Description of planned analyses, scenarios and models for the post 2020 time horizon

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Executive summary

The project Market4RES has identified a number of market design options affecting short and long-term electricity markets that could enable a successful integration of renewable energy. Work package 5 (WP5) is the part of the Market4RES project that deals with the quantitative analysis of different market design adjustments. This report is the first deliverable of the work package. It describes the planned analyses of different sets of market design options in terms of their capacity to accommodate a large share of renewable energy sources and generate incentives for investments into flexible generation to guarantee sufficient security of supply in the year 2030. These analyses represent a continuation of the analyses of the studies of the Target Model until 2020 that have being performed in work package 4, which are focused on the transition from the feed-in tariff (FIT) to the price premium (PP), as well as the influence of a more flexible demand side. In WP5 both types of support, FIT and PP will be analysed as well as a number of other design options.

Four project partners, EEG, IIT-Comillas, RTE and SINTEF will each carry out analyses over parts and all of the ENTSO-E area for the assessment of a number of different market design options.

Table 0: Areas of market design assessed in the project

Market design options related to short-term markets	Market design options related to long-term markets
Timing of short term markets	Design and use of capacity remuneration mechanisms
Design principles for balancing mechanisms	Long-term effects of RES support mechanisms
Short-term effects of RES support mechanisms	Participation of demand in long-term markets
Demand response in short term markets	

EEG shall carry out an analysis of different balancing market arrangements. In particular, it will look into the following aspects of balancing mechanisms:

- Procurement of balancing capacity and energy products,
- Procurement of upward and downward capacity products,
- Minimum bid size,
- Pricing of balancing products,
- Imbalance pricing system,
- Settlement period.

The analyses are to focus on Central Europe and the target year 2030.

IIT-Comillas shall perform two types of analyses. The first will **quantify the effects of prospective RES support mechanisms on short-term markets** (long-term capacity auctions, long-term clean energy auctions, certificates and feed-in premium auctions). The second analysis will look into the **impacts of bringing the day-ahead market towards the real time** in terms of improved prediction of intermittent generation and consequently a more efficient use of reserves.

The target year is 2030 and the geographical scope is Portugal, Spain and France in the first and Spain in the second case.

RTE shall perform two types of analyses. The first will **focus on the analysis of capacity remuneration benefits**. Here, the energy only market with different price caps is to be compared to a market with CRM in terms of attracting sufficient flexible capacity. The second analysis shall study and compare the **effects of implicit and explicit support for RES** (carbon tax and RES support mechanisms).

The **performance of different capacity remuneration mechanisms (CRM) and RES support mechanisms** shall be evaluated by SINTEF. The investigations are to analyse the evolution of the energy mix under different combinations of CRM and RES support mechanisms in order to see how the market is able to attract sufficient investments into both RES and flexible capacity under different scenarios.

The target year is 2030 and the analyses shall be performed over the entire ENTSO-E area with a focus on Northern Europe.

To evaluate the market design options, all investigations shall make use the key performance indicators (KPI) that are defined in work package 3 for each of the areas of interest given in Table 0.

All options are to be evaluated under the scenarios prepared on the basis of ENTSO-E's Ten-Year Network Development Plan and its *"Scenario Outlook and Adequacy Forecast 2014-2030"* with inputs from a number of other sources. Main scenarios are described next.

Table 1: Overview of scenarios used in analyses

Scenario name	Cost of capital	CO_2 price	Fuel prices	Wind and solar capacities
2020 scenario (based on ENTSO-E publications for 2020 and consistent with the 2020 standard scenario in WP4)	favorable economic and financial conditions	low CO_2 price	low primary energy prices	current RES targets for 2020
2030 Reference scenario (based on ENTSO-E "Green transition scenario" (TYNDP 2030 Vision 3))	favorable economic and financial conditions	high CO_2 price	low primary energy prices	current RES targets for 2030
2030 High scenario (based on ENTSO-E "Green revolution scenario" (TYNDP 2030 Vision 4))	favorable economic and financial conditions	high CO_2 price	low primary energy prices	higher share of renewables
2030 Low scenario (based on **ENTSO-E "Slow progress scenario" (TYNDP Vision 1))**	less favorable economic and financial conditions	low CO_2 price	high primary energy prices	lower share of renewables

The scenarios have been chosen in a way that represents plausible future developments and stresses the relevant parameters that the investigations are to evaluate. They involve setting values for some system variables, including the installed capacities of different technologies, emissions factors, fuel costs, efficiencies, variable and fixed costs, CO_2 costs, transmission capacities etc.

Finally, the report includes a classification and a description of the different modeling tools employed by the four partners.

The topics of the analyses carried out in WP5, the partners in charge and the models used are summarized in the table below.

Table 2: Overview of planned analyses

Section of this report	Topics of analyses	Partner in charge	Tool used	Appendix providing tool description
3	Validation of possible future Balancing Market mechanisms	EEG	EDisOn+Balancing	B
4	Short-term effects of RES support mechanisms	IIT Comillas	ROM	C
5	Impact of changing the timing of markets	IIT Comillas	ROM	C
6	Long-term competition between DSR and RES induced by RES support schemes	RTE	Micado	D
7	Comparative advantages of explicit support schemes and carbon pricing in achieving high shares of RES in the power system	RTE	Micado	D
8	Energy only market v. remuneration of capacity under risk aversion	RTE	SIDES	E
9	Long-term analysis of CRM, RES mechanisms and the energy only market	SINTEF	EMPS	F

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List of abbreviations

ATC	**Available transmission capacity**
BRP	**Balance Responsible Party**
BSP	**Balancing Service Provider**
CRM	**Capacity Remuneration Mechanism**
ENTSO-E	**European Network of Transmission System Operators for Electricity**
ETS	**Emissions trading scheme**
FIP	**Feed-in Premium**
FIT	**Feed-in Tariff**
GHG	Greenhouse gas
IGCC	International Grid Control Cooperation
KPI	**Key Performance Indicator**
LCOE	**Levelized cost of Electricity**
NREAP	**National Renewable Energy Action Plan**
PHES	Pumped Hydro Energy Storage
SoS	**Security of supply**
TSO	**Transmission System Operator**
TYNDP	**Ten-Year Network Development Plan**
WACC	**Weighted Average Cost of Capital**
WP	**Work Package**

1 Introduction

1.1 Scope of the studies

In the last years, support for renewable energy sources (RES) and the consequent increase in RES capacity have resulted in overcapacity and a level of prices below the **levelized cost of electricity** (LCOE) for a significant part of the generation mix. Meeting renewable energy targets for 2030 means the share of RES in the electricity mix will have to increase from today's 28% to 44% and then further. To provide sufficient stimulus for investments into RES and at the same time maintain enough flexible capacity to keep security of supply at desired levels, new market instruments will have to be introduced.

The project Market4RES has identified and assessed 10 key areas with corresponding market instruments [1, 2] of market design that can be improved upon in order to achieve a successful market integration of high levels of RES until 2030. Six areas are dedicated to short-term markets and four areas to long-term markets as listed below. Of these ten areas we have picked seven that will be further investigated with different models. Ideally we would have evaluated all ten areas, but given the time frame this is not possible. The selection has been made based on the capabilities of the available modeling tools to simulate different market design options and not on judgments about the importance of the different areas for the evolution of the target model. Table 3 below lists all ten key areas with the selected seven highlighted in blue in the upper part of the table:

Table 3: Areas of market design assessed in the project

Market design options related to short-term markets	Market design options related to long-term markets
Timing of short term markets	Design and use of capacity remuneration mechanisms
Design principles for balancing mechanisms	Long-term effects of RES support mechanisms
Short-term effects of RES support mechanisms	Participation of demand in long-term markets
Demand response in short term markets	
Areas identified in the project but not included in the studies	
Network representation	Long-term cross-border products
Bidding protocols	

This report describes the planned investigations that will evaluate market design options pertaining to the seven of the ten identified areas. The different settings entailed by the selected seven areas will produce valuable information for policy making. All the areas have been thoroughly assessed in *Developments affecting the design of short-term markets* [3] and *Developments affecting the design of long-term markets* [4].The scenarios used in the investigations are a continuation of those used for the 2020 analyses [4]. They are mainly based on ENTSO-E's *“Scenario Outlook and Adequacy Forecast 2014-2030"* and the Ten-Year Network Development Plan, and are chosen in a way that will test the different market design options in a set of diverse circumstances in order to be able to draw conclusions about their robustness.

Our investigations also draw on the Key Performance Indicators defined in [3]. This document defined sets of KPIs specific to each of the 10 mentioned areas of market design options. Not all of the defined KPIs will be evaluated and a selection was made based on the characteristics of each partner's modeling tools.

1.2 Role of WP5 in the Market4RES project

This report summarizes the planned investigations of alternative market designs for the time period 2020-2030. These investigations are part of the larger project, and represent the continuation of investigations of the target model in the time frame 2013-2020 (called Work Package 4 in the project). The results of these investigations along with the discussions on the opportunities, challenges and risks related to the integration of renewable energy sources (RES) into the EU electricity market (internally to the project Work package 2) and the assessment of the most promising options for RES integration (Work package 3), constitute the basis for recommendations and guidelines for policy makers which are developed in Work Package 6.

The analyses are undertaken by four institutions, IIT-Comillas, EEG, RTE and SINTEF Energy Research, with significant contributions from Technofi.

1.3 Structure of this report

The rest of the report is structured in the following way:

Section 2 describes the scenarios that underlie the analyses. All scenarios are mostly based on the National Renewable Energy Action Plans (NREAPs), ENTSO-E's Ten-Year Network Development Plan, ENTSO-E's “Scenario Outlook and Adequacy Forecast 2014-2030” as well as a few other sources. The first of the four scenarios is the 2020 standard scenario that is included in the 2020 analyses [4]. The remaining three scenarios represent a wide range of plausible scenarios for 2030, with the reference ENTSO-E *"Green transition"* scenario based on current RES targets, the *"Slow progress"* scenario being a pessimistic and the *"Green revolution"* an optimistic scenario.

Section 3 is the first section dedicated to the description of planned analyses. Four partners are tasked with carrying out the analyses. Section 3 includes the analyses of different balancing market arrangements that will be performed by EEG.

Section 4 describes the first of the two types of analyses performed by IIT-Comillas. This first type will focus on the effects of different RES-E support mechanisms on the functioning of short term markets.

Section 5 describes the second of the IIT-Comillas analyses which will simulate the move of the wholesale market towards the real time. It will investigate the impact of this move on the efficiency of the dispatch and required reserves. The geographical scope will be limited to Spain, due to its high share of wind production, which will stress the effects of uncertainty of high wind penetration.

Section 6 includes the first study carried out by RTE; it explores medium and long terms competition between DSR and RES induced by RES support schemes.

Section 7 contains the second of RTE's analyses where the effects of implicit and explicit support for RES are compared. The carbon tax allows for more efficient valuation of different technologies than RES support mechanisms. However, it also implies higher risks and capital costs for investors in RES. The analysis will study the circumstances under which one or the other policy performs better.

Section 8 contains the third of RTE studies, which analyses the benefits of capacity remuneration mechanisms. Here the energy only market with different price caps is compared to a market with CRM in terms of attracting sufficient flexible capacity, with a focus on the risk taken by investors in the different cases. To fit a context of moderate to no demand growth and increasing RES generation capacity, the models not only consider investments, but also closing existing plants.

Section 9 addresses the analyses planed by SINTEF. These will compare the evolution of the North European electricity mix in the post 2020 context under four different settings, the energy only market, a market with capacity remuneration mechanisms (CRM), a market with renewables support and a market with both CRM and RES support.

Appendixes include a detailed description of the models used by each partner.

2 Scenario description

2.1 Rationale for WP5 scenarios and general overview

The quantitative studies carried out under WP5 require elaborating prospective scenarios which do not represent a probable vision of what the electricity sector will look like in 2030 but, solely, plausible situations at this time, contrasted enough to put stress on parameters which could have a significant impact on the variables of interest in our research objectives.

2.2 Requirements

The different studies carried out within this Work Package involve several different modeling approaches, described in the previous part of this report:

- Short term decision
  - Optimal dispatch;
- Long-term decision
  - Optimal mix and dispatch;
  - Projects profitability assessment;

- System dynamics: mix evolution following investment decisions (based on projects' profitability); this approach requires a starting point scenario (a 2020 scenario would be a logical choice).

The following table describes the type of hypotheses required as input for each type of tool:

Table 4: Hypotheses required as input for each type of the tool used in WP5

		Optimal dispatch	Optimal mix	Profitability assessment	Investment decision
Hourly load		Yes	Yes	Yes	Yes
SoS criterion, VOLL		Yes	Yes	Yes	Yes
Installed capacity for each technology		Yes	Constraints on some technologies	Yes	Constraints on some technologies
Variable costs of assets	Fuel cost, CO_2 price and emission factors, short-term constraints	Yes	Yes	Yes	Yes
Interconnection capacities (NTC)		Yes	Yes	Yes	Yes
Fixed costs of assets	Overnight cost, fixed operation costs, economic lifetime	No	Yes	No	Yes
	Cost of capital, long-term risk representation	None	Discount factor	Objective function (risk aversion)	Objective function (risk aversion)
2020 scenario		No	No	Yes/No	Yes
Typical size of scenarios		*1 - 10 years*	*several weeks - 10 year*	*1 - 10 years*	*1 - 10 years*

2.3 Scenarios and Monte-Carlo time series

In some cases, it will be useful to characterize other sources of uncertainty in a Monte-Carlo style of approach, which means that a great number of time series representing distinct realizations of one or several random variable(s) such as weather conditions, will be generated and combined so that, after running our tools, we obtain a good representation of the distribution of the indicators we are computing, given the uncertainty on the selected random variables.

Scenario-based and Monte-Carlo approaches are very different, and they are not used to account for the same nature of uncertainties. Monte-Carlo methods, although very greedy in terms of computation power, allow computing a probabilized vision of the indicators of interest, but they require a characterization of the distribution of each random variable; they are therefore fit for weather uncertainty. Scenarios, on the other hand, are fitter to account for events that are very difficult to probabilize such as those depending on political decisions.

They are however not incompatible and where required (for instance to study SoS from a probabilistic point of view), we have prepared Monte-Carlo time-series for each scenario.

2.4 Overview of all scenarios

Table 5 below presents the main features of the scenarios that have been elaborated for the studies in a synthetic and qualitative manner. All scenarios are described in detail in section 2.5.

Table 5: Main features of each scenario

Scenario name	Cost of capital	CO_2 price	Fuel prices	Wind and solar capacities
2020 scenario (based on ENTSO-E publications for 2020 and consistent with the 2020 standard scenario in WP4)	favorable economic and financial conditions	low CO_2 price	low primary energy prices	current RES targets for 2020
2030 Reference scenario (based on ENTSO-E "Green transition scenario" (TYNDP 2030 Vision 3))	favorable economic and financial conditions	high CO_2 price	low primary energy prices	current RES targets for 2030
2030 High scenario (based on ENTSO-E "Green revolution scenario" (TYNDP 2030 Vision 4))	favorable economic and financial conditions	high CO_2 price	low primary energy prices	higher share of renewables
2030 Low scenario (based on ENTSO-E "Slow progress scenario" (TYNDP Vision 1))	less favorable economic and financial conditions	low CO_2 price	high primary energy prices	lower share of renewables

The geographical scope considered by these scenarios comprises 34 countries whose TSOs are members of ENTSO-E (the European Network of Transmission System Operators for Electricity). However, the studies presented in this report (Chapters 3, 4, 5, 6, 9) focus on a subset of this geographical scope. Figure 1**Error! Reference source not found.** shows the total consumption evolution (in TWh) by country for 2030 scenarios.

