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Market Power Under Nodal and Zonal Congestion Management Techniques

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Abstract

Contrary to the common thought that nodal pricing provides more opportunities for a strategic player to exert market power than the zonal model, we show that in the latter one because of the need for re-dispatch or counter-trading, another extra place is created letting more gaming possibilities. Therefore, if proper market power mitigation approaches are not utilized in both day-ahead and re-dispatch markets, then zonal pricing may be more susceptible to market power, especially in zonal model which is based on available transfer capacity (ATC), strategic player's profit and social welfare can be very volatile. In general, the more network constraints are incorporated in day-ahead market (100% in nodal and almost zero in ATC), the more social welfare is attainable. Hence, nodal model is acquitted from the more market power denunciation.

Keywords: Market design, congestion management, available transfer capacity (ATC), market power, flexibility cost of re-dispatch or counter-trading

1 Introduction

In designing the efficient electricity markets, dealing with congestion is always a controversial issue. For many years, there was an objection to nodal pricing which has the more potential of exercising market power and the argument was that due to the more price areas by less producers and therefore less competition in each node than zonal pricing, strategic player finds more opportunities to exercise market power. Therefore, the first suggested solution is to aggregate some nodes into larger zones and hence creates more competition across a wider area by limiting the power of strategic player.

In this paper, we are examining this claim through an illustrative example. Specifically, compare the market power potential of nodal versus zonal pricing with Available Transfer Capacity (ATC) which is the dominant method to allocate capacity to cross-border interconnections in Europe.

Electricity exchange is subject to the constraints of the transmission network. Congestion occurs when the transmission lines do not hold enough capacity to fulfill the market requirements. Therefore, congestion management (CM) techniques are deployed to dispatch an optimal power resulted from the market such that network constraints are not violated. Congestion management techniques can be categorized into five groups (Vries and Hakvoort (2002)):

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1. Explicit auctions
2. Implicit auctions
3. Market splitting
4. Re-dispatching
5. Counter-trading

Vries and Hakvoort (2002) drew a comprehensive economic comparison among these methods based on their theoretical economic efficiency. They concluded that all these methods potentially lead to economic efficiency in the short term. However, they may result in different distribution of costs, implementation costs, openness to strategic behavior as well as the long-term incentives for generators and transmission system operators.

European Commission also have the same classification as Vries and Hakvoort (2002). This document put a great emphasis on the concept of "economic rent or surplus". Economic rent means how to exploit the arbitrage between markets with different prices.

An state-of-the-art review of (CM) techniques is done by Pillay et al. (2015). They just classified it into avoiding or relieving congestion methods. Besides discussions on (CM) methods, various optimization techniques for solving CM as well as their adaption in different countries are mentioned.

In general, various CM techniques can be distinguished by the level of integrating energy and transmission. In one side, there is an explicit auction with a 100% separation of energy and transmission in which the capacity on the international interconnections (in Europe) is auctioned in a separate auction from energy. Therefore, the prices of these two commodities are not correlated.

On the other side, nodal pricing which is the perfect realization of implicit auction, fully merges energy and transmission such that electricity prices cannot be decomposed into energy and transmission prices. Zonal pricing implemented in the whole Europe, can be considered as an intermediate implicit auction.The first stage of zonal pricing which is energy market is operated by several power exchanges (PXs), each of them control some pre-defined bidding areas or price zones. These price zones are linked by "transfer capacities (TCs)"[1]between zones which are provided by transmission system operators (TSOs). Then in the second stage, depending on the market design (which can be market splitting, re-dispatching or counter-trading), TSOs are responsible of securely dispatching the obligations from their related energy market such that intra-zonal congestion never happens.

Though implementing the stages of zonal pricing seems straightforward, there still exists a lot of details about the collaboration among PXs as well as TSOs. The collaboration among PXs was dealt with by implementing market coupling in Europe. The initiative of price coupling of European PXs started in 2009. The aim of price coupling of regions (PCR) is to develop a single price coupling solution to increase liquidity, efficiency and social welfare all through the Europe EPEX-SPOT (2017). But there is still a lack of the same consensus among TSOs about how to share information with each other as well as the algorithm can be utilized.

Oggioni and Smeers (2012), Oggioni et al. (2012), Oggioni and Smeers (2013) analyzed different versions of market coupling with respect to various degrees of coordination among TSOs. They assume that TSOs has to do counter-trading in order to reach a viable intra-zonal network solution on their control area. Therefore, they concluded that the high level of their collaboration and more significantly the right ATC adoption, could bring about as efficient results as benchmark nodal pricing case. Kunz (2013) pursuing the same approach as Oggioni and Smeers (2013) for the study region of Austria, Czech Republic, Germany, Poland and Slovakia. They wrapped up with this conclusion that the higher the coordination and sharing network information, the more efficient is the market coupling.

Regardless of how zonal pricing is designed, the efficiency of it compared to nodal pricing has been debated in several papers. For instance, in Bjørndal (2000), Bjørndal and Jørnsten (2001), Bjørndal et al. (2003), Bjørndal

[1]Based on Van den Bergh et al. (2016) definition, "the Available Transfer Capacity (ATC) is calculated as the maximum commercial exchange between two market areas, compatible with the physical transmission constraint and operational security standards. In order to calculate the ATC, TSOs estimate the parallel flows that will result from the market outcome. The ATC calculation method is based on heuristic rules and day-2 estimations of the market outcome (i.e., the so-called Base case). The ATC value is determined for each cross-border link (interface) and can depend on the flow direction of the line due to the assumptions made in the ATC parameter calculation."

and Jörnsten (2007), writers argue that choosing the right number and citing of zones make zonal approach a thoroughly challenging congestion management method. Because it can make very great impacts on the amount and distribution of surpluses among market participants and network operator.

On the other hand, zonal pricing has been always advocated by some policy makers due to its less potential of exercising market power. By reasoning that joining several nodes together culminate in having more competitors in each zone. Therefore, the power of each firm can be suppressed compare to the nodal pricing approach.

However, Hogan (1999) and more specifically Harvey and Hogan (2000) refute this idea by giving several illustrative examples and show that zonal pricing makes poorer incentives for investment and socializing the higher costs to consumers, requires more administrative rules and more payments to generators for reducing production in the case of intra-zonal congestion. This behavior is not in align with market definition.

