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The economic value of storage in renewable power systems - the case of thermal energy storage in concentrating solar plants☆

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Abstract

In this article we analyze the value of thermal energy storages in concentrating solar power plants depending on the electricity generation mix. To determine the value from a system integrated view we model the whole electricty generation market of the Iberian Peninsula. Key findings for thermal energy storage units in concentrating solar power plants include an increasing value in electricity systems with higher shares of fluctuating renewable generation and a potentially significant role in primarily renewable based electricity systems. Due to the relatively high investment costs concentrating solar power plants with or without thermal energy storages are not cost efficient in today's electricity markets. However, expected cost reductions due to learning curve effects and higher fluctuating renewable generation may lead to a comparative cost advantage of concentrating solar power plants with thermal energy storages compared to other renewable technologies.

Keywords: Fluctuating renewables, value of storage, concentrated solar power, power plant optimization

JEL classification: C61, Q40

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1. Introduction

As an attempt to fight global warming, many countries try to reduce CO_2 emissions from electricity generation by significantly increasing the share of renewables (RES-E). One major challenge in this transition

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is the balancing of fluctuating generation by wind or solar technologies and demand against the background of limited cost-efficient electricity storage options. One technology which might contribute significantly to solving these problems are concentrating solar power (CSP) plants equipped with thermal storage units (TES). In CSP plants, the sun's heat is absorbed by collectors and concentrated to heat a fluid which is then used to generate electricity in a steam turbine. Specific to CSP systems is the inherent option to integrate a TES capacity, used to generate electricity in hours with low or no solar radiation. Dependent on the CSP technology and the site characteristics, TES can even reduce the sites production costs per kilowatt-hour due to a higher usage of the capital intensive power plant block.

Today, demand in European electricity systems has a midday peak when solar radiation is also highest. Thus electricity prices are above average when CSP plants can directly feed into the grid. When stored thermal energy is used to generate electricity, such as during night hours, electricity is often produced in hours with comparatively low prices.[1] However, the structure of the hourly price curve depends on the specific characteristics of the electricity system. Particularly, a higher share of solar technologies could reverse the midday peak. Feed-in-tariffs may set, in today's electricity markets, an inefficient incentive to invest in thermal storage units for concentrating solar plants as tariffs do not take the hourly price curve into account.

In this paper, we try to quantify the value of thermal energy storages in CSP plants in today's electricity market and the impact of a higher share of fluctuating renewables. The value of electricity storage options has been analyzed in a number of papers as described in Xi et al. (2011). One of the most commonly approaches is the so called 'energy arbitrage', which essentially analyzes the option of charging storage when electricity prices are low and discharging when high (e.g. Graves et al. (1999); Sioshansi et al. (2009)). We use a simulation approach, calibrating the use of CSP to the electricity market of the Iberian Peninsula, instead of an econometric 'energy arbitrage' analysis for several reasons: First, empirical data of high RES-E electricity systems are not available yet. Secondly, the investment decision in TES is compared to all other investment options which contribute to meet demand cost-efficiently. Thirdly, the price curve within our electricity market model is endogenously determined and the influence of investments in generation or storage technologies is captured by the structure of the price curve.

[1]TES can also be used to shift generation to early evening hours when in some markets demand and thus prices are even higher than at midday. However, electricity prices are on average higher in hours with high sun radiation.

2. Related literature

A number of studies analyze the technical, geographical and economical feasibility of solar energy to supply a significant share of the electricity demand. This includes the assessment of the technical feasibility of balancing demand and generation in high-solar scenarios as well as the economic value of CSP and thermal energy storage technologies both from an investor's viewpoint and for the economy as a whole.

Sargent and Lundi (2003) and Pitz-Paal et al. (2005) describe the functional principle of different CSP technologies and thermal energy storage options and assess their future cost development. For example Sargent and Lundi (2003) expect significant cost reductions for parabolic trough and solar tower technologies in the mid-term, mainly due to a combination of technological innovation, plant scaling and increased production volumes. Fthenakis et al. (2009) investigate the technical, geographical and economical feasibility of solar energy and demonstrate that a significant percentage of electricity demand can be supplied by photocoltaic and CSP plants in the long-term.

The value of concentrating solar power and thermal energy storage from an investor's viewpoint has been examined by Sioshansi and Denholm (2010) and Laing et al. (2010). Sioshansi and Denholm (2010) show that the addition of thermal energy storages increases the value of CSP plants both by allowing CSP generation to be shifted to hours with higher energy prices and by increasing the usage of thermal energy from a CSP plant's solar field. However, despite these benefits, their results suggest that at current investment costs, thermal energy storages cannot be economically justified on energy value alone: only if the value of ancillary service sales and capacity are included, thermal energy storages become cost-effective in a number of cases. The value of concrete thermal energy storage options for parabolic trough power plants has been assessed by Laing et al. (2010), taking into account the additional cost of integrating the thermal storage into the power plant.

In contrast to Sioshansi and Denholm (2010) and Laing et al. (2010), who focus on the value of CSP systems from an investor's viewpoint, Poullikkas et al. (2010) investigate the economic costs of integrating parabolic trough CSP plants in isolated Mediterranean power systems using the example of Cyprus. By comparing scenarios that differ with respect to new investments in CSP plants (with and without thermal storage) and natural gas-fired power plants, the study comes to the conclusion that CSP plants with storage units are the most cost-effective investment option. However, since no other generation options are considered, the results are based on the specific scenario assumptions. Moreover, the results may not be valid for other power systems, as Cyprus misses for example other storage units such as large pump-storage plants.

3. Approach and model description

3.1. Scenario analysis

To analyze the value of thermal energy storage units in CSP plants, we simulate two scenarios with a dynamic linear investment and dispatch model to determine the cost-minimal electricity mix for the Iberian Peninsula until 2050. The analysis is conducted for the Iberian Peninsula for several reasons: First, Spain and Portugal are countries with an annually high solar radiation and secondly Spain has worldwide the highest installed capacity of CSP plants - a significant number of plants recently commissioned or under construction include thermal storage units (NREL, 2011). Finally, Spain has a feed-in-tariff-system for the promotion of renewable energies.

In the 'illustrative scenario', we analyze the value of thermal energy storage units in CSP plants in today's electricity market and the impact of a higher intermittent RES-E generation. CSP plants with TES may have higher cost reductions than CSP plants without thermal storage units due to learning curve effects in regards to the storage unit. The purpose of the 'illustrative scenario' is to separately analyze the effect of an increasing share of intermittent RES-E generation on the value of TES. Thus today's electricity system in the Iberian Peninsula is carried forward until 2050, assuming today's investment costs, electricity demand as well as fuel and CO_2 prices. In order to analyze the effects of an increasing share of CSP and other fluctuating RES-E generation the following RES-E and CSP quotas are incorporated (Table 1).

Table 1: Framework of the 'illustrative scenario'

	2020	2030	2040	2050
RES-E quota	$\geq 30\,\%$	$\geq 40\,\%$	$\geq 60\,\%$	$\geq 80\,\%$
CSP quota	$\geq 3.5\,\%$	$\geq 10\,\%$	$\geq 17.5\,\%$	$\geq 25\,\%$

The role of CSP plants with and without thermal storage units in a possible transformation process to a primarily renewable based electricity system is analyzed in the 'high RES-E scenario'. In contrast to the 'illustrative scenario', only a RES-E and no CSP quota is modeled for the Iberian Peninsula (Table 2). Moreover, an increasing electricity demand is assumed and possible investment cost reductions of RES-E due to learning curve effects are taken into consideration. This scenario thus incorporates two effects potentially favoring CSP plants with storage units in the long-term: An increasing share of intermittent RES-E generation and a decreasing cost-difference between CSP plants with and without storages.

Table 2: Framework of the 'high RES-E scenario'

	2020	2030	2040	2050
RES-E quota	$\geq 30\,\%$	$\geq 40\,\%$	$\geq 60\,\%$	$\geq 80\,\%$
Demand	377.3 TWh	432.2 TWh	493.3 TWh	560.8 TWh

It should be noted that the scenario setting chosen is only one possible option for the Iberian Peninsula's electricity system and that it is neither a forecast nor the most likely outcome. We focus on the role of thermal storage units in CSP plants used to balance the fluctuating generation of solar and wind technologies.

