EUROPEAN GRID STUDY 2030/2050

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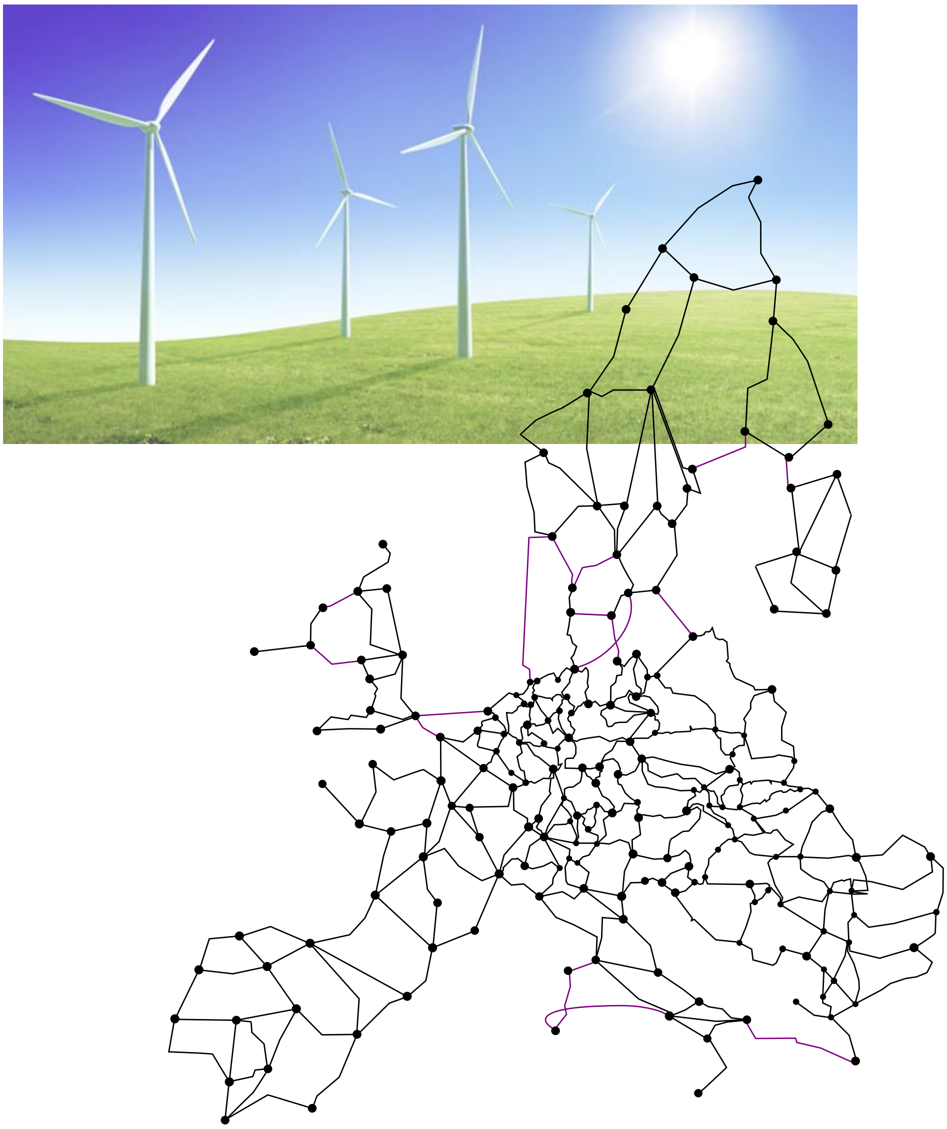

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SUMMARY

This study follows the 2009 analysis by energy**nautics** and Greenpeace International titled 'Renewables 24/7 Infrastructure to Save the Climate', which looked at the feasibility of integrating over a 90% share of renewable energies in the European power system for 2050, based on Greenpeace's Energy [R]evolution scenario (Greenpeace International, EREC, 2009). This report investigates in more detail the strategic options for reaching this outcome in 2050 and how to optimise the use of all the installed renewable energy sources. The revised Energy [R]evolution for 2010 now forecasts 97% renewable energy sources (RES) for the European grid in 2050. This new study was commissioned to investigate various operating scenarios in the year 2030 and 2050 and to develop a methodology for optimising the use of installed renewable energy sources in our simulations.

THE OPTIMISED 2030 GRID

Optimal grid infrastructure planning relies heavily on power flow studies that reveal how much electricity is generated and transported by which generator and along which path. In the scenario created by Greenpeace, the demand for electricity increases in the future and the energy mix shifts from a fossil-fuel based to almost entirely renewables-based power generation. For this to happen, the European transmission infrastructure will require several reinforcements and upgrades. To tackle this challenge, energy**nautics** has developed a new methodology to model the electricity consumption and generation in a 2030 scenario; where renewable energy provides 68% of our electricity production. The model uses DIgSILENT Power Factory to perform optimal power flow simulations to identify critical areas where infrastructure needs to be upgraded. The methodology developed for the 24/7 Report was enhanced to include simulations of operation over a whole year under standard operating conditions as well as the simulations of operation under extreme weather conditions, to ensure the secure supply of electricity at all times. This approach improves the analysis of energy utilisation characteristics, and means we can calculate the electricity generated by each energy source, the amount of renewable energy curtailed, and the associated levels of CO_2 emission in the year 2030.

By assessing the network with this methodology, the study found that for the European electricity grid to move from today's state to that of 2050 envisioned by Greenpeace, heavy investment is needed to build up the transfer capacity between South and Central Europe. The large load centres such as London, Paris and Brussels are mainly located in the centre of Europe, and local renewables will not be sufficient to power them.

> The grid will need to transfer large quantities of mainly solar energy from southern countries such as Spain, Portugal and Italy, and simultaneously bring wind energy southwards, requiring a North Sea offshore grid.

Corresponding to the strong draw of energy from the poles of the system, transmission corridors, particularly through Portugal-Spain-France, require significant strengthening. Up to 65 GW in 2030 of wind power is expected to be available for harvesting in the North Sea region, and providing adequate transfer capacity to harness this power will be absolutely essential. Besides these, upgrades in the order of several tens of gigawatts transfer capacity will also be required in parts of Eastern Europe and the Nordic region to allow for greater power exchange.

In optimising the use of renewable energy in the grid, optimum power flow simulations were performed giving priority on a European level to power generated from non-controllable renewable resources such as solar PV and wind compared to sources such as fossil-fuels and biomass, which can be stored and used later in time. With a global prioritisation method, much less renewable energy would be curtailed compared to the methodology that was used in the 24/7 Report.

This new study actually shows it is possible to reduce the level of curtailed renewable energy from 12% to 4% for the same scenario applying the global prioritisation method.

However, a significant quantity of wind power would still be curtailed, particularly from offshore wind power plants, due to the lack of transfer capacity between the North-Sea offshore grid and the main load centres. Using the new optimisation method shows how the integration of renewable resources can be optimised by finding out the point where the cost of adding transmission infrastructure between the wind source and the sinks matches the cost of savings from reducing renewable energy curtailment. In this way, the overall curtailment could be cut down from 4% to approximately 1%.

2030 PATHWAY OPTIONS

To reach the 2050 grid with 97% renewable energy requires a suite of technical strategies to help make the transition. These include the implementation of demand-side management (DSM), dedicated storage devices, electrical vehicles (EV), and fast-reacting backup gas turbines in addition to generally upgrading the network so that renewable energy can be transferred to where it is needed. This study investigated three levels of DSM, assuming that in 2030 it will be possible to increase or decrease demand by 5%, 10% or 20% according to the available local renewable supply. It found that higher levels of DSM allow better use of the local renewable energy sources, however not in significant proportions.

The DSM levels did not create significant differences to the grid infrastructure required in 2030, or the amount of CO_2 emissions mitigated. With the implementation of storage mediums and EVs, the impact in reducing the amount of curtailed energy was minimal, unless unrealistically large quantities of storage are placed at unique points within the system.

The study also assesses the validity of including backup gas turbines, which was deemed unnecessary given that the grid is sufficiently upgraded to maintain a secure electricity supply for a standard operating scenario for a year.

If a certain proportion of coal and nuclear power is considered as inflexible generation that cannot be easily varied, there is a negative impact on the utilisation of renewables. The production from RES is reduced from 65% to 59% because the inflexible generation must remain online.

REACHING THE 2050 GRID

The same methodology to build a theoretical grid for 2030 was used to model 2050 with 97% renewable energy. Starting with the optimised 2030 grid, the electricity consumption and generation in 2050 were modelled and DIgSILENT Power Factory was used to perform optimal power flow simulations to identify critical areas where infrastructure needs to be upgraded. It was revealed in this process that more upgrades would be required between South and Central Europe, implying that a 'Supergrid' structure, based on new high-voltage direct current technology, would be valuable to transport large quantities of energy from the solar sources in the south to the load centres in Central Europe.

IMPORT FROM NORTH AFRICA IN 2050

In addition to this Supergrid structure, further transfer capacity was added to assess the impact of the build-up of concentrated solar power (CSP) in the Mediterranean region and in Northern Africa, in particular the Desertec project. Two scenarios were assessed, one with 60 GW of energy imports made available from North Africa, and another without any imports. For these two scenarios it was discovered that, for the energy mix to be 97% renewable, additional solar and wind capacity would be required within Europe to meet the energy demand under standard operating conditions, as well as having sufficient backup power to maintain security of supply. In the scenario with 60 GW of import, up to 800 GW of solar PV (an increase of 260 GW compared to the advanced E[R] scenario distributed in the south of Europe) would be required to cover the energy demand, and up to 225 GW of biogas/biomass (an increase of 112 GW compared to the advanced E[R] scenario distributed all over Europe) would need to be installed as backup to maintain security of supply. In the scenario where no import capacity is considered, up to 1090 GW of solar PV (an increase of 470 GW compared to the advanced E[R] scenario distributed all over Europe), 690 GW of wind (an increase of 170 GW compared to the advanced E[R] scenario distributed all over Europe), and 360 GW of biogas/biomass (an increase of 236 GW compared to the advanced E[R] scenario distributed all over Europe) would be required. In addition, with such an elevated share of solar PV, dedicated storage mediums would need to be included in the grid to maximize the use of solar power. The grid costs resulting from these two scenarios fall in between the range of 149 billion euro to 679 billion euro, including the Supergrid infrastructure.

> The resulting grid upgrade costs cover a large span of options, where in one case the grid is cheaper but more power plant investment is required, and in the other the grid is more expensive but results in lower curtailment.

The optimisation of such a complex grid with almost 100% of renewable energy is a difficult task which cannot be easily carried out without additional modelling of generation costs and further economic studies, however this was out of the scope of this report.

An overview of the key results of all scenarios is shown in the following table.

	Base Scenario 2030	Base Scenario 2030 with DSM20%	Base Scenario 2030 with storage	Base Scenario 2030 with inflexible generation	2030 Grid optimized for curtailment	2050 Grid with 60GW import	2050 Grid without import
Total generation (TWh)	3 886	3 888	3 863	3 782	3 867	4 492	4 543
RES (TWh)	2 537	2 643	2 543	2 250	2 567	4 438	4 517
% RES	65%	68%	66%	59%	66%	99%	99%
Curtailed RES (TWh)	98	89	77	150	32	219	294
% curtailed	4%	3%	3%	6%	1%	4%	5%
Grid investments (billion euro)	50 – 70				19 to 58 in addition to Base Scenario 2030 (70 to 98 vs. 2010)	458 to 544 in addition to 2030 (528 to 679 vs. 2010)	74 to 79 in addition to 2030 (149 to 173 vs. 2010)

Table 1: Overview of key results of all scenarios. Source: energy**nautics**

ACKNOWLEDGEMENT

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LIST OF ABBREVIATIONS

ATSOI	Association of the Transmission System Operators of Ireland
CAES	Compressed Air Energy Storage
CCS	Carbon Capture and Storage
CHP	Combined Heat and Power
CSP	Concentrated Solar Power
DLR	German Aerospace Centre (DeutschesZentrumfürLuft-und Raumfahrt)
DSM	Demand Side Management
E[R]	Energy [R]evolution
ENTSOE	European Network of Transmission System Operators for Electricity
EREC	European Renewable Energy Council
EU	European Union
EV	Electric Vehicle
EWEA	European Wind Energy Association
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
LCC	Line Commutated Converter
NCEP	National Centres for Environmental Prediction
NOAA	National Oceanic and Atmospheric Administration
NTC	Network Transfer Capacity
OPF	Optimal Power Flow
PV	Photovoltaics
RES	Renewable Energy Source
SoS	Security of Supply
TSO	Transmission System Operator
TYNDP	Ten Year Network Development Plan
UCTE	Union for the Coordination of Transmission of Electricity
UKTSOA	UK Transmission System Operators Association
VSC	Voltage Source Converter

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1. INTRODUCTION

1.1. BACKGROUND

Renewable energy has been growing spectacularly over recent years in Europe. In 2009, despite the economic crisis, renewable energy technologies accounted for 61% of new electricity generating capacity connected to the grid.

This strong growth of renewable electricity sources, especially wind energy and solar PV, has started to challenge the electricity system in countries such as Spain and Germany. More often, wind turbines in some regions are switched off – so-called ‚curtailment' – during periods with high winds, because their electricity cannot be integrated in the grid anymore.

The main cause of this problem is bottlenecks in the electricity grid. Currently renewable electricity surpluses cannot be transferred to another region with a net demand. For economic and ecological efficiency, it has become urgent that Europe adapts the electricity system to optimise the integration of renewable sources.

Greenpeace research (Greenpeace International, EREC, 2010) on the economic potentials for further growth of renewable electricity sources has demonstrated that by 2030, renewables could supply some 68% of all electricity and by almost 100% by 2050. Coal and nuclear power plants could almost be entirely phased out by 2030, with gas plants playing a role of bridging fuel towards an entirely renewable electricity sector by mid-century.

This report focuses on how the electricity system must be adapted (grids, production mix, storage, and demand management) to integrate such high levels of renewable sources by 2030 and 2050, while maintaining a high level of security of supply 24/7. This is done through an optimisation process, which means keeping investments in grid extension and storage to a minimum, avoiding situations where wind and solar PV are constrained, avoiding an increase in non-renewable back-up production and keeping CO_2 emissions as low as possible.

In 2009, energy**nautics** developed a European grid model which was used in a study for Greenpeace to investigate the required network upgrades for operating a power system with 90% renewable energy supply in Europe in 2050. That study however, did not include the different possible pathways to get to 2050 nor was the generation portfolio optimised.

Greenpeace therefore wants to outline in this report how the power system in Europe with a large proportion of renewable energy sources would be operated and managed in 2030 and 2050.

The objective of this report is three-fold:

- ▷ Determine the level of investment in grid infrastructure required to integrate 68% and 97% renewable electricity while ensuring security of supply.
- ▷ Determine the optimal generation mix of fossil fuel power stations considering a certain CO_2 ceiling from the electricity sector for 2030 and 2050 which leads to a minimum transmission network upgrade, i.e. already existing gas fuel power stations will be used in extreme situations for back-up supply, which will reduce the need for transmission upgrades.

▷ Determine the possible impact of storage (e.g., pump storage and electric cars), demand-side management, delayed phase-out of inflexible generation, and energy imports from North Africa on the required network upgrades and optimal generation mix.

In this context, this document reports the method and findings of the study conducted for Greenpeace International by energy**nautics** on the outlook of the European electricity grid in 2030 and 2050 based on the advanced E[R] scenario (Greenpeace International, EREC, 2010).

1.2. SCOPE AND ASSUMPTIONS

According to the Ten Year Network Development Plan published by ENTSO-E (ENTSO-E, 2010), the main drivers for investment in grid infrastructure are Security of Supply (SoS), integration of Renewable Energy Sources (RES), and Internal Energy Markets. In our study however, energy**nautics** focuses on two of these issues, namely the SoS and integration of RES (Figure 1).

Maintaining security of supply is of utmost importance in transmission grid operation and planning. For a future grid, where both demand and supply are expected to grow, this can be ensured by increasing transfer capacity in the grid, and by introducing storage and demand-side management (DSM) schemes, which also act to facilitate the use of renewable energy sources. However, if the aim is shifted to maximizing the utilization of RES, further grid upgrades, storage, and DSM measures would need to be implemented beyond the level demanded by maintaining SoS. On the other hand, if additional generating capacity is added as a 'backup' to maintain SoS in extreme situations, this would not affect the utilization of RES under standard operating conditions. Therefore these options must be evaluated in a separate manner, through studies based on simulations of standard operating conditions as well as under extreme weather conditions. Only in this way can the plethora of options be adequately explored, and a true optimised outcome be found.

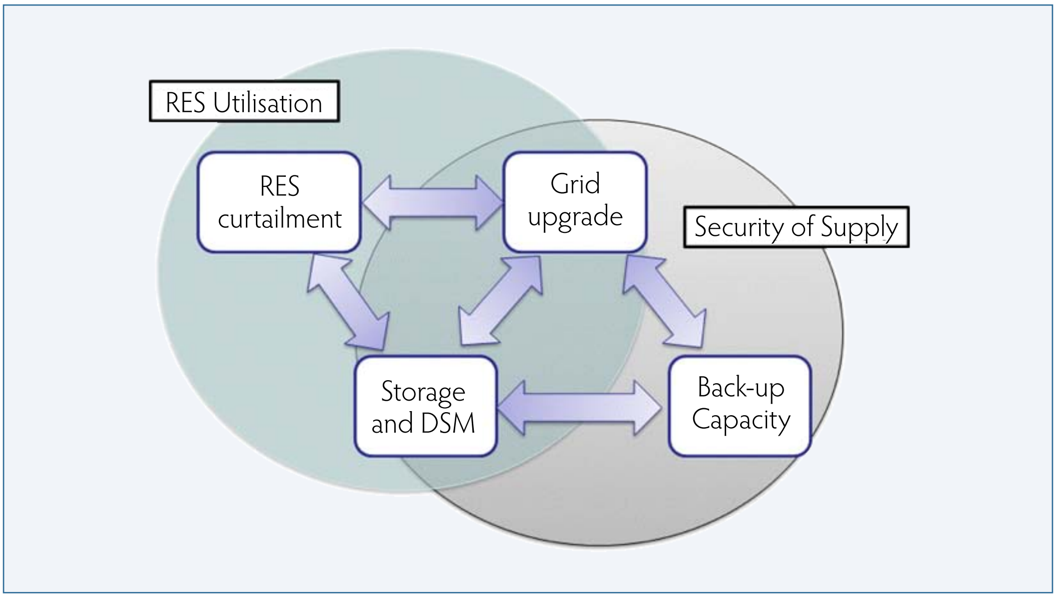

Figure 1: Trade-off between various drivers for grid investment. Source: energy**nautics**

Exclusions from the scope of this study include:

- The distribution network. Distribution is not explicitly assessed in this study. However, it will need to be upgraded to provide an adequate interface between the new, decentralised renewable generation and the transmission system, as well as the consumption.

- Overall economic power system optimisation or the economics of operating the power system in 2030 and 2050. The only economic issues investigated are related to the required network upgrades and the cost of curtailment of renewable energy and thus the increase of non-renewable production to compensate for curtailed RES.
- Further regulatory and policy implications are also not explicitly assessed within this study.

The study focuses on the long-term security of supply issues, i.e. design of the transmission system and sufficient generation mix to supply a given demand in 2030 and 2050. Hence, the simulations focus on extreme situations (similar to the 24/7 Report) and do not consider day ahead planning or short-term balancing issues. As a high increase in additional grid capacity all over Europe is expected, which will be largely based on voltage source converter HVDC systems, the main driver of costs will be the upgrade of transmission capacity itself and not additional necessary compensation to ensure voltage stability or to cope with other dynamic issues. Thus voltage and dynamic issues have not been investigated in this study.

