Congestion Management in a Stochastic Dispatch Model for Electricity Markets

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Recently, more renewable generation resources have been introduced in electricity systems around the world. A large part of these resources have an intermittent nature, with variable generation capacity, which is uncertain until close to real-time delivery. This development has presented a need for more balancing resources, and research into dispatch models that takes uncertainty about real-time availability of generation capacity and load into consideration when determining the day-ahead dispatch.

In this paper, we study an energy-only market with two settlements, for instance day-ahead and real-time. In the day-ahead market intermittent generation and load is uncertain, while all uncertainty is resolved at the real-time stage. Moreover, we assume that real-time flexibility comes at a cost, i.e., extra costs will be incurred if a flexible generator or consumer has to deviate from initial (day-ahead) plans in real-time. In this setting, we consider and compare two different dispatch models:

- A myopic or conventional dispatch, where day-ahead and real-time markets are cleared separately and sequentially, based on bids to each market.
- A stochastic or integrated dispatch, where the day-ahead plan is determined by taking into account the uncertainty in real-time generation and load, i.e. solving a stochastic programming problem for the two markets simultaneously.

A key question is which operating constraints should be included in the two market stages. In real-time all relevant constraints must be complied with, however this is not the case for the day-ahead stage. In particular, we consider different types of congestion management regimes (nodal, zonal or uniform pricing) for the day-ahead part of the market, and for the stochastic dispatch model, we also consider if it can make sense to relax the energy balance constraints in the day-ahead part of the problem.

Our results show that for the stochastic dispatch model, given that the uncertainty is accurately reflected in the model, there is no need to include network flow constraints and even energy balance constraints in the day-ahead part of the problem. If the stochastic programming problem representing the dispatch is convex, it is easy to show that the following ranking of the solutions holds:

- Unconstrained: no network flow constraints and energy balance constraints in day-ahead.
- Balanced: no network flow constraints, but energy balance in day-ahead.
- Max [Zonal, Nodal]: includes zonal or nodal network flow constraints as well as energy balance.

The ranking is due to the fact that moving up the list involves removing constraints from the optimal dispatch problem. The ranking between zonal or nodal pricing for the day-ahead market depends on which parameters are used for the power transfer limits between zones in the zonal model. If the transfer limits are set equal to or higher than the sum of capacities on the lines between zones, then the zonal model is a relaxation of the nodal model, and the zonal model will yield at least as good results as the nodal model. However, if the aggregated transfer capacities are lower than the capacities of individual lines, and this happens often in practical implementations of zonal pricing, then the zonal model may be a restriction of the nodal model, and may yield inferior results. Table 1, which is based on a three-node example from Bjørndal et al. (2016), illustrates how the different model variants may differ with respect to expected cost. The unconstrained model gives a cost value that is 114.9 % of the wait-and-see value, i.e. the expected optimal value with perfect information, while the corresponding values for the balanced and nodal models are 117.4 % and 127.4 %, respectively. Hence, the relaxation of the balance constraint and the network capacities will improve the solution in this case. The zonal network constraints can be tighter or looser than the corresponding nodal constraints. When the interzonal capacity is set at 10000 MWh/h, i.e., equal to the sum of the individual line capacities, the zonal model is a relaxation of the nodal model, and we see that the objective function value is slightly better, at 124.4 % of the wait-and-see value. However, if the interzonal capacity is set too tight, e.g., at 5000 MWh/h, the value of the zonal model becomes much worse than the nodal model, at 352.8 % of the wait-and-see value.

The unconstrained solution, i.e. without energy balance constraints in the day-ahead part, may involve day-ahead over- or under-booking, depending on the relative cost for up- and down-regulation. If up-regulation is expensive and down-regulation is cheap, solving the unconstrained stochastic dispatch model may for instance involve over-booking of generation in the day-ahead schedule, i.e.,

Model	€	Relative
Wait-and-see	66360	100.0 %
Unconstrained	76250	114.9 %
Balanced	77922	117.4 %
Nodal	84515	127.4 %
Zonal ($cap_{\{\{1\},\{2,3\}\}}$ = 5000)	234144	352.8 %
Zonal ($cap_{\{\{1\},\{2,3\}\}}$ = 10000)	82578	124.4 %

Table 1. Optimal expected cost with stochastic market clearing.

more generation than load is planned. Table 2 illustrates this for the example, where the uncertainty is given by three scenarios for wind generation (Low, Medium, High). We see that the unconstrained model will over-book by scheduling 1500 MWh/h more production than load in the day-ahead market. Since the real-time schedule has to be balanced, there is a net down-regulation of 1500 MWh/h in each of the scenarios. We see from that the nodal model chooses to up-regulate one of the hydro generators in the scenarios with low and medium wind. This up-regulation is costly and can be avoided if over-booking is allowed.

