Design and impact of
a harmonised policy for
renewable electricity in Europe

D5.2 Report

Assessment report on the impacts of RES policy design options on future electricity markets

Authors:

Pablo Frías, Pedro Linares, Luis Olmos, Michel Rivier
Fernando Banez-Chicharro, Camila Fernandes;
COMILLAS

Marian Klobasa, Jenny Winkler; FRAUNHOFER ISI

André Ortner; TU WIEN / EEG

Georgios Papaefthymiou; Ecofys

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Web:	www.res-policy-beyond2020.eu
General contact:	beyond2020@eeg.tuwien.ac.at

Project consortium:

Energy Economics Group	Vienna University of Technology, Institute of Energy Systems and Electrical Drives, Energy Economics Group (EEG), Austria *(Project coordinator)*
Fraunhofer ISI	Fraunhofer Institute for Systems and Innovation Research (ISI), Germany
CSIC Consejo Superior de Investigaciones Científicas	Consejo Superior de Investigagiones Cientificas (CSIC), Spain
University of Oxford	University of Oxford, United Kingdom
BBH Becker Büttner Held Rechtsanwälte · Wirtschaftsprüfer · Steuerberater	Becker Büttner Held (BBH), Belgium
	Czech Technical University in Prague (CVUT in Prague), Czech Republic
axpo	AXPO Austria GmbH (AXPO), Austria
ECOFYS	Ecofys b.v. (Ecofys), The Netherlands
Universidad Pontificia ICAI ICADE Comillas Madrid	Comillas Universidad Pontificia Madrid (Comillas), Spain
IREES Institute for Resource Efficiency and Energy Strategies	Institute for Resource Efficiency and Energy Strategies (IREES), Germany
EnBW	Energie Baden-Württemberg AG (EnBW), Germany

The beyond*2020* project *at a glance*

With Directive 2009/28/EC the European Parliament and Council have laid the grounds for the policy framework for renewable energies until 2020. **Aim of this project** is to **look more closely *beyond 2020*** by designing and evaluating feasible pathways of a harmonised European policy framework for supporting an enhanced exploitation of renewable electricity in particular, and RES in general. Strategic objectives are to contribute to the forming of a European vision of a joint future RES policy framework in the mid- to long-term and to provide guidance on improving policy design.

The work will comprise a detailed elaboration of feasible policy approaches for a harmonisation of RES support in Europe, involving five different policy paths - i.e. uniform quota, quota with technology banding, fixed feed-in tariff, feed-in premium, no further dedicated RES support besides the ETS. A thorough impact assessment will be undertaken to assess and contrast different instruments as well as corresponding design elements. This involves a quantitative model-based analysis of future RES deployment and corresponding cost and expenditures based on the Green-X model and a detailed qualitative analysis, focussing on strategic impacts as well as political practicability and guidelines for juridical implementation. Aspects of policy design will be assessed in a broader context by deriving prerequisites for and trade-offs with the future European electricity market. The overall assessment will focus on the period beyond 2020, however also a closer look on the transition phase before 2020 will be taken.

The final outcome will be a fine-tailored policy package, offering a concise representation of key outcomes, a detailed comparison of pros and cons of each policy pathway and roadmaps for practical implementation. The project will be embedded in an intense and interactive dissemination framework consisting of regional and topical workshops, stakeholder consultation and a final conference.

Contact details:

<< Project coordinator >>

Gustav Resch
Vienna University of Technology, Institute of Energy Systems and Electrical Drives, Energy Economics Group (EEG)
Gusshausstrasse 25/370-3
A-1040 Vienna
Austria
Phone: +43(0)1/58801-370354
Fax: +43(0)1/58801-370397
Email: resch@eeg.tuwien.ac.at

<< Lead author of this report >>

Pedro Linares
Instituto de Investigación Tecnológica
Comillas Pontifical University (Comillas)

C/Alberto Aguilera 23
28015 Madrid
Spain
Phone: +34 91 5422800
Fax: +34 91 5423176
Email: pedro.linares@upcomillas.es

This report

Assesses quantitatively the major interactions between RES-E support instruments and electricity markets and networks. In particular, the report looks at price effects (including merit-order effect, negative prices and price volatility), balancing costs and needs, network investment and operation, and system adequacy.

Authors:
Pablo Frías, Pedro Linares, Luis Olmos, Michel Rivier Fernando Banez-Chicharro, Camila Fernandes; COMILLAS
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André Ortner; TU WIEN / EEG
Georgios Papaefthymiou; Ecofys

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1 Introduction

Previous reports within the Beyond2020 project have already emphasized the need to analyse carefully the interactions between RES-E support instruments and electricity markets, grid policies and regulatory designs. As stated in these reports, the growing penetration of RES-E into European power systems makes the saliency of these interactions larger, and the need to address them more pressing.

Deliverable 5.1 of this project reviewed these interactions between RES-E support instruments and electricity markets, networks and regulatory designs, based on the existing literature on the topic. In fact, given the scarcity of previous studies, particularly on how regulatory design of RES-E and wholesale markets and grid regulation affects both the RES-E deployment and the overall power systems efficiency, the report even tried to advance the discussion about these issues, although from a mostly qualitative approach.

The first contribution of the report was to propose a methodology that, instead of taking the different RES-E support instruments as such, decomposed them into design elements, which are the ones that actually determine outcomes and interactions. Table 1 shows how the policy pathways considered in the project can be decomposed into design elements.

Table 1 List of policy design elements influencing markets and grids

Common design elements					
Techologies eligible for support (all vs. only new plants)					
Flow of support (constant or decreasing)					
Duration of support					
Cost burden (taxpayers, consumers)					
	Concerned pathways				
Instrument specific design elements	FIT	FIP	QUO	QUO(b)	TEN
Demand orientation	x				
Technology specific support	x	x		x	x
Size-specific support	x	x		x	x
Location-specific support	x	x		x	x
Minimum/maximum support prices (cap/floor/penalty)		x	x	x	
Cost-containment mechanisms	x	x			
Purchase obligation	x				x*
Forecast obligation	x				x*
Support adjustments	x	x	x	x	
Distribution of proceeds from penalties/deposit			x	x	x*
Regulatory / support framework					
Cooperation with third countries					
Eligibility of plants in other countries					
Distribution of grid connection costs					
Degree of harmonisation					
General support characteristics					
Exposure to market risk (support tied to hourly market prices)					
Support based only on ETS					

* Depends on the actual organisation of the tender

The report then showed the multiple interactions that appear between these design elements and electricity markets and networks, and identified the more relevant ones. These are: the merit-order effect (including the assessment of how RES-E may influence the probability of negative prices); price volatility; system adequacy; balancing costs and needs; and grid investment and operation effects.

- Merit order effect: the introduction of RES generally depresses wholesale market prices, although this depends on the system configuration: In some cases, average prices might remain stable (if the marginal technology remained the same), or might even increase (if the marginal technology is the same and fuel costs, CO2-costs or cycling costs increase). When prices do go down, the signal for new investment that the market sends is reduced, and income for existing producers also decreases. This might be corrected with other instruments.
- Price volatility: the intermittency of RES will increase the volatility of wholesale market prices.
- Negative prices: when RES are subsidized, negative prices may increase their frequency (negative prices are not only caused by RES promotion), since RES will be interested in being dispatched at negative prices in order to keep receiving the subsidy, if the subsidy is linked to generation (the limit for the negative price is the amount of the subsidy). This effect is reinforced when there is priority of dispatch for RES.
- Market power may also be affected depending on the policy instrument chosen. When RES power plants bid into the wholesale market and their income depends, even partly, on wholesale prices, the amount of inframarginal energy increases and hence the incentive for agents to exert their market power if any.
- Generation adequacy: a large introduction of RES may affect the adequacy of the generation system, that is, its ability to supply demand at all times. Current systems may not be flexible enough to respond to intermittent RES. This is compounded with the price depression effect, which reduces the signal for new investment and therefore limits the possibility of adjusting the system with more flexible capacity (demand side management, storage and conventional power plants).
- Network effects: Depending on how it is done, introducing more RES into the power system will require the expansion of the power grid. Using them efficiently (and also building additional capacity) may also require designing the right rules for cross-border trade and cost recovery.

In this report, deliverable 5.2, we try to assess quantitatively these interactions. Given its relevance for the assessment of some of the effects, we have also estimated the impact of the different policy pathways on the market value of RES-E.

Unfortunately, we have not been able to provide a joint, consistent assessment of all interactions. This would have required the combination of many assessment methodologies into a single instrument, which would then be applied to the entire European region. Because of the serious limitations in the availability of both data and modelling tools, we resorted instead to using different tools, applied to different regions in Europe. However, and in order to be able to compare to some extent our results, we have used (except for the assessment of system adequacy) the same scenarios for RES-E deployment. These scenarios were generated in WP4 with the Green-X model. Also, the same set of prices for fuels, carbon allowances, etc., have been used, in this case taken from PRIMES high-res scenario.

Although the lack of an integrated tool prevents us from providing consistent, global estimates of the total impact of RES-E support on electricity markets and grids, it does allow for understanding the magnitude of these impacts and how they depend on the support instrument chosen or other factors, so that they can be taken into account when designing support instruments, electricity market rules, or grid regulation.

Section 2 presents the different methodologies that we have followed to assess the different impacts of RES-E policy pathways on electricity markets and networks. Section 3 provides detailed information on the scenarios, both from a general point of view, and for the specific assessments carried out. Section 4 shows the results obtained and the implications for electricity markets and grids. Finally, section 5 offers some conclusions.

2 Methodology

2.1 Assessment of price effects

The model used to assess price effects (PowerACE model)

Rising shares of renewable are expected to decrease average wholesale market prices due to the merit order effect. In addition, renewables are expected to earn less in the market, i.e. their market value decreases, when shares are increasing due to the relative simultaneity of their production. Another expected effect of increasing shares of renewable on prices is increasing price volatility as well as more hours with negative prices (in markets where prices below zero are allowed for and when RES have some type of economic support).

In order to predict some of these price developments it is useful to apply a model that is able to represent future market conditions in a realistic way. For this purpose, the agent based electricity market simulation model PowerAce was used[1].

PowerAce simulates the central processes regarding the trading, generation and distribution of electricity in Europe. The most important actors of the electricity market are represented by agents in the model. These include for example utilities selling electricity produced by thermal units and storage devices and agents trading electricity from renewable sources. On the demand side, an aggregated supplier bids a demand profile into the market. Markets represented in the model include the spot market, the reserve markets and a market for CO_2 certificates.

The model calculates hourly electricity market prices for 27 EU countries based on the bidding of the different conventional power plants. There are three steps in the model to achieve an optimal dispatch for each individual hour. In a first step, pump storage facilities optimise their bids based on expectations of future electricity prices. In a second step, plants are contracted for the balancing markets. In a third step, the bidding for the regular day-ahead market takes place. The resulting price is based on the bidding of the different plants. In a normal situation, the plants bid according to their marginal production costs (fuel costs and CO2 prices are included as input data). In addition, cycling costs are included into the bids. When there is scarcity in the market, a mark-up is added to the bid prices[2]. In the model, plants that are contracted in the balancing market bid a very low price into the regular market in order to be dispatched and be able to offer the necessary balancing services.

The hourly electricity production from renewables, as well as the demand curve are included as input data into the model. The data for variable renewables (wind and PV) is derived from two separate models ISI-PV Europe and ISI-Wind Europe taking into account renewable potential and weather conditions at different locations[3]. In the current version of the model, renewables are bid into the market by the grid operator- trader agent (representing the case of feed-in tariffs) at a fixed minimum price. Curtailment is possible at times when renewable production on its own is higher than the domestic demand plus possible exports. The data for the demand profiles is taken from past demand curves i.e. demand flexibility or future changes of the demand structure are not included as an option in the modelling, the supply side has to follow the demand curve at all times.

[1] This model has so far been extensively used in the German context, e.g. to quantify the merit order effect or CO_2 reductions based on the extension of renewables (see Sensfuß 2011, Klobasa et al 2009). On a European level, mostly a different version of the model was used to simulate a cost-optimal technology mix for Europe (see e.g. DII 2013).

[2] For further details on the mark up see Genoese et al (2007).

[3] For further details about these models see Schubert (2012).

The main advantage of PowerAce compared to other models is its very detailed representation of the conventional power plants (by plant unit) as well as weather conditions and renewables generation (geographically and timely). Also, the market is cleared for all of Europe in hourly intervals which allows for observing volatility effects in a detailed manner.

In addition, PowerAce is an agent-based electricity market model. Agent-based simulation aims to incorporate the players' perspective into the modelling. Thus, for example strategic bidding strategies, learning effects or imperfect markets and information can be represented in such models, which is not possible in the case of optimisation models.

In terms of grid capacity, PowerAce currently only includes interconnector capacities between the different European countries. Thus, the effect of domestic grid constraints on prices cannot be modelled. In some countries, e.g. with zonal prices, this leads to different price effects than in reality. In general, it is important to notice that PowerAce has only been calibrated for the German market – therefore the resulting prices for other countries do not necessarily reflect reality. Nevertheless the results can give an impression of the order of magnitude of the impact of renewable on prices.

Figure 1 gives an overview of the different agents and markets represented in the model. More detailed descriptions of different model versions can be found among others in Sensfuss (2007).

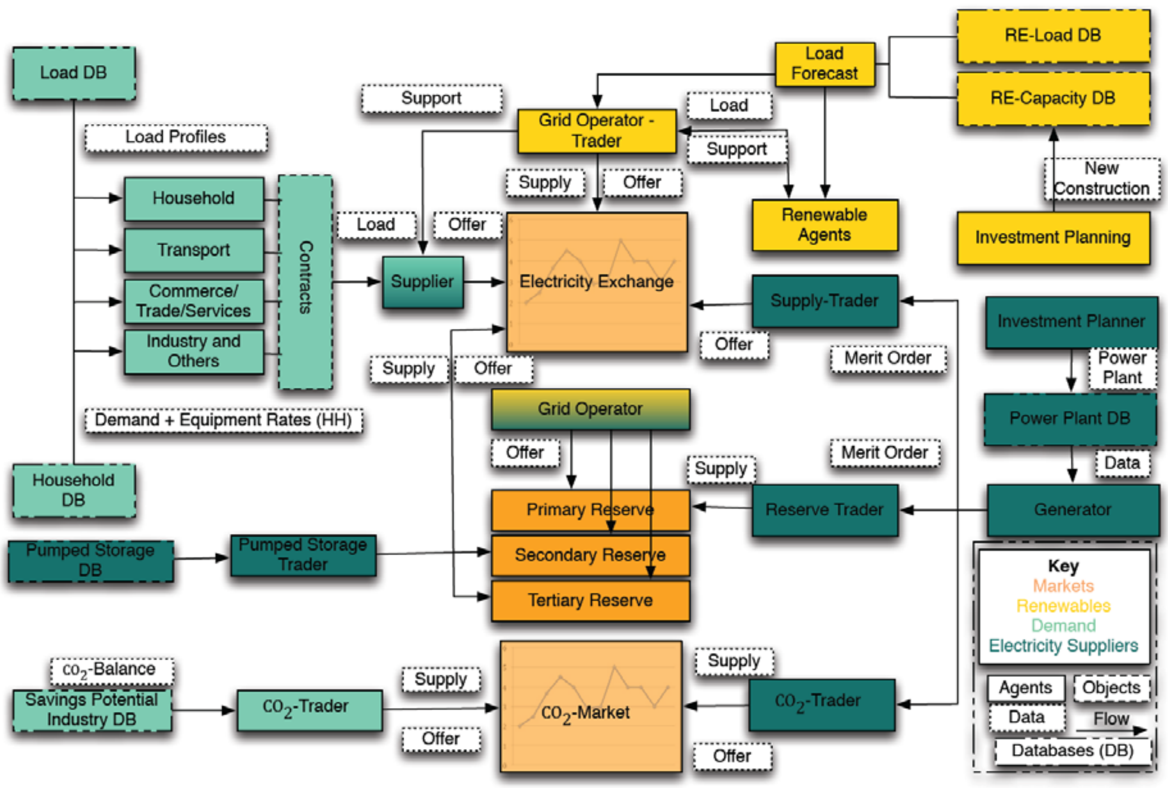


Figure 1 Overview of markets and actors in the PowerAce model

2.2 Assessment of balancing costs and needs

The PowerAce model presented above does take into account balancing markets. However, it does so in a deterministic way, assuming a certain production of all technologies. This limits to a certain extent the realism of results if we assume a large penetration of RES-E: since the production of these technologies is variable, and difficult to forecast, it is more realistic to consider this RES-E production as stochastic. Therefore, we complement the PowerAce model with another model, the ROM model, that is able to include the stochasticity of RES-E into the assessment. Unfortunately, and due to the increased complexity of this model, it was impossible to assess the impact of RES generation on balancing costs and needs at the European level. This study will therefore be performed for the Spanish power system and the results can only be considered as indicative.

The ROM model is a mid-term operation model that simulates power system operation during one year with daily periods and hourly time steps. It has been developed at the Instituto de Investigación Tecnológica of Universidad Pontificia Comillas and has been used as tool to analyse the impact of high shares of RES generation on power systems operation in several EU-funded projects such as SUSPLAN (www.susplan.eu), MERGE (www.ev-merge.eu) and TWENTIES (www.twenties-project.eu). Here, the ROM model is used to analyse the hourly operation of the Spanish power system during the year 2030 for each one of the scenarios described in Chapter 3.

The ROM model is a unit commitment model where the economic dispatch is decided in two stages. The first stage represents the day-ahead market in which the unit commitment problem for each day of the year is solved minimizing system operation costs. The second stage represents an intraday market in which the unit commitment is revised and generators are redispatched depending on unit outages occurred after the day-ahead market is closed and on wind forecasting errors.

In the first stage, the unit commitment and hourly dispatch of all thermal and hydro units, as well as the assignment of upward and downward reserves to these units, are decided through deterministic optimization. The unit commitment problem is described in detail in Dietrich et al (2012). Operation costs for the whole system are minimized in the objective function. These costs include fixed and variable costs of thermal units (no-load, start-up, fuel, operation & maintenance costs, and CO2 emissions), penalty for shortcoming of upward and downward reserve, and non-supplied energy costs.

Detailed operation constraints are also taken into account in the unit commitment model:

i) Demand and generation balance and supply of operating reserves. Up and down reserve requirements are input data to the model and include two main components: the first is related to wind forecasting errors, and the second is related to unit outages. These reserve requirements can be compared to the supply of secondary and tertiary reserves requirements for the Spanish systems, which take into account demand and wind generation forecast errors and the failure of the largest thermal unit.

ii) For thermal units: start-up/shutdown time, bound on power reserve and power output, up and down ramps and exponential start-up costs.

iii) For hydro units: bound on pumped storage up and down reserves, water inventory in hydro reservoirs and pumped storage, bounds on hydro power output and daily hydro output target. Decisions above the daily scope, as the weekly scheduling of pumped storage hydro plants, are done internally by the model respecting economic criteria. Yearly hydro scheduling of storage hydro plants is done by a longer term model (hydrothermal coordination), such as the one presented in Ventosa et al (2000) and it has to be provided as input data to the operation model.

Series of distributed generation and wind generation are estimated and introduced in the model as input data. Distributed generation comprises cogeneration, small hydro, solar and biomass technologies. Regarding wind generation, three series are used in the model: the first one corresponds to the hourly wind generation forecasted at the time of the day-ahead market (prediction DAM); the second one corresponds to a better estimation of wind generation when unit commitment is modified (prediction IDM); and the third series corresponds to the real wind production.

In order to simulate the system operation during a whole year, the model runs 365 daily unit commitment problems (each one of them with 24-hour time steps). The initial conditions of each day depend on the final schedule of the previous day. The model is run as a single-node unit commitment. Hence, it is assumed that the network is not constraining the operation of the system in any way. Figure 2 presents an overview of the model for a single day. The process represented in the figure is repeated 365 times (for each day of the year).

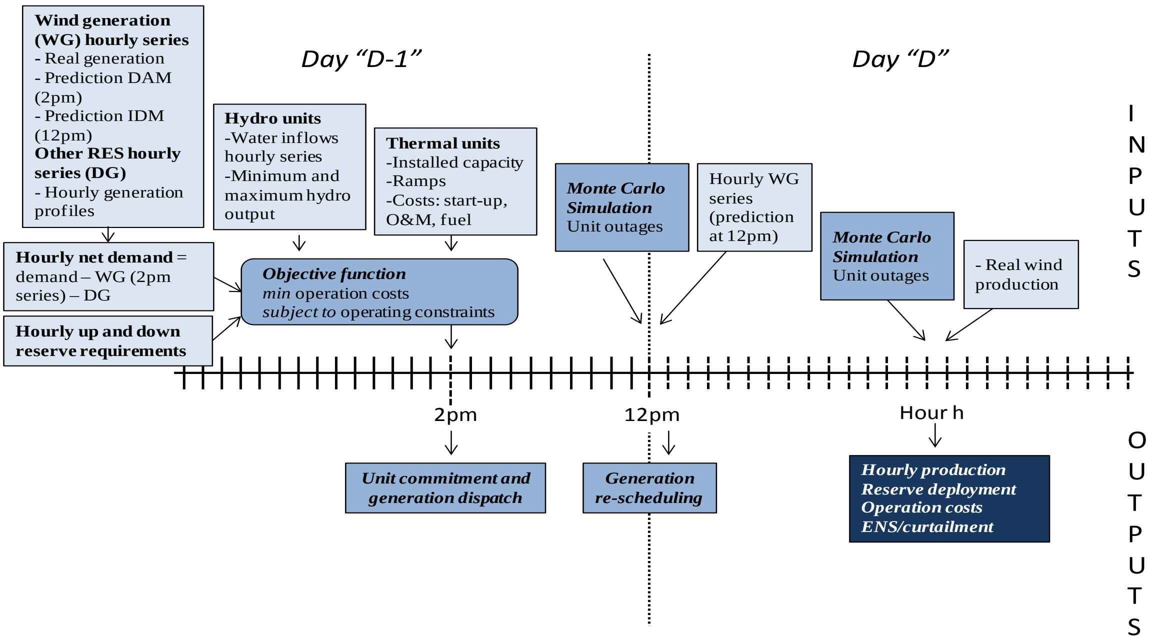


Figure 2 ROM model overview

In the second stage, the model revises the schedule obtained in the day-ahead market and redispatches generation at 12 pm of ''D-1'' in case unit outages occurred after the day-ahead market is closed (2 pm of ''D-1''). Monte Carlo simulation is run to simulate unit outages. The second stage is divided in two parts:

a) At midnight, unit commitment is modified to account for unit outages (determined by Monte Carlo simulation) that occurred after the day-ahead market is closed. This is assumed to be the last hour at which a thermal unit can be committed to reach the morning demand ramp. The objective is to reduce the difference between generation and demand to a safe margin (approximately, 1 GW).
b) Subsequently, the model simulates unit outages and corrective actions are applied for production deviations due to these outages and due to wind forecast errors. The order in which these actions are applied follows economic criteria: (1) hydro reserve deployment; (2) pumping units reserve deployment; (3) thermal reserve deployment and (4) commitment of gas turbines in real time. If generation and load balance is not achieved after reserve is deployed, two operating situations can happen: (i) non-supplied energy, if generation is not able to cover demand and (ii) RES energy curtailment, if there is an excess of production.

The main outcomes of the operation model are hourly generation by technology, use of reserves, energy curtailment (excess of production at a single node), system and reserve marginal cost.

2.3 Assessment of grid investments and operation

This section presents the methodology used to evaluate the influence of different policy frameworks for supporting the deployment of RES on the development of the transmission network and main operation variables related to the existence of the grid. This methodology allows us to compute an estimate of the investment and operation costs of the transmission network to achieve the most efficient outcome of the system from an economic point of view, which at the same time is compatible with preserving quality of supply levels and achieving environmental policy objectives, considering different RES generation scenarios.

However, due to the complexity and size of the problem, only the power systems of Portugal, Spain and France are analyzed in detail. The network model we consider includes a fully detailed representation of these systems[4], while the rest of the European network is modelled in a simplified way, with one node per country and equivalent corridors between them and France. The network outside the countries of interest (Portugal, Spain and France) is included for the purpose of computing exchange flows between France and its neighbouring countries, instead of assuming pre-specified values for these flows that might not be coherent with the rest of system variables.

The analysis is performed using a network expansion planning model. This model is fed with input data including: a network model of the 2008 transmission system for the concerned countries plus equivalent corridors linking the rest of EU countries and these to France; the set of available conventional power plants and their features expected for the year 2030 together with the location of these plants at node level; the pattern of RES power production and electricity demand available for a set of operation snapshots that aim to be representative of the operation of the system in the whole year; and a list of possible network reinforcements and new elements to consider for the expansion. Figure 3 illustrates the overall methodology. The most important elements or building blocks of the methodology applied will be further explained in the following subsections.

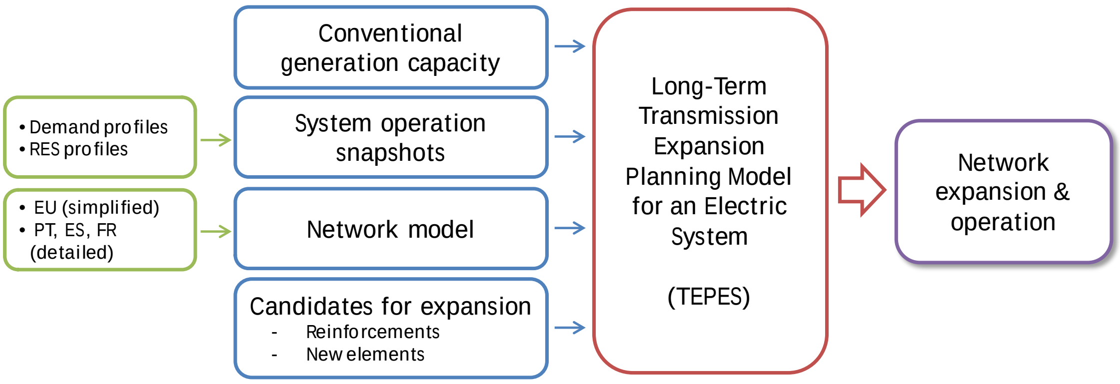


Figure 3 Overall methodology for the assessment of grid investments and operation

2.3.1 Description of the TEPES model

Given the intermittent nature of the power output of most of RES based generation, the deployment of large amounts of this generation is expected to result in a significant increase in the power flows among areas in a region comprising several systems, as well as an increase in the variability of system conditions. As a result of this, the development of the network of all the systems in the region should be planned in an integrated way and operation snapshots to consider in the planning process should probably increase. Given the large size of the network to consider in the planning process, the amount of possible combinations of network reinforcements to consider turns out to be huge, while the number of operation situations increases significantly. Then, computing the optimal expansion of the transmission network for each Policy scenario considered requires making use of computer tools able to automatically produce expansion plans.

Transmission expansion planning tools determine the set of new network facilities (lines and other network equipment) required to supply the forecasted demand at minimum cost. The planning horizon considered in our study is about 15 years. This means that we are performing tactical planning, which is mainly focused on providing guidelines to be applied when deciding the future structure of the transmission network and global estimates of costs incurred in the development of this network.

[4] About 1500 nodes and more than 2000 lines are considered.

We have made use of a decision support tool called TEPES, which was designed and built to determine the transmission expansion plan of large-scale electricity systems at a tactical level. Candidate lines to become network reinforcements considered by the TEPES model are pre-defined by the user. Then, the model chooses the optimal reinforcements among these.

Main features of the TEPES model include:

- Dynamic: the model is able to compute the optimal evolution of the network over a long period of time considering system operation requirements at different time horizons, 2020 and 2030 for example.
- Stochastic: several stochastic parameters associated with the long term evolution of the electricity system that can influence optimal transmission expansion decisions are considered. Besides, the model may consider stochasticity scenarios associated to: renewable primary energy availability, electricity demand, hydro inflows, and fuel costs. The latter, short to medium term, uncertainty sources are modelled through the consideration of several operation scenarios for a certain year and a set of snapshots for each scenario, including: operation snapshots (hydroelectricity, etc.) and reliability snapshots (N-1 generation and transmission contingencies)
- Multicriteria: some of the main quantifiable objectives of the expansion of a transmission network are included into the objective function to be minimized by the model. The model aims to jointly minimize transmission investment, variable operation costs (including generation emission costs), and reliability costs associated to N-1 generation and transmission contingencies.

The optimization method used is based on the functional decomposition of the problem into an automatic network expansion plan generator (based on optimization) and a module assessing transmission expansion plans from different points of view (operation costs for several operation conditions, reliability assessment for N-1 generation and transmission contingencies, etc.). The problem solved by the model is formulated as a two-stage stochastic optimization one. Benders' decomposition is applied, where the master problem proposes network investments, the operation subproblem determines the operation cost resulting from these investment decisions, and the reliability subproblem determines the amount of non-served power caused by generation contingencies given the aforementioned network investment decisions.

The operation model (evaluator) computes network flows that comply with DC load flow equations. By nature, transmission investment decisions are binary. Given that network assets considered in the problem formulation correspond to specific lines, investment options assessed involve also the construction of specific network elements. The current network topology is considered by the TEPES model as a starting point for the development of the network.

2.3.2 Network model and candidates for expansion

The initial network considered for the power systems of Portugal, Spain and France, which is represented in Figure 6, has been obtained from network models available at IIT, based on information publicly available like that from the network model developed by Prof. Bialek[5]. The size of equivalent corridors connecting the rest of European countries and France has been set to the Net Transfer Capacity (NTC) values among these systems provided by the ENTSO-E for the year 2008.

[5] This network model is publicly available.

