Possible Effects of Balancing Market Integration on Performance of the Individual Markets

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***Abstract*— Different cross-border arrangements for exchange of balancing services in electricity markets can potentially have different effects on the behavior of market parties and consequently market performance as a whole. This paper focuses on BSP-TSO trading (foreign bidding) as one of the main four arrangements proposed for exchange of balancing services across borders. We analyze the case of Norway and the Netherlands as a main balancing market integration case in Northern Europe and investigate the possible effect of enabling BSP-TSO trading (as one step towards full balancing market integration) between these countries on the performance of the two individual markets. An agent-based model is developed in MATLAB through which we study the possible change in behavior of market parties as a result of BSP-TSO trading implementation.**

I. Introduction

Balancing generation and consumption in a power grid plays a critical role in secure and reliable operation of the system. Imbalances have a direct effect on system frequency and deviations in frequency can create serious system stability problems. This task of balancing is performed by the Transmission System Operator (TSO) by procuring "balancing services" through a market-based mechanism known as "balancing market". Each country (region) generally has its own balancing market. The European Commission has expressed in the energy sector inquiry from January 2007 that current balancing service markets are highly concentrated and create entry barriers, that the enlargement of balancing zones will help enhancing competition, and that the harmonization of balancing market designs is an important step to achieve this [1]. Furthermore, the European Regulator's Group for Electricity and Gas (ERGEG) stresses that 'a lack of integration of balancing markets is a key impediment to the development of a single European electricity market' [2].

Considering the fundamental design differences in different countries, integration of balancing markets cannot be done in one single step. This issue has led to various reports discussing different possible arrangements to exchange balancing services across borders. These arrangements differ in the level of "change" necessary for enabling cross-border exchanges. Some can be achieved with minor changes in design of the markets at the national level and some require fundamental changes. Therefore, these arrangements can be seen as different steps towards full market integration [3]. We distinguish between four main arrangements introduced by European Network of Transmission System Operators (ETSO) as "conceptual trading models" [4-5]. Although these models have been proposed in different reports, they still remain conceptual models simply because no serious study is performed on the possible impacts of each model. The idea behind this paper is to clarify what could possibly happen, in terms of behavior of market parties, in case of implementation of these different arrangements. We study the BSP-TSO trading as the easiest-to-implement model which enables cross-border exchange of balancing services. In this arrangement the Balance Service Providers (BSPs) of one area sell their service directly to the TSO of the other area.

In this paper, we use the case of Norway and the Netherlands as part of the balancing market integration plan for Northern Europe. Norway is a hydro-dominant system which generates almost 100% of its production from hydro plants which are both cheap and quick, and therefore perfect for balancing purposes. The Netherlands, on the other hand, is a thermal system which procures its need for balancing services mainly from relatively expensive gas and oil plants. With the 700-MW HVDC cable between the two countries, which was operationalized in 2008, this case study can be used as a proper case for investigating how different cross-border arrangements for exchange of balancing services can possibly change the behavior of the market parties and the market performance as a whole.

As mentioned earlier, we focus on BSP-TSO trading in this paper and study the impact of foreign bidding on both the Dutch and Norwegian markets. We have developed an agent-based model in MATLAB which models the behavior of balancing service providers (the sellers in the market) in two cases; no cross-border exchange, and BSP-TSO trading (foreign bidding). The model is described in details in the next section.

II. Cross-border Balancing Arrangements

As mentioned above, we distinguish between four main arrangements: Area Control Error (ACE) netting, BSP-TSO trading, an additional voluntary pool, and a common merit order list. The last three have been introduced by European Network of Transmission System Operators (ETSO) as "conceptual trading models" [4-5]. The first arrangement of ACE netting has been formulated and implemented as a

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separate integration step in the integration of the German balancing markets of Transpower, 50Hertz and EnBW [6].

ACE netting simply prevents activation of balancing energy services in different control areas in opposite directions. In the UCTE zone of continental Europe, each control area is required to get its Area Control Error down to zero within fifteen minutes, by means of Load-Frequency Control. ACE netting is realized by netting of the ACEs of different control areas, and redistributing the remaining error, resulting in reduced activation of balancing energy in those areas.

