Flexibilization of steam power plants as partners for renewable energy systems

M. Richter[1], F. Möllenbruck[1], F. Obermüller[2], A. Knaut[2], F. Weiser[2], H. Lens[3], D. Lehmann[3]

[1]Chair of Environmental Process Engineering and Plant Design, University Duisburg-Essen, 45141 Essen, Germany
[2]Institute of Energy Economics at the University of Cologne, 50827 Cologne, Germany
[3]STEAG Energy Services GmbH, 45128 Essen, Germany

Abstract – **Increasing the flexibility of conventional power plants is one key challenge for the massive integration of highly volatile renewable energy resources into the German and European power system. Flexible power plants ensure the security of supply by compensating fluctuations in the electrical grid caused by intermittent renewable energy production from wind and sun.**

In this paper, the future development of the German electricity market is predicted and evaluated in terms of the future flexibility demand of coal-fired power plants based on simulation studies for four distinct years. As the flexibility measures for coal-fired power plants generally use inherent capabilities of the existing power plant systems, they are usually restricted by limiting factors. Here, the limiting factors for reducing the minimum load and increasing load change rates are discussed and potential measures to mitigate their influence are presented.

An alternative way to increase the flexibility lies in properly integrating thermal energy storages. This integration is presented and evaluated using a dynamic power plant model in EBSILON®Professional. Simulations show that by integrating this storage concept the electrical minimum load can be reduced while simultaneously increasing the load change rate.

Keywords: Dynamic power plant simulation, Electricity market modeling, Power plant flexibility, Thermal energy storage, Unit commitment model

I. INTRODUCTION

According to the latest version of the German Renewable Energy Sources Act (EEG) from August 2014, the share of renewable energies in power production in Germany is to increase towards the targets of 40 - 45 % in 2024, 50 - 60 % in 2034 and 80 % in 2050 [1].

In the current energy system, mainly flexible conventional power plants ensure the stability of the system by compensating fluctuations in the grid caused by intermittent renewable energy supply (PV and wind) [2]. Considering the increasing installation of these renewable energy sources, the demand for flexible power plants becomes increasingly important. In summary the flexibility features to be provided by future power plants are:

- Optimized start-up procedure
- Reduced minimum load
- Increased load change rates
- (Increased) Provision of control power.

As the majority of current power plants, especially coal-fired power plants, have been designed with a focus on stable operation, a considerable potential for increasing the flexibility can be presumed for existing power plants. For this reason the German research project "Partner Steam Power Plant" [3] was executed to contribute to a scientifically sound assessment of future flexibility demand of coal-fired power plants and possible flexibility measures. In order to have a realistic foundation, a reference power plant has been selected for the detailed technical assessment.

Thus, this paper is structured as follows: Section II introduces the model MORE and the assumptions made for the simulation of the future German electricity market. From these results the future flexibility requirements for coal-fired power plants are predicted. Section III summarizes possible flexibility measures and discusses typical limiting factors, focusing on reducing the minimum load and increasing the load change rates. In Section IV, the dynamic modeling of the reference power plant with EBSILON®Professional is presented, as dynamic power plant simulations could be a promising tool to optimize the flexibility features of coal-fired power plants. Section V finally presents the integration of a thermal energy storage (TES) into the power plant model. Such an integration is one possible flexibility measure from Section III, aiming at the reduction of the electrical minimum load while simultaneously increasing the load change rate.

II. FUTURE DEVELOPMENTS OF THE GERMAN ELECTRICITY MARKET IN A EUROPEAN CONTEXT

A. Description of the unit commitment model MORE

MORE is a fundamental cost minimizing unit commitment model for the European electricity market of the Institute of Energy Economics at the University of Cologne. Cross-border electricity flows are restricted by the installed interconnector capacities. Conventional power plants are modelled blockwise for 8,760 hours per scenario year.

The objective function is to minimize the total costs of electricity production and can be expressed as

$$\text{Min}\, TotalCosts = \sum_{h,p}[VarCosts(h,p) + StartUpCosts(h,p)] \quad (1)$$

for hour h from 0 to 8,760 and power plant p. StartUpCosts arise if a power plant starts operating. The actual StartUpCosts are dependent on the power plant p as well as on the non-production duration (time steps since last time operating). The objective function is subject to typical electricity market restrictions like supply-demand balance which is

$$\sum_p production(p) + \sum_{sm} import\,(sm) - \sum_{sm} export(sm) = \sum_{sm} demand\,(sm) \quad (2)$$

and holds for every hour h and every spot market sm. Here, import considers the electricity flow from other countries (spot markets) to the respective one and vice versa for exports.