Nevertheless, so far nodal pricing has mainly been objected by European politicians. For instance, the German government believes that nodal pricing could have destructive effects on market competition and liquidity (Goldthau (2016)) by saying that: " Smaller bidding areas tend to have an adverse effect on the market structure and competition on the wholesale and retail markets, because the probability of profitable exhibition of market power by incumbent market players increases. "

Moreover, to keep market liquidity at high levels some extra measures such as defining a virtual system price for all bidding zones as reference price for forward contracts and hedging instruments based on contract for differences (CFD) or financial transmission rights (FTR) should be taken into account.

In order to test this assertion mentioned by many European politicians about less market power of zonal pricing, several papers were modeling re-dispatch or counter-trading to assess strategic behavior of generators. However, detecting strategic behavior is very difficult to prove especially in hydro power plants, since quantifying the water value independent of energy value is practically impossible.

Holmberg et al. (2015) which is based on Nash equilibrium notion, compared three congestion management techniques - nodal, zonal (uniform pricing) and discriminatory (pay-as-bid)- from game-theoretical point of view. With the assumption of perfect competition, inelastic certain demand and the full participation of all agents in real-time market, they came to the conclusion that the three mentioned market designs are equally socially efficient. But in zonal pricing with counter-trading, the payments from TSOs to producers is higher than nodal pricing and pay-as-bid.

There could be several reasons that make analyzing strategic behavior a very challenging task. For example, the geographical placement on the network could make an opportunity for some players to earn more profit. Furthermore, the bidding strategy analysis of a generator that have several assets on different nodes or zones is certainly different from a single one. The last but not the least is the marginal cost of generator in its production area. Hers et al. (2009) consider four different varieties of strategic behavior in re-dispatch model; locating in constrained-on or -off region combined with price or volume bidding. Then, test the results on the real Dutch network by COMPETES model. They conclude that by implementing re-dispatch, more firms will be allowed to enter into the market in which none of them would come now because of the current situation of the market.

Dijk and Willems (2011) tries to compare nodal pricing with counter-trading with respect to their long-term effects on entry and investment decisions. By drawing the final inference that counter-trading is an in efficient congestion management tool as well as unproductive instrument to incentivize competition in the electricity market.

In our paper, we examine which of the two congestion management mechanisms 'nodal pricing' and 'zonal pricing with Available Transfer Capacity (ATC)' shows the more potential of exercising market power.

This paper is different from all previous papers that considering market power under various congestion management techniques with respect to the following main aspects:

1- The arbitrage possibility between day-ahead and real-time market is given to the strategic generator to see if it is more profitable to behave strategically in both markets than one-stage nodal pricing benchmark case.

2- Whether and how different ATC quantities for a cross-border line do affect on the strategic behavior of generators. Do they result in higher or lower surpluses than nodal benchmark case.

3- Owing to the hardship of resetting plans close to the real-time delivery especially for inflexible generators, flexibility cost of production has been considered in the real-time market (Morales et al. (2014), Bjorndal et al. (2016)). It means that generators are capable to submit different offers in real-time market than day-ahead.

The rest of this paper is organized as follows: In section 2 which is related to the modeling part, at first the assumptions and mathematical notation and then the mathematical formulation for nodal and zonal-ATC with re-dispatching are mentioned. Section 3 is allocated to the definition of 3-bus illustrative example as well as the results when strategic player plays strategically just in one of the day-ahead or real-time markets or in both and finally we conclude the paper in section 4.

2 Model

2.1 Modeling assumptions

The main assumptions of the model are listed below:

1- The model represents the strategic decision of an individual strategic generator in different market designs- nodal, zonal with ATC and zonal with FBMC. All the other generators and demands are price takers, therefore, they offer their marginal cost and benefit to the market.

2- For simplicity, a single-period market has been considered but it can be extended to the multi-period case. In studying market power, especially in hydro-dominated electrical systems, inter-temporal decisions could make great differences in the profit of strategic player.

3- DC representation of the network that includes first and second Kirchhoff laws has been considered.

4- Following to EUPHEMIA algorithm (PCR (2013)), linear offer and bid curves are considered respectively for generators and consumers.

5- Any kind of uncertainties are not taken into account.

6- Nodal pricing is just one stage model because the whole physical network is modeled in day-ahead market. However, in zonal pricing, due to the overlooking physical network in day-ahead, intra-zonal network constraints are considered in real-time market to avoid congestion.

2.2 Notation

We adopted almost the same mathematical formulation as Bjorndal et al. (2016). The model entails I participants either generators with positive or consumers with negative values. For each $i \in I$, there exists solutions x_i and X_i for day-ahead and real-time markets respectively.

C_i^1 represents the set of feasible solutions corresponding to participant i for day-ahead market, whereas C_i^2 proportionates to the real-time market feasible solutions which is dependent on the decision x_i from the day-ahead market. Therefore, a feasible solution to both day-ahead and re-dispatch markets must satisfy the following constraints:

$$x_i \in C_i^1 \qquad i \in I \tag{1}$$

$$X_i \in C_i^2(x_i) \qquad i \in I \tag{2}$$

Each generator and load i locates in a specific node $n \in N$ as well as a pre-determined zone $z \in Z$. Nodes of the network are connected by a set of physical transmission lines L. Corresponds to each line l, there is a flow $f = (f_l)_{l \in L}$. If ν_0 and ν_1 show the starting and ending nodes of line l and $f_l > 0$, then it means that power is flowing from ν_0 to ν_1.

For every adjacent zones which are connected by physical connections l, there exists an inter-zonal interface $e \in E$ which conveys commercial flows between zones. Likewise the definition of f_l, corresponds to each inter-zonal interface e, there is a flow $(f_e)_{e \in E}$. If ω_0 and ω_1 show the starting and ending zones of interface e and $f_e > 0$, then it means that commercial flow is flowing from ω_0 to ω_1.

U^1 and U^2 represents network constraints in the day-ahead stage of nodal and zonal models respectively. More detailed explanation about network constraints are given in sections 2.3 and 2.4.

2.3 Nodal pricing

In nodal pricing method, market clearing prices are calculated for locations on the network called nodes. The nodal price composed of the marginal cost of energy plus the marginal cost of transmission which composed of loss and congestion costs. As mentioned before, these two elements can not be decomposed into two energy and transmission prices due to the implicit approach behind their calculation. The majority of US markets trade electricity on a nodal basis with very efficient market result experience (Neuhoff and Boyd (2011)). The market operator clears the market by maximizing the social welfare subject to the physical network constraints in a lossless DC approximation of the network flows. As mentioned in 2.2, consumers can be considered as generators with negative values. Therefore, their benefit curve with negative values is likewise a cost curve. Hence, the objective function can just be outlined by costs. By virtue of full network consideration in day-ahead market, just day-ahead costs are included in the objective function of nodal model.

