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Solar import from Africa: the Italian and the European perspective

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Abstract

Goal of the present work is to provide a first preliminary analysis on the effect of African solar energy import on the Italian system at 2030.
In particular, the aim is to provide a first preliminary answer to questions like:

- what flow will prevail in Italy at 2030 (wind from the Northern border or solar from the Southern border);
- how could the market prices be modified as the effect of RES import from North and from South.

The scenario analyses presented in this study are the result of a collaboration between the Joint Research Centre of the European Commission and Ricerca sul Sistema Energetico, which developed, respectively, a pan-European approach and a detailed model of the Italian system.

Keywords

Transmission Planning, RES Integration, Mediterranean Solar Plan

1. Introduction

The energy and climate change targets fixed for 2020 (the so-called "20-20-20") represent a first concrete action of the European Union (EU) to achieve a low-carbon energy economy for the future. Further ambitious measures are expected to be put forward: the EC 2050 Roadmap ([1]) hints at a future "low carbon 2050 strategy", which should include a commitment to reduce greenhouse gas emissions by 80-90% by 2050 compared to 1990 levels. To attain such ambitious targets, a structured plan for Renewable Energy Sources (RES) deployment has to be put in place, both incentivizing the production within the EU countries and creating the technical-economic background for importing RES generation from where these potentials exist. First of all, the attention is turned to the countries of the so-called MENA region (Middle East and North Africa), located in or around the Mediterranean Basin, that are close to Europe and at the same time feature a sizable potential for RES generation. This is the rationale for the establishment of initiatives such as the DESERTEC Industrial Initiative (DII, [2]) and Medgrid [3], aiming at fostering the development of renewable generation in the MENA region and related transmission capacity between the two shores of the Mediterranean Sea. The 200 MW El Zayt wind farm pilot project in Egypt is a first concrete example for the implementation of these concepts.

However, even putting aside any political considerations on the current instability of the North-African region and not considering the non negligible problems connected with bringing Saharian solar energy up to the shores of the European countries, another important set of difficulties arises in transporting this energy farther up to the big consumption centres in Central-Europe. The European network is not ready for this and has to be considerably reinforced ([27]). According to estimates of the German Energy Agency DENA ([4]), towards a massive RES integration, Germany alone will require at least 3600 km in new energy routes, wherever in the past five years only 90 km have been added. The document Energiekonzept ([5]), from the German Government, stresses that a specific investment has to be carried out in a dedicated highway (overlay-network) to transport energy on the north-south axis. The need for a pan-European highway has then been highlighted by the European Commission (EC) in its Energy Infrastructure Package ([6], 2010) and the recent proposal for a new infrastructure investment instrument ([7], 2011) as well as by the ENTSO-E (European Network of Transmission System Operators for Electricity) ([8]). Coming to Italy, that is, along with Spain, the most likely docking point for RES energy from Africa, the two long north-south oriented backbones of the transmission system (Tyrrhenian and Adriatic), already now affected by regular bottlenecks in some critical sections, would be even more stressed by a massive energy flow from Africa. Moreover, the geographically closest injection areas for RES energy (Sicily and Sardinia) are both weakly connected to the mainland.

In this framework, the present paper will describe two interrelated studies, one from a European perspective, carried out by the Joint Research Centre of the European Commission (EC JRC), and one from a national (Italian) perspective, carried out by RSE. Both studies consider 2030 as time horizon. The former investigates the effect of North-African imports on the European power system and transmission flows, whilst the latter takes border condition from this study and performes an in-depth grid analysis of the impact on the Italian grid, seen as the crossroad between wind energy imported from central Europe and solar energy coming from Africa.

On the basis of scenarios set up for the year 2030, concerning both network layout, generation set and system demand, these two studies will respectively:

- provide an overview of European cross-border electricity flows and assess the impact on the European total marginal generation costs;

- single out the eventual criticalities and possible solutions on a national/regional scale in Italy.

Chapter 2 illustrates background information on the prospects for solar generation in the African countries and its import to Europe till 2030. Chapter 3 explains the integrated approach: chapter 3.1 and 3.2 show, respectively, details on the EC JRC approach and of the RSE analysis. Chapter 4 illustrates the results of both scenario analyses. Chapter 5 draws conclusions and provides an outlook for further work.

2. The Euro-Mediterranean framework

As highlighted in [9], by examining the regions building the Northern and Southern shores of the Mediterranean Sea, some evident differences emerge. In 2010, the GDP (Gross Domestic Product) of the EU countries on the upper coasts of Mediterranean Sea was 2.5 times higher than the GDP of the Southern coast. This ratio becomes 4.7 times if Turkey is excluded. This ratio, yet foreseen to reduce itself to 3.7 times by 2015, is destined to remain relevant even in the following years.
From the electricity point of view, the Southern coast can be divided into four macro regions:

- South-West region, including Algeria, Morocco and Tunisia. These countries are quite well interconnected, mutually and with the EU region, being synchronously interconnected among them and to Spain via cable link. Further development of new specific interconnections, especially between Morocco and Spain, can be envisaged.
- East region, including Turkey. In particular, Turkey has a GDP double than Egypt and already initiated a dialogue for joining the EU. From 2011, Turkey is also synchronous with the continental ENTSO-E network.
- South-East region, from Libya through Egypt to Syria. This area is the most problematic one, concerning both the geo-politic point of view and the development of the grid infrastructures. In this area, Egypt, Lebanon, Israel and Palestine can be considered as independent energy islands.

Yet having the population of the Northern shores of the Mediterranean the same size as that of the Southern area (about 200 million people), the energy consumption per person is 2.5 times higher in the North zone. As a whole, the energy consumption in the North zone is 6457 kWh, against 1704 kWh in the South zone.
As also forecast by the document [24] underlines, the contribution of oil and coal to the electrical generation 2030 should diminish against a significant increase of renewable generation.
In this framework, the most important challenges for the future development of the electrical infrastructure in the EU are the integration of a growing generation from variable RES together

with an increasing integration of the electricity markets so as to remove bottlenecks and ensure security of supply.
In the Mediterranean region, there is a clear interest in increasing the level of exchanges. In this direction, the Medring project ([10]) should bring in a future to realise a stable interconnection ring between all the relevant countries. However, the present situation still sees many weak points that prevent a rapid achievement of the goal.
The Mediterranean region is rich of important resources of renewable energy. The MENA region receives every year 200 TWh of solar radiation, more than double of the entire Europe. The idea is that a massive development of RES generation, especially in arid and desert lands could contribute on one side to satisfy the European demand of electricity and on the other side to the development of these countries. However, it has to be remembered that a lot of technical, economical and political barriers make this process slow and complex. From the technical point of view, a huge extension of infrastructures has to be foreseen with a lot of problems to be solved, tied with the necessity to build very long lines in hostile environments. From the financial point of view, huge capitals have to be at hands, while the investment is to be carried out in regions that are sometimes not politically stable (hence a great investment risk).
In spite of this, significant initiatives have already been set up:

- July 2008: Mediterranean Solar Plan
- July 2009: creation of the DESERTEC Industrial Initiative
- July 2010: creation of the industrial consortium Transgreen, then become Medgrid
- September 2010: EC launching the project “Pave the Way”
- July 2011: expert meeting to re-launch the Mediterranean Solar Plan.

Aim of the DESERTEC consortium (more than 60 partners) is to build up project in order to satisfy an important part of the MENA consumption at the year 2050 plus 15% of the European one. Pilot projects are launched to show feasibility and open the way to a successive large scale deployment.
The Medgrid consortium has, instead the aim to realize a network of undersea interconnections across the Mediterranean basin, complementing the generation development to be realised by DESERTEC on the Southern shore.
However, what is often overlooked in these initiatives is to study the implications for the European networks of a massive injection of solar power from Africa. It has to be expected that important bottlenecks arise, prompting for significant investments for safely reaching the big consumer centres in Central Europe. A macro vision can suppose a future competition between two big poles of RES production: wind on- and off-shore power plants in North-West and North Europe and solar from South Europe and, most notably, from Africa.
Italy has a particular geographical position, favourable for importing wind energy from North and for becoming an important hub for the future solar energy from Africa. Depending on the prevailing flow, the internal network will be stressed in a completely different manner, bringing to completely different investment needs.
In this framework, the goal of the present work is to provide a first preliminary analysis on the effect of African solar energy import on the Italian system at 2030.
In particular, the aim is to provide a first preliminary answer to questions like:

- What flow will prevail in Italy at 2030 (wind from the Northern border or solar from the Southern border)?
- How could the market prices be modified as the effect of RES import from North and from South?

3. The adopted methodology for an integrated approach

3.1. The European approach

3.1.1 EUPowerDispatch Overview

The adopted methodology for studying the impacts of North African energy imports on the European system in 2030 is based on EUPowerDispatch, a minimum cost dispatch model developed by the Smart Electricity Systems [11] research group of the EC-JRC. EUPowerDispatch, a mixed-integer linear program coded in the General Algebraic Modeling System (GAMS), is a Minimum Cost Flow Problem (MCFP) which takes into account generation and transmission constraints. Its objective function is the minimisation of the annual variable electricity production costs in the interconnected European power system.

In order to provide a European perspective on the study presented in this paper, EUPowerDispatch examines the European electricity system in 2030 by taking into account the impact of imports from North Africa. The model includes 32 nodes, each one representing a European country with its generation and load demand, and 72 equivalent interconnections, each one representing a European cross-border corridor. In addition, the interconnections between North Africa and Southern Europe (Spain and Italy) are included and studied for three different main scenarios.