As a unit commitment model, MORE is a mixed-integer model. Each power plant has a range of feasible production which can be described by

$$production(p) = 0 \;\text{ or}$$
$$minload(p) \le production(p) \le capacity(p). \quad (3)$$

Further restrictions, such as grid capacity constraints, are implemented similarly. Details of technical flexibility are considered as to part load and full load efficiencies, minimum load, load change rates and start-up times. Techno-economic parameters include fuel costs, CO_2 costs and emission factors. Demand side management is considered as load shifting and shedding processes. MORE also accounts for CHP and pumped storage plants which are modelled with their technical features.

B. Model assumptions

MORE is used to calculate the future scenario years 2020, 2024 and 2034. Assumptions need to be made as to uncertain developments like installed capacity of conventional power plants and renewable resources, grid extensions, as well as for fuel and CO_2 prices. Primarily, official published sources are used, i.e.:

- Power plant development based on the power plant list of the German regulator Bundesnetzagentur for Germany [4] and on EU Energy Trends 2050 (2013) [5] for rest of Europe
- Renewables based on German grid development plan (Netzentwicklungsplan) [6] for Germany and EU Energy trends 2050 (2013) [5] for rest of Europe
- CO_2 prices as to German grid development plan [6]
- Fuel prices based on World Energy Outlook [7]
- Grid extensions as to ENTSO-e data [8].

Based on the assumptions, fuel prices are expected to increase slightly while CO_2 prices increase almost linear from 7 EUR/t to 48 EUR/t CO_2 in 2034. The main assumptions with respect to renewable capacities are visualized in Fig. 1. The strong increase promotes the demand for flexibility.

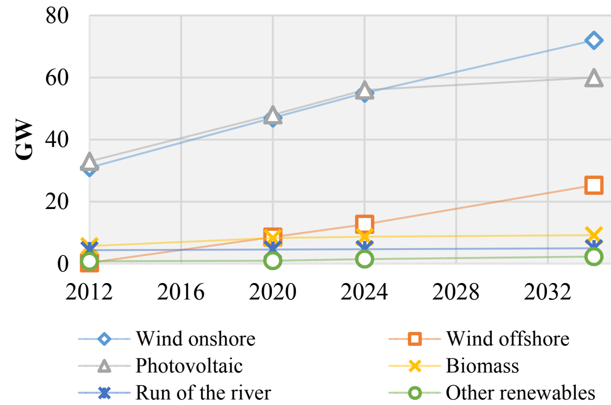

Figure 1. Development of installed capacity of renewable energies

C. Results of the economic model

The results of the economic model give insights about the fundamental relationships of the cost-minimal fulfillment of the exogenous electricity demand. Under the exogenous capacity adjustments and market circumstances, the production in the German electricity market changes according to Fig. 2.

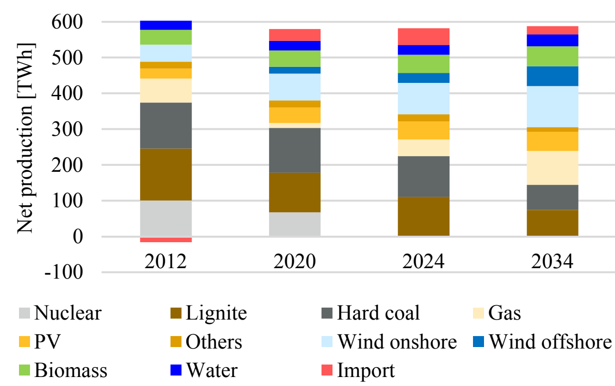

Figure 2. Development of the German electricity production (water includes run-of-river and pumped storage)

The share of renewable energies in power production increases while the conventional production decreases. Nuclear power plants will be completely shut down at the end of 2022 by German law. The share of hard coal and lignite power plant production declines and will be compensated by gas power plants and renewable production. This results in different prices, stated in histograms in Fig. 3.

In 2034, the price volatility is increased and the general price level is higher. A driver for higher prices are higher CO_2 costs. The short term marginal costs of production of a typical coal-fired power plant can be found in Table I. This data is complemented by the CO_2 and fuel costs.