2. METHODOLOGY

This chapter explains the methodology that is used to determine future grid upgrades and to set up different pathway scenarios. The approach includes four main steps:

- ▷ Build a model of the European electricity grid for the target year (2030 or 2050) which is used to simulate electricity production from renewable sources based on historical weather data. This involves revising energy**nautics**' optimal power flow grid upgrade method so that it considers 'typical' operating conditions as well as extreme weather conditions. (See Section 2.1.)
- ▷ Evaluate the base scenario energy utilisation characteristics using hourly wind and solar data for a standard year for the target year (2030 or 2050). (See Section2.2.)
- ▷ Investigate the impact of different pathway scenarios on the energy utilization characteristics. Implementation of the following measures are considered:
  - Different levels of DSM (See Section 2.2.1.)
  - Different developments of storage (See Section 2.3.2.)
  - Inflexible conventional power output (See Section 2.3.3.)
  - Different developments of a European supergrid (See Section 2.3.4.)
  - Large energy import from North Africa (See Section 2.3.5.)
- ▷ Optimise the grid to economically minimize RES curtailment. (See Section 2.4.)

2.1. BUILDING THE BASE SCENARIO GRID

2.1.1. Revision of the energy**nautics** optimal power flow grid upgrade method

To get from today's grid to a future grid structure that can support massive amounts of RES as specified by the E[R] scenarios, a methodology was developed by energy**nautics** which studied the grid requirements for 2050 and features in the 24/7 Report. The model determined areas of the grid that required upgrading based on an assessment of the system's ability to deliver a secure supply of electricity 24-7, and was verified against known extreme weather conditions, for example low wind, low sun and high electricity demand in mid-winter.[1] For the 2030 and 2050 grid study this methodology was extended to include simulations of typical operating conditions over one year in order to see what happens when renewable energy is generating in conjunction with fossil fuels, and to see how much is likely to be curtailed.

To assess the level of infrastructure required to maintain a secure supply of electricity similar to today's standards given the generation and demand levels specified by the advanced E[R] scenario (68% RES by 2030 and almost 100% by 2050), the following methodology was used.

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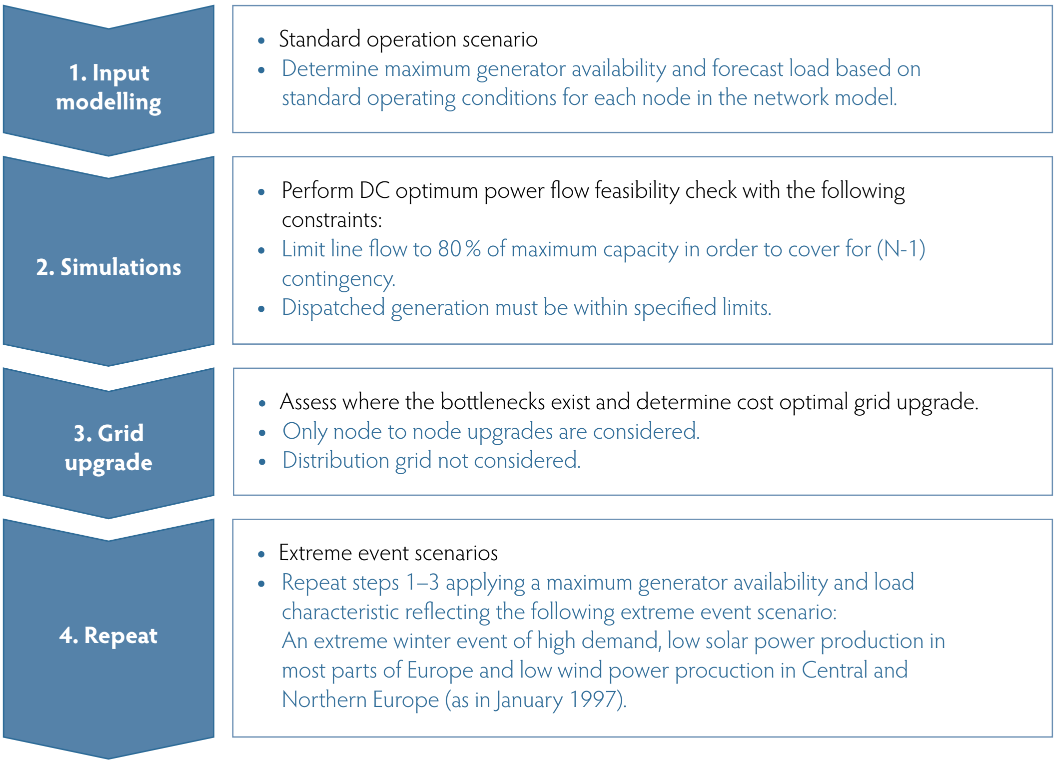
[1] Dynamic issues not considered at this level of system design



1. Input modelling

- Standard operation scenario
- Determine maximum generator availability and forecast load based on standard operating conditions for each node in the network model.

2. Simulations

- Perform DC optimum power flow feasibility check with the following constraints:
- Limit line flow to 80 % of maximum capacity in order to cover for (N-1) contingency.
- Dispatched generation must be within specified limits.

3. Grid upgrade

- Assess where the bottlenecks exist and determine cost optimal grid upgrade.
- Only node to node upgrades are considered.
- Distribution grid not considered.

4. Repeat

- Extreme event scenarios
- Repeat steps 1–3 applying a maximum generator availability and load characteristic reflecting the following extreme event scenario:
  An extreme winter event of high demand, low solar power production in most parts of Europe and low wind power procuction in Central and Northern Europe (as in January 1997).

Figure 2: Schematic of energy**nautics**' grid upgrade methodology. Source: energy**nautics**

Input modeling

First, the maximum amount of generation based on the advanced E[R] scenario that is available to serve the load forecasted for 2030 or 2050 is determined based on technical considerations as outlined in section 2.1.3. This information is expressed as hourly data for a whole year, assuming standard operating conditions. The load data is developed based on hourly data available on ETSOVISTA, taking into consideration regional population densities, season variation in demand and demand-side management.

Simulations

This data is then assigned to each node in the grid model where generation and load are estimated. Hourly feasibility Optimal Power Flow (OPF)[2] simulations are performed, and the amount of energy produced by each generator required to meet demand is calculated. In doing so, the maximum available generation at each node and the maximum line flow limit (specified as 80% to account for N-1 contingencies) must be respected by the OPF algorithm.

Grid upgrade

Where a solution cannot be found, this indicates that the existing network does not have the capacity to transfer necessary amounts of electricity, and therefore must be upgraded. For a DC simulation model the upgrade required is limited to increases in thermal capacities (i.e. carrying capacity of power lines).

After assessing all hours of the period in this way, the model produces a list of all the upgraded lines, so it is possible to calculate the cost of each (refer to section 2.4.1 for cost consideration). Then, the most expensive upgrades are removed from the network model and the simulation is run again for all hours of the period. This is because it is most likely that during the process of adding network upgrades in a chronological hour to hour basis, some redundancy is built up that can be removed to reduce grid upgrade cost. If successful, the next expensive upgrade is removed until a grid with minimum upgrades is revealed.

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[2] Using PowerFactory from DIgSILENT

Repeat for extreme event scenarios

In order to ensure that the resulting network is robust enough to cover demand under all weather conditions, the network must also be subject to a 'stress test', demonstrated by periods where generation capacity is restricted due to extreme weather conditions or the network experiences sudden outages, combined with a situation when demand levels are high. The most extreme was considered to be an extreme winter event of high demand, low solar power production in most parts of Europe and low wind power production in Central and Northern Europe (as in January 1997).

Precautions against unexpected outages are typically covered by performing what is called an N-1 analysis. A system is N-1 secure if any element in the system may fail without overloading any other element (Hug-Glanzmann, et al., 2009). As the model does not exactly represent each physical line in the network, but instead aggregates a number of lines, the N-1 security cannot be assured by evaluating each single line. Instead, a maximum loading of 80% on the lines has been allowed to approximate for N-1 security.

The number of network reinforcements required for the system to 'keep the lights on' under extreme conditions forms the resulting picture of the network in 2030 or 2050 subject to the advanced E[R] scenario.

2.1.2. Grid Model

The grid upgrade methodology is based on a series of simulations using a DC simulation model of the European electricity grid, which was built by energy**nautics**. It is a simplified model of the European power system, based on the methodology proposed by Zhou and Bialek (Bialek, 2005). It includes Central, East and Southern Europe (UCTE) as well as Scandinavia (Nordel), Britain (UKTSOA), Ireland (ATSOI), Albania and the Baltic region. The following figure shows the map of energy**nautics**' grid model for Europe and represents the situation today.

Figure 3: Map showing energy**nautics**' model of the high-voltage network of Europe (Status 2010), based on 224 grid-connected nodes. Source: Reproduced with permission of ENTSO-E by energy**nautics**

In this model, the real physical grid is simplified by aggregating transmission lines as connections between 224 nodes. The nodes are the points where the transmission network feeds into the distribution network. The aggregated generation and demand at this node are modelled as described in the following sections and fed in or out at these nodes. Generally, the more detailed the modelling of the grid the more realistic the simulated load flows result. However, for a European-wide grid study a highly detailed model would be overly complicated for efficient analysis of the focus areas. This is why energy**nautics**' grid model is well suited for a general European grid upgrade study; it maintains a sufficient level of accuracy to calculate realistic load flows while keeping the model simple enough to enable the relevant areas and lines to be studied.

2.1.3. Generation and demand modeling

The maximum demand and available generation capacity in 2030 and 2050 for the 27 European states are outlined in the report 'Energy [R]evolution Towards a Fully Renewable Energy Supply in the EU 27'. (Greenpeace International, EREC, 2010) Figures for the advanced E[R] scenario are shown below.

(GW)	2007	2015	2020	**2030**	2040	**2050**
Total generation	808	944	1 069	1 223	1 379	1 550
Fossil	453	449	376	258	132	28
Coal	121	118	73	7	3	0
Lignite	76	67	41	10	0	0
Gas	181	205	226	228	127	27
Oil	67	51	32	10	0	0
Diesel	8	7	5	3	1	0
Nuclear	132	106	59	17	3	0
Hydrogen	0	0	0	0	0	4
Renewables	223	389	634	949	1 244	1 518
Hydro	140	153	155	157	159	163
Wind	57	147	251	376	443	497
PV	5	45	144	241	381	498
Biomass	20	38	59	77	93	100
Geothermal	1	2	7	34	58	96
Solar Thermal	0	2	15	43	73	99
Ocean Energy	0	0	3	21	37	66
Fluctuating RES (PV, Wind, Ocean)	62	193	398	637	861	1 061
Share of fluctuating RES	7.7%	20.5%	37.2%	52.1%	62.4%	68.4%
RES share (domestic generation)	27.6%	41.2%	59.3%	77.5%	90.2%	98.0%

Table 2: Installed Capacity in GW for EU27 in the Advanced Energy [R]evolution scenario (2010).
Source: Greenpeace

The expected energy production by each of these generators, and the total energy consumption for the 27 European states for the advanced E[R] scenario are also shown below.

(TWh)	2007	2015	2020	**2030**	2040	**2050**
Total generation	**3 327**	**3 397**	**3 422**	**3 553**	**3 720**	**4 222**
Fossil	1 863	1 707	1 509	1 035	463	92
Coal	601	518	349	35	10	0
Lignite	390	307	194	54	2	0
Gas	760	815	925	926	450	92
Oil	104	60	36	17	0	0
Diesel	8	7	5	3	1	0
Nuclear	935	755	425	118	22	0
Hydrogen	0	0	0	0	1	20
Renewables	**529**	**934**	**1 488**	**2 400**	**3 234**	**4 110**
Hydro	309	345	355	365	377	391
Wind	104	320	564	939	1196	1392
PV	4	50	158	289	467	622
Biomass	105	199	318	420	515	554
Geothermal	6	13	38	183	307	507
Solar Thermal	0	6	45	141	262	446
Ocean Energy	1	1	10	63	110	198
Import	318	333	335	398	650	975
Import RES	64	98	127	239	637	970
Export	308	305	295	230	190	170
Distribution losses	204	183	185	185	195	210
Own consumption electricity	294	280	275	270	260	255
Electricity for hydrogen production	0	3	40	60	144	289
Final energy consumption (electricity)	**2 840**	**2 959**	**2 963**	**3 206**	**3 581**	**4 274**
Fluctuating RES (PV, Wind, Ocean)	109	371	732	1 291	1 773	2 212
Share of fluctuating RES	3.3%	10.9%	21.4%	36.3%	47.7%	52.4%
RES share (domestic generation)	**15.9%**	**27.5%**	**43.5%**	**67.6%**	**86.9%**	**97.3%**

Table 3: Electricity generation in TWh/a for EU27 in the Advanced Energy [R]evolution scenario (2010).
Source: Greenpeace

The electricity generation resources considered are categorised into:

- non-controllable renewables: solar PV, on- and offshore wind, geothermal, wave and tidal and run-of-the-river hydro schemes;
- controllable renewables: Concentrated Solar Power (CSP), biomass (CHP) and hydro schemes with reservoirs; and
- conventional resources: coal, gas and nuclear.

The total sum of each of these generation sources across the 27 European states is specified by Greenpeace in the advanced E[R] scenario as shown in Table 2 (Greenpeace International, EREC, 2010). However, the scenario does not assign capacities to regions across the European network; so the amount of new renewable energy entering the network at each node had to be determined.

The first consideration was the detailed split up of different renewable sources within Europe from the TRANS-CSP study (DLR, 2006). However, this study is much more focused on concentrating solar power (CSP), whereas in the E[R] scenario photovoltaics play a major role. Thus, the TRANS-CSP scenario was scaled to match the figures provided in the E[R] report.

Further adjustments were made by including the results of the TradeWind study (EWEA, 2009), the national Energy [R]evolution scenarios[3], as well as performing a reasonability check (for example, the share of solar power has been reduced in Scandinavia and increased in the Mediterranean area) based on energy**nautics**' expertise.

An overview of the resources in each country used for this study for 2030 and 2050 is provided as Appendix A.

The available generation capacity for each of the 224 nodes was determined based on these figures. In a next step, hourly weather data (solar radiation and wind speeds) were applied at each node to simulate the available generation capacity from the installed solar and wind capacities at each node. Assumptions and details for this process are described below for each technology.

Wind

To determine the amount of wind power produced at each node for each hour, the approach described in the Trade Wind study (EWEA, 2009) has been applied. For each region wind speed data is obtained from the National Centre for Environmental Prediction (NCEP) reanalysis data source (NOAA Climate Prediction Centre). Only 6-hourly data is available however, therefore linear interpolation is used to fill out the gaps in between. This approach shows a good correlation to measured site data as seen in Figure 4. The corresponding power production capacity is calculated based on regional power curve(s) developed in the Trade Wind study, and scaled to meet the maximum capacity at that node as specified by Greenpeace. For the extreme event scenario, actual wind data from January 1997 is used. The simulation of a standard year is based on wind data from a typical year.

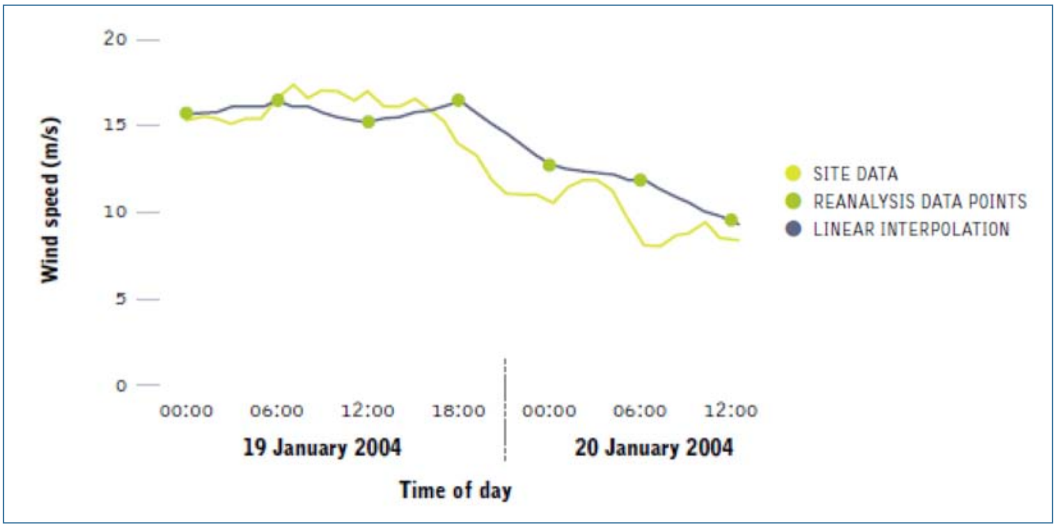

Figure 4: Comparison of NCEP-2 reanalysis and interpolation based on site data. Source: EWEA, 2009

Solar PV

PV generation profiles are based on hourly solar radiation data obtained from S@tel-Light. This hourly data is multiplied by a factor to account for the angle of incidence of the solar rays on

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[3] A.o.Greenpeace regional Energy [R]evolutions scenarios. http://www.energyblueprint.info/1142.0.html

the PV panel. The amount of power that can be produced with this amount of radiation for the amount of photovoltaics installed at each node is then calculated. For the extreme event scenario, actual solar radiation data from January 1997 is used, whereas the standard year simulation is based on data from a typical year.

Geothermal

Geothermal power is not expected to have a high share of capacity in 2030 or 2050 in the advanced E[R] scenario. Typically, geothermal plants run at full load, but to account for maintenance work and failures in geothermal power plants, the power output is set to 90% of rated capacity.

Ocean Energy

Wave and tidal power only have a small share within the E[R] scenario, thus a detailed analysis of the prevailing waves or tides during the time frame of the scenario has not been carried out. Instead, a typical mean value of 34% of the installed capacity is taken.

Hydro Power

Hydro power has been divided into power plants with and without a reservoir. Run-of-river hydro schemes typically do not have a capacity for energy storage and are therefore not controllable, whereas those with reservoirs can be considered controllable. The power output of run-of-river schemes can vary depending on the region and season. For controllable hydro schemes up to 70% of the total capacity is considered available however the overall output within a year is restricted to within typical full-load hours.

Biomass

Biomass is a generation technology that is applicable almost all over Europe. It is a controllable energy source, producing power on demand. For the purpose of this study 90% of the installed capacity of biomass is considered available as back-up for non-controllable renewable energy sources such as wind power production. Due to its limited resources in Europe however, the overall annual production of biomass is restricted to 420 TWh/a in 2030 and 554 TWh/a in 2050 (see Table 3). In the context of this study, the installed capacity of biomass power plants for back-up purposes can be increased, but since the annual production remains within the abovementioned limits, an increasing biomass capacity will thus result in a lower load factor.

Concentrated Solar Power

Concentrated Solar Power (CSP) plays an important role within this study, as these plants can supply electricity on demand, and excess energy during the day can be stored as heat for use at night to produce electricity (Greenpeace International; Solar Paces; ESTELA, 2009). The available power is calculated according to the approach described for PV, but taking only direct sunlight into account. In addition to the installed capacity within Europe, another 60 GW will be installed in North Africa for power export to Europe via HVDC lines by 2050.

Conventional Power

Conventional power plants such as coal, nuclear and gas power plants are controllable sources of power. Despite this, coal and nuclear-based power plants are typically operated with a flat profile because they are not suited to fast output variations. However, gas power plants can react to fast changes in output, and are therefore suitable as a backup to balance power supply when renewable power production is low.

Demand

Demand is modelled based on the country-by-country vertical load profiles found on ETSOVISTA. Vertical load is a measure of the amount of power delivered at the interface of the transmission and distribution networks. In the model, the hourly values are allocated to nodes in proportion to the population that exists in that area, to reflect the high correlation between population and energy intensive activities such as industry (Bialek, 2005). The population density can be found in the statistics database of the European Commission (European Commission).

The continent-wide profile of energy consumption in 2030 and 2050 can be assumed to be similar to that of today because we do not expect any major changes in patterns of energy-intensive human activity.

