MEMORANDUM

Date:
9. marts 2018

ARBITRAGE BETWEEN THE DAY-AHEAD AND INTRADAY MARKET

- Implicit grid loss handling on the Skagerrak Interconnector

If implicit handling of grid loss is introduced at a border in the day-ahead market but not in the intraday market, arbitrage opportunities can arise between the two markets, as the capacity that may be unused in the day-ahead market, as a result of optimisation with implicit grid loss handling, may be used in the intraday market.

It should be noted, however, that work is currently being done in the European intraday project, XBID, to introduce the opportunity to have implicit grid loss handling in the intraday market. It is anticipated that this – depending on the analysis – can be implemented in 2020. This means that when implicit grid loss handling on the Skagerrak Interconnector is introduced, there might be a limited period during which there will only be implicit grid loss handling in the day-ahead market.

Currently, the intraday market is primarily used in the Nordic countries for handling balancing by balance responsible parties. Implementation of implicit grid loss handling does not change the risk of the market participants and thus their fundamental need for balancing. It must therefore be expected that the trades in the intraday market will continue to be motivated by the need of balance responsible parties to balance themselves. However, the implementation of implicit grid loss handling will also result simultaneously in changes in the electricity price differences in the day-ahead market. It will therefore be more attractive for some market participants in certain situations to trade in the intraday market, but the magnitude and quantity of these transactions can be difficult to assess.

A worst case scenario will be that the entire capacity from the day-ahead market is unused but is instead used in the intraday market. This will introduce a cost for grid loss in the intraday market, where there is no congestion income, and thereby reduce the socio-economic gain that the introduction of implicit grid loss in the day-ahead market has created.[1] In the great majority of cases, the reduction will not be greater than the total socio-economic gain from the day-ahead market, and society will not be worse off with implicit grid loss handling only in the day-ahead market, compared to a situation with explicit grid loss handling in both markets. Therefore, the implementation of implicit grid loss in the day-ahead market prior to the intraday market is in line with the CACM regulation article 23 (3b). This article regarding “methodologies for operational security limits, contingencies and allocation constraints” states

1 See illustration in appendix

that "constraints intended to increase the economic surplus for single day-ahead or intraday coupling", thereby an allocation constraint may be implemented if it increases the economic surplus of either single day-ahead or intraday coupling.

If we look at simulations in the Simulation Facility[2] of historic data over a period of 16 months from February 2014 to May 2015, we see that the number of hours in which there is no planned flow on the Skagerrak Interconnector in the day-ahead market increases from 1081 hours (corresponding to 9.7 percent of the time) when there is no implicit grid loss handling, to 2836 hours (which is 25.5 percent of the time) when implicit grid loss handling is introduced. This follows the expectation in connection with the introduction of implicit grid loss handling. We are unable to model the extent to which the electricity prices in the intraday market will result in the capacity being traded there. We have therefore used the NorNed Interconnector between Norway and the Netherlands as a case for describing the impact between the day-ahead and the intraday markets when implicit grid loss handling is not introduced in both markets.

On 18 November 2015, implicit grid loss handling was introduced in the day-ahead market on NorNed with a loss factor of 3.2 percent.