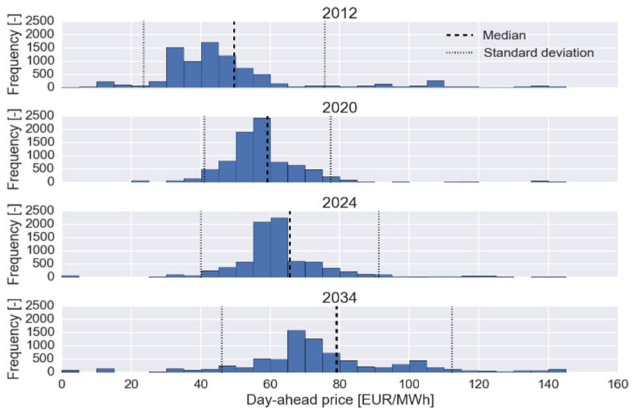

Figure 3. Development of the German day ahead market prices

TABLE I. EXEMPLARY DEVELOPMENT OF VARIABLE COSTS OF A COAL-FIRED POWER PLANT

Scenarioyear	Possible price developments		
	Variable costs [€/MWh$_{el}$]	*CO_2 price [€/t CO_2]*	*Fuel costs [€/MWh$_{th}$]*
2012	35.67	7.35	11.06
2020	52,07	21,40	12,52
2024	59.51	29.00	12.77
2034	76.93	48.00	12.94

Table I shows that the increase in variable costs for coal-fired power plants is primarily driven by an increase in CO_2 costs and not fuel costs. Furthermore, Table II shows the future number of start-ups and full load hours which tend to decrease due to the merit order effect.

TABLE II. DEVELOPMENT OF OPERATION OF A TYPICAL COAL-FIRED POWER PLANT

Scenario-year	Future number of start-ups				
	Full load hours [h]	Number of total starts	Number of cold starts	Number of warm starts	Number of hot starts
2012	6.694	23	10	13	0
2020	4.392	31	23	8	0
2024	6.201	31	13	18	0
2034	2.428	52	32	20	0

Here, hot or warm starts denote start-ups within 8 or 48 hours of downtime, respectively. Cold starts are starts after more than 48 hours since last operation. The full load hours tend to decrease until 2034 with an increase in 2024 due to the phase out of German nuclear power plants. The decrease in full load hours comes with an increase in the total number of start-ups for a typical coal-fired power plant. The number of starts is twice as much in 2034 compared to 2012. Among the starts, cold starts become more relevant.

With respect to the future operation in different load levels of a typical coal-fired power plant, the hours operating in full load show a tendency to decrease (cf. Table III). Compared to that, the share of hours operating at minimum load increases from 4.7 % in 2012 to 11.2 % in 2034.

TABLE III. DEVELOPMENT OF OPERATION HOURS AT DIFFERENT LOAD LEVELS OF A TYPICAL COAL-FIRED POWER PLANT

Scenario-year	Future operation at different load levels			
	Full load hours [h]	Hours operating at full load [h]	Hours operating at minimum load [h]	Share of hours operating at minimum load to hours operating in full load [%]
2012	6.694	6575	306	4,7
2020	4.392	4274	274	6,4
2024	6.201	6090	255	4,2
2034	2.428	2300	258	11,2

D. Implications for the future flexibility demand to coal-fired power plants

By the model results for the scenario years up to 2034, conventional power plants are still necessary to supply the electricity demand in a cost-minimal way and have a price setting behavior in most of the analyzed hours. But compared to today, coal-fired power plants are less often infra-marginal and therefore more often price setting or extra-marginal.

This implies that coal-fired power plants are still needed but are not used like today as a base load or mid load generator with a high share of full load hours. In comparison to today, profitable situations for coal-fired power plants become less frequent and more often occur instantaneously. Therefore, coal-fired power plants need to operate more flexibly. They need to perform more start-ups and stay at a minimum load level for longer periods. This is especially the case for an hourly operation of power plants, as it is optimized in MORE. When it comes to sub-hourly schedules also high load change rates are going to play an important role in the future. Higher load change rates enable power plant operators to trade electricity more flexibly in short-term markets, such as the quarter-hourly intraday market, and to gain additional profits. These implications are the reason for the following investigations how coal-fired power plants (as a representative of steam power plants) can increase their flexibility to cope with the future demand of electricity markets.

III. FLEXIBILITY MEASURES FOR COAL-FIRED POWER PLANTS

A. Description of flexibility measures

Optimized start-up and reduced minimum load

Both optimized start-up and reduced minimum load have the same goal, namely, to reduce costs which would occur due to starting the plant [9]. On the one hand, the optimization of the start-up procedure aims at reducing the oil consumption during the start-up process and making the process reproducible in terms of timing until synchronization in order to avoid unnecessary waiting times.

On the other hand, reduced minimum load aims at completely avoiding the costs for start-up by bridging time intervals in which the plant would have been normally shut down due to low energy prices usually caused by a high energy infeed of renewables. Hence, if the minimum load is decreased, the loss due to operating the plant in these time intervals is decreased as well.

Increased load change rates and control power

To counteract unpredictable events, such as outages of power plants or prediction errors regarding the energy consumption and the volatile energy production of intermittent sources, the current energy system offers services (control power) which are based on providing fast load changes by reliable energy producing units, i.e. flexible conventional power plants.