Each offer $i \in I$ is associated with a linear day-ahead marginal cost and benefit function $a_i + b_i x_i$ with non-negative parameters a_i and b_i. To keep conciseness, we assume that inverse demand curve take negative values $x_i < 0$. Thus, the corresponding curve $a_i + b_i x_i$ has a downward slope. Accordingly, the total day-ahead cost of participant i, which is the area under marginal cost or benefit curve, is a quadratic cost or benefit function $c_i(x_i) = a_i x_i + \frac{1}{2} b_i x_i^2$.

To sum up, the mathematical formulation for nodal pricing is as follows:

$$\text{Minimize}_{x,f} \quad \sum_{i \in I} c_i(x_i) \tag{3}$$

$$\text{subject to:} \quad x_i \in C_i^1, \qquad i \in I \tag{4}$$

$$\tau_n(f) + \sum_{i \in n} x_i = 0, \qquad n \in N \tag{5}$$

$$\tau_n(f) = \sum_{l:\nu_1(l)=n} f_l - \sum_{l:\nu_0(l)=n} f_l, \qquad n \in N \tag{6}$$

$$f \in U^1 \tag{7}$$

$\tau_n(f)$ represents the net inflow of power in node n from the network. Moreover, U^1 denotes all physical network constraints related to a DC load flow model. Consequently, (7) is equivalent to the following constraints:

$$f_l = Y_l.(\Theta_{\nu_1(l)} - \Theta_{\nu_0(l)}) \qquad l \in L \tag{8}$$

$$-\,cap_l \leq f_l \leq cap_l \qquad l \in L \tag{9}$$

$$\Theta_1 = 0 \tag{10}$$

(8) shows that flow is dependent on line characteristic parameter Y_l which is the susceptance of line l as well as phase angel Θ of related starting and ending nodes. In constraint (9), cap_l shows the thermal capacity of line l. Finally, By (10), the first node is considered as a reference node.

2.4 Zonal pricing with ATC

All European electricity markets except Scandinavia and Italy, were organized nationally such that each country concentrates on self-sufficiency of its electricity supply. Therefore, zonal approach was suggested by ENTSO as an electricity trading target model, to couple all these interconnected markets which are called bidding zones. So as to accomplish a global social welfare goal throughout the whole continent, the interconnection capacity among bidding zones should be considered in the trading process. But the physical transmission network creates limitations on international trade. Thus, how the available capacity for trading is calculated could have profound impact on market result and efficiency. Thus far, excluding central western European countries, the ATC mechanism is the dominant method to allocate capacity to cross-border interconnections.

ATC is related to the simplified zonal view of the transmission system in the day-ahead market and means that the Kirchhoff laws that describe the physical power flow are partially ignored in day-ahead market. The ATC calculation method is discussed in several papers; for example see Rious et al. (2008). However, the calculation of the ATC is vague and not published or informed by TSOs. To gain a maximal social welfare in the whole Europe, Jensen et al. (ress) and Aravena and Papavasiliou (2017) mentioned that ATCs should not be determined exogenously, rather should be optimized endogenously synchronized with day-ahead and real-time markets. The ATC calculation discussion is beyond the scope of our paper, but something that distinguishes this paper from former ones is how different ATC quantities for a specific inter-zonal interface $e \in E$ could encourage or discourage market power. These inter-zonal interfaces are different from physical connections l.

The day-ahead market is a pool composed of all fully coordinated power exchanges whom receives offers and bids of their related zones as well as the interface ATCs from their corresponding TSOs. The mathematical formulation for day-ahead market is as follows:

$$\text{Minimize}_{x,f} \quad \sum_{i \in I} c_i(x_i) \tag{11}$$

$$\text{subject to:} \quad x_i \in C_i^1, \qquad i \in I \tag{12}$$

$$\tau_z(f) + \sum_{i \in z} x_i = 0, \qquad z \in Z \tag{13}$$

$$\tau_z(f) = \sum_{e:\omega_1(e)=z} f_e - \sum_{e:\omega_0(e)=z} f_e, \qquad z \in Z \tag{14}$$

$$f \in U^2 \tag{15}$$

$\tau_z(f)$ declares the net inflow of power in zone z from all inter-zonal interfaces $e \in E$. Unlike nodal day-ahead market, just commercial flows which do not reflect physical network constraints are modeled in zonal day-ahead market. U^2 only shows the inter-zonal trade capacities and is equivalent to the following constraints:

$$-ATC_e \leq f_e \leq ATC_e \qquad e \in E \tag{16}$$

Due to disregarding real characteristics of electrical network in day-ahead market, it is very probable that day-ahead solution does not satisfy the physical network constraints in the real-time stage. Therefore, a remedial action is invoked by TSOs to release congestion after clearing of the energy market. Based on the design and settlement methods of real-time market, several corrective actions have been explored and argued in many papers. For example, van Blijswijk and de Vries (2012) evaluates which of the three corrective mechanisms 'system re-dispatch', 'market splitting' and 'market re-dispatch' is mostly congruent with Dutch electricity transmission grid. Whereas, Oggioni and Smeers (2013) and Dijk and Willems (2011) focused on counter-trading owing to lack of the documentation of the other methods.

The aim of counter-trading is finding optimal deviations from day-ahead scheduling. Hence, two re-adjustment actions should be taken to balance supply and demand in nodes connected to congested lines:

- Down-regulation: the generators in the constrained-off area (area with excess of energy) have to decrease their production by buying-back the deviated quantities from day-ahead market or consumers have to increase their consumption.
- Up-regulation: as opposed to down-regulation, the generators in the constrained-on area (area with deficit of

