Impact of dynamic line rating on redispatch

Gerald Blumberg
Christoph Weber
House of Energy Markets and Finance
University of Duisburg-Essen
Essen, Germany
gerald.blumberg@uni-due.de

***Abstract*--This paper analyzes the impact of dynamic line rating (DLR) on both redispatch amounts and costs in Germany for a best and a worst case redispatch scenario in 2020. The basic methodology is divided into three steps: First, hourly weather dependent maximal ampacities of overhead lines are derived in order to analyze the impact of DLR. Uncertainty issues regarding forecast errors or measurement problems are thereby addressed by using weather data of larger or smaller areas around the overhead lines and wind velocities in different heights. Second, by mapping the load and generation schedules of seven European countries (CWE + CH) to their transmission grid nodes, hourly grid congestions in Germany are identified with a DC power flow. Third, German redispatch amounts and costs are calculated by applying a modified Optimal Power Flow which takes the beforehand determined plant schedules and technical restrictions into account. The results reveal significant reduction potentials of redispatch amounts and costs even under consideration of the least positively influencing weather conditions.**

***Index Terms*—dynamic line rating, redispatch, combined market and grid modelling**

I. INTRODUCTION

Decarbonized future energy systems are characterized by a high share of energy provided from variable renewable energy sources (vRES). This increasing amount of vRES, mainly located where their natural potential is best induces new challenges for the transmission grid system since it is frequently located far from load centers. In the long run, network and storage extensions as well as flexible electricity based market participants (e.g. electric vehicles, heat pumps) may contribute to balancing demand and supply under consideration of grid restrictions, albeit being mainly connected to the distribution grid. However, since those adoptions require time, redispatch of market results from zonal electricity markets is and will remain a key measure in the short run to cure transmission grid overloads. For instance, Germany had an overall redispatch (RD) volume of 15,529 GWh leading to RD costs of 387.5 million EUR in 2018 [1].

One measure to reduce both redispatch amounts and costs that may be introduced rather rapidly and with relatively low capital expenditures (capex) [2] may be weather dependent dynamic line rating (DLR). DLR is generally well known [2–4] but rarely investigated towards its impact on redispatch in large-scale power system models aiming to depict real world situations. While [5] proves the general potential under multiple sources of uncertainties in real-time operation stage using a modified 24-bus IEEE RTS system, [6] investigates the impact of utilizing DLR in North-West Germany. However, the paper at hand contributes to estimate the DLR potential by introducing DLR into an existing large-scale model framework capable of assessing RD amounts and costs for entire Germany. By translating market results from all European countries into plant operation schedules, import and export series, DLR implications on transmission system congestions can notably be assessed through a DC power flow (DC-PF) for all CWE countries and CH (CWE+). Thus, an integrated estimation of transmission line overloads in Germany is ensured. Finally, the redispatch amounts and costs are determined through a modified optimal power flow (OPF) which hereinafter is called Redispatch-OPF (RD-OPF) [7, 8].

II. MODEL FRAMEWORK

Transmission system congestions and thus, redispatch quantities and costs are driven by multiple factors. In this chapter we shortly introduce the existing model framework which is used to determine RD amounts and costs. Thereby light is shed on the depiction of market driven power plant dispatch under consideration of multiple factors, e.g. Flow-Based-Market-Coupling (FBMC), CHP Must-Run constraints, vRES infeed and other RD drivers. Furthermore, the applied DLR Model is introduced.

A. Existing Model Framework

The existing model framework comprises seven major steps which are shortly summarized hereinafter. Details can be found in [7–13]. Figure 1 illustrates the framework in a simplified manner and shows at which point DLR is introduced.

In the first step, the “vertical load” (net load at transmission grid level) is calculated using the eponymous model [11] which notably sums up the estimated generation from small-scale power plants connected to medium- or low-voltage levels (obtained from an initial Joint Market Model (JMM) run), nodal vRES and electrical demand time series [7].

