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Electricity Transmission Modeling

Economic Impact of Technical Characteristics

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Economic Impact of Technical Characteristics[1]

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Abstract:

The ongoing liberalization of the European electricity markets with the aim to achieve one integrated market requires a fundamental understanding of the technical characteristics of electricity generation and transportation. The aim of our paper is to estimate the economic implications of three different technical problems of transmission grids particularly under the projected wind capacity increase. Based on a simplified model of Northwest Europe we analyze the costs of re-dispatch under different congestion management mechanisms, the cost of supply security due to the N-1 criterion and the obtainable gains by flexible switching possibilities. The models are based on a welfare maximizing approach, power flows are calculated following the DC-Load Flow approach.

Key words: electricity, network modeling, Europe, N-1 criterion.
JEL-code: L94, L51, D61

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1 Introduction: Network Modeling of Electricity Markets

Electricity markets have specific technical characteristics that distinguish them from other network industries like natural gas or water. Stoft (2002) describes two “demand side flaws” that make a sector specific market design a necessity. First the unresponsiveness of demand to prices resulting in a nearly inelastic demand for electricity. This can lead to significant problems with strategic company behavior as small changes in the generation structure can lead to large price increases. The second flaw is the non controllability of power flows to specific customers, namely the physical laws that determine flows within a network “regardless” of economic criterions.

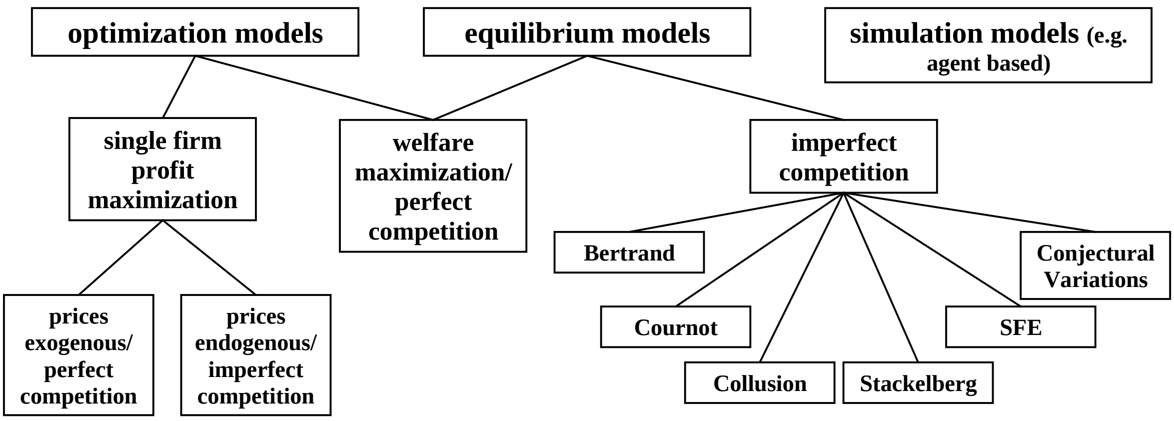
We take up the latter problem and analyze three different technical issues related to power flows and their economic impact. These questions gain increasing importance in the spot light of the ongoing liberalization of the European electricity markets with the aim to achieve one integrated market and simultaneously to increase the share of renewable energy sources. Whereas the large US markets are already incorporating network constrained locational pricing (PJM, New England, New York, Midwest ISO) or planning to do so (California, Texas) that allow an optimal transmission capacity allocation continental Europe is still struggling for an efficient cross border management. This “slackness” to reform the market design leads to increased social costs. However, further technical questions deserve attention in the design of an efficient European electricity market as well.

In the scope of the described developments we first analyze the impact of neglecting locational pricing that leads to an increased need for re-dispatching and thus higher transfer costs that consumers will have to bear in the end. The second issue takes up the question what security constrained pricing has to take into account. The N-1 criterion (the system has to bear the breakdown of any one unit) is one of the main technical drivers for the definition of network security; thus an according representation within the price finding mechanism seems necessary. Finally we look at one possible measure to improve network performance in the future. Whereas the switching of specific lines has always been a component of secure network operation it can become a major element of dealing with the highly volatile energy input of renewable energy sources. By adopting the optimal grid topology within short time the existing transmission capacity can be utilized more efficiently reducing extension requirements and thus saving time and money.