EUPowerDispatch models one year with 52 weekly simulations with 1-hour time-step. A preliminary yearly run with weekly time-steps sets the hydro seasonal reservoir levels at the start and end of each week. Hydro reservoirs are the only storage element with an annual management represented in the model. Therefore, it is assumed that the other variables, like generation levels and line flows mainly, can be modelled with 52 different weekly simulations.

Apart from the interconnection capacity limits between North Africa and Europe, the main model inputs are the installed net generation capacities, load time-series at each node, European cross-border transmission capacity limits, weather data (including solar radiation, wind speed, run of river flows and hydro reservoir inflows) and variable electricity production costs for each energy source type. The main model outputs include generation levels, cross-border flows, marginal variable electricity production costs and CO_2 emissions.

3.1.2 Model Inputs

The electricity load is modelled using 1-hour time-series for each European country provided by ENTSO-E for 2010 ([12]). Installed net generation capacities at each node are represented for different energy sources including nuclear, fossil fuels, hydro and renewable energies. A virtual power plant for each energy source representing the total installed generation capacity is modelled at each node. Different availability factors are considered, like eg. 84.5% for nuclear [13] and 90% for fossil fuels [14]. These values take into account planned and unplanned unavailability of nuclear and fossil-fired power plants.

Nuclear virtual power plant's output is limited between 70 and 100% of the available power capacity. Power plants based on lignite and hard coal are considered differently than the other fossil fuel-based generation plants due to their operational characteristics regarding start-up time, ramp-up rate and shut-down time. The same approach is used for both types of plants. The total installed generation capacity in a country is divided into single units with a rated available power around 750 MW and represented by a binary variable which describes their operation, in other words, if they are turned on or switched off. The binary values, which transform a linear program into a mixed integer linear program, are implemented in order to keep the time between shut-down and start-up and vice versa to a minimum of 4 hours. This short time represents a hot start-up. However, a more realistic approach would include larger start-up and shut-down times, which cannot be implemented due to computational constraints, as the number of equations and hence the computation time increase as minimum set start-up time increases [15]. The power output of each unit is limited between 70 and 100% of their rated power.

Gas, oil and mixed fuels (oil and gas) fired power plants are modelled using the same approach. A virtual power plant as for nuclear is considered. Its power output is only limited by the available installed capacity due to the average effect of summing all the installed capacities in a country and the fast reacting characteristics of such fuels.

Hydro power plants are classified in three categories: run of river plants with an uncontrollable generation which depends on natural inflows; seasonal storage plants with an upper reservoir which is fed by a natural inflow and which is managed with seasonal and daily strategies; pure pumping plants which have a daily dispatch strategy and where water is pumped from a lower reservoir into an upper one with no natural inflow. In reality, hydro power systems can be much more complex, but in order to simplify the modelling and data collection efforts for representing hydro power systems across Europe, these three types of hydro models are used. In mountainous countries like Austria, Norway, Switzerland or Sweden, water can be pumped in seasonal storage reservoirs which are also fed by natural inflows. An ideal flexibility is assumed with negligible start-up, shut-down, ramp-up or ramp-down costs. Reservoir levels are optimized for overall variable electricity production costs only and the lower limits are set to 30% on seasonal reservoir levels in order to partially consider environmental and landscape constraints. Round trip pumping efficiency is assumed to be 75%. The main source of information is the 2010 ENTSO-E dataset [16], complemented by figures from research projects [17][18], national TSOs and electricity producers.

Renewable energy sources including wind (both onshore and offshore), solar (photovoltaic, PV and concentrated solar power, CSP) and biomass are modelled using the same approach of a virtual power plant per country/node. 2010 6-hour wind speed time series [19], linearly interpolated in time, with 2.5 degrees latitude – longitude spatial resolution, are used together with regional installed wind farm installed capacity data [20] in order to obtain an average onshore and offshore wind power outputs for each hour of the year for each country. For solar energy, the 1-hour solar radiation data time-series [22] have been used to represent the energy output delivered to the grid (kW hour/MW installed) with a 1.51 degrees latitude – longitude spatial resolution. Due to data unavailability, PV installed capacity is assumed to be equally distributed across a single country. For biomass, including solid, liquid and gas forms, the virtual power plant at each node is only constrained by the installed generation capacity. Its weekly availability is kept at 50% in order to take into account the fuel's accessibility. In addition, geothermal energy, modelled as a negative load, is only considered for Italy in order to better integrate and compare the model results with the detailed Italian model outputs.

Electricity transfer between the 32 European nodes is represented by 72 equivalent interconnections defined by their bi-directional maximum net transfer capacities. Network losses, comprising distribution and national transmission losses, are included in the load time-series. However, cross-border transmission is also subject to relatively small losses in order to avoid free and unrealistic flows across Europe. These are assumed also based on geographical elements of the two interconnected countries. This approach serves as a method to avoid cross-border transfer through very long distances at no cost. In addition, the model includes the electricity interconnectors from North Africa whose number and capacity vary depending on the scenario which will be described in the following. The availability of such interconnectors is assumed to be constantly equal to their capacity. In addition the electricity flowing across them from Africa to Europe is assumed to have a constant variable cost.

Finally, the objective function of EUPowerDispatch is the minimisation of the European total annual electricity variable production costs. Variable electricity generation costs are different for each energy source and they comprise variable maintenance and operational costs, fuel costs and CO_2 taxes.

3.1.3 Scenarios

In this section the scenarios considered in the European-wide study are described together with the data sources for each model input category. The reference time horizon considered for modelling the European power system and the imports from North Africa is 2030.
The installed generation capacities for each energy source in every European country under analysis are based on the 2025 Best Estimate Scenario of ENTSO-E's Scenario Outlook & Adequacy Forecasts (SO&AF) 2011 – 2025 [23] with the exceptions for Italy and Germany for which the scenario dataset, provided by RSE, has been updated including the German nuclear phase-out plans, the Italian current situation related to the dismantling of the nuclear programme, and the Italian and German extremely large deployment of PV installations.
The same ENTSO-E scenario is used to calculate the expected electricity consumption increase in Europe between 2010 and 2030 together with [24] for the proportional increase for different countries.

Table 1 shows the electricity variable production costs assumed for 2030 and equal in every European country. The values are obtained from own calculations based on a TradeWind project deliverable [22] and assuming a CO_2 tax of 35 Euro/tonne.

Table 1 - Electricity variable production cost per energy source (Euro/MWh)

Nuclear	Lignite	Hard Coal	Gas	Oil
11.0	62.9	55.0	61.9	108.7
Mixed Fuels	Hydro	Wind	Solar	Biomass
114.5	3	2	0	53.1

The variable production cost of electricity coming from North Africa is assumed to amount to 41.25 Euro/MWh which is lower than European fossil-fired sources but higher than European nuclear sources. This value takes also into account the fact that the interconnections from North Africa, as originally planned, will serve also to dispatch thermal (mainly gas-based) generation.

In the results section of the paper, this value is varied in terms of its position in the merit of order with the purpose of performing a sensitivity analysis. In this sense, a scenario with the lower price of 10.52 Euro/MWh, due to much higher solar contribution than thermal generation, has been taken into account as well.

To build up the cross-border transmission system evolution scenario in Europe from the current state (2010-2011) up to 2030, an approach similar to the one developed by RSE and utilised within REALISEGRID [25] and SUSPLAN [26], has been followed.

To devise the future development of European cross-border interconnections from 2010-2011 up to 2030, the information and the data contained in several public sources regarding existing interconnection projects (ongoing, planned, under study, potential) in Europe have been taken into account. Among these, the key reference has been the first ENTSO-E's Ten-Year Network Development Plan (TYNDP) 2010-2020 [27] in addition to other sources of the former UCTE, NORDEL and BALTSO associations. The retrieved information has been also complemented by public data on projects of merchant lines (not included in the TYNDP) as well as by those ones available by EWEA concerning offshore grids developments.

The aim pursued by this exercise has been the determination of the values of the future 'maximum cross-border transmission capacity'[1] (for both flow directions at each border) in the European system, starting from the reference year 2010. The analysis has begun from the available NTC values (by ETSO/ENTSO-E) for summer 2010 and winter 2010-2011[2]. Given the difficulty of estimating, for each cross-border corridor, both a summer and a winter NTC value, it has been decided to define only a single annual value corresponding to the maximum NTC estimated value (in the vast majority of cases, the winter one).

For the estimation of future cross-border capacity of interconnections within the ENTSO-E, in absence of information about the expected net capacity increase provided by the single expansion project, opportune assumptions have been made by RSE, also based on the fact that, due to existing internal network constraints, only a quota of the theoretically available capacity increase can be effectively considered as net capacity increment[3]. In this sense, the assumptions for capacity increase by new HVAC lines take account of 300 MW for 220 kV ties, 900 MW for 380 kV ties (single circuit), 1500 MW for 380 kV ties (double circuit). Exceptions to this approach have been made for the Balkan power systems, where the internal congestions very much limit the net available capacity: in those cases, in line with currently in place capacity limits, lower values of increased capacity for new 380 kV lines have been conservatively assumed. For new HVDC links, the rated capacity increase has been fully taken into consideration [28][29].

Figure 1 shows the assumed level of net cross-border capacities in Europe at 2030.