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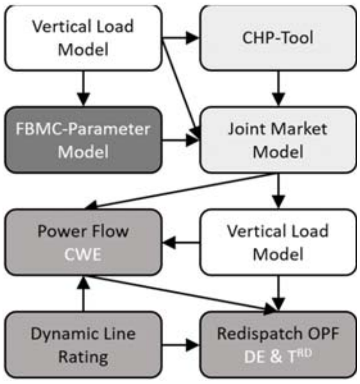

Figure 1: DLR within a simplified illustration of existing model framework

Since German electricity markets are coupled through FBMC with other markets of the CWE region, FBMC data like zonal power transfer distribution factors (zonal PTDFs) or remaining available margins (RAM) are needed to calculate market results and power plant dispatch. These inputs are provided by the FBMC-Parameter Model [7]. Besides RES infeed and FBMC parameters, market outcomes are driven by heat demand restrictions of combined heat and power (CHP) plants. The CHP plant design is typically directly linked to fulfill a certain heat demand which implies site-specific (must-run) restrictions. Since endogenous modelling of such individual restrictions faces multiple limitations, CHP plant modelling is done separately by the CHP-Tool [12, 13] by utilizing price expectations from an initial (simplified) JMM run.

As a second major step, power plant schedules as well as shadow prices for pumped-hydro and reservoir plants are calculated through the JMM for whole Europe. These outcomes are either translated directly to grid nodes, or, if not modelled within the underlying grid model area (i.e. in the present case outside of the CWE+ region), translated to im- and export time series at the grid model interconnectors. Furthermore, information on power plant restrictions induced through plant constraints like reserve or CHP restrictions are conveyed to the RD-OPF [7], [8]. Utilizing the JMM results, also the earlier Vertical Load Model outcomes are updated, notably regarding the small-scale power plant schedules.

Third, a DC-PF performed in MATPOWER [14] for the CWE+ region is conducted for each hour of the year. Critical hours (T^{RD}) characterized by line overloads in Germany are identified. For all T^{RD}, a RD-OPF is executed in order to determine the redispatch amounts and costs. This RD-OPF is based on the idea that the TSOs aim is to "avoid line overloads while causing least additional system costs possible" [8]. Thus, the RD-OPF can be seen as cost-based RD which calculates the costs that arise through TSOs interference into the unit schedules which are handed over from the JMM; i.e. additional costs for increased generation of power plants minus saved variable costs from power plants which reduce their generation plus costs from RES curtailment which arise through lost revenues from the renewables support scheme in Germany [8]. As shown in Figure 1, this existing large-scale model framework is now extended by the DLR approach in order to use weather dependent line ampacities (and thus, transmission capacities) within the DC-PF and the RD-OPF.

B. *Assessment of Thermal Overhead Line Capacity*

Analogously to [3] and [15], the DLR concept reflects the energy balance of heat gains through joule heating P_J and solar radiation P_s on the one hand and heat losses through convective cooling P_c and radiative cooling P_r on the other hand:

$$\begin{aligned} P_J + P_S &= P_c + P_r \\ &= I_c^2 \cdot R(T_c) + P_S \end{aligned} \tag{1}$$

As explained in [16], corona heating as well as evaporative cooling is neglected in (1). Since solar radiation P_S, convective and radiative cooling P_c and P_r are affected by ambient temperature (T_a), wind velocity (v) and solar radiation (gr), the maximal thermal ampacity I_c is weather dependent and consequently also a function of time. Throughout this paper we assume a conservative and constant wind to conductor angle of 30°.

Since the maximum ampacity of a conductor is not only limited through its temperature and sag but also through other factors like electromagnetic tolerance levels or the transmission system protection system, two flexible parameters are introduced in order to limit I_c. First, a maximum value $I_{c,max}$ is defined to avoid extreme values. Second, a maximum scale factor sc_{max} is defined which ensures that each line's standard ampacity I_{base} is not increased too much. Equation (2) summarized the impact of both limitations:

$$I_c = \min(I_c; sc_{max} \cdot I_{base}; I_{c,max}) \tag{2}$$

C. *Processing of Weather Data*

A real world application of dynamic line rating must incorporate weather forecast errors [5]. However, weather data for the whole CWE+ area for all line routes and different forecast horizons as well as exact route information would be necessary in the presented large-scale modeling framework. Since the paper at hand does not aim to address forecast limitations or measurement errors nor wants to overestimate DLR impacts, two simplified approaches are used which are illustrated by Figure 2.