Very often it is possible to improve load gradients as well as to pre-qualify the power plant for providing control power by adapting the control algorithms in the unit control system in such a way that existing storage capabilities of, e.g., the water-steam cycle are used in a coordinated way [10, 11]. Consequently, substantial and expensive modifications of power plant components can be avoided.

B. Limiting factors

Increasing the flexibility of conventional power plants is subject to limitations that define to which extent the respective flexibility strategies can be implemented. With appropriate measures, such limitations can be overcome or at least be mitigated in order to improve the flexibility in a desired way.

From a technical point of view, the aspects described in the following sections are particularly important for increasing the flexibility of coal-fired power plants in general. Here, apart from simply listing the limitations, potential measures to deal with these limitations are discussed as well. Please note that in this paper only some key issues are mentioned, focusing on reducing the minimum load and increasing load change rates. Several further restrictions or specific criteria may need to be considered.

Reduction of minimum load

In order to reduce the load, the firing rate must be reduced. At very low firing rates, the flame may become unstable and flame detection problems may occur. Also, the minimum air flow velocity must be taken into consideration in order to prevent backfiring. Potential measures are:

- Changes in the air/fuel proportion
- Increase of air swirl and turbulence
- Reduction of the cooling air of inactive burners
- Changes at the burner construction
- Changes in the mill operation (classifier and mill pressure)
- Transition to one mill operation
- Use of smaller mills
- (Partial) Indirect firing with pulverized dried coal.

In the water-steam cycle, a considerable reduction of the load requires the transition into circulation mode, in which a part of the feed water is not evaporated and is separated to the start-up vessel. For this, a reliable and stable operation in circulation mode during several hours is needed. This requires suitable actuators for the circulation water and the feed water and suitable, optimized control concepts.

The turbine may be a limiting component due to insufficient steam flow. This causes windage, also known as ventilation, which increases the steam temperature in the turbine. While to a certain extent the temperature may be reduced in the final stages of the low pressure turbine by spraying, ventilation can be a hard limit.

The dynamic behavior of power plants at very low loads is different from full load. The control loops and the supervisory unit control generally need to be revised and optimized to reach a satisfactory control performance and to eliminate oscillations.

If the boiler load cannot be reduced further, a thermal energy storage may be used to reduce the electrical power output and to release the energy during higher loads. This flexibility measure will be evaluated with a dynamic simulation model of a coal-fired power plant in the Section V.

More details on the technical aspects of minimum load reduction are described in [9] and [12].

Increase of load change rates

Considering the increase of the load change rates not only physical limitations have to be taken into account but also the dynamic behavior of the components concerned. Generally, the following effects have to be overcome in order to get a faster response of the energy output of the power plant:

- Storage processes for mass and energy
- Delays and dead times due to transportation processes

The resulting limitations to be maintained by increasing the load change rate are:

- Thermal stress of primarily thick-walled components
- Thermal stress of generator windings
- Deterioration of actuators
- Cavitation.

As load change rates are usually restricted by rate limiters implemented in the control system of the power plant which are often set up in a conservative way, the increase of the load change rate can be achieved by accordingly adapting the control structure of the power plant. However, process variables which are related to the above-mentioned limitations need to be carefully monitored by (potentially) additional sensors to ensure that the plant will be driven within its physical bounds.

IV. Dynamic Power Plant Model

A. Dynamic simulation model of a coal-fired power plant

Dynamic power plant simulations could be a promising tool that can be used to calculate and optimize the transient operational behavior of existing or newly-built power plants.

The dynamic simulation model presented in the following was built up by means of the power plant simulation software EBSILON®Professional. The dynamic simulation model consists of a combination of static and dynamic component models, as classified in Table IV. The distinguishing criterion is the time response of the components to a change in the thermodynamic boundary conditions (e.g. a change in temperature). Dynamic components have relatively slow time constants in comparison to static components, which is accounted for by time derivatives in the balance equations for energy, mass and momentum.

TABLE IV. Classification of power plant components into static and dynamic based on [13]

Static components	***Dynamic components***
Steam turbine	Heat exchanger
Pump	Steam pipe
Valve	Mixing point
Compressor	Feed water tank
..	Coal mill
	..

The water-steam cycle of the dynamic simulation model in EBSILON®Professional includes turbine train, condenser, preheating line and feed water tank. Besides these components, a detailed dynamic model of the steam generator was built up consisting of coal-mills, air preheater, combustion chamber, nine heat exchangers and three injection coolers.