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[1] This definition has been meant to be more proper than the one of NTC (Net Transfer Capacity), because the (present and future) NTC estimation can be only carried out by TSOs and is officially published by ETSO/ENTSO-E. However, the two concepts are similar.

[2] In case of discordant NTC values between TSOs at the same border and flow direction, the choice to consider the highest value of the two possible options has been made.

[3] This situation is assumed not to change by 2030.

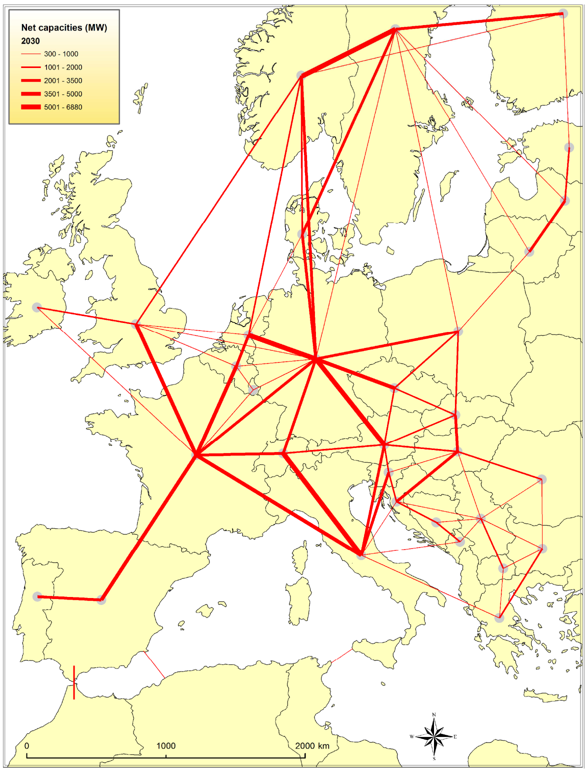

Figure 1 - The assumed net cross-border capacities in Europe at 2030

3.2. The Italian approach

3.2.1 Methodology and tool overview

The Italian study is tightly and consistently interrelated with the European approach. The methodology adopted for evaluating the impact of the electricity imports from North Africa on the Italian system at 2030 has been based on a transmission planning oriented approach. This has consisted in the analysis of grid simulation results for the Italian system in which 2030 scenarios for generation, load demand, fuel costs, CO_2 penalty tax and cross-border interconnections have been considered while the internal transmission network (at 220 and 380 kV level, also including equivalents of 132/150 kV portions) has been taken into account mainly in its 2020 shape. The purpose is then to investigate how congested the transmission network might be in 2030, given the different boundary conditions, while maintaining the circuit-system mainly frozen at 2020 and including the new interconnections, also comprising the ones with North Africa, according to the different case studies. Some expansion options are also evaluated.
The Italian study is carried out using the tool REMARK [31], developed by RSE. REMARK is able to conduct analysis of static reliability of complex electric systems that operate in a liberalized market context and are divided in areas. In comparison to conventional planning tools, this tool quantifies two types of indicators, like those ones generally used to assess reliability of electric systems and those ones aimed at innovatively evaluating from the economic

point of view the effects and the eventual criticalities caused by the market structure on the transmission system evolution.
Main features of this tool can be hereinafter summarised:

- full network representation adopting the simplified direct current model;
- an Optimal Power Flow (OPF) algorithm;
- possibility of incorporation of power flow controlling devices and mixed AC/DC modelling;
- probabilistic simulation of one year of operation of the power system using a non-sequential Montecarlo method starting by the reliability characteristics of the system components (components of both the transmission system and the generation set);
- probabilistic definition of the characteristics of variable wind generation, that is treated by the Montecarlo methodology as well;
- quantitative assessment of the reliability and economic benefits, as well as other types of benefits.

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3.2.2 Model inputs and scenarios

To model the inputs for the Italian study, the Italian power system situation at 2010 has been considered as starting point for building up the 2030 scenarios. Table 2 introduces the amounts of the installed net generating capacity for Italy used for both European and Italian studies. Several references, including data from Terna (http://www.terna.it/), GSE (http://www.gse.it), as well as from [32] and [23], have been duly taken into account as sources of the data for the present (2010-2011) situation as well as for the estimation of the future (2020 and 2030) evolution of the generation park in Italy. In particular, the trends emerged during 2011 concerning the boosting penetration of PV (recorded by over 12000 MW capacity level in 2011), the PV incentive target (23000 MW capacity installed by 2016) and the interruption of the nuclear programme have been fully considered towards the estimation of 2020 and 2030 potential generation. The high PV capacity assumed for 2020 and 2030 reflects this update. For the forecast of other RES (non-PV) penetration the 2020 targets set by the Italian NREAP 2020 have been taken into due account, whereas the estimation of future thermal generation capacity is mainly based on [23] and opportune assumptions made by RSE.

Table 2 - Total installed net generating capacity in Italy (in MW)

Electricity source	2010	2020	2030
Hydroelectric	21521	22000	23000
Geothermal	728	920	1086
Solar (PV)	3470	28600	35000
Solar (CSP)	0	600	1000
Wind (onshore)	5814	12000	20000
Wind (offshore)	0	680	1000
Biomass	4832	6340	6700
Nuclear	0	0	0
Thermal (coal)	6600	7000	7000
Thermal (gas)	50979	60089	64000
Thermal (oil)	8179	4235	4000
Thermal (mixed)	6811	7113	7113

Concerning the generation park in Italy, most of it is connected to the transmission network, while a continuously increasing quota, especially RES (like PV and biomass), is distributed over the downstream (LV-MV[4] distribution) grids. The focus of this study is on transmission and its grid-connected generation impact; moreover, most downstream generation (by PV, biomass, hydroelectric, geothermal sources) has been taken into account as well, either directly or indirectly (via compensation balance of local loads). The whole wind generation capacity has been directly and fully considered in the analysis.

Further steps in the 2030 generation scenario building-up have consisted first in the regional breakdown and then in the repartition among the connection voltage levels of the different generation capacities, where relevant. Concerning this analysis the data available for the current (2010-2011) situation as well as those ones related to ongoing and future installed generation projects by ANEV (http://www.anev.org/), Terna ([33]) GSE, NREAP 2020 [32], [34] have been essential to estimate detailed projections. This evaluation has then led to the choice of nodal injection location by the different generation sources in the transmission grid.

Concerning wind generation capacity repartition, the estimation has been based starting from [34] and GSE data (see Table 3).

Table 3 - Wind capacity repartition among Italian regions (in MW)

	2010 (GSE)	**2030 (Forecast)**
ABRUZZO	218.4	250.0
BASILICATA	279.9	1000.0
CALABRIA	671.5	1300.0
CAMPANIA	803.3	1400.0
EMILIA ROMAGNA	17.9	0.0
FRIULI VENETIA GIULIA	0	0.0
LAZIO	9.0	60.0
LIGURIA	19.0	30.0
LOMBARDY	0.0	0.0
MARCHE	0.0	0.0
MOLISE	367.2	500.0
PIEDMONT	14.4	0.0
APULIA	1287.6	13000.0
SARDINIA	638.9	1000.0
SICILY	1435.6	2400.0
TUSCANY	45.4	60.0
TRENTINO ALTO ADIGE	3.1	0.0
UMBRIA	1.5	0.0
VALLE D'AOSTA	0.0	0.0
VENETO	1.4	0.0
	5814.10	**21000.0**

[4] LV: Low Voltage; MV: Medium Voltage; HV: High Voltage; EHV: Extra High Voltage.

The nodal repartition of ongoing and future wind generation projects among the transmission network buses has been carried out following the approach based on the data available from Terna [33][35]. The onshore (20 GW) and offshore (1 GW) wind amounts have been distinguished for the 2030 scenario.
The tool REMARK models wind generation according to specific hourly profiles (for both onshore and offshore installations) and is granted dispatch priority. The wind profiles used for the Italian areas are based on the ones used in [28]. In a similar way to wind, but with their own profiles, other RES (based on RES biomass, PV, hydroelectric and geothermal sources) are also taken into account by REMARK and dispatched with priority. On the other hand, the thermal (non-RES) generation is treated to simulate a merit order dispatch: it is then priced based on the variable generation costs adopted in the European study (see Table 1) and dispatched from the most convenient generation source up to the marginal one, given the system, zonal, interconnection and nodal constraints [31].
Regarding the biomass generation capacity, in consistency with the RES targets for 2020, a national power capacity of 4180 MW of RES biomass has been assumed for 2030, of which 2228 MW, located on downstream (LV-MV) networks, has to be homotetically deducted from the load considering a yearly efficiency of 4380 hours.
The total solar power capacity installed in Italy in 2030 has been evaluated at 36 GW (of which 35 GW PV and 1 GW CSP), even if with remarkable differences among the regions, as it might be deducted from regional capacity values estimated by RSE based on current (2011) and 2020 target repartition (see Table 4).