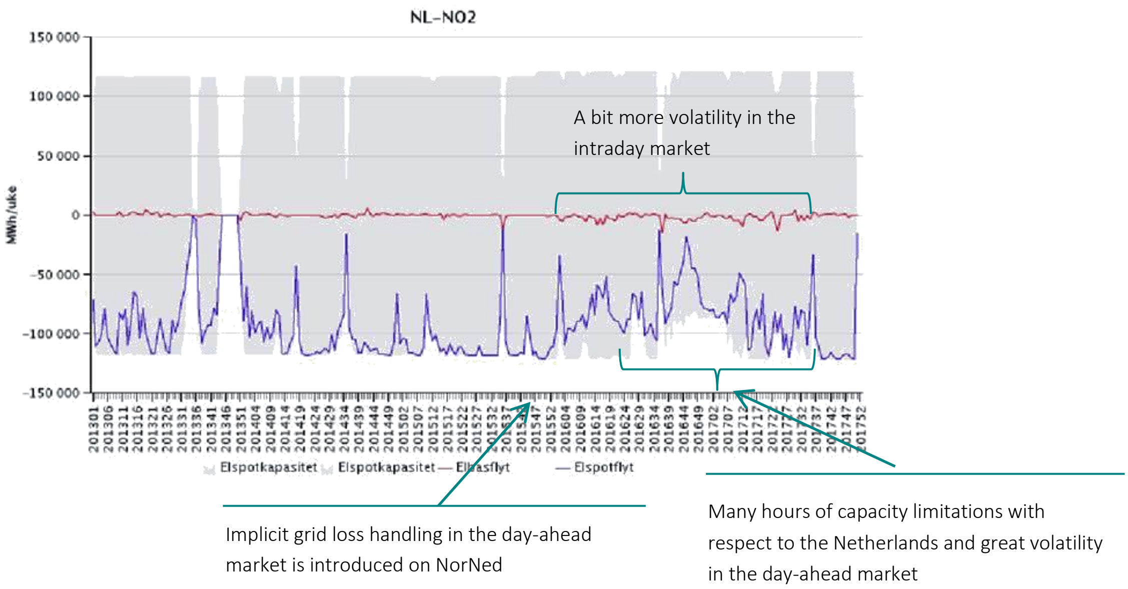

Figure 1 Trading over NorNed. Day-ahead trading (blue line), intraday trading (red line) and capacity provided to the market (grey area). The figures are stated in MWh/Week

The analysis shows a bit more volatility in the intraday market after the introduction of implicit grid loss handling in the day-ahead market. However, the impression is that these are minor ripples that cannot only be attributed to the introduction of implicit grid loss handling. It is evident that, in the same period, the day-ahead market is also more volatile and the capacity with respect to the Netherlands has been limited, which can also result in greater activity in the intraday market. All in all, it is evident that marked changes have not occurred in transactions in the intraday market after the introduction of implicit grid loss handling in the day-ahead market, and it must be concluded that the arbitrage effect between the two markets has been small.

2 Simulation Facility is a tool that is made available to the TSOs by the electricity exchanges in Europe. The tool uses "What-if" analyses on realised historic order books and system topologies.

It is important to point out that, because of the different magnitude of the electricity price differences between the bidding areas on NorNed and the bidding areas on Skagerrak, the above analysis is not fully representative for Skagerrak.

Data for the electricity prices in the bidding areas related to NorNed show that there is an average electricity price difference of EUR 15.3, EUR 14.1 and EUR 20.8, respectively, for the years 2013, 2014 and 2015.[3] Electricity prices vary, of course, but as Figure 2 indicates, in more than 90 percent of the hours there is an electricity price difference on the NorNed Interconnector. The standard deviation of EUR 12.8, EUR 9.9 and EUR 11.4, respectively, for the same series of years indicates that approximately 70 percent of the hours have an electricity price difference that is within one standard deviation from the mean. Thus, there will be hours with a minor or no electricity price difference, but given the high average, the results indicate that there will still be a marked electricity price difference between the bidding areas.

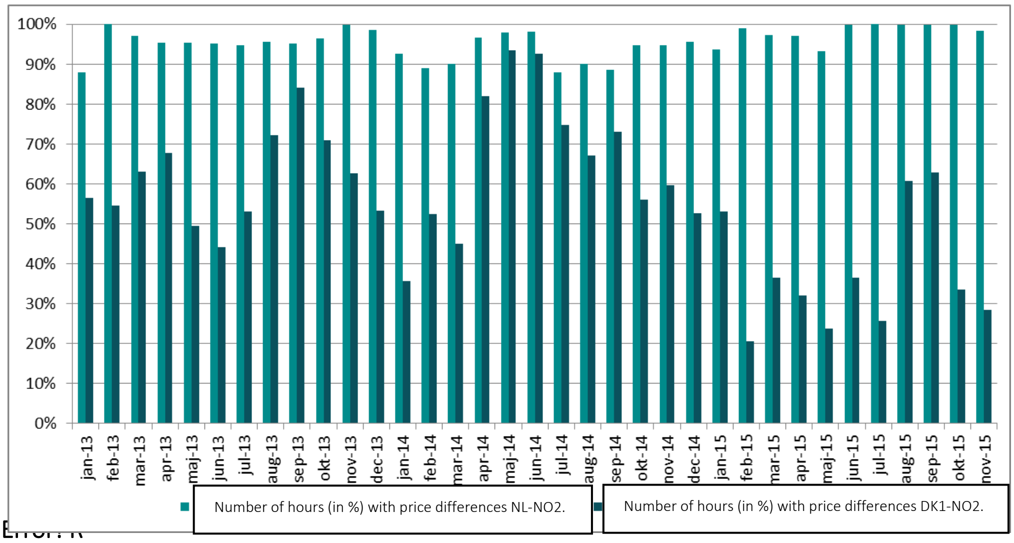

Figure 2 Percent of hours with an electricity price difference between the bidding areas NL-NO2 and DK1-NO2

