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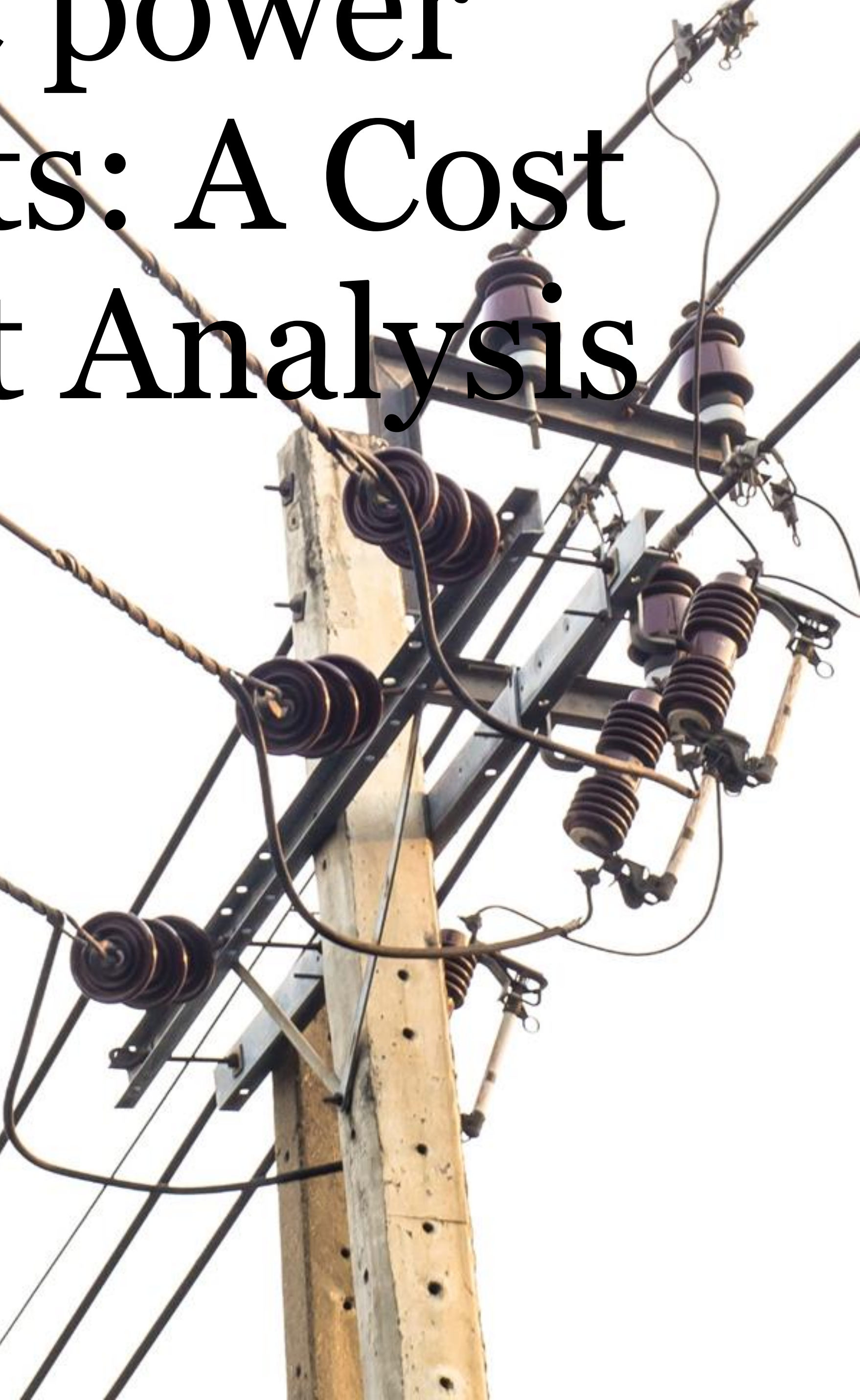
Finer time resolution in Nordic power markets: A Cost Benefit Analysis



Energinet, Fingrid, Statnett and Svenska kraftnät
30 October 2017

Preface

This cost-benefit analysis is part of the Nordic Finer Time Resolution project, which aims to evaluate the consequences of moving to finer time resolution, and prepare implementation of finer time resolution, in accordance with the European Electricity Balancing Guideline (GL EB).

The objective of this analysis is not to assess whether or not finer time resolution should be implemented, as this is now given by the GL EB. Instead, the objective is to analyse the consequences of implementing finer time resolution in different ways. Important elements include what tempo the finer time resolution is implemented and how coordinated the implementation should be between the Nordic countries.

This study has been led by Copenhagen Economics, and supported by E-Bridge primarily with respect to cost collection and conceptual clarification of benefits from finer time resolution. The Nordic TSOs have greatly supported the study by conducting concrete analyses, and providing input and feedback during the project. The report has been written by:

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Executive summary

When market participants in the Nordic electricity market cause imbalances in the system, these imbalances are settled in an imbalance settlement process. This process is national but similar across the Nordic countries. An important feature of this process is the duration of the so-called imbalance settlement period (ISP) which in all Nordic countries is 1 hour. This implies that balance responsible parties (BRPs) are financially responsible for their net accumulated energy imbalance over the period of 1 hour.

However, imbalances occur continuously and a significant share of the total imbalances caused to the system are 'netted out' and therefore not facing any imbalance fees, even though they cause instantaneous imbalances.[1] The resulting lack of financial incentives creates a misalignment between BRPs incentives to behave and the actual costs imposed to the system from this behaviour. Concretely, inflexibility does not face the true cost it imposes to the system.

Going forward, the need for flexibility in the system is likely to increase. More intermittent generation sources are expected to enter the market, and traditional flexible generation sources (such as large power plants) may close down. This makes it important that the market offers the true price for flexibility.

Moreover, the imbalance settlement periods across EU are quite different, ranging from 60 minutes in the Nordics, to 15 minutes in Germany and the Benelux. This lack of harmonisation reduces, or directly inhibits, market participants' ability to trade across borders in the intraday market. This is a major reason for why the EU has called for harmonisation and has approved the Electricity Balancing Guideline to harmonise the imbalance settlement period across the EU at 15 minutes.

Based on the approved Electricity Balancing guideline, all EU countries (as well as some non-members, such as Norway) should implement an ISP of 15 minutes no later than Q4 2020.[2] Some flexibility is allowed for in this framework, specifically allowing for both earlier implementation and potential extension of the deadline ultimo 2024 at the latest.

An imbalance settlement period of 15 minutes will entail a number of other changes in the market design, including the ability to trade 15-minute products in the intraday market and the regulating-power market (market time unit of 15 minutes). Changes to the day-ahead market is not included in this analysis, since they are not necessary for the implementation of 15 min ISP and will have to be coordinated across EU.

1 If a BRP has a negative imbalance in the first half hour and an equally sized positive imbalance in the second half hour, he will technically be assessed to have zero imbalances in the hour, and therefore not face financial imbalance settlement.
2 In the following, we will refer to implementation before 2021 instead of Q4 2020.

Main changes with finer time resolution

Imbalance settlement period
60 min → **15 min**

Market time unit on intraday market
60 min → **60/15 min**

Market time unit on regulating power market
60 min → **15 min**

Source: Copenhagen Economics

In this analysis, we take for given that the Nordic countries will have to implement 15 minute ISP as stated in the Electricity Balancing guideline. The focus of the analysis is to investigate the pros and cons of the different implementation choices. Specifically, we look at 1) implementing finer time resolution earlier than 2021 and 2) implementing later (2025). Moreover, we assess the implications of the Nordic countries implement simultaneously or not, e.g. one or more countries moving ahead or postponing relative to the others.

Our first main conclusion is that going to 15 minute imbalance settlement period is a step in the right direction. This change would bring immediate benefits to the Nordic region through better use of existing interconnectors, increased possibilities for trading flexibility with neighbouring countries, and improved frequency quality through in particular reductions in the current large jumps in imbalances that occur around the hour shift. An important additional benefit is that a 15 minute imbalance settlement period would lead to a more accurate price for flexibility or lack hereof. This will affect current investment incentives and shape the future demand and supply mix in becoming more flexible. This is a highly valuable characteristic in the future electricity system, facing the challenge of integrating volatile energy sources at a very large scale.

Our second main conclusion is that there seems to be indications that a very early implementation (2018) and a late implementation (2025) have the lowest net benefits, and therefore not preferred. None of the other years of implementation seem significantly better than others. The earlier finer time resolution is implemented the earlier additional benefits can be reaped. Conversely, earlier implementation will also push forward investments (e.g. in industrial meter equipment) that could otherwise have been delayed. We find that there are indeed important benefits to be reaped by going to finer time resolution, but that the costs also are sizeable. It turns out that the quantifiable benefits and the costs are in the same ballpark for most of the implementation years, and given the significant uncertainty related to the estimates, we do not find strong evidence for favouring a particular year of implementation.

We do find indications that a simultaneous Nordic implementation seems beneficial. In particular, market participants would find a system of more than one time resolution more administratively difficult, and some relatively minor costs would also be associated with maintaining parallel infrastructure systems including TSO and E-sett settlement systems. Most market participants we have interviewed state a preference for a single Nordic system. Some participants do however see a benefit of moving to finer time resolution as soon as possible in order to reap the benefits herewith. Most market participants indicate that they would find it very difficult to be ready for implementation already in 2018, and indicate that they would need around 2 years in order to implement the necessary changes with respect to e.g. IT system.

Recognising that several of the benefits of finer time resolution are difficult or impossible to quantify, we have made quantitative assessment of only some of the benefits (a full list of all the benefits can be seen in the figure below). These quantifiable benefits we estimate to be around € 20 million per year. The main socioeconomic benefit is better use of interconnectors (estimated to about € 2 million per year for existing interconnectors in 2021), trade benefits from improved market coupling (about € 6 million per year for existing interconnectors in 2021) and improved frequency quality (about €1 million per year). On top of the benefits accrued from the existing interconnectors, additional benefits from ramping (about € 4 million per year) and market coupling (about € 7 million per year) will accrue when new interconnectors come online. In addition to these quantifiable benefits, there are several non-quantifiable benefits such as improved access for some resources types in the intraday and regulating-power market, and importantly that a more precise price will be put on flexibility as mentioned above, which will shape the future energy system in the right direction.

While the above estimates are uncertain, we believe that they are on the conservative side especially for the estimates on frequency quality.[3]

Ensuring operational security in the power system is naturally a key objective for TSOs. While it is relatively easy to address system imbalances that are relatively predictable and gradually changing, it is significantly harder to address large, unexpected changed in the system imbalance. Due to the current time resolution of 60 minutes, there are often very large 'jumps' in the system imbalance around the hour shift. These jumps can be as large as around 5.000 MW. Reducing the time resolution to 15 minutes can reduce these jumps by around 20 per cent on average, and even as high as 30 per cent for the largest jumps. This is likely to improve operational security significantly.

3 The (technical) reasons are explained in Chapter 2.

Summary of benefits

Effect	Impact	Over or under-estimation?
Reduction of net system imbalances around the hour shift	About 20 per cent About 30 per cent for the largest jumps	May be underestimated if BRPs will trade away more than 50 per cent of the newly settled imbalances
Better use of interconnectors	€4 million per year*	
Market coupling	€11 million per year*	
Improved frequency quality	€1 million per year*	Underestimated
Improved investment incentives	More accurate pricing of flexibility More flexible energy system in the future	
Improved access to regulating power market	More participants can offer energy in RPM	

Note: * Quantifiable benefits are measured in 2021 and include benefits for existing and new interconnectors. Value of interconnectors could be underestimated due to potential future change of ramping restrictions.

Source: Copenhagen Economics and E-Bridge based on TSO input.

The main costs from implementing finer time resolution are primarily related to upgrades of IT systems capable of handling the new data management and the increase in the size of data flow. This is the case for both stakeholders such as Balance Responsible Parties (BRPs), Distribution System Operators (DSOs), energy suppliers and energy traders, but also for the IT-infrastructure underpinning the different market platforms such as the stock exchanges, the common Nordic settlement provider E-sett,[4] and internal TSO systems. In addition, some existing meters would have to be either replaced or reconfigured.[5] Not all meters must be changed or reconfigured to 15 minutes resolution to ensure correct settlement. Smaller consumption units and retail customers can be profiled based on the measured hourly values. Requiring meters with 15 minutes resolution are relevant for producers, large consumers, country borders and network points (TSO/DSO). The number of meters to be replaced or reconfigured at household level depends on the use of profiling, which can be used until a smart meter would be installed anyway. Requirements for

4 Not including Denmark

5 The number of meters to be replaced or reconfigured at household level depends on the use of profiling, which can be used until a smart meter would be installed anyway. Requirements for meters is a national decision.

meters is a national decision. We estimate that bringing implementation of finer time resolution forward by one additional year would cost about €2-6 million for a typical Nordic country due to the need for earlier investments, and about € 15 million for the Nordics simultaneously.

Chapter 1

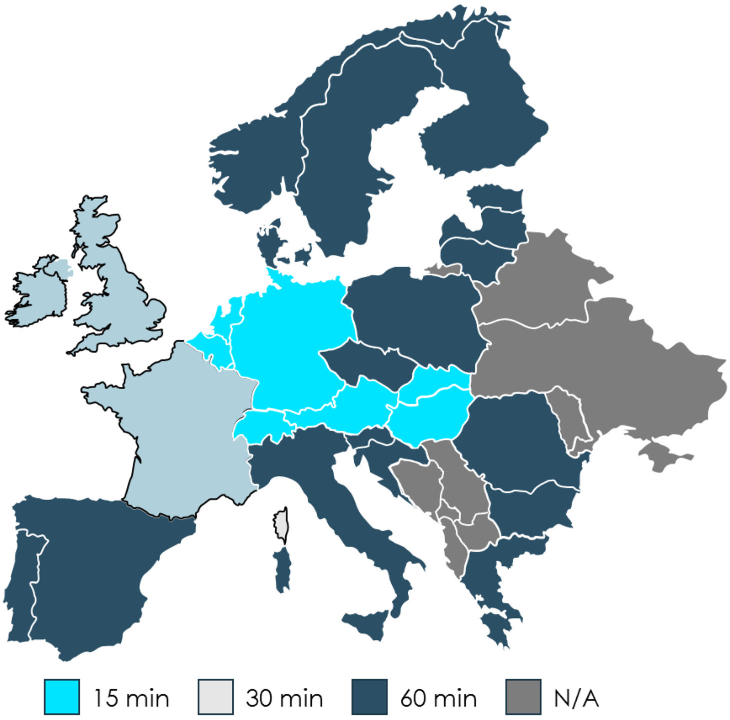
What is finer time resolution?

All across Europe, power markets are in transition. The significant increase in intermittent energy sources is challenging the functioning of the market by adding more volatility in the system, as well as crowding conventional – typically more flexible – energy sources out of the system. One of the main challenges to European and Nordic power markets is therefore that the system remains flexible enough to ensure that production and consumption balance at all times in a situation with more and more volatile production.[6] An important element in meeting this challenge is that the market participants are facing a correct price for flexibility to incentivise adequate investments and decisions to make the system more flexible.

While the day-ahead market in Europe is operating with 60-minute market-time units, the time units on intraday markets vary from country to country usually following the imbalance settlement period. The lack of harmonisation reduces or directly inhibits market participants' ability to trade across borders in the intraday market; this is one reason why the EU has called for harmonisation and approved that countries with an ISP above 15 minutes must reduce the ISP to 15 minutes.[7]

6 See e.g. Nordic TSOs (2016), Challenges and opportunities for the Nordic power system
7 Electricity Balancing Guideline, Article 53

Figure 1 Current imbalance settlement period in Europe



Note: Balancing Service Providers (BSPs) in Italy are required to have 15 minutes imbalance settlement period.

Source: ENTSO-E (2016), Cost Benefit Analysis for Imbalance Settlement Period Harmonisation

With the approval of the Guideline on Electricity Balancing, it is expected that all EU countries, as well as some non-members, such as Norway, implement an imbalance settlement period of 15 minutes no later than 2021.[8] Some flexibility is however contained in the framework, specifically allowing for both earlier and later implementation (although no later than 2025).

What is 'finer time resolution'

The key element in finer time resolution is the so-called imbalance settlement period (ISP), which ensures that market players are incentivised to behave as they have committed to in the market place. The imbalance settlement period will be reduced from 60 minutes to 15 minutes. Following from that, both the intraday and the regulating-power market trading platforms will allow for trading in 15 minutes products in addition to, or as a supplement to, the existing 60-minute products.

Concretely, when we refer to finer time resolution in this report, we are considering the following changes:

[8] Electricity Balancing Guidelines, Article 53

Figure 2 Main changes with finer time resolution

Source: Copenhagen Economics

Importantly, no changes will have to take place in the day-ahead market from the change of ISP. Shortening of the market time unit on the day ahead market may conceivably take place later in time due to other regulatory changes.

The shortening of the imbalance settlement period is the driver of the changes in the intraday and regulating-power markets. If the imbalance settlement period is set at 15 minutes, balance responsible parties face a potential imbalance cost of not being in balance in any given 15 minute interval. Consequently, balance responsible parties would either have to act more flexibly or use a market instrument to be able to address potential imbalances.

Timing of implementation

As mentioned, the guideline on Electricity Balancing stipulates that a 15-minute ISP should be implemented no later than 2021.[9] If a country's TSO or regulatory authority applies for a postponement this can be granted up until no later than 2025. A country can also implement earlier than 2021.

In the cost benefit analysis of this study, we explore the impact of the timing of the implementation, including the impact of implementing simultaneously in the Nordics or not. We have defined the following scenarios, see Figure 3. In Chapter 5, we describe the implementation choices and design in more detail.

9 Our interpretation is in the fourth quarter of 2020.

Figure 3 Main scenarios

Baseline: Common Nordic implementation by 2021
Frontrunner scenario(s), where one or multiple countries implement before 2021
Postponement scenarios: One or multiple countries implements in 2025

Source: Copenhagen Economics

Relation to other market developments

Finer time resolution is one among many ongoing changes to the Nordic and European electricity markets. Many of these changes will be interrelated, and enhance the effect of the others. Worth mentioning is in particular the European-wide efforts at harmonising intra day markets (through the XBID market project) and regulating-power markets (through European standard products for manual balancing reserves). Together with finer time resolution, these initiatives will improve the possibilities to trade electricity across borders.

