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Abstract

As the share of intermittent renewable electricity generation increases, the remaining fleet of conventional power plants will have to operate with higher flexibility. One of the methods to increase power plant flexibility is to integrate a thermal energy storage (TES) into the water-steam cycle of the plant. TES can provide flexibility and achieve profits by engaging in energy arbitrage on the spot markets and by providing additional power on the control power markets. This paper considers a reference coal-fired power plant with an integrated TES system for the year 2019 in Germany. Optimal dispatch for profit maximisation with TES is simulated on the hourly day-ahead and quarter-hourly continuous intraday markets as well as on the markets for primary (PRL) and secondary (SRL) control power. Analysing the effects of TES round-trip efficiency and storage capacity on dispatch and the profits, I find that smaller TES systems with up to one hour of storage capacity can achieve substantial profits on the PRL market while also realising profits from energy arbitrage on the continuous intraday market. Higher TES round-trip efficiencies can help TES achieve significant profits also on the day-ahead market. The analysis shows that a storage capacity of 2–3 hours is enough to realise most of the energy arbitrage potential, while larger storage capacities can greatly increase TES profits on the SRL market. Small TES systems are found to increase the full load hours of the plant marginally. However, the increase becomes significant with larger storage capacities and can lead to higher CO_2 emissions for the individual plant.

Keywords: coal-fired power plant, flexibility, thermal energy storage, energy arbitrage

JEL classification: Q40, Q49

1. Introduction

The share of renewable energies in global electricity generation has grown substantially in the last decades and is expected to further increase in the future. International Energy Agency, in its Stated Policies scenario of the World Energy Outlook 2019, foresees the global share of wind and solar PV in the electricity mix to increase from 7% in 2018 to 17.2% in 2030. In the Sustainable Development scenario, which considers a setting with a higher probability of reaching the climate targets, this share increases to 25% (IEA, 2019). Intermittent renewable generation is highly weather-dependent and fluctuations are largely compensated by conventional power plants in the current energy system. As the share of intermittent renewables further increases and conventional capacity decreases, the remaining fleet of conventional power plants will need to operate with increased flexibility.[1]

The main specifications of a conventional power plant that define its flexibility are its minimum load, load change rate (i.e. ramping rate), and start-up duration and start-up costs.[2] A relatively flexible plant would be characterised by a low minimum load, a high load change rate and low start-up duration with lower start-up costs. While lowering the minimum load of the plant reduces the losses in low price hours and helps avoid shut-downs and subsequent start-ups, increasing the load change rate would allow to generate additional revenues on the electricity markets (e.g. on intraday and control power markets). As such, increased flexibility can directly translate to higher profits for the power plant operator. Additionally, increased flexibility of power plants can also have system benefits as they allow the integration of more wind and solar power (Agora Energiewende, 2017). With increased wind penetration, the ramping capabilities of the existing power plant fleet becomes much more important, since more flexible operation of the existing fleet would allow for a higher degree of intermittent wind integration (Hong et al., 2012). Moreover, flexible thermal power plants can help reduce wind curtailment and increase resilience to wind ramping (Kubik et al., 2015).

An effective method to increase power plant flexibility is to utilise thermal energy storages (TES). Zhao et al. (2018b) and Zhao et al. (2018a) simulate a coal-fired power plant and show that, by controlling the internal thermal storages inherent to the thermal system of the plant, it is possible to enhance the ramping rate of the plant.[3] More substantial increases in flexibility are possible by integrating a thermal energy

[1]Using optimal power flow simulations to compare the years 2013 and 2020, Eser et al. (2016) finds that increased penetration of renewables in Central Western and Eastern Europe can cause the number of starts of power plants to increase by up to 23% and the number of load ramps by up to 181%.

[2]For more information on these parameters, see Hentschel et al. (2016), Agora Energiewende (2017) and Richter et al. (2019).

[3]Among the strategies investigated in these papers, the largest additional contribution to ramping rates has an average power ramp rate of 6.19% per minute (40.89 MW/min) with a very limited energy capacity of 5.58 MWh.

storage into the water-steam cycle of the plant. With these configurations, the TES is charged with the heat extracted from the water-steam cycle of the plant when power demand is low (i.e. electricity prices are low) and the stored energy is then discharged to the plant cycle when power demand is high (i.e. electricity prices are high), allowing energy arbitrage to be conducted. Wojcik and Wang (2017) investigate the integration of a TES into a sub-critical oil-fired conventional power plant, focusing on the simulation of charging and discharging processes. Li et al. (2017) consider a combined-cycle gas turbine plant with integrated TES. Li and Wang (2018) and Cao et al. (2020) analyse the feasibility of integrating a high temperature thermal energy storage in a coal-fired power plant. Richter et al. (2019), also simulating a coal-fired plant, consider the integration of a steam accumulator TES. In all of these studies, it is shown that plant load can be reduced or increased significantly by charging or discharging the TES, respectively. The investigated concepts and the associated parameters are summarised in Table 1.

Table 1: An overview of the various simulations of TES applications in power plants observed in the literature

Source	Considered power plant	TES-charging Δ net power	TES-discharging Δ net power	Storage capacity
Wojcik and Wang (2017)	Oil-fired (375 MW)	-13%	14%	n/a
Li et al. (2017)	CCGT (137 MW)	-11.7%	5.8%	0.3 h
Li and Wang (2018)	Coal-fired (600 MW)	-13.3%	7.4%	1-4 h
Cao et al. (2020)	Coal-fired (600 MW)	-16.7%	6.2%	8 h
Richter et al. (2019)	Coal-fired (695 MW)	-7.0%	4.3%	0.5 h

In Germany, the share of wind and solar PV in gross electricity generation has increased from 8% in 2010 to 28.6% in 2019 (AG Energiebilanzen, 2020), reaching its highest percentage observed until then. As such, the flexibility requirements on thermal power plants has also increased substantially. This makes the case of Germany in 2019 particularly suitable for the analysis of the applicability of TES-integrated plants and their optimal dispatch. As the economic benefits of flexibility improvements in hard coal power plants are potentially higher than the benefits from similar changes at gas-fired plants (Hübel et al., 2018), it is especially worth considering the case of coal-fired power plants. While a TES investment in coal-fired plants in Germany due to the coal exit decision[4] may not be practical any more, the analysis of the German case can nevertheless be indicative for other regions having significant coal-fired capacities, where high renewable penetration is expected in the medium-term.

In this context, this paper analyses the effects of an integrated TES system on the optimal (profit maximising) dispatch of a coal-fired power plant in Germany for the year of 2019. For this purpose, a mixed

[4] Germany has passed legislation to end coal-fired generation by 2038 at the latest. (Source: Kohleverstromungsbeendigungsgesetz - KVBG, 08.08.2020)

integer linear programming (MILP) model is developed to simulate the optimal dispatch of the plant with TES. Additional profits due to TES on various electricity markets (i.e. day-ahead, intraday, primary (PRL) and secondary (SRL) control power markets)[5] are calculated. The relevance of individual TES parameters regarding the profit potential on the individual markets is analysed and charging/discharging patterns are identified.

Considering a reference TES system specification as presented in Richter et al. (2019), I find that the TES with a 0.5 hours of storage capacity can achieve 377,000 EUR of additional profits in the dispatch year of 2019, increasing the total profits of the plant by 2.4%. Profits on the PRL market are found to make up a large majority (about 60%) of the profits, followed by those obtained via energy arbitrage due to dispatch on the intraday continuous market (about 20%). Larger storage capacities allow for higher energy arbitrage profits; albeit the incrase in profits due to arbitrage is limited. In contrast, very substantial increases in the profits on the SRL market can be achieved with larger storage capacities. Considering also an alternative high-efficiency TES, I show that energy arbitrage profits on both day-ahead and intraday markets can be greatly increased if the round-trip efficiency of the TES system is higher. While the analysis shows that integrating a TES system can provide the plant with significant additional flexibility and profits, TES is found to increase the full load hours of the plant. The increase is marginal (less than 1%) for a TES storage capacity of 0.5 h; however, it becomes significant with larger capacities and can potentially increase the CO_2 emissions of the individual plant.

This paper is primarily related to two streams of literature. The first relevant stream of literature deals with simulating optimal dispatch using MILP models. MILP models have been widely used in the literature for solving unit commitment problems (see Ostrowski et al. (2012), Frangioni et al. (2009) and Richter et al. (2016)). It is also common to apply MILP models to determine optimal scheduling of individual power plants and to simulate profitability and conduct techno-economic analyses. Kazempour et al. (2008) provides an optimal dispatch model for a pumped-storage plant that is active in both energy and regulation markets, simulating expected weekly profits. Knaut and Paschmann (2017) uses a MILP model to compare profitability of a CCGT plant to that of a lignite-fired power plant on different electricity markets in Germany (i.e. day-ahead auction and intraday auction). Beiron et al. (2020) analyses various flexibility options using a MILP optimal dispatch model for a waste incineration plant with combined heat and power (CHP). Similarly, Beiron et al. (2020) uses a MILP-based approach for the analysis of a CCGT CHP plant's flexibility potential.