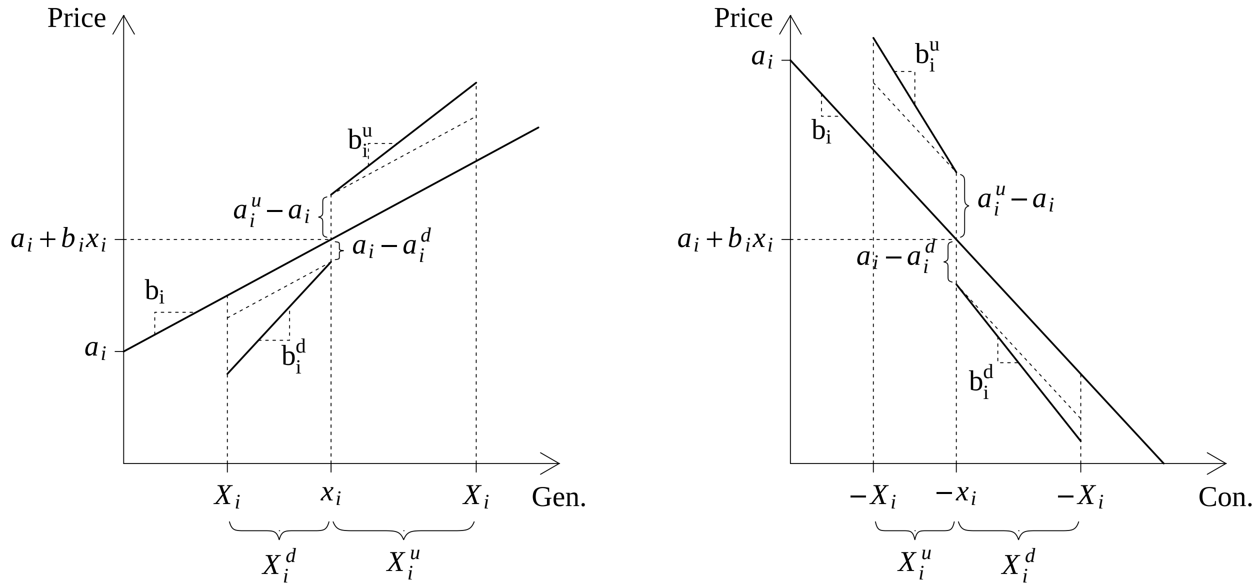
energy) have to increase their production or consumers decrease their consumption by selling the day-ahead market contracted electricity they decided not to use.

But changing the plan of the system (which was arranged in day-ahead) in a time-interval close to the delivery hour, requires flexible sources. This flexibility can originate from various sources like energy storage, demand-side management, etc. Another essential source of flexibility is conventional generators' ability to change their output to follow varying load. The ability of changing production in a short interval depends on technological aspects such as minimum up/down times, ramp rates, minimum generation levels and start-up costs (Palchak and Denholm (2014)) whereby some additional costs will be enforced to generators as well as the system.

Hentschel et al. (2016) evaluate the monetary value of conventional power plant flexibility options through developing a valuation tool which relates a change in technical parameters to an economic effect and revenue. Therefore, generators and consumers can have a different cost and benefit curve (offer/bid curve) in real-time ascribed to flexibility costs. If in real-time the generators are asked to increase their production beyond the day-ahead level, then flexibility cost means that the cost of generation is higher than the day-ahead marginal cost. If they reduce production from the day-ahead level, then they have to repurchase this deviated quantity which is less valuable than their day-ahead marginal cost. On the opposite side, if the consumers increase their consumption in real-time, their bid will be lower than in day-ahead, because it is not as valuable as if it was planned in day-ahead and if they reduce their consumption, they are eager to be compensated by asking higher than their day-ahead willingness to pay.

The relation between day-ahead and real-time cost and benefit functions is shown in fig.1. The left-handside figure represents an offer (supply) curve for a generator, while the bid (demand) curve of a consumer is illustrated on the right-handside. Moreover, the real-time flexibility costs in the case of deviation from day-ahead market is shown in both figures.

Flexibility costs results in different cost and benefit function parameters in re-dispatch stage. If $i \in I$ is a generator, then parameters a_i^u and b_i^u are used for up-regulation and a_i^d and b_i^d for down-regulation where $a_i^d \leq a_i \leq a_i^u$ and $min\{b_i^u, b_i^d\} \geq b_i$. For the demand-side, flexibility parameters look similar.



(a) supply function for a specific generator

(b) demand function for a specific consumer

Figure 1: supply and demand functions for a specific generator and consumer offers/bids to the day-ahead market plus the flexibility costs incurred in real-time

With respect to fig.1, redispatch model is as follows:

$$\text{Minimize}_{X_i^u, X_i^d, F} \quad \sum_{i \in I} c_i(X_i) + \widetilde{c}_i(x_i, X_i) \tag{17}$$

$$\text{subject to:} \quad X_i \in C_i^2(x_i), \qquad i \in I \tag{18}$$

$$\tau_n(F) + \sum_{i \in n} x_i + \sum_{i \in n} X_i^u - \sum_{i \in n} X_i^d = 0, \qquad n \in N \tag{19}$$

$$\tau_n(F) = \sum_{l:\nu_1(l)=n} f_l - \sum_{l:\nu_0(l)=n} f_l, \qquad n \in N \tag{20}$$

$$F \in U^1 \tag{21}$$

In (17), $\widetilde{c}_i(x_i, X_i)$ illustrates the additional cost caused by flexibility in the re-dispatch market. The flexibility cost is dependent on the day-ahead quantity x_i as well as the revised quantity X_i after running the re-dispatch and is constructed as follows:

$$\widetilde{c}_i(x_i, X_i) = (a_i^u - a_i)X_i^u + 0.5(b_i^u - b_i)(X_i^u)^2 + (a_i - a_i^d)X_i^d + 0.5(b_i^d - b_i)(X_i^d)^2 \tag{22}$$

Where $X_i^u = \max\{\, X_i - x_i, 0\}$ and $X_i^d = \max\{\, x_i - X_i, 0\}$. Further examples and discussions are provided in Bjorndal et al. (2016).

Definition of $\tau_n(F)$ and U^1 are the same as nodal model mentioned in section 2.3. However, F illustrates the physical flow in re-dispatch model. It should be noticed that in balancing constraint (19), x_i is fixed from day-ahead market result. Hence, just re-adjustments X_i^u and X_i^d will be optimized such that all physical network flows are satisfied.

2.5 Measuring market power

After the deregulation of electricity industry, generation companies submit their offers/bids to the market operator instead of revealing their real costs. Since the aim of these bidding strategies is to maximize their profit then the potential for market power exercise will be created. Market power can be defined as the ability to profitably lifting prices above marginal cost, which results in inefficiencies mainly due to suboptimal plant dispatch.

Several reasons for the existence of market power are identified (Rahman (2011)) such as:

- Transmission constraints and market fragmentation
- High degree of concentration
- Inelastic demand
- Peak demand conditions and instantaneous balancing
- Strong national incumbents
- Joint capital control of generation and transmission capacities
- Gaps in market arrangements

However, the reason of market power can be very specific to the examined market since each market has its own loopholes that can be exploited by market participants to exercise market power. In this paper the main focus is investigating the effect of market design on market power. To understand the extent of existed market power, measuring tools are needed. They can be categorized into two main classic and dynamic methods.

