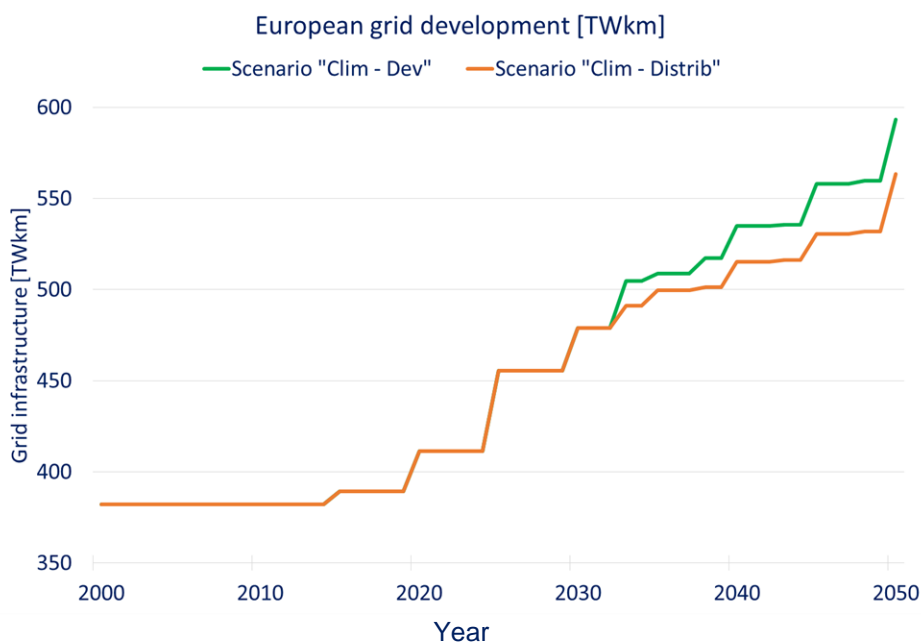


Figure IV-45 – European transmission grid infrastructure from 2000 up to 2050 for the two scenarios "Clim-Dev" and "Clim-Distrib" [TWkm]

To further analyse the impact of representing the distribution grids, the transmission grid requirements of the two scenarios can be compared for the period 2030-2050. The results are gathered in Table IV-2. The reinforcement requirements are shown in the first line and are lower for "Clim-Distrib". Then, the structure of these reinforcements between HVAC and HVDC is shown and it can be observed a clear shift between the two scenarios. In "Clim-Dev", the grid is mostly upgraded with HVDC technologies (70%

of HVDC). On the opposite with "Clim-Dev", most of the reinforcements are done with HVAC cables (69% of HVAC). However, this distribution is closer to the distribution from 2010-2030 (74% of HVAC). Finally, the total budget needed for these reinforcements is lower for "Clim-Distrib" with 7.2 b\$/year compared to 9.7 b\$/year for "Clim-Dev".

These outputs are the consequences of the explanations given in the previous paragraph: there is a cascade effect with the integration of the distribution grids. The power flows around the regions "IDF", "HDF" and "PACA" are modified and consequently, it impacts the neighbouring regions and then the overall Europe.

Table IV-2 – Transmission grid investments for the two scenarios "Clim-Dev" and "Clim-Distrib"

Scenario		2010 - 2030	2030 - 2050	
			"Clim - Dev"	"Clim - Distrib"
Transmission grid	Grid added [TWkm]	97	114	85
	-- HVAC [%]	74%	30%	69%
	-- HVDC [%]	26%	70%	31%
	Total grid investment [b\$]	180 (≈9b\$/year)	194 (≈9.7b\$/year)	143 (≈7.2b\$/year)

The effect of using EUTGRID&D can also be observed on the location of the reinforcement projects. Figure III-7 displays two maps of the transmission grid reinforcements for the period 2030-2050. The left map corresponds to the scenario "Clim-Dev" and the right map corresponds to the scenario "Clim-Distrib". HVAC and HVDC are distinguished respectively in black and pink.

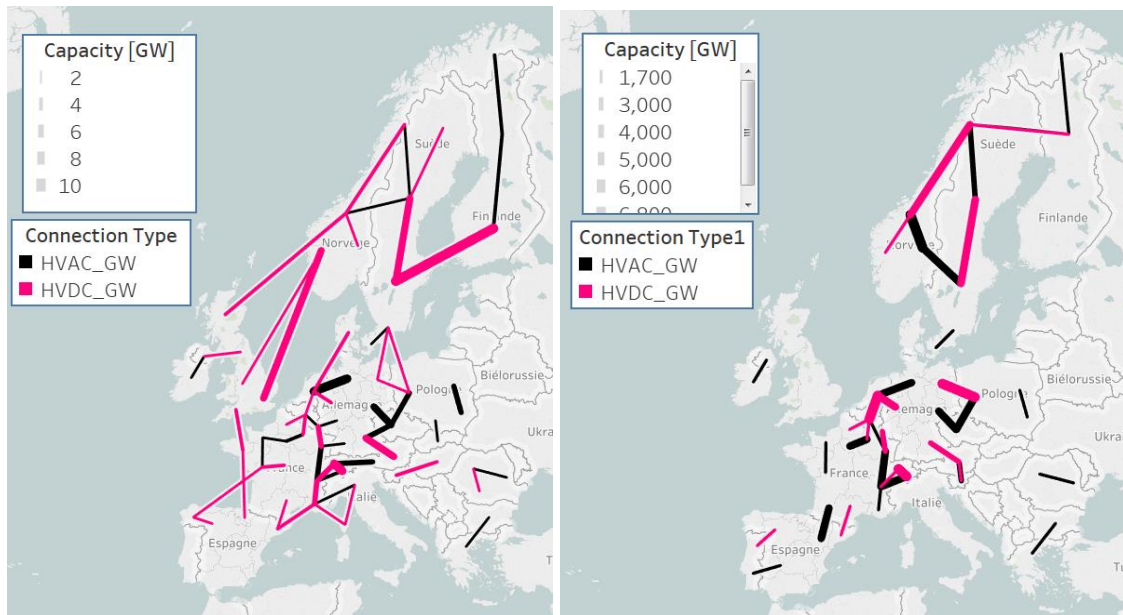


Figure IV-46 – Total transmission grid needs in scenario "Clim – Dev" (left) and in "Clim - Distrib" (right) for 2030-2050 [GW]

The location of the reinforcements differs between the two scenarios. In "Clim-Dev", Europe is being more interconnected with a focus on the connection in the North Sea. However, in "Clim-Distrib", there is a concentration of reinforcement project on three areas. The main corridor connects Benelux, France, Germany and Switzerland. Then the Scandinavian area is being highly reinforced. Finally, interconnections between Germany and Poland are upgraded to solve the congestions provoked by the German wind off-shore production. The French-Spanish interconnection is an important corridor to integrate the Spanish solar production. Despite their differences, these two scenarios have some reinforcement projects in common such as the Benelux corridor, the Scandinavian area and the French-Spanish interconnection. These findings underline the fact that it exists different solutions for the development of the grid infrastructure, but it can highly change with different modelling hypotheses.

Conclusions

Because most of the VRES installed capacities are located in the distribution grids, new issues arise which complicate the operation of the power system. There are mostly congestion and overvoltage. As the distribution grids cover all Europe, with the large integration of VRES, it will affect the operation of the transmission grid. For this reason, the model EUTGRID has been improved with the implementation of linearized AC equations to represent voltage and reactive power.

The new model EUTGRID&D is then used to analyse the issues in three representative distribution grids as the share of VRES increases. In rural grids, overvoltage situations occur first and then congestions. In semi-urban and urban grids, only congestions appear. To solve these issues, different solutions are then used, and their net present values are being compared for different targeted shares of VRES. The results show that for high share of VRES above 60% of reinforcement is the preferred solution. For lower share, curtailment of VRES production or installation of storage capacities can be cheaper. A combination of the presented solutions might be more realistic, but the results indicate that the distribution grid will face issues with the large-scale integration of VRES as simulated in the different scenarios in POLES.

To understand how the inclusion of representative distribution grids will affect the outputs in the long-term energy scenarios, a scenario with EUTGRID&D coupled with POLES is presented. It uses the same climate energy policy described in the previous chapter. The emissions within the regions are greater as more back-up technologies are needed. It is confirmed with the analysis of the energy mixes which shows a reduction of import and export and an increase in production from fossil with no CCS. The use of flexibility options increases but with a delay: the batteries located in the distribution nodes are limited by the congestions and cannot be used for flexibility.

The consequence of the modification of the dispatching within each region is a lower development of the transmission grid. It affects also the choice of reinforcement technologies with a shift from HVDC to HVAC around the regions with representative distribution grids. On the European level, a cascade effect can be observed together with an amplification of these findings: the neighbouring regions see a modification of the exchanges and consequently modify their dispatch. It results in slower transmission grid development and the installation of more HVAC cables.