For the myopic dispatch model we cannot find similar analytical results as for the stochastic model. However, by simulation in simple but representative examples, we see that the expected value of the dispatch depends both on the bids to the day-ahead market from the uncertain generators, AND on the network flow constraints in the day-ahead part of the problem. For the myopic model we only consider different congestion management methods. Removing the energy balance constraints can also be done in the myopic case, but then the sum of over- or under-booking of generators and load must be determined explicitly before clearing the day-ahead market.

Entity	Node	Nodal model				Unconstrained model			
		Day-ahead schedule	Real-time adjustment			Day-ahead schedule	Real-time adjustment		
			Low	Medium	High		Low	Medium	High
Wind	1	153	-153	6847	9849	0		7000	10000
Thermal	1	5000		-5000	-5000	5000		-5000	-5000
Load	1	-15000				-15000			
Nuclear	2	4998				5000			
Hydro	2	155	-153	245	-155	1500	-1500		-1500
Hydro	3	4694	306	-2092	-4694	5000		-3500	-5000
Total		0	0	0	0	1500	-1500	-1500	-1500

Table 2. Optimal schedules (MWh/h) with stochastic market clearing.

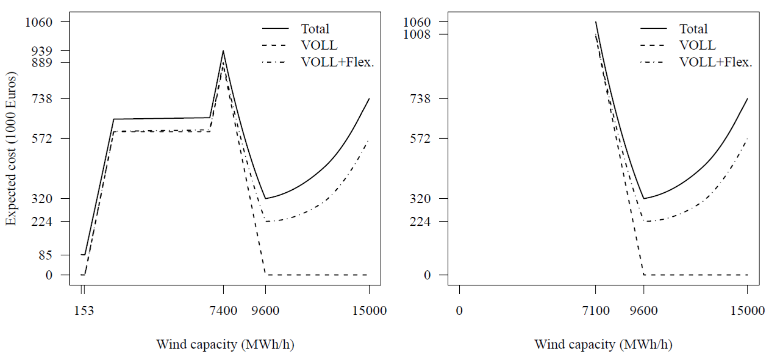

Figure 1. Myopic model with nodal (left) or balance (right) constraints.

In the myopic dispatch the optimal capacity bid for uncertain generation is usually not equal to the expected capacity. This holds for a system perspective, but also for individual players. Moreover, leaving too many constraints to be resolved in the real-time market only, can lead to infeasibilities in the system. For instance, it may be that so much inflexible power is dispatched day-ahead that it is not possible to comply with all relevant real-time constraints, even if there is enough flexible resources in the system. In other instances it may be very costly to do the necessary real-time adjustments. Figure 1 shows expected cost for the myopic model with different values of the day-ahead wind bid from 0 MWh/h to 15000 MWh/h, and where we have split the total cost into load shedding cost (VOLL), flexibility costs due to real-time regulation, and regular generation costs. We see that the nodal model has (approximately) the same optimal wind bid as the optimal wind in the stochastic market clearing model with nodal constraints, i.e., 153 MWh/h. For the model with only balance constraints, the best solution is to set the wind bid equal to 9600 MWh/h, which yields expected cost equal to 320' €, most of which, 224' €, is made up of extra flexibility costs related to real-time regulation. Below the wind bid value of 9600 MWh/h, load shedding is necessary, and VOLL makes up an increasing part of total cost. For wind bid values below 7100 MWh/h, the balanced model will generate a day-ahead schedule that is infeasible with respect to network capacities, and which includes so much inflexible nuclear generation that it is not possible to achieve feasibility by making real-time adjustments.

Solving a stochastic dispatch model to accommodate more intermittent generation in the dispatches may seem to be a fruitful choice in a market with more emphasis on renewable resources. However, a stochastic dispatch model also poses many different issues when it comes to information and implementation. Bidding formats, distribution of revenues, and incentive issues are important topics to address in future research.

Reference

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