The first category is just measuring market concentration and the well-known metrics are the Four-firm Concentration Ratio (I4), Herfindahl Hirshman Index (HHI) and Pivotal Supplier Index (PSI). But as we mentioned earlier there would be other reasons than just market concentration. Hence, these methods are not powerful metrics to measure the existence of market power.

The second category can be divided into two ex-post analysis and equilibria modeling. In the former approach, the difference between the actual market price and marginal cost of production shows the amount of market power while in the latter one the examined market is simulated to find the equilibria, then the difference between equilibrium prices and the marginal cost of production illustrates the amount of market power.

In this paper, the ex-post analysis approach has been adopted to measure market power. However, we tailored the measuring metrics as follows:

$$S_i = x_i.\lambda_{z:i\in z} + (X_i^{up} - X_i^{dn}).\lambda_{n:i\in n} - (c_i(X_i) + \widetilde{c}_i(x_i, X_i)) \tag{23}$$

$$SS = -(\sum_{i\in I} c_i(X_i) + \widetilde{c}_i(x_i, X_i)) \tag{24}$$

S_i and SS respectively represent the surplus of participant i and the overall social surplus. After running both markets the shadow price of equation.(13) shows the day-ahead market clearing price for each zone z, λ_z, and similarly λ_n extracted from equation.(19) represents the re-dispatch market clearing price. If i is a generator, then the first and second terms in equation.(23) are respectively the income from day-ahead and re-dispatch markets while the last parenthesis calculates the overall cost of production in both markets. With respect to the assumption of negative values x_i for consumers, the first two terms in equation.(23) represents the consumer payments and the last term is its benefit from both markets. Hence, in overall, for both kind of participants surplus is a suitable term.

With the same analogy, social surplus is equal to the consumers' benefits (bids) minus generators' costs (offers).

These two indexes are used to compare the market power of different players. The more the social surplus is, the more efficient is the market design.

3 Results and discussion

In this section we make use of a small three-node system to illustrate and compare three congestion management approaches from market power point of view.

3.1 Illustrative example

The three different congestion management models are compared using the three-node system depicted in fig.2. This system is composed of eight conventional generators (G_1,G_2,...,G_8), three demands (D_1,...,D_3) and three lines (L_{12},L_{13},L_{23}). All three demands are assumed to be elastic. Data related to the whole system is shown in Table.1.

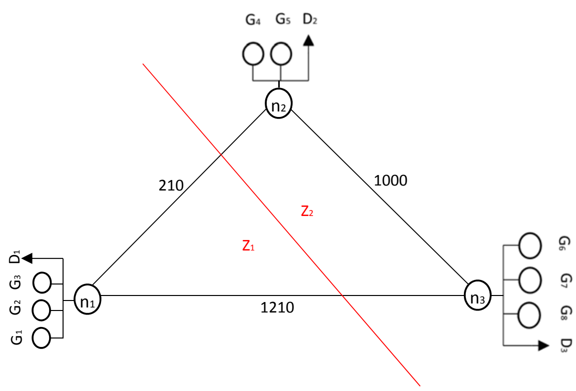


Figure 2: Three-bus power system

Table 1: Data-Three bus system

Day-ahead market			Network	
Node	Supply	Demand	Line	Capacity
1	a_{G_1}=0 , b_{G_1}=0.01 a_{G_2}=0 , b_{G_2}=0.05 a_{G_3}=0 , b_{G_3}=0.06	a_{D_1}=3000 b_{D_1}=0.3	1-2	210
2	a_{G_4}=0 , b_{G_4}=0.05 a_{G_5}=0 , b_{G_5}=0.05	a_{D_2}=3000 b_{D_2}=1.2	1-3	1210
3	a_{G_6}=0 , b_{G_6}=0.02 a_{G_7}=0 , b_{G_7}=0.2 a_{G_8}=0 , b_{G_8}=0.15	a_{D_3}=3000 b_{D_3}=0.24	2-3	1000

Real-time market		
Up/Dn	Actor	Coefficient
up-regulation	generator	$\gamma_{G_i}^{up} * b_{G_i}$
	consumer	$\gamma_{D_j}^{up} * b_{D_j}$
dn-regulation	generator	$\gamma_{G_i}^{dn} * b_{G_i}$
	consumer	$\gamma_{D_j}^{dn} * b_{D_j}$

b_{G_i} represents the slope of G_i's marginal cost function and a_{D_j} and b_{D_j} are respectively the intercept and slope of D_j's marginal benefit function.

As you can see in supply column, G_1 is the cheapest generator in n_1 as well as the whole system and G_6 is the cheapest in Z_2 and the second cheapest in the whole system while D_3 is the most expensive demand in the network. All lines have the same reactance equal to one.

The last column in RT market illustrates that for up- and dn-regulation, costs and benefits are connected to day-ahead related ones by multipliers $\gamma_{G_i}^{up}$, $\gamma_{G_i}^{dn}$, $\gamma_{D_j}^{up}$, $\gamma_{D_j}^{dn}$ where a value of 1 indicates that the re-dispatch costs and benefits are equal to the day-ahead ones, while higher values indicate extra costs of re-dispatch. In all cases of this paper, it is assumed that $\gamma_{G_i}^{up}$=$\gamma_{G_i}^{dn}$=2 and $\gamma_{D_j}^{up}$=$\gamma_{D_j}^{dn}$=1.5. It means that both marginal cost and benefit functions in RT market entail steeper slope than DA market which shows the higher costs and benefits of re-dispatching.

It is assumed that all generators and demands in the illustrative example are flexible enough to participate in RT market.

As we mentioned before, congested transmission network can result in market power and some generators can take advantage of their geographic location and transmission capacity constraints to exercise the market power. Therefore, to test the effect of this item on market power, the results will be examined by choosing distinct strategic players on different nodes.

