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Future market value of flexibility, related technical requirements and consequential strategies for coal power plant operators

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1 Introduction

The flexibilization of conventional power plants has been and is an ongoing topic for utilities. From a utility's point of view, flexibility relates to a flexible production of electricity vs. time, but also, e.g., to the range of fuels that can be used. This paper deals with the first aspect of flexibility, with a specific focus on the flexibility required for coal power plants to act as partners of the renewable energy sources in the future. To act as such partners, power plants need to be able to cover the fluctuating residual load in an economic way. Hence, not only the technical requirements but also the market value of flexibility is an important issue. Therefore, this paper considers both the expected market value of this aspect of flexibility and the technical aspects related with it.

The results presented in this paper have been elaborated in the joint research project "Partner Steam Power Plant" [1] which has dealt with questions on the future value of flexibility, the requirements steam power plants will have to meet, and how they may be able to do so.

In Section 2, the paper first introduces the assumptions and the modelling approach that have been applied. The scenarios that are used for market simulations are presented in Section 3, before we discuss the results of those market simulations in Section 4. Section 5 then deals with the technical aspects related to flexibility improvements. Finally, we draw some conclusions in Section 6.

2 Future of the German Electricity Market in a European Context

2.1 Market model

In order to assess the future need and value of flexibility, the Institute of Energy Economics at the University of Cologne has conducted market simulations for different years in the future using their model MORE (Market Optimization of Electricity with Redispatch in Europe) [2]. This model consists of a fundamental model of the full European market with hourly resolution under consideration of transport capacity limits between countries. In each hour, the marginal power plant determines the marginal cost of electricity, which corresponds to the price under the assumption of perfect competition. This means that the model is not able to consider negative prices.

The power plant capacities in Germany are modeled block-wise, whereas the capacities in other European countries are modeled in an aggregated way. The model has been adapted to meet the specific needs of the project. In particular, flexibility parameters such as load change rate, minimum load, start-up costs, and start-up time have been considered in much more detail. Because it is of course not feasible to determine the exact parameters for each plant in the model, power plants have been assigned to vintage classes. The technical parameters of each class have been compiled from input from the utilities involved in the project.

For the parametrization of the model, the following assumptions have been agreed upon by the partners of the project:

- The infeed of renewables is based on data from 2012. The marginal cost of wind and photovoltaics is assumed to be zero, which means that these sources feed in their complete power available. No limitations or requirements on the dispatchability of renewable sources are considered in the model.
- The development of the installed capacity of power plants in Germany is based on the grid development plan 2014 ("Netzentwicklungsplan", NEP) [3] of the German TSOs. The installed capacities for 2012 (real values), 2024, and 2034 are listed in Table 1.
- The installed capacity of power plants in other European countries is based on the reference scenario of the EU Energy Trends 2030.
- The future load remains at the same level as in 2012 (535 TWh in Germany), which is also based on the NEP 2014.
- The installed transmission grid capacities are sufficient such that redispatch measures are not required.
- The fuel price development is based on the World Energy Outlook (WEO) 2013 New Policies.
- The CO2 certificate price is also based on the NEP 2014 [3], see Table 2.

Table 1: Assumptions on the installed capacity of conventional and renewable sources for Germany according to the grid development plan 2014 ("Netzentwicklungsplan", NEP) [3].

Installed conventional capacity [GW]	**2012**	**2024**	**2034**	**Installed renewable capacity [GW]**	**2012**	**2024**	**2034**
Nuclear	12.1	0	0	Run-of-the-river hydro	4.4	4.7	5
Lignite	21.2	15.4	11.3	Wind onshore	31	55	72
Hard coal	25.4	25.8	18.4	Wind offshore	0.3	12.7	25.3
Natural gas	27	28.2	37.5	Photovoltaics	33.1	56	59.5
Oil	4	1.8	1.1	Biomass	5.7	8.7	9.2
Storage	6.4	10	10.7				
Other conventional	4.1	3.7	2.7	Other renewable	0.8	1.5	2.3
Sum conventional	**100.2**	**84.9**	**81.7**	**Sum renewable**	**75.3**	**138.6**	**173.3**

Table 2: Assumption on the CO_2 certificate price.

[EUR/t]	2012	2024	2034
CO_2 certificate price	13	29	48

2.2 Characteristics of forecasted residual load

In order to examine the future evolution of the market, in this section the corresponding residual load, which is defined as

$$P_{\text{Residual}} = P_{\text{Total}} - P_{\text{PV}} - P_{\text{Wind, onshore}} - P_{\text{Wind, offshore}}$$

and its characteristics are investigated in more detail.