The detail of the profiles however, must be modified to take into account technical changes put forward in the advanced E[R] scenario. To meet emissions targets, there must be a decrease in electricity demand in industrial, residential, and service sectors through energy efficiency measures. However, the overall electricity demand in the advanced E[R] scenario would rise due to many more electric vehicles, and the accelerated phase-out of fossil fuels used for heating in industrial processes moving towards electric heat pumps and hydrogen. The advanced E[R] scenario also assumes the expansion of smart grids, demand-side management (DSM) and storage capacity from the electric vehicles and pumped hydropower. These measures together will contribute to better grid integration and power generation management.

▷ Demand-side management

Figure 5 shows how demand-side management works in the case of PV production at one node. Depending on the supply of electricity from PV at that node, demand is increased or decreased to align with PV production. The maximum amount of power that can be shifted at any one instant largely depends on the type of technology in place in the future, as well as the robustness of the network. With wide-scale integration of smart grids and intelligent networks that have significant capacity for energy consumers to interact with the grid, it may be possible for 20% of the power to be increased or decreased at any one instant by 2030. However, a realistic figure for 2030 would more likely to be 5 to 10%, and 15% for 2050. Furthermore, the ability of the system to shift energy within one day, excluding dedicated storage mediums, is expected to be no more than 10%. This also depends on the extent of the technology implemented in the future, particularly of electric vehicles.

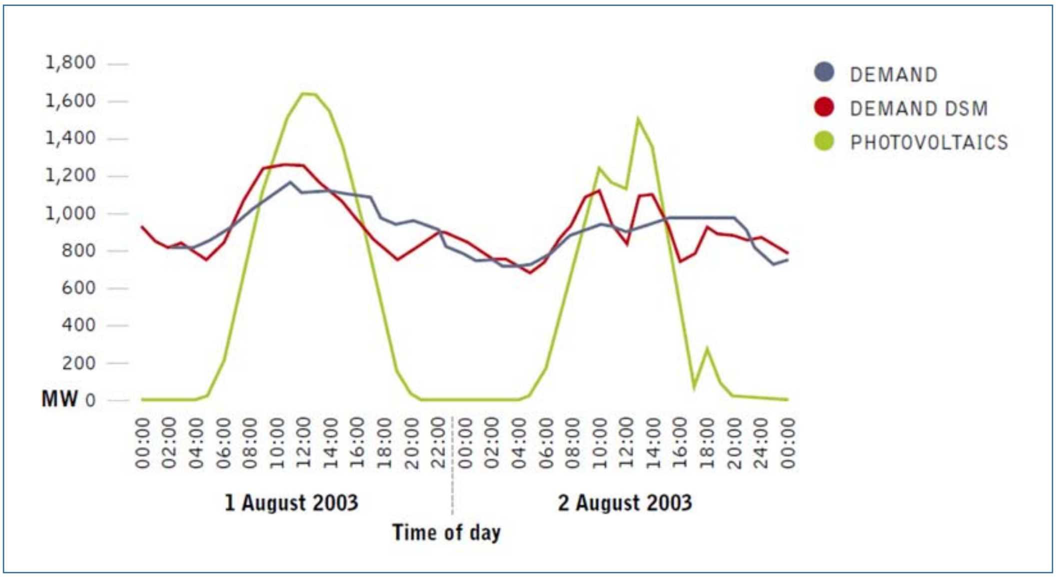

Figure 5: Example of demand-side management aligned with PV production at an example node.
Source: energy**nautics**

2.2. BASE SCENARIO ENERGY UTILISATION

The energy used under a base scenario represents 'standard' operation conditions. The base scenario is then used to estimate how much energy curtailment can be prevented through the optimisation process, and to determine the impact of implementing DSM and storage in 2030. This is done by performing OPF simulations for a standard year prioritising the use of renewable energy supply at a European-wide level.

2.2.1. Electricity production and RES curtailment

The amount of electricity produced by each energy source is calculated based on the generation dispatched by Power Factory when solving the OPFs. In the case of noncontrollable RES, the amount of electricity produced at each node for each hour is split between wind, solar PV, geothermal, tidal/wave and run-of-river hydro sources according to the available power production. Controllable sources on the other hand are attributed to production by renewable sources such as biomass, CSP and hydro power with storage schemes first, then the residual load is covered by conventional sources such as coal, nuclear and gas.

Curtailed energy is calculated as the discrepancy between the maximum available renewable generation capacity at a particular node at an instant and the actual generation dispatched to find the OPF.

2.2.2. CO_2 emissions

The quantity of CO_2 emission associated with power generated from gas and coal-based generators was calculated using CO_2 intensities outlined in the advanced E[R] scenario. The intensities used are summarized in the following table.

CO_2 intensity (Mill t/TWh)	2007	2015	2020	2030	2040	2050
Coal	0.984	0.898	0.834	0.830	0.767	0.744
Gas	0.440	0.442	0.447	0.453	0.433	0.417

Table 4: CO_2 intensities in Mill t/TWh calculated based on the advanced E[R] scenario. Source: energy**nautics**

2.3. SETTING UP THE PATHWAY SCENARIOS

This study opened up a number of pathways to get to the 2050 clean energy supply. The assessment investigated the operational scenarios of: different levels of demand-side management (5%, 10% and 20%), the inclusion of storage devices, and extended use of conventional power as well as carbon capture and storage.

2.3.1. Demand-side management

DSM is a key part of maintaining sound operation when integrating renewable supply into the electricity grid. As a general term it means consumption patterns are adapted somewhat to match the availability of renewable electricity production. To do this effectively however, new technology must be installed at various levels in the grid, which is likely to take some time. With smart grids and micro grids gaining attention of governments and investors now, by 2030 it is possible that power consumption could be increased or decreased up to 20% at one instance, using DSM technologies.

In order to evaluate the impact of different levels of DSM on the grid, three scenarios were assessed, with a maximum of 5%, 10% and 20% of power shift enabled, according to the amount of local RES available at any instant. The effect of different levels of DSM on the necessary grid upgrades and energy utilisation is assessed and reported in section 3.2.

2.3.2. Storage

In combination with variable RES, like wind and solar power, storage is being considered and developed as a way to make renewable power more reliable.

Simulation results of the 24/7 Report (Greenpeace International, EREC, 2009) showed that a high share of renewables, especially solar PV, had to be curtailed. Due to the fact that solar power is available every day, this would be an ideal source to combine with short-term storage.

The following figure gives an example, of storage utilisation with wind and PV power.

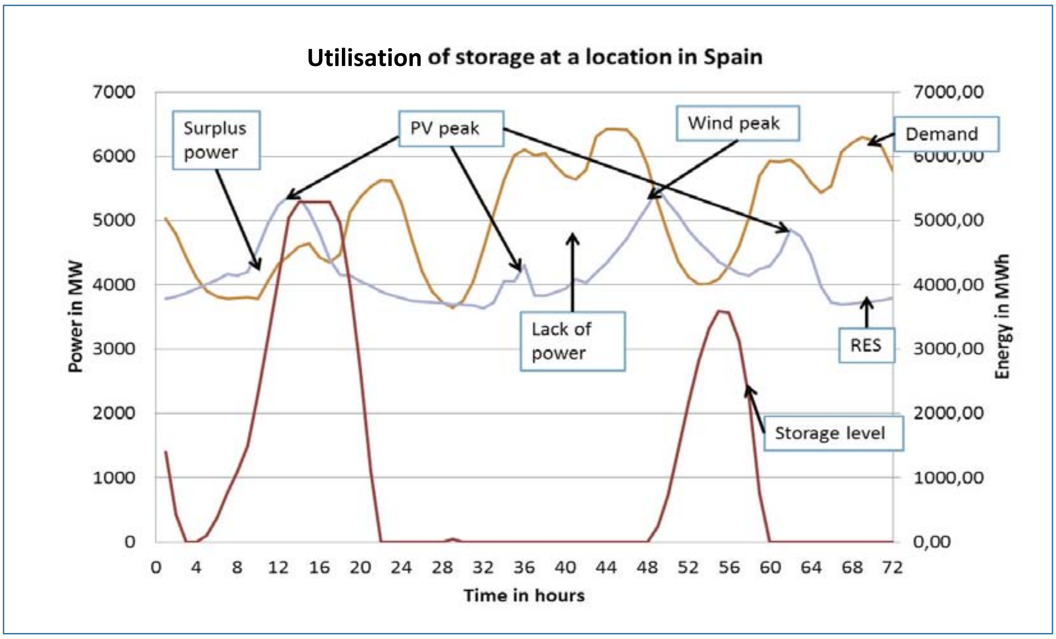

Figure 6: Example for storage utilisation. Source: energy**nautics**

Several strategies to pick the right size of storage are possible. The sizing criteria may be aimed at either reducing the amount of the curtailed renewable energy or at reducing the necessary amount of network upgrades. For the former strategy, the storage is sized based on the amount of curtailed renewable energy after the simulation of the complete year has been done (also called a posteriori). During this whole year the network does not rely on the availability of storage power at any instant. Here, the storage is placed only where large amounts of renewable energies are curtailed. In contrast, in the latter strategy, the necessary grid upgrades are affected by the availability of storage capacity when the model is created (called a priori). This means that in order to determine the necessary network upgrades the simulation of the complete year is run with the storage in operation. Using this approach the storage is smaller in scale and could be provided by electric vehicles (EV). EVs should contribute to load coverage locally, relieving transmission lines to some extent.

The algorithm has been designed so storage can be discharged globally, although it can only be charged locally by the surplus power of the variable RES.

A more realistic strategy for storage sizing is to assume electric vehicles distributed uniformly all over Europe. The model uses the development goals of the German government to estimate the penetration of EV by 2030. In this case, the resulting power and capacity ratings are smaller than in the case of estimating storage for curtailment reduction.

2.3.3. Inflexible conventional power generation

Conventional power generation such as coal and nuclear are generally built to respond to large-scale baseloads and tend to be 'inflexible' due to the nature of its technology and operation.

They cannot change their outputs rapidly in response to demand or residual demand, and therefore often simply stay running even though there may be sufficient power from renewable energy to cover the demand at a particular instant. In this situation the renewable energy is curtailed, and not fed into the grid. To understand the impact of these factors, this scenario demonstrates what would happen in generated electricity and resulting curtailment if the use of inflexible coal and nuclear power plants is prolonged.

2.3.4. European supergrid

To support the future demand with the quantities of RES predicted in the E[R] report, large upgrades to the European electricity grid are expected. Especially to transport large quantities of solar power from the south of Europe to the central region and to deliver the energy from the North Sea offshore grid to the load centres in Central Europe. Since the area of production (Southern Europe or North Sea) are at some distances away from the load centres, it would make sense to install HVDC super-highways to transfer directly the energy from the point of production to the point of consumption rather than building up the HVAC network in rural areas of Spain and France. Therefore the European Supergrid is envisioned as an HVDC grid structure which transports large quantities of energy over long distances directly from the source to users, which replaces the necessity to upgrade HVAC capacity at each node along the existing network.

2.3.5. Energy import from North Africa

It is anticipated that by 2050 there would be substantial build-up of solar PV and solar CSP technologies in the north of Africa for electricity production. In addition, the interconnection with Europe is expected to be stronger, so that the solar energy can be exported from these countries to Europe. According to the 24/7 Report, up to 60 GW of power is expected to be available for import from North Africa by 2050. A scenario is thus built to simulate the availability of an additional 60 GW of solar-based energy from North Africa, which is transported directly to the load centres in Europe via the Supergrid as mentioned in section 2.3.4.

2.4. OPTIMISING THE GRID TO REDUCE THE CURTAILMENT OF RENEWABLE ENERGY

In the base scenario simulations large quantities of RES, particularly offshore wind power, is curtailed. In order to reduce curtailment while keeping grid upgrades to a minimum an optimisation method was developed by energy**nautics**. It consists of placing a price on upgrades required to reduce curtailment. The optimal level of grid upgrade is the point where the cost of additional upgrades equals the reduction costs of curtailed energy.

After the 2030 base scenario is modified to achieve minimum energy curtailment with minimum upgrades, it is then subject to the extreme event scenario, where further upgrades are made if necessary to reveal a network that ensures a secure supply of electricity at all times.

2.4.1. Grid upgrade costs

The cost of grid upgrades depends on the type of technology used, terrain, length and power rating of lines. The following assumptions have been made based on (ICF Consulting, 2002), (Oeding, 2004), (Lazaridis, 2005), and (Spahic, 2009).

	Fixed Cost (euro/MW)	Variable Cost (euro/MW/km)
HVAC (Overhead line)	–	400
HVDC (Cable)	150 000	1 500

Table 5: Fixed and variable costs for transmission lines. Source: energy**nautics**

Variable costs were adjusted depending on the terrain of the region covered by the transmission line, allowing for up to 50% higher costs for lines crossing mountainous regions. The fixed cost for HVDC transmission lines includes the cost of the converters at each end.

As shown in Table 5, the cheapest way to get transmission capacity is by installing overhead lines using High Voltage Alternating Current technology (HVAC). This is common practice in today's power system. High Voltage Direct Current (HVDC) is generally only used for offshore connections, where cables have to be used, due to high compensation needs of reactive power demand of cables in HVAC systems.

In this report, priority is given to HVAC system upgrades, making use of existing routes. However, since the Energy [R]evolution would require a major expansion of the transmission grid, the existing routes will often not be sufficient to take the necessary upgrades. The model limits the upgrade per route to three times today's installed capacity. Any additional power would have to be transported via HVDC connections, granted that it is larger than 1 GW; in this case either overhead lines or cables can be used. The costs for cables are, however, almost four times higher than for overhead lines.

Such onshore HVDC connections will most likely form an HVDC Supergrid overlaying the HVAC grid to transport high power over long distances.

HVAC technology is a long-established technology, and there is hardly any potential for price reduction. HVDC does provide some opportunities for cost reductions through market development, both for LCC[4] and VSC[5]. However, there are no reliable estimates of learning curves available for this technology: thus learning curves have been disregarded in this study for HVAC and for HVDC costs.

2.5. ASSESSMENT OF RESULTS

The aim of the modelling is to evaluate the costs associated with upgrading infrastructure, and the extent of technology integration efforts that would be required in order to achieve the desired E[R] scenario, so that the use of renewable energy and CO_2 emission are within the expected range.

Outputs from the calculations used to reach these conclusions include:
- network reinforcements required,
- the amount of energy that will be used and lost, and
- the quantity of CO_2 emissions that will result from each of these scenarios.

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[4] LCC – Line Commutated Converter

[5] VSC – Voltage Source Converter

3. RESULTS SCENARIO 2030

The results for the 2030 simulations are presented in this section, in this sequence:

- Electricity production and RES curtailment for the 2030 base scenario.
- Evaluations of the several pathway scenarios in comparison to the base scenario.
- The levels of grid upgrades required in 2030 for the base scenario and the optimised scenario.

The following table summarises the different scenarios investigated.

2030 Scenario	Base Scenario	DSM 5/10/20%	Storage	Inflexible	Optimised for curtailment
Based on grid	Base Scenario 2030	Grid investments to secure supply 24/7 for 5% DSM	Base Scenario 2030 + Storage	Base Scenario 2030	Increase grid investments on Base Scenario 2030 to limit curtailment
Key elements	• Electricity generation mix from Energy [R]volution for 2030, allocated to 224 nodes. • Grid investments to secure supply 24/7 • European-wide priority dispatch for RES • 10% DSM	• Electricity generation mix from Energy [R]evolution for 2030, allocated to 224 nodes. • European-wide priority dispatch for RES • Different levels of DSM (5%, 10%, and 20%)	• Electricity generation mix from Energy [R]evolution for 2030, allocated to 224 nodes. • Nominal storage power 0.5 of max curtailment power. X 24 hour storage = max cap • 0,33 x max cap is starting storage cap • 7 top curtailment sites • European-wide priority dispatch for RES • 10% DSM	• Renewable electricity generation mix from Energy [R]evolution for 2030, allocated to 224 nodes. • Conventional electricity generation mix changed from Energy [R]evolution for 2030 to allocate 50% of gas to 'inflexible' generation. • Inflexible generation given same dispatch priority as RES • 10% DSM	• Electricity generation mix from Energy [R]evolution for 2030, allocated to 224 nodes. • European-wide priority dispatch for RES • 10% DSM • Optimisation between grid investments and costs of curtailment

Table 6: Summary of the 2030 Scenarios. Source: energy**nautics**

3.1. BASE SCENARIO

The base scenario is a depiction of the European electricity grid in 2030, designed to deliver electricity under standard operating conditions for the demand and generation availability specified by the advanced E[R] scenario, including a significant increase in electricity from renewable sources. It is designed using energy**nautics**' grid upgrade methodology, and is used for comparison with all ensuing scenarios. For all scenario studies in 2030, a demand-side management level of 10% is assumed, except for the assessment of the impact of different levels of DSM.

Electricity production and RES curtailment

The following table gives an overview of the amount of electricity generated by different sources during a standard year operation of the base scenario. To keep the lights on, the demand has to be met at all times. This is ensured through optimum power flow calculations where local generation is favoured over importing energy from a remote location.

	Advanced E[R] scenario	Base Scenario with prioritised local generation dispatch method		
(TWh)	Electricity generation EU-27	Electricity generation EU-27	Electricity generation Europe	Curtailed Energy Europe
Total generation	**3 553**	**3 553**	**3 848**	
Fossil	**1 133**	**1 485**	**1 567**	
Coal	89	82	83	
Gas	926	1 302	1 383	
Nuclear	118	101	101	
Renewables	**2 400**	**2 068**	**2 281**	Total energy curtailed (TWh) **297**
Hydro	365	377	512	17
Wind	939	554	573	233
PV	289	267	291	29
Biomass	420	480	510	–
Geothermal	183	202	206	13
Solar Thermal	141	123	123	14
Ocean Energy	63	65	67	6
Final energy consumption (electricity)	**3 206**	**3 227**	**3 560**	In percentage (%) **12%**
Fluctuating RES (PV, Wind, Ocean)	1 291	886	930	
Share of fluctuating RES	36%	25%	25%	
RES share	68%	59%	60%	

Table 7: Energy utilisation of Base Scenario 2030 with prioritised local generation dispatch method in TWh. Source: energy**nautics**

The model outputs expected from most renewable energy sources are in line with the advanced E[R] scenario, except for wind power. In total, the amount of electricity generated from renewables is lower than the advanced E[R] scenario, with the renewables share reaching only 60% of total generation. The main reason is that a large amount of renewable energy is curtailed, particularly solar PV and wind energy, requiring extra non-RES generation. The curtailment happens because the energy generated closest to the node is given preference in the dispatch process in an attempt to minimise line flows. Because local generation gets first priority, a conventional sources is used before the surplus generation from another node, even if it is from a renewable generator. Wind energy, particularly offshore wind must be exported to mainland Europe because there is little to no demand in the middle of the ocean. However, due to the dispatch process, it will only be used at other nodes which are not meeting local demand with local generation (including RES that can be easily stored in its raw form like biomass, and even fossil-fuel based power generators).

In order to make better use of the available renewable resources, the simulation's dispatch priority has to be changed, so that power from non-controllable renewable sources is used first, even if produced at another node. This is achieved by modifying the generator model in the simulations to have two separate generators; one for non-controllable RES, and the other for controllable sources. Prices were assigned to these generators so that it would be cheaper to dispatch energy from a non-controllable RES generator compared to a controllable generator, wherever it was located. With this adjustment, the optimum power flow simulations dispatch the non-controllable RES such as wind and solar PV over controllable RES and conventional sources.

With the use of RES prioritized in the new dispatch method, curtailment should be reduced compared to the previous base scenario, offsetting the use of fossil-fuels and decreasing CO_2 emissions.

The electricity generation resulting from this simulation is shown in Table 8 below.