In addition, there is some development in the Nordic countries towards a more accurate price signal for BRPs based on the cost of balancing. Concretely, the cost of being in imbalance may increase for balance responsible parties. This will work together with finer time resolution in incentivising balance responsible parties to achieve balance, and thereby substantiate several of the benefits identified in the subsequent chapter.

Chapter 2

Impacts on the market and power system

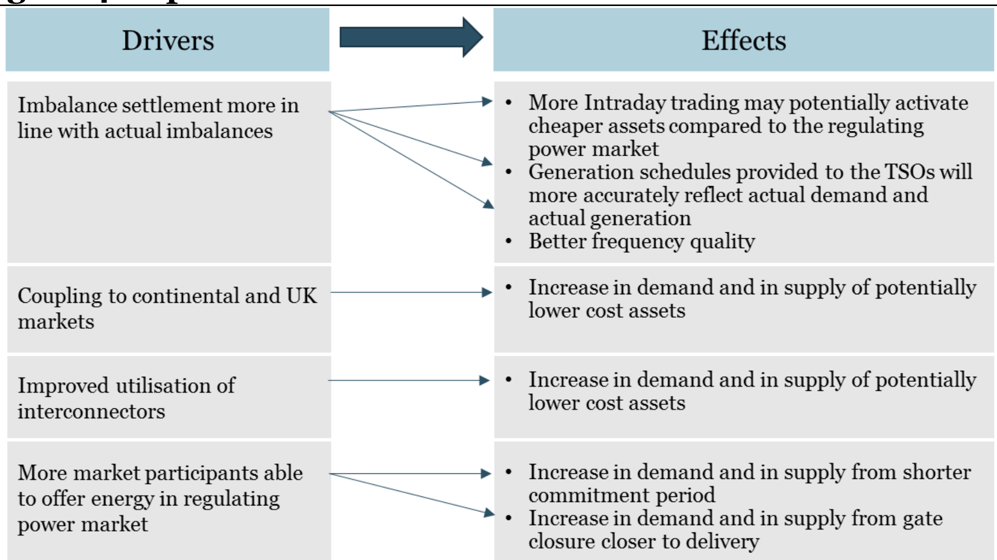
Implementing finer time resolution is likely to have several different impacts on the Nordic power market and power system. The impacts will primarily be driven by changed behaviour by balance responsible parties due to different financial incentives, but also by technical changes in the underlying market function, which can provide new opportunities for market participants. The changed incentives are primarily related to balance responsible parties addressing more of their underlying imbalances thereby reducing the structural system imbalances.[10] The new opportunities are primarily related to better possibilities of offering flexibility to neighbouring markets and better use of interconnectors. In this chapter, we illustrate the different drivers and effects we expect to see from going to finer time resolution, and we assess the magnitude and significance of these.

Finer time resolution affects the system through four drivers

The change of the ISP creates four types of incentives – the so-called drivers – that motivate changes in behaviour from the market participants. Each of these four drivers has some observable effects on the system, which in turn have an impact on the important criteria of a well-functioning energy system. Figure 4 illustrates these connections, which we will describe in detail in the following sections.

10 Finer time resolution is not likely to affect the so-called stochastic imbalances, which occur due to unforeseen events e.g. a rapid change in wind speed close to the operational hour.

Figure 4 Impact chain



Source: Copenhagen Economics

2.1 Imbalance settlement more in line with actual imbalances

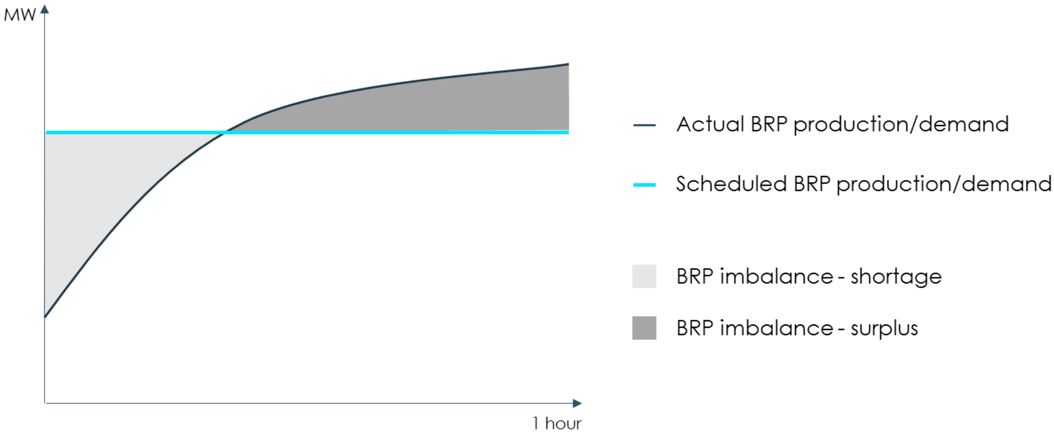
Balance responsible parties are responsible for ensuring that the transactions they have engaged in in the wholesale power market are also delivered in the hour of operation. If not, they will be deemed in imbalance vis-à-vis their market commitment, and the imbalance will be settled by the TSO. The settlement price will either be the price on the RPM or the Day ahead market depending on the specific circumstances. If a balance responsible party learns that it is likely to be in imbalance vis-à-vis its day ahead transaction, it can either trade away this imbalance with other market participants in the intraday market, or carry through the imbalance for the TSO to handle it in the regulating-power market and face imbalance settlement.

The current imbalance settlement period of 60 minutes leads to two related and undesirable consequences compared to a finer imbalance settlement period.

1. Imbalances that net out over the hour are not settled as an imbalance
2. Large jumps in imbalances occur around hour shifts because of this

If a balance responsible party contributes with both a shortage and an equally large surplus during an hour of operation, this balance responsible party will not face a cost for any imbalances, because they are netting out over the hour, see Figure 5. This is so even though the balance responsible party has in fact been in imbalance the entire hour.

Figure 5 Balance responsible parties can net out their imbalances over an hour



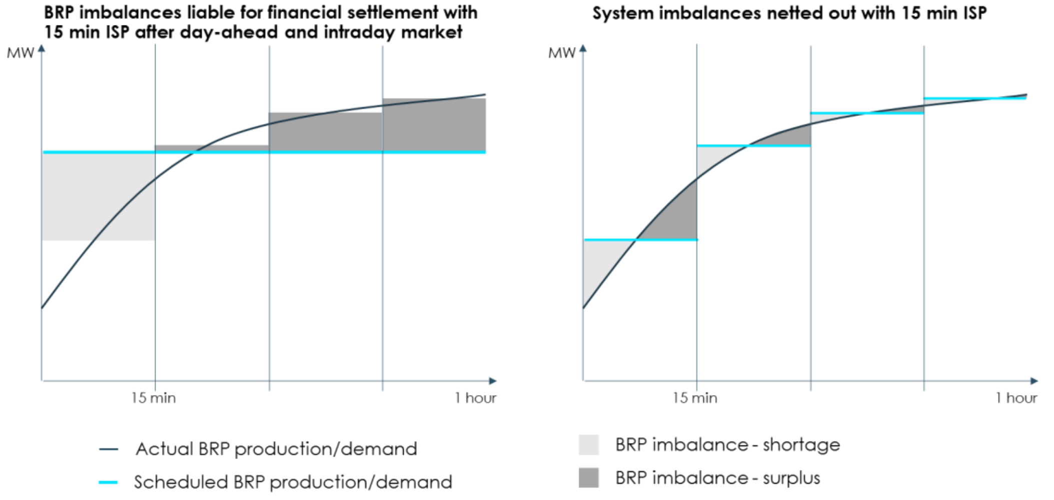
Note: The figure is an illustration

Source: Copenhagen Economics

With finer time resolution a large share of the balance responsible party imbalances that were netted out over the hour will now be visible and considered an imbalance and therefore liable to financial settlement unless traded away in the intraday market. This is illustrated in Figure 6 (left panel), where a large share of the total imbalance over the hour is now also treated as an imbalance for the balance responsible party. This will incentivise balance responsible parties to consider whether it is optimal to trade away the expected resulting imbalances in the intraday market or face the imbalance settlement by leaving the imbalance for the TSOs to address in the regulating-power market. In a situation where balance responsible parties choose to trade away all their 'newly settled' imbalances in the intraday market,[11] the system imbalance faced by the TSO will be reduced, as illustrated in Figure 6 (right panel).

[11] By newly settled imbalances we mean the imbalances that were previously 'netted out' over the hour, but now will be settled in a quarterly system.

Figure 6 Market players face settlement on more imbalances



Note: The figure is an illustration.

The left figure assume that the balance responsible party is not trading away their 'new' market imbalances

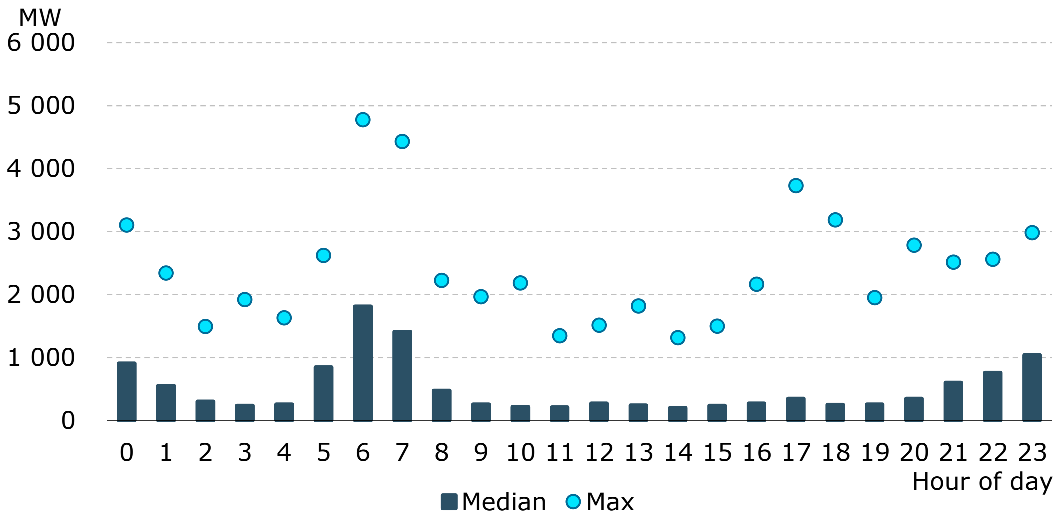
The right figure assumes that the balance responsible party have traded away their 'new' market imbalances thereby reducing system imbalances.

DAM refers to Day-Ahead Market

Source: Copenhagen Economics and E-bridge.

Imbalances in the Nordic power system change continuously over the hour. At the hour shift, however, the imbalance can change significantly, or "jump", from one minute to the next. The jumps can vary significantly during the day; see Figure 7, which illustrates the average Nordic imbalances in 2016. In most days, the average "jump" in imbalance varies between 200-2000 MW as shown in the columns in Figure 7. The highest change in imbalances is shown as the dots in Figure 7, the highest reached in 2016 almost 5.000 MW.

Figure 7 Change in imbalance during hour shifts



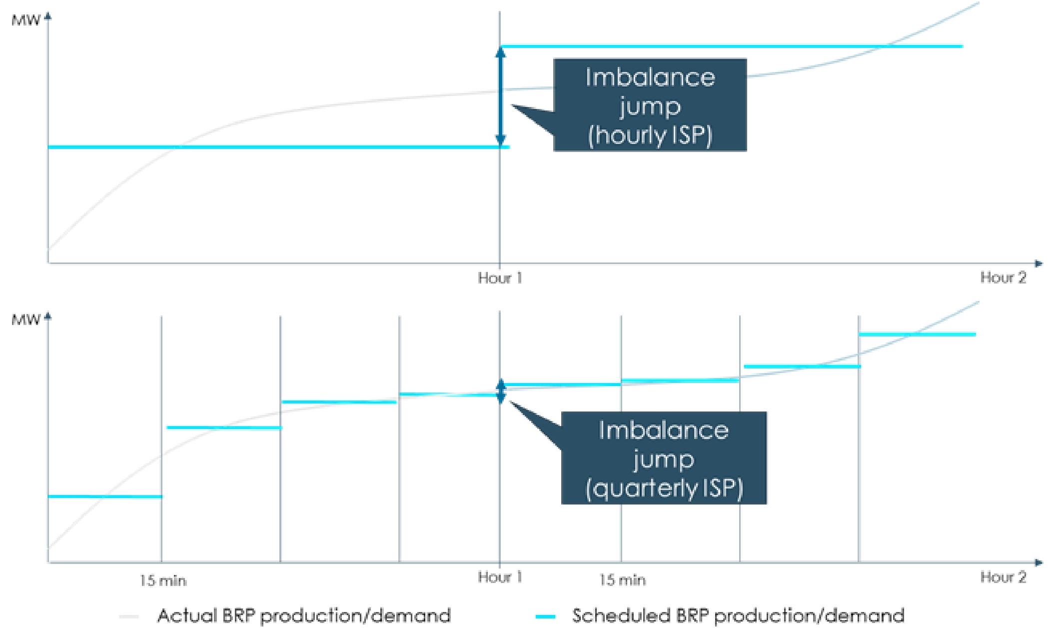
Note: Illustration based on average imbalances in 2016 for the entire Nordic system. Max measures the highest change in imbalances for each hour. The Median measures the middle observation in a ranked set of all imbalances in 2016.

Source: Copenhagen Economics based on TSO input

The nature of the power system is such that constant or smooth imbalances are not necessarily problematic, as TSOs relatively easily can address this by activating balancing resources. Conversely, large and sudden changes in system imbalances are much more likely to pose problems, as the needed actions by the TSOs to balance the system increases significantly.

This behaviour can to a large extent be attributed to the hourly resolution of the market time units in the intraday and day-ahead markets, and with finer time resolution the large imbalance jumps around the hour shift are likely to be reduced. The balance responsible parties responsible for the large variations over the hour shift are now incentivised to trade away their imbalances before the hour of operation on a quarterly basis. If the balance responsible parties trade away the “newly settled” imbalances they are facing with a 15 min ISP, the scheduled production/demand of the last quarter of one hour will be closer to the scheduled production/demand for the first quarter of the next hour. This will in most cases mean the jump in imbalances between the hour shifts are reduced.

Figure 8 Imbalance jumps will be reduced

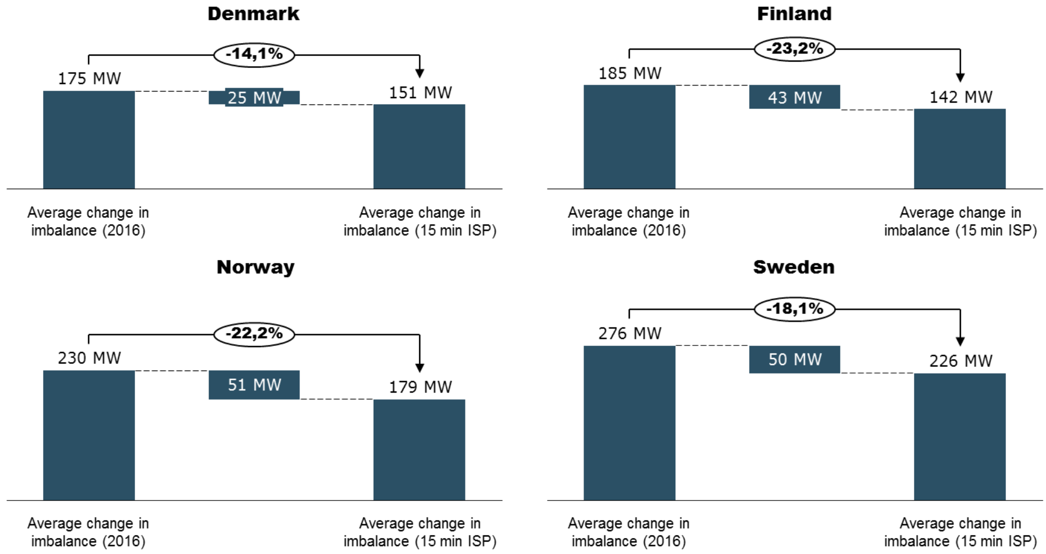


Note: Illustrative figure.

Source: Copenhagen Economics

Concretely we estimate that the average imbalance jump around hour shifts can be reduced by about 20 percent in each country (see Figure 9). The reductions differ significantly by geographical area. Finland and Norway experience the largest change in imbalances around the hour shifts with reductions of 22-23 %, whereas Sweden experiences a reduction of 18 % and Denmark 14 %.

Figure 9 Reduction in change in imbalance during hour shift

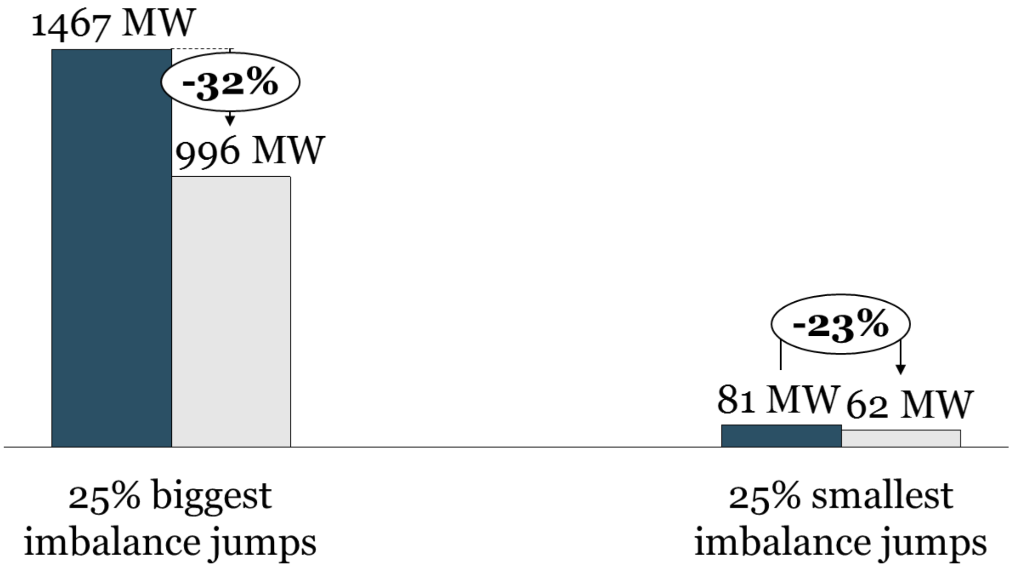


Note: Imbalances measured as the absolute change in imbalance from the last minute of one hour to the first minute of the next hour.

