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The value of stochastic programming in day-ahead and intra-day generation unit commitment

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ABSTRACT

The recent expansion of renewable energy supplies has prompted the development of a variety of efficient stochastic optimization models and solution techniques for hydro-thermal scheduling. However, little has been published about the added value of stochastic models over deterministic ones. In the context of day-ahead and intra-day unit commitment under wind uncertainty, we compare two-stage and multi-stage stochastic models to deterministic ones and quantify their added value. We present a modification of the WILMAR scenario generation technique designed to match the properties of the errors in our wind forecasts, and show that this is needed to make the stochastic approach worthwhile. Our evaluation is done in a rolling horizon fashion over the course of two years, using a 2020 central scheduling model based on the British power system, with transmission constraints and a detailed model of pump storage operation and system-wide reserve and response provision. We show that in day-ahead scheduling the stochastic approach saves 0.3% of generation costs compared to the best deterministic approach, but the savings are less in intra-day scheduling.

1. Introduction

In recent years the deregulation of energy markets and expansion of volatile renewable energy supplies have led to a significant increase of uncertainty in optimal power systems planning and operation. Several studies have discussed new sources of uncertainty which stem from unpredictable renewable energy supplies: Weber et al. [1] developed WILMAR, a stochastic programming model to assess the impact of increased wind power generation on power systems, and Tuohy et al. [2] apply this model to test data of the Irish power system. Sturt and Strbac [3] apply stochastic rolling horizon planning to a model of the British power system with a significant amount of wind power, and Constantinescu et al. [4] use wind scenarios from a numerical weather prediction model in a two-stage stochastic model. Similarly, Ji et al. [5] use two-stage stochastic programming to plan power systems operation under uncertain wind power supply and Falsafi et al. [6] investigate the effects of demand response mechanisms in this context. Other studies have identified an increase in traditional uncertain parameters such as load: Nowak and Römisch [7] and Carøe and Schultz [8] both apply stochastic programming to a power system with uncertain demand. These developments have increased interest in stochastic optimization models for short-term power plant scheduling, that is, day-ahead and intra-day generation UC (unit commitment), and a variety of specialised techniques have been developed to speed up the solution of these computationally challenging problems.

1.1. Solution and evaluation techniques

Many popular algorithms for SUC (stochastic unit commitment) problems are based on decomposition techniques. They can be divided into three groups: Benders decomposition [9], Progressive Hedging [10], and Lagrangian relaxation [11] or Dantzig-Wolfe decomposition [12]. All three approaches are applicable to two-stage or multi-stage models and can be used to decompose the problem by stages, scenarios, or generation units. The different ways of decomposing the problem are reviewed in Römisch and Schultz [13]. Besides the development of decomposition techniques, there have been efforts to accelerate the solution of stochastic problems by bound strengthening through cutting planes: Rajan and Takriti [14] devised facets of the polytope described by minimum up- and downtimes of the generation units and Jiang et al. [15] show that these are also facets of the stochastic formulation.

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Although substantial efforts have gone into improving solution methods for mixed-integer SUC models, they remain computationally difficult problems. Despite that, comparatively little has been published about the added value of stochastic scheduling models over deterministic ones. In the literature, there are two different approaches to evaluate the expected cost of UC schedules:

1. Evaluation via Monte-Carlo simulation: for the given schedule, a dispatch solution is calculated on a large number of day-long sample paths generated from a simulator that is thought to represent reality. This is typically done for a set of representative days, e.g. one day per season of the year. The performance of different schedules is measured by their expected dispatch cost.
2. Rolling horizon evaluation: a rolling scheduling and dispatch procedure is defined in which the system is scheduled for a few hours and evaluated against a historic trajectory by a dispatch model. Following the evaluation, the next few hours are scheduled and the process is repeated. Performance is measured by the dispatch cost on the historic trajectory. This is sometimes referred to as time domain scheduling simulation.

A major disadvantage of the Monte-Carlo simulation approach is that it is not possible to be certain whether the simulator is a correct representation of reality. Also, inter-temporal constraints such as minimum up- and downtimes cannot be considered beyond the end of the simulated day. These shortcomings are avoided in the rolling horizon approach.