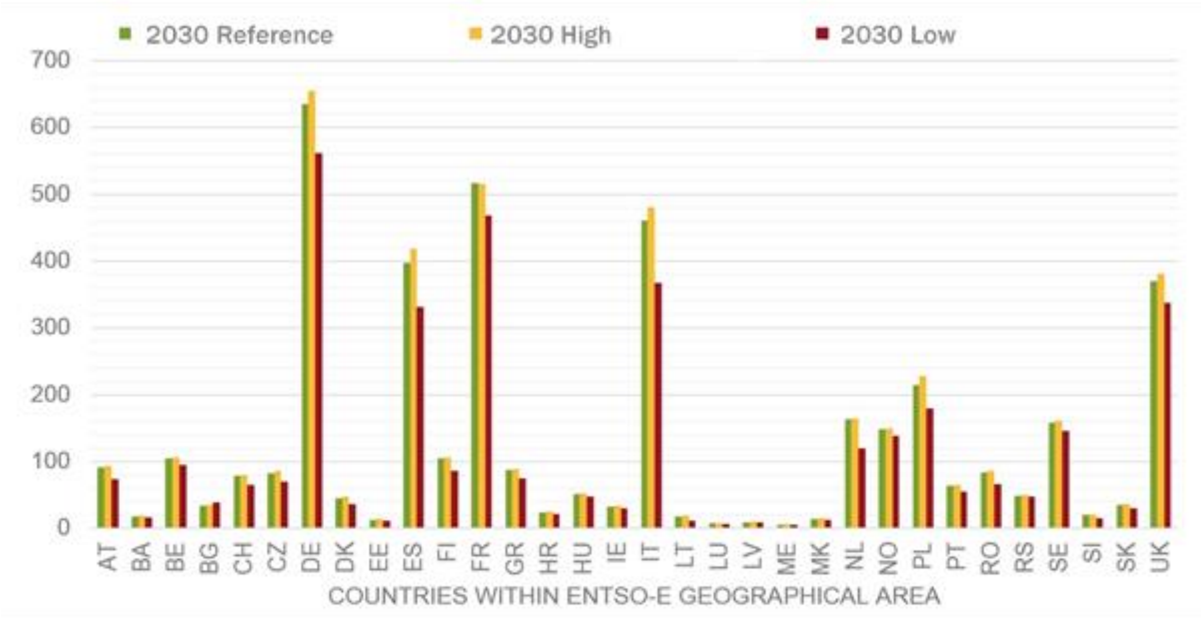

Figure 1: Total consumption (TWh) evolution by country for 2030 scenarios

2.5 Detailed description of scenarios

2.5.1 2020 scenario from WP4

As a reference and a starting point to launch analyses with the investment decision modelling tools, we shall consider the 2020 (standard) scenario provided by WP4 and described in detail in D4.1 *"Specifications of the most adequate options for flexibility markets and RES support schemes to be studied in a cross-border context"*[1]. This scenario has been built upon the following bricks:

- RES installed capacities at 2020 are based on National Renewable Energy Action Plans (NREAPs) published in 2010. However, recent developments have led to a review of the NREAPs' objectives in terms of installed capacities. Updates have been provided by EWEA and SolarPower Europe.
- Thermal installed capacities at 2020 are those of the Scenario B ("Best Estimate") of ENTSO-E's "Scenario Outlook and Adequacy Forecast 2014-2030" (SO&AF), published on 3 June 2014.
- Peak load is also taken from the Scenario B of the SO&AF. But, the values given in the SO&AF are "under normal climatic conditions". Because of that, these values are relatively low. Testing the scenario with different levels of peak load values and their impact on the generation mix has led to increase the SO&AF figures by 10%.
- The cross-border capacities at 2020 have been computed by adding to the present cross-border capacities the additional capacities created by the "transmission projects of pan-

[1] Available at http://market4res.eu/wp-content/uploads/Market4RES_WP4_D4-1.pdf.

European significance" at 2020, as gathered in ENTSO-E's Ten Year Network Development Plan (TYNDP) 2014.

- For coal, gas, oil and CO2 prices, the main reference for estimating these average prices at 2020 has been the EC document "EU Energy, Transport and GHG Emissions, Trends to 2050, Reference Scenario 2013" published in December 2013.

Within WP4, a limited geographic scope covering 11 countries of Western Europe has been considered. For WP5, the 2020 scenario is extended to cover the whole Europe.

Quantitative details about this scenario can be found in D4.1.

2.5.2 Building 2030 scenarios

In order to build our analyses on a known and recognized basis, and consistently with the WP4 scenarios, we have chosen to make sure that our scenarios remain coherent with those used by ENTSO-E in its reference *Ten years development plan* (TYNDP, 2014 version). We are therefore reusing a number of ENTSO-E core hypotheses, made public on the organization's website[2].

On the occasion of an expert workshop held in May 2015 in Brussels, the consortium also consulted external experts on their vision of contrasted scenarios and key parameters for economic modeling of the power system.

The group established a list of parameters that would vary across scenarios:

- Parameters linked with energy policy:
  - Share of renewable;
  - Level of development of the transmission grid;
  - Political will to phase out nuclear power;

- Technological parameters:
  - Development of energy efficiency;
  - Development of industrial demand response;
  - Development of distributed demand response (including on-site storage, for instance, thanks to electric vehicles);

- Macroeconomic factors:
  - Economic growth;
  - Price of fuels (CO_2 price being an endogenous variable, at least in some simulations);
  - Cost of capital (with a semi-endogenous technology-specific component, in particular cost of capital for RES projects given the risk taken by investors).

Then, we have picked up contrasted but coherent sets of values for these parameters to build the following set of 2030 scenarios.

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[2] https://www.entsoe.eu/major-projects/ten-year-network-development-plan/tyndp-2014/Pages/default.aspx, accessed in September 2015.

2030 Reference scenario

This scenario corresponds to the current RES targets at 2030. It is based on ENTSO-E "Green transition scenario" (TYNDP, 2014 version, Vision 3), corresponding to favourable economic and financial conditions, reinforced national energy politics, parallel national R&D research schemes, high CO2 prices and low primary energy prices.

Cost of capital

The International Energy Agency (IEA) in the *"Technology Roadmap: Solar Photovoltaic Energy - 2014 edition"*[3], considers a Weighted Average Cost of Capital (WACC) of 8% on average. This is in line with the WACC considered by the International Renewable Energy Agency (IRENA) in "Renewable Power Generation Costs in 2014"[4], which is of 7.5% in OECD countries.

Therefore, in this scenario the WACC is set at **8%.**

CO_2 and fuel costs

The CO_2 price is 93 €/ton. Fuel costs given in €/MWh are presented in Table 6 below.

Table 6: Fuel prices (€/MWh) for the 2030 reference scenario

Nuclear	Lignite	Hard coal	Gas	Light oil	Heavy oil	Oil shale
1.36	1.58	7.96	28.48	60.23	35.57	8.28

(Source: ENTSO-E "Green transition scenario" (TYNDP, 2014 version, Vision 3))

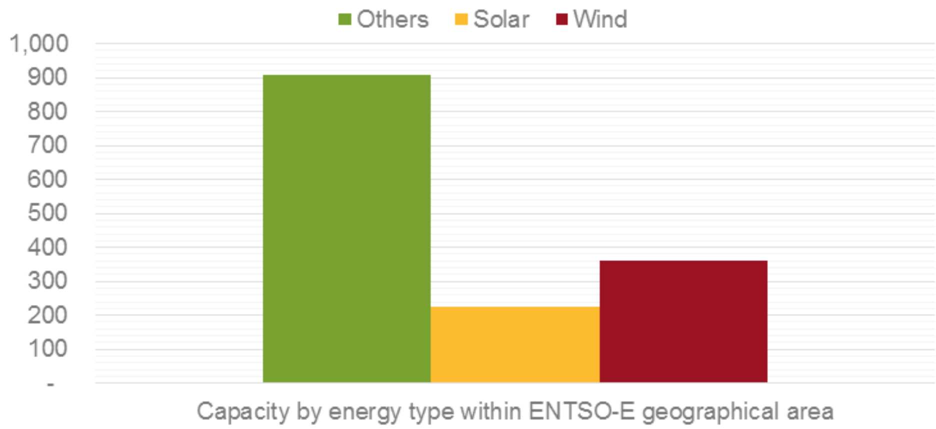
Wind and solar capacities

Wind and solar energy generation capacity, respectively, are 361 GW and 224 GW within ENTSO-E geographical area. Figure 2 shows the generation capacities in GW for the 2030 Reference scenario.

[3] Available at https://www.iea.org/media/freepublications/technologyroadmaps/solar/TechnologyRoadmapSolarPhotovoltaicEnergy_2014edition.pdf.

[4] Available at http://www.irena.org/DocumentDownloads/Publications/IRENA_RE_Power_Costs_2014_report.pdf.

Figure 2: Generation capacities in GW (2030 Reference scenario)



2030 High scenario

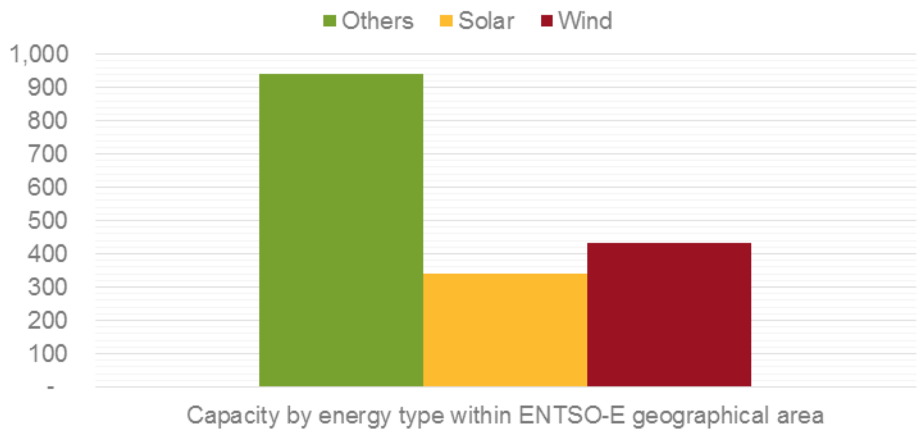
This scenario corresponds to a higher share of renewables. It is based on ENTSO-E "Green revolution scenario" (TYNDP 2030 Vision 4).

By contrast with the reference 2030 scenario, this scenario corresponds to implementing a single European energy policy and a European R&D scheme, leading to higher wind and solar capacities. On the other hand, CO_2 price, fuel prices and cost of capital are unchanged.

<u>Wind and solar capacities</u>

Wind and solar energy generation capacity respectively are 431 GW and 339 GW within ENTSO-E geographical area. Compared to the reference 2030 scenario, we have an increase of 20% and 52% respectively for wind and solar generation capacity. Figure 3 presents the generation capacities in GW for the 2030 High scenario.

Figure 3: Generation capacities in GW (2030 High scenario)



2030 Low scenario

This scenario is based on ENTSO-E “Slow progress scenario” (TYNDP Vision 1), corresponding to less favourable economic and financial conditions, reinforced national energy politics, parallel national R&D research schemes, low CO_2 prices and high primary energy prices.

In this scenario, there is therefore a lower share of renewables.

Cost of capital

We set in this scenario a higher WACC compared to the other two 2030 scenarios. We, therefore, consider the maximum value of WACC for OECD countries as displayed in IRENA’s “Renewable Power Generation Costs in 2014”. This is **12%**.

CO_2 and fuel costs

The CO_2 price in the reference scenario is divided by three to compute its value here, i.e. it is **31 €/ton**. Fuel costs given in €/MWh are presented in Table 7 below.

Table 7: Fuel prices (€/MWh) for the 2030 Low scenario

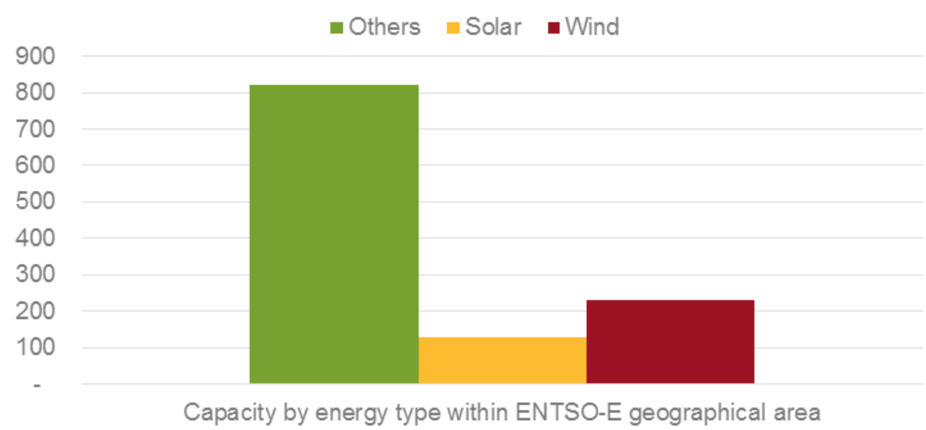
Nuclear	Lignite	Hard coal	Gas	Light oil	Heavy oil	Oil shale
1.36	1.58	12.53	37.01	83.52	49.32	8.28

(Source: ENTSO-E “Slow progress scenario” (TYNDP, 2014 version, Vision 1))

Wind and solar capacities

Wind and solar energy generation capacity, respectively, are 232 GW and 128 GW. Compared to the reference 2030 scenario, we have a decrease of 36 % and 43 % respectively for wind and solar generation capacity. Figure 4 presents the generation capacities in GW for the 2030 Low scenario.

Figure 4: Generation capacities in GW (2030 Low scenario)



3 Analyses description (EEG): Validation of possible future Balancing Market mechanisms

3.1 Description of planned analyses

Different possible future Balancing Market mechanisms shall be evaluated within this analysis, notably for the target year 2030. The analysis considers the expected installed capacities of conventional power plants and also generation based on Renewable Energy Sources (RES). The main target is the quantitative and qualitative measurement of the system operation outcomes for each mechanism and, consequently, to compile the ranking of the analysed balancing market designs.

3.2 KPIs and market designs to be evaluated

In **Error! Reference source not found.** a selection of the balancing arrangements resulting from Work Package 3 (WP3) are shown. The aim of this analysis is to assess Most of them, knowing that it is not possible to consider all of them. E.g. balancing & intraday trading cannot be evaluated, because the intraday market is not implemented in the model.

Table 8: Summary of the assessment of balancing arrangements

Competition among BSPs			
Procurement of balancing capacity and balancing energy products	Joint	Separated	
	Poor	Good	
Procurement of upward and downward balancing capacity products	Joint	Separated	
	Poor	Good	
Minimum bid size	Large (> 5MW)	Medium (1MW-5MW)	Small (≤1 MW)
	Poor	Poor to fair	Good
Pricing of balancing products	Pay-as-bid	Marginal	
	Poor to fair	Good	

Adequate incentives on BRPs			
Imbalance pricing system	Dual	Single	Combined
	Poor to fair	Fair to good	Good
Settlement period	Long (1 hour)	Average (30 min.)	Short (15 min.)
	Poor	Fair	Good

Source: D3.2 Developments affecting the design of short-term markets [1].

The *efficiency of the pricing scheme of balancing products* (pay-as-bid or marginal pricing) can be measured with the associated quantitative KPI **marginal cost reflectivity**, which is the ratio of the products price to the marginal cost of providing the corresponding balancing capacity or energy. When comparing pay-as-bid and marginal pricing, the fact that the average price is lower under pay-as-bid does not mean that pay-as-bid is more efficient. Here it should be assessed whether prices of products reflect their marginal supply costs. Products should be priced according to their market value, which is related to the cost of providing an extra unit of them.