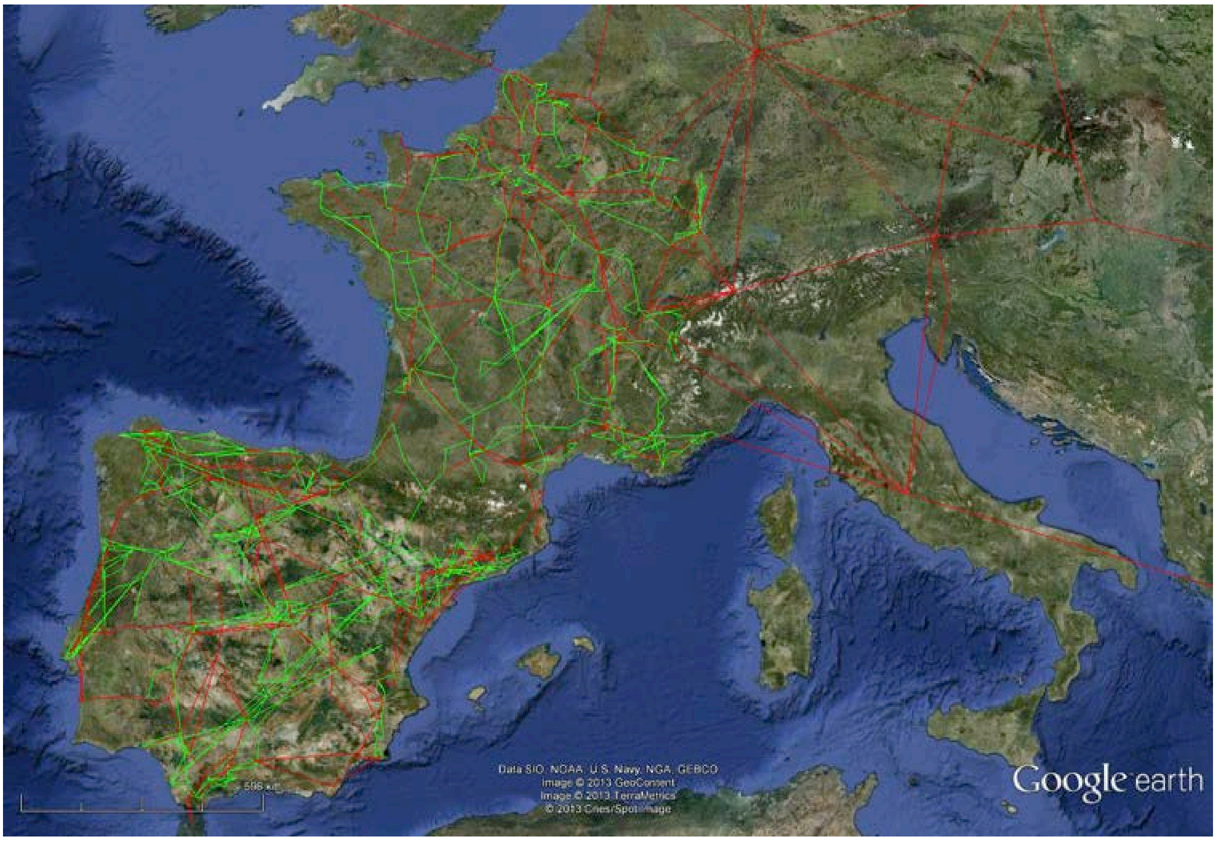


Figure 6 Initial network considered for the power systems of Portugal, Spain and France and the equivalent corridors among the rest of the EU countries

As previously explained, in order to compute the optimal expansion of the network in the region for the different RES generation scenarios, we have provided the TEPES model with candidates for investment. Candidates considered in our analysis include the following:

- Reinforcements of all existing lines, transformers and corridors. In order to consider economies of scale in investment, for each existing network asset, candidates of different sizes are included. Moreover, more than one candidate of each size is proposed for those elements of the system network that may need to be largely upgraded.
- New lines, i.e. those connecting nodes that were not directly linked previously. All the offshore lines that connect the current mainland network to the projected offshore wind farms, as well as new interconnection lines between Spain and France are considered.

Table 2 shows the different network technologies and types of investment that are provided as reinforcement options to the model. Specific unit construction costs and losses have been considered for each technology and type of investment.

Table 2 Transmission technologies and types

Technology	Investment type
AC	Overhead line
	Underground cable
Transformers	-
DC	Overhead line
	Underground cable
	Submarine cable

Regarding the modelling of the flow of power in the network, the first Kirchkoff law (transportation model) has been considered for DC lines and corridors and the first and second Kirchkoff laws (DC model) for AC lines and transformers. Transmission losses have also been taken into account but, due to the size of our network model, they have been computed as proportional to the power flows in the network. However, we have made the proportionality factor used to determine transmission losses in each network element dependent on the characteristics (technology, length) of this element.

Investment decisions affecting individual network assets, like AC lines, transformers and offshore lines in Spain, France and Portugal, are discrete, i.e. only a discrete number of units of this asset can be built. Due to the fact that the system of the rest of the European countries has been represented in a simplified way, investment decisions affecting corridors among these countries are continuous. The decommissioning of already existing elements is not considered when computing the network expansion.

2.3.3 System operation and selection of snapshots

We have considered several snapshots to represent the operation of the power system throughout the whole year. Due to the large size of the network model considered, only four operation snapshots have been modelled. These snapshots are aimed at representing relevant operation situations driving the development of the network of a system with a high penetration of RES generation. They have been selected using clustering techniques looking for the following situations:

- One snapshot that represents peak demand hours in the system. Given that demand data are common to all scenarios, the same hour has been considered in the four RES generation scenarios.
- One snapshot that represents those hours with largest power flows among the zones considered for the system. Large power flows among zones would stress the grid. Power flows among zones have not been computed explicitly for each of the hours of the year in order to select the most demanding conditions in this regard. Instead, we have chosen those hours when there were the largest differences among net demands (demand less RES power production available) in system zones, i.e. those when there were largest positive and negative net demands together, as those hours where power flows would be largest as well. Due to the fact that net demands in zones depend on RES power production, different hours were considered for different scenarios. Nevertheless, the pattern of expected network flows in snapshots selected for high RES penetration scenarios (HARMFIT, HARMQUO and NATFIP) were similar, with power flowing from Spain and Portugal to France and Central Europe.
- The last two snapshots selected represent the rest of hours in the year. Due to the fact that those hours corresponding to peak demand and large power exchanges among zones had been previously selected, these two last snapshots represent "average" system operation conditions.

Figure 4 and Figure 5 depict the methodology that has been followed to select the snapshots considered in our analysis. First, hours (h_1) with the highest demand are selected and a representative of them is chosen. Within the remaining hours, those expected to feature largest power flows among zones (*h2*), i.e. those with both highest positive and negative net demands in zones, are again selected and their representative is chosen. Finally, the rest of the hours ($8760 - h_1 - h_2$) are clustered into two groups and their representatives are computed to represent the operation throughout the rest of the year.

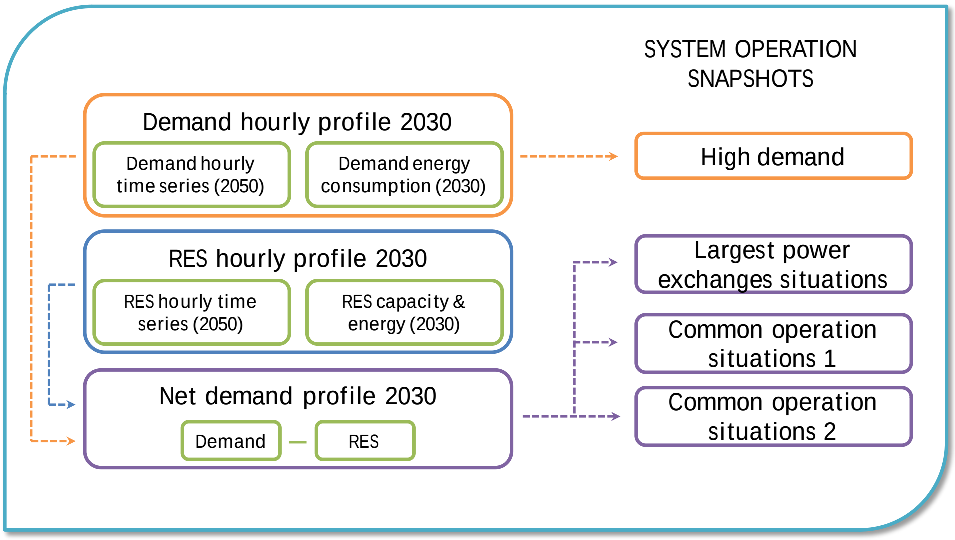


Figure 4 Data flows occurring in process to select system operation snapshots

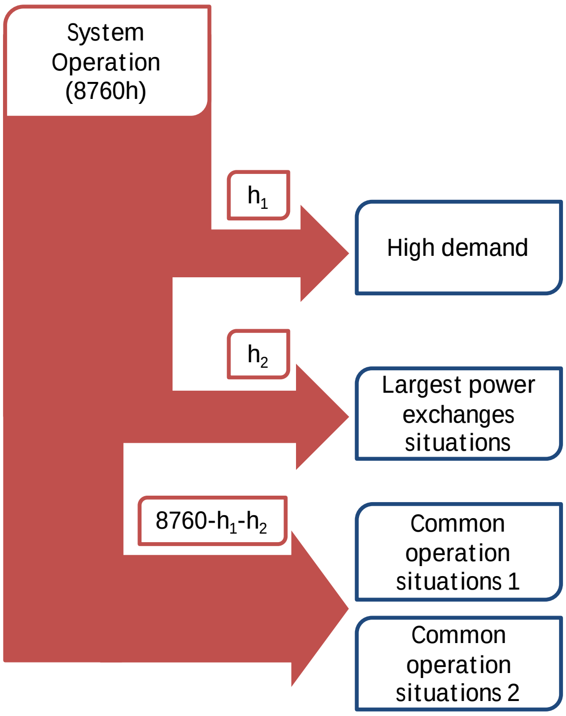


Figure 5 Procedure to select the system operation snapshots

No priority dispatch for RES technology is considered when computing the operation of the power system. Thus, both conventional and RES generation units are dispatched based on their operation costs.

2.4 System adequacy

System adequacy and reliability are terms used interchangeably to describe the ability of a power system to carry out its function of delivering electricity to the consumer. System adequacy corresponds to the existence of sufficient facilities within the system to satisfy demand (Billinton and Allan, 1996)

To investigate the effects of RES on the system adequacy and the impacts from the application of an integrated approach to capacity provision, the Ecofys multi-area reliability model is used, which is presented in the next section. The model considers the capacity and demand within the countries, but also the capacity and reliability of the interconnections. In this way, the optimal back-up capacity for an interconnected system can be compared to the necessary capacity on a national level.

The way this methodology has been used differs however from other sections, due to time constraints: Instead of simulating the impact of different RES policy scenarios (policy pathways), here only one RES scenario has been simulated and compared against the business-as-usual scenario.

2.4.1.1 Generation system Adequacy: background

The generation system adequacy is described by indices like the loss of load probability (LOLP) or loss of load expectation (LOLE). A loss of load is given if the available generation capacity is not sufficient to cover the system load. The LOLE (for example one day in ten years) is calculated by summing up the LOLPs of each time step in the considered time period.

In a single area reliability calculation, the LOLP is calculated as follows. The system is represented by a copperplate and network restrictions are neglected. For each conventional power generator, a forced outage rate represents the probability of its outage. A convolution leads to a cumulative probability function stating the probability of each possible generation state [BIL96]. The probabilities of available conventional generation are used in conjunction with the load time series to compute the LOLE. The outage probabilities are assumed to be independent of the load levels. For renewable power sources like wind power and PV, the temporal correlation of the resource availability and the load have to be considered. For this, they are introduced as negative load and the load levels are diminished by the corresponding generation levels. The resulting net system load is then used to perform the reliability calculation.

In multi-area reliability calculations, an interconnected system is considered and the transfer capacities of the tie lines are taken into account. The areas can for example refer to countries, geographic zones or control areas. One main motivation for multi-area reliability calculations is to evaluate the enhancement of reliability due to interconnection and due to market integration. Next to the parameters described above, the transmission capacities of the tie lines (the maximum power that can be transferred between each pair of areas) are required. In this framework it is also possible to consider outages of tie lines. The LOLP can be calculated for each country separately and for the system as a whole.

The reliability calculation is used for the system planning process. A reference or target reliability is thereby defined for each area and/or for the complete system. Power plants are then added to the system until the reference reliability level is reached. In a multi-area system, the reference reliability can be reached by different combinations of additional power plants as a new power plant in one area can also improve the reliability in another area. A second criterion to assess the required additional plants is given by the investment costs. The combination of added power plants is chosen that has the lowest costs and that guarantees the target reliability in all areas.

The total system available generation capacity is assessed by taking into account the probability of outages of all system components, i.e. plants and tie-lines. If one would try to enumerate the possible states of the system, one would need to estimate all combinations coming from 2 states

(ON/OFF) for each system component; for N components this leads to a total number of 2^N. For example, in a three area system with only two power plants in each area (6 power plants and 3 tie lines), there are 512 (2^9) combinations of generation and tie line availabilities. In a four area system with three power plants in each area (12 power plants and 6 tie lines), there are already 262144 combinations. In real systems, the number of power plants is substantially higher and different load levels have to be considered. Therefore, methodologies should be devised that can deal with this complexity.

In the next section the methodology for the estimation of multi-area generation system adequacy is presented, motivated by the complexity of the problem. Different algorithms are applied in order to solve the problem. The system is first represented by a flow-network so that maximum flow calculation techniques like the Ford-Fulkerson method can be applied. Based on the maximum flow calculations, a decomposition approach is performed classifying the possible system states into loss-of-load states and acceptable states. The decomposition can be enhanced in order to consider several load levels at the same time (simultaneous decomposition) or new power plants in the same system state space (global decomposition). A pre-clustering of load levels may be used in order to reduce the calculation time.

2.4.1.2 Multi-area generation system adequacy

For reliability calculations, the multi-area power system is usually formulated according to the network flow problem (Doulliez and Jamoulle, 1972). The areas are represented by nodes and the connections are called arcs, see Figure 6. A source node S and a sink node T are added to represent the generation capacity and the load. The generation capacity of an area is given by the arc connecting the source with its node. More precisely, each level of available generation capacity (depending on the number of outages) is represented by one state of the arc. In the same way, a tie-line that is either working or out-of-order is represented by two states of the corresponding arc. The arc between the node and the sink stands for the load. Each state of the system is given by the combination of the states of all arcs, corresponding to the respective generators and tie lines outages.

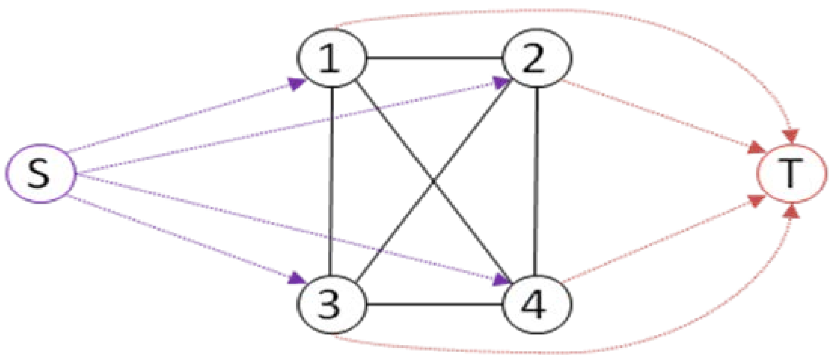


Figure 6 Network representation of the interconnected system

For each state of the system, there is a maximum flow going from S to T. If the maximum flow is below the total demand, there is a loss of load (one or more arcs going to T are not fully used). The sum of the probabilities of all states with loss of load is the LOLP. There are several algorithms to estimate the maximum flow of the system (e.g. the Ford-Fulkerson algorithm).

Due to the huge number of system states (given by all combinations of arc states), decomposition approaches were developed to classify sets of states and reduce the dimension of the problem. Decomposition was first presented in (Doulliez and Jamoulle, 1972) and applied to power system in (Clancy et al, 1981; Clancy et al, 1983) in two approaches, A and B decomposition:

1. The A decomposition is applied in order to find sets of acceptable states. Starting with the maximal states at all arcs (all capacities are available), the maximum flow is calculated giv-

ing a flow result for each arc (maximum flow state). Assuming that there is no loss of load, all arc states that are larger than the maximum flow state will also be acceptable. These states constitute a first set of acceptable states.

2. The B decomposition leads to state sets that have similar area loss of load characteristics (i.e. for all states of one set, the same areas experience loss of load). The LOLP per area is then calculated by summing the probabilities of the states that are classified in the relevant sets. The system-wide LOLP is given by the sum of probabilities of all loss of load states (which is not equal to the sum of the area LOLPs if there are loss-of-load events in several areas at the same time). For this study, the B decomposition was applied, following the description in [CLA83].

The decomposition is applied in an iterative way. First, the complete state space is considered. After the first decomposition, unclassified states remain. The decomposition is then applied to this sub-set. An exhaustive decomposition would lead to a classification of the complete state space. However, in practice, the effectiveness of the decomposition decreases with the number of iterations. A convenient characteristic is that the total probability of the unclassified states is known. This probability added to the LOLP therefore gives an upper-bound for the LOLP. Hence, depending on the computational power and the required level of accuracy, the number of iterations can be adapted.

The decomposition has to be run for each load situation. However, many internal steps of the decomposition may be repeated by this approach. The calculation efficiency can be increased by regarding several load situations in one decomposition, called Simultaneous Decomposition-Simulation (Singh and Lago-González, 1990). It is based on the fact that an identical increase of the load and the generation capacity (if firm capacity is added) does not change the reliability. Assuming that there are two load situations, only the first load situation is considered for the load arcs. The remaining state space is then doubled and, in the new states, the generation capacity levels are raised by the load differences. Repetitive states are then aggregated in order to reduce the state space and the decomposition can be run simultaneously for several load situations.

The number of load levels is however still limited due to calculation time. A load clustering is therefore applied before the decomposition. In the clustering, the situations with the highest global and area (residual) load levels are considered explicitly. All load situations below a certain threshold (e.g. below 70% of the peak load) are aggregated and assigned to the threshold load level as they do not contribute to the LOLP in an important way. The remaining load levels are clustered by a k-means approach.

Finally, the LOLP calculation is applied for the generation planning, i.e. the derivation of the required power plants. For this application, only power plants of one type (size, FOR) are added. The following heuristic approach is then sufficient to deliver results that are close to the optimum (even though optimality cannot be guaranteed) and that is also similar to the way the process can be imagined in reality.

1. The calculated LOLPs are compared to the reference reliability for each area.
2. One power plant is then added to the area with the biggest gap.
3. The LOLPs are again calculated (as the new power plant may also have changed the reliability in other areas) and
4. The steps 1-3 are repeated until the target reliability is achieved everywhere.

An overview of the methodology as well as of the input and output parameters is given in Figure 7.

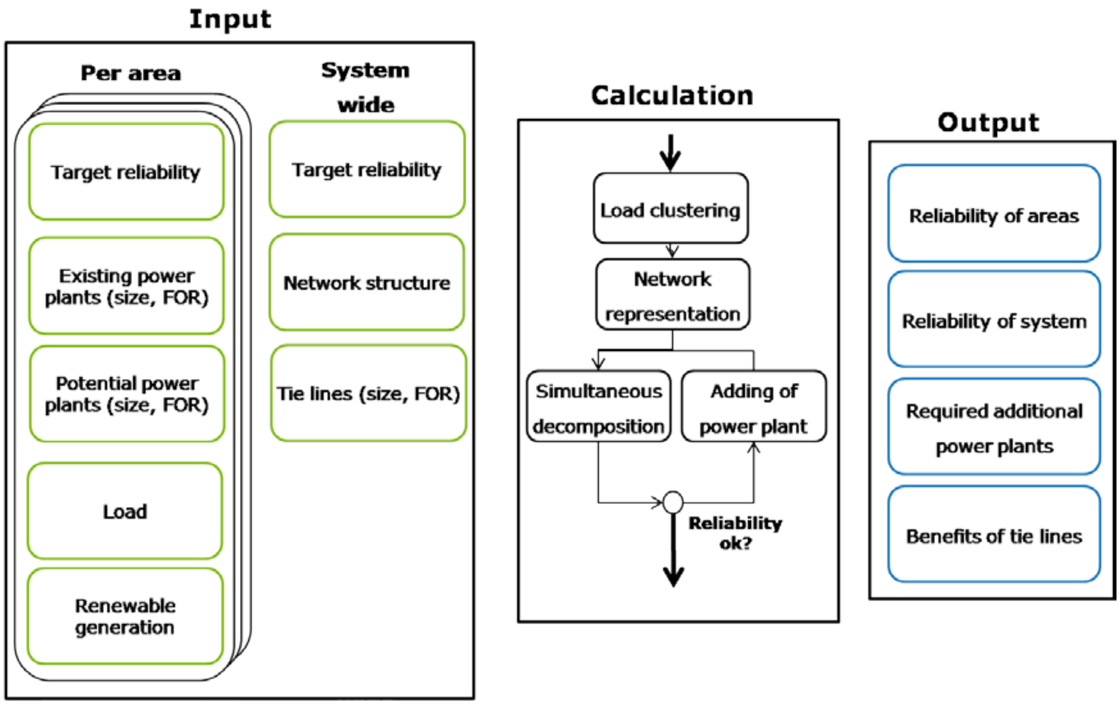


Figure 7 Multi-area reliability calculation

3 Scenarios

3.1 The policy pathways

The data regarding installed capacities of renewables in different European countries for modelling the effects of increasing shares of renewables on electricity markets was taken from the output of the Green-X model (used mainly in Workpackage 4 of the project). For the market modelling, four policy scenarios were selected out of the list of possible policy pathways (as developed by the project) and analyzed in order to represent a wide variety of outcomes. For the analysis of price and grid effects, data for all European countries was used (although with a limited level of detail in the case of the grid effects outside Southwestern Europe), effects on reserve markets were modelled with data for Spain. As mentioned earlier, the effects on system adequacy were only modelled for one high-RES scenario.

The first of these scenarios **"NOPOL"** serves as a baseline under which renewables are only supported by an ETS system after 2020. This policy pathway results in a lower overall share of renewables compared to the other pathways. Electricity market prices are relevant for investment decisions and thus technology choice and locations of renewable plants in this scenario.

In the other scenarios, an equal share of renewables is reached (at the European level, not at the regional level) and support levels are set in order to enable cost recovery for renewable plants. Under policies where price risks are taken by investors in renewable plants (i.e. quota systems and feed-in premiums), risk premiums are included in the calculation of necessary support levels, through the WACC.

The scenarios considered are:

- A harmonized quota system (**"HARMQUO"**):
  In this scenario, the support given is technology neutral and does not differ between locations. Market price signals (represented by expected average market revenues per technology) are taken into account by investors in RES plants.
- A harmonized feed-in tariff (**"HARMFIT"**):
  Under this policy, the support to renewables is given as a harmonized fixed feed-in tariff. However, tariffs are not equal across Europe but differ between geographic locations based on resource quality. Differences in electricity market prices have no influence on location or technology mix as the income for renewables is independent of electricity market prices.
- A national feed-in premium (**"NATFIP"**):
  Under this policy, all member states use the same support instrument, a fixed feed-in premium. Support levels thus differ between member states and market price levels influence investment decisions.

3.2 Green-X model results

Green-X input data include prices for fossil fuels and CO2 prices. These data have been used for modelling market and grid effects and are shown Table 3:

Table 3 Fuel prices and carbon prices used as input data (EU Energy Roadmap, 2013)

	Unit	2015	2020	2030
Hard coal	€/MWh-p	11,7	15,0	17,7
Oil	€/MWh-p	38,5	46,2	57,5
Gas	€/MWh-p	32,7	32,4	41,6
CO_2 price	€/t CO2	13,0	25,8	36,1

In Green-X, the four policy pathways lead to different renewable shares, technology mixes and locations of renewables. The results for the different policy pathways are shown in the following:

3.2.1 Renewables Share

The share of renewables in the electricity sector across Europe is the same in all scenarios where renewables are supported after 2020. It increases from 22.5% in 2012 to 24.8% in 2015, 35.0% in 2020 and 58.0% in 2030 (58.2% in the "NATFIP" case). Under the "NOPOL"-scenario, the shares are equal until 2020 (as the achievement of the NREAPs is assumed) but increases only to 39.5% in 2030.

There are however differences across the countries in the different scenarios, which are shown for 2030 in Table 4. It becomes clear from the comparison that a harmonized quota leads to a higher concentration of renewables in few countries with high potentials, while a national feed-in premium leads to a smoother distribution of renewables across member states. As expected, the harmonised feed-in tariff lies in between both extremes.

Table 4 2030 renewable shares under different policy pathways across member states (highest share for each country shaded in yellow, lowest share among support scenarios shaded in blue)

	NOPOL	NATFIP	HARMFIT	HARMQUO
AT	82.0	97.3	96.7	91.0
BE	11.3	24.2	23.1	27.0
DK	68.3	122.5	77.0	117.6
FI	49.7	58.4	60.7	56.8
FR	38.9	56.1	56.7	55.5
DE	31.0	46.4	43.5	49.5
GR	32.9	54.9	48.2	47.3
IE	69.1	86.9	87.8	78.2
IT	33.0	44.5	38.0	38.1
LU	7.0	10.6	10.2	10.2
NL	26.0	49.8	54.2	60.4
PT	66.8	89.0	94.6	90.0
ES	52.4	89.0	94.0	84.2
SE	74.6	81.2	85.1	85.5
UK	36.0	65.6	71.2	68.8
CY	20.1	35.2	35.1	32.8
CZ	25.1	33.1	32.9	32.3
EE	50.4	73.9	74.1	72.6
HU	22.2	32.9	32.0	30.9
LV	82.0	108.0	105.7	106.8
LT	45.8	68.3	68.9	68.2
MT	12.6	38.8	38.8	30.1
PL	26.6	39.0	38.0	40.7
SK	28.1	36.4	36.5	33.6
SI	47.6	55.3	54.9	52.2
BG	37.3	50.4	53.7	50.0
RO	54.0	67.5	69.2	69.8

3.2.2 Technology mix

The four policy pathways also lead to differences in the technology mix of renewables. This in turn influences both the market prices and grid requirements as RES plants are installed at different locations with differing feed-in profiles. This is especially true for the weather-dependent renewables, namely wind and solar PV as well as run-of-river hydro power.

The differences in the overall technology mix across Europe are shown in Figure 8. It can be seen that the overall technology mix under the HARMFIT and NATFIP scenarios is quite similar, while there are bigger differences to the 2020 mix for the HARMQUO support policy as well as the NOPOL-case.

In all scenarios but the NOPOL scenario, the share of PV in the renewable technology mix will decrease in the future (even if electricity produced from PV increases in absolute terms), and this decrease will be most pronounced under a harmonized quota. Under this policy, also solar thermal electricity expands less than under the other two support policy pathways. Another difference is the importance of offshore wind in the future technology mix – in the HARMQUO case it will contribute 21% of all renewable electricity while in the NOPOL case only 8% of renewable electricity (with a much lower overall production) will come from offshore.

Of course the results also differ between the European countries. This will also create differences in the assessment of balancing costs and grid effects throughout Europe. Within this study the focus for estimating these effects has been laid on the example of Spain and Southwest Europe, respectively (see Section 4).

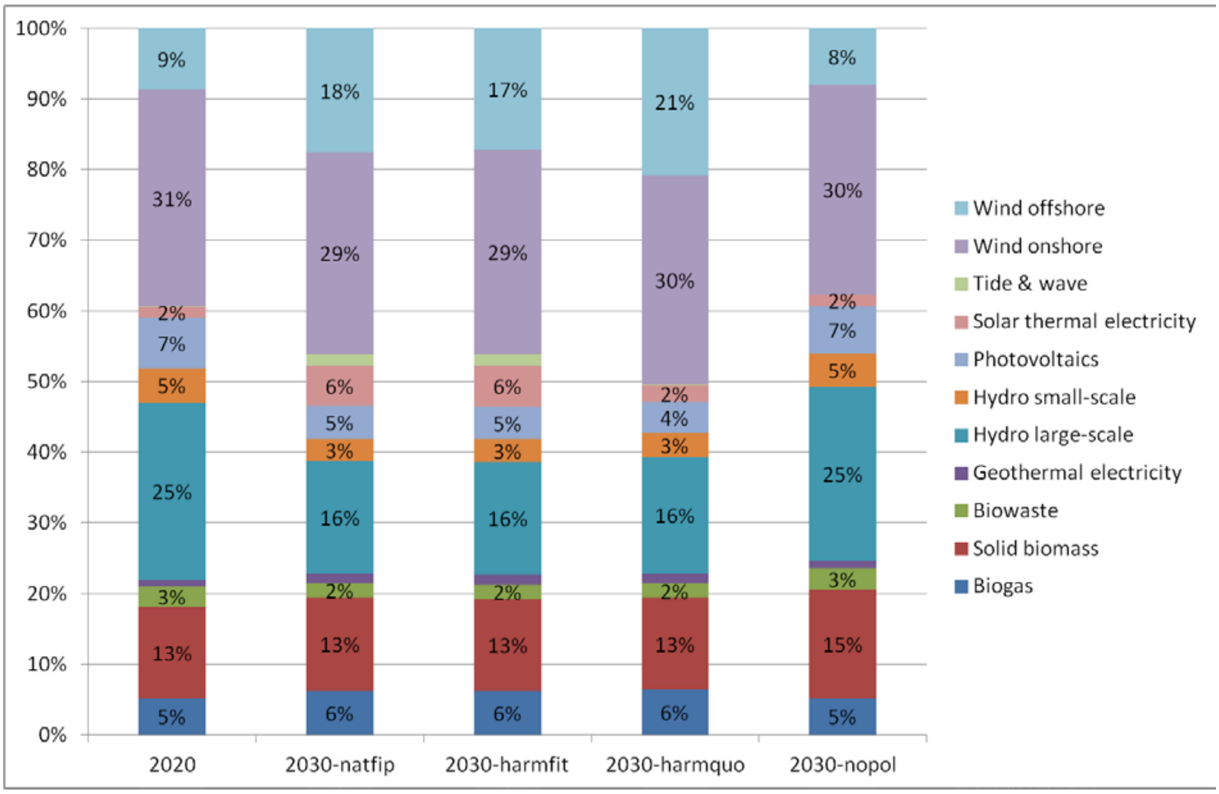


Figure 8 Renewable electricity mix resulting from the four policy pathways

As mentioned earlier, these data are common for all assessment exercises. We now go on to describe the specific data and assumptions employed for each of the impacts assessed.