3.2. Electricity market model

To analyze the value of storage units in CSP plants, we use a dynamic linear investment and dispatch model to determine the cost-minimal electricity mix for the Iberian Peninsula until 2050.[2] The objective of the model is to minimze total system costs, which include investment costs, fixed operation and maintenance costs, variable production costs and costs due to ramping thermal power plants. The model includes possible investments in nuclear, conventional, carbon capture and storage (CCS), storage and renewable technologies. We model several CSP plants with and without thermal storage units in order to determine the value of storage capacities in CSP plants.

Investment decisions are based on the dispatch requirements which are incorporated by modeling the dispatch for three days (Saturday, Sunday and a weekday) per season on a hourly basis (scaled to 8760 hours). Three days per season are used to account for the different demand structures on weekends and weekdays. Typical feed-in structures for each season for wind and solar technologies are modeled, including days with both very low windpower and high-wind days. In addition, we model several wind regions within the countries to account for different wind speeds.

3.2.1. Key model elements

The objective of the model is to minimize the total system costs ($TCOST$), which are defined by investment and fixed operational and maintenance costs (FC), variable production costs which comprise of fuel and CO_2 prices (VC) for all technologies (a), countries (c) and years (y) and costs due to ramping thermal power plants ($VCRTO$). Total costs are reduced by the remunerations combined heat and power plants (CHP) can earn on the heating market (HB). All costs and earnings are inflation-adjusted and

[2]The model used in this analysis is an extended version of the long-term investment and dispatch model for conventional, storage and transmission technologies of the Institute of Energy Economics (University of Cologne) presented in Richter (2011). The model is based on several electricity market optimization models; mainly the model developed by Bartels (2009).

discounted with a 5 % rate (dsc).[3]

$$minimize\ TCOST = \sum_{y,c,a} \left[dsc(y) \cdot (FC(y,c,a) + VC(y,c,a) + VCRTO(y,c,a) - HB(y,c,a)) \right] \tag{1}$$

Investment costs occur for new investments in generation units and are annualized including a 5 % interest rate for the depreciation time ($annuity$). The fixed operation and maintenance costs (fom) represent staff costs, insurance charges, rates and fixed maintenance costs.

$$FC(y,c,a) = CAPADD(y,c,a) \cdot annuity(a) + INSTCAP(y,c,a) \cdot fomc(a) \tag{2}$$

The variable generation costs (VC and $VCRTO$) depend on the cost-minimizing dispatch. Equation 3 shows the determination of VC by fuel prices ($fuelpr$), CO_2 price ($copr$), CO_2 emission-factor ($emissionfac$), net efficiency (η) and the generation of all technologies (GEN).

$$VC(y,c,a) = \sum_{d,h} GEN(y,c,a,d,h) \cdot \left[\frac{fuelpr(y,a) + copr(y) \cdot emissionfac(a)}{\eta(a)} \right] \tag{3}$$

Modeling ramp-up restrictions and ramping costs of thermal power plants is difficult in linear optimization models. To fully account for technical restrictions a mixed-integer optimization is needed. However, a mixed-integer optimization strongly increases computational time and is thus difficult to implement in models with very detailed technological, regional and/or hourly resolutions. We simulate ramp-up costs by referring to the power plant blocks and by setting a minimal load restriction. Depending on the minimum load and start-up time of thermal power plants, additional costs for ramping occur (attrition ($attc$) and extra fuel costs).

$$VCRTO(y,c,a) = \sum_{d,h} CAPUP(y,c,a,d,h) \cdot \left[\frac{fuelpr(y,a) + copr(y) \cdot emissionfac(a)}{\eta(a)} + attc(a) \right] \tag{4}$$

The remunerations of CHP plants in the heating market (HB) are determined by the price on the heat market ($heatpr$), the heat-to-power-ratio of CHP plants and the generation of CHP plants. Heat in co-generation can be produced by gas, coal and lignite plants (with or without carbon capture) as well as by biomass and geothermal units. However, only a limited amount of generation in CHP plants receives a reward on the heating market accounting for a maximum potential for heat in co-generation within each country. The inflexibility of CHP power plants is represented by longer ramp-up-times.

$$HB(y,c,a) = \sum_{d,h} heatpr(y) \cdot heatratio(a) \cdot GEN(y,c,a,d,h) \tag{5}$$

[3]The description of all model parameters and variables can be found in the Appendix A.

Apart from the basic cost equations the model incorporates all common elements of linear dispatch models such as storage equations, net transfer possibilities and restrictions due to local resource availabilities (e.g. lignite) or due to political decisions (e.g. ban of nuclear power). The availability of conventional, nuclear, dispatchable renewable energies and storage capacities is reduced by potential breakdowns and maintenance times.

3.2.2. Modeling renewable energies and CSP-plants

The model includes the following renewable energy technologies: roof and ground photovoltaic systems (PV), wind (onshore and offshore), biomass (solid and gas), biomass CHP (solid and gas), geothermal, hydro (storage and run-of-river) and CSP technologies. Biomass, geothermal and hydro technologies are modeled as dispatchable renewables. The availability ($avail$) of fluctuating renewable energies (wind and solar technologies) highly depends on weather conditions. The availability parameter represents the (maximum possible) feed-in of wind and solar sites within each hour. This approach allows the possibility of wind and solar curtailment when needed to meet demand or when total system costs can be reduced due to lower ramping costs of thermal power plants.[4]

$$GEN(y, c, a, d, h) \leq avail(c, a, d, h) \cdot INSTCAP(y, c, a) \tag{6}$$

For wind and solar technologies, an available space potential in km^2 per region is assumed. Biomass fuels are restricted to a certain potential in MWh_{th} (Section 4). The generation of renewable energies needs to exceed the quota of the net electricity demand.

$$\sum_{res,d,h} GEN(c, res, d, h) \geq quota(c) \cdot \left[\sum_{d,h} demand(c, d, h) \right] \tag{7}$$

In concentrating solar plants the heat of the sun is absorbed by collectors and concentrated to heat a fluid which is then used to generate electricity in a steam turbine. The heat can be saved in a storage unit and the electricity generation can take place later. The maximum storage level is determined by the volume factor ($volfac$) which is the ratio of storage to turbine capacity.

$$STO(y, c, a, d, h) \leq volfac(a) \cdot INSTCAP(y, c, a) \tag{8}$$

Equation 9 shows the power balance of the CSP system in each hour h. The injection variable (INJ) represents the solar energy which is absorbed by the collectors. It is modeled as a variable with the restriction

[4] Wind sites are usually larger than solar sites and therefore transaction costs for solar curtailment are assumed to be higher than for wind sites. We use negligible small variable costs for offshore wind and even smaller ones for onshore wind sites. Therefore the model chooses offshore wind curtailment first.

to be lower than the absorbed heat of the sun in this specific hour (*sunpower*) which is determined by the size of the collector field and the efficiency for the absorption. CSP plants with storage units are able to shift the energy (SIN) of the absorbed sun to hours with less or no solar radiation ($SOUT$). Losses in storage processes occur due to energy consumption in pumps during charging (η_{sin}) and discharging processes (η_{sout}), efficiency losses in heat exchangers and losses of stored energy over time. Efficiency losses over time for stored energy in the TES are negligible (Sioshansi and Denholm, 2010) and therefore not incorporated in the model.

$$INJ(y,c,a,d,h) + SOUT(y,c,a,d,h) \cdot \eta_{sout}(a) - GEN(y,c,a,d,h)/\eta_{tur}(a) - SIN(y,c,a,d,h) = 0 \quad (9)$$

Equation 10 shows the change of storage level ($SLEVEL$) from hour h to hour $h+1$. The change of storage level depends on the storage operation in the specific hour considering losses during the charging process (η_{sin}).[5]

$$SLEVEL(y,c,a,d,h+1) - SLEVEL(y,c,a,d,h) = SIN(y,d,h,b,a) \cdot \eta_{sin}(a) - SOUT(y,c,a,d,h) \quad (10)$$

As we focus on the renewable energy generation of CSP plants in this analysis, the option of co-firing of natural gas is not included in the model. Natural gas co-firing is another option to achieve a higher utilization rate of the capital intensive power plant block and to increase the capacity factor of the plant. Hence, co-firing with natural gas is in most cases an option to increase the economic value of CSP plants.

