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Cycling of conventional power plants: Technical limits and actual costs

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ABSTRACT

Cycling of conventional generation units is an important source of operational flexibility in the electricity generation system. Cycling is changing the power output of conventional units by means of ramping and switching (starting up and shutting down). In the literature, a wide range of technical and cost-related cycling parameters can be found. Different studies allocate different cycling parameters to similar generation units. This paper assesses the impact of different cycling parameters allocated to a conventional generation portfolio. Both the technical limitations of power plants and all costs related to cycling are considered. The results presented in this paper follow from a unit commitment model, used for a case study based on the German 2013 system. The conventional generation portfolio has to deliver different residual load time series, corresponding to different levels of renewables penetration. The study shows, under the assumptions made, that although the dynamic limits of some units are reached, the limits of the conventional generation portfolio as a whole are not reached, even if stringent dynamic parameters are assigned to the generation portfolio and a highly variable residual load is imposed to the system. The study shows also the importance of including full cycling costs in the unit commitment scheduling. The cycling cost can be reduced by up to 40% when fully taken into account.

1. Introduction

The way of operating conventional power plants is changing as a consequence of the increasing penetration of intermittent renewables in the electricity generation system [1]. Electricity generation from intermittent renewable sources, like wind energy and solar energy, is variable, partly unpredictable and not or limitedly dispatchable [2]. As a consequence, a flexible electricity system is required to deal with the variations in renewable generation and to cope with forecast errors [3]. Holttinen estimated that, for a 10% energy penetration level of wind in Scandinavia, reserve requirements increase with 1.5–4% of installed with capacity [4]. Albadi and El-Saadany foresee an increase in balancing costs with increasing wind penetration [5].

A well developed and flexible grid, responsive electricity demand, curtailment of renewable generation and storage of electric energy are often cited as operational flexibility options to accommodate intermittent renewables in the electricity generation system [6]. However, these flexibility sources are only to a limited extent available in current systems. The main source of operational flexibility nowadays is cycling of conventional power plants. Cycling is defined as changing the output of a power plant by starting up, shutting down, ramping up or ramping down [7]. Conventional power plants refer to centralized and dispatchable units, like nuclear power plants, coal and lignite-fired steam power plants, and gas-fired plants.

The integration of intermittent renewables in the electricity generation system causes an increase in conventional power plant cycling. The link between renewables deployment and cycling behavior of conventional power plants is extensively discussed in the literature. Troy et al. show that, based on a case study of the 2020 Irish electricity system, cycling of base-load generation units increase with increasing wind penetration [8]. Cochran et al. discuss the evolution of coal fired units from base-load to peak-load generation [9]. Tuohy et al. show that more robust and cost efficient generation schedules are produced by stochastic optimization which takes account of the intermittent character of renewables [10]. Although cycling (costs) are increasing at higher renewables penetration, overall operational generation costs decrease due to fossil fuel savings as shown by Strbac et al. for a case study of the UK [11] and by Ummels et al. for the Dutch system [12].

Different studies allocate different cycling parameters – costs and technical limits – to similar generation units. In the literature, a wide range of technical cycling parameters is reported. However the sensitivity of the allocated cycling parameters on the final cycling behavior is never investigated. This paper complements

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the existing literature on conventional power plant cycling by focusing on the cycling parameters itself and their impact on cycling behavior, rather than on the cause of the increased cycling behavior.

An important question is how flexible conventional generation units are – from a technical viewpoint – and what the additional costs are related to a flexible operation of these units [13,14]. This paper investigates the influence of the variability in technical parameters on the operation of power plants. The scheduling of the same set of power plants is optimized for a case with high-dynamic cycling parameters and a case with low-dynamic cycling parameters assigned to the power plants. In addition, the different costs of conventional cycling and their impact on the total generation costs are quantified in this study. The results presented in this paper follow from a case study based on the 2013 German generation system. A dedicated operational partial equilibrium model of the electricity generation sector, i.e., a unit commitment model, is developed for this study.

The added value of this paper lies in its focus on the uncertainty related to cycling parameters – both technical and cost-related parameters. To address this issue, the impact of different cycling parameters on the power plant scheduling is studied. As such, this study contributes to the ongoing discussion on compatibility between variable generation of renewables and conventional electricity generation [15].

Section 2 discusses the technical and cost-related aspects concerning conventional power plant cycling. Section 3 presents the 2013 German electricity generation system as a case study and describes the unit commitment model used in this paper. Section 4 presents the results and discussion. Section 5 concludes.