	Advanced E[R] scenario	Base Scenario with prioritized RES dispatch method		
(TWh)	Electricity generation EU-27	Electricity generation EU-27	Electricity generation Europe	Curtailed Energy Europe
Total generation	**3 553**	**3 553**	**3 886**	
Fossil	**1 133**	**1 253**	**1 349**	
Coal	89	72	74	
Gas	926	1 096	1 191	
Nuclear	118	85	85	
Renewables	**2 400**	**2 300**	**2 537**	Total energy curtailed (TWh) **98**
Hydro	365	381	530	0
Wind	939	738	760	91
PV	289	311	339	4
Biomass	420	438	470	–
Geothermal	183	221	224	2
Solar Thermal	141	139	139	2
Ocean Energy	63	73	74	1
Final energy consumption (electricity)	**3 206**	**3 227**	**3 560**	In percentage (%) **4%**
Fluctuating RES (PV, Wind, Ocean)	1 291	1 121	1 173	
Share of fluctuating RES	36%	32%	30%	
RES share	68%	65%	65%	

Table 8: Energy utilisation of Base Scenario 2030 with prioritised RES dispatch method in TWh.
Source: energy**nautics**

Comparing Table 7 and Table 8, energy production from solar PV and wind would increase significantly using the adjusted dispatch method by 16% and 33%. This brings the RES share up to 65% for Europe from 60% when giving local generation priority. As predicted, production from RES increases and generation from fossil and nuclear sources decreases. The effect is particularly noticeable for power generated by gas, where production decreases by 14% compared to the base scenario.

Comparing the amount of curtailed energy under the two dispatch methods, the amount of non-renewable backup electricity to compensate for curtailed renewable energy has reduced significantly, from 12% to 4% for all renewable sources. In particular, curtailed on- and offshore wind energy have more than halved. All other energy sources have less than 1% curtailment.

Despite the substantial reduction, offshore wind still remains the highest curtailed energy source, with approximately 17% of available energy going unused. The reason for this is that under the base scenario, there is insufficient transfer capacity to bring the available production in the North Sea offshore grid to the demand centres in mainland Europe. This result clearly indicates that there is an opportunity to better integrate offshore wind energy with further investment in the grid. This is studied under the scenario optimised to reduce curtailment (see section 3.5).

3.2. DEMAND-SIDE MANAGEMENT

The base scenario as developed in section 3.1 is assessed assuming that a demand-side management (DSM) level of 10% would be implemented by the year 2030. In this section the same base scenario was assessed with two other levels of DSM so that three levels of DSM; 5 %, 10%, and 20%, could be compared. These values were chosen as levels of DSM that are realistically achievable by 2030. Corresponding to these DSM levels, the demand profile which is used as an input to simulations was modified according to the method described in section 2.1.3.

Electricity production and RES curtailment

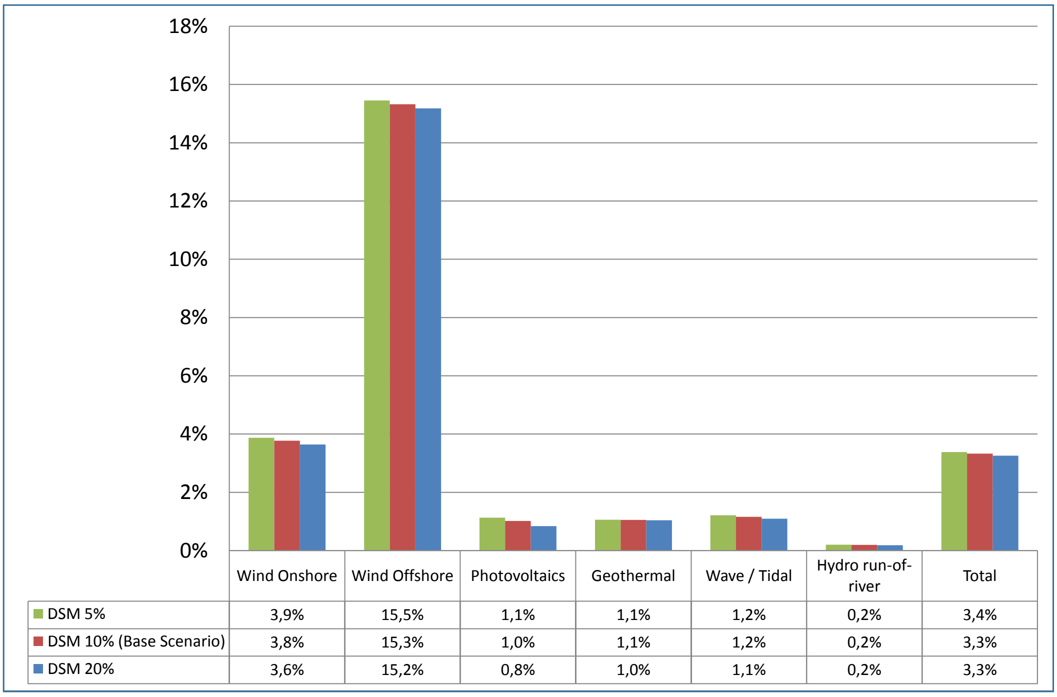
Demand-side management (DSM) refers to changing energy usage patterns, so that peaks are 'evened out' and overall the network does not need as much capacity. DSM is linked to energy efficiency in many cases. With higher levels of DMS we would expect less energy curtailment, allowing higher use of renewable energy sources. Also, fewer upgrades are likely to be required. In order to assess the impact of DSM on energy utilisation, the grid model was kept the same for all three scenarios. This is to ensure that the results observed are due to the different levels in DSM and not the impact of changing the network topology. In this assessment the European electricity grid upgraded for Base Scenario 2030 with 5% DSM was used and subjected to inputs based on 10% and 20% DSM. The electricity generation resulting from these simulations is summarised in the following table.

	Advanced E[R] scenario Electricity generation EU-27	Base Scenario with DSM								
		Electricity generation EU-27			Electricity generation Europe			Curtailed Energy Europe		
(TWh)		DSM 5%	DSM 10%	DSM 20%	DSM 5%	DSM 10%	DSM 20%	DSM 5%	DSM 10%	DSM 20%
Total generation	**3 553**	**3 563**	**3 563**	**3 564**	**3 888**	**3 888**	**3 888**			
Fossil	**1 133**	**1 166**	**1 165**	**1 162**	**1 250**	**1 248**	**1 246**			
Coal	89	60	59	59	61	61	60			
Gas	926	1 028	1 026	1 025	1 110	1 108	1 106			
Nuclear	118	79	79	79	79	79	79			
Renewables	**2 400**	**2 397**	**2 399**	**2 402**	**2 638**	**2 640**	**2 643**	Total energy curtailed (TWh) **92**	**91**	**89**
Hydro	365	374	373	373	521	520	518	0	0	0
Wind	939	742	743	744	765	766	767	85	84	83
PV	289	310	310	311	338	338	339	4	3	3
Biomass	420	516	519	522	555	558	561			
Geothermal	183	221	221	221	224	224	224	2	2	2
Solar Thermal	141	161	160	159	161	160	159			

	Advanced E[R] scenario Electricity generation EU-27	Base Scenario with DSM								
		Electricity generation EU-27			Electricity generation Europe			Curtailed Energy Europe		
(TWh)		DSM 5%	DSM 10%	DSM 20%	DSM 5%	DSM 10%	DSM 20%	DSM 5%	DSM 10%	DSM 20%
Ocean Energy	63	73	73	73	74	74	74	1	1	1
Final energy consumption (electricity)	3 206	3 516	3 481	3 515	3 871	3 833	3 871	In percentage (%) 3%	3%	3%
Fluctuating RES (PV, Wind, Ocean)	1291	1124	1126	1128	1176	1178	1180			
Share of fluctuating RES	36%	32%	32%	32%	30%	30%	30%			
RES share	68%	67%	67%	67%	68%	68%	68%			

Table 9: Energy utilisation of Base Scenario 2030 with DSM levels 5%, 10%, and 20% in TWh.
Source: energy**nautics**

Contrary to expectations, the amounts of electricity generated from each renewable and conventional resource do not vary significantly between different levels of DSM. The same is evident in the amount of curtailed renewable energy. This can be seen in detail in Figure 7 below.



	Wind Onshore	Wind Offshore	Photovoltaics	Geothermal	Wave / Tidal	Hydro run-of-river	Total
🟩 DSM 5%	3,9%	15,5%	1,1%	1,1%	1,2%	0,2%	3,4%
🟥 DSM 10% (Base Scenario)	3,8%	15,3%	1,0%	1,1%	1,2%	0,2%	3,3%
🟦 DSM 20%	3,6%	15,2%	0,8%	1,0%	1,1%	0,2%	3,3%

Figure 7: Curtailed energy from different RES for Base Scenario 2030 with DSM 5%, 10%, and 20%.
Source: energy**nautics**

The total amount of curtailed energy does decrease with more DSM in the system, however the difference is minimal. Offshore wind energy experiences around 15% curtailment. This is because the transfer capacity to access wind power in the North Sea offshore grid is still restricted below its maximum power production capacity.

3.3. STORAGE

The base scenario developed in combination with storage for variable RES, like wind and solar power is often mentioned as a solution to make renewable power more reliable. This scenario was created to examine the impact of storage on a future power system.

The base scenario as developed in section 3.1 is assessed assuming that a storage system with nominal power at one node of up to around 4 895 MW and continuous discharge capability for 24-hour periods at nominal power would be implemented by the year 2030. These dimensions were selected to accommodate large amounts of surplus wind power which would otherwise be curtailed. By 2030, this level of storage could be a reality by means of Compressed Air Energy Storage (CAES) and large pumped hydro storage. In this section, results of the a posteriori method are reported: Storage sizing is based on the amount of curtailed renewable energy at each node. An alternative method for designing storage based on EV integration showed that the impact on the transmission system was very low, so no further simulations were carried out using that method.

Design issues

Initially, storage was thought to complement the operation of mostly solar PV, and in effect reduce its curtailment. However, the changes to the optimisation strategy without any storage, simply prioritising renewable energy across Europe (Chapter 3.1), reduced the amount of curtailed solar PV to below 1%. This removes the need to design storage proportional to solar PV (i.e. 12hour storage). Instead, it has to be sized related to wind, which has the highest share of curtailed energy. It is expected that in the 2050 scenario, with a lower share of controllable sources and a higher share of solar PV, the curtailed amount of PV would be higher and would be the driver for the design of storage as expected.

As mentioned above, when the aim is to reduce curtailment, storage units are placed at the nodes where large amounts of renewable energies are curtailed. The storage should be utilised well, that is, it should be charged and discharged frequently. The suitable nodes are mostly those located onshore close to large onshore and offshore wind resources; which requires a relatively sparse storage placement. Accordingly, the necessary power rating and capacity of the storage units must be quite high to accommodate the large surplus power. The power rating of the largest storage unit designed in this scheme is 4 895 MW and was located in Poland near the coast. No storage was placed on the offshore nodes themselves because there is not enough space for the large systems on the offshore platforms. Since storage units were assumed to deliver their rated power over a period of 24 hours, this would lead to a necessary capacity of up to 117 500 MWh and a rated power of 4 895 MW. Such high power and capacity ratings could only be implemented by using CAES or large pumped hydro storage. For comparison: Europe's largest pumped hydro power plant today, Vianden in Luxembourg has a power rating of 1 100 MW. If the storage "plant" described above is constituted of EVs, each having a power rating of 2.76 kW and taking a factor of simultaneity of 0.394 (Bunk, 2010) into account, this would require nearly 700 000 EVs to achieve 4 895 MW at this node only, which is a very ambitious amount. However, the simulation results showed that even with storage this large the amount of curtailed energy is not substantially reduced. This is because the largest amount of wind energy is curtailed at the offshore nodes, where no large-scale storage can be placed.

A more realistic strategy for storage sizing is to distribute electric vehicles uniformly all over Europe. This scenario used the development goals of the German government to estimate the penetration degree of EVs by 2030. Under these assumptions, the power and capacity ratings required are smaller than in the case of curtailment reduction. Starting with the availability of storage a priori, the model then predicts what grid upgrades are needed. This storage placement strategy has little impact on necessary transmission grid upgrades in comparison with the base scenario. Hence, this method was not followed further. However, the effect should be more pronounced in distribution grids.

Electricity production and RES curtailment

The amount of electricity generated by each source is summarized in the following table.

	Advanced E[R] scenario	Base Scenario with storage		
(TWh)	Electricity generation EU-27	Electricity generation EU-27	Electricity generation Europe	Curtailed Energy Europe
Total generation	**3 533**	**3 533**	**3 863**	
Fossil	**1 133**	**1 212**	**1 320**	
Coal	89	75	77	
Gas	926	1 053	1 159	
Nuclear	118	84	84	
Renewables	**2 400**	**2 321**	**2 543**	Total energy curtailed (TWh) **77**
Hydro	365	377	516	0
Wind	939	751	773	75
PV	289	311	339	1
Biomass	420	444	472	–
Geothermal	183	221	224	0
Solar Thermal	141	143	143	–
Ocean Energy	63	73	75	0
Final energy consumption (electricity)	**3 206**	**3 121**	**3 569**	In percentage (%) **3%**
Fluctuating RES (PV, Wind, Ocean)	1 291	1 133	1 170	
Share of fluctuating RES	37%	32.1%	32.6%	
RES share	68%	66%	66%	

Table 10: Energy utilisation of Base Scenario 2030 with storage in TWh. Source: energy**nautics**

As expected, when compared to the base scenario results in Table 8, electricity production from wind increases as a result of introducing storage. Correspondingly, the overall RES share increases from 65% to 66%. Also, as production from RES goes up, generation from fossil and nuclear sources drops by almost 2%.

Figure 8 below compares the amount of curtailed energy between the base scenario and the scenario with storage.

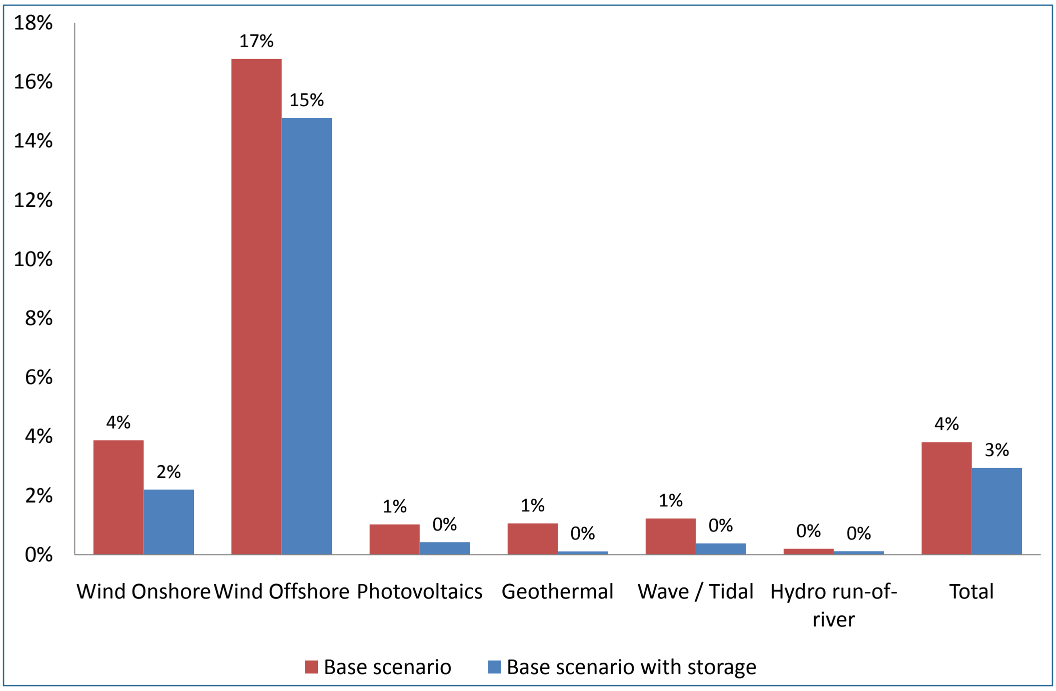


Figure 8: Curtailed energy from different RES for Base Scenario 2030 with DSM 10%, prioritised for dispatch of RES and with storage. Source: energy**nautics**

In this scenario the amount of curtailed renewable energy has been reduced overall. In particular, curtailed wind energy, both on- and offshore, was reduced by 2%. All other energy sources experience less than 1% curtailment.

Again, despite the reduction, offshore wind still remains the most curtailed energy source, with approximately 15% of available energy being wasted. The reason as with all the other scenarios ist that the transfer capacity to bring the available production in the North Sea offshore grid to mainland Europe is lower than its maximum power production capacity.

The conclusion from this analysis is that if transmission capacity were replaced by storage designed primarily to reduce the amount of curtailed energy, a very high amount would be needed. This may be an acceptable solution in special cases when the necessary grid upgrade gets close to possible limits. However, the costs of such storage would greatly exceed the cost of the grid upgrades in most cases based on today's costs.

3.4. INFLEXIBLE CONVENTIONAL POWER GENERATION

Coal, and especially nuclear power plants are 'inflexible' in nature because they cannot change their outputs rapidly in response to variations in demand or residual demand. This is different to the case for gas turbines which can adapt their output relative to sudden changes in electricity demand much faster. To investigate this effect, this scenario changes the generation mix so that 50% of the gas capacity is replaced by inflexible power, representing the extended use of coal and nuclear power. A future with this energy mix could occur due to political motivations and the wide-spread uptake of carbon capture and storage (CCS) technology.

Electricity production and RES curtailment

With increased inflexibility in conventional power generation, it is expected that the share of electricity from RES would fall. The following table gives a summary of the electricity generated by each source resulting from the simulations.

	Advanced E[R] scenario	Base Scenario with inflexible conventional power		
(TWh)	Electricity generation EU-27	Electricity generation EU-27	Electricity generation Europe	Curtailed Energy Europe
Total generation	3 533	3 533	3 782	
Fossil	1 133	1 499	1 532	
Inflexible conventionals (coal, nuclear, CCS, etc)	207	1 300	1 322	
Gas	926	199	209	
Renewables	2 400	2 034	2 250	Total energy curtailed (TWh) 300
Hydro	365	385	519	2
Wind	939	682	703	128
PV	289	291	318	16
Biomass	420	322	350	79
Geothermal	183	217	220	2
Solar Thermal	141	68	68	71
Ocean Energy	63	70	71	2
Final energy consumption (electricity)	3 206	3 056	3 494	In percentage (%) 12%
Fluctuating RES (PV, Wind, Ocean)	1 291	1 042	1 093	
Share of fluctuating RES	37%	29%	29%	
RES share	68%	58%	59%	

Table 11: Energy utilisation of Base Scenario 2030 with inflexible conventional power in TWh.
Source: energy**nautics**

Compared to the base scenario in Table 8, the RES share in this scenario drops from 65% to 59%. The result of the dispatched generation in comparison to the base scenario can be seen more clearly in the following figure.

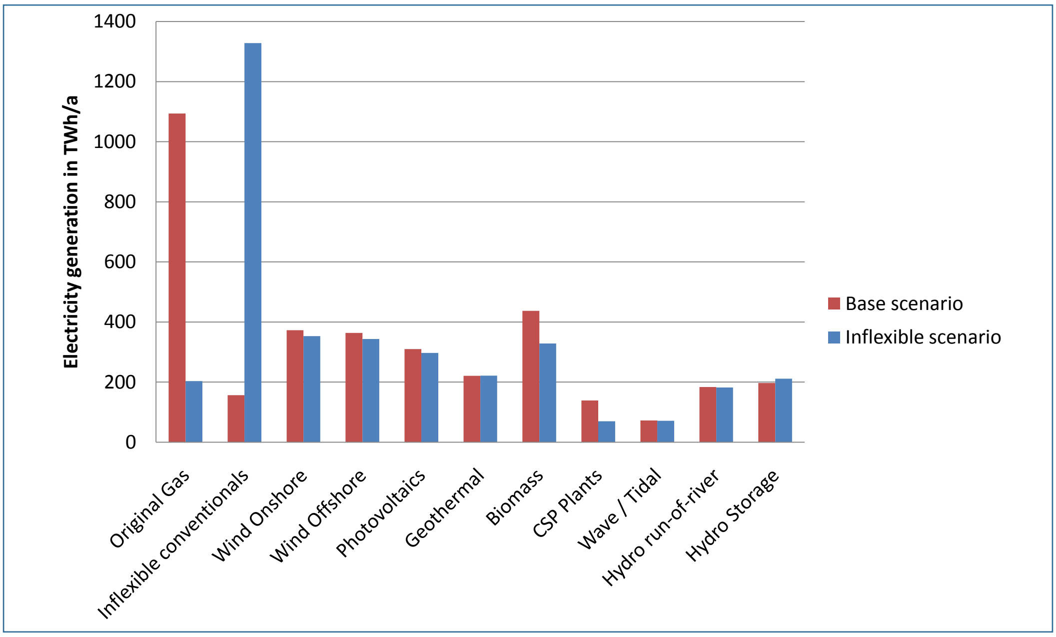


Figure 9: Electricity generation in TWh/a for Base Scenario with and without 'inflexible' conventional power.
Source: energy**nautics**

It can be seen that generation from inflexible coal and nuclear sources effectively doubles. To compensate for this, production from most RES decreases, with outputs from biomass and CSP being most affected as these are controllable renewable sources that we have assumed to have a lower priority in comparison to non-controllable RES. Essentially they are replaced by conventional power sources.