Source: Copenhagen Economics based on TSO input.

Importantly, finer time resolution is able to reduce the size of the imbalance jumps in the situations where the jumps are the highest. The 25 % of the hours in the Nordics with the biggest imbalance jumps, would experience a reduction in the change in imbalance of 32%, see Figure 10. The 25% of the hours with the smallest jump in imbalance will experience a reduction in the change in imbalance of 23%. This implies that finer time resolution will reduce imbalances at the instances when they are the most critical to operational security, namely when the jumps are the highest. This effect is not something we are able to include in our quantifications of the benefits in the remaining analysis, and therefore a source of underestimation of the benefits.

Figure 10 Reduction in Nordic imbalance change between hours

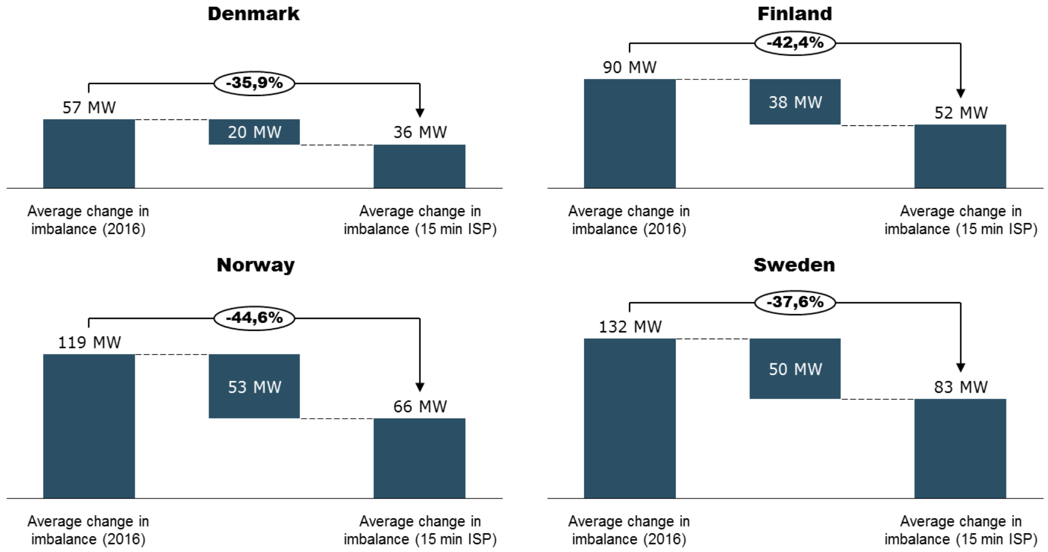


Note: Figures calculated on the assumption of 50% of the new imbalances being moved to the intraday market.

Source: Copenhagen Economics based on TSO input.

In addition to a reduction in imbalances at the hour shifts, there will also be a reduction in average imbalance between consecutive 15 minute time periods during an hour of operation, as shown in Figure 11. While Figure 9 shows the change in imbalances from the 59th minute of the hour to the 1st minute of the next hour, Figure 11 shows the change in average quarterly imbalance between each quarter of the hour.

Figure 11 Average change in imbalance during all four quarters



Note: Imbalances measured as the absolute change in the average quarterly imbalance between each quarter in an hour.

Source: Copenhagen Economics based on TSO input.

Whether or not the balance responsible parties will undertake effort to address imbalances, and thereby affect the jumps around the hour shift, will depend on what will be the cheapest for them.[12] For example, trading away imbalances in the intraday market or investing in equipment to increase flexibility of a generator or demand side resources will only happen if the balance responsible parties deem this optimal compared to carrying through the imbalance and facing imbalance settlement.

In the four figures above, we assume that 50% of the newly settled imbalances[13] will be handled by the balance responsible parties e.g. traded away in the intraday market. In the analysis below, we will relax this assumption and assume instead that at least 25 per cent of the newly settled imbalances will be handled by the market, potentially increasing to 100 per cent. The actual behaviour of BRPs and the volume they choose to trade will be highly influenced by the cost of being in imbalance, which is likely to increase in the future. Moreover, the percentage could be high, as finer time resolution address the so-called structural imbalances (as opposed to stochastic imbalances), which are easier to predict and therefore address.

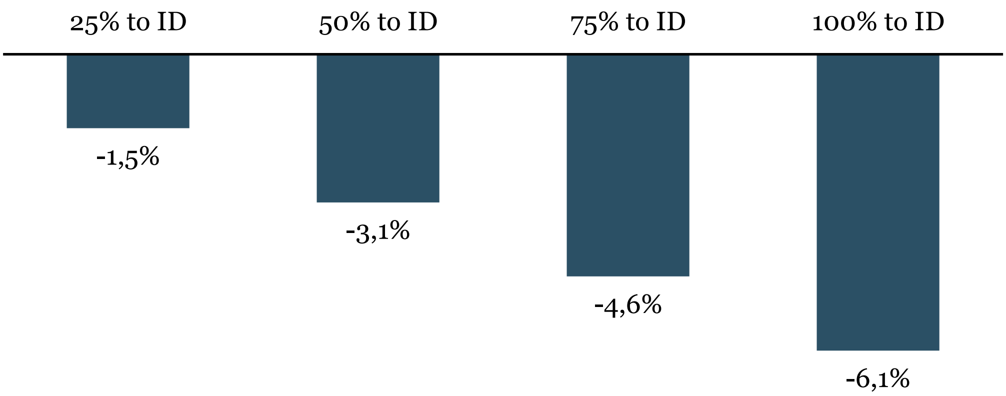
In addition to lowering the imbalance jumps, finer time resolution will also reduce the average system imbalance as explained in Figure 6. The average net system imbalances in the Nordic will be reduced by between 2-6 per cent (see Figure 12) depending on the extent of imbalances addressed by market parties. The lower impact on the net imbalance compared to the change in imbalances is because in most hours the Nordic system (net

12 In some countries, it is a legal obligation for BRPs to plan themselves into balances.

13 By newly settled imbalances we mean the imbalances that were previously 'netted out' over the hour, but now will be settled in a quarterly system.

for all areas) has either a positive or negative imbalance in all or most minutes of the hour. In these cases 15 minute ISP has no impact on the hourly net imbalance, but will still make the imbalance less volatile as shown in Figure 11.

Figure 12 Reduction in average hourly net system imbalance in the Nordic countries



Note: Imbalances measured as hourly net imbalances. "25% to ID" is a scenario, where 25% of the new imbalances from introducing 15 min ISP is traded away on the intraday market. "50% to ID" is a scenario, where 50% of the new imbalances from introducing 15 min ISP is traded away on the intraday market and so on.

Source: Copenhagen Economics based on TSO input.

We have identified two effects, which the above drivers are likely to give rise to, which is separately described below.

1. Improved frequency quality
2. More intraday trading could activate cheaper assets compared to trading in the regulating-power market

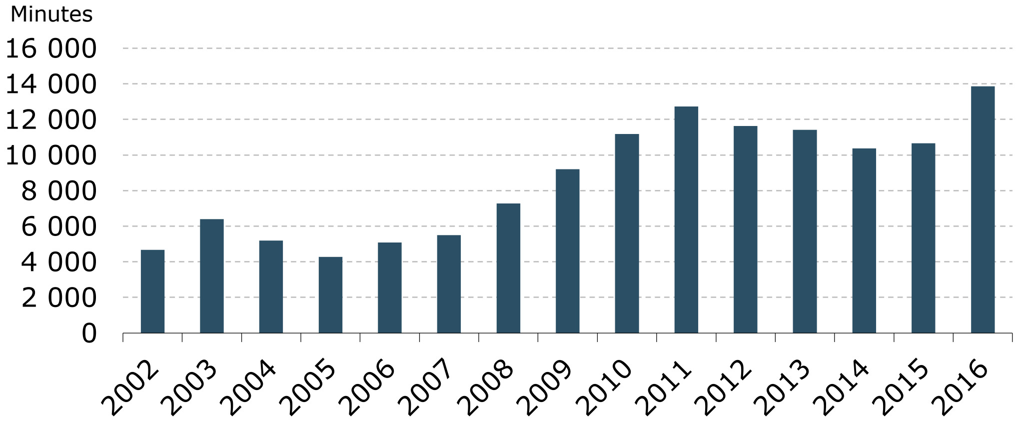
Improved frequency quality

Frequency quality is a measure of operational security in the power system. Typically, it is measured as the number of minutes that the system frequency is outside the normal band of operation, which is +/-100mHz around the required 50 Hz. Deviations from 50 Hz reflects that demand and supply are deviating from each other.

A slight deviation away from 50 Hz is not a problem as such, but makes the system more vulnerable to a trip in a large power plant or an interconnector. The further away from 50 Hz, the larger is the likelihood that such a trip will cause a brownout or a blackout.

In the last decade or so, frequency quality in the Nordic power system has deteriorated significantly. Since 2002, the number of minutes outside the normal band has increased by 200 per cent to about 14,000 minutes in a year (see Figure 13). Going forward, pressure on frequency quality is predicted to increase further due to the increased amount of intermittent energy sources and reduced controllable capacity and inertia.[14]

Figure 13 Minutes outside the normal frequency band (MoNB) have increased significantly since early 2000

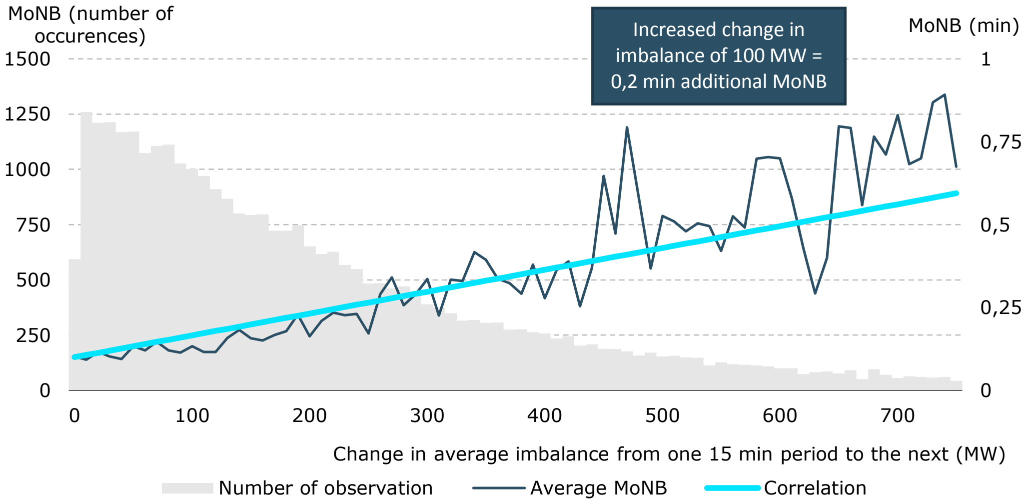


Source: Copenhagen Economics based on TSO input.

There is a positive relation between the imbalance between market time units and the minutes outside of normal frequency band. Figure 14 illustrates that a larger change in the imbalance from one time period to the next increase the observed number of minutes outside of normal frequency band. When the magnitude of the imbalance jumps increase by say 100 MW, the amount of minutes outside the normal band increases by 0.2 minutes.

[14] See e.g. Fingrid (2016), Electricity market needs fixing – What can we do?

Figure 14 Larger MoNB from increased change in imbalance between time periods



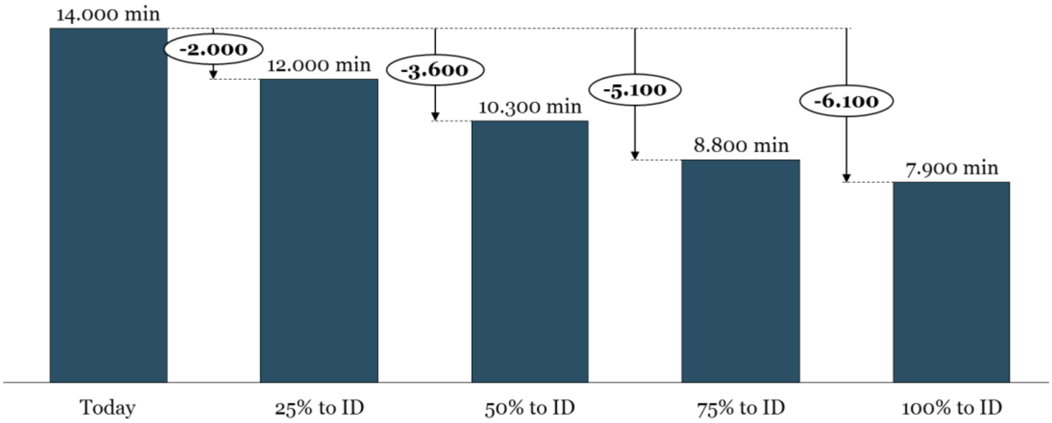
Note: MoNB per change in avg. imbalance between 15 minutes time periods. Note, that while the fitted relationship becomes less clear when the change in imbalances is high (the right part of the figure), the bulk of the data points (the left-axis) is for relatively small changes in imbalances, suggesting that the estimated fit of the regression line is well founded.

Source: Copenhagen Economics based on TSO input.

Based on the relationship illustrated in Figure 14, we have estimated the improvement in minutes outside of normal frequency band when reducing imbalances due to finer time resolution. Introducing 15 minutes imbalance settlement period will reduce the amount of minutes outside of normal frequency band (MoNB) between 2.000-6.000 minutes annually. This is heavily dependent on the amount of imbalances moved to the intraday market, see Figure 15.

Finer time resolution cannot fully eliminate minutes outside the normal band since it only addresses structural imbalances and not stochastic imbalances. Structural imbalances occur as a result of the market design and underlying system. They therefore follow a repetitive pattern and are rather predictable. Stochastic imbalances occur due to unforeseen events or changes e.g. sudden change in wind speed. These imbalances are an inherent part of the power system and are not expected to change as a consequence of finer time resolution.

Figure 15 MoNB per year from introducing 15 minutes imbalance settlement period



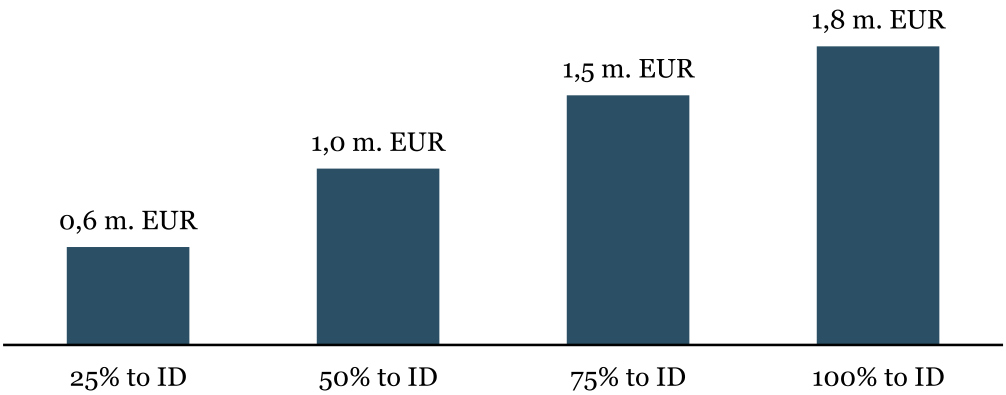
Note: Percentages refer to the share of the market players "new" imbalances moved to the intraday market players' trade.

Source: Copenhagen Economics based on TSO input.

A reduction in minutes outside of normal frequency band can be translated into a reduced risk of a brown-out (here defined as controlled load shedding due to under-frequency). Based on modelling work done in the ENTSO-E project on frequency quality we have estimates on the risk of a load-shedding event given the number of minutes outside the normal band, and a number of characteristics of the power system, such as inertia and frequency containment reserves (FCR). Going from 10.000 MoNB per year to 5.000 MoNB with a FCR D reserve of 1250 MW will halve the risk of a brown-out from once every 11 years to once every 22 years.[15,16] Each brown-out is associated with some costs from load shedding which can be thought of as e.g. loss of production in industries. The socioeconomic loss in case of a brown-out event is assumed to be 21-38 million euro.[17] By assuming a linear relationship, we can then estimate the value of reducing MoNB by one minute to be 200-380 euro.[18] Given the associated reduction in minutes outside the normal band, we estimate that there will be benefits of around 0.6-1.8 million EUR per year in the Nordics (see Figure 16).

15 Assuming a median inertia case of 186 GWs and 1250 MW of FCR D.
16 ENTSOE (2016), Interim report 'Frequency Quality, phase 2 project'
17 Assuming the event last for three hours, covers 1000 MW and the cost for each kWh is 7-13 euro. Sources: ENTSOE (2016), Interim report 'Frequency Quality, phase 2 project'
18 Example with socioeconomic loss in case of brown-out is 21 mill. EUR: (21 mill.€ / 11 years – 21 mill.€ / 23 years)/(10.000 MoNB – 5.000 MoNB)

Figure 16 Socioeconomic benefit of improved frequency quality from introducing finer time resolution



Note: Percentages refer to the share of the market players "new" imbalances moved to the intraday market players' trade.

Source: Copenhagen Economics based on TSO input and ENTSOE (2016), Interim report 'Frequency Quality, phase 2 project'.

Assessing the value of avoiding a brown-out is not an easy task due to the vast uncertainty in estimating the value of un-served energy (or lost load). In addition to the changed input parameters such as size of FCR-D, the socioeconomic loss stemming from an UFLS event is extremely uncertain, as it is very rare and varies significantly from event to event. Changing the assumptions slightly provide bounds in the range 0.6-2.3 mill. EUR per year with the scenario, where 50% of the new imbalances are traded away on the intraday market, see Table 1.