Table 4 - Regional and voltage connection level breakdown of solar capacity (MW) in Italy (2030)

	LV-MV-HV	HV-EHV
ABRUZZO	1000	-
BASILICATA	450	-
CALABRIA	400	200
CAMPANIA	740	360
EMILIA ROMAGNA	3600	200
FRIULI VENEZIA GIULIA	1100	-
LAZIO	2460	340
LIGURIA	200	-
LOMBARDY	3770	190
MARCHE	1250	250
MOLISE	250	-
PIEDMONT	3300	200
APULIA	2800	2200
SARDINIA	900	600
SICILY	1900	600
TUSCANY	1500	-
TRENTINO ALTO ADIGE	800	-
UMBRIA	900	-
VALLE D'AOSTA	40	-
VENETO	3240	260
	30600	**5400**

5.4 GW of solar capacity (15% of the total amount) has been assumed to be connected to the HV/EHV level in Italy at 2030, and is then directly impacting on the transmission system. After that this quota has been apportioned among the regions, and then subsequently among the grid nodes, in a calibration proportional to the current (2011) situation, the remaining part has been detracted region by region from the hourly load.
The estimation of the national hourly demand for 2030 has been based starting from the 2010 data for the total energy consumption (amounting to 311879.777 GWh) and the load profiles (source GSE). The latter are hourly demand profiles specified for each region and have been used to represent the scenario up to 2030: towards this scope an average yearly growth rate has been applied to these regional profiles over the years, keeping the area distinction, as shown in Table5[5]:

Table 5 - Average yearly load growth rate in Italian areas

Area	% 2010-2021	% 2021-2030
North	1.6	1.0
Centre	1.8	1.0
South	2.3	1.0
Islands	1.6	1.0

Concerning the 2010-2021 period the yearly load growth rate has been taken from TERNA load forecast 2021 ([36]) in view of a moderately high growth scenario, whereas the 2021-2030 load forecast has been based on a conservative estimation made by RSE (also in line with [23]). The total energy consumption in Italy at 2030 amounts to 435362.049 GWh and consistently corresponds to the total value assumed in the European analysis for Italy by JRC.
The subsequent step for building up 2030 scenarios has consisted in reducing the resulting demand profiles by the PV and biomass generation amount connected to the downstream (MV-LV) distribution over the country.
To calculate the PV generation in Italy, instead of irradiation, the actual PV output has been taken into account by data (W/kW installed with 1 hour time-step) available for all of those points depicted as dots in Figure 2 [22].

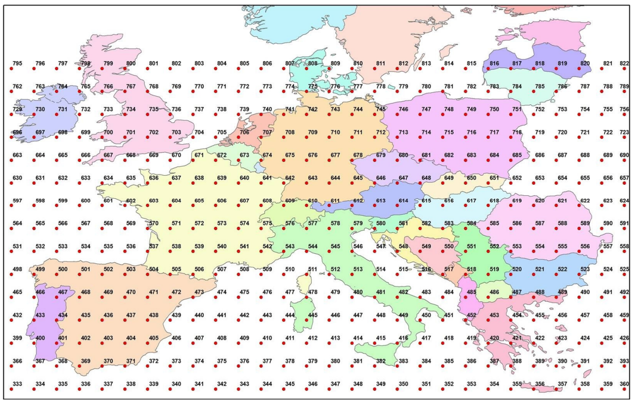

Figure 2 - PV output

[5] The Italian areas are subdivided as in the following: North (Piedmont, Valle d'Aosta, Lombardy, Trentino Alto Adige, Friuli Venetia Giulia, Liguria, Emilia Romagna), Centre (Tuscany, Umbria, Marche, Lazio), South (Abruzzo, Campania, Molise, Apulia, Basilicata, Calabria), Islands (Sicily, Sardinia).

For Italy the actual PV output of the corresponding 21 points (represented as dots in Figure 2) has been considered. These values take into account effects such as temperature (performance drops with increasing temperature), low irradiance and reflection from the PV panels. Figure 3 shows, for the Italian case, that the hours with the highest solar irradiation values are in spring, around March, although the highest average irradiation occurs during the summer.

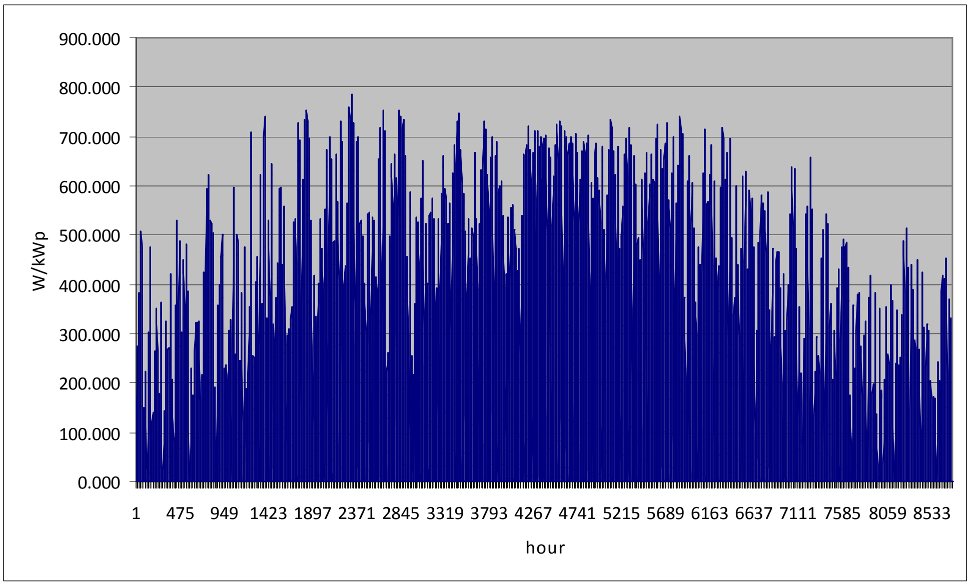

Figure 3 - PV output along the year

A further explanation of the graph in Figure 3 is that the modules are inclined at optimum angle which in Italy ranges from around 30 degrees in the south to 35 degrees in the north. This is the optimum for the whole year which is a weighted compromise between what would be optimal for summer (almost horizontal) and winter (quite steep angle). The result is actually optimal for spring and autumn, where at noon the sun will be shining almost perpendicular onto the panels. In winter and summer the sunlight will always be at some angle from perpendicular, so the in-plane irradiance is lower at noon.
Concerning the losses of the panels, the AC power output is estimated as 90% of the DC power, taking into account inverter losses, as well as dirt, snow, occasional shadows etc.
The regional productivity has then been calculated as average value of those dots in Figure 1 defining the required area. For instance the outline for the region Sicily has been valued as the average of the surrounding dots 414-415-416-382-383.

Once the load profiles have been built, a discretization is needed to better allow the REMARK tool to cope with such a huge amount of data with a lower calculation time. Therefore, four time-slices have been set to draw the load over each day, considering the differences inside the four seasons and keeping the distinction between working and weekend day, resulting then in 32 time-slices for a year (see Table 6). It has to be highlighted here that the choice of hourly profiles subdivision has been also based on the impact of large PV penetration on peak load over the daily hours in the different seasons.

Table 6 - Time-slices subdivision for Italian profiles (2030)

	Hour package			
Winter	1-6	7-9, 21-24	10-16	17-20
Spring	1-6	7-9, 22-24	10-17	18-21
Summer	1-7	8-9, 23-24	10-18	19-22
Autumn	1-6	7-9, 22-24	10-17	18-21

Concerning the building-up of transmission network evolution, it has been highlighted that, in order to investigate potential weaknesses of the Italian transmission network due to 2030 scenarios, the followed planning approach has consisted in the analysis of the main 2020 Italian grid complemented by the new interconnections foreseen and planned up to 2030. These include the three submarine links of Italy with North Africa, namely with Algeria (via Sardinia) and with Tunisia and Libya (both via Sicily). The starting point of this analysis has been the opportune adaptation of the 2020 Italian grid model developed in [37] and updated with the most recent and relevant reinforcements contained in [33].
Table 7[6] displays the list of existing and future cross-border transmission interconnections around Italy taken into consideration in the 2030 study (in accordance with the set scenarios) [27][33]. The corresponding net capacity values between Italy and bordering countries are then set in consistency with these 2030 interconnections: those values have been calculated by RSE according to the approach described in 3.1 and have been used first in the European study and then in the Italian specific case.

Since in the Italian study the analysis does not take into account the grids of bordering countries, in order to evaluate the effect of cross-border flows (import and export) across Italy, a simplified, yet effective, modeling approach has been followed. Namely, each cross-border interface (listed in Table 7) has been represented by its link (line or cable) rated at its capacity with the foreign bus having both a generator (sized twice the link capacity) and a load (rated as the link) there connected. In this way, REMARK tool is able to simulate the import and the export flows across the Italian borders, based on the merit order dispatch. The equivalent foreign bus generators are considered like thermal power plants participating in the merit order with the corresponding hourly marginal prices resulting from the European analysis by JRC. The exceptions to the approach of using equivalent generators concern the links with Malta and with Corsica (France), where only a load is seen on the foreign side. Since in the Italian case there is also the interconnection with Albania, which is not taken into account in the European study, opportune assumptions, also based on current and future generation park evolutions in Albania (source: ERE, http://www.ere.gov.al/index.php?lang=EN), have been made by RSE to correspondingly estimate the hourly marginal generation cost in Albania at 2030 in the most consistent way.

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[6] HVAC: High Voltage Alternating Current; HVDC: High Voltage Direct Current. It has be remarked that some links in the table refer to existing interconnections to be expanded, like the one between Italy and Greece (from 500 MW to 1000 MW) or to be repowered, like the one between Italy and France (Corsica) (from 300 MW to 600 MW). The Italy-Austria link to Thaur via Brennertunnel may be based on HVAC via GIL (Gas Insulated Line) technology or on HVDC. The Italy-Malta link is based on 220 kV HVAC submarine cable. It has to be also said that on many cross-border links with the Alpine region (France, Switzerland, Austria, Slovenia) power flow controlling devices like PST (Phase Shifting Transformers) exist or will be installed, to increase the cross-border capacity and overcome congestions.

