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Decision Support

Bidding in sequential electricity markets: The Nordic case

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ABSTRACT

For electricity market participants trading in sequential markets with differences in price levels and risk exposure, it is relevant to analyze the potential of coordinated bidding. We consider a Nordic power producer who engages in the day-ahead spot market and the hour-ahead balancing market. In both markets, clearing prices and dispatched volumes are unknown at the time of bidding. However, in the balancing market, the market participant faces an additional risk of not being dispatched. Taking into account the sequential clearing of these markets and the gradual realization of market prices, we formulate the bidding problem as a multi-stage stochastic program. We investigate whether higher risk exposure may cause hesitation to bid into the balancing market. Furthermore, we quantify the gain from coordinated bidding, and by deriving bounds on this gain, assess the performance of alternative bidding strategies used in practice.

1. Introduction

With 73% of the total physical power exchange in the Nordic region being traded at Nord Pool in 2011 (Nord Pool, 2011), this is Europe's largest and most liquid market place for electricity. More specifically, Nord Pool operates the day-ahead spot market Elspot for the physical exchange of production and consumption. This market covers Norway, Sweden, Denmark, Finland and Estonia, and had 350 members and an impressive turnover of 294.4 terawatt hour in 2011.[1]

Although the spot market facilitates day-ahead balancing of expected production and consumption, real-time imbalances may still occur. It is the responsibility of the local electricity system operator, e.g. in Norway, Statnett, in Sweden, Svenska Kraftnät, and in Denmark, Energinet.dk, to ensure the physical balancing of supply and demand by activation of so-called balancing or regulating power. There exists a common Nordic market for regulating power, referred to as the balancing market. Regulating power can therefore be activated anywhere in the Nordic region, although each transmission system operator clears the market locally. The balancing market has few members, e.g. in Denmark only 6. Despite a significant total supply of regulating power, total demand is much larger, which may be explained by a hesitation to enter this market.[2] Furthermore, the need for supply of balancing services is expected to increase with the increasing growth in fluctuating renewable production, as pointed out by e.g. (Holttinen, 2008; Holttinen et al., 2009).

The above electricity market design applies not only in the Nordic region, but analogies to day-ahead spot and near real-time balancing markets are found in e.g. the Netherlands and Portugal/Spain, although with different bidding rules and market setups.

For electricity market participants able to engage in sequential markets such as the Nordic spot and balancing markets, it is relevant to analyze the potential of coordinated bidding. Nevertheless, a hesitation to enter the balancing market can sometimes be observed in practice. This motivates the following research questions: Can the hesitation be explained by differences in price levels and risk exposure between the two markets? Is it profitable to hold back capacity in the spot market to facilitate subsequent offering of up regulation, or to put forward capacity in the spot market such as to offer down regulation? If so, what is the gain from doing so?

To answer these questions, we consider a power producer who trades in a day-ahead spot market and an hour-ahead balancing market. In both markets, clearing prices and dispatched volumes are unknown at the time of bidding. However, in the balancing market, the market participant faces an additional risk of not being

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[1] In comparison, the intra-day adjustment market Elbas, which is likewise operated by Nord Pool, had 100 members and a turnover of only 2.7 terawatt hour.

[2] It should be taken into account that part of the Danish demand for regulating power is usually covered by import from Norway and Sweden.

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dispatched. Taking into account the sequential clearing of these markets and the gradual realization of market prices, we formulate the bidding problem as a multi-stage stochastic program.

Our contribution is threefold:

- We develop a multi-stage stochastic programming model for coordinated bidding into two sequential markets, taking into account market price uncertainty and existing market rules. This model can be used for market exchange irrespective of the production or consumption technology.
- When generating market price scenarios, we put efforts into preserving autocorrelations and cross-correlations. Since separate scenario sampling and reduction may alter correlations, we alternate between the two methods in a stage-wise fashion.
- To assess the performance of alternative bidding strategies used in practice, we derive bounds on the gain from coordinated bidding. These bounds can be computed without actually solving the multi-stage stochastic coordination problem.

The paper is organized as follows. Section 2 first provides an overview of electricity market bidding in the literature. We proceed to introduce the Nordic electricity markets, including the spot and balancing markets in Section 3, and formulate a multi-stage stochastic programming model for coordinated bidding into these markets in Section 4. Section 5 is concerned with the generation of market price scenarios that serve as input to the stochastic programming model. We derive bounds on the gain from coordinated bidding in Section 6, and numerically quantify this gain in Section 7. Section 8 concludes our analysis.

2. Electricity market bidding in the literature

The problem of optimal electricity market bidding is an optimization problem under uncertainty, given that the outcome of market clearing is unknown at the time of bidding. Naturally, the formulations of and solutions to the bidding problem found in the literature reflect the variety of approaches to optimization under uncertainty.