BSP-TSO trading allows the BSPs to choose to offer their balancing services either to the TSO of their own control area or the TSO of another area. Therefore, BSPs have the freedom to choose the market they like to offer their services in. The implementation of this arrangement only requires the opening up of balancing markets to bids of other areas. This arrangement simply means introduction of "foreign bidding".

An *additional voluntary pool* represents the creation of an additional Balancing Service Market on the regional level, on which the TSOs of the cooperating control areas can offer balancing service bids to other TSOs on a voluntary basis. In this model, in contrast to BSP-TSO trading, the TSOs decide on which bids to share.

A *common merit order list* is realized by full integration of the different balancing service markets in the balancing region into one regional market, creating one regional bid ladder, or merit order list. There will be one regional system operator who will activate balancing bids for maintaining the system balance of the entire balancing region.

In BSP-TSO trading which is the focus of this paper, suppliers have the freedom to choose which market they like to offer their bids into. As a clarifying example, consider the case of BSP-TSO trading between two areas, area 1 with cheap resources and area 2 with more expensive ones. Since in this arrangement, the TSOs are not directly involved in selection of the bids that will go to the other market, the foremost concern is that too much bids go to area 2 in search for higher profits, which might leave the cheaper area with not sufficient resources to resolve its own area imbalances. This impact, from a system security perspective, is not acceptable at all. Even if after the shifting of bids to area 2, area 1 still has sufficient resources for internal use, the market price in area 1 might increase dramatically because less bids are available, the excess of supply in area 1 decreases, and therefore there is more opportunity for abuse of market power by suppliers in area 1. In this paper, we investigate the validity of this concern for the case of Norway and the Netherlands using an agent-based model described in the next section.

III. The Developed Model

In this model, we look at the problem from a balance service provider (BSP) perspective. Different BSPs decide on their bid price and bid capacity in an iterative procedure. In each iteration, they bid into the market and based on the market outcomes (the market price and their individual profit) they adjust their bid price (in €/MWh) and bid capacity (in MW) for the next round. In the first case, there is no exchange of balancing services, and in the second case, BSPs are allowed to bid in the foreign market. We look at the change of behavior of the BSPs in the second case in order to study the possible effect of introducing BSP-TSO trading.

Therefore, the model is built using the agent-based modeling concept. Each agent is a BSP (with different generating plants which comprise its generation portfolio) who has to decide on its bids in the two (Dutch and Norwegian) markets. In order to model the tendency of BSPs for strategic behavior, we assume each BSP divides its total available capacity into two parts. The first part of a generating plant's capacity is bid into the market at the marginal cost (plus a certain profit margin). Thus, the BSP does not try to increase the market clearing price by strategic behavior using this part of its capacity. In other words, with this part of its capacity, the BSP does not take any risk, and so we call it the *risk-averse* part of the BSP's portfolio. However, each BSP uses the second part (the remaining) of its capacity to increase the market price by strategic behavior. With the use of this part of its capacity, the BSP takes the risk of not getting selected in the market (because of bidding at a higher price) in order to increase the market price. This second part we call the *risk-prone* part of the BSP's portfolio. The relative size of the two parts shows the tendency of the BSP for taking risks in its bidding procedure. We consider two bidding agents with the above-mentioned strategies representing the risk-averse and risk-prone part of each BSP.

In addition to the bid price, each agent adapts its offered capacities in the two markets (for the next round) by comparing its individual relative profits in the two markets and shifting some capacity (depending on the size of the difference in profit) from the less profitable to the more profitable market. Thus in each round, each BSP submits two capacities and two prices for the two markets. The bid price and capacity adaptation strategies of the BSPs are designed as follows:

A. Bid Price Adaptation

Agents decide on their bid prices in the Dutch and Norwegian markets separately. Depending on their attitude towards risk-taking, agents use either of the following strategies to decide on their bid price:

1) Risk-averse agent: In case of bidding for the risk-averse part of the portfolio, if the BSP's bid is selected in the market (in a specific round), the BSP will keep its current bid price in the corresponding market for the next round. If its bid is not selected, it will reduce its bid price in order to be among the selected bids in the next round. The reduction of the bid price is as follows:

$$BP_{i,n} = BP_{i,n-1} - r \times PSS_{i,n} \quad (1)$$

where $BP_{i,n}$ is the bid price of agent i for round n, $PSS_{i,n}$ is the price step size of agent i at round n, and r is a uniform random number between 0 and 1. The price step size for an agent is assumed to be a percentage of the agent's total operating costs and is fixed throughout the simulation.