The aim of our paper is to estimate the economic implications of these three technical problems particularly under the projected wind capacity increase. The paper is structured in the following way: First we give an overview of the literature on modeling of electricity markets. Section 2 describes the basic model approach and data. We implement a DC load flow model for a simplified network of Northwest Europe. Section 3 presents the results of the re-dispatch analysis. Given the missing economic signals of cost based re-dispatch the obtained results show a clear disadvantage of this method compared to a locational priced system. In Section 4 the impact of security constraints on market prices is evaluated. A full representation of the N-1 criterion is compared to simplified security modeling approaches concluding that the obtained price differences are not neglectable. Section 5 presents the impact of switching possibilities on market prices. The increased freedom to determine favorable network topologies shows a potential to deal with problems resulting from variable demand and generation situations. The paper concludes in Section 6 that technical restrictions are important for determining economic aspects of electricity networks.

The modeling of electricity markets has accerlated in recent years due to higher computer calculation capacities. Ventosa et al. (2005), Smeers (1997), Kahn (1998), and Day et al. (2002) provide an overview about different model approaches used for electricity markets. Models can be classified into three top groups: either optimization, equilibrium or simulation models. The last ones are for example agent based models and do not follow a single mathematical formulation. The former two groups can further be distinguished by the modeled market form: either competitive or imperfect competition. In addition optimization models can either focus on single firm optimization or welfare maximization (Fig. 1). Perfect competition relates to price taking behavior whereas imperfect competition requires some kind of strategic company behavior ranging from classic Betrand and Cournot competition to mathematical more demanding Supply Function Equilibria (SFE). In addition to these classifications also combinations are possible. Maximization problems with equilibrium constraints (MPEC) require a single objective e.g. a single firm profit that is subject to some form of equilibrium e.g. the locational price formulation of an ISO. If the single objective is replaced by more objective functions that are maximized simultaneously one gets an equilibrium problem with equilibrium constraints (EPEC).

Figure 1: Modeling approaches in electricity markets



In terms of model usage Hobbs (2007) distinguishes three types. First large scale models for grid operation and planning applying numerical solutions; second very small models that are used to gain insights within policy debates applying easy to track structures; finally in-between models for forecasting and impact analyses of policies. Based on the evaluation of energy model researchers in 2006 he reviews the upcoming questions electricity modelers are faced with to define which modeling capacities are presently unavailable but needed. Within dispatch and operation issues ancillary service coordination and power system security are ranked second and third, showing an immanent need for the integration of technical characteristics in economic models. Beside these technical issues the main questions are investment modeling, risk modeling and strategic behavior.

Regarding the impact of technical issues on economic models several different aspects have been analyzed so far. Overbye et al. (2004) compare the DC-load flow approach with a full AC-model to determine the impact of neglecting reactive power issues. Giving the difficulties in solving a full power flow model due to convergence problems and computation limitations the approximation with a DC power flow model is a common way when obtaining locational prices in economic electricity market models. They conclude that although there is some loss of accuracy when using a dc approach, the results are close to the full ac formulation. However, in cases of high reactive and low real power flows the difference can become significant. Bautista et al. (2006) take up the same question in the context of analyzing market power in electricity markets. As the main concern of market power is with active power the impact of reactive power and voltage related issues is generally neglected. Via simple examples they show that the introduction of reactive power increases the strategic space for market participants thus the results differ from a simple DC approximation. They conclude that in the context of economic policy detailed representations may be unnecessary. However, they are unable to classify to what extend simplified assumptions provide misleading market results. Hogan (1993) conducts a similar analysis without the focus on market power. He concludes that a full AC-price model is necessary if line limits are subject to voltage constraints.

Chao and Peck (1998) analyze the possibilities to design an incentive scheme for system operators to obtain welfare optimal reliability. They distinguish three main criteria for determining transmission capacity: for short distance networks the thermal limit, for long distance lines voltage stability and for very long distance systems dynamic stability. Whereas these technical criterions can be accommodated by applying the proper modeling structures system security adds a new dimension to the problem. Power flows are additionally constrained by security levels to handle unexpected outages. Chao and Peck show that in a decentralized market structure the simple and practical solution to make the system operator financially responsible for meeting system requirements will improve the efficiency of the whole system.