4. Assumptions

In this section, the assumptions concerning the development of electricity demand and potential heat generation in CHP plants, the economic-technical parameters of conventional, storage and renewable technologies and the political targets are described. The analyzed concentrating solar power plants are explained in detail.

4.1. Electricity demand and potential heat generation in CHP plants

The development of the electricity demand depends on social, economical and technological factors. This includes the population and economic growth and the technological development. Within the next decades a significant increase of the population and a strong development of the economy is predicted for Spain and Portugal (Capros et al., 2010). Moreover, the introduction of new technologies as well as the greater

[5] The storage level is set to 10 percent at the beginning of each model year which has to be reached in the last modeled hour again.

usage of electricicty in the transportation sector are expected to lead to a higher overall electricity demand. Therefore, we assume a strong increase in electricity consumption of 1.9 % per year until 2020, followed by an increase of about 1.4 % per year until 2050. Table 3 shows the assumed electricity demand in Spain and Portugal until 2050.

Table 3: Net electricity demand in TWh

	2010	2020	2030	2040	2050
Spain	265.9	298.6	344.9	396.3	453.2
Portugal	50.6	55.9	64.5	74.1	84.8

Based on the assumptions regarding the development of the population and the economy, the heat generation by CHP plants is assumed to increase as well. The slight decrease in demand for district heating due to energy efficiency improvements is assumed to be compensated by an increase in process heat demand. Table 4 shows the assumed heat generation by CHP plants for Spain and Portugal.

Table 4: Potential heat generation in CHP plants in TWh

	2010	2020	2030	2040	2050
Spain	57.9	59.0	59.9	60.7	61.5
Portugal	13.6	13.9	14.0	14.3	14.5

The generated heat is remunerated by the assumed gas price considering an efficiency factor for the heating system which roughly represents the opportunity costs for households and industries.

4.2. Conventional and storage technologies

Assumptions about investment costs and techno-economical characteristics of conventional power plants and storage technologies are based on IEA (2010a) and Schlesinger et al. (2010).

The investment costs for already existing conventional power plants and storage technologies are assumed to be the same as today but learning effects lead to lower investment costs for new technologies. These learning costs may materialize through the deployment of improved materials and process techniques: future hard coal plants ('hard coal innovative') will for example be able to run at 700 degrees celsius and higher pressures (350 bars). Due to these improvements, the efficiency is assumed to increase by 4 % points to 50 %. Investment costs are above today's standard technologies but are assumed to decrease due to learning effects by about 1/3 until 2050. Future lignite technologies ('lignite innovative') use a more efficient drying process and can therefore increase their efficiency to 48 %. Investment costs are just above today's newest technologies. CCS Technologies are assumed to be commercially available and applicable to hard coal, lignite and combined-cycle gas power plants starting from 2030.

As can be seen in Table 5, standard and innovative technologies can be fitted with CCS and/or CHP technology. The investment costs of CCS technologies decrease until 2050. The investment costs of CHP plants also include additional costs for the grid and the extraction of heat. Due to limited space, pump storage and hydro storage plants are not an investment option. Compressed air energy storage (CAES) technologies have investment costs of 850 €$_{2010}$ per kW.

Table 5: Investment costs of conventional and storage technologies in €$_{2010}$/kW

Technologies	2010	2020	2030	2040	2050
Hard Coal	1,500	1,500	1,500	1,500	1,500
Hard Coal - innovative	2,500	2,250	1,875	1,750	1,650
Hard Coal - CCS	-	-	2,000	1,900	1,850
Hard Coal - innovative CCS	-	-	2,475	2,300	2,200
Hard Coal - innovative CHP	2,650	2,650	2,275	2,150	2,050
Hard Coal - innovative CHP and CCS	-	-	2,875	2,700	2,600
Lignite	1,850	1,850	1,850	1,850	1,850
Lignite - innovative	1,950	1,950	1,950	1,950	1,950
Lignite - CCS	-	-	2,550	2,500	2,450
OCGT	700	700	700	700	700
CCGT	1,250	1,250	1,250	1,250	1,250
CCGT - CCS	-	-	1,550	1,500	1,450
CCGT - CHP	1,500	1,500	1,500	1,500	1,500
CCGT - CHP and CCS	-	-	1,700	1,650	1,600
Pump storage	-	-	-	-	-
Hydro storage	-	-	-	-	-
CAES	850	850	850	850	850

Table 6 shows the efficiency grades, CO_2 emission factors, technical availability, operational and maintenance costs and the technical lifetime for nuclear, thermal energy and storage plants. Efficiency grades are based on the specifications of power plants in construction. For 'innovative' technologies, higher efficiencies are assumed due to the described technical developments. The generation efficiency of plants with CCS are assumed to be lower. Moreover, higher operational and maintenance costs occur due to the additional costs for the pipe and the storage system. Combined heat and power generation units have lower electrical but higher total efficiency grades. Operational and maintenance costs also include the costs for the heat extraction system.

Table 6: Economic-technical parameters for conventional and storage technologies

Technologies	η_{gen} [%]	η_{load} [%]	CO_2 factor [t CO_2 /MWh_{th}]	avail [%]	FOM-costs [€$_{2010}/kW$]	Lifetime [a]
Nuclear	33.0	-	0.000	84.50	96.6	60
Hard Coal	46.0	-	0.335	83.75	36.1	45
Hard Coal - innovative	50.0	-	0.335	83.75	36.1	45
Hard Coal - CCS	42.0	-	0.034	83.75	97.0	45
Hard Coal - innovative CCS	45.0	-	0.034	83.75	97.0	45
Hard Coal - innovative CHP	22.5	-	0.335	83.75	55.1	45
Hard Coal - innovative CHP and CCS	18.5	-	0.050	83.75	110.0	45
Lignite	43.0	-	0.406	86.25	43.1	45
Lignite - innovative	46.5	-	0.406	86.25	43.1	45
Lignite - CCS	43.0	-	0.041	86.25	103.0	45
OCGT	40.0	-	0.201	84.50	17.0	25
CCGT	60.0	-	0.201	84.50	28.2	30
CCGT - CCS	53.0	-	0.020	84.50	40.0	30
CCGT - CHP	36.0	-	0.201	84.50	88.2	30
CCGT - CHP and CCS	36.0	-	0.030	84.50	100.0	30
Pump storage	87.0	83.0	0.0	95.00	11.5	100
Hydro storage	87.0	-	0.0	95.00	11.5	100
CAES	86.0	82.0	0.0	95.00	9.2	40

4.3. CSP plants and other renewable technologies

CSP plants are determined by three independent components. The size of the collector's field determines the energy which is absorbed by the sun. Thermal energy storage units give the opportunity to shift energy to later hours. The turbine size determines the maximum electricity that can be generated. In this analysis three CSP plants (Table 7) are modeled based on Sioshansi and Denholm (2010). As we use a linear model the technologies are defined by 1 MW capacity units. As explained in Section 3.2, the option of co-firing is not considered in this analysis. Therefore, the three CSP systems are designed to generate electricity from solar energy only.

Table 7: Modeled CSP technologies

	Collector surface [m^2]	Storage volume [MWh_{th}]	η_{field}[%]	$\eta_{turbine}$[%]	$\eta_{load/unload}$[%]	Multiple
CSP A	7,376	0	42.0	37.7	-	1.3
CSP B	11,384	20 (7.5 h)	42.0	37.7	96.0/97.0	2.0
CSP C	15,887	40 (15.0 h)	42.0	37.7	96.0/97.0	2.8

The modeled CSP technologies differ with respect to storage volume and size of collector surface. CSP A has a collector surface of 7,376 m^2 and no storage capacity. Thus the thermal energy has to be used to generate electricity at the time it is absorbed by the sun. CSP B represents plants with an average solar field of 11,384 m^2 and an average storage unit of 20 MWh and CSP C has a large solar field of 15,887 m^2 and a storage unit of 40 MWh. All three CSP technologies have a common solar collector and turbine efficiency of 42 % respectively 37.7 %, but a different solar multiple, which indicates the extent to which the solar field is over-sized in relation to the turbine capacity.[6]

Table 8 gives an overview of the modeled renewable energy technologies and their assumed specific investment costs over time (based on IEA (2010c), Arens et al. (2010) and EWI (2010)). Besides CSP, the model includes the renewable energy technlogies photovoltaics (base and roof), wind onshore, wind offshore (deep and shallow water), biomass (solid and gas), hydro (run-of-river and storage) and geothermal power. Investment costs are assumed to decrease over time due to learning effects. This applies especially to photovoltaics and offshore wind. To account for technological process apart from cost reductions, we model 6 MW onshore (5 MW offshore) wind turbines until 2025 and 8 MW onshore (8 MW offshore) turbines starting from 2030. Todays onshore wind sites are assumed to be 3 MW turbines on average.

