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Data Article

Data for the modelling of the future power system with a high share of variable renewable energy

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ABSTRACT

Energy and power system models have become necessary tools that provide challenges and technical and economic solutions for integrating high shares of Variable Renewable Energy. Models are focused on analysing strategies of power systems to achieve their decarbonisation targets. The data presented in this paper includes the model algorithm, inputs, equations, modelling assumptions, supplementary materials, and results of the simulations supporting the research article titled “Facing the high share of variable renewable energy in the power system: flexibility and stability requirements”. The analysis is based on data from the system operator of one of the European Union member states (Spain). The developed

Abbreviations: CC, Combined-cycle power plants; CIL, Critical Inertia Level; CR, Cogeneration and non-renewable waste; DG, Distributed Generation; ENTSO-E, European Network of Transmission System Operators for Electricity; ENTSO-G, European Network of Transmission System Operators for Gas; ERCOT, Electric Reliability Council of Texas; EU, European Union; GCA, Global Climate Action; LCOE, Levelized Cost of Electricity; LIR, Rotational Inertia Lost in a Contingency; PHS, Pumped Hydro Storage; PV, Photovoltaic; REE, Spanish Electricity System Operator (Red eléctrica de España); ROCOF, Rate of Change of Frequency; ST, Sustainable Transition; TR, Renewable thermal and other renewables; TS, Solar thermal; TSI, Total System Inertia; TYNDP, Ten Year Network Development Plan; VBA, Visual Basic for Applications; VRE, Variable Renewable Energy.

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model allows making projections and calculations to obtain the power generation of each technology, the international interconnections, inertia, emissions, system costs and flexibility requirements of new technologies. These data can be used for energy policy development or decision making on power capacity and the balancing needs of the future power system.

Specifications Table

Subject	Renewable Energy, Sustainability, and the Environment
Specific subject area	Power system modelling
Type of data	Table Raw data Equation Figure Chart
How the data were acquired	Historical and literature data were used for model parameters, and equations were developed from the latter and modelling rules. Modelled data were obtained by applying model parameter values, installed capacities of power system technologies and interconnections to the equations
Data format	Raw Analysed Filtered
Description of data collection	Data collection was based on the input data and parameters needed to design a power system model that allows obtain power generation based on flexibility and stability restrictions to make future scenarios. (1) Historical data were obtained from the transmission system operator (TSO) of the Spanish Power System "Red Eléctrica de España" (REE). (2) For the modelling, literature data were used as well as installed capacities provided by the Ten-Year Network Development Plan (TYNDP) of the European Network of Transmission System Operators for Electricity (ENTSO-E) (3) Visual Basic for Applications (VBA) was used for the development of the rule-based power system model. The data obtained are for different scenarios: 2017, Sustainable Transition (ST)-2030, ST-2040, Distributed Generation (DG)-2030, DG-2040, and Global Climate Action (GCA-2040).
Data source location	Country: Spain Primary dataset: “Red Eléctrica de España”, table “Generation mix (MW)” from 01 January 2017 to 31 December 2017. Link: https://demanda.ree.es/visiona/peninsula/demanda/tablas/2017-01-01/2
Data accessibility	Repository name: HARVARD Dataverse Data identification number: 10.7910/DVN/R2IVYN Direct link to the dataset: https://doi.org/10.7910/DVN/R2IVYN [A1]
Related research article	K. Guerra, P. Haro, R. E. Gutiérrez, A. Gómez-Barea, Facing the high share of variable renewable energy in the power system: flexibility and stability requirements, Appl. Energy. 310 (2022) 118561 https://doi.org/10.1016/j.apenergy.2022.118561

Value of the Data

- These data are useful for the modelling of future power systems. These data include inputs, equations and parameters that can be used to design and represent the behaviour of the electricity system. The data also provide insights into the possibility of achieving the decarbonisation targets considered by national and international organisations.
- These data are useful for representing the challenges of integrating high shares of variable renewable energy (VRE; wind and solar) in the power system as they enrich and expand flexibility and stability parameters that have not been addressed in previous studies.
- These data include flexibility parameters of generation technologies and grid stability (inertia) that limit the generation of renewable energies. Therefore, the use and modelling from these parameters would allow obtaining the curtailment of VRE and the requirement of synchronous technologies (e.g., combined cycle).
- Researchers, stakeholders and policy-makers can use the model algorithm to explore future scenarios of other power systems with different VRE shares, interconnections, and power generation mix. Therefore, this manuscript provides the research community with modelling characteristics to obtain power generation, emissions, costs, inertia, curtailment, and synchronous generation requirements at an hourly resolution.
- The model reflects the need to ensure a stable and reliable supply rather than optimising power generation. Therefore, the results of the modelling could also be used by the research community to compare with other simulation and optimisation studies (Spain is used as a case study).
- Further studies could use these data to analyse power technologies that might support the increasing penetration of VRE, provide inertia to the grid to ensure stability and achieve the decarbonisation targets. For example, these data might be used to assess the role of energy storage systems that could help to reduce curtailment and increase flexibility in the power system.

1. Data Description

The research paper linked to this data models the integration of high shares VRE into the power system considering flexibility and stability constraints. The model is called Future Renewable Energy Performance into the Power System (FEPPS), and the parameters and variables used to analyse future scenarios are provided in Table 1. The extended flowchart of the model can be seen in Appendix 1, and the selected European Union (EU) member state to carry out the simulations was Spain.

Fig. 1. shows the flowchart of the model with its main characteristics.

1.1. Methodology data

1.1.1. Demand, VRE, solar thermal, and hydro

The historical demand function was calculated according to the hourly demand data and the minimum demand of the year. Later, it allows calculating the projected demand. The final demand is obtained by discounting the interconnections. For VRE, solar thermal, and hydro the historical function is obtained from the historical installed capacity and power output. From that function and a new installed capacity, the available power is calculated. The equations that allow obtaining the variables are shown in Table 2.

Table 1
Parameters and variables used in the model.

Symbol	Unit	Parameter
D	MW	Historical power demand
D_m	MW	Minimum historical demand
C_w	MW	Installed wind capacity (historical)
C_{pv}	MW	Installed photovoltaic capacity (historical)
C_{ts}	MW	Installed solar thermal capacity (historical)
P_{tst}	MW	Nominal power of a solar thermal power plant
C_{hy}	MW	Installed hydropower capacity (historical)
C_{phs}	MW	Installed PHS capacity (historical)
E_{phy}	%	Pumping efficiency
E_{ohy}	%	PHS discharge efficiency
P_{hyd}	MW	Nominal power of a hydropower plant
P_w	MW	Wind power output (historical)
P_{pv}	MW	Photovoltaic power output (historical)
P_{ts}	MW	Solar thermal power output (historical)
P_{hy}	MW	Hydropower output (historical)
IC_{fi}	MW	Historical import capacity of the interconnection with France
IC_{fe}	MW	Historical export capacity of the interconnection with France
IC_p	MW	Historical export and import capacities of the interconnection with Portugal
IC_{mi}	MW	Historical import capacity of the interconnection with Morocco
IC_{me}	MW	Historical export capacity of the interconnection with Morocco
IC_{bi}	MW	Historical interconnection capacity with the Balearic Islands (and between them)
PI_f	MW	Historical imported power - Interconnection with France
PI_p	MW	Historical imported power - Interconnection with Portugal
PI_a	MW	Historical imported power - Interconnection with Andorra
PI_m	MW	Historical imported power - Interconnection with Morocco
NI_f	MW	Historical exported power - interconnection with France
NI_p	MW	Historical exported power - interconnection with Portugal
NI_a	MW	Historical exported power - interconnection with Andorra
NI_m	MW	Historical exported power - interconnection with Morocco
EB	MW	Historical exported power - interconnection with the Balearic Islands
ib	%	Historical contribution of the Peninsula to the Balearic Islands in covering demand
IC_{pm}	MW	Limit of the Peninsula power output with Mallorca
C_{cr}	MW	Installed Cogeneration and non-renewable waste (CR) capacity (historical)
P_{cr}	MW	Nominal power of a CR power plant
PMh_{cr}	MW	Maximum CR power output (historical)
$Pmih_{cr}$	MW	Minimum CR power output (historical)
RD_{hcr}	$\%C_{cr}$ per hour	Maximum CR ramp-down rate (historical)
RU_{hcr}	$\%C_{cr}$ per hour	Maximum CR ramp-up rate (historical)
C_{tr}	MW	Installed renewable thermal and other renewables (TR) capacity (historical)
P_{tr}	MW	Nominal power of a TR power plant
PMh_{tr}	MW	Maximum TR power output (historical)
$Pmih_{tr}$	MW	Minimum TR power output (historical)
RD_{htr}	$\%C_{tr}$ per hour	Maximum TR ramp-down rate (historical)
RU_{htr}	$\%C_{tr}$ per hour	Maximum TR ramp-up rate (historical)
C_n	MW	Installed nuclear capacity (historical)
n_h	Integer	Historical number of nuclear power plants in a year
P_n	MW	Nominal power of a nuclear power plant
$Pmit_n$	$\%P_n$	Minimum theoretical load of a nuclear power plant
R_{tn}	$\%P_n$ per hour	Theoretical ramp rate of a nuclear power plant
PMh_n	MW	Maximum nuclear power output (historical)
$Pmih_n$	$\%C_n$ or MW	Minimum nuclear power output (historical)
RD_{hn}	$\%C_n$ or MW per hour	Maximum nuclear ramp-down rate (historical)
RU_{hn}	$\%C_n$ or MW per hour	Maximum nuclear ramp-up rate (historical)
C_c	MW	Installed coal capacity (historical)

(*continued on next page*)

