Energy System Modelling: Power Plant Dispatch and Electricity Generation Costs

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***Abstract*— The growing share of intermittent renewable energy on the electricity production has also an influence on the remaining thermal power plants. The full load hours, especially of fossil fired power plants, are decreasing over time. In the meantime, the energy surplus produced by renewable sources is increasing and without building new controllable power plants, the back-up capacity is decreasing because old fossil fired power plants will shut down. A lot of modelling has been done in this field yielding to very different results. This paper shows a generic approach to the calculation of the power plant dispatch and the electricity generation cost. The main focus is on the influence different scenario assumptions can have on the outcome of the investigation. The aim is to show how important an extensive sensitivity analyses is. As the ambitious climate targets of the government, the strong development of intermittent renewable energies as well as the nuclear phase out provide very good scenarios, the model will be explained on the example of Germany.**

Keywords—renewable energy; power plant dispatch; electricity generation costs; energy storage

I. Nomenclature

Variables

A	Discounted sum	P	Power
CC	Certificate costs	p	price
E	Energy Generation	r	Discount rate
F	Fuel costs	S	Closedown costs
h	hours	T	period of time
I	Investment costs	η	Efficiency
LG	Load gradient	κ	Non-controllable factor
M	O & M costs	τ	time delay factor
n	amortization period	ϕ	emissions

Indices

BM	Biomass	p	production
CO2	CO_2	PP	Power plant
d	Demand	PV	photovoltaic
el	electricity	R	Rated
ES	Energy Storage	spe	Specific
FL	full load	ST	starting time
HP	Hydropower	st	starting
min	minimum	t	time segment
off	offline	u	unit

Abbreviations

BAU	Business as usual
CCS	Carbon Capture and Storage
CCP	Combined cycle power plant
GC	Guaranteed capacity
GPC	Gross final power consumption
RE	Renewable energy
SGT	Single Gas Turbine
TSO	Transmission system operator
WACC	Weighted average cost of capital

II. Introduction

Germany is witnessing a paradigm shift away from fossil fired and especially nuclear power plants towards a sustainable and save energy supply based on renewable energies. Since the promotion of renewable energies started with the first renewable energy law in the year 2000, the renewable energy sector has grown enormously. In 2012 already 22 % of the total energy production came from renewables. The installed amount of renewable energies at the end of 2012 was in the range of the yearly peak load. This shows that with continuing expansion of the renewable sector, there are more and more situations that will occur with an energy production just from renewables that exceed the load demand.

As the renewable sector in Germany is mainly based on fluctuating renewable sources like wind and sun, the additional problem of fast changes in production and predictability come into play. Higher residual load variations will have to be covered by a smaller amount of controllable power plants. To achieve the transition to a mainly renewable based power supply, flexible and fast reacting power plants will be necessary. The question to answer is what will be the price for this flexibility. The electricity generation costs are highly influenced by the time the power plant is producing energy. A reference value for this are the full load hours. The full load hours are calculated as the quotient of the yearly produced energy and the installed power. In 2010 nuclear power plants had the most full load hours (7700 h), followed by lignite (6700 h), coal (4300 h) and natural gas (3400 h) [1], [2]. Studies on the future development of full load hours of thermal power plants up to the years 2020 or 2050 are coming to very different results [3], [4], [5], [6], [7], [8]. This is due to different assumptions regarding the development of renewable energies, the closedown of thermal power plants, newly built power plants, the development of fuel and CO_2 certificate prices as well as the development and deployment of units with carbon capture and storage (CCS) technologies. In this paper a modeling approach is explained to calculate the power plant dispatch, the full load hours and the electricity generation costs taking into account all the before mentioned variables. It is a generic approach and thus can be applied for all regions and countries. It is here explained on the example of Germany.

III. MODELLING

In this section the modelling of the different parts of the electricity supply system is explained. Fig. 1 shows the general structure of the program. Before the program is started the scenarios have to be defined and all data until the desired final year of investigation have to be set. On the one side these are the reference scenario data like load demand curves, feed-in curves of renewable energies (how these can be obtained, see part A. 1 of this chapter) and the composition of the power plant mix as well as all technical data of the power plants. On the other side this includes predictions for load data, installed capacities of renewable energies and conventional generation units as well as the development of prices for primary energy carriers and CO_2 certificates. How these variables are taken into account for the simulation is as well shown in this chapter. After all input parameters are set, the residual load is calculated for each year until the desired year but maximum until 2050. When this is done the algorithm tries to cover the residual load with the available power plants at minimum costs. Like this the yearly efficiency and full load hours of each units are obtained. Based on these outcomes the electricity generation costs of newly built power plants can be calculated to show possible investment incentives.