Table 1 Uncertainty in benefits from avoided UFLS

50 % to ID	100 % to ID
0.6-2.3 mill. EUR/year	1.0-3.8 mill. EUR/year

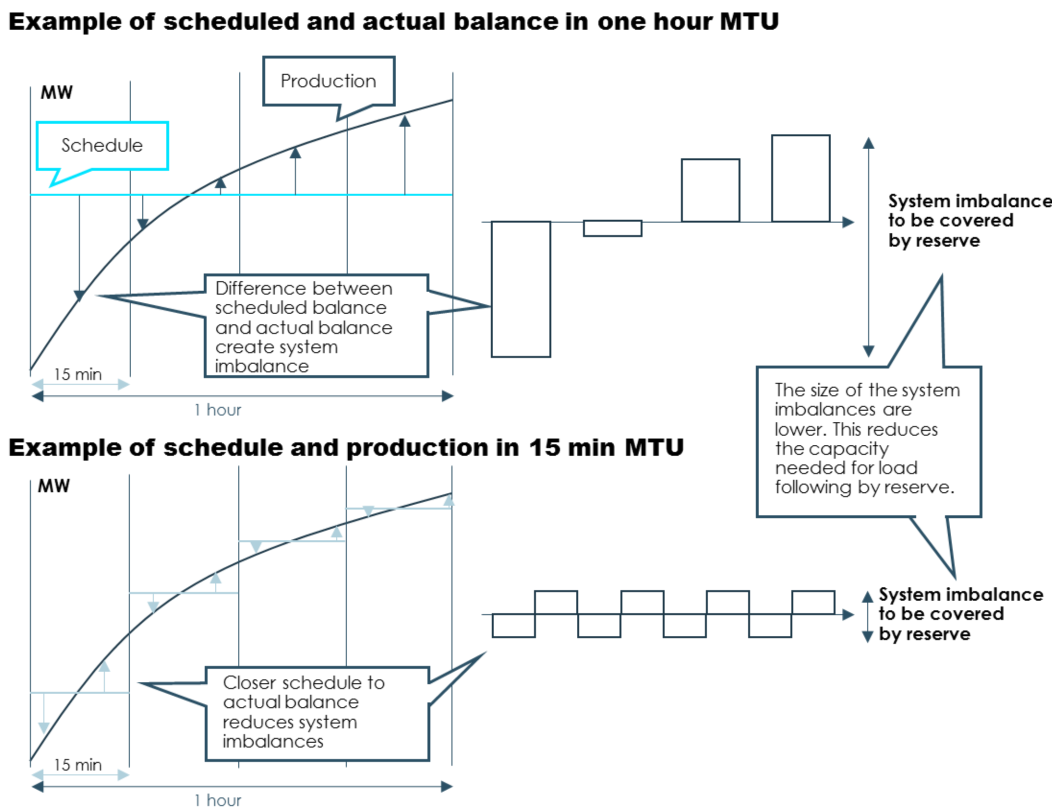
Note: Low estimate refer to a scenario with 10.000 MoNB as baseline and 1350 FCR D. High estimate refer to a scenario with 15.000 MoNB as baseline and 1150 FCR D.

Source: Copenhagen Economics based on TSO input and ENTSOE (2016), Interim report 'Frequency Quality, phase 2 project'

The above assessment is based on estimating the value from preventing a brownout. This assessment crucially depends on to what extent reduced imbalances reduce the risk of a brownout, which ultimately depends on the current power-system characteristics, such as reserve-capacity and inertia available in the system. Consequently, the value of finer time resolution on frequency quality can also be estimated by the avoided need for reserve capacity, see Figure 17. While the existing reserves currently are dimensioned according to the N-1 criterion, and therefore might not be downsized due to finer time resolution, this dimensioning may not be sufficient, as system imbalances are likely to increase following deployment of more volatile generation. Consequently, our estimate above – uncertainties aside – is likely to underestimate the value from improved frequency quality in a situation when imbalances will increase and inertia is likely to be reduced. This is in part because the risk of a brownout increases for each additional minute outside the normal frequency band, and in part, because improved frequency quality may help alleviate the pressure on acquiring more reserves.

Another reason for why our estimates are likely to be on the conservative side, is that we are assuming that avoiding one minute outside the normal frequency band has the same value for operational security. In reality, the risk to operational security increases the further away the frequency is from the normal band. As we depict in Figure 10, finer time resolution will have a larger dampening effect on imbalances when the jumps around the hour shift are the highest. This means that finer time resolution will reduce the minutes where frequency is far from the normal band more than the minutes closer to the normal band.

Figure 17 Reduced imbalances may reduce need for reserves



Note: The figure is an illustration. MTU abbreviation for market time unit.

Source: Copenhagen Economics

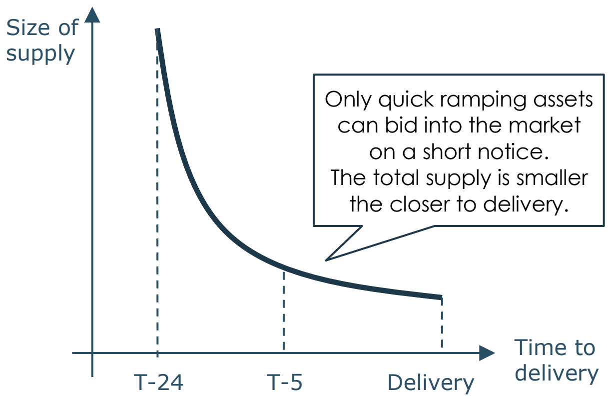
In addition to the direct losses incurred from a load-shedding event, there is also likely to be less tangible effects such as lost reputation for the TSO and national security of supply more broadly, which could impact the attractiveness of a country for electricity intensive industry and may potentially lead to increased need for local back-up generation.

More intraday trading may potentially activate cheaper assets compared to trading in the regulating-power market
There are different reasons for why the market players may be more efficient in trading away imbalances in the intraday market than the TSOs are in the regulating-power market. Based on stakeholder interviews, we have identified the main reasons why the intraday market might be cheaper than the regulating-power market:

- Due to long activation time, there may be cheaper assets available in the intraday than in the regulating-power market
- Uncertainty about activation of regulating-power market bids.

Cheaper assets may be available in the intraday market when power plants with long ramping time are excluded from participation, or only offer limited capacity, in the regulating-power market because the ramping time of these assets exceeds the response time for delivery. When market players trade away more imbalances in the intraday market, volumes will increase and allow slow-ramping assets to participate. This makes it possible for lower cost assets to be activated. The magnitude of this benefit depends on the extent and efficiency of TSO-regulating actions before the regulating-power market. TSOs[19] also engage in so-called smoothing and shifting regulating activities before the RPM, where activation choices can also reflect ramping time and costs.

Figure 18: Time to delivery affects the available supply of power



Note: The figure is an illustration.
Source: Copenhagen Economics

Some stakeholders indicate that they have greater uncertainty about delivery in the regulating-power market compared to the intraday market. In the intraday market the market players find a buyer or seller and agree about the delivery. In the regulating-power market however, the market players do not know whether their bids will be activated and for how

[19] Primarily Statnett.

long. This means market players face increased risk of not being able to utilise their flexible supply and demand fully. This is included in their pricing as a risk premium.

Other stakeholders indicate that if they have had bids accepted in either the day-ahead market or intraday market, they are not excluded from participating in the regulating-power market but can still offer flexibility. Producers can offer down-regulation and consumers up-regulation. This decreases the risk of trading on the intraday market compared to the regulating-power market.

Activation of cheaper assets or with less risk is a socioeconomic benefit as the same amount of power can be delivered at a lower cost.

2.2 Coupling to continental and UK markets

In order to establish cross-border trade, the traded products must be the same. Currently, products in intraday markets and regulating-power markets differ from country to country. Specifically, the time unit of the trade products is 60 minutes in the Nordic countries, while in the most important neighbouring countries it is 15 minutes intraday, as illustrated in Table 2. This implies that existing demand for flexibility in neighbouring markets at a 15 minute level cannot be met by Nordic flexibility, and a potential for welfare improving transactions are foregone.

Table 2 Imbalance settlement period in neighbouring countries

Country	Current imbalance settlement period	Connection to Nordic countries
Germany	15 min	Denmark, Sweden, Norway (2020)
Netherlands	15 min	Norway, Denmark (2019)
Great Britain	30 min	Norway (2021), Denmark (2022)
Poland	60 min	Sweden
Estonia	60 min	Finland
Lithuania	60 min	Sweden

Source: Copenhagen Economics

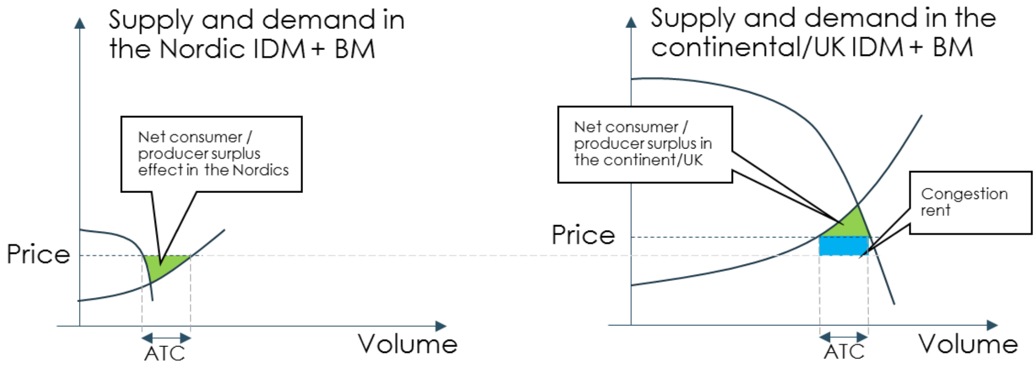
Enhanced integration of both intraday markets and balancing markets are likely expected in line with the European guidelines.[20] The goal is that there will be one integrated European intraday supply and demand curve, and one integrated European supply curve for each European standard balancing product. Conceptually, this can be seen as an extension of the current Nordic practices to the rest of Europe.

The overall effect of this market integration will be that the demand and supply base for flexibility will extend from the Nordic to the European level. This may attract flexibility supply in the Nordic and European markets, which is out of merit in the isolated markets today. Figure 19 shows that increased supply base allows for more efficient utilisation of flexible generation assets in the coupled markets. In some hours/quarters, there will be

[20] Capacity Allocation and Congestion Management Guideline and Electricity Balancing Guideline

lower prices in the Nordic region, while in other hours/quarters prices might go up. In the hours with lower prices, consumers will benefit, whereas in the hours with higher prices, producers will benefit. While the changes in prices might not be a net benefit for both consumers and the producers in the Nordic region, in aggregate the total welfare surplus is positive.

Figure 19 Market coupling have positive effect on welfare



Note: The figure is an illustration. ATC = Available Transmission Capacity.

Source: Copenhagen Economics and E-bridge.

In order to assess the value to the Nordics from increased coupling with neighbouring markets, we have evaluated both the likely variation between the markets at a 15 minutes level and the expected interconnector capacity available for the intraday markets. We do not consider increase value from increase day-ahead trading as it will continue working on 60 minute market time resolution.

Variation in demand and supply is different in quarterly intervals than over the full hour. In practice, there will be hours in which there will be balance across the entire hour, but where there can be excess demand in the first quarter but excess supply in the last quarter.

In order to calculate the effects of market coupling, we have used the German quarterly intraday prices and normalised them to the German day-ahead prices to make them comparable with the Nordic Day ahead prices. By using historical data on capacity available on interconnectors, we can calculate the benefits from hourly and quarterly markets. The difference between the two is the additional benefit from implementing a finer time resolution.

For the existing interconnectors not connected to the German market, we have assumed the same pattern of German ID prices in other neighbouring countries. This is assumed as a good proxy for most of the markets, although some markets might experience less volatile distribution of 15 minutes intraday prices than Germany. In these cases, we will overestimate the benefits.

Similar estimates have been made for new interconnectors. The future interconnectors are assumed to have the same benefit per MW on import and export as the four existing interconnectors to Germany. The benefit per MW is multiplied on the capacity of each interconnector.

An overview of the existing and future interconnectors is show in Table 3.

Table 3 Existing and future interconnectors in the Nordics

Existing interconnectors	Capacity
DK1-DK2	600 MW
DK1-NO2	1600 MW
DK1-SE3	700 MW
DK1-DE	1500 MW
DK2-DE	600 MW
FI-EE	1000 MW
NO2-NL	700 MW
SE4-DE	700 MW
SE4-LT	700 MW
SE4-PL	600 MW

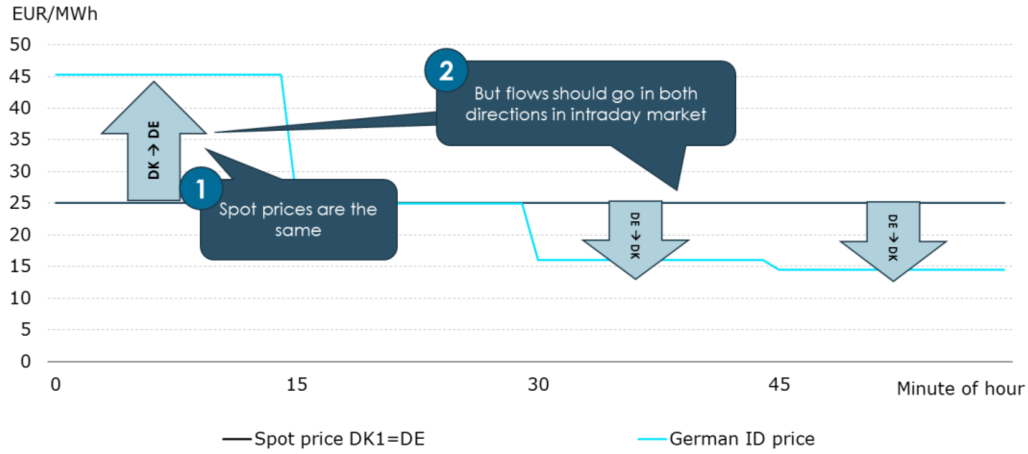
Future interconnectors	Capacity
DK2-DE (2019) – Kriegers Flak	400 MW
DK1-NL (2019) – COBRA	700 MW
NO2-DE (2020) – Nord Link	1400 MW
NO2-GB (2021) – North Sea Link	1400 MW
DK1-GB (2022) – Viking Link	1400 MW

Note: The number after the interconnector indicated the expected year of operation

Source: Copenhagen Economics based on TSO input.

Even though we see large price variation between markets at 15 minutes time units, there is only limited interconnector capacity available for the intraday market. Concretely, the intraday market can only utilise the residual amount of capacity that is not already allocated via the day-ahead market. In addition, the full interconnector capacity can be used to trade in the opposite direction of the flow determined by the day-ahead market, see Figure 20. This is a conservative approach, which is likely to underestimate the benefits. This is due to no inclusion of interdependency between each quarter of the hour as well as not accounting for trade in one quarter will free up more capacity in the other direction for the rest of the hour. If the day-ahead market determines full flow from Norway to Germany, there is no room for more flow from Norway to Germany via the intraday market, but there will be full capacity to trade flows from Germany to Norway.

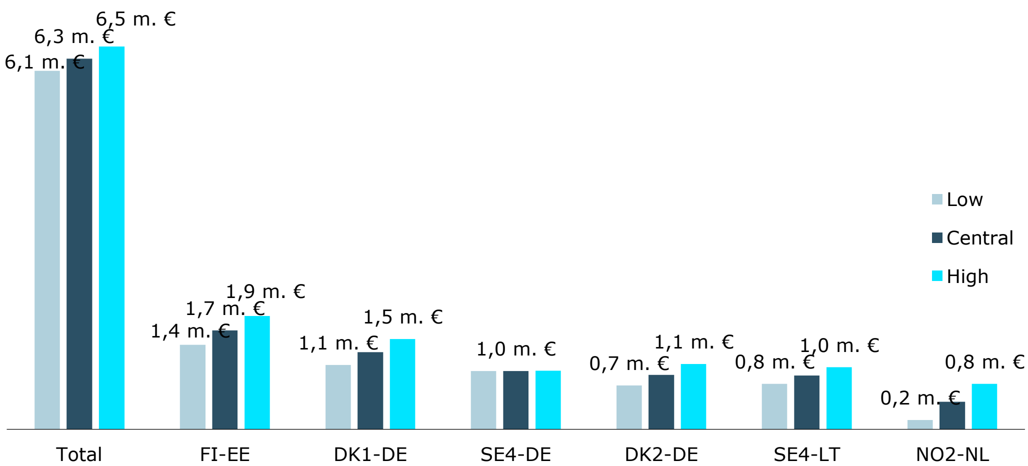
Figure 20 Optimal flows can change during an hour



Source: Copenhagen Economics

We find that in total, market coupling benefits amounts to 6.3 million EUR per year for the existing interconnectors in the central estimate, see Figure 21. The central estimate is calculated as the average benefit for the years 2015 and 2016. The low and high estimates show the lower and higher value for both years.

Figure 21 Benefits from market coupling on existing interconnectors

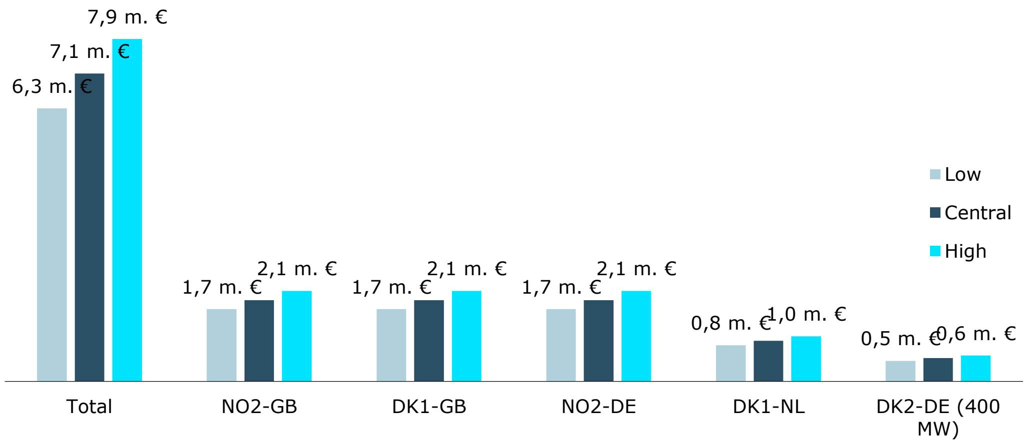


Note: Benefits measured as 50% of the aggregate benefits on each interconnector. The benefits can only be reaped if the neighbouring country also has 15 min market time units. Central estimate is average benefit calculated on data for the years 2015-2016. Low is the year with the lowest benefit, high is the year with the highest benefit (differ from interconnector to interconnector).