2) *Risk-prone agent:* The same strategy, as for risk-averse agents, for reducing their bid prices in case of not being

selected in a market is used here as well. The difference is that risk-prone agents do not necessarily keep their current bid price if they are selected in the market. They try to influence (increase) the market clearing price at the next round by increasing their bid price even if their bid is currently selected in the market:

$$BP_{i,n} = BP_{i,n-1} + r \times PSS_{i,n} \quad (2)$$

So they take the risk of not being selected in the next round in order to increase the market clearing price. The price step size for an agent is assumed to be a percentage of the agent's total operating costs, but it might be decreased throughout the simulation. Assume that the bid of agent i (a risk-prone agent) was not selected at round *n-1* but was selected at round n. It means that the bid price of the agent has been reduced by $PSS_{i,n-1}$ (the price step size of agent i at round *n-1*) for round n and the new bid price is low enough to get selected in the market. Since the agent is risk-prone, it tries to increase its bid price for round *n+1*. Using the same price step size will put the agent in the same situation as round *n-1*. Therefore, using the same high step size will put the agent in a cycle of not being selected in one round and being selected in the next, constantly increasing and decreasing its bid price in subsequent rounds. Thus, in this situation, the agent should use a lower step size for increasing its bid price for round *n+1*; competition among bidders limits the opportunity of influencing the market price by risk-prone agents. We introduce a variable, ε (between 0 and 1), which is the factor by which the price step size of a risk-prone agent is reduced in this situation; in case a risk-prone unit's bid is not selected in one round (*n-1)* and gets selected in the next round (*n*). Therefore, adaptation of the price step size is performed as follows:

$$PSS_{i,n+1} = \begin{cases} PSS_{i,n} \times \varepsilon \ ; \ \text{if} \ \ BP_{i,n-1} > MP_{in-1} \text{ AND } BP_{i,n} \le MP_n \\ PSS_{i,n} \ ; \ \text{Otherwise} \end{cases} \quad (3)$$

where MP_n is the market price at round n.

B. Bid Volume Adaptation

In each round, all agents adapt their offered volumes in the two markets for the next round, based on market outcomes of the current round. They calculate their average profits per MW of their capacity (in €/MW/hour) in the two markets and withdraw some of their capacity from the less profitable market and add it to their offered capacity in the other market The volume step size of an agent, by which the offered volume is shifted between the two markets for the next round, depends on the agent's difference in profit in the two markets. The higher the difference in profit, the more capacity is shifted between the markets. A simple linear relationship is used in this simulation:

$$VSS_{i,n} = VSS_i^{\max}(1 - profratio_{i,n-1}) \quad (4)$$

where $VSS_{i,n}$ is the volume step size of agent i at round n, $VSS_i^{\max}$ is the maximum volume step size for agent i, and $profratio_{i,n-1}$ is the profit ratio (average profits per MW of capacity) in the two markets for agent i at round *n-1*. Thus, in case an agent's profit in one of the two markets is zero at one round, the maximum volume is shifted to the other market for the next round. And in case an agent's profits in the two markets are equal, no volume is shifted between the two markets for the next round (the current level of offered volumes is used for the next round).

IV. Numerical Results

We have used the power plant list of the Netherlands in [7], in which the names of the owners are presented as well. Each owner with its portfolio (the group of its generating plants) is considered to be one BSP. We are modeling the market for secondary control (or the regulation market) here. A plant in order to be eligible to bid in this market has to have a minimum response speed of 7% per minute; it needs to be able to fully activate its offered capacity in 15 minutes. The power plants which can meet this requirement are oil, gas and hydro units [8]. According to [7], there are 21 oil and gas units in the Netherlands which we consider as the units which can bid in the regulation market. In case of Norway, due to lack of public data, we do not have a complete list of the generating plants. Therefore, we use the approach used in [9] which models each of the five areas in Norway by one aggregate generating plant, each representing generation in the corresponding area.