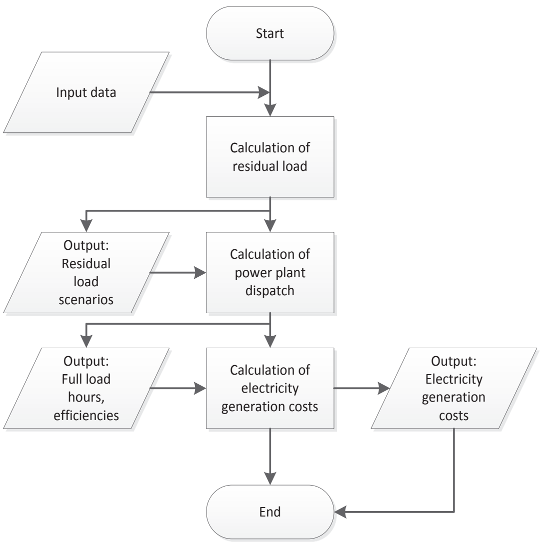

Fig. 1. General structure of the programming algorithm

A. Calculation of residual load

The calculation of the residual load is explained in (1). It is set as the load demand minus the non-controllable electricity production from renewable sources. This includes wind and solar power but also a part of hydropower, mostly small non-controllable run-of-the-river plants. The load data were obtained by the German transmission system operators (TSOs) and are available in 15 minute values. As load data are not always available in 15 minute values, the calculations in this paper are made with hourly values to allow a better transferability to other regions and countries.

$$RL(t) = P_d(t) - P_{Wind}(t) - P_{PV}(t) - \kappa_{HP} \cdot P_{HP}(t) \qquad (1)$$

For future scenarios the load curves are normalized and then scaled accordingly to the desired energy production/consumption.

1) Renewable Energies

The feed-in from renewable energies can be calculated in three different ways. As a default setting the program uses real feed-in curves from the years 2011 and 2012. The curves are then normalized and scaled accordingly with the desired amount of installed power. Another option is the use of real weather data of past years together with technical models. The third option is to produce stochastical feed-in curves with weather data from the past years together with technical models of various intermittent renewable energy technologies. For a better reproducibility, in this paper the public available feed-in curves for wind and PV from the German TSOs from the years 2011 and 2012 are taken as a base for future scenarios. Offshore wind data curves are obtained by the published 2012 feed-in curves from TenneT TSO.

2) Thermal power plants

Thermal power plants are modelled in a simplified way. As the minimum time step of the simulation is 15 minutes, dynamic behavior of the power plants is neglected. For the investigation, the following data can be set for each technology: Installed power (in MW), number of units, efficiency curves for part load operation, range of possible part load operation (in %/P_R), load gradient of each unit (in %/P_R/min), starting time for cold and warm start. Furthermore priorities for different technologies and units can be defined for the operation order. In default settings the power plant with the lowest costs has the highest priority. Most of technical data used in this paper were taken from [15] and are summarized in Table 1.

TABLE 1 DYNAMIC PARAMETERS OF FOSSIL FIRED POWER PLANTS FOR ACTUAL UNITS/ MODIFIED UNITS/ POTENTIAL FOR NEW UNITS [12]

Unit type	Coal	Lignite	CCP	Gas turbine
LG [%/P_R/min]	1.5 / 4 / 6	1 / 2.5 / 4	2 / 4 / 8	8 / 12 / 15
part load [%/P_R]	40 - 90	40 - 90	40 – 90	40 - 90
Min. load [%/P_R]	40/ 25/ 20	60/ 50/ 40	50/ 40/ 30	50/ 40/ 30
Cold start [h]	3/ 2.5/ 2	6/ 4/ 2	1.5/ 1/ 0.5	< 0.1
Warm start [h]	10/ 5/ 4	10/ 8/ 6	4/ 3/ 2	0.1

B. Power Plant Dispatch

The power plant dispatch is differentiated into initial state, short term and long-term control of the power plants. For the initial state setting it is assumed that all power plants are available to cover the residual load, so the cheapest power plant mix is covering the residual load in the first hour of investigation. If there is a surplus the power plant dispatch starts with its regular control mechanism as explained in the next passages as soon as the residual load turns positive. The general controlling structure is that the power plant with the lowest electricity generation costs serves the load first. If technical boundaries do not allow the power plant to cover the demanded load, the next power plant with higher generation costs is used to cover the load. In all cases the system has to fulfill equation (2). The power output of all units plus the surplus (P_{su}) and shortage (P_{sh}) of power has to be equal to the residual load demand.

$$P_{RL}(t) = \sum_{u=1}^{N} P_u(t) + P_{su}(t) + P_{sh}(t) \tag{2}$$

$$P_{sh}(t) \leq 0$$

$$P_{su}(t) \geq 0$$

For the simulation some time constraints have to be defined. The starting time (T_u^{st}) is influenced by the time the power plant is offline (X_u^{off}) and how long the power plant can perform a warm start after having been switched off ($T_{warm,u}^{off}$). If $X_u^{off}(t)$ is smaller or equal than $T_{warm,u}^{off}$ the starting time is the warm start starting time plus the minimum time the power plant needs to be offline (T_u^{off}). Else, the power plant needs the additional time for a cold start to be again available for the grid.