For a time period of two weeks, Figure 1 shows the total load, which is assumed to be almost identical for all three years considered, and the residual load for each year. Also, the dotted lines show the total dispatchable capacity, which is the capacity that is available to cover the residual load in the respective year. It also covers pumped storage and biomass power plants. However, unavailability is not considered in the total dispatchable capacity. Finally, the two rectangles show the generation capacity of pumped storage in GW (height) and their energy capacity in GWh (area). The position of the rectangles is not relevant. The assumption for 2024 and 2034 on pumped storage is almost identical and assumed to correspond to the natural limit of pumped storage in Germany.

It can be seen from Figure 1 that the volatility of the residual load increases considerably and covers a much larger range in the future. While on day three, the residual load is almost identical to the total load, it reaches negative values on day 8, corresponding to an excess of energy.

Hence, on the one hand Figure 1 shows that the future dispatchable capacity will be necessary to keep the security margin between peak (residual) load and capacity in order to guarantee security of supply, while on the other hand at other times the capacity is not needed at all. The figure also shows that even a much higher increase of the pumped storage capacity would not be a solution towards replacing other dispatchable generation capacity without energy capacity limits.

Figure 2 shows the histogram of the residual load in Germany. It can be clearly observed that the load is spread to lower values, indicating an increase in the requirement for conventional power plants to be able to run at low load and/or to shut down and restart.

Due to the fact that the model is based on hourly values, the market value of faster load changes cannot be derived from the results. This is also the reason that items such as control power are not considered in this paper. However, a qualitative statement on the increased need for flexibility with respect to load changes can be derived from the height of the residual load change between hours.

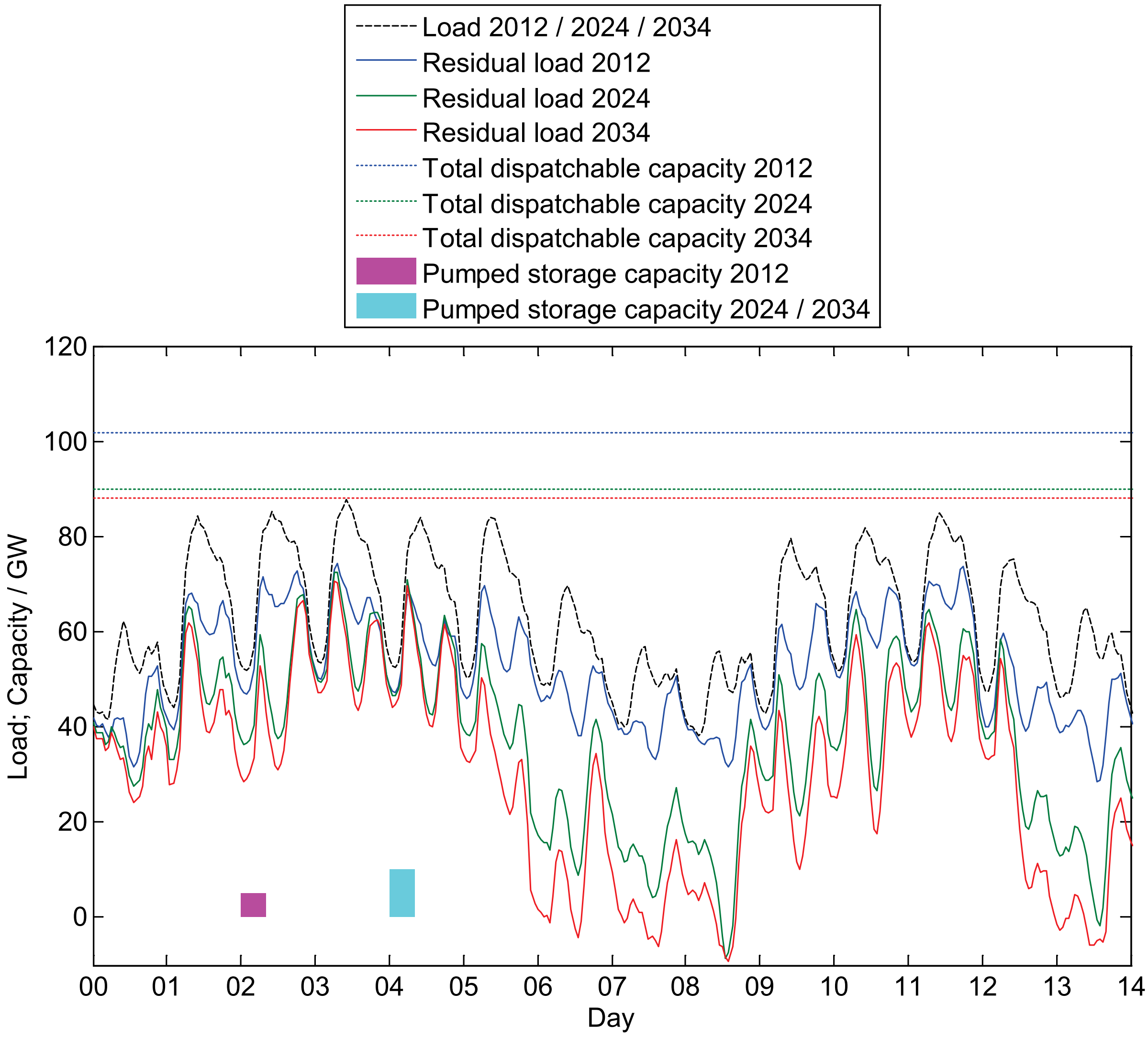

Figure 1: Time series of the residual load in Germany in a two week period in late spring.