One critical input to the model is the day-ahead (DA) market prices in the two countries because these prices influence the minimum/maximum bid prices in the upward/downward regulation markets. Let us take upward regulation as an example. In Norway it is not allowed to bid at a price lower than the DA price in the corresponding hour. In the Netherlands, there is not an explicit rule addressing this issue. However, the regulation market is the last market the generators can sell their capacities in. Therefore, the capacity sold in the regulation market is the capacity that is still available after the closure of all the other electricity markets (including DA), so it is the capacity that was not selected in the other markets. Thus, the upward regulation price has to be higher than the day-ahead market prices under normal operating conditions. Therefore in this simulation, in case of upward regulation bids, the minimum bid price for Norway is considered to be the DA price in Norway, and for the Netherlands it is assumed to be the maximum of the DA price (in the Netherlands) and the marginal operating costs of each unit, because the bid price has to be higher than both the DA price and the marginal cost of the unit.

In case of downward regulation bids, the maximum bid price for Norway is assumed to be the DA price in Norway, and for the Netherlands it is assumed to be the minimum of the DA price and the marginal operating costs of each unit, because the downward regulation bid price has to be lower than both the DA price and the marginal cost of the unit.

Figure 1 shows the average DA prices for Norway and the Netherlands in 2009.

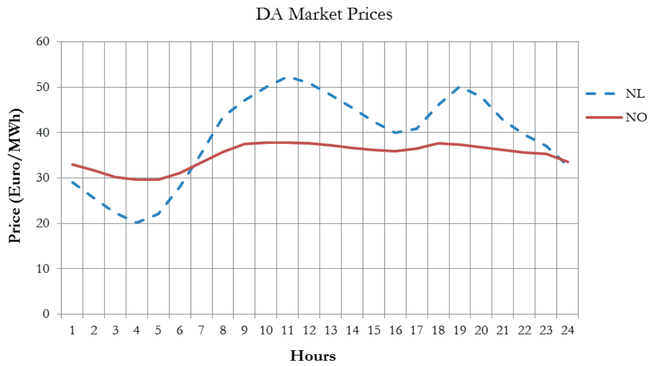

Figure 1- Average day-ahead prices for Norway and the Netherlands, 2009.

Based on the graphs, and considering the crucial effect of the DA prices on the simulation outcomes, we define two periods: Off-peak hours (from hour 00 to 07), in which the DA price in Norway is higher than the price in the Netherlands, and Peak hours (from hour 08 to 24), in which the DA price in Norway is lower than the price in the Netherlands. We simulate these two periods separately, using two different sets of DA prices as inputs.

Therefore, for upward regulation we will have two sets of outcomes, one for peak and one for off-peak hours. The same applies to downward regulation. Another important input is the system imbalances in the two countries. These real-time imbalances have to be resolved by activation of regulating power. Therefore, these imbalances determine the "market demand" in the regulation market. Studying the real data regarding activated regulating power in Norway [10] for 2009, we found out that it fits a normal distribution function with a mean of -30 MW and a standard deviation of 370 MW. Same trend can be seen for the activated regulating power in the Netherlands in 2009; a normal distribution function with a mean of -12 MW and a standard deviation of 102 MW. For each direction (upward and downward), and for each period (peak and off-peak), we take many samples of these two distribution functions (representing the demand in the two markets) and run the model once for each pair of demand values.

Figure 2 shows the upward regulation market prices in the Netherlands during off-peak hours. The market is cleared for three available interconnection capacities; 0 MW, 100MW, and 300MW. The first curve with zero interconnection capacity available between the two countries represents no market integration, because there is no room for cross-border exchange of balancing services, and therefore, the two markets are cleared separately and no capacity is offered by BSPs in the foreign markets. The other two curves show the change in the market price in the Netherlands as a result of market integration (enabling foreign bidding between the two markets). In all the following figures, we use this set of interconnection capacities. The horizontal axis shows the demand in the Dutch market; 200 samples were drawn from the distribution functions mentioned above.