$$T_u^{st}(t) = \begin{cases} T_u^{off} + T_u^{warm} & ,\forall t \rightarrow X_u^{off}(t) \leq T_{warm,u}^{off} \\ T_u^{off} + T_u^{cold} & ,\forall t \rightarrow X_u^{off}(t) > T_{warm,u}^{off} \end{cases}$$

$$X_u^{off}(t) = \begin{cases} X_u^{off}(t-1) + 1 & ,\forall t \rightarrow P_u(t) = 0 \\ 0 & ,\forall t \rightarrow P_u(t) > 0 \end{cases}$$

The availability factor (V_u) is introduced to see if the power plant could be used for the next simulation step or if there are restrictions that prevent the commitment. The power plant is available if it is already online ($O_u(t) = 1$) or it if it is long enough offline to start again in the next time step. It is not available if the power plant is offline ($O_u(t) = 0$) and the minimum time offline is not yet reached or if the power plant is already running with rated power. The online factor (O_u) only indicates if the unit is online. That means it has to be connected to the grid and feeding power to the grid.

$$V_u(t) = \begin{cases} 1 & ,\forall t \rightarrow O_u(t) = 1 \cup X_u^{off}(t) \geq T_u^{st}(t) \\ 0 & ,\forall t \rightarrow (O_u(t) = 0 \cap X_u^{off}(t) \leq T_u^{st}(t)) \cup P_u(t) = P_u^{max} \end{cases}$$

$$O_u(t) = \begin{cases} 1 & ,\forall t \rightarrow P_u(t) > 0 \\ 0 & ,\forall t \rightarrow P_u(t) = 0 \end{cases}$$

For the down regulation and the shutdown of a power plant respectively, an unavailable factor (D_u) is introduced to ensure that the power plant is not switched off during the minimum time it has to stay connected to the grid (T_u^{on}). For that purpose X_u^{on} counts the time the power plant is connected to the grid.

$$D_u(t) = \begin{cases} 1 & ,\forall t \rightarrow X_u^{on}(t) \geq T_u^{on} \\ 0 & ,\forall t \rightarrow X_u^{on}(t) < T_u^{on} \end{cases}$$

$$X_u^{on}(t) = \begin{cases} X_u^{on}(t-1) + 1 & ,\forall t \rightarrow P_u(t) > 0 \\ 0 & ,\forall t \rightarrow P_u(t) = 0 \end{cases}$$

Long-term control is the decision if a power plant needs to start, shut down or stay online with minimum capacity. Long-term dispatch is only made for nuclear, lignite, coal and combined cycle (CCP) power plants. Single gas turbines (SGT) as well as energy storage technologies are assumed to be able to be online in less than one hour and are therefore only controlled by the short term control scheme in Fig. 2. The long-term control – the decision to start or to shut down a power plant - can be explained looking at (3) and (4). If the rated power of all power plants and biomass units online is less than the average residual load (*RL*) from the time of possible grid connection (c_1) to the time the power plant should minimum stay online (c_2) minus the minimum load of the unit ($P_{\min}$) and the rated power of already starting units ($P_{R,u,st}$), the power plant will be prepared of starting. This can be made analogous for the shutdown of a unit, see (4). The main difference in the decision to start or to shut down an unit, is that for stopping a power plant no starting times have to be considered.

$$\sum_{u=1}^{u_{\text{onl}}} P_{\text{R,u,i}} + \sum_{BM=1}^{BM_{\text{onl}}} P_{\text{R,BM,i}} < \frac{\sum_{i=c_1}^{c_2} P_{RL}(i) - P_{\text{min,u}} - \sum P_{\text{R,u}_{st}}}{T_u^{on}} \tag{3}$$

$$\sum_{i=1}^{u_{\text{onl}}} P_{\text{R,u,i}} + \sum_{i=1}^{BM_{\text{onl}}} P_{\text{R,BM,i}} \geq \frac{\sum_{i=c_3}^{c_4} P_{RL}(i) + P_{\text{min,u}} + \sum P_{\text{R,u}_{\text{st}}}}{T_u^{off}} \tag{4}$$

$$c_1 = \begin{cases} t & ,\forall t \rightarrow X_u^{off}(t) \geq T_u^{st}(t) \\ t + \left(T_u^{st}(t) - X_u^{off}(t)\right) & ,\forall t \rightarrow X_u^{off}(t) < T_u^{st}(t) \end{cases}$$

$$c_2 = c_1 + T_u^{on}$$

$$c_3 = \begin{cases} t & ,\forall t \rightarrow X_u^{on}(t) \geq T_u^{on} \\ t + \left(T_u^{on} - X_u^{on}(t)\right) & ,\forall t \rightarrow X_u^{on}(t) < T_u^{on} \end{cases}$$

$$c_4 = c_3 + T_u^{off}$$

The short-term control of all units online and of the ones, which have starting times less than the minimum step size, is shown in figure 2 for upwards regulation. Downwards regulation is made analogous. The control range is from $P_{\min}$ to P_R taking into account the merit order and the load gradient of the particular unit. The decision is based on the load gradient of the residual load and the aim of the control is to bring this load gradient to zero, so that the production meets the demand. If e.g. the cheapest unit cannot ramp-up quick enough ($LG_u < LG_l$) another unit is needed to support the power plant during the ramp-up period. The same appears when the LG_u is high enough but the difference between the actual and rated power of the unit cannot cover the demanded power.