The following figure shows the full-load hours of the conventional power generators.

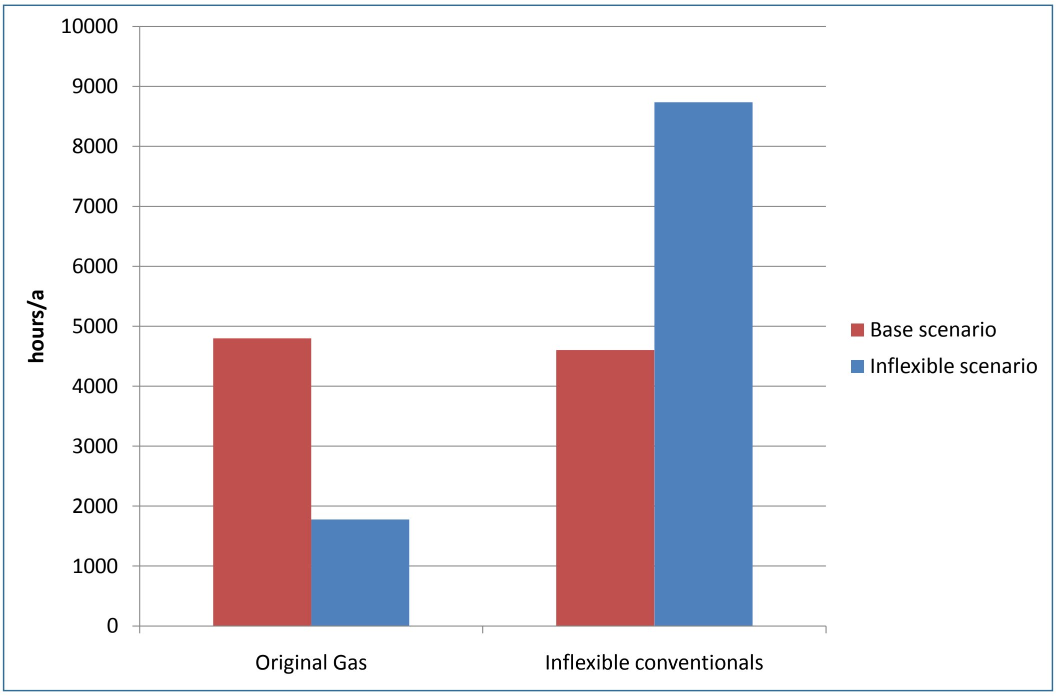


Figure 10: Full-load hours in hours per annum for Base Scenario with and without inflexible conventionals.
Source: energy**nautics**

The inflexible power plants have higher full load hours in this scenario compared to the base scenario because they are assumed to be operating all the time, whereas simulation results from the base scenario showed that these technologies are used much less in summer.

With the capacity of installed gas halved in the inflexible scenario the full-load hours have also dropped to from 4800 h/a to 1800 h/a compared to the base scenario. On the other hand, since coal and nuclear have been increased in capacity and fixed, the full-load hours have almost doubled.

The graph below displays the curtailed energy resulting from this dispatch process. As more inflexible, conventional power is prioritised in the dispatch process, the system cannot respond to fluctuating RES as effectively. This means increased curtailment for all non-controllable RES.

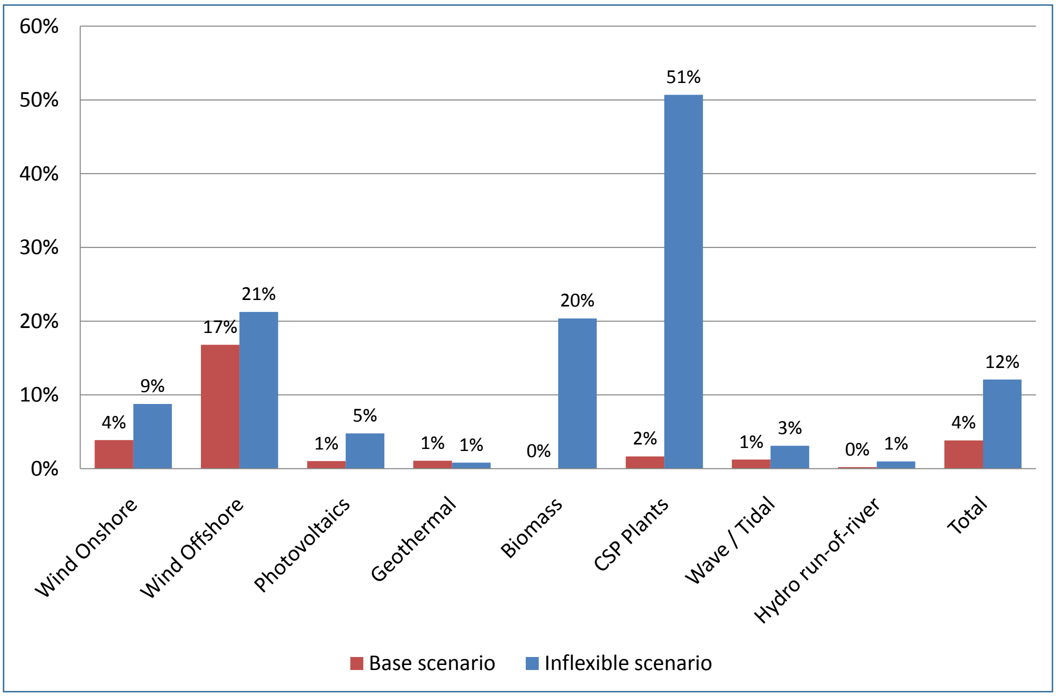


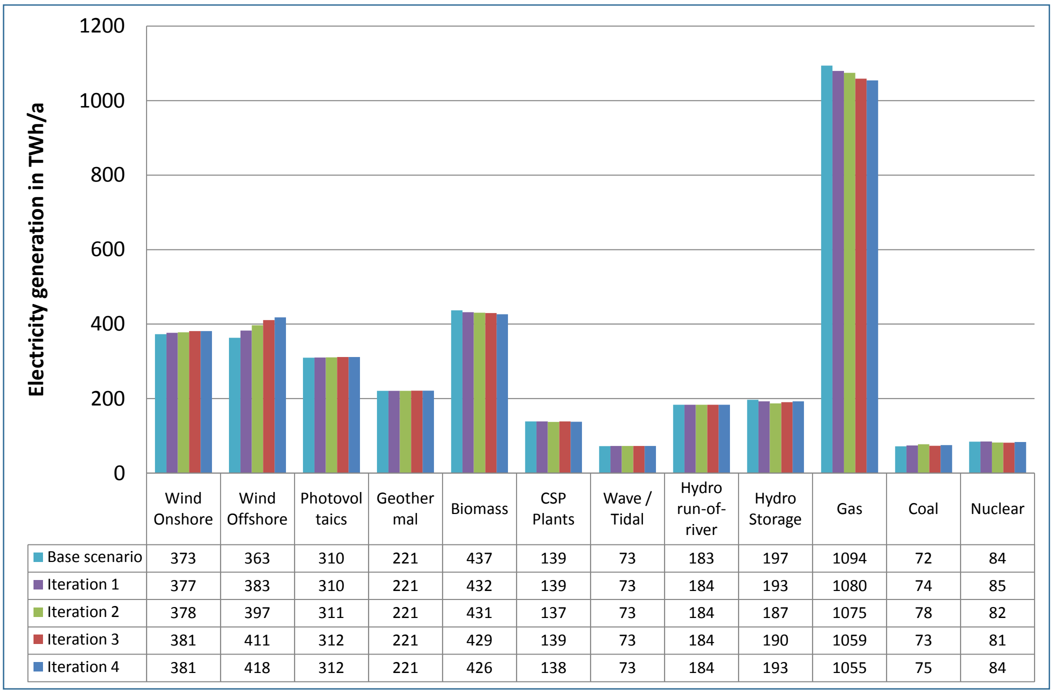
Figure 11: Curtailed energy resulting from dispatch with inflexible conventionals. Source: energy**nautics**

3.5. OPTIMISATION TO REDUCE CURTAILMENT

By their nature, wind and solar are instantaneous sources of energy. The power must be used in the instant that it is available, especially in the absence of dedicated storage mediums. With the dispatch method used in the base scenario, the level of overall curtailed energy is quite low at 4%, however the curtailed amount of offshore wind power is disproportionately high, with 17% of energy being curtailed, due to restricted transfer capacity between the North Sea offshore grid and load centres in Central Europe as previously mentioned.

Electricity production and RES curtailment

To best represent the reality of network upgrades, transfer capacity at certain locations were incrementally increased over several iterations to enable the integration or RES. This is because network upgrades are discrete events that depend on the power flow solution resulting from a specific load and generation scenario. Figure 12 below shows the amounts of electricity generated by each energy source for each iteration of the optimisation process. When this is done, the output from wind offshore in particular increases as more infrastruc-ture is added to access the power in the North Sea offshore grid. Also, as more wind power is utilised, less power from gas turbines is required.



	Wind Onshore	Wind Offshore	Photovoltaics	Geothermal	Biomass	CSP Plants	Wave / Tidal	Hydro run-of-river	Hydro Storage	Gas	Coal	Nuclear
Base scenario	373	363	310	221	437	139	73	183	197	1094	72	84
Iteration 1	377	383	310	221	432	139	73	184	193	1080	74	85
Iteration 2	378	397	311	221	431	137	73	184	187	1075	78	82
Iteration 3	381	411	312	221	429	139	73	184	190	1059	73	81
Iteration 4	381	418	312	221	426	138	73	184	193	1055	75	84

Figure 12: Electricity generation of the Base Scenario and optimisation iteration steps in TWh. Source: energy**nautics**

Figure 13 below shows the reduction in curtailed energy through the optimisation process where the number of network upgrades is increased in order to allow wind energy to be delivered to the load centres rather than being curtailed.

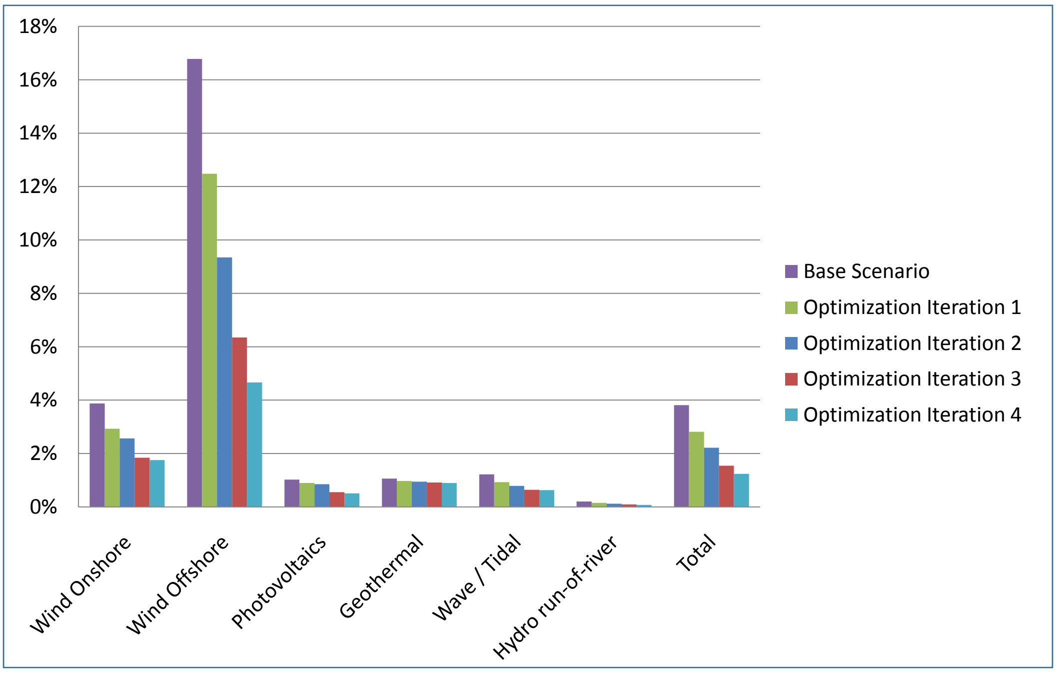


Figure 13: Curtailed energy in percent resulting from the optimisation process. Source: energy**nautics**

In this scenario, transmission lines connecting the North Sea offshore grid to significant load centres such as London, Paris and Amsterdam have been reinforced in each iteration.

Evaluation of upgrade costs VS. curtailment costs

If the capacities of the HVDC connections which constitute the offshore grid are increased, less and less energy will be curtailed. However, HVDC links are expensive to construct and install, therefore an economic evaluation is required to see what level of additional upgrades would be required to minimise energy curtailment, taking into account the money saved by reducing curtailment.

The following figure shows the level of investment required to prevent curtailment of wind energy and instead deliver it to the load centres. These investments come on top of the grid extensions listed under the base scenario, which are required for security of supply.

The costs associated with the number of upgrades made in each iteration step are shown in orange (the last two bars in the series), whereas the costs of curtailed energy are blue (the first three bars in the series).. Note that the cost of curtailed energy is evaluated based on three future prices for electricity; 10 cents, 5 cents and 3 cents per kWh (all are euro cents). According to the advanced E[R] scenario, the aggregated electricity price in 2030 will be approximately 10 cents/kWh. However, this price is effectively an average of electricity generated from RES and conventional fuels. The price for renewable energy is expected to be lower than conventional power, and even more so if large quantities of offshore wind power become available. This is why the cost of upgrades is compared against 5 cent and 3 cents per kWh scenarios as well.

Analysis shows that the cost of curtailing energy is significantly higher than the costs of installing additional grid infrastructure at an electricity price of 10 cents/kWh. The reason for this is the long service life of the transmission equipment, which is estimated to be approximately 40 years. In calculating the cost of curtailed RES, the expected cost of electricity in 2030 is applied for 40 years to the amount of energy that is curtailed (no inflation or discount rate is considered).

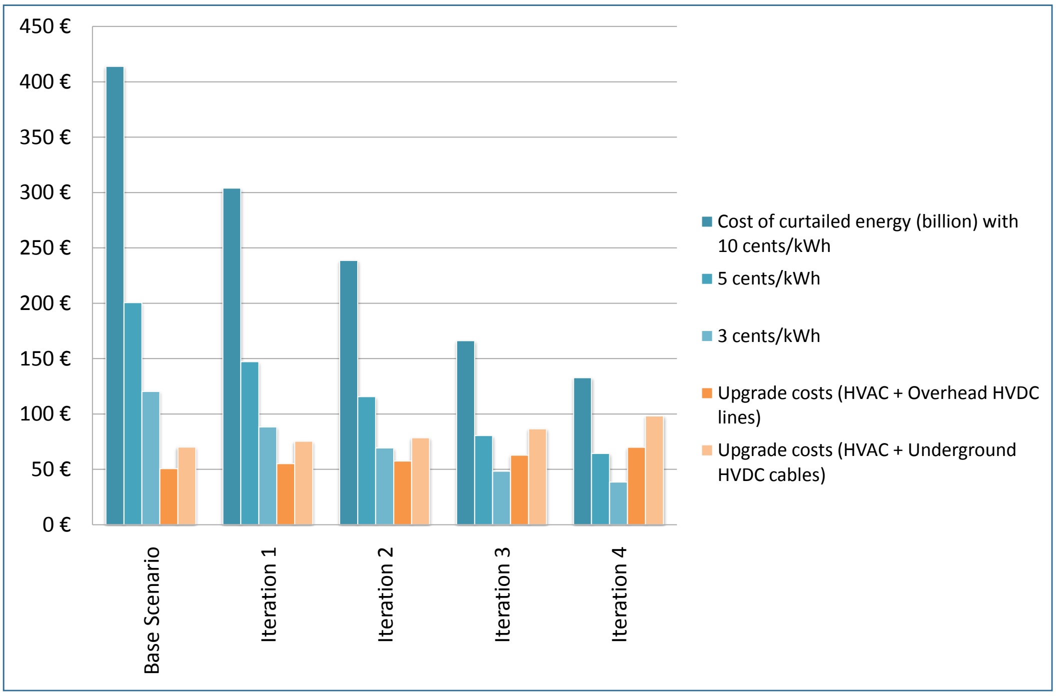


Figure 14: Comparison of upgrade costs and costs of curtailed energy in billion euros. Source: energy**nautics**

However, with a lower curtailment cost, after the third optimisation iteration, the costs of reinforcing the network and curtailing energy become equal. At this point, any additional investment in network infrastructure ceases to provide significant savings compared to reduced curtailment.

A further analysis has been done on the cost of upgrades that would be required to reduce the amount of curtailed renewable energy; or a 'shadow price'. The shadow price indicates the amount of investment required in the transmission network that will reduce RES curtailment in euro cents per kilowatt. When this value hits 3 cents/kWh the cost of increasing upgrades ceases to provide significant reductions in costs of curtailed energy, and the optimisation iteration process is stopped. Figure 15 below demonstrates this situation.

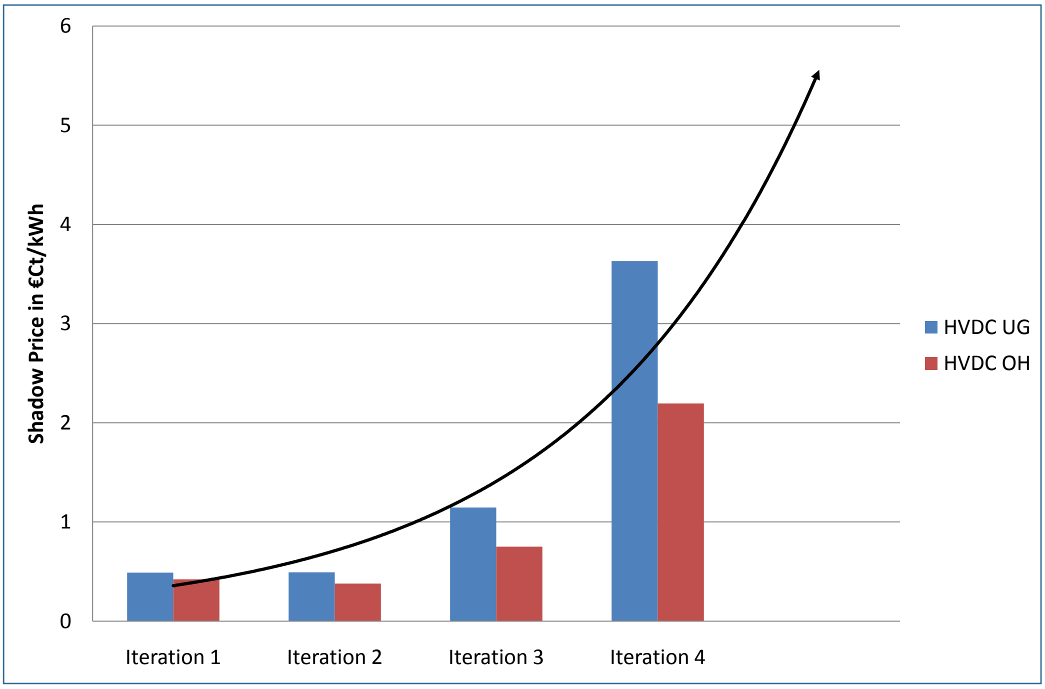


Figure 15: Shadow price in comparison with previous iteration step in €ct/kWh. Source: energy**nautics**

Therefore we stop at iteration 4. The resulting electricity generation from the optimised scenario is shown in the following table.