B. Power plant control system

Apart from the power plant process, also the control system has to be considered in the dynamic power plant model. The control system calculates set points and control variables for the operation of a power plant. The following control structures are implemented in the dynamic power plant model to achieve a sufficient accuracy of the simulation results:

- Unit Control
- Feed water control
- Steam temperature control
- Recirculation control

The main task of the unit control, for example, is to adapt the actual power output to the required power output which is given by the load dispatcher or the power plant schedule, respectively. To guarantee a stable and safe operation of the power plant, a step change of the power output target is transferred into a ramp signal with the maximum permissible rate of change $\dot{P}_{perm}$ (in MW/min) as its gradient.

C. Model validation

In order to validate the dynamic power plant model, the simulation results are compared to measurement data from the underlying coal-fired power plant. The trajectory of the power output, shown in Fig. 4, is mainly influenced by the unit control. The power output target, represented by the black dashed line, is the only input variable to the dynamic power plant model. The results of the dynamic simulation model (blue line) show a high correlation to the measured values (orange line) during the load profile. The essential dynamic fluctuations in the gross electrical power output (e.g. between 5:00 and 6:00 due to the startup of two coal mills) are also represented by the dynamic power plant model.

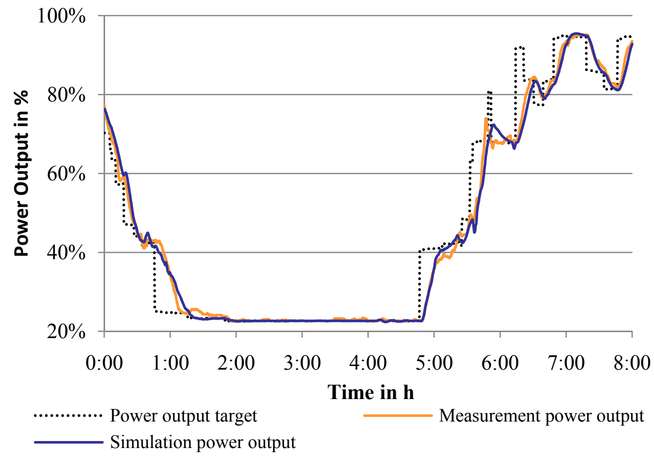

Figure 4. Comparison of simulated and measured power output

Additionally, Fig. 5 shows the comparison of water-steam temperatures to prove the validity of the detailed dynamic steam generator model. The curves also show a good accordance. Due to the transition of the water-steam cycle to circulation mode, the economizer inlet temperature rises between 1:00 and 5:00 in measurement and simulation.

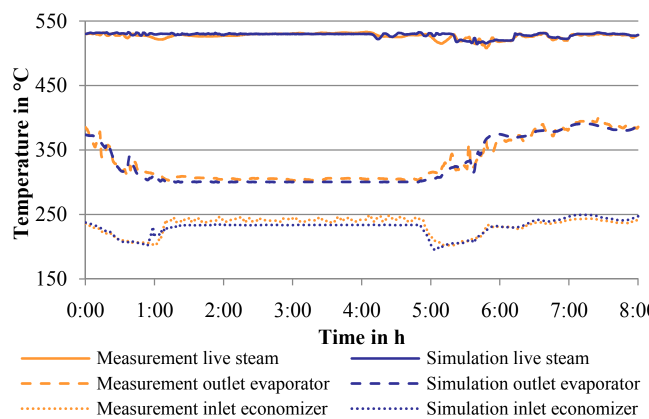

Figure 5. Comparison of simulated and measured water-steam temperatures

In summary, the comparison of simulated and measured values shows a good accordance in different load points and also during load changes. Consequently, the model allows reasonable investigations about flexibility measures for coal-fired power plants such as the integration of a thermal energy storage, as presented in the next section.

V. INTEGRATION OF A THERMAL ENERGY STORAGE

A. Reduction of the (electrical) minimum load

The integration of TES is one possible flexibility measure that can be evaluated by means of the dynamic power plant model. TES can have various effects on the flexibility, depending on concept, point of integration and capacity. They can be used to improve the power plant start-up and shut-down procedures, to provide control power or to increase the load change rates. Furthermore, TES can be used for a load shift between minimum load and full load. If a power plant is operated in minimum load - usually in times with a low spot market price - the storage can be charged with energy from the water-steam cycle. Charging the storage reduces the electrical minimum load. In times of high spot market prices the energy from the storage can be integrated into the preheating line, leading to an additional electrical power output at full load by the reduction of extraction steam for preheating.

Fig. 6 shows the integration of a TES concept for the load shift between minimum load and full load. The TES is charged with energy from an additional extraction of cold reheat steam. During discharge-mode, energy from the storage system is integrated between low-pressure preheater 3 (LP-PH 3) and the feed water tank (FWT).