An example of the power plant dispatch for a residual load curve in 2050 is shown in figure 3. As can be seen there are no more nuclear power plants connected and there is a high surplus produced by renewable energies (pink). Biomass (green) has the highest full load hours, followed by lignite (brown), coal (black), CCP (red) and single gas turbines (light blue). The dark blue spots are the peaks that cannot be covered by the power plant mix because of a lack of capacity. Two main things can be observed in the power plant dispatch with high renewable energy shares and the appearance of times with negative residual load. First, shown in the left plot of Fig. 4, the surplus of energy due to minimum load constrains. Some base load units will stay connected with minimum load, even though not needed, if the residual load is expected to rise again in less than the starting time of the unit. Second, shown in the right plot of Fig. **4**, the preferential use of fast reacting units because of high load fluctuations. When the time between two negative residual load values is less than the minimum time a base load unit should stay online, it will not be started.

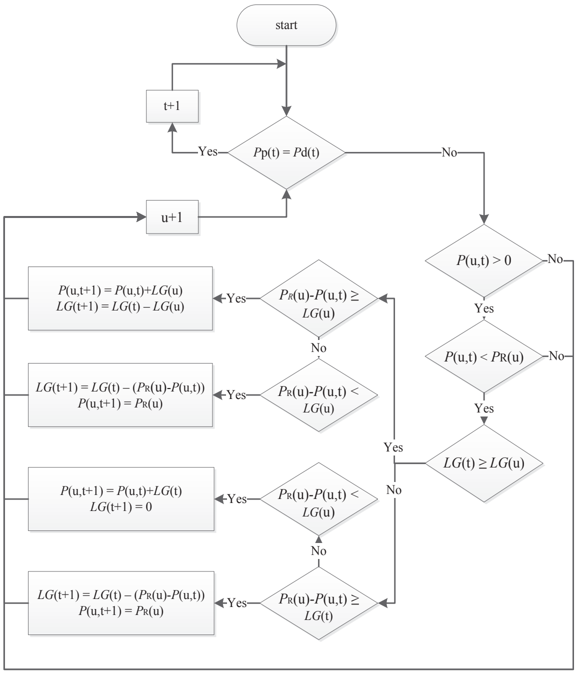

Fig. 2 Short-term control of power plant operation

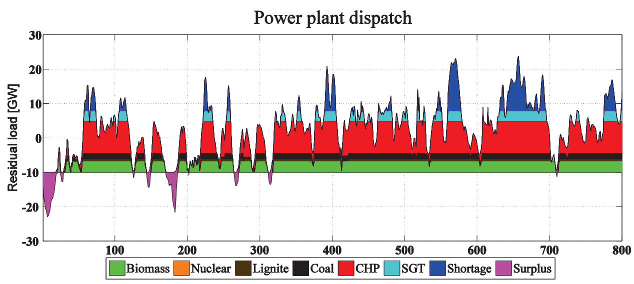

Fig. 3 Power plant dispatch for the year 2050 with no newly built power plants

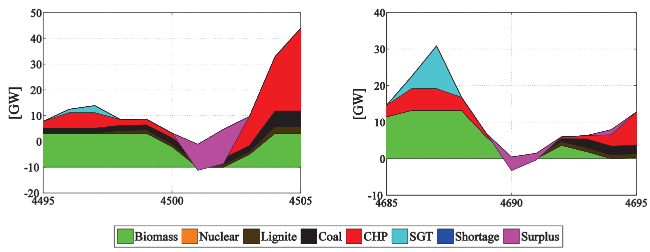

Fig. 4 Surplus of energy due to starting times of base load units (left) and preferential use of fast units because of high load fluctuations (right)

C. *Electricity Generation Costs*

The electricity generation costs are calculated with the levelized costs of electricity (LCOE). This method is based on the net present value method and represents the life-cycle costs including all expenses incurred over the whole life time of the power plant [13], [14]. In (4) I_0 represents the investment costs, E_{el} the electricity generation and A_t is the annual overall costs, discounted on the time of commissioning. The amortization period in years are marked as n. The weighted average cost of capital (WACC) is usually in a range of 5 % to 10 %. In this paper it is set to 7.5 % and is represented by i. t is the year within the range of n. The annual overall costs can further be separated into fixed operating costs on the one side and variable operating costs on the other side, see (5). Fixed costs include labor costs, insurance costs and maintaining costs, all summarized by the variable M_t. The variable costs are mainly determined by fuel costs F_t and certificate prices for CO_2, CC_{CO2}. The efficiency of the power plant η has to be taken into account as well. At the end of the lifetime of a power plant additional costs for the closedown and deconstruction appear. These costs are summarized by the variable S. As it is difficult to assume these costs for newly built power plants, S is assumed to be 5 % of the initial investment costs [15].