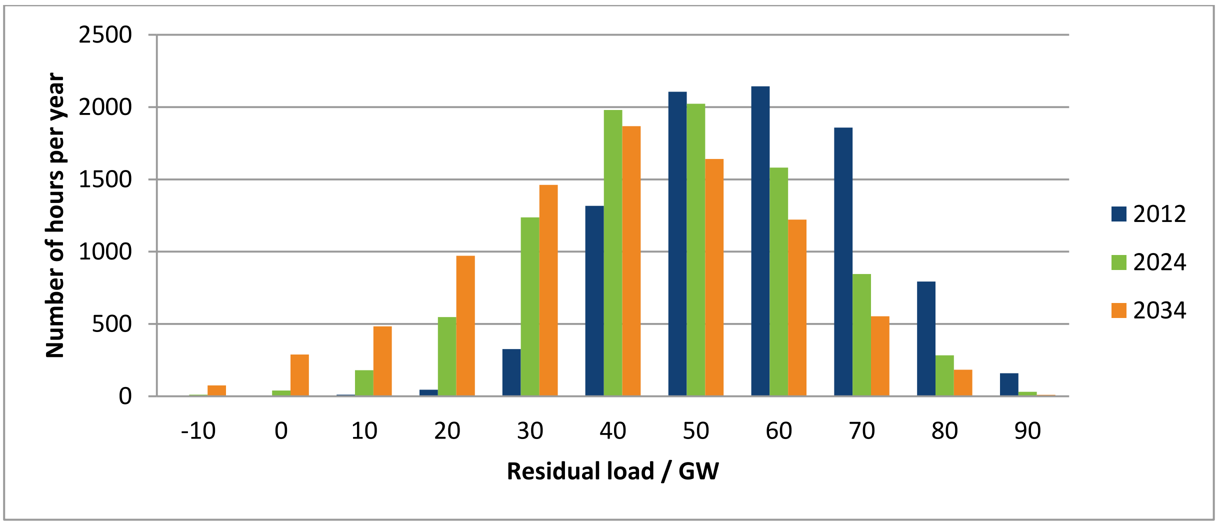

Figure 2: Histogram of the residual load in Germany (width of the histogram bins is ± 5 GW)

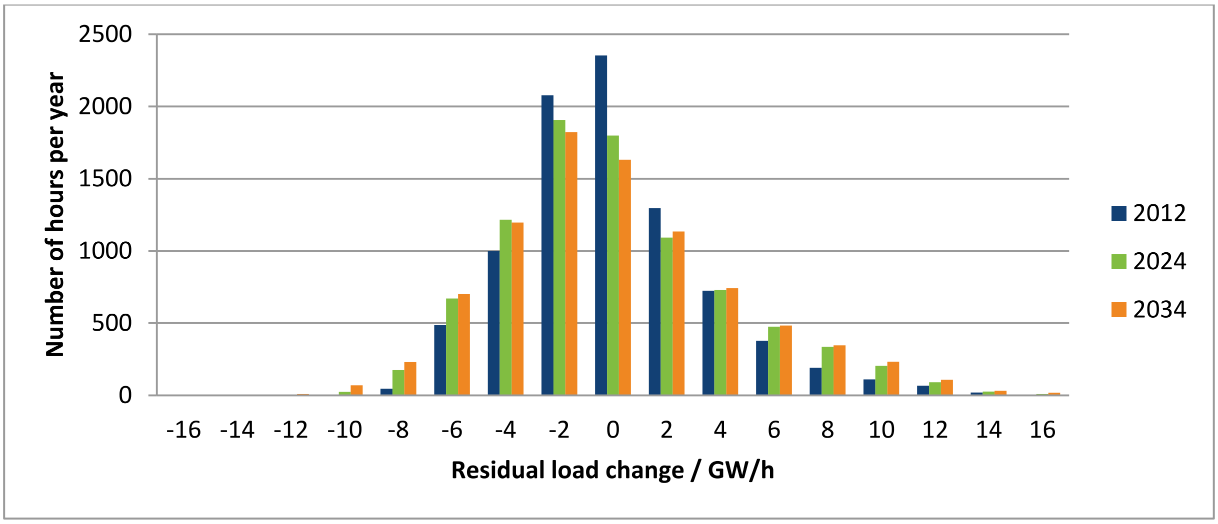

Figure 3: Histogram of the residual load changes between consecutive hours (width of the histogram bins is ± 1 GW/h).