Beside techno-economic models of direct grid operation also the extension of existing generation and network capacities plays an important role in the development of competitive electricity markets. Economic investment analyses often do not take account of externalities on the electricity system which are computed ex-post via technical simulation to investigate failure probabilities and security constraints. Models taking into account both aspects have to make simplifications in order to remain computable. For example Jeske et al. (2007) take a look at the impact of wind energy generation on planned and needed network investments in Europe. By taking into account the locational impact of wind generation on the power flow they develop a mechanism that determines economical optimal extension measures. They show that the integration of large scale wind capacities requires only few additional grid extensions whereas the majority of new lines is necessary to overcome already existing bottlenecks on cross borders. Vovos and Bialek (2005) develop a mathematical technique to convert fault level constraints in existing optimal power flow (OPF) model formulations to use the OPF for new capacity allocation. In general, generation expansion planning is based on heuristics to take account of thermal, voltage and fault level limits and thus the expected short circuit current. Beside the advantage of an easier adoption of the problem in existing model structures the direct inclusion of fault levels allows to take account of the shadow costs are respected and influence the overall optimum

2 Model and data: Welfare optimization taking into account power flows

2.1 Model formulation

The analyses are based on Elmod, a DC-load flow network model as presented in Leuthold et al. (2007). The optimization for all three scenarios is based on a social welfare approach derived by obtaining the gross consumer benefit and subtracting total generation expanses (1). Thus, the model represents a fully competitive market environment with price taking generators. Optimal dispatch is determined respecting physical laws and technical conditions, namely the energy balance (2) and capacity constraints of lines (3) and power plants (4):

$$\max \quad W = \sum_{n} \left(\int_{0}^{q_n^*} p(q_n)\, dq_n - \int_{0}^{g_n^*} c(g_n)\, dg_n \right) \qquad (1)$$

s.t.

$\left\lvert P_{jk} \right\rvert \leq P_{jk}^{\max}$	line flow constraint	(2)
$g_n - q_n = netinput$	energy balance constraint	(3)
$g_n \leq g_n^{\max}$	generation constraint (per type of plant)	(4)

The reference period referred to is one hour making the model time static thus start-up and ramping conditions and costs are not considered. Furthermore the approach is based on marginal costs neglecting investment and fixed operation costs for generator and network operators.

Power flows are based on the DC Load Flow Model (DCLF) as described by Schweppe et al. (1988) and Stigler and Todem (2005). According to the DCLF real power flows P_{jk} between two nodes j and k depend on the voltage difference Θ_{jk} and the line series susceptance b_{jk}. In order to derive b_{jk} the networks incidence matrix is used which defines starting and end nodes for each line. Furthermore, the calculation is carried out as a per unit calculation and the voltage differences are assumed to be very small. This yields a linear equation for the lossless line flows:

$P_{jk} = b_{jk} \cdot \Theta_{jk}$	power flow between node *j* and *k*	(5)

The basic model is adjusted according to the requirements of the scenarios. Details are given in the sections. The optimization is coded up in GAMS.

2.2 Data

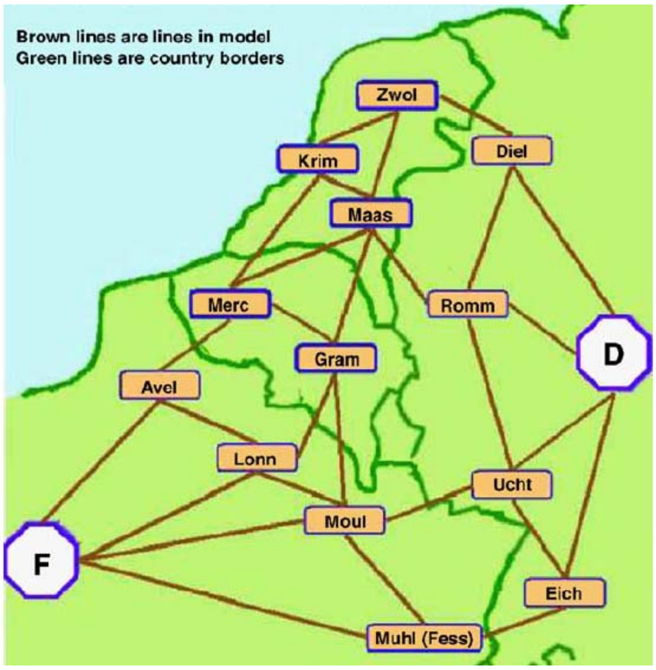
The network model is based on a simplified grid connecting Germany, the Benelux, and France as presented in Neuhoff et al. (2006) consisting of 15 nodes and 28 lines. The nodes connecting France and Germany with their neighbors are auxiliary nodes without associated demand or fossil generation. Each country node has given generation capacities and a reference demand level. For additional simplification, generation capacities are classified into eight types with the same marginal generation costs in all countries. Table 1 gives an overview of the types, installed capacities, and marginal generation costs.