$$LCOE = \frac{I_0 + \sum_{t=1}^{n} \frac{A(t)}{(1+i)^t}}{\sum_{t=1}^{n} \frac{E_{\mathrm{el}}(t)}{(1+i)^t}} \tag{4}$$

$$A(t) = M(t) + \frac{E_{El}(t)}{\eta} \cdot \mathrm{F(t)} + \frac{E_{El}(t)}{\eta} \cdot CC_{CO2} + S \tag{5}$$

For the further investigations the focus will be on the development of the variable costs. As thermal power plants are major technologies we assume that there is no further learning rate. This seems to be justifiable as the investment cost of thermal power plants have been stable over the last decades.

1) Developemt of fuel prices

The fuel prices are strongly dependent on global demand of energy. The price for oil is taken as a benchmark for fuels like gas and coal. Most of experts see an increase in oil prices although there are still a lot of uncertainties regarding the exact development. The only primary energy carrier that is relatively independent of the world price of other fuels, is lignite. This is due to the fact that lignite has a low energy density and transportation over long distances is not economic. Against this background lignite is assumed to have a stable price for the next decades, as it is only dependent on national hauling structure [13], [16]. Table 4 shows two different development scenarios for fuel prices.

TABLE 2 DEVELOPMENT OF FUEL PRICES IN A BUSINES AS USAL (BAU) AND AN ALTERNATIVE (ALT) SCENARIO UP TO THE YEAR 2050 [14]

$€_{2007}$/GJ	Scenario	2010	2020	2030	2040	2050
Lignite	BAU	0.96	0.96	0.96	0.96	0.96
	ALT	1.36	1.36	1.36	1.36	1.36
Coal	BAU	2.45	2.79	3.03	3.08	3.14
	ALT	2.28	2.62	2.69	2.73	2.76
Natural gas	BAU	8.33	9.96	10.79	11.20	11.40
	ALT	8.02	8.88	9.25	9.40	9.47

2) CO_2 Certificates

The costs for CO_2 emissions play an important role for the transition towards a low carbon energy supply system. As power plants with low fuel prices produce most carbon dioxide (lignite, coal), units with low carbon footprint are more expensive to operate (gas). Thus the price of CO_2 certificates can influence an investment decision. The base for the amount of certificates each power plant needs is the specific emissions of each unit, ϕ_{CO2}. In addition to this the yearly full load hours h_{FL} has to be taken into account as well as the rated power P_R of the unit and the average yearly efficiency η_t. Equation (6) demonstrated the calculation of the yearly amount a power plant has to pay for its CO_2 certificates.

$$p_{CO2} = CC_{CO2} \cdot \frac{h_{FL} \cdot P_R \cdot \phi_{spe,CO2}}{\eta_t} \quad (6)$$

The Specific emissions of lignite, coal and natural gas are set to 0.4235t/MWh, 0.3847t/MWh and 0.2739t/MWh respectively [17]. Actual certificate prices in Germany are between 4 € and 5 € (Dec. 2013). There are different approaches on decreasing the amount of certificates to raise the prices. In this paper a price increase of 6 %/y is assumed.

3) Carbon Capture and Storage Power Plants

A possibility to realize the ambitious CO_2 targets without turning down the use of CO_2 intensive power plants, is the carbon capture and storage technology. There are 3 different technologies available, the post-combustion, the oxyfuel and the pre-combustion method. All can achieve a separation of CO_2 of up to 90 %. The disadvantages are an efficiency loss of 5-12 percentage points, an increase in investment costs of 1.5-2 times the initial ones and an already starting public opposition against the storage of CO_2. For a more detailed view on CCS technologies, prices and storage options, see [13], [15], [18], [19]. For the further investigation the transport and storage costs for CO_2 are assumed to be 8 €/t.

D. Further Assumptions

The investment costs and the lifetime of each type of power plant that is assumed for the calculations in this paper are shown in Table 3. In contrast to Table 2 the prices are shown in $€_{2013}$ which is also the value for the further calculations. For the conversion a yearly inflation rate of 2 % has been set. For the reference scenario the base for the fuel prices are the average prices on the European Energy Exchange (EEX). The price increase is set to 0.5 %/y for lignite and 1.5 %/y for coal and gas. In case of the whole electricity system, no import/export of energy is considered in this paper. Furthermore the grid reinforcement and extension is supposed to be fast enough that no bottlenecks will appear and that the energy produced by renewable generation units and thermal power plants can be transported to the user. It is important to mention that no dead times are considered for maintenance or revision.