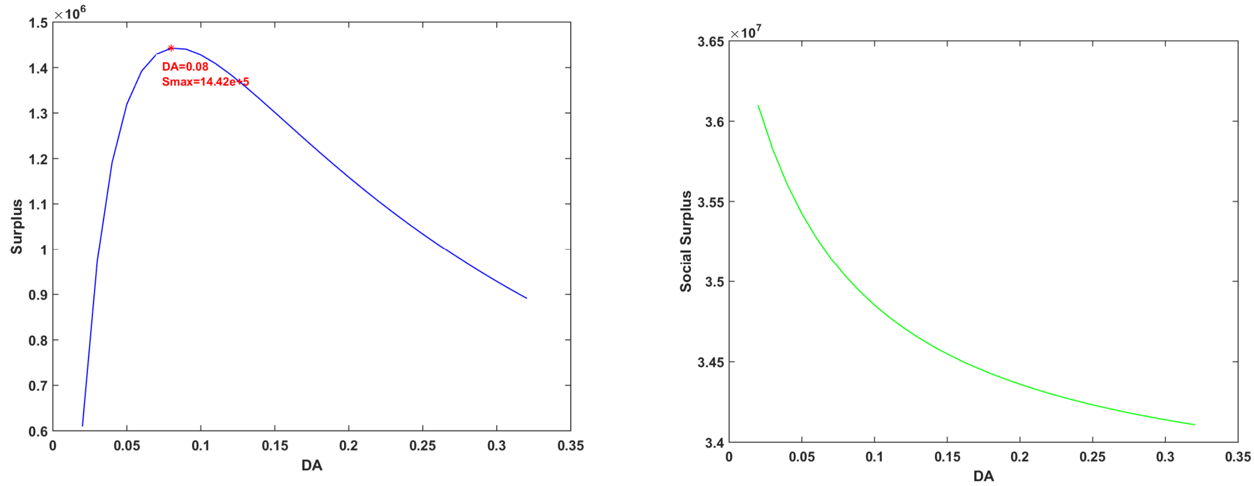
We assume that all generators except one and all consumers are price-taker participants, which means that they all submit their true costs and benefits as represented in table.1. Hence, just one strategic generator can be price-maker - sets manipulated energy prices which are far from its marginal cost. At first G_6 in Z_2 (n_3) is assumed to be the strategic player and the results for each pricing mechanism will be demonstrated in section 3-2. Then the same analysis will be done in section 3-3 for G_2 if it plays strategically.

3.2 Strategic bidding of G_6 When plays strategically in both day-ahead and real-time markets

In this section we assume that G_6, owing to its size, location and flexibility is able to submit strategic bids that will increase its profit. In the following sections, the effect of market structure on its market power will be investigated.

3.2.1 Strategic bidding of G_6 in the Nodal model

Given the bids of the other participants are consistent with their true costs and benefits, G_6 submits a strategic bid to DA market in order to maximize its surplus. The G_6's true cost coefficient is 0.02 which results in the lowest surplus for it, while the social surplus is at the highest level. By varying this bid, G_6 can reach to the highest surplus of $14.42 * 10^5$ for DA offer equals to 0.08 (58% rises), where the corresponding social surplus is $35.033 * 10^6$ (3% reduction). From the social surplus point of view, offering true cost is the most efficient option. G_6's surplus and social surplus of the system in case that G_6 is the strategic player are depicted in fig.3. The decreasing social surplus curve demonstrates the detrimental effects of market power in nodal pricing model.



(a) G_6 surplus

(b) Social surplus

Figure 3: Nodal pricing results

3.2.2 Strategic bidding of G_6 in the zonal-ATC model

Regardless of the fact that how TSOs are picking out ATCs, it is interesting to see how strategic players can benefit from irrelevant ATCs. Therefore, the results will be inspected for two end points 0 and 10000 (infinite).

3.2.2.1 ATC=0 means that DA market is running for two seperate (detached) markets and balancing individual supply and demand in each zone Z_1 and Z_2. Z_1 which contains the cheapest generator G_1, clears with much lower zonal price 71 compared to 235 in Z_2 which contains the most expensive demand D_3. Hence, generators in Z_1 are eager to export to Z_2 to increase the price in their related zone.

In RT market, due to the existence of lines L_{12} and L_{13}, they find this opportunity to sell to consumers in Z_2 . Hence, as you can see in fig.4, all generators in n_1 do up-regulation. Since in DA market, L_{23} was neglected and D_3 is the most expensive consumption, generators in n_2 produce as much as they can but in RT market, due to the limited capacity of L_{23}, they have to do dn-regulation. In opposite, although G_7 and G_8 in n_3 are the most expensive ones, they have to do up-regulation in order to satisfy very high demand of D_3 from DA which is 11520. Thus, this expensive up-regulation in n_3 results in very high RT clearing price 545 versus very low price -71 in n_2.

But what can G_6 do as an strategic player? Based on fig.5 and with respect to the fact that G_6 can submit different offers for up- and dn-regulation than DA, its optimal strategy is (DA,up,dn)=(0.14,0.14,whatever). Since G_6 is the second cheapest generator in the system and is located in the same node as D_3 (most expensive demand), it seems that it is always profitable for it to do up-regulation. Thus, dn-regulation offers are not the matter of importance in this case. In fig.5(b), up and DA coordinates are replaced by each other in order to show that for the lowest DA offer 0.02, the surplus of G_6 is the lowest while the social surplus is the highest, which shows the negative correlation between its surplus and social surplus irrespective of up- and dn-regulation offers.

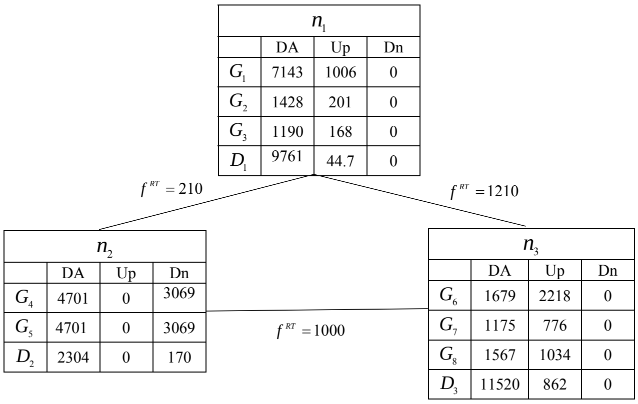
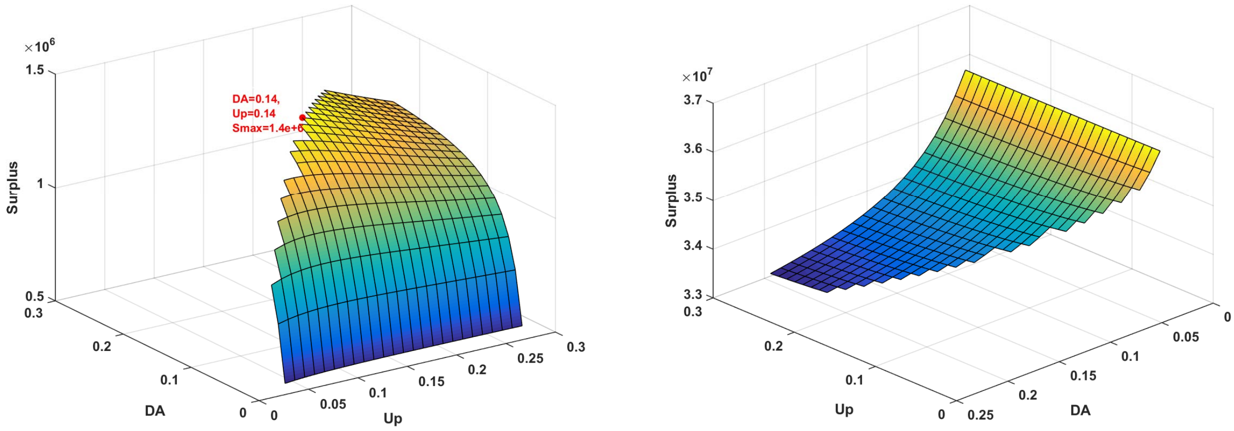