[5]PRL is also referred to as Frequency Containment Reserve (FCR.) SRL is also referred to as Frequency Restoration Reserve with Automatic Activation (aFRR)

The second stream of literature relevant to this paper focuses on techno-economic assessment of storage systems and energy arbitrage. Energy arbitrage with storage systems has been a common topic in literature (see Walawalkar et al. (2007), Sioshansi et al. (2009) and Bradbury et al. (2014)), where the research has focused on optimal location, sizing and parametrisation of various storage technologies. With decreasing battery costs, recent years have especially seen a surge in studies analysing energy arbitrage with Li-Ion batteries. Dufo-López (2015), simulating the operation of a Li-Ion battery storage system for the Spanish electricity market pool of 2013, finds that the considered storage system is not profitable with the contemporary investment costs. Arcos-Vargas et al. (2020), similarly considering a Li-Ion battery system for the Iberian market during the period 2016–2017, finds that energy arbitrage will only be profitable from 2024 onward with sustained decreases in battery costs. Metz and Saraiva (2018) simulates energy arbitrage with a Li-Ion battery on the German hourly and quarter-hourly intraday auctions for the period 2011–2016, finding that the analysed system does not break even with the historical volatility of prices and the contemporary storage investment costs.

Energy arbitrage with TES has been considered in the literature for different types of energy systems. Sioshansi and Denholm (2010) shows that TES can increase the value of concentrated solar power (CSP) plants as it allows the shifting of generation to hours with higher electricity prices. Scapino et al. (2020) considers an energy system with sorption TES for the electricity markets of Belgium in 2013 and the UK in 2017, and finds that the TES system is not profitable when only operating on the day-ahead market, but becomes profitable when it also provides balancing services. Risthaus and Madlener (2017) simulates the optimal dispatch of a heat pump with TES, which is integrated partially[6] (i.e. only for the discharging phase) to a coal-fired power plant and a CCGT in Germany, as well as to a CSP in Spain, for the year of 2016. The study finds that revenues from energy arbitrage are not enough to cover the high investment costs.

Against this backdrop, the contribution of this paper can be summarised as follows: The analysis conducted in this paper is the first of its kind, providing insight into the optimal dispatch of a coal-fired plant with a TES that is completely integrated in the steam-water cycle. Moreover, the paper distinguishes itself by the inclusion of the primary and secondary control power markets as well as the intraday continuous market in the dispatch simulation. Optimal profits of the system in the participated spot and control powers are calculated and the effects of TES parametrisation on dispatch and profits are

[6] During the charging phase, the heat is generated by the heat pump and is stored in the TES. The heat is then supplied from the TES to the plant water-steam cycle during discharging.

investigated. The analysis is conducted for a power plant located in Germany with German historical market prices. However, the methodology can also be applied to other regions.

2. Model

In this section, I introduce a dispatch model of a power plant with an integrated TES system. The overall structure of the stylised model is schematically depicted in Figure 1. In line with Richter et al. (2019), the TES is integrated in the power plant water-steam cycle between the steam generator and the turbine. As such, steam from the steam generator can be directed to the TES, charging the TES and reducing the turbine output. Similarly, the TES can be discharged and the stored steam can then be used to increase the turbine output. In this setting, the plant operator has the task of maximising the total profit by optimising the dispatch decisions on various markets the power plant is active on. When doing this, the operator needs to take into account, in addition to the standard power plant constraints, also the additional constraints of the TES system.

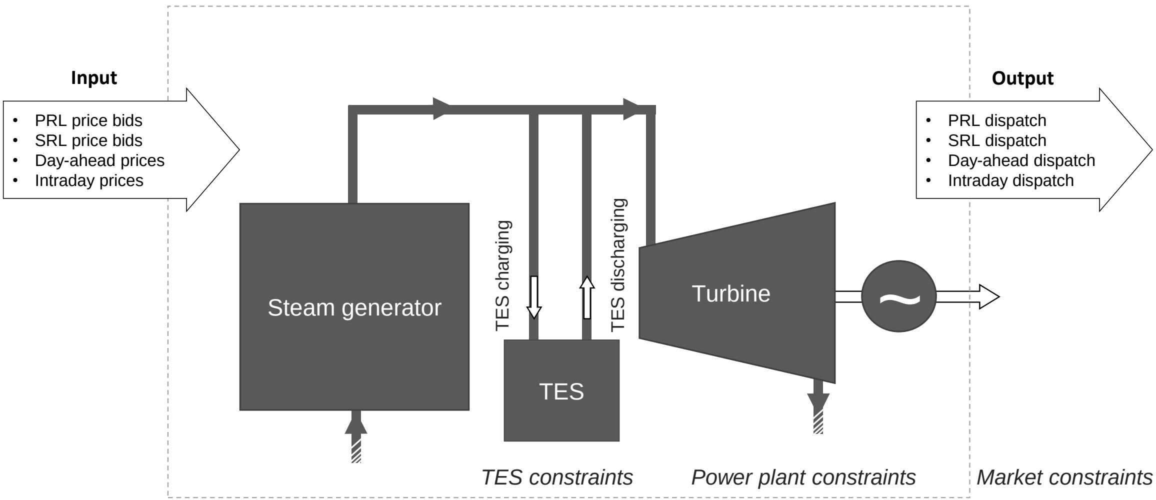

Figure 1: Schematic representation of the model structure

The problem of the plant operator is formulated as a mixed-integer linear programming (MILP) model. The objective function corresponds to maximising total profits from the dispatch on the wholesale electricity markets and the markets for control power, subject to power plant and TES system constraints and various market-specific constraints (i.e. prequalification criteria for providing control power). The considered wholesale electricity markets are the day-ahead (DA) auction with hourly products and the continuous intraday (ID) trade with quarter-hourly products. The continuous ID market with quarter-hourly products is particularly chosen due to its higher volatility, which makes it theoretically more profitable for storage systems. Additionally, the plant is assumed to provide primary and secondary control power, PRL and SRL, respectively.

Taking prices for the PRL, SRL, DA and ID markets as input, the model optimises the dispatch on these markets. Optimising the dispatch on PRL and SRL markets simultaneously with the DA market allows the optimal capacities on the control power markets to be endogenously determined by the model. The coal-fired plant without the TES system is assumed not to be able to participate on the continuous ID market by itself as it lacks the necessary operational flexibility. The TES, however, can be activated within several minutes (Richter et al., 2019), providing the necessary flexibility to be able to react to price signals and offer capacities on the continuous ID market. Similarly, the TES increases the technical capability for providing control power on the PRL and SRL markets. The plant operator is assumed to be price taker and to have perfect foresight. Therefore, the optimal total profit obtained by the model represents an upper benchmark.

The operator maximises the total profit which is equal to the sum of total revenues R_{da} on the DA, R_{id} on the ID, R_{srlp} on the positive SRL, R_{srln} on the negative SRL and R_{prl} on the PRL markets, minus the variable costs C_{var} and the start-up costs C_{su}. The objective function of the problem can then be written as follows:

$$\max Profit = \sum_{t}^{T}(R_{da}^t + R_{id}^t + R_{srlp}^t + R_{srln}^t + R_{prl}^t - C_{var}^t - C_{su}^t) \tag{1}$$