TABLE 3 SPECIFIC INVESTMENT COSTS AND ASSUMED LIFE TIME FOR GENERATION UNITS (LICENSING BETWEEN 2015 AND 2020) [15],[20],[21]

Unit type	Specific investment costs	Assumed life time of unit
Lignite	1689 €/kW	40 y
Lignite – CCS	2702 €/kW	40 y
Coal	1464 €/kW	40 y
Coal – CCS	2478 €/kW	40 y
CCP	788 €/kW	30 y
CCP – CCS	1577 €/kW	30 y

All projections are made in 10 years steps. For the years in between the values are linearly interpolated. Biomass counts as renewable energy but is not taken into account for the calculation of the residual load. This is due to the fact the biomass units are fast reacting and serve well for controlled operation. Nonetheless, for the further investigation it is also assumed that preferential feed-in of renewable energies will continue.

IV. RESULTS

In this section first a reference scenario is introduced and discussed in detail. For the other scenarios only changes to the reference scenario are highlighted. The aim is to show the impact different assumptions can have on the outcome of the simulation. Regarding the plots with the full load hours (Fig. 5 and Fig. 6), it has to be stated that for the surplus and the shortage of energy, the displayed hours are not full load hours but the sum of the hours of appearance.

A) Reference scenario

The reference scenario is for the time period of 2012 to 2050 and is based on load and feed-in curves of the year 2011. Future predictions for the development of RES-E and thermal power plants are shown in Table 4. This includes the closedown of old production units. The construction of new units is not considered here.

TABLE 4 DEVELOPMENT OF INSTALLED CAPACITY OF UNIT TYPES WITHOUT NEW POWER PLANTS, TAKING INTO ACCOUNT THE CLOSEDOWN OF OLD UNIS [4],[9],[10]

[GW]	2012	2020	2030	2040	2050
Nuclear	16.9	7.8	0	0	0
Lignite	18.5	13.2	5.3	3.96	1.32
Coal	25	21	14	8	3
CCP	18.8	18.8	18.8	18.8	18.8
SGT	6	6	6	6	6
Hydro	4.40	4.70	4.92	5.09	5.2
Wind	31.30	49.0	97.2	77.5	82.8
-onshore	31.0	39.0	43.7	48.0	50.8
-offshore	0.28	10.0	23.5	29.5	32.0
PV	32.6	53.5	61.0	63.3	67.2
Biomass	7.65	8.96	10.0	10.38	10.38
RE-total	76.0	116.8	147.8	166.3	179,0
GPC	594	573	558	572	584
% of GPC	22.9	47.1	67.6	78.4	85.8

The resulting full load hours for each power plant for the period of investigation are shown in Fig. 5. In the first years up to 2020, the classic base load units (lignite and nuclear) reach full load hours of more than 7500 h. This is even more than in reality because periods for maintenance and revision have not been taken into account. Coal and biomass are, with around 5000 full load hours, in the range of medium load units, whereas CCP units are, with around 3000 full load hours, classic peak power plants. Single gas turbines have very low full load hours up to 2020 and there is neither a surplus nor a shortage of energy. The reason for the low full load hours of gas turbines at this time is the step size of one hour. Fast load changes that are normally covered by these units cannot be displayed correctly. A big cut in the diagram is the nuclear phase out in 2022, where all other technologies show a strong increase in full load hours and shortages appear for the first time, as no new power plants are considered in this scenario. Although the number of units decreases over time because of closing down of old unit, the full load hours of especially base load units but also mid load units are decreasing. The only technology with an increase of full load hours is the single gas turbine.

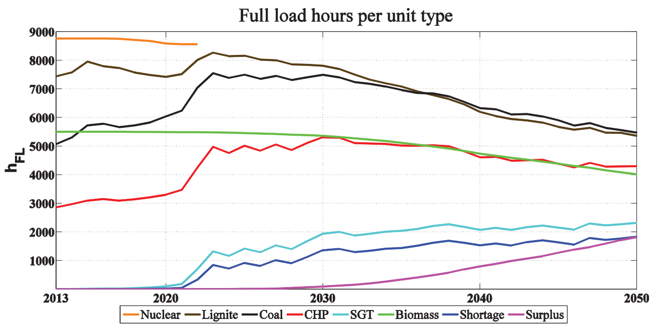

Fig. 5 Full load hours of each unit type for reference scenario

This is due the high appearance of fast load changes where the single gas turbine is the best option. It can be seen as well that mentionable surpluses of renewable energies start to appear around 2030 and continue increasing to almost 2000 hours a year.