Conclusions and perspectives

Conclusions

The concomitant policies to increase competition and speed up the decarbonisation of the power system have accelerated the large-scale integration of renewable energies. Most of these renewable energies use wind and solar, which have characteristics that are different from the ones of conventional power plants: they are non-dispatchable and their important variability can threaten the reliability and the security of the system. To overcome these issues, solutions are needed such as flexibility options. For example, storage technologies or demand response can be used to integrate the surplus of VRES energy and displace the energy stored later in the days.

Furthermore, VRE sources are unevenly located both within Europe and inside the countries. Solar potential is mainly located in the South while wind potential is higher in the North. In each country, the maximum technical potential is limited by many factors such as the existence of natural parks, the type of areas and even social acceptance. Therefore, some regions will see a high share of renewable energies and might provoke some congestions within the grids if the planning had not anticipated this new rise of VRES.

Two families of models exist to study the issues related to the integration of VRES: the long-term integrated energy models and the power sector models. The first family uses long-term energy scenarios to assess the implementation of climate energy policies and understand how it affects the technologies development. The second family focuses on technical issues faced in the grid. The literature review conducted shows that an important work has recently been done to represent the issues faced with the integration of VRES.

In long-term energy models, it is mainly related to the representation of back-up needs and the use of flexibility options with the use of specific power sector models. In the power system models, the aim is to represent with high details the grid operations in specific cases. For simplicity and also by lack of data availability, the representation of the different grid levels is kept simple in the long-term energy models: only the transmission grid is described and usually, it only has one node by country. Therefore, congestions are not well represented, and the consequences are a potential over-estimation of the VRES shares. For this reason, the transmission grid must at least be described in more detail.

As a result, several improvements to the previous version of the European power sector module are performed and presented in this study. It consists in:

- i. a more detailed representation of the transmission grid, with more nodes per country,

- ii. the implementation of DC load flow to realistically calculate power flows and finally,
- iii. the development of a transmission grid mechanism.

This mechanism is based on the detection of congestions using nodal prices and the bottlenecks are alleviated through reinforcements. These new reinforcement projects can be chosen between HVAC and HVDC technologies and are accepted only if the payback period is low enough. This threshold ensures that they are economically assessed. These new developments form a new power sector module called EUTGRID (EUropean Transmission Grid Investment and Dispatch).

EUTGRID can be used as a standalone model, but its key advantage is its coupling with the long-term energy model POLES. It allows to get dynamic development of the transmission grid and it consists a major improvement to the state-of-the-art in the long-term energy modelling families. Because of the lack of data availability on regional hourly production and regional installed capacities on the European level, two methods are presented and used to calculate the adequate databases for EUTGRID: the first one uses reanalysis data to provide hourly production and the second one uses historic regional installed capacities together with population density, production potential etc. to find linear allocation keys.

EUTGRID has been tested and validated on three different levels: first, interconnections flows were compared with historic data; then the resulting energy mix for France was compared with historic data; finally, the total transmission grid requirements were determined for the period 2010-2030 and confronted with the planned investments by ENTSO-E.

The transmission grid development is then analysed using different long-term energy scenarios. All the studied scenarios implement a climate-energy policy that aims at maintaining the rise of global temperature under 2°C before the end of the century. The resulting effect is a large-scale integration of VRES. Two types of scenarios are distinguished: scenarios where the development of the transmission grid is allowed and the ones where the investments are frozen around 2040 to simulate a situation of low social acceptance.

The reference case represents the default situation, where full grid development is allowed. In the second grid development scenario, the investments costs for VRES capacities and for batteries are reduced, while the demand response potential is increased.

For the “frozen grid after 2040” scenarios, four sub-scenarios have been set up: the first one is in default situation and the investments stop in 2040, the second one adds VRES investments reduction costs, the third one further reduces the battery costs with the previous

hypotheses and the last one has a higher demand response potential. The results show that the grid infrastructure development is highly dependent on the speed of VRES integration. The needs for transmission grid expansion almost doubles while the share of VRES increases by ten points. In this context of important energy production from VRES with zero marginal costs, HVDC technologies are mostly chosen for the reinforcement projects. The uneven distribution location of VRES has an impact on the location of the new upgrades: new corridors emerge such as the North Sea region to benefit from the wind offshore production or the interconnections between England, France and Spain.

If the investments in the transmission grid are limited, then the analysis of emissions and energy mixes for the different scenarios demonstrates that the security of supply is not achieved while the emissions increase. The use of flexibility options has increased but it is insufficient to alleviate the congestions provoked by the large-scale integration of VRES. A complementary work, which replaces the least-cost approach by using LCA emissions factors shows that the European emissions can be further reduced. The investments in the transmission grid increase largely as the share of VRES rises but they are slightly lower than in a scenario using the least-cost approach.

In the analysis of the transmission grid, the main hypothesis used assumes that there is no congestion within each region. However, most of installed VRES capacities are connected to the distribution grids, which already face overvoltage and congestions issues. These situations need to be solved with adequate solutions and the long-term energy models do not represent them. For this reason, EUTGRID has been further improved with the implementation of linearized AC equations to represent the active and reactive powers together with the voltage levels.

This contribution is the second major one of this work: to our knowledge, no power sector module coupled with a long-term energy model, does represent the power system from the transmission to the distributed grids with technical constraints. This upgraded module EUTGRID&D (EUTGRID plus Distribution grid representation) is validated on a test case and then applied on three representative distribution grids (rural, semi-urban and urban). The issues related to the VRES integration are highlighted: overvoltage situation occur in rural grids while congestions appear in urban and semi-urban grids. Typical solutions such as reinforcement, storage batteries, curtailment and OLTC are applied and a cost comparison is carried out with a Monte-Carlo approach to get more robust results.

The findings show that if a high share of VRES is targeted, then reinforcement is the cheapest solution. However, if the target aims around 40%-60% of total consumption, then other solutions should be used: in rural distribution grids, the OLTC and the storage technologies

appear to be the cheapest solutions. In urban grids, the curtailment of VRES production is the cheapest. For semi-urban grids, storage batteries and reinforcement seem to be the only solutions. Finally, EUTGRID&D is coupled with POLES and a climate energy scenario with transmission grid development at European level is analysed.

Even though there are only three distribution grids represented, the impacts are important: first, the emissions have increased in all regions as back-up are used to solve congestions and voltage issues. The analysis of the energy mixes for each region shows a reduction of power flows with the neighbours and the resulting effect is a lower use of flexibility options. The use of these flexibilities, which are now located in the distribution grids is limited by the grid capacities. The consequence is a lower development of the interconnections capacities around these regions with distribution grids. Thus, the European transmission grid requirements are modified both in total budget and in structure towards HVAC technologies.

Perspectives

Following the work presented in this manuscript, new perspectives can be drawn to further improve the analysis of the role of the power sector in the long-term energy transition perspective. Other types of scenarios could be analysed with different sets of carbon values, technology developments or with the integration of new technologies. The outcomes of these scenarios would help to better assess the role of each component of the power system.

The European power system is the most interconnected and EUTGRID covers almost all the European countries. An interesting perspective would be to extend the detailed representation to other countries or regions. The results would be an important improvement to the analysis of their long-term energy evolution. The availability of the data becomes less and less a problem with the strong open-data movement. For example, the transmission grid covering all Europe, North of Africa, Turkey and Russia is freely available by ENTSO-E. Other interconnected power systems such as the United-States could also be easily implemented. Similarly, more representative distribution grids could be included to better represent its important diversity. The main difficulty lies in the computing limitations.

Other improvements are related to the representation of operations in EUTGRID. The first one deals with the use of typical days for demand and VRES production. Currently, two typical days are used for the demand and 12 days for the VRES production. In a context of high demand flexibility, more typical days are needed, and they could be determined on a regional scale instead of a national scale. The resulting effect would be a better representation of dispatching on a yearly basis. As the climate change affects the efficiency

of the VRES production (increase of temperature affects wind speed, rainfalls...), it would also be interesting to modify the typical VRES production days during the progress of the simulation. Another linked issue is related to the uncertainty of the VRES production, which affects the real operation of the power system. The representation of this phenomenon through a stochastic approach, for example, would help to integrate the hidden costs of VRES uncertainty and better represent the power sector operations. The second improvement involves storage technologies. Their operations are currently limited to a daily strategy. However, some weekly, or even seasonal strategies exist such as hydro power plants and should be captured, as it would affect the congestions within the transmission and the distribution grids.