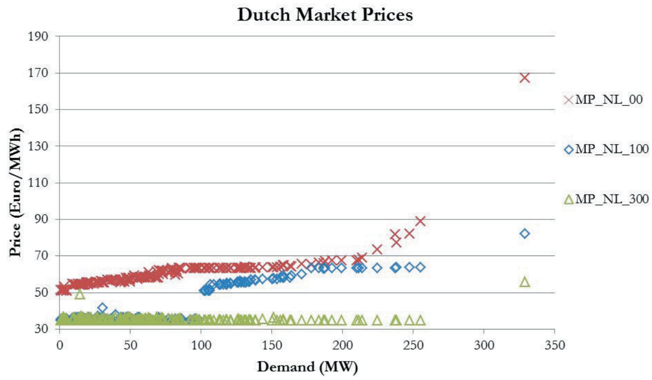

Figure 2- Upward regulation prices in the Netherlands for three available interconnection capacity values- Off-Peak hours

As can be seen, with no market integration, the price in the Netherlands is the highest; it starts from 50 €/MWh, and increases up to 170 €/MWh as the demand increases up to 340 MW. When 100MW interconnection capacity is available from Norway to the Netherlands, Norwegian BSPs start bidding in the Dutch market which would consequently bring the Dutch market price down. If the demand is lower than 100MW, the entire Dutch demand can be met by the Norwegian bids so the market price would go down to the level of the Norwegian market price. For demand values higher than 100MW, although the market price would still decrease (because 100MW of the demand is met by the Norwegian bids), the remaining demand has to be met by Dutch bids. Therefore, one can see a jump in the Dutch price at a demand value of 100MW. In the third case, 300MW interconnection capacity is available; therefore demands up to 300MW can be fully met by bids from Norway. So the Dutch market price goes down to the Norwegian market price, for demand values lower than 300MW.

Figure 3 shows the upward regulation prices in Norway during off-peak hours for the three available interconnection capacities. Thus Figure 3 is the counterpart of Figure 2 for Norway. As one can see from the figure, there is no noticeable change in the Norwegian market price as a result of market integration. The three curves lie on one another. Therefore, the main potential disadvantage of BSP-TSO arrangement, which is shifting of too much capacity from the cheap market (Norway) to the expensive market (Netherlands) to the extent that the market price in the cheaper market increases, is not a valid concern in case of Norway and the Netherlands. One important reason is the huge excess of supply in the Norwegian market. During off-peak hours, the offered capacity in the regulation market in Norway was 9,320MW on average in 2010, while the activated upward regulation in Norway was less than 290MW on average. This means a market with a supply 30 times higher than demand on average! Such an extremely high excess of supply limits the extent to which BSPs can behave strategically and increase the market price by abusing their market power. In addition, demand in the Netherlands is low, therefore shifting of some capacity to the Netherlands that can meet the whole Dutch demand does not have a noticeable effect on the competitiveness in the

Norwegian market, and consequently on the Norwegian market price.

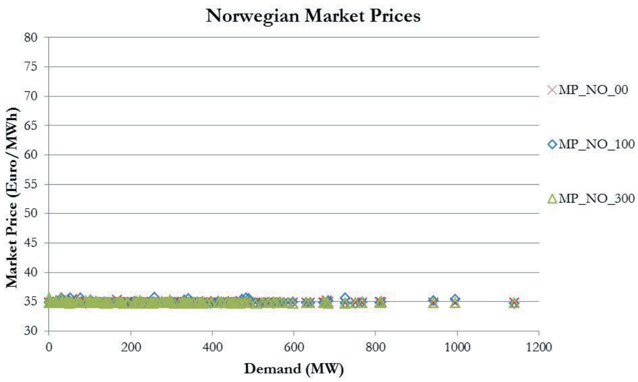

Figure 3- Upward regulation prices in Norway for three available interconnection capacity values- Off-peak hours

Figure 4 shows the evolution of the market prices throughout the simulation. The horizontal axis shows the iteration number. A case of extremely high demand (in both countries) is used in this figure; the demand in the Netherlands is 342 MW, and demand in Norway is 976MW. As usual, three interconnection capacities are considered in this case, so for each country there are three curves in the figure. As can be seen, without market integration (zero interconnection capacity) the market price in the Netherlands starts from 70 €/MWh (based on the initial bids of the Dutch BSPs), and as the risk-prone BSPs start to behave strategically, the market price constantly increases in every iteration up to 175 €/MWh, which is the steady state price of the market; price cannot be increased by BSPs beyond that because of competition in the market. When BSP-TSO trading is enabled (the other two cases), the market price in the Netherlands drastically reduces, by almost 90 €/MWh when 100 MW interconnection is available; 100 MW of the most expensive bids in the Netherlands can be replaced by cheap bids from Norway. The Dutch price decreases even more in the third case. However, since the Dutch demand is higher than 300 MW, even in the third case, the Dutch price does not go as low as the Norwegian price. In all the three cases, the Norwegian market price is the same, as shown on the figure.