3.3 Assumptions for the assessment of price effects

In order to assess the price effects, scenarios for 2015, 2020 and 2030 were modelled. As price effects depend heavily on the possible exchange of electricity between neighbouring countries, different grid extension scenarios were modelled for the later years. For 2015 it was assumed that 2013 net transfer capacities are still valid. For 2020, in one scenario, the 10-Year-Network Development Plan (TYNDP) (ENTSO-E, 2012a) was assumed to be realized, while in a second less optimistic scenario only half of the envisaged capacities are realized. For 2030, the optimistic scenario assumes that in addition to the TYNDP the necessary grid capacities resulting from the grid modelling (see Section 4) are implemented for each of the policy scenarios, the pessimistic scenario uses the TYNDP capacities.

In addition, the price floor was varied in the simulation – results were calculated with a floor price of 0, -50 and -150 Euro. The different price floors reflect varying pricing rules in different European countries and enable conclusions regarding the interconnections between market regulation and the influence of renewables. Fuel and CO_2 prices as well as conventional plant capacities are taken from the PRIMES High Renewables scenario (European Commission, 2013). There are no differences between the scenarios analyzed regarding this input data.

3.4 Assumptions for the assessment of balancing costs and needs

The main inputs required by the ROM model include data on renewable generation, conventional generation and electricity demand. Regarding renewable generation, different installed capacities were considered according to the RES policy scenario studied (section 3.1). Apart from RES installed capacities, all other input data used in the model do not vary across the different RES policy scenarios.

Total estimated electricity demand in the Spanish in 2030 is approximately 364 TWh (PRIMES High RES scenario). RES installed capacities in Spain by 2030 under each one of these scenarios were taken from the Green-X model results (see section 3.2). Conventional generation installed capacities are taken from the results for 2030 of the PRIMES model (High RES scenario). Figure 9 presents the total installed capacity in Spain under the different RES policy scenarios.

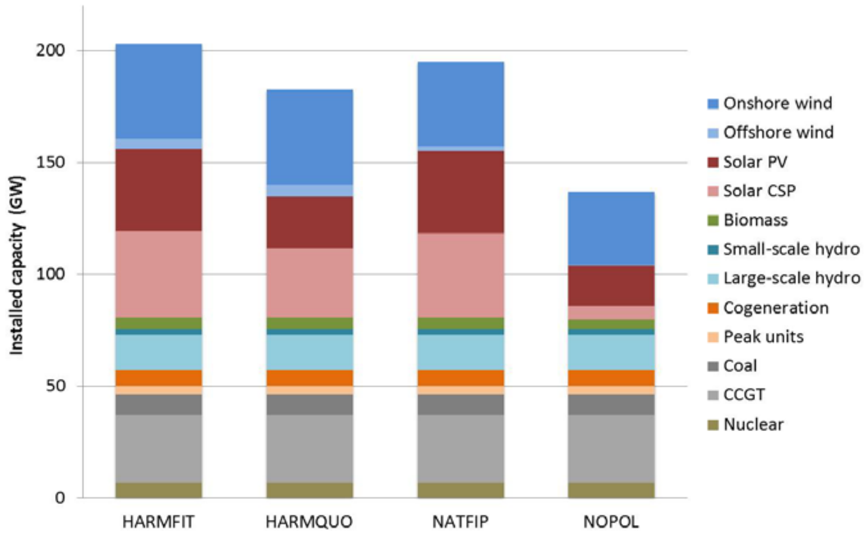


Figure 9 2030 scenarios for Spain

Hourly wind generation series were modelled from past production profiles and extrapolated to 2030. It was assumed that onshore and offshore generation variability is the same. Distributed generation series were obtained from average production profiles of these technologies in Spain. These profiles are shown in Figure 11.

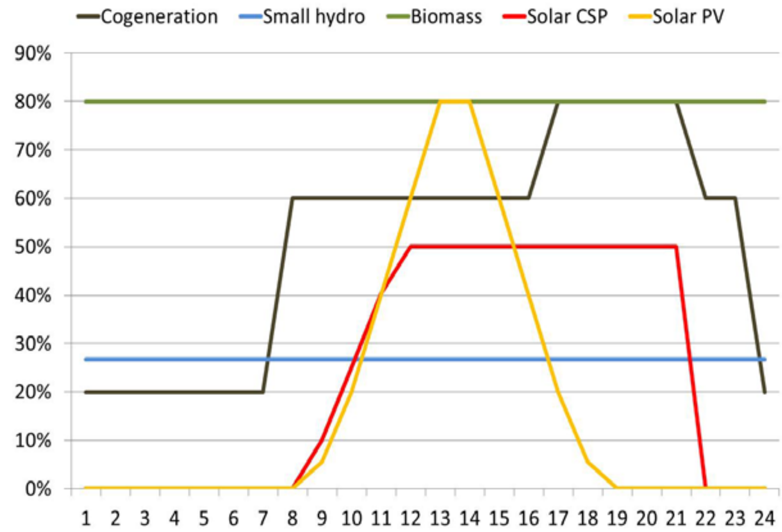


Figure 10 Distributed generation profiles in Spain

3.5 Scenarios and data for the network analysis

As mentioned before, the assessment of the impacts of RES scenarios on the network has focused on the Southwest part of Europe, with a large detail of the French, Spanish and Portuguese network, but only an approximation of the rest of the European network.

3.5.1 Demand and generation (RES and conventional)

Hourly demand series for each country have been gathered previously by Comillas. These series have then been scaled so that aggregate annual demand values are consistent with data computed in PRIMES analyses. For Portugal, Spain and France it has been assumed that demand will be located in the year 2030 in the same nodes as today (year 2008)[6]. Besides, the demand in each node has been deemed to evolve over the year analogously to the overall demand in the country. Hence, the annual demand series for each node of a country has been obtained by scaling down the demand series for the whole country according to the ratio between the peak demand in the country and that in this node. Annual electric energy demand and peak demand figures for the power systems of interest and the rest of the European countries are displayed in Table 5..

Table 5 Demand and peak demand for the year 2030

		PT	ES	FR	REST	TOTAL
Demand	[TWh]	64	364	558	2677	3663
Peak demand	[GW]	12	63	103	424	595

Overall amounts of installed capacity of conventional generation of each type (technology) for each national system for the year 2030 have also been obtained from PRIMES data. Then, conventional generation capacity existing in the network model has been scaled to match the aforementioned

[6] Each of the rest of the European countries is represented only by one node; therefore all demand (and generation) is located in this node.

system totals. Total installed capacity of each conventional generation technology within each system is displayed in Table 6.

Table 6 Installed capacity of conventional generation for the year 2030

		PT	ES	FR	REST	TOTAL	
Gas	[MW]	0	814	1318	86065	88197	19%
CCGT	[MW]	2791	29283	8808	103771	144653	31%
Coal	[MW]	568	9180	957	94465	105170	23%
OCGT	[MW]	2467	0	2456	0	4923	1%
Oil	[MW]	774	3714	5829	17821	28138	6%
Nuclear	[MW]	0	2875	44696	41938	89509	19%
TOTAL	[MW]	6600	45866	64064	344060	460590	

The hourly power production time series for each RES generation technology within each country have been computed from those provided by Fraunhofer-ISI for similar scenarios. These have been scaled up or down to match aggregate national power production levels for each country provided in Green-X analyses carried out for each of the considered scenarios.

Regarding the geographical location of RES power production in France, Spain and Portugal, zonal distribution factors have been computed by Fraunhofer-ISI for the time horizon of our analysis so as to be able to allocate overall production within each country to a set of zones defined in this country. Zones for Spain are north-west, north-east, centre, south-west and south-east. Zones for France are south-west, south-east, centre and north. A single zone has been considered for Portugal. Zonal distribution factors have been computed based on the renewable generation potential of each zone, related to the availability of primary renewable energy resources in this zone. Within each zone, RES power production for each technology and hour has been distributed among network nodes according to the level of power production for this technology in each node within the network model. If power production so allocated to a node exceeds a security threshold, the excess over this threshold has been distributed homogeneously over the rest of power plants of the same type in the area. The power production security threshold considered for each node corresponds to the maximum amount of power generation that could be installed within a single node while complying with system security constraints in contingency situations, like stability ones. Overall annual RES electricity production levels and peak ones expected for the different countries in the time frame of the study are provided in Table 7.

Table 7 RES generation energy and peak expected for the year 2030

			PT	ES	FR	REST	TOTAL
HARMFIT	Peak RES expected production	[GW]	17	98	75	314	435
	RES energy expected	[TWh]	60	339	315	1679	2393
HARMQUO	Peak RES expected production	[GW]	18	87	73	326	447
	RES energy expected	[TWh]	57	303	309	1720	2389
NATFIP	Peak RES expected production	[GW]	16	92	74	314	429
	RES energy expected	[TWh]	57	321	312	1706	2396
NOPOL	Peak RES expected production	[GW]	15	57	54	248	339
	RES energy expected	[TWh]	43	189	216	1243	1691

Fuel costs considered correspond to those available from PRIMES 2030 analyses. Specifically, these are 68 €/boe, 53 €/boe and 23 €/boe for oil, gas and coal, respectively. The price of CO_2 emissions for the year 2030 is assumed to be 36 €/tonCO_2 for the high RES penetration scenarios (HARMFIT, HARMQUO and NATFIP) and 54 €/tonCO_2 for the NOPOL scenario, as computed with the Green-X model when defining policy scenarios. Variable RES production costs correspond to those in the Green-X database.

3.5.2 Definition of the operation snapshots considered to represent policy scenarios for grid analysis

This section describes the snapshots considered to represent policy scenarios in the grid analysis. The annual level of those system variables that are dependent on the operation of the system results from the selection of operation snapshots carried out. The network model and the capacity of conventional generation (presented in sections 2.3 and 3.5.1) remain the same for all the scenarios and do not depend on the snapshot selected. However, RES generation capacity levels vary across the different policy scenarios, while demand levels are common to all scenarios but depend on the snapshot selected. Finally, other variables like RES power production are specific to each scenario and are modelled through the consideration of an appropriate set of operation snapshots. Annual values of the later system variables, which result from the snapshots selected, should at least roughly amount to the specific levels that correspond to each scenario. The snapshots described in this section are obtained following the methodology explained in section 2.3.

The case study considered in network analyses comprises the Portuguese, Spanish and French systems. Policy scenarios differ in the overall amount and geographical distribution of demand and RES generation within this region, as well as the distribution of RES generation among areas. Demand should exactly be the same in all scenarios. However, the annual load profile has been represented using a specific set of operation snapshots for each scenario (see section 2.3.3), which has resulted in slightly different load amounts per scenario, though they are all roughly the same. The main features of the snapshots selected for our four scenarios of the south-west regional system are presented in Table 8. Features provided are the percentage of the annual peak demand and percentage of annual peak RES power production in each snapshot. Those snapshots where expected power exchanges are largest have similar demand and RES power production levels compared to peak ones for the three high RES penetration scenarios (this is especially true for the HARMFIT and NATFIP scenarios). Common operation situations represented by the last two snapshots have similar relative demand and RES power production levels in the four scenarios.

Table 8 Demand and RES power production w.r.t. peak levels of Portugal, Spain and France for the different scenarios

	Harmfit		Harmquo		Natfip		Nopol	
	Demand	RES	Demand	RES	Demand	RES	Demand	RES
High demand	89%	68%	89%	68%	89%	68%	89%	68%
Largest power exchanges	66%	81%	68%	73%	66%	85%	70%	67%
Common operation situations 1	54%	35%	68%	51%	65%	49%	54%	38%
Common operation situations 2	64%	45%	51%	30%	51%	34%	68%	46%

Load levels for the whole region obtained using these snapshots range between 910 TWh for the NATFIP scenario and 957 TWh for the NOPOL scenario, see Table 9 showing the geographical distribution of load within the south-western region.

Table 9 Geographical distribution of load

[GWh]	Harmfit	Harmquo	Natfip	Nopol
ES_C	65766	69873	65698	66633
ES_NE	75353	80058	75275	76346
ES_NW	67626	71848	67555	68516
ES_SE	73555	78148	73479	74524
ES_SW	58542	62198	58482	59314
FR_C	115098	114225	114739	121440
FR_N	245587	243480	244812	259266
FR_SE	105028	104194	104698	110837
FR_SW	59012	58505	58826	62299
PT	61641	59196	47366	58178
Total	927209	941723	910929	957352

The geographical distribution of gross power production from renewable energy sources in the region for each scenario is shown in Table 10. As can be seen, the geographical distribution of RES varies across scenarios. Different RES policies result in different sets of locational signals for the installation of RES generation. Revenues of RES generation in each area are linked to energy market prices to different degrees in the different scenarios. At the same time, RES policies in place in each scenario may favour some specific technologies, whose primary energy sources are abundant in specific regions. This results in levels of deployment of RES generation in each area that also differ by scenario. Thus, for example, RES production is largest in the Spanish Central zone in the HARMQUO scenario, while it is largest in the French South-Western zone in the NOPOL scenario.

Table 10 Geographical distribution of RES power production

[GWh]	Harmfit	Harmquo	Natfip	Nopol
ES_C	90064	82864	97584	46288
ES_NE	65068	55069	56772	34107
ES_NW	74106	69720	73932	45867
ES_SE	60629	52677	60561	30048
ES_SW	10675	17746	8118	13711
FR_C	72328	60841	70062	45274
FR_N	56380	61929	59131	37506
FR_SE	83739	70720	89022	63844
FR_SW	49610	59485	57563	65967
PT	57054	43988	39173	35855
TOTAL	619653	575041	611918	418468

3.6 System adequacy scenario

As mentioned earlier, the scenarios assessed in the case of system adequacy are a bit different that for the other impacts. Here, a benchmark high-RES scenario for the year 2030 for the Central Western Europe (CWE) market coupling area is used, assuming a large increase in renewable energy sources in the electricity sector. The key scenario assumptions considered are a constant electricity demand, a large-scale deployment of RES-E capacity and a stagnating conventional fleet (as consequence of the RES-E deployment, as discussed in section 0). As presented in Figure 7, the system adequacy scenario consists of detailed datasets of system load and variable renewable generation (hourly values), detailed data on the fleet and characteristics of conventional and renewable power plants and interconnector capacities. The key characteristics of the scenario datasets are presented in more detail below.

The area under investigation consists of the countries that are integrated in the CWE market coupling: France, Belgium, Netherlands and Germany (with Luxembourg), with the addition of Austria (which shares a single electricity market with Germany), as shown in Figure 11. In total, there are 5 interconnecting borders between these 5 countries.

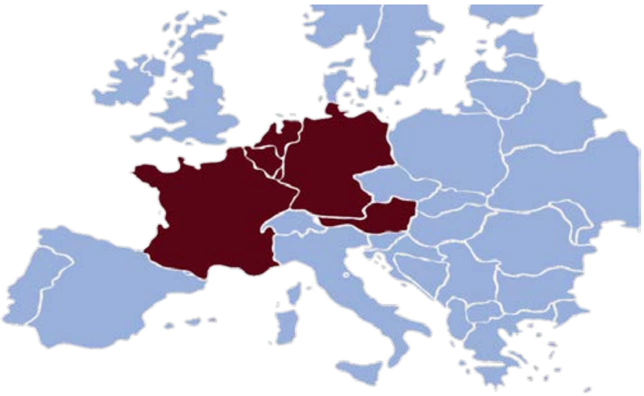


Figure 11 Overview of the countries taken into account in the analysis.

For each country, hourly load data from 2008, (ENTSO-E, 2012b), are used to represent the demand volatility in 2030. As discussed, no load growth is considered, assuming that the effects of economic growth versus increased energy efficiency are counterbalancing each other. The annual peaks are given in Table 11.

Table 11 Annual electricity demand peak

	AT	BE	DE/LU	FR	NL
Peak (GW)	9.4	13.6	77.8	84.7	18.5

The conventional power plants fleets are derived from Ecofys databases (based on the Platts PowerVision database, http://www.platts.com). For this study only power plants that already exist or that are under construction are considered. The resulting capacities per country and power plant characteristics are shown in Table 12. The life times are taken from the European Climate Foundation (2011) and the forced outage rates (FOR) are based on VGB (2006). For this assessment, no difference is made between gas and oil power plants. In total, 200 power plants are considered (93 in Germany and 58 in France). Small power plants (<50 MW) of the same technology class are aggregated. The FOR of these aggregates is set to one but their capacity is reduced by the FOR of their technology class (as an aggregate of small plants is more reliable than one large power plant, but a percentage of the small plants will always be out of order).

Table 12 Conventional Power Plants: overview of characteristics

Tech	Parameters		Capacities in 2030 (GW)				
	Life time	*FOR*	*AT*	*BE*	*DE/LU*	*FR*	*NL*
Coal	40	6.3%	0.8	0	16.2	0.8	4.7
Gas CC	30	3.3%	3.4	4.8	21	11.9	10.7
Gas GT	30	2.6%	0	0.2	1.2	2.7	0
Gas ST	30	3.2%	0.2	0.7	1	0.2	0
Lignite	40	5.8%	0	0	11	0	0
Nuclear	45	5.5%	0	0	0	38.2	0.5
Waste	100	6.3%	0.1	0.1	1.1	0.3	0.2
Total conventional capacity			**4.5**	**5.8**	**51.5**	**54.1**	**16.1**

The renewable energy and pump storage capacities are modelled according to the EU National Renewable Energy Action Plans (NREAP) (ECN, 2011). The development between 2020 and 2030 is extrapolated assuming that 30% of the capacity increase between 2010 and 2020 can be repeated in the later decade (the number 30% is derived from indications in the EU Roadmap 2050, (European

Climate Foundation, 2011)). The pump storage capacities are partially based on (Eurelectric, 2011).. The capacities considered for the study are presented in Table 13. As discussed, the scenario shows a high deployment of RES capacity. In combination with a stagnating conventional fleet, the scenario leads to high RES capacity shares (as share of conventional capacity), as indicated in Table 13.

Table 13 Renewable energy: capacities considered

Tech	Capacities in 2030 (GW)				
	AT	*BE*	*DE/LU*	*FR*	*NL*
Bio	1.3	3	9.7	3.6	3.3
Solar	0.4	1.6	62.7	6.9	0.9
Offshore wind	0	0	13	7.8	6.7
Onshore wind	3	5.4	38.4	23	7.2
Geothermal	0	0	0.4	0.1	0
Hydropower	9.2	0.1	4.4	29.1	0.2
Pump storage	4.3	1.3	9.7	7.4	0
Total RES capacity	**18.2**	**11.4**	**138.3**	**77.9**	**18.3**
RES Capacity Share (% of conventional)	**404%**	**197%**	**269%**	**144%**	**114%**
Variable RES Share	**76%**	**121%**	**222%**	**70%**	**92%**

The generation time series for variable RES (VRES), namely wind and PV, are modelled based on meteorological data of wind speed and solar irradiation from 2008 (weather data and transformations to normalized power time series delivered by Eurowind GmbH, http://www.windprognose.de). The generation is included as negative load, so subtracted from the corresponding load time series. Correlations between demand, wind and PV are thus taken into account. Biomass is considered as firm capacity but the capacity is reduced by their FOR (assumed equal to the FOR of coal; see also the remark about small power plants above). The hydro capacities (including pump storage) are represented in a simplified way. 41% of the capacity is considered as firm capacity according to indications about the typical availability of hydro plants at full capacity (IPCC, 2011)..

After the consideration of renewable energy, the clusters of the residual load are generated. The residual load is represented by 18 clusters. As discussed, one year of data were used for this study; for a more detailed assessment and (especially for the effects of the variable renewable in-feed), more data years should be considered (Hasche et al, 2011).

In the base scenario, the transmission capacity of each interconnection is set to the NTC values published by ENTSO-E for the winter of 2010-11 (ENTSO-E, 2012c) see Table 14. If the NTC value between two countries differs on its direction, the minimum value is taken for conservative estimations. The NTCs are applied as linear transmission constraints neglecting the impact of loop flows (i.e. the NTC capacities of all interconnection can be used simultaneously). In addition, no outages are considered for the interconnections. Line outages could be considered in the calculation but they increase the calculation time. These simplifications are considered acceptable because NTC values are calculated for the normal trading process and N-1 security margins are already taken into account.

Table 14 Applied NTC values

Country A	Country B	NTC Value (MW)
AT	DE/LU	2000
BE	FR	2300
BE	NL	2400
DE/LU	FR	2700
DE/LU	NL	3000

The reliability target for the LOLP in each country is set to 0.000274. This corresponds to one day of loss of load in ten years which is a typical reference value in the literature (Ibanez and Milligan, 2012). 500 MW gas power plants (FOR equal to 2.6%) are added until the reliability target is reached in all countries.

4 Results

4.1 Price effects

The objective of the price assessment is to find out in how much increasing shares of renewable influence the price level and volatility in future electricity markets. In addition, the effects on the market values of renewables are assessed.

As the price level is not only influenced by the share of renewable and the interconnector capacity but also by the flexibility and existing capacities in the remaining electricity system, it would also be interesting to vary these factors in order to gain additional insights. Another approach would be to optimize the entire system so that conventional capacities, interconnector capacities, storage and demand side devices fit together. However, due to financial and time constraints, such an approach was not possible in the context of this project. Electricity demand is modelled as an inflexible factor throughout; conventional capacities are in all scenarios based on the same PRIMES scenario; the network is taken as given. As a consequence, with increasing shares of renewable, overcapacities in the system increase as well and this might contribute to decreasing average prices. Therefore, all results have to be interpreted carefully as they only show what follows from increasing the shares of renewable electricity while not adapting the whole electricity system.

One also needs to notice that the model was mainly calibrated to reflect market prices in Germany. Prices estimated for other countries are therefore likely to not exactly reflect the observed prices in these countries. Nevertheless the model is able to show the order of magnitude of the effect of rising renewable shares (as long as their production does not react to market signals and the remaining electricity system does not change in a significant way).

Figure 12 and Figure 13 show the development of simulated prices from 2015 to 2030 in the different scenarios. It can be seen that prices first rise until 2020 mainly due to increasing fuel and CO_2 prices. Then prices decrease in the cases where substantial renewable investment is realized. The results will be explained and analyzed in more detail in the following sections.

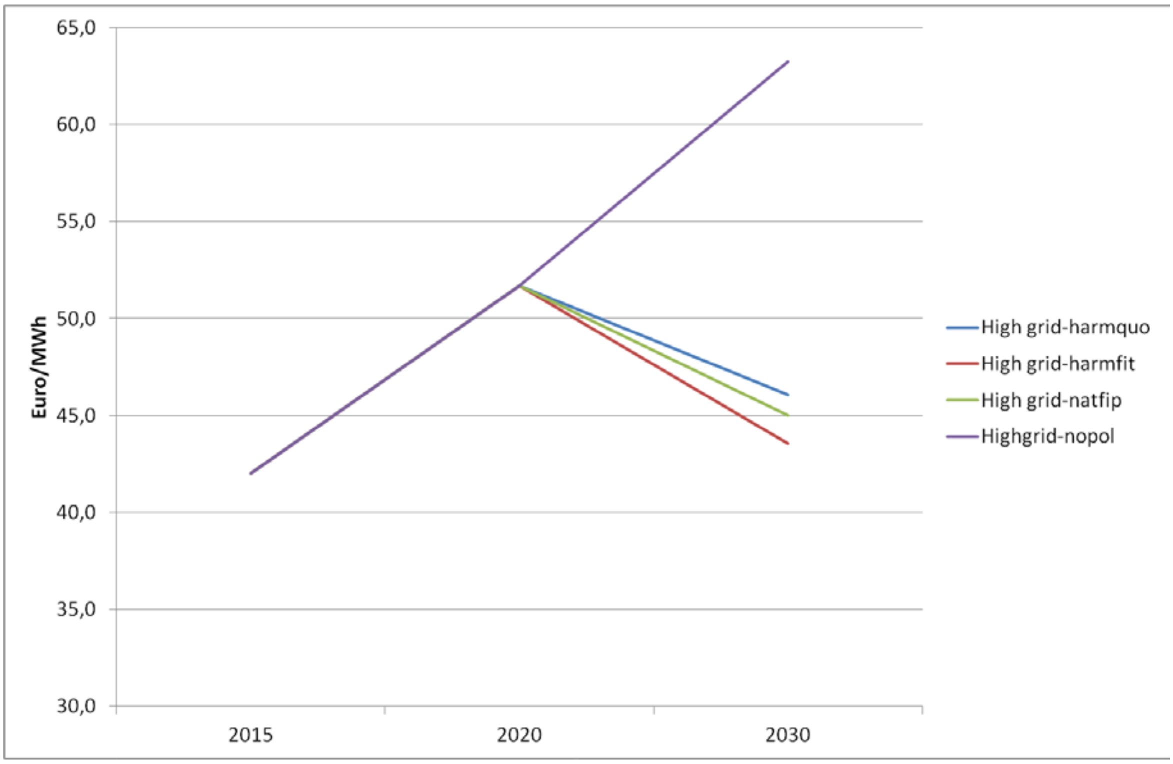


Figure 12 Development of average market prices from 2015 to 2030 in different policy scenarios with optimistic grid extension (realization of TYNDP until 2020)

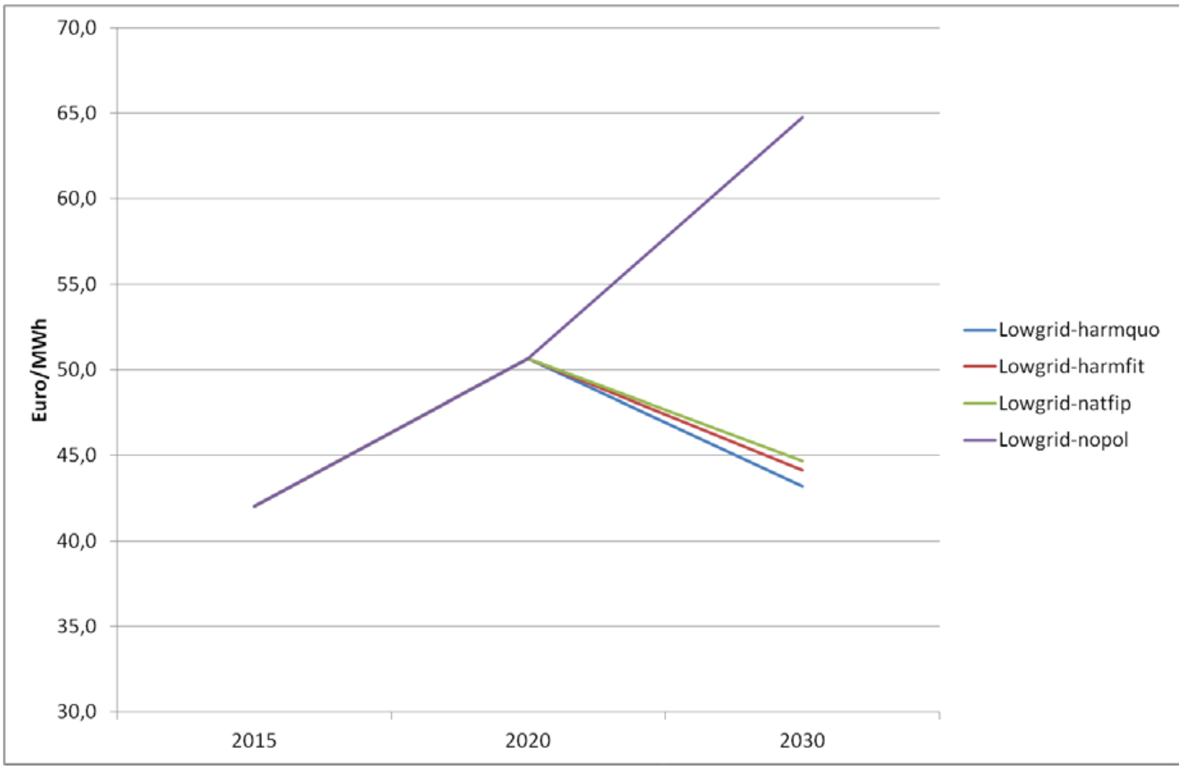


Figure 13 Development of average market prices from 2015 to 2030 in different policy scenarios with low grid extension (realization of TYNDP until 2030)

4.1.1 The impact of renewables on average prices

During the last years, it has been observed in many European countries that renewables lead to reduced electricity market prices. In the longer term, it is however expected that the electricity system adapts to the new circumstances by increasing the share of more flexible plants with higher marginal costs (e.g. gas turbines) and thus prices might increase again. In addition, rising fuel and CO_2 prices can also contribute to higher prices in the longer run. In the modelling experiment, only the first effect can be tested as the conventional power plant park in PRIMES only adapts to a different renewable share, technology mix and geographical distribution.