While the "line" approach takes weather data for all locations between the from- and to-bus locations of the line l (hereinafter: used weather coordinates (UWC_l)), the "diamond" approach takes it's UWC_l from coordinates from the points at the edge of a rhombus around the line. For each rhombus a width to length proportion of 0.7 is used. In both approaches all UWC_l have a distance of 5 km from one to another. Wind speed at 10 meters height, solar radiation and ambient temperature are afterwards obtained for each *UWC* by inverse weighting of each weather information (*wi*) by the weighted *UWC* distance (*d*) to the four next Cosmo-EU grid Points (*i*) by (3). The Cosmo-EU weather data grid contains 665x657 equidistant points for whole Europe with a mesh size of roughly 7 km [17].

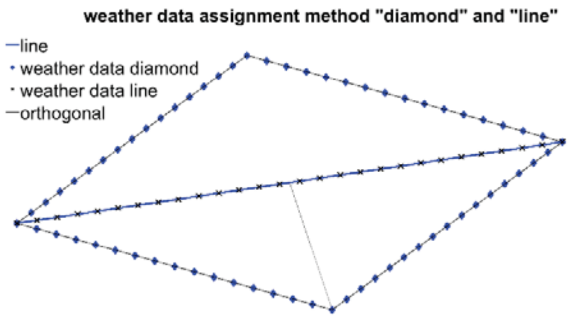

Figure 2: Assignment of weather data to lines

$$wi_{UWC} = \frac{1}{\sum_{i=1}^{4}\frac{1}{d_i^{\alpha}}}\sum_{i=1}^{4}\left[\frac{1}{d_i^{\alpha}} \cdot wi_i\right]; \forall\, wi \in \{gr, v, T_a\} \quad (3)$$

After the calculation of all wi_{UWC} the least positively influencing value is chosen to calculate the ampacity for each line; i.e. minimum of gr and v and maximum of Ta. As a result, a conservative estimation of the DLR impact is obtained which accounts for the above mentioned uncertainties.

Furthermore, the impact of wind velocities in different heights is analyzed because DLR dependent ampacity reacts more sensitive to applied wind velocity and ambient temperature than to solar irradiance [18]. However, especially wind velocity is a function of height (and the roughness length of the location). In this paper the wind speed in different heights is calculated through (4) with $h_{ref} = 10\ m$ as in [19].

$$v(h) = v_{h_{ref}} * [\ln\left(\frac{h}{z_0}\right) / \ln(\frac{h_{ref}}{z_0})] \quad (4)$$

III. Case Study

For all cases, weather data from 2015 are used and a distance weight of $\alpha = 2$ is applied in (3). All calculations are carried out for the year 2020 and are either designed to consider a "best case" or a "worst case" scenario for redispatch, i.e. the developments up to this year are selected as to reduce respectively increase the redispatch volume. In particular, all network extension measures of [20] and [21] with a commissioning date of 2020 are expected to be realized at the beginning of the year in the best respectively one year later in the worst case scenario. DLR is "only" applied to the entire 380 kV voltage level since upgrades of 220 kV voltage level are assumed to be preferred for these usually older lines.

A large-scale modelling framework like the one used in this paper requires manifold datasets. Hereinafter, the most relevant are specified. The load data from [22] are augmented by a surplus for transmission losses from [23] and then multiplied with a growth factor of 97.5% in the best and 102.5% in the worst scenario. As explained above, RES infeeds are calculated by the Vertical Load Model. In the paper at hand, weather data from 2013 from [17] and RES capacities from [24] are used; thereby the lower scenario is used when the "best scenario" for redispatch is investigated (higher in the worst case). Furthermore, an empirically validated power plant data set for Europe is employed for all models which was updated through information from [25] and [26].

TABLE I. Specification Overview (Best and Worst Case Scenarios 2020)

Specification name	h_{ref}	sc_{max}	Ic_{max}
Ref	-		I_base
Diamond_10	10	1.3	3,500
Line_10	10	1.3	3,500
Line_10_4	10	4	3,500
Line_50	50	1.3	3,500
Line_50_4	50	4	3,500

In order to have a reference case, RD costs and volumes are calculated in the "Ref" specification without DLR. The other specifications differ regarding the applied wind height h_{ref}, the maximum scale factor sc_{max} and the UWC approach. Tab. 1 summarizes the investigated specifications which are all calculated for both the best and worst case scenario.