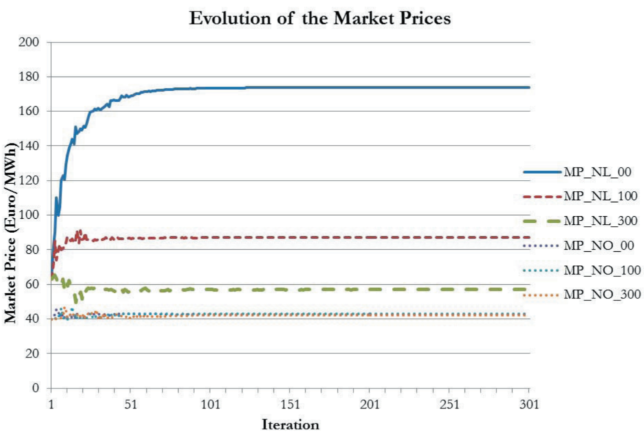

Figure 4- Evolution of the market prices (upward regulation) in the two countries for three interconnection capacity values

We saw the same trends for upward regulation during peak hours as well, and therefore we skip presenting the graphs representing peak hours.

For downward regulation, the situation can be different. In contrast to upward regulation, bids are sorted in the decreasing order on the bid ladder for downward regulation; a higher bid price is to be activated first. The reason is simply the sign convention for downward regulation; a positive downward bid price is the price the BSP is willing to "pay" the system operator in order to decrease its power output. The BSP has already sold the power in other markets, so if it reduces its output, it will save its operating costs. Therefore if it bids at zero for downward regulation, it is actually making an extra profit equal to its operating costs in the regulation market. Thus if it pays the system operator any price lower than its operating costs, it will still make a profit. The downward regulation price can become negative too, in which case the BSP is asking the system operator to pay him for lowering his output. As mentioned earlier, we use the minimum of the unit's marginal cost and the day-ahead price, as the maximum downward regulation bid price of a generating unit.

Marginal cost of the units eligible for bidding in the regulation market in the Netherlands are higher than those in Norway, simply because of the generation technology, oil and gas plant in the Netherlands and hydro in Norway. Therefore, if in an hour, the DA price in the Netherlands is higher than Norway, then the maximum bid price for downward regulation would be higher as well in the Netherlands, which means the bid prices can potentially be higher in the Netherlands, meaning for downward regulation the bids in the Netherlands can be more attractive. According to Figure 1, during peak hours, the Dutch DA price is higher on average which implies that the Dutch bids for downward regulation can be more attractive than the Norwegian ones, and therefore the Netherlands can export downward regulation to Norway.

Figure 5 shows the downward regulation market prices in the Netherlands during peak hours for the three interconnection capacities available.

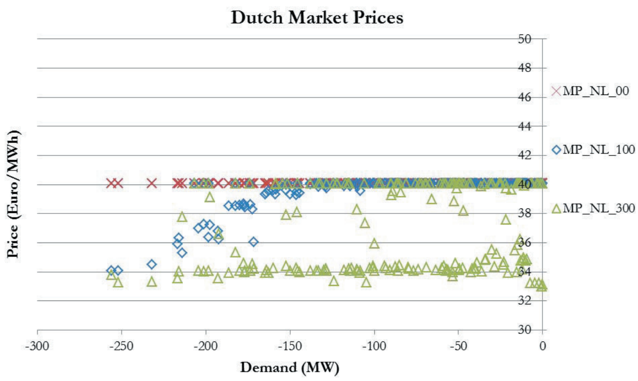

Figure 5- Downward regulation prices in the Netherlands for three available interconnection capacity values- Peak hours