Figure 3 shows the histogram of the change of residual load between hours. It can be observed that in the future, the number of higher residual load changes will increase both for negative and positive directions with a tendency that positive residual load changes occur more often. This does not only mean that power plants will be required to perform faster load ramps but also to start-up more often. Hence, the importance of both start-up costs and time is expected to increase also due to the rate of change of the residual load.

3 Market simulations

3.1 Preliminaries

Simulations with the market model for the years 2012, 2024, and 2034 have been carried out to assess the need for and the value of flexibility of coal power plants. To this end, a reference scenario and two flexibility scenarios have been defined. In each flexibility scenario, the flexibility of a single coal power plant, which is referred to as the 'reference plant' in the following, is improved by changing related technical parameters:

- Reference scenarios: no changes
- Minimum load reduction scenarios: reduced minimum load
- Start-up optimization scenarios: reduced start-up cost and start-up time.

However, the assumption that all other power plants remain unchanged was deemed to be unrealistic and to likely lead to an overestimation of the value of flexibility. Therefore, it is assumed that the flexibility of all coal power plants also moderately improves. The details of each scenario are described in the following sections.

3.2 Reference scenarios

In the reference scenarios, the technical parameters of the power plant classes are assumed to remain unchanged compared to today. However, due to the fact that older power plants are assumed to be decommissioned and newer power plants to be built, the share of power plants in classes with better parameters increases, such that the average technical parameters improve over time. This effect occurs in all scenarios for all power plant technologies.

3.3 Minimum load reduction scenarios

The minimum load reduction scenarios are based on the same model as the reference scenarios, however with a reduced minimum load. The minimum load of the reference power plant is reduced by 15% points (absolute). All other lignite and hard coal power plants have been assumed to be improved by a reduction of their minimum load relative to their original minimum load equivalent to a 5%-point improvement of the reference plant. This means that if the original minimum load of the reference plant was 40%, an absolute improvement by 5% points corresponds to a relative improvement of 12.5%. Hence, the minimum load of all coal power plants would be reduced by 12.5% relative to their original minimum load.

This has been done to estimate a modest average improvement in other power plants as well, in order not to overestimate the effect of the minimum load reduction in the reference plant. The height of the improvement has been chosen in a range that was deemed realistic and at the same time to lead to a significant effect.

Moreover, the technical "price" of a reduced minimum load in terms of a further decreased efficiency has also been taken into account. This effect is depicted in Figure 4.

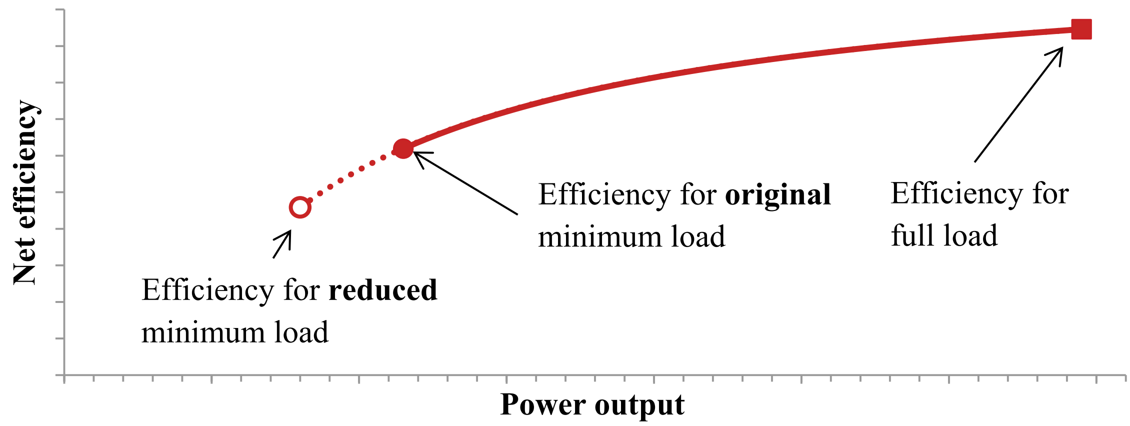

Figure 4: Nonlinear efficiency characteristic for reduced minimum load (qualitative).

3.4 Start-up optimization scenarios

The start-up cost and time optimization scenarios are also based on the same assumptions as the reference scenarios. However, the required energy for start-up has been reduced by 20% for the reference power plant and by 10% for all other coal and lignite power plants. The start-up time for hot start-ups is reduced by 50% for the reference plant and by 30% for all other coal and lignite power plants. As for the minimum load, the reduction has been chosen in a realistic order of magnitude.