The capacity offered on the DA market equals the actual total output X_{da} of the plant with TES on the DA market, plus the volumes that were initially sold on the DA auction but are bought back on the ID market $TES_{id,in}$ by charging the TES. Thus, the DA revenue is obtained by mutliplying the total capacity offered on the DA market with the corresponding DA prices, and with 0.25 since the model has a quarter-hourly resolution:

$$R_{da}^t = 0.25p_{da}^t(X_{da}^t + TES_{id,in}^t) \tag{2}$$

The ID revenue equals the volumes sold on the ID market $TES_{id,out}$ by discharging the TES minus the volumes bought $TES_{id,in}$ by charging, multiplied with the ID prices:

$$R_{id}^t = 0.25p_{id}^t(TES_{id,out}^t - TES_{id,in}^t) \tag{3}$$

On top of the standalone SRL capability PL_{srlp} of the plant, TES can provide additional positive SRL capacity TES_{srlp} by discharging. The revenue obtained on the positive SRL market consists of two components: the capacity component and the energy component. The operator generates revenue by offering control power capacity, independent of whether the plant is activated for SRL or not. The price it receives per MW of capacity is represented by $p_{srlp,c}$. As for the energy component, I assume that the plant can be activated for positive SRL with an exogenous average probability of w_{srlp}, receiving the SRL energy price of $p_{srlp,e}$. Similarly, TES can increase the total negative SRL offered by the plant by TES_{srln} on top of the standalone capacity PL_{srln}. The operator receives the capacity price $p_{srln,c}$, and with an average probability of w_{srln} the energy price $p_{srln,e}$. The capacity prices for both positive and negative SRL products ($p_{srlp,c}$ and $p_{srln,c}$) correspond to the pay-as-bid capacity prices of the power plant, which are directly derived from its opportunity costs over the DA market[7] and are limited by the historical marginal capacity prices. The revenues for providing positive and negative SRL then become:

$$\begin{aligned} R^t_{srlp} &= (p^t_{srlp,c} + 0.25 p^t_{srlp,e} w_{srlp})(PL^t_{srlp} + TES^t_{srlp}) \\ R^t_{srln} &= (p^t_{srln,c} + 0.25 p^t_{srln,e} w_{srln})(PL^t_{srln} + TES^t_{srln}) \end{aligned} \tag{4}$$

The standalone PRL capacity offered by the plant is PL_{prl}. Note that PRL is a symmetrical product. Therefore, the plant offering PRL is obligated to provide the same capacity in both directions, i.e. when it reduces or increases output depending on the PRL activation signal. As such, being able to reduce turbine output by charging and to increase it by discharging, TES can increase the offered PRL capacity by TES_{prl}. The PRL revenue is then equal to the total offered capacity multiplied by the PRL price p_{prl}[8]:

$$R^t_{prl} = p^t_{prl}(PL^t_{prl} + TES^t_{prl}) \tag{5}$$

Variable costs of the plant are represented by a linear approximation of the fuel costs using the methodology presented in Swider and Weber (2007) as shown in Equation 6. Given fuel costs p_{fuel} and the efficiency, the variable costs depend on the plant output X_{pl}, the upper bound of which is defined by the maximum plant capacity $k_{pl,max}$. The minimum load $k_{pl,min}$ defines its lower bound. Note that the plant output X_{pl} is the electrical representation of the output of the steam generator. Hence, it corresponds to the standalone output of the plant without the TES. As the efficiency at minimum load η_{ml} is lower than the efficiency at full load η_{fl}, the operator is incentivised to reduce plant output when the wholesale prices

[7]See Müsgens et al. (2014), Knaut et al. (2017) and Künle (2018) for the methodology.

[8]PRL prices are also assumed to correspond to the opportunity cost bids over the DA market, limited by the historical PRL settlement prices.

are not profitable. The variable costs also include other variable costs represented by c_{ot}. Note that the binary variable B_{on} is equal to 1 when the plant is online.

$$C_{var}^{t} = 0.25p_{fuel}\left(\frac{X_{pl}^{t}}{\eta_{fl}} + \left(\frac{1}{\eta_{ml}} - \frac{1}{\eta_{fl}}\right)(k_{pl,max}B_{on}^{t} - X_{pl}^{t})\frac{k_{pl,min}}{k_{pl,max} - k_{pl,min}}\right) + 0.25c_{ot}X_{pl}^{t} \tag{6}$$

When the plant is switched on, it incurs start-up costs while ramping up to reach the minimum load. Those costs mainly ensue from the usage of secondary fuel and are represented by Equation 7, where the binary variable B_{su} is equal to 1 when the plant starts up. To avoid additional complexity, the model does not distinguish between different start-up types (e.g. cold, warm, hot); rather, a single start-up type with average representative costs c_{su} is assumed.

$$C_{su} = c_{su}B_{su}^{t} \tag{7}$$

The plant output is defined by Equation 8, where it is either equal to zero when turned off or lies between the minimum load and the maximum plant capacity when online.

$$\begin{aligned} &X_{pl}^{t} = k_{pl,min}B_{on}^{t} + X_{overmin}^{t}, \\ &where \quad X_{overmin}^{t} \leq (k_{pl,max} - k_{pl,min})B_{on}^{t} \end{aligned} \tag{8}$$

Equation 9 considers that the change in plant output between the time periods $t-1$ and t (when the plant is online in both time periods) is restricted by the load change rates; namely, equals to r_{up} when ramping up and r_{down} when ramping down. Additionally, it is ensured that when the plant has started up and has become online, it starts at minimum load. Likewise, when the plant is shutting down, it reduces its output to minimum load first and then to zero.

$$\begin{aligned} &X_{pl}^{t} - X_{pl}^{t-1} \leq r_{up}B_{on}^{t-1} + k_{pl,min}(B_{on}^{t} - B_{on}^{t-1}) \\ &X_{pl}^{t-1} - X_{pl}^{t} \leq r_{do}B_{on}^{t} + k_{pl,min}(B_{on}^{t-1} - B_{on}^{t}) \end{aligned} \tag{9}$$

The binary states of starting up B_{su} and shutting down B_{sd} are defined, taking into account the corresponding durations d_{su} and d_{sd}, respectively:

$$B_{on}^{t} - B_{on}^{t-1} = \sum_{t1=t-d_{su}}^{t1<t} B_{su}^{t1} - \sum_{t=t1-d_{sd}}^{t<t1} B_{sd}^{t} \tag{10}$$

An additional restriction ensures that the shut-down and start-up periods do not intersect:

$$B_{su}^{t} + \sum_{t1>t}^{t1\leq t+d_{sd}} B_{sd}^{t1} + \sum_{t1>t}^{t1\leq t+d_{sd}+d_{su}} B_{su}^{t1} \leq 1 \tag{11}$$

At time point t, if not offline, the plant can only be active in one of the states "starting up" (B_{su}), "online" (B_{on}) or "shutdown" (B_{sd}):

$$B_{su}^t + B_{on}^t + B_{sd}^t \leq 1 \tag{12}$$

The output level of the plant X_{pl} is determined by the markets it is actively providing capacity for and whether the TES is being charged or discharged as expressed in Equation 13. Discharging the TES on the DA market with the power $TES_{da,out}$ increases the total capacity active on the DA market X_{da}. Similarly, charging the TES on the DA market with $TES_{da,in}$ decreases the total capacity active on the DA market. The plant output level is also determined by the total positive and negative SRL provision multiplied with the respective activation probabilities.

$$\begin{aligned} X_{pl}^t + TES_{da,out}^t - TES_{da,in}^t = & X_{da}^t + TES_{id,in}^t \\ & + w_{srlp}(PL_{srlp}^t + TES_{srlp}^t) - w_{srln}(PL_{srln}^t + TES_{srln}^t) \end{aligned} \tag{13}$$

The capacity provided in the respective markets is constrained by the physical plant restrictions. As expressed in Equation 14, the total capacity provided on the day-ahead market ($X_{da} + TES_{id,in}$) plus the positive SRL and PRL capacities, in case they are fully activated, cannot be greater than the maximum plant capacity modified by the net TES output (discharging minus charging). Similarly, Equation 15 shows that the total day-ahead capacity minus a full activation of negative SRL and PRL capacities cannot be lower then the minimum load of the plant, which is modified by the net TES output. Additionally, PRL provision by the plant requires that the plant output is above a certain threshold, which necessitates the inclusion of an additional binary term that increases the required minimum plant output by an additional f_{prl} percent of total plant capacity.[9]

$$X_{da}^t + TES_{id,in}^t + PL_{srlp}^t + PL_{prl}^t \leq k_{pl,max} B_{on}^t + TES_{da,out}^t - TES_{da,in}^t \tag{14}$$

$$X_{da}^t + TES_{id,in}^t - PL_{srln}^t - PL_{prl}^t \geq k_{pl,min} B_{on}^t + f_{prl} k_{pl,max} B_{prl}^t + TES_{da,out}^t - TES_{da,in}^t \tag{15}$$

In order for the plant output with TES not to exceed the minimum and maximum achievable total load levels when providing PRL and SRL, additional constraints are included as shown in Equations 16–18.