The PRIMES high RES scenario assumes a decrease of conventional capacity in EU27 to 450 GW until 2030, which is a reduction of 24 % compared to the status 2015 (see Figure 14). Although total capacity decreases in the high RES scenario until 2030, investment in new capacity would be necessary as a large share of the existing capacity is in operation for more than 24 years (see Figure 15). Several tens to more than 100 GW of conventional capacity must be replaced or refurbished in the next 15 years, if a technical lifetime of 40 years for hard coal or lignite power plants or 25 years for gas turbines is assumed.

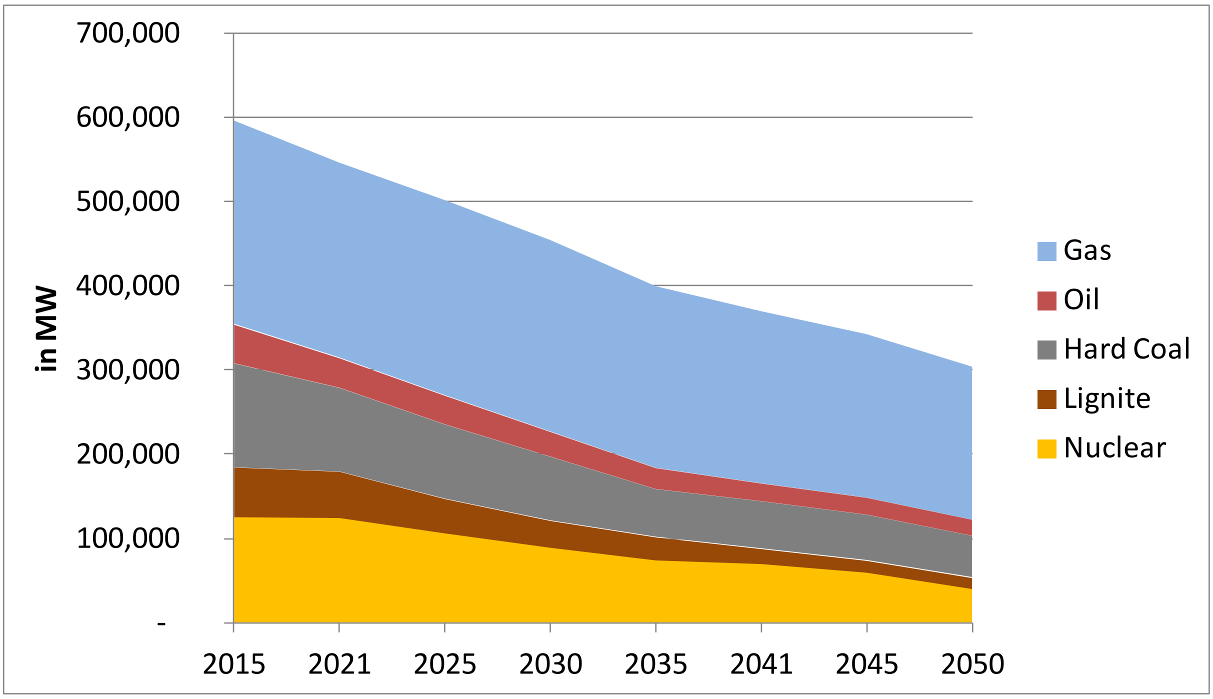


Figure 14 Development of conventional capacity in EU 27 from 2015 until 2050 (own graphic, based on PRIMES High Renewables Scenario)

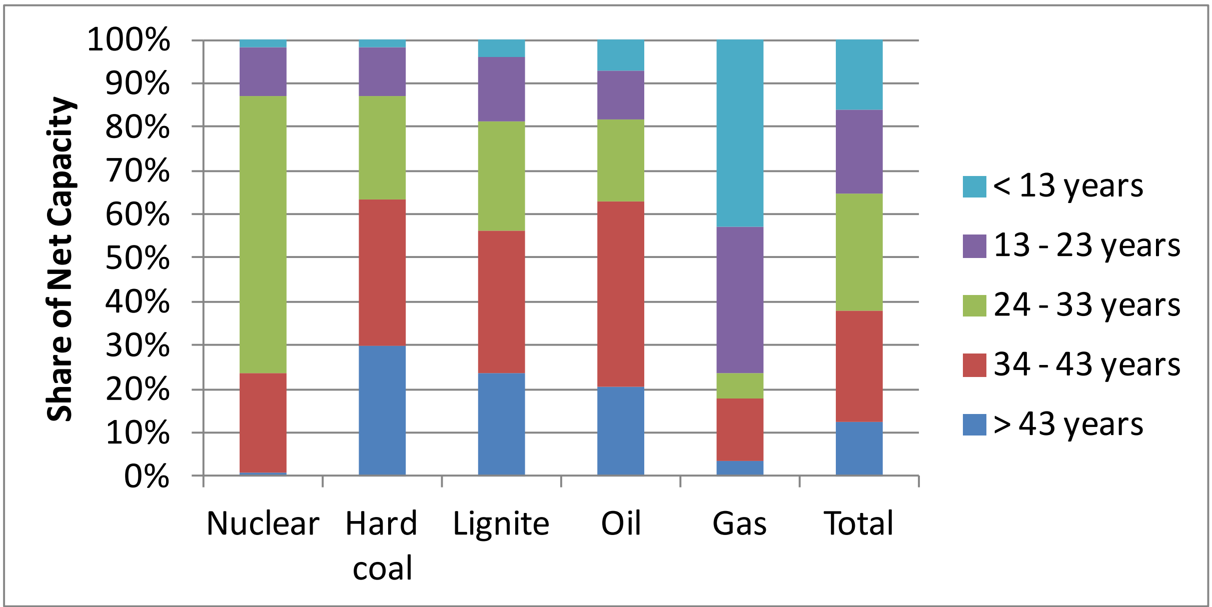


Figure 15 Share of net capacity related to years of operation in EU 27 (Source: Platts Power Plant Database, Status End 2011)

4.1.1.1 Base case results – year 2015

The year 2015 with a floor price of -50 €/MWh is taken as a baseline for the analysis. For this year, prices are simulated based on the assumption that renewable capacities are expanding according to the NREAPs, conventional capacities are installed according to the PRIMES scenario and interconnectors are left in the state of 2013. The weather of 2008 is used to model the distribution of generation from PV and wind over the different hours of the year. Also the development of demand over the individual hours is based on data from 2008. Thus, possible deviations in generation (due to different locations, techniques such as higher towers in the case of wind plants or installation practices such as PV panels orientated east or west instead of south) are not taken into account. The simulation results for 2015 show that, on average, the electricity price in Europe under the given assumptions will be 42.02 €/MWh which is more or less in line with current price levels. The average decreases slightly to 41.74 €/MWh if a price floor of -150 Euro/MWh is adapted and increases slightly to 42.17 €/MWh if the floor price is set to 0 €/MWh. Some countries have higher prices than the average, in others prices are much lower. This is on the one hand due to assumed interconnector capacities, on the other hand the price level is dependent on the individual electricity mix.

4.1.1.2 Effects on average prices in 2020

For 2020, two scenarios were modelled. In both, renewable capacities are extended according to the NREAPs and conventional capacity develops according to the PRIMES scenario. The two scenarios differ regarding the interconnection capacities – in the optimistic scenario, all grid extensions foreseen in the TYNDP are realized, in the less optimistic scenario only half of the capacity foreseen in the TYNDP is implemented on all interconnectors. Again, a floor price of -50 €/MWh is assumed.

The average market price in 2020 is estimated to be much higher than the price in 2015. At a first glance this contradicts the assumption that increasing renewable shares as well as overcapacities lead to a decrease in prices. The main reasons for the higher price are the assumed fuel price and CO2 price developments: As shown in Table 15, between 2015 and 2020 there is a sharp increase in both the gas price (from 22.03 to 30.15), the CO_2 price (from 12.6 €/tCO_2) and the price of other fuels. As in 2020, power plants based on fossil fuels still set the price in the electricity markets in a large number of hours, their increasing marginal costs lead to a substantial increase of the average market prices.

Table 15 Fuel and CO_2 price development

	gas (€/MWh)	hardcoal (€/MWh)	oil (€/MWh)	waste (€/MWh)	CO_2 €/t CO_2
2015	22,03	10,91	35,81	35,81	12,65 €/tCO_2
2020	30,15	11,90	40,77	40,77	25 €/tCO_2
2030	30,93	13,33	40,08	40,08	35 €/tCO_2

A surprising result of the simulation is a further increase of the average of European market prices from 50.67 €/MWh to 51.69 €/MWh when grid extension is increased, although the difference is not significant. In addition, the impact of the additional extension differs between countries. In France, Austria, Bulgaria, Czech Republic, Germany, Denmark, Estonia, Finland, Hungary, Lithuania, Latvia, Portugal, Romania, Slovenia and Slovakia, prices increase, sometimes substantially. In Cyprus, prices stay constant as there is no interconnection to the rest of Europe anyway. In other countries, namely Belgium, Spain, Greece, Ireland, Italy, Luxemburg, Malta, the Netherlands, Poland, Sweden and the UK an increase in interconnector capacities leads to decreasing electricity prices. The fact that with increased grid extension, prices rise in some countries and decrease in others depending on the previous price in the individual market is logical – the price in all countries should tend more towards the common average. The effects of full market coupling (without grid congestion) on electricity prices in two countries are shown graphically in Figure 16.

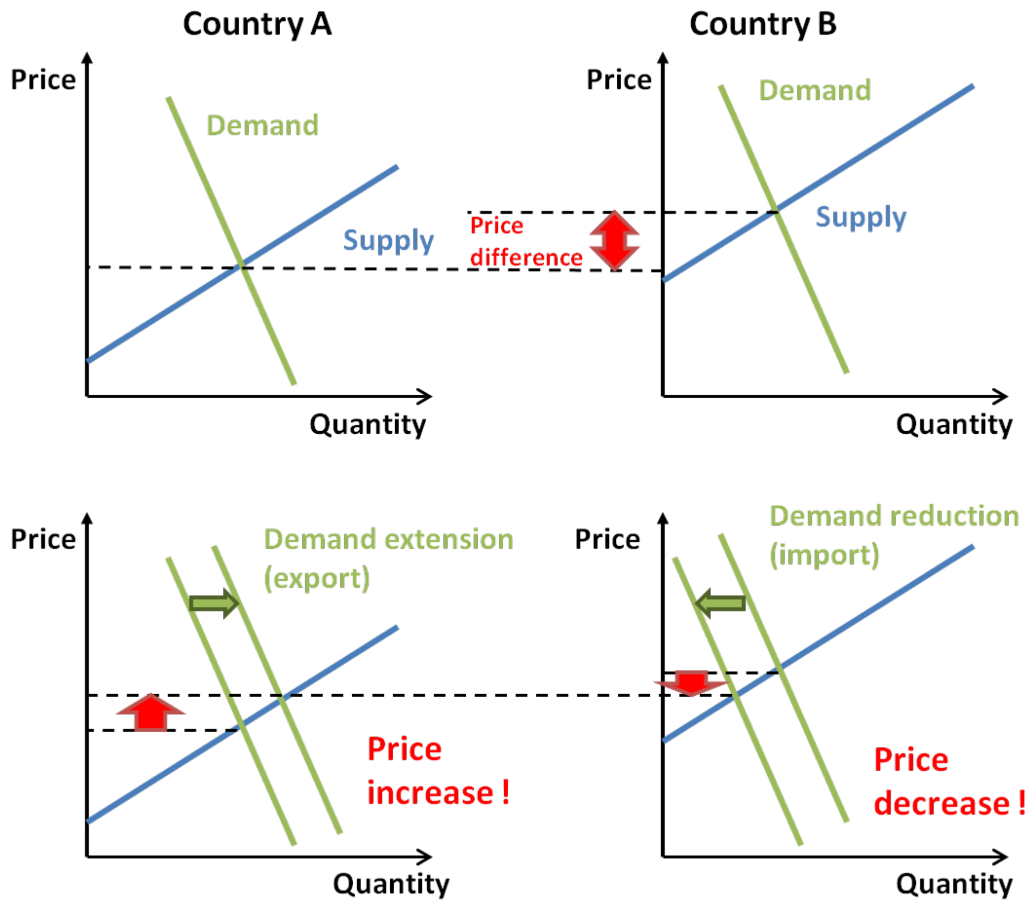


Figure 16 Effects of market coupling on electricity prices

However, if the hourly electricity prices are weighted with the hourly electricity consumption in each country, overall costs should decrease. Also, the grid extension leads as expected to smaller differences between the average electricity prices in the individual countries as the standard deviation of average electricity prices decreases from 18.3 to 16.6.

Overall, the effects of the increasing share of renewable cannot be separated from the more important influence of the sharply increasing fuel and CO_2 prices. One can conclude from this that rising input prices can counteract the merit order effect at least in the medium run. This is also reflected by the current developments – as CO_2 prices and gas prices are currently at a relatively low level, the electricity price is also low. Of course, there is nevertheless also an influence of the overall capacity and the existing renewable shares.

It can also be observed that under the assumption of perfect markets and marginal cost pricing, in some countries the electricity price will remain very low even in the future and thus impede investments in new power plants and other flexibility options.

4.1.1.3 Effects on average prices in 2030

In 2030, the impact of the different policy pathways on the level and distribution of renewable energy shares becomes visible as there are no assumptions regarding minimum targets etc. for each of the EU countries. Therefore, for 2030, the impacts of the four different policy pathways (HARMQUO, HARMFIT, NATFIP and NOPOL) on average electricity prices can be analyzed. For 2030, 8 scenarios were simulated, based on the different policy pathways and two different grid scenarios.

Figure 17 shows the European average electricity prices for 2030. These are calculated as the average of average country prices which means that the different demand capacities between countries are not taken into account. It becomes obvious that the differences between the three scenarios with increasing renewable shares are quite small, while in the scenario without additional support for renewable (NOPOL) resulting prices are considerably higher. This could be interpreted as evidence for the influence of renewable on decreasing electricity prices. However, the interpretation is not as straightforward. As in all scenarios the conventional power park is kept constant, the lower prices in the renewable support scenarios could simply reflect existing overcapacities as the overall capacity is increasing with the rising renewable shares. In the NOPOL-scenarios, overall installed capacity is lower and thus the occurrence of higher average prices is logical. The same explanation is valid for the fact that prices in 2030 in scenarios with a renewable support policy are below 2020 prices while the prices of the NOPOL-scenario are generally above 2020 prices.

In contrast to the observations in 2020, it can be seen, that in all scenarios but the HARMFIT-scenario an increase in grid capacities leads to overall lower prices. The effect is quite low in the case of the NATFIP-scenario. This makes sense as both the NATFIP (individual national feed-in premiums) and the HARMFIT (a harmonized feed-in tariff with different payments according to resource quality) scenario lead to a relatively even development of renewables in all countries; and thus compensatory effects from the grid are less critical. As expected, the effect is most prominent in the case of a harmonized quota system where renewables are situated according to potentials and thus additional transmission capacities become extremely important for an efficient electricity generation and distribution. If hourly prices and consumption in individual countries are accounted for, the overall costs of electricity should decrease in all scenarios with increasing interconnection capacities.

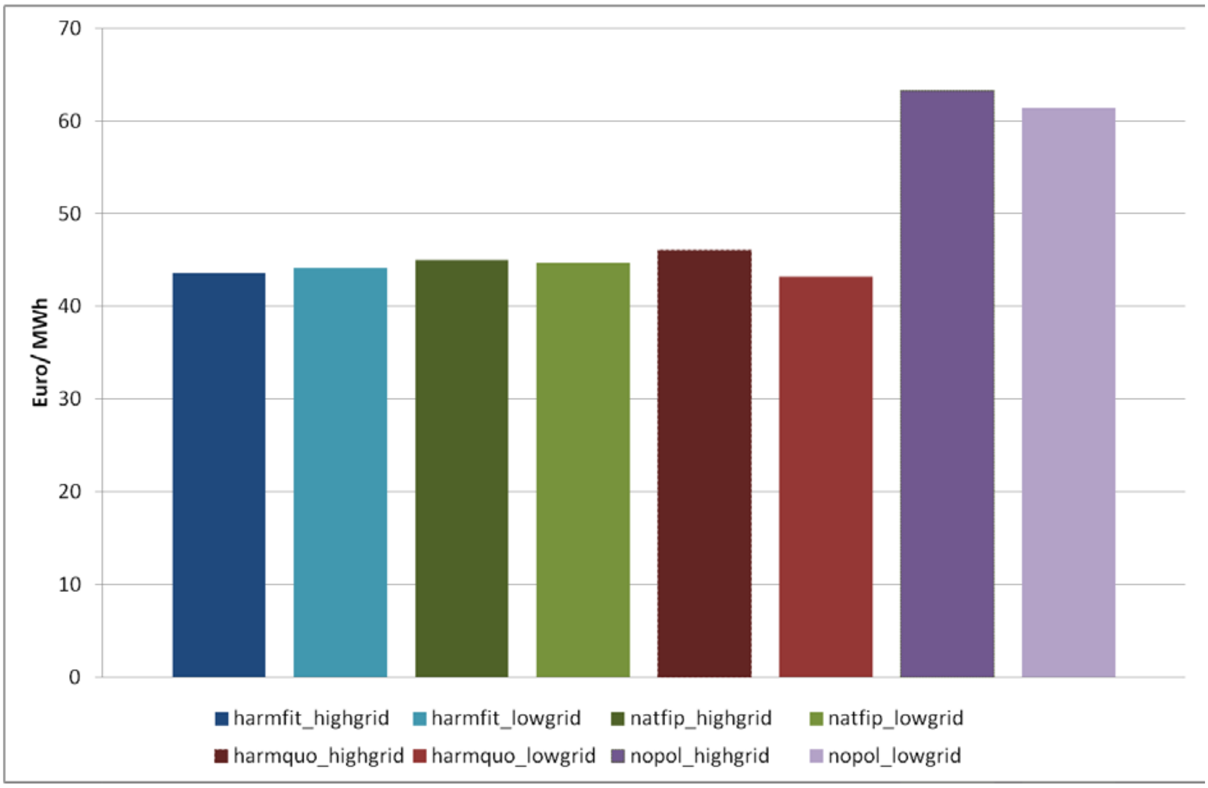


Figure 17 Average European electricity prices 2030 with a floor price of -50 €/MWh for different policy and grid scenarios

A look at the individual countries shows in general the same trend – prices in the different renewable support scenarios are relatively similar, while prices under the NOPOL-scenario with overall lower capacities are higher.

However, an interesting observation can be made with regard to the price level in Romania and Bulgaria. Under the given market conditions with a floor price of -50 €/MWh which enables the occurrence of negative prices, the average electricity price in these two countries becomes negative. Thus, according to the simulation results, electricity generators would on average have to pay for generating electricity. Of course such a situation would not happen in reality as this would cause mass plant retirement and thus blackouts etc. which would lead the regulator to intervene in advance e.g. by raising the floor price to at least 0 €/MWh. Nevertheless, it is interesting to analyse the reason for the occurrence of these negative average electricity prices in the model.

The reasons lie partly in the model – all renewable are herein taken as totally irresponsive of price fluctuations and thus even dispatchable technologies such as biomass do not react to market signals. This is sufficiently realistic in the case of fixed feed-in tariffs; under a feed-in premium or quota regime however, these renewables would react to market signals to a certain extent thus negative prices would still occur but be less pronounced. In addition to the modelling inaccuracies, both countries have a high share of inflexible nuclear capacities and (in the case of Romania) a high share of run-of-river hydro. As these technologies have very low marginal costs and lack in flexibility, this leads to a considerable number of hours with overproduction as well as low prices in the remaining hours. The maximum price reached in the Bulgarian electricity market decreases from 127 €/MWh in the NOPOL-scenario to 63 €/MWh in the HARMFIT-scenario. In Romania, the maximum price decreases from 89 €/MWh in the NOPOL-scenario to 63 €/MWh in the HARMFIT-scenario.

4.1.1.4 Summary

The hypothesis that rising shares of renewables had a decreasing effect on electricity prices cannot be confirmed by the modelling results. It could however be shown that a variety of factors influences the electricity price level – these include the overall installed capacities compared to the demand, fuel and CO_2 prices as well as the technology mix and renewables shares in individual countries and the capacity of interconnectors. In a complex simulation model, it is rather difficult to attribute the price variations to one specific change in the underlying electricity system. Policy makers can nevertheless learn from this analysis – even if an increase in renewable capacities is planned, this must not necessarily bring about low prices and impede investments in other capacities. Prices will however decrease, if capacities are too high in general or if the electricity mix and flexibility of the system do not correspond to the needs of the rising renewable shares.

4.1.2 Impacts of renewables on price volatility

As weather dependent renewables have variable production patterns, increasing renewables shares are assumed to increase price volatility as they bring about an additional stochastic variation in addition to the demand fluctuations. In this section, the price volatility in the different scenarios is analyzed in order to find out whether the hypothesis of increased price volatility holds true under the assumptions made. The standard deviation of electricity prices is taken as the analytic means to assess price volatility. In addition, the occurrence of negative electricity prices is analyzed as an indication for surplus situations in the electricity system.

4.1.2.1 Results regarding price volatility

Figure 18 and Figure 19 show the development of the average standard deviation in European countries for the different policy scenarios for the case of a slow grid extension (Figure 18) and more optimistic grid extension (Figure 19). In both cases it becomes clear that, as expected, higher shares of renewables lead to a higher price volatility. This is reflected by the pronounced difference in the development between the NOPOL-scenarios where the renewable shares remain slightly lower and the cases where an effective renewable support policy is in place. A national independent policy (NATFIP) seems to lead to a higher volatility possibly because fluctuations within each country are increased. A harmonized technology neutral support scheme across Europe as in the HARMQUO-scenario leads to higher volatilities than a technology-specific support scheme with support levels tailored to resource quality as in the case of the HARMFIT-scenario. This can be explained be the fact that a more evenly distributed renewable capacities reduce the simultaneity of electricity generation[7].

As expected, a faster grid extension leads to a substantial decrease in price volatility. This is due to the fact that by increasing the interconnector capacities additional smoothing effects between the different neighbouring countries regarding demand fluctuations and renewable in-feed can be accessed. In the NOPOL-case, the additional grid extension even leads to a decrease in price volatilities between 2020 and 2030 even with an increasing renewable share. This means the adequate grid extension might help to keep price volatilities low at least until a certain share of renewable generation is reached.

Table 16 shows a detailed overview of the electricity price volatility in the EU countries under different scenarios. The very high standard deviation above 150 in some countries and scenarios reflect the occurrence of scarcity pricing. When there are scarcities in the model, the price is set to 2000 €/MWh which is way above the usual marginal cost pricing and therefore leads to a considerably higher price volatility.

[7] This effect depends however heavily on the applied support scheme and resulting distribution as can be seen from the results regarding the NATFIP-case.

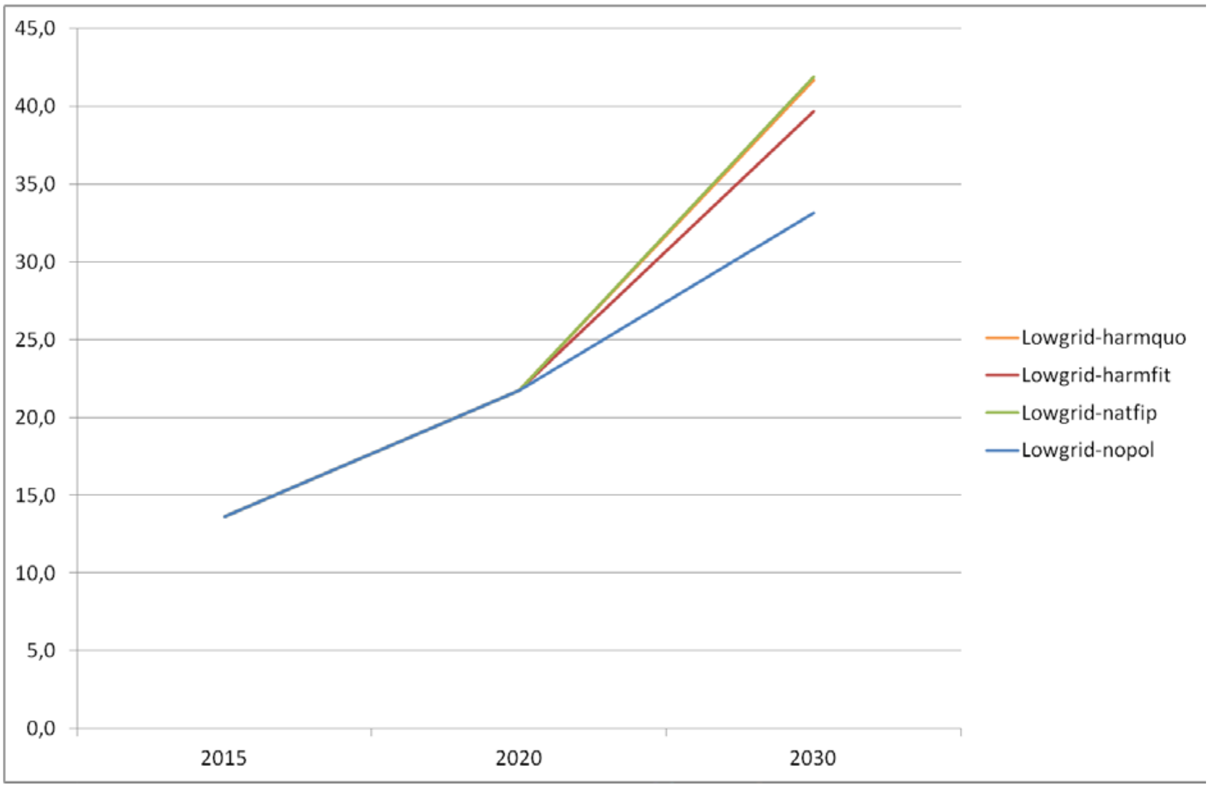


Figure 18 Development of price volatility (standard deviation of hourly electricity prices) from 2015 to 2030 in different policy scenarios and with slow grid extension (realization of TYNDP until 2030)

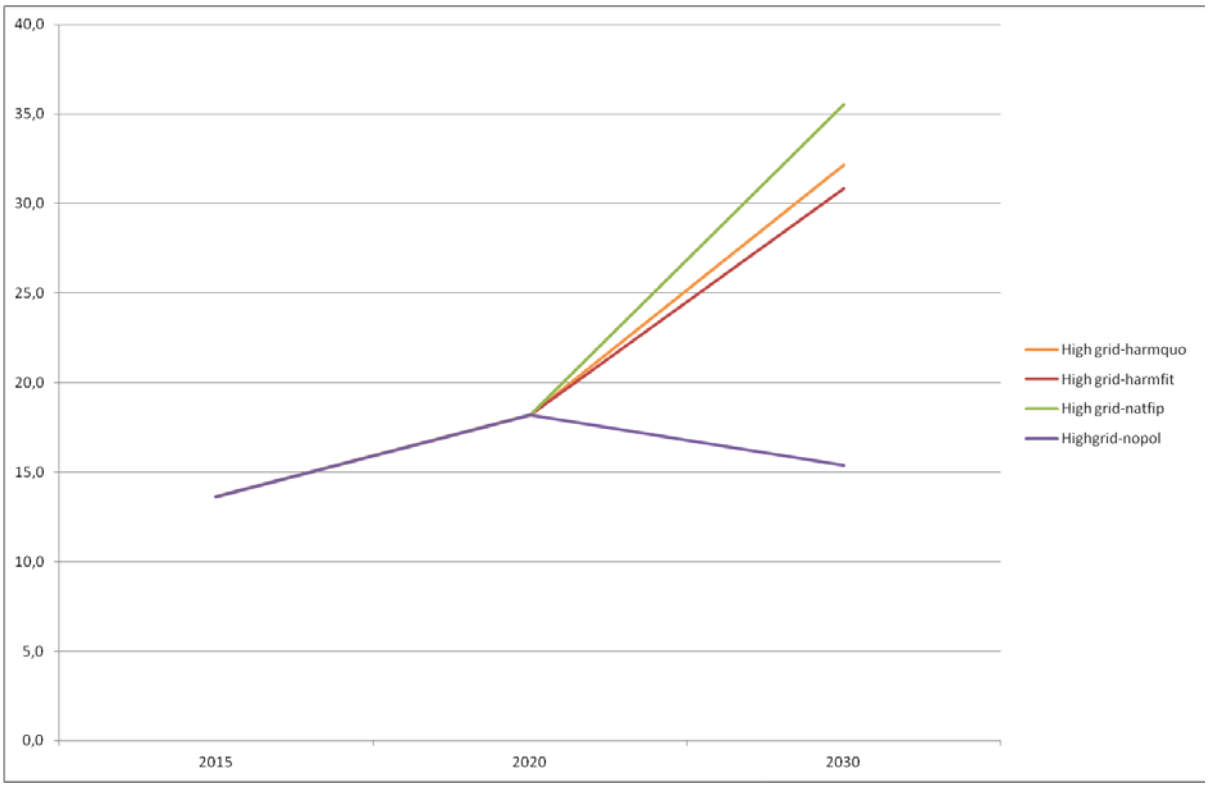


Figure 19 Development of price volatility (standard deviation of hourly electricity prices) from 2015 to 2030 in different policy scenarios with optimistic grid extension (realization of TYNDP until 2020)

Table 16 Standard deviation of electricity prices in European countries under different scenarios

Countries	2015	2020		2030							
		Low grid	High grid	Low grid				High grid			
				HARMFIT	NATFIP	HARMQUO	NOPOL	HARMFIT	NATFIP	HARMQUO	NOPOL
FR	22,0	25,6	29,2	39,9	40,4	39,2	25,0	37,8	38,8	39,0	20,2
AT	6,1	11,4	11,4	28,2	22,4	26,6	23,4	19,1	23,6	26,2	11,0
BE	7,2	11,4	12,9	20,7	22,1	29,0	11,7	18,8	22,4	26,2	10,9
BG	6,7	16,9	17,0	24,9	24,5	24,8	22,5	24,0	23,0	22,4	22,0
CY	25,3	29,0	29,0	31,3	31,4	35,2	24,5	31,3	31,4	35,2	24,5
CZ	5,1	12,0	11,7	16,5	18,9	22,6	7,7	17,0	21,5	24,8	6,8
DE	5,9	11,4	11,4	19,3	23,0	29,1	12,4	18,7	24,7	28,5	11,1
DK	11,1	16,2	13,8	31,0	44,3	44,2	25,1	22,0	25,2	28,8	11,7
EE	2,8	15,6	20,2	160,1	165,8	152,6	219,4	64,1	94,1	27,0	12,0
ES	37,5	34,1	30,6	55,0	55,2	54,2	26,4	55,0	54,0	54,2	25,3
FI	19,5	25,1	19,3	33,1	36,7	37,6	31,2	23,0	24,9	24,5	11,8
GR	21,1	24,2	23,1	32,6	37,9	34,2	26,5	30,8	29,1	36,4	18,5
HU	7,9	13,5	11,8	17,5	19,8	23,4	8,6	19,3	23,4	25,0	10,8
IE	18,4	36,1	24,1	50,7	50,1	49,4	40,9	50,4	49,9	49,1	40,7
IT	21,5	30,8	27,3	14,6	31,2	14,8	13,4	14,1	26,9	34,1	13,2
LT	4,8	31,6	11,4	37,6	38,0	38,4	24,3	34,7	34,0	26,2	10,0
LU	33,9	28,7	13,5	28,3	21,9	26,8	24,6	19,3	22,8	26,4	11,5
LV	11,9	32,6	11,4	37,6	38,0	38,4	24,3	34,7	34,0	26,4	11,0
MT	26,8	33,6	30,3	55,0	55,2	54,2	26,4	55,0	54,0	54,2	25,3
NL	3,7	10,1	10,5	25,0	25,0	34,8	9,8	19,4	24,3	28,7	10,6
PL	3,6	9,9	10,2	15,9	18,5	22,3	5,6	16,9	20,7	25,2	6,6
PT	8,0	27,0	27,8	55,4	55,3	54,3	26,3	55,3	54,2	54,3	25,5
RO	7,2	15,6	15,6	24,7	24,1	24,6	21,8	24,1	23,2	23,1	22,1
SE	23,5	44,3	19,4	136,2	143,3	126,5	181,9	47,2	89,1	25,8	11,7
SI	5,9	15,4	23,9	16,6	24,1	18,9	12,5	16,9	24,2	25,8	12,1
SK	17,7	13,4	11,8	16,6	18,9	22,5	7,7	17,0	21,5	24,8	6,8
UK	2,7	10,8	11,9	47,1	44,5	46,5	10,5	46,8	44,4	45,6	11,1

4.1.2.2 The occurrence of negative prices

With increasing shares of renewables, the likelihood that the electricity production at a certain point in time exceeds demand increases. As long as the generation from renewables does not react to market signals, is subsidised, and the market regulation allows for negative prices, the number of hours with negative prices is expected to increase. It is however important to mention here that negative prices are not only caused by renewables. Usually, in hours with negative prices, there are still a number of conventional power plants in the system that either have high opportunity costs when stopping generation (like nuclear power plants due to regulatory issues) or are active in the ancillary services market and can therefore not reduce their output. Thus, the usage of renewables for ancillary services as well as increasing flexibility in the overall electricity system can reduce the probability of negative prices. In the model however, neither additional flexibilities nor the possibility of renewables participating in the balancing market or reacting to market prices is currently implemented. Therefore the results regarding the occurrence of negative prices must be interpreted as a maximum scenario.

