D4.1 Specifications of the most adequate options for flexibility markets and RES support schemes to be studied in a cross-border context

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May, 2015

Version 1.1

Dissemination level: Public

Agreement n.:	IEE/13/593/SI2.674874
Duration	April 2014 – September 2016
Co-ordinator:	SINTEF Energi AS
Supported by:	Co-funded by the Intelligent Energy Europe Programme of the European Union

DOCUMENT INFORMATION

Deliverable number	D4.1
Deliverable name	Specifications of the most adequate options for flexibility markets and RES support schemes to be studied in a cross-border context
Reviewed by	Andrei Morch, Eline Hegvik, SINTEF Consortium
Date	May 2015
Work Package and Task	WP4, T4.1
Lead Beneficiary for this Deliverable	TECHNOFI

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VERSION CONTROL

Version	Date	Author	Description of Changes
v1.0	[2015-05-05]	TECHNOFI	Initial draft
V1.1	[2015-05-13]	TECHNOFI	Comments from RTE, SINTEF and EEG incorporated
V1.2	[2015-05-19]	TECHNOFI	Executive summary added

EXECUTIVE SUMMARY

The present D4.1 report provides the detailed specifications of the studies that will be performed within Market4RES WP4 with the OPTIMATE prototype simulation platform to analyse and compare selected short-term electricity market architecture options based on quantitative indicators relying on the three pillars of the European energy policy (economic efficiency, Security of Supply, Sustainability).

In a nutshell the methodology that will be used to compare and market architecture options is a sequence of four steps: the *Inputs* of the process, which consist in the elaboration of representative scenarios[1] and the choice of a range of market design options to be studied; the *Core*, namely the use of the OPTIMATE tool to perform simulations; the *Outputs*, i.e. the analysis of the results of the simulations based on standard quantified indicators; the *Scope*, namely the analysis of the impacts of the OPTIMATE modelling assumptions on the results as well as other qualitative issues not measured by the simulator. The implementation of this methodology will lead on to first policy recommendations. The present document is focused on the first step of this methodology (Inputs) and its related tasks. It also provides insights about the indicators that will be studied for each set of scenarios and market architecture options.

Due to the prototype nature of the tool, Market4RES WP4 studies will focus on the Day-Ahead processes. In this framework, two main studies will be performed:

- The impacts on the day-ahead market outcomes of different RES support schemes, including Feed-in-Tariffs and Price Premium, will be assessed;
- The impacts on the day-ahead market outcomes of large-scale deployment of demand flexibility will be assessed.

The above-mentioned short–term market architectures will be tested under three representative scenarios, with different renewable energy penetration levels:

- 2013 scenario: This reference scenario mimics the current situation, notably in terms of renewable penetration.
- 2020 standard scenario: This scenario represents what can be reasonably expected at 2020, based on official publications.
- 2020 RES+ scenario: This alternative 2020 scenario represents a more optimistic (contrasted but still realistic) situation in terms of renewable penetration.

For each of the three scenarios, a default OPTIMATE case will be run, which will provide a starting point from which variational studies, covering the two above-mentioned types of market architecture options, will be performed. In total, nine OPTIMATE cases will be run, covering the three scenarios and the two types of market architecture options. Each case will be run over selected

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[1]Scenarios are sets of coherent data describing the initial state of the European system and consistent with a reference equilibrium of the market

periods of the year covering different seasons (for instance one winter month, one summer month and one mid-season month). Hence, in total, OPTIMATE simulations will be run over around twenty-seven case variants.

The geographical scope foreseen for the Market4RES WP4 studies covers the following countries: Austria, Belgium, France, Germany, Great-Britain, Italy, Luxembourg, Netherlands, Portugal, Spain and Switzerland, which covers 76% of the total consumption of the European Union and Switzerland.

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LIST OF ABBREVIATIONS

ACER	Agency for the Cooperation of Energy Regulators
ANTARES	A New Tool for Adequacy Reporting of Electric Systems
ATC	Available Transfer Capacity
CEER	Council of European Energy Regulators
CHP	Combined Heat and Power
CSP	Concentrated Solar Power
EC	European Commission
ENTSO-E	European Network of Transmission System Operators for Electricity
EEX	European Energy Exchange
ESTELA	European Solar Thermal Electricity Association
FiT	Feed-in-Tariff
IEA	International Energy Agency
LBD	"learning-by-doing"
NREAPs	National Renewable Energy Action Plans
NTC	Net Transmission Capacity
PP	Price Premium
PTDF	Power Transfer Distribution Factor
PV	Photovoltaic
RES	Renewable Energy Sources
SO&AF	Scenario Outlook and Adequacy Forecast
SS	Support Schemes
TSO	Transmission System Operator
TYNDP	Ten-Year Network Development Plan
WP	Work Package

1 INTRODUCTION

1.1 Role of WP4 in the Market4RES project

The Work Package 4 (WP4) of the Market4RES project aims to quantify the impacts of different market architecture options, assuming as an input the generation fleet expected for 2020. It therefore lies in the first Work Stream of the project[2].

The tool used to quantify the impacts of market architecture options is the OPTIMATE prototype simulation platform. This prototype tool was developed during an FP7 project[3] which aimed at developing a numerical test platform to analyse and to validate new market designs which may allow integrating massive flexible generation dispersed in several regional power markets[4].

1.2 Purpose of this report

The purpose of the present report D4.1 is to provide detailed specifications of the studies that will be performed within Market4RES WP4. This document will be presented at an "expert workshop" organized on the 22nd of May, 2015 in Brussels. Experts will be invited to provide their views upon these specifications both during the workshop and through a written public consultation. These specifications may evolve in time, not only to take into account the above-mentioned experts' feedback, but also because when performing the OPTIMATE studies some of the parameters may need to be fine-tuned.

The preliminary results of the studies will be presented in an intermediate report that will be discussed at a stakeholder event to be organized in Nice during autumn 2015. A final report will be delivered in spring 2016.

1.3 Structure of this report

This report is structured as follows:

In **Chapter 2**, the methodology and tools used to quantify and compare the impacts of different market architecture options are presented, as well as the main modelling assumptions of the prototype OPTIMATE tool (section 2.1). This methodology consists of four main steps:

- Inputs of the process are described in section 2.2. They consist of scenarios (sets of coherent data describing the initial state of the European system and consistent with a reference equilibrium of the market) and a range of market architecture options.

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[2] For more information see http://market4res.eu/.

[3] Grant Agreement 239456.

[4] More information can be found on the OPTIMATE website http://optimate-platform.eu/.

- The OPTIMATE tool then simulates the sequence of actions conducted by market players (section 2.3), from day-ahead to real-time**.** Due to the prototype nature of the tool, only the day-ahead module is fully implemented. The studies performed within Market4RES will therefore be focused on the day-ahead markets.
- Once the core simulation is over, outputs are delivered and studied using standard quantitative indicators addressing the three pillars of the EU energy policy (section 2.4).
- Finally, the scope of the analysis is taken into account, namely the impacts of OPTIMATE modelling assumptions on the results as well as qualitative issues not measured by the simulator (section 2.5).

This will lead on to first policy recommendations based on the implementation of the methodology described.

In **Chapter 3**, the market architecture options to be studied are presented. Two main studies will be performed (section 3.1):

- The impacts on the day-ahead market outcomes of different RES support schemes, including Feed-in-Tariffs and Price Premium, will be assessed.
- The impacts on the day-ahead market outcomes of large-scale deployment of demand flexibility will be assessed.

Common indicators to be analysed for the two studies as well as specific indicators for each study are presented in section 3.2.

In **Chapter 4**, three scenarios are described. They will allow performing the two above-mentioned studies in different contexts, notably with different renewable energy penetration levels. The three scenarios are qualitatively described in section 4.1:

- 2013 scenario: This reference scenario corresponds to the current situation, notably in terms of renewable penetration.
- 2020 standard scenario: This scenario represents what can be reasonably expected at 2020, based on official publications.
- 2020 RES+ scenario: This alternative 2020 scenario represents a more optimistic (contrasted but still realistic) situation in terms of renewable penetration.

The hypotheses and data related to each scenario are described in details in sections 4.2 to 4.5. They include in particular assumptions regarding:

- The geographical scope,
- The simulation period,
- The maximum load within each country,
- The renewable installed capacities,

- The thermal installed capacities,
- The cross-border capacities, and
- Fuel and CO_2 prices.