A final perspective is related to the traditional objective function implemented in the unit commitment and dispatch models, which only minimizes the costs. However, more and more customers may in the future modify their energy strategy to maximize their self-consumption. The integration of these strategies in the distribution grids would be an important progress: with a high-share of self-consumers, the impacts on the distribution grids and on the transmission grid could be important and should be assessed. This would allow to study the consequences of a truly radical innovation in the management of future electricity grid.

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Annexes

Annex A - List of electricity producing technologies used in POLES

41 production technologies are included in POLES and are listed in the table Table A-1.

Table A-1 – Technologies in POLES for the electricity module (adapted from [12])

Fuel	Technology name (in POLES)	Description
Nuclear	NUC	Conventional nuclear
	NND	New nuclear design
Coal	CCT	Coal Conventional Thermal
	LCT	Lignite
	PFC	Pressurised coal supercritical
	PSS	Pressurised coal supercritical with CCS ²²
	ICG	Integrated coal gasification with CC ²³
	ICS	Integrated coal gasification with CC and CCS
Gas	GCT	Gas Conventional Thermal
	GGT	Gas turbine
	GGC	Gas CC
	GGS	Gas CC with CCS
Oil	OCT	Oil Conventional Thermal
	OGC	Oil CC
Hydro	HRR	Hydraulic run-of-river
	HLK	Hydraulic with reservoir
	HPS	Pumped-storage hydroelectricity
	SHY	Small hydroelectricity (<10MW)
	OCE	Tidal and wave
Earth	GEO	Geothermal

²² CCS : Carbon Capture and Storage

²³ CC : Combined Cycle

Biomass	BTE	Biomass Thermal	Conventional
	BCS	Biomass Thermal with CCS	Conventional
	BTC	Biomass with CHP ²⁴	
	BGTE	Biomass and Gasification	
	BGTC	Biomass and Gasification with CHP	
	BGAE	Biogas	
	BGAC	Biogas with CHP	
	BWC	Biodegradable waste with CHP	
Wind	WN1 – WN3	Wind onshore with three different classes of quality	
	WO1 – WO3	Wind offshore with three different classes of quality	
Solar	CPV	Centralised PV power plant	
	DPV	Decentralised PV	
	SPP	Solar thermal power plant	
	SPPS	Solar thermal power plant with thermal storage	
Decentralised technologies	CHP	Decentralised CHP	
	HFC	Hydrogen fuel cell	
	GFC	Gas fuel cell	
Storage	CAE	Adiabatic Compressed Air Energy	
	BAT	Lithium-ion batteries	
	V2G, G2V	Vehicle-to-grid and Grid-to-vehicles batteries	
	DSM	Demand response	

²⁴ CHP : Combine Heat and Power

In POLES, these technologies can be decomposed into three types: the decentralised technologies (CHP, HFC, GFC and DPV), the “must-run” ones (large-scale PV, nuclear and hydro) and the rest which is used for the dispatch.

This classification becomes less true with the introduction of the unit commitment and dispatch module: most of technologies are now dispatchable, storage is better managed and curtailment of VRES production is realistically determined. It must be noted that the technologies are aggregated to a country or a region.

Annex B – Capacity validations

Validations of distributions keys for VRES

Having well-defined distribution keys is necessary to get appropriate conclusions on flows and congestions. Indeed, an important misplaced VRES capacity will have impacts on the investments chosen. Therefore, coefficients used by the project “e-highway 2050” were tested by using total installed wind capacity in France in 2014. The differences between historic data and using the distribution key were not satisfactory (Figure B-1).

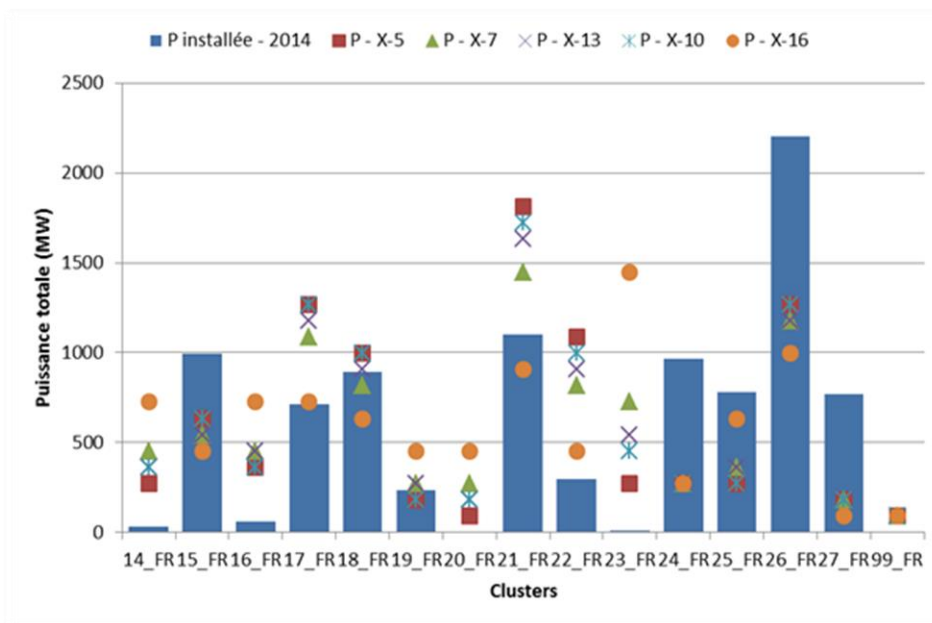


Figure B-1 – Wind installed capacities versus results using e-HIGHWAY 2050's distribution keys (case France 2014 – nodes)

For this reason, new coefficients were determined and Figure B-2 shows the comparisons between historic data and using the distribution keys. Differences still exist as it is extremely difficult to capture the dynamic of VRES installation within a country.

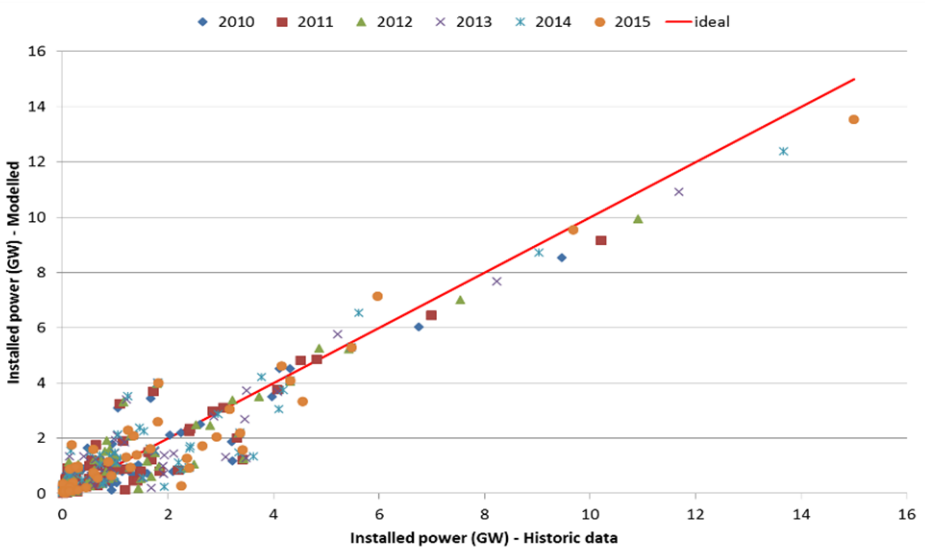


Figure B-2 – Wind installed capacities - Model versus historic data

Annex C – Production validations

The equations presented in [118] and the adequate reanalysis data available at [117] were used to calculate the hourly variable renewable production for each node. We present here these equations for solar and wind production together with the validations methodology.

Solar production data

(iii) Production equations

For each hour and each point within the 24 countries, the capacity factor $CF_{Lat,Long}$ is calculated using the following equation (29).

$$CF_{Lat,Long} = \eta_{rel}(G, T) * \frac{G}{G_{STC}} \quad (29)$$

where Input data:

- G is the total down welling irradiance [W/m^2]
- G_{STC} is the total down welling irradiance under standard test conditions [W/m^2]

$$G_{STC} = 1000 \text{ W}/m^2$$

Function:

- $\eta_{rel}(G, T)$ is the relative efficiency of the considered PV panel. It can be calculated with equation (30)

$$\eta_{rel}(G, T) = [1 + \alpha \Delta T_{mod}] * \left[1 + c_1 \ln \left(\frac{G}{G_{STC}} \right) + c_2 \ln^2 \left(\frac{G}{G_{STC}} \right) + \beta \Delta T_{mod} \right] \quad (30)$$

with

$$\Delta T_{mod} = T_{mod} - T_{STC} \quad (31)$$

$$T_{mod} = T + (T_{NOCT} - T_0) * \frac{G}{G_0} \quad (32)$$

where Input data:

- T is the measured ambient air temperature in [K]
- T_{STC} is the temperature under standard test conditions in [K]
- T_{NOCT} is the nominal operating cell temperature under ambient temperature T_0

$$T_0 = 20^\circ C$$

$$T_{NOCT} = 48^\circ C$$

Constants:

- $\alpha = 4.20 * 10^{-3} K^{-1}$
- $\beta = -4.60 * 10^{-3} K^{-1}$
- $c_1 = 0.033$
- $c_2 = -0.0092$
-

Function:

- T_{mod} is the temperature of the module in [K] using equation (32)

(iv) Validations

To validate the power output calculations, the historic Belgium hourly capacity factor for the year 2012 was computed by dividing the hourly production and the installed capacities [121]. Then it was plotted versus the hourly mean capacity factor over Belgium using the equations described above. Figure C-3 shows the results.