IV. Results

An overview on the obtained RD volumes is given in Figure 3 for the specifications of Tab. 1 while the corresponding costs are presented in Figure 4.

Before comparing the different scenarios, the "Ref" scenario results are first briefly discussed qualitatively. In 2018, an overall redispatch (RD) volume of 15.529 TWh was observed in Germany, leading to RD costs of 387.5 million EUR in [1]. The "Ref" results of the best/worst scenario are hence plausible with roughly 11.6/ 34.5 TWh and costs of 266.54/ 1,270.5 million EUR. Obviously redispatch volumes and costs are very sensitive with respect to network extension measures, RES infeeds and other factors and thus, this comparison does not provide a detailed model validation (which is beyond the scope of this paper) but rather a rough check of plausibility. For instance, the commission of one network extension measure named "Thüringer Strombrücke" in Germany on September 9, 2017 reduced the number of hours with overloads from 1,836 in Q4 2015 to 18 hours in Q4 2017 [27]. Given the range observed in the scenarios, year-ahead redispatch forecasts are obviously subject to a high level of uncertainty. At this point it is yet sufficient to state that the RD volume is roughly three times higher in the worst case scenario under the "ref" specification compared to the best case scenario and that the corresponding costs are even roughly five times higher. This over- proportional cost increase reflects the rising costs per kWh RD demand.

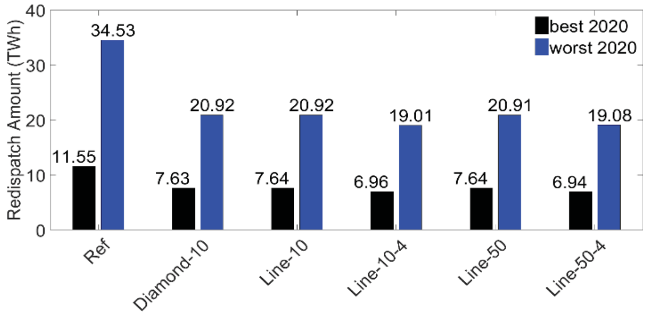

Figure 3: Sum of RD amounts (up and down) for DE 2020 scnearios

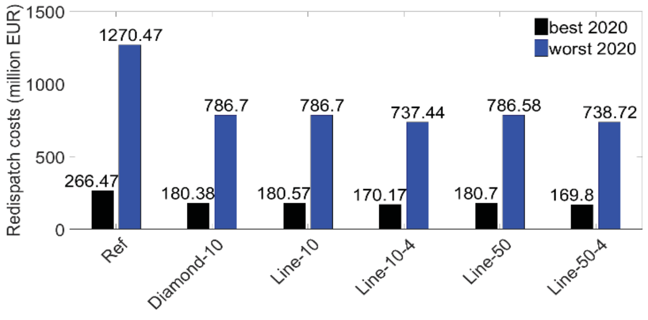

Figure 4: Sum of RD costs (up and down) for DE 2020 scnearios

For all other specifications, the RD volumes and costs are significantly lower for both the best and the worst case scenario because DLR is applied. While DLR reduces the RD volume in the "Line_10" specification to 66% of the "Ref" specification in the best case, a reduction to 61% is achieved in the worst case. In term of costs, 68 % remain in the best and 62 % in the worst case. Furthermore it turns out that the application of the "diamond" approach for the UWCs has no impact. When using DLR, ampacities are limited by the line section with the least favorable weather conditions. As both approaches reflect this by taking the minimum v as well as the maximum T_a and gr of all UWCs, both approaches seem to consider a sufficient number of UWCs to identify the allowable ampacities with similar accuracy. Consequently, only the line approach is applied hereinafter.