Wind generation capacities are distributed according to their geographic location including auxiliary nodes. At first the situation in 2006 with about 20 GW installed capacity is modeled. Afterwards the expected increase of on- and particularly offshore wind farms in 2012 is simulated increasing the capacity to 38 GW; conventional plant capacities remain unchanged. The actual wind input is determined via availability factors representing stormy and calm situations. The linear demand behavior at nodes is derived from the reference load level, a price of 30 € and an assumed price elasticity at this point of -0.25. The load level can be adjusted to off-peak, average and peak load situations by multiplying the reference demand with 0.7, 1 or 1.3 respectively.

Table 1: Plant characteristics

Plant type	Installed capacity	Marginal generation cost	Plant type	Installed capacity	Marginal generation cost
Nuclear	83 500 GW	10 €/MWh	Steam	28 000 GW	45 €/MWh
Lignite	21 000 GW	15 €/MWh	Gas turbine	5 500 GW	60 €/MWh
Coal	51 250 GW	18 €/MWh	Hydro	17 000 GW	0 €/MWh
CCGT	18 500 GW	35 €/MWh	Pumped storage	13 000 GW	28 €/MWh

Figure 2: Simplified grid of North West Europe (Neuhoff et al., 2006)



3 Re-dispatching: Inefficiencies due to missing price signals

3.1 Concept and Model Adjustments

It is generally accepted that locational marginal pricing is the efficient way to account for transmission constraints within the wholesale pricing mechanism. However, in continental Europe most electricity markets still apply a uniform pricing approach and cross border capacity allocation is partly explicit. This market structure makes re-dispatching necessary as local impacts of generation and demand are neglected in the market results. However, the network operator has to take into account all network restrictions and if the obtained market solution is infeasible re-dispatching becomes necessary. Specific power plants have to reduce output while other have to increase or even start up. The incurred costs are allocated to all consumers thus any local price information of congestions is abolished.

In order to derive the necessary re-dispatching costs with the model a two stage approach is used. First the market results are derived by neglecting capacity restrictions for inner country lines (3). Afterwards the demand level is fixed and the line limits are reintroduced. The resulting plant dispatched is compared to the market result and the resulting costs are derived.

Three different scenarios are compared to locational pricing: uniform pricing for all nodes, a uniform price within the Benelux, Germany, and France and finally uniform prices in each country. Cross border lines remain their capacity levels when deriving market results in the last two cases. All scenarios are simulated for several load and wind cases.

3.2 Results

When all countries are integrated into one single uniform market welfare compared to a nodal pricing market increases and the average price decreases. However, the obtained market results are not a feasible solution for the network operator and a large amount of re-dispatching becomes necessary. Due to the high aggregation of the model only in cases of off-peak load and no wind input the model is able to re-dispatch the market results at all which states the inefficiency of this pricing mechanism. Compared to a full nodal pricing regime the welfare taking into account re-dispatch costs is 0.6% lower.

If the Benelux is grouped to one price zone the peak load situations remain infeasible thus the network operator would not be able to obtain the market solution within the grid. In average and off-peak load cases up to 10% of the welfare amount has to be reallocated due to the re-dispatching processes making the nodal pricing benchmark about 0.25% better on average. Surprisingly, in cases of high wind input the necessary re-dispatching amount decreases significantly. This may be due to the high aggregation of the grid which neglects local effects particularly in Northern Germany.