The time needed for cold and warm start-ups is not considered as it is shorter than the downtime before the start-up. It is assumed that the start-up simply starts on time. The effect of unexpected start-ups cannot be covered by the model. The time needed for hot start-ups can also be interpreted as a minimum downtime.

4 Results

4.1 Market

Figure 5 shows the average marginal cost of electricity computed by the model. The main reason for increasing prices between years are the changed assumptions with respect to fuel and CO_2 costs. Hence, a comparison of the prices between years does not provide an indication on the value of flexibility.

Note that the increase in flexibility of all coal power plants may lead to a different price level in the market. A more flexible generation mix is expected to yield lower system costs and hence a lower price average. For this reason, the comparison of different scenarios of the same year also needs to be performed with care. It can be concluded from Figure 5, however, that the average price values of the scenarios of the same year are rather similar.

4.2 Reference plant

In a second step, the behavior of the reference plant is analyzed. Figure 6 shows a histogram of the load of the reference plant in each scenario. From this histogram it can be seen that there are indeed differences in the way the plant is operated. In particular, the minimum load reduction has the effect that the number of hours of downtime is lower. This means that the flexibility allows the power plant to participate in the market more often.

In the simulation for 2034, even the full load hours increase significantly due to the minimum load reduction. Because the plant is running more often, it is also available for full load during relatively short price peaks. Also, an earlier start-up may become profitable due to reduced losses in minimum load. This can be seen from Figure 7, which shows that in the minimum load scenario of 2034, the reference plant is able to generate more revenues in full load than in the other scenarios of that year. The revenues in minimum load are negligible.

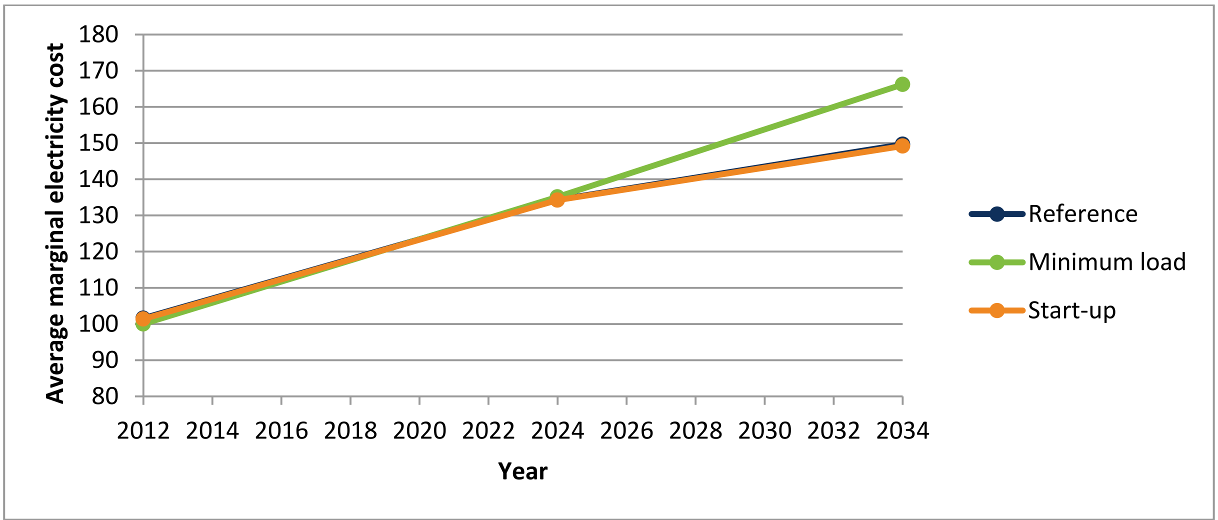

Figure 5: Simulation results for the average marginal cost of electricity (index 100 = average marginal electricity cost of the reference scenario 2012)

The effect of this on the contribution margin can be seen in Figure 8. While it reduces for all scenarios in 2024, a significant recovery can be observed in 2034 in the minimum load scenario: The contribution margin of the reference plant is more than 50% higher than in the reference scenario. It is important to note that these effects can be observed even though *all other* coal power plants have been flexibilized as well and the price level is lower than in the reference scenario. This means that the minimum load reduction allows the plant to better exploit price fluctuations and short price peaks in particular.