As can be seen, when 100 MW interconnection capacity is available and so the Netherlands can export up to 100 MW of downward regulation to Norway, for high demand values (higher than almost -150 MW), the market price decreases (corresponding to "increase" of market price for upward regulation) in the Netherlands as a result of the export to Norway. This shows that the basic concern for BSP-TSO trading (change of the market price of the exporting country because too much capacity is shifted to the foreign market) is valid in case of downward regulation for the Netherlands. This means what did not happen in case of upward regulation for Norway (see Figure 3) does happen in case of downward regulation for the Netherlands. The main reason is lower excess of supply in the Netherlands; on average, the offered volume in the Dutch market for downward regulation during peak hours is about 600 MW. Thus, if 100 MW is exported to another market (and the demand in the Netherlands is sufficiently high), it can easily have a noticeable effect on the market price because it increases the opportunities of the BSPs to behave strategically and change the market price to their advantage. As shown before, this did not happen in case of Norway (for upward regulation) because of the huge excess of supply in Norway. According to the figure, if 300 MW interconnection capacity is available, then the Dutch market price decreases even for very small demand values in the Netherlands, as a result of exporting downward regulation bids to Norway.

Figure 6 shows the downward regulation prices in Norway for peak hours (corresponding to Figure 5 for the Netherlands). The price without cross-border exchanges is 34 €/MWh, and when the exchange is enabled (the other two cases), the market price for low demand values increases (corresponding to a price "decrease" for upward regulation; a reduction of balancing costs). For higher demand values in Norway, since the whole demand cannot be met with the bids from Dutch BSPs, the Norwegian bids need to be activated as well, and therefore the price decreases again.

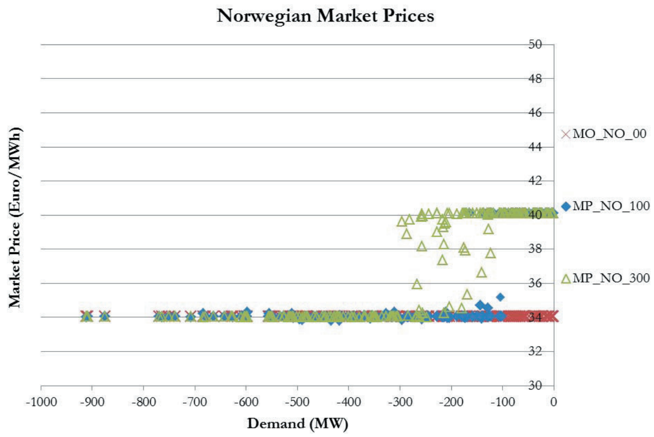

Figure 6- Downward regulation prices in Norway for three available interconnection capacity values- Peak hours

CONCLUSIONS

Four main models for cross-border exchange of balancing services have been proposed and in this paper we only analyzed the possible effects of one of them (BSP-TSO trading) on the behavior of market parties. We specifically looked at whether or not enabling this arrangement would lead to shifting of too much capacity from the cheap market to the expensive one to the extent that the market price in the cheap market considerably increases. We studied the case of Norway and the Netherlands. Our first finding is that these questions have to be answered on a "case-specific" basis, simply because there are numerous factors that influence the answer to the question, such as the level of day-ahead prices, supply size, demand size, generation portfolios, typical marginal costs, and the number of market players. Thus, there is no "general" answer to the question whether or not BSP-TSO trading has a negative or positive effect on the market prices. In this specific case of Norway and the Netherlands, according to our results, the market price in Norway (when it is the exporting country) does not change noticeably (no undesirable effect on the market price in Norway), because of the huge excess of supply and the flat bid ladder (almost fully hydro system) in Norway. However, when the Netherlands is the exporting country (downward regulation during peak hours), this cross-border exchange has an undesirable effect on the Dutch market price. In other words, the market price in Norway is much more resistant to market integration, while the price in the Netherlands is more sensitive and more likely to change as a result of market integration. Since the positive effect of cross-border exchanges on the market price in the Netherlands is higher than the negative effect (see Figure 2 and Figure 6) we conclude that enabling BSP-TSO trading in this case has a positive (desirable) effect on lowering the balancing costs in total.

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