The *efficiency of imbalance settlement designs*, comprising the imbalance prices and settlement period defined ex-ante, can be measured ex-post as the **ratio of the unit price paid for imbalances to the sensitivity of system balancing costs** with respect to changes in the corresponding agent's imbalance. When comparing single and dual pricing, or average vs. marginal, prices paid should be deemed cost-reflective to the extent that they correspond to the impact on system costs of the changes in the system variable being priced. Then, prices paid by agents should be as similar as possible to the sensitivity of system balancing costs with respect to an increase in the imbalance by these agents. The performance of dual pricing and single pricing can be also assessed according to the **difference between the revenues** of System Operators (SOs) from the payments made by Balancing Responsible Parties (BRPs) and the payments made to Balancing Service Providers (BSPs). This difference should be as small as possible in order not to produce a surplus to be inefficiently allocated afterwards.

The *liquidity of the balancing market* is influenced by features of this market like:

- the minimum bid size,
- the possibility of aggregation of bids,
- the possibility to offer separately up- and downward products,
- whether gate closures for capacity bids are close to real time,
- or the possibility of offering balancing energy without providing capacity.

Market *liquidity* is intimately linked by aspects of the market functioning like the **number and homogeneity of market participants** (entrants vs. incumbents vs. cross-border) and **types of bids.** However, it is difficult to assess these features of a market using a model or by its results. Instead, the **average price levels and/or the overall amount of balancing capacity and energy costs** of several market designs implemented can be compared to define their level of liquidity. An increase in the number of market participants, and therefore, the level of competition in the market, should result in lower average prices and overall payments for balancing capacity and energy. Having products with a large number of characteristics shall probably decrease the level of liquidity in the market since it leads to market fragmentation according to, for example, where in the electricity system (e.g. on which voltage level, etc.) the services are delivered in case of activation (when having in mind aggregators in the future), or which type of technology is behind the different bids/activations (e.g. primary fuel type for generation, or type of storage technology).

Table 9: Key performance indicators for assessment of balancing market alternatives

KPIs related to balancing markets	
Key performance indicator	**Explanation**
Ratio of the price of products to the marginal cost of providing the corresponding balancing capacity or energy.	Used to compare the efficiency of the pricing scheme of balancing products (pay-as-bid vs. marginal pricing). **This KPI is a measure of efficiency of the market**
Ratio of unit price paid for imbalances to the sensitivity of system balancing costs with respect to changes in the agent's	The KPI is used to compare single against dual pricing and average against marginal pricing. **This KPI is a measure of efficiency of the market**

imbalance	
Difference between the revenues of SO from the payment by BRPs and the payments made to BSPs	The KPI is used to compare single against dual pricing. The indicator should be as small as possible in order to limit the surplus that can potentially be allocated inefficiently. **This KPI is a measure of efficiency of the market**
Average price levels and/or the overall amount of balancing capacity and energy costs	Lower average prices and costs reflect a presence of a higher number of market participants and consequently increased competition for a given number of products traded. **This KPI is a measure of liquidity in the market**

3.3 Temporal and geographical scope

The model is to be validated with the 2013 data and the current balancing market design. Afterwards, different scenarios of 2030 shall be analysed.

The geographical scope comprises central Europe, meaning that the control zones of Austria, Slovenia (for testing Imbalance Netting), Switzerland and Germany will be considered in detail. The Netherlands, Belgium and the Czech Republic are only to be taken into account if all the data needed is available and there is sufficient time for gathering them. The remaining countries like Hungary, Slovakia (currently no direct interconnection to Austria) and Italy shall be considered for Day-ahead market activities only, because there are no existing plans that these countries to explicitly participate in the International Grid Control Cooperation (IGCC) in the near future. The current state of the IGCC is shown in **Error! Reference source not found.**.

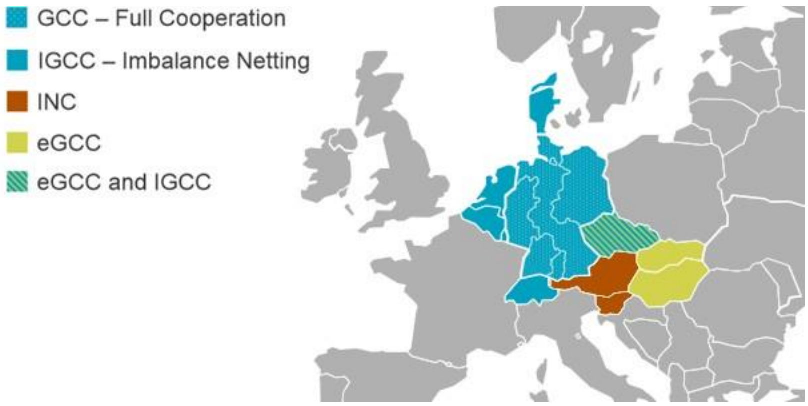


Figure 5: Current state of the International Grid Control Cooperation (IGCC)

Source: presentation of Amprion, 6. February 2014.

3.4 Assumptions, strengths and limitations of the model and analytical approach

EDisOn computes the optimal (cost minimal) dispatch of power plants in the electricity system and is also considering RES generation from wind, PV and run-of-river. It is designed as a linear programming problem (binary on-/off-conditions are linearized) and is deterministic in nature, assumes a perfect competitive market with perfect foresight, and has hourly resolution to compute the operation over a full year. In addition, transmission and (Pumped-) Hydro Energy Storage (PHES) are represented with much detail.

EDisOn+Balancing is an extension of the above-mentioned model that also considers in two further steps the balancing market mechanisms. Firstly, the procurement of Balancing Capacity, which also has an hourly resolution, is computed and, subsequently, the activation of Balancing Energy for balancing the control areas' imbalances with a ¼ hourly resolution is determined.

Figure 6 shows an overview of the different optimization steps of the EDisOn+Balancing Model and in Table 10 the strengths and weaknesses of the model are pointed out.

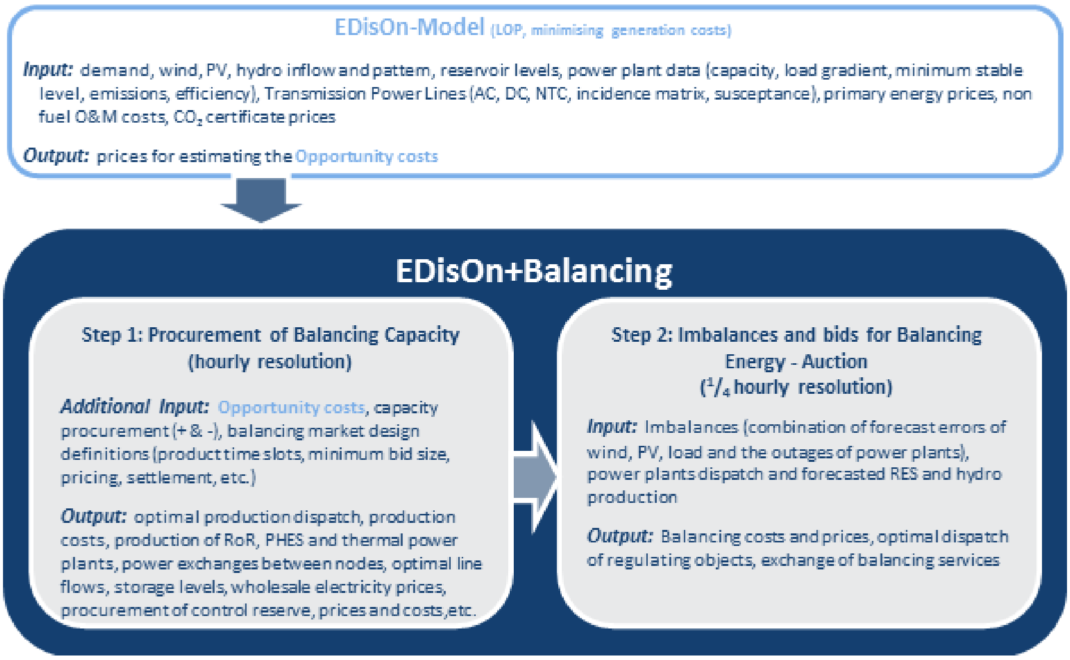


Figure 6: Flowchart of EDisOn+Balancing

Table 10: Strengths and weaknesses of the EDisOn+Balancing Model

Strengths	Weaknesses
• Frequency Restoration Reserves activated automatically and manually (FRRa and FRRm) and Replacement Reserves (RR) are considered • Day-ahead market is simulated • An imbalance Netting mechanism is included • Balancing capacity and energy, upward (positive FRR, RR) and downward (negative FRR, RR) are considered	• Frequency Containment Reserves (FCR) are not considered • No Intraday market is implemented • Not all European countries are considered, only a few • Not all Balancing market design options can be modelled and, therefore, validated

4 Analyses description (IIT-Comillas): Short-term effects of RES support schemes

4.1 Description of planned analyses

This analysis evaluates the performance in the short-term of the different schemes to support the deployment of RES generation. The idea behind this analysis is to compare how the adoption of a RES support scheme affects the short-term operation of the power system.

Thus, the operation of the power system without considering any support scheme for RES generation is compared to the operation of the power system obtained when applying different RES support schemes. The consideration of a support scheme implies changing the net costs faced by RES operators in the dispatch (productions costs net of revenues associated to operation decisions, like support payments earned). Therefore, RES support schemes may alter competitive bids by agents and, consequently, the operation of the power system could be very different from the optimal.

The ROM model is employed for this analysis.

4.2 KPIs and market designs to be evaluated

This analysis evaluates only the most promising options for RES support schemes identified in WP3 taking into account both long-term and short-term perspectives. The several support schemes evaluated are:

- Long term clean capacity auction,
- Long-term clean energy auction,
- Certificates,
- FIP (auction).

The main KPIs that are to be considered for the assessment of these support schemes are:

- System welfare (changes in this are to be computed as those occurring in the overall operation costs)
    - This reflects social welfare: changes in this may also be computed as those occurring in overall operation costs.
- Marginal cost reflectivity: Difference between market prices/revenues and (system and RES) marginal costs.
    - Occurrence of negative prices.
- Liquidity: impact of the amount of bids on the efficiency of prices computed.
- Robustness: Changes in efficiency KPIs due to a change in system conditions (different scenarios or snapshots may be considered).
- Cost efficiency: overall amount of funds mobilized to pay RES generation.

Next, the main KPIs to be considered and the way to compute them are provided.

Table 11: KPIs related to RES support mechanisms

KPIs related to RES support mechanisms	
Key performance indicator	**Explanation**
Efficiency: - Social Welfare - (Marginal) cost reflectivity - Liquidity	• Difference between overall prices/revenues earned by RES generation and system marginal supply costs. • Occurrence of negative prices • Volume of RES based Market Orders (for RES vs. total)
Cost efficiency	• Level of global earnings of RES generation in all markets and through all schemes implemented, including support ones.
Robustness	• Changes in the efficiency of the support mechanism in the short term (inversely proportional to the aggregate difference between prices earned by RES generation and short term marginal supply costs) with changes in the system conditions (among scenarios or operation hours).

Besides, changes in the generation dispatch shall be computed and analysed.

4.3 Temporal and geographical scope

The geographical scope of this analysis comprises the South-Western region of Europe: Portugal, Spain and France. The network of the power systems involved is not considered.

Figure 7: Geographical scope of the analysis of RES support schemes

The time scope of the analysis is one year (8760 hours) of operation of the system. The reference, or target, year considered is 2030.

4.4 Assumptions, strengths and limitations of the model and analytical approach

As previously mentioned, the ROM model is used for this analysis. A more detailed description of this model may be found in the annexes to this document (see Appendix C).

In this analysis, only the unit commitment module of the ROM model, representing the day-ahead market, shall be used. The methodology employed for the analysis is as follows:

1. Obtain the operation of the power system without considering any RES support scheme. This situation is considered as the optimal short-term operation of the power system.
2. Determine the level of support payments required for the several RES support schemes explored to achieve the deployment of the required amount of RES generation. These support levels are computed using the operational results just obtained with the ROM model (marginal prices, production levels) and assuming an investment cost for the different RES generation technologies forecasted to be installed. The support levels must ensure the recovery of the investment cost incurred in the deployment of the RES generation capacities required.
3. The support levels just computed for each scheme are considered in another run of the ROM model, where the operation of the power system is simulated again.
4. For each RES support scheme, check if the investment cost of installing the required RES generation capacity is recovered using the support levels previously computed and the

operational results just obtained. If this is not the case, the process should be repeated starting from point 2.

5. Compare operation results with RES support in place with the operation of the power system without any RES support scheme.

Main strengths are related to the fact that this analysis allows computing the operation under a wide set of support mechanisms. At the same time, the operation of the system in each case is computed with much detail, which allows determining the impact of changing the design of support on a multiplicity of variables. Besides, support payments computed are made coherent with the long term requirements of RES operators in terms of profitability, which makes the analysis coherent with the corresponding evolution of the system, to the extent the expected profitability of generation is concerned.

However, few countries are considered in the analysis, which has to do with the limited set of data available to conduct the study. Besides, the impact of support schemes kn the risk perceived by RES investors is not considered.

5 Analyses description (IIT-Comillas): Impact of changing the timing of markets

5.1 Description of planned analyses

This analysis assesses the impact of bringing the day-ahead market closer to the real time operation of the power systems. By bringing the day-ahead market closer to the real time, the uncertainty in the availability of power production from RES generation units that is faced by RES operators decreases and, therefore, the efficiency of the dispatch in the day-ahead market increases. This is because the costs of making this dispatch feasible decrease. In addition, reducing the RES generation uncertainty involves reducing the reserve requirements, which are necessary to maintain the reliability of the power system.

The analysis to be performed should compare the operation of the power system with the current timing of the day-ahead market with that for the case where the day-ahead market is closer to the real time operation. Several time horizons for the day-ahead market are to be considered. The ROM model shall be applied to compute the operation of the power system in both situations.

5.2 KPIs and market designs to be evaluated

This analysis is to assess the impact on system operation efficiency of getting the day-ahead market closer to the real-time operation of the power system.

The KPIs that are to be considered for the assessment of this option are:

- Difference between the price calculated in the day-ahead and the marginal cost in real-time operation, or ratio of short term price to marginal supply cost.
- Re-dispatch costs.

- RES curtailment.
- Load curtailment.
- Total social welfare.
- Changes in efficiency KPIs with respect to a change in system conditions (different scenarios or snapshots may be considered).

Table 12: KPIs related to the timing of short term markets

KPIs related to the timing of short term markets	
Key performance indicator	**Explanation**
Efficient price signals	• Ratio of short-term market price to real-time marginal production cost. Also relevant is the difference between one and the other.
Market modelling imperfection costs	• Re-dispatch costs • RES curtailment • Load curtailment
Ensure the availability of a complete set of time frames to trade the products and Global coherence of markets	• Total social welfare
Robustness against different scenarios	• Impact of a change from a reference scenario to alternative scenarios (involving for g. different levels of RES penetration and electric vehicle penetration) on the indicators defined to study the different market designs for the timing of markets

5.3 Temporal and geographical scope

The geographical scope of this analysis only includes the Spanish system. The network of the power system is not to be considered.

Figure 8: Geographical scope for the analysis of the impact of the timing of markets

The time scope of the analysis is one year (8760 hours) of operation of the system. The reference, or target, year considered is 2030.

5.4 Assumptions, strengths and limitations of the model and analytical approach

As previously mentioned, the ROM model is to be used for this analysis. A more detailed description of this model may be found in the annexes to this document (see Appendix C).