Table 1 (*continued*)

c_h	Integer	Historical number of coal power plants in a year
P_c	MW	Nominal power of a coal power plant
$Pmit_c$	$\%P_c$	Minimum theoretical load of a coal power plant
R_{tc}	$\%P_C$ per hour	Theoretical ramp rate of a coal power plant
PMh_c	MW	Maximum coal power output (historical)
$Pmih_c$	$\%C_c$ or MW	Minimum coal power output (historical)
RD_{hc}	$\%C_c$ or MW per hour	Maximum coal ramp-down rate (historical)
RU_{hc}	$\%C_c$ or MW per hour	Maximum coal ramp-up rate (historical)
C_{cc}	MW	Installed combined-cycle (CC) capacity (historical flexible and inflexible)
cc_1	Integer	Historical number of CC power plants in a year
P_{cc}	MW	Nominal power of a CC power plant
$Pmit_{cc}$	$\%P_{cc}$	Theoretical minimum load of a CC power plant
R_{tcc}	$\%P_{cc}$ per hour	Theoretical ramp rate of a CC power plant
PMh_{cc}	MW	Maximum CC power output (historical)
$Pmih_{cc}$	$\%C_{cc}$ or MW	Minimum CC power output (historical)
RD_{hcc}	$\%C_{cc}$ or MW per hour	Maximum CC ramp-down rate (historical)
RU_{hcc}	$\%C_{cc}$ or MW per hour	Maximum CC ramp-up rate (historical)
n_{1w}	%	First level of wind curtailment
n_{2w}	%	Second level of wind curtailment
n_{3w}	%	Third level of wind curtailment
n_{1p}	%	First level of photovoltaic curtailment
n_{2p}	%	Second level of photovoltaic curtailment
n_{3p}	%	Third level of photovoltaic curtailment
n_{2h}	%	Hydropower reduction level
n_{2t}	%	Curtailment level of solar thermal
n_i	s	Average rotational inertia constant for nuclear
c_i	s	Average rotational inertia constant for coal
cc_i	s	Average rotational inertia constant for combined-cycle
hy_i	s	Average rotational inertia constant for hydropower and PHS
cr_i	s	Average rotational inertia constant for CR
tr_i	s	Average rotational inertia constant for TR
tso_i	s	Average rotational inertia constant for solar thermal
if_i	s	Average rotational inertia constant for NPI_f
ip_i	s	Average rotational inertia constant for NPI_p
im_i	s	Average rotational inertia constant for NPI_m
feh	-	Emission factor for hot-start of flexible *CC*
fet	-	Emission factor for constant-operation of flexible *CC*
tss	min	Fraction of start-up time where power is not yet fed into the grid ($t_0 \rightarrow t_1$)
ttm	min	Minutes in an hour (60)
Symbol	Unit	Variable
ND_m	MW	New minimum demand
PD	MW	Projected initial demand
f_h	-	Historical demand function
PD_1	MW	Projected final demand
D_n	MW	Initial net load
$Comp$	MW	Load to adjust to match demand
f_w	-	Wind projection function
f_{pv}	-	Photovoltaic projection function
f_{ts}	-	Solar thermal projection function
f_{hy}	-	Hydropower projection function
NC_w	MW	New installed wind capacity
NC_{pv}	MW	New installed photovoltaic capacity
NC_{ts}	MW	New installed solar thermal capacity
NC_{hy}	MW	New installed hydropower capacity
NP_w	MW	Wind power available
NP_{pv}	MW	Photovoltaic power available
NP_{ts}	MW	Solar thermal power available
NP_{hy}	MW	Hydropower available
$\overline{NP_{hy}}$	MW	Annual average of NP_{hy}

(*continued on next page*)

Table 1 (*continued*)

NP_{w1}	MW	Wind power output (final)
NP_{pv1}	MW	Photovoltaic power output (final)
NP_{ts1}	MW	Solar thermal power output (final)
NP_{hy1}	MW	Hydropower output (final)
ts_2	Integer	Number of solar thermal power plants for each hour
NIC_{fi}	MW	New import interconnection capacity with France
NIC_{fe}	MW	New export interconnection capacity with France
NIC_{pi}	MW	New import interconnection capacity with Portugal
NIC_{pe}	MW	New export interconnection capacity with Portugal
NIC_{mi}	MW	New import interconnection capacity with Morocco
NIC_{me}	MW	New export interconnection capacity with Morocco
NIC_{bi}	MW	New interconnection capacity with the Balearic Islands (and between them)
$Nibl$	%	New contribution of the Peninsula to the Balearic Islands in covering demand
NPI_f	MW	New import power - interconnection with France
NNI_f	MW	New export power - interconnection with France
NPI_p	MW	New import power - interconnection with Portugal
NNI_p	MW	New export power - interconnection with Portugal
NPI_m	MW	New import power - interconnection with Morocco
NNI_m	MW	New export power - interconnection with Morocco
NEB	MW	New export power - interconnection with the Balearic Islands
PIB	MW	Import balance of international interconnections
NIB	MW	Export balance of international interconnections
NC_{cr}	MW	New installed CR capacity
Pmi_{cr}	MW	Minimum CR power output
RD_{cr}	MW per hour	CR ramp-down rate limit
RU_{cr}	MW per hour	CR ramp-up rate limit
NP_{cr}	MW	CR power output (final)
cr_2	Integer	Number of CR power plants for each hour
PM_{cr}	MW	Maximum CR power output
NC_{tr}	MW	New installed TR capacity
Pmi_{tr}	MW	Minimum TR power output
RD_{tr}	MW per hour	TR ramp-down rate limit
RU_{tr}	MW per hour	TR ramp-up rate limit
NP_{tr}	MW	TR power output (final)
tr_2	Integer	Number of TR power plants for each hour
PM_{tr}	MW	Maximum TR power output
n	Integer	Number of nuclear power plants assumed for a future year
NC_n	MW	New installed nuclear capacity
PM_n	MW	Maximum nuclear load
RD_n	%NC_n or MW per hour	Nuclear ramp-down rate limit
RU_n	%NC_n or MW per hour	Nuclear ramp-up rate limit
Pmi_n	%NC_n or MW	Minimum nuclear load
$nu2$	Integer	Final number of nuclear power plants for each hour
NP_n	MW	Nuclear power output (final)
nu	Integer	Initial number of nuclear power plants for each hour
$nu0$ $nu1$ $maxNu$	Integer	Code variables that allow obtaining nu2
c	Integer	Number of coal power plants assumed for a future year
NC_c	MW	New installed coal capacity
PM_c	MW	Maximum coal load
RD_c	%NC_c or MW per hour	Coal ramp-down rate limit
RU_c	%NC_c or MW per hour	Coal ramp-up rate limit
Pmi_c	%NC_C or MW	Minimum coal load
$co2$	Integer	Final number of coal power plants for each hour
NP_c	MW	Coal power output (final)
co	Integer	Initial number of coal power plants for each hour
$co0$ $co1$ $maxCo$	Integer	Code variables that allow obtaining co2

(*continued on next page*)

Table 1 (*continued*)

NC_{phs}	MW	New installed PHS capacity
L_{phs}	MW	PHS installed capacity limit
L_{hy}	MWh/day	PHS availability limit
$Compst$	MW	Load available for storage
F_{ph}	%	Pumping factor
$Comp_{1n}$	MW	Excess load pending of reduction (does not meet the condition L_{hy})
$Comp_{2p}$	MW	Unsupplied power demand (before PHS)
St_y	MW	Cumulative storage load (unlimited)
St_{y1}	MW	Storage load up to its limit
St_2, St_{22} St_{23}, St_{24}, St_{25}	MW	Code variables that allow obtaining St_{y2}
St_{y2}	MW	Load that remains in storage after charges and discharges
$Comp_{1r}$	MW	Unsupplied power demand (after PHS)
$Comp_{2r}$	MW	Excess load pending reduction (could not be stored)
F_{sty}	MW	Final load in storage
P_{sty}	MW	Variable that allows obtaining the PHS power output
P_{phs}	MW	PHS power output (final)
$Comp_{pb}$	MW	Total load to adjust after PHS
hy_2	Integer	Final number of PHS power plants for each hour
NC_{cc0}	MW	New installed inflexible CC capacity
RD_{cc0}	% NC_{cc0} or MW/ per hour	Inflexible CC ramp-down rate limit
RU_{cc0}	% NC_{cc0} or MW per hour	Inflexible CC ramp-up rate limit
Pmi_{cco}	%C_{cc} or MW	Minimum inflexible CC power output
NC_{cc1}	MW	New installed flexible CC capacity
NP_{cc0}	MW	Inflexible CC power output
NP_{cc}	MW	Variable that allows obtaining NP_{cc1}
NP_{cc1}	MW	Flexible CC power output
NP_{fcc}	MW	Flexible CC power output (after inertia constraints)
cc_2	Integer	Final number of CC (flexible + inflexible) power plants for each hour
NP_{cc2}	MW	CC power output (flexible + inflexible)
NC_{cc}	MW	New installed CC capacity (flexible + inflexible)
ci_n	MJ	Average rotational inertia contribution for nuclear
ci_c	MJ	Average rotational inertia contribution for coal
ci_{cc}	MJ	Average rotational inertia contribution for combined-cycle
ci_{hy}	MJ	Average rotational inertia contribution for hydropower and PHS
ci_{cr}	MJ	Average rotational inertia contribution for CR
ci_{tr}	MJ	Average rotational inertia contribution for TR
ci_{ts}	MJ	Average rotational inertia contribution for TS
ci_{if}	MJ	Average rotational inertia contribution *for* NPI_f
ci_{ip}	MJ	Average rotational inertia contribution for NPI_p
ci_{im}	MJ	Average rotational inertia contribution for NPI_m
TSI	MJ	Total system inertia
ΔP	MW	Power lost in the largest system contingency
NF	Hz	Nominal system frequency
$ROCOF$	Hz/s	Rate of change of frequency
LIR	MVA•s	Rotational inertia lost in ΔP contingency
CIL	MJ	Critical inertia level
V_i	MJ	Inertia variation
Eo	(tCO_2 eq/h)	Start emissions (flexible CC)
So	(tCO_2 eq/h)	Emissions of the fraction of start-up time where power is not yet fed into the grid ($t_0 \rightarrow t_1$)
Sto	(tCO_2 eq/h)	Stop emissions of (flexible CC)
1*st Criteria*	(tCO_2 eq/h)	Start and stop emissions
Pi	MW	Production of each power plant when the power output increases
Et	(tCO_2 eq/h)	Emission in constant operation (flexible CC)
Eh	(tCO_2 eq/h)	Emission when the power output increases
Es	(tCO_2 eq/h)	Emissions of the fraction of start-up time where power is not yet fed into the grid ($t_0 \rightarrow t_1$) for the 2nd criteria

(*continued on next page*)

Table 1 (*continued*)

2nd Criteria	(tCO_2 eq/h)	Increase in power output, constant operation and start emissions
Pd	MW	Production of each power plant when the power output decreases or when the number of plants is constant in the previous or next hour.
Ec	(tCO_2 eq/h)	Emissions in constant operation for the 3rd criteria
Ep	(tCO_2 eq/h)	Stop emissions for values that increased previously for the 3rd criteria
El	(tCO_2 eq/h)	Stop emissions for values that decreased previously for the 3rd criteria
3*rd Criteria*	(tCO_2 eq/h)	Decrease in power output, constant operation and stop emissions
4*th Criteria*	(tCO_2 eq/h)	Constant operation emissions not previously contemplated
Ei	(tCO_2 eq/h)	Emissions for values that have decreased and increase in the next hour
Eg	(tCO_2 eq/h)	Stop emissions for values that increased previously for the 5th criteria
Ef	(tCO_2 eq/h)	Stop emissions for values that decreased previously for the 5th criteria
Ep	(tCO_2 eq/h)	Emissions from each plant to calculate Ev
Ev	(tCO_2 eq/h)	Stop emissions for values that have previously started
5*th Criteria*	(tCO_2 eq/h)	Decrease in power output and stop emissions not previously contemplated
6*th Criteria*	(tCO_2 eq/h)	Constant operation emissions when the next value increases
Code counters		
j, l, b, k, a	-	Hour counter (j). Counters every 24 hours (l, b). Day counters in the year (k, a)
Hours	h	Number of hours in the year minus one
Hoursc	h	Number of hours in the year