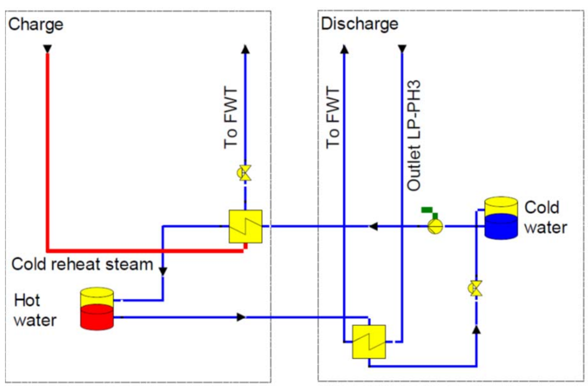

Figure 6. Schematic structure of the considered storage concept

Charging the TES with a heat flow of 56 MW_{th} leads to a reduction of the electrical minimum load by 2.0 percentage points. During discharge-mode, the integration of 56 MW_{th} enables an additional electrical power output at full load of 1.3 percentage points. This is achieved by reducing the heating steam to the FWT and a correspondingly higher power of the LP turbine. Table V provides an overview of the TES concept.

TABLE V. PARAMETER OF THE TES CONCEPT

Minimum load reduction	% - points	2.0	Additional electrical power	% - points	1.3
Heat flow (Charging / Discharging)	MW_{th}	56	Capacity of storage	MWh	168
Pressure hot water tank	bar	10	Pressure cold water tank	bar	5
Temperature hot water tank	°C	170	Temperature cold water tank	°C	140
Time (Charging / Discharging)	h	3	Water mass storage system	t	5,000

The thermal efficiency of this TES concept comes out to 67 %. The comparison of the power output between the reference process and the power plant model with TES integration is shown in Fig. 7.

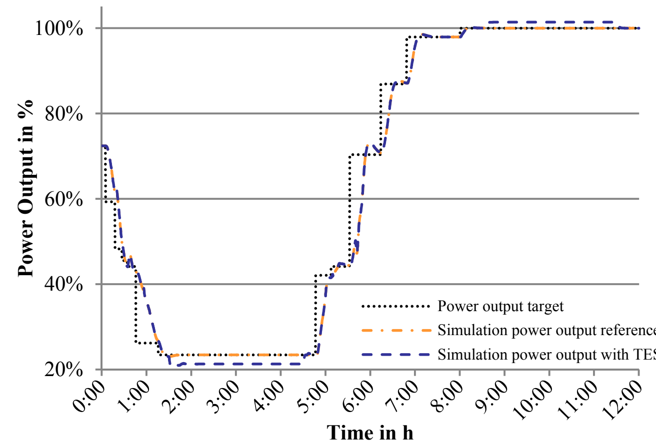

Figure 7. Simulation results for the load shift between minimum load and full load by a TES integration

The heat flow of the TES during charge- and discharge-mode is limited to about 56 MW_{th} by a minimal extraction of heating steam to the FWT, as shown in Fig. 8. Throttling of the low pressure preheaters in front of the FWT would allow higher heat flows, but also would lead to a decrease in the thermal efficiency of the TES.

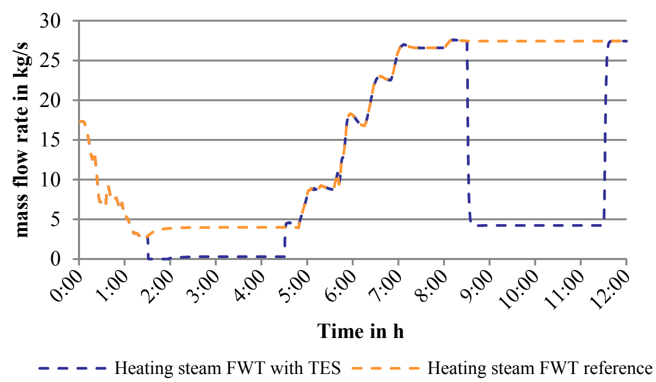

Figure 8. Comparison of simulated heating steam mass flow rates to the FWT with and without TES integration

B. Increase of the load change rate

Beside the load shift between minimum load and full load the presented TES can also be used to increase the load change rate. This can be reached by switching the TES to charging-mode for negative load changes and vice versa.