One strand of literature is based on optimal control and dynamic programming, and focus on the characterization and derivation of closed-form solutions to the bidding problem. An example is Anderson and Philpott (2002) who formulate a non-linear control problem and find necessary conditions for optimality. In their formulation, the authors make use of a so-called market distribution function, representing the probability that a generator is not fully dispatched at a given bid price and volume. For a price-taker, this is equivalent to the probability that the bid price exceeds the realized market price at a given volume, which is also what we use. Whereas an efficient approach to solving the non-linear problem remains an open question, Neame, Philpott, and Pritchard (2003) derive optimality conditions for a hydroelectric reservoir with continuous output range, and solve the bidding problem by a discretization of this range and the application of dynamic programming. A similar approach is taken by Pritchard and Zakeri (2003) who likewise find offer curves for hydro reservoirs, and by Pritchard, Philpott, and Neame (2005) who decompose the hydropower optimization into an inter-stage scheduling problem and an intra-stage bidding problem. In general, it is difficult to handle complex constraints and multiple state variables by the optimal control approaches, and the bidding formulations may often account for operational restrictions only through the reward function, take into account only one market, and do not include the costs of non-compliance with the market commitments.

In contrast, mathematical programming formulations easily allow for various constraints, and furthermore, through the extension to stochastic programming, for multiple sources of uncertainty. Examples of bidding models for price-taking electricity producers are (Contreras, Candiles, de la Fuente, & Gómez, 2002; Fleten & Kristoffersen, 2007; Fleten & Pettersen, 2005; Ladurantaye, de Gendreau, & Potvin, 2007; Lu, Chow, & Desrochers, 2004; Ni, Luh, & Rourke, 2004). These models include many details such as ramping restrictions, capacity limits, storage balances, start-up costs, and risk constraints. Reviews on optimal electricity scheduling and market exchange have been given by Wallace and Fleten (2003) and Kristoffersen and Fleten (2010).

Here, we extend the work in Fleten and Kristoffersen (2007) to sequential markets. This problem has already been addressed by Plazas, Conjeo, and Prieto (2005) who consider bidding into three sequential short-term markets. For the Nordic markets, contributions include Fosso, Gjelsvik, Haugstad, Mo, and Wangensteen (1999) who consider production scheduling with a view towards the spot, balancing and futures markets, and Faria and Fleten (2011) who focus on the day-ahead Elspot market and intra-day Elbas market. To the best of our knowledge, very few have explicitly addressed the problem of coordinated bidding into the spot and balancing markets, the only example we could find being Olsson (2005). Whereas Fosso et al. (1999) model only price insensitive bids, Olsson (2005) assumes smooth bidding curves instead of the piece-wise linear curves prescribed by the market rules, and Plazas et al. (2005) do not distinguish between the process of bidding into the balancing market (before market clearing) and the settling of imbalances in this market (after market clearing). The major difference to previous work, however, is our modeling of market dynamics. Existing market models are static, making the sequential bidding problem two-stage or three-stage. In contrast, we capture the dynamics of the two markets in a multi-stage model such that spot market bidding decisions are day-ahead and balancing market decisions are hour-ahead.

With many details and the inclusion of uncertainty, mathematical programming models can be computationally hard and time consuming. Efforts to efficiently solve the bidding problem have been made by Klæboe (2011) who resorts to Bender's decomposition, and Nascimento and Powell (2009) and Loehndorf, Wozabal, and Minner (2013) who apply approximate dynamic programming to integrate scheduling and bidding decisions for energy storage.

As an alternative to approximating the stochastic programming problem by cutting planes or simulation, we suggest to reduce computation time through careful generation of scenarios. Variations of scenario generation methods from the literature include (Høyland & Wallace, 2001, 2003) who propose moment/property matching by optimization or simulation. Another commonly used approach is to model the underlying stochastic processes, simulate a large number of sample paths/scenarios, and subsequently reduce this number by clustering. Central references on this method are (Dupačová, Gröwe-Kuska, & Römisch, 2003; Heitsch & Römisch, 2003, 2007) for two-stage programs, Heitsch and Römisch (2009) for multi-stage programs, and Gröwe-Kuska, Heitsch, and Römisch (2003) for applications to power planning problems. For the particular case of bidding into sequential electricity markets, see Olsson and Söder (2008) who include the balancing market. Our scenario generation likewise relies on scenario sampling and reduction. However, whereas the existing literature often applies the two methods separately, we alternate between scenario sampling and reduction in a stage-wise fashion with the aim to better preserve the statistical properties of the stochastic processes.

From a practical point of view, there may be further challenges in implementing and solving the coordination problem (e.g. since this requires modeling software). This is finally our motivation for relating its solutions to alternative bidding strategies used in practice, and assessing the gain from coordination without actually solving it.