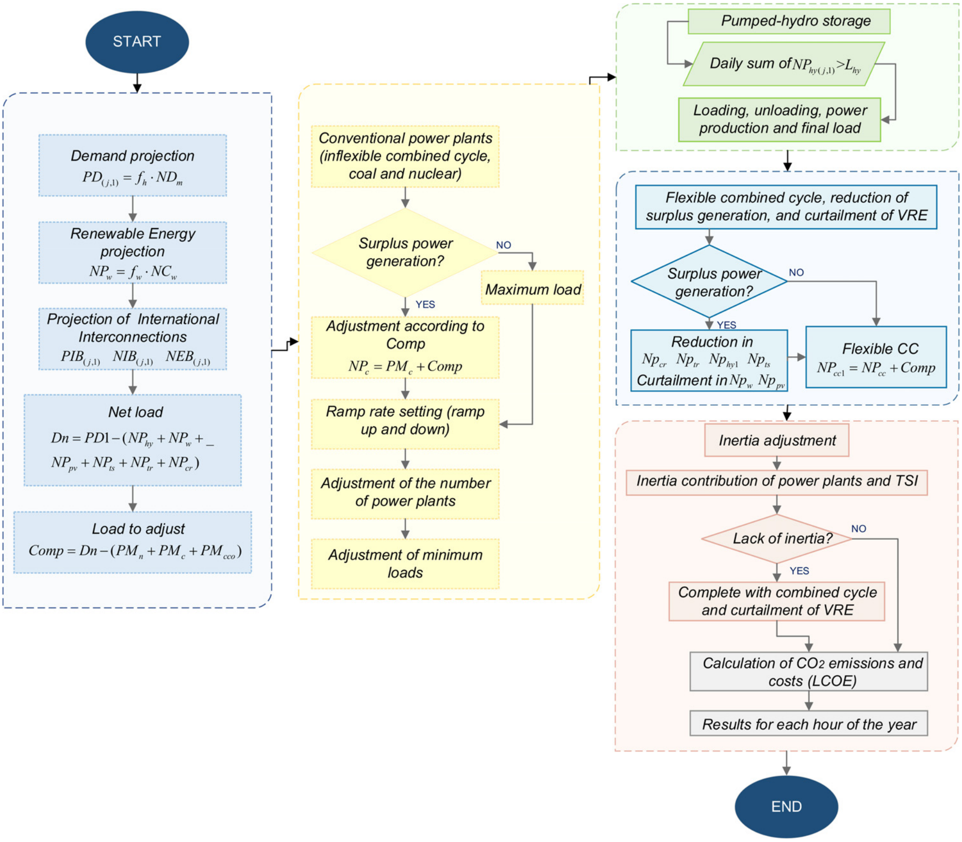

Fig. 1. Flowchart of the model. The extended flowchart of the model can be seen in Appendix 1. Modified from [1]

Table 2
Demand, VRE, solar thermal and hydro variables.

Variables	Eq.	No
Historical demand function	$f_h = \frac{D}{D_m}$	(1)
Projected initial demand (MW)	$PD = f_h \cdot ND_m$	(2)
Projected final demand (MW)	$PD1 = PD - PIB - NIB - NEB$	(3)
Initial net load (MW)	$D_n = PD1 - (NP_{hy} + NP_w + NP_{pv} + NP_{ts} + NP_{tr} + NP_{cr})$	(4)
Wind projection function	$f_w = \frac{P_w}{C_w}$	(5)
Solar PV projection function	$f_{pv} = \frac{P_{pv}}{C_{pv}}$	(6)
Solar thermal projection function	$f_{ts} = \frac{P_{ts}}{C_{ts}}$	(7)
Wind power available (MW)	$NP_w = f_w \cdot NC_w$	(8)
Solar PV power available (MW)	$NP_{PV} = f_{pv} \cdot NC_{pv}$	(9)
Solar thermal power available (MW)	$NP_{ts} = f_{ts} \cdot NC_{ts}$	(10)
Number of TS power plants for each hour	$ts_2 = \frac{NP_{ts1}}{P_{tst}}$	(11)
Hydropower available (MW)[a]	$NP_{hy} = P_{hy} \cdot (1 - F_{ph})$	(12)
Pumping factor[a]	$F_{ph} = \frac{0.047 \cdot NC_{phs}}{C_{phs}}$	
Hydropower projection function	$f_{hy} = \frac{NP_{hy}}{C_{hy}}$	(13)
Hydropower available (MW)[b]	$NP_{hy} = f_{hy} \cdot NC_{hy}$	(14)

[a] Consumption by pumping represented 4.7% of the total annual hydropower generation in 2017. This percentage is assumed as the share of the PHS, which is modelled separately. Therefore, to obtain the available hydro (before making any projection), the new pumping factor (which depends on the installed capacity) is discounted from the historical power output.
[b] The same variable is used as it is recalculated according to the projection function.

Table 3
Balance of historical international interconnection exchanges in Spain (2017) [2].

Interconnection	Import (GWh)	%	Export (GWh)	%
France	15561	65.6	3094	21.2
Portugal	8190	34.5	5505	37.7
Andorra	0	0	233	1.6
Morocco	8	0.03	5756	39.5

Table 4
Import and export power of International Interconnections.

Variable	Eq.	No
New import power with France (MW)	$NPI_f = \frac{PI_f}{IC_{fi}} \cdot NIC_{fi}$	(15)
New export power with France (MW)	$NNI_f = \frac{NI_f}{IC_{fe}} \cdot NIC_{fe}$	(16)
New import power with Portugal (MW)	$NPI_p = \frac{PI_p}{IC_p} \cdot NIC_{pi}$	(17)
New export power with Portugal (MW)	$NNI_p = \frac{NI_p}{IC_p} \cdot NIC_{pe}$	(18)
New import power with Morocco (MW)	$NPI_m = \frac{PI_m}{IC_{mi}} \cdot NIC_{mi}$	(19)
New export power with Morocco (MW)	$NNI_m = \frac{NI_m}{IC_{me}} \cdot NIC_{me}$	(20)
Import balance (MW)	$PIB = NPI_f + NPI_p + PI_a + NPI_m$	(21)
Export balance (MW)	$NIB = NNI_f + NNI_p + NI_a + NNI_m$	(22)
New export with the Balearic Islands (MW)	$NEB = \frac{EB \cdot Nibl}{ib}$	(23)

1.1.2. International interconnections

REE provides the total annual energy (GWh) for each interconnection, i.e., the historical import balance (positive values) and export balance (negative values). Therefore, a participation percentage for 2017 was obtained for each interconnection [2]). With these percentages, the power of the time series was decoupled. Table 3 shows the participation percentage of each international interconnection by 2017.

The equations to calculate the new power of imports and exports of each international interconnection and the balances are shown in Table 4.

1.1.3. Conventional power generation

Table 5 provides the equations to calculate the limits of minimum and maximum power output, ramp rates and the number of power plants of each hour of renewable thermal and other renewables (TR), cogeneration and non-renewable waste (CR). It also shows the equations to calculate the nominal power of a typical plant and the new installed capacities for coal and nuclear. With the historical installed capacity, the nominal power of a typical plant, the historical minimum power output (%) and the minimum theoretical load (%), through linear regression, we obtain the equation to find the minimum load percentage and its value in MW to apply in the model. The equation to find the maximum ramp rates for each technology (in share) is obtained through linear regressions. In this way, with the new installed capacity, the maximum ramp up and down rates in MW can be found.

For 2017, the model identifies the maximum number of power plants each day to limit the minimum coal and nuclear loads. The model establishes one limit for nuclear and three limits for coal. Therefore, the maximum number of coal power plants participating in the day is divided by three. The result and its multiples are defined as the final number of power plants, limiting the minimum loads for that day. For example, if the maximum number is 12 (initial number), dividing by three, the result is 4 and the multiples 8 and 12. Therefore, 4, 8, and 12 are the new limits. If the initial number of plants in an hour of that day is 6, the final number of plants for that hour will be 8 since it must be adjusted to the new upper limit, and the minimum load will be limited to 910 MW (see Table 6). The equations to calculate the variables of the combined-cycle are also provided.

The minimum load data for nuclear and coal to which the generation must be adjusted are shown in Table 6.

1.1.4. Pumped hydro storage (PHS)

Spain has recorded the lowest hydropower production in October 2017 since 1990 monthly records, followed by November [3]. The annual average of the hourly hydropower available (2017) was 1966 MW, and the average production for October and November (1195 MW) represents 60.8% of the annual average. Therefore, the availability limit was calculated according to Eq. (1):

$$L_{HY} = \left(\overline{NP_{HY}} \cdot 24h \cdot 0.608\right) \tag{1}$$

This limit shows the value of hydropower generated in a day, below which it is assumed that pumping will not be available for the following day due to low generation. In this way, if hydropower generation does not exceed the limit, pumping will not be available for the next day. It should be noted that this limit has been set because Spain has both pure and mixed PHS, and mixed PHS depends on weather conditions.

The monthly average production of hydropower obtained from the hourly data reported in REE (once the pumping has been discounted) can be seen in Table 7.

After PHS participates, the model allows the calculation of the excess load pending reduction (Comp_{2r}), which cannot be used for pumping (because it does not meet the limit) and must be reduced by other sources. It also determines the unsupplied power demand (Comp_{1r}). Finally, the model calculates the total load to adjust Comp_{pb} (pending to cover or reduce) after this technology participates. The equations used to calculate the variables of pumped hydro storage (PHS) can be seen in Table 8.

Table 5
TR, CR, nuclear, coal and inflexible CC variables.