2 METHODOLOGY AND TOOLS TO QUANTIFY AND COMPARE THE IMPACTS OF DIFFERENT MARKET ARCHITECTURE OPTIONS

2.1 Overview of the methodology and main modelling hypotheses

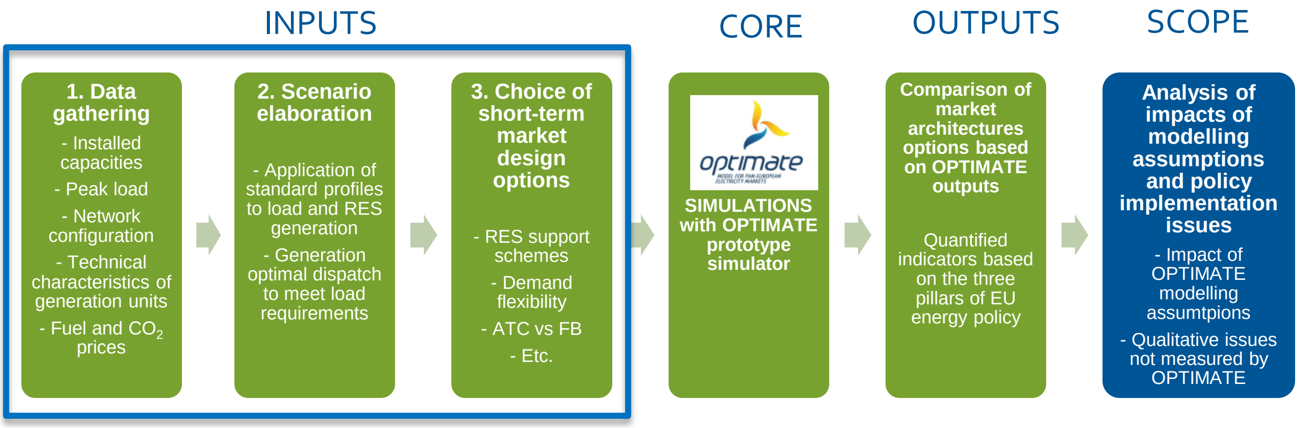
2.1.1 OPTIMATE methodology to compare market architecture options

OPTIMATE is a numerical simulation platform[5] designed to compare wholesale short-term electricity market architecture options integrating massive intermittent energy in Europe, complying with the three EU energy pillars (economic efficiency, climate policy and security of supply). The OPTIMATE prototype platform was developed during an EC-funded FP7 project (2009-2012[6]) under the technical direction of RTE.

The OPTIMATE simulator has been designed rather to give trends in order to ease discussions among electricity stakeholders on system and market design updates, than to lead to absolute results. Consequently, variational studies are conducted: a reference set of designs will be set, leading to the comparison of results based on selected indicators.

In a nutshell, the methodology to compare market architecture options is the sequence of four elements: Inputs, Core, Outputs and Scope.

Figure 1. *Methodology to compare electricity market architectures*



The present document D4.1 is focused on the first step of this methodology (INPUTS) and its related tasks. It also provides insights about the indicators that will be studied for each set of scenarios and market architecture options.

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5 http://www.optimate-platform.eu/

6 "An Open Platform to Test Integration in new MArkeT designs of massive intermittent Energy sources dispersed in several regional power markets" (contract no:239456),

1. INPUTS: First of all, **scenarios** are generated. A scenario gathers a set of coherent data describing the initial state of the European system and consistent with a reference equilibrium of the market. Then, a range of **market architecture options** is set.
2. CORE: The OPTIMATE core then simulates the sequence of actions conducted by market players. It is made of four main processes: Day-Ahead, Intra-Day, Real-Time (including imbalance settlements) and the (feedback) learning-by-doing loop. Each process is made of modules conducting a specific task.
3. OUTPUTS: Once the core simulation is over, outputs are delivered and studied using standard quantified indicators relying on the three pillars of the EU energy policy.
4. SCOPE: Finally the scope of the analysis is taken into account, namely the impacts of OPTIMATE modelling assumptions on the results as well as other qualitative issues not measured by the OPTIMATE simulator.

2.1.2 Main modelling assumptions of the OPTIMATE prototype simulator

As in all models and simulators, real operations and market behaviours are so complex that assumptions have to be made. Understanding these assumptions is important when interpreting the results of the studies performed with the OPTIMATE simulator.

The main modelling assumptions taken in the OPTIMATE simulator are the following [1]:

- **(almost) Perfect competition:** all market players try to maximise their profits based on price forecast and generation scheduling. They behave as price-takers and do not try to influence the market price through their potentially predominant position on the market. However, at day-ahead they do anticipate on intraday liquidity.[7]
- **Market players behave considering their portfolio**. They are allowed to re-dispatch their day-ahead delivery requirements according to unit commitment considerations of their whole portfolio and also based on their expectations on Intraday and balancing prices.
- **Forward contracts are not considered**. All trading and dispatch takes place at day-ahead, intraday and real-time.
- **The shortest time granularity** is 30 minutes.
- **Network limits are never trespassed at real-time.** In case of problems, load or generation curtailment is undertaken.
- **Electric network nodes are aggregated per clusters**. It is assumed that commercial exchanges within a market area function without internal network constraints. It is possible to define several clusters within a market area as required.

[7] See chapter 3.2.2. for more details

- **Thermal generation is modelled with minimum and maximum load**, start-up costs, gradients, minimum run-time and off-time, planned outage possibility, probabilistic risk of sudden breakdowns.
- **Load shedding** is (next to forced curtailment in case of network restrictions) also possible voluntarily in case of high market prices. A given percentage can be shed at a defined price per cluster.
- **Forecast errors** decrease with time-to-go. Usually, the closer to real-time, the lower the forecast error for each technology (i.e. intermittent RES, such as wind energy and solar, and load).
- **TSOs are jointly responsible for congestion management**, with equal allocation of costs and revenues. TSOs can be assigned different levels of risk aversion which will influence their reserve provisions. Each TSO is also responsible for balancing its own control block.

In addition to the above mentioned assumptions, the simulator version OPTIMATE 1.10 (used for the Market4RES studies) has the following limitations, which are related to the prototype stage of the simulator:

- **Only the day-ahead market process will be taken into consideration in the simulations;**
- Market design options are exactly the same in all market zones, i.e., market design is fully harmonised, with the exception of RES support schemes and demand flexibility level;
- The average reference water value, which determines the marginal production cost for hydro power plants, is set exogenously (using the expected marginal production cost[8]) and the simulator only updates this value.

2.2 Inputs to simulations with OPTIMATE prototype simulator

The inputs to OPTIMATE simulations are the **scenarios** and the **market architectures**.

2.2.1 Scenarios elaboration for OPTIMATE

A scenario gathers assumptions on the state of the European electricity system and is consistent with a reference equilibrium of the market. It refers to the market players and their assets.

A scenario includes both:

- Raw data, such as:
  - Thermal (nuclear, coal, gas, oil) and RES (wind, solar, hydro dams, must-run[9]) installed capacities at cluster level;

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[8] Issued from the reference market equilibrium, see next page.

[9] Must-run includes run of river, CHP and biomass units.

  - Peak load at cluster level;
  - Load profiles and RES generation profiles (wind, PV, run of river, thermal must-run);
  - Fossil fuel and CO_2 prices;
  - Cross-border capacities at country level;
  - Characteristics of underlying power network (PTDF at cluster level).
- And configurations for more sophisticated parameters, such as:
  - Thermal generation technical parameters (start-up cost, variable cost, flexibility parameters, etc.);
  - Load flexibility parameters (modelled as load shedding: capacity of load to be voluntarily shed above a certain price);
  - Market operators' portfolio composition: repartition of units among portfolios within a market area.

As OPTIMATE simulates short-term processes, market players are assumed to have a rough expectation about how these processes will take place. Hence, they have access to forecasts, which usually improve when getting closer to real-time. Such forecasts are derived from a **reference market equilibrium**[10]. In other words, OPTIMATE generation, exchange and load initialisation are derived from a reference optimum and forecast time series. These forecasts will help market players assess the situation they expect will happen in order to improve their action.

The reference equilibrium of the whole electricity system, including power levels (generation, consumption), costs, prices, and exchanges, is built based on a multi-area unit-commitment process, which is performed, within Market4RES, using RTE's proprietary tool ANTARES[11]. ANTARES is an optimal dispatch software program performing a least cost optimization, which minimizes the costs of supplying the forecast load, given a certain cross-border capacity. The outputs obtained from ANTARES are the expected power plant dispatch (also called programs), expected marginal costs, expected (reference) prices and expected cross-border exchanges that are part of the OPTIMATE simulation inputs. In terms of network, OPTIMATE uses an aggregated electricity network, which is described using clusters (i.e. aggregation of electric nodes) in order to reduce the computation time of the simulator (Figure 2).