Finally the year 2050 is taken as an example for a more detailed discussion of the results. In 2050 the total surplus of energy from renewable sources reaches 29.79 TWh. The shortage caused by missing power plant capacity is 27.11 TWh. Both are in the same range, which already shows a good operation possibility for energy storage systems. Table 7 shows further outcomes of the simulation for this year. It can be seen that the guaranteed capacity is not high enough to fulfill the peak-load-plus-10%-criteria. Without decentralized energy storage systems together with renewable energy units the GC of renewables (PV: 1%, Wind: 10%) and the remaining fossil fired power plants is almost 26 GW below the needed GC. Even when assuming a higher GC of wind (20 %) and PV (10 %) by combining these with energy storage systems, the total GC reaches 67.08 GW, which is still more than 7 GW below the needed. This shows that there is a need for additional GC. As the CO_2 emissions of the simulated power plant mix already reaches 70.68 Mt, it will be hardly possible to install new fossil fired power plants (especially coal and lignite) without using the CCS technology as the CO_2 emission targets of the German government are 85 Mt by 2050.

TABLE 5 OUTCOME OF THE SIMULATION OF THE REFERENCE SCENARIO FOR THE YEAR 2050

Peak load +10 %	74.25 GW
$GC_{thermal\ units}$	25.08 GW
$GC_{RE\ w/o\ ES}$	23.32 GW
$GC_{RE\ w\ ES}$	42 GW
$\sum GC_{w/o\ ES}$	**48.4 GW**
$\sum GC_{w\ ES}$	**67.08 GW**
Φ_{CO2}	**70.68 Mt**

B) Different load and feed-in curves

In this scenario the difference in the results taking other load and feed-in curves is highlighted. For that purpose the simulation has been made with load and RE feed-in curves from 2012. Same as in the previous scenarios the curves have been normalized and scaled accordingly with the load demand and installed capacity of renewable energies shown in table 1. At the end the share of RE on the GPC stays equal. Nonetheless the results of the simulation are quite different. The total fluctuations of the residual load are higher thus resulting in a needed GC of 81.93 GW, which is more than 7 GW higher than with the input curves from 2011. Also the structure of the full load hours changes. Biomass and lignite have little lower operation time whereas coal and CCP units stay on the same level. Gas units increase, as only unit type, the full load hours. This is caused be higher fluctuations due to a stronger feed-in from PV in 2012 and thus at high shares of RE, more flexible and fast reacting units are needed. Furthermore shortages and surpluses of energy appear more often during the year (around 2200 times) causing also higher overall values, in 2050 namely 29.88 TWh and 31.2 TWh respectively. Also the electricity generation costs, see Fig. 7, are higher in this scenario for the base load units coal and lignite. This shows that just changing the year of the input data can have a significant impact on the outcome of the simulation. For that reason it is always reasonable to compare multiple years of input data. For the following scenarios the again data from 2011 is taken as a base.

C) Different RE development

In this scenario different RE development paths are investigated. One path takes into account a stronger development of wind power and the other one a stronger development of solar power but both resulting in the same share on the GPC, see table 8. The basic problem is that different development of different RE-technologies influences the residual load. As PV has lower full load hours than wind power a higher capacity is needed to produce the same amount of energy. Thus a higher share of PV produces higher peaks regarding the power surplus. On the other side PV is more predictable than wind due to its day-night characteristic whereas wind can blow over periods of multiple days. How different RE developments can influence e.g. the energy storage needs can be seen in [23]. The difference regarding the full load hours and the electricity generation costs are relatively low, see also Fig. 7. The full load hours in 2050 are slightly lower in the Wind-scenario for all unit types. Consequently the electricity generation costs per unit type are higher in the Wind-scenario. Only the base load units running with lignite have overall lower electricity generation costs in this scenario. The reason why there are no significant differences is the step size of one hour. When using 15 minute input data, the results change. This is due to a higher influence of the technical data shown in table 3, especially the load gradient.

TABLE 6 OVERVIEW OF INSTALLED CAPACITY OF WIND AND PV FOR A SCENARIO WITH A FAVORED DEVELOPMENT OF WIND (WIND) AND A FAVORED DEVELOPMENT OF PV (PV)

[GW]	2020	2030	2040	2050
	Wind / PV	**Wind / PV**	**Wind / PV**	**Wind / PV**
Wind onshore	41 / 38	47.7 / 43.7	53 / 46	69.8 / 60
Wind offshore	12 / 8	27.5 / 16.5	43.5 / 26.5	51 / 40
PV	35.5 / 61.5	40 / 77.2	43.3 / 93.3	52.2 / 110

D) Building new coal units

The scenarios investigated before did not have enough power plant capacity to ensure a secure operation of the electricity sector. The GC was even far below its desired value. For that reason a scenario with an extension of the power plant mix is calculated. For that purpose 7 lignite and 10 coal fired power plants with a total capacity of 19 GW will be connected to grid stepwise between the years 2018 and 2029. CCP plants and single gas turbines will not be expanded. Fig. 6 shows the development of the full load hours until 2050. It can be seen that the full load hours of each unit type is decreasing. For coal and lignite this can be explained by the higher number of units installed and thus sharing the amount of energy demand. Especially lignite is losing a high amount of operating hours compared to the reference scenario but also coal will have more than 1000 full load hours less than in 2013. The full load hours of biomass are just decreasing marginally. This is due to the preferential feed-in from these units as they count as renewable. In contrast to the reference scenario CCP and gas turbines are no longer needed to this high extend for medium load coverage. This is now made be coal and lignite power plants. As a result of an overall higher installed capacity the hours of the year where there are shortages of energy are decreasing strongly. An effect of a higher number of slow starting base load units is a slight increase in hours with a surplus of energy. This can be explained by a more often appearance of moments where lignite units do not shut down although there is no need to produce energy, because the residual load is supposed to raise soon again. Like this a surplus is produced during positive residual load, see Fig. 4.