Figure 20 show the increase of hours with negative prices for the different policy scenarios under the assumption of a slow grid development. In 2015, 0.3% of hours have negative prices. In 2020, this number increases slightly to 1.4%. Effective renewable support policies and increasing shares of renewables by 2030 lead to a sharp increase to around 10% of hours with negative prices. This can on the one hand enable financial viability for storage or demand side management as well as new forms of electricity usage (power-to-heat, electric vehicles); on the other hand it also implies a lower income for renewables and possibly also conventional power plants. Like for price volatility, a more optimistic grid extension (as shown in Figure 21) can dampen the effects of an increasing renewable share. This effect is most pronounced in the case of a harmonized technology-neutral support scheme and less important for the technology-specific harmonized support scheme.

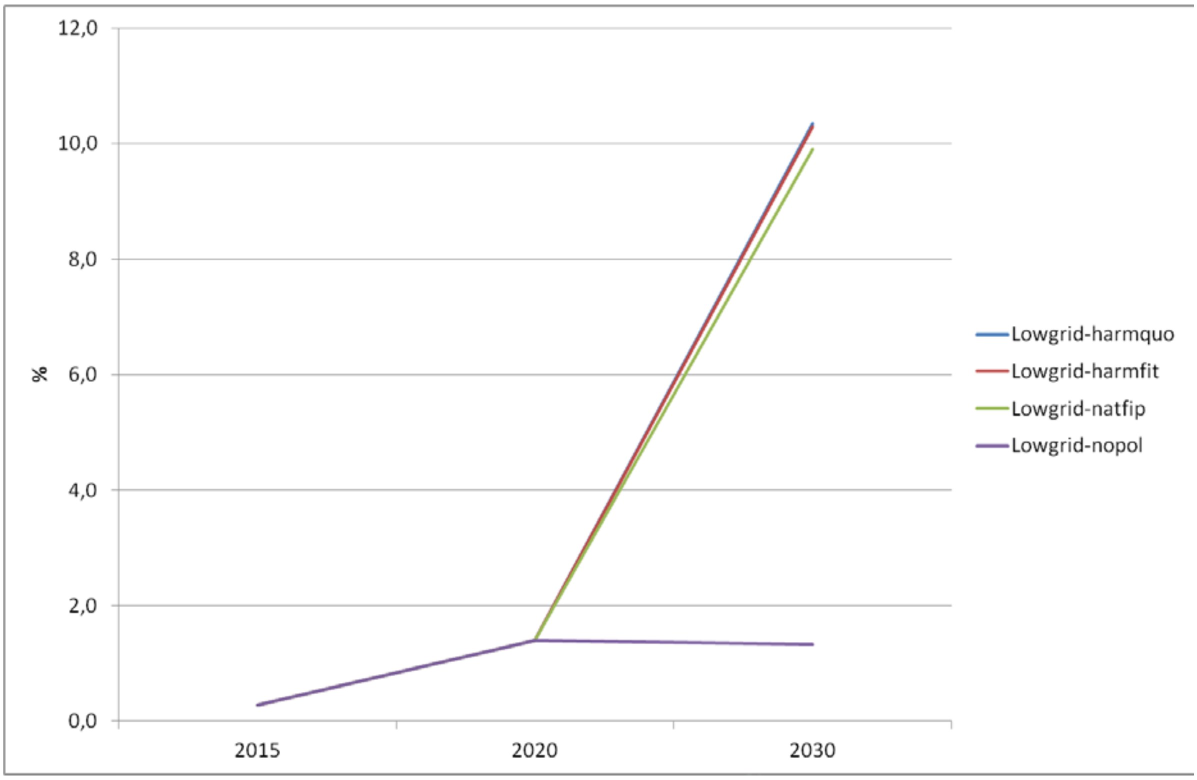


Figure 20 Development of percentage of hours with negative prices from 2015 to 2030 in different policy scenarios with slow grid extension (realization of TYNDP until 2030)

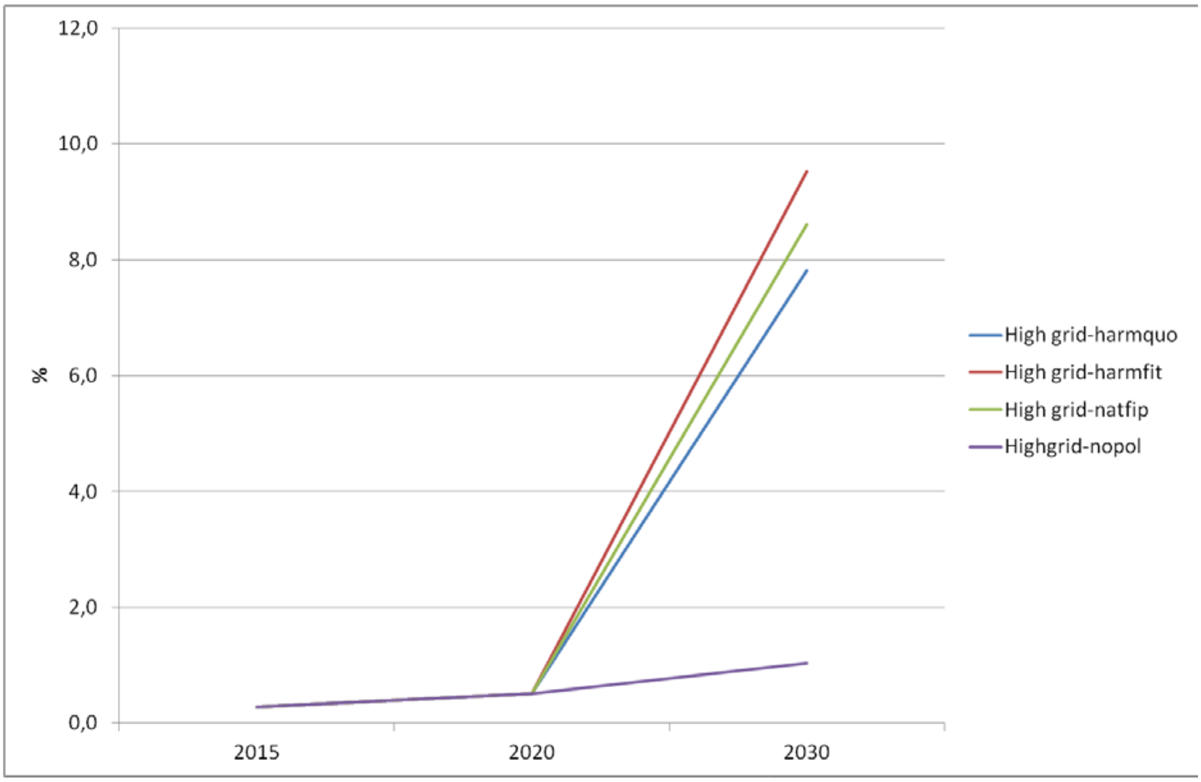


Figure 21 Development of percentage of hours with negative prices from 2015 to 2030 in different policy scenarios with optimistic grid extension (realization of TYNDP until 2020)

4.1.2.3 Summary

The modelling results confirm the hypothesis that increasing renewable shares lead to higher price volatility and a more frequent occurrence of hours with negative prices. Both effects can be partially mitigated by a more extensive grid extension.

4.1.3 Assessment of renewable market values

The market value of renewables represents the income that renewables can generate from the regular electricity market. It depends on the average electricity price as well as the relative value of renewable electricity compared to this average price (market value factor). Most renewable energies (except for biomass) have very low marginal costs of generating electricity. Thus, due to the merit order effect, electricity prices in the market are lower at times with a high share of renewables. As the weather dependent and fluctuating renewables (wind and solar) can only influence generation by investing in certain sides of curtailing generation, their market value factor is supposed to decrease with increasing share of renewables.

For modelling the market value factors, a floor price of 0 €/MWh was assumed as allowing for negative market prices leads to invalid results for a number of countries (e.g. Bulgaria and Romania, see section 4.1.1.3 for more detailed information) due to the assumed non-price-responsive bidding behaviour of renewables.

Figure 22 to Figure 27 show the development of the market value factors for PV, wind onshore and wind offshore for the different scenarios as a European average. In general, it can be observed that as expected the market value of renewables decreases over time and with rising renewable shares. However, there are remarkable differences between technologies and scenarios.

4.1.3.1 Results for solar PV

The first interesting effect is the development of the market value for PV: While in the NATFIP- and HARMFIT-scenarios the market value factor decreases sharply from above 1 to 0.9, it remains quite stable in the case of the HARMQUO and NOPOL- scenarios. This can however be easily explained by the fact that under a technology neutral support policy or with only the ETS to support renewables, there are no incentives to extend PV and thus its share even decreases between 2020 and 2030. Thus the relatively constant market share is in line with the hypothesis. In the case of a faster grid extension, the value is even higher for the HARMQUO-scenario in comparison to the NOPOL-scenario due to the differences in assumed interconnector capacities. In general more interconnection capacities lead to higher market value factors as smoothing effects can be used more effectively. Differences between scenarios also become more obvious in the case of faster grid extensions as in the deviations in the resource distribution become more important for the market factor when more international electricity trading is enabled.

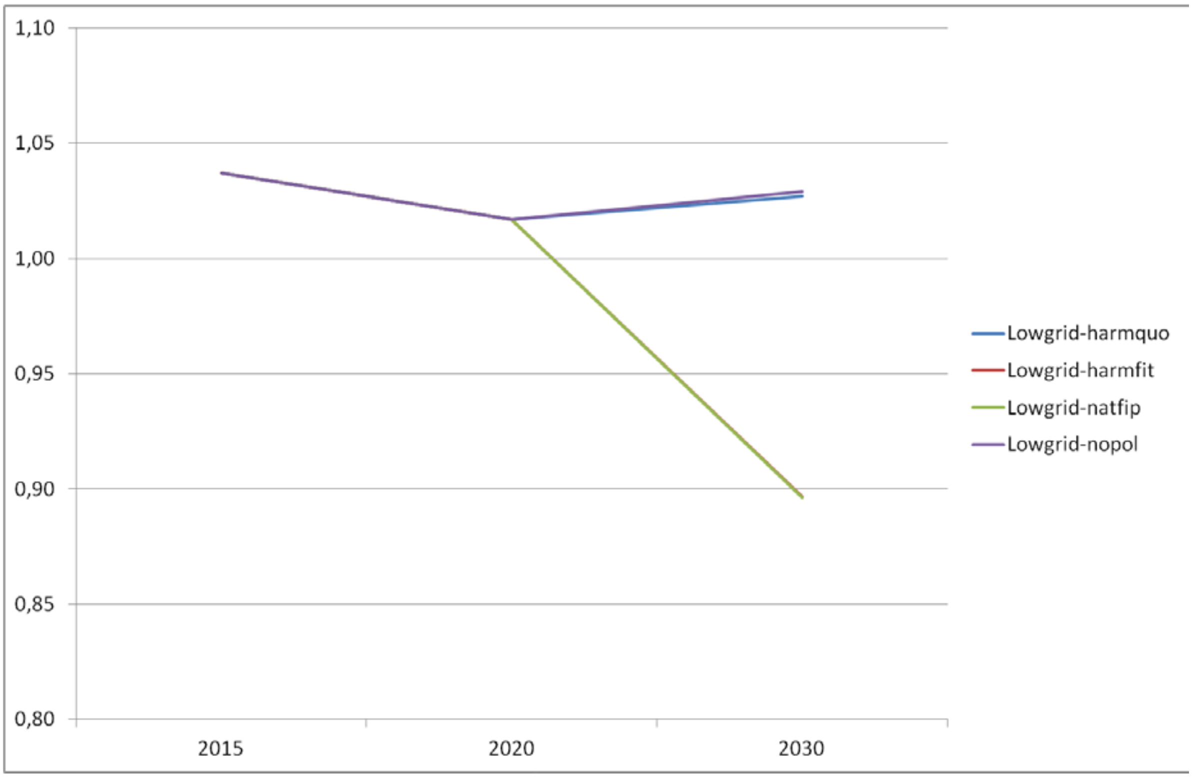


Figure 22 Development of market value factor for PV from 2015 to 2030 in different policy scenarios with slow grid extension (realization of TYNDP until 2030)

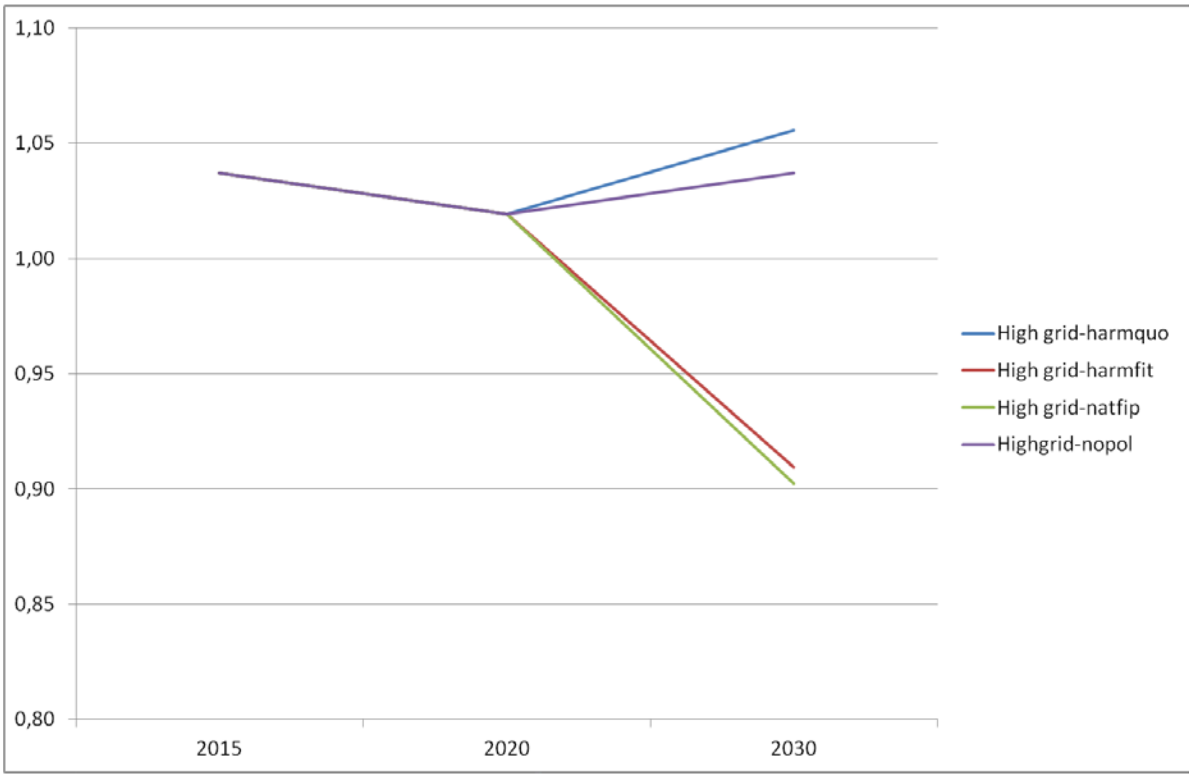


Figure 23 Development of market value factor for PV from 2015 to 2030 in different policy scenarios with optimistic grid extension (realization of TYNDP until 2020)

4.1.3.2 Results for wind onshore

Onshore wind has a market value factor below 1.0 already in 2015 which corresponds to reality. With an increasing share of onshore wind, there is a further decline until 2020, which is slightly dampened in the case of faster grid extension. In 2030, the market value factor drops further in all but the NOPOL-scenario. The steepest decline occurs in the HARMQUO-scenario. These developments are according to expectations as a technology-neutral support regime leads to a fast deployment of currently low-cost technologies – i.e. the HARMQUO-scenario implies the highest shares of onshore-wind. In contrast to solar PV, the differences in the market value factor between the similar HARMFIT- and NATFIP-scenarios become less pronounced with more grid capacities.

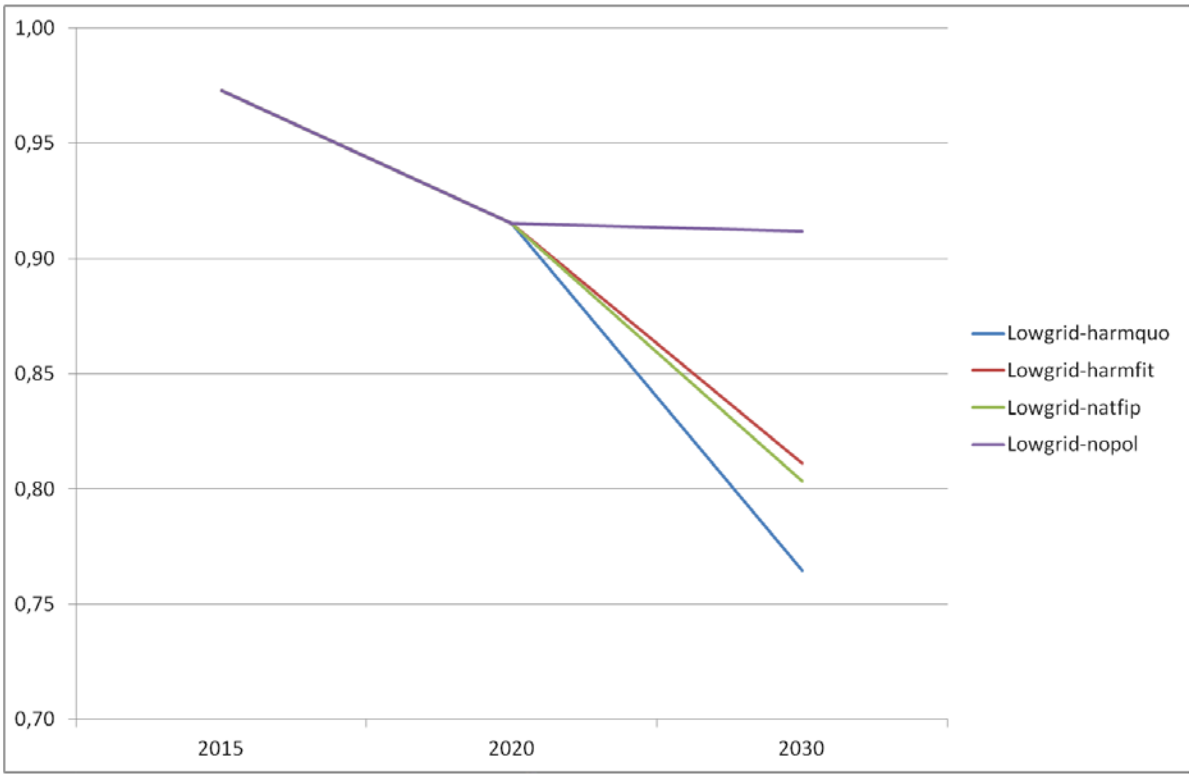


Figure 24 Development of market value factor for wind onshore from 2015 to 2030 in different policy scenarios with slow grid extension (realization of TYNDP until 2030)

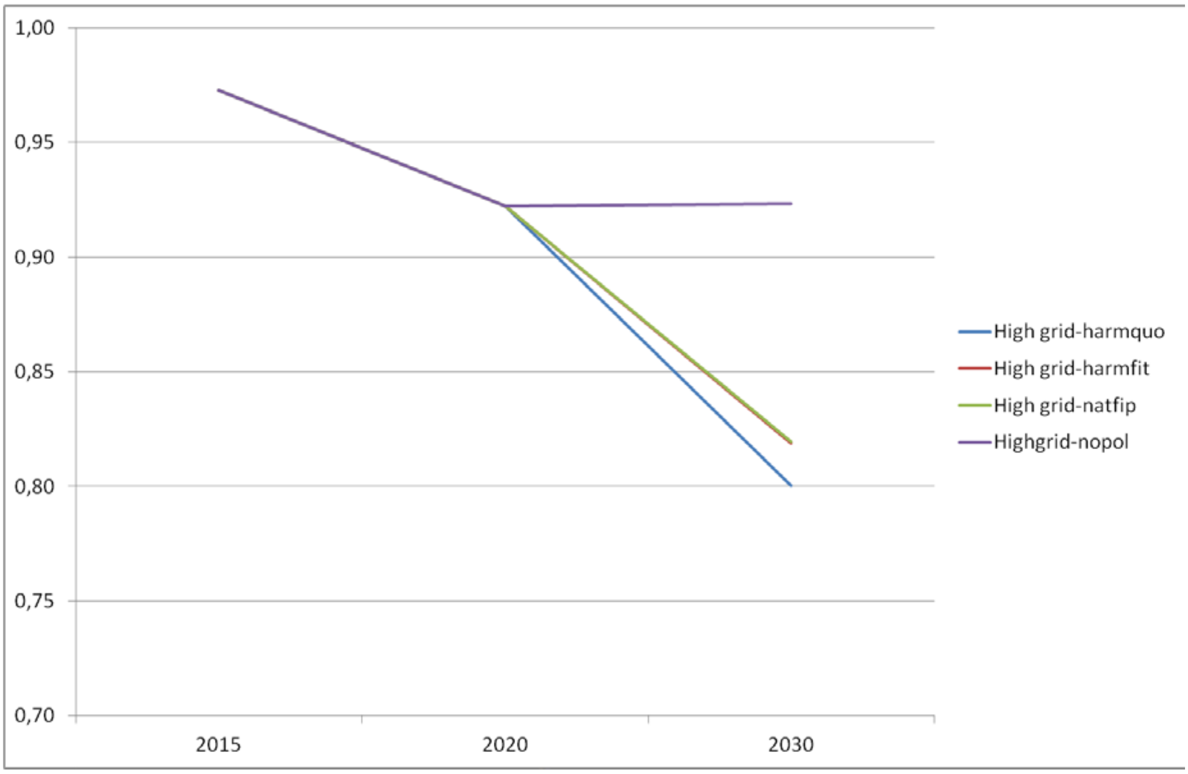


Figure 25 Development of market value factor for wind onshore from 2015 to 2030 in different policy scenarios with optimistic grid extension (realization of TYNDP until 2020)

4.1.3.3 Results for offshore wind

The development of market value factors for offshore wind resembles the development for onshore wind. Under the cost assumptions taken, the highest shares of offshore are also reached in the HARMQUO-scenario and the market value factor is lowest in this scenario.

Increased grid extension leads to a higher market value factor. There is however one difference between the offshore and onshore cases – for offshore wind, extended grid extension leads to a convergence of market value factors between the HARMQUO- und HARMFIT-/NATFIP-scenarios. This can be explained by the fact that the smoothening effect is more important when capacities are centralized in one or few countries which is the case for offshore in the HARMQUO-scenario. Onshore wind resources are more distributed in the HARMQUO scenario as almost all potentials of this cheapest technology are used under the technology-neutral support regime.