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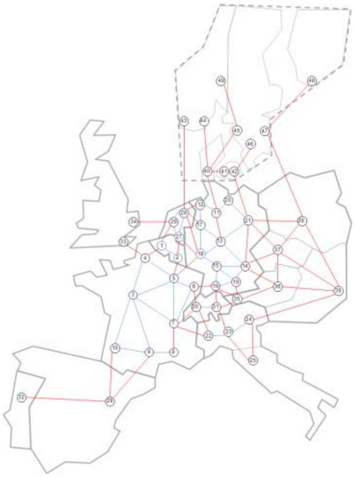
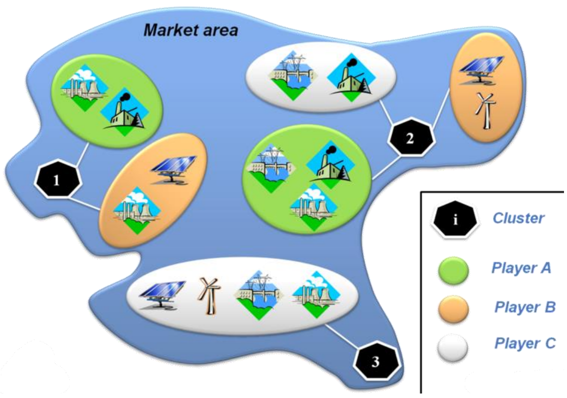
10 In OPTIMATE, reference equilibrium is everything that happens before the Day-Ahead chain.
11 ANTARES: A New Tool for Adequacy Reporting of Electric Systems

Figure 2. *Aggregated European electricity transmission network*



Both generation and load units are described as an input. Their geographic (cluster) location is set, as well as their ownership (portfolio) and technical characteristics and portfolios configuration. In OPTIMATE simulator, a unit is a physical entity which generates or consumes electricity. It is geographically located inside one and only one cluster, and belongs to one and only one portfolio. A portfolio is an entity which both owns and operates a set of generation units.[12]

Figure 3. *Example of portfolio configuration*



2.2.2 Choice of short-term market architectures

In OPTIMATE vocabulary, an ***architecture*** describes the way the players interact with each other. One architecture comprises the **market design**, the **TSOs' behaviour and coordination**, and the **capacity model.**

[12] A portfolio may currently own either generation or consumption units, but not both (in order to force all energy exchanges to happen within the market).

Market4RES studies will focus on the day-ahead module using version V1.10 of the prototype simulator (cf. section 2.1.2).

The day-ahead module mimics the functioning of TSO's actions (such as capacity calculation or reserve requirements), market players' behaviour (such as bids and offers construction), and power exchanges actions (such as capacity allocation, i.e. market coupling with either Available Transmission Capacity (ATC) or Flow-Based parameters). A change in the day-ahead market closure time can also be simulated.

Market designs

The following market design options are available for the day-ahead module:

- **Bidding type:** whether the unit commitment is made using portfolios (**portfolio bidding**) or individual units (**unit bidding);**
- **Day-ahead price minimum/maximum**: minimum/maximum price authorized on the day-ahead market;
- **Day-ahead capacity model**: cross-border management scheme used by the day-ahead market coupling (ATC, zonal Flow-Based);
- **Day-ahead gate closure time**: 12h or 19h;
- **RES support schemes**:
    - Feed-in-Tariffs: fixed regulated prices per MWh generated, whatever the electricity market price with priority dispatch ;
    - Price premiums : RES producers receive the electricity market price and a fixed regulated premium over the spot electricity price with no priority dispatch;
    - In OPTIMATE the user sets the percentage of generation sold under premium prices, i.e. the relative part of the overall variable generation which is under price premium support (rather than feed-in tariff);
- **Demand flexibility levels**: At each hour, a certain percentage of the load is willing to be shed if the day-ahead market price is above a certain price (€/MWh).

TSOs' behaviour

The following TSOs parameters can be set by the user:

- **Risk aversion on cross-border capacity**: risk level taken by the TSO when computing the cross-border capacities and maximum commercial flows (more risk adverseness means less available capacity);
- **Market border day-ahead NTC bounds from seasonal NTC**: bounds, relative to the seasonal NTC, within which the TSO is allowed to set the day-ahead NTC;

- **ENTSO-E regulatory reserves level**: deterministic margin power level set by ENTSO-E that the TSO must reserve;
- **TSO reserve risk coefficient**: risk level taken by the TSO when computing its probabilistic margin (more risk means less margin).

Market players

- **Anticipation on intraday liquidity** (in % integer from 0 to 100): initial anticipated intraday market share used by the portfolios to compute the power level that they reserve for intraday exchanges.

2.3 OPTIMATE prototype simulator modular structure

2.3.1 OPTIMATE modules

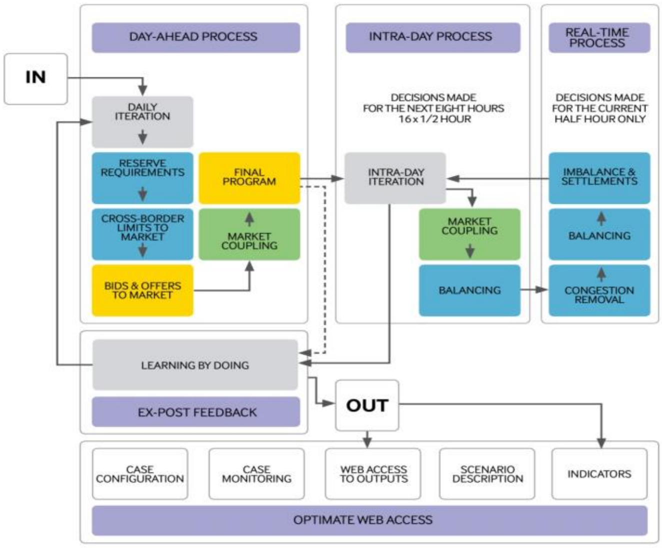
OPTIMATE has a modular structure, each module mimicking one segment of the electricity market, from day-ahead to real-time:

- The **Day-Ahead chain** models processes taking place the day before electricity delivery;
- The **Intra-Day chain** models tasks conducted between 8 hours and half-hour before electricity delivery. It models successive half-hourly actions by TSOs and market players; these actions take place several times each day[13];
- The **Real-Time chain** models TSOs processes taking place less than half an hour before delivery;
- At last, the ex-post "**learning-by-doing" (LBD) module** allows market players and TSOs to improve the quality of their forecasts based on historical learning, i.e. by assessing the average offset between raw forecasts and realized data. The LBD process mimics the fact that market players do have memory even in a context of almost perfect competition. This means that market players can use market outputs from previous days to improve their future price expectations and adjust their bidding.

Figure 4 below illustrates the general modules processing in OPTIMATE simulator.

[13] The time granularity of ID actions is user-defined.

Figure 4. ***OPTIMATE simulator modular structure***



2.3.2 Status of the development of each module

The current status of the prototype simulator (V1.9), which will be used for the Market4RES studies is as follows:

- **Day-ahead process:** it is fully implemented;
- **Real-time process:** it is partially implemented. TSOs balancing activities can be simulated, but alternative balancing market designs[14] cannot be tested yet;
- **Intraday process:** it is currently under development.

2.4 Comparison of market architecture options based on OPTIMATE outputs

The raw outputs (generation unit's production hour by hour, detailed market bids and offers, etc.) are complemented by a set of indicators covering the three pillars of the EU energy policy:

- **Economic Efficiency indicators**, which are used to show the impacts of market architecture changes on economic efficiency and include: social welfare, electricity prices, generation costs;
- **Sustainability indicators**, which are used to show how a change in market architecture favors or disfavors the deployment of renewables; participates in reducing CO_2 emissions and favours or not less polluting power generation technologies. They include RES-E share and CO_2 output;

[14] Such as pay-as-bid or marginal pricing for reserve procurement for balancing services,.

- **Security of supply indicators**, which are used to show whether an improved welfare from a change in market design comes at a price of a reduction in security of supply. These indicators include margin constitution, load curtailment, etc.

The redistributive effects among players and geographic areas can also be measured (in terms of social welfare, consumer surplus, generator surplus, congestion revenue, etc.) so as to highlight possible issues when implementing a new architecture. In OPTIMATE, the welfare indicators are defined as follows [1]:

- The **day-ahead generation surplus** is calculated as the aggregate monetary value of the difference between marginal cost and day-ahead market price outcome for each separate generation units in each hour and for each market area.
- The **day-ahead consumer surplus** is for 95% of the load calculated as the aggregate monetary value of the difference between the Value Of Lost Load (VOLL), also referred to as the maximum willingness to pay of consumers in scarcity, and the day-ahead market price outcome in each hour and for each market area. The remaining 5% are valued at 100 €/MWh.
- The **day-ahead congestion revenue** is the sum of all energy flows through interconnectors multiplied with the respective day-ahead price differences between the adjacent markets in each hour.

2.5 Analysis of the impacts of modelling assumptions and policy implementation issues

The impact of OPTIMATE internal modelling assumptions (described in section 2.1) and the limitations due to the prototype stage of the simulator should be considered when interpreting the results of the studies performed with the simulator.

Finally, the analysis of qualitative issues, not measured by the OPTIMATE simulator, which could impact the results (such as the interactions among different markets, market players' strategic behaviour) as well as different barriers to the implementation of a recommended market design should be considered when taking a decision on its possible implementation.