Source: Copenhagen Economics based on TSO input.

Our estimates for the new interconnectors that will come into operation suggest that there will be an additional benefit of about 7.1 mill. EUR per year from additional market coupling benefits in the central estimate, see Figure 22.

Figure 22 Benefits from market coupling on future interconnectors



Note: Benefits measured as 50% of the aggregate benefits on each interconnector. The benefits can only be reaped if the neighbouring country also has 15 min market time units. Central estimate is average benefit calculated on data for the years 2015-2016. Low is the year with the lowest benefit, high is the year with the highest benefit (differ from interconnector to interconnector).

Source: Copenhagen Economics based on TSO input.

2.3 Improved utilisation of interconnectors

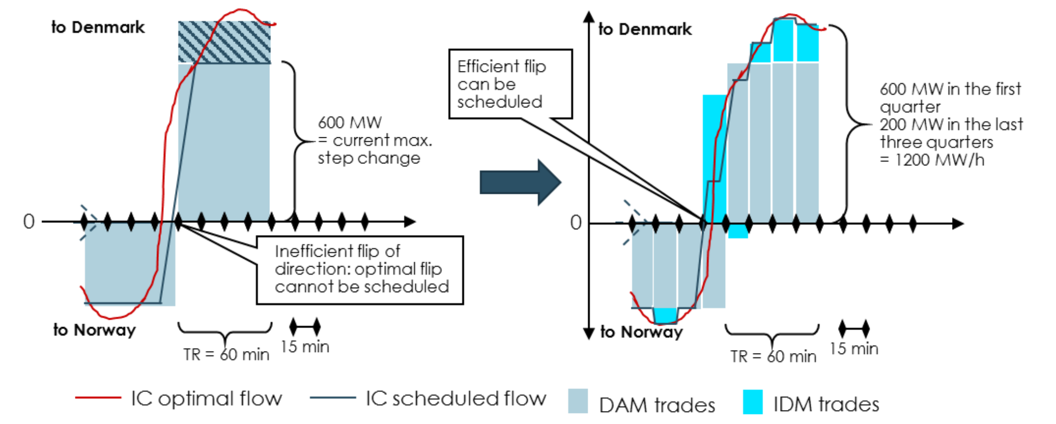
The interconnectors connecting the Nordic region to the Continent currently have a limit to how much the flow of power can change during an hour of operation. The limitation restricts the speed of the ramping and the duration of the ramping. The ramping speed restriction is a physical restriction that relates to how much of a change the power system can handle in a short period. This restriction is currently 30 MW/min. In practice, interconnectors are ramped for a maximum period of 20 min.[21] Consequently, the total amount of possible ramping in an hour of operation is currently 600 MW/h. This restriction applies to both the day-ahead and intraday markets.

With finer time resolution, it is envisaged that this ramping restriction can be relaxed. The main reason is that additional trades will be performed in the quarter shift instead of at the hour shift. If interconnectors could be ramped 7.5 minutes before and after each quarter shift, it could effectively be ramped continuously over the full hour equalling 1800MW/h. In the following, we have used an assumption of a ramping rate of 20 MW/min, which amounts to a potential change in power of up to 1200 MW over the full hour. This assumption is based on analysis from the ENTSO-E's currently ongoing "continuous ramping project".

21 Specific start and end time of ramping varies among the interconnectors.

By utilising the full hour for ramping on the HVDC interconnectors, there will be hours where more capacity can be offered to the market. If there is also a price difference between the regions in these hours, the additional capacity will be utilised, thereby increasing welfare through a more efficient use of assets across price areas, see Figure 23. Consequently, the additional capacity and ramping capability will only be utilised if a trade is performed. In addition to the increased ramping potential, there could also be an economic potential through a more frequent change in direction. This is likely rather limited though since an efficient flow requires a certain threshold of price difference caused by HVDC losses.

Figure 23 Increased ramping ability on interconnectors



Note: The figure is an illustration.

Source: Copenhagen Economics and E-bridge

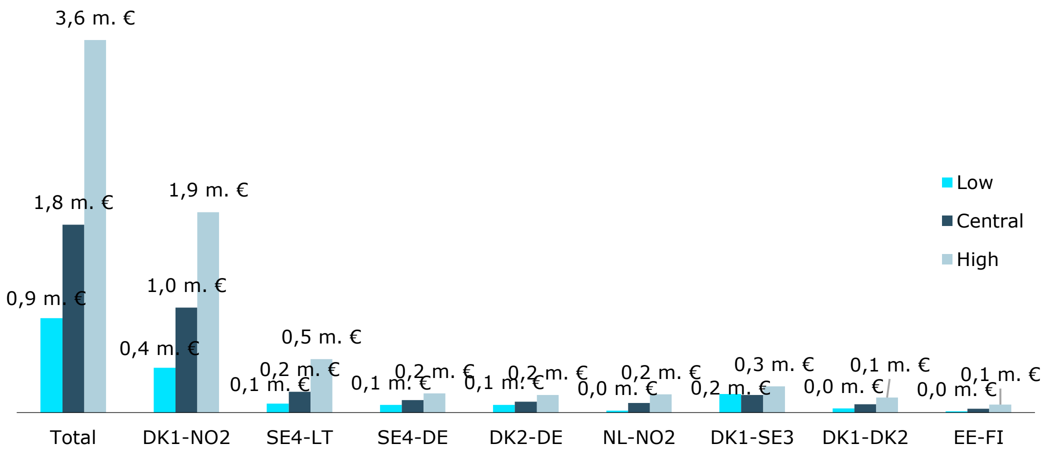
The current ramping limit of 600 MW/h is based on an overall assessment of the operational security in the Nordic synchronous area, and the potential accumulated imbalances that rapid changes in interconnector capacity may inflict. Given, among others, the expected built-up of new interconnectors, it is very likely that the current ramping limit of 600 MW/h may actually be reduced going forward. In the following calculations, we have assumed an increase in the ramping restriction from 600-1200 MW/h, however we have also assessed a situation where the baseline ramping restriction is reduced to 400 MW/h.

In order to assess the benefits from reducing ramping restrictions, we evaluate 1) to what extent reduced ramping limits would actually give rise to higher ramping and 2) if yes; how large the benefits from this additional trade would be.

Firstly, we find that in 2016 about 7 % per cent of the hours the current ramping restriction actually restricted trades that would otherwise have taken place on the existing interconnectors (a higher number when using 400 MWh/h as baseline). This means that in these hours, the market would have wanted to trade more, but the interconnector capacity could not be made available to the market even though it was not fully utilised. In total in 2016, we estimate that an additional 1.2 TWh would have been traded in the absence of ramping restrictions.

Secondly, we have identified that in the particular hours where the ramping restriction was binding, there was an average price difference between the two connected markets of about 2.5 €/MWh. By increasing the ramping rate from the existing 600MW/h to 1200MW/h, we find that the Nordic countries could achieve benefits from increased ramping of about 1.8 mill. EUR per year, by utilising the existing HVDC interconnectors better.[22]

Figure 24 Benefits from increased ramping on existing interconnectors



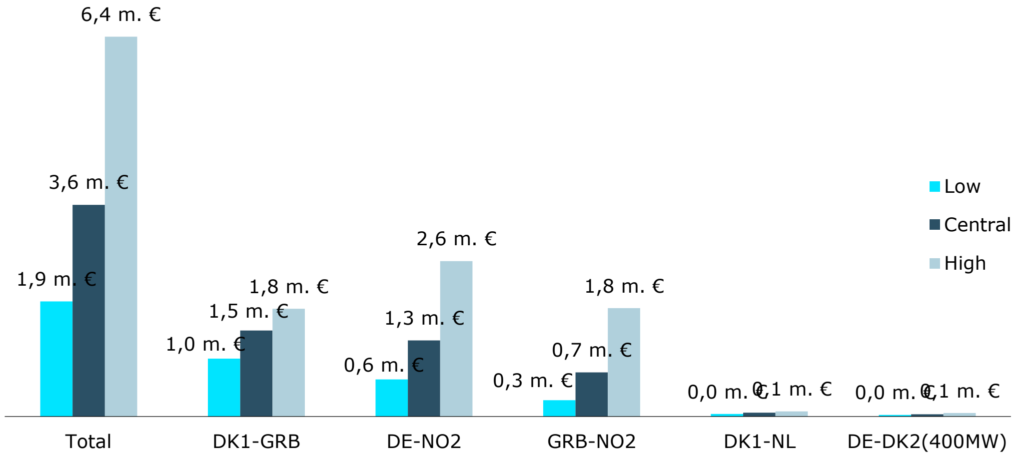
Note: Units are million euros. Benefits measured as 50% of the aggregate benefits on each interconnector, except internal Nordic interconnectors, which are measured as 100% of the benefits in each direction. The central case is calculated as the additional congestion rent from increasing the ramping rate from 600 MW/h to 1200 MW/h based on the years 2012-2016. The low case is the additional congestion rents for the year 2015 and the high case is the additional congestion rate for the year 2013.

Source: Copenhagen Economics based on TSO input.

In addition, new interconnectors will come online in the years to come. Our estimates suggest that there will be an additional benefit of about 3,6 mill. EUR per year by improving the ramping rate from 600 to 1200 MW/h. In order to assess the value of the future interconnectors we have assumed a constant benefit per MW of capacity, see Appendix B for more details on the calculations.

[22] Going to unlimited ramping from 600 MW/h would increase the benefits to between 3.0 mill. EUR in the central case and 1.7-5.4 mill. EUR in the low and high case.

Figure 25 Benefits from increased ramping on future interconnectors



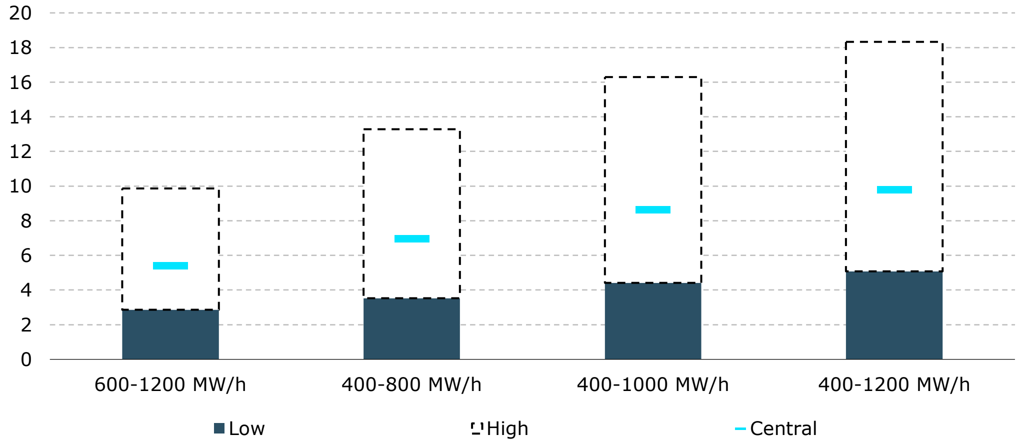
Note: Benefits measured as 50% of the aggregate benefits on each interconnector.

Source: Copenhagen Economics based on TSO input.

In total, we find that by increasing the ramping rate from 600-1.200 MW/h, Nordic welfare can be improved by around €5 million per year, varying between €3-10 million (see Figure 26).[23] In the future, it might be necessary to decrease the ramping rate when e.g. new interconnectors are coming online. When and how much the ramping will decrease is currently not known. However, a decrease of the ramping rate will significantly increase the potential benefits of implementing a finer time resolution. Increasing the rate from 400-1.000 MW/h increases the value to € 9 million (see Figure 26). This is because a low ramping rate will restrict more trades that would otherwise have taken place, than a higher ramping rate.

[23] The sensitivity is assessed by doing the calculation for all years 2012-2016 and taking the lowest and highest value respectively.

Figure 26 Benefits from increased ramping depend on base ramping restriction



Note: 600-1200 MW/h indicates the ramping capacity going from 600 MW/h to 1200 MW/h. The central case is calculated as the average additional value for the years 2012-2016. The low case is the additional value for the year 2015 and the high case is the additional value for the year 2013.

Source: Copenhagen Economics based on TSO input.

2.4 More market participants able to offer energy in regulating-power market

When balancing service providers bid into the Nordic regulating-power market, they have to submit their bids 45 minutes before the start of the hour of operation and are committing to deliver power up to potentially the whole hour of operation. By implementing finer time resolution, additional market participants may be allowed to bid into the regulating-power market through two effects:

- Shorter commitment period
- Gate closure closer to time of delivery (if rolling-gate closure in regulating-power market)

Firstly, if the market time unit in the regulating-power market is changed from 1 hour to 15 minutes, so would the period where assets must commit themselves to stand ready for. This shorter commitment period will benefit assets such as batteries and industrial power facilities where the existing requirement of committing to deliver power for a full hour can make bidding unattractive. These types of assets may be more inclined to bid if they only have to commit their availability for 15 minutes.

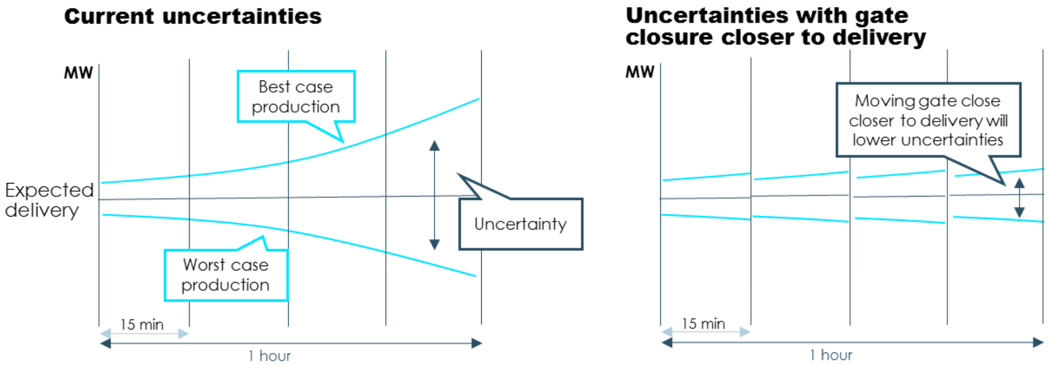
Some industrial consumers and one aggregator have in our interviews indicated that a 15 minutes market time unit on the regulating-power market will allow them to more easily provide their flexibility to the markets. The industrial consumer will experience less rest time after activation resulting in an increased ability to supply flexibility. There is very little aggregator activity in the Nordics currently, but a finer time resolution will provide better market conditions for aggregators in the future.

One producer also indicated the possibility of offering its supply in the last quarter of the regulating-power market if it had to deliver energy the upcoming hour. If activated, it could ramp up during the regulating-power market instead of waiting until the hour shift.

Secondly, if the regulating-power market would also operate with a rolling-gate closure – meaning that bids would have to be submitted 45 min before the *quarter* of operation – the cost of providing balancing resources could be reduced. The reason is that market players currently have to submit bids for the entire hour and therefore have to predict and schedule accurately for the entire hour of delivery. The duration from the current gate closure to the final quarter of operation is 1.5 hours, and some asset owners will find it difficult to predict accurately their availability this far into the hour. Changing the market time unit to 15 minutes with a rolling-gate closure will imply that balance providers will never have to predict more than 45 minutes ahead. This will reduce the risk to the balancing providers when offering balancing power, see Figure 27, and in theory reduce the cost of providing balancing power.

There may be other elements that pull in the other direction. Some plants might require a higher price to participate as they may only be activated in just 15 minutes, and they have activation costs. In addition, the requirements on getting a new meter may prevent some market players to participate.

Figure 27 Less uncertainties for volatile producers with gate closure closer to delivery



Note: The figure is an illustration

Source: Copenhagen Economics and E-bridge.

2.5 Changed investment incentives and impact on future energy mix

When market participants decide on investments in the power market, they of course consider the expected returns from such investments. One important implication of finer time resolution is that it will change the expected returns of different types of investments through:

1. As the ‘price’ of being inflexible will increase, the ability to deliver flexibility becomes more valuable and inflexibility becomes more costly
2. Increased ramping rates of interconnectors and benefits from market coupling will to increase the business case of having flexible assets

This will make it more attractive to undertake e.g. investments to make existing and/or new assets more flexible, and improve/reduce the business case of entire asset classes depending on their inherent flexibility.

By paying more accurately for the imbalances that are inflicted on the system, future investments in new assets will therefore better reflect the true costs and value to the system from (in-)flexibility. The market players will thus face incentives to invest in assets that are more in with the actual needs of the power system.

For this impact, it is important to note there might be political goals for e.g. introducing more renewable energy (which in many cases are volatile). This implies that the overall deployment of volatile sources may not necessarily change. Nevertheless, the underlying remuneration incentives ensure that the assets giving rise to the imbalances are also facing the costs.

Note that finer time resolution does not increase the *overall system demand* for flexibility. Instead, the demand for flexibility shifts from being the responsibility of the TSO to the responsibility of the market players. Going forward the overall system demand is however also likely to increase for other reasons including the entry of more volatile production assets. In addition, the cost per MWh of imbalance is also likely to increase going forward, all pointing to a future where the remuneration of flexibility in the power market increases.

Chapter 3

Costs from introducing a finer time resolution

The introduction of finer time resolution will lead to additional costs for different market participants and system infrastructure. These costs include development as well as adaptation of IT-systems or investments in new infrastructure and systems. The main aim of the cost analysis is to assess the total costs of different stakeholders in each different Nordic country of implementing finer time resolution.

As with the benefits, the objective of this analysis is not to estimate the total cost of implementing finer time resolution, but assess how specific implementation choices affect these costs. In particular, we have looked into 1) what year finer time resolution is implement and 2) whether it is implemented simultaneously in the Nordic countries.

If finer time resolution is implemented 'early', then investments will also have to be held earlier. This constitutes an additional cost through 'premature' investments costs and a cost from not being able to accumulate a return on this investment through other placements. In addition, potentially increased operational costs may occur earlier.

If finer time resolution is not implemented simultaneously in the Nordic countries, there will be a period where different systems and procedures would need to be able to handle both a 15 minute and 60 minutes imbalance settlement period. This will give rise to additional costs.