2. Cycling of conventional units

Cycling of conventional units causes additional costs for generators and is limited by the technical characteristics of the unit. Both aspects are discussed in detail in this section.

2.1. Cycling cost

Cycling has a degenerating effect on units. When a generation unit varies its output, various components in the unit are subject to stresses and strains. During the shutdown of a unit, components undergo large temperature and pressure stresses. These stresses and strains lead to accelerated component failures and forced outages [16]. Starting up a unit is even more demanding. Wear and tear on the components of the generation units is exacerbated by a phenomenon known as creep-fatigue interaction [17].

The cost associated with power plant cycling consists of several components. Kumar et al. mention 5 distinct groups of cycling costs [18]:

(1) the cost for fuel, CO_2 emissions and auxiliary services during start-up, further referred to as direct start costs;
(2) the capital replacement costs and maintenance cost due to start-ups, further referred to as indirect start costs;
(3) the cost of forced outages due to cycling, which is the opportunity cost of not generating during an outage, further referred to as forced outage costs;
(4) the capital replacement costs and maintenance cost related to load following, further referred to as ramping costs;
(5) the cost of a decrease in rated efficiency due to cycling, further referred to as efficiency costs.

The total cost of cycling is not always well understood. Operators might underestimate total cycling costs and only take the fuel and CO_2 emission cost of a start-up (i.e., direct start cost) into account when making unit commitment decisions, even though this cost might be quite small compared to the total cycling cost. Cycling costs depend on many factors like the type and age of the power plant. It is difficult to put one number on the cycling costs of conventional power plants. According to Lefton et al., it is estimated that cycling costs of conventional fossil-fuel-fired power plants can range from US$ 2,500 to US$ 500,000 per single on/off cycle, depending on the type of the unit, age, usage pattern, etc. [16]. Similarly, Kumar et al. report cycling costs with a factor 100 difference between the lowest and highest cycling cost [18]. A study of Schröder et al. on the costs of electricity generation also reports such a wide range of cycling costs [19]. In an electricity generation system with increasing levels of renewables, cycling costs are a growing concern for power plant operators and system operators. Therefore, taking the correct cycling costs into account during the scheduling of the units is of great importance.

An important challenge is to allocate correctly the long-term cycling costs, such as indirect start costs and efficiency costs, into a short-term operational decision like power system scheduling. One possible approach is to model cycling cost dynamically, i.e., as a function of the number of start-ups [20]. This approach is especially valuable when looking at one generation unit in detail. Another approach, more common for studies with a system perspective, is to work with one fixed start-up costs for each generation type. This start-up cost represents the short-term operational costs related to the start-up, but a markup is added to correct for long-term costs. The latter approach is applied in this paper.

2.2. Dynamic limits

Technical limits constrain the cycling of conventional power plants. A power plant operates between a minimum and maximum power output and its ramping is constrained by ramping limits. A third dynamic constraint imposes minimum up and down times. Conventional power plant cycling is also closely related to partial load operation. Operating a power plant at less than its rated power output goes together with a decrease in operating efficiency.

In the literature a wide range of cycling parameters, used in generation scheduling models, can be found. Table 1 gives an overview of outer limits of cycling parameters and Fig. 1 shows typical part load efficiency curves (as used in this study). A cycling parameter can reflect a hard-technical constraint (e.g., a minimum down time is needed to synchronize a generator to the grid frequency) or a more cost-related constraint (e.g., an operator might impose minimum up times to reduce the cost of startups and shutdowns) The cycling parameters allocated to power plants might hence reflect just the technical limits of the power plant or could also include cost-related considerations.

In this paper, simulations are run for a low-dynamic power plant portfolio and for a high-dynamic power plant portfolio. Both portfolios contain the same set of power plants, but with different cycling parameters. In the low-dynamic portfolio, the power plants have stringent cycling parameters (see Table 1, upper bound of minimum power output, lower bound of ramping gradients and upper bound of minimum up and down times). In the high-dynamic portfolio, less constraining cycling parameters are assigned to the same set of power plants (see Table 1, lower bound of minimum power output, upper bound of ramping gradients and lower bound of minimum up and down times). The difference between the low and high-dynamic portfolio can be interpreted as a difference in technical characteristics of the power portfolio or as a difference in the way the portfolio is operated (e.g., stringent limits reflect a more conservative mode of operation). In both portfolios, the operators face the same cost parameters for generation and cycling.