3 DAY-AHEAD MARKET ARCHITECTURE OPTIONS TO BE STUDIED

Two main aspects of the day-ahead markets are proposed to be the focus of the OPTIMATE studies performed within Market4RES:

- RES support schemes,
- Demand flexibility.

For each of these two study fields,

- The main question to be analyzed by each sub-study is introduced;
- Several options consistent with the 2020 horizon are proposed to be studied thanks to the OPTIMATE simulator;
- A first list of indicators which will be used for the analysis of the results is presented[15].

The results of the proposed studies will be presented in the forthcoming Market4RES deliverables D4.2 and D4.3.

3.1 Proposed studies and options to be compared

3.1.1 Comparison of RES support schemes

The European Commission's new environmental and energy State Aid Guidelines **[2]** aim at better integrating renewables into the internal electricity market, through the gradual introduction of market based mechanisms, reflecting the increasing maturity of RES technologies. Hence, the guidelines envisage:

- the gradual move from Feed-in-Tariffs to Feed-in Premium scheme;
- exposing RES generators to standard balancing responsibilities;
- measures to be put in place in order to ensure that RES producers have no incentive to generate electricity under negative prices.

Therefore, the purpose of this study field is to assess *how the gradual move from Feed-in-Tariffs to Feed-in Premium schemes impact day-ahead market outcomes*.

The options proposed to be studied are the following:

- Feed-in-Tariff (FiT), which guarantees a fixed regulated price per unit of electricity generated (MWh) fed into the grid over a specific time period (whatever the electricity market price) and encompassing a legal requirement that subsidised energy has priority access to the network (priority dispatch). Hence, under the FiT scheme, the remuneration of RES producers is always guaranteed independent from the market price in the OPTIMATE model. This means

[15] **These indicators will progressively be refined during the project's lifetime and made consistent with the KPIs to be elaborated by Market4RES WP3.**

that RES production is integrated as a "must-run". Since within OPTIMATE the whole generation is offered to the day-ahead market, this is modelled as if RES producers submit bids at the minimum authorised price (i.e. - 3000 €/MWh). FiT is the support scheme currently applied in most EU countries, both for wind and for PV. Since in most cases a change in support schemes cannot be retroactive, FiT will continue to be applied to existing RES units for years even if price premium is introduced for new units.

- Price Premium (PP), where RES producers receive the electricity market price and a fixed regulated premium (extra bonus) over the spot electricity market price for the feed-in of renewable energy. They have no priority dispatch. Under this scheme, RES producers have positive income as long as the market price is not more negative than the premium amount. As explained above, price premium is the target set by the new EC State Aid Guidelines.
- No support schemes: studying the impacts of this fictitious[16] option will allow isolating the impacts of RES support schemes on market outcomes. In OPTIMATE, this option is modelled by a price premium at zero applied to 100% of the RES production.

3.1.2 Evaluation of the impacts of the deployment of demand flexibility

Demand response is one of the major demand activation measures: it consists in reducing or activating the load level of consumers for some time when the price of electricity reaches a high/low enough level. This reduction/activation can either be directly controlled by the so-called "demand managers" or be left to consumers' decisions, provided that they are informed about the actual price of electricity.

In the OPTIMATE simulator, as a default option, demand is considered inelastic, i.e. voluntary load shedding is not possible. However, demand can be set to have a flexible part (relative to the overall schedule), which can be voluntarily shed when price signals are adequate. For example, when prices are very high, part of the electricity consumption may lead to economic losses, and load units may prefer to decrease their consumption.[17]

Hence, the purpose of this study field is to assess *how demand flexibility would impact the day-ahead market outcomes.*

The following options are proposed to be studied:

- Low load flexibility: as default, demand flexibility is 0%, so that no voluntary load shedding is possible;

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[16] This is a purely theoretical case since at least existing renewable plants will be under FiT for several years.
[17] By contrast, as a last resort means of balancing the system, involuntary load shedding, due to scarcity at maximum prices, is applied in the OPTIMATE model whatever the level of load flexibility chosen by the user.

- High load flexibility: in this case, a certain percentage of the overall load in each market area is willing to shed if the day-ahead market price is above a certain price. The exact values of these parameters will be determined when performing the studies.

3.2 Indicators to be analysed to evaluate the impacts of the studied options

3.2.1 Common indicators to all studies

The following standard indicators are proposed to be analysed in priority for the two studies. These indicators will be analysed over the whole period considered (year) and may be differentiated by month or season if relevant.

Table 1. ***Standard indicators to be analysed for all studies***

Families of indicators	Detailed indicators	Purpose
Generation mix (per country)	Generation from renewable sources	The impact of market architecture options on the generation mix is the very first point to analyse: a change in the generation mix is indeed the main driver to other indicators, such as market prices, CO_2 emissions, etc.
	Generation from nuclear	
	Generation from coal	
	Generation from gas	
	Generation from oil	
Costs and profits, welfare (per country)	Day-ahead market welfare	The impacts of market architecture options on variable costs, day-ahead producer surplus and market welfare is key in a context of low profitability of certain power plants and discussion around capacity remuneration mechanisms.
	Generation costs	
	Producer surplus per type of energy source	
Market prices (per market area)	Average market prices	The impact of market architecture options on market prices is key to analyse, in line with the EU objectives of competitive energy prices.
	Prices first and last centile[18]	
Sustainability (per country)	Share of renewable production covering the domestic consumption	The objective is to study whether a market design option favours or disfavours the integration of RES and the reduction of CO_2 emissions, in line with the EU 2020 objectives.
	CO_2 emissions	
Cross-border exchanges	Amount of cross-border exchanges	The impacts of market architecture options on cross-border flows, price differentials and

[18] Different centiles can actually be monitored.

(per border)	Average price differentials Day-ahead congestion revenue	congestion revenue are important indicators to evaluate how the complementarity between the national generation parks is exploited.

3.2.2 Indicators tailored to the comparison of RES support schemes

The following additional indicators will be analysed to assess the impact of changes in RES support schemes (SS).

Table 2. ***Additional indicators to be analysed to evaluate the impacts of RES SS***

Families of indicators	Detailed indicators	Purpose
Generation mix (per country)	Wind generation Solar generation	These figures will allow assessing the impact of changes in support schemes on wind and solar generation in more details.
Market prices (per market area)	Occurrence and magnitude of negative prices	RES support schemes are expected to have an impact on negative prices.

3.2.3 Indicators tailored to the evaluation of the deployment of demand flexibility

The following indicators are proposed to be analysed to assess the impact of the deployment of demand flexibility.

Table 3. ***Additional indicators to be analysed to evaluate the impacts of demand flexibility***

Families of indicators	Detailed indicators	Purpose
Generation mix (per country)	Amount of load shedding	The magnitude of load shedding will be analysed.
Costs and profits, welfare (per country)	Day-ahead producers and consumers surplus	These figures will allow assessing redistributive effects of load flexibility.
Security of supply	Amount of tertiary reserve power, load curtailment duration	The impacts of load flexibility on security of supply indicators, which are expected to be positive, will be quantified.

4 ELABORATION OF SCENARIOS TO COMPARE MARKET ARCHITECTURE OPTIONS

The above-mentioned market architecture options will be studied and compared on the basis of different scenarios, in order to assess the sensitivity of the impacts of each option with regards to the main features of the electric system (installed generation capacities, demand level, network capacities, etc.).

4.1 Choice of scenarios to compare market architecture options

4.1.1 Qualitative description of the selected scenarios

Table 4 below presents the main features of the scenarios being elaborated for the studies in a synthetic and qualitative manner.

Table 4. ***Main features of each scenario***

Scenario name	Thermal generation			RES generation	Demand	Transmission network
	Installed capacities	*Flexibility*	*Economic parameters*			
2013 scenario (reference scenario)	Current installed capacities	Current flexibility level	Current CO_2 price and fuel costs	Current installed capacities	Current level of peak demand	Current cross-border capacities
2020 standard scenario	Installed capacities at 2020 as foreseen today	Current flexibility level	Foreseen values at 2020	2020 RES objectives	Level of peak demand at 2020 as foreseen today	2020 cross-border capacities as foreseen today
2020 RES+ scenario	Significant decrease in thermal installed capacities	Higher flexibility of thermal units	Higher CO_2 price (impact on merit order curve)	Additional RES capacities	Level of peak demand at 2020 as foreseen today	2020 cross-border capacities as foreseen today

The 2013 scenario, also called reference scenario, mimics the current situation of the power system (see Section 4.3).

The 2020 standard scenario mimics the situation of the power system which can reasonably be expected at 2020. It is based on official publications such as the National Renewable Energy Action Plans (NREAPs) [3], ENTSO-E's Ten-Year Network Development Plan (TYNDP) 2014 [4], ENTSO-E's Scenario Outlook and Adequacy Forecast (SO&AF) 2014-2030 [5], etc. (Section 4.4).