In order to estimate the costs, we have engaged closely with market participants as they should have the best available overview of the likely costs of implementing finer time resolution. We have interviewed all market participant categories, as they will all face some kind of additional cost. In addition to the TSOs, we have interviewed DSOs, balance responsible parties, energy suppliers, energy traders, and system infrastructure entities such as eSett and the power exchanges. The data gathered from the interviews has been supplemented with answers based on questionnaires from the cost-benefit analysis made for ENTSO-E.[24] We have identified stakeholders from all Nordic countries to account for potential regional differences. We would like to stress that while market participants are in the best position to estimate their costs, all interviewed participants highlighted that their estimates were highly uncertain, and not the result of a rigorous assessment.

3.1 Results from stakeholder interviews

The number the interview partners related to their role and country is shown in Table 4. In total 16 balance responsible parties, balancing service providers and DSOs from the

[24] Frontier (2016), CBA of a Change to the Imbalance Settlement Period

various Nordic countries have been interviewed, in addition to interviews conducted with TSO experts, eSett, the power exchanges and non-Nordic flexibility providers.

Table 4 Overview of interview partners in the stakeholder process

	BRP/BSP/electricity supplier/trader	DSOs	Esett, PX, demand side, TSOs	**Country total**
Norway	4	0		**4**
Sweden	2	1		**3**
Denmark	3	1		**4**
Finland	4	1		**5**
Nordic total	**13**	**3**	**7**	**23**

Source: Copenhagen Economics and E-Bridge

In addition, we interviewed internal TSO resources, eSett, Power exchanges, and a demand side aggregator

Based on the analysis we have identified three main cost categories: IT and data costs, metering investments and costs for settlement and exchange infrastructure.

IT and data costs

We find that the primary cost driver is the IT and data costs. These costs covers DSOs, BRPs, energy suppliers and traders and include e.g. new software for trading, additional capacity to process 15 min data etc. Although the cost for each individual company in most cases is not too high, the sheer number of market participants make this item very costly on an aggregate level.

Meters

Meters is the second most important cost category. For this study, we have defined three categories for meters, large, medium and small meters.

Large meters, which includes grid meters and big production units are the most expensive to replace. The majority of these meters however are already capable of handling 15 minute ISP or is already planned to be replaced, so quite few additional need to be replaced.

Medium sized meters are mainly used for production units, large consumers and DSO-TSO settlement. This is the most costly metering category due to the large number of meters being replaced.

Small meters include meters for e.g. household use. We assume that none of the small meters has to be changed, since they are already being changed in most countries, and that the remaining households can be ‘profiled’ instead, where their intra-hourly consumption is estimated instead of measured. The profiling costs are included under the (DSO) IT and data costs.

The specific numbers of meters and cost inputs in each country is described in Appendix C.

Settlement and power exchanges

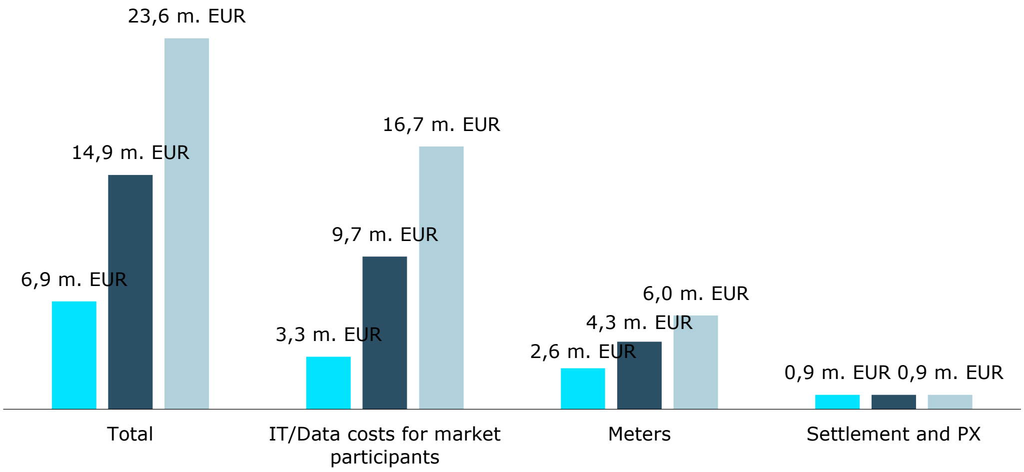
The TSO IT systems used for e.g. cross-border settlement, the power exchanges IT systems used for trading, and the BRP settlement systems (eSett and Energinet) have to be capable of handling 15 minute data. In addition to the costs estimated, there are also costs related to maintaining several e.g. trading and settlement systems in case of a non-simultaneous implementation. We find the costs for maintaining parallel system to be relatively low. The cost data for the power exchanges is sensitive and any specific cost estimates for this cost category will not be published.

Total costs of implementing finer time resolution early

Based on our interviews, we find that the total Nordic additional costs from implementing finer time resolution one year earlier (in 2020 instead of 2021) is about 15 million EUR, see Figure 28. The majority of these costs (10 million EUR) stem from IT and data costs for the different market players and DSOs. The other major cost is the costs from investing in meters a year early, which amounts to 4 million EUR. Settlement and power exchanges constitute about 1 million EUR.

The results are quite sensitive to changes in the input assumptions with a total varying between 7-24 million EUR, see Figure 28. Especially the IT and data costs are sensitive to the input assumptions and varies between 3-13 million EUR.

Figure 28 Total Nordic costs from introducing a finer time resolution in 2020



Note: Measured as the additional cost of implementing finer time resolution in 2020 compared to 2021 in present (2017) values. The central estimate for DSO IT/Data costs defines a scenario where the DSO are faced with OPEX of 0.5 EUR per customer in IT and data costs. Low and high are 0.1 and 1 EUR respectively. The central estimate for BRP/BSP IT/Data costs is 3.5 ct/MWh produced energy in CAPEX. Low and high are 2 and 4.5 ct/MWh produced energy respectively. The central estimate for meters are cost estimates as explained in Appendix C, with 50% of the medium sized meters being changed, the rest being reconfigured. Low and high is 25% and 75% of meters being changed respectively. There are no variance in the settlement and power exchange estimates due to a low number of observations. These numbers are based on stakeholder interviews and are explained further in Appendix C.

Source: Copenhagen Economics based on stakeholder input.

Chapter 4

Net results of analysis

4.1 Costs and benefits of the different implementation scenarios

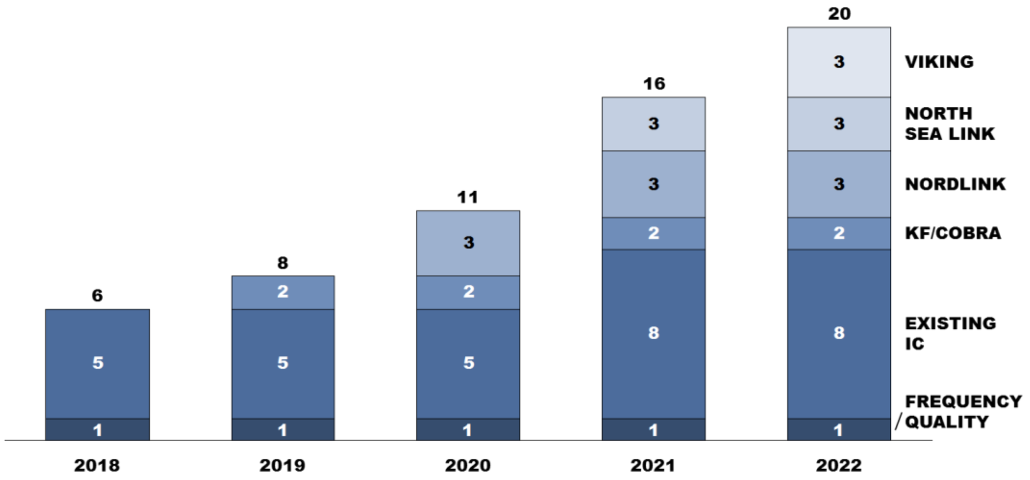
Benefits in each scenario

In this section, we accumulate all estimated quantifiable benefits from finer time resolution, and evaluate how they differ with different timing of implementation. This includes benefits from market coupling, increased ramping of interconnectors and frequency quality. In the below section we assess market coupling and ramping benefits together, as they both depend on the existing and new interconnectors. In addition to the quantifiable benefits there are benefits which are not quantified in this report e.g. changed investment incentives and therefore different future energy mix.

We estimate that if finer time resolution was hypothetically implemented in 2018, this would give rise to about 6 million EUR additionally per year (see Figure 29): 5 million from better use of interconnectors (both coupling and ramping benefits), and about 1 million from frequency quality. The estimate for frequency quality is, as previously discussed, very uncertain and could be both significantly higher or lower. For each additional new interconnector coming online, the benefits from finer time resolution increases correspondingly. In 2022, the benefits will have increased to about 20 million EUR.[25]

[25] Benefits from existing interconnectors increase slightly from 2021. This is because we assume that benefits from the links to the Baltics (FI-EE and SE4-LT) occur when these countries also implement finer time resolution (assumed to be in 2021)

Figure 29 Total annual benefits



Note: Values are million euros. Benefits on interconnectors outside the Nordics are valued at 50 % of their estimated total benefits.

Source: Copenhagen Economics based on TSO input.

Starting implementation early will add further value by reaping the benefits earlier. Seen from a total Nordic perspective, total accumulated value of implementing as early as 2018 is about 26 million EUR, see Table 5. This includes the accumulated value of reaping the yearly benefits already in 2018 and in the years towards 2021.

If the Nordic countries agree on postponing implementation until 2025, the total Nordic loss of benefits will be around 65 million EUR, see Table 5. This is a combination of not reaping the benefits from market coupling and ramping until 2025 and not obtaining the value from improved frequency quality.

The benefits estimated are subject to uncertainty on the underlying input data and the assumptions used as shown in Table 5. See Chapter 2 for a description of the uncertainties around the estimates. Note that the frequency quality analysis is uncertain in particular, and that the range below may not fully reflect this.

Table 5 Accumulated Nordic benefits from early or late implementation

	2018	2019	2020	2021	2025
Market coupling	15 m. EUR	11 m. EUR	6 m. EUR	0 m. EUR	-41 m. EUR
Ramping	9 m. EUR	6 m. EUR	4 m. EUR	0 m. EUR	-20 m. EUR
Frequency quality	3 m. EUR	2 m. EUR	1 m. EUR	0 m. EUR	-3 m. EUR
Total (simultaneous implementation)	**26 m. EUR**	**19 m. EUR**	**11 m. EUR**	**0 m. EUR**	**-65 m. EUR**
Sensitivity (m. EUR)	(19)-(38)	(14)-(28)	(8)-(16)	0 m. EUR	(-49)-(-90)

Note: Positive value indicates a benefit. Negative value indicates a loss of benefit. DK1-DK2, DK1-NO2 and DK1-SE3 measured as 100 % of the benefits. Values are million euros. Calculated with a social discount rate of 4%. Lower/higher bound is lowest/highest estimate for ramping and market coupling. Frequency quality is the low/high estimate based on the assumptions in Table 1 for the case where 50% of the "new" imbalances are moved to the intraday market.

Source: Copenhagen Economics based on TSO input.

We have included the two intra-Nordic HVDC connections in the total calculation.[26] These benefits will be reaped if the relevant countries implement finer time resolution simultaneously.[27]

While the quantifiable estimates are quite uncertain, we believe that they are on the conservative side for several reasons:

Frequency quality is underestimated for two reasons:

- Finer time resolution will have a stronger impact on the minutes outside the normal frequency band that are the furthest away from the band, and therefore the most challenging for operational security.
- It is estimated given the existing amount of reserves and inertia in the system, and is likely to be higher going forward in a situation when imbalances will increase and inertia is likely to be reduced.

In our estimates we assume that 50 per cent of the 'newly settled' imbalances will be addressed by market participants, e.g. by trading them away in the intraday market. It is difficult to assess whether this is correct, but there are at least two reasons for why this percentage could be higher:

- The cost of being in imbalance is likely to go up in the future giving a larger incentive for BRPs to address their imbalances
- The imbalances addressed by finer time resolution are so called structural imbalances (as opposed to stochastic imbalances), which are easier to predict and therefore address before market schedules are submitted.

In addition to the quantitative benefits, there are a number of qualitative benefits as well, summarised in Figure 30 below.

[26] DK1-NO and DK1-SE

[27] Or come to a special agreement that would be able to reap the benefits.

Figure 30 Summary of benefits

Effect	Impact	Over or under-estimation?
Reduction of net system imbalances around the hour shift	About 20 per cent About 30 per cent for the largest jumps	May be underestimated if BRPs will trade away more than 50 per cent of the newly settled imbalances
Better use of interconnectors	€4 million per year*	
Market coupling	€11 million per year*	
Improved frequency quality	€1 million per year*	Underestimated
Improved investment incentives	More accurate pricing of flexibility More flexible energy system in the future	
Improved access to regulating power market	More participants can offer energy in RPM	

Note: *Quantifiable benefits measured in the year 2021. . Value of interconnectors could be underestimated due to potential future change of ramping restrictions.

Source: Copenhagen Economics and E-Bridge based on TSO input.

Costs in each scenario

The Nordic accumulated cost of implementing as early as 2018 is about 50 million EUR, see Table 6**Feil! Fant ikke referansekilden.**. This includes the costs for the IT Updates, the adaptations in the metering infrastructure and other costs for TSOs, trading system and settlement process. Moreover, there will be costs from having to invest in new meters early primarily for large industrial consumers and very large grid meters. Implementing just one year earlier (2020) will give rise to an additional cost of about 15 million EUR.

If the Nordics agree on postponing implementation until 2025, the total saved costs will be around 52 million EUR, see Table 6. The later the needed investments take place, the greater are the savings from simultaneous late implementation. This is primarily driven by savings on OPEX. The avoided costs from installing metering does not increase significantly, since it is assumed that a share of the meters are changed each year to new meters in any case. The year 2025 is according to GL EB the latest possible date for the implementation of finer time resolution.

The results are sensitive to different assumptions on the cost inputs. The total accumulated costs from implementing in 2018 varies between 24-80 million EUR, see Table 6**Feil! Fant ikke referansekilden.** The input assumptions for the bounds are described further in Chapter 3 and Appendix C.

The avoided costs from simultaneous late implementation are sensitive to input assumptions as described above. The total accumulated avoided costs from late implementation are assumed to be in the range of 24-83 million EUR.

Table 6 Accumulated Nordic costs from early or late implementation

	2018	2019	2020	2021	2025
IT/Data cost for market participants	-30 m. EUR	-20 m. EUR	-10 m. EUR	0 m. EUR	35 m. EUR
Meters	-17 m. EUR	-10 m. EUR	-4 m. EUR	0 m. EUR	14 m. EUR
Settlement and PX	-3 m. EUR	-2 m. EUR	-1 m. EUR	0 m. EUR	3 m. EUR
Total (simultaneous implementation)	**-50 m. EUR**	**-32 m. EUR**	**-15 m. EUR**	**0 m. EUR**	**52 m. EUR**
Sensitivity (m. EUR)	(-24)-(-79)	(-15)-(-51)	(-7)-(-24)	0 m. EUR	(24)-(83)

Note: Values are million euros. Calculated with a social discount rate of 4%.

Source: Copenhagen Economics and E-Bridge based on stakeholder interviews.

When we just look at the *quantifiable* benefits versus the costs, we find that they are within the same ballpark for all implementation years, except for 2018, which seems quite negative. Very early implementation (2018) and a late implementation (2025) have the lowest net benefits, and are therefore not preferred. With the significant level of uncertainty around especially the cost estimates, it is not possible to conclude that any implementation years in between seems to be preferred over the other. Late implementation avoids significant benefits from especially new interconnectors coming online. Very early implementation implies that a large share of meters would have to be prematurely replaced, and that additional OPEX would be paid for several years.

In addition to the quantifiable benefits, there are other benefits to be considered, in particular related to changed market investment incentives that are more in line with the actual needs of the power system.

Chapter 5

Details of common Nordic concept

Based on the recommendation to implement simultaneously, the common Nordic concept has been detailed. The concept entails mandatory 15 minutes imbalance settlement period for all balance responsible parties, both production and consumption. The implementation of mandatory 15 minutes imbalance settlement period affects both the trading options provided to balance responsible parties, the existing settlement process and metering requirements. Each of these factors is described separately below.

Trading options

With 15 minutes imbalance settlement periods balance responsible parties must have the opportunity to trade 15 minutes products on at least one market place. The trading option provided to BRPs will be 15 minutes products on the intraday market. The products will be traded through the XBID platform, currently being developed as part of the implementation of the European Guidelines, and potentially other markets.

The XBID system will be able to provide 15 minutes products, both within bidding zones and on bidding zone borders, already at the first go-live in 2018, if requested by the TSOs. The XBID system is designed to apply a rolling-gate closure. The market time unit will be 15 minutes in the Nordics, and hence the ID market will have a rolling gate closure every 15 minutes.

The choice of rolling-gate closure or a fixed gate closure is closely linked to the operational processes at the TSOs and the choice of gate closure for the common European mFRR platform. The common European mFRR platform is expected to follow the rolling-gate closure planned for XBID. TSO processes are expected to be compatible with a rolling-gate closure; alternatively, adjustments can be made in order to accommodate the rolling-gate closure.

Liquidity on the Nordic intraday market is currently low and some market players have expressed concern about this[28]. The project recognizes the concern, but liquidity is expected to increase as the XBID platform allows for trading with other countries (given available interconnector capacity) and balance responsible parties are incentivized to trade their 15 minutes imbalances in the intraday market when finer time resolution comes into force.

The Nordic TSOs are in dialogue with neighbouring TSOs on the implementation of an intraday auction similar to the German intraday auction. This initiative runs independently of the introduction of 15 minutes imbalance settlement period, but can provide a more efficient trading tool, especially for small balance responsible parties. Additionally, the

Winter package or “clean energy for all Europeans” package discusses changing the day-ahead market from 60 minutes resolution to 15 minutes resolution in 2025.