Since the annual generation and feed-in structure of wind and solar technologies depends on local weather conditions, it generally differs between various regions of a country. To account for these differences, the Iberian Peninsula is divided in five solar and five wind regions.[7]

Table 8: Investment costs for renewable technologies in €$_{2010}$/kW

	2010	2020	2030	2040	2050
CSP A	3,722	2,220	1,700	1,400	1,290
CSP B	6,794	3,437	2,300	2,100	1,963
CSP C	10,082	5,500	3,800	3,100	2,693
Photovoltaics base	3,000	1,796	1,394	1,261	1,199
Photovoltaics roof	3,500	2,096	1,627	1,471	1,399
Wind onshore 6 MW	1,350	1,221	-	-	-
Wind onshore 8 MW	-	-	1,161	1,104	1,103
Wind offshore 5 MW (shallow)	3,200	2,615	-	-	-
Wind offshore 8 MW (shallow)	-	-	2,512	2,390	2,387
Wind offshore 5 MW (deep)	3,800	3,105	-	-	-
Wind offshore 8 MW (deep)	-	-	2,956	2,811	2,808
Biomass gas	2,400	2,398	2,395	2,393	2,390
Biomass gas - CHP	2,600	2,597	2,595	2,592	2,590
Biomass solid	3,300	3,297	3,293	3,290	3,287
Biomass solid - CHP	3,500	3,497	3,493	3,490	3,486
Hydro (run-of-river)	4,500	4,500	4,500	4,500	4,500
Geothermal power	15,000	10,504	9,500	9,035	9,026

[6] The solar multiple is defined as the ratio of the actual size of a CSP plant's solar field compared to the field size needed to feed the turbine at design capacity at reference solar irradiance of about 1kW/m^2 (IEA, 2010b).

[7] The regions are based on specific wind and solar data from Sperling and Hänsch (2009). The wind and solar regions are not identical.

4.4. Fuel prices

Table 9 shows the fuel prices assumed for thermal power plants in the scenarios. The fuel prices are based on international market prices and transportation costs to the power plants. The coal price is assumed to increase from 11.90 $€_{2010}/MWh_{th}$ in 2010 to 17.60 $€_{2010}/MWh_{th}$ in 2050. For domestic lignite a constant price of 1.40 $€_{2010}/MWh_{th}$ is assumed. Despite the current excess supply and low prices of natural gas we assume a significant increase up to 28.00 $€_{2010}/MWh_{th}$ in the long term. As the model includes several biomass technologies, only a range for the price of biomass solid and gas is given in Table 9. The price for biomass solid is assumed to increase up to 18.80-37.50 $€_{2010}/MWh_{th}$ and biomass gas up to 0-85.10 $€_{2010}/MWh_{th}$. The price of CO_2 emissions is assumed to increase from 14.00 $€_{2010}$/tCO_2 in 2010 to 40.00 $€_{2010}$/tCO_2 in 2050.

Table 9: Fuel prices in $€_{2010}$/MWh$_{th}$ and CO_2 price [$€_{2010}$/tCO_2]

	2010	2020	2030	2040	2050
Nuclear	3.40	3.30	3.30	3.30	3.30
Coal	11.90	13.10	13.60	15.10	17.60
Lignite	1.40	1.40	1.40	1.40	1.40
Natural Gas	16.90	20.90	22.90	25.60	28.00
Biomass (solid)	5.00-27.70	5.00-27.70	15.70-34.90	16.70-35.10	18.80-37.50
Biomass (gas)	0-70.00	0-67.20	0-72.90	0-78.80	0-85.10
CO_2 price [$€_{2010}$/tCO_2]	14.00	20.00	25.00	30.00	40.00

4.5. Political assumptions

Political plans for Spain and Portugal include the transformation to a primarily renewable based and low carbon electricity system starting from 2050. In the scenarios 80 % of the electricity generation must come from renewable energies in 2050. The 'illustrative scenario' additionally assumes a CSP quota to analyze the effects of a high share of CSP generation on the value of thermal energy storage.[8]

Table 10: RES-E and CSP generation quotas [%]

	2010	2020	2030	2040	2050
RES-E quota [%]	-	40.0	50.0	60.0	80.0
CSP quota [%]	-	2.5	7.5	15.0	25.0

[8] The electricity generation from CSP plants can contribute to the RES-E generation quota.

5. ‘Illustrative scenario’: The value of thermal storage units in CSP plants

In the ‘illustrative scenario’, we analyze the value of thermal storage units in CSP plants depending on the share of fluctuating RES-E generation. In the future, CSP plants with thermal storage units might have a comparative advantage compared to CSP plants with no storage capacity for two reasons: first, due to learning curve effects of storage technologies, the cost difference between CSP plants with and without storage capacities is likely to decrease; and secondly, the value of thermal storage capacities is likely to increase with a higher share of fluctuating RES-E generation. For the exclusive illustration of the later effect, i.e. the development of the value of thermal storage units as a function of the share of fluctuating RES-E generation, today’s environment (e.g. demand or investment costs) is carried forward. This includes the costs of CSP plants and hence the cost differences between CSP plants with and without storage capacities are kept constant at current levels. Only the share of RES-E and CSP in particular are assumed to significantly increase over time, by modeling both a rising RES-E (80 % in 2050) and CSP generation quota (25 % in 2050).

5.1. Overview of the generation system

An overview of the cost-efficient capacities and gross electricity generation in the ’illustrative scenario’ for the Iberian Peninsula until 2050 is given in Figure 1. Against the background of the implied transformation to a renewable based electricity system, the total capacity increases until 2050. In this scenario, nuclear is not an investment option and the combination of fuel and CO_2 prices favours gas generation. Thus the conventional generation system is dominated by gas capacities - some equipped with CHP.[9] To reach the RES-E and CSP generation quota, mainly CSP plants and wind onshore sites are built. Existing photovoltaic capacities are not rebuilt after their technical lifetime ends.

[9] The data for 2000/2008 is based on EUROSTAT (2010). CHP capacities and generation is included in gas and coal capacities in 2000 and 2008.