[9]The minimum PRL threshold of the plant is assumed to be 60% of full load. Hence f_{prl} equals 40% as the minimum load is assumed to be 20% of full load.

$$X_{da}^{t} + TES_{id,in}^{t} + PL_{srlp}^{t} + PL_{prl}^{t} + TES_{id,out}^{t} \leq B_{on}^{t} k_{pl,max} + k_{tes,max,out}(1 - B_{prl}^{t}) \tag{16}$$

$$X_{da}^{t} + TES_{id,in}^{t} + PL_{srlp}^{t} + PL_{prl}^{t} + TES_{id,out}^{t} \leq B_{on}^{t} k_{pl,max} + k_{tes,max,out}(1 - B_{srl,pos}^{t}) \tag{17}$$

$$X_{da}^{t} - PL_{srln}^{t} \geq B_{on}^{t} k_{pl,min} - k_{tes,max,in}(1 - B_{srl,neg}^{t}) \tag{18}$$

TES power output when charging and discharging depends directly on the plant output (X_{pl}) (Richter et al., 2019). Therefore, I include this variation in the model by linearising the power capacity as shown in Equation 19 with the use of exogenous parameters $\gamma_{0,in}$ and $\gamma_{1,in}$ when charging, and $\gamma_{0,out}$ and $\gamma_{1,out}$ when discharging.

$$\begin{aligned} TES_{da,in}^{t} + TES_{id,in}^{t} + TES_{srln}^{t} + TES_{prl}^{t} &\leq \gamma_{0,in} B_{on}^{t} + \gamma_{1,in} X_{pl}^{t} \\ TES_{da,out}^{t} + TES_{id,out}^{t} + TES_{srlp}^{t} + TES_{prl}^{t} &\leq \gamma_{0,out} B_{on}^{t} + \gamma_{1,out} X_{pl}^{t} \end{aligned} \tag{19}$$

TES charging and discharging power on the day-ahead and intraday markets are additionally restricted and binary variables $B_{tes,in}$ (equal to 1 when charging) and $B_{tes,out}$ (equal to 1 when discharging) are defined:

$$\begin{aligned} TES_{da,in}^{t} + TES_{id,in}^{t} &\leq k_{tes,max,in} B_{tes,in}^{t} \\ TES_{da,out}^{t} + TES_{id,out}^{t} &\leq k_{tes,max,out} B_{tes,out}^{t} \end{aligned} \tag{20}$$

The minimum charging and discharging power for the TES are restricted at 1 MW (as the binary variables are either 0 or 1):

$$\begin{aligned} TES_{da,in}^{t} + TES_{id,in}^{t} &\geq B_{tes,in}^{t} \\ TES_{da,out}^{t} + TES_{id,out}^{t} &\geq B_{tes,out}^{t} \end{aligned} \tag{21}$$

The energy flow $E_{tes,in}$ into the TES is equal to the energy input by charging on the DA and ID markets as well as charging due to activation of negative SRL, as shown in Equation 22. The overall energy losses incurred by the TES system are considered with the average round-trip-efficiency η_{tes} and included in the charging phase.[10] Likewise, Equation 23 shows the energy output of the TES, $E_{tes,out}$, which consists of discharging on the DA and ID markets and the activation on the positive SRL market.

$$E_{tes,in}^{t} = 0.25 \eta_{tes} (TES_{da,in}^{t} + TES_{id,in}^{t} + w_{srln} TES_{srln}^{t}) \tag{22}$$

$$E_{tes,out}^{t} = 0.25 (TES_{da,out}^{t} + TES_{id,out}^{t} + w_{srlp} TES_{srlp}^{t}) \tag{23}$$

[10] Note that the model and the conducted analysis in this paper assumes average round-trip efficiencies for the TES system. In reality, the round-trip efficiency varies in real-time as it also depends on the plant-load level the TES system is charged and discharged at.

Stored energy in TES at time period t is equal to the stored energy in the previous time period $t-1$ plus the net energy exchange that occurs in t as shown in Equation 24.[11]

$$S^t_{tes} = S^{t-1}_{tes} + E^t_{tes,in} - E^t_{tes,out} \tag{24}$$

Due to the prequalification requirements on the control power markets, storage level needs to account for the necessary energy when providing control power. TES needs to have enough energy when discharging in order to provide positive SRL and PRL. Similarly, TES needs to have enough storage capacity when charging for providing negative SRL and PRL. These requirements are represented by Equations 25–28, where t_{srlp}, t_{srln} and t_{prl} stand for the necessary durations for prequalification on the respective market.[12]

$$S^t_{tes} \geq t_{srlp} TES^{bh}_{srlp} \tag{25}$$

$$S^t_{tes} \leq s_{tes,max} - t_{srln} TES^{bh}_{srln} \tag{26}$$

$$S^t_{tes} \geq t_{prl} TES^{bh}_{prl} \tag{27}$$

$$S^t_{tes} \leq s_{tes,max} - t_{prl} TES^{bh}_{prl} \tag{28}$$

There are also various logical constraints that represent the physical restrictions of the TES system. TES is not allowed to charge and discharge at the same time:

$$B^t_{tes,in} + B^t_{tes,out} \leq 1 \tag{29}$$

Further, TES can be charged or discharged only when the power plant is online:

$$B^t_{tes,in} + B^t_{tes,out} - B^t_{on} \leq 0 \tag{30}$$

TES cannot be simultaneously active in more than one market:

$$B^t_{tes,srlp} + B^t_{tes,srln} + B^t_{tes,prl} + B^t_{tes,in} + B^t_{tes,out} \leq 1 \tag{31}$$

In the case that the plant is active on the SRL markets, it is assumed to bid all its SRL capability:

$$\begin{aligned} PL^t_{srlp} &= v_{srl,max} B^t_{srlp} \\ PL^t_{srln} &= v_{srl,max} B^t_{srln} \end{aligned} \tag{32}$$

[11] The model does not consider any standby heat losses from the TES since those tend to not exceed 1% per day (Evans et al., 2012) and are thus negligible for the considered storage capacities in this paper.

[12] $t_{prl} = 0.75$ h and $t_{srlp} = t_{srln} = 5$ h. (Source: Präqualifikationsverfahren für Regelreserveanbieter (FCR, aFRR, mFRR) in Deutschland, 26. October 2018)

The additional SRL capacity bids due to TES are allowed to vary. The maximum additional positive and negative SRL capacities of TES are limited by the maximum discharging and charging power of the TES, respectively.

$$
\begin{aligned}
&TES^t_{srlp} \geq v_{srl,min} B^t_{tes,srlp} \\
&TES^t_{srln} \geq v_{srl,min} B^t_{tes,srln} \\
&TES^t_{srlp} \leq k_{tes,max,out} B^t_{tes,srlp} \\
&TES^t_{srln} \leq k_{tes,max,in} B^t_{tes,srlp}
\end{aligned}
\tag{33}
$$

Due to technical limitations (Richter et al., 2019), TES can only provide additional capacity when the plant is providing SRL, but cannot provide standalone SRL capacity on its own. This condition is included with logical constraints as follows:

$$
\begin{aligned}
B_{tes,srlp} - B_{srlp} \leq 0 \\
B_{tes,srln} - B_{srln} \leq 0
\end{aligned}
\tag{34}
$$

In the case that the plant is active on the PRL market, it is assumed to bid all its PRL capability:

$$
PL^t_{prl} = v_{prl,max} B^t_{prl} \tag{35}
$$

Additional PRL capacity via TES ia allowed to vary. It cannot be less than the minimum PRL capability $v_{tes,prl,min}$ of the TES and cannot be greater than the maximum PRL capability $v_{tes,prl,max}$ of the TES:

$$
\begin{aligned}
&TES^t_{prl} \geq v_{tes,prl,min} B^t_{tes,prl} \\
&TES^t_{prl} \leq v_{tes,prl,max} B^t_{tes,prl}
\end{aligned}
\tag{36}
$$

Note that in contrast to SRL provision, TES can provide standalone PRL capacity even if the plant is not providing PRL. Therefore, additional constraints such as in Equation 34 are not included for the case of PRL provision.

Finally, the quarter hourly control power capacities are mapped to corresponding 4-hour-blocks:

$$
\begin{aligned}
PL^{bh}_{srlp} = PL^t_{srlp},\ PL^{bh}_{srln} = PL^t_{srln},\ PL^{bh}_{prl} = PL^t_{prl} \\
TES^{bh}_{srlp} = TES^t_{srlp},\ TES^{bh}_{srln} = TES^t_{srln},\ TES^{bh}_{prl} = TES^t_{prl}
\end{aligned}
\tag{37}
$$

The problem is solved with a quarter-hourly resolution and in weekly time blocks (i.e. $T = 672$). Optimising in weekly blocks instead of a complete year helps the problem to have reduced solution times. The weekly blocks are linked by carrying over the optimal solutions for the plant production level X^q_{pl} and the TES energy level S^q_{tes} ensuing at the end of a week as the initial values to the next week.

3. Results

3.1. Input Data

The considered reference power plant in this paper is assumed to be a newer generation coal-fired power plant (e.g. similar to Walsum 10 in Germany) with a relatively high efficiency and low minimum load. The parameters of the plant are presented in Table 2.