	Advanced E[R] scenario	Base Scenario optimised to reduce curtailment		
(TWh)	Electricity generation EU-27	Electricity generation EU-27	Electricity generation Europe	Curtailed Energy Europe
Total generation	3 533	3 553	3 867	
Fossil	1 133	1 211	1300	
Coal	89	75	76	
Gas	926	1 053	1 140	
Nuclear	118	83	83	
Renewables	2 400	2342	2 267	Total energy curtailed (TWh) 32
Hydro	365	376	516	0
Wind	939	682	703	28
PV	289	311	339	2
Biomass	420	426	456	–
Geothermal	183	221	224	2
Solar Thermal	141	137	137	–
Ocean Energy	63	73	75	0
Final energy consumption (electricity)	3 206	3 227	3 560	In percentage (%) 1%
Fluctuating RES (PV, Wind, Ocean)	1 291	1 182	1 234	
Share of fluctuating RES	36%	33%	32%	
RES share	68%	66%	66%	

Table 12: Energy utilisation in 2030 optimised to reduce curtailment in TWh. Source: energy**nautics**

Overall, the optimisation process improves the use of wind energy by 8%, and reduces the total curtailed energy to 1% of total available production capacity. With a better use of available wind power, the share of RES increases to 66%, which is closer to the advanced E[R] scenario. The share of fluctuating RES also reaches a third of total electricity production.

Ensuring security of supply

In order to guarantee a secure electricity supply, further simulations were carried out for an extreme weather event (where there is low wind and sun and high electricity demand) for the base scenario, demand-side management scenarios, storage scenario and optimised scenario. In all cases there were no need for further grid upgrades to ensure the secure supply of electricity during extreme weather situations to guarantee the lights to stay on 24/7. This is partly due to the high installed capacity of gas and partly due to the strong grid upgrades that would be necessary to guarantee a secure supply during the standard year.

3.6. ASSESSMENT OF GRID UPGRADES

Areas of reinforcement

The number of grid upgrades required was determined based on optimum power flow feasibility simulations using energy**nautics**' 2010 network model of the European electricity grid with input data representing standard operating conditions in 2030 for one year. The top six priority areas where significant reinforcements will be required are presented in Table 13 below.

	Required upgrade	
Region	GW	km
1. Spain-France-Central	**80.60**	**19,907**
Within Spain	10.00	2,730
Spain-France NTC	19.55	6,546
Spain-France Corridor within France	26.25	5,849
France other	24.80	4,782
2. North Sea Offshore Grid	**31.00**	**14,401**
Offshore grid	16.50	7,250
Onshore grid	14.50	7,151
3. Italy-Central	**39.65**	**8,270**
Within Italy	16.20	4,529
Italy-France NTC	8.00	1,259
Italy-Central Corridor through Switzerland and Austria	15.45	2,482
4. GB	**16.50**	**7,840**
Within GB	7.00	1,850
GB-Central NTC	6.00	865
GB-Norway NTC	3.50	5,125
5. Eastern Europe	**39.80**	**5,811**
6. Nordic Countries	**11.12**	**5,927**

Table 13: Summary of major upgrades required per region for Base Scenario 2030. Source: energy**nautics**

In evaluating the simulation results it becomes apparent that Central and Northern Europe will have a net demand whereas Southern Europe will have surplus production. The resulting load flow is therefore from Southern to Central Europe. In particular, interconnections between

Spain and France, Italy and France, as well as Great Britain, to Norway and Central Europe would have to be strengthened.

▷ **RES integration through Spain-France-Central Europe:**
Significant upgrades would be required between Spain and France and the ensuing corridor to central Europe to make the Energy [R]evolution a reality. This is to make use of the large quantities of solar PV, CSP and wind energy available in the southern parts of Spain and Portugal. With a growing production expected in the extremities of the Iberian Peninsula, the transmission network in Spain must be strengthened to accommodate the increased flows. To transport this power across to France, the NTC must be increased by up to 20 GW. Furthermore, substantial upgrades will be required to carry the imported RES through the network in France to the load centres in the centre of Europe.

▷ **North Sea offshore grid and surroundings:**
Realisation of the HVDC North Sea grid is critical for this future network scenario. It is likely that it would have to be reinforced beyond its initial capacity in order to harness the large quantities of wind power plants; predicted to be up to approximately 68 GW (Greenpeace Belgium, 3E, 2008). In this study, the largest amount of curtailed RES is the wind power in this region. For an optimised scenario over 20 GW of further upgrades would be required to effectively connect the available production capacity with the load centres in Great Britain, Norway and Central Europe. This includes reinforcements of the North Sea offshore grid itself, as well as connections to the onshore grid.

▷ **RES integration from Italy to Central Europe:**
Substantial upgrades of about 40 GW would also be required to effectively deliver wind and solar PV from Italy to Central Europe. Approximately 25 GW of this consist of an increase in NTC between the regions.

▷ **Stronger links to Great Britain:**
HVDC transmission infrastructure across the English Channel and between Norway and Great Britain would be necessary to support the energy consumption of London.

▷ **Transfer capacity within Eastern Europe:**
Transfer capacity within Eastern Europe must also be increased by about of 40 GW to allow smoother power exchanges between countries and to make the network more versatile for RES integration. An additional 14 GW of capacity needs to be installed to optimise the use of newly installed renewables and reduce curtailment.

In addition, the capacity would need to increase by several times within the Nordic region to deliver hydropower and offshore wind power from the North Sea to the load centres in Oslo and Stockholm.

Minor upgrades are also required near load centres such as Paris and Munich, as well as in Italy, to support the high energy demand of Central Europe.

The following map shows the locations where upgrades are required in the European electricity grid. These are marked by the lines marked in red.

Figure 16: Map of the high-voltage network of Europe (Status 2030) with the overlaying simplification marking upgrades of the European power system. Source: Reproduced with permission of ENTSO-E, energy**nautics**

Upgrade costs

These upgrades are required because there is little local energy supply in the central European region and the population centres need to gain access to the large quantities of solar PV and wind energy available in the southern parts of Europe. To transport this energy over the long distances it would be preferable to use efficient HVDC technology, rather than HVAC lines, since existing routes will most likely be at their capacity limit, and using HVAC requires reactive compensation for the high energy losses. Thus, a scheme was applied where HVAC capacity upgrades are restricted to three times the initial capacity. Any further upgrades that are larger than 1 GW are then replaced by underground or overhead HVDC lines.

Upgrade costs associated with the base scenario and optimised scenario are presented in the following table.

	Upgraded Capacity (GW) compared to 2010		Upgraded Distance (km) compared to 2010		Total cost of upgrades (billion euro)	
	HVAC	HVDC	HVAC	HVDC	HVAC + underground HVDC	HVAC + overhead HVDC lines
Base Scenario 2030	204	58	44,731	25,841	70.34	50.86
Optimised scenario	258	86	60,794	38,678	98.32	69.98
Increase associated with optimisation	54	28	16,063	12,837	27.98	19.12

Table 14: Summary of upgrades required for Base Scenario and Optimised Scenario compared to the 2010 network capacity in GW, length in km and costs in billion euros. Source: energy**nautics**

The 2030 network compared to the current grid in 2010 would require more than 258 GW of upgrades. This corresponds to a 37% increase in transfer capacity across the whole of Europe. To achieve this number of upgrades requires approximately €70 billion if all HVDC lines are made underground cables, and €51 billion if overhead lines are used for onshore installations.

If the network is optimised to reduce curtailed RES, 344 GW of grid upgrades would be required, corresponding to a 49% increase in transfer capacity over 2010 figures across the whole of Europe. In comparison to the base scenario, 82 GW, or 9% of additional grid upgrades would be required.

In this case the expected investment is approximately €28 billion in additional upgrade costs compared to the base scenario if all HVDC lines are made underground cables, and €19 billion if overhead cables are used for onshore installations.

In comparison, the ten year network development plan (TYNDP) published by ENTSO-E in June 2010, puts forward a total cost of upgrades of €70 to 100 billion for Europe by 2020, of witch 23 to 28 billion euros by 2040. This figure is comparable to the expenditures predicted in this study.

Perimeter	Investments (billion €)
RG North Sea	12 to 14
RG Baltic Sea	11 to 13
RG CCS	11 to 12
RG CCE	8 to 9
RG CSW	6 to 7
RG CSE	4 to 5
Total ENTSO-E	23 to 28

Table 15: Investment costs of transmission projects of European significance to be completed within the period 2010–2014. Source: Ten Year Network Development Plan, ENTSO-E[6]

The costs presented here are based on a strategy to upgrade the transmission paths from point to point where they currently exist. However, the benefit to the local communities in Spain and southern Europe would not be significantly increased by this type of reinforcement in the local networks, and the cost of converter stations at each segment constitutes an unnecessary cost. Rather than simply following existing paths it may be better to find new solutions like building new HVDC transmission lines directly from the renewable energy sources to Central Europe

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[6] RG: Regional Group, CCS: Continental Central South, CSW: Continental South West, CSE: Continental South East. (ENTSO-E, 2010)

and kicking off the HVDC Supergrid. This strategy would be even more effective when considering the infrastructure that will be built to support the planned Desertec project in North Africa, which plans to install large amounts of concentrating solar power to export to Europe.

The following map gives an idea of the type of HVDC network that would result from this approach. With this type of construction, the HVDC network will form an adequate base for the Supergrid to connect expected power imports from Desertec in North Africa.

Figure 17: Map of the high-voltage network of Europe with the proposed HVDC grid (Status 2030). Source: ENTSO-E, energy**nautics**

Impact of demand-side management on upgrades

DSM by principle makes better use of local renewable resources. Electricity consumption in homes and businesses is encouraged when there is a large availability of wind and solar power, and discouraged when power from these sources is naturally low (i.e., during the night). With DSM, more power would be used locally, so less power needs to be imported from remote locations, reducing the number of upgrades required. This effect is visible from the results of the simulations presented below.

	Upgraded Capacity (GW) compared to 2010		Upgraded Distance (km) compared to 2010		Total cost of upgrades (billion euro)	
	HVAC	HVDC	HVAC	HVDC	HVAC + underground HVDC	HVAC + overhead HVDC lines
DSM 5	248	68	55,511	28,884	87.52	61.04
DSM 10 (Base Scenario)	204	58	44,731	25,841	70.34	50.86
DSM 20	200	57	44,363	25,966	70.01	50.53

Table 16: Summary of upgrades required for Base Scenario 2030 with different DSM levels. Source: energy**nautics**

With more DSM implemented, fewer upgrades are required, both for HVAC and HVDC transmission lines. Despite this, the areas where reinforcements are required do not change significantly between the three scenarios. Most upgrades are still related to enabling energy transfer from Southern to Central Europe as described in the previous section.

The method used to apply DSM in these scenarios modifies the demand by up to 20% according to the availability of local distributed RES. Because of this, in some areas and in some instances where demand is already high it becomes even higher, causing a shortage of supply on a European level. An alternative method would be to adjust all demand points according to the available RES in the whole of Europe. However this approach would only be meaningful if the grid is close to a copper-plate with no bottlenecks in transfer capacity. The ideal method to reflect reality would be a regional DSM, where demand points in a region are adjusted according to RES availability in a region and related with neighbouring regions, for example, through regional pricing.

3.7. RESULTING CO_2 EMISSIONS

The CO_2 emission associated with power generated from gas and coal-based generators was calculated using CO_2 intensities outlined in Table 4. The resulting CO_2 emission for the base scenario network is approximately 556 million tonnes per annum for EU 27 (600 million tonnes p/a for whole of Europe). This result is actually 62 million tonnes more than is predicted under the advanced E[R] scenario. The discrepancy comes from the different modelling and techniques used for the simulations, since the Greenpeace figure is based on a copper-plate study whereas energy**nautics**' figure is taking into account grid limitations. With a copper-plate model fewer barriers are encountered in delivering energy from source to sink, and therefore a higher level of offshore wind energy can be used, whereas the more detailed energy**nautics**' model reveals more difficulties in making use of offshore wind energy due to the network limitations.

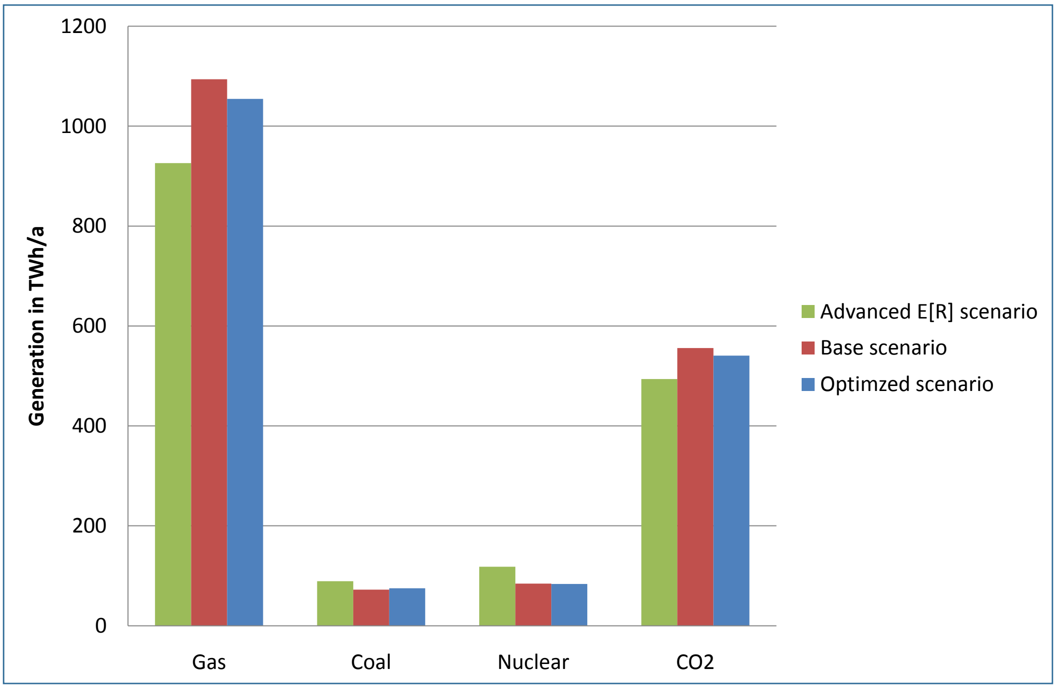

Figure 18: Conventional power generation (TWh/a) and CO_2 emissions (Mill t/a) of Base Scenario 2030 and optimised scenario compared the advanced E[R] scenario. Source: energy**nautics**

Under the optimised scenario, optimise 540 million tonnes per annum of CO_2 would be emitted by EU 27 (581 million tonnes/a for whole of Europe). Compared to the base scenario this is 15 million tonnes lower, but compared to the advanced E[R] scenario it is still 46 million tonnes higher. These results are in line with what is expected, as the utilisation of RES has increased in the optimised scenario in comparison to the base scenario.

Demand-side management

Since there is no dramatic change in the share of RES with different levels of DSM, the predicted CO_2 emissions do not change significantly between the three scenarios. The results can be seen in the following figure.

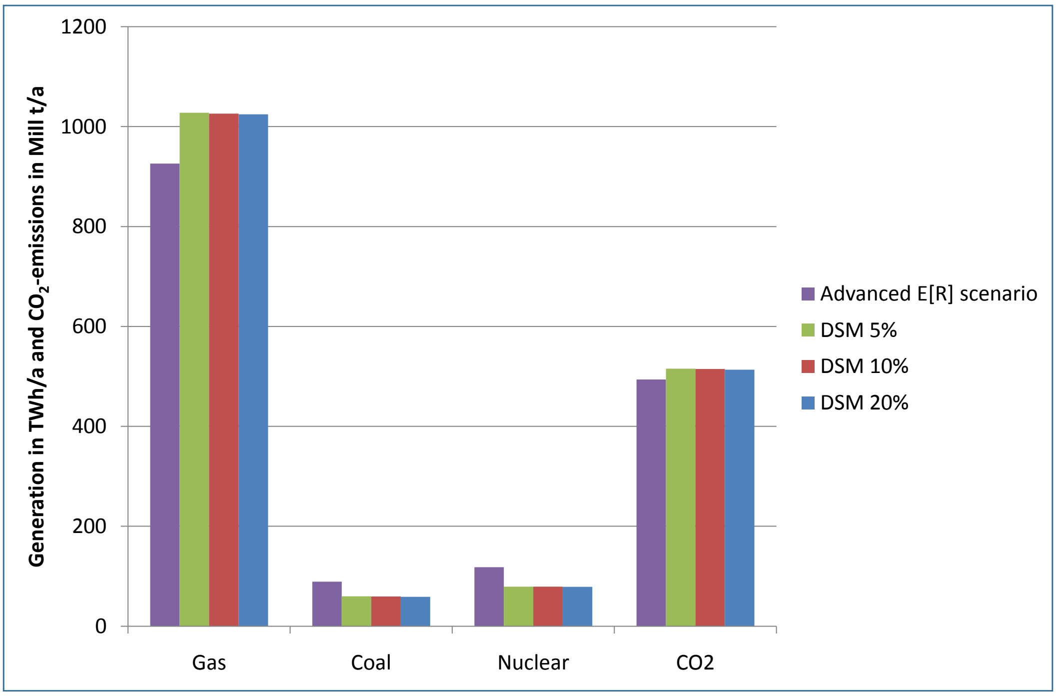

Figure 19: Conventional power generation (TWh/a) and CO_2 emissions (Mill t/a) of Base Scenario 2030 with DSM 5%, 10% and 20%. Source: energy**nautics**

Storage

The resulting CO_2 emission for the base scenario with storage is approximately 541 million tonnes per annum for EU 27 (590 million tonnes p/a for whole of Europe). This is a reduction compared to the base scenario without storage by approximately 15 million tonnes. Obviously this is due to the fact that RES production has increased, offsetting the need to generate electricity using conventional and polluting power sources. The results can be seen in the following figure.

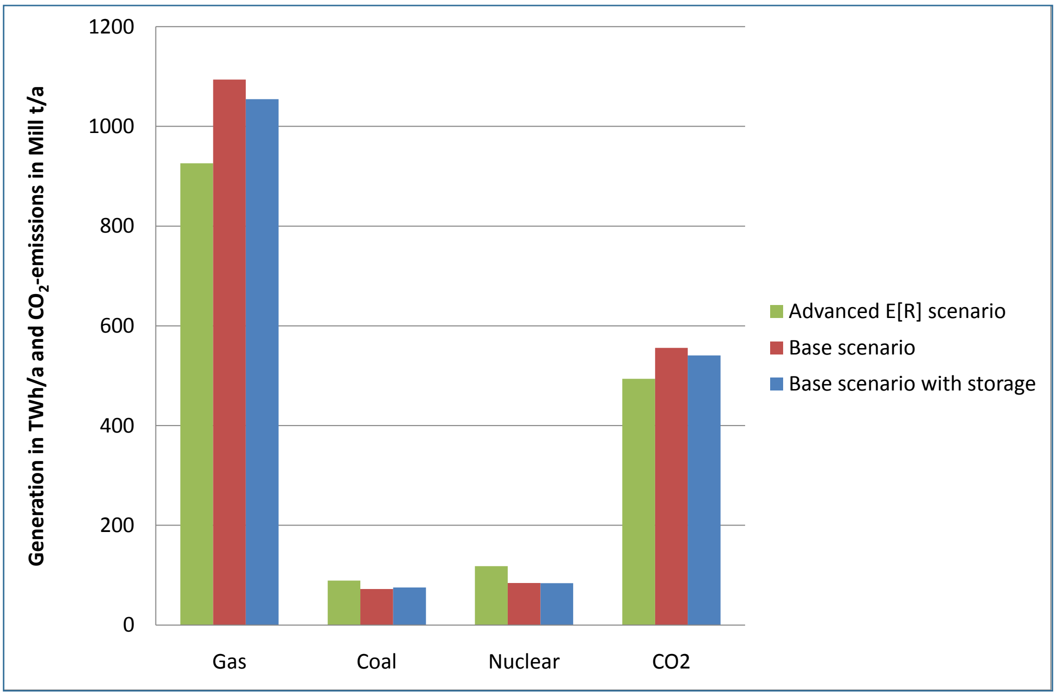

Figure 20: Conventional power generation (TWh/a) and CO2 emissions (Mill t/a) of Base Scenario 2030 with and without storage. Source: energy**nautics**

4. RESULTS SCENARIO 2050

The assessment of the level of network reinforcements required by 2050 is based on the same method used for the 2030 scenario. Starting with the European electricity grid designed for the optimised 2030 scenario, feasibility OPF simulations were performed applying demand and generation input data developed based on the 2050 figures of the advanced E[R] scenario.