Figure 4: DA and RT quantities when ATC=0



(a) G_6 surplus

(b) Social surplus

Figure 5: Zonal results with ATC=0

3.2.2.2 ATC=10000 Concerning the line capacities, ATC equal to 10000 can be considered as infinite transfer capacity between two zones in DA. Therefore, DA market is equivalent to the uniform pricing model and equal prices of the two zones confirm this assumption (table.2). Thus, in DA market all generators located in n_1 and n_2 sell as much as they can to D_3.

But in RT, they have to come up against physical network constraints. Hence, all of them have to dn-regulate in favor of generators in n_3. By playing strategically, G_6's best offer is (DA,up,dn)=(0.17,0.17,whatever). Identical to ATC=0 and fig.5, for the lowest DA offer equals to 0.02, G_6's surplus is at minimum level while social surplus is maximum.

Table 2: zonal and nodal prices for ATC=10000

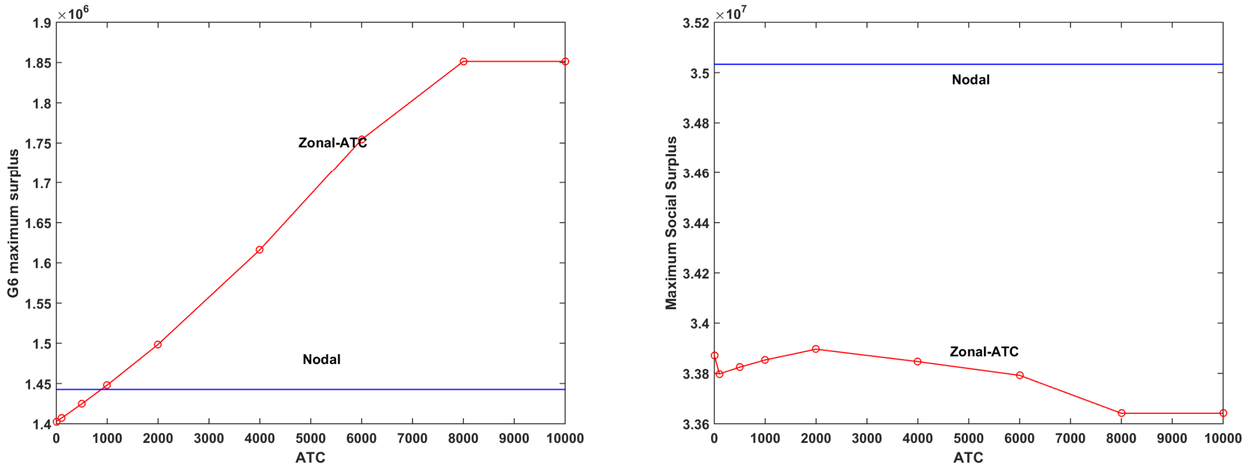
$\lambda_{Z_1}^{DA}$	$\lambda_{Z_2}^{DA}$	$\lambda_{n_1}^{RT}$	$\lambda_{n_2}^{RT}$	$\lambda_{n_3}^{RT}$
123.4	123.4	40.4	38.3	648.5

3.2.3 Discussion on market power potential of G_6

The maximum attainable surplus and social surplus from all investigated models in this paper when G_6 plays strategically is shown in fig.6.

Based on the participants behavior analyzed in sections 3.2.2.1 and 3.2.2.2, by increasing ATC from 0 to 10000, G_6's surplus has a great increase from 1,402,703 to 1,851,429 (almost 25%).The main reason is that G_1

which is the cheapest generator is located in z_1. Moreover, D_3, the most expensive demand is located in the same node as G_6 is located. Therefore, increased ATC lets G_1 to produce as much as it can in day-ahead market as well as generators in n_2 (G_4 and G_5) to produce without considering physical network constraints. Hence, all these conditions let the second cheapest strategic player G_6, to profitably utilize the non-feasibility of flows resulted from day-ahead market by playing with its day-ahead and real-time offers. Thus, the best offering strategy for G_6 when ATC is rising, is to shift some part of its production from day-ahead to real-time. Even though, by increasing ATC, the G_6's surplus will rise up to 25%, the maximum variation of social surplus is just 0.8% which is not considerable. By comparing G_6's surplus of nodal versus zonal-ATC model, the highest surplus it can get from nodal model is $14.42 * 10^5$ while by increasing ATC, its surplus can reach to $18.5 * 10^5$, which shows the sensitivity of the market power to ATC quantities. However, for very low ATCs, its market power is lower than nodal model.