The load change rate of a power plant can be calculated using the 90 percent method [14]. The criterion for the calculation is the time the power plant needs to reach 90 percent of the required load change. If a power plant, for example, should perform a negative load change from 100 % to 75 % and needs 15 minutes to reach 77.5 %, the load change rate with the 90 percent method is calculated as

$$\frac{dP}{dt} = \frac{0.9 \cdot (100-75)\%}{15\text{min}} = 1{,}5\ \%/_{\text{min}} \tag{4}$$

To evaluate the impact of the TES integration on the increase of the load change rate, the unit control has to be adjusted to correctly consider the (partial) decoupling of steam generation and turbine power output. In particular, the unit control is adapted in a way that the power output target is transferred into two set points, as visualized in Fig. 9. A step change of the power output target (black dashed) is transferred to a set point for the power output (orange) and a set point for the steam generator (blue). The set point for the power output is adjusted by the loss in electrical power when switching the TES to charge-mode at the beginning of the load change. The steam generator set point is equivalent to the reference case at the beginning of the load change. At the end of the load change, the loss in electrical power through the TES integration is added to the steam generator set point leading to a higher firing rate to reach the power output target.

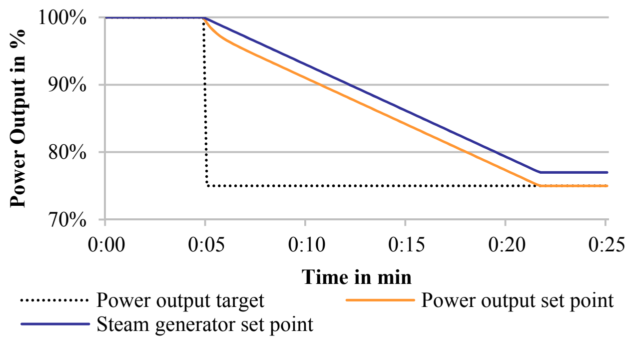

Figure 9. Input and output variables of the modified unit control

After modifying the unit control, positive and negative load steps are simulated with the dynamic power plant model. Fig. 10 shows the simulated time curves of the power output for the reference process (orange) and the process with TES integration (blue) for a negative load step of from 100 % to 75 %. The TES is switched to charge-mode at the beginning of the load step leading to a fast reduction of the power output. After about two minutes the "conventional" load decrease through adjusting the thermal input to the steam generator takes control of the process leading to nearly parallel time curves for both configurations. The power output of 77.5 % (90 percent method) is reached after 20:00 minutes with the reference process, whereas the configuration with TES integration reaches this value after about 18:40 minutes. Hence, the load change rate can be increased from 81 % to 87 % related to the permissible change rate $\dot{P}_{perm}$ within the unit control.

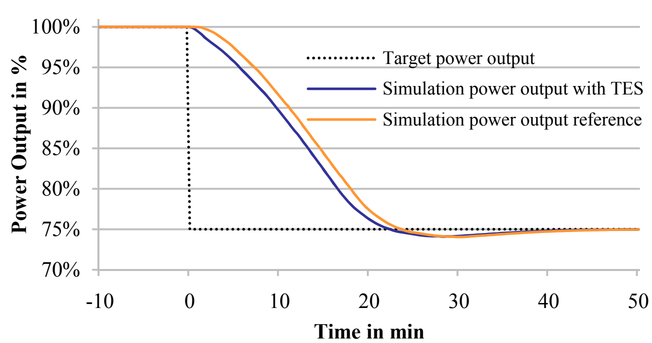

Figure 10. Comparison of simulated power output of a negative load step with and without TES integration

Fig. 11 summarizes the evaluation of the impact on the load change rate for two positive and negative load steps. The following conclusions can be drawn for the TES integration regarding the impact on the load change rate:

- The load change rate can be increased for all considered load steps through the TES integration
- The increase of the load change rate is rather small, as the main part of the load change process still has to be realized through the "conventional" adjustment of the thermal input to the steam generator due to the limited influence on the power output by the TES
- The impact on the load change rate gets smaller for bigger load steps
- For TES concepts with a higher heat flow, respectively a bigger influence on the power output, the impact on the load change rate increases.

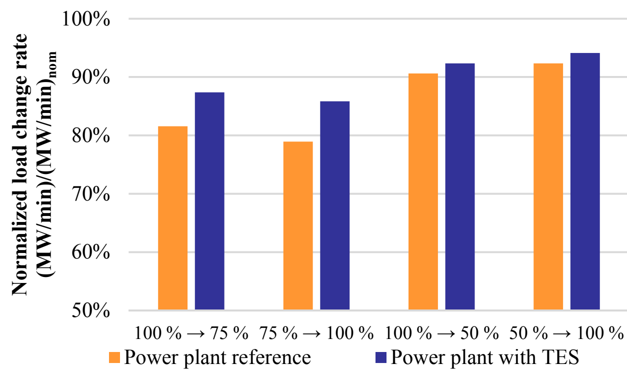

Figure 11. Increase of load change rate through TES integration

VI. Conclusion and Outlook

A. Conclusion

The electricity market simulations show a significant reduction of full load hours, an increased number of start-up processes and an increased share of minimum load operation for a typical coal-fired power plant for the future due to an increasing share of renewable energies in power production. Consequently, steam power plants face increased flexibility requirements to provide the residual load and ensure security of supply also in the future.