This analysis employs both modules of the ROM model: the unit-commitment module (representing the day-ahead market) and the real-time operation module, simulating the process of adaptation of the day-ahead market dispatch to real time system conditions. This is necessary in order to evaluate the impact of reducing forecast errors on wind and other intermittent production on the final dispatch (not in the day-ahead one).

The methodology employed for the analysis is as follows:

1. Compute the operation of the power system without changing the timing of markets.
2. Modify the estimate of power production from RES generation units representing a reduction in the error made when forecasting real time conditions for RES. This results from reducing the time difference between the day-ahead market and real time. In addition, reserve requirements should also be reduced.
3. Obtain the operation of the power system with the new timing of the day-ahead market.
4. Compare the system operation computed in steps 1 and 3.

This process should be repeated considering different time horizons for the day-ahead market.

Main strengths relate to the simplicity of the analysis to be carried out and the reduced size of the set of data to be employed. This is made compatible with computing a realistic estimate of the impact of taking the day-ahead market closer to real time.

Main limitations are related to the inability to compute the impact of other changes to the sequence of markets, like changes in the timing of longer term markets. Besides, few countries are considered in the analysis, which has to do with the limited set of data available to conduct the study.

6 Analyses description (RTE): Long-term competition between DSR and RES induced by RES support schemes

6.1 Description of planned analyses

6.1.1 Aim of the study

The policies aiming at developing RES technologies beyond the levels at which their profitability is ensured by the sole market price affect adversely the profitability of the other capacities constituting the electricity mix and, in particular of demand response. Demand response however, is regarded as one of the major levers to enable the electricity mix to welcome high shares of RES and, it could therefore be detrimental to their integration if it was prevented from developing in a timely manner due to the middle-term depression of market prices induced by RES policies.

The aim of the study is to measure the extent to which the integration of RES (and specifically variable RES) into the power system restrains the profitability of demand response objects and put it in perspective of the desirable long-term development of such objects. It should therefore lead to recommendations on the need and, if applicable, the level of support required to drive DSR to its correct penetration level arising from the support to RES.

6.1.2 Methodology

This study requires two types of simulations performed with the Micado tool:

- **Long-term optimal generation mix**: the optimal generation and DSR mix will be evaluated for each scenario described above (only some constraints on capacities being taken into account to allow finding optimal capacities for each technology); the contrasted levels of RES penetration will give indications to understand the possible complementarities between DSR and variable RES.
- **Short-term evolution of the dispatch if some capacities are added into the mix**: the dispatch and profitability of DSR options under deviations from the optimal situations, in particular in terms of installed variable RES capacities, will then be computed. The perspective is to understand the effect of forcing the RES penetration into the energy mix on the economic space available for the development of DSR.

6.2 KPIs and market designs to be evaluated

Table 13: KPIs related to economic efficiency

KPIs related to economic efficiency	
Key performance indicator	**Explanation**
Total system costs / total social welfare	Yearly system costs are computed as the sum of the variable dispatch costs (related to fuel mainly) and the annualized fixed costs related to the capital invested in the generation assets. Demand is regarded as inelastic except for the elasticity corresponding to the preferences expressed through the variable cost of DSR. The rest of consumption is regarded as having an arbitrarily high utility of consumption. As we are only comparing several situations, the level of this utility does not matter. Total cost or total social welfare should be as small as possible. **This KPI is a measure of the efficiency of the market**
Level of use of public funds	The study may conclude that some subsidies are required to deploy DSR. The level of subsidies may in this case be computed (and compared with, for instance, the level of subsidies to RES generation). **This KPI is a measure of the implementability of the market**

6.3 Temporal and geographical scope

In order to limit results to a size that allows one to interpret them, and also in reason of the lack of hypotheses on the DSR potential and costs in a wider area, the geographical scope of this analysis is limited to only one country (France). No internal grid constraint is considered.

Figure 9: Geographical scope for the analysis of the impact of RES support policies on the economic space for demand response

The time scope of the analysis is 52 weeks (8736 hours) of operation of the system weeks are selected within a dozen of historical weather scenarios so as to be representative of the full distribution of consumption and whether conditions in 2030

6.4 Assumptions, strengths and limitations of the model and analytical approach

6.4.1 Hypotheses: modelling DSR

Three types of DSR objects are regarded in this study, their costs and availability hypotheses are taken from previous works[5]:

- Industrial DSR through load shedding or self-production, considered without rebound effect and available during working hours. The maximum capacity in France is set to 8 GW with costs increasing as a function of the installed capacity from 10 to 55 k€/MW/year by 1 GW steps; their variable cost is 300 €/MWh. Industrial DSR is available only during work hours.

[5] RTE, Socioeconomic assessment of smart grids, 2015. Summary in English and full report in French.

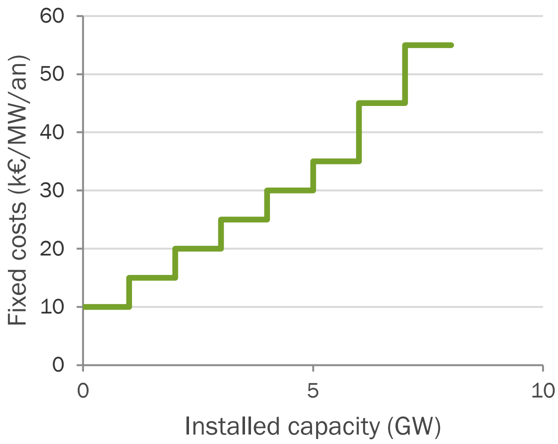


Figure 10 - Industrial DSR potential and fixed costs

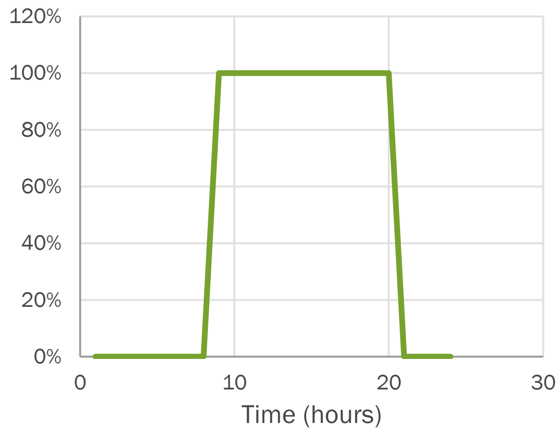


Figure 11 - Industrial DSR availability profile (working day)

- Distributed DSR on electric heating:
  - In the tertiary sector, a maximum capacity of 3 GW is considered, with a fixed cost of 18 kW/MW/year, a variable cost of 50 €/MWh and a 100 % rebound spread over the 6 hours subsequent to the shedding;
  - In the residential sector, a maximum capacity of 6 GW is considered with the same characteristics except for the fixed costs, set at 29 k€/MW/year.

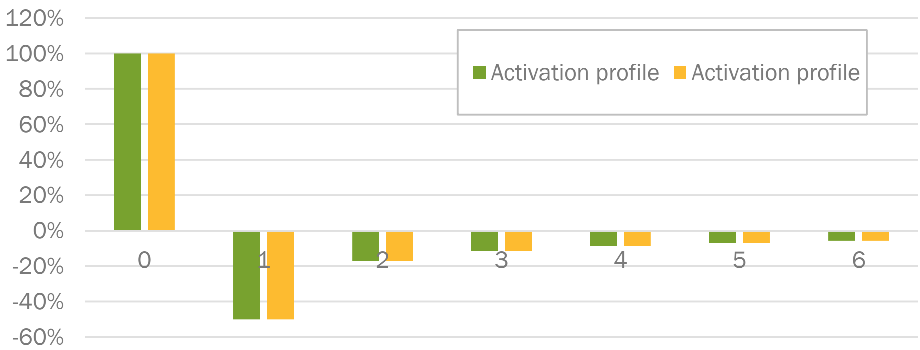


Figure 12 - Activation profile for distributed DSR

The availability of distributed DSR is computed based on the per household-average consumption of electric heating in France in each scenario.

6.4.2 Limitations

The use of an optimization model assumes perfect competition in the wholesale market.

Within Micado, the modelling of hydroelectric reservoirs is a 2 steps process: first, the energy that should be produced each week is allocated based on a heuristic formula taking weekly consumption and variable RES production into account and, then, this the corresponding hourly production is optimized over the week assuming no uncertainty.

For computability purposes, we use a virtual year, reconstituted after around a hundred of Monte-Carlo series thanks to a pre-selection of relevant “weeks”. Some slight numeric accuracy losses are inevitable in this process but they are limited here in particular due to (i) the fact that only one country is considered and (ii) that the pre-selection does not need to be robust to the variable RES penetration level.

7 Analyses description (RTE): comparative advantages of explicit support schemes and carbon pricing in achieving high shares of RES in the power system

7.1 Description of planned analyses

The purpose of RES development policies is to be a springboard for immature technologies which should eventually become competitive and allow, through a large deployment, to decarbonize our electricity (and, in addition, help reducing our dependence on fossil fuel imports).

The reduction of our greenhouse gases (GHG) emissions is also the aim of the EU Emissions trading scheme (ETS) which provides an EU-wide carbon price. Being linked to a cap on the volume of GHG emissions, this latter price alone is seen by many stakeholders as representing the correct level of incentives, in particular to foster the appropriate level of investment in RES generation across Europe. It has, indeed, the merit of setting up a levelled playing field for competition between all options to reduce our (industrial) emissions. This should in principle ensure economic efficiency in CO_2 abatement – i.e. doing it at the lowest possible cost. Its other advantage is that it should have implications beyond the development of RES. For instance, if the CO_2 price is high enough, it may reorder the economic merits of coal and gas so as to use the latter – much cleaner – energy instead of the former. In the latest years, the economic conditions however have made this price too low and insufficient to trigger investments in electricity generation from RES and many advocate for supporting the CO_2 price which could for instance result of a reduction of the total allowance.

While the arguments in favour of an “implicit” support (through the sole CO_2 price – were it high enough) are numerous, on the other hand, the “explicit” support schemes tend to be disregarded today because they introduce market distortions:

- over the short term, variable RES often having the incentive to produce even when the price is negative and no interest to help the system operation whereas, thanks to their technical features, they could provide relatively inexpensive flexibility;
- and over long term, investment in RES technologies being decided on criteria that do not necessarily value the assets in the order of their social value.

Their merit beyond ensuring that RES producers get a relatively high level of revenue for their production is also to give them long-term visibility on this revenue, which the ETS may not provide for. This lowers RES investors’ risk and is therefore of a nature to limit the cost of reaching our RES penetration targets.

This study, performed with Micado modelling system, aims at assessing the framework to decarbonize electricity in Europe by simulating the long-term evolution of the electricity mix under a constraint on GHG emissions implemented through:

- "explicit" support schemes limiting the price risk of RES projects hence the cost of financing them;
- "implicit" support through a high CO_2 price, also altering the dispatch order of non-RES technologies but increasing the profitability demanded by RES project carriers;
- options combining both of the above and possible adjustment of the ETS (for example a carbon price floor).

7.2 KPIs and market designs to be evaluated

Table 14: KPIs used in comparison of explicit and implicit RES support

Key performance indicator	Explanation
Total system costs	Yearly system costs are computed as the sum of the variable dispatch costs (related to fuel mainly) and the annualized fixed costs related to the capital invested in the generation assets. The cost of CO_2 at the ETS price is subtracted from the total cost in order to make results comparable, and the CO2 is valued according to a reference cost (several hypotheses) so as to take the externality into account. Demand being regarded as inelastic, this total cost paid by the consumers to finance electricity production, is a proxy to measure the total social welfare. It should be as small as possible. **This KPI is a measure of efficiency of the market**
Financial transfers between countries	Whether implemented through harmonized support mechanisms or through a common, high enough CO_2 price, reaching regional level CO_2 emissions targets implies transfers of funds from some countries to others. These transfers should be, in net terms, relatively small in order not to discourage some participating countries to accept the scheme. Transfers caused by the ETS are somehow "implicit" and only exist when assessed as relative to a reference allocation of the national emission caps; the emissions in the 2020 situation envisaged in WP4 shall be used as a reference point to compute this allocation. **This KPI is a measure of the implementability of the market**

7.3 Temporal and geographical scope

This study is carried out considering six countries: Portugal, Spain, France, Belgium, the Netherlands and Germany. Interconnections are regarded through a ATCs vision and no internal grid constraint is considered.

Figure 13: Geographical scope for the analysis of the long-term merits of RES support schemes

The time scope of the analysis is 52 weeks (8736 hours) of operation of the system, but these weeks are selected within a dozen of historical weather scenarios so as to be representative of the full distribution of consumption and whether conditions in 2030. The same weeks are selected in all countries so as to keep existing inter-zones correlations.

7.4 Assumptions, strengths and limitations of the model and analytical approach

The use of an optimization model means that (i) perfect competition is assumed in the wholesale market and (ii) that the assessment of the risk taken by investors in RES projects is not embedded in the model. Instead, this risk is represented through the discount rate used when computing the annualized fixed costs of technologies.

The modelling of variable RES at different penetration levels is relatively unsophisticated and imprecise since RES production is computed for each hour as the product of the installed capacity by a load factor which does not depend on the penetration level.

The modelling of hydroelectric reservoirs is a 2 steps process similar to the one used in ANTARES: first, the energy that should be produced each week is allocated based on a heuristic formula taking weekly consumption and variable RES production into account and, then, this the corresponding hourly production is optimized over the week assuming no uncertainty.

In addition, for computability purposes, we use a virtual year, reconstituted based on a hundred Monte-Carlo series thanks to a pre-selection of relevant weeks. Some numeric accuracy is inevitably lost in this process.

8 Analyses description (RTE): Energy only market vs. remuneration of capacity under risk aversion

8.1 Description of planned analyses

Historically, the energy market is supposed to fulfil two functions: short-term efficiency and long term signals for investors. The experience of liberalization shows that the former is ensured, the energy market allowing to dispatch, among the existing generating units, the least costly at any time. On the long-term window, the energy market must conduct to the right level of investments; in the current context of low to no demand growth, the investment decisions face many challenges: the replacement of ageing power plants, political hesitation regarding some generating technologies such as nuclear and an increasingly penetration of variable RES.

To tackle these challenge, many European countries decided to implement capacity mechanisms. Among the variety of possible designs, the study focuses on capacity-wide mechanisms based providing a remuneration to capacities to the extent that they allow to increase security of supply, i.e., mainly, by being available to the markets during peak hours.

This study aims at computing the long-term social value of completing an energy only market with such a capacity market under the different scenarios envisaged in this work package. More precisely it assumes a continuous increase of the installed RES generating capacity towards the 2030 targets set in these scenarios to investigate whether higher RES penetration make capacity remuneration mechanisms more relevant. In practice, the gradual addition of new variable RES capacity will influence the investors in their decision: closing, mothballing or keeping existing power plants in operation or creating new ones.

The study will be performed with the SIDES model, which focuses on dynamic evolutions of electricity systems based on the representation of decision rules. Financial risks will be taken into consideration in the analyses.

We will see how a classical thermal mix is developing during a 15 years period under

- an energy only market with a cap price of 3,000€/MWh,
- an energy market with a cap price of 20,000€/MWh,
- or coupled energy & capacity markets.

8.2 KPIs and market designs to be evaluated

The energy only market design with a cap price of 3,000 €/MWh, the energy only market design with a cap price of 20,000€/MWh and a coupled energy and capacity market design are to be assessed.