However, no significant change in the plant behavior is observable after start-up optimization, as Figure 6 shows. This may be due to the rolling horizon and to nonlinear effects in the model, see Section 4.3 for details. While even for an unchanged number of start-ups, the savings per start-up yield a higher contribution margin, this effect is rather small. For this reason, both the load histogram and the contribution margin of the start-up scenario shown in Figure 6 and in Figure 8 are almost identical to the reference scenario for all years considered. In 2024, the number of full load hours of the start-up scenario as is slightly lower than in the reference scenario; in 2034 it is slightly higher. In both years, the contribution margin is slightly higher for the start-up scenario. However, the difference is very small (ca. 2%) and should not be overrated.

4.3 Summary of the results and notes on the interpretation

As discussed in Section 4.2, for the minimum load reduction scenario a significant positive effect on the contribution margin could be observed in the simulations for 2034. Hence, the value of minimum load flexibility in this scenario increases over time. However, no significant effect was visible in the start-up scenarios. In this section, we will discuss possible reasons for this and why the results in general are likely to underestimate the value of flexibility.

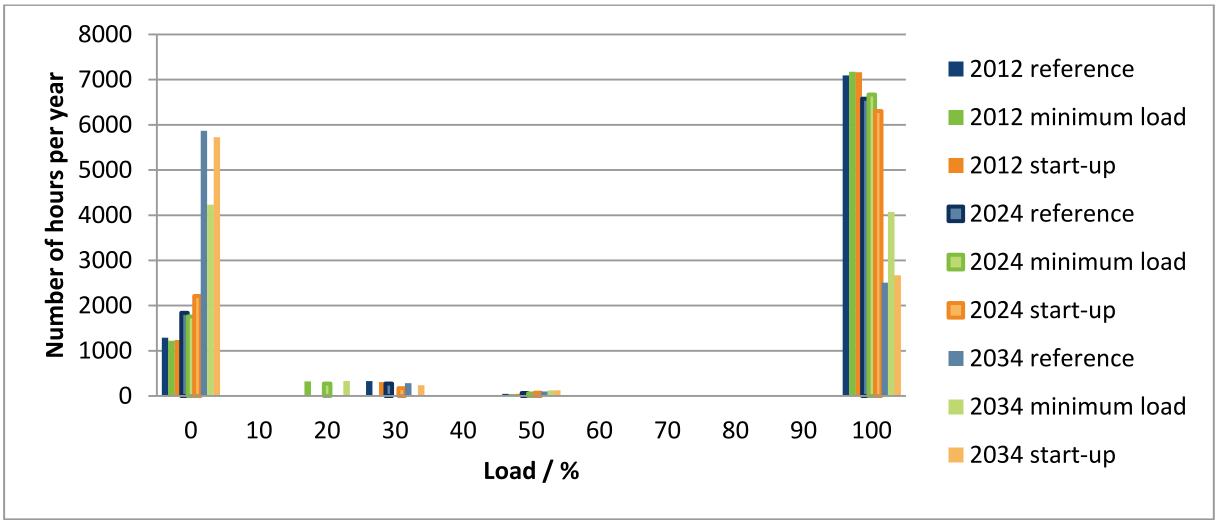

Figure 6: Load histogram of the reference plant (width of the histogram bins is ± 5%)

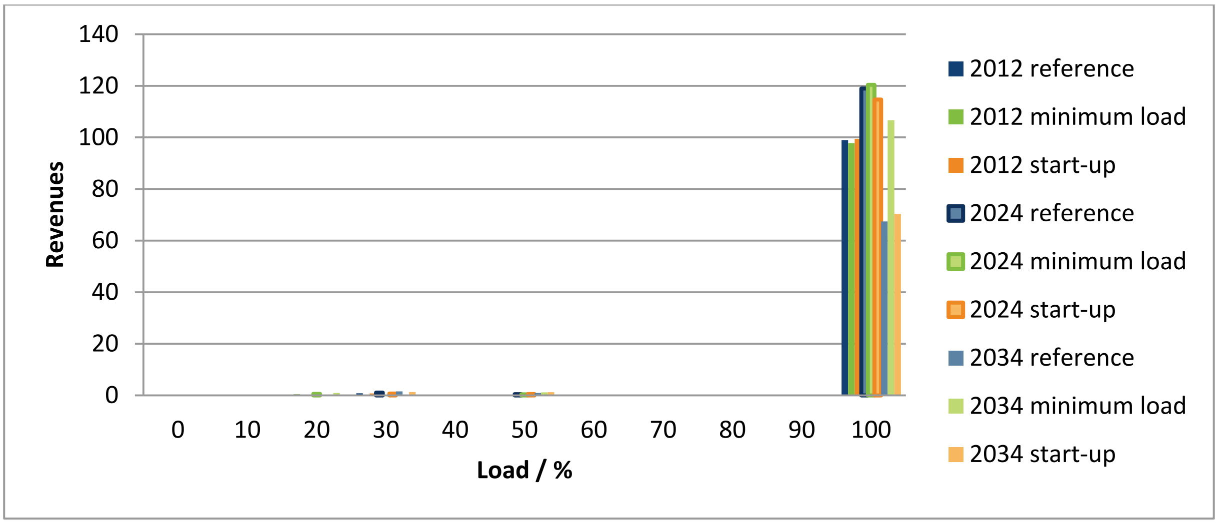

Figure 7: Revenues of the reference plant at different loads (index 100 = total revenues in the reference scenario 2012, width of the histogram bins is ± 5%))