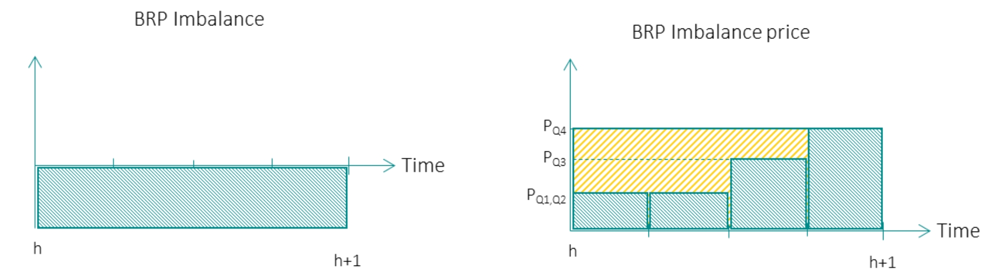
Settlement process

The regulating-power market will change from 60 minutes bids to 15 minutes bids (European standard balancing products) at the same time as 15 minutes imbalance settlement period is implemented

Changing the resolution on the regulating-power market is not only affected by the change of imbalance settlement period but also by the implementation of standard balancing products and a common European mFRR platform. The standard products are designed to fit in a 15 minutes scenario and the common platform is planned to be in operation at the latest four years after GL EB enters into force, i.e. one year after implementation of 15 minutes imbalance settlement period. By this time, the regulating-power market is therefore bound to change in one way or the other.

Keeping the regulating-power market with hourly resolution for an interim period after a 15 minutes imbalance settlement period has been implemented and before the common mFRR platform is operational may lead to perverse incentives for balance responsible parties. If the imbalance price is calculated as the marginal price of activated bids in each quarter of an hour and the TSO activates bids continuously during the hour, an imbalance in the last quarter of an hour will be more expensive than in the first quarter of an hour. The balance responsible parties activated on the regulating-power market will however still receive the highest of the four quarterly marginal prices regardless of when their bid was activated. This can affect the bidding strategy of balance responsible parties without truly reflecting the cost of the imbalance posed to the system.

Figure 31 Potential distortion in BRP incentives with 15 and 60 min market time unit in the RPM



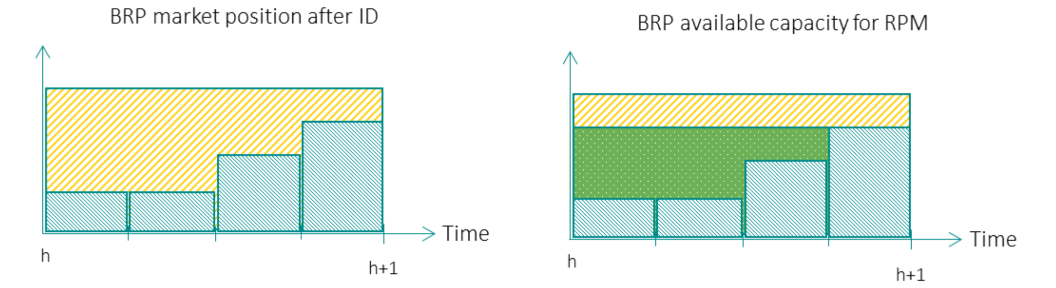
Note: The balance responsible party will pay the imbalance according to the volume and prices illustrated by the blue boxes. The balance responsible party will receive payment for an activated mFRR bid according to the yellow box (PQ4) regardless of when the bid was activated.

Source: TSOs

If the imbalance price of all four quarters of an hour is set to the marginal price of the most expensive bid activated during the hour, the balance responsible party will not be able to net imbalances over the hour, but the imbalance price will not reflect the actual situation of the system within the imbalance settlement period. The finer price signal resulting from moving from 60 minutes imbalance settlement period to 15 minutes imbalance settlement period will therefore be lost for the pricing of imbalances.

Having a 60 minutes regulating-power market and 15 minutes imbalance settlement period is likely to have a negative effect on the capacity balance responsible parties can provide to the regulating-power market. Balance responsible parties that have traded 15 minutes products on the intraday market may have different market positions for each quarter of an hour. Having to provide an hourly bid to the regulating-power market, the balance responsible party will have to take into account its position in each quarter of the hour, which limits the available capacity the most. This can lead to less capacity being available on the regulating-power market, even if the capacity is physically available in the system.

Figure 32 Less capacity offered in RPM with 15 min ISP and 60 min market time unit in RPM



Note: The balance responsible party has a market position as illustrated by the blue boxes and a maximum available capacity for the market as illustrated by the yellow box. The balance responsible party will not be able to offer the capacity in the green box to the regulating-power market due to the different time resolutions.

Source: TSOs

Metering requirements

Not all meters must be changed or reconfigured to 15 minutes resolution to ensure correct settlement. Smaller consumption units and retail customers can be profiled based on the measured hourly values. Meters with 15 minutes resolution are relevant for producers, large consumers, country borders and network points (TSO/DSO).

Some of the TSOs (Statnett and Energinet) already have ongoing projects for changing transmission grid meters, i.e. meters on interconnectors and large units connected to the transmission grid. The meters in connection points between TSO and DSO grids are often owned and operated by DSOs, which is also the case for meters belonging to production units and large consumers.

Appendix A
Calculation methodology for market coupling benefits

The access to data and the fact that new interconnectors are being built between the Nordics and neighbouring systems provides for three types of cases and thereby three approaches to the analysis:

1. Existing interconnectors from the Nordics towards Germany
2. Existing interconnectors from the Nordics towards other countries expected to implement 15 min ISP (including the Netherlands)
3. New interconnectors from the Nordics towards countries expected to implement 15 min ISP

In case no. 1, the historic data on interconnector capacity provided to the market, the prices for 15 min products in the German Intraday auction, and the Day Ahead prices in both Germany and the Nordics are used to calculate the trade benefits. In case no. 2, the historic data on the interconnector capacity provided to the market and the Day Ahead prices in both the Continental countries and the Nordics are used. In order to estimate the price of 15 min products, the price pattern from the German Intraday auction is assumed to be applicable for the other countries on the continent. In case no. 3, there is no historic data on the interconnector capacity provided to the market. These interconnectors are therefore assumed to have the same trade benefit per installed MW interconnector capacity as for the interconnectors in case 1.

The analysis aims at a simple, transparent methodology and will assume static market prices i.e. assumed trading volumes will not change the historic market prices.

Analysis of interconnectors belonging to case 1
Relevant interconnectors are: DK1-DE, DK2-DE (Kontek) and SE4-DE (Baltic Cable). The individual steps of the analysis are described below.

Step 1: Create a link between German 15 min prices and German Day ahead price
It is not possible to obtain 15 min prices for the Nordic bidding zones. The analysis is therefore based on 60 min prices in the Nordics and 15 min prices in Germany.

For the analysis the 15 min prices from the German ID auction performed in D-1 15:00 is used and not the prices from the continuous Intraday trade. For the Nordics, the Day Ahead price is used instead of the Intraday price, since the volume on the Nordic Intraday market is very low. This has the following implications:

- The 15 min prices used in the analysis are settled in D-1 and thereby several hours before real time (opposite to trading continuous Intraday). This makes the comparison with the Nordic Day Ahead prices more realistic due to the same timeframe and trading mechanism
- The 15 min prices used in the analysis does not fully capture the volatility in the German 15 min Intraday market. Especially in quarters where prices are both positive and negative within the same quarter in the continuous market. This is part of the market dynamics and considered on the same level as assuming that market prices are static despite of a different trade pattern.

The 15 min German Intraday price is tracked against the 60 min German Day ahead price is the following formula:

$$Realized\ German\ 15\,\mathrm{min}\, ID\ price - \frac{\sum Realized\ German\ 15\,\mathrm{min}\, ID\ price_{Q1-Q4}}{4} + 60\,\mathrm{min}\, German\ Day\ ahead\ price$$

Step 2: Calculate the additional benefit of quarterly trades

The additional value of trading 15 min products has to account for the value of trading hourly products. The value is calculated by use of the formula below.

$$\left(\left|\underbrace{\left(P_{DE,15\,min} - P_{Nordic\ price\ zone,\ \ 60\ min}\right)}_{Trade\ benefit\ of\ quarterly\ products}\right| - \left|\underbrace{\left(P_{DE,60min} - P_{Nordic\ price\ zone,60\ \mathrm{min}}\right)}_{Trade\ benefit\ of\ hourly\ products}\right|\right) = X\ EUR$$

In quarters where trading of quarterly products yields less benefit than trading hourly products, i.e. the result of the above formula is negative, the additional value of trading 15 min products is set to 0 Euro. This is based on the assumption that the trade will not be performed in case of negative value.

Step 3: Add the capacity and expected direction of flow
The capacity is allocated towards each quarter taking account of ramping restrictions and the historical capacity made available for the market in a specific hour. For quarter 1 the binding ramping constraint is 300MW or the actual capacity made available to the market if this is below 300 MW. For quarter 2-4 the binding constraint is the minimum of ramping restrictions of 100MW and the actual capacity made available to the market if below 100MW. The 300MW constraint in quarter 1 is based on the maximum ramping restriction of 600MW. In case the flow changes direction from one quarter to the other, the constraint of 300MW ensures that the ramping restrictions are not violated. The same applies for quarter 2-4, where 200MW is the binding ramping restriction.

The available capacity is compared with the price direction and benefit for each quarter is calculated. Finally, the calculated value is divided by four since it is quarterly trades and not hourly trades.

All interconnectors follow the same method except for the DK1-DE interconnector. For this interconnector the following adjustments have been made:

- Due to the existing congestion on the border, it is assumed that it will not be possible to release extra capacity in quarter 2-3. The capacity in these quarters are therefore set to 0MW.
- In the hour shifts we've applied a restriction on 600MW or the historical capacity if this is lower than 600MW. The 600MW corresponds to the total capacity restriction through the hour on all other ICs. The ramping restrictions do not apply to this border and in practice the IC could ramp 1500MW in hour shifts. This is however highly unlikely – even if capacity would be available – for two reasons. One is that this amount of capacity is unlikely to be provided by DK1 alone and available IC capacity from Norway, Sweden or DK2 would therefore be a prerequisite. The second is that the volume on the German 15 min ID (auction) is often much lower than 1500MW.

Analysis of interconnectors belonging to case 2
Relevant interconnectors are: FI-EE, NO2-NL and SE4-LT

The analysis is carried out following the same methodology as for interconnectors belonging to case 1, assuming that the pattern of the 15 min German ID prices are representative for the price pattern in the other countries.

For the FI-EE IC, the capacity was adjusted to only be half of the capacity compared to other ICs i.e. 150MW in hour shifts and 50MW in quarter shifts. This is due to the low volume on the Estonian market and baseload compared to Germany and Finland. With the low Estonian volumes, it's expected that the traded volume of quarterly products is also low and price convergence is quickly reached.

Analysis of interconnectors belonging to case 3
Relevant interconnectors are: DK2-DE (Kriegers Flak), DK1-NL, NO-GB, DK1-GB, SE-DE, and NO-DE.

For these interconnectors it is not possible to compare prices in specific hours and quarters, since there are no historic capacities. Instead, it is assumed that the benefit per installed MW equals the benefit per installed MW from interconnectors belonging to case 1. The estimated market coupling benefit for these interconnectors is 2.435 Euro/MW.

Appendix B
Methodology of ramping benefits

Imbalance data
The analyses presented in this report of imbalance volumes, imbalance jumps, frequency quality and additional imbalance volumes traded in the intraday market are based on a dataset representing the year 2016. The dataset contain average values for each minute of:

- Imbalance per bidding zone
- Nordic frequency
- Total activated balancing power
- Production shifts
- 15-minute production plans (Norway only)
- Smoothing (Norway only)

The dataset covers the Nordic synchronous area, and DK1 is therefore not included.
The imbalance per bidding zone is a calculated value, derived from the difference between planned and realized exchange:

$$Imbalance = measured\ flow - scheduled\ flow - activated\ reserves$$

Where:

- *Scheduled flow* is the total planned flow after day-ahead and intraday trades
- *Meansured flow* is the sum of flow on all AC tie-lines out of a zone, based on 10-second values from Statnetts SCADA system
- *Activated reserves* is the sum of FCR-N (calculated as the product of the frequency deviation and the frequency bias factor), FRR-A (sum of activation signals per area), FRR-M, Quarterly movements

This means that the imbalances per bidding zones are net values, and do not distinguish between groups of market participants (including TSOs). The gross sum of settled imbalances will therefore be higher.
Based on this dataset, the following values are calculated:

- Average imbalance for 60 minutes
- Average imbalance for 15 minutes
- Net imbalance for Norway, Sweden and the Nordic system as the sum of the imbalances of the individual bidding zones

Imbalances moved to a 15-minute ID market
An important assumption of the analyses is that the introduction of 15-minute market time units will not have a significant impact on the average 60-minute imbalances, since the BRPs already have incentives to predict and correct these imbalances in the current intraday market.

Thus, relative to the 60-minute imbalance, the 15-minute imbalances is:

$$15min\ imbalances = average\ imbalance\ (15min) - average\ imbalance\ (60min)$$

With perfect foresight, these net imbalances could be expected to be traded in the 15-minute intraday market. However, as the 60-minute settlement shows, one cannot reasonably expect all imbalances to be corrected at the planning stage. Therefore, unless explicitly stated otherwise, the assumption in the analyses is that 50 % of the 15-minute imbalances are traded in the intraday market.

$$\textit{Traded 15min imbalances} = 50\ \% * \textit{15min imbalances}$$

Analysis of imbalances
The imbalances after the introduction of 15-minute ISP was calculated by subtracting the traded 15-minute volumes from the system imbalances:

$$Imbalance_{15min} = imbalance - 50\ \% * [\text{average imbalance (15min)} - \text{average imbalance (60min)}]$$

Change in imbalance during hour shift (Figure 9)
The change in imbalance during hour shift was found by subtracting the imbalance in the first minute the one hour from the last minute in the previous hour.

$$\text{Imbalance during hour shift} = imbalance_{h-1,\,59} - imbalance_{h,\,0}$$

The impact from 15min ISP was calculated as the difference between this result for the original imbalance data, and the imbalance_{15min}.

Change in average imbalance between 15min MTUs (Figure 11)
The change in imbalance between 15-minute periods was found by first finding the average imbalance for each 15-minute period, and then calculating the change between each consecutive 15-minute average.

The impact of 15-minute ISP is then the difference between these results for the original imbalance, and the imbalance_{15min}.

Reduction in average system imbalances (Figure 12)
The reduction in average system imbalance was calculated as the difference between the absolute sum of the original imbalances, and the imbalance_{15min}.

Analysis of impact on frequency quality
Relationship between frequency deviations imbalances (Figure 14)
In this analysis, we used the number of minutes with system frequency outside the normal band (MoNB: 49.9-50.1 Hz) as a measure for the frequency quality.
The correlation between the frequency quality and the Nordic imbalances was tested for both the size of the imbalances and the change in imbalances. The results showed that the best correlation was between change in average imbalance between 15-minute periods, and the frequency deviations in these same 15-minute periods.

Using a linear best-fit function in Excel, the relationship between change in average 15-minute imbalance between two 15-minute periods P and P-1 and average MoNB in these periods was found as:

$$Exected\ MoNB = 0.1 + 0.0066 * |imb15_{P-1} - imb15_{P}|$$

The data and the line fit is shown in figure 12.

Impact on minutes outside normal band (MoNB) (Figure 15)
The impact from 15-minute ISP on frequency quality was calculated from the average change in 15-minute imbalances for the original net Nordic imbalance and $imbalance_{15min}$, and the relationship between MoNB and change in Nordic imbalance:

$$Impact\ on\ MoNB = (exected\ MoNB_{15min\ ISP} - exected\ MoNB_{60min\ ISP}) / exected\ MoNB_{60min\ ISP}$$

This result was applied to the historically recorded MoNB of 2016 to get the results shown in figure 13.

Analysis of increased ramping rate (Figure 24 and Figure 25)
The market coupling benefit was calculated for multiple ramping rates for each existing and future interconnector by performing simplified simulations of the day-ahead market. The benefit from increasing the allowed ramping rate was the difference between the result with higher rate, and the result with a lower rate.
The ramping constraints are the restrictions on change in flow from one market time unit (MTU) to the next. In these analyses, the duration of the MTU was 60 minutes.
The calculations were based on some simplifications:

> <u>Static area prices:</u> the simulations used the historic prices in the day-ahead market from 2012-2016, and the prices were not impacted by changes in flow volumes. The benefit was to make the results for each interconnector independent of the ramping rate applied at other interconnectors, and to allow a linear modelling of the problem. This also meant that all change in market welfare was recorded as congestion rent.
>
> <u>Full transmission capacity:</u> all interconnectors were assumed to have a 100 % availability over the simulated period. The benefit was to make the results independent of specific events that had an impact on historic availability of the interconnectors.

When applying the above simplifications, the optimal flow and the total market benefit on an interconnectors can be modelled for any number of hours as:

$$MAX\left(\sum_{h\in hours} flow_h * (price_{area1,h} - price_{area2,h})\right)$$

Subject to these constraints:

$$minimum\ flow\ \le flow_h \le maximum\ flow$$
$$ABS(flow_h - flow_{h-1})\ \le ramping\ rate$$

This calculation was performed for all days from 2012-2016, for all interconnectors, and for multiple ramping constraints. The maximum and minimum flow on each interconnector was set to the maxNTC value (when not considering losses) as of end 2016 for the existing interconnectors, and to the planned capacity for the future interconnectors.

Appendix C
Input for cost analysis

In order to identify the main cost driver of different market participants and quantify these costs for the different countries in the Nordic region stakeholder interviews with various market participants have been conducted. The high diversity of the interview partners (roles and nations) delivers sufficient information to form the expectations of costs for implementing a finer time resolution for various market participants and representative stakeholders.

The data has been collected through qualitative interviews with representative stakeholders from each Nordic country. In addition to the data from the interviews, we have used data from the previous ENTSO-E study for those respondents who were willing to share their answers.

Based on the stakeholder input, we have used different approaches to scaling the interview outputs for the entire Nordics. The output from the interviews as well as the scaling factors are presented in this appendix.

Cost categories
An overview of the methodology for scaling and different cost input is presented in Table 7.