Table 15: KPIs related to efficiency

KPIs related to efficiency	
Key performance indicator	**Explanation**
Total system costs	Yearly system costs are computed as the sum of the variable dispatch costs (related to fuel mainly) and the annualized fixed costs related to the capital invested in the generation assets. Demand being regarded as inelastic, this total cost paid by the consumers to finance electricity production, is a proxy to measure the total social welfare. It should be as small as possible. **This KPI is a measure of the efficiency of the market**
Spot energy market price	Global coherence of market designs implemented. **This KPI is a measure of the efficiency of the market**

8.3 Temporal and geographical scope

In order to facilitate the interpretation of the results, the geographical scope of this analysis is limited to France. No internal grid constraint is considered.

Figure 14 - Geographical scope for the analysis of the social welfare of a CRM

The time scope of the analysis is the fifteen year period from 2015 to 2030.

8.4 Assumptions, strengths and limitations of the model and analytical approach

One of the main assumptions made in the SIDES model is that centralized investment and decommissioning processes are decided by a single agent; however, this agent is price-taker in the short-term market and the capacity market, if there exists one; he acts in the long-term so that each of its power plants is profitable (therefore, he has no market power over the long-run either).

To model a certain degree of “myopia”, investment, mothballing and closing decisions are taken after a profitability assessment concerning the five years following its decisions (although assets have a longer economic life-time).

No political interference with economic decision-making is considered, except for that being related to the definition of the scenarios (level of RES targets, presence of nuclear, etc.).

9 Analyses description (SINTEF): Long-term analysis of CRM, RES mechanisms and the energy only market

9.1 Description of planned analyses

SINTEF shall use the EMPS model to simulate the European power market. The objective of the analyses is to assess the impact of the implementation of extra market mechanisms on the power markets (RES-E and CRM). Thereby, their individual as well as mutual effect should be investigated.

We consider scenarios for 2030 and assume an energy-only market in Europe based on the ENTSO-E vision. The CO_2 price is taken as an input parameter. We run four simulations to compare the system costs resulting from two groups of explicit support mechanisms, capacity and RES support:

a. Energy only market without any support. Flexible generation production and capacity and RES capacity are outputs of the analysis

b. Energy only market with RES support. RES share is given, while flexible production and capacity is are outputs.

c. CRM without RES support. Total installed flexible capacity is given, while RES generation is an output.

d. CRM and RES support. Both types of installed capacity are given.

Primarily, EMPS is a long-term operation planning model considering exogenous installed capacities for generation and transmission. However, when including the additional investment module, the long-term development of the power system can be computed with EMPS, including capacity constraints.

To assess the effects of the mechanisms considered, constraints on the objected capacities (either RES under RES-E or other generation capacity for CRM) are defined. Such a constraint concerns the sum over all types of installed generation capacity which are objected with the mechanism. In the case where there is the possibility of allowing cross-border exchanges within the mechanism, the sum covers the several areas. The resulting generation portfolio (installed capacity of each type in each area) is the output of the analysis. Furthermore, the analysis provides the shadow cost for each of the constraints, which can be interpreted as its marginal cost.

We compare, over all options, the total resulting CO_2 emissions and costs that include the cost of support mechanisms and energy not supplied. We also compare the share of income of parties from different sources: support, energy only market, CRM.

Case study definition: Simulations are run for the entire ENTSO-E. The analyses are carried out for Norway, Sweden, UK, Germany, Finland and Denmark.

9.2 Market designs to be evaluated

The analyses shall focus on long-term CRMs and RES support mechanisms. The objective is to assess the impact of these mechanisms on the system dispatch and the development of the system.

CRM mechanisms to be analysed are the centralized targeted and non-targeted capacity markets (targeted and non-targeted, which result in two different simulations)

Previous WPs in the project provide a classification of CRMs according to different criteria. EMPS, the model employed in these analyses, does not allow the actual modelling of these mechanisms. What is performed is a calculation of the missing money under different scenarios in order to estimate the total capacity cost.

RES mechanisms to be analysed:

- **Long-term capacity auction;** authorities determine the required new capacities and call an auction. This mechanism can be targeted at individual technologies through separate auctions or a set of technologies in a common auction. Payments to individual bidders can be dealt with through pay-as-bid arrangements, where successful bidders receive their initial bidding price, or pay-as-clear arrangement, where all bidders receive the clearing price.
- **Long-term clean energy auction;** successful bidders receive a payment for a predetermined amount of energy produced within specified periods (month, quarter, year). The payments can be carried out in the form of a full price, a price premium or a contract for difference with respect to a given price level. The energy produced in excess of the amount auctioned can be sold in other markets.
- **Feed-in Tariff with auction;** investors receive a fixed amount - the feed-in tariff - for every MWh generated. An auction is used to create competition and reduce the cost of this mechanism. Investors bid in the auction what they consider a satisfactory price for their energy. This should ensure that FIT cover all costs and provide the required return on investment.

- **Feed-in Premium resulting from an auction;** generators receive a price premium over the day-ahead market price. Unlike in the case of FIT, with FIP investors are exposed to market price fluctuations. The level of the premium is a result of an auction. In addition to the level of the premium over prices, the mechanisms can include a payment cap and floor.

9.3 KPIs to be evaluated

The analyses shall focus on the long-term development of the system, and therefore target mostly long-term KPIs, though some short-term KPIs are nevertheless included. The first group of indicators to be computed are related to the long-term effects of capacity remuneration mechanisms (Table 1616).

Table 16: KPIs related to the long-term analysis of capacity remuneration mechanisms in SINTEF analyses

KPIs related to the long-term analysis of capacity remuneration mechanisms	
Key performance indicator	**Explanation**
Capacity bid prices	These should reflect the level of profitability on the energy only market and/or consumers' utility in case of demand response. **This KPI is a measure of the efficiency of the market.** More precisely it is a measure of marginal cost reflectivity.
Total capacity cost	As above, this KPI reflects the missing money from the energy only market. **This KPI is a measure of efficiency of the market**
Loss of load or energy not supplied	The value of lost load should be close to the marginal cost of added capacity. **This KPI is a measure of efficiency of the market**
Missing money	**This KPI is a measure of effectiveness in the market**

The first KPI, **Capacity bid prices,** will not be a direct output of simulations. What will rather be performed is a calculation of the level of support – the bid prices - that will secure an acceptable level of profitability. The **total capacity cost** will be the sum of revenues from the energy market and the support from the capacity markets. The level of support will be calculated, as mentioned above, by considering the required levels of return for investors in flexible capacity.

When it comes to RES support mechanisms, the analyses shall evaluate three KPIs: the revenues and costs of RES technologies, the sensitivity of revenues to changes in the scenario and the sensitivity of installed RES capacity to changes in the scenario (Table 17).

Table 17: KPIs related to the long-term analysis of RES support mechanisms in SINTEF analyses

KPIs related to the long-term analysis of RES support mechanisms	
Key performance indicator	**Explanation**
Difference in costs and revenues	Difference between the revenues of RES generation in long term markets and other revenues of RES generation and the costs as defined by the scenarios **This KPI is a measure of efficiency of the market.**
Sensitivity of cost and	Derived from the above KPI.

revenue with respect to a change of scenario	This KPI is a measure of the robustness of the mechanism
Sensitivity of the amount of installed RES capacity with respect to a change of scenario	Installed capacities are given by the scenario. These values represent the starting point for a dynamic analysis of investments. This KPI is a measure of the robustness of the mechanism

9.4 Temporal and geographical scope

The analyses shall consider ENTSO-E 2030 visions covering the European power system. However, the focus of the analysis is on the Nordic and the north European countries: Denmark, Finland, Sweden, Norway, Netherlands, Germany and Great Britain.

The optimisation horizon of EMPS is one year, while taking into account several years of climatic data (hydro inflow, wind speeds, solar radiation and temperature). The temporal resolution can be 1 hour, while a 2 hourly resolution shall be used in the analysis.

Figure 15: Geographical scope of studies

9.5 Assumptions, strengths and limitations of the model and analytical approach

Generation system: The generation system is made up of dispatchable hydropower plants, thermal power plants as well as intermittent RES (wind solar). The model is solved as a dispatch and unit commitment problem, making a linear approximation.

Network representation: The transmission system is represented through a transport model with net transfer capacities between the various areas. The division of the power system into areas is based on country borders, regularly congested transmission corridors, as well as the geography of the water courses in the Nordic system.

Stochastic weather data: The optimization is based on several (~75) years of weather data, which is essential for a proper long-term operational planning of hydropower, but also is relevant for other RES, such as wind power production and solar power production. The model considers weekly hydro inflow data and hourly data for wind speeds and solar radiation

9.6 Summary of all planned analyses

In sum, nine analyses of market design options will be carried out under four scenarios that are described in Section 2. Table 18: Overview of planned analyses shows an overview of the planned investigations.

The first analysis performed by EEG will compare a number of options that govern the balancing market.

IIT-Comillas will perform two types of analyses. The first type will focus on the effects of different RES-E support mechanisms on the functioning of short term markets. The second of IIT-Comillas' analyses will simulate the move of the wholesale market towards the real time. It will investigate the impact of this move on the efficiency of the dispatch and required reserves. The geographical scope will be limited to Spain, due to its high share of wind production, which will stress the effects of uncertainty of high wind penetration.

RTE will perform three types of investigations. The first one described in Section 6 will look into the effects of the share of RES in the generation mix on the profitability of demand response. Demand response represents a key component for the successful integration of RES but policies aimed at promoting RES that are decoupled from energy market prices, can be detrimental to the development of demand response.

In the second of RTE's analyses the effects of implicit and explicit support for RES will be compared. The carbon tax allows for more efficient valuation of different technologies than RES support mechanisms. However, it also implies higher risks and capital costs for investors in RES. The analysis will study the circumstances under which one or the other policy performs better.

The third of RTE studies, will analyze the benefits of capacity remuneration mechanisms. Here the energy only market with different price caps is compared to a market with CRM in terms of attracting sufficient flexible capacity, with a focus on the risk taken by investors in the different cases. To fit to a context of moderate to no demand growth and increasing RES generation capacity, the model does not only let them invest but also close existing plants.

Finally, SINTEF will compare the evolution of the North European electricity mix in the post 2020 context under four different settings, the energy only market, a market with capacity remuneration mechanisms (CRM), a market with renewables support and a market with both CRM and RES support.

Table 18: Overview of planned analyses

Section of this report	Topics of analyses	Partner in charge	Tool used	Appendix providing tool description
3	Validation of possible future Balancing Market mechanisms	EEG	EDisOn+Balancing	B
4	Short-term effects of RES support mechanisms	IIT Comillas	ROM	C
5	Impact of changing the timing of markets	IIT Comillas	ROM	C
6	Long-term competition between DSR and RES induced by RES support schemes	RTE	Micado	D
7	Comparative advantages of explicit support schemes and carbon pricing in achieving high shares of RES in the power system	RTE	Micado	D
8	Energy only market v. remuneration of capacity under risk aversion	RTE	SIDES	E
9	Long-term analysis of CRM, RES mechanisms and the energy only market	SINTEF	EMPS	F

10 References

[1] L. Olmos et al.: *"Developments affecting the design of short-term markets"* 2015.

[2] L. Olmos et al.: *"Developments affecting the design of long-term markets"* 2015.

[3] L. Olmos et al.: *"Definition of Key Performance Indicators for the assessment of design options"*, 2015.

[4] S. Dourlens-Quaranta, T. Pagano: *"Specifications of the most adequate options for flexibility markets and RES support schemes to be studied in a cross-border context"*, 2015.

A. Appendix: Model classification

The inventory of the diverse tools brought by the members of the consortium allowed classifying them into three categories, according to their respective functions and capabilities.

A.1 Unit commitment tools

Tools of this type typically model the operation of generation units (but also possibly of storage facilities or demand response options) based on either an optimization at the global scale (for all the available options) or on the decisions of the markets' players (essentially the producers) given market conditions and their respective market strategies. Such tools often work with an hourly time step, but, depending on their features (in particular regarding unit commitment at the balancing timeframe), they may have a higher time resolution.

The first sub-class within this type usually involves solving an optimization problem, either deterministic (in which case climatic uncertainty can be represented through the use of several or numerous scenarios) or stochastic (in particular to enable a proper management of storage facilities). Demand is typically regarded as inelastic and a very high cost is attributed to unserved load. Generating units that are not constrained by an energy stock are essentially described by a variable cost, proportional to their output. The programme, then, either maximizes social surplus or minimizes total cost, as a proxy to the former, and serving the load is considered a constraint for each hour of the simulation period (in practice, it is always achievable through the use of a virtual perfect generating unit of "infinite" capacity representing unserved load). This kind of problems simulates the centralized optimal production decisions of a monopoly or, in an equivalent manner, the dispatching that should result from market players' bids under the assumption of pure and perfect competition.

The second sub-class aims at describing an altered situation where some of the postulates of pure and perfect competition are not fulfilled – for instance the market players are not purely rational or have market power – therefore, it essentially falls under the game theory type of tools.

A.2 Projects' profitability assessment tools

Tools of this class are used to assess the potential profitability of the project of building up a new power plant. This typically requires from the producer to make hypotheses about the future market conditions and, on their basis, compute a number of financial KPIs reflecting the amount of money that will be generated by selling the energy produced by this new facility to the market and whether or not investors may be willing to take the risk associated with this investment, given the rent it is expected to produce. This type of indicators are used to decide whether or not the project can be started (depending on the risk policy of the company contemplating it) and also, very often, its financing structure, the debt-to-capital ratio being determined by the risk inherent to the project.

Such tools require making hypotheses on the costs of projects and on some factors conditioning their future revenues. These include market prices (which can be computed in many ways, for instance through a "physical" approach based on the supply of projected demand by projected generation; or through time-series analysis of the historic prices, on the basis of market forward products, etc.) and the behaviour of the studied facility.

A.3 Tools for long-term studies

Here again, two types of approaches are possible, the first one being based on the "centralized" optimization of the system expansion and operation, and the second one relying on the simulation of market players' decisions (players being investors in this case).

The aim in models of the type is to find out the structure of the generation mix which provides the least expensive solution to cope with a given demand, ensuring a specified level of security of supply. The result of this is, therefore, a static vision of a target ideal mix. However, tools of this class do not give any information on how to reach this target from a previous state, neither do they indicate whether market players' decisions would lead to reaching such a target or not. Such tools usually require solving huge optimization problems in an approximate manner, based on heuristics.

On the other hand, in tools of the second type, the final generation mix (if a stable state can be reached) results from the cumulative investment decisions made by simulated market players on the basis of the use of projects' profitability assessment tools and hypotheses on their risk aversion and strategy. This kind of tools rely on a description of how market design items influence the revenues from running a generating unit or a storage facility to determine how market features alter investors' decisions and, thus, change the prevalence of each technology in the resulting mix. Tools of this class are also very resource-greedy, since running them usually requires the repeated appraisal of several projects against many future scenarios over many years.

Running models that follow the two approaches is useful to measure the extent to which the mix resulting from the decisions of investors exposed to a given market design minimizes the collective cost of electricity, which is a key indicator in the assessment of public energy policies.