If all countries are regarded as separate pricing zones the amount of necessary re-dispatch reduces and is in most cases close to zero. Thus the improved consideration of network constraints in this zonal approach has a positive effect on the feasibility of market results. However, compared to a full nodal pricing approach a welfare gap of up to 0.2% remains. The increasing amounts of wind energy production in the future have only minor effects on the necessary re-dispatching which again may result from the simplified grid structure.

The results indicate that a neglecting of network constraints can lead to wrong price and welfare assumptions as the congestion costs will occur anyway but in a separated non-market process.

4 N-1 Criterion: Finding the right price for supply security

4.1 Concept and Model Adjustments

One of the main security issues in electricity network operation is the N-1 criterion. In terms of transmission it expresses the ability of the system to loose a line without causing an overload failure elsewhere. Thus the actual capacity limit of a line may be significantly below the static thermal limit which in turn has an impact on the feasible power flows within the system.

In order to apply the N-1 criterion to the above described model structure we add a further dimension to the incidence matrix which is given to the model as an exogenous parameter and necessary for the line susceptance calculation. The additional dimension accounts for 29 different grid conditions one for each possible line outage. Due to the changed incidence matrix 29 voltage angel differences Θ_{jk} and power flows P_{jk} are derived. As the net input, demand and generation in all cases have to be the same the resulting prices account for the full consideration of all outage possibilities.

The results are then compared to an ideal case without any security consideration and a static way of accounting for N-1 security: lump-sum transmission line capacity reductions, e.g. reducing maximum line capacities by 20%. Furthermore the impact of increased wind input is derived.

4.2 Results

Comparing the ideal case with full line capacity availability with the N-1 restriction a significant shift in prices and load flows can be observed with some nodes decreasing in price whereas others increase (Table 2). Particularly the cross border flows between Germany and Netherlands decrease by roughly 45% leading to higher prices in the Netherlands. As the N-1 criterion lowers the available transmission capacities nodes depending on imports have to face higher prices whereas exporting nodes face similar or even lower prices as more generation capacities are available for local demand rather than export. General effects of applying the criterion are a 0.33% decrease in welfare and a 1% increase in production cost.

Compared to a static reliability margin of 20% the general effects on welfare and costs are similar to the N-1 case. However, local prices and power flows differ. The disadvantage of a static consideration increases when generation and demand conditions change. The reliability margins implied by the N-1 model tend to vary around 15%-29% assuming that specific lines would be fully utilized without the criterion. Particularly during peak load situations security margins would need to be higher than on average. The growing impact of wind energy on Europe’s transmission system in the future will further increase the error by static reliability margins thus a correct representation of security restrictions is only possible with an according N-1 consideration within the pricing mechanism.

Table 2: Price Pattern with N-1 considerations, Average Case

Node	Ideal case	Full n-1	Static n-1
Germany	22.00 €/MWh	22.00 €/MWh	22.00 €/MWh
France	21.94 €/MWh	20.62 €/MWh	20.79 €/MWh
Zwol	40.62 €/MWh	45.00 €/MWh	42.06 €/MWh
Krim	45.00 €/MWh	45.00 €/MWh	45.00 €/MWh
Maas	61.63 €/MWh	68.34 €/MWh	67.16 €/MWh
Merc	30.00 €/MWh	27.67 €/MWh	22.00 €/MWh
Gram	20.10 €/MWh	22.00 €/MWh	22.00 €/MWh

5 Network switching: Modern technologies for future grids?

5.1 Concept and Model Adjustments

In a last step we take a closer look at possibilities for network operators to adopt to changing demand and generation patterns. In general economic models use static grids that only allow for one switching state whereas technical developments and applications allow for a more flexible switching behaviour. The system operator can take appropriate action by changing the network topology, thereby changing the power flow pattern and resulting market prices. Particularly, the increased share of wind energy input into the European transmission grid causes externalities and highly variable power flow patterns. A flexible grid topology may allow a better integration of wind energy without too much resulting congestion problems.

In order to allow for a flexible grid topology the incidence matrix has to be adopted by introducing binary decision variables that either set a connection off- or online. The resulting line series susceptances are adjusted accordingly.

5.2 Results

First the base case (average demand, no wind input) with a fixed grid topology is compared to the same situation under flexible conditions. 11 of the 28 lines are switched off transferring the grid into a more radial structure and the resulting welfare increases by 0.4% with a 2.6% decrease in total generation expanses. The price pattern is slightly shifted although the impact is minimal for most nodes (Table 3).