The consideration of limiting factors and potential measures to overcome these limitations indicates that increasing flexibility is not limited to newly-built coal-fired power plants. In fact, since the control algorithms currently implemented in existing power plants are generally designed to guarantee stability without focusing so much on the transient behavior, many flexibility measures can be implemented by adapting the automation of the power plant. Consequently, the chances for successfully implementing these measures also in existing power plants are generally promising. Furthermore, the integration of TES could be a promising measure for the flexibilization of steam power plants.

The results of the detailed dynamic power plant model show a good accordance to operating data. First simulation studies about the flexibilization of the power plant process through a TES integration outline the possibility of a load shift between minimum load and full load as well as the increase of the load change rates.

B. Outlook

Further development of the electricity market simulations towards the intraday market (quarter-hourly products) and the consideration of the balancing market are planned, to allow the economic evaluation of flexibility measures regarding load change rates and the supply of control energy.

Regarding the TES integration, additional simulation studies are planned that focus on the supply of control energy and/or the start-up process. Moreover, further flexibility measures will be evaluated like adapting control structures as well as changes in the power plant process (e.g., the retrofit of an indirect firing system).

ACKNOWLEDGMENT

The authors would like to thank the German Federal Ministry for Economic Affairs and Energy (BMWi) and the companies E.ON, RWE and Vattenfall for the financial support of the project "Partner steam power plant for the regenerative power generation" [3] in the frame of the COORETEC program (Grant No. 03ET7017G). Also we would like to thank STEAG GmbH for the acquisition of design and process data of the reference power plant.

Gefördert durch:

Bundesministerium für Wirtschaft und Technologie

aufgrund eines Beschlusses des Deutschen Bundestages

REFERENCES

[1] EEG 2014, Gesetz für den Ausbau erneuerbarer Energien (Erneuerbare-Energien-Gesetz) of 21. Juli 2014. Available web site: http://www.gesetze-im-internet.de/eeg_2014/

[2] U. Tomschi, B. Weidmann and S. Eckstein: "Anforderungen an die konventionellen Kraftwerke und deren Möglichkeiten." Proceedings of 10. GMA/ETG-Fachtagung Netzregelung und Systemführung, Munich, Germany, 2011.

[3] VGB PowerTech e.V., VGB Research Project 375: Partner steam power plant for the regenerative power generation. Available web site: http://www.vgb.org/en/research_project375.html

[4] Kraftwerksliste der Bundesnetzagentur, 19.02.2014. Available web site: http://www.bundesnetzagentur.de/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/Versorgungssicherheit/Erzeugungskapazitaeten/Kraftwerksliste/kraftwerksliste-node.html

[5] European Comission, "EU energy, transport and GHG emissions: trends to 2050 : reference scenario 2013," ISBN: 978-92-7-33728-4, European Union, 2014.

[6] 50Hertz Transmission GmbH, Amprion GmbH, Tennet TSO GmbH, TransnetBW GmbH: "Netzentwicklungsplan Strom 2014: Zweiter Entwurf,"Available web site: www.netzentwicklungsplan.de/NEP_2014_2_Entwurf_Teil1.pdf

[7] Organisation for Economic Co-operation and Development, World energy outlook 2013. Paris: International Energy Agency, 2013.

[8] Entso-e „NTC matrix (summer/winter). Feb. 2011. Available web site: https://www.entsoe.eu/publications/market-reports/ntc-values/ntc-matrix/Pages/default.aspx

[9] H. Lens and M. Nolte, "Reduction of the minimum generator output of hard-coal fired power plants through control and process engineering," VGB PowerTech Journal, (4) pp. 41-46, 2015.

[10] M. Kurth, H. Lens, J. Marquard, A. Dengel, W. Schweißthal and C. Kolligs: "Vergleich und Einsatz von Speichertechnologien aus Sicht eines Kraftwerksbetreibers." In VGB PowerTech Journal, (12), pp. 68-75, 2011.

[11] M. Kurth and G. Kallina: "Möglichkeiten zur Verbesserungen des Regelverhaltens von Dampfkraftwerksblöcken." Proceedings of 9. GMA/ETG-Fachtagung Netzregelung und Systemführung, pp. 68-73, Munich, Germany, 2008.

[12] H. Lens: "Mid-Load Operation of Large Coal-Fired Power Plants." Proceedings of PowerGEN Europe, Cologne, Germany, 2013.

[13] Epple, B.; Leithner, R.: Simulation von Kraftwerken und Feuerungen, Springer, Wien, 2012.

[14] VDI/VDE 3508. Unit control of thermal power station