A4. Map of the available tools

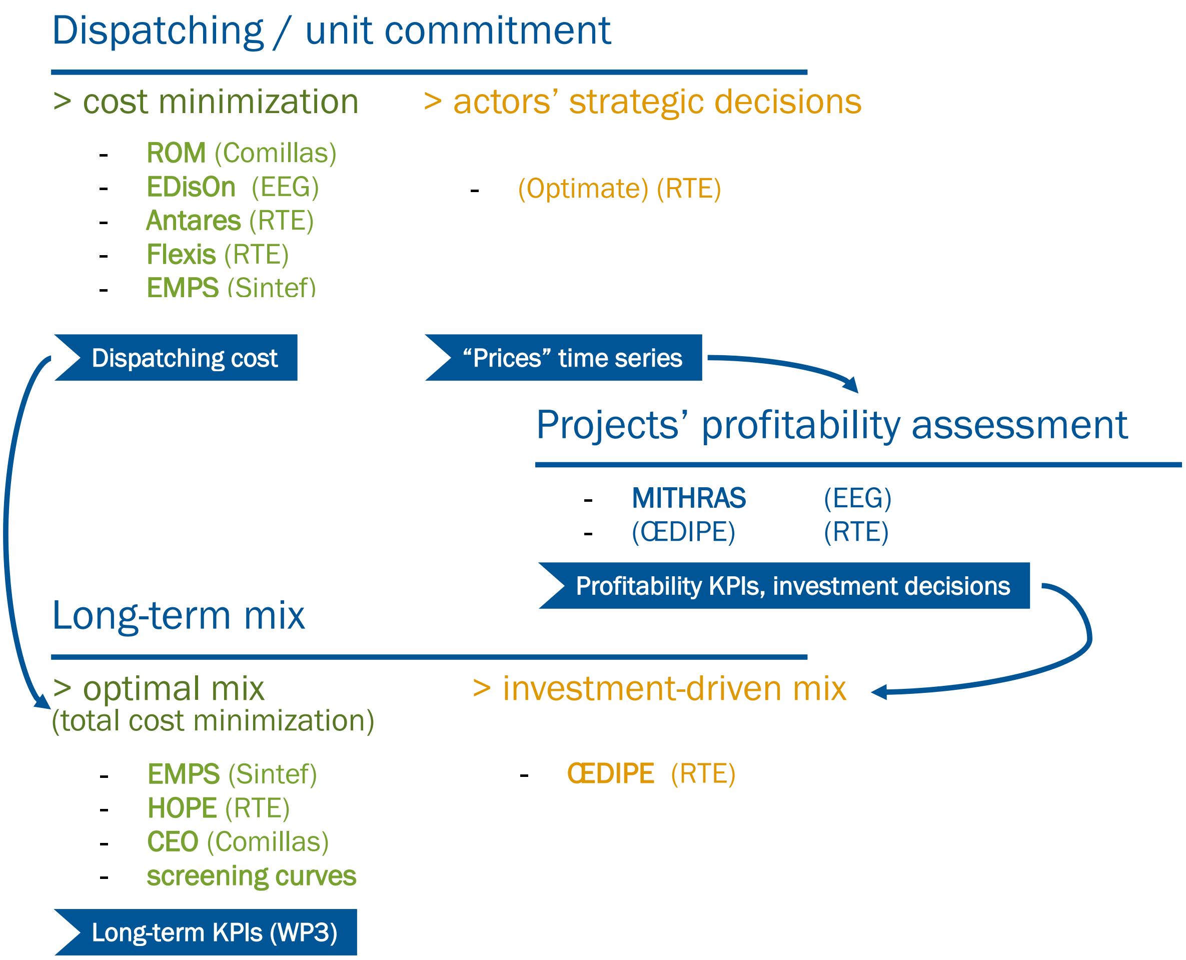


Figure 16 - Classification of the available tools

A5. Models used in the different analyses

The topics of the analyses carried out in WP5, the partners in charge and the models used are summarized in the table below.

Table 19: Overview of analyses and models used

Section of this report	Topics of analyses	Partner in charge	Tool used	Appendix providing tool description
3	Validation of possible future Balancing Market mechanisms	EEG	EDisOn+Balancing	B
4	Short-term effects of RES support mechanisms	IIT Comillas	ROM	C
5	Impact of changing the	IIT	ROM	C

	timing of markets	Comillas		
6	Long-term competition between DSR and RES induced by RES support schemes	RTE	Micado	F
7	Comparative advantages of explicit support schemes and carbon pricing in achieving high shares of RES in the power system	RTE	Micado	F
8	Energy only market v. remuneration of capacity under risk aversion	RTE	SIDES	G
9	Long-term analysis of CRM, RES mechanisms and the energy only market	SINTEF	EMPS	**Error! Reference source not found.**

B. Appendix: Model descriptions – EDisOn (EEG)

EDisOn is a unit-commitment tool based on centralized optimization.

B.1 Objective

EDisOn computes the optimal (cost minimal) dispatch of power plants in the electricity system of Austria for a whole year and is also considering RES-E generation of Wind, PV and Run of River. In addition a detailed transmission and (pumped) hydro storage representation is implemented. Other relevant system operation variables are also computed, including the level of NSE, RES-E curtailment, congestion rents, social welfare, CO2 emissions, etc.

B.2 Functional description

EDisOn is designed as a linear programming problem and is deterministic in nature, assumes a perfect competitive market with perfect foresight, and uses an hourly resolution of a full year. EDisOn covers the whole transmission system of Austria (220 and 380kV) as well as its interconnections to neighbouring countries. Generation capacities are given exogenously. The power flows between nodes are simulated via Power Transfer Distribution Factor (PTDF) matrix. (Pumped)-hydro storage and Run of River are following an annual pattern. Electricity generation of Wind and PV are considered based on historical data, but it is also possible to implement a time series based on a stochastic process.

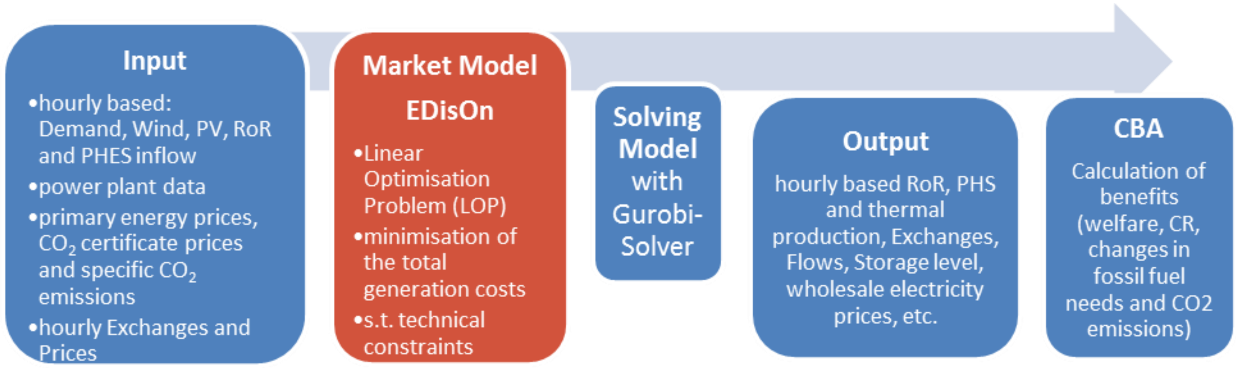


Figure 17: Methodology

B.3 Required data and hypotheses

Input data required by model EDisOn include:

- List of conventional power plants and their main features in each considered node: capacity, fixed and variable production costs (or their efficiency rate), minimum output, level of CO2 emissions, maximum power ramps, etc.
- Hourly time series of electricity production for Wind, PV and Run of River
- Hourly time series of demand
- CO2 price
- Cost of NSE (Value of Lost Load – VoLL)

Main hypotheses:

- Demand scenarios
- RES capacity scenarios
- Thermal technologies characteristics & fuel costs
- Investments in grid and power plants (transmission power line scenarios)
- Energy flow analyses

B.4 Limits and development perspectives

The optimization of the Austrian system (24 nodes and 35 transmission power lines) for a whole year takes around 15 minutes. For the TransnetBW control zone of Germany (137 nodes and 194 transmission power lines) the simulation takes approximately one hour.

The implementation of balancing markets is the planned development of EDisOn within Market4RES.

B.5 Examples of past studies carried out using this tool

GridTech project (www.gridtech.eu)

Used for the case study analyses of the Austrian and a part of the German transmission system. In the Austrian case study there has been considered 17 nodes within Austria and 7 neighbouring nodes. In the German case study the number of considered nodes is 137. The aim of the case study analysis is to investigate the benefits/costs of innovative grid-impacting technologies, like Flexible AC Transmission System (FACTS), Dynamic Line Rating (DLR) or High-voltage DC (HVDC) lines.

C. Appendix: Model descriptions – ROM (Comillas)

The ROM model follows a combined modelling approach that replicates the sequence of planning and real-time operation process in the power systems from the System Operator´s (SO) point of view. A daily optimization problem is solved to compute the unit commitment (UC) and the economic dispatch (ED) for each day taking into account the uncertainties of the power system (e.g. generators maintenance, wind and demand forecast errors). This represents the day-ahead market. The optimization stage is followed by a simulation stage where the adaption of the day-ahead schedule to correct power imbalances caused by stochastic events is computed. This represents the real-time operation. The model considers the chronology in the operation for the whole year, sequentially running the 365 days and being able to capture intermittent generation variability. Weekly hydro scheduling, such as the daily hydro production or pumping, is determined internally in the model following a heuristic criterion. Figure 12 presents an overview scheme of the model functioning.

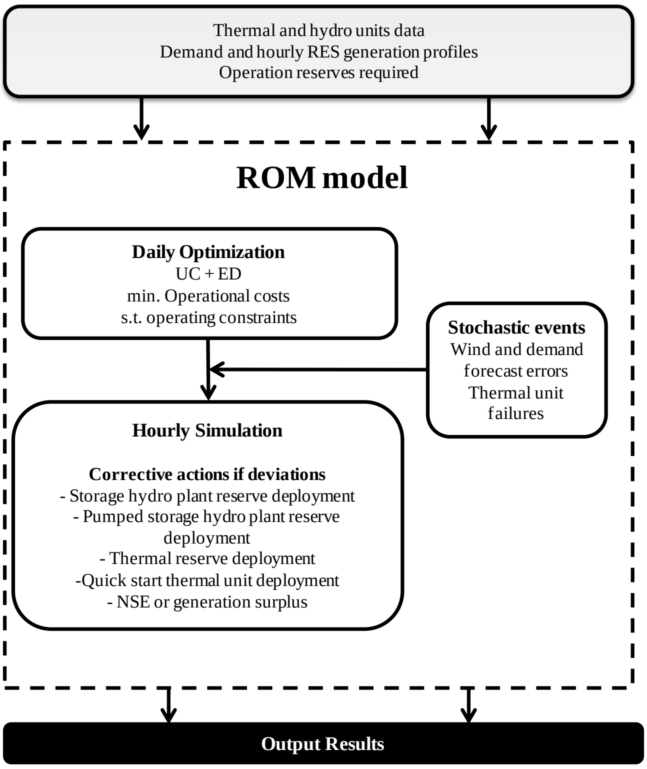


Figure 18: General overview of the model

ROM: Reliability Operation Model

ROM is a unit-commitment tool based on centralized optimization.

C.1 Objective

The ROM model solves the unit commitment problem for a power system, thus computing the commitment state of units as well as their schedule throughout a whole day (or time span considered in the day-ahead time frame). Other relevant system operation variables are also computed, including the level of NSE, RES energy spillages, CO2 emissions, etc.

C.2 Functional description

In order to compute the short-term system operation and asses, for example, the level of integration of RES generation, the ROM tool follows a combined modelling approach whereby a daily optimization model [9] is followed by a sequential hourly simulation [12], with a resolution of one hour. This replicates the sequence of markets cleared and operation decisions made in real life systems. Thus, the ROM model is able to reproduce the hierarchy and chronology of decisions made and allows representing the fact that uncertainty is revealed over time (forecasting techniques become more accurate when the target hour approaches). A chronological approach is used to sequentially compute the system operation for every day of a year. Decisions above this scope, as the weekly scheduling of pumped storage hydro plants, are made internally within the model applying heuristic criteria. The management of hydro resources and seasonal pumped storage that exceeds the week time frame must be computed by another, higher–level, model and be taken as an input into the ROM model. Monte Carlo simulation of many yearly scenarios is used to deal with the stochasticity of the demand and the intermittent generation.

Detailed operation constraints (minimum load, ramping rates…) are included into the daily unit commitment model. The hourly simulation of real-time operation is run afterwards to account for intermittent generation production errors and unit failures, and therefore provides an update of the previous schedule. Differences between the system operation costs corresponding to optimization and simulation decisions can be deemed to represent the value of the perfect Intermittent Generation forecast.

C.3 Required data and hypotheses

Input data required by model ROM include:

- List of conventional power plants and their main features: capacity, fixed and variable production costs (or their efficiency rate), minimum output, level of CO2 emissions, scheduled and forced outage rate, maximum power ramps, etc.
- Hourly time series of gross power production by each RES generation technology (or each RES power plant)
- Hourly demand time series.
- CO_2 price
- Cost of NSE
- Hourly time series of the forecasting error made for wind power production, and demand, for each hour of the next day in the day-ahead time frame, and in hour 24 of the day-ahead of delivery.

Main hypotheses:

- Network constraints can be represented using a very limited number of zones.
- Centralized, cost-driven operation of the power system
- Network losses are negligible

C.4 Limits and development perspectives

The operation of a real-life system of a large size, like the Spanish one, network constraints are neglected can be computed over a whole year in between 1 hour (check).

No developments of the ROM model are expected over the time frame of the project.

C.5 Examples of past studies carried out using this tool

TWENTIES

Investigating costs and benefits resulting from the provision of AASS by wind generation. Once the level of penetration of wind generation was set, and the scenario was defined in terms of available wind output per hour and available thermal capacity, the model was used to compute the impact on System Operation of having wind generation providing regulation reserves and mobilizing them, or instead obtaining it from conventional generation

Analyses conducted for the Spanish power system in the 2020 time horizon. Management of storage is taken as given. Evolution of the system computed using other models

Outputs produced include power production by power plants in each technology, overall operation costs and marginal ones, CO_2 emissions, RES energy spillages, amount of NSE, etc.

BEYOND2020

Investigating the consequences for the operation of the system of having each of several RES energy policies in place leading to several different compositions of the generation park

Analyses conducted for the Spanish power system and others in the 2030 time horizon. Management of storage is taken as given. Evolution of the system computed using other models

Outputs produced include power production by power plants in each technology, overall operation costs and marginal ones, CO_2 emissions, RES energy spillages, amount of NSE, etc.

VERDE, MERGE

Investigating the consequences for the operation of the system of having each of several penetration levels of EVs. Investigating also the effect if charging EVs according to each of several strategies.

Analyses conducted for the Spanish power system and others in the 2020 and 2030 time horizons. Management of storage is taken as given. Evolution of the system computed using other models

Outputs produced include power production by power plants in each technology, overall operation costs and marginal ones, CO_2 emissions, RES energy spillages, amount of NSE, etc.

D. Appendix: Model descriptions – Micado (RTE)

Micado stands for Model for Investments and Capacities Development based on Optimization.

Micado is a tool for long-term studies, based on centralized optimization (optimal mix).

D.1 Objective

Micado computes a long-term optimal generating mix in a central optimization logic. It outputs the optimal mix given a SoS criterion and deterministic hypotheses on demand and the availability (or load factors) of technologies. It embeds a modelling of both industrial and distributed demand response.

To keep the problem computable, Micado solves adequacy problems on an hourly basis on time horizon of the magnitude of one year. Therefore, stochastic hypotheses represented by a large number of scenarios must be simplified. To this aim, Micado is paired with a problem-reduction algorithm which aims at ensuring the representativeness of the dataset while limiting the number of variables in the optimization problem to an acceptable (feasible) number.

D.2 Functional description

Functioning principles

Micado implements a linear (linearized) modelling of the dispatch problem, i.e. a cost-minimization of the production required to meet demand under a predetermined security of supply criterion (usually, 3 hours of loss of load expectation yearly). The originality of this model is that it regards installed capacities as variables instead of input parameters, associated with the fixed cost of generating and DSR technologies. Thus, installed capacity and the energy produced by each technology for each hour of the year are jointly optimized and the optimal mix is computed at once.