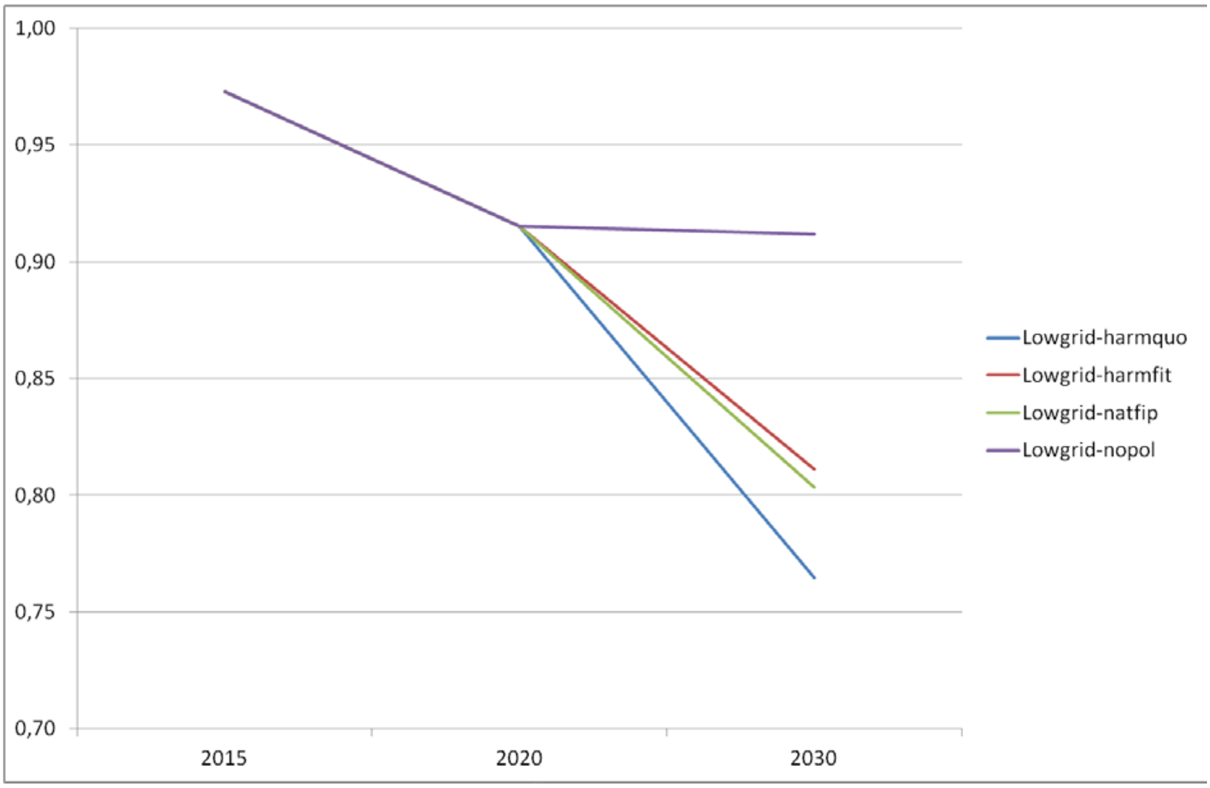


Figure 26 Development of market value factor for wind offshore from 2015 to 2030 in different policy scenarios with slow grid extension (realization of TYNDP until 2030)

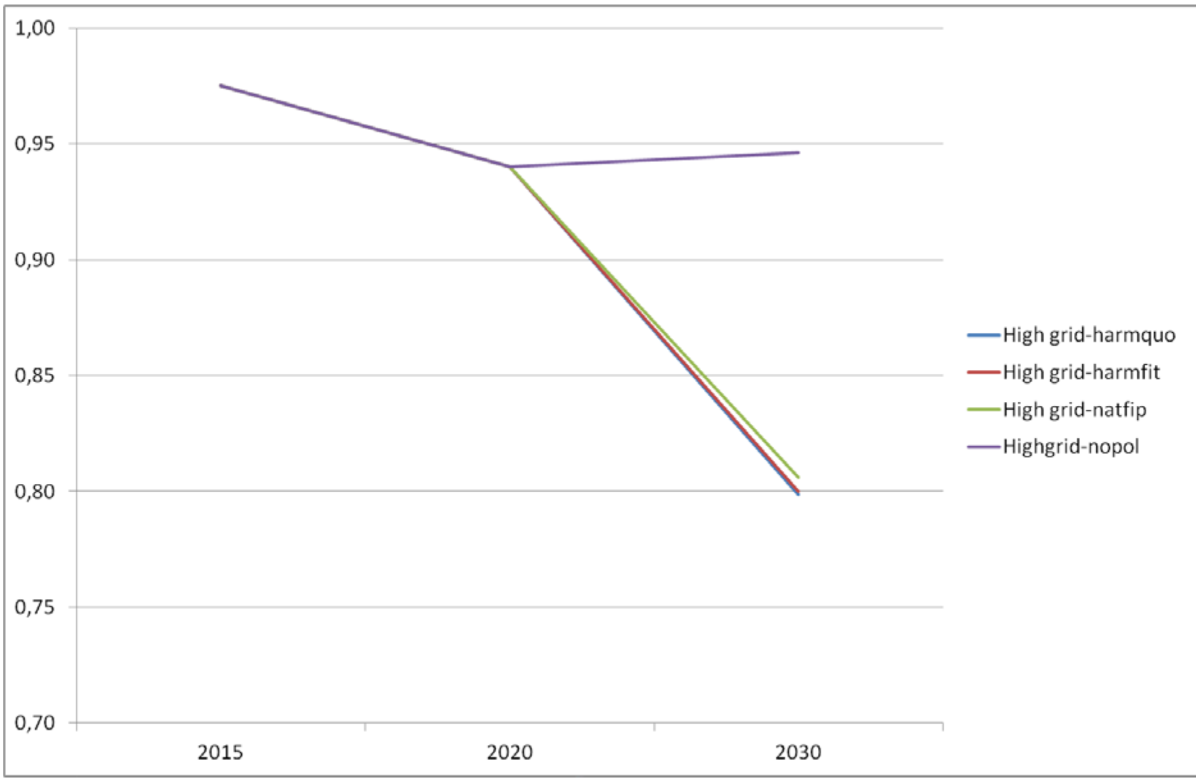


Figure 27 Development of market value factor for wind offshore from 2015 to 2030 in different policy scenarios with optimistic grid extension (realization of TYNDP until 2020)

4.1.3.4 Summary

As expected, increasing shares of renewables lead to decreasing market value factors for all technologies. The effect can be dampened by more grid extension especially in the case of a European harmonized support policy without support levels adapted to local resource quality (as in the case of the HARMQUO-scenario). Other factors apart from grid extensions that can contribute to higher market value factors such as increased demand or supply side flexibility were not part of the assessment.

4.2 Balancing costs and needs

In this section the results obtained with the ROM model for the Spanish power system are presented. The section is divided into two parts: first, the impact of the different RES policy scenarios on the Spanish power system operation and balancing needs is discussed. After that, the resulting system operation costs are presented.

It should be kept in mind that, contrary to the previous impact, in this case only results for Spain have been assessed. And that means that the total amount of RES installed is different for each policy scenario. This prevents comparing purely the scenarios in terms of policy design, but does offer an opportunity to compare results based on the total amount of renewable capacity installed.

4.2.1 Power system operation and balancing needs

Figure 28 presents the resulting generation mix in 2030 for the different RES policy scenarios considered. As explained in section 3.4.1, wind and distributed generation series are input data of the ROM model. Based on the amount of RES generation, the model decides the dispatch of conventional generators. Also, depending on the system state in a specific hour (i.e. level of RES generation, online conventional generation and demand), RES production may be curtailed. In this sense, the total resulting RES generation differs, in general, from the total amount given as input data. As shown in Figure 28, RES generation varies from 43% in the NOPOL scenario to 70% in the HARMFIT scenario. Total renewable generation in HARMQUO and NATFIP scenarios correspond to approximately 66% of 2030 electricity demand in Spain.

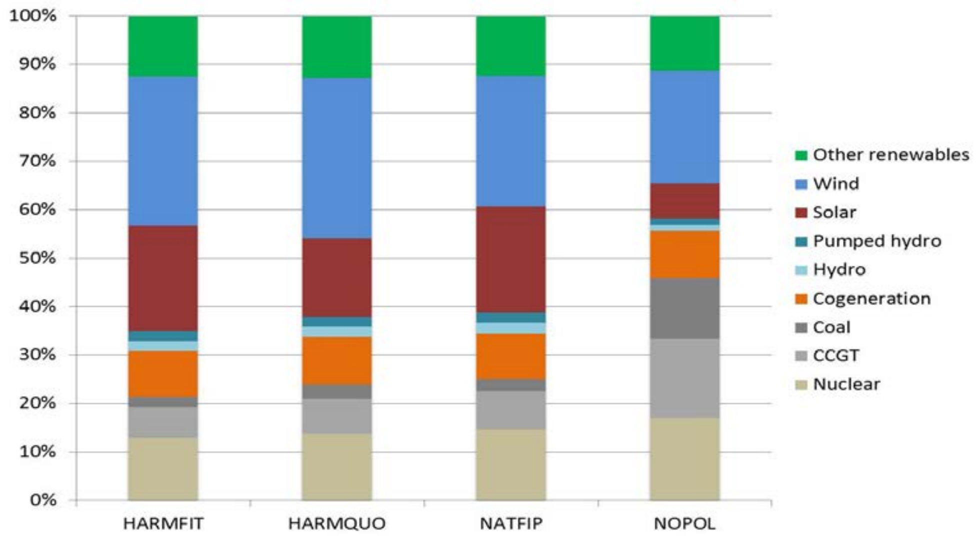


Figure 28 Generation mix results

The significant penetration of RES generation changes the operation of conventional power plants by increasing the number of times these units are shut down and started up and by reducing their utilization factor. This not only increases these power plants' maintenance costs but it also makes the investment in conventional generation capacity less profitable. Figure 29 presents the equivalent operation hours for each RES scenario. The equivalent operation hours are computed as the total annual energy produced divided by the total installed capacity for each conventional generation technology.

Comparing the scenarios with some kind of RES support scheme (i.e. HARMFIT, HARMQUO, NATFIP) with the scenario with no policy for RES generation (i.e. NOPOL), the most significant reductions are observed for coal and CCGT generation, which are the most expensive technologies in terms of marginal production costs. It was observed that coal power plants' production is reduced by 76% in HARMQUO (lowest reduction) and by 83% in HARMFIT (highest reduction) in relation to the NOPOL scenario and CCGT generation decreases from 50% (NATFIP) up to 59% (HARMFIT). Lower reductions are observed for nuclear and large-scale hydro power production: nuclear generation is reduced from 11% in NATFIP to 20% in HARMFIT in relation to the NOPOL scenario, while for hydro generation reductions vary from 7% in HARMQUO to 10% in HARMFIT. In the case of nuclear power, this smaller reduction is explained by the relatively lower flexibility of this technology in comparison to their conventional power plants. As for hydro power, variations from the scheduled yearly production are related to changes in production to counteract thermal generation outages or wind forecast errors.

On the other hand, pumped hydro production is increased in all scenarios with some kind of RES policy. The lowest increment is observed in the HARMQUO scenario (73% in relation to NOPOL) and the highest is observed in the HARMFIT scenario (84% in relation to NOPOL). This higher production is due to the significantly higher use of pumped hydro as storage for RES generation in order to avoid energy curtailment.

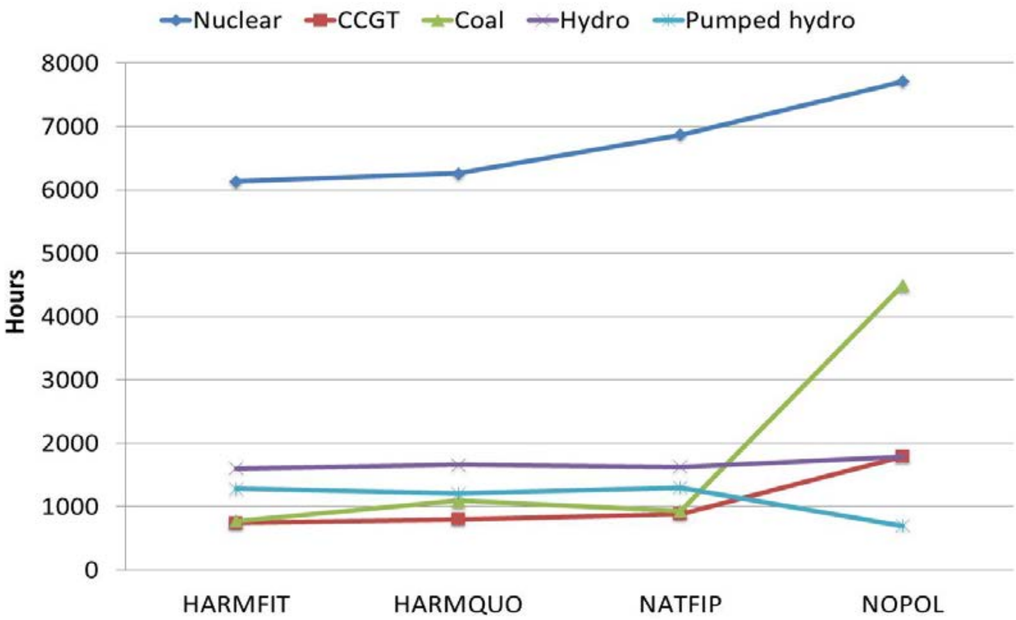


Figure 29 Equivalent operation hours of conventional power plants

Figure 30 presents the variations in the total use of upward and downward reserves in the different scenarios with some kind of RES policy in relation to the NOPOL scenario. As it can be seen in the figure, total upward reserves use increase from 20% in the NATFIP scenario to 43% in the HARMQUO scenario in relation to the NOPOL scenario. The increase in the use of upward reserves in HARMFIT, HARMQUO and NATFIP scenarios in relation to the NOPOL scenario is explained by the higher penetration of intermittent RES generation (wind and solar) in the former scenarios, which is around 52% and 38% and 37% higher than in the latter, respectively.

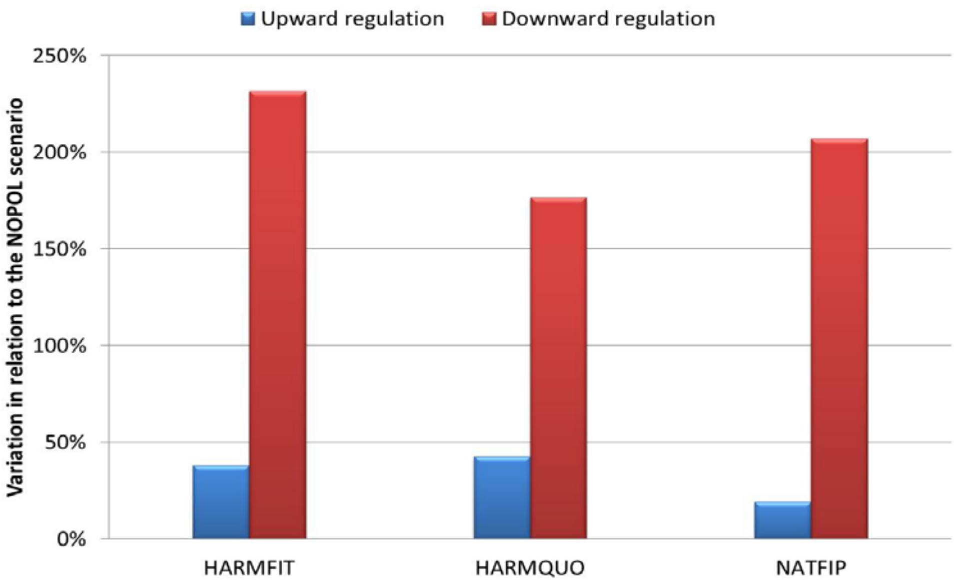


Figure 30 Variation in the use of reserves in relation to the NOPOL scenario

As can be seen in the figure, the increase in the use of downward reserves is significantly higher than the one observed for upward reserves. This can be explained by the fact that downward reserve use increases not only to balance forecast errors of intermittent generation but also to avoid curtailment of RES energy when there is an excess of generation in the system. As shown in Figure 28, in the scenarios with some kind of RES policy total RES generation shares vary between 66% and 70%. In these scenarios, during several hours, only wind and solar generation is enough to cover the system demand. Nevertheless, nuclear power plants are baseload plants and run almost all times throughout the year. Furthermore, in order to comply with upward and downward reserve requirements, and taking into account that RES generators such as wind and solar are not allowed to provide these services, flexible conventional generators must also be online.

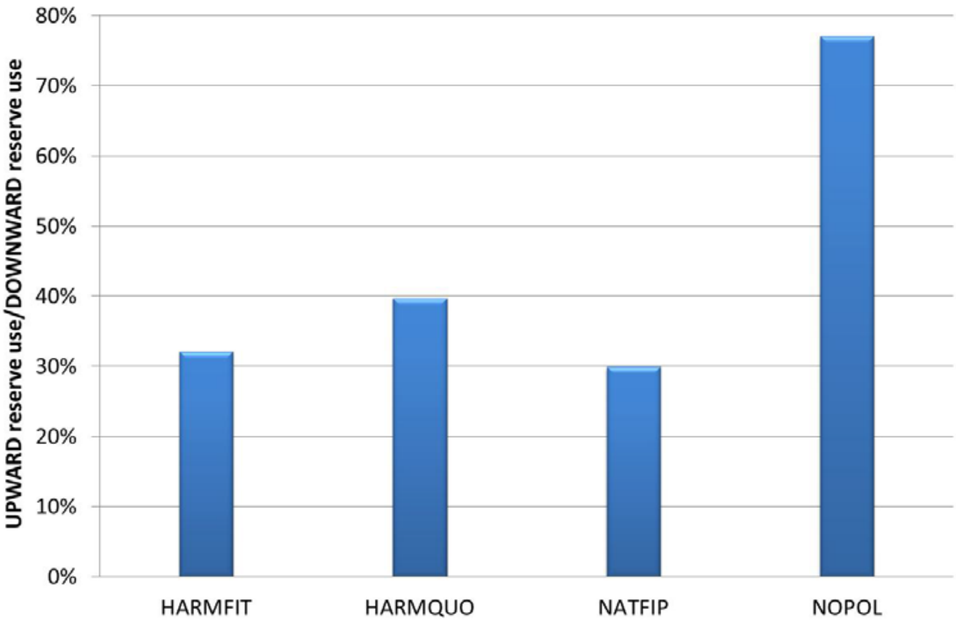


Figure 31 Relation between the use of upward and downward reserves

Figure 31 presents the ratio between the use of upward reserves and the use of downward reserves in the different scenarios. It can be observed that the use of downward reserves is higher than the use of upward reserves in all scenarios, although the difference between total upward regulation and total downward regulation is significantly lower in NOPOL compared to the remaining scenarios. This is due to the significant lower penetration of RES generation in the former and, consequently, to the lower number of hours during which excess of generation occurs.

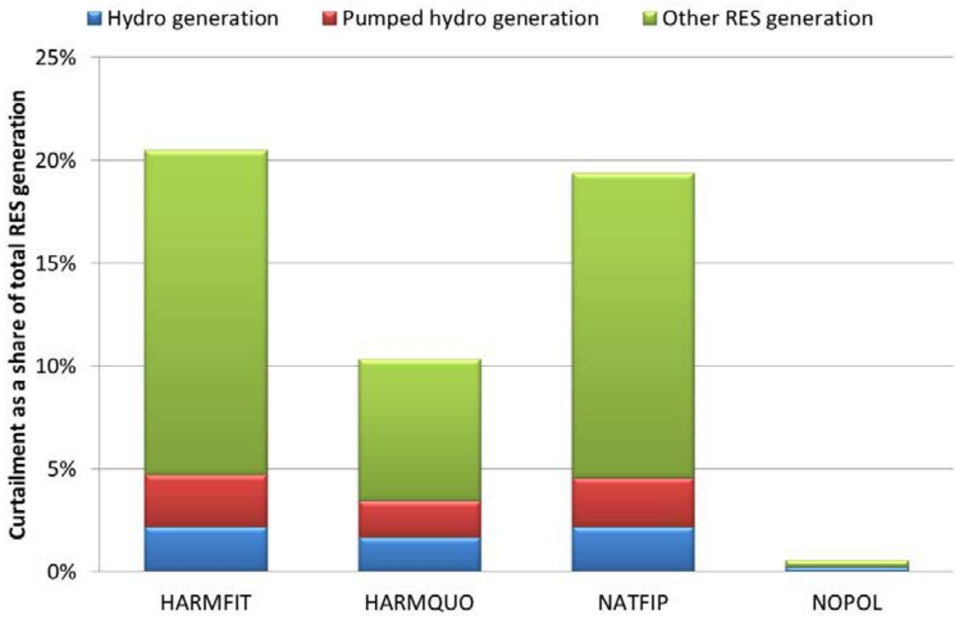


Figure 32 RES energy curtailment as a share of total RES generation

Figure 32 presents RES energy curtailment by technology as a percentage of total RES generation for each scenario. As it can be seen in the figure, even in the scenario with the lowest RES share (i.e. NOPOL) energy curtailment is required during some hours of the year. According to the results, RES energy curtailment in the NOPOL scenario represents less than 1% of the total RES generation in that scenario. Nevertheless, the level of curtailment increases significantly in the scenarios with higher RES shares. As previously explained, these high levels of curtailment are not only due to the full deployment of downward reserves during some hours but mainly to the fact that during several hours system demand could be covered only by wind and solar generation. In this sense, if only conventional generators are allowed to provide reserves in systems with massive RES penetration, increasing reserve requirements will require more RES generation to be curtailed. This type of curtailment currently occurs in Spain when there is too much intermittent generation in the system and the TSO has to curtail part of this generation (programmed curtailment) and commit conventional generation in order to comply with reserve requirements.

Based on the results obtained from the simulations the possible contribution from non-conventional RES generators to upward reserve provision was estimated. In order to compute this contribution, the hours during which non-conventional RES generation curtailment was programmed were compared to the hours when upward reserve was deployed. The results of this analysis are shown in Figure 33. According to the results, if non-conventional RES generators were allowed to provide reserves in the scenarios with some kind of RES policy, at least 52% of total upward regulation could be provided by these generators. Even in the scenario with no RES policy almost 10% of upward regulation could be provided by RES generators. This would reduce total RES generation curtailment by 6%, 13%, 7% and 38% in HARMFIT, HARMQUO, NATFIP and NOPOL, respectively.

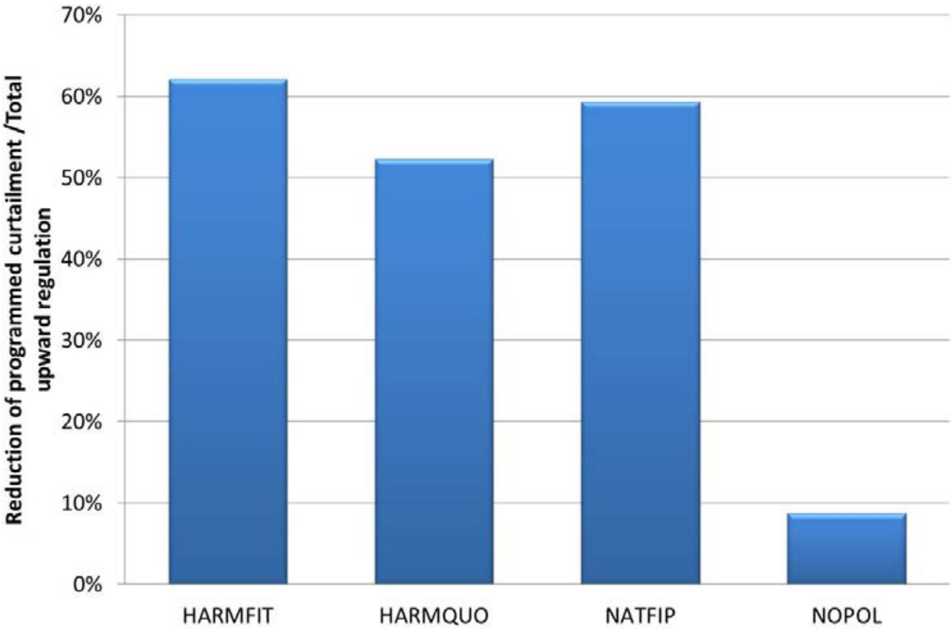


Figure 33 Estimated participation of non-conventional RES generators in upward regulation

4.2.2 System operation costs

This section adds more detail to the results presented in 4.1 (and obtained with the PowerAce model). In fact, what is shown here is system marginal costs, which, under a perfectly competitive market, would be equivalent to system wholesale prices. However, the results are not fully comparable, given that the amount of renewables in the system is different, given that only the Spanish system is being studied here.

Figure 34 presents the system marginal cost duration curve in 2030 for the different RES scenarios. As shown in the figure, the displacement of thermal generation with RES generation in the scenarios with high renewable penetration (HARMFIT, HARMQUO, and NATFIP) reduces system marginal costs significantly and increases the number of hours with zero marginal cost. In the NOPOL scenario, the hourly system marginal cost is set by coal or CCGT power plants during more than 7900 hours. In HARMFIT, HARMQUO, and NATFIP scenarios these hours are reduced to 4048, 4650 and 4507, respectively. In average, the system marginal cost decreases 48%, 42% and 44% in HARMFIT, HARMQUO, and NATFIP, respectively, in comparison to the NOPOL scenario.

Compared to the results presented for PowerAce, the amount of hours with zero marginal cost is significantly higher (10% for PowerAce, 40-50% for ROM), although of course this may be due to the different configuration of the system.

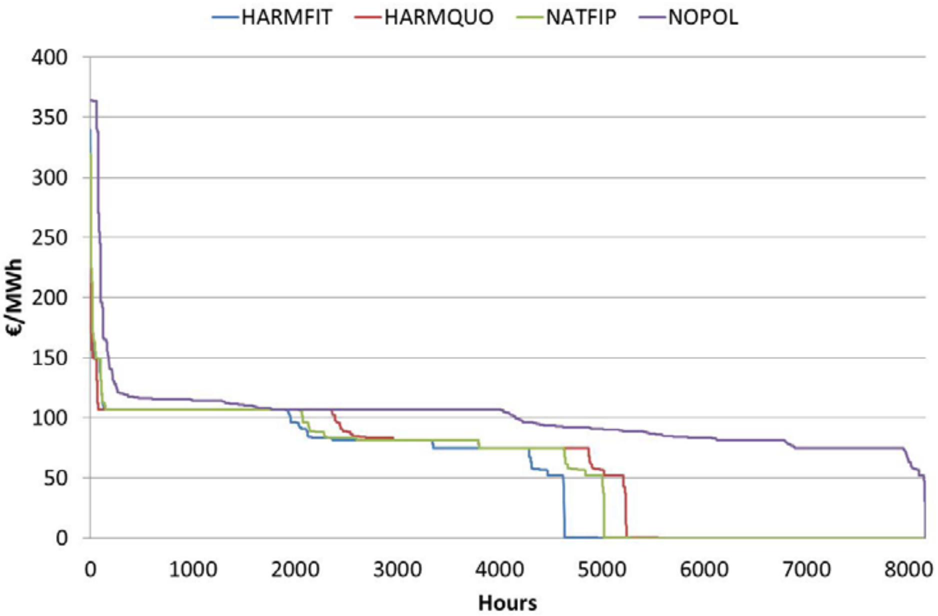


Figure 34 System marginal cost

Regarding these results, two remarks must be made. First, the conventional generation portfolio is the same in all scenarios regardless RES generation penetration level. In this case, marginal costs will, in general, be higher in the NOPOL scenario since the most expensive units must be scheduled to supply the system demand. If investment decisions were taken into account in this analysis, conventional generation portfolio would differ in across the different scenarios. In scenarios with high RES generation levels probably more investment would be made in peak units and less baseload units would be available. In this sense, higher marginal costs than the ones obtained in this analysis would be observed in the scenarios with higher RES generation levels (although the average marginal cost would still be lower in those scenarios in comparison to low RES generation scenarios). Second, marginal costs do not take into account support schemes (i.e. feed-in tariff, premium, etc.) paid to RES generators. Nevertheless, these support schemes must be taken into account when computing RES generation integration costs.

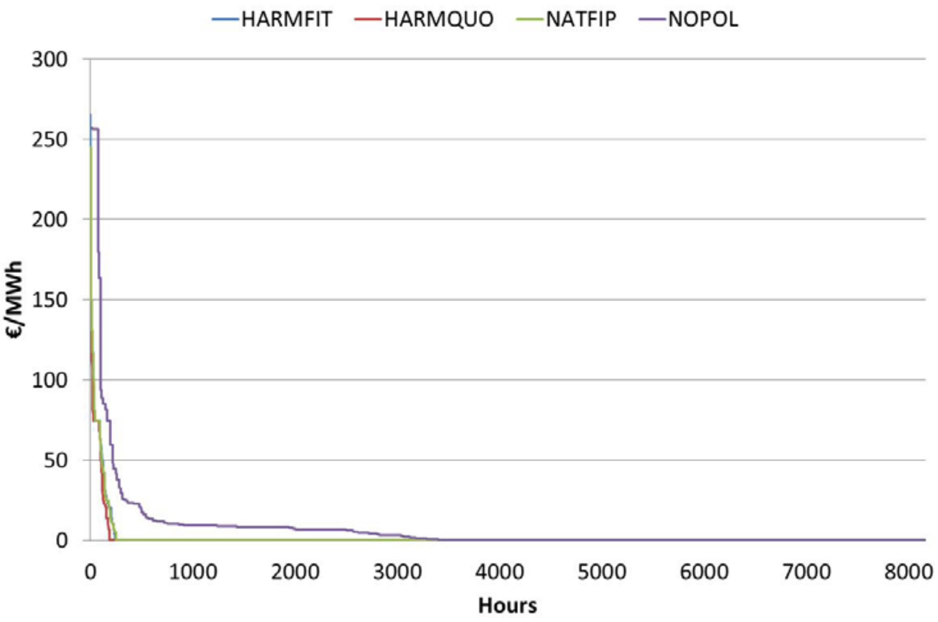


Figure 35 Upward reserve marginal cost

Reserve marginal costs are computed by the model as the increment in system operation costs resulting from keeping thermal units operating above their minimum output operation point (for downward reserve provision) and below their maximum output operation point (for upward reserve provision). Figure 35 presents the upward reserve marginal cost duration curve for the different RES policy scenarios. As can be observed, upward reserve marginal cost is significantly lower than the system marginal cost in all scenarios. In principle, bids to participate in the reserve market should correspond to the opportunity cost of the generator, which is the difference between its variable cost and the market price. Since CCGT power plants are in general the units setting the marginal market price and these units have similar variable operation costs, their bids into the reserve market are generally low. Higher reserve prices in the NOPOL scenario in relation to the remaining scenarios can be explained by the use of more expensive units for upward reserve provision during peak hours. Finally, yearly average downward reserve marginal costs are nearly zero in all scenarios.

The significant availability of hydro resources and pumped storage in the Spanish system also contributes to low reserve prices. Figure 36 presents the participation of each technology in reserve provision in 2030 for the different scenarios. As shown in the figure, hydro power plants and pumped storage units provide a significant share of upward and downward reserves to the system. Comparing all the scenarios, the main difference is the reduced share of pumped hydro storage in the provision of upward reserve in the NOPOL scenario. This is due to the high consumption of pumped hydro storage in hours of zero system marginal cost in the high RES generation scenarios, which is more than three times higher than the observed in the NOPOL scenario.

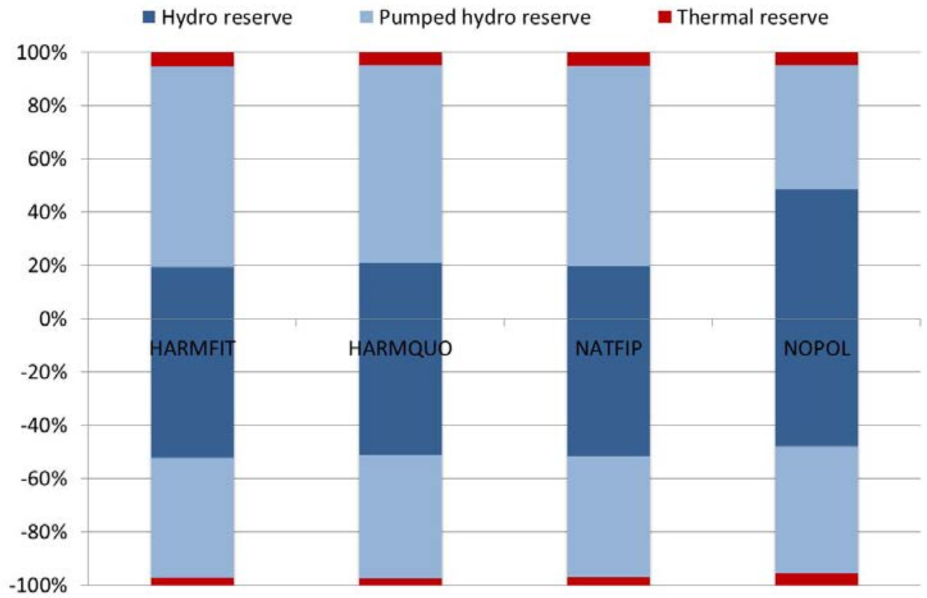


Figure 36 Provision of upward (positive) and downward reserve (negative) by technology

Figure 37 presents the variation in total upward reserve costs and in the average upward reserve marginal cost in the scenarios with higher RES generation in relation to the NOPOL scenario.