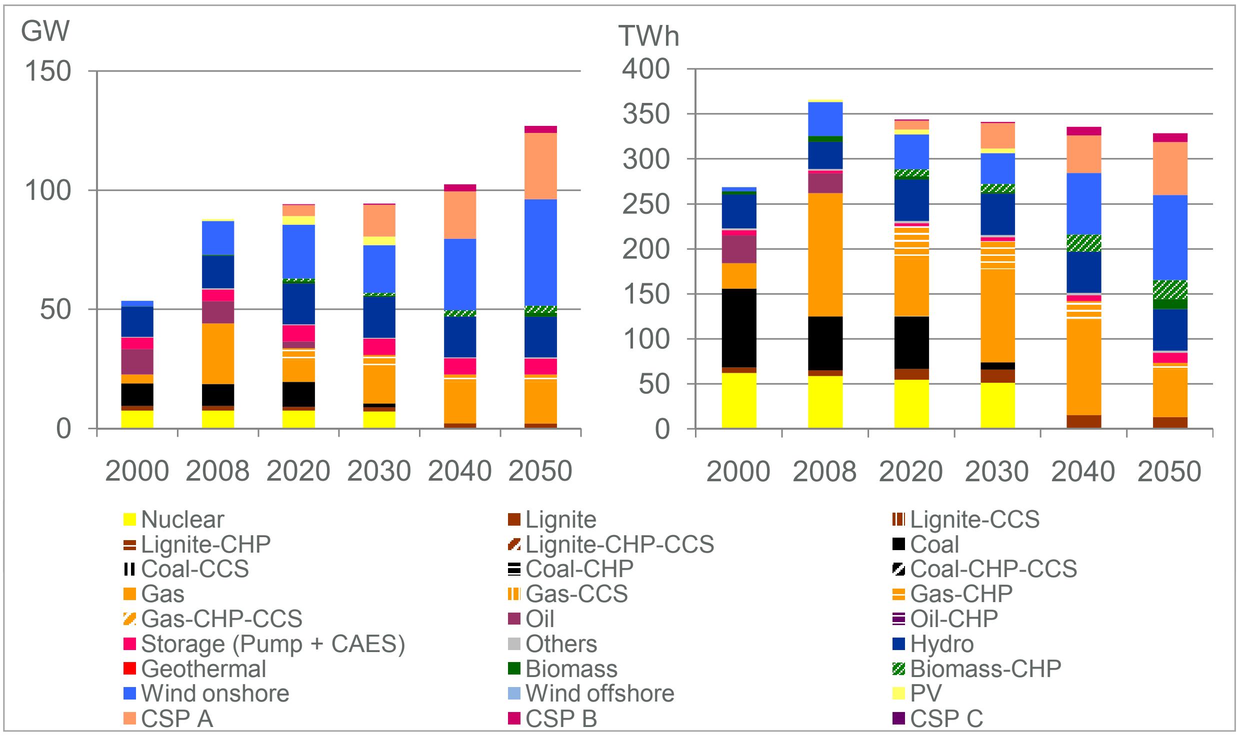

Figure 1: Capacities [GW] and generation [TWh] in the 'illustrative scenario' (2000/2008 based on EUROSTAT (2010))

In the short-term, the electricity generation is similar to today's electricity mix. Base load generation takes place in nuclear, lingite and coal capacities. After 2030, the conventional generation occurs mainly in gas-fired power plants and lignite capacities. The renewable generation is provided by CSP plants, onshore wind turbines, biomass and hydro plants. Also, the generation in pump storages increases in the long term. In sum, gross electricity generation decreases over time (despite the constant demand) due to the transformation to a renewable based system. RES-E technologies apart from biomass capacities have no own electricity consumption.

CSP plants are built in order to fullfill the increasing generation quota over time.[10] In the short term only CSP plants with no storage capacities (CSP A) are constructed. CSP plants with small storage capacities (CSP B) with the ability to shift generation to later hours are cost efficient when the penetration of fluctuating RES-E generation exceeds a certain limit. In this scenario, about 10 % of the CSP plants are equipped with small storage capacities when the RES-E share reaches 80 % and when CSP generation makes up 25 % of total generation. The installed capacities of CSP plants are shown in Table 11.

[10]The CSP generation quota is binding in all years.

Table 11: Installed capacities of CSP technologies in GW

	2010	2015	2020	2025	2030	2035	2040	2045	2050
CSP A	0.5	3.1	4.6	10.6	14.4	18.7	21.1	24.8	32.3
CSP B	0.4	0.4	0.4	0.4	0.4	0.0	3.4	3.4	3.4
CSP C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

5.2. The value of thermal storage units in CSP plants

The model results are based on the favorable feed-in structures of solar technologies in order to meet electricity demand. CSP plants and photovoltaics generate electricity when demand is usually high. Hence, at a low penetration of fluctuation RES-E, there is no benefit from having additional storage capacities and being able to shift electricity generation to later hours. Therefore thermal storage units in CSP plants are not cost-efficient in electricity systems in the short-term. Figure 2 shows the feed-in structures of fluctuating generation technologies (wind, solar photovoltaic and CSP plants), the model demand, and the marginal of the power balance for the example of the Spanish electricity market.[11]

The marginal on the power balance can be interpreted as the value of generation in a specific hour. In general, high generation by technologies with negligible variable generation costs such as wind or solar technologies lead to a lower marginal of the power balance. As can be seen in Figure 2, the marginal of the power balance is primarily influenced by the height of the model demand. Fluctuating renewables play a minor role in the short-term because generation of wind turbines, photovoltaics or CSP plants is relatively low compared to the demand.

[11] The equilibrium condition 'power balance' assures the balance of electricity generation and demand in each hour. The marginal of the power balance represents the partial derivative considering the total system costs.

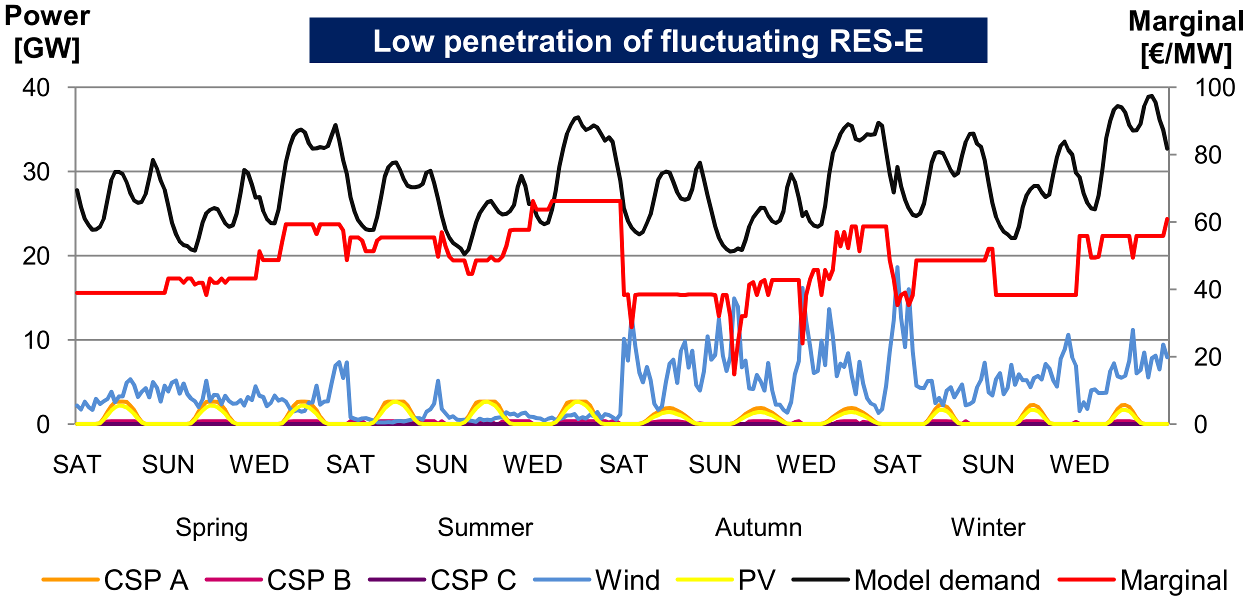

Figure 2: Low fluctuating RES-E penetration

Figure 3 shows the development of renewable generation and the marginal in an electricity system with a medium penetration of fluctuating RES-E. The increasing generation of fluctuating renewable technologies leads to a more volatile marginal. As can be seen, additional CSP capacities (CSP A) with a relatively high generation at midday cause relatively low marginals on the power balance in these specific hours.