The first observation is that the model fits well the real data with a R^2 of 0.90. However, it should be pointed out that the model slightly over-estimates the power production.

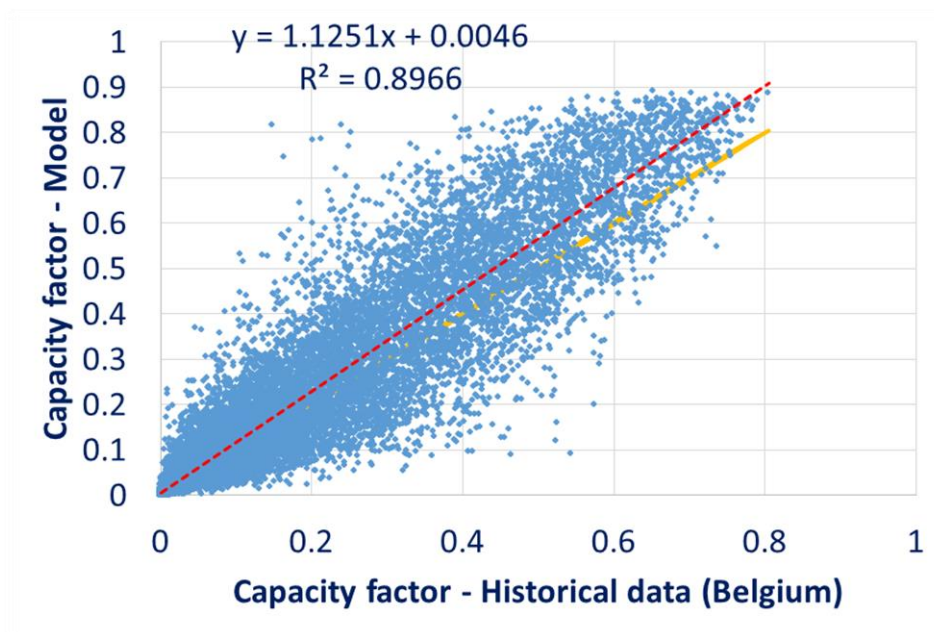


Figure C-3 – Solar calculated capacity factor versus real data for Belgium (2012)

Wind on-shore and off-shore production data

(v) Wind production

Wind power production only depends from wind speed and the height of the turbine. To calculate the power output, we firstly use the power coefficient of a one typical model of ENERCON, a wind-turbine manufacturer [199]. The curve is shown in red in Figure C-4. However, with the use of real wind production data for Belgium for the year 2012 [120], it was possible to plot the aggregated power curve for all Belgian wind turbines. The curve is shown in blue in Figure C-4.

The differences between the two curves show the effect of aggregating different types of turbines in a region: some models will perform better in areas with high speed while other models will be able to produce more in areas with low speed. Therefore, in EUTGRID, we implemented a power curve based on the Belgian historic data in grey in Figure C-4.

Wind off-shore production was calculated using the same methodology and it used data from Belgium as well.

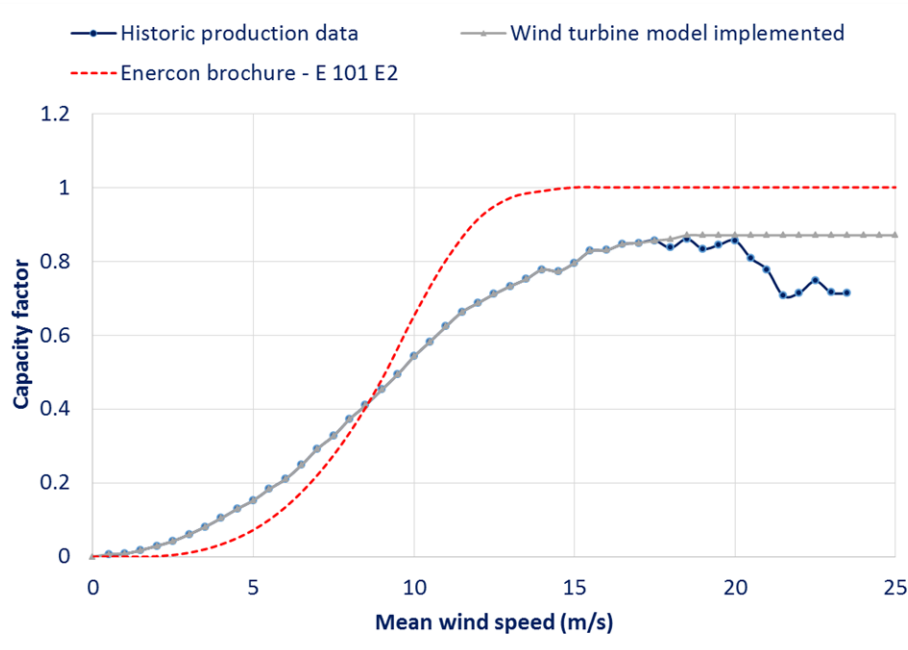


Figure C-4 – Wind power curves for ENERCON's turbine, real data (Belgium 2012) and implemented in EUTGRID

(vi) Validations

Similarly, to solar production, wind on-shore production was validated by plotting historic capacity factor versus the computed hourly capacity factor. The result is shown in Figure

C-5. Unlike solar production, the model underestimates wind power outputs but the fitting is still very good with a R^2 equal to 0.84.

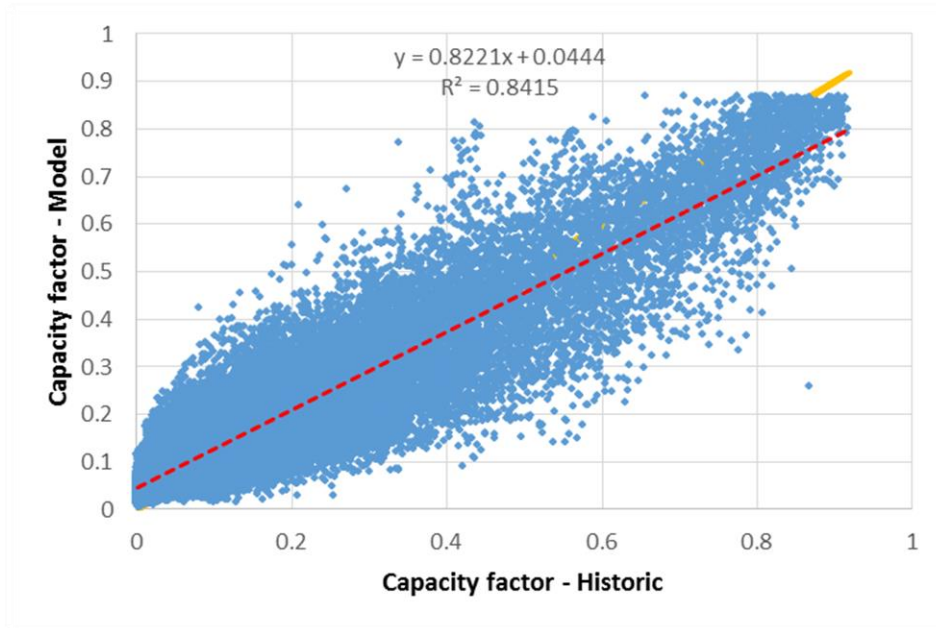


Figure C-5 – Wind on-shore calculated capacity factor versus real data for Belgium (2012)

European validations

To further validate the two methods presented, the mean absolute error was calculated for all the countries where wind and solar production were available for at least one year. The results are gathered in Figure C-6. For solar production, the mean absolute error ranges between 2% and 9% for solar. For wind on-shore, it is slightly higher as it goes from 5% up to 14%. For wind off-shore, as the sizes of the wind farms are smaller, the power curve is really dependent of the location and range from 10% to 15%. However, there were only two nodes available for comparison.