1.2. Previous evaluations

The following studies use Monte-Carlo simulation to evaluate UC schedules: Ruiz et al. [16] report on an evaluation of deterministic and two-stage SUC under load and generator failure uncertainty, using the IEEE reliability test system [17]. Papavasiliou and Oren [18] apply Lagrangian relaxation and Benders decomposition to solve two-stage stochastic problems with uncertain wind production and security constrained problems with contingency scenarios. They compare different formulations with respect to fuel cost and security of supply by evaluating a typical spring day in the California ISO test system. Constantinescu et al. [4] include wind scenarios obtained from a numerical weather prediction model in a two-stage stochastic model. They evaluate this against a deterministic model, using three days of wind data from Illinois and a ten generator test system.

Tuohy et al. [2] apply the WILMAR model [1] to data of the Irish electricity system and perform a one year rolling evaluation of deterministic and multi-stage SUC. They report savings between 0.25% and 0.9% when using a stochastic approach instead of a deterministic one, depending on the length of the first stage. However, the authors use perfect information on the first stage, which biases the solutions to become better if the length of the first stage is extended. Additionally, the problems are only solved to an optimality tolerance of 1%. Sturt and Strbac [3] report on the difference between deterministic and stochastic rolling planning in a thermal power system with high wind penetration and a given level of storage capacity, which represents the British power system in 2030. However, mainly continuous relaxations of integer models are used, and transmission network issues arising from the geographical disparity of wind, storage and conventional generation are not addressed.

1.3. Our approach

In this paper we compare the performance of stochastic and deterministic UC approaches in day-ahead and intra-day planning under wind uncertainty, using a two-stage stochastic model in the day-ahead context and a multi-stage stochastic model in the intra-day context. Our study is performed in a rolling horizon fashion over an evaluation period of two years. We use a mixed-integer scheduling model based on the British power system from the perspective of a central scheduler. It includes transmission restrictions between network areas, a detailed pump storage model, and a model of system-wide reserve and response provision. Hence the model can be used to effectively evaluate strategies for dealing with wind forecast errors against the backdrop of the system's flexibility in generation, storage and reserve provision under transmission restrictions. We investigate the fundamental interactions between wind uncertainty, storage and scheduling methods, and these issues are most clearly understood in the setting of a centrally scheduled system. The centrally scheduled situation can provide a reference model when comparing different market structures, but these market issues are not considered in this paper. The system data we use correspond to National Grid's figures for 2020 under the Gone Green Scenario, with a wind penetration of 30% in terms of installed capacity.

While stochastic models are computationally challenging, the savings achieved with these techniques are typically a small percentage of the overall cost, implying the necessity of small optimality tolerances. To solve the problems efficiently to a gap of 0.1%, we use a scenario decomposition approach based on Dantzig-Wolfe decomposition. The method is described in detail in Ref. [19]. To generate our scenario trees, we use techniques published in the WILMAR [20] study, however we demonstrate that they need to be adapted to incorporate forecast level dependency of wind forecast errors in order to make the stochastic approach worthwhile.

The remainder of this paper is organised as follows: Section 2 has a formulation of our UC model; Section 3 has details of the input data, scenario generation and scenario tree construction techniques; Section 4 has a description of the rolling horizon evaluation procedure; Section 5 has the evaluation results; and Section 6 has the conclusions.

2. Stochastic unit commitment model

The UC model used for our rolling horizon evaluation includes an aggregated representation of the transmission system with generation zones and transmission links between them. There are limits on the power flow under normal operation. These are expressed in terms of individual transmission links and additional boundaries, each of which splits the network in two and imposes a real power flow limit on the sum of transmissions crossing it in each direction. The limits are derived by the network operator, using physical network feasibility criteria, N-1 security and contingency analyses [21]. The model contains pump storages which can be used for providing ancillary services and storing wind energy. Each pump storage scheme is modelled as a closed reservoir system, connected to a single plant which contains multiple pump-turbines. Wind power availability is treated as uncertain and a scenario model is used to approximate its possible realisations. Excess wind power can be curtailed at no cost. Load shedding is also permitted, but at a high cost.

In terms of thermal generation units we distinguish fast-start units from slow units. Fast-start units are OCGT (open-cycle gas turbines) which can be started within the hour. All other thermal units are categorised as slow and must be notified at least an hour before they can become available to generate.