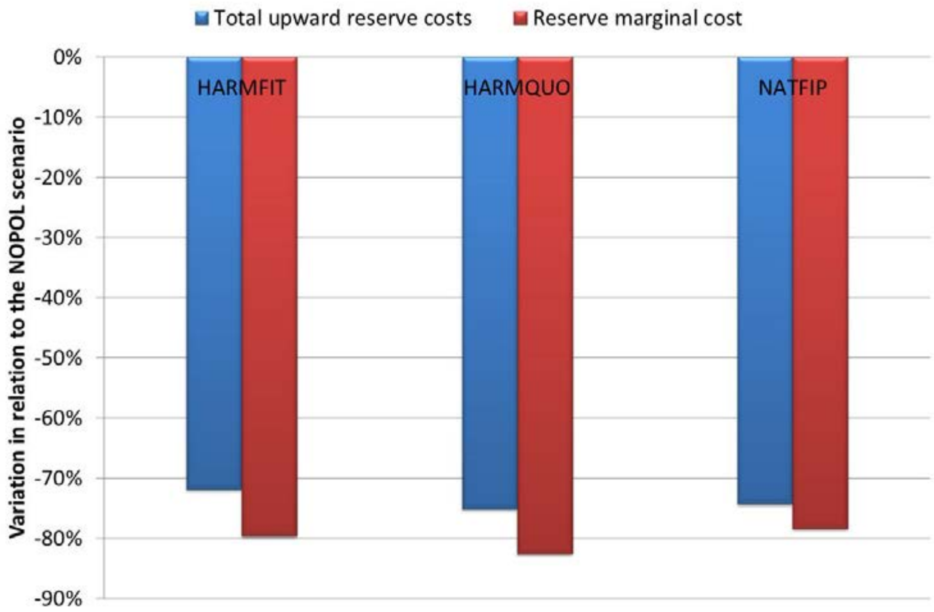


Figure 37 Variation in total upward reserve costs in relation to the NOPOL scenario

As it can be seen in the figure, the average upward reserve marginal cost is reduced by 80%, 83% and 79% in HARMFIT, HARMQUO, and NATFIP in comparison to the NOPOL scenario, respectively. As previously explained, these reductions are related to the provision of reserves by more expensive thermal units in the latter. Due to this reduction, total upward reserve costs decrease in the scenarios with higher RES penetration compared to the NOPOL scenario although reserve requirements and use are higher in the former. As shown in Figure 37, total upward reserve costs decrease 72%, 75%, and 74% in HARMFIT, HARMQUO and NATFIP scenarios in relation to NOPOL, respectively.

Regarding these results, attention must be drawn to the fact that the availability and the cost of reserve provision depend strongly on the conventional generation mix considered in this analysis. In this sense, if the conventional generation mix is more adapted to a context of high RES penetration, i.e. higher number of peak units and lower number of baseload units, cost results would probably differ from the ones obtained in this analysis. Furthermore, the availability of hydro generation and pumped storage capacity provides Spain with relatively cheap regulating resources.

4.3 Network effects

This section presents the numerical results of the analysis of the development of the network within the South-Western European region for the several policy scenarios considered within this project. As previously explained, the methodology described in section 2.3 has been applied to characterize scenarios presented in section 3.4.1. First, the results on network development and system operation are provided in section 4.3.1. Then, these results are thoroughly analyzed in section 4.3.2. Finally, the main conclusions are extracted in section 5.1.3.

4.3.1 Numerical results on the development of the network and system operation

In order to determine the influence of different RES policies in the development of the network, its optimal expansion in the 2030 time horizon is computed for the four RES policy scenarios previously described. As previously explained, due to the complexity of the problem, only the region comprising Portugal, Spain and France is considered.

The TEPES model is applied to compute the optimal expansion of the network. The regional network existing in the year 2008 has been taken as the starting point. Making use of this model, we have carried out a static analysis of network expansion needs. This means that the required network reinforcements at intermediate time points between 2008 and 2030 have not been determined.

In order to carry out network analyses, the operation of the systems in the region has been optimized together with the expansion of the transmission network. Conventional generation electricity production per zone and scenario is shown in Table 17, while RES generation output is very similar to RES available in each zone and scenario, see Table 18. This is due to the fact that RES generation exhibits much lower variable production costs than conventional one, which involves that the development of the system network computed should allow RES operators to inject in the network most of their available primary RES energy. Table 18 provides the difference between available RES energy and RES power production in each scenario. RES energy spillages are below 2% for all of the scenarios except for HARMFIT[8]. Note that RES energy spillages are lowest in relative terms in the NOPOL scenario, which is consistent with the fact that the RES penetration level and power production is also lowest for this scenario. As mentioned below (see e.g. Section 4.3.2) the market value of RES output in the NOPOL scenario is larger than that in other scenarios on average terms, since RES power production is more likely to be replacing expensive thermal generation in the former. Hence, integrating an extra amount of RES generation into the grid is more profitable in the NOPOL scenario than in others. Within “green” scenarios, spillages for the HARMQUO and NATFIP scenarios are similar and very low, while the highest RES energy spillages occur in the HARMFIT scenario.

[8] This is a significantly smaller rate than for the ROM model. Although the TEPES model account for grid effects (which could increase the rate of spillage), it only looks at certain snapshots, whereas the ROM model accounts for the whole year.

Table 17 Conventional generation production within the south-western region per zone and scenario

[GWh]	Harmfit	Harmquo	Natfip	Nopol
ES_C	14594	16248	14594	22572
ES_NE	1605	21220	2895	32832
ES_NW	3480	5492	3489	32932
ES_SE	12283	25326	12064	71656
ES_SW	26499	25299	20000	38985
FR_C	103870	104303	104338	105273
FR_N	168290	169099	168526	233751
FR_SE	83178	83343	83297	89508
FR_SW	37627	37668	37673	37755
PT	236	5250	1997	18214
TOTAL	451661	493248	448874	683478

Table 18 Overall RES power production available and achieved in each scenario; RES energy spillages

	RES potential [GWh]	RES generation [GWh]	RES surplus [%]
Harmfit	619653	601001	3.01%
Harmquo	575041	568650	1.11%
Natfip	611918	604919	1.14%
Nopol	418468	415909	0.61%

Network investments costs in each scenario are provided in Table 19, where numbers are expressed in million € per year. Costs are highest for the HARMFIT and NATFIP scenarios. These are also the scenarios where renewable generation power production is largest (and conventional power production is lowest). This may have some impact on network investment costs, since, the geographical distribution of RES power production at any time is, generally speaking, not aligned with that of demand, which results in large power flows among areas in the region. In line with this, power exchanges among countries in Europe are expected to increase with the level of penetration of RES generation. However, relative differences among the overall output of renewable generation in the scenarios considered are much lower than relative differences among network development costs in these same scenarios.

Table 19 Cost of network investments required per zone and scenario

[M€ annual]	Harmfit	Harmquo	Natfip	Nopol
ES_C	110	49	72	72
ES_NE	167	122	151	105
ES_NW	79	50	42	46
ES_SE	147	132	146	73
ES_SW	175	120	171	86
FR_C	157	160	138	155
FR_N	130	91	119	160
FR_SE	141	81	105	95
FR_SW	112	110	84	187
PT	61	42	40	32
TOTAL	1279	957	1067	1011

Table 20 Unit network investment cost per MWh of RES generation

	[M€/MWh]
Harmfit	2.13
Harmquo	1.68
Natfip	1.76
Nopol	2.43

RES spillage levels decrease with the cost of the connection of new RES generation[9]. The latter tends to decrease with grid-related locational signals sent to the new RES facilities. The unit network investment cost per MWh of RES power production for the different scenarios is displayed in Table 20. Among the high RES penetration scenarios, the HARMFIT has the highest unit network investment cost. This means that the development of the network required to integrate RES generation in this scenario is more expensive than that in the other two. Because the level of RES and load is similar among these three scenarios (especially in the HARMFIT and NATFIP), the market value of RES output is also similar. Therefore, differences among the quantity of RES energy dispatched (not spilled) in these three scenarios mainly depend on the cost of the reinforcements to the network that are required to integrate additional RES output. This results in the HARMFIT scenario featuring the highest level of RES spillages. As previously mentioned, the market value of RES output is highest for the NOPOL scenario. Cost savings of integrating an additional unit of RES output clearly exceed the associated network costs. Hence, maximizing RES power production in the NOPOL scenarios is efficient from an economic point of view.

Differences in network investment costs among scenarios are also closely related to the amount of use made of the regional grid. The aggregate use made of the network of the French, Spanish and Portuguese systems throughout the target year in each of the scenarios is provided in Table 21, where numbers are expressed in TWh*km. By comparing Table 19 and Table 21, one can realize that the two scenarios where network investment costs are larger (HARMFIT and NATFIP) are also the ones where the use made of the network is largest, while the two where network development costs are lower also exhibit a relatively low overall network use. This involves that the further power production is from load at each time of the year, the larger network investments required are, which seems to be quite logical. Then, policy frameworks encouraging the development of new RES generation in areas that are close to load, i.e. importing areas, where market prices tend to be higher, should result in lower network investments than those not sending appropriate grid locational signals. Linking market revenues of RES generation and power prices should probably result in a reduction of network investment costs, though there are other aspects determining the development of the network, like the differences among incremental flows produced by new RES generation and the traditional pattern of flows in the network. The larger the latter the more probable it is that additional network investments will be needed to accommodate these incremental flows. Next subsection will analyze in more detail how the features of each RES policy scenario determine the development of the grid in that scenario.

Overall annual network investment costs in any scenario are in the range of 1000M€ in the South-Western region. These are about one order of magnitude lower than variable production costs, which range between about 11000M€ for the green scenarios and 25000M€ for the NOPOL scenario, where RES production is lower.

Table 21 Overall annual use of the regional network per scenario

	Network use [TWh km]
Harmfit	180131
Harmquo	165750
Natfip	181002
Nopol	164085

Transmission losses are provided in Table 22 both in GWh per year and as a percentage of overall demand in the corresponding scenario. Differences in losses among scenarios are analogous to those in network use. Losses are highest in the NATFIP and HARMFIT scenario, where power production

[9] The cost of the connection of new RES generation is not only the cost of connecting the RES facility to the system network, but also the cost of the network reinforcements that are required to transport its power production to consumption areas.

(mainly from RES) is furthest from demand. Losses are lowest in the NOPOL scenario and then in HARMQUO, where generation seems to be closer to demand probably driven by RES policy.

Table 22 Network losses per scenario

[GWh]	Harmfit	Harmquo	Natfip	Nopol
Line_Losses	11684	10720	11987	10836
Conv_Losses	1268	1354	1222	1158
TOTAL	12952	12075	13209	11994
Losses/Demand	1.40%	1.28%	1.45%	1.25%

Before discussing network development costs computed for each scenario, in the remainder of this subsection we discuss the size and geographical distribution of network reinforcements incurred in each scenario, see Figure 41. We also try to link the size of network reinforcements required to the geographical distribution of annual demand, conventional and RES generation power production in the zones of the region, as well as to aggregate annual energy flows taking place among these zones, see Fig. 42. Together with overall RES and conventional power production in each zone and exchange flows among zones, Fig. 42 also provides the overall cost of network investments in each zone, previously shown in Table 19. Five zones have been defined within the Spanish system (South-West, South-East, Centre, North-West and North-East), four within the French one (South West, South-East, Centre, and North) and a single one for Portugal.

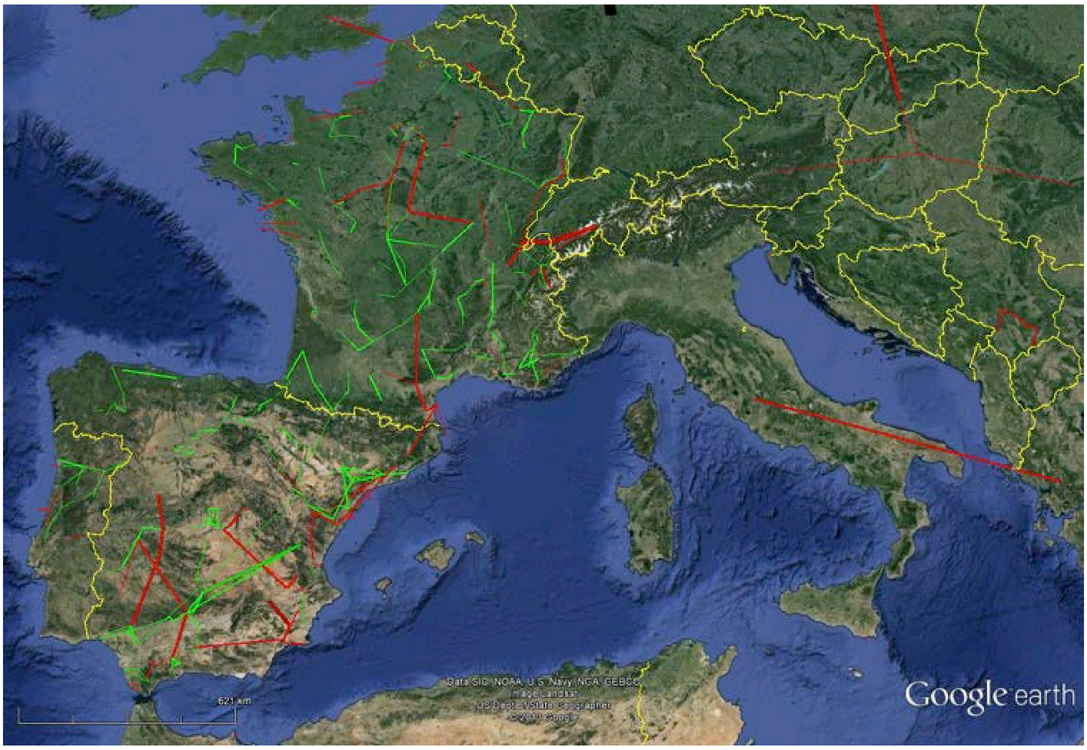
Network reinforcements are represented in Fig. 41 using different colours for different voltage levels. Thus, 220 or lower kV lines are represented in green, while 400kV and EHV lines are represented in red. The latter include HVDC lines, which have been deemed to be operated at 400KV or 750KV. HVDC lines built include those required to connect offshore generation to mainland and some main interconnection options between Spain and France. The width of lines representing network reinforcements corresponds to the amount of transmission capacity built between the corresponding two nodes in the network. This capacity may have been built as a single reinforcement (reinforcements of different sizes have been considered) or as a collection of them.

New lines built outside France, Spain and Portugal have been represented as reinforcements to equivalent HVDC interconnectors among these other countries and between them and France. As already mentioned when describing the methodology followed to carry out grid analyses, reinforcements to the European grid outside the South-Western region have been considered in order to compute cross-border flows between the French and neighbouring systems that are consistent with the operation of the system in the target region. However, they are not aimed to be an accurate estimate of the reinforcement needs of the grid of third countries.

HARMFIT reinforcements

HARMQUO reinforcements

NATFIP reinforcements



NOPOL reinforcements

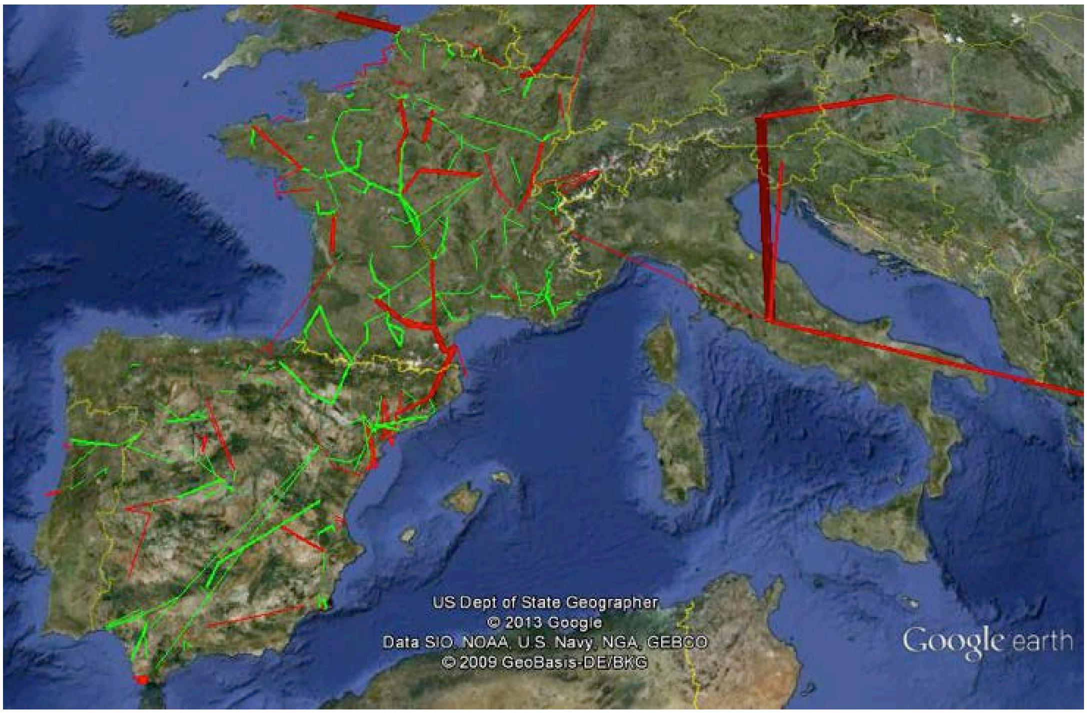


Figure 38 Geographical location of network reinforcements in each scenario

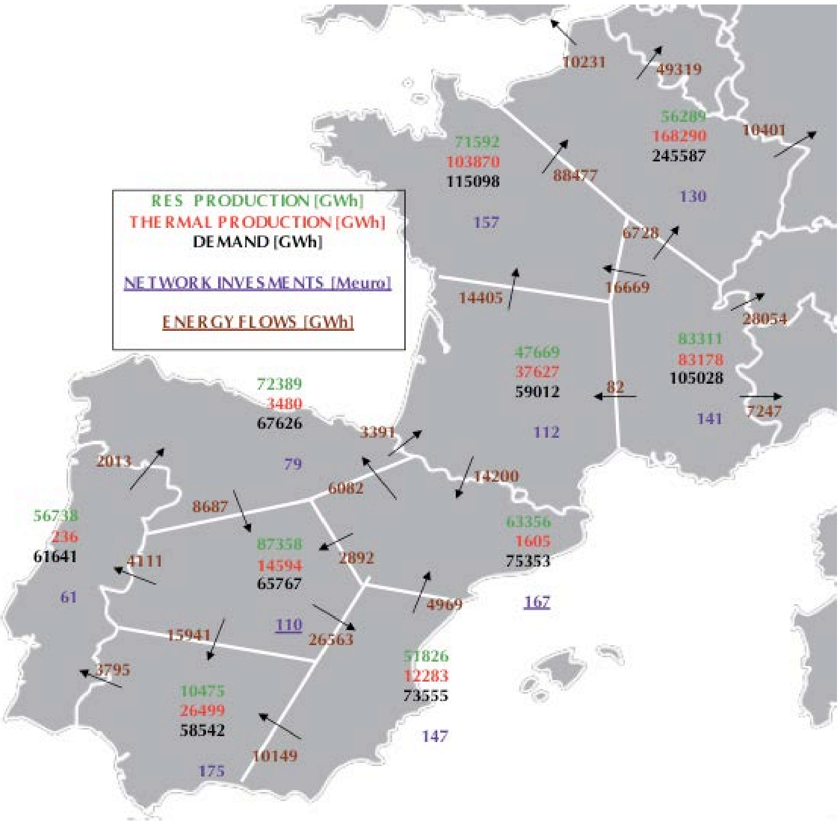
One first conclusion to be drawn from the maps of reinforcements is that many of the reinforcements are common to all scenarios. On top of these reinforcements, there are some other specific to each of the scenarios. Reinforcements within the Spanish system mainly take place within the South and North-eastern parts of the country, while those in the French system mainly take place in the Centre region.

Investments to increase transfer capacity between the French and Spanish systems mainly take place in the NOPOL scenario, where new interconnection capacity and reinforcements in the south of the French system are largest. As it can be seen in Fig. 42, net interconnection flows throughout the year are also largest for the NOPOL scenario, though those on the eastern side of the interconnection, which is the one where most reinforcements take place, are low. Contrary to what happens in “green” scenarios (HARMFIT, HARMQUO and NATFIP), where net exports from Spain to France are negative, cross-border flows in the NOPOL scenario are from Spain into France and are quite relevant. Moreover, the NOPOL scenario is the only one where a new interconnection facility between Spain and France is built (connecting the North Western zone of Spain with the South Western zone of France). This great amount of exports from Spain may be the reason behind the need to heavily reinforce the interconnection and the South-western part of the French grid in this scenario.

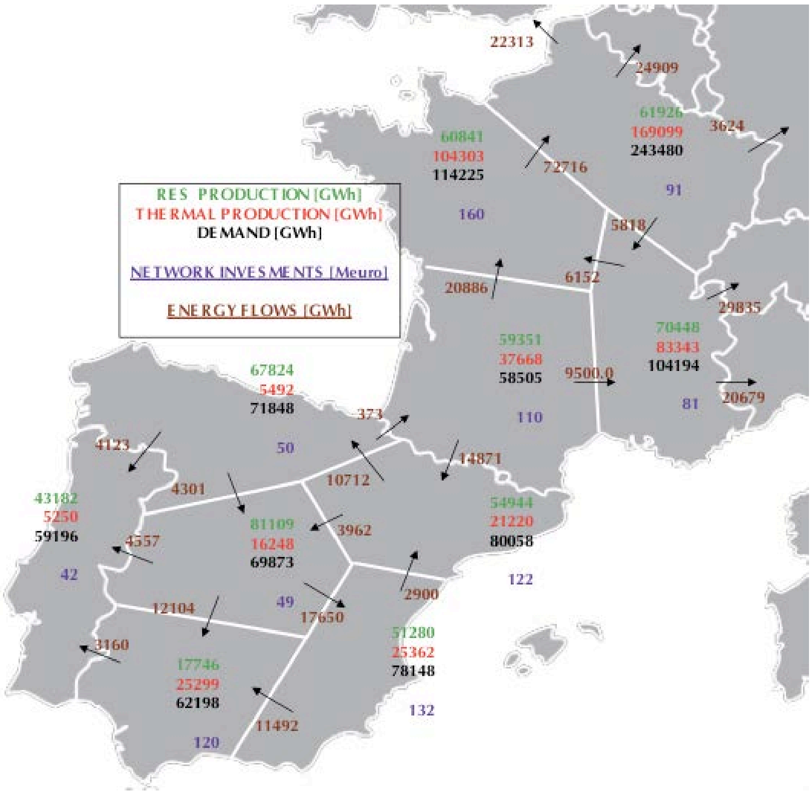
Reinforcements to the Southern part of the Spanish grid mainly occur in the HARMFIT and NATFIP scenarios, where import flows into the South-Eastern and South-Western zones are also largest. This is due to the fact that thermal production in the south of Spain in these two scenarios is quite low compared to the two other scenarios (RES power production in the South-Western zone is very low in all scenarios). Then, it looks like allowing big import flows into the south of Spain causes a significant number of network investments.

Regarding the French system, and leaving aside the Centre region, where network investments are quite similar in all scenarios, a distinction can be made among the scenarios: investments in the HARMFIT and NATFIP scenarios mainly take place in the North and South-Eastern region; while investments in the NATFIP and NOPOL occur in the South-Western region (particularly in the NOPOL scenario).

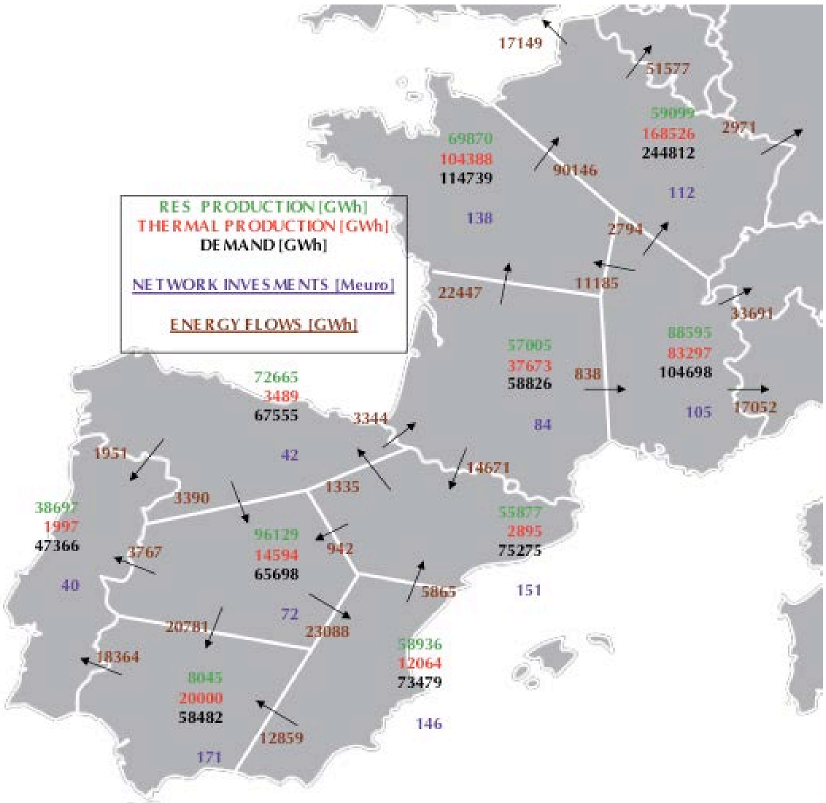
HARMFIT scenario



HARMQUO scenario



NATFIP scenario



NOPOL scenario

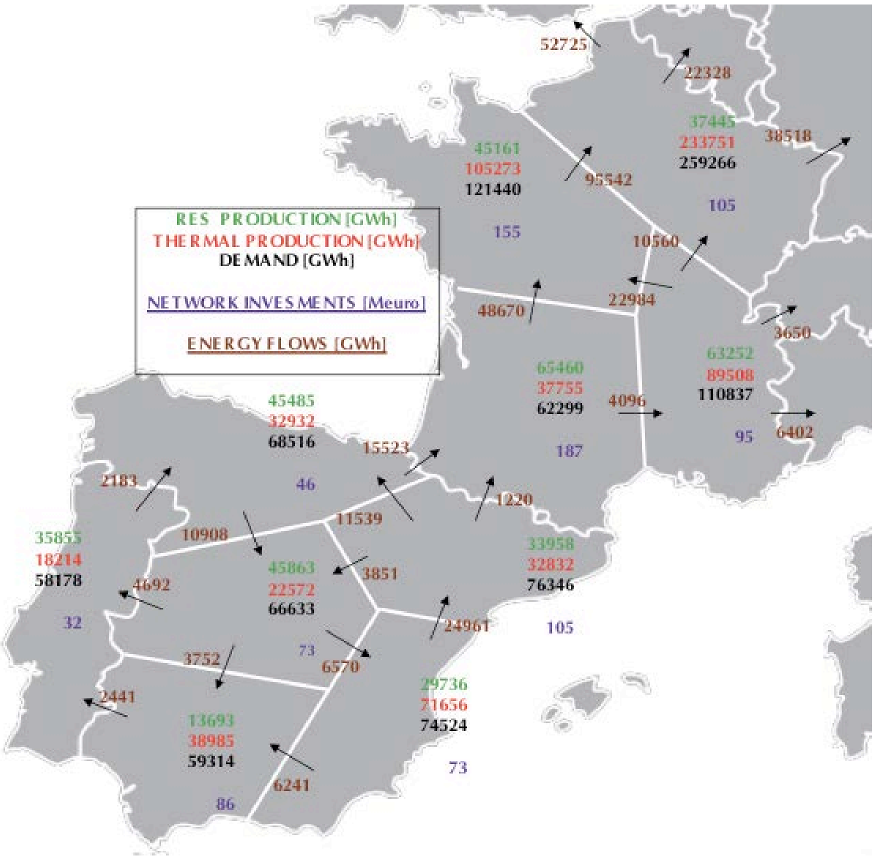


Figure 39 Power balance and flows among zones in the several scenarios

4.3.2 Analysis of the results on the costs of development of the grid in each scenario

When analyzing grid development results, one must bear in mind the fact that grid analyses have been conducted for the South-western Europe region, instead of the whole European system. The level of deployment of RES at European level is the same for all green scenarios: HARMFIT, HARMQUO and NATFIP. However, this does not happen to be the case for the South-western region, where differences among RES power production among scenarios are between 4000GWh and 36000GWh, which amounts to about 4% of demand.

Network development costs in the South-western region are lowest for the HARMQUO scenario (about 950 M€ annually), where a quota type RES support scheme is in place encouraging the deployment of most efficient RES generation required to achieve the overall RES deployment target level. Then, RES generation is installed where market revenues are expected to be larger. Market revenues depend on renewable primary energy available and energy prices. Then, the decision by RES operators on where to install new generation should be driven by both system variables. Given that market prices tend to be higher in importing areas than in exporting ones, there is an incentive in place for new RES generation to be located close to load. In line with this, the overall use of the network in this scenario (about 165000TWh*km) is the lowest one together with that in the NOPOL scenario. The level of penetration of RES generation in this scenario is a bit lower but close to that in the other two green scenarios. Then, this is unlikely to be a key factor in driving network development costs when comparing these three scenarios.