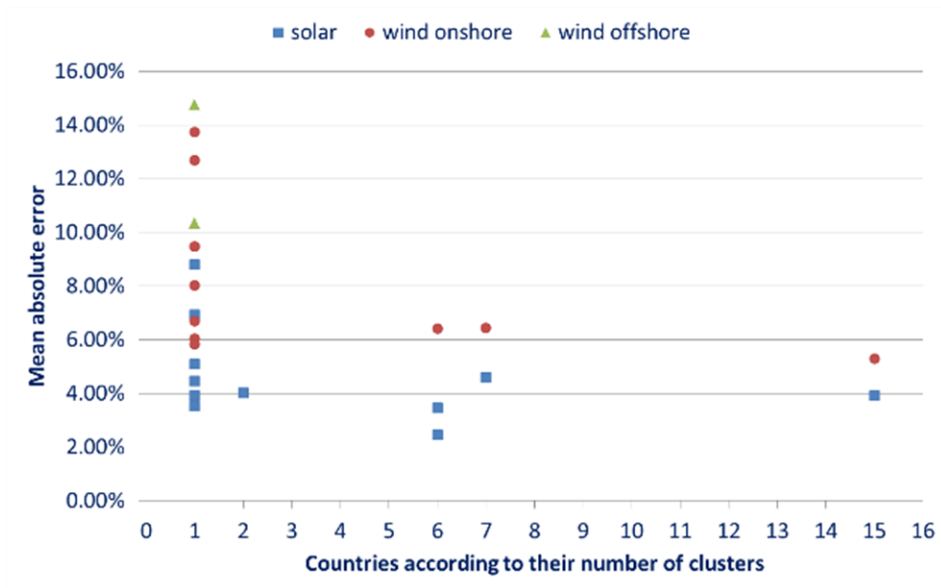


Figure C-6 – Mean absolute error (%) for different countries according to their number of nodes

Annex D – Urban, rural and mountainous regions

In [108], Eurostat classified European NUTS 3 levels based on different characteristics. We further simplified this listing to get three different sort of regions: urban, rural and mountainous. The equivalent tables are shown in Table D-2:

Table D-2 – Equivalence between the classification from Eurostat and the one used for EUTGRID

urban/rural including remoteness	
Predominantly urban regions	urban
Intermediate regions, close to a city	urban
Predominantly rural regions, close to a city	rural
Predominantly rural, remote regions	rural
Intermediate, remote regions	rural

mountain regions	
other regions	
> 50 % of surface	mountain
> 50 % of population and 50 % of surface	mountain
> 50 % of population	mountain

Using equation (11), we can distinguish the different European regions depending of the classifications (see Figure D-7). For example, the centre of France, the north of Scandinavia and the eastern countries are very rural. The South of England, the Benelux countries and part of northern Germany are very urban. The clusters in the Alps, in the Pyrenees and almost all Norway are mountainous which will highly increase the investments costs if some reinforcements are needed. A table of the average coefficient used for each node is provided (see Table D-3).

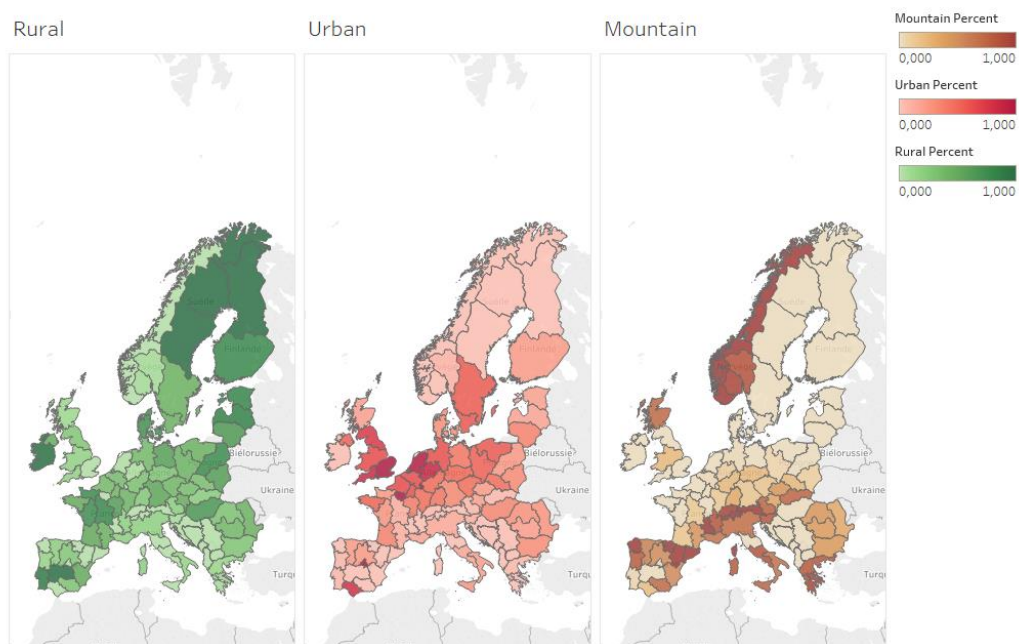


Figure D-7 – Typology of the different nodes in Europe

Table D-3 – Grid coefficient values for each node

Nodes	Grid coefficient	Nodes	Grid coefficient	Nodes	Grid coefficient
01_ES	2.05	30_NL	1.37	59_RO	1.57
02_ES	1.69	31_DE	1.26	60_RO	1.51
03_ES	1.62	32_DE	1.16	61_RO	1.43
04_ES	2.05	33_DE	1.43	66_BG	1.56
05_ES	2.05	34_DE	1.41	68_GR	1.89
06_ES	2.05	35_DE	1.41	69_GR	1.99
07_ES	1.38	36_DE	1.5	72_DK	1.11
08_ES	1	37_DE	1.27	74_FI	1.1
09_ES	1.51	38_DK	1.11	75_FI	1.08
10_ES	1.75	39_CZ	1.33	79_NO	2.05
11_ES	1.54	40_CZ	1.55	80_NO	1.98
12_PT	1.86	41_PL	1.09	81_NO	2.05
13_PT	1.07	42_PL	1.21	82_NO	1.93
14_FR	1.28	43_PL	1.4	83_NO	2.05
15_FR	1.52	44_PL	1.26	84_NO	2.05
16_FR	1.75	45_PL	1.22	85_NO	1
17_FR	1.1	46_SK	1.8	86_SE	1

18_FR	1.17
19_FR	2.05
20_FR	1.87
21_FR	1.2
22_FR	1.09
23_FR	1.38
24_FR	1.15
25_FR	1.31
26_FR	1.24
27_FR	1.23
28_BE	1.28
29_LU	1.38

47_CH	2.02
48_CH	2.05
49_AT	2.05
50_AT	1.81
51_AT	1.43
52_IT	1.78
53_IT	1.1
54_IT	1.95
55_IT	1.77
56_IT	1.89
57_SI	1.91
58_HU	1.13

87_SE	1
88_SE	1.22
89_SE	1.22
90_UK	1.38
91_UK	1.32
92_UK	1.46
93_UK	1.28
94_UK	1.82
95_UK	1.2
96_IE	1.01
98_IT	1.85
99_FR	2.05

Annex E– Sensitivity analysis for the different solution on the energy mix in the distribution grids

A sensitivity analysis was performed with different shares of solar and wind in the different representative distribution grids. The method used is the same as described in IV.3.2. Figure E-8 displays the different distribution of the least cost options as follows: the distribution grids are distributed on each column and the different share of energy mixes on each line. From left to right, it can be analysed the rural grid, the semi-urban grid and the urban grid. Finally, from top to bottom line, the energy mixes are visible from 100% solar production to the last one (10% solar production and 90% wind production).