The expectation on this average market electricity price difference is that a market participant will not necessarily seek the intraday market when implicit grid loss is implemented. This is because the expectation for the great majority of hours will be that the electricity price difference in the day-ahead market is high enough to ensure a gain that can cover the introduced cost of implicit grid loss. This is also reflected in Figure 1 above, where there are no marked changes in the intraday trading after implementation of implicit grid loss on NorNed.

However, this is not the same situation for the trading on Skagerrak between the bidding areas Western Denmark and Southern Norway, where on average there is an electricity price difference of EUR 1.6, EUR 3.4 and EUR 3.3, respectively, for 2013, 2014 and 2015.[4] The standard deviation of EUR 46.5, EUR 10 and EUR 9.5, respectively, for the years 2013, 2014 and 2015 is relatively higher than in NorNed. Furthermore, between Western Denmark and Southern Norway there has only be an electricity price difference of approximately 61 percent, 65 percent and 38 percent, respectively, of the hours in the years 2013–2015. Given the low electricity price difference, compared to the high standard deviation, it suggests that the great

[3] For the sake of comparison, data are used from the period before implementation of implicit grid loss on NorNed.
[4] For the sake of comparison, data are used from the period before implementation of implicit grid loss on NorNed.

majority of hours are characterised by a minor electricity price difference, where there are usually a few hours with a high electricity price difference. For example, when seen in isolation, when there is a limitation on Skagerrak in situations with high wind production in Western Denmark.

Overall, when the electricity price difference is very low during most hours, and there is only a minor share of hours over a year with a high electricity price difference, then the expectation is that there will be greater interest among market participants in moving the trading from the day-ahead market to the intraday. This is because the smaller electricity price difference also means that the marginal grid loss cost (which is included in the electricity price in the day-ahead market) will result in a greater drag on the gain in the day-ahead market, which is why market participants may choose to instead trade in the intraday market.[5]

However, the balance responsible party who chooses to bet on this arbitrage opportunity accepts a great risk if, instead of setting a bid in the day-ahead market, it bets on obtaining a gain in the intraday market. Among other things, it is a risk with respect to the balance responsible party being exposed to any new information that may arise during the period of time from the day-ahead market to the intraday that may affect the electricity price. This is particularly also the case in Denmark, where wind production affects the electricity price to a large extent. The balance responsible party must also be sure that it has a counterpart in the intraday market, which depends on the liquidity in the market. Furthermore, many of their deliberations here are based on game theory, as the balance responsible party cannot allow itself to speculate with the entire portfolio on the above arbitrage opportunity and must also consider the acts of the other balance responsible parties. A balance responsible party will only make use of the described arbitrage opportunity if risks are made up for by the potential gain. It is concluded that, based on the minor losses on the cable, the potential gain is not high enough for there to be major shifts from the day-ahead over to the intraday market.

[5] This is also illustrated in the example on page 35 in the NWE report "NWE Day-Ahead Market Coupling Project Introduction of loss factors on interconnector capacities in NWE Market Coupling" from April, 2013.

Appendix – Illustration of worst case example

To illustrate the worst case example, let us suppose that we have a connection between area A and area B and there are only these two areas. If we assume that the connection can transfer 100 MW and further assume that there is a loss factor of 2 percent on the connection, then at full flow on the connection 2 MW of energy will be lost that is purchased by the TSO through explicit grid loss handling.

In order to ensure that the example is not complicated too much, we assume that we look at one hour, and we assume that the exchange of energy can only occur from area A to area B. It is further assumed that the capacity that is not used in the day-ahead market is fully used in the intraday market. [6]

The example below assumes that the supply and demand curves are identical in the day-ahead and the intraday market, i.e. that there are congestion income and loss costs, which is essential for the socio-economic result.

Let the electricity price in area A be P_A and the electricity price in area B be P_B.