Table 7 - Interconnections at Italian borders considered in 2030 scenario

Node	Country	Node	Country	Type
TIVAT	Montenegro	VILLANOVA	Italy	HVDC (future)
ZUWARAH	Libya	CHIARAMONTE	Italy	HVDC (future)
EL HAOUARIA	Tunisia	PARTANNA	Italy	HVDC (future)
EL HADJAR	Algeria	RUMIANCA	Italy	HVDC (future)
ARACHTHOS	Greece	GALATINA	Italy	HVDC (existing)
CANDIA	Italy	KONJSKO	Croatia	HVDC (future)
DIVAČA	Slovenia	REDIPUGLIA	Italy	HVAC (existing)
OKROGLO	Slovenia	UDINE OVEST	Italy	HVAC (future)
DIVAČA	Slovenia	PADRICIANO	Italy	HVAC (existing)
VOLPAGO	Italy	LIENZ	Austria	HVAC (future)
CARDANO	Italy	THAUR	Austria	HVAC or HVDC (future)
GLORENZA	Italy	NAUDERS/WEST TIROL	Austria	HVAC (future)
BABICA	Albania	BRINDISI SUD ST.	Italy	HVDC (future)
ROBBIA	Switzerland	TIRANO/S. FIORANO	Italy	HVAC (existing)
CAGNO	Italy	MENDRISIO	Switzerland	HVAC (existing)
MUSIGNANO	Italy	LAVORGO	Switzerland	HVAC (existing)
MORBEGNO	Italy	LAVORGO	Switzerland	HVAC (future)
MESE	Italy	SOAZZA	Switzerland	HVAC (existing)
VERDERIO	Italy	SILS	Switzerland	HVDC (future)
MESE	Italy	GORDUNO	Switzerland	HVAC (existing)
AVISE	Italy	RIDDES	Switzerland	HVAC (existing)
VALPELLINE	Italy	RIDDES	Switzerland	HVAC (existing)
PONTE	Italy	AIROLO	Switzerland	HVAC (existing)
PALLANZENO	Italy	SERRA	Switzerland	HVAC (existing)
GRAND'ILE	France	PIOSSASCO	Italy	HVDC (future)
RONDISSONE	Italy	ALBERTVILLE	France	HVAC (existing)
VENAUS	Italy	VILLARODIN	France	HVAC (existing)
BROC CARROS	France	CAMPOROSSO	Italy	HVAC (existing)
MAGHTAB	Malta	RAGUSA	Italy	HVAC (future)
LUCCIANA	France (Corsica)	CODRONGIANUS	Italy	HVDC (existing)
LUCCIANA	France (Corsica)	SUVERETO	Italy	HVDC (existing)

4. Case studies

For the interconnection expansion between North Africa and ENTSO-E, realistic estimations have been carried out, shifting the implementation of very ambitious plans (like the ones of DESERTEC Initiative [2]) to the post-2030 period. Thus, each corridor analysed at this interface, namely at Spain-Morocco, Spain-Algeria as well as at Italy-Tunisia, Italy-Algeria, Italy-Libya borders, in the most optimistic scenario has been considered by a maximum NTC equal to 2000 MW. In order to provide European and Italian perspectives of the power imports from Africa on the interconnected European electricity system and the Italian grid, three scenarios, pessimistic ("A"), reference ("B") and optimistic ("C"), are assumed in terms of the interconnectors between North Africa and Europe and their maximum transfer capacity. Table 8 shows the maximum transfer capacities from Africa for the three scenarios (see also Figure 4).

Table 8 - Interconnection capacities between Africa and Europe for the three main scenarios (MW)

Interconnector	Pessimistic Scenario	Reference Scenario	Optimistic Scenario
Morocco – Spain	1400	2000	2000
Tunisia – Italy	1000	1000	2000
Algeria – Spain	1000	1000	2000
Algeria – Italy	-	1000	2000
Libya - Italy	-	1000	2000

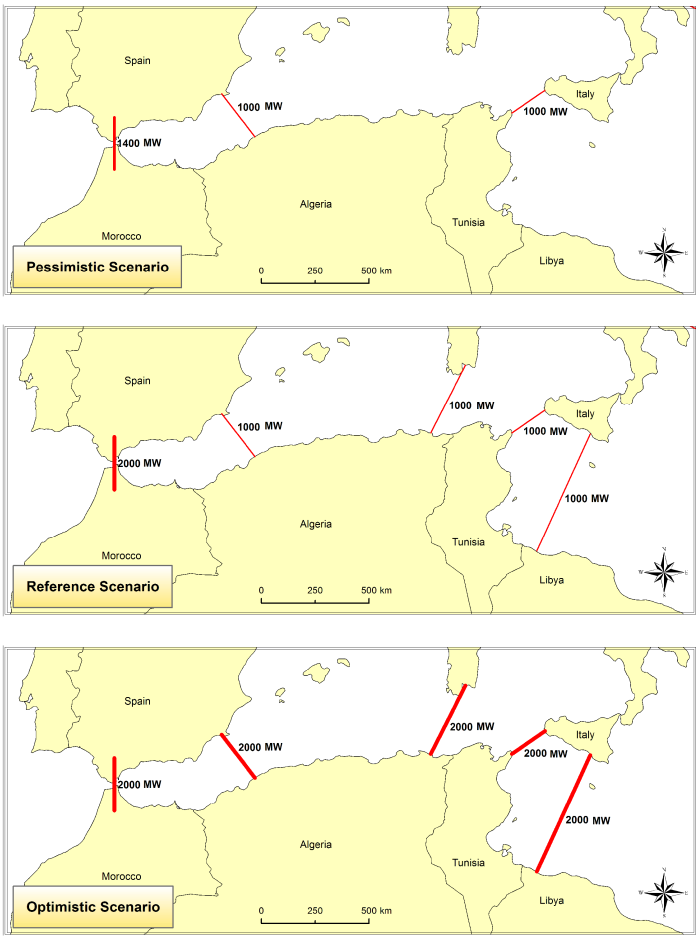

Figure 4 - The three main 2030 scenarios for the interconnection between North Africa and Europe

In addition, in order to better understand the effects and the possible benefits of importing electricity from Africa, the model is run for a scenario with no power imports from Africa (scenario "D"). Finally, a sensitivity analysis based on the optimistic scenario with the African interconnectors is performed by lowering the African electricity variable production cost (from 41.25 to 10.52 Euro/MWh) below the European electricity variable production cost for nuclear sources and therefore varying the merit of order (scenario "C1").

4.1 European Perspective

EUPowerDispatch is run for each of the previously defined 2030 scenarios.
The European perspective on power imports from North Africa in 2030 is assessed in terms of three variables: the annual cross-border net exchanges, the hourly marginal energy source in each European country and the economic impacts of the power imports from Africa on the total annual variable electricity generation costs in Europe.
The main and most visible finding is that for the three scenarios the interconnectors between North Africa and Italy are practically 100% loaded in every hour of the year. The interconnectors between North Africa and Spain instead are fully loaded for the 99.9% of the hours of the year. There are very few hours of the year during which the Spanish cheaper energy sources (including hydro, wind, solar) and in some cases the convenient imports (from Portugal mainly) are

sufficient to meet the local load and therefore the power imports from Africa are not needed. In other few hours of the year the African imports are the marginal energy source in Spain (and/or Portugal) and the interconnectors are not fully loaded.

Figure 5 provides the annual cross-border net exchanges in Europe for each of the three main scenarios. A first observation is that the net power exchanges tend to follow the direction from South to North. In addition, in contrast with the present situation, Spain and Italy are clearly shown to be net exporters of electricity. Together with the expected high wind and solar installed generation capacities in Spain and Italy, the power imports from Africa highly contribute to this behaviour. In fact, the optimistic scenario, which represents a larger import from Africa, shows higher Italian and Spanish power exports than the reference and pessimistic scenarios. It has to be said that this outcome would reflect an ideal situation. In fact, it is important to highlight the assumption behind the European analysis that consists in considering no internal transmission congestions and no possible loop flows which could limit the North-African power imports and/or the Spanish and Italian exports. The Italian perspective study analyses this issue more in detail by focusing on the Italian grid in all its aspects.