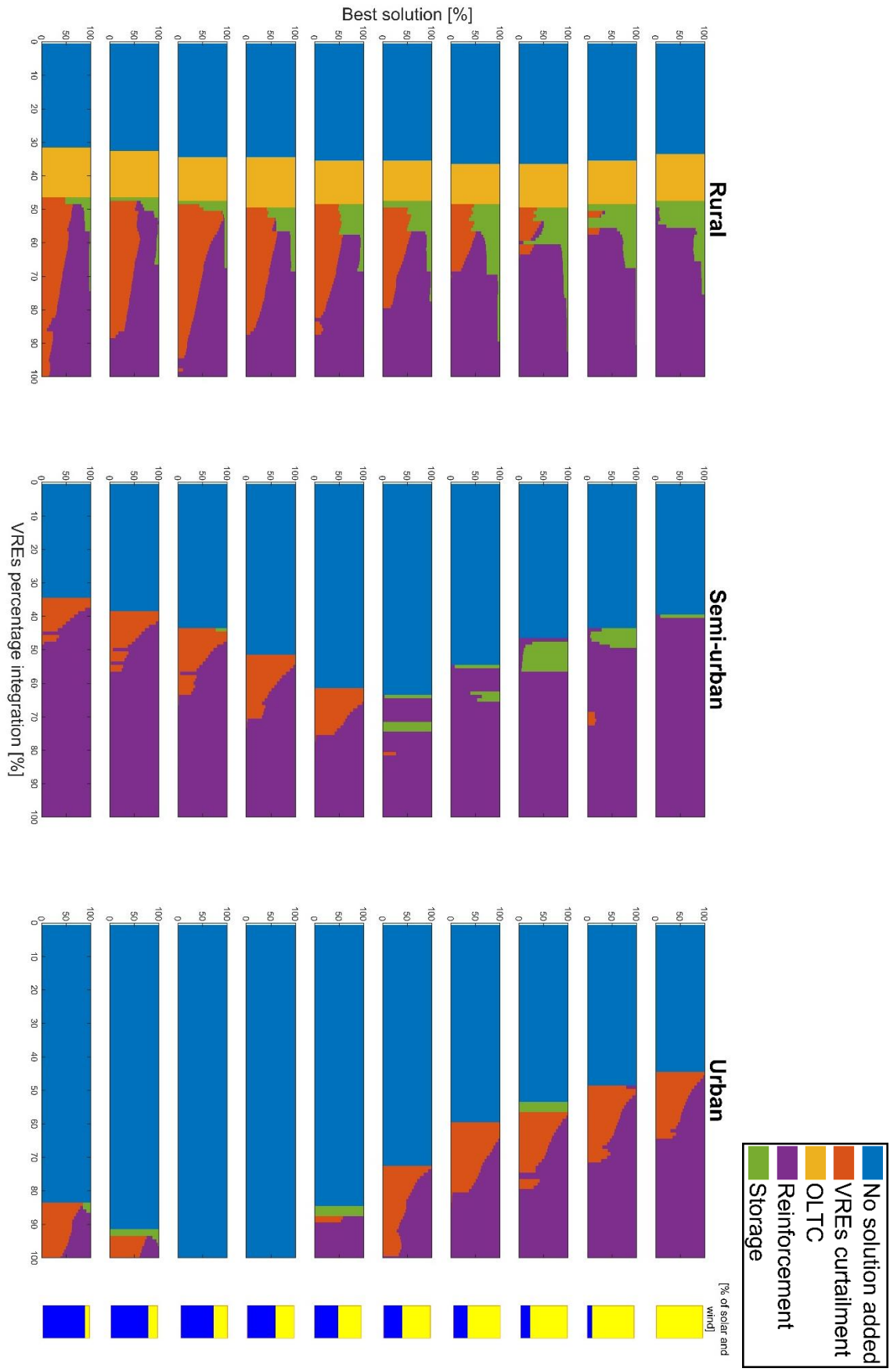


Figure E-8 – Distribution of least-cost options for different share of solar and wind in the representative distribution grids

Annex F– CO₂ emissions factors for fossil production in POLES

The long-term energy model POLES determines the CO₂ emissions for the electricity production using specific factors for each fuel. It only considers coal, oil and gas and the emissions factors are gathered in Table F-4.

Table F-4 – CO₂ emissions factors in [tCO₂/MWh] for fossil production (from POLES's database)

Fuel	CO ₂ emissions factor (tCO ₂ /MWh)
Coal (C_{coal})	0.342
Oil (C_{oil})	0.272
Gas (C_{gas})	0.201

Résumé de la thèse

Au cours des dernières années, le système électrique européen a connu d'importants changements dans son paradigme, principalement dû à deux défis importants. Le premier défi concerne la libéralisation de l'industrie européenne de l'électricité avec l'introduction de la première directive européenne en 1996. Le réseau électrique européen peut se décomposer entre la production et la demande avec le réseau de transport qui transporte l'électricité jusqu'au consommateur final. Il a été développé de manière verticale avec une production d'électricité importante et centralisée, associée à un réseau de transport étendu qui garantit la robustesse et la fiabilité du système. L'objectif de la directive et des suivantes était d'introduire de la concurrence dans ces monopoles naturels et de créer un marché européen de l'électricité. La conséquence qui en découle est l'apparition de nouveaux acteurs principalement du côté de l'offre et de la demande. Ce contexte a permis l'essor de la production distribuée dans le système électrique. Ces sources d'énergie à petite échelle sont locales et modifient le rôle des consommateurs. Auparavant, ils étaient considérés comme des acteurs passifs qui devaient être fournis à tout moment. Maintenant, ils peuvent contrôler leur consommation d'énergie avec ces capacités décentralisées et devenir des «prosommateurs»: ils sont à la fois producteur d'énergie et consommateur d'énergie. La conséquence de cette libéralisation a accru la complexité du système électrique européen ainsi que la nécessité de mieux contrôler ses opérations pour assurer sa sécurité et sa fiabilité.

Le deuxième défi concerne la montée des préoccupations liées au climat et l'introduction de politiques énergétiques pour réduire les émissions de gaz à effet de serre. Cela a commencé avec les accords internationaux tels que le protocole de Kyoto ou les différentes conférences des Nations Unies sur le changement climatique qui se tiennent chaque année depuis 1995. Dans ce contexte, le secteur de l'électricité et du chauffage représente 40% des émissions mondiales de CO₂ et d'importants efforts sont déployés pour réduire cette part. En Europe, des politiques spécifiques ont été mises en place, qui fixent des objectifs de réduction des émissions de gaz à effet de serre, d'augmentation de la part des énergies renouvelables et d'amélioration de l'efficacité énergétique. Cela correspond au «paquet climat et énergie 2020» dont les objectifs sont fixés à 20% chacun.

Plus récemment, la Commission européenne a élaboré un nouveau paquet pour 2030 avec des objectifs encore plus ambitieux. Les principaux objectifs concernent la réduction de 40% des émissions de gaz à effet de serre, un taux des énergies renouvelables atteignant 27% de la consommation énergétique et un marché de l'électricité plus intégré avec le

développement de 10% à 15% d'interconnexions électriques entre les pays. Les sources d'énergie renouvelables présentent certaines caractéristiques clés qui leur permettent de jouer un rôle clé dans les politiques énergétiques climatiques. Tout d'abord, elles ne produisent aucune émission directe de CO₂. Par conséquent, une plus grande intégration de ces énergies va progressivement remplacer les grands moyens de production centralisés utilisant du combustible fossile. Ces énergies renouvelables rassemblent l'énergie solaire, éolienne, hydroélectrique et la biomasse ; et leur potentiel est conséquent sur l'ensemble de l'Europe pour le solaire et l'éolien alors que la biomasse est disponible grâce aux forêts et à l'agriculture. Avec une production plus décarbonée dans le mix énergétique, cela réduit d'autant plus la dépendance aux ressources pétrolières et gazières. Dans un contexte de limitation de ces ressources et de contextes géopolitiques, la résolution de ce problème devient une tâche importante et favorise la tendance à l'électrification de nouveaux usages tels que l'utilisation de véhicules électriques.

En raison de la grande complexité du système énergétique et de ses interactions importantes avec l'économie mondiale, ces politiques énergétiques climatiques doivent être évaluées avant d'être mises en œuvre. Pour ces raisons, des modèles énergétiques de prospective long terme ont été mis au point pour représenter l'évolution à long terme du secteur de l'énergie et ses différents impacts, tels que les émissions ou les prix de l'énergie. Leur objectif est de comprendre les principaux moteurs de l'évolution des technologies, l'émergence de nouveaux usages. À l'aide de scénarios prospectifs, ils permettent de discuter des impacts des options de décarbonisation (par exemple, l'intégration d'énergies renouvelables variables, le développement de technologies de stockage et l'émergence de technologies de capture et de stockage du CO₂ ou encore l'utilisation des options de flexibilité). Enfin, ces scénarios prospectifs constituent un outil important pour aider les décideurs lors de l'élaboration de nouvelles politiques énergie climat.