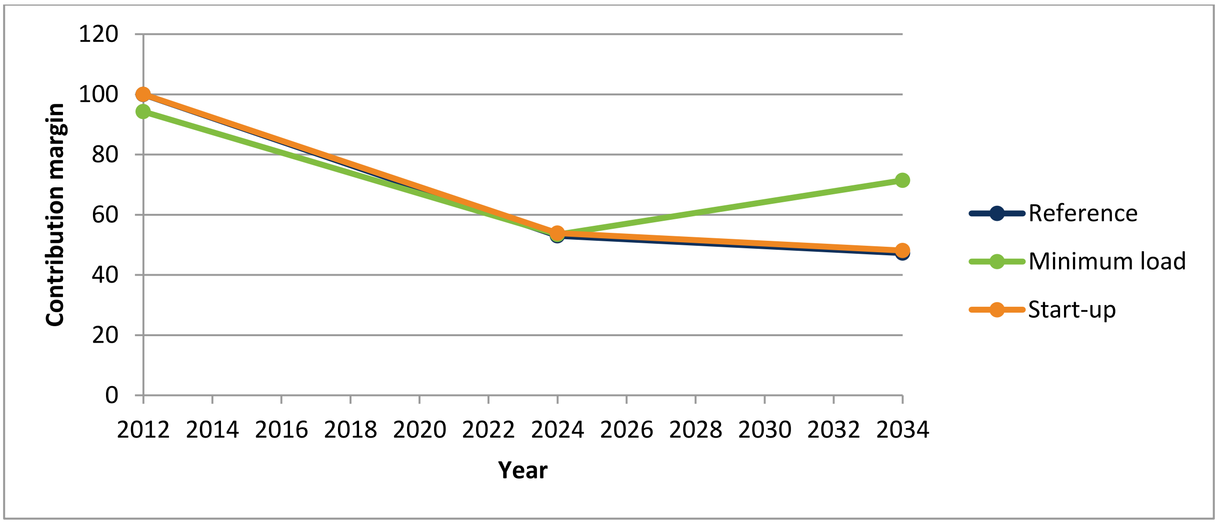

Figure 8: Contribution margin of the reference plant (index 100 = contribution margin of the reference scenario 2012)

In the simulation, the dispatch of all German power plants and power plant clusters in Europe is computed such that the residual power is covered at minimum overall cost. Due to the high number of power plants and power plant groups, this is a highly dimensional computational problem. In order to limit the computational effort, the algorithm uses a rolling horizon and solves the model for intervals of a few days. For each interval, a perfect forecast of the residual load and of the price curve for the next days is assumed. On the one hand, this is more realistic than a perfect forecast for the whole year. On the other hand, forecast errors on short notice that are expected to generate a need for flexibility are not considered.

The limited length of intervals has the additional effect that start-ups are not carried out if the resulting contribution margin is not positive at the end of the interval, while it would be after a longer time interval. This means that it turns out that a rolling horizon may underestimate the value of improved start-up costs.

Moreover, increased flexibility may not show a significant effect due to nonlinearities. For example, start-up costs may be decreased, but due to the price curve there may not be a significant change in number of start-ups. From a certain start-up cost reduction however, the number of start-ups increases, possibly dramatically. A further improvement then again does not have a significant effect. Hence, it is possible that the chosen reduction of start-up costs described in Section 3.4 is insufficient to trigger additional start-ups.

Further limitations of the model that may lead to an underestimation of the value of flexibility are:

- The model is based on the profile of the renewable generation of 2012. The volatility of this assumption also defines the volatility of the residual load for the future scenarios.
- The model does not consider the intraday market and has an hourly resolution.
- The model has only limited accuracy with respect to the technical parameters. However, within the project Partner-Steam-Power-Plant, a considerable effort has been made by both the involved utilities and EWI in order to reach as realistic parameters as possible.
- The assumptions of the NEP 2014 contain a significant increase in gas fired generation capacity. The need for flexibility from coal fired power plants will be even higher if this increase fails to appear.
- A comparison of the results for the reference scenario of 2012 with the real price curve shows that the model tends to underestimate price peaks (both positive and negative).

5 Technical flexibility requirements

5.1 Technical limitations of flexibility

All flexibility aspects considered in this paper are subject to limitations. With appropriate measures, such limitations can be overcome or at least be shifted in order to improve flexibility.