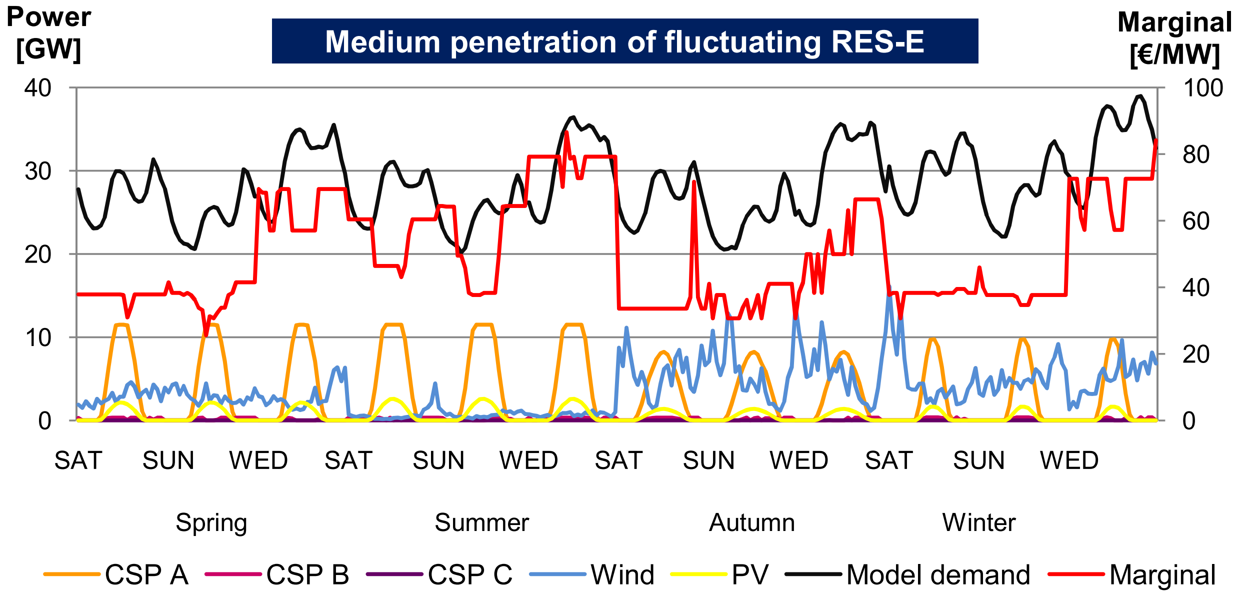

Figure 3: Medium fluctuating RES-E penetration

The influence of CSP generation on the marginal increases significantly due to the concentrated generation at midday in this scenario. Around midday when generation by solar technologies is high, the marginal on the power balance - especially in the summer - is starting to be even lower than at night. The structure of the marginal is almost reverse compared to today (especially in the summer): lower marginals when electricity demand is high around midday and higher marginals when electricity demand is low by night.

Figure 4 shows the value of CSP storage units in a high fluctuating RES-E scenario. A high share of fluctuating RES-E capacities - especially solar - leads to a low value of additional generation around midday. Therefore the value of storage options in CSP plants increases. This leads to investments in CSP plants with small storage capacities (CSP B) in order to shift generation to later hours. The CSP plants with storage units are able to balance the generation from fluctuating wind and CSP plants without storage units (CSP A) and the demand.

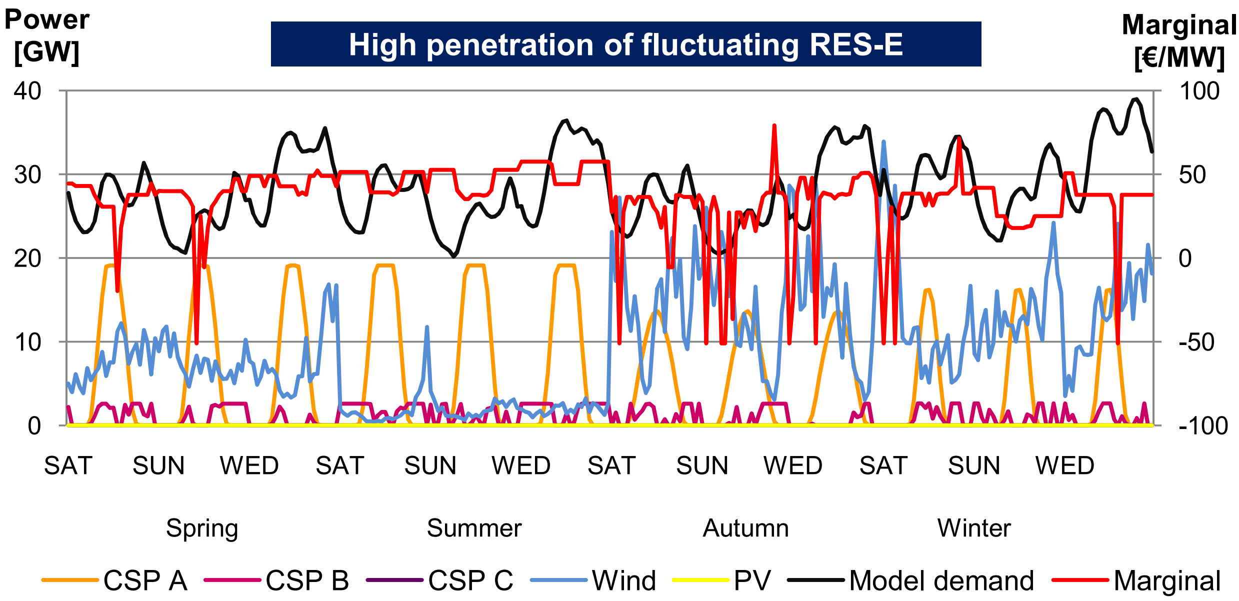

Figure 4: High fluctuating RES-E penetration

From the results of the 'illustrative scenario', we draw the following conclusions: first, investments in CSP plants with storage units in today's electricity systems of Spain and Portugal are not cost-efficient from a system integrated viewpoint. The growing investments in CSP plants with storage units in the Spanish market result from the specific design of the Spanish RES-E promotion system and do not reflect investment signals of the competitive electricity market, which would favor CSP plants without storage units. Second, we come to the conclusion that the value of storage units in CSP plants increases when the share of electricity generation by CSP plants without storage units and other intermittent RES-E increases. However, the share of intermittent RES-E has to reach a substantial magnitude and cause an almost reverse structure of the marginal on the power balance compared to today, until CSP plants with storage units become cost efficient.

6. 'High RES-E scenario': The role of CSP plants in a high RES-E scenario for the Iberian Peninsula

In this scenario, we analyze the role of CSP plants and thermal storage units in a possible transformation to a low-carbon and mainly renewable based electricity system of the Iberian Peninsula. As described in the Section 3, at least 80 percent of the electricity consumption has to be generated by renewable capacities starting from 2050 (40 % in 2020). In contrast to the 'illustrative' scenario, no lower limit for the generation of CSP plants is modeled. The model results are based on the assumptions described in Section 4. Other assumptions (e.g. other fuel prices) may lead to a different cost-minimal electricity mix.

6.1. Capacities and generation mix

The implied transformation of the electricity system results in a large extension of RES-E capacities until 2050. The generation of fluctuating RES-E depends on weather conditions and therefore the maximum yearly generation per unit is lower compared to conventional power plants. Due to this effect the sum of capacities increases significantly. The demand in 2050 is twice as high as in 2000 but generation capacities triple until 2050. Figure 5 shows the installed capacities and generation in this scenario.[12]

To achieve the implied RES-E generation quota mainly wind onshore sites are expanded (retrofit options are taken as well) and biomass capacities are used in the short term. Starting in 2020 CSP technologies with small storage capacties (CSP B) are constructed. Due to the scenario assumptions, the model chooses CSP systems over photovoltaics. In the long term larger CSP plants with 15 hours of storage capacity (CSP C) have a comparative cost advantage compared to smaller CSP plants. Additionally, the value of thermal storage units in CSP plants increases in higher RES-E scenarios as shown in the 'illustrative scenario'.

The assumptions concerning the conventional generation technologies, fuel prices and flexibility requirement of the power plant mix lead to a gas-dominated conventional generation system. Lignite and hard coal capacities (often equipped with CHP technology) replace nuclear capacities as base load generation.

[12]The power balances for Spain and Portugal are shown in Appendix B.