Les différentes politiques énergétiques européennes ont commencé à modifier le fonctionnement du système électrique avec l'intégration des énergies renouvelables. Traditionnellement, les moyens de production se composent de centrales thermiques dont la production est contrôlable et pilotable. Une distinction doit être faite entre les centrales électriques de base (c.-à-d. centrales nucléaires) qui ont besoin de temps pour démarrer et qui fonctionnent aux alentours de 8000 heures par an et les centrales pour la pointe (c.-à-d. les turbines à gaz et à charbon) qui peuvent augmenter leur production en moins d'une heure mais qui fonctionnent aux alentours de 3000 heures par an (Pour satisfaire l'hyperpointe, certaines centrales fonctionnent moins de 500 heures par an). Dans ce contexte, les opérateurs doivent uniquement prévoir la demande ainsi que la disponibilité des centrales électriques avant d'effectuer le dispatching. Cependant, les énergies renouvelables ont

introduit de nouveaux types de caractéristiques. Les énergies renouvelables, telles que la biomasse ou l'hydroélectricité, peuvent encore être pilotable mais ce n'est pas le cas avec les productions éoliennes et solaires. Ces technologies ne peuvent pas être pilotées (elles sont appelées technologies «non dispatchables») et on les appelle souvent EnRV (sources d'énergie renouvelable variables): leur production varie de manière rapide (dans l'heure avec des variations importantes durant la semaine ou entre différentes saisons). Pour résoudre ces difficultés, les centrales de pointe peuvent être utilisées pour suivre ces variations, mais cela signifie une électricité plus coûteuse et une augmentation des émissions ; ce qui va à l'encontre des objectifs de réduction d'émissions de CO₂. D'autres solutions existent qui consistent à augmenter la flexibilité à la demande avec l'insertion de technologies de stockage ou des programmes de réponse à la demande. Le développement de technologies de stockage avec des batteries stationnaires ou des véhicules électriques présente un intérêt majeur : le surplus d'énergie produit serait stocké à midi par exemple pour ensuite être réutilisé pendant les heures de pointe. De la même façon, les clients pourraient retarder leur consommation d'énergie (par exemple, en retardant le démarrage de leur machine à laver).

Les problématiques liées à ces évolutions importantes du système électrique européen sont ensuite étudiées grâce à l'utilisation de modèles énergétiques de prospective long-terme. Le système électrique y est représenté de manière plus fine, mais certaines hypothèses utilisées limitent leur analyse. De nombreuses études ont calculé le potentiel de chaque source d'énergie renouvelable au niveau européen et ce potentiel est inégalement réparti en Europe mais aussi à l'intérieur d'un pays. Le profil de production est aussi modifié par la typologie du terrain qu'il soit urbain, rural ou montagneux. De plus, l'existence de zones réglementées (parcs naturels, aéroports ou habitations) ou même d'une très faible acceptation sociale est l'un des nombreux facteurs qui limitent l'installation de capacités éoliennes et solaires. Avec une intégration à grande échelle des EnRV, la conséquence immédiate est une augmentation de la production dans des régions spécifiques et ces volumes d'énergie doivent être transportés vers les consommateurs qui sont généralement situés loin des sites de production. Cependant, les réseaux de distribution où la plupart des capacités éoliennes et solaires sont connectées rencontrent déjà des problèmes liés à l'intégration des EnRV. Ils ont été conçus pour voir des flux unidirectionnels, mais avec ces sources de production, des flux inverses apparaissent provoquant des situations de surtension ainsi que des phénomènes de congestion des lignes. Dans le réseau de transport qui connecte toute l'Europe, les congestions sont les principaux problèmes et pourraient potentiellement limiter l'intégration massives des EnRV à long-terme.

Ces différentes questions amènent à s'interroger sur le rôle du réseau dans les scénarios énergétiques à long terme et sur son impact sur l'évolution du mix énergétique.

Le principal défi scientifique concerne la représentation des différents niveaux de tension du réseau en Europe. Si le réseau est explicitement représenté dans les modèles énergétiques à long terme actuel, cela ne concerne que le réseau de transport qui ne comporte généralement qu'un nœud par pays. Les échanges électriques qui en résultent peuvent être considérés comme des échanges commerciaux et ne tiennent pas compte des caractéristiques du réseau. En ce qui concerne le réseau de transport, il devrait inclure davantage de nœuds pour représenter de manière adéquate les congestions, et obtenir des flux d'énergie plus réalistes. La modélisation du système électrique devrait également intégrer une représentation des réseaux de distribution afin d'analyser les problèmes liés à l'intégration des EnRV. Un défi scientifique associé concerne la représentation de la variabilité des EnRV au sein de chaque région et la répartition de leurs capacités. Les modèles énergétiques à long terme fournissent généralement des données au niveau national et, même si le mouvement « Open data » connaît un essor important, les données manquent concernant la production locale au pas de temps horaire ainsi que la localisation géographique des capacités des centrales électrique. Par conséquent, des méthodes de calcul de la production des EnRV par région et leur répartition doivent être développées. Enfin, l'évolution à long terme de l'architecture du réseau doit être intégrée dans l'analyse des scénarios afin d'observer ses effets sur l'évolution du mix énergétique.

Pour ces raisons, un nouveau module du secteur électrique a été développé avec d'importantes améliorations. Il consiste en une représentation plus détaillée du réseau de transmission avec plus de nœuds par pays, l'intégration d'un calcul de répartition des charges calculer de manière réaliste les flux d'énergie et, enfin, le développement d'un mécanisme d'investissement dans le réseau de transport. Ce mécanisme utilise les prix nodaux pour détecter et réduire les congestions grâce aux renforcements. Ces nouveaux projets de renforcement peuvent être choisis entre les technologies HVAC et HVDC et ils ne sont acceptés que si la période de remboursement est inférieure à 10 ans. Ces nouveaux développements forment un nouveau module du secteur électrique EUTGRID (EUropean Transmission Grid Investment and Dispatch). Il peut être utilisé seul, mais son principal avantage réside dans le couplage avec le modèle de prospective énergétique à long terme POLES. Il permet une évolution dynamique du réseau de transport et constitue une amélioration majeure par rapport aux autres modèles de prospective énergétique à long terme. En raison du manque de données disponibles sur la production horaire régionale et des capacités régionales, deux méthodes sont présentées pour calculer les bases de données adéquates pour faire fonctionner EUTGRID : la première utilise des données spatiales pour calculer une production horaire, la deuxième méthode consiste à déterminer des clés de répartition prenant en compte la densité de population, le potentiel de production,

etc. EUTGRID a ensuite été testé et validé sur trois niveaux différents : premièrement, les flux aux interconnexions ont été comparés aux données historiques; ensuite, le mix énergétique résultant pour la France a été comparé aux données historiques; enfin, les besoins en investissement du réseau de transport ont été déterminés pour la période 2010-2030 et comparés aux investissements prévus par ENTSO-E.

Le développement du réseau de transport est ensuite analysé à l'aide de différents scénarios énergétiques à long terme. Tous les scénarios étudiés mettent en œuvre une politique climat-énergie visant à maintenir la hausse de la température mondiale à 2°C en 2100. Le principal impact est une augmentation de la part des EnRV dans le mix énergétique. Deux types de scénarios sont définis: les scénarios où le développement du réseau de transport est autorisé et ceux où les investissements sont gelés vers 2040 pour simuler une situation de très faible acceptation sociale. Le scénario de référence correspond à la situation par défaut où le développement du réseau est autorisé et pour le second scénario de développement, les coûts d'investissement pour les capacités des EnRV et pour les batteries ont été réduits, tandis que le potentiel de réponse à la demande a été augmenté. Pour les scénarios « gel des investissements après 2040 », quatre sous-scénarios ont été mis en place : dans le premier, les investissements sont arrêtés en 2040, le second ajoute l'hypothèse de réduction des coûts des investissements des EnRV, le troisième réduit aussi les coûts de la batterie avec les hypothèses précédentes et dans le dernier le potentiel de réponse à la demande est plus élevé. Les résultats montrent que le développement de l'infrastructure du réseau dépend fortement de la vitesse d'intégration des EnRV. Les besoins d'expansion du réseau de transport ont presque doublé alors que la part des EnRV n'a augmenté que de dix points. Ces quantités d'énergie importantes, sans coûts variables, font que les technologies HVDC sont principalement choisies pour les projets de renforcement. La répartition inégale des EnRV peut être observé en analysant le renforcement des lignes ainsi que leur expansion : de nouveaux corridors émergent comme autour la région de la mer du Nord afin de bénéficier de la production éolienne offshore ou des interconnexions entre l'Angleterre, la France et l'Espagne. L'analyse des émissions et des mix énergétiques pour les différents scénarios montrent qu'avec des investissements limités, la sécurité d'approvisionnement n'est pas atteinte alors que les émissions augmentent. L'utilisation des options flexibilités a augmenté mais elles sont insuffisantes pour réduire les congestions provoquées par l'intégration massive des EnRV. Un travail exploratoire a été mené qui remplace la minimisation des coûts par la minimisation des indicateurs d'analyse de cycle de vie (ACV). Les résultats montrent que les émissions européennes peuvent être encore réduites avec des investissements moindres dans le réseau de transport.