Demand

The final electricity consumption in 2050 is expected to be 33% higher than the demand in 2030 due to the increase in electric vehicles and heat pumps. However, the implementation of demand-side management and storage is expected to progress, so the demand profile was modified to include 15% DSM.

Generation

Compared to the 2030 scenario the Greenpeace advanced E[R] scenario for 2050 has substantially more renewable energy in the energy mix, increasing from 68% to 97%. Electricity production from all renewable sources is expected to rise. Particularly notable are the almost doubling of CSP, geothermal and ocean energy, as well as the 115% increase of energy from solar PV. Electricity production from wind energy is also expected to grow by about 50%. On the other hand, all nuclear and coal-fired power plants are expected to be decommissioned, and gas capacity is expected to shrink to 10% of the level of 2030. With a higher share of solar PV in the energy mix, a bigger role is expected for dedicated storage mediums, and with less conventional units the utilisation of biomass, CSP and geothermal units is expected to become more prominent. Another notable difference between the two scenarios is that in 2050, large quantities of energy will be available as cross-border imports from North Africa and Turkey. This amounts to approximately 800 TWh of imported energy for the entire year, mainly from sources such as CSP and wind, therefore being treated as base load generation.

Preliminary investigations of the extreme event and standard year data showed that, at some instances the grid experiences a shortage of supply on a European level. This can be addressed to a certain extent by assuming that in the 2050 a higher wind output (in terms of full-load hours) is expected compared to the 2030 scenario, however a larger part of the energy shortage can only be covered by assuming a large import component from North Africa and Turkey, by increasing the installed capacity of wind and solar generation within Europe, or a combination of the both. The import capacity assumed in the E[R] scenario however, would require a far too expensive Supergrid infrastructure to transport the energy to the load centres in Central Europe. Therefore in our simulations the import from North Africa was limited to 60 GW.

To assess the impact of these situations, the following two grid scenarios were developed.

- **Import Scenario:**
  60 GW of import capacity (mainly CSP) is available from North Africa and Turkey, transported via a Supergrid to Central Europe. The Supergrid also has capacity to transfer solar energy generated in the south of Europe directly to Central Europe. PV capacity is raised in Southern Europe to cover the shortage in energy and biomass capacity is increased all over Europe to ensure adequate back-up power supply.

- **Regional Scenario:**
  No import from North Africa is considered. Therefore the Supergrid transfers only solar energy from the south to Central Europe. Shortage in supply is covered by increasing PV and wind capacity everywhere in Europe, while biomass capacity is increased to ensure adequate back-up power supply.

The following sections present the results of these two scenarios in terms of the type of grid upgrades required, their costs, and the energy production characteristics.

4.1. IMPORT SCENARIO

For some instances in the standard year, a supply shortage was seen on a European-wide level. To ensure that there is enough generation to meet demand at all times, 60 GW of import capacity is considered from Northern Africa in this scenario. However, this was still insufficient to cover for the supply shortage; therefore 260 GW of extra solar PV capacity was added to cover the energy demand and 120 GW of extra biomass capacity was added as back-up power to the energy mix. This is because in the advanced E[R] scenario, the import power was considered a base load whereas in our scenario it was more used as back-up, creating the need for more generators such as wind and solar PV. For a detailed distribution of the capacities refer to Appendix C.

With an increased capacity of solar PV in the south of Europe, it is expected that there would be more curtailed solar PV energy, because the larger installations produce even more energy in summer when demand is lower.

In order to reduce the curtailment of solar PV in summer and reduce the reliance on biomass (as it is a limited resource), the introduction of storage mediums become important. It was found that in excess of 300 TWh of energy is curtailed during summer from solar PV and wind sources, and 340 TWh of energy is generated by biomass during summer. This indicates that reliance on biomass units can be reduced if storage devices with the capacity to store the amount of energy equivalent to that curtailed are introduced to the system.

Since the storage is assumed to be used largely on a daily basis storing solar energy during the day and supplying consumers in the night, the inclusion of storage was simulated by increasing DSM from 15% to 30%.

The energy production resulting from this situation is shown below.

Electricity production and RES curtailment

The following table gives an overview of the amount of electricity generated by different sources during a 'standard year' operation of scenario 1.

	Advanced E[R] scenario	Import scenario with increased PV capacity in south and biomass capacity all over Europe with storage		
(TWh)	Electricity generation EU-27	Electricity generation EU-27	Electricity generation Europe	Curtailed Energy Europe
Total generation	**4 202**	**4 202**	**4 492**	
Fossil	**92**	**53**	**54**	
Coal	0	0	0	
Gas	92	53	54	
Nuclear	0	0	0	
Renewables	**4 110**	**4 149**	**4 438**	Total energy curtailed (TWh) **219**
Hydro	391	378	529	4
Wind	1 392	1 262	1 297	62
PV	622	860	912	131
Biomass	554	621	674	–
Geothermal	507	471	478	17
Solar Thermal	446	376	376	–
Ocean Energy	198	182	173	5
Import	805	241	241	
Final energy consumption (electricity)	**4 739**	**4 853**	**4 645**	In percentage (%) **4%**
Fluctuating RES (PV, Wind, Ocean)	2 212	2 304	2 382	
Share of fluctuating RES	53%	51%	49%	
RES share	98%	99%	99%	

Table 17: Energy utilisation of the 2050 import scenario in TWh. Source: energy**nautics**

The outputs modelled from most RES are in line with the advanced E[R] scenario. However, by increasing the biomass and PV capacities, the energy production from these sources have increased. The quantity of solar PV energy that has been curtailed is also quite high, although the quantity has been mitigated a lot by including storage. In some hours however, such as during the night when energy production from solar PV is not available and there is no storage, biomass is needed to cover the energy demand.

4.2. REGIONAL SCENARIO

The import scenario would require large quantities of upgrades which might not be realistic due to cost or public acceptance. For this study, a second scenario was developed where grid upgrades were limited to around 200 billion euros worth of expenditure. This scenario assumes that there is no solar energy import available from North Africa and Europe must supply its own energy demand with a 98% RES-share.

For this to happen, the installed capacities of PV and wind were increased to cover the energy shortage and biomass was increased to ensure adequate power supply as shown below.

(GW)	Advanced E[R] scenario carriage EU-27	Modified capacities for regional scenario
Biomass	100	336
PV	498	974
Wind	497	667

Table 18: Installed capacities in GW for biomass, PV, and wind for the 2050 regional scenario. Source: energy**nautics**

For a detailed distribution of the capacities refer to Appendix D.

For similar reasons to that of the import scenario, it is anticipated that by increasing the capacities of variable RES such as solar PV and wind the amount of energy curtailed will also increase. Storage was also implemented in this case, sized so that half of the maximum curtailed power can be stored for up to 24 hours at all nodes that experienced curtailment.

The energy utilisation characteristics resulting from these new capacities are shown below.

	Advanced E[R] scenario	Regional scenario with increased PV, wind and biomass all over Europe with storage		
(TWh)	Electricity generation EU-27	Electricity generation EU-27	Electricity generation Europe	Curtailed Energy Europe
Total generation	**4 202**	**4 202**	**4 543**	
Fossil	**92**	**25**	**26**	
Coal	0	0	0	
Gas	92	25	26	
Nuclear	0	0	0	
Renewables	**4 110**	**4 177**	**4 517**	Total energy curtailed (TWh) **294**
Hydro	391	294	390	4
Wind	1 392	1 541	1 600	182
PV	622	998	1 116	86
Biomass	554	577	633	–
Geothermal	507	452	459	12
Solar Thermal	446	133	133	–
Ocean Energy	198	182	186	10
Import				
Final energy consumption (electricity)	**4 739**	**4 616**	**5 408**	In percentage (%) **5%**
Fluctuating RES (PV, Wind, Ocean)	2 212	2 721	2 901	
Share of fluctuating RES	53%	65%	64%	
RES share	98%	99%	99%	

Table 19: Energy utilisation of the 2050 regional scenario in TWh. Source: energy**nautics**

By increasing the capacities of PV and wind, the energy production increases correspondingly. Also by including storage, the curtailed amount RES is kept to a minimum.

4.3. ASSESSMENT OF GRID UPGRADE APPROACHES

In 2050 the following grid upgrades are required to support the advanced E [R] scenario.

Import scenario

In the import scenario, most of the energy production is in the south, as imports from North Africa enter Europe through Spain, Italy, and Greece, and solar PV is increased in the southern states to make up for the deficit in energy supply on a European level. This contributes to a large number of upgrades required to transfer the energy from the south to load centres in Central Europe. This situation is similar to that seen in the case for 2030. To meet the scenario needs, it would be ideal to build up a Supergrid which transports the imported energy from the injection points in the south to the major load centres in Central Europe such as Paris, London and Brussels. Such a Supergrid would need to carry at least 60 GW of energy imports. In addition, the quantity of solar energy produced in the southern states of Europe, particularly in Portugal, Spain and Greece are big enough to be drawn by load centres in Europe, requiring extensive upgrades. This need can be replaced somewhat also with the Supergrid, up to a capacity of 75 GW.

Despite the Supergrid structure modelled, in the import scenario even more upgrades are required to transfer energy from Spain and Portugal to Central Europe through France, with the NTC between Spain and France needing 18 GW of enhancements. A lot of upgrades are also required within Spain to deliver the solar energy harvested in the south to the collector point of the Supergrid. The same is the case in the Balkan region, where an injection point to the Supergrid is located in Greece. Up to 108 GW of upgrades are required to collect much of the dispersed solar energy so that it can be sent to Central Europe via the Supergrid. One characteristic that contrasts the 2050 scenario with the Supergrid to the 2030 scenario is the number of upgrades required in Central Europe itself. Once large quantities of energy are transported directly from the south and injected at certain points in Central Europe, then it needs to be distributed to users within Central Europe. For this, up to 200 GW of upgrades would be required in Central Europe. The North Sea Offshore grid also requires large quantities of upgrades to support the growing wind power production capacity in the North Sea into the year 2050. Since the Supergrid does not contribute to load relief in Eastern Europe or the Nordic region, the number of upgrades required in those regions remains quite high.

Regional scenario

In the regional scenario, there is much less pressure on the transmission system to transport large quantities of energy from one location to another because of the increase in local solar PV and wind generation capacity all over Europe. In this case, significantly fewer upgrades are required in Spain and France compared to the import scenario. There would still be some upgrades required within Spain and France, but this is more due to delivering solar energy to the collection point of the Supergrid in Spain or distributing energy from the injection point at Paris to other load points within France. This is the same in the Balkan region and in Great Britain where up to 30 GW and 22 GW upgrades are required to deliver the solar energy to the collection point and from the distribution point of the Supergrid, Since the upgrades related to transferring energy from south to Central Europe is no longer dominant, the area that would requires the most upgrading is the Nordic region and the North Sea offshore grid, where hydro and wind energy must be delivered to the load centres which are far away from the energy sources. In addition, about 25 GW of upgrades are required in Eastern Europe to facilitate power exchange.

		Optimised Scenario 2030	Import Scenario 2050	Regional Scenario 2050
Capacity (GW)	HVAC	879	1,311	995
	HVDC Onshore	71	1,221	266
	HVDC Offshore	97	419	161
	Total	**1,046**	**2,951**	**1,421**
Distance (thousand km)	HVAC	170	242	190
	HVDC Onshore	19	125	26
	HVDC Offshore	43	135	62
	Total	**233**	**501**	**278**
Cost of upgrades vs 2010 grid (billion euro)	HVAC	20	59	31
	HVAC Onshore	21–49	300–452	65–89
	HVAC Offshore	29	168	53
	Total	**70–98**	**528–679**	**149–173**
Cost of upgrades vs 2030 grid (billion euro)	HVAC	–	39	10
	HVAC Onshore	–	279–403	40–44
	HVAC Offshore	–	139	24
	Total	**–**	**458–581**	**74–79**

Table 20: Summary of grid upgrades required for 2050 scenarios. Source: energy**nautics**

The 2050 grid to meet the Energy [R]evolution scenario compared to the current grid in 2010 requires between 1421 and 2951 GW of network upgrades. The costs fall between 149 and 679 billion euros, corresponding to the regional scenario and import scenario evaluated in this section. It should be kept in mind that the regional scenario relies on a heavy increase in installed capacity of new generators such as solar PV, wind and biomass within Europe. Of course, the costs of installing extra generation capacity may be far beyond the discrepancy between the two grid costs evaluated here.

Figure 21: Map showing energynautics' model of the high-voltage network of Europe (Status 2050), based on 224 grid-connected nodes. Source: Reproduced with permission of ENTSO-E by energy**nautics**.

5. CONCLUSIONS AND RECOMMENDATIONS

For the European electricity grid to support up to 68% electricity from renewable energy sources by the year 2030, the current grid must be reinforced significantly in the following locations:

- **South to Central Europe** with up to 20 GW transfer capacity across the border of Spain and France, and 26 GW of transfer within France associated with delivering this to the load centers in Central Europe. A similar level of capacity is also required between Italy and Central Europe.
- **North Sea offshore grid and surroundings** with approximately 16 GW offshore and 15 GW onshore infrastructure to deliver the wind power to load centers in mainland Europe and Great Britain.
- **Support to Great Britain** across the English Channel and to Norway is required in excess of 15 GW in addition to a strong connection to the North Sea offshore grid.
- Up to 40 GW of additional transfer capacity within **Eastern Europe and the Balkans** to allow for greater power exchange in support for renewables integration.
- Approximately 10 GW additional transfer capacity **in the Nordic countries,** to improve access to the hydro schemes and North Sea offshore grid.

This is a minimum requirement for the 2030 grid, based on simulations using the energy mix proposed by the advanced Energy [R]evolution scenario. The cost associated with this level of network reinforcement is 50 to 70 billion euros, depending on the type of transmission technology used. To maximise the use of renewable energies, so that curtailment of non-controllable RES is reduced from 12% to 1%, would require additional upgrades in excess of 20 GW in the North Sea offshore grid and corresponding connections to the load centres on main land Europe. This could be done with an additional investment in the order of 20 to 27 billion euros, corresponding to a shadow price of less than 4 euro cents per kilowatt-hour to access the curtailed renewable (mainly wind) energy.

Contrary to initial thought, the 2030 scenario results indicate that different levels of demand-side management in the system and inclusion of storage devices would not result in significant impact on the type of upgrades required or the amount of curtailed energy that could be reduced. However, these measures are very important for better operation and effective energy management and thus should not be neglected from investment and development. In continuing this study towards the scenario in 2050, it would be sensible to assume that a certain level of demand-side management and storage will be implemented by 2030, and this would only grow towards 2050, as it aids in the management of power system operations.

In fact results of the 2050 simulations indicate that with increased reliance on RES for base energy production, the role of DSM and storage become more important in reducing curtailed renewable energy. Particularly in the case of storage, when coupled together with solar PV, it makes it a more stable energy source, suitable to cover the base load. If the level of storage supporting the solar PV systems is low, much of the energy produced during the days in summer will never be used, either because there is a demand shortage or there is insufficient network transfer capacity for it to be used elsewhere, and in the evenings when there is a high-load, another energy source such as biomass would need to be used to cover for the lack of solar PV power. However, by combining solar PV with storage so that the energy produced during noon can be stored and used during the evening when there is peak-load, not only is curtailment of solar energy reduced, but the consumption of biomass power is reduced, making it available as a backup power at other times when emergency power is required to maintain security of supply. Therefore for the two 2050 scenarios, inclusion of storage plays a critical role in reducing curtailment, especially of solar PV.

Another point to note is the necessity and usefulness for a 'back up' generation capacity in the case of unexpected situations. It was found through our simulations that, no additional backup capacity would be required if the network is upgraded for adequate access to the available renewable energy sources under standard operating conditions, because an extremely large grid is required to accommodate 97% renewable energy. This enhances the argument for reliability of renewable energy because it shows that, in combination with an extended grid, adequate energy will be available at some part of the system which can be transported to another part of the system at any time, even in extreme weather situations.

On the other hand, if a certain proportion of coal and nuclear power is considered as inflexible base generation, there is a negative impact on the utilisation of renewables. Since the output from inflexible generation cannot be easily varied and is more or less 'fixed' for a large part of the year, it displaces RES in the generation mix from 65% to 59%.

As highlighted in the 2030 chapter, the grid structure in 2030 would incorporate more HVDC transmission links compared to the current network in 2010. This is because to transport large quantities of solar energy from the south of Europe to the centre, building HVDC lines that travel directly from the south to the centre is likely to be more economical compared to building up small segments of HVAC infrastructure along long distances. New and efficient HVDC technology will begin to form the basis for a Supergrid, and aid to the development towards elevated use of RES in 2050.

For the 2050 scenario with close to 97% of renewables, a demand-side management of 15% was applied, with storage, and with two different energy import scenarios using the Supergrid. The types of grid upgrades that are required by 2050 depend on the strategy taken to supply the energy demand. If a Supergrid is built to import energy from North Africa and the quantity of solar PV in Southern Europe is increased in the case of the import scenario, large amounts of grid upgrades are required to bring the energy production in the south of Europe to the load centres in Central Europe. This scenario requires 1,905 GW of transmission network upgrades from 2030, totalling to a cost between 458 to 581 billion euros, depending on the type of HVDC technology used. In addition to the grid infrastructure, up to 260 GW increase in solar PV capacity in South Europe, and up to 112 GW of biogas/biomass capacity all over Europe is required in comparison to the advanced E[R] scenario. On the other hand, the regional scenario where no import from outside of Europe is considered, the energy production all over Europe must be increased up to 470 GW in solar PV, up to 170 GW in wind, and up to 236GW in biogas/biomass compared to the advanced E[R] scenario. In this second case however, the upgrade costs are much more limited because the need to transfer so much energy from the South to Central Europe is no longer there. The corresponding grid upgrades in this case is in the vicinity of 375 GW, totalling to an amount of 74 to 79 billion euros.

The regional scenario presents a much more economical option in terms of the grid upgrades. However, considering the quantity of generation capacity that must be increased all around Europe, as well as the level of storage that should ideally accompany the increase in solar PV installations, the costs for building up this infrastructure may greatly exceed that of the import scenario, which has a seemingly high level of upgrade costs. Future studies will need to incorporate generation costs and more accurate grid costs to calculate the optimal development of renewable energy sources and grid infrastructure which can provide adequate security of supply. For example, it may turn out that, the most economical solution is to keep upgrading the trans-mission infrastructure because it is cheaper comparative to installing new solar PV capacity. However, it is somewhat questionable whether public acceptance of increasing transmission infrastructure to such an extent is likely. Therefore the ideal solution is certain to be a combination of grid upgrade, generation capacity expansion, RES curtailment reduction, and better management of demand. More tools need to be developed in this regard, to be better able to calculate the economic optimum of this complex system.

An overview of the key results of all scenarios is shown in the following table.