Explicit handling of grid loss in the day-ahead market:

Day-ahead market: 10 MW flow from area B to area A $P_A = P_B = 10\ EUR$.

Congestion income is thus:

$$(P_B - P_A) * flow = (10 - 10) * 10\ MW = 0\ EUR$$

⇨ No congestion income.

The grid loss cost[7] for the TSO is:

$$lost\ energy * price\ bidding\ zone\ B = 0{,}2\ MW * 10\ EUR = 2\ EUR$$

The total TSO day-ahead cost is thus:

$$Congestion\ incomme\ - Grid\ loss\ costs = 0\ EUR - \ 2\ EUR = -2\ EUR$$

Intraday market: 90 MW flow from area B to area A

No congestion income is generated in the intraday market.

The grid loss cost for TSOs is provided by:

$$lost\ energy * price\ bidding\ zone\ B = 1{,}8\ MW * 10\ EUR = 18\ EUR$$

The total TSO intraday cost is thus:

$$Congestion\ incomme - Grid\ loss\ costs = 0\ EUR - \ 18\ EUR = -18\ EUR$$

Seen as a whole, the TSO thus has a cost of:

TSO day-ahead cost + TSO intraday cost = -20 EUR

[6] In reality, it is probably not likely that all capacity in the day-ahead market remains unused and that all trading will occur exclusively on the intraday market, based on the risk that is involved.

[7] In this entire example, the grid loss cost is calculated at the electricity price in the export area (which is B) where the loss is purchased, which is the method on Skagerrak. On the Kontek Interconnector, for example, it is always Eastern Denmark that constitutes the reference electricity price. The socio-economic loss as a result of consumer loss is generally attributed to the import area. However, this is not included in the calculation here.

By introducing implicit grid loss in the example above, where there is no full flow and no electricity price difference, the flow can become smaller while at the same time an electricity price difference arises in the day-ahead market.

<u>Implicit handling of grid loss in the day-ahead market:</u>

<u>Day-ahead market:</u> 5 MW flow from area B to area A $P_A = 10{,}2, P_B = 10\ EUR$

"Congestion income" is thus:

$$lost\ energy\ *\ price\ bidding\ zone\ B = 0{,}1\ MW * 10\ EUR = 1\ EUR$$

The grid loss cost is[8]:

$$lost\ energy\ *\ price\ bidding\ zone\ B = 0{,}1\ MW * 10\ EUR = 1\ EUR$$

The total TSO day-ahead income/cost is thus:

$$Congestion\ incomme - grid\ loss\ costs = 1\ EUR - \ 1\ EUR = 0\ EUR$$

⇨ No congestion income.

<u>Intraday market:</u> 95 MW flow from area B to area A

No congestion income is generated in the intraday market.

The grid loss cost for TSOs is provided by:

$$lost\ energy\ *\ price\ bidding\ zone\ B = 1{,}9\ MW * 10\ EUR = 19\ EUR$$

The total TSO intraday cost is thus:

$$Congestion\ incomme - grid\ loss\ costs = 0\ DKK - \ 19\ EUR = -19 EUR$$

<u>Seen as a whole, the TSO thus has a cost of:</u>

TSO day-ahead cost + TSO intraday cost = -19 EUR

Ostensibly, the cost for the TSO is reduced by EUR 1 by implementing implicit grid loss. However, this is only ostensibly, because the loss cost for the day-ahead market flow of 5MW has moved from the TSO to the market participants.

This means in principle that a surcharge must be imposed on the market participants in the day-ahead market that is equal to:

$$Loss\ factor * MW\ flow\ i\ day\ ahead\ market * price\ bidding\ zone\ B$$
$$= 0{,}02 * 5MW * 10\ EUR = \ 1\ EUR$$

The above EUR 1 , which shall be allocated to the market participants, is added to the intraday market cost of EUR 19 for the TSO, after which the total loss cost is obtained.

As with explicit loss handling, the total loss cost with implicit grid loss is thus EUR 20 as well.

Based on the underlying assumptions, this example shows that the worst case outcome from full transfer from the day-ahead to the intraday market leads to implementation of implicit grid loss not resulting in any socio-economic change in relation to the situation with explicit grid loss handling.[9]

[8] It is no longer the TSO that bears this cost. Under implicit grid loss, the cost is assigned to the consumer in the electricity price.

[9] In reality, this is probably not the case, but the expectation is nevertheless that the situation will not become worse.