Variables	Eq.	No
Maximum TR[a] power output (MW)	$PM_{tr} = \frac{NC_{tr} \cdot PMh_{tr}}{C_{tr}}$	(24)
Number of TR power plants for each hour	$tr_2 = \frac{NP_{tr}}{P_{tr}}$	(25)
Minimum TR power output (MW)	$Pmi_{tr} = \frac{NC_{tr} \cdot Pmih_{tr}}{C_{tr}}$	(26)
TR ramp-down rate limit (MW per hour)	$RD_{tr} = RD_{htr}(\%) \cdot NC_{tr}$	(27)
TR ramp-up rate limit (MW per hour)	$RU_{tr} = RU_{htr}(\%) \cdot NC_{tr}$	(28)
Maximum CR power output (MW)	$PM_{cr} = \frac{NC_{cr} \cdot PMh_{cr}}{C_{cr}}$	(29)
Number of CR power plants for each hour	$cr_2 = \frac{NP_{cr}}{P_{cr}}$	(30)
Minimum CR power output (MW)	$Pmi_{cr} = \frac{NC_{cr} \cdot Pmih_{cr}}{C_{cr}}$	(31)
CR ramp-down rate limit (MW per hour)	$RD_{cr} = RD_{hcr}(\%) \cdot NC_{cr}$	(32)
CR ramp-up rate limit (MW per hour)	$RU_{cr} = RU_{hcr}(\%) \cdot NC_{cr}$	(33)
Nominal power of a nuclear power plant	$P_n = \frac{C_n}{n_h}$	(34)
New installed nuclear capacity (MW)	$NC_n = P_n \cdot n$	(35)
Maximum nuclear load (MW)	$PM_n = \frac{NC_n \cdot PMh_n}{C_n}$	(36)
Nuclear ramp-down rate limit (%NC_n per hour)	$RD_n\ (\%) = (-0.0021 \cdot NC_n) + 19.145$	(37)
Nuclear ramp-up rate limit (%NC_n per hour)	$RU_n(\%) = (-0.0021 \cdot NC_n) + 19.166$	(38)
Nuclear ramp-down rate limit (MW per hour)	$RD_n = RD_n(\%) \cdot NC_n$	(39)
Nuclear ramp-up rate limit (MW per hour)	$RU_n = RU_n(\%) \cdot NC_n$	(40)
Minimum nuclear load (%)	$\%Pmi_n = (-0,0005 \cdot NC_n) + 75,468$	(41)
Minimum nuclear load (MW)	$Pmi_n = NC_n \cdot \%Pmi_n$	(42)
Initial number of nuclear power plants for each hour	$nu = \frac{NP_N}{P_c}$	(43)
Final number of nuclear power plants for each hour	*nu2 Redimensión*	(44)
Nominal power of a coal power plant (MW)	$P_c = \frac{C_c}{c_h}$	(45)
New installed coal capacity (MW)	$NC_c = P_c \cdot c$	(46)
Maximum coal load (MW)	$PM_c = \frac{NC_c \cdot PMh_c}{C_c}$	(47)
Coal ramp-down rate limit (%NC_c per hour)	$RD_c(\%) = (-0.0079 \cdot NC_c) + 92.895$	(48)
Coal ramp-up rate limit (%NC_c per hour)	$RU_c(\%) = (-0.0084 \cdot NC_c) + 93.099$	(49)
Coal ramp-down rate limit (MW per hour)	$RD_c = RD_c(\%) \cdot NC_c$	(50)
Coal ramp-up rate limit (MW per hour)	$RU_c = RU_c(\%) \cdot NC_c$	(51)
Minimum nuclear load (%)	$\%Pmi_n = (-0,0005 \cdot NC_n) + 75,468$	(52)
Minimum nuclear load (MW)	$Pmi_n = NC_n \cdot \%Pmi_n$	(53)
Initial number of coal power plants for each hour	$co = \frac{NP_c}{P_n}$	(54)
Final number of coal power plants for each hour	*co2 Redimensión*	(55)
New installed inflexible CC capacity (MW)	$NC_{cc0} = \frac{PM_{cc0} \cdot C_{cc}}{PMh_{cc}}$	(48)
Nominal power of a CC power plant (MW)	$P_{cc} = \frac{C_{cc}}{cc_1}$	(49)
Inflexible CC ramp-down rate limit (% NC_{cc0}/per hour)	$RD_{cc0} = = (-0,0099 \cdot NC_{cc0}) + 105,15$	(50)
Inflexible CC ramp-up rate limit (%NC_{cc0} per hour)	$RU_{cc0} = (-0,0099 \cdot NC_{cc0}) + 105,17$	(51)
Inflexible CC ramp-down rate limit (MW per hour)	$RD_{cc0} = RD_{cc0}(\%) \cdot NC_{cc0}$	(52)
Inflexible CC ramp-up rate limit (MW per hour)	$RU_{cc0} = RU_{cc0}(\%) \cdot NC_{cc0}$	(53)
Minimum inflexible CC power output (%)	$\%Pmi_{cc0} = (-0,0016 \cdot NC_{cc0}) + 40.807$	(54)
Minimum inflexible CC power output (MW)	$Pmi_{cc0} = NC_{cc0} \cdot \%Pmi_{cc0}$	(55)
New installed CC capacity (flexible + inflexible) (MW)	$NC_{cc} = NC_{cc0} + NC_{cc1}$	(56)
Final number of CC (flexible + inflexible) power plants for each hour	$cc2 = \frac{(NP_{cc0} + NP_{cc1})}{P_{cc}}$	(57)
	Resize (curtailment adjustments) $cc2 = \frac{NP_{cc2}}{P_{cc}}$	(58)
CC power output (flexible + inflexible) (MW)	$NP_{cc2} = (NP_{cc0} + NP_{cc1})$ *Resize (curtailment adjustments)*	(59)
New installed CC capacity (flexible + inflexible) (MW)	$NC_{cc} = NC_{cc0} + NC_{cc1}$	(60)
Flexible CC power output (after inertia constraints) (MW)	$NP_{fcc} = NP_{cc2}(resize) - NP_{cc0}$	(61)

[a] Includes biogas, biomass, marine, and geothermal.

Table 6
Minimum nuclear load according to the number of power plants (MW).

n	Pmi_n	c	Pmi_c	c	Pmi_c	c	Pmi_c	c	Pmi_c
0	0	0	0	8	910	16	1217	24	922
1	762	1	147	9	981	17	1213	25	842
2	1514	2	284	10	1043	18	1200	26	754
3	2255	3	412	11	1096	19	1177	-	-
4	2987	4	530	12	1139	20	1145	-	-
5	3707	5	639	13	1172	21	1103	-	-
6	4418	6	739	14	1197	22	1052	-	-
7	5118	7	829	15	1212	23	992	-	-

Table 7
Average hourly data of hydropower available-2017.

Months	$\overline{NP_{hy}}(MW)$	Months	$\overline{NP_{hy}}(MW)$
Jan	2701	Jul	1436
Feb	2594	Aug	1317
Mar	3341	Sep	1564
Apr	2312	Oct	1077
May	2335	Nov	1311
Jun	2016	Dec	1627

Table 8
PHS variables.

Variables	Eq.	
New installed PHS capacity	$NC_{phy} = \frac{C_{phs} \cdot NC_{hy}}{C_{hy}}$	(62)
PHS installed capacity limit	$L_{phs} = NC_{phs}$	(63)
Load available for storage	$Compst\ (resize)$	(64)
Final load in storage	$F_{sty} = St_{y2}$	(65)
Final number of PHS power plants for each hour	$hy_2 = \frac{(NP_{hy1} + P_{phs})}{P_{hyd}}$	(66)

Table 9
Power system mix for France and Portugal considered for future scenarios [4,5].

Percentage (%)	Nuclear	Combined-cycle	Wind	Solar	Hydro	Cogeneration and waste	Renewable thermal	Coal
France	51	8	19	7[a]	12	0	3	0
Portugal	0	31	27	8[a]	16	10	8	0
Morocco	0	0	20	20[b]	12	0	0	48[c]

[a] TYNDP does not specify the share of participation of solar photovoltaic and solar thermal separately. Therefore, it has been assumed that 20% of the total share corresponds to solar thermal for the two countries.
[b] It has been assumed that 4% is for solar thermal.
[c] Reported as thermal, assumed as coal.

1.1.5. Inertia

The contribution (%) of each technology for France and Portugal was obtained from TYNDP (see Table 9) [4]. The rotational inertia constant is obtained through a weighted average (considering the inertia constants) (see Eq. (2)).

$$\begin{aligned} &Average\ rotational\ inertia\ constant\ for\ NPI_f \\ &\quad = (\%N \cdot n_i) + (\%C \cdot c_i) + (\%CC \cdot cc_i) + (\%HY \cdot hy_i)\ + (\%\ TS \cdot tso_i) + (\%CR \cdot cr_i) \\ &\qquad + (\%\ TR \cdot tr_i) \end{aligned} \tag{2}$$

The inertia contribution of power plants is calculated using the equations presented in Table 10, which consider the final number of plants, the inertia constant by type of generator, and the power plants' nominal power.

Table 10
Average rotational inertia contribution by technology (MW·s).

Variables	Eq.	No
Nuclear	$ci_n = nu_2 \cdot n_i \cdot P_n$	(67)
Coal	$ci_c = co_2 \cdot c_i \cdot P_c$	(68)
CC	$ci_{cc} = cc_2 \cdot cc_i \cdot P_{cc}$	(69)
Hydro and PHS	$ci_{hy} = hy_2 \cdot hy_i \cdot P_{hyd}$	(70)
CR	$ci_{cr} = cr_2 \cdot cr_i \cdot P_{cr}$	(71)
TR	$ci_{tr} = tr_2 \cdot tr_i \cdot P_{tr}$	(72)
TS	$ci_{ts} = ts_2 \cdot tso_i \cdot P_{tst}$	(73)
NPI_f	$ci_{if} = NPI_f \cdot if_i$	(74)
NPI_p	$ci_{ip} = NPI_p \cdot ip_i$	(75)
NPI_m	$ci_{im} = NPI_m \cdot im_i$	(76)

The total system inertia (TSI) was calculated according to Eq. (3) and the critical inertia level (CIL) according to Eq. (4) used in Johnson et al. [6] where ΔP_{MW} represents the power lost in the greatest contingency. In Continental Europe, being an interconnected system, the regulatory contingency or reference incident (which represents the loss of the two largest generating facilities) is 3000 MW [7].

$$TSI = ci_n + ci_c + ci_{cc} + ci_{hy} + ci_{cr} + ci_{tr} + ci_{ts} \tag{3}$$

$$CIL = \frac{\Delta P}{2 \cdot ROCOF} \cdot NF + (LIR) \tag{4}$$

LIR refers to the rotational inertia lost in this contingency. That is equal to (MVA•H). MVA refers to the apparent power capacity representing the largest contingency, and H is the inertia constant for these plants. In ERCOT, the largest contingency is represented by two nuclear power plants. The apparent power capacity of the two nuclear power plants (2750 MW) was 460.69 MVA. Therefore, for a power capacity of 3000 MW, the apparent power capacity is assumed to be 502.57 MVA. The inertia constant of these power plants has a value of 4.07. ROCOF is the Rate of Change of Frequency and NF is the nominal frequency of the power system (50 Hz).