The alternative 2020 scenario RES+ is derived from the 2020 standard scenario (Section 4.5). RES+ mimics a situation in which RES capacities replace some thermal capacities, the latter being both more flexible and more costly.

All scenarios have common hypotheses which are described in section 4.2.

4.1.2 Combining the market architecture options to be studied with the selected scenarios: the selected cases

For each of the three scenarios defined in Section 4.1.1, a default OPTIMATE case will be run: it will provide a starting point from which variational studies, covering the two types of market architecture options defined in Chapter 3, will be performed. These default cases will be based on the following hypotheses:

- No RES support scheme;
- Low demand flexibility.

Table 5 presents how the parameters of the default cases will be modified for each of the proposed scenarios. In total, 9 OPTIMATE cases will be run, covering the three scenarios and the two types of market architecture options. Each case will be run over selected periods of the year covering different seasons (for instance one winter month, one summer month and one mid-season month): hence, in total, OPTIMATE simulations will be run over around 27 case variants.

Table 5. ***Proposed combinations of scenarios and market architecture options***

Studies	#	Scenarios	RES SS	Demand flexibility
Default cases	1	2013	None	Low
	2	2020 standard	None	Low
	3	2020 RES+	None	Low
Study on RES support schemes	4	2013	Current RES SS (FiT and/or PP)	Low
	5	2020 standard	Current RES SS (FiT and/or PP) for old, PP for new units	Low
	6	2020 RES+	Current SS (FiT and/or PP) for old, PP for new units	Low
Study on demand flexibility	7	2013	None	High
	8	2020 standard	None	High
	9	2020 RES+	None	High

Other possible combinations of scenarios and market architecture options could be considered. For instance, depending on the results of the studies on load flexibility and RES support schemes, studying the combination of high load flexibility with different RES support schemes could be of interest.

4.2 Common hypotheses to all scenarios selected

4.2.1 Geographical scope

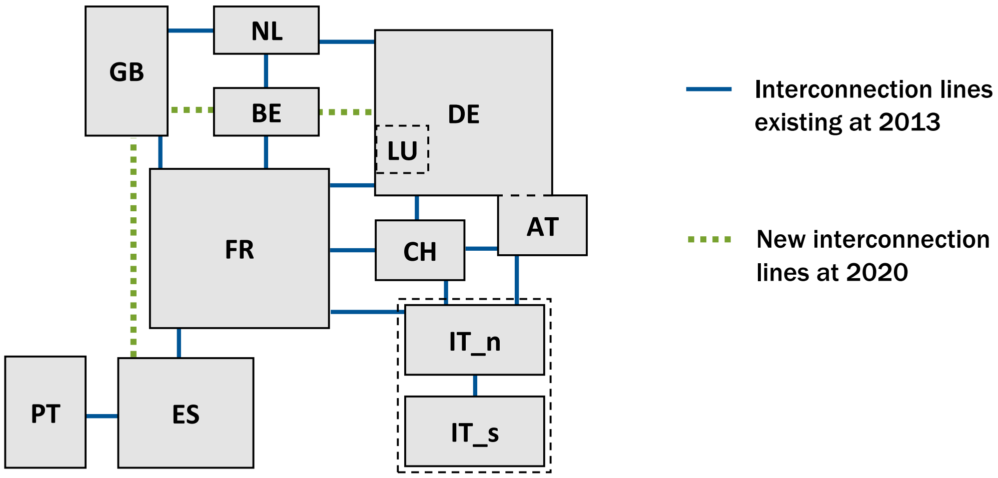
The geographical scope foreseen for the Market4RES WP4 studies is composed of the following countries: Austria, Belgium, France, Germany, Great-Britain, Italy, Luxembourg, Netherlands, Portugal, Spain and Switzerland (seeFigure 5). In terms of electricity consumption, this area covers 76% of the total consumption of the European Union + Switzerland.[19] In terms of power transmission network, Figure 5 shows the existing cross-border interconnections as well as the new interconnections foreseen at 2020 (see section 4.3.4).

The following modelling hypotheses have been taken into account:

- Luxembourg is considered as a part of the German market. In the following tables, the area named "DE" actually covers Germany and Luxembourg.
- Germany and Austria also form a single market zone (single price, no interconnection capacity allocation between them). However, Austria and Germany are modelled as two different zones, since national market designs (e.g. RES support schemes) may be different.
- The Italian market is actually split into six price zones. This split has been simplified with only two zones modelled: "IT_n", corresponding to the actual Northern Italy zone, and "IT_s", corresponding to the aggregation of the actual Central-Northern Italy, Central-Southern Italy, Southern Italy, Sardinia and Siciliy zones.

[19] Source: Eurostat, Office fédéral de l'énergie (Switzerland)

Figure 5. ***Geographical scope of the studies***



4.2.2 Simulation Period

Scenarios will be run over a full year of operations, while market design studies (OPTIMATE simulations) will be run over selected periods covering different seasons (for example one winter month, one summer month and one mid-season month).

4.2.3 Modelling of thermal generation capacities

23 different types of thermal generation units are considered:

- 5 for nuclear,
- 6 for coal,
- 10 for gas, and
- 2 for oil.

Each of these 23 different types of generation units has different technical features (nominal capacity, start-up duration, gradient, variable cost…) which mimic, in a simplified and aggregated way, the features of actual generation units. Actual installed capacities are distributed amongst these different types according to the expertise embedded in OPTIMATE and updated information provided by TSOs.

4.3 Quantitative description of the 2013 scenario (reference scenario)

In this section, we describe the features of the 2013 scenario in detail.

4.3.1 Load features at country level

The peak load for each country considered for the 2013 scenario is presented in Table 6 below. It has been elaborated as follows:

- For harmonization purposes with the data used for 2020 scenario (see section 4.4.1), the data is based on figures from Scenario B of ENTSO-E's "Scenario Outlook and Adequacy Forecast (SO&AF) 2014-2030" published on 3 June 2014 [5], despite the fact that it corresponds to the year 2014 instead of 2013.
- These figures may significantly differ from the realized 2013 peak load as published by ENTSO-E in Country Packages[20]. This is because the values given in the SO&AF 2014-2030 are "under normal climatic conditions" whereas the Country Packages correspond to realised data of a given year. Because of that, these values are relatively low compared to realised values. 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%.

Load profiles are embedded within the OPTIMATE tool.

Table 6. ***Peak load at 2013 (MW)***

AT	BE	FR	DE	GB	IT	NL	PT	ES	CH
11,770	14,806	91,630	97,581	51,290	56,419	18,051	8,723	42,251	10,780

(Source: ENTSO-E, with adaptation by TECHNOFI)

4.3.2 Renewable generation features at country level

RES installed capacities within each country are presented in Table 7. The sources of the data are the following:

- For wind and PV, EWEA's "Wind in power: 2013 European statistics" [6] and EPIA's "Global Market Outlook for Photovoltaics 2014-2018" [7] have been considered as references.
- For hydro, the global value has been taken from ENTSO-E's website[21]. The capacity of hydro dams has been determined by the OPTIMATE project. The run-of-river values have been updated by difference between the latter two.
- The thermal must-run capacities (mainly CHP units) are provided by OPTIMATE.

As for load, renewable profiles are embedded within the OPTIMATE tool. Since these profiles do not specifically correspond to the year 2013, the total electricity generation corresponding to the 2013 installed capacities may not correspond precisely to the actual RES generation at 2013.

[20] See https://www.entsoe.eu/db-query/country-packages/production-consumption-exchange-package.
[21] https://www.entsoe.eu/db-query/country-packages/net-generating-inventory-package

Table 7. *RES installed capacities at 2013 by energy source and country (MW)*

Energy source	AT	BE	FR	DE	GB	IT	NL	PT	ES	CH	Total (GW)
Hydro											
Dams	8,000	1,310	17,800	6,700	2,740	15,000	0	3,020	12,000	10,500	77
Run of river	5,427	120	7,634	5,214	1,229	7,009	38	2,632	7,382	3,305	40
Wind	1,684	1,651	8,254	33,730	10,531	8,551	2,693	4,724	22,959	60	95
PV	613	2,983	4,673	35,715	3,375	17,928	665	278	5,340	737	72
Thermal must-run (CHP, ...)	4,229	2,750	3,731	7,871	682	15,639	3,927	2,000	14,608	355	56

(Source: ENTSO-E, EWEA, EPIA, OPTIMATE)

4.3.3 Thermal installed capacities at country level

Table 8 presents the installed capacities considered within the 2013 scenario. The sources used to gather these data are the following:

- ENTSO-E published on 3 June 2014 the "Scenario Outlook & Adequacy Forecast (SO&AF) 2014-2030" and the corresponding dataset [5]. It provides different scenarios including installed capacities per type of energy source. Scenario B ("Best Estimate"), which corresponds to the expectations of TSOs, is the main source used for the reference scenario, and will also be used for the 2020 standard scenario.
- The SO&AF 2014-2030 dataset does not provide detailed figures for Austria. Therefore, information published by the Austrian regulator E-Control has been used [8].