Dans le cadre présenté précédemment, l'hypothèse principale utilisée suppose qu'il n'y a pas de congestion à l'intérieur de chaque région. Cependant, la plupart des capacités d'EnRV installées sont connectées aux réseaux de distribution et cela provoque des problèmes de surtension ainsi que de congestions. Ces situations doivent être résolues avec des solutions adéquates qui ne sont pas représentées dans les modèles de prospective énergétique à long terme. Pour cette raison, EUTGRID a encore été amélioré avec l'implémentation d'équations AC linéarisées pour représenter les puissances actives et réactives ainsi que les niveaux de tension. Cette contribution constitue la deuxième amélioration majeure dans le domaine des modèles de prospective énergétique long-terme. Ce module mis à jour EUTGRID&D (EUTGRID avec représentation des réseaux de distribution) a été validé sur un cas test puis appliqué sur trois réseaux de distribution représentatifs (rural, semi-urbain et urbain). Les problèmes liés à l'intégration des EnRV sont ensuite mis en évidence : des problèmes de surtension apparaissent uniquement dans les réseaux ruraux étudiés, tandis que les congestions apparaissent dans les réseaux urbains et semi-urbains. Des solutions telles que le renforcement, l'utilisation de batteries de stockage, le délestage de la production ainsi qu'un OLTC sont analysés. Une comparaison des coûts est réalisée en utilisant une approche Monte-Carlo afin d'obtenir des résultats robustes. Les résultats montrent que si une proportion élevée d'EnRV est ciblée, le renforcement est la solution la moins coûteuse. Toutefois, si l'objectif se situe aux alentours de 40%-60%, d'autres solutions peuvent être utilisées : dans les réseaux de distribution ruraux, les technologies OLTC et de stockage sont les solutions les moins coûteuses. Dans les réseaux urbains, le délestage de la production des EnRV est la moins chère. Pour les réseaux semi-urbains, les batteries de stockage et le renforcement semblent être les seules solutions économiquement intéressantes. Enfin, EUTGRID&D est couplé à POLES et un scénario 2°C avec développement du réseau de transport est analysé. Bien qu'il n'y ait que trois réseaux de distribution représentés, les impacts sont importants : premièrement, les émissions ont augmenté dans toutes les régions, car les capacités de back-up sont utilisées pour résoudre les problèmes de congestion. L'analyse des mixes énergétiques pour chaque région montre une réduction des échanges entre les régions et l'effet est une utilisation plus faible des options de flexibilité. L'utilisation de ces flexibilités qui se trouvent maintenant dans les réseaux de distribution est limitée par les capacités du réseau. Cela provoque un effet en cascade sur les investissements dans le réseau de transport européen qui sont modifiés à la fois en terme de budget total et de structure.

À la suite des travaux présentés dans ce manuscrit, certaines perspectives peuvent être dégagées pour améliorer l'analyse du rôle du secteur électrique dans le cadre de la transition énergétique à long-terme. D'autres scénarios prospectifs pourraient être analysés avec

différentes valeurs de carbone, d'autres développements technologiques ou l'intégration de nouvelles technologies. Les résultats de ces scénarios contribueraient à mieux évaluer le rôle de chaque composant du système énergétique.

Le système électrique européen est le système plus interconnecté dans le monde et EUTGRID couvre presque tous les pays européens. Une perspective intéressante serait d'étendre la représentation détaillée à d'autres pays. Les résultats constitueraient une amélioration importante pour l'analyse de leur évolution énergétique à long terme. La disponibilité des données devient de moins en moins problématique avec le fort mouvement de l'« Open Data ». Par exemple, le réseau de transport couvrant toute l'Europe, le nord de l'Afrique, la Turquie et la Russie est librement accessible par l'ENTSO-E. D'autres systèmes d'alimentation interconnectés tels que les États-Unis pourraient également être facilement intégrés dans EUTGRID. De même, davantage de réseaux de distribution pourraient être inclus pour mieux représenter son importante diversité. La principale difficulté réside dans la disponibilité des données et les limitations de l'ordinateur.

D'autres améliorations concernent la représentation des opérations du système dans EUTGRID. La première concerne l'utilisation de jours types pour la demande et la production des EnRV. Actuellement, deux jours types sont utilisés pour la demande et 12 jours pour la production des EnRV. Dans un contexte de grande flexibilité de la demande, plus de journées typiques sont nécessaires et pourraient être déterminées à l'échelle d'une région plutôt qu'à l'échelle d'un pays. L'impact serait une meilleure représentation du dispatching au niveau annuel. Les changements climatiques affectant l'efficacité de la production des EnRV, il serait intéressant de modifier les jours de production typiques des EnRV tout au long du scénario. L'incertitude de la production des EnRV ayant un impact important sur le fonctionnement du secteur électrique, la représentation de ce phénomène par le biais d'une approche stochastique aiderait à intégrer leurs coûts cachés. La deuxième amélioration concerne les technologies de stockage. Leurs opérations se limitent actuellement à une stratégie quotidienne. Cependant, certaines stratégies hebdomadaires, voire saisonnières, telles que pour les centrales hydroélectriques, existent et devraient être prises en compte car elles affectent les congestions dans les réseaux de transport et de distribution.

La fonction-objectif mise en œuvre dans les modèles électriques est la minimisation des coûts. Cependant, certains clients modifient leur stratégie énergétique pour maximiser leur auto-consommation. L'intégration de cette stratégie dans le réseau de distribution constituerait un progrès important : avec un pourcentage élevé d'auto-consommateurs, les impacts sur les réseaux de distribution et sur la transmission pourraient être très importants et nécessiteraient d'être évalués

Abstract / Résumé

Abstract

The power system is facing a major shift with the large-scale development of VRES (Variable Renewable Energy Sources). The traditional architecture was built vertically and centralized to ensure the robustness and reliability of the system. However, VRES are intermittent and less predictable. To face such a challenge, the system needs to add more flexibility with new options such as demand side management, storage technologies and VRES curtailment. In addition, renewable energies potentials are unevenly distributed in Europe and, with high shares of VRES, power flows exchanges will increase between specific regions. As a result, the existing transmission grid would face congestions and these flexibility options might not be sufficient to alleviate these power bottlenecks. To analyse these impacts, the work carried out in this thesis uses the long-term energy model POLES (*Prospective Outlook on Long-term Energy Systems*) coupled with the new European power sector module EUTGRID (*European Transmission Grid Investment and Dispatch*). It includes a detailed transmission grid infrastructure and more realistic power flows with a linearized optimal power flow (DC-OPF). A grid investment mechanism is also incorporated to determine the grid investments based on nodal prices. This new model coupling enables to get a dynamic evolution of the transmission grid. The role of the transmission grid is being assessed and compared with other flexibility options. Results show that congestions cannot be alleviated only with flexibility options but also with an important increase of grid investments. Finally, an exploratory work is being carried with the introduction of generic distribution grids (urban, semi-urban and rural) in EUTGRID. The results show that the reinforcements can be slightly delayed with a greater use of back-up technologies and an increase of total CO₂ emissions.

Résumé

L'intégration massive des énergies renouvelables variables (EnRV) provoque d'importants changements dans le système électrique. Le système était développé de manière verticale et centralisée afin d'assurer sa robustesse et sa fiabilité. Cependant, la production des EnRV est intermittente et peu prévisible. Ainsi, le système doit être plus flexible grâce à de nouvelles options telles que la maîtrise de la demande, le stockage ou l'effacement de la production EnRV. Cependant, le potentiel des EnRV est réparti inégalement en Europe. Avec d'importants taux de pénétration d'EnRV, les échanges d'électricité entre les régions vont augmenter provoquant des congestions dans le réseau. Ainsi, les options de flexibilité ne pourront peut-être pas réduire ces congestions. Pour analyser ces effets, le travail mené dans cette thèse utilise le modèle de prospective long terme POLES (*Prospective Outlook on Long-term Energy Systems*) couplé avec le nouveau module du secteur électrique EUTGRID (*EUropean Transmission Grid Investment and Dispatch*). Ce module inclut une représentation détaillée du réseau de transport européen d'électricité avec un calcul des flux plus réaliste. De plus, les renforcements sont déterminés suivant les coûts de congestion de chaque ligne. Ce nouveau couplage permet d'avoir une évolution dynamique du réseau de transport. Le rôle du réseau de transport est ensuite analysé et comparé avec les autres options de flexibilité. Les investissements dans le réseau augmentent ainsi fortement avec d'importants taux de pénétration des EnRV alors que les options de flexibilité ne peuvent pas intégralement remplacer le réseau. Finalement, un travail exploratoire est mené avec l'introduction de réseaux de distribution génériques (urbain, semi-urbain et rural) dans EUTGRID. Les résultats montrent que les renforcements sont légèrement décalés avec une augmentation de l'utilisation des technologies de back-up (comme les centrales à gaz) ; ce qui augmente les émissions totales de CO₂.