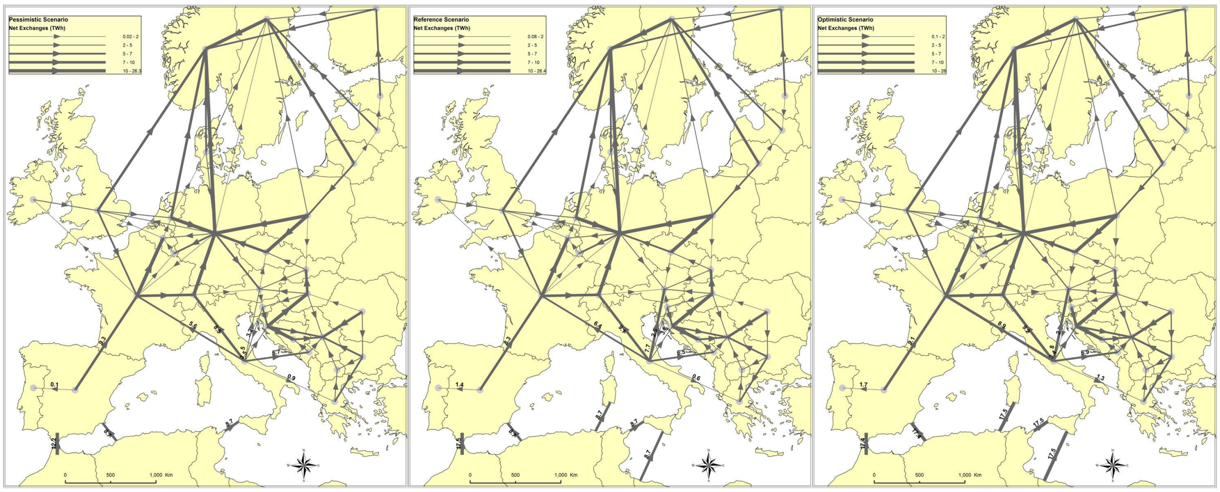

Figure 5 - Annual cross-border net exchanges for the pessimistic, reference and optimistic scenarios

Table 9 shows the number of hours in the year during which each of the energy sources is the marginal producer in Italy, Spain and their neighbouring countries. The first observation for each of the countries considered is that gas is the marginal fuel during the majority of the hours of the year. Looking at the different scenarios it can be observed that as the interconnection capacities between North Africa and Europe increase, the number of hours in which African generation is marginal increases in Spain and Portugal. In addition, there are few hours during which hydro power is the marginal source. During these hours the interconnectors between Africa and Spain are not used as previously described (see Figure 1). For Italy, instead, the African imports, in this analysis, do not represent in any scenario the marginal source proving and showing that the African interconnectors feeding the Italian grid are always practically 100% loaded (the situation will however look different in the Italian study considering the whole national system and the internal bottlenecks). Furthermore, changes in marginal generation sources throughout the year can be observed in all the countries interconnected to Italy and/or Spain. The power imports from North Africa affect the overall European interconnected network. The effects decrease from South to North but still affect every country which is interconnected to Italy and/or Spain.

Table 9 - Hours of marginal energy sources

Pessimistic Scenario

	ES	PT	FR	IT	GR	ME	HR	SI	AT	CH	DE
hydro	0	23	0	0	14	0	0	0	0	0	0
nuclear	0	0	0	0	0	0	0	0	0	0	0
African gen.	16	10	0	0	0	0	0	0	0	0	0
biomass	106	58	31	0	9	0	0	0	0	0	0
coal	194	298	50	4	41	3	4	4	4	4	11
gas	8420	8347	8274	8732	8245	6906	8672	8672	8495	8428	8437
lignite	0	0	374	0	427	1827	60	60	237	304	288
oil	0	0	7	0	0	0	0	0	0	0	0

Reference Scenario

	ES	PT	FR	IT	GR	ME	HR	SI	AT	CH	DE
hydro	0	21	0	0	14	0	0	0	0	0	0
nuclear	0	0	0	0	0	0	0	0	0	0	0
African gen.	25	12	0	0	0	0	0	0	0	0	0
biomass	120	72	32	0	5	0	0	0	0	0	0
coal	191	302	52	5	41	3	4	4	4	5	11
gas	8400	8329	8271	8731	8245	6925	8672	8672	8498	8427	8441
lignite	0	0	374	0	431	1808	60	60	234	304	284
oil	0	0	7	0	0	0	0	0	0	0	0

Optimistic Scenario

	ES	PT	FR	IT	GR	ME	HR	SI	AT	CH	DE
hydro	0	22	0	0	14	0	0	0	0	0	0
nuclear	0	0	0	0	0	0	0	0	0	0	0
African gen.	60	26	0	0	0	0	0	0	0	0	0
biomass	138	84	33	1	6	0	0	0	0	1	0
coal	262	339	65	21	46	4	15	15	15	20	21
gas	8276	8265	8252	8714	8290	6779	8654	8654	8482	8408	8423
lignite	0	0	379	0	380	1953	67	67	239	307	292
oil	0	0	7	0	0	0	0	0	0	0	0

Scenario without African power imports

	ES	PT	FR	IT	GR	ME	HR	SI	AT	CH	DE
hydro	0	22	0	0	14	0	0	0	0	0	0
nuclear	0	0	0	0	0	0	0	0	0	0	0
African gen.	0	0	0	0	0	0	0	0	0	0	0
biomass	58	30	31	0	8	0	0	0	0	0	0
coal	139	281	45	3	40	2	3	3	3	3	9
gas	8538	8402	8283	8733	8234	6802	8666	8666	8496	8434	8444
lignite	1	1	370	0	440	1932	67	67	237	299	283
oil	0	0	7	0	0	0	0	0	0	0	0

The sensitivity analysis performed using the optimistic scenario and assuming a lower variable generation cost for North-African imports shows very similar results in terms of the overall behaviour of the European power system. Few changes are observed in terms of interconnection loading between Africa and Spain. Due to the lower variable generation cost, more power is transported from Africa to Spain. However, this difference remains almost insignificant due to the already extremely high average loading of such cross-Mediterranean interconnectors.

Finally, the three main scenarios ("A", "B", "C") and the one used for the sensitivity analysis ("C1") are compared to the scenario without North-African imports ("D") in terms of annual electricity variable generation costs for whole Europe. Table 10 shows the savings in terms of annual variable generation costs for each of the 4 scenarios compared to the one without interconnections between North Africa and Europe.

Table 10 - Economic Evaluation

Scenario	A	B	C	C1	D
Annual European Variable Generation Cost (BILLION Euro)	134.158	133.692	132.977	130.294	134.763
Annual Savings with respect to Scenario D (MILLION Euro)	605	1071	1786	4469	N/A
Variable Generation Cost of African Power (Euro/MWh)	41.25	41.25	41.25	10.52	N/A
Annual electricity generation in Africa (TWh)	29.689	52.39	87.294	87.349	N/A
Annual African Variable Generation Costs (BILLION Euro)	1.225	2.161	3.601	0.919	N/A
Threshold Value for Investment Evaluation (BILLION EURO)	**1.830**	**3.232**	**5.387**	**5.388**	N/A

The fourth scenario ("C1") shows a much higher value of possible savings due to the lower variable generation cost of the electricity produced in Africa. However, this difference (between scenarios "C" and "C1") does not affect the threshold value below which the investment would be profitable. The threshold value, also provided in Table 10 gives the value below which the investment annuity of importing power from North Africa to Europe is profitable. The investment annuity should be calculated considering the overall project's lifetime, the "annual-correspondent" generation and transmission investments and the annual fixed and variable generation costs.

4.2 Italian Perspective

The same boundary conditions seen in the European study have been then applied to the Italian case at 2030, considering then the three main scenarios ("A", "B", "C") together with the variant ("C1") and the base scenario ("D") with no link between Africa and Europe. The runs of REMARK tool have provided several results, which are summarised in terms of exchange flows between market zones (Table 11 and Figure 6) and in terms of average marginal generation costs (Figure 7 and Table 12) for the five cases. The Italian system is considered to be split in the following market zones[7]: North, Center-North, Center-South, South, Sicily and Sardinia. In the run cases, a 2000 MW NTC has been considered on the South-Sicily interface; furthermore,

[7] The difference between Italian zones and areas (see 3.2) is that while North is the same in both categories, Center-North zone includes the regions of Tuscany, Marche, Umbria, while Lazio, Campania, Abruzzo belong to Center-South zone; Sardinia and Sicily are individually considered as zones whereas the remaining regions are part of South zone.

between Sardinia and Center-North (through Corsica) the limit is given by the SA.CO.I. cable link capacity, namely 600 MW, while between Sardinia and Center-South the maximum capacity transfer amounts to 1000 MW (due to SA.PE.I. rating). Other inter-zonal limits in Italy in the 2030 scenarios have not been taken into account.

A first very important outcome of the analysis is that there is a clear, relevant flow of electricity from North Africa to Italy (Sicily and Sardinia). This import reaches its peak in scenarios "C" and "C1" as expected, but in relative terms the case "B" sees the most favourable conditions. In the latter scenario, for most yearly hours the interconnectors are almost fully loaded; it can be however appreciated that for very few hours Sicily is also able to export electricity to Tunisia and Libya. This applies also in the other relevant cases. In scenarios "C" and "C1" the maximum utilisation of each corridor's capacity amounts to ca. 80%, while in the case "B" this value can reach even 99% ca. This difference means that an increase of each interconnector's capacity (from 1000 to 2000 MW) does not necessarily lead to an increased import from North Africa to Italy for the facts that internal grid constraints exist and limit this flow but also due to local RES generation in Sardinia and Sicily that is dispatched prior to North-African electricity. In fact, this occurs in "C" and "C1" in Sardinia and can be highlighted by the not full exploitation of inter-zonal links with the Italian peninsula (SA.CO.I. and SA.PE.I. are in fact averagely loaded for a maximum of less than 50%) mainly because of internal Sardinian constraints. In the case of Sicily, instead, the constraint of the link with South zone plays a major role in this reduced North-African import.
It has to be also highlighted that in the cases "C" and "C1" the largest African exporter is represented by Libya: its electricity also serves to supply the fixed 250 MW load in Malta.