Table 8. *Thermal installed capacities at 2013 by energy source and country (MW)*

Energy source	AT	BE	FR	DE	GB	IT	NL	PT	ES	CH	Total (GW)
Nuclear	0	5,930	63,100	12,070	8,980	0	490	0	7,580	3,200	101
Coal	1,585	410	10,500	51,240	18,600	18,930	6,690	1,760	11,080	0	121
Gas	5,119	6,880	5,800	28,960	29,880	41,640	20,060	3,830	31,750	100	174
Oil	360	210	6,700	3,450	2,290	6,860	0	0	0	0	20

(Source: ENTSO-E, E-CONTROL)

The thermal installed capacities are distributed amongst a list of 23 "standard" units, as explained in section 4.2.3.

4.3.4 Cross-border capacities at country level

Net transfer capacities (NTCs) have been gathered from ENTSO-E's transparency platform[22]. For each border, hourly values have been aggregated into one average winter value (from 01/01 to 30/04 and from 01/10 to 31/12) and one average summer value (from 01/05 to 30/09). The following peculiarities have been taken into account:

- Austria and Germany form a single market area: there is no day-ahead capacity allocation between these two countries. In the table below, the corresponding cells therefore mention an "infinite" capacity (which is modelled, within OPTIMATE, by a capacity set at 99,999 MW). The two areas have not been merged into one single area because capacity is separately allocated at the Austrian-Swiss and German-Swiss borders.
- The transfer capacity between the OPTIMATE zones Italy_North and Italy_South correspond to the capacity between the actual Italian zones "North" and "Central North". They have been gathered from Terna website[23].

The NTCs at 2013 are presented in Table 9.

Table 9. ***NTCs at 2013: average winter and summer values (MW)***

from *to*	AT	BE	FR	DE	GB	IT n	IT s	NL	PT	ES	CH
AT				**∞** *∞*		**116** *82*					**1,196** *1,189*
BE			**2,645** *2,510*					**1,356** *1,309*			
FR		**1,571** *1,304*		**2,509** *2,637*	**1,449** *1,652*	**1,068** *951*				**908** *882*	**1,100** *1,108*
DE	**∞** *∞*		**1,795** *1,784*					**2,179** *2,319*			**4,000** *4,000*
GB			**1,449** *1,664*					**1,005** *958*			
IT n	**255** *197*		**2,297** *1,555*				**1,850** *1,550*				**3,257** *2,088*
IT s						**3,470** *2,790*					
NL		**1,379** *1,325*		**2,102** *2,256*	**1,005** *958*						
PT										**1,511** *2,027*	
ES			**1,068** *994*						**1,610** *1,853*		
CH	**483** *555*		**3,179** *2,915*	**945** *1,126*		**1,855** *1,536*					

Bold: average winter values - *Italic*: average summer values

(Source: ENTSO-E, TERNA)

22 http://www.entsoe.net/.

23 http://www.terna.it/default/Home/SISTEMA_ELETTRICO/mercato_elettrico/stima_domanda_oraria.aspx.

4.3.5 Fuel and CO_2 prices

Within OPTIMATE, fuel and CO_2 prices are supposed to be uniform over the whole period considered and the whole geographical scope.

The following references have been taken to estimate these average prices:

- For CO_2, the market price established by EEX is generally quoted as a reference. EEX's Emission Spot Primary Market Auction Report 2013 [9] allows for calculating an average 2013 CO_2 price of 4.38 €/t.
- For gas, the main reference is the one used in ACER/CEER's Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2013 [10], namely the International Gas Union gas wholesale prices survey 2014 [11]. The average gas wholesale price in Europe was 11 $/MMBTU in 2013, which corresponds to 28.26 €/MWh.[24]
- For coal, ACER and CEER in [10] mention the "coal-CIF ARA price" as a reference. The graph presented in this report allows for calculating an average 2013 coal price of 61.67 €/t.
- For oil, the International Energy Agency in its Oil Medium-Term Market Report 2013 [12] quotes the Brent Crude price as a reference. The 2013 average value considered by the IEA is 109 $/bbl.

Regarding the conversion rate between dollars and euros, an average rate of 1.33 US$/€ has been taken into account for 2013.[25]

The prices considered for each product are summarized in Table 10.

Table 10. ***Fuel and CO_2 prices at 2013***

	Average prices
CO_2	4.38 €/t
Gas	28.26 €/MWh
Coal	61.67 €/t
Oil	109 $/bbl

(Source: EEX, ACER/CEER, IEA – Calculations: TECHNOFI)

4.4 Quantitative description of the 2020 standard scenario

In this section, we describe in detail the features of the 2020 standard scenario.

[24] The IMF, in its Commodity Market Monthly report, provides a similar value (11.2 $/MMBTU) for the "Russian in Germany" natural gas index, see http://www.imf.org/external/np/res/commod/pdf/monthly/070114.pdf.
[25] Source: www.x-rates.com

4.4.1 Load features at country level

The peak load estimated at 2020 within each country is presented in Table 11.

As announced in section 4.3.1, the source of the data on load profiles is ENTSO-E's "Scenario Outlook and Adequacy Forecast 2014-2030", published on 3 June 2014 [5].

The SO&AF 2014 report sets out three scenarios for generation and demand:

- the "EU2020" scenario, which is derived from the National Renewable Action Plans (NREAPs) in compliance with the European 3x20 objectives or from other governmental or national documents and policies;
- Scenario B ("Best Estimate"), which is based on the expectations of TSOs;
- Scenario A ("Conservative"), which is derived from Scenario B, taking into account only the generating capacity developments which are considered secure.

For the purpose of Market4RES studies, the data about load provided in Scenario B have been considered. As for the 2013 scenario, the figures provided by SO&AF report have been increased by 10% also for the 2020 scenario.

Table 11. ***Maximum load at 2020 (MW)***

AT	BE	FR	DE	GB	IT	NL	PT	ES	CH
13,090	15,609	94,820	97,647	53,647	64,328	19,437	9,207	47,399	12,100

(Source: ENTSO-E, with adaptation by TECHNOFI)

4.4.2 Renewable generation features at country level

The RES installed capacities estimated at 2020 within each country are presented in Table 12 below.

Basically, RES installed capacities at 2020 are based on National Renewable Energy Action Plans (NREAPs) published in 2010 [3]. However, recent developments have led to a review of the NREAPs' objectives in terms of installed capacities. The following sources have therefore been used:

- For wind, EWEA's central scenario for 2020 as published in July 2014 has been considered (see [13]). The values provided by EWEA for this central scenario significantly differ from the NREAPs figures, in particular in France, Great Britain, Netherlands, Portugal and Spain, where the installed capacities now assessed by EWEA are significantly lower than the official 2020 objectives set in 2010. For Switzerland, since no scenario is published by EWEA, the value given by ENTSO-E SO&AF, scenario B, has been considered.
- For PV, EPIA has kindly provided the installed capacities corresponding to its 2020 Baseline Scenario. The NREAPs values indeed needed to be updated, since for example in several countries (Austria, Belgium and Great-Britain) the official objectives in terms of installed capacities were already reached in 2013. With the exception of Spain and Portugal, EPIA

foresees higher installed capacities than what was foreseen by the NREAPs in its 2020 Baseline Scenario.

- Concentrated Solar Power (CSP) is expected to develop in the four Mediterranean countries within our scope (Spain, Portugal, France and Italy). Installed capacities foreseen at 2020 in the NREAPs have been considered.
- For hydro, no major developments are expected up to 2020. Therefore, the values considered in the 2013 scenario (Table 7) remain unchanged for the 2020 standard scenario.
- Installed capacities in "thermal must-run" are difficult to assess. Since the main developments expected will be related to biomass, the installed thermal must-run capacities at 2020 have been assessed as the installed thermal must-run capacities at 2013 plus the expected additional generation capacities from biomass as foreseen by ENTSO-E in the SO&AF, scenario B [5].

Table 12. *RES installed capacities at 2020 by energy source and country (MW)*

Energy source	AT	BE	FR	DE	GB	IT	NL	PT	ES	CH	Total (GW)	*Comp / 2013*
Wind												
Onshore	3,400	3,000	18,500	45,000	11,500	12,000	4,000	5,700	26,000	1,200	**130**	*159%*
Offshore	-	1,500	1,500	6,500	9,500	-	1,400	25	5	-	**20**	
Solar												
PV	2,013	3,903	10,273	53,215	10,029	24,428	2,615	688	7,140	2,407	**117**	*161%*
Solar thermal	-	-	540	-	-	600	-	500	5,079	-	**7**	*-*
Thermal must-run (CHP, biomass ...)	4,229	3,120	4,230	9,160	1,972	17,598	4,017	2,100	14,758	355	**62**	*110%*

(Source: EWEA, EPIA, NREAPs, ENTSO-E, OPTIMATE)

Within OPTIMATE, installed capacities for intermittent sources are complemented by standard production profiles.