Network development costs in the NOPOL scenario (about 1000M€) are low compared to the green scenarios but the HARMQUO. The level of penetration of RES generation in the NOPOL scenario is significantly lower than in the other three. Then, a lower amount of RES generation needs to be connected to the grid in this scenario. A significant part of new generation connected to the grid in this scenario is conventional one, whose output is controllable and is primarily used to serve local demand. In other words, conventional generation is, on average, closer to demand than RES generation. Besides, given that no RES generation support policy is in place, RES generation has a natural incentive to be installed in areas where electricity prices are high, since revenues of RES operators come from the sale of power in the market. Then, RES generation in the NOPOL scenario tends to be installed in areas where a deficit of local power production has traditionally existed, and therefore close to demand. As a result of all this, the level of use of the regional network in this scenario is the lowest (about 164000 TWh*km).

However, operation costs and electricity market prices in this scenario are highest. This is due to the fact that RES generation is less abundant than in the rest of scenarios. Hence, the market value of power produced by RES generation is highest in this scenario, which encourages the network planner to build network investments required to reduce RES energy spillages to the extent possible. This, together with the fact that the RES output profile in the NOPOL scenario is more volatile than in other scenarios like HARMQUO, given the lower penetration level of RES generation technologies in this scenario, involves incurring larger network investments per unit of RES generation integrated into the system (see Table 20). Besides this, in the NOPOL scenario there is the need to connect to the grid a non-negligible amount of new conventional generation, which is required to serve the system peak load due to the smaller contribution of RES generation to this peak load. All this taken together results in overall network development costs in this region being a bit higher in the NOPOL scenario than in the HARMQUO scenario, though clearly lower than in the HARMFIT and NATFIP ones.

Network development costs are highest in the HARMFIT and NATFIP scenarios (a bit less than 1300 and 1100M€, respectively). Revenues of RES generation in the HARMFIT scenario do not depend on market prices, since prices earned by this generation correspond to a common Feed in Tariff set at regional level. Hence, RES generation is encouraged to be installed where RES generation resources (and then production levels) are largest, regardless of the market value of power produced by RES generation, or market prices in the area where this power is produced. Given that the geographical distribution of primary renewable energy significantly differs from that of demand, power produced by the large amount of RES generation that exists in the HARMFIT scenario needs to be transported over long distances to reach load. As a result of this, the level of use of the network in the HARMFIT scenario is the largest one together with that in the NATFIP, about 180000TWh*km. This results in very significant network investments required to connect RES generation to demand.

A very significant amount of RES generation must also be connected to the grid in the NATFIP scenario. However, prices earned by RES power plants in NATFIP are the result of adding up market prices and premiums set by authorities in each country. Therefore, unlike in the HARMFIT scenario, final prices used to remunerate RES power production are linked to the level of market electricity prices. Then, should harmonized price premiums be applied in the region, RES generation would have an incentive to be installed close to main load centres, or importing areas, where market prices are highest. What is more, under harmonized premiums, RES generation would also be driven to manage its output so as to make it coincident in time with peak or high load in the system. All this should lead to relatively low network investment costs.

However, premium levels applied in the NATFIP scenario can vary largely across countries, areas, or technologies, since, according to the assumptions made in this scenario, different countries apply different policies in this regard. This may distort network locational signals and results in an increase in network investments costs. Countries applying high RES support payments for a specific technology attract large amounts of RES generation of this technology regardless of whether the power production profile of this RES generation technology in this country and location of primary energy sources for this technology in this country are close to the time profile and location of demand in the country. This seems to result in large amounts of power flowing over long distances in the network, which corresponds to the highest use of the transmission network, specifically about 181000 TWh*km. Besides, incremental flows produced by new RES generation seem to differ significantly from traditional ones caused by conventional generation, leading to high network investments for NATFIP, as already mentioned.

4.4 System adequacy

We present now the analysis of the impact of a high penetration of renewables on system adequacy. It should again be reminded that, in this case, and contrary to the previous assessments, only one RES-Policy scenario has been assessed against the baseline one. We still provide at the end of the section some hints on how to extrapolate results to the scenarios covered in other sections

4.4.1 The impact of market integration on system adequacy

The model presented in section 0 has been applied for the estimation of the number of additional power plants needed to reach the reliability targets for the high-RES scenario presented before. To assess the role of market integration, the following scenarios were investigated:

1. *No market integration (NO INT)***:** Each country fulfils the reliability requirements without sharing resources with neighbours
2. *Market integration (INT)***:** The countries are allowed to share resources through interconnection.
3. *Market integration with increased interconnection (INT+20)***:** This case corresponds to a higher market integration, where the interconnection capacities between the market zones (NTC values, see Table 14) are increased by 20%.

To assess the impact of the RES deployment to the system adequacy, in Table 23, the resulting surplus capacity margin is given for each country as well as the resulting LOLE for the different scenarios. The margin stands for the total installed capacity (including the capacity share of biomass, geothermal and hydropower) minus the peak of the residual load (equal to the load minus wind and

PV). In Germany, France and Belgium, a significant lack of capacities is observed. These shortages are explained by the fact that the large-scale deployment of RES capacity acts as a disincentive to the deployment of conventional power plants. By investigating the margin as a percentage of the peak load it can be observed that Belgium presents a significant lack of capacity (-30%) followed by France (-12%). The resulting LOLE values show that this significant lack of capacity in Belgium means that practically the country cannot serve its load in case it does not share resources with neighbours (LOLE 8760 for the No INT case); market integration brings a significant decrease of LOLE to 11h and to 2.7h for the INT+20 scenario. Similar results are obtained for all countries, showing how market integration partly counterbalances the impacts to the system adequacy for each country, by allowing reserves to be shared internationally.

Table 23 Surplus capacities and reliability for each country

	AT	BE	DE/LU	FR	NL
Margin (GW)	+ 1.9	- 4.1	- 7	- 10.1	+ 2.2
Margin (% Peak Load)	+ 20%	- 30%	- 9%	- 12%	+ 12%
$LOLE_{No\ INT}$	0	8760	62.6	1049	1.8
$LOLE_{INT}$	0	11	7	209	0
$LOLE_{INT+20}$	0	2.7	3.4	138	0

Further, the heuristic approach described above was applied to investigate the number of additional (backup) capacity needed to ensure system adequacy. The system reliability was calculated for a stepwise addition of 500MW gas power plants for the different scenarios.

As can be seen in Figure 40, the number of backup power plants needed for reaching the reliability targets depend on the market design. In the No INT case, in total 54 power plants (27GW) are needed: 25 in France, 20 in Germany and 9 in Belgium. Market integration (INT case) leads to a significant reduction to this number to a total of 21 power plants (10.5GW): 17 in France, 4 in Germany and no new capacity needed in Belgium since reliability is ensured by the surplus capacity in neighbouring countries. For the case with increased cross-border capacity (INT+20), only 16 power plants (8GW) for backup capacity are needed and this capacity addition is mainly concentrated in France (15 power plants). The positive impact of market integration to the system adequacy is clearly manifested in the analysis: market integration leads to a 60% reduction of the needed backup capacity, while a further 13% is reached by increasing the cross-border capacity.

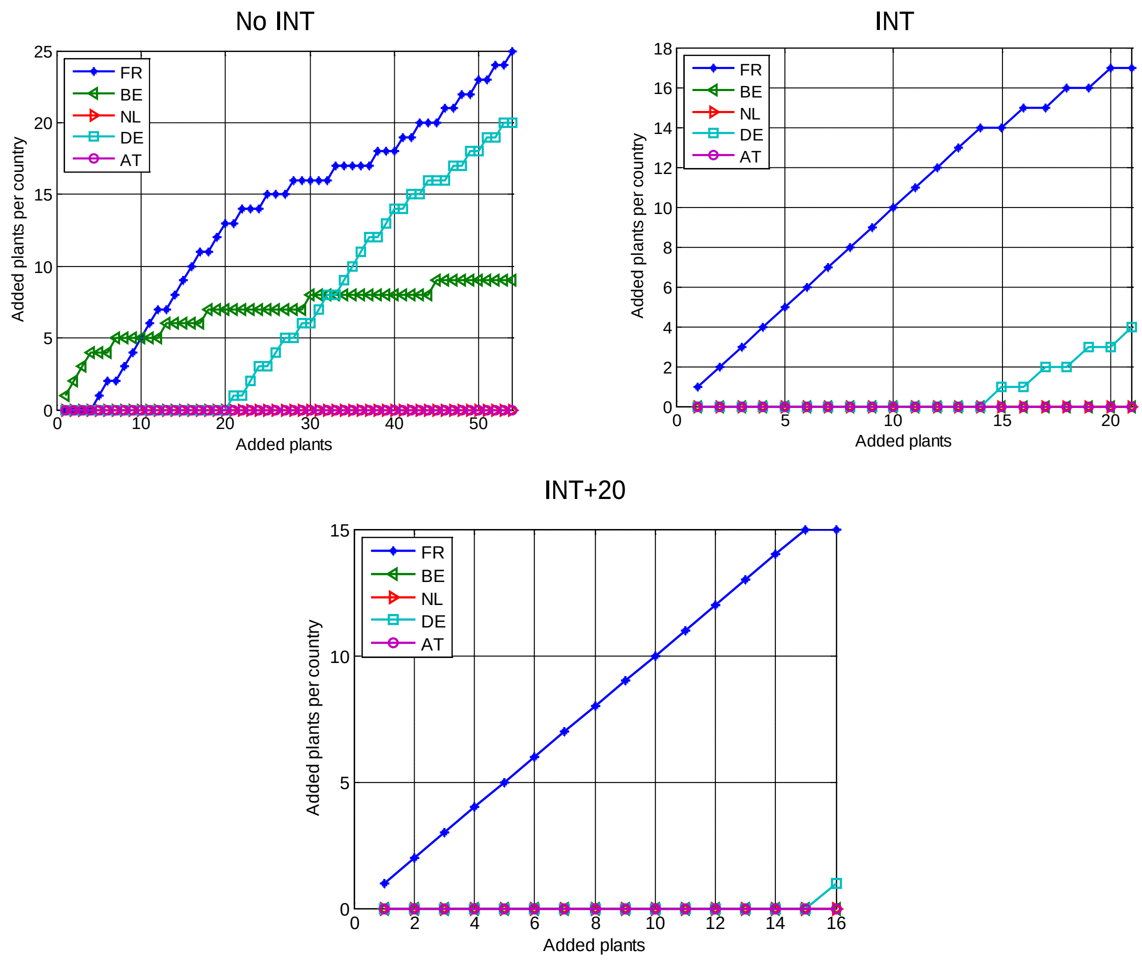


Figure 40 Added power plants per country for the 3 scenarios.

The respective development of the reliability with respect with the deployed additional backup capacity is shown in Figure 41. As expected, adding backup capacity brings a reduction to the loss of load expectation (LOLE). The convergence speed of the LOLE indices depends highly on the assumed market design: more integrated markets lead to a faster reduction of the global LOLEs. Further, as can be seen, the relationship between LOLE and backup capacity is not linear; instead, the first added power plants bring a higher impact on the system adequacy while a converging effect is observed the more power plants are added (when LOLE is low, adding a backup power plant brings a marginal impact). This reflects the significance of capacity mechanisms, since by securing some additional capacity, much higher adequacy levels can be reached.

Looking at the INT case, with 10 added plants in France, LOLE is still at 15 hours per year; by adding another plant LOLE drops to 12 hours. At the same time, the LOLEs in Germany and Belgium decrease slightly indicating that adding this capacity in France does not impact the adequacy in the other countries. France is the area with the highest LOLE and therefore power plants are added in this area till the 13th power plant when the LOLE levels between France and Germany are equalised; afterwards power plants are added interchangeably between the two countries; After the addition of the 21th power plant, the LOLEs of all countries are below the reliability target (indicated by the dash-dotted line). The LOLE of the total system gives the probability that there is a loss of load event in any of the countries. It is therefore naturally higher than the national LOLEs. However, it is not exactly equal to their sum, as loss of load events may occur in several countries at the same time. For the INT case, it is equal to 4.59 hours, whereas the sum of the national LOLEs is slightly higher, equal to 4.69 hours. This small difference shows that a loss of load event in several countries at the same time is relatively unlike.

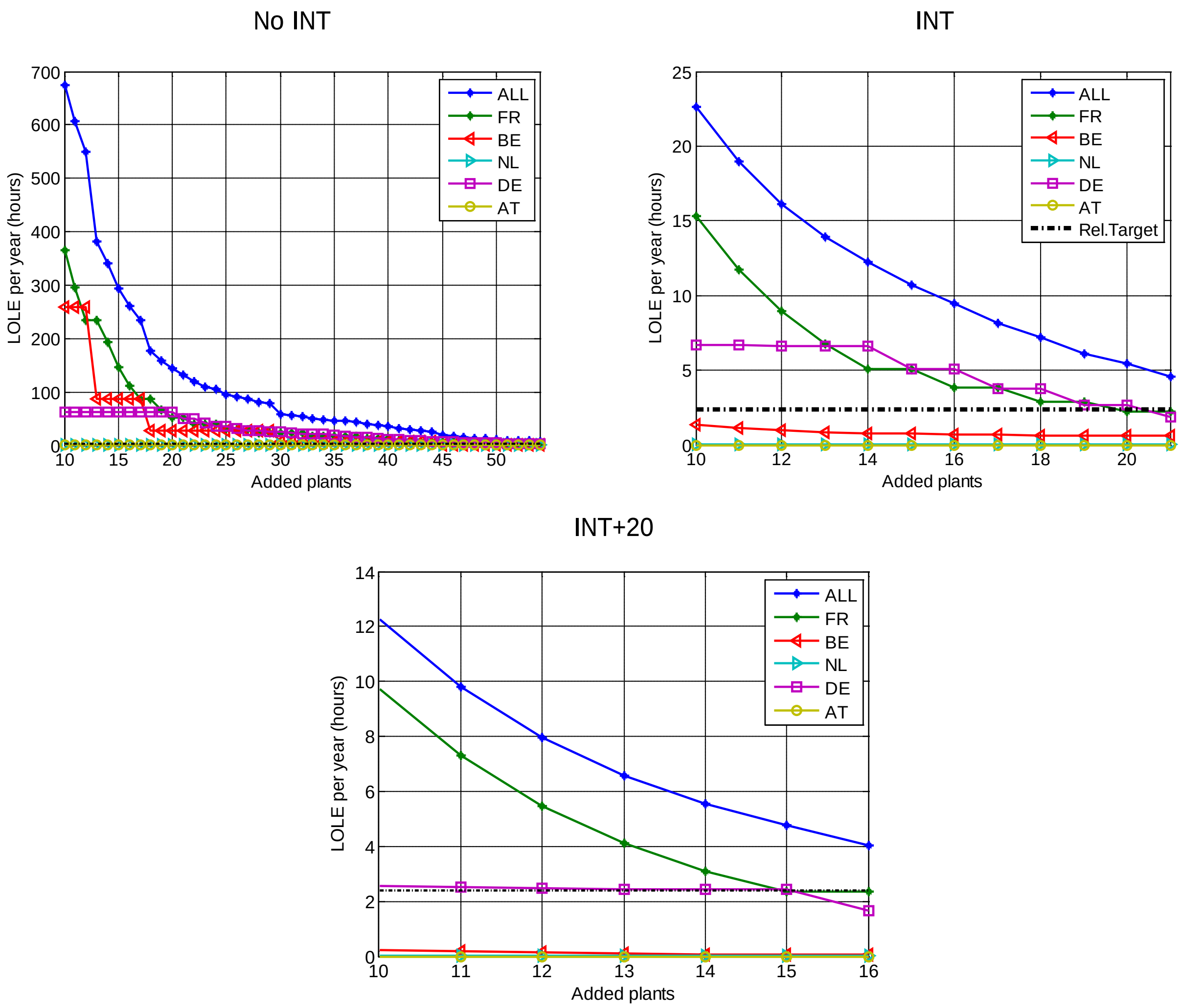


Figure 41 Change of LOLE with added plants for the 3 scenarios.

How can these results be extrapolated to other policy scenarios like those presented in the document (NATFIP, HARMFIT, or HARMQUO)? These policy scenarios assume a higher RES deployment and a higher demand growth. Assuming the same capacity development in the countries (a stagnating conventional generation fleet), the scenarios lead to a higher capacity deficit in the region with the same general pattern: France, Belgium and Germany present again the most significant capacity deficit. Comparing the scenarios with each other, similar levels of backup capacity are needed for the HARMFIT, HARMQUO and NATFIP scenarios (although higher than the benchmark scenario). The NOPOL scenario cannot be directly compared, as the conventional generation fleet would increase. In any case, the general conclusions would remain the same.

5 Conclusions

In this final section we summarize the major conclusions obtained in our assessments. We present first separately the conclusions obtained for each of them, and then summarize the joint lessons that we can extract from the exercise.

5.1 Conclusions for the different impacts assessed

5.1.1 Price effects

The analysis of the price effects had the following results:

- A number of factors influence the general price level in electricity markets: These include the CO_2 and fuel prices, the capacity level compared to overall demand, the degree of interconnection and market coupling, the share of renewables in the system and system flexibility.
- Therefore, rising renewable shares do not necessarily lead to lower average electricity prices. Prices will however decrease, if capacities are too high in general or if the electricity mix and flexibility of the system do not correspond to the needs of the rising renewable shares.
- The analysis confirms that rising renewable shares increase price volatility in the electricity spot market. Negative prices (or very low prices if negative prices are excluded by regulation) occur more often in a system with higher shares of renewables.
- Both effects might increase risk premiums for investments in both, renewables and conventional power plants or other flexibility options. They can however be partially mitigates by using smoothing effects through more extensive interconnector capacities. The impact of increased interconnector capacities is most pronounces in scenarios with a harmonized support scheme.
- The market value factor of renewables decreases as expected with higher shares of the respective renewable technology. The effect can also be mitigated by further interconnection capacities.

In general, the analysis confirms that rising shares of renewables have an influence on electricity market prices. These effects can however be superseded by other factors such as fuel price developments etc. Nevertheless, investment conditions for conventional power plants and other flexibility options might become more risky and hence more expensive in a system with high renewable shares. All effects can however be partially mitigated by increasing grid capacities and system flexibility.

5.1.2 Balancing needs

As mentioned in section 2.2, the impact of different RES policy scenarios on balancing needs and costs in 2030 was assessed for the Spanish system so that indicative results could be obtained for the European power system. In this sense, the results presented in this section must be carefully analysed. First, the total RES generation share in Spain in 2030 (70% in HARMFIT, 66% in HARMQUO and NATFIP, and 43% in the NOPOL scenario) is higher than the RES share assumed to be achieved in Europe by 2030 (around 55% in HARMFIT, HARMQUO and NATFIP, and 35% in the NOPOL scenario. Furthermore, the particular characteristics of the Spanish power system (i.e. conventional generation and interconnection capacity) may also influence the resulting impact of RES generation on balancing needs and costs. Finally, the fact that conventional generation capacity is kept constant in all policy scenarios has important implications on the results of this analysis.

Despite this, some important conclusions can be extracted from the study performed in Section 4.3:

1) As a result of higher RES penetration levels in HARMFIT, HARMQUO and NATFIP scenarios, the number of operation hours of conventional generation technologies is significantly lower in comparison to the NOPOL scenario. Consequently, the system marginal cost is also reduced, which, together with fewer operation hours, decreases the incentives to invest in conventional generation technologies, which are the main providers of balancing resources.
2) At the same time it displaces conventional generators, RES production increases system balancing needs. As it was seen in section 4.3, upward reserve use increase in HARMFIT, HARMQUO and NATFIP scenarios in comparison with NOPOL mainly due to higher intermittent generation forecast errors. Nevertheless, downward regulation increase not only due to higher production forecast errors, but also due to more frequent situations of excess of generation in the system. It also observed that the full deployment of downward reserve required RES curtailment during several hours in the scenarios with high RES penetration. In this sense, if non-conventional RES generators are not allowed to provide reserves in systems with massive penetration of intermittent generation imposing higher reserve requirements will increase RES generation curtailment.
3) Regarding balancing costs, the model computes marginal reserve costs as the increment in system operation costs resulting from keeping thermal units operating above their minimum output operation point (for downward reserve provision) and below their maximum output operation point (for upward reserve provision). Due to use of more expensive generation units for reserve provision in the NOPOL scenario, helped by the availability of cheap regulating resources (hydro power plants and pumped hydro storage capacity) in the Spanish system, reserve costs decreased in the scenarios with high RES penetration in comparison to the NOPOL scenario. However, it is important to have in mind that the conventional generation mix can be significantly different in a system with relative low RES generation penetration from the one in a system high RES penetration. This could have important implications on reserve costs.

In the light of these results some recommendations can be drawn: first, the participation of non-conventional RES generators in ancillary services provision will be essential for the integration of massive RES generation. Other sources of flexibility should also be integrated in power systems, such as storage capacity, demand response and virtual power plants. Furthermore, interconnection capacity plays a major role in the integration of power systems and can contribute significantly for a higher RES integration. Finally, market rules must be adapted in order to facilitate a higher participation of RES generation in electricity markets.

5.1.3 Network effects

The results presented and analyzed in the previous sections indicate that the network investment costs for a system are very much related to the amount of new RES generation installed in the system and the location of this new RES generation. In general, network costs should be higher:

- The higher RES generation is;
- And the further RES generation is from load centres

RES generation tends to be located far from load and conventional generation. Thus, the greater the production with RES, the more different the power flows should be from traditional ones. Therefore, required reinforcements of existing transmission lines should be larger and possibly new transmission lines should also be built where RES generation is installed and no previous conventional generation was located.

The main conclusions for each of the considered RES policy scenarios follow:

- The HARMFIT scenario features the highest network development costs because its level of RES generation is high and the location of this generation is not guided by energy market prices. As a consequence, new RES generation in it is installed far from the load.
- Network investment costs in the NATFIP scenario are also high because new RES generation in this scenario, which is largest, has an incentive to be installed close to load centres within each country but, not having a harmonized scheme of support payments at European level, the distribution of RES generation among countries and technologies may be far from being optimal.
- The HARMQUO scenario features the lowest network investment costs because it has less RES generation in the considered region (France, Spain and Portugal) than the other two "green" scenarios and this generation is installed where market revenues tend to be larger, i.e. it is installed closer to demand than in other scenarios.
- The NOPOL scenario features the lowest investment costs after the HARMQUO scenario. RES generation in the NOPOL scenario is less abundant than in the other three scenarios. Moreover, RES generation in the NOPOL scenario has a natural incentive to be placed close to demand, since its revenues are a function of market prices. These two factors should press network investment costs low. However, given that the market value of RES generation in this scenario is very high, developing the network to maximize the integration of available RES generation into the grid makes economic sense, while in other scenarios some RES energy spillages can be justified. Besides, some additional conventional generation needs to be connected to the grid in this scenario to serve the system peak load (the contribution of RES generation to serve peak load in this scenario is lower than that in other scenarios). All this taken together results in final network costs in NOPOL being low but, still, a bit higher than those in the HARMQUO scenario.

5.1.4 System adequacy

The analysis presented in section 4.4 allows the extraction of the following generic results:

- *Impact of RES deployment:* large-scale deployment of RES capacity acts as a disincentive to the deployment of conventional power plants, leading to insufficient capacity margins and endangers system adequacy. Assuming a stagnating conventional generation fleet, Germany, France and Belgium are countries in the CWE region that will need substantial backup capacity.
- *Role of market integration:* for integrated markets, the required amount of back-up capacity more than halves compared to the case of isolated countries. For specific countries, market integration is enough to ensure sufficient generation system adequacy, without the need of extra backup capacity (as in the case of Belgium).
- *Role of interconnection:* By increasing interconnection capacity in integrated markets, further gains in generation system adequacy are achieved, since further cross-border share of backup capacity is possible. For the CWE region, increasing the interconnection capacity by 20%, leads to a further decrease in needed backup capacity by 24%.
- *Centralised vs decentralised approach:* The system-wide LOLE is lower than the sum of the national LOLEs due to the fact that that a loss of load event in several countries at the same time is relatively unlikely. Adopting an integrated system approach for the assessment of the generation system adequacy in Europe would therefore be a more cost-optimal solution. For this, a transformation of the national reliability targets to European reliability targets should be required.
- *Capacity needed*: The results also indicate that only a limited amount of back-up capacities is required in order to maintain the generation adequacy in a European system with high shares of renewable power sources. However, for more detailed assessment of the impact of variable renewable infeeds, the analysis should be performed for a longer time period.

- *Capacity mechanisms:* For systems with low generation adequacy, securing some additional capacity, is shown to increase the system adequacy levels significantly, which reflects the significance of capacity mechanisms.

5.2 Overall conclusions

We now try to formulate general conclusions that can be extracted from assessing all the impacts in this study. A first interesting result is that, given a certain amount of RES penetration, impacts do not depend much on the policy instrument chosen. Although the choice of policy instrument will of course have an influence on the amount of RES, and also on the share of the different technologies and their location, most of the impacts depend mostly on:

- the total amount of RES deployed
- the availability of the grid infrastructure

Even when there are some differences between instruments, these are not due to the instrument itself, but to its design elements (e.g., the stability of the regulation, whether the support is technology neutral or technology specific, the harmonized or national character of the policy, etc.).

In fact, most of the differences between policy pathways result from their dependence on the grid. Thus, those pathways that result in a more even development of renewables across Europe (NATFIP, HARMFIT) depend less on the development of the grid, since the compensatory effects of the network are less critical. Instead, for HARMQUO, the effects of the grid expansion are more important.

Other than that, and for all the policy pathways assessed, the results we have obtained confirm many of the results derived from the literature, although with some particularities:

- A significant price decrease effect: average wholesale prices in Europe are expected to be 30% lower in 2030 compared to the no-RES policy scenario. The price level would be only slightly above today's values. However, it is not clear whether this effect is derived from an increased RES penetration or from the increased capacity that accompanies it. Capacities were taken from the Primes High-RES scenario. Modeling results showed that this leads to sufficient or even overcapacity across Europe.
- Price volatility also increases with RES penetration. In general this effect is dampened with grid reinforcement. Without grid reinforcement price volatility will increase even in the no-RES policy scenario. This increase is however much higher when the grid is reinforced, since then the no policy scenario results in lower price volatility in 2030. When there are grid limitations, increased RES do not result in volatilities much higher than the no policy scenario.
- Negative prices appear more frequently in 2030 when RES are strongly developed. The exact amount differs: with the PowerAce model we find 10% of the hours, whereas for the ROM model (used only for Spain) zero-price hours increase up to 40-50% of the year. That shows the strong impact of the grid and system connections. As would be expected then, grid reinforcement also dampens the number of hours with negative prices.
- The impact of RES on generation adequacy depends on the degree of market and network integration. When there is little European integration, some countries will suffer from a significant loss of adequacy in their systems (increased loss of load probability). However, when systems are well integrated this risk is very much reduced.
- In both cases additional capacity will be required to back-up RES, what raises the issue of whether this capacity will come online if prices are depressed (and therefore the investment signal is reduced). Currently, the European electricity market is characterized by a situation of overcapacity, so this should not be an issue in the medium term, and will anyway depend on the strength of the incentive for new investments (be them in the generation or demand side).

- Balancing needs significantly increase under strong RES support. Upward regulation grows almost 50%, whereas downward regulation increases 200% (basically to prevent spilling RES).
- However, the costs of these balancing services need not increase, depending on the system. In the exercise run in Spain, with significant overcapacity and a large share of hydro, balancing costs actually decrease. These costs will depend strongly on the conventional generation mix considered in the analysis.
- Finally, regarding the cost of grid expansion, our results for Southwest Europe show that these costs will depend on three major factors: the amount of RES incorporated, its location, and its market value. In general the calculated grid extension costs are rather low compared to RES generation costs (e.g. for Southwest Europe in the range of 1.7 to 2.5 €/MWh related to RES generation). Here the choice of policy instrument does create a small difference: for example, a harmonized quota system would probably induce RES to be installed where its market value is higher (closer to the load) and this would result in lower network costs (lower even than under a no policy scenario). Under a feed-in-tariff this may not be the case and network costs may increase.

All these results show that there will be significant impacts on electricity markets and grids, and that is therefore a need to change the way they are designed if we are to accommodate more RES.

Below we provide some recommendations based both in the modeling and the extensive literature review:

- Improved cross-border transmission policies will facilitate the efficient operation of the grid under increased RES penetration. Grid extension will dampen price volatility and the numbers of hours with negative market prices. Thus, substantial internal and cross-border grid investments are needed, which requires sufficient investment signals. Current regulations should be adapted if the foreseen extensions (TYNDP) could not be realized. Also nodal prices might be an instrument to improve grid investment and operation decisions.
- The costs and need for balancing can be reduced by more frequent and shorter scheduling intervals. Balancing markets should be made more flexible so that renewables and demand side sources can participate more easily. The coordination of balancing areas is also important to reduce balancing costs.
- Increased RES penetration leads to an augmented need for flexibility in system operation. Therefore, incentives for demand response or other flexibility options could be considered after an in-depth analysis of all their strengths and weaknesses.
- Pricing and bidding rules in electricity markets should be analyzed in detail. Possibly, complex instead of simple bids could be beneficial for systems with a high renewables penetration. Also, joint bids for energy production and balancing services could be useful. Non-discriminatory pricing could be used to internalize non-convex-cost related components of the actual value of electricity market prices.

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