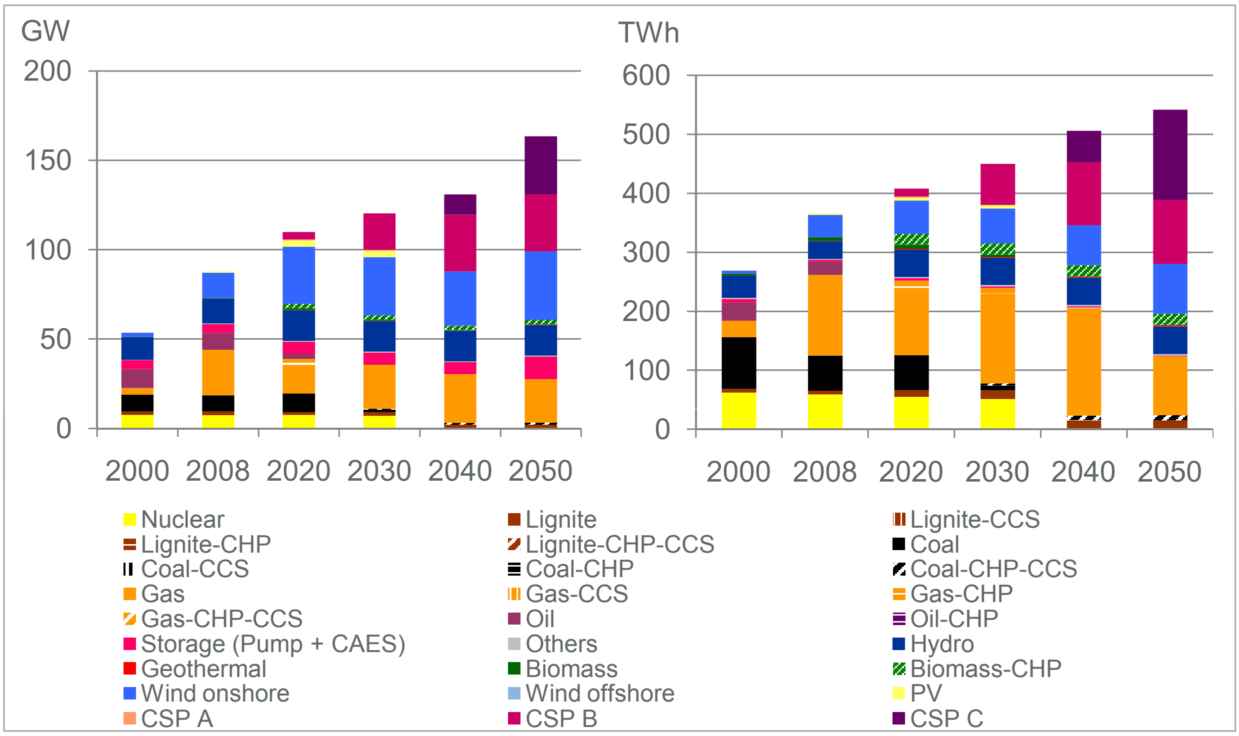

Figure 5: Capacities [GW] and generation by fuels [TWh] (2000/2008 based on EUROSTAT (2010))

6.2. The usage of storage units in high RES-E scenarios

A higher generation by fluctuating RES-E technologies leads to a more volatile residual electricity demand. This requires a higher share of flexible conventional generation such as combined cycle or open cycle gas turbines to balance generation and demand. The costs of ramping thermal power plants rises with high generation by fluctuating RES-E capacities.

Figure 6 shows the model demand (black line), the model demand after subtracting the generation by fluctuating RES-E (blue line), the model demand after subtracting the generation by fluctuating RES-E and storage operations (yellow line) as well as the final residual demand (green line), which has to be met by thermal power plants for the Iberian Peninsula in 2020. The system is characterized by 10 % electricity generation by fluctuating RES-E and large hydro capacities (hydro and pump storage). Due to the large storage capacities, the residual demand is relatively constant compared to the model demand. As a result, quick changes of the generation of thermal power plants is rarely needed. However, a high generation by wind technologies in autumn leads to a more volatile residual demand, the usage of storage capacities in pump operation (yellow line is above the green line in Figure 6) and costs for ramping thermal power plants.

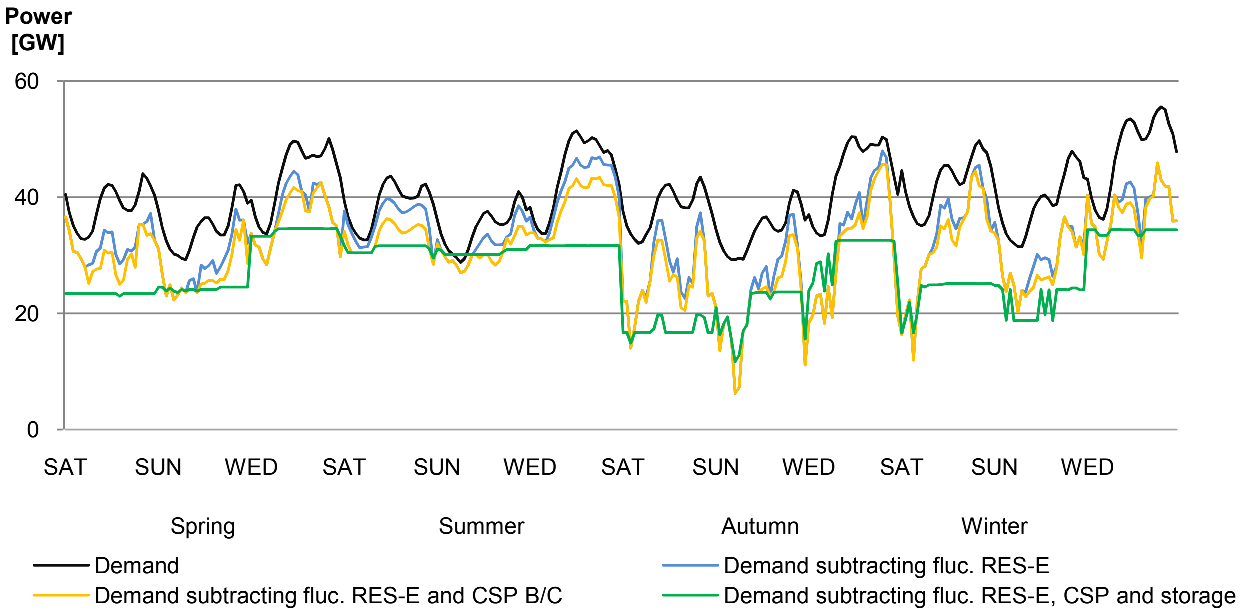

Figure 6: Different residual demands [GW] for the Iberian Peninsula in 2020

Figure 7 shows different residual demands for the Iberian Peninsula in 2050. A higher share of fluctuating RES-E technologies would lead to a more volatile residual demand and higher costs for ramping thermal power plants. This is observable by comparing the demand after subtracting the fluctuating RES-E generation in 2020 (blue line in Figure 6) with the demand after subtracting the fluctuating RES-E generation in 2050 (blue line in Figure 7).

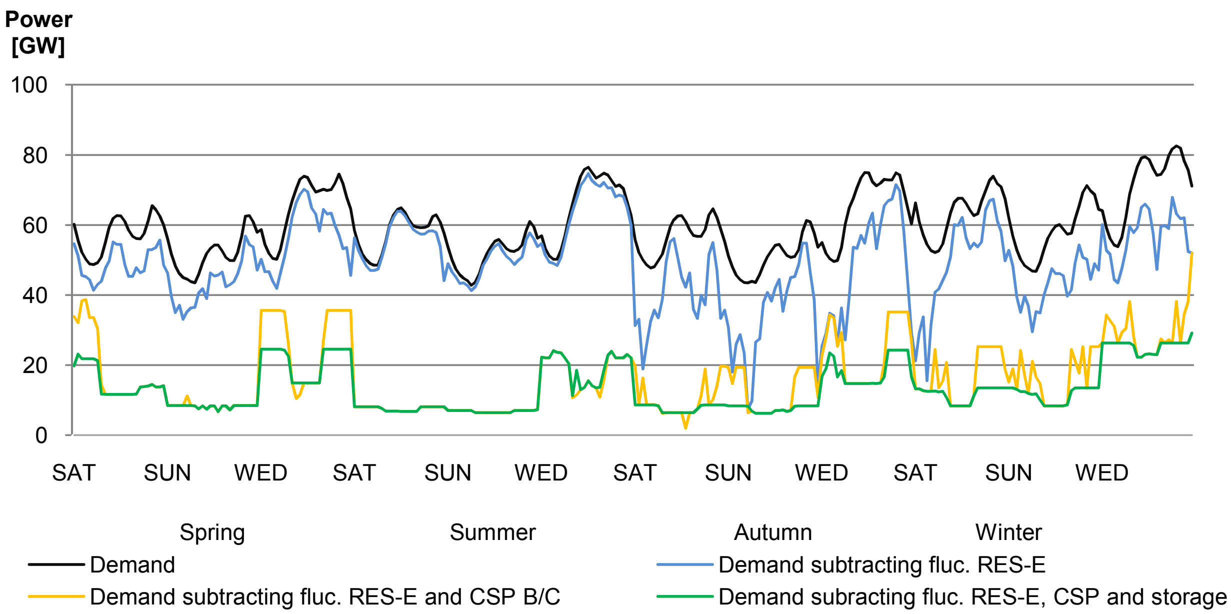

Figure 7: Different residual demands [GW] for the Iberian Peninsula in 2050

CSP technologies with storage units are able to shift generation from one hour to another and can therefore help balancing generation and demand. In connection with other storage capacities (hydro and pump storage) the residual demand can kept more or less constant in most hours. In the 'high RES-E scenario' CSP technologies with storage units are rather built than additional wind technologies for several reasons: the potential for cost-efficient onshore wind sites is limited, the investment costs for CSP plants with storage capacities decrease significantly until 2050 and the value of storage capacities increases as shown in the 'illustrative scenario'. As can be seen in Figure 7, CSP plants with the ability to shift electricity generation lead to a smoother residual demand even considering the higher RES-E generation in 2050.