(a) Maximum attainable surplus for G_6

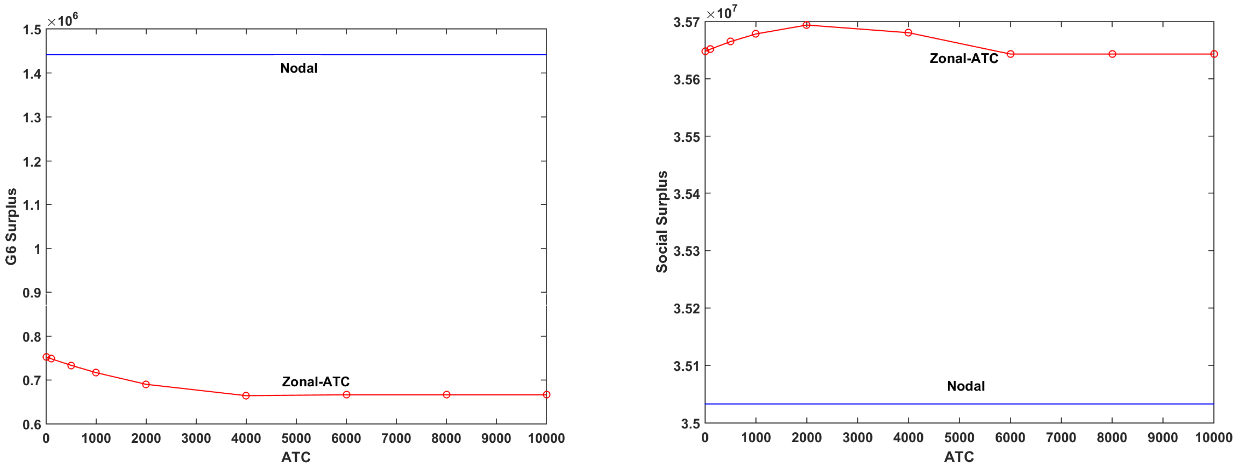
(b) Maximum attainable Social surplus

Figure 6: Maximum surplus from all models

3.3 Strategic bidding of G_6 When plays strategically just in day-ahead market

The surplus of G_6 if it can just utilize its market power in day-ahead and plays competitively in real-time, is shown in fig.(7(a)). It is obvious that since in the nodal model it considers all network constraints at the time of decision making and plays strategically with the full knowledge about it, G_6 can earn the highest surplus.

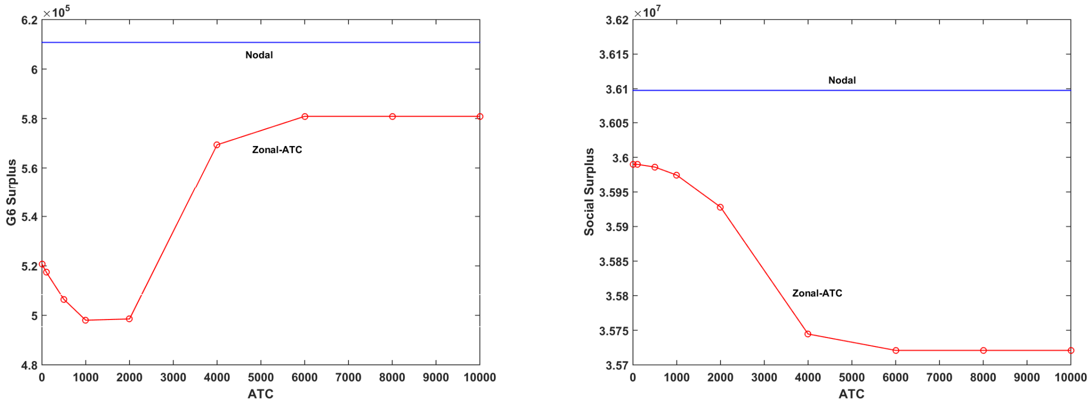
In general, the more network information is considered at the time of strategic decision making (which is DA market in this case), the more potential exists for strategic player to exercise market power (fig.7(a)). Therefore, nodal model leads to the lowest social surplus. In zonal-ATC model, no matter what ATC is, since it does not reflect real network constraints in DA stage, it does not result in huge profit for G_6. Finally, since in FBMC models, they are in between of nodal and zonal-ATC with respect to considering network constraints, they are placing in the middle of ranking.



(a) Maximum attainable surplus for G_6

(b) Maximum attainable Social surplus

Figure 7: Maximum surplus from all models when G_6 plays strategically just in DA market



(a) Maximum attainable surplus for G_6

(b) Maximum attainable Social surplus

Figure 8: Maximum surplus from all models when G_6 plays strategically just in RT market

3.4 Strategic bidding of G_6 When plays strategically just in Real-time market

The figures and numbers show that having possibility to just exercise market power in real-time leads to much lower profits for G_6 in comparison to the cases where it plays strategically just in day-ahead or both markets. In contrast, social surplus is the highest, Especially with nodal model. In zonal-ATC model, choosing very high ATC culminates in very low social surplus, because it signifies a very different solution of day-ahead than real-time, therefore G_6 finds more opportunity to play with its offers in real-time.

4 Conclusion

Several reasons have been mentioned for market power existance such as market design, market rules, geographical concentration, congested network and so on Song (2003).

Market structure can be an important cause of exercising market power, for example which pricing mechanism is implied (pay-as-bid or market-clearing-price), how future or forward contracts are designed, do demands participate in the market or not, etc.

In this paper we investigated the common objection -usually is mentioned by European politicians- to the nodal pricing which inherently entails more potential of market power than zonal pricing. But since in zonal pricing, re-dispatch is necessary to achieve a feasible flow, the market power possibility should be probed in both markets. Therefore, for zonal market structure, three following cases of gaming are allowed to the strategic player:

- Day-ahead:strategic, Re-dispatch:strategic : In this case, strategic player takes an optimal decision by knowing that market is just running with simplified network or cross-border constraints at day-ahead stage, then it finds another new opportunity in re-dispatch market to fix its first stage decision by new offering based on real-time flexibility cost of re-dispatch. Therefore, in comparison to one stage gaming possibility of nodal model, the latter pricing approach surpasses the former one. In general, we can conclude that the more network constraints are incorporated in day-ahead market, the less opportunity has the strategic player to change its decision in re-dispatch stage. Therefore, The nodal is less susceptible to market power than zonal-ATC model.
- Day-ahead:strategic, Re-dispatch:non-strategic : In this case, if the re-dispatch market does not allow the strategic behavior, then the strategic player can play very blindly in day-ahead when nothing about network is considered and does not have another opportunity to fix the decision taken in the previous stage. Therefore, by this assumption, the potential of exercising market power will reduce and from social surplus point of view zonal-ATC outperforms nodal model.
- Day-ahead:non-strategic, Re-dispatch:strategic : Since in this case strategic behavior is not allowed in day-ahead stage and re-dispatch is just based on deviations from day-ahead, strategic player finds very little space to maneuver. Therefore, this case entails the highest social surpluses in both models.

Hence, it is important to do extensive investigation about market power mitigation approaches especially in zonal models which entail two stages of incorporating network. Singh (1999) and Hogan et al. (2001) discuss about some mitigating market power approaches which is mostly suitable for one-stage nodal model. Thus, further market power mitigation studies for zonal models can be a very interesting topic for future research.

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