From a technical point of view, the technical aspects described in the following sections are particularly important for the flexibility of coal fired power plants in general. Of course, this can only be a concise overview of aspects that should be considered. Apart from the limitations, possible measures are touched on as well.

5.2 Requirements regarding 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. Possible measures are:

- changes in the air/fuel proportion
- increase of air swirl and turbulence
- reduction of the cooling air of inactive burners to the lower firing rate

- 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 coal

In the water steam cycle, a considerable reduction of the load requires the transition into circulation mode, in which a part of the feedwater is not evaporated and separated to the Benson 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 feedwater and suitable, optimized control concepts.

Usually, the temperature of the high pressure and reheated steam cannot be kept at their set-points for very low loads. It is necessary to make sure that this temperature reduction takes place with a controlled rate of change, since temperature changes that occur to fast may cause inadmissible thermal stress in the turbine.

The turbine itself also 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. In order to reach the lowest load possible, the unit limit control should be optimized such that the steam temperatures are automatically kept in the admissible range.

A high dust catalyst also poses a restriction, as the flue gas temperature must not fall below a certain value, usually about 290 °C. Otherwise, the catalyst's reactivity decreases and the catalyst may foul. A steam or flue gas bypass of the economizer may reduce the heat transfer in the economizer and hence support the flue gas temperature.

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 storage may be used to reduce the electrical power output and to release the energy during higher loads.

More details on the technical aspects of minimum load reduction are described in [4].

The market simulations show that minimum load reduction is an investment that can be expected to have long term positive effects. The real limitation of the minimum load of a particular plant should be investigated in tests. Optimization of unit automation and control has low investment costs and can help to shift the minimum load to this limitation. In further steps, investments in retrofits in order to overcome active limitations and further reduce the minimum load may be evaluated.

5.3 Requirements regarding fast start-up

The most important limiting components for start-ups are the thick-walled components of the boiler and the turbine. The temperature increase during start-up causes thermal stress in these components. For this reason, the thermal stress must be monitored, possibly by dynamical models, and the steam temperature control must limit the temperature increase such that the stress limits are exploited but not exceeded. As the limitations depend on the wall thickness, measures reducing this thickness will allow for faster temperature increases.

Another limitation is posed by the physics: the metal of the boiler components must be heated to the desired temperature by a certain steam flow. Optimal control of fuel and high-pressure bypass allows for a faster pressure build-up with less fuel [5].

Apart from this, optimized start-up procedures may help to reduce unnecessary waiting times and to replace costly start-up fuel by coal as early as possible. Also, additional heat sources such as burners in the hot primary air channels may support an early start of coal mills.

Changed turbine start-up procedures may enable earlier rolling of the turbine and faster load increase after synchronization. However, some of the possible measures may reach a faster start-up at the cost of a higher consumption of equivalent operating hours (EOH).

The market simulation results do not show a strong effect of start-up optimization on the way of operation. As mentioned, this may be due to the limited length of the time intervals used by the simulation algorithm. Yet, the cost of optimization of the start-up automation are comparatively low and in an order of magnitude such that the saved start-up costs – even without a change in the number of start-ups – generally lead to a payback period of not more than one year if the power plant is not a must-run plant.

6 Conclusions

In the future, electricity supply will require flexible dispatchable capacity. Only if renewable energy sources and dispatchable energy sources complement each other as partners, it will be possible to reach the goal of an increased share of renewables with the same level of security of supply.

Market simulation results show that in this context, the value of flexibility is expected to increase. In particular, positive effects of a reduced minimum load could be identified. Due to different reasons, the effect of start-up optimization probably has been underestimated, but the increasing number of hours of very low or even negative residual load show the evident need for shut-downs and start-ups.

However, the market simulation results also indicate that under the assumptions made, the – possibly underestimated – value of flexibility alone will not be sufficient for an economic operation of flexible power plants. Even though increased flexibility improves the contribution margin, the simulations show that the contribution margin of hard coal power plants reduces to about 40 to 60% of its current value. Either other market mechanisms that have not yet been considered in the model, such as intraday markets, will lead to higher price fluctuations and hence to a higher value of flexibility, or new market mechanisms will be needed to compensate for the effects at least partially.

While hard coal power plants show considerable flexibility even today, further improvements are possible. Independent of the exact future development of the energy market, coal fired power plants will need to be as flexible as possible. As Section 5 has shown, the limitations of flexibility are numerous. For this reason, a power plant operator should prioritize the options for flexibility improvements with regard to their effects and their cost. It is not possible to provide general recommendations that are valid for each power plant, because each power plant is different. As a general strategy, in a first step the true limitations of the power plant should be determined. By optimization of the unit automation and control in a second step, the operation of the power plant can be modified so that its idle flexibility potential is capitalized.

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