	Base Scenario 2030	Base Scenario 2030 with DSM20%	Base Scenario 2030 with storage	Base Scenario 2030 with inflexible generation	2030 Grid optimised for curtailment	2050 Grid with 60GW import	2050 Grid without import
Total generation (TWh)	3 886	3 888	3 863	3 782	3 867	4 492	4 543
RES (TWh)	2 537	2 643	2 543	2 250	2 567	4 438	4 517
% RES	65%	68%	66%	59%	66%	99%	99%
Curtailed RES (TWh)	98	89	77	150	32	219	294
% curtailed	4%	3%	3%	6%	1%	4%	5%
Grid investments (billion euro)	50 – 70				19 to 58 in addition to Base Scenario 2030 (70 to 98 vs. 2010)	458 – 544 in addition to 2030 (528 to 679 vs. 2010)	74 – 79 in addition to 2030 (149 to 173 vs. 2010)

Table 21: Overview of key results of all scenarios. Source: energy**nautics**

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7. APPENDICES

COUNTRY	WIND	PHOTO-VOLTAICS	GEO-THERMAL	BIOMASS	CSP PLANTS	WAVE/ TIDAL	HYDRO-POWER	GAS	COAL	NUCLEAR	TOTAL	MAX DEMAND
Europe	386.23	263.49	34.50	82.34	43.00	21.48	212.71	240.66	17.31	17.00	**1 318.71**	605.61
Albania	0.20	1.00	0.00	0.50	0.00	0.00	1.50	1.43	0.00	0.00	**4.63**	1.70
Austria	5.16	5.32	0.91	2.05	0.00	0.00	13.40	3.78	0.00	0.00	**30.63**	5.88
Bosnia-Herzegovina	1.10	1.73	0.00	0.67	0.00	0.00	3.13	0.00	0.00	0.00	**6.63**	2.33
Belgium	5.93	3.54	0.00	1.30	0.00	0.00	0.12	7.62	0.84	0.00	**19.35**	14.90
Bulgaria	2.59	6.50	0.18	0.49	0.00	0.00	2.84	0.92	0.80	1.58	**15.90**	7.88
Switzerland	0.60	8.00	0.00	1.00	0.00	0.00	13.22	1.32	0.00	0.00	**24.13**	9.45
Czech Republic	1.80	4.13	0.00	1.41	0.00	0.00	2.48	2.86	1.06	1.41	**15.17**	12.49
Germany	67.23	29.53	6.80	12.29	0.00	0.97	7.25	31.07	8.37	0.00	**163.51**	77.01
Denmark	8.75	2.73	0.00	1.22	0.00	0.24	0.01	3.41	0.43	0.00	**16.79**	7.11
Estonia	1.55	1.54	0.00	0.84	0.00	0.24	0.00	0.45	0.00	0.00	**4.62**	1.72
Spain	50.42	23.63	5.44	5.94	24.77	3.87	23.13	33.33	0.70	0.00	**171.21**	50.07
Finland	3.84	1.77	0.00	3.96	0.00	0.22	3.74	3.17	0.13	1.37	**18.19**	14.54
France	54.03	38.39	3.38	11.10	0.00	3.63	27.58	25.35	0.36	9.59	**173.39**	102.49
United Kingdom	58.52	18.00	0.06	5.20	0.00	5.32	4.61	32.78	0.20	0.98	**125.67**	65.33
Greece	6.76	11.81	1.42	1.28	3.37	0.73	5.29	5.64	0.00	0.00	**36.29**	12.37
Croatia	2.00	2.39	0.10	0.72	0.00	0.10	2.42	0.20	0.33	0.00	**8.26**	3.43
Hungary	1.08	5.91	4.24	1.28	0.00	0.00	0.52	4.53	0.49	0.00	**18.04**	7.45
Ireland	6.08	2.43	0.00	0.88	0.00	0.60	0.59	3.54	0.00	0.00	**14.12**	5.47
Italy	22.21	29.53	8.24	6.92	8.92	3.38	23.99	39.80	0.60	0.00	**143.60**	66.00
Lithuania	1.33	1.77	0.00	0.84	0.00	0.12	0.21	0.60	0.00	0.00	**4.88**	2.14
Luxembourg	0.22	1.18	0.00	0.08	0.00	0.00	1.26	0.25	0.00	0.00	**2.99**	1.06
Latvia	0.90	1.77	0.00	0.84	0.00	0.24	1.77	0.92	0.00	0.00	**6.44**	1.52
Montenegro	0.10	0.30	0.00	0.30	0.00	0.20	0.90	0.30	0.00	0.00	**2.10**	0.78
Macedonia	0.05	1.73	0.00	0.25	0.00	0.00	0.80	0.75	0.00	0.00	**3.59**	1.99
Netherlands	8.46	5.91	0.30	2.24	0.00	0.19	0.04	9.50	0.84	0.00	**27.47**	15.47
Norway	6.00	4.93	0.00	1.11	0.00	0.20	30.34	5.66	0.00	0.00	**48.23**	24.82
Poland	41.42	17.72	0.39	4.97	0.00	0.11	2.88	8.10	1.43	0.00	**77.01**	27.34
Portugal	10.81	11.81	1.35	2.02	5.94	0.76	5.94	4.77	0.35	0.00	**43.74**	8.96
Romania	3.96	6.50	0.15	2.51	0.00	0.00	6.33	2.99	0.32	1.08	**23.84**	10.11
Serbia	0.10	2.40	0.40	0.80	0.00	0.00	3.40	3.00	0.00	0.00	**10.10**	7.55
Slovakia	0.36	3.46	0.77	0.70	0.00	0.00	2.95	1.18	0.06	0.99	**10.46**	5.72
Slovenia	0.65	1.98	0.09	0.46	0.00	0.00	1.37	0.90	0.00	0.00	**5.45**	2.34
Sweden	12.01	4.13	0.30	6.21	0.00	0.36	18.71	0.53	0.00	0.00	**42.25**	28.24

Appendix A: Installed capacity and maximum demand (both in GW) based on E[R] advanced scenario for 2030.

Source: energy**nautics**

COUNTRY	WIND	PHOTO-VOLTAICS	GEO-THERMAL	BIOMASS	CSP PLANTS	WAVE/ TIDAL	HYDRO-POWER	GAS	COAL	NUCLEAR	TOTAL	MAX DEMAND
Europe	510.51	544.04	97.11	106.80	99.11	67.50	220.67	43.93	0.00	0.00	1 689.66	746.79
Albania	0.26	2.06	0.00	0.65	0.00	0.00	1.56	0.17	0.00	0.00	4.71	2.26
Austria	6.83	10.98	2.57	2.66	0.00	0.00	13.90	0.45	0.00	0.00	37.39	7.93
Bosnia-Herzegovina	1.07	3.58	0.00	0.86	0.00	0.00	3.25	0.00	0.00	0.00	8.77	2.93
Belgium	7.84	7.32	0.00	1.68	0.00	0.00	0.13	2.92	0.00	0.00	19.88	18.43
Bulgaria	3.43	13.41	0.51	0.63	0.00	0.00	2.95	0.11	0.00	0.00	21.05	9.89
Switzerland	0.79	16.52	0.00	1.31	0.00	0.00	13.72	0.16	0.00	0.00	32.50	11.26
Czech Republic	2.38	8.54	0.00	1.83	0.00	0.00	2.58	1.34	0.00	0.00	16.67	14.82
Germany	88.89	60.98	19.13	15.94	0.00	3.04	7.52	3.74	0.00	0.00	199.24	98.67
Denmark	11.57	5.63	0.00	1.58	0.00	0.75	0.01	0.41	0.00	0.00	19.96	8.60
Estonia	2.05	3.17	0.00	1.09	0.00	0.76	0.00	0.05	0.00	0.00	7.12	2.10
Spain	66.67	48.78	15.30	7.70	57.09	12.15	24.00	4.01	0.00	0.00	235.69	62.03
Finland	5.08	3.66	0.00	5.13	0.00	0.68	3.88	0.38	0.00	0.00	18.81	18.07
France	71.43	79.27	9.50	14.39	5.00	11.39	28.62	5.05	0.00	0.00	224.65	117.56
United Kingdom	77.37	37.17	0.17	6.75	0.00	16.71	4.78	7.94	0.00	0.00	150.89	77.97
Greece	8.94	24.39	3.98	1.65	7.76	2.28	5.49	0.68	0.00	0.00	55.18	14.85
Croatia	2.97	4.94	0.31	0.93	0.00	0.31	2.51	0.02	0.00	0.00	11.99	4.32
Hungary	1.43	12.20	11.92	1.65	0.00	0.00	0.53	0.54	0.00	0.00	28.28	9.99
Ireland	7.94	5.02	0.00	1.14	0.00	1.90	0.61	0.43	0.00	0.00	17.03	6.71
Italy	29.37	60.98	23.20	8.97	15.55	10.63	24.90	4.78	0.00	0.00	178.38	87.72
Lithuania	1.76	3.66	0.00	1.09	0.00	0.38	0.22	0.07	0.00	0.00	7.18	2.64
Luxembourg	0.29	2.44	0.00	0.10	0.00	0.00	1.31	0.03	0.00	0.00	4.17	1.35
Latvia	1.19	3.66	0.00	1.09	0.00	0.76	1.84	0.11	0.00	0.00	8.65	1.82
Montenegro	0.13	0.62	0.00	0.39	0.00	0.63	0.93	0.04	0.00	0.00	2.74	0.98
Macedonia	0.07	3.58	0.00	0.33	0.00	0.00	0.83	0.09	0.00	0.00	4.90	2.53
Netherlands	11.19	12.20	0.84	2.90	0.00	0.61	0.04	4.14	0.00	0.00	31.92	20.30
Norway	7.93	10.18	0.00	1.44	0.00	0.63	31.48	3.68	0.00	0.00	55.34	29.75
Poland	54.77	36.59	1.10	6.44	0.00	0.34	2.99	0.97	0.00	0.00	103.20	35.10
Portugal	14.29	24.39	3.79	2.62	13.70	2.39	6.11	0.57	0.00	0.00	67.86	9.91
Romania	5.24	13.41	0.43	3.25	0.00	0.00	6.56	0.36	0.00	0.00	29.25	12.70
Serbia	0.13	4.96	1.13	1.04	0.00	0.00	3.53	0.36	0.00	0.00	11.14	9.48
Slovakia	0.48	7.15	2.16	0.90	0.00	0.00	3.06	0.14	0.00	0.00	13.88	7.13
Slovenia	0.86	4.09	0.25	0.60	0.00	0.00	1.42	0.11	0.00	0.00	7.33	3.09
Sweden	15.87	8.54	0.84	8.05	0.00	1.14	19.42	0.06	0.00	0.00	53.92	33.87

Appendix B: Installed capacity and maximum demand (both in GW) based on E[R] advanced scenario for 2050.
Source: energy**nautics**

COUNTRY	WIND	PHOTO-VOLTAICS	GEO-THERMAL	BIOMASS	CSP PLANTS	WAVE/ TIDAL	HYDRO-POWER	GAS	COAL	NUCLEAR	TOTAL	MAX DEMAND
Europe	510.51	805.86	97.13	226.41	99.1	67.48	220.68	28.93	0.00	0.00	2056.10	931.36
Albania	0.26	2.06	0.00	1.43	0.00	0.00	1.56	0.17	0.00	0.00	5.48	3.07
Austria	6.83	10.98	2.57	4.72	0.00	0.00	13.90	0.45	0.00	0.00	39.45	10.43
Bosnia-Herzegovina	1.07	3.58	0.00	0.86	0.00	0.00	3.25	0.00	0.00	0.00	8.76	3.89
Belgium	7.84	7.32	0.00	5.83	0.00	0.00	0.13	0.92	0.00	0.00	22.03	22.04
Bulgaria	3.43	10.73	0.51	1.13	0.00	0.00	2.95	0.11	0.00	0.00	18.87	12.91
Switzerland	0.79	16.52	0.00	2.03	0.00	0.00	13.72	0.16	0.00	0.00	33.22	15.03
Czech Republic	2.38	8.54	0.00	3.39	0.00	0.00	2.58	0.34	0.00	0.00	17.24	17.52
Germany	88.89	60.98	19.13	32.87	0.00	3.04	7.52	3.74	0.00	0.00	216.16	120.10
Denmark	11.57	5.63	0.00	3.44	0.00	0.75	0.01	0.41	0.00	0.00	21.81	11.08
Estonia	2.05	3.17	0.00	1.32	0.00	0.76	0.00	0.05	0.00	0.00	7.36	2.65
Spain	66.67	149.30	15.30	20.65	57.09	12.15	24.00	4.01	0.00	0.00	349.17	85.87
Finland	5.08	3.66	0.00	6.86	0.00	0.68	3.88	0.38	0.00	0.00	20.54	19.31
France	71.43	76.80	9.50	27.41	5.00	11.39	28.62	3.05	0.00	0.00	233.19	137.56
United Kingdom	77.37	37.17	0.17	24.60	0.00	16.71	4.78	3.94	0.00	0.00	164.74	89.42
Greece	8.94	58.96	3.98	3.78	7.76	2.28	5.49	0.68	0.00	0.00	91.87	20.57
Croatia	2.97	4.94	0.31	1.04	0.00	0.31	2.51	0.02	0.00	0.00	12.11	5.68
Hungary	1.43	11.79	11.92	4.12	0.00	0.00	0.53	0.54	0.00	0.00	30.33	13.53
Ireland	7.94	5.02	0.00	3.06	0.00	1.90	0.61	0.43	0.00	0.00	18.96	8.21
Italy	29.37	161.15	23.20	27.19	15.55	10.63	24.90	4.78	0.00	0.00	296.77	120.64
Lithuania	1.76	3.66	0.00	1.42	0.00	0.38	0.22	0.07	0.00	0.00	7.51	3.36
Luxembourg	0.29	2.44	0.00	0.24	0.00	0.00	1.31	0.03	0.00	0.00	4.31	1.86
Latvia	1.19	3.66	0.00	1.59	0.00	0.76	1.84	0.11	0.00	0.00	9.15	2.31
Montenegro	0.13	0.62	0.00	0.55	0.00	0.63	0.93	0.04	0.00	0.00	2.90	1.24
Macedonia	0.07	3.10	0.00	0.74	0.00	0.00	0.83	0.09	0.00	0.00	4.83	3.19
Netherlands	11.19	12.20	0.84	8.07	0.00	0.61	0.04	1.14	0.00	0.00	34.09	24.60
Norway	7.93	10.18	0.00	4.52	0.00	0.63	31.48	0.68	0.00	0.00	55.42	36.70
Poland	54.77	36.59	1.10	10.85	0.00	0.34	2.99	0.97	0.00	0.00	107.61	45.16
Portugal	14.29	56.99	3.79	4.17	13.70	2.39	6.11	0.57	0.00	0.00	102.01	13.43
Romania	5.24	13.41	0.43	4.88	0.00	0.00	6.56	0.36	0.00	0.00	30.88	16.55
Serbia	0.13	4.96	1.13	2.67	0.00	0.00	3.53	0.36	0.00	0.00	12.78	11.70
Slovakia	0.48	7.15	2.16	1.54	0.00	0.00	3.06	0.14	0.00	0.00	14.53	9.23
Slovenia	0.86	3.09	0.25	1.09	0.00	0.00	1.42	0.11	0.00	0.00	7.81	4.28
Sweden	15.87	8.54	0.84	8.34	0.00	1.14	19.42	0.06	0.00	0.00	54.21	38.24

Appendix C: Installed capacity and maximum demand (both in GW) for the import scenario for 2050.
Source: energy**nautics**

COUNTRY	WIND	PHOTO-VOLTAICS	GEO-THERMAL	BIOMASS	CSP PLANTS	WAVE/ TIDAL	HYDRO-POWER	GAS	COAL	NUCLEAR	TOTAL	MAX DEMAND
Europe	689.24	1 089.25	97.13	360.50	99.1	67.48	220.68	28.93	0.00	0.00	2 652.31	885.03
Albania	0.30	2.62	0.00	0.94	0.00	0.00	1.56	0.17	0.00	0.00	5.60	2.77
Austria	6.83	8.78	2.57	4.51	0.00	0.00	13.90	0.45	0.00	0.00	37.04	9.49
Bosnia-Herzegovina	1.18	5.07	0.00	1.38	0.00	0.00	3.25	0.00	0.00	0.00	10.87	3.49
Belgium	24.00	33.36	0.00	13.44	0.00	0.00	0.13	0.92	0.00	0.00	71.84	22.58
Bulgaria	5.81	25.55	0.51	4.41	0.00	0.00	2.95	0.11	0.00	0.00	39.34	11.83
Switzerland	1.38	37.19	0.00	5.89	0.00	0.00	13.72	0.16	0.00	0.00	58.34	13.74
Czech Republic	8.82	42.21	0.00	10.15	0.00	0.00	2.58	0.34	0.00	0.00	64.11	17.87
Germany	115.76	146.51	19.13	62.26	0.00	3.04	7.52	3.74	0.00	0.00	357.96	119.67
Denmark	13.76	8.47	0.00	3.62	0.00	0.75	0.01	0.41	0.00	0.00	27.03	10.32
Estonia	2.17	3.51	0.00	1.58	0.00	0.76	0.00	0.05	0.00	0.00	8.08	2.42
Spain	66.67	48.78	15.30	7.70	57.09	12.15	24.00	4.01	0.00	0.00	235.70	73.82
Finland	10.31	12.93	0.00	7.51	0.00	0.68	3.88	0.38	0.00	0.00	35.69	20.29
France	100.36	184.52	9.50	65.28	5.00	11.39	28.62	3.05	0.00	0.00	407.72	136.71
United Kingdom	114.98	114.55	0.17	45.43	0.00	16.71	4.78	3.94	0.00	0.00	300.56	90.88
Greece	8.94	19.51	3.98	1.77	7.76	2.28	5.49	0.68	0.00	0.00	50.41	18.11
Croatia	3.71	8.80	0.31	1.87	0.00	0.31	2.51	0.02	0.00	0.00	17.54	5.16
Hungary	1.47	13.46	11.92	2.62	0.00	0.00	0.53	0.54	0.00	0.00	30.55	12.14
Ireland	10.72	7.97	0.00	3.95	0.00	1.90	0.61	0.43	0.00	0.00	25.57	7.77
Italy	36.26	114.42	23.20	32.25	15.55	10.63	24.90	4.78	0.00	0.00	262.00	107.01
Lithuania	2.14	5.09	0.00	1.91	0.00	0.38	0.22	0.07	0.00	0.00	9.81	3.02
Luxembourg	0.41	3.42	0.00	0.78	0.00	0.00	1.31	0.03	0.00	0.00	5.94	1.64
Latvia	1.19	2.93	0.00	1.17	0.00	0.76	1.84	0.11	0.00	0.00	7.99	2.06
Montenegro	0.13	0.62	0.00	0.39	0.00	0.63	0.93	0.04	0.00	0.00	2.74	1.15
Macedonia	0.09	5.29	0.00	1.23	0.00	0.00	0.83	0.09	0.00	0.00	7.54	2.94
Netherlands	20.84	29.14	0.84	14.18	0.00	0.61	0.04	1.14	0.00	0.00	66.79	24.69
Norway	14.94	34.12	0.00	8.53	0.00	0.63	31.48	0.68	0.00	0.00	90.38	34.53
Poland	64.73	60.15	1.10	23.70	0.00	0.34	2.99	0.97	0.00	0.00	153.98	40.43
Portugal	14.29	19.51	3.79	2.62	13.70	2.39	6.11	0.57	0.00	0.00	62.98	11.88
Romania	8.82	21.58	0.43	6.55	0.00	0.00	6.56	0.36	0.00	0.00	44.31	15.14
Serbia	0.45	21.25	1.13	4.18	0.00	0.00	3.53	0.36	0.00	0.00	30.90	11.34
Slovakia	0.76	16.53	2.16	3.85	0.00	0.00	3.06	0.14	0.00	0.00	26.50	8.54
Slovenia	1.07	6.56	0.25	1.34	0.00	0.00	1.42	0.11	0.00	0.00	10.75	3.79
Sweden	25.95	24.85	0.84	13.51	0.00	1.14	19.42	0.06	0.00	0.00	85.77	38.78

Appendix D: Installed capacity and maximum demand (both in GW) for the regional scenario for 2050.
Source: energy**nautics**