According to Eq. (5) and Eq. (6), the inertia variation and the increase in the combined-cycle, respectively, are calculated.

$$V_i = CIL - TSI \tag{5}$$

$$NP_{cc2} = (NP_{cc0} + NP_{cc1}) + \left(\frac{Vi}{cci}\right) \tag{6}$$

1.1.6. CO_2 emissions (mode of operation of the CC)

The criteria for calculating the flexible combined-cycle CO_2 emissions according to the mode of operation are:

- 1st Criteria “Start and stop emissions”: Start of operation from 0, which includes hot start (with an emission factor of 0.59 tCO_2 / MWh) and the emissions of the fraction of start-up time where power is not yet fed into the grid ($t_0 \rightarrow t_1$). This fraction added to these hours will be proportional to t_o until t_1, which is 12 min. Emissions from stops (up to 0) are also considered with a proportional time of 12 min.
- 2nd Criteria "Increase in power output, constant operation and start emissions": If there is power in the previous hour, the hourly power corresponding to each plant is calculated assuming an exact division of the power output for the number of plants. Subsequently, the emission of these plants in constant operation (0.37 tCO_2/MWh) is calculated. The emission of the hot start and the fraction of start-up time are also calculated according to 1st criteria.
- 3rd Criteria "Decrease in power output, constant operation and stop emissions": If there is power in the previous hour and the power is reduced, the power corresponding to each plant and the emission in constant operation is calculated (0.37 tCO_2 / MWh). This criterion includes the emission of stops with the proportion explained in the 1st criteria.

- 4th Criteria "Constant operation emissions not previously contemplated".
- 5th Criteria "Decrease in power output and stop emissions not previously contemplated": fourth criteria do not contemplate the hours in which the number of power plants has decreased and in the subsequent hour increase. This criteria also considers the emissions of the stops. In this case, three criteria are considered for the stops: stops when in the previous hour the number of power plants is maintained or had fallen; when in the previous hour the number of power plants had increased; and when in the previous hour the power plants had started to operate.
- 6th Criteria "Constant operation emissions when the next value increases".

The flowchart of these criteria can be seen in Appendix 2.

1.2. Results data

1.2.1. Parameters and variables for 2017 and future scenarios

The historical installed capacities of 2017 are shown in Table 11 and parameters for nuclear, coal and combined-cycle in Table 12.

Table 11
Historical installed capacity of 2017 (GW).

Technology	Installed capacity
Wind	22.922
Solar PV	4.439
Solar Thermal	2.304
Nuclear	7.117
Coal	9.536
Combined-cycle	21.856
Hydro	17.03
PHS	3.329
CR	6.277
TR	0.975

Table 12
Parameters of 2017 for nuclear, coal and combined-cycle.

Parameters	Nuclear	Coal	CC	CR	TR
Maximum load (MW)	7114	8727	17 054	4078	492
Minimum load (MW)	5118	772	511	2562	261
Minimum load (% of Installed capacity)	72.19	8.10	2	-	-
Ramp-down rate limit (MW)	294	1681	1736	262	52
Ramp-down rate limit (% of installed capacity per hour)	4.13	17.63	12.71	4.17	5.33
Ramp-up rate limit (MW)	285	1195	1680	261	46
Ramp-up rate limit (% of installed capacity per hour)	4.00	12.53	12.30	4.16	4.72
Number of power plants	7	26	48	-	-

The values assumed[1] or calculated (as input[2] or as a result[3]) for the model are presented in Table 13. Theoretical[4] values are also shown. For CR and TR with 2017 installed capacities, the same historical[5] values were obtained.

[1] Assumed: assumed value used as input of the model.
[2] Calculated values before being used as inputs to the model, based on theoretical and historical reference values.
[3] Calculated (as a result): value obtained because of the model.
[4] Theoretical: value found in the literature, used as input.
[5] Historical: actual values of the reference year.

Table 13
Values used or calculated in the model with historical data.

Variables	Nuclear	Coal	Inflexible CC	CR	TR	Flexible CC
New installed capacity (MW)	7117[a]	9536[a]	13 654[a]	6277[b]	975[b]	8202[c]
Maximum load (MW)	7114[a]	8727[a]	9334[b]	4078[a]	492[a]	5607[c]
Minimum load (MW)	5118[a]	753[a]	2589[a]	2562[a]	261[a]	-
Minimum load (% of Installed capacity)	71.91[a]	7.90[a]	18.96[a]	-	-	-
Ramp-down rate limit (MW)	299[a]	1675[a]	1740[a]	262[a]	52[a]	-
Ramp-down rate limit (% of installed capacity per hour)	4.20[a]	17.56[a]	12.74[a]	4.17[a]	5.33[a]	-
Ramp-up rate limit (MW)	300[a]	1239[a]	1743[a]	261[a]	46[a]	-
Ramp-up rate limit (% of installed capacity per hour)	4.22[a]	13.00[a]	12.76[a]	4.16[a]	4.72[a]	-
Number of power plants assumed for a future year	7[b]	26[b]	-	-	-	-
Nominal power of a power plant (MW)	1017[a]	367[a]	520[a]	7.93[d]	7.93[d]	-
Minimum theoretical load (% of nominal power)	75[e]	40[f]	40[f]	-	-	-
Theoretical ramp rate (% of nominal power per hour)	17[g]	90[f]	100[f]	-	-	-

[a] Calculated (as input),
[b] Assumed,
[c] Calculated (as a result),
[d] Avg. obtained from [8],
[e] Theoretical (avr. obtained from [9]),
[f] Theoretical (values obtained from [10]),
[g] Theoretical (value obtained from [11])

The variables used for hydro and PHS and solar thermal are presented in Table 14.

Table 14
Values of hydro and solar thermal used or calculated in the model with historical data.

Variables	Nuclear
New installed hydropower capacity (MW)	17 030[a]
New installed PHS capacity (MW)	3329[a]
Annual average of hydropower available (MW)	1966[b]
PHS installed capacity limit (MW)	3329[b]
PHS availability limit (MWh/day)	28 685[b]
Pumping efficiency (%)	85[a]
PHS discharge efficiency (%)	85[a]
Pumping factor (%)	0.048[b]
Nominal power of a hydropower plant	14.6[c]
Nominal power of a solar thermal power plant	45.2[d]

[a] Assumed (pure and mixed power plants),
[b] Calculated (as input),
[c] Average obtained from [12],
[d] Average obtained from [13].

Table 15 shows the required curtailment of wind and photovoltaic for system stability for different levels of ROCOF for the 2017 scenario.

In Fig. 2, it can be seen how the CIL decreases with the increase in ROCOF.

The values of the variables used in the model for the sustainable transition ST-2030 scenario are in Table 16. These variables are calculated as input, assumed, theoretical values or calculated due to the model.

The variables used for hydro and PHS and solar thermal for ST-2030 can be seen in Table 17.

To project and model the 2040 scenario, the model requires a new installed capacity for all technologies, except for the combined-cycle, which will be obtained. Therefore, we tried to

Table 15
Required curtailment for system stability for different levels of ROCOF (2017).

CIL (MW•s)	ROCOF (Hz/s)	Wind curtailment (GWh)	PV Curtailment (GWh)	Power grid failure (GWh)
152045	0.5	42 341	7010	69 494
127045	0.6	40 776	5973	28 115
109188	0.7	33 858	2723	7577
95795	0.8	21 018	576	1264
85379	0.9	9457	69	133
77045	1	3670	1	6
70227	1.1	1303	0	0
64545	1.2	425	0	0
59738	1.3	114	0	0
55617	1.4	26	0	0
52045	1.5	1	0	0
48920	1.6	0	0	0

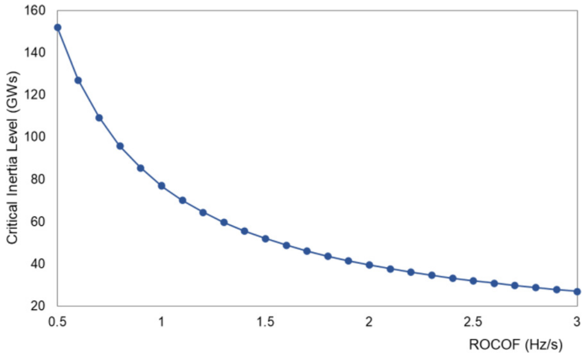

Fig. 2. Critical inertia level (CIL) VS Rate of change of frequency (ROCOF) in the model (GWs).

Table 16
Values used or calculated in the model by ST-2030.

Variables	Nuclear	Coal	Inflexible CC	CR	TR	Flexible CC
New installed capacity (MW)	7117[a]	4768[a]	13 654[a]	8500[b]	2550[b]	21 959[c]
Maximum load (MW)	7114[a]	4364[a]	9334[b]	5522[a]	1286 [a]	15 011[c]
Minimum load (MW)	5118[a]	1172[a]	2589[a]	3469[a]	682[a]	-
Minimum load (% of Installed capacity)	71.91[a]	24.59[a]	18.96[a]	-	-	-
Ramp-down rate limit (MW)	299[a]	2633[a]	1740[a]	355[a]	136[a]	-
Ramp-down rate limit (% of installed capacity per hour)	4.20[a]	55.23[a]	12.74[a]	4.17[a]	5.33[a]	-
Ramp-up rate limit (MW)	300[a]	2529[a]	1743[a]	353[a]	120[a]	-
Ramp-up rate limit (% of installed capacity per hour)	4.22[a]	53.05[a]	12.76[a]	4.16[a]	4.72[a]	-
Number of power plants assumed for a future year	7[b]	13[b]	-	-	-	-

[a] Calculated (as input),
[b] Assumed,
[c] Calculated (as a result).

approximate our data to the data provided by the TYNDP 2018 from ENTSO (ENTSO-E, ENTSO-G) for the Sustainable Transition ST-2040 scenario, as can be seen in Table 18.

The demand for DG-2030 was 293676 GWh, 317688 for DG-2040 and 290439 GWh for GCA-2040, approximating to TYNDP values. Table 19 provides the installed capacities of the rest of the technologies.

1.2.2. PHS generation and histograms of power output 2017- ST-2030

Fig. 3. shows the hydropower production, as well as the PHS limit, which is 28 685 MWh for 2017. We also assume that PHS pumps water with an efficiency of 85% [14].

Table 17
Values of hydro and solar thermal used or calculated in the model by ST-2030.