Comparing the "Line_10" scenario with the "Line_50" scenario, no additional impact of the higher wind velocities in the "Line_50" scenario can be observed. sc_{max} is only 1.3, meaning a maximum increase of 30% is allowed within these scenarios. Hence potential additional ampacity gains from higher wind velocities are not used; i.e. the 30% are already attained when using the lower wind velocities at 10m height. An additional explanation is that high wind energy infeed is a main driver for RD and thus, wind velocities during critical hours T^{RD} are already high at 10 m height [18]. However, even with an increased $sc_{max} = 4$ in the "Line_10_4" respectively the "Line_50_4" specifications, additional impacts are limited. For instance, RD costs drop to 737.44 million EUR in the "Line_10_4" worst scenario which is a drop by 49 million EUR or 6.3 % of the costs of the "Line_10" scenario (10 million EUR or 5.7 % for the best case). Again, higher wind velocities do not produce large changes since most ampacities attain the Ic_{max} ampacity limit of 3,500 A before reaching $sc_{max} = 4$. This additional limit reflect practical restrictions in grid operation arising from protection issues, electromagnetic tolerance levels or other technical constraints.

In view of an economic cost-benefit analysis, an estimation of capital and operational expenditures is necessary. Yet there is only limited empirical evidence available in literature. In [2], comparably low capital expenditures costs for DLR are estimated at 80,000-120,000 $ per "circuit" without defining it more precisely but with an example of a 30 km long circuit. Since exact line route information are not given, the distance for all lines where DLR is applied (in the CWE+ region) is estimated as the direct distance multiplied by a factor of 1.3 leading to a total distance of 63,955 km in the worst and 64,504 km in the best scenario for the CWE+ region. Based on an exchange rate of 1.14 $/EUR and costs 120,000 $ per 30 km line length, capital expenditures of roughly 226 million EUR are hence necessary for DLR systems in the best respectively 224 million EUR in the worst scenario. In any case, these costs would be paid back within a few years, even with the relatively low RD savings of 86 million EUR/year in the best scenario. However, [28] quantifies the capital expenditures totally different at 80,000 EUR per double-circuit and kilometer. A simplified translation to 40,000 EUR per circuit and kilometer would already lead to average payback periods of 6 to 8 years for interest rates of 3 to 8 percent – even in case of the worst scenario's high annual savings and without considering any other costs. In the best scenario with its low annual savings, there is then hardly any business case for the extensive DLR approach used in this paper but likely for a few heavily overloaded lines.

Furthermore, neither operational costs, nor costs for maintenance, nor costs of forced aging through higher line utilizations, nor costs through an increased failure risk, e.g. through local hotspots, are considered in this analysis. Again, the empirical evidence available in literature is limited. In [29], operational and maintenance costs per year are estimated at 0.1 – 2.5 percent of the capital expenditures. Correspondingly, it seems appropriate to focus on equipping appropriately chosen lines with DLR systems in view to achieve similar impacts of DLR at considerably lower cost.

V. Conclusion

In this paper, the impact of DLR on both redispatch volumes and cost in Germany is analyzed by introducing it into a large-scale modelling framework. In particular, hourly weather dependent ampacities are determined for seven European countries (CWE + CH) based on historical COSMO-EU [18] weather data from 2015. Thereby wind velocities, radiations and temperatures from the equidistant 7x7 km meshed weather data grid are assigned in two different ways to all 380 kV overhead lines and the least positively influencing conditions are utilized. In addition to this conservative procedure, two thresholds limiting the maximum ampacity gains through DLR are introduced to depict other technical restrictions existing aside thermal limitations of overhead lines.

In order to evaluate the impact of DLR respectively the determined maximal ampacities, a best and a worst case scenario in terms of redispatch requirements are designed for 2020. It turns out that DLR provides promising benefits with cost reductions of 38 % or 484 million EUR in the worst case respectively 32% or 86 million EUR in the best case scenario. Furthermore, the impact of used weather coordinates is marginal, if noteworthy at all, which could be seen as an indicator that forecast errors are manageable if a sufficient number of weather data is taken into account and the worst conditions out of the data are utilized. Finally, the impact of higher wind velocities is approximately investigated but proven to have a limited impact since other restrictions would limit the maximum ampacity beforehand.

While DLR is technically well established, this paper indicates the capital expenditures may be recovered within a few years for low cost assumptions, even in a scenario with low RD amounts. On the contrary, DLR investments for all lines are hardly profitable when assuming high capital expenditures. Thus, further research is needed to assess the costs including operational as well as the long term costs, too. In addition, future analyses should define methods to attentively choose the most RD impacting lines beforehand instead of equipping all 380 kV lines.

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