Table 2: Input parameters assumed for the coal-fired power plant

Installed net capacity	740	MW
Minimum load	148	MW
Efficiency at full load	46	%
Efficiency at minimum load	36.8	%
Start-up duration	3	h
Shut-down duration	2.5	h
Load change rate	±10	MW/minute
SRL capability	50	MW
PRL capability	20	MW
Start-up costs	70,000	EUR
Fuel costs	18.54	EUR/MWh$_{th}$
Other variable costs	1.3	EUR/MWh

Note that start-up costs are assumed to be on average 70,000 EUR in line with Schill et al. (2016) and 1.3 EUR/MWh of other variable costs are assumed (r2b, 2019). Fuel costs include the 2019 historical average ARA FOB thermal coal price of 9.1 EUR/MWh$_{th}$ plus additional transport costs of 1.25 EUR/MWh$_{th}$ (r2b, 2019). On top of this, costs for emission certificates are added with the average 2019 EU ETS CO_2 price of 24.86 EUR/tCO_2 and an assumed specific emissions factor of 0.33 tCO_2/MWh$_{th}$ (Agora Energiewende, 2017). The data for fuel cost calculation is presented in Table 3.

Table 3: Input data for fuel cost calculation

Thermal coal price	9.1	EUR/MWh$_{th}$
Transport costs	1.25	EUR/MWh$_{th}$
CO_2 price	24.86	EUR/tCO_2
Specific CO_2 emissions	0.33	tCO2/MWh$_{th}$

For input DA electricity prices, historical hourly time series data from EPEX SPOT for 2019 is used. For the continuous ID prices, quarter hourly weighted average price series for 2019 are used. The statistics of the input prices are summarised in Table 4. The average prices in both markets are almost identical. However, by comparing the average daily standard deviation of the prices, it can be seen that the volatility on the intraday market is significantly higher.

Table 4: Statistics of input prices on the hourly day-ahead and the quarter-hourly continuous intraday electricity markets (in EUR/MWh)

	Mean	Avg. daily std. dev.	Min.	Max.
Day-ahead	37.69	8.80	-90.01	121.46
Intraday	37.77	12.97	-244.47	577.25

Historical marginal capacity and settlement prices for the year 2019 are used in the method of calculating bids on SRL and PRL markets as mentioned in Section 2, respectively. For the energy prices in the SRL market, we assume that the plant bids on average its variable costs with a mark-up. The plant is assumed to bid double its variable costs as energy prices on the positive SRL market and half of its variable costs on the negative SRL market. On both SRL markets, an average 20% probability of activation is assumed.

3.2. Dispatch without TES

The optimal power plant dispatch in 2019 on the German day-ahead electricity market and the control power markets for SRL and PRL is simulated without TES. The results of the simulation are summarised in Table 5. Market-specific profits are provided. The profits on the DA market correspond to a case where the plant is only active on the DA market. Profits on PRL market corresponds to additional profits when the plant is providing PRL in addition to being active on the DA market. In the same manner, profits for SRL are the additional profits the plant realises when it provides SRL on top of its DA and PRL commitments.

Table 5: Summary results of the power plant dispatch simulation without TES

Profits TOTAL (EUR)	Profits DA (EUR)	Profits PRL (EUR)	Profits SRL (EUR)	Full load hours (h)	Start-ups
15,532,855	14,000,255	32,915	1,499,685	3232	39

Note that the comparably low PRL profits are strongly driven by the significant decreases in the price of the PRL product in the last years due to increasing battery capacities that provide PRL with much lower costs. In contrast, profits from SRL provision are substantial and make up almost 10% of the total profits. The relatively low full load hours and the high number of start-ups reflect the requirement for flexible operation in a market with depressed average electricity prices due to increasing RES share and increased fuel costs with higher CO_2 prices.[13]

[13]The Walsum 10 power plant, being similar to the reference power plant used in this paper with respect to its technical parameters, had 3462 full load hours and 42 start-ups in 2019 (ENTSO-E Transparency Platform, 2020).

3.3. Dispatch with TES

In this section, the optimal dispatch of the reference coal-fired plant with TES is simulated. The analysis includes two TES variants: A reference TES whose parameters are derived from the TES specifications stated in Richter et al. (2019) and a similar TES but with a higher round-trip efficiency.The discharging power of the high-efficiency TES at full load is adjusted accordingly to reflect the higher efficiency and the charging power at full load is increased proportionally. The parameters of both TES types are presented in Table 6. Charging and discharging power of the TES depends on at which plant load level the TES is charged and discharged, respectively. The discharging power is less than the charging power due to efficiency losses. Further, note that discharging power of the TES at minimum plant load is very restricted.[14] This variation in the charging and discharging power is included in the model as a linear function of plant load level.

Table 6: Technical parameters of the analysed TES systems

	Plant load	Charging power (MW)	Discharging power (MW)	Avg. round-trip efficiency
Reference TES	20%	51.8	6.7	61.4%
	100%	37.0	31.8	
High-efficiency TES	20%	51.8	6.7	85.0%
	100%	51.2	44.0	

The optimal dispatch for the reference TES with 2 hours of storage capacity at charging power is plotted in Figure 2 for a representative day. On this particular day (January 16th, 2019) the TES is active on all four markets (DA, PRL, SRL and ID). The figure of the plant dispatch with TES shows the generator output (without control power activation), the intraday volumes bought and sold by charging and discharging the TES, and the control power volumes bid by the plant and those provided by the TES. The second figure below plots the TES load and stored energy, where the charging and discharging power on day-ahead and intraday markets and the corresponding energy level can be seen. Note that the stored energy level includes the activation probability of SRL provision. In these figures it can be seen that the TES is used to provide PRL and negative SRL during time periods when the price spreads are not profitable for energy arbitrage. In the periods when spreads are profitable the TES is charged and discharged accordingly to engage in energy arbitrage on DA and ID markets. Since the amount of profitable spreads are determined by the round-trip efficiency of the TES, TES systems with higher efficiencies can result in increased energy arbitrage. A dispatch example that illustrates this effect is provided in Appendix B for the high-efficiency TES.

[14] For more information on technical characteristics of charging and discharging powers see Richter et al. (2019).

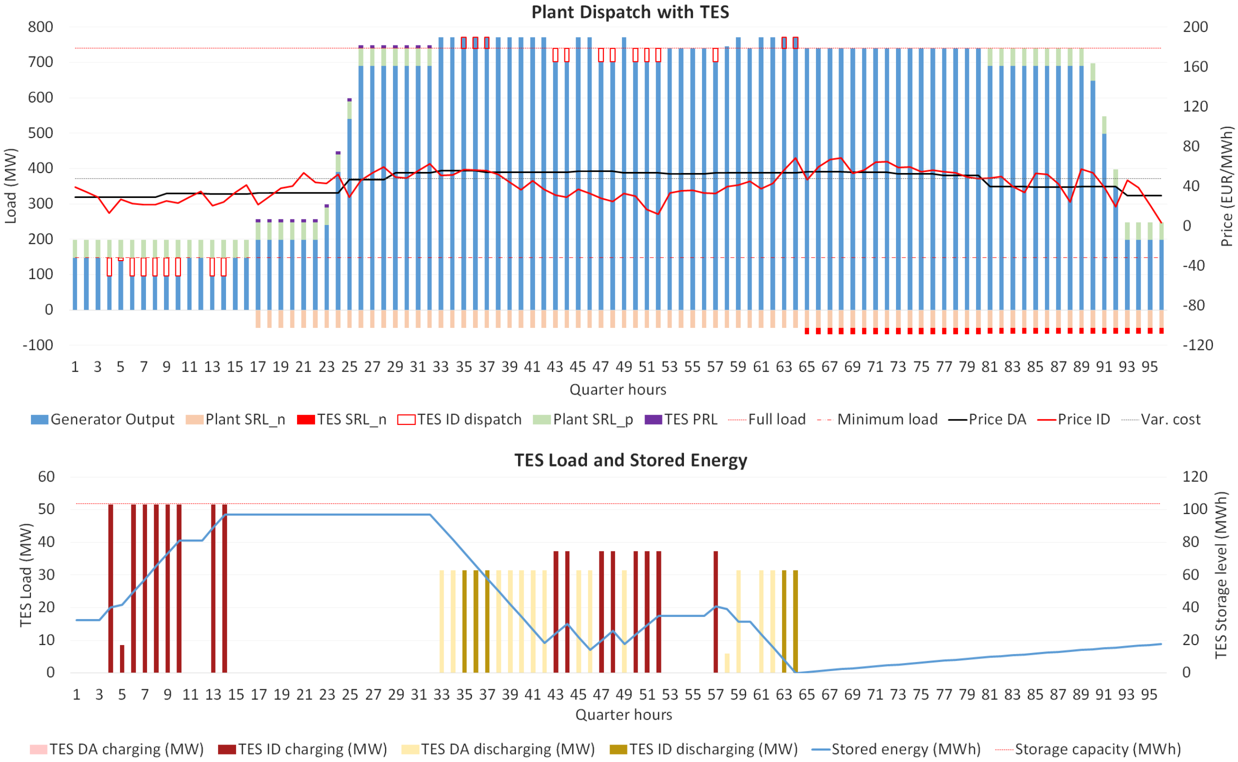

Figure 2: Dispatch example of the reference TES with 2 hours of storage capacity on the simulated day of January 16th, 2019