Variables	Nuclear
New installed hydropower capacity (MW)	23 050[a]
New installed PHS capacity (MW)	8280[a]
Annual average of hydropower available (MW)	2463[b]
PHS installed capacity limit (MW)	8280[b]
PHS availability limit (MWh/day)	35 941[b]
Pumping efficiency (%)	85[a]
PHS discharge efficiency (%)	85[a]
Pumping factor (%)	0.018[b]
Nominal power of a hydropower plant (MW)	14.6[c]
Nominal power of a solar thermal power plant (MW)	45.2[d]

[a] Assumed,
[b] Calculated (as input),
[c] Average obtained from [12],
[d] Average obtained from [13].

Table 18
Model Installed capacity for ST-2040.

Technology	TYNDP Installed capacity (ST-2040) (MW)	MODEL Installed capacity (2040) (MW)
Wind	39 561	39 561
Solar PV	51 394	51 394
Solar Thermal	3363	3363
Nuclear	3100	3050[a]
Coal	0	0
Combined-cycle	24 560	48 340[b]
Hydro	23 050	23 050
PHS	8280	8280
CR	8500	8500
TR	2550	2550
Demand	282 705	282 682[c]
France (import)	9000	9000
France (export)	9000	9000
Portugal (import)	4000	4000
Portugal (export)	4700	4700
Morocco (import)	1500	1500
Morocco (export)	1500	1500
Balearic Islands	927	927

[a] Approximate value to the TYDNP, obtained in the model with 3 nuclear power plants.
[b] Calculated (as a result).
[c] Approximated value to the TYDNP, obtained in the model with a ND_m of 20955 MW.

Table 19
Installed capacities for DG-2030-2040 and GCA-2040.

Technology	Installed capacityDG-2030 (MW)	Installed capacityDG-2040 (MW)	Installed capacityGCA-2040 (MW)
Nuclear	7117	3050[a]	3050[a]
Coal	734	0	0
Solar Thermal	2304[a]	2304[a]	3363[b]
Hydro	23 050[b]	23 050[b]	24 920[b]
PHS	8280[b]	8280[b]	10 150[b]
CR	8500[b]	8500[b]	8500[b]
TR	2550[b]	2550[b]	2550[b]

[a] Approximated value to the TYDNP.
[b] Value taken from TYNDP.

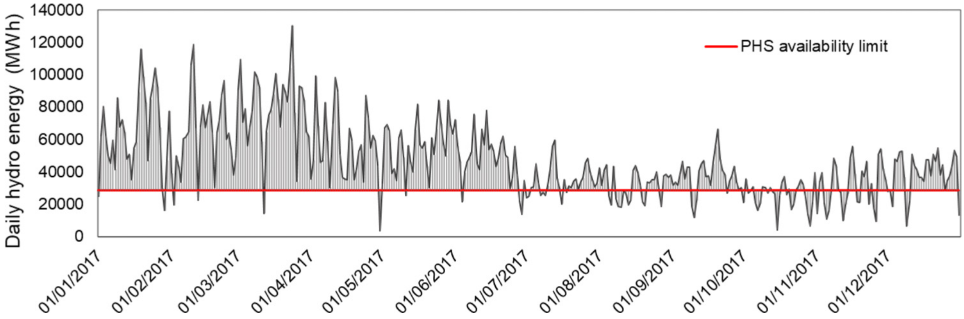

Fig. 3. Hydropower generation (2017) and PHS availability limit.

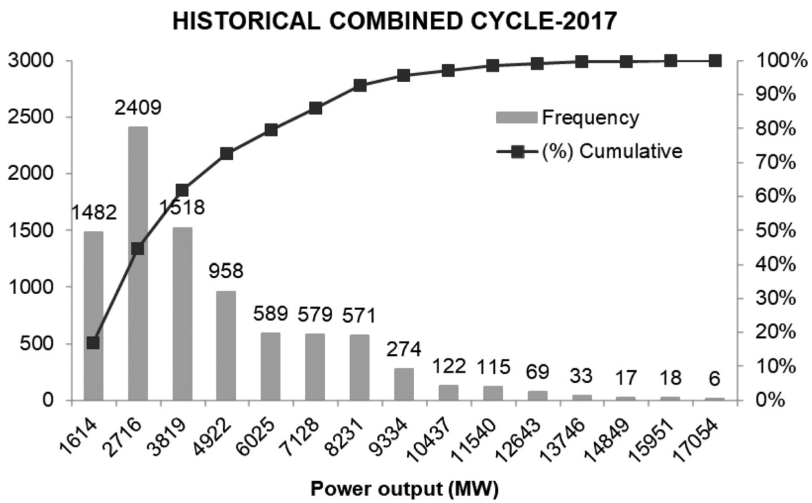

Fig. 4. Histogram of combined-cycle power output 2017 (MW).

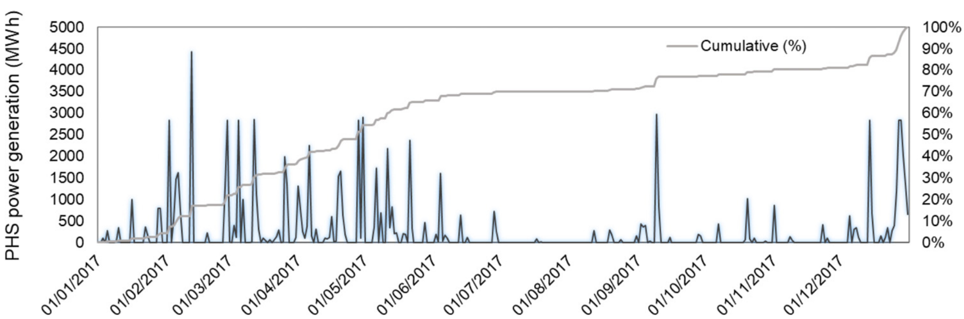

Fig. 5. Power generation from the PHS (model with historical data (MWh)).

Regarding combined-cycle (CC) the histogram of the power output is shown in Fig. 4.

The power generation of the pumped hydro storage (PHS) in the simulation with historical data can be seen in Fig. 5.

Fig. 6 shows the frequency histogram of the power output for the modelled technologies compared to the historical data.

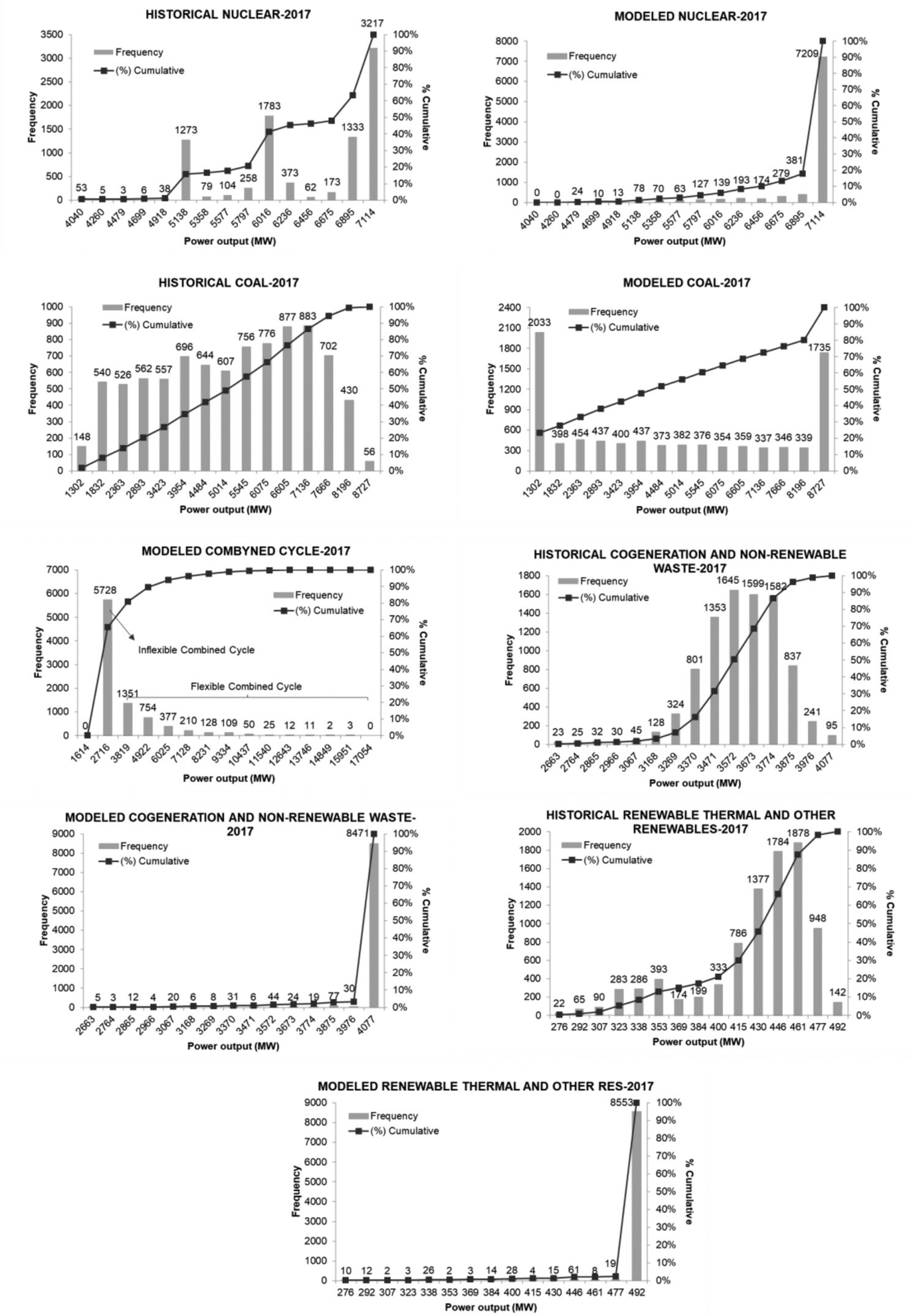

Fig. 6. Frequency Histograms of the historical and modelled power output (model with historical data).

Fig. 7 shows the PHS generation obtained in the sustainable transition ST-2030 scenario.

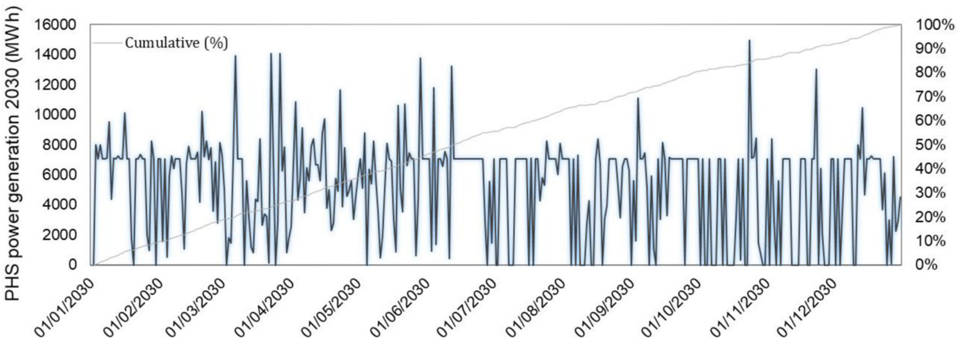

Fig. 7. Power generation from the PHS by ST-2030 (MWh).