Another important outcome of the study is that in all cases Italy is a net electricity importer from the bordering countries of the Alpine region, namely France, Switzerland, Austria, Slovenia. This difference with respect to the European study (with exception of the Italy-Slovenia interface, where the trend is confirmed) is a fact that is depending on the internal grid bottlenecks and cross-border constraints that limit the possibility that the RES generation, mostly concentrated in the southern and insular parts of the Italian peninsula, reach the northern borders to be exported. The same applies to the African imports and their impact on northern borders.
Concerning the flows at its eastern borders with the Balkan region, here the situation is partially reverse as Italy is heavily exporting to Montenegro and this export increases with the import from North Africa. A similar trend with increasing export through the scenarios is recorded with Albania and Greece, although the amount of exported energy is less high with respect to Montenegro. The same trend does not occur with Croatia where the net flow has the sign of import in all cases, even if there are more hours in which Italy exports to Croatia, with the peak situation in case "B".
Another important result is that, with the increased import from North Africa, the net flows of electricity are more and more directed from the islands and from the south of the country up to the north where large consumption is mainly concentrated. This trend can be seen from scenario "B" where the net power flow between the zones of Center-North and North is reversed in direction with respect to the cases "A" and "D": this confirms the impact of Italian RES generation location as well as the African import influence.
Further elements of analysis can be derived from the results in Table 12 (whose details are plotted in Figure 7), in which the average yearly marginal costs are displayed for the different

market zones as weighted with respect to loads, where present. From Figure 7 the comparison among the scenarios “A”, “B”, “C” and “D” has been considered in detail for the Italian market zones, having considered the red colour associated to the minimum value of the scenario and the blue to the maximum.
It is evident that the averagely weighted locational marginal costs in Table 12 are strongly dependent on the marginal generation source, which in most zones in all scenarios is represented by thermal (gas) production. The exceptions to this outcome are given by the Italian market zones of Sicily and Sardinia in which, especially in cases “C” and “C1”, the impact of import from North Africa is strong and makes the marginal costs lower or even much lower than in the rest of Italian zones in those scenarios. The same does not occur in the other Italian zones mainly due to internal grid bottlenecks, as said. This is surely an important result. Instead, scenario “A” has led to a reduction of the zonal prices differences with respect to the scenario “D”: the price of Sardinia is unvaried whereas the zones of South and Sicily show a slight increase.
It can be additionally highlighted that also Malta’s marginal cost is strongly influenced by North-African import, being even slightly lower than the average one in Sicily.

Table 11 - Exchange flows across zones

Exchange flows in GWh		**Scenario"C"**		**Scenario "C1"**	
From/To	**From/To**	→	←	→	←
NORTH	**FRANCE**	7,654	24,931	7,660	24,884
NORTH	**SWITZERLAND**	9,656	27,156	9,105	27,654
NORTH	**AUSTRIA**	9,578	10,481	9,553	10,291
NORTH	**SLOVENIA**	5,957	10,179	6,192	10,007
CENTER-NORTH	**CROATIA**	2,455	5,202	2,418	5,240
CENTER-SOUTH	**MONTENEGRO**	8,183	336	8,185	337
SOUTH	**ALBANIA**	2,462	1,817	2,528	1,748
SOUTH	**GREECE**	5,871	2,515	5,973	2,416
SARDINIA	**ALGERIA**	-	12,404	-	12,405
SICILY	**TUNISIA**	181	11,212	158	10,971
SICILY	**LIBYA**	104	13,788	110	14,071
SICILY	**MALTA**	2,186	-	2,186	-
NORTH	**CENTER-NORTH**	4,509	17,894	5,005	17,733
CENTER-NORTH	**CORSICA**	11	4,157	11	4,158
SARDINIA	**CORSICA**	5,023	2	5,024	2
CENTER-NORTH	**CENTER-SOUTH**	3,147	25,493	3,438	25,228
CENTER-SOUTH	**SARDINIA**	1	4,180	1	4,166
CENTER-SOUTH	**SOUTH**	-	49,419	-	49,137
SOUTH	**SICILY**	75	16,945	55	16,984