The drawback of this method is that it constrains the modelling complexity (hence fidelity) of the short-term dispatch, therefore the dynamic flexibility issue is not well represented (if at all): there is no dynamic constraint on the output of capacities and the variations in short-term reserves requirements are not represented (all the more as they may not vary linearly with installed capacities).

However, it still allows a relatively good modelling on other issues. Interconnections are managed as (hourly) NTCs (but no internal grid constraint is considered) limiting energy transfers between countries. Hydroelectricity is modelled in the same way as it is in Antares, i.e. through a two steps approach:

- First, an energy production objective per week is determined through a heuristic approach based on consumption;
- Then this energy is dispatched in an optimized way throughout each week, with perfect knowledge of the weekly conditions.

Demand response features are close to those of thermal generation (it has an availability profile, a fixed cost and a variable cost representing the consumer's loss of utility) but may also include a rebound effect and a maximum activation duration per day.

Approaching a Monte-Carlo representation of uncertainty

A high number of yearly subsets in a data set tends to quantify in a better way the uncertainties on the forecasted load (by using a Monte Carlo method), but it increases considerably the computing time especially while solving a big and highly constrained model. The optimization model, that has been developed to minimize the costs of an energy mix, is typically run over one year. As it is already complex and takes up to an hour to be computed, it is not feasible to solve it for each of the years available in the data sets within the Monte Carlo approach.

Thus, a preliminary computation is performed, which aims at reducing the number of input data while keeping the precision's loss to a minimum. A contraction method for the data sets is implemented by selecting series of electricity consumption on a weekly basis. The used approach is to select weeks among all the weeks represented in the data sets (N years = 52.N weeks) and to aggregate them all together to reconstitute a year.

The aim of this technique is to keep a good representation of all possibilities for load peaks, RES activity etc. But it is also important to keep coherence in the organization of the set. The frequency of the sampling cannot be too high as the junctions between samples is no longer coherent. It also has to be compatible with the representation of hydro in Micado. For both these reasons, the week was regarded as a satisfying duration unit, keeping coherence between two following load values for instance (i.e. energy gradient between two consecutive hours) and enabling to perform a medium-term storage hydro dispatch along a full week.

The ultimate goal is to select a set of weeks for which the solution of the optimization problem is close to the one we would have found by solving the problem for the complete data set (knowing that a data set is already a sample of the entire set of possibilities). Micado's optimization problem being an enhanced version of the mere computation of the optimal mix based on load duration curves, the idea underlying this problem reduction algorithm was to make so that the load duration curve computed over the subset "looked alike" that of the full set, or in other terms, that it was close to it as measured by a distance.

The selected criterion is given in the following equation. It is based on the Root Mean Square difference between the load duration curve of the subset and that of the full set:

$$Error = \frac{\sqrt{\sum_{t=1}^{8736}(NLDC_t - \widetilde{NLDC_t})^2}}{\sum_{t=1}^{8736}\widetilde{NLDC_t}} \quad \text{in ‰}$$

$NLDC_t - \widetilde{NLDC_t}$ being the algebraic (signed) distance between the two load duration curves at hour t.

Among all the randomly selected sets of 52 weeks, the one with the smallest Error is kept. This enables to obtain a selection of weeks which characterize the overall net load duration curve of the data set.

Micado's modelling of DSR

Demand response technologies are similar to generation technologies (availability, fixed and variable cost) but they may include additional constraints: a maximum number of hours of activation per day can be set and they may have a rebound effect over several hours after activation, according to a predefined profile. The rebound effect corresponding to an activation occurring at the end of the week may happen at the beginning of the same week to avoid non-realistic arbitrages in the case the weeks are not ordered in a chronological way (for instance due to the week selection process).

D.3 Required data and hypotheses

Studying adequacy and long-term planning involves being able to represent the uncertainty in demand and supply conditions. A Monte-Carlo approach is used: for each country, demand, availability of conventional units, load factors for RES and hydro stock are represented by a large number (typically 10 to 1000 years) of time series, generated after a preliminary analysis of the historic data and their correlations.

The variable cost of each technology must also be specified. In addition, a normative variable cost of unsupplied load which is necessary the LOLD (SoS criterion) into a cost that can be taken into account within the optimization problem; however this cost can also be computed by a research algorithm to reach a predefined criterion (e.g. 3 hours of loss of load expectation, yearly).

Finally, annualized fixed costs (cost of capital and fixed O&M) are necessary; they are computed on the basis of "overnight costs", fixed O&M costs and a discount rate that can be to different values for each technology given different typical financing structure of projects for each of them.

The problem reduction algorithm selects weeks of data so as to obtain a reduced dataset, representative of the overall distribution of the possible realization of consumption, weather conditions and power plant availability.

D.4 Current limits

Computing speed

Running Micado on a standard recent computer, for six interconnected countries and 10 technologies, it takes around **20 minutes** to find the optimal generation mix and its optimal dispatch over 52 weeks.

More precisely, for the purpose of this test, technologies include:

- Variable RES (solar PV, wind, run-of-river hydro), generation capacity being constrained for political reasons;
- Lake hydro, generation capacity being constrained for technical reasons;
- Conventional thermal (hard coal, lignite, CCGT, OCGT, fuel turbines), lignite generation capacity being constrained in some countries for economic reasons;
- Nuclear, generation capacity being constrained in some countries for political reasons.

Micado' s modelling limits

Micado is not focused on technical flexibility since it does not embed any representation of dynamic constraints on generation (start-up costs, ramping times, etc.) nor does it include operational reserves requirements. Installed generation capacity is regarded as being a continuous variable. It implements a perfect dispatch which assumes perfect competition.

The dispatch of hydroelectric plants is represented in a 2 steps process: first, the energy that should be produced each week is allocated based on a heuristic formula taking weekly consumption and variable RES production into account and, then, this the corresponding hourly production is optimized over the week assuming no uncertainty.

Finally, Micado's description of the network is relatively rough as it is based on NTCs which simplify the actual constraints on the cross-border commercial fluxes, especially in the perspective of a generalized use of flow-based approaches. In addition, no internal constraint is considered, although countries could be split in several price zones.

D.5 Examples of studies carried out in the past using this tool

Micado was used in 2015 to carry out prospective studies on the long-term evolution of the generation mix as the result of policies aiming at constraining the installed capacity of RES.

The aim was to compute the "replacement rates" of each of the conventional technologies (i.e. how much of them 1 GW of RES replaces) and the cost of integration of RES (i.e. how much more expensive the system with RES is, in comparison with the system without RES). This latter cost of integration was split into two additive parts:

(i) a non-competitiveness cost, representing the fact that RES are, from a LCOE point of view, more expensive than the average MWh generated by the conventional mix without RES;
(ii) an intermittency cost, representing the fact that RES need "back-up", i.e. installing RES implies that the optimal conventional mix that serves the residual load has more peaking units and less base units than the mix without RES.

The former part of the integration cost is highly uncertain as the learning curves of RES seem to remain quite steep (in particular, it seems that the cost of solar PV may continue to decrease); to the contrary the cost incurred by conventional generation due to the integration of RES seems less sensitive to hypotheses.

The long-term intermittency costs were computed in a simulation carried out over six countries as shown in the figure below, both on average (from 0 to the 2030 target) and marginally (for each MW of additional variable RES around the 2030 target). To understand the impact of the interconnections on intermittency costs, the study was carried out in two situations: isolated countries and interconnected area.

Figure 19 - Assessment of the "intermittency cost" of RES for six European countries with Micado

E. Appendix: Model descriptions – SIDES (RTE)

SIDES : *Simulator of Investment Decisions in the Electricity Sector*.

SIDES is a tool for long-term studies, the mix being driven by actors' decisions based on projects' profitability (or existing assets' unprofitability) assessment.

E.1 Objective

The aim is to assess the impact of new market rules on the evolution of the generation mix as driven by investment (or decommissioning) decisions. It could for instance be used to study how a capacity mechanism would change the mix, what CO_2 price would trigger investment in RES without support scheme, or the investors' willingness to develop demand response according to their type or a specific market design.

E.2 Functional description

SIDES belongs to the "system dynamics" class of models. It includes theoretical modelling of market players' behaviour (enabling to take risk aversion into account) and can be supplemented with any fit-for-modelling market rule. SD modelling is increasingly used to study the electricity sector and in particular to estimate benefits of capacity mechanisms.

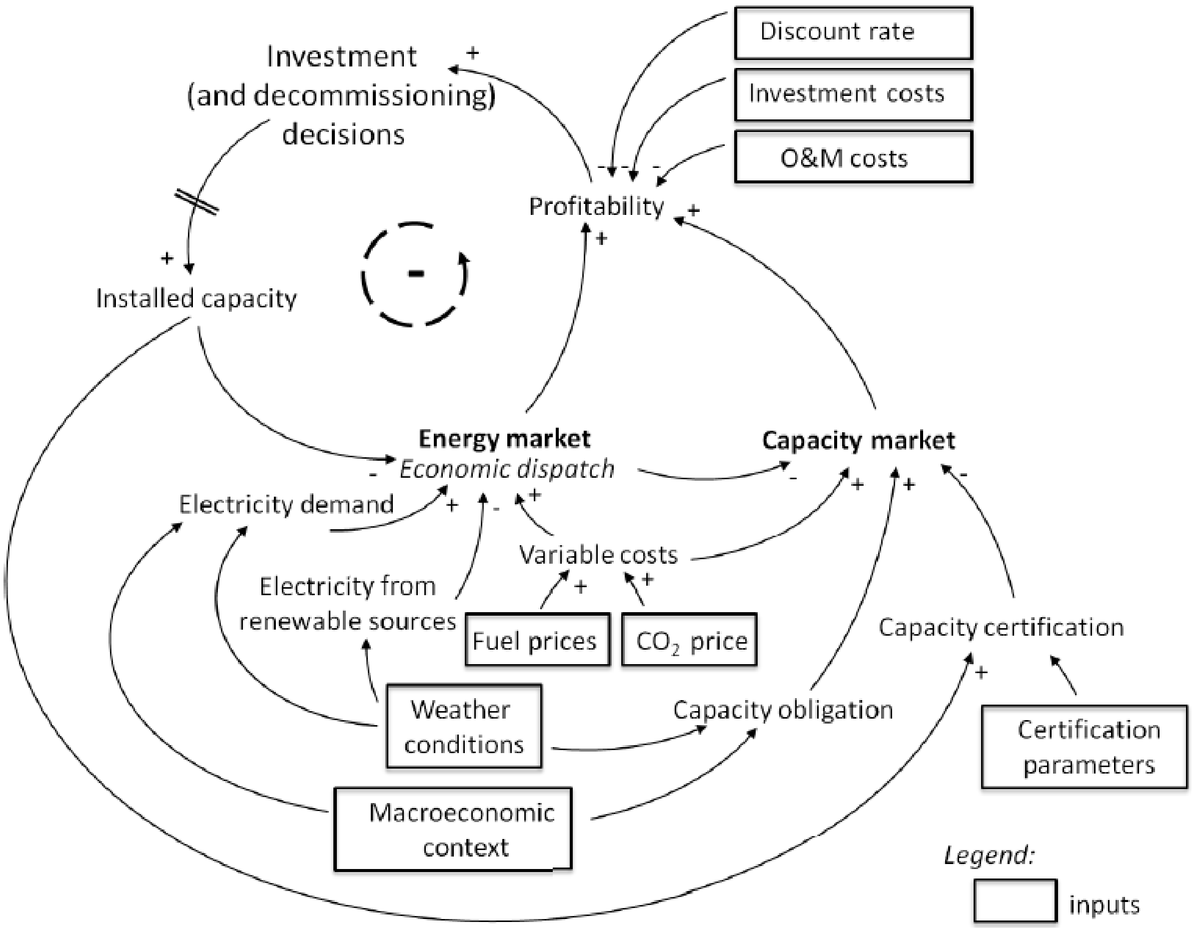


Figure 20 - SIDES functional model

The modelling of investment and decommissioning decision-making was built on the basis of an extensive literature review and consulting some key players in the French power sector. Two versions are available according to which KPI is used to assess the profitability of projects: the Net Present Value in one case, the Internal Rate of Return in the other.

This module relies on a single player taking decisions given its expected revenues from a simulated energy-only market, or of both energy and capacity markets according to the generation mix (the yearly dispatching assumes the conditions of a perfect competition). The player's anticipation is imperfect and limited in time (to 5 years), based on scenarios including three components:

- a meteorological one (demand and RES load factor time series);
- a macro-economic one (global level of demand);
- a political one (price of carbon, possible subsidy to RES).

Each year, many future scenarios are computed so as to obtain a distribution of future expenses and revenues for each generating unit within the player's decision-making scope. This agent is assumed to be technologically-neutral; in Market4RES studies, it is also assumed to be risk-neutral.

The current dispatching model assumes a single area without congestion constraints. Although the generation mix is limited to only a few types of technologies; hydroelectric units can be handled in a simplified way through monthly production time series.

E.3 Required data and hypotheses

The simulations require hypotheses on the initial generation mix, the available investment/mothballing/decommissioning options, the macroeconomic anticipations of players, demand and RES load factors scenarios.

E.3 Current limits and development perspectives within the timeframe of the project

Computing speed

Several hours are necessary to compute the mix' evolution over 30 years.

Level of detail of current modules

The energy market functioning is simplified to hourly merit order curves based on marginal costs. This implies that flexibility is not valued.

A module has been added to enable the simulation of the impact of a capacity mechanism; demand response can also be included (represented in a simplified way, essentially as a generation technology).

E.4 Examples of studies carried out in the past using this tool

SIDES was used to study the existence and level of a carbon price that would enable the development of RES (namely onshore wind) without support scheme.

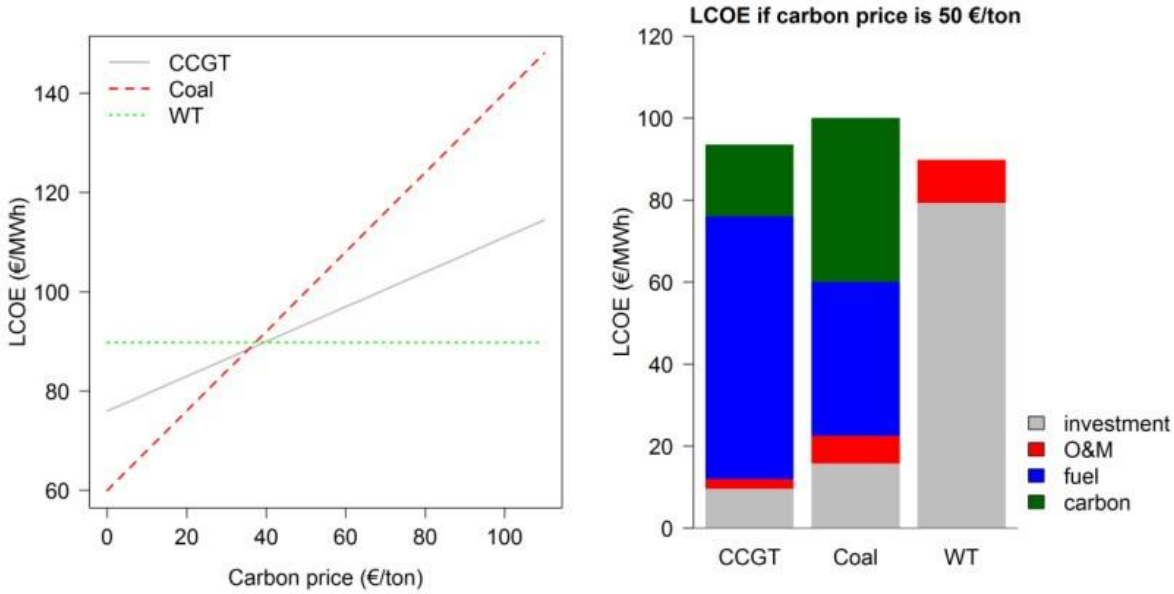
The total annual energy demand in the future depends on macroeconomic anticipations. The model considers 3 macroeconomic assumptions which correspond to an annual growth of 1%, an annual decrease of 1% and no evolution. Demand and wind load factor were represented through the use of 12 historic time-series (therefore in total, 36 scenarios were evaluated to take investment decisions).