Regarding solar generation, because CSP units are often equipped with trackers and storage facilities, the daily profile of CSP generation is significantly different from the PV profile (production is even possible after sunset); in addition, CSP units are more efficient.

To take this development into account, while keeping using the profiles embedded within OPTIMATE, the following methodology has been applied:

- A CSP yearly profile has been built by combining the profile of CSP generation during a summer day in Spain as published by ESTELA in [14] and the yearly PV profile embedded within OPTIMATE;
- For each country, a consistent pair of installed capacity (MW) and electricity generation (GWh) at 2020 have been considered to calibrate these profiles thanks to a national ratio corresponding to the amount of GWh generated per MW installed (Table 13); these pairs of figures come from the NREAPs;

- For consistency, this calibration has also been done for countries with no CSP capacities.

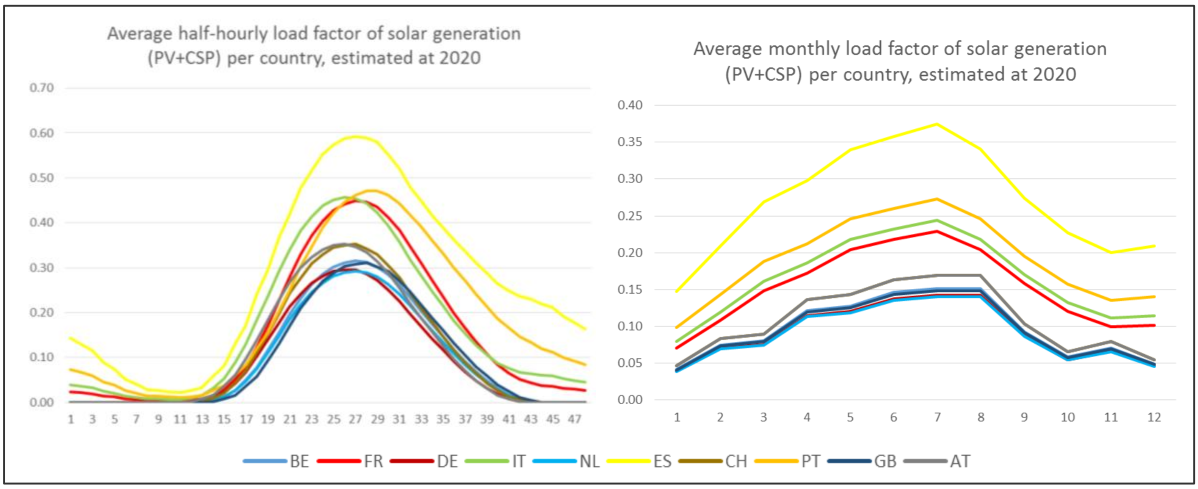
The resulting average profiles are presented in Figure 6 below.

Table 13. ***Average ratio of annual electricity generation from solar sources compared to the installed capacities, as targeted at 2020 (GWh/MW)***

Energy source	AT	BE	FR	DE	GB	IT	NL	PT	ES	CH
PV	0.95	0.85	1.27	0.80	0.84	1.21	0.79	1.48	1.71	0.95
CSP	-	-	1.80	-	-	2.83	-	2.00	3.02	-

(Source: NREAPs – Calculations: TECHNOFI)

Figure 6. ***Average profiles of solar generation as foreseen at 2020***



(Source: OPTIMATE, ESTELA, NREAPs – Calculations: TECHNOFI)

Regarding wind generation, the development of offshore farms within many countries must also be taken into account. Offshore capacities are indeed more efficient than onshore ones. As for solar generation, the profiles already embedded within OPTIMATE have been calibrated thanks to consistent pairs of targeted electricity generation at 2020 and targeted 2020 installed capacities (Table 14 – Data from NREAPs). For consistency, this calibration has also been done for countries with no offshore wind capacities.

Offshore wind generation is also more regular than onshore wind generation. However, this feature is not taken into account here, because doing so would have meant to introduce new profiles not necessarily consistent with the ones embedded within OPTIMATE. The spatial and temporal correlations of wind generation in the different EU countries make it indeed necessary to work with a consistent set of profiles for all countries.

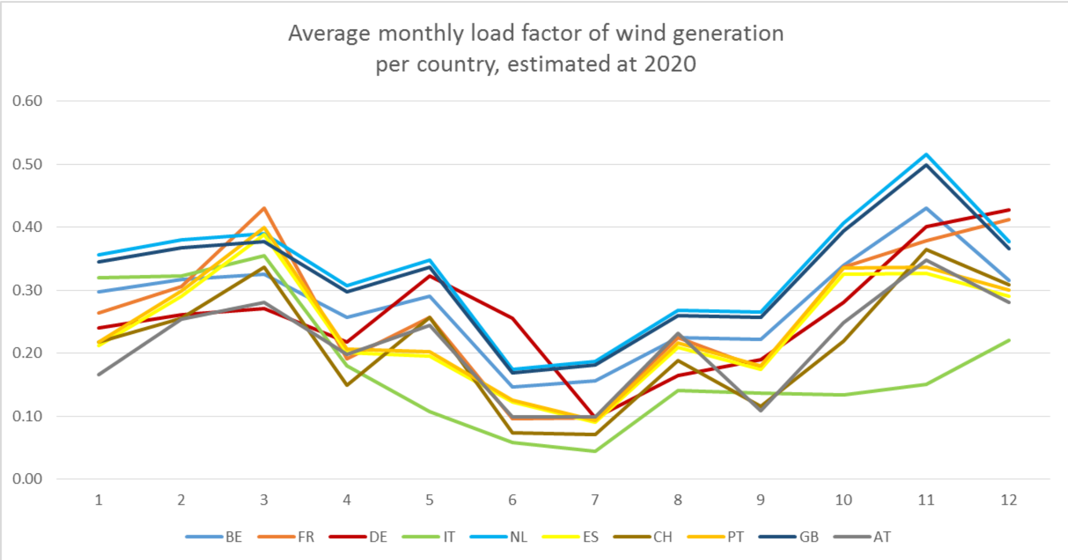
The resulting profiles are presented in Figure 7.

Table 14. *Average ratio of annual electricity generation from wind compared to the installed capacity, as targeted at 2020 (GWh/MW)*

AT	BE	FR	DE	GB	IT	NL	PT	ES	CH
1.87	2.42	2.32	2.28	2.81	1.58	2.90	2.12	2.06	1.87

(Source: NREAPs – Calculations: TECHNOFI)

Figure 7. *Average profiles of wind generation as foreseen at 2020*



(Source: OPTIMATE, NREAPs – Calculations: TECHNOFI)

4.4.3 Thermal installed capacities at country level

The thermal installed capacities, foreseen at 2020, are presented in Table 15. The main source for these data is ENTSO-E's SO&AF report and dataset, scenario B [5]. For Austria, since ENTSO-E's data were incomplete, detailed data were kindly provided by the Energy Economics Group (EEG) of the Vienna University of Technology.

Table 15. *Thermal installed capacities at 2020 by energy source and country (MW)*

Energy source	AT	BE	FR	DE	GB	IT	NL	PT	ES	CH	Total (GW)	*Comp / 2013*
Nuclear	0	5,060	63,100	8,110	8,980	0	490	0	7,580	2,800	**96**	*95%*
Coal	1,700	0	8,200	44,010	15,560	18,010	5,590	580	9,930	0	**104**	*86%*
Gas	7,800	7,920	7,500	27,910	30,530	42,870	20,020	5,590	31,980	100	**182**	*105%*
Oil	100	0	2,900	2,410	990	6,610	0	0	0	0	**13**	*65%*

(Source: ENTSO-E, EEG)

4.4.4 Cross-border capacities at country level

ENTSO-E's Ten Year Network Development Plan (TYNDP) 2014 [4] has been used to assess the NTCs at 2020 horizon.

Table 16 presents an extract of the list of the "transmission projects of pan-European significance" and an estimate of the grid transfer capability increase expected thanks to these projects. The projects with the following features have been selected:

- Impact on the grid capacities within the relevant geographical scope;
- Commissioning date not beyond 2020.