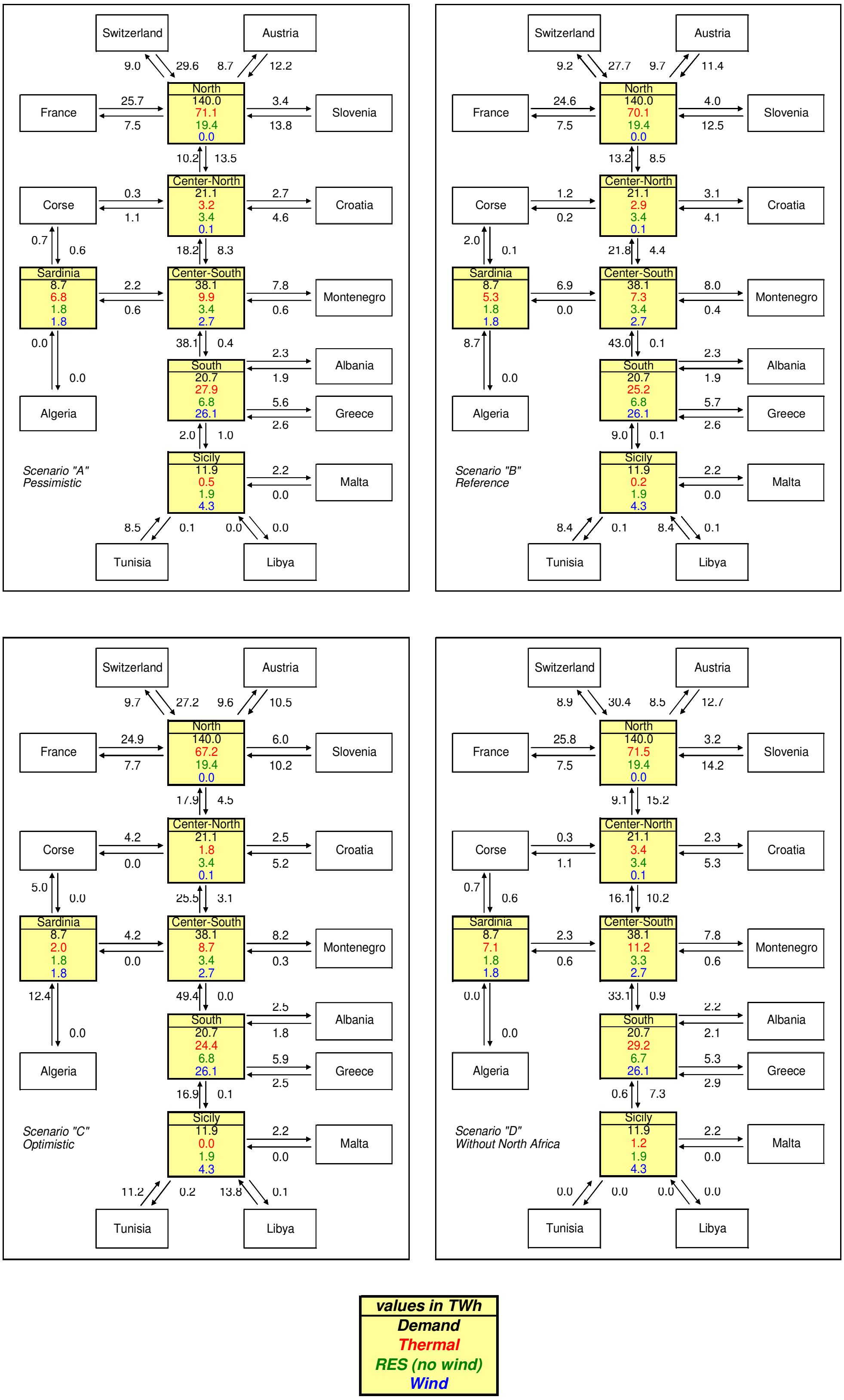

Figure 6 - Flows and electrical power balances

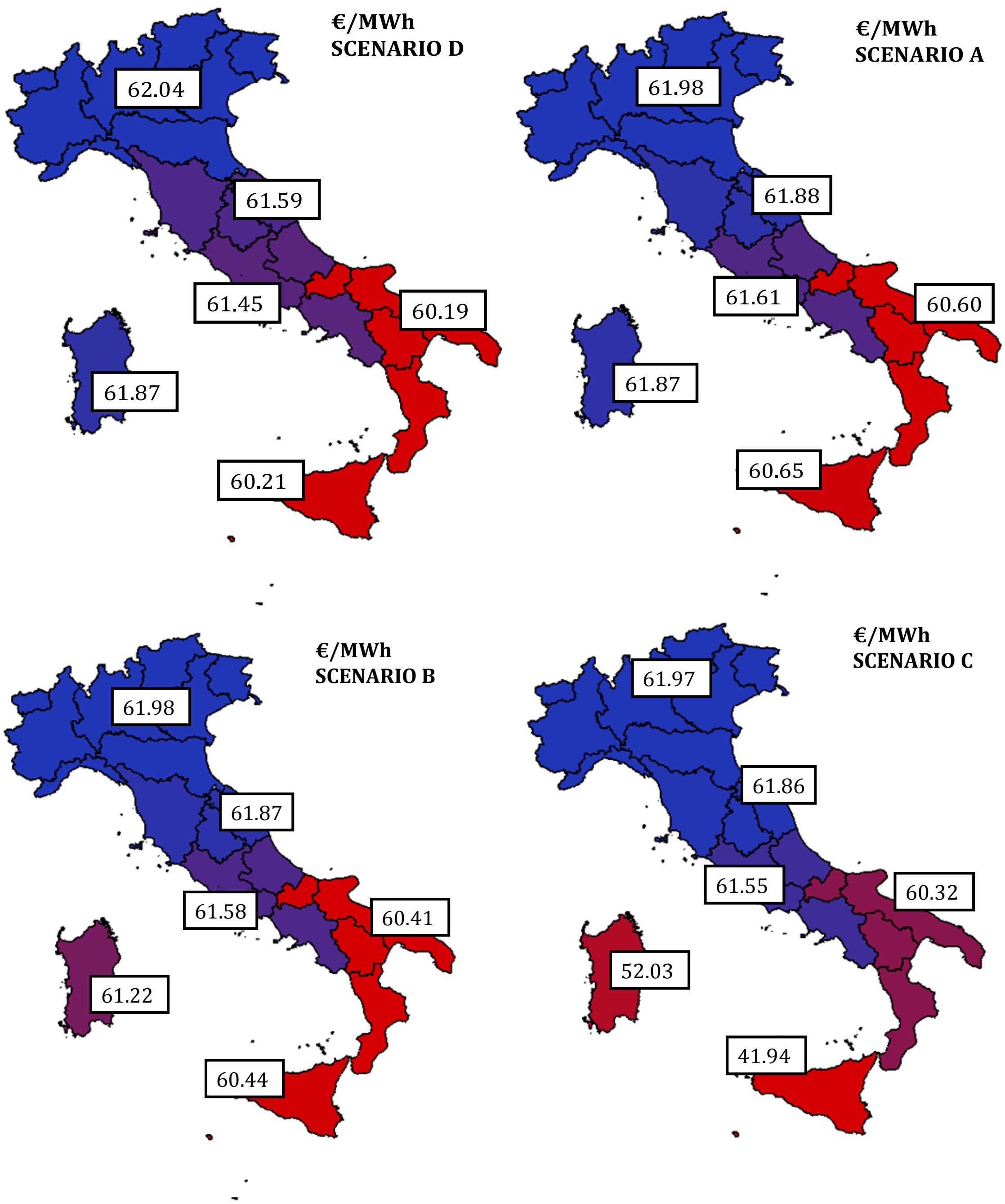

Figure 7 - Zonal prices in different scenarios

Table 12 - Locational Marginal Prices

Locational Marginal costs in €/MWh	Scenario "D"	Scenario "A"	Scenario "B"	Scenario"C"	Scenario "C1"
NORTH	62.04	61.98	61.98	61.97	61.97
CENTER-NORTH	61.59	61.88	61.87	61.86	61.86
CENTER-SOUTH	61.45	61.61	61.58	61.55	61.12
SOUTH	60.19	60.60	60.41	60.32	59.06
SICILY	60.21	60.65	60.44	41.94	12.23
SARDINIA	61.87	61.87	61.22	52.03	37.59
FRANCE	62.28	62.25	62.28	62.28	62.26
CORSE	61.89	61.87	61.82	61.80	61.73
SWITZERLAND	62.19	62.16	62.20	62.19	62.17
AUSTRIA	61.97	61.96	61.97	61.96	61.96
SLOVENIA	61.91	61.91	61.91	61.89	61.90
CROATIA	61.89	61.89	61.90	61.88	61.88
MONTENEGRO	62.32	62.42	62.35	62.06	62.06
ALBANIA	61.86	61.88	61.87	61.85	61.83
GREECE	61.08	61.42	61.28	61.14	60.43
LIBYA			41.25	41.25	10.52
TUNISIA		41.11	41.25	41.25	10.52
ALGERIA			41.25	41.25	10.52
MALTA	60.21	60.65	60.44	41.74	11.75

Considering the results of the study in terms of transmission grid behaviour, it has been also essential to analyse the possible weaknesses of the internal Italian network and the potential reinforcement options to overcome them.

This analysis has led to the conclusions that several areas in the Italian system present a critical situation, especially in the scenarios “B”, “C”, “C1”. These critical portions of the grid are mainly located in Sardinia, around the metropolitan areas of Rome, Naples, Milan, in Tuscany, in Center-South along the Tyrrhenian and Adriatic axes and at the interface between Center-South and South. The latter cases have been then specifically investigated with focus on the case “B”. In particular, the effect of the utilisation of the five internal PSTs, of which two located at Villanova in Center-South zone (to control the flows on both Adriatic axis lines), one located at Foggia in South zone (to control the flow due to massive local RES generation) and two located at Bisaccia in Center-South zone (to control the flow between the two Tyrrhenian and Adriatic axes), can be seen by comparing the case “B” without PSTs and the reference case “B”. From Table 13 and Figure 8 it emerges the impact of these devices in flow dispatch allowing eg. a larger export from Italy to Montenegro and also to Croatia and reducing the total dispatch costs of 21 M€.

Another reinforcement option taken into account has been the doubling of the line Latina-Garigliano located in Center-South zone between the areas of Rome and Naples: the aim is in fact to alleviate the congestions existing in this grid portion. This line’s impact can also be seen in terms of total dispatch cost reduction, leading to a total saving of 4 M€.

Table 13 - Flows in scenario "B" and its variants

Exchange flows in GWh		Scenario "B" without PST		Scenario "B"		Scenario "B" with reinforcement Latina-Garigliano	
From/To	From/To	→	←	→	←	→	←
NORTH	FRANCE	7,573	24,541	7,526	24,597	7,544	25,007
NORTH	SWITZERLAND	10,434	23,711	9,230	27,688	9,048	27,641
NORTH	AUSTRIA	9,571	12,155	9,662	11,358	9,242	11,710
NORTH	SLOVENIA	3,887	12,497	4,039	12,501	4,739	11,305
CENTER-NORTH	CROATIA	1,886	5,069	3,054	4,078	2,987	4,309
CENTER-SOUTH	MONTENEGRO	7,047	832	7,954	397	8,022	389
SOUTH	ALBANIA	2,427	1,824	2,335	1,898	2,376	1,850
SOUTH	GREECE	5,415	2,725	5,664	2,568	5,669	2,570
SARDINIA	ALGERIA	-	8,672	-	8,672	-	8,671
SICILY	TUNISIA	240	8,296	91	8,372	34	8,479
SICILY	LIBYA	269	8,285	55	8,391	58	8,390
SICILY	MALTA	2,186	-	2,186	-	2,186	-
NORTH	CENTER-NORTH	7,041	15,394	8,513	13,200	8,478	13,268
CENTER-NORTH	CORSICA	165	1,595	158	1,210	149	1,450
SARDINIA	CORSICA	2,379	72	1,987	58	2,232	56
CENTER-NORTH	CENTER-SOUTH	4,250	22,515	4,408	21,771	4,489	21,455
CENTER-SOUTH	SARDINIA	12	6,452	1	6,899	1	6,524
CENTER-SOUTH	SOUTH	135	42,851	125	42,967	127	43,255
SOUTH	SICILY	424	9,329	77	9,036	33	9,146

Considering scenario "B" and its variants (without PSTs and with reinforcement Latina-Garigliano) in terms of marginal costs (see Figure 8), it can be noticed how the former variant would lead to a bottleneck between the South and the Center-South, determining a net price difference; the latter variant has a higher price homogeneity. In both cases the Sardinia situation improves with respect to the case "B".

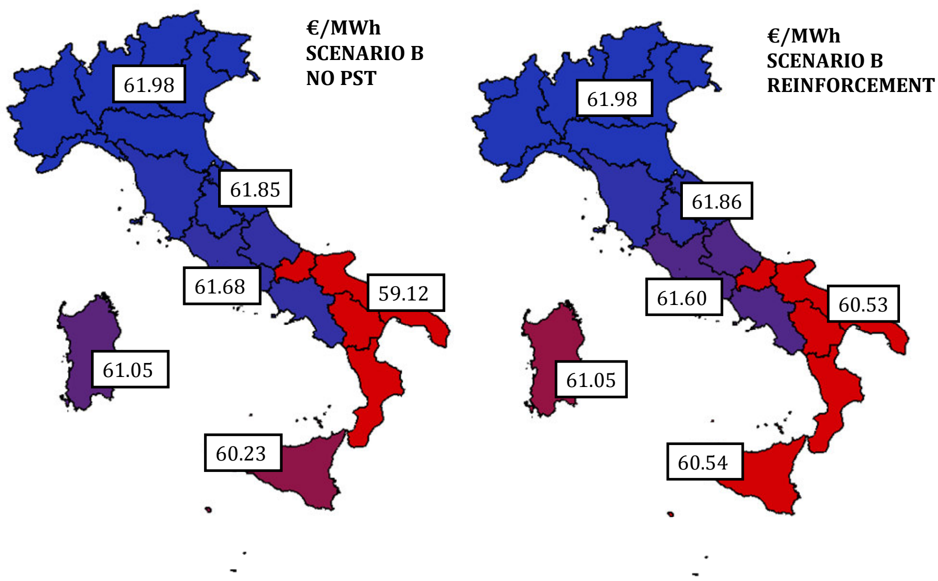

Figure 8 - Zonal prices (sensitivity scenario "B")

5. Conclusions and future work

The presented joint studies show how importing African solar power significantly impacts on the European and Italian 2030 flows and prices. The results of the implementation of selected potential reinforcement alternatives on the Italian grid have been shown as well.
A further future investigation might consist in a detailed evaluation of the investments on the African side (generation and grid) so as to be allowed to carry out a detailed cost-benefit analysis of the investment alternatives.

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