3.3.1. Effect of TES parameters on dispatch and profits

TES storage capacity and efficiency are the major parameters which affect how the plant with TES is dispatched, determining the amount of additional profits obtained via TES. Therefore, in this section, plant dispatch is simulated with the reference and the high-efficiency TES variants where the TES storage capacity is varied. Figure 3 plots the development of the full load hours of the plant and the number of start-ups with respect to TES storage capacity. A storage capacity of 0 corresponds to dispatch without TES. It can be seen that the TES system slightly increases the full load hours of the plant. For a small-sized TES with 0.5 h of capacity, full load hours increase marginally by 0.4% with the reference TES and 1.1% with the high-efficiency TES. As the storage capacity gets larger, the increase in full load hours gets more pronounced, which eventually starts plateauing after a capacity of 2-3 h. For the largest storage capacity of 8 h considered in this analysis, the increase in full load hours rises with the reference TES to 7% and with the high-efficiency TES to 9%. In Figure 3 it can also be observed that the TES can marginally increase or decrease the number of start-ups; however, a clear relationship between the TES storage capacity and number of start-ups cannot be identified.

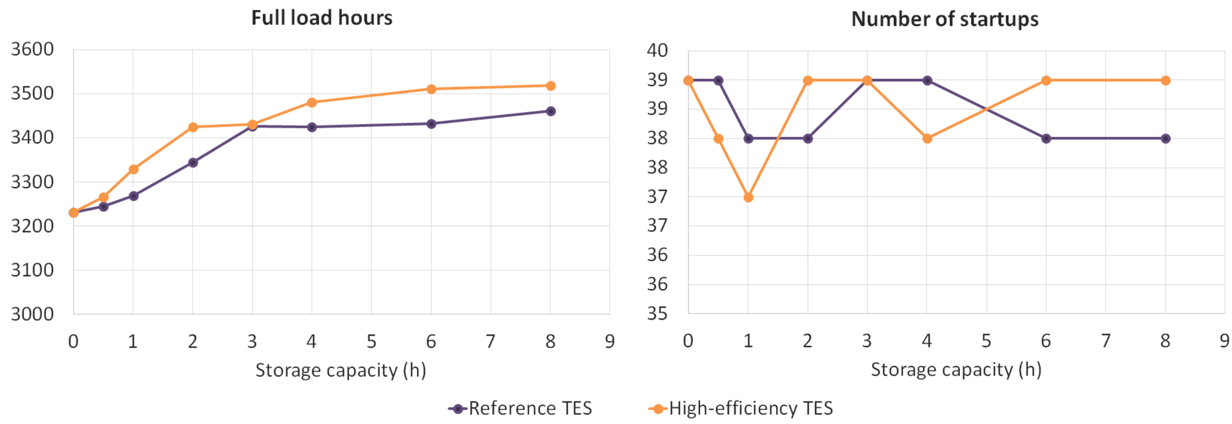

Figure 3: Impact of TES on overall plant dispatch characteristics

The effect of TES storage capacity and efficiency on the profits the system achieves on individual markets is also analysed in this section. Figure 4 plots the additional profits achieved by TES dispatch with respect to storage capacity for both the reference and the high-efficiency TES variants. The reference TES with a 0.5 hours of storage capacity can provide additional profits of 377,000 EUR, increasing the plant profits by 2.4%. The high-efficiency TES with the same size brings 545,000 EUR of additional profits; a 3.5% increase in the plant profits. Moreover, it can be seen that as the storage capacity increases, the additional profits with TES also significantly increase. However, the relative increase in the profits reduces as the storage capacity gets larger. This effect becomes more pronounced with the reference TES for capacities greater than 4 hours, and in the case of high-efficiency TES, for capacities greater than 6 hours.

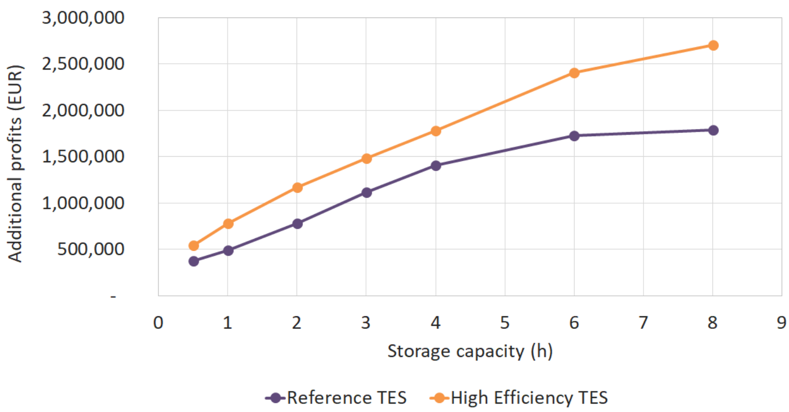

Figure 4: Additional profits due to TES

The development of TES profits with respect to storage capacity and efficiency can be better understood by analysing the share of profits realised in the respective markets that TES participates in, as shown in Figure 5. For this analysis, the markets that TES participates in are extended one by one (i.e. DA only, DA+PRL, DA+PRL+SRL, DA+PRL+SRL+ID) and the consecutive difference in the total profits is calculated in each case to obtain the additional profits on the included market.

Significant differences in the profit distribution between the reference and the high-efficiency TES can be observed. For the reference TES with lower round-trip efficiency, price spreads on the DA market are not high enough and the profit on the DA market remains limited. On the other hand, high-efficiency TES achieves substantial profits on the DA market. Despite its lower efficiency, reference TES can nevertheless obtain significant profits on the ID market thanks to higher price volatility on the ID market. A storage capacity of 3 hours is found to be enough to maximise the ID profits. In the case of the high-efficiency TES, the ID profits are maximised around a storage capacity of 2 hours and are on average higher than twice the ID profits of the reference TES. Thus, it can be concluded that profits from energy arbitrage are strongly correlated with the round-trip efficiency of the TES, as expected.

Looking at the profits obtained from control power provision for both TES types, it can be seen that smaller TES systems (storage capacity < 1h) can nevertheless achieve substantial additional profits on the PRL market. However, due to increased storage requirement for prequalification on the SRL market, smaller TES systems can provide only a limited amount of SRL power and therefore achieve low SRL profits. In contrast, SRL profits constitute the major portion of total profits for larger storage capacities. For the reference TES, SRL profits exceed all other profits combined starting from a storage capacity of slightly less than 3 hours, whereas for the high-efficiency TES this occurs at a capacity slightly larger than 4 hours. For the reference TES, profits obtained by providing control power (i.e. SRL+PRL) make up the majority of total profits irrespective of the considered storage capacities in this analysis.

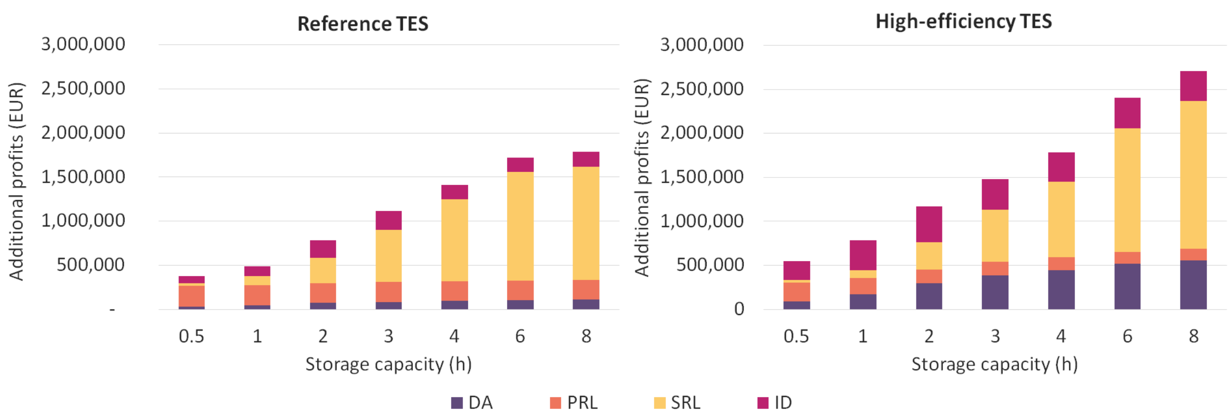

Figure 5: Distribution of TES profits on the participated markets

3.3.2. Charging and discharging patterns

In contrast to the perfect foresight assumption in this paper, dispatching the TES system with the coal-fired power plant would occur in reality under imperfect information and price uncertainty. This requires the plant dispatch with charging and discharging instances of the TES to be planned according to forecasts and would deviate from the optimal results. In this respect, analysing the optimal dispatch simulation and identifying patterns in charging and discharging instances at respective plant load levels would support developing TES dispatch strategies.