Fig. 8 shows the frequency histogram of the power output for the modelled technologies by ST-2030.

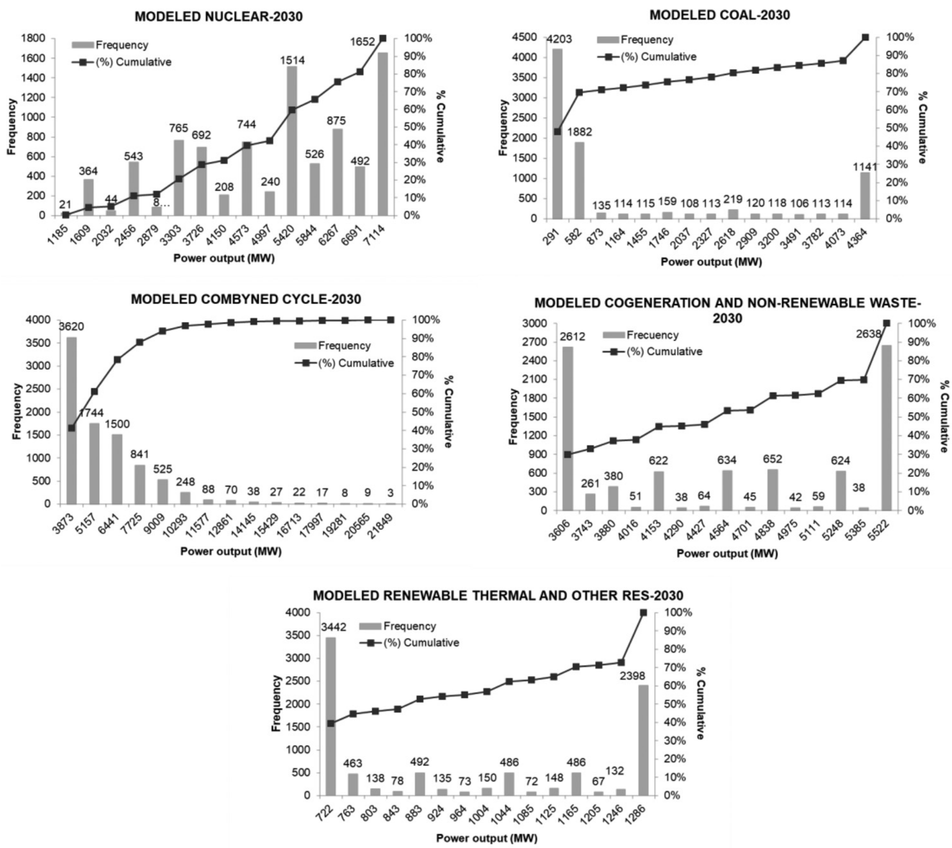

Fig. 8. Frequency Histograms of the modelled power output by ST-2030.

1.2.3. Power generation and curtailment for ST-2040, DG-2030, DG-2040 and GCA-2040

The results for the ST-2040 scenario are shown in Table 20.

Table 20
Annual energy generation by technology ST-2040.

Technology	Power generation of the model without curtailment (for flexibility and stability) (GWh)	Power generation of the model with curtailment (ROCOF 1) (GWh)
Wind	81 370	47 267
Solar PV	98 184	52 412
Solar Thermal		7410
Nuclear	18 520	18 520
Coal	0	0
Combined-cycle	48 077	67 804
Hydro	23 051[a]	21 119
PHS	-	1475
CR	37 653	37 653
TR	7789	7789
PHS consumption	-2126	-2126
Balearic Islands	-1480	-1480
International Interconnections Balance	24 837	24 837
Total generation balance (TG) or Final demand	282 682	282 682

[a] Hydro + PHS

The curtailment results for ST-2040 are shown in Table 21.

Table 21
Annual curtailment for ST-2040.

Technology	Curtailment required by inflexible operation (GWh)	%[a]	Curtailment required for stability (ROCOF 1 Hz/s) (GWh)	%[a]	Total Curtailment (GWh)	%[a]
Wind	17 205	21	16898	21	34 103	42
Solar PV	35 232	39	2830	3	38 061	42
Solar Thermal	300	4	-	0	300	4
Hydro	458	2	-	0	458	2

[a] Curtailment percentage of the availability of renewable generation.

The power output results for DG-2030, DG-2040 and GCA-2040 scenarios are provided in Table 22.

Table 22
Annual energy generation by technology, DG-2030, DG and GCA-2040.

Technology	Scenario DG-2030(GWh)	Scenario DG-2040(GWh)	Scenario GCA-2040 (GWh)
Wind	46 890	52 452	56 790
Solar PV	51 838	66 509	55 452
Solar Thermal	5261	5249	7327
Nuclear	45 975	22 064	15 745
Coal	2406	0	0
Combined-cycle	52 839	79 733	67 666
Hydro	21 493	21 479	22 048
PHS	1986	1917	1570
CR	39 296	39 421	35 658
TR	8211	8196	7208
PHS consumption	-2792	-2689	-2277
Balearic Islands	-1480	-1480	-1480
International Interconnections Balance	21 760	24 837	24 837
Total generation balance (TG) or Final demand	293 676	317 688	290 439

The curtailment results for DG and GCA scenarios are shown in Table 23.

Table 23
Annual curtailment for DG-2030, DG-2040 and GCA-2040.

Technology	DG-2030 (ROCOF 1) (GWh)	%[a]	DG-2040 (ROCOF 1.2) (GWh)	%[a]	GCA-2040 (ROCOF 1.2) (GWh)	%[a]
Wind	16 872	26	21 258	29	48 104	46
Solar PV	31 177	38	51 272	44	80 098	59
Solar Thermal	22	0.4	34	1	383	5
Hydro	84	0.4	97	0.5	572	3

[a] Percentage of curtailment of the availability of renewable generation.

Table 24 shows the required curtailment for each technology by ST-2030-2040 due to system stability. It also contains the power grid failures.

1.2.4. CO_2 emissions

The results by technology for 2017, ST-2030 and ST-2040 obtained using Red Eléctrica de España (REE) methodology are shown in Table 25.

The emissions obtained by technology for 2017 and the base scenarios ST-2030-2040 can be seen in Table 26. It also provides the emissions obtained for the CC after applying the mode of operation for 2030 and 2040.

Table 24
Required curtailment of VRE due to system stability for different ROCOF levels (ST-2030-2040).

CIL (MW.s)	ROCOF (Hz/s)	Wind curtailment 2030 (GWh)	PV Curtailment 2030 (GWh)	Power grid failure 2030 (GWh)	Wind curtailment 2040 (GWh)	PV Curtailment 2040 (GWh)	Power grid failure 2040 (GWh)
152045	0.5	46 011	38 066	39 674	55 573	44 640	39 077
127045	0.6	41 518	29 577	12 173	50 286	33 827	11 851
109188	0.7	32 861	14 887	2473	41 897	21 822	2307
95795	0.8	22 573	6699	233	32 130	12 514	225
85379	0.9	13 649	2475	8	23 684	6319	3
77045	1	7512	793	0	16 898	2830	0
70227	1.1	3980	242	0	11 665	1148	0
64545	1.2	2181	60	0	7903	426	0
59738	1.3	1213	6	0	5297	144	0
55617	1.4	652	0	0	3526	37	0
52045	1.5	337	0	0	2326	6	0
48920	1.6	166	0	0	1530	0.6	0
46163	1.7	82	0	0	1029	0	0
43712	1.8	35	0	0	705	0	0
41519	1.9	12	0	0	488	0	0
39545	2	4	0	0	341	0	0
37760	2.1	3	0	0	240	0	0
36136	2.2	2	0	0	170	0	0
34654	2.3	22	0	0	120	0	0
33295	2.4	1	0	0	85	0	0
32045	2.5	0.5	0	0	62	0	0
30892	2.6	0.1	0	0	44	0	0
29823	2.7	0	0	0	31	0	0
28831	2.8	0	0	0	20	0	0
27908	2.9	0	0	0	11	0	0
21045	3	0	0	0	4	0	0
26239	3.1	0	0	0	0.5	0	0
25483	3.2	0	0	0	0	0	0

Table 25
Emissions by technology for the model and TYNDP ST-2030-2040 (Mt CO_2/year).

Scenario	Coal	Combined-cycle	CR
Historical 2017	40.6	12.6	8.7
Model 2017	37.2	10.7	10.0
Model 2030	9.2	16.0	11.0
TYNDP 2030	6.8	16.1	10.8
Model 2040	0	25.1	10.5
TYNDP 2040	0	17.7	10.8

Table 26
CO_{2eq} emissions by technology for 2017, ST-2030 and ST-2040 (kt of CO_2 eq.).

Technology	2017	ST-2030[a]	ST 2040[b]
Nuclear	1338	948	407
Wind	458	448	473
Solar PV	313	1890	2096
Solar Thermal	106	104	148
Biomass	123	225	241
Biogas	274	97	92
Marine	-	4	3
Geothermal	-	17	16
Hydro (impoundment)	252	309	306
Hydro diversion	8	11	10
PHS	0.1	2	2

[a] Emissions for the CC are 16977 kt.
[b] Emissions for the CC are 26641 kt.

Table 27 shows the TSI, the total emissions, and the emission factors (weighted average) when decreasing the ROCOF for 2017, ST and DG 2030.

Table 27
Inertia and emission factor results for 2017, ST and DG-2030.

	2017	ST-2030 (no restrictions)	ST-2030 (ROCOF 1.2 Hz/s)	ST-2030 (ROCOF 1 Hz/s)	DG-2030 (no restrictions)	DG-2030 (ROCOF 1.2 Hz/s)	DG-2030 (ROCOF 1 Hz/s)
TSI (GWs)	747 732	717 348	728 483	758 621	763 708	770 997	796 558
Total Emissions (Mt CO_2)	60.9	38.1	38.9	41.2	36.0	36.6	38.5
Medium emission factor (kgCO_2/ /MWh)	241	144	148	157	131	133	141

Table 28 shows the TSI, the increase in total emissions, and the emission factors (weighted average) when by 2040.

Table 28
Inertia and emission factor results for ST, DG and GCA-2040.