The investment criterion was that a project had to show an internal rate of return on mean cash flow above 8 % (no risk aversion).

Decommissioning is considered if a plant is expected to be unprofitable (based on short-term cost only, not investment costs that are considered sunk cost at this stage) over the upcoming year (i.e. has a negative Estimated Net Profit at year $y + 1$). If it is the case, the net profit is also estimated over the 5 following years and, if it is also negative, the plant is decommissioned. Mothballing a power plant is considered if the short-term costs imply an unprofitable period and if the long-term costs imply a return to profitable days.

Investment can occur in one of these four technologies: CCGT, coal-fired plants, oil-fired combustion turbines and wind turbines.

The model is ran for CO_2 prices ranging from 0 to 100 €/ton. The comparative Levelized Costs of Electricity are represented on Figure 21.



Notes: Discounting rate is equal to 8%. Thermal load factor is 85%.

Figure 21 - Levelized costs of electricity as a function of carbon price
Notes: Discounting rate is equal to 8%. Thermal load factor is 85%.

Interestingly, whereas wind turbines have a lower LCOE than both CCGT and coal-fired units for a CO_2 price above roughly 40 €/ton, a significant development of wind generation is not to be expected before the carbon price rises to 70 €/ton, as shown on Figure 22.

It should also be noted that if nuclear power is available for investment, the CO_2 price needed to trigger investment in wind is either very much higher or does not exist.

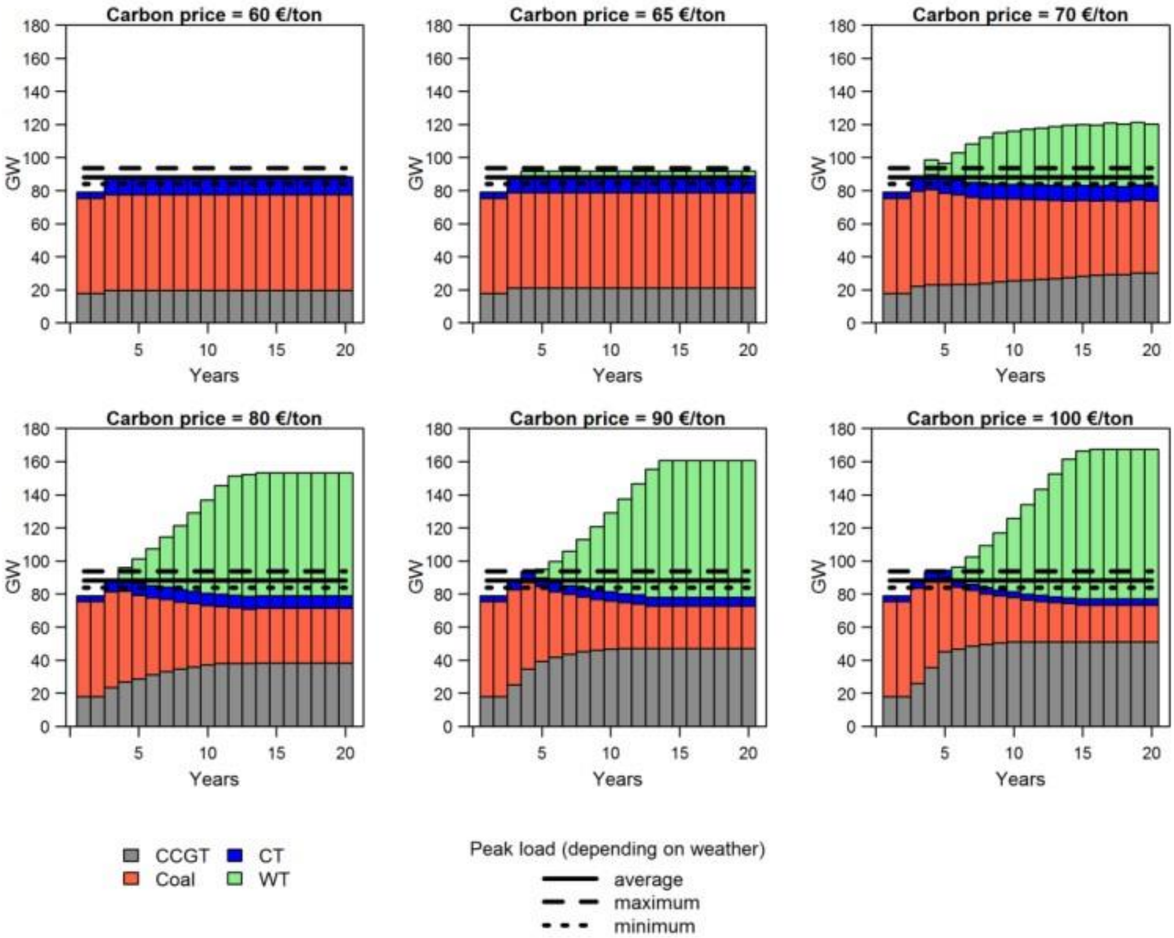


Figure 22 - Installed generation mix over time for different carbon prices

F. Appendix: Model descriptions – EMPS (SINTEF)

EMPS: EFI's Multi-area Power-market Simulator

EMPS is a unit-commitment tool based on centralized optimization, with long-term optimal mix capabilities (that includes interconnections in long-term optimization).

F.1 Objective

EMPS is a long-term operation optimisation model, specifically developed for hydro-thermal power systems. It calculates the optimal dispatch of hydro and thermal power plants, taking into account the uncertainty of climate variables and determining the optimal strategy for handling hydro reservoirs.

In addition the newly developed investment module uses the results of the operation optimisation to identify the profitability of various assets in order to compute the optimal generation and transmission capacities in the power system.

F.2 Functional description

There is a significant difference between thermal-based and hydro-based power systems. While the thermal ones are capacity constrained, hydro power systems are energy constrained. For hydropower this means, operating a hydro power plant has negligible marginal cost, while there is only a limited amount of water stored in reservoirs. In order to determine the optimal strategy for using the water stored in the reservoirs, the opportunity cost, or water value has to be calculated. This water value calculation is one of the main objectives in EMPS.

Operation optimisation model

In general the operation optimisation model EMPS consists of two parts:

- Strategy part
- Simulation part

In the strategy part the water values are calculated based on stochastic dynamic programming. Within the calculation the stochasticity of climate variables, such as the inflow to hydro reservoirs, wind power production and temperature are taken into account. The results are water values, representing the marginal value of storing the water in the reservoir. The water value is used as the production cost for the according hydropower plants.

In the second part of the model the power system is simulated, based on a LP-model. The simulation can have down to hourly resolution, while several climatic years (75 as of today) are simulated. The simulation can include start-up costs for thermal units as well as reserve requirements for the various countries. Moreover, the optimal dispatch for hydropower generation in detailed water courses is determined. The result is the optimal system dispatch (including generation and transmission) for all the hours within all the climatic years. Furthermore, area prices for all the defined areas are calculated.

Investment analysis

The investment module uses the results from the system simulations in order to determine the optimal generation portfolio as well as transmission expansion for a power system. The investment analysis is implemented as an iterative process including the steps system optimisation and a profit analysis of investment objects (assets).

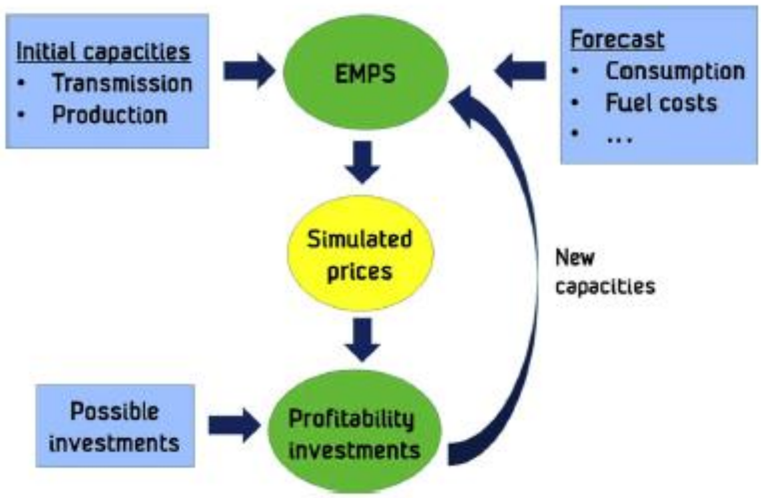


Figure 23 - Schematic of the investment algorithm

At first, an optimisation for the initial power system is executed. Then the profits of various assets (power plants and transmission lines) are calculated, based on the dispatch and prices of the system simulation. In case the profit of an asset is higher than its investment cost, the capacity of the asset is increased. This profit analysis is done for all assets. After the capacity of all assets is adjusted according to the previous rule an operation optimisation given the new capacities is run. With the new results the profit analysis is reapplied. However, in case now the profit is less than the investment costs, some of the newly invested capacity is withdrawn. The investment algorithm converges when the profits equal the investment costs, meaning that the capacities of the assets are not changed any longer.

F.3 Required data and hypotheses

The power system which shall be simulated / analysed has to be defined by a dataset. The power system can be divided into areas, which are connected by transmission lines. To that a transport model is used including quadratic losses. The dataset includes generation capacities, transmission capacities and the demand that can be defined for each area. Furthermore, hydro water courses can be defined for the hydro power installed in the areas. As EMPS is a long-term optimisation model, time series for inflow, wind power production, solar power production, temperature and demand are required. Moreover, the marginal production costs of the power plants need to be specified, including the potential of prices for demand (demand response).

When using the investment module, investment costs as well as maintenance cost for all the assets, which shall be included in the investment analysis have to be defined.

F.4 Limits and development perspectives

Due to the number climatic years (scenarios) which are used throughout the system optimisation, there has to be the model details and the temporal resolution of the simulations. Specifically, when running the investment analysis includes running a large number of system optimisations. Thus, simplifications have to be done when specifying the dataset for the power system.

F.5 Examples of past studies carried out using this tool

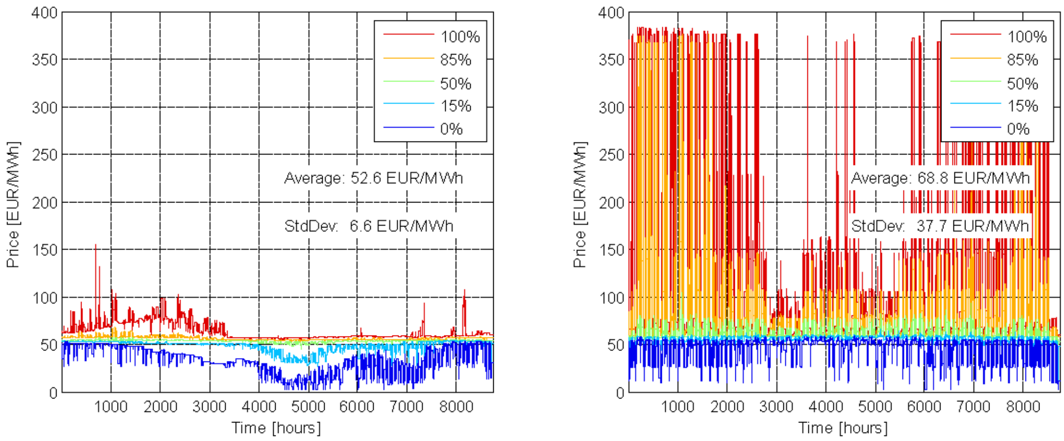
The long-term operation optimisation tool EMPS is in everyday use at hydro producers, TSOs, consulting companies as well as regulators throughout Scandinavia.

EMPS, including the investment analysis was used in the EU-FP7 project TWENTIES to analyse the impact of large amounts of offshore wind power production in the North Sea and the potential of the Norwegian hydropower system to balance this wind power resources.

Nordic hydro power has ideal characteristics for providing balancing energy and increases the production flexibility in the power system. In order to effectively utilise this production flexibility, a sufficient amount of transmission capacity has to be available between the Nordic area and Northern Europe. This report determines the possibilities of flexible hydro power production in the Nordic area to support the European power system under the influence of large scale WPP for the years 2020 and 2030.

The analysis includes three interrelated simulation steps. The first step focuses on the strategic use of hydro energy in the day-ahead market. The analysis considers the detailed modelling of water courses and hydro production in the Nordic region. In the second step, grid expansion scenarios are evaluated based on the day-ahead market results, considering both - offshore and onshore grid connections. Cost-benefit analyses for selected transmission expansion scenarios are carried out, taking operational cost savings and investment costs of newly built transmission capacity into account. Investments in transmission capacity result in a better utilisation of hydro power, wind and other renewables in the system. Finally, the results of the two previous simulation steps are verified, based upon detailed flow-based power market simulations using a detailed grid model for the whole European system.

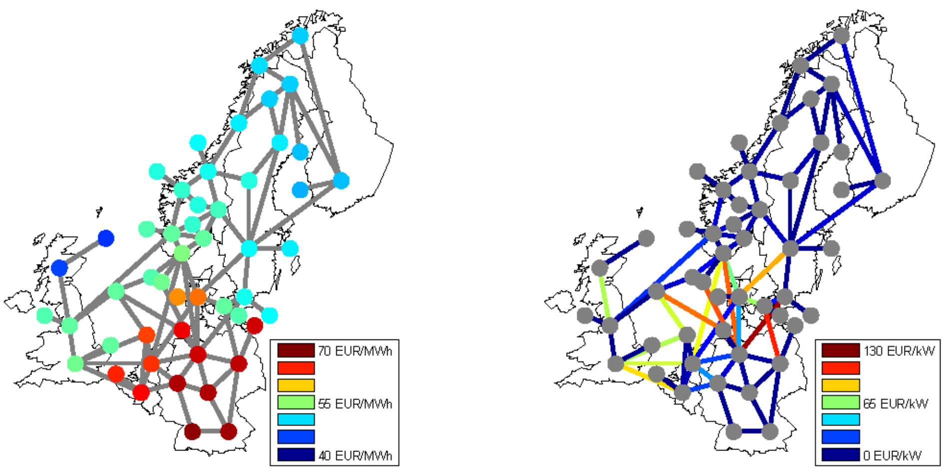
EMPS was used for the first two steps. Figure 24 shows the resulting prices for Norway and Germany, providing the potential for investments in transmission capacity. The figure shows the percentiles for the 75 different climatic years, indicating a short-term as well as long-term variability of prices, whereas there are rather different characteristics in the hydro-based Norwegian system and the thermal-based German power system.



a) Norway *b) Germany*

Figure 24 - Percentiles of area prices in the 2030 scenario

Looking on the geographic distribution of prices in Figure 24 a) shows a rather significant gradient in prices from North to South resulting in a significant profitability of transmission lines (shown in Figure 24 b)). These high profits resulted in expansion on the transmission corridor from Sweden, across Germany and Netherlands to England and Scotland.



a) Area prices *b) Transmission line profitability*

Figure 25: Average area prices and transmission line profitability throughout the simulated power system