Figure 6 illustrates the distribution of charging and discharging instances at different plant load levels for the reference TES with respect to storage capacity. For this analysis, plant load is considered in four levels of equal load range and any instances, where TES is charging or discharging in these load levels, are summed up. The overwhelming majority of TES activity (i.e. charging or discharging) is found to occur close to plant minimum load (20–40% load range) and around plant full load (80–100% load range), while TES activity in the mid ranges (40–80% load range) is very limited.

The majority of charging occurs around minimum load while the majority of discharging occurs around full load. This is as expected since—assuming no control power is provided—the plant would run at minimum load during low electricity prices that lie below its variable costs and would run at full load during higher profitable prices. Nevertheless, both the ratio of charging around full load and the ratio of discharging around minimum load increase as the storage capacity gets smaller. For small TES capacities (<1h) these occurrences are very substantial. With the 0.5 h capacity TES, about 40% of the total charging instances occur near full load and almost 30% of discharging takes place near minimum load. This is because the smaller storage capacity restricts the arbitrage potential between minimum load and full load periods where the absolute spreads are highest, and instead, forces more of the arbitrage to be made in shorter intervals on constant load levels.

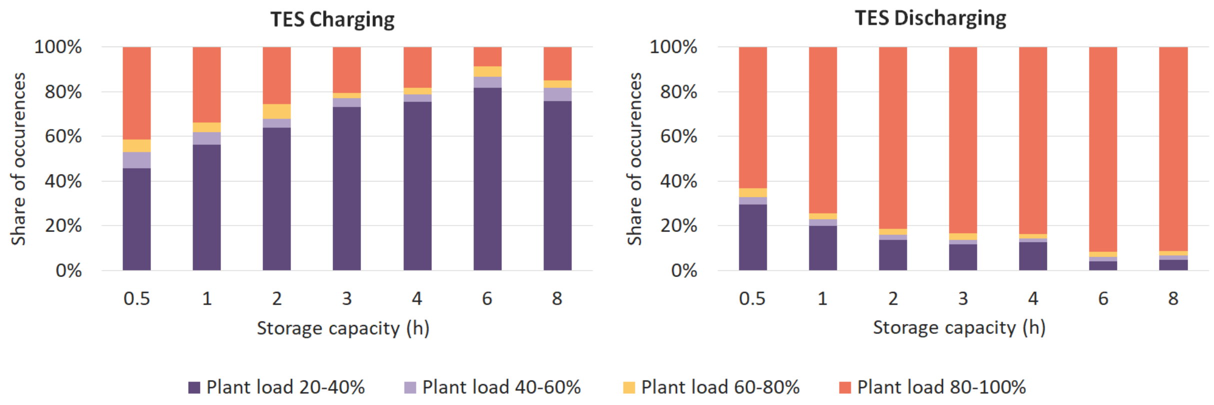

Figure 6: Distribution of charging and discharging instances of the reference TES at different plant load levels

The same analysis is provided in Figure 7 for the high-efficiency TES. The frequency of discharging is similar to the reference TES case and takes place predominantly near full load. The charging frequencies, however, differ significantly from those of the reference TES. The ratio of charging instances near full load increases substantially for all the considered storage capacities. Similarly, this ratio increases with decreasing storage capacity, making up 64% of total charging instances for a TES with 0.5 h of capacity. The same reason of restricted arbitrage potential between the minimum load and full load periods due to limited storage capacity is also valid here. However, due to increased efficiency, more of the spreads can be profitably utilised for arbitrage, which significantly increases the share of charging instances near full load.

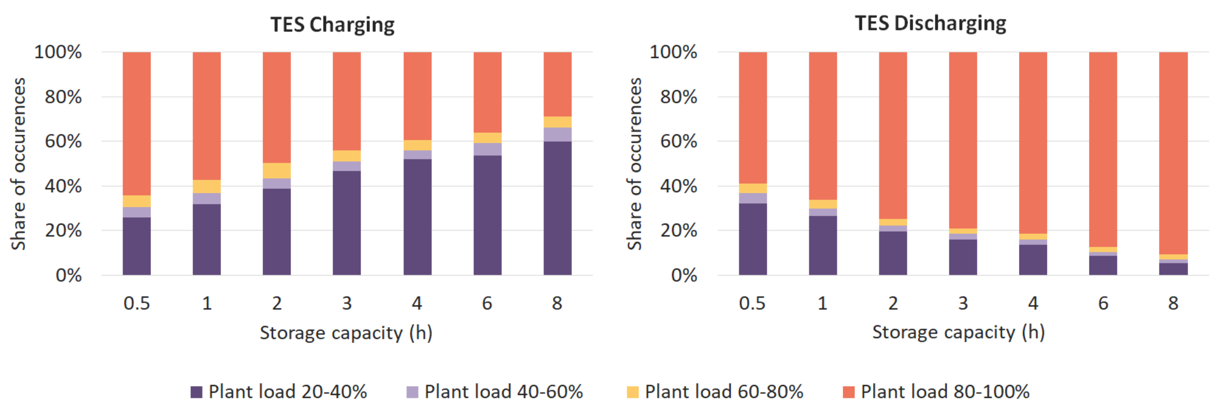

Figure 7: Distribution of charging and discharging instances of the high-efficiency TES at different plant load levels

4. Conclusion

This paper analyses the optimal dispatch of a coal-fired power plant with an integrated TES system in Germany for the year of 2019, using a mixed integer linear programming model. The TES is assumed to be able to conduct energy arbitrage on the hourly day-ahead and the quarter hourly continuous intraday markets. Moreover, it can enhance primary and secondary control power provision. In this context, the effects of TES on the dispatch characteristics of the plant is investigated and additional profits due to TES are calculated. The relevance of individual TES parameters regarding the profit potential on the respective markets is shown and charging/discharging patterns are identified.

I find that smaller TES systems (storage capacity $\leq$ 1 h) achieve substantial profits (about 230,000 EUR) on the PRL market by providing additional PRL flexibility and can also realize significant profits from energy arbitrage on intraday market (up to about 115,000 EUR) thanks to the more volatile price structure. Increasing the round-trip efficiency of the TES system can allow a higher share of profits to be realised also on the day-ahead market and greatly increase total gains via energy arbitrage. I also show that a storage capacity of 2–3 h is enough to exploit most of the energy arbitrage potential. However, further increasing the storage capacity enhances profits on the SRL market. I find that the TES system with lower round-trip efficiency is predominantly charged close to minimum plant load and discharged near full load because of the limited availability of profitable price spreads due to low efficiency. With higher efficiency, charging near plant full load becomes more common as the number of profitable spreads increases.

The analysis shows that the TES systems increase the full load hours of the power plant. This increase can especially be significant for large TES systems, meaning that TES systems can also increase the CO_2 emissions of the individual plants. Despite that, the net effects on the system would depend on the specific CO_2 emissions of other technologies which provide similar type of flexibility to the system. As such, increasing the flexibility potential of conventional power plants via TES can nevertheless help integrating significant shares of renewables in the medium term. As noted also by Agora Energiewende (2017), countries with few other flexibility options and large share of inflexible conventional plants such as Poland and South Africa can especially benefit from the additional flexibility.

The analysis conducted in this paper shows only the energy arbitrage and control power provision potential of the TES. However, TES can also be used to provide other types of flexibility. For instance, TES can provide additional heat during start-up in order to reduce start-up time and costs. TES systems can also be integrated into combined heat and power plants that provide district heating, providing additional flexibility between the heating and the electricity market. Those aspects can be considered in future research by extending the presented model. The existing modelling framework assumes perfect foresight and provides an upper benchmark. For a more realistic dispatch and profit simulation under imperfect information, the model could be extended with stochastic components to account for price uncertainty. This paper does not provide assumptions or modelling regarding the costs of TES investment and integration of the TES into the plant. In future research, the analysis could also be extended to take these costs also into account in order to evaluate the profitability of the investment.