Table 16. ***Additional cross-border capacities at 2020 according to TYNDP 2014***

Project name	Countries	Project ID	Expected date	Increase in NTC (MW)			
Eastern France-Spain interconnection	ES, FR	5 & 213	2015	ES>FR	1400	FR>ES	1200
Portugal-Spain	ES, PT	4	2016	PT>ES	400	ES>PT	1000
PST Arkale	ES, FR	184	2016	ES>FR	500-900	FR>ES	100-500
ElecLink	FR, GB	172	2016	GB>FR	1000	FR>GB	1000
Doetinchem – Niederrhein	DE, NL	113	2016	DE>NL	1400	NL>DE	1400
E15	AT, IT	210	2017	AT>IT	150	IT>AT	150
BRITIB	ES, FR, GB	182	2018	ES>FR	1000	FR>ES	1000
BRITIB	ES, FR, GB	182	2018	ES>GB	1000	GB>ES	1000
BRITIB	ES, FR, GB	182	2018	GB>FR	1000	FR>GB	1000
NEMO	BE, GB	74	2018	BE>GB	1000	GB>BE	1000
Greenconnector	CH, IT	174	2018	CH>IT	800	IT>CH	800
ALEGrO	BE, DE	92	2019	BE>DE	1000	DE>BE	1000
France-Italy	FR, IT	21	2019	FR>IT	1200	IT>FR	1000
Dutch Ring	NL	103	2019	NL>DE	500	DE>NL	500
IFA 2	FR, GB	25	2020	GB>FR	1000	FR>GB	1000
Belgium-Luxembourg	BE, LU	40	2020	BE>LU	700	LU>BE	700
Lake Geneva West	CH, FR	22	2020	FR>CH	500	CH>FR	200
Belgian North Border	BE	24	2020	BE>NL	1000-1500	NL>BE	1000-1500
Italy North and Center	IT	33	2020	IT_n>IT_s	600	IT_s>IT_n	600

(Source: ENTSO-E)

The new capacities, as presented in Table 16, have been added to the 2013 capacities from Table 9:

- No distinction has been made for the new capacities between summer and winter values: the TYNDP provides high level values which make it irrelevant to consider the relatively small seasonal effect on capacities;
- When the TYNDP2014 provides a range for the new capacity, the average between the two extremes values have been taken into account.

The results are presented in Table 17.

Table 17. ***Estimated NTCs at 2020: average winter and summer values (MW)***

from / *to*	AT	BE	FR	DE	GB	IT n	IT s	NL	PT	ES	CH
AT				**∞** *∞*		**266** *232*					**1,196** *1,189*
BE			**2,645** *2,510*	**1,700** *1,700*	**1,000** *1,000*			**2,606** *2,559*			
FR		**1,571** *1,304*		**2,509** *2,637*	**4,449** *4,652*	**2,068** *1,951*				**4,008** *3,982*	**1,300** *1,308*
DE	**∞** *∞*	**1,700** *1,700*	**1,795** *1,784*					**4,079** *4,219*			**4,000** *4,000*
GB		**1,000** *1,000*	**4,449** *4,664*					**1,005** *958*		**1,000** *1,000*	
IT n	**405** *347*		**3,497** *2,755*				**2,450** *2,150*				**4,057** *2,888*
IT s						**4,070** *3,390*					
NL		**2,629** *2,575*		**4,002** *4,156*	**1,005** *958*						
PT										**2,511** *3,027*	
ES			**3,568** *3,494*		**1,000** *1,000*				**2,010** *2,253*		
CH	**483** *555*		**3,679** *3,415*	**945** *1,126*		**2,655** *2,336*					

Bold: average winter values - *Italic*: average summer values - Underlined: new interconnections

(Source: ENTSO-E – Calculations: TECHNOFI)

4.4.5 Fuel and CO_2 prices

The main reference for estimating these average prices at 2020 is the EC document "EU Energy, Transport and GHG Emissions, Trends to 2050, Reference Scenario 2013" [15] published in December 2013.

- For CO_2, the price projected at 2020 by the EC in [15] is 10 €/t.
- For gas, the price projected at 2020 in [15] is 80 $/boe, which is equal to 37.03 €/MWh (assuming the same exchange rate between euros and dollars compared with 2013).
- For coal, the price projected at 2020 in [15] is 30$/boe, which is equal to 108.20 €/ton.
- For oil, the price projected at 2020 in [15] is 115 $/bbl.

The prices considered for each product are summarized in Table 18.

Table 18. ***Fuel and CO_2 prices estimated at 2020***

	Average prices at 2013 (Table 10)	Price forecasts at 2020	*Evolution 2020 / 2013*
CO_2	4.38 €/t	10 €/t	*+128%*
Gas	28.26 €/MWh	37.03 €/MWh	*+31%*
Coal	61.67 €/t	108.2 €/t	*+75%*
Oil	109 $/bbl	115 $/bbl	*+6%*

(Source: EC – Calculations: TECHNOFI)

4.5 Quantitative description of the 2020 RES+ scenario

In this section, we describe the features of the 2020 RES+ scenario, which differ from those of the 2020 standard scenario: RES installed capacities, thermal installed capacities and flexibility characteristics and CO_2 price.

This third scenario aims to assess the sensitivity of the tested market design options to the structure of the generation mix. The features of this scenario have therefore to be significantly different from those of the 2020 standard scenario, while not being totally unrealistic.

4.5.1 Renewable installed capacities at country level

Regarding the RES installed capacities, the use of the figures of "high" scenarios provided by EWEA and EPIA has been considered, but finally not chosen, because they would not be sufficiently contrasted with the 2020 standard scenario. Rather, the building of fictitious figures has been chosen corresponding to doubling the increase in RES installed capacities from 2013 to 2020. In other words, they are built by doubling the spread between the 2013 and 2020 standard scenario, as if the rhythm of installation of new capacities was twice as expected. The resulting RES installed capacities proposed for the 2020 RES+ scenario are presented in Table 19 below.

Table 19. ***RES installed capacities for the 2020 RES+ scenario (MW)***

Energy source	AT	BE	FR	DE	GB	IT	NL	PT	ES	CH	Total (GW)	*Comp / 2020 standard*
Wind												
Onshore	5,116	4,349	28,746	56,270	12,469	15,449	5,307	6,676	29,041	2,340	166	*127%*
Offshore		3,000	3,000	13,000	19,000		2,800	50	10		41	*200%*
Solar												
PV	3,413	4,823	15,873	70,715	16,683	30,928	4,565	1,098	8,940	4,077	161	*138%*
Solar thermal			1,080			1,200		1,000	10,158		13	*200%*
Thermal must-run (CHP, biomass ...)	4,229	3,490	4,729	10,449	3,262	19,557	4,107	2,200	14,908	355	67	*109%*

The generation profiles remain unchanged compared to the 2020 standard scenario.

4.5.2 Thermal generation features at country level

It is proposed to build the thermal installed capacities by applying the same reasoning as for RES installed capacities and doubling the spread between the 2013 and 2020 standard scenarios. For countries where the 2020 standard scenario figure is lower than half of the 2013 scenario figure (for example for the oil-fired units in Austria, which are at 360 MW in 2013 and 100 MW in the 2020 standard scenario), the capacities are set at zero. The resulting thermal installed capacities proposed for the 2020 RES+ scenario are presented in Table 20 below.

Table 20. ***Thermal installed capacities* for the 2020 RES+ scenario *(MW)***

Energy source	AT	BE	FR	DE	GB	IT	NL	PT	ES	CH	Total (GW)	*Comp / 2020 standard*
Nuclear	0	4,190	63,100	4,150	8,980	0	490	0	7,580	2,400	91	*95%*
Coal	1,815	0	5,900	36,780	12,520	17,090	4,490	0	8,780	0	87	*84%*
Gas	10,481	8,960	9,200	26,860	31,180	44,100	19,980	7,350	32,210	100	190	*105%*
Oil	0	0	0	1,370	0	6,360	0	0	0	0	8	*59%*

It is also proposed to simulate an increase in the flexibility of thermal plants: new gas plants are indeed likely to have a greater flexibility (higher maximum gradient, lower minimum duration, and lower start-up duration), and coal plants may also be retrofitted to gain flexibility. The parameters that are proposed to be modified are presented in Table 21. Values have been chosen consistently with the figures presented in [16].

Table 21. ***Flexibility parameters of coal and gas plants in the RES+ 2020 scenario***

	Coal units *(for a nominal capacity of 300 MW)*		Gas units *(for a nominal capacity of 200 MW)*	
OPTIMATE parameters	Initial parameters	RES+ scenario parameters	Initial parameters	RES+ scenario parameters
Maximum Gradient (MW/h)	500	1,000	500	1,000
Minimum Duration (h)	2	1	0.5	0.25
Start-up Duration (h)	3.5	1.75	0	0

(Source: OPTIMATE – Adaptation: TECHNOFI)

4.5.3 CO_2 price

Finally, it is proposed to keep the fuel prices similar to the 2020 standard scenario, but to simulate an increase in CO_2 price in such a way that the position of gas and coal plants in the merit order curve is switched (the so-called “coal-to-gas switch”). Analysts in the power sector provide different values for such CO_2 price (see [17]). We consider here the highest of these values, which is 40 €/t.

5 REFERENCES

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