When wind capacities are introduced the resulting cost benefits from switching range between 0 to 3.7% with welfare increases between 0 and 0.5%. Higher wind power input results in less benefit from switching. The reason for this effect can be found in the switching states. The higher the wind power, the higher the flows over all lines and the lower the possibility that lines are switched off. So in a scenario with high wind power the number of switched-off lines is lower than in the case without wind. Price differences between the nodes decrease when switching is possible. However, in comparison to the benefit of increased wind, the benefit of switching is rather low.

When load levels (off-peak, average, and peak load) are changed in addition the results become more varying. A general trend that welfare increases due to switching reduces with rising load is observable. This can be explained by the higher capacity usage of the transmission grid which makes line shut downs impossible. However, the results are sensitive to the actual wind input level. The approximated wind capacity level of 2006 results in decreasing welfare values for higher wind and load levels but partly increasing generation costs. The levels of 2012 have an improving impact on the welfare increase due to switching. This average surplus ranges between 0.3% to 0.4%. Furthermore the generation costs decrease in all wind/load combinations. This divergence may be explainable by a more evenly distributed wind generation in 2012 (Table 4).

The price patterns in general show a slight price decrease due to the switching possibility. However the price impact caused by wind or load changes is higher compared to the average case than the impact of switching. Nevertheless, as the model itself is highly aggregated the impact may be underestimated.

Table 3: Price Pattern with N-1 considerations, Average Case

Node	Fixed Grid	Flexible Grid
Germany	22.00 €/MWh	22.00 €/MWh
France	21.94 €/MWh	22.00 €/MWh
Zwol	40.62 €/MWh	42.62 €/MWh
Krim	45.00 €/MWh	45.00 €/MWh
Maas	61.63 €/MWh	60.38 €/MWh
Merc	30.00 €/MWh	26.95 €/MWh
Gram	20.10 €/MWh	19.15 €/MWh

Table 4: Effects due to Switching on Welfare and Costs

Wind	Load	Flexible Grid 2006 Welfare	Flexible Grid 2006 Generation costs	Flexible Grid 2012 Welfare	Flexible Grid 2012 Generation costs
Low Wind	Off-peak	+0.25%	-2.06%	+0.37%	-0.69%
	Average	+0.21%	+1.20%	+0.34%	-2.63%
	Peak	+0.22%	+1.57%	+0.34%	-0.95%
High Wind	Off-peak	+0.01%	-0.41%	+0.42%	-1.67%
	Average	+0.01%	+0.90%	+0.35%	-3.68%
	Peak	±0.00%	+0.00%	+0.23%	-2.85%

6 Conclusion

In this paper we analyze the impact of three different technical restrictions of electricity markets on the resulting prices. Based on a simplified model of Northwest Europe we show that the neglecting of these characteristics can lead to different price patterns and thus to misleading implications for policy and economy.

First the impact of neglecting transmission capacities is estimated. Most of the European markets have a uniform priced wholesale market thus location of demand and generation have no impact on the pricing process. This mechanism requires a re-dispatching of generation units in case of inner country congestion. We show that a higher degree of grid aggregation leads to a larger amount of necessary re-dispatch which in turn will add a cost block for consumers. The impact of wind energy on the re-dispatch amount within the model is positive thus less capacity needs to be rescheduled. However, this result may stem from the high aggregation of the grid.

Secondly we take up the question of security and system reliability. The widely used N-1 criterion is often neglected in economic market models. However, the need to account for possible outages reduces available transmission capacity and thus increases prices. Our results show that neither neglecting the criterion nor using a static margin can capture the impact completely.

The last analysis is focused on the possibility for network operators to improve network management by switching the networks topology. Generally the network operators tries to avoid negative impacts of loop flows by adopting a more radial grid structure. However, in case of a high capacity usage during peak load or high wind input the possibilities to improve the flow diminishes and thus the impact is rather little. A more detailed grid structure may improve the impact.

The results show that electricity markets are subject to several technical characteristics that have an impact on prices. Although simplifications can yield reasonable results in average cases, the volatile structure of demand and generation lead to several different cases that require a more detailed representation to obtain robust conclusions.

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