	ST-2040 (no restr.)	ST-2040 (1.2 Hz/s)	ST-2040 (1 Hz/s)	DG-2040 (no restr.)	DG-2040 (1.2 Hz/s)	DG-2040 (1 Hz/s)	GCA-2040 (no restr.)	GCA-2040 (1.2 Hz/s)	DG-2040 (1 Hz/s)
TSI (GWs)	641 077	682 471	739 121	756 020	778 532	817 131	590 014	651 478	719 985
Total Emissions (Mt CO_2)	33.5	36.7	41	42.5	44.2	47	30.6	35.4	40.4
Medium emission factor (kg CO_2/MWh)	129	142	159	145	150	160	115	134	153

1.2.5. Levelized cost of electricity (LCOE)

Table 29 shows the LCOE data used to calculate system costs. LCOE input depends on the capacity factor resulting from each scenario.

Table 29
Input LCOE for all scenarios considered in the study.

Scenario	Full load hours (capacity factor %)	Input LCOE (€/MWh)
2017 Wind (no restrictions)	2053 (23%)	79
2017 PV (no restrictions)	1760 (20%)	68
2017 Coal	4109 (47%)	65
2017 Nuclear	8547 (98%)	45
2017 CC (no restrictions)	1264 (14%)	136
2017 Wind (1.1 Hz/s)	1996 (23%)	79
2017 PV (1.1 Hz/s)	1760 (20%)	68
2017 CC (1.1 Hz/s)	1324 (14%)	133
ST 2030 Wind (1.2 Hz/s)	1618 (18%)	79
ST 2030 PV (1.2 Hz/s)	1200 (14%)	75
ST 2030 Coal	2022 (23%)	99
ST 2030 Nuclear	6054 (69%)	60
ST 2030 CC (1.2 Hz/s)	1046 (12%)	147
ST 2030 Wind (no restrictions)	1688 (19%)	75
ST 2030 PV (no restrictions)	1202 (14%)	75
ST 2030 CC (no restrictions)	983 (11%)	148
ST 2030 Wind (1 Hz/s)	1446 (17%)	88
ST 2030 PV (1 Hz/)	1182 (13%)	76
ST 2030 CC (1 Hz/)	1217 (14%)	139
DG 2030 Wind (1.2 Hz/s)	1636 (19%)	77
DG 2030 PV (1.2 Hz/s)	1127 (13%)	80
DG 2030 Coal	3280 (37%)	73
DG 2030 Nuclear	6460 (74%)	57
DG 2030 CC (1.2 Hz/s)	1069 (12%)	147
DG 2030 Wind (no restrictions)	1680 (19%)	75
DG 2030 PV (no restrictions)	1129 (13%)	79
DG 2030 CC (no restrictions)	1036 (12%)	148
DG 2030 Wind (1 Hz/s)	1513 (17%)	84
DG 2030 PV (1 Hz/)	1099 (13%)	82
DG 2030 CC (1 Hz/)	1184 (14%)	140
ST 2040 Wind (1.2 Hz/s)	1422(16%)	89
ST 2040 PV (1.2 Hz/s)	1067(12%)	84
ST 2040 Coal	0	0
ST 2040 Nuclear	6072 (69%)	60
ST 2040 CC (1.2 Hz/s)	1167 (13%)	141
ST 2040 Wind (no restrictions)	1622 (19%)	78
ST 2040 PV (no restrictions)	1075 (12%)	83
ST 2040 CC (no restrictions)	995 (11%)	148
ST 2040 Wind (1 Hz/s)	1195 (14%)	106
ST 2040 PV (1 Hz/)	1020 (12%)	88
ST 2040 CC (1 Hz/)	1403 (16%)	128
DG 2040 Wind (1.2 Hz/s)	1573 (18%)	80
DG 2040 PV (1.2 Hz/s)	1052 (12%)	85
DG 2040 Coal	0	0
DG 2040 Nuclear	7234 (83%)	52
DG 2040 CC (1.2 Hz/s)	1259 (14%)	136
DG 2040 Wind (no restrictions)	1668 (19%)	76
DG 2040 PV (no restrictions)	1068 (12%)	84
DG 2040 CC (no restrictions)	1180 (13%)	140
DG 2040 Wind (1 Hz/s)	1464 (17%)	86
DG 2040 PV (1 Hz/)	994 (11%)	90
DG 2040 CC (1 Hz/)	1395 (16%)	129
GCA 2040 Wind (1.2 Hz/s)	1285 (15%)	99
GCA 2040 PV (1.2 Hz/s)	784 (9%)	114
GCA 2040 Coal	0	0
GCA 2040 Nuclear	5162 (59%)	68
GCA 2040 CC (1.2 Hz/s)	1012 (12%)	148
GCA 2040 Wind (no restrictions)	1502 (17%)	84
GCA 2040 PV (no restrictions)	801 (9%)	112
GCA 2040 CC (no restrictions)	783 (9%)	155
GCA 2040 Wind (1 Hz/s)	1114 (13%)	114
GCA 2040 PV (1 Hz/)	720 (8%)	125
GCA 2040 CC (1 Hz/)	1272 (15%)	136

Table 30 shows the total costs and the LCOE (weighted average) when going from the scenario without inertia constraints to the restricted ones for 2017 and ST and DG 2030.

Table 30
Inertia and LCOE results for 2017, ST and DG-2030.

	2017	ST-2030 (no restrictions)	ST-2030 (ROCOF 1.2 Hz/s)	ST-2030 (ROCOF 1 Hz/s)	DG-2030 (no restrictions)	DG-2030 (ROCOF 1.2 Hz/s)	DG-2030 (ROCOF 1 Hz/s)
Total Costs (M€)	16 612	20 235	20 562	21 081	21 761	21 975	22 394
Medium LCOE (€/MWh)	68	77	78	80	79	79	81

Table 31 shows the total costs and the LCOE (weighted average) when going from the scenario without inertia constraints to the restricted ones for ST, DG and GCA 2040.

Table 31
Inertia and LCOE results for ST, DG and GCA-2040.

	ST- 2040 (no rest.)	ST- 2040 (1.2 Hz/s)	ST-2040 (1 Hz/s)	DG-2040 (no rest.)	DG-2040 (1.2 Hz/s)	DG-2040 (1 Hz/s)	GCA-2040 (no rest.)	GCA-2040 (1.2 Hz/s)	GCA-2040 (1 Hz/s)
Total Costs (M€)	21 762	22 621	24 171	25 053	25 342	25 847	24 670	26 238	27 499
Medium LCOE (€/MWh)	83	86	89	84	85	87	91	97	102

Table 32 shows the maximum and minimum LCOE and the frequency of values greater than € 85/MWh for each scenario.

Table 32
Results of maximum and minimum LCOE of the base scenarios.

Scenario	Frequency in the impacted area (> 85 €/MWh)	Maximumannual LCOE (€/MWh)	Minimumannual LCOE (€/MWh)	Annual frequency (> 85 €/MWh)
ST 2030 No restrictions	41 (3%)	104	62	784 (9%)
ST 2030 1.2 Hz/s	379 (27 %)	104	62	1200 (14%)
ST 2030 1 Hz/s	1113 (29 %)	104	62	1874 (21%)
DG 2030 No restrictions	14 (1%)	109	62	1495 (17%)
DG 2030 1.2 Hz/s	185 (15%)	109	62	1699 (19%)
DG 2030 1 Hz/s	850 (26%)	109	62	2252 (26%)
ST 2040 No restrictions	207 (6%)	117	65	2543 (29%)
ST 2040 1.2 Hz/s	2151(60%)	113	65	4752 (54%)
ST 2040 1 Hz/s	4063(72%)	109	65	6238 (71%)
DG 2040 No restrictions	10 (0.4%)	115	63	3330 (38%)
DG 2040 1.2 Hz/s	599 (25%)	112	63	3934 (45%)
DG 2040 1 Hz/s	2351(59%)	108	63	5513 (63%)
GCA 2040 No restrictions	3426 (75%)	124	68	6972 (80%)
GCA 2040 1.2 Hz/s	4178 (92%)	121	71	8267 (94%)
GCA 2040 1 Hz/s	6229 (96%)	119	71	8516 (97%)

The results in the linked paper regarding emissions (~113 $kgCO_2$/MWh) were calculated by replacing the emission factor of the combined-cycle with the one that allows reaching Paris targets (through a weighted average of the generation and emissions of the other technologies). Regarding LCOE (~134 €/MWh), it was obtained averaging with the LCOE of the other technologies allowing obtain 102 €/MWh for the whole system (weighted average).

Hourly results for each scenario can be found at https://doi.org/10.7910/DVN/R2IVYN

2. Materials and Methods

The historical data were obtained from the Spanish Transmission system operator REE for mainland Spain and the Balearic Islands (the Canary Islands and the Autonomous Cities of Ceuta and Melilla are not included since they represent isolated grids). REE provides the real, planned and programmed demand, power generation for each technology and international interconnections, and the CO_2 emissions associated with each technology, all with a ten-minute resolution [15]. The historical hourly demand is obtained through an average of the ten-minute values, as well as the historical power output of VRE, hydro and interconnections. The code for the modelling was developed in Visual Basic for Applications (VBA). It is a ruled-based power model based on the merit order stack. After applying technical and inertia constraints considering the methodology described in the accompanying publication, future scenarios' demand and hourly generation were obtained.

Wind, solar photovoltaic, solar thermal, hydro (Impoundment and diversion hydropower plants) power generation were obtained through projections. International interconnections with France, Spain, Portugal, Andorra and Morocco, and the power with the Balearic Island was also projected. The power outputs of renewable thermal and other renewables (TR), cogeneration and non-renewable waste (CR), nuclear, coal, pumped hydro storage (PHS), and the combined-cycle were modelled considering the flexibility parameters. Hydro, renewable thermal and other renewables (TR) and cogeneration and non-renewable waste (CR) were obtained in a single time series as presented by REE. Projections and modelling were based on the installed capacities provided by the Ten-year Network Development Plan (TYNDP-2018) from ENTSOE [16].

The flexible combined-cycle power output depends on the critical inertia level (CIL) of the system, which in turn rely on the Rate of Change of Frequency (ROCOF) considered. A sensitivity analysis was carried out to determine the ROCOF where there are no curtailment and power grid failures. Finally, CO_2 emissions and the Levelized cost of electricity (LCOE) were obtained with the hourly power generation and literature parameters.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data Availability

Hourly results for the future power system in Spain (2030, 2040) (Original data) (Dataverse).

CRediT Author Statement

K. Guerra: Methodology, Investigation, Formal analysis, Data curation, Software, Writing – original draft; **P. Haro:** Conceptualization, Methodology, Supervision, Validation, Visualization, Writing – review & editing; **R.E. Gutiérrez:** Data curation, Visualization, Investigation; **A. Gómez-Barea:** Writing – review & editing.

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Supplementary Materials

Supplementary material associated with this article can be found in the online version at doi:10.1016/j.dib.2022.108095.

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