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Appendix A. Model sets, parameters and variables

Table A.7: Sets, parameters and variables of the model

Abbreviation	Dimension	Description
Sets		
$t \in T$		Quarter-hourly model temporal resolution
$t1 \in T$		Alias of t
$bh \in BH$		SRL and PRL product time periods, in four-hour-blocks
Parameters		
p_{da}	€/MWh	Hourly day-ahead auction price
p_{id}	€/MWh	Quarter-hourly continuous intraday price
$p_{srlp,c}$	€/MW	Positive SRL capacity price
$p_{srln,c}$	€/MW	Negative SRL capacity price
$p_{srlp,e}$	€/MWh	Positive SRL energy price
$p_{srln,e}$	€/MWh	Negative SRL energy price
p_{prl}	€/MW	PRL capacity price
p_{fuel}	€/MWh$_{th}$	Fuel costs
w_{srlp}	%	Activation probability of positive SRL
w_{srln}	%	Activation probability of negative SRL
η_{fl}	MWh$_{el}$/MWh$_{th}$	Plant efficiency at full load
η_{ml}	MWh$_{el}$/MWh$_{th}$	Plant efficiency at minimum load
$k_{pl,max}$	MW	Plant generation capacity at full load
$k_{pl,min}$	MW	Plant generation capacity at minimum load
c_{ot}	€/MWh	Other variable costs
c_{su}	€	Average startup costs
η_{tes}	%	TES round-trip efficiency (electricity-to-electricity)
$k_{tes,max,in}$	MW	TES maximum charging power
$k_{tes,max,out}$	MW	TES maximum discharging power
$\gamma_{0,in}$	MW	TES constant for charging power linearisation
$\gamma_{1,in}$	%	TES slope for charging power linearisation
$\gamma_{0,out}$	MW	TES constant for discharging power linearisation
$\gamma_{1,out}$	%	TES slope for discharging power linearisation
$s_{tes,max}$	MWh	TES maximum storage volume
t_{srlp}	quarter-hour	TES prequalification requirement for positive SRL
t_{srln}	quarter-hour	TES prequalification requirement for negative SRL
t_{prl}	quarter-hour	TES prequalification requirement for PRL, in quarter hours
$v_{srl,max}$	MW	Maximum SRL capacity bid (plant and TES combined)
$v_{srl,min}$	MW	Minimum SRL capacity bid (plant and TES combined)
$v_{prl,max}$	MW	Maximum PRL capacity bid (plant only)
$v_{prl,min}$	MW	Minimum PRL capacity bid (plant only)
$v_{tes,prl,max}$	MW	Maximum PRL capacity bid (TES only)
$v_{tes,prl,min}$	MW	Minimum PRL capacity bid (TES only)
f_{prl}	%	Minimum plant load factor to be able to provide PRL
r_{up}	quarter-hour	Positive load change rate
r_{do}	quarter-hour	Negative load change rate
d_{su}	quarter-hour	Startup duration
d_{sd}	quarter-hour	Shutdown duration

Abbreviation	Dimension	Description
Binary variables		
B_{on}		1 if the plant is currently online
B_{su}		1 if the plant has started up
B_{sd}		1 if the plant has shut down
$B_{tes,in}$		1 if the TES is charging
$B_{tes,out}$		1 if the TES is discharging
B_{srlp}		1 if the plant is offering positive SRL
B_{srln}		1 if the plant is offering negative SRL
B_{prl}		1 if the plant is offering PRL
$B_{tes,srlp}$		1 if the TES is offering positive SRL
$B_{tes,srln}$		1 if the TES is offering negative SRL
$B_{tes,prl}$		1 if the TES is offering PRL
Variables		
R_{da}	€	Total revenue on the day-ahead market
R_{id}	€	Total revenue on the intraday market
R_{srlp}	€	Total revenue on the positive SRL market
R_{srln}	€	Total revenue on the negative SRL market
R_{prl}	€	Total revenue on the PRL market
C_{var}	€	Variable costs
C_{su}	€	Startup costs
Positive Variables		
X_{da}	MW	Total output on the day-ahead market (Plant + TES)
X_{pl}	MW	Plant output without TES
$X_{overmin}$	MW	Plant output that is above the minimum load
PL_{srlp}	MW	Plant output on the positive SRL market
PL_{srln}	MW	Plant output on the negative SRL market
PL_{prl}	MW	Plant output on the PRL market
$TES_{da,in}$	MW	TES charging on the day-ahead market
$TES_{da,out}$	MW	TES discharging on the day-ahead market
$TES_{id,in}$	MW	TES charging due to buying back on the intraday market
$TES_{id,out}$	MW	TES discharging on the intraday market
TES_{srlp}	MW	TES discharging power marketed on the positive SRL market
TES_{srln}	MW	TES charging power marketed on the negative SRL market
TES_{prl}	MW	TES charging/discharging power marketed on the PRL market
$E_{tes,in}$	MWh	Energy flow into TES when charging
$E_{tes,out}$	MWh	Energy flow out of the TES when discharging
S_{tes}	MWh	Stored energy in the TES

Note: Unless specified, all the power (MW) and energy (MWh) units are electrical.

Appendix B. Dispatch example for the high-efficiency TES

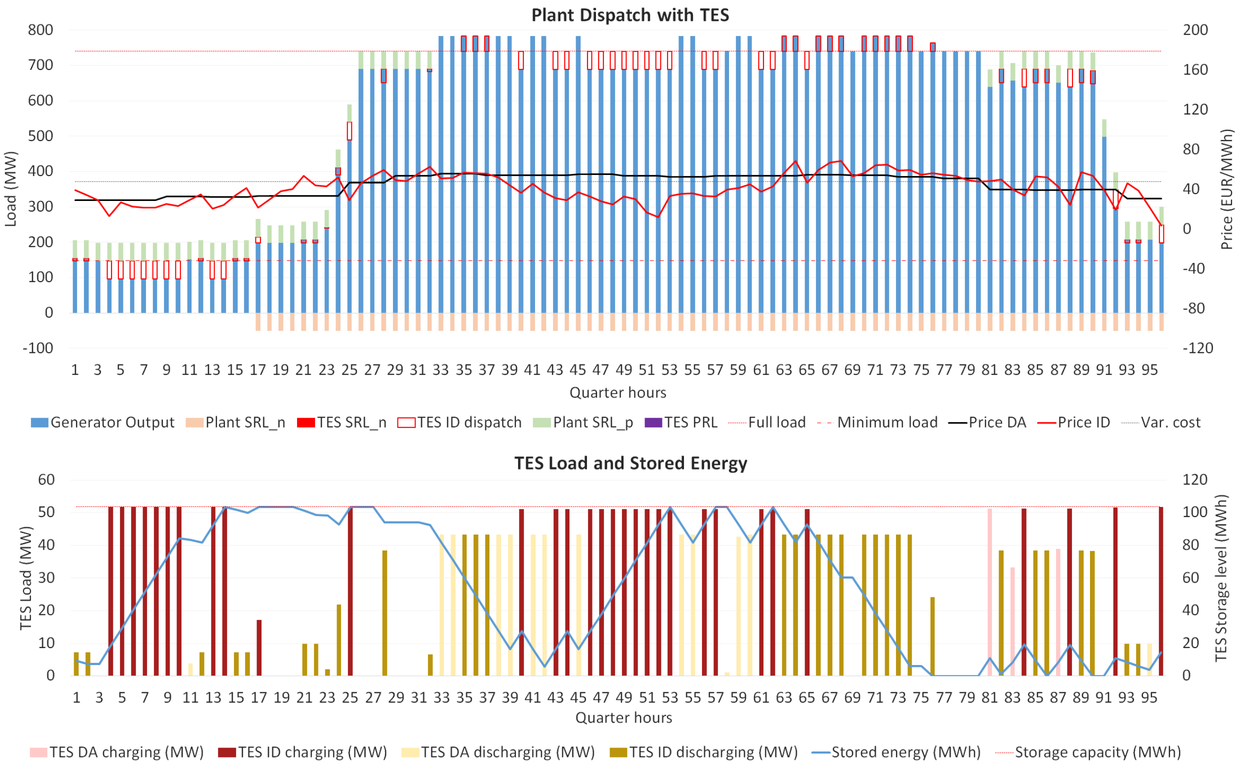

Figure B.8: Dispatch example of the High Efficiency TES with 2 hours of storage capacity on the simulated day of January 16th, 2019