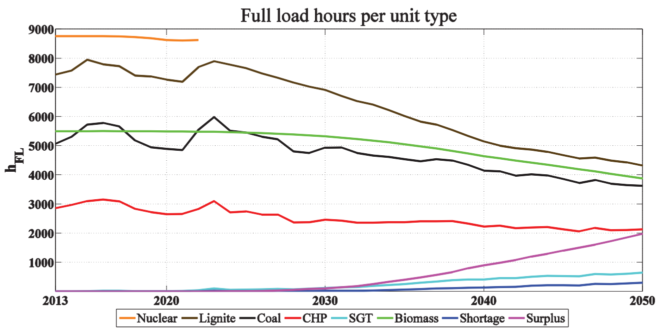

Fig. 6 Full load hours per unit type for a scenario with new comissioned coal and lignite power plants between 2018 and 2029

E) Stronger increase of certificate prices

In the last scenario a stronger increase of certificate prices is assumed. Instead of 6 % a yearly increase rate of 10 % is set. As an outcome of this scenario it can be stated that even with a higher increase of certificate prices power plants without CCS technology are still cheaper. Furthermore CCS would only make sense for lignite and with even higher increasing certificate prices for coal. This shows that either the prices for CO_2 increase or there must be strict regulatory boundary for the overall CO_2 emissions to fulfill the emission target of the German government. The benchmark for a CO_2 certificate price increase where a power plant with CCS has lower electricity generation costs is 12 %. As can be seen in Fig. 7 the LCOE for CCS plant with lignite and coal are lower than without CCS. Furthermore it can be seen that the impact of certificate prices is highest for lignite and moderate for CCP units. In general high certificate prices do not much affect the LCOE of CCS units. Nonetheless the increase of the certificate prices, even when they are small, have an impact on the electricity generation prices and thus influence the outcome of the simulation, see Fig. 6. The same outcome could be derived with a stronger increase of fuel prices.

F) Summary

As can be seen in Fig. 7 the electricity generation costs of the first four scenarios are showing small differences. The highest difference compared to the reference scenario can be observed in Scenario B) with load and feed-in curves from the year 2012. A high difference can be observed in the scenarios with a number of new power plants and with increasing costs for CO2 certificates. It can be seen that the LCOE of lignite and coal units react stronger to CO_2 prices because of their higher over CO_2 emissions. CCS plants on the other side are not that dependent on the certificate prices. On the other side when assuming the commissioning of new base load units the full load hours will go done and the LCOE will increase strongly.

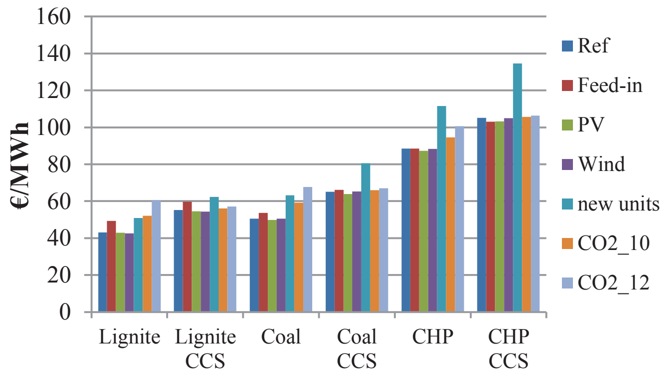

Fig. 7 Overview of electricity generation costs per unit type for all scenarios investigated (CO2_10 represents a yearly increase of certificate prices of 10 % and CO2_12 of 12 % respectively)

V. CONLUCSION AND OUTLOOK

In this paper a model has been explained on the example of Germany to calculate the power plant dispatch and the electricity generation costs of an electricity supply system with a high share of renewable energies. It has been demonstrated that the input data and the assumptions taken can influence the outcome of the same model significantly. This shows the importance of a sensitivity analyses. For the future work the model has to be extended to an interconnected system because an islanded system does not show the flexibility interconnection can provide. There is a high potential of lowering surpluses as well as shortages when improving the interconnection to neighboring countries, e.g. [24]. Further investigation of energy storage system operation strategies for different optimization horizons will be made. This includes the optimization targets like minimum CO_2-emissions, maximum integration of renewable energies, minimum needed back-up capacity of conventional units and minimum electricity generation costs. Linear programming together with developed optimization strategies are used to produce results.

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