Table 7 Approaches for the determination of the different cost categories

Cost category	Scaling factor/Approach
DSO IT/Data Costs	• Based on the interviews the costs per customer are estimated (average of all given answers and then used as scaling factor. • Number of customers contains the number of households and medium/big consumers. • Cost estimates range from 0.1-1.0 €/customer (based on the interviews) → 0,5 €/per Customer is chosen for the calculations • All costs are OPEX due to (especially for external software provider)
BRP/BSP IT/Data Costs	• Specific costs per produced domestic electrical energy are identified as suitable scaling factor for the BRP/BSP (incl. supplier) costs • IT-costs are closely related to the amount of the produced energy → Higher costs with a higher market/production share and supply of customers (range from 2-4.5 ct/MWh in the interviews). • BRP/BSPs expect approximately 10 % of the CAPEX as additional operational costs.
Metering Costs	• Assumptions used in the estimation based on the interviews and TSO expert knowledge: o We assume DK1 does not have to change. o 50% of medium meters are assumed to be changed o 100% of the big meters are changed o Costs for profiling are assumed to be negligible and are set to zero (→ Households, small meters) o 15 years lifetime for small and medium meters and 25 years for large meters o No resale of scrapped meters
TSO IT Costs	• Costs for the IT-updates are based on expert knowledge: o Fifty (SW/NOR): Cost estimations have been elaborated together with TSO Working groups. IT- update investment costs are expected, while the additional operational costs are not relevant. o Assumption for FIN/DK: In sum the same amount of costs is taken for the system adaptations in Finland and Denmark o NOIS: it is assumed that NOIS has also comparable adaptation costs like FIFTY o Parallel systems (with 15 minutes and 1 hour): 50 % higher (additional) investment costs are expected for each IT software in order to handle parallel systems
Trading Systems Costs	• IT-investment costs for the update of Trading systems based on expert knowledge: o Small investment costs for software updates at each Power Exchange o Additional operational costs are not relevant • Maintaining of two parallel systems (15 minutes and 1 hour): o Additional investment costs of 25 %
Settlement costs	• FIN/NOR/SW settlement Costs o The costs for the development of the 1-hour settlement system (eSett) are the basis for the estimations. It is assumed that the additional costs for 15 minutes adaptations will be 10 % of the original costs (investment and operational costs) • DK settlement Costs o 1/3 of the total eSett costs • Maintaining of two Parallel systems (15 minutes and 1 hour): o Only the OPEX are affected by the maintaining of two parallel systems (with 15 minutes and 1 hour) o Doubling of the operational costs.

Note: Specific costs for trading systems and TSO IT costs are not shown due to the sensitive nature of the trading systems costs.

Source: E-Bridge

DSO IT/Data Costs

The Table 8 gives an overview to the results for the estimations to the DSO IT/Data costs in the different Nordic countries. The costs per customer are based on the results from the stakeholder interviews as average costs from the given answers. The IT-costs are also related to the amount of customers. Higher costs correlate with a higher market/production share and supply of customers. The cost estimates range was from 0.1-1.0 €/customer (based on the interviews).

All costs are OPEX, since all interviewed DSOs had external IT providers and therefore no CAPEX involved. The provider of the IT systems will make the actual investments and experience the changes as a CAPEX, but will “rent” the IT systems to the DSOs, which will experience the investments as an OPEX. The socioeconomic costs are in both cases the same.

The average of the analysed costs is around 0.5 € per customer, so that this value has been chosen for the calculations. The amount of the customers is determined by number of the households and medium/big consumer. Based on the given information from the TSOs and available publıc data the numbers for the total customer have been determined.

For the sensitivity analysis we have varied the cost input from 0.1 EUR per customer in the low case to 1.0 EUR per customer in the high case. The range is based on the input from the stakeholder interviews.

Table 8 DSO IT/Data Costs

Country	Input	Scaling Factor	Output	
Denmark	Per Customer:0.5 €	3.3 m. customers	CAPEX: 0 EUR	OPEX: 1.7 m. EUR
Finland	Per Customer:0.5 €	2.6 m. customers	CAPEX: 0 EUR	OPEX: 1.3 m. EUR
Norway	Per Customer:0.5 €	2.2 m. customers	CAPEX: 0 EUR	OPEX: 1.1 m. EUR
Sweden	Per Customer:0.5 €	5.3 m. customers	CAPEX: 0 EUR	OPEX: 2.7 m. EUR

Note: Specific costs for trading systems and TSO IT costs are not shown due to the sensitive nature of the trading systems costs.

Source: E-Bridge

BRP/BSP IT/Data Costs

The results for the BRP/BSP (incl. suppliers) IT/Data costs are shown in Table 9. Specific costs per produced domestic electrical energy are identified as suitable scaling factor for the BRP/BSP (supplier) costs. Higher costs correlate with a higher market/production share and supply of customers.

The input for the calculations is based on the results from the stakeholder interviews (concrete estimations) and the available public data to the total domestic production of the different Nordic country. The CAPEX are based on an average value of the costs per produced energy, which have been collected in the stakeholder process during the interviews.

The assumption for the OPEX with 10 % of the expected CAPEX was the most frequent answer of the interview partners to their estimation regarding the additional operational costs (in relation to the expected investment costs).

For the sensitivity analysis we have varied the cost input from 2 ct/MWh per produced domestic energy in the low case to 4.5 ct/MWh per produced domestic energy in the high case. The range is based on the input from the stakeholder interviews.

Table 9 BRP/BSP IT/Data costs

Country	Input	Scaling Factor	Output	
Denmark	a) CAPEX per produced domestic energy: 3,5 ct/MWh b) OPEX per produced domestic energy: 0,35 ct/MWh	34 TWh	CAPEX: 1.2 m. EUR	OPEX: 0,12 m. EUR
Finland	a) CAPEX per produced domestic energy: 3,5 ct/MWh b) OPEX per produced domestic energy: 0,35 ct/MWh	67 TWh	CAPEX: 2.4 m. EUR	OPEX: 0,24 m. EUR
Norway	a) CAPEX per produced domestic energy: 3,5 ct/MWh b) OPEX per produced domestic energy: 0,35 ct/MWh	128 TWh	CAPEX: 4.5 m. EUR	OPEX: 0,45 m. EUR
Sweden	a) CAPEX per produced domestic energy: 3,5 ct/MWh b) OPEX per produced domestic energy: 0,35 ct/MWh	149 TWh	CAPEX: 5.2 m. EUR	OPEX: 0,5 m. EUR

Note: Specific costs for trading systems and TSO IT costs are not shown due to the sensitive nature of the trading systems costs.

Source: E-Bridge

Metering Costs

Table 10 summarizes the results for the metering costs with the three categories of large (Grid meters), medium (big consumer, production units) and small meters (households). The specific cost values for the three categories are based on the results from the Stakeholder interviews and the ENTSO-E study[29]. The total amount for the different categories is determined by the information given from the Nordic TSOs and if the data was not available, adequate own estimations have been made (e.g. same share of medium meters of all meters are assumed for those countries, where the data was not available).

Assumptions used in the estimation based on the interviews and TSO expert knowledge:

- DK1 does not have to change any meters.
- 50% of medium meters are assumed to be changed.
- 100% of the large meters are changed.
- Profiling will have no cost impact on the meters
- 15 years lifetime for small and medium meters and 25 years for large meters.

29 Frontier Economics, CBA of a change to the imbalance settlement period, A report for ENTSO.E, 2016.

For the sensitivity analysis, we have varied on the number of medium meters assumed to be changed. In the low case we assume 25% of the meters identified to either changed or replaced will be changed. In the high case we assume the same number to be 75%.

Table 10 Metering Costs

Country	Input	Scaling Factor	Output	
Denmark	a) Costs change large meter: 3000 EUR b) Costs change medium meter: 500 EUR c) Costs change small meter: 100 EUR d) Reconfiguration costs: 20 EUR	*Change/Reconfiguration:* 150 large meters 14.400 medium meters 0 small meters (profiling) *Note: Meters in DK1 are assumed to be fully compatible with 15 min ISP.*	CAPEX: 4 m. EUR	OPEX: 0 m. EUR
Finland	a) Costs change large meter: 3000 EUR b) Costs change medium meter: 500 EUR c) Costs change small meter: 100 EUR d) Reconfiguration costs: 20 EUR	*Change/Reconfiguration:* 100 large meters 75.000 medium meters 0 small meters (profiling)	CAPEX: 20 m. EUR	OPEX: 0 m. EUR
Norway	a) Costs change large meter: 3000 € b) Costs change medium meter: 500 EUR c) Costs change small meter: 100 EUR d) Reconfiguration costs: 20 EUR	*Change/Reconfiguration:* 0 large meters 65.000 medium meters 0 small meters (profiling)	CAPEX: 17 m. EUR	OPEX: 0 m. EUR
Sweden	a) Costs change large meter: 3000 EUR b) Costs change medium meter: 500 EUR c) Costs change small meter: 100 EUR d) Reconfiguration costs: 20 EUR	*Change/Reconfiguration:* 3.500 large meters 140.000 medium meters 0 small meters (profiling)	CAPEX: 48 Mio m. EUR	OPEX: 0 m. EUR

Note: Meters which are already planned to be changed/reconfigured are not included.

Assumption based on stakeholder interviews: 100% of the large meters are to be changed. 50% of the medium meters are to be changed.

Source: E-Bridge

Aggregating and interpreting the cost elements

When assessing the costs in the CBA defining the baseline scenario is important. The baseline scenario should contain all information, plans and decisions available today. This means that only incremental costs in a scenario should be considered. If there are plans on reinvesting in infrastructure, when the depreciation period is over, this cost should be included in the baseline and the scenarios.

In the perspective of the Finer Time Resolution CBA-project, it is not a decision on whether or not to implement a finer time resolution, but rather when and how. The finer time resolution will be implemented before a certain point in time. The baseline is then to have the current time resolution until the implementation date after which the finer time resolution will be implemented. Investments related to the finer time resolution have to be made either way; it is only a question of when.

Costs for incremental investments from introducing finer time resolution should be included in the cost estimates. Investments cover both physical investments in e.g. infrastructure and equipment, and one-off costs for implementation, e.g. additional courses for employees etc. Bringing an investment forward in time should not change the investments that have to be done. However, in the perspective of the Finer Time Resolution-project, there can be additional costs from frontrunners.

Bringing investments forward in time is slightly different from considering a new investment. There are four different costs to be considered when bringing forward an investment:

- Implementation costs
- Increased maintenance
- Premature investment in new assets
- Opportunity costs

Below these elements are further explained, and suggested questions for covering the item is included.

Implementation costs
Since finer time resolution is implemented at a certain date, the full cost of the implementation should be included in order to calculate the opportunity cost from bringing the investment forward in time.
Investments also include e.g. additional one-off servicing or modifications that has to be done due to certain regulations.

Maintenance costs
Early investment or readjustments could change the maintenance costs for a particular equipment or infrastructure, e.g. new equipment might require less servicing.

Premature investment in new assets
By introducing finer time resolution, the new investments replace assets that were still useful for maybe several years. If the asset owner is not able to resell the old assets, the owner will effectively have "payed double" for covering the same period with the benefits from the asset staying the same. This means the costs for investing in new assets early is the use of new the capital in production on top of the opportunity costs. Intuitively, this can be thought of as the depreciation value of an additional year of capital use.

Opportunity costs

When investing earlier than planned, the opportunity cost for spending the money e.g. a year earlier has to be considered. The money could have been investing in other assets. This is valued through the social discount rate, which is set at 4% in accordance with standard CBA-methodology, see e.g. European Commission (2016), *Guide to Cost-Benefit Analysis of Investment Projects*.

Appendix D
Country specific costs and benefits

In the following, we will show the country specific costs and benefits presented in Chapter 4. This country-distribution of benefits is estimated by using the assumption that the benefits are obtained by the countries that are linked by the particular interconnectors. This is not a solid assumption, as benefits can also accrue to neighbouring countries, implying that the country distribution should be treated more cautiously than the accumulated Nordic benefits.

Benefits

Table 11 Accumulated country specific benefits from early or late implementation

Denmark	2018	2019	2020	2021	2025
Market coupling	9 m. EUR	7 m. EUR	3 m. EUR	0 m. EUR	-16 m. EUR
Ramping	2 m. EUR	2 m. EUR	1 m. EUR	0 m. EUR	-6 m. EUR
Total	**11 m. EUR**	**8 m. EUR**	**4 m. EUR**	**0 m. EUR**	**-23 m. EUR**

Finland	2018	2019	2020	2021	2025
Market coupling	0 m. EUR	0 m. EUR	0 m. EUR	0 m. EUR	-5 m. EUR
Ramping	0 m. EUR	0 m. EUR	0 m. EUR	0 m. EUR	0 m. EUR
Total	**0 m. EUR**	**0 m. EUR**	**0 m. EUR**	**0 m. EUR**	**-6 m. EUR**

Norway	2018	2019	2020	2021	2025
Market coupling	3 m. EUR	3 m. EUR	2 m. EUR	0 m. EUR	-14 m. EUR
Ramping	3 m. EUR	2 m. EUR	2 m. EUR	0 m. EUR	-8 m. EUR
Total	**6 m. EUR**	**5 m. EUR**	**4 m. EUR**	**0 m. EUR**	**-22 m. EUR**

Sweden	2018	2019	2020	2021	2025
Market coupling	3 m. EUR	2 m. EUR	1 m. EUR	0 m. EUR	-6 m. EUR
Ramping	1 m. EUR	0 m. EUR	0 m. EUR	0 m. EUR	-1 m. EUR
Total	**3 m. EUR**	**2 m. EUR**	**1 m. EUR**	**0 m. EUR**	**-7 m. EUR**

Nordic	2018	2019	2020	2021	2025
DK1-NO2 (ramping)	3 m. EUR	2 m. EUR	1 m. EUR	0 m. EUR	-3 m. EUR
DK1-SE3 (ramping)	0 m. EUR	0 m. EUR	0 m. EUR	0 m. EUR	-1 m. EUR
Frequency quality	3 m. EUR	2 m. EUR	1 m. EUR	0 m. EUR	-3 m. EUR
Total (simultaneous implementation)	**26 m. EUR**	**19 m. EUR**	**11 m. EUR**	**0 m. EUR**	**-65 m. EUR**

Note: Positive value indicates a benefit. Negative value indicates a loss of benefit. Calculated with a social discount rate of 4%. Country distribution based on 50 % of the benefits of each interconnector. DK1-DK2, DK1-NO2 and DK1-SE3 measured as 100 % of the benefits.

Source: Copenhagen Economics based on TSO input.

Table 12 Sensitivity of accumulated benefits from early or late implementation

	2018	2019	2020	2021	2025
Denmark	(9)-(14)	(7)-(11)	(3)-(5)	0	(-18)-(-28)
Finland	0	0	0	0	(-5)-(-6)
Norway	(3)-(9)	(3)-(8)	(2)-(6)	0	(-15)-(-34)
Sweden	(3)-(4)	(2)-(2)	(1)-(1)	0	(-6)-(-9)
Total	**(19)-(38)**	**(14)-(28)**	**(8)-(16)**	**0**	**(-49)-(-90)**

Note: Values are million euros. Calculated with a social discount rate of 4%. Lower/higher bound is lowest/highest estimate for ramping and market coupling. Frequency quality is the low/high estimate based on the assumptions in Table 1 for the case where 50% of the "new" imbalances are moved to the intraday market.

Source: Copenhagen Economics based in TSO input.

Costs

Table 13 Accumulated costs from early or late implementation

Denmark	2018	2019	2020	2021	2025
IT/Data cost	-6 m. EUR	-4 m. EUR	-2 m. EUR	0 m. EUR	7 m. EUR
Meters	-1 m. EUR	-1 m. EUR	0 m. EUR	0 m. EUR	1 m. EUR
Settlement and PX	-1 m. EUR	0 m. EUR	0 m. EUR	0 m. EUR	1 m. EUR
Total	**-7 m. EUR**	**-5 m. EUR**	**-2 m. EUR**	**0 m. EUR**	**8 m. EUR**
Finland	**2018**	**2019**	**2020**	**2021**	**2025**
IT/Data cost	-6 m. EUR	-4 m. EUR	-2 m. EUR	0 m. EUR	7 m. EUR
Meters	-4 m. EUR	-2 m. EUR	-1 m. EUR	0 m. EUR	3 m. EUR
Settlement and PX	-1 m. EUR	0 m. EUR	0 m. EUR	0 m. EUR	1 m. EUR
Total	**-10 m. EUR**	**-6 m. EUR**	**-3 m. EUR**	**0 m. EUR**	**10 m. EUR**
Norway	**2018**	**2019**	**2020**	**2021**	**2025**
IT/Data cost	-7 m. EUR	-5 m. EUR	-2 m. EUR	0 m. EUR	8 m. EUR
Meters	-3 m. EUR	-2 m. EUR	-1 m. EUR	0 m. EUR	3 m. EUR
Settlement and PX	-1 m. EUR	0 m. EUR	0 m. EUR	0 m. EUR	1 m. EUR
Total	**-11 m. EUR**	**-7 m. EUR**	**-3 m. EUR**	**0 m. EUR**	**11 m. EUR**
Sweden	**2018**	**2019**	**2020**	**2021**	**2025**
IT/Data cost	-12 m. EUR	-8 m. EUR	-4 m. EUR	0 m. EUR	14 m. EUR
Meters	-9 m. EUR	-6 m. EUR	-2 m. EUR	0 m. EUR	7 m. EUR
Settlement and PX	-1 m. EUR	0 m. EUR	0 m. EUR	0 m. EUR	1 m. EUR
Total	**-22 m. EUR**	**-14 m. EUR**	**-6 m. EUR**	**0 m. EUR**	**22 m. EUR**
Total (simultaneous implementation)	**-50 m. EUR**	**-32 m. EUR**	**-15 m. EUR**	**0 m. EUR**	**52 m. EUR**

Note: Calculated with a social discount rate of 4%.

Source: Copenhagen Economics based in TSO input.

Table 14 Sensitivity of accumulated costs from early or late implementation

	2018	2019	2020	2021	2025
Denmark	(-3)-(-12)	(-2)-(-8)	(-1)-(-4)	0	(3)-(14)
Finland	(-5)-(-16)	(-3)-(-10)	(-1)-(-5)	0	(5)-(17)
Norway	(-5)-(-17)	(-3)-(-11)	(-2)-(-5)	0	(6)-(17)
Sweden	(-11)-(-34)	(-7)-(-22)	(-3)-(-10)	0	(10)-(35)
Total	**(-24)-(-79)**	**(-15)-(-50)**	**(-7)-(-24)**	**0**	**(24)-(83)**

Note: Values are million euros. Calculated with a social discount rate of 4%.

Source: Copenhagen Economics based in TSO input.