7. Conclusions

We have shown that thermal energy storage units in CSP plants in today's electricity systems of Spain and Portugal are not cost-efficient from a system integrated viewpoint due to the relatively high demand at midday when solar radiation is also highest. Therefore, flat feed-in-tariffs lead to an inefficient generation mix as tariffs set an incentive to install thermal energy storage units in CSP plants which can reduce average generation costs and hence maximize profits. The value of TES in CSP plants increases with a higher share of wind and solar generation as storage technologies can help balancing fluctuating generation and demand. Due to specific learning curve effects in regard to the thermal storage unit, the cost difference between CSP plants with and without thermal storage is likely to decrease. As also shown, CSP plants play a potentially significant role in a transformation to a primarily renewable based electricity system.

The analysis approach could be improved and extended in several ways. It would be desirable to include co-firing of natural gas as another option to fully understand the value of storage units in CSP plants. In addition, a more realistic mapping of the electricity system could be achieved by modelling transmission constraints. It would also be interesting to analyze the effects of different locations for energy storages on transmission requirements, which are expected to be the lower the closer the energy storage is located to the (solar) power plant (Denholm and Sioshansi, 2009). Due to the neglection of uncertainty, forecast errors of wind and solar power or short notice power plant outages are not included in the model. Therefore, additional balancing services by thermal storage units in CSP plants are not fully considered. However, Black and Strbac (2006) or Sioshansi and Denholm (2010) show that it is preferable to integrate the balancing markets. The impact of uncertainty and balancing services on the value of thermal energy storages in CSP plants or other storage options from a system integrated viewpoint provides an interesting area of further research.

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Appendix

7.1. Appendix A - Abbreviations

Table 12: Abbreviations including model parameters and variables

Abbreviation	Dimension	Description
General		
CSP		Concentrating solar power
TES		Thermal energy storage
RES-E		Renewable energy sources - electricity
CCS		Carbon capture and storage
CHP		Combined heat and power
PV		Photovoltaic
Model parameters		
dsc	%	Discount rate
annuity	€$_{2010}$/kW	Annuity for technology specific investment costs
fomc	€$_{2010}$/kW	Fixed operation and maintenance costs
fuelpr	€$_{2010}$/MWh_{th}	Fuel costs
copr	€$_{2010}$/t CO_2	Costs for CO_2 emissions
emissionfac	t CO_2 /MWh_{th}	CO_2 emissions per fuel consumption
η	%	Net efficiency
attc	€$_{2010}$/MWh_{el}	Attrition costs for ramp-up operation
heatpr	€$_{2010}$/MWh_{th}	Heating price for end-consumers
heatratio	MWh_{th}/MWh_{el}	Ratio for heat extraction
avail	%	Availability of generation units
quota	%	Quota on RES-E generation
demand	MW	Model demand
volfac	MWh/MW	Ratio of storage size and turbine capacity
η_{sout}	%	Net efficiency of storage in discharging operation
η_{sin}	%	Net efficiency of storage in charging operation
Model variables		
TCOST	€$_{2010}$	Total system costs
FC	€$_{2010}$	Fixed costs
VC	€$_{2010}$	Variable costs
VCRTO	€$_{2010}$	Variable costs due to ramp-up operation
HB	€$_{2010}$	Revenues from heating generation
INSTCAP	MW	Installed capacity
CAPADD	MW	Commissioning of new power plants
GEN	MWh_{el}	Electricity generation
CAPUP	MW	Ramped-up capacity

7.2. Appendix B - CSP projects in Spain based on NREL (2011)

Table 13: CSP projects in Spain based on NREL (2011)

Project	Start Production	Turbine [MW]	Solar-Field [m^2]	Storage [h]
Alvarado I	2009	50	n.a.	0
Andasol-1 (AS-1)	2008	50	510,120	7.5
Andasol-2 (AS-2)	2009	50	510,120	7.5
Andasol-3 (AS-3)	2011	50	n.a.	7.5
Andasol-4 (AS-4)	2020	50	510,120	7.5
Arcosol 50 (Valle 1)	2010	49.9	n.a.	7.5
Central Solar Termoelectrica La Florida	2010	49.9	552,750	7.5
EL REBOSO II 50-MW	2011	50	319,057	0
EL REBOSO III 50-MW	2012	50	518,469	2.3
Extresol-1 (EX-1)	2010	50	510,120	7.5
Extresol-2 (EX-2)	2010	49.9	510,120	7.5
Extresol-3 (EX-3)	2010	49.9	510,210	7.5
Gemasolar Thermosolar Plant (Gemasolar)	2010	17	318,000	15.0
Helios I (Helios I)	n.a.	49.9	n.a.	0
Helios II (Helios II)	n.a.	49.9	n.a.	0
Ibersol Ciudad Real (Puertollano)	2009	50	287,760	0
La Dehesa	2011	49.9	552,750	7.5
Lebrija 1 (LE-1)	2010	49.9	412,020	0
Majadas I	2010	50	n.a.	0
Manchasol-1 (MS-1)	2011	49.9	510,120	7.5
Manchasol-2 (MS-2)	2010	49.9	510,120	7.5
Palma del Río I	2011	50	n.a.	0
Palma del Río II	2010	50	n.a.	0
Planta Solar 10 (PS10)	2007	11.02	75,000	1.0
Planta Solar 20 (PS20)	2009	20	150,000	1.0
Puerto Errado 1 Thermosolar Power Plant	2009	1.4	n.a.	n.a.
Puerto Errado 2 Thermosolar Power Plant	2012	30	n.a.	n.a.
Solnova 1	2009	50	300,000	0
Solnova 3	2009	50	300,000	0
Solnova 4	2009	50	300,000	0
Vallesol 50 (Valle 2)	2020	49.9	510,120	7.5

7.3. Appendix C - Power balance of Spain and Portugal in the 'high RES-E scenario'

Table 14: 'High RES-E scenario' - Power balance for Spain in TWh (2000 and 2008 based on Eurostat (2010))

	2000	2008	2020	2030	2040	2050
Net electricity consumption	188.5	265.4	298.6	344.9	396.3	453.2
Transformation losses	19.0	20.0	27.1	26.1	18.4	14.7
Thermal plant consumption	14.0	15.0	22.2	21.1	15.9	9.2
other transformation	5.0	5.0	5.0	5.0	5.0	5.0
Grid losses	20.0	16.0	13.5	13.5	13.5	13.5
Storage consumption	2.6	1.1	4.4	2.6	1.7	1.5
Gross electricity consumption	230.1	302.5	342.7	387.1	432.4	482.4
Net imports	4.4	-11.0	-0.4	-0.8	1.3	-0.7
Gross electricity generation	225.6	313.5	344.1	387.8	431.1	483.1

Table 15: 'High RES-E scenario' - Power balance for Portugal in TWh (2000 and 2008 based on Eurostat(2010))

	2000	2008	2020	2030	2040	2050
Net electricity consumption	38.5	48.4	55.9	64.5	74.1	84.8
Transformation losses	2.3	2.4	3.6	3.4	5.4	3.7
Thermal plant consumption	1.7	1.8	3.0	2.8	4.8	3.1
other transformation	0.6	0.6	0.6	0.6	0.6	0.6
Grid losses	3.6	4.2	3.8	3.8	3.8	3.8
Storage consumption	0.2	0.2	0.9	0.8	1.0	0.2
Gross electricity consumption	44.6	55.2	64.1	72.5	84.2	92.5
Net imports	0.9	9.4	0.2	0.7	-1.4	0.6
Gross electricity generation	43.